IMO Independent Electricity Market Operator

Market Pricing Working Group

Market Evolution Program

Fundamentals of Pricing in the IMO-Administered Markets

May 25, 2004

Objective

- Provide an overview of the pricing fundamentals and formulation
- Provide an overview of the implementation of the pricing formulation via the dispatch algorithm and its use in
  - constrained schedule sequence
  - market schedule sequence
- Discuss a number of examples that illustrate the implications of constrained (market) and constrained (operations) calculations

Independent
Electricity
Market Operator

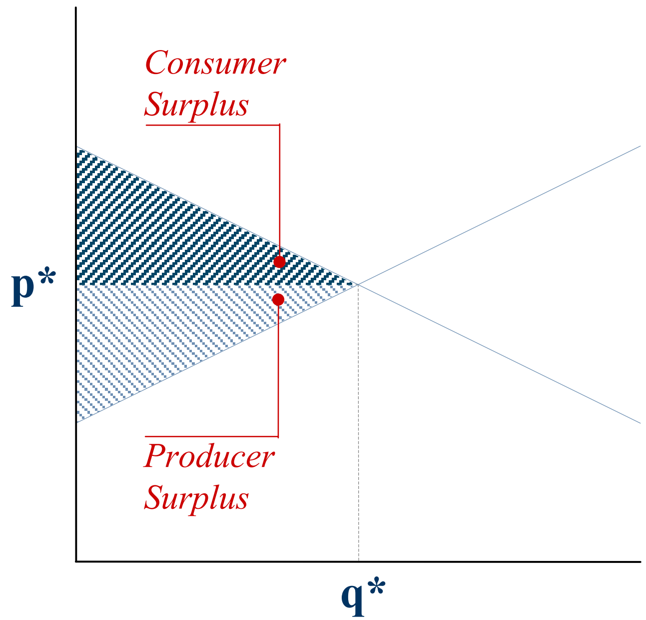
IMO-Administered Market

- Least cost bid dispatch: co-ordinate the simultaneous production and consumption of electricity in accordance with the offers and bids, and electricity industry reliability rules/standards

- Real-time spot market: settle trade between electricity producers and electricity consumers via an anonymous spot market wherein all successful transactions are settled at the market clearing price

The Economic Optimum

- (p*, q*) is the equilibrium point at which:
  - the marginal cost of production is equal to the marginal benefit from consumption
  - the sum of the consumer and producer surpluses are maximized
  - there are no further possible gains from trade, i.e. moving to a point other than q*, would lead to trades which would improve participant positions



Independent Electricity Market Operator

Dispatch Algorithm

- The market clearing logic or dispatch algorithm is the formulation by which offers of electricity supply and bids for electricity demand are selected (i.e. scheduled and dispatched) to achieve a balance between electricity production and consumption.

- The implementation of this formulation creates a least bid cost scheduling and dispatch tool or mechanism

Some Facts About Electricity

- Electricity is not as simple as other commodities - it cannot be stored and must be consumed the very instant it is produced

- Electrical energy cannot be delivered by itself - it comes bundled with a number of ancillary services (e.g. operating reserve, regulation, reactive power, etc.) that are vital to achieving reliable delivery of electrical energy.

The Market Clearing Price

- What is it:
  - marginal or incremental price of the next (≅ last) unit (offer or bid) of electricity scheduled (or dispatched)
  - mathematically it is the shadow price determined from the dispatch algorithm

- Only the prices of flexible resources, i.e. those which can be dispatched up or down can set the marginal cost

Price Setting - Inflexible Resources

- Why doesn't plant at its limit (for whatever reason) set the market price?
  - Because it is not capable of supplying the next unit, since it is constrained
  - The market price is given by the cost of meeting an additional unit of load from the next available source or combination of sources, if constraints in the system mean that more than one source will supply the next marginal unit
  - Imagine that we can obtain widgets from two sources, A and B, (with B more expensive than A), but that we have exhausted the supply from A (not because of the capability of A's plant, but because A cannot acquire further necessary inputs to its production process); then B sets the price because it was necessary to acquire the additional unit(s) from B.

Price Setting: (cont)

- (continued)
  - Thus plant which is constrained by a ramping limit, cannot supply a further unit of energy (at the margin). Some other plant must be ramped in order to provide the additional unit, and it is this (or a combination of such plant) which will set the price
  - If one plant is at its limit for whatever reason, while another plant is not, it is clear that the algorithm has exhausted the former, but still has some capability in the latter - and presumably this is the optimal economic dispatch
  - For instance, plant which is ramping at its maximum rate can not be called on for reserve duty; there is no capability for it to respond. Therefore, it would not be paid for reserve and it would not set the market clearing price.

Energy and Reserve Optimization

Joint- or Co-optimization:

- Trades off or selects combinations of energy and reserve which lead to the lowest overall cost for the dispatch of a given load, not to the lowest energy cost and/or lowest reserve cost; energy and reserve are not independent

- Yields prices under which plant will be indifferent as to whether dispatched for energy or dispatched for reserve or a combination of both.

Uniform Pricing

- At the outset in Ontario we have adopted a pricing regime with a uniform market clearing (and settlement) price across all of Ontario
- Zonal pricing has been adopted across interties to capture congestion of these connections
- It is uniform pricing that gives rise to the notion of being "constrained on" or "constrained off", since the algorithm will dispatch plant to achieve least cost bid dispatch irrespective of the uniform price.

Uniform Pricing (cont)

(continued)

- Due to constraints in the system, plant which is more expensive (bid more than the "market" price) may be scheduled on (constrained on) and plant which is less expensive may be scheduled off (constrained off), respectively
- In such circumstances, side payments will be required to compensate these participants for their "operating losses"
- Basically, whenever there is one basis for determining price and another basis for determining quantities, there needs to be some adjustment to make the "price received" consistent with the quantity or the dispatch instruction.

How to Calculate a Uniform Price

- Options were:
  - the unconstrained price
    - simple stack
    - market schedule
  - weighted average of nodal prices
  - other … ?

- Choice was to calculate what the price would have been in an uncongested system (market schedule) and pay it to all generators for the energy they supply

Constrained-on/off Payments

- An adjustment that would leave the market participant financially indifferent relative to the action they might have otherwise taken at the uniform market clearing price thus eliminating any incentive for them not to comply with dispatch instructions received.

- Calculated as Congestion Management Settlement Credit (CMSC) payments in the settlement equations

The Dispatch Algorithm

- Detailed in Chapter 7 and in Appendix 7.5
- Implements the pricing fundamentals and market clearing logic
- Effectively the design specifications for the Dispatch and Scheduling Optimizer (DSO)
- "The *IMO* shall, as far as practical, use the outputs of the *dispatch algorithm* to determine the *dispatch instructions* that guide actual physical operations of the *electricity system*. However, because any *dispatch algorithm* is only an approximation of a complex physical reality and may sometimes malfunction, the *IMO* may modify or override the results of the *dispatch algorithm* when issuing *dispatch instructions* pursuant to section 7." [C7 s4.2.2]

The Algorithm Contains ...

- An objective function
  - Describes what is to be optimized
- A number of variables
  - Independent, such as generation and demand
  - Dependent, such as line flows
- A number of constraints
  - Require the value of variables and combinations of variables to be within given limits

Objective Function

- Determines what is to be optimized.
- Maximizes the "Net Benefit", where

$$
\begin{aligned}
NetBenefit = & \sum_{\{j,p \mid j \in \text{PURCHASEBIDBLOCKS}_p, \text{where } p \in \text{BIDS}\}} \text{PurchaseBidPrice}_{p,j} \times PurchaseBlock_{p,j} \\
& - \sum_{\{j,g \mid j \in \text{GENERATIONOFFERBLOCKS}_g, \text{where } g \in \text{OFFERS}\}} \text{GenerationOfferPrice}_{g,j} \times GenerationBlock_{g,j} \\
& - \sum_{\{j,r \mid j \in \text{RESERVEOFFERBLOCKS}_r, \text{where } r \in \text{RESERVEOFFERS}\}} \text{ReserveOfferPrice}_{r,j} \times ReserveBlock_{r,j} \\
& - ViolationPenalties
\end{aligned}
$$

IMO Independent Electricity Market Operator

Violation Penalties

- Allow a “solution” to be found when no feasible solution actually exists.
- Constraints with associated violation variables are relaxed at a price.
- Constraints without violation penalties are not relaxed.
- Provide a diagnostic to allow the dispatcher to readily determine what the problem is.

