Market Power Framework
For the IESO-Administered Electricity Market

Proposed Framework for
Identification of the Exercise of Market Power

Discussion Paper prepared by the Market Surveillance Panel

November 2006

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1 Introduction

The Market Surveillance Panel has monitored the operation of the IESO-administered markets since the opening of the electricity market to competition in May, 2002. We have now published eight semi-annual monitoring reports. These reports are the vehicle through which we meet one of our key objectives: to identify and explain anomalous outcomes in the IESO-administered markets. Our explanation and analysis of anomalous outcomes has led us to recommend changes in both market rules and operational procedures. Most of our recommendations have been implemented and have eliminated gaming opportunities, increased transparency and enhanced efficiency.

Our second key objective is to investigate instances of abuse or potential abuse of market power, and to make recommendations where we find they exist. To date we have not found any such instances, and we have launched no investigations.

This paper concerns itself with the exercise of market power, pricing behaviour that is distinct from the more serious abuse of market power but still relevant to our assessment of the state of competition in the energy market. On the basis of both our monitoring experience, and the post-2002 changes in the operation and structure of the IESO-administered markets, we have concluded that a well-articulated analytical framework that would allow us to recognize when market power has been exercised in the electricity spot market is desirable to enhance our ability to meet our objectives in market monitoring.

This paper sets out the general framework we propose to employ, for discussion and comment by market participants. While we believe the framework is conceptually appropriate, and reasonably robust, there are many areas of judgment as to how it should be applied in practice. We welcome comment and feedback on the framework itself, on the practical issues of application, and on how we intend to use it in our ongoing monitoring work.

The framework is intended to codify the practices developed by the MSP to enable us to infer that there has been an exercise of market power in the IESO market. Unlike related assessments which may be conducted in some other jurisdictions, it is not the basis for an automatic mitigation process or any sanctioning activity. Its purpose is simply to help the MSP gain a better understanding of both the conduct of market participants and events that occur in the market.

This paper is organized in the following way:

- The balance of this chapter addresses, at a conceptual level, what the exercise of market power is and why it is important to monitor for it. It also examines the relationship between the exercise of market power and the abuse of market power – in the context of our mandate -- and outlines how we intend to use the results of our monitoring for the exercise of market power to inform our work. A critical issue we address is how, and to what extent, we can report the exercise of market power when it does occur, given the confidentiality constraints under which we operate.
- Chapter 2 sets out an analytical discussion of the exercise of market power that adds rigor to the conceptual overview in Chapter 1. Using this framework, the chapter develops the conceptual framework for the three tests that would be applied in monitoring for the exercise of market power -- a conduct test; a price impact test, and a profitability test. Certain generation and price conditions do not require testing by the framework; exceptions are identified in this chapter.
- Chapter 3 outlines in considerable detail how we would apply these tests in practice, in different situations. In some cases, there are comparable types of tests used in other electricity markets, and the application of the tests in Ontario is relatively straightforward; but in other cases application is much more complex and we are breaking new ground. Chapter 3 also identifies a number of specific issues where we are seeking input from market participants and other interested observers.
- Chapter 4 sets out our timetable, and anticipated next steps in the process of developing and implementing the framework.

1.1 The Exercise of Market Power: Some General Considerations

1.1.1 Market Power and Competitive Pricing

A market participant has market power where it has an incentive and the ability – through its own actions – to move the market price away from the competitive level. Market power can be used to increase price above the competitive level, to augment profit, or to decrease price below the competitive level to disadvantage competitors or discourage entry, thus reducing competition and increasing profit over the longer term. The framework that we propose in this paper is intended to deal with those cases where the exercise of market power has the effect of increasing the market price above the competitive level. Although we are not proposing a formal framework to assess predatory or exclusionary pricing in this paper, we have monitored and will continue to monitor the market for low prices that appear anomalous.

In the context of this framework, market power is exercised where a market participant acts unilaterally to raise the market price above the competitive level with the expectation that it will profit by doing so. In essence, the exercise of market power involves either the restriction of the supply available to the market ("withholding") or pricing above the relevant measure of cost by the marginal supplier in the market ("pricing-up"). Both have the effect of transferring wealth from consumers to suppliers. Withholding has the further effect of causing relatively high cost suppliers to be called to market to replace withheld capacity. This inefficient choice of suppliers raises the aggregate cost of supply to the market.[1]

It is important to recognize that withholding and pricing-up are not prohibited by the rules governing the Ontario market. An essential feature of the Ontario spot market is that it is a voluntary market. Participants are not compelled to offer. Nor is there any restriction on the prices at which supply may be offered (other than a maximum offer price of $2,000 and the closing of the bid window prior to real-time). As well, there is a free flow (subject to

[1] As described in our December 2003 Monitoring Report covering The First Eighteen Months (May 2002 - October 2003), efficient dispatch of domestic generation requires that available generating units be dispatched in order of

transmission limitations) of exports to and imports from other markets which contributes to market efficiency and has proven to be beneficial to Ontario electricity consumers.

Withholding and pricing-up are not issues in and of themselves. While either one of these is a necessary condition for drawing an inference that market power has been exercised, neither is a sufficient condition. What is also required, in the Panel's view, is that this action raises the market price, profits the market participant involved and has no persuasive alternate rationale. When these conditions are satisfied we are then in a position to properly consider it as intentional market participant behaviour as distinct from other causes of price increases, such as equipment failure, market design flaw, system operator error or scarcity.

The following section discusses the concepts of withholding and pricing-up in more detail and identifies some of the conditions that may indicate that a market participant exercised market power.

1.1.2 Exercise of Market Power

As stated above, market power may be exercised either by pricing-up or withholding supply from the Ontario market:

In the Ontario wholesale market the market clearing price (MCP) is determined by the offer for the first MWh of energy not taken in the auction. The marginal supplier is the market participant that offers at this price. Because the demand for energy is inelastic and the offer stack or market supply schedule is discontinuous, the marginal supplier may have room to increase the offer for the first MWh not taken and therefore increase the market price. The limit on this ability would be the offer price of the next MWh not taken. Where the marginal supplier increases its offer above its costs, it effectively 'prices-up' to the next highest alternative. If demand is inelastic this pricing-up does not change dispatch or lead to inefficient operation of the market but it does result in a wealth transfer from loads as a group to generators.

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their incremental cost (merit order). The efficiency of the decision to import requires that domestic generating units

Withholding raises the market price by restricting supply. In essence, withholding creates an artificial scarcity in the market. Withholding leads not only to a wealth transfer associated with a higher price but also results in inefficient dispatch as higher cost sources of energy are called to market before lower-cost resources. There are a number of ways in which supply may be withheld from the market:

- Supply can be offered at prices that are higher than costs with the consequence that higher cost but lower priced offers are selected instead. This is commonly referred to as economic withholding.
- Supply may simply not be offered into the market thus requiring the market to turn to higher cost sources. This is commonly referred to as physical withholding.
- Supply that can be offered for a limited number of hours (such as hydroelectricity produced from limited supplies of water) may be offered to the market in such a way as to increase the market price in peak periods without substantially reducing the market price in off-peak or shoulder periods. As explained in Chapter 3, this may involve economic withholding (pricing above opportunity cost) or physical withholding or both.

In the Panel's view, drawing an inference that a market participant has exercised market power by any of the means described above requires that the offer involved have the effect of increasing the market price and that the market participant involved also have other offers that are accepted into the market (inframarginal offers) thereby profiting from the higher market price. Drawing an inference that there has been either pricing-up or economic withholding requires that the offer involved be priced above the relevant measure of cost. Drawing an inference of physical withholding would require persuasive evidence that the alleged withholding was not the result of a planned outage or a legitimate forced outage. In the case of energy-limited resources, the Panel would look for persuasive evidence that the resource involved could reasonably have been offered in higher priced periods.

The evidence described above is essentially behavioural in nature. In the Panel's opinion, the nature of the Ontario market is presently such that reliance on structural evidence of the ability to exercise market power would not be instructive. There is a dominant generator in the Ontario

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and imports be accepted in pre-dispatch in order of their respective incremental costs.

market but supply conditions are sufficiently tight that smaller market participants may also have frequent opportunities to exercise market power. Nevertheless, structural evidence may provide additional insights under some circumstances, for example, in the case that an importer has sole access to an intertie.

1.1.3 Market Power and Scarcity

It is a characteristic of electricity markets that when available resources are barely adequate to meet demand (referred to as scarcity conditions), market prices can rise to very high levels. When supply runs short, the market price may be determined by the bid of a dispatchable load rather than by the offer of a generator. That is, a high price may be the means by which the market rations a limited available supply. In this case, a high price simply reflects the scarcity value of electrical energy. High prices alone do not imply that there has been an exercise of market power. To the extent they reflect scarcity, such prices are an essential signaling device to ensure that the market operates effectively both in the short term and in the long term. In its reports, the Panel has repeatedly emphasized the importance of allowing market prices to reflect conditions of scarcity. The Panel has also tried to focus attention on the conditions of scarcity that have prevailed in the Ontario market and the impact they have had on the market price. To this end, the Panel has developed an analytical concept referred to as the ‘supply cushion’ to assess the relative tightness of the market.

However, scarcity also brings with it an increased opportunity to exercise market power. When supply is relatively tight and the market reaches equilibrium on the steep portion of the offer curve, the withholding of even small quantities of energy can drive up prices substantially. At such times, even small suppliers may be able to exercise market power. In this case, the effects of true scarcity may be aggravated by the artificial scarcity resulting from the exercise of market power.

1.1.4 Market Power in Electricity Markets

In most markets in the economy, participants have some ability to exercise market power. This is normally constrained by the ability of their existing competitors to expand their output or draw down inventories, the ability of new competitors to enter the market and the ability of consumers either to refrain from purchasing for a period of time or to turn to substitute products. Cases in which there is a sustained and material exercise of market power arising from either a collusive agreement among competitors (joint dominance) or exclusionary behaviour by a dominant firm are generally considered as abuses of market power for which remedies exist under competition or anti-trust legislation.

Most electricity markets lack some of the sources of market discipline on pricing behaviour normally associated with competitive markets. Demand is inelastic, the product cannot be stored for future consumption and new supply sources are limited in the short-to-medium term by transmission capacity limitations and relatively long construction lead-times for new generation. The concern that market forces may be insufficient to induce competitive behaviour at least under some circumstances, has led to the establishment of provisions for market monitoring and mitigation of the exercise of market power in many electricity markets. The specific provisions adopted depend on the design, structure and regulatory history of the market involved and most are continuing to evolve. There is a great deal of variety and it may be more accurate to think of them as regulatory regimes that rely on market style incentives to varying degrees than as markets with varying degrees of regulatory intervention.

Some markets, such as those in Alberta and Australia, are characterized by large numbers of bidders, few transmission constraints and a relatively comfortable supply cushion and are able to rely to a considerable degree on the forces of competition to constrain the exercise of market power. Nevertheless, the rules in these markets provide for limitations on the exercise of market power (bid caps) as well as the possibility of sanctions under some circumstances. In some South American markets, dispatch decisions are based on cost information provided by generators rather than real-time bids. This obviates concerns about pricing-up and economic withholding. The benefits of these markets flow largely from the fact that they allow for decentralized decision-making with respect to investment in and management of generation.

In the United States, the Federal Energy Regulatory Commission (FERC) has specified the market monitoring obligations of Regional Transmission Organizations (RTOs). As well as formal monitoring, the design of U.S markets includes bid caps and in some cases provides for the real-time modification of offer prices. This is referred to as an automatic mitigation procedure (AMP) and is employed, for example, in the New York and PJM electricity markets. Under an AMP, bids are compared to defined thresholds. Where these defined thresholds are exceeded and this is likely to have a substantial impact on the market price, the market operator may modify the offer in question before the market price is determined. A more detailed explanation of automatic mitigation in the New York and PJM markets is provided in Appendix A of this paper.

1.2 Market Power in the Ontario Electricity Market and the Role of the MSP

The description of market power set out above and, in particular, the necessary condition that either supply is withheld from the market or priced-up in order to exercise market power, suggests that market power will be most easily exercised where there is a dominant generator with a large portfolio. With a large portfolio, the price effect of withheld supply on the portfolio more than compensates for the lost profits on the energy withheld. Alternately, with a large portfolio there may be more price ranges and broader price ranges in which pricing-up can take place before hitting the limit imposed by the next most costly supplier. In the Ontario market, the dominant position of Ontario Power Generation (OPG), which at market opening in 2002 supplied 77 percent of provincial generation,[2] created conditions in which market power existed and could potentially be exercised.

The original market design dealt with this situation through the Market Power Mitigation Agreement (MPMA) which was a condition of OPG’s license. The original design included a commitment by the government to divest some of OPG’s generation assets so that within ten years of market opening OPG would account for no greater than 35 percent of the capacity in the market. The MPMA set out a timetable for divestiture. It also provided for a rebate to consumers if the market price exceeded an average of $38/MWh and the structure of the rebate included incentives for OPG to divest assets. When the Market Surveillance Panel was set up,

[2] This was after divesting control of the Bruce plant. In 2000 OPG accounted for 89 percent of the generation in Ontario.

our mandate was defined in terms of monitoring for and investigating the abuse of market power, not the exercise of market power. One of the IESO's license conditions[3] directed the Market Surveillance Panel to the arrangements of the MPMA, making it clear that OPG had the right to act unilaterally to achieve any price outcome it felt appropriate and if the resulting price exceeded the MPMA threshold ($38/MWh) the 'sole remedy' was the rebate. We have interpreted this license condition as constraining our ability to suggest any remedial action outside the framework of the MPMA, but not in any way restricting our ability to monitor OPG's behavior in the market.

As the market has evolved over the past few years, there have been a number of changes. The most significant, for the purposes of this paper, are briefly reviewed below.

The current government has committed to maintain OPG's generating assets under public control. The policy of divesting assets is no longer in force and the MPMA effectively expired at the end of 2004. The current mitigation framework with respect to OPG's market power is set out in a Regulation under the Ontario Energy Board Act.[4] The Regulation distinguishes between prescribed and non-prescribed assets. The price OPG receives on prescribed assets will be regulated on the basis of long-term contracts with periodic price adjustments made by the Ontario Energy Board. Prescribed assets include baseload hydroelectric and nuclear plant with an allowance for baseload hydroelectric generation above 1900 MW to receive the market price. The current contracts effectively fix the price for prescribed assets to OPG at between $33 and $49.50 per MWh. Prescribed assets which receive these fixed prices account for about 56 percent of OPG's production.[5]

The mitigation framework for non-prescribed assets effectively requires OPG to rebate to the IESO the difference between the market price and $47/MWh on 85 percent of the output of its

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[3] At this time, the MSP was appointed by and reported to the Committee of Independent Directors of the IESO (referred to as IMO at the time). As of January, 2005, the Panel is appointed by and reports to the Ontario Energy Board.

[4] The main elements are set out in a Regulation made by the Governor in Council under the authority of the Ontario Energy Board Act, 1998 and dated February 16. 2005. See: ROC 42/2005 respecting "Payments made under Section 78.1 of the Act".

non-prescribed assets,[6] excluding production from the Lennox generating station. Non-prescribed assets subject to this rebate arrangement amount to about 35 percent of OPG's production. This rebate arrangement for non-prescribed assets took effect from April 1, 2005 and was recently extended until April 30, 2009; there is no long-term framework governing market power mitigation for non-prescribed assets.

The OEB approved a Reliability Must Run contract between OPG and IESO for production from the Lennox units, effective for one year, starting October 1, 2005.[7] The contract provides sufficient payments to cover fixed and variable costs plus a further 5 percent of the market revenues for energy produced.

All of OPG's production, whether covered by regulated prices or not, must be offered into the market and Paragraph 27 of Schedule B to the Regulation states that "with respect to its non-prescribed generating facilities, OPG shall maximize their value to the people of Ontario by operating those facilities in response to the price signals of the IESO-administered markets. OPG's conduct in the IESO-administered markets under this direction is subject to review by the Market Surveillance Panel of the Ontario Energy Board."

The current mitigation framework, Lennox RMR contract and shareholder guidance to OPG to maximize the value of its non-prescribed assets to the people of Ontario reduce, but do not eliminate the incentive for OPG to exercise its market power. If the additional net revenue received on the portion of OPG's generation that continues to be accepted in the market and is not subject to fixed price contracts or rebate requirements exceeds the net revenue foregone on generation withheld, a withholding strategy would be profitable for OPG.[8] The Panel is satisfied

[5] This is based on 2004 production, with baseload hydro production above 1900 MW, 15 percent of coal production, Lennox, and Lakeview excluded from the sub-totals for prescribed and non-prescribed assets with fixed prices.
[6] This applied in the period April 2005 to April 2006, but is slightly different over the period to 2009.
[7] A new 12 month contract is being reviewed by the OEB.
[8] It is recognized, of course, that although adjusting for fixed prices may show no net profit, all other suppliers of electricity to the Ontario market still benefit from the higher-than- competitive price that results, whether it is an exercise of market power or not.

that the portion of OPG's generation that continues to receive the market price is such that a withholding strategy remains potentially profitable for it.[9]

OPG is not the only participant in the Ontario electricity market with fixed prices nor is it the only participant that has the potential to exercise market power. The Ontario Power Authority (OPA) has entered into many contracts with large and small generators such as Bruce Power (for Bruce A facilities), TransAlta, Brighton Beach (and other early movers), and future generation suppliers as well. However, depending on the supply cushion in the market at the time, almost any market participant with generation outside these fixed-price arrangements could theoretically exercise market power. Even with a single generating unit, the market participant can structure bid laminations in a way that the full capacity of the unit is not selected, with consequent impacts on price and the participant's own profitability.

We first discussed the possibility of introducing a framework to monitor for the exercise of market power in our monitoring report of June 2004.[10] Our rationale for the framework is not to change our mandate in any way, but to help us more effectively fulfill the obligation we have to monitor behaviour in the IESO-administered markets and to investigate abusive or potentially abusive behaviour. We believe that the framework we propose will assist us in the following ways:

First, with regard to monitoring, we have interpreted our monitoring function as including the responsibility to identify anomalous behaviour in the marketplace and to explain it to our satisfaction. Two consequences flow from this: first, we are able to satisfy ourselves and report to the public as to whether or not the anomalies we observe have arisen from abusive behaviour, and where we believe they have, we are in a position to launch an investigation; second, explaining anomalies often leads to the discovery of unintended consequences of market rules and operating procedures, and provides a basis for recommending changes that will improve the

[9] The Panel recognizes the further mitigating effect of Paragraph 27 of Schedule B of the Regulation (referred to in the text) on any inclination on the part of OPG to exercise market power and also notes that a portion of any profits OPG might realize would be remitted to the government of Ontario.
[10] See Market Surveillance Panel, "Monitoring Report on the IMO-Administered Markets for the Period November 2003-April 2004", pp. 108-109.

operation of the markets. The task of the Panel in explaining price spikes is to understand whether the prices involved result strictly from scarcity, or whether withholding or pricing-up is also a factor. If there has been withholding or pricing-up, the task becomes one of determining if this represents an exercise of market power. In our monitoring to date, we have occasionally found instances of behaviour that we felt warranted discussion with market participants and we have pursued such discussions to gain a better sense of the considerations driving such behaviour. We have done so without a formal framework, although we have been guided by concepts similar to those proposed in this paper. While this has worked reasonably well to date, we believe that both the Panel and market participants will benefit if there is a more rigorous and transparent analytical framework that is understood and accepted by market participants.

The second reason we feel that a formal framework will be useful has to do with our interpretation of our investigative mandate. We have the statutory authority to investigate any activity related to the conduct of a market participant.[11] Ontario Energy Board By-law #3 directs our attention to inappropriate or anomalous conduct by a market participant, including abuse of market power.[12] We have consistently emphasized the distinction between the exercise and abuse of market power. We believe that the exercise of market power is not necessarily abusive, and we recognize the role that the current mitigation framework plays in reducing the incentive to exercise market power and mitigating the wealth transfer impact that occurs when it is exercised. We do not have formal criteria or guidelines for what we would consider abusive (other than the references we have made to behaviour that contravenes competition laws, such as predatory pricing, collusive behaviour (including bid rigging or price fixing) or other actions that substantially lessen or prevent competition) and we believe this is appropriate. Nonetheless, if our monitoring revealed a persistent, sustained and substantial exercise of market power (implying that the normal corrective forces of competition were weak or inoperative) this might well be considered abusive and be the basis for an investigation under the *Act.* Without a framework that defines when market power has been exercised, however, it is not possible to monitor for persistent and sustained exercises of market power.

