Real-Time Energy and Reserve Co-optimization

Tongxin Zheng, Technical Manager
Business Architecture & Technology (BAT)

ISO new england

Objective

- Provide a basic understanding of the Real-Time Energy and Reserve Market in New England, and answers to the following questions:
  - What are the features of the Real-Time Market?
  - How are reserves modeled and designated?
  - How are reserve prices calculated?
  - How do reserve penalty factors influence market clearing prices?
  - What are the maximum reserve prices?
  - What is the relationship between energy and reserve prices and the corresponding cleared quantities?

Outline

- Overview of Real-Time Energy-Reserve Co-optimization
- Quick Review of Energy Only Market
- Introduction to the Real-Time Energy-Reserve Market
  - Features of the Real-Time Market
  - Why Co-optimization?
  - Real-Time Reserve Modeling and Designation
  - Market Clearing Prices and Properties
  - Understanding Energy and Reserve Prices and Designations

Outline (cont.)

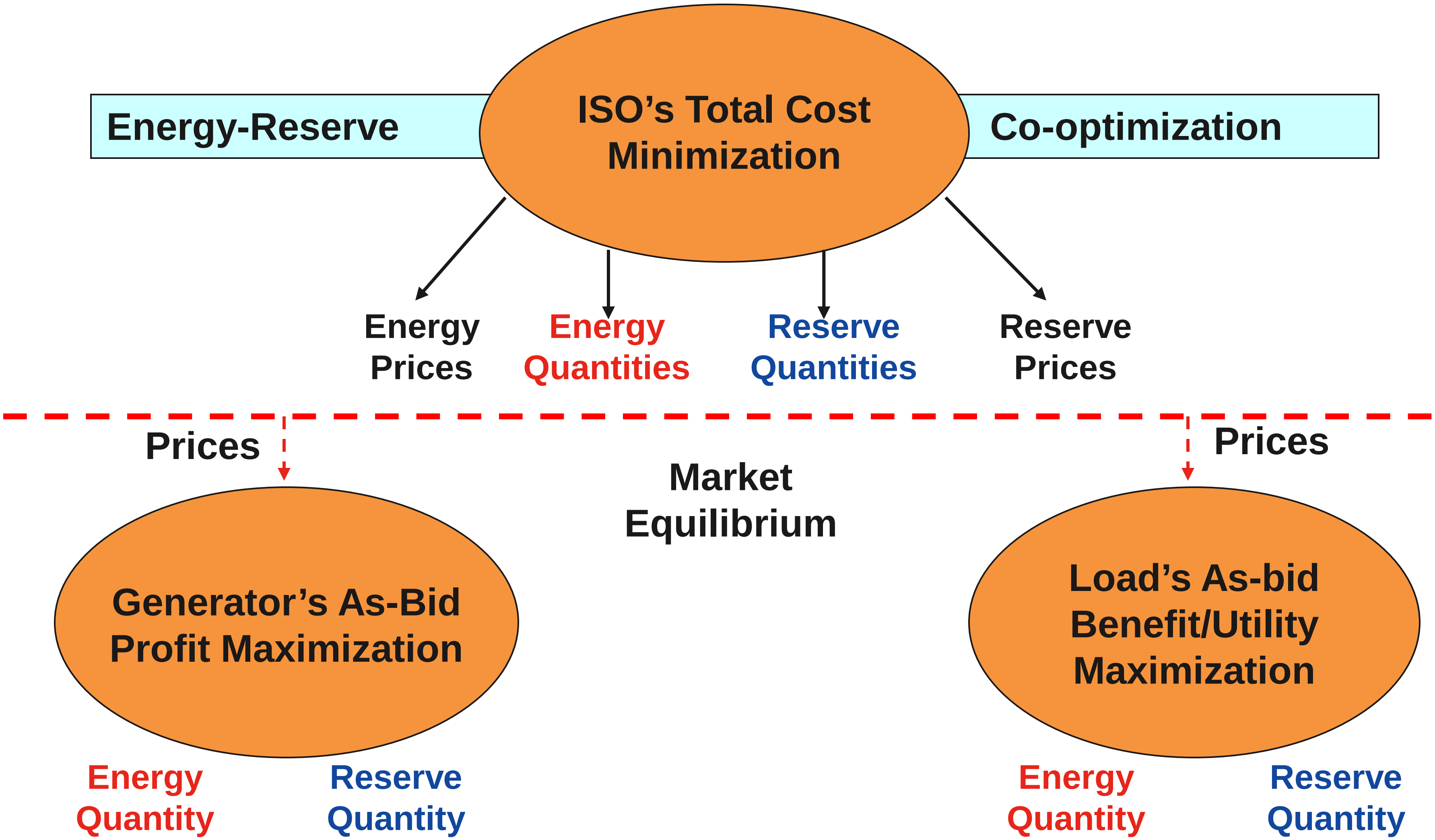
- Examples with System Reserve Requirements Only
  - Normal Scenario (Base Case)
  - Re-dispatch Scenario
  - Physical Reserve Shortage Scenario
  - Economic Reserve Shortage Scenario

Overview of Real-Time Energy-Reserve Co-optimization

What is Energy-Reserve Co-optimization?

- Real-time power system operations require
  - Meeting Energy Demand (Energy Market)
  - Meeting Reserve Requirement (Reserve Markets)
- Real-time energy-reserve co-optimization is to jointly clear the energy market and reserve markets in a least cost fashion.

Concept of Co-optimization



Why Co-optimization?

- Energy and reserve are naturally coupled.
  - Energy and reserve can be provided from the same physical resource, and the trade-off has to be made when a resource faces two markets.
- Clearing energy and reserve in a sequential way failed to
  - reveal the coupling effect between energy and reserve prices;
  - provide incentives for resources to follow dispatch instructions;
  - maximize the total social surplus.

Benefits of Co-optimization
The System Operator's View

- Provides the cheapest way of meeting energy demand while maintaining the system reliability.
- Effectively determines the market clearing prices for both energy and reserve simultaneously.
- Provides incentives for following dispatch.
- Effectively identifies units for system redispatch as well as proper compensation.
- Enhances the reserve shortage pricing.

Benefits of Co-optimization
The Market Participant's View

- Provides the optimal energy and reserve allocation that maximizes the total as-bid profit of a generating resource based on its bid-in parameters.
- Provides the optimal energy and reserve allocation that maximizes the total as-bid benefit/utility of a dispatchable load based on its bid-in parameters.

