Measuring the Competitiveness Benefits of a Transmission Investment Policy: The Case of the Alberta Electricity Market

by

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Abstract

Several theoretical papers, most notably Borenstein, Bushnell and Stoft (2000), have demonstrated that transmission expansions can increase the amount of competition faced by wholesale electricity suppliers with the ability to exercise unilateral market. This perceived increase in competition faced by these strategic suppliers causes them to behave more aggressively and set market-clearing prices closer to competitive benchmark price levels. These lower wholesale market-clearing prices are the competitiveness benefit of this transmission policy to electricity consumers. This paper quantifies empirically for an actual wholesale electricity market the competitiveness benefits of a transmission expansion policy that causes strategic suppliers to perceive a very small frequency and duration of transmission constraints to limit the competition they face. Using hourly generation-unit level offer, output, market-clearing price and congestion data from the Alberta Wholesale Electricity Market from January 1, 2009 to December 31, 2011, this paper builds on the expected profit-maximizing offer model in Wolak (2003 and 2007) and best-reply offer pricing model in McRae and Wolak (2012) to compute two counterfactual no-perceived congestion (by the five largest strategic suppliers in Alberta) hourly market-clearing prices that are used to compute an upper and lower bound on the hourly competitiveness benefits of this transmission policy. Both competitiveness consumer benefits measures show economically substantial benefits from such a transmission policy. The lower bound approach which does not assume any actual transmission expansions, only a change in the perceived frequency of congestion, yields an average hourly consumer benefit of 3,067 Canadian Dollars (CAD). The upper bound which assumes that the perceived amount of congestion turns out to be the actual amount of congestion yields an average hourly consumer benefit of 79,590 CAD. Taken together, these empirical results argue in favor including competitiveness benefits in transmission planning processes in order to ensure that all transmission expansions with positive net benefits to electricity consumers are undertaken.

1. Introduction

The transition from a price-regulated, vertically-integrated regulated monopoly regime to the wholesale market regime in electricity supply industry has dramatically altered the role of the transmission network. Under the vertically-integrated monopoly regime, the price-regulated electric utility had a requirement to serve all demand in its service territory at the regulated price. This mandate provided a strong incentive for the utility to operate its existing generation units in a least-cost manner given the geographic location of daily electricity demand and make investments in additional transmission capacity when this was the least-cost approach to supply load growth in a given geographic area. In contrast, under the wholesale market regime the owner of the transmission network is financially independent of any generation unit owner and receives a regulated revenue stream that is largely independent of the level of congestion in the transmission network. An owner of multiple generation units selling into a wholesale market can therefore find it expected profit-maximizing to exploit the configuration of the transmission network to cause transmission congestion and shrink the size of the geographic market over which its units face competition in order to increase the revenues it receives from participating in the wholesale market.

For all of these reasons, the transmission network takes on a new role in the wholesale market regime as facilitator of competition. Specifically, the configuration of the transmission network determines the extent of competition that each supplier faces for a given geographic distribution of electricity demands. Transmission expansions can increase the number of hours of the year that a supplier faces sufficient competition to cause it to submit offer curves close to its marginal cost curve and thereby yield lower market-clearing prices than would be the case in the absence of the transmission expansion. Borenstein, Bushnell and Stoft (2000) use a two-node model of quantity-setting imperfect competition between two suppliers separated by finite-capacity transmission line serving price-responsive demands at both nodes to derive two theoretical results related to this question. First, limited transmission capacity between the two locations can give each firm an additional incentive to restrict its output in order to congest the transmission line into its local market in order to raise the price it receives for its output. Second, relatively small investments in transmission capacity may yield significant increases in the competitiveness of realized market outcomes.[1]

The purpose of this paper is to quantify empirically the magnitude of the competitiveness benefits from transmission expansions for an actual wholesale electricity market. Several estimates are computed of the change in hourly short-term market prices and wholesale energy costs to consumers in the Alberta Wholesale Electricity Market (AWEM) that result from increasing the extent of competition that the five largest suppliers face because of a perceived reduction in the frequency and duration of transmission constraints. These counterfactual prices differ in terms of how the configuration of the transmission network is assumed to alter the extent of competition that these suppliers actually face. All of these counterfactual prices demonstrate economically significant competitiveness benefits to electricity consumers from a transmission policy that causes them to perceive a low frequency and duration of transmission constraints. These results imply that failing to account for this source of consumer benefits in the transmission expansion planning process for regions with formal wholesale electricity markets can leave transmission expansions with positive net benefits to electricity consumers on the drawing board.

The approach used to assess the competitiveness benefits of transmission expansions builds on the models of expected profit-maximizing offer behavior described in Wolak (2000, 2003, and 2007), where suppliers submit hourly offer curves into the short-term market to maximize their expected profits from selling energy given the distribution of residual demand curves they face. As shown in Wolak (2000), this residual demand curve distribution determines the extent of competition that a supplier faces, and therefore how close the supplier's offer curve is to its marginal cost curve. Transmission expansions typically flatted out the realized residual demand curves that a supplier faces because more offers from other locations in the transmission network are not prevented from competing with that supplier because of transmission constraints. These flatter residual demand curves cause an expected profit-maximizing supplier to submit an offer curve closer to its marginal cost curve. If all strategic suppliers face flatter

[1] Arrellano and Serra (2008) extend this result to the case of a cost-based short-term market similar to the ones in a number of Latin American countries. The amount of transmission capacity between the two regions impacts the mix of high fixed-cost and low variable cost base load capacity and low fixed-cost and high variable cost peaking capacity suppliers choose, with additional transmission capacity causing suppliers at both locations to choose a capacity mix closer to the socially efficient level.

residual demand curve realizations because of increased transmission capacity, then they will all submit expected profit-maximizing offer curves closer to their marginal cost which will yield market-clearing prices closer to competitive benchmark levels.

The major challenge associated with computing these counterfactual offer curves for each strategic supplier is quantifying how the curves will change in response to each supplier facing flatter residual demand curve distribution. The approach used here is based on framework implemented by McRae and Wolak (2012) to determine much a supplier's hourly offer prices (along its offer curve into hourly short-term market) changes in response to changes in the form of the hourly residual demand it faces. An econometric model relating the hourly offer price submitted by a supplier to the hourly inverse semi-elasticity of the residual demand curve (defined in McRae and Wolak (2012)) faced by that supplier is estimated for each of the five large suppliers in the AWEM using the hourly curves submitted by all market participants over the period January 1, 2009 to December 31, 2011. The hourly generation unit-level offer curves submitted by each of the five strategic market participants are used to compute each supplier's hourly offer price and the hourly market demand and aggregate offer curves of all other market participants are used to construct the hourly residual demand curve facing each strategic supplier.

This estimated relationship between the hourly offer price and hourly inverse semi-elasticity for each market participant is used to compute a counterfactual offer curve for each supplier that is the result of the perceived increased competition that the strategic supplier would face as result of increased transmission capacity. This is accomplished through the following three-step process. First, a no-congestion residual demand curve is computed for each hour for each supplier using the offer curves actually submitted by all suppliers. This residual demand curve assumes that the offer curves of all other suppliers, besides the firm under consideration, can compete against the offers of the firm under consideration. Second, the inverse semi-elasticity of this hourly no-congestion residual demand curve is computed and the coefficient estimates from the regression of the hourly offer price for that supplier on the actual hourly inverse semi-elasticity (that reflects actual transmission constraints) that the supplier faced is used to compute a counterfactual Canadian Dollar (CAD) per Megawatt-hour (MWh) reduction in the hourly offer price due to the smaller inverse semi-elasticity of the no-congestion residual demand curve. This CAD/MWh reduction is applied all the hourly offer prices for all steps on that supplier's offer curve. The final step of the process uses these counterfactual offer curves for the five largest suppliers and the actual offer curves of the remaining suppliers to compute an aggregate counterfactual offer curve. The counterfactual hourly market price is computed by crossing the resulting aggregate offer curve with the actual demand for that hour. This three-step procedure is then repeated for all hours in the sample period.

The final step of the process is repeated in two ways in order to compute an upper and lower bound on the level of the counterfactual price that results from no perceived transmission constraints by the five large strategic suppliers. To compute a lower bound on the counterfactual no-congestion price (and upper bound on the economic benefits from transmission expansions), the counterfactual aggregate supply curve is computed using the adjusted offer curves for the strategic firms and actual offer curves for all other firms. The price at the intersection of this curve with the aggregate demand curve yield a lower bound on the counterfactual no-congestion price, because it assumes that there is sufficient transmission capacity that all of the offers on the aggregate offer curve below this counterfactual price can be accepted to supply energy.

To compute an upper bound on the counterfactual no-congestion price (and lower bound on the economic benefits from transmission expansions), the counterfactual aggregate supply curve is constructed using only quantity steps on the individual offer curves that were actually accepted. This implies that the counterfactual price is equal to the highest offer price with a positive quantity accepted from it in the actual hourly dispatch process. This second approach provides an extremely conservative estimate of the market price with no perceived transmission congestion because it assumes that exactly the same dispatch of generation units in the system and same amount transmission congestion as actually occurred. It is more likely to be the case that more the competitive behavior by strategic suppliers, even with same amount of transmission capacity, will allow some energy now offered at a lower price to sell energy and set a lower market-clearing price.

Both of these counterfactual prices indicate significant competitiveness benefits from transmission expansions that decrease the inverse semi-elasticity of the residual demand curve that the strategic supplier faces. These competitiveness benefits appear to correlated with the level of system demand for two reasons: (1) at high levels of system demand transmission constraints are more likely to limit the amount energy that compete against the strategic suppliers, and (2) at higher levels of the demand all suppliers typically face steeper residual demand curves even in the absence of transmission constraints because higher variable cost units are needed to serve demand. In both cases, increasing the amount of transmission capacity increases the semi-elasticity of the residual demand curve (and decreases the inverse semi-elasticity) each suppliers faces, which our regression results imply will yield a lower offer price. There is also considerable variation in these competitiveness benefits across years in the sample, consistent with changes in the supply and demand balance over the three years of our sample.

The sample average hourly consumer benefit using the upper bound on the counterfactual no-perceived-congestion price is 3,067 CAD. However, this average hourly value varies considerably over the thirty-six months of the sample. During one month it exceeds 25,000 CAD. The sample average hourly competitiveness benefit using the lower bound on the counterfactual no-perceived-congestion price is 79,590 CAD. This magnitude also varies over months of the sample, taking on a value greater than 500,000 CAD for one month.

Translating these two consumer benefit measures from the perceived elimination of transmission constraints into percentages of the total cost of wholesale energy implies a lower bound on the consumer competitiveness benefits for the entire sample of 0.64 percent of total wholesale energy costs, with this percentage reaching has high as 2 percent of total wholesale energy costs in one month of the sample. For the entire sample, the upper bound on the competitiveness benefits is 16.8 percent of total wholesale energy costs. During a number of months, this percentage is substantially higher. For example, it is more than 45 percent of actual wholesale market revenues in one month. For most of the months this percentage is below 20 percent, but it never falls below 5 percent.

The remainder of this paper proceeds as follows. The next section describes the basic features of the AWEM and the process used to set market-clearing prices given the offers submitted to Alberta Electric System Operator (AESO). This section also presents summary statistics on the market structure and market outcomes in the AWEM. The third section describes the details of how the two counterfactual prices are computed. The fourth section presents the results of these computations. Section 5 discusses the implications of these results for the design of transmission planning processes in organized wholesale electricity markets.

2. The Alberta Wholesale Electricity Market

The AESO was formed in 2003 as a not-for-profit entity that is independent of all industry participants and owns no transmission or generation assets. It operates the AWEM, which in 2011 had approximately 164 participants and processed close to $8 billion in electricity-related transactions. The AESO is governed by an independent board composed of members with backgrounds in finance, business, electricity, oil and gas, energy management, regulation, and technology development.

The AESO operates an hourly real-time energy market using a single-zone pricing model where one province-wide price of energy is set for each of hour of the day. Ancillary services are procured and dispatched by the AESO through an independent third-party market and over-the-counter transactions. The AESO dispatches these ancillary services to maintain adequate operating reserves throughout the day.

As shown in Table 1, thermal generation accounts for most of Alberta's energy production. Coal-fired generation accounts for slightly more than 46% of the installed capacity in Alberta. Natural gas-fired cogeneration is 27%, with natural gas-fired combined-cycle generation and natural gas-fired combustion turbine together accounting for slightly more than 11% of the installed capacity. The remaining capacity is wind, and biomass and other renewables. The dominant share of thermal capacity in the generation mix and significant differences in the variable cost across these generation technologies implies that there can be significant differences in the variable cost of the highest cost unit operating on the system throughout the day.

Table 1: Installed Capacity by Prime Mover

Prime Mover	**Capacity in MW**	**Capacity Share (%)**
Coal	6,232	46.29
Natural Gas Cogeneration	3,712	27.57
Hydroelectric	879	6.53
Natural Gas Combined Cycle	843	6.26
Wind	777	5.77
Natural Gas Combustion Turbine	753	5.59
Biomass and other renewables	266	1.98
Total Installed Capacity	13,462	100.00

The concentration of ownership of this generation capacity among suppliers to the Alberta market can influence the ability of suppliers to take unilateral actions to increase the profits they receive from selling energy into the AWEM. Table 2 lists the generation capacity controlled or owned by the five largest suppliers. These suppliers together control more than three-quarters of the installed capacity in Alberta.[2] The Firm E controls almost 20% of the installed capacity, followed by Firm D at 17.49%. The smallest of the five largest firms is Firm B, which controls more than 10% of the installed capacity in Alberta. This concentration of ownership of generation assets implies that high levels of fixed price forward contracts between generation unit owners and electricity retailers will be necessary to limit the incentive of these suppliers to exercise unilateral market power.

The benefits transmission expansions that cause of each of these suppliers to compete over the largest possible geographic market as many hours per year as possible are likely to be larger as a result of this concentration in generation capacity ownership. This logic implies that the competitiveness benefits of transmission expansions for this market are likely to substantial, even if suppliers have high-levels of hourly fixed-price forward contract obligations and therefore have limited incentives to exercise unilateral market power during most hours of the year. As shown in McRae and Wolak (2012), suppliers with hourly fixed price forward contract obligations close to the hourly output of their generation units have a significantly reduced incentive to take advantage of their ability to exercise unilateral market power. However, both unexpectedly high and unexpectedly low levels of output from a supplier's portfolio of generation units can create short periods when these suppliers have both the ability and incentives to exercise a significant amount of unilateral market power. A robust transmission network where transmission congestion is infrequent will limit the incentive to submit offer curves that reflect the exercise of substantial unilateral market power.

Table 2: Capacity Owned and Capacity Share of Five Largest Firms

Owner	**Capacity (MW)**	**Share of System (%)**
Firm A	1,349	16.52
Firm B	1,507	11.19
Firm C	1,897	14.09
Firm D	2,354	17.49
Firm E	2,580	19.17
Total of Five Largest Firms	9,687	78.46

[2] The identities of individual market participants have been omitted to maintain confidentiality, although these firm names are consistent throughout the paper. Specifically, Firm A refers to the same firm and Firm B refers to the same firm, and so on, in all tables and figures.

Figure 1(a) plots the annual demand duration curves for the AWEM for 2009, 2010, and 2011. The highest recorded system peak demand is 10,609 MW. This was hit on January 16, 2012. System peaks in 2009, 2010, and 2011 were within a few hundred MWs of this level. The horizontal axis on Figure 1(a) is the percentage of hours of the year from zero to 100 and the vertical axis is, from left to right, the hourly demand from the highest demand hour that occurred during the year to the lowest demand hour that occurred during the year. For a given percentage value on the horizontal axis, say 70 percent, MWh value on the vertical axis is the demand level that 70 percent of the hours of the year is above. Figure 1(a) shows that a significant amount of generation capacity is needed less than 5 percent of hours of the year. Figure 1(b) plots the curve for the 1 percent of the hours of the year with the highest hourly demands. For 2009, the difference between the annual peak demand and the demand at the highest 1^{th} percentile of the hourly demand distribution is almost 700 MWh. For 2010 and 2011, this difference is closer to 300 MWh.

Figure 2(a) plots the annual hourly price duration curves for 2009, 2010, and 2011. These curves are much flatter than the demand duration curves for all but the highest 15 percent of the hours of all three years. For the highest-priced 10 to 15 percent of the hours of the year, the curves become extremely steep, which is consistent with the earlier logic that the high levels of concentration of generation unit ownership can allow significant amounts of unilateral market power to be exercised during a small percentage of the hours of the year. Figure 2(b) plots the price duration curve for the highest 10 percent of hours of the year. For 2009 and 2010, this curve does not start to become steep until the highest 5 percent of hours of the year, whereas for 2011 this curve increases at close to a slope for the 10^{th} percentile to the highest priced hour of the year. For more than 10 percent of the hours of the year in 2011, prices are above 100 Canadian Dollars (CAD) per MWh. For 2009 and 2010, prices are above 100 CAD/MWh for approximately 5 percent of the hours of the year.

Transmission expansions that increase the competitiveness of the short-term market can also increase the incentive suppliers have to enter into fixed-price forward contract obligations. A supplier that faces greater competition more hours of the year as a result of increases in transmission capacity can create an additional incentive for that supplier to enter into a fixed-price forward contract that commits it to produce a higher level of output in the short-term market. This higher market-wide level of fixed-price forward contract coverage of final demand leads all suppliers to submit offer prices closer to their marginal cost of production, which yields market prices closer to competitive benchmark levels. These lower market prices are the primary source of benefits to electricity consumers from a higher capacity transmission network.

