Assessment of Static Efficiency in Alberta's Energy-Only Electricity Market

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

December 21, 2012

PREFACE

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

Under the circumstances outlined above it is obviously important that competition is doing its job in regulating market outcomes. The MSA can and does exercise its responsibilities to monitor market participant behaviour to ensure that it conforms to the standard set out in the *Electric Utilities Act* and amplified in the *Fair, Efficient and Open Competition Regulation*; however from time to time a more searching broad-based assessment needs to be made. This is the purpose of the MSA's State of the Market report.

As part of the work leading to that report the MSA is releasing a number of preliminary reports. In the view of the MSA, competition is a means to an end. The end is economic efficiency. While it is recognized that there must be sufficient transfers from consumers to producers in order to incentivise efficient investment, these transfers must not be excessive or result in significant short-run losses of efficiency. Measurement of these losses is the purpose of this report.

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

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Overview

Our Motivation

The Market Surveillance Administrator (MSA) is currently undertaking a State of the Market report, envisioned as an assessment of the state of competition within, and the efficiency of, the Alberta wholesale electricity market. The report presented herein represents a building block to provide input to the MSA's broader State of the Market assessment. Part of the State of the Market report is aimed at establishing an appropriate benchmark, *effective competition*. Testing against that benchmark can be broken down into a number of components. One of these requires the measurement of short run inefficiencies.

What We Looked At

Static efficiency considerations are broken down in two parts: productive and allocative. Productive efficiency relates to the minimization of production costs at each point in time, while allocative efficiency is about the maximization of gains from trade at each point in time. Formal definitions are provided, along with a detailed explanation of how efficiency losses may occur within the wholesale electricity market. For purposes of exposition we rely on a simplified representation of the electricity market.

While the efficiency concepts are relatively straight forward to define, estimation of efficiency losses is more difficult. The assumptions made regarding the costs of production and the price responsiveness of demand are considered in detail. In the interests of transparency, the MSA has relied on publicly available data regarding the costs of production.[1] Moreover, in assessing the price responsiveness of demand one of the simplest formulations available was selected. As a result of the assumptions made, some sources of static efficiency are excluded from analysis. Alternate or more elaborate assumptions on costs and demand estimates are possible and the MSA may return to address these issues in future work.

What We Found

The analysis concludes that the combined static efficiency losses are relatively small in Alberta's electricity market. In the four years studied, the average pool price was approximately $66/MWh, while the average static efficiency loss was approximately $0.72/MWh, i.e., about 1.1% of the pool price. Given differences in market structure across jurisdictions there are no directly comparable results to which this value can be compared. Instead, we consider what factors might be driving losses to be small.

One factor that reduces the productive efficiency loss is that many generators have similar costs, which means total costs do not change substantially if one generator is replaced by another in the market. Alberta has two major electric generation technologies: coal and natural gas. Recently low natural gas prices have resulted in the short run costs of the two technologies being much closer at present than in the past. Allocative efficiency losses will tend to be small if demand is insensitive to the pool price. This is commonly the case in real time electricity markets and Alberta is not an exception. The appropriateness of the magnitude of related transfers from consumers and producers is the subject of another part of the State of the Market report.

[1] The alternative would be for the MSA to request confidential records from market participants. In some areas this may improve the estimates but at a significant loss of analytical transparency.

1. Introduction

To assess the economic performance of a market over a lengthy period of time, an appropriate benchmark is required. With respect to Alberta's energy-only electricity market, the appropriate benchmark must account for the fundamental characteristics of the market: investment in electricity generation capacity and demand management programs both involve considerable fixed costs, investment opportunities tend to be lumpy[2], demand is not very responsive to price, and the future is uncertain.

The purpose of this report is to describe an appropriate benchmark for assessing the economic performance of Alberta's market over time and to provide a methodology by which this assessment can be implemented using observed market data.

The most commonly employed benchmark in economic analysis is related to the *model of perfect competition*. Application of this benchmark amounts to a comparison of market price outcomes to the variable cost of the last unit of production (or, equivalently, assessing whether supply is offered to the market at variable cost). The appeal of this benchmark is that it corresponds to an outcome widely considered to be best: the greatest possible amount of economic gains result from profit seeking by individual economic agents (producers and consumers) that leads to efficient and sustainable market outcomes through time, with competition keeping prices low and disciplining behaviour. However, very few real markets meet the stringent assumptions necessary to make this benchmark applicable. Energy-only electricity markets are not an exception.

Notwithstanding the inapplicability of *perfect competition* as a benchmark, a number of real world markets achieve many of the same desirable outcomes. In electricity markets, competition can still act to lower prices such that the fixed costs associated with prudent investment can just be recovered, and the market remains sustainable. As a general matter, any market that reaches such an outcome can be thought of as *effectively competitive*. In the context of the characteristics of the electricity market, the MSA defines *effective competition* as:[3]

> A level of competition (and related outcomes) that (i) achieves efficient investment with the lowest possible short-run inefficiencies, (ii) does so over a reasonable timeframe, and (iii) ensures neither collusion, abuse, or anti-competitive practices.

The definition of *effective competition* explicitly recognizes that achieving efficient outcomes over time is one of the principal objectives of the market. To that end, it is acceptable for there to be some degree of efficiency loss in the short-run. A testable benchmark for *effective competition* must ensure that average price outcomes over time are no higher than needed to ensure the market sustains itself, i.e., transfers are sufficient to cover prudently incurred costs over time, but are not excessive.

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[2] 'Lumpy' means that some technologies benefit from scale of production capacity and are not, therefore, economically sensible to install on a small scale (formally, some capacity investments are indivisible).

[3] Critically, an *effectively competitive* outcome does not depend on any assumptions being made about the particular market under consideration. As such, the model of *perfect competition* can be thought of as constituting a special case of a wider class of models where a particular set of assumptions is made that reaches an equivalent outcome. In other words, *perfect competition* implies *effective competition* but *effective competition* does not necessarily imply *perfect competition*. An equivalent designation for *effective competition* is *workable competition*; a term relied on by many competition authorities. While the terms are synonymous, the label *workable* connotes a standard of minimum sufficiency of market performance that is neither intended nor correct.

In order to test for *effective competition*, the MSA considers four aspects of the market:

- measure short run inefficiencies;
- assess whether there is evidence of dynamic efficiency over time;
- ensure that price outcomes over the medium term are no higher than they need to be to ensure the market is sustainable (new investment occurs when it is profitable); and
- determine whether market participants meet the appropriate standard of conduct (i.e., support a fair, efficient and openly competitive market).

This report is principally concerned with developing a methodology for assessing the first part of this test. The other parts are addressed in another part of the State of the Market report.[4] Measuring short run inefficiencies and ensuring they are relatively small can be broken into a number of parts. First, we need to specify the precise meaning of each component of static efficiency—productive and allocative efficiency—and discuss how inefficiencies associated with each are manifested in the market (Section 2). Second, we need a process for estimating generators' costs and market demand (Section 3). Third, we combine the two to estimate each type of inefficiency (Section 4). Empirical results are reported in Section 5 and Section 6 concludes.

[4] For example, the assessment of price outcomes over the medium term is made in another 'building block' report entitled *A Comparison of the Long-Run Marginal Cost and Price of Electricity in Alberta – An assessment undertaken as part of the 2012 State of the Market Report.*

2. Static efficiency

This section specifies precise meanings of each component of static efficiency and describes how market inefficiencies can occur.

2.1 Static efficiency loss in the Alberta energy-only market

There are two components of static efficiency: productive and allocative efficiency. The MSA defines them as:

- **Productive efficiency** – at a given point in time if a given level of output is produced consuming the least amounts of inputs (lowest cost) then the outcome is said to be productively efficient.
- **Allocative efficiency** – at a given point in time if resources are allocated such that the net benefit attained through their use is maximized, then a market is said to be allocatively efficient. The role of price is key in achieving allocative efficiency since it serves as a signal to:
  - consumers to consume until the price rises above their willingness to pay; and
  - producers to produce until the price is insufficient to cover the costs of production.

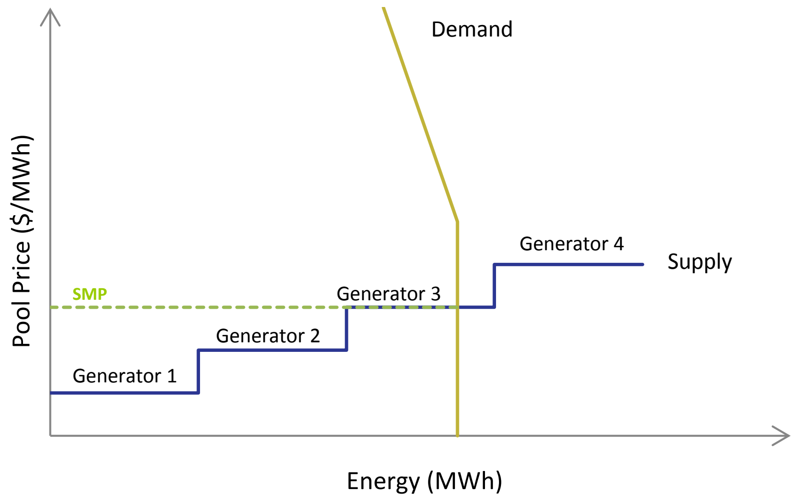
Put simply, if it is possible for the market demand to be met at lower costs the market is not productively efficient. If it is possible for both a producer and a consumer to gain through additional trade then the market is not allocatively efficient.[5] Productive and allocative efficiency are tests conducted at a given point in time and together they comprise static efficiency, the subject of this report.

To aid in the explanation of the concepts of productive and allocative efficiency and their application to Alberta's energy-only market, a simplified representation of the market is adopted (Figure 2.1). Figure 2.1 is comprised of a supply and a demand curve. The supply curve is comprised of the offers of four illustrative generators numbered 1 through 4.[6] Each generator is assumed to offer its whole output at a single price, indicated by the value corresponding to each offer on the vertical axis. The demand curve is represented as a kinked curve. The vertical portion of the curve represents demand that is not price responsive (i.e., perfectly inelastic demand) while the downward-sloping portion of the curve represents demand that is price responsive. The system marginal price (SMP) is set equal to the offer price of the highest price generator dispatched. In the simplified representation, the market clears at a price equal to generator 3's offer price with generators 1 and 2 fully dispatched and generator 3 partially so.

[5] These definitions are reproduced from the MSA's *Offer Behaviour Enforcement Guidelines* (2011).

[6] While the illustrative generators are equally sized, this is of no practical importance to the analysis.

Figure 2.1: A simplified representation of the energy market



2.2 Productive efficiency

Productive efficiency – at a given point in time, if a given level of output is produced consuming the least amounts of inputs (lowest cost), then the outcome is said to be productively efficient.

