



# Introduction to Ontario's Physical Markets

**IESO Training**

Revised: October, 2011





## Introduction to Ontario's Physical Markets

### AN IESO TRAINING PUBLICATION

This guide has been prepared to assist in the IESO training of market participants and has been compiled from extracts from the market rules or documents posted on the web site of Ontario's Independent Electricity System Operator. Users of this guide are reminded that they remain responsible for complying with all of their obligations under the market rules and associated policies, standards and procedures relating to the subject matter of this guide, even if such obligations are not specifically referred to herein. While every effort has been made to ensure the provisions of this guide are accurate and up to date, users must be aware that the specific provisions of the market rules or particular document shall govern.

The Independent Electricity System Operator  
Box 4474, Station A  
Toronto, Ontario  
M5W 4E5

Reception: (905) 855-6100

Fax: (905) 403-6921

Customer Relations: Tel: (905) 403-6900

Toll Free 1-888-448-7777

Website: [www.ieso.ca](http://www.ieso.ca)



# Table of Contents

<b>1. Introduction.....</b>	<b>1</b>
1.1 Market Participants.....	2
1.2 Dispatchable vs. Non-dispatchable Participants .....	3
1.3 Market Participants Without Physical Facilities .....	5
1.4 Energy Market Participant Summary .....	5
1.5 Skill Check: Types of Market Participants .....	6
<b>2. Bids and Offers: The Basis for Determining Market Prices.....</b>	<b>8</b>
2.1 Bids and Offers in the Ontario Real-time Energy Market.....	8
2.2 Skill Check: Bids and Offers .....	12
<b>3. Determining the Market Clearing Price.....</b>	<b>14</b>
3.1 Determining the Market Clearing Price (MCP).....	14
3.2 Non-dispatchable Loads and Generators .....	19
3.3 Components of Supply and Demand .....	20
3.4 Prices: 5-Minute MCP vs. HOEP .....	23
3.5 Skill Check: Determining the Market Clearing Price .....	24
<b>4. Market Schedules.....</b>	<b>26</b>
4.1 What is a Market Schedule.....	26
4.2 Skill Check: Market Schedules .....	29
<b>5. Determining Dispatch Instructions.....</b>	<b>32</b>
5.1 The Constrained Mode of the Dispatch Algorithm .....	32
5.2 Dispatch Instructions.....	37
5.3 Skill Check: Determining Dispatch Instructions .....	38
<b>6. Congestion Management Settlement Credits.....</b>	<b>42</b>
6.1 Operating Profit .....	42
6.2 Congestion Management Settlement Credits .....	44
6.3 Skill Check: Congestion Management Settlement Credits .....	50
<b>7. Timelines.....</b>	<b>52</b>
7.1 Types of Bids and Offers.....	52
7.2 Dispatch Algorithm Timelines .....	53
7.3 Skill Check: Timelines .....	56
<b>8. Operating Reserve .....</b>	<b>58</b>

8.1 What is Operating Reserve? .....	58
8.2 Skill Check: Operating Reserve .....	62
<b>9. Additional information .....</b>	<b>64</b>

## 1. Introduction

This workbook explains the basic rules and processes for trading energy within Ontario. You will learn how participants buy and sell energy products in Ontario's IESO-administered markets, how energy prices are set, and how we dispatch facilities to meet the demand for electricity.

We begin with a discussion of:

- Types of market participants
- How participants offer to supply electricity or bid to buy electricity
- Energy bids and offers

Once we have explained bids and offers, we move on to:

- How we determine the price of electricity in Ontario
- How the amount of electricity participants supply or consume is determined
- How the physical limitations of the electricity system create the need for congestion management settlement credits (CMSC)

The last chapter explains operating reserve (i.e., 'stand-by' energy).

We end with a section listing 'Additional Information'. Please refer to this section for sources of in-depth explanations of some of the topics covered in this introductory workbook.

*Please note:* this workbook deals only with energy sales and purchases within Ontario. For details on imports and exports, see the [Interjurisdictional Energy Trading](#) workbook, available on the [Training](#) web pages.

# 1. Types of Market Participants

Ontario's IESO administers the wholesale electricity market and directs the operation of the high voltage transmission grid. In this document, 'we', 'us', and 'our' refer to the IESO.

The term 'market participant' normally refers to any company participating in any of the IESO-administered markets, but for the purposes of this document, we use it to refer to those who participate in the energy and operating reserve markets. Also, the term 'grid' refers to the IESO-controlled grid.

## Objectives

After completing this section, you will be able to:

- Identify the different types of participants in the physical markets
- Distinguish between dispatchable and non-dispatchable participants

## 1.1 Market Participants

To become a market participant, you must register with us and pay an application fee. There may be additional registration requirements depending on which role you wish to play in the markets. You can have more than one market role. For example, your company could be both a generator and a wholesale seller.

While companies may choose to participate in the markets, a company must become a market participant if it:

- Has equipment directly connected to the grid. (Generally, a facility is directly connected if it is connected to the transmission system at the 50 kilovolt level or higher.)
- Plans to convey electricity into, through or out of the grid.

Participants with physical facilities can be either directly connected or 'embedded'. Embedded participants are connected to the grid via a local distribution company (LDC).

There are also participants who do not have any physical facilities, such as wholesalers (who import and export) and retailers.

## 1.2 Dispatchable vs. Non-dispatchable Participants

We can classify participants by how they interact with us – that is, whether they are ‘dispatchable’ or ‘non-dispatchable’.

### Dispatchable participants

Dispatchable participants:

- Submit bids and offers:
  - An offer tells us how much energy a supplier has to sell and what price they want to receive for it
  - A bid tells us how much energy a consumer wants to purchase and what price they are willing to pay for it
- Respond to dispatch instructions:
  - We use bids and offers, as well as transmission system information, to determine when and how much energy a dispatchable supplier should provide or a dispatchable consumer should consume.
  - We then send dispatch instructions to the participant indicating what their operating point should be. We determine dispatch instructions for each 5-minute interval of the day, 24 hours a day, 365 days a year.

Dispatchable generators provide most of the energy produced in Ontario. Most directly connected generators over 10 megawatts (MW) are dispatchable. A generator connected to a distribution system (i.e., one that is ‘embedded’) can also choose to register as dispatchable. Nuclear, large natural gas, and hydro-electric facilities with storage and coal-fired facilities are examples of dispatchable generators.

Directly connected and embedded loads over 1 MW that can respond to five-minute dispatch can choose to be dispatchable.

Dispatchable participants play an essential role in maintaining the reliability of the grid. Adjusting the operating point of dispatchable facilities is our primary method of ensuring the continuing balance between supply and demand, while respecting transmission security limits.

### Non-dispatchable participants

Non-dispatchable participants do not provide bids and offers and do not receive dispatch instructions. Instead, they accept the market clearing price at the time they produce or consume energy, regardless of what the price is.

Both generators and loads (consumers) can be non-dispatchable.

### **Non-dispatchable generators**

There are two types of non-dispatchable generators:

- **Self-scheduling generators** submit schedules to us indicating the amount of energy they will be providing and when they will provide it. Then they follow their submitted schedules – we do not send them dispatch instructions. In most cases, a generator must be rated between 1 and 10 MW to be classified as self-scheduling.
- **Intermittent generators** operate intermittently as a result of factors outside the operators' control. As a result, they have even less ability to know in advance the amount of energy they will generate than self-schedulers do. Intermittent generators enter forecasts that estimate the energy they will provide and predict when they will be producing. Intermittent generators include wind and run-of-the-river hydro-electric facilities.

### **Non-dispatchable loads**

Non-dispatchable loads simply draw electricity from the grid as needed. They pay the wholesale market price for electricity at the time of consumption, regardless of what the price might be. We determine wholesale prices for non-dispatchable loads on an hourly basis.

Examples of market participants who are non-dispatchable loads include directly connected loads, embedded loads that choose to register in the wholesale market, and local distribution companies (LDCs). LDCs take electricity from the grid and deliver it directly to retail consumers at the correct voltage for their needs. Your local electricity utility is an example of a distributor.

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

### **Transmitters**

Although they are not active participants in terms of the energy markets, transmitters are key market participants. They provide the paths for energy to flow from producers to consumers and their actions have significant impact on reliability and the markets. Transmitters own and maintain the equipment that makes up the grid, which physically connects generators and loads throughout the province and to other jurisdictions (e.g., Quebec and New York).

### 1.3 Market Participants Without Physical Facilities

Many companies participate in the markets without having physical facilities that either produce or consume electricity.

#### Wholesalers

Wholesalers buy energy on the wholesale market, and sell energy and services to other Ontario-based market participants. They can also act as importers or exporters:

- Importers bring energy into Ontario from one of our five neighbouring jurisdictions: Quebec, Manitoba, Michigan, Minnesota or New York
- Exporters purchase energy in Ontario and export it into these neighbouring jurisdictions

### 1.4 Energy Market Participant Summary

In the Ontario wholesale electricity market, there are:

- Generators that are directly connected to the high voltage grid.
- Transmission companies that own, operate and maintain the high voltage system.
- Consumers who are directly connected to the high voltage grid.
- Wholesale sellers who act as retailers or as importers and exporters.
- Local distribution companies (LDCs) who take electricity from the high voltage grid, step it down to lower voltages, and then distribute it to retail customers.
- Embedded generators and large consumers. These can choose to enter the wholesale market if they qualify (e.g., they must be at least 1 MW in size and install wholesale metering). Even if they do not become market participants, generators and large consumers within distributor networks are settled using the wholesale price.

**1.5 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 grid.
  - c) All companies with equipment that is directly connected to the grid must be market participants.
  - d) A company may play only one role in the markets.
  
2. Match the correct term from Column B to the statement in Column A

**COLUMN A**

- \_\_\_ 1. Supply most of the energy in Ontario
- \_\_\_ 2. Account for most of the energy consumed in Ontario
- \_\_\_ 3. Supply energy to retail customers
- \_\_\_ 4. Own the equipment that makes up the IESO- controlled grid
- \_\_\_ 5. Not directly connected to the grid
- \_\_\_ 6. Must be able to adjust power consumption in response to our instructions
- \_\_\_ 7. Submit forecasts of energy production to us
- \_\_\_ 8. Your local electricity 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

**COLUMN B**

- a. Transmitters
- b. Distributors
- c. Dispatchable Generators
- d. Non-dispatchable Generators
- e. Dispatchable Loads
- f. Non-dispatchable Loads
- g. Embedded Facilities

## Skill Check Answers

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 grid.
  - c) **All companies with equipment that is directly connected to the grid must be market participants. ✓**
  - d) A company may play only one role in the markets.
  
2. Match the correct term from Column B to the statement in Column A

### COLUMN A

- c 1. Supply most of the energy in Ontario
- f 2. Account for most of the energy consumed in Ontario
- b 3. Supply energy to retail customers
- a 4. Own the equipment that makes up the IESO- controlled grid
- g 5. Not directly connected to the grid
- e, c 6. Must be able to adjust power consumption in response to our instructions
- d 7. Submit forecasts of energy production to the IESO
- b 8. Your local electricity 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

### COLUMN B

- a. Transmitter
- b. Distributors
- c. Dispatchable Generators
- d. Non-dispatchable Generators
- e. Dispatchable Loads
- f. Non-dispatchable Loads
- g. Embedded Facilities

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

Bids and offers include information we use to:

- Calculate prices
- Determine dispatch instructions

### Objectives

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

- Explain the three main pieces of information included in a bid or offer

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

Dispatchable market participants submit energy bids and offers.

- Dispatchable generators submit offers to sell energy
- Dispatchable loads submit bids to buy energy

Market participants enter bids and offers via the Energy Market Graphical User Interface Workspace in hourly blocks. Collectively, all information included in a bid or offer is referred to as 'dispatch data.' Dispatch data includes three main elements – price/quantity pairs, ramp rates, and the facility's 'Resource ID'.

#### Price /Quantity Pairs

Price/quantity pairs indicate:

- The minimum price a generator will accept for producing a quantity of energy
- The maximum price a load is willing to pay for a quantity of energy

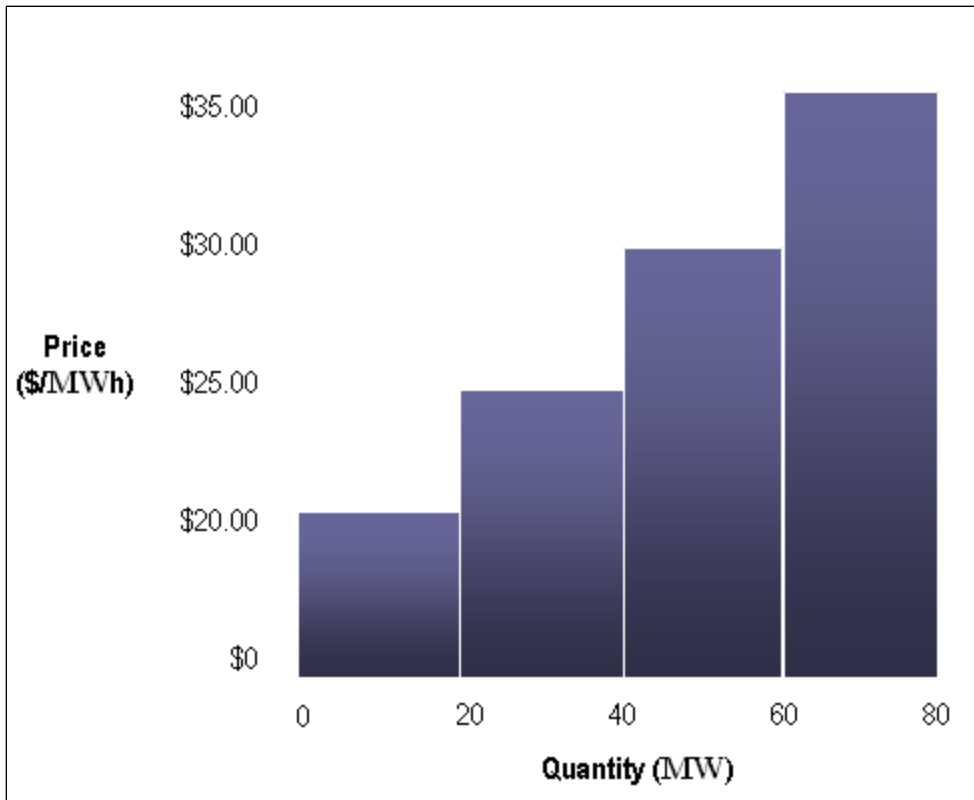
For example:

- A generator might want to sell 100 MW of energy if the price is \$35 or higher. In that case, they would enter a price/quantity pair of (35,100).
- A load might want to buy 50 MW of energy if the price is \$1900 or less. In this case, their price/quantity pair would be entered as (1900,50).

Participants may include up to 20 price/quantity pairs within a single energy bid or offer. For example:

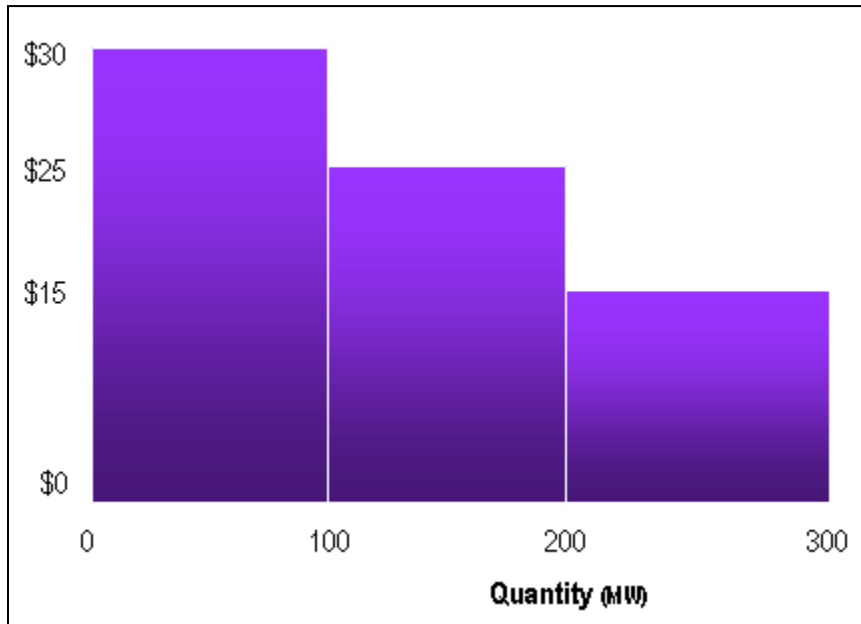
Generator A is willing to provide:

- Up to 20 MW of electricity if the price is between \$20 and \$25
- Up to 40 MW if the price is between \$25 and \$30
- Up to 60 MW if the price is between \$30 and \$35
- Up to 80 MW if the price is above \$35



Load A will consume:

- Up to 100 MW if the price is no higher than \$30
- Up to 200 MW if the price is no higher than \$25
- Up to 300 MW if the price is no higher than \$15



Multiple price/quantity pairs allow the participant to reflect their variable costs (generator) or benefits (load) at different dispatch levels.