The analysis in this paper does not capture this forward contracting source of consumer benefits from transmission expansions. It only models the change in offer behavior brought about by each strategic supplier facing a more elastic residual demand curve because of the increased number of suppliers able to compete against it to supply energy because of the transmission expansion, not the potential change in that supplier's forward contracting decision and the forward contracting decisions of its competitors.

The consumer benefits of transmission expansions also depend of mechanism that translates the offer curves generation unit owners submit into the prices they are paid for the energy they produce. Generators in Alberta are able to set up to seven price and quantity pairs for each hour of the day for each generation unit in their portfolio. If (p_{ik},q_{ik}) i=1,2,3…,7 is the set of price level and quantity increment pairs for a generation unit k (k=1,2,..,K) owned by the supplier, that supplier's aggregate offer curve is constructed by ordering the offer price and quantity increment pairs from the lowest to highest offer price (regardless of generation unit) and then compute a step function with the height of each step equal to an offer price and the length of the step equal to the sum of the total amount of quantity increments across all generation units in that supplier's portfolio associated with that offer price. This yields the aggregate offer curve associated with that supplier.

Call the aggregate offer curve for supplier n during hour h, $S_h(p,\Theta_n)$, where Θ_n is the $14(K_n)$-dimensional vector of offer price and quantity increment pairs for the K_n generation units owned by supplier n. This curve gives the maximum amount of energy supplier n is willing to sell at price p during hour h. If there is no transmission congestion, then the market-clearing price is determined as the price where the aggregate supply curve intersects the aggregate demand during hour h, QD_h Mathematically, the market-clearing price, p^*, solves

$$S_h(p,\Theta_1) + S_h(p,\Theta_2) + ,,, + S_h(p,\Theta_N) = QD_h, \quad (2.1)$$

where N is the total number of suppliers submitting offer curves during hour h.

` When there is transmission congestion that prevent the AESO from accepting a supplier's quantity increment, this quantity increment and its associated offer price is dropped from that supplier's offer curve. Define $SC_h(p,\Theta_n)$ as the transmission-constrained offer curve for supplier n during hour h. By definition of being transmission constrained, the following inequality holds for all price levels

$$SC_h(p,\Theta_n) \le S_h(p,\Theta_n) \text{ for } p \tag{2.2}$$

and holds as a strict inequality for all prices greater than the lowest offer price at which a quantity increment cannot be accepted because of transmission constraints. Consequently, when there are transmission constraints, the market-clearing price, p^*, solves

$$SC_h(p,\Theta_1) + SC_h(p,\Theta_2) + ,\, ,\, , + SC_h(p,\Theta_N) = QD_h, \tag{2.3}$$

Figure 3 plots the aggregate offer curve not accounting for transmission constraints (called the Ideal Aggregate Offer Curve) and the offer curve with transmission constraints accounted for (called the Feasible Aggregate Offer Curve) for hour 12 of May 12, 2010. The vertical line in the graph is QD, the aggregate demand during that hour. The two curves satisfy inequality (2.2) for all prices from 0 to 1,000 CAD/MWh. Moreover, point of intersection of QD_h with the Ideal Aggregate Offer Curve yields a price that is much lower than the price at the intersection of the Feasible Aggregate Offer Curve, which determines the actual market-clearing price. The difference between the prices at the two points of intersection is almost 800 CAD/MWh. This price difference indicates the potential for significant consumer benefits from eliminating the transmission congestion that led to the need to use equation (2.3) to set the market-clearing price rather than equation (2.1).

If expected profit-maximizing suppliers believe that the transmission-constrained or Feasible Aggregate Offer Curve will be used to set prices rather than the unconstrained or Ideal Aggregate Offer Curve, these suppliers are likely to submit offer curves that make less capacity available at every output level relative to the case where they believe that the Ideal Aggregate Offer Curve will be used to set prices. The converse of this logic implies if each of the five large strategic suppliers believes that no quantity increment offers its competitors will be prevented from selling energy because of transmission constraints, then each strategic supplier will find it expected profit-maximizing to submit an offer curve closer to its marginal cost curve. This will yield lower market-clearing prices, whether or not some of its competitors' quantity increments are ultimately constrained from actually selling energy.

The next section describes how I estimate the change in each strategic supplier's offer curve in response to that supplier's belief that transmission constraints will not limit the competition that it faces for its output. The approach uses insights from the model of expected profit-maximizing offer behavior developed in Wolak (2000, 2003 and 2007). A methodology for computing both an upper bound and a lower bound on the "no-perceived-congestion" market-clearing price that assumes no change in forward contracting behavior by the five large strategic suppliers is also derived.

3. Computing the "Perceived No-Congestion" Offer Curves and Counterfactual Market-Clearing Prices

This section summarizes the basic features of the model of expected profit-maximizing offer behavior introduced in Wolak (2000) and tested empirically in Wolak (2003 and 2007). This theoretical model and the empirical analysis in McRae and Wolak (2012) is the theoretical and empirical foundation for the procedure used to compute the "no-perceived-congestion" offer curve for each strategic supplier. These counterfactual offer curves and the actual offer curves of the remaining suppliers are used to compute the no-perceived-congestion counterfactual aggregate offer curves that are used to compute the counterfactual market prices associated with additional transmission capacity. Two counterfactual market-clearing prices are used to provide upper and lower bounds on the potential competitiveness benefits associated with a transmission network where congestion is expected to be infrequent.

My empirical modeling framework is based on the assumption that suppliers choose their offer curves to maximize the expected profits from selling energy given the distribution of aggregate demand and supply uncertainty and the offer curves chosen by their competitors. The offer curves of competitors and aggregate supply (primarily generation and transmission outages) and aggregate demand uncertainty creates a distribution of residual demand curve realizations that the supplier faces. As discussed in Wolak (2000), an expected profit-maximizing supplier picks the vector of parameters of its aggregate offer curve, Θ in the notation of the previous section, to maximize the expected value of the realized profits over the distribution of residual demand curves that it faces, subject to the constraints placed on the elements of Θ by the market rules. For example, in the AESO, all offer prices must be greater than or equal to zero and less than the offer cap, which is currently 1,000 CAD/MWh. The offer quantity increments must be greater than or equal to zero and their sum less than or equal to the capacity of the generation unit.

The price at the point of intersection of the supplier's offer curve with each residual demand realization determines the market-clearing price and amount of output that the supplier sells in the short-term market for that realization of residual demand uncertainty. This price and quantity pair, along with the supplier's variable cost function, determines the supplier's realized variable profits for that residual demand realization. A described in detail in Wolak (2003 and 2007), an expected profit-maximizing supplier chooses the elements of Θ, the parameters of its offer curve, $S(p,\Theta)$, to maximize the expected value of these variable profit realizations with respect to the distribution of residual demand curve realizations.

It is important to emphasize that the assumption that suppliers maximize expected profits subject to the strategies of other market participants and the realizations of all supply and demand uncertainty is equivalent to that supplier exercising all available unilateral market power. A market participant is said to possess the ability to exercise market power if it can take unilateral actions to influence the market price and profit from the resulting price change. This means that the supplier faces a distribution of upward sloping residual demand curve realizations.

A shareholder-owned firm's management has a fiduciary responsibility to its shareholders to take all legal actions to maximize the expected profits it earns from participating in the wholesale market. Consequently, a firm is only serving its fiduciary responsibility to its shareholders when it exercises all available unilateral market power subject to obeying the wholesale market rules. A maintained assumption of our analysis is that both before and after a transmission upgrade, suppliers will choose their offer curves to maximize expected profits given the distribution of residual demand curves that they face. Consequently, if a transmission upgrade changes the distribution of residual demand curves that suppliers with the ability to exercise unilateral market power face, then the expected profit-maximizing offer curve each supplier submits should change. The remainder of this section describes how the change in offer behavior as a result of a reducing the incidence of transmission congestion is computed and how this change in offer behavior by the five strategic suppliers changes market-clearing prices.

3.1. Measuring the Ability to Exercise Unilateral Market Power in Bid-Based Markets

The residual demand curve that a supplier faces determines its ability to exercise unilateral market power. It is constructed from the offer curves submitted by all market participants besides the one under consideration. Let $S_n(p)$ denote the ideal offer curve of supplier n and $SC_n(p)$ the feasible offer curve of suppler n that accounts for transmission constraints.[3] At each price, p, the function $S_n(p)$ gives the total quantity of energy that supplier n is willing to sell and the function $SC_n(p)$ gives the amount of energy supplier n is able to sell given the level and geographic location of demand, the offer curves submitted by its competitors and the configuration of the transmission network.

As shown in Figure 3, the offer curves from each supplier can be used to construct the Ideal Aggregate Offer Curve and the Feasible Aggregate Offer Curve. We can re-arrange equation (2.1) to derive the Ideal Residual Demand Curve for any supplier, which measures the ability of the supplier to exercise unilateral market in the absence of transmission constraints. To measure this ability of supplier j to exercise unilateral market power, equation (2.1) can be re-written as:

$$S_j(p) = QD - (S_1(p) + S_2(p) + ...+ S_{j-1}(p) + S_{j+1}(p) + ...+ S_N(p)) = QD - SO_j(p), \qquad (3.1)$$

where $SO_j(p)$ is the aggregate willingness-to-supply curve of all firms besides supplier j. Define $DR_j^I(p) = QD - SO_j(p)$ as the Ideal Residual Demand Curve facing supplier j. The ideal residual demand of supplier j at price p is defined as the market demand remaining to be served by supplier j after the ideal willingness-to-supply curves, $S_k(p)$ for all $k \neq j$ have been subtracted out.

The Feasible Residual Demand Curve facing supplier j can also be computed by re-arranging equation (2.3) in an analogous manner. This residual demand curve captures supplier j's ability to exercise unilateral market power given the actual configuration of the transmission network, location of demand and other generation units. In this case, equation (2.3) can be re-written as:

$$\begin{aligned} SC_j(p) &= QD - (SC_1(p) + SC_2(p) + ...+ SC_{j-1}(p) + SC_{j+1}(p) + ...+ SC_N(p)) \qquad (3.2) \\ &= QD - SCO_j(p), \end{aligned}$$

where $SCO_j(p)$ is the aggregate feasible willingness-to-supply curve of all firms besides supplier j. Define $DR_j^F(p) = QD - SCO_j(p)$ as the Feasible Residual Demand Curve facing supplier j. The feasible residual demand of supplier j at price p is defined as the market demand remaining to be served by supplier j after the feasible willingness-to-supply curves, $SC_k(p)$ for all $k \neq j$ have been subtracted out.

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[3]For simplicity, I have suppressed the dependence on Θ_k, the vector of price offers and quantity increments for supplier k.

Equation (2.2) implies the following relationship between the Ideal and Feasible residual demand curves

$$DR_j^F(p) \geq DR_j^I(p) \text{ for all p.} \tag{3.3}$$

This relationship holds as a strict inequality for all prices greater than the lowest offer price associated with the first quantity offer from any firm besides supplier j that is prevented from being taken because of the configuration of the transmission network.

Figure 4(a) to 4(e) plot the Ideal and Feasible residual demand curves for the five largest suppliers in the Alberta market for hour 13 of May 16, 2010. The firms correspond to the firms Table 2. The vertical line on each graph shows how much energy the supplier actually sold during that hour. For all five suppliers, the point of intersection between the Ideal Residual Demand Curve and the amount that the firm actually sold occurred at price that was substantially lower than price at which the Feasible Residual Demand curve intersected the amount the firm actually sold, which is also very close to the actual market-clearing price for that hour.

The expectation of facing a substantially steeper distribution of Feasible Residual Demand Curves would cause an expected profit-maximizing strategic supplier to submit a higher offer price for its output than it would if it faced the flatter distribution of Ideal Residual Demand Curves. Because I observe what offer curve each supplier actually submitted and what Feasible Residual Demand Curve it actually faced, using insights from the model of expected profit-maximizing offer behavior in Wolak (2000), I can follow the approach of McRae and Wolak (2012) to estimate the relationship between a supplier's hourly offer price and the form of the residual demand curve that it actually faced. This empirical relationship can then be used to estimate how the supplier's offer price would change in response to change in the form of the residual demand curve that it faced from the Feasible Residual Demand Curve to the Ideal Residual Demand Curve.

3.2. Measuring of the Ability to Exercise Unilateral Market Power from a Simplified Model of Expected Profit-Maximizing Offer Behavior

This section develops a simplified model of expected profit-maximizing offer behavior that motivates the linear regression model I estimate to predict how the hourly offer price of each of the five large strategic suppliers will change in response to facing the Ideal Residual Demand Curve for that hour rather than the Feasible Residual Demand Curve for that hour. This linear regression model has been employed by McRae and Wolak (2012) to predict how strategic suppliers in the New Zealand wholesale electricity market will change their half-hourly offer prices in response to changes in the form of the half-hourly residual demand curve they face. McRae and Wolak (2012) found that even after controlling for differences input fuel costs across days of their sample, when each of the four large New Zealand suppliers faced less competition, as measured by the half-hourly value of the inverse semi-elasticity of their residual demand curve, each of the firms was predicted to submit a significantly higher half-hourly offer price.

Although a supplier does not know with certainty the market demand and the willingness-to-supply offers of other suppliers when it submits its offers, the supplier does have a very good idea of the set possible realizations of the residual demand curves it might face. The characteristics of each generation unit owned by the supplier's competitors and the market rules can significantly constrain the set of offers curves a supplier can submit. The pattern of hourly electricity demands throughout the day is very similar across weekdays within the same season of the year. In addition, all market participants understand the impact of weather conditions on the demand for electricity and the likely availability of intermittent resources like hydroelectric energy and wind energy. Finally, all suppliers monitor the daily prices of the fossil fuel inputs and the availability of these inputs.

All of these factors imply that a large supplier has a very good idea about the set of possible residual demand curve realizations that it might face. For each possible residual demand curve realization the supplier can find the ex post profit-maximizing market price and output quantity pair given its marginal cost curve following the process described above. This is the market price and output quantity pair that the supplier would like to achieve for that residual demand curve realization.

Figure 5(a) illustrates the construction of an expected profit-maximizing willingness to supply curve using this process for the case of two possible continuously differentiable residual demand curve realizations. For each residual demand curve realization, intersect the marginal cost curve with the marginal revenue curve associated with that residual demand curve realization. For example, for Residual Demand Curve 1 the marginal revenue curve for this residual demand curve (not shown on the figure) intersects the marginal cost curve at the quantity Q_1. The output price associated with this output level on Residual Demand Curve 1 is P_1. Repeating this process for Residual Demand Curve 2 yields the profit-maximizing price and quantity pair (P_2,Q_2). Note that because both residual demand curves are very steeply sloped, there is a substantial difference between the market price and the marginal cost at each output level. If these two residual demand realizations were the only ones that the supplier faced, its expected profit-maximizing offer curve would pass through both of these points because regardless of the residual demand realization this offer curve would cross at an ex post expected profit-maximizing level of output. The straight line connecting the points (P_1,Q_1) and (P_2,Q_2) in the figure is one possible expected profit-maximizing offer curve.

To illustrate the impact of more elastic residual demand curves on the offer curves submitted by an expected profit-maximizing supplier, Figure 5(b) repeats the construction of an expected profit-maximizing offer curve for the case of two more elastic residual demand curve realizations. The line connecting the points (P_1,Q_1) and (P_2,Q_2), which is an expected profit-maximizing offer curve for these two residual demand realizations, is much closer to the supplier's marginal cost curve. Specifically, for each residual demand realization, the price associated with the profit-maximizing level of output for that residual demand curve realization is closer to the marginal cost of producing that level of output than it was in Figure 5(a). This outcome occurs because each residual demand realization is much more elastic than the residual demand realizations in Figure 5(a).

Figure 5(c) considers the case in which the two residual demand curve realizations are infinitely elastic, meaning that for each realization the supplier faces enough competition that the entire market can be satisfied at a fixed price. By the logic described above, the supplier will find it unilaterally profit-maximizing to produce at the intersection of each residual demand curve realization with its marginal cost curve, because the marginal revenue curve for each residual demand realization is equal to the residual demand curve. In this case, the supplier's expected profit-maximizing offer curve, the line connecting the profit-maximizing output levels for each residual demand curve realization, is equal to the supplier's marginal cost curve. This result illustrates a very important point that if a supplier faces sufficient competition for all possible residual demand curve realizations then it will find it unilaterally expected profit-maximizing to submit an offer curve equal to its marginal cost curve.

The examples in Figures 5(a) to 5(c) utilize continuously differentiable residual demand curves. However, the same process can be followed to compute an expected profit-maximizing offer curve for the case of step-function residual demand curves. Figure 5(d) shows how this would be done for the more realistic case of step function residual demand curves with two possible residual demand realizations. For each residual demand curve realization, the supplier would compute the ex post profit-maximizing level of output and market price for the marginal cost curve given in Figure 5(d). For DR_1 this is the point (P_1,Q_1) and for DR_2 this is the point (P_2,Q_2). If these two residual demand curve realizations were the only possible residual demand curve realizations that the supplier could face, then a step function offer curve that passes through these two points would be an expected profit-maximizing offer curve.

Computing the expected profit-maximizing offer curve for a supplier is generally more complex than passing an offer curve through the set of ex post expected profit-maximizing price and output quantity pairs every possible residual demand curve realization. That is because the market rules can prevent a supplier from achieving the ex post profit-maximizing market price and output quantity pair for all possible residual demand realizations. Specifically, unless all of these ex post profit-maximizing price and quantity pairs lie along a willingness-to-supply curve for the supplier that the market rules allow it to submit, it is not possible for the supplier to submit a willingness to supply curve that always crosses the realized residual demand curve at an ex post profit-maximizing price and quantity pair for that residual demand curve realization.

