Introduction to Ontario's Physical Markets

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AN IESO MARKETPLACE TRAINING PUBLICATION

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Table of Contents

Introduction

This course introduces the rules and processes for trading energy within Ontario. You will learn how participants buy and sell energy products in Ontario's IESO-administered markets and how the price for these products is established. You will also learn how physical limitations impact the price of energy in Ontario.

The course is intended to introduce the components of Ontario's physical markets one piece at a time. The course begins with an explanation of the types of market participants. From there, we look at how certain participants offer to supply electricity or bid to buy electricity. We begin by considering simple bids and offers, then introduce multiple bids and offers and the concepts of marginal cost and marginal benefit.

Once the basis for bids and offers is established, we move on to how the price of electricity in Ontario is determined. From here, we discuss how the IESO determines the amount of electricity participants will supply or consume. This introduces concepts such as losses and constraints. These losses and constraints create the need to compensate some participants through the use of congestion management settlement credits.

By this point, we will have introduced most of the major concepts involved in Ontario's physical markets. The next step is to discuss the timing of bids and offers in Ontario, as well as the timing of reports the IESO makes available to participants. Finally, we discuss the treatment of operating reserve in Ontario's market.

If, after completing this course, you require further detail on energy trading in Ontario, you can refer to Modules 5-7 in the Ontario Energy Trading capability course, as well as the Market Participant Interface Training Manual, all available on the IESO web site at
www.ieso.ca/iesoweb/marketplaceTraining/training_overview.asp

Principles of the IESO-controlled Markets

The Market Rules, which govern the Real-time Energy Market in Ontario, have been written to reflect the six guiding principles outlined in Appendix One. While all six principles are reflected in all the rules, the discussion in this document is strongly influenced by three of the principles

1) Efficiency
2) Fairness
3) Reliability

The rules governing the buying and selling of energy products through the IESO-administered markets must balance these three principles. It is essential that energy costs to consumers be kept as low as possible. At the same time, the supply of electricity must meet high reliability standards, both today and in the future. Finally, it is essential that the IESO-administered markets operate in a fair manner, with unbiased access to the market. This means there cannot be artificial barriers to participating in the market. Any requirements that may limit participation in the market must reflect legitimate requirements to protect the market and other market participants.

1. Types of Market Participants

Ontario's IESO administers the wholesale electricity market and controls the transmission grid in Ontario. The term "market participant" refers to any company participating in any of the IESO-administered markets.

Objectives

After completing this section, you will be able to:

- Identify the different types of participants in the IESO-controlled markets
- Distinguish between dispatchable and non-dispatchable facilities

In order to become a market participant, you must first register with the IESO and pay an application fee. There may be additional registration requirements depending on which role you wish to play in the IESO-administered markets. It is also possible for a market participant to play more than one role in the market. For example, a market participant could be both a generator and a wholesale supplier.

There are different ways to classify the types of companies that participate in the IESO-administered markets. One classification is based on the company's physical assets. Some companies have their own equipment that produces or uses electricity; some companies participate in the market without actually producing or using electricity.

Companies with physical assets may be connected directly to the IESO-controlled grid, or they may be "embedded". Embedded companies are connected to a distributor, who is either connected directly to the IESO-controlled grid or to another distributor who is connected directly to the grid.

Participants with Physical Facilities (may be directly connected to the IESO-controlled grid or may be embedded)
Transmitters (the IESO-controlled grid is composed of transmitters' physical facilities) Distributors Loads Generators

Participants without Physical Facilities
Wholesalers Financial Market Participants Retailers

1.1 Physically Connected Market Participants

While many companies may choose to participate in the IESO-administered markets, any company with equipment directly connected to the IESO-controlled grid to convey electricity into, through or out of the grid **must** become a market participant.

Market participants who are connected to the grid can be further classified according to their interaction with Ontario's IESO. It is also important to know how they are compensated or charged. In the case of generators and loads, we also need to know if they are dispatchable or non-dispatchable.

Transmitters

The term *transmitter* refers to the market participants who own the equipment that makes up the IESO-controlled grid. Transmitters do not buy or sell energy; rather, they add value by creating and maintaining the grid that connects generators and wholesale loads throughout the province.

Transmitters are compensated by an approved uplift (overhead) charge applied to all electricity purchased through the IESO-administered market.

Distributors

The term *distributor* refers to the local distribution company (LDC) which takes electricity from the IESO-controlled grid and distributes it to retail consumers. Distributors add value by delivering electricity directly to retail consumers, at the appropriate voltage for their needs. Distributors are compensated by payments made to them by their own customers.

The Ontario Energy Board is responsible for licenses and regulations related to distributors. Your local municipal utility is an example of a distributor.

GENERATORS

Dispatchable Generators

Dispatchable generators must be able to adjust the amount of their generation in response to instructions from the IESO. These instructions are called “dispatch” instructions, and the generators are called “dispatchable”.

The IESO issues dispatch instructions for each 5-minute interval of the day. Dispatchable generators must be equipped to receive and respond to dispatch instructions from the IESO 24 hours a day, 365 days a year.

The dispatch instructions to reach a specific level of generation are based primarily upon the generator’s offers to sell electricity at specific prices relative to the bids and offers from other facilities. For example, a generator may agree to sell 50 megawatts (MW) of energy if the price is $22/MW or higher, but may not wish to sell if the price is lower than $22. If there is demand for energy priced at $22 or more, the generator will receive dispatch instructions from the IESO telling it the amount to generate. If the only demand is for energy priced below $22, the IESO will send dispatch instructions telling the generator not to generate the 50 MW.

Most of the energy supply in Ontario is provided by dispatchable generators

Non-Dispatchable Generators

Non-dispatchable generators do not submit offers to provide energy; instead, they submit estimates or forecasts of energy production. They agree to be paid the current market price when they generate electricity, regardless of what that price might be.

There are three types of non-dispatchable generators: self-scheduling, intermittent and transitional scheduling generators (a temporary category of generation facility, which operates essentially as a self-scheduling generator).

- An example of a self-scheduling generator is a generator running on hydraulic power from a small river. If the generator has no ability to store the water, it might not always be able to provide energy in response to IESO dispatch instructions. This type of generator would register as self-scheduling. Self-scheduling generators submit schedules to the IESO indicating the amount of energy they will be providing for each hour of the day. Self-scheduling generators are restricted by size - in order to be classified as self-scheduling, a generator must be rated between 1 and 10 MW.

- Intermittent generators have even less ability to forecast the amount of energy they will generate. They operate intermittently as a result of factors outside the owner’s control. For example, a windmill is classified as an intermittent generator because it must rely on wind for its operation.

Cogeneration Facilities

A cogeneration facility produces electricity as well as another form of useful energy (such as steam) which is used for industrial, commercial, heating or cooling purposes. Typically, the facility's main product is the other form of energy, with electricity as a by-product.

Most existing cogeneration facilities previously fell under the "non-utility generation (NUG)" category. A cogeneration facility may now register to participate in the IESO-administered markets as one of the following:

- Dispatchable generator
- Self-scheduling facility (even if the facility is rated over 10 MW)
- Intermittent generator

The impact of producing other forms of energy within the facility may affect electricity production; therefore, a cogeneration facility may be allowed to operate under wider compliance bands than other generators.

LOADS

Dispatchable Loads

As with dispatchable generators, dispatchable loads must be able to adjust their power consumption in response to instructions from the IESO. These instructions are called "dispatch" instructions, and the loads are called "dispatchable".

The IESO issues dispatch instructions to dispatchable loads for each 5-minute interval of the day, and the loads must be equipped to receive and respond to dispatch instructions from the IESO 24 hours a day, 365 days a year. (Dispatchable loads account for only a small portion of the energy consumed in Ontario at this time.)

The dispatch instructions to reach a specific level of consumption are based primarily upon the load's bids to purchase electricity at specific prices relative to the bids and offers from other facilities. For example, a load may submit a bid to purchase 20 MW of energy if the price is $25/MW or below, but may not wish to purchase if the price is higher than $25. If there is available energy that costs $25 or less, the load will receive dispatch instructions from the IESO telling it how much energy to withdraw from the grid. If the only available energy costs more than $25, the IESO will send dispatch instructions telling the load not to withdraw the 20 MW from the grid. The dispatch instructions must also take into account the facility's ability to adjust its energy consumption levels.

Non-Dispatchable Loads

Non-dispatchable loads consume electricity in much the same way as you do at home. They simply draw electricity from the IESO-controlled grid as needed for their equipment. They agree to pay the wholesale market price for electricity at the time of consumption, regardless of what that price might be. Examples of non-dispatchable loads include municipalities, hospitals, and large factories. Wholesale prices for non-dispatchable loads are set on an hourly basis.

Some non-dispatchable loads act as distributors; that is, they take electricity from the IESO-controlled grid (or from another distributor) and distribute it to retail consumers at a lower voltage. (Your local municipal utility is an example of a distributor.)

Non-dispatchable loads account for most of the energy consumed in Ontario.

Embedded Facilities

Embedded facilities are not connected directly to the IESO-controlled grid. Instead, they are connected to a distributor, who, in turn, is connected to the grid.

Rules regarding embedded consumers vary according to the volume of electricity consumed.

Regulations under Bill 4 and Bill 210 set interim electricity prices for low volume retail customers and certain designated consumers. Bill 100 supersedes these regulations, but prices for these consumers will continue to be regulated under the Regulated Price Plan, which took effect April 1, 2005. This price applies to residential, small business and designated consumers, such as schools, hospitals, and qualifying farms.

Large-volume embedded facilities have a choice as to how they interact with the wholesale electricity market. They may contract with the distributor to buy or sell electricity, or they may choose to become a market participant. If the embedded facility becomes a market participant, it may buy or sell energy through the real-time markets and may also enter into physical bilateral contracts.

1.2 Market Participants without Physical Facilities

Many companies will participate in the IESO-administered markets without having physical facilities that produce or consume electricity. These companies may participate in both the real-time markets and the financial markets.

Wholesalers and Retailers

Wholesalers buy energy on the wholesale market, and sell energy and services to other market participants; retailers sell energy and services to consumers at the retail level (that is, they may sell to non-market participants). Both wholesalers and retailers are re-selling electricity rather than producing electricity themselves. They may also act as importers or exporters. Importers bring energy products into Ontario from one of the five neighbouring jurisdictions: Quebec, Manitoba, Michigan, Minnesota or New York. Exporters export electricity from Ontario into these neighbouring jurisdictions.

1.3 Financial Markets

Market participants may also participate in the IESO-administered financial markets. These markets do not affect the actual delivery of electricity. The financial markets allow market participants to reduce price risks. They involve the transfer of funds only; they do not involve the transfer of energy.

The transmission rights market is the only IESO-administered financial market that is currently operating.

The Transmission Rights (TR) Market

Prices in Ontario may be different from prices in other jurisdictions. The use of Transmission Rights, or TRs, allows importers and exporters to reduce the price risk associated with trading between Ontario and jurisdictions outside of Ontario.

1.4 Skill Check: Types of Market Participants

1. Select the two correct statements:
   a) You can be a market participant even if you have no physical facilities.
   b) All market participants must be directly connected to the IESO-controlled grid.
   c) All companies with equipment that is directly connected to the IESO-controlled grid must be market participants.
   d) A company may play only one role in the IESO-administered markets.