### Ramp Rates

Ramp rates are also part of dispatch data. Ramp rates tell us:

- How quickly a generator can increase or decrease the amount of energy it is producing
- How quickly a load can increase or decrease the amount of energy it is using

We will not dispatch a facility to move faster than its submitted ramp rate.

Ramp rates are submitted using megawatt breakpoints; each breakpoint represents the level at which there is a change in the facility's ramping capability. The format is (breakpoint, ramp rate up, ramp rate down). The breakpoints do not have to align with price changes in the price-quantity pairs.

For example, submitting the ramp rate **(70,3,6),(120,4,8)** tells us the facility can:

- Ramp up in the range from 0 to 70 MW at 3 megawatts per minute and ramp down in the range from 70 to 0 MW at 6 megawatts per minute.
- Ramp up in the range from 70 MW to 120 MW at 4 megawatts per minute and ramp down in the range from 120 to 70 MW at 8 megawatts per minute.

Each energy bid or offer can include up to five sets of ramp rates. This allows dispatchable facilities to ensure that their dispatch instructions reflect the facility's actual ramp capability.

### **Resource ID**

We assign a Resource ID to each physical facility that registers in the market. The Resource ID is a unique reference that identifies where the facility connects to the grid.

- Entering a Resource ID with an offer tells us where the supplied energy will enter the grid.
- For a load, the Resource ID tells us where the energy will be withdrawn

This location information is used in our model of the grid and allows us to evaluate the impact of an injection or withdrawal by the facility. This influences what dispatch instructions we will send the facility.

## 2.2 Skill Check: Bids and Offers

1. Which of the following is not dispatch data:
  - a) Price/quantity pairs
  - b) Outage schedules
  - c) Ramp rates
  - d) Resource ID
  
2. If a generator submits a ramp rate of (60,4,6), what does it tell us?
  - a) The facility can ramp from 0 MW of generation to 60 MW in 4 minutes and ramp down to 0 MW from 60 MW in 6 minutes.
  
  - b) The facility can ramp from 0 MW of generation to 60 MW at a rate of 4 MW per 5-minute interval and ramp down to 0 MW from 60 MW at a rate of 6 MW per 5-minute interval
  
  - c) The facility can ramp from 0 MW of generation to 60 MW at a rate of 4 MW per minute and ramp down to 0 MW from 60 MW at a rate of 6 MW per minute
  
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 the price of electricity.

**Skill Check Answers**

1. Which of the following is not dispatch data:
  - a) Price/quantity pairs
  - b) Outage schedules ✓**
  - c) Ramp rates
  - d) Resource ID
  
2. If a generator submits a ramp rate of (60,4,6), what does it tell us?
  - a) The facility can ramp from 0 MW of generation to 60 MW in 4 minutes and ramp down to 0 MW from 60 MW in 6 minutes.
  - b) The facility can ramp from 0 MW of generation to 60 MW at a rate of 4 MW per 5- minute interval and ramp down to 0 MW from 60 MW at a rate of 6 MW per 5-minute interval
  - c) The facility can ramp from 0 MW of generation to 60 MW at a rate of 4 MW per minute and ramp down to 0 MW from 60 MW at a rate of 6 MW per minute ✓**
  
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 the price of electricity.

## 3. Determining the Market Clearing Price

So far, we have discussed bids and offers. The next step is to look at what we do with this dispatch data. This chapter explains the basic concepts behind how we determine the market clearing price. A later chapter will look at how we determine the operating instructions we send to dispatchable participants (i.e., 'dispatch instructions').

### Objectives

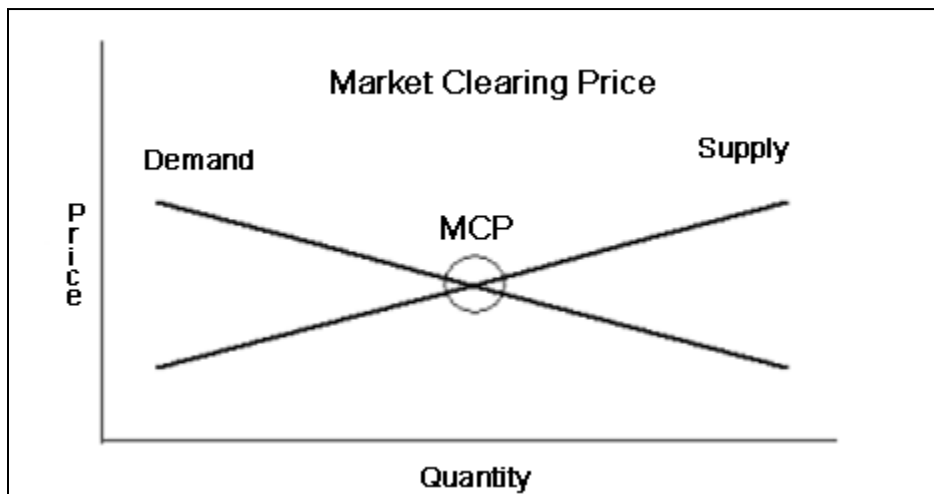
After you have completed this section, you will be able to:

- Determine the market clearing price for an interval, given the bids, offers and demand
- Identify components of supply and demand in Ontario

### 3.1 Determining the Market Clearing Price (MCP)

In a competitive market, the price of a product is based on supply and demand:

- The quantity demanded tends to increase as the price drops
- The quantity produced tends to increase as the price increases
- The price tends to be stable when it provides enough incentive to produce the quantity demanded



In the case of electricity, some forms of generation have higher fuel costs than others. If the price of electricity does not cover the cost of the fuel used to produce the electricity, the company might be better off not running their plant. And, if the price of electricity is high, consumer demand should fall through measures such as conservation and load shifting.

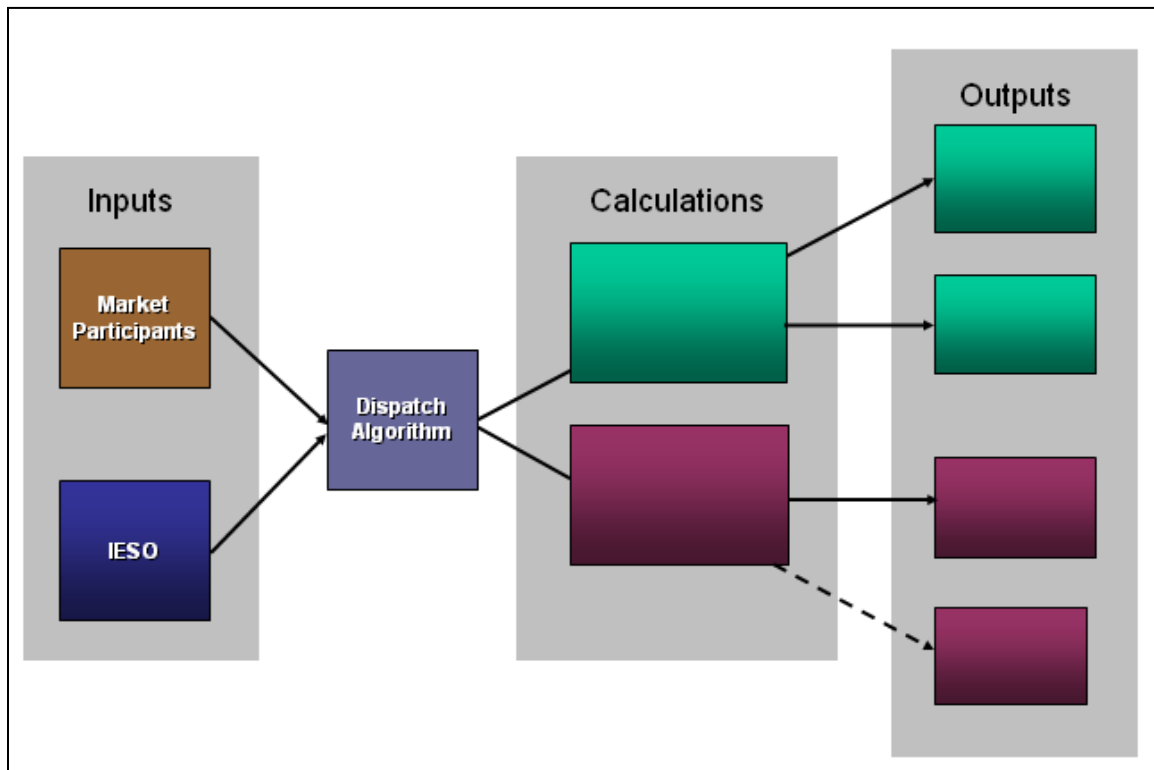
#### The dispatch algorithm

Once market participants have submitted their bids and offers, we take this information and run it through an optimization program referred to as the ‘dispatch algorithm’. The dispatch algorithm determines the settlement price and dispatch instructions to meet demand for each 5-minute interval of every day.

The dispatch algorithm must consider many factors. Some are provided by market participants (like bids and offers), and some are provided by us (like a model of the transmission system).

The dispatch algorithm is run in two modes:

Unconstrained Mode	Constrained Mode
Ignores most physical limitations of the system inside Ontario	Considers all physical limitations of the system
Produces settlement prices and ‘market schedules’	Produces dispatch instructions and informational ‘shadow prices’

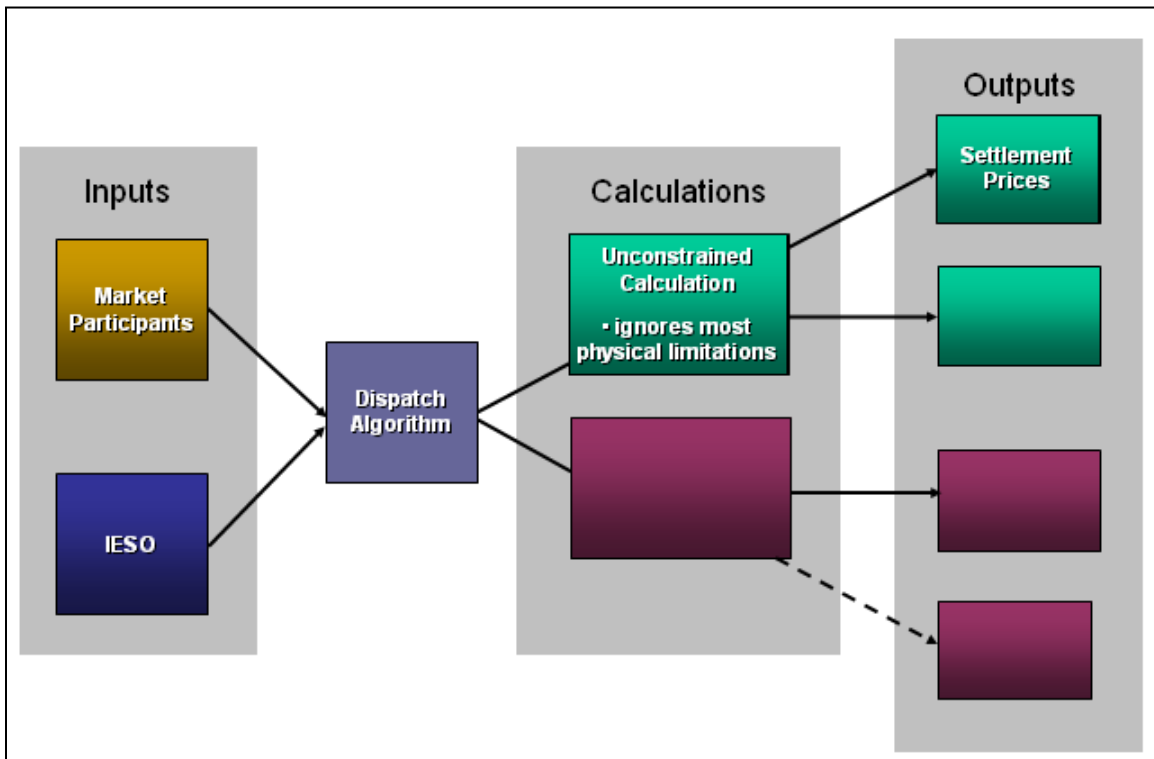


Each of these modes has two outputs. We will discuss these outputs through much of the rest of this document.

#### The Unconstrained Mode and Price Setting

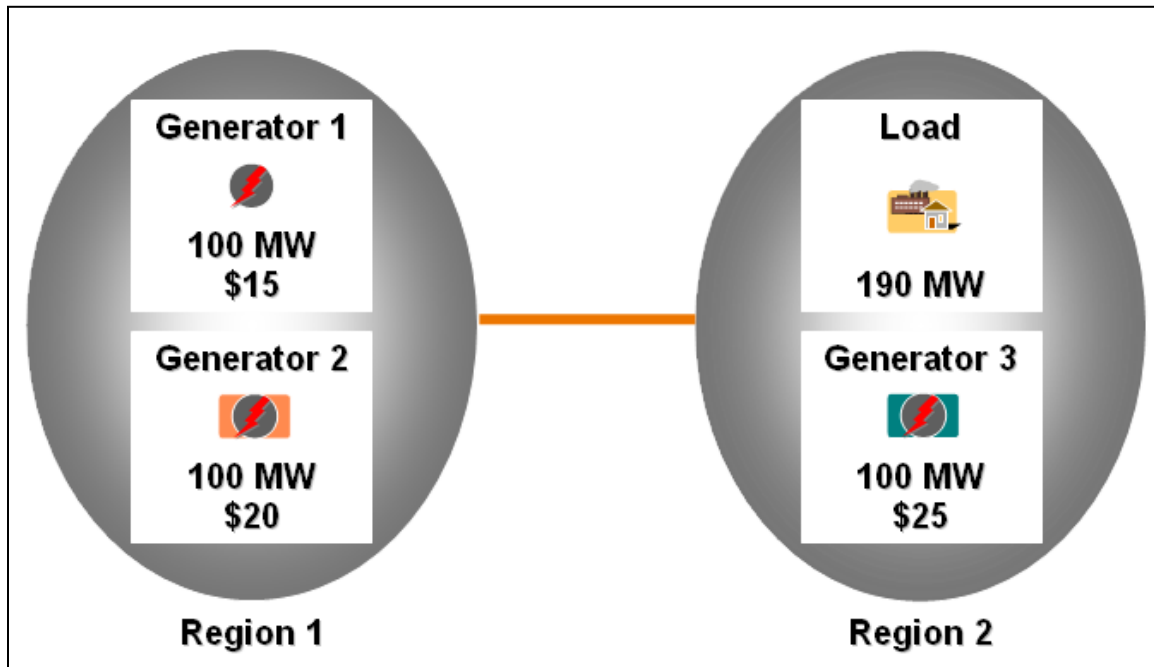
One of outputs of the unconstrained mode is the 5-minute market clearing price (MCP) for electricity within Ontario. This price is the same throughout the province.

To calculate a uniform price, the unconstrained mode ignores the existence of a transmission system inside Ontario. It assumes that all Ontario load and generation are located at the exact same point on the grid. This allows it to develop a market clearing price that is the same for all load and generation throughout the province because it ignores the losses or other restrictions that can cause prices to differ from location to location on the grid.