Quick Review of Energy-only Market

Energy-only Market

- The market clearing process can be described as solving an optimization problem.
- Current energy market is cleared through a Security Constrained Economic Dispatch (SCED) algorithm.
  - The objective of the SCED is to minimize the total cost (or equivalently to maximize the total social welfare), while maintaining system reliability.
  - The results of SCED are resource output levels (Desired Dispatch Points -DDP) in MW and LMPs at each Generator node (nodal dispatch rates).

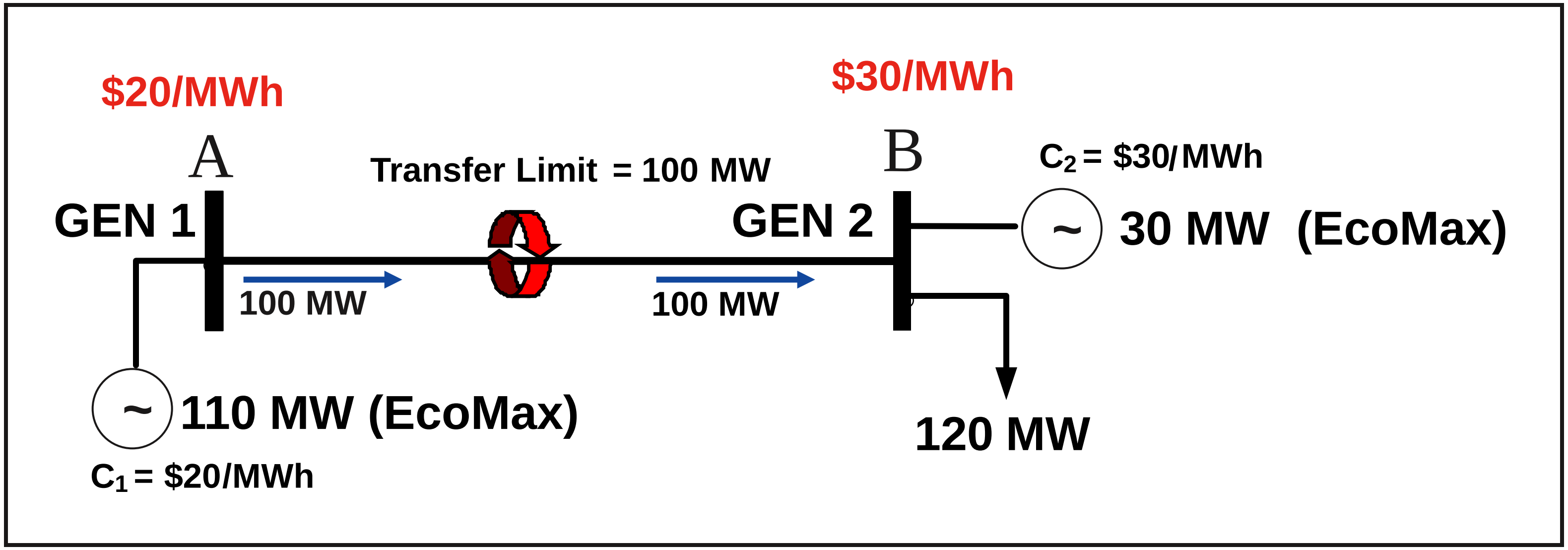
Energy-only SCED Formulation

- The objective is to minimize the total cost.
- Subject to the following constraints:
  - I. Energy Balance
    Energy Supply = Energy Demand + Losses
  - II. Transmission Constraints
    Energy Flow $\leq$ Transmission Limit (Lines/Interfaces)
  - III. Resource Level Constraints
    - Capacity Constraints
    - Ramp Constraints
    - Regulation Constraints

Locational Marginal Price (LMP)

- LMP is the minimum cost increment to optimally deliver an increment of energy at a location while respecting all related constraints.
- LMP is a function of shadow prices from all related constraints.
- LMP can be decomposed into three components:
  - Energy(Reference)
  - Loss
  - Congestion

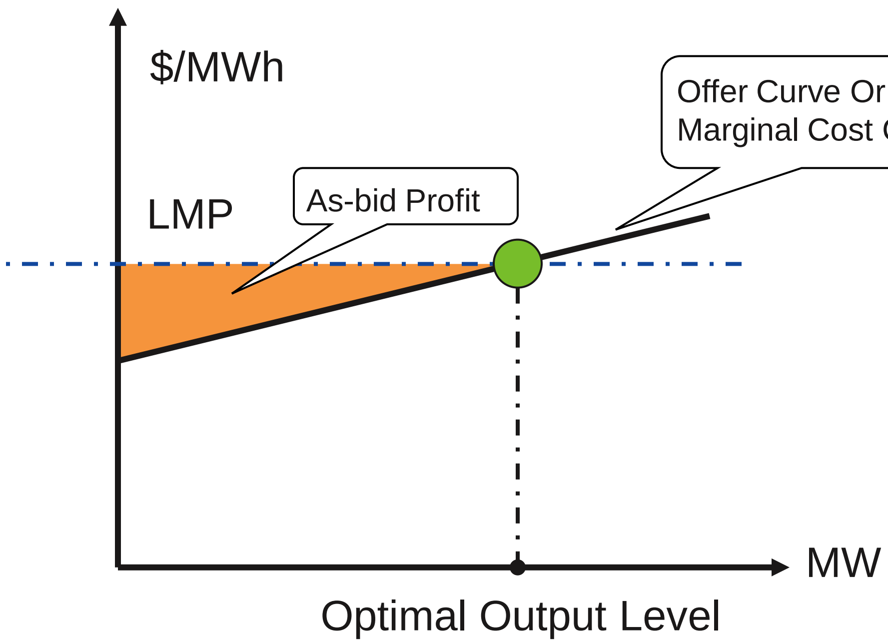
Example: Economic Dispatch with Congestion



- The binding transmission constraint causes price separation. Both Generators become marginal and set the prices at their respective locations.
- The price at Generator 1 will be $20/MWh.
- The price at Generator 2 will be $30/MWh.