2. Match the correct term from Column B to the statement in Column A

	COLUMN A	COLUMN B
__	1. Supply most of the energy in Ontario	a. Transmitters
__	2. Account for most of the energy consumed in Ontario	b. Distributors
__	3. Supply energy to retail customers	c. Dispatchable Generators
__	4. Own the equipment that makes up the IESO-controlled grid	d. Non-dispatchable Generators
__	5. Not directly connected to the IESO-controlled grid	e. Dispatchable Loads
__	6. Must be able to adjust power consumption in response to instructions from the IESO	f. Non-dispatchable Loads
__	7. Submit forecasts of energy production to the IESO	g. Embedded Facilities
__	8. Your local municipal utility is an example of one	
__	9. A windmill is an example of one	
__	10. Consume electricity in much the same way you do at home	

3. Transmission Rights:

   a) are used to ensure prices in Ontario are identical to prices in other jurisdictions

   b) are used to reduce price risk associated with trading between Ontario and other jurisdictions

   c) market will open in 2005

Skill Check: Answers

1. Select the two correct statements:

   a) **You can be a market participant even if you have no physical facilities.** 4
   b) All market participants must be directly connected to the IESO-controlled grid.
   c) **All companies with equipment that is directly connected to the IESO-controlled grid must be market participants.** 4
   d) A company may play only one role in the IESO-administered markets.

2. Match the correct term in Column B to the statement in Column A

Answer	COLUMN A	COLUMN B
c	1. Supply most of the energy in Ontario	a. Transmitters
f	2. Account for most of the energy consumed in Ontario	b. Distributors
b	3. Supply energy to retail customers	c. Dispatchable Generators
a	4. Own the equipment that makes up the IESO-controlled grid	d. Non-dispatchable Generators
g	5. Not directly connected to the IESO-controlled grid	e. Dispatchable Loads
e	6. Must be able to adjust power consumption in response to instructions from the IESO	f. Non-dispatchable Loads
d	7. Submit forecasts of energy production to the IESO	g. Embedded Facilities
b	8. Your local municipal utility is an example of one	
d	9. A windmill is an example of one	
f	10. Consume electricity in much the same way you do at home	

3. Transmission Rights:
   a) are used to ensure prices in Ontario are identical to prices in other jurisdictions
   b) **are used to reduce price risk associated with trading between Ontario and other jurisdictions** 4
   c) market will open in 2005

2. Bids and Offers: The Basis for Determining Market Prices

The price of energy in the IESO-administered market is based on the market forces of supply and demand, within the constraints of the physical limitations imposed on the market. In the IESO-administered physical markets, the price for electricity is established independently of dispatch instructions. The market prices discussed in this course pertain only to energy purchased or sold within Ontario; price determination for imports and exports is not covered.

In this section and in Section 3, you will learn how the market clearing price (MCP) is established and how dispatchable and non-dispatchable facilities impact the MCP. In later sections we will examine what happens when we introduce losses and other constraints.

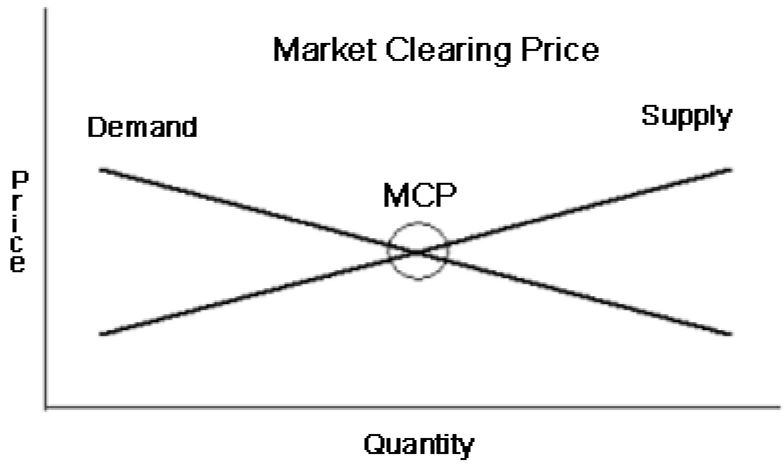
Objectives

After you have completed this section, you will be able to:

- List the unique features of electricity
- Explain the basis of a marginal cost offer and a marginal benefit bid for electricity

2.1 Bids and Offers in the Ontario Real-time Energy Market

In a competitive market, prices are set based on supply and demand. The total quantity of a product demanded will tend to increase as the price of the product drops while the total quantity of product produced will tend to increase as the price of the product increases. A stable price occurs when the price provides enough incentive to produce the quantity demanded.



In the case of electricity, some forms of generation have higher production fuel costs than others. If the price of electricity were not sufficient to cover the cost of the fuel used to produce the electricity, the company would be better off not running their plant. At the same time, if the price of electric heating is high relative to the cost of heating with oil, consumers will, over time, tend to move toward alternatives such as oil heating, reducing the demand for electricity.

The market clearing price for electricity in Ontario is set based on offers to produce electricity and bids to consume electricity. Offers from generators create supply, and bids from users (loads) create demand for electricity.

It is also important to remember that electricity is a unique commodity:

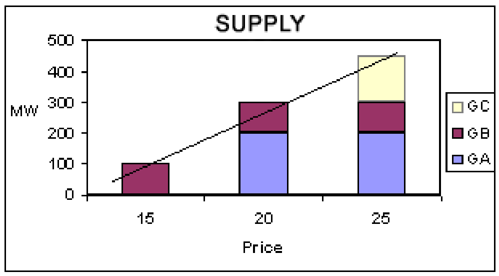
- Electricity cannot be effectively stored in large quantities
- In order to maintain electricity quality within defined standards, the production of electricity must match the consumption of electricity on a continuous basis
- Suppliers and consumers must be linked through physical transmission facilities. These facilities have inherent losses as well as limitations on how much electricity they can carry.

As we will see throughout this course, these features have a great impact on the price of electricity in the IESO-administered markets.

2.2 Offers from Dispatchable Generators

Dispatchable generators participate in the IESO-administered markets by offering electricity to the market for a given price. For example:

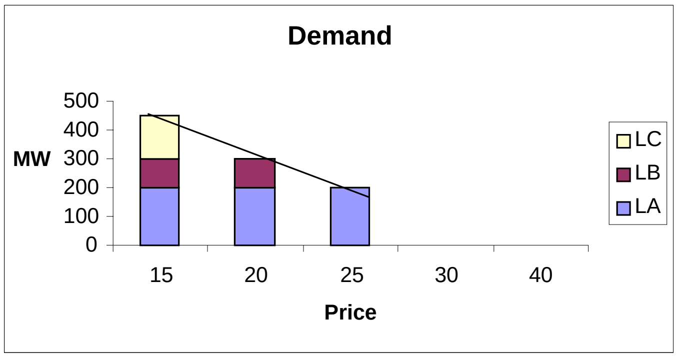
- Generator A is willing to provide 200 MW of electricity if the price is $20/MW or above
- Generator B is willing to offer 100 MW if the prices is $15/MW or above
- Generator C is willing to offer 150 MW if the price is $25/MW or above



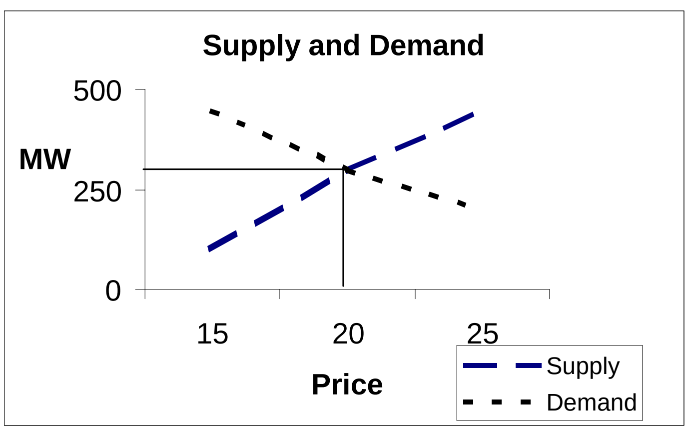
2.3 Bids from Dispatchable Loads

Just as generators place offers on the supply side, loads will bid for electricity consumption based on the price.
For example:

- Load A is willing to consume 200 MW if the price is $25 or below
- Load B is willing to consume 100 MW if the price is $20 or below
- Load C is willing to consumer 150 MW if the price is $15 or below



Putting the supply and demand together, we see that if this simple example represented the market, the market-clearing price for electricity would be $20 (the point where the supply and demand intersect).



At a price of $20, 300 MW of electricity will be consumed. This means that Generator C will not produce any electricity, and Load C will not consume any electricity. Note that all loads pay $20 per MW and all generators receive $20 per MW; the market clearing price is the same for all dispatchable generators and dispatchable loads within Ontario.

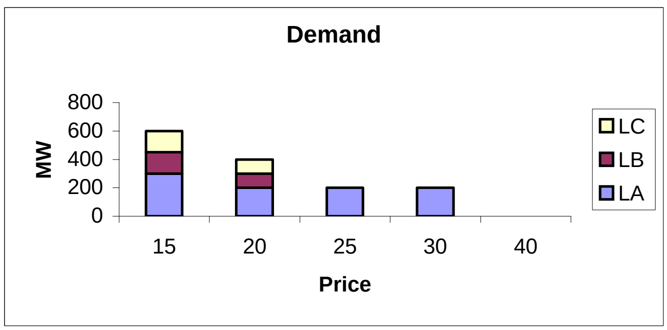
Of course this is a simplified example. There will be many generators offering energy and many loads bidding for energy in the market. In addition, as discussed below, the market rules also allow for companies to place multiple bids and offers.

2.4 Multiple Bids and Offers

The market rules allow participants to place multiple bids or offers for the same time period. A participant may place up to 20 bids or offers for any given time period. This means that they can adjust their energy consumption or production based on price.

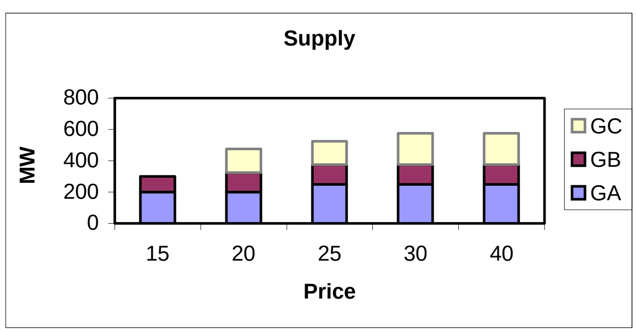
For example:

- Load A is willing to consume 300 MW if the price is $15 or under, but only 200 MW if the price is between $15 and $30, and none if the price is above $30
- Load B is willing to consume 150 MW if the price is under $15, but only 100 MW if the price is between $15 and $20, and none if the price is above $25
- Load C is willing to consume 150 MW if the price is under $15, 100 MW if the price is between $15 and $20, and none if the price is above $20



On the supply side:

- Generator A is willing to provide 200 MW of electricity if the price is between $15 and $20/MW, and another 50 MW if the price is above $20
- Generator B is willing to offer 100 MW if the price is between $10 and $15/MW, and another 25 MW if the price is above $15
- Generator C is willing to offer 150 MW if the price is between $20 and $25/MW, and an additional 50 MW if the price is above $25/MW



2.5 Marginal Cost Offers

The previous discussion of multiple bids and offers implies that a single participant will have different preferences on the quantity of electricity to consume or produce depending on its cost. The market rules have been written assuming that participants will base their offers on the marginal cost of producing electricity, and will base their bids on the marginal benefit of consuming electricity.

Marginal cost refers to the increase in total cost to produce the next megawatt of electricity. Capital costs (e.g., plants, buildings, vehicles, etc.), and even labour, are generally independent of the amount of electricity produced in the very short term. Therefore, capital costs are considered 'fixed'. Marginal cost, or the cost that changes with the amount of electricity produced, is strongly influenced by fuel cost.