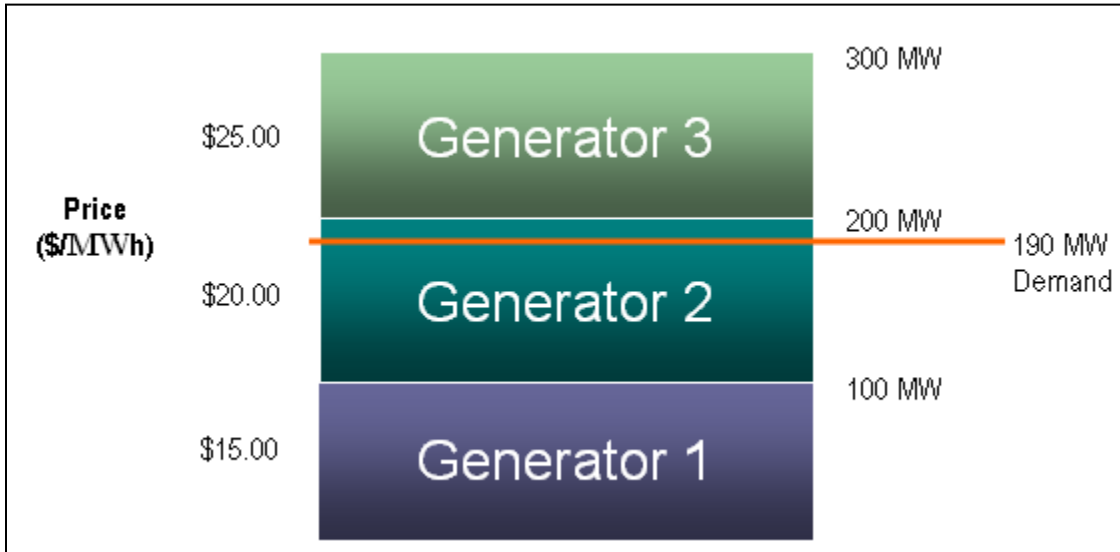


Let's look at a basic example of how the unconstrained mode works. Assume that:

- There are two regions in the market.
- In Region 1, Generator 1 offers 100 MW if the price is \$15 or higher and Generator 2 offers 100 MW if the price is \$20 or higher.
- 190 MW of load is located in Region 2. Also in Region 2 is Generator 3, which offers 100 MW if the price is \$25 or higher.



To determine the market clearing price, the unconstrained mode stacks these offers from least expensive to most expensive. It then determines the demand: 190 MW in this example. The market clearing price would be set at \$20 because there is 190 MW of supply priced at or below \$20.



In this example, the transmission line between the two regions was capable of carrying all of the energy from Region 1 to Region 2. Would the market clearing price be different if the transmission line were restricted to a maximum flow of 150 MW?

The answer is: No, it would not be different, because the unconstrained mode of the algorithm does not recognize transmission limits inside Ontario.

### **3.2 Non-dispatchable Loads and Generators**

Dispatchable facilities place bids and offers that indicate the price they are willing to pay or receive for electricity. We then instruct these facilities where to operate.

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

Although non-dispatchable supply and load do not provide price information, they do have an impact on price as we will explain in the next section.

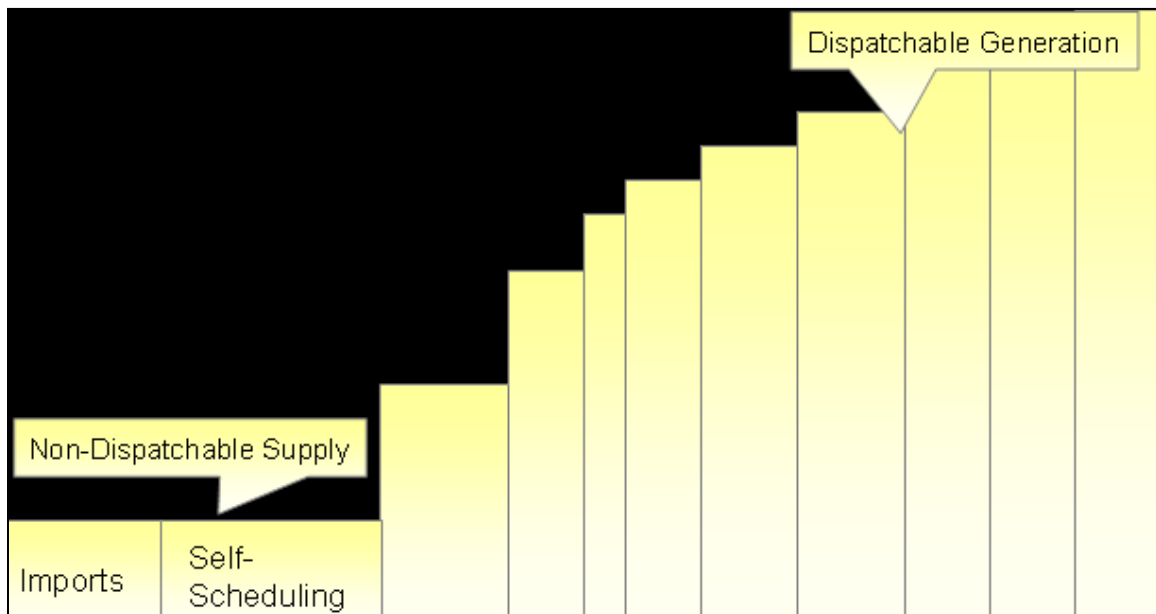
### 3.3 Components of Supply and Demand

Dispatchable generators are not the only suppliers of energy. Self-scheduling and intermittent generators and imports also play a role.

Self-scheduling and intermittent generators are 'price takers' because they accept whatever the prevailing price is at the time they generate, no matter how low. This makes them the least expensive available supply. Therefore, we use electricity available from these sources first, as a block, before we consider energy available from dispatchable facilities.

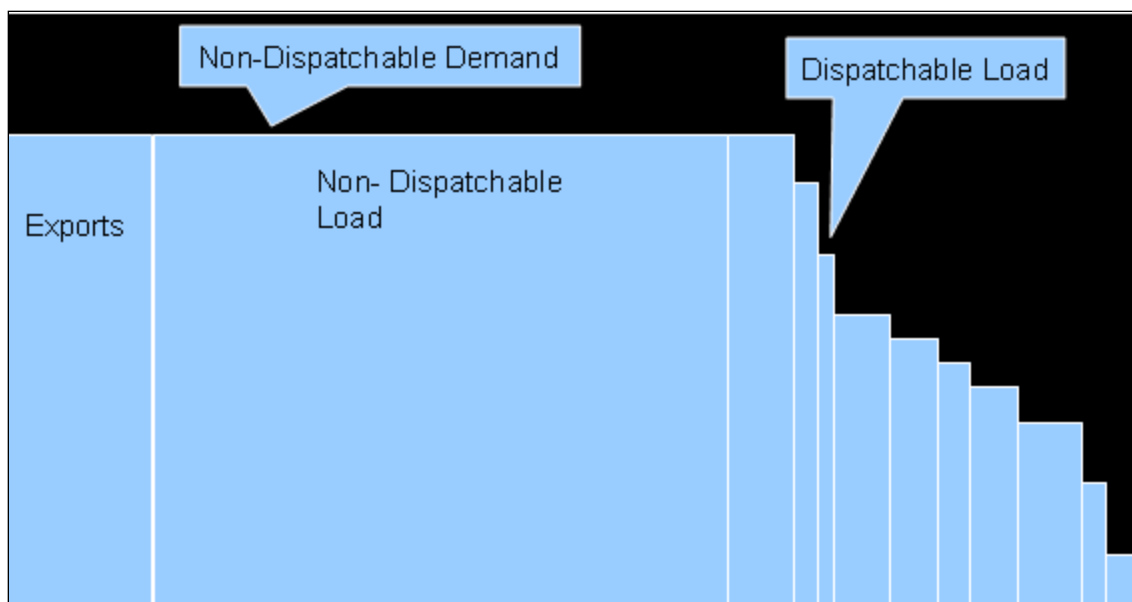
Imports are supply that is scheduled to enter the province from another jurisdiction. Due to scheduling protocols, they are scheduled hour-ahead. Therefore, in real-time operation, for any given hour, imports are fixed. This means that they are scheduled to flow for the entire hour regardless of the price. As a result, they are treated like non-dispatchable generation in real-time, i.e., must-take megawatts. (For more information on imports and exports, see the [Interjurisdictional Energy Trading](#) workbook, available in the [Training](#) web pages.)

Offers from dispatchable generators provide the only variable resources in the supply stack available to the dispatch algorithm.

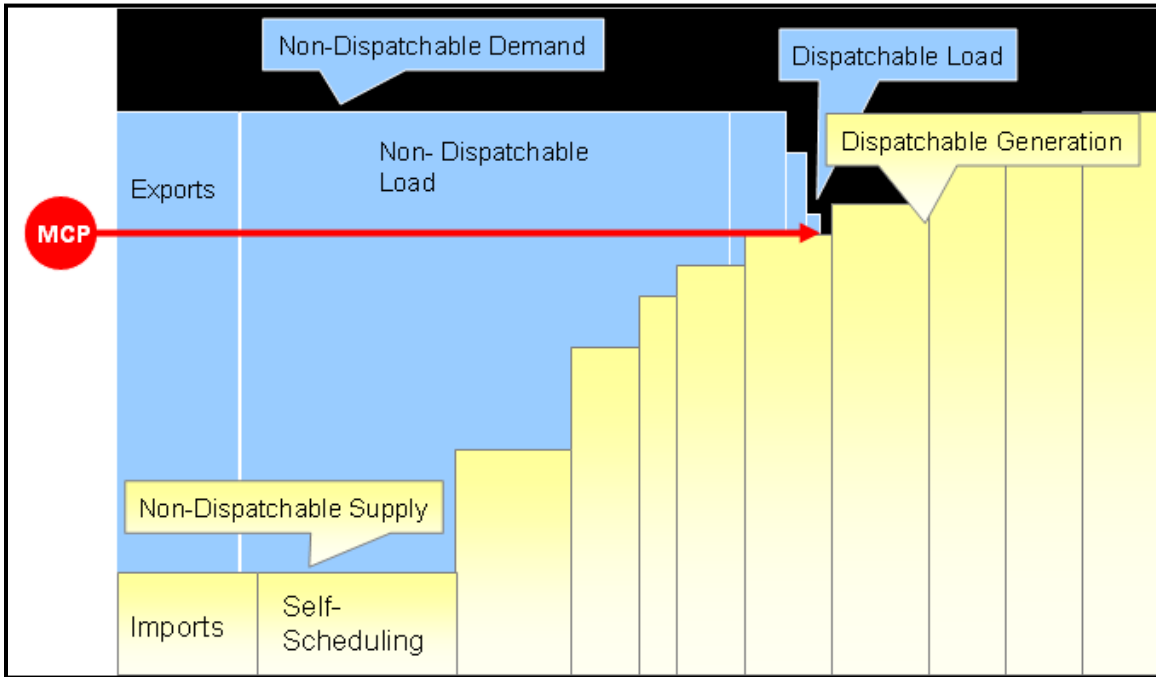


Demand is also made up of several components. It includes:

- Bids from dispatchable loads.
- Non-dispatchable load.
- Exports – like imports, exports are fixed within the hour time window.
- Losses that occur when moving electricity through the province. These must be made up by ensuring that slightly more energy is supplied than the other forms of demand will consume.
- Exports, non-dispatchable loads, and losses 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 5-minute MCP is set based on where these two curves intersect.



### 3.4 Prices: 5-Minute MCP vs. HOEP

#### **Dispatchable facilities**

Dispatchable facilities are expected to respond to dispatch instructions that are determined every five minutes. The market clearing price (MCP) used for dispatchable facilities is set every five minutes, matching each dispatch interval.

#### **Non-dispatchable facilities**

Non-dispatchable facilities are different. They are 'price takers'. They set their own generation or demand levels without dispatch instructions.

Non-dispatchable facilities are paid for their production or pay for their consumption based on the Hourly Ontario Energy Price (HOEP). This price is the average of the twelve five-minute prices during the hour.

### 3.5 Skill Check: Determining the Market Clearing Price

For the following examples, determine the market clearing price:

**Exercise 1:**

Gen X offers up to 125 MW if the price is \$20 or higher

Gen Y offers up to 100 MW if the price is \$25 or higher

Gen Z offers up to 75 MW if the price is \$15 or higher

Load A is a non-dispatchable load consuming 150 MW

**Exercise 2:**

Gen X offers up to 75 MW if the price is \$28 or higher

Gen Y offers up to 75 MW if the price is \$18 or higher

Gen Z offers up to 150 MW if the price is \$25 or higher

Load A is a non-dispatchable load consuming 250 MW

**Exercise 3:**

Gen X offers up to 125 MW if the price is \$20 or higher

Gen Y offers up to 80 MW if the price is \$30 or higher

Gen Z offers up to 150 MW if the price is \$25 or higher, and up to 200 MW if the price is \$30 or higher

Load A is a non-dispatchable load consuming 150 MW

Load B will consume up to 75 MW if the price is \$25 or less

Load C will consume 125 MW if the price is \$20 or less

**Skill Check: Answers****Exercise 1:**

Gen X offers 125 MW at \$20

Gen Y offers 100 MW at \$25

Gen Z offers 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 offers 75 MW at \$28

Gen Y offers 75 MW at \$18

Gen Z offers 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 offers up to 125 MW if the price is \$20 or higher

Gen Y offers up to 80 MW if the price is \$30 or higher

Gen Z offers up to 150 MW if the price is \$25 or higher, and up to 200 MW if the price is \$30 or higher

Load A is a non-dispatchable load consuming 150 MW

Load B will consume up to 75 MW if the price is \$25 or less

Load C will consume 125 MW if the price is \$20 or less

**Answer: Market clearing price is \$25**

## 4. Market Schedules

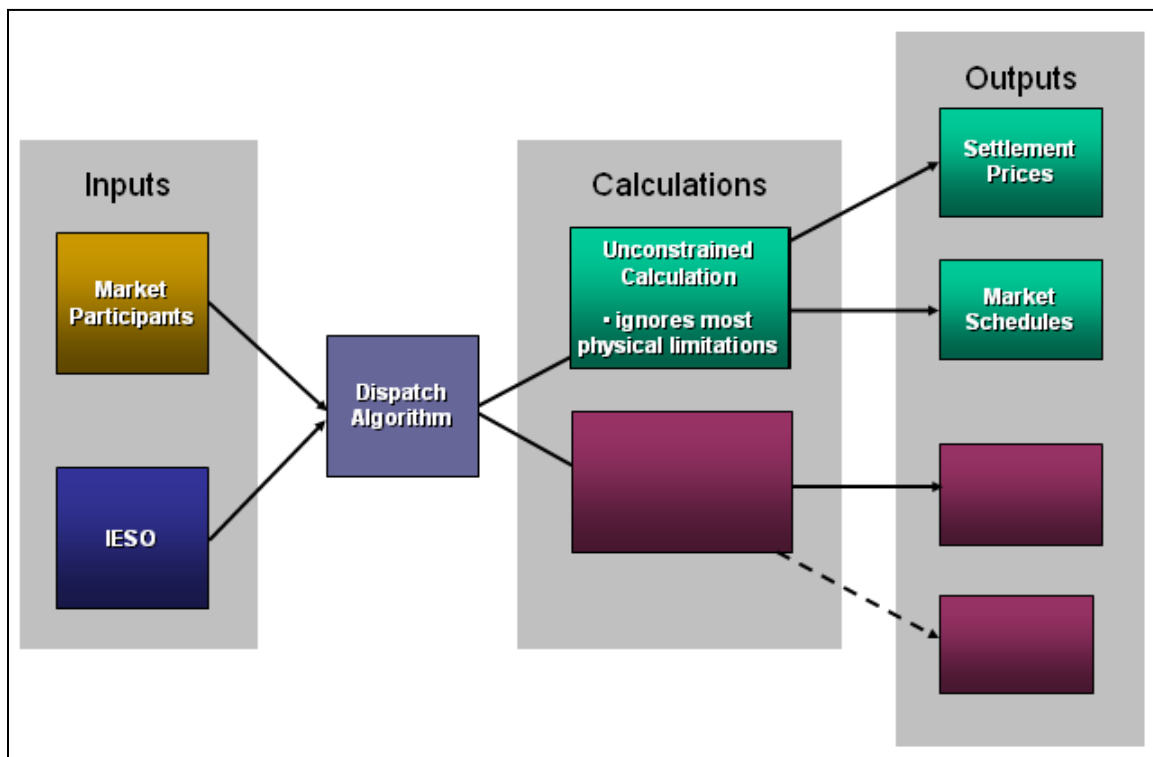
In addition to determining price, the unconstrained mode of the algorithm also determines 'market schedules'.

