MARKET SURVEILLANCE PANEL

MONITORING REPORT ON

THE IMO-ADMINISTERED ELECTRICITY MARKETS

FOR

THE FIRST FOUR MONTHS

MAY – AUGUST 2002

OCTOBER 7, 2002

Preface

This is the first report of the Market Surveillance Panel, covering the first four months of Ontario's new electricity marketplace. Electricity markets are complex and the Ontario market is brand new. Hence we feel it important in this first report to spend some time describing why competition is important, the particular characteristics of the Ontario energy market, and how this market operates. This background information is presented in Chapter 1 and we hope it will provide the reader with a helpful context to understand our description of how the market has worked in practice over the past four months. This description, and accompanying analysis, is presented in Chapter 2. We expect that future reports will be focused more intensively on operational and behavioural issues.

The Market Rules require us to provide a general assessment of the state of competition and the efficiency of Ontario's wholesale electricity market on an annual basis. However, we felt it would be helpful to provide such an assessment reasonably soon after market opening. As the report points out, all participants and the Panel itself have learned a lot since market opening. By sharing our perceptions with others we hope that we can assist the more efficient functioning and more effective future development of the market.

Our conclusions, and some issues that we believe require further analysis and attention are presented in Chapter 3. On balance, we find that the market has performed reasonably over the first four months. In particular, we find no evidence of abusive or potentially abusive behaviour by market participants. However, there are some serious challenges facing the Ontario electricity market. The challenges are not new, but the first months of operation of a competitive market have made them more apparent. Our role is to assist in making the competitive market more effective, to the benefit of all Ontarians, and we hope that our findings and recommendations will help in this process.

We welcome comments on the matters we have raised in this report and on other matters that we may have overlooked.

Finally, we thank the dedicated and talented staff of the Market Assessment Unit of the IMO. They have provided incredible support in preparing for market opening, in our ongoing monitoring activity and in the intensive process of preparing this first report. Their professionalism and competence are reflected throughout the Report and we are very appreciative of the extraordinary efforts they made to assist us in producing it.

Fred Gorbet, Chair   Don McFetridge   Tom Rusnov

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1. Introduction

The Government of Ontario opened the electricity marketplace to competition on May 1, 2002. This action followed several years of study, review, debate and preparation. Although the market is now intended to operate competitively, competition will occur within a framework of legislation, Market Rules, regulation and oversight. Some of this framework, such as the *Competition Act,* applies broadly to all competitive market activity in Canada. But most of the framework has been designed to meet the specific challenge of fostering competition in Ontario's electricity market. The purpose of this framework is to ensure that competition is effective, so that the marketplace will work well and provide the benefits of competition to Ontario consumers.

The Market Surveillance Panel (MSP) is an important part of the oversight framework for the new electricity marketplace. The *Electricity Act, 1998* created the Independent Electricity Market Operator (IMO) with a mandate to establish and operate wholesale markets for electricity in the province. This *Act* also requires the IMO Board to appoint a Market Surveillance Panel with the power to " ...investigate any activity related to the IMO-administered markets or the conduct of a market participant."[1] The IMO Board – which is composed of both independent directors and stakeholder representatives – delegated the appointment of the MSP to the Committee of Independent Directors.[2]

The MSP's objective is to contribute to the development of an efficient, competitive and reliable marketplace for the wholesale sale and purchase of electricity and ancillary services in Ontario.

[1] Section 37, *Electricity Act, 1998.*
[2] Article 8.4, Independent Electricity Market Operator, Governance and Structure By-Law.

The Panel's role is to monitor behaviour in the markets that the IMO administers.[3] Specifically, the Panel monitors the activities and conduct of market participants to identify:

- inappropriate or anomalous behaviour in the marketplace, including gaming and the abuse of market power;
- actual or potential design flaws and inefficiencies in market rules and procedures; and
- actual or potential design flaws in the overall structure of IMO-administered markets.

In addition the MSP may investigate any of these matters it feels appropriate in light of its objective. At the request of the Panel, the government recently proposed legislative changes to the MSP's powers to compel information and testimony from market participants in the course of an investigation of anomalous or abusive behaviour. Those changes were enacted in the *Reliable Energy and Consumer Protection Act, 2002*, which received Royal Assent June 27, 2002.

The MSP is also charged with reporting the results of its monitoring and investigations, and making any recommendations it feels are appropriate.[4]

This is the first monitoring report of the Market Surveillance Panel. It covers the period from May 1 through August 31, 2002. Because this is our first report, we have taken some time to set out some general observations in the remainder of this chapter. We

[3] These markets are: the real-time auction markets for energy and operating reserves; the procurement markets for ancillary services; and auction markets for financial transmission rights (FTRs) that allow market participants to manage financial risk associated with energy flows. The structure and operation of these IMO-administered markets are described in more detail later in this chapter and additional information may be found at www.theIMO.com.

[4] A backgrounder released in April 2002 titled " The Market Surveillance Panel in Ontario's Electricity Market: Monitoring, Investigating and Reporting" explains how the Panel will discharge its responsibilities. The Market Surveillance Panel is supported in its activities by the Market Assessment Unit (MAU) within the IMO. The MAU conducts day-to-day monitoring and reports regularly to the MSP. For a copy of the Backgrounder, see IMO web site at www.theIMO.com and follow the link to 'Market Surveillance'.

believe that these observations and descriptions of how the new marketplace operates will be useful in providing context for the review of activities and conclusions we present in Chapter 2 of this report and will present in future reports. Chapter 2 reports on activity in, and the operation of, the IMO-administered markets over the period under review, with an emphasis on the real-time markets. Our conclusions and issues identified for further observation and assessment are presented in Chapter 3.

In the balance of this chapter, we discuss:

- the concept of effective competition and its application to electricity markets;
- an overview of the structural characteristics of the Ontario electricity market;
- some of the operational aspects of the new electricity marketplace in Ontario.

2. Effective Competition and Electricity Markets

2.1 Why is competition important?

The virtue of competitive markets is that they make the best use of the resources available. Supply is drawn from the most efficient sources at any point in time. Output is allocated to the highest valued uses. In competitive markets, prices guide the decisions of customers as well as existing and potential suppliers. Markets work best when price signals are accurate and when both suppliers and users can see them and are able to respond to them.

Properly functioning markets provide the information necessary to facilitate decentralized decision-making. This allows for a variety of supply and demand responses to changes in underlying cost and demand conditions. Over time, competition from the more efficient sources of supply and from superior new technologies drives out the less efficient sources. Competitive markets also allow for an efficient distribution of risk. Risk is typically borne in competitive markets by shareholders who have chosen to bear it rather than by customers and taxpayers who typically bear the risk associated with government-owned monopolies.

2.2 Perfect competition versus effective competition

Perfection is hard to find outside of textbooks. This is true not only with respect to markets but also with respect to regulatory regimes and government enterprises. Perfect competition is an ideal construct; the practical question is whether competition is effective, that is, whether it results in more efficient consumption, supply and investment decisions than government-owned monopolies with regulated prices.

Insofar as electricity markets are concerned, effective competition can be defined in a variety of ways. At one extreme, effective competition can be defined as the absence of any significant manifestation of market power. The presence or absence of market power can, in turn, be assessed in a variety of ways, both structural and behavioural.

Structural indicators of the extent of market power include the number and size-distribution of competing sellers and buyers in the market, the conditions of entry into the market, mobility conditions within the market (the ability of fringe competitors to expand) and the ability of customers to postpone consumption or to avail themselves of substitute products. While measures of generator concentration (such as the Herfindahl-Hirschman Index or HHI) are useful indicators of the possible extent of market power in electricity markets, they are far from sufficient.[5] In particular, market power may continue to be exercised in an electricity market which appears unconcentrated in the aggregate if ownership of price-setting capacity remains concentrated.

One type of behavioural measure of the extent to which market power has been exercised involves the determination of the extent to which market prices have departed from the perfectly competitive benchmark of marginal cost. This requires a comparison of the market price with the marginal cost of the hypothetical marginal supplier (on the assumption of no withholding) in the market at each point in time. Competition is then regarded as ineffective if the market price exceeds marginal cost by more than a specified

[5] The HHI is the sum of the squares of the respective market shares of each of the competitors in the market. The HHI is higher the fewer the competitors in the market and the more unequal they are in size.

percentage over a given period of time. This approach is used to assess the state of competition in some electricity markets.[6] It has the disadvantage, however, of relying on estimates of marginal cost derived from engineering studies. Such estimates may diverge considerably from average incremental cost and from opportunity cost, which may be the relevant cost benchmarks in many situations. A simple alternative is to infer incremental cost from past bidding behaviour. For the market as a whole, the market price can be compared with a historic reference price, which prevailed under similar circumstances.[7]

Another type of behavioural approach to measuring the exercise of market power focuses on capacity offered rather than price-cost relationships. In the context of wholesale electricity markets, it involves the determination of the extent to which generating capacity has been withheld from the market in order to bring on higher cost sources of supply and raise the market price. Withholding can involve either refusing to offer available supply into the market (physical withholding), or offering supply but at prices that are so high the probability of the supply being called is minimal (economic withholding). It could also involve exporting to lower price markets in order to reduce supply and raise price in the home market. The examination of possible instances of withholding, especially under conditions of tight supply, is also used to assess the state of competition in some electricity markets.[8]

An approach to the definition of effective competition lying at the other end of the spectrum is simply to treat electricity markets the same as most other markets for industrial and consumer goods and services in the economy. This approach views competition as effective if the structural conditions are satisfied, that is, if the opportunities for significant unilateral exercise of market power are limited under normal

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[6] See, e.g., Borenstein, S. and J. Bushnell. 1999. An Empirical Analysis of the Potential for Market Power in California's Electricity Industry. *Journal of Industrial Economics* **47**(3), September: 285-323.
[7] See, e.g., NYISO, *Compliance Filing of NYISO Regarding Comprehensive Market Mitigation Measures and Request for Interim Extension of Existing Automated Mitigation Procedure,* FERC, Docket No. ER01-3155-000, March 20, 2002.
[8] See Patton, D., R. Sinclair, and P. LeeVanSchaick (May 2002) "Competitive Assessment of the Energy Market in New England".

conditions, and if behaviour in the market concerned does not violate competition or antitrust law. Specifically, this approach deems competition to be effective if:

- there is no joint (collusive) exercise of market power and no predatory or exclusionary behaviour, and
- opportunities for the unilateral exercise of market power are limited by the timely entry of new competition or expansion of existing competition, by consumer substitution or by technological change.

This approach does not consider the unilateral exercise of market power (charging a price above cost or restricting output) to be anticompetitive in and of itself. It focuses instead on conduct aimed at restraining or preventing competition. This approach allows for a distinction between the *exercise* of market power and the *abuse* of market power with the latter being actions which prevent corrective competitive responses to price signals.

The Panel is of the view that it is important to understand when and under what circumstances prices in IMO-administered markets have been significantly affected by the exercise of market power. The Panel is also of the view, however, that its first priority should be to ensure that the market forces which normally counteract any sustained exercise of market power are not impeded by the design and implementation of the market, by the regulatory environment or by the actions of market participants. In essence, the Panel sees its role more as one of preventing the abuse of market power than with mitigating the effects of the exercise of market power.[9]

There is a concern however, which we share, that because the demand for electricity tends to be highly inelastic (insensitive to price increases or decreases), particularly in the short term, the exercise of even modest amounts of market power can result in very high prices and very large and possibly regressive transfers of wealth from consumers of electricity to importers or generators. This is a special aspect of the electricity market that motivated the market power mitigation framework[10] in Ontario and which has led to

[9] See the backgrounder referred to in footnote 4 above.
[10] The market power mitigation framework is described in section 3.2 of this chapter.

ongoing mitigation activities by electricity market operators in other jurisdictions. It warrants continuing attention – both to the behaviour of participants and to whatever features of the rules or frameworks might constrain the ability of existing or potential market participants to adjust quickly when market power is exercised. At this stage in the evolution of the Ontario marketplace we are monitoring a number of indicators to assist us in coming to an overall view about the effectiveness of competition and ways in which it may be improved.[11]

2.3 What makes competition effective

Markets do not function in a vacuum. All markets that work operate within a framework defined by laws, regulations and rules. Some aspects of this framework – such as property rights, contracts, bankruptcy, etc. – are basic to the establishment of any functioning market. Other laws of general application, such as competition law, seek to ensure that behaviour of participants in a given marketplace does not unduly lessen or prevent competition. Some markets are also subject to specific laws and regulations, where public policy has deemed it desirable to expand the framework to take account of particular characteristics of such markets. Examples include regulations regarding health, safety and environmental standards, land use and zoning requirements, ownership restrictions, professional qualifications, disclosure and transparency requirements, or protection of privacy. Laws, regulations and rules of this nature can have a critical impact on the effectiveness of competition in the markets to which they apply.

Where they exist, wholesale electricity markets were essentially created from first principles, and quite recently. This is in contrast to markets for other goods and services, which have evolved over time, often many years. Competitive wholesale electricity markets also are characterized by an extremely complex set of special operating rules and procedures that are aimed at ensuring reliability of supply and creating a marketplace that is transparent and where all participants are treated fairly. While the rules and procedures

[11] A list of the monitoring indicators that are used by the Panel in its work is provided on the IMO web site

of the Ontario marketplace have benefited from considerable analysis of the experiences in other jurisdictions, and from extensive testing, it is still the case that they have only been in operation in a real-world setting for a little more than four months. One of our key functions – in monitoring activity in the IMO-administered markets – is to assess how well these rules and operational practices are contributing to the effectiveness of competition.

While the framework is important, the effectiveness of competition also depends on the elasticities of supply and demand for the product concerned and the contestability of the market. When supply and demand are highly inelastic in the short-run and new entry into the marketplace is not always easy or quick, markets can function poorly in the sense that supply/demand imbalances lead to extremely high and often volatile prices that do not result in very quick or substantial market adjustments. This is a characteristic of most electricity markets when capacity becomes tight. And it results in a situation where market power can be exercised to effect substantial transfers from electricity users to suppliers. In such a situation, however, the high and volatile prices are symptoms. The underlying cause of the problem is much more likely to lie not in the behaviour of the market participants but in the shortage of capacity. If competition is effective, high prices should signal to new entrants that capacity shortages are emerging and should induce new supply, through imports or new investment. Similarly, high prices should signal to energy users that it pays to economize on use, seek substitutes, or consider 'time-shifting' activities.[12] But again, the effectiveness of these signals can be short-circuited through the framework within which the market operates. Environmental and other regulations will affect the ability and speed of investors to site and construct new capacity and connect it to the grid. Users may not have the appropriate information and incentives to adjust their behaviour quickly in response to price movements.

www.theIMO.com at the 'Market Surveillance' link.

[12] In the electricity market, where use and price vary by time of day, 'time-shifting activities' refer to shifting activity to use electricity in off-peak rather than peak periods.

2.4 Special considerations related to electricity markets

There are a number of specific aspects of electricity markets that distinguish them from virtually all other markets. These differences need to be addressed in the overall framework of market design, including those aspects that govern competition.

First, most consumers regard electricity as an essential product, vital to maintaining the standard and quality of modern life. Reliability – 'keeping the lights on' – is a fundamental requirement that must be engineered into the design and operation of electricity systems. Reliability means that in addition to the production of sufficient electricity to satisfy the instantaneous customer demand, a quantity of generating capacity must be kept in reserve, called operating reserve, available to respond to emergencies on short notice. It also means that generators and the transmission system must be able to withstand outages to their various elements without causing widespread or prolonged power interruption. These factors are governed by international agreements to which the IMO is a party. Therefore, operation of all large power systems must be monitored continuously, 24 hours per day, 365 days per year to ensure that reliability is maintained.

Ontario's power system is interconnected with adjacent utilities in Manitoba, Minnesota, Quebec, New York and Michigan. These utilities in turn are interconnected with their neighbouring utilities in the U.S. south to Texas and west to the Rocky Mountains.
This huge North American power system has been and continues to be vital to providing and maintaining reliability to all interconnected utilities and for providing trading opportunities for market participants. A failure of components anywhere on this massive grid can have negative impacts on many other areas, even those in other jurisdictions and such failures must be guarded against or consequences minimized.[13]

[13] With the exception of Quebec, all generators in these interconnected systems operate in 'synchronism' which means that they all produce electricity at 60 Hertz (cycles/second) and can transfer power among themselves instantaneously, subject only to the physical capacity of their respective transmission systems and interconnections and to commercial agreements.

Second, electricity is a manufactured product but, unlike most other manufactured goods, it cannot be stored in any significant quantities. There are no buffers, order backlogs or inventories that are common in other markets and hence electricity must be consumed instantaneously as it is being produced. Supply and demand must also balance continuously within geographic areas such as Ontario and even smaller areas within Ontario determined by the capability of the transmission grid to move power between areas. Supply may be provided or supplemented by imports for reliability or commercial purposes.

Third, electricity flows on the grid according to the laws of physics and these laws determine how heavily individual components (transmission lines, transformers etc.) are loaded at every instant in time. Power flows along all available transmission paths between generators and points of consumption, but in proportion to the 'strength' of those paths. For example, importing electricity from a supplier in New York State can result in 70 percent of the power coming in over our interconnections at the border with NY, while 30 percent may flow on transmission lines south of Lake Erie and into Ontario at the Michigan border. The ratio would reverse (although not necessarily precisely) for imports from Michigan with most of the power flowing in at the Michigan border and lesser amounts from New York at Niagara and Cornwall. Similarly, power flows on Ontario's internal transmission lines change for every change in the pattern of operating generators within Ontario and this affects the loading on transmission lines and related system elements. Therefore the loading on all grid elements must be monitored continuously and kept within their design ratings to avoid damage and, more importantly, to avoid harm to staff and the public.

The changing conditions described above can and often do result in 'congestion'[14] i.e., potential overloading on the grid which in turn requires system operators to constrain certain generators off and constrain others on to keep from violating loading criteria. The

[14] Congestion is a term coined to describe a condition on power systems which is crudely analogous to traffic 'congestion' on streets and at intersections. When market participants try to send electricity to a geographic area in excess of what the intervening lines and stations can safely carry, these facilities are considered to be congested and system operators must take action to avoid such occurrences.

congestion can create market power in geographic sub-markets, sometimes referred to as 'load pockets'.

The implications of these special aspects of electricity is that in all electricity markets there is a central 'system or market operator' who has the responsibility for monitoring and operating the power system, administering the marketplace and ordering the dispatch of electricity from suppliers. As noted above, all of these functions must be carried out on a continuous basis. The role of the central operator – in Ontario, the IMO – is to manage the marketplace in a way that protects the reliability of supply. From time to time this may require the market operator to engage in actions that are not strictly consistent with commercial market results. This has indeed been the case in Ontario over the first four months of operations and we will review some of these 'out-of-market' actions and discuss their implications in Chapter 2.

A further special characteristic of electricity, as noted above, is that the demand appears to be highly inelastic (does not quickly respond to price signals) in the short term and can vary substantially, quickly and sometimes unexpectedly with weather conditions. The first four months have shown that relatively small changes in demand, when supply conditions are tight, can lead to very large changes in prices.

Finally, due to the unique characteristics of power systems, competitive wholesale electricity markets will typically involve complex operating rules and procedures. This complexity can provide 'gaming' opportunities for market participants. Gaming occurs when someone deliberately exploits a loophole in the Market Rules or procedures, and it does not necessarily involve fraudulent conduct. The potential for gaming in electricity markets requires monitoring of activity and behaviour on an ongoing basis, and mechanisms to adjust the rules quickly where necessary.

3. The Ontario Electricity Market: An Overview

As noted above, the performance of any market depends greatly upon the underlying characteristics of demand and supply, the structure of the marketplace, and the rules of its operation. This section provides some relevant background information on each of these aspects of the Ontario electricity market.

3.1 Electricity demand and supply conditions in Ontario

The demand for electricity is believed to be highly inelastic, at least in the short term, and this short-term inelasticity is alleged to be a major contributing factor to price-spikes in competitive electricity markets. One of the issues that needs to be addressed is whether demand is truly unresponsive to price in the short run (that is, consumers cannot or will not reduce demand even when prices rise considerably) or whether the structure of the marketplace is such that consumers are not getting appropriate and timely information about the true price they are paying for energy, and therefore lack the ability and incentive to adjust their behaviour. We discuss the responsiveness of demand to price in more depth later in this report and, indeed, we flag this as a major issue that must be addressed if the Ontario electricity market is to reap the full benefits of competition.

On the supply side, electricity can be delivered through generation from existing capacity within Ontario, imports into Ontario from other jurisdictions, or the addition of new capacity in Ontario. In the short-term, the responsiveness of supply to higher prices will depend upon the extent of unused but available capacity within the province, and the potential for imports into Ontario, which will be limited by available capacity in other jurisdictions and capacity limits in transmission systems. Over the longer-term, new supplies depend upon the economic incentive to invest in Ontario and the time it takes to license and construct capacity additions.

We return to an examination of supply/demand adequacy, and its implications for the effective functioning of the competitive marketplace in Chapters 2 and 3 of this report.

The following sections provide background information on the current supply/demand balance in Ontario's electricity market.

3.1.1 The demand for electricity

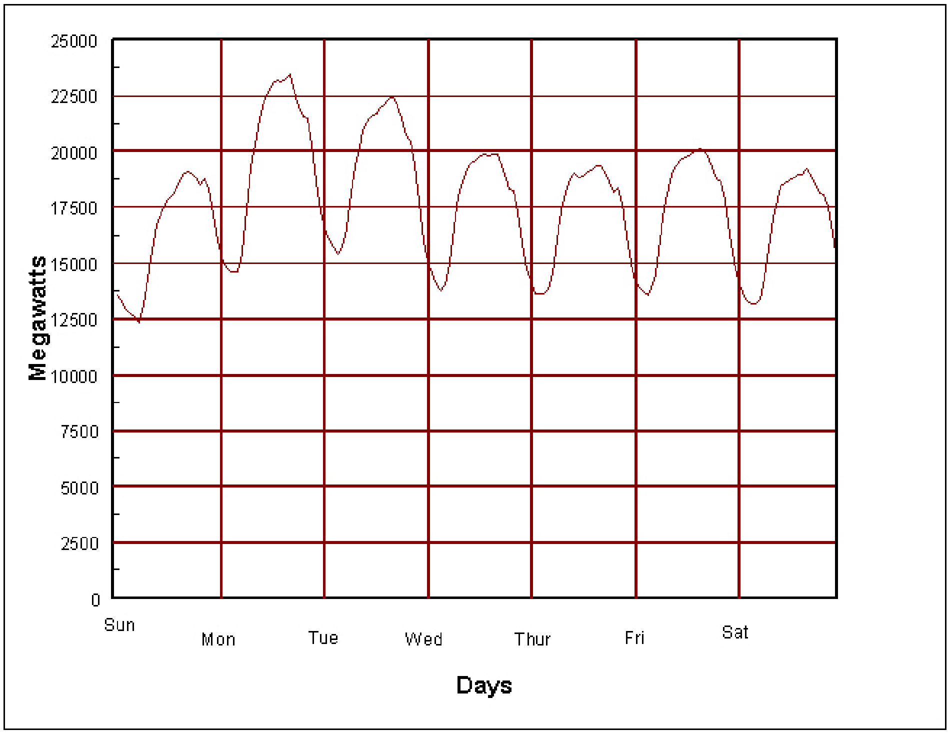
The demand for electricity (or 'load', as it is more commonly referred) is typically measured as the number of megawatts (MW) collectively required by electricity end-users at any point in time plus the number of MW used to transport electricity to end users. As discussed above, an important characteristic of electricity markets is that reliability dictates that demand must be satisfied by generation at all points in time since it is difficult to store electricity. Demand varies greatly depending upon both the time of day and season of the year.

Daily load patterns reflect the pattern of residential consumption and economic activity over a 24-hour period and peaks in demand typically occur in the late morning (in summer) and early evening (in winter) hours. Figure 1.1 shows a family of 24-hour load curves for a week in July 2002.[15]

The peaks and troughs within each day are clearly discernible from the family of curves. One can also see the difference between the 'week-day' curves and the 'week-end' curves, with the demand for energy being lower on a typical Saturday or Sunday than on a working day. The figure also shows the relatively rapid increase and decrease in demand that is part of the daily cycle.

[15] The relatively higher peak demands shown for Monday and Tuesday are a reflection of hot weather experienced during this week and they are not necessarily typical of load curves in other weeks.

Figure 1.1: Daily Load Curves
Week of July 7, 2002 – July 13, 2002



The significance of annual peak loads is that they are a proxy for the required installed capacity to serve the maximum demand and allow for reserve capacity, maintenance schedules and unforeseen outages.

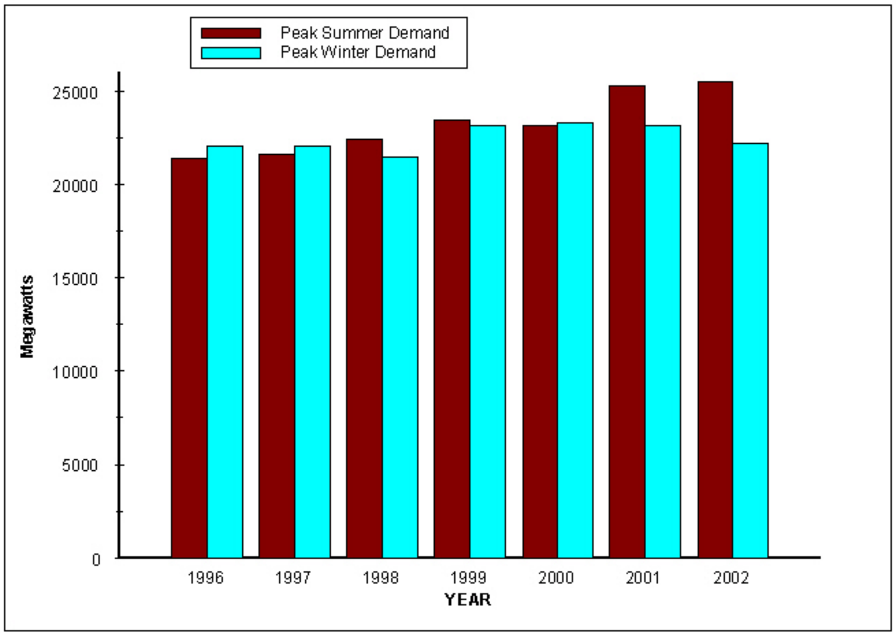
Historically, Ontario experienced annual peaks in winter.[16] Over the last few years, with the penetration of air-conditioning load, the annual peaks have shifted to summer in June, July or August. Usually, there is not a very large difference between summer and winter peak loads, giving rise to dual annual or seasonal peaks.

This dual-seasonal peak distinguishes Ontario from many geographically adjacent markets where peaks are distinctly summer[17] or winter (Quebec) but not both. Figure 1.2

[16] The annual seasonal peak load is defined as the highest demand for electricity in one hour occurring in each of the winter and summer seasons. In keeping with industry practice, the winter season covers December, January and February, so for example the 1998 winter peak occurred in December 1997.
[17] These include ISO New England, Inc. (ISONE), the New York Independent System Operator (NYISO), and PJM Interconnection, L.L.C. (PJM), responsible for the operation and control of the bulk electric power system throughout major portions of five Mid-Atlantic states and the District of Columbia.

illustrates how the summer peak has overtaken the winter peak (in 1998) and in the past two years has grown quite strongly.[18] In general there has been a significant growth in peak demand over the period (from 22,403 MW in 1998 to 25,414 MW in 2002).

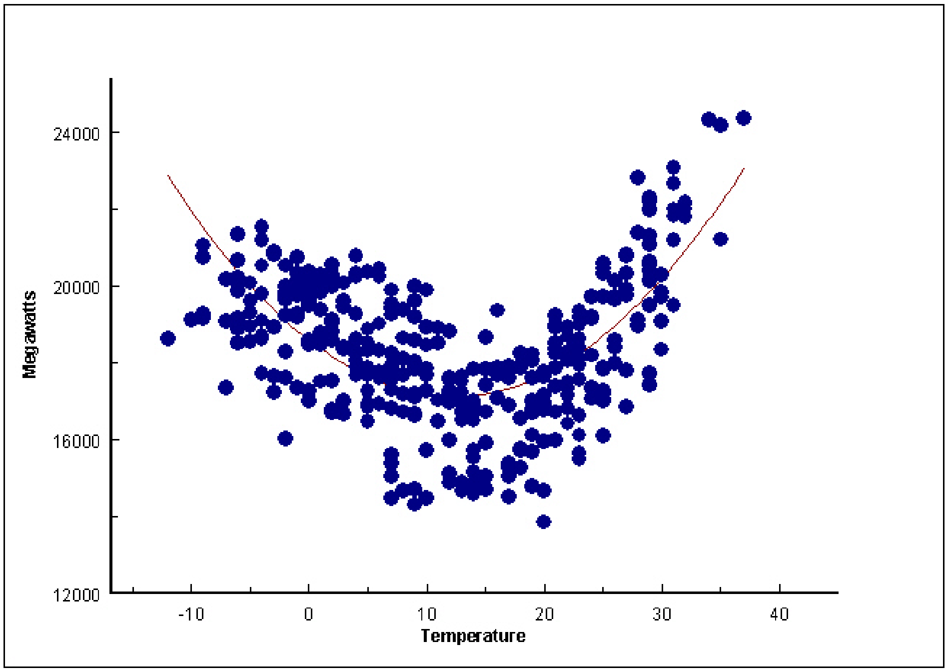
Figure 1.2: Ontario Seasonal Peaks for 1996-2002



The precise timing and extent of seasonal demand peaks are very sensitive to weather. Figure 1.3 shows the relationship between daily peaks in energy demand and temperature for 2001.

[18] Some observers note that the Ontario generation system was built around the winter peak where abundant water in the winter provided a relatively cheap source of electricity. This may not be the best generation mix for summer peaking when water is less abundant. See section 3.1.2.1 for a discussion of Ontario plant.

Figure 1.3: Daily Peaks and Temperature, 2001



Understanding the potential responsiveness of demand to price requires further information about who uses energy in Ontario and how they are charged for the energy they use. A common distinction is between dispatchable and non-dispatchable loads. Dispatchable loads are generally large industrial customers that are capable of adjusting their electricity consumption in response to a five-minute dispatch instruction from the IMO.[19] These customers participate directly in the wholesale market by making hourly bids to buy electricity. There were only two dispatchable loads in the Ontario market in the May-August period and their purchases were less than 1 percent of total consumption.

Non-dispatchable loads make up the rest of the electricity end-users in Ontario. These loads do not directly bid to buy energy in the IMO market. Instead, they simply draw electricity from the IMO-controlled grid as they need it and pay the wholesale price of electricity at the time of consumption, regardless of the price unless they have chosen an

[19] See section 3.3.1 for a brief overview of the operation of Ontario's energy market, or consult the IMO web site at www.theIMO.com

alternative price option. The wholesale price of electricity[20] for non-dispatchable loads is set on an hourly basis. Loads, whether non-dispatchable or dispatchable, may enter into bilateral contracts to protect themselves against price fluctuations.[21]

The classification of load into dispatchable and non-dispatchable is not, however, the whole picture. About 90 market participants, large industrial concerns, are directly connected to the IMO-controlled grid and account for about 15 percent of total consumption or roughly 3,000 MW in a typical peak hour. These customers have interval meters, which can measure and report hourly consumption. They would be in a position to respond to changes in prices by altering their consumption, depending on the nature of their business and their evaluation of the impact of the price of electricity. We do not have information on the extent to which this occurred over the period.

The remaining end-users are described as 'embedded'. In other words, they are connected to a distributor[22] and not directly connected to the IMO-controlled grid. They represent most of the consumption of electricity within the province, with distributors accounting for about 80 percent of purchases over the May-August period.

Most embedded customers are smaller consumers who do not have interval meters, and therefore lack the technology, information and incentive to adjust their use in response to short-term variations in electricity prices.[23]

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[20] This is known as the Hourly Ontario Energy Price or HOEP.

[21] Bilateral contracts can be 'physical' or financial. By 'physical' we mean those physical bilateral contracts reported to the IMO for inclusion in the settlement process. Where there is a contract for a fixed MW amount, not tied to actual consumption, a load still has an incentive to respond to price signals, for example by reducing consumption and effectively selling energy back into the market when prices are high.

[22] Distributors are sometimes referred to as 'wires' companies. These are the entities that are responsible for connecting the bulk transmission grid to the end-use customer. An example would be Toronto Hydro-Electric System Limited.

[23] These end users buy from their distributor under the Standard Supply Service arrangements defined by the Ontario Energy Board (OEB). Smaller customers (i.e. those without interval meters) are charged a fixed rate, 4.3 cents per kilowatt-hour as currently set by the OEB, with an annual true-up to the actual HOEP in the market. Alternatively, most distributors have applied to the OEB and received approval to charge these smaller customers the HOEP directly, based on an assumed monthly profile. Embedded

However, larger embedded customers do have interval meters and are billed for their consumption at the wholesale rate[24] with various wholesale and retail additions to the charges. Such metering and pricing arrangements provide opportunities for such customers to adjust energy use in response to price, even in the short-term. The precise number of embedded customers who have installed interval meters is not known at this time, but IMO staff estimates suggest that there may be several thousand MW of embedded load (perhaps on the order of 20 percent of total load) measured with interval meters.[25] This could be as large or larger than the 3,000 MW of directly connected loads.