Constrained Sequence

- Respect network constraints
  - Operating Security Limits
  - Thermal Limits (Continuous, Limited Time Rating)
- Respect non-network constraints
  - Ramp rates, Energy limits, Regulation range
- Model IMO-controlled grid in detail
- Model external by equivalent network
- Compute actual schedules for all dispatchable facilities
- Compute nodal prices

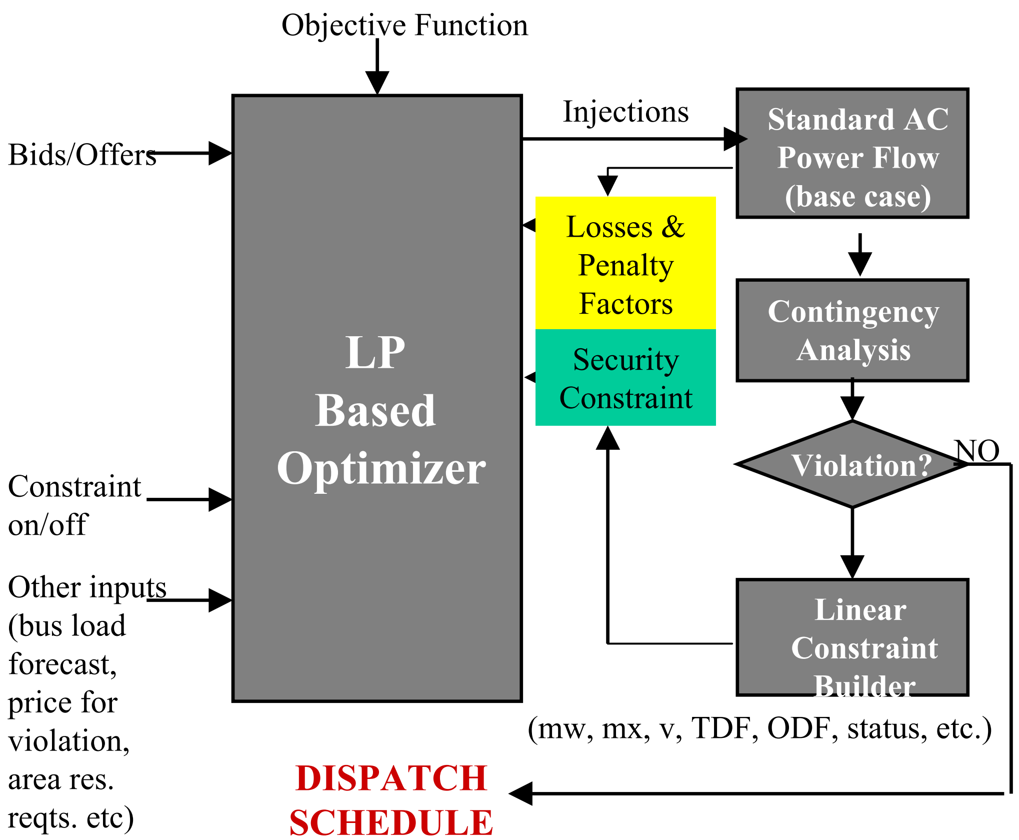
Unconstrained Sequence

- Respect interface scheduling limits
- Respect non-network constraints
- Model Ontario as one node
- Model external network by isolated nodes
- Compute unconstrained (market) schedules for all dispatchable facilities (for CMSC calculation)
- Compute provisional prices??
- Compute settlement prices

Overview - Operations Sequence

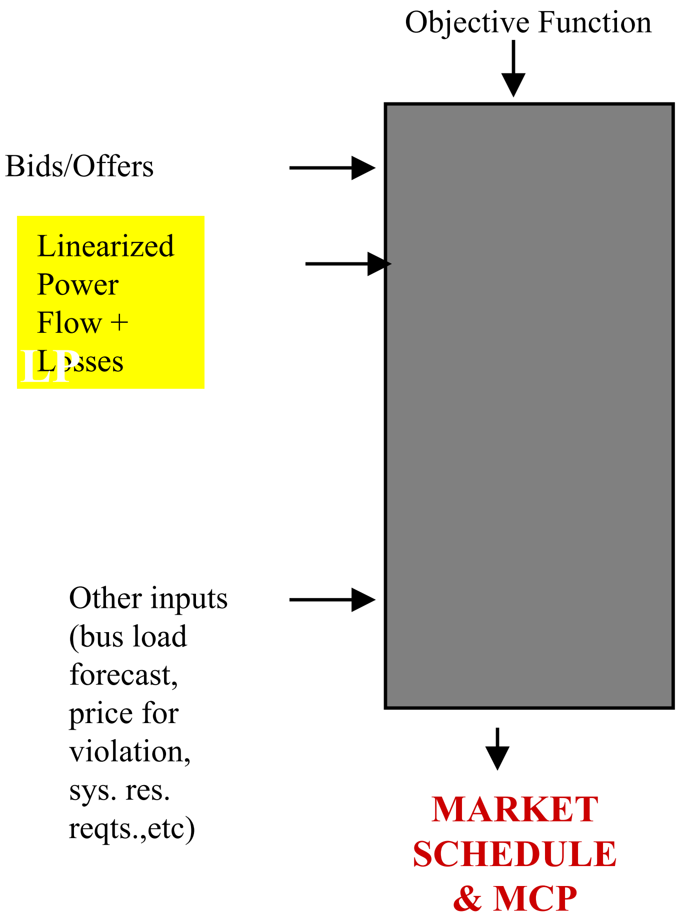
- The dispatch optimizer uses a linear programming engine. The transmission constraints must be linearized around the operating point.
- Base case and post contingency operating limit are checked.
- Violated limits are formulated as linear constraints and passed to the optimizer.

Constraint dispatch Formulation



Overview - Market Sequence

Unconstraint dispatch Formulation



Independent Electricity Market Operator

Joint Optimization

- Reserve prices cannot be implied from reserve offers; they are a function of the constraints in the system and of the energy offers, or the energy-reserve pairings, as well
- When the dispatch calls for an additional unit of reserve, it does not merely choose the next available unit of reserve in the "reserve stack"; that reserve could come from backing off already fully-committed units and a dispatching of even more expensive energy, but which leads to a marginal reserve cost which is the sum of the gains and losses associated with increasing and decreasing the energy and reserve dispatch quantities for a number of generating units
- The above two points apply also to energy. When the dispatch calls for an additional unit of energy, it does not merely choose the next available unit of energy in the energy stack. The energy could come from backing off the reserve dispatched from a unit to allow it to produce more energy. Energy price is a function of the constraints on the system, energy offers and reserve offers.

Example 1: Converting Energy to Reserve

- For a given dispatch interval,
  - The sum of all energy and operating reserve offers is 21,000 MW with offer prices ranging up to $50/MWh and operating reserve offers range up to $5/MW.
  - 15,000 MW of non-dispatchable load plus an additional 100 MW of dispatchable load bid at $500/MWh
  - The operating reserve requirement is 1399 MW.