Figure 5(e) provides an example of this phenomenon. This figure shows the ex post profit-maximizing price and quantity pairs for three residual demand curves. Note that the profit maximizing point for DR_3 lies below and to the right of the profit maximizing point for DR_1. This makes it impossible for the supplier to submit a non-decreasing step function offer curve that passes through the three ex post profit-maximizing price and output quantity pairs. In this case, the supplier must know the probability of each residual demand curve realization in order to choose the parameters of its expected profit-maximizing willingness to supply curve.

Figure 5(e) demonstrates that the expected profit-maximizing residual demand curve does not pass through any of these three ex post profit-maximizing price/quantity pairs. Instead, as discussed in Wolak (2003 and 2007), the form of the expected profit-maximizing willingness-to-supply curve depends on both the form of each residual demand curve realization and the probability of that residual demand curve realization. This curve, shown in Figure 5(e), yields market-clearing price and quantity-sold pairs for the firm for each of the three residual demand curve realizations that maximize the expected profits the firm earns subject to this offer curve being in the set of offer curves the market rules allow a supplier to submit. As shown in Wolak (2003) and Wolak (2007), the supplier chooses the price level and quantity increments that determine its offer curve to maximize its expected profits over the distribution of possible residual demand curve realizations that it faces.

The basic intuition from the continuously differentiable residual demand curve analysis also holds for the general case of step function residual demand curve. When a supplier faces a flatter distribution of residual demand realizations, it will find it expected profit-maximizing to submit a willingness-to-supply curve with offer prices closer to its marginal cost of production. Following McRae and Wolak (2012), I use the simplified model of expected profit-maximizing offer behavior to derive a summary measure of the hourly unilateral ability of a supplier to exercise market power from the realized residual demand curve that the supplier faced during that hour. This measure, called the Inverse Semi-Elasticity of the realized residual demand curve at the actual market-clearing price provides an ex post measure of the ability of a supplier to exercise unilateral market power. Specifically, this inverse semi-elasticity quantifies the $/MWh increase in the market-clearing price that would have occurred if the supplier had reduced the amount of output it sold in the market by one percent. This interpretation of the inverse semi-elasticity of the residual demand curve does not rely on the assumption that the realized output level and market-clearing price maximize the supplier's ex post profits as is the case for the continuously differentiable residual demand curve realizations in Figures 5(a) to 5(c).

As shown in McRae and Wolak (2012), the simplified model of expected profit-maximizing offer behavior described in Figures 5(a) to 5(c), implies a linear relationship between the offer price along the supplier's offer curve, its marginal cost of production and the inverse semi-elasticity of the realized residual demand curve. The first-order conditions for ex post profit-maximization for these two residual demand realizations in Figure 5(a) imply:

$$P_i = C_i - [DR_i(P_i)/DR_i'(P_i)], \quad i=1,2. \tag{3.4}$$

Equation (3.4) implies that the offer price for the supplier at its output level for residual demand curve realization 1 or 2 (P_i for i=1,2) is equal to the marginal cost of the highest cost unit owned by that supplier operating for that residual demand curve realization (C_i for i=1,2) plus the value of the residual demand curve at that offer price divided by the absolute value of the slope of the residual demand curve at that offer price for the residual demand curve realization ($[DR_i(P_i)/DR_i'(P_i)]$ for i=1,2).

Define η_i (i=1,2) as the inverse semi-elasticity of the residual demand curve i, as:

$$\eta_i = - (1/100)[DR_i(P_i)/DR_i'(P_i)]. \tag{3.5}$$

at offer price P_i for i=1,2. This magnitude gives the $/MWh increase in the market-clearing price associated with a one percent reduction in the amount of output sold by the supplier. In terms of this notation, equation (3.4) becomes

$$P_i = C_i + 100\eta_i, \; i=1,2. \tag{3.6}$$

Thus, the simplified model of expected profit-maximizing offer behavior implies that higher hourly offer prices for the supplier should be associated with higher values of the hourly inverse semi-elasticity.

As discussed above, because offer curves in the AWEM are step functions, defining a value of η_i, the inverse semi-elasticity, for a step function residual demand curve requires choosing a method for computing a finite difference approximation to the slope of the residual demand curve at a specific value of the offer price. This logic also implies that because actual residual demand curves are step functions, equation (3.6) will not hold with equality for the computed values of the inverse semi-elasticity. However, the general model of expected profit-maximizing offer behavior with step function offer curves and residual demand curves described above implies that when a supplier has a greater ability to exercise unilateral market power as measured by the size of η_i, that supplier's offer price is likely to be higher. Wolak and McRae (2011) presented empirical evidence consistent with this hypothesis for the four largest suppliers in the New Zealand wholesale electricity market.

The method for calculating the finite difference slope of the step-function residual demand curve at the firm's actual hourly output level requires choosing the output change used to compute the finite-difference approximation to the slope. These output changes should be large enough to ensure that price steps on the residual demand curve are crossed so that a non-zero slope is obtained, but not too large that the implied output change is judged implausible for the supplier to implement. McRae and Wolak (2012) experimented with a number of approaches to computing this finite difference approximation to the slope and found their empirical results were largely invariant to the approach used. I follow their preferred approach to computing the finite difference slope of the residual demand curve that enters into the computation of the hourly inverse semi-elasticity of the residual demand curve for each strategic supplier.

3.3. The Counterfactual No-Perceived-Transmission-Constraints Offer Curve

This section describes how I compute the counterfactual offer curve for each strategic supplier under the assumption of no perceived transmission constraints, which means that the strategic suppliers expect to face the Ideal Residual Demand Curve rather than the Feasible Residual Demand Curve. I first compute the hourly inverse semi-elasticity of the Feasible Residual Demand curve facing each strategic supplier for the entire sample period. Then for each strategic supplier, I compute a linear regression analogue of equation (3.6) where the supplier's hourly offer price at its actual output level for that hour is regressed on day-of-sample and hour-of-day fixed effects (that control for across-day changes in input prices and within-day variation in operating costs) and the hourly inverse semi-elasticity of the Feasible Residual Demand Curve faced by that supplier.

The coefficient estimate on the hourly inverse semi-elasticity is used to compute the predicted change in the supplier's offer price as a result of facing the Ideal Residual Demand Curve instead of the Feasible Residual Demand Curve. This offer price change is applied to all offer prices along that firm's willingness-to-supply curve. The process is repeated for all hours of the sample period to compute a counterfactual no-perceived-congestion offer curve for each hour of the sample period. This process is then repeated for all strategic suppliers.

The second column of Tables 3(a) to 3(e) lists the daily averages of the inverse semi-elasticities of the Feasible Residual Demand Curve for hour h for supplier (n=A, B, C, D, and E), η_{nh}^{F}, for each hour of the day over the sample period January 1, 2009 to December 31, 2011. The third column in each table lists the daily averages of the inverse semi-elasticities for Ideal Residual Demand Curve for the hour h, η_{nk}^{I}, for the same five suppliers for each hour of the day over the sample period January 1, 2009 to December 31, 2011. Note that consistent with the inequality in (3.3) the sample mean of η_{nh}^{F} is greater than the sample mean of η_{nk}^{I} for all hours of the day for all five strategic suppliers. The differences are much larger during the peak demand hours of the day when transmission constraints are likely render more quantity offers unable to be accepted to supply energy. This result is consistent with more of the competitiveness benefits of transmission investments being realized during the high demand hours of the day, week, and year.

In order to describe the linear regression analogue to equation (3.6) that I estimate to predict changes in each strategic supplier's offer price as result of facing the Ideal Residual Demand Curve rather than the Feasible Residual Demand Curve, a definition of a supplier's hourly offer price is required. Figure 6 presents the actual hourly offer curve for a hypothetical Firm 1. The dispatched quantity of energy for Firm 1 during that hour is 1,508 MW. The offer price along Firm 1's willingness-to-supply curve for that hour is found by extending a vertical line up from the horizontal axis at 1,508 MW until it intersects Firm 1's willingness-to-supply curve. In this case, the offer price for the dispatched quantity for Firm 1 is equal to $145/MWh, which is the offer step directly above the quantity level 1,508 MW. In general, the offer price for output level Q^* for supplier k during hour h is computed as the solution to the following equation in P: $Q^* = S_{hn}(P)$, where $S_{hn}(P)$ is supplier n's willingness-to-supply curve during hour h.

Equation (3.6) from the simplified model of expected profit-maximizing offer behavior by a supplier facing a distribution of downward sloping continuously differentiable residual demand curves implies that,

$$P_{hn} = C_{hn} + \beta\eta_{hn}^{F}, \tag{3.7}$$

where P_{hn} is the offer price of supplier n during hour h, C_{hn} is the marginal cost of the most expensive generation unit owned from supplier n that is operating during hour h, and η_{hn}^{F} is the inverse semi-elasticity of the Feasible Residual Demand Curve of supplier n during hour h, and β is an unknown parameter to be estimated. Equation (3.7) implies that after controlling for the opportunity cost of the highest cost generation unit operating during that hour, C_{hn}, a supplier's offer price at the quantity of energy that it sells in the short-term market should be an increasing function of the value of the inverse semi-elasticity.

Let P_{jhdm}(offer) equal the offer price at the actual level of output sold by supplier j during hour h of day d during month of sample m, η_{jhdm}^{F}, the inverse semi-elasticity of supplier j's Feasible Residual Demand Curve during hour h of day d during month of sample m. I control for differences across hours during our sample period in the variable cost of the highest cost generation unit owned by that supplier operating during hour h by allowing for day-of-sample fixed effects and hour-of-day fixed effects for each supplier. The following regression is estimated for each supplier j:

$$P_{jhdm}(\text{offer}) = \alpha_{dmj} + \tau_{hj} + \beta_j\eta_{jhdm} + \varepsilon_{jhdm}, \tag{3.8}$$

where the α_{dmj} and γ_{dmj} are day-of-month d and month of sample m fixed effects and the τ_{hj} and are hour-of-the-day fixed effects for supplier j. The ε_{jhdm} are mean zero and constant variance regression errors.

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Table 3(a): Daily Means of Hourly Feasible and Ideal Inverse Semi-Elasticites for Firm A

Hour	Feasible Inverse Semi-elasticity	Ideal Inverse Semi-elasticity
0	6.3913	4.5223
1	4.5759	3.0814
2	4.1091	2.5671
3	3.1988	1.7622
4	3.7905	2.1794
5	4.0035	2.3963
6	9.2222	6.283
7	29.2169	24.9878
8	21.7098	11.7629
9	41.5394	33.8444
10	41.1473	29.7382
11	50.5034	28.8659
12	29.4344	19.192
13	42.7524	21.8586
14	29.8361	19.1386
15	51.7264	30.8415
16	56.1854	33.2363
17	79.4979	54.4671
18	52.3705	29.9049
19	35.7296	17.0578
20	37.1703	29.5469
21	28.7581	16.9043
22	11.0723	6.3052
23	9.0169	4.5579

Table 3(b): Daily Means of Hourly Feasible and Ideal Inverse Semi-Elasticities for Firm B

Hour	Feasible Inverse Semi-elasticity	Ideal Inverse Semi-elasticity
0	6.9569	4.7097
1	4.8931	3.0866
2	4.5806	2.6925
3	4.427	1.9455
4	5.2092	2.3134
5	4.7518	2.494
6	9.9295	6.5786
7	29.1587	24.9033
8	22.5017	12.8093
9	41.8103	33.5288
10	30.1607	22.3046
11	51.2066	28.7834
12	27.7195	17.8637
13	40.7075	28.6439
14	28.6991	19.2485
15	47.7725	36.331
16	59.0699	30.445
17	65.9477	49.8988
18	69.1007	32.5257
19	31.3424	14.4765
20	57.4056	30.3224
21	26.4011	13.5428
22	10.4818	6.378
23	8.7793	4.76

Table 3(c): Daily Means of Hourly Feasible and Ideal Inverse Semi-Elasticites for Firm C

Hour	Feasible Inverse Semi-elasticity	Ideal Inverse Semi-elasticity
0	9.4245	5.4906
1	7.0398	3.7746
2	6.2446	3.1617
3	5.1674	2.4551
4	7.2173	3.0502
5	8.8495	4.5622
6	10.7127	6.3759
7	23.544	19.1729
8	25.4544	14.6554
9	39.3389	32.0813
10	33.5831	23.8562
11	42.7017	22.2442
12	30.062	17.0049
13	38.7434	20.3458
14	37.0706	22.4362
15	39.0619	25.1733
16	51.8622	31.265
17	54.6498	45.0149
18	58.7102	24.103
19	34.7564	15.9928
20	39.4	28.7643
21	28.7876	17.1298
22	12.1551	7.735
23	10.2982	5.808

Table 3(d): Daily Means of Hourly Feasible and Ideal Inverse Semi-Elasticities for Firm D

Hour	Feasible Inverse Semi-elasticity	Ideal Inverse Semi-elasticity
0	6.3966	4.5438
1	4.3691	2.8889
2	4.0839	2.59
3	3.3936	1.9453
4	3.6537	2.1542
5	4.0189	2.3412
6	11.5959	7.2019
7	29.6453	25.3327
8	24.3716	13.4542
9	41.5292	33.4996
10	28.4284	21.3949
11	53.8608	34.1311
12	24.1888	15.9755
13	37.0122	21.3211
14	26.4141	16.9625
15	39.6917	28.9546
16	49.7388	31.4801
17	60.6202	48.4901
18	57.5477	26.639
19	27.3654	15.7026
20	34.4431	27.0927
21	23.3192	12.2585
22	9.9137	6.0877
23	8.0715	4.7127

Table 3(e): Daily Means of Feasible and Ideal Hourly Inverse Semi-Elasticities for Firm E

Hour	Feasible Inverse Semi-elasticity	Ideal Inverse Semi-elasticity
0	13.5245	8.1049
1	8.6496	4.1487
2	13.5271	7.8086
3	9.0608	4.2187
4	10.877	4.2615
5	12.7985	7.0101
6	18.0116	11.7573
7	39.0842	31.6787
8	27.4971	16.1518
9	60.5141	35.5801
10	57.4434	28.3626
11	53.2884	32.6641
12	38.4105	21.6951
13	44.8432	24.5349
14	63.6096	22.1926
15	63.5564	43.7651
16	72.6378	40.3488
17	87.5616	61.5054
18	76.4675	37.6527
19	41.8704	19.8875
20	42.128	32.6894
21	34.3374	15.5131
22	14.2099	7.9596
23	12.8844	6.3362

These fixed effects control for variation in costs and operating conditions and across days of the sample and within days. Input fossil fuel prices and hydroelectric water levels change at most on a daily basis. Because there is a different fixed effect for each day and month combination during our sample period, these fixed effects completely account for the impact of daily changes in fossil fuel prices and water levels during our sample period on the variable cost of the highest cost generation unit owned by supplier j that is operating during each hour during the day. For these reasons, these day-of-sample fixed-effects completely account for any day-to-day change in the prices of input fossil fuels such as natural gas and coal paid by supplier j. The hour-of-day fixed-effects account for differences across hours of the day in the variable cost of the highest cost generation unit in that supplier's portfolio operating. This strategy for controlling for variable cost changes across hours of the sample implies that more than 1,100 parameters determine the hourly variable cost values for each supplier over the sample period Multiplying this figure by five implies more than 5,500 parameters determine the hourly variable cost of the highest cost generation unit operating during a hour of sample across the five strategic suppliers. For all of these reasons, the day-of-sample and hour-of-day fixed effects for all five strategic suppliers should be more than sufficient to account for changes in the variable cost of the highest cost unit operating during hour h of day d of month of sample m.

Table 4 presents the estimated values of β_j and the estimated standard errors for each of the five largest suppliers from estimating equation (3.8) for each supplier over our sample period of January 1, 2009 to December 31, 2011. The values of β_j are positive, precisely estimated and economically meaningful for all regressions.

Table 4: Coefficient Estimates of β_j in Regression (3.8) for Supplier j

	Coefficient Estimate	**Standard Error**
$\beta_{\text{Firm A}}$	0.097143	0.002224
$\beta_{\text{Firm B}}$	0.057410	0.001564
$\beta_{\text{Firm C}}$	0.042383	0.001491
$\beta_{\text{Firm D}}$	0.055298	0.002048
$\beta_{\text{Firm E}}$	0.054662	0.001370

Note: Each line of the table corresponds to a different regression with 1,095 day-of-sample and 24 hour-of-day fixed effects included in each regression.

Each of these regression coefficient estimates implies that holding all other factors constant, if the inverses semi-elasticity of the residual demand curve faced by one of the five large suppliers falls, then the offer price for that firm is predicted to fall by the change in the semi-elasticity times the estimated value of β_j for that supplier. Tables 5(a) to 5(e) contain the hourly sample standard deviations of the hourly Feasible and Ideal inverse semi-elasticities. The standard deviations for the Feasible inverse semi-elasticities are in the range of 300 to 600 CAD/MWh during a number of hours of the day for each of the suppliers. This implies that a one standard deviation increase in the hourly inverse elasticity for one of these hours of the day predicts an increase in supplier's hourly offer price of 15 to 40 CAD/MWh for the regression coefficient estimates in Table 4.