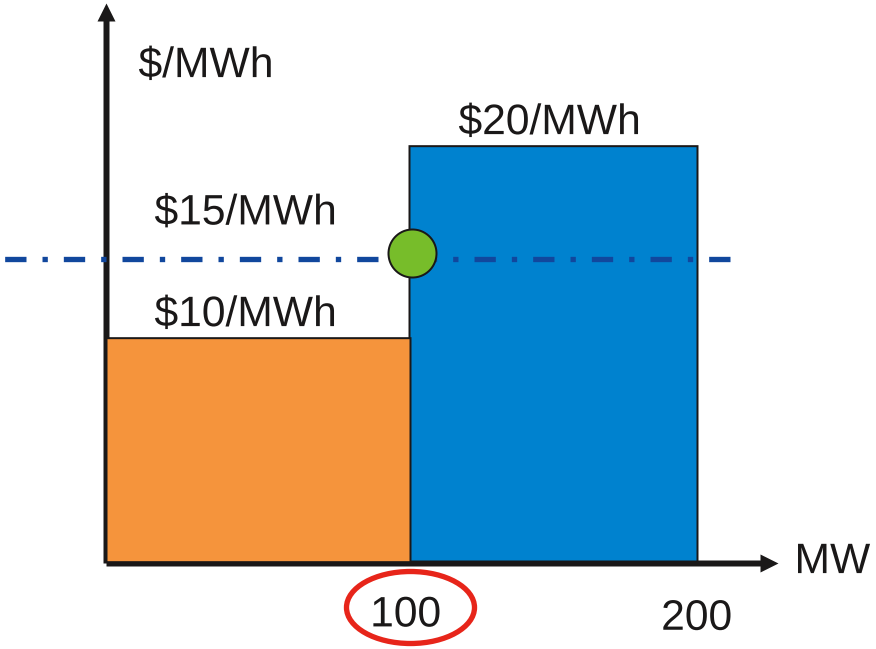
Generator's Profit Maximization

- Under the perfectly competitive market, the profit maximization strategy drives a generator to produce at a level where its marginal cost equals the market clearing price at its location.



Question 1

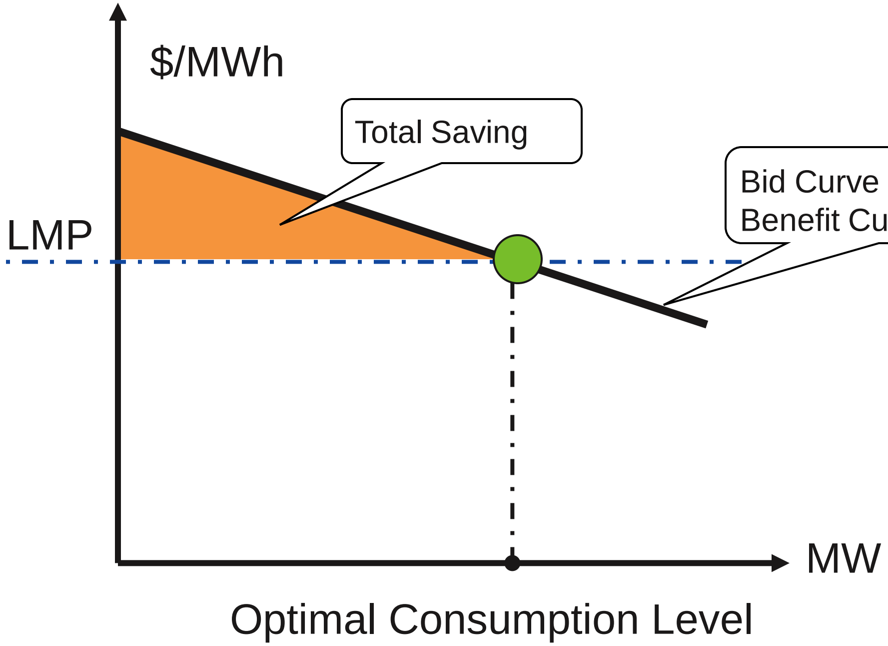
- If the LMP is $15/MWh, what is the optimal output level of this unit? How much is its profit?



Energy Profit = (15 - 10) x 100 = $500

Demand's Benefit Maximization

- Under the perfectly competitive market, the benefit maximization strategy drives a demand to consume at a level where its marginal benefit equals the market clearing price at its location.



Introduction to the Real-Time Energy-Reserve Market

Features of the Real-Time Market (RTM)