Example 1: Converting Energy to Reserve

Non-Dispatchable Load Reserve Reqt				15000.0 1400.0	15000.0 1399.0
X	Xmin	Xmax	$/MW	X	X
Energy Offer 1	0.0	3500.0	25.0	3500	3500
Energy Offer 2	0.0	3500.0	30.0	3500	3500
Energy Offer 3	0.0	3500.0	35.0	3150	3151
Energy Offer 4	0.0	3500.0	40.0	3150	3150
Energy Offer 5	0.0	3500.0	45.0	1800	1799
Energy Offer 6	0.0	3500.0	50.0	0	0
Reserve Offer 1	0.0	350.0	2.5	0	0
Reserve Offer 2	0.0	350.0	3.0	0	0
Reserve Offer 3	0.0	350.0	3.5	350	349
Reserve Offer 4	0.0	350.0	4.0	350	350
Reserve Offer 5	0.0	350.0	4.5	350	350
Reserve Offer 6	0.0	350.0	5.0	350	350
Dispatchable Load Bid 1	0.0	100.0	-500.0	100	100
Dispatchable Load Bid 2	0.0	0.0	-25.0	0	0
Dispatchable Load Bid 3	0.0	0.0	-23.0	0	0
Dispatchable Load Bid 4	0.0	0.0	-21.0	0	0
Energy Surplus	0.0	9999.0		0	0
Energy Deficit	0.0	20000.0		0	0
Reserve Deficit	0.0	1400.0		0	0
Objective Function (net cost)				$465,700	$465,686.50
Constraints				Marg. Cost	Marg. Cost
Power Balance Reqt				$45.0	$45.0
Reserve Reqt				$13.5	$13.5

Example 1: Converting Energy to Reserve

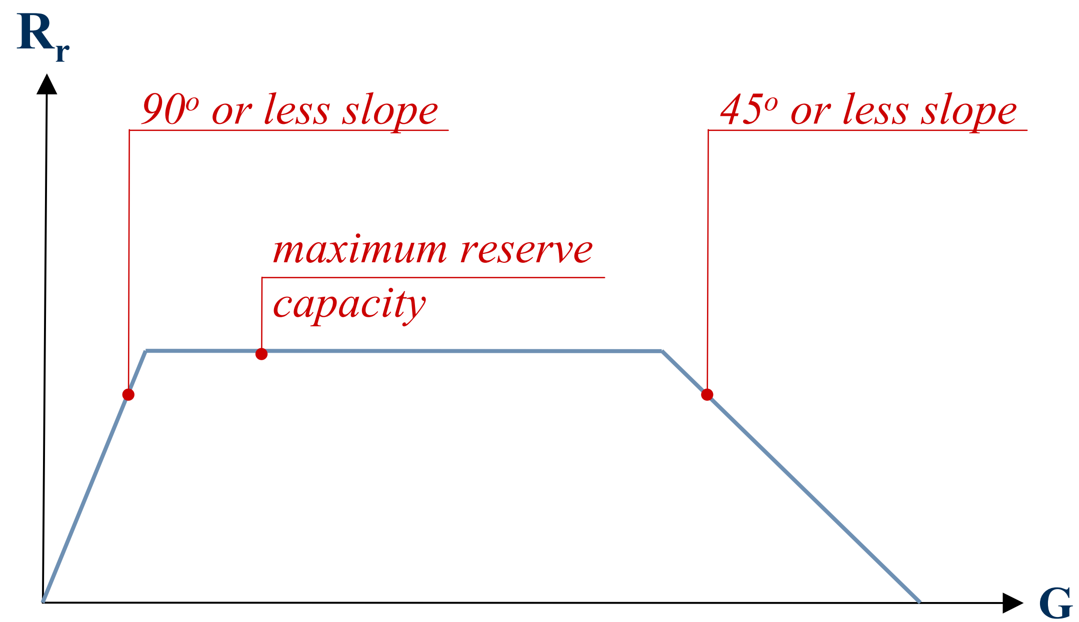
- Comparing the outputs, you'll see that to supply the 1400th MW of reserve, the LP optimization effectively did the following:
  - Reduced Energy3 from 3151 to 3150 (net benefit + $35)
  - Increased Energy5 from 1799 to 1800 (net benefit - $45)
  - Increased Reserve3 from 349 to 350 (net benefit - $3.50)
  - for a total reduction in net benefit of $35-$45-$3.50 = -$13.50 (or an increase in cost of $13.50), which yields the marginal cost of reserve.

- This is also given by the change in objective function values: $465,700-$465,686.50=$13.50

Example 1: Converting Energy to Reserve

- One can look at the components of this cost to be representative of an offer price for operating reserve plus a lost "opportunity cost".
- The lost opportunity cost is $45-$35 = $10, i.e. the net benefit impact of having to reduce the amount of the $35 offer taken by one MW and increase the amount of $45 offer taken by one MW. This is the same as the energy profits foregone by the market participant who submitted energy offer 3.
- In receiving a price of $13.50, the market participant is compensated for both its OR offer and profit foregone.

Example 2: Force-Loading a Generator for Reserve



- Reserve for any generating unit can normally be expressed as an "inverted bathtub" function with respect to generation level. This is the reserve or reserve response function.
- Generation can only supply reserve as a function of their current operating point with respect to generation.

IMO Independent Electricity Market Operator

Example 2: Force-Loading a Generator for Reserve

- Algorithm requires 122 MW of reserve and has two options:
- Option 1:
  - Gen A offered 150 MW of reserve at $20
- Option 2:
  - Gen 2 offered 500 MW of energy at $63.88 and reserve at $9.98. Gen 2 also has RR =7MW per minute and OLP=125 MW
- Current Energy price is $48.58
- To get 122 MW of reserve from Gen 2 must schedule it for 72 MW of energy
- Marginal price of getting MW of reserve from Gen 2 includes:
  - $9.98 reserve offer price
  - (($63.88-$48.58)*72)/122=$9.10
  - Marginal reserve price is therefore $19.08

IMO Independent Electricity Market Operator

Example 3

- For a given dispatch interval:
  - The sum of all energy and operating reserve offers is 21,000 MW with offer prices ranging up to $50/MWh and operating reserve offers range up to $5/MW.
  - The total non-dispatchable load is 20,000 MW.
  - The operating reserve requirement is 1400 MW.
  - There are no dispatchable load bids.

Results for Example 3

Non-Dispatchable Load Reserve Reqt				15000.0 1400.0	19000.0 1400.0	19599.0 1400.0	19600.0 1400.0	19601.0 1400.0	19800.0 1400.0	20000.0 1400.0	20500.0 1400.0	21000.0 1400.0	21001.0 1400.0
X	**Xmin**	**Xmax**	**$/MW**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
Energy Offer 1	0.0	3500.0	25.0	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500
Energy Offer 2	0.0	3500.0	30.0	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500
Energy Offer 3	0.0	3500.0	35.0	3150	3150	3150	3150	3151	3350	3500	3500	3500	3500
Energy Offer 4	0.0	3500.0	40.0	3150	3150	3150	3150	3150	3150	3200	3500	3500	3500
Energy Offer 5	0.0	3500.0	45.0	1700	3150	3150	3150	3150	3150	3150	3350	3500	3500
Energy Offer 6	0.0	3500.0	50.0	0	2550	3149	3150	3150	3150	3150	3150	3500	3500
Reserve Offer 1	0.0	350.0	2.5	0	0	0	0	0	0	0	0	0	0
Reserve Offer 2	0.0	350.0	3.0	0	0	0	0	0	0	0	0	0	0
Reserve Offer 3	0.0	350.0	3.5	350	350	350	350	349	150	0	0	0	0
Reserve Offer 4	0.0	350.0	4.0	350	350	350	350	350	350	300	0	0	0
Reserve Offer 5	0.0	350.0	4.5	350	350	350	350	350	350	350	150	0	0
Reserve Offer 6	0.0	350.0	5.0	350	350	350	350	350	350	350	350	0	0
Dispatchable Load Bid 1	0.0	0.0	-500.0	0	0	0	0	0	0	0	0	0	0
Dispatchable Load Bid 2	0.0	0.0	-25.0	0	0	0	0	0	0	0	0	0	0
Dispatchable Load Bid 3	0.0	0.0	-23.0	0	0	0	0	0	0	0	0	0	0
Dispatchable Load Bid 4	0.0	0.0	-21.0	0	0	0	0	0	0	0	0	0	0
Energy_Surplus	0.0	9999.0		0	0	0	0	0	0	0	0	0	0
Energy_Deficit	0.0	20000.0		0	0	0	0	0	0	0	0	0	1
Reserve_Deficit	0.0	1400.0		0	0	0	0	1	200	400	900	1400	1400
Objective Function				$511,200	$703,950	$733,900	$733,950	$734,766	$900,270	$1,073,295	$1,537,605	$2,047,500	$2,048,640
Constraints				Marg. Cost	Marg. Cost	Marg. Cost	Marg. Cost	Marg. Cost	Marg. Cost	Marg. Cost	Marg. Cost	Marg. Cost	Marg. Cost
Power Balance Reqt				$45.0	$50.0	$50.0	$50.0	$815.6	$831.6	$852.3	$898.2	$1,000.0	$1,000.1
Reserve Reqt				$13.5	$18.5	$18.5	$18.5	$784.1	$800.1	$816.3	$857.7	$900.0	$900.1
Violation Variables				PenFunc	PenFunc	PenFunc	PenFunc	PenFunc	PenFunc	PenFunc	PenFunc	PenFunc	PenFunc
Energy Surplus				510.2	818.6	871.0	871.1	871.2	889.0	907.0	952.9	1000.0	1000.1
Energy Deficit				510.2	818.6	871.0	871.1	871.2	889.0	907.0	952.9	1000.0	1000.1
Reserve Deficit				459.2	736.7	783.9	784.0	784.1	800.1	816.3	857.6	900.0	900.1