### Objectives

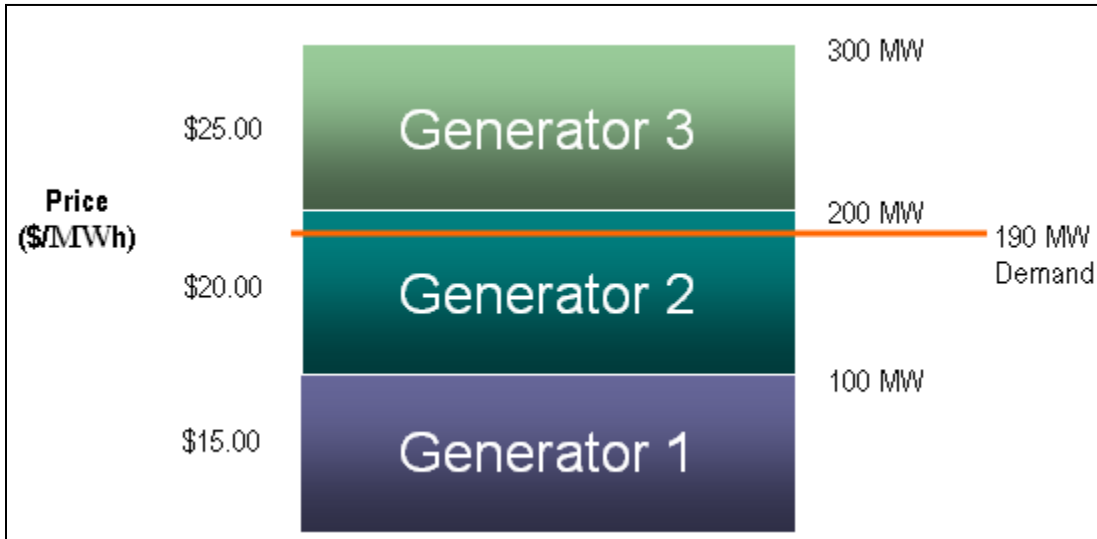
After you have completed this section, you will be able to define a market schedule.

#### 4.1 What is a Market Schedule

A facility's market schedule is how the unconstrained mode of the dispatch algorithm would have dispatched the facility – think of it as a purely economic solution based on bids and offers. (Recall that the unconstrained mode ignores most physical limitations on the grid.)

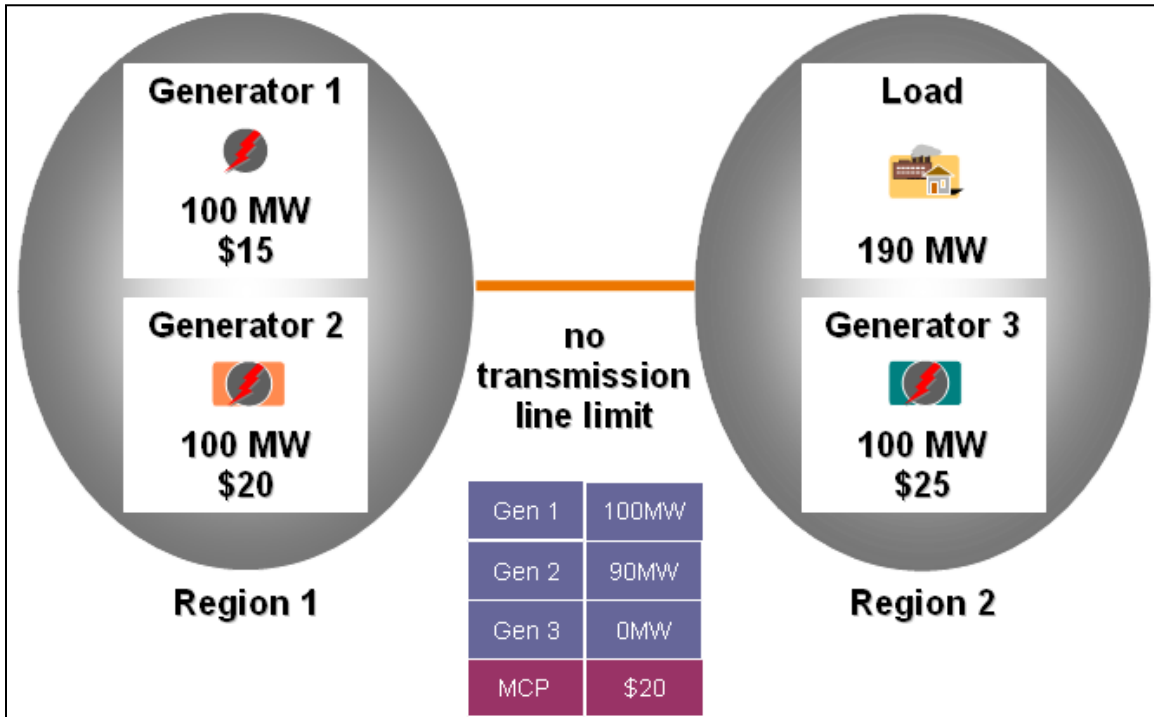


Let's look at the price-setting example from above. In this example, the unconstrained mode stacked the offers from least expensive to most expensive, and determined that the market clearing price would be \$20.



What would the generator's market schedule be?

- Generator 1 had the most economical offer at \$15. With a market clearing price of \$20, Generator 1's market schedule would be 100 MW – all that it offered.
- Generator 2 had the next most economical offer. Demand fell part way across Generators 2's offer. Therefore, Generator 2 would have a market schedule of 90 MW.
- Because Generator 3's \$25 offer lies entirely above the market clearing price, it would have a market schedule of 0 MW.



Market schedules can be different from actual dispatch schedules, as we will discuss in the next chapter. This difference can affect a facility's economics. We will discuss this in Chapter 6 *Congestion Management Settlement Credits*.

## 4.2 Skill Check: Market Schedules

For the following examples, determine the market schedules for the dispatchable facilities.

### Exercise 1:

Gen A offers 110 MW at \$25

Gen B offers 50 MW at \$35

Gen C offers 25 MW at \$15

Load A is a non-dispatchable load consuming 150 MW

### Exercise 2:

Gen X offers 130 MW at \$15

Gen Y offers 75 MW at \$20

Gen Z offers 100 MW at \$17

Load A is a non-dispatchable load consuming 200 MW

### Exercise 3:

Gen X offers up to 125 MW if the price is \$20 or higher

Gen Y offers up to 80 MW if the price is \$30 or higher

Gen Z offers up to 150 MW if the price is \$25 or higher, and up to 200 MW if the price is \$30 or higher

Load A is a non-dispatchable load consuming 150 MW

Load B will consume up to 75 MW if the price is \$25 or less

Load C will consume 125 MW if the price is \$20 or less

**Skill Check: Answers**

For the following examples from Section 3, determine the market schedule for the dispatchable facilities:

**Exercise 1:**

Gen A offers 110 MW at \$25

Gen B offers 50 MW at \$35

Gen C offers 25 MW at \$15

Load A is a non-dispatchable load consuming 150 MW

**Market schedules:**

Gen A = 110 MW

Gen C = 25 MW

Gen B = 15 MW

**Exercise 2:**

Gen X offers 130 MW at \$15

Gen Y offers 75 MW at \$20

Gen Z offers 100 MW at \$17

Load A is a non-dispatchable load consuming 200 MW

**Market schedules:**

Gen X = 130 MW

Gen Y = 0 MW

Gen Z = 70 MW

**Exercise 3:**

Gen X offers up to 125 MW if the price is \$20 or higher

Gen Y offers up to 80 MW if the price is \$30 or higher

Gen Z offers up to 150 MW if the price is \$25 or higher, and up to 200 MW if the price is \$30 or higher

Load A is a non-dispatchable load consuming 150 MW

Load B will consume up to 75 MW if the price is \$25 or less

Load C will consume 125 MW if the price is \$20 or less

**Market schedules:**

Gen X = 125 MW

Gen Y = 0 MW

Gen Z = 100 MW

Load B = 75 MW

Load C = 0 MW

## 5. Determining Dispatch Instructions

Now that we have discussed the concepts behind determining the electricity price and market schedules, we can examine how dispatchable participants receive their dispatch instructions. These dispatch instructions take into account both economics and physical limitations.

### Objectives

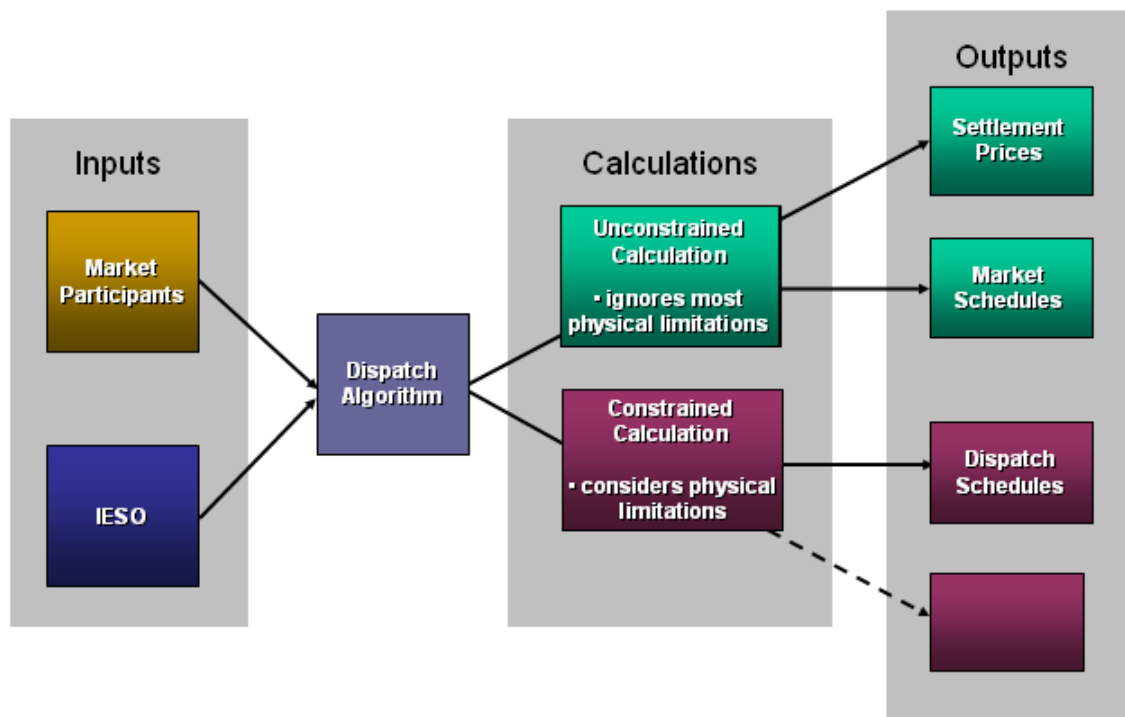
After you have completed this section, you will be able to:

- Identify types of physical limitations that impact dispatch instructions
- Determine dispatch instructions, given supply, demand, and system conditions

### 5.1 The Constrained Mode of the Dispatch Algorithm

As we have seen, the unconstrained mode of the dispatch algorithm ignores physical limitations of the electricity system when it determines prices and market schedules.

While we can use this method to determine market economics, we cannot use it when deciding how to dispatch facilities. We must consider the actual physical characteristics of the grid, or else system reliability will be compromised.



We use the constrained mode of the algorithm to determine dispatch instructions because it considers both economics and system limitations. Initially, it stacks offers and bids economically. It then determines whether or not it can dispatch the facilities in economic order and still respect system limitations. The limitations considered are:

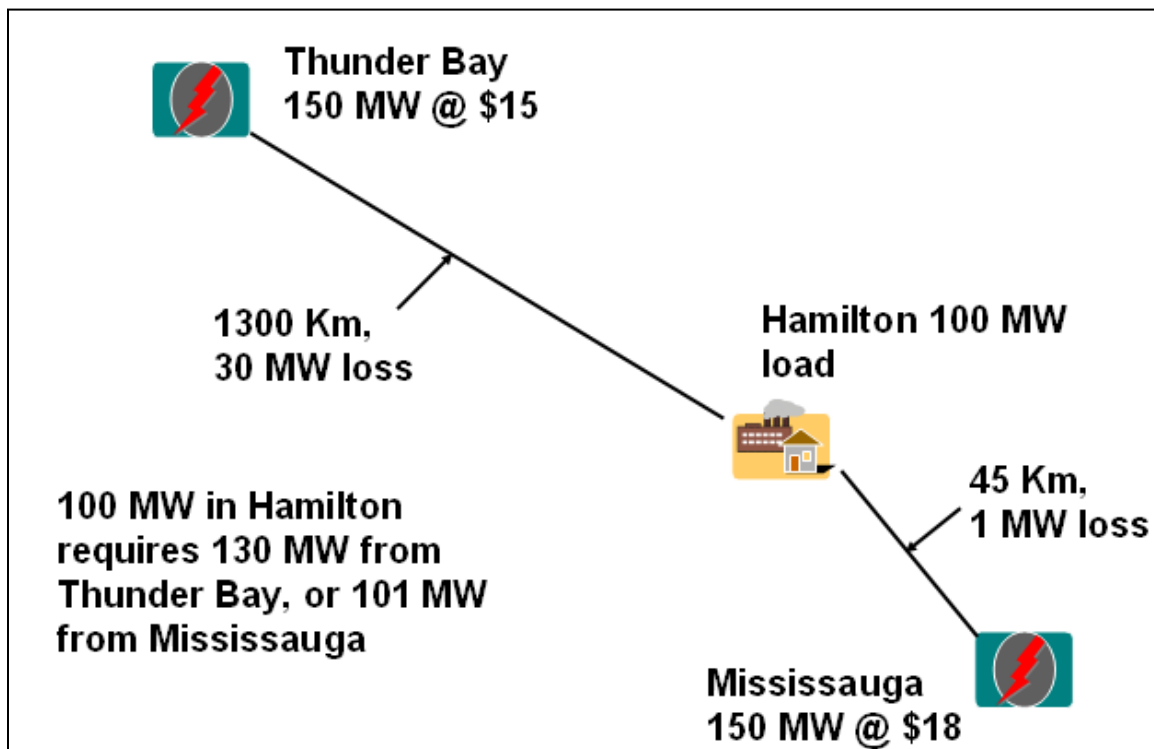
- Losses associated with moving electricity through the system
- Limitations on how much electricity can be moved through the transmission lines, while respecting security limits
- The ability of facilities to change their operating point (i.e., their ramp rate)

We can illustrate how the constrained mode determines dispatch instructions with some examples.

### Impact of losses on dispatch instructions

Assume a simple case with only two suppliers and one load in the market.

- In Hamilton, there is a 100 MW load
- A generator in Thunder offers 150 MW if the price is \$15 or greater
- The generator in Mississauga offers 150 MW if the price is \$18 or more



Recall that the market clearing price ignores losses. In this example, the market clearing price is \$15 because the Thunder Bay supplier can provide enough electricity to satisfy the entire load.