As a simple example, assume a combustion turbine capable of producing up to 100 MW requires $35 in fuel to produce one additional MW when operating at 70 MW. This would mean a marginal cost of $35. Since the only increased expenditure for the additional MW is the fuel cost of $35, any market clearing price above $35/MW would lead to increased profits for the company if they produced one more MW.

While the total costs of production, including fixed costs such as rent, may be greater than $35, the company is still better off producing power if the revenue is greater than the marginal cost. Any revenue above marginal costs can be used to pay off some of the fixed costs. In the longer term, a company must be able to recover both marginal and fixed costs to remain viable; however, in the short term, operating decisions are usually based on marginal costs.

It is quite possible, however, that the efficiency of the turbine will vary depending on where it is operating. For example, operating efficiency might be lower at 80 MW than at 70 MW. This would mean the marginal cost of additional energy would be higher, possibly $38 instead of $35. A market price of $35 would not induce the owner to produce additional energy at this point, as they would be $3 worse off for each additional MW produced. At this point, the participant requires at least $38 to induce increased output.

The market rules have been written to recognize varying production costs for electricity. A participant offering energy into the market can split their offer into up to 20 price-quantity pairs. For example the participant could offer up to 70 MW if the price is $35, with an additional 10 MW offered if the price is $38.

2.6 Marginal Benefit Bids

Just as generators face marginal costs, loads face marginal benefits (or "profits") from using electricity. The following example demonstrates how a dispatchable consumer may decide how much electricity to purchase at a given price. We can examine this by starting with a simple examination of the impact of electricity prices on total cost, then move to a more complicated example.

First, consider Powercorp, which produces a product called widgets that sell for $150.

The total cost to produce 10 widgets is $1,000 plus the cost of electricity. The total revenue from these 10 widgets is $1500. Provided the cost of electricity is below $500, Powercorp will be better off consuming the electricity and producing the 10 widgets:
Cost = $1,000 + electricity
Profit = $1,500 - Cost

If we assume the total cost of producing 15 widgets is $1300, how much should Powercorp be willing to pay for the electricity to produce those five additional widgets?

The cost of the five additional units is the increased cost to the company of producing five units, or $300, plus the cost of the electricity:
Marginal cost of five units = ($1,300 - $1,000) + increased electricity = $300 + electricity

1. The increased revenue from the five additional units is $750:
   Marginal Revenue = 5 **x** $150 = $750

At the break even point 0 = 750 - $300 - cost of additional electricity
Cost of additional electricity = $450

As long as the additional revenue is greater than the additional cost, Powercorp is better off producing the five additional units. So, if the cost of the *additional* electricity is less than $450, Powercorp should buy the electricity and produce the units. From a marginal cost point of view, Powercorp will be better off if it pays up to $500 for enough electricity to produce 10 units, and up to $950 for enough electricity to produce 15 units.

In this case, we examined a company that was operating below their peak efficiency. Their cost per unit became lower as they increased the number produced. Now let's examine a situation where the company is already operating at their peak efficiency. Rather than looking at total cost, let’s look at per unit costs. Again, consider Powercorp's facility. We know the following:

A widget sells for $150 and the widget market is very strong. Powercorp can sell as many widgets as they can make. At the same time, widgets are a commodity and their price is fixed at $150

Each widget requires:

- One hour of labour, at $20 per hour
- $75 in materials (Powercorp has a long term contract for these materials)
- Exactly 1 MWh of energy is required to produce one widget

Powercorp has strict internal policies that employees cannot be sent home during a shift. The normal staff level is sufficient to produce 100 widgets per hour. Additional staff can, however, be brought in to deal with increased production demands.

Cost per widget if production is below 100:

- Labour: $20
- Material: $75
- Electricity: 1 MWh

But should labour be considered a marginal cost? Does the labour cost to Powercorp increase if they decide to produce an additional widget?

Because Powercorp’s labour stays the same whether one or 100 widgets are produced, labour costs are fixed within the shift. Since the cost of labour is fixed for the duration of the shift, it should not be used in deciding whether to produce an additional widget – up to 100 widgets. (In the same way, the cost of rent, taxes and other overheads do not play into the decision on how many widgets to manufacture that day.)

So, how much can Powercorp pay for electricity, and still be able to cover its costs? When the cost is exactly covered, the profit – or marginal benefit - will be zero.

To determine the price Powercorp is willing to pay for electricity, Powercorp will look only at marginal costs:

Marginal benefit per widget equals the price of a widget, minus the cost of producing one extra widget, or:
Marginal Benefit = Price - Marginal Cost

Since the Marginal Cost is equal to the cost of electricity plus the cost of material, the equation becomes:
Marginal Benefit = Price - (Cost of 1 MWh + Material)

If we set the marginal benefit to zero, the price of the widget will *just* cover the cost of producing it.
Price = Cost of 1 MWh + Material
So, to determine what Powercorp is willing to pay for 1 MWh:

Cost of 1 MWh = Price - Material = $150 - $75 = $75

Thus, for producing up to 100 widgets, Powercorp should be willing to pay up to $75 per MWh. Powercorp's bid for electricity would reflect consumption of 100 MWh for a price up to $75, but zero for a price above $75.

If the price of electricity is lower than $75, Powercorp increases its marginal benefit (which is used to pay for fixed costs and profit). If the price of electricity is above $75, Powercorp loses money on each widget it produces, so there is no benefit in operating.

We mentioned above that Powercorp could bring in additional staff to deal with increased production. In fact, when Powercorp wishes to produce more than 100 widgets, they can do so by doubling their labour. If Powercorp doubles their labour, they can produce 150 widgets per hour with the same equipment and material.

Widget production cost becomes:

- 2 hours labour at $20 per hour
- Material costs of $75
- Cost of 1 MWh of electricity

The first hour of labour is still a fixed cost, however the second hour of labour is now a marginal cost. The new cost of electricity that produces a zero net benefit is:

$150 - $75 - $20 = $55

What does this mean to Powercorp's electricity bids? It means that any time the price of electricity is below $55, Powercorp is better off to bring in additional staff and produce additional widgets. Since they can sell every widget they can make, their bid for electricity would be:

- 150 MW of electricity for a price at or below $55
- 100 MW of electricity for a price between $75 and $55
- Zero MW of electricity for a price above $75

2.7 Bid and Offer Duration

A bid to purchase electricity and an offer to produce electricity must have an associated time limit. In addition, marginal costs may vary over time. For example, labour costs may increase on weekends and night shifts.

Bids and offers made in the IESO-administered markets are for a one-hour period. In the example of Powercorp, the company would place a bid for electricity for each hour of operation. Similarly, the three generators discussed would offer electricity by the hour. We will examine the timing of bids and offers in more detail later.

2.8 Skill Check: Bids and Offers

1. Select the **incorrect** statement:

   Electricity is a unique commodity because:

   a) It incurs losses as it is transmitted over distances

   b) It cannot be effectively stored in large quantities

   c) It does not follow the general laws of supply and demand

   d) Production must match consumption on a continuous basis

2. The Market Rules have been written assuming that market participants will base their offers on the marginal cost of producing electricity. Which two of the following items are generally included in marginal cost?

   a) Usual labour costs

   b) Additional labour costs (to deal with increased production)

   c) Fuel

   d) Capital costs

3. True or False:

   Market participants can submit up to 20 price-quantity pairs for each hour. This allows participants to adjust energy consumption or production based on price.

Skill Check: Answers

1. Select the **incorrect** statement:

   Electricity is a unique commodity because:

   a) It incurs losses as it is transmitted over distances

   b) It cannot be effectively stored in large quantities

   c) **It does not follow the general laws of supply and demand** 4

   d) Production must match consumption on a continuous basis

2. The Market Rules have been written assuming that market participants will base their offers on the marginal cost of producing electricity. Which two of the following items are generally included in marginal cost?

   a) Usual labour costs

   b) **Additional labour costs (to deal with increased production**) 4

   c) **Fuel** 4

   d) Capital costs

3. **True** 4 or False:

   Market participants can submit up to 20 price-quantity pairs for each hour. This allows participants to adjust energy consumption or production based on price.

3. Determining the Market Clearing Price

So far we have discussed placing bids and offers. We have not yet considered what the IESO does with bids and offers, or how the IESO communicates with dispatchable loads and generators. The IESO's first step is to determine a market clearing price.

Objectives

After you have completed this section, you will be able to:

- Determine the market clearing price for a specific interval, given the applicable bids and offers
- Identify components of supply and demand in the Ontario physical markets

When all the market participants submit their bids and offers, the IESO takes this information and runs it through an optimization program referred to as the dispatch algorithm. The algorithm compares the supply and demand information to determine the optimum solution for the province.

The algorithm must consider many factors. It produces "unconstrained" and "constrained" schedules. We will consider additional details and introduce more complexity throughout this course, but for now we will simply work with the unconstrained algorithm matching supply and demand for electricity in Ontario. At this stage we will ignore physical limitations and losses incurred when moving electricity throughout the province. We will assume all supply and load is at a single location in the centre of the province, just as the unconstrained algorithm does. We will also limit our discussion to a static situation. This means we will ignore the impact of demand fluctuations on price.

The algorithm provides a market clearing price for electricity that most closely matches supply and demand based on the bids and offers received. In fact, it chooses the cost of supplying one more megawatt of electricity beyond the point where supply and demand intersect.

Let's look at another example to confirm how this works. Assume the following information is given to the IESO:

On the supply side:

Gen X is willing to provide up to 175 MW:

- 0 MW if MCP is less than or equal to $20
- 100 MW if MCP is greater than $20 but less than or equal to $25
- 150 MW if MCP is greater than $25 and less than $30
- 175 MW if MCP is above $30

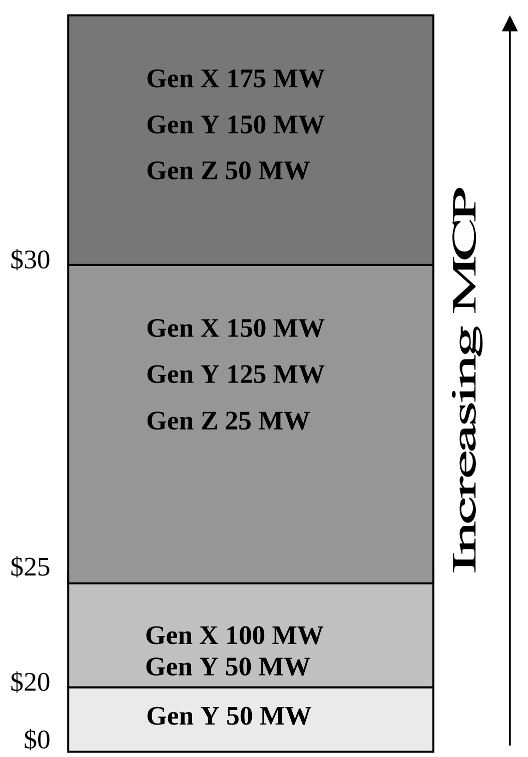
Gen Y is willing to provide up to 150 MW:

- 50 MW for any MCP less than $25
- 125 MW if MCP is equal to or greater than $25, but less than $30
- 150 MW if MCP is above $30

Gen Z is willing to provide up to 50 MW:

- 0 MW if MCP is less than $25
- 25 MW if MCP is greater than or equal to $25 but less than $30
- 50 MW if MCP is above $30

The algorithm will stack the electricity offers from lowest to highest as seen here. Note that there are multiple offers for some prices. This means there is a block of 300 MW of electricity available if MCP goes above $25 and an additional block of 75 MW if the MCP goes above $30.