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[11] See the *Electricity Act, 1998,* Subsection 37(1) and the specific reference to abuse of market power in subsection 38(1).

1.3 The MSP's use of the Framework

As will become apparent from Chapters 2 and 3 of this paper, any analytical framework that purports to determine when market power has been exercised is difficult to apply and requires considerable judgment. While the concepts may be reasonably straightforward, the development of practical behavioural tests for pricing-up or withholding and estimating their consequences are not. Data are imperfect and considerable judgment may be required to distinguish among competing explanations of a market participant's conduct.

There are many considerations that go into developing tests for the exercise of market power and, to a large extent, the nature of the tests is driven by the use to which the assessment is to be put. For example, in the New York and the PJM markets, the framework is used to override participants' offers in real-time. This real-time mitigation has led to a series of tests with thresholds that might appear in other circumstances to be relatively generous. For example, in the New York market, if a participant's offer is not judged to affect the market price by more than $100/MWh or 300 percent, then it is not regarded as an exercise of market power. **How to prescribe these thresholds for identifying exercises of market power in formulating our tests is one of the judgmental areas where the MSP wishes to receive advice and comments from market participants.** The point here is that there are tradeoffs that need to be considered. If the tests are too rigorous, there is a risk of finding the exercise of market power where in fact none exists; if the tests are not rigorous enough there is the risk of the exercise of market power going undetected. Where to strike the balance, in our view, depends in large part on how the framework will be used, and this section sets out our views on this.

As suggested above, in discussing our mandate, we are not proposing that the framework lead to automatic mitigation in the Ontario market, either ex ante or ex post. Nor is it intended that the framework lead to any other automatic response or result. Our objective is to implement it as a tool to assist us in our monitoring and investigative activities, which do not include mitigation, automatic or otherwise. We would use the framework in the following way.

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[12] See Articles 4.1.1 (a) and 5.1.1 (a) of Ontario Energy Board By-law #3.

First, with regard to monitoring for anomalous price behaviour, there may be instances where the framework suggests that market power has been exercised. Should this be the case, our response would be to commence discussions with the market participant concerned, through the Market Assessment Unit in the first instance, to ascertain whether there are particular circumstances of which we are not aware that have led to the observed behaviour. If we are satisfied that there is a legitimate competitive justification for the participant's actions, we would not carry the issue any further. Where we are not satisfied that this is the case, we would report that the exercise of market power was one of the factors leading to the anomalous price result that we had observed. Because we operate under confidentiality constraints that do not allow us to name individual market participants in our public monitoring reports, we would do little more in these reports than indicate that the Panel observed the exercise of market power by a participant and that this was a factor in the observed price outcome.

Second, in cases where the above process leads us to conclude that a market participant has been exercising market power in a sustained or persistent manner, we may decide to commence an investigation into whether this might constitute an abuse of market power. The rules and procedures for such an investigation are set out in the *Electricity Act, 1998* and in By-law # 3 of the Ontario Energy Board. Where our investigation results in a report with recommendations related to the abuse of market power it may lead to an amendment to the market rules or licence of a market participant at the discretion of the Ontario Energy Board as described in section 38 of the *Electricity Act, 1998.*

1.4 Scope of the Market Power Framework

The proposed framework would not be applied to all generation or in all circumstances. The table below summarizes the conditions and type of generation which would be exempt, as explained in greater detail in Chapter 2.

Table 1: Categories and Conditions Where Framework Not Applied

Category	Conditions
Low Market Prices	HOEP below $50 / MWh
Nuclear generation	Exempt from tests for economic withholding
NUG contracted supply	Individual generators without generation at market prices
OPA contracted supply	Must demonstrate contract has price unrelated to market price; and not be part of a portfolio with generation receiving market price
Dispatchable load	Not part of a portfolio with generation

2 Basic Concepts for Assessing the Exercise of Market Power

This chapter begins with some definitions of market power and other related terms. Following this are a number of examples of what may or may not be interpreted as an exercise of market power. Because generation costs are central to determining competitive market prices and whether market power has been exercised, various cost concepts and structures associated with generation and the IESO market are also reviewed. These lead finally into the basic tests needed in the framework.

2.1 Some Definitions

A market participant (buyer or seller in a market) has ***market power*** if that market participant has both the ability and profit incentive to move the market price away from the competitive level. A market participant has ***exercised market power*** if it has so moved the market price and has profited or will profit from so doing. In this framework, the Panel is interested in identifying exercises of market power that have raised the market price, rather than establishing the existence of market power in theory.

The ***competitive price level*** is the price that would prevail in equilibrium in an idealized perfectly competitive market. Under perfect competition, the price at which a competitive market clears is equal to the short-run marginal cost of the marginal supplier and is at least as great as the marginal supplier's average variable cost. (These and other costs concepts are discussed later.) This is called the short-run competitive equilibrium price.

In general, the exercise of market power by suppliers involves both raising the market price above the competitive level and restricting supply below the competitive level. In the simplest terms, it is necessary to restrict the supply offered to the market in order to raise the price because market demand generally decreases as the market price increases. In the context of electricity markets it may be possible to raise the market price without restricting supply. The reason for this is that, over a fairly broad range of prices, demand (load) does not decline when the market price increases so that the market will absorb the same supply even though the price is higher.

In this paper we use the term "***pricing-up***" to refer to a situation in which the marginal supplier raises its offer price above its incremental cost. Since the market price is set by the offer of the marginal supplier, pricing-up necessarily increases the market price. Pricing-up need not reduce market demand (load) and does not change the sources of supply that are called to market. That is, pricing up does not lead to inefficient dispatch.

Withholding is defined as producing a smaller quantity of output than the output that would maximize profits at the competitive price. ***Economic withholding*** is defined as offering otherwise inframarginal capacity at a price that exceeds the market clearing price. ***Physical withholding*** is defined as a failure to offer available and otherwise inframarginal capacity into the market. Withholding takes lower cost sources of supply out of the merit order and brings on higher cost sources of supply to replace it. In so doing, it raises the market price and results in an inefficient choice of sources of supply (inefficient dispatch) as well.

Scarcity conditions or a scarcity period has been defined as "one in which market demand is high relative to the available supply".[13] During periods of scarcity, the market must turn to relatively high costs sources of supply to meet demand and this results in market prices that are higher, sometimes much higher than usual. During periods of extreme scarcity when virtually all available capacity is in use, a dispatchable load may back down in order to equate demand with the available supply. In this case, the market price is set by the offer of the dispatchable load involved and this offer may be priced well above the offer of the marginal generator. In essence, in times of extreme scarcity, the market price may be determined by the scarcity value of electrical energy rather than by its cost of production. Scarcity conditions and resulting higher prices may or may not be accompanied by the exercise of market power.

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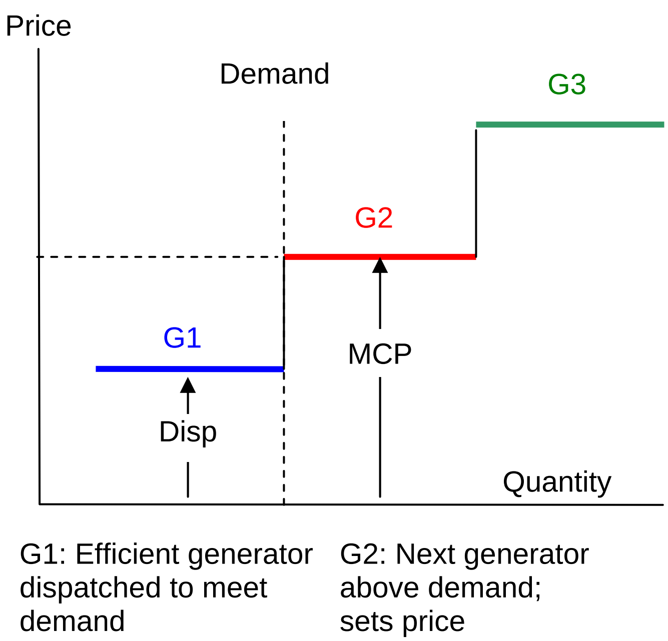
[13] Larry E. Ruff, Market Power Mitigation: Principles and Practice; Charles River Associates November 14, 2002, p. 6. The Panel has developed an analytical tool referred to as the supply cushion to quantify periods of tight supply. See, for example, previous monitoring reports on the Ontario electricity market.

2.2 Some Examples

To better appreciate what may or may not be considered an exercise of market power, we present the following stylized examples. They begin with what might occur in a competitive situation and move through a variety of cases where, typically, offer prices are increased.

We begin with a competitive base case, Figure A, and work through a number of examples of economic withholding, pricing-up, and physical withholding. As well we include examples where increasing offer prices would not constitute an exercise of market power.

Figure A: Competitive Market

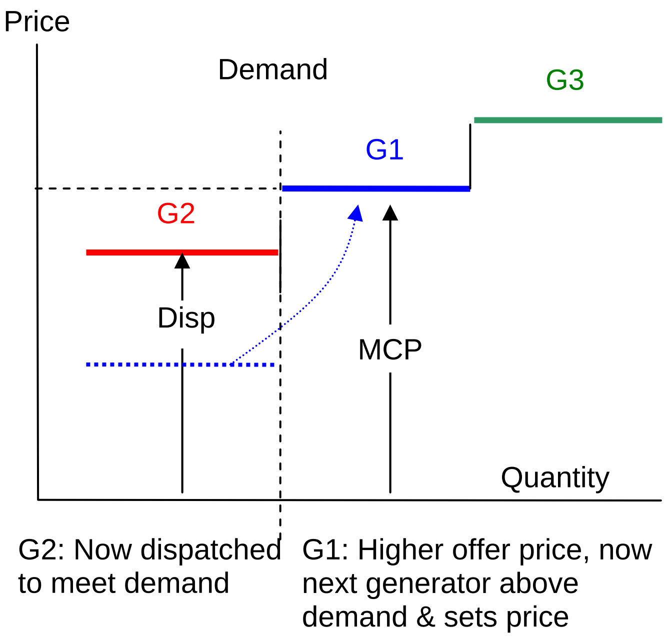


In the base case Generators 1, 2 and 3 all bid their incremental cost. All are the same size and only one is needed to meet the demand.

Generator 1, the lowest cost unit, is dispatched. This is the efficient dispatch.

Generator 2, which would satisfy the next MW of demand, sets the market clearing price. This is the competitive price outcome.

Figure B: Economic Withholding

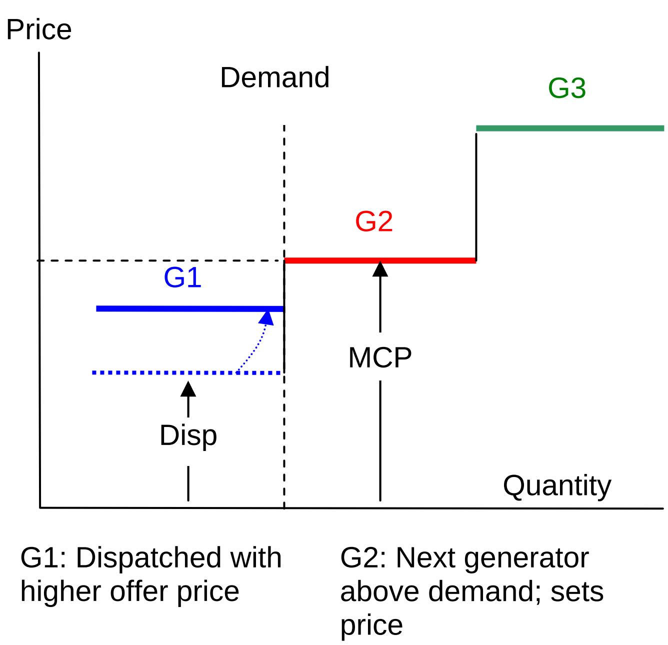


Generator 1 increases its offer price above the incremental cost of Generator 2. Generator 2 is now dispatched instead of Generator 1, which is inefficient. Generator 1 sets the MCP at a higher price.

- The dispatch is changed and inefficient.
- There is an increase in the MCP.

If Generator 1 has other dispatched generators in its portfolio and the profits they realize from the higher MCP exceed the profit Generator 1 foregoes when it is not dispatched, this would **likely constitute an exercise of market power.**

Figure C: Price Increase by an Infra-marginal Generator

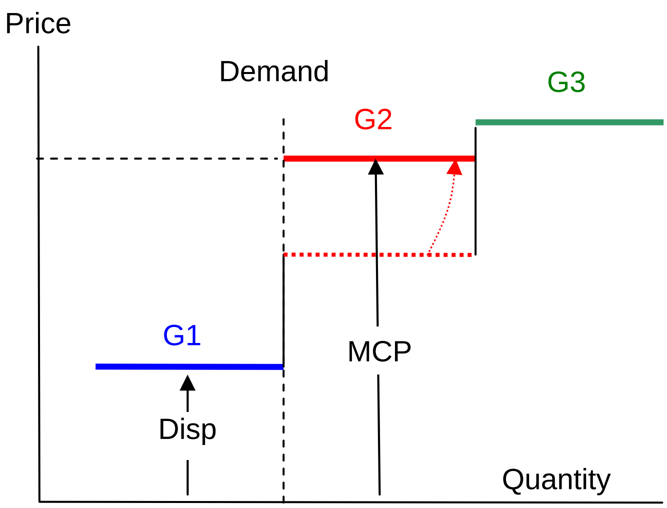


Generator 1 increases its offer price but remains below the incremental cost of Generator 2.

- There is no change to the dispatch.
- There is no change to the MCP.

There is no exercise of market power.

Figure D: Pricing-Up by the Price Setting Generator



G1: Efficient generator dispatched to meet demand

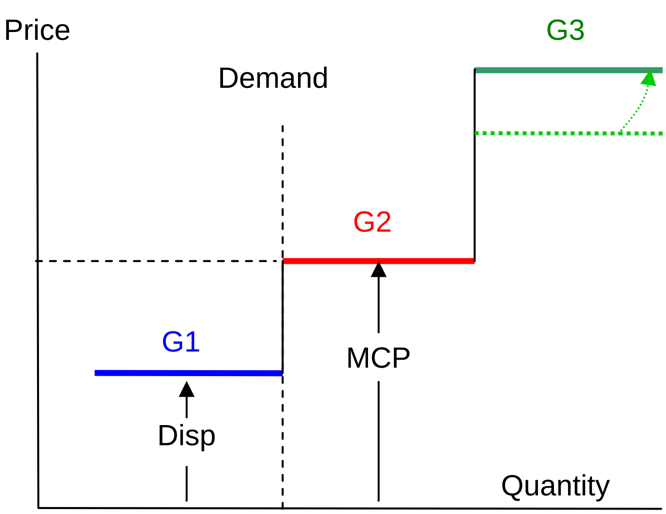
G2: Next generator above demand; higher offer price sets price

Generator 2 increases its offer price.

- There is no change to the dispatch.
- There is an increase in the MCP.

If Generator 2 has other dispatched generators in its portfolio so that it profits from the higher MCP, this would **likely constitute an exercise of market power**.

Figure E: Price Increase by an Extra-Marginal Generator



G1: Efficient generator dispatched to meet demand

G2: Next generator above demand; sets price

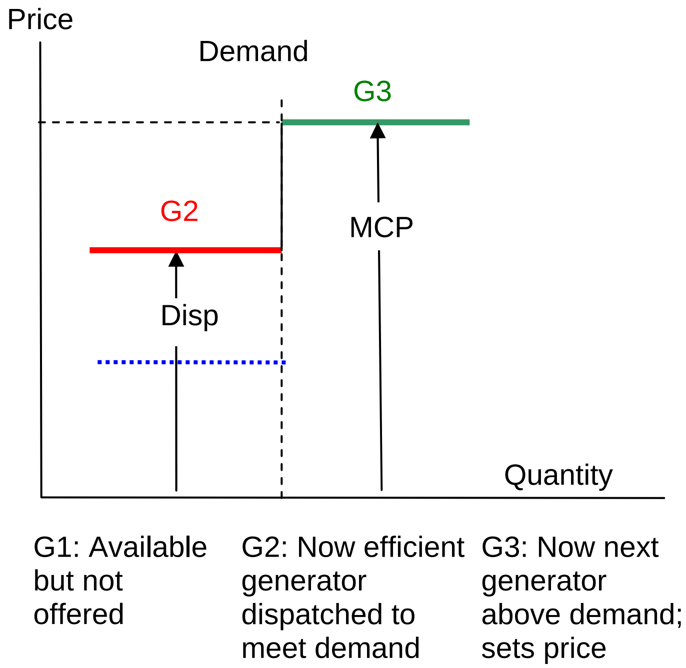
G3: Higher offer price; no effect on dispatch or MCP

Generator 3 increases its offer price.

- There is no change to the dispatch.
- There is no change to the MCP.

There is no exercise of market power.

Figure F: Physical Withholding



Generator 1 is available but does not submit an offer. Generator 2 is dispatched. Generator 3 sets MCP.

- The dispatch is changed and inefficient.
- There is an increase in the MCP.

Assuming Generator 1 has other dispatched generators in its portfolio and profits from the higher MCP, this **would likely constitute an exercise of market power**.

2.3 Cost and Pricing Concepts

Throughout the discussion of this framework we make reference to a variety of cost measures. In this section we describe what these are and why they are relevant.

Of primary interest are the cost structures of price-setting generators. These include fossil-fired units, whose direct production or engineering costs are typically considered, or energy-limited hydroelectric generation and their opportunity costs.

2.3.1 Fossil Fuelled Generation

In section 2.1 it was stated that the price at which a textbook, perfectly competitive market clears is equal to the short-run marginal cost of the marginal supplier and is at least as great as the marginal supplier's average variable cost. A profit-maximizing perfectly competitive (price-taking) firm produces a quantity of output per period of time such that its marginal cost is just equal to the market price. If the market price is less than the firm's average variable cost it will not produce at all. In the longer run, the market price must be sufficient to cover the firm's average total cost or it will leave the market.

For a multi-product firm, the cost concepts are slightly different. A multi-product firm can be viewed as having both joint and common costs which are not attributable to any product line and product-specific costs. Product-specific costs are comprised of product-specific fixed costs which are incurred if the product line is offered and variable costs. Expressed on a per unit of output basis, product-specific cost is known as **average incremental cost** (AIC). For each product line, a price-taking multi-product firm produces a quantity of output per period of time such that the marginal cost of that product is equal to its market price. If the market price of a product is less than its AIC, the product will not be offered at all. Over the longer term, the firm must also cover its joint and common costs if it is to remain in the market. Coverage of joint and common costs requires that the prices of at least some of its product lines exceed their respective average incremental costs. To the extent that the price of a product exceeds its AIC, that product is said to be making a contribution toward the recovery of joint and common costs.

Multi-product cost concepts can be applied to an electrical generation plant. The decision to start up a generator can be viewed in the same way as the decision to offer a product line. There are fixed and variable costs of starting and running a generator. Expressed on a per unit of output basis, this is the generator's average incremental cost. There are also plant level joint and common costs. Viewed in the abstract, a profit-maximizing generating plant operating in a competitive market would operate a generator at an output level such that its marginal cost (MC) is equal to the market price of electrical energy. If the market price is less than the generator's

AIC, it would not start up. Over the longer term, prices must exceed average incremental costs by enough to cover plant level joint and common costs if the plant is to remain in operation.