2.2.1 Productively efficient outcomes

In this simplified electricity market, productive efficiency is achieved when the total cost of meeting a given level of demand is minimized given the set of available generators. If it is possible to re-arrange production, i.e., replace one generator with another, and lower total costs, then the outcome is not productively efficient; equivalently, there is a loss of productive efficiency. It is a static concept in that it does not consider whether total costs could be reduced if additional generation sources were available.

For purposes of illustration, assume that the four generators shown in Figure 2.1 have offered at their short-run marginal costs (SRMC) and that $\mathrm{SRMC}_1 < \mathrm{SRMC}_2 < \mathrm{SRMC}_3 < \mathrm{SRMC}_4$, where SRMC_x is the SRMC of generator x. By definition it is not possible to re-order the generators and lower total cost and hence the outcome is productively efficient.

Consider an alternate ordering where generators 2 and 4 are interchanged and all other factors remain the same. This profile can meet load as generator 2 and 4 have the same MW available. The original profile has a lower total cost than the new one because $\mathrm{SRMC}_4 > \mathrm{SRMC}_2$. Furthermore, it can be shown that the original profile actually has the lowest cost to meet the load among all feasible production profiles and is hence productively efficient.

Short run marginal cost (SRMC) and long run marginal cost (LRMC)

Marginal cost is the added cost of producing a unit increment of output or, equivalently, the avoided cost of producing a unit decrement of output. The distinction between SRMC and LRMC relates to the time frame under consideration and has implications regarding the manner in which a firm can adjust its production process. In the short run, at least one factor of production is constant, e.g., the capacity of a generator. In the long run, all factors of production are variable.

The case illustrated in Figure 2.1 assumes that each generator offers at its SRMC. However, it is the selection of generators that is important from the perspective of productive efficiency. For example, if generators 1 through 4 offered at levels other than SRMC but the dispatch was the same (i.e., generators 1 and 2 are fully dispatched, generator 3 is partially dispatched, and generator 4 is not dispatched at all), productive efficiency is maintained. More formally, what matters are the ordered categorical relations, i.e., infra-marginal (generators 1 and 2), marginal (generator 3), and extra-marginal (generator 4). For any given set of offers, as long as generators maintain the same category, offer behaviour does not affect productive efficiency.

In the cases illustrated in Figures 2.2 and 2.3, productive efficiency is maintained but offer prices are not made at SRMC. In Figure 2.2, generator 1 offers between $SRMC_2$ and $SRMC_3$, while generator 4 offers above $SRMC_4$. Since each generator remains within the same category as in the productively efficient case illustrated in Figure 2.1, the result is also productively efficient. This result is not dependent upon generators 1 and 4 simultaneously changing their offers; indeed, the same result would be reached had either acted independently and alone. As well, the result is not dependent upon the SRMC being the same as in Figure 2.1. As long as the categorical ranking of generators is maintained then a productively efficient outcome is achieved.

In Figure 2.3, generator 3 offers higher than $SRMC_3$ but below the offer of generator 4. As in the previous case, since each generator remains within the same category as in the productively efficient case illustrated in Figure 2.1, the result is also productively efficient.

Figure 2.2: Productively-efficient outcome where generators 1 and 4 offer above SRMC

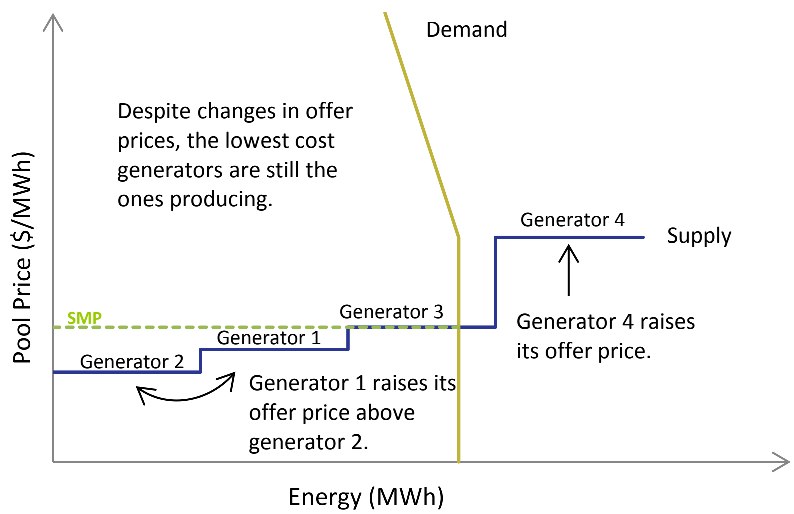
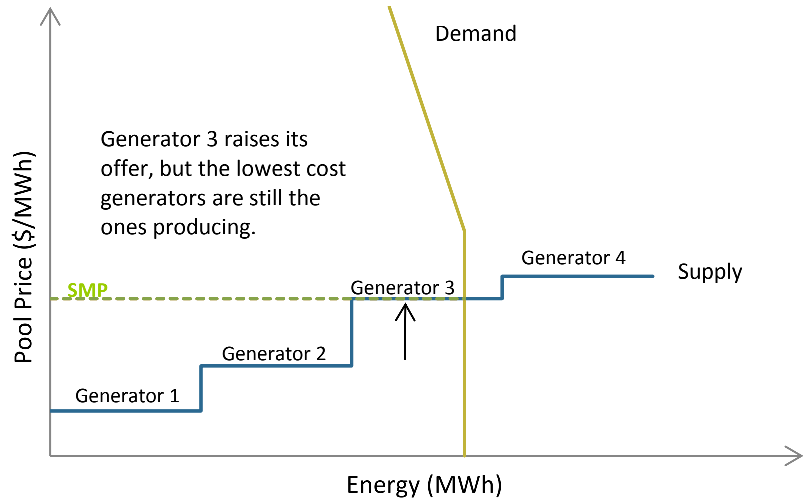


Figure 2.3: Productively-efficient outcome where marginal generator offers above SRMC



2.2.2 Causes of productive efficiency loss

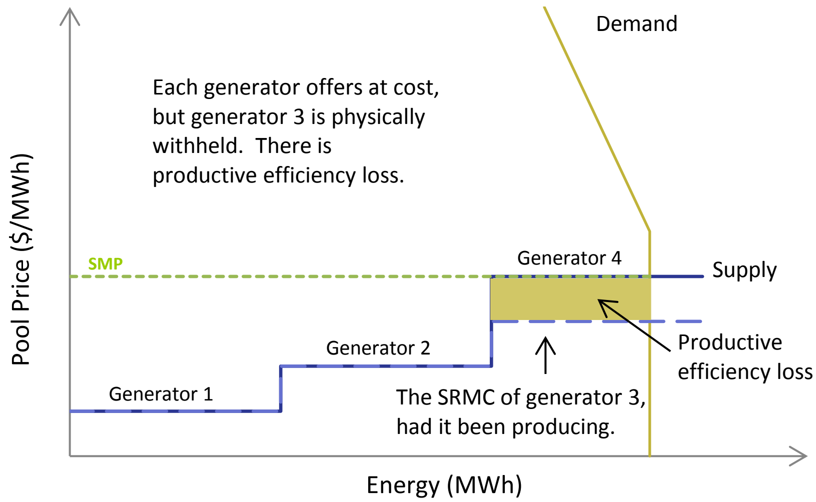
Productive efficiency losses arise under various circumstances where the categorical ordering of generators is altered in comparison to the case illustrated in Figure 2.1. Some such circumstances are considered in this section.

2.2.2.1 Physical withholding

Physical withholding is a term used to describe a situation where a generator that is otherwise available is not offered into the market. Physical withholding is not generally associated with the Alberta market as generators must be offered unless they have an 'acceptable operational reason' as defined under the ISO rules. In some other circumstances generators may not be in the merit order if they are offline and have declared themselves as such with a long lead time (these generators are available but only after some time). Physical withholding can result in an efficiency loss. Note that if a generator is unavailable (e.g., due to an outage) there is no loss of productive efficiency since productive efficiency is defined 'given the set of available generators'.

Figure 2.4 illustrates a case where generator 3 engages in physical withholding. As a result, the SMP is set by the offer price of generator 4. Assuming that generator 3 is available but not offered, generator 4 is offered at SRMC, and $SRMC_4 > SRMC_3$, the generation dispatched does not minimize the short-run cost of meeting demand. The overall productive efficiency loss is shown in the shaded area.

Figure 2.4: Productive efficiency loss due to physical withholding



2.2.2.2 Economic withholding

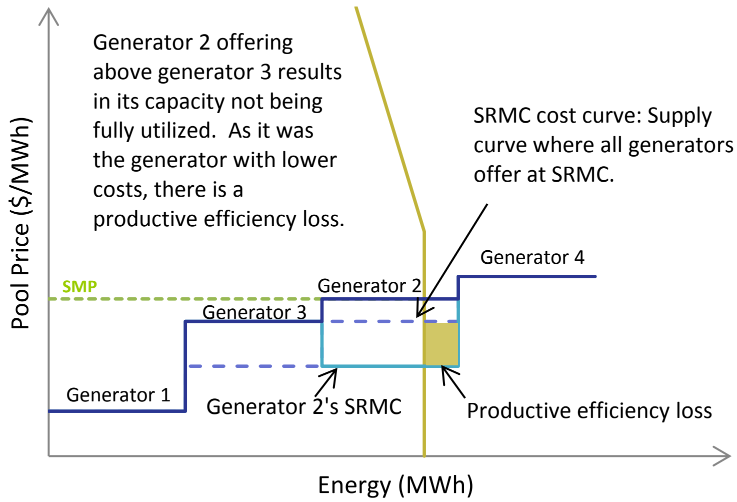
In the MSA's *Offer Behaviour Enforcement Guidelines* (OBEG), economic withholding was defined as:

> offering available supply at a sufficiently high price in excess of the supplier's marginal costs and opportunity costs so that it is not called on to run and, as a result, the pool price is raised. Such a strategy is only profitable for a firm that benefits from the higher price in the market.

The OBEG sets out the MSA's view that market participants are free to pursue individually profit maximizing behaviour, including economic withholding. However, economic withholding has implications for static efficiency.

Figure 2.5 illustrates a scenario where generator 2 offers between $SRMC_3$ and $SRMC_4$. The result is that generators 1 and 3 are fully dispatched and generator 2 is partially dispatched. In this case, the SMP is given by generator 2's offer price. Since $SRMC_2 < SRMC_3$, the new production profile is not productively efficient. The associated loss is shown as the shaded area in Figure 2.5.