Clearly the embedded interval-metered load adds to the potential for developing demand elasticity in the Ontario market.[26] However such customers may face impediments in the current design and market procedures that limit their ability to so.

- First, becoming a dispatchable load may not be feasible for them. As a dispatchable load they need to respond to five-minute dispatch instructions. Typically, large industrial customers require considerable lead-time in order to reduce their consumption effectively in response to price increases. Moreover, they must be ready to reduce demand for an extended period of time, one hour or more.
- Second, there is a high degree of uncertainty regarding the benefit of decreasing consumption. Most load would need to rely on a forecast of prices from the IMO. As discussed in Chapter 2, the current price forecasts may not be sufficiently accurate for consumers to make such decisions with confidence. Demand-side management (DSM) programs, which are offered

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customers, whether large or small, may alternatively choose to be supplied under contract with a retailer or may even be a participant in the IMO market.

[24] This is the HOEP as determined by the IMO, but is referred to in the Retail Settlement Code as the Spot Market Price.

[25] IMO estimates are in the order of more than 10,000 embedded customers across the province. All previously existing embedded consumers over 1 MW had been required to have interval meters, as must any new customers over 500 KW. Individual distributors can elect lower thresholds for installing these meters. For example Milton Hydro's standard has been 100 KW and is moving towards interval meters for all customers over 50 KW. Milton may be atypical with their low threshold and proportion of load above 100 KW, but they indicate that more than 50 percent of their load currently has interval meters.

[26] Exporters also buy energy out of the IMO market and add further to the price responsiveness of total demand in the market. See the discussion of the bid curve and exports in section 3.3.1.1.

in several U.S. jurisdictions at the retail level, provide payments for reducing consumption, not just price avoidance, and thus provide some certainty to loads participating in these programs, but such programs are not available in Ontario.

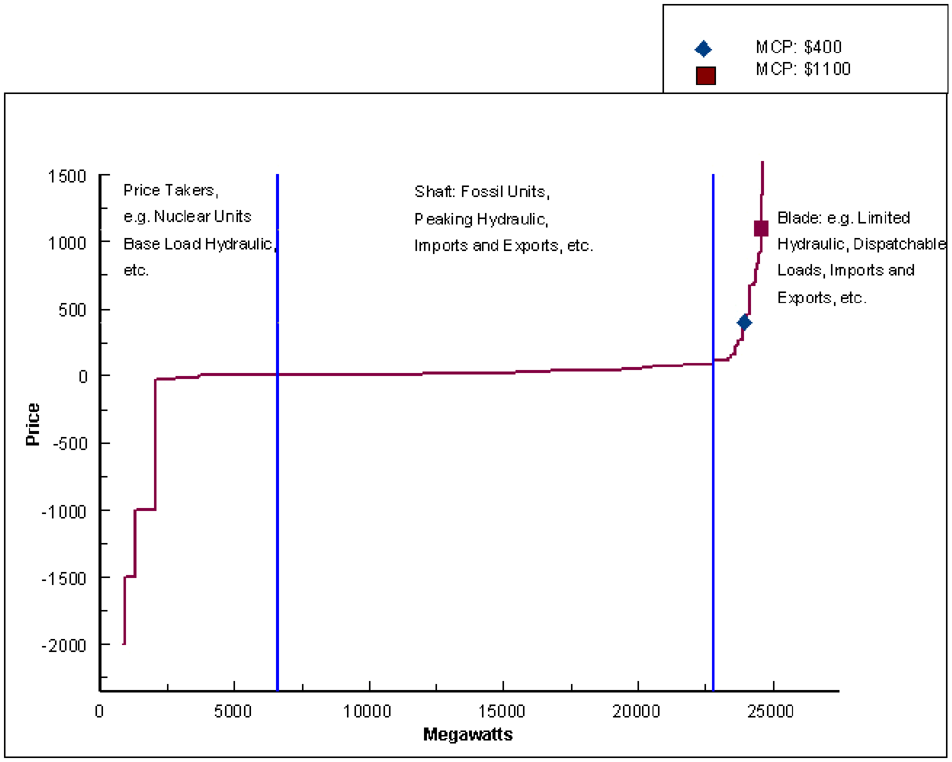
- Third, the access to the relevant information, the potential to automatically identify opportunities and the equipment necessary to respond to control load, may require additional capital investment, making the decision even more difficult to evaluate in light of the first two considerations above.

3.1.2 The supply of electricity

At any point in time, the amount of electricity available to satisfy market demand is referred to as the 'offer curve', or 'offer stack'. In the regulated market, prior to competition, the offer stack would be typically determined by looking at the operating cost of alternative generating units and ordering the dispatch of electricity from the lowest-cost unit to the highest-cost unit until the market demand is met. If available resources were not adequate, energy would be imported into the province and Ontario Hydro would pay whatever price was necessary to secure such energy. The price of imports was factored in with all the other costs and did not directly affect the price in the marketplace, which was set by Ontario Hydro's board after review by the OEB.

In the competitive marketplace, the offer curve is derived in an analogous way except that each generator offers energy into the marketplace at a price at which it is prepared to sell. The offers are stacked from lowest price to highest price. It is the intersection of the offer curve and the bid curve that establishes the market-clearing price (MCP).
Figure 1.4 shows a typical offer curve for the month of July. There are several points to note.

Figure 1.4: Typical Offer Curve for July 2002



First, the offer curve is generally partitioned into three components. The first part of the curve includes offers at negative prices. These are generally offers from importers, who may have a contractual position in the market and want to ensure that their import is scheduled regardless of the price, or from nuclear units that offer a large share of their capacity at negative prices in one period to ensure the unit is not shut down and hence unavailable for supply in other, more profitable periods.

Self-scheduling and intermittent generators also make negative or zero price offers. These generators, representing about 1,200 MW of offers, consist mainly of the former non-utility generators (sometimes referred to as 'NUGs'). Because of the special status accorded them in the past, they are paid for their production according to contracts administered by the Ontario Electricity Financial Corporation. So, while they submit hourly offers to the IMO, their revenue stream is not affected by the interval-by-interval change in the wholesale electricity price. They agree that they will use best efforts to supply the specified quantity so long as the market price is above zero.[27]

The next two parts of the offer curve are often referred to as the 'hockey stick' (at least in Canada!). The first part of the hockey stick is the 'shaft' this is the horizontal portion presented in Figure 1.4. This portion of the curve typically consists of offers from nuclear plants, base load hydroelectric, peaking hydroelectric, imports and coal-fired fossil units. The second part of the hockey stick is the 'blade'. This is the portion of the curve that increases sharply and becomes nearly vertical. This part of the offer curve typically begins with the gas-fired fossil plants and then quickly moves upwards with the offers from the energy limited hydroelectric units, combustion turbine units and expensive imports.

It is clear from the 'hockey-stick' shape of the typical offer curve and from the short-term inelasticity of demand that peaks in demand are more likely to coincide with the 'blade' rather than the 'shaft' portion of the offer curve and in such situations very small variations in demand will result in large price movements. It is this situation that gives rise to price volatility and occasional 'price spikes' that characterize all electricity markets where the price is not regulated. In general, volatility and the frequency of price spikes will both be less the greater is the available supply relative to demand.

Figure 1.5 shows how the Available Reserve[28] in Ontario has evolved since 1996. Installed capacity fell substantially in 1998 as nuclear units went out of service and have not yet returned. As well, the chart shows that virtually no new capacity has been added since that time, with the result that the Available Reserve has been progressively shrinking as peak demand has continued to grow.

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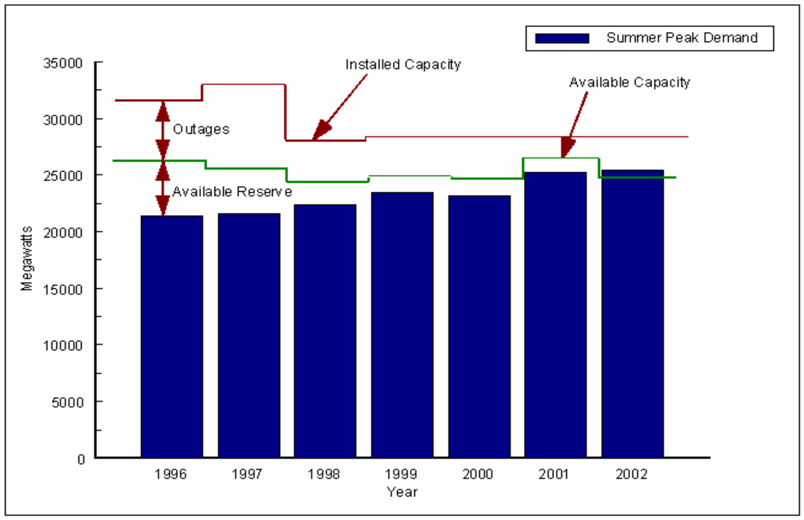
[27] See section 2.5.2 in Chapter 2 for a discussion of the impact of self-scheduling and intermittent generators on the difference between pre-dispatch price forecasts and real-time prices.
[28] Available Reserve is the difference between the available capacity and peak demand. Peak demand is defined as the peak demand in the province plus firm exports. Available capacity is the installed capacity within the province adjusted for outages and some small miscellaneous categories.

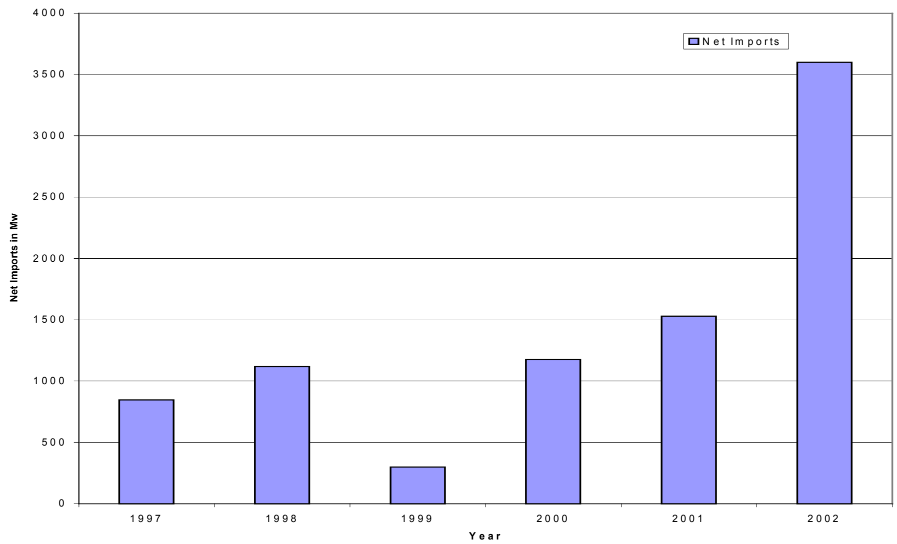
Figure 1.5 also shows the progressive shrinking of the Available Reserve over time until, in 2002, the peak demand exceeds the reserve.

Figure 1.5: Available Reserve for 1996 - 2002



Finally, to complete this brief overview of Ontario supply characteristics, Figure 1.6 shows that the need for imports to satisfy peak requirements has been a consistent and growing feature of the evolution of the Ontario electricity market since 1997. The increased level of imports in 2002 compared to 2001 can be attributed to a number of factors, including: increased demand, a nuclear unit outage, deratings on fossil-fired generators due to environmental limits, and less hydroelectric energy available.

Figure 1.6 Net Imports for Summer Peak Hours, 1997-2002



At any point in time, available supply to Ontario consumers is affected by four factors:

- the existing plant in Ontario that is capable of producing and willing to offer electricity to the market;
- imports, which are limited by available generation in neighbouring jurisdictions and the capacity of the transmission system at the interties;
- exports, and;
- the characteristics of the transmission system within Ontario, which may contain bottlenecks that prevent the most efficient allocation of electricity from generators to loads, effectively requiring potentially available supply to actually exceed demand in order to satisfy all loads.

Each of these is discussed briefly below.

3.1.2.1 Existing Ontario plant

As depicted in Figure 1.5 the total in service installed capacity in Ontario is roughly 27,560 MW.[29] Close to 10,000 MW of new generation has been announced for the

[29] The IMO's most recent "10-Year Outlook" records installed capacity as 29,622 MW. The higher number is the result of including OPG's Pickering A nuclear units as part of the existing installed capacity. See the Forecasts link under www.theIMO.com

province in the next 4 years, up to and including 2006.[30] Table 1.1 lists the new generation and returned nuclear plant under application to the IMO.[31]

Table 1.1: Proposed New Generation and Returned Nuclear Capacity

Proponent	Location	Proposed Size	In-service Date
2003			
TransAlta Energy Corp.	Sarnia	510 MW	Q1
Ontario Power Generation Inc.	Pickering	515 MW	Q1
Bruce Power Inc.	Kincardine	1470 MW	Q3
AGSTAR Power Inc.	Tilbury	88 MW	Q4
Ontario Power Generation Inc.	Pickering	515 MW	Q4
Total		**3098 MW**	
2004			
AGSTAR Power Inc.	Tilbury	538 MW	Q1
Enron Canada Corp.	Sarnia	505 MW	Q2
Imperial Oil Ltd.	Sarnia	98 MW	Q2
ATCO Power Ltd.	Windsor	578 MW	Q2
Ontario Power Generation Inc.	Pickering	515 MW	Q2
Northland Power Inc.	Thorold	273 MW	Q3
Toronto Hydro ES Inc.	Portlands	180 MW	Q3
Toronto Hydro ES Inc.	Portlands Alternative Connection to John TS	180 MW	Q3
Northland Power Inc.	Kirkland Lake	48 MW	Q4
Ontario Power Generation Inc.	Pickering	515 MW	Q4
Total		**3430 MW**	
2005			
Ontario Power Generation Inc.	Portlands Energy Centre formally "Hearn"	550 MW	Q1
Sithe Canadian Holdings Inc.	Goreway Brampton	932 MW	Q2
AES Kingston Inc.	Leamington	530 MW	Q2
Calpine Canada Power Holdings	Sarnia	870 MW	Q3
Total		**2882 MW**	
2006			
Sithe Canadian Holdings Inc.	Southdown Mississauga	**763 MW**	Q2

[30] 10,000 MW represents the total additional capacity of the projects listed in the IMO's "18 Month Outlook", plus the return to service of the Pickering A nuclear units.
[31] Pursuant to Chapter 4, section 6 anyone planning a new or modified connection to the IMO-controlled grid must apply to the IMO for approval. The information in Table 1.1 is drawn from the latest "Status of Current Applications" published by the IMO (September 20, 2002) and news reports regarding the return of the Pickering units.

It is difficult to report with any certainty how much of this announced capacity will actually come into service, particularly as the plans extend farther into the future.

Nearly two-thirds of the new capacity is projected to come on stream in 2003 and 2004. Only two of the greenfield projects in Table 1.1 are in the construction phase: the TransAlta Energy Corporation facility in Sarnia and the ATCO Power Ltd. project in Windsor. Prior to the TransAlta installation, the last major addition to generation capacity in the province was the addition of the fourth Darlington nuclear unit in 1993. According to published reports work is actively underway on the return to service of the nuclear units announced by Ontario Power Generation (OPG) and Bruce Power. This represents roughly 3,500 MW of additional generation for the province planned for by the end of 2004. With such a large potential addition to capacity, it would not be unreasonable to suggest that other potential investors have made their plans contingent on a judgement as to whether, and when, these nuclear units will return.

Table 1.2 shows the diverse mix of resources used to generate electricity in Ontario. The largest share increase is Oil/Gas because all the new investment is gas-fired generation.

Table 1.2: Ontario-based Generation Resource Mix, Actual (2002) and Projected (2006)[32]

	2002		2006	
Resource Type	**MW**	**Share (%)**	**MW**	**Share (%)**
Nuclear	8,748	32	12,278	33
Coal	7,553	27	7,553	20
Oil/Gas	3,662	13	9,755	26
Hydroelectric	7,522	27	7,522	20
Miscellaneous	77	0.28	77	0.21
Total	**27,562**		**37,165**	

[32] Source: IMO, "Status of Current Applications" (September 20, 2002); "10-Year Outlook: An Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario from January 2003 to December 2012".

Hydroelectric resources are a much more important source of energy in Ontario than in all neighbouring jurisdictions (PJM, New England, New York) except Quebec and Manitoba. For example, in Quebec hydroelectric generation is by far the most dominant source of electricity, accounting for 94 percent of Hydro-Quebec's installed capacity, with the remaining 6 percent being thermal and nuclear resources.

The generation resource mix has important implications for electricity markets because of the different operating characteristics of different plants, and how these may be reflected in offer strategies.[33] Nuclear generation is base load generation[34] because of the importance of keeping the facility running – start up and changes in output are slow and expensive. Fossil generation has ramp rate[35] limitations and provincially imposed emissions limits. Ramp rates are not an issue for hydroelectric generation, which can provide electricity almost immediately so long as water is available. For this reason, some hydroelectric generation is peaking capacity, capable of responding quickly to rapid changes in demand. Hydroelectricity is also an energy-limited resource, linked to the availability of water, which varies according to the season: plentiful in winter and typically more limited in summer, especially during periods of drought. Certain hydroelectric resources in the province and high-efficiency steam electric plants are also regarded as base load plants.

Insofar as the ownership of Ontario generating capacity is concerned, Ontario Power Generation (OPG), owned by the Government of Ontario, accounts for 90 percent of in-service installed generation capacity in the province.[36] Great Lakes Hydro Income Fund represents 3 percent. The remaining capacity in the province, approximately 6 percent, is accounted for by the transitional self-scheduling and intermittent generators.

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[33] Figure 1.4 showed how the different generation resources are reflected in a typical offer curve.
[34] Base load is generating capacity that tends to operate continuously and steadily.
[35] The ramp rate is the rate at which a generator can increase or decrease its output. This is usually expressed in megawatts per minute, so, for example, a 500 MW coal-fired unit may require 20 minutes to increase output from 100 to 200 MW. The ramp rate varies depending on whether the unit is already generating or is cold, and also the level of output at which it is running. A fossil unit typically needs two to 12 hours to start up before it can come into service, depending on the length of time for which it had been shut down.
[36] Bruce Power operates 11 percent of this capacity through a long-term lease.

3.1.2.2 Trade flows and net imports

The interties are capable of supporting imports or exports to several interconnected jurisdictions. Table 1.3 shows the current capabilities:

Table 1.3: Intertie Flow Limits

Interconnection	Limit – Flow Out of Ontario (MW)		Limit – Flow Into Ontario (MW)	
	Summer	Winter	Summer	Winter
Manitoba	287	287	336	336
Minnesota	140	140	90	90
Quebec North	95	115	65	84
Quebec South (East and Ottawa)	740	760	1452	1452
New York St. Lawrence	400	400	400	400
New York Niagara (60 Hz & 25 Hz)	1990	2285	1444	1656
Michigan	2350	2400	1500	1600

According to this table, the simple arithmetic sum of the import capability of the various interties is about 5,300 MW in the summer and 5,600 MW in the winter. However, the actual coincident capability to import is only about 4,000 MW or less depending on the generation and load pattern within and around Ontario and on transmission limitations.[37] This represents a potential of nearly 15% of the domestic installed capacity of 27,560 MW, but achieving this potential depends on availability of supply and market conditions in neighbouring jurisdictions.

Similarly, the sum of the individual export capabilities is about 6,000 MW in the summer and 6400 MW in winter but the coincident export capability is only about 6,100 MW.

Hydro One has a variety of plans for expanding the intertie capability. Its Transitional Transmission Licence, which was granted by the Ontario Energy Board, requires best efforts to expand intertie capacity to neighbouring jurisdictions by approximately 2,000 MW within 36 months of market opening. The 2,000 MW figure was based mainly on

[37] For example, the QFW (Queenston Flow West) limit, can reduce the use of internal or external resources in the Niagara area, limiting imports from New York.

estimates in 1998 of the potential increases possible from building a high voltage direct current tie with Hydro Quebec and adding phase shifters to the Michigan interties.

The phase shifters with Michigan are able to control an additional 600 MW of flow between Ontario and Michigan. These are expected to be fully operational in January 2003. Due to the phase shifter project, the overall Michigan intertie capability increases by some 500 MW, some of which has already been achieved. When fully installed there will be a further increase in import capability by about another 150 MW and exports by more than 300 MW in winter.

In the summer of 2001, there were improvements of some 200 MW on the Quebec intertie at Masson.

The largest project that has been contemplated is the Hydro Quebec DC tie, which would create an additional 1,250 MW intertie capability.[38] The facility's probable in-service date is the third quarter of 2005.[39]

Hydro One has another project that may contribute to meeting its licence conditions of a 2,000 MW expansion within 36 months. The Lake Erie 990 MW high voltage direct current link has been proposed as a joint venture between Hydro One and TransEnergie US. The "10 Year Outlook" stated the in-service date for this project was the second quarter of 2004. There is continuing evaluation of its prospects and continuation of the project would next depend on contract offers being made for this tie. Since it is proposed as a merchant project, where the cost of the line is not rolled into the Hydro One tariffs

[38] Due to the nature and design of the Hydro Quebec system it is not possible for it to operate in synchronism with the rest of North American power systems. Instead when power is exchanged with Quebec it must be done in one of two ways. One way is to disconnect one or more generators from one system and physically reconnect them to the other system, a slow and cumbersome process. Another way is to build 'Direct Current' ties between the adjacent systems thus allowing the continuous transfer of power in either direction simply and efficiently. The latter is the means by which Hydro-Quebec trades electricity with New York and New England, while the former is the method now used to trade with Ontario.
[39] IMO, "Status of Current Applications" (September 20, 2002)

for all customers, it will not proceed unless investors are reasonably assured of a satisfactory return.

3.1.2.3 Transmission congestion

Transmission congestion refers to the situation where flows on some part of the transmission system[40] have reached an allowed limit. As a result, additional flow that would otherwise be economically efficient is restricted.

Because of congestion, aspects of the transmission system within Ontario may from time to time result in the need to 'rebalance' generation within the province in order to ensure that electricity can get to where it is needed. This would effectively be done by constraining off the grid some generators who have indicated that they are willing to produce, when their output cannot flow to where it is needed, and constraining other generators on to the grid even though their offers indicated that they were not willing to produce at the market price. The net impact of congestion within the transmission system is to reduce the efficiency of the system and raise the average cost of power. Prior to the restructuring of the electricity market, this was managed by Ontario Hydro dispatching more costly units to cope with congestion, thus raising the overall cost of meeting demand. In the competitive marketplace a similar result is obtained through the IMO 'constraining off' some units and 'constraining on' others. These actions result in payments to these units, known as Congestion Settlement Management Credit (CMSC) payments, which are recovered from all energy users through the uplift.[41] The way in which this system works, its relationship to the exercise of local market power, and the calculation and amount of the uplift are described in more detail in the section of this chapter dealing with the operation of the marketplace, and in Chapter 2. The main point to recognize here is that the capacity and configuration of the transmission system plays an important role in determining how much generating capacity is required to meet any

[40] By the transmission system we refer to the linkages between generators (including importers) and immediate customers, which may be distribution companies, or large industrial loads who are connected directly to the grid. The retail distribution network is not included.
[41] Uplift is added to the commodity price for energy, and is discussed in section 3.3.1.5

given demand, and as a consequence creates the conditions under which some participants may exercise market power.

3.2 Market power mitigation framework

The design of the Ontario marketplace recognizes that market power exists and has attempted to deal with it in a number of ways.

- OPG is subject to a Market Power Mitigation Agreement (MPMA) that sets out a rebate mechanism, requires OPG to offer all available capacity into the market as operating reserve, and requires OPG to divest a minimum amount of generation capacity within fixed time periods.
- The IMO is empowered to mitigate revenues that it judges to be due to the exercise of local market power.
- Price caps are in place for the operating reserve and energy markets.

These measures are elaborated below.

3.2.1 Market Power Mitigation Agreement (MPMA)

The MPMA's main objectives are to limit OPG's incentives and ability to exercise market power and redress the distributive implications of higher prices. The two key components of the MPMA are the rebate mechanism and the divestiture requirement.

3.2.1.1 Price cap and rebate mechanism

The price cap is set at $38 MWh and is effective for the first four years of market operation.[42] At the end of each year of the market, an average annual weighted price will be compared to the $38 cap to determine whether and, if so, the amount OPG will be required to rebate to consumers. The average annual weighted price is calculated using hourly quantities as weights against each HOEP in the year.

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[42] The price cap and rebate may terminate earlier if the OEB determines that 10-year decontrol target is met.

The hourly quantities were set in 1998 and were intended to represent approximately 90 percent of OPG expected production for Ontario load in each hour of the year, as forecast at that time. Based on these forecasts the price cap applies to just over 100 terrawatt hours (TWh)[43] annually. With current Ontario energy consumption somewhat less than 150 TWh annually, the price cap applies to about 70 percent of the wholesale energy purchased in Ontario.

The amount of production subject to the rebate may be reduced as OPG divests control of generating capacity to others. For every MW divested, the coverage of the rebate declines by 1.1 MW, providing an incentive to OPG to move forward with the divestiture program. All reductions in rebate coverage must be approved by the OEB and OPG has recently applied to the OEB for such a reduction pursuant to the long-term lease it entered into with regard to the operation of the Bruce plant.

3.2.1.2 Divestiture of control obligations

Within 42 months of market opening (i.e., by December 31, 2005), OPG must transfer to others effective control over in-service tier 2 capacity such that OPG's effective control of total Ontario in-service tier 2 capacity will be 35 percent or less. Tier 2 capacity includes price-setting generating capacity such as fossil fuel generation, potential imports and dispatchable load. Effective control over a minimum of 4,000 MW of in-service capacity must be transferred. At OPG's discretion, up to 1,000 MW of hydroelectric generation could be substituted for tier 2 capacity.

OPG must commit to developing a strategy for reducing effective control of enough of its total capacity (tier 1 and tier 2) so that by no later than the end of the tenth year after the market opens, OPG's effective control of the total of tier 1 and tier 2 capacity will be 35% or less.

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[43] A TWh is one million MWh.

There are some restrictions on what will count as transfer of control. Transfers will not count in reducing OPG's divestiture targets if such transfers give the recipient more than 25 percent of either tier 2 capacity or total tier 1 and tier 2 capacity. Nor would a transfer count if there is an arrangement that facilitates interdependent behaviour between OPG and the recipient.

To date, OPG has leased or sold two of its facilities, the Bruce Nuclear facilities (3,160 MW at Bruce B, or a total of 6,236 MW at Bruce A and B combined) and the hydroelectric units of the Mississagi river system (488 MW).[44]

3.2.2 Local market power

As indicated in section 3.1.2.3, transmission constraints can sometimes require the demand for electricity to be satisfied in ways that are not the most efficient. Generators that may have offered at prices above the MCP may be 'constrained on' because their output is essential to supply a particular region within Ontario, and other generators may be 'constrained off', notwithstanding the fact that their offers are at prices below the MCP, because they cannot get to where the demand is needed.

When a generator is constrained on or constrained off, it receives a Congestion Management Settlement Credit (CMSC). These payments are determined by the difference between the MCP and offer price and are meant to pay generators at the price they offered (above the MCP) when they are required to run and to compensate generators for lost opportunity when they are constrained off. Similarly, CMSC payments also can be made to dispatchable loads that are dispatched on or off.[45] CMSC payments provide incentives to suppliers to comply with IMO dispatch instructions. The

[44] Assuming the OEB approves these two transactions as transfer of effective control, to reach the 35 percent of tier 1 and tier 2 capacity, OPG would have to decontrol roughly another 10,000 MW of generation. This calculation depends on assumptions regarding return to service of Pickering A, Bruce A, the addition of other resources and the treatment of intertie capacity. For tier 2, roughly 3,500 MW would appear to be the required amount of decontrol needed by December 2005.

[45] CMSC may also be paid to imports and exports if these are constrained on or off due to constraints inside Ontario.

payments are recovered by the IMO from all energy users in the province through the uplift.

CMSC payments are a direct consequence of the fact that Ontario has a uniform wholesale energy price throughout the province. In other jurisdictions, where market prices are set by supply and demand at nodal points, congestion is handled through the variation in intra-regional prices and a congestion management payment regime is not required. In Ontario, the issue of whether to institute a locational marginal pricing regime is one that the IMO must review after one year following the market opening.

Congestion leads to the possibility that generators may be able to exercise local market power through constrained on and constrained off payments. For example, if a generator knows that transmission conditions are such that it is highly likely to be constrained on or constrained off, it can manipulate its offer price so as to maximize its congestion management payment – offering at exceptionally high prices when it believes it will be constrained on and at exceptionally low (even negative) prices when it believes it will be constrained off.

The Market Rules recognize this and charge the IMO, through the Market Assessment Unit (MAU), with monitoring CMSC payments and mitigating these payments under certain circumstances.

3.2.3 Operating reserve and energy price caps

Because the IMO has determined that the market for operating reserves is not yet competitive – due to the dominant position of OPG – it has entered into arrangements with OPG whereby OPG offers operating reserves according to price schedules that contain both inquiry thresholds and caps. The agreement and OPG's transitional licence also obligates OPG to offer all available capacity as operating reserve.

The IMO has established caps for the prices of energy (the Maximum Market Clearing Price, or MMCP), and operating reserves (the Maximum Operating Reserve Price, or MORP). Setting a maximum price is a mitigation measure designed to address the lack of price-responsive load while allowing prices to reflect some amount of scarcity when shortages of operating reserves or energy exist.

MMCP, set at $2,000 per MWh, is the maximum price that a market participant may be charged or be paid for energy in the Ontario spot market. It also establishes the maximum and minimum bid or offer prices that market participants may submit to the IMO for energy. Specifically, such prices may be no less than negative MMCP and no greater than positive MMCP. In a similar fashion MORP, also set at $2,000 per MWh, limits the operating reserve offer prices to be between zero and MORP.

3.3 The operation of the marketplace

Competition is most effective where the rules and operating procedure of the marketplace are well understood and transparent to all market participants. This section outlines, at a high level of generality, how the IMO actually administers the markets for which it is responsible.[46] It discusses, in turn, the real-time energy market (including operating reserves); the market for ancillary services; and the market for financial transmission rights. It also introduces and defines some concepts that are important to understanding the analysis in Chapter 2 of this report, including the constrained and unconstrained dispatch schedules, joint optimization of energy and operating reserves, pre-dispatch information, and the uplift.

In the description of the real-time market below reference is made to the market prices for energy. In the settlement processes suppliers and consumers would normally be paid or pay these 'spot market' prices. However, market participants may enter into contracts between themselves and may submit information about these to the IMO, as physical

[46] The Market Rules and supporting interpretive material and manuals are all available on the IMO web site at www.theimo.com

bilateral contract data. This leads to the IMO removing these quantities from the market settlement, so that the buyers and sellers can settle the contract between themselves. The submission of this data does not affect the manner in which the IMO makes dispatch decisions, only the settlements performed.

3.3.1 The real-time energy market

Every five minutes, the IMO sets the MCP for electricity in Ontario through an auction process whereby generators and dispatchable loads offer supply into the market at various prices. The following description is a stylized representation of how the auction system works:

1) Each day, at approximately noon, the IMO determines the first pre-dispatch schedules for each of the 24 hours of the dispatch day. The dispatch day is the period that begins at midnight, and it is divided into 24 dispatch hours. Dispatch hour 1 would be the hour ending at 1 am EST; dispatch hour 15 would be the hour ending at 3 pm EST; etc.
2) The IMO calculates the pre-dispatch schedules taking into account the following information:
    a. offer and bid data submitted by market participants;
    b. the IMO's forecast of non-dispatchable load;
    c. the requirement for each class of operating reserve;
    d. technical and physical aspects of the generation and transmission systems, such as ramping rates, planned outages, transmission congestion, losses, etc.
3) The IMO calculates and distributes two pre-dispatch schedules: an **unconstrained pre-dispatch schedule** and a **constrained pre-dispatch schedule** for their offers and bids**.** The **unconstrained** schedule is the simple ranking of offers by price and the pre-dispatch price is determined from the unconstrained schedule by the point at which the required estimated load and operating reserve requirement for the hour in question is satisfied. The offer at that point becomes

the marginal (or price-setting) offer and the price of that offer becomes the pre-dispatch price. The **constrained** pre-dispatch schedule takes into account realities in the transmission system, bottled operating reserve[47] or other factors, that may for reliability reasons compel the IMO to constrain some participants off the system and others on. The constrained pre-dispatch schedule is not used to determine price, but does provide participants with indications of likely operating patterns, and also signals likely CMSC payments.

4) These two pre-dispatch schedules for the dispatch day are revised every hour. Thus for dispatch hour 1 there would have been 12 unconstrained and constrained pre-dispatch schedules created, one for each hour beginning at noon the previous day and continuing until 11 pm. For dispatch hour 24 there would have been 36 pre-dispatch schedules prepared and distributed, with the last pre-dispatch schedules determined at 10 pm on the dispatch day.
5) Beginning at noon, and in each of the next 35 hours, all market participants receive their pre-dispatch schedules for all relevant hours of the dispatch day. Generators and dispatchable loads receive the projected constrained and unconstrained schedules for their facilities, and any security constraints or load curtailments affecting the facilities for each of the hours of the dispatch day. In addition, the following information is published for market participants and the general public:[48]
    a. projected uniform market prices for energy and operating reserve in Ontario and in each intertie zone outside Ontario;
    b. projected total system load and losses;
    c. regional operating reserve requirements and regional operating reserve shortfalls;
    d. aggregated outage estimates;

[47] Generating units not producing energy can provide operating reserve. However local transmission limits may prevent running these facilities in response to a contingency elsewhere on the system. That is, there would be a transmission limit reached after a contingency. These are referred to as bottled resources.
[48] This data is available publicly on the IMO web site at http://www.theimo.com/imoweb/marketdata/marketData.asp. and ftp://aftp.theimo.com/pub/reports/PUB/

e. aggregated load curtailment exercises, i.e. anticipated shortfalls that could lead to reducing non-dispatchable load;
f. IMO system advisory reports (warning of upcoming or recently emerging significant events or problems on the system);
g. shadow prices for major nodes in Ontario.

