Measuring Generator Market Power

An assessment undertaken as part of the 2012 State of the Market Report

October 31, 2012

Market Surveillance Administrator | 403.705.3181 | #500, 400 – 5th Avenue S.W., Calgary AB T2P 0L6 | www.albertamsa.ca

PREFACE

The distinguishing feature of the Alberta market compared to most organized electricity markets is that it is 'energy-only'. In an energy-only market, the private sector bears the risk and decides on retirement of generation and investment in new capacity, mainly driven by revenues derived or expected to be derived from the wholesale market. There is no regulated and centrally administered resource adequacy and planning mechanism. Apart from a price cap and price floor, prices in the spot market are regulated by the forces of competition, within the parameters of the Alberta market design and supporting rules and procedures. Finally, unlike most other organized electricity markets, participants are free to unilaterally engage in strategies to attempt to move the pool price (as long as they do not impede competitive responses) and there is no mechanism to administer prices or offers at some proxy of cost.

Under the circumstances outlined above it is obviously important that competition is doing its job in regulating market outcomes. To that end the MSA is undertaking a state of the market report on competition and efficiency. One element of this is to gain an understanding as to whether market participants have the ability to exercise market power. This could be participants who are loads, active on the intertie or those controlling generation assets. This report focusses on structural measures of generation market power, i.e. do participants with generation assets have the ability to affect market prices. The report does not address the extent to which this market power is exercised in practice. This will be addressed in the 'conduct' section of the final State of the Market Report.

The Market Surveillance Administrator is an independent enforcement agency that protects and promotes the fair, efficient and openly competitive operation of Alberta's wholesale electricity markets and its retail electricity and natural gas markets. The MSA also works to ensure that market participants comply with the Alberta Reliability Standards and the Independent System Operator's rules.

Table of Contents

List of Tables and Figures

Overview

Our Motivation

The Market Surveillance Administrator (MSA) is currently undertaking a State of the Market report, envisioned as an assessment of the state of competition within, and the efficiency of, the Alberta wholesale electricity markets. The report presented herein represents a building block to provide input to the MSA's broader State of the Market assessment. In this report, the MSA has undertaken a study of the current literature and the empirical approaches to analyzing generator market power, and has applied these economic principles and methods to the Alberta wholesale market.

The existence (or exercise) of market power in any product market is not by itself a cause for concern (unless it is to such an extreme degree that there is little possibility for competition, e.g. single firm monopoly). As outlined in the MSA's *Offer Behaviour Enforcement Guidelines*, competition concerns only arise if this market power is extended or abused. Nevertheless, reporting on and understanding market power is an important responsibility of the MSA because it is the starting point of any meaningful assessment of competition and efficiency. We plan to refine the measures laid out in this foundational study over time in addition to integrating the findings into our final State of the Market report.

In simple terms, market power refers to the ability of firms to profitably move market prices. The absence of market power provides a guarantee that market power cannot be exercised to result in significant and durable deviations away from competitive outcomes. The existence of market power means the market monitor needs to scrutinize the behaviour of market participants to ensure that it doesn't exercise market power in a way that undermines competition. Similarly, policy makers need to be satisfied that the framework of rules and policies governing the market does not facilitate anticompetitive conduct or create artificial barriers to entry preventing new participation in the market or the threat of new participation from producing competitive outcomes over the long run.

What We Looked At

The first step in assessing market power is determining the relevant market in which competition takes place. This process of 'defining the market' involves determining which good(s) and which geographic locations compete with one another (i.e. make up the relevant market). Section 2 of this report outlines the economic theory surrounding market definition and compares the market definition within the *Fair, Efficient and Open Competition Regulation* (FEOC regulation) to the approach typically used by competition authorities.

Section 3 of the report uses the market definition within the FEOC regulation to analyze how measures of market concentration have changed on an annual basis since the market's deregulation. Section 3 also outlines some important limitations which underlie this approach.

In Section 4 of the report we analyze alternative approaches to measuring generator market power. This includes analyzing the potential for local market power and improving the market concentration approach by dealing with some of the limitations discussed in section 3. In Sections 4.3 and 4.4 of the report we outline the Residual Suppler Index (RSI) and discuss a Residual Demand approach to measuring market power. The Residual Supplier Index measures the concentration of market supply relative to the prevailing level of demand. Fundamentally the RSI illustrates the extent to which a particular firm is 'pivotal' to the clearing of the energy-market.[1] The Residual Demand approach

[1] A supplier is defined as pivotal if total market demand exceeds the available capacity that is under the offer control of other market participants. In other words, some of the supplier's generation is required for the market to clear.

considers the prevailing market demand as well as the shape of the offer curves submitted by a participant's competitors. Simply put, the Residual Demand analysis illustrates the extent of competing generation that a firm faces around the market clearing price.

What We Found

We confirmed the obvious that the Alberta generation market is concentrated among a few firms. Using different measures of concentration we found that the five largest suppliers account for about 70 percent of total market capacity, although there has been a slight decrease in concentration over time since 2008. Applying Alberta data to the more informative measure of concentration, the Residual Supplier Index, showed that the largest firms in Alberta frequently have a notable amount of structural market power, that is, the ability (but not necessarily the incentive) to move market price. For example, the largest firm in Alberta was 'pivotal' to the clearing of the energy market in 80% of the hours during 2011. This falls dramatically (tenfold) when generation that cannot readily be used is removed from the calculation.

An analysis of hourly market shares highlights that the supply-side of the Alberta electricity market is dynamic; a result that will come as no surprise to close observers of the market. The concentration of supply available can change considerably from one hour to the next with unit outages and capacity derates, volatile wind supply, and varying flows on the interties. The more informative measures of generator market power, the Residual Demand analysis and an adjusted Residual Supplier Index, highlight that for a large percentage of hours there is sufficient competition to limit the ability of generators within Alberta to exercise market power. They also show that in a small percentage of hours the larger firms do have the ability to move the market price quite substantially.

To be clear, this paper addresses the 'structural' market power held by generators in Alberta. These structural metrics examine the ability of market participants to exercise unilateral market power in the Energy market. They do not measure whether they in fact do. For example, a market participant with considerable offer control but equivalent forward market sales may have the ability to affect market prices but not the incentive. The MSA will consider this issue in more detail in the conduct section of the final State of the Market Report.

Finally, in terms of incorporating this analysis into our market monitoring role, the MSA believes that it is prudent to employ a range of measures when analyzing market power, while recognizing the strengths and weaknesses of each approach. In addition, it is likely that any analysis undertaken to assess market power will be influenced by a number of circumstances (whether congestion is an issue for example), as well as the overriding purpose of the analysis (market power through economic withholding versus market power via physical withholding for instance). Variants of the Residual Supply Index and Residual Demand analysis both capture important elements in assessment of market power and competition in the Alberta Energy market. Working with stakeholders to refine these metrics over time will lead to further insight into the measurement of market power and provide an important and continuing window on the market.

1. Introduction

The definition of unilateral market power is the ability of a single firm to profitably move market prices away from the competitive level. The 'competitive level' price refers to the price that would result if all participants offered their energy into the market at variable cost. The Alberta electricity market is not a cost-based market and generators are under no obligation to offer their energy at some proxy of variable cost. Implicitly then the design of Alberta's energy-only market relies on the generation sector being workably competitive such that no one participant can significantly control market outcomes through the exercise of market power. Consequently, measuring the extent of market power within the Alberta wholesale market is an important component in assessing the Alberta market.

The MSA has a mandate to monitor the Alberta wholesale market to ensure that it operates in a fair, efficient and openly competitive manner. As part of its duties the MSA must report annually on the market share of offer control of generation market participants and in no case may a generation participant have more than 30% offer control.[2] It is the MSA's view that a lack of concentration of control over generation can contribute in a significant way to the development and maintenance of a fair, efficient and openly competitive market. However, it is important to recognize that measures of market shares are imperfect measures of competition. In particular, there are notable controversies and important judgments to be made when defining the relevant market. Furthermore, even with an 'ideal' market definition, concentration metrics may not consider important market fundamentals including the characteristics of market demand and the long-run contestability of the market.

The reader should note that the focus of this report is on structural unilateral market power. The metrics reported here are used to analyze the ability of individual firms to exercise market power through economic withholding. There are two important points here. Firstly, the metrics do not seek to gauge whether or not market power has actually been exercised. This is an important distinction since the incentives of a profit-maximizing firm to exercise market power may not be consistent with the firm's ability to do so; a firm's incentive to exercise market power will also depend upon the extent to which the firm is exposed to the real-time price. The second distinction is that the metrics throughout analyze the ability of generators to move the pool price through economic withholding rather than through the physical withholding of generation. Accordingly, control over generation capacity is assigned to the participant with offer control rather than the participant with operational control.

1.1 Background

Competition authorities commonly rely upon measures of market concentration to analyze the nature and extent of competition in an array of markets. More specifically, measures of market concentration are frequently used to indicate the potential ability for a firm to exercise unilateral market power.[3] In US power markets for example, FERC uses market shares as one of two screening mechanisms to determine whether a firm has market power.[4]

[2] See Market Share Offer Control 2012.

[3] Unilateral effects arise from individual market participants responding to incentives and acting alone. Coordinated effects refer to concerns where two or more market participants directly or indirectly act to promote their combined self-interest. For further discussion see the *Offer Behaviour Enforcement Guidelines*, Section 2.2.

[4] See FERC (2007) at paragraph 13.

1.1.1 Unilateral Market Power

The MSA's Offer behavior Enforcement Guidelines (OBEGs) distinguished two kinds of unilateral conduct:

1. Single participant conduct aimed at capturing surplus (profits) that a market participant has created independent of the conduct's effect on rivals. This type of conduct has been termed 'extraction'.
2. Single participant conduct that increase surplus (profits) by weakening or eliminating the competitive constraints imposed by rivals. This would include conduct that resulted in an impediment or prevention of competitive response. This type of conduct has been termed 'extension'.

The OBEGs note that conduct of the first kind is considered competitive and consequently would not result in enforcement action from the MSA. Conduct of the second kind poses a concern and is likely to be subject to investigation and potential enforcement action.

The MSA further noted that:

> In a workably competitive market the use of both strategies is disciplined by the actions of competitors such that there is no expectation that a market participant can exert **significant** control over market outcomes. The MSA is mindful that dynamic efficiency gains are not assured if the price signal is effectively controlled by one or more market participants – new entrants and investment will be dissuaded if they believe prices are only high because of market participant control, reasoning that post entry the controlling incumbent may set prices at a level that would not enable the entrant to recover costs. Potential entrants may also be deterred if they observe a large amount of capacity being economically withheld. The MSA will closely monitor episodes of this nature to determine whether the pattern of behaviour is consistent with a plausible theory of predation, that is, evidence of sufficient market power to create a **barrier to entry** for potential competitors. [emphasis added]

A key test of '**significance**' is that prices exceed not only short-run marginal cost but also long-run marginal cost.[5] Testing for barriers to entry is sometimes characterized as a test for '**durability**' – that profits associated with market power persist over time and the entry of competitors (or threat thereof) does not limit the exercise of market power. Durability is not the same as unilateral market power being continuous. In electricity markers, outages and changes in demand can make market power come and go but it may still be durable in that it recurs unchecked over time.

[5] This is the subject of a forthcoming MSA paper.

2. Market Definition

To calculate even simple market concentration measures it is necessary to first define the product(s) being analyzed and to determine the geographic boundaries of the market. The product definition involves determining which products are demand-side substitutes, and the geographic dimension involves determining the locations of competing firms that produce the same product - supply side substitutes.[6]

In many industries, the choice of relevant products and locations are contentious issues because these definitions can have significant effects upon the implications of market concentration analysis. A market that is too 'narrow' excludes substitutes that impose important competitive constraints and will lead to concentration measures that overestimate the ability of firms to exercise market power. Conversely, a market definition that is too 'broad' will yield concentration metrics that underestimate the market power of firms since the market includes products and production locations that are not close substitutes and do not exert meaningful competitive constraints.[7]

2.1 Product Definition

Given that electricity is a perfectly homogeneous good with no reasonable substitutes, defining electricity as the sole product is a fairly innocuous assumption. In addition, it is clear that capacity, as opposed to energy production, is the correct measure to be used in power markets. As noted by Borenstein et al. (1999), using energy-sales to calculate market concentration is fundamentally misguided since the very act of exercising market power involves reducing energy-sales. Hence, if relatively large firms exercise unilateral market power and the withheld output is replaced by smaller firms, the exercise of market power misleadingly suggests a decrease in market concentration.

2.2 Geographic Definition

In terms of delineating the geographic bounds of power markets, there are two major approaches used. The first approach, utilized by the Canadian Competition Bureau and by the US competition authorities, defines the boundaries of an antitrust market by considering whether a hypothetical monopolist would profitably implement a Small but Significant Non-transitory Increase in Price (SSNIP). In the Merger Enforcement Guidelines the Competition Bureau notes:

> Conceptually, a relevant market is defined as the smallest group of products, including at least one product of the merging parties, and the smallest geographic area, in which a sole profit-maximizing seller (a 'hypothetical monopolist') would impose and sustain a small but significant and non-transitory increase in price ('SSNIP') above levels that would likely exist in the absence of the merger.[8] In most cases, the Bureau considers a five percent price increase to be significant and a one-year period to be non-transitory. Market characteristics may support using a different price increase or time period.[9] [emphasis added]

Using the SSNIP analysis to define the relevant antitrust market can be a non-trivial task in electricity markets. In particular, depending on the prevailing supply and demand conditions, as well as on the state of the transmission system, the ability to supply power from one geographic area to another may be

[6] Church and Ware (2000) at p.470.
[7] Church and Ware (2000) at p.604.
[8] A market may consist of a single homogeneous product or a group of differentiated products.
[9] Paragraph 4.3 page 11.

severely limited at certain times and less so at others. Therefore, the relevant antitrust market can vary according to the prevailing market fundamentals, including the degree of congestion of the transmission system, which in turn may depend upon the actions taken by market participants.

The second approach is more straightforward. This approach defines the relevant economic market using the classical 'law of one price' test. Using this method the relevant economic market is defined as the geographic location within which the same thing is sold for the same price at the same time, with allowance being made for transportation costs.[10] The underlying principal here is that the boundaries of an economic market should include all the firms and their products that interact to determine prices.

If the geographic bounds of the market are delineated using the Law of One Price method, this yields a fairly straightforward geographic boundary for electricity markets. The remaining clarifications include whether all market capacity, in particular variable capacity such as wind or hydro, should be treated as equivalent to thermal capacity, and whether the Available Transmission Capacity (ATC) of intertie connections and behind-the-fence capacity should be included as part of the relevant market.

In Alberta some direction is given by the *Fair, Efficient and Open Competition Regulation* (FEOC Regulation). Section 5 specifies that a market participant shall not hold offer control in excess of 30% of the total Maximum Capability of generating units in Alberta. In this Regulation, the defined market is Alberta generation capacity, as measured by an asset's Maximum Capability; this definition treats all capacity as equivalent and does not include the capacity of intertie connections.

The market definition established within the FEOC Regulation is inherently based upon the Law of One Price method. As highlighted above, this method is distinct from the approach taken by the Canadian Competition Bureau and US competition authorities, where an antitrust market is defined as the smallest market in which a hypothetical monopolist would profitably implement a Small but Significant Non-transitory Increase in Price (SSNIP). Consequently, the concentration thresholds established by these competition authorities are not readily comparable with the threshold established within the FEOC Regulation. The market definition used within the FEOC legislation is 'broader' than the approach taken by competition authorities; a firm would not require offer control over all of Alberta's generation capacity to profitably implement a SSNIP. Therefore, such comparisons would tend to understate the underlying concentration of the Alberta wholesale market.

One reason for this differential is that to decipher whether or not a single firm can profitably implement a SSNIP requires considering the elasticity of market demand. Since there are few substitutes to consuming power in the short-run, the demand function for electricity is notably inelastic. This market characteristic is implicitly considered in the SSNIP analysis since as the demand function becomes less elastic, firms require less market share to achieve the same level of market power. A market definition based upon the law of one price will not account for this demand-side characteristic. This is clearly an imperfection that should be recognized when applying the 'law of one price' market definition. This issue, along with others, is raised and discussed in Section 3.

[10] Twomey et al. (2005).

3. Measures of Market Concentration

3.1 Market Shares and Concentration Ratios

Once the relevant market is clearly defined, calculation of market shares is straightforward. A company's market share is given by the firm's percentage of the total market:

$$MS_{it}(\%) = \frac{S_{it}}{\sum_{i=1}^{N} S_{it}} * 100$$

Where MS_{it} is the Market Share of Firm i at time t, and S_{it} is the share of firm i. The denominator is simply the total market (the sum of shares of all N firms).

In the Alberta electricity market, the market share of a participant is typically measured according to which participant has offer control over capacity, and this is the approach adopted throughout this report.[11] The offer control of generation is frequently distinct from operational control and/or the ownership of a generating facility.

To make inferences regarding overall market competitiveness, market shares are often aggregated to report Concentration Ratios. Concentration Ratios are percentage statistics showing the total market share controlled by the largest *n*-number of participants. For instance, the four-firm Concentration Ratio (CR4) would detail the total market shares of the largest four firms. No particular guidance is given on the 'correct' value of *n*, although CR4 and CR8 measures are commonly used to compare industries.

3.2 The Herfindahl-Hirschman Index

Concentration Ratios are often criticized because they do not account for the relative distribution of market shares. In particular, Concentration Ratios will not consider the relative sizes of the leading firms, nor will they indicate the distribution of smaller firms that are not included in the calculation. For example, a market in which three firms each have a 30% market share will have the same three-firm concentration ratio (CR3) as a market where the leading three firms have market shares of 60%, 20%, and 10%. Similarly, a market in which the three leading firms have a market share of 30% and the fourth firm has a 10% market share will yield a CR3 of 90%. One would derive the same CR3 if the market structure was three firms each with 30% and ten small firms each with a 1% stake.

In recognition of these deficiencies, competition authorities such as the US Department of Justice and the Federal Trade Commission place more emphasis on alternative measures of overall market competition; notably the Herfindahl-Hirschman Index (HHI). The HHI is defined as the sum of the squares of market shares for all (N) firms within the relevant market.

$$HHI_t = \sum_{i=1}^{N} (S_{it})^2$$

Where S_{it} is the share of firm i at time t.

A higher HHI is indicative of greater market concentration. The HHI is bounded by 0 (an infinite number of negligible firms) and 10,000 (a single firm). The HHI will increase if there are fewer firms in the market and/or if there is a greater variation in the distribution of market shares.

[11] This is the approach set out in Section 5 of the *Fair, Efficient and Open Competition* Regulation.

Theoretical Justification for Market Concentration Measures

The theoretical justification for using market concentration metrics to measure of market power is that a company's profit is maximized in a Cournot Equilibrium when the price-cost margin is proportional to the market share of the company, and inversely proportional to the price elasticity of market demand (See Church and Ware (2000) Section 8.2 for a detailed outline of the Cournot economic model).

$$\frac{(p - mc)}{p} = \frac{s_i}{\varepsilon}$$

The underlying intuition here is that as the market share of a particular firm increases, the ability of its competitors to respond to price changes will generally fall. Larger firms will often face less supply-side competition and consequently larger firms will have a greater ability to exercise unilateral market power. In contrast, a firm with low market share will typically face greater competition as its rivals are larger and more able to increase supply as price rises. All else equal, a smaller firm trying to raise the market price by withholding output will face a greater supply response as prices rise, and the firm will have less unilateral market power as a result.