Figure 2.5: Productive efficiency loss due to economic withholding



Efficiency losses due to binding transmission constraints do not constitute losses of productive efficiency. The definition of productive efficiency implies that losses are incurred if a given level of output is not produced using the least-cost inputs available. Thus, non-use of inputs whose use is restricted due to binding transmission constraints is not a source of productive inefficiency. For example, Transmission Must Run (TMR) directives are used to manage transmission congestion in certain areas of Alberta. TMR may result in generators running when they would not otherwise be, thereby causing a deviation from the uncongested merit order. Hence, transmission congestion results in the no-congestion production profile being physically *unfeasible*. Consider the situation illustrated in Figure 2.4 and assume that generator 4 is kept online because of transmission congestion and, as a result, generator 3 is dispatched offline. There is no productive efficiency loss because dispatching generator 4 is required to satisfy demand. This simple example assumes that the generator dispatched offline has the highest SRMC of those that would generate in the absence of the constraint. If generators are dispatched offline in a non-reverse merit order, then productive efficiency losses will be incurred.

The simplified cases considered do not capture some of the factors that may cause SRMC for a given generator to vary. For example, a generator may incur costs on start-up or shut-down that would otherwise be avoidable. These are real costs for which generators are expected to include in their offer strategies. As a result, a generator choosing to offer at high prices to avoid start-up costs (or low to avoid shut-down costs) does not necessarily imply a productive efficiency loss.

2.3 Allocative efficiency

Allocative efficiency can be best understood from the perspective of social (or total) surplus, which is the sum of consumers' surplus (CS) and producers' surplus (PS).

Consumers' & producers' surplus

When examining the market for a given good in the short run, economists refer to the outcome that maximizes total surplus – the sum of consumers' surplus and producers' surplus – as being allocatively efficient.

Consumers' surplus

Consumers decide how much they are willing to pay for each level of consumption of a good. An individual consumer's willingness-to-pay depends on factors such as their preferences and financial resources. Suppose a consumer values units of electricity at $100/MWh and the SMP is $60/MWh. The consumer's surplus is the difference between willingness-to-pay and the SMP, $40/MWh in this case, multiplied by the number of units it consumed. Consumers' surplus in the market as a whole is the sum of individual surpluses of all the consumers.

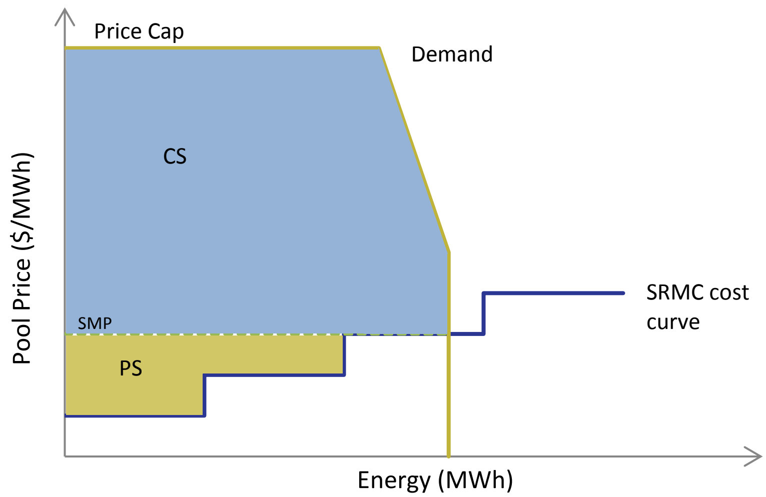
Producers' surplus

Producers' surplus is similar to consumers' surplus: it is the difference between the SRMC of each successive unit sold and the price received for it. Suppose the SRMC of one MWh of electricity is $20 but the price is $50. The generator receives a $30 gain on that MWh. Economists refer to this margin, summed across all units of output, as the producer's surplus. Producers' surplus in the market as a whole is the sum of individual producer's surpluses.

Figure 2.6 illustrates the concepts of CS and PS in the context of the example illustrated in Figure 2.1. Assume that each generator offers at their SRMC. A horizontal line is included at the price cap; the most consumers can pay.[7] The SMP is indicated by the intersection of the supply and demand curves. The area between the SMP and the marginal cost curve represents producer surplus, and the area between the SMP, demand curve is consumer surplus. Total surplus is simply the sum of consumer surplus and producer surplus.

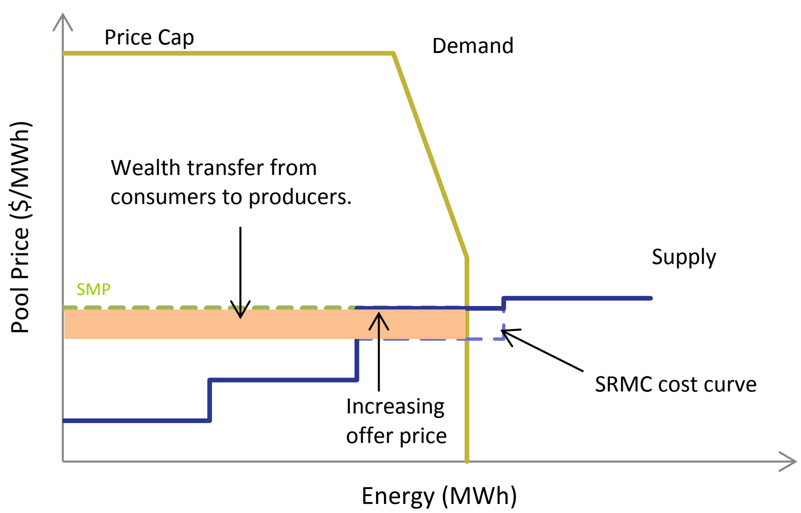
[7] Note that CS extends above the price cap since at least some consumers are willing to pay more. For the purposes of our estimation, we are generally interested in changes in CS that occur at levels below the price cap.

Figure 2.6: CS and PS



The fact that allocative efficiency is concerned with total surplus is important. Suppose that due to an increase of the SMP, CS falls and PS increases by the same amount. Total surplus remains the same and there is no loss in allocative efficiency. There is, however, a wealth transfer from consumers to producers that accompanies the SMP change. For instance, consider the case illustrated in Figure 2.7. This case has the same setup as in Figure 2.6 except that marginal generator 3 is offering at a price higher than its SRMC but below the offer price of generator 4. The SMP rises even though the traded quantity and total surplus are unchanged. Thus, offering at prices above SRMC does not necessarily result in an allocative efficiency loss. However, there is a wealth transfer from consumers to producers in this case. While such a transfer has no efficiency loss in this case, it remains important but is beyond the scope of this paper.[8]

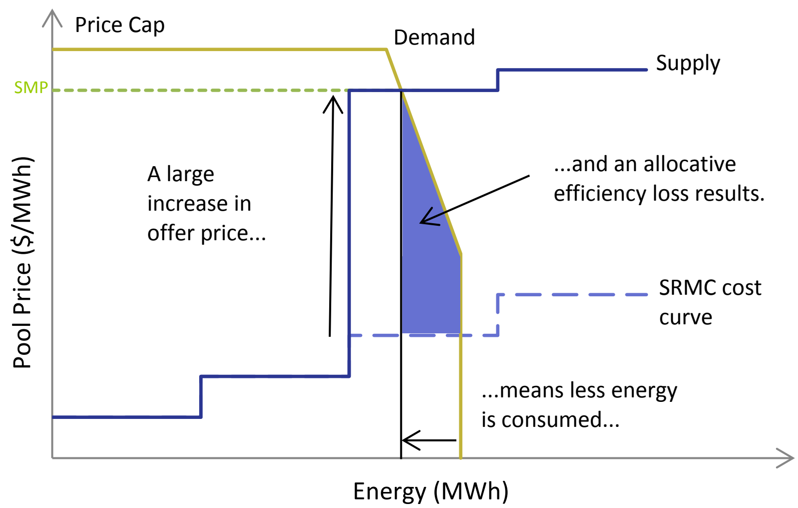
Figure 2.7: Transfer of wealth between consumers and producers



[8] See the MSA's report *A Comparison of the Long-Run Marginal Cost and Price of Electricity in Alberta – An assessment undertaken as part of the 2012 State of the Market Report* for a related discussion.

Allocative efficiency losses arise when the quantity of traded energy decreases. Figure 2.8 illustrates a similar situation as in Figure 2.7, but here the marginal generator is offering so high that the equilibrium quantity is determined on the sloped part of the demand curve. As a result, the amount of energy traded is reduced, CS declines, and PS increases. Since the decline of CS exceeds the rise of PS, total surplus declines and an allocative efficiency loss is incurred. This loss is illustrated as the shaded area in the Figure.

Figure 2.8: Allocative efficiency loss



The situation illustrated in Figure 2.8 shows both generators 3 and 4 offering above their SRMC. This is a special case. As a general matter, all that is required for there to be a loss of allocative efficiency is that SMP changes by a sufficient amount such that the traded quantity changes. If the illustrated demand was higher, then a single generator offering at a sufficiently high price would create an allocative efficiency loss.

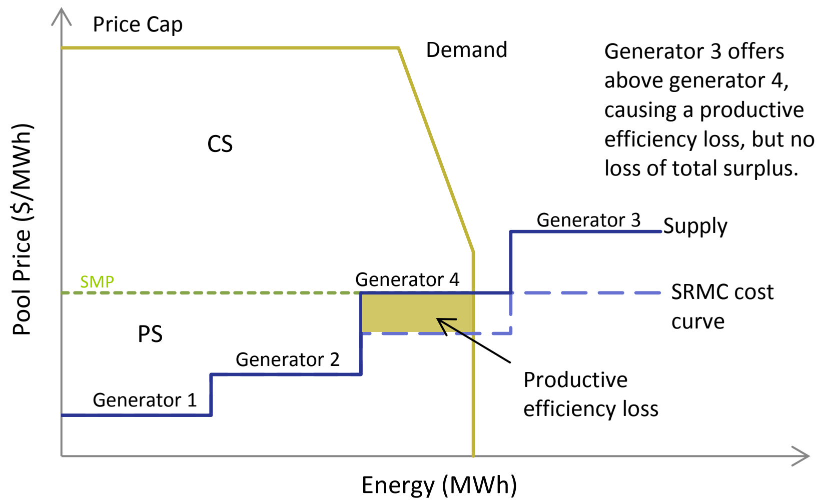
2.4 Relationship between productive and allocative efficiency

All generators offering their output to the market at SRMC is a sufficient (but not necessary) condition for achieving both productive and allocative efficiency. Under the Alberta market design, with competition occurring between a small number of firms, there is little reason to expect this condition to be satisfied.