A number of practical considerations intrude on this conceptual discussion. First, the market price that is the principal subject of monitoring activity is an hourly price, that is, a price per megawatt hour (MWh). For purposes of comparability, costs should also be expressed on an hourly basis. Thus, marginal cost becomes marginal cost per MWh and, in the case of fossil generators, it is an increasing function of the number of megawatts generated per hour. AIC becomes average incremental cost per MWh. Since the incremental cost of starting and running a generator includes some one time costs such as start-up costs, AIC depends on the number of hours the generator runs. Other things being equal, the more hours a generator runs, the lower is its AIC. This is because one time costs are averaged out over more hours. This raises the possibility that realized AIC could differ from anticipated AIC if the number of hours a generator is expected to run differs from the number of hours it actually does run. Moreover, if start-up costs cannot be avoided by shutting down, AIC depends on whether a generator has already been started or not. The implication is that AIC can vary with the circumstances. The Panel's proposed operational definition of AIC for purposes of price-cost comparisons is discussed in Chapter 3 of the paper.

A second practical consideration is that generators are subject to capacity limitations so the output they are able to offer to the market may stop well short of the point at which their marginal cost is equal to the market price. Moreover, output is offered into the market in discrete increments called laminations rather than in infinitesimally small increments. The marginal cost of a lamination is an approximation, possibly an average but it need not be.

A third practical consideration is that the technology of fossil generation plants is such that marginal cost is an increasing function of output and average incremental cost is a U-shaped function. This further implies that marginal cost is below average incremental cost at low levels of output and above it at high levels of output. Coverage of both marginal and average incremental cost then requires that fossil generation be offered into the market at a price at least equal to average incremental cost or marginal cost, whichever is the greater. This implies that a fossil generation unit should be offered at higher prices for both low and high levels of output than for intermediate levels of output. The rules of the Ontario market make this difficult to do. Ontario requires that offer prices increase monotonically with the amount of output offered.[14] To illustrate, suppose a generator has a capacity of 160 MW and it is offered into the market in four laminations of 40 MW each. Suppose the first lamination is offered at a price of $50. The second lamination must be offered at a higher price, say, $60 and the third lamination at a still higher price and so on. This raises the possibility that an offer schedule that covers the AIC of the first lamination will result in offers well in excess of the marginal cost of the final lamination or that an offer schedule that just covers the marginal cost of the final lamination will fail to cover the AIC of the first lamination. The manner in which Panel proposes to take these issues into account is explained in Chapter 3 of this paper.

2.3.2 Hydroelectric Generation

Hydroelectric plant can be characterized as run-of-river or as peaking. Peaking hydroelectric facilities normally do not have sufficient water to run at all hours in the day. During some periods of the year (such as spring freshet), however, a plant may be run-of-river even though it is a peaking plant at other times. These two types of generation have different cost characteristics.

Run-of-river plants have little or no storage capability in the forebay immediately above the plant and must run when the water is available. If this water is not used for production it is spilled yielding no revenue.[15] If it does generate electricity, the actual out-of-pocket cost of production is minimal except for water rental fees, which must be paid to the government. In essence, the marginal cost of run-of-the-river generation is minimal both from an out-of-pocket cost perspective and from an opportunity cost perspective.

Peaking plants have limited water and limited storage. They normally cannot run in all hours of the day no matter how attractive market prices might be. Their out-of pocket costs, water rental

[14] In contrast the NYISO and other markets provide for three-part bids, representing start-up costs, minimum loading costs and incremental energy costs. This allows the offers of fossil generators to reflect their cost structure.
[15] In some cases, environmental or regulatory concerns do not allow spilling.

and other minimal costs are essentially irrelevant to their decision of when to run. For a peaking plant, using limited water to generate in one hour means foregoing the opportunity to use it at some other time. For a peaking plant, the relevant cost concept is an opportunity cost. This is the revenue foregone in the highest priced hour in which it does not operate. A profit-maximizing peaking hydroelectric generator in a competitive market would, in theory at least, offer into the market at its opportunity cost.

2.4 Basic Tests for Inferring the Exercise of Market Power

For the purposes of this framework, we conclude that market power has been exercised when certain pricing and profitability criteria have been met. In this section we state these criteria (the necessary and sufficient conditions for inferring the exercise of market power) and explain in general terms how we propose to translate them into operational tests. In Chapter 3 we then describe how we would apply these tests to different categories of domestic generation and to imports.

2.4.1 Necessary and Sufficient Conditions

The necessary and sufficient conditions for inferring that a seller's offer into the Ontario market represents an exercise of market power are that:

- the offer price equals or exceeds the market price and both exceed the seller's average incremental and marginal costs and
- the seller has profited from this offer strategy.

Expressed algebraically, an exercise of market power is inferred if, for some portion of a seller's offered capacity Q, the following condition holds:

$$\text{Offer Price}(Q) \geq \text{MCP} > \text{Max}\,[\text{MC}(Q), \text{AIC}(Q)] \text{ and}$$

$$\Pi(Q^A) > \Pi(Q^C)$$

where

$\prod(Q^A)$ is the actual profit earned by the seller when the market clears at a price equal to MCP and the seller is selected to provide Q^A units of output in the auction; and

$\prod(Q^C)$ is the hypothetical profit that the seller would have earned had it offered its output at a price equal to the greater of AIC or MC and produced Q^C units of output.

The first condition ensures that the seller's offer strategy raises the market-clearing price above the competitive level. In cases of pricing-up, the offer price would equal the market-clearing price. In cases of economic withholding the offer price would exceed the market-clearing price. The conditions for physical withholding can be captured within this same test if a very large offer price is imputed to the period when no offer is submitted. The second condition establishes that the seller has profited from the pricing strategy adopted.

We refer to these as sufficient conditions in the sense that these establish a prima facie case that market power has been exercised. In practice, a market participant may provide some explanation for the pricing behaviour observed or may explain that the facts of the case were incompletely represented by the MSP's initial analysis.

2.4.2 The Basic Tests

Following from these necessary and sufficient conditions, this section describes the set of three initial tests proposed by the MSP to identify exercises of market power. There is also a price materiality screen which is proposed for the framework recognizing that during periods of low demand and thus low prices there is less incentive to exercise market power.

Identifying the exercise of market power typically requires evidence of some specified conduct (e.g. withholding) and an impact (i.e. causing prices to increase profitably above competitive levels). Accurately detecting the conduct and hence the impact requires a firm understanding of both sellers' production cost functions their opportunity costs. Given that the MSP has incomplete information regarding sellers' costs, any indicator devised to produce evidence of conduct and impact will be subject to measurement error. The tests may lead to false positive results (detecting an exercise of market power when there was none) or false negatives (concluding no exercise of market power when one has occurred). Either type of error is undesirable but some error is not avoidable.

In developing its criteria for inferring the exercise of market power, the MSP has been cognizant of the need to weigh the consequences of false positives against those of false negatives. In this regard, the Panel has given priority to reducing the incidence of false positives. The Panel takes the view that, given the costs to all concerned of resolving matters of this nature, the focus of inquiry should be on incidents in which a number of indicators point unambiguously in the direction of the exercise of market power with material consequences for the market. To this end, the approach proposed by the Panel includes the following:

- The market circumstances must be such that the exercise of market power is plausible (price materiality screen);
- The offer involved must qualify as an exercise of market power under a series of three tests including a conduct test, a market price impact test and a profitability test;
- The conduct test makes use of alternate cost benchmarks including a reference price based on past offers as well as cost functions based on heat rates;
- The application of the conduct test allows for normal variation around the appropriate benchmarks.

Materiality Screen

It is proposed that the application of the conduct and market impact tests for the exercise of market power by domestic generators and importers be confined to the delivery hours in which the pre-dispatch price exceeds $50/MWh. During hours when the pre-dispatch price is below $50 there is generally sufficient excess capacity available to discipline any potential exercise of market power.

Conduct, market impact and profitability tests

The following set of conduct and market impact threshold tests follow from the necessary and sufficient conditions above. Because of the uncertainties mentioned and the concern over false positives, these tests should be applied with some margin, i.e. relative to some higher threshold, that strengthens the conclusion that market power has been exercised.

- ***Participant Conduct Test*** identifies occurrences of potential (economic or physical) withholding or pricing-up by a market participant;

- ***Market Price Impact Test*** determines whether a participant's potential withholding or pricing-up had a material impact on market-clearing prices;

- ***Profitability Test*** assesses whether the potential withholding or pricing-up was profitable to the participant. This corresponds to the condition, $\prod(Q^A) > \prod(Q^C)$.

As will be seen in the next chapter, for some applications (non-energy-limited resources and imports) the conduct test corresponds to the condition, Offer Price(Q) ≥ MCP > Max [MC(Q), AIC(Q)]. For energy-limited generation, the test is somewhat different although it can be interpreted in terms of the relationship between the offer prices and opportunity costs of the seller concerned.

The MSP would infer that a market participant has exercised market power only if a market participant's action triggers each of these three tests, that is, exceeds the thresholds in each of these tests.

2.5 Exemptions under the Framework

The framework does not need to be applied for all facilities in the IESO market or under all circumstances. Where it is reasonably unlikely that a Market Participant has incentive to exercise market power or has the ability to do so, we would exclude that from at least some of the framework tests.

Above, we explained there is limited ability to exercise market power for prices below about $50 per MWh. In addition there are various generators not likely to profit from exercising market power at other times, including those with nuclear units, self-scheduling generation and generation under contract to OPA, subject to certain limitations. For energy limited generation (ELG) (hydroelectric) for which a daily analysis is proposed, the $50 per MWh limit would be applied as exempting the day if all HOEP prices were below that threshold. Since this is fairly uncommon, the materiality limit in practice would have little effect on the application of the framework to ELG.

Attempting to economically withhold generation (by increasing offer prices) could be problematic for a nuclear unit. There are very stringent physical limitations on the ability of nuclear units to ramp up and down. Ramping could be costly because of the stresses imposed on the reactor or other parts of the generation system. Increasing offer prices from cost-based - where they are almost always inframarginal – to a higher range where they are not scheduled, could leave them in a position where they need to ramp up and / or down in response to occasionally volatile market prices. However, the shut-down of a nuclear unit and start-up a few days later is less of a problem and could potentially cause prices to rise enough so there was an overall profit on a portfolio of plant. Consequently, we propose to exclude nuclear units from the conduct test for economic withholding, but not from the test for physical withholding. Whether reviewed in the conduct test or not, nuclear units would be part of the portfolio profit test for a market participant if any of its resources did trigger the conduct test and the market price impact test.

There is about 1900 MW of generation under fixed price contracts ("NUG" contracts) arranged with Ontario Hydro, some 15 to 20 years ago. Because these generators receive payments according to the contract price, they do not have incentive to push up market price by being unavailable. These generators would be exempt from the framework, as long as they do not have other supply in their portfolio which does attract market prices.

Another group potentially exempt from the framework tests is other generation with contracts that fix their price. These include "early movers" with contracts from OPA and other OPA contract arrangements such as the Clean Energy Supply (CES) generation not yet operating. To be exempt the generator would have to demonstrate that the contract terms prevent payments substantially related to the market price. However, the exemption would not apply if the generator also had other resources receiving market prices.

Although OPG has much of its generation receiving fixed prices as regulated or non-regulated assets, there is still a significant portion receiving market prices - baseload hydroelectric above 1900 MW and 15 percent of non-regulated production. As such, all its generation will still be reviewed under the conduct test etc., including the Lennox units but excluding tests for economic withholding of its nuclear units.

Finally, dispatchable load has the ability to influence market prices, but raising prices (the focus of this framework) seems unlikely to benefit a load. If a dispatchable load also had a relatively large generation portfolio, that might provide incentive to consume more than is economic, in order to drive up prices. However, higher prices could similarly be achieved with non-dispatchable load or uneconomic exports. These would require very different analyses, beyond tests on generation or import offers, and are outside the scope of this framework.

Summary: Where Framework Will not be Applied[16]

- HOEP less than $50/MWh
- Nuclear generation/economic withholding
- NUGs
- Some generation with OPA contracts

[16] See text for details

3 Framework Tests for the Exercise of Market Power

In Chapter 2 we outlined the three basic tests to be performed to assess whether market power has been exercised. These are the conduct test, the price impact test and the profit test. The MSP intends to apply this market power framework to market participants that operate generation facilities within Ontario and to market participants that supply energy to Ontario through imports. The market power framework set out in this chapter distinguishes three different supply categories: non-energy limited generation, imports and energy limited generation. These supply categories differ especially with respect to their cost characteristics and our three basic tests apply differently to each. This chapter sets out the three basic tests as they apply to each supply category.

The material in this chapter is fairly specific. However, actual implementation of the framework will introduce even greater specificity. **We welcome comments both on the approach and on measures that can be taken to assist with its practical implementation. We also recognize that as the Panel and market participants gain more experience with the use of the framework in real-world situations, its application will continue to evolve and become more refined.**

3.1 Application to Fossil Units - Non-Energy Limited Generation

We define non-energy limited generation as being either fossil-fueled or nuclear-fueled. As indicated in Chapter 2, we propose to exempt nuclear generators from the tests for pricing-up and economic withholding. Fossil-fueled generation includes all coal-fired or natural- gas fired generation units that do not face an emerging emissions limit or other environmental limits, or a fuel shortage due to factors outside of the control of the owner of the unit.

3.1.1 Overview of Tests and Questions

This section describes the three basic tests to be followed to establish whether there may have been an exercise of market power. While the Panel is satisfied that there should be a conduct test, price impact test and a profit test, it is seeking input whether there are better mechanisms for defining and applying these tests. Some sample overview questions are also provided.

The Conduct Test

The conduct test establishes whether there has been any pricing-up or withholding. For non-energy limited generation, two forms of the conduct test are proposed, one for physical withholding and another for economic withholding and pricing up.

The conduct test is triggered by virtue of either economic withholding or pricing-up if the following three conditions hold: (1) The relevant offer price is equal to or greater than the market-clearing price, the HOEP; (2) The HOEP is greater than the estimated cost/MWh of the generating unit involved; (3) The relevant offer price exceeds a threshold value which is based on its costs and past accepted offers.

Our cost estimates come from two sources. The first is a historical reference price. The second is the cost function of the generating unit involved. Cost functions are derived, in turn, from unit heat rates. In order to draw an inference of economic withholding or pricing-up, we would require, first, that the HOEP exceed the reference price as well as both the average incremental cost and the marginal cost implied by the cost function and, second, that the offer price concerned exceed both the reference price plus a statistically determined margin and the unit's maximum average incremental cost as implied by its cost function.

We propose to infer that physical withholding has occurred in instances in which a significant amount of available generation is not offered into the market, or is forced out and the HOEP is greater than the estimated cost/MWh of the generating unit involved.

Price Impact Test

For the market price impact test, we intend to replace the actual offer price with the larger of the reference price and marginal cost of the generating unit involved and then simulate what the

HOEP would have been in this situation. A comparison of the actual and simulated HOEP determines the impact that the potential exercise of market power had on the market price. Since small price impacts are not of great concern, and again because of uncertainties regarding costs in a given instance, the price impact test will build in a threshold (an additional margin or premium above estimated cost) that must be exceeded before the test is triggered.

Profit Test

The ***profit test*** is relatively straightforward, comparing the market participant's profit on its generating portfolio as implied by the actual market schedule with the profit implied by the simulated market schedule. This indicates whether the market participant involved profited from the pricing-up or withholding of generation. In the case of physical withholding associated with forced outages, there is a question how hourly results may need to be supplemented by analyses over longer periods. For example, the generator may profit in the hour in question but not over the entire period of the outage.

Sample Questions

These are examples of some questions or issues on which the MSP would welcome stakeholder feedback:

- **Is there a better way to estimate costs in the conduct test, for example, alternatives to the definition of the historic reference prices or the fuel price adjustment?**
- **Are the two cost thresholds for the conduct test for pricing-up and economic withholding – based on an "extraordinary" historical result and the maximum engineering costs –appropriate?**
- **For the physical withholding test, is there a justifiable rationale for not offering generation which would lead to establishing higher thresholds?**
- **Are the thresholds for the price impact tests appropriate for identifying significant price excursions which may be indicative of exercising market power?**
- **Is there other information that can be taken into account for the profit calculation?**

- **Given the extended and overlapping nature of forced outages, what conclusions can be drawn from hourly analyses alone?**
- **Would participants prefer interaction with the MAU / MSP regarding specific events earlier in the process? Is there additional data that generators may find useful to provide the MSP on an ongoing basis in advance of the application of these framework tests?**

3.1.2 Participant Conduct Test – Pricing-up and Economic Withholding

Three conditions must be satisfied in order to trigger the conduct test for pricing-up or economic withholding. First, the offer price concerned is equal to or greater than the HOEP. Second, the HOEP must be greater than the marginal cost, the average incremental cost and the historic reference price of the generating unit involved. Third, the offer price concerned must exceed both its historic reference price plus a statistically determined margin and the maximum average incremental cost of the generating unit involved.

To satisfy the third condition for economic withholding, the offer price of the generating unit involved would have to exceed its reference price by an unusual amount, that is, an amount that is too great to be attributed to chance. In addition, it would have to exceed the unit's maximum average incremental cost. Maximum average incremental cost is calculated at the unit's minimum generation level, and may include start-up costs for the unit [17]. This ensures that all avoidable costs could be recovered when running at this price, even at the unit's minimum output.

In essence, the conduct test for economic withholding or pricing-up compares a generation unit's hourly energy offer to a benchmark offer for the unit to assess whether or not the hourly offer was anomalous. The conduct test consists of five steps:

(1) Confirm that the offer price in question is at least as great as the HOEP;

[17] In advance of starting the unit, incremental costs including start-up costs are avoidable. The generator would be willing to incur these costs only if the energy payments are sufficient to compensate him. On days where a unit may have been running overnight, there are no start-up costs to incur and no minimum run-time restriction. Actual maximum incremental or avoidable costs at such time would exclude start-up costs.

(2) Compute unit-specific average incremental and marginal costs (for the range of possible production quantities);

(3) Calculate a unit-specific reference price curve;

(4) Confirm that the HOEP exceeds the reference price, average incremental cost and marginal cost;

(5) Confirm that the offer price in question exceeds both the reference price plus a statistical margin and the maximum average incremental cost of the unit.

Computed costs

The marginal and average incremental costs of a fossil-fueled generating unit can be computed using generation unit-specific cost data based upon the appropriate heat rates, O&M costs and associated costs for their fossil units that market participants are required to submit to the MSP as part of the data catalogue. [18]

In general terms, the Fuel Consumption Cost Curve for a fossil unit is given by:

$$FC(s) = (A + B.s + C.s^2)*(OEF.FP) + OM.s$$

where

FC is the total cost of production ($/hour);

s is net generation output (MWh);

A, B, C are the coefficients of the input/output equation (heat rate coefficients);

OEF is the operating efficiency factor;

FP is the spot fuel price;

OM is the marginal maintenance and environmental adder.

This fuel cost function implies the following marginal cost function:

[18] To aid the MSP in its surveillance activities, the Market Rules mandate that Market Participants are to submit specified data on an ongoing basis. Such data are described in http://www.ieso.ca/imoweb/pubs/marketAdmin/ma_SurvDataCat.pdf

$$MC(s) = (B + 2Cs).(OEF.FP) + OM$$

Adding start-up costs and taking minimum run time into account implies the following average incremental cost function:

$$AIC(s) = [FC(s) + S / H^*] / s$$

where

S is the unit start up cost (for hot, cold and warm starts or no start-up).

H* is the minimum period of time during which the unit must operate at its minimum output level or higher in order to avoid unnecessarily damaging the unit.

The AIC function is U-shaped, declining initially as output increases. The maximum AIC of a fossil-fueled generating unit occurs when it operates at its minimum load for its minimum run time. Thus:

$$MAXAIC = [FC(q^*) + S / H^*] / q^*$$

where

q* is the minimum output level at which a unit can run without ignition support.

The application of this threshold to a unit's actual offer recognizes market participants who expect their generation units to be marginal price setters may offer at higher prices. These prices will cover the possibility of being scheduled at minimum load levels and incurring start-up cost and speed no load costs for the period of their minimum run time.