This result indicates that the potential for economically significant competitiveness benefits from transmission expansions that reduce both the mean and standard deviation of the hourly inverse semi-elasticities. The standard deviations of the Ideal inverse semi-elasticities are uniformly smaller than the corresponding values for the Feasible inverse semi-elasticities. This result demonstrates an additional source of competitiveness benefits from transmission expansions that reduce the frequency and magnitude of congestion. These expansions reduce the incidence of extremely large inverse semi-elasticities which the results in Table 4 imply will lead to substantially larger offer prices and substantially larger market-clearing prices.

The final step in the process of computing the counterfactual no-perceived-congestion offer curve adjusts each offer price submitted by supplier j during hour h by the difference between the Feasible semi-elasticity and the Ideal semi-elasticity times the estimated value of β_j. Mathematically, if P_{jhk} is the offer price for bid quantity increment k for supplier j during hour h, then the no perceived congestion offer price for this bid quantity increment is:

$$P_{jhk}^{NC} = P_{jhk} - \beta_j(\eta_{hn}^F - \eta_{hn}^I) . \tag{3.9}$$

Repeating this process for all bid quantity increments yields a new vector of offer price and quantity increment pairs, Θ^{NC}. This vector is composed of the modified offer prices, P_{jhk}^{NC}, from (3.9) and original offer quantity increments. Let $S_h(\Theta_n^{NC})$ denote the modified no perceived congestion offer curve for the supplier n during hour h.

Figure 7(a) to 7(c) illustrate the process used to compute $S_h(\Theta_n^{NC})$, from $S_h(\Theta_n)$, original offer curve for supplier n during hour h for hypothetical Firms 1 and 2. The upper step function in Figures 7(a) and 7(b) are the original willingness-to-supply curves for Firms 1 and 2. The lower step functions in the figures are the shifted down no-perceived congestion willingness-to-supply curves of Firms 1 and 2. The upper step function in Figure 7(c) is the original aggregate willingness-to-supply curve of Firms 1 and 2 and the lower step function is the shifted no-perceived-congestion aggregate willingness-to-supply curve for the two firms. Figure 7(c) demonstrates that for the same level of aggregate demand, the shifted no-perceived-congestion aggregate willingness-to-supply curve will set a lower market-clearing price than the original aggregate willingness-to-supply curve. This market price reduction is the source of the competitiveness benefits to electricity consumers from transmission investments.

4. The Competitiveness Benefits of Congestion-Reducing Transmission Investments

This section describes the calculation of the two counterfactual no-perceived-congestion market-clearing prices. The results of computing these two prices for all hours from January 1, 2009 to December 31, 2011 are described and then several calculations are presented to demonstrate the magnitude of consumer benefits from transmission expansions that reduce the frequency and magnitude of transmission congestion.

The first counterfactual price takes an extremely conservative approach to computing the competitiveness benefits of transmission expansions. It assumes no change in what offer quantities can be accepted because of transmission constraints. The only difference is that the Feasible Offer Curve for the five large strategic suppliers uses the adjusted offer prices from equation (3.9). In terms of the notation of Section 3, the offer curves for the strategic suppliers are defined as $SC_h(\Theta_n^{NC})$, the Feasible Offer Curve defined in Section 2 evaluated at Θ_n^{NC}, instead of Θ_n. This counterfactual price provides a very slack upper bound on market-clearing price that would result if all strategic suppliers faced the Ideal Residual Demand curve instead of the Feasible Residual Demand curve.

Table 5(a): Daily Standard Deviations of Hourly Feasible and Ideal Inverse Semi-Elasticites for Firm A

Hour	Feasible Inverse Semi-Elasticity	Ideal Inverse Semi-Elasticity
0	41.561	40.743
1	15.322	14.893
2	13.31	12.571
3	9.364	7.605
4	10.295	7.981
5	10.924	9.633
6	40.067	35.372
7	292.143	290.078
8	132.398	60.35
9	343.616	311.174
10	253.786	235.329
11	292.157	164.427
12	98.242	74.311
13	274.736	102.382
14	134.156	97.913
15	359.722	215.827
16	271.568	206.438
17	456.373	308.841
18	280.885	227.526
19	254.419	71.31
20	235.152	226.993
21	162.497	110.504
22	48.755	32.261
23	44.892	18.773

Table 5(b): Daily Standard Deviations of Feasible and Ideal Hourly Inverse Semi-Elasticities for Firm B

Hour	Feasible Inverse Semi-elasticity	Ideal Inverse Semi-Elasticity
0	42.075	41.232
1	15.016	14.058
2	15.484	12.636
3	29.114	7.747
4	29.606	7.938
5	13.884	9.509
6	40.304	35.644
7	291.856	289.94
8	133.435	64.155
9	342.833	310.167
10	119.003	106.736
11	283.955	170.37
12	93.317	72.353
13	254.823	235.151
14	114.195	98.2
15	316.323	302.876
16	337.785	202.272
17	322.559	286.61
18	611.637	289.342
19	158.011	59.6
20	469.176	234.132
21	136.791	60.309
22	34.966	32.301
23	30.378	18.867

Table 5(c): Daily Standard Deviations of Hourly Feasible and Ideal Inverse Semi-Elasticites for Firm C

Hour	Feasible Inverse Semi-elasticity	Ideal Inverse Semi-elasticity
0	54.056	42.118
1	25.593	16.602
2	23.678	12.669
3	15.524	8.921
4	31.927	11.829
5	43.152	33.979
6	40.43	31.318
7	194.786	191.771
8	144.113	77.799
9	320.685	286.365
10	195.535	125.898
11	236.523	106.898
12	104.398	68.418
13	235.702	80.995
14	177.397	151.047
15	202.042	164.03
16	290.463	204.292
17	355.793	353.725
18	548.399	201.402
19	221.705	57.52
20	232.545	221.435
21	151.768	90.505
22	42.209	40.508
23	32.312	22.947

Table 5(d): Daily Standard Deviations of Feasible and Ideal Hourly Inverse Semi-Elasticities for Firm D

Hour	Feasible Inverse Semi-elasticity	Ideal Inverse Semi-elasticity
0	41.834	41.227
1	14.433	14.01
2	13.116	12.704
3	11.299	9.914
4	9.708	7.875
5	10.881	9.48
6	96.537	48.327
7	296.072	292.202
8	155.372	75.309
9	343.144	310.183
10	116.518	104.384
11	328.037	239.922
12	84.439	68.17
13	251.092	100.32
14	111.537	89.703
15	232.572	212.737
16	288.604	209.807
17	300.503	284.992
18	555.296	222.229
19	127.804	64.702
20	227.523	219.968
21	131.424	59.054
22	35.701	32.304
23	29.438	20.325

Table 5(e): Daily Standard Deviations of Feasible and Ideal Hourly Inverse Semi-Elasticities for Firm E

Hour	Feasible Inverse Semi-elasticity	Ideal Inverse Semi-elasticity
0	65.299	59.51
1	26.253	12.322
2	125.547	116.741
3	43.99	17.537
4	54.178	19.225
5	61.63	51.984
6	79.64	71.81
7	320.28	313.171
8	140.397	73.597
9	497.988	311.275
10	485.63	133.104
11	291.225	204.085
12	167.336	84.217
13	250.864	88.981
14	774.835	96.416
15	362.656	320.241
16	429.877	321.408
17	400.863	335.92
18	630.742	345.018
19	253.976	91.884
20	312.371	305.789
21	174.459	77.193
22	37.217	31.736
23	34.718	17.451

To compute this counterfactual price for hour h, $SC_h(\Theta_n^{NC})$ is used for each of the five large strategic suppliers and the original feasible offer curve is used for all other suppliers. For simplicity assume that n=1,2,..,5 corresponds the five strategic firms and the remaining non-strategic firms are indexed n=6,7,..,N. The first counterfactual no-perceived transmission congestion market-clearing price for hour h is computed by solving for the smallest price such that:

$$SC_h(p,\Theta_1^{NC}) + SC_h(p,\Theta_2^{NC}) + ,\,,\,, + SC_h(p,\Theta_5^{NC}) + SC_h(p,\Theta_6), + \ldots, + SC_h(p,\Theta_N) = QD_h, \quad (4.1)$$

Because the highest offer price accepted during h could be from a non-strategic firm, even though all of the adjusted offer prices of the strategic suppliers in Θ_n^{NC} (n=1,2,…,5) are less than the original offer prices in Θ_n (n=1,2,…,5), this market-clearing price, PC_h^F, is less than or equal to the actual market-clearing price, P_h. This weak inequality holds as a strict inequality unless the offer price of a non-strategic firm set the original market-clearing price.

To compare this Feasible Offer Curve counterfactual price-setting process to the actual hourly price-setting process used by the AESO, I also compute an estimate of the actual market-clearing price using the original Feasible Offer Curves of all suppliers. Let PP_h^F denote the smallest price that solves:

$$SC_h(p,\Theta_1) + SC_h(p,\Theta_2) + ,\,,\,, + SC_h(p,\Theta_5) + SC_h(p,\Theta_6), + \ldots, SC_h(p,\Theta_N) = QD_h, \quad (4.2)$$

Note that original offer price and feasible offer quantities are used in the Feasible Offer Curves of all suppliers to compute the Predicted Feasible Actual market-clearing price, PP_h^F.

Figure 8 plots the daily average value of the actual market-clearing price and the daily-average of the Predicted Feasible Actual market-clearing price. In spite of the fact that daily average of actual prices is extremely volatile, sometimes exceeding 600 CAD/MWh, the daily average of the Predicted Feasible Actual market-clearing price is virtually identical for days of the sample period from January 1, 2009 to December 31, 2011.

The second counterfactual no-perceived congestion market-clearing price yields a lower bound on the no-perceived-congestion counterfactual price. It assumes that all suppliers face no transmission constraints so that the counterfactual market-clearing price is computed from the Ideal Offer Curves of the five strategic suppliers using the offer prices adjusted as described in equation (3.9) and the Ideal Offer Curves of the non-strategic suppliers. Mathematically, the counterfactual no-perceived congestion price, PC_h^I, is the smallest price that solves:

$$S_h(p,\Theta_1^{NC}) + S_h(p,\Theta_2^{NC}) + ,,, + S_h(p,\Theta_5^{NC}) + S_h(p,\Theta_6), + \ldots, + S_h(p,\Theta_N) = QD_h, \quad (4.3)$$

Note that the aggregate offer curve is the sum of the Ideal Offer Curves evaluated at Θ_n^{NC} (n=1,2,..,5) for the five strategic suppliers and Θ_n (n=6,…,N) for remaining suppliers. This price is lower than PC_h^F because it assumes that no quantity offers are prevented from selling energy because of the transmission constraints. For this reason, it provides an lower bound on the market-clearing price that would result if all strategic suppliers faced the Ideal Residual Demand curve instead of the Feasible Residual Demand curve but kept the same fixed-price forward contract obligations.

As noted earlier, if a supplier faces greater competition during all hours of the year because that supplier does not expect quantity offers from other suppliers to be preventing from selling energy because of transmission constraints, that supplier is potentially more likely to sell more fixed-price forward contract obligations in order to pre-commit to being a more aggressive competitor (submit offer curves closer to its marginal cost curve) in the short-term market. Neither of the two counterfactual prices attempts to capture this additional source of potential competitiveness benefits from a commitment to transmission investments that significantly reduce the frequency and magnitude of transmission congestion.

Following the analogous logic to computing the Predicted Feasible Actual market-clearing price, a Predicted Ideal Actual market-clearing price can be computed by constructing an aggregate supply curve from the sum of the Ideal Offer Curve for all suppliers. Mathematically, the Predicted Ideal Actual market-clearing price, PP_h^I, is the smallest price that solves:

$$S_h(p,\Theta_1) + S_h(p,\Theta_2) + ,,, + S_h(p,\Theta_5) + S_h(p,\Theta_6), + \ldots, S_h(p,\Theta_N) = QD_h, \quad (4.4)$$

This price should be less than or equal to the actual market-clearing price because it assumes that the Ideal Offer Curves are used for all suppliers, including the five strategic suppliers. Particularly, during the high-priced hours of the day, PP_h^I is significantly less than the actual market-clearing price and the Predicted Feasible Actual market-clearing price.

Figure 9 plots the daily average actual price and the daily average Predicted Ideal Actual price. Although the daily average Predicted Ideal Actual prices follow the same general pattern as the daily average actual prices, they are typically lower and less volatile than the actual prices. This result suggests that even without a change in suppler offer behavior, increasing the amount of transmission capacity to reduce the number and total volume of offer quantities that cannot sell energy because of transmission constraints has significant consumer benefits in terms of lower average wholesale prices and less volatile wholesale prices.

For each of the two counterfactual prices, I compute two measures of the competitiveness benefits of transmission investments that commit to a reduced frequency of congestion. The first is the difference between the actual market price and the counterfactual price times the total demand in the AESO. The second is a relative measure, the reduction in wholesale market costs as a percentage actual wholesale market costs, the actual market-clearing price times the total demand in the AESO. In terms of our previously defined notation, the first two hourly measures are:

$$\Delta R_h^F = (P_h - PC_h^F)QD_h \text{ and } \Delta R_h^I = (P_h - PC_h^I)QD_h, \qquad (4.5)$$

which are the difference in wholesale market costs from consumers paying the counterfactual Feasible Market Price and the difference in wholesale market costs from consumers paying the counterfactual Ideal Market Price. The second two measures are the ratio of the difference in wholesale market cost over some time horizon divided by actual wholesale market costs over that same time horizon. Let H equal the number of hours in that time horizon, then

$$\Delta RR_h^F = 100 * \frac{\sum_{h=1}^{H}(P_h - PC_h^F)QD_h}{\sum_{h=1}^{H} P_h * QD_h} \text{ and } \Delta RR_h^I = 100 * \frac{\sum_{h=1}^{H}(P_h - PC_h^I)QD_h}{\sum_{h=1}^{H} P_h * QD_h}, \qquad (4.4)$$

which are the change in wholesale energy costs over horizon H as a percent of actual wholesale energy purchase costs over horizon H for both the Feasible and Ideal counterfactual prices.

Table 6 lists the annual average of the hourly wholesale cost changes for the Ideal and Feasible Counterfactual Prices for 2009, 2010 and 2011. It also lists the average hourly wholesale cost changes for the entire sample period. Third column of the table lists the average hourly wholesale market revenue for each year and for the entire sample. The fifth column shows the annual average hourly wholesale cost difference using the Ideal Counterfactual price as a percentage of annual average hourly wholesale market revenues. The last row in the table gives the sample hourly average hourly wholesale cost difference using the Ideal Counterfactual price as a percentage of sample average of hourly wholesale market revenues. The last column shows the annual average hourly wholesale cost difference using the Feasible Counterfactual Price as a percentage of annual average hourly wholesale market revenues. The last row gives the sample average hourly wholesale cost difference using the Feasible Counterfactual Price as a percentage of sample average of hourly wholesale market revenues.

Table 6: Annual and Sample Average Hourly Revenue Differences for Ideal and Feasible Counterfactual Prices in CAD and as Percentage of Annual Wholesale Energy Costs

Year	Ideal Price Cost Difference	Feasible Price Cost Difference	Wholesale Energy Costs	Ideal Cost Difference as a Percent of Wholesale Revenues	Feasible Price Cost Difference as a Percent of Wholesale Revenues
2009	61,912.99	2,734.43	398,345.3	15.54254	0.686447
2010	81,648.03	2,080.56	426,525.7	19.14258	0.487792
2011	102,963.6	5,043.68	653,753	15.74962	0.771496
Sample	79,590.19	3,066.67	472,816.4	16.83321	0.648596

Figure 10(a) and 10(b) plot the monthly average values of the hourly wholesale cost changes for the Feasible and Ideal Counterfactual Prices. The average monthly demand served in the AESO is also plotted in each figure. The average monthly wholesale cost changes using the Feasible Counterfactual Price shown in Figure 10(a) finds modest, but economically significant competitiveness benefits from suppliers submitting offer prices under the expectation of no congestion, but actually facing the same amount of congestion as actually occurred during that hour. Although the average hourly revenue change over the sample is 3,067 CAD, during one month it exceeded 25,000 CAD. Comparing the pattern of the monthly average demand in the AWEM to the monthly average values of the Feasible Counterfactual Price wholesale cost difference shows a positive correlation between the two monthly values.

Figure 10(b) finds substantially larger revenue changes associated with the strategic suppliers submitting offer prices under the expectation of no congestion and the realization that there is actually no congestion, the Ideal Counterfactual Price hourly wholesale cost difference. The sample average hourly wholesale cost difference using the Ideal Counterfactual Price is 79,590 CAD. There is even a month when the average hourly wholesale cost difference with the Ideal Counterfactual price is greater than 500,000 CAD. There appears to be a positive correlation between the monthly average value of this cost difference and the monthly average value of demand in the AWEM.

The pattern of the monthly value of the wholesale cost differences using in the Feasible Counterfactual price as a percentage of actual monthly wholesale market revenues in Figure

11(a) replicates the pattern of the monthly wholesale cost differences in Figure 10(a). For the entire sample the Feasible Counterfactual price wholesale cost difference is 0.64 percent of total wholesale energy costs. However, during certain months, this percentage is substantially higher. In fact, it is more than 2 percent of monthly wholesale energy costs during one month of the sample.

For the entire sample, the Ideal Counterfactual price wholesale cost difference is 16.8 percent of total wholesale energy costs. As shown in Figure 11(b), during certain months, this percentage is substantially higher, and in one month more than 45 percent of actual wholesale market revenues. Although for most of the months this percentage is below 20 percent, it never fall below 5 percent, indicating that during all months of the sample period there are substantial competitiveness benefits from suppliers expecting there to be no transmission constraints that prevent quantity increments offered by them and their competitors from selling energy and this expectation in fact turns out to be case.