A productive efficiency loss does not necessary imply an allocative efficiency loss, nor vice versa, since productive efficiency relates to the minimization of production costs while allocative efficiency relates to the exhausting of all desired trade opportunities.

Figure 2.9 illustrates a situation where there is a productive efficiency loss without a loss of allocative efficiency. In this situation, generator 3 offers higher than generator 4. As a result, generator 4 is marginal while generator 3 is extra-marginal. Since we have assumed that $SRMC_4 > SRMC_3$, the outcome is not productively efficient. However, no allocative efficiency loss is incurred because there is no reduction in the quantity traded. In other words, even with the productive efficiency loss, all desirable trade opportunities are exhausted and there is no loss of allocative efficiency.

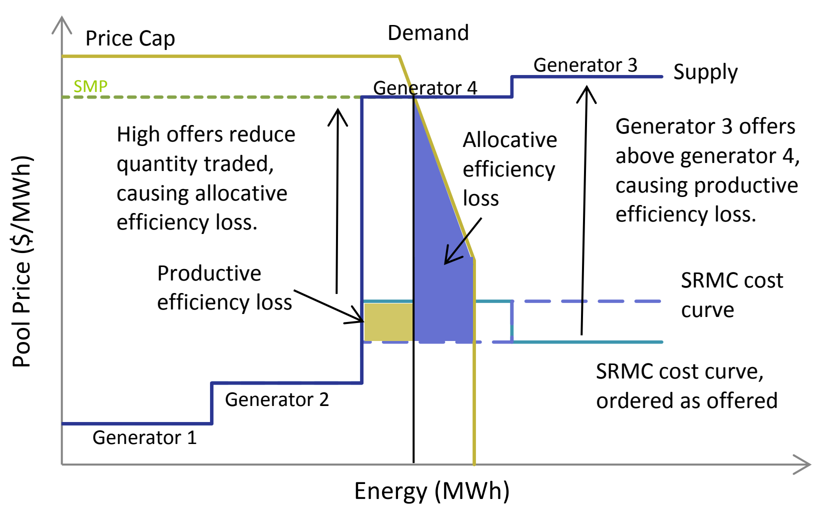
Figure 2.9: Productive efficiency loss only



Similarly, there can be cases where there is a loss of allocative efficiency, but not of productive efficiency. In Figure 2.8 there is a loss of allocative efficiency since all desired trade opportunities are not exhausted. However, there is no productive efficiency since the cost of meeting demand is minimized.

In other instances, economic withholding can cause both productive and allocative efficiency losses. For instance, in Figure 2.10, generator 3 is offering higher than generator 4 and is extra-marginal. Generator 4 is the marginal generator and is partially dispatched. Productive efficiency losses occur because $SRMC_4 > SRMC_3$, while allocative efficiency losses occur because all desirable trade opportunities have not been exhausted (there are consumers who have a willingness-to-pay that is above the SRMC of generator 4 but they do not consume).

Figure 2.10: Both productive and allocative efficiency losses



2.5 Numerical examples

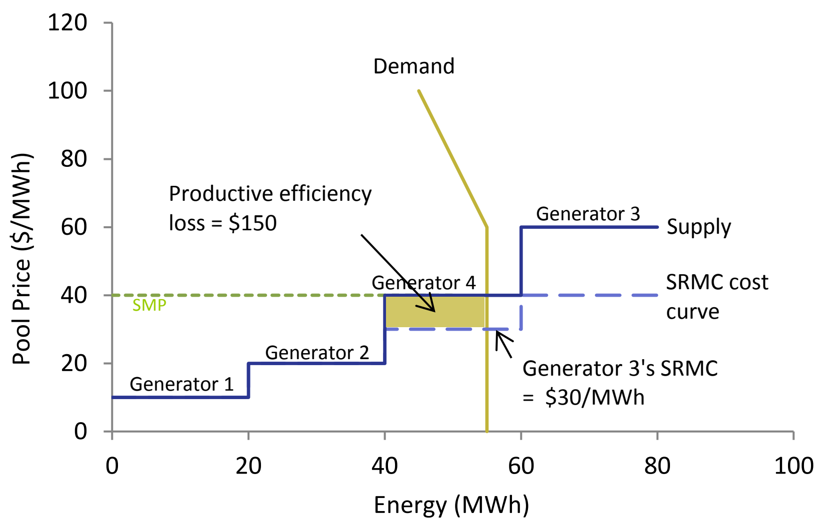
To illustrate the static efficiency concepts described above, consider the simple scenario where four generators each offer their full available capacity of 20 MW into the market at marginal cost. Assume that the SRMC for the four generators are $10/MWh, $20/MWh, $30/MWh, and $40/MWh, respectively.

Assume that demand is 55 MWh when the SMP is below $60/MWh and decreases by 1 MWh for every $4/MWh increase in price above $60/MWh. If all generators offer at their SRMC, the SMP would be $30/MWh and the equilibrium quantity of energy would be 55 MWh. The least-cost dispatch would have generators 1 and 2 produce 20 MWh and generator 3 produce 15 MWh. The production cost would be $1,050.[9]

Example 1:

Assume that generator 3 raises its offer price to $60/MWh and generator 4 offers at its marginal cost of $40/MWh. The SMP will be $40/MWh and the quantity of traded electricity will be 55 MWh. Figure 2.11 illustrates this example. The production cost is now equal to $1,200.[10] The difference in production costs of $150 constitutes a loss of productive efficiency. Note that no allocative efficiency loss occurs in Figure 2.11 since the quantity of electricity traded is the same as if all offers had been made at SRMC.

Figure 2.11: Example 1 – Productive efficiency loss



Example 2:

Assume that generators 3 and 4 raise their offer prices to $90/MWh and $80/MWh, respectively. The SMP will be $80/MWh, with 50 MWh of electricity traded. Figure 2.12 illustrates this example. Since (1) the lowest SRMC generators are not dispatched to meet demand and (2) the amount of traded electricity declines as a result of this offer behaviour, there will be losses of both productive and allocative efficiency. The loss of productive efficiency is $100; the shaded rectangle is the Figure.[11] The loss of allocative efficiency is $200; the shades trapezoid in the Figure.[12]

Both efficiency losses are measured in dollars reflecting the total value of lost surplus. However, with load increases, the total losses can increase even though the relative efficiency does not change. To illustrate, consider a scenario where supply and demand double. As a result, both the productive and allocative efficiency losses will double. To control for the size effect, efficiency losses can be normalized by dividing through by the equilibrium quantity. In the example the equilibrium quantity was 50MW

[9] $1,050 = ($10/MWh x 20 MWh) + ($20/MWh x 20 MWh) + ($30/MWh x 15 MWh).

[10] $1,200 = ($10/MWh x 20 MWh) + ($20/MWh x 20 MWh) + ($40/MWh x 15 MWh).

[11] $100 = (50 MWh – 40 MWh) x ($40/MWh - $30/MWh).

[12] $200 = [(($80/MWh - $30/MWh) + ($60/MWh - $30/MWh)) x (55 MWh – 50 MWh)] / 2.

and the productive and allocative efficiency losses were \$100 and \$200 respectively, the normalized efficiency losses are given by:

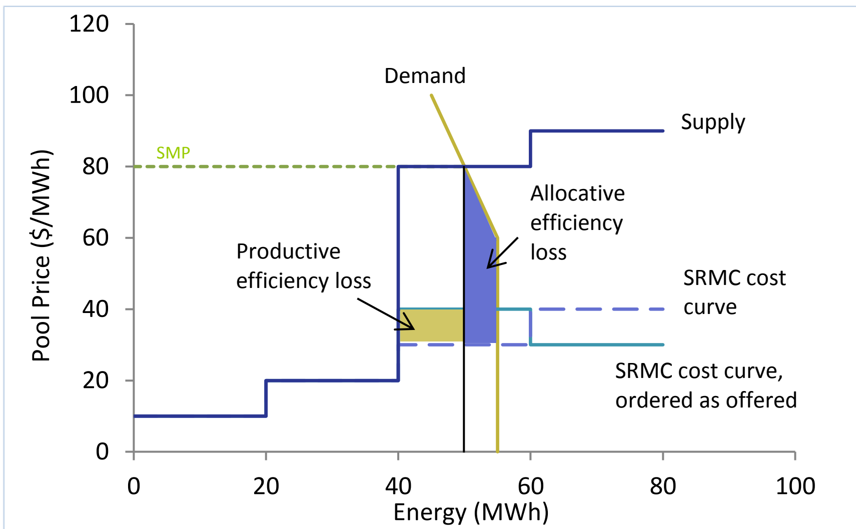
$$\text{Normalized production efficiency loss} = \frac{\$100}{50\ \text{MWh}} = \$2/\text{MWh}$$

and

$$\text{Normalized allocative efficiency loss} = \frac{\$200}{50\ \text{MWh}} = \$4/\text{MWh}$$

The normalized productive efficiency losses measure the average cost savings that would have been realized if the market demand had been produced optimally. The normalized allocative efficiency loss quantifies the unrealized gains from trade.

Figure 2.12: Example 2 – Productive and allocative efficiency loss



3. Estimating the SRMC and the demand curve

In the previous section, we have shown that productive and allocative efficiency losses can be estimated if the marginal costs of generators and the demand curve are known. In this section we discuss a methodology for estimating both. As this is the first time the MSA has presented the methodology we have adopted a relatively simplistic set of assumptions, along with a sensitivity analysis. The MSA expects that the methodology can be refined over time by incorporating additional data and more a sophisticated treatment of generating technologies and price-responsive loads. Also, the estimates of short run marginal costs do not consider additional start-up / shut down costs that might be incurred by generators offering into the market.

3.1 Estimating SRMC

Short Run Marginal cost (SRMC) is the added cost of producing a unit increment of output or, equivalently, the avoided cost of producing a unit decrement of output holding at least one factor of production is constant, e.g., the capacity of a generator.

SRMC should include all costs directly incurred as a consequence of generating electricity: the generation fuel costs; the costs of satisfying any carbon emission regulations; and the cost of marginal wear and tear. To precisely estimate each part of marginal cost is difficult. A simpler alternative is relying upon offer data to estimate marginal cost. Given the different characteristics of generating technologies the assumptions that are used vary.

3.1.1 Coal-fired generators

For coal-fired generators, short-term marginal cost is estimated from offers in the merit-order. An alternative, applicable to most coal-fired generators is to examine the cost data contained with the Power Purchase Arrangements (PPA), however this would not account for changes in costs since they were implemented (for example, emission related costs). Merit-order offer data has also been made public by the AESO since September 1, 2009, thereby representing a transparent data source.