6) Two of the most important pre-dispatch schedules are the five-hour ahead and the one-hour ahead schedules. The five-hour-ahead schedule produces the last information that market participants receive before the bid/offer window closes. From hour 4 to hour 2 participants are allowed to change both their energy and price by +/- 10 percent. From hour 2 to the dispatch hour no further changes are allowed. The one-hour ahead unconstrained pre-dispatch schedule fixes the unconstrained intertie schedules for the dispatch hour. Thus exports (also known as offtakes) and imports (also known as injections) are fixed one-hour ahead of real time, and are selected depending upon their offer or bid relative to the one-hour-ahead pre-dispatch price. In other words the pre-dispatch price that is published can be set by external or internal generators to Ontario.
7) The one-hour ahead unconstrained pre-dispatch schedule, adjusted to reflect the selection of offtakes and injections, then becomes the unconstrained schedule, or offer-stack, for the dispatch hour. This schedule is similar in concept and shape to the offer curve described in Figure 1.4 of section 3.1.2 above.
8) For every five-minute interval within the dispatch hour, the MCP is determined by the offer in the unconstrained schedule that enables load to be satisfied for that five-minute interval with the imports and exports being set by the most recent unconstrained pre-dispatch run. The MCP is the market clearing price for energy throughout the province, and the price at which generators get paid for the energy they produce in any five-minute interval. The simple average of the MCPs over an hour is the Hourly Ontario Energy Price (HOEP) and is the price charged to non-dispatchable load.

In reality, the process of setting the five-minute price, and the operation of the market is more complex than this stylized description implies. Some of the specific complexities, and their implications, are discussed below.

3.3.1.1 The bid curve and exports

One additional complexity is the bid curve and the treatment of exports and dispatchable load. Conceptually, bids received from these participants are used to create a bid curve that is compared with the offer curve. Market clearing quantity and price are determined where the offer curve and the bid curve cross. In this way bids by exporters and dispatchable load help create a direct price and volume relationship in the pre-dispatch or dispatch processes and reflect part of the overall demand elasticity of the market.

Exporters are either Ontario-based suppliers or wholesalers who sell their spare energy to neighbouring control areas, or entities located in other control areas[49] that buy Ontario-based energy. As indicated earlier, exporters place hourly bids to buy Ontario energy in the IMO markets. These bids are accepted or rejected in the IMO's one-hour ahead pre-dispatch market. Bids that are accepted in pre-dispatch are fixed in the real-time market and as such do not respond to changes in MCP.

The degree of price responsiveness of dispatchable load and exporters is directly captured in the IMO's optimization routine through their bids. In contrast, non-dispatchable loads do not place bids into the market; their price responsiveness is not directly captured in the optimization routine. Instead, the non-dispatchable load's electricity consumption is assumed to be a fixed quantity.[50]

[49] Control area means a region on the electricity transmission grid in which supply and demand are kept in balance through generation dispatch decisions by the system operator. Most of the Ontario transmission system operates as a single control area operated by the IMO.

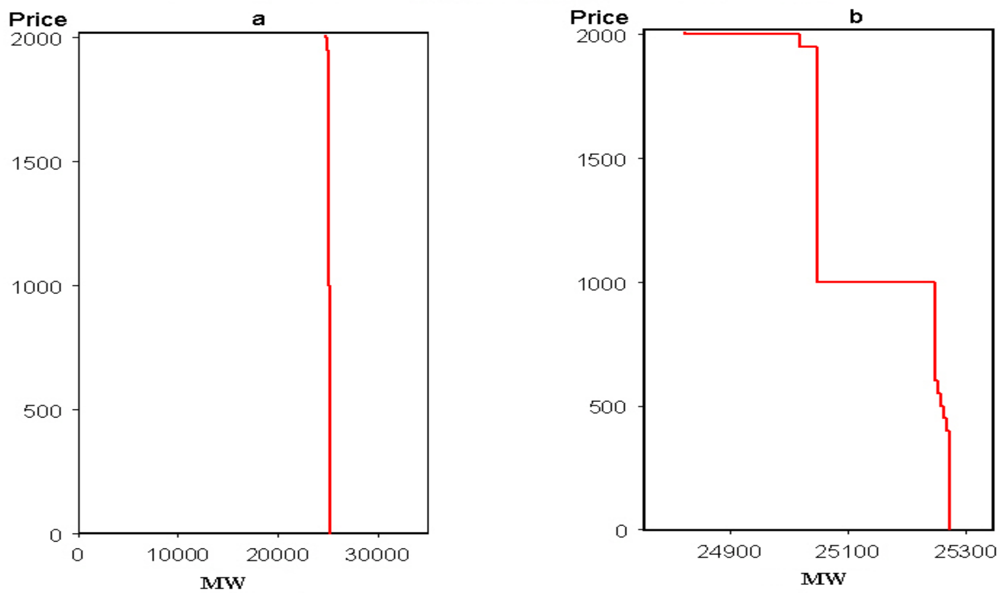
[50] That is, unresponsive to price variations. In the pre-dispatch markets, the consumption of the non-dispatchable load is forecast as a single estimate. In the real-time unconstrained market, the actual consumption of the non-dispatchable load is instantaneously estimated through the use of telemetry readings.

Figure 1.7 provides an illustration of a typical bid curve for an actual hour with near peak load conditions in July. Panel (a) provides a broad level view of the typical bid curve.[51] As illustrated, the bid curve is essentially a vertical line corresponding to the non-dispatchable load estimate. In this example, the non-dispatchable load class accounts for 98.5 percent of the total electricity demanded when price is zero and 100 percent of the total electricity demanded at a price of $2,000 MWh. Approximately 500 MW of price responsive dispatchable loads and exports represents the remainder of the bid curve.

In Panel (b) the scale of the x-axis is expanded in the relevant range to highlight the effect of dispatchable load and exporters on the bid curve. As prices move from about $400 to $600 MWh the quantity demanded is reduced by approximately 25 MW in several small steps. As price reaches $1,000 MWh, a 200 MW export would no longer be scheduled. As prices approach $2,000 quantity demanded would reduce by a further 300 MW.

[51] This is a pre-dispatch bid curve as it includes bids by exporters. In real time export quantities would be fixed at the scheduled pre-dispatch levels.

Figure 1.7: Typical Bid Curve for July 2002



In summary, exporters tend to act as arbitrageurs in the market and as such do not represent true price responsiveness in Ontario. At relatively low Ontario prices, exporters represent an additional draw on Ontario resources and act to raise prices by requiring higher-priced Ontario resources to be scheduled. At relatively higher prices, these exports become less profitable and hence disappear from the market.

3.3.1.2 The pricing of imports into Ontario

Because imports must be fixed one hour before real-time, in order to accommodate arrangements at the interties between Ontario and neighbouring jurisdictions, they are selected for physical scheduling on the basis of the hour ahead unconstrained pre-dispatch result for inclusion in the price setting five-minute unconstrained market schedule. They are then included in the offer-stack, but in a way which precludes them from setting the MCP during the hour. When there is little or no difference between the pre-dispatch price and the MCP, this way of dealing with imports does not create a problem. In the operation of the Ontario market during the first four months, however, it became apparent that the MCP was fairly consistently lower than the pre-dispatch price, and at times considerably lower. The reasons why and broader implications of this performance are discussed more fully in Chapter 2.

Prior to market opening, a rule change was put in place to ensure that importers selected in pre-dispatch would receive their offer price if, and only if, the real-time prices were below their offer prices. In the absence of this Intertie Offer Guarantee (IOG), importers faced a risk that the actual HOEP they received, after being accepted and committing to the market, could be considerably lower than their expectations. The IMO's concern was that in such circumstances importers might substantially reduce their offers and that this might threaten the reliability of supply. The experience with the IOG, and some issues surrounding its application, are discussed further in Chapter 2.

3.3.1.3 Reliability, operating reserves and joint optimization

To meet its mandate of ensuring reliability, the IMO operates markets for operating reserves, which provide additional potential supply that can be activated to meet unforeseen events. There are three categories of operating reserves: 10-minute spin; 10-minute non-spin; and 30-minute reserves. Minimum required operating reserves in each of these categories are established by international rules. The total operating reserve is determined as 100 percent of the capacity that would be lost by the occurrence of the single largest contingency event plus 50 percent of the capacity lost by the occurrence of the second largest contingency event. For the IMO-administered energy market traditionally, both the single largest and the second largest contingency are normally Darlington nuclear units. Effectively, therefore, the required reserves are 150 percent of the output of a Darlington unit, or 1,380 MW.

Operating reserves can be obtained from dispatchable generators in Ontario, dispatchable loads and imports. On occasion exports can also be curtailed to supply operating reserves.

On several occasions throughout the first four months, the market failed to supply adequate operating reserves and 'out-of-market' mechanisms were used to ensure required reserve levels were met. In an effort to attract more offers as operating reserves, the IMO announced that from June 25 forward the demand for operating reserve would be increased by 200 MW (from 1,380 MW to 1,580 MW) for all hours between 6:00 am and 8:00 pm (EST).

Against this demand for operating reserves, market participants submit offers to supply each of the three categories of operating reserve at various prices. Because the IMO has determined that the market for operating reserves is not yet competitive – due to the dominant position of OPG – it has entered into arrangements with OPG whereby OPG offers operating reserves according to price schedules that contain both thresholds and caps. These thresholds and caps have been negotiated between the IMO and OPG. Where the OPG offer is below the threshold it is accepted by the IMO. Where the offer is above the threshold but below the ceiling a further discussion about relative costs will ensue, with the possibility of dispute resolution. But the resolution of such discussion cannot result in a price that exceeds the negotiated price cap. Market participants other than OPG are free to bid operating reserves into the market at any price they wish. The thresholds and caps do not prevent OPG from receiving higher payments when the clearing price for operating reserve is higher.

Both OPG and other participants will enter offers throughout the day for both operating reserves and energy. Subject to the constraints on OPG's offers described above, and the MORP of $2,000, the price of operating reserves is in principle determined every five minutes through an auction process similar to that used to determine the MCP. That is, the offers are stacked and the offer that effectively balances supply and demand sets the price of operating reserves.

In fact, because market participants are offering both operating reserve and energy, the Dispatch Scheduling Optimizer (DSO), jointly satisfies the demands for operating reserves and for energy against an objective function that results in minimum cost subject to meeting the operating reserve requirement. The determination of the MCP in any five-minute interval is therefore linked to the operating reserve position within that interval. In the period leading up to the opening of the market when the systems were being tested it became apparent that the DSO was extremely sensitive to very small variations in operating reserve shortages and relying entirely on the DSO to perform the optimization led to price and dispatch volatility that was judged to be excessive. The IMO Board therefore authorized the IMO to undertake 'out-of-market' actions in periods where operating reserves were deficient, and the market continues to operate under this regime. This also has implications for market performance, which are discussed in Chapter 2.

3.3.1.4 Constrained dispatch and CMSC

Having determined the MCP on the basis of the unconstrained schedule and five-minute loads, the IMO will then issue dispatch instructions to generators and dispatchable loads to ensure that demand is met in the most economic way, given reliability concerns and system constraints. This will result in a constrained schedule for each five-minute interval within the hour and this constrained schedule will in most cases differ from the unconstrained schedule.

Where a market participant's dispatch instructions require performance that differs from the participant's unconstrained schedule, the market participant will be eligible to receive a CMSC payment, as discussed previously. The bulk of CMSC payments will be related to transmission congestion, but some may be related to other aspects of reliability.

3.3.1.5 The market price and the price consumers pay

The MCP is the commodity price for electricity that is set by the interaction of supply and demand in the market, as described above. But it is not the consumer price of electricity.

The price the consumer pays also includes transmission and distribution charges; a specific charge to service the stranded debt (DRC);[52] a rural or remote electricity rate protection charge and various other charges that together make up the uplift.[53]

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[52] The stranded debt refers to the debt incurred by the old Ontario Hydro that was judged to be incapable of being repaid from continuing operations. In the process of restructuring Ontario Hydro to create OPG and Hydro One the relevant debt was assumed by the Government of Ontario and transferred to the Ontario Energy Finance Corporation. It will be repaid by a charge – the debt retirement charge or DRC - to all electricity consumers of $7 MWh.

[53] A description of these various charges is available on the IMO web site at http://www.theimo.com/imoweb/pubs/media/Electricity_Charges.pdf.

The uplift essentially reflects the amount of money that the IMO spends, on a net basis, to administer the markets. These include the IMO fee, certain hourly uplift charges (calculated and applied hourly to hourly energy consumption) and some non-hourly uplifts (calculated and applied monthly to monthly energy consumption). The hourly uplift would include items such as payments for operating reserves, transmission-related losses, CMSC payments, and Intertie Offer Guarantee payments. The non-hourly uplift would include payments for contracted ancillary services, and other monthly charges such as costs incurred in purchasing Emergency Energy.

Uplifts appear to wholesale and retail participants in a variety of ways because of different aggregations taking place. For retail customers, the allowance for uplift – called the Wholesale Market Service charge - is estimated on an annual basis by the OEB with a true-up to the actual amounts incurred taking place over time. The estimated charge is currently $6.20 per MWh (or 0.62 cents per KWh) and includes the rural and remote settlement debit, the IMO fee, and all the hourly and non-hourly uplift components.[54] Transmission and distribution charges appear separately.

For wholesale customers most of these components appear as separate charge codes on their settlements statements. However, the IMO also publishes on its web site an estimate of the total of the hourly uplift components, referring to these as the Wholesale Hourly Uplift Charge estimate.[55] The actual charges for the hourly uplift have turned out to be quite substantial in some hours and are examined later in Chapter 2.

3.3.2 The ancillary services market

Under the current design of the Ontario wholesale electricity market, the IMO procures through contracts certain ancillary services that enable the IMO to ensure the reliability of Ontario's power system. These are services that currently cannot feasibly be provided

[54] The IMO fee is $0.959 per MWh; the rural and remote settlement debit is $1 per MWh.
[55] See http://www.theimo.com/imoweb/role/upliftCharge.asp

competitively within the day-to-day operation of the real-time market. The ancillary services for which the IMO contracts include: Voltage Control and Reactive Support; Regulation Service or Automatic Generation Control (AGC) Service; and Black Start Capability.[56]

The Market Design Committee (MDC), as part of its final design recommendations to the Minister, contemplated that the IMO would tender competitive bids for these services for a given period of time (i.e., a month, six months etc). Any generators capable of providing the services would be eligible to bid and the IMO would select the lowest priced bid to provide each service. When the first contracts were sought, no generators other than OPG offered to provide these services to the IMO. The MDC recognised that this was a possibility in the early days of the market. As an interim alternative, the MDC recommended that the IMO and OPG negotiate a cost-based contract for these services. In the event that the IMO and OPG could not reach an agreement on these services, the OEB would be consulted and act as adjudicator to the contract.

It is anticipated that as the market becomes more competitive, there will be a significant number of alternate providers in the market for these services.

3.3.3 Financial transmission rights

When there is congestion at an intertie, the intertie zone price can be different from the uniform Ontario price, creating a price risk for these transactions. Financial Transmission Rights (FTRs) were established as a financial means to mitigate this price risk by compensating the FTR holder for the difference between the two prices. Each 1

[56] Voltage Control and Reactive Support are services that maintain transmission system voltages within proper range. Regulation Service or Automatic Generation Control (AGC) Service is essentially energy provided by generators that is used to balance generation with load minute-by-minute, and to keep the overall grid frequency at 60 hertz. Black Start Capability refers to services provided by generators that can start and run without external electrical supply, and can be used to start other generators in a blackout situation.

MW of FTR entitles the owner to a payment of 1 MWh times the price difference, for each hour in the period (calendar month) where the price difference is positive.

Financial Transmission Rights (FTRs) are auctioned regularly by the IMO. Those who purchase them are entitled to a revenue flow on a specified intertie, for a specified period of time, should that intertie become congested. FTR's do not affect the supply of energy. They are essentially a financial hedging instrument that allows market participants to protect themselves against the financial consequences of transmission congestion. The FTR does not grant the holder any physical rights or preferences to transactions at the interties.

Chapter 2: Market Activity in the Period May-August, 2002

1. Introduction

When the energy market opened in May we were in a period where the weather was warming, but not extraordinarily hot, and where the spring run-off had been relatively normal, leaving hydroelectric power providers with ample water. There was also considerable uncertainty about how the new market rules would operate.

The first four months of market operation was a learning experience for all participants, and for the Panel. Through the early part of the period, prices were not as volatile as might have been expected given the participants' lack of experience with the Market Rules and the IMO's lack of operating experience with the DSO, the optimization tool that schedules resources and establishes prices.[57] As well, available supply generally exceeded demand by a reasonable margin leading to price determination that was more often associated with the 'shaft' of the hockey stick, rather than the 'blade'.[58]

As we moved through the period, however, demand and supply conditions changed quite substantially. Water became less abundant and more 'precious', raising the opportunity cost of hydroelectric power. A number of fossil generating units were forced out of service for technical reasons at critical points during this time. And heat waves, particularly in early and late July and parts of August, led to serious reductions in reserve margins – to the point where substantial reliance on imports was required to balance supply and demand, where the IMO appealed to energy users to curtail use in peak periods in order to minimize the possibility of brownouts, where operating reserve deficiencies began to occur on a more or less regular basis, and where, on 6 occasions,

[57] DSO stands for Dispatch Scheduling Optimizer. section 3.3.1 of Chapter 1 provides a brief overview of the optimization process.
[58] See Figure 1.4 and the related discussion in Chapter 1.

the IMO issued Power Advisory Notices.[59] The IMO also made emergency purchases of imports on 38 occasions on several days in order to assure reliability. In response to these factors, average prices moved up, and volatility increased, through the period.

This chapter reports on activity in the IMO-administered markets over the May to August period. Most of the chapter focuses on the energy market, where the presentation of data is supplemented by the analysis of specific issues undertaken by the MAU on behalf of the Panel.

2. The Real-Time Markets for Energy and Operating Reserves

2.1 The energy market

We have pointed out on other occasions that there is no unambiguous set of metrics that allows us to conclude as to the appropriateness of any particular set of price outcomes in a competitive market, and we do not have preconceived notions about values that prices should track. It does help, however, in looking for outcomes that warrant further investigation, to set up a methodology and criteria that can be used to identify observations that should be analyzed in detail. At this stage in the development of the market, our approach is still evolving.

The MAU in the IMO monitors market activity on a continuing basis on behalf of the Panel and reports to us regularly. Through ongoing observation, the MAU is developing a good understanding of the critical elements that influence market outcomes. As we gain further experience and insight into the operation of the market, and as data reflecting the operating experience of generators in a competitive market become increasingly available, we intend to develop criteria that can more objectively assist in pointing to price outcomes that may be anomalous, or indicate potential abuse of market power.

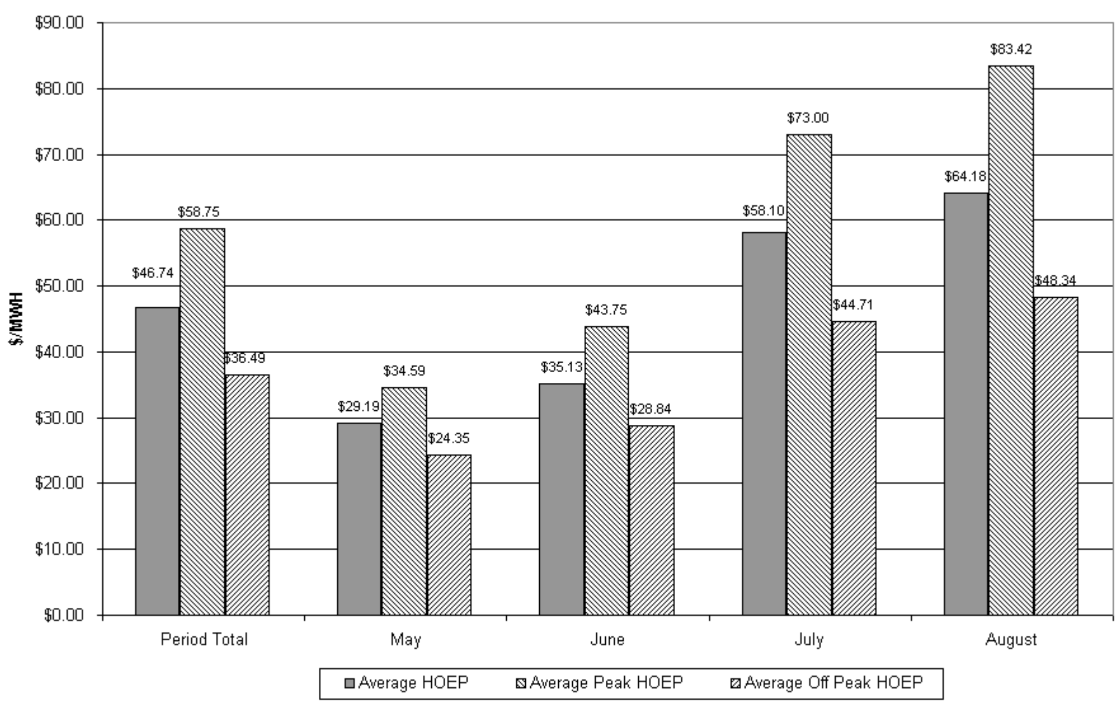
[59] A Power Advisory Notice urges electricity users to conserve supply and a System Advisory Report advises generators and importers that more supply is needed.

In this first report our focus is on how prices in Ontario have evolved over the period and in relation to neighbouring jurisdictions that also operate competitive wholesale electricity markets. We have asked the MAU to pay particular attention to 'high-price hours' as part of the monitoring for anomalous events. Section 2.3 below summarizes the critical factors underlying these high-priced hours.

2.1.1 Ontario wholesale prices, May-August 2002

Figure 2.1 shows the average HOEP in Ontario, as well as the average values during peak and off-peak time periods.[60]

Figure 2.1: Average HOEP for May-August 2002



The data in Figure 2.1 clearly show the increase in average prices as the period progresses. Over the period as a whole, the average HOEP was $46.74/MWh; but this value rose progressively from a low of $29.19/MWh in May to a high of $64.18/MWh in August. Looking at the peak values, one sees an even greater relative increase through the months, as well as a progressive increase in the average peak/off-peak price ratio. The upward trend in price was generally attributable to increasing demands associated with increasing temperatures through the period, and decreasing availability of hydroelectric and other energy limited resources through the summer months.

The average prices presented in Figure 2.1 mask the substantial variability of price that occurred throughout the first four months. Table 2.1 below provides the frequency of hourly prices occurring in different ranges.

Table 2.1: Frequency Distribution of HOEP through May-August 2002[61]

HOEP Price Range ($/MWh)	Period Total % of hours	May % of hours	June % of hours	July % of hours	August % of hours
<$10	0.31	0.67	0.01	0.00	0.00
$10.01-$20.00	5.18	15.32	15.0	0.00	0.00
$20.01-$30.00	19.28	31.45	31.0	9.01	6.85
$30.01-$40.00	37.50	46.24	46.0	29.30	25.40
$40.01-$50.00	9.18	2.82	3.0	12.10	18.28
$50.01-$60.00	5.56	1.34	1.0	9.27	8.60
$60.01-$70.00	7.11	1.08	1.0	12.23	10.48
$70.01-$100.00	11.62	0.93	2.78	21.10	21.38
$100.01-$200.00	3.56	0.13	0.70	6.71	6.58
$200.01+	0.71	0	0.14	0.26	2.38
Average On-Peak	$58.75	$34.59	$43.75	$73.00	$83.42
Average Off-Peak	$36.49	$24.35	$28.24	$44.71	$48.34
Average	$46.74	$29.19	$35.13	$58.10	$64.18

As the period progressed, the frequency of higher prices increased. In May, for example, 96.5 percent of all the hourly prices observed were below $50/MWh and in only 1.06 percent of the hours did HOEP exceed $100/MWh. By contrast, in July and August prices exceed $100/MWh 7 to 9 percent of the time and were less than $50/MWh only about half the time.

[60] In this context, on peak refers to the period from 7 am to 11 pm EST, on business days.

One of the features of the market that was observed in the first four months was the heavy reliance on imports to assure reliability in times of very tight supply (particularly through the heat waves in July and August). This led to large payouts to importers through the Intertie Offer Guarantee (IOG). These IOG payments increase the cost of energy to consumers but they are charged through the hourly uplift[62], rather than affecting HOEP itself. In addition to the IOG, Congestion Management Settlement Credits (CMSC) are another significant part of this hourly uplift. Because these elements of the uplift can vary quite substantially hour by hour, in July the IMO began calculating a running estimate of the hourly uplift charge and publishing this information every hour on its web site.[63] Table 2.2 shows the frequency distribution of HOEP through the period, with the addition of the hourly uplift.

Table 2.2: Frequency Distribution of HOEP, plus Hourly Uplift

HOEP + Uplift Price Range ($/MWh)	Period Total % of hours	May % of hours	June % of hours	July % of hours	August % of hours
<$10	0.30	0.67	0.55	0.00	0.00
$10.01-$20.00	4.44	13.84	3.89	0.00	0.00
$20.01-$30.00	16.09	26.34	27.36	6.05	4.97
$30.01-$40.00	37.64	51.34	52.08	28.36	19.22
$40.01-$50.00	11.04	3.36	3.33	14.38	22.72
$50.01-$60.00	5.52	1.75	3.33	7.39	9.68
$60.01-$70.00	6.10	1.21	3.61	9.14	10.35
$70.01-$100.00	12.13	1.21	4.86	21.37	20.83
$100.01-$200.00	5.18	0.27	0.83	11.56	7.93
$200.01+	1.56	0.00	0.14	1.75	4.30
Average On-Peak	$66.45	$36.47	$46.30	$86.00	$96.57
Average Off-Peak	$38.18	$25.39	$29.45	$46.95	$50.58
Average	$51.20	$30.63	$36.94	$65.43	$71.35

[61] The frequency of HOEP is presented as the percentage of hours within a month. For May, July and August there are 744 hours in the month, 720 hours in June, totalling 2952 hours for the four month period.
[62] The hourly uplift is described in Chapter 1 section 3.3.1.5
[63] The data provided are estimates for the hours just ended. Also available is a downloadable file containing previous estimates for the current and previous days.

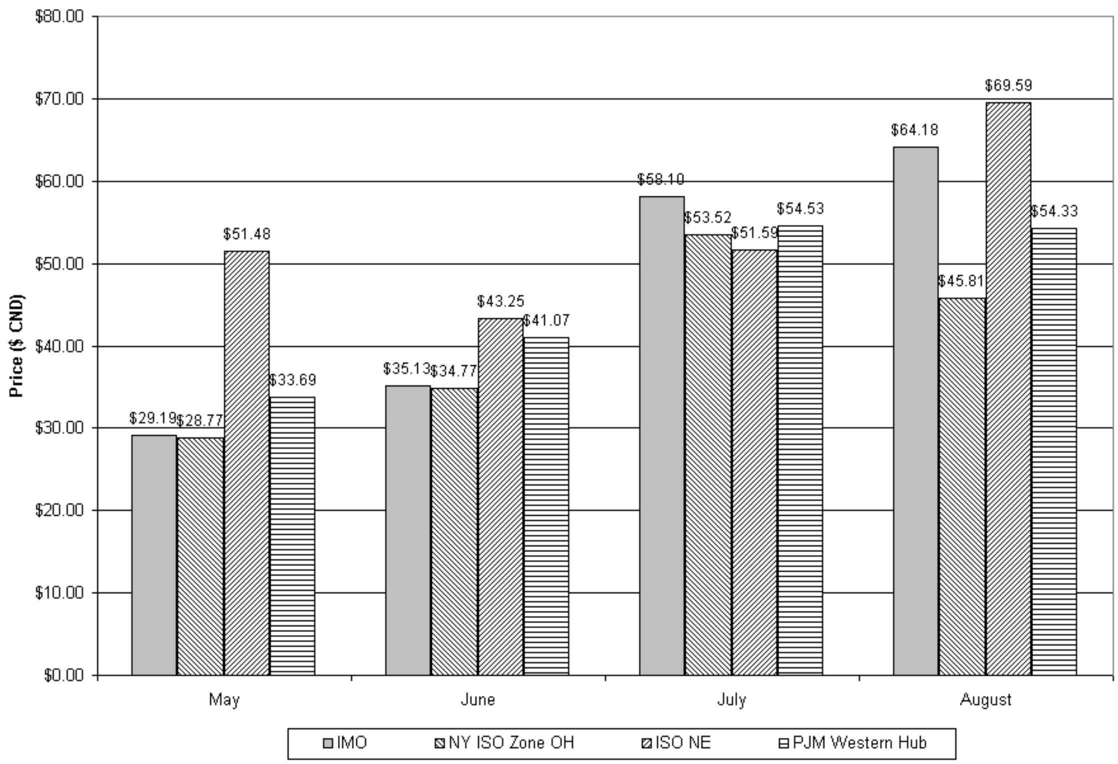
On average, these totals exceed the HOEP by less than \$2/MWh in May and June and by over \$7/MWh in July and August. On peak the July and August differences are more dramatic, being some \$13/MWh higher than the energy price alone. This can also be seen in that the frequency of occurrence of prices above \$100 in July almost doubles to more than 13 percent, and the frequency of occurrence of prices above \$200 almost doubles in August.

These results reflect the dramatic increase in the IOG and CMSC payments that occurred when supply problems arose and it was necessary to rely on higher priced imports. This is discussed further in section 2.4.

2.1.2 Prices in Ontario and neighbouring jurisdictions

Figure 2.2 provides some comparative information on price behaviour in Ontario, relative to prices in neighbouring jurisdictions that also have competitive wholesale markets for electricity. What is compared is the HOEP in Ontario against the spot prices determined in each of the other jurisdictions, converted to Canadian dollars. Although average prices actually paid may differ because of market characteristics such as uplift, day-ahead markets, use of bilateral contracts, or other specific features, the spot market price nonetheless provides a meaningful comparison of what it costs to buy energy in the market in any given hour. Figure 2.2 shows the same general trend to increased prices in all three markets, as demand rose with the onset of summer heat. Relatively lower Ontario prices in May and June, and relatively higher prices in July may also reflect differences in the available fuel-types through the period, with Ontario benefiting from a substantial portion of low-cost hydroelectric power in the May-June period when water was more plentiful.

Figure 2.2: Average HOEP Relative to Neighbouring Jurisdictions



2.1.3 Prices and the 'supply cushion'

One way of assessing the impact of supply and demand on price is to examine the 'supply cushion'. The supply cushion is a measure of the amount of unused energy that is available for dispatch in a particular hour. It is expressed as a percentage derived arithmetically as:

$$SC = \frac{EO - (ED + OR)}{ED + OR} x100$$

where,

EO = total amount of available energy offered

ED = total amount of energy demanded

OR = operating reserve requirements.[64]

[64] EO measures only 'available' energy offers in the sense that it does not include offered quantities from fossil units that are not running nor does it include offered quantities that are made unavailable due to an

The supply cushion differs from the Available Reserve referred to in Chapter 1 in that it focuses on energy *offered* instead of a measure of available capacity. It is also distinct in that it includes energy offers from importers; the Available Reserve focuses entirely on the adequacy of Ontario supply.

Both the Available Reserve and the supply cushion are measures of supply adequacy in Ontario. The Available Reserve, with its focus on installed capacity, provides a longer-term view of supply adequacy. It is best employed for assessing the adequacy of domestic supply to meet yearly-expected peak demand values. The Available Reserve is an indicator of the need for investment in new capacity. The supply cushion, given its focus on hourly available energy offered, is a better indicator of the adequacy of supply at a point in time, specifically a particular delivery hour. It provides a measure of how well the market is working to induce suppliers to make existing capacity available for supply.

As an hourly measure of adequacy, the supply cushion should also have a closer relationship with the hourly clearing prices. This relationship is captured in the two scatter diagrams presented in Figure 2.3. The first scatter diagram plots the relationship between the real-time supply cushion and the HOEP for the months of May through August. The second scatter diagram plots the relationship between the pre-dispatch supply cushion and the one-hour ahead pre-dispatch price for the same period.[65] In both cases we have statistically estimated the relationship between supply cushion and price, and the fitted values of this relationship are also plotted in the two diagrams in Figure 2.3. The estimating model allowed the potential for monthly variability in the relationship and the fitted values illustrate that such variability was statistically significant. As the supply cushion declines, the fitted values branch into three curves in real-time and four curves in

unplanned outage or derating. For the purpose of calculating the supply cushion, ED consists of the non-dispatchable load component of demand plus the quantity demand by dispatchable load and exporters at a price of $2,000, the MMCP. EO, ED, and OR are each reported as hourly values calculated as the arithmetic average of the twelve five-minute values in the hour.