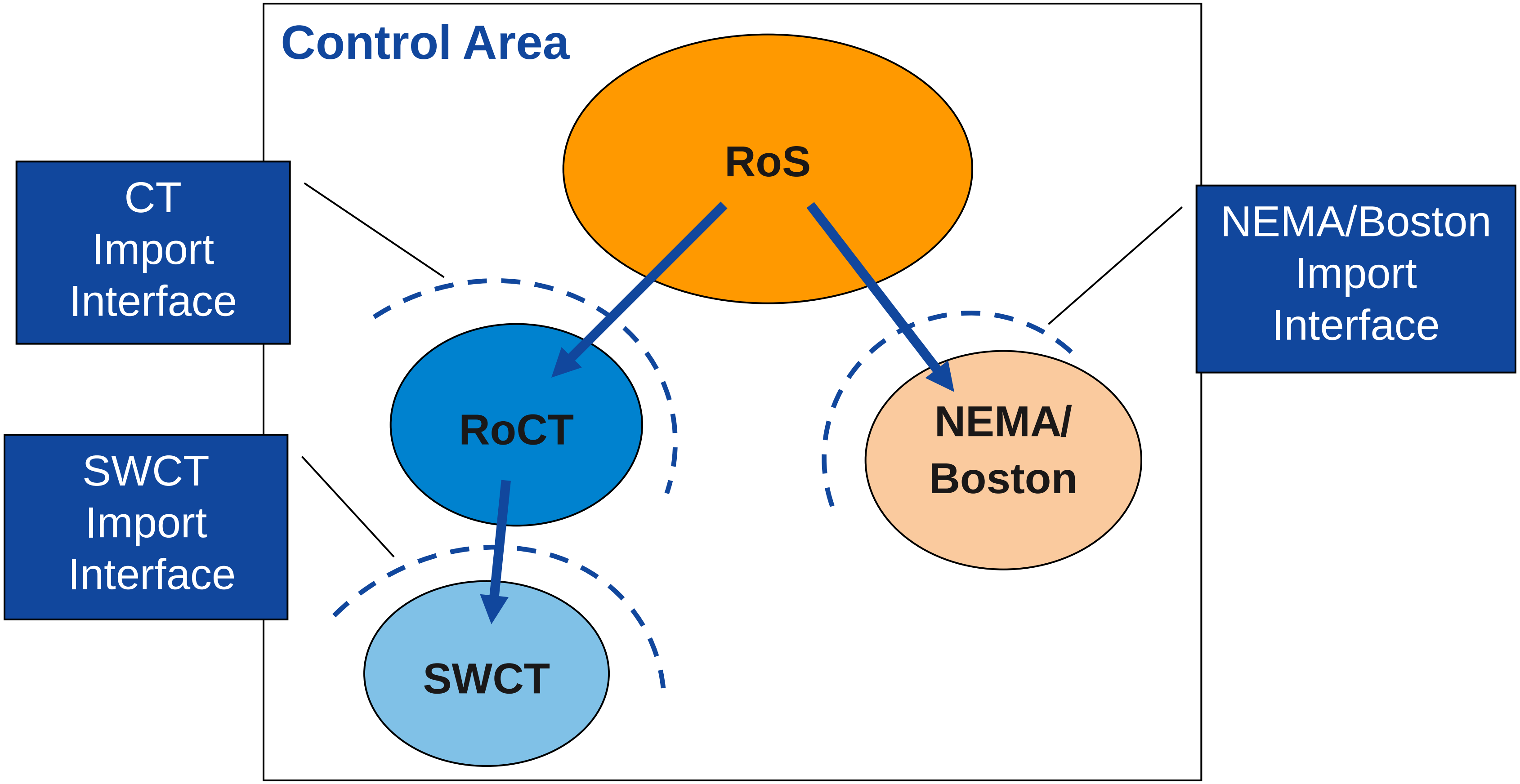
Features of RTM

- Bids for the RTM
  - Energy and Asset Related Demand (ARD)
  - External Transaction Purchases and Sales
  - No Real-Time availability bids for reserves.
- Energy and Reserve Co-optimization
- Locational Reserve Modeling
- Reserve Shortage Pricing
- Reserve Price Cascading

Current Reserve Products

- Ten-Minute Spinning Reserve (TMSR)
- Ten-Minute Non-Spinning Reserve (TMNSR)
- Thirty-Minute Operating Reserve (TMOR)

Reserve Zones and Pricing Locations



Note: **Three** Local Reserve Requirements (for three Interfaces), **Four** Pricing Locations (or four Reserve Zones), and Three Reserve Products (for each Reserve Zone).

RoS: Rest of System **RoCT: Rest of Connecticut**

Qualified Resources

- Online Units
  - Online dispatchable units
  - Units on Automatic Generation Control (AGC)
- Off-line Units
  - Qualified 10 minutes capable unit
  - Qualified 30 minutes capable unit
- Asset Related Demands (ARD)
  - Dispatchable ARDs
  - Pumps (pumped-storage unit)

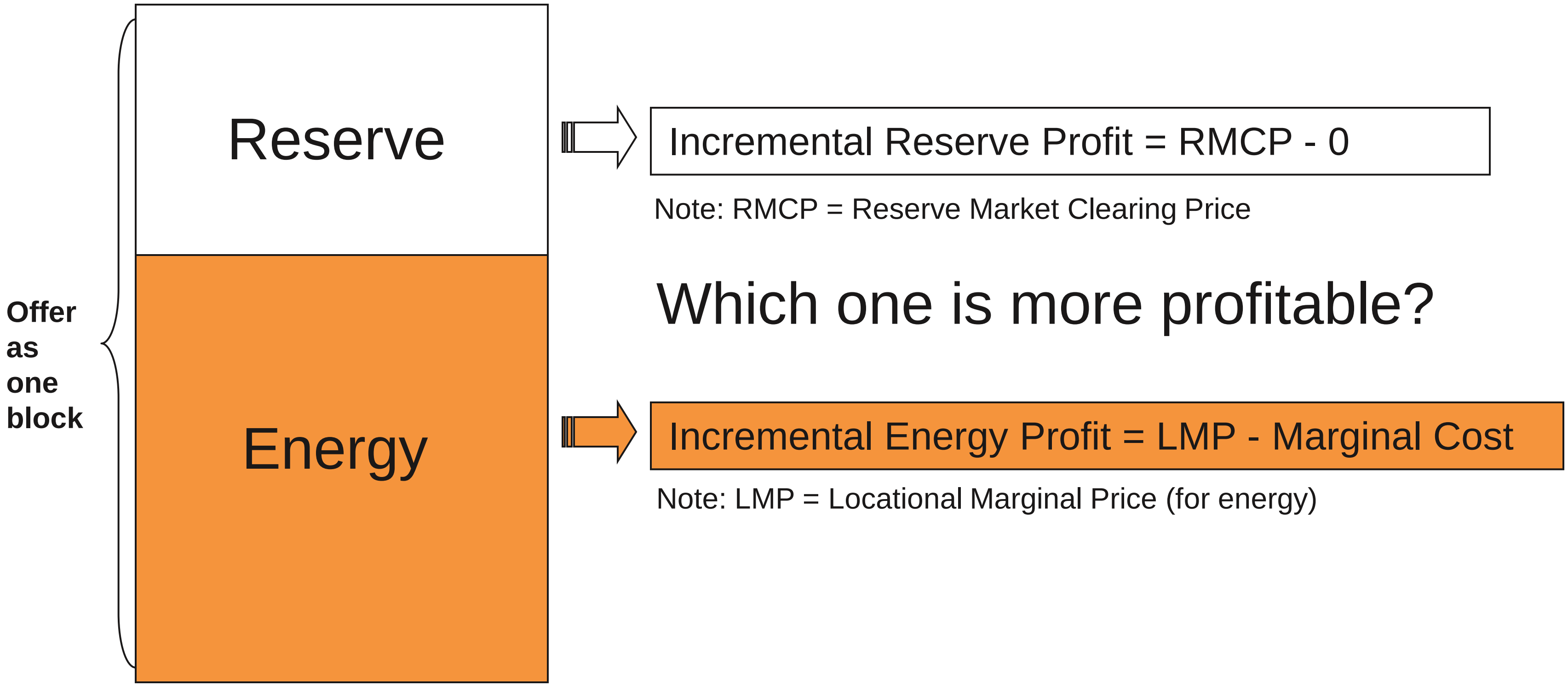
Why Co-optimization?