Further to this, a dominant firm supplying large quantities into the market may have a greater incentive to raise the market price than a small firm. If the larger firm has a greater amount of supply exposed to the spot price, the larger firm will have a greater incentive to increase this price in order to raise total revenues. In the context of power markets, it should be noted that market participants may alter their exposure to the spot price through financial trading and other forward market transactions. These trades and transactions can meaningfully change the incentives of a firm to exercise unilateral market power.

It is also argued that market concentration measures have an additional effect in bid-based markets. As the number of competitors within the market decreases, the probability that any one firm sets the system marginal price increases; firms with a larger proportion of the market have a greater chance of setting the system marginal price than smaller firms. Therefore, in highly concentrated markets, firms have a larger incentive to raise the price of their offers as the probability that these offers will clear the market, and set price, is higher.

3.3 Simple Market Concentration Metrics in the Alberta Electricity Market

3.3.1 Market Definition

To calculate market concentration measures in a transparent and useful manner, it is necessary to clearly define the relevant market that is being analyzed. The market definition used in this section is consistent with the definition which underlies the FEOC Regulation. The defined product is electrical production capacity.[12] Full wind capacity is included in the total market capacity; however, wind units are not assumed to be under the offer control of market participants.[13] To account for Small Power Producers and non-wind assets which do not offer into the power pool, these units have been approximated to represent a consistent total of 250 MW. The geographic bounds of the market are generally delineated by the Alberta provincial borders[14] and intertie capacities are not included. We consider the implication of this assumption in more detail in Section 3.4.3.

Finally, it is important to reiterate that, as a result of the PPAs and the joint ownership of generation, in the Alberta wholesale market the control of offers for a generating asset is often distinct from the actual ownership of the facility. Market shares have been assigned to the participant with offer control of a particular asset, or a specific MW portion of the asset's capacity. The Minimum Stable Generation capacity is treated likewise, and is generally assumed to be under the offer control of the PPA buyer.[15]

3.3.2 Market Shares

Figure 3.1 illustrates how the market shares of today's largest five firms have changed on an annual basis from 1999 to 2011, with the annual snapshot generally being at the end of each year. January 2001 is included to show the initial impact of the PPAs on the market shares of these firms. At the current time the market participant with the sixth largest share is the Balancing Pool. The Balancing Pool aside, these five firms reported have consistently been the participants with the largest amount of offer control since the initial PPA auctions came into effect.

The figure highlights that from 2001 to 2006 the total capacity under the offer control of these five participants increased from 52% to 73% as these generators added new capacity and purchased additional generation from smaller participants. The value peaked in 2006 with the five largest firms controlling 73% of the total market capacity. This has declined to around 70% since then, as wind capacity and additional cogeneration has developed.

The figure also shows a notable increase in concentration between 2004 and 2006. During this time, Genesee 3 (GN3) came online, the PPA for Sheerness 1 and 2 (SH1 and SH2) was sold and the Calpine Power Income Fund entered into a series of long term tolling arrangements (and eventual sale) of the Calgary Energy Centre (CAL1).

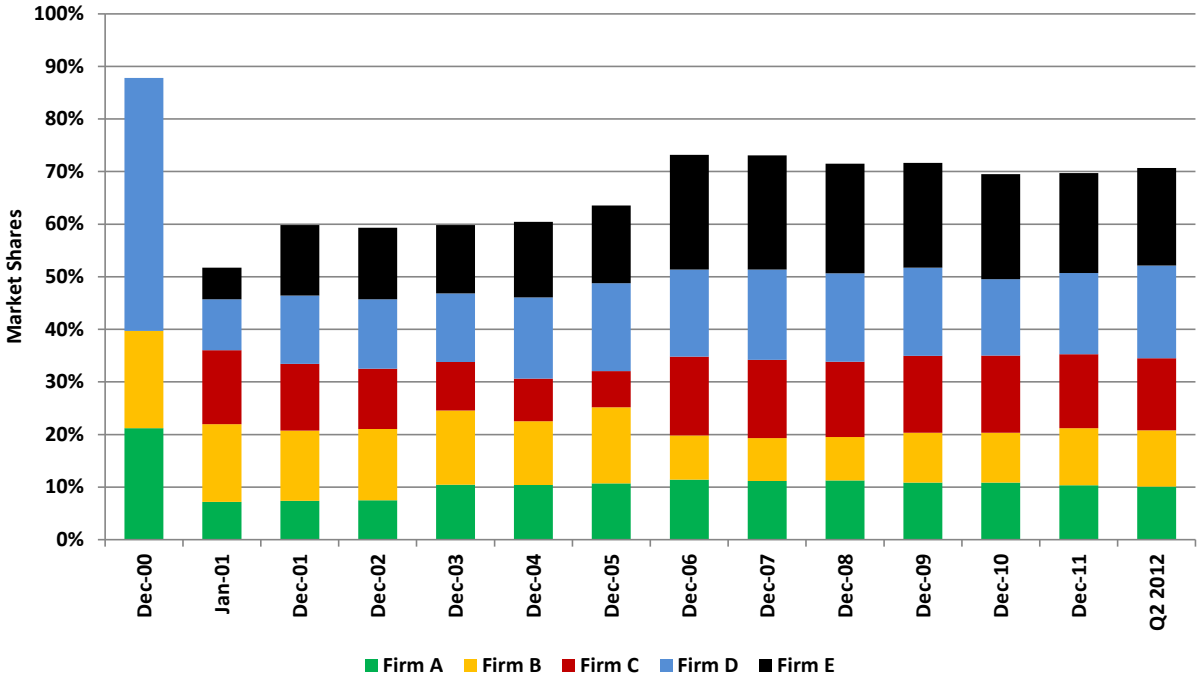
[12] Prior to 2008, capacity is defined as the Maximum Continuous Rating of a unit; thereafter, capacity is measured by Maximum Capability (MC). For assets which have an MC that is currently discounted because of transmission constraints, the asset's MC is used for the entire sample. The capacity of Sundance A is included throughout.

[13] The wind capacity that is currently being offered into the pool under a pilot program is assumed to be under the offer control of the relevant participant in the Q2 2012 calculations

[14] The exception to this is that the Fort Nelson (FNG1) asset is included in the analysis. This asset is physically located in BC but electrically is connected to the Alberta grid.

[15] This results in a slightly different assignment of offer control than is used in the Market Share Offer Control assessment published annually by the MSA.

Figure 3.1: The Annual Market Shares of Today's Largest Five Firms



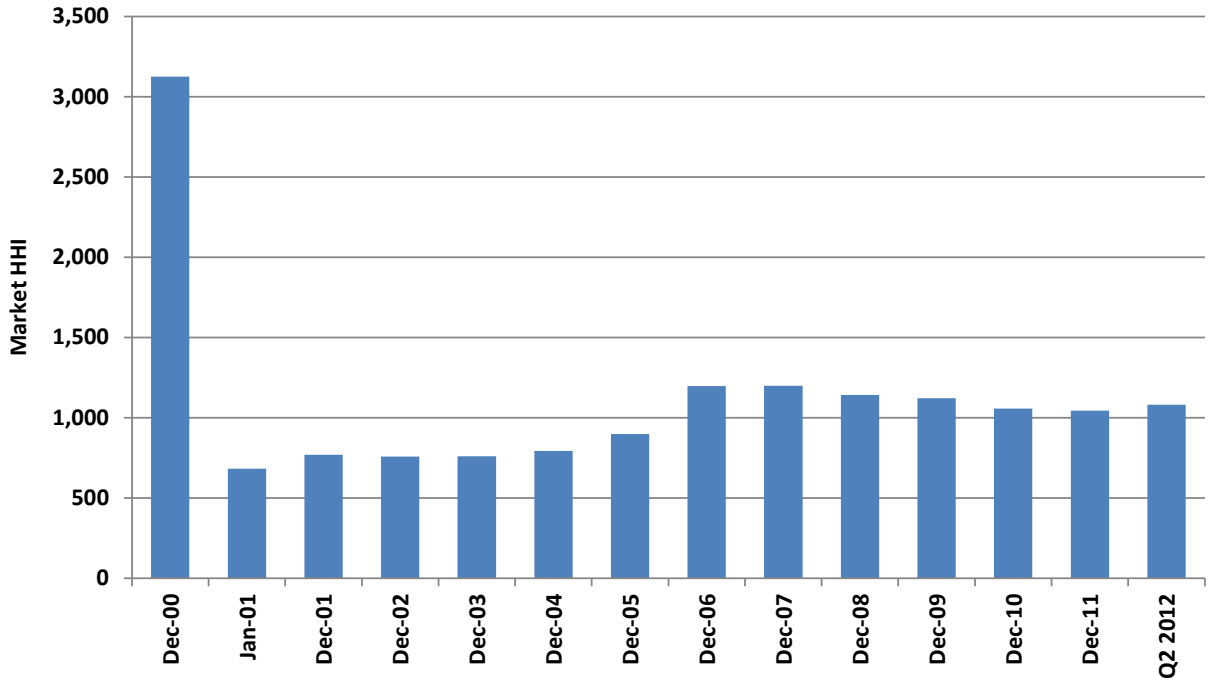
3.3.3 The Herfindahl-Hirschman Index (HHI)

Figure 3.2 shows annual estimates of HHI based on the capacity of units at the end of each year. Again, the capacity of units has been allocated according to offer control. Assets under the control of the Balancing Pool or under the control of strip holders as result of subsequent Market Achievement Plan (MAP) auctions have been assumed to represent diverse ownership (i.e. add no points to HHI).[16]

Overall, the HHI calculations highlight the same concentration patterns as the market shares measure discussed above. The market concentration falls from over 3,000 to below 700 as a result of the initial PPA auctions, and market concentration is shown to increase notably in 2001, 2005 and 2006. As well, the market HHI is shown to peak at the end of 2006 with a value of 1,165. Since then, the annual HHI calculations imply that the market has become less concentrated, as independent energy companies have built additional capacity and total wind capacity has increased by almost 600 MW.

[16] Making an alternative assumption that assets under Balancing Pool control and PPA strips are treated as a single participant, the values for HHI between Jan 2001 and Jan. 2006 are higher but follow a similar trend.

Figure 3.2: Annual Market HHI Based on Offer Control of Capacity



3.4 Limitations of Simple Market Concentration Metrics

It is widely recognized that concentration measures are limited in their ability to analyze the extent of competition in power markets as the measures provide a poor proxy for the market power of wholesale generators. For example, Sheffrin (2001) highlights that under certain definitions of the relevant market no single supplier in California had a market share as high as 20 percent during the market crisis. Likewise, Blumsack et al. (2002) calculate a market HHI of 664 for the deregulated California market.

> [T]he generic weaknesses of diagnosing market power with concentration measures are magnified in the electricity industry.
>
> (Borenstein, Bushnell and Knittel (1999))

> A major criticism of market share and HHI analysis for electricity markets is that even where the most dominant net seller has a relatively small market share they may still be able to exercise market power.
>
> (Twomey, Green, Neuhoff and Newbery (2005))

3.4.1 Why is Market Power an Issue in Electricity Markets?

To understand why simple market concentration measures may understate the market power of firms in wholesale electricity markets, it is necessary to highlight that electricity markets are unique in a number of important ways:

- **Capacity Constraints and Non-Storability** – Electricity is a distinct commodity because it cannot readily (economically) be stored and its production is subject to strict capacity constraints in the short-run. Therefore during times of high demand rival firms are often meaningfully constrained

because generation cannot be increased beyond physical capacity limits and electricity cannot be generated beforehand and stored in anticipation of the market conditions. Consequently, the supply response can be significantly limited at times of peak demand and the price rise a firm can obtain by economically withholding a relatively small amount of generation may be substantial during these periods.

- **Outages and Unit Derates** – Unit outages and derates are a major factor in the supply of electricity. Generating assets can go on outage or be derated for a number of reasons (operation issues, required unit maintenance and prevailing weather conditions are all examples) and the supply-side of the market can be considerably affected for extended periods of time. Outages and derates at the generating facilities of competing firms will serve to increase the market power of a market participant because the supply-response it faces is reduced. Outages and derates at a firm's own generating facilities will limit the extent to which the firm can exercise market power through economic withholding.
- **Congestion** – Congestion can limit the ability of competitors to respond to attempts to exercise market power. In some electricity markets, market wide concentration metrics are often abandoned in favor of those examining local market power, where the locality is defined by limitations in the transmission system.
- **Lack of Substitutes (Demand Inelasticity)** - As the market demand becomes increasingly inelastic (less sensitive to price increases) the unilateral market power of firms increases. Simply put, with inelastic demand economically withholding a given amount of output has a larger impact on price. In contrast, if market demand is very responsive to price changes, a firm withholding a large amount of capacity may only realize a small increase in price. The demand for electrical power is almost perfectly inelastic in the short-run because there are few, if any, substitutes for electricity. Price responsive loads are usually limited to a small number of industrial consumers that monitor prices in real-time and curtail demand when prices spike above a certain level. Programs to create additional demand response have been introduced in some markets but not without problems.

Aside from tending to understate the unilateral market power of firms in power markets there are other issues that limit the applicability of simple market concentration metrics. We consider these briefly in the next two sections. In Section 3.4.2, we highlight some of the fundamental or theoretical flaws with using market concentration measures to assess market power. In Section 3.4.3, we discuss the important practical issues that arise when applying concentration metrics in the context of Alberta's wholesale market.

3.4.2 Theoretical Flaws of Market Concentration Metrics

Once the relevant market is determined, concentration measures are simple to calculate and easy to comprehend. However, even with a clear and accurate definition of the relevant market, there are still a number of important market fundamentals which are not accounted for by measures of market concentration.

Market Demand – Measures of market concentration do not consider the demand-side of the market. In particular, concentration measures will not consider variations in the level of demand, or the responsiveness of demand to changes in price. The market power of sellers will increase as total market demand rises and/or as the demand function becomes less responsive to price (i.e. becomes less elastic). Conversely, the market power of sellers will decline as the level market demand falls and/or the function becomes more elastic.

As discussed in the previous section, the market power of firms will vary importantly as the prevailing level of market demand changes. At peak levels of demand, rival firms can be meaningfully constrained and consequently the price rise a firm can obtain by economically withholding a relatively small amount of generation may be substantial. On the other hand, when demand is low there is generally a significant amount of excess capacity and the ability of firms to exercise market power is usually limited.

The ability or willingness of consumers to substitute away from the underlying product also has an important impact upon the market power of suppliers. As the market demand becomes increasingly inelastic, the unilateral market power of firms increases. Because participants will face a lower fall in demand, participants can raise the market price more substantially by economically withholding a relatively small amount of output. In the Alberta wholesale market, there is typically no more than 300 MW of price-responsive load at any given time. As a result market demand is very inelastic, with only a small amount of demand responding to major changes in price.

Market Contestability - For incumbent firms to sustain a significant level of market power in the long-run requires barriers to entry in order to prevent new firms from entering the market and eroding the market power of incumbent firms. Concentration metrics calculated using a Law of One Price market definition will not consider whether there are important competitive constraints provided by potential market entrants.

The theory of contestable markets implies that market concentration measures cannot be used to gauge market power and instead highlights entry and exit conditions as the major determinants of firms' ability to raise prices above the competitive level. For instance, Baumol, Panzar and Willig (1982) contend that the existence of only a few firms does not imply a lack of competition since the threat of entry can be effective in disciplining market power within an industry. As a result, firms that enjoy high market shares do not necessarily have a high amount of unilateral market power in the absence of entry barriers.

Broadly speaking, entry barriers can be defined as factors that can allow incumbent firms to exercise market power without attracting entry because entrants anticipate non-positive profits.[17] The major economic factors that affect the entry decisions of new firms are the sunk costs of entry, and the expected profitability of entry. For a given level of expected profits, the greater the sunk costs associated with entry, the less likely entry is to occur. However, even if the sunk costs are relatively low, no firm would consider entering the market if post-entry competition was expected to result in margins so small that the costs of entry would not be recovered.

The important point here is that the ability of market shares to accurately gauge the competitiveness of the market will depend implicitly upon the extent and the nature of barriers to entry and exit. If barriers to entry and exit are small, market shares will fail to consider the competitive constraints provided by potential entrants, and will overstate the market power of incumbent firms. On the other hand, if there are considerable barriers to entry and exit, then incumbent firms within a concentrated industry will be more able to sustain a significant level of unilateral market power without being constrained by the threat of new entrants. The 'nature' of entry barriers may also be important. For example, potential entrants may be dissuaded from entering the market if they believe high prices are artificially driven by the market power of incumbent firms rather than by other supply and demand conditions that they observe and model. Equally, potential firms might reason that the risk of non-recovery is too large because the market is overly competitive for post-entry prices to be sufficiently high.

Incentives versus Ability – Simple measures of market shares are defined as structural, ex-ante, measures of market power. These metrics are used to analyze the ability of firms to exercise market

[17] Church and Ware (2000) at pg. 514 paragraph 2.

power, and do not seek to gauge whether or not market power has actually been exercised. This distinction is particularly important in wholesale power markets where the incentives of a firm to exercise market power may not be consistent with the firm's ability to exercise market power. Market concentration measures based solely upon the capacity under a firm's offer control explain that a firm's ability to exercise market power will increase as this capacity control increases relative to the total market capacity. However, a firm's incentive to exercise market power will also depend upon the extent to which the firm is exposed to the market clearing price. In wholesale power markets, firms can meaningfully alter their net position by selling or buying power forward at a fixed price. As a result, there can be an important disconnect between a firm's ability to exercise market power and a firm's incentive to exercise market power.

Generating firms in Alberta can, and do, alter their net positions by buying or selling power in the forward financial or forward physical markets, by participating in the retail market, or by entering into bilateral agreements. A large supplier that sells a significant amount of its generation through fixed-price forward contracts will have little incentive to exercise unilateral market power in real-time. Simple concentration measures will indicate only that this firm has the ability to exercise market power.

Firm Efficiency - As highlighted in the discussion on market contestability, even with a clear and accurate definition of the relevant market, the use of concentration measures will not illustrate whether an increase in market concentration should lead to concerns regarding overall competitiveness or market efficiency. The argument forwarded here is that if one firm in a market is more efficient[18] than the competition, it should be expected that this firm will move to gain market share at the expense of its rivals. As a result, market concentration increases might be expected to occur even in a fiercely competitive environment. It is fundamentally mistaken to equate such an increase of concentration with a lessening of competition or a decrease in market efficiency.

3.4.3 Issues with a Simple Market Definition

As discussed in Section 2, determining the relevant market is a controversial and non-trivial task. In many ways, the market definition used in Section 3.3 is too simplistic to obtain an accurate gauge of market power within Alberta's wholesale market. More specifically, the analysis treats all capacity within the province as equal in terms of its ability to compete in the market.

Imports - The market definition outlined in the FEOC regulation and analyzed in Section 3.4 does not account for the extent to which imports compete in the Alberta energy market. At present, imports into Alberta act as price takers and must be offered at $0. Typically, the two interties between Alberta and neighboring jurisdictions have combined import Available Transmission Capacity (ATC) of around 600 – 750 MW, and in Q2 2012 more than 1,000,000 MWh of energy were imported into Alberta. It is clear that imports into the Alberta energy market do impact the ability of local generators to engage in profitable economic withholding. By failing to account for this capacity, the aforementioned market definition will understate the overall size of the Alberta market and overstate the market concentration levels. Control over firm transmission holdings on the interties is a less significant issue since firms cannot easily withhold that capacity.

