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Strategic Behaviour Analysis and Modelling of Electricity Prices of Australian National Electricity Market

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Copyright in Relation to This Thesis

Statement of Originality

The work contained in this thesis has not been previously submitted to meet requirements for an award at this or any other higher education institution. To the best of my knowledge and belief, the thesis contains no material previously published or written by another person except where due reference is made.

Signature: Ali Ghahremanlou

Date: 06 February 2021

To my father, Ezzatollah Ghahremanlou, and my mother, Nahid Saadati, and my brothers Amir and Davoud for nursing me with affection and love and their selfless devotion for success in my life.

Abstract

The Australian electricity market has a unique structure for determining wholesale prices. Market prices have been high, volatile, average prices have risen dramatically since market deregulation in 1997 to 2017-2018 and there has been significant concerns over future electricity supply security and investment. This dissertation provides three economic studies addressing challenging areas for development in the Australian National Electricity Market, namely price formation, generators' bidding behaviour and decomposing the price development in this market.

This dissertation embodies a comprehensive dataset pertaining to each five-minute dispatch interval. Seven different data files were obtained from Australian Energy Market Operator. Advanced programming scripts have been developed to process the data, rectify the issues found, extract generators' specific attributes like fuel type and capacity, track the history of their bidding activity, identify the associated market information and to concatenate all of them as one dataset.

The first paper examines an important issue in the Australian National Electricity Market (NEM): what are the quantitative implications of the bidding/rebidding rules in the current market design? We apply and extend existing literature on electricity markets with the objective of quantifying the market effects of generator behaviour. We utilise bid data in conjunction with price and quantity observations to determine whether there are consistent variations in equilibrium prices occurring year-round in the NEM as a result of rebidding. We achieve this by emulating a modified version of the market dispatch algorithm. This allows us to examine the dynamics of market outcomes from the time of initial offer to the time of dispatch. We analyse market outcome dynamics in conjunction with the corresponding number of rebids to elucidate any relationships that are present. The results are of policy importance given the flaws of the market design are found out and draws attention for immediate consideration.

The second paper investigates how market signals in dispatch equilibria in the Australian National Electricity Market (NEM) impacts the electricity generating firms' bidding behaviour. We examine the information observed by generators at each five-minute auction to analyse how generators restate their initial and subsequent offers in response to such information. Utilizing the constructed high frequency dataset which consists of the intra-day supply bids of each generator, we illustrate that firms actively respond to the market signals in dispatch equilibria by rotating their supply curves within each trading interval. We disaggregate the effect of dispatch equilibria by the type of the generator. Further, we extend our specifications to account for difference in responses to change in prices arising from generators' bidding behaviour over dispatch intervals.

The third paper extends existing theoretical frameworks describing electricity markets where each generator provides the Market Operator (MO) with a supply schedule in advance. The MO combines these with demand forecasts to produce equilibrium prices and instructs firms on their dispatch. We incorporate the possibility that generating firms may rebid (or revise) their supply schedule prior to dispatch - an important feature of markets in many countries which has not previously been included in theoretical models. We show that a dominant firm can gain substantially by manipulating its bids, and take advantage of the opportunity to submit rebids. In the Australian National Energy Market (NEM) where settlement prices are an average of six dispatch prices, it can, for example, withhold capacity at lower prices for the first bid in a period, creating a price hike, and then add capacity at lower prices to ensure dispatch. Using data from the Australian NEM we provide the first empirical evidence consistent with the hypothesized theoretical behaviour in the observed data.

Keywords

Electricity Markets, Market Design, Rebidding, Spot Prices, Auction, Strategic Rebidding, Market Power, Information Flow, Australia.

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Preface

Authority of Access

Statement Regarding Published Work Contained in Thesis

This thesis constitutes collaborative efforts with my supervisors. Chapters 2 and 3 are joint works with Dr. Clinton J. Levitt (current primary supervisor). Chapter 4 is coauthored with late Professor Mardi Dungey (former primary supervisor) and Professor Ngo Van Long which is published as a working paper in the Center for Economic Studies and ifo Institute (CESifo), Munich (CESifo Working Paper No. 6819).

The non-published content of the thesis may be made available for loan in accordance with the Copyright Act 1968 but copying and communication of any part of this thesis is prohibited for two years from the date this thesis was signed for submission. Due to the inclusion of research papers prepared for publication there is unavoidable repetition of material between chapters in this thesis.

Signature: Ali Ghahremanlou
Date: 06 February 2021

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Chapter 1

Introduction

1.0 Overview of history of the Australian National Electricity Market

The Australian electricity market undertook a reform in 1990 to develop an interconnected National Electricity Market. The context for the reform, however, lies between 1960s to 1990s when the Australian economy was somewhat insular with poor comparative financial performance and low productivity growth. From 1980, a greater exposure to international competition due to gradual change in trade reform created pressure for better delivery of utility services. Late 1980, the initial reforming process began in water, telecommunication, road and electricity. In early 1990s, industry commission found that poor investment decisions and excess capacity had impeded the electricity market to perform at its full potential which was an evidence of the electricity supplied not being at least cost. In 1991, the commission recommended that the Gross Domestic Product could be improved by restructuring the electricity supply industry, introducing competition into retail and generation, privatising generation, transmission and distribution along with extension of interconnectors between New South Wales, Victoria, South Australia, Queensland and Tasmania [Australian Energy Market Commission, 2013]. An agreement on the need for the national competition policy was reached between Australian Commonwealth, State and Territory governments at a Special Premiers Conference in 1991 to carry out the reform.

The National Electricity Market (NEM) became functional by 1998 through a staged transition when NSW, VIC, SA and QLD were interconnected. Tasmania joined the NEM via Basslink interconnector in 2005.

2.0 Institutional setting of the Australian National Electricity Market

The Australian NEM has a unique structure, characterised as a single settlement real-time structure where bids to supply electricity are submitted by individual energy generators to a market operator a day prior to trading day. Generators can alter their offered volumes (and not the prices) by the process of rebidding up to 5 minutes before the actual dispatch of the electricity. The 5 minute prices pertaining to each dispatch interval are not the final settlement price for the power supplied - instead this is the average of each of the 5 minute prices over each half hour. The NEM is an energy-only market which means that there is no capacity payment in the NEM and the generators are only compensated for the energy supplied to the gross market pool where output from electricity producers are aggregated and scheduled to meet the forecast demand [Australian Energy Market Operator, 2010, p. 4].[1]

Balancing the demand and supply of electricity constitutes the primary responsibility of the Australian Energy Market Operator (AEMO). In relation to the electricity market, AEMO manages the NEM, oversees reliability and security of the NEM and protects power system operations through instructions of load shedding to re-balance supply and demand (see Australian Energy Market Operator [2010]). AEMO and other institutions like Australian Energy Market Commission (AEMC) and Australian Energy Regulator (AER) work closely to focus on long term interests of consumers. Under the National Electricity Law, AEMC makes and amends the National Electricity Rules which govern the operation of the NEM. AEMC does not propose rules while it manages the rule change process through consultation [Australian Energy Market Operator, 2010, p. 23]. Responsibility of enforcing and monitoring compliance with the existing rules is carried out by the AER. If a generator breaches National Electricity Law or Rules, AER can issue infringement notices or begin court proceedings [Australian Energy Market Operator, 2010, p. 23]. The heads of AEMO, AEMC and AER along with an independent chair and independent deputy chair sit at Energy Security Board (ESB). ESB oversees the whole system ensuring energy security and reliability.

[1] This is in contrast to energy and capacity market like the one in the Western Australia (see Independent Market Operator [2012]).

3.0 Overview of economic issues pertaining National Electricity Market

Over the next few years Australia faces the prospect of a transformation that will challenge every aspect of the electricity sector. The debate will include the issues of energy security and the role of renewable energy, the physical constraints imposed by transmission infrastructure and, most importantly, the spot price of electricity.[2] The need for an overhaul of the system has emerged at a time when Australian electricity sector is already struggling to maintain the delivery of affordable and reliable electricity.[3] Affordability, sustainability and supply security are electricity system goals that the market needs to achieve simultaneously. Consequently, a deeper analysis and resolution of some of the issues affecting the electricity market are key priorities to the process of change so as to safeguard the integrity of supply and simultaneously ensure that the price of electricity is not unnecessarily volatile.

One of the key issues in this debate is the notion of productive efficiency which may be interpreted as maintaining the supply of existing outputs at the lowest cost. In the National Electricity Market (NEM) productive efficiency is pursued by means of a competitive bidding process which leads to a least-cost generating configuration for any given level of required output. The Australian Electricity Market Operator (AEMO) equilibrates short-term demand and supply estimates which result in dispatch orders to individual generators. The AEMO provides demand projections and in turn, each individual generator bids their supply schedule for each of 48 half-hour intervals beginning at 04:00 each morning. Each generator can specify up to 10 price bands and the associated incremental quantities it is willing to supply for every 30 minute trading interval. A feature unique to the NEM, however, is that generators are permitted to rebid quantity (but not price) up to 5 minutes before actual dispatch. Although there has been significant work undertaken on the Australian electricity market, few studies have yet addressed the question of rebidding in the context of strategic bidding behaviour and market prices; see for example Hesamzadeh et al. [2020], Clements et al. [2016], Hurn et al. [2016] and Hu et al. [2005].[4] The purpose of this thesis is to provide insights into the role of rebidding on achieving market efficiency.

[2]The Australian National Electricity Market was subject to an inquiry on its settlement and spot price arrangements. See Australian Energy Market Commission [2017a] for the final rule determination.

[3]See The Guardian, 29 September 2016, ”Malcolm Turnbull says South Australia blackout a wake-up call on renewables” by Gareth Hutchens.

[4]There has been other significant studies on the Australian NEM, but none have incorporated rebidding in their studies. See Apergis et al. [2016], Wild et al. [2015], Nepal et al. [2014] and Janczura et al. [2013]

Increasingly it is now being realised that the pursuit of productive efficiency in terms of the competitive bidding process just described, provides an unusual set of incentives to market participants to engage in manipulative or speculative behaviour (see Hurn et al. [2016]). For example, large generators can have an incentive to withhold capacity in order to force higher-cost producers to fill the gap and thus increase the average spot price of electricity. Chapter 2 of the thesis investigates the implications of rebidding on wholesale prices in the Australian NEM and provides evidence on how large generators impact the dispatch prices through rebidding.

It has been suggested by different market participants that the market structure is responsible for game-playing behaviour in the electricity market prompting a number of enquiries into the behaviour of this market; for example in December 2014 the South Australian government asked for inquiry into clarification of the rule that rebidding must be conducted in "good faith". Consequently, in December 2015 the AEMC announced a rule change which effectively increased the documentation requirements for late rebids (that is rebids made within 15 minutes of dispatch). In December 2015, Sun Metals proposed a rule change to have 5 minute settlement pricing (removing the 30 minute averaging), on the grounds that it leads to market distortions and inefficiencies. The 5 minute prices are averaged over 30 minute interval which Australian Energy Market Commission [2017b] illustrates to be one of the causes of inefficiencies. The 5 minute settlement rule will come into effect from 1 October 2021. Chapter 3 of the thesis provides interesting insights into whether rebidding provides the market with an opportunity to achieve economic efficient market outcomes. The last chapter incorporates rebidding in the theories describing the electricity markets and provides further empirical work consistent with the proposed theory.

The arguments made by the respondents to the enquiry concerning the pricing approach clearly lay out the competing interests. A number of large suppliers argue that more competitive markets show increased activity as the time of price determination approaches, as information becomes more accurate and complete, and market operators respond to competitive forces. Thus, rebidding up to dispatch is a sign of healthy competition. Other suppliers, typically with generators which have longer response times to meet signals from the market, argue that as many parts of the market have no opportunity to respond due to these ramp up/down times, the practice of late rebidding is used to distort market prices. Market participants are supposed to supply their bids in 'good faith' with full intent to supply. The accusation made in various reviews of the market is that gaming behaviour is occurring, abetted by the structure of the market (see Australian Energy Market Commission [2017a].

4.0 Contributions and Outline

This research project goes to the heart of the conflict between the pursuit of productive efficiency and rent seeking by strategic use of the competitive bidding. This research develops and implements methods to assess the contribution of current market design to undesirable outcomes in electricity markets. In particular, rebidding is investigated to extend the literature while considering the undesirable outcomes transpired by this mechanism. Despite of market transitioning to a 5 minute settlement in 2021, the rebidding and its associated impact on the wholesale prices have still been subject to controversies [Australian Energy Market Commission, 2018b]. Wood and Blowers [2018] argued whilst the Five Minute Settlement rule will stop generators benefiting from high thirty minute trading price, generators that are able to game the system may gain increased reward from a high five minute price even after the rule change. Our analyses consist of five minute prices to account for the implications of generators' bidding behaviour at every five minute interval.

The problems discussed are unique to the Australian NEM given the NEM features discussed in this thesis are unique to the Australian NEM. There are international energy-only electricity markets similar to Australia but their regulatory framework around bidding/rebidding is unlike the Australian one. Alberta has a gate closure of 2 hours before the point of dispatch which means that unlike Australia generators' response to price spikes is substantially delayed; Similar to Australia, Singapore has a gate closure of 5 minutes for rebidding before dispatch but any rebids within 65 minutes prior to dispatch can only be made for reasons like additional quantities at the same price; New Zealand allows generators to revise their bids up to 2 hours prior to dispatch but unlike the NEM rebids that occur within the two hour period must be for genuine physical reasons only [Competition Economists Group, 2014].

The first research paper investigates the effect of rebidding on wholesale electricity prices in the NEM. The implications of such effect are illustrated by computing the sequence of equilibria for each dispatch interval from initial offer to the time of dispatch by emulating a modified version of NEM's dispatch algorithm. Given the sequence of five minute dispatch prices, the trading prices are also computed. The constructed bidding history and market outcomes for each dispatch interval allows us to quantify the extent to which individual generators can influence the wholesale prices through rebidding. Further, this research contributes to the literature by characterising when the bidding activity occurs, when the changes in prices occur and which generators tend to have large influence over prices at each dispatch interval in the everyday operation of the market and not only in the case of extreme pricing events. This is in contrast to previous studies which focused on very large but infrequent price spikes.

Observing the effects single generators have on wholesale prices through rebidding, the second research paper investigates the driving factors behind rebidding. Generators can revise their supply bids up to five minutes prior to dispatch. The economic argument for allowing rebidding close to dispatch is that generators can quickly respond to the current market conditions thereby improving the economic efficiency of the market. In particular, rebidding gives generators the opportunity to respond to the market signals contained in the 5-minute dispatch equilibria. We empirically study the link between rebidding and the flow of market information contained in the five-minute dispatch equilibria. Specifically, we empirically characterise how firms revise their bids in response to 5-minute dispatch equilibria. We show that generators actively respond to the market information in the dispatch equilibria through rebidding. In addition, we show that generators have different responses depending on dispatch interval as well as their type of technology.

The third research paper builds on the research work thus far by extending the theoretical models in the literature. It reviews some of the major theoretical models on bidding in the electricity markets followed by developing a model of collusive bidding. The theoretical model illustrates incentives for collusive firms to misreport their costs to the market operator, and also how they might signal their costs to each other through rebidding. The ability to rebid the standing offers is an important feature of many electricity markets which has not previously been incorporated in theoretical models. In addition, this work outlines how a dominant generator may gain substantially by manipulating its bid in a trading interval via rebids. This work also presents data on bidding behaviour of generators. It shows the observed behaviour is consistent with the constructed theoretical model, with rebidding occurring in a strategically profitable manner across alternative generation methods and geographic locations.

Chapter 5 concludes the outcome of this research project by providing an overview of the main findings.

Chapter 2

Investigating the Effect of Rebidding on Wholesale Electricity Prices in the Australian National Electricity Market

1.0 Introduction

A primary objective of the 1990s deregulation of the Australian electricity markets was to develop a deregulated market that would foster competition and promote efficient pricing. The primary mechanism introduced to foster competition was the Australian National Electricity Market (NEM). The NEM is now one of the largest deregulated electricity markets in the world. Every year it supplies over 200 terawatt hours of electricity to around 9 million customers located in almost every Australian state or territory.[1] The NEM is an energy-only market organised as a first-price, uniform auction. The auction mechanism and supporting market rules were designed to promote gains in productive, allocative and dynamic efficiency via competitive pricing. However, since the NEM's introduction in 1997 to 2017-2018 there has been a more-or-less continuous discussions concerning the effectiveness of the market rules in achieving the desired gains in efficiency.[2] Particular interest has focused on the existence of market power and the potential for strategic bidding by market participants to manipulate wholesale prices

[1]The exceptions are Western Australia and the Northern Territory.

[2]For general discussions of the early results of deregulation see Chester [2006] and Simshauser [2006]. For an overview of more recent discussion see Simshauser [2014] and the consultancy report Wood and Blowers [2018] together with the response of the Australian Energy Market Commission [2018b]

[see for example Hu et al. [2005], Clements et al. [2016] and Wood and Blowers [2018]].[3]

Persistent price volatility and high prices have been a consistent feature of the NEM since market deregulation in 1997 to 2017-2018 [Energy Security Board, 2020].[4] These market outcomes are determined by the interaction of suppliers operating within a set of market rules and there continues to be concern that these rules create opportunities for market participants to manipulate wholesale prices [Australian Energy Market Commission, 2015b, p. 4]. Specifically, rules governing rebidding in the auctions are often cited as a key mechanism through which bidders can act strategically to increase prices [Australian Energy Market Commission [2015b] reports that rebidding has been used strategically; see also Australian Energy Market Commission [2016b]]. For example, bidders can rebid late in a trading interval to increase the price for that trading interval [see Clements et al. [2016] for a study on bid-splitting].[5] Late rebidding does not give other bidders time to respond to any new information signalled in revised dispatch prices. Bid-splitting as well as withholding information through late rebidding can lead to spot price volatility and price spikes [Australian Energy Market Commission, 2015b, p. 5].[6]

Rebidding mechanisms were included in the market rules to promote efficient price signals by allowing bidders to accommodate emerging market events into their bid schedules. The argument is that if initial bid schedules reflect the genuine intention of generators then rebidding would facilitate price discovery yielding efficient market outcomes: Rebidding allows the generators to adjust their position when new information is observed improving market efficiency. However, strategic bidding has potentially impeded the intended price discovery function of bidding and has introduced inefficiency into the market [Australian Energy Market Commission, 2015b, p. 14]. Rebidding opportunities late in dispatch intervals create incentives for suppliers to bid less meaningful initial supply schedules. Various downstream stakeholders have argued that the market outcomes resulting from rebidding demonstrate anti-competitive

[3] Indeed, market power and strategic behaviour is a common concern in deregulated electricity markets. Applied studies include Wolfram [1999], Sweeting [2007], Borenstein et al. [2002], Green et al. [2006]) and Weigt and von Hirschhausen [2008].

[4] Government incentives, technology advancement and declining cost together with consumer interests in renewable energy contributed to recent low wholesale prices. See Energy Security Board [2020]

[5] ROAM Consulting found that late rebidding and price spikes had a statistically significant relationship in Queensland in 2014 [Australian Energy Market Commission, 2015b, p. 96].

[6] Price spikes and price volatility are undesirable in electricity markets for a number of reasons including creating difficulties for suppliers to forecast their revenue and dispatch quantity, and for consumers (particularly large companies) to forecast their costs and increasing the price of electricity contract by creating more risk [Australian Energy Market Commission, 2015b]

behaviour [Australian Energy Market Commission, 2016b]. The persistent issues concerning strategic rebidding in the NEM has motivated policy discussion about how to mitigate incentives for generators to bid strategically.[7]These discussions have led to regulators implementing additional regulations governing rebidding. One such rule is the “Bidding-in-Good-Faith” rule which became effective on 1st July 2016. This rule requires generators to record reasons for rebids made during a trading day. The Australian Energy Market Operator (AEMO) argued that the rebidding activity close to dispatch was intended to withhold information regarding supply intentions thereby creating inefficiencies and adversely affecting the confidence in information in forward markets [Australian Energy Market Commission, 2015a]. Providing material reasons for changing bids established an objective ground for Australian Energy Regulator or a court to infer a generators’ intent. Moreover, any rebid should be made as soon as material change in conditions leading to rebid is observed. This rule was implemented to dissuade generators submitting rebids for only strategic reasons. Later in 2020, Australian Competition and Consumer Commission [2020] introduced prohibited conducts to further increase its enforcement powers in dealing with strategic bidding (these new changes are not included in our data spanning from 2015 to 2017). These recent prohibited conducts emerged despite of transitioning to 5 minute settlement from October 2021 to dissuade generators in behaving strategically suggesting the persistent issues concerning strategic rebidding.

This paper examines the quantitative implications of the bidding/rebidding in the NEM. Our objective is to characterise the potential for market power by directly computing how much influence single generators have on dispatch prices and ultimately on trading prices through rebidding. Previous studies tended to focus on very large but infrequent price spikes. In contrast, our focus is on quantifying the effect of rebidding on prices in the “everyday” operation of the market, not only in the case of extreme pricing events.

The literature on market power and strategic bidding in the NEM is relatively small. Hu et al. [2005] examined the original supply bids made by generators in the NEM from May 2002 to 2003 to characterise bidding behaviour and concludes that the descriptive data are consistent with generators employing a variety of bidding strategies to influence wholesale

[7]Energy Security Board [2020] discusses various market design challenges like resource adequacy and ageing thermal generators, technology advancement that need to be updated through Post-2025 market design project. This project does not focus on rules governing rebidding but complies with Australian Energy Market Commission [2017b] rule change that focuses on transitioning from 30 minute settlement to 5 minute settlement. Australian Energy Market Commission [2017b] illustrates various policy discussions in relation to transitioning to 5 minute settlement and its impact on generators’ bidding behaviour.

prices. However, the empirical work in Hu et al. [2005] focused primarily on analysing original bids made by generators (bids made prior to the start of the trading day) across time; Hu et al. [2005] did not analyse sequences of rebids for target trading intervals and their effect on market prices. Consequently, this analysis misses the main mechanism through which generators behave strategically: rebidding.

There are a few studies that examine extreme-pricing events and the bidding strategies that produce these price spikes. Hurn et al. [2016] studied price spikes in Queensland between 2007 and 2009 to investigate the effect of deregulation on the probability of extreme-pricing events occurring in a trading interval. They find that the probability of price spikes occurring increased post 2007 deregulation and continued to increase throughout 2008 and 2009. In addition, Hurn et al. [2016] determined that these short-lived price events were largely due to generators using bid-splitting strategies.[8] Clements et al. [2016] also studied price spikes in dispatch prices to determine if these events are linked with bid-splitting. They find empirical evidence consistent with bid-splitting leading to spikes in dispatch prices (they studied data from June 2015 to May 2015).[9]

The infrequent spikes in dispatch prices studied in Hurn et al. [2016] and Clements et al. [2016] have a large impact on trading prices for the specific trading interval when they occur. However, price spikes are infrequent and evidence suggests that they cannot explain the overall increase in average wholesale prices [see for example the data presented in Wood and Blowers [2018]]. We contribute to this existing literature by directly computing how much influence single generators have on five-minute dispatch prices and ultimately on trading prices through their rebidding in the everyday operation of the market. If rebidding is a significant mechanism through which generators exert market power and create inefficiencies through price manipulation then we should observe significant changes in prices given rebids. In addition, we characterise when the bidding activity occurs, when the changes in prices occur and which generators tend to have large influence over prices.

The market rules concerning the settlement prices will transition from thirty minute settlement to five minute settlement from October 2021. Generators will still be allowed to rebid

[8]Bid-splitting strategies involve withholding capacity to raise the dispatch prices, and if successful, followed by rebidding all available capacity at the floor price knowing it will not be paid the floor price but the half-hourly settlement price.

[9]We note that there is an interesting literature on the time-series properties of prices in the NEM [see Higgs [2009], Ignatieva and Truck [2016], Janczura et al. [2013], Manner et al. [2016]].

until 5 minute prior to dispatch time. We study five-minute dispatch prices because strategic bidding directly affects these five-minute prices and there is very little analysis of these prices in the literature. This is consistent with Wood and Blowers [2018] who argued that even after the five minute settlement rule change generators may still game the system to have an increased revenue. Half hourly trading prices (settlement prices) prior to five minute settlement rule are computed as the average of the five-minute dispatch prices. We track the effects of rebidding by single generators on prices by directly computing the sequence of equilibria for each dispatch interval from initial offers to the time of dispatch by emulating a modified version of NEM's dispatch algorithm. In particular, we compute a new equilibrium for each five-minute dispatch interval for every rebid made by any generator. Given the sequence of equilibria for each dispatch interval, we then compute the sequence of trading prices for each 30-minute trading interval. Studying each rebid allows us to quantify the extent to which individual generators can influence wholesale prices through their rebidding and the timing of rebidding events.

We use generator-level bid data in conjunction with demand observations to construct complete bidding histories and market outcomes for each 5-minute dispatch interval in the 30-minute trading intervals. We construct these sequences of rebids for all generators in New South Wales (NSW) for the 16:30 trading interval for all days from 2015 to 2017. We analyse 2015 to 2017 for a few reasons: The period covers the "bidding-in-good-faith" regulation implemented July 2016; the wholesale price of electricity increased significantly over this period and was the main driver forcing consumers' electricity prices up [see Wood and Blowers [2018]]; and, there are no empirical studies on NEM auction data covering this period.

The rest of the paper is organised as follows. In section two we describe the institutional setting in which electricity is supplied in Australia. In sections three and four we outline the data set and dynamic equilibrium computation method that we utilise. In section four we apply the data to the equilibrium computation model and examine if the results support or negate our hypotheses. Section 5 concludes the main findings.

2.0 Overview of Bidding and Prices in the NEM

The Australian Energy Market Operator regulates the NEM and is tasked with overseeing its operation including providing price and demand forecasts, balancing supply and demand,

and monitoring anti-competitive behaviour. The NEM was established in December 1998 by combining the regional markets of Queensland, New South Wales, Victoria, South Australia and Tasmania.[10] The NEM is an energy-only market organised as a first-price, uniform auction. Our objective is to characterise the influence that individual generators have on the wholesale price given the bidding rules in the NEM. Therefore, we first provide a brief overview of the bidding rules governing the wholesale auction.

2.1 Bidding

We start our overview by describing the timing of bidding in the auctions. A trading day, denoted by t, lasts for 24 hours beginning at 04:00 (see panel (a) in figure 2.1 for an illustration of a trading day). The trading day is divided into 48 half hour trading intervals and each trading interval is further divided into six five minute dispatch intervals (two trading intervals are illustrated in panel (b) in figure 2.1. Generators are required to provide details of their availability for each of the 48 half-hour dispatch intervals prior to start of the the target trading day t and before any supply bids are submitted [NEMMCO, 2005].

Generators are required to submit their initial supply bids prior to 12:30 (gate closure), the day prior to the start of the target trading day (see figure 2.1). A generator's initial bid is 48 supply schedules consisting of 10 price-quantity pairs; generators bid a supply schedule for each trading interval in a trading day. The range of prices are bound by a price-cap and a price-floor: Prices are capped at $14,200 and quantity cannot be bid at prices less than $-1,000.[11] The supply bid for a trading interval applies to all six dispatch intervals in the trading interval unless a generator submits a rebid. Panel (b) in figure 2.1 illustrates the timing of bids for two adjacent trading intervals (4:00 to 4:30 and 4:30 to 5:00). The initial supply bid (48 price-quantity supply schedules) apply to all the trading intervals illustrated by the green bar, had there been no rebids.

A generator may revise their current bid for a target interval by submitting a rebid. Any rebid overwrites all previous bids. A rebid can involve a change to one or more of the quantities in the price-quantity pairs. However, generators cannot revise their initial prices. Generators can shift

[10] Western Australia and the Northern Territory are not physically connected to the NEM primarily due to distance between networks and operate their own system although the Northern Territory follows some parts of national electricity market's rule (see Australian Energy Market Commission [2018a, p. 17]).

[11] These price limits can change overtime: The market price cap for our study period was $13500 in 2015 and $1400 and $14200 in 2016 and 2017 respectively. The price floor has remained $-1,000 [see Australian Energy Market Operator [2018], Australian Energy Market Commission [2016a], and Australian Energy Market Commission [2016b]].

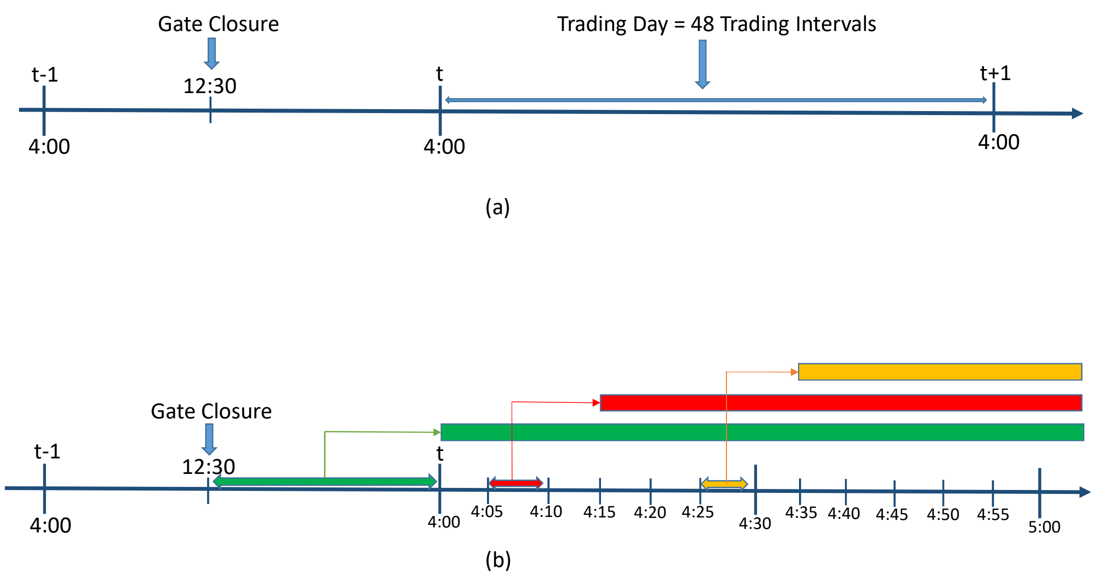


Figure 2.1: (a) Schematic representation of a trading day; (b) Schematic representation of the applicability of a rebid submitted before the start of the trading day (Green bar) and during the trading day (Red and Yellow bars)

capacity between price bands, add quantity, remove quantity, or make no changes. Revised bids only affect dispatch intervals at least one dispatch interval away from the dispatch interval in which the rebid was made. The red bar in figure 2.1 (panel (b)) illustrates the consequence of a rebid made in the second dispatch interval (4:05pm to 4:10pm). The revised supply bid applies to dispatch interval 4:15 to 4:20 and onward until a new rebid is made. Occurrence of another rebid like the one in dispatch interval 4:25 to 4:30 overwrites the previous rebid; The yellow bar replaces the red bar from 4:35 onward.

The Australian Energy Market Commission requires that offers, bids, and rebids to be made in “good faith” and “not false, misleading, or likely to mislead”, although this definition is generally subjective and hard to enforce [Australian Energy Market Commission, 2015b, p. 3]. If a generator submits a rebid within the late rebidding period (15 minutes prior to start of the trading interval) they must also submit the material conditions and circumstances which gave rise to the bid and the timing of these events. If a generating unit makes a rebid before the late rebidding period, they must still provide a brief, verifiable and specific reason for the rebid, and the time at which the event occurred. Because initial offers are unenforceable, generators may potentially have no incentive to consider their true short-run marginal cost when bidding and may engage in strategic bidding behaviour. In June 10, 2020 the Australian Competition and Consumer Commission (ACCC) increased its enforcement power by introducing prohibited conducts. One of these conducts outlined by Australian Competition and Consumer Commission [2020] pertains to generators’ bidding and rebidding behaviour. If a generator’s bidding behaviour, including their initial offer, is carried out ‘fraudulently, dishonestly or in bad faith’ for the ‘purpose of distorting or manipulating prices’ in the wholesale electricity market, the ACCC can investigate the case with various enforcement options available (See Australian Competition and Consumer Commission [2020]).

2.2 Prices

A market supply function is constructed for each of the six dispatch intervals using the supply schedules bid by each generator. The market supply function is constructed by cumulatively aggregating quantity ordered by lowest price (see for example figure 2.2 which illustrates the sequence of observed market supply step functions we constructed from all supply bids submitted by generators). The equilibrium price for each dispatch interval is determined when cumulative supply equals demand. The equilibrium dispatch price is the lowest price that clears the market. The price that generators receive, known as settlement price or trading price, is computed as the average of the six dispatch prices. All generators that supply electricity in a trading interval receive the same price. Note that a rebid made in the last dispatch interval of a trading interval applies to the second dispatch interval of the next trading interval (illustrated by the yellow area in figure 2.1 panel (b)). Consequently, the rebid would have no effect on the trading price for the trading interval in which the schedule was bid. The rebid would influence the trading price in the next trading interval.

3.0 Data and Analytical Framework

Analysing the impact of generators' rebidding on dispatch and wholesale prices requires computing the equilibrium for each of the six dispatch intervals after each occurrence of a rebid by any generator. To compute each equilibria, we first construct the initial market supply for each dispatch interval using the last supply schedule bid by each generator prior to gate closure. We then recompute market supply after each rebid to obtain a sequence of market supply functions for each dispatch interval. It is important to note that we collected total demand, initial supply and cleared supply but we used cleared supply to compute the equilibria because it measures the amount of electricity dispatched including scheduled loads and interconnector losses.[12] All the data used to construct the market supply was collected from the AEMO.[13] The bid data covers all the six dispatch intervals of the 16:30 trading interval for each day from 2015 to 2017.

The bid data for each generator includes the ten prices and the corresponding quantity bid at each price as well as any quantity rebid. Recall that prices cannot be altered. Generators are identified using a unique identifier (DUID) and every bid is time-stamped. Using these data, a complete sequential history is constructed of all bidding activity for all generators for a target trading interval. This bidding history is then used to compute the sequence of market supply functions. In figure 2.2, we illustrate the sequence of market supply functions we computed for the first dispatch interval in the 16:30 trading interval on 05 January 2015 in New South Wales.

The supply functions generally have key distinct features which we illustrate in figures 2.2 and 2.3. Typically, significant quantity is offered at or just above the price floor of $-\$1000$.

[12] In practical terms there is only a small difference between total demand, initial supply and cleared supply.
[13] All of the data is publicly available from *nemweb.com.au*.