Energy Price (System Lambda) = Marginal Cost of the Power Balance Constraint
Reserve Price = Marginal Cost of the Operating Reserve Constraint

Penalty Functions for Energy = Maximum of {((NDL/Sum of energy offers)^2)x1000.0} or {Maximum Dispatchable Load Bid Price -1}
Penalty Functions for Reserve = 0.9 x Energy Penalty Function Value

Example 4

- Same as example 3 plus an additional 100 MW of dispatchable load bid at $500/MWh.

Results for Example 4

Non-Dispatchable Load				15000.0	19000.0	19599.0	19600.0	19601.0	19800.0	20000.0	20500.0	21000.0	21001.0
Reserve Reqt				1400.0	1400.0	1400.0	1400.0	1400.0	1400.0	1400.0	1400.0	1400.0	1400.0
X	Xmin	Xmax	$/MW	X	X	X	X	X	X	X	X	X	X
Energy Offer 1	0.0	3500.0	25.0	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500
Energy Offer 2	0.0	3500.0	30.0	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500
Energy Offer 3	0.0	3500.0	35.0	3150	3150	3150	3150	3151	3350	3500	3500	3500	3500
Energy Offer 4	0.0	3500.0	40.0	3150	3150	3150	3150	3150	3150	3200	3500	3500	3500
Energy Offer 5	0.0	3500.0	45.0	1800	3150	3150	3150	3150	3150	3150	3350	3500	3500
Energy Offer 6	0.0	3500.0	50.0	0	2650	3150	3150	3150	3150	3150	3150	3500	3500
Reserve Offer 1	0.0	350.0	2.5	0	0	0	0	0	0	0	0	0	0
Reserve Offer 2	0.0	350.0	3.0	0	0	0	0	0	0	0	0	0	0
Reserve Offer 3	0.0	350.0	3.5	350	350	350	350	349	150	0	0	0	0
Reserve Offer 4	0.0	350.0	4.0	350	350	350	350	350	350	300	0	0	0
Reserve Offer 5	0.0	350.0	4.5	350	350	350	350	350	350	350	150	0	0
Reserve Offer 6	0.0	350.0	5.0	350	350	350	350	350	350	350	350	0	0
Dispatchable Load Bid 1	0.0	100.0	-500.0	100	100	1	0	0	0	0	0	0	0
Dispatchable Load Bid 2	0.0	0.0	-25.0	0	0	0	0	0	0	0	0	0	0
Dispatchable Load Bid 3	0.0	0.0	-23.0	0	0	0	0	0	0	0	0	0	0
Dispatchable Load Bid 4	0.0	0.0	-21.0	0	0	0	0	0	0	0	0	0	0
Energy Surplus	0.0	9999.0		0	0	0	0	0	0	0	0	0	0
Energy Deficit	0.0	20000.0		0	0	0	0	0	0	0	0	0	1
Reserve Deficit	0.0	1400.0		0	0	0	0	1	200	400	900	1400	1400
Objective Function				$465,700	$658,950	$733,450	$733,950	$734,766	$900,270	$1,073,295	$1,537,605	$2,047,500	$2,048,640
Constraints				Marg. Cost	Marg. Cost	Marg. Cost	Marg. Cost	Marg. Cost	Marg. Cost	Marg. Cost	Marg. Cost	Marg. Cost	Marg. Cost
Power Balance Reqt				$45.0	$50.0	$500.0	$500.0	$815.6	$831.6	$852.3	$898.2	$1,000.0	$1,000.1
Reserve Reqt				$13.5	$18.5	$468.5	$468.5	$784.1	$800.1	$816.3	$857.7	$900.0	$900.1
Violation Variables				PenFunc	PenFunc	PenFunc	PenFunc	PenFunc	PenFunc	PenFunc	PenFunc	PenFunc	PenFunc
Energy Surplus				510.2	818.6	871.0	871.1	871.2	889.0	907.0	952.9	1000.0	1000.1
Energy Deficit				510.2	818.6	871.0	871.1	871.2	889.0	907.0	952.9	1000.0	1000.1
Reserve Deficit				459.2	736.7	783.9	784.0	784.1	800.1	816.3	857.6	900.0	900.1

Energy Price (System Lambda) = Marginal Cost of the Power Balance Constraint
Reserve Price = Marginal Cost of the Operating Reserve Constraint

Penalty Functions for Energy = Maximum of {((NDL/Sum of energy offers)^2)x1000.0} or {Maximum Dispatchable Load Bid Price -1}
Penalty Functions for Reserve = 0.9 x Energy Penalty Function Value

Uniform Pricing

- Load and generation are not expressed as being at particular points in the system. All load and generation are considered connected at a single bus and losses are considered incurred at that bus

- The “energy market clearing price” is then the shadow price associated with the power balance equation, and is the marginal cost (based on the offers made by generators) of supplying an additional unit of load at the “market clearing bus”