5. Conclusions

These empirical results demonstrate economically sizeable competitiveness benefits from facing strategic suppliers with residual demand curves that reflect little likelihood that transmission constraints will limit the quantity increments of other firms from selling energy. Even if these expectations do not turn out to be the case, because strategic suppliers with these expectations about the extent of competition that they face are predicted to submit lower offer prices, the resulting market-clearing prices, even with the same amount of transmission congestion as actually occurred, will be lower. These Feasible Counterfactual Offer Curve market-clearing prices imply sizeable average wholesale cost differences, an average of 3,067 CAD per hour. Over the three–year sample, the total wholesale cost difference from the five largest strategic suppliers in AWEM expecting that none of the quantity increments of their competitors will be unable to supply energy because of transmission constraints is more than 94 million CAD, even if there were no change in the actual realized transmission congestion.

If these expectations of limited congestion by the strategic suppliers actually hold and no suppliers are actually prevented from selling energy because of transmission constraints and the Ideal Counterfactual Offer market-clearing prices are the relevant price paid by electricity consumers, the total wholesale cost savings for the sample period is more than $2 billion dollars.

Clearly, this amount of wholesale cost savings over a three-year period could fund a substantial amount of transmission expansions.

Taken together, these results provide persuasive empirical evidence that the competitiveness benefits of transmission expansions should be accounted for in the transmission planning processes for formal wholesale electricity markets. Given the magnitude of these benefits, many transmission expansions with net economics benefits to electricity consumers may not be undertaken because this source of economic benefits is not accounted for. This is particularly the case for the AWEM market given the ownership shares of generation capacity of the five strategic suppliers and the dominant share that coal and natural gas-fired generation plays in the electricity supply mix. The extremely steep offer curves that suppliers submit, particularly during periods when there is likely to be transmission congestion, argues in favor of a transmission policy that accounts for these competitiveness benefits.

These results also support the view that planning and constructing the transmission network in Alberta in a forward-looking manner to limit the frequency and magnitude of congestion can yield sizeable net benefits to electricity consumers in the province as demonstrated by both the Feasible and Ideal Counterfactual price wholesale market cost differences changes.

Finally, it is important to emphasize that a potentially sizeable source of additional competitiveness benefits was not accounted for in this analysis. Specifically, the incentive for a supplier to change its fixed-price forward contract obligations in response to the reduced number of opportunities to exercise unilateral market power because of the increased competition it faces because of the significantly reduced frequency and magnitude of transmission congestion is not accounted for. Such an analysis would require information on the fixed-price forward market obligations of the five largest strategic suppliers in the AWEM. This data is currently considered confidential by market participants and is not available to the AESO. However, given the current concentration of generation ownership in the AWEM and the structure of offer curves submitted to the AESO during the sample period, this forward contracting competitiveness benefit from a transmission planning and construction policy that limits the frequency and magnitude of transmission congestion is likely to be economically significant.

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Figure 1(a): Annual Demand Duration Curves for 2009, 2010, and