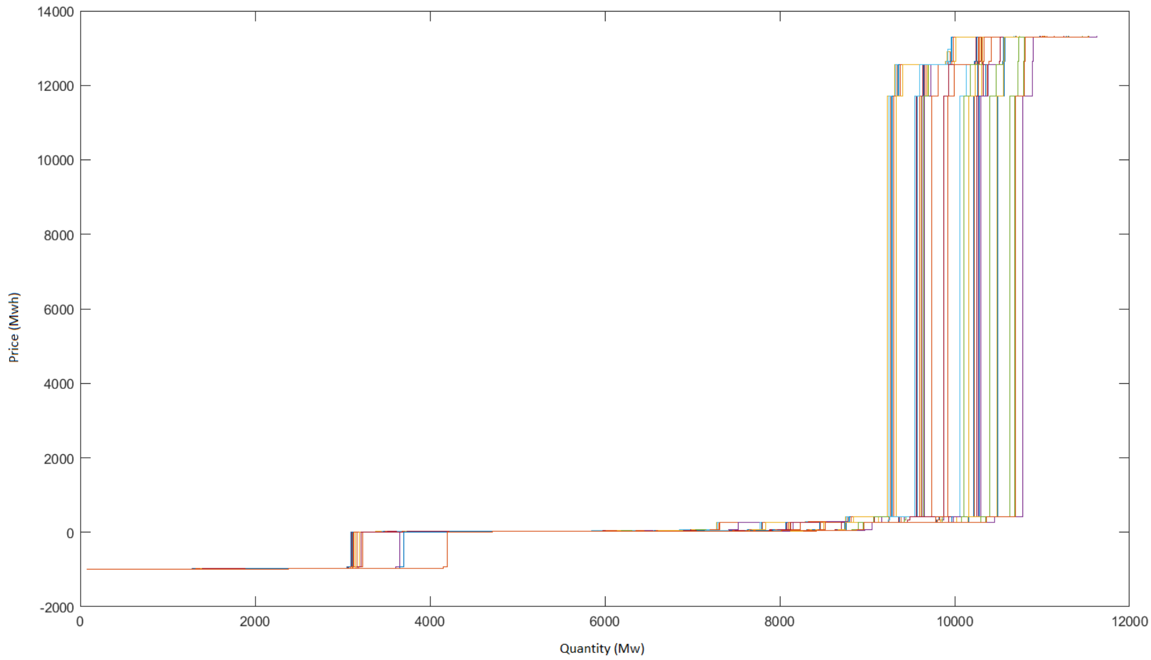
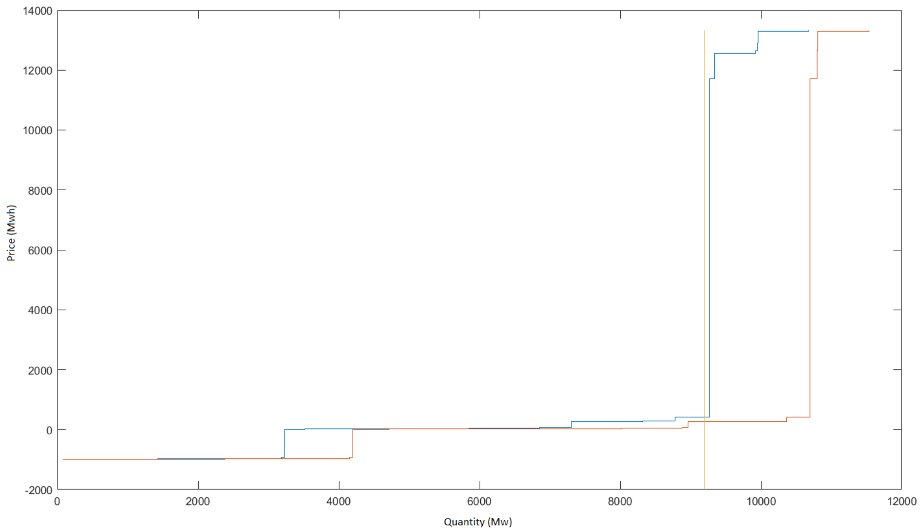


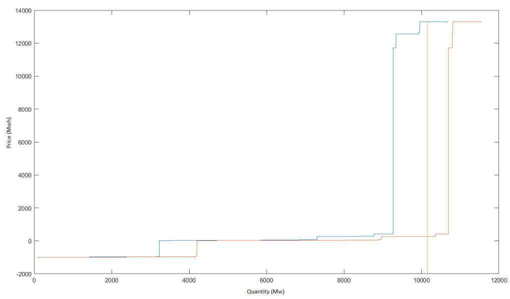
Figure 2.2: Sequence of Market Supply Functions for 16:05 dispatch interval on 05 January 2016 in New South Wales

Recall that the NEM is a uniform price auction; the price a dispatched generator receives is the lowest bid that clears the market, not the price bid at the dispatched quantity by the generator. Generators (generally coal-fired plants) bid quantities at negative prices to ensure dispatch. The second distinctive feature is the flat portion of the supply curve where changes in quantities are compensated by only small changes in prices. The last feature is the highly inelastic region where small changes in quantity are associated with large changes in prices. These regions of the supply function in relation to market demand are important for determining the effect of rebidding on dispatch prices.

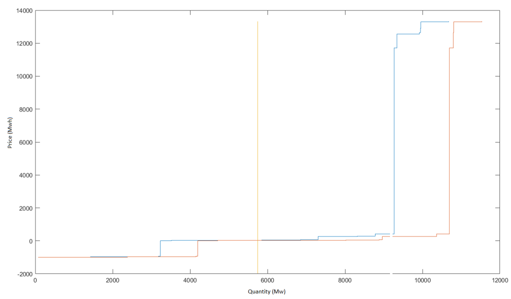
To illustrate the characteristics of five-minute dispatch equilibria and rebidding, we plot the equilibrium using bids at gate-closure and the final equilibrium after all rebids in panel (a) in figure 2.3. The blue step-function is the supply curve at gate closure and the red step-function is the final supply after all rebids. Realised dispatch quantity is illustrated by the perfectly inelastic line. We characterise the possible effects of rebidding by looking at three regions of the market supply: the low price elastic region, the region of inelastic supply (vertical region) and the region near the price cap. For this dispatch interval, rebidding in panel (a) resulted in an increase in supply causing the computed dispatch price to drop from \$418.72 to \$279.08.



(a) Observed Equilibrium



(b) Large Price Change



(c) Small Price Change

Figure 2.3: Comparing Equilibria. Blue line shows supply curve of initial offer at gate closure, red line shows final rebid and the vertical yellow line shows the demand curve. The only difference between the three panels is the location of demand curve.

The effect of rebidding on the dispatch price depends on the location of demand relative to the supply-function. If demand intersects the regions near the inelastic region of the supply functions (see panel (b)), then rebidding would have caused a significant fall in the dispatch price: an example of the extreme pricing events was studied in Clements et al. [2016]. There is also scope for small changes in prices if demand was located in the other two regions. These are not extreme changes in prices; however, small price changes aggregated over multiple trading intervals and over extended periods of time could be having a larger impact on the prices in the NEM than relatively rare extreme pricing events. Moreover, notice that demand could be such that rebidding actually had no effect on dispatch prices (see panel (c)). These multiple outcomes is why we examine every dispatch interval in 16:30 trading interval over a three year period.

Table 2.1: Bidding Activity

	Supply Schedules	Mean	Median	Std. Dev.	Maximum	Minimum
1st Dispatch Int.	117853	108	103	40	274	20
2nd Dispatch Int.	118279	108	103	40	268	20
3rd Dispatch Int.	118925	109	104	40	267	20
4th Dispatch Int.	119635	109	105	40	271	20
5th Dispatch Int.	120348	110	105	40	274	20
6th Dispatch Int.	121184	111	106	41	278	20
Trading Interval	716224	655	627	241	1632	120

4.0 Results

4.1 Bidding Activity

Rebidding in the wholesale auction is a prevalent feature of the NEM. In table 2.1 we provide an overview of bidding activity in each dispatch interval and for the trading interval over the sample period. The total number of bids in our sample is just over 716 thousand. The average number of rebids in a trading interval was 655 over the three years by 53 participating generators. There tended to be a slightly more bidding activity in the later dispatch intervals. There was substantial variability in rebidding activity with a standard deviation equal to 241 rebids.

4.2 Dispatch Prices

Dispatch prices were recomputed after each rebid by any generator. In table 2.2 we provide a statistical overview of the effect that rebidding had on dispatch prices as well as on the 30-minute trading price. In particular, the table reports descriptive statistics on changes in prices caused by rebidding. Price changes are computed as the difference between the prevailing price and the new price after a rebid; a positive change means that the rebid caused prices to increase. These price changes are computed for each dispatch interval. Trading prices are computed as the average of the six dispatch prices.

Rebidding for the 16:30 trading interval both increased and decreased dispatch prices over the dispatch intervals. Although the empirical distribution is skewed to the right meaning the majority of rebidding caused prices to increase. Panel (A) of table 2.2 characterises rebids that

Table 2.2: Price changes

	Supply Schedules	Mean	Median	Std. Dev.	Maximum	Minimum
Panel A:Rebids that caused prices to increase						
1st Dispatch Int.	5357	834	29	3034	14703	0.01
2nd Dispatch Int.	5226	903	27	3169	14703	0.01
3rd Dispatch Int.	5012	983	33	3301	14703	0.01
4th Dispatch Int.	4925	1113	35	3511	14703	0.01
5th Dispatch Int.	4925	1164	40	3588	14703	0.01
6th Dispatch Int.	4632	1198	42	3636	14703	0.01
Panel B:Rebids that caused prices to decrease						
1st Dispatch Int.	7487	-532	-12	2425	-0.01	-13866
2nd Dispatch Int.	7335	-561	-12	2493	-0.01	-14419
3rd Dispatch Int.	7092	-602	-12	2582	-0.01	-14419
4th Dispatch Int.	6920	-685	-13	2760	-0.01	-14703
5th Dispatch Int.	6579	-697	-14	2780	-0.01	-14703
6th Dispatch Int.	6477	-710	-14	2801	-0.01	-14419
Panel C:Aggregate effect including zeros						
1st Dispatch Int.	116759	4	0	922	14703	-13866
2nd Dispatch Int.	116859	5	0	946	14703	-14419
3rd Dispatch Int.	116398	6	0	969	14703	-14419
4th Dispatch Int.	117108	6	0	1024	14703	-14703
5th Dispatch Int.	117312	7	0	1012	14703	-14703
6th Dispatch Int.	117336	8	0	1019	14703	-14419

caused dispatch prices to increase. While the number of rebids falls towards the last dispatch interval, the mean of the price changes increases. The variability of rebidding activity is more in the last dispatch intervals. Panel (B) of table 2.2 characterises the rebids that caused prices to decrease. A similar pattern to Panel (A) is observed in panel (B). Rebids tend to decrease prices more in the later dispatch prices shown by the mean values. The variability of rebidding activity in this panel is less than Panel (A) over the dispatch intervals.

Panel (C) characterises the aggregate effect of rebidding. The number of rebids are quite higher in comparison to other panels due to zeros. Zeros indicate that rebids did not cause any price changes. Unlike both Panel (A) and Panel (B), the number of rebids increases in the last dispatch intervals. Rebids tend to increase prices towards the last dispatch intervals. The variability of rebidding activity is less than the other two panels.

Figure 2.4 illustrates the distribution of price changes given every rebid across the dispatch

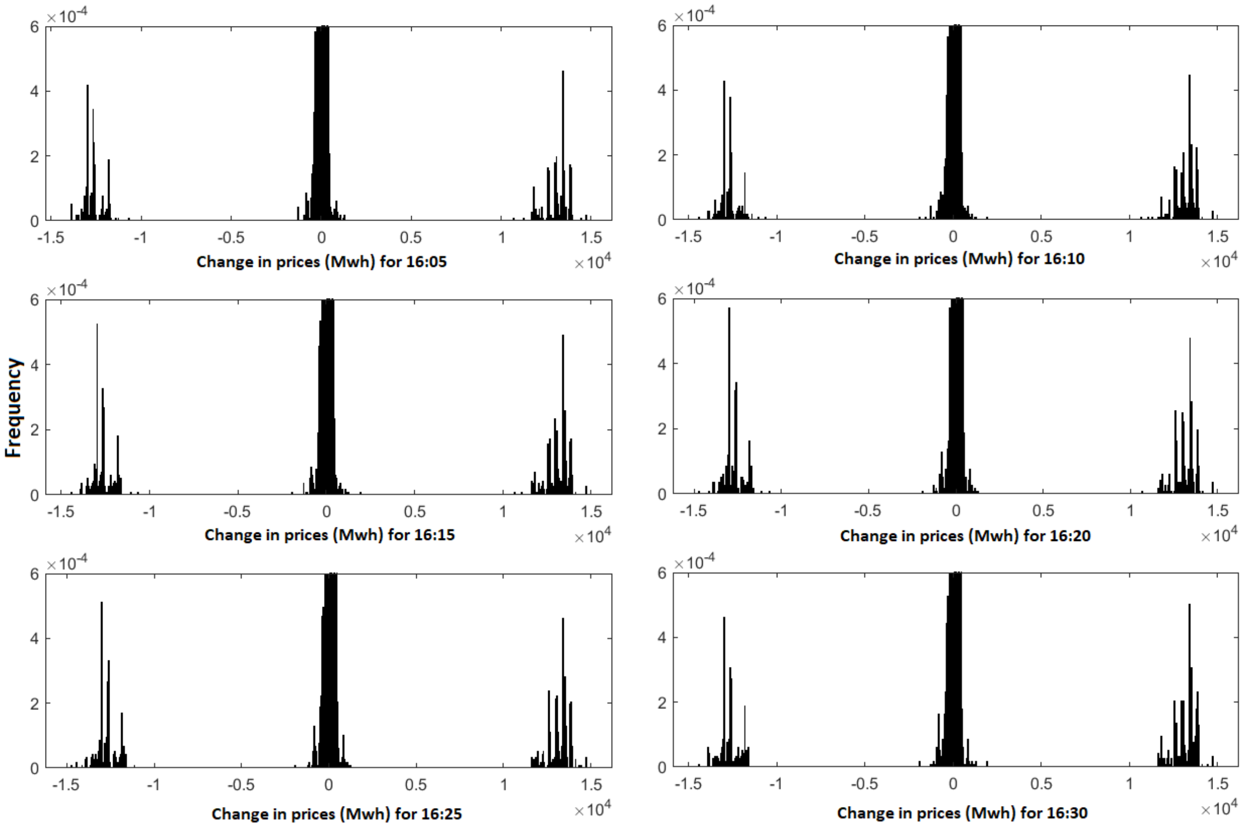


Figure 2.4: Empirical distribution of price changes for the six dispatch intervals in the 16:30 trading interval. The Y axis is frequency reported in relative probabilities. Note that the y-axis is truncated at 0.0006 to visualize the tails of the distribution.

intervals in 16:30 trading interval.[14] The three distinct areas in empirical distributions correspond to the steps of the supply function. Majority of the rebids caused a price change between \$-5 to \$5. The percentage of rebids causing a price change between \$-5 to \$0 is approximately %2 while from \$0 to \$5 is %90. This indicates that small changes in prices were observed much more often than price spikes.

Both tails of each panel in figure 2.4 show the presence of some significant price spikes. The percentage of such spikes is small and their occurrence is infrequent. Most of such prices are due to the initial rebids made in a trading day. However, rebids most likely reduce these prices as we approach the point of dispatch. In each panel of figure 2.4, the frequency of positive price spike is more than the negative ones and this becomes even bigger towards the last dispatch intervals. Table 2.3 characterises the price spikes over each panel in figure 2.4. This reports the frequency of price changes greater than \$12000 and less than \$-12000. The $\pm$\$12000 was chosen based on the observations in each panel given from approximately $\pm$\$2000 to $\pm$\$12000

[14]Note that we refer to an interval by its end point; 16:30 trading interval refers to 16:00 to 16:30.

Table 2.3: Frequencies in % for price changes in each panel of figure 2.4

	Dispatch Interval 1	Dispatch Interval 2	Dispatch Interval 3	Dispatch Interval 4	Dispatch Interval 5	Dispatch Interval 6
Less than $-12000	0.0021	0.0023	0.0023	0.0026	0.0025	0.0025
Greater than $12000	0.0024	0.0027	0.0028	0.0032	0.0031	0.0031

no price changes can be seen in figure 2.4.

What is important in table 2.3 is the higher number of price spikes in the late rebidding period; the last 15 minutes of each trading interval. In July 2016, the Australian Energy Market Commission introduced bidding in “Good Faith” rule insisting on generators to rebid as soon as possible after observing changes that form the basis of the rebids to avoid deliberately late rebids [Australian Energy Market Commission, 2015a]. Although it may be the case that “Good Faith” rule had some positive impact on rebidding behaviour of the generators but presence of strategic rebidding behaviour remained a problem [Australian Energy Market Commission, 2017b, p. 21].[15] Of course, there can be different reasons associated with price spikes but the frequencies of price spikes from dispatch interval 4 onwards reflect rebidding behaviour consistent with late rebidding. In fact, Australian Energy Regulator [2014, p. 8] reports that most of the rebids over the summer of 2013-2014 in Queensland were made in the last three dispatch intervals leading to high prices. Certainly, the same observation can be pointed out for New South Wales (NSW) from table 2.2 where the mean of the price changes from dispatch interval 4 onwards is more than the first three dispatch intervals.

A work by Ernst & Young reported in Australian Energy Market Commission [2015b, p. 6] outlines that deliberately late rebidding added eight dollars per megawatt hour to the price of caps in Queensland in the last quarter of 2014 and seven dollars per megawatt hour in the first quarter of 2015 which led to additional expenditure of $170 million across the market; specifically suggesting frequent small increases in prices can result in substantial increase in wholesale costs. To provide insights into aggregate price changes in NSW caused by rebidding we computed an estimate of the change in total cost caused by rebidding for each year in our study for only 16:30 trading interval. The cost is computed using

$$C = \sum_{t=1}^{T} \sum_{i=1}^{I} \Delta P_{dti} q_{dt} \tag{2.1}$$

[15] Australian Energy Market Commission [2017b, p. 21] also outlines the driving factors behind transitioning from 30 minute settlement to 5 minute settlement. This rule change becomes effective on 1 October 2021.

where ΔP_{dti} is the change in prices after rebid i for trading interval d (d= 16:30) on day t and q denotes aggregate dispatched quantity for that trading interval. T is the number of days for each year and I is the number of rebids in each day t.[16] The associated cost with rebidding causing price changes was \$71,226,000. Total wholesale expenditure for electricity dispatched in 2015 for 16:30, however, was \$91,132,000,000. The difference between the two costs draws the impact of rebidding, regardless of how small the changes might be. After all, these costs are only for one trading interval out of the 48 intervals in a trading day. Moreover, magnitude of the costs is relatively big due to the number of rebids in each trading day. The associated cost with rebidding causing price changes for 16:30 was \$1,192,900,000 for 2016 while the total wholesale expenditure for 16:30 was \$117,400$\times 10^6$ whereas it was \$43,114$\times 10^6$ and \$12,272$\times 10^9$ respectively for 2017. The computed costs over the three year sample period suggest that rebidding has increased the cost in the Australian NEM.

In addition, figure 2.4 shows that rebidding can cause prices to increase or decreases by different magnitudes as well as having no effect on prices. We illustrate how bidding can cause these price dynamics for an observed trading interval in figure 2.5. We plot the path of prices for an observed sequence of rebids for 16:05 dispatch interval on 03 January 2015 in NSW. The price corresponding to rebid 1 in the figure is the prevailing price after the initial bids. The price corresponding to rebid 2 is the price that would have prevailed after the first rebid, and so on.

The price path shows that rebids both increased and decreased prices and some rebids had no effect on prices. There are a few reasons why bids sometimes have no or small effect on dispatch prices: changes in quantity could be occurring at prices above the equilibrium price (see figure 2.3), the rebids involve relatively small changes in quantity, the changes in quantity are on the flat portion (elastic part) of the supply curve. The first series of rebids tended to impact prices more than the later rebids but, the final trading price was determined by the 101st rebid. There were instances of rebids causing a relatively large change in the dispatch price. However, rebidding brought the dispatch price down to the pre-spike level. An interesting question that arises from figure 2.4 and figure 2.5 concerns determining the instances rebids change the prices.

To provide insights on when rebids cause a change in prices and the magnitude of the change in prices, we use coefficient of variation together with number of rebids. This coefficient is the

[16]The index T for 2015 is 365 days and for 2016 is 366 days as it is a leap year and 365 days for 2017. The index I can vary depending on the day.

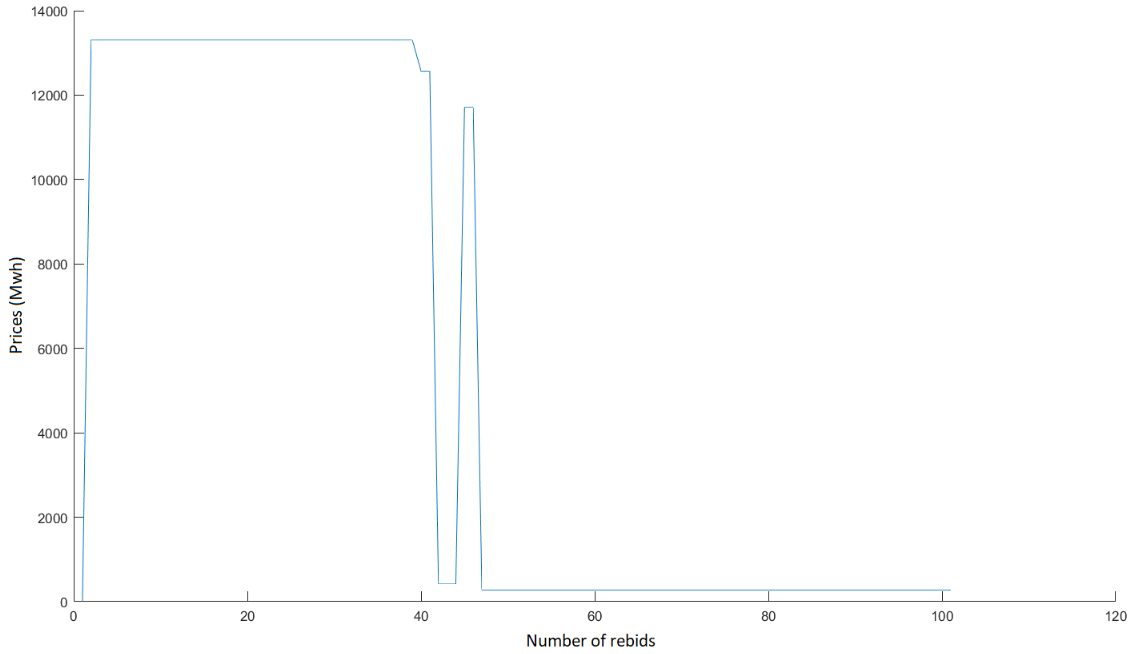


Figure 2.5: Price Path for 16:05 on 03 January 2015 in NSW

standard deviation of the price changes over the whole sample divided by the mean of the price changes over the whole sample period. It is computed over the sequence of price changes as a result of rebidding for each of the six dispatch intervals. Coefficient of variation takes both change in supply curve direction and magnitude of the price changes into consideration. This is useful given rebids do not shift the supply function in one direction only. In fact, multiple rebids may change the supply functions in opposite direction. Figure 2.6 illustrates the relationship between the number of rebids for 16:30 trading interval and the coefficient of variation. The line in the plot is a least square regression between the two variables.

The average number of rebids for all the six dispatch intervals was around 109 and the maximum number of rebids was 278 (see table 2.1 for descriptive statistics on bidding activity). There is a positive correlation between coefficient of variation and the number of rebids in all the dispatch intervals. The correlation coefficient for all the dispatch intervals lies between 0.25 to 0.3 and is statistically significant at the %1 level. The figure suggests that the more prevalent was rebidding for a dispatch interval the greater was the effect on increasing the dispatch prices. However, the plot also shows substantial variation in such an effect on dispatch prices at lower number of bids. This suggests that significant price changes can occur without a long history of bidding. This potentially means that an important determinant of such price changes can be the generator submitting the bid.[17] In the following section, we empirically characterise generators' bidding behaviour on prices.

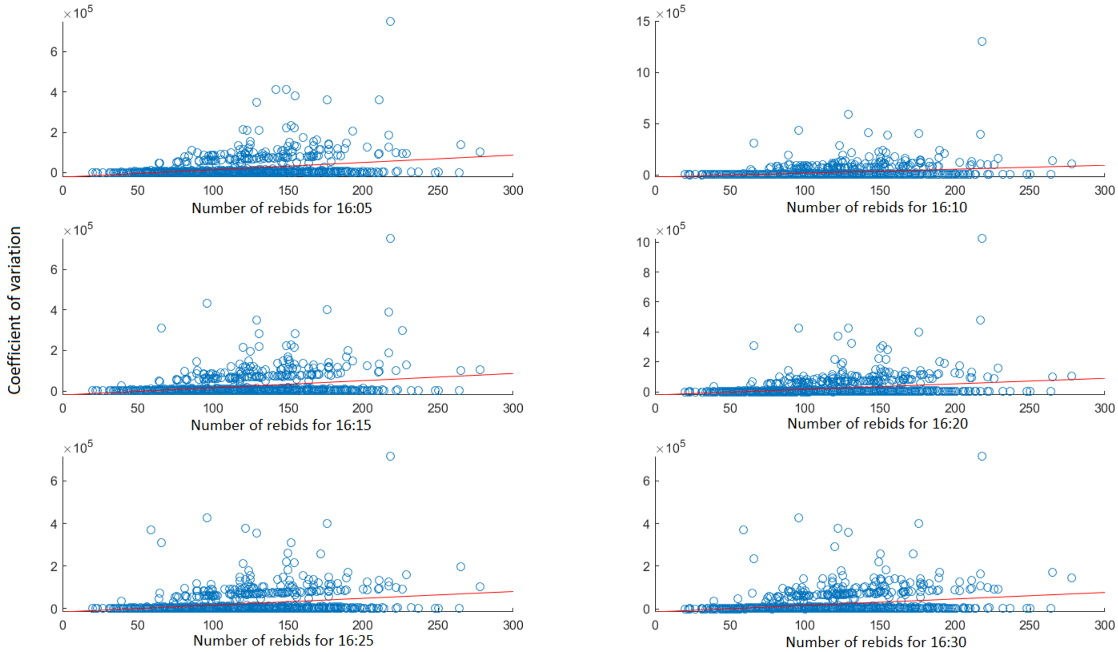


Figure 2.6: Relation between Coefficient of Variation (Y axis) and number of rebids (X axix) in 16:30 target over the three years in NSW

4.3 Generators, Bidding and Prices

Rebidding was implemented so generators could efficiently respond to changes in supply and demand. Hence, it may not necessarily be the case that rebidding creates inefficiency in this market. The results presented in section 4.2 showed that not all rebids cause substantial changes in trading prices. In a competitive market if a generator withholds capacity to increase prices other generators would step in to supply the market with no effect on prices. However, if generators submitting rebids supply a significant share of demand then the capacity might not be able to be replaced at a lower price. Perhaps it is rebidding by firms with market power that potentially introduce pricing inefficiencies into the market.

The NSW regional market is characterised by a small set of large generators supplying the

[17]The outlier observed in all the panels belongs to the price changes on 23 February 2016. On this day, there are 211 rebids submitted and there is a big difference between the initial rebid and the final one. The dispatch price for 16:05 on this day was $13514 when the first rebid was submitted and it dropped to $74.56 after the final rebid was submitted. Also, the same price was observed for 16:30 dispatch interval due to the first rebid but it dropped to $283.76 after the final rebid.

bulk of electricity. From 2015 to 2017, 53 generators participated in the wholesale auction in NSW. These generators are owned by 19 firms. We examine the effect of bidding by individual generators on trading prices. In figure 2.7, we look to see if rebidding by large generators as measured by capacity have larger effect on prices than smaller generators. We define a critical bid to be one that caused the trading price to change. There is a strong correlation of %84 between the size of generators and the number of critical bids which is also significant at %1 significance level. The rebids of larger generators tended to change prices more often than the rebids of smaller generators. The outliers are generators with DUID, TUMUT3 and UPPTUMUT owned by Snowy Hydro: the size of the generator clearly means that rebids made from these generators often influence the trading price.

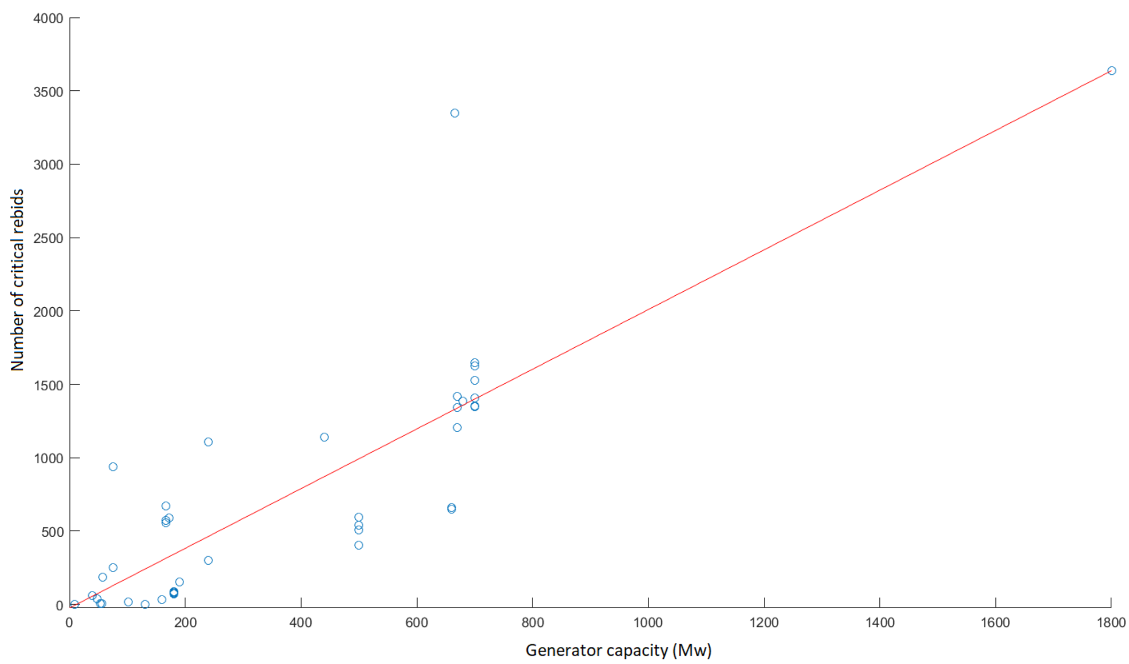


Figure 2.7: Critical rebids and generator capacity in NSW

In figure 2.8 we present data on the number of critical rebids for each generator that was active in 2015 to 2017 in NSW. The critical bids are decomposed into those that increased (blue shaded area) or decreased trading prices (red shaded area). There is substantial heterogeneity in the number of critical bids across generators.[18] The number of critical bids range from less

[18]These generators from left to right are: BLOWERNG, BW01 to BW04, CG1 to CG4, ER01 to ER04, GUTHEGA, HUMENSW, HVGTS, LD01 to LD04, MP1 and MP2, NYNGAN1, SHGEN, SHPUMP, SITHE01, SNOWPY, TALWA1, TUMUT3, UPPTUMUT, URANQ11 to URANQ14, VP5 and VP6, WOODLWN1, BROKENH1, MOREESF1, GULLRSF1 and WRWF1. To access generators' real name, see NEM Registration and Exemption List

than 5 critical bids to almost 4000 for the 16:30 trading interval. Generators 29 and 30 are the two outliers belonging to the Snow Hydro that have the maximum critical numbers.

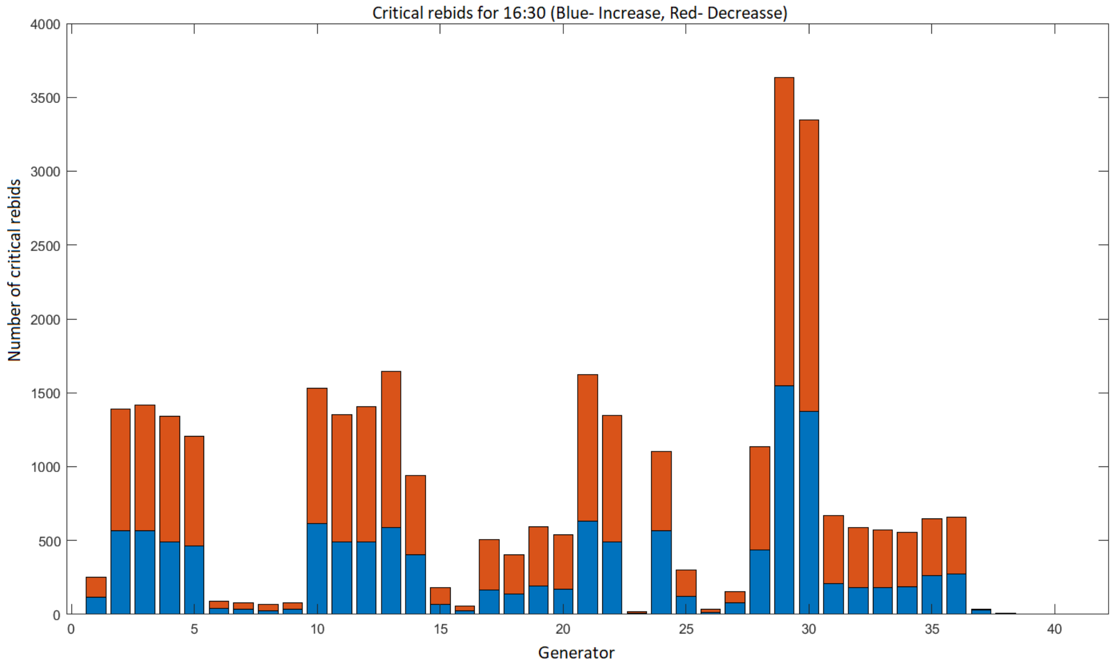


Figure 2.8: Critical rebids and generators in NSW

The relatively large number of generators illustrated in figure 2.8 are owned by a small set of firms. The Australian Energy Regulator [2014, p. 15] outlines that market participants in the Australian NEM employ rebidding to maximise their profit across their portfolio- all the generators in varying locations owned by one firm. This report indicates that a rebid submitted by one unit is followed by another rebid from another unit owned by the same portfolio and emphasises the importance of portfolio in driving late rebids. In light of this, we aggregated the generators into their parent firm and computed the number of critical bids at the firm level. These data are reported in figure 2.9. Again, the red shaded area illustrates the number of critical bids that reduced trading prices and the blue shaded region shows the number of bids that increased prices. Once again, there is a lot of heterogeneity in the number of critical bids made by firms.

The number of critical bids are disproportionately made by four firms- firm 1; AGL Macquarie, firm 2; Origin Energy Electricity, firm 4; Energy Australia and firm 5 is Snowy Hyrdo.[19]

https://www.aemo.com.au/-/media/Files/Electricity/NEM/Participant_Information/NEM-Registration-and-Exemption-List.xls

[19]The remaining firms are: firm 3; Delta Electricity, firm 6; Origin Energy Uranquinty Power, firm 7; Marubeni

These four firms supply around %80 of the NSW generation [Australian Energy Regulator, 2017]. This explicitly elaborates that the bigger the firm the bigger is their critical bids submitted by them. The red shaded regions are more which means most of these critical rebids have decreased the prices by different magnitudes. Besides, as the sequence of rebids have been investigated, those critical rebids could be in the beginning of the trading day where its effect is different from the critical rebid made closer to the 16:30 target. Our results in this sections are similar to Hu et al. [2005] which mentioned that rebidding by larger firms may not necessarily lead to an efficient outcome given that firms with bigger generation capacity may have a better insight regarding the market supply situation and therefore affect the supply situation through rebidding.