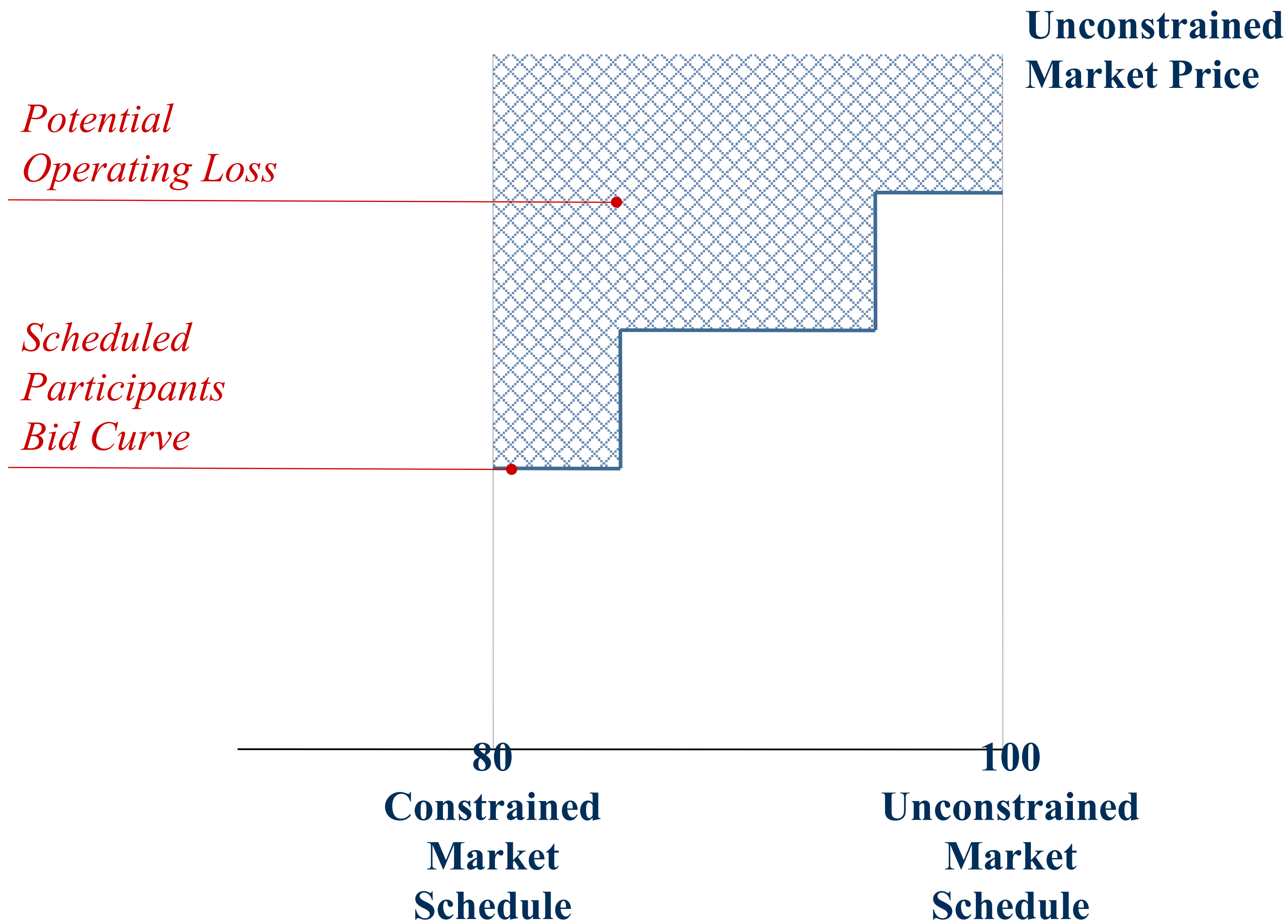
Uniform Pricing (cont)

- When used in dispatch mode, the algorithm calculates a dispatch schedule which recognizes the constraints in the system, expensive plants may be constrained on or less expensive plants may be constrained off.

- Side payments to compensate these participants

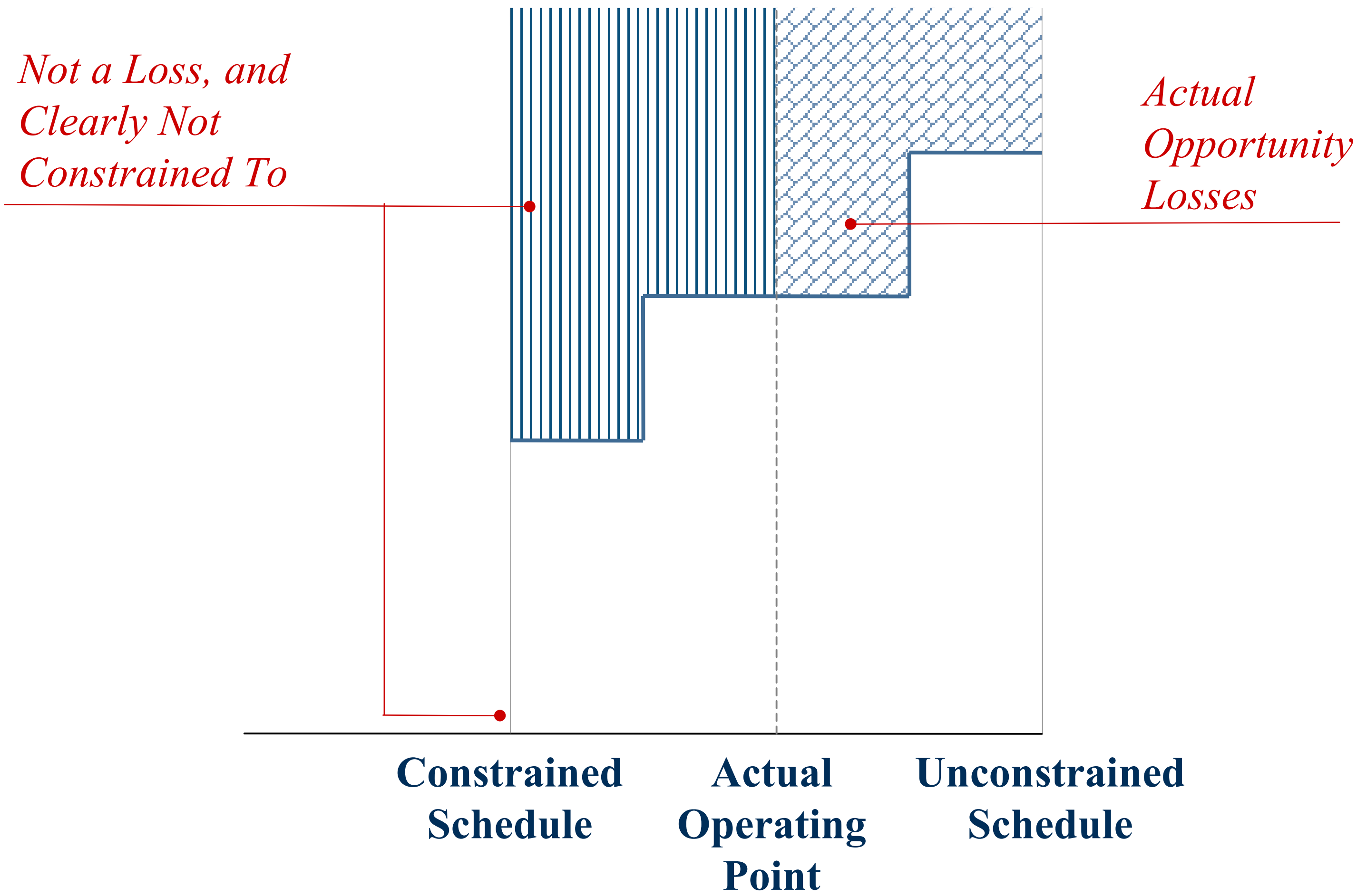
- CMSC payment = Profit based on Market Schedule - the Maximum of (profit based on the dispatch schedule and the profit based on the actual output)