But does it make sense to actually have Thunder Bay supply the electricity? For illustrative purposes, we assume a 30 MW loss for energy travelling from Thunder Bay to Hamilton. This means that the generator must input 130 MW at Thunder Bay to have 100 MW actually reach the load. The combined cost to serve the load and to overcome losses would be:

$$130 \text{ MW} \times \$15 = \$1950$$

Assume that to get energy from Mississauga to Hamilton involves a loss of only 1 MW. The total cost to have the Mississauga supplier serve the load would be:

$$101 \text{ MW} \times \$18 = \$1818$$

Because getting the energy from Mississauga is so much less expensive, we will:

- Determine the MCP at \$15, based on the unconstrained algorithm, which does not recognize system losses
- Dispatch Mississauga to generate 101 MW
- Pay Mississauga \$15 per MW for the energy. They will also receive another \$3/MW through a congestion management settlement credit (covered in Chapter 6)

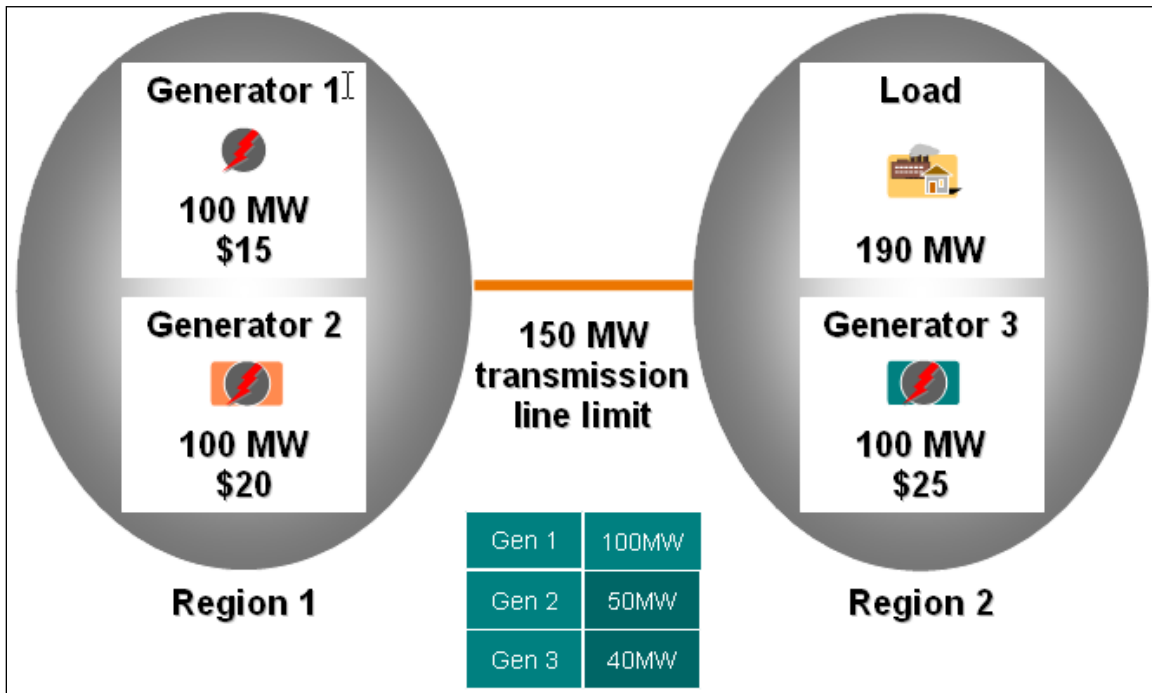
Because the Thunder Bay offer price is the same as the MCP, they are indifferent to whether or not they operate, because they would see no profit over and above their costs (at a market clearing price of \$15).

### **Impact of transmission limits on dispatch instructions**

Let's look at an example of how transmission limits impact dispatch instructions.

This is the same example used earlier to discuss setting the market clearing price. This time, though, the transmission lines linking the two regions can carry only 150 MW.

- Generator 1 has the least expensive offer at \$15. Therefore, we would dispatch Generator 1 to provide all 100 MW that it offered. That leaves 50 MW of available transmission capacity between the regions.
- Generator 2 has the next most economical offer. Therefore, we would want to cover the remaining 90 MW of load. Dispatching it this way, though, would compromise reliability because there is insufficient transmission line capacity. We would dispatch Generator 2 to 50 MW to respect the transmission line limit.
- That gives us 150 MW flowing from Region 1 to Region 2. We have to meet all 190 MW of load, however as it is non-dispatchable. Therefore, we would dispatch Generator 3 to 40 MW to serve the remaining demand.

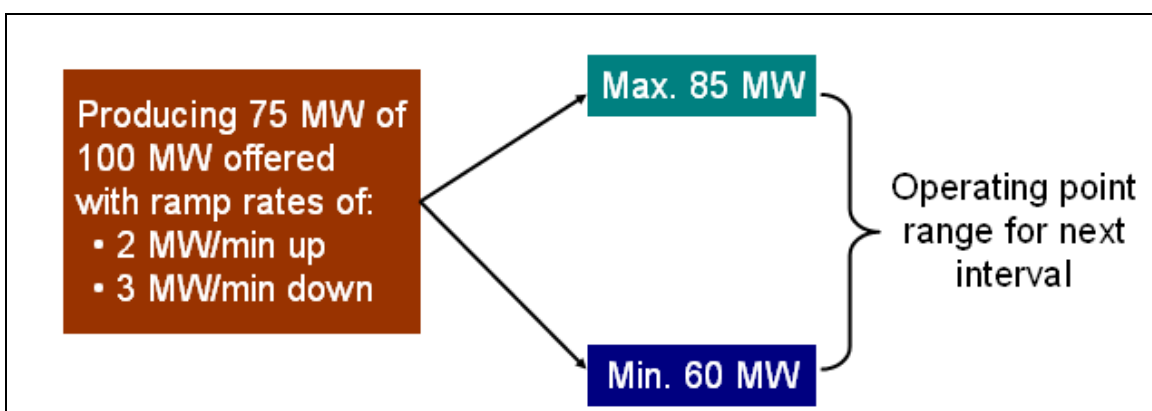


### The impact of ramp rates on dispatch

Facilities cannot adjust their electricity production or consumption instantly. For example, a generator requires time to move from 100 to 200 MW of output. Conversely, it would need time to reduce its output from 200 MW back down to 100 MW.

When the algorithm creates dispatch instructions, it takes into account the current operating point of the facility and the rate of change that the facility can achieve, as indicated by the ramp rates submitted as part of the bid or offer.

The ramp rate creates a range of possible dispatches for a facility. For example, assume that a generator offers 100 MW with a ramp rate of 2 MW/minute up and 3 MW/minute down. This means that it can increase its output by 10 MW or decrease its output by 15 MW during a 5-minute dispatch interval.



If this generator is currently producing 75 MW, it can increase its output to 85 MW or decrease its output to 60 MW during the next 5-minute interval. We would not dispatch it outside of this range, because doing so would compromise the unit and harm reliability.

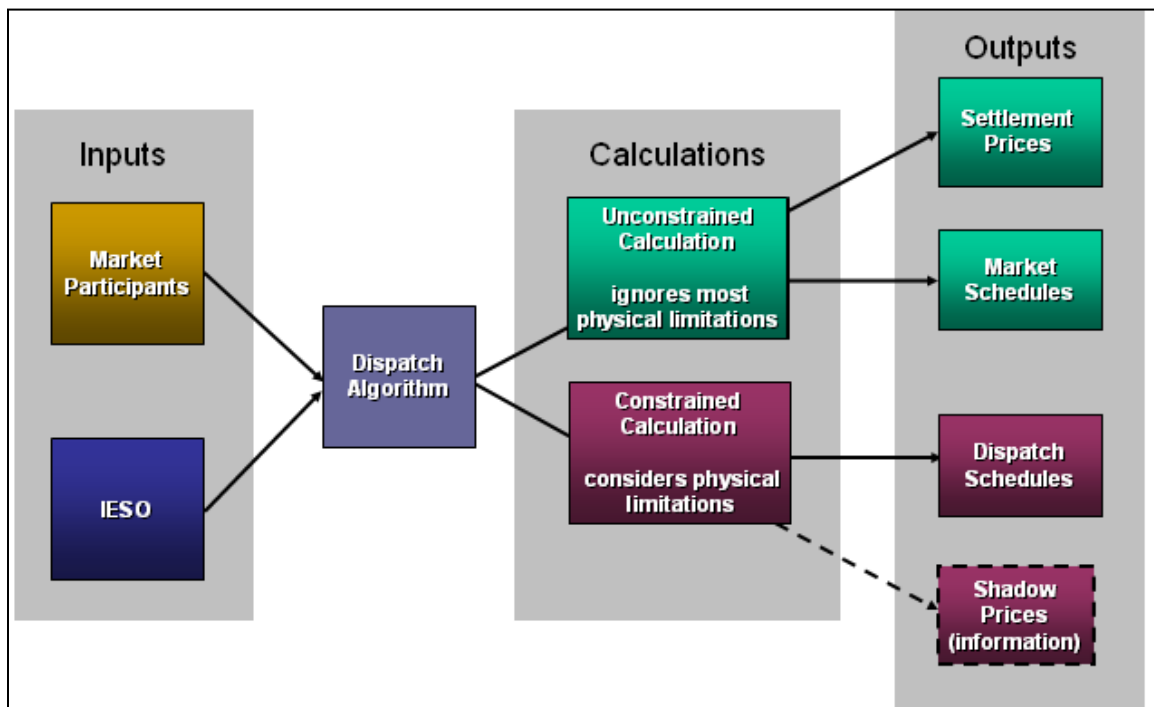
### Shadow Prices

The constrained mode has another output in addition to dispatch instructions - shadow prices. Shadow prices are the cost of energy at each injection and withdrawal point in Ontario. We produce shadow prices for informational purposes only.

Participants are paid and charged using the unconstrained price as explained above. We do not settle participants using shadow prices. Instead, shadow prices reflect how a participant was actually dispatched because these prices include the effects of losses, ramp rates and transmission congestion at their location. This means that if the shadow price at a generator's location was:

- Higher than their offer price, they were dispatched on
- Lower than their offer, they were dispatched off
- Equal to their offer, they were partially dispatched on

Dispatchable participants can use this information to adjust their bidding or offering strategy. Shadow prices are published on our 'ftp' web page, which you can access via a link from our Market Data page.



### **Constrained Mode Summary**

The constrained mode of the algorithm takes into account all the physical limitations of the system – including losses, transmission limitations and ramp rates – when creating dispatch instructions. It also produces informational shadow prices.

The constrained mode considers economics; as far as possible, it dispatches resources in order, from least to most expensive. However, it will not violate the reliability of the grid by ignoring the physical limitations of the system or ramp rates of the dispatchable resources. This means that two generators offering electricity at the same price can be dispatched differently depending on the effects of these physical limitations.

## **5.2 Dispatch Instructions**

The constrained mode of the dispatch algorithm determines dispatch instructions for every 5-minute interval. They are sent at the start of an interval and indicate the energy operating point that the facility should achieve by the end of interval.

We send dispatch instructions to participants' dispatch workstations. A dispatch workstation is a dedicated computer that is used solely to manage dispatch instructions.

We send dispatch instructions only if there is a required change in operating point. If a facility does not receive an instruction for a particular interval, it means that they are to maintain an operating point according to the last instruction received.

Because of the essential role that dispatchable facilities play in maintaining system reliability, facilities must comply with dispatch instructions as closely as possible.

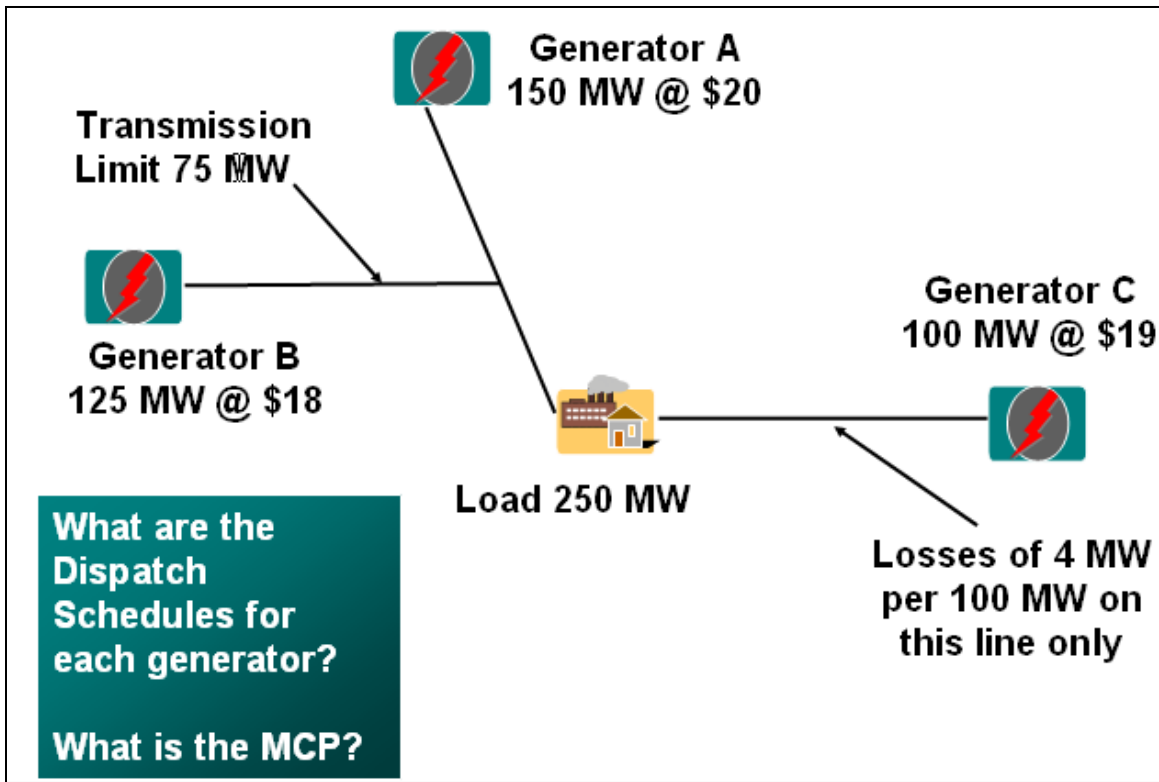
There are exceptions, however. You can refuse dispatch instructions for reasons of public or worker safety, equipment damage, or legal requirements.

### 5.3 Skill Check: Determining Dispatch Instructions

1. Dispatch instructions are determined by:
  - a) The unconstrained mode of the dispatch algorithm
  - b) The constrained mode of the dispatch algorithm
  - c) The unconstrained mode of the dispatch algorithm, taking current system conditions into consideration
  - d) The constrained algorithm, ignoring system conditions
  
2. If a dispatchable load is currently consuming 50 MW, and has a ramp rate of 3 MW/minute up and 6 MW/minute down, what is the range of possible dispatches for the next interval:
  - a) Up to 53 MW or down to 44 MW
  - b) Up to 56 MW or down to 44 MW
  - c) Up to 65 MW or down to 38 MW
  - d) Up to 65 MW or down to 20 MW
  
3. True or False:

Participants are charged or paid based on the shadow price at their location.

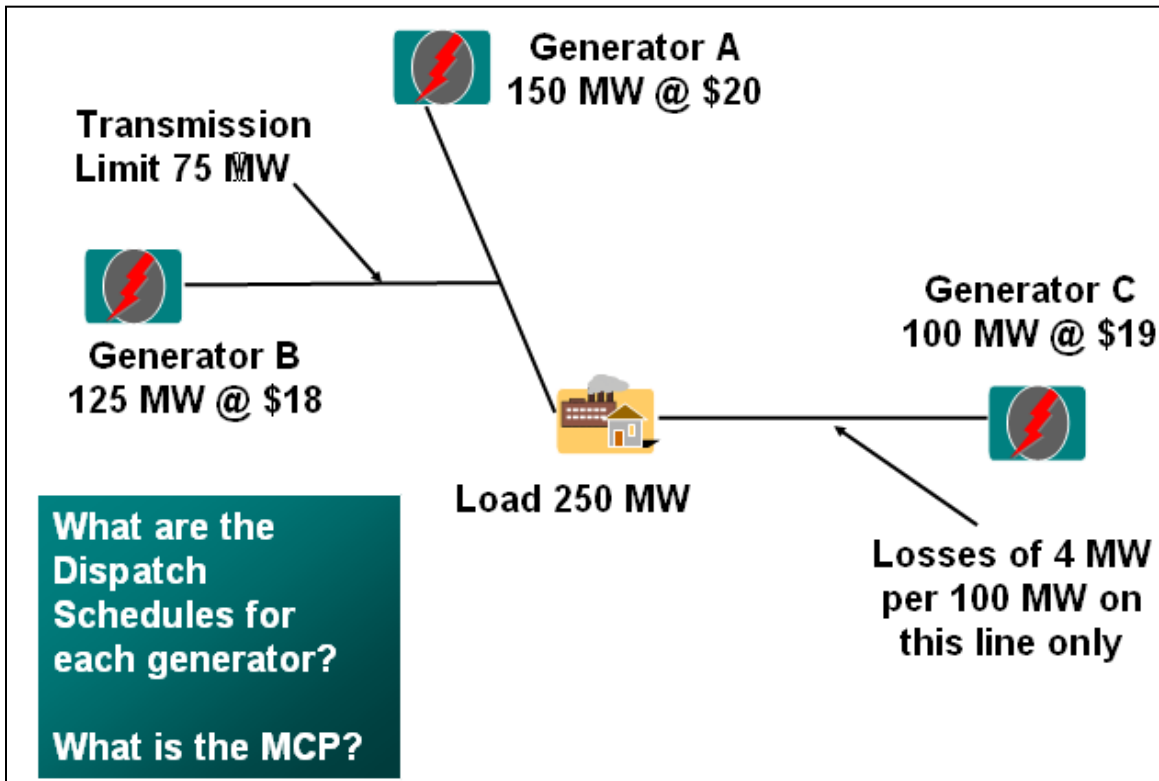
4. In the following chart, determine the dispatch instructions and market clearing price.