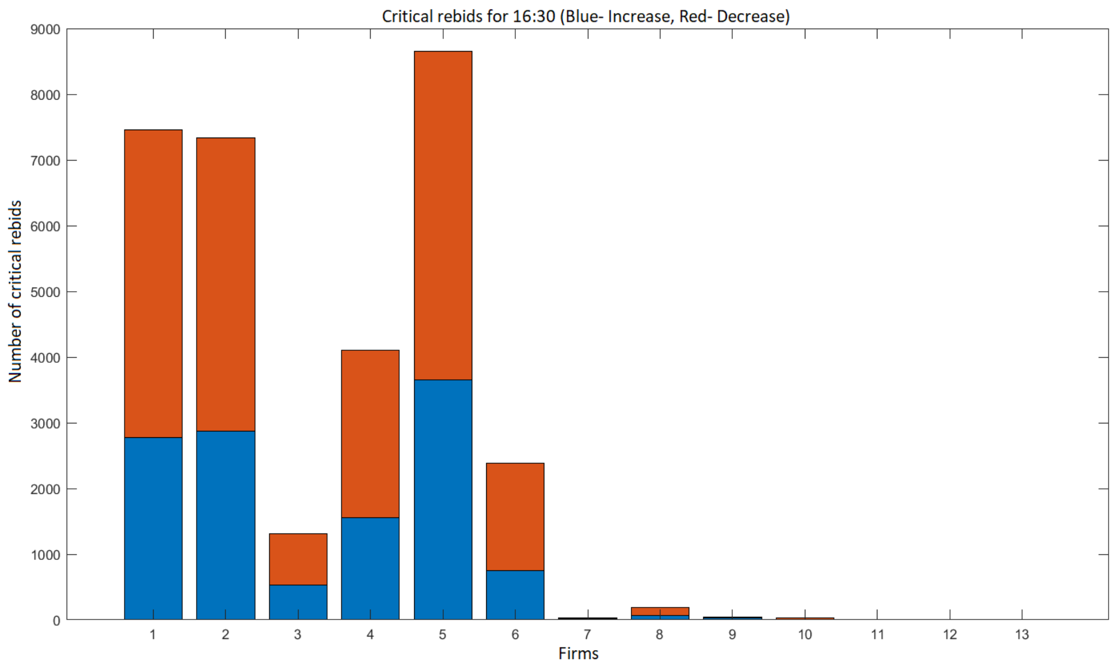


Figure 2.9: Critical rebids and firms in NSW

5.0 Conclusion

It is a significant policy issue to design the electricity market in such a way that it will run as efficiently as possible. An important aspect of this is analysing whether the bidding/rebidding behaviour of suppliers can lead to outcomes that are often associated with anti-competitive

Australia Power Services, firm 8; GPS Energy, firm 9; Woodlawn Wind, firm 10; AGL Hydro Partnership, firm 11; Moree Solar Farm, firm 12; New Gullen Range Wind Farm and firm 13 is White Rock Wind Farm.

behaviour. There is no clear relationship between deregulation and price trends, because the NEM was deregulated in 1997 and afterwards electricity prices followed previous trends for another 10 years. There are indications that a large proportion of this price rise in Australia could also be attributable to market power. We determine if rebidding activity by generators is attributable to part of this price deviation.

Computing the sequence of equilibria for each dispatch interval in a trading interval throughout a three year sample period from 2015 to 2017 reveals an upward trend in shifting the supply function to the left. This provides evidence that generators consistently try to push the prices up which means higher trading prices. To our understanding, this is why the average trading prices have been in rise after the 1997 deregulation. Besides, the attribute of market power is disclosed by observing generators from firms with bigger share of the market supply have a bigger role to play in price volatility.

6.0 Connection between chapter 2 and chapter 3

In chapter 2, we characterised the potential for market power by computing the impact single generators can have on dispatch prices through rebidding. We found that each single generator has the market power to influence the dispatch prices through rebidding. Given that generators have the ability to affect the market prices by rebidding, it is important to investigate the driving factors behind rebidding. For this reason, in chapter 3, we characterise generators' rebidding behaviour; specifically, we investigate generators' rebidding behaviour in response to market conditions.

Chapter 3

Strategic Rebidding behaviour: Driving factors in the Australian National Electricity Market

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1.0 Introduction

This paper addresses an important policy issue in the Australian National Electricity Market (NEM): the (re)bidding behaviour of generators in the NEM and its impact on market outcomes [Australian Energy Market Commission, 2015a]. The wholesale market in the NEM is organised as a uniform, first-price, sealed-bid auction. A key set of rules of the auction, and a relatively unique feature of the NEM, are the rules governing bidding and rebidding. Generators can submit any number of rebids up to 5-minutes prior to dispatch. A key economic argument for allowing rebidding close to dispatch is its potential for improving the economic efficiency of the market because generators can quickly respond to changes in current market conditions. One indicator of current market conditions is the sequence of 5-minute dispatch equilibria: rebidding provides generators the opportunity to respond to any market signals contained in these 5-minute dispatch equilibria. This link between rebidding and the market information in the dispatch equilibria is the focus of this paper: we empirically characterise how firms revise their bids in response to the information in the 5-minute dispatch equilibria.

The rules and structures governing the auctions in the NEM affect the decisions generators make through the incentives they create. An important set of rules govern how the market clears and how prices are determined. Since the NEM's introduction there has been a continuous discussions concerning the effectiveness of the market rules in achieving the desired gains in efficiency expected from deregulation.[1] The rules governing bidding in the market have often been a source of controversy. Flexible rebidding is a feature of the market design intended to promote efficiency through efficient pricing signals. However, rebidding has often been claimed to be the mechanism through which generators exercise their market power by bidding strategically to increase settlement prices over 1997 to 2017-2018.[2] These conflicting market incentives suggest that the effect of rebidding on the market outcomes in the NEM is an open empirical question. The objective of studying the link between rebidding and the market signals in the sequence of dispatch equilibria is to provide insight into this empirical question by better understanding the bidding behaviour of generators and the implications for market outcomes.

The empirical literature investigating the bidding behaviour in the Australian NEM is relatively small but growing. Most research focuses on specific bidding strategies. For example, Hurn et al. [2016] studied price spikes in Queensland between 2007 and 2009 to investigate the effect of deregulation on the probability of extreme-pricing events occurring in a trading interval. They find that the probability of price spikes occurring increased post 2007 deregulation and continued to increase throughout 2008 and 2009. In addition, Hurn et al. [2016] determined that these short-lived price events were largely due to generators using bid-splitting strategies.[3] Clements et al. [2016] also studied price spikes in dispatch prices to determine if these events are linked with bid-splitting. They find empirical evidence consistent with bid-splitting leading to spikes in dispatch prices (they studied data from June 2015 to May 2015). They argue that this opportunistic bidding behaviour leads to extreme price spikes which does not reflect the economic cost of electricity supply and also results in changes in regional supply conditions. Higgs and Worthington [2003] describes how an inappropriately designed market mechanism and information asymmetry can lead to price volatility in electricity markets. Our study differs from these studies in that we look at all rebidding for a trading interval and do not focus on particular bidding strategies.

There is also a literature on the relationship between market information and bidding in

[1] For general discussions of the early results of deregulation see Chester [2006] and Simshauser [2006]. For an overview of more recent discussion see Simshauser [2014] and the consultancy report Wood and Blowers [2018] together with the response of the Australian Energy Market Commission [2018b].

[2] See Australian Energy Market Commission [2015b] and Australian Energy Market Commission [2017a] for discussions on strategic bidding. See Hesamzadeh et al. [2020] for an example of strategic bidding behaviour and market power in the Australian NEM.

[3] Bid-splitting strategies involve withholding capacity to raise the dispatch prices, and if successful, followed by rebidding all available capacity at the floor price knowing it will not be paid the floor price but the half-hourly settlement price.

electricity markets. Olmstead et al. [2020] empirically investigated rebidding after disclosing market information in Alberta electricity market. The objective was to provide insights into the impact information disclosure had on market outcomes. Their analysis found that hourly Alberta electricity price rose by an average of 4.2 percent between 2010 and 2015. Darudi et al. [2016] demonstrated that disclosure of information in Alberta's electricity market gives generators who behave strategically, particularly, the ones with higher dispatchable capacity, an opportunity to withhold capacity to set the market prices high and earn a greater profit. Brown et al. [2018] focuses on how generators used the disclosed information to identify their rivals' supply bid to coordinate bidding and achieve higher prices. Their analysis found that when generators rebid their supply offers to prices above $\$100$ in response to the observed information, they bid closer to the next highest offer.

The objective of rebidding is to provide firms with an opportunity to respond to changing market conditions. We contribute to the literature on rebidding in electricity markets by investigating the link between the the sequence of information in dispatch equilibria and rebidding. In particular, do generators respond to the market signals in the dispatch equilibria by rebidding? If generators do rebid, are the revised supply bids consistent with supply changes that would be observed in efficient markets? In addition, do responses differ across power producing technologies or across dispatch intervals? Unlike the previous studies, we analyse all rebids and dispatch equilibria over each trading day from 2015 to 2017. Our methodology is to take the observed market signals together with generators' supply bids to investigate the impact of market signals on generator's bidding behaviour. Our analysis provides evidence on rebidding not only meeting its goal but being consistent with efficient market outcomes.

The remaining parts of the paper are organised as follow: Section 2 provides an overview of Australian NEM, the wholesale market and different types of information available to generators and emphasises on the flow of information in the Australian NEM. Section 3 outlines concerns raised in the literature regarding rebidding. Section 4 explains the empirical strategy and empirical models. Section 5 describes the data followed by exploratory data analysis. Section 6 outlines the results. Section 7 discusses implications of our results and section 8 concludes.

2.0 Australian National Electricity Market

2.1 Overview of the Market

The National Electricity Market (NEM) is Australia's largest electricity market. It was established by combining the regional markets of Queensland, New South Wales, Victoria and South Australia in December 1998, with Tasmania joining in 2005.[4] The NEM is an energy-only market which means that there is no capacity payment in the NEM and generators are only compensated for the electricity supplied to the gross market pool.[5] Each state in the NEM has their own regional energy market with interconnectors allowing energy generated in one regional market to be sold in another. In general, these interconnectors allow the NEM to function as a single market with single price, however in extra ordinary circumstances the interconnectors capacity will be insufficient and the prices in different regions will diverge. Although the price received by the generators across regions will differ, the price received by the generators within a region are the same.

2.2 Auction Mechanism in the Wholesale Market

The NEM is a continuous uniform, first-price, sealed-bid auction. A trading day starts at 04:01 on day t and ends at 04:00 on day $t + 1$. Each trading day is divided into 48 trading intervals of 30 minutes each (see figure 1(a)). Each trading interval consists of 6 dispatch intervals (five minutes each) and an auction is held for each dispatch interval. There are 288 five minute auctions in a trading day. Generators submit supply bids for each trading interval. The supply bids are applicable to each dispatch interval unless a generator submits a rebid. Supply bids consist of 10 price bands and 10 corresponding quantities. Bid prices- the 10 prices offered by the generators, range between the market floor price of -\$1000 and the market price cap.[6]

[4]Western Australia and the Northern Territory are not physically connected to the NEM primarily due to distance between networks and operate their own system although the Northern Territory follows some parts of national electricity market's rule (see Australian Energy Market Commission [2018a, p. 17]).

[5]This is in contrast to energy and capacity market like the one in the Western Australia (see Independent Market Operator [2012]).

[6]The Market Price Cap was \$13500 in 2015 and \$1400, \$14200 and \$14500 in 2016 until 2018 respectively according to Australian Energy Market Operator [2018], Australian Energy Market Commission [2016a], Australian Energy Market Commission [2016b]. Successive changes in price caps in an energy-only market is to allow firms to conduct various trading activities without a price constraint [Clements et al., 2016]. While price cap is also a tool to mitigate late rebidding by reducing the incentive on generators to submit late rebids, it gives marginal generators an opportunity to spike the price necessary to recover their fixed and marginal cost [Competition Economists Group, 2014]. If price caps are not determined appropriately it can blunt efficient signals

Initial supply bids are submitted on a day-ahead basis prior to gate closure which is 12:30 on day $t-1$. The Market is cleared through a dispatch algorithm which ranks the submitted bids by price and selects the least costly offers to satisfy the quantity demanded at each dispatch interval. At the end of each thirty minute trading interval, the spot price for a megawatt hour of electricity is computed as an arithmetic average of the six five minute dispatch prices. This is then paid to each dispatched generator for the amount of electricity the generator dispatched.

2.2.1 Rebidding

The rules of the auction allow generators to submit rebids. Rebidding is a mechanism by which generators shift, add, or reduce their quantities at different price bands to adjust their position in the market. A rebid replaces the supply bids for all 48 trading intervals in the standing offer. A generator cannot change the price bands in a rebid but it can change the quantity associated with each price. Rebidding is a dynamic process. We illustrate the timing of rebidding in Figure 1(b). It can occur anytime from the gate closure until 5 minutes before the dispatch time.

A rebid that is submitted between 12:30 on day $t-1$ and 04:00 on day t applies to 48 trading intervals (illustrated by the green bar). A rebid that is submitted within a trading interval on day t, for example at 04:07, illustrated by the red bar in Figure 1(b), applies to 5 minutes after the rebid was submitted and to all subsequent dispatch periods. The yellow bar also illustrates the occurrence of a rebid, just after 04:25 where the impact of the rebid falls in the next trading interval.

2.3 Information

The AEMO provides two sets of information at different point of time during a trading day, namely pre-dispatch information and dispatch information. Pre-dispatch information for trading day t is released after gate closure on trading day $t-1$ while dispatch information is released once trading day starts. The following subsections outline both types of information.

for investment in new capacity [Australian Energy Market Commission, 2015b].

2.3.1 Pre-Dispatch Information

Pre-dispatch information in the NEM consists of forecasts of regional prices of the upcoming trading interval, aggregate demand, aggregate supply (computed from supply bids submitted prior to gate closure), and ancillary service reserve in order to facilitate better operational decisions.[7] The pre-dispatch information is released by the AEMO at 12:30 on day $t-1$. This information covers all the 48 trading intervals within trading day t. The AEMO reviews the pre-dispatch information every half hour to account for any changes in the predicted demand or if a rebid is submitted. Depending on what changes the rebid includes, the inputs used in the pre-dispatch process like ancillary services and bid data will be updated.

2.3.2 Dispatch Information

Dispatch information includes results of the auction held at each dispatch interval. Generators observe this latest market information [Australian Energy Market Operator, 2017b, p. 11] after each dispatch interval. For instance, for dispatch interval 04:00 to 04:05, results of the auction held at 04:00 namely market dispatch prices and aggregate demand are observed after 4:05. The first round of this information for trading day t is released by the AEMO at 04:05 and the last one is released at the following 04:00. Note, each interval is represented by the end point. Dispatch interval 04:00 references to 03:55 to 04:00.

Sequence of dispatch information is used by the AEMO to update its planning process to account for any limitations on the generators' capacity to supply. This sequence also produces dynamic price signals, guiding generators in bidding process to supply electricity in the market [Australian Energy Market Operator, 2010, p. 17]. Our objective is to investigate if generators' rebidding behaviour is affected by the sequence of dispatch information.

[7] The public part of the pre-dispatch information is accessible by all the generators and is made available to the general public at the end of the trading day. It has an aggregate generic nature which includes regional clearing prices known as pre-dispatch prices, total demand, daily energy requirement (sum of Energy Demands for all trading intervals in a trading day) and short-term capacity requirement. Each generator also receives confidential information which is specifically related to that generator. This information includes the total forecast of MWs cleared during each trading interval, initial MW (the value of initial metered loading), energy market ramp rates and unit ancillary services dispatch data. For detailed explanation of the pre-dispatch information and the inputs used at each pre-dispatch run, refer to Gillett [2010].

3.0 Empirical Problem

An important issue concerning rebidding in the Australian NEM is the potential for this mechanism to have detrimental effect on the ability of the market to reach an efficient outcome. In the Australian NEM, generators observe results of the auction for each dispatch interval over a trading day. This information is used by the generators to evaluate and perhaps update their standing bids. Generators can update their standing bid up to 5 minutes prior to dispatch. The Australian Energy Market Commission [2015b, p. 7] illustrates that the ability of generators to rebid up to 5 minutes prior to dispatch can compromise the ability of the market to reach an efficient outcome. Studies concerning rebidding illustrate various problems associated with generators' rebidding behaviour but no study has yet investigated the role the sequence of dispatch information can play in generators' rebidding behaviour. We contribute to the literature on rebidding behaviour in the Australian NEM by investigating if the sequence of dispatch information affects generators' rebidding behaviour. In pursuing our objective, following subsections summarise some of the problems associated with generators' bidding behaviours identified in the literature.

3.1 Timing

The AEMO provides the generators with dispatch prices and aggregate demand at each dispatch interval over a trading day. This information allows the generators to infer how the market is operating in the NEM. Generators in the knowledge of this information and their dispatchable capacity can respond to their rivals through rebidding. Market rules allow generators to make subsequent changes to their bids until 5 minutes prior to dispatch. With this rule and the fact that the auction outcome is disclosed at every dispatch interval, Australian Energy Market Commission [2015b, p. 12] illustrates that generators have an incentive to delay their rebid until the point of dispatch- the last possible moment to obtain the greatest amount of information upon which it can finalize their rebid .

This behavior is further encouraged by the settlement rules. Generators, despite of auctioning their bids at every dispatch interval, are paid over a thirty minute trading interval. This uniform price is an average of the six dispatch prices over that trading interval.[8] Generators

[8]The 30 minute settlement will be replaced by 5 minute settlement on 1 October 2021. This rule change was approved in 2017 given the concerns transpired by various stakeholders about generators taking advantage of 30

by delaying their rebids can withhold information from the other participants to manufacture a price spike at a dispatch interval which will increase the average price paid at the end of that trading interval. The Australian Energy Market Commission [2015b, p. 20] outlines that such a behaviour can lead to inefficient price signals adversely impacting productive efficiency.

Having such rules in place, may discourage the generators to bid or rebid in good faith [Australian Energy Market Commission, 2015b, p. 14].[9] This means that generators may not disclose their true initial bids in anticipation of distorting the pre-dispatch information to misinform them. This will degrade the quality of pre-dispatch information as it is initially computed from the initial bids to provide the generators with a forecast information. Similarly, the quality of this information is further degraded when rebids are submitted late as the new supply bid contained in the rebid may not be incorporated in the pre-dispatch update. This, in turn, may discourage the generators to rely on this information in making rebids. Zainudin et al. [2015] argues that the pre-dispatch information is not sufficient to explain the bidding behavior of the generators because the spot prices that would be expected based on this information that generators receive is below the observed spot prices.

3.2 Bidding

Generators in the same firm may utilise the rebidding policy to artificially raise wholesale prices by adopting different bidding strategies. This may result in generators engaging in capacity withholding and bid-splitting. Withholding of capacity can be either physical withholding or economic withholding. Physical withholding is when generators withdraw their capacity to create a shortage of supply. Economic withholding, however, is when generators withhold capacity at higher price bands. Both types aim to manufacture price spikes [Biggar, 2011, p. 10]. Hurn et al. [2016, p. 5] illustrates that generators may engage in bid splitting by withholding some of their capacity at lower price bands to ensure getting dispatched and the rest of their capacity close to the cap price to drive up the spot prices.

Different bidding strategies arising from the market rules can be manifested by different

minute settlement; See Australian Energy Market Commission [2017b]. Wood and Blowers [2018] illustrated while five minute rule change will stop generators benefiting from high half hourly prices the generators' ability to rebid until 5 minute prior to dispatch time even after the rule change may allow an increased revenue for generators that are able to game the system.

[9] In order to avoid submission of late rebids, the Australian Energy Market Commission made it a rule since July 1, 2016 that all the generators, if needed to rebid, must do so in good faith- have a genuine intention to honor it at the the time submitted, see Australian Energy Market Commission [2015a] for further information.

types of generators. Intermittent generators, scheduled and peak generators differ in their rebidding behaviour as they have different ramp up/down rate and synchronisation rate. Hurn et al. [2016] argues that the generators take advantage of their ability to ramp their generation up and down within a short time to manufacture price spikes and the fact that these irregular price events may be attributes of strategic behaviour. For instance, base-load generators like coal have higher start up cost but comparatively lower marginal cost. These generators usually bid close to the market floor price to ensure getting dispatched [Hurn et al., 2016, p. 3]. The significance of different types of generators becomes apparent in this market where the spot prices of electricity is settled on an half-hourly basis. In such an arrangement, generators may withhold capacity early in a trading interval to push the spot prices up. Once a price spike is realized, the available capacity is offered back in the later dispatch intervals in that trading interval knowing the average of the dispatch prices will be the final settlement price.

With market rules allowing the generators to make rebids close to the point of dispatch and the incentive to do so becomes apparent with the settlement rules, the role the sequence of dispatch prices can play in generators' decision making process is important to be investigated.

4.0 Empirical Strategy

Market rules in the NEM provide generators with the bidding flexibility to revise their existing supply bid up to 5 minutes prior to dispatch. These revisions can include redistribution, addition and reduction of quantities over the 10 price bands. Recall that generators cannot change the prices in their supply offer after gate closure. One stated purpose of this flexibility is to allow generators the opportunity to respond to market signals in dispatch equilibria [Australian Energy Market Commission, 2015b, p. 4]. We investigate whether generators are motivated to revise their supply bids by the market signals in the dispatch information.[10] Specifically, we empirically study how dispatch equilibria affect generators' rebidding.

To analyse how the flow of dispatch information affects bidding by generators we map the sequence of dispatch equilibria to the sequence of generators' rebids. The first dispatch interval

[10]Energy Security Board [2020] illustrates that effective market signals are essential in ensuring efficient dispatch of existing capacity. This report suggests that uptake of new technologies by the consumers together with fast penetration of variable renewable energy places downward pressure on prices that may undermine investment signals. Energy Security Board acknowledges these changes and advises market designs; See Energy Security Board [2020].

on trading day t is 04:00 to 04:05. We use the end point of an interval to refer to that interval. Hence, dispatch interval 04:05 refers to the 04:00 to 04:05 interval.[11] The auction for this interval occurs at 04:00. At 04:05 the outcome of this auction- the market equilibrium price and quantity is observed. The outcome of each auction provides generators with an opportunity to re-evaluate their standing bids.[12] Generators choose whether to submit a rebid or not after each auction which occurs 48×6 times in a trading day. This dynamic process of updating the standing bids in response to the signals contained in the dispatch equilibria is what we study.

Observing frequent market equilibria provides generators with an opportunity to respond to the market signals in the dispatch equilibria. Our aim is to characterise generators' response to the sequence of dispatch equilibria. For instance, consider Figure 3.2 which shows two bids made by Eraring power station which is a black coal station on February 4, 2017. The pink line represents two supply bids: the original supply bid submitted on February 3, 2017 at 09:44:55 and a second rebid submitted on February 4, 2017 at 04:16:18. The red dashed line represents the first rebid at 04:12:47. The market dispatch price was \$69.94 at 04:10.[13] In the first rebid (red dashed line), the generator moved 60 MW from band 4 and 40 MW from band 5 and placed these quantities in band 9. In the second rebid (back to the pink line), the generator shifted the red supply curve back to the original curve at 04:16:18. The dispatch price before this rebid time was \$67. We investigate whether rebidding illustrated by this example is a response to the market signals in the dispatch equilibria. We construct a framework to track the movement of quantities and the direction of change in response to dispatch equilibria.

One of the challenges to analysing rebidding in response to the equilibria at each dispatch interval is that generators bid supply schedules. Each generator upon making a rebid submits a vector of 10 price-quantity bands. Changes in a generator's supply curves occur through adjusting quantities over the 10 price bands. For each auction, there can be multiple vectors submitted by different generators. To characterise generator's rebidding in response to dispatch equilibria, we need a measure of the changes in the distribution of quantities across the 10 price-quantity bands.[14]

[11] The same reference applies to trading intervals. 04:30 trading interval refers to 04:00 to 04:30.

[12] There can also be some other information such as generator's perception over risk in trading that may impact generators' response but we do not observe these information. Our empirical models employ generators fixed effect regression to control for the unobserved information.

[13] There are times lines fall on each other. This means that the megawatt quantity offered at those bands are the same.

[14] For example, if an average of quantity weighted by price over the 10 bands was used, this will cause a loss of information relative to dispatch equilibria. Our interest is in analysing the change in distribution of quantities

We introduce three regions to effectively measure the changes in the distribution of quantities across the 10 price bands. In this framework, we split the 10 price-quantity bands into three regions based on market dispatch prices, generator's supply bid and dispatched quantity. This is because realization of market equilibrium price together with generator's supply bid determines quantity dispatched, quantity nearly dispatched and what is not dispatched on a generator's supply curve. Figure 3.4 illustrates these regions. At time d, quantity q_5 is dispatched in the market. Region 1 is the area under the supply curve up to the dispatched quantity. We define this area as the dispatched area. Region 2 is the area that starts from just after the dispatched quantity until the quantity band that lies above and closest to the market price. We define this area as marginal area. In figure 3.4, region 2 starts from quantity q_5 to quantity q_6 as it is just above the market price P_d. Region 3 is the area from quantity q_6 to quantity q_{10}. This is the last region which is the remaining area of the supply curve covering the quantity not dispatched. We define this area as not dispatched area.

Changes made to the three regions by generators through their rebidding is the objective of interest. Figure 3.5 illustrates an example of a generator's supply curves S_d and S'_d. At dispatch interval d, the three regions remain the same as illustrated in Figure 3.4. We observe a rebid S'_d between dispatch interval d and $d+1$. Given the rebid S'_d, the quantity that would hypothetically be dispatched relative to market price P_d is up to q_7. Red double arrows with a name on top show the regions for supply curve S'_d. The change in regions 1 between S_d and S'_d is the addition of q_6 and q_7. Region 2 is changed from the area between q_5 and q_6 at S_d to the area between q_7 and q_9 at S'_d. Region 3 is changed to q_9 to q_{10} from q_6 to q_{10}. To measure the changes in the distribution of quantities between S'_d and S_d we construct the regions on S'_d relative to P_d. This allows us to measure how generators change the quantities that were dispatched, the quantities that were marginally dispatched and the quantities that were not dispatched through their rebid. Essentially, these three measures summarise the rotation and shift in the supply curve relative to market price. Thus, investigating these new changes between the supply curves at each region relative to market equilibrium price allows us to study the effect of dispatch equilibria on generators' rebidding.

We measure the changes between generators' supply schedules in each region. $CH^r_{i,k,t(d)}$ in equation 3.1 computes the changes in distribution of quantities in region r where generators

relative to dispatch equilibria. The mean gives us a point on the supply curve without informing us about the change in the distribution.

are identified by i; time is identified by a combination of k, showing the trading day, t showing which of the 48 trading intervals from that day the data relates to and, d showing which of the 6 dispatch intervals in that trading interval the data relates to.

$$CH^r_{ikt(d)} = \sum_{b=1}^{N} p^r_{bik}(q^r_{bikt(d)} - q^r_{bikt(d-1)}). \tag{3.1}$$

The change in area of region r is calculated by multiplying generator i's bid price, p, with the difference in quantities, q, over each price band b in that region and summing the results. This measure is useful given p_i never changes during trading day k. Effectively, this allows us to focus on the changes in the distribution of quantities at each region.

4.1 Empirical Models

4.1.1 Baseline Model

The first empirical specification focuses on the link between $CH^r_{i,k,t(d)}$ and dispatch equilibria assuming the response is the same across different generators type. Consider the following fixed-effect regressions for each region.

$$\begin{aligned} CH^1_{i,k,t(d)} = \beta_1 DIP_{i,k,t(d-1)} + \beta_2 CH^2_{i,k,t(d)} + \beta_3 CH^3_{i,k,t(d)} + X'_{i,k,t(d-1)}\phi \\ + \beta_4 D_{k,t(d-1)} + \gamma_i + \alpha + \epsilon_{i,k,t(d)} \end{aligned} \tag{3.2}$$

$$\begin{aligned} CH^2_{i,k,t(d)} = \beta_1 DIP_{i,k,t(d-1)} + \beta_2 CH^1_{i,k,t(d)} + \beta_3 CH^3_{i,k,t(d)} + X'_{i,k,t(d-1)}\phi \\ + \beta_4 D_{k,t(d-1)} + \gamma_i + \alpha + \epsilon_{i,k,t(d)} \end{aligned} \tag{3.3}$$

$$\begin{aligned} CH^3_{i,k,t(d)} = \beta_1 DIP_{i,k,t(d-1)} + \beta_2 CH^1_{i,k,t(d)} + \beta_3 CH^2_{i,k,t(d)} + X'_{i,k,t(d-1)}\phi \\ + \beta_4 D_{k,t(d-1)} + \gamma_i + \alpha + \epsilon_{i,k,t(d)} \end{aligned} \tag{3.4}$$

The key explanatory variable is $DIP_{i,k,t(d-1)}$ outlined in equation 3.5 which is the difference between market price, $P_{k,t(d-1)}$, and bid price, $p_{i,k,t(d-1)}$, by generator i. This difference is computed using the information contained in the closest dispatch equilibria prior to rebid. This means if there is a rebid at time d, we use the market information contained in $d-1$ dispatch equilibrium.

$$DIP_{i,k,t(d-1)} = P_{k,t(d-1)} - p_{i,k,t(d-1)} \tag{3.5}$$

Drawing on Figure 3.5, $DIP_{i,k,t(d-1)}$ is the difference between the equilibrium price P_d and bid price p_5 (price of the dispatched quantity) prior to the rebid S'_d. Note that S'_d is a rebid that occurred after dispatch interval d and so the $d-1$ market signals are P_d and p_5. The distance between generators' bid price and market price informs us about relative position of generators' current supply bid relative to how the market is operating. Generators price their marginal quantity differently. Having the difference between bid price (price of the marginal quantity) and equilibrium price incorporates generator's relative position in the market whereas just using the equilibrium price does not capture how generators value their marginal quantity. Therefore, investigating new changes between the supply curves at each region relative to $DIP_{i,k,t(d-1)}$ allows us to estimate the impact of market signals in dispatch equilibria on the $CH^r_{i,k,t(d)}$.

We also include the other two regions as explanatory variables in the regression equations. When generators decide to distribute quantities around region 1, they simultaneously decide the distribution of quantities in the other two regions. For instance, in the first regression equation (equation 3.2) if the coefficient sign for both $CH^2_{i,k,t(d)}$ and $CH^3_{i,k,t(d)}$ is positive then increase in supply in region 2 and region 3 correlates with increase in supply in region 1.[15] These two variables on the right hand side allow us to track the direction of shift in quantity between the three regions. Further, these two variables help us in understanding the magnitude of change at each region within each equation. We can then compare these changes with the other models to gain a better picture of changes in each region across the three models. This allows us to illustrate how much emphasis a generator puts on each region while shifting quantity in response to $DIP_{i,k,t(d-1)}$.[16]

The $X'_{i,k,t(d-1)}$ variable is a vector of generator specific control variables. This vector

[15] Another possibility is that increase in supply in region 1 correlates with increase in available capacity. This means that generators may add more quantities across the regions without moving quantities between the regions.

[16] Note that $CH^r_{i,k,t(d)}$ are jointly determined. This means that our dependent variables are functions of each other also, rather than just independent variables. This simultaneity poses difficulties in estimating the statistical parameters as dependent variables on the right hand side violate the assumption of being strictly exogenous. A system of simultaneous equations could be used to overcome this challenge. However, the problem is we do not have enough exogenous variables to act as instruments for our endogenous variables. Thus, none of the equations can be identified and simultaneous equations cannot be used. If the two $CH_{i,k,t(d)}$ variables on the right hand side are removed the problem of omitted variables becomes an issue. Therefore, our only option is to include the two variables.

includes dispatched quantity divided by capacity and generator capacity. The first variable measures how close to maximum capacity is the generator. Generators close to capacity may have a different response to dispatch equilibria against the generator with majority of its capacity not dispatched. The capacity variable is dispatchable quantity available at each dispatch interval. This is the sum of quantities over the ten price bands in a generator's supply bid. The capacity variable allows the model to account for the size of the generator.

$D_{k,t(d-1)}$ is the aggregate demand observed at $d-1$. Generators bid to meet demand for which generators need to be adaptive to changes in demand. This variable plays a vital role in the decision making process that generators face. Thus, using $D_{k,t(d-1)}$ allows us to estimate its impact on generators' bidding behaviour. γ_i is generator fixed effect controlling for the unobserved heterogeneity across generators. Generators bidding in the same firm are not independent from each other and γ_i accounts for this dependency. α is a vector of dummy variables controlling for calendar year, month, day of the week, forty eight trading intervals and six dispatch intervals to capture the seasonal changes. The error term $\epsilon_{i,k,t(d)}$ is to control for the unobserved components.

Net interchange or the interconnector flow is another variable which might have an impact on the rebidding behavior of the generators. This variable indicates how much energy in MW has been imported to New South Wales or exported out of New South Wales. However, this variable is not observable at each dispatch interval. Thus, generators' rebidding behaviour may not be affected by the net interchange in real-time. This variable could be examined in future research.

4.1.2 Technology Specific Model

The demand for electricity can be reasonably volatile depending on the time of the day and the season. To ensure the demand is met throughout all the trading intervals, different types of generators based on their fuel type are required. These generators consist of Hydro, Natural Gas, Black Coal, Kerosene, Wind and Solar. Each type of generator is distinct from the other ones in their ramp up/down rate and synchronisation rate. This distinction can give rise to different responses by different types of generators. We extend the baseline model to allow for different responses by different types of generators. In the following specification the effect of $DIP_{i,k,t(d-1)}$ on $CH^r_{i,k,t(d)}$ is broken down by interacting it with the $Type_i$ variable.[17] This

[17] Generators use different technologies to produce electricity. The $Type_i$ variable identifies these technologies. It consists of Hydro, Natural Gas, Black Coal, Kerosene, Wind and Solar. Note that Natural Gas consists of OCGT,

variable allows us to answer questions such as: Do coal fired generators respond differently to dispatch equilibria compared to natural gas or hydro plants? Further, this interaction term allows the slope β_1 to vary with the type of generator.

$$CH^1_{i,k,t(d)} = \beta_1(DIP_{i,k,t(d-1)} \times Type_i) + \beta_2 CH^2_{i,k,t(d)} + \beta_3 CH^3_{i,k,t(d)} + X'_{i,k,t(d-1)}\phi + \beta_4 D_{k,t(d-1)} + \gamma_i + \alpha + \epsilon_{i,k,t(d)} \quad (3.6)$$

$$CH^2_{i,k,t(d)} = \beta_1(DIP_{i,k,t(d-1)} \times Type_i) + \beta_2 CH^1_{i,k,t(d)} + \beta_3 CH^3_{i,k,t(d)} + X'_{i,k,t(d-1)}\phi + \beta_4 D_{k,t(d-1)} + \gamma_i + \alpha + \epsilon_{i,k,t(d)} \quad (3.7)$$

$$CH^3_{i,k,t(d)} = \beta_1(DIP_{i,k,t(d-1)} \times Type_i) + \beta_2 CH^1_{i,k,t(d)} + \beta_3 CH^2_{i,k,t(d)} + X'_{i,k,t(d-1)}\phi + \beta_4 D_{k,t(d-1)} + \gamma_i + \alpha + \epsilon_{i,k,t(d)} \quad (3.8)$$

4.1.3 Time Specific Model

We extend the technology specific model to allow for different responses by generators over the six dispatch intervals. In the following specification the impact of $DIP_{i,k,t(d-1)} \times Type_i$ is further investigated by adding another interaction term which is the dispatch interval. This is a categorical variable that captures the information observed at each five minute intervals within a trading interval. Generators based on their type may differ in their bidding over a trading interval. For instance, a coal generator may take 20 minutes to respond to market signals observed early in a trading day while a gas generator can respond in one minute. The $DispatchInt_d$ allows us to illustrate this bidding behaviour by different generators over the dispatch intervals. Moreover, the slope β_1 allows the response variable to vary by both type and dispatch interval in response to market signals. In this model, α does not include the dispatch intervals.