On the demand side:

Load A will consume:

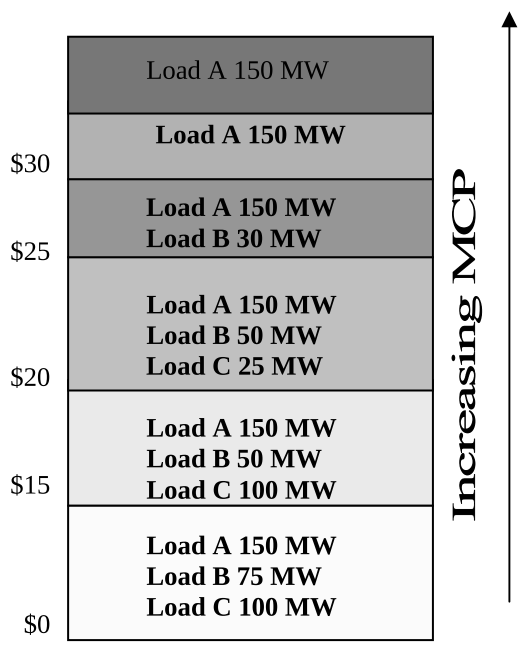
- 150 MW regardless of the market clearing price

Load B can consume a maximum of 75 MW, but will reduce that consumption as a function of energy price. They want to consume:

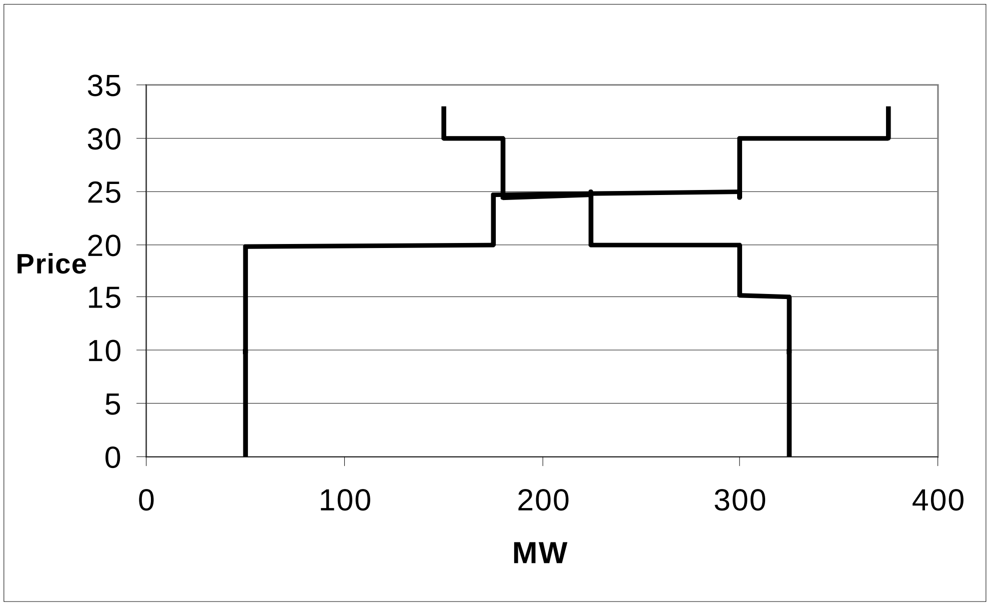
- 75 MW if the MCP is less than $15
- 50 MW if the MCP is $15 or greater, but less than or equal to $25
- 30 MW if the MCP is greater than $25, but less than or equal to $30
- 0 MW if the MCP is more than $30

Load C can consume a maximum of 100 MW, but will reduce that consumption as a function of energy price. They want to consume:

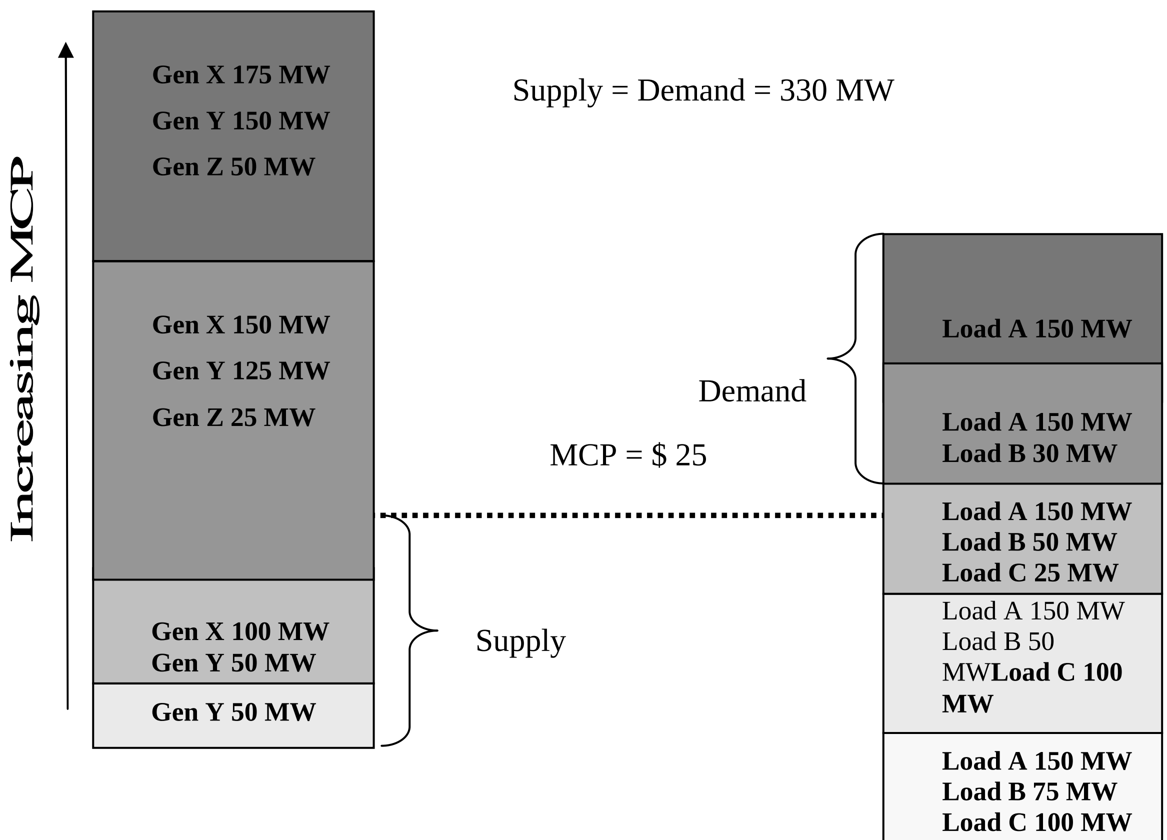
- 100 MW if the MCP is $20 or less
- 25 MW if the MCP is greater than $20, but less than or equal to $25
- 0 MW if the MCP is greater than $25



Just as in the supply side, the algorithm will stack the bids for electricity. The graph below represents the data from above. The supply and demand meet at $25. We can see that at $25 there is actually more supply available than demand. The cost of one more megawatt remains $25 and so the MCP will be set at $25.



Looking at the stacks of bids and offers we have:



As MCP increases, consumption decreases while production increases.

Consider the load stack; only Load A, who was willing to consume regardless of price, and 30 MW of Load B will be served when the MCP is $25. The remainder of

Load B and none of Load C will be served, as this price is higher than they are willing to pay.

On the generation side, we can see that the blocks of generation from Gen X and Gen Y offered below MCP will be accepted. The next block generation offered at MCP is actually larger than required. What happens in this case? We do not need that much power, so not all the generators should expect to run to the full extent of their offers. This might seem unfair, but recall that their offers are assumed to reflect their marginal costs. If the market clearing price is the same as their offer, they should be indifferent to operating at this price. Even if they offered 25 MW at $25, they should be just as happy if they aren't actually asked to produce any power. We will discuss how the algorithm allocates the production within this block when we introduce physical constraints. Before we move on to constraints, we will expand the definition of supply and demand.

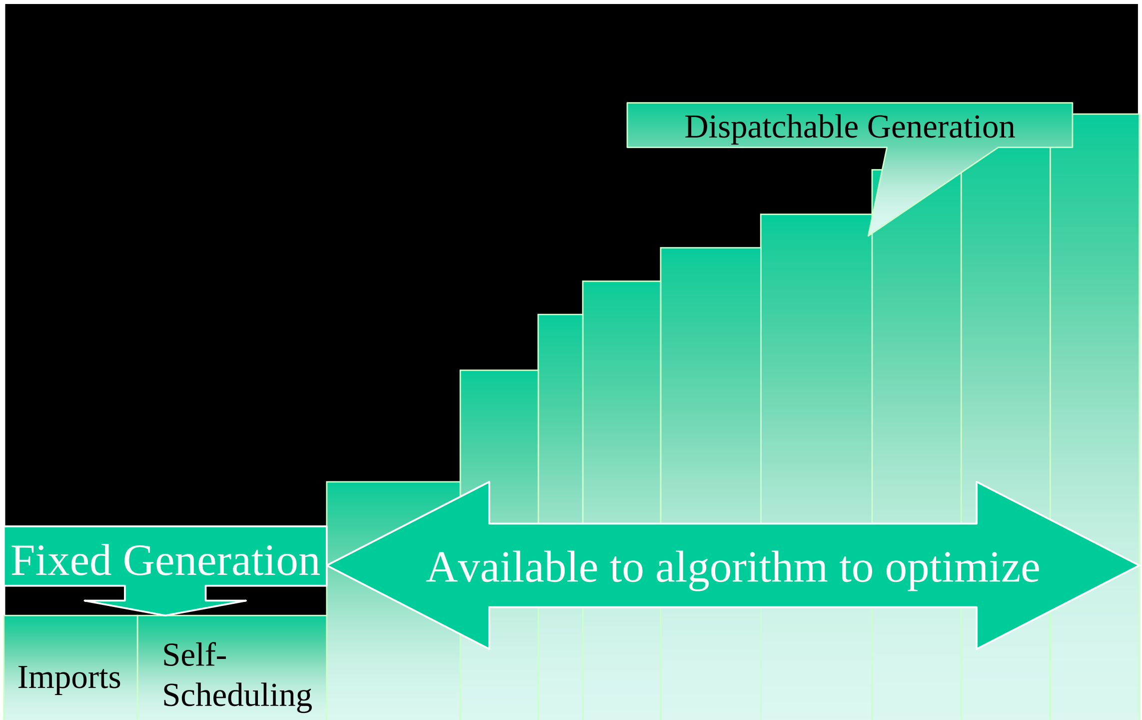
3.1 Non-dispatchable Loads and Generators

So far we have only looked at the impact of dispatchable loads and generators on the IESO-administered markets. Dispatchable facilities place bids and offers which indicate exactly what they are willing to pay or receive for electricity. The IESO then instructs these facilities where to operate based on those bids and offers.

Non-dispatchable facilities set their own generation or consumption level just the way you control your electricity consumption in your home. What this effectively means is that a non-dispatchable load agrees to pay the market price for electricity consumed, no matter what it is. Similarly, a non-dispatchable generator agrees to accept the market price for the electricity that it generates, no matter what that price is.

3.2 Components of Supply and Demand

The supply of electricity is the total supply from self-scheduling, intermittent, transitional scheduling, and dispatchable generators. Because self-scheduling, intermittent, and transitional scheduling generators are "price-takers", electricity available from these sources is used first as a block. We have not discussed imports from other jurisdictions yet; however, they are scheduled on an hourly basis. In real-time operation, for any given hour, imports are fixed. Together, these sources create a fixed energy supply that the dispatch algorithm must take into account when determining the 5-minute MCP in Ontario. Offers from dispatchable generators provide the only variable resources in the supply stack available to the dispatch algorithm.