**Skill Check: Answers**

1. Dispatch instructions are determined by:
  - a) The unconstrained mode of the dispatch algorithm
  - b) **The constrained mode of the dispatch algorithm ✓**
  - c) The unconstrained mode of the dispatch algorithm, taking current system conditions into consideration
  - d) The constrained algorithm, ignoring system conditions
  
2. If a dispatchable load is currently consuming 50 MW, and has a ramp rate of 3 MW/min up and 6 MW/min down, what is the range of possible dispatches for the next interval:
  - a) Up to 53 MW or down to 44 MW
  - b) Up to 56 MW or down to 44 MW
  - c) Up to 65 MW or down to 38 MW
  - d) **Up to 65 MW or down to 20 MW ✓**
  
3. True or **False ✓**  
Participants are charged or paid based on the shadow price at their location.

4. In the following chart, determine the dispatch instructions and market clearing price.



Market Clearing Price = \$20

Generator A dispatch instruction = 79 MW

Generator B dispatch instruction = 75 MW

Generator C dispatch instruction = 100 MW

## 6. Congestion Management Settlement Credits

In the previous chapter we saw how introducing physical constraints can lead to dispatch instructions that are different from what we would like to do if there were no physical constraints. In this chapter we discuss how we settle the affected facilities.

### Objectives

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

- Determine operating profits, given offer or bid price, the market clearing price (MCP) and schedules
- Determine congestion management settlement credits given supply, demand, system limitations and the MCP

### 6.1 Operating Profit

Operating profit is a key concept. The market rules assume that participants place bids and offers based on their marginal cost and benefit. If a participant's dispatch schedule is different from their market schedule, their operating profit may be affected.

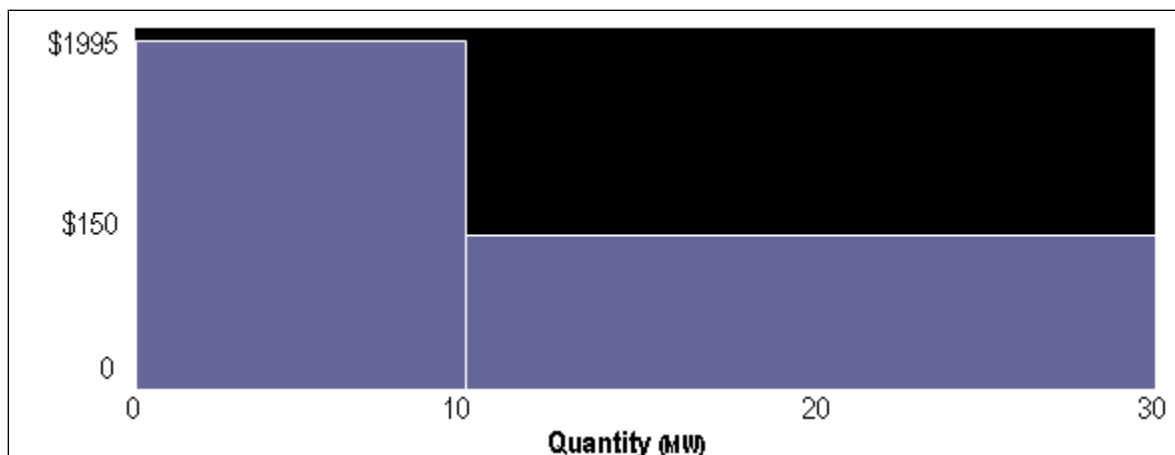
Operating profit for a generator is the difference between the revenue received for the energy sold and the cost of supplying the energy, as represented by their offer price.

For a dispatchable load, operating profit is the difference between the cost of purchasing energy, and the benefit they realize by using the energy, as represented by their bid price. Therefore:

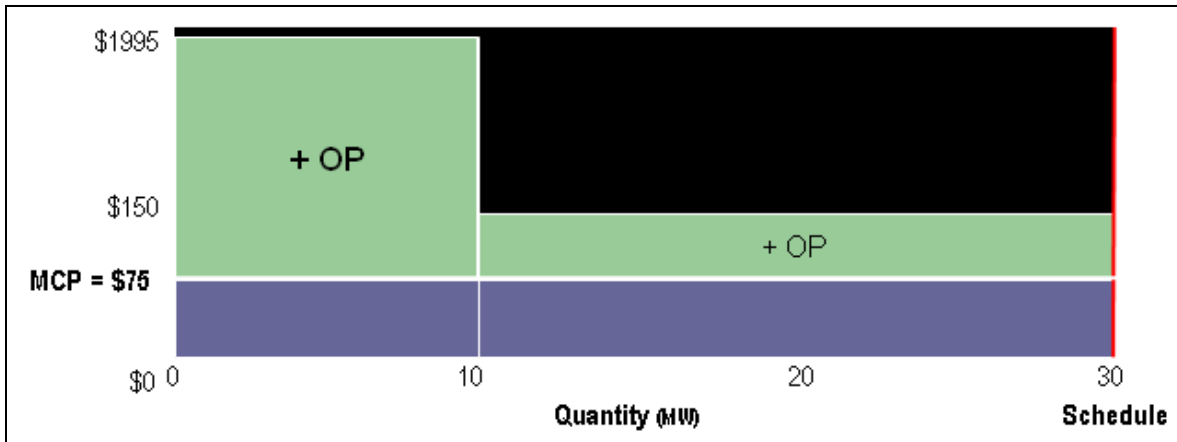
- For generators: Operating Profit = (MCP - Offer Price) x Quantity
- For loads: Operating Profit = (Bid Price - MCP) x Quantity

#### Examples:

Assume that a load bid \$1995 for the first 10 MW of consumption and \$150 for the next 20 MW of consumption.

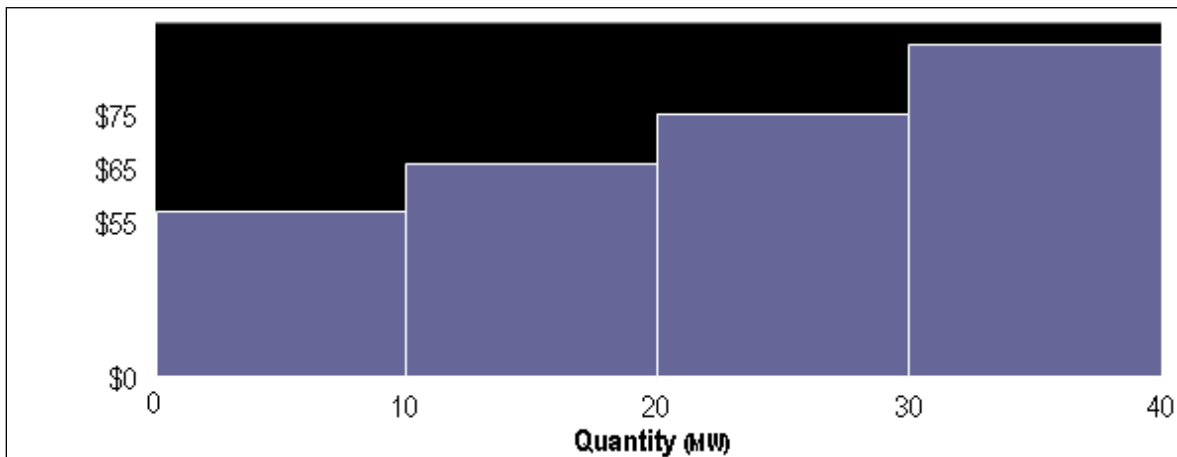


A load's operating profit is the difference between what they are willing to pay and what they have to pay. If the market clearing price was \$75 and the load was scheduled to 30 MW, the area above the MCP line in the figure below is the operating profit (represented by +OP).

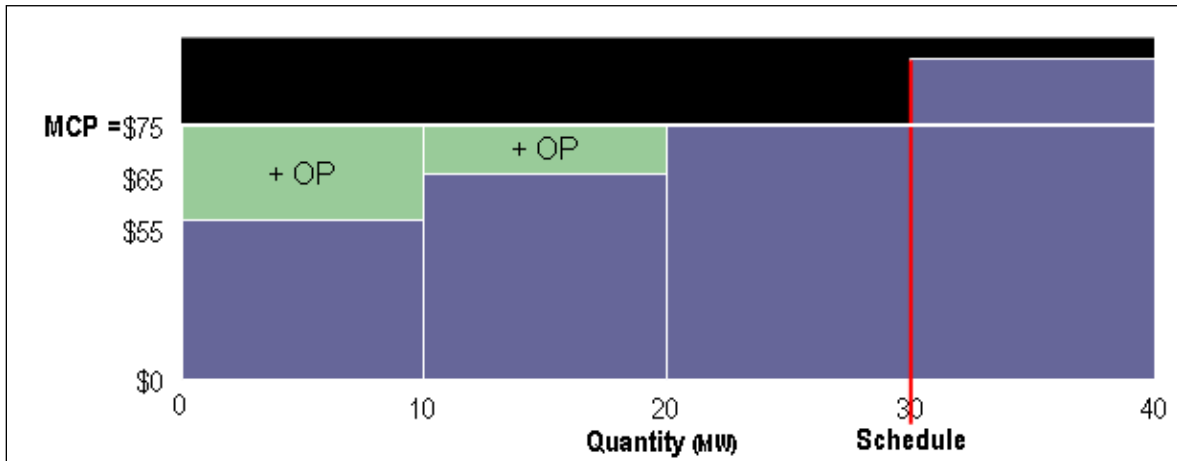


$$\begin{aligned} \text{Operating Profit} &= ((\$1995 - \$75) \times 10\text{MW}) + ((\$150 - \$75) \times 20\text{MW}) \\ &= \$20,700 \end{aligned}$$

What about for a supplier? Assume that a generator made the following offer:



For a supplier, operating profit is the difference between what they want to get paid for their energy and what they are actually paid for it. If the market clearing price was \$75 and this generator was scheduled to 30 MW, their operating profit would be the area below the MCP line:



Note that there is no profit for the 20 MW to 30 MW portion of the offer. This was offered at the same price as the MCP. There was no difference between what this generator wanted to get paid for this portion of its energy and what the market is going to pay it. Therefore, there is no operating profit for that lamination. Overall, the operating profit for the generator would be:

$$\begin{aligned} \text{Operating Profit} &= ((\$75 - \$55) \times 10 \text{ MW}) + ((\$75 - \$65) \times 10 \text{ MW}) \\ &= \$300 \end{aligned}$$

## 6.2 Congestion Management Settlement Credits

When a facility is dispatched differently by the constrained mode of the algorithm than it would have been by the unconstrained mode, we refer to the facility as being either constrained-on or constrained-off.

A facility is constrained on if it is dispatched to either produce or consume when its offer or bid is uneconomic

A facility is constrained off if it is not dispatched to either produce or consume when its offer or bid is economic

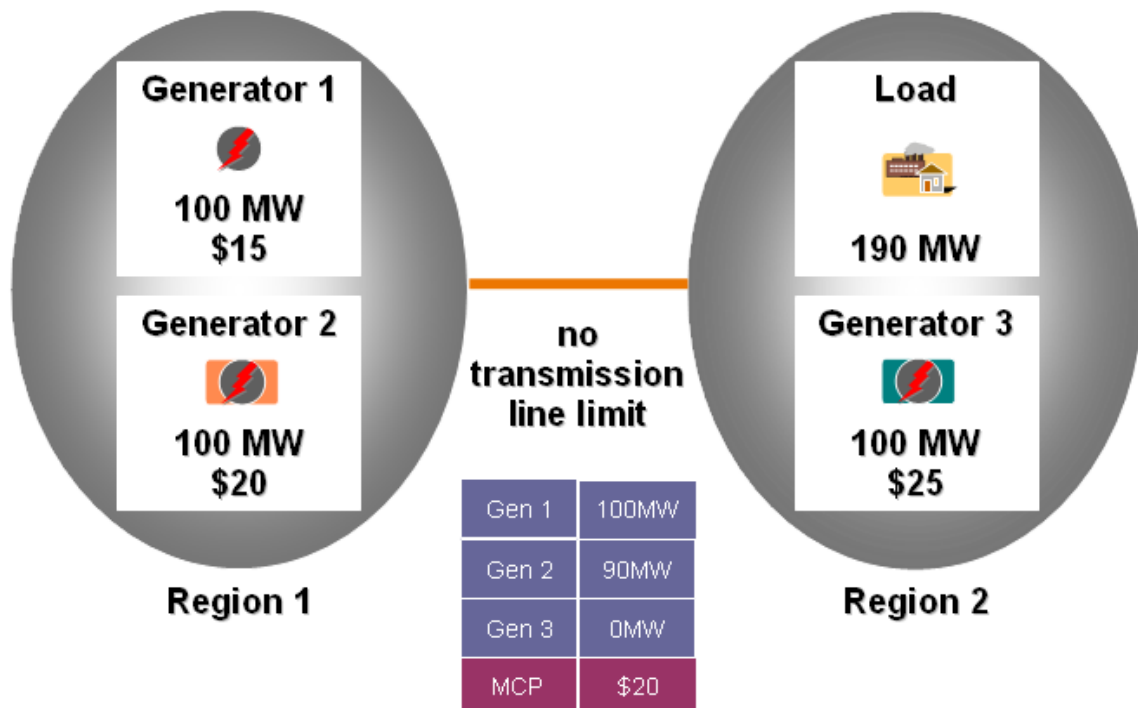
In the earlier example of two generators (one in Thunder Bay and another in Mississauga), the Thunder Bay generator was dispatched off even though it was willing to offer electricity at the market clearing price. On the other hand, Mississauga generator was dispatched to run even though its offer was above the market clearing price. In this case, Thunder Bay was constrained off, and Mississauga was constrained on.

But how should they be settled?