Cogeneration Assets - Many of the cogeneration assets in Alberta have been developed to take advantage of economies of scope[19] in supplying on-site demand for both electricity and steam. The limitations

[18] Efficiency in this context implies a firm has lower production costs or greater operational expertise than rivals who have the same access to inputs.

[19] Economies of scope occur when it is cheaper to produce goods together rather than apart. Economies of scope arise from shared inputs – in this case, fuel that can be used for electricity and steam at the same time.

imposed by steam requirements impacts their participation in the electricity market and the extent to which offer control over such assets results in increased market power. In addition, many cogeneration assets consistently declare an Available Capability (AC) that is notably less than the asset's stated Maximum Capability (MC).[20] As well, cogeneration units may declare MC on a gross (total possible production) or a net basis (total possible flow to the grid) such that MC for different assets are not directly comparable. Including the entire MC of cogeneration assets will tend to overstate the extent to which these assets compete in the Alberta wholesale market.

Wind Capacity – Over 1,000 MW of Alberta's total capacity is wind generation. Wind capacity is included in the denominator of our simple market definition, but not assigned to any participant in terms of offer control. Wind generation is rarely available at a level indicated by its MC. Including the entire capacity of wind within the market definition fails to reflect the seasonality / timing of this generation, and will tend to understate market concentration and unilateral market power of generators.

Hydroelectric Capacity – Approximately 7% of Alberta's total capacity comes from hydroelectric generation. Some of the province's hydro assets are highly constrained by minimum flow and other environmental constraints such that there is very limited discretion for the controlling market participant. Other hydroelectric units have lower must-run obligations but are constrained by the seasonality of water flows and by storage limitations. As a result, hydro units cannot maintain generation at levels close to the assets' stated MC for a sustained period. Using the MC of hydro units in the market definition likely exaggerates the ability of these units to compete in the market, particularly in a long-run analysis, and fails to show the seasonal effects of water flows on the market.

The Electricity Market is Dynamic - A final and more general critique is that an annual snapshot of capacity concentration fails to illustrate the dynamic nature of supply-side competition in Alberta's wholesale market. The concentration of supply available can change considerably from one hour to the next with unit outages and capacity derates, volatile wind supply, and varying flows on the interties. These variables have been observed to change the extent of market competition significantly. While an hourly analysis of market power is, in and of itself, a short-run point of view, persistent market power in the short-run clearly translates into a longer term dynamic.

[20] For a generating unit AC is defined as the maximum quantity (in MW) that the generating asset is physically capable of providing during a particular hour. A generating unit's MC is the maximum quantity (in MW) that the generating asset is physically capable of providing under optimal operating conditions.

4. Alternative Approaches

In this section, we consider alternatives to the simple annual market concentration metrics outlined in the previous section. These alternative metrics address some of the shortcomings associated with the simple approaches. In this section we consider:

- Local Market Power
- Alternative Capacity Definitions
- The Residual Supply Index
- Residual Demand Analysis

4.1 Local Market Power

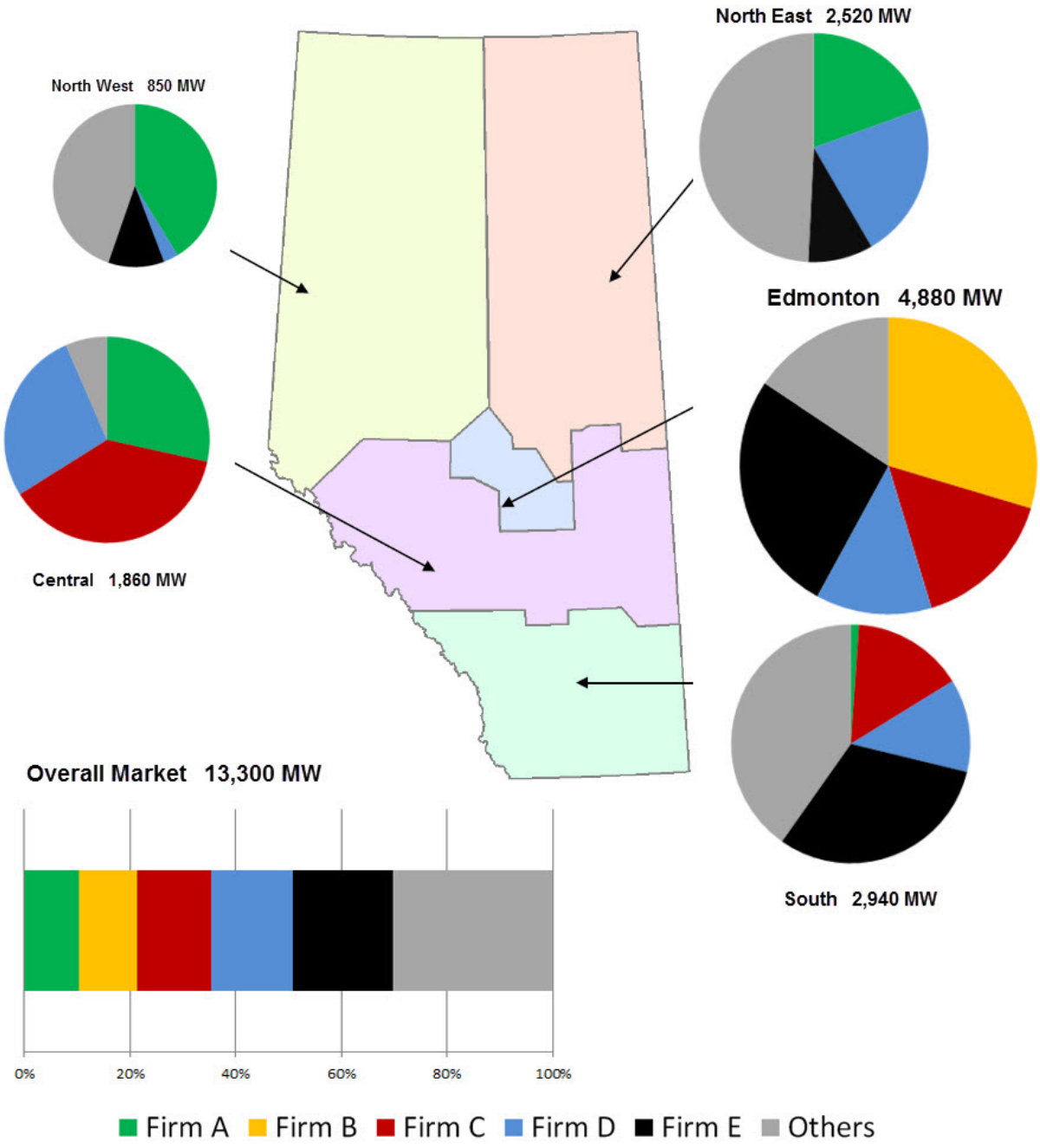
The *Transmission Regulation AR86/2007* requires the AESO to plan and build a transmission system with little or no congestion such that all generators can compete to serve load. However, it is not always possible to build transmission ahead of the needs and there are periods of time when congestion may occur. In the event of congestion, local market power may be a concern. ISO Rule 302.1 sets out the procedures the AESO will follow in determining dispatch in the event of real time congestion. This may result in generators downstream of the constraint facing less competition than would have otherwise been the case and therefore being more able to exercise market power.

To provide a simple demonstration of how market power can change in the event of transmission constraints, we consider the local market shares in Dec. 2011 for each of the major planning regions within Alberta. The market shares in each region are calculated using the Maximum Capability of generating assets within the region. Small power producers and non-wind generating assets which do not offer into the power pool are not included in the regional calculations and so the sum of the regions is approximately 250 MW less than the total market size. Wind assets are included (using MC), although they are assigned in the offer control of 'Others'.

The resulting market shares are seen to vary considerably from one region to another, as illustrated by Figure 4.1 on the following page. The largest local market in terms of generation capacity is the Edmonton planning region. Four of the five large participants have a significant stake here, with two firms controlling almost 60% of the local capacity. The Southern region of Alberta is shown to be relatively unconcentrated, largely because there is a significant amount of wind capacity within this region. Removing wind capacity entirely gives the largest participant in the South a local market share figure of over 40%. In the Northeast, local capacity is dominated by cogeneration units and the market is shown to be relatively competitive as a result; 50% of the capacity controlled by Other firms. Even the 20% offer control highlighted for two of the larger firms likely overstates their offer control over these assets. The central region of Alberta is arguably the most concentrated local market. In Central Alberta 'Other' firms have a very limited presence and one firm controls close to 40% of the local capacity. Likewise, the Northwest market, which is the smallest of the planning regions, is largely dominated by a single firm with 40% offer control, although the remainder of the market is relatively competitive as Others control some 45%.

Considerations of local market power can also be combined in more complicated metrics, but that is beyond the scope of this report.

Figure 4.1: Offer Control of Local Capacity by AESO Planning Region (December 2011)



4.2 Alternate Capacity Definitions

In this section we consider two alternatives that address some of the issues with relying upon Maximum Capability (MC) values to determine unilateral market power.

4.2.1 Market Shares based on Monthly Effective Capacity

In Section 3.4.3 we noted issues with using MC for cogeneration units, wind farms and hydroelectric generators. Section 3.4.3 also highlights that imports are an important factor in market competition. Here we instead estimate a monthly 'effective capacity' of generation assets and imports using the following steps. The method is intended to be illustrative of the impact that reliance on MC has on estimates of markets shares.

- **Thermal Units (including cogeneration assets)** - The monthly effective capacity for a thermal unit is calculated as the 95th percentile of the hourly Available Capability[21] for any given month. The 95th percentile was chosen to avoid extreme outliers which are not reflective of a unit's ability to compete.[22] The adoption of this assumption for thermal assets means a unit on a prolonged outage would not be included in the market share estimates for that month.
- **Wind and Hydroelectric Capacity** - To illustrate the capacity of hydro and wind generation to compete in the market, metered volume data is used. The monthly effective capacity for wind and must-run hydro assets is estimated by calculating the average hourly dispatch within a given month. To reflect the fact that some hydro units are able to store water and arbitrage their dispatch levels, the monthly capacity for these hydro units is calculated as the average dispatch during peak hours within the given month.
- **Imports** - The same assumption used for thermal capacity is applied to imports - using the 95th percentile of the hourly scheduled flows for a given month.
- **Small power producers** (units which do not offer an AC into the market) are treated in simple manner by assigning a constant effective capacity of 150 MW.

The resulting monthly effective capacity figure is shown by fuel type in Figure 4.2. As shown by the monthly total capacity estimates, the definition of the Alberta market using MC overstates the overall size of the relevant market and the capacity actively competing in the wholesale market is much smaller. The largest total monthly effective capacity was 11,300 MW in December 2010, compared to a total MC at that time of 12,700 MW. For cogeneration, wind and hydroelectric generation the differences are quite pronounced.

- **Cogeneration Units** - The highest monthly effective capacity for cogeneration units was set in February 2012 when the estimated capacity was 2,760 MW compared to total MC of over 3,300 MW, and at this time the CSD page noted the total capacity of cogeneration units in Alberta to be in the region of 3,900 MW.[23] The lowest capacity estimate for cogeneration units was 2,070 MW in June of 2008 when the MC of these units was close to 3,000 MW.

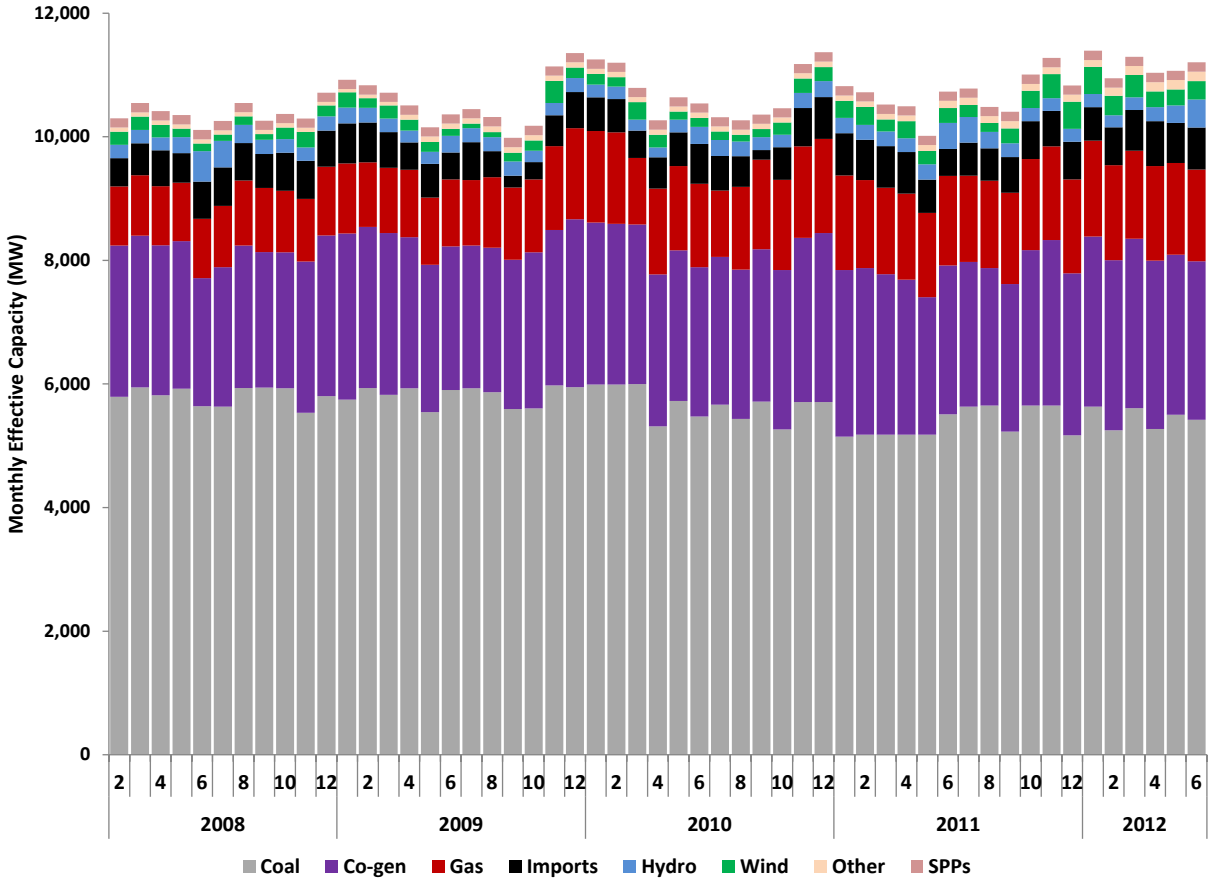
[21] Under the ISO Rules in the absence of an Acceptable Operating Reason, AC must equal MC. However, AC changes over time as units experience derates or outages.

[22] For example, some cogeneration units may experience unusual operating conditions that result in declaration of a particularly high AC in a handful of hours.

[23] The capacity figure noted on the CSD page is larger than the MC figure because some cogeneration units report their MC to be their net-to-grid capacity rather than the unit's gross production capacity which is shown on the CSD.

- **Wind Generation** - The highest monthly effective capacity was 440 MW in December of 2011; at that time the total MC of wind generation was over 860 MW. The lowest aggregate monthly estimate for wind occurred in July 2009 when the average hourly supply was under 80 MW.
- **Hydroelectric Generation** - The largest aggregate effective capacity figure was set in June 2009 when the estimated effective capacity was 492 MW with the lowest value of 162 MW being recorded in April 2010. The total MC of the hydro units which offered into the market during the sample period was 836 MW.

Figure 4.2: Monthly Effective Capacity (MW) by Fuel Type



To obtain monthly market shares metrics using the monthly effective capacity requires assignment of offer control. Imports and wind generation were not assigned as under the offer control of any market participant, but were included in the total market supply. The assignment of offer control on the remaining units is the same as assumed in Section 3.3.

Figure 4.3 shows the monthly market share estimates using monthly effective capacity. The figure shows that the five firms generally control less than 70% of the market capacity and since 2011 the monthly figure has varied between 66% and 69%. The highest monthly market share for the five firms was noted in September 2010 when the five firms controlled 73% of the market, with the lowest value occurring in April 2011 at 66%. Total effective capacity fell notably at the beginning of 2011 because of prolonged outages at SD1 and SD2 which also reduced the offer control of one of the five firms.

Table 4.1 compares the range of monthly effective capacity market shares for the first half of 2012 with the market shares estimated in Section 3.3. For the sake of comparison, the figures reported in Table 4.1 have removed the Sundance A units from the earlier analysis. The principal driver behind the differences shown is that using monthly AC data shrinks the capacity of cogeneration units as compared with the earlier analysis, which used MC figures. As a result, the overall market capacity is smaller, and participants with thermal capacity that is not cogeneration are shown to have a larger share of the market, while firms controlling cogeneration facilities have a lower share of the total effective-capacity.

Figure 4.3: Monthly Market Shares based on Effective Capacity

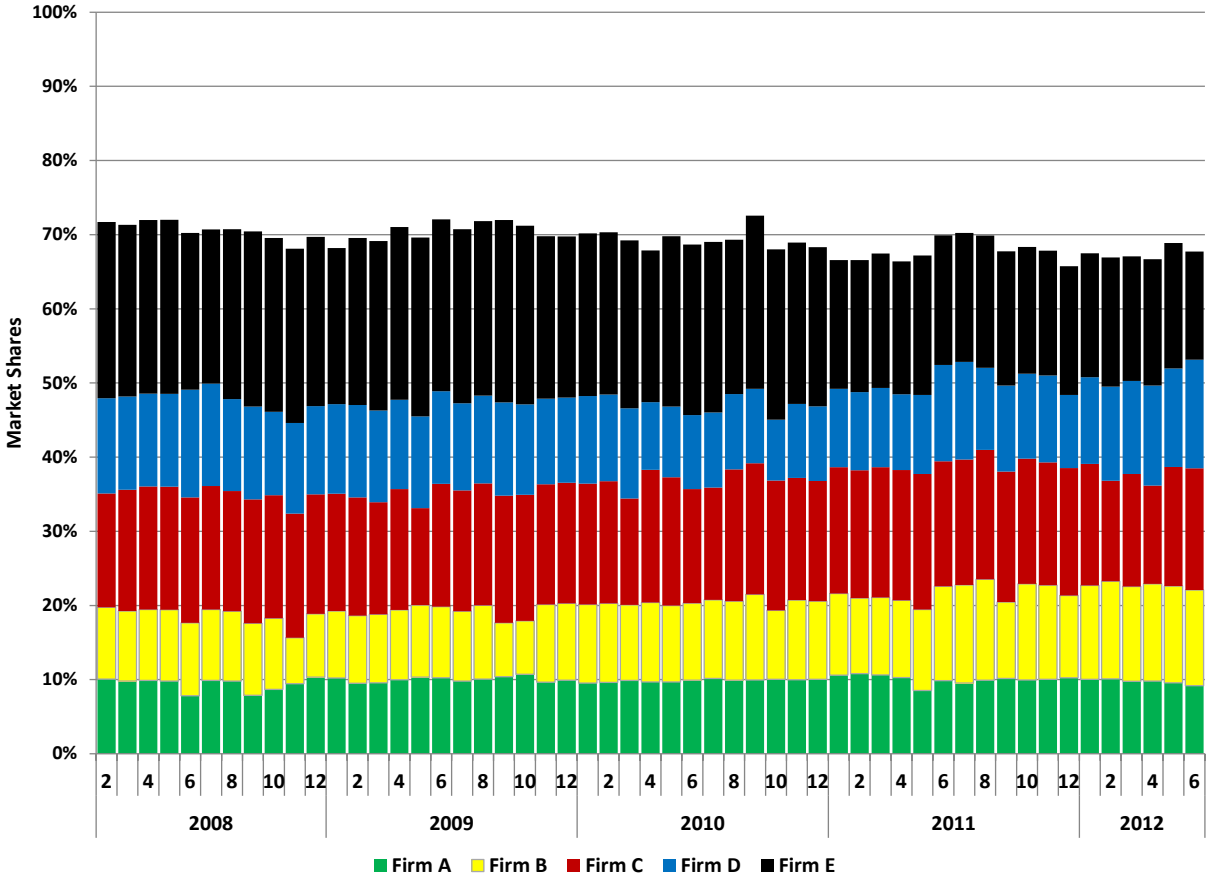


Table 4.1: A Comparison of Estimated Market Shares in 2012

	Section 3.3 Q2 2012 (excluding SD1 and SD2)		Q1-Q2 2012 Range using Monthly Effective Capacity	
Firm A	1,380 MW	11%	1,030 – 1,140 MW	9 - 10 %
Firm B	1,460 MW	11%	1,440 – 1,445 MW	13%
Firm C	1,870 MW	14%	1,460 – 1,870 MW	14 - 16%
Firm D	2,400 MW	18%	1,330 – 1,640 MW	13 - 15%
Firm E	1,960 MW	15%	1,630 – 1,909 MW	15 - 17%
Total A,B,C,D,E	**9,060 MW**	**69%**	**7,330 – 7,690 MW**	**67 - 69%**
Total Capacity	**13,050 MW**		**10,950 – 11,390 MW**	

4.2.2 Market Shares based on Hourly EMMO Capacity

Annual or monthly market shares will fail to capture the impact shorter term outages have on market power. In this section we use hourly Energy Market Merit Order (EMMO) data on MW available for dispatch. The hourly market share for a given firm *i* in a particular hour is equal to:

$$MS_{ih} = \frac{Available\_MW_{ih}}{Total\ Supply_h} * 100$$

Total Supply is calculated to reflect the total capacity available in the EMMO. Included are imports, dispatches for DDS and energy supplied as TMR. Wind generation which does not offer in the merit order is also included (using an average net-to-grid for any given hour). Capacity committed to the operating reserves market is not included in either the total supply or in the offer control of market participants. Energy available in any given hour from hydroelectric generation is not discounted further in this short-term analysis. Any long-lead time units that could compete but have chosen to be offline are not included. In summary, this hourly analysis takes a short-term perspective and will illustrate the ability of a firm to affect the pool price within a particular hour through the economic withholding of generation in the merit order.