Uniform pricing (cont)
Constrained off payments

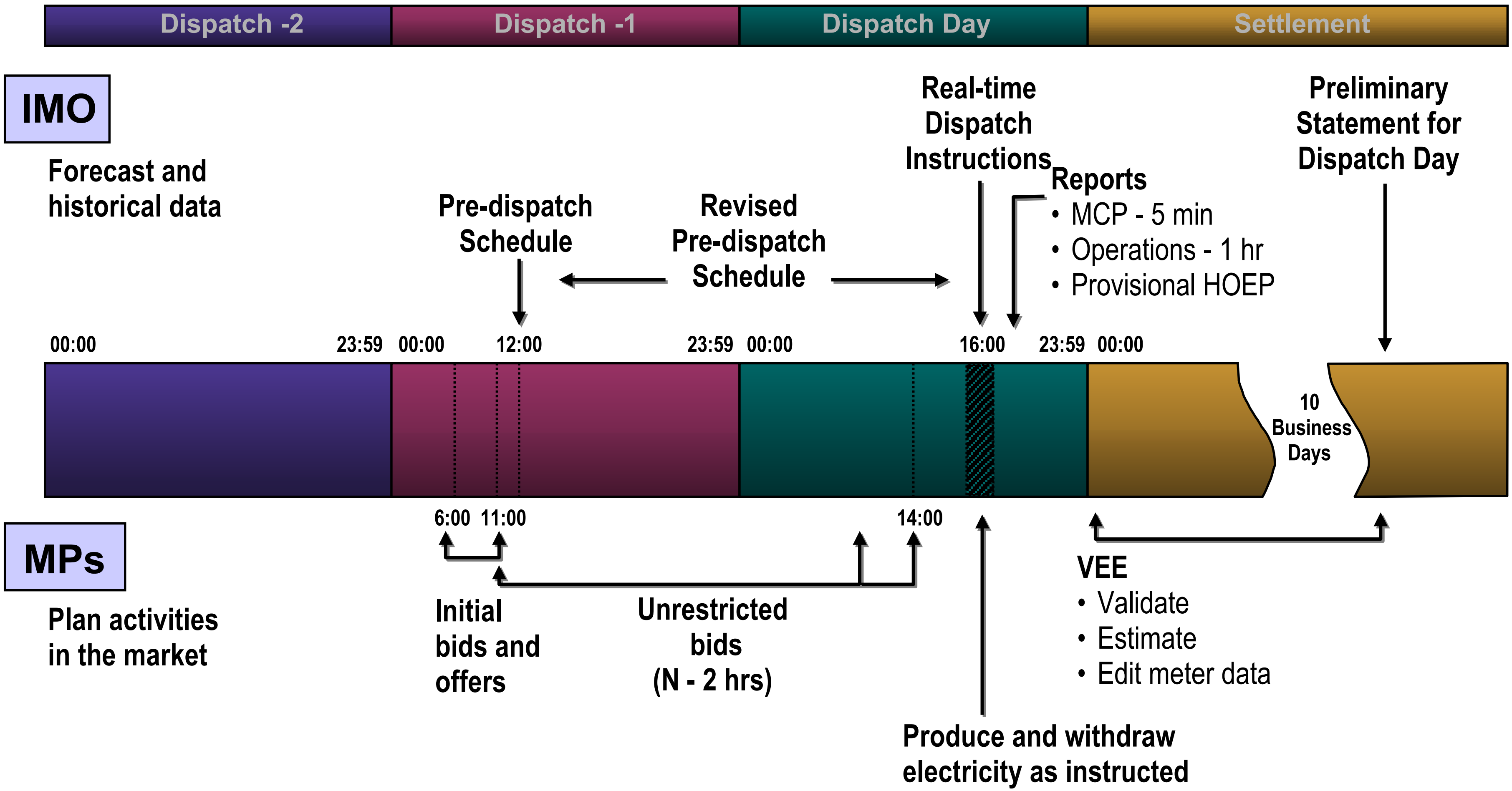


Uniform pricing (cont)