At the same time, demand is made up of several components. Demand includes the non-dispatchable loads that withdraw electricity without dispatch instructions. It also includes losses that occur when moving electricity across the province (losses must be made up and the cost of losses is passed on to electricity consumers). Exports, like imports, are fixed within a one-hour time window. Exports and non-dispatchable loads act as a fixed load that the dispatch algorithm must serve. Bids from dispatchable loads provide the only variable resources in the demand stack available to the dispatch algorithm.

The dispatch algorithm balances supply and demand and determines prices using these offers and bids to arrive at the optimal solution.

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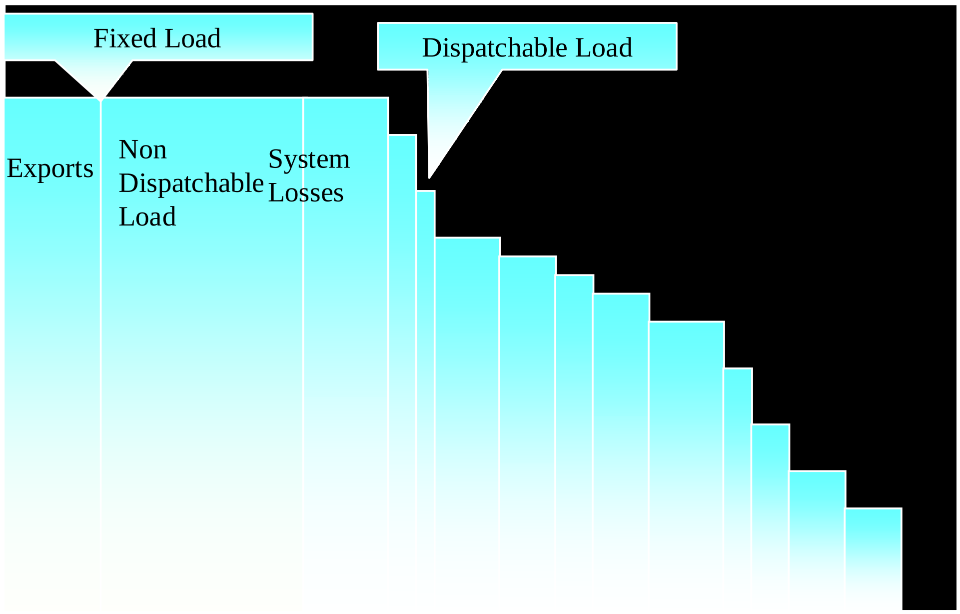
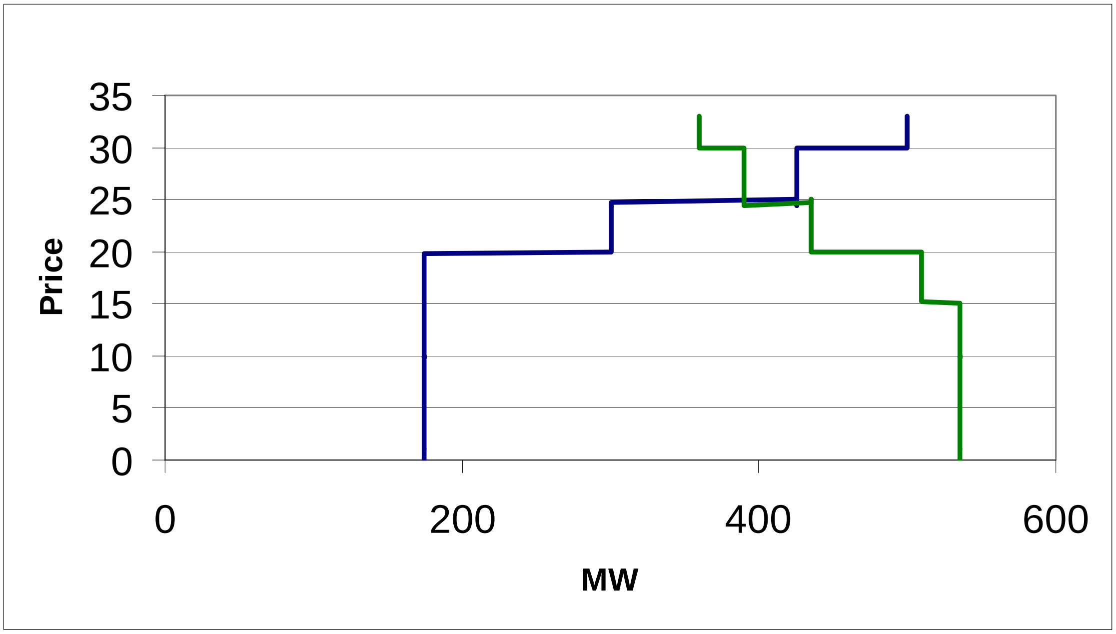


If we use the data from our earlier example, we can add the following:

- Non-dispatchable loads consume 150 MW
- System losses consume 10 MW
- Exports consume 50 MW
- Imports provide 50 MW
- Self scheduling, intermittent, and transitional scheduling generators plan to provide 75 MW for the period in question

Imports and self-scheduling generation totaling 125 MW will be used first.

Exports, losses and non-dispatchable loads of 210 MW will be accommodated first, before optimizing.



In this example, the MCP is still $25. However, consumption has increased from 200 to 410 MW.

3.3 Prices: MCP vs. HOEP

As we discussed earlier, dispatchable facilities work on a five-minute time window with their dispatch instructions. The market clearing price used for dispatchable facilities is set every five minutes, matching each dispatch interval. Non-dispatchable facilities are, however, treated differently.

Non-dispatchable market participants are “price-takers”. They set their own generation or demand. They are not directed to adjust their production or demand based on movements in the five-minute market clearing price. Non-dispatchable facilities get compensated for their production or pay for their consumption based on the Hourly Ontario Energy Price (HOEP). This price is an average of the twelve five-minute prices during the hour.

3.4 Skill Check: Determining the Market Clearing Price

For the following examples, determine the market clearing price:

Exercise 1:

- Gen X is offering 125 MW at $20
- Gen Y is offering 100 MW at $25
- Gen Z is offering 75 MW at $15

- Load A will consume 150 MW, no matter what the price is

Exercise 2:

- Gen X is offering 75 MW at $28
- Gen Y is offering 75 MW at $18
- Gen Z is offering 150 MW at $25

- Load A will consume 250 MW no matter what the price is

Exercise 3 (Optional):

- Gen X is offering 125 MW at $20, and an additional 35 MW at $27
- Gen Y is offering 10 MW at $10, an additional 25 MW at $25 and an additional 45 MW at $30
- Gen Z is offering 150 MW at $25 and an additional 100 MW at $30

- Load A will consume 120 MW, regardless of price
- Load B will consume up to 75 MW if the price is $25 or less, but only 60 MW if the price is between $25 and $30
- Load C will consume 125 MW if the price is $20 or less, but only 100 MW if the price is between $20 and $25, and only 50 MW if the price is over $25

Exercise 4 (Optional):

- Gen X is offering 125 MW at $20, and an additional 35 MW at $27
- Gen Y is offering 10 MW at $10, and additional 25 MW at $25 and an additional 45 MW at $30
- Gen Z is offering 150 MW at $25 and an additional 100 MW at $30

- Load A will consume 50 MW if the price is $25 or less
- Load B will consume 100 MW if the price is $20 or less, but only 50 MW if the price is between $20 and $30
- Load C will consume 100 MW if the price is $40 or less

Skill Check: Answers

For the following examples, determine the market clearing price:

Exercise 1:

- Gen X is offering 125 MW at $20
- Gen Y is offering 100 MW at $25
- Gen Z is offering 75 MW at $15

- Load A will consume 150 MW, no matter what the price is

Answer: Market clearing price is $20

Exercise 2:

- Gen X is offering 75 MW at $28
- Gen Y is offering 75 MW at $18
- Gen Z is offering 150 MW at $25

- Load A will consume 250 MW no matter what the price is

Answer: Market clearing price is $28

Exercise 3:

- Gen X is offering 125 MW at $20, and an additional 35 MW at $27
- Gen Y is offering 10 MW at $10, an additional 25 MW at $25 and an additional 45 MW at $30
- Gen Z is offering 150 MW at $25 and an additional 100 MW at $30

- Load A will consume 100 MW, regardless of price
- Load B will consume up to 75 MW if the price is $25 or less, but only 60 MW if the price is between $25 and $30
- Load C will consume 125 MW if the price is $20 or less, but only 100 MW if the price is between $20 and $25, and only 50 MW if the price is over $25

Answer: Market clearing price is $27

Exercise 4:

- Gen X is offering 125 MW at $20, and an additional 35 MW at $27
- Gen Y is offering 10 MW at $10, and additional 25 MW at $25 and an additional 45 MW at $30
- Gen Z is offering 150 MW at $25 and an additional 100 MW at $30

- Load A will consume 50 MW if the price is $25 or less
- Load B will consume 100 MW if the price is $20 or less, but only 50 MW if the price is between $20 and $30
- Load C will consume 100 MW if the price is $40 or less

Answer: Market clearing price is $25

4. Determining Dispatch Instructions

Now that we understand how the price of electricity is determined, we can examine how dispatchable participants receive their instructions on how much electricity to produce or consume in a specific time period. These dispatch instructions must take into account the physical limitations involved in moving electricity.

Objectives

After you have completed this section, you will be able to:

- Identify types of physical limitations that impact dispatch instructions
- Determine dispatch instructions and market clearing price, given supply, demand, and transmission constraints

4.1 Constrained and Unconstrained Algorithm

Up until now, we have ignored physical limitations that occur when moving electricity throughout the province; we have been looking at the unconstrained algorithm. The unconstrained algorithm assumes a single point load and a single point generator at the exact same location when determining the market clearing price of electricity in Ontario. This common price is then used for all electricity within the province. (The value of using "locational" pricing, that is different prices for different regions of the province, has not yet been evaluated. Data is being gathered during the first six months of market operations, and locational pricing will be evaluated after that six-month period.)

In reality, there are losses associated with moving electricity long distances. Furthermore, there are limitations on how much electricity can be moved through a section of transmission line. Finally, maintaining power quality and the reliability of the IESO-controlled grid can impose additional limitations on how much electricity can move through various sections of the grid at various times.

The constrained algorithm takes all these physical limitations into account when determining the optimum solution for the province. The output of the constrained algorithm is used to create the instructions given to dispatchable facilities.

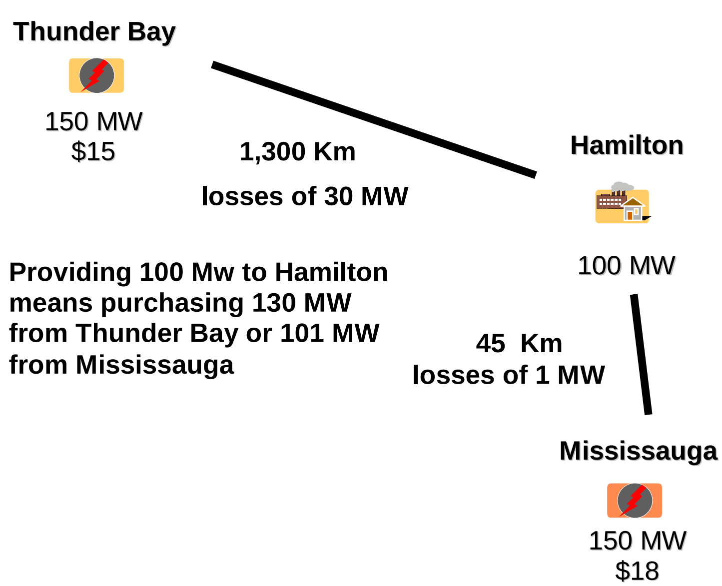
4.2 The Constrained Algorithm and Dispatch Instructions

We have already reviewed how the unconstrained algorithm is used to determine the market clearing price for electricity in Ontario. Because of physical limitations, we cannot simply assume that bids and offers from dispatchable facilities will automatically be accepted based on the market clearing price. We can illustrate how the constrained algorithm works with two examples.