[65] The pre-dispatch supply cushion differs from the real-time supply cushion in the following ways. First, the pre-dispatch cushion uses forecast values for energy demand and operating reserve requirements. Second, the pre-dispatch supply cushion uses all offers from importers and those export quantities bid at a price of $2,000. The real-time supply cushion uses only the scheduled amounts of net imports. Finally, the pre-dispatch supply cushion does not reflect outages that may happen in real-time.

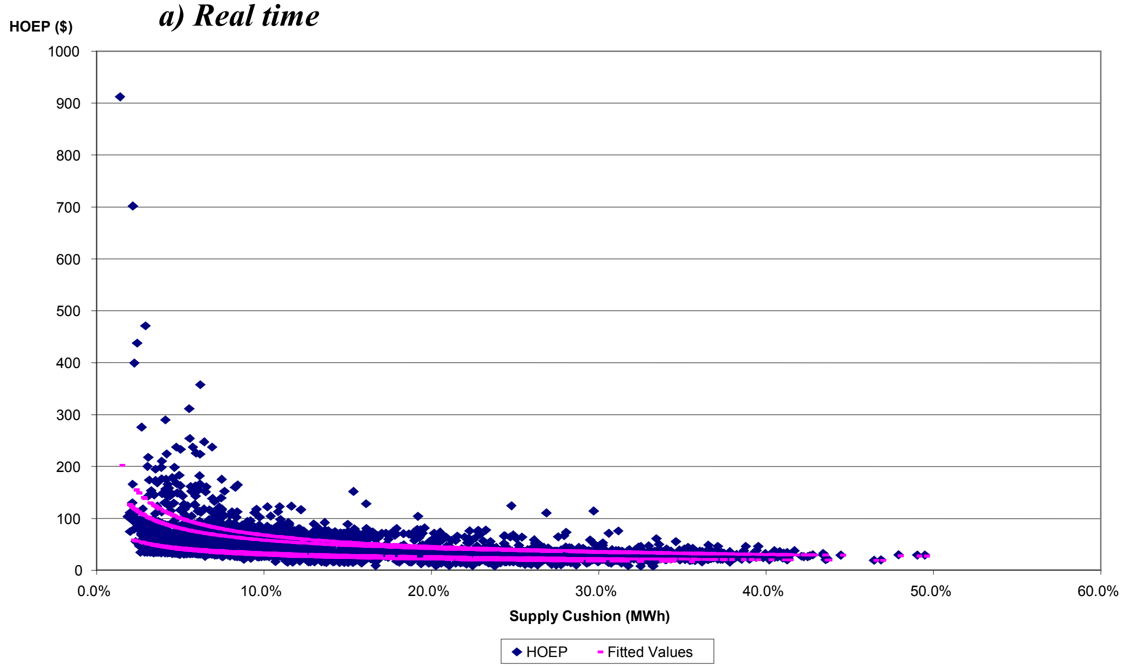
pre-dispatch, indicating that for a given supply cushion, prices would be predicted to be higher in August than in either July or May.[66]

The scatter diagrams and fitted curves illustrate that there is a negative relationship between the clearing price and the supply cushion with a smaller supply cushion implying a higher clearing price. It also suggests that as the supply cushion declines, there is more volatility in the clearing prices – the scatter points around the fitted curve are more spread-out as the cushion falls below 10 percent in real-time and 20 percent in pre-dispatch.

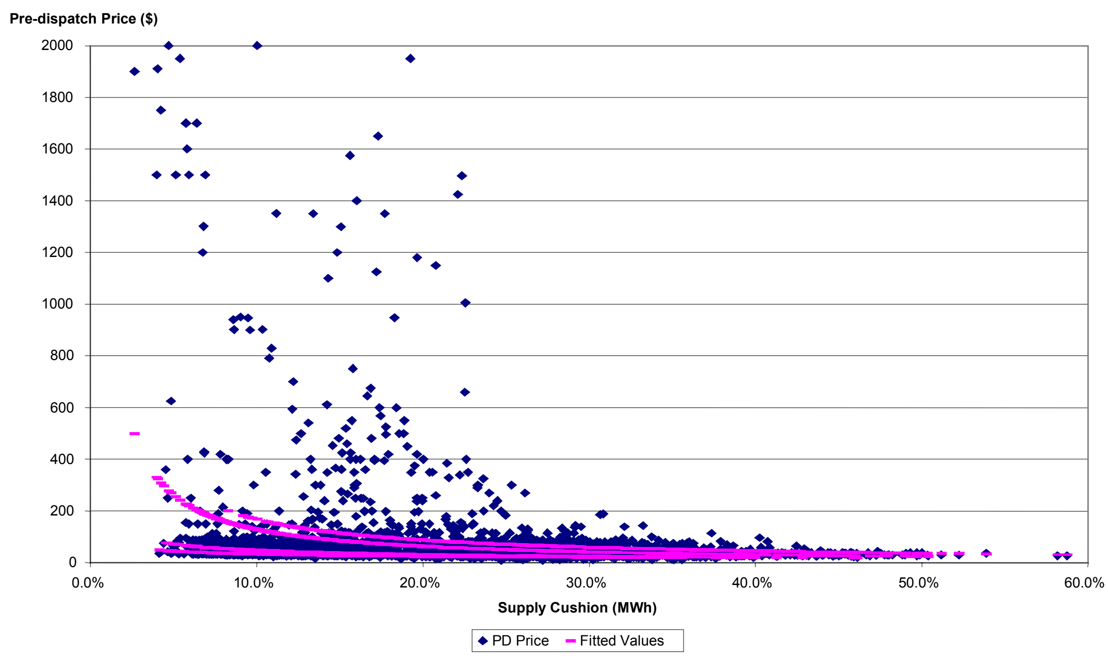
[66] Summary statistics and regression results are available on request.

Figure 2.3: Relationship between Price and the Supply Cushion

a) Real time

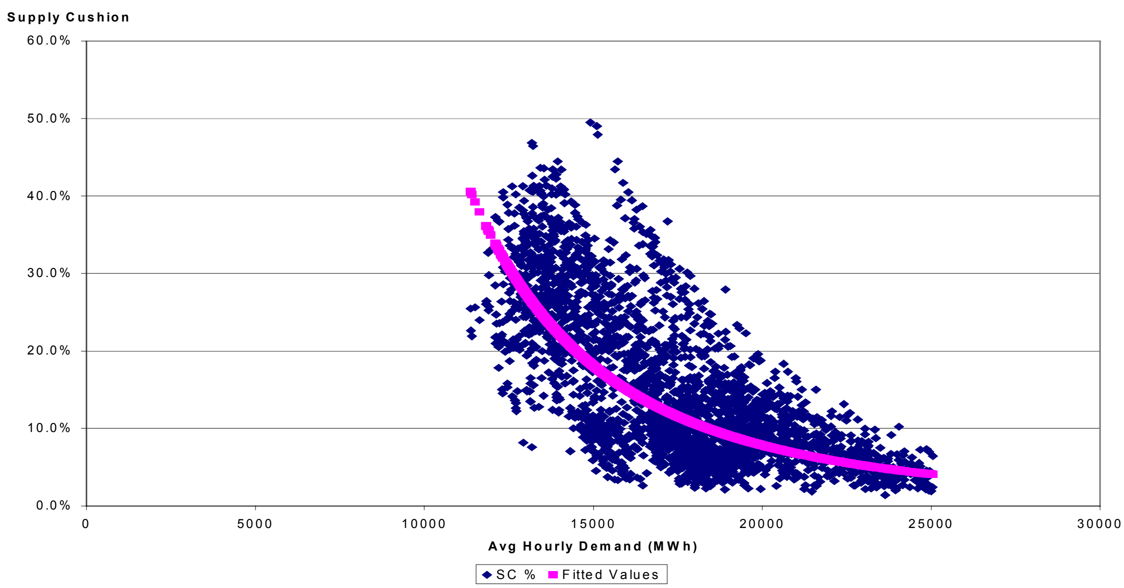


b) Pre-dispatch



The negative relationship between the clearing price and the supply curve reflects the general shape of a typical offer curve, as illustrated in Figure 1.4 of Chapter 1. As demand increases the supply cushion generally decreases, particularly as demand approaches the level of installed capacity where there is little additional energy to be offered. This relationship is illustrated in Figure 2.4 using real-time values for demand and the supply cushion.

Figure 2.4: Relationship between the Supply Cushion and Demand



Referring back to Figure 1.4, one can see that, as demand increases, it intersects the offer curve higher up towards the blade portion with higher clearing prices resulting.

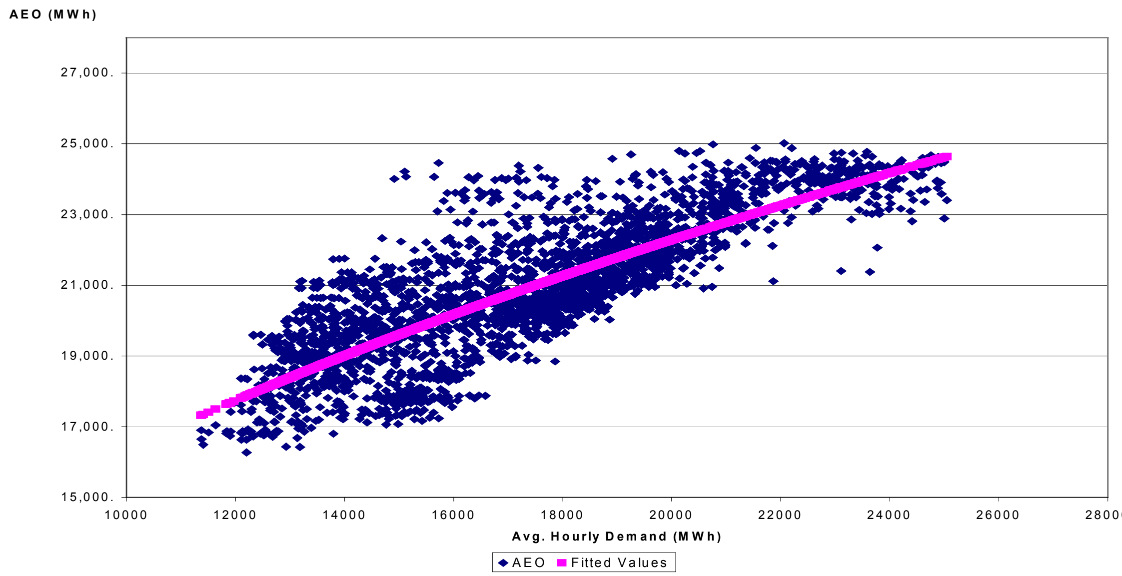
Nonetheless, a small supply cushion can occur even for relatively low demand values. This is illustrated in Table 2.3 that shows the number of hours in each month for which the real-time supply cushion was less then 10 percent. Although it is difficult to see precisely from Figure 2.3, a level of the supply cushion lower than 10 percent appears to be the range where most of the high HOEP values occur. As illustrated, there were nearly twice as many instances where the cushion was less than 10 percent in June than in August and yet the average demand in June was almost 1,500 MW less than in August.

Table 2.3: Number of Hours When Supply Cushion Less Than 10%, May, - August

	May	June	July	August
Total Hours	744	720	744	744
Hours with SC < 10%	334	383	291	214
Avg. Demand (MW)	15,847	16,732	18,633	18,274

The data suggest that this might be explained by a positive relationship between the amount of available energy offered and demand, with more energy being offered at higher demand levels. Figure 2.5 provides the scatter diagram and the fitted values of the estimated relationship. One explanation is as follows: in order for the owner of a fossil-based generation unit to make its unit available for real-time supply, it must expect that prices will be at a level that will cover its start-up cost and minimum no-load cost as well as its marginal running cost. At relatively low demand values, these owners may expect low prices and choose not to offer their units for supply or offer them at prices that would ensure that if chosen for even a short time frame, they would cover these costs. This means that at relatively low demand levels, fewer fossil units are likely to be on-line and available for delivery; the result is that the supply cushion can be low (see Figure 2.3). As demand increases, more of these units are made available. The trend continues until the market reaches the level of installed capacity, at which point no more energy can be made available regardless of the level of demand. As Figure 2.5 suggests, the data appear to flatten around the 24,000 MWh level of available energy offered, where the Ontario market is reaching its peak available capacity.

Figure 2.5: Relationship between Available Energy Offered and Demand



The two panels in Figure 2.3 provide a comparison between the real-time market and the one-hour ahead pre-dispatch market with respect to the price/supply cushion relationship. There are clear differences between the two relationships. First, in pre-dispatch there are numerous observations with prices that exceed $1,000. In contrast, the real-time HOEP never exceeds $1,000. Also, there is a greater degree of dispersion around the fitted line for supply cushions lower than 20% in pre-dispatch. This suggests that the pre-dispatch market is vulnerable to 'price spikes' even when it appears that supply adequacy is not an issue. There are several reasons for the difference between the real-time and pre-dispatch price/supply cushion relationships with no one factor providing a dominant effect. The causes for the differences are discussed in more detail in sections 2.3 and 2.5.

For some monitoring applications it is often constructive to modify the supply cushion so that it includes only those available energy offers made by domestic generation facilities, thereby ignoring the impacts of imports and exports. One application of this 'domestic' supply cushion is that it can be used to provide an indication of the role of imports in maintaining supply adequacy in any given hour. Given that supply and demand must be in balance at all times, when the domestic supply cushion is negative, it implies that imports were required to maintain this balance. Table 2.4 uses the domestic supply cushion to illustrate Ontario's reliance on imports in the May to August period. In May, given the relatively low demand levels and the relative abundance of hydroelectric energy, there were no instances in real-time when the domestic supply cushion was negative. This picture changed dramatically over the next months however, with the number of hours increasing to as many as 159 hours in real-time in July and August; roughly 21 percent of the hours in the month.

Table 2.4: Negative Supply Cushion Events, May – August 2002

	Domestic Supply Cushion Number of Hours Negative	
	Real-time	**Pre-dispatch**
May	0	7
June	18	114
July	128	168
August	159	174

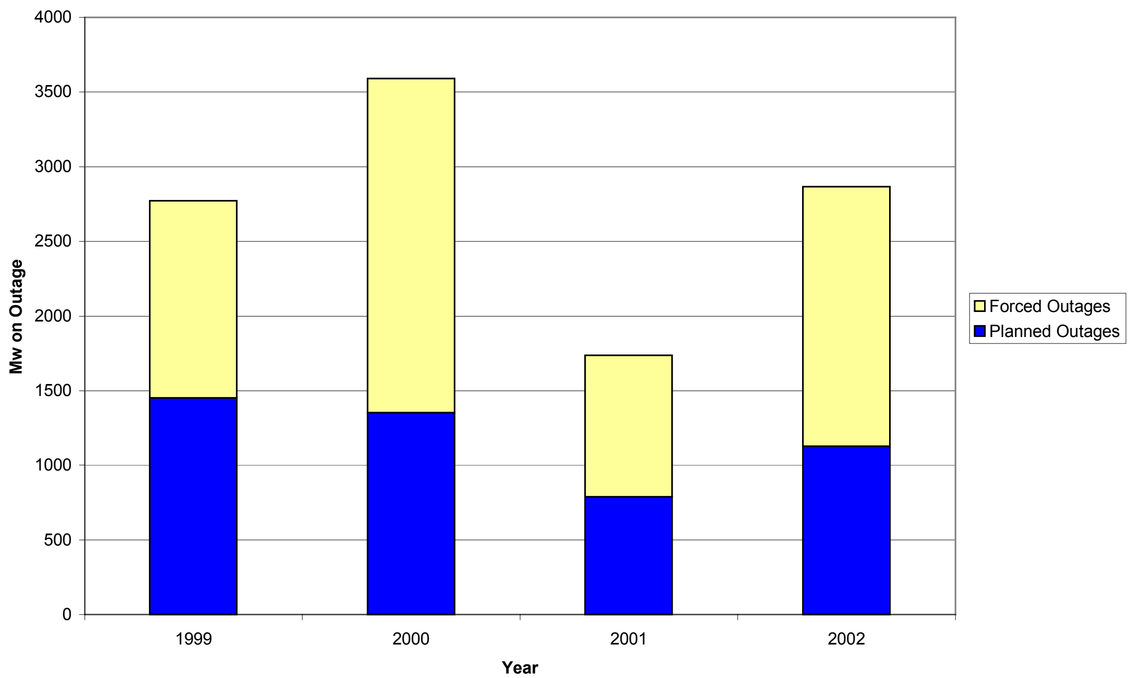
2.1.4 Unavailability of supply

The unavailability of generation and transmission can have an impact on the functioning of the marketplace. Unavailability is particularly significant during periods where there are limited reserves, but can have an influence on efficiency during other periods as well.

Generators may be unavailable due to planned or unplanned events, the latter being referred to as forced outages. Planned outages are allowed by the IMO to the extent they do not impact reliability. But, in accordance with the Market Rules, the IMO does not assess these for their efficiency impacts. If planned outages take place during high load periods, the system risk increases, from both reliability and price perspectives. Any additional supply interruptions at such times (due, for example, to forced outages) create even greater risks. As an example of this, the forced extension to a planned outage of a major nuclear unit exacerbated the supply issue throughout the summer.

Figure 2.6 provides a comparison of the outages both planned and forced for the peak hour of the summer for the years 1999 to 2002. It shows that for the snapshot hour, outages were not dissimilar to previous years.

Figure 2.6: Total Outages in the Summer Peak Hour 1999 to 2002



We have asked the MAU in the coming months to track the magnitude and timing of outages, in particular forced outages, from year to year and season to season. An increase in planned and forced outages in critical periods would be a signal to review why this is taking place.

Planned or unplanned transmission outages that result in available supply not being able to get to market can have substantial impacts on the efficient use of generation and on CMSC payments.[67] Ideally, transmission outages would be coordinated with generator availability in order to minimize such impacts. It is not clear that the competitive

[67] Forced outages of transmission tend to be fairly short-lived, perhaps a day or two, and are of much shorter duration than some planned outages, which may last weeks.

marketplace provides appropriate mechanisms and incentives for such coordination to take place.

For example, planned transmission outages in May prevented hydroelectric capacity that would have been available at relatively low cost from coming to market. In one instance a transmission outage on the K3D line between May 6 and May 24 led to constraining off units. The average daily CMSC induced was $17,900 during the outage, and $5,400 on other days during the same month. Thus the additional CMSC paid may have been on the order of $237,000.[68] The planned outage was approved on grounds that it did not impact reliability and, indeed, it may be the case that it was in fact the most appropriate time to do the maintenance work necessary from a broader efficiency and cost perspective. But there is no assurance in our market framework that this will be the case.

We have asked the MAU to consider this issue of coordinating outages, to monitor it over the coming months and to consider whether it is significant enough to warrant greater attention by the Panel.

2.1.5 Price setters

Another picture of market outcomes over the May-August period is obtained by identifying those who set price in real time or in the one-hour ahead pre-dispatch. This is done by identifying the facility that was selected from the offer stack as the least price offer to satisfy total demand in the five-minute interval (i.e., the price setter), identifying the type of resource generation associated with the offer, and aggregating this information across all intervals in the four-month period.

Table 2.5 provides information on the type of generation resource that was responsible for setting the real-time price. Recall that under the current market design neither

[68] Nineteen days times the difference of $12,500 per day. This estimate includes both the constrained off cost and associated constrained on costs.

imports (injections) nor exports (offtakes) can set the price in real-time, so the table relates only to Ontario generation.

A first observation is that coal-fired generation was the dominant and relatively constant price setter during the period. As expected, nuclear generation, as base load capacity, was not a price-setter.[69]

Over the period, oil/gas generation became progressively more important as price setting capacity while hydroelectric became less important, except for a resurgence in August. Hydroelectric generation makes up 27 percent of the installed capacity within the province but its production during the high-priced periods of the summer is extremely restricted by water availability.

Table 2.5: Share of Real-Time MCP Set by Resource, May – August 2002

Resource	May	June	July	August
Oil/Gas	1%	5%	19%	16%
Coal	75%	80%	70%	68%
Nuclear	0%	0%	0%	0%
Hydroelectric	24%	15%	10%	16%

Table 2.6 shows a growth in energy demand through the period of approximately 1.8 TWh and at the same time a reduction of hydroelectric energy production of 1.3 TWh comparing May and August. Since nuclear production remained relatively constant through the period, it was necessary in August to supply close to 3 TWh of additional energy from fossil plants and/or imports (compared with May).

[69] In fact nuclear generation did set the MCP on a handful of occasions but this amounted to a fraction of one percent and is lost in a rounding to the nearest percentage. Similarly, dispatchable loads also set the real-time price on a handful of occasions – amounting to less than 1 percent.

Table 2.6: Resources Selected in the Real-Time Market Schedule (MWh)

Source	May	June	July	August
Imports	190,824	286,710	653,353	1,040,435
Nuclear	5,364,858	5,383,515	5,629,942	5,566,214
Hydroelectric	3,929,183	3,644,626	3,082,593	2,646,178
Fossil	2,515,307	3,083,596	4,710,615	4,507,398
Total	**12,000,172**	**12,398,447**	**14,076,502**	**13,760,225**

Table 2.7 displays the source of the total energy selected in the real time market schedule.[70] In May hydroelectric energy was selected to satisfy roughly one third of the load, by August this figure had fallen to 19 percent. As less and less hydroelectric energy is available to supply the demand due to less water availability after the end of the spring melt and low inflow conditions during the heat of summer, the gap is satisfied by fossil-fired generation and/or import offers.

Table 2.7: Share of Total Energy in the Real-Time Market Schedule, by Source

Source	May	June	July	August
Imports	1.6%	2.3%	4.6%	7.6%
Nuclear	44.7%	43.4%	40.0%	40.5%
Hydroelectric	32.7%	29.4%	21.9%	19.2%
Fossil	21.0%	24.9%	33.5%	32.8%

Indeed, Table 2.7 shows that imports selected in real time increase almost five-fold from May to August and fossil generation increases by about 50 percent. In the first four months, imports supplied 4 percent of the Ontario load on average and 6 percent of load during peak periods. This may appear small on average but was significant for maintaining adequate supplies during the higher load periods.

Over the four months as a whole, actual (constrained schedule) imports were almost five times as large as exports, at some 2.28 TWh versus 0.46 TWh. Ontario was a net importer of electrical energy during both peak and off-peak periods.

Another perspective on the increasing importance of imports to the Ontario market over the summer period is contained in Figures 2.7 and 2.8. Figure 2.7 shows that in May imports set the price in the one-hour ahead pre-dispatch schedule 5 percent of the time compared to 39 percent of the time in July and 61 percent in August. While the pre-dispatch price is set 92 percent of the time by domestic generation in May, by August this figure had steadily fallen to 32 percent of the time across all hours.

Figure 2.7: Market Segment Setting Price in Pre-dispatch by Month

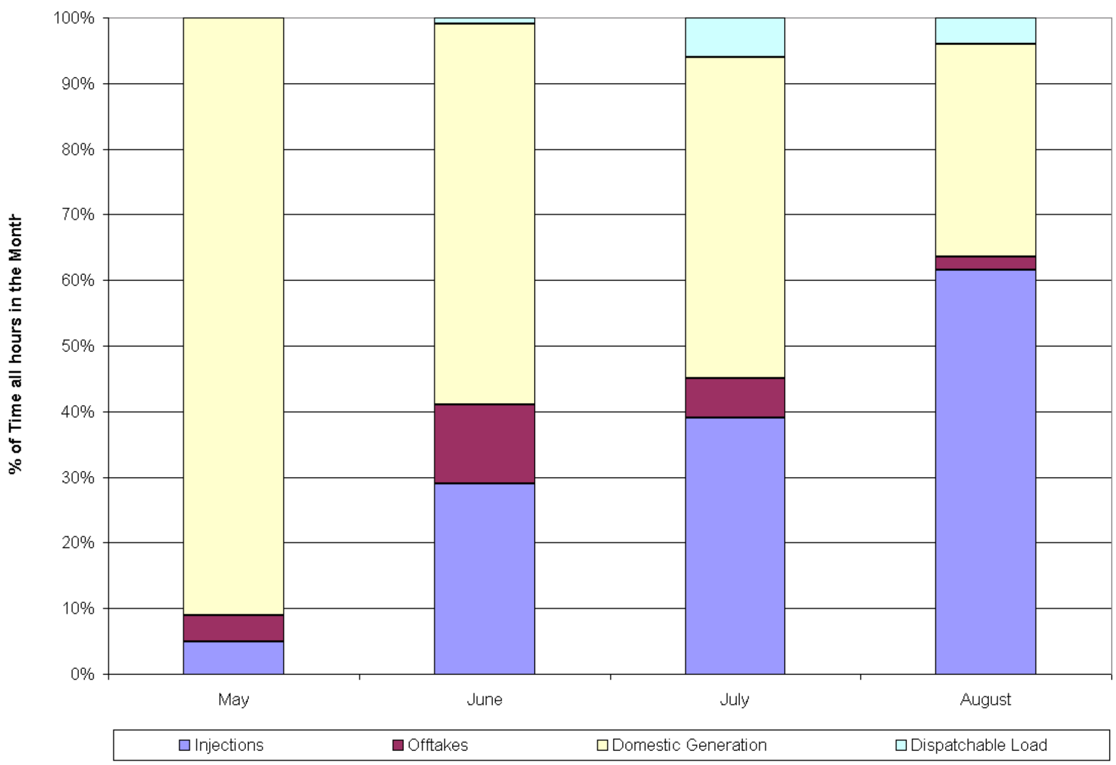
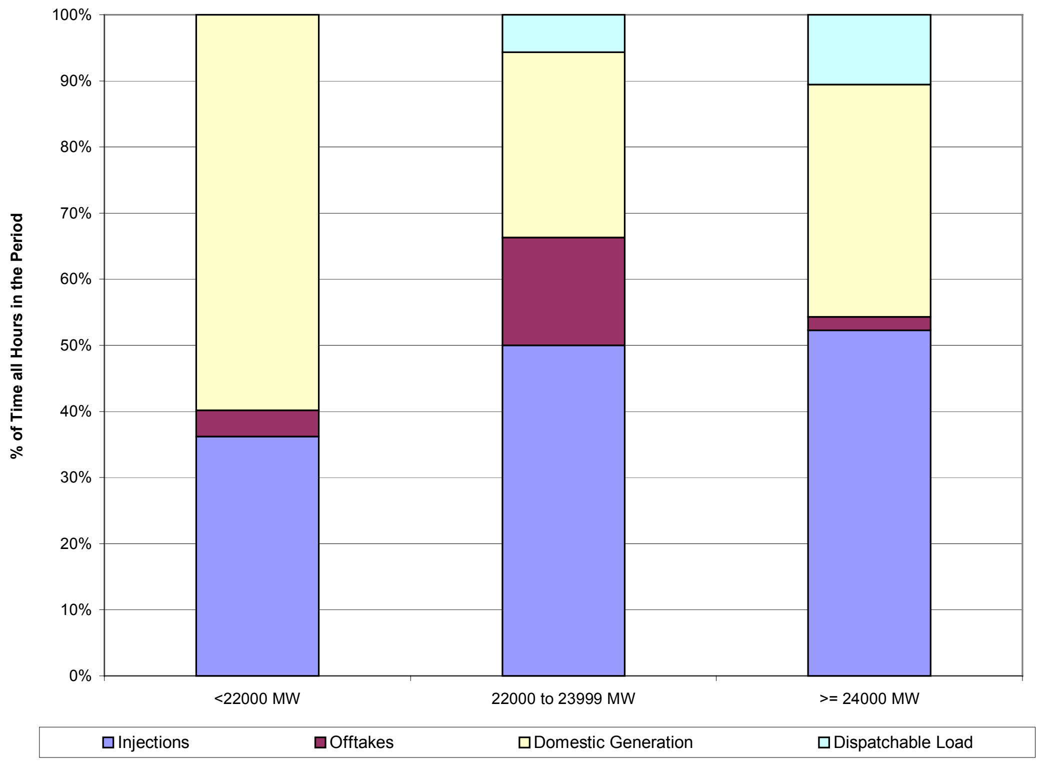


Figure 2.8 shows that in high-load periods (defined as 24,000 MW and above), imports into Ontario set the pre-dispatch price 51 percent of the time. In the range from 22,000 MW to 24,000 MW imports set the price 50 percent of the time. For market demands below 22,000 MW, Ontario generators set the price 60 percent of the time. Clearly, as demands increase above 22,000 MW imports begin to dominate as price setters in the one-hour ahead pre-dispatch sequence.

[70] Since this is the unconstrained schedule, the data should not be interpreted as market shares. The actual energy dispatched is set by the constrained schedule.

Figure 2.8: Market Segment Setting Price in Pre-dispatch by Load Range for Period May-August 2002



2.2 The market for operating reserves

The operating reserve market exists to provide additional potential supply of electricity for contingency situations. There are three separate categories of operating reserve (OR): 10-minute spin, 10-minute non-spin and 30-minute, and these reflect the speed with which they have to be activated. Ten-minute spin is frequency responsive as it is connected to the grid at all times and can react practically immediately to changes in frequency or demand.

We found that the market outcomes in the OR markets over the first four months of operations were heavily influenced by three main factors:

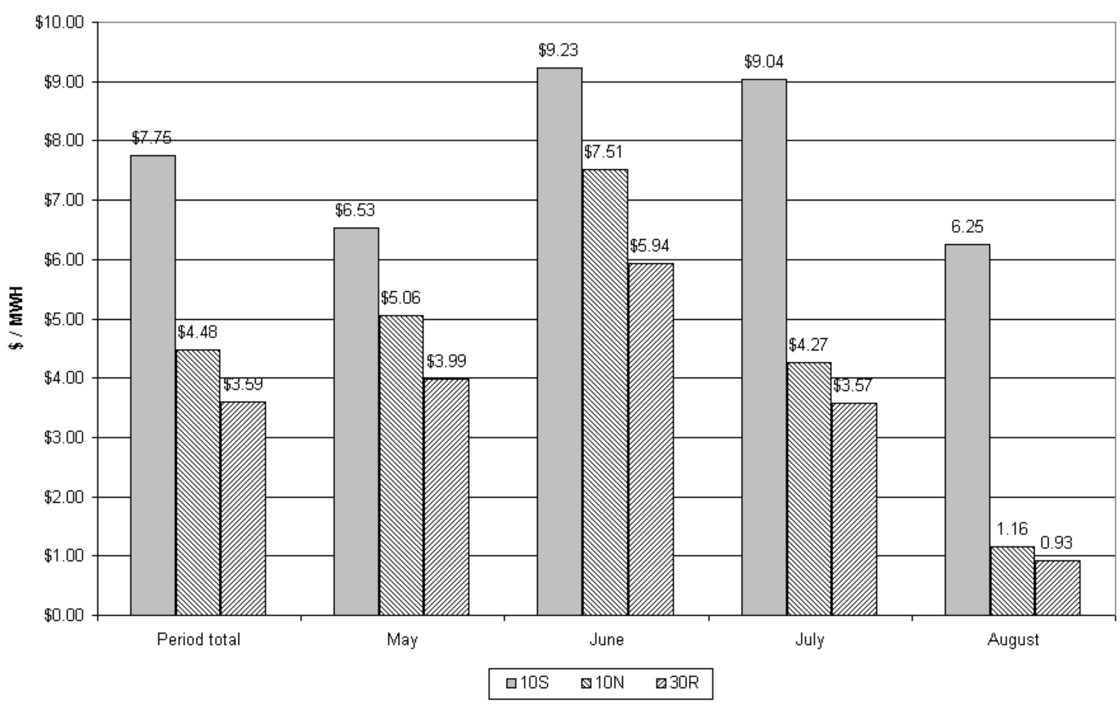
- the dominance of OPG and the consequent special obligations placed on it,
- the changing resource mix offered in the OR markets, and

- ‘out-of-market’ actions by the IMO in response to OR shortfalls

As explained in Chapter 1, because of the dominant market position of OPG, it was required to enter into an agreement with the IMO establishing price limits or caps which it could not exceed. The agreement with the IMO includes an oversight mechanism and reference to OPG costs when its offers exceed established thresholds even before the price caps are engaged. OPG is also required, pursuant to its operating licence to offer the maximum available amount of each category of OR, “consistent with good utility practices”, for each OPG generation unit capable of providing such services.

Figure 2.9 gives a summary picture of OR prices over the period. After rising in June, prices declined in July and August for each class of OR, although less dramatically for 10-minute spin where prices were higher than for the other two classes.

Figure 2.9: Average Hourly Operating Reserve Prices, May-August 2002



The pattern of prices reflects the shift in the type of generation resources that participated in the OR markets as the summer progressed. In the later months water became scarce and, as a consequence, hydroelectric generation was offered at higher prices (often ‘out of the money'), in the energy market and at lower prices in the OR markets in order to at least gain some revenue. In turn, fossil-fired generation shifted from the OR markets, to become fully utilized in the energy market.