Trade-off Between Energy and Reserve

- If not constrained by ramping capability, any potential MW of energy is a trade-off for a potential MW of reserve provided by the same unit.
- The profit maximization will drive the unit's decision as to producing energy or providing reserve.
- Energy-reserve co-optimization provides ISO Operations with the modeling capability to dispatch both energy and reserve optimally and simultaneously.
- The optimal solution provides the best outcome to all dispatchable resources as well.

Trade-off Between Energy and Reserve

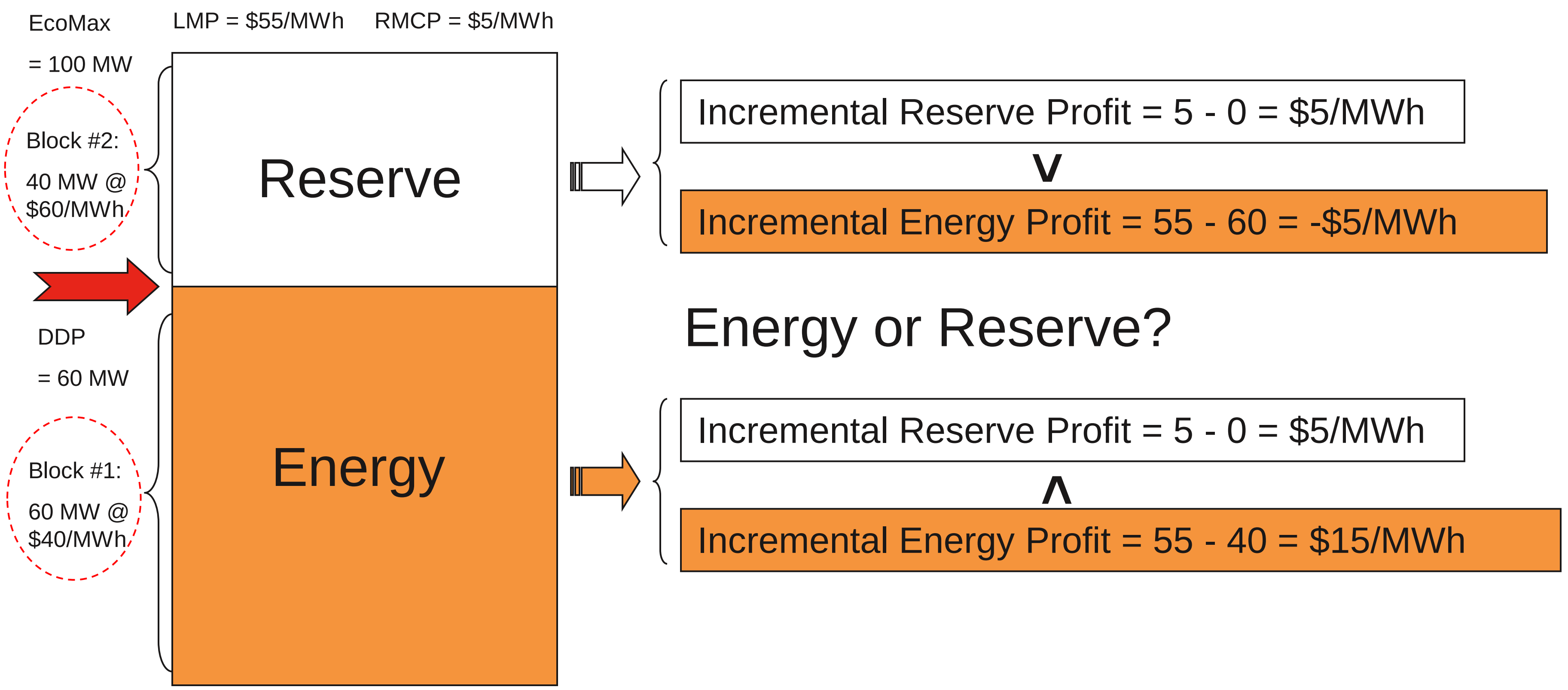
Conceptual Illustration



Energy-reserve Co-optimization provides the optimal allocation of energy and reserve for each unit.

Trade-off Between Energy and Reserve

Base Case Example

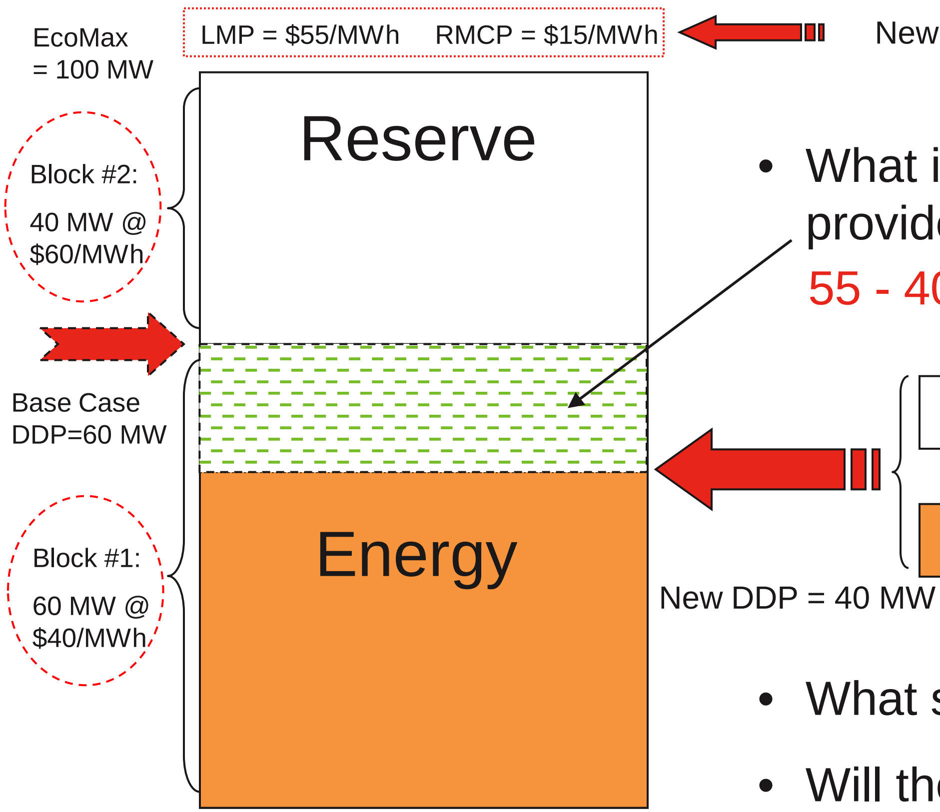


Unit maximizes its profit when operating at 60 MW Desired Dispatch Point (DDP):

- If DDP > 60 MW, providing reserve makes more profit than producing energy. Unit will choose to back down energy and provide more reserve.
- If DDP < 60 MW, producing energy makes more profit than providing reserve. Unit will choose to increase energy and reduce reserve.