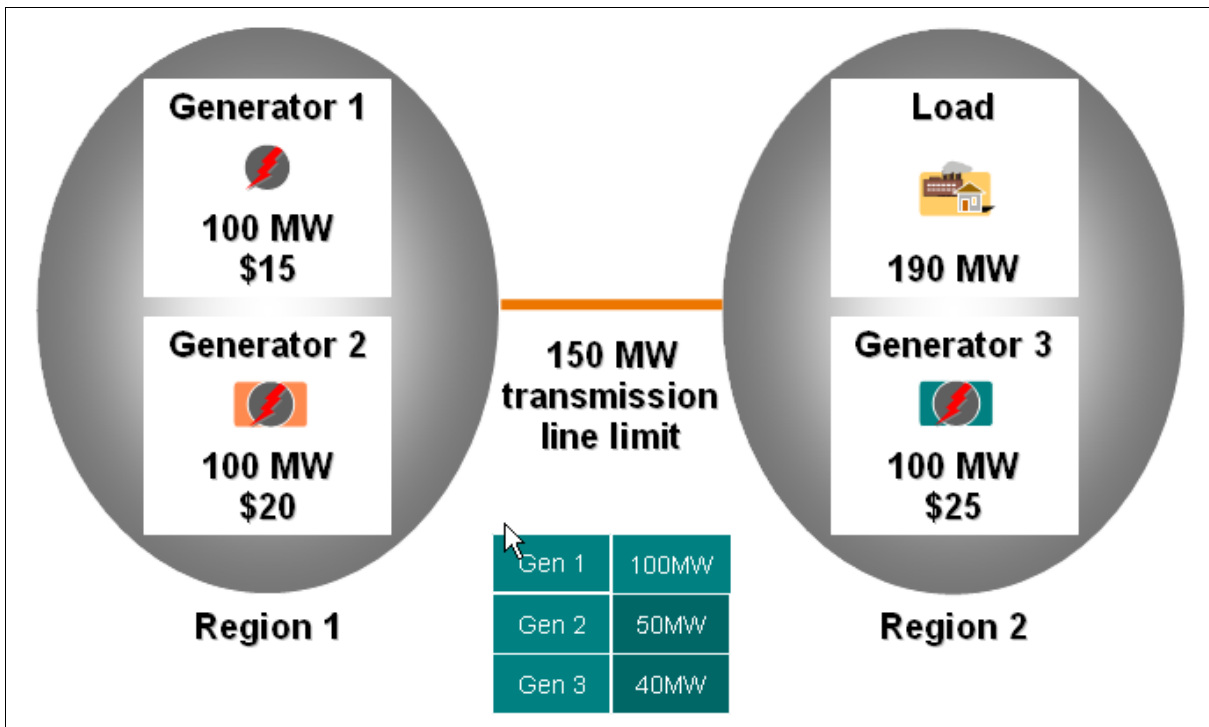
We use congestion management settlement credits to bring the market participant to the same level of operating profit they would have obtained from their market (unconstrained) schedule. In this way, they are not economically harmed by their relationship to the grid.

**Example**

Recall the example we used to illustrate price setting and market schedules.



We returned to this example to see how we determine dispatch instructions.



You will see that the market and dispatch schedules differ:

Generator	Market Schedule	Dispatch Schedule
1	100	100
2	90	50
3	0	40

Under its 0 MW market schedule, Generator 3 has an operating profit of:

$$\begin{aligned}
 (\text{MCP} - \text{Offer}) \times \text{Market schedule} &= (\$20 - \$25) \times 0 \text{ MW} \\
 &= \$0
 \end{aligned}$$

We had to dispatch Generator 3 to 40 MW in order to serve the load. This means that Generator 3 is suffering a loss (called a 'negative operating profit') for each megawatt that we require it to produce.

$$\begin{aligned}
 (\text{MCP} - \text{Offer}) \times \text{Dispatch Schedule} &= (\$20 - \$25) \times 40 \text{ MW} \\
 &= - \$200
 \end{aligned}$$

This is a problem on two levels:

- This loss may affect Generator 3's market behaviour in the future. Generator 3 might limit when it offers its supply to try and avoid times when it thinks it might be asked to produce at a loss.
- Generator 3 may choose not to comply with dispatch because of the loss. This would compromise grid reliability.

We use congestion management settlement credits (CMSC) to deal with situations like this. In this case, Generator 3 would receive \$200 in CMSC payments. This would return them to the \$0 operating profit that they would have had under their market schedule:  
 (- \$200 + \$200 = \$0)

The formal calculation of CMSC is:

Operating profit under the market schedule minus the greater of:

- The operating profit under the dispatch schedule, or
- The operating profit based on the allocated quantity of energy produced or consumed. (Generally this is metered energy either produced or consumed by the facility unless there is a physical bilateral contract. For further information please see the [Physical Bilateral Contracts](#) workbook available on the [Training](#) pages of our website.)

For a generator:

$$\begin{aligned} \text{CMSC} &= \text{OP (MQSI)} - \text{MAX (OP(DQSI), OP (AQEI))} \\ &= (\text{MCP- Offer}) \times \text{MQSI} - \text{MAX ((MCP- Offer) \times \text{DQSI}, (\text{MCP- Offer}) \times \text{AQEI})} \end{aligned}$$

Where:

MQSI = Market Quantity Scheduled for Injection (i.e., the facility's market schedule)

DQSI = Dispatch Quantity Scheduled for Injection (i.e., the facility's dispatch schedule)

AQEI = Allocated Quantity of Energy Injected (i.e., the facility's actual metered injection)

Assume that Generator 3 actual production was equal to their dispatch instruction.

CMSC for Generator 3 would be calculated as:

$$\begin{aligned} \text{CMSC} &= (\text{MCP- Offer}) \times \text{MQSI} - \text{MAX ((MCP- Offer) \times \text{DQSI}, (\text{MCP- Offer}) \times \text{AQEI})} \\ &= (\$20 - \$25) \times 0 \text{ MW} - \text{MAX ((\$20 - \$25) \times 40 \text{ MW}, (\$20 - \$25) \times 40 \text{ MW})} \\ &= \$0 - \text{MAX (- \$200, -\$200)} \\ &= \$200 \end{aligned}$$

What about Generator 2? They had a market schedule of 90 MW, but a dispatch schedule of only 50 MW. DO they get CMSC?

First, what was their operating profit under their market schedule?

$$\begin{aligned} (\text{MCP} - \text{Offer}) \times \text{Market schedule} &= (\$20 - \$20) \times 90 \text{ MW} \\ &= \$0 \end{aligned}$$

Generator 2 has no operating profit under their market schedule because their offer price and the MCP are the same. Does this change just because they are asked to produce less under the dispatch schedule? No.

$$\begin{aligned} (\text{MCP} - \text{Offer}) \times \text{Dispatch schedule} &= (\$20 - \$20) \times 50 \text{ MW} \\ &= \$0 \end{aligned}$$

CMSC is not intended to compensate for lost revenue – just for operating profit differences. Therefore, Generator 2 would not receive any CMSC.

$$\begin{aligned} \text{CMSC} &= (\text{MCP} - \text{Offer}) \times \text{MQSI} - \text{MAX} ((\text{MCP} - \text{Offer}) \times \text{DQSI}, (\text{MCP} - \text{Offer}) \times \text{AQEI}) \\ &= (\$20 - \$20) \times 90 \text{ MW} - \text{MAX} ((\$20 - \$20) \times 50 \text{ MW}, (\$20 - \$20) \times 50 \text{ MW}) \\ &= \$0 - \text{MAX} (\$0, \$0) \\ &= \$0 \end{aligned}$$

### CMSC When Dispatch and Allocated Quantities are Different

In the above example, Generator 3 produced according to its dispatch schedule. What if Generator 3 had produced more energy than it was dispatched to? Would Generator 3 get a higher CMSC payment?

Let's assume that Generator 3 actually produced 50 MW instead of 40 MW.

$$\begin{aligned} \text{CMSC} &= (\text{MCP} - \text{Offer}) \times \text{MQSI} - \text{MAX} ((\text{MCP} - \text{Offer}) \times \text{DQSI}, (\text{MCP} - \text{Offer}) \times \text{AQEI}) \\ &= (\$20 - \$25) \times 0 \text{ MW} - \text{MAX} ((\$20 - \$25) \times 40 \text{ MW}, (\$20 - \$25) \times 50 \text{ MW}) \\ &= \$0 - \text{MAX} (-\$200, -\$250) \\ &= \$200 \end{aligned}$$

Generator 3 would receive the same CMSC payment for producing 50 MW that it had for producing 40 MW. This is because of the 'MAX' term in the equation. It refers to using the higher of the operating profit under the dispatch scheduled amount and the allocated quantity amount. The higher of - \$200 and - \$250 is - \$200. Generators cannot receive more CMSC if they generate more.

What about if they generate less? What if Generator 3 had produced only 30 MW?

$$\begin{aligned}
 \text{CMSC} &= (\text{MCP} - \text{Offer}) \times \text{MQSI} - \text{MAX} ((\text{MCP} - \text{Offer}) \times \text{DQSI}, (\text{MCP} - \text{Offer}) \times \text{AQEI}) \\
 &= (\$20 - \$25) \times 0 \text{ MW} - \text{MAX} ((\$20 - \$25) \times 40 \text{ MW}, (\$20 - \$25) \times 30 \text{ MW}) \\
 &= \$0 - \text{MAX} (-\$200, -\$150) \\
 &= \$150
 \end{aligned}$$

Generators cannot receive more CMSC for under-producing.

### CMSC for Dispatchable Loads

Dispatchable loads are also eligible for CMSC:

$$\begin{aligned}
 \text{CMSC} &= \text{OP}(\text{MQSW}) - \text{MAX}(\text{OP}(\text{DQSW}), \text{OP}(\text{AQEW})) \\
 &= (\text{Bid} - \text{MCP}) \times \text{MQSW} - \text{MAX}((\text{Bid} - \text{MCO}) \times \text{DQSW}, (\text{Bid} - \text{MCP}) \times \text{AQEW})
 \end{aligned}$$

Where:

MQSW = Market Quantity Scheduled for Withdrawal (i.e., the facility's market schedule)

DQSW = Dispatch Quantity Scheduled for Withdrawal (i.e., the facility's dispatch schedule)

AQEW = Allocated Quantity of Energy Withdrawn (i.e., the facility's actual metered withdrawal)

### Example:

$$\text{MCP} = \$35$$

Load A bid for 200 MW at \$40 /MW

Market schedule = 200 MW

Dispatch scheduled = 100 MW

$$\begin{aligned}
 \text{CMSC} &= (40 - 35) \times 200 - \text{MAX} [(40 - 35) \times 100, (40 - 35) \times 100] \\
 &= \$500
 \end{aligned}$$

### In conclusion:

Congestion management settlement credits ensure that participants receive operating profit based on their market schedule. In most situations, this is a payment to the participant. However, CMSC can also be a charge if the operating profit under the market schedule is less than the operating profit under the dispatch schedule.

The cost of CMSC payments is passed on to electricity consumers as a settlement charge.

### 6.3 Skill Check: Congestion Management Settlement Credits

1. For Hour 1:

- Gen Y offers 100 MW in total: 50 MW at \$25 and 50 MW at \$27
- Gen Y is dispatched for all 100 MW
- The MCP is \$28 for all intervals of the hour

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

- a) \$150
- b) \$175
- c) \$200
- d) \$400

2. Congestion management settlement credits 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. Given the following, what is the congestion management settlement credit for Load A:

- Bid \$1700/MW for 100 MW
- MCP = \$200
- Dispatch schedule = 90 MW
- Actually consumed 95 MW

**Skill Check: Answers**

1. For Hour 1:

- Gen Y offers 100 MW in total: 50 MW at \$25 and 50 MW at \$27
- Gen Y is dispatched for all 100 MW
- The MCP is \$28 for all intervals
- What is Gen Y's operating profit for the hour?
  - a) \$150
  - b) \$175
  - c) **\$200 ✓**
  - d) \$400

**Comments:**

50 MW at cost of \$25/MW; paid at \$28/MW: Operating Profit = 50 x \$3 = \$150

50 MW at cost of \$27/MW; paid at \$28/MW: Operating Profit = 50 x \$1 = \$50

Total: \$200

2. Congestion management settlement credits are used to:

- a) **Bring the market participant to the same level of operating 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. Given the following, what is the congestion management settlement credit for the load situation?

- Bid \$1700/MW for 100 MW
- MCP = \$200
- Dispatch schedule = 90 MW
- Actually consumed 95 MW

$$\text{CMSC} = \text{OP MQSW} - \text{MAX} (\text{OP DQSW}, \text{OP AQEW})$$

$$= (\text{Bid} - \text{MCP}) \times \text{MQSW} - \text{MAX} ((\text{Bid} - \text{MCP}) \times \text{DQSW}, (\text{Bid} - \text{MCP}) \times \text{AQEW})$$

$$= (\$1700 - \$200) \times 100 - \text{MAX} ((\$1700 - \$200) \times 90, (\$1700 - 200) \times 95)$$

$$= \$150,000 - \text{MAX} (\$135,000, \$142,500)$$

$$= \$150,000 - \$142,500$$

$$= \$7500$$

## 7. Timelines

Now that we have discussed how we set the market clearing price and how we determine dispatch instructions, we can look at the timing of the market.

### Objectives

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

- State when the window for submitting bids and offers opens
- Explain the differences between a standing and a daily bid or offer
- Explain the differences between pre-dispatch and dispatch timelines
- State the timing differences between the constrained and unconstrained modes of the algorithm

### 7.1 Types of Bids and Offers

We must manage the supply and demand for electricity within close tolerances on a continuous basis. In order to help this process, we issue dispatch instructions to dispatchable facilities 12 times an hour.

For this process to work, it is essential that all market participants plan in advance. It is also important that information be freely available to help participants and us make our decisions. To help ensure a smoothly operating market, the process of bids and offers starts out well in advance, and becomes more detailed and firm as the dispatch interval approaches.

There are two basic types of bids and offers.

#### Daily bids and offers

Daily bids and offers apply for only one day. The window for entering daily bids and offers opens at 6 a.m. the day before the energy will flow (i.e., the day before the 'dispatch day'). For example, market participants can start entering bids and offers Tuesday at 6:00 a.m. for transactions they want to happen on Wednesday.

#### Standing Bids and offers

There are also standing bids and offers. Standing bids and offers apply for more than one day. They stay in our system until changed or withdrawn, or until you enter an expiry date. Standing bids and offers are best used if you expect your price sensitivity to remain the same from day-to-day or from week-to-week.

Standing bids and offers convert to daily bids and offers at 6 a.m. the day before the dispatch day.

You can adjust your daily or standing bids and offers as more information about the specific hour becomes available. Please see the *Energy Market Graphical User Interface Workspace Training Manual*, available on the [Training](#) web pages, for details on revision rules and timelines.

### **The Day-Ahead Commitment Process (DACP)**

Revision timeline rules are affected by the DACP.

The DACP improves the efficiency of the electricity market through the advanced scheduling and commitment of resources required to provide electricity on a daily basis, and by optimizing existing and anticipated generation more effectively, while ensuring reliability.

Under DACP, once we have issued the 'Schedule of Record', there may be restrictions to changes you can make to your bids and offers. For details, please see the [Guide to the Day-Ahead Commitment Process](#) and [DACP recorded presentations](#) on the [Training](#) web pages, and Market Manual 9.4: *Real-Time Integration of the DACP*, available on the [Rules and Manuals](#) web page.

## **7.2 Dispatch Algorithm Timelines**

The dispatch algorithm is run in two timeframes: pre-dispatch and dispatch.

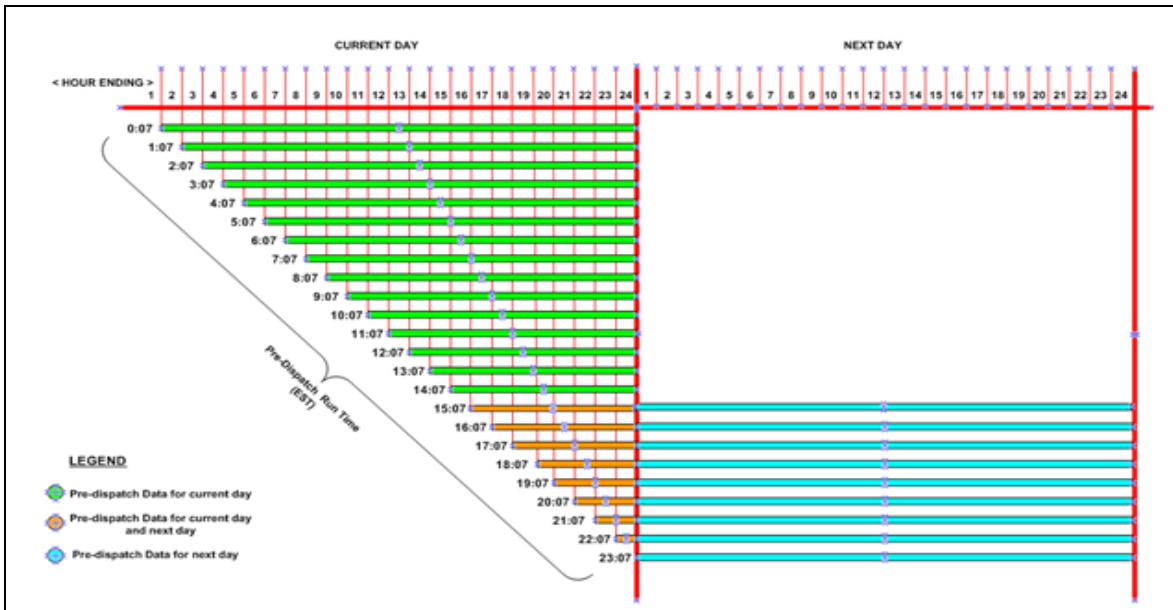
### **Pre-Dispatch**

The dispatch algorithm is run hourly in 'pre-dispatch' in both the constrained and unconstrained modes. Pre-dispatch determines projected prices and schedules over a number of future hours. It also determines schedules for imports and exports for the next hour.