Constrained off payments

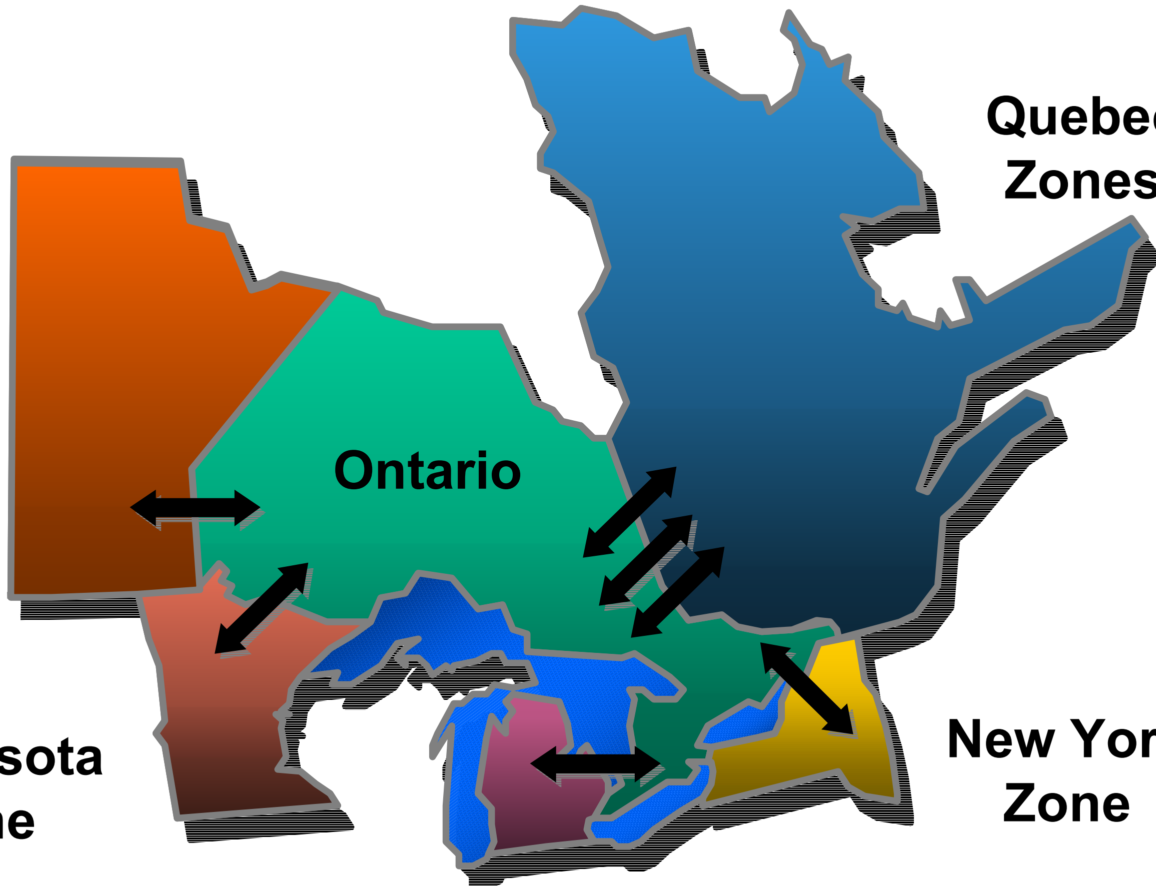


Transaction Timeline



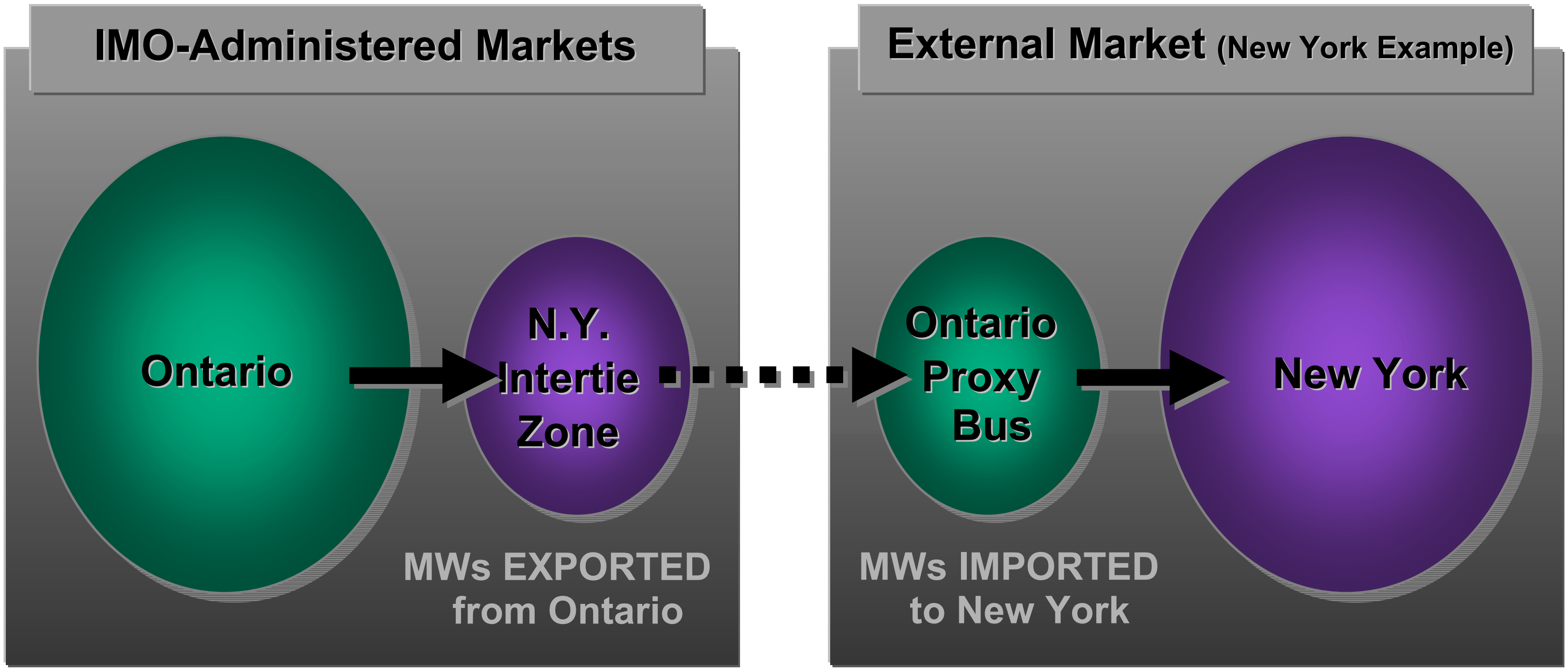
Independent Electricity Market Operator

Intertie Zones



IMO Independent Electricity Market Operator

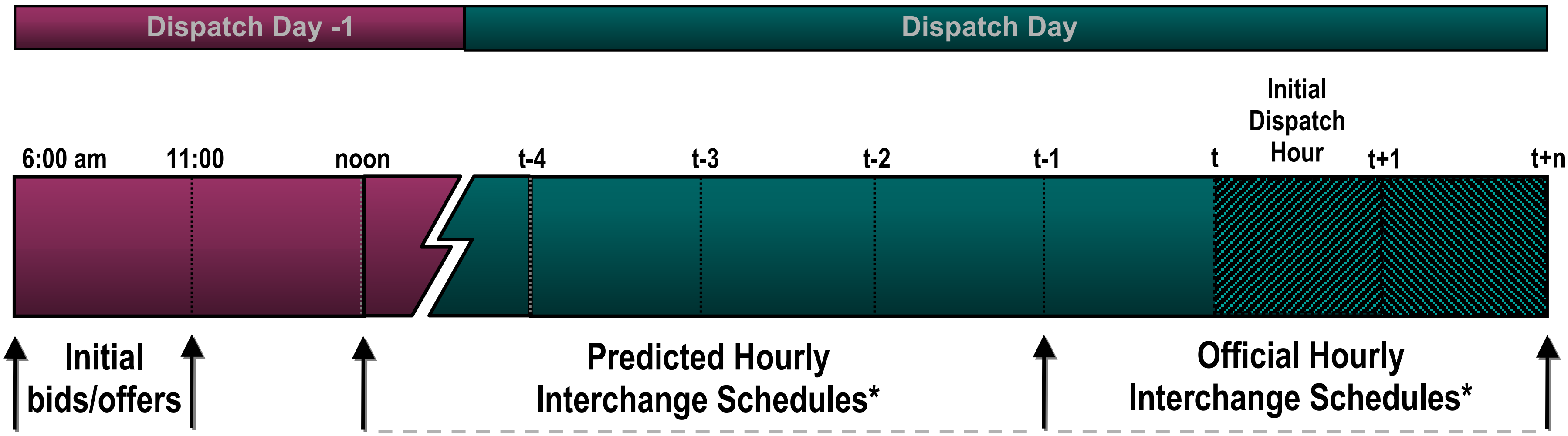
Multi-Market Navigation



Transfer of MWs from one market to the other is achieved when both markets are navigated successfully

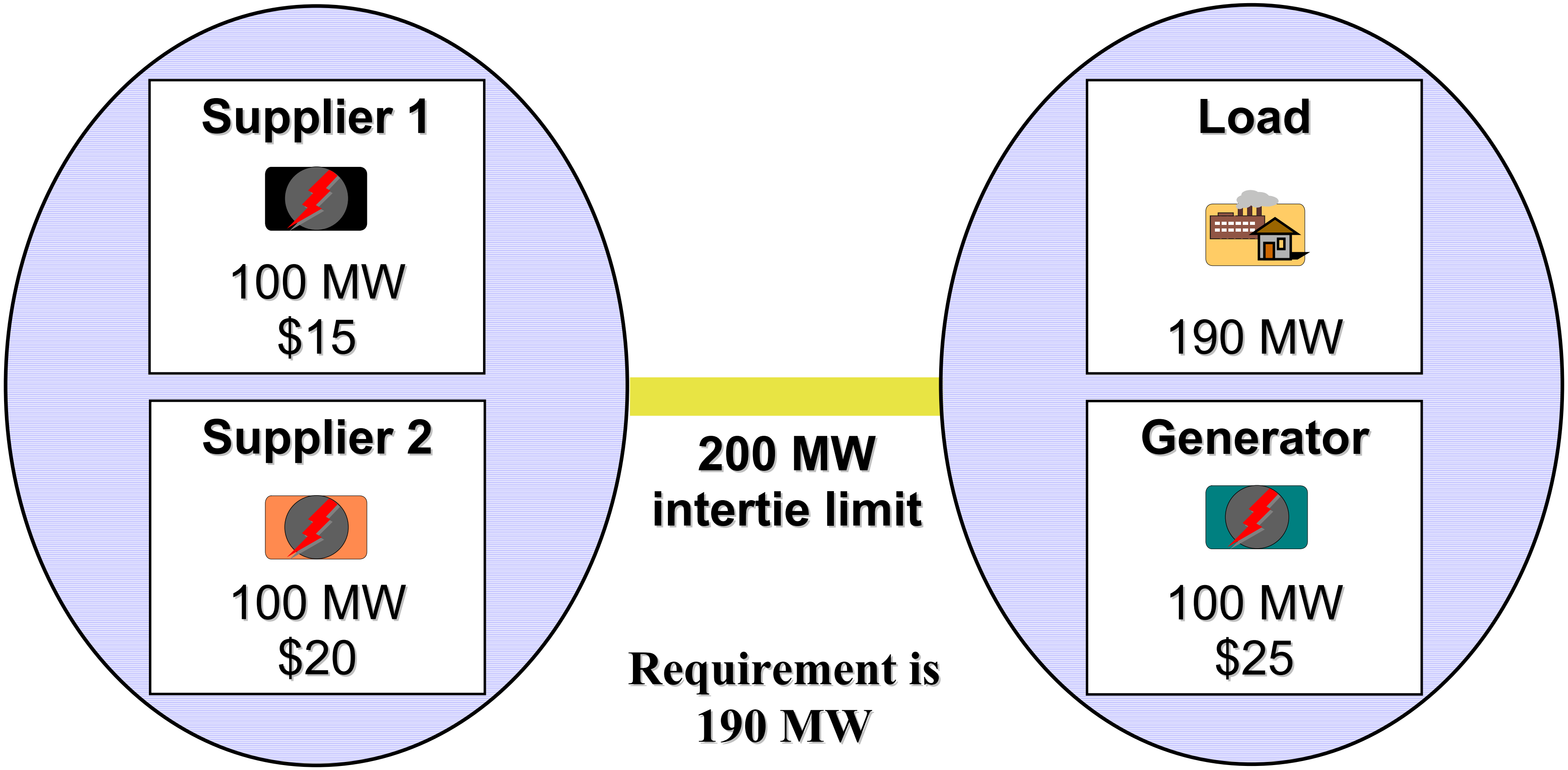
Independent
Electricity
Market Operator

Pre-Dispatch Schedule Process



* Interchange Schedule is fixed over all 5-minute intervals within the dispatch hour.