The use of hourly data allows some further refinements regarding offer control. MW providing dispatch down service (DDS) are included in a market participant's offer control, whereas MW dispatched to provide Transmission-Must-Run (TMR) are not since TMR generation cannot be withheld. As with the preceding sections, wind and imports are not assigned to the offer control of any market participant and only the excess energy / increased capacity on PPA units is assigned to the owner.

Figure 4.4 shows annual duration curves for the hourly sum of the market shares for today's five largest participants (effectively the 5-firm Concentration Ratio (CR5)) from Feb 2008 through Q2 2012. The figure illustrates that market shares vary significantly in different hours and that the hourly energy market has generally become less concentrated since 2008. Figure 4.5 also highlights these two trends.

At the individual firm level, the hourly concentration metric illustrates the impact of unit outages on market shares. Figure 4.6 shows the average hourly market shares for the large 5 firm on a monthly basis. The figure implies that declines in the average hourly market share for a given month tend to correspond to major unit outages.

Figure 4.4: Duration Curves Showing the Hourly CR5 by Year

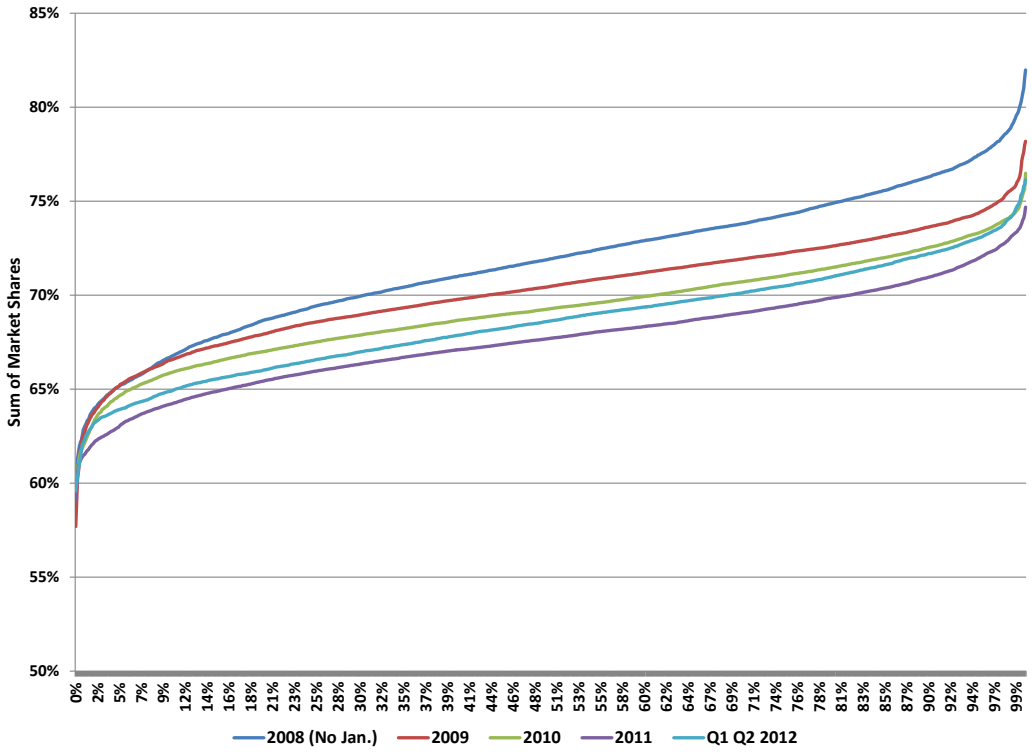


Figure 4.5: The Average, Minimum and Maximum Hourly CR5 by Quarter

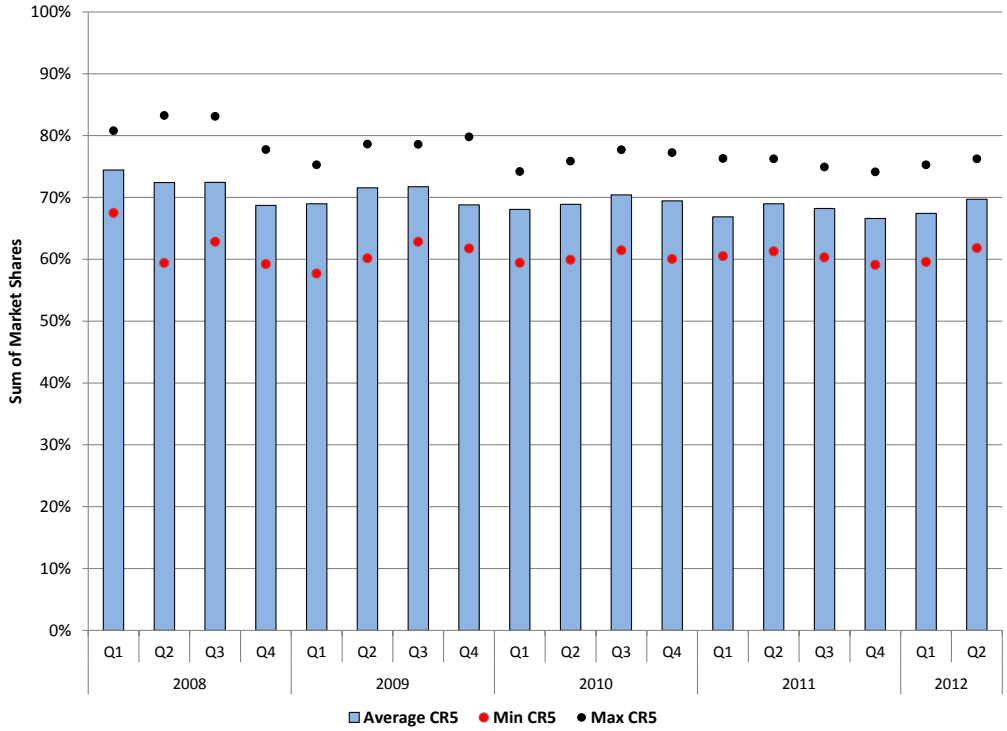
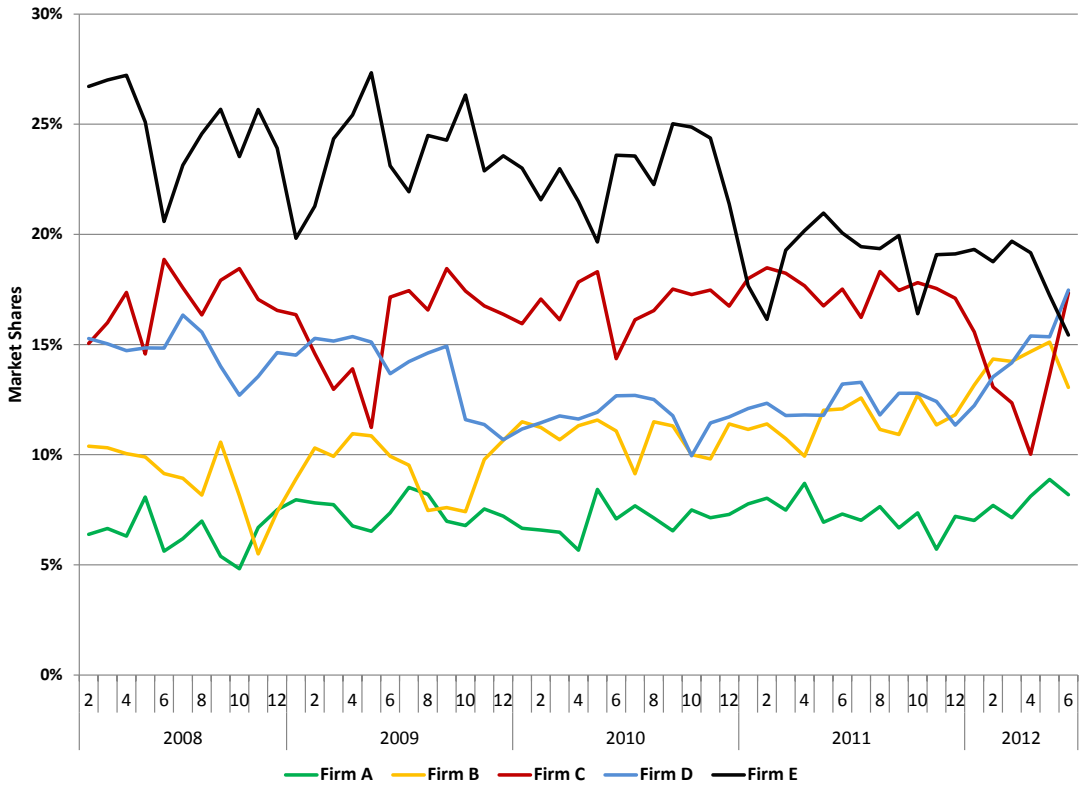


Figure 4.6: Average Hourly EMMO Market Shares by Month



4.3 The Residual Supplier Index

A principal deficiency of the concentration measures used in the previous sections is that they fail to account for variations in market demand. For example, during off-peak hours (notably overnight) the demand for electricity falls substantially, whereas supply capability remains relatively stable. Consequently, unilateral market power in these hours is likely to be significantly lower than during on-peak periods when the supply demand balance is tighter. This distinction will not be shown by analysis of annual or monthly market shares.

In this section we estimate a Residual Supplier Index (RSI) which measures the concentration of offer control relative to the prevailing level of demand.[24] It is important to highlight again that the RSI calculated here is a structural measure of market power. That is, the RSI analysis does not account for a firm's portfolio position and therefore it does not illustrate whether a firm has the incentive to exercise market power. Also, the RSI calculation does not indicate whether or not market power has been exercised.

Fundamentally the RSI is a measure illustrating the extent to which a particular firm is 'pivotal' to the clearing of the energy-market. A supplier is defined as pivotal if total market demand exceeds the available capacity that is under the offer control of other market participants. In other words, some of the supplier's generation is required for the market to clear. The MSA's *Analytical Framework* outlined that tests for pivotal suppliers will form one element of the suite of metrics to be employed by the MSA in its regular assessment of the health of competition in the Alberta electricity market.

[24] In its 2006 report Market Concentration Metrics, the MSA first produced tests for pivotal suppliers and the RSI metric was introduced specifically in the Quarterly Report: October – December 2010.

The RSI for market participant j (MP_j) during a given hour is calculated using the Energy Market Merit Order (EMMO) snapshot data. A simplified version of the calculation is shown by the following equation:[25]

$$RSI(MP_{jh}) = \frac{(Total\ Supply_h - Supply\ Controlled\ by\ MP_{jh})}{Total\ Demand_h}$$

When the RSI metric is less than or equal to 1, a market participant is pivotal, while a value greater than 1 indicates they are not pivotal. In practical terms there is a richness to the RSI metric that is an improvement beyond simply measuring whether a market participant is pivotal. A lower value of the RSI indicates a firm has greater ability to exercise unilateral market power. More specifically, the RSI metric will decrease as total demand rises, as the Available MW under a participant's offer control increase, and/or as total supply falls.

4.3.1 Residual Supply Index Estimates

In this section we show estimates for the hourly RSI from February 1, 2008 to June 30, 2012.[26] We consider aggregate measures that track the RSI of the largest n market participants within a given hour and RSI estimates for the five largest market participants.

4.3.1.1 Aggregate RSI Measures

At an aggregate level, useful RSI measures to consider are the 'market RSI' (or 1-firm RSI), the 2-firm RSI, and the 3-firm RSI. Each of these measures shows the extent to which the largest n-market participants are pivotal in the Alberta Energy market. For example, the 3-firm RSI will be less than 1 if the capacity of the 3 largest firms is required to meet the prevailing market demand:

$$3\ firm\ RSI_h = \frac{(Total\ Demand_h - (SC_{1h} + SC_{2h} + SC_{3h}))}{Total\ Supply_h}$$

Where SC_{1h} shows the supply controlled by the largest market participant in hour h, SC_{2h} shows the supply controlled by the second largest participant in that hour and similarly for SC_{3h}.

In Figure 4.7 we show the distribution of the 1, 2 and 3-firm RSI metrics. A metric similar to the 3-firm RSI metric is used by the market monitor for the PJM Interconnection[27] in order to determine whether the market is structurally competitive in times of congestion.[28] The "Three Pivotal Supplier Test" test is used to examine whether structural market power exists in the event of transmission constraints. A test failure indicates that the ownership of the supply needed is concentrated among few suppliers and therefore those suppliers have the potential to exercise market power.

The results for the 1-firm RSI show that for almost 90% of the hours from February 1, 2008 through June 30, 2012, the largest market participant in that hour is pivotal. The 2-firm RSI shows that the largest two

[25] The more exact formulation is consistent with the analysis in the MSA's 2010 Q4 report and is outlined in Appendix A of this document.

[26] This time period results in a total of 38,540 hourly observations. Approximately 120 hours are not included due to data quality issues.

[27] The PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

[28] See *The Three Pivotal Supplier Test in the PJM Real-time Energy Marke*t.

market participants are almost always pivotal and the metric has on occasion fallen below 0.6. The 3-firm RSI was less than or equal to 0.8 for all hours in the sample period and has fallen to values as low as 0.4, implying that the three largest firms have a significant amount of structural market power at times.

Figure 4.7: Duration Curves for Aggregate RSI metrics (Feb 2008 – Q2 2012)

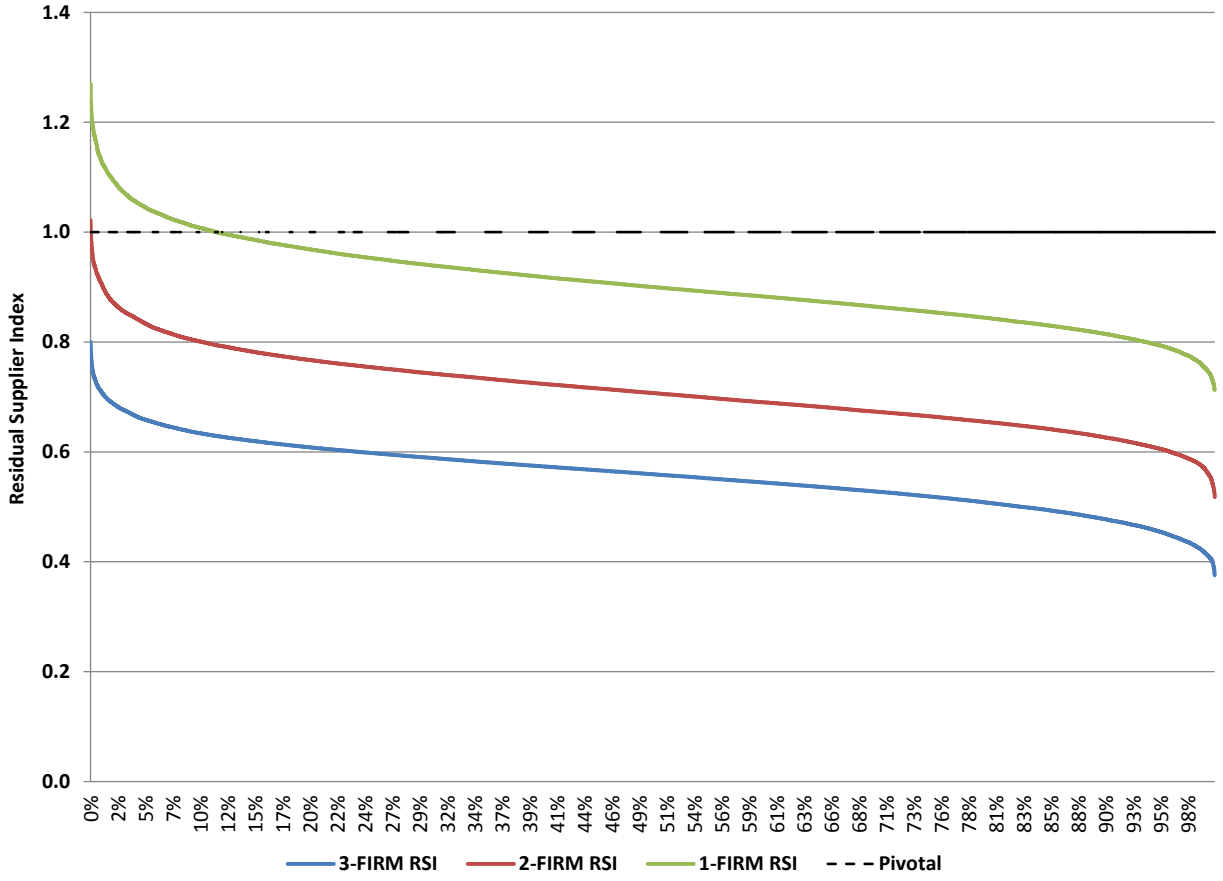


Figure 4.8 shows that over time the monthly average levels for RSI metrics have been trending upwards, suggesting the ability to exercise market power is actually declining, albeit remaining pivotal in many hours. Monthly averages may not accurately capture the distribution of pivotal and non-pivotal hours within a month. Figure 4.9 shows more detailed dates for the 1-firm RSI that support the idea that ability to exercise market power has declined since 2008. The duration curves also show the distribution of the 1-firm RSI has remained relatively stable (i.e. the curves are similar in shape albeit at different levels).