Trade-off Between Energy and Reserve

Reserve Requirement Increased by 20 MW



- What is the unit’s lost opportunity cost to provide reserve instead of producing energy? 55 - 40 = $15/MWh.

Incremental Reserve Profit = 15 - 0 = $15/MWh

=

Incremental Energy Profit = 55 - 40 = $15/MWh

- What should be the right RMCP?
- Will the unit maximize its profit and follow DDP?

When the new prices send the right market signal, unit maximizes its profit when following the System Operator’s Desired Dispatch Point (DDP) - 40 MW.

Real-Time Reserve Modeling and Designation

Reserve Requirements

- Reserve requirements are based on System or Local contingency recovery needs within 10 or 30 minutes.
- At Local level (NEMA/Boston, CT, and SWCT), the real-time market design has only a 30-minute reserve requirement.

System Reserve Requirements

- Ten-Minute Spinning Reserve (TMSR) Requirement currently equals 50% of the largest First Contingency in the system.
- Total Ten-Minute Reserve (including TMSR and TMNSR) Requirement equals the largest First Contingency in the system.
- Total Thirty-Minute Operating Reserve (including TMSR, TMNSR and TMOR) Requirement is equal to the sum of 100% of the largest First Contingency and 50% of the largest Second Contingency in the system.

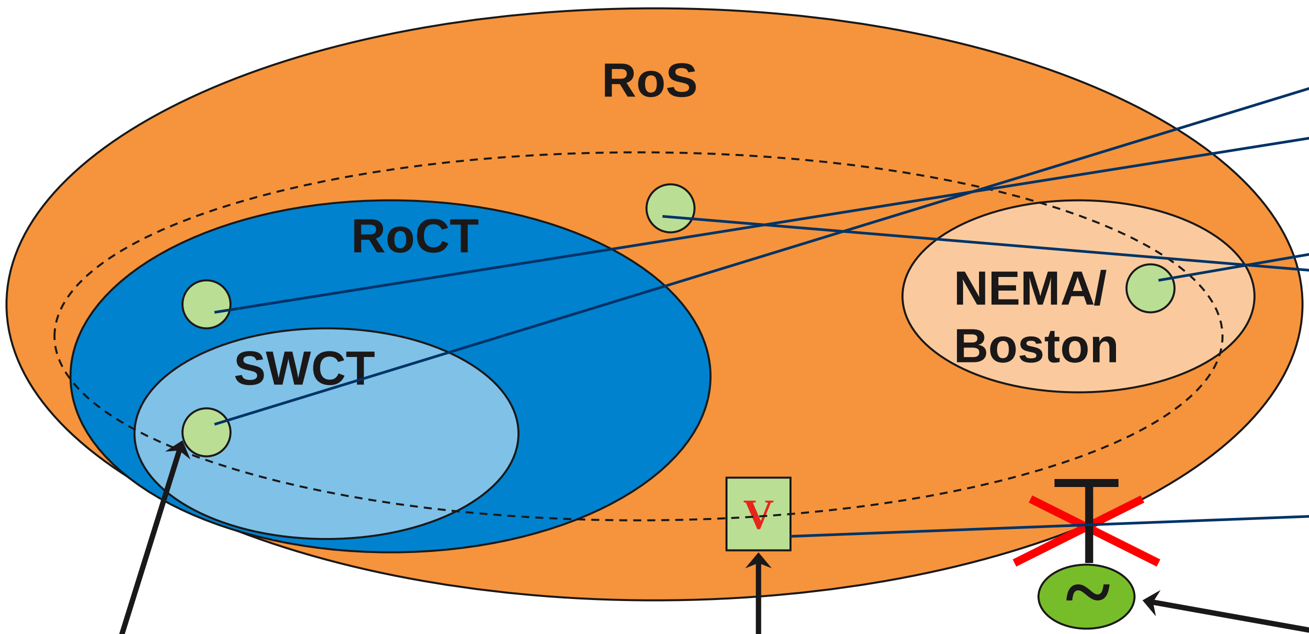
Locational Reserve Requirement

- In local areas, such as NEMA/Boston, CT, and SWCT, there is no 10-minute reserve requirement.
  - Anticipates that the local largest First Contingency recovery requirements can be met by operating at the (N-1) import Interface limit.
- The real-time market design has only a 30-minute reserve requirement to meet 100% of the largest Second Contingency recovery needs in the local area subject to the (N-1) import Interface limit.

Reserve Constraint Penalty Factor (RCPF)

- RCPF is associated with a certain contingency that requires the deployment of reserves and can be considered as a “virtual” reserve resource that ISO operations can deploy upon a contingency at a cost of the RCPF value.
- In practice, RCPF is used to prevent infeasible solutions of an optimization problem. The value of RCPF **does** affect the market clearing and pricing.
- Current RCPF values are:
  - $ 50/MWh for system-wide TMSR constraint
  - $850/MWh for system-wide total 10-minute reserve constraint
  - $100/MWh for system-wide total 30-minute reserve constraint
  - $ 250/MWh for each local reserve constraint