In the first example, assume that there are two suppliers of electricity and one single load in the province. In this simplified example, the market clearing price is set at $15 because the Thunder Bay supplier is willing to supply electricity for the 100 MW of non-dispatchable load.

But does it make sense to actually have Thunder Bay supply the electricity? In the example here, we assume a 30 MW loss from Thunder Bay and only a 1 MW loss from Mississauga. If we look at the total cost of supplying the load with 100 MW:

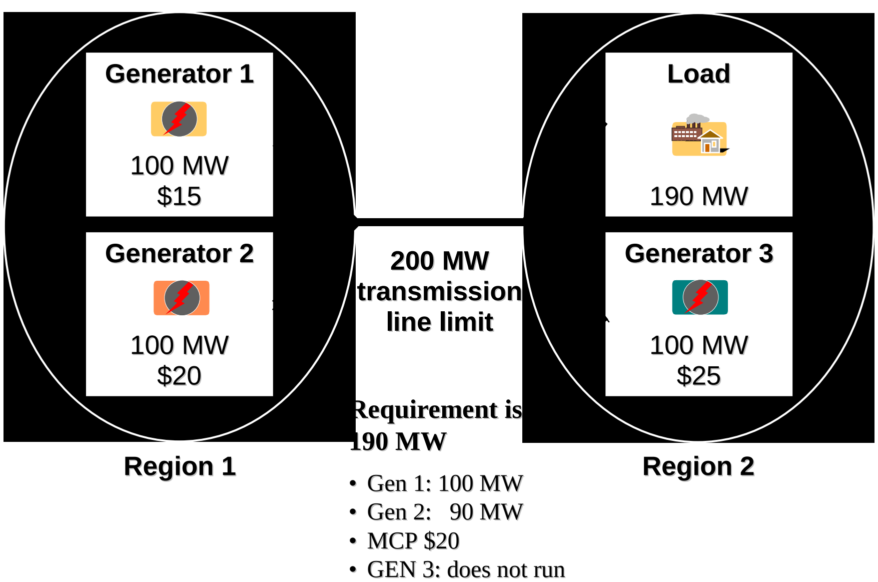
- From Thunder Bay: 130 **x** $15 = $1950 (note: an additional 30 MW must be supplied due to losses, resulting in a total of 130 MW required)
- From Mississauga: 101 **x** $18 = $1818 (note: an additional 1 MW must be supplied due to losses, resulting in a total of 101 MW required)



The cost to service the load will, in fact, be lower even if Mississauga is dispatched at $18 per MW. The MCP will be set at $15 based on the unconstrained algorithm. Mississauga will, however, be dispatched to generate 101 MW and will be paid $18 per MW (we will discuss where the additional $3 comes from in the *Constraint Payments* section). Because the Thunder Bay bid is also the MCP, Thunder Bay should be indifferent to whether or not they operate (assuming that their offer was based on marginal costs).

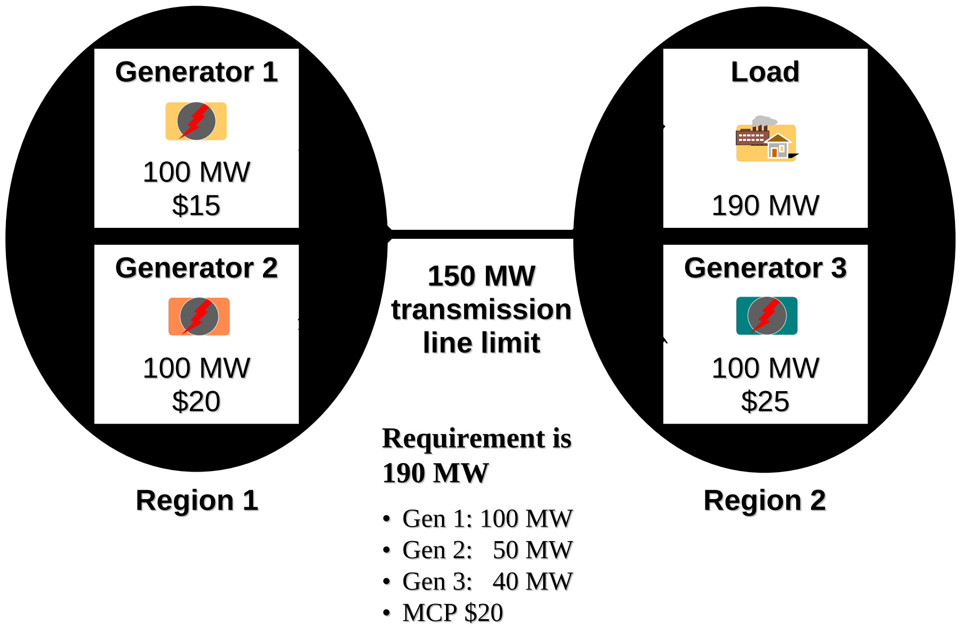
The constrained algorithm takes the physical losses into account when dealing with bids and offers from dispatchable facilities. The dispatch instructions will reflect these losses in order to reduce the cost of electricity in the province. We will examine the impact of these dispatch instructions on market prices and revenue in the *Constraint Payments* section below. However, let's first look at an example of the impact of physical limitations on dispatch instructions.

In this example, a market clearing price of $20 will induce sufficient generation to meet the demand of 190 MW. The transmission lines linking the two regions are capable of carrying 200 MW; therefore, Generator 1 will provide 100 MW, Generator 2 will provide 90 MW and Generator 3 will not be required.



But what happens if the transmission lines cannot carry the full load?

In the example below, the only change is a 150 MW limit on the transmission facility. In this case, even though there is cheaper electricity in Region 1, it cannot fully supply the load in Region 2 because of transmission limitations. As a result, Generator 3 must be dispatched for the additional 40 MW of electricity required.



The transmission limits require running Generator 3 for 40 MW, but the unconstrained algorithm produced a market clearing price of only $20. Given this market clearing price, why should Generator 3 be willing to generate 40 MW? Constraint payments are used to compensate Generator 3 for these situations (see Section 5, *Constraint Payments*).

4.3 Ramp Rates

Physical facilities cannot adjust their electricity production or use instantly. For example, a generator will require time to move from 100 to 200 MW of output. The amount of time required is a function of the characteristics of the facility.

When the optimizing algorithm creates dispatch instructions for a facility, it takes into account the current operating point for the facility, and the rate of change that the facility can achieve (as supplied by the participant).

For example, assume Facility A offers up to 150 MW at $25 per MW, with a ramp rate of 2 MW/minute. The MCP is currently $24, and Facility A is not producing electricity.

Due to a sudden increase in demand, the MCP rises to $26 and there is sufficient demand for 100 MW from Facility A. Unfortunately, Facility A cannot instantly move to 100 MW of production. The optimizing algorithm will send out dispatch instructions to Facility A based on their ramp rates. Dispatch instructions are sent every five minutes.

In this example, at the end of the first five-minute interval, Facility A will be expected to be able to produce 10 MW, at the end of the second five-minute interval, 20 MW and so on.

Each five-minute dispatch instruction will be based on the current operating state of each facility, taking into account the ramp rates provided by the participant.

In summary, the constrained algorithm will take all the physical limitations, including losses, transmission limitations and ramp rates, into account when dispatch instructions are created. Two generators offering electricity at the same price can be dispatched differently based on all these factors. Bids, offers and MCP alone will not tell you how a facility will be dispatched. In addition, the unconstrained algorithm also takes ramp rates into account when determining the market clearing price in Ontario.

While the unconstrained algorithm uses ramp rates, it uses 60-minute ramp rates when setting energy prices. This means a generator with a 2 MW/minute ramp rate is assumed to be able to move 120 MW in a five-minute interval. The net effect is that ramp rates have very little impact on the clearing price of energy.

4.4 Skill Check: Determining Dispatch Instructions

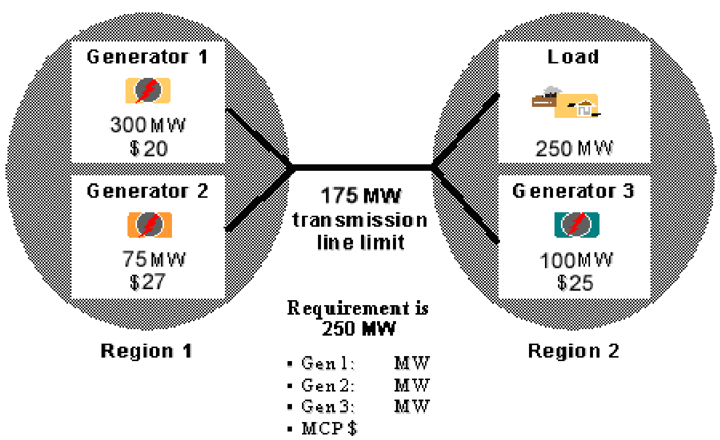
1. Dispatch instructions are determined by:

   a) the unconstrained algorithm
   b) the constrained algorithm
   c) the unconstrained algorithm, taking locational pricing into account
   d) the constrained algorithm, taking locational pricing into account

2. Select the correct statement:
   a) Losses are considered in the unconstrained algorithm
   b) Dispatch instructions are determined according to the lowest price offered, regardless of location
   c) Dispatch instructions reflect losses in order to reduce the overall cost of electricity in Ontario

3. True or False:
   If your generator is offering energy at the same price as Generator Y, you can count on receiving the same dispatch instructions as Generator Y.

4. In the following chart, determine the dispatch instructions and MCP.



Skill Check: Answers

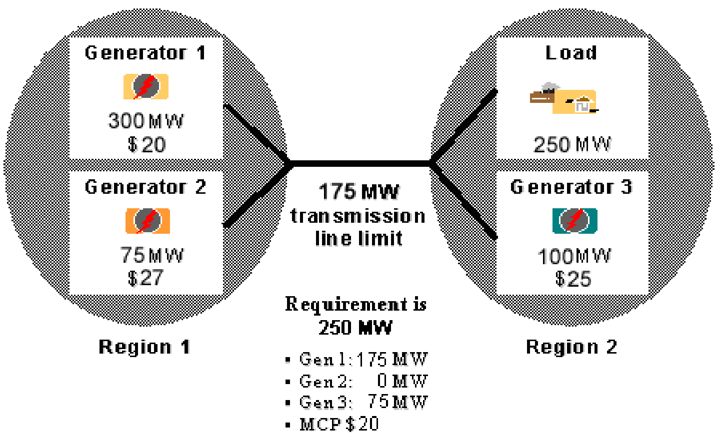
1. Dispatch instructions are determined by:

   a) the unconstrained algorithm
   b) **the constrained algorithm** 4
   c) the unconstrained algorithm, taking locational pricing into account
   d) the constrained algorithm, taking locational pricing into account

2. Select the correct statement:
   a) Losses are considered in the unconstrained algorithm
   b) Dispatch instructions are determined according to the lowest price offered, regardless of location
   c) **Dispatch instructions reflect losses in order to reduce the overall cost of electricity in Ontario** 4

3. True or **False** 4:
   If your generator is offering energy at the same price as Generator Y, you can count on receiving the same dispatch instructions as Generator Y.