The $DispatchInt_d$ also allows us to capture the common strategic reference point in generators' bidding strategies. The strategic reference points are the first and the last dispatch intervals in a trading interval which are enough for generators to achieve a desired price outcome [Australian Energy Market Commission, 2017a, p. 30]. Australian Energy Market Commission

CCGT and steam. This is often done in the literature. See Clements et al. [2016], Hurn et al. [2016].

[2017a] illustrates that generators use these dispatch intervals to achieve a high sale or to manufacture a price spike in that trading interval. For example, if a generator achieves high sales early in trading interval could then shift its capacity to last dispatch intervals in an attempt to manufacture a price spike and thereby obtain higher settlement prices [Australian Energy Market Commission, 2017a, p. 30].

$$\begin{aligned} CH^1_{i,k,t(d)} &= \beta_1(DIP_{i,k,t(d-1)} \times Type_i \times DispatchInt_d) + \beta_2 CH^2_{i,k,t(d)} \\ &\quad + \beta_3 CH^3_{i,k,t(d)} + X'_{i,k,t(d-1)}\phi + \beta_4 D_{k,t(d-1)} + \gamma_i + \alpha + \epsilon_{i,k,t(d)} \end{aligned} \tag{3.9}$$

$$\begin{aligned} CH^2_{i,k,t(d)} &= \beta_1(DIP_{i,k,t(d-1)} \times Type_i \times DispatchInt_d) + \beta_2 CH^1_{i,k,t(d)} \\ &\quad + \beta_3 CH^3_{i,k,t(d)} + X'_{i,k,t(d-1)}\phi + \beta_4 D_{k,t(d-1)} + \gamma_i + \alpha + \epsilon_{i,k,t(d)} \end{aligned} \tag{3.10}$$

$$\begin{aligned} CH^3_{i,k,t(d)} &= \beta_1(DIP_{i,k,t(d-1)} \times Type_i \times DispatchInt_d) + \beta_2 CH^1_{i,k,t(d)} \\ &\quad + \beta_3 CH^2_{i,k,t(d)} + X'_{i,k,t(d-1)}\phi + \beta_4 D_{k,t(d-1)} + \gamma_i + \alpha + \epsilon_{i,k,t(d)} \end{aligned} \tag{3.11}$$

5.0 Data

The AEMO maintains operational data of the NEM and makes these available to public in various on-lin platforms. However, lack of transparency and the difficulties involved in working with such data has been an obstacle for the researchers [Dungey and Ghahremanlou, 2018]. These data files can be obtained from different sources. The most recent 12 months of data can be accessed via AEMO's dashboard while data older than 12 months can be accessed via NEMWEB.[18] The NEMWEB is the source of our data for this paper. 'BIDPEROFFER' and 'BIDDAYOFFER' are names of the data files used to construct the sequence of rebids. These files contain bids submitted by the generators. Market aggregate demand and total available supply at each five minutes are extracted from data file labelled as 'DISPATCHREGIONSUM'. 'DISPATCHPRICE' is the name of the date file used to obtain the price of electricity at each five minutes. 'DISPATCHLOAD' is the name of the data file used to obtain the quantity of electricity that is dispatched by a generator. To complete the data construction for a span of three years

[18]Link to the AEMO data: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data-dashboard. Here is the link to the NEMWEB data: http://www.nemweb.com.au

from January 1, 2015 to December 31, 2017 two more data files namely 'BIDPEROFFER_D' and 'BIDDAYOFFER_D' are employed which include the public summary of energy for each dispatch interval.[19]

To identify the driving factors in submitting a rebid by an individual generator, our data is constructed as a panel data containing the characteristics and bidding behaviour of all the generators. The panel features high frequency data consisting of 12,754,944 observations, spanning each 5 minute dispatch interval from 2015 to 2017. This comprehensive panel data captures all the equilibrium points at which the information is observed by the generators. This facilitates investigating whether occurrence of rebid between two 5 minute equilibrium points, say point A and point B, is derived by the information observed at equilibrium point A. For instance, a rebid that occurred at 4:17am falls in the fourth dispatch interval which is 4:15am to 4:20am. 4:15am is the equilibrium point at which the information was observed. It should be noted that when there are multiple rebids by one generator between two equilibrium points, the recent one is only taken into consideration which is aligned with AEMO dispatch algorithm.

5.1 Exploratory Data Analysis

As a precursor to our empirical results, we present an exploratory analysis of changes made in the distribution of quantities through rebidding across the three regions. The first panel of Table 3.1 reports the change in sum of quantity in each region due to occurrence of a rebid. Throughout the sample period, the mean values suggest that generators take away quantities from region 1 and place that in region 2 and region 3. The quantity being transferred to region 2 is greater than region 3. Region 1 and 3 have a higher standard deviations. Besides, the maximum quantity taken away is 1780 MW from region 1 and the maximum added is in region 3 which is 1779 MW.

In the second panel of Table 3.1, the dependent variable outlined in Equation 3.1 is explored. $CH^{r}_{i,k,t(d)}$ for each region is the difference between the quantities of each band of the rebid offer and the latest offer prior to the rebid within that region multiplied by the corresponding price and then summed up. The mean indicates that the value of the change in quantity in region 1 is negative while it is positive for the other two regions. This suggests that generators take away

[19]Some of the rebids in the data sets 'BIDPEROFFER' and 'BIDDAYOFFER' have no initial offer which does not allow us to construct the supply curve of generators. 'BIDPEROFFER_D' and 'BIDDAYOFFER_D' are used to obtian these missing initial offers.

quantities from region 1 and put that in region 2 and region 3. However, the shifted quantity is heavily placed in region 3 than region 2. One of the reasons of such a bigger magnitude in this part of the table is presence of the corresponding prices which magnifies the values. This result is more consistent with generators bidding behaviour outlined in different investigations (see Australian Energy Market Commission [2015b]; Clements et al. [2016]; Hu et al. [2005]) which gives credit to how our dependent variable is constructed. The standard deviation for $CH^3_{i,k,t(d)}$ indicates substantial changes made in the distribution of quantities in this region.

Recall from Section 3.0, our conjecture is that generators exhibit different strategies in moving their quantities across the three regions depending on the dispatch interval the rebid occurred in. First panel of Table 3.2 shows the change in sum of quantity due to rebid in each region across the six dispatch intervals. Generators take away quantities from region 1 across all the dispatch intervals and add that into region 2 and region 3. However, the mean of each region across the six dispatch intervals indicate that generators are more active in the first two dispatch intervals and the last two dispatch intervals. Hence, the volatility in the observations is also more in the said dispatch intervals shown by the standard deviation. Like the first panel of Table 3.1, the shifted quantity from region 1 is more transferred to region 2 than region 3 based on the magnitude of the mean values in region 2.

In the second panel of the Table 3.2, the summary statistics of each region across the six dispatch intervals are reported based on the three dependent variables. The mean of the value of change in quantity indicates that generators move out quantities in the first dispatch interval across the three regions. Quantity is taken away in region 1 at dispatch intervals 2, 5 and 6 and add the quantities in region 2 and region 3 at the same dispatch intervals. Similarly, the first 2 and last 2 dispatch intervals are the main intervals in which generators are more active than the middle two intervals and hence the observations at these intervals are more dispersed. The exploratory analysis in Table 3.2 illustrates that generators bid differently across the six dispatch intervals. This gives credit to our specification in time specific model outlined in Section 4.1.3.

Figure 3.6 is a box plot to visually represent how the values of the difference between the rebid offer and the latest offer prior to the rebid look like in each region. The middle box is shrunk due to excessive number of observations around zero and hence the median is always zero. It can be observed that the lower %25 of region 1 is more skewed towards the negative part while the upper %25 of region 2 and region 3 is more skewed towards the positive part.

This is seen in first panel of the Table 3.1 where the mean is negative for region 1 and positive for region 2 and 3. Figure 3.7 represents second part of Table 3.1. It can be seen how important the nominated prices are in better understanding the movement of quantities across the three regions as the higher regions are more populated with observations. The length of box plot in region 3 is also an indication of the very high standard deviation.

Figure 3.8 shows box plots of the change in supply offers due to rebid for each dispatch interval in region 1. It shows that every dispatch interval has a median of close to zero, while dispatch intervals do not have an exactly even balance between increasing and decreasing average price, it is not observable in these box plots. However these dispatch intervals differ greatly in the tails. Dispatch intervals 1, and 4 have longer negative tails, these periods experience rebids that reduce the value by 1500. Dispatch interval 2 is similar in that, it has a longer negative tail, in this case it is due to the shorter positive tail. The other dispatch periods, 3, 5, and 6 are even with rebids balanced between positive and negative.

Figure 3.9 shows the same information for region 2. All dispatch periods in region 2 show a larger positive tails, though the extent differs between the nearly balanced period 6 and the extreme difference of period 5. The periods for region two show their activity clustered between 500 and -500 with only a few rebids outside this range.

Figure 3.10 shows the results for region 3. The dispatch periods for region 3 shows a mix of positive tails, period 1, balanced tails, periods 2, 5, and 6, and negative tails in dispatch periods 3 and 4. These dispatch periods differ in how tightly their rebids are clustered, with period 2 having almost no rebids outside of 500 to -500 while periods 4, 5, and 6 have rebids from 1000 to -1000. Earlier periods, 1, and 3, are mirrors of each other, with 1 having a range from 1000 to -500 and 3 having a range from 500 to -1000.

Figures 3.11, 3.12, and 3.13 show the box plots for the dependent variable, showing the average change of a supply curve in regions 1, 2, and 3 respectively. Figure 3.11 shows this change in region 1. There are significant differences between the periods for region 1, however they are united by having far more extreme negative rebids than positive. They differ in the extent of the extremes, the earlier periods, 1, 2, and 3 are more clustered closer to zero while the later 3 periods have rebids more spread out. In region 2 the variance between periods is immediately obvious. Period 1 has a denser negative spread but the positive tail is more extreme. This pattern is repeated in period 2, while it is reversed in periods 4, and 5. Periods

3 and 6 are evenly spread with 3 having an even spread from zero to the positive and negative extremes while period 6 has its rebids clustered around zero. Region 3 rebids are much less clustered around zero than other regions, with all periods having rebids more evenly spread from zero to their positive and negative extremes than other regions. In addition, none of the periods in region 3 lead to positive or negative rebids, all periods are relatively evenly balanced.

Our exploratory analysis illustrate different changes in distribution of quantities across three regions and six dispatch intervals. Of course our exploratory analysis are only suggestive but our model specifications aim to establish presence of different generators' responses arising from various factors, in particular, market signals in dispatch equilibria across each region and extend that over each dispatch interval. In the following section, we present the empirical results of our investigation.

6.0 Results

Results for the baseline model are reported in the first panel of Table 3.3. Column 1 reports estimates for the dispatched region of the generator's supply bid (region 1), column 2 reports the estimates for the marginal region (regions 2), and column 3 reports the estimates for the not-dispatched region (region 3). The estimated coefficients for the difference between market price and generators' bid price for the marginal quantity ($DIP_{i,k,t(d-1)}$) suggests that generators tended to increase supply in the dispatched region as well as in the not-dispatched region given an increase in the difference between the dispatch price and the generator's bid for the marginal quantity. Generators increase supply at the lower price bands and the higher price bands relative to the generator's supply bid for the marginal quantity. This suggests that generators rotate their supply schedule in regions 1 and 3 to the right in response to larger differences between the market price and their bid for the marginal quantity. Generators tended to decrease supply in the marginal region. This means that generators rotated their supply schedule to the left. The value of the supply changes tended to be larger in region 3.

We illustrate the interpretation of the estimated coefficients for prices in Figures 3.14 and 3.15. Figure 3.14 contains an example of only the dispatch region for a hypothetical generator. The generator's initial supply bid is S_1. The equilibrium dispatch price is P_d and the quantity dispatched by this hypothetical generator is q_2. Recall that the last unit dispatched (q_2) is defined as the marginal unit. The generator's bid p_2 is the generator's valuation of the marginal quantity q_2. Therefore, in this example the variable $DIP_{i,k,t(d-1)}$ is the difference between P_d and p_2. The positive coefficient estimated for DIP suggests that generators tended to supply more at the prices in the dispatch region when the difference between the market price and the generator's value of its last dispatched unit increases. The hypothetical generator in the diagram increased its quantity offered at price p_1. The generator is now willing to supply the quantity $\delta q = q_1' - q_1$ at the lower price p_1 rather than at p_2. Therefore, the estimated coefficient for DIP suggests that generators rotate (or shift) their supply schedule in the dispatch region to the right in response to larger differences between the market price and their bid for the marginal quantity.

Figure 3.15 extends the example of the hypothetical generator to include all three regions. The generator increased supply in both region 1 and region 3, but lowered supply in region 2. In region 3, the generator rebid q_3 at p_5 instead of at p_6. The generator is willing to supply more quantity at a lower priced band in region 3 in response to larger differences in prices. In region 2, an increase in $DIP_{i,k,t(d-1)}$ suggests that the generator supplied less at the marginal price. In the diagram, the generator rebid the original supply q_2 at p_3 and placed that at higher price band p_4.

Supply changes to region 2 (CHRegion 2) and region 3 (CHRegion 3) were included in the regression for region 1 because supply decisions for this region likely depend on the supply choices for the other two regions. Of course, the same argument also applies to the regression equations for regions 2 and 3. The estimated coefficients indicate that there is a positive relationship between the changes in supply in region 1 and region 3: Generators that increase supply in region 3 tended to also increase supply in region 1; similarly, generators that increased supply in region 1 tended to also increase supply in region 3. In other words, the positive relationship between the changes in supply in regions 1 and 3 illustrate that generators rotate their supply schedule to the right. In contrast, there is a negative relationship between changes in supply in regions 2 and 3. These estimated coefficients together with the results for the difference in prices suggest that when generators increase supply in region 3, they may be transferring quantity from region 2 to region 3.[20]

The ratio of dispatched quantity to the aggregate supply bid by the generator (Disqcap) was

[20]Although this argument is consistent with the results, it is not conclusive because we do not estimate a system of equations. Moreover, generators can also simply add more quantity to supply bids rather than just redistributing quantity across price bands.

included to determine how the size of unpaid capacity bid into the market affects generator's rebidding. A ratio close to one indicates that most of the quantity bid by the generator was dispatched, and; therefore, earned a return. The coefficient estimates across the three regions suggest that generators tended to rebid more supply at the higher price bands when more of their capacity was dispatched in the previous dispatch interval. The ratio for region 1 was estimated to be statistically insignificant: Generators tended not to change supply offers in the dispatch region in response to the size of unpaid capacity bid into the market. The largest estimated effect is in region 3. These results are consistent with generators bidding more quantity into the market and these quantities were bid into regions 2 and 3; at price bands higher than the bid-price of the marginal unit.

The second panel of Table 3.3 reports the results for the specification allowing generator's response to vary across technology. These regressions are used to investigate whether responses to the market signals in the dispatch equilibria vary by types of generators. We first focus on the different responses to the difference in prices (DIP) across the different types of generators. Allowing generators' responses to vary by technology revealed that hydro, coal and natural gas had different rebidding strategies than wind and solar. Hydro, coal and natural gas generators tended to increase supply in region 1 and region 3. Wind and solar generators tended to not change supply in region 1 and reduced supply in region 3. Hydro and coal tended to have a larger response relative to the other technologies. Note that the estimates for the other dependant variables are consistent with those reported in the first panel.

In Table 3.4, we present the results for the specification allowing generator's response to vary across technology and dispatch intervals. In these specifications, we investigate whether generators respond to the information in dispatch equilibria across the 6 dispatch intervals differently. Varied rebidding activity across dispatch intervals has often been claimed as an indicator of generators strategically bidding to increase prices.[21] The direction of supply changes in rebids across the dispatch intervals are consistent with previous results. For example, generators generally increase supply in region 1 and region 3 given an increases in the difference between the dispatch price and the bid-price for the marginal unit (the exception are solar and wind

[21] Rebidding combined with how the market price is determined are commonly cited as providing the incentives for generators to have a rebidding strategy that involves rebidding differently across dispatch intervals. Specifically, trading prices are computed as the average of the six dispatch prices. Incentives exist for generators to implement strategies to increase dispatch prices in the latter dispatch intervals to earn higher prices for electricity already dispatched.

generators). Any difference across dispatch intervals will be in magnitudes. For most generators there is no clear pattern of rebidding behaviour across the dispatch intervals. Coal generators seem to be the only exception. Differences in prices tended to have a larger effect on supply as a result of rebids from coal generators in the last three dispatch intervals compared to the first three. The rebids by coal generators tended to increase supply in region 1 by greater amounts during the last three dispatch intervals compared to the first three.

7.0 Implications and Discussions

Recall that generators can submit any number of rebids for a 5 minute-dispatch auction up to five minutes prior to the dispatch time. The intended objective of allowing rebidding in the dispatch auctions is to give generators the flexibility required to respond to changes in market conditions. The flexibility to respond to changing market conditions is key to ensuring efficient market outcomes. A key mechanism through which generators learn about changing market conditions is the information in the 5-minute dispatch equilibria; specifically, the dispatch price that clears the market. How generators respond to the flow of market information in the dispatch equilibria through their rebidding is an important empirical question because it informs the debates concerning whether rebidding promotes market efficiency or is exploited by firms strategically bidding to increase prices (abuse of market power). In this section, we use the results presented in section 6.0 to characterise generators' rebidding in response to the pricing signals in the sequence of five-minute dispatch equilibria.

One focus of our empirical framework is on the effect that dispatch prices have on generators' rebidding. The regression models determine the extent that generators revise their supply bid after observing each five-minute dispatch equilibria. A basic necessary condition for rebidding to lead to more efficient market outcomes is that generators actually respond to the information in the sequence of dispatch equilibria through the rebidding mechanism. In particular, generators should be responding to the pricing signals observed in the dispatch equilibria. The results described in section 6.0 indicate that generators do respond to the information in the sequence of dispatch equilibria. The three regression specifications indicate that firms tend to revise their supply bids after observing the dispatch price. If the stated objective of rebidding is to allow generators opportunities to respond to current market conditions, then the statistical evidence reported in section 6.0 is consistent with this objective.

The second key part of the economic argument for given generators the flexibility to respond to market conditions is that rebidding will lead to more efficient market outcomes. We have only established so far that generators revise their supply bids in response to observing dispatch prices. We have not yet established that generators' supply responses are consistent with improving market outcomes. Consequently, we use the regression results to determine if generators responses to dispatch prices are consistent with efficient markets. All three regression specifications indicate that the large generators (coal, natural gas, hydro) generally increase their supply in dispatched region (region 1) of their supply bid as well as in the not dispatched region (region 3) given a larger gap between the dispatch price and the bid price for the generator's marginal quantity (recall figure 3.15).[22] This observed response by the generators is consistent with economic theory. If the difference between the market price and the generator's bid price for the marginal unit is increasing, then generators are likely earning greater surplus for each unit dispatched. Earning larger surplus on the marginal unit causes the generator to increase supply to increase profits. To illustrate the argument consider an example where generators bid their marginal cost. In this case, the greater the difference between the market price and the generator's bid price for the marginal unit, the larger is producer surplus for each unit dispatched. In particular, producer surplus for the last unit dispatched is an increasing function of the difference in prices (the difference between marginal revenue and marginal cost is increasing). Therefore, the generator has an incentive to increase supply to earn additional profits. This response by generators is consistent with efficient markets; specifically, productive efficiency. The role of prices is to inform the suppliers about the willingness to pay for an extra unit of electricity. In an efficient market, larger returns (or higher relative dispatch prices), signals to the generators that they can earn additional profit by supplying more to the market.

The results concerning how firms respond to the ratio of dispatched quantity to bid quantity are also consistent with standard economic theory. Generators with excess capacity bid into the market tend to rebid less supply at the higher price bands.[23] Alternatively, generators that dispatched more of their capacity in a dispatch interval tended to rebid an increase in supply at higher price bands. These responses are consistent with efficient markets: generators respond to their tight supply by offering more supply at higher price bands; generators respond to relative

[22]The rationale behind generators increasing their supply in region 3 maybe they expect higher prices in the subsequent dispatch intervals.

[23]Excess capacity in this case refers to quantity bid into the market that does no get dispatched in a dispatch interval. Recall that the NEM is not a capacity market.

scarcity of their capacity by offering quantities at higher price bands. The results concerning generators' rebidding in response to prices and dispatched quantities are consistent with efficient markets. It is important to be clear that our results are consistent with efficient market responses; we do not make the claim that markets are efficient. We only argue that our results provide statistical evidence that rebidding meets the desired objective of promoting efficient market outcomes.

The majority of power in NSW is supplied by coal generators followed by hydro and and the natural gas generators [Australian Energy Regulator, 2017, p. 30]. The previous discussion concerning rebidding in response to the information in the sequence of dispatch equilibria largely pertains to these generators. The results reported in section 6.0 suggest that the relatively smaller solar and wind suppliers rebid differently than the coal, hydro and natural gas generators. The rebids submitted by wind and solar generators tended to not change the supply bid in region 1 in response to changing differences between the dispatch price and their bid-price for the marginal unit and decreased supply in region 3. The difference in rebidding behaviour in response to differences in prices is likely due to the small capacity of these generators relative to conventional and hydro plants as well as being intermittent generators. Solar and wind suppliers can be reliable to produce electricity when the weather conditions permit. One limitation faced by wind suppliers is that it cannot increase with demand since wind is intermittent. Therefore, solar and wind are classified as semi-scheduled generators given they cannot be scheduled in the usual way.

Results reported in Table 3.4 suggest that most generators are largely consistent in their responses to changes in the difference between dispatch prices and their bid-price for the marginal quantity across dispatch intervals. Only coal generators seemed to have a slight tendency to have a larger supply response in the last three dispatch intervals relative to the first three; however, this supply response is only prominent in the dispatched region. Moreover, any rebidding in the later dispatch intervals involves larger increases in supply in region 1 given an increase in the difference in prices. This result is not consistent with the argument that generators might try to increase trading prices by bidding up dispatch prices near the end of a trading interval. Note that our conclusion only refers to rebidding supply in response to the difference in dispatch prices and the bid-price of the generators marginal unit. In this case, our results are consistent with generators responding to the market signals in the dispatch equilibria in a way that works towards efficient market outcomes.

Our contribution to the literature on rebidding in the Australian NEM is unique. Unlike previous studies, we empirically investigate all the equilibrium points over each trading day encompassing all rebids by various technologies. We provide evidence consistent with economic theory on the role of rebidding and prices: First, rebidding meets its goal of providing generators with an opportunity to respond to market conditions and second, generators' response to prices is consistent with economic of efficient markets. Our evidence is particularly interesting given the Australian National Electricity Market will transition to five minute settlement from October 2021. The evidence provides empirical support for rebidding and the role it plays in achieving efficiency.

8.0 Conclusion

Since the Australian National Electricity Market was established, there has been continuous discussions regarding the effectiveness of some of the market rules in achieving the desired gains in efficiency. In particular, rules pertaining to rebidding have often been a source of controversy (in combinations with settlement rules). Rebidding has often been claimed as the potential mechanism for firms to exercise their market power by bidding strategically to increase settlement prices. The intended objective behind rebidding is to allow generators to quickly respond to market conditions thereby improving market efficiency. One indicator of market condition that is observable to generators in real-time is the sequence of market signals in each of the 5-minute dispatch equilibria.

We characterised generators' response to market signals in dispatch equilibria to provide insights into generators rebidding behaviour and its implications for the market outcomes. Our results suggest that rebidding meets its objective of enabling generators to respond to market conditions. We also provided evidence that generators' rebidding behaviour being consistent with efficient market outcomes. In addition, our specifications established that generators' response to market conditions is conditional on their technology which leads to difference in responses among various generators across each dispatch interval.

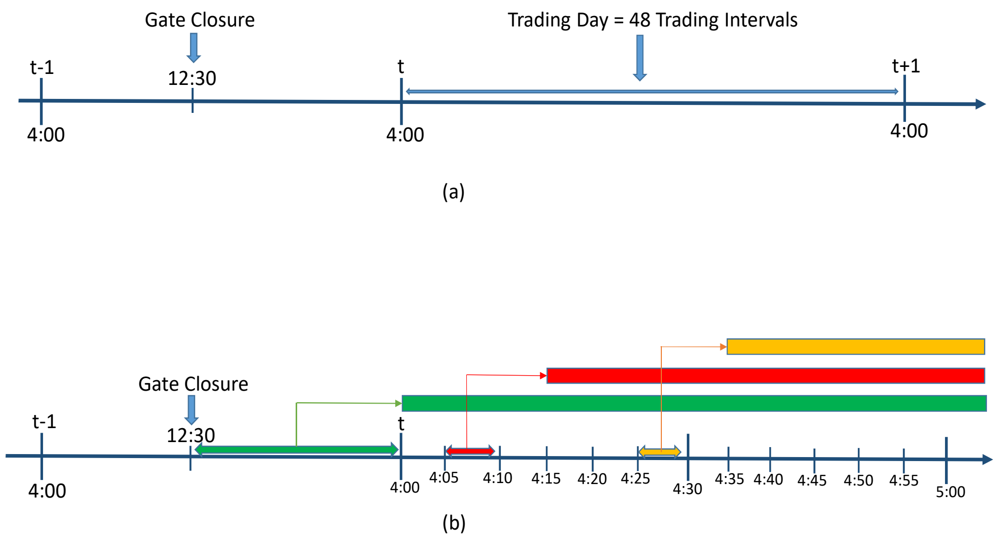

Figure 3.1: (a) Schematic representation of a trading day and the time before which all the supply offers should be submitted (b) Effectiveness of a rebid submitted before the start of the trading day (Green bar) and during the trading day (Red and Yellow bars)

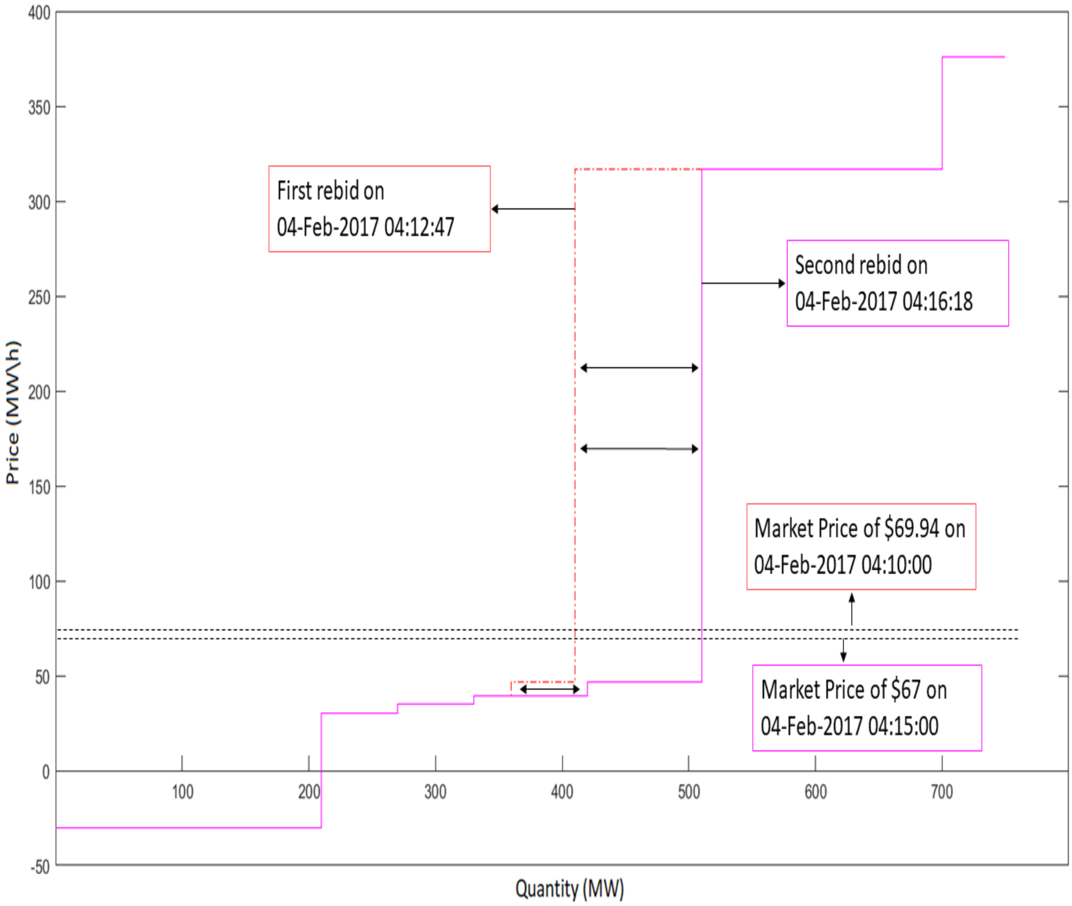

Figure 3.2: Supply curves of Eraring power station known by DUID of ER01 which is a black coal station and owned by Origin Energy Electricity on February 4, 2017 at 4:30 trading interval. The horizontal axis indicates the supply bids while the vertical axis is the corresponding nominated prices. Note: The original prices (price(a)) in bands 1, 9 and 10 as shown in the following supply bid are quite high which shrink the other parts of the plot. The plot with price(a) is shown in the following page. To display the circled area of that plot, the prices offered in those bands are changed (price(b)) which is shown here.

$$\begin{bmatrix} band & 1 & 2 & 3 & 4 & 5 & 6 & 7 & 8 & 9 & 10 \\ price(a) & -982.9 & 30.25 & 35.09 & 39.14 & 46.75 & 54.98 & 68.61 & 294.93 & 13171 & 13761 \\ price(b) & -30 & 30.25 & 35.09 & 39.14 & 46.75 & 54.98 & 68.61 & 294.93 & 317 & 376 \\ bid & 210 & 60 & 60 & 90 & 90 & 0 & 0 & 0 & 190 & 50 \\ rebid & 210 & 60 & 60 & 30 & 50 & 0 & 0 & 0 & 290 & 50 \end{bmatrix}$$

Supply bids of Eraring Power station (ER01) for February 4, 2017.

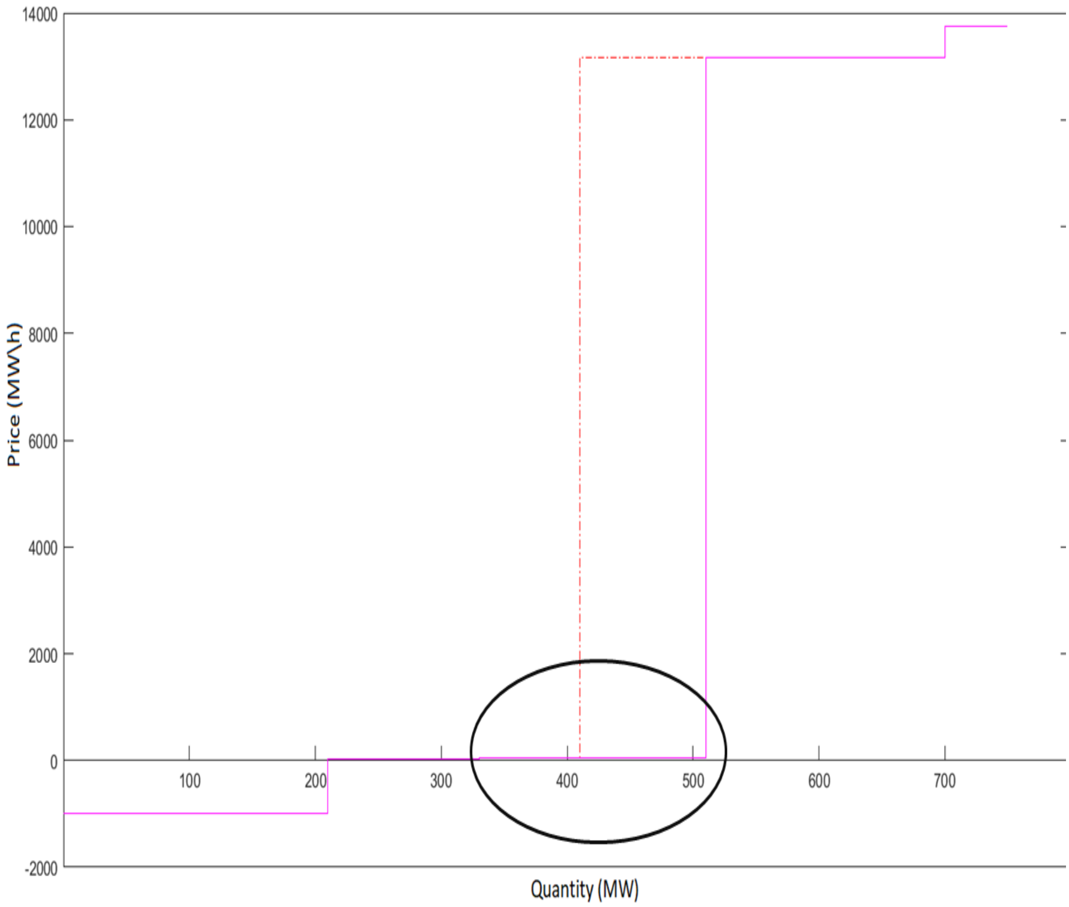

Figure 3.3: Supply curves of Eraring power station known by DUID of ER01 which is a black coal station and owned by Origin Energy Electricity on February 4, 2017 at 4:30 trading interval. The horizontal axis indicates the supply bids while the vertical axis is the corresponding nominated prices. Note: This plot uses the price(a) of the supply bid above.