Table 2.8 shows this shift in resources for two classes of OR. The most dramatic is 30-minute reserve where hydroelectric accounts for 99 percent of product in August compared to 44 percent in May and the reverse occurs with fossil generation, as its share declines dramatically in July and August.[71]

Table 2.8: Share of OR Scheduled by Resource Generation Type, May – August 2002[72]

	May		June		July		August	
Resource Type	**10 min. non-spin**	**30 min.**	**10 min. non-spin**	**30 min.**	**10 min. non-spin**	**30 min.**	**10 min. non-spin**	**30 min.**
Fossil	25%	42%	20%	39%	12%	7%	13%	1%
Hydroelectric	73%	44%	74%	57%	86%	89%	86%	99%
Combustion Turbine Unit (CTU)	0%	0%	0%	0%	0%	1%	1%	0%
Other	2%	14%	6%	4%	2%	3%	0%	0%

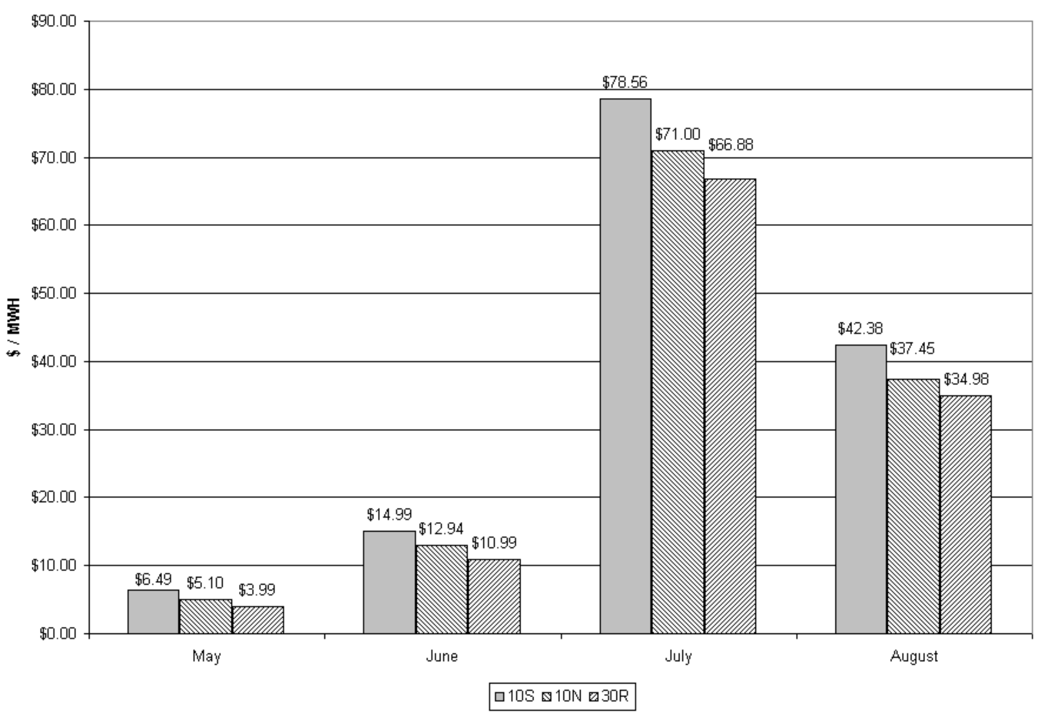
Another observation drawn from Figure 2.9 is the higher price of 10-minute spin compared to the other two classes of OR and its less dramatic price decline from June to August. One would expect the price for this class of OR to be highest because in some hours a fossil unit would have to be started or a hydroelectric unit that is not operating will have to be 'motored' and will consume power from the grid. In other words, the cost to deliver this resource to the market is higher than the other classes of OR and one would it expect it to be priced accordingly.

An important feature of the OR market in the May-August period, discussed in detail later in this chapter, relates to the impact of joint optimization of the energy and OR markets and the 'out-of-market' actions taken over the period to deal with OR shortfalls.

[71] The other side of this picture is replicated for the energy market in Tables 2.6 and 2.7, showing the decline in hydroelectric resources scheduled in the energy market over the period.
[72] These statistics are for the unconstrained (market) schedule.

Recall that under joint optimization the DSO simultaneously satisfies the demands for OR and energy by choosing the cheapest combination of resources offered into the marketplace. Small variations in the amount of resources available can result in a reconfiguration of the resources selected in the three OR markets and the energy market and a consequent (and at times dramatic) change in price. One of the implications of the introduction of 'out-of-market' control actions was a depressing effect on real-time OR (and energy) prices. This is very evident when one compares the pre-dispatch prices for OR, as shown in Figure 2.10 with the actual OR prices in Figure 2.9. For example, in July the pre-dispatch OR price was close to $80, almost nine time higher than the average hourly price that actually cleared the market. Why this happened is explained in section 2.5.

Figure 2.10: One Hour-Ahead Pre-Dispatch OR Prices, May- August 2002



2.3 Analysis of high priced hours

A key responsibility of the Market Assessment Unit, under the direction of the Panel, is to monitor regularly for 'anomalies' in the market. These are behaviours or outcomes that are inconsistent with expectations, or activities that fall outside of predicted patterns or norms. The MAU's definition of anomalous activity and the metrics that they apply to identify their occurrences are still evolving. Currently, the MAU monitors market activity on a daily basis, always trying to identify the crucial factors that influenced each day's events. Each morning, as part of a market watch committee, the MAU reports their findings to key IMO officials; a forum which provides a form of 'peer review' for developing a more rigorous understanding of the dynamics of the new market and the functioning of the market systems and algorithms. Through ongoing observations, the MAU is developing a keener understanding of the crucial factors influencing market outcomes. It is also beginning to identify emerging patterns in participant behaviour. As the market data reflecting these factors and patterns become increasingly available, we have asked the MAU to continue to develop more rigorous metrics for discerning market anomalies, which will streamline its market monitoring activities.

During the first four months the MAU focussed its work on understanding the critical factors underlying high priced hours. Initially this simply meant assessing the circumstances leading to high HOEP. As the market evolved and uplift charges became a more important feature, the MAU also began examining the underlying factors leading to high composite prices, the HOEP plus hourly uplift.

In the following two sections we report the results of this analysis for the two sets of data. For purposes of this report, we have arbitrarily selected $200/MWh to define our 'high-price' cases. The $200 threshold is well over three times the average HOEP for the four-month period. It also exceeds what is generally known to be the incremental costs of the highest cost fossil generating units in the province. Section 2.3.1 summarizes the findings of the analysis of the hours with a HOEP of at least $200 and section 2.3.2 does the same thing for instances where the hourly uplift charge exceeded the HOEP. Appendix 1 provides details of representative cases for each of these types of event.

2.3.1 Hours with HOEP above $200

Over the four-month period there were 21 hours where the HOEP exceeded $200. Table A1.1 in Appendix 1 provides the key data for each of these instances. This appendix also contains a detailed description of how events unfolded for two cases: Case 1, June 11, hour 10; and Case 4, August 13, hour 17.

An assessment of the 21 hours under scrutiny leads to the identification of a number of common factors that explain the high prices. It is usually not a single factor that explains the observed price swing but rather a combination, although not all the identified factors are present in each and every high-price event. In all situations the supply cushion was relatively low in pre-dispatch and subsequently it became even tighter in real-time. In all cases the squeezing of the supply cushion was caused by one or more of the following factors:[73]

- Real-time demand was much higher than the pre-dispatch forecasts of demand (7 cases)
- One or more imports failed real-time delivery (19 cases)
- Real-time provision of energy by self-scheduling and intermittent generators was less than scheduled in pre-dispatch (21 cases)
- One or more generating units were made unavailable in real-time as a result of a forced outage or derating (7 cases)

Each of these factors is discussed and linked to one of the representative cases.

[73] See section 2.5, an examination of the reasons why pre-dispatch price signals and real-time prices often did not match, for additional information on these factors.

Real-time demand was much higher than the pre-dispatch forecasts of demand

Higher demand, by itself, will cause higher prices to occur as demand moves toward the blade of the offer curve. However, the under-forecast of demand in pre-dispatch can also influence the amount of available supply in real-time in two ways. First, an under-forecast of demand means that the one hour ahead pre-dispatch sequence will schedule fewer imports (or more exports) for the real-time market, than would have otherwise been scheduled. Because imports must be fixed one-hour before real-time, in order to accommodate arrangements at the interties between Ontario and neighbouring jurisdictions, imports not selected in the one hour ahead pre-dispatch are made unavailable for supply in real-time. Second, at times, an under-forecast of demand sends incorrect signals to domestic suppliers regarding the profitability of when to start up their fossil-based facilities. If a supplier determines that based on the daily forecasts, it is unprofitable to start a unit for supply in an upcoming delivery hour, that unit will be unavailable for supply in real-time, even if the actual price would have rendered the starting of the unit profitable. Both of these factors cause the blade of the offer curve to shift to the left in real-time, thereby further exaggerating the upward price effect of the under-forecast of demand.

Case 1 in Appendix 1 is a classic example of the impact of an under-forecast of demand in pre-dispatch – actual demand exceeded the forecast by 629 MW on June 11. This case also illustrates the unfortunate impact of an underestimated demand in pre-dispatch on the availability of fossil-fired generation in real-time. Fossil units who had offered their capacity at prices higher than the pre-dispatch average price of $40 for the core part of the day were not selected and therefore were not available in real-time when prices increased well above these offer prices. Recall that fossil-fired units may need 2-12 hours to start up before coming into service. Had suppliers within the province assumed that real-time prices would have exceeded what was shown in pre-dispatch they could have ensured their selection by offering at or below this price hoping to be compensated by a higher market clearing price in real-time. However, the average on-peak price in

May was only $35[74] and pre-dispatch had been regularly over-forecasting prices up until that time.

One or more imports fail real-time delivery

When an import fails to be delivered in real-time, the real-time supply curve shifts to the left causing the market to clear higher up on the blade of the offer curve. In other words, when an import scheduled in pre-dispatch fails to materialize in real-time, the DSO then selects more expensive offers from Ontario-based generation. This situation is illustrated in Case 4, August 13, 2002, when the HOEP rose to $437.57 in Hour 17.

On August 13 the one-hour ahead pre-dispatch schedule selected 4039 MW of imports for hour 17. At the beginning of the hour 901 MW of these imports were not available for dispatch. Because of the protocol established for scheduling between jurisdictions, the 4039 MW of imports had been determined and fixed in the hour ahead pre-dispatch sequence.[75] There was no possibility of selecting additional import offers for the five-minute intervals of Hour 17, even if these higher priced offers would have impacted the real-time price. As a consequence, to compensate for the sudden loss of 901 MW of imports, the DSO selected Ontario generating capacity that was farther up the existing offer stack and prices rose during the hour.

Imports can fail for different reasons. It may be that the entity managing the transaction decides to buy energy from, for example, the New York market at a price well below prevailing NYISO prices in the hopes that the market clears at this lower level and the energy can be profitably sold into Ontario. However, the entity's expectation of low prices in New York may not be realised and it may be unsuccessful in buying energy out of New York to import to Ontario. In such a case, because of the tight timing between the checkout procedures in New York and Ontario, it may not have time to provide the IMO with notice of the outcome before the IMO runs its final pre-dispatch sequence.

[74] Even in June the average HOEP of $35.13 was below the $40 pre-dispatch average price of June 11.

Therefore, the transaction appears and is locked into the one-hour ahead pre-dispatch and counted on for delivery in real time. When real-time arrives the transaction fails.

While arbitrage between markets is usually beneficial, in the circumstances outlined above, failed intertie transactions can have and, indeed, have had a serious impact on market outcomes in Ontario. In recognition of the potential for some participants to speculate on intertie transactions without a legitimate likelihood of success, the IMO instituted a rule prior to market opening that provides for stiff penalties to deter this conduct.[76] A number of investigations are underway within the IMO's Market Assessment and Compliance Division related to potential breaches of this rule.

The IMO has also recognized that scheduling issues between it and NYISO complicate intertie transactions and discussions are underway between the two organizations to try to ameliorate these 'seams' issues.

The one-hour ahead pre-dispatch schedules more energy from self-scheduling and intermittent generators than is actually scheduled or provided in real-time

When pre-dispatch schedules more megawatts from self-scheduling and intermittent generators than is scheduled in real-time, it means that the pre-dispatch may have selected too few imports or failed to schedule the start of a fossil unit for real-time dispatch. The overall effect is that there is less supply available in real-time and the market clears higher up the blade of the offer curve.

Once again, this is a situation where less energy is dispatched in real-time than was anticipated based on the one-hour ahead pre-dispatch schedule and, once again, the DSO must quickly compensate for the shortfall by selecting higher-priced offers. As the market progressed through the period, the IMO and self-schedulers worked hard to

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[75] See Chapter 1, section 3.3.1 and Chapter 2, section 2.5.3 for more information.
[76] See IMO Market Manual Part 2.15: Intertie Transaction Non-Compliance Financial Penalty, available at www.theIMO.com.

correct these types of discrepancies. Table A1.1 in Appendix 1 indicates under-generation by self-schedulers occurred regularly in all the high price hours. On June 11, delivery hour 10 (Case 1), under-generation by self-schedulers was an aggravating factor causing the HOEP to reach $701.69.

One or more units are made unavailable in real-time as a result of a forced outage or derating

When a unit is forced out of service or derated in real-time, the market must call upon suppliers with higher price offers (or bids from dispatchable loads) to meet the energy demand, thereby forcing up the market-clearing price. As with the other causes of a real-time shortfall that have already been discussed, a derating means that less supply will be available in the real-time market than would otherwise have been available and the market is more likely to clear higher up the blade of the offer curve.

Case 1 in Appendix 1 illustrates how the derating loss of about 79 MW in Hour 10 on June 11, 2002 became another contributing factor leading to a HOEP of $701.69. The DSO reduced the operating reserve requirements[77] to free up energy in order to meet the higher demand encountered in three intervals. On each occasion the next available resource in the market schedule able to satisfy demand in real time was at $1,950.

2.3.2 Hours where the hourly uplift charge is higher than HOEP

There were 7 high-price hours in which the hourly uplift fee exceeded the HOEP. This was a surprising occurrence to us, and something we wanted to understand better. These 7 hours occurred in just two days, July 3 and August 1, and in each case the dominant component of the hourly uplift was the IOG. In all but one of the hours the IOG alone

[77] The activation of operating reserve to replace the lost supply and the subsequent reduction in the operating reserve requirements through an 'out-of-market' control action can lower the real time price as explained at length later in the Chapter at section 2.5.4. As detailed in Appendix 1, this eventually happened in Case 1.

was greater than HOEP. Cases 2 and 3 in Appendix 1 provide summaries of our review of these 7 hours.

High hourly IOG payments are coincident with the occurrence of three other events in the market. First, there must be a 'large' difference between the pre-dispatch price and the HOEP. As discussed in Chapter 1, to protect importers selected in the pre-dispatch sequence from receiving a payment that is below their offer price, the IOG compensates them for any difference between their offer price and the HOEP. The greater the difference between the pre-dispatch price and HOEP, the greater is the number of imports likely affected by such a difference and the larger is the IOG that is likely to result. As Cases 2 and 3 show, in each of the high priced hours of July 3 and August 1, the pre-dispatch price was at least $1,200/MWh higher than the HOEP.

Second, high hourly IOGs occur in hours when energy demand is greater than domestic supply (i.e., hours when the domestic supply cushion is negative). In these hours, imports are required in order to maintain the Ontario supply/demand balance, and prevent the IMO from having to implement additional emergency control actions. This was the case on July 3 and August 1 where in all of the high priced hours identified, the domestic supply cushion in pre-dispatch was never greater than –3 percent and at one point was as low as –8 percent. As a result, a large quantity of imports was accepted for real-time delivery. As Case 2 indicates, on July 3, the amount of imports accepted in the unconstrained pre-dispatch ranged from 2,460 MW to 2,674 MW. On August 1 (Case 3), the reliance on imports increased with the amount accepted in the unconstrained pre-dispatch ranging from 3,237 MW to 4,355 MW.

Third, high hourly IOGs coincide with hours for which a large percentage of the imports scheduled in pre-dispatch were scheduled at a price greater than HOEP. In each of the 7 hours identified, typically 90 percent of the imports accepted in the unconstrained pre-dispatch were accepted at prices above the eventual HOEP. As a result, roughly 90 percent of all imports received an IOG payment. This coupled with the high quantity of imports selected and the large divergence between the pre-dispatch price and the HOEP contributed to the occurrence of the high hourly IOG in these hours.

Two of the factors contributing to the occurrence of high hourly IOG's are factors that we had already identified as being problematic to the Ontario market - namely the often large and persistent difference between the pre-dispatch price and the HOEP, and the adequacy of domestic supply. We discuss these issues in more detail in other sections of this report. However, in reviewing the instances of high hourly IOGs and the factors causing their occurrence, we also identified an additional concern regarding the behaviour of market participants.

Following the July 3 events, the MAU began to identify the occurrence of 'implied wheeling'. This occurs where a trader exploits the predicted differences between the high guaranteed import price and the eventual lower real-time Ontario price by offering an import into Ontario and bidding an export of an equal quantity out of Ontario. The trader is guaranteed the high import offer price through the IOG but pays for the export at the lower real-time price. The end result is that the trader earns a profit (paid by Ontario consumers) equal to the difference between the offer price and the HOEP even though no energy was actually supplied to the market.

As a result of the MAU's identification of this behaviour, the IMO's urgent rule committee quickly responded to eliminate the profit opportunity from implied wheeling. The group made a rule change that eliminated the payment of the IOG for 'wheeling-through' transactions. For traders that have imports and exports scheduled in the same hour, only the net quantity of imports is now eligible to receive the IOG.

2.4 The determination of the uplift

Table 2.2 presented the overall impact of the hourly uplift on the HOEP. This section describes in more detail the composition of the uplift and discusses the evolution of some of the major components through the first four months of the market.[78]

There are four major components of the hourly uplift:

- payments for operating reserves (OR),
- line losses on the transmission system,
- Intertie Offer Guarantee (IOG) payments, and
- Congestion Management Settlement Credits (CMSC).

Table 2.9 shows, for the first four months, the total hourly uplift and the amount contributed by each of the four major components.

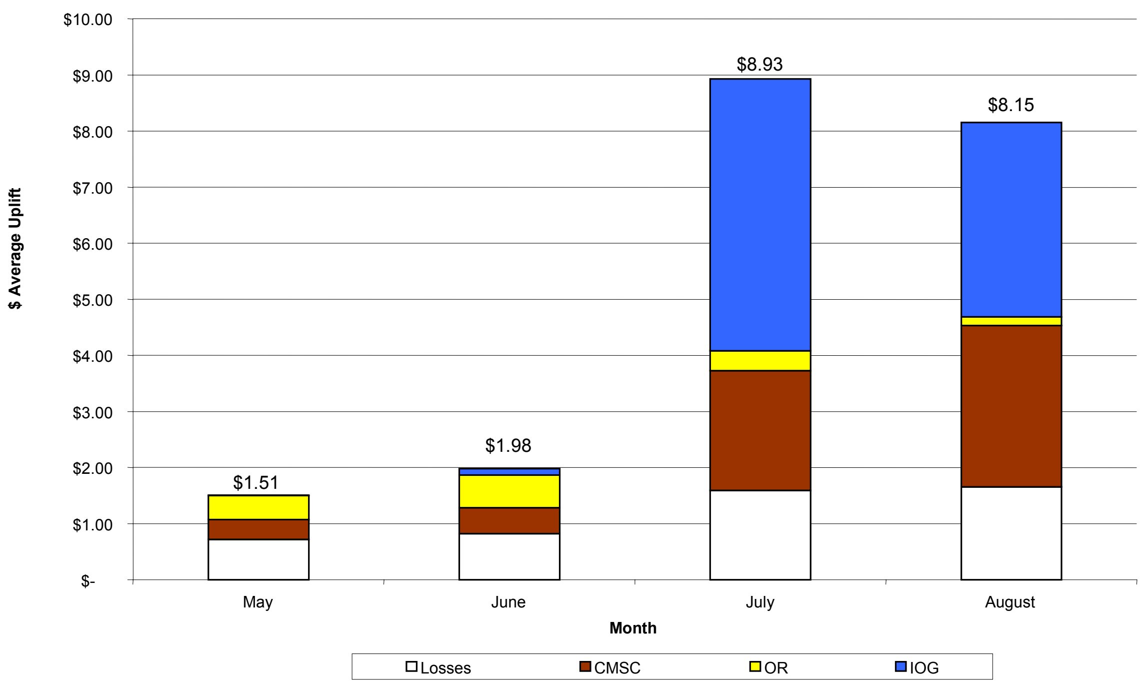
Table 2.9: Total Hourly Uplift Charge ($ millions), May-August 2002

	Total Hourly Uplift	IOG	CMSC	Operating Reserves	Losses
May	$ 17.8	$ 0.1	$ 4.1	$ 5.0	$ 8.5
June	$ 24.5	$ 1.4	$ 5.6	$ 7.1	$ 10.4
July	$ 123.1	$ 67.0	$ 29.5	$ 4.8	$ 21.3
August[79]	$ 109.9	$ 46.7	$ 38.8	$ 2.0	$ 22.3
Period Total	$ 275.3	$115.3	$ 78.0	$ 18.9	$ 62.5

Figure 2.11 portrays the same information in the form of the average impact per MWh. The total charge per MWh is small compared to the monthly HOEP average charge in May and June, only 5 percent, but in July and August the hourly uplift exceeds $8/MWh and is more significant, 13 percent to 15 percent, relative to the monthly average HOEP.[80]

[78] The hourly uplift statistics presented in this section are the actual charges associated with those components of uplift included in the Wholesale Hourly Uplift Charge Estimate provided by the IMO. See Chapter 1, section 3.3.1.5 for other charges associated with the consumption of energy.
[79] Note that the numbers for August are preliminary.
[80] Note these averages in Figure 2.11 are slightly different from those implied by Tables 2.1 and 2.2 which are the unweighted averages of the hourly payments.

Figure 2.11: Average Hourly Uplift, by Month, by Component, May-August 2002



The activity in the operating reserve market was described in section 2.2. The losses component due to the transmission of the energy is generally not controllable and is a function of the characteristics of the transmission system and the energy price. The IOG and CMSC payments are both integral parts of market design, and together accounted for 70 percent of the total hourly uplift over the period. Each of these latter two important payment streams is further examined below.

2.4.1 Intertie Offer Guarantee payments

The rationale for the IOG and the way it works were described in Chapter 1. The IOG was by far the largest single contributor to the hourly uplift in the first four months of the market, with IOG payments amounting to $115.3 million. Close to 90 percent of these payments, however, accrued in ten days when substantial amounts of imports were required to meet very tight supply conditions in Ontario. Table 2.10 shows the ten days in which the largest IOG payments were recorded. The table shows the strong relationship between IOG payments and hourly peak demand, in that all of the top ten days were associated with peak loads greater than 24,000 MW.

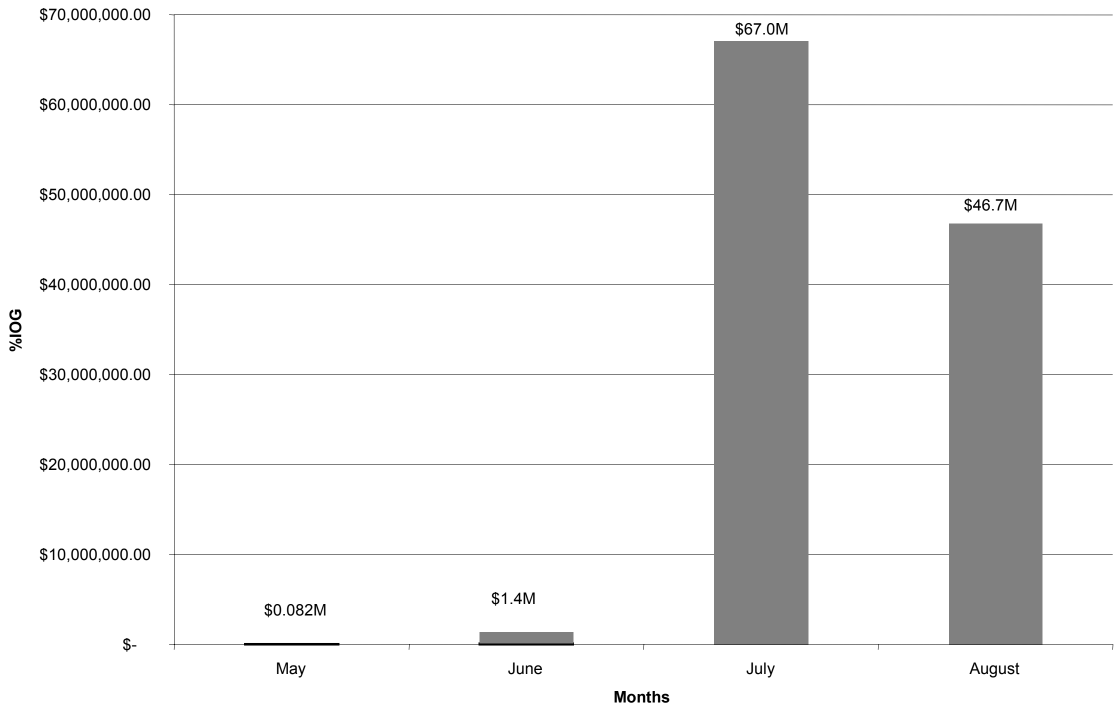
Table 2.10: IOG Payments, May-August 2002

Time period	Guaranteed Imports (MWh)	IOG payment ($ million)	Average IOG Payment ($/MWh)	Peak Demand in 5-min interval (MW) [81]
July 3	22,279.38	21.9	$ 984	25,560.6
August 1	32,127.90	21.5	$ 669	25,446.1
July 22	28,885.15	11.9	$ 411	24,931.7
July 2	15,187.94	11.3	$ 747	25,120.6
July 31	24,027.90	8.9	$ 372	24,505.4
August 13	32,092.20	8.6	$ 269	25,384.1
August 12	34,176.77	7.7	$ 227	25,140.0
July 29	25,130.30	4.8	$ 190	25,079.0
August 16	19,229.30	2.7	$ 140	24,021.6
July 30	16,482.81	2.6	$ 157	24,163.0
Subtotal	---	102.0	---	---
Period Total	---	115.3	---	---

Figure 2.12 shows for each month how the IOG payments were distributed across the five interconnected markets from which power was imported into Ontario.

[81] Peak demand numbers are based on the unconstrained model.

Figure 2.12: IOG Payments by Month, May-August 2002



This figure illustrates the importance of the Michigan, New York and Quebec imports to Ontario reliability. It was the relatively large imports across these interties in the high load periods of the summer months that helped maintain reliability in Ontario. The figure illustrates that the increasing shortage of supply in July and August drove these imports and the IOG payments. As reported earlier in Table 2.7, on a monthly energy basis imports contributed a small portion of the overall supply in the market schedule, ranging between 1.6 and 7.6 percent over the period. However, the peak constrained schedule import of 4,015 MW accounted for more than 16 percent of the peak load that hour.[82] It is also notable that of the total $115.3M payments only $2.7M were off-peak.[83]

[82] On August 1, 2002, hour 20, there were only 3 MW of export at the time. During the peak hour that day, hour 16, the import was smaller and accounted for only 10 percent of the peak supply.
[83] Similar observations about the impact of the interties and imports are discussed in other sections as well. See the discussion of price setting facilities (section 2.1.5), the analysis of high priced hours (section 2.3.1), CMSC (section 2.4.2) and the discussion of intertie utilization (section 3).

Table 2.11: Total IOG Costs per MWh

	May	**June**	**July**	**August**
IOG payment	$ 82,417	$ 1,420,557	$ 67,046,801	$ 46,746,336
Guaranteed Imports (MWh)	11,251	68,695	281,286	339,831
Average IOG Payment ($/MWh)	$ 7	$ 21	$ 238	$ 138

The pattern of IOG across the months indicates that both the total payments as well as payments per MWh were increasing into July and started to decrease in August. Although total guaranteed imports increased in August over July, because average payments were much lower in the latter part of August, the August monthly average was well below the July value. Again, the payments and average pricing were driven by the shortage of resources in these months, coupled with a persistent gap between the pre-dispatch price and the HOEP. The narrowing of this gap as the average HOEP increased in August accounted for a large part of the reduction in average IOG payments in that month.

2.4.2 Congestion Management Settlement Credits

The rationale for congestion management payments and the IMO's role in administering them in a way that mitigates abuse of local market power were described in Chapter 1. CMSC payments accounted for $78 million, or roughly 28 percent of the total hourly uplift payments for the four months of the market. Table 2.12 shows the CMSC payments for the period and by month.

Table 2.12: CMSC Payments, May-August 2002 ($ million)[84]:

	Energy CMSC Payments		Total Energy	Operating Reserves	Total Payments
	Constrained-On[85]	Constrained-Off			
May	1.05	2.58	3.63	0.51	4.14
June	1.71	3.66	5.37	0.28	5.65
July	25.29	3.94	29.04	0.45	29.49
August [86]	28.76	7.57	38.58	0.10	38.68
Period Total	56.81	17.75	76.62	1.34	77.96

The relationship between constrained-on and constrained-off payments is interesting. Through May and June constrained-off payments for energy were more than twice as great as constrained-on payments. In July, as the supply/demand balance tightened and prices rose, constrained-on payments surged. This increase can be attributed to imports accounting for more than half of the constrained-on payments in July (about $12 M) and about three-quarters of those in August (about $22 M). These payments would have been made to imports that were not selected in the unconstrained pre-dispatch, and therefore they did not receive IOG payments, but they were required as the result of the constrained pre-dispatch and received CMSC. In July and August there was another $4 million CMSC for exports reduced in the constrained pre-dispatch schedule.

The distribution of CMSC payments was highly concentrated through the first four months. Although CMSC payments have been made to more than 300 internal and external "facilities"[87], the ten facilities receiving the most payments for energy and operating reserves received 50 percent of the payments and the top five facilities received

[84] The sum of constrained-on and constrained-off CMSC payments does not equal the total energy figure in some months. This is due to the process for assigning the constrained-on or constrained-off label to individual intervals not yet being complete.
[85] As reported in this table 'constrained-on' refers to a situation where additional supply is needed, requiring a generator or import to be constrained on, i.e. increased, or dispatchable load or export to be constrained off or decreased. For the 4 month period the constrained-on CMSC payments for reduced loads and exports were about $6M, mostly in July and August.
[86] Note that the numbers for August are preliminary.
[87] Internal facilities here include individual generating units and dispatchable loads. For imports and exports a "facility" refers to a notional resource, as offered or bid by the participant. As a result, a given participant could receive CMSC for several import or export resources at a given intertie.

slightly more than 36 percent of the payments. For energy payments only, the results are more concentrated, as shown in Table 2.13.

Table 2.13: Concentration of CMSC Energy Payments, May-August 2002 (Percent)[88]

	Share of total payments received by top 10 facilities		Share of total payments received by top five facilities	
	Constrained-off	**Constrained-on**	**Constrained-off**	**Constrained-on**
May	66.0	65.1	53.5	53.2
June	67.5	65.7	47.6	47.3
July	69.1	52	59.1	42.1
August	71.2	78	54.6	68
Period Total[89]	64	54	50	43

The following tables 2.14, 2.15, and 2.16 provide some information about the facilities that received the highest CMSC payments and those which received them most regularly.

Table 2.14: Top 10 Constrained-On Facilities[90]

Facility	CMSC Payment $M	% Days in Period Receiving CMSC
Import 1 - south	6.4	48
Import 2 – south	5.1	40
Import 3 – south	4.7	65
Import 4 – south	4.3	30
Facility 5	2.2	3
Import 6 – south	2.1	11
Facility 7	1.1	23
Facility 8	0.9	46
Facility 9	0.9	51
Import 10 – south	0.9	5

88 These percentages are based on positive CMSC payments for the period only. It is possible for the calculated CMSC to be negative, in which case the facility is charged rather than paid CMSC. These negative payments have also been excluded from the calculated percentages shown in Tables 2.12 through 2.15.

89 Percentages are based on net positive CMSC payments only, and are not entirely consistent with values in Table 2.12 because of the noted constrained-on and constrained-off labelling limitation and as the result of preliminary data changing daily over the course of the analysis.

Table 2.14 shows that the highest constrained-on CMSC payments have gone to imports into the southern part of Ontario. This is the result of the shortages experienced in the summer, which are seen as more severe in the constrained schedule, where some resources are less available for use than in the unconstrained pre-dispatch. On a dollar per MWh basis, these CMSC would be higher in a given hour, but still comparable in magnitude to IOG payments. An export entity and dispatchable load included in this list had their schedules reduced and received CMSC payments for the same reasons. Two other units received their payments primarily as the result of being constrained on early on many days in anticipation of the daily load pickup.

Table 2.15: Top 10 Constrained-Off Facilities[91]

Facility	CMSC Payment $M	% Days in Period Receiving CMSC
Facility 1	5.1	50
Facility 2	2.9	92
Facility 3	2.7	94
Facility 4	1.6	15
Facility 5	1.4	79
Facility 6	1.1	93
Facility 7	0.9	11
Facility 8	0.8	80
Facility 9	0.6	87
Facility 10	0.5	72

There appears to be two main reasons for the CMSC payments to most of the facilities listed in Table 2.15. Transmission limitations in the northwest part of the province, typically the east-west tie, lead to fairly persistent payments. Imports from Manitoba and a facility in the area are affected by more local constraints as well. The other main cause for CMSC payments is a persistent transmission limitation in the Niagara area. Here, three facilities have been regularly constrained-off.

[90] As explained earlier, exports included in this list of "constrained-on" facilities have had the quantity reduced as a result of the constrained pre-dispatch. The identity of these facilities is masked because of the confidentiality provisions of the Market Rules.
[91] The identity of these facilities is masked because of the confidentiality provisions of the Market Rules.

Table 2.16 shows facilities that are not included in Tables 2.15 but were constrained-off with a high frequency and the associated CMSC payments are substantial (no less than about half the CMSC of the 10th facility in the Table 2.15).