To illustrate the impact of market demand has on the RSI metric Figure 4.10 illustrates the 1-firm RSI in different years at different levels of Total Demand. The increases in RSI (decreases in market power) are particularly notable at lower load levels and much less so at higher load levels.

Figure 4.8: Average of Hourly Aggregate RSI Metrics by Month

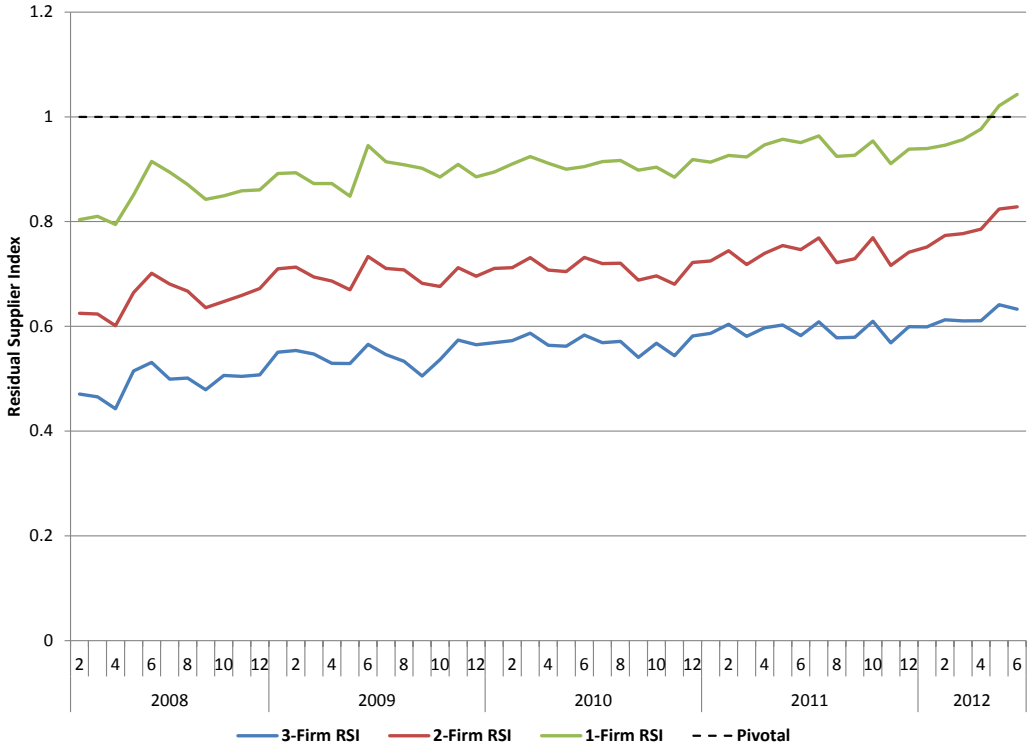


Figure 4.9: Duration Curves for the 1-Firm RSI by Year

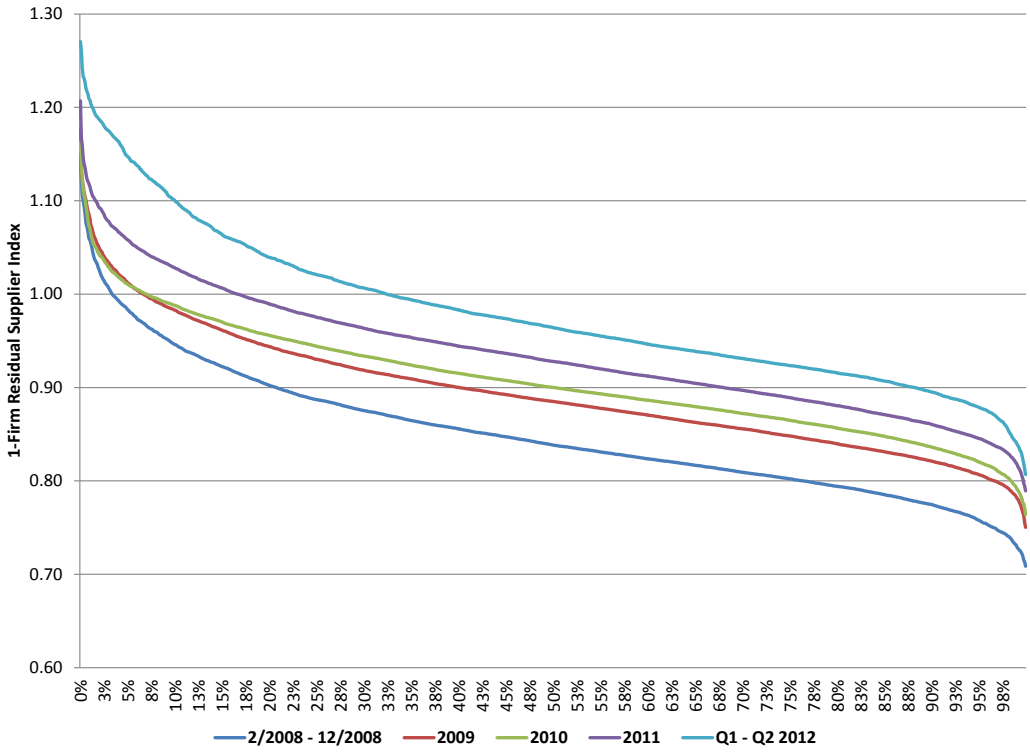
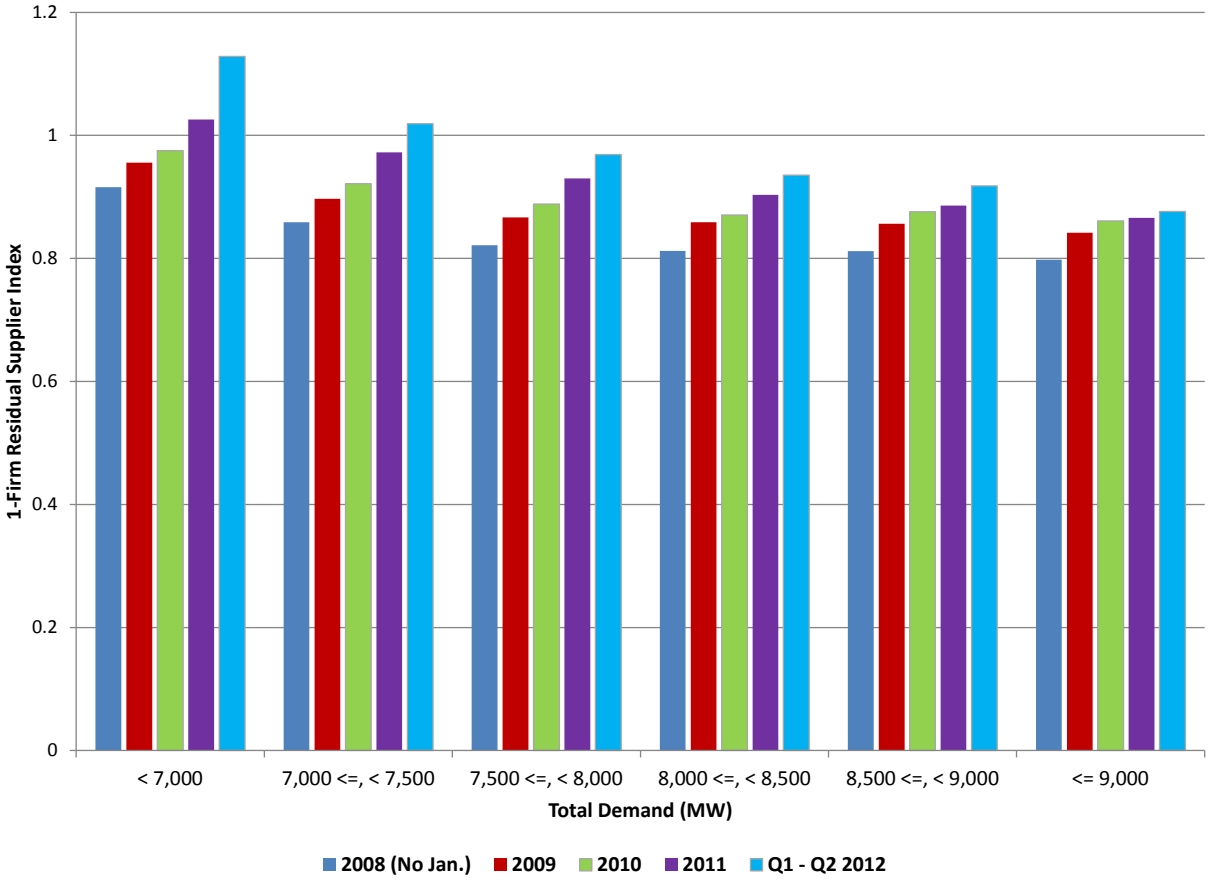


Figure 4.10: The 1-Firm RSI Measure at Different Levels of Total Demand and Across Years



4.3.1.2 Residual Supplier Index by Firms

One aspect the aggregate measures of RSI do not capture is whether or not the set of largest market participants changes over time. This may be important from the perspective of competition since a frequently changing set of large market participants may be consistent with the idea that no single participant or small set of participants can consistently influence market outcomes.

In Figure 4.11 we show the RSI for each of the five largest firms and, for purposes of comparison, the 1-firm RSI. The lowest firm RSI is only slightly above the 1-firm RSI indicating that one market participant is consistently the largest (and pivotal 88% of the time).

Figure 4.11: Duration Curves Showing the RSI by Firm (Feb 2008 – Q2 2012)

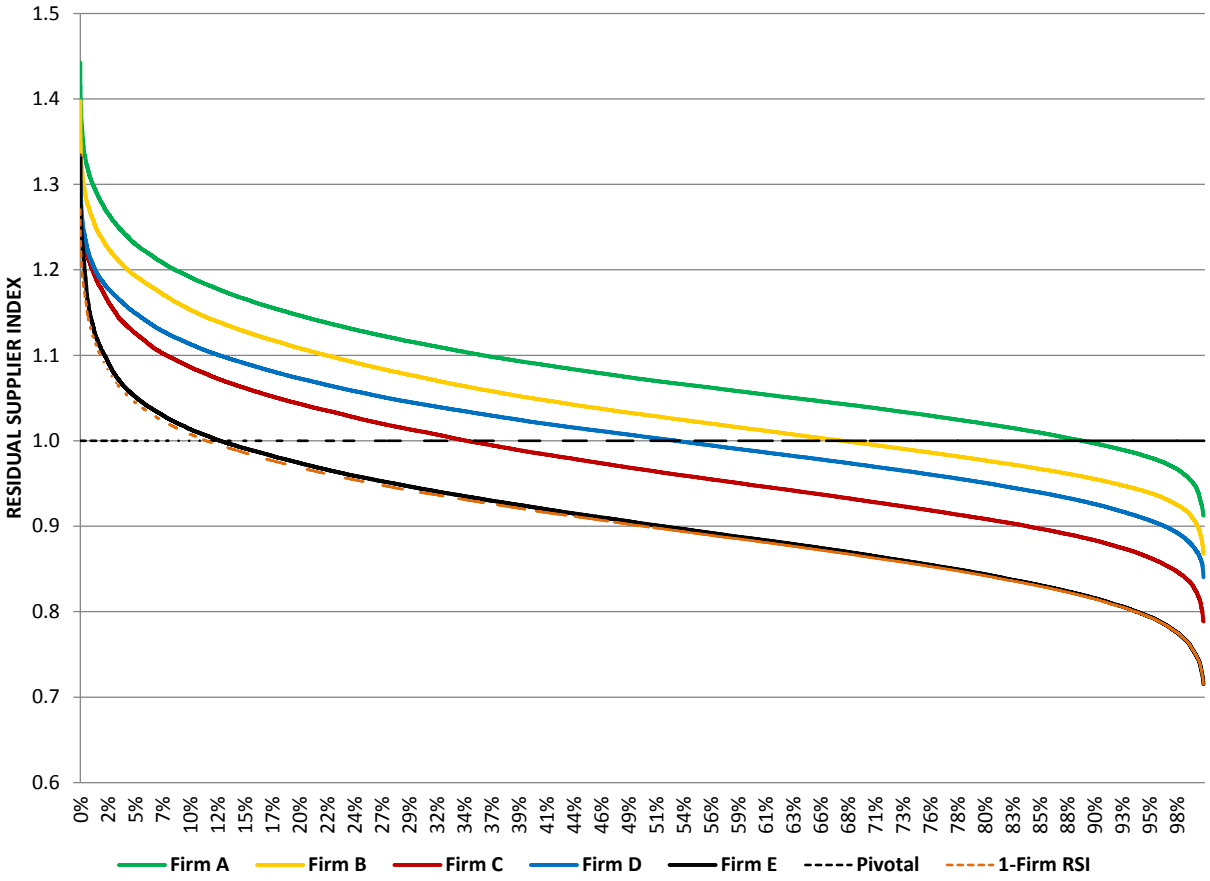


Table 4.2 summarizes how the structural market power (as measured by the RSI metric) has changed over time for the five major participants. More specifically, the table details the percentage of hours in which a firm's supply was pivotal to the clearing of the energy market. Consistent with the aggregate metrics most firms experienced a decrease in the numbers of hours in which they were pivotal since 2008. While the aggregate measures also show a continued decrease in 2011, the firm specific measures show that most firms were pivotal more often that year.

Table 4.2: Percentage of Hours in which Various Firms were Pivotal by Year

	2008 (No Jan.)	2009	2010	2011	Q1 & Q2 2012
Firm A	20%	8%	7%	12%	5%
Firm B	40%	21%	28%	39%	37%
Firm C	81%	61%	65%	73%	34%
Firm D	75%	49%	29%	42%	38%
Firm E	96%	93%	93%	81%	64%

4.3.2 Adjusted Residual Supply Index

One criticism of the assumptions underlying the Residual Supply Index estimated in the previous section is that market participants may not be able to exercise control over all of the MW at their disposal. For example, at cogeneration units the requirement for steam for industrial processes may limit the practical control of a unit's output. Similarly, hydroelectric facilities may have obligations to flow water. The flexibility of thermal units may also be restricted by the requirement to need to run at some minimum level (minimum stable generation). While these units could choose not to run in the short-term, costs may be incurred during start-up and shut-down. Typically, must-run and minimum stable generation levels form the majority, but not all, of the offers made to the market at $0.[29]

In this section we consider a simple modification to the RSI to consider only MW offered above $0 in the energy market merit order. The metric is likely to understate actual unilateral market power, but serves a reference point to compare the RSI estimated in the previous section. [30]

We define the Adjusted RSI metric by:

$$Adj.\ RSI(MP_{ih}) = \frac{(Total\ Supply_h - (Supply\ MP_{ih} > \$0))}{Total\ Demand_h}$$

where the definitions of Total Supply and Total Demand are consistent with the previous analysis.

And

$$(Supply\ MP_{ih} > \$0) = [Total\ Supply\ MP_{ih}\ -\ (Supply\ MP_{ih} = \$0)]$$

The interpretation of the metric remains the same as the unadjusted RSI measure and a lower value of the Adjusted RSI is indicative of greater structural market power. In general, the Adjusted RSI may be a good indicator of short term market power for periods when the economic withholding of must-run generation is rare. This has typically been the case over the sample period, but may not continue to be the case going forward. One disadvantage may be that it begins to move away from a structural measure of ability to a measure of incentives (i.e. offers at zero may be a function that a firm has decided not to exercise market power, not that they lacked the ability).

In Figure 4.12 we show the monthly trend of average adjusted RSI and for purposes of comparison repeat the equivalent figure for the unadjusted RSI. Unsurprisingly, in comparison with the RSI metrics, the Adjusted RSI metrics shows higher monthly values indicating less structural market power. The monthly average of the 2-firm RSI, for example, has typically been in the region of 0.6 - 0.8 whereas the Adjusted RSI figure has been around 1. In terms of trends over time, none of the Adjusted RSI metrics show the distinct upward trend that is evidenced in Figure 4.8, although both illustrate a notable decrease in market power during Q1 and Q2 2012.

[29] See MSA Report on Zero Dollar Offers for a general discussion of why firms might offer at $0.

[30] It should be noted that while these must-run megawatts may not increase the firm's ability to exercise market power, they will impact the incentives of a firm to exercise market power. A large number of must-run megawatts exposed to the spot price will increase the firm's incentives to raise the market price, although this position maybe offset by selling forward fixed-price contracts.