Offers from coal-fired generators can be thought of as falling into one of three categories: offers made at $0/MWh that often reflect minimum stable generation constraints; offers that reflect short run costs; and offers that reflect economic withholding. Under the ISO rules offers are made in seven price and quantity pairs, labeled block 0 through block 6. The offers have to be made in as cending order, such that $0/MWh offers must be made in block 0. Consequently, the first block with a positive price is almost always block 1.

In hours in when the supply cushion is relatively large (greater than 1,500 MW)[13], economic withholding is less likely to be profitable and the MSA believes that the incentives to offer generation at marginal cost during such times is relatively strong. Therefore, by analyzing offers in these hours, it is more likely that a generator's offers will be reflective of marginal costs.

In Table 3.1 we show the median (the 50th percentile) and 5th percentile[14] of the offers made on block 1 in hours when the supply cushion is greater than 1,500 MW. The analysis is done on an annual basis for 2008 through 2011. Unsurprisingly, generators that were built at similar times and form part of the same Power Purchase Arrangement make similar offers. The Table reports the means of the medians and 5th

[13] The supply cushion is simply a measure of the undispatched supply in the energy market merit order. For more details see the MSA's report *Supply Cushion Methodology and Detection of Events of Interest*.

[14] A percentile is the value of a variable below which a certain percent of observations fall.

percentiles for several of these generators, which are similar. In the absence of theory or evidence to suggest that these generators have been offered at less than marginal cost, we have adopted the 5th percentile as the estimator of SRMC.

The method described above does not produce useful estimators for two generators, WB4 and HRM. The WB4 generator was decommissioned on March 31, 2010. Offer data for this generator predominantly consists of offers made at $0/MWh. In this case we have estimated the generator's SRMC based on the heat rate and fuel cost found in the Wabamun PPA. By assuming a variable operations and maintenance (O&M) cost of $7/MWh, its inflation-adjusted SRMCs for the years 2008, 2009, and 2010 are $15.23/MWh, $15.41/MWh, and $15.61/MWh, respectively.

Analysis of the block 1 offers from the HRM generator showed that they exhibited significantly more variation than other coal-fired generators. The HRM generator has made more use of coal to natural gas fuel switching capabilities than has been the case at other generators, which may explain some of the variation observed. For purposes of this analysis the MSA has estimated marginal costs based on the heat rate and fuel cost specified in the PPA. However, this too poses some challenges because changes have occurred to the generator's source of coal since the PPA was formulated. Assuming a fuel cost of $1/GJ and a variable O&M cost of $8/MWh, we estimate an inflation-adjusted short run marginal cost from 2008 to 2011 are $22.36/MWh, $22.62/MWh, $22.92/MWh, and $23.46/MWh, respectively.

The MSA considers the assumptions made for WB4 and HRM are likely poor proxies of actual short run marginal costs but, given the size of the generator, the assumption is not believed to materially affect the overall results.

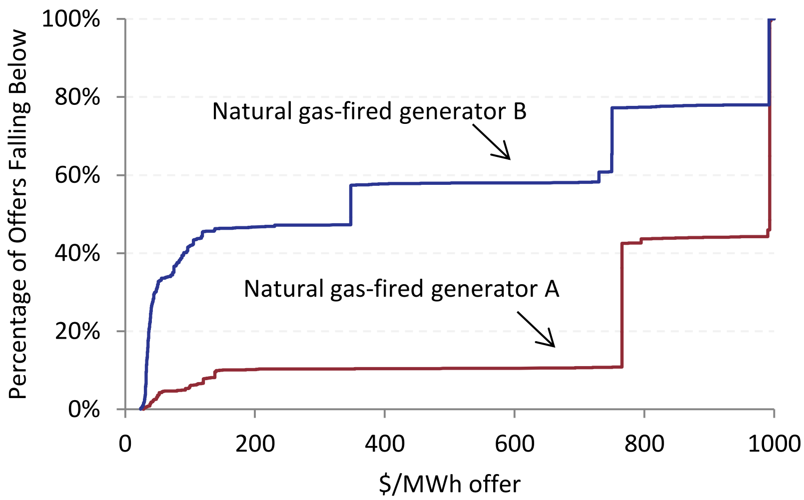
Table 3.1: Offer prices by generator

5th Percentile Offer Price ($/MWh)								
	BR3/4	BR5	GN1/2	GN3	KH1/2	SD3/4	SD5/6	SH1/2
2008	12.85	12.04	7.60	5.00	14.50	9.41	8.51	11.91
2009	11.03	7.84	7.85	6.00	10.97	11.66	9.30	12.72
2010	12.93	12.94	8.09	6.50	12.93	14.39	8.39	10.95
2011	11.91	11.82	8.09	6.57	12.04	14.62	10.67	11.11
Median Offer Price ($/MWh)								
	BR3/4	BR5	GN1/2	GN3	KH1/2	SD3/4	SD5/6	SH1/2
2008	15.63	15.80	7.60	5.45	14.53	12.46	8.51	13.56
2009	15.15	13.02	7.85	6.50	13.49	14.53	11.66	14.57
2010	14.47	13.43	8.09	6.50	13.13	19.01	9.41	13.45
2011	15.07	13.05	11.93	11.15	13.18	18.18	15.46	12.18

3.1.2 Natural gas-fired generation

As with coal-fired generators, the SRMC of natural gas-fired generators can be approximated by analyzing block one offers in hours when the supply cushion is relatively large (>1,500 MW). However, even in these hours the block 1 offer price of natural gas-fired generators is far more volatile. Figure 3.1 plots the duration curve of block 1 offer price for two natural gas-fired generators, labeled A and B. The results indicate that A's block 1 offer price clusters around $770/MWh and $999/MWh, while B's analogous offer price clusters around $25/MWh, $350/MWh, $780/MWh, and $999/MWh. In comparison to coal-fired generators, natural gas-fired generators tend to be designed for meeting peak levels of demand. When demand is low and prices are unlikely to be sufficient for natural gas-fired generators to cover their SRMC, they will rationally offer at high prices in order to avoid dispatch and associated start-up costs. In addition, the SRMC of natural gas-fired generators is highly influenced by prevailing natural gas prices. In combination, these factors suggest a different approach to estimating the SRMC of natural gas-fired generators.

Figure 3.1: Block 1 offer price distribution of two natural gas-fired generators



Among Alberta's natural gas-fired generation there is wide variety of generation technologies. The most prominent distinction is between cogeneration generators and other forms of natural gas-fired generators. In the following sections, we describe the process used for different types of natural gas-fired generation. In each case we rely primarily on offer information and prevailing natural gas prices. A comparison of the results is made to nameplate heat rates for different technologies. In a few instances we make assumptions about a comparative turbine configuration and a corresponding nameplate heat rate that is sourced from publically available information. The MSA could have relied upon data obtained from market participants but chose instead to use the above method where it can be transparent on the assumptions made. Table A.1 in the appendix lists the heat rates of various related turbine configurations.

3.1.2.1 Cogeneration

Cogeneration generators typically produce both steam and electricity for industrial use. In many cases these generators have additional electricity for sale to the grid. Typically, these generators offer a large proportion of their electricity production into the market at $0/MWh. From the perspective of efficiency we assume there are considerable benefits of cogeneration outside the electricity market and therefore attribute a $0/MWh SRMC for volumes of cogeneration offered at $0/MWh, i.e., there is no efficiency loss associated with the volumes offered and dispatched at $0/MWh.

There are 10 cogeneration generators that always offer at $0/MWh and another 2 that do so in all but a few hours. These are listed along with their MC values in Table 3.2.

Table 3.2: Cogeneration generators always offering at $0/MWh

Asset ID	MC
CNR5	103
EC04	94
HMT1	30
IOR1	180
MEG1	92
NX02	220
PR1*	95
PW01*	5
SCL1	510
SHCG	19
TLM2	13
UOA1	39

The remaining cogeneration generators have a mix of $0/MWh and non $0/MWh offers. To estimate the SRMC associated with the non $0/MWh offers, we examine hourly offer data and daily natural gas prices from 2008 to 2011 to derive an implied market heat rate. As with coal-fired generation, we consider only hours where the supply cushion is greater than 1,500 MW to analyze priced offers at cogeneration generators. It is not uncommon to see a cogeneration generator offering a block with zero MW in size so rather than considering only block 1 offers, we examine all offer blocks with non-zero volumes. Tables 3.3 and 3.4 list the estimated 5th and 1st percentile heat rates from the 2008 to 2011 dataset. The 5th and 1st percentile heat rates are selected for analysis because a cogeneration generator would not normally offer dispatchable energy below its marginal cost.[15] For comparison, the Tables list the turbine configuration for the generator and a name plate heat rate for this, or a comparable turbine configuration. In both cases we have included only publicly available information. Table 3.3 only includes those cogeneration generators whose 5th and 1st percentile of offer prices are reasonably close to the nameplate heat rate. The generators whose 5th and 1st percentile offer prices are extremely low are listed in Table 3.4.

[15] There are a few exceptions to this. For example, a market participant who is financially short and has market power may have an incentive to offer low in an attempt to reduce pool price. Other markets may also distort incentives in the energy market. For example participation in the dispatch down service (DDS) may cause generators to offer at less than cost when seeking to be dispatched down. Some generators may also offer lower in order to avoid dispatch costs associated with being on the margin.

Table 3.3: Heat rates of natural gas-fired cogeneration

Asset ID	5th percentile implied market heat rate from non-zero offers (GJ/MWh)	1st percentile of implied market heat rate from non-zero offers (GJ/MWh)	Turbine & configuration from public Information	Turbine & configuration assumed *	Nameplate heat rate (GJ/MWh)*
ALS1	6.10	4.60	GE 7001EA	GE 7001EA, CG	8.44
APS1	12.81	10.54	GE 75A and one Alstom steam turbine		
DOWG	7.53	6.07	Various, including a GE 7EA	GE 7EA,CG	8.44
JOF1	8.72	7.42	Westinghouse 501F and one Toshiba steam turbine	Westinghouse 501F, CCCG	7.17
MKR1	7.10	6.39	GE 7EA, CG	GE 7EA, CG	8.44
RB5	13.40	11.20	LM6000 and one heat recovery steam turbine	LM6000 PC LM6000 PC, CCCG	10.34 8.23
RL1	12. 71	10.20	LM6000 and one heat recovery steam turbine	LM6000 PC LM6000 PC, CCCG	10.34 8.23
SCR1	5.34	4.40	Various, including 2 x Alstom 11N2 and 1xGE 7EA	Alstom 11N2, CG GE 7EA, CG	6.89 8.44
TC01	5.36	4.14	GE LM6000 PD SPRINT,CCCG	GE LM6000 PD SPRINT,CCCG	6.01

*See Appendix A1 for sources of nameplate heat rates for various turbine configurations.