Pre-Dispatch Intertie Congestion



Requirement is 190 MW

- Sup 1: I.S. = 100 MW
- Sup 2: I.S. = 90 MW
- Gen : not dispatched

Intertie Zone

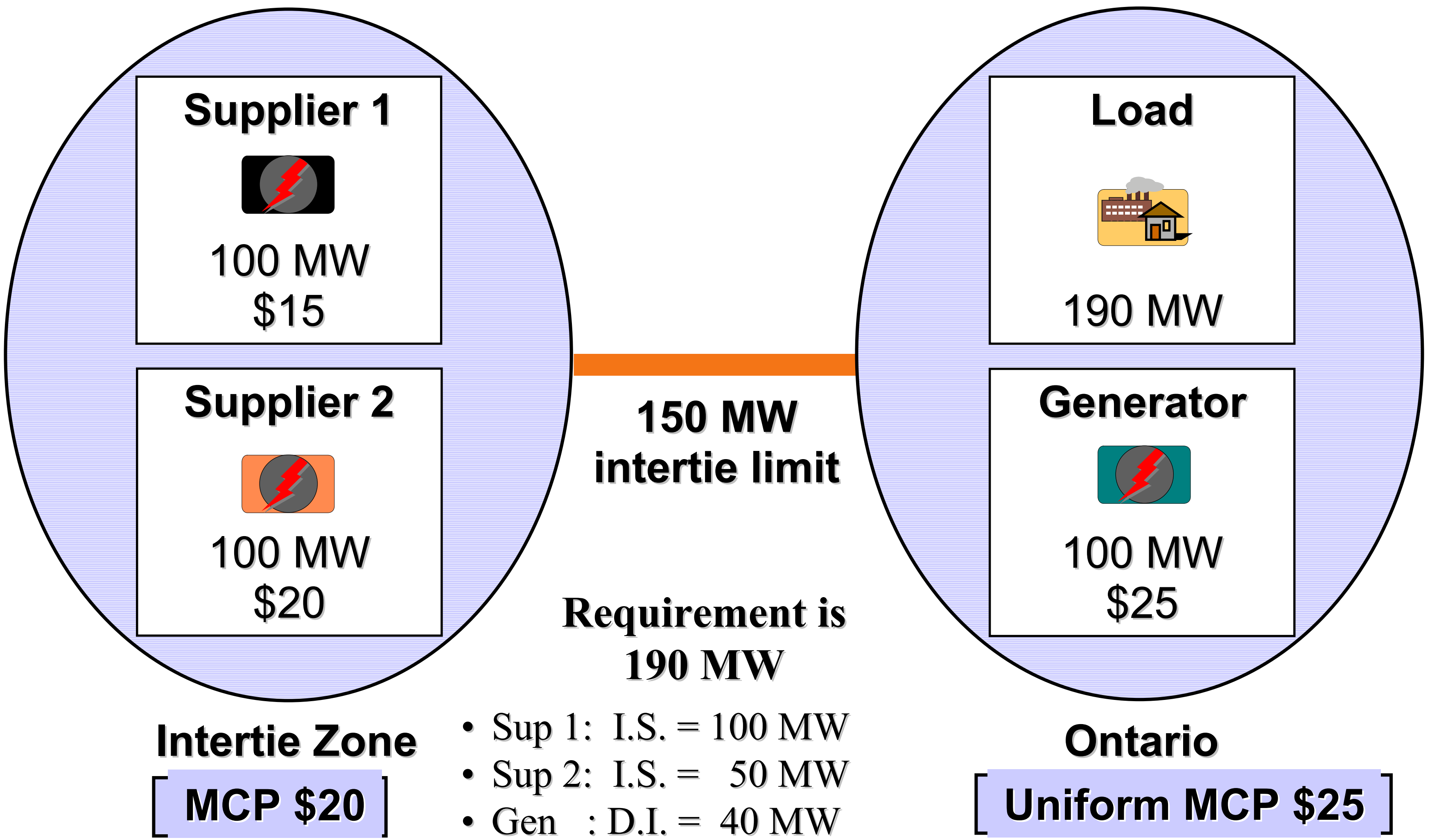
MCP $20

Ontario

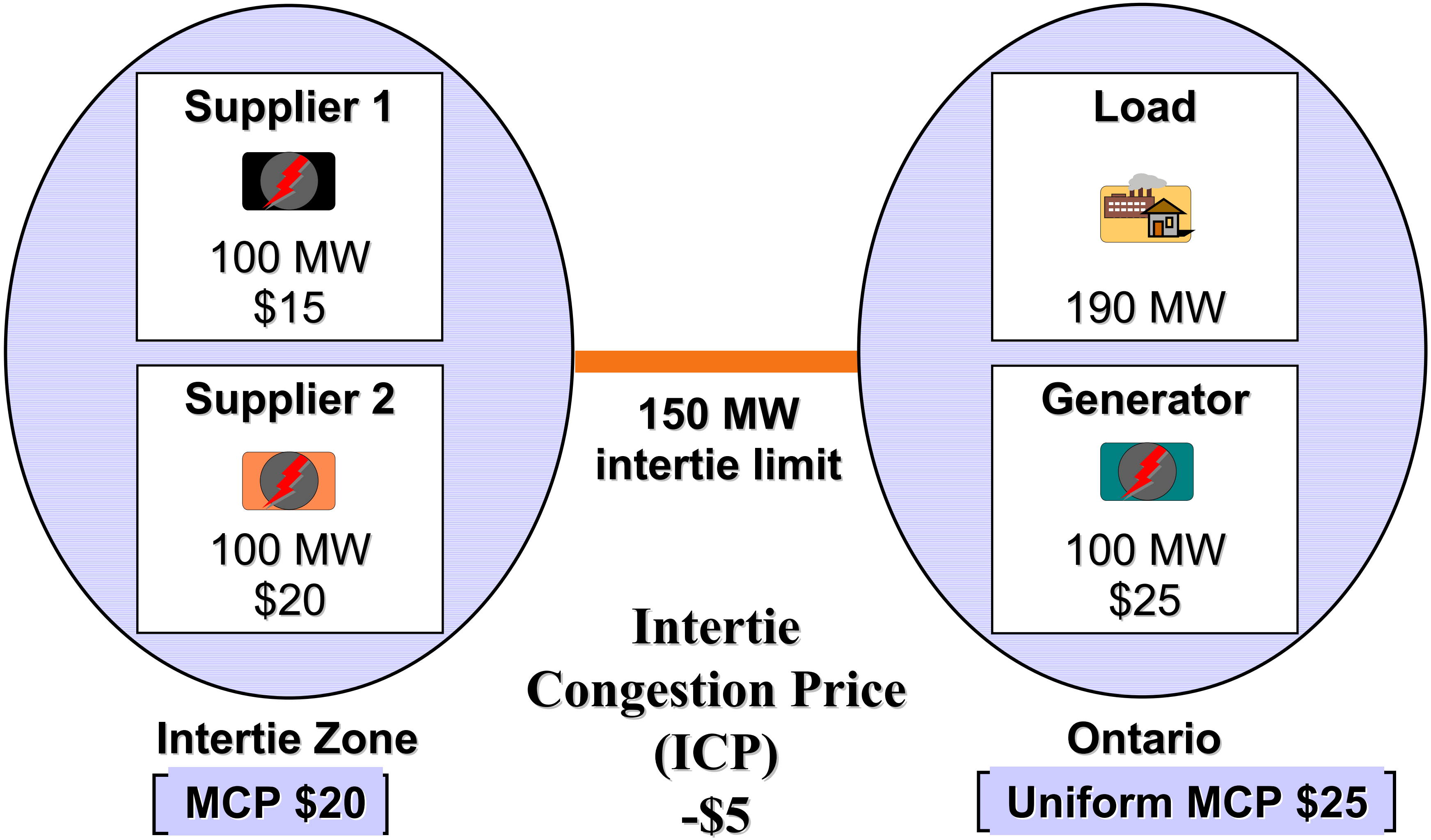
Uniform MCP $20

Independent Electricity Market Operator

Pre-Dispatch Intertie Congestion (2)



Pre-Dispatch Intertie Congestion (3)



Independent Electricity Market Operator

Calculation of Intertie Energy Price

Ex-post 5-min. MCP	+	Ex-ante ICP*	=	Total Intertie Energy Price**

* Ex-ante ICP can be a negative value

** Calculated for each 5-minute interval of the dispatch hour

End of Slides