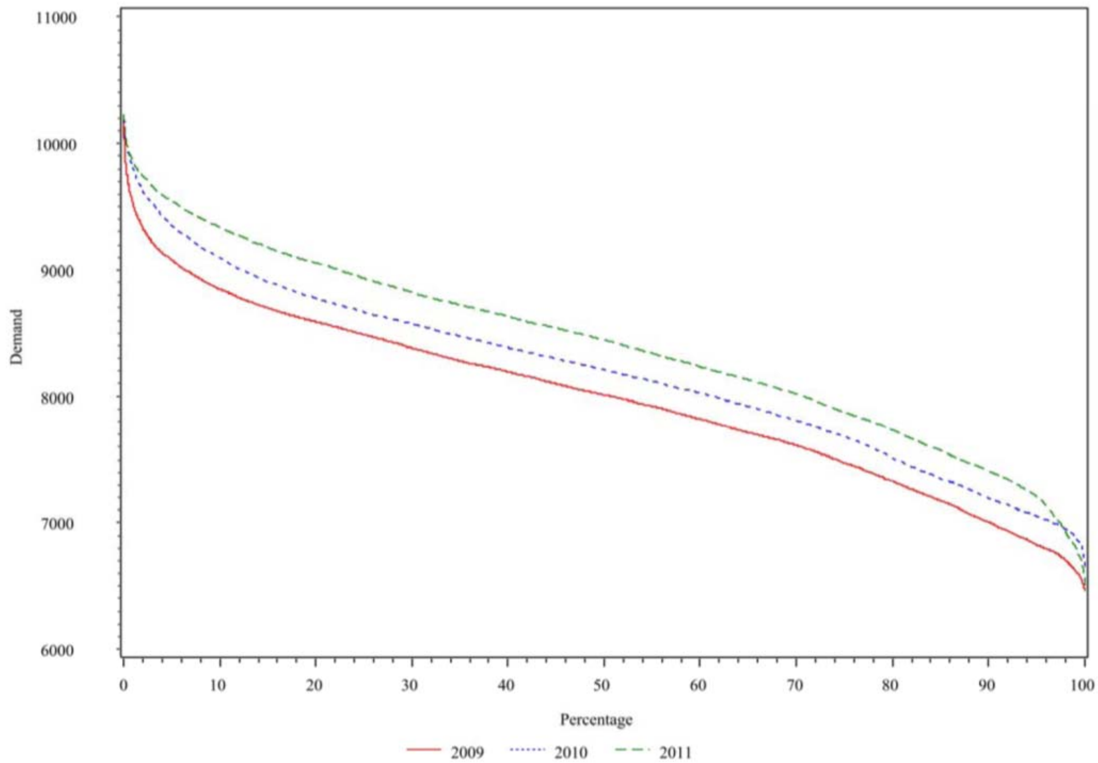

Figure 1(b): Highest 1 Percent of Annual Demand Duration Curves 2009, 2010,

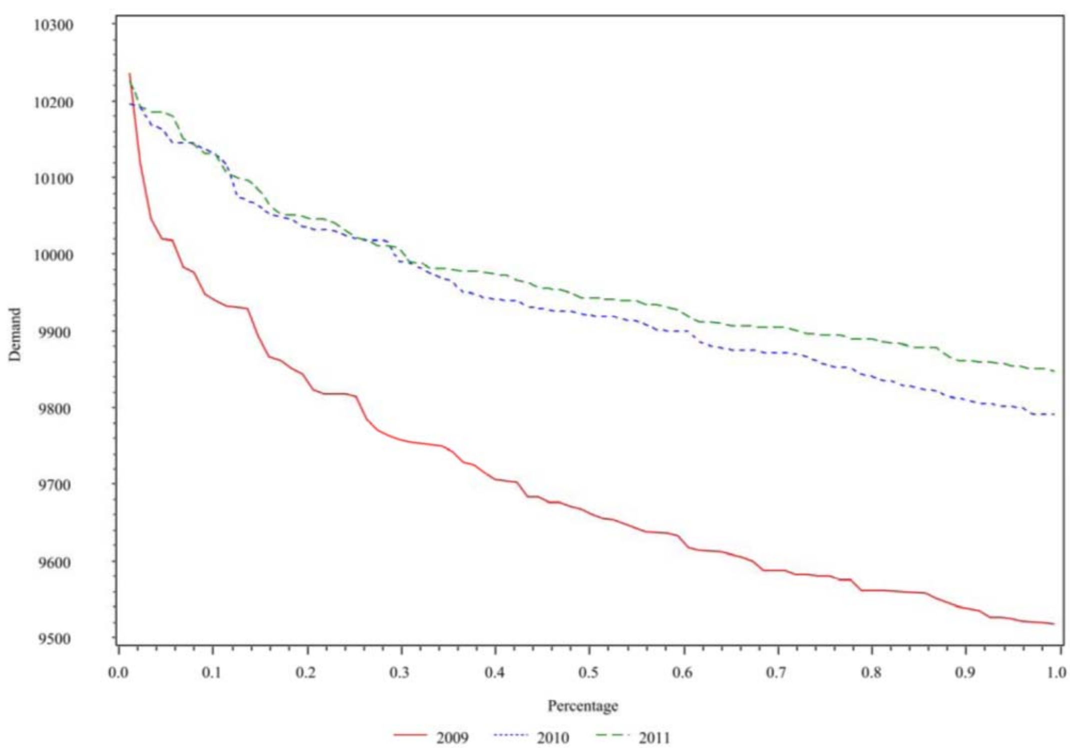

Figure 2(a): Annual Price Duration Curves 2009, 2010, and 2011

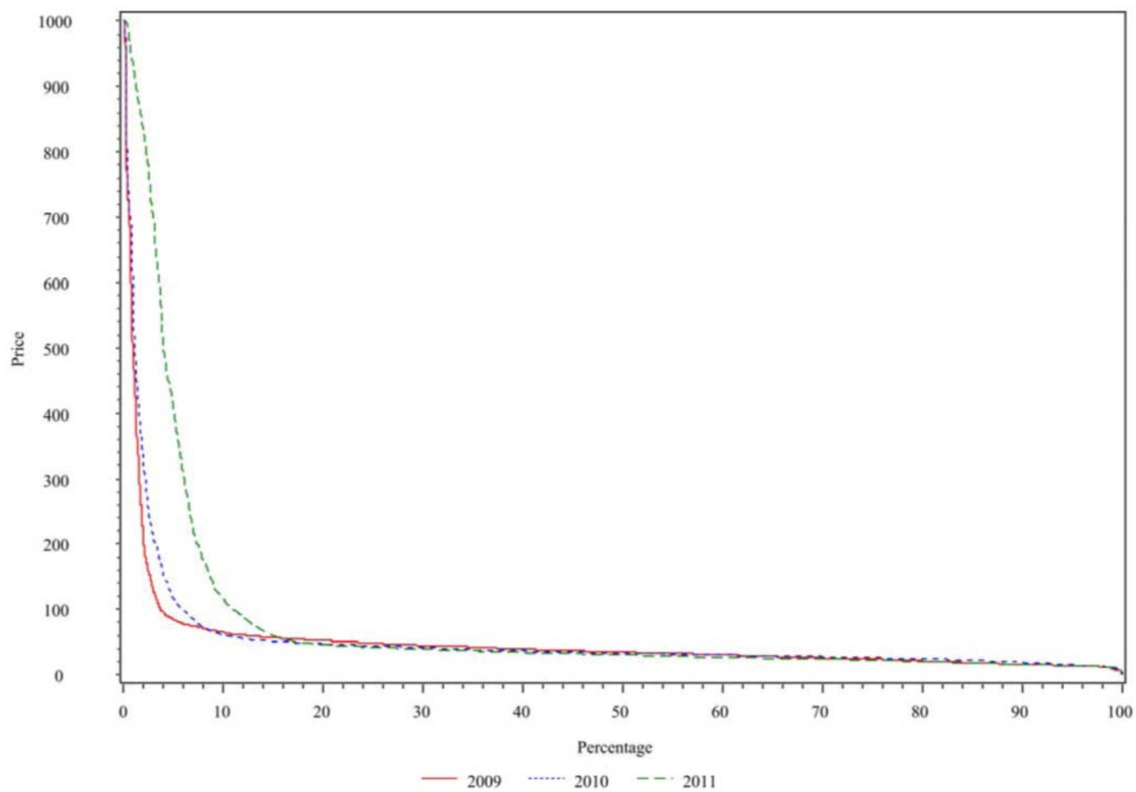

Figure 2(b): Upper 10 Percent of Annual Price Duration Curves 2009, 2010, 2011

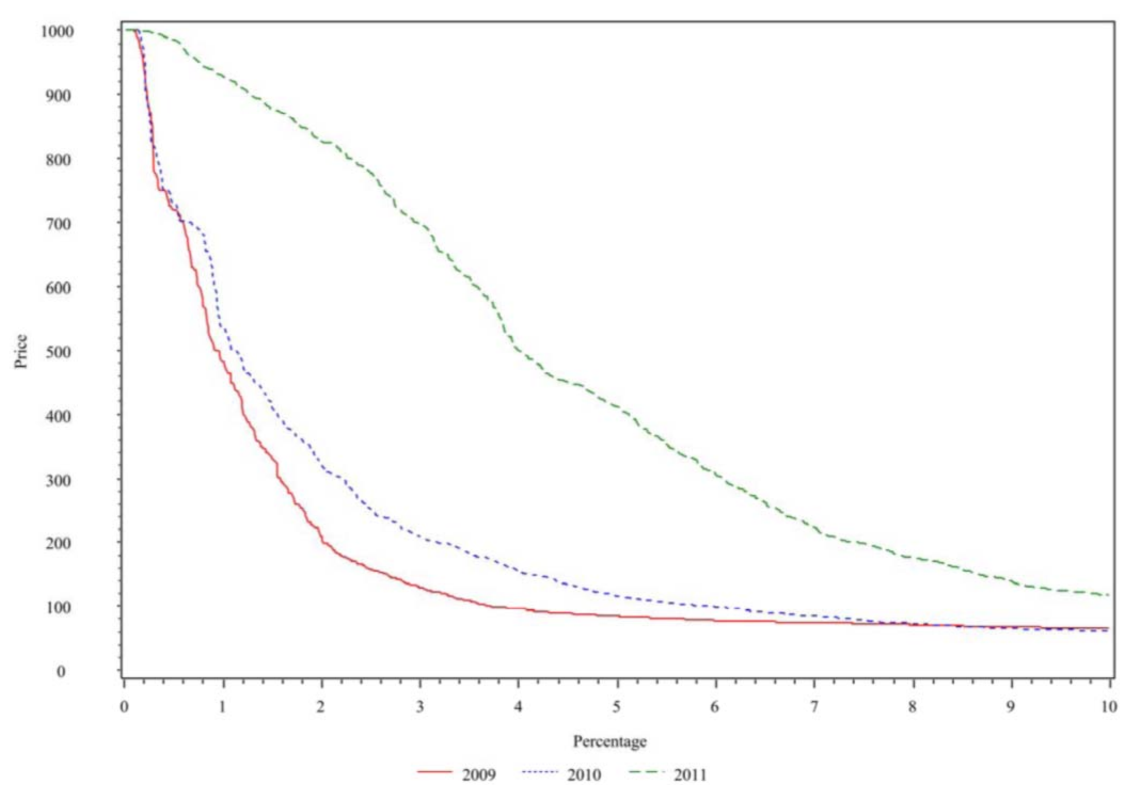

Figure 3: Ideal and Feasible Aggregate Offer Curve for Hour 12 of 5/12//2010

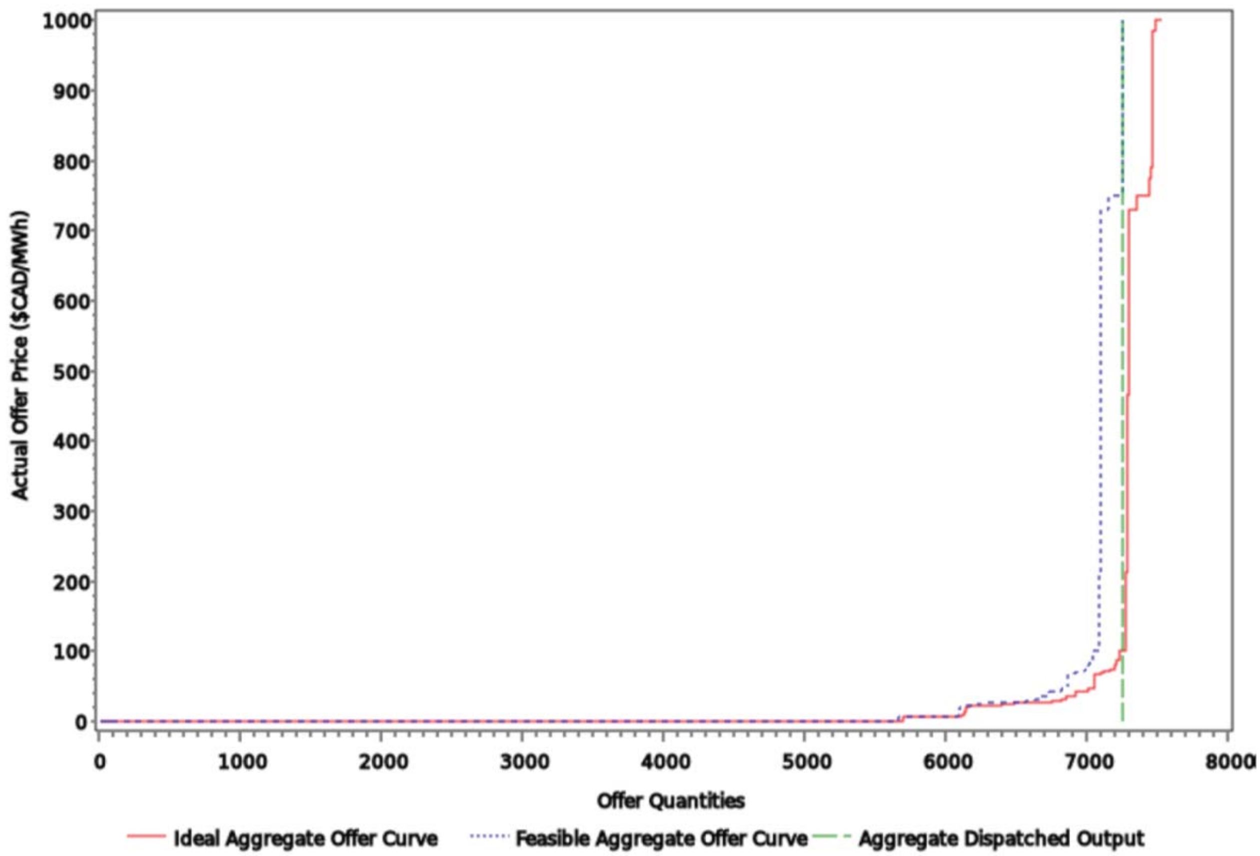

Figure 4(a): Ideal and Feasible Residual Demand Curves for, Hour 13 of 5/16/2010

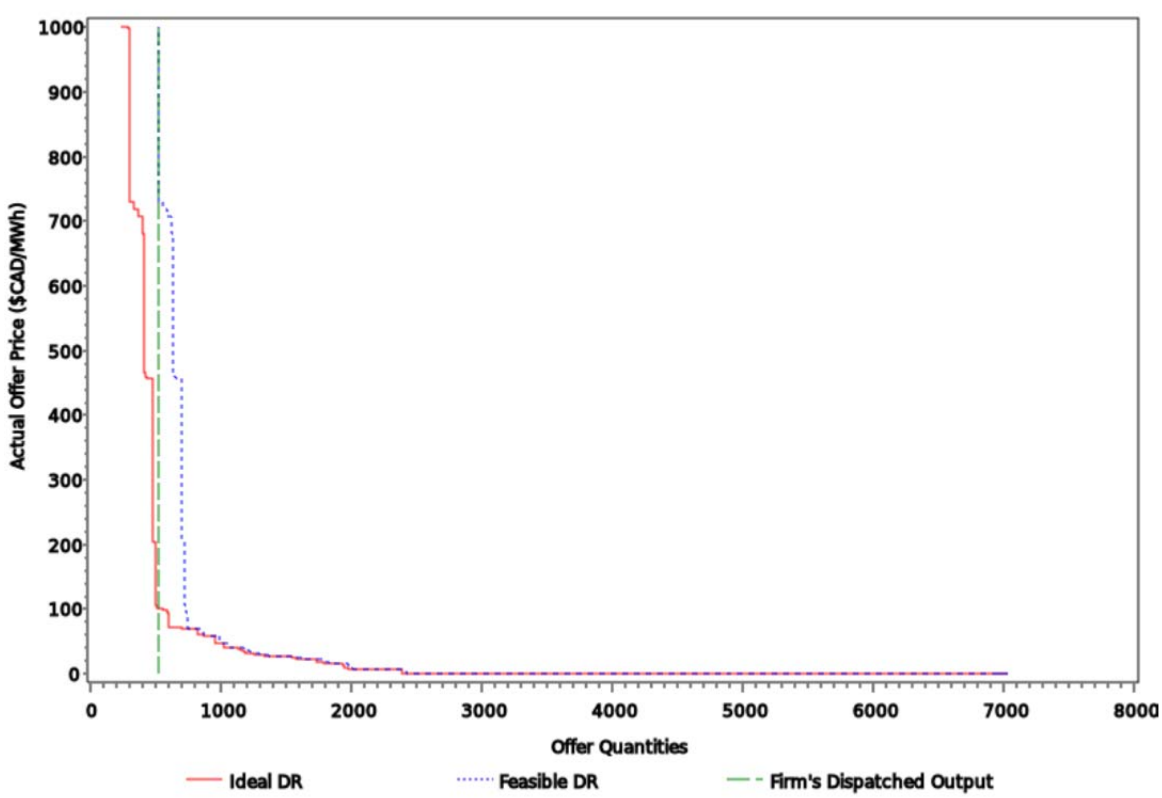

Figure 4(b): Ideal and Feasible Residual Demand Curves for Firm B, Hour 13 of 5/16/2010

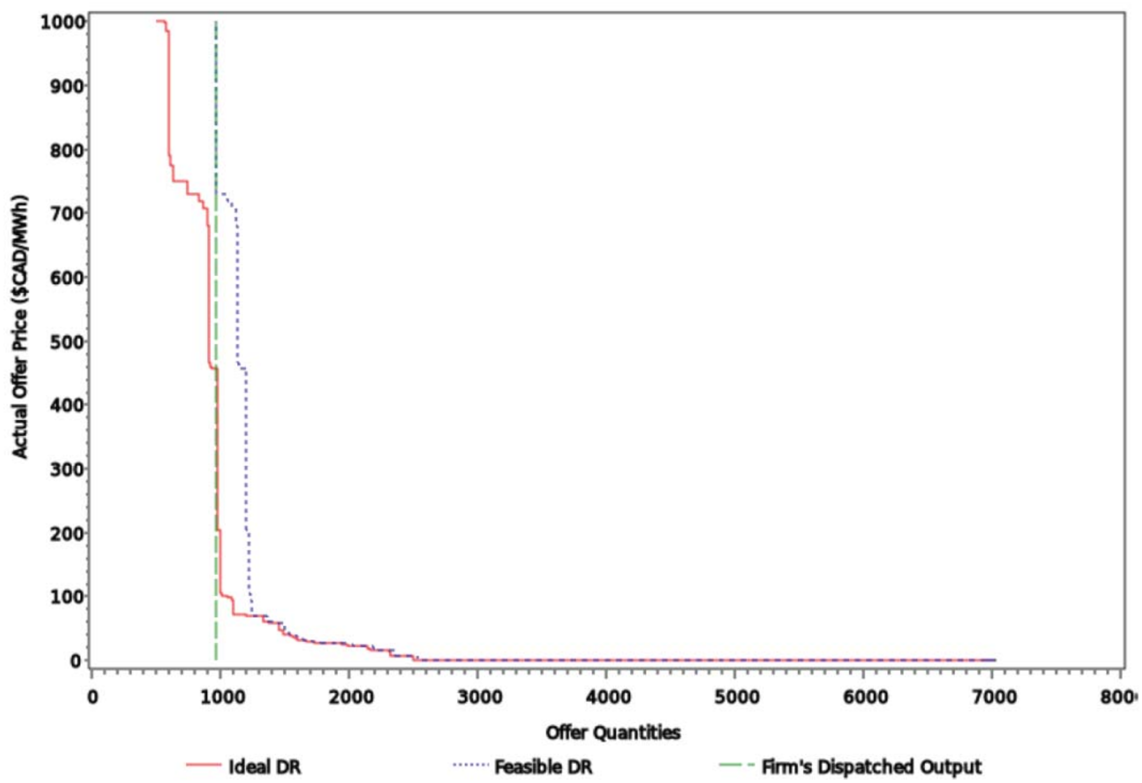

Figure 4(c): Ideal and Feasible Residual Demand Curves for Firm C, Hour 13 of 5/16/2010

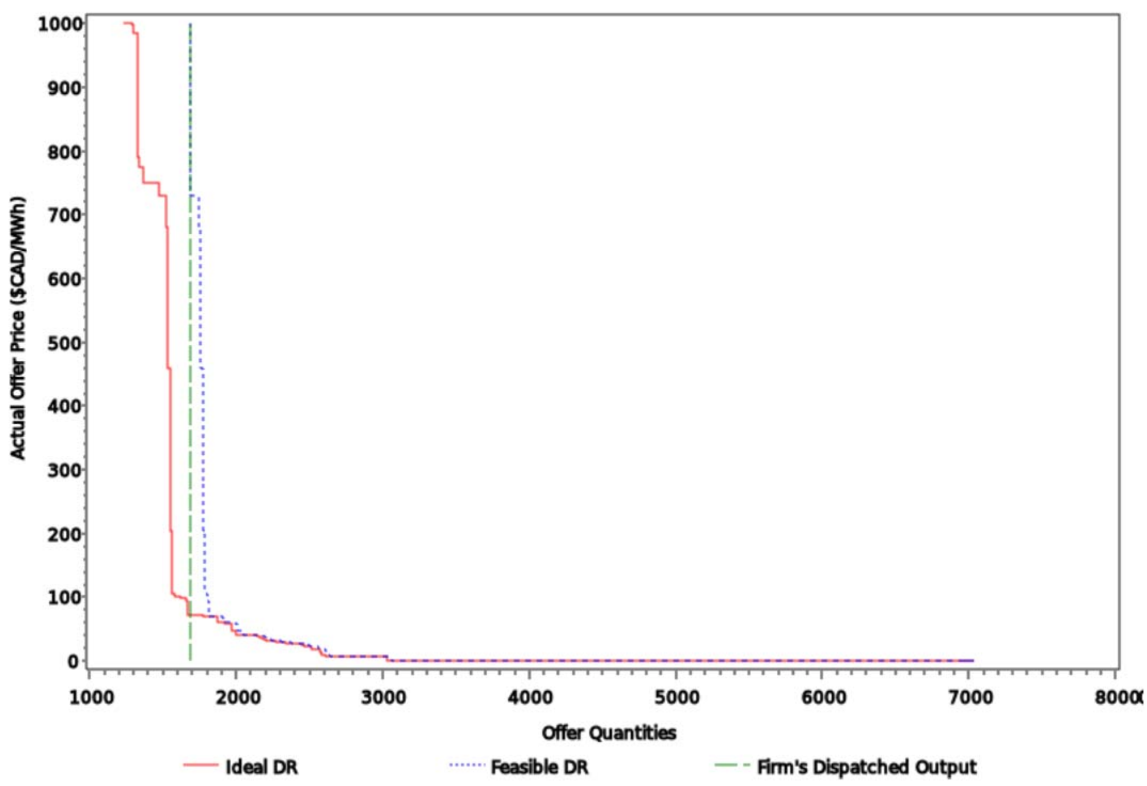

Figure 4(d): Ideal and Feasible Residual Demand Curves for Firm D, Hour 13 of 5/16/2010

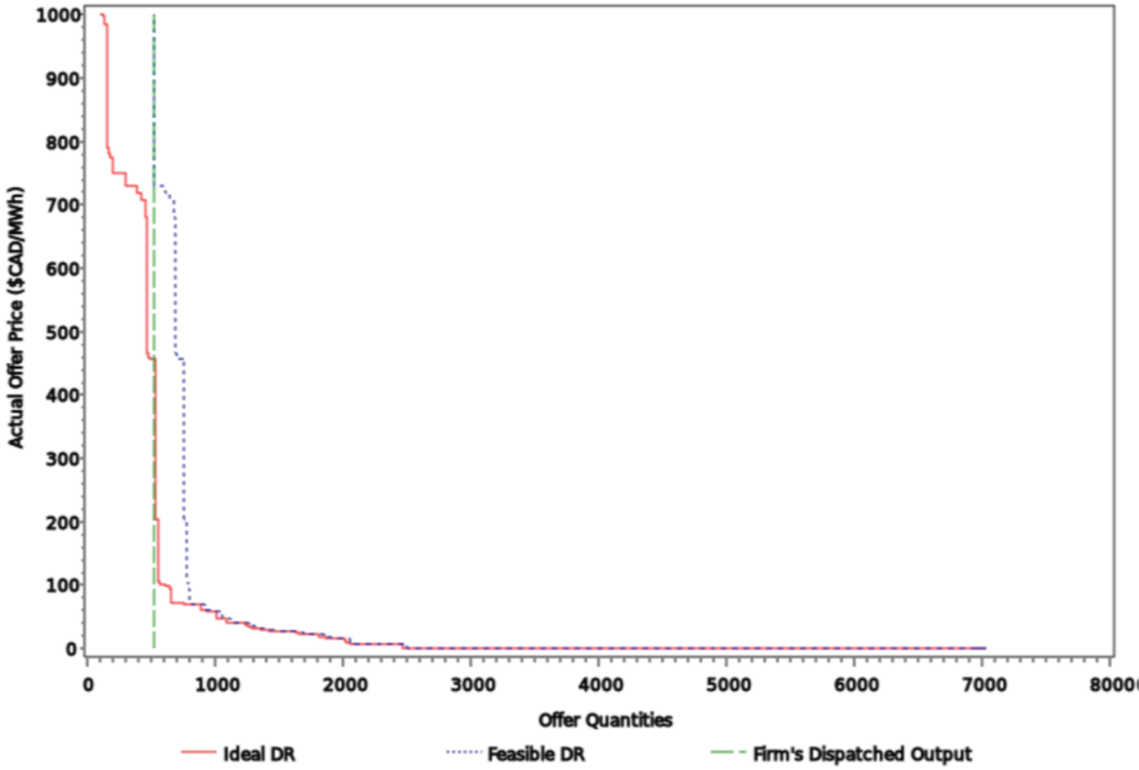

Figure 4(e): Ideal and Feasible Residual Demand Curves for Firm E, Hour 13 of 5/16/2010

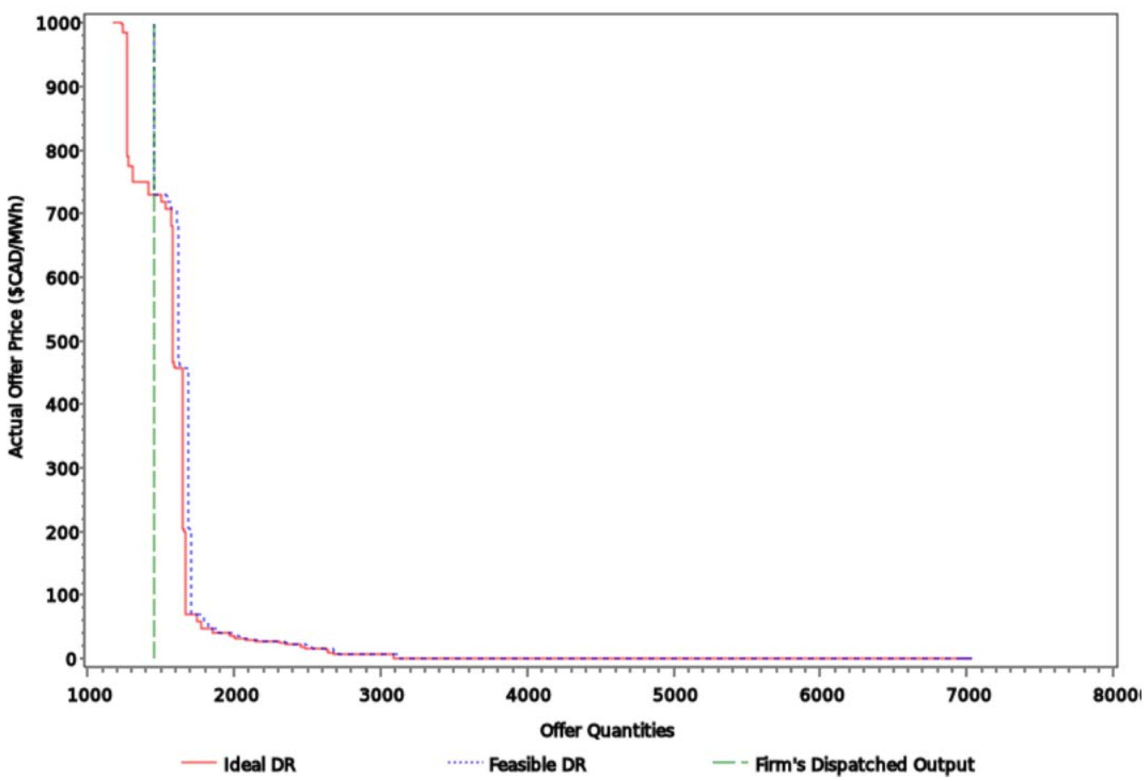

Figure 5(a): Derivation of Expected Profit-Maximizing Offer Curve

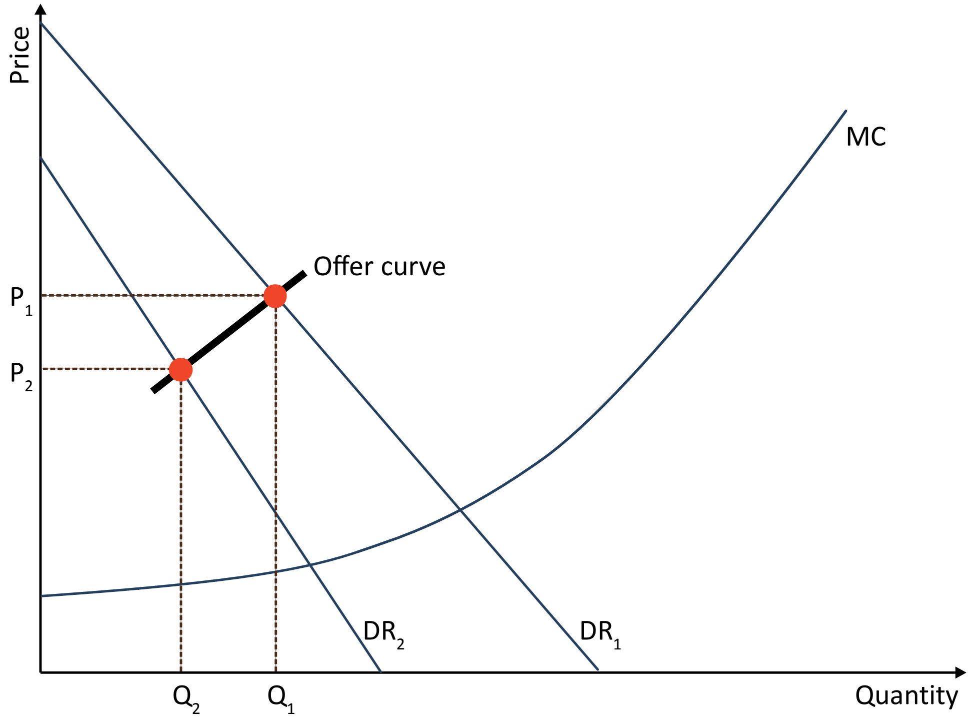

Figure 5(b): Expected Profit-Maximizing Offer Curve (flatter residual demands)