Table 3.4: Cogeneration generators where offer prices and name plate heat ratings are inconsistent

Asset ID	5th percentile implied market heat rate from non-zero offers (GJ/MWh)	1st percentile of implied market heat rate from non-zero offers (GJ/MWh)	Turbine & configuration from public Information	Turbine & configuration assumed *	Nameplate heat rate (GJ/MWh)*
BCRK	3.69	2.74	Rolls Royce Trent	Rolls Royce Trent	7.17
BCR2	1.47	1.39	Rolls Royce Trent	Rolls Royce Trent	7.17
MKRC	1.44	1.36	GE 7FA	GE 7FA, CC	6.42
TC02	1.91	1.39	GE LM 6000 PD	GE LM 6000 PD, CG	6.01

*See Appendix A1 for sources of nameplate heat rates for various turbine configurations.

For the purposes of our static efficiency assessment, for all generators in Table 3.3 we have assumed non-zero dollars offers have a SRMC equal to the 5th percentile implied market heat rate multiplied by the prevailing natural gas price. For the generators shown in Table 3.4, both the 5th percentile and 1st percentiles imply market heat rates that are substantially lower than the corresponding nameplate heat rate. For these generators we have assumed that non-zero dollars offers have a SRMC equal to the nameplate heat rate multiplied by the prevailing natural gas price.

3.1.3 Other natural gas-fired generators

To estimate the SRMC of other natural gas-fired generators we follow a similar approach to that used for cogeneration generators. The key difference is that volumes offered at zero dollars are not assumed to be efficient. Tables 3.5, 3.6, and 3.7 summarize the results of analyzing offer behaviour and nameplate heat ratings. Table 3.5 lists generators where the implied market heat rate based on offer prices approximates the nameplate heat rating. Table 3.6 lists those instances where it does not and these generators represent about 6% of the maximum capability (MC) of all natural gas-fired generators in Alberta.[16] Table 3.7 lists small generators for which there is little information on nameplate heat rates and they represent less than 1% of the maximum capability (MC) of natural gas-fired generators.

[16] These generators constitute 347 MW out of a total of 5,733 MW of Alberta's natural gas-fired generation capacity.

Table 3.5: Heat rates of natural gas-fired non-cogeneration generators

Asset ID	5th percentile implied market heat rate from non-zero offers (GJ/MWh)	1st percentile of implied market heat rate from non-zero offers (GJ/MWh)	Turbine & configuration from public Information	Turbine & configuration assumed *	Nameplate heat rate (GJ/MWh)*
CAL1	7.70	6.95	Westinghouse 501FD and Fuji steam turbine		6.9@250, 10@300**
CMH1	4.94	4.43	Various, includes two LM2500 (27 MW) and one LM6000 (42 MW) and 66 MW steam turbine		
CRS1	11.96	9.81	GE LM6000 PF, Sprint	GE LM6000 PF Sprint	8.62
CRS2	11.18	9.93	GE LM6000 PF, Sprint	GE LM6000 PF Sprint	8.62
CRS3	10.96	9.80	GE LM6000 PF, Sprint	GE LM6000 PF Sprint	8.62
EC01	4.43	2.63	GE LM6000 PC, Sprint and steam turbine	GE LM6000 PC, , CC	8.55
ENC1	8.69	7.87	GE LM6000	GE LM6000 PC	10.34
ENC2	8.69	7.87	GE LMS100	GE LMS100	8.3
ENC3	8.82	7.84	GE LMS100	GE LMS100	8.3
FNG1	13.76	12.16	GE LM6000 PF and a steam turbine	GE LM6000 PF	8.62
NX01	7.96	7.26	GE LM6000 and a Dresser Rand steam turbine	GE LM6000 PC,CC	8.55

*See Appendix A1 for sources of nameplate heat rates for various turbine configurations.

** The generator CAL1 has different heat rates at the threshold 250 MW: 6.9 until the threshold value and 10 after the threshold (See RTO West Benefit/Cost Analysis, Tabors Caramanis & Associates, 2002).

Table 3.6: Non-cogeneration generators where offer prices and name plate heat ratings are inconsistent

Asset ID	5th percentile implied market heat rate from non-zero offers (GJ/MWh)	1st percentile of implied market heat rate from non-zero offers (GJ/MWh)	Turbine & configuration from public Information	Turbine & configuration assumed *	Nameplate heat rate (GJ/MWh)*	MC (MW)
NPP1	54.93	13.20	GE 7EA	GE 7EA	12.66	93
PH1	93.38	69.93	GE LM 6000	GE LM 6000 PD	8.63	48
RB1	132.62	130.64	Westinghouse W201	Westinghouse W201	15	30
RB2	122.43	89.91	Brown Boveri Type 11S		15**	40
RB3	307.45	290.48	Brown Boveri Type 11L		15**	20
ST1	135.66	131.75	Brown Boveri, simple cycle		15**	8
ST2	135.67	131.75	Brown Boveri, simple cycle		15**	8
VVW1	100.19	71.31	GE LM6000	GE LM6000 PC	10.34	50
VVW2	140.95	112.76	GE LM6000	GE LM6000 PC	10.34	50

*See Appendix A1 for sources of nameplate heat rates for various turbine configurations.

**No publicly available data. We have assumed a nameplate heat rate of 15 for Brown Boveri turbines.

Table 3.7: Other small natural gas-fired generators

Asset ID	MC (MW)
GOC1	5
DRW1	6
ALP1	7
ALP2	7
ME02	8
ME03	7
ME04	6
NPC1	12

For the purposes of our static efficiency assessment, for all the generators in Table 3.5 we have assumed a SRMC equal to the 5th percentile implied market heat rate multiplied by the prevailing natural gas price. For the generators shown in Table 3.6 we have assumed a SRMC equal to the nameplate heat rate multiplied by the prevailing natural gas price. For the generators shown in Table 3.7 we have assumed that they operate efficiently (i.e., no efficiency loss is associated with the operation of these generators).

3.1.4 Imports, hydro, wind, and biomass generation

For imports we have made the assumption that they are always efficient. This is consistent with the idea that we are only measuring efficiency losses in Alberta. To incorporate imports into the analysis we would need information on costs of production incurred to generate electricity for import but this information is not readily available.

For hydroelectric generation, SRMC is likely to depend on whether the generators have storage. For run-of-river hydroelectric generators (those without storage) SRMC are likely to approximate zero dollars. For hydroelectric resources with storage, water that is not produced now can be used later and SRMC thus equates to an opportunity cost. An assessment of those costs is beyond the scope of this report. Instead, for hydroelectric generation that is in–merit we assume there is no loss of efficiency and equally no loss of efficiency for out of merit hydro generators.

Wind generators do not offer in the merit order. A simple consequence of this is that they do not feature in our assessment of static efficiency. In practice this is equivalent to assuming they have a SRMC of $0/MWh.

For biomass generation, only 4 generators offer into the market and only two of those do so above $0/MWh. As a consequence offers are unlikely to provide much information about SRMC. The generation technologies and fuel sources used make an assessment based on nameplate heat rates problematic. In general biomass generators would be expected to have relatively low fuel costs. In our analysis we make a simple assumption that for biomass generation that is in–merit we assume there is no loss of efficiency and equally no loss of efficiency for biomass generation out of merit.

3.2 Demand curve

A demand curve describes the relationhsip between the price of a commodity and how much a consumer is able and willing to purchase at a given price. In this report we adopt a very simple formulation of an aggregate demand curve. Only a few loads are thought to have a significant price response in the short term and that price response only occurs above a certain price threshold. For the purposes of this report we focus on six industrial loads that have previously been indentifed as price responsive.[17]

Figure 3.2 shows the relationship between the pool price and aggregate load of these six market participants from year 2008 to 2011. Below $75/MWh, there are wide range of load levels but there is not strong evidence of a link between load and price. Above $75/MWh the linkage appears to be stronger and anecdotal evidence suggests some loads begin to respond at around these price levels.

Figure 3.2 also shows a quadratic trend line estimated by using an oridnary least squares regression (OLS). From this we derive a simple kinked demand curve, vertical (invariant to price) below $75/MWh and downward sloping above $75/MWh. More formally:

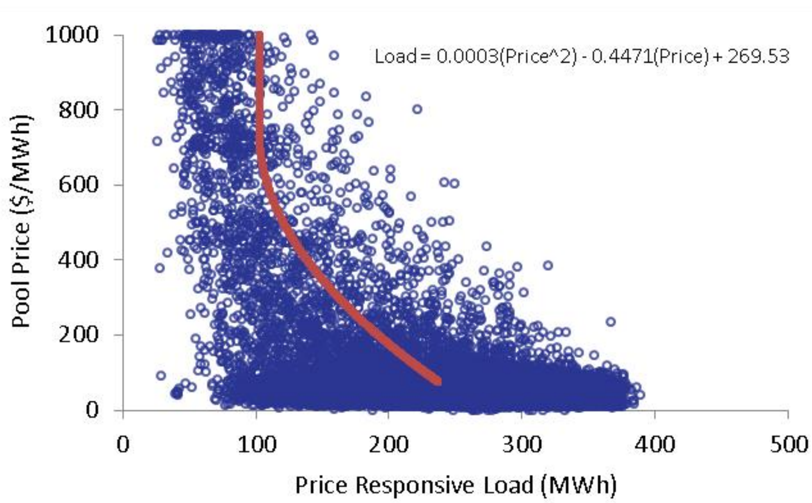
$$price\ responsive\ load = \begin{matrix} a + \varepsilon \quad if\ pool\ price\ \leq 75 \\ \beta_0 + \beta_1 * pool\ price + \beta_2 * pool\ price^2 + \varepsilon \quad if\ pool\ price > 75 \end{matrix}$$

[17] In practice, there are almost certainly others. In the MSA's report *Identification of Impediments to Forward Contracting*, half of the companies responding to the survey (11 respondents) indicated that they altered production processes in real time to manage pool price risk. Three of these companies also had on-site generation, which may indicate that they varied electricity production rather than their conventional output. See Section 2.2 of that report for further details. The inclusion of other price responsive loads would, all else equal, increase the estimated allocative efficiency loss.

It is important that the demand curve is connected at price level of $75/MWh, i.e., describes a demand level for each price. This can be achieved by setting a in the above equation to equal $\beta_0 + \beta_1 * 75 + \beta_2 * 75^2$ for all prices below $75/MWh. The simple method for estiamnting the demand curve does have some implications:

- As noted above, observations of price and demand are always observations of interactions between the supply and demand cuve. The estimates of price responsive demand might be contaminated by movements in supply. More sophisticated techniques, such as the use of instrumental variables, might be able to control for this effect.[18]
- The quadratic demand curve also starts to bend backwards slighlty at very high pool price levels (around $745/MWh). Rather than adopt a more complicated formulation was assume there is no change in pricie reponsive load above $745/MWh.
- By assumption, there is no allocative efficiency loss below $75/MWh (because of the assumed vertical demand curve at price less than $75/MWh). If there is in fact price responsive load below this level allocative efficiency loss will be underestimated. We consider this assumption in more detail in our sensitivity analysis.