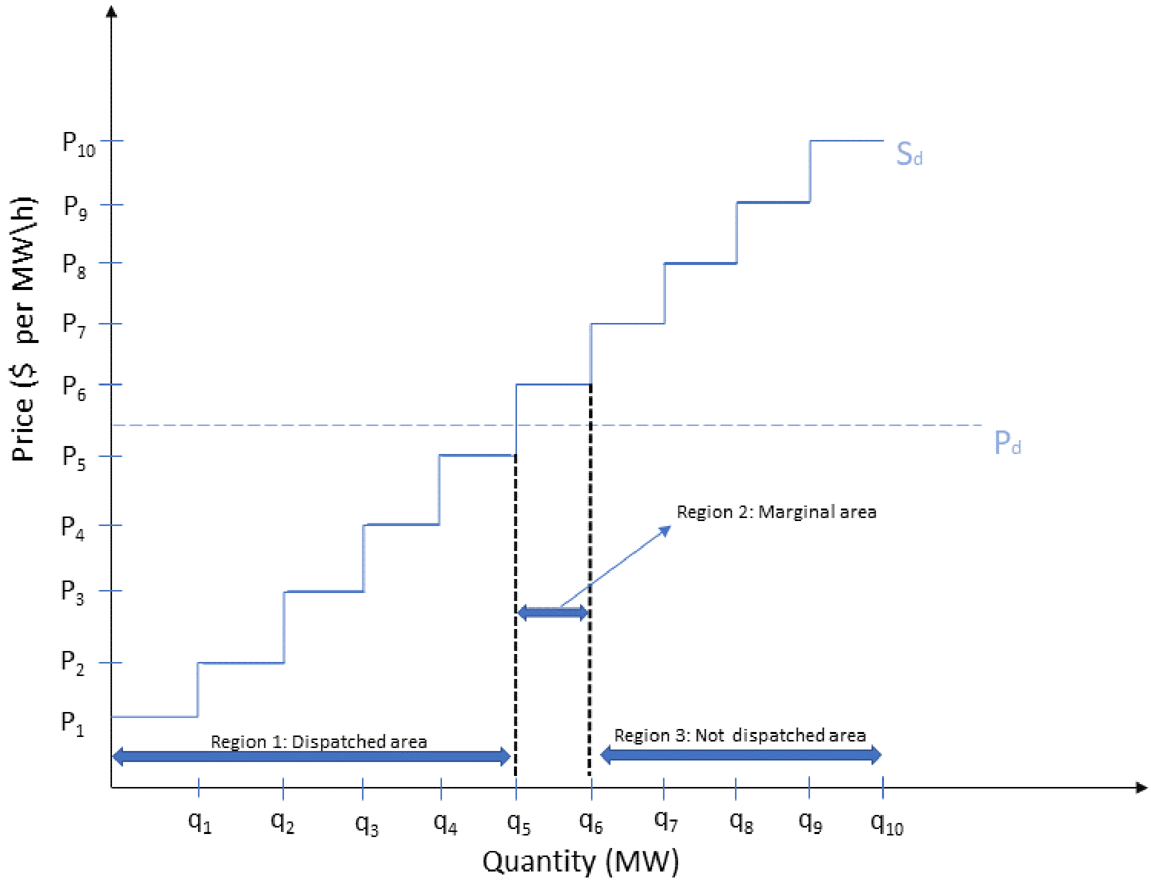

Figure 3.4: This figure illustrates the three defined regions on a generator's supply curve S_t with market price of P_t.

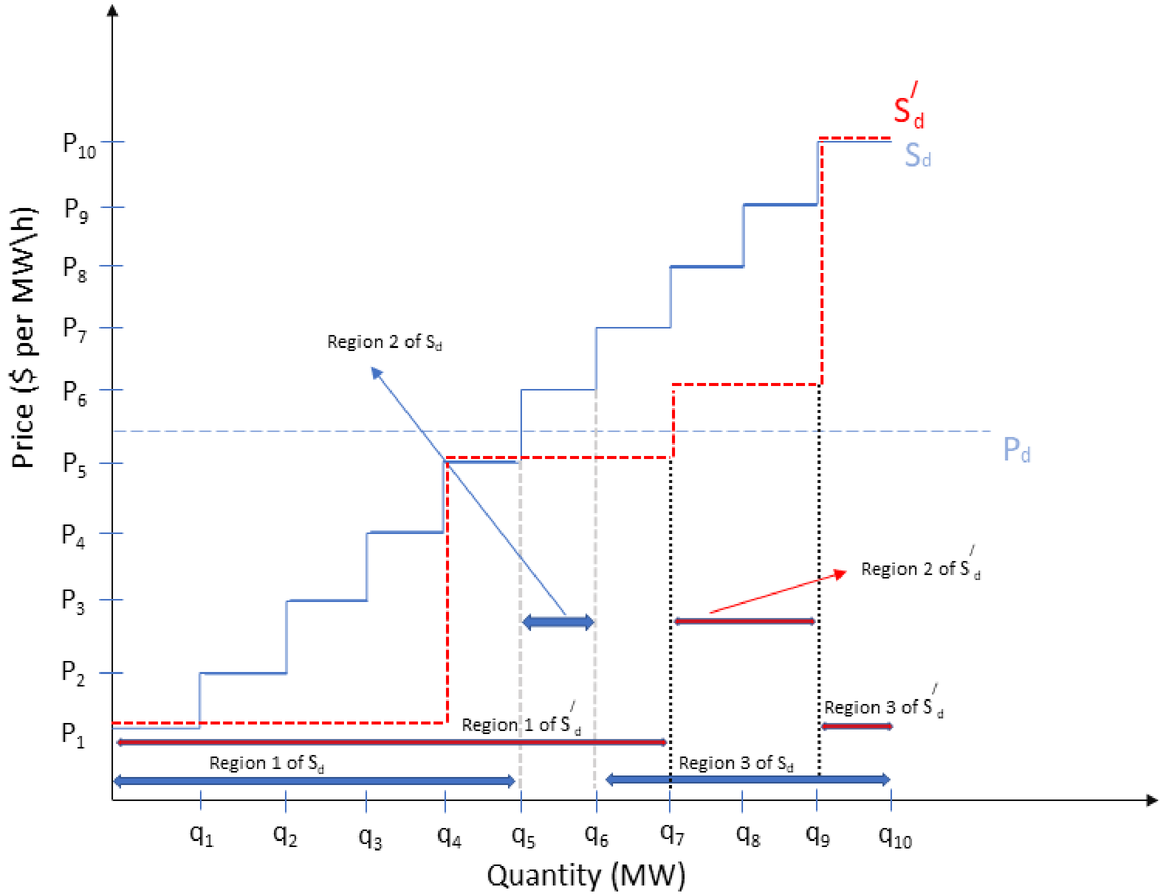

Figure 3.5: This figure illustrates a change in three defined regions on a generator's supply curves S_d and S'_d with market price of P_d.

Table 3.1: Table of Statistics for Each Region

	Region 1	Region 2	Region 3
Change in Volume			
Mean	-9.3036	4.3601	0.7784
Minimum	-1780	-1241	-1350
Maximum	1350	1731	1779
Standard Deviation	67.8597	52.1654	61.4820
The Dependent variable			
Mean	-1907.38	50.004	2229.0384
Minimum	-7882435	-7883387	-15669790.11
Maximum	1761666	7356904	14565770.9
Standard Deviation	69132.98	73507.55	473891.766

Table 3.2: Table of Statistics of Each Region Across the Six Dispatch Intervals

	Dispatch Interval 1	Dispatch Interval 2	Dispatch Interval 3	Dispatch Interval 4	Dispatch Interval 5	Dispatch Interval 6
Change in Volume						
Region 1						
Mean	-12.4659	-11.105	-9.6583	-8.7959	-5.6472	-13.7885
Minimum	-1780	-1000	-1741	-1713	-1731	-1731
Maximum	741	593	1131	1060	1350	1250
Standard Deviation	73.9579	65.4588	67.2517	65.4812	61.1407	82.02
Region 2						
Mean	4.3824	3.2587	3.3742	2.8062	5.2963	5.9268
Minimum	-550	-620	-490	-600	-755	-1241
Maximum	1360	1000	1000	1000	1731	1731
Standard Deviation	55.3775	48.9725	49.1415	46.5284	51.0760	63.0312
Region 3						
Mean	0.4441	0.4009	0.5269	0.5674	0.2051	3.6499
Minimum	-741	-607	-1131	-1167	-1350	-1250
Maximum	1180	660	864	1000	1779	1680
Standard Deviation	62.0379	57.2268	57.5938	57.9319	62.5658	70.0808
The Dependent variable						
Region 1						
Mean	-3460.1224	-1879.2321	-1603.9711	-2566.0337	-1049.1227	-2148.7836
Minimum	-2101028.9	-2446281.6	-1891196.7	-7882434.81	-7199351.1	-4214709
Maximum	1761666	946500	1647856.5	1695356.1	1713170.7	1467075
Standard Deviation	60982.11316	66151.51801	50259.62964	91906.24651	63166.13839	83845.07365
Region 2						
Mean	-154.1341	566.7386	-414.2799	-1355.2344	263.4955	1222.4495
Minimum	-3006957.9	-1333352.4	-2002560.5	-7883386.89	-6832756	-2345376.6
Maximum	7356904.11	7356904.11	2107329.6	791615.4	3904432	2770653.9
Standard Deviation	96070.4895	70175.0349	63516.5452	94163.2299	62786.1623	57805.0390
Region 3						
Mean	-1824.503	1705.3533	169.6286	1101.6825	660.6767	15185.901
Minimum	-11799556.02	-10827823.62	-15669790.11	-10876025.85	-13143614.36	-12088770.92
Maximum	7712425.2	9144174.6	9730258.75	11481534.29	14565770.9	10924745.96
Standard Deviation	483436.8677	465996.5789	467377.0321	441465.9565	457860.5316	550744.6355

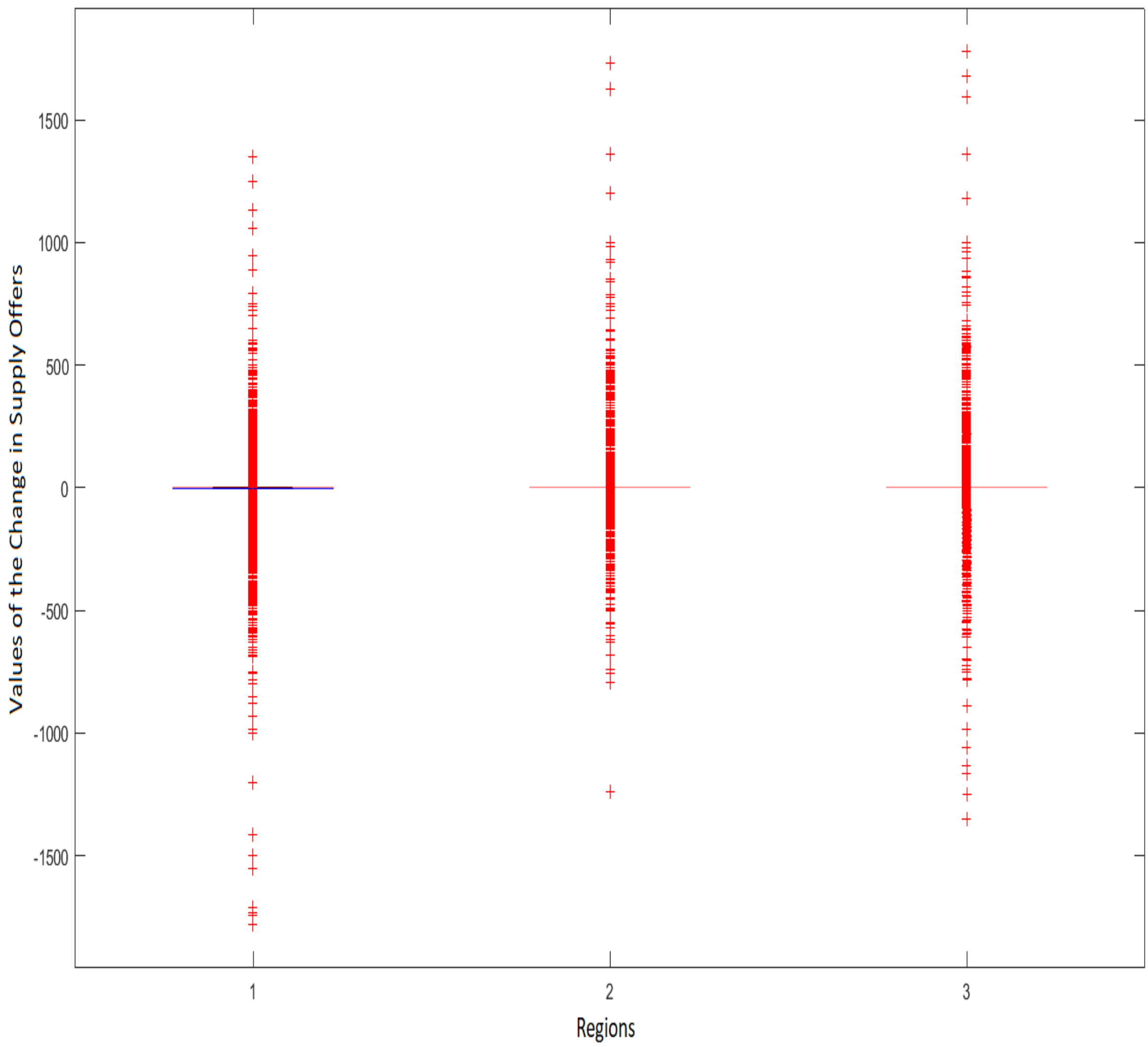

Figure 3.6: Values of the difference between a new rebid offer and the latest offer prior to rebid across the three regions.

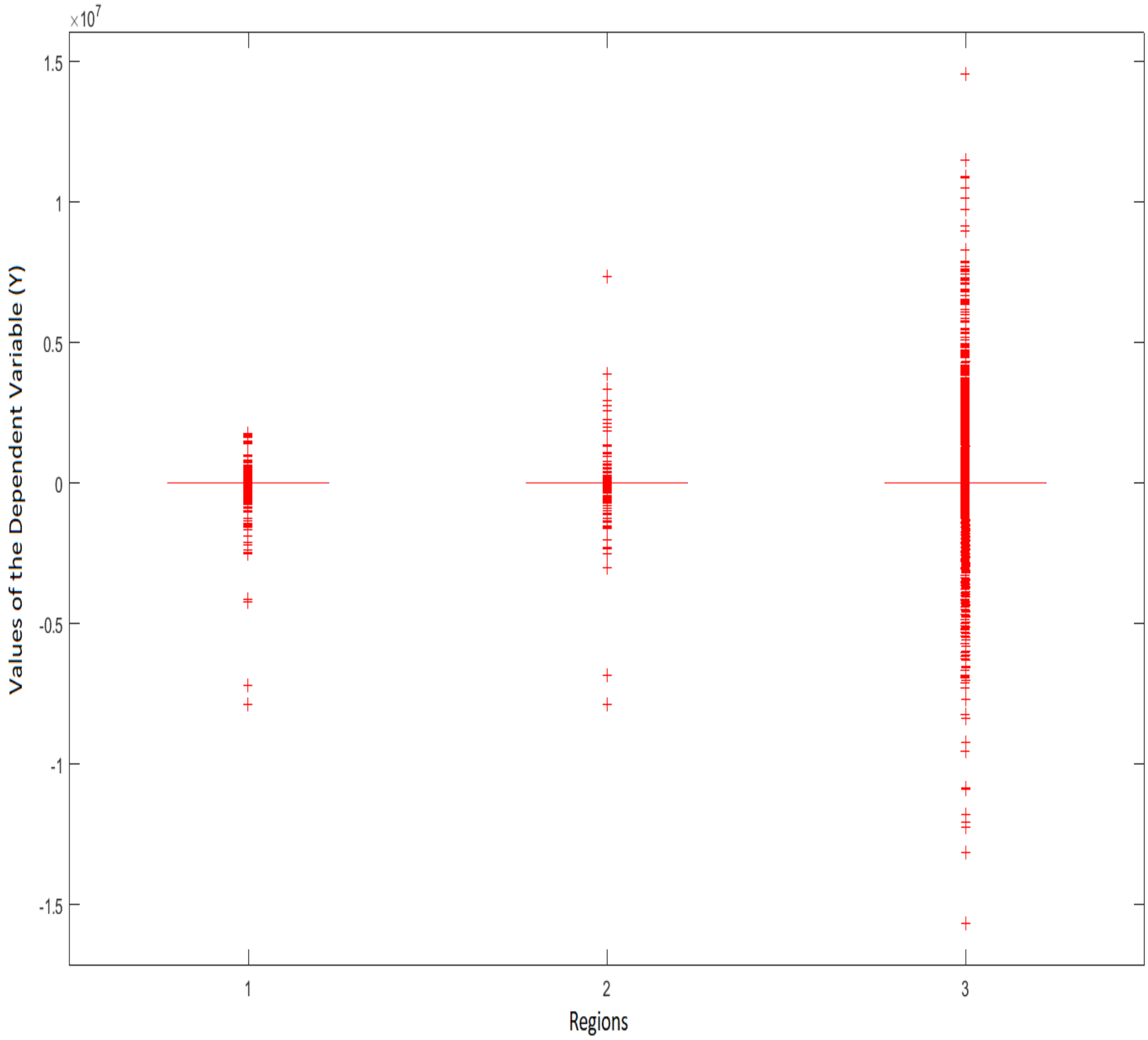

Figure 3.7: Values of the change in left hand side variable of the models across the three regions.

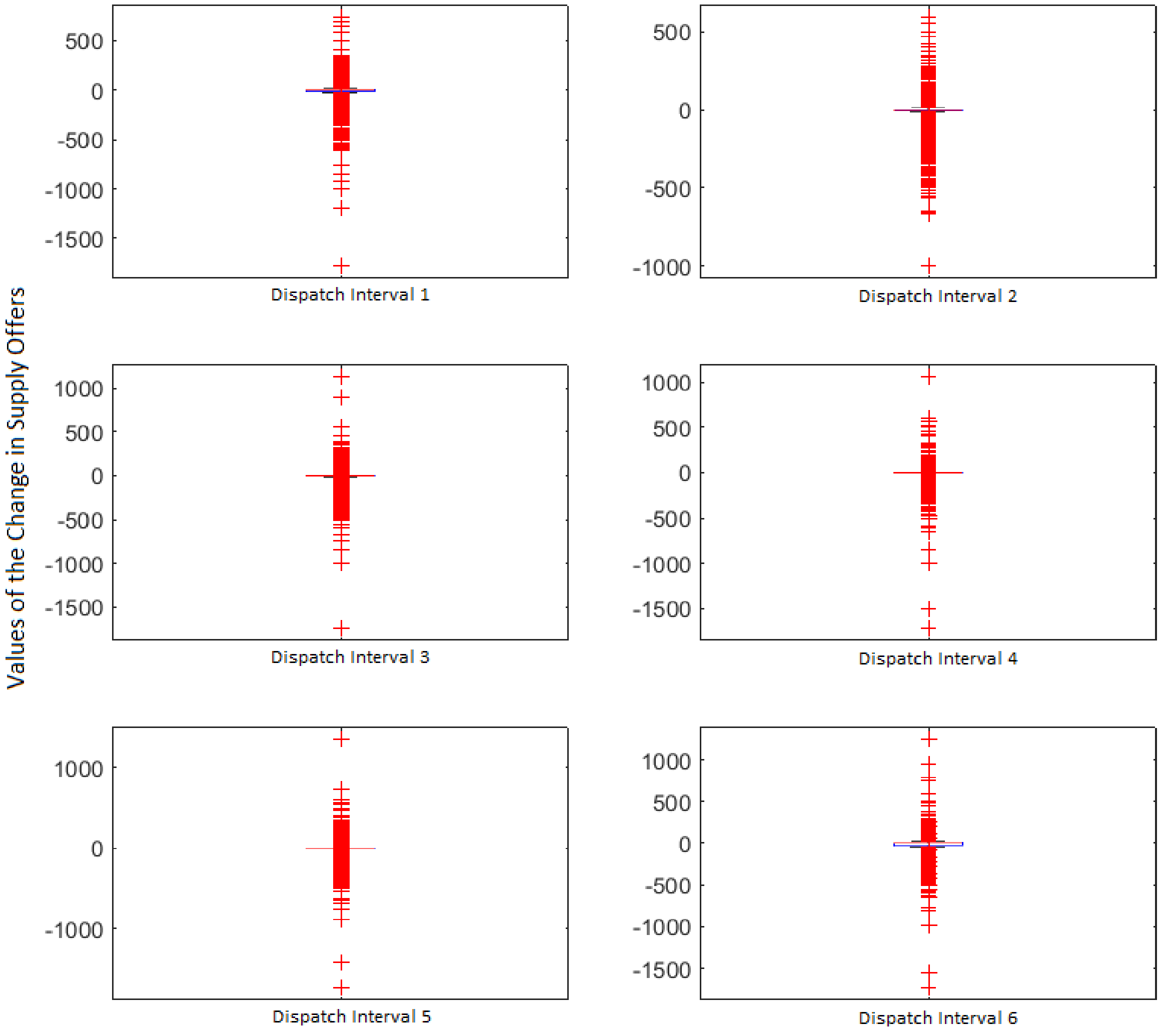

Figure 3.8: Values of the difference between a new rebid offer and the latest offer prior to rebid in region 1 across the six dispatch intervals. The x axis shows different dispatch intervals and the y axis shows the value of the change from one supply offer to a new one.

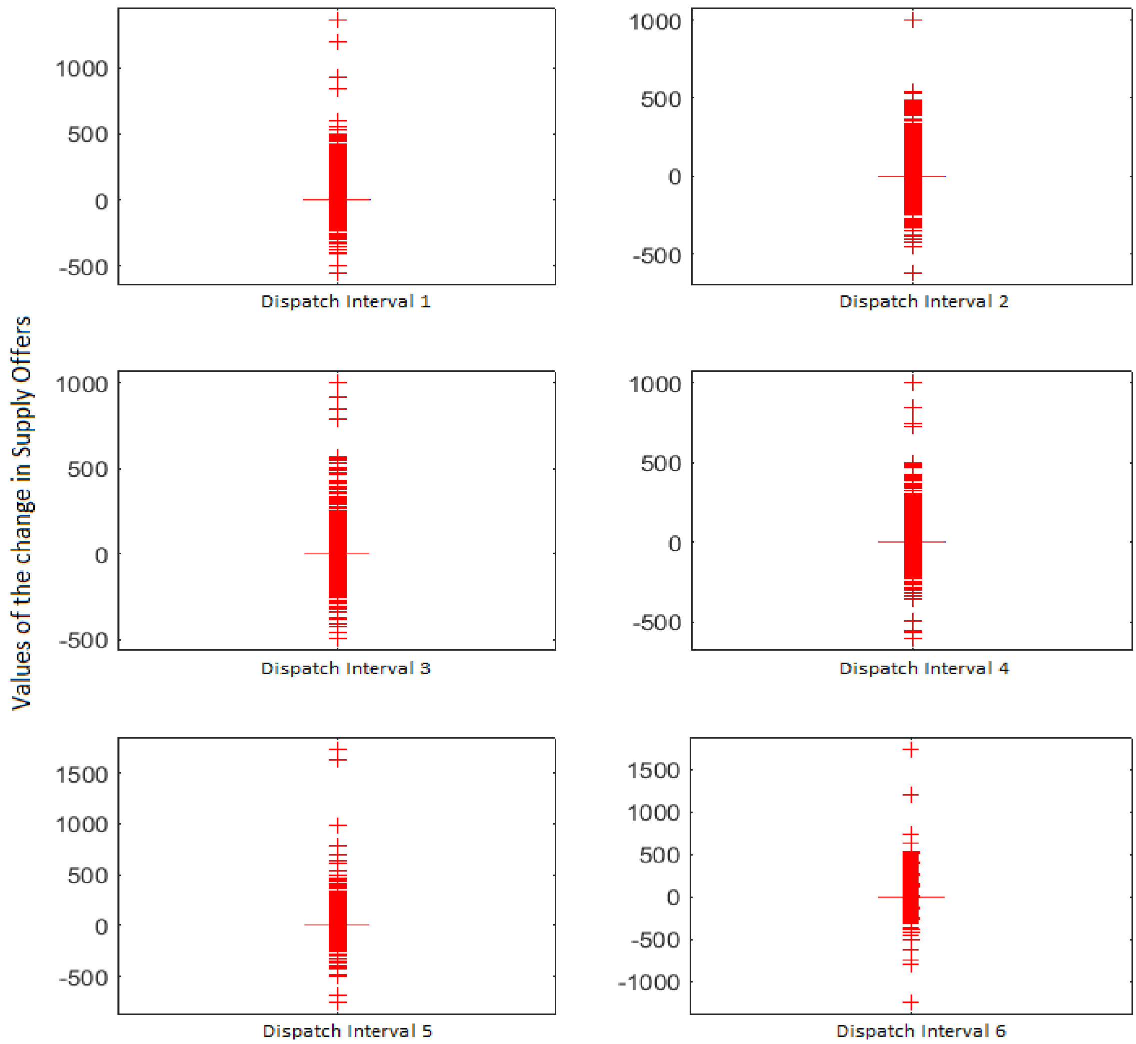

Figure 3.9: Values of the difference between a new rebid offer and the latest offer prior to rebid in region 2 across the six dispatch intervals. The x axis shows different dispatch intervals and the y axis shows the value of the change from one supply offer to a new one.

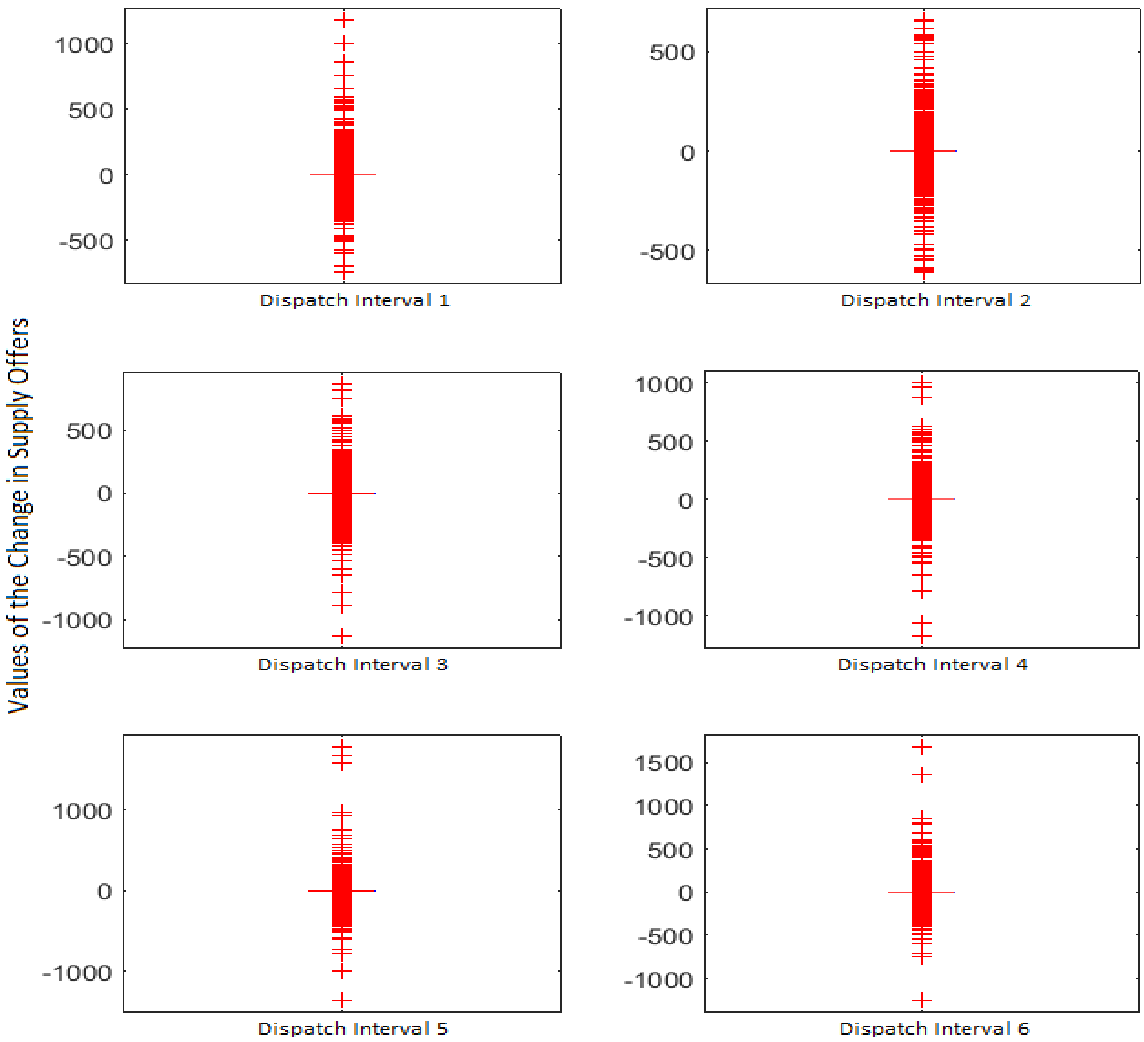

Figure 3.10: Values of the difference between a new rebid offer and the latest offer prior to rebid in region 3 across the six dispatch intervals. The x axis shows different dispatch intervals and the y axis shows the value of the change from one supply offer to a new one.

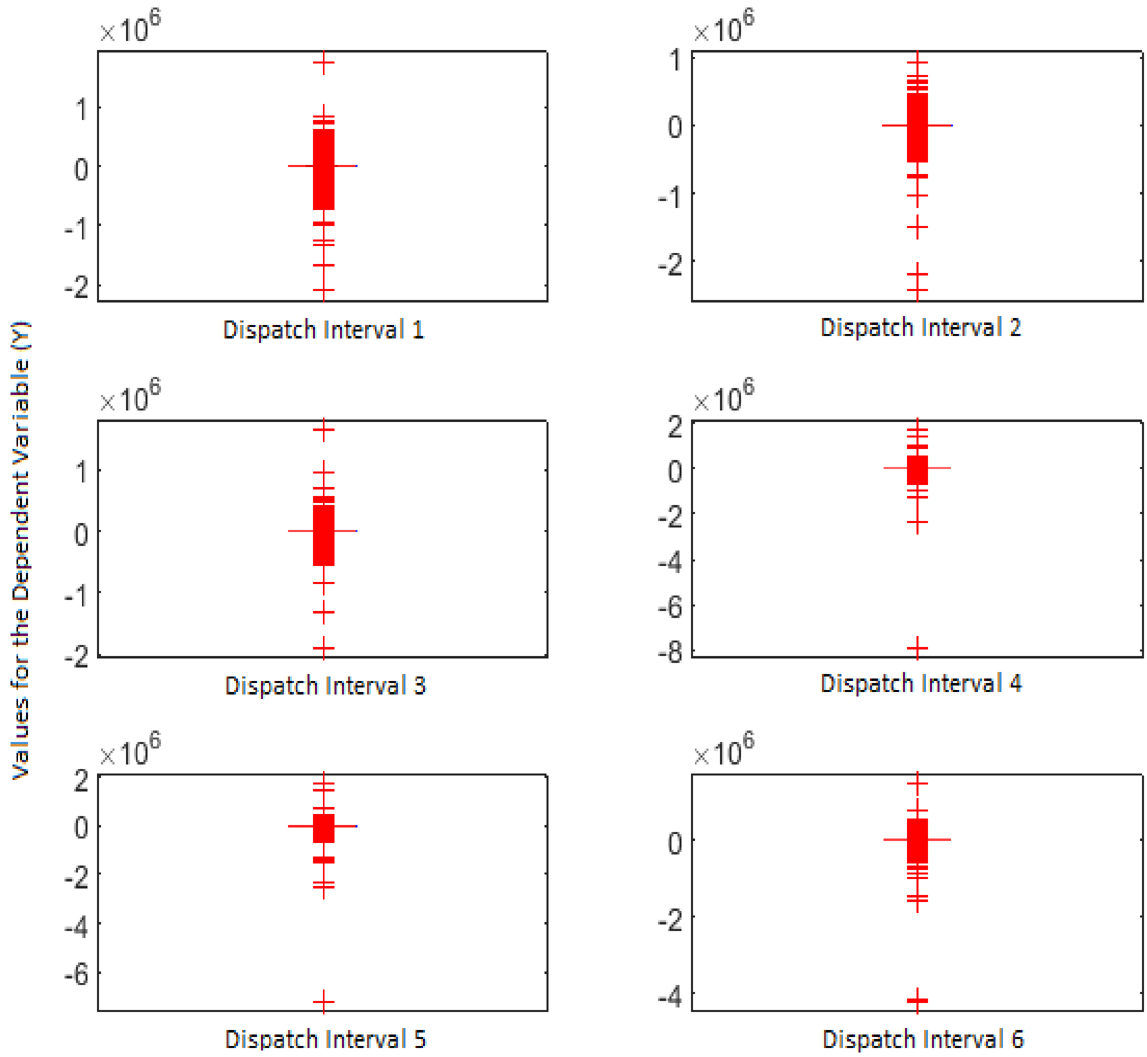

Figure 3.11: Values of the $CH^1_{i,k,t(d)}$ in region 1 across the six dispatch intervals. The x axis shows different dispatch intervals and the y axis shows the value of the $CH^1_{i,k,t(d)}$.

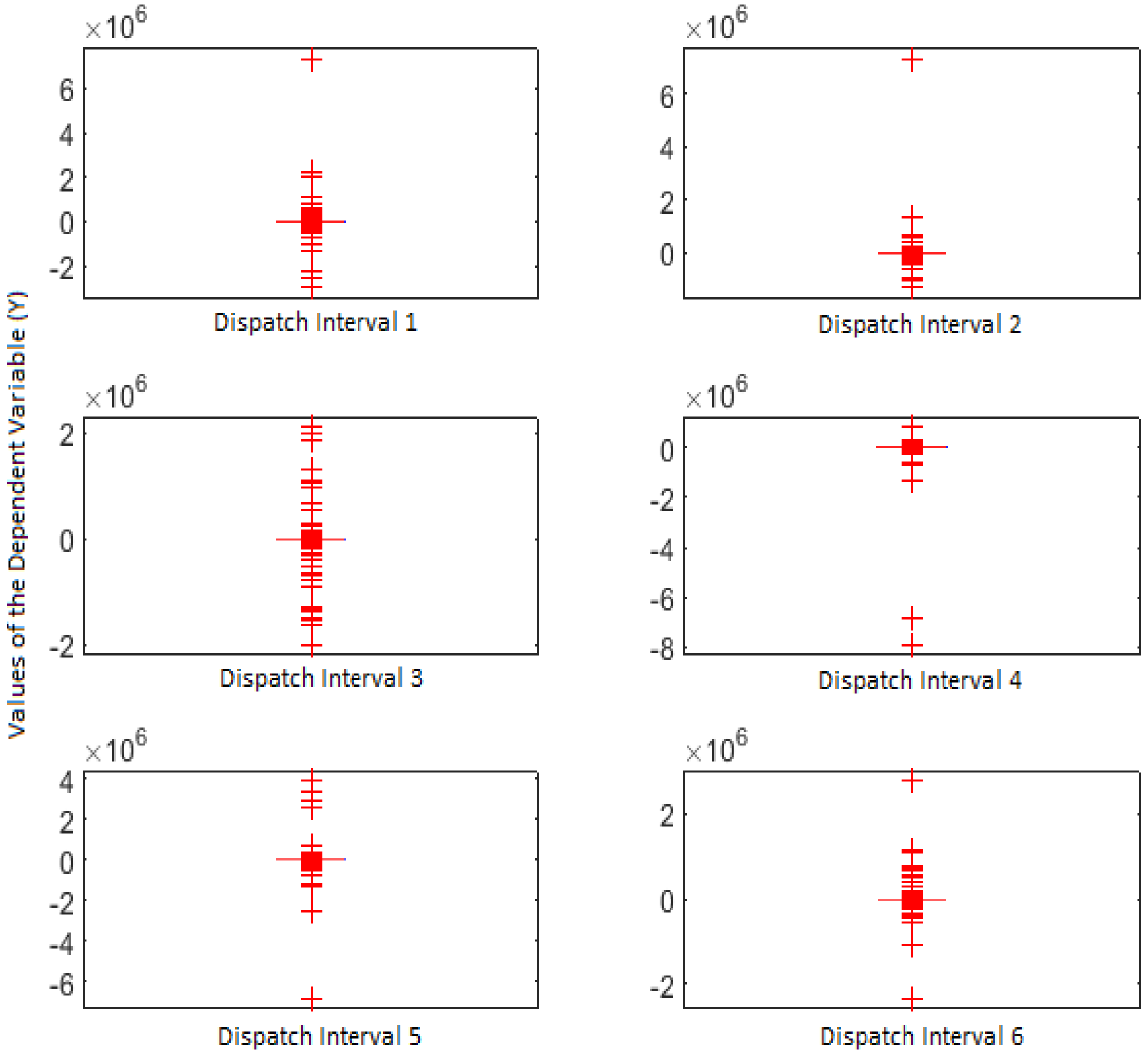

Figure 3.12: Values of the $CH^2_{i,k,t(d)}$ in region 2 across the six dispatch intervals. The x axis shows different dispatch intervals and the y axis shows the value of the $CH^2_{i,k,t(d)}$.