Figure 4.12: Average of Hourly Aggregate Adjusted-RSI Metrics by Month

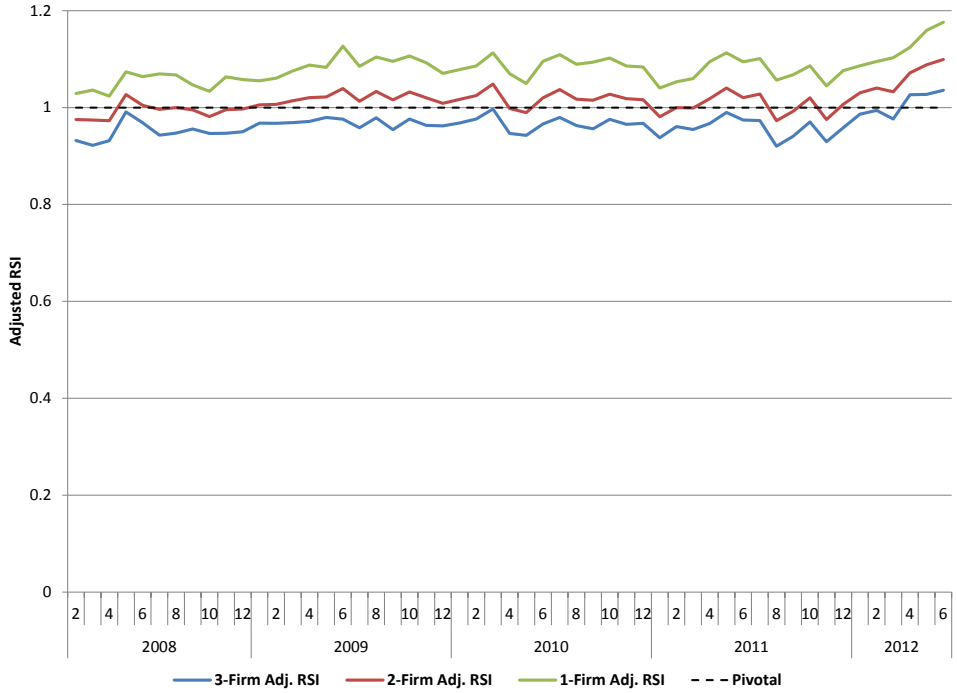


Figure 4.13: Average of Hourly Aggregate RSI Metrics by Month

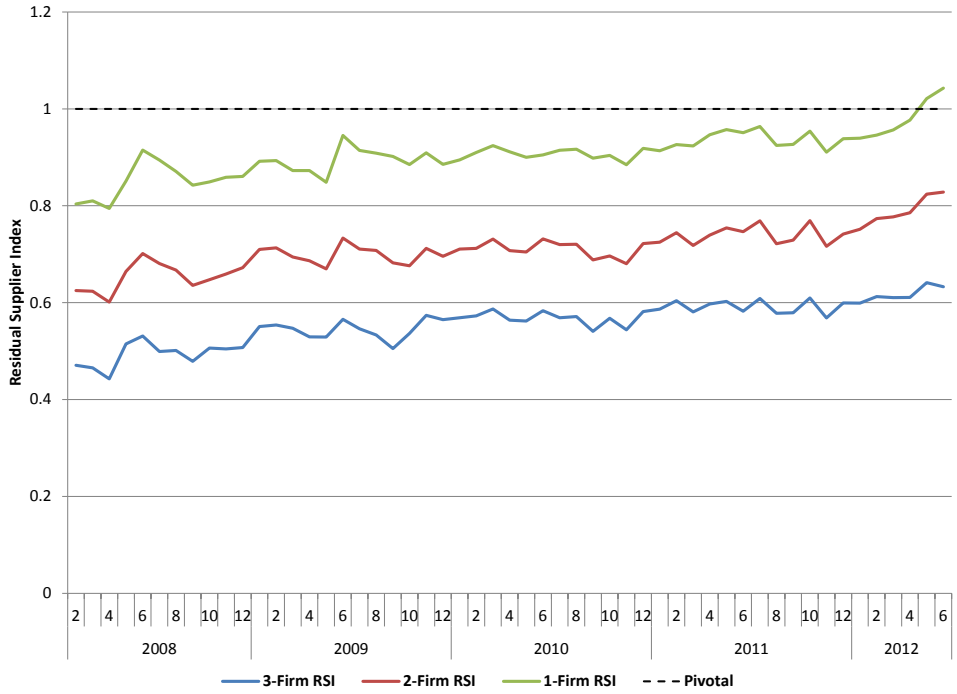
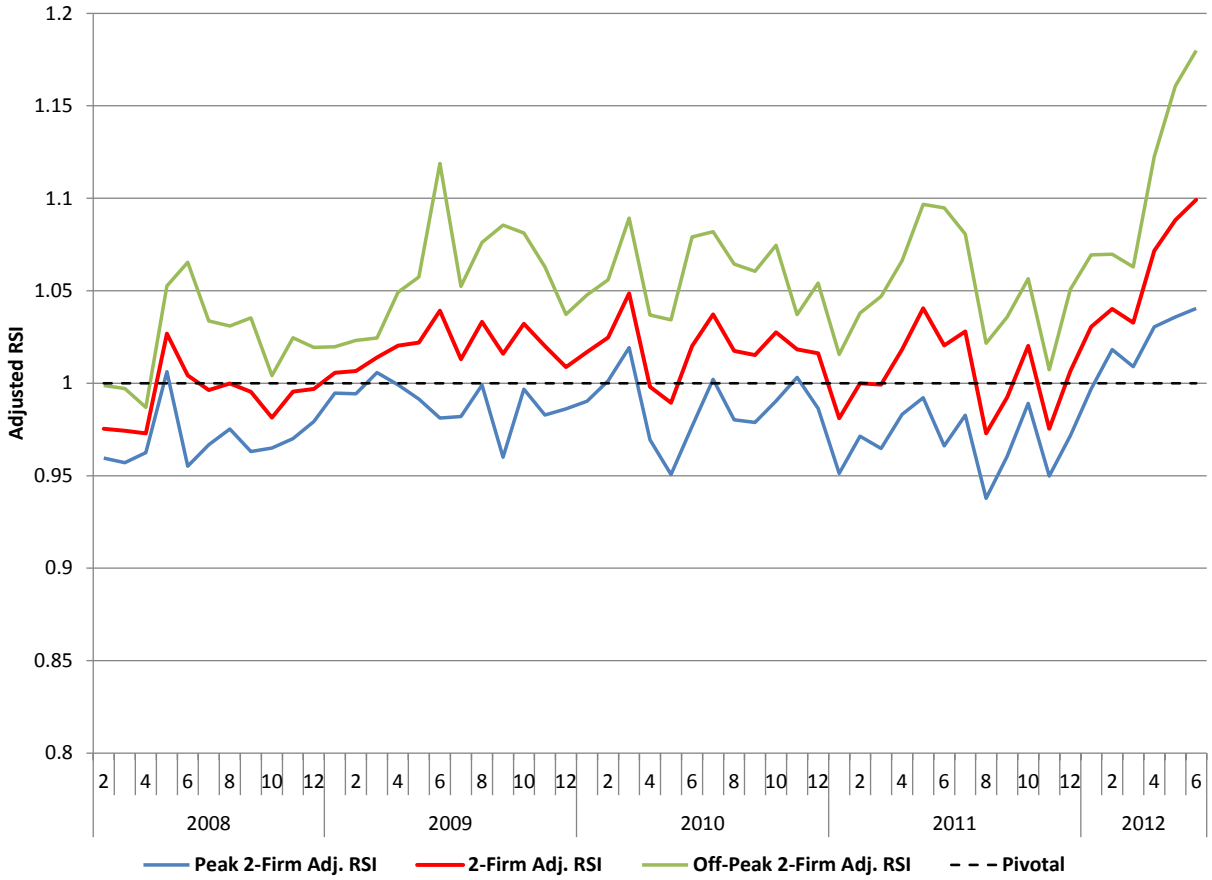


Figure 4.14 illustrates the same long-term analysis for the 2-firm Adjusted RSI and distinguishes between on and off-peak hours. Unsurprisingly, adjusted RSI is lower in on-peak hours when demand is typically higher. Again no clear trend is observable for either the on-peak or off-peak hours, and the off-peak adjusted RSI has increased more significantly in 2012.

Figure 4.14: Average of Hourly Peak and Off-Peak Aggregate Adjusted-RSI Metrics by Month



Duration curves for the adjusted RSI (Figure 4.15) show that individuals firms are still pivotal in some hours. The interpretation is that if they choose to move the prices associated with all energy offered at a positive price, they could determine the pool price unilaterally. The percentage of hours in which this is the case is notably higher in 2008 and 2011 than in other years (Table 4.3).

Figure 4.15: Duration Curves Showing the Adjusted RSI by Firm (Feb 2008 – Q2 2012)

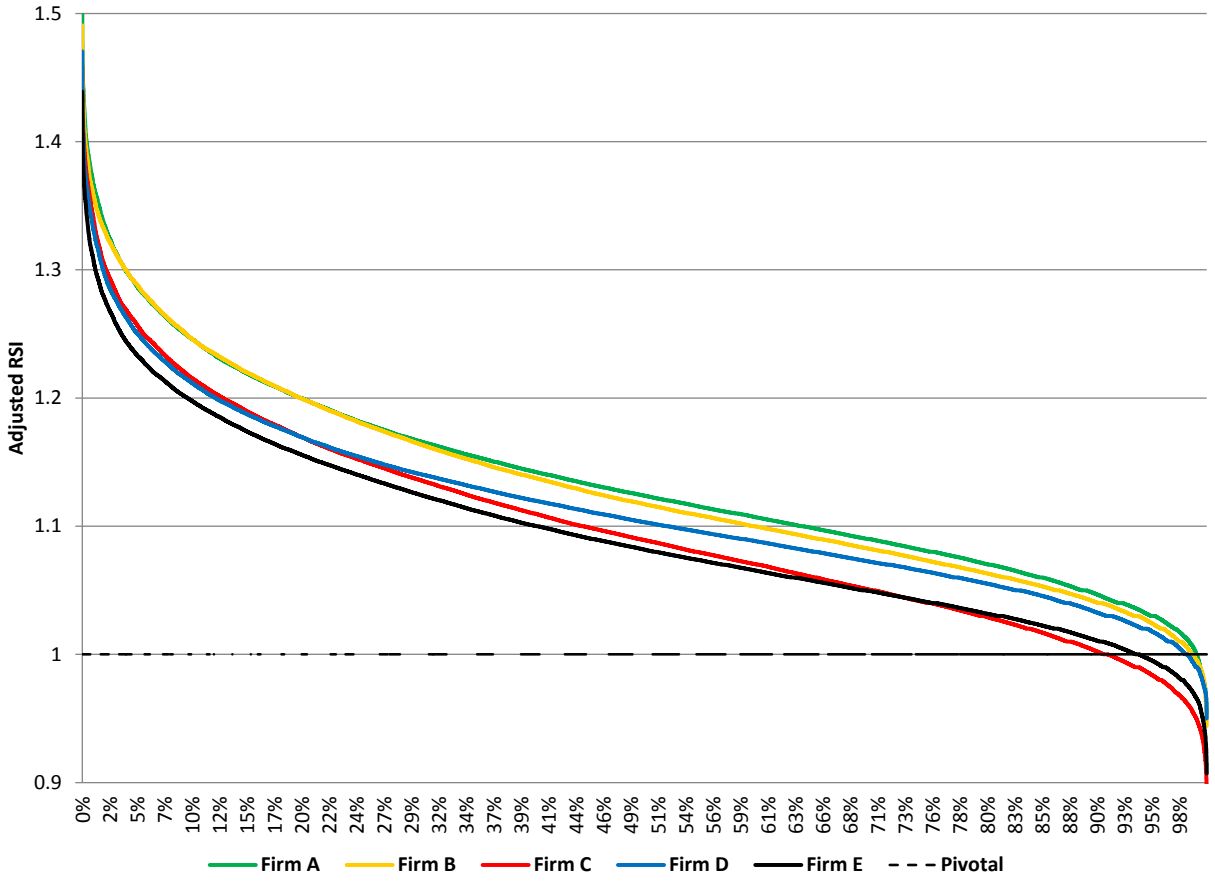


Table 4.3: Percentage of Hours in which Various Firms were Pivotal by Year using the Adjusted-RSI

	2008 (No Jan.)	2009	2010	2011	Q1 & Q2 2012
Firm A	1.5%	0.5%	0.7%	1.1%	0.6%
Firm B	2.1%	1.0%	0.8%	1.4%	0.3%
Firm C	18.9%	2.8%	5.3%	13.1%	0.4%
Firm D	3.7%	0.8%	1.3%	1.9%	0.4%
Firm E	8.1%	4.8%	4.6%	8.3%	2.7%

4.4 Residual Demand Analysis

An alternative to the RSI metric is to consider a firm's ability to alter the market price given the offers submitted by the firm's competitors. This type of analysis has been termed Residual Demand Analysis. The name comes from the idea that a particular firm can supply only those MW not supplied by its competitors. This method can be readily applied to electricity markets because the data on real-time offers is often publicly available and consequently it has been used to analyze market power in a number of markets. For example, Wolak (2003) quantifies market power in California, Wolak (2009) analyzes the New Zealand market, and Wolak (2012) examines the Alberta market using a residual demand approach.

A firm's Residual Demand is the market demand that is 'left-over' given the offer functions submitted by competing firms. Mathematically, a firm's residual demand is calculated by subtracting from the total demand curve all the offers submitted into the market by other participants:

$$RD_{1h}(p) = QD_h(p) - SO_{1h}(p)$$

Where $RD_1(p)$ is Firm 1's residual remand at price p, $QD(p)$ is the market demand at price p, and $SO_1(p)$ is the supply of all other firms at price p; the h subscript simply shows that the measures are hourly.

The derivation of a firm's residual demand function is illustrated by Figures 4.16 and 4.17 on the following page. Figure 4.16 shows an illustration of the hourly Energy Market Merit Order (labeled as 'Market Supply') and the total energy dispatched from the EMMO (labeled 'Total Demand'). As shown, market demand is assumed to be insensitive to price and hence is a vertical line. The Supply of Other Firms function illustrates the offers submitted by the firm's competitors. The difference between market supply and the supply of other firms is thus the offer curve of the firm under consideration. This offer curve is plotted in Figure 4.17 along with firm's residual demand function. The firm's residual demand function does not depend directly on its own offer strategy, but it is a function of the prevailing market demand and the offer strategies employed by competing firms. Intuitively, a firm's residual demand function shows the quantity of output that a firm's competitors allow it to sell at any price given the prevailing market demand.

A firm's residual demand is a negative function of price. As the pool price rises market demand is potentially reduced and the supply of other firms will generally increase. Both of these serve to decrease the residual demand of a particular firm. Conversely, as the market price falls other suppliers will tend to reduce output and market demand may rise, causing a firm's residual demand to increase.

The ability of a supplier to exercise market power at a particular time depends critically on the prevailing elasticity (responsiveness) of these market supply and demand fundamentals. As market demand and the supply of other firms become more responsive to price changes, the ability of a participant to affect the market price by altering its supply is reduced. That is, the ability of a firm to exercise unilateral market power will decrease as other suppliers become increasingly able to alter their generation in response to price changes, and/or as consumers become increasingly willing (or able) to respond to price changes.

Figure 4.16: Energy Market Fundamentals and the Construction of a Firm's Residual Demand Curve

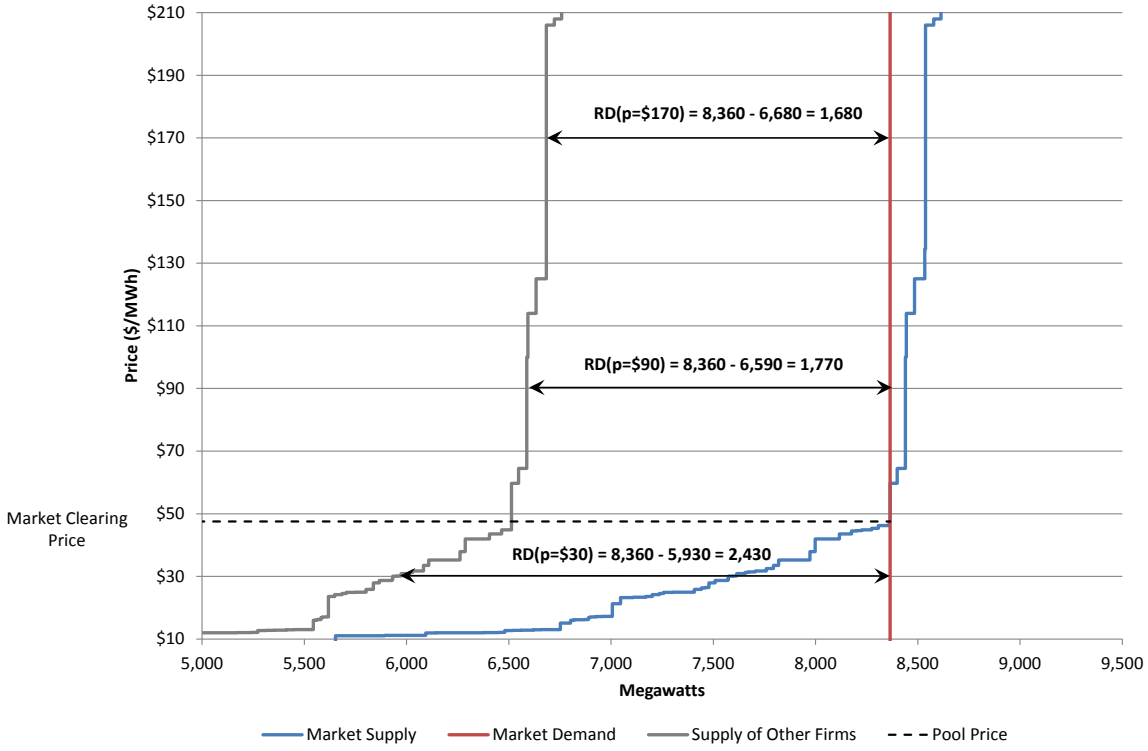
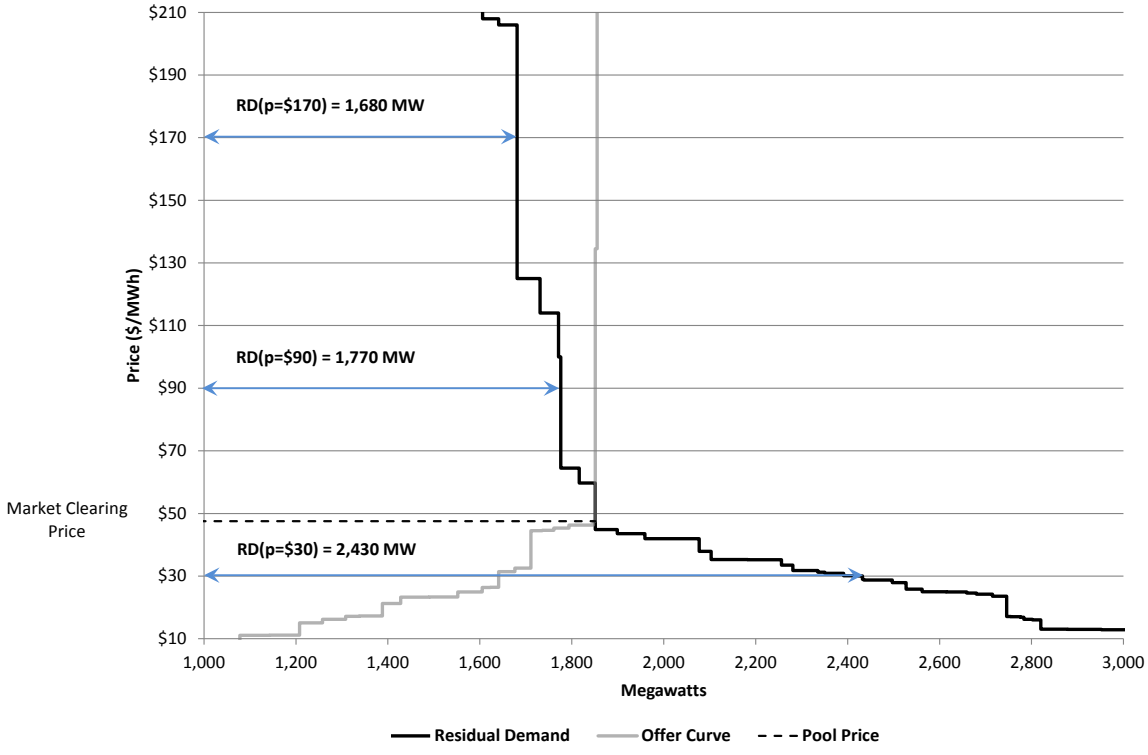


Figure 4.17: The Residual Demand Function and Offer Curve



Since a firm's residual demand depends on the market demand and the supply of other firms, analyzing the residual demand function can accurately capture these market fundamentals. As shown by the above discussion, the slope of a firm's residual demand will depend directly upon the slope of the aggregate offer function submitted by competing firms. Therefore, the residual demand curve that a supplier faces summarizes the firm's ability to impact the market price through changes in its own offer curve, holding the offer curves of all other suppliers constant.

In the above example, the residual demand curve is shown to be fairly steep above the market clearing price, as the presence of competing generation was relatively sparse in this price region. The implication is that price was relatively sensitive to a decrease in the firm's supply; there are only 250 MW offered by other firms between the SMP and the 'shelf' just below $210. Therefore, by economically withholding 250 MW the firm could have increased price from under $50 to over $200. The steep slope of the firm's residual demand function above the market clearing price illustrates that the market participant could have driven the price upwards through economic withholding. That is, the slope of the residual demand function above the market price is informative as to the potential ability that the firm had to increase the market price in this hour.

The slope of a firm's residual demand curve below the market clearing price is also informative. In particular, the MSA views the slope of the residual demand curve below the market price to be indicative of the market power that a firm had to increase the market price to the realized level. In the above example, the slope of the firm's residual demand function below the market equilibrium is relatively flat, implying that the firm had little ability to increase price to the level realized.