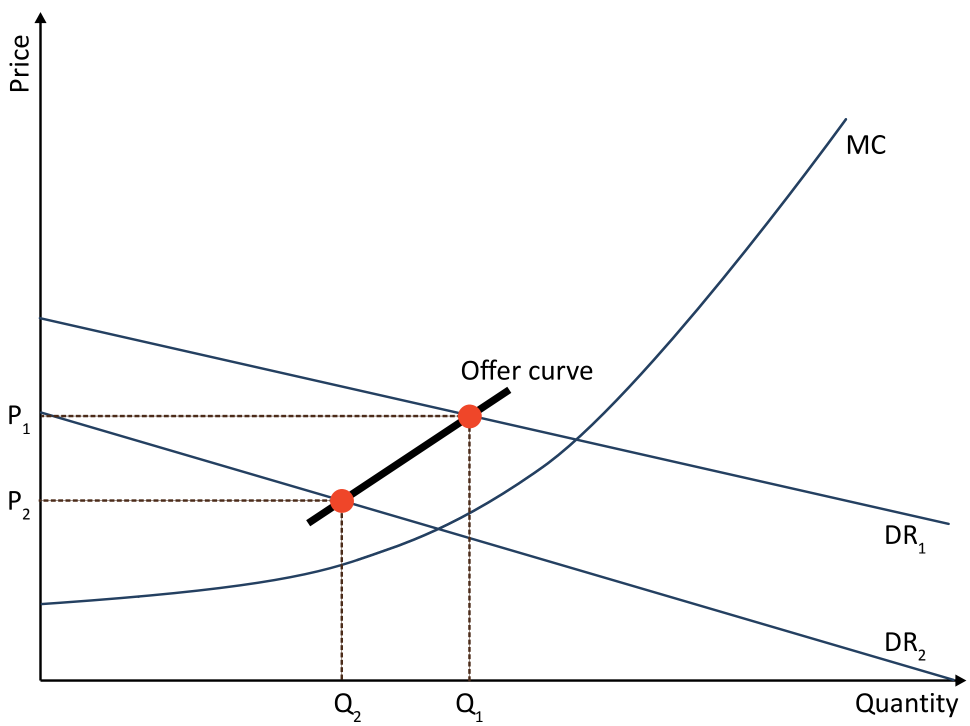

Figure 5(c): Expected Profit-Maximizing Offer Curve (perfectly elastic residual demands)

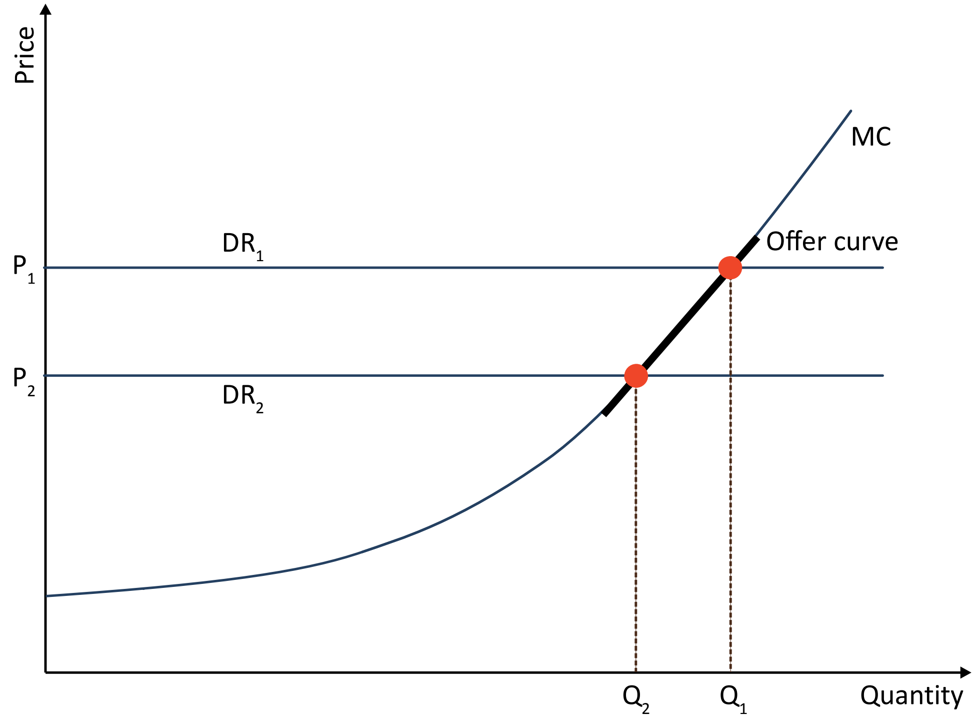

Figure 5(d): Impact of Step Functions on Expected Profit-Maximizing Offer Curve

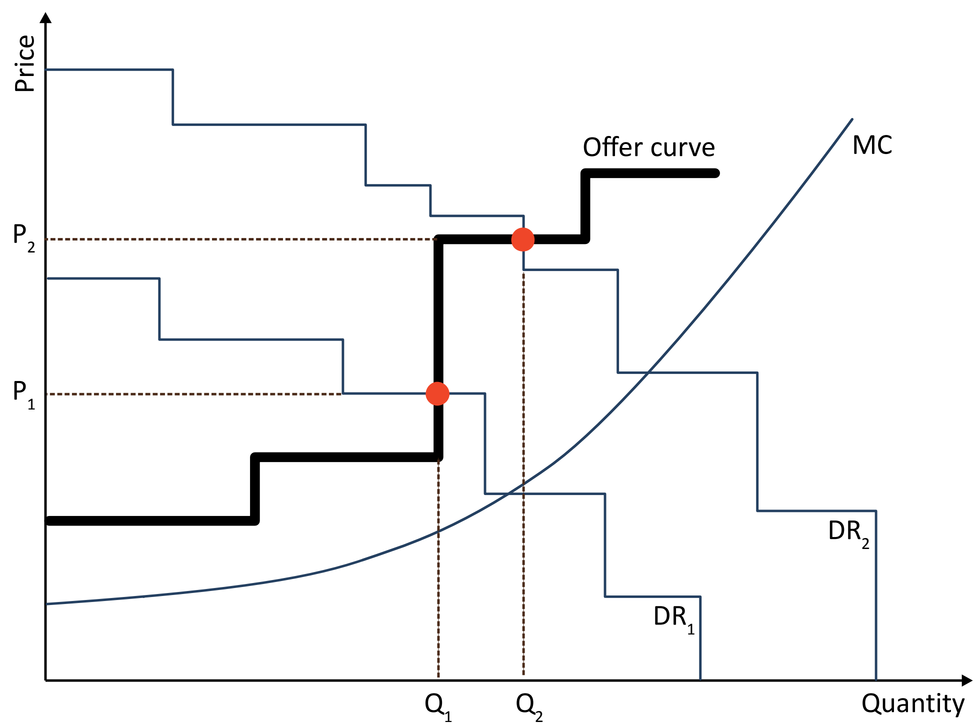

Figure 5(e): Expected Profit-Maximizing Step-Function Offer Curve

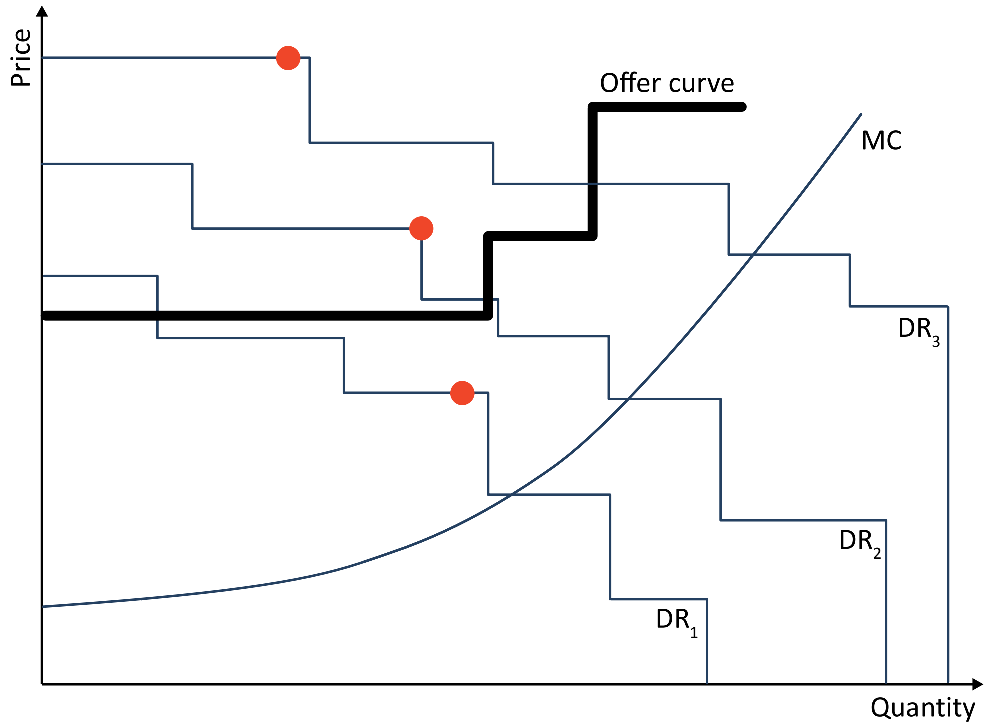

Figure 6: Sample Calculation of Hourly Offer Price for Firm 1

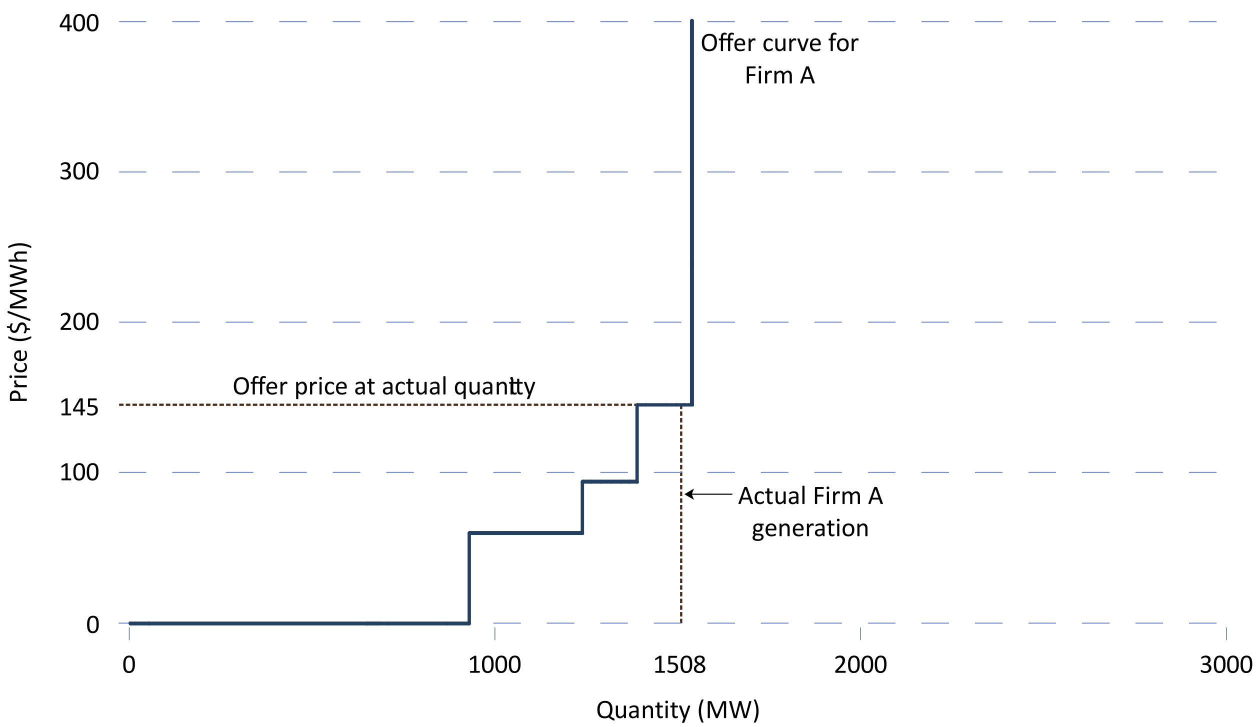

Figure 7(a): Actual and Shifted No-Congestion Offer Curves for Firm 1

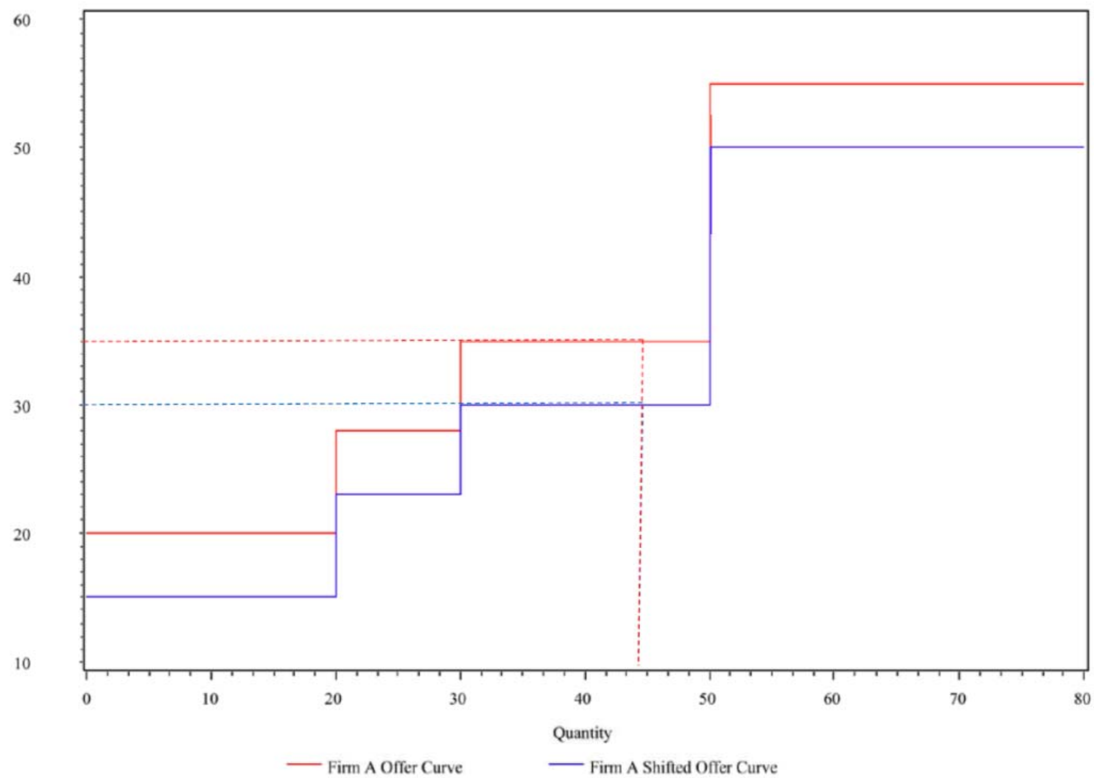

Figure 7(b): Actual and Shifted No-Congestion Offer Curves for Firm 2

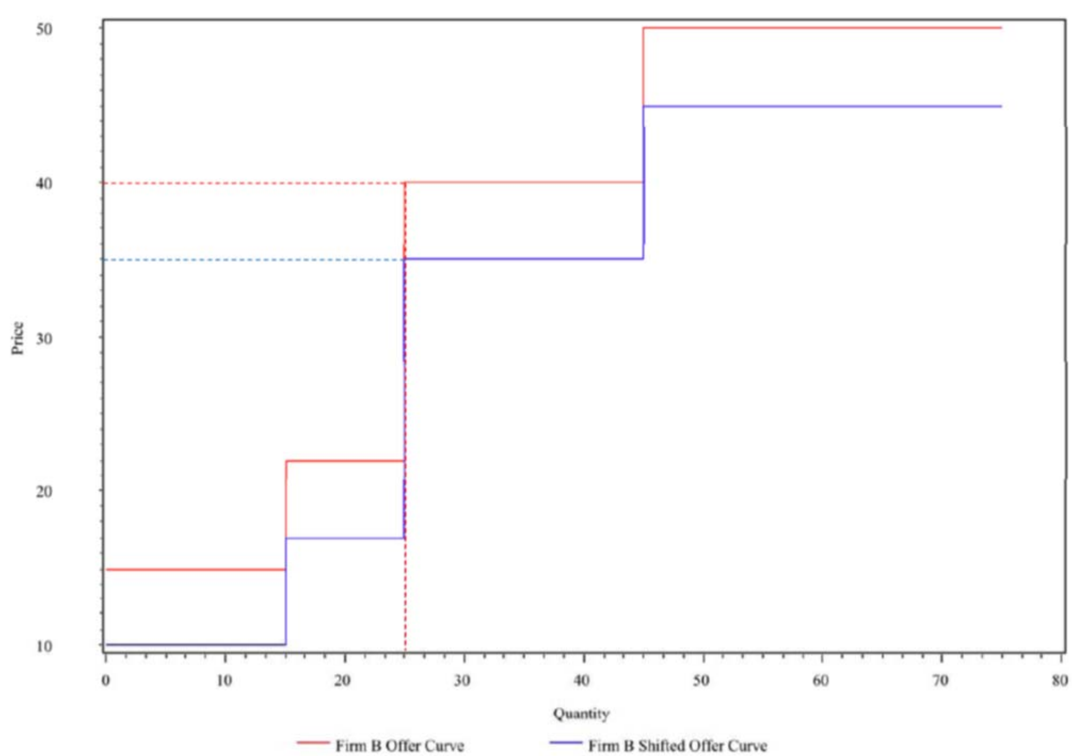

Figure 7(c): Actual and Shifted No-Congestion Aggregate Offer Curves for Firm 1 and Firm 2