4. In the following chart, determine the dispatch instructions and MCP.



Comments:

MCP is determined by the unconstrained algorithm. In this case, the entire 250 MW required by the load would have been supplied by Generator 1 if there had been noconstraints; therefore, MCP is $20.

5. Constraint Payments

In the previous section we saw how introducing physical constraints can lead to dispatch instructions that are different from what we would expect if there were no physical constraints. In some cases, a generator may not be dispatched to supply electricity even though it is willing to supply at, or even below, the market clearing price. This creates situations where a generator would, in effect, be penalized for its location relative to the location of demand. In this section we discuss how these situations are dealt with in the Ontario markets.

Objectives

After you have completed this section, you will be able to:

- Determine operating profits, given costs and dispatch instructions
- Determine constraint payments given supply, demand, system limitations and the market clearing price

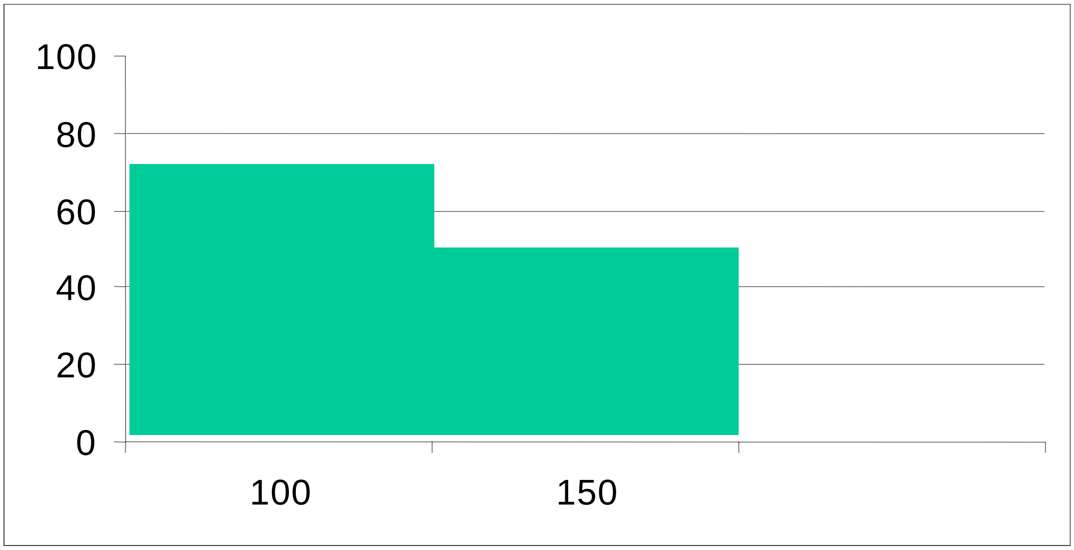
5.1 Operating Profit

The market rules are written as if participants will place bids and offers based on their marginal cost and benefit. This means that a participant should be indifferent toward consumption or production if the price of electricity is exactly what they bid. For example, in the Powercorp-widget example discussed previously, at a market price of $75 for electricity, Powercorp is no better off financially making widgets than not making widgets. Once Powercorp pays for the material and the electricity, there is nothing left to help pay off their fixed costs.

If, however, the market price for electricity is, in fact, $35, then Powercorp can make a $45 contribution to its fixed costs for every MWh of electricity consumed. This $45 represents an economic gain from consuming electricity. It is referred to as operating profit.

The chart below represents the bids placed by Powercorp: 100 MW for $75 and an additional 50 MW if the price is $55 or less.

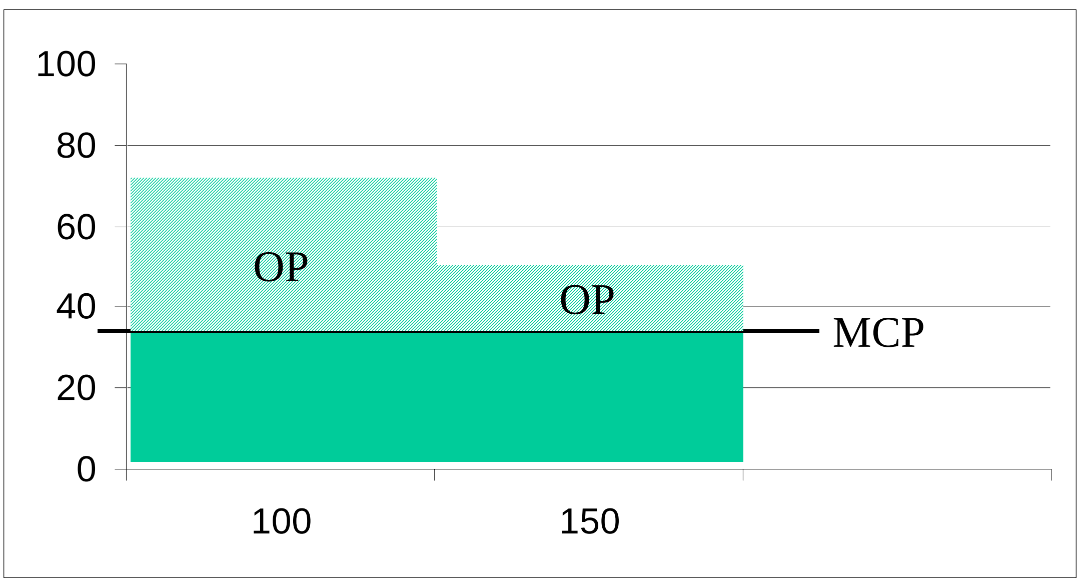
$/MWh



MWh

If the market clearing price is only $35, then the electricity consumed produces a benefit for Powercorp. This benefit, called operating profit can be seen in the chart below as the shaded section above $35 and below the upper limit of Powercorp's bid.

$/MWh



MWh

5.2 Congestion Management Settlement Credits

When a facility is dispatched differently by the constrained algorithm than it would have been by the unconstrained algorithm, we refer to the facility as being either constrained on or constrained off. Constraint payments are used to bring the market participant to the same level of operating profit they would have obtained from the unconstrained algorithm.

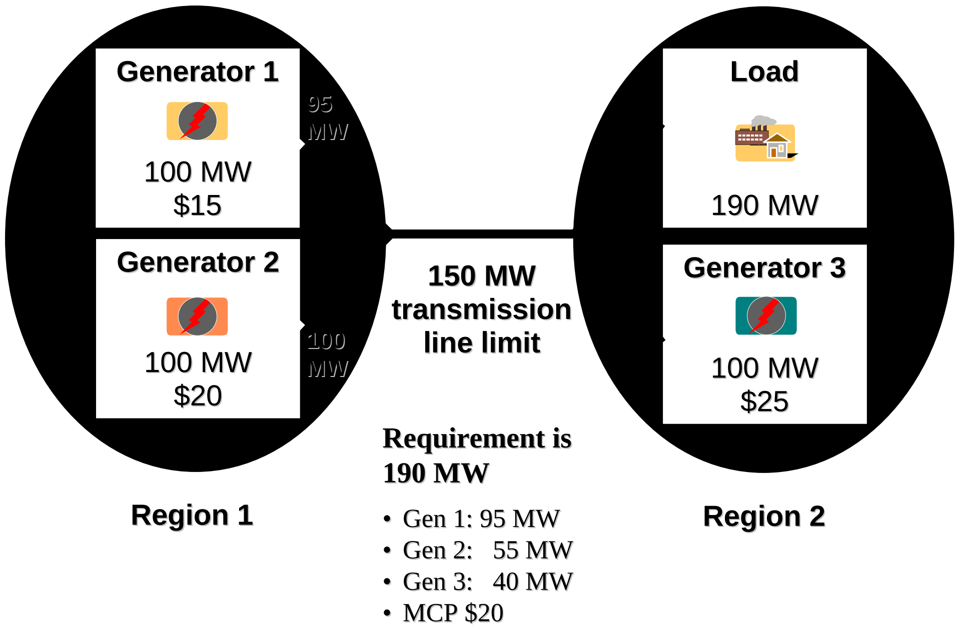
In the previous example of two generators (one in Thunder Bay and another in Mississauga) the Thunder Bay station was dispatched off even though it was willing to offer electricity at the market clearing price. On the other hand, Mississauga was dispatched to run even though its offer was above the market clearing price. In this case, Thunder Bay was constrained off, and Mississauga was constrained on. But how should they be compensated?

Remember, the market rules are based on the assumption that facilities will bid their marginal benefit, and offer at their marginal cost. A facility whose bid is the same as the market clearing price should be indifferent to operating as there is a zero operating profit at this point. If a facility offers electricity below the market clearing price, the operating profit is the difference between the market clearing price and their offer.

In the example above, Thunder Bay would have had an operating profit of zero since their offer was the same as the market clearing price of $15. They are indifferent to the constraint and require no compensation.

Mississauga, however, offered power at $18. Payments based on a market clearing price of $15 would lead to a $3 per MW operating loss. In order to compensate Mississauga, the IESO will provide them with a constrained on payment of $3 per MW.

Let's work again with the example of the transmission constraint we used earlier. Let's examine the situation where the line to Generator 1 is limited to 95 MW. This will allow us to see how constrained on and constrained off payments are made.



In this case, Generator 1 can supply only 95 MW of the demand. Generator 2 is limited to 55 MW by the transmission line between regions, so Generator 3 must supply 40 MW. The market clearing price is set by the unconstrained algorithm and remains at $20.

If we look at the impact on operating profit we can see that Generator 2 is unaffected. Their offer price is equal to the market clearing price, so their operating profit is unaffected by their dispatch instructions.

Generator 3 is dispatched to 40 MW so they require a constrained on payment of:

40 x (offer price - MCP) = 40 x (25-20) = $200

Providing Generator 3 with the difference between their offer price and the market clearing price will bring their operating profit to zero, eliminating their potential loss.

Generator 1 is dispatched; however, they are only dispatched to 95 MW. In the absence of the transmission constraint, they would have been dispatched to 100 MW. For Generator 1, the constrained off payment will be:

- Change in dispatch quantity x (MCP - offer price)
- (100-95) x (20-15) = $25

This payment leaves Generator 1 with the same operating profit that would have been received if they were dispatched solely according to price.

Generator 2 was only dispatched at 50 MW; however, since their offer was equal to the market clearing price, their operating profit is unchanged by the dispatch instructions.

In conclusion, constraint payments are made to ensure participants receive the operating profit based on the unconstrained schedule (ignoring losses and constraints). In most situations, this is a payment to the participant. In some situations, however, this could involve the participant paying excess operating profit back to the IESO. The cost of constraint payments is passed on to electricity consumers as an uplift. Uplift charges are discussed in Section 8, *Uplift.*

5.3 Skill Check: Constraint Payments

1. For Hour 1:
   - Gen Y offers 100 MW at cost: 50 MW at $25 and 50 MW at $27
   - Gen Y is dispatched for all 100 MW; the MCP for 75 MW is $28, and for the remaining 25 MW the MCP is $32.

   What is Gen Y's operating profit for the hour?

   a) $150
   b) $175
   c) $300
   d) $400

2. Constraint payments are used to:
   a) bring the market participant to the same level of operating profit they would have obtained from the unconstrained schedule
   b) provide operating profit to market participants who offer or bid at market clearing price, but are constrained on or off
   c) equalize operating profit among all market participants

3. Constraint payments are paid by:
   a) an increase in the next hour's market clearing price
   b) electricity consumers, in the form of an overhead charge (called an *uplift*)
   c) electricity producers, in the form of an overhead charge (called an *uplift*)

4. Please refer to Question 4 in Section 4.4. What, if any, constraint payments will be made?

Skill Check: Answers

1. For Hour 1:

- Gen Y offers 100 MW at cost: 50 MW at $25 and 50 MW at $27
- Gen Y is dispatched for all 100 MW; the MCP for 75 MW is $28, and for the remaining 25 MW the MCP is $32.