Table 2.16: Additional Constrained Off Facilities[92] with High Frequency and Significant CMSC Payments

Facility	CMSC Payment $M	% Days in Period Receiving CMSC
Facility 1	0.3	94
Facility 2	0.4	84
Facility 3	0.3	84
Facility 4	0.2	83
Facility 5	0.4	82

Two of the facilities in Table 2.16 are also in the northwest and experience persistent transmission limitations. The other facilities appear to be constrained-off regularly as the result of the twelve-times ramp rate[93] used in the unconstrained but not the constrained schedule. Such facilities would tend to have offer prices relatively close to the MCP, so the CMSC would not be very large for each event.

Tables 2.15 and 2.16 together suggest that the persistence of transmission limits in the northwest and in the Niagara area led to the significant constrained-off CMSC payments over the period considered. Only one facility, an import, has received relatively large CMSC payments as the result of low offers. Payments made as the result of the twelve times ramp rate, although persistent, are not particularly large.

Two overall observations emerge from this data: CMSC payments are high when the system is short of supply; and persistent transmission constraints have led to relatively large CMSC payments over the period. In light of this it is relevant to note that to date

[92] The identity of these facilities is masked because of the confidentiality provisions of the Market Rules.
[93] As a means for dealing with the volatility of market schedules and prices as a result of looking out only five minutes, the IMO uses a multiplier, currently twelve times, to represent ramping rates in the market schedule. Since the multiplier is not used in the constrained schedule, the two schedules will differ and lead to CMSC payments.

the local market power review has resulted in only a very small fraction of these payments being recovered.

Related to the short supply, there are two factors in the local market power review that have limited the ability to adjust CMSC even when offer or bid prices are unusually high. For a review to continue it must be determined that there is a transmission constraint causing the event, and there is not sufficient competition.[94] With the relatively large number of participants competing to import energy into southern Ontario, the MAU has been concluding in almost all instances that there has been sufficient competition. As well, the high level of constrained-on imports have been needed for adequacy, and thus the MAU again has been treating this as not transmission induced, even though the adequacy problem is exacerbated by transmission.

2.5 Pre-dispatch price signals versus real-time price outcomes

As noted previously, pre-dispatch prices have been consistently higher than real-time prices during the first months of the competitive market, particularly in July and August. This is a cause for concern for at least two reasons. First, inaccurate or unreliable pre-dispatch prices can lead to inefficient production. The pre-dispatch prices are intended to provide market participants with an 'advance notice' of the likely value of electricity in Ontario in an upcoming hour. Many market participants require this advanced notice in order to prepare their facilities for the future periods.[95] Suppliers with fossil generation facilities can require anywhere from two to twelve hours lead-time in order to start their units and ramp them towards their desired real-time production levels, and large industrial customers may require several hours notice before cancelling shifts and

[94] See sections 1.3.10 and 1.3.12 of Appendix 7.6 of the Market Rules

[95] For dispatchable loads and generators, the key price signals are the 36-hour to 5-hour ahead pre-dispatch prices; within this time frame they can modify their entire bids/offers in response to the price signal. The 4- and 3-hour ahead pre-dispatch prices can be used as information to revise bids/offers within 10 percent. For those non-dispatchable loads that can modify their energy consumption at any time to avoid paying higher hourly prices, all pre-dispatch prices can be used as signals for revising consumption plans.

shutting-down production lines. When the pre-dispatch price is an accurate and reliable forecast of the real-time price, market participants can plan their actions with more certainty. This certainty ensures that only those customers who value the electricity at the real-time price will be consuming it (others will have had time to make other arrangements), and the cheapest and precise amount of suppliers are on-line and available to produce it. Over time, the ability of pre-dispatch forecasts to predict actual outcomes relatively closely is important to potential investors in signalling the integrity and credibility of the marketplace.

Second, an inaccurate pre-dispatch can cause real-time scheduling inefficiencies. The selection of imports and exports for real-time delivery is done in the one-hour ahead pre-dispatch. The schedules of these imports and exports are fixed during the delivery hour regardless of the real-time price. If the pre-dispatch over-forecasts the real-time price, then too many imports (too few exports) are chosen. Cheaper domestic facilities are dispatched off instead of the relatively higher-cost imports, and export customers who were willing to pay more for the electricity than the real-time price cannot use it for their productive uses.[96] When the one-hour pre-dispatch price is an accurate reflection of the real-time price, a more efficient choice of imports and exports is made.

The MAU has undertaken a detailed analysis of the differences between the pre-dispatch and real-time prices, and this analysis is summarized in this section. The main conclusion is that there is no single factor that explains the divergence. A number of different forces are at play – relating to market design, the operation of the DSO and the behaviour of participants.

Table 2.17 below shows the magnitude of the discrepancies between the pre-dispatch price forecast and the HOEP over the first four months. The table compares both the five-hour ahead and one-hour ahead pre-dispatch prices. The five-hour ahead price was chosen since it represents the last price signal dispatchable market participants receive

[96] There is a view that attracting more imports in pre-dispatch can provide insurance to deal with real-time contingencies that can cause potential supply shortfalls and price spikes. This is discussed more below.

before the closing of the offer/bid window. The one-hour ahead price was chosen as it is essentially the price that determines the import and export schedules.

Table 2.17: Measures of Difference between Pre-dispatch Prices and the HOEP

	First Four Months	May	June	July	August
5-hour ahead pre-dispatch price minus real-time price ($/MWh)					
Average difference	39.61	1.03	8.14	108.65	38.02
Maximum difference	1932.36	33.61	420.15	1929.05	1932.36
Minimum difference	-661.69	-64.08	-661.69	-51.75	-501.20
Standard deviation	195.55	8.18	43.10	323.27	132.38
Average difference as a % of the HOEP	42.20%	10.12%	25.15%	128.9%	48.23%
1-hour ahead pre-dispatch price minus real-time price ($/MWh)					
Average difference	29.17	1.61	7.24	77.94	40.04
Maximum difference	1929.71	47.89	365.46	1929.71	1506.00
Minimum difference	-661.69	-62.89	-661.69	-48.78	-572.2
Standard deviation	159.95	8.03	36.44	266.52	166.81
Average difference as a % of the HOEP	55.05%	10.88%	23.17%	91.94%	50.06%

The data show a growing average difference, and increasing volatility as the period progressed. In August, however the size of the over-forecast and its volatility declined considerably. This is true for the differences between both the five-hour ahead and one-hour ahead pre-dispatch prices and HOEP. The differences and volatility narrow as pre-dispatch approaches real time, but only slightly. The table also shows that the average difference as a percentage of the HOEP increased significantly from May to July and then declined in August. In July the average pre-dispatch price was nearly twice as large as the HOEP.

Figure 2.13 shows an alternative representation of the difference between the one-hour ahead pre-dispatch price. The histograms for each of May, June, July and August show clearly that the difference is biased upward, and that the upward bias increased as the period progressed.[97]

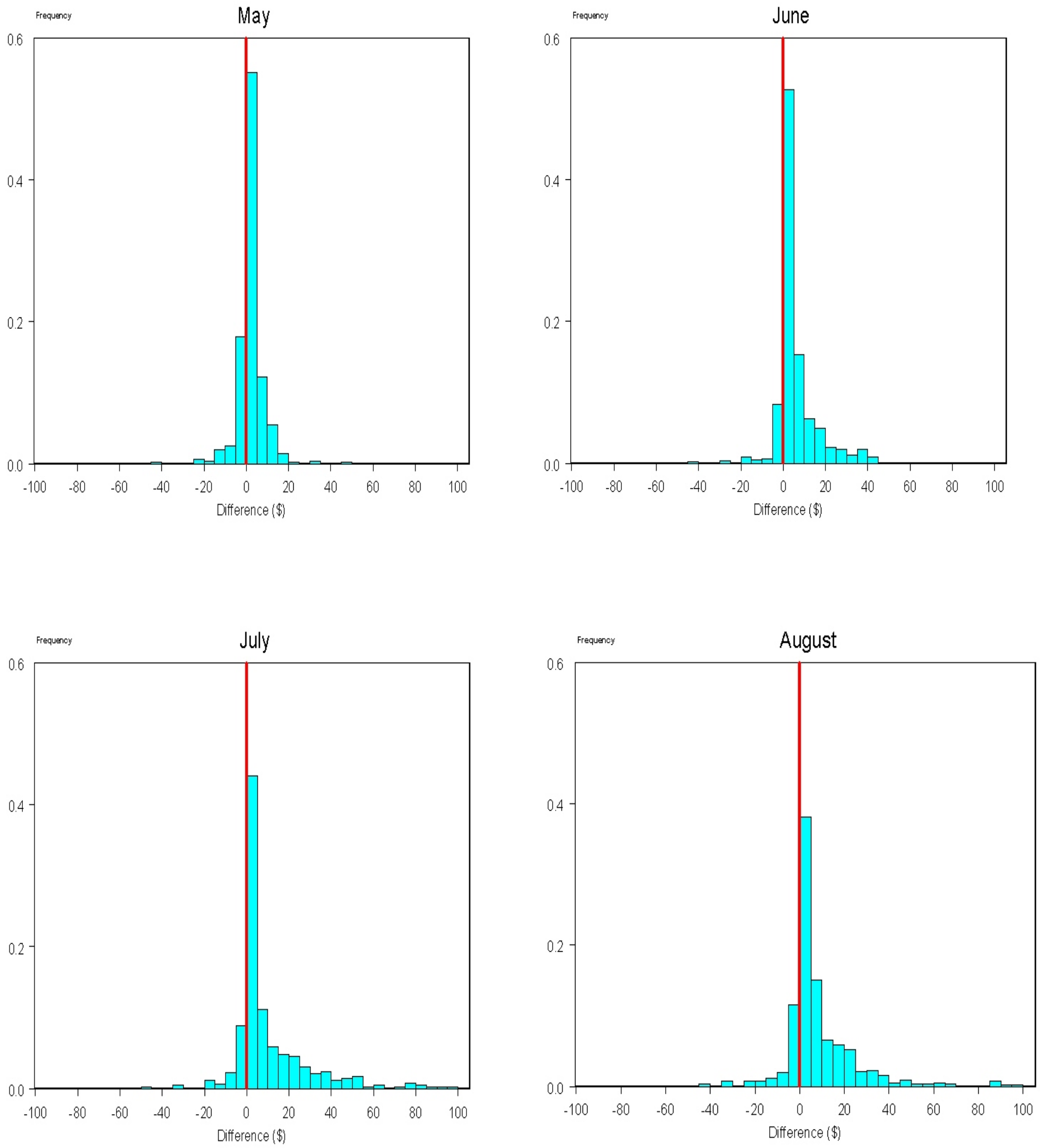
The key factors contributing to differences between the IMO's pre-dispatch forecasts and HOEP appear to be:

- demand forecast error;
- the under performance of self-scheduling and intermittent generators;
- the role of imports and exports in pre-dispatch and real time;
- 'out-of-market' control actions in response to operating reserve shortfalls; and
- miscellaneous factors.

Each of these is described below.

[97] The diagrams for July and August are presented with a $100 cut-off so that the scale is comparable to May and June. However, there were a number of observations that existed beyond the $100 value for July and August.

Figure 2.13: Differences between the One-hour Ahead Pre-dispatch Price and the HOEP, May- August 2002



2.5.1 Demand forecast error

The pre-dispatch prices are directly influenced by the IMO's forecast of demand for a given dispatch hour. At the risk of oversimplification, the IMO forecasts peak primary demand (non-dispatchable load plus dispatchable load) for a given hour and then runs the DSO to determine the pre-dispatch price. If the IMO demand forecast is biased upward, then the pre-dispatch price (other things held constant) will also be biased upward.

The IMO's pre-dispatch demand forecast has contributed to the general tendency for the pre-dispatch price to over-forecast the HOEP in two ways. First, the practice in the pre-dispatch sequence of using the peak demand value expected within the hour as opposed to using the average demand value expected within the hour introduces a natural bias in the forecasting of the HOEP.[98] Second, the pre-dispatch forecasts have also tended to over-forecast the peak demand value in each hour, implying that there is an upward bias in the forecast of demand.[99]

It should be pointed out though, that on the other side of the coin, the use of average demand for the hour would induce both a price bias in the opposite direction and an under scheduling of resources for the peak periods of the hour, leading to potential reliability issues.

Table 2.18 shows some summary measures for the mean difference of the demand in the first four months. It separates the difference due to the use of peak rather than average from the general forecast error by calculating the general forecast error as the difference between the forecast for the hour and actual peak demand in the hour.

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[98] The rationale for using peak demand, which was introduced as a result of the testing that took place prior to market opening, is that it helps address a potential reliability issue by pre-scheduling additional fossil units during periods when the demand changes rapidly within the hour. The additional fossil units ensure that sufficient supply is available (and on-line) to absorb the potentially large interval-to-interval changes in demand. Having the additional fossil units on-line also reduces short-term price volatility.
[99] The demand values used in this study represent only the non-dispatchable load component of primary demand. It is calculated as the sum of the unconstrained schedules of all generation plus net imports minus dispatchable load.

Table 2.18: Forecast Bias in Demand during the First Four Months

	Mean forecast difference: pre-dispatch minus average demand in the hour (MW)		Mean forecast difference: pre-dispatch minus peak demand in the hour (MW)	
	5-hour ahead	1-hour ahead	5-hour ahead	1-hour ahead
May	277	301	41	65
June	502	454	236	188
July	616	535	325	244
August	363	381	78	96
	Mean forecast difference: pre-dispatch minus average demand divided by average demand (%)		**Mean forecast difference: pre-dispatch minus peak demand divided by peak demand (%)**	
	5-hour ahead	1-hour ahead	5-hour ahead	1-hour ahead
May	1.88	1.98	0.45	0.34
June	3.17	2.82	1.49	1.15
July	3.48	2.96	1.82	1.31
August	1.99	2.08	0.42	0.52

The table shows that the mean forecast difference increased considerably from May to July before declining in the month of August. It also suggests that what one might call the 'pure' forecast difference (that is the forecast versus actual peak demand) accounts on average for a significant part of the total difference and during the four months has demonstrated a significant upward trend. Note also that the forecast difference measured as a percentage of the actual demand also increased from May to July, indicating that even when accounting for demand growth through the summer, the demand forecast difference continued to increase in relative magnitude. It should be noted that precise electrical demand forecasting is an extremely difficult issue. As an example, a 1% change in peak demand can be caused by less than 1°C change from forecast in temperature and humidity on a hot summer day.

The standard for the IMO forecast error is to be within 3 percent of the actual demand value on a daily basis. Table 2.18 indicates that the IMO was certainly well within this standard across the four months when the peak demand value is used as the benchmark; the highest monthly difference occurred in July when the forecast was on average only

1.31 percent higher than the peak value. Nonetheless, in the new deregulated market, an error of 3 percent can represent more than 600 MW, which particularly on a day when supply is tight, can translate into a large difference between the pre-dispatch and real-time prices. This highlights that there is little margin for demand forecast error under the current approach for pre-dispatch price forecasting and the extreme sensitivity of price to any differences between pre-dispatch and real-time. Chapter 3 provides some suggestions for improving the price signalling information provided to participants.

2.5.2 The under-performance of self-scheduling and intermittent suppliers

Another factor that can distort the pre-dispatch price forecast is the difference between the offered quantities and the real-time operational metered quantities of self-scheduling and intermittent generators (SS generators). These generators submit hourly schedules to the IMO that specify a quantity and a 'zero' price (the price above which they are willing to sell all of their offered quantity). They agree that they will use best efforts to supply the specified quantity so long as the price is above their 'zero' price. This quantity is used to determine the pre-dispatch price. In real-time, the actual quantities supplied by SS generators are estimated by telemetry readings of the facilities' operational meters and inputted (with a 10-minute lag) as the unconstrained schedule for each generator. Should the scheduled quantities differ from the operational meters, there is potential for the pre-dispatch price forecast to be inaccurate.

The discrepancies between offered quantities and the real-time operational metered quantities of SS generators are summarized in Table 2.19. There are instances where the operational meters registered higher production levels relative to what was offered and accepted in pre-dispatch, which would tend to lower the real-time price relative to the pre-dispatch price. But, on balance, the table shows that the operational meters have registered lower real-time production levels relative to what was offered and accepted in pre-dispatch. The overall impact of this factor would be, therefore, to make the HOEP higher relative to pre-dispatch and to offset the tendency of other factors that lead to a consistent overestimate.

Table 2.19: Discrepancy Between SS Generators' Offered Quantities and Operational Metered Quantities

	Offer quantities of SS generators minus operational metered quantities (MW)			
	Total MW offered	**Maximum difference**	**Minimum difference**	**Average difference**
May	817,296	261.4	-124.3	65.1
June	802,703	350.0	-334.0	65.9
July	878,350	299.5	-74.8	46.2
August	844,939	241.4	-82.4	62.2

There are two principal causes for the discrepancy between the offered quantities and real-time operational metered quantities of SS generators. The first cause is general non-compliance; SS generators failing to deliver the exact quantities that were offered. Over the last four months, the IMO control room staff have worked diligently with SS generators to ensure that production targets were met in real-time. This work contributed towards a reduction in the discrepancy in the month of July. The second cause relates to deficiencies or inaccuracies with operational meters or telemetry readings. The IMO has identified a number of SS generators whose operational meters provide inaccurate readings of actual production levels. The IMO is considering options for improving the status of these generators' metered readings.

2.5.3 The role of imports and exports in pre-dispatch and real time

Recall that because of the need to schedule exports and imports in cooperation with neighbouring jurisdictions, flows are determined in the one-hour ahead pre-dispatch sequence. Imports offered at prices below the pre-dispatch price and exports bid at prices above the pre-dispatch price are all accepted for real-time dispatch, and all other export bids and import offers are rejected. In real-time, the accepted flows are fixed for the entire delivery hour and do not adjust with changes in the five-minute MCP. This is in fact accomplished by placing net imports (scheduled imports minus scheduled exports) at the bottom of the offer curve at a very low price.

As a result of this treatment, there are two ways in which imports and exports can affect the discrepancy between the pre-dispatch and real-time prices.

First, transactions that have been scheduled in pre-dispatch may fail to materialize in real time. There may be many reasons why this occurs.[100] When a scheduled intertie transaction fails, however, the IMO must either find more expensive generation to replace a failed import, or must dispatch down generation to compensate for a failed export. Failed imports raise the HOEP, and failed exports lower the HOEP, relative to the pre-dispatch price.

Table 2.20 shows the incidence, and average magnitude of failed intertie transactions since the market opened. The incidence of failed transactions has increased since the start of the market, and exports have tended to dominate imports, both in magnitude and incidence.

Table 2.20: Incidence and Average Magnitude of Failed Intertie Transactions

	Failed Imports into Ontario			Failed Exports from Ontario		
	Number of incidents	**Maximum Hourly Failure (MW)**	**Average Hourly Failure (MW)**	**No. of Incidents**	**Maximum Hourly Failure (MW)**	**Avg. Hourly Failure (MW)**
May	66	220	61.3	120	400	120.2
June	154	300	60.5	275	600	144.4
July	256	1,000	167.8	339	800	247.7
August	218	1,121	171.1	279	900	264.9

Second, even when intertie transactions take place as scheduled, the way in which they are handled in real-time tends to exacerbate any discrepancy that may exist between the pre-dispatch and real-time prices. This is particularly so when supply conditions are tight and a relatively large quantity of imports is required to meet Ontario energy demands.

[100] The term ‘seams issues’ is used to denote those rules and operating procedures that prevent the seamless flow of power from one jurisdiction to another. The failure of scheduled intertie transactions are a source of disruption to both the markets concerned and discussions among ISO’s are underway to attempt to resolve ‘seams issues’. The IMO has a rule in place to prevent gaming by heavily penalizing market participants that offer exports or imports in pre-dispatch that are not bona fide offers.

The reason why this occurs is complex and technical. An example, using actual experience from July 22, is provided at Appendix 2.

2.5.4 'Out-of-market' control actions

The IMO's use of 'out-of-market' actions in response to an operating reserve shortfall in the real-time market contributes to differences between the pre-dispatch and real time prices.

Operating reserve shortfalls occur when either the total amount of available MW offered in the market for a class of operating reserve is less than the IMO's requirement for that class of reserve, or when the total amount of available MW offered for energy is insufficient to simultaneously satisfy both the energy demand and to back the full operating reserve requirement.[101] Operating reserve shortfalls are often triggered in real-time as a result of an unexpected loss of supply due to failed imports, under-generation by self-schedulers or other generators on forced outages or unit derating.

As indicated in Chapter 1, operating reserve requirements are determined by reliability considerations that must satisfy both Ontario and industry standards.[102] During the IMO's pre-market tests, there were many periods in which the market experienced operating reserve shortfalls, generally from a shortage of energy offers. In such circumstances, both the energy and operating reserve prices were quickly affected, with the energy price

[101] For example, the 10-minute spin requirement has typically been 414 MWh. If market participants collectively offer a total of 400 MWh of 10-Minute spinning operating reserve, there will be insufficient offers to meet the IMO's requirement and an operating reserve shortfall of 14 MWh in the class will occur. Alternatively, the IMO typically requires a total of 1580 MW of operating reserve (10 spin, 10 non-spin and 30 minute reserve combined). Assume that the market energy demand is 20,000 MWh and that market participants collectively offer a total of 21,000 MWh of energy (with 1,800 MWh corresponding to operating reserve offers). The market would fail to provide sufficient energy to meet both the market demand and back the full operating reserve requirement -- a total of 21,580 MWh. The market would experience an operating reserve shortfall of 580 MWh.

[102] The applicable conditions are set out in the Ontario Market Rules and by the Northeast Power Coordinating Council (NPCC) and North American Electric Reliability Council (NERC) and are described in Section 3.3.1 of Chapter 1.

in particular displaying substantial volatility and a tendency to move toward the maximum market-clearing price of $2,000/MWh.

However, while the market may have failed to provide sufficient offers to meet the full operating reserve requirements, the IMO recognized that overall, it was not deficient. There were a number of 'out-of-market' measures that could be used to assure that reliability conditions were met. Such measures are essentially actions that were available to manage reliability concerns in the previously regulated environment, but for which no available commercial products yet existed in the new marketplace. Their use could therefore be considered as a transition to the new market, pending the availability of sufficient competitive supply.

These 'out-of-market' measures include:

- 'recallable' export transactions, which in effect provide additional generation, and vary depending on participant bids,
- 3 percent and 5 percent customer voltage reductions, which reduce customer load by 300 and 500 MW respectively, and
- permitting a temporary shortfall in operating reserve, according to NPCC rules which provide for temporary shortfalls in 30-minute reserve (up to 4 hours) and 10-minute non-spinning reserve (up to 30 minutes).

Prior to market opening, and based on the results of the testing, the IMO introduced several measures aimed at providing a greater level of stability in the market. One of these was the ability of the IMO to utilize 'out-of-market' mechanisms in times of operating reserve shortfalls. They were integrated into the operation of the market in the following manner.

- In the pre-dispatch sequences, market-supplied operating reserve is assumed to be the only source of reserve – 'out-of-market' measures cannot be used. If an operating reserve shortfall occurs in pre-dispatch, higher prices will result in both the energy and operating reserve markets in order to provide a signal to the market of the need for additional supply.

- In real-time, if there are insufficient available offers for energy and/or operating reserve, the IMO can use 'out-of-market' measures to satisfy the operating reserve shortage. The operating reserve made available through such actions has no associated price attached and as such is treated as a free good to Ontario electricity consumers.

- The IMO integrates the 'out-of-market' measures into the market through a simple manual process. When the IMO observes or expects a shortage of operating reserve offers in an upcoming interval, the reserve requirement in the real-time *constrained* schedule is manually reduced to the level of market resources that have been offered into the reserve markets. The IMO focuses on the constrained schedule, as this is the schedule by which it manages reliability. The reduction permitted is up to the amount of reserve available from 'out-of-market' measures. This manual reduction in reserve requirement has the effect of allowing the market to clear with available operating reserve offers.

- This manual reduction in reserve requirement to the level of available offers in the real-time constrained sequence is also applied equally to the real-time *unconstrained* sequence for the purpose of determining clearing prices for all markets.

- Of note is the fact that while non-compliance of units has no direct impact on price, the secondary impact is that non-compliance by generators can lead to a shortage of market operating reserve in real-time in the constrained schedule, leading to a reduction in the 'market' operating reserve requirement which, as discussed, can lead to a reduction in price.

The manual implementation of 'out-of-market' measures in the real-time market but not the one-hour ahead pre-dispatch sequence can contribute to the divergence between the one-hour ahead pre-dispatch price and the real-time price. The one-hour ahead pre-dispatch sequence rarely exhibits an operating reserve shortfall (it occurred in only 2 hours in the period) while the real-time constrained sequence frequently exhibits reserve shortfalls. The reason for the difference between the two sequences is due to events that occur in real-time that reduce the supply cushion and hence threaten reliability. These can include such things as an unanticipated surge in demand, a failed import, a unit outage or under-generation by self-scheduling units. When the magnitude of the reduction in operating reserve requirement more than offsets any real-time event such as a failed import, outage etc, the result is a real-time price that is lower than the pre-dispatch price.

Furthermore, the practice of applying an equal reduction in the operating reserve requirements for both the constrained and unconstrained sequences can cause the MCP to fall, even when there is no operating reserve shortfall in the unconstrained schedule. The reserve shortfall is typically realized first in the real-time constrained schedule rather than in the real-time unconstrained schedule. This is a result of transmission constraints that 'bottle' energy capacity, making it unavailable for delivery to load in other parts of the IMO grid. The shortfall in the constrained schedule can often exceed the shortfall in the unconstrained schedule by as much as 300 to 400 MW. As a result, as energy demand increases and the IMO begins to detect a shortfall or pending shortfall in operating reserves in the constrained schedule, the market-clearing price, which is derived from the unconstrained schedules, may not yet be signalling the pending shortage. If the IMO reduces the operating reserve requirement by say 300 MW in both the constrained and unconstrained sequence, they will free up 300 MW of energy offers in the unconstrained sequence, thereby causing the MCP to fall. This sends a false signal to the market about the true shortage of energy and operating reserve available from the market; prices are falling even though demand is increasing. Reductions in operating reserve requirements that persist for a number of hours will therefore cause the real-time price to understate the true shortage of supply (energy and market based operating reserve).

Table 2.21 provides an indication of the frequency with which the market based operating reserve requirement used in the one-hour ahead pre-dispatch run differed from the operating reserve requirement used in the real-time market (unconstrained sequence). A lower operating reserve requirement in real-time (other factors constant) causes the HOEP to be lower than the pre-dispatch forecast price. As Table 2.21 indicates, the frequency with which the real-time operating reserve requirement was reduced from its pre-dispatch level was highest in June and July.

Table 2.21: Percentage of Intervals with Operating Reserve Reductions (Unconstrained Sequence), May-July 2002

	> 0 MW	>200 MW	>400 MW	>800 MW
May	2.65	1.57	.57	.18
June	10.72	9.59	4.73	1
July	10.83	9.86	5.11	1.83
August	6.06	5.25	3.77	1.44

2.5.5 Additional factors

There are a number of additional factors that can contribute towards the difference between the pre-dispatch price and the HOEP. We did not provide data on these factors in this report because either the data was unavailable, or the factor did not have a large or persistent effect on the price difference. The following is a brief description of each of these factors and their impact on the price difference.

Unit forced outages or deratings

When a unit is either forced out of service or derated, it means that the DSO must find higher cost generation to replace it and hence puts upward pressure on the clearing price. When the outage or derate happens after the final pre-dispatch schedule, the pre-dispatch price will not capture this effect of the lost supply. This causes the pre-dispatch price to be lower than the real-time price.

Non-compliance by generators other than self-schedulers and intermittent generators

At times, there can be a considerable amount of under or over generation by generators other than the self-scheduling generators. For the May – August period, there was an average under-generation of 10.6 MW by generators other than self-schedulers. Unlike self-schedulers however, when these facilities under generate, it does not have a direct effect on the clearing price - the unconstrained schedules for these generators ignores non-compliant dispatch and hence the price (which is determined in the unconstrained sequence) is not impacted. Non-compliant dispatch by generators other than self-schedulers can however have an indirect affect on the real-time price if it is serious enough to cause the constrained schedule to be short energy and operating reserve. If this is the case, the IMO must respond by applying 'out-of-market' control actions. As discussed above, these actions have contributed towards reducing the real-time price relative to the pre-dispatch price.

The application of the daily energy limit in pre -dispatch but not real-time

Energy limited resources such as hydroelectric generators are required to submit with their hourly offers an estimate of the amount of energy that is available from the unit in the day. This information is used to warn the IMO of the potential shortfalls of energy and operating reserve that could occur throughout the day. The daily energy limit is also used in the pre-dispatch unconstrained sequence for scheduling purposes. If the DSO determines in pre-dispatch that a resource has reached its daily energy limit (measured as the amount of energy provided throughout the day in the *unconstrained* schedule) it will not schedule the unit for the upcoming delivery hour. The unit may however still have energy available. For example, if the unit was constrained-off all day, while its unconstrained schedule may indicate its energy limit was reached, in reality the unit will not have run and will still have energy available. In these instances, the IMO will use the offers of these unit in real-time and as a result, these units can affect the real-time price. In effect, the real-time offer curve shifts to the left relative to the pre-dispatch offer curve causing the real-time price to be lower than the pre-dispatch price. Case 3 in Appendix 1, provides an example of how the treatment of daily energy limits causes a difference between the pre-dispatch price and HOEP.

3. *The Market for Financial Transmission Rights and Intertie Utilization*

This section reports on both FTR activity and, related to it, the scheduled utilization of the interties.

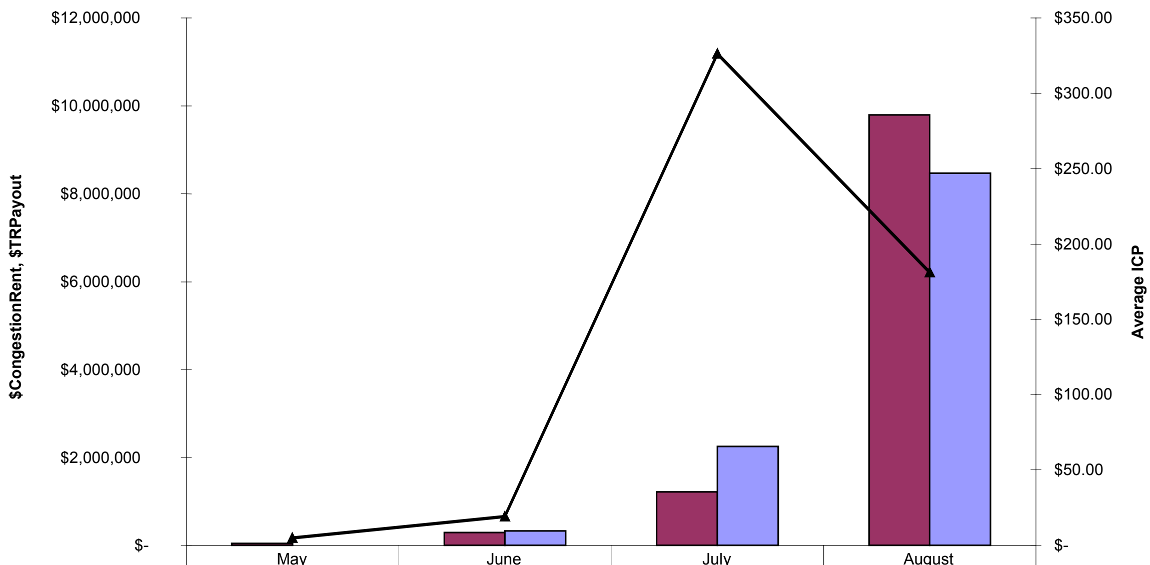
As explained in Chapter 1, Financial Transmission Rights (FTR) provide importers a financial hedge against the risk of an intertie becoming congested and restricting their ability to flow. When an intertie becomes congested, and congestion rents occur, holders of FTRs receive payments that provide an offset to the congestion rents.

Congestion rents occur when energy payments to suppliers are less than the payment by the loads (e.g. when zonal prices are less than Ontario prices). For example, assume that prices are very high in Ontario, $500/MWh, causing many importers to attempt to bring in energy at one intertie. Assume that this competition to sell into Ontario results in that intertie reaching its maximum capacity of 1,000 MW and becoming congested. This would lead to a lower price being set in that zone (say for example, $100/MWh, reflecting the marginal offer that could be accommodated). The IMO would pay the importers $100/MWh times 1,000 MW for this energy. But the loads that receive this energy pay the IMO the uniform Ontario price of $500/MWh. Thus the IMO receives $400/MWh more than it pays out for this 1,000 MW of imports. This excess is what is referred to as 'congestion rent'. In this situation the holder of a FTR for 1 MW would receive $400 for the hour. If there were 900 MW of FTRs, there would be more rents collected than payments for the FTRs, assuming the flow into Ontario is 1,000 MW.

During the first four months of the market, the IMO operated nine auctions of FTRs beginning in June. A total of 33,893 FTRs (each representing the potential right to a revenue stream on 1 MW of energy) was sold at auction for a total amount of $8.56

million. Intertie congestion increased through the period, particularly on the Manitoba intertie and one of the interties linking Ontario to Quebec, with congestion not being a predominant feature of the Ontario-U.S. interties. Through these first months, the IMO collected $11.3 million in congestion rents and paid out $11.0 million in FTRs, leaving a positive balance of slightly more than $9 million in the FTR account.