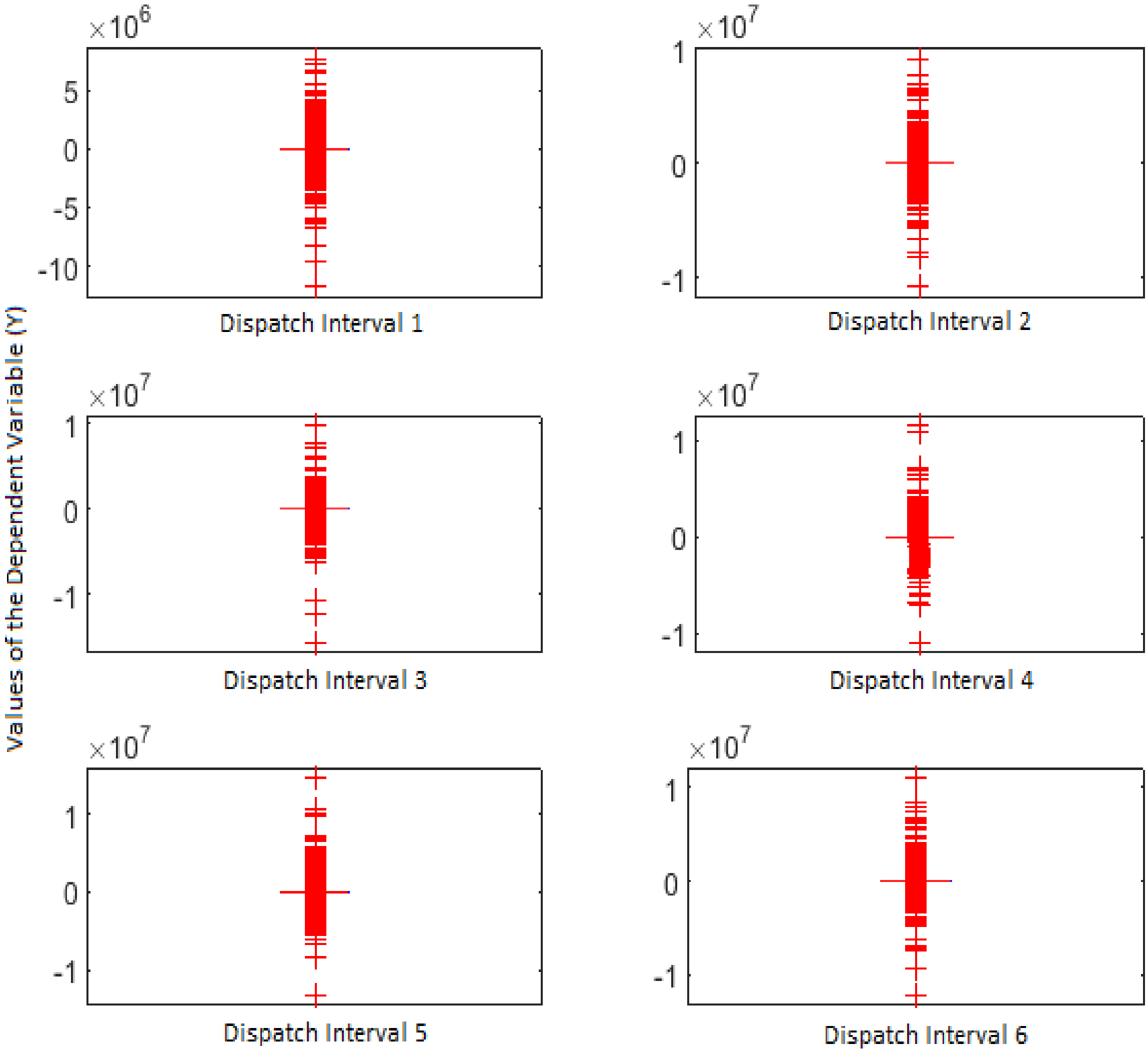

Figure 3.13: Values of the $CH^3_{i,k,t(d)}$ in region 3 across the six dispatch intervals. The x axis shows different dispatch intervals and the y axis shows the value of the $CH^3_{i,k,t(d)}$.

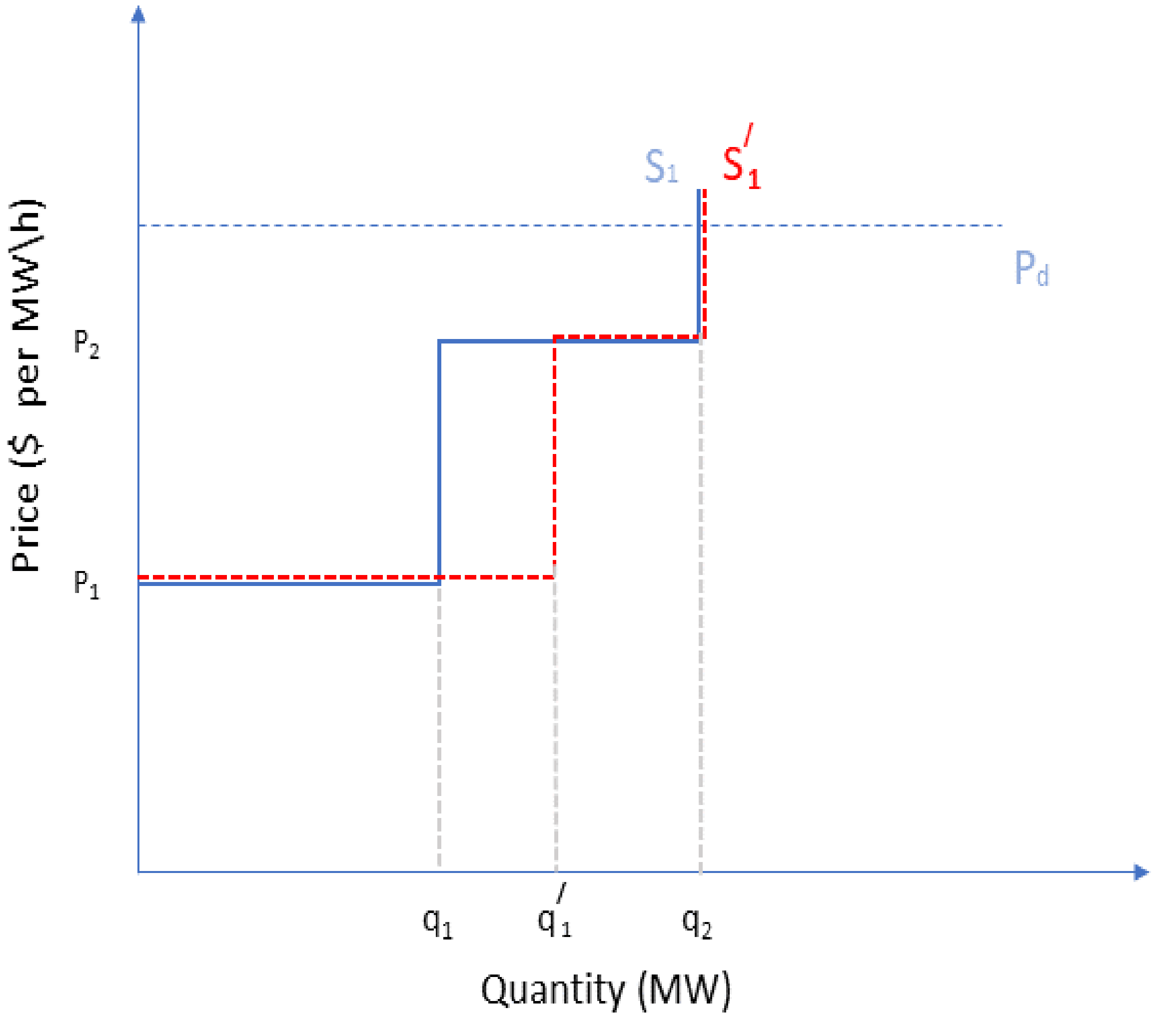

Figure 3.14: Increase in supply from supply S_1 to supply S'_1 due to a rebid in region 1. At equilibrium price (P_d), the dispatched quantity is q_2.

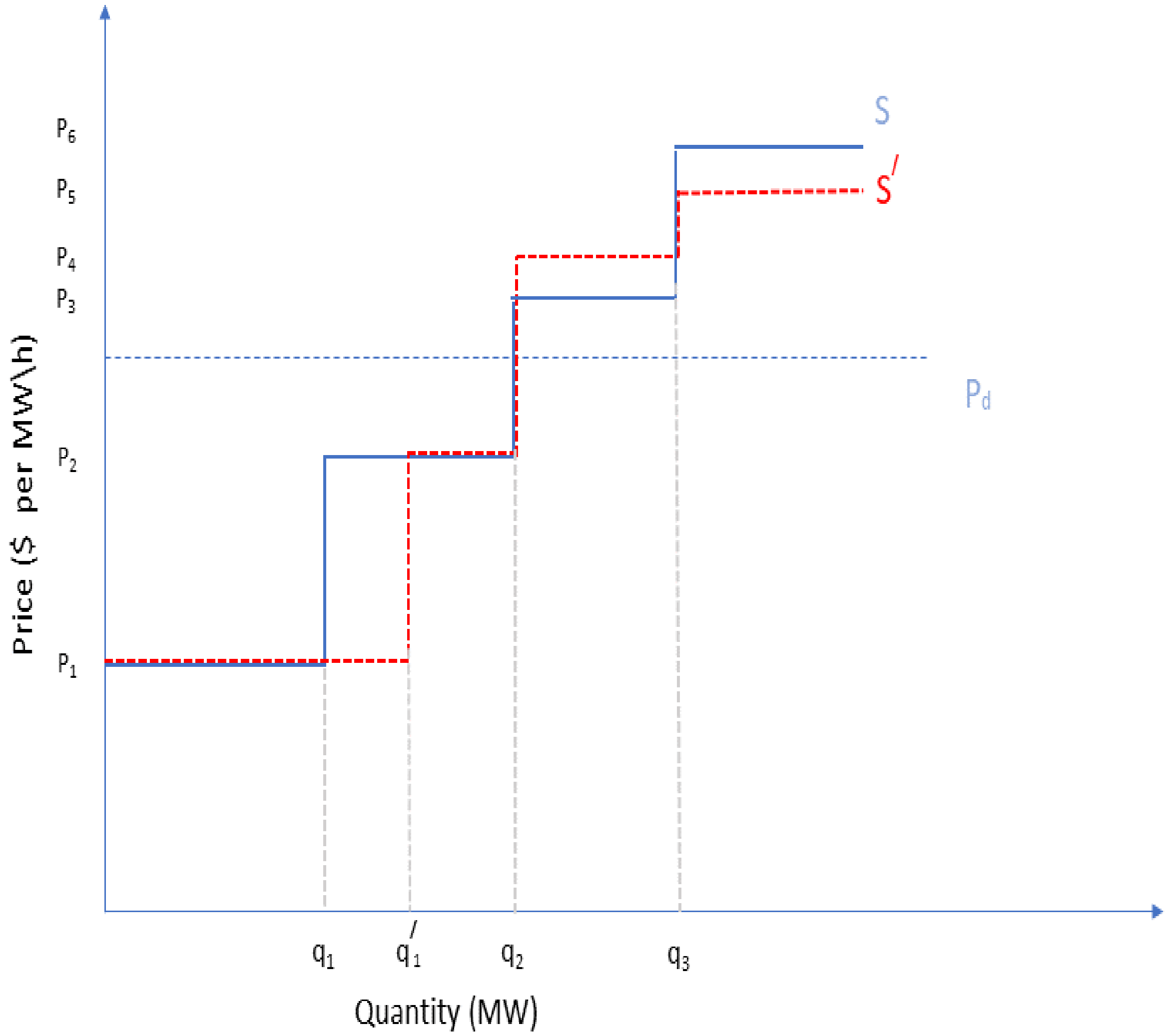

Figure 3.15: Change in supply from supply S to supply S' due to a rebid across all regions. At equilibrium price (P_d), the dispatched quantity is q_2.

Table 3.3: Results from Baseline and Technology Specific Models with DIP

	CHRegion 1	CHRegion 2	CHRegion 3
Baseline Model			
DIP	0.0388***	-0.0684***	0.497***
	(0.00247)	(0.00262)	(0.0169)
CHRegion 1	-	0.0242***	0.212***
	-	(0.000298)	(0.00192)
CHRegion 2	0.0214***	-	-0.0854***
	(0.000263)	-	(0.00180)
CHRegion 3	0.00452***	-0.00206***	-
	(0.0000408)	(0.0000434)	-
Disqcap1	5.833	66.41***	1122.5***
	(6.301)	(6.700)	(43.18)
Total Demand	-0.0480***	0.00744**	-0.0329*
	(0.00234)	(0.00248)	(0.0160)
Availability	-0.0725***	-0.103***	-2.558***
	(0.0132)	(0.0141)	(0.0907)
_cons	327.4***	-42.90	516.6***
	(21.36)	(22.71)	(146.4)
Control Variables	Yes	Yes	Yes
Technology Specific Model			
Generator Type×DIP			
Hydro	0.0427***	-0.140***	1.443***
	(0.00664)	(0.00706)	(0.0455)
Natural Gas	0.0200***	-0.0229***	0.526***
	(0.00479)	(0.00509)	(0.0328)
Black Coal	0.0486***	-0.0746***	0.346***
	(0.00328)	(0.00349)	(0.0225)
Kerosene	0.0361	-0.0108	-0.00792
	(0.0539)	(0.0573)	(0.369)
Wind	0.00659	-0.0280	-0.529***
	(0.0193)	(0.0205)	(0.132)
Solar	0.0118	-0.0484**	-0.926***
	(0.0143)	(0.0152)	(0.0981)
CHRegion 1	-	0.0242***	0.212***
	-	(0.000298)	(0.00192)
CHRegion 2	0.0214***	-	-0.0853***
	(0.000263)	-	(0.00180)
CHRegion 3	0.00452***	-0.00205***	-
	(0.0000408)	(0.0000434)	-
Disqcap1	12.16	66.20***	1296.7***
	(6.761)	(7.189)	(46.33)
Total Demand	-0.0481***	0.00748**	-0.0439**
	(0.00234)	(0.00249)	(0.0160)
Availability	-0.0772***	-0.104***	-2.762***
	(0.0135)	(0.0143)	(0.0922)
_cons	328.6***	-44.47	607.0***
	(21.38)	(22.73)	(146.5)
Control Variables	Yes	Yes	Yes

1. The Standard Errors are reported in the parentheses. 2. * $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$.

Table 3.4: Results from Time Specific Model with DIP

	CHRegion 1	CHRegion 2	CHRegion 3
Time Specific Model			
Generator Type×Dispatch Interval×DIP			
Hydro×1	0.0377**	-0.0158	1.055***
	(0.0115)	(0.0122)	(0.0786)
Hydro×2	0.0499***	-0.0197	1.038***
	(0.0136)	(0.0144)	(0.0930)
Hydro×3	-0.000177	-0.0650***	2.558***
	(0.0153)	(0.0163)	(0.105)
Hydro×4	0.0699***	-0.964***	1.681***
	(0.0162)	(0.0172)	(0.111)
Hydro×5	0.0271	-0.0612***	1.500***
	(0.0165)	(0.0176)	(0.113)
Hydro×6	0.0824***	0.0450**	1.420***
	(0.0162)	(0.0173)	(0.111)
Natural Gas×1	0.0261**	-0.0548***	0.718***
	(0.00890)	(0.00946)	(0.0610)
Natural Gas×2	0.0120	-0.00663	0.161**
	(0.00903)	(0.00960)	(0.0619)
Natural Gas×3	0.0277**	-0.0122	0.491***
	(0.0101)	(0.0107)	(0.0692)
Natural Gas×4	-0.00330	-0.00408	0.588***
	(0.0117)	(0.0124)	(0.0799)
Natural Gas×5	0.0353*	-0.00743	1.045***
	(0.0140)	(0.0149)	(0.0960)
Natural Gas×6	0.0370*	-0.0613***	0.423***
	(0.0172)	(0.0183)	(0.118)
Black Coal×1	0.00471	-0.108***	0.209***
	(0.00602)	(0.00640)	(0.0412)
Black Coal×2	0.00533	-0.00787	0.143**
	(0.00662)	(0.00704)	(0.0454)
Black Coal×3	0.00670	-0.188***	0.333***
	(0.00771)	(0.00820)	(0.0529)
Black Coal×4	0.0587***	-0.0239*	0.976***
	(0.00989)	(0.0105)	(0.0678)
Black Coal×5	0.194***	-0.0339**	0.736***
	(0.0110)	(0.0117)	(0.0754)
Black Coal×6	0.250***	-0.0166	0.229**
	(0.0111)	(0.0119)	(0.0764)
Kerosene×1	0.0276	-0.0106	-0.0121
	(0.127)	(0.135)	(0.827)
Kerosene×2	0.0452	-0.0113	-0.0121
	(0.121)	(0.128)	(0.827)
Kerosene×3	0.0441	-0.0130	0.00998
	(0.152)	(0.162)	(1.042)
Kerosene×4	0.0339	-0.0116	-0.00590
	(0.127)	(0.135)	(0.868)
Kerosene×5	0.0342	-0.0123	-0.00243
	(0.132)	(0.140)	(0.901)
Kerosene×6	0.0357	-0.0107	-0.00698
	(0.111)	(0.118)	(0.760)
Wind×1	0.00665	-0.0303	-0.533**
	(0.0256)	(0.0272)	(0.175)
Wind×2	0.00870	-0.0301	-0.521**
	(0.0255)	(0.0271)	(0.175)
Wind×3	0.00631	-0.0308	-0.549**
	(0.0261)	(0.0277)	(0.179)
Wind×4	0.00698	-0.0301	-0.549**
	(0.0256)	(0.0277)	(0.179)
Wind×5	0.00842	-0.0302	-0.468**
	(0.0256)	(0.0273)	(0.176)
Wind×6	0.00620	-0.0297	-0.521**
	(0.0253)	(0.0269)	(0.173)
Solar×1	0.00942	-0.0524	-0.909***
	(0.0254)	(0.0270)	(0.174)
Solar×2	0.0106	-0.0522	-0.930***
	(0.0254)	(0.0270)	(0.174)
Solar×3	0.0136	-0.0536	-0.942***
	(0.0259)	(0.0275)	(0.177)
Solar×4	0.00964	-0.0524	-0.923***
	(0.0255)	(0.0271)	(0.175)
Solar×5	0.0182	-0.0527	-0.865***
	(0.0256)	(0.0273)	(0.176)
Solar×6	0.0135	-0.0517	-0.899***
	(0.0254)	(0.0270)	(0.174)
CHRegion 1	-	0.0242***	0.212***
	-	(0.000298)	(0.00192)
CHRegion 2	0.0214***	-	-0.0852***
	(0.000263)	-	(0.00180)
CHRegion 3	0.00452***	-0.00205***	-
	(0.0000408)	(0.0000434)	-
Disqcap1	10.82	71.08***	1276.1***
	(6.775)	(7.204)	(46.43)
Total Demand	-0.0485***	0.00755**	-0.0454**
	(0.00234)	(0.00249)	(0.0160)
Availability	-0.0749***	-0.108***	-2.741***
	(0.0135)	(0.0143)	(0.0922)
_cons	335.6***	-41.51	621.3***
	(21.04)	(22.37)	(144.2)
Control Variables	Yes	Yes	Yes

1. The Standard Errors are reported in the parentheses. 2. * $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$.

9.0 Connection between chapter 3 and chapter 4

In chapter 3, we investigated the link between generators' rebidding behaviour and the sequence of market signals in each dispatch equilibria. Our results showed that rebidding satisfies its intended objective of providing generators with the flexibility to respond to market signals. In addition, we found that generators' rebidding behaviour is consistent with efficient market outcomes; specifically productive efficiency. Therefore, in chapter 4, we explore the theoretical models describing the electricity markets. Further, we extend the theoretical frameworks by incorporating generators' rebidding behaviour to provide insights into its potential to influence price volatility.

Chapter 4

Strategic Bidding of Electric Power Generating Companies: Evidence from the Australian NEM

1.0 Introduction

The operations of de-regulated markets for electricity have generated a number of interesting questions: Do electricity generators have a lot of market power? Do they exercise their market power by collusion, or by non-cooperative strategic bidding? To what extent do observed price hikes reflect strategic bidding behaviour of generators? Do late rebids exacerbate price hikes?

A number of papers have addressed some of these issues both at the theoretical and the empirical level. One must bear in mind, however, that different electricity markets operate in different institutional settings. This makes it difficult to make comparisons across markets and to offer a 'general' theory. Nevertheless, prominent researchers on electricity pricing in deregulated markets in the past two decade seem to have reached the consensus that oligopoly theories, together with analyses of the data suggest that electricity generators have been able to exploit their market power.

However, the existing literature ignores the real-world feature that in many national or regional markets, generators can revise their bids and make strategic use of the opportunity to submit their rebids. For example, in Alberta and Ontario, Canada, generators are allowed to make rebids up to two hours before dispatch.[1] In Texas, bids may be changed up until one hour

[1]See Appendix E of Australian Energy Regulator [2015] for an international comparison of rules relating to rebids.

prior to the operation hour.[2] In the Australian National Electricity Market (NEM), more than 300 generators can rebid up to five minutes before dispatch.[3] In this paper, we make specific references to the institutional setting of the NEM. Electricity-generating firms in the NEM are invited to submit, on date $t-1$, their bids (i.e., their supply schedules) for each of the 48 half-hour intervals for date t. Using these bids, the Market Operator (MO) provides forecast of the equilibrium prices, called 'pre-dispatch prices' (for each of the 48 half-hourly trading intervals, and under several different demand scenarios). Generators are allowed to revise their bids (supply schedules) up to 5 minutes before dispatch. Some interesting questions arise. Even if costs conditions do not change, will generators find it optimal to rebid in the light of the pre-dispatch prices? Does the opportunity to rebid give generators an incentive to make misleading bids? [4]

This paper extends the existing literature to particularly consider the issue of strategic rebidding of electricity supply with evidence from the Australian NEM. We first lay out the existing frameworks to address market power in electricity generation, and then extend this theoretical framework to match the unique structure of the Australian market. This issue has remained critical as market power from generators has been blamed for everything from volatile wholesale prices, increased retail power prices and concerns over energy security (See Hesamzadeh et al. [2020], Australian Energy Market Commission [2018b]). Although the entirety of the situation is complex, the role of rebidding is poorly understood: This paper aims to fill that gap and provide the first empirical evidence we are aware of that the rebidding structure is strategically important in price determination.

Electricity generating companies have been modelled as Cournot rivals, Borenstein et al. [2002], as one-shot oligopolists which adopt static Nash behavior and do not try to collude (as in Klemperer and Meyer [1989]) and subject to capacity constraints (Green and Newbery [1992]). Using the Cournot model, Borenstein et al. found that 59 percent of the quadrupling in Californian wholesale electricity expenditure between 1998 and 2002 can be attributed to

[2]Hortaçsu and Puller [2008, p .89] mentioned this feature of the Texan market, but they did not analyse how firms might strategically make use of the rebidding opportunity.

[3]The Australian set-up is similar to the bidding and re-bidding process in Ontario, Canada, and in New Zealand. In Ontario, a pre-dispatch schedule is published at 11:00 a.m. the day before dispatch. Suppliers are allowed to make re-bids up to 2 hours before dispatch.

[4]Chester [2006] mentioned a number of papers that argue that rebidding exposes the NEM to electricity-generating companies with significant market power. Handika et al. [2014] studied price spikes in the Australian electricity market, but they did not address the issue of strategic behaviour.

market power.[5] Sweeting [2007] also found significant market power in the England and Wales wholesale electricity market, known as the Pool, for the period 1995-2000. Complementing this analysis with an alternative approach, using data on generators' bids and cost, he found that the two largest generators, National Power (NP) and PowerGen (PG), significantly deviated from the static non-cooperative behavior, and concluded that 'their behaviour was consistent with tacit collusion' [Sweeting, 2007, p. 654].[6]

The literature on supply function equilibrium (SFEs) begins with the work of Klemperer and Meyer [1989] for an oligopoly facing a stochastic demand curve. Klemperer and Meyer [1989] study Nash equilibrium when firms' strategies are 'supply schedules' and find that there are many possible equilibria. The non-uniqueness of outcomes makes predictions problematic. Adapting SFE theory to the electricity spot market Green and Newbery [1992] find that there is a multiplicity of SFEs, but they argue that amongst these equilibria, the equilibrium that yields the maximum profit for each firm is the focal point SFE.[7] Using this focal point as a prediction of firms' bids, Green and Newbery [1992] calibrate the model and calculate the potential deadweight loss for consumers. They find that the results are 'extremely disturbing' in terms of welfare loss [Green and Newbery, 1992, p. 946].

The Klemperer and Meyer [1989] framework assumes that each firm knows everything about their rivals. However, Hortaçsu and Puller [2008] point out that in the Texas spot market, bidders are bound by (previously signed) bilateral agreements with their customers in the wholesale market, agreements that are unobserved by rivals. Such obligations surely affect their bids in the real-time spot market. These bilateral contracts, which account for a substantial fraction of the power supply, are private information. Thus, Hortaçsu and Puller [2008] argue that one should look for a Bayesian-Nash equilibrium characterization of the bidding game, using the formulation proposed by Wilson [1979], Wilson [2002]. Using data on bidders' marginal cost functions, they calculate an ex-post optimal supply schedule, which is an equilibrium bid function under the assumption that bid functions are additively separable in the private information possessed by bidders. Comparing the ex-post optimal bid schedules with the

[5] The Californian market is quite complex because there are two primary institutions, the Power Exchange (PX), and the Independent System Operator (ISO), which determine respectively the date-ahead market and the real-time electricity spot market. Firms could change their date-ahead positions by transacting in the spot market.

[6] Sweeting [2007, p. 656] notes that 'a complication is that generators signed unobserved quantities of financial contracts which hedged their exposure to pool prices'.

[7] Green and Newbery [1992] add a capacity constraint for each firm, and reinterpreting the random variable in the K&M model as time (since electricity demand varies with time).

actual bids, they find that large Texan firms actual bids are close to the profit-maximising bids, but small Texan firms use excessively steep schedules, indicating deviation from profit maximisation.[8]

The purpose of this paper is to explore the strategic implications of the opportunity to make rebids, and analyze the rebidding data of the NEM to understand the significance of rebidding, given the institutional set up of the NEM.

Section 2.0 outlines the working of the Australian wholesale electricity market. In Section 3.0, we review some major existing theoretical models on bidding in the electricity market, with emphasis on supply function equilibria under non-cooperation. In section 4.0, we turn to collusive behavior, and develop a model of collusive bidding, assuming firms offer linear affine supply schedules. We explore incentives for collusive firms to misreport their costs to the Market Operator, and also how they might signal their costs to each other.

In section 5, we turn to the non-collusive case with a dominant generator and a fringe of competitive generators, and show how the dominant firm may gain by taking advantage of rebids. We provide a simple example showing that a dominant generator can gain substantially in a 30-minute trading interval by manipulating its bid, and taking advantage of the opportunity to submit rebids. It can, for example, withhold capacity for the first bid, creating price hike in the first 5-minute dispatch interval, and then bring back its capacity in the following rebid which applies to the five remaining 5-minute dispatch intervals.

Finally, in Section 6, we present data from the NEM drawn from the tens of millions of rebids tendered to the Australian Energy Market Operator (AEMO) over the period 2015 to 2017, which is suggestive of the supply-curve behavior of Australian electricity generators. We show that the observed behavior is consistent with our theoretical framework, with rebidding occurring in a strategically profitable manner across alternative generation methods and geographic locations. This is the contribution of the paper to the literature over others. To our knowledge, this is the first empirical evidence of strategic rebidding extracted from a population of electricity generation data anywhere in the world.[9]

[8] Hortaçsu and Puller [2008, p. 106] argue that perhaps it is too costly for small firms to calculate the optimal mark-up.

[9] This paper does not review approaches to forecasting electricity prices. (See Weron [2014] for a comprehensive review of the literature on forecasting electricity prices.)

2.0 The Australian National Electricity Market

The Australian National Electricity Market (NEM), which began operation in December 1998, is a gross pool market for electricity, involving generators, electricity retailers, and large consumers, called 'scheduled loads'. Generators are required to make bids (i.e., to offer a supply schedule) and scheduled loads can also make demand-side bids. Both can make rebids. As pointed out in a document issued by Australian Energy Market Operator [2017a, p. 2], the NEM is an *'energy-only market'* in the sense that generators are only compensated for the energy they supply to the central pool.[10] The NEM encompasses five Australian states: Queensland, New South Wales, Victoria, South Australia and Tasmania. The state markets are connected by interstate 'imports' and 'exports' via a limited number of interconnectors. Spot prices differ across states, because of inter-regional transmission-capacity constraints which limit the scope for arbitrage. For example, Queensland is connected to other parts of the NEM only via two transmission lines to New South Wales, and only a single undersea interconnector links the Victorian and the Tasmanian electricity grids. This section gives an overview of the bidding rules, the determination of the spot price, and a brief account of the possibility of price manipulation.[11]

2.1 Rules on bidding and rebidding

Generators submit supply bids (and rebids) to the Australian Energy Market Operator (AEMO), who determines for each 5-minute interval a price, called the 'dispatch price' (to be distinguished from 'pre-dispatch prices' which are issued before the final rebids come in). Dispatch is the process whereby the Market Operator determines which generators should operate to meet the five-minute expected demand for electricity. The dispatch price is the bid of the most expensive generator that needs to be called on in order to equate supply to demand.[12] Dispatch prices are not prices at which accounts are settled. Instead, generators are paid the 'settlement price' (also called 'spot price'), which is calculated for each half-hourly interval. It is an average of the six five-minute dispatch prices during that interval. For example, if the dispatch prices for

[10] This is in contrast to an energy-and-capacity market (e.g. Western Australia, which does not belong to the NEM) where suppliers also receive payments for their presence.

[11] Note that we focus on the spot market. There are hedge contracts between generators and retailers, but an examination of this issue is beyond the scope of this paper.

[12] Dispatch prices (every five minutes) are available on the website of AEMO, which also provides half-hourly spot prices.

9:05am, 9:10am, 9:15am etc., are denoted by D_1, D_2, D_3 etc., the settlement price for 9:30am is $P = (D_1 + D_2 + D_4 + D_5 + D_6)/6$. This means that if a generator can manufacture a hike in the dispatch price of the last five-minute interval it will be able to increase the revenue for its previous dispatch outcomes within the 30 minute trading interval.[13] In September 2017, the AEMC [Australian Energy Market Commission, 2017a] issued a draft policy to change this rule to 5-minute settlement, with technical details in Australian Energy Market Operator [2017a]. Under the five minute settlement rule generators are still able to rebid until 5 minute prior to dispatch. As yet there are many technical difficulties to be resolved, and the earliest implementation of the change is likely to be 2021. In March 2019, the Energy Council requested the Energy Security Board to make recommendations about the current Australian Market design recognising the challenges faced so far. Energy Security Board [2020] illustrates the proposals put forth for post market design 2025.

In the prevailing NEM structure (since 1998) each electricity trading day t commences at 4:00am on that day and ends at 4:00am on the following day. For each electricity trading day, bids are due before 12:30pm on the day prior (but rebids are allowed up to five minutes before each 5-minute dispatch interval). The trading day is divided into 48 periods (each lasting 30 minutes). By 12:30pm on date $t-1$, electricity generating companies must submit their bids for all 48 half-hourly periods of the trading date t. Each bid must specify up to 10 price bands and 10 corresponding quantities (*capacity increments)* that the firm commits to supply. The nominated prices can be anywhere between the floor price of $-\$1000$ per MWh and the market price ceiling (MPC) imposed by regulation.[14] Below is a stylised example of a bid. Negative prices reflect the costs which generators face in shutting off production at short notice.[15]

$$\begin{bmatrix} band & 1 & 2 & 3 & 4 & 5 & 6 & 7 & 8 & 9 & 10 \\ price\text{ (\$per MWh)} & -999 & -45 & 2 & 8 & 20 & 25 & 35 & 60 & 220 & 400 \\ qty & 0 & 50 & 0 & 0 & 60 & 40 & 0 & 0 & 0 & 0 \end{bmatrix}$$

[13] Demand-side responses by electricity retailers and large customers include switching on fast-response generators. The incentives to invest in short-duration demand response systems are limited because of the time-weighted 30 minute pricing.

[14] MPCs vary, but can be as high as $\$14,500$ per MWh.

[15] Coal-fired generators have very long start-up and shut-down times. It is better for them to stay online and face low or negative market prices for a number of trading intervals. Some coal-fired plants need a start-up time of three days or more [Australian Energy Market Commission, 2015b, p. 16].

This schedule shows the cumulative amounts the generator is willing to dispatch; up to 150 units if the dispatch price is $\$25$ per MWh (or higher).

After receiving the bids, the Market Operator uses an algorithm to determine how forecast demand (for each of the 48 half-hourly periods) can be satisfied in the least costly way. This algorithm generates an estimated price, called "pre-dispatch price," for each of the 48 periods in date t, which we denote by $P^e_{t,\tau}$ for $\tau = 1, 2, .., 48$. and a set of pre-dispatch bounds $P^{+\Delta}_{t,\tau}$ and $P^{-\Delta}_{t,\tau}$ for higher or lower demand outcomes (± 200 MWh). Four-hour ahead and twelve-hour ahead forecasts of demand, spot price, and available capacity are made available to market participants.

Generators use the information in pre-dispatch prices, and other up-dated information (weather, repairs), to submit rebids. In submitting rebids, they are not allowed to change the 10 prices that they initially specified in their bids; their rebids are restricted to changes in the quantities to be made available at each price band.[16] While offers apply to a whole 30-minute trading interval, rebids can be made during the trading interval and these affect the remaining 5-minute dispatch interval(s). Generators can shift the quantities offered between the different price bands in response to changing market conditions. All rebids must be accompanied by an explanation.[17] Generators can submit rebids up to five minutes before the actual dispatch. A rebid that shifts capacity from a lower price band to a higher price band has the effect of shifting the supply curve upwards, thus raising the price.[18]

Chester [2006, p. 364] gives the following illustrative example of re-bidding by a 600 MW generating unit. The original bid is

[16] A similar restriction holds in the England and Wales market [Wolak, 2000]: generators cannot change the price bid for each increment for the entire day, but they can vary the amount they are willing to supply from that capacity increment on a half-hourly basis.

[17] The rules have been tightened [Australian Energy Market Commission, 2015b, p. xi]. Effective from 1 July 2016, if a rebid is made during a 30-minute trading interval or less than 15 minutes before the commencement of the trading interval, the generator must make a contemporaneous record setting out the material conditions and circumstances' giving rise to the rebid. The record must be made available to the Australian Energy Regulator (AER) upon request. In the Federal Court case 'AER v. Stanwell', Justice Dowsett dismissed AER's application. He found that a trader's subjective expectations could be part of the material conditions and circumstances upon which a rebid could be based. [Australian Energy Market Commission, 2015b, p. 111].