Figure 3.2: Estimate demand curve from price responsive load



[18] For a discussion of instrumental variables and demand curve estimation, see Hayashi (2000).

4. Methodology

This section describes how we use the assumptions made regarding SRMC and price responsive load to estimate a static efficiency loss. Losses are estimated on an hourly basis using a snapshot of the energy merit order that is generally obtained 30 minutes into the hour. Merit order snapshots are available from February 2008 onward, but due to certain data issues, are unavailable for a small number of hours. Three data items are required to estimate a static efficiency loss. They are:

- generator availability and SRMC;
- which of the available generators were dispatched; and
- observed demand.

In addition, the observed hourly pool price is used.[19]

Allocative and productive efficiency losses are then estimated as follows:

a) We estimate the actual total cost of meeting the supply/demand level by summing the SRMC of all dispatched generators.

b) Based on those generators that are available we can construct an ordering from lowest cost to highest cost – this is the 'SRMC cost curve' illustrated in Figure 2.12. We re-estimate the total cost of meeting demand using this cost curve.

c) Productive efficiency loss is the difference between the costs calculated in a) and b)

d) We calculate the counterfactual load by assuming demand is met using the SRMC cost curve, and therefore pool price is set by the SRMC of the last dispatched generator on the SRMC cost curve. The incremental load is calculated as the difference between the observed load and the counterfactual load.

e) Allocative efficiency loss is the area surrendered by the estimated demand curve, the efficient marginal cost curve and the supply/demand level (for an illustration see Figure 2.12).

In the next section we provide an example calculation of allocative and static efficiency in a single hour.

4.1 Example

This section gives a detailed example on the calculation of efficiency losses based on the estimates of SRMC and price-responsive load. The example used is HE 9 of 22 January 2009. The pool price for this hour settled at $260.49/MWh. At the time of the merit order snapshot, the energy market dispatched a total of 7,956 MW. After excluding all the energy that is assumed to be efficient (co-generation at $0/MWh for example), the supply / demand level was 6,929 MW. Following the steps outlined above we estimate the losses as follows:

a) Summing up the total SRMC cost of supplying the 6,929 MW yields $97,594.

b) The total cost of providing the 6,929 MW based on the efficient cost curve is estimated at $93,971.

c) Productive efficiency loss is thus $3,623 ($97,594 - $93,971).

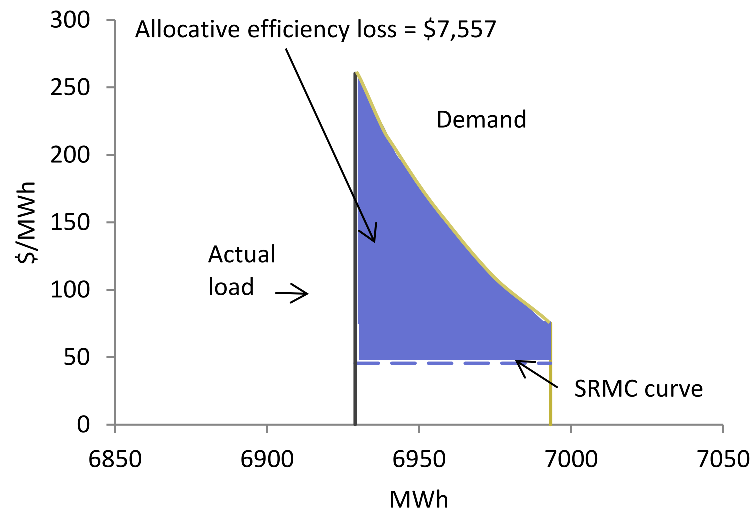
[19] An alternative would be to use the SMP at the time of the snapshot. We have chosen to use pool price due to the manner in which price responsive load was estimated (i.e., using hourly average data rather than a snapshot of price responsiveness).

d) The highest SRMC of generators needed in that hour is estimated to be $45.54/MWh. Since this is less than $75/MWh, some load is assumed to have curtailed in the hour. We estimate the additional load that would have consumed at this lower price as:

$$0.0003 \times (\$75^2 - \$260.49^2) - 0.4471 \times (\$75 - \$260.49) = 64.3 \text{ MW}$$

Therefore, the vertical part of demand curve is estimated to be at 6,929 + 64 = 6,993 MW. Allocative efficiency loss is the area under the estimated demand curve between the realized (6,929 MW) and vertical demand level (6,993 MW) and above the SRMC cost curve (see the shaded area in Figure 4.1). In this example, we estimate the total allocative efficiency losses to be $7,557.

Figure 4.1: Allocative efficiency loss at HE 9, January 22, 2009



5. Results

5.1 Interpretation

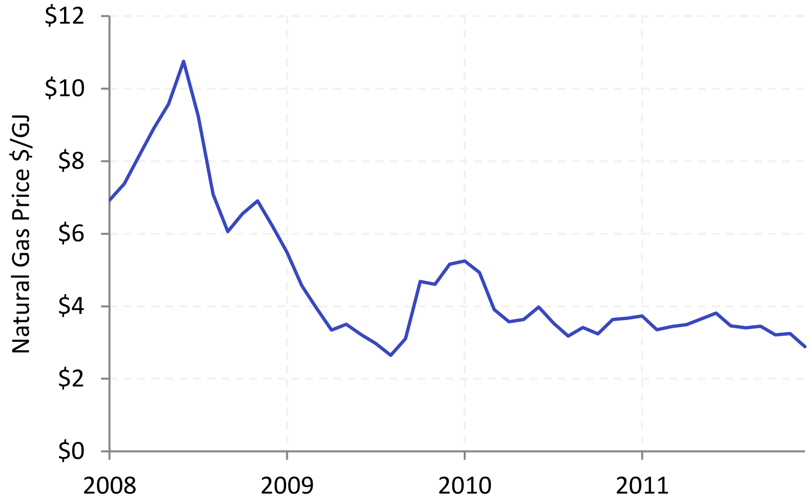
In the previous sections we have set out a number of assumptions. Some are worthy of additional comment. Our static efficiency assessment is focused on a *very* short-run period. For example, it doesn't include efficiency losses that might result from outage scheduling but rather takes the availability of generators as given. Similarly it does not examine whether efficiency loss occurs because of the commitment of generators to provide operating reserves, or indeed losses associated with the activation of specific generators. Some elements of SRMC are also excluded. For example costs associated with start-up, shut-down and additional marginal costs associated with ramping. For all these reasons the results need to be interpreted with some caution.

The results should help to identify whether static efficiency losses have been changing from year to year and whether the introduction of the MSA's *Offer Behaviour Enforcement Guidelines* (OBEGs) in early 2011 have had a significant impact on static efficiency losses. The OBEGs clarified the MSA's enforcement stance on, among other things, economic withholding and, to the extent that economic withholding increased, this would be expected to cause the estimated static efficiency losses to rise.

The estimated yearly average efficiency losses and normalized efficiency losses are listed in Table 5.1. The normalized efficiency losses are the hourly efficiency losses divided by intersection of supply and demand in that hour. Note that this is not the same as the Alberta Internal Load reported by the AESO since that includes demand not directly in the market. Normalized efficiency losses are included because they offer a convenient starting point to compare efficiency loss to pool price.

From 2008 to 2011, average production efficiency loss decreases from $4,442.85 per hour to $3,617.37 per hour and the corresponding normalized loss decreases from $0.68/MWh to $0.55/MWh. The lowest estimate of both is in 2009. The results do not support the hypothesis that overall productive efficiency losses have increased since the introduction of the OBEGs. Instead they point to a different factor driving productive efficiency losses: natural gas prices. As illustrated in Figure 5.1, natural gas prices were approximately $7.8/GJ in early 2008 (increasing until about June of that year) and subsequently fell to $3.4/GJ in 2011. To understand why falling natural gas prices are important, consider an example where a low cost coal-fired generator with a SRMC of $15/MWh is economically withheld and replaced by a natural gas-fired generator with a 10 GJ/MWh heat rate. All else equal, the static efficiency loss for 1 MW withheld would be $63/MWh ((10x$7.8)-$15) at a $7.8/GJ natural gas price and only $19/MWh at a $3.4/GJ natural gas price.

Figure 5.1: NGX monthly natural gas price, $/GJ



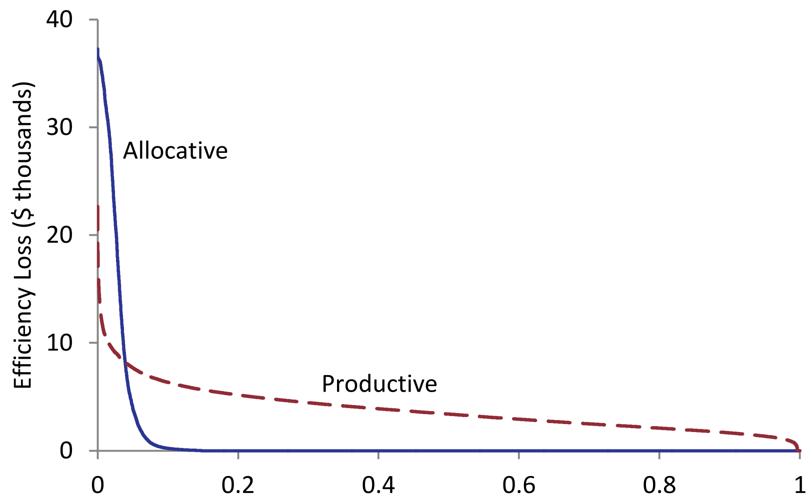
Allocative efficiency losses also observe a drop in 2009 and 2010 but reach the highest level in 2011. The largest driver here is the number of hours with a pool price above $75/MWh (by assumption there is no allocative efficiency loss below this level). From 2008 to 2011, the number of hours with pool price greater than $75/MWh is 2,829, 588, 671, and 1152, which mimics the trend of allocative efficiency losses quiet well. The allocative efficiency losses in 2011 (post-OBEGs) are larger than experienced in 2008. Supply demand conditions in the two years, as measured by the MSA's supply cushion metric average 965 MW and 1,255 MW respectively. That means market conditions were somewhat tighter in 2008 (i.e., higher cost resources would be needed in order to satisfy load). All else equal, these tighter market conditions would be expected to reduce allocative efficiency losses.