Figure 2.14: Congestion Rents, FTR Payouts and Average ICP, May – August 2002



	May	June	July	August
Congestion Rents	$42,348.61	$299,156.22	$1,542,978.71	$9,788,899.77
TR Payout	$-	$323,158.72	$2,246,291.68	$8,468,241.63
Average ICP	$4.81	$19.15	$326.24	$181.28
Frequency ICP (events)	139	112	78	50

Month

Congestion Rents TR Payout Average ICP Frequency ICP

Figure 2.14 provides an overview of the operation of the FTR market through the first four months. It shows the magnitude of congestion rents, FTR payments, and the average zonal price differences (intertie congestion price or ICP) in each month. Congestion rents and ICP were fairly small in May and June.[103] In July and August we saw FTR payments rise. In July, the higher ICP and rents were due in large part to one participant who misunderstood the magnitude of the intertie limit and placed offers that exceeded the capability of the tie. In August, however, the payout was much greater as the two interties that were congested, New York and Michigan, had a much larger number of FTRs being held. Also note that for June and July rents are lower than payouts as the result of

[103] There were no FTRs auctioned for May so there were no payments.

internal transmission limits restricting the actual MW that could flow through these constrained interties. When this occurs the congestion rents fall, because there is no or little energy flowing, but the FTR payments remain large, being based on the quantity of FTRs sold and ICPs generated.

In July most of the payments resulted from congestion on the ties with Quebec, Manitoba and to some extent Minnesota. These are the ties where there are only one or two active importers. However, there is no evidence to suggest that the importers dominating these interties are acting to increase revenues by congesting the ties and receiving FTR payments.

Even if the interties have not reached their limit in the market schedule, it is informative to look at the degree to which they were used. Table 2.22 shows the extent to which the various interties were utilized for the constrained schedule relative to their full capability, indicating that on average there was only moderate utilization of any of the interties.

Table 2.22: Spare Capacity on Interties in July 1 to August 15 Constrained Schedule

	SPARE >= 200	*SPARE >= 400*	*SPARE >= 600*	*SPARE >= 800*	*Average Import Limit*
New York	99.28%	98.37%	97.29%	94.66%	1694
Michigan	98.73%	97.10%	92.40%	83.89%	1360
Quebec	99.91%	95.75%	88.14%	78.64%	1527

A more careful examination of specific hours and components of the interties[104] would show that at times some interties were very close to their limits. A more complete view of utilization is provided by Figures 2.15 to 2.17, which show the distribution of net imports (import less export each hour) for the three major connections with neighbouring systems.

[104] The Quebec intertie total capability and flows is comprised of eight individual interties, whose usage can be quite independent. For example, one tie could be near its import limit while another intertie with Quebec might not have any flow.

Figure 2.15: Duration Curve of Import Flow on NYSI Interface from July 1 to August 15[105]

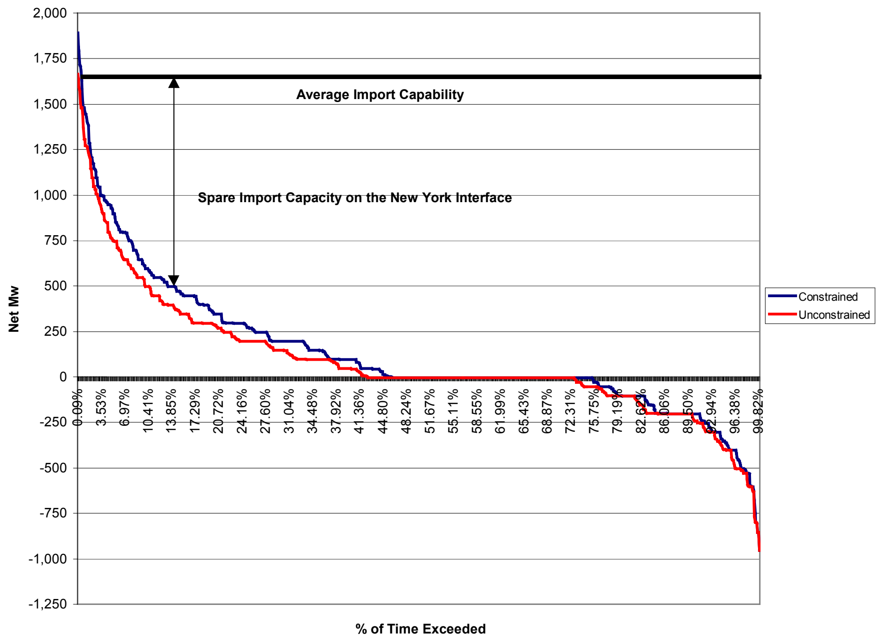
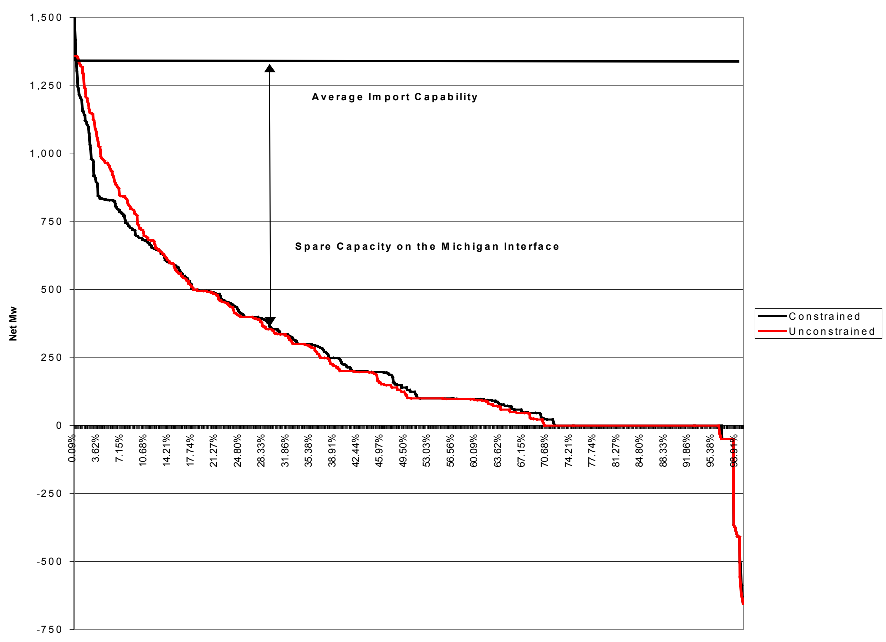


Figure 2.16: Duration Curve of Net Flows on Michigan Interface from July 1 to August 15



[105] "% of Time Exceeded" refers to the fraction of the period that the Net MW is equal to or greater than the amount shown on the Y-axis.

Figure 2.17: Duration Curve of Net Flows on Quebec Interface from July 1 to August 15

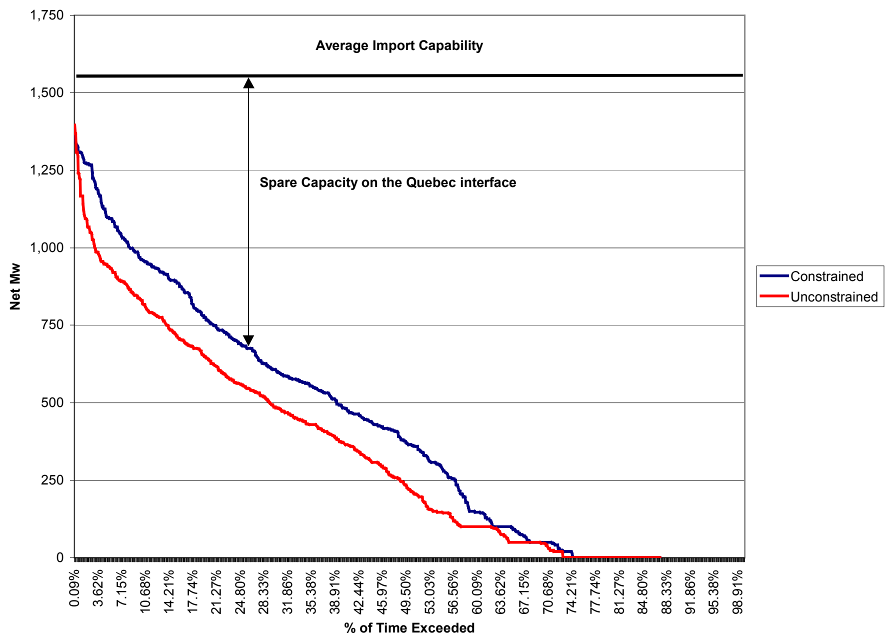


Figure 2.17 demonstrates how often the Quebec interties exhibit relatively higher utilization, even if they do not often reach the limit. For example, for the constrained schedule the intertie exceeds 75 percent of the combined limit about 5 percent of the time and exceeds 50 percent of the limit about 18 percent of the time, which would tend to coincide with higher load periods and tighter resources in Ontario. By contrast the New York and Michigan ties exceed the 75 percent utilization level only 2 to 3 percent of the time, and the 50 percent level 5 percent to 14 percent of the time.

The usage of these interties is affected both by the supply shortages and high pre-dispatch prices in Ontario, as well as the characteristics of the players or markets at the interties. For institutional reasons there are effectively only one or two market participants active as importers at each of the interties with Manitoba, Minnesota and Quebec. With one or two entities it has been possible for offers to be placed with a much lower probability that the intertie will be congested. For the New York and Michigan interfaces the reason for the lack of congestion in July would appear to be that available imports were insufficient to congest the ties.

Appendix 1: Analysis of high priced hours: Reference Cases

This appendix provides a more detailed discussion of the four representative cases identified in section 2.3 of Chapter 2. Case 1 (June 11, delivery hour 10) and Case 4 (August 13, delivery hour 17) are selected examples for which the HOEP was greater than $200. In each case, we discuss the factors that contributed towards the high HOEP. Table A1.1 provides summary statistics for all of the 21 hours in the months of May to August for which the HOEP exceeded $200. Case 2 (July 3, delivery hours 12 through 17) and Case 3 (August 1, delivery hour 17, 18, and 19) are the hours in which the hourly IOG exceeded the HOEP. The specific factors causing the high IOGs are outlined in each case. Table A1.2 also provides summary statistics for each of Cases 2 and 3.

Case 1: June 11, 2002, Delivery Hour 10

On June 11, the HOEP was $701.69 in delivery hour 10. This was the second highest HOEP in the period and was the first 'high-price hour' of the new market. The dominant factor contributing to the unusually high hourly price was an unexpected demand increase, one that was more than 600 MW higher than the one-hour ahead pre-dispatch forecast.[106]

Pre-dispatch market

The forecast for the hourly peak demand used in the one-hour ahead pre-dispatch for delivery hour 10 was 19,592 MW. The pre-dispatch supply cushion was 9.4 percent for the hour. This was not an atypical cushion; the cushion for delivery hour 10 had ranged between 7 percent and 10 percent in the hour for May and June and HOEP for these hours had averaged $39/MWh, with the highest HOEP being $103/MWh. The 9.4 percent supply cushion included 1,758 MW of energy offered from importers. A total of

427 MW of these offers were accepted and scheduled for delivery in real-time. At the same time, 201 MW of exports were scheduled so that the net amount of imports scheduled for real-time delivery was 226. The forecast price for the upcoming delivery hour was $40.

There were several fossil units that had submitted energy offers for delivery hour 10. However, these units were not selected to run in the pre-dispatch schedule for hour 10 or even for hour 11. As a result, the owners did not start these units. Given that it takes a minimum of approximately two hours to start a fossil unit and bring it to a point were it can reliably provide energy to the market, these units would not be available to provide energy or operating reserve in real-time in delivery hour 10. This would affect the real-time supply cushion.[107]

Real-time market

By the time the delivery hour started, temperatures and humidity levels had changed considerably. While the high temperature for the day had initially been forecast to be 27 degrees, by the start of the hour temperatures had already risen to 30 degrees with high humidity. As a result, demand in the hour was much higher than expected. The average demand in the hour was 19,951 MW while the peak demand for the hour was 20,221 MW -- i.e., 629 MW more than was forecast in pre-dispatch. When demand comes in higher than forecast, it naturally places increased pressure on the five-minute MCP, as it requires higher-priced generation to be utilized. It also implies however that relatively too few imports are likely to be chosen in pre-dispatch and hence available for real-time.

[106] Unless specifically stated, in these examples demand refers to non-dispatchable load plus the transmission losses incurred in servicing this load.

[107] All of these units were offered in the hour at prices that reflected what would be required to cover both their marginal running cost and their start-up and minimum no-load costs. The offer prices exceeded the pre-dispatch prices through the day. Furthermore, prior to June 11, the pre-dispatch price had been regularly exceeding the real-time price. To the extent that participants were using the pre-dispatch price as a signal of the real-time price it is reasonable to think that they would be discounting the price signal, expecting actual daily prices to be lower than the pre-dispatch price.

At the same time, a number of other factors were at work causing the amount of available supply to be lower than expected in pre-dispatch. First, self-scheduling generators, as a group, were providing an average of 180 MW less than offered in pre-dispatch in the hour. Second, there were a number of units that were derated between the time of the final pre-dispatch and the start of delivery hour 10; approximately 79 MW of energy was unavailable as a result. The under forecast of demand accompanied with the loss of approximately 274 MW of supply placed considerable strain on the real-time supply cushion. Recognizing as well that the 1,331 MW of import offers that were not accepted in pre-dispatch were no longer available in real-time meant that the average real-time supply cushion for the hour fell to just 1 percent.[108]

The delivery hour started with a demand of 19,625 MW in interval 1. This was 33 MW more than the forecast peak for the hour. This increase, coupled with the reduced supply resulting from the under-generation of self-scheduling units and the derated units, caused the market to clear at a price of $48.53/MWh, which was $8.53 higher than forecasted. Demand continued to increase over the next three intervals and prices gradually increased to $52/MWh. In interval 5, demand increased by 157 MW to 19,934.6 MW. At this point, the supply cushion was negligible. The DSO automatically reduced the operating reserve requirement[109] from a total of 1,380 MW to 1,291 MW, freeing up 89 MW of energy to meet the demand. The price cleared in the interval at $1,950/MWh.

For the next two intervals, demand continued to grow (by 34 MW in interval 6 and 150 MW in interval 7). As there was no available energy remaining outside of that being held for operating reserve, the DSO automatically continued to reduce the operating reserve requirement (by the same amount as the increase in demand), to free up energy to meet the demand. The price remained at $1,950/MWh.

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[108] There were 50 MW of exports that failed real-time delivery due to scheduling issues between the IMO and the NYISO. While a failed export acts to relieve the strain on supply, in this event, the 50 MW were clearly overwhelmed by the other factors.

[109] For simplicity within this report when it is explained that operating reserve requirements were reduced, this is the operating reserve required from the market. In times of market deficiencies in operating reserve, the IMO uses 'out-of-market' forms of reserve, not available commercially. At no time during the May-August period did the IMO have insufficient reserve to meet its obligations.

In interval 8 demand declined by 80 MW. At the same time, the IMO responded to the shortage of operating reserve by *manually* reducing the total operating reserve requirement by 250 MW, reducing total operating reserve requirements to 970 MW. These two events together acted to reduce the total energy requirement by approximately 330 MW; essentially demand shifted down the supply curve and the price fell to $57/MWh.

Over the next three intervals demand increased slightly and prices fluctuated between the $80/MWh and $130/MWh range. By interval 12, demand reached its peak value in the hour, increasing by 105 MW from the previous interval. This caused the price to spike back to $1,950/MWh and the operating reserve requirement being reduced automatically by the DSO to meet the energy demand.

At the turn of the hour, the supply situation changed for the better. First, the pre-dispatch demand forecast was increased considerably for delivery hour 11 and as a result, an additional 182 MW of net imports (a total of 458 MW) was scheduled for real-time. Also a derating on a fossil unit was removed freeing up an additional 20 MW of energy. Finally, an additional 50 MW of self-scheduling generation was offered and provided to the market in this hour. In total, an additional 252 MW was made available in delivery hour 11. At the same time, the operating reserve requirement was reduced by another 140 MW across the hour, essentially adding a net increase of 390 MW to the supply cushion. The peak demand value in the hour was only 363 MW more than the peak value realized in interval 12 of the previous hour. As a result, while supply remained strained (the supply cushion hovered around the 2 percent level) demand cleared lower down the blade of the offer curve and HOEP was $89/MWh, with a peak price in the hour of $250/MWh.

As the day progressed, and the market realized that the demand was going to be higher than the pre-dispatch forecast due to the unexpected increase in temperatures and humidity, it became profitable for additional fossil units to start. As a result, the supply cushion increased across the day and prices stabilized, ranging between $65/MWh and $87/MWh across the peak hours.

Case 2: July 3, 2002, delivery hours 12 through 17

July 3 began with a temperature forecast of a high of 34 degrees and a peak demand forecast of over 25,000 MW. By 10:40 am, the IMO began issuing System Status Reports indicating energy and operating reserve shortfalls for delivery hours 11 through 19. The mandatory and restricted bidding window was opened for these hours in order to solicit new and revised offers that would eliminate the shortfalls.[110] The bidding windows were left open until just before the start of delivery hour 17.

In each of delivery hours 12 through 16, the IOG component of the hourly uplift exceeded $100/MWh. The significantly high IOGs in each of these hours was a product of:

- a significant amount of imports being scheduled due to a near record high demand and an inadequate amount of domestic supply to meet this demand;
- a large difference between the pre-dispatch price and the HOEP;
- a large share of the selected imports being priced well above the eventual HOEP.

A significant quantity of imports scheduled

The magnitude of the hourly IOG charge depends on the volume of imports selected for real-time delivery; the more imports accepted, the larger the number of imports potentially eligible for IOG payments. As mentioned above, July 3 was a day in which

[110] As discussed in Section 3.3.1 of Chapter 3, from 4 hours to 2 hours before the delivery hour, market participants are restricted to changes in their offer prices/quantities of no more than 10 percent. In the two hours before real-time, it is mandatory that market participants follow through with their offers/bids. When the mandatory and restricted offer/bid window is open, it implies that market participants are free to modify their offer/bids as they see fit. The IMO's rational for opening the window is to attract additional supply to the market in times when there is a shortfall of supply expected.

demand reached near record highs. In hours 12 through 17 the pre-dispatch forecast demand was between 24,800 MW and 25,300 MW. The total amount of available energy offered from Ontario based generation fell short of the energy demand in each hour and well short of the total energy requirements (energy demand plus operating reserve requirements). As a result, the domestic supply cushion was negative in each hour indicating a heavy need for imports. The domestic supply cushion for hours 12 through 17 ranged from a low of –10.48 percent in hour 16 to –9.21 percent in hour 13. In terms of MW required, this translated into a need for 1,998 MW of imports in hour 13 and 2,392 MW of imports in hour 16. In comparison, there were only six other hours in the May-August period in which the amount of imports required was greater than the amount required in delivery hour 16. The hours reviewed for July 3 were ranked in the top 1 percent of the hours with the highest requirement for imports.

<u>A large difference between the pre-dispatch price and the HOEP</u>

An importer is eligible for an IOG when the HOEP is lower than the importer's offer price as accepted in pre-dispatch. When this occurs the importer is paid the IOG, which is equal to the difference between its offer price and the HOEP. The larger the difference between the pre-dispatch price and the HOEP, the larger the difference is likely to be between the prices of accepted offers of importers and the HOEP. Hence the larger the IOG is likely to be.

In each hour reviewed, the one-hour ahead pre-dispatch price was at least $1,190/MWh higher than the actual HOEP. In hour 12, the difference was as large as $1,684/MWh. Hours 12 through 17 all ranked in the top 1 percent of hours with the largest difference between the pre-dispatch price and the HOEP for the four-month period. The causes of the discrepancy depended on the specific hours.[111]

[111] Section 2.5 of Chapter 2 provides a discussion of the many factors that cause the pre-dispatch price forecast to diverge from the real-time price.

In hour 12, the IMO over-forecast the hourly peak demand by 175 MW and the hourly average demand by 338 MW. The implications of the over forecast of demand on the pre-dispatch to real-time price discrepancy are two-fold. First, lower demand in real-time means that the real-time price will be lower. Second, an over-forecast of demand in pre-dispatch also means there is likely to be a disproportionate reliance on imports. As discussed in Appendix 2, this can further exaggerate the discrepancy between the pre-dispatch and real-time price as it means that relatively more imports are inserted in the real-time offer curve at a very low price, causing the real-time offer curve to shift to the left at demand values lower than the pre-dispatch demand forecast. Another factor contributing to the price discrepancy in hour12 was the reduction of operating reserve requirements. On July 3, as a result of considerable storm activity in the Northwest, transmission limits were reduced and a large share of the offered energy and operating reserve was made unavailable to the east. As a result, at least in part, the constrained schedule was experiencing operating reserve shortfalls all day. In hour 12, in response to the operating reserve shortfalls in the constrained schedule, the IMO reduced the operating reserve requirement from the 1,580 MW pre-dispatch amount by an average hourly amount of 331 MW. This reduction was applied equally to the constrained schedule and to the unconstrained schedule. This freed up roughly 331 MW of energy (energy previously being held on stand-by to meet the operating reserve requirements) to be used to satisfy energy demand. A large share of this energy was from fossil generation whose energy offer price was well below the pre-dispatch price. As a result of these factors real-time price was reduced and the difference between the pre-dispatch and real-time prices in hour 12 was the largest of the day at a difference of $1,684/MWh.

In hours 13 through 15, the IMO demand forecast was within 100 MW of the hourly peak demand value. In these hours the largest contributor to the price discrepancy was the reduction of operating reserve requirements due to shortfalls in the constrained schedule.

The reductions in operating reserve were between 1,026 MW in hour 13 and 1,380 MW in hour 15.[112]

In hour 16, the price discrepancy was driven once again by a slight over-forecast of demand in pre-dispatch (206 MW) and the reduction in operating reserve requirements. It was further aggravated by a failed export of 250 MW. When exports are scheduled in pre-dispatch but fail delivery in real-time they cause the real-time price to be lower than the forecast as less energy is demanded from Ontario sources than initially expected.

The forecast of demand for hour 17 was perfect. The IMO picked the peak demand within .4 MW. The IMO reduced the operating reserve requirement for the hour by 1,380 MW due to shortfalls in the constrained schedule. This reduction caused the real-time price to be $1,190/MWh less than the pre-dispatch price.

<u>A large share of the selected imports are offered at a price above the HOEP</u>

Simply put, the more imports scheduled at prices above the HOEP, the more MW eligible for an IOG payment and the higher the eventual IOG payment. On July 3 roughly 90 percent of the imports selected in pre-dispatch were priced above the HOEP in hours 12 through 17. This amounted to as many as 2,343 MW in hour 16; the low was 2,083 in hour 14. Each of hours 12 through 17 ranked in the top ten hours of the month in terms of the percentage of imports priced above the HOEP.

<u>*Case 3: August 1, 2002, delivery hours 17 through 19*</u>

August 1 was a hot hazy day with a high of 34 degrees. Demand was expected to reach near record highs in excess of 25,000 MW. Temperatures were high and humid in all

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[112] Note that in hour 13 the IMO actually under-forecast the hourly peak demand by 88 MW. There were also a total of 275 MW of imports that failed real-time delivery. This amounts to a total loss of 363 MW of supply in real-time, which puts upward pressure on the real-time price. However, the reduction of operating reserve requirement of 1,026 MW more then offset the reduction in supply causing the real-time price to be much lower than forecast.

surrounding control areas and demand was pressing the capacity of supply in all markets. At approximately 3:30 am, the IMO contacted the surrounding control areas to discuss the availability of capacity in each area in the event that emergency purchases were required. It was reported that there was very limited spare capacity during the peak hours of the day that could be made available for emergency purchase by the IMO.

In each of hours 16, 17, 18 and 19, the hourly uplift exceeded the HOEP. The IOG was always the largest component of the hourly uplift and ranged from $58.14/MWh in hour 16 to $143.98/MWh in hour 19 – the highest hourly IOG of the four-month period.

<u>A significant quantity of imports scheduled</u>

Despite the warnings regarding the spare energy available, there were significant amounts of imports offered into Ontario and scheduled in pre-dispatch in hours 17 through 19 on August 1. Demand was similar to the demand realized in the same hours of July 3, (25,000 MW). However, the amount of imports scheduled was significantly more than on July 3. In all hours imports scheduled exceeded 3,500 MW, whereas in July the amount of imports scheduled was approximately 2,500 MW in each of hours 12 through 17. Other things equal, the larger is the amount of imports scheduled, the greater is the hourly IOG. The 3,500 MW of imports scheduled (unconstrained sequence) in each of hours 17, 18, and 19 on August 1 were among the top 10 hours in terms of the amount of imports selected for the May-August period.

It is important to note, however, that many of the imports scheduled from New York and Michigan in the unconstrained sequence were not scheduled in the constrained sequence as a result of developments in the New York or the Michigan control area (i.e., limited internal ramping capabilities or transmission security issues). When transmission or security issues interfere between markets, traders may not be able to arbitrage large price differences between two control areas, even if it appears profitable to do so.

Therefore, while in theory there were significant imports offered and available, in reality only a limited volume of imports was available from these jurisdictions. For example, in hour 17 a total of 936 MW of imports was scheduled in the unconstrained sequence in pre-dispatch from the Michigan intertie while only 827.5 MW were scheduled in the constrained sequence. In the same hour, 1,480 MW were scheduled from New York in the unconstrained sequence, enough to congest the intertie. However, only 1,177 MW were scheduled in the constrained sequence for this hour.

Furthermore, a significant portion of the imports scheduled in pre-dispatch was not actually delivered in real-time. A large volume of imports from New York that was scheduled in pre-dispatch failed to be delivered to Ontario in real-time due to the 'seams' issues that exist between the two markets. For, example, in hour 17, a total of 203 MW in the constrained sequence and 214 MW in the unconstrained sequence were scheduled as imports from New York in pre-dispatch but failed to be delivered in real-time. Many of the import offers failed because there was only a limited amount of energy available in New York to be delivered to Ontario and all of the importers were competing against each other in the New York market to buy this limited energy. The importers all had offers that were accepted in Ontario. Given the limited spare energy in New York, however, only a fraction could have been accepted to buy energy in New York and those that were not successful must necessarily have failed to follow through with their original offer to Ontario. As a consequence exports to Ontario from New York were lower in real-time than was initially expected in pre-dispatch.

<u>A large difference between the pre-dispatch price and the HOEP</u>

Pre-dispatch prices were significantly higher than the eventual HOEP during hours 17 to 19. The difference was generally in the range of $1,227/MWh to $1,506/MWh. This was a unique day with respect to the causes of the discrepancy. First, the demand forecast errors in each of the three hours reviewed were insignificant. The difference ranged from an under-forecast of 63 MW in hour 17 to only 15 MW in hours 18 and 19. Second, the operating reserve requirements in these hours were left essentially unchanged from the pre-dispatch levels. At the same time however, there was a significant volume of failed imports in each hour: 269 MW, 210 MW and 415 MW in hours 17 through 19 respectively. This coupled with roughly 75 MW of under-generation by self-schedulers in each hour should have put considerable upward pressure on the real-time price. Real-time prices should have been higher than pre-dispatch prices but the opposite turned out to be the case.

One reason for the large difference between the pre-dispatch price and real-time prices during hours 17 to 19 was a result of the treatment of a number of limited energy hydroelectric resources in Ontario. A number of these resources were identified as being energy-limited. Because of their energy limitations, these units were manually constrained off in real-time by the IMO between hours 10 and 15, so as to ensure their energy could be used later, to help meet demands for the peak hours of the day (hours 16 through 19). Given the offer prices of these units in hours 10 to 15, however, these facilities were often being scheduled in the unconstrained sequence. Thus, while no energy was actually being generated, as far as the DSO was concerned, these units were gradually running out of energy.

By delivery hour 16, the DSO had now identified many of these units as having exhausted their generating capacity. As a result, these units were never scheduled in the pre-dispatch sequences (constrained or unconstrained). This meant that more expensive generation was required (such as imports) to meet the demand in the pre-dispatch market. However, in reality these units did have energy available since they had not been used all day. In recognition of this, the offers of these units were left in the real-time market and allowed to influence the real-time prices. The amount of additional hydroelectric supply made available for energy or operating reserve in real time in hours 16 to 19 was roughly 350 to 500 MW. This additional energy was offered at prices well below pre-dispatch prices. Furthermore, the additional supply made available in real-time in these hours more than offset any loss in supply due to failed imports. The net effect was that more supply was made available to meet the demand in real-time than was initially anticipated in the determination of the pre-dispatch price. As a result of the increase in real-time supply, the real-time price was much lower than the pre-dispatch prices in these hours.

<u>A large share of the selected imports are offered at a price above the HOEP</u>

As was the case on July 3, in hours 17, 18 and 19, the percentage of imports scheduled in the unconstrained market and priced above the eventual HOEP was significant: 79 percent, 82 percent, and 80 percent respectively. These percentages were lower than those experienced on July 3. However, the volumes of imports affected were much higher on August 1. There were a total of 2,256 MW, 2,879 MW and 3,492 MW of imports that were accepted in pre-dispatch at offer prices that exceeded the eventual HOEP in delivery hours 17, 18, and 19. These three hours ranked in the top 10 hours of the four-month period with respect to the amount of imports scheduled at prices above the eventual HOEP.

<u>*Case 4: August 13, 2002, Delivery Hour 17*</u>

On August 13, the HOEP reached $437.57/MWh in delivery hour 17. This hour is an illustration of how failed imports can place upward pressure on the real-time price and how reductions in the operating reserve requirements can dampen the price effects of failed imports (or other supply shortfalls that occur in real-time). In fact in this example, the reduction in market operating reserve requirement more than offsets the price effect of the failed imports and caused the real-time price to be below the pre-dispatch price of $1,650. The dominant factor contributing to the unusually high hourly price was a large incidence of failed imports -- 901 MW. The factors that prevented the HOEP rising to the level of the $1,650/MWh pre-dispatch price was the reduction of the real-time 30 minute reserve and 10 minute non-spin requirements to zero.

Pre-dispatch market

By hour 17, temperatures had peaked for the day. The IMO's demand forecast was for a peak energy demand of 25,189 MW. Earlier in the day, the IMO had issued a notice to participants that Ontario was in an Emergency Operating State predicting shortfalls in operating reserves for most of the day. Market participants were informed that the mandatory and restricted offer/bid window was open for new or revised offers and bids until further notice. In hour 17 the mandatory and restricted window was still open, and in this hour the pre-dispatch price increased to $1,650/MWh, up from $750/MWh and $500/MWh respectively in the two previous pre-dispatch runs for hour 17.

The pre-dispatch supply cushion was in the range of 7.4 percent. However the domestic supply cushion was –10.41 percent indicating a heavy reliance on imports. There was a considerable volume of imports *offered* to Ontario in hour 17 -- a total of 7,072 MW. Many of the offers were made over the New York and Michigan intertie and in both cases the offers exceeded the capacity of the intertie so that both interties were congested during hour 17. In the case of New York, imports offered exceeded the intertie capacity by as much as 2, 209 MW. A total of 4,039 MW of imports were *scheduled* in pre-dispatch for hour 17. As a result of the congestion of both the New York and Michigan interties, the zonal prices (i.e., the offer price of the last MW accepted) in New York and Michigan were $547 and $500 respectively, substantially less than the $1650 pre-dispatch price.

Real-time market (causes of the high HOEP)

While the HOEP in this hour was high relative to our arbitrary standard of $200, it was still considerably lower than the price predicted in pre-dispatch. The fact that the HOEP was relatively high was largely a result of a significant amount of imports failing to be delivered in real-time. The fact that the HOEP was considerably lower than the pre-dispatch price was primarily a result of the lowering of the operating reserve requirements in real-time.

Many of the usual factors that cause a high HOEP were not a factor in hour 17 on August 13. For example, the IMO's demand forecast was accurate within 40 MW. The forecast was for a demand of 25,189 MW while the actual peak demand was 25,158 and the average hourly demand was 25,004 MW. Also the amount of under-generation by self-scheduling generators was a relatively low 28.4 MW. There were also no significant forced outages or deratings of units in real-time.

There were however a considerable number of import offers from New York that failed the 30-minute prior checkout between Ontario and New York. A total of 901 MW (unconstrained sequence) of imports, which were selected in pre-dispatch, became unavailable in the real-time market. As a result, the real-time supply curve effectively shifted to the left, placing upward pressure on the real-time price.

The IMO recognized before the start of the hour that as a result of the failed imports, there would be an operating reserve shortfall in the hour. The IMO quickly responded to the shortfall by reducing the 30-minute reserve and 10-minute non-spin requirement to zero and using out-of market mechanisms such as 3 percent and 5 percent voltage cuts to satisfy industry standards for reserves. Only 280 MW of 10-minute spinning reserve was purchased from the market. Even after reducing the operating reserve requirement to their minimum levels, the real-time supply cushion had fallen to a low of just under 2 percent, largely as a result of the sheer magnitude of the amount of failed imports.

The reduction in total operating reserve requirements from 1,580 MW in pre-dispatch to 280 MW in real-time (a difference of 1,300 MW) more than offset the loss of the 901 MW of failed imports. As a result, the real-time prices cleared at levels that were considerably lower than the pre-dispatch price.

Interval 1 of hour 17 began with demand being at its hourly peak value. The MCP in the interval reached $741.23/MWh. For the remaining intervals, demand fluctuated by 100 MW around the 25,000 MW level. The MCP also fluctuated in these intervals ranging from $530/MWh in interval 2 to $360.37/MWh in interval 11.