The pre-dispatch run that begins at around 15:00 Eastern Standard Time is the first run that looks out not only for the rest of the day, but also for all of the next day. This run looks from 16:00 today to 12:00 midnight the next day.

The runs after 15:00 decrement by an hour until 15:00 the next day is reached, at which point the cycle repeats.

(Please note: the markets are on Eastern Standard Time all year round)

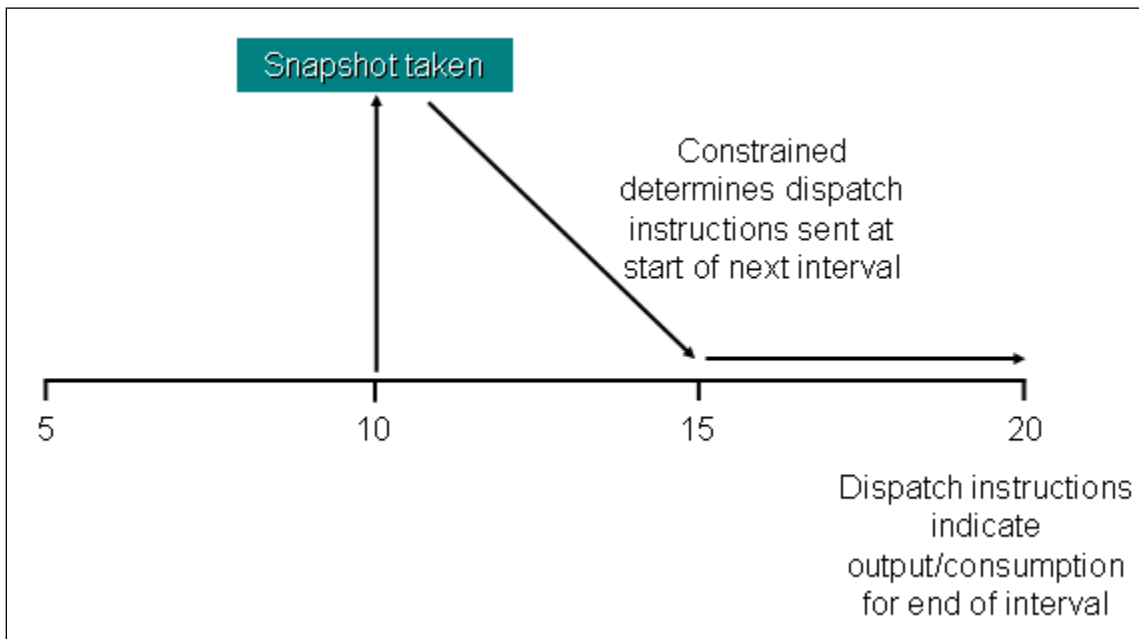


**Real-time**

The dispatch algorithm is run in both constrained and unconstrained modes every five minutes in real-time to determine actual prices and schedules.

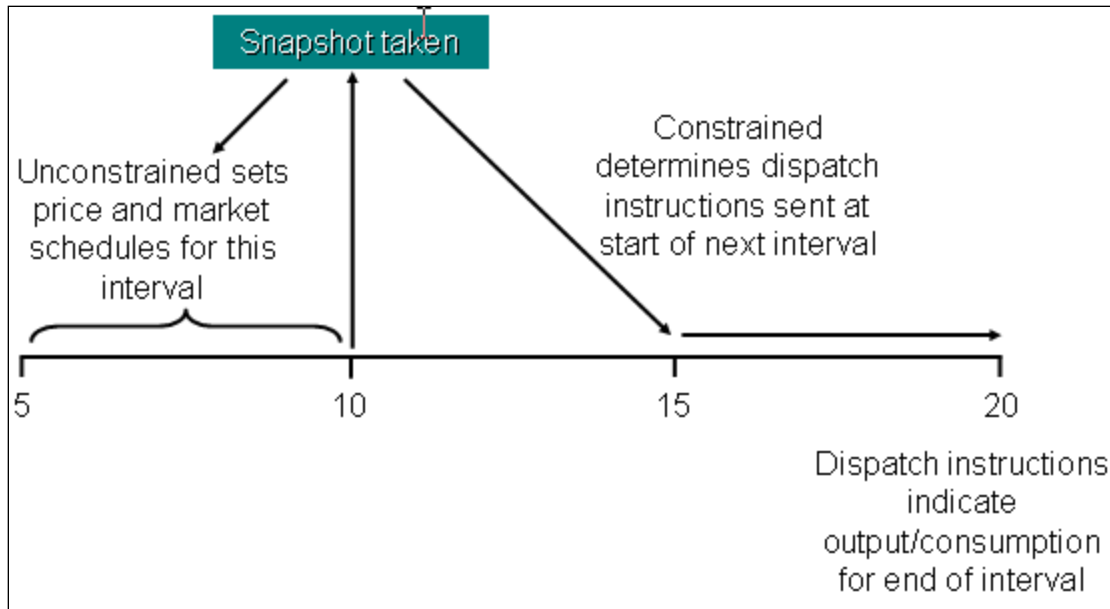
There are important timing differences between the real-time unconstrained and constrained runs. Every five minutes, the dispatch algorithm takes a ‘snapshot’ of system conditions including:

- Demand
- Output and consumption levels by each dispatchable resource



The constrained mode 'trends' current demand forward to project what it will be at the end of the next interval. It then determines what resources it can dispatch to meet that demand, given the available offers and bids, the facilities' current production or consumption and ramp rates, transmission limits, and losses. It then sends dispatch instructions at the start of the next interval, indicating the operating point that needs to be reached by the end of the interval.

The unconstrained mode is quite different. It looks backwards to the interval that just ended in order to determine the price and market schedules for that interval.



### 7.3 Skill Check: Timelines

1. Fill in the blanks:

- The window for bids and offers for a given day opens at \_\_\_\_\_ the day before you want the energy to actually flow.
- A market participant expecting to offer the same quantity at the same price for all hours every Monday would enter a \_\_\_\_\_ \_\_\_\_\_.

2. A standing bid converts to a daily bid at what time?

- a) 6:00 DST the day before the dispatch day
- b) 16:00 EST the day before the dispatch day
- c) 6:00 EST on the dispatch day
- d) 15:00 EST on the dispatch day
- e) 6:00 EST the day before the dispatch day

3. Circle the correct word:

The unconstrained mode looks to the next/last interval while the constrained mode determines dispatch instructions that are sent at the start of the next/last interval.

**Skill Check: Answers**

1. Fill in the blanks:

- The window for bids and offers for a given day opens at **6:00 a.m.** the day before you want the energy to actually flow.
- A market participant expecting to offer the same quantity at the same price for all hours every Monday would enter a **standing bid**.

2. A standing bid converts to a daily bid at what time?

- a) 6:00 DST the day before the dispatch day
- b) 16:00 EST the day before the dispatch day
- c) 6:00 EST on the dispatch day
- d) 15:00 EST on the dispatch day
- e) **6:00 EST the day before the dispatch day ✓**

3. Circle the correct word:

The unconstrained mode looks to the next/last✓ interval while the constrained mode determines dispatch instructions that are sent at the start of the ✓next/last interval.

## 8. Operating Reserve

Operating reserve provides us with a supply 'cushion' of additional energy we can call upon quickly in the event of an unexpected shortfall of energy. This energy can be supplied by a generator increasing its output or by a load reducing its demand.

### Objectives

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

- Identify the three classes of operating reserve
- Explain how we determine payments for operating reserve

### 8.1 What is Operating Reserve?

Operating reserve (OR) is stand-by power that can be called on with short notice to deal with an unexpected mismatch between generation and load. We purchase OR from participants through an OR market.

We determine the quantity of scheduled OR in accordance with reliability standards established by standards authorities like the North American Electricity Reliability Corporation (NERC) and the North East Power Coordinating Council (NPCC).

#### Classes of operating reserve

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

- 10-minute spinning (synchronized or spinning)
- 10-minute non spinning (non-synchronized or non-spinning)
- 30-minute

We must have enough 10-minute operating reserve to cover the largest single contingency that is likely to occur given the current grid configuration. Typically, this is the loss of the single largest generation unit. If the largest generator on the grid is 900 MW, we must schedule an equal quantity of megawatts of operating reserve from facilities whose energy can be made available within 10 minutes of the loss of that unit.

Normally, 25% of this 10-minute capacity must be 'spinning' or 'synchronized'. Spinning operating reserve comes from generators and loads that are already synchronized to the grid. Generators and dispatchable loads can offer 10-minute spinning reserve.

The remaining portion of 10-minute operating reserve does not have to be spinning. We can use dispatchable loads, dispatchable generators, imports and exports to satisfy 10-minute non-spinning reserve requirements.

We must also maintain 30-minute operating reserve over and above the 10-minute requirement. There must be enough 30-minute reserve to cover one half of the second largest likely single contingency on the grid. We can use dispatchable loads, dispatchable generators, imports and exports to satisfy 30-minute operating reserve requirements.

### **Operating reserve markets**

We have a market for each of the three types of operating reserve. This allows us to purchase OR efficiently.

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 the participant has entered 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 is 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 schedules for both energy and operating reserve through a process called 'joint optimization'. (For details on joint optimization, please see [Quick Take 20: Joint Optimization](#), available on the [Training](#) web pages.)

Participants who are scheduled for operating reserve receive a payment at the market clearing price for the class of operating reserve. They receive this stand-by payment for all intervals during which they are scheduled to supply operating reserve.

Scheduled operating reserve suppliers may be 'activated'. If they are, they must then actually provide the energy. This must be done within the ramp period for the product activated.

- If activated for 10-minute reserve, a facility has 10 minutes to provide the energy.
- If activated for 30-minute reserve, a facility has 30 minutes to provide energy.

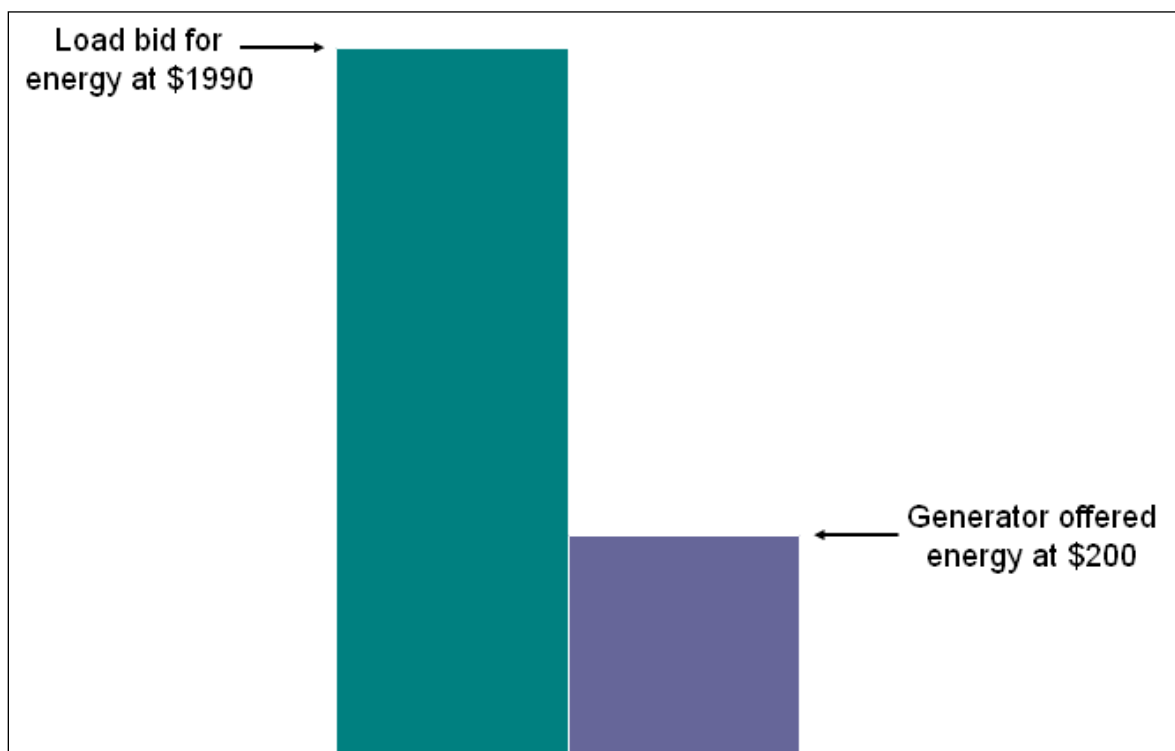
**How do we settle activated participants?**

- Consumers and suppliers receive CMSC in the operating reserve market if they had been economic, but were constrained off in the operating reserve market when they were activated.
- Consumers also receive constrained-off CMSC in the energy market if their energy bid was higher than the energy MCP at the time of their activation.

Suppliers receive the MCP in the energy market for the energy produced in response to activation. They also receive constrained-on CMSC if their energy offer was higher than the energy MCP at the time of their activation.

Operating reserve is an important reliability tool. It is essential that activated participants provide all of their energy dispatch instruction. We may claw back operating reserve payments if a participant does not provide the energy when called upon for reserve. Also, the Market Assessment and Compliance Division may investigate.

We typically activate scheduled operating reserve in reverse order based on the energy market offer or bid price. For example, assume a load bid for energy at \$1990 and a generator offered energy at \$200.



Assume that the MCP in the energy market is \$90 at the time we are looking to activate these resources

If we activate the generator, we will have to pay them the energy market CMSC based on the difference between their offer price and the MCP. That works out to CMCS of \$110 for every megawatt they produce in response to an OR activation.

If we activate the load, we will owe \$1900 per MW in CMSC (\$1990 bid- \$90 MCP). Because of this cost differential, unless there is a reliability reason to activate the load, we will go ahead and activate the less expensive resource, in this case, the generator.

## 8.2 Skill Check: Operating Reserve

1. The three classes of operating reserve are:
  - a)
  - b)
  - c)
  
2. Are the following statements true or false?
  - 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.

**Skill Check: Answers**

1. The three classes of operating reserve are:
  - 10-minute spinning (synchronized)
  - 10-minute non-spinning (non-synchronized)
  - 30-minute
  
2. Are the following statements true or false?
  - a) An offer of operating reserve can only be made if there is a corresponding bid or offer for energy. **True**
  - b) The dispatch algorithm simultaneously determines the optimum solution for both energy and operating reserve. **True**
  - c) Participants who are successful in offering operating reserve receive the market clearing price for energy when they are on stand-by. **False**

## 9. Additional information

This workbook introduces you to Ontario's Physical Markets. For more detailed information on some of the topics mentioned in the workbook, please refer to our [Training](#) web pages.

For more information on:

- Dispatchable loads, please see the [Dispatchable Load Operating Guidelines](#) and [Quick Take 7: Dispatchable Loads](#) on the Training web pages.
- Regulated Price Plan, please see the Ontario Energy Board website [www.oeb.gov.on.ca](http://www.oeb.gov.on.ca).
- Entering offers, bids, schedules and forecasts please see the [Energy Market Graphical User Interface Workspace Training Manual](#) available on the Training pages of our web site.
- Compliance with dispatch instructions, please see the interpretation bulletin [Compliance with Dispatch Instructions Issued to Dispatchable Facilities](#) available on the Compliance pages of our website.