Reference Price

In recognition of the possibility that the perceived costs of a market participant may differ from the marginal and average incremental costs implied by its fuel, OM and start-up costs, we propose also to employ a generating unit's historic reference price as an alternate cost benchmark. The competitive reference price for non-energy limited generation is computed based on a unit's accepted offers in the market schedule (unconstrained sequence) over the previous 90 days. The offers are adjusted or normalized to reflect the changes in fuel costs over the period. Separate reference prices are computed for peak and off-peak hours for each unit.

The rationale for using past offers as a proxy is based on the view that in a competitive market, a seller (absent market power) maximizes its profit by offering to produce output whenever it expects the market-clearing price to be at least as high as its average incremental and marginal costs. It is reasonable to assume that in most hours of the day, the competitive conditions of the market provide sellers with a strong incentive to offer at the higher of their MC and AIC to ensure they are scheduled whenever there is a profit opportunity. If this is the case, previously accepted offers are likely to be a good estimate of a generating unit's incremental costs. The limitation to this of course is that these historical offers may also exhibit market power, and may over time move up gradually, without ever triggering the conduct test. This implies that on occasion reference prices should also be reviewed to ensure they are reasonable.

The competitive reference prices for non-energy limited generation are computed as follows:

- Reference prices are calculated for the entire output range of a generating unit between the reported minimum loading level, and the reported maximum capacity of the unit or the maximum quantity offered from the unit. Separate prices are determined for different output ranges or laminations.
- Laminations are divided into 10 MW ranges. The reference price for a specific lamination is computed as the lower of the mean or median of the accepted unconstrained offer for each respective lamination over the previous 90-day period, for respective peak or off-peak periods.[19]
- Adjustments are made to the historical "average" accepted offers to account for fuel price differences in the historical period and the day for which the test is applied. More

[19] NYISO applies the same definition in their Automatic Mitigation Procedure (See Appendix A). For our calculations the mean is somewhat more consistent than the median since later we use a threshold assuming the reference price and standard deviation (which is based on the mean value). However, because these historical values may also be used to replace the offers, using the median avoids the value being skewed by some high outliers.

specifically, if P_q is the “average” accepted price for lamination q over the previous 90 days on date T, and f_t is the fuel price on date t, the reference price for lamination q (RP_q) is adjusted for changes in fuel prices according to the following rule.

$$RP_q = 0.9P_q\left(\frac{f_T}{\sum_{t=T-1}^{T-90} f_t \Big/ 90}\right) + 0.1P_q$$

Underlying this adjustment is the assumption that 90 percent of the unit’s costs are attributable to fuel costs. The adjustment is the ratio of the study day’s fuel price to the average fuel price in the period. The other 10 percent of costs may or may not be stable in the period, but these other cost factors cannot easily be separated, measured or adjusted.

Relationship to Market Clearing Price

For the conduct test to be triggered it must be shown that for any lamination Q,

Offer Price (Q) $\geq$ HOEP $>$ max (AIC(Q), MC(Q), Reference Price (Q))

This ensures that the conduct test is triggered only if there has been economic withholding or pricing-up. If the offer price exceeds the HOEP and the HOEP exceeds the highest estimate of the cost of generation, an otherwise inframarginal market participant has priced itself out of the money and this supports an inference of economic withholding. If the offer price just equals the HOEP and the HOEP exceeds the highest estimate of the cost of generation, this is consistent with pricing–up. Viewed the other way, if the offer price is below the HOEP, it does not matter whether it is above cost because the merit order and the HOEP would not be affected. Similarly, if cost is above the HOEP it does not matter whether the offer price is above cost because the unit would not have been scheduled and could not have set the market price.

<u>Offer Price Thresholds Applied in the Conduct Test</u>

The conduct test is applied in each delivery hour, and to each of the non-energy limited generation units. This final part of the test compares the offer price against two threshold measures. A non-energy limited generation unit's offer triggers this part of the conduct test if its actual hourly offer for a given lamination exceeds both:

(a) its reference price plus a statistically determined margin; and
(b) its minimum load AIC based on its heat rate and relevant start-up costs.

These conditions can be combined and expressed as:

Offer Price (Q) > max (Reference Price Threshold, MAXAIC)

The balance of this section sets out the manner in which we propose to calculate the thresholds to be used in this part of the conduct test.

(a) **Reference Price Threshold:**

We are proposing that the margin to be applied to the reference price be derived statistically as two standard deviations above the adjusted mean value of the reference price (RP_q) that was computed for each of the unit's quantity laminations. [20, 21] The threshold would then be the reference price plus this margin, i.e.

Reference Price Threshold = Reference Price + 2 standard deviations.

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[20] The standard deviation is an estimator that describes the spread of the data around the mean. If a dataset is normally distributed, then about 68 percent of the data lie within one standard deviation from the mean; about 95 percent of the data lie within two standard deviations from the mean and roughly 99 percent of the data lie within three standard deviations from the mean. Note that to characterize the dispersion of the data in this manner necessarily requires that the dataset be normally distributed. We choose a threshold of two standard deviations in acknowledgement that 95 percent of the data will be within 2 standard deviations of the mean. Then any data point that is above the 2 standard deviation threshold is deemed “unusual” or “extraordinary”. For non-normal distributions there are other ways to identify situations that are similarly “unusual”.

[21] Unlike the reference price, the standard deviation is not adjusted for fuel price changes in the period.

In some periods the standard deviation can be quite small with the effect that the threshold is quite close to the reference price. Some mechanism is needed to ensure that the threshold is meaningfully larger than the reference price. One way to do this would be to define the threshold as being at least the reference price plus a fixed amount, $Y/MWh. The MSP would welcome comments on whether this modification should be adopted and, if so, what the basis for calculating the fixed amount should be.

(b) **Maximum AIC**:

Given that the Ontario market is a single price auction, generation units must cover their start-up costs and speed no-load costs entirely through the market-clearing prices (energy and operating reserve). This often requires a unit to earn a price above its short-run marginal cost, particularly for low levels of energy production.[22] At the same time, the market rules require a unit's offer to be monotonically increasing in price and quantity. As a result, if a generator expects that it is likely to run at low levels of capacity in a given hour it may have to offer at prices above its marginal cost to cover all of its AIC. This is most likely to apply to generators in hours when they expect to be the price setter.[23] Given that the competitive reference prices computed above do not distinguish between hours when a generator was likely infra-marginal (and may have offered only at its marginal cost) and when it was likely marginal (necessitating offers at its AIC, above its marginal cost), these reference prices may understate the AIC of a generator in hours when the generator expects to be a price setter. In this situation, applying the reference price threshold described above may lead to a false trigger of the conduct test.

[22] At lower levels of production AIC exceeds MC. It is only at high output that MC may exceed AIC.

[23] The IESO's Spare Generation on Line Program (SGOL) offers generators with long start-up times a mechanism for recovering their avoidable fixed costs such as start-up cost and speed-no load costs in the event that market clearing prices are insufficient to cover these costs over a short period of time, defined by the unit specific minimum run time. This program, in theory should encourage these generators to offer at their marginal cost rather than their AIC.

Illustrative Application

To demonstrate how the conduct test for economic withholding might apply, consider the following illustrative example. It is based on a mock-up of data roughly representative of a gas-fired unit with an efficiency of about 7500 BTU per kWh and gas prices averaging about $10 Cdn per MCF (typical of 2005 prices).

Figure 3-1: Illustrative Costs

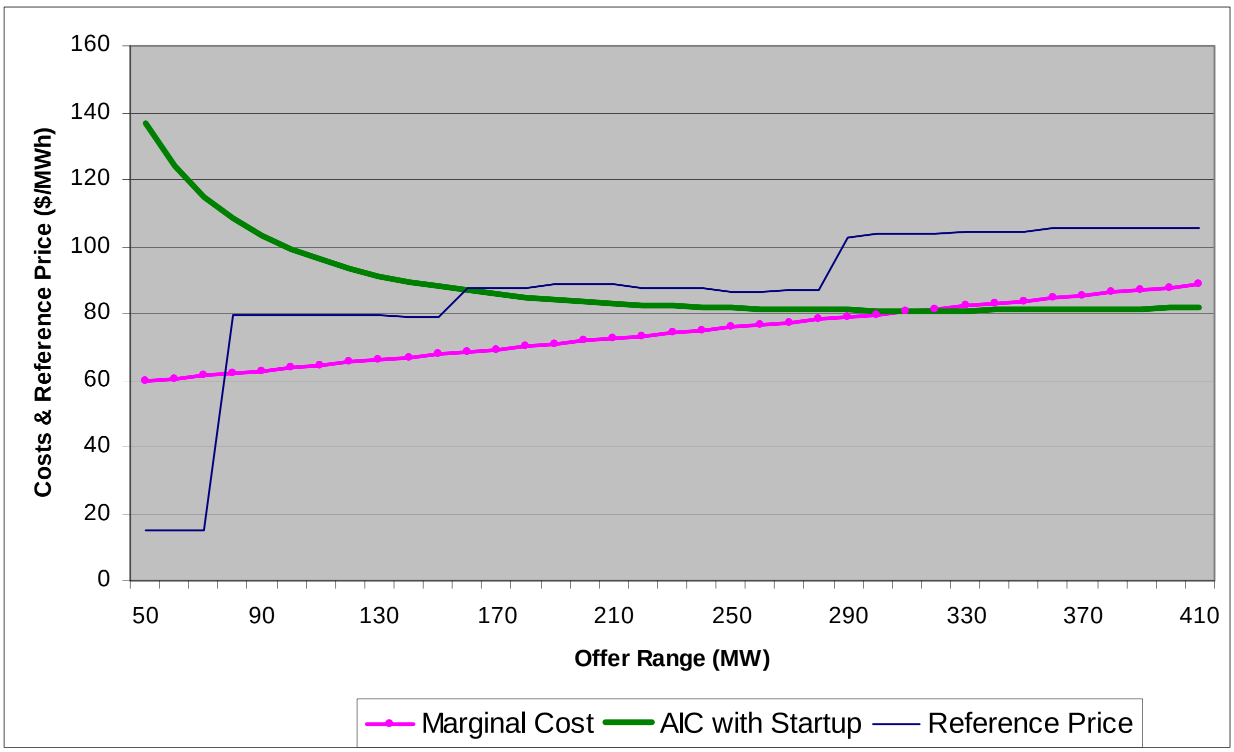

Figure 3-2: Illustrative Reference Prices and Thresholds

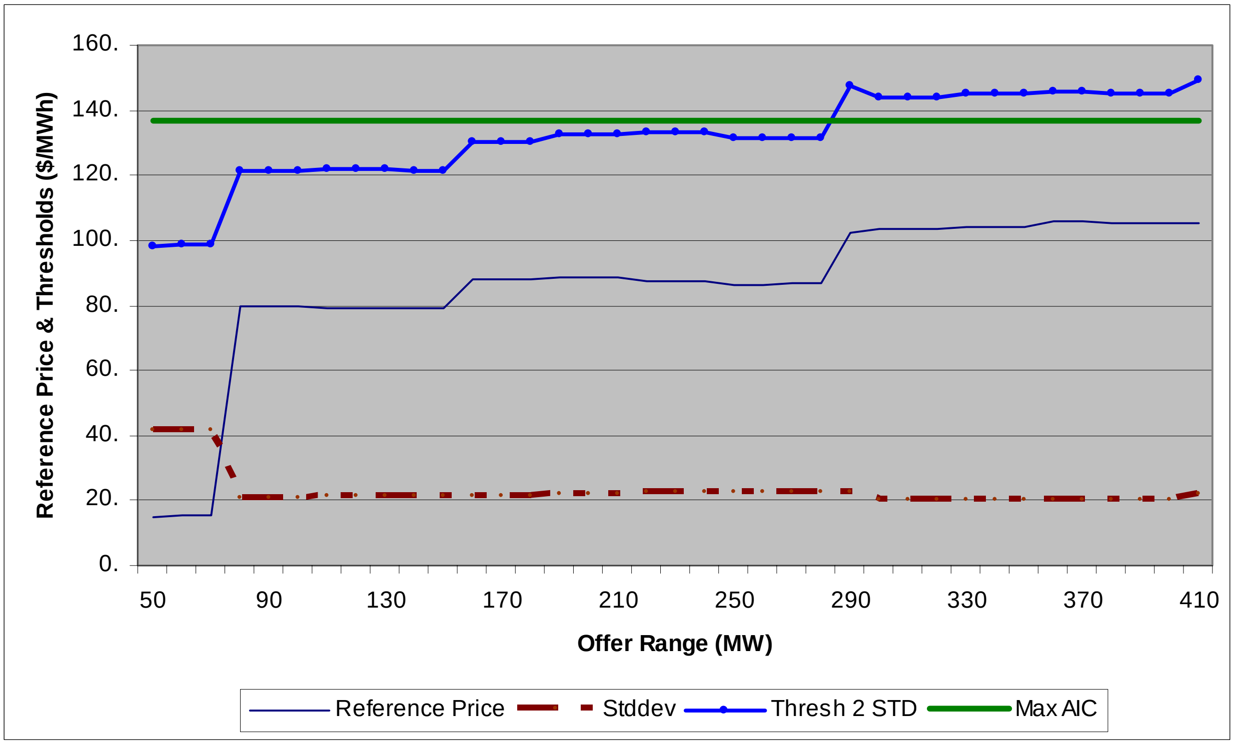

Figure 3-1 shows marginal costs and average incremental costs for the unit, ranging from the assumed minimum of 50 MW to its maximum output of 410 MW. Also shown is an illustrative reference price curve, for 10 MW laminations, notionally derived as the mean of historical offers. For the assumed heat rate characteristics and startup costs, the marginal cost is below the average incremental cost up to about 320 MW. At that point marginal costs are higher and the average incremental costs begin to rise. Note that the lowest levels of output exhibit average offers (the reference price) much lower than actual marginal costs or average incremental costs, consistent with a generator often offering low prices to ensure the unit runs at no less than this level. The reference prices over the rest of the range are higher or lower than the AIC but are always higher than the marginal costs in this example.

Figure 3-2 provides illustrative values for the two proposed thresholds, one based on reference prices and standard deviations, the other being the Maximum AIC. The MAXAIC is the highest value from figure 3-1. For the lower laminations there is a high standard deviation around the reference price, consistent with offers in this range varying considerably depending on market conditions.

In this example the MAXAIC is larger than the threshold based on the reference prices except for the highest laminations in the range, where it is slightly less. A conduct test applied for a facility with this data would compare the offer price against the MAXAIC over most of the range. Thus, for this case, even though typical offers are shown to be in the $80 to $105 range (the reference prices), not unless an offer exceeded about $140 to $150 would the offer be considered sufficiently extraordinary to trigger the conduct test for economic withholding or pricing up.

3.1.3 Participant Conduct Test – Physical Withholding

We propose to apply the conduct test for physical withholding to generating units available but not offered or units unavailable due to forced outages or deratings. We would begin by identifying both capacity that is available and capable of providing energy in the Ontario market but is not offered and capacity that has been declared unavailable due to forced outages, derates and extension of planned outages. The conduct test would generally not apply to capacity that is out of service for maintenance in accordance with the IESO maintenance schedule protocol.[24] If, however, the MSP suspects that a seller has falsely declared a planned outage for the purpose of physical withholding, it will refer the matter to the IESO's compliance division to investigate whether the outage constitutes a breach of the market rules.

For physical withholding there may be no offer from the facility for the range of production withheld, and therefore no offer price. When production is physically withheld, we deem the offer price on the withheld production to be high enough to exceed both the HOEP and the offer price threshold. The remaining element of the conduct test would apply as in the case of potential economic withholding. That is, the capacity involved would have to have been inframarginal or:

[24] A market participant may be able to exercise market power by planning maintenance at times during the year where this is likely to have a large impact, driving up prices. The MSP does not intend to review such practices under the Market Power Framework.

HOEP > max (AIC(Q), MC(Q), Reference Price(Q)).

In recognition of the possibility that false positives may arise from difficulties in identifying available capacity and in distinguishing instances in which derates and forced outages were avoidable, we propose two additional sets of conditions, one of which must be satisfied in order to support an inference of physical withholding. These conditions essentially limit the application of the conduct test to instances in which the amount of inframarginal capacity potentially withheld is significant.

The first requirement is that the gap between available capacity and the amount offered must exceed a specified minimum threshold amount. The second requirement is that the gap between the amount of capacity offered historically and the amount available in the hour concerned must exceed a specified minimum threshold amount. These tests would apply to both individual generating units and to a market participant's generation portfolio.

<u>Unit Test</u>:

(a) Potential physical withholding of available capacity:

This test would be applied in situations in which the amount of capacity offered is less than the amount available. The test would be triggered whenever the difference between a unit's available amount and its offer is greater than 100 MW or 20 percent of its availability. That is, if *a* is the available capacity and *x* is the amount of energy offered in a given hour, then a unit's offer would be flagged for potential physical withholding if, for x < a:

$$\frac{a-x}{a} > 0.2 \quad \text{or} \quad a - x > 100MW$$

(b) Potential physical withholding through a forced outage or derate:

This test would be triggered whenever the difference between a unit's maximum hourly offer over the previous 90 days and the amount available in a given hour (after the derate or forced outage) is greater than 200 MW or 50 percent of its previous maximum offer. That is, if q is a unit's maximum hourly offer over the previous 90 days and a is the amount available during the hour in question , then the unit's offer would be flagged for potential physical withholding if:

$$\frac{q-a}{q} > 0.5 \quad \text{or} \quad q-a > 200MW$$

<u>Portfolio Test</u>

The portfolio tests are similar to the unit tests, although the calculations are performed over the entire portfolio of non-energy limited generating assets of the market participant concerned and the thresholds differ.

The two portfolio tests are:

$$\frac{A-X}{A} > 0.1 \quad \text{or} \quad A-X > 200MW$$

where A is the total available operating capacity of the non-energy limited generation portfolio of the market participant involved; and

X is the total amount of energy offered from this generation portfolio, and X < A ;

and

$$\frac{Q-A}{Q} > 0.15$$

where Q is sum for all non-energy limited generation of each unit's maximum hourly capacity offered over the previous 90 days by the market participant concerned and A is the total amount of energy available from these units during the hour in question.

With these portfolio tests, smaller amounts of withholding or outages/deratings across several units may flag further review since the cumulative impact may become significant. The 15 percent threshold is suggested since it is roughly twice the average forced outage rate of individual thermal (steam) units.

3.1.4 Market Price Impact Test

The market price impact test is devised to identify those situations in which a market participant's conduct has raised the HOEP significantly above the competitive level. Any offers that trigger the conduct test (for pricing-up, economic withholding, or physical withholding) would then be reviewed under the market price impact test.

To measure the price impact, we propose to estimate what the HOEP would have been in the delivery hour concerned, had the offer that triggered the conduct test been made at the reference price of the generating unit involved. We will estimate the HOEP that would have prevailed in the absence of withholding or pricing-up by simulating the unconstrained market for the hour (all twelve intervals) holding all other inputs (offers/bids, demand levels) constant except for the offers of the unit (or units if more than one unit in the portfolio of the market participant involved triggers the conduct test) under review.[25]

(a) If a unit triggered the conduct test for economic withholding or pricing-up, we are proposing to replace the unit's actual offers with its reference price curve in our simulation.

(b) If a unit or a market participant's generation portfolio triggered the conduct test for physical withholding we propose to assume that the unit or units involved were available and offered at their respective reference prices for purposes of our simulation.

[25]Import and export schedules may also be adjusted. See discussion of the Role of the Pre-dispatch Scheduling below.

In cases in which the reference price is not representative due to the limited number of accepted offers over the preceding 90-day period, estimates of marginal cost derived from unit-specific cost data (heat rates etc) submitted to the MSP as part of the Data Catalogue process may be used instead.

We propose that the market price impact test be triggered if the actual hourly Ontario energy price (HOEP) in the hour under review, is substantially higher than the simulated price, called the competitive price and denoted as PE^c. The test is triggered if either of the following thresholds are violated:

$$HOEP - PE^c > \$50MWh \quad \text{or} \quad \frac{HOEP - PE^c}{PE^c} > 100\%\,;$$

These thresholds imply that for HOEP above $100, if it is also more than $50 above the competitive price there is a sufficient basis for continuing to test for the exercise of market power. For HOEP below $100, the assessment would continue only if HOEP is more than twice the competitive price.