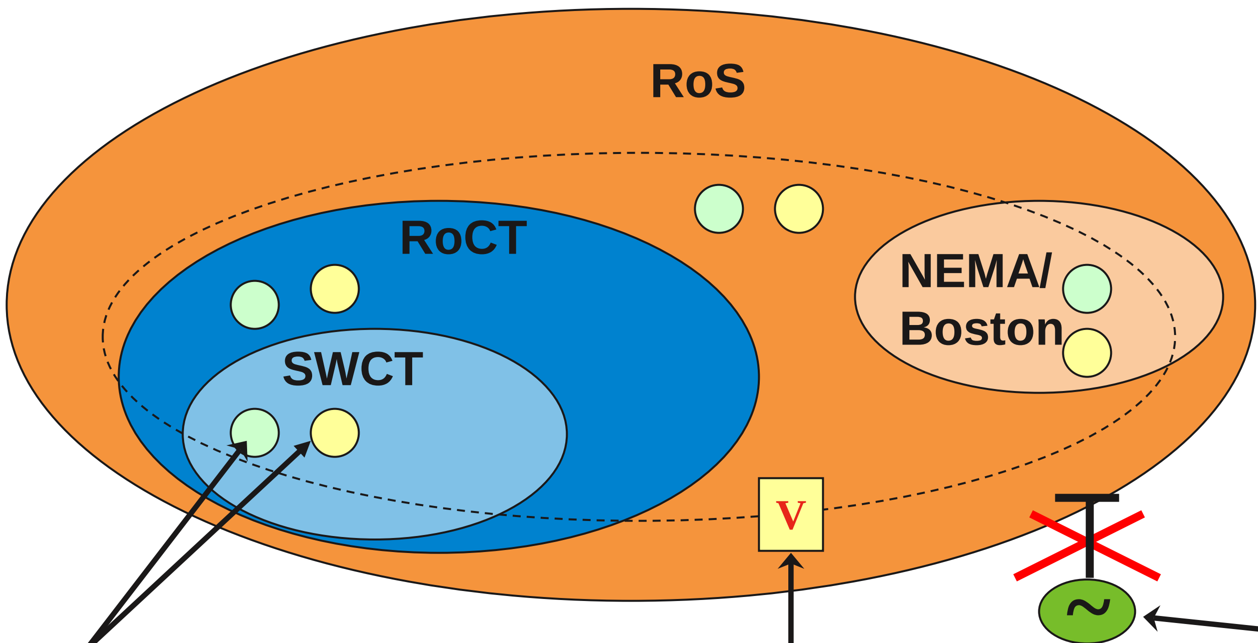
Meeting System
TMSR Requirement



Constraints / Resources		System TMSR
SWCT	TMSR	Yes
	TMNSR	
	TMOR	
RoCT	TMSR	Yes
	TMNSR	
	TMOR	
NEMA/ Boston	TMSR	Yes
	TMNSR	
	TMOR	
ROS	TMSR	Yes
	TMNSR	
	TMOR	
SWCT RCPF		
CT RCPF		
NEMA/Boston RCPF		
System	TMSR RCPF	Yes
	Total 10 RCPF	
	Total 30 RCPF	

TMSR from all Resources + **Reserve from TMSR RCPF Resource** >= **System TMSR Requirement**

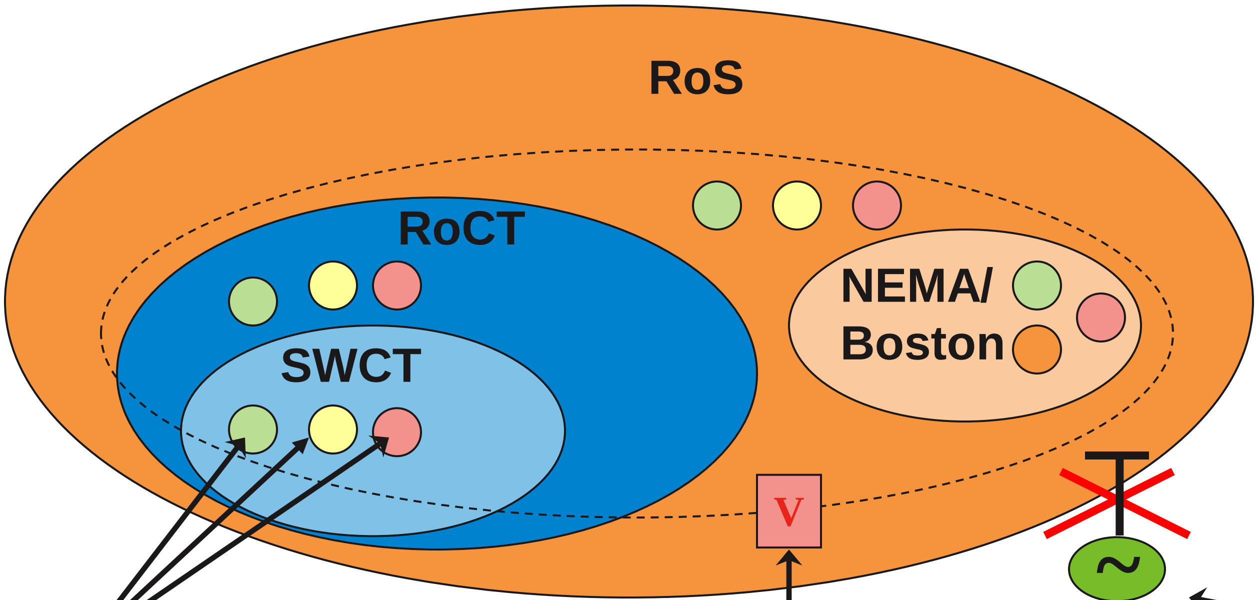
Meeting System
Total 10-minute Reserve Requirement



Constraints / Resources		System
		Total 10
SWCT	TMSR	Yes
	TMNSR	Yes
	TMOR	
RoCT	TMSR	Yes
	TMNSR	Yes
	TMOR	
NEMA/ Boston	TMSR	Yes
	TMNSR	Yes
	TMOR	
ROS	TMSR	Yes
	TMNSR	Yes
	TMOR	
SWCT RCPF		
CT RCPF		
NEMA/Boston RCPF		
System	TMSR RCPF	
	Total 10 RCPF	Yes
	Total 30 RCPF	

TMSR and TMNSR from all Resources + **Reserve from total 10-minute RCPF Resource** >= **System total 10-minute Reserve Requirement**