[18] The frequency at which capacity was shifted to price bands above \$300 per MWh was higher in Queensland than in other regions of the NEM; see Australian Energy Market Commission [2015b, p. 83]. Note that any price above \$100 per MWh is considered abnormally high, see Hurn et al. [2016, p. 712].

$$\begin{bmatrix} band & 1 & 2 & 3 & 4 & 5 \\ price & -20 & 25 & 55 & 90 & 120 \\ qty & 100 & 200 & 100 & 75 & 125 \end{bmatrix}$$

and the rebid is

$$\begin{bmatrix} band & 1 & 2 & 3 & 4 & 5 \\ price & -20 & 25 & 55 & 90 & 120 \\ qty & 0 & 0 & 50 & 0 & 125 \end{bmatrix}$$

The third row entries have changed but the entries in the first and second rows must remain unchanged. Diagrammatically, this means that the generating unit is allowed to re-draw its step-like supply schedule, keeping the height of each step unchanged, but the width of each step can shrink to zero, or can widen.

Chester [2006, p. 365] reports that "at least 40% of re-bids are made within one and a half hours of dispatch and at least 50% of re-bids have moved the volume of generation capacity from the original bid price-band to another price-band". For the year ending March 2001, in about 50% of cases, technical plant reasons were cited. Other reasons cited include 'market conditions', 'portfolio adjustment' and 'financial optimisation' Chester [2006, p. 366].[19] Whenever spot price exceeds $\$5000/MWh$, the Australian Energy Regulator (AER) is required to publish a report covering the circumstances relating to the price hike, including an assessment as to whether rebidding contributed to the event.[20] There have been concerns that generators may deliberately delay their rebids to withhold information. More recent reports, prepared by ROAM Consulting and Oakley Greenwood for AEMC, suggest that since 2007, there has been an increasing trend for late rebids and some evidence of more rebids toward the end of the 30-minute trading intervals, particularly in Queensland and to some extent in South Australia

[19]Clements et al. [2016] examined strategic bidding and rebidding in the Queensland region of the NEM. In particular, they presented aggregative evidence suggestive of rebidding after the extreme price spike on 28 August 2013.

[20]For instance, on 1 June 2009, the spot market price in Tasmania reached $\$9159/MWh$ for the 30-minute trading interval ending at 10:00am, while the forecast spot price, announced 4 hours earlier, was $\$59/MWh$. This price hike was due to Hydro Tasmanian shifting about 1000 MW of capacity from prices below $\$300/MWh$ to prices above $\$9000/MWh$. The rebid was made about 90 minutes before dispatch. The reason given for the rebid was 'portfolio optimization.'

[Australian Energy Market Commission, 2015b, p. v & 82-87] , and even more recently (see Australian Energy Market Operator [2017a]).

2.2 Price manipulation in Queensland

A study by ROAM Consulting [Australian Energy Market Commission, 2015b, p. 80-87] found that the tendency to make late rebids (i.e. close to dispatch time) is greater in Queensland than in any other region of the NEM. Price spikes above $300 per MWh in Queensland during 2014 were found to be more frequent in the last 5-minute dispatch interval of the 30-minute trading interval (though this was not the case in 2007-2011). There was a positive correlation between price spikes and the number of late rebids moving capacity to high price bands. The likelihood of late rebids that move capacity into high price bands increases the incidence of binding transmission constraints and decreases in the spare capacity for interconnectors to import energy.

Empirically, Hurn et al. [2016] credits extreme price events in Queensland to "strategic behavior on the part of the generators" (p. 711). While their paper does not offer a formal theory of strategic bidding, it provides some explanation of how prices can be manipulated. In Queensland, the base-load generators are mainly coal-fired. They have low marginal costs but high cost of starting up and cooling down. In contrast, higher marginal cost gas-fired turbines are used mainly in peak periods. Hurn et al. [2016, p. 710] suggest that a base-load generator can influence the price by reducing to zero the width of lower steps of its supply schedule, i.e. *by withholding capacity at the lowest price bands*.[21] This has the effect of shifting its supply schedule upward, forcing the market operator to raise the dispatch price. Once this is done, the base-load generator can *rebid all its available capacity in the next and subsequent 5-minute intervals* at the floor price to ensure it will be instructed to dispatch more, knowing that it gets paid not the floor price but the half-hour settlement price (which has been jacked up by the increase in the five-minute dispatch prices). Since the generator was not shut down, it does not take much time to ramp up to meet the instruction to increase the dispatch, giving these generators a strategic advantage. Even in the case where the manufactured price hike lasts only five minutes, the base-load generating units still gain because the price hike is translated into a

[21] This can be done either by declaring that the capacity is no longer available, or by shifting that capacity to a very high price band, say more than $300 per MWh, as ROAM Consulting suggested [Australian Energy Market Commission, 2015b, p. 83].

higher spot price for the half-hour interval. When price hikes are of sufficiently short duration, peaking capacity operators, such as gas-fired turbines, cannot participate because the increase in the settlement price is not sufficient to cover their high marginal costs.

The empirical strategy employed by Hurn et al. [2016] relies on the intuition that isolated half-hour high price events are more likely to be due to strategic behavior than those which continue for an hour or more (that is two or more consecutive settlement periods). They use this classification to determine whether there has been a change in the probability of observing abnormal price episodes after deregulation in July 2007. After July 2007, 44% of price episodes lasted for half an hour, while before July 2007, the corresponding number was 39%. The authors find that there is a significant increase in the probability of observing isolated half-hourly abnormal price episodes after the transition to the competitive market.

3.0 The theory of supply function equilibrium: non-collusive bidding

The pioneering theory of supply function equilibria by Klemperer and Meyer [1989] considers the case where oligopolistic firms commit to supply to the market specific quantities at specific market prices.[22] Each of these firms announces a supply schedule, taking as given the supply schedules offered by other firms. Since there are just a few firms, these supply schedules are strategically chosen and do not correspond to marginal cost curves. Equilibrium price is where the market demand curve intersects the horizontal sum of the strategically chosen supply schedules. Klemperer and Meyer [1989] postulate that firms must announce their supply schedules before knowing the realization of a random variable that affects the demand curve. Several subsequent authors find that this theory is most suited to the study of deregulated markets for electricity [Bolle, 1992, Green and Newbery, 1992, Newbery, 1998] .

3.1 Supply function equilibrium with smooth supply schedules

Each of the n firms (electricity generators) must submit a bid, which takes the form of a schedule $q_i(p)$. For each spot price p, the firm is committed to supply a corresponding quantity, denoted by $q_i(p)$. For simplicity, for the moment we assume that p is a real number that can take any

[22] In other words, they are neither Cournot players, which commit to quantities, nor Bertrand players, which commit to prices.

value in $[0, \infty)$, and assume that $q_i(p)$ is a smooth function.[23] The quantity demanded depends on two variables, p and a, where p is the spot price, and a is a random term (or, in a different interpretation of the model, a refers to time of the day, suitably re-ordered, so that $D_a > 0$).[24]

$$Q^d = D(p, a)$$

Assume that $D_p < 0$ and $D_a > 0$. A simple specification is $D(a, p) = a - bp$, i.e., the 'random term' a influences only the vertical intercept of the demand curve. We shall refer to any realization a as 'the state of the world', or simply 'state' a.

The firms must submit their supply schedules, and commit to them, before the 'random variable' a is realized. The market operator (MO) then determines, for each a, the equilibrium price $p(a)$ that clears the market, i.e., $p(a)$ is the implicit function determined by the market-clearing condition

$$D(p, a) = \sum_{i=1}^{n} q_i(p)$$

For a given realization of a, firms are required to supply the quantities $q_i(p(a))$, and are paid the amount $p(a) \times q_i(p(a))$. Firm i's realized profit in 'state' a is then

$$\pi_i(a) = p(a) \times q_i(p(a)) - C_i\left[q_i(p(a))\right]$$

where $C_i(.)$ is the total cost function.

Suppose firm i knows the supply functions of all other firms $j \neq i$. Then it knows that at any a, it faces the 'residual demand function'[25]

$$R_i(p, a) \equiv D(p, a) - S_{-i}(p)$$

where $S_{-i}(p)$ is the aggregate quantity supplied by all other firms at the price p:

$$S_{-i}(p) \equiv \sum_{j \neq i} q_j(p).$$

[23] An alternative formulation would be to require that $q(p)$ be a step-like supply function [von der Fehr and Harbord, 1993]. These authors show that with this formulation, in general there is no equilibrium in pure strategies. Repeated auctions are difficult to solve when there is no pure strategy equilibrium.

[24] See Green and Newbery [1992], and Newbery [1998].

[25] Firm i's "residual demand curve" shows, at any price p, the difference between industry demand and the sum of quantities that all other firms are willing to supply at that price.

Then, in 'state' a, firm i's profit given that it must produce to satisfy the residual demand is

$$\Pi_i(p,a) \equiv p \times R_i(p,a) - C_i\left[R_i(p,a)\right]$$

As Klemperer and Meyer pointed out, firm i's optimal (i.e. best response) supply function can be solved by positing that it is as if the firm would choose a price p (corresponding to each a) to maximize the profit $\Pi_i(p,a)$ for each realization of a. The first order condition (FOC) is[26]

$$R_i(p,a) + p\frac{\partial R_i(p,a)}{\partial p} - C_i'\left[R_i(p,a)\right]\frac{\partial R_i(p,a)}{\partial p} = 0 \tag{4.1}$$

This equation determines the profit-maximizing price for the firm at a given a.

If $\Pi_i(p,a)$ is strictly concave in p, then the FOC determines a unique price $p_i^*(a) \equiv f(a)$ that firm i would want to achieve for each value of a. At that price, the quantity supplied by i is

$$q_i^*(a) \equiv R_i(p_i^*(a), a)$$

If the function $p_i^*(a) \equiv f(a)$ is invertible,[27] then we can solve for firm i's optimal (i.e. best reply) supply function $q_i = S_i(p)$:

$$q_i = S_i(p) = q_i^*(f^{-1}(p))$$

EXAMPLE 1: Assume that firm i's cost function is

$$C_i(q_i) = \frac{1}{2}\gamma_i q_i^2$$

Let the demand function be

$$D(p,a) = a - bp$$

and assume that the (aggregate) supply function of other firms is

$$S_{-i}(p) = \beta p, \text{ where } \beta \geq 0.$$

[26]The second order condition is satisfied if R_i is concave in p and $C_i(q_i)$ is a convex function.

[27]Given that $D_a < 0$ and $C'' \geq 0$, a sufficient condition for the invertibility of $f(.)$ is that $D_{pa} = 0$ identically, as this ensures that Π_{pa} does not change sign.

Then the residual demand function facing firm i is

$$R_i(p,a) = a - (b+\beta)p$$

The FOC (4.1) gives

$$[a-(b+\beta)p] - [p-\gamma_i\,(a-(b+\beta)p)]\,(b+\beta) = 0$$

This yields

$$p_i^*(a) = \frac{a\,[1+\gamma_i(b+\beta)]}{(b+\beta)\,[2+\gamma_i(b+\beta)]}$$

and

$$q_i^*(a) = a - (b+\beta)p_i^*(a) \tag{4.2}$$

The function $p_i^*(a)$, also denoted by $f(a)$, can be inverted to yield $a = f^{-1}(p)$

$$a = \frac{(b+\beta)\,[2+\gamma_i(b+\beta)]}{1+\gamma_i(b+\beta)}p_i^* \tag{4.3}$$

Then we obtain firm i's optimal supply function by substituting for a in equation (4.2)

$$\begin{aligned} q_i &= \frac{(b+\beta)\,[2+\gamma_i(b+\beta)]}{1+\gamma_i(b+\beta)}p - (b+\beta)p \\ &= \frac{(b+\beta)p}{1+\gamma_i(b+\beta)} \equiv \omega p \end{aligned}$$

In this example, using the assumption that the random variable a can take on any value in the half line $[0,\infty)$, we have shown that, *given* that other firms' supply functions (i.e., "strategies") are linear in p, firm i's "best response" is a linear supply function. If there are only two firms, and $\gamma_1 = \gamma_2$, we must have $\beta = \omega$, and thus obtain a unique symmetric SFE in linear strategies:

$$q_i = \frac{1}{2}\left[-b + \sqrt{b^2 + \frac{4b}{\gamma}}\right] p,\, i = 1,2 \tag{4.4}$$

As Klemperer and Meyer [1989] point out, this result does not rule out the possibilities that there exists SFEs in which firms bid non-linear supply functions for some range of p (see Klemperer and Meyer [1989, p. 1260]).

3.2 SFE when the random variable is bounded above

Green and Newbery [1992] do not think that it is realistic to allow the variable a to take on arbitrarily large values. Assuming an upper bound on a (i.e. $a \leq a_{\max}$) and constant marginal cost, Newbery [1998, p. 732] considers the two-firm case, and shows that SFE can be found by solving the following differential equation[28]

$$\frac{dq}{dp} = \frac{q}{p - C'(q)} + D_p. \tag{4.5}$$

Assuming $D_p = -b < 0$, and $C'(q) = 0$, Newbery (1998, p. 732) shows that in equilibrium the supply function of each firm takes the form

$$q(p) = Ap - bp \ln p, \text{ for } 0 < p < \frac{a_{\max}}{3b}$$

where A is a constant of integration. It follows that there is a continuum of SFEs, each corresponding to a value of the constant of integration A.[29]

Newbery [1998] generalises the supply function equilibrium to the case of n identical firms with constant marginal cost, under linear demand with bounded vertical intercept. He shows that the more firms there are, the lower is the highest aggregate supply schedule.[30]

3.3 The step-like supply functions

In the real world, each generating company typically operates several generating units (or 'sets') and offers step-supply schedules. In an innovative paper, von der Fehr and Harbord [1993] argue that if sets are of significant size, the results obtained under the assumption of smooth supply functions may not hold. Their alternative model suggests that 'high-cost sets may be bid in at lower offer prices than lower-cost sets' [von der Fehr and Harbord, 1993, p. 532].

Consider the model of von der Fehr and Harbord [1993], which belongs to the literature on multiple-unit auctions.[31] There are N generating companies, indexed by $g = 1, 2, ..., N$.

[28] See Appendix A for the derivation of this equation.

[29] Newbery shows that any value of A in the interval $(0, b(1 - \ln(3b/a_{\max})))$ defines a pair of equilibrium supply schedule for some range of p.

[30] Another complication is capacity constraint. Klemperer and Mayer assume that firms do not face any capacity constraints. Green and Newbery [1992] add realism to the SFE approach by imposing capacity constraints.

[31] McAfee and McMillan [1987, p. 724-5] provide a brief review of this literature. Kastl [2011] offers a more general treatment of the theory of discrete bids and discusses the empirical inference in this context. With discrete

Assume that generating company g has m_g generating units (or 'sets'). Let k_{gs} denote the capacity of the s-th set of generating company g. Define the capacity of the generating company g by

$$k_g = \sum_{s=1}^{m_g} k_{gs}.$$

The capacity of the industry is

$$K = \sum_{g=1}^{N} k_g.$$

With perfectly inelastic demand, regardless of the price, the quantity demanded is d, which is a random variable with distribution $G(d)$. Each generator g submits bid prices p_{gs} for $s = 1, 2, ..., m_g$. Assume that the bids are not allowed to be higher than an exogenous ceiling price $\overline{p}$. The market operator ranks the bids to obtain a market supply curve. Upon the realization of the random variable d, the spot price is determined by equating demand and supply. All operating units that actually supply a positive output receive the same spot price.[32] If two sets have the same bid prices, they are equally likely to be called into operation.

von der Fehr and Harbord assume that each generating company g has constant marginal cost c_g for all its sets. By convention, the companies are labelled so that $c_{g+1} \geq c_g$. They point out that typically firms will play mixed strategies in equilibrium, because a firm that offers a fixed bid is likely to be undercut by other firms: with a block supply, the gain from undercutting can be substantial. (This is in sharp contrast to the case where each set is 'infinitesimally small'). The authors derive the mixed strategy equilibrium for the case of duopoly with $0 = c_1 \leq c_2 \equiv c$, and for the case of n generating companies with identical costs.[33] They find that the expected spot price is decreasing in N. They conclude that "for a given number of generating sets in the industry, system marginal price will be a decreasing number of owners" (p. 537).

The theoretical model of von der Fehr and Harbord [1993] is not meant to be tested directly. The authors find that actual bidding behavior is consistent with the predictions of the model.

bids, a firm's residual demand function is a step function. However, Hortaçsu and Puller [2008] found that in practice the calculations of ex-post profitability under the "unsmoothed" residual demand do not differ much from the ex-post profitability under the the "smoothed" residual demand.

[32] As pointed out by the authors, in the UK, in most half-hour periods (called Table A periods), each dispatched generating set (genset) is paid, in addition to the system marginal price, a capacity element which reflects the probability of loss of load (a power shortage).

[33] See their working paper version, 1992.

3.4 Discriminatory versus uniform auctions

Wholesale electricity markets are typically organized as uniform, first-price auctions. In March 2001 the UK introduced a discriminatory (pay-as-bid) auction format. Fabra et al. [2006, p. 23] report, 'The British regulatory authority (Ofgem) believed that uniform auctions are more subject to strategic manipulation by large traders than are discriminatory auctions.'. However, they also point out (p. 24) that there are no consensus on the superiority of one form of auction over the other.[34]

The two forms of auctions are compared in Fabra et al. [2006], but their main analysis is based on the special assumption that the firms observe the realization of demand before they submit their bids. This assumption may be suitable for markets in which the price offers (bids) are short-lived, such as in Spain; it is not suitable for markets in which price offers must remain fixed for the whole day, e.g., in Australia.[35]

4.0 Collusive bidding by heterogeneous oligopolists

Let us turn to a simple model of collusive behavior. Assume that the industry consists of only two firms, denoted by $i = 1, 2$.[36] Their outputs are denoted by q_1 and q_2 respectively. Their combined output is $Q = q_1 + q_2$. Assume that the firm i's true marginal cost is $\alpha_i + \beta_i q_i$, and its total cost is

$$C_i(q_i) = \alpha_i q_i + \frac{\beta_i}{2}(q_i)^2$$

The demand function is

$$D(P) = \begin{cases} \frac{A-P}{B} & \text{if } P \leq A \\ 0 & \text{if } P > A \end{cases}.$$

from which we obtain the demand curve $P(Q)$

$$P(Q) = A - BQ$$

[34] Second-price auctions, first practised by the poet Goethe in 1797 (see Moldovanu and Tietzel [1998]) are common on the internet (e.g. ebay auctions), but have not been used for electricity bidding.

[35] Fabra et al. [2006] also briefly consider the case of 'long-lived bids' in which suppliers face time-varying demand, see p. 34-36. They are only able to characterize the mixed-strategy equilibria in the case each supplier has only one generating set, i.e., the step function has only one step.

[36] Extension to the case of n heterogeneous firms is straightforward.

We assume that the price intercept of the demand curve is higher than the intercept of the marginal cost schedules, A$>$ max (α_1,α_2).

4.1 The benchmark scenario

Assume for the moment that the firms have perfect knowledge of the parameters A and B. If they collude, they will behave such that the industry marginal revenue equals the industry's marginal cost. For any desired industry output level Q, the collusive firms will choose q_1 and q_2 to minimize the production cost subject to q_1 + q_2 = Q. The cost-minimizing outputs for the collusive firms are

$$q_1 = \left(\frac{\beta_2}{\beta_1+\beta_2}\right)Q + \left(\frac{\alpha_2-\alpha_1}{\beta_1+\beta_2}\right) \equiv q_1(Q) \tag{4.6}$$

$$q_2 = \left(\frac{\beta_1}{\beta_1+\beta_2}\right)Q + \left(\frac{\alpha_1-\alpha_2}{\beta_1+\beta_2}\right) \equiv q_2(Q) \tag{4.7}$$

For the collusive firms, their total cost of supplying the aggregate quantity is

$$C(Q) = \alpha_1 q_1(Q) + \frac{\beta_1}{2}\left(q_1(Q)\right)^2 + \alpha_2 q_2(Q) + \frac{\beta_2}{2}\left(q_2(Q)\right)^2$$

The collusive firms equate marginal revenue with marginal cost to determine their collusive aggregate output:

$$Q^* = \frac{A\left(\beta_1+\beta_2\right) - \left(\alpha_1\beta_2+\alpha_2\beta_1\right)}{\beta_1\beta_2 + 2B\left(\beta_1+\beta_2\right)}$$

The optimal outputs of the firms are are[37]

$$q_1 = \left(\frac{\beta_2}{\beta_1+\beta_2}\right)\left(\frac{A\left(\beta_1+\beta_2\right) - \left(\alpha_1\beta_2+\alpha_2\beta_1\right)}{\beta_1\beta_2 + 2B\left(\beta_1+\beta_2\right)}\right) + \left(\frac{\alpha_2-\alpha_1}{\beta_1+\beta_2}\right)$$

and

$$q_2 = \left(\frac{\beta_1}{\beta_1+\beta_2}\right)\left(\frac{A\left(\beta_1+\beta_2\right) - \left(\alpha_1\beta_2+\alpha_2\beta_1\right)}{\beta_1\beta_2 + 2B\left(\beta_1+\beta_2\right)}\right) + \left(\frac{\alpha_1-\alpha_2}{\beta_1+\beta_2}\right)$$

[37]We assume that $\max\{\alpha_1-\alpha_2, \alpha_2-\alpha_1\}$ is small enough so that firms' outputs are positive.

4.2 Achieving the collusive output by coordinating supply functions

Now, suppose that the collusive firms cannot directly set quantities nor price. Instead, they have to 'bid' by providing to the Market Operator their 'supply functions', and the latter will determine the price that equates demand to supply. What are the 'supply functions' that will achieve the highest profit for the collusive firms? Can the firms achieve the monopoly profit by bidding linear 'supply functions'?

Suppose the firms are required to offer supply functions (bids)

$$q_i(P) = \frac{P - a_i}{b_i}$$

The Market Operator then construct the aggregate supply schedule S(P)=q_1(P)+q_2(P), and for a given realization of A, the firms' supply schedules must be such that a_1, a_2, b_1 and b_2 satisfy the conditions

$$b_1 = \beta_1 + \frac{(\beta_1 + \beta_2)B}{\beta_2} \tag{4.8}$$

$$b_2 = \beta_2 + \frac{(\beta_1 + \beta_2)B}{\beta_1} \tag{4.9}$$

$$a_1 = \alpha_1 + \frac{(\alpha_1 - \alpha_2)B}{\beta_2} \tag{4.10}$$

and

$$a_2 = \alpha_2 + \frac{(\alpha_2 - \alpha_1)B}{\beta_1} \tag{4.11}$$

Suppose $\beta_1 = \beta_2 = \beta$. Then their supply functions will have the slope

$$b_1 = b_2 = \beta + 2B \tag{4.12}$$

, i.e., both firms exaggerate the slope of their marginal cost curves. And the intercepts will be

$$a_1 = \alpha_1 + (\alpha_1 - \alpha_2)B/\beta \tag{4.13}$$

$$a_2 = \alpha_2 + (\alpha_2 - \alpha_1)B/\beta \tag{4.14}$$

Thus the firm with the higher (lower) intercept will overstate (understate) its intercept.

4.3 Sending signals

In the preceding section, we assume that firms know each other's true marginal costs. Suppose that each firm i knows its α_i and β_i at the beginning of each day, but they cannot directly communicate this information to the other firm (perhaps because of anti-trust legislation). Then one way of communication would be to submit to the Market Operator (MO) the numbers (a_i, b_i). The MO will then construct the supply curve, and announce the forecasted dispatch price, P_F^{MO}.(Here the subscript F indicates that the price is only a forecast price, subject to change that the MO will make upon receiving the revised bids.) Upon receiving P_F^{MO}, firms will make some inferences about the true costs of the other firm. (We have to model a 'reasonable' inference process.) They will then revise their bids, with the objective of maximizing their joint profits.

Consider the simplest case, where the only random cost parameter is α_1 (i.e., the other three parameters, α_2, β_1 and β_2 are not random). Suppose that α_1 is either high ($= \alpha_1^H$) or low ($= \alpha_1^L$). Suppose the firms are allowed to revise their bids only once. When firms make their first round bids, firm 1 already knows the realization of α_1, but firm 2 does not. The latter supposes that $\alpha_1 = \alpha_1^H$ with probability p and $\alpha_1 = \alpha_1^L$ with probability $1 - p$. Let us suppose that the firm 2 makes its first round bid as if $\alpha_1 = p\alpha_1^H + (1 - p)\alpha_1^L \equiv E\alpha_1$. Then its 'reported' first-round linear supply function is

$$q_2(P) = \frac{P - a_2}{b_2}$$

where,

$$a_2 = \alpha_2 + (\alpha_2 - E\alpha_1)B/\beta$$

and

$$b_2 = \beta + 2B$$

Suppose that firm 1's first-round bid uses a similar rule, i.e., $b_1 = \beta + 2B$ and, when the realized value of α_1 is α_1^H, its reported value is

$$a_1^H = \alpha_1^H + (\alpha_1^H - \alpha_2)B/\beta$$

while if $\alpha_1 = \alpha_1^L$, then

$$a_1^L = \alpha_1^H + (\alpha_1^H - \alpha_2)B/\beta$$

If a_1^H is reported, the market operator will calculate that the aggregate supply schedule, and announce the dispatch price that would equate demand and supply. Now comes round 2. At this stage, firm 2, having observed A, and having received the price sent by the market operator, can infer (with certainty) whether firm 1 has reported a_1^L or a_1^H. The round 2 bids will reflect the firms' perfect knowledge about α_1.

5.0 Strategic bid and rebid by a dominant firm

In the preceding section, the focus was on collusive behavior of suppliers that are similar. In this section, we turn to the case of an industry consisting of a large dominant firm and a competitive fringe. We show that the dominant firm has a strong incentive to submit bids and rebids strategically in order to generate a price hike over a short time interval (say, half an hour).

The dominant firm can manufacture a price hike either toward the end of the 30 minute trading interval, or at the beginning of it. Let us illustrate both possibilities.

5.1 Manufacturing a price hike in the first dispatch interval

Let us consider a simple numerical example. Assume that the electricity demand for each 5-minute interval is $\overline{Q} = 120$ MW. There is a base-load generator (which we call the 'dominant firm') that has two generating sets with capacity of 42MW and 38MW respectively. Their corresponding marginal costs are $\$0$ per MWh and $\$5$ per MWh. There are a large number of higher cost generators (which we call the 'fringe') that can collectively supply the first 40 units of capacity at the marginal cost of $\$15$per MWh, a further 10 units of capacity with a marginal cost of $\$30$ per MWh, and another 10 units of capacity at a marginal cost of $\$80$ per MWh. Any further increase in output from the fringe would involve a marginal cost of $\$1000$ per MWh.[38] Assume that if the dispatch price in the first five-minute interval turns out to be abnormally high, there will be some lagged demand-side response in the forms of self-supply:

[38]Bid prices in the vicinity of $\$14,000$ per MWh have been observed in Queensland, though the average price is below $\$80$ per MWh. See e.g. Hurn et al. [2016]

for example, retailers can switch on their own gas-fired turbines. We assume that such demand-side responses will take time: 10 units of capacity can be brought online for second five-minute interval, and 20 units at the third and each subsequent five-minute interval.

Suppose for the moment that all firms are truthful and bid according to their marginal costs. Then a truthful bid of the dominant generator will be, for example,

$$\begin{bmatrix} band & 1 & 2 & 3 & 4 & 5 & 6 & 7 & 8 & 9 & 10 \\ price & -999 & 0 & 5 & 15 & 30 & 80 & 100 & 500 & 800 & 1000 \\ qty & 0 & 42 & 38 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \end{bmatrix}$$

and the fringe's bid will be

$$\begin{bmatrix} band & 1 & 2 & 3 & 4 & 5 & 6 & 7 & 8 & 9 & 10 \\ price & -999 & 0 & 5 & 15 & 30 & 80 & 100 & 500 & 800 & 1000 \\ qty & 0 & 0 & 0 & 40 & 20 & 10 & 0 & 0 & 0 & 10 \end{bmatrix}$$

To satisfy the demand of 120 MW, the MO will instruct to dominant firm to dispatch 80 MW, and the fringe firms to dispatch 40 MW for each of the five-minute intervals. Since 5 minutes amounts to $1/12$ of an hour, over the five minutes, the energy outputs they produce are respectively $80 \times (1/12)$ MWh and $40 \times (1/12)$ MWh. The dispatch price is $\$15$ per MWh. It reflects the marginal cost of the fringe firms. For each 5-minute interval the dominant firm will earn a profit of

$$(15 - 0) \times 42 \times (1/12) + (15 - 5) \times 38 \times (1/12) = \$84.167$$

Its profit for the 30 minute trading interval is \$505

Now consider a possible strategic move by the dominant firm. Just five minutes prior to the trading interval, it submits a rebid that offers to supply the 38 units of capacity from the second generating set only at the ceiling price of $\$14,000$ per MWh, indicating that it would supply only 42 units of capacity from the first generating set if the price is positive but below $\$14,000$

per MWh:

$$\begin{bmatrix} band & 1 & 2 & 3 & 4 & 5 & 6 & 7 & 8 & 9 & 10 \\ price & -999 & 0 & 5 & 15 & 30 & 80 & 100 & 500 & 800 & 1000 \\ qty & 0 & 42 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \end{bmatrix}$$

Then, to satisfy the demand of 120 MW, the MO must set the dispatch price $D_1 = \$1000$ for the first 5-minute interval. We assume that this very high dispatch price triggers a demand-side response: the output from gas peaking generators owned by retailers will become available. Suppose 10 units of capacity will be available for second five-minute interval, and 20 units of capacity for the third and each subsequent five-minute interval. Consequently, the MO operator must satisfy a net demand of 110 MW in the second 5-minute interval, and a net demand of 100 MW in each of the subsequent 5-minute intervals. The dispatch prices for these five-minutes intervals will be $D_2 = \$80$ (since 110 units are dispatched, consisting of 42 units from the dominant generator and 68 units from the fringe), and $D_3 = D_4 = D_5 = D_6 = \$30$ (since 100 units are dispatched, consisting of 40 units from the dominant generator and 60 units from the fringe).

The 'settlement price' is the time-weighted average of the dispatch prices

$$\begin{aligned} P &= (D_1 + D_2 + D_3 + D_4 + D_5 + D_6)/6 \\ &= (1000 + 80 + 30 + 30 + 30 + 30)/6 \\ &= \$200 \text{ per MWh} \end{aligned}$$

At this settlement price, the profit of the dominant firm per five minute interval is

$$200 \times 42 \times (1/12) = \$700$$

Its profit for the 30 minute trading interval is

$$700 \times 6 = \$4,200$$

This is much greater than the profit of $\$505$ that the firm would earn with an honest bid. Thus, it pays to withhold capacity from the second generating set for the whole 30 minute trading period.

However, we will show below that the dominant firm can do even better by rebidding (after the dispatch price peak of $\$1,000$), offering the 38 MW capacity from the second generating set for the second and subsequent 5-minute intervals at the low price of $\$5$ per MWh. Effective from the second 5-minute interval,

$$\begin{bmatrix} band & 1 & 2 & 3 & 4 & 5 & 6 & 7 & 8 & 9 & 10 \\ price & -999 & 0 & 5 & 15 & 30 & 80 & 100 & 500 & 800 & 1000 \\ qty & 0 & 42 & 38 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \end{bmatrix}$$

In the second 5-minute interval, the Market Operator must satisfy a net demand of 110 units (recall that, as a demand-side response, in the second 5-minute interval, the retailers can bring online 10 units of capacity, and 20 MW capacity will be available during each subsequent 5-minute interval). To satisfy this net demand, the MO will ask the dominant firm to dispatch 80 units and the fringe to dispatch 30 units. Since the fringe's marginal cost is $\$15$ per MWh, the dispatch price for the second 5-minute interval is $\$15$ per MWh.

In the third 5-minute interval, the Market Operator must satisfy a net demand of 100 units. This is done by asking the dominant firm to dispatch 80 units and the fringe to dispatch 20 units. Again the dispatch price is $\$15$ per MWh. The settlement price is

$$\begin{aligned} P &= (D_1 + D_2 + D_3 + D_4 + D_5 + D_6)/6 \\ &= (1000 + 15 + 15 + 15 + 15 + 15)/6 \\ &= \$179.17 \text{ per MWh} \end{aligned}$$

The profit of the dominant firm in the first 5-minute interval is

$$179.17 \times 42 \times (1/12) = \$627.10$$

and its profit in each of the five subsequent 5-minute intervals is

$$179.17 \times 42 \times (1/12) + (179.17 - 5) \times 38 \times (1/12) = \$1,178.60$$

Its total profit for the 30 minute trading interval is

$$627.10 + 5 \times (1178.60) = \$6,520.10$$

This is much greater than the profit of $\$4,200$ that it would obtain if it did not rebid (i.e. if it continued to withhold 38 units of capacity for the last five 5-minute intervals).

5.2 Manufacturing a price hike in the last dispatch interval

In the preceding subsection, we assumed that a firm can withhold capacity for the first 5-minute dispatch interval to increase the first 5-minute dispatch price (and consequently the settlement price for the half-hour trading interval), and subsequently rebid the capacity for the second 5-minute interval. In some cases, such behavior can be risky: the regulator may have have grounds to prosecute the firm. It may be safer to withhold capacity in the sixth 5-minute dispatch interval rather than in the first 5-minute dispatch interval. This will increase the dispatch price for the sixth 5-minute dispatch interval, and consequently raising the settlement price for the firm's five earlier dispatches. If the firm's competitors could anticipate the settlement price hike, they would increase their capacity offers, and it would not be worthwhile for the firm to withhold capacity. It is crucial, therefore, that the firm's withholding of capacity for the sixth 5-minute interval be made public as late as possible, so that the 'surprise price hike' gives the competitors little time to react.

6.0 Rebidding in the Australian Electricity Market

For a number of years the market operator has reported little evidence of rebidding activity. For example Australian Energy Market Commission [2015b] engaged ROAM Consulting to undertake a quantitative analysis of rebidding in the NEM. ROAM's key findings for 2007-2014 were reported on page 80 of AEMC [Australian Energy Market Commission, 2015b] with four relevant conclusions. First they found little evidence of a systematic tendency for rebidding toward the end of trading intervals or in rebidding just prior to dispatch, with the exception of recent episodes in Queensland and to some extent in South Australia. Second, a strong statistically significant relationship exists between the probability of price spikes and late rebidding in QLD in 2014 and SA in 2013. In QLD and SA the rebidding generally shifted capacity to high price bands, and in 2013 and 2014 QLD markets showed evidence of generation withholding capacity to high price bands towards the end of the trading intervals.

The evidence used to support the lack of systematic rebidding presented in Figure 8.2 of the Australian Energy Market Operator [2017a] report strongly suggests that further investigation is necessary. First, the data provided take no account of potential diurnality or seasonality effects. By collating all 'last 5-minute dispatch' rebids for every settlement period into a single representation over a year, the graph masks time-of-day, day-of-week and seasonal patterns. Similarly, by aggregating the rebids across all generators the data masks the strategic behavior taken at both generator and potentially portfolio level, given that there are fewer electricity generating firms than generators.