<u>The Role of the Pre-dispatch Scheduling</u>

When a market participant attempts to exercise market power, it must anticipate the competitive response of other suppliers (and buyers). This includes the response of imports and exports. More specifically, when a market participant engages in economic withholding (or physical withholding that affects the unit's availability in pre-dispatch), it faces the risk that the final pre-dispatch will schedule additional imports or fewer exports which would mitigate some of the potential real-time price increases and hence the potential profitability of the strategy.

We recognize that all else held constant, when a market participant engages in pricing-up or withholding and its offer (or failure to offer capacity in the case of physical withholding) is included in the final pre-dispatch, this conduct will generally lead to more imports or fewer exports being selected in the final pre-dispatch. If we were to simulate the HOEP without recognizing that fewer imports or more exports than would otherwise have been selected in pre-dispatch, the simulation would understate the true competitive price level and hence overstate both the price impact and the profitability of the withholding or pricing-up strategy. To eliminate this source of bias, we propose to begin the market price impact test by simulating the final pre-dispatch using all the same inputs with the exception of the flagged offer(s) by the market participant being reviewed. These flagged offer(s) would be replaced by the relevant reference price(s).[26] This pre-dispatch simulation will enable us to determine what imports and exports would have been in the absence of the withholding or pricing-up in question. The import and exports volumes from the pre-dispatch simulation would then be incorporated into the real-time simulation to compute what the HOEP would have been if the flagged offers had been made at their reference prices.

3.1.5 Profitability Test

Our proposed definition of the exercise of market power requires that the seller's conduct cause a *profitable* increase in the market price. The MSP recognizes that the profitability of a certain action by a market participant depends on the set of market positions of that participant including: the portfolio of resources owned by the participant, all physical forward energy purchases or sales, and all private financial contracts such as contract for differences and option contracts. The MSP does not have complete information on all of a seller's market positions. As a result, the profitability test is devised to identify those cases where it is unlikely that the conduct could have been profitable for the seller, in order to eliminate these events from further MSP review. Information about regulated assets or contracts with OPA will be used if available.

Any offers that trigger the conduct test and the market price impact test are then reviewed under the profitability test. For the profitability test, the MSP assumes the most favorable conditions for the market participant to exercise market power by assuming that it has not sold forward any of its energy through physical or financial contracts (except for regulated assets or OPA contracts). In this respect, if the market participant's actions do not trigger the profitability test, it is reasonable to conclude that the actions were not part of a strategy to exercise market power.

[26] It is explained later that if an import by the same market participant triggers its conduct test, its reference offer price would also replace the offer in the pre-dispatch.

With these assumptions the MSP then calculates the profitability of the seller's conduct by comparing the profits earned under the actual HOEP against the profits earned with PE^c, the simulated competitive price level.

In general, when there are no regulated prices or contracts, the seller's conduct would be profitable and will trigger the profitability test if the profit or net revenue (revenue minus cost) based on HOEP ($\prod^W$) exceeds the profit based on competitive prices ($\prod^C$). After some re-arrangements of terms this becomes:

$$\begin{aligned}\prod^{w} - \prod^{C} &= (HOEP - PE^{c})\sum_{i \in I} Q_i + \sum_{j \in J}(HOEP.Q_j^W - C(Q_j^W)) \\ &\quad - (PE^{C}.Q_k^C - C(Q_k^C)) > 0\end{aligned}$$

The above condition includes three terms. The first term, $(HOEP - PE^{c})\sum_{i \in I} Q_i$, represents the additional revenue earned by the market participant at the higher price from the scheduling of energy on the market participant's infra-marginal generation portfolio, units $i \in I$. The second term, $\sum_{j \in J}(HOEP.Q_j^W - C(Q_j^W))$ recognizes that withholding of some generation by the market participant may have caused the scheduling of one or more of the market participant's higher cost generating units, $j \in J$. The third term represents the foregone profit margin that would have been earned on the withheld generation, unit k, by the market participant had the market participant offered unit k at the competitive reference price. Q_k^C is the additional energy scheduled and would have receive the competitive price PE^c . If there are several units (denoted by the set K) withheld by the market participant, the last term becomes a summation for all units $k \in K$. In cases in which the market participant involved is paid either regulated or contract prices instead of the HOEP for some of its generation, the profit test would be modified to reflect the contract price rather than HOEP or PE^c . In situations where this leads to the same price and quantity applied for both the actual and simulated cases, in practice these terms can be dropped from the calculation

Constrained Schedule

If a market participant regularly triggers the conduct and price impact tests but fails to trigger the profit test, we may investigate whether the conduct involved is earning profits in the constrained schedule. A resource may appear to be losing profit when its offer price is increased, but may in fact be gaining additional constrained schedule revenues and profits. The treatment of local market power under Appendix 7.6 of the Market Rules affects only a very small fraction of constrained schedule payments. Looking at constrained schedule results will not be a formal part of the market power framework. However, the MSP may conduct other assessments from time to time which may include impacts of both constrained and unconstrained schedules.

The seller's portfolio of energy resource is larger than its Ontario generation units

A seller may purchase energy from other sellers through physical or financial contracts. Under these contracts, the seller will have a larger portfolio of energy exposed to the spot market price. In this situation, the simulation of the seller's profits from withholding will understate the true incentive to withhold. If a seller regularly triggers the conduct and market impact thresholds, and yet the profitability test indicates that there is no profit motive, the MSP may request that the seller provide the MSP with a list of all of the seller's contractual position in Ontario.

3.1.6 Additional Considerations

If an offer triggers the conduct, price impact and profitability tests, this raises a rebuttable presumption that the market participant concerned has exercised market power. Before taking any further action, the MSP would direct the MAU to contact the market participant involved in order to review the test results and to provide an opportunity for comment and for the provision of any additional information regarded as being relevant to the inquiry. As part of this process, the MAU may request evidence regarding the contractual position of the market participant involved and use it to check the validity of the profitability test. In the case of physical withholding, the MAU may seek evidence from the IESO regarding the circumstances of forced outages or derates as well as from the market participant involved.

3.2 Application to Imports

3.2.1 Overview

Our proposed method of inferring whether market power has been exercised by importers recognizes that the cost of an import is an opportunity cost. Ideally, the opportunity cost of energy imported into Ontario is the best price at which this energy could be sold in any of the neighbouring markets. Given that traders are likely to incur costs or encounter risks specific to the markets in which they are attempting to sell, we would expect them to offer into each market at a different price. For this reason, depending on the intertie, imports may be offered into Ontario at either a premium or a discount to the highest price prevailing in neighbouring markets.

The methodology we propose assumes that there is a stable relationship between offers into Ontario at a given intertie and prices in other markets. For example, imports at a given intertie in a given hour might normally be offered at a price that is 110 percent of the highest price prevailing in neighbouring markets during that hour. We call the ratio of the offer price of an import to the highest external price in the hour concerned the import offer ratio. Our test for the exercise of market power by importers focuses on import offers for which the import offer ratio is significantly above normal.

The ***conduct test*** for an importer at a given intertie would compare its current offer price to a threshold based on the historical average of the import offer ratio for that intertie. We propose the threshold be two standard deviations above the mean.

If the conduct test is triggered we would perform a ***market price impact test*** for the pre-dispatch price. For this we would replace the import offer with a price consistent with its historical values, calculated as the highest external price in the hour multiplied by the average historical import offer ratio. This represents the deemed 'historical' offer price, analogous to the reference price for non-energy limited imports described in the previous section.

If the price test triggers we can infer from the existence of a market schedule, that the importer increased its profit by raising its price. A more complete ***profit test*** calculation is needed only when the import has generation units which triggered the generation conduct test.

Again, the Panel is seeking input whether there are better mechanisms for defining and applying these tests. For example the Panel is interested in your views regarding the following:

- **Is there a better proxy the MSP can use for determining the opportunity cost for an import?**
- **Are the thresholds for the price impact tests appropriate?**
- **Is there other information that should be taken into account for the profit calculation that is readily available?**
- **Is there additional data that importers may find useful to provide the MSP on an ongoing basis in advance of any such assessments?**

3.2.2 Conduct Test for Imports

To illustrate our proposed approach, consider the situation in which an importer sells power into Ontario and in so doing foregoes the opportunity to sell to New York at the New York price. In this case the New York price is the opportunity cost of selling into Ontario and the importer has an incentive to offer into Ontario at a price that is at least as high as the New York price. If there were several markets to sell into, the opportunity cost for selling into Ontario would be the highest price prevailing in these markets.

In our proposed approach, the maximum price for the hour in the surrounding markets is used as a proxy for the opportunity cost of the importer. We refer to this as the Importer's Best Alternative (IBA). In an idealized, frictionless world, import offers into Ontario would just equal to the relevant IBA. Given the possible costs and risks of selling into Ontario and, indeed, uncertainty about what an importers best alternative is at a given point in time, we cannot expect importers' offers to equal their respective IBA's. Instead, we base our test on the assumption that there is a stable relationship between importers' offers and their respective IBA's. This relationship should reflect the typical costs, risks and alternative opportunities of importers offering into Ontario at each interface.

<u>Calculating the Import Offer Ratio and the Reference Offer Index</u>

We begin by calculating the hourly Import Offer Ratio (IOR) which is the ratio of the Import Offer Price (IOP) to the Importers Best Alternative (IBA). This import offer ratio uses the offer price in the hour corresponding to the import quantity selected in the market schedule. Each import quantity is associated with a 50 MW lamination.

The hourly values of the IOR are then used to develop an average, the reference offer index, which is defined to be the mean of all the import offer ratios (IOR) at a given intertie in a specific lamination over all hours of the last 365 days. This reference offer index, ROI_i, represents a long-run average of the import offer ratios for the selected lamination at a given intertie, and is calculated as $\mathrm{ROI}_i = \sum_j \mathrm{IOR}_{i,j} / N_i$, where N_i is the number of occurrences j of a market schedule in lamination i at the intertie over all hours of the previous 365 days.

If there are multiple schedules selected in a given hour at an intertie, each would be counted that hour for its corresponding lamination. However, we do not propose to use every import offer in our ROI calculation. Imports with negative offer prices can be excluded, assuming these are contracted imports or otherwise not sensitive to the external or internal prices.[27] Where a market participant has an import scheduled with an equal sized export also scheduled, this is also excluded from the determination of the ROI. These restrictions should be applied to ensure that the resulting statistic is applicable to competitive import offers that are responding to prices in the various markets.

[27] By the same token, if a negative offer price is encountered for testing in some hour either the import offer is below the clearing price in those hours and because it is infra-marginal does not represent an exercise of market power, or the import offer is higher than the clearing price and given the market price materiality threshold is a positive number, for example $50 per MWh, the hour is not considered because of the low price.

Sample ROI calculations for five interfaces in the Ontario market are provided in Appendix B. Since the IBA used in the calculation of the IOR is the same value for all interfaces in a given hour, the ranking of average IOR values is the same as the ranking of average offer prices. The ROI calculations show that the 365 day IOR averages range from just above 0.10 on the lowest priced interface to more than 1.10 on the highest with Manitoba and Minnesota at the low end and New York and Quebec at the high end.. This is not surprising given that the IBA, is usually either the New York or the New England price. While it is apparent that New England and New York are not directly accessible to imports from Manitoba and Minnesota and the New England and New York prices do not represent their true opportunity cost, IOR values at the Manitoba and Minnesota interfaces are fairly stable. The implication is that the ROI is a reasonable historic benchmark against which to determine whether import offers at a given intertie are unusually high.

The Appendix also explains that the ROI's for different laminations are statistically different, which supports the approach for using laminations rather than averaging all offers independent of the size of the offer.

Thresholds Applied in the Conduct Test

There are two parts to our proposed conduct test. The first would compare the import offer involved with an historic reference price threshold. The second part would compare the offer involved with the market- clearing pre-dispatch price.

(a) Offer Price Threshold:

The comparison of the import offer with the reference price is intended to identify unusually high-priced import offers. For this reason we set a reference price threshold such that only extraordinarily high offer prices exceed it. To this end we propose that in order to trigger the conduct test the offer price concerned must satisfy the following condition:

$$\text{Offer Price} > (ROI_i + 2 \text{ standard deviations}) * IBA$$

where the right-hand side of this expression represents a statistical upper bound for the offer, based on the average ROI, historic variation around the ROI and the highest external price (IBA).

This threshold is applicable to any offer at a specified intertie, with the maximum quantity being in lamination i. The standard deviation is calculated around the mean, ROI, using the 365 days of hourly values of the import offer ratio. Appendix B shows these threshold factors for each interties for each lamination i, where there are data. Like the ROI themselves, the thresholds can be fairly high, from 1.5 to more than 2.0, in the case of Quebec and New York interties, more moderate for Michigan , and relatively low for Manitoba and Minnesota, which are typically about 1.0 or lower.

(b) Relationship to Market Clearing Price:

The second part of the conduct test requires that: (i) the offer is not infra-marginal which means the offer price is at least as high as the market clearing price; and (ii) the cost is below the market clearing price and therefore could have affected the clearing price result. This was expressed earlier by the condition: Offer Price ≥ MCP > Cost. To apply this for imports we are proposing that the hourly pre-dispatch energy price (PDP) is the relevant clearing price and the reference offer index (ROI) should be the basis for the cost proxy. The ROI must first be translated into a price for the hour, the Reference Offer Price (ROP) which is defined for each quantity lamination i as the index times the external price normalization factor, or $ROP_i = ROI_i * IBA$. Again for this part of the test we propose using the "best estimate" of the cost, rather than the upper bound applied in the threshold test. Therefore, the second part of the conduct test requires testing for:

$$\text{Offer Price} \geq \text{Pre-Dispatch Price} > \text{Reference Offer Price} = ROI_i * IBA$$

3.2.3 Market Price Impact Test

If an offer triggers this conduct threshold, we would then perform the ***market price impact test*** for the pre-dispatch hour in question. The price impact test involves replacing the offer price concerned with the relevant reference offer price and simulating the hour ahead pre-dispatch market and deriving a competitive market clearing price. Depending on the circumstances, it may also require simulating the real-time schedules and prices as well.

Pre-Dispatch Scheduling

In the event that an import offer triggers the conduct test in a given delivery hour, we are proposing to estimate the competitive price level by re-running the unconstrained pre-dispatch market for the hour holding all inputs (offers/bids, demand levels) constant with the exception of the offers from the market participant that have triggered the conduct test. Both import offers and generation offers, would be adjusted for the simulation. For imports that trigger the conduct test, the offer would be replaced by the reference offer price (ROP) for the intertie and lamination. Any generation offer that had triggered its conduct test would be replaced by the competitive reference price for the unit.

The simulated market clearing pre-dispatch price is treated as the competitive price and is denoted as PDE^c. We propose that the market price impact test be triggered if the actual pre-dispatch energy price (PDP) in the hour under review, is such that either of the following thresholds are exceeded:

$$PDP - PDE^c > \$50MWh \quad \text{or} \quad \frac{PDP - PDE^c}{PDE^c} > 100\% \, ;$$

With these proposed thresholds, for PDP above \$100 and more than \$50 above the competitive price or when PDP is below \$100 but more than twice the competitive price, there may be a sufficient basis for continuing the assessment and concluding the exercise of market power.

Role of Real-Time Market Scheduling

If the pre-dispatch price impact thresholds have not been exceeded, there is no need to run real-time simulations except in cases where Ontario generating units have also been flagged in their own conduct tests.

If Ontario generating units have been flagged, both pre-dispatch and real-time need to be simulated, and the real-time price impact tested. This process was described in connection with the price impact test for non-energy limited units and would be required whether the import triggers its pre-dispatch price impact test or not. If both imports and Ontario generation have been flagged in their respective conduct tests, their offers would be replaced in the pre-dispatch simulation by their respective reference prices. Changes to imports and exports observed in the pre-dispatch simulation are then included in the real-time simulation.

We are also interested in knowing whether there are changes to HOEP when HOEP exceeds the offer price of the import, since the import would be paid HOEP in this situation. This has implications for the profit test, but does not require real-time simulations. This is explained further in the profit test.

We are proposing that real-time influences should not be considered for imports in other cases, that is, in situations where the market participant has no internal generation, or none of that generation has been flagged in the conduct test. We would review the import(s) based on the pre-dispatch price effect and only for the import profit impact. This has two implications. We would not be considering a further price impact test for HOEP as the result of changes to import offers only. Nor would we consider the real-time profit impacts for the market participant's generation.

In other words, we view the import potential to exercise market power as taking place primarily in the pre-dispatch. There is a much different treatment of imports in real-time and a tendency for real-time prices to be lower than pre-dispatch, except where unexpected events take place in real-time (i.e. import failures, generation outages or higher than forecast demands). Given the differences that exist between pre-dispatch and real-time we view these as sufficiently decoupled for the purpose of testing for the exercise of market power.

3.2.4 Profit Test

The profit test is triggered if the profit based on actual schedules and prices exceeds the "competitive" profit, which is based on the reference offer price (ROP) and the resulting simulated schedules and prices.

If the importer has no Ontario generating units flagged for review, the profit test is applied for the import alone. There are three possible cases:

- If there is no market schedule for the import offer concerned , the importer's price-increasing conduct is not directly profitable and the profit test is not triggered.

- Where there is a market schedule for the import offer concerned and the HOEP exceeds the offer price the import is paid the HOEP. If applying the reference offer price were to lead to a lower HOEP, this represents a lesser profit for the import and should trigger the profit test. However it is not necessary to run the real-time simulation to know whether the HOEP may change. If the pre-dispatch simulation leads to more net imports being scheduled and placed at the bottom of the stack for real-time, this can be assumed to lead to a lowering of HOEP, even if only by a small amount.[28] Thus if net imports increase, we assume the profit test is flagged.
- Where there is a market schedule for the import offer concerned and the offer price exceeds HOEP, the import is paid the offer price. Replacing the offer price with the reference offer price leads to a lower payment for the import. Either the ROP establishes the new payment price or, if it is lower than HOEP, the HOEP becomes the payment

[28] Of course very small net import changes might not actually reduce HOEP if there is a large enough lamination at that price. However, in practical terms this is highly unlikely given that there are 12 intervals each with different conditions and prices.

price. In both cases the payment is lower and as a result the profit is lower. Again, it can be assumed for this case that the profit test is flagged.

If the importer also has generating units flagged, the real-time simulations are required and the full profit test applied, as described for non-energy limited generation. That calculation would need to be augmented as described above to include the profits derived from higher priced import offers.

If the appropriate profit test does show a gain for the market participant, all three tests have been triggered. As for non-energy limited generation the MAU might then contact the market participant for more information about the event.

3.3 Application to Energy Limited Generation (ELGs)

Energy-limited generation (ELG) resources include hydroelectric plants that have limited water inflows and storage capability, as well as fossil units that may experience output restrictions due to fuel shortages or emission limits. The essential feature of these resources is that they cannot run in every hour and must choose those hours in which to make their generation available to the market. To use the resource in any given hour means it is not available at a later time. There is an opportunity cost associated with this choice and it is the value of the best alternative use of the available fuel (or flow limit or emission limit, etc.). This best alternative use of generation is the highest priced hour in which it does not run. While the same general approach can be applied in cases involving shortages of fossil fuel and emissions limits, the focus of this discussion is on hydroelectric generation.

An energy-limited generator (ELG) may exercise market power by allocating relatively more water to off-peak (i.e. lower priced) periods than to on-peak (i.e. higher priced) periods. This allocation would cause prices in off-peak hours to be somewhat lower, but on-peak prices to be much higher than they would have been under a more efficient allocation. If the owner of the ELG has a portfolio of generation, it may profit from this strategy by accepting relatively lower revenues from the ELG in off-peak periods but much higher revenues from its portfolio in the on-peak periods.

The test for exercising market power by an ELG should identify either of two related conditions:

i) pricing generation above its opportunity cost in high-priced hours thereby causing even higher prices during those hours; or

ii) pricing generation below its opportunity cost in low-priced hours, making it unavailable for use in the higher priced-hours.