What is Gen Y's operating profit for the hour?

a) $150
b) $175
c) $300 4
d) $400

Comments:
50 MW at cost of $25/MW; paid at $28/MW: Operating Profit = 50 x $3 = $150
25 MW at cost of $27/MW; paid at $28/MW: Operating Profit = 25 x $1 = $ 25
25 MW at cost of $27/MW; paid at $32/MW: Operating Profit = 25 x $5 = $125
Total: $300

2. Constraint payments are used to:

a) bring the market participant to the same level of operating profit they would have obtained from the unconstrained schedule 4
b) provide operating profit to market participants who offer or bid at market clearing price, but are constrained on or off
c) equalize operating profit among all market participants

3. Constraint payments are paid by:
a) an increase in the next hour's market clearing price
b) electricity consumers, in the form of an overhead charge (called an *uplift*) 4
c) electricity producers, in the form of an overhead charge (called an *uplift*)

4. Please refer to Question 4 in Section 4.4. What, if any, constraint payments will be made?
Generator 1:
no constraint payment; MCP is the same as the offer price
Generator 2:
no constraint payment; would not have been scheduled by the unconstrained algorithm, and is not dispatched
Generator 3:
Constraint payment of $375:
75 x (offer price - MCP) = 75 x (25-20) = $375

6. Pre-dispatch vs. Real-time Operations

Now that we have discussed how the market clearing price is established and how dispatch instructions are determined, we can look at the timing of the market.

Objectives

After you have completed this section, you will be able to:

- State the timetable rules for submitting and revising bids and offers
- Explain the advantage of submitting standing bids and offers

Remember that the IESO must manage the supply and demand for electricity within close tolerances on a continuous basis. In order to help this process, the IESO issues dispatch instructions to dispatchable facilities up to 12 times an hour. (Dispatch instructions are issued only if there is a change relative to the facility's most recent dispatch instruction.) These instructions also reflect the physical limitations of the facility.

It is essential that all the market participants plan in advance to make the process work. It is also important that information be freely available to help all participants and the IESO make their decisions. In order to help create a smoothly operating market, the process of bids and offers starts out well in advance and becomes more detailed and firm as the minute at hand approaches.

6.1 Pre-dispatch

The window for bids and offers for any given day opens at 6 a.m. the day before. For example, market participants can start putting in bids and offers for Wednesday at 6 a.m. on Tuesday. Market participants place bids and offers for a one-hour time window. Recall that a bid or offer can contain up to 20 price-quantity pairs. For example, starting at 6 a.m. on Tuesday, a market participant could put in a bid that says:

From 1 p.m. to 2 p.m.

- 0 to 10 MW if the price is greater than $3000
- 10 to 20 MW if the price is between $2500 and $3000
- 20 to 30 MW if the price is between $100 and $2500
- 30 to 40 MW if the price is between $0 and $100

6.2 Standing Bids and Offers

It is possible for both dispatchable loads and generators to submit standing data to the IESO. Standing data allows for a set of bids or offers to remain active until changed by the participant.

For example, in our earlier example using Powercorp, if they wanted to place a bid for electricity based on operating costs, they could place bids to reflect:

Monday to Friday:

- 8 a.m. to 12 p.m.: $75 for the first 100 MW, $55 for an additional 50 MW
- 12 p.m. to 1 p.m.: zero MW (shut down over lunch hour)
- 1 p.m. to 5 p.m.: $75 for the first 100 MW, $55 for an additional 50 MW
- 5 p.m. to 8 a.m.: zero MW

Saturday and Sunday:

- Zero MW

Powercorp need only revise their bids if their cost structure changes or if their demand for electricity changes.

6.3 Revisions to Bids and Offers

Participants can adjust their bids and offers as more information about the specific hour becomes available. Participants can adjust their bids and offers without restriction up to 2 hours prior to any given hour. For example, Facility A can change its bid for electricity for the period between 1 and 2 p.m. without restriction up until 11 a.m. that day.

6.4 Skill Check: Pre-dispatch vs. Real-time Operations

Fill in the blanks:

a) The window for bids and offers for a given day opens at ____ the day before.

b) A market participant may submit up to ___ price-quantity pairs for each hour of the day. This allows the participant to ___________________________________

c) A market participant expecting to offer the same quantity at the same price for all hours every Monday would enter a __________ _______

d) Participants can adjust their bids and offers without restriction up to ___ _____ prior to the given trading hour.

Skill Check: Answers

Fill in the blanks:

a) The window for bids and offers for a given day opens at **6:00 a.m.** the day before.

b) A market participant may submit up to **20** price-quantity pairs for each hour of the day. This allows the participant to **adjust their energy production or consumption based on price**.

c) A market participant expecting to offer the same quantity at the same price for all hours every Monday would enter a **standing bid**.

d) Participants can adjust their bids and offers without restriction up to **2 hours** prior to the given trading hour.

7. Operating Reserve

In situations where the IESO-controlled grid suffers from an unexpected shortfall of energy in real-time, the IESO needs to either call upon sources of supply or reduce consumption in order to restore the supply/demand balance. For example, an unexpected outage by a generator creates a shortfall equivalent to the energy that unit had been supplying to the IESO-controlled grid.

Objective

When you have completed this section, you will be able to:

- Identify the three classes of operating reserve
- Explain how payments for operating reserve are determined

Operating reserve (OR) is essentially stand-by power that can be called upon with short notice to deal with an unexpected mismatch between generation and load. The IESO has created an OR market to efficiently purchase OR from market participants.

Ontario's IESO must adhere to reliability standards established by standards authorities like the North American Electricity Reliability Council (NERC) and the North East Power Coordinating Council (NPCC) when determining operating reserve requirements. Operating reserve requirements are based on the largest single unexpected event (contingency) that could occur under a given IESO-controlled grid operating configuration. Typically, this means the loss of the single largest generator.

There are three classes of operating reserve, determined by the time required to bring the energy into use and physical behaviour of the facilities that can provide it.

1. 10 minute spinning (synchronized or spinning)
2. 10 minute non-spinning (non-synchronized or non-spinning)
3. 30 minute

The IESO must have sufficient 10 minute operating reserve to cover the largest single contingency. If the largest generator on the grid is 750 MW, there must 750 MW of operating reserve whose energy can be made available within 10 minutes of the loss of that unit to restore the supply/demand balance.

Normally, 25% of this ten-minute capacity must be spinning or synchronized. Spinning operating reserve is generation that is already synchronized to the grid. This spinning reserve helps reduce the impact of the contingency on system frequency before any of the energy associated with the operating reserve is activated. Only generators can provide ten-minute spinning reserve.

The remaining portion of ten-minute operating reserve does not have to be spinning. Dispatchable loads/generators, imports and exports can be used to satisfy ten-minute non-spinning reserve requirements. If a load or export can be dispatched to reduce demand within ten minutes then it can offer this load reduction as operating reserve.

The IESO must also maintain 30 minute operating reserve over and above the ten-minute requirement. There must be sufficient thirty- minute reserve to cover one-half of the second largest single contingency on the IESO-controlled grid. Dispatchable loads/generators, imports and exports can be used to satisfy 30 minute operating reserve requirements.

The IESO has created a market for all three types of operating reserve. This allows the IESO to purchase this service in the most efficient manner possible.

Dispatchable facilities can place offers for operating reserve, just as they place bids and offers for energy. An offer of operating reserve can only be made if there is a corresponding bid or offer for energy. For example, a load could bid for 150 MW of energy in total, and offer up to 150 MW of operating reserve. If the participant is dispatched to consume 100 MW of energy and is scheduled for 25 MW of 10 minute operating reserve, this means that, if called upon, the facility must reduce their consumption by 25 MW (from 100 to 75 MW) within 10 minutes.

Similarly, a generator might offer up to 200 MW of energy. They can, at the same time, offer up to 200 MW of operating reserve. If the participant is dispatched to 150 MW, and scheduled for 25 MW of 10 minute operating reserve, they must be able to produce 25 additional MW within 10 minutes of being called upon to do so.

The dispatch algorithm simultaneously determines the optimum solution for both energy and operating reserve.

Participants who are successful in offering operating reserve will receive a payment at the market clearing price for the class of operating reserve. They will receive this stand-by charge for all intervals they have been scheduled to supply operating reserve. If, during this period, they are called upon to deliver the energy associated with their operating reserve offer, they will be paid the market clearing price for the energy they supply.

Should a participant be unable to provide electricity when called upon for reserve, there will be a clawback of the operating reserve payments made prior to the call.

7.1 Skill Check: Operating Reserve

1. Three types of operating reserve are:

   a)
   b)
   c)

2. Select the two correct statements:

   a) An offer of operating reserve can only be made if there is a corresponding bid or offer for energy.

   b) The dispatch algorithm simultaneously determines the optimum solution for both energy and operating reserve.

   c) Participants who are successful in offering operating reserve receive the market clearing price for energy when they are on stand-by.

   d) Any market participant may offer 10 minute spinning operating reserve.

Skill Check: Answers

1. Three types of operating reserve are:

   a) **10 minute spinning (synchronized)**
   b) **10 minute non-spinning (non-synchronized)**
   c) **30 minute**

2. Select the two correct statements:

   a) An offer of operating reserve can only be made if there is a corresponding bid or offer for energy.

   b) The dispatch algorithm simultaneously determines the optimum solution for both energy and operating reserve.

   c) Participants who are successful in offering operating reserve receive the market clearing price for energy when they are on stand-by.

   d) Any market participant may offer 10 minute spinning operating reserve.

8. Uplift

In Section 5 we discussed the use of Congestion Management Settlement Credits to compensate participants for lost operating profit. Unfortunately, these credits represent a cost to the market and must be paid for. The IESO-administered markets have been designed so that consumers of electricity (loads) will pay for costs associated with the market.

Statements and invoices will provide participants with details on exactly how much they must pay for each type of cost.

In addition to congestion, these costs include items such as:

- Operating Reserve - The cost of ensuring there is sufficient stand-by power available to ensure reliable operation of the power system in the event of an unexpected event
- Losses - Losses associated with moving electricity throughout the province
- Services - The IESO must pay for services such as voltage regulation and black start capability (the ability to restart electrical supply in the unlikely event of a complete loss of supply on the IESO-administered grid)
- Administration - Costs associated with administering the markets

The IESO will, on a regular basis, determine the cost of these types of items and distribute them to participants based on their activities in the market. For further detail on uplift charges, please refer to the Capability Training course, *Settlement Statements and Invoices*.

Appendix One:
Principles of the IESO Market Rules

Principle	Description
Efficiency	The market should promote allocative, productive and dynamic efficiency in the provision of electricity by minimizing the total resource costs of providing power to all customers, and by enhancing market participants' choices in conducting commercial transactions within the market.
Fairness	The market should provide for open, non-discriminatory access by all who meet reasonable publicly stated prudential and technical standards. There should be no artificial barriers to entry or exit.
Reliability	The market should promote high standards of reliability and quality of electrical service and of access to electricity.
Transparency	The market should be as simple and transparent as feasible and should promote timely, non-discriminatory release of non-confidential market and system information to all market participants.
Robustness	The market rules and protocols should be sufficiently comprehensive so as to ensure that only extraordinary circumstances can upset the functioning of the market.
Enforceability	The market rules should include authorities and mechanisms that promote and enforce adherence to the rules.