In their 2017 reports the Australian Energy Market Operator [2017a] and Australian Energy Market Commission [2017a] provide evidence that the price spikes that are expected to occur as a result of the bidding and settlement structure outlined in this paper are present, see particularly the text from page 29 onwards in Australian Energy Market Commission [2017a]. These data provide evidence on the non-random nature of price spikes, and their excess occurrence in the first five-minutes of the settlement period.[39] AEMC, however, have not yet provided evidence concerning the behavior of individual generators, or the extent of capacity being moved between price bands to achieve these outcomes.

AEMO provide extensive public data on rebidding on their website. Unfortunately, it is neither particularly transparent nor easy to use or manipulate.[40] Drawing on the datasets available from AEMO we have isolated the rebidding behaviour of each generator in the NEM for the period 01/09/2015 to 31/03/2017 to obtain a picture of the differing activities available.

It is fair to say that the variety of strategies employed is remarkable, no doubt contributing to the difficulties in pinning down these behaviours at an industry level. However, it is also true

[39]From July 2016 a stricter criteria against late-rebidding, within 15 minutes of dispatch, tended to push price spikes even more towards the first 5-minute period.

[40]The issues are somewhat parallel to the difficulties encountered in the transparency of high frequency financial market data in the 1990s, see Brandt and Kavajecz [2004].

that evidence of strategic behaviour in the form of rebidding occurs across all States and forms of power generation. For some generators the evidence occurs only rarely, sometimes associated with periods of market stress. In other generators the behaviour is evident for sustained periods of time and occurs multiple times in the same day.

We isolate rebidding from the dataset by finding changes in the quantity offered at the price bands in effect for each generator on that day. To simplify the problem slightly we concentrate only on rebids which occur for dispatch on the same day as the rebid (because of the structure of the bidding it is possible to rebid for a dispatch period on a different date). This leaves us with the possibility of rebidding for 48 possible settlement periods in each day. The rebids can occur at any time of day, and we specifically focus on those which change the volume for immediate dispatch periods up to the end of the following settlement period (that is from the point of rebid until the end of the next 30 minute settlement period). The structure of the rebidding system is such that when a generator rebids, it rebids the volume for all half-hour periods of that day. That is, if we imagine the day as running from $t = 0, ..., 48$, then regardless of when the rebid occurs, there may be volume changes recorded for all t, *regardless* of whether that period is in the past or not. This creates some particular difficulties in constructing the dataset, as clearly bids cannot be revised post-dispatch. This quirk of the dataset contributes greatly to the difficulty in assessing strategic changes in the supply schedule as past schedules need to be carefully constructed from an evolving dataset.

A convenient means of illustrating a rebid for a single point in time for a single generator is given in Figure 1. The top right hand panel represents the rebidding activity of a particular generator at 8:06:55 on May 24, 2016 (thus the heading for each panel is read as yyyymmddhhmmss). Along the right hand horizontal axis are the price bands ordered from lowest to highest. The left hand horizontal axis gives the dispatch period to which the supply bids apply. The vertical axis gives the quantity (in MW) of the **change** in volume offered by the generator in each of the bands pertaining to each dispatch period compared with the previously offered supply curve. That is, the charts show how the generator is realigning its volume up and down the supply curve at various points. Where the surface is flat there is no change in the supply of volume in that price band for this rebid. Valleys (or dips below zero) indicate volume is being removed from that price band, and hills (above zero) indicate volume being added to that price band. Note that in the vast majority of cases generators offer all their supply capacity at some price on the curve, and hence valleys and hills will generally net to zero as the volume is simply being shifted along the supply curve at each point in time. It is important to note that this three dimensional representation consists of a stack of supply curves which refer to individual points in time. As post-generation electricity is not currently storable in any meaningful way power is not being transferred from one dispatch period to the next by the actions of the generator.

The first point to note about the rebid given in the top left of Figure 1 is that it occurs at 8:06:55am. Consequently, all of the pre-8:06 changes in volume offered are irrelevant. That is most of the periods at the very front of the figure where volume is taken from the highest price band and moved to the lowest price band are simply irrelevant. The other dominant feature on the figure is the move of volume from a previously very low price band to the highest price bands - indicated by the red arrow. This rebid is taking volume from its previously lowest possible price band to the highest possible price band. In particular, this includes contributing to a steeper aggregate supply curve for the afternoon peak period from around 3pm - 5pm. The figure in the right hand top panel of Figure 1 shows the same generator rebidding again (its next rebid) later in the day at 15:13:03. It is apparent that now for the dispatch periods after 3:13pm volume is removed from the highest price bands to the lowest price bands. That is, compared with the original 'in good faith' bid by this generator volume was moved from the lowest to higher price bands at one point in the day, and then immediately prior to dispatch moved back from highest to lower price bands. Note that in the second rebid the same generator also moves volume for later in the evening from previously placed low price bands back to high price bands - perhaps in anticipation of the potential for later strategic plays. Because this generator is only one of a portfolio owned by the power generating company the strategic game is likely to be far more complex than the illustration from a single generator here as firms optimise across their suite of available generators.

A second example of rebidding behaviour is given in the lower panels of Figure 1. The lower left panel shows a bid on May 26, 2016 at 09:13:45am when volume is moved from the lowest to highest price bands as shown by the red arrow. A few minutes later, at 09:20:56am volume is moved back from the highest price band to the lowest for a subset of the original rebid.

While the individual generator stories are fascinating AEMO received between 6 and 8 million rebids annually between 2010 and 2015, making analysis of individual rebids infeasible. Table 4.1 provides descriptive statistics for rebids for eight sample generators across the period of September 2015 to March 2017 by generator type and location; it includes generators of varying sizes from different States involved in NEM across a range of power generation types - coal, gas, hydro and wind including at least one representative of the dominant capacity production types (black and brown coal, gas, hydro, wind).

The generators do not all look the same (and it is worth noting that the price bands for each are not necessarily the same either across generator or across time). However, it is clear that each of the coal fired stations (GSTONE1, GSTONE6, LYA1) bid most of their volume in lowest price bands, bands 1 and 2, (recall that this is not the price they receive, it merely indicates that the costs of not dispatching are very high for coal fired stations). The fact that the highest median is in band 2, rather than band 1, reflects that band 1 is often placed at the allowed price floor of $1000 per MWh, and reveals the skewness in the volume data. Coal fired stations also manage to allocate rather more to the highest price band on average than to bands 3 to 9. And price band 10 has a relatively high standard deviation, which is unsurprising given that it incorporates the highest allowable price of $14,000 per MWh. The two gas generators look quite different, AGLHAL has median volume concentrated at the top band and band 7, with a mean distribution which however reflects more volume dispatched towards the lower price bands. The difference between the mean and median volumes is prima facie evidence that there are some curiosities about the behaviour of these markets. PPCCGT, on the other hand, is primarily bidding volume in its lowest and highest price bands, reflected in both the mean and median results. The standard deviations are also highest in these bands. The two hydro stations are also quite different. Bastyan is a small generator and provides volume mainly at high price bands, while Tarraleah is a larger generator and tends to provide volume at its lowest price bands. Notably, however, the next highest standard deviations of these volumes are found in the higher price bands.

As discussed the diurnality and seasonality of rebids is a potentially difficult detail. Sun Metals [Sun Metals, 2015] provided details of six particular instances when price spikes resulted from generators withholding volume. They claimed a lack of evidence of rebidding in the first 15 minutes of 30 minute dispatches and a preponderance of occurrences in the last 5 and 10 minutes. To provide some more background to this problem we provide a sample of the diurnal pattern of rebidding for GSTONE1 generator and AGLHAL in Figure 4.2 compiled by cumulating the number of rebids by 5-minute time interval over the day during the sample period. Prima facie there seems to be evidence of diurnal patterns, both within the day, where there is clearly more rebidding activity in and around the peak demand periods for power in the morning prior to 8am and early evening. Additionally there are potentially hourly and/or half-hourly patterns consistent with the rebidding patterns proposed for the profit maximising firm by the theoretical framework.

To provide preliminary evidence that this is indeed the case we fit a sinusoidal curve of the form $x_t = A.sin(\omega * t + \phi)$ to each of the rebid counts of the form given in Figure 4.2 where x_t represents the number of rebids in the 5-minute interval. The results where no-breaks are allowed within the day are remarkably consistent across different generators, giving statistically significant estimates of a cycle with a period of just over 15 minutes in each case.[41] This is consistent with the idea that the generators may rebid more in the 10 minutes after the hour, and 10 minutes before the end of the half-hour than at other times. When we break the day into several sub-periods, from 4:00am to 10:00am (early morning), from 10:00am to 3:00pm (peak work) and from 3:00pm to 10:00pm (evening) we see that although the periodicity does not vary significantly, the amplitude of the cycle (that is the extent of rebidding) is substantially and significantly higher in the peak activity periods. These results are indicative that there is diurnality in the rebidding activity. Overall, the results support the claims by Sun Metals that there is more bidding in the late part of the half-hour dispatch period, but not clearly that there is none in the early part. However, the Sun Metals claim related specifically to rebidding related to price spikes. The relationship to price spikes by generator and time of day is complex, and beyond the scope of this paper (it will be addressed in future research).

In an attempt to deal with some of the perceived strategic bidding behaviour, a 'late-bidding' rule was introduced to the market effective from July 1, 2016, midway through our sample period; AEMC (2015). This rule established that when a generator created a rebid during the last half of the relevant 30 minute dispatch period they could be required to provide detailed records of the reasons behind those bids, thus putting the onus of proving 'good faith' onto the generator. To demonstrate its effect we divide our sample period in halves, pre-July 2016 and post-July 2016. Figure 4.3 presents the proportion of bids which occur in the last 15 minutes of the half-hour intervals by a number of generators. It is clear that for the vast majority (Bastyan is the only exception) the proportion of rebidding activity meeting the late re-bidding

[41] The period is given by $2\pi/\omega$. The individual estimations are not presented in order to conserve space, and because while the cycle estimated is significant, the fit is poor and little is gained from the detailed results. A more sophisticated econometric approach is required to estimate the form of the diurnality properly, and is underway in future research. The preliminary results are available from the authors on request.

category has dropped discernibly after the introduction of the rule. Our estimate here may be biased downwards, as the announcement of the new late rebidding requirements occurred in December 2015, and the market was aware that AEMC was examining this issue from at least mid-2015 when Sun Metals made submissions concerning this issue to both the AEMC and the Queensland Government (Sun Metals [2015]). It may also be notable that the absolute number of rebidding events has also dropped considerably for these generators across the two sample periods - although it is difficult to distinguish how much of this is due to changing underlying conditions or to the increased awareness of rebidding activity by regulators and analysts.

Finally, we provide evidence that the rebidding is not uniformly distributed across the price bands. In particular, for the eight generators shown in Table 4.1 we consider the extent to which rebidding events result in the removal of volume from/to the top two price bands to the lowest two price bands and vice versa. This is the most likely evidence of volume changes for strategic reasons consistent with the modelling framework presented in this paper, as it represents substantial changes in volume available at either end of the supply curve, either for a strategic reason or as a result of extremely poor forecasting. Given the profitability of electricity generation in Australia in recent years the former seems a more likely explanation.

Table 4.2 gives three rows for each generator. These divide the total number of megawatts offered by the generator in their rebid actions and the volume which is shifted. The first row for each generator captures the vast majority of all rebid activity, where there is no change in the volume bid in that price band - consistent with the flat areas in Figure 1. In all cases over 85 percent of the generating volume offered does not change price band during the rebid. The second and third row indicate how much generation capacity is moved from one end of the supply curve to the other in the rebids. It is clear, from simply adding up all the shifted capacity in these three categories that there is almost no rebidding which lies out side these groups - all of the totals add up to 98 percent or greater of rebids. This means there are disproportionately large shifts in volume occurring between the lowest and highest price bands, consistent with strategic bidding activity. The wind generator, HALLWF2 shows least evidence of this, which is consistent with wind being a non-synchronised, non-baseload generation source. The largest proportions of capacity offered shifting between the two tails occur for the coal stations in Queensland, consistent with the literature presented in Section 2.2 outlining the evidence for price manipulation in that State.

7.0 Conclusion

Electricity generation supply systems around the globe have attempted to solve the problem of determining competitive prices for power when faced with oligopolistic suppliers. Theoretical frameworks have been developed to capture the salient features of these markets, but one potentially important feature has thus far been neglected. Many of the existing systems allow for electricity generators to rebid their original offers to supply in the lead-up to the actual dispatch. While pragmatically this has been an acceptable solution to the problem of relatively infrequent observations on electricity demand, it has previously been unclear to what extent it may facilitate strategic supply curve behaviour on the behalf of the generators.

This paper has developed a theoretical framework to incorporate rebidding behaviour into our understanding of the provision of supply by electricity generators and its potential to influence price volatility at wholesale level. Both higher wholesale prices and volatility are passed to retail consumers in the form of higher prices. Using data for the Australian NEM we have for the first time, to our knowledge, provided evidence of strategic behaviour across the supply curve by individual generators which shows the potential of supply curve strategies which impact prices in precisely the way predicted by our theoretical model. Only recently has empirical evidence on this behaviour begun to emerge, at least partly due to the complexity of the datasets and a need to utilise big data techniques to control for diurnality, seasonality and other non-annual patterns in extracting the summary statistics to describe the observed outcomes. Future work will aim to quantify the extent to which portfolios of generators could result in more nuanced strategic behaviours than revealed here via individual generators. However, the fact that we can detect strategic supply curve behaviour in individual generators, across alternative power generating sources and geographic locations in the NEM provides ample support of the incentives created by the market design to create profitable opportunities. The problems inherent in this market draw attention to the importance of market design and implementation when trading off the pragmatic need for technical solutions detailed in Australian Energy Market Operator [2017a] with the incentives faced by firms generating financial profits.

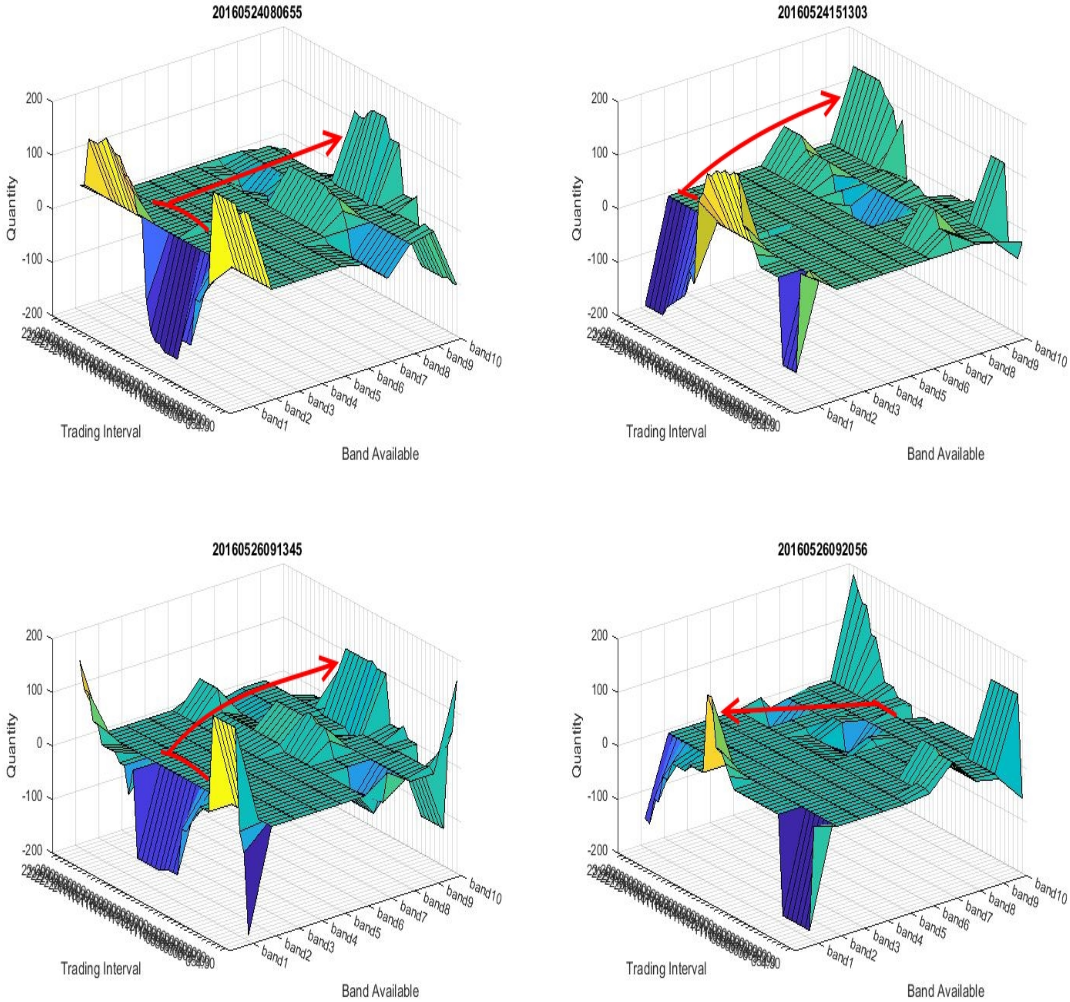

Figure 4.1: Changes in volume via rebid for a specific generator. The title for each panel is in the form YYYYMMDDHHMMSS, the upper panels present two consecutive rebids on May 24, 2016 and the lower panels two consecutive rebids on May 26, 2016. The right horizontal axis on each figure represents ascending price bands and the left horizontal axes gives the trading interval with the earliest towards the front of the figure. The vertical axis gives the change in volume. The arrows show the direction of shifts between band 1 and band 10.

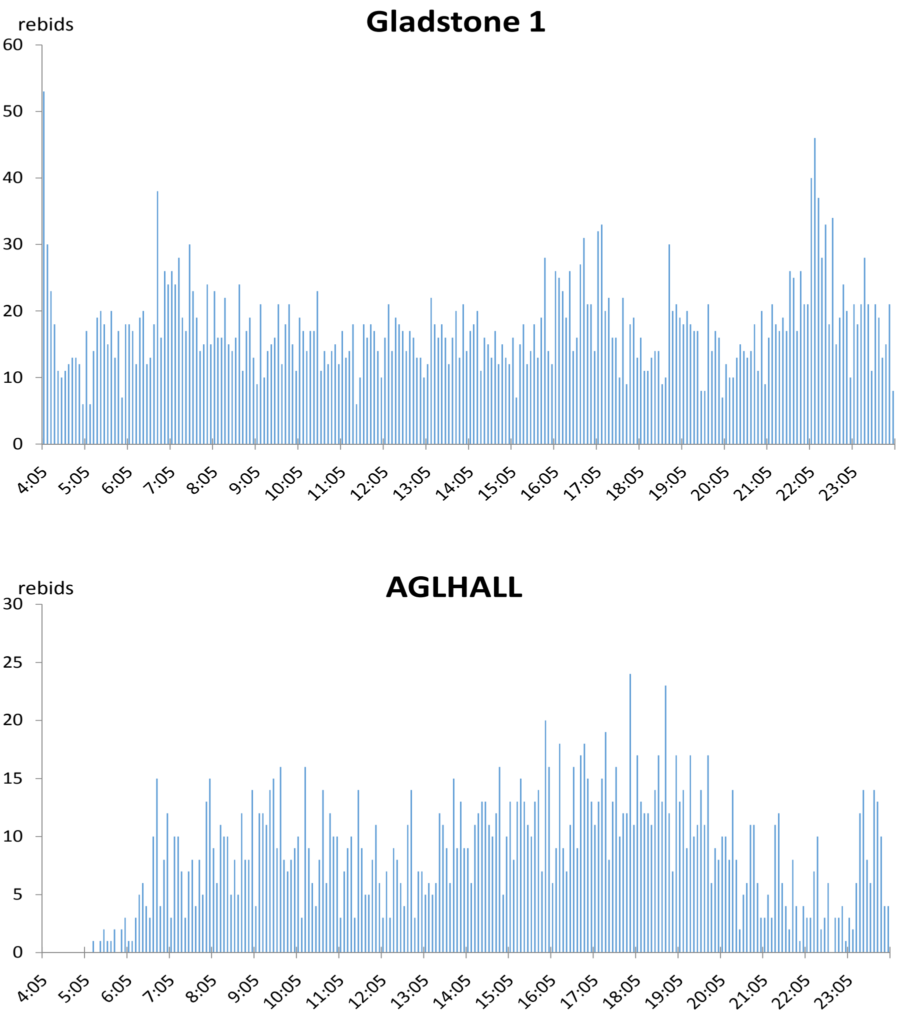

Figure 4.2: Rebidding activity by number of rebids in a 5-minute period over a day for 2015-2016 by generator

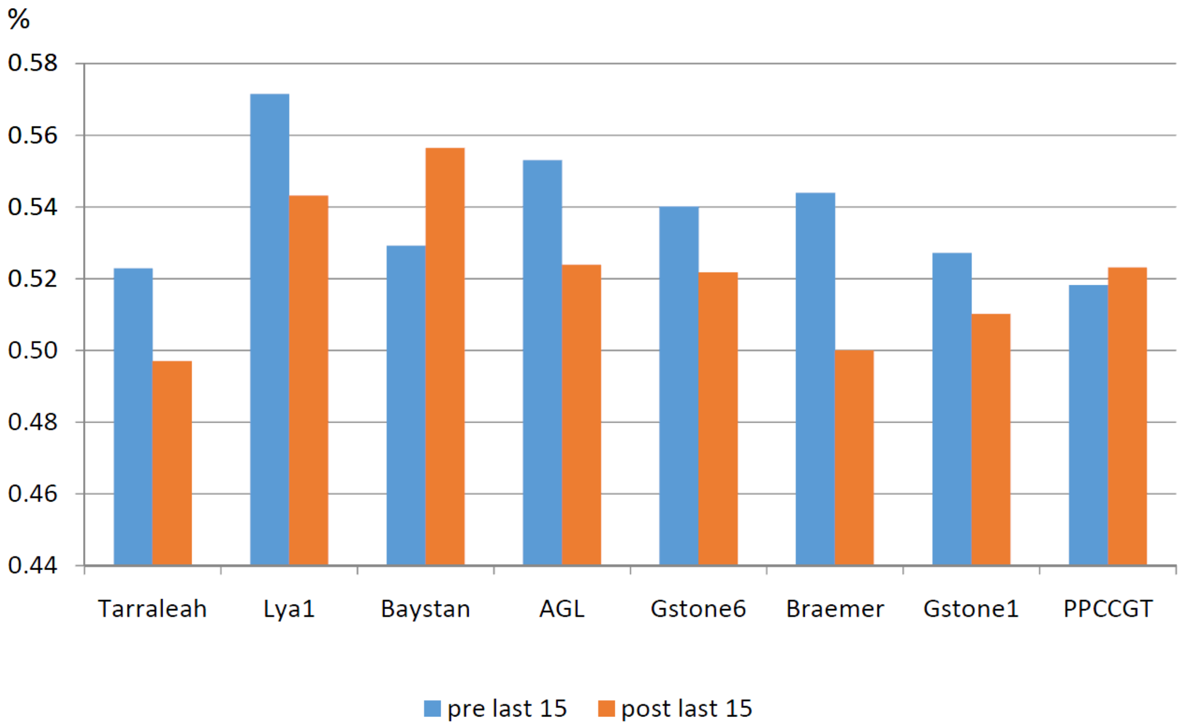

Figure 4.3: Proportion of rebidding activity taking place in the last 15 minutes of each half-hour pre the implementation of late-bidding rules and post the change to late-bidding rules

Table 4.1: Descriptive statistics for volume available by price band for sample electricity generators (MWh) for September 1, 2015 to March 31, 2017

State	Type	Generator	Stat	Band1	Band2	Band3	Band4	Band5	Band6	Band7	Band 8	Band9	Band10
SA	Gas	AGLHAL	Mean	14.84	1.6	0.87	1.7	1.78	4.68	45.31	0.43	0.78	1.48
			Median	0	0	0	0	0	0	50	0	0	160
			Stdev	31.78	9.32	5.8	8.62	8.69	9.29	21.86	4.06	5.63	30.49
	Gas	PPCCGT	Mean	157.28	11.1	13.78	9.47	21.07	45.25	17.74	6.31	19.92	209.44
			Median	160	0	0	0	0	0	0	0	0	220
			Stdev	38.54	27.68	31.85	23.69	39.25	48.99	37.24	10.96	34.78	89.52
	Wind	HALLWF2	Mean	28.11	1.67	0	0	0.78	37.57	0	0.02	0	2.86
			Median	0	0	0	0	0	71	0	0	0	0
			Stdev	34.47	10.76	0	0	7.4	35.43	0	0.67	0	13.31
QLD	Black	GSTONE1	Mean	38.74	77.17	30.12	33.13	17.02	6.90	6.86	15.89	0.21	29.41
	Coal		Median	0	110	10	30	10	0	0	10	0	45
			Stdev	56.11	54.61	38.74	31.38	23.02	11.60	10.99	18.16	2.14	50.83
	Black	GSTONE6	Mean	47.29	70.98	35.78	31.81	12.29	5.50	6.89	16.63	0.42	57.81
	Coal		Median	0	110	20	20	0	0	0	10	0	45
			Stdev	56.92	60.01	44.57	34.75	18.13	9.98	11.48	18.68	3.60	49.96
TAS	Hydro	Bastyan	Mean	1.60	16.10	13.88	7.59	2.21	1.38	0.95	5.5	28.03	10.72
			Median	0	0	0	0	0	0	0	0	3	8
			Stdev	6.26	19.23	20.81	16.92	8.88	5.89	6.35	18.69	36.29	13.70
	Hydro	Tarraleah	Mean	33.29	21.04	0.55	0.00	0.00	0.00	0.00	0.53	13	6
			Median	0	0	0	0	0	0	0	0	13	6
			Stdev	34.36	29.04	3.04	0.11	0.01	0.08	0.1	5.03	24.29	20.06
VIC	Brown	LYA1	Mean	425.99	19.01	43.00	13.44	15.32	2.08	0.84	8.37	30.17	31.74
	Coal		Median	400	0	0	0	0	0	0	0	0	30
			Stdev	121.94	96.30	66.68	24.51	37.31	18.02	9.61	38.11	71.42	28.60

AGLHAL (Hallet Power Station), PPCCGT (Pelican Point Power Station) HALLWF2 (Hallet Wind Farm 2), GSTONE (Gladstone), BASTYAN (Bastyan Power Station), Tarralea (Tarraleah Power Station), LYA1 (Loy Yang A Power Station).

Table 4.2: Proportion of volume (MWh) shifted in rebids between bands, September 1, 2015 to March 31, 2017

State	Type	Generator		Volume shifted	Percent of total
SA	Gas	AGLHAL	No Shift	70998	89
			Shift from Bands 9-10 to Bands 1-2	2464	3
			Shift from Bands 1-2 to Bands 9-10	5902	7
	Gas	PPCCGT	No Shift	79364	92
			Shift from Bands 9-10 to Bands 1-2	1747	2
			Shift from Bands 1-2 to Bands 9-10	3029	4
	Wind	HALLWF2	No Shift	1894	99
			Shift from Bands 9-10 to Bands 1-2	8	0.5
			Shift from Bands 1-2 to Bands 9-10	8	0.5
QLD	Black	GSTONE1	No Shift	150366	87
	coal		Shift from Bands 9-10 to Bands 1-2	8999	5
			Shift from Bands 1-2 to Bands 9-10	12273	7
	Black	GSTONE6	No Shift	138112	87
	coal		Shift from Bands 9-10 to Bands 1-2	8319	5
			Shift from Bands 1-2 to Bands 9-10	11635	7
TAS	Hydro	Bastyan	No Shift	49478	93
			Shift from Bands 9-10 to Bands 1-2	1543	3
			Shift from Bands 1-2 to Bands 9-10	1823	4
	Hydro	Tarralea	No Shift	24548	96
			Shift from Bands 9-10 to Bands 1-2	243	1
			Shift from Bands 1-2 to Bands 9-10	636	3
VIC	Brown	LYA1	No Shift	89219	96
	coal		Shift from Bands 9-10 to Bands 1-2	1483	2
			Shift from Bands 1-2 to Bands 9-10	2078	1

AGLHAL (Hallet Power Station), PPCCGT (Pelican Point Power Station) HALLWF2 (Hallet Wind Farm 2), GSTONE (Gladstone), BASTYAN (Bastyan Power Station), Tarralea (Tarraleah Power Station), LYA1 (Loy Yang A Power Station).

APPENDIX

APPENDIX: SYMMETRIC SFEs

Suppose there are two firms, i and j. The cost of producing q_i is $C_i(q_i)$, a convex function, with $C_i' \geq 0$. Assume firm j's supply function is $S_i(p)$. Then firm i's residual demand function is

$$R_i(p, a) = D(p, a) - S_j(p)$$

Firm i's equilibrium output in state a must satisfy the residual demand, i.e..

$$q_i(a) = D(p, a) - S_j(p)$$

Firm i's profit function in state a is

$$\Pi_i(p, a) \equiv p \times R_i(p, a) - C_i\left[R_i(p, a)\right]$$

In state a, given the rival's supply function $S_j(p)$, firm i would like to choose a p that maximizes its profit. The FOC for firm i is

$$R_i(p, a) + p\frac{\partial R_i(p, a)}{\partial p} - C_i'\left[R_i(p, a)\right]\frac{\partial R_i(p, a)}{\partial p} = 0$$

This eq can be re-written as

$$D(p, a) - S_j(p) = -\left[p - C_i'(q_i)\right]\left[\frac{\partial D(p, a)}{\partial p} - S_j'(p)\right] \tag{A.1}$$

Using the market clearing condition $q_i = D(p, a) - S_j(p)$, firm i's optimality condition (A.1) becomes

$$\frac{q_i}{\left[p - C_i'(q_i)\right]} = S_j'(p) - \frac{\partial D(p, a)}{\partial p} \tag{A.2}$$

Similarly, given firm i's supply function $S_i(p)$, firm j's optimality condition is

$$\frac{q_j}{\left[p - C_j'(q_j)\right]} = S_i'(p) - \frac{\partial D(p, a)}{\partial p} \tag{A.3}$$

Solving the pair of differential equations (A.2) and (A.3), one obtains a SFE. Consider the case where both firms have the same cost function. Then we seek a symmetric SFE where both firms bid identical supply functions $q = q(p)$. We thus face only a single differential equation

$$\frac{dq}{dp} = \frac{q}{p - C'(q)} + D_p \tag{A.4}$$

If $C'(q) = \gamma q$, $\gamma > 0$, and $D_p = -b < 0$, this equation can be solved analytically, yielding a unique SFE, provided that we insists that all $p \in [0, \infty)$ are possible; see Klemperer and Mayer, p. 1260.

Remark: In the main text, we showed that if firm j's supply function in $S_j(p) = \beta p$, then firm i's best response is

$$q_i(p) = \frac{(b + \beta)}{1 + \gamma_i(b + \beta)} p \equiv \omega p$$

If the two firms have identical cost functions, i.e. $\gamma_i = \gamma_j = \gamma > 0$, then in a symmetric equilibrium, we must have $\omega = \beta$. Thus we can solve for ω from

$$\frac{(b + \omega)}{1 + \gamma(b + \omega)} = \omega \; (\gamma \neq 0)$$

Then[42]

$$\omega^2 + b\omega - (b/\gamma) = 0.$$

Choosing the positive root (because we require an upward-sloping supply function), we obtain

$$\omega = \frac{1}{2}\left[-b + \sqrt{b^2 + \frac{4b}{\gamma}}\right]$$

which is the same as in Klemperer and Meyer [1989, p. 1261].

[42] If $\gamma = 0$, then above equation has no solution for $b \neq 0$.

Chapter 5

Conclusions

This doctoral thesis presents three research papers addressing the conflict between pursuit of productive efficiency and rent seeking by strategic use of rules governing the bidding process in the Australian National Electricity Market over 2015-2017. These rules play a key role in firms' decision-making process through the incentives they create. One of these rules, and relatively a unique feature of the NEM, is the rule pertaining to firms' rebidding activity. Firms are allowed to revise their supply bid up to five minutes prior to dispatch time. The intended objective behind rebidding close to dispatch time is to allow generators to quickly respond to market conditions thereby improving the economic efficiency in the market.

In the first research paper, we quantified the implication of rebidding in the NEM. We characterised the potential for market power by directly computing how much influence single generators have on dispatch prices and ultimately on trading prices through rebidding. We used generators' bid data in conjunction with aggregate demand to construct complete bidding histories and market outcomes for each 5-minute auctions in a trading interval to obtain a picture of differing effect of rebidding on prices. Our analysis of the data indicated that each single generator influenced the market prices through rebidding. Rebids caused dispatch prices to increase as well as decrease and also sometimes rebids had no effect on the dispatch prices. However, empirical distribution of price changes was skewed to the right indicating that majority of rebids caused dispatch prices to increase. On average, rebids tended to increase prices more in the later dispatch intervals. In addition, generators' rebidding caused additional expenditure across the market. In fact, our results indicated that a potential determinant of price changes can be the generator submitting the bid. Essentially, firms with bigger market share have a bigger impact on the market outcomes through rebidding. In this research paper, the implications of rebidding on the wholesale prices for one trading interval is investigated and it will be valuable for the future studies to investigate all the trading intervals across each trading day.

Results of the first paper showed that single generators can impact dispatch prices through rebidding. Given that firms have this market power to affect the market prices through rebidding, it is important to understand what drives rebidding by these generators. In the second paper, we shifted our attention to the driving factors behind rebidding. In particular, we investigated the effect of market information in each dispatch equilibria on generators' rebidding behaviour as one potential reason firms rebid. This is important given one indicator of current market conditions is the sequence of five-minute dispatch equilibria and rebidding provides firms with an opportunity to respond to any market signals contained int these five-minute dispatch equilibria. In pursuit of our objective, our results showed that rebidding meets its stated goal of allowing generators to respond to market signals. Essentially, our results indicated that firms' response to price changes is consistent with efficient market outcomes; specifically productive efficiency. Our results concerning difference in responses to change in prices arising from generator's technology indicated that scheduled generators; coal generators followed by hydro and natural gas generators had a different rebidding behaviour than semi-scheduled generators; wind and solar. This is aligned with our finding in the first research paper; firms with bigger market share (like scheduled generators) have a bigger impact on the market outcomes. Further, we observed that most of the generators are consistent in their responses to change in prices across each dispatch interval. This research paper pertains to power producing generators in New South Wales and future studies with the same subject matter will complement this study by investigating the other states operating in the Australian National Electricity Market.

Thus far, we established the implications of rebidding followed by detecting the driving factors behind rebidding. In the last research paper, we extended existing theoretical frameworks describing electricity markets by incorporating the possibility that firms may rebid their supply bid prior to dispatch. This is a salient feature of the Australian NEM and many other international power markets which has not previously been included in the theoretical frameworks. We used a hypothetical situation to outline that a dominant generator can gain substantially by strategically rebidding. Specifically, a dominant generator can withdraw their quantity from lower price bands of their supply schedule through rebidding and offer that at higher price bands. We showed that this has the effect of spiking one of the dispatch prices which ultimately increased the settlement price; the price that the dominant generator received. Using data for the Australian NEM, we found out that generators tend to place their attention on the first and last two dispatch intervals. This result is consistent with strategic behaviour on behalf of power producing generators in the Australian NEM. Essentially, observing such a behaviour across various generators, geographic locations provide insights into the incentives created by the market design to create profitable opportunities. Our results draw attention to the significance of market rules governing generators bidding and rebidding when trading off productive efficiency with rent seeking by firms.

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