The former may be viewed as economic withholding. The latter is a form of physical withholding. Either or both of these conditions suggest a sub-optimal allocation of available water, raising the possibility this has been motivated by a desire to exercise market power in order to increase prices and profits.

Dealing with market power tests for ELGs is more complex than for other resources since the opportunity cost of generating in a particular hour depends on the price at which that generation could be sold in other hours. In addition, each generating plant has a different storage capability or horizon[29] over which its energy could be produced. These different storage periods or renewal periods potentially lead to a different opportunity cost for each plant in a given hour.

Ideally, ELG that has the objective of maximizing the value of its generation would attempt to allocate the water available to the plant during a given storage period so as to generate during the highest priced hours expected to prevail during that period. In so doing, it would cover its opportunity cost by definition. If, for example, a plant has H hours of water available to it during a day, the unconstrained ideal would be for it to allocate this water to the H highest HOEP hours expected to prevail during that day. The opportunity cost of this H hours of water would be the HOEP expected to prevail during the $(H+1)^{th}$ highest priced hour in the day.

For hydroelectric generation, physical limitations and dependencies on upstream and downstream plant operation mean that the allocation of water over time is not driven solely by anticipated market prices. The availability of H hours of water over the next few days does not

[29] The storage horizon is the renewal period for the fuel, by which time it must be used, since additional fuel or other limited resource is expected to arrive at that point. Equivalently, it is the maximum period for which it can be stored.

necessarily mean this water can be used to generate in the H highest price hours, even if these could be forecast accurately in advance. For many plants, the unconstrained ideal allocation of water within a time period is never attained. Thus, there is nothing significant in the failure of an ELG facility to attain the unconstrained ideal.

A more realistic methodology for allocating the available water so as to maximize its value would account for storage capabilities, inflows, market prices for both energy and operating reserve, the conversion efficiency for water to energy over the entire operating range of the units involved, lake level and river flow limitations and upstream or downstream relationships. Since this is not feasible to implement, the approach taken here is to rely on each plants historic performance relative to the unconstrained ideal as a benchmark against which to assess its current performance.

We note that other jurisdictions do not have analytical frameworks for dealing with the exercise of market power by energy-limited hydroelectric generation. In some markets such as PJM and markets in some South American countries, hydroelectric generation is scheduled by the market operator with the goal of maximizing its value (and minimizing system generation costs). This precludes the exercise of market power by withholding water during high price periods. Other jurisdictions such as NYISO and Cal-ISO have the potential to investigate for the possible exercise of market power by hydroelectric generators but in practice there is no rigorous testing and no action has been taken[30]. This is partly because hydroelectric resources do not account for a sufficiently large part of these systems and partly because the determination of the opportunity costs of hydroelectric generation is difficult with no established approaches for inferring the extent to which water has been intentionally withheld from higher valued periods. New Zealand constitutes an exception of sorts. In New Zealand, hydroelectric generation is the primary source of energy, with large reservoirs for water storage. New Zealand has operated on the assumption that competition in its market is sufficient to deter attempts to exercise market power although it has recently started to consider this possibility.

[30] NYISO cannot apply automatic mitigation (AMP) to hydroelectric generation.

In the absence of models from other jurisdictions, we are obliged to break new ground. Given the complexity of the process of allocating water optimally over time, the tests proposed below should be regarded as preliminary. They are, however, consistent with the reference price approach being taken for non-energy limited generation and the opportunity cost approach taken with imports. These tests are presented with the expectation that a collaborative effort will follow, with stakeholders taking an active role in helping develop more refined models and tests.

Plant, Facility or Unit

For clarity it is important to distinguish a plant from the facility or units at the plant. A "unit" is the collection of equipment which constitute an individual generating unit at a plant, comprised of the integrated turbine and generator components and other equipment dedicated to their functioning. Each unit is physically separate from one another although they would normally be housed in the same building. Fossil units each have their own boiler (source of steam) with production from each unit typically independent, except when there may be some common energy limitation imposed because of limited fuel availability or emission restriction. Hydroelectric units may share the same intake and certainly are subject to the common limitations imposed by the forebay capability and upstream or downstream requirements. A "facility" (as represented by the defined term in the market rules) is a bidding and scheduling construct used in the IESO market which may be an individual generating unit or may be the aggregate of a few units. For fossil plants, units and facilities are typically synonymous, except for combined cycle arrangements. For hydroelectric plant typically a few units are aggregated as a facility with the plant commonly comprised of multiple facilities. For a very small number of hydroelectric plants a single facility represents more than one plant which are nearby to one another.

Because of the common restrictions on fuel availability and usage, in the analyses which follow it is proposed that all units at an energy limited generating plant be aggregated and the plant be treated as a single entity. This means that schedules for all facilities at a plant would be summed and any ratios or rescheduling be performed on the plant as a whole. Where a facility represents multiple plants, the facility would be used without disaggregation for these analyses.

3.3.1 Overview

This section summarizes the three groups of tests for the exercise of market power in the case of energy-limited generation. Questions regarding issues specific to these tests are posed at the end of Section 3.3.

The actual physical limitations on a hydroelectric plant are complex, dynamic and difficult to model accurately without a large amount of information. Consequently, it is difficult to determine the hours on a given day in which a given plant seeking to maximize the value of its water subject to constraints actually should run.

We propose instead a conduct test based on a plant's history of water allocation relative to its unconstrained ideal allocation. If, in the recent past, a plant has allocated the water available to it each day so as to yield an average of 90 percent of the revenues that it would realize from the unconstrained ideal allocation of this water and this has not varied markedly from day to day, then a daily allocation that yields only 70 percent of the ideal, for example, would be questionable. Has too much water been placed in low price hours? Even though this reduces the revenue from the plant involved, does it increase the HOEP in the higher price hours and thus increase profits on the rest of the market participant's portfolio?

For the ***conduct test*** for a hydroelectric generating plant we propose to compare the plant's daily water allocation efficiency ratio (WAER - the ratio of actual revenue to ideal revenue) against a threshold based on the historical values of this ratio. If the value of the WAER on a given day is well below its usual past values, this implies that a relatively large volume of water has been withheld from higher priced hours that day.

We recognize that differences in pre-dispatch and real-time conditions can render an allocation of water inefficient in real-time even though it was efficient in pre-dispatch. In the Panel's view, the allocation of water should be relatively inefficient in both pre-dispatch and real-time in order to support an inference that market power has been exercised. For this reason, the application of the conduct test requires the calculation of two versions of the WAER, one using real-time prices and schedules (actual outcomes) and a second based on pre-dispatch prices and schedules one hour ahead of real-time (the final projection for the hour). The latter ratio is less affected by pre-dispatch to real-time differences.

To trigger the conduct test, both daily allocation efficiency ratios, real-time and pre-dispatch, must be below their respective historical thresholds. We propose that a WAER should be defined as being below its historical threshold if it is below most (say, 98 percent) of its past values and if it is also less than a specified percentage (say 85 percent) of its past average value. This last condition effectively confines the remaining tests to instances in which there is a material difference between the daily WAER and its past average value.

In the event that the conduct test is triggered, additional tests may be applied before continuing to the price impact test. We would investigate whether pre-dispatch information (earlier than one hour ahead) that was more unstable than usual or less accurate than usual may have contributed to unusually low values for both ratios. We would also look into conditions for plants on a common river system where unexpected upstream (or downstream) events, such as the release of water from a constrained-on facility, could explain relatively low WAERs. Further, we would test to see if an unusually low amount of water was scheduled that day, since we have noted some relationship between lower flows and lower WAERs.

If the conduct test is triggered by a low water allocation efficiency ratio and none of the extenuating circumstances listed above prevail, we would then apply the ***market price impact*** test**.** To simulate the price impact of a below normal allocation of water to higher price hours, we would create a revised allocation of water consistent with the historical average allocation efficiency (for real-time), create equivalent offers which would achieve this allocation and estimate the HOEPs for the day based on these adjusted offers. Since the allocation of water required to replicate the historic average WAER is not unique, the revised sequence of schedules chosen will be that which requires the least reallocation of the actual schedules. The impact on prices in each hour will be assessed to determine if the net of hourly increases and decreases exceeds the price thresholds specified.

If the price impact test is triggered, the ***profit test*** follows. We propose to calculate the profits of the market participant involved under the actual market schedules and under the adjusted simulated schedules for hours where a reallocaton of water has occurred. The profit test is triggered if the market participant's profit is greater under the actual allocation than under the simulated competitive allocation.

We intend to apply these tests each day, assuming a 24 hour renewal horizon. Many plants appear to be scheduled using a daily renewal period (for allocating a pre-determined amount of daily water). This may be in addition to a longer renewal period. However, the methodology as proposed is not applicable for longer storage horizons.

We are considering the merits of excluding base load hydroelectric plant, in particular Beck and Saunders, from daily testing. The Saunders plant has almost no flexibility for scheduling its water while its scheduling by the IESO is complicated by occasional operation in segregated mode.[31] The Beck plants have limited flexibility but are able to produce more during peak hours than off-peak. The operation is complicated by the existence of the pump-storage facility, the provision of AGC by Beck 2 units and reduced availability of water on-peak during the tourist season. The Saunders and Beck plants would be excluded from daily testing only if further analysis shows that this is appropriate. The factors that must be considered in this regard include the average WAERs at each plant, the reasons for any materially below average WAERs that are observed and whether reallocations of water in these instances led to meaningful schedules.

As identified in Chapter 1, we limit reviews to hours where HOEP exceeds $50. Since, for energy-limited hydroelectric plant we look at the impact over the day, this means the materiality test translates into requiring the highest HOEP for the day must be greater than $50. There are

[31] Segregated mode of operation (SMO) is the direct connection of a generator to a neighbouring system, with the appearance that the facility is not available or generating.

few days with maximum HOEP this low, so in practice, we would apply the ELG framework almost every day.

3.3.2 The Conduct Test

The conduct test is based on a ratio that measures the relative efficiency with which a hydroelectric plant allocates its available water over a given 24 hour period (referred to as the storage period or storage horizon). The methodology we are proposing is to calculate the ratio of the actual revenue earned by a given plant during a given 24 hour period to the revenue that plant would have earned that day if it had allocated its water both with perfect foresight (i.e., as if it had perfect information with respect to its water availability and the eventual market clearing prices) and without constraints other than its capacity limit. This ratio for a given day is compared to recent historical values of the ratio.

This approach is comparable to determining references prices for fossil fueled generators based on their recent offer histories. It is also comparable to the proposed conduct test for import offers that is based on departures from the historic relationship between an importer's offer price and its opportunity cost. These approaches focus on changes in behaviour and thus presume that the historical benchmarks on which they rely are reflective of workably competitive conditions. To the extent that the historical benchmarks reflect past exercises of market power, these tests could produce a disproportionate number of false negatives.

We have considered applying the conduct and other tests for the exercise of market power by hydroelectric generation to periods longer than 24 hours where the storage horizon or renewal period for the generation involved is also longer than 24 hours. The reason for this is that an attempt to exercise market power could manifest itself through less efficient allocation of water over several days as well as over the hours of a day. We propose at this time to confine our tests to 24 hour periods for the following reasons. First, we observe that even when there is a longer storage horizon, it is typical to plan for release of a specified amount of water each day and to schedule this amount of water over the hours of the day. In other words, longer planning horizons nest a series of daily water allocation decisions each of which can be tested for the intra-day exercise of market power. It is reasonable to assume that a market participant withholding water from high priced days would also withhold water from high priced hours each day and this would show up in the daily conduct tests. Second, while the possibility remains that a generating plant with a longer storage horizon may withhold water from higher priced days but not withhold it from higher priced hours each day, the prediction of higher priced days is likely to be highly problematic for market participants. While pre-dispatch prices create a publicly available forward price curve for 24 hours, no corresponding projections are available for a longer period of time. As a consequence, inter-day WAERs are likely to be much lower and more variable than intra-day WAERs making past inter-day WAERs less useful as a norm. In sum, if inter-day withholding is perceived to be a problem, another form of conduct test will have to be developed to address it.

The details of the proposed conduct test for energy limited hydroelectric generation are presented below. Our approach uses many simplifying assumptions. In part, this has been done because of the limitations of the tools available and the potentially prohibitive cost of creating more sophisticated tools to deal with the complete problem. The simple approach is also a reasonable starting point for the dialogue we hope to initiate regarding the framework for energy-limited resources. Appendix C elaborates on some of the assumptions.

Step 1: Determine the Amount of Energy Available for Scheduling

To determine the amount of water available to an ELG during a given day (the assumed replacement period T), we would assume it is directly proportional to the actual amount of energy scheduled in the unconstrained schedule during the day This is equivalent to saying we assume the production efficiency for the available water is a constant. For example, if the plant involved was scheduled to generate a total 800MWh of energy during a few hours of the day, we would assume that the volume of water available to it was sufficient to generate 800MWh at any time during that day. Production efficiency is dependent on output level and the head (how far water drops) but we assume it is constant for the purpose of the methodology below.

Two separate quantities would be calculated, one representing total energy in the real-time schedules the other representing total energy in pre-dispatch schedules.

Step 2: Determine the Maximum Daily Revenue Possible

To determine an optimal allocation of the available water within the day, we would assume the generator involved could have anticipated the highest priced hours in the day and allocated its water to them. Given this assumption, the allocation decision is simple. We do not need to use any formal optimization tools, since the ideal allocation is derived by ordering HOEP from highest to lowest and assigning energy, up to the plant maximum, in each successive hour, until all available energy is scheduled. The maximum revenue, V*, is the total hourly revenue corresponding to this ideal allocation:

$$V^* = \sum_{\mathrm{h}} (E_h^{\,*} \,.\, \mathrm{HOEP}_h)$$

where $E_h^{\,*}$ is the ideal market schedule for hour h.

We would do this for real-time based on the HOEP and the real-time daily energy available as determined in Step 1. Similarly, we would do this for pre-dispatch, based on the final pre-dispatch hourly prices (instead of HOEP) and pre-dispatch daily energy. Appendix C describes the allocation more formally.

Step 2 yields the ideal water allocation revenue in real-time and pre-dispatch respectively. These ideal allocation revenues are the denominators in the day's real-time and pre-dispatch water allocation efficiency ratios. The water allocation model used in Step 2 is a drastic simplification of the complete problem, which must recognize other limitations related to flows and water levels and interactions with other plants on the same river system, and water conversion efficiency. We emphasize that we do not propose to evaluate participants' conduct relative to this naïve ideal. Instead, our proposed conduct test looks for instances in which an ELG has done significantly worse than usual relative to the ideal. The use of historic performance relative to the ideal as a benchmark implicitly recognizes the constraints faced by ELG in their water allocation decisions. To the extent that the constraints faced on a given day are the same as normally faced by a given ELG plant, they wash out.

Research by the MAU has shown that the daily water allocation efficiency ratios for energy limited generation can change dramatically over time, both in terms of the average ratio as well as the variance of the ratios. In essence, the constraints faced by an ELG plant can vary over time (for example, from season to season) with the result that it may do better or worse relative to the ideal for reasons unrelated to the exercise of market power. This could increase the incidence of false positives and false negatives if the test does not take changes in constraints into account. We propose to take changes in the constraints faced by an ELG plant into account in four ways. First, we would confine our concerns to the lowest values (say, the lowest 2 percent) of a plant's water allocation efficiency ratio (WAER). Second, we would also confine our concerns to WAER values that are well below a moving average of past WAER values. The use of a moving average allows the benchmark WAER to reflect changes in constraints over time. Third, we would confine our concerns to instances in which the WAER is unusually low in both hour ahead pre-dispatch and real-time. Fourth, we have identified many of the factors that can affect the ability of energy limited generation to allocate water efficiently and we would review instances of unusually low WAER values to determine whether any of these factors may have been responsible. (This is discussed further in Step 5.)

Step 3: Calculate the Daily Revenue for the Actual Schedule

For a given ELG plant on a given day, the total value of the energy actually scheduled in real-time, V^a, is simply the sum of the hourly revenues from energy generated during the day.

$$V^a = \sum_h (E_h^a \, . \, \text{HOEP}_h)$$

where E_h^a is the sum of actual market schedules for all facilities at the plant for hour h.

For $E_h{}^a$ corresponding to real-time schedules, this is the revenue derived in real-time from the plant's actual allocation of water. A similar actual daily revenue calculation is also made using energy actually scheduled in pre-dispatch and hour ahead pre-dispatch prices, in place of HOEP.

Step 4: Calculate the Daily Water Allocation Efficiency Ratio

The daily water allocation efficiency ratio (WAER) is the ratio of the revenue the ELG would derive from the actual total facility schedules to the revenue it would derive from the ideal total schedule. This ratio can be written as

$$WAER = 100 \frac{V^a}{V^*}$$

The WAER is calculated for real-time and pre-dispatch using respective values for the actual schedules and revenues V^a (from Step 3) and ideal schedules and maximum revenues possible, V* (from Step 2).

Step 5: Determine if the Current Daily Ratio is Below a Threshold Based on Past Performance

We propose to derive our performance benchmarks from the values of the daily WAER over the preceding 90 days. Shorter time periods have the advantage of incorporating changing constraints more quickly but they are also more open to manipulation and there is also a loss of information. Research by the MAU finds that the use of shorter time periods does not have any systematic effect on the frequency with which the conduct test is triggered.

We propose to infer that a daily WAER is unusually low (thus triggering the conduct test) if both the real-time and pre-dispatch WAER values are: (1) among the bottom 2 percent of their respective WAER values observed during the previous 90 days and (2) less than 85 percent of a 90-day moving average of their respective past WAER values (materiality limit).

The materiality limit has two purposes. First, it recognizes that there is always a potential for lower ratios, because forecast uncertainties always exist (primarily prices and the timing and availability of water) and because sometimes a participant can quite simply miss some scheduling opportunities. If a plant typically has high WAER (high average WAER and high 2 percentile threshold) unless the ratios falls below some materiality threshold it may still not represent a substantial movement of the energy out of higher priced periods; equivalently the energy may have moved to hours with prices that are not that much lower than the peak prices. We would view this as more likely the result of other factors than an indication of an attempt to exercise market power. Secondly, the materiality limit increases the likelihood if the plant triggers the conduct test and has energy reallocated for the price impact test, the potential reallocation will also be material.

Choosing a materiality limit is somewhat an arbitrary selection. A limit of 85 percent of the 90-day moving average removes about 25 percent to 45 percent of the plants that might otherwise trigger the conduct test, based on the 2 percentile threshold alone.[32]

Step 6: Consider Other Factors

In the event that a daily WAER is found to be unusually low in Step 5, we propose to consider possible explanations other than the exercise of market power before proceeding to the price impact test. These could include the following:

i) unusual instability, volatility or error in the pre-dispatch price several hours ahead:
   For example, 5 hour ahead pre-dispatch prices for peak hours may have provided an unusually poor forecast of hour ahead and real-time prices.
ii) atypical minimum levels scheduled that appear to be induced by river flow limitations:

[32] Based on a simulation from April to August 2005, the MAU noted the 85 percent limit removed about 25 percent of the facilities with real-time ratios below the 2 percentile threshold, 35 percent of those below the pre-dispatch threshold and almost 45 percent below a combined threshold (both real-time and pre-dispatch). For the combined threshold (real-time and pre-dispatch) there were some 337 facilities which triggered over the 5 months, with only 186 remaining after applying an 85 percent materiality limit.

Comparing off peak or minimum hourly generation against the recent past would indicate possible changes in river flow restrictions, but additional knowledge about the river system would be needed to confirm this.

iii) unexpected water conditions due to constrained on or constrained off releases of water upstream or downstream:

An unusually poor allocation of water at one plant may be the result of upstream or downstream facilities being constrained on or off. Additional information about the river system and facilities involved may be needed to determine whether this was the case.

iv) unusually low levels of total daily energy (which may occur more commonly on weekends):

A low WAER may be the result of a low level of generation for the day. This is more likely the case if price projections were unusually poor (see point i) or on a weekend if the energy scheduled were small but fairly constant across the day, indicating possible minimum flow requirements (see point ii).

v) trends in the WAER that may be associated with changing seasons or water conditions:

The daily WAER may be unusually low because the WAER is on a recent downward trend which is not yet reflected in its 90 day moving average. It would still be necessary to confirm that the trend involved was due to changing constraints rather than increasingly poorer water allocations associated with an escalating exercise of market power.