Table 5.1: Average efficiency losses ($) and normalized efficiency loss ($/MWh), by year

Efficiency Loss	Units	Year 2008	Year 2009	Year 2010	Year 2011
Average Productive Eff. Loss	$/hour	4,442.85	3,067.20	4,086.76	3,617.37
Average Allocative Eff. Loss	$/hour	1,326.27	482.94	659.67	1,951.53
Normalized Productive Eff. Loss	$/MWh	0.68	0.46	0.61	0.55
Normalized Allocative Eff. Loss	$/MWh	0.17	0.06	0.09	0.25

Figure 5.2 illustrates duration curves showing the distribution of estimated hourly losses of productive and allocative efficiency. As shown by the figure, most hours involve some productive efficiency loss but it is rarely above $10,000. For allocative efficiency, about 90% of the hours analyzed observe no loss at all. This is an expected result since by assumption allocative loss happens only when pool price is greater than $75/MWh.

Figure 5.2: Duration curve of productive and allocative efficiency losses, 2008-2011

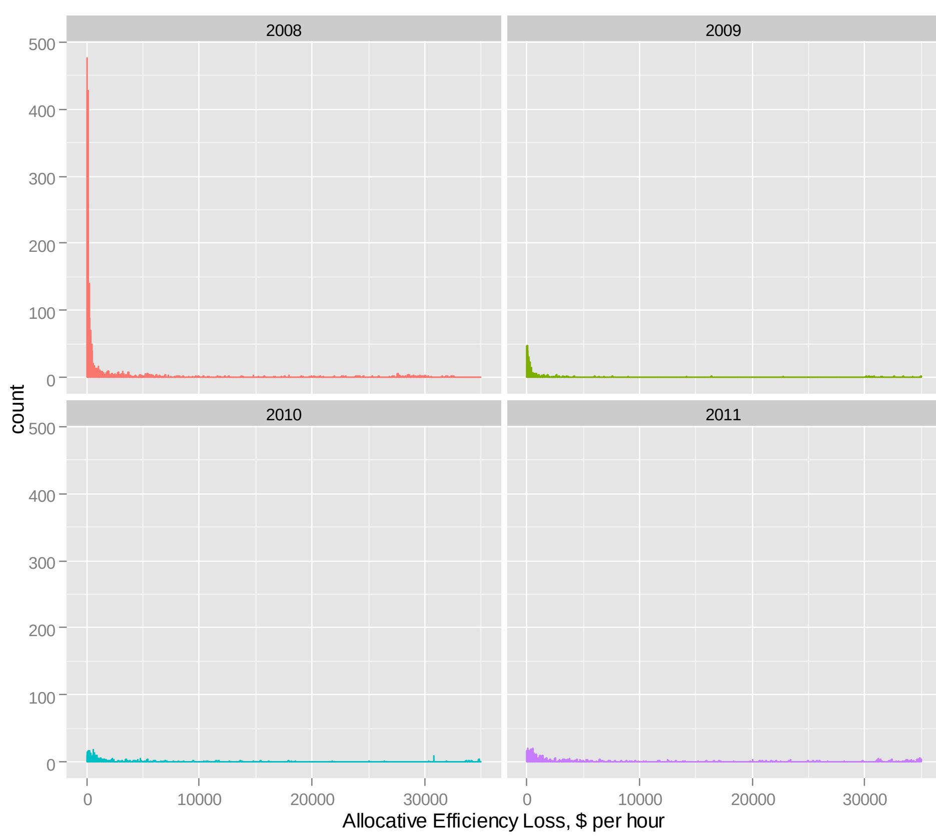


In Figures 5.3 and 5.4 we show the same data presented in a histogram to show the distribution of losses by year. In all years, the distribution of productive efficiency losses has a right hand tail. This implies that there are a few hours with large production efficiency losses but in the majority of hours these losses are small.

Similarly, Figure 5.4 presents the distribution of allocative efficiency losses by year. To make it easier to read, this figure excludes the hours with zero allocative efficiency loss, i.e., hours with pool price less than $75/MWh. Years 2009 and 2010 have relatively few hours with a loss in allocative efficiency. Specifically, 2011 has a high average allocative efficiency loss due to a cluster at high loss level.

Figure 5.3: Distribution of productive efficiency loss, by year

Figure 5.4: Distribution of allocative efficiency loss, by year



5.2 Sensitivity analysis

Our estimated productive and allocative efficiency losses are largely determined by SRMC and the demand curve. Though SRMC affects both types of efficiency losses, the demand curve only impacts allocative efficiency loss. This section presents some sensitivity analysis by relaxing or changing some of the assumptions made around the SRMC and demand curve analysis.

In examining the cost assumptions made in Section 3, in at least some cases the costs assumed for natural gas-fired generation appear relatively low. More work would be needed to assess whether other costs are in fact incurred that should be included in SRMC. Consequently we examine a simple sensitivity analysis where the heat rate for all natural gas-fired generators is increased by 2 GJ/MWh, with all else kept equal. Table 5.2 shows the results of this sensitivity analysis. Both productive and allocative efficiency losses decrease. With a higher level SRMC, productive efficiency loss shrinks since the difference between pool price and efficiency SRMC curve decreases. Similar argument holds for allocative efficiency loss. However, the sensitivity results are similar to the base case, i.e., the result is not sensitive to a small increase in costs for all natural gas-fired generators.

Table 5.2: Sensitivity Analysis - higher heat rates for natural gas-fired generators

Efficiency Loss	Units	Year 2008	Year 2009	Year 2010	Year 2011
Average Productive Eff. Loss	$/hour	5,638.37	4,253.00	4,984.29	4,638.04
Average Allocative Eff. Loss	$/hour	1,182.81	462.44	633.57	1,891.47
Normalized Productive Eff. Loss	$/MWh	0.87	0.64	0.74	0.70
Normalized Allocative Eff. Loss	$/MWh	0.15	0.06	0.08	0.25

We also consider a sensitivity analysis for our estimate of the demand curve by relaxing the assumption of a vertical demand curve below $75/MWh (i.e., demand is still responsive below this level). Table 5.3 presents the estimated allocative efficiency losses. Unsurprisingly the estimates are somewhat higher although still relatively small.

Table 5.3: Sensitivity Analysis - Alternate demand curve

Efficiency Loss	Units	Year 2008	Year 2009	Year 2010	Year 2011
Average Allocative Eff. Loss	$/hour	1,390.77	508.38	687.04	1,891.47
Normalized Allocative Eff. Loss	$/MWh	0.18	0.07	0.09	0.26

6. Conclusion

This report develops a methodology for estimating static efficiency losses in Alberta's energy-only electricity market. We look at two sources of static efficiency loss: productive and allocative. Both are assessed over a short time frame where the availability of generators is taken as given. The focus is on losses that result from generation offer prices that diverge from the SRMC. The assessment takes a relatively simplistic view of costs. In particular, it overwhelmingly relies on generators offer data to infer SRMC. Any costs associated with ramping, e.g., start-up and shut-down costs, that are not incorporated in the offer behaviour will be ignored. The methodology developed could be extended to consider a wider range of cost factors.

Given the assumptions made, the MSA believes the results should be treated as indicative but are nonetheless interesting. What we have found is that productive and allocative efficiency losses are relatively small. In the four years studied, the average pool price was approximately $66/MWh, while the average static efficiency loss was $0.72/MWh (both productive and allocative), i.e., about 1.1% of the pool price. We also note that estimates of losses in 2011 are not significantly dissimilar to those in earlier years, suggesting changes in participant behaviour as a consequence of the MSA *Offer Behaviour Enforcement Guidelines* have not had a dramatic impact on static efficiency loss. There are no equivalent results from other electricity markets or industries that would further help us interpret the relative size of these losses. Instead we consider what factors might be driving losses to be small.

One factor that reduces the productive efficiency loss is that the costs of many generators are not that dissimilar. This means that total production costs do not change much if one generator is replaced by another. Alberta has two major electric generation technologies: coal and natural gas. Low natural gas prices have resulted in the short run costs of the two technologies being much more similar now than in the past. As a result of this, productive efficiency losses have been relatively low recently. Allocative efficiency losses will tend to be small if demand is insensitive to price. That is commonly the case in real time electricity markets and Alberta is no exception.

In conclusion, small static efficiency losses in essence mean that the market would essentially meet the efficiency goals set out under the *Electric Utilities Act*, even if the gains from dynamic efficiency were relatively modest. Further, the size of static efficiency losses doesn't imply anything about the distribution of benefits between consumers and producers. In order for the electricity market to be sustainable a further two things are needed. First, producers must have an opportunity to recover fixed as well as short run costs. Second, consumers must benefit from the efficiency gains of the market over the longer term.

Appendix A: Data sources

In Table A.1, two major data sources are used to estimate nameplate heat rates are the General Electric website and heat rate data reported by Northwest Power and Conservation Council (NPCC).[20]

Table A.1: Nameplate heat rate of turbines and sources

Turbine & configuration	Nameplate heat rate (GJ/MWh)	Source
GE 7001EA	10.99 8.44 (CG)	http://www.ge-energy.com/content/multimedia/_files/ downloads/dataform_2047583989_2809802.pdf and NPCC
GE 7EA	7.17(CC) 8.44(CG) 12.66	NPCC
GE 7FA	6.42(CC)	http://www.ge-energy.com/content/multimedia /_files/downloads/dataform_2046207337_2809806.pdf
GE LM 2500	11.29	NPCC
GE LM 6000 PC	10.34 8.23(CCCG) 8.55 (CC)	NPCC
GE LM 6000 PC Sprint	8.93	http://www.ge.com/mining/docs/2981884_1346772682_ GE_Aeroderivative_Product_and_Services_Solutions.pdf
GE LM6000 PD	8.63	The same as above
GE LM6000 PD Sprint	8.62 6.01 (CCCG)	The same as above NPCC
GE LM6000 PF Sprint	8.62 7.70(CG)	The same as above. NPCC
GE LMS100	8.3	The same as above.
Westinghouse 501F	7.17(CCCG)	NPCC
Alstom 11N2	10.71 6.86 (CG)	http://www.netl.doe.gov/technologies/coalpower /turbines/refshelf/handbook/1.1.pdf and NPCC
Rolls Royce Trent	7.17	NPCC
Solar Taurus	13.68(SC) 5.77(CG)	NPCC

[20] These data are available at the website of *www.nwcouncil.org* after searching for “Log of Changes to AURORA Input Data Tables: Draft to Final Sixth Power Plan Forecast”. The heat rate used is from the “For AURORA” column and is converted from Btu/KWh to GJ/MWh.

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Market Surveillance Administrator

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