It is important to reiterate that this analysis does not infer whether or not a firm has the necessary incentive to economically withhold output. In particular, the above residual demand analysis does not consider a firm's overall portfolio position. A firm that has shortened its position to the spot price by selling fixed-price power in the retail market, or by selling fixed-price forward contracts in the financial markets, may have little incentive to exercise any available unilateral market power. Therefore, it is important to distinguish between the *ability* of a firm to exercise unilateral market power and the *incentives* of a firm to utilize this market power. The analysis here uses the above intuition to estimate the ability of a firm to exercise unilateral market power. A firm that faced a residual demand function which was steep around the market clearing price is shown to have had an ability to affect the market price through withholding output. However, the metric does not show whether the exercise of this market power would have been profitable for the firm given its overall portfolio position.

4.4.1 Estimating the Slope of a Residual Demand Function

Using the intuition outlined above, the slope of a firm's residual demand function around the market clearing price provides an *ex-post* assessment of the extent of supply competition that the participant faced in the relevant section of the merit order. Since both the areas above and below the market clearing price are insightful in measuring the ability of a firm to move price, we consider a metric that estimates the residual demand slope around the market clearing price. The steeper the slope, the less competition was faced from other generators, implying a greater level of unilateral market power. The metric is not influenced by a firm's prevailing generation or financial portfolio, but depends only upon the offer strategies that were employed by other firms around resulting market equilibrium. In practical terms, the

estimated slope provides a dollar-estimate of a firm's ability to increase the market price by withholding 1 MW of energy.[31]

To estimate the slope of a firm's residual demand function around the market clearing price, the MSA follows the estimation approach utilized by McRae and Wolak (2009). Details of the method are outlined in Appendix B. The appendix also considers a number of practical issues in the Alberta market, such as the treatment of Dispatch Down Service (DDS), Transmission Must Run (TMR) and the assignment of offer control to units which are controlled by multiple parties. In summary assumptions about DDS and TMR are relatively straightforward. However in contrast to RSI and simple concentration measures, the residual demand analysis requires precise assignment of offer control to each energy block in the merit order.

The metric considered does not account for price-responsive loads (effectively assuming the demand curve is vertical or perfectly inelastic). In practice the Alberta market has a number of price-responsive loads that in effect reduce the effectiveness of economic withholding. The residual demand analysis can incorporate price-responsive load although there are some practical issues in doing so. That refinement is beyond the scope of this report.

4.4.2 Analysis of the Residual Demand Slope

The slope of the residual demand function can be calculated at any point in time. Focusing on a single hour may not be appropriate since a market participant may not be aware that it had market power in that hour (or were unable to change offers close to real time). In this report, we consider a rolling average metric to track unilateral market power over a longer time frame. Figure 4.18 illustrates the peak and off-peak 30-Day Rolling Averages for the Residual Demand Slope for one large participant from March 2008 through Q2 2012.[32] As highlighted previously, the reported slope provides a dollar-estimate of a firm's ability to increase the market price by withholding 1 MW of energy. Therefore, an increase in this metric is indicative of greater market power.

[31] To be specific and consistent with economic terminology, the metric reported is the absolute-value of the slope of a firm's inverse residual demand function around the SMP. The 'inverse' residual demand function means that the function is plotted with price on the y-axis and quantity on the x-axis (the measure is consistent with the illustrations). Since the residual demand function is downward sloping, the function has a negative slope coefficient. The absolute-value of the slope is reported here for simplicity and ease of interpretation.

[32] The peak and off-peak rolling averages are calculated in the same manner as the Rolling Average Pool Prices detailed in the PPA agreements. This yields a daily estimate of market power that depends upon the slope of the residual demand functions on the day and the previous 29 days.

Figure 4.18: Rolling Averages of the Estimated Residual Demand Slope for a Single Firm

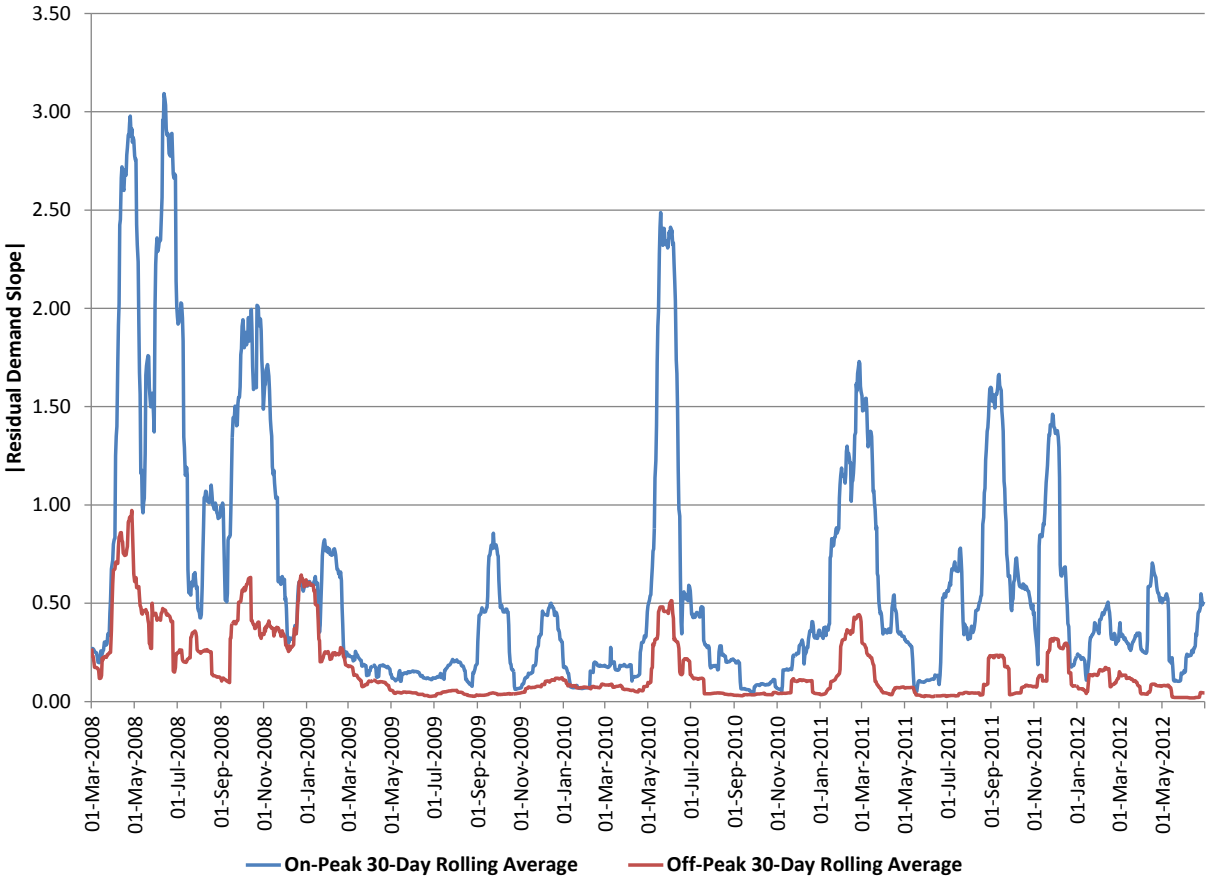


Figure 4.18 illustrates that the firm saw notable highs in on-peak market power throughout large periods of 2008, and the 30-Day on-peak rolling average peaked just above $3.00/MW in the middle of June. The metric indicates little market power through much of 2009 and 2010, with May 2010 being a notable exception. The firm's market power was also seen to increase at the beginning and the end of 2011. The figure illustrates that the firm had relatively little ability to exercise market power in Q1-Q2 of 2012.

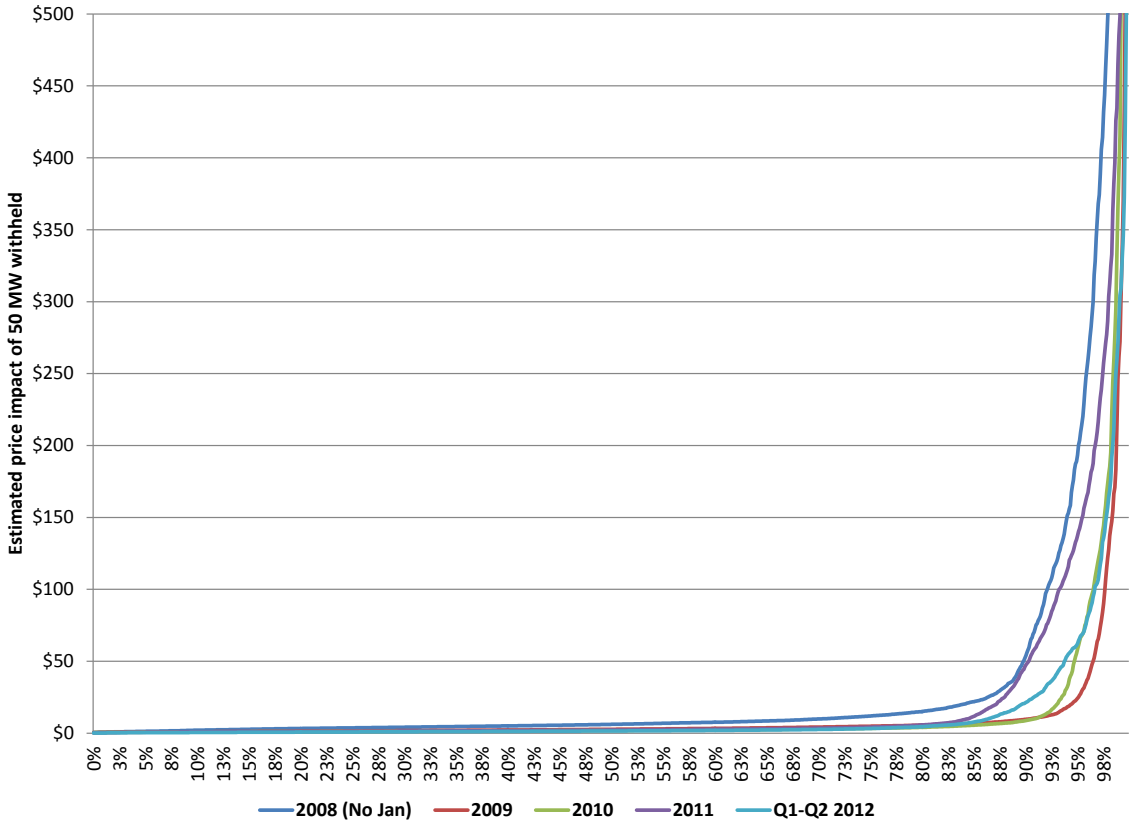
To illustrate the overall distribution of market power in the energy market, Figure 4.19 below illustrates the annual duration curves for the hourly 'average' residual demand slope. To be specific, the 'average' slope is simply calculated using the residual demand slopes for the five major participants:

$$Average\ RDS_h = 50 * \frac{\sum_{i=1}^{5} |RDS_{ih}|}{5}$$

Where RDS_{ih} is the residual demand slope for firm i in hour h.

As shown in the formula, the average slope is multiplied by 50MW. Therefore, the metric reported here provides a dollar estimate of the average large firm's unilateral ability to increase the market price by withholding 50MW of energy. This scaling was done to provide an element of practicality and also to make the points being made easier to illustrate.

Figure 4.19: Duration Curves showing Hourly Average Slope multiplied by 50MW, 2008 to 2012



The first point to note regarding Figure 4.19 is the distribution of the estimated unilateral market power. In each year the duration curves show a distinct 'hockey-stick' shape indicating that for the majority of hours the average large firm has relatively little market power, and occasionally the large firms have a significant ability to move the market price. For example, in 2011 the 75th percentile was estimated at $4.21, the 95th percentile was almost $135 and the 99th percentile was over $400. These figures show that for many hours in 2011 the market was relatively competitive and in a few hours the average large firm had the potential to move prices significantly with a relatively small amount of generation.

The second point to highlight here is that the figure also shows that there was some important variation between years (Table 4.4 provides more summary statistics to illustrate this point). As with the RSI metrics, 2008 was shown to be the tightest year. The range between the 85th and 95th percentile in 2011 is also shown to be higher in comparison with other years. 2009, 2010 and Q1-Q2 2012 have all seen the larger firms being more limited in their ability to exercise unilateral market power.

Table 4.4: Summary Statistics, 2008-2012

Percentile	2008	2009	2010	2011	Q1-Q2 2012
10%	$2.07	$0.97	$0.90	$0.95	$0.49
50%	$6.15	$2.72	$1.95	$2.20	$1.55
75%	$11.95	$4.86	$3.37	$4.21	$3.25
95%	$188.9	$23.37	$55.38	$134.6	$60.99

5. Summary and Conclusions

In this paper we have considered structural market power metrics. These all examine the ability of market participants to exercise unilateral market power in the power pool. They do not measure whether they in fact do. For example, a market participant with considerable offer control but equivalent forward market sales may have the ability to affect market prices but not the incentive. The MSA will consider this issue in more detail in the conduct section of the final State of the Market Report.

Notwithstanding this, structure matters. The absence of structural market power provides a guarantee that market power cannot be exercised to result in significant and durable deviations away from a workably competitive level. With evidence of structural market power there is no such guarantee and in the event that market power is exercised it is crucially important that there are no barriers to entry such that new investment is unable to correct for long term deviations from competitive outcomes.

The following briefly summarizes the issues explored and the main findings in the body of this report: Measuring Generator Market Power.

Market Definition:

Electricity markets are generally defined by deciding which generation capacity competes to set the market price. This method of defining a market is distinct from the standard antitrust approach because it does not consider the characteristics of market demand nor whether the market is contestable. As a consequence, conventional measures of market concentration are less useful in electricity markets, and the concentration thresholds established within power markets are not directly comparable with the thresholds set by antitrust authorities.

Generation capacity is typically the sole product that is included in the relevant market,[33] so the definition of capacity is important. In Alberta a unit's Maximum Capability is often not a relevant measure of capacity since it overstates the capacity that is usually available to compete in the market. When analyzing market power on a long-term basis, a unit's stated Available Capability is a more useful measure of competing generation capacity, although for 'variable capacity', such as wind and hydro generation, metered volume data should be used instead. In addition, the availability of import capacity is an important factor that needs to be considered within the relevant market. When studying the ability of a firm to move the pool price within a particular hour, the MSA views the supply available in the Energy Market Merit Order, in addition to the prevailing wind generation, as a sensible definition of the megawatts competing to set pool price.

Measures of Market Concentration:

As with any measure of market power, the usefulness of market concentration metrics will implicitly depend upon whether the relevant market is correctly defined. Concentration measures which are based upon an incorrect market definition are of little practical use. With the correct market definition however, a decreasing trend in market concentration resulting from the entry of new market participants, or the expansion of relatively smaller suppliers, would generally support the hypothesis that Alberta market is operating in an openly competitive manner. In contrast, a persistent increase in market

[33] Arguably price-responsive load is also an important competitive factor, although price-responsive load is relatively small (200-300 MW in Alberta) in comparison with total generation capacity.

concentration would be sufficiently concerning to the MSA to prompt further scrutiny of barriers to entry, particularly if prices are sufficiently high.[34]

Using the market definition established by the FEOC regulation, an annual analysis of market shares shows that the five largest suppliers in Alberta control approximately 70% of the total market capacity. Over time, these annual market shares showed an increase in the offer control of these five firms from 2001 through 2006. Since 2006 the annual offer control of these five firms has followed a slight downward trend

Using a more accurate definition of the relevant market for a given month also illustrates that the five largest suppliers in Alberta typically control approximately 70% of the market. As well, this monthly analysis highlights a slight decrease in the offer control of these firms in recent years. However, the distribution of market shares is not consistent with the annual analysis and large participants with thermal capacity that is not cogeneration are shown to have a larger share of the market, while firms controlling cogeneration facilities are seen to have comparatively lower market shares.

An analysis of hourly market shares highlights that the supply-side of the Alberta electricity market is dynamic. The concentration of supply available can change considerably from one hour to the next with unit outages and capacity derates, volatile wind supply, and varying flows on the interties. That said, for the majority of hours the largest five firms generally control between 65% and 75% of the hourly Energy Market Merit Order. Again, this hourly analysis shows a slight decrease in the market shares of the large five firms since 2008.

Alternative Approaches:

Even with a solid definition of the relevant market, measures of concentration fail to capture important aspects of competition in electricity markets. In particular, simple measures of market concentration will not consider the prevailing level of market demand. The level of market demand is a factor which is variable and critical to understanding the ability of firms to exercise market power.

The Residual Supplier Index and the analysis of a firm's Residual Demand function are two approaches to measuring market power which consider the prevailing level of market demand. Both of these metrics calculate an hourly estimate of market power using the market supply and demand fundamentals. The MSA recognizes that an hourly analysis of market power is, in and of itself, a short-run analysis. However, analyzing these short-run dynamics over a longer horizon allows for conclusions to be drawn regarding the persistence of these market fundamentals.

Analysis of the Residual Supplier Index metric implies that the largest firms in Alberta frequently have a notable amount of structural market power. For example, the largest firm in Alberta was 'pivotal' to the clearing of the energy market in 80% of the hours during 2011. It is important to note that the Residual Supplier Index does not consider the fact that a large amount of generation within Alberta is must-run generation that cannot readily be used by market participant to exercise market power. The Adjusted RSI metric uses $0 offers as a proxy for such constraints. Analysis of the Adjusted RSI metric implies that large firms do have structural market power in some hours although less frequently than is implied by the original RSI measure. For example, using the Adjusted RSI metric, the same firm is estimated to have been pivotal to the energy market only for 8% of the hours in 2011.

Using a Residual Demand analysis highlights the same market power distribution as the Adjusted RSI metric. In particular, the analysis highlights that for a large percentage of hours there is sufficient

[34] Whether prices are "sufficiently high" ultimately depends upon whether prices are above long-run marginal cost of production. This is a subject that will be broached by the MSA's upcoming report on long-run marginal costs.

competition to limit the ability of generators within Alberta to exercise market power. However the Residual Demand approach also illustrates that in a small percentage of hours the larger firms do have the ability to move the market price quite substantially.

Finally, in terms of incorporating this analysis into our market monitoring role, the MSA believes that it is prudent to employ a range of measures when analyzing market power, while recognizing the strengths and weaknesses of each approach. In addition, it is likely that any analysis undertaken to assess market power will be influenced by a number of circumstances (whether congestion is an issue for example), as well as the overriding purpose of the analysis (market power through economic withholding versus market power via physical withholding for instance). Variants of the Residual Supply Index and Residual Demand analysis both capture important elements in assessment of market power in the Alberta Energy market. Working with stakeholders to refine these metrics over time will lead to further insight into the measurement of market power and provide an important and continuing window on the market.

Appendix A: Residual Supply Index

The expanded RSI formula for a particular market participant (MP) is:

$$RSI(MP_{i=j}) = \frac{\left[\sum_{i=1}^{n}(E_i, I_i) + \sum_{i=1}^{n} DDS_i^D + \sum_{i=1}^{n} W_i\right] - \left[\sum_{i=j}(E_i) + \sum_{i=j} DDS_i^D - \sum_{i=j} TMR_i^D\right]}{\sum_{i=1}^{n}(E_i^D, I_i) + \sum_{i=1}^{n} TMR_i^D + \sum_{i=1}^{n} W_i}$$

Where:

E_i is the Available MWs in the Energy Market Merit Order (EMMO) under the offer control of MP_i

E_i^D is the Dispatched MWs in the EMMO under the offer control of MP_i

I_i is the Imported MWs under the offer control of MP_i

W_i is the Dispatched MW in the EMMO under the offer control of MP_i

DDS_i^D is the DDS MWs dispatched in the dispatch down service merit order (DDSMO) under the offer control of MP_i

TMR_i^D is the TMR MWs dispatched in the ancillary services merit order (ASMO) under the offer control of MP_i

For:

i = 1…n (Sums overall market participants)

i = j (is for the jth Market Participant)

A.1 Total Supply

This is the sum of all energy offers and imports to the EMMO in a given hour, plus all dispatched DDS in the DDSMO, plus the sum of wind generation.