As mentioned earlier, some plants may need special consideration. Beck and Saunders have limited flexibility for moving their water and production from one hour or another. There is a possibility that because of these restrictions, these plants do not need to be monitored. This will need further testing and review, as stated earlier.

Some units operate in segregated mode (SMO) and this raises a further complication. Segregated mode of operation for a unit typically means direct connection to and energy flow into the Quebec system. The associated facilities appear as unavailable and are not scheduled, when in fact they are exporting energy to Quebec. Typically not all units at the plant operate in segregated mode at the same time. The WAERs may not be particularly sensitive to such operation if units are treated as being on outage during the SMO.

3.3.3 Market price impact test

If the daily WAER falls below the thresholds in the conduct test and there are no obvious mitigating circumstances, we propose to estimate the price impact using a revised schedule. This revised schedule represents the "competitive" schedule or allocation of water. The approximation we would use for this revised allocation is based on a reference allocation efficiency ratio for the plant, which is the historical average real-time WAER over the previous 90 days. From the revised "competitive" allocation we would estimate the change in the HOEP for the hours affected by the rescheduling. This is analogous to using the historical reference price for non-energy limited generation in the corresponding price impact test.

Revised schedules can be determined individually for each ELG that triggers the conduct test. The reallocations for all such ELGs would be combined for purposes of determining the price impact.

Revised Allocation

Revising the water allocation of an ELG plant relies on two related assumptions: i) a given ELG can be rescheduled by itself, without considering the effects from other plants that might fail the conduct test, and ii) the rescheduling of the ELG does not (initially) change the market prices. It is later in the determination of price impact that the combined impact of several plants is considered, and that prices are allowed to change.

The revision proposed is to create total plant schedules for the day consistent with the average real-time water allocation efficiency ratio for the previous 90 days, i.e., the 90-day rolling average of the daily ratios . If over this period a resource was able to achieve, for example, an average allocation efficiency ratio of 90 percent, it is reasonable in the price impact test to expect no better than average performance. So we devise total schedules which achieve 90 percent of the ideal real-time revenue for the day.

The revised total schedule which would yield the requisite revenue per day is not unique. We propose to choose revised schedules that meet the revenue requirement with the minimum change in the actual hourly total schedule of the facilities involved. Presumably, the original market schedules best represents the assessment of the plant and river system restrictions as well as economic opportunity by the market participant involved. Creating a revised schedule which departs minimally from this would arguably continue to be reasonably consistent with the participant's view of these restrictions and opportunities.

In recognition of plant or river limitations, if the ELG has been scheduled with some production in every hour, we can treat this as a minimal level that must be respected for the revised allocation. Such minimal production may be indicative of minimum water flows, which would be important to capture in the rescheduling. If other plant limitations are known and can be readily modeled as minimum or maximum levels in the various hours, these could be additional limitations incorporated in the revised allocation.

This minimal reallocation approach for the revised schedule also has the advantage of causing the least shifting of MW's between hours and thus tends to minimize possible impacts on market prices. This is a desirable feature, in contrast to an optimal schedule which could shift a large amount of power from one hour to another. Such shifting might lead to only a small overall improvement in the total revenue while creating large increases and decreases in prices in the affected hours.

The revised allocation problem can be expressed as minimizing the difference function, representing the sum of the squares of the hourly total reallocation, plus the cost associated with a slack variable:

$$\text{Min: } \sum_h (E_h^r - E_h^a)^2 + S.P_S \qquad \text{difference function}$$ [33]

subject to

$$E_h^{min} < E_h^{r} < E_h^{max} \qquad \text{hourly limits on production}$$

$$\sum_h E_h^r = \sum_h E_h^a \qquad \text{total energy scheduling equality}$$

$$V^r + S \geq RWAER_T . V^* \qquad \text{target revenue}$$

where

E_h^{r} is the revised sequence of plant total energy market schedules for hours h of the current day;

E_h^a is the plant total actual market schedule for hour h;

E_h^{min}, E_h^{max} are the minimum and maximum plant total hourly schedules allowed, which may reflect hourly flow limitations as well as plant capacity limits;

$V^r = \sum_h (E_h^r . HOEP_h)$ is the revenue implied by the revised schedule;

$V^* = \sum_h (E_h^* . HOEP_h)$ is the revenue implied by the optimal schedule (in Step 2);

$RWAER_T$ is the reference ratio, which is the rolling average value of the water allocation efficiency ratio over the 90 days prior to day T;

$RWAER_T . V^*$ is the target revenue which is less than the derived optimal revenue; and

S is a slack variable and $S.P_S$ is the associated cost, to allow a feasible solution in the event that the target revenue $RWAER_T \cdot V^*$ is not achievable given the minimum and maximum hourly schedule limits. P_S is some high cost per unit of S.

There are a few significant features for this allocation model. First, the minimum reallocation is achieved by summing the squares of the hourly differences. This leads to the model selecting for example a 1 MW increase in each of two hours rather than a 2 MW change in one hour (since $1^2+1^2 < 2^2$). Secondly, known or deduced flow limits can be represented by upper or lower production limits hourly. Finally, there is a target daily revenue for the reallocation based on the optimal revenue and the 90-day rolling average water allocation efficiency ratio.

[33] The sum of squares is a quadratic loss function that has the property of returning values which are closer to some mean, rather than allowing large and small excursions with the same mean. Other loss functions have similar properties, for example the family (ABS[$E_t^{\ r}$ - $E_t^{\ a}$])^p, p>1, but the quadratic function is simple, more common than

The following is a simplified example of how this might apply.

Assume a 3 hour period in which a 1 MW plant with 1 MWh of water must produce its energy. Prices in the three hours are $80, $100 and $100 per MWh and its original schedule has all the energy in the first hour. The optimal revenue is 1 MWh * $100 = $100. Assuming the average water allocation efficiency ratio is 90 percent, the target value for reallocation of 0.90 * $100 = $90. Assume no plant production limits other than its 1 MW capacity limit.

Table 2: Simplified Reallocation Example

Hour	HOEP ($/MWh)	Actual (MWh)	Revised (MWh)
1	80	1	0.5
2	100	0	0.25
3	100	0	0.25
Total		1	1

Applying the reallocation model leads to moving 0.25 MWh from hour 1 into each of hours 2 and 3. This solution demonstrates that not all the energy must be moved to the highest price hours; only the minimal amount necessary to achieve the target revenue is moved out of hour 1. Secondly, it shows that rather than moving the 0.5 MWh into a single hour, it reallocates the smallest amount possible into each of the two higher priced hours. If there were a flow limit in hour 1, this might be partially respected by the resulting revised schedule.

<u>Measuring Hourly Price Impacts</u>

The rescheduling of ELG described above decreases the HOEP in some hours and increases it in others, depending on whether additional energy has been scheduled into or out of the hour. Because prices are likely to increase and decrease in different hours depending on whether

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others and may be easier to solve as a non-linear programming problem. Solutions can differ depending on the loss function selected and complexity of the problem.

energy is removed or added, the price impact test should incorporate some form of netting of these individual hourly impacts.

This requires estimating revised prices essentially in all hours where rescheduling has occurred, which might be all hours of the day.

To derive the revised hourly price for each hour, the total net change in ELG allocations for the hour can be treated as a single increment (decrement) of available low-priced energy.[34] Because imports and exports might have responded to the different allocation of energy, the pre-dispatch model must be simulated first to identify the possible change in net imports. The net import change then would be fed into the real-time simulations, in addition to the net change in ELG allocation, again represented as a single increment of low-priced energy. The simulated HOEP would be derived by simulating the 12 intervals for the hour and averaging the resulting MCPs.

For example, consider some hour with a HOEP of $150 and a pre-dispatch price of $200 / MWh. The net reallocation for several ELG plants leads to an additional 500 MW of ELG energy for the hour. Adding this to the pre-dispatch results in a pre-dispatch price drop from, say, $200 to $140 and a corresponding decrease of 300 MW of imports. The 500 MW of reallocated ELG less the reduction of 300 MW of imports means there are 200 MW of additional low-priced energy available for the real-time simulations. Assume further that this additional 200 MW of energy leads to a simulated average price for the hour of $120. Given the assumed HOEP of $150, the estimated price effect of the conduct in question would be $30. The example illustrates that the response of imports can reduce the magnitude of the additional energy available in the simulated hour, and by inference can also reduce its simulated price effect.[35]

Market Price Threshold Tests

The market price impact test for ELG must recognize that withholding water from higher price hours increases the market price during those hours but also decreases the market price during

[34] There are various ways to achieve this, such as reducing (increasing) load by an equivalent amount.

lower price hours. The net effect of this conduct on the prices prevailing over the course of a day is the weighted sum of hourly price increases and decreases. This leads to a price impact test that adds the hourly changes:

$$\sum_{h} w_h.(HOEP_h - PE_h{}^c) > threshold$$

where w_h is some weighting, which can give higher weights to hours with higher demand and thus greater impact on loads. For hours h within the 24 hour period T, the weighted price changes are summed and compared with some threshold.

We have explored some of the options for weightings and observed that the weights should be approximately 1.0; individual values can be higher or lower depending on relative market demand in the hours. We had considered hourly weights equal to the portion of total daily market demand, but this effectively reduces the price impact in each hour by a factor of 24. To use hourly weightings we would need to normalize these with the factor 24, so the weight becomes the ratio of hourly demand to the daily average hourly demand. For example, on a day with average market demand of 20,000 MW, two hours with market demands of 24,000 and 16,000 would have weights of 1.2 and 0.8 respectively.

The primary question for this test is how high the threshold should be. To ease comparisons with the price impact test for non-ELG, we re-write the test as:

$$\sum_{h} w_h.(HOEP_h - PE_h{}^c) > n.\$50 / MWh$$

where n is some small number greater than or equal to 1.0, and w_h is the ratio of hourly market demand for hour h to the daily average market demand.

If the threshold were the same as for non-energy limited generation, e.g. $50 per MWh with n=1, the ELG test would be more sensitive to price changes since the non-ELG $50 threshold applies to the change in a single hour, not the total over all the hours in the relevant period. For ELG there could be 5 hours of smaller price effects, adding to $50, which would trigger the test. For non-energy limited generation, smaller price changes of this size would be ignored.

[35] For typical offer curves the additional 300 MW of import energy would create a very noticeable price change.

At the other extreme is setting the ELG threshold to be something like \$50 times the number of hours in the period, or the number of hours where price dropped in the simulation. Unfortunately, this leads to triggering only when the average price impact exceeds \$50. For a case with 2 hours of \$50 price decreases, 2 hours of \$30 decreases and negligible price increases in other hours, assuming n = 4 requires the total net price impact to exceed n.\$50 = \$200. For the 4 hours of price decreases the daily total price impact is only \$160, so no triggering occurs. An average price impact of \$40 is lower than the hourly threshold for non-ELG, but because of the cumulative effect over the day it should not be ignored. Price increases of \$160 in a day are significant.

With \$50 price impact in 2 hours, one might suggest another threshold test based on hourly values only. However, this ignores the effect of off-setting price impacts in other hours, so is not a reliable test either.

Above, we showed an example with n = 1 that could be overly sensitive to triggering, and another with n = 4 that may be too insensitive. These cases suggest a bracket for the threshold range, implying values around n = 2 or 3 are better. These correspond to a daily net price impact threshold between \$100 and \$150. Thresholds in this range will not avoid false positives or false negatives, but these values provide a reasonable tradeoff.

3.3.4 Profit Test

Triggering Step 5 of the Conduct Test subject to the consideration of other factors in Step 6 implies that the actual allocation of water by the market participant involved was significantly less profitable than normal for the specific energy-limited plant. Triggering the price impact test further implied that the change in prices was significant over the day. To conclude that there has been an exercise of market power it must also be shown that that this sacrifice of profit for the

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This is less likely in off-peak hours when price tends to be near the flatter portion of the offer curves.

poorly allocated generation was more than offset by the portfolio effect of higher prices during peak periods.

The profitability test requires a comparison of the actual profits of the market participant involved with the profits realized under the adjusted schedules, E_h^r. The comparison of profits would be done for all hours of the day, or at least those hours where schedules changed. The profit test is triggered if the market participant's profit is greater with the actual allocation.

The expression for the profit test for non-energy limited resources is valid for ELG if applied as a sum of net profit each hour. However that form of the calculation is more difficult to understand for ELG since it separates withheld generation and replacement generation, which are not well-defined for ELG cases where generation may be withheld in one hour and used uneconomically in another. It is more straight-forward to compare daily profit based on actual market schedules (W or withholding conditions) with profit based on competitive market schedules (C or competitive conditions as simulated for the price impact test). Thus the profit test becomes:

$$\sum_h (\Pi_h{}^W - \Pi_h{}^C) > 0$$

where

$$\Pi_h{}^w = \sum_{i \in I} [HOEP_h - C(Q_{ih}^w)].Q_{ih}^w \text{ and}$$

$$\Pi_h{}^c = \sum_{j \in J} [PE_h^c - C(Q_{jh}^c)].Q_{jh}^c$$

for $C(Q_{ih}{}^w)$ the cost of production for generator i at the scheduled level $Q_{ih}{}^w$

$C(Q_{jh}{}^c)$ the cost of production for generator j at the simulated level $Q_{jh}{}^c$

I, all of the market participant's generation actually scheduled, and

J, all of the market participant's generation in the revised competitive schedule.

Where generation is not under contract or subject to regulated prices, HOEP and PE^C in the above expressions represent the actual hourly prices and simulated competitive prices. For any generation which has prices adjusted due to contract or regulation, the adjusted prices would apply and would be used assuming that the contract (or regulated) price was based on the market schedule quantity. This means $HOEP$ is replaced by $HOEP_r$ representing the adjusted (regulated) price for a given $HOEP$ for some generation, and PE^c is replaced with PE_r^c representing the adjusted price corresponding to an hourly market price of PE^c . Where the contract price for some generation is the same in the two cases, irrespective of $HOEP$ or PE^c, and the quantity scheduled is the same, the profit component for this generation would be the same in the two cases and in practice could be removed from the calculation.

We include cost in the profit calculation for all generation in the portfolio. For hydroelectric generation this represents water rental fees and any incremental costs, which tend to be small. Since the total water scheduled is assumed to be the same in actual and simulated cases, the total cost of production for hydroelectric units is essentially constant for the two cases. In practice, the costs for hydro production could also be dropped for the profit comparison.

3.3.5 Questions

In addition to price impact and profit related questions for previous supply types, the Panel is interested in your views regarding the following:

- **Is the concept of an historical allocation efficiency ratio for available water a useful concept? Is there a better way to define the ratio or to apply it?**
- **For the initial implementation we are considering not using production efficiency curves. Under what circumstance would this substantially affect the accuracy of the estimates given that the typical hydroelectric curve is rather flat-bottomed? Can production efficiency curves be adapted to apply to aggregate facilities that are offered?**
- **Is it reasonable when reallocating energy to treat actual minimum hourly schedules as minimum production levels induced by storage level or river flow restrictions? Is there a simple mechanism for deducing how flow restrictions might create upper limits on facility production? Are there simple mechanisms available to provide the MSP / MAU with sufficiently accurate data to model plant and river limitations?**

- **Is there additional data that generators may find useful to provide the MSP/MAU on an ongoing basis that can help explain unusually low allocation efficiency ratios?**
- **The tests for hydroelectric generation rely on ex-post HOEP data and pre-dispatch price data. Are there suggestions for what other publicly available information may have influenced the generator's scheduling decisions?**
- **Regarding the assumed use of market schedules for the assessment, to what extent is water allocated according to anticipated market schedules as opposed to anticipated dispatch schedules?**
- **Please provide comment on the thresholds for the conduct test and price impact test, regarding the underlying concept as well as levels proposed.**
- **How might the 24 hour approach be extended to apply to longer horizons?**
- **The tests for energy limited generation have been developed with hydroelectric plants in mind, but with the expectation these may be applicable to other (fossil) resources as well. What modifications would participants see as beneficial in order to ensure applicability for energy limited fossil generation?**

4 Summary and Process for Consultation

4.1 Summary

This document sets out a proposed framework for assessing the exercise of market power which will aid the MSP in reviewing anomalous events in the market place and possibly contribute to recognizing abuse of market power.

Separate evaluations are described for non-energy limited generation, imports and for energy limited generation. Common to each are the three basic tests under-pinning the framework:

- a conduct test to identify pricing-up, economic or physical withholding,
- a market price impact test to determine if pricing-up or withholding had a significant impact on the market, and
- a profit test to determine if a market participant gained from higher prices across its portfolio.

The MSP proposes that triggering the thresholds for each of these tests constitutes a priori supposition that market power has been exercised. However, the MAU will look for other factors that may be pertinent and may contact a market participant to provide additional information which may explain the results observed.

Conclusions of exercising market power will not lead to sanctions, identification of market participants or any automatic adjustment of offers or prices in the market, beyond those currently incorporated in the Market Rules.

The above tests would be applied only to hours with HOEP above $50 per MWh. Further, it is intended that the tests not be applied in situations where it is unlikely a market participant has profited from this identified situation, which include:

- economic withholding of nuclear generation;
- NUGs which are paid according to contract prices;

- generation contracted to OPA, paid according to contract prices; and
- dispatchable load.

These exemptions do not apply if there is an associated generation portfolio receiving market prices.

4.2 Process for Consultation

The publication of this document has been the first step in the process of consulting with stakeholders to develop this framework. Over the next few months the MSP and MAU will be meeting with participants to provide further explanation about the proposed framework. We wish to hear your questions and comments face to face but will also request formal submissions from you which will be publicly posted. The MAU will also begin informal application of the tests described in this framework, and may in the course of events contact individual market participants regarding their observations. This will serve as a useful dry run for the MSP, MAU and some market participants and inform us about the effectiveness of the methodologies described.

Following the period for formal comments we will provide feedback to you, reporting what we've learned to that point and indicating our initial reaction. Needed modifications to the framework or detail will follow that, with identification and testing of options by the MAU. We expect to publish the details of the final framework in about four months, and at that point we will also begin the process for modifying the data catalogue to add new data which has been identified as necessary for the framework.

We anticipate that these activities should take place over the next several months according to the following plan:

- Publish Framework Discussion Paper
- Begin informal review for behaviours and results identified in discussion paper.
- Solicit public comments from stakeholders and other interested parties.
- Meet with stakeholders to explain proposal and answer initial questions.

- Review comments, including possible one-on one follow-up by MAU and MSP to clarify issues raised.
- Report on comments to date and initial MSP reaction, possibly at a stakeholder meeting.
- MAU / MSP Development and Testing Options.
- Publish Framework
- Begin the process to modify Data Catalogue

4.3 Questions for Discussion

The Panel is interested in hearing your views regarding this framework. We welcome a variety of comments that may range from our identified need for a framework through details about its implementation. The following are just some of the questions to consider.