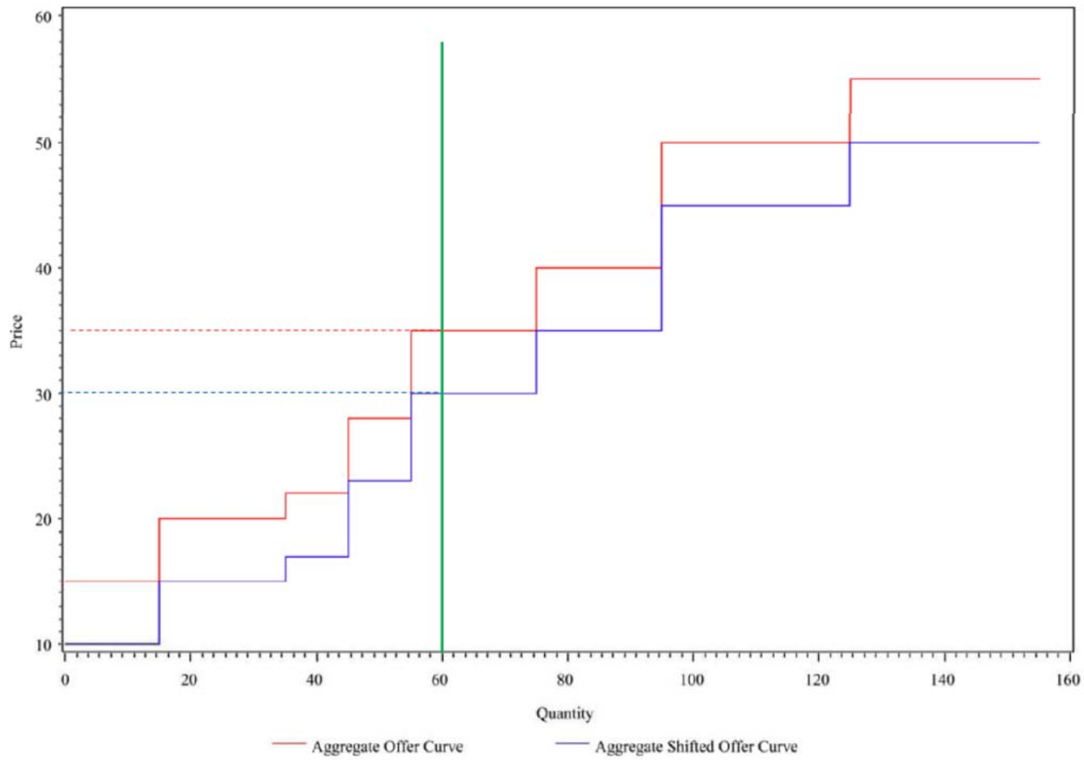

Figure 8: Daily Average Actual Prices and Predicted Feasible Actual Prices

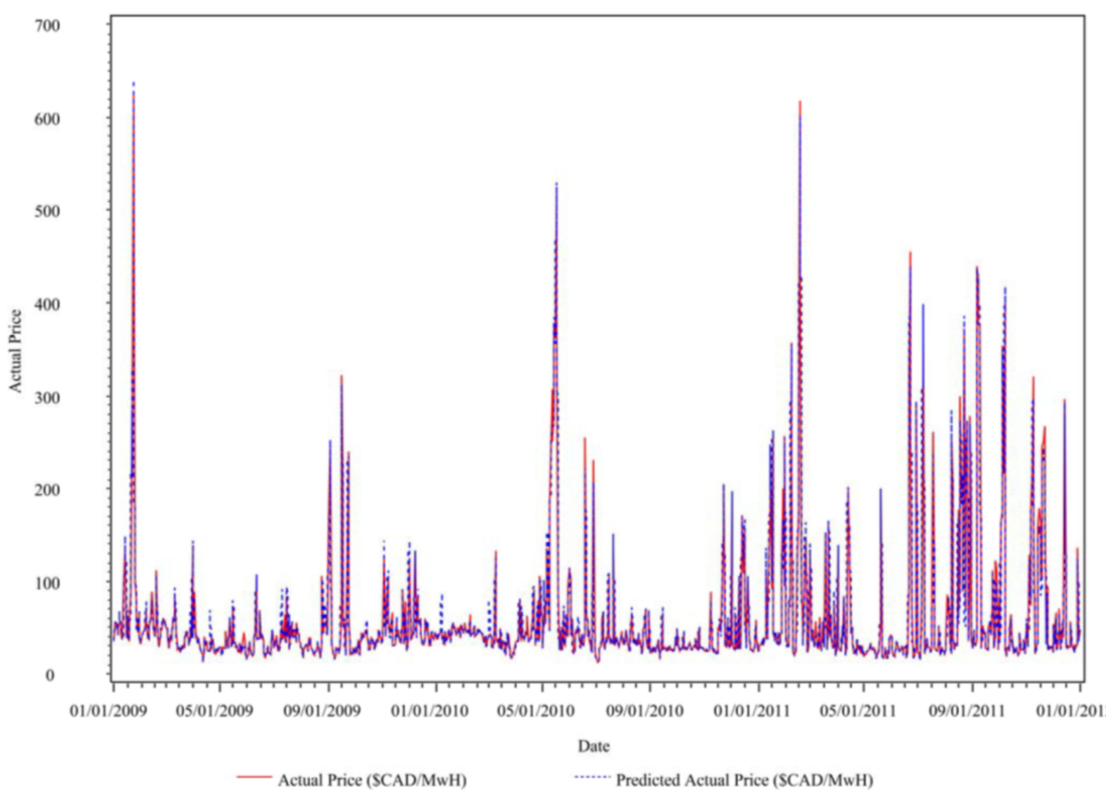

Figure 9: Daily Average Actual Prices and Predicted Ideal Actual Prices

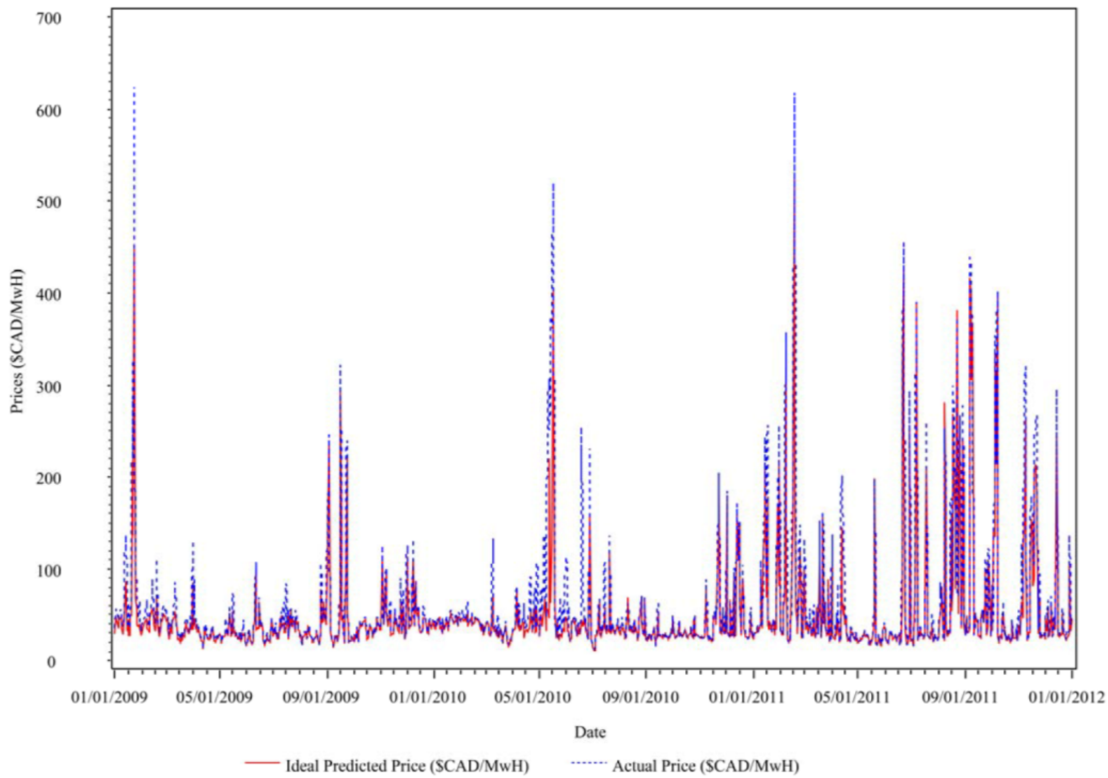

Figure 10(a): Monthly Average Wholesale Revenue Change with Feasible Price and Monthly Average Demand

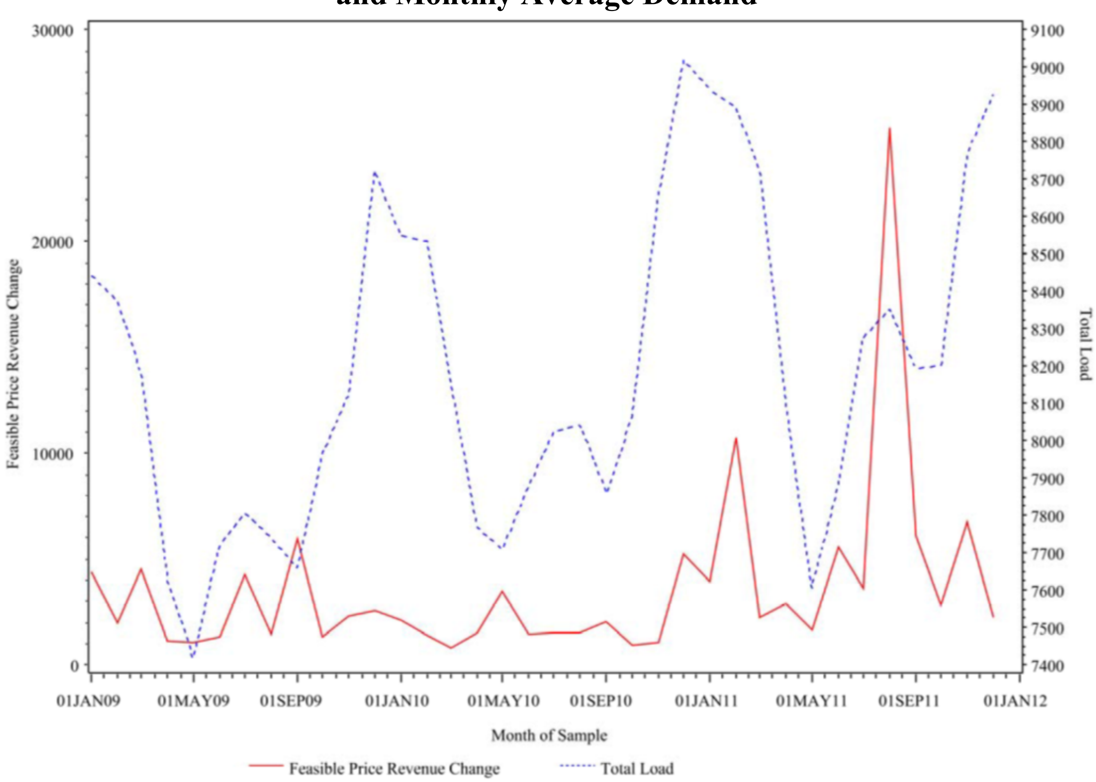

Figure 10(b): Monthly Average Wholesale Revenue Change with Ideal Price and Monthly Average Demand

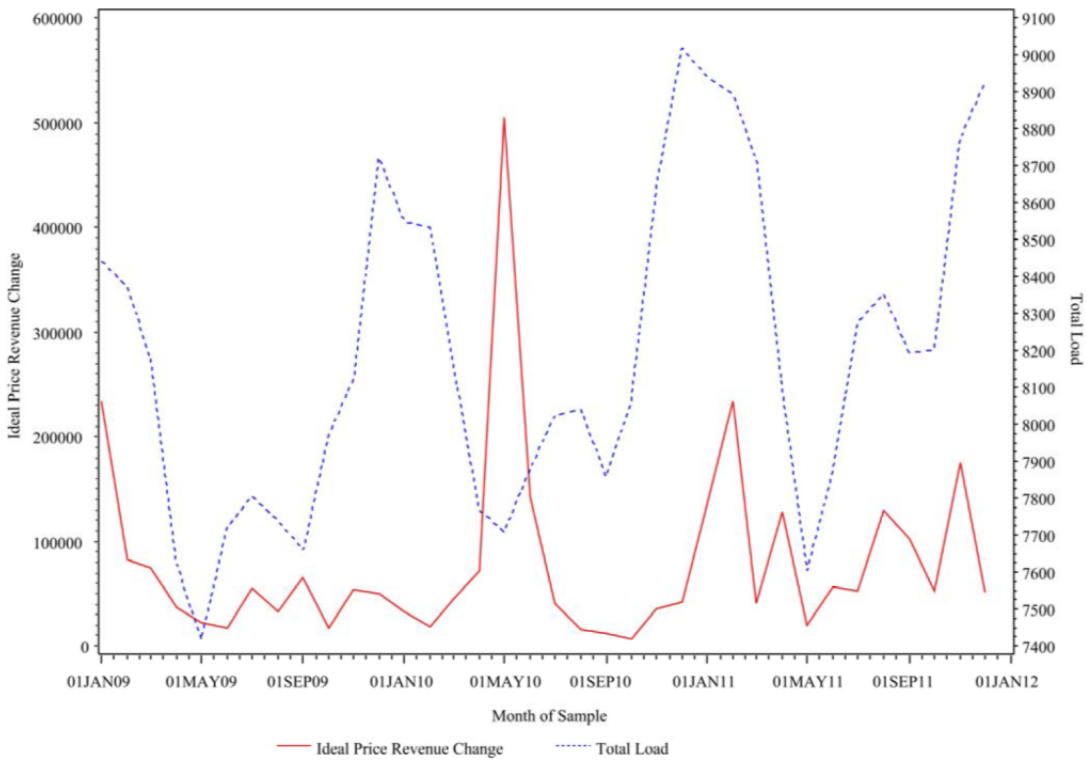

Figure 11(a): Monthly Wholesale Revenue Change with Feasible Price as a Percentage of Actual Monthly Wholesale Revenues and Monthly Average Demand

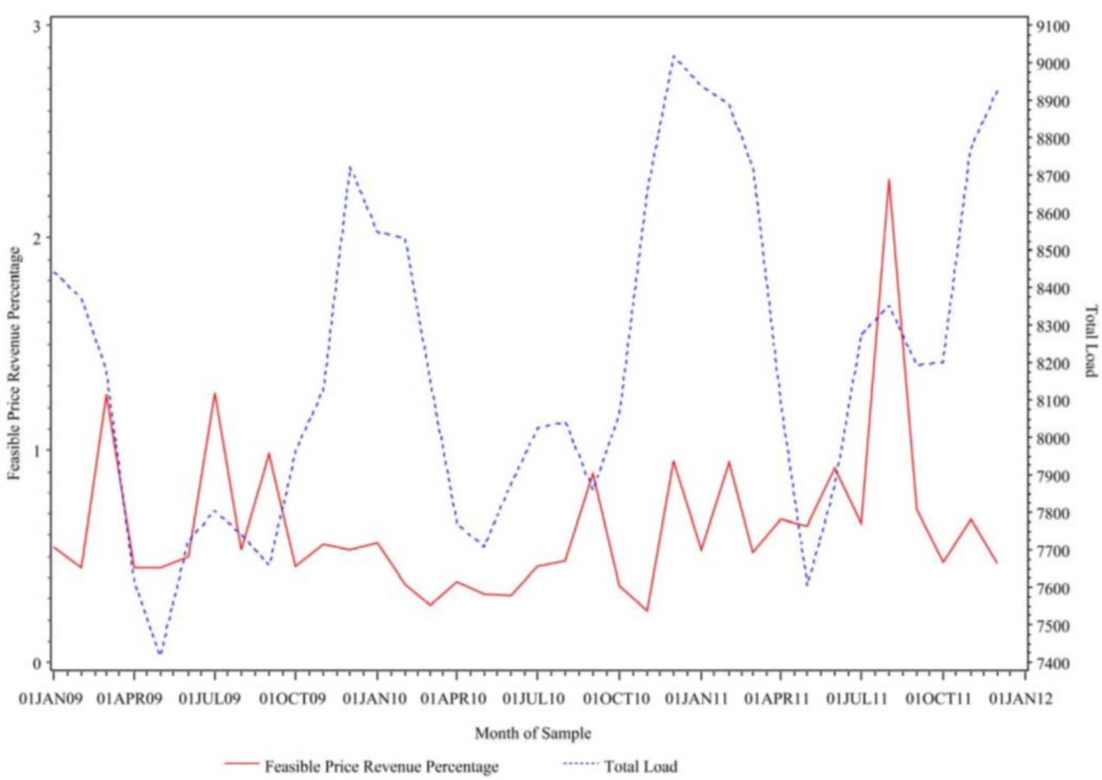

Figure 11(b): Monthly Wholesale Revenue Change with Ideal Price as a Percentage of Actual Monthly Wholesale Revenues and Monthly Average Demand