Table A1.1: Summary Data on Hours with HOEP Greater than $200

Delivery Date	**11-Jun**	**02-Jul**	**30-Jul**	**01-Aug**	**01-Aug**	**13-Aug**	**13-Aug**	**13-Aug**	**13-Aug**	**13-Aug**	**13-Aug**	**13-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**15-Aug**	**15-Aug**
Delivery Hour	**10**	**16**	**12**	**13**	**14**	**14**	**15**	**16**	**17**	**18**	**20**	**21**	**12**	**13**	**15**	**16**	**17**	**19**	**20**	**11**	**14**
HOEP ($)	701.69	471.00	200.00	399.44	217.57	247.48	311.40	289.66	437.57	244.06	912.20	357.12	237.09	253.96	210.31	232.98	237.01	223.59	237.10	225.51	275.55
Hourly Uplift ($)	54.29	98.16	15.97	71.83	107.29	28.46	25.57	86.63	229.91	93.46	24.96	18.25	13.26	14.36	17.93	13.31	13.18	11.07	7.42	14.61	16.88
Ont Pre-dispatch Price ($)	40	1,950	275.22	400	645	425	520	1,400	1,650	600	340	400	239.60	300	385	350	325	270	135	151.51	148.01
Pre-dispatch Demand (MW/h)*	19,592	25,399	23,397	24,842	24,918	25,113	25,201	25,384	25,189	24,948	23,541	23,288	23,368	23,725	24,268	24,094	23,981	23,165	22,574	22,919	24,141
Average Actual Demand (MW/h)	19,951	24,709	22,894	24,606	24,741	25,050	24,643	24,383	25,004	24,414	23,639	23,111	23,004	23,285	23,672	23,880	23,717	22,629	22,667	23,008	23,734
Actual Peak Demand (MW/h)	20,221	24,765	23,033	24,846	24,828	25,263	24,813	24,685	25,158	24,665	23,788	23,656	23,086	23,416	23,820	24,006	23,904	22,814	22,759	23,325	23,807
Failed Imports (MW/h)**	0	785	50	375	512	357	814	1,121	901	761	795	601	250	477	600	260	100	100	0	102	466
Failed Exports (MW/h)**	50	104	0	0	0	125	0	0	0	0	0	0	0	150	15	150	0	150	150	0	0
Self Schedule Under-generating (MW/h)**	180	300	82.8	96	114	91.2	87.6	73.2	28.8	18	12	55.2	57.6	57.6	67.2	43.2	36	16.8	18	70.8	67.2
Pre-dispatch Supply Cushion (%)	9.4	3.7	10.6	10	8.8	6	6	6.5	7.4	7.5	13.6	14.9	14	12.4	10.4	11	11.7	15	17.4	13.3	10.8
Real-Time Supply Cushion (%)	1.1	3.2	2.1	3.1	2.3	5.6	4.7	3.3	1.6	3.4	0.6	5.4	5.5	4.7	3.1	4.2	4.8	5.2	3.8	5	1.9
MW made unavailable in the hour	79	0	0	0	0	143.1	347.2	148.4	0	8	1.5	0	0	0	0	0	0	0	195.75	0	0

* All demand values reported are the non-dispatchable load plus losses component of demand, calculated as the sum of the unconstrained schedules of all generation plus net imports minus dispatchable load.
**All figures calculated as the arithmetic average of the 12 interval unconstrained sequence values in that hour.

Table A1.2: Summary Data on High Priced Hours with an Hourly Uplift Greater than HOEP

Delivery Date	**03-Jul**	**03-Jul**	**03-Jul**	**03-Jul**	**03-Jul**	**03-Jul**	**01-Aug**	**01-Aug**	**01-Aug**
Delivery Hour	**12**	**13**	**14**	**15**	**16**	**17**	**17**	**18**	**19**
Ontario Pre-dispatch Price ($)	$ 1,750.00	$ 1,700.00	$ 1,600.00	$ 1,500.00	$ 1,500.00	$ 1,301.00	$ 1,300.00	$ 1,575.00	$ 1,350.00
HOEP ($)	$ 65.31	$ 96.20	$ 129.99	$ 102.99	$ 102.90	$ 110.96	$ 72.45	$ 69.00	$ 69.40
Price discrepancy ($)	$ 1,684.69	$ 1,603.80	$ 1,470.01	$ 1,397.01	$ 1,397.10	$ 1,190.04	$ 1,227.55	$ 1,506.00	$ 1,280.60
Domestic Supply Cushion (%)	-9.59	-9.21	-9.86	-9.81	-10.48	-9.85	-8.21	-7.17	-5.64
Pre-dispatch Supply Cushion (%)	1.62	2.56	2.95	3.31	1.4	4	7.3	8.55	10.55
Total Imports Offered (MW/h)	3020	3308	3507	3559	3253	3778	5718	5518	5532
Imports Scheduled in pre-dispatch (unconstrained)(MW/h)	2626.2	2503.5	2545.5	2501.2	2674.9	2459.8	3187.6	3451.1	4305
Hourly Uplift ($)	122	121	125	126	140	107	149	153	136
Hourly IOG ($)	127	127	110	112	116	95	82	120	144
Total IOG Payments ($)	3,114,264	3,141,348	2,706,686	2,757,082	2,868,305	2,356,628	2,015,963	2,895,392	3,415,441

Table A1.2: Summary Data on High Priced Hours with an Hourly Uplift Greater than HOEP (cont.)

Delivery Date	**03-Jul**	**03-Jul**	**03-Jul**	**03-Jul**	**03-Jul**	**03-Jul**	**01-Aug**	**01-Aug**	**01-Aug**
Delivery Hour	**12**	**13**	**14**	**15**	**16**	**17**	**17**	**18**	**19**
Imports paid an IOG (MW/h)	2,254.5	2,216.5	2,083.5	2,239.6	2,343.7	2,197.8	2,556.6	2,879.1	3,492.0
Imports paid an IOG (%)	90%	89%	89%	90%	90%	89%	86%	87%	89%
Number of MPs offering to import	8	9	9	8	8	8	16	16	14
Pre-dispatch Demand (MW/h)**	24,852.6	24,815.7	24,978.2	25,043.0	25,280.2	25,095.0	24,942.0	24,644.4	
Average Demand (MW/h)	24,514.0	24,772.1	24,838.3	24,949.9	25,001.4	24,916.5	24,878.1	24,416.4	24,175.4
Peak Demand (MW/h)	24,677.5	24,903.8	24,893.8	25,029.6	25,074.0	25,094.6	25,005.5	24,630.3	23,990.3
Failed Imports (MW/h)***	109.7	275.0	200.0	24.6	69.2	0.0	269.0	210.0	24,190.7
Failed Exports (MW/h)***	0.0	0.0	0.0	0.0	250.0	0.0	0.0	0.0	451.0
Self Schedule under-generation (MW/h) ***	39.6	54	50.4	63.6	72	87.6	82.8	75.6	71
Reduction in operating reserve requirement from total of 1580 MW/h***	331	554	325	200	350	200	0	83	0

* This is the highest hour ahead price posted from either New York (Zone OH and Zone HQ), New England and PJM. It includes an additional $15 buffer to reflect costs that may be incurred by importers (transmission charges, exit fees etc).
** All demand values reported include the non-dispatchable load plus losses component of Ontario demand. It is calculated as the sum of the unconstrained schedules of all generation plus net imports minus dispatchable load.
*** All figures calculated as the arithmetic average of the 12 interval unconstrained sequence values in that hour.

Appendix 2: Impact Of Boundary Entities On Discrepancy Between Pre-Dispatch And Real-Time Prices

In the pre-dispatch markets, boundary entities submit offers to import power into Ontario from external control areas or bids to export power out of Ontario to external control areas. Boundary entity schedules are established in the one-hour ahead market so as to provide each affected control area sufficient time to coordinate the transactions. When the IMO runs its pre-dispatch schedule, these offers and bids are treated in exactly the same manner as domestic offers and bids. Imports and exports schedules are establish on the basis of their offer and bid prices, and if the marginal offer (bid) is from a boundary entity, that offer (bid) will establish the market-clearing price – the IMO's pre-dispatch forecast price.

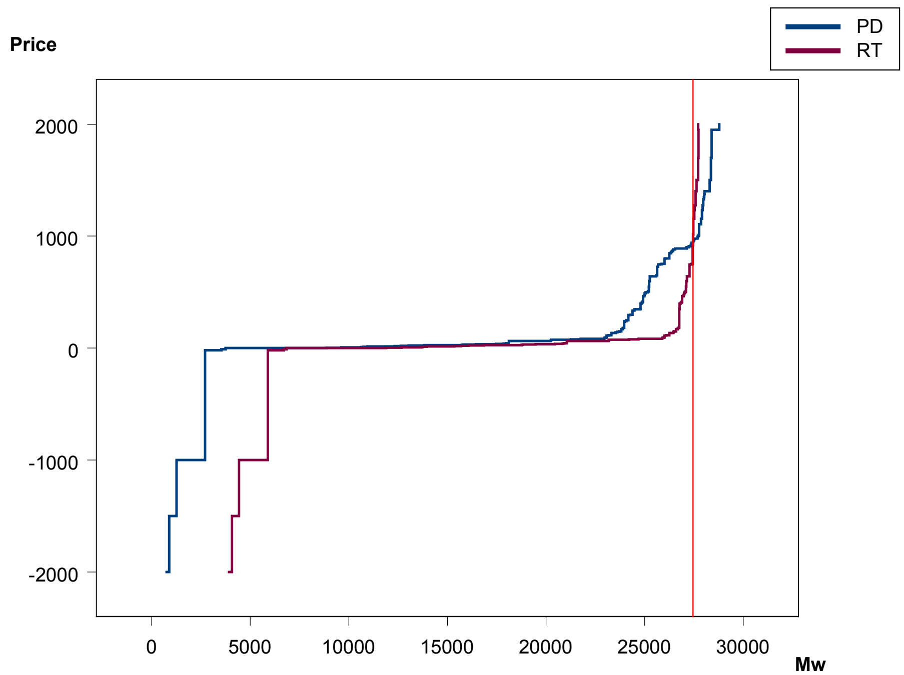
In the real-time markets, boundary entities are treated differently. The real-time schedules for boundary entities are selected in the one-hour ahead pre-dispatch run. Imports (exports) with offer (bid) prices at or below (above) the pre-dispatch clearing price are accepted for real-time dispatch. All other offers (bids) are rejected and rendered unavailable for real-time dispatch. The schedules of the accepted imports and exports are fixed for the entire delivery hour and do not adjust with changes in the real-time MCP. Their offers (bids) are removed from the real-time offer (bid) curve and their quantities are placed at the bottom of the curve at a very low price so that they do not influence the MCP.

The disparate treatment of imports in the pre-dispatch and real-time markets is illustrated in Figure A2.1 below. Figure A2.1 presents two different offer curves: a one-hour ahead pre-dispatch offer curve, labeled PD and a real-time offer curve, labeled RT. The two curves are reconstructions of the actual offer curves used in the market on July 22, for delivery hour 12. The pre-dispatch offer curve includes all import offers (the offer quantities and offer prices). The real-time offer curve is constructed by using only the quantities of the import offers that were accepted in the one-hour ahead pre-dispatch run. Import quantities that were not accepted in pre-dispatch are removed from the offer curve. Import quantities that were accepted in pre-dispatch are included in the real-time offer curve but at an offer price of negative $2,000 rather than at the price that they had initially been offered (i.e., accepted imports become price takers in real-time).

Treating accepted imports as price takers in the real-time market causes the real-time offer curve to pivot around the pre-dispatch demand forecast (identified as the vertical red-line). To the left of this point, the real-time offer curve swings below the pre-dispatch offer curve. This part of the offer curve includes those imports that were accepted in the one hour ahead market and inserted in the real-time offer curve at the negative $2,000 price. To the right of the demand forecast, the real-time offer curve swings above the pre-dispatch offer curve. This part of the offer curve removes those imports that were rejected in the one-hour ahead market.

The disparate treatment of offers and bids from boundary entities in the pre-dispatch vs. real-time schedules can exaggerate the wedge between the pre-dispatch price forecast and HOEP. This is particularly true on days when there is insufficient domestic supply available to meet Ontario energy demand and operating reserve requirements and a relatively large quantity of imports is required. On these days, the import offers tend to be clustered at prices levels that are above the bulk of the domestic-based offers. Since a large quantity of imports is required to satisfy the forecast demand, the one-hour ahead pre-dispatch schedule accepts many of these imports. These imports are also likely to set the pre-dispatch clearing price at a relatively high offer price.

Figure A2.1: Pre-dispatch vs. Real-time Offer Curves and the Effects of Imports



As Figure A2.1 illustrates, on July 22, delivery hour 12, the pre-dispatch price was set at $950.66. This price was established by an import, and a total of 3,319.4 MW of imports was accepted for real-time time dispatch at this price. The real-time offer curve pivots considerably around the pre-dispatch demand forecast. Notice that with the pivot of the real-time offer curve, if the real-time demand is even slightly lower than what was forecasted or the operating reserve requirements are reduced[113], the real-time MCP will be set at a much lower price. On July 22, delivery hour 12, this is precisely what occurred. The pre-dispatch demand value for the delivery hour was 24,828 MW and the total operating reserve requirement was 1,580 MW. The peak real-time demand was 24,661.7 MW and the total operating reserve requirement was 370 MW – a combined difference of 1,376.3 MW. As a result the real-time price cleared at $168, rather than the $950.66 initially forecast.[114]

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[113] The operating reserve requirement never changes but the market requirement is altered using 'out-of-market' control actions when there is insufficient operating reserve available within the market.
[114] Other factors such as a failed import and export and SS generation differences also contributed to the setting of the real-time price and the need to reduce the market-based operating reserve requirement.

Note that had the real-time demand been 24,828 MW as initially forecasted and the operating reserve requirement maintained at 1,580 (and all other factors such as self-scheduling generation levels, exports and imports were as expected) the real-time price would have been higher than the pre-dispatch price forecast at $1,275. This was the price of the next MW of energy offered, which was set by a domestic offer. This illustrates that the disparate treatment of boundary entities in the pre-dispatch vs. the real-time market does not cause a divergence between the pre-dispatch and real-time prices. This is caused by some other factor such as an over-forecast of demand. The disparate treatment of boundary entities will, however, exaggerate the impact of the over-forecast of demand, particularly on days when there is a large quantity of imports (all offered at or around the market clearing price) required to meet Ontario demand.

Chapter 3: Conclusions

1. Main Conclusions

The first four months of market operation have been a learning experience for market participants, for the IMO and for the Panel. From the Panel's perspective we draw six main conclusions from our review of activity over this period:

1. There is a serious capacity problem in Ontario, which has shown up in extremely tight supply/demand conditions during the summer peak periods. If steps are not taken to address this situation Ontario could face even more serious reliability problems, leading to the possibility of supply interruptions and continued upward pressure on price in periods of peak demand.

2. The structure of the market is not yet conducive to effective competition. Generation remains concentrated, and the government, through OPG, remains the largest single owner of generating facilities. Measures are in place to divest generation over time but, in the interim, private investors are being relied upon to make the investment decisions necessary to provide incremental capacity to Ontario. It is not clear that the signals they have been receiving through the first four months of market operation are clear, credible and consistent enough to encourage the investment that is desirable in new capacity.

3. Similarly, we have some concerns about whether coordination mechanisms and incentives are adequate to ensure that existing transmission capacity is used most effectively and that new investments are made expeditiously, and in appropriate locations.

4. The full benefits of effective competition are unlikely to be realized unless a much greater portion of demand is price-responsive; when customers cannot respond to high prices by lowering their consumption, they cannot discipline price increases from suppliers.

5. The design and structure of energy markets are critical to effective signalling and credibility. It is important that the IMO aggressively pursue options to develop the markets further, including measures that will deal with some of the issues raised in this report.

6. The behaviour of market participants needs to continue to be monitored. As well, some aspects of market design may be conducive to gaming and should be reviewed where this is the case.

Each of these main conclusions is elaborated below.

2. There is a Shortage of Capacity in Ontario

As reported in Chapter 1, there has been virtually no new capacity installed in Ontario over the past five years. Indeed, with the removal from service of Pickering and Bruce units, some 4,643 (gross) MW has been removed from available capacity since 1997. As shown in Chapter 1, the Available Reserve in Ontario at summer peak – that is, the percentage by which total available capacity exceeds the summer peak demand for energy– has fallen from 19.2% in 1996 to –1.5% in 2002. This decline reflects both growth in peak demand and the decrease in capacity.

As a result of growth of demand relative to capacity over the past five years, it has been necessary every summer since 1998 to rely on imports to balance supply and demand and this was particularly so this summer. At peak periods this summer, imports in the range of 3,700 to 4,000 MW were required, most of them purchased at very high prices.

The most recently available information on the intention of market participants indicates that about 9,600 MW of new capacity will be installed between now and the end of 2005. Some 3,500 MW, or more than 37% of this total, is accounted for by the projected return to service of Pickering and Bruce nuclear units by the end of 2004. Of the 6,000 remaining MW of capacity projected to be in service by 2005, 1,088 MW (less than 20%) are currently under construction.

Given the uncertainty surrounding the cost and timing of the return to service of the nuclear units, and given the relatively long time frames necessary to receive regulatory approvals and construct new generating capacity, we are concerned that these planned increments to capacity may not materialize on the schedule foreseen. If they do not, and if steps cannot be taken to make demand more responsive to price than it now appears to be, then Ontario may be hard-pressed to meet peak demands next summer.

Ontario benefits from being part of a larger trading area for electrical power. At the same time, undue reliance on imports carries certain risks. The magnitude of the additional imports required may strain existing intertie connections. They may not even be available if demand is simultaneously peaking in neighbouring jurisdictions. It is also the case that scheduling imports in the hour ahead pre-dispatch market constrains their ability to meet unanticipated surges in demand in real time. At a minimum, increased reliance on imports to meet demand will put serious upward pressure on price.

3. The Structure of the Market and Effective Signalling to Potential Investors

It is critically important that market participants receive signals that enable them to plan their actions with a high degree of confidence. In a competitive marketplace these signals come through price determination that is the result of the interaction of decisions made by many independent buyers and sellers. While the Ontario electricity market has been opened to competition, it is not yet an effectively competitive marketplace in this sense. Relatively few energy users have the information, ability and incentive to adjust their demand on the basis of prices charged. And supply is still highly concentrated, with

OPG being the major electricity provider within the province. The government is committed to having OPG divest generating capacity, particularly price-setting capacity, and indeed it is a condition of OPG's license that it do so within a specified time frame. But the corollary is that OPG is not expected to build new capacity and it is therefore important that appropriate signals be sent to private investors so that Ontario's capacity requirements are met in a timely way.

Price, while important, is not the only signal of importance to potential investors. Others include the attitude of the government toward competition and its role as owner of the major generating entity in the province; the timing of returning Pickering and Bruce nuclear units to service; the actions of the IMO in operating the marketplace and, in particular, the effect of these actions on the market price for energy; and ways in which the market is expected to develop. All of these dimensions are important, and what is most important about them is that potential investors receive signals that are clear, credible and consistent. Each of these dimensions is discussed more fully below.

3.1 The role of government

The Government of Ontario continues to play an important role in the marketplace. With market opening, the government has delegated its authority to make Market Rules to the IMO, but it retains a broad public policy role through its legislative power and through its regulatory actions, including those that affect the construction of new generating and transmission capacity.

The government also owns OPG and Hydro One, both of which are important market participants. In the period since the market opened, the government has made it clear that it intends to maintain a majority ownership position in Hydro One. Through OPG it continues to own 90% of all generating capacity in the province (although 11 percent of generating capacity is operated by Bruce Power under the terms of a long-term lease). OPG's operating licence requires it to transfer effective control of its plants in two tranches such that by May 2012, it holds no more than 35 percent of in-service generating capacity in Ontario.

We believe it is important to the credibility of the market that OPG's divestiture program proceed as rapidly as possible.

3.2 Pickering and Bruce nuclear units

The four units of Pickering A station were taken out of service in December 1997 for refurbishing. Each unit has a capacity of about 500 MW. The most recent information from OPG suggests that the first unit will be returned to service in the first quarter of 2003, with the remaining three units following at six-to-nine month intervals.

Two units at Bruce A, each about 750 MW capacity, were withdrawn from service in 1998. The most recent information from Bruce Power indicates that a hearing before the Canadian Nuclear Safety Commission is scheduled for December to consider returning the units to service and, if all goes well, the first unit may be on stream by April 2003 with the second unit available for the summer months.[115]

In the case of Pickering, the original timetable for refurbishment has proved to be optimistic. There is no question that an additional 3,500 MW through the course of 2003-2004 will make a substantial difference to Ontario's capacity, although it is worth noting that given the demand growth since 1997 the Available Reserve would still be tight, even after the return of the nuclear units.

In the short term, uncertainty about the timetable of refurbishing the Pickering and Bruce units detracts from the clarity of signals to private investors about the time frame in which they might profitably make new investments in Ontario. This uncertainty makes it difficult for potential investors to plan. It would be desirable if OPG and Bruce Power

[115] Bruce Power press release (Bruce A restart ahead of schedule), July 29, 2002.

could provide regular updates to the marketplace on progress towards bringing these units back into service.

3.3 The role of the IMO

We are concerned at the continuing disparity between pre-dispatch information and real-time outcomes. We should stress that we do not necessarily expect real-time outcomes to match pre-dispatch in all cases. There are too many variables at play. However, we would expect that the errors should be more randomly distributed and less systematic than we have observed over the past four months. Systematic overestimates of load and/or price will not provide market participants with clear, consistent and credible signals.

We have spent considerable time assessing why this disparity persists and our analysis is presented in Chapter 2. The analysis shows there is no single reason for the disparity but there are some factors that do cause us particular concern.

The use of 'out-of-market' actions to meet operating reserve shortfalls, introduced to meet reliability concerns in times of tight supply, has the effect of substantially reducing real-time price because of the way in which the operating reserve adjustments are made in the constrained schedule and are then used in the unconstrained schedule. Our understanding is that the inflexibility that leads to this result is a characteristic of the design of the software that is used to operate the market. Complete reliance on the software to solve for operating reserve shortfalls is unacceptable as it cannot provide assurance that the IMO will at all times have sufficient operating reserves to meet its international reliability obligations. Manual adjustments using 'out-of-market' measures can provide reliability assurance for up to one-hour ahead. However, the use of manual adjustment requires that the exact amount of operating reserve adjustments obtained in the constrained schedule be applied, *without adjustment,* to the unconstrained schedule for the purpose of determining the MCP. This result is determined by the design of the software and it has the perverse effect of leading to substantial reductions in real-time prices from what the market-based solution would have generated, at precisely the times that energy is in shortest supply. This seems to us counterintuitive and likely to send misleading signals to the marketplace about the real resource value of electricity in such circumstances.

If 'out of market' measures are to be used to create additional operating reserves, and we think they should be, then they should be integrated into the market in a manner that is transparent to participants and avoids such counterintuitive price signals. We believe that a necessary first step is for the IMO to make changes to the software to increase flexibility in implementing manual adjustments. In particular, when energy is in short supply and operating reserves are being enhanced by 'out-of-market' measures that carry no price tag, we believe that allowing such reserve enhancements to increase the unconstrained offer curve for energy sends inappropriate signals to the marketplace. The software should allow the price-determination mechanism in the unconstrained schedule to permit the imputation of some value to the 'out-of-market' actions that would be reflected in the energy price and thus facilitate recognition of the underlying scarcity.

The manual adjustment of operating reserves has been an important contributor to the differences between pre-dispatch and real-time prices observed over the first four months. But as detailed in Chapter 2 it is not the only contributor. We therefore also urge the IMO, together with other market participants, to consider whether there are additional practical ways of increasing the accuracy and the usefulness of pre-dispatch information. For example, would it be helpful to the operation of the market if the pre-dispatch price forecast were accompanied by a range, with the limits of the range indicating prices that would obtain in pre-dispatch if load were some fixed percentage lower and higher than the forecast amount? Our sense is that additional pre-dispatch information that might assist market participants in understanding the shape of the offer curve in the relevant range might be helpful. For example large loads might find the sensitivity of price to load variation in pre-dispatch useful in deciding whether to curtail their demands for a given hour. Before implementing any changes it would be useful for the IMO to have discussions with market participants on this, or on other potential ways that the usefulness of pre-dispatch information might be improved. The IMO has recognized this issue and in early August initiated discussions with Market Participants on ways to address it. We strongly support this process.

3.4 The evolution of the market

Finally, all participants in Ontario's energy market -- suppliers, distributors and users -- have a strong interest in ensuring that the future evolution of the marketplace enhances effective competition by ensuring, to the extent practical, that market signals are clear, consistent and credible. We discuss the process currently underway and some specific directions in section 6 of this chapter.

4. Transmission Issues

The capacity problem that concerns us is exacerbated by internal transmission constraints that force the rescheduling of generators, constraining some off and some on to respect these constraints. This reduces the efficiency of internal resource use as well as limiting the quantity of imports and increasing congestion payments. Neither the MAU nor the Panel has been able over the past four months to analyze transmission issues as fully as we would like. We question whether the mechanisms to coordinate planned outages of transmission with available generating capacity are being managed as well as they might be. Our understanding is that the current situation is such that the Market Rules require that applications for transmission outages be assessed by the IMO solely on grounds of reliability and adequacy and not taking into account the overall efficiency of resource use. Another issue relates to how signals to expand transmission capacity to relieve particular bottlenecks are sent and whether incentives are adequate to encourage Hydro One to act on such signals. These are important issues that we intend to pursue.

5. The Importance of Demand Responsiveness to Price

In section 3 we discussed the importance of signals – price and non-price – to potential investors in Ontario's electricity market. Ensuring that energy users receive accurate and timely information about prices, and have the incentive to modify their demands in response to such information, is at least as important. Indeed, given the large capital costs of additional supply and the long lead times to bring it to market, it may be much more efficient to consider ways to make demand more price sensitive.

We have tried to obtain robust data on how many users are now price sensitive, or have the capacity to become price sensitive at various levels of investment in new metering and communication equipment. The information we have available, while sketchy, suggests that there may be as much as 35 percent of total load (retail and wholesale) that is now served by interval meters, providing at least one of the necessary conditions for price responsiveness. Of this 35 percent, retail customers who have interval meters but who may lack the information or incentive to allow them to take full use of the potential for cost savings that such meters provide could represent as much as 20 percent of total load.

We believe that interval meters and pricing plans that permit consumers to take advantage of load management by paying at hourly rates rather than average rates offer substantial potential benefits to both individuals and to the market as a whole. It appears, however, that the way in which local distributors currently charge retail customers provides little or no incentive for either the distributor or the customer to invest in the capital equipment necessary to facilitate load management by individuals. Even where the retail customer is billed on the basis of the HOEP, as opposed to an averaged price, it is not clear that residential customers with interval meters have or can easily obtain the necessary information about expected prices that will permit them to adjust their usage patterns to reduce costs. Further research should be undertaken in this area and it could be very helpful to encourage some pilot projects as well. Because the Ontario Energy Board has the primary responsibility for the retail market and, more particularly, has jurisdiction over the pricing regimes that local distributors offer to retail customers we believe that the OEB should play a leadership role in developing and supporting such research and pilot projects. The OEB should encourage initiatives from local distributors and retailers, and should work to create a climate of receptivity to such initiatives in terms of its responsibilities to regulate retail-pricing plans.

We have also been informed that some local distributors used to have in place programs that would allow them to manage the load of their customers within limits, and that Ontario Hydro's former rate structure allowed them to be compensated for doing so. With the opening of the market, however, the incentive to maintain these load management programs has apparently disappeared. This is unfortunate, and we believe it would be helpful if the OEB considers ways to restore these incentives and encourage the widespread adoption of load management programs.

There are currently two market participants that have chosen to become dispatchable loads, meaning that they bid their demands into the market and at some price they are prepared to be curtailed by the IMO, on a five-minute basis. There are also about 90 large loads, accounting for about 3,000 MW of total demand (or about 15 percent of total load), that purchase their energy in the wholesale market and are directly connected to the high-voltage grid. These are potentially responsive loads but they have chosen not to become dispatchable, presumably because it is not in their interest to adjust their energy consumption with only five minutes notice. The IMO has negotiated fixed-price agreements with some loads for the purchase of capacity (by not supplying them) in times of emergency. We question whether there are ways that might be explored to provide them with opportunities to become dispatchable load, at intervals that may be more compatible with their usage profiles. For example, if such loads could bid into the hour-ahead pre-dispatch market in the same way as imports and exports, would they be interested in doing so and would this make a difference in terms of increasing demand responsiveness in the marketplace? We believe this issue is worth considering further.

6. The Further Evolution of the Markets

The IMO has set up a Market Advisory Council to consider priorities for the further development of the IMO-administered markets. The Council held its inaugural meeting on August 13 and considered a "Straw-Plan for the Evolution of the Ontario Market Design"[116]. The plan proposes as the key objective for future market evolution "to improve price and operational predictability while ensuring reliability". Virtually all of the issues that we have expressed our concern with over the first four months of market operation are recognized in this document. Specifically, the document puts considerable emphasis on:

- better aligning pre-dispatch information and real-time outcomes,
- dispatchable load and demand-side responsiveness,
- interface with the retail market.

As well, the "straw-plan" identifies other issues that we have not focused on to the same extent in this report, but which are important and should be pursued. These include:

- the need to achieve better optimization over time,
- the design and implementation of a day-ahead market,
- the design and implementation of a futures market,
- locational marginal pricing,
- rational alignment with U.S.markets.

We strongly support this process of stakeholder consultation and look forward to the enhancements discussed in the "straw-plan" as important opportunities to address many of the issues that we have noted in this report. Over the past four months our efforts have been focused on developing our approach to monitoring, and on a few key issues that we have observed in the operation of the market as it is now structured. We intend in our future work to develop a better appreciation of the implications of changes in market design, such as day-ahead markets and locational marginal pricing, and as we do so we will report our conclusions to the IMO Board.

[116] IMO, "Straw-Plan for the Evolution of the Ontario Market Design", Public Issue 1.0 (IMO_PLN_0037), August 7, 2002.

7. Behaviour of Market Participants and the Market Rules

We are mandated to report on inappropriate or anomalous behaviour of market participants and, in particular, whether there are any instances of abuse of market power or gaming that have led us to commence an investigation.

The Market Assessment Unit monitors the conduct of market participants on behalf of the Panel and reports to us on a regular basis. The MAU has ongoing discussions with market participants to clarify behaviour that raises questions and to ensure that participants are aware that regular monitoring is taking place. At times the MAU has undertaken such discussions on its own initiative and at times it has done so at our request. During the four-month period under review, the MAU has not reported any instances that have led us to conclude that an investigation of participant behaviour is warranted under section 3.4.1 of the Market Rules. Most significantly, we have not identified any instances of the abuse or potential abuse of market power, in the sense of collusive or predatory conduct or other types of behaviour designed to restrain or prevent competition.

As reported in Chapter 2, we have noted the very high prices demanded, and secured, by importers when supply has been tight in Ontario. In these tight circumstances imports from the Quebec, New York and Michigan interties were each essential to satisfy Ontario demand.

Although tight market conditions led to circumstances where very high prices of imports and associated high uplifts resulted, we found no evidence that any market participant sought to create or sustain market power. Our analysis of the high-price hours presented in Chapter 2 leads us to conclude that the high prices and uplifts we observed this summer do not reflect the abuse of market power. Essentially, they result from the tight supply/demand balance, and appropriate short-term measures to address them include making demand more responsive to price and increasing supply by bringing Pickering and Bruce nuclear units back to market as quickly as possible.

We did observe that certain aspects of the Market Rules and operating procedures are conducive to gaming, and as reported in Chapter 2, we participated in IMO-initiated action to implement rule changes to remove the financial incentive that the IOG may have provided to wheel power through Ontario. This 'implied wheel' transaction, as described in more detail in Chapter 2, is an example of gaming in the sense of exploiting an unintended consequence of a rule. There was no allegation of fraudulent behaviour associated with it.

There were no other instances of gaming brought to our attention, although before market opening, we also supported a rule change to impose penalties on participants whose import or export transactions fail for reasons within their control.[117] Our analysis in Chapter 2 shows that failed import transactions were an important part of explaining many of the high-price hours we examined. Some of these failed transactions are being investigated by the IMO's Market Assessment and Compliance Division to establish whether they were indeed, bona fide. Whether the failures were caused by inappropriate behaviour or the misalignment of scheduling and dispatch with adjacent jurisdictions, we believe that efforts to limit their occurrence should have a high priority.

Before the market opened, we expressed our concern about the potential for gaming that was created by the framework for dealing with congestion, and particularly payments made to facilities that are constrained-off. We monitored CMSC payments closely through the May-August period and our observations are reported in Chapter 2. The MAU has not reported any behaviour that suggests these rules are being abused, but we have noted and reported the high concentration of payments to a relatively few facilities, and the high frequencies with which some facilities receive payments. We have asked the MAU to pay particular attention to CMSC payments in its ongoing monitoring activities. We also propose to undertake an in-depth examination of the rationale for, design of, and experience with CMSC payments, and particularly constrained-off payments. To facilitate this review we will be issuing a discussion paper setting out our concerns and suggestions later in the fall and, following a process of consultation with market participants, we will report our conclusions to the IMO Board.

[117] See Chapter 2, section 2.3.1.