4.3.1 General

- **Assuming there is currently no significant exercise of market power taking place, do you expect the formal monitoring by the MSP along the lines proposed would alter market participant behaviour, to the detriment of the marketplace?**
- **Given that the three types of tests are required – conduct test, price impact and profit tests - are there better mechanisms for applying these tests for any of the three identified groups of supply?**
- **How can the tests proposed be improved from the viewpoint of:**
    - **more accurately capturing actual exercises, or**
    - **more accurately ruling out events which are not an exercise of market power?**
- **Specifically, are there more effective tests or thresholds that can be applied, taking into account the goal of the MSP is to identify the exercise of market power in order to explain outcomes in the market?**
- **Is there additional information which you believe the MSP will need to conclude there is an exercise of market power?**
    - **Is this fairly static or highly dynamic information?**

- **Can / should market participants be providing this in advance, or only after the MSP identifies events for further review?**
- **Would the provision of such additional data be costly / onerous for the market participants, if provided on an ongoing or occasional basis in advance or in response to specific reviews?**

- **Do you anticipate the occasional interactions with the MAU and the provision of data to require significant additional effort?**

4.3.2 Non-Energy Limited Generation and Import Tests

- **Are the proposed proxies for generation costs reasonable? Is there a better way for the MAU to identify these costs?**
- **Is it reasonable to link import opportunity cost to external market prices, through the proposed historical indices? Is there a better way for the MAU to identify these costs?**

4.3.3 Energy Limited Generation Tests

- **We have proposed accounting for plant and river limitations by modeling the apparent minimum required level of production. Are there other simple mechanisms available to provide the MSP / MAU with sufficiently accurate data to model plant and river limitations?**
- **The daily tests for hydroelectric units rely on ex-post HOEP data and pre-dispatch price data. Are there suggestions for how ex-ante information (forward prices) can be used that would be publicly available, transparent and representative for a variety of market participant decisions, that would be useful for extending the proposed 24 hour analysis to longer storage periods? What other data may be helpful for assessments longer than 24 hours?**
- **The tests for energy limited generation have been developed with hydroelectric plant in mind, but are expected to be applicable to other (fossil) resources as well.**

What modifications would you see as beneficial in order to ensure applicability for energy limited fossil units?

4.4 Changes to the Data Catalogue

To implement the proposed market power framework, market participant's may be asked to provide the MSP additional data under the Market Surveillance Data Catalogue process.

For the framework described in Chapter 3, we have identified the following as data items which could be added to the Data Catalogue:

- start-up costs for fossil units, minimum run times and minimum shut-down times
- average unit heat rate for fossil or nuclear units not currently providing heat rate information and non-fuel incremental energy costs (i.e. variable O&M);
- for newer fossil plant, projected outage rates for the coming year;
- production function or conversion efficiency curves which identify the relationship between hydroelectric facility output (in MW) and the input water required for this level of production. Where there is an aggregated facility, individual curves must be aggregated by the market participant to correspond to the registered facility and the typical structure of their offers.
- corresponding to this, the production level which represents the maximum efficiency point for utilizing water.
- maximum or minimum plant production levels which correspond to water level or river flow restrictions, where these are relatively constant.
- time delay for water to travel between plants on a river system;
- water rental charges.

Appendix A: Treatment of Exercises of Market Power in Other Jurisdictions

A.1 Spectrum of Treatments

The many electricity markets which now exist around the world have a variety of approaches to the exercise of market power. This ranges from the arm's length monitoring of market pricing outcomes through to the identification of unusually high offer prices and intervention in the market through the mitigation of these prices.

In the National Electricity Market in Australia,[36] there is a price cap of $10,000 AUS per MWh. If prices reach this level and are sustained for a period of time (i.e. cumulative prices of $150,000 AUS within a 7 day period), for whatever reason, a lower administrative price is applied as a cap on the market price. There is very limited control over market participant offers themselves. Monitoring of market outcomes (e.g. high prices) and for possible abuse of market power does take place. The only specific restriction on bidding appears to be that once an offer has been submitted it may be changed only once and this may be only for bona fide reasons. If not bona fide, the behaviour may represent a breach of market rules which could lead to a penalty and publication of the incident.

In the U.S. FERC has established expectations regarding the monitoring for the exercise of market power and mitigation of prices offered into the markets. Consequently, U.S. markets include the formal monitoring and possible modification of offer prices. Typically, prices are compared to defined thresholds. If these conduct thresholds are exceeded and other conditions met (e.g. price impact), offer prices may be modified before market prices are determined. These are typically referred to as automated mitigation procedures (AMP).

It is worth describing the tests performed in two of these jurisdictions – NYISO and PJM – for the purpose of comparing the proposed identification procedures for the IESO. It will be seen that the NYISO approach,[37] which is almost identical to that used by ISO New England, has strong similarities to tests and thresholds suggested in this discussion paper.

A.1.1 NYISO

These ISO market power mitigation measures are intended to mitigate the market effects of any conduct that would substantially distort competitive outcomes in the ISO Administered Markets, while avoiding unnecessary interference with competitive price signals.

NYISO monitors for:

a) physical withholding;
b) economic withholding;
c) uneconomic production for the purpose of causing and benefiting from a transmission constraint; and
d) gaming which manipulates prices or impairs the efficient operation of the market

Thresholds have been defined for bidding into the overall market, with additional thresholds specified for constrained areas, which include the In-City area (New York City) and any other area that has been identified by the ISO as subject to transmission constraints that give rise to significant locational market power.

If the behaviour thresholds and market price impacts thresholds are exceeded, the ISO may replace the bid prices with default prices (the reference price) prior to the determination of market prices.

The ISO may implement automated mitigation procedures in real-time for a Generator that is not in a Constrained Area if the ISO, in consultation with the Market Advisor, determines that the bid is inconsistent with competitive conduct, i.e. if the conduct would not be in the economic interest of the Market Party in the absence of market power.

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[36] Undergoing restructuring to AEMC-Australian Energy Market Commission which runs the market, with monitoring and compliance activities going to the AER-Australian Energy Regulator

[37] A recent ruling by the US Court of Appeals for the District of Columbia Circuit has placed some doubt on the extent to which the automated mitigation may be applied. The ruling vacated two previous orders by FERC that

NYISO's AMP is rarely activated for ISO wide mitigation, but is regularly applied in constrained areas.

<u>Conduct Thresholds</u>

a) Thresholds for Identifying Physical Withholding

The thresholds for physical withholding apply to "unjustified" deratings, and the portions of a generator's output that is not bid or subject to economic withholding, but does not include a forced outage or planned outage, subject to verification (as may be appropriate) that an outage was forced.

(i) Withholding that exceeds:
- the lower of 10 percent or 100 MW of a Generator's capability, or
- the lower of 5 percent or 200 MW of a bidding entity's total capability;

(ii) Operating a Generator in real-time at an output level that is
- less than 90 percent of the ISO's dispatch level for the Generator (i.e., basepoint);

For constrained areas, there is an additional threshold based on a minimum quantity criteria.

b) Thresholds for Identifying Economic Withholding

For Energy and Minimum Generation Bids the threshold is:
- A 300 percent increase or an increase of $100 per MWh, whichever is lower.

Energy or Minimum Generation Bids below $25 per MWh shall be deemed not to constitute economic withholding.

NYISO has also defined thresholds for Operating Reserves and Regulation Service Bids, as well as time-based and other bid parameters.

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allowed the ISO to apply AMP in the day-ahead market outside New York City. The issue is whether the ISO has shown a need for imposing such "a heavy hand" outside of heavily congested areas.

For constrained areas, there is an additional threshold based which is:

- 2 percent of the 12 month average price divided by the fraction of the year the generator was in a constrained area.[38, 39]

c) Thresholds for Identifying Uneconomic Production

Uneconomic production that may warrant the imposition of a mitigation measure:

(i) Energy scheduled at a LBMP that is less than 20 percent of the applicable reference level and causes or contributes to transmission congestion; or

(ii) Real-time output from a Generator that exceeds 110 percent of the ISO's real-time dispatch instruction (i.e., basepoint), and causes or contributes to transmission congestion.

Reference Levels

A reference level for each component of a Generator's Bid shall be calculated on the basis of the following methods, listed in the order of preference subject to the existence of sufficient data:

(i) The lower of the mean or the median of a Generator's accepted Bids or Bid components in competitive periods over the previous 90 days for similar hours or load levels, adjusted for changes in fuel prices;

(ii) The mean of the LBMP at the Generator's location during the lowest priced 25 percent of the hours that the Generator was dispatched over the previous 90 days for similar hours or Load levels, adjusted for changes in fuel prices; or

(iii) A level determined in consultation with the Market Party submitting the Bid or Bids at issue, provided such consultation has occurred prior to the occurrence of the conduct being examined by the ISO, and provided the Market Party has provided data on a Generator's operating costs in accordance with specifications provided by the ISO. The reference level for a Generator's Energy Bid is intended to reflect the Generator's marginal costs.

[38] That is, the threshold exceeds the average price if the area is constrained less than 2 percent of the time.

[39] Note, in ISO New England the thresholds are quite similar, except that the constrained area threshold is either 50 percent or $25 above the reference price.

Market Impact Thresholds

Mitigation Measures shall not be imposed unless the identified conduct leads to a material change in prices, or substantially increases guarantee payments to participants.

(i) in the hourly Day-Ahead or Real-Time Energy LBMP at any location, or of any other price in an ISO Administered Market
   - an increase of 200 percent of $100 per MWh, whichever is lower; or

(ii) for Generators in a Constrained Area in guarantee payments to a Market Party for a day
   - an increase of 200 percent, or 50 percent

Automated Mitigation

If the above criteria are met, the ISO may substitute the submitted bid with a default bid equal to the reference level for that component. Automated mitigation procedures shall not be applied to:

(i) to hydroelectric resources or External Generators;

(ii) to bids by a Market Party or its Affiliates for an amount of capacity that totals 50 MW or less;

(iii) if the price effects of the measures would cause the average day-ahead energy price in the mitigated locations or zones to rise over the entire day.

A.1.2 PJM

Automatic mitigation occurs in PJM also, but is only applied in congested areas where there is local market power. Whenever the bid prices exceed the specified offer caps, and there are no more than three pivotal suppliers, the bid is replaced with the offer cap. Offer caps are equal to the units' marginal costs (defined in detail in PJM Manual M-15 as marginal cost plus 10 percent to reflect measurement errors), submitted daily by the units' owners and subject to verification by the Market Monitoring Unit. Offer capping occurs only when the otherwise applicable unit offer would have resulted in a market price greater than the competitive level, defined as the marginal cost of the marginal unit.

As reported in the recent State of the Market offer, capping levels increased slightly in 2004 because of congestion and a larger service territory, but remained low overall.[40]

Applicability

Any time that any generation resource is dispatched out of economic merit order to maintain system reliability as a result of limits on transmission capability and the relevant market (need for constraint relief and incremental effective supply available to relieve the constraint) to resolve the constraint has no more than three pivotal suppliers, the offer prices for energy from such resource shall be capped at the levels specified below. This evaluation is done in real time in the Balancing Market and during the actual clearing of the Day Ahead Market on an hourly basis. If possible offer prices shall be capped only during each hour when the transmission limit affects the schedule of the affected resource, and otherwise shall be capped for the entire Operating Day.

The energy offer prices as capped shall be used to determine any Locational Marginal Price affected by the offer price of such resource. Generation resources subject to an offer price cap shall be paid for energy at the applicable Locational Marginal Price. In other words, units with local market power may not set the LMP at a level in excess of marginal cost but receive the higher of the otherwise applicable market price or their offer cap.

Offer price caps do not apply when relieving the Western, Central and Eastern reactive limits in the PJM Control Area or other transmission limit as to which the FERC has determined that offer price caps shall not be applicable. It has been determined that there is not likely to be significant local market power when these major interfaces are constrained.

Similarly, offer price caps shall only apply for an hour in which there are three or fewer generation suppliers available for redispatch that are jointly pivotal with respect to the

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[40] PJM 2004 State of Market; Market Monitoring Unit; March 8, 2005

transmission limit. If the Market Monitoring Unit determines that a reasonable level of competition will not exist with more than three suppliers, it may propose removal of the restriction to FERC.

Offer capping does not apply to certain generation resources constructed during a period when PJM rules provided for an exemption from offer capping, since removed by FERC. However, if the PJM Market Monitor concludes that such a generation resource exercises significant market power, PJM may request that FERC remove the exemption.

Level

The offer price cap shall be one of the amounts below, specified in advance by the Market Seller for the affected unit:

(i) the weighted average Locational Marginal Price at the generator bus during a specified number of hours during which the resource was dispatched for energy in economic merit order;

(ii) the incremental operating cost of the generation resource plus 10 percent;

(iii) for a unit that is offer capped for 80 percent or more of its run hours, the incremental operating cost of the generation resource, plus the higher of $40 per megawatt-hour or the agreed unit-specific going forward costs; or

(iv) an amount determined by agreement between the Office of the Interconnection and the Market Seller.

In practice only options (i) and (ii) have been applied by PJM. The cost plus $40 per MWh cap was recently introduced to help ensure that units running primarily under offer caps receive revenue adequate to cover annual costs.

Appendix B: Import Reference Offer Index

B.1 Example Calculations of Import Reference Offer Index

An initial set of Reference Offer Indices (ROI) and threshold values have been developed to demonstrate the nature of these numbers. Table B-1 shows the average value and the threshold for the 5 intertie groups. In this table we have aggregated imports from the various Quebec interties into a single set of factors. Values are based on the period from December 1, 2004 to November 30, 2005.

The ROI averages for this period range from 0.11 up to 1.14. Values at the Manitoba and Minnesota interties tend to be smaller. This appears to be related to two factors: prices for energy in this area tend to be lower (because of the lower cost coal and hydroelectric available); and flows from the northwest part of the province are often limited leading to resources being constrained off. The ROI average at the Michigan intertie also appears to be lower than the New York and Quebec interties, likely the result of lower-priced generation typically available through this intertie. The ROI for New York are close to 1, indicating that the offers from New York tend to track the price in New York, which is commonly close to the maximum price in the area.

Several of the thresholds exceed 1 because of the size of the standard deviation for the particular intertie. Again the threshold is defined as:

$$ROI_i + 2 * \text{standard deviation}$$

The thresholds tend to be the highest for the Quebec and New York interties.

For example, from the table the threshold factor for the interval from 150-199 MW at the New York intertie is 1.63. If the highest external market price was $100 CDN based on this threshold factor, any import offer at the New York intertie in the range 150 to 199 MW and which is higher than 1.63 * $100 = $163 would be flagged for further review. (Note this is an illustrative example only.)

B.1.1 Test for Homogeneity of Import Offers across Interfaces

The MAU conducted some statistical tests on earlier sample data to examine whether the laminated import offers on an interface can be analyzed as a single group of offers on that interface. If this is true, then there would be no need to partition the import offers into various laminations on an interface. In that case a single reference offer index and a single threshold can be used to assess all import offers on an interface. A single lamination has the advantage of providing more points within a give period, allowing a shorter period than 365 days for developing meaningful statistics.

The test results strongly rejected the aggregation of import offers on the interfaces. Although the statistical results are not shown, looking at the averages in Table B-1 across laminations for an intertie shows the considerable variation of the averages for the laminations. Based on the statistical evidence, the MAU has provided data using partitioned import offers.

Table B-1: Threshold factors for Five Interfaces in Ontario

Dec 2004 to Nov 2005

	Michigan		Manitoba		Minnesota		New York		Quebec	
Interval	**Threshold**	**ROI**	**Threshold**	**ROI**	**Threshold**	**ROI**	**Threshold**	**ROI**	**Threshold**	**ROI**
0 - 49	1.20	0.70	1.12	0.38	1.02	0.45	1.56	0.97	1.60	0.76
50 - 99	1.29	0.72	0.51	0.15	0.92	0.51	1.62	0.88	1.58	0.89
100 - 149	1.42	0.80	0.41	0.11			1.69	0.96	2.87	0.94
150 - 199	1.26	0.73	0.73	0.25			1.63	1.01	2.01	1.04
200 - 249	1.39	0.77	0.77	0.28			1.59	0.98	1.65	1.00
250 - 299	1.35	0.72	0.93	0.44			1.47	1.00		
300 - 349							1.56	1.05	1.55	0.98
350 - 399									1.56	0.97
400 - 449							1.67	1.14	1.48	0.96

Appendix C: Further Comments on the Assessment for Energy Limited Generation

The specification of the approach in the conduct test and price impact test for ELG is based on three important assumptions, related to the efficiency of converting water to energy, the possibility of spilling of water, and the role of constrained versus unconstrained schedules. These are described below. In addition we provide a formal statement of the optimization implicit in the ELG ideal allocation for Step 2 in the conduct test.

C.1 Assumptions

The first assumption in the ELG assessment is that the efficiency of converting water to energy is assumed constant over the range of scheduled values. We know there are variations in efficiency depending on output level and head (how far the water drops), so this assumption implies that the variations in efficiency are not that large, or that scheduling always occurs at the same level, nominally the maximum efficiency point for the generation. Neither of these is necessarily the case although there may well be a tendency to schedule units at efficiency – except when prices spike or so much water is available the units would tend to run flat out at maximum gate and production. The alternative to this assumption is to account for varying efficiency in the calculations, which may require the MSP requesting facility production functions (conversion efficiency curves) for each ELG, aggregated to be consistent with any aggregated facilities offered. Obtaining the data should be possible through a modification to the data catalogue process, but we anticipate there could be issues associated with representative curves for aggregated facilities, and their application.

The second assumption being made is that spilled water could not have been avoided. In general, it would not be efficient for an ELG to spill water, although during certain periods of the year this may occur as a natural outcome of the supply demand balance, when baseload plant availability exceeds demand, or simply when water exceeds the storage capacity and the maximum flow allowed through the generation. It is assumed that spilled water cannot contribute to providing additional energy.

The final assumption relates to the use of the market schedule quantities. We should say at the outset that neither the market schedule nor constrained schedule is perfect for the tests being performed. We wish to determine how much water / energy was available to the market participant for scheduling and how the resulting schedules interact with market prices.

The constrained schedule is attractive in that it is a truer representation of actual water / energy available. Given that actual production is similar to the constrained schedules, these approximate the actual energy flowing into the plant or released from storage. Seemingly, the allocation problem is to schedule this water to optimize value. But given that we are focusing on impacts on market price, one cannot simply reallocate constrained production. Constrained on energy cannot be moved from the period it was scheduled, even though price was too low, since it was required by the IESO. Similarly, energy cannot be moved into periods when constrained off, even though price may be attractive, because this could violate some security constraint. Clearly, we cannot compare constrained schedules and reallocated market schedules.

More importantly, the total constrained schedule energy likely does not equal the unconstrained energy. There are two extreme cases which can illustrate this. During certain conditions in the north, hydroelectric plant must be run off-peak. When this coincides with limited water in storage and low daily flows to the plant, hydro facilities may be constrained on in the early morning or overnight, leaving no energy for day-time production. As a consequence, there could be little or no energy appearing in the on-peak market schedules. Reallocating the constrained on water to higher priced periods would simply result in misleading conclusions about the plants' possible scheduling. The second extreme case is the plant with a few hours of water that is constrained off in all hours when it appears in the market schedule. The constrained schedule energy would be zero and the plant would not be evaluated. However, this generator may be no less likely to be attempting to exercise market power, which might be observed if all the scheduling occurred only in off-peak periods.

We do recognize that market schedule quantities are also not perfect. The main limitation is that the same energy may be scheduled several times in a day, if it were constantly being constrained off. This overstates the actual energy available, but oddly does not overstate the total energy which influences market prices. There may be some theoretical objections to rescheduling this energy, e.g. rescheduling more energy than is really available. However, this may not lead to the wrong conclusion, if for example water was being offered off-peak when it was less economic.

To summarize, a large portion of the constrained schedule energy may not be discretionary, so it could be misleading to use this for modifying market schedules. Since the market power framework in general focuses on market schedules and impacts on market prices, we have selected the market schedules for ELG as the basis for testing.

C.2 Ideal Allocation

The ideal allocation described for ELG in Step 2 of the conduct test uses the available energy in the highest priced hours. In Step 2 the ideal revenue was described as simply the sum of the highest HOEP for the hours of available water. More formally, the ideal revenue and corresponding ideal allocation is derived from the following optimization model:

$$Max : \sum_h (E_h^r.HOEP_h) \qquad \text{daily revenue}$$

subject to

$$E_h^r \leq \overline{E}_h \qquad \text{plant scheduling limit for hour h}$$

$$\sum_h E_h^r = \sum_h E_h^a \qquad \text{total energy scheduling equality}$$

where E_h^r are revised hourly energy schedules; and

E_h^a are the actual hourly energy schedules

and the maximum revenue possible from the scheduled energy becomes $V^* = \sum_h (E_h^*.HOEP_h)$

where E_h^* is the ideal hourly allocation for hour h.