Dispatched DDS was included as available supply because it is energy that is available above reference price and it is not otherwise represented in the EMMO. Wind generation is typically equal to the amount of wind available, the exception being when wind generation is constrained down, which is usually accounted for in a lower DDS dispatch.

A.2 Total Demand

Total demand is equivalent to the sum of all dispatched Energy and Imports in the EMMO, plus the sum of all TMR dispatched in the ASMO, and the sum of wind generation. No additional adjustment is made for exports since export levels are accounted for in the total level of energy dispatched, needed to meet the market demand.

A.3 Supply Controlled by MP_i

The 'Supply Controlled by MP_i' is the sum of energy offered in the EMMO, plus the sum of dispatched DDS, less the sum of dispatched TMR, all under the control of MP_i. The sum of dispatched TMR is

deducted from a market participant's share as the applicable units are required to run for reliability reasons and cannot be withdrawn from the market.

The majority of wind generation was not included as under the offer control of a market participant, as wind generation has generally been a price taker and cannot be withdrawn from the market through economic withholding. The exceptions to this are the two assets involved in the AESO's wind pilot. Similarly, imports attributable to market participants were not included in this term, as imports cannot be priced into the market, and therefore cannot be economically withheld.

The *Market Share Offer Control 2010 Report*[35] was used to define a market participant's share of the market. For this reason, RSI metrics were only constructed for the market participants with offer control greater than 5%. For units that are controlled by two participants, such as some units subject to Power Purchase Arrangements (PPAs) and the GN3 / KH3 assets, some assumptions were necessary to allocate the unit availability between the participants, particularly with respect to derates.

For units subject to a PPA, it was assumed that Owners would incur any derate first, and if a derate exceeded the Owner's share of the unit's capacity, the derate was then applied to the Buyer's portion. The ISO rules apply derates in available capability to the highest priced offer block which could belong to either the Owner or the Buyer, and this is a source of error. DDS offers from PPA units are attributed to the PPA Buyers, as is any dispatched TMR. For GN3 and KH3, all aspects are split evenly between the partners.

[35] MSA Report, 2010,"Market Share Offer Control"

Appendix B: Estimation of the Residual Demand Slope

The purpose of this section is to detail how the slope of a participant's Residual Demand function can be calculated from data available on the AESO website. The overall approach taken follows that of McRae and Wolak (2009) who analyze the New Zealand electricity market.

B.1 Estimation Procedure

To estimate the metric we first construct the ex-post residual demand function faced by a particular supplier based on merit order snapshot data midway through a given settlement hour. The residual demand function faced by a particular supplier *j* is given by the following equation:

$$DR_{jh}(p) = QD_h - SO_{jh}(p)$$

Where *QD* represents the realized market demand and $SO_j(p)$ is the Supply of all Other Firms function.

Firstly, total market demand is found by summing all Dispatched MW, excluding the power that is dispatched as exports (exported energy is already considered by the in-merit energy).

The Supply of Other firms function (*SOj*) is an upward sloping step function which indicates the aggregate willingness-to-supply of all other market participants at a particular price. To calculate the *SOj* function requires specifying which participant is responsible for submitting each offer block. Some practical issues are discussed in the next section. Having defined offer control, the Supply of Other firms function faced by a participant is derived from the Dispatched MW and Available MW columns of the EMMO. At offer prices less than or equal to the market clearing price (p*), the supply of others is computed using the Dispatched MW column and for offer blocks that are above the SMP, the calculation uses the declared Available MW.

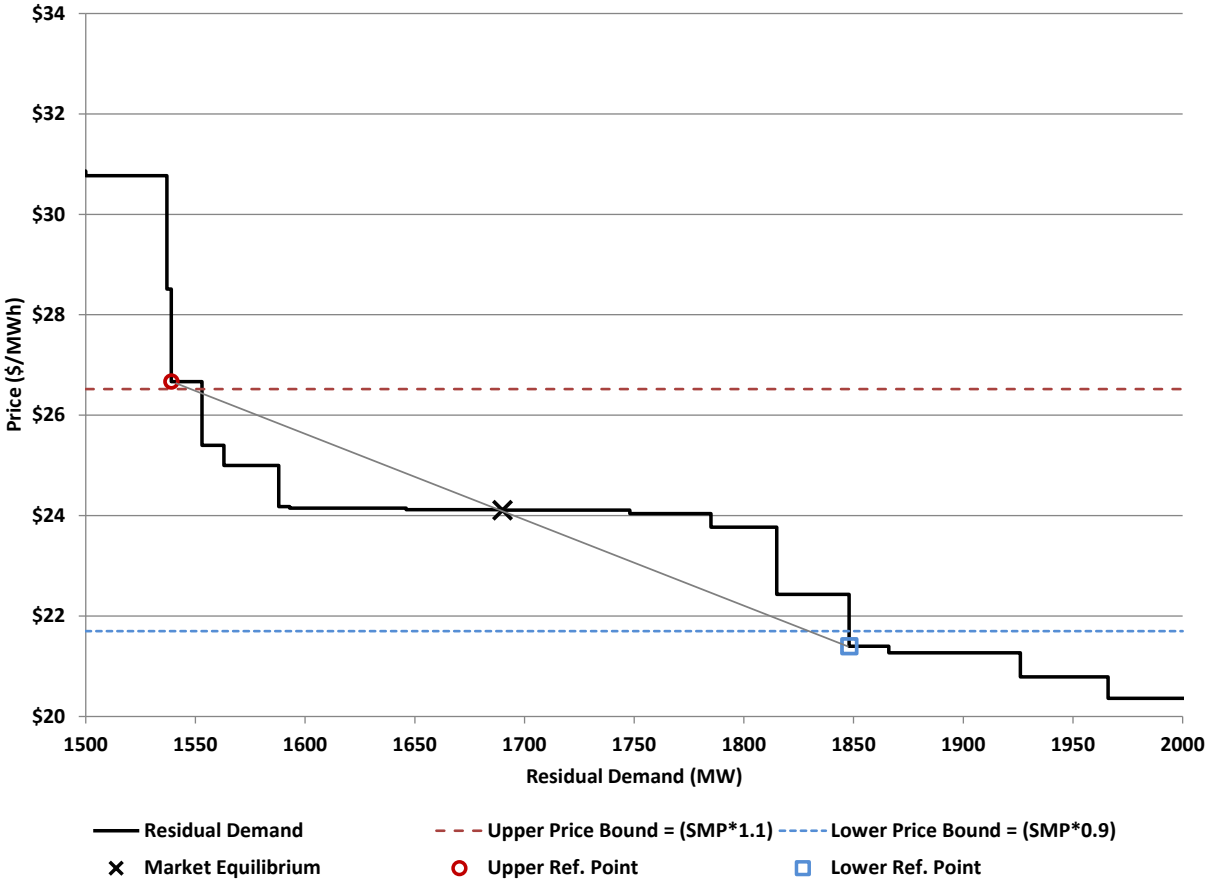
The corresponding residual demand curve is obtained by subtracting the supply of other firms at each price from the realized total market demand (see figure 4.16 in main text). Since the aggregate supply of all other participants is a step function, so too is the residual demand function faced by a firm. Consequently, to estimate the slope of the residual demand requires using a finite-difference approximation.

McRae and Wolak (2009) note a number of desirable qualities in selecting the output change to be used in approximating this slope. Firstly, the output change should be large enough in order to attain a good representation of the residual demand function around p*. Secondly, it is important for the output change to be reasonably feasible for a supplier to implement. Finally, it is important that the procedure chosen should be robust. That is, altering the size of the output changes used to compute the slope should not have a material impact upon the implications of the metric.

The procedure utilized here to calculate the slope of a firm's residual demand function around p* follows the approach taken by McRae and Wolak (2009). This method begins by constructing a 10% 'price window' around the market clearing price. Figure B.1 illustrates the construction of this price window.

The general idea is that the hypothetical output changes implemented by the firm should cause the equilibrium price to change by at least ten percent in order to get a good representation of the residual demand function. The method proceeds to find the two steps on the residual demand function that are just outside the constructed price window.

Figure B.1: Example 1



In the above example, the step just above the upper price bound is a 14MW block offered at $26.67. At a price of $26.67 this 14 MW is dispatched, and the firm's residual demand is 1,540 MW, as highlighted by the red circle in the top left of Figure B.1.

At the lower bound, the initial step outside the price window is an 18 MW block offered at $21.40. This reference point is highlighted by the blue square in the bottom right of the figure. At this reference price level the firm's residual demand equals 1,850 MW.

The slope of the Residual Demand function is then estimated by calculating the slope of the linear function between these two reference points. In our example, this process is highlighted by the grey line in Figure B.1. Hence, the slope of the residual demand around the market clearing price *(RD'(p*))* is calculated as:

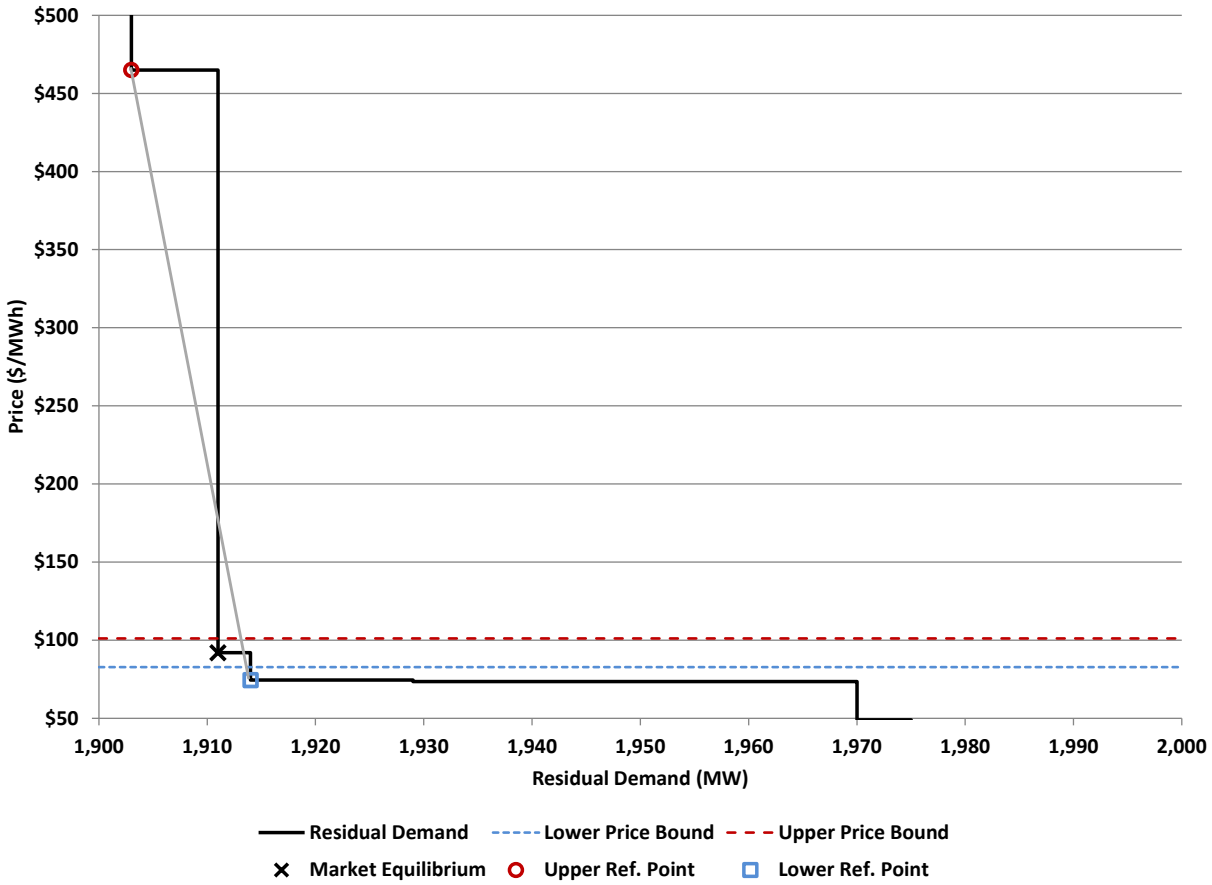
$$RD'(p^*) = \left|\frac{(26.67 - 21.40)}{(1{,}539 - 1{,}850)}\right| = 0.017$$

Note the || brackets indicate an absolute value calculation.

The resulting low value indicates that the slope of the firm's residual demand function was relatively flat around the SMP. The implication here is that the market was relatively competitive in this hour and the firm had little ability to influence the market price.

As a contrast, Figure B.2 below illustrates an example in which the residual demand function is estimated to be relatively steep. In this example the market cleared at $92 and, because of the huge vertical step above equilibrium, the upper price point is over $460. Relative to its market clearing quantity, the firm's residual demand falls by only 8 MW from this hypothetical price increase. Beneath the SMP, the lower reference price is $74.50 at which point the firm's residual demand is 1,914 MW. Calculating the slope of the line between the two reference points yields a slope estimate of 35.5, illustrating that in this hour the firm had a relatively notable amount of structural market power.

Figure B.2: Example 2



B.2 Practical Issues in Alberta

Ownership Issues

Offer control of most units in Alberta is relatively clear. There are two sources of ambiguity relating to PPA units and some joint venture arrangements. Firstly, PPA units which have excess energy / increased capacity in a particular hour will potentially mean that both the PPA buyer and the PPA owner have offer control over different energy blocks from that unit. Secondly, there are two coal units which have been built as joint ventures and these are controlled by two of the large participants in Alberta. These two units are offered independently into the market with each participant controlling half of the unit's capacity.

The analysis included in this report has taken a relatively simple approach to resolving these ambiguities. Complete offer control of PPA assets is assigned to the PPA Buyer, and the offer blocks on the two joint

venture assets are split equally between the two relevant parties. The AESO is in the process of implementing some additional offer control reporting, in accordance with Section 6 of the FEOC Regulation that should resolve any ambiguities in the future.

Dispatch Down Service and the TMR Reference Price

As with the RSI metric we have adjusted the available MW for any volumes dispatched for DDS, since these would return to the market if price went about the TMR Reference Price and be removed from the market when if price went below the TMR Reference Price.

Transmission Must Run Generation

The AESO manages transmission congestion by procuring Transmission Must Run (TMR) generation through the Ancillary Services (AS) market. As well as being dispatched in the AS market, TMR output is included in the Energy Merit Order and if the price is high enough the output is dispatched as Energy rather than as TMR. When these megawatts are dispatched from the energy market there is no increase in electrical generation and so this energy is removed from the energy merit order.

The Price Cap and Price Floor

In hours when the market clearing price (SMP) is high enough, the upper price bound (1.1*SMP) is greater than $1,000. In these hours the upper price bound is set at $1,000 and the calculation estimates the residual demand slope between the lower reference price and the price cap.

In hours when the SMP is $0 the slope is calculated between the origin (0, 0) and the firm's residual demand at $5. Given the large number of $0 offers typically available this yields a slope coefficient that is close to 0 reflecting the fact that firms have very little market power in these hours.

References

Statues and Regulations

Transmission Regulation AR 86/2007 with amendments to AR 153/2010

Fair Efficient and Open Competition Regulation, AR 159/2009

Market Surveillance Administrator

Market Share Offer Control Process, September 24, 2009.
http://albertamsa.ca/uploads/pdf/Archive/2009/Market%20Shares%20Process%20%20092409.pdf

Information Request Market Share Offer Control, May 4, 2011
http://albertamsa.ca/index.php?page=notice-information-request-market-share-offer-control

Market Share Offer Control 2012
http://albertamsa.ca/uploads/pdf/Archive/2012/Market%20Share%20Offer%20Control%202012.pdf

Zero Dollar Offers
http://albertamsa.ca/files/Zero_Offers_042903.pdf

Independent System Operator

Merit Order Offer Control Reporting, November 24, 2010
http://www.aeso.ca/downloads/Merit_Order_Offer_Control_Reporting_Recommendation_Paper_FINAL.pdf

Other

Church and Ware (2000), "Industrial Organization: A Strategic Approach." New York: McGraw-Hill:
http://works.bepress.com/cgi/viewcontent.cgi?article=1022&context=jeffrey_church

FERC (2007) Docket No. RM04-7-000; Order No. 97. Available at:
http://www.ferc.gov/whats-new/comm-meet/2007/062107/E-1.pdf

Tirole, J. (1988) The Theory of Industrial Organization. Cambridge: MIT Press

The Three Pivotal Supplier Test in the PJM Real-time Energy Market
http://www.pjm.com/committees-and-groups/closed-groups/~/media/committees-groups/task-forces/tpstf/postings/20080926-real-time-energy-market-tps-test-documentation.ashx

Baumol, W., Panzar, J. and R. Willig (1982) *Contestable Markets and the Theory of Market Structure.* New York: Harcout Brace Jovanovich

Borenstien, S., Bushnell, J. and C. Knittel (1999), "Market Power in Electricity Markets: Beyond Concentration Measures" *The Energy Journal*, 20(4), 65-88. Available at:
http://www.ucei.berkeley.edu/PDF/pwp059.pdf

Blumsack, S. and Lave, L.B. (2003), "Mitigating Market Power in Deregulated Electricity Markets", mimeo, available at:
http://www.personal.psu.edu/sab51/usaee.pdf

Sheffrin (2001) "Critical Actions Necessary for Effective Market Monitoring" Draft Comments Department of Market Analysis, California ISO, FERC RTO Workshop October 19. Available at: http://www.caiso.com/docs/2001/10/19/2001101915352626702.pdf

Twomey, P., Green, R., Neuhoff, K. & Newbery, D. (2005) "A Review of the Monitoring of Market Power: The Possible Roles of TSOs in Monitoring for Market Power Issues in Congested Transmission Systems" *Journal of Energy Literature,* 11(2), 3-54. Available at: http://web.mit.edu/ceepr/www/publications/reprints/Reprint_209_WC.pdf

Wolak, F.A. (2003) "Measuring Unilateral Market Power in Wholesale Electricity Markets: the California market 1998-2000" *The American Economic Review*, 93(2): 425-430

McRae, S.D. and Wolak (2009), F.A. "How Do Firms Exercise Unilateral Market Power? Evidence from a Bid-Based Wholesale Electricity Market", Technical Report, EUI RSCAS 2009/36. Available at: http://cadmus.eui.eu/bitstream/handle/1814/12098/RSCAS_2009_36.pdf?sequence=1

Wolak, F.A. (2009) "An Assessment of the Performance of the New Zealand Wholesale Electricity Market", Report for the Commerce Commission, available at: http://www.comcom.govt.nz/investigation-reports/

Wolak, F.A. (2012) "Measuring the Competitiveness Benefits of a Transmission Investment Policy: The Case of the Alberta Electricity Market", Draft August 9th. Available at: http://www.stanford.edu/group/fwolak/cgi-bin/sites/default/files/files/alberta_transmission_benefits_aug_2012.pdf

The Market Surveillance Administrator is an independent enforcement agency that protects and promotes the fair, efficient and openly competitive operation of Alberta's wholesale electricity markets and its retail electricity and natural gas markets. The MSA also works to ensure that market participants comply with the Alberta Reliability Standards and the Independent System Operator's rules.

Market Surveillance Administrator | 403.705.3181 | #500, 400 – 5th Avenue S.W., Calgary AB T2P 0L6 | www.albertamsa.ca