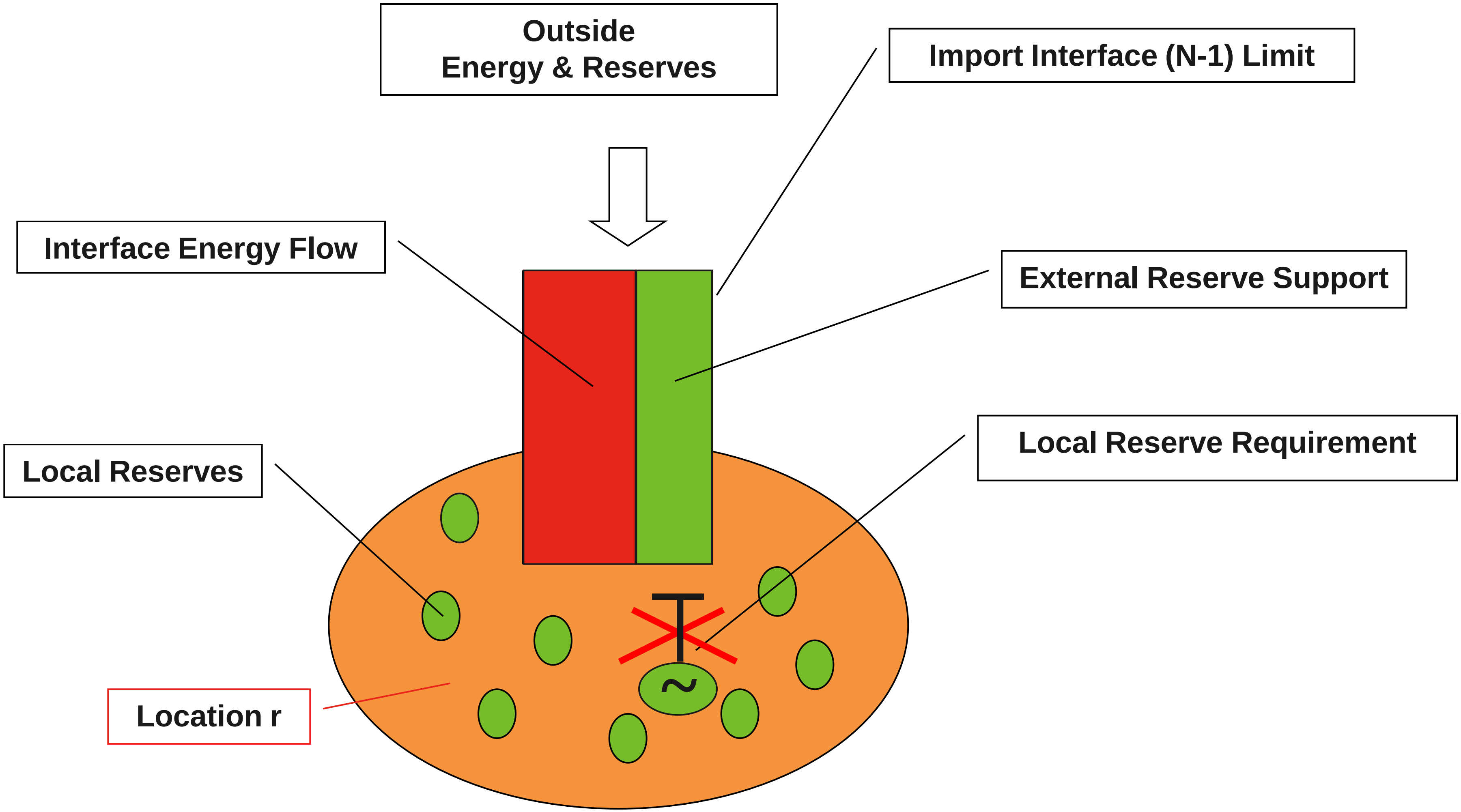
Meeting System
Total 30-minute Reserve Requirement



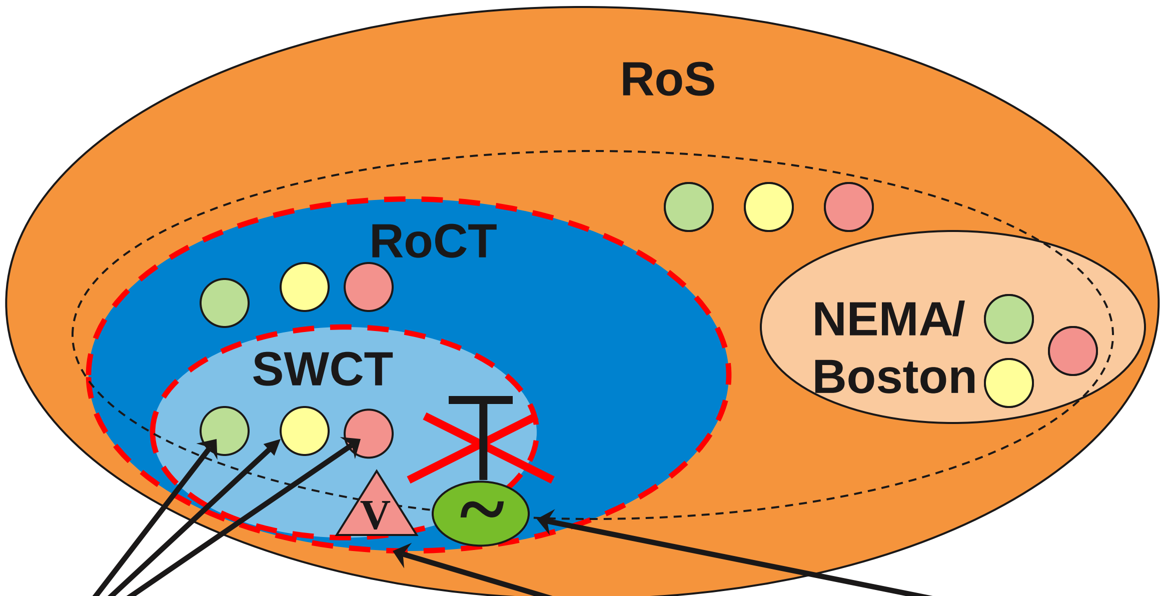
Constraints / Resources		System Total 30
SWCT	TMSR	Yes
	TMNSR	Yes
	TMOR	Yes
RoCT	TMSR	Yes
	TMNSR	Yes
	TMOR	Yes
NEMA/ Boston	TMSR	Yes
	TMNSR	Yes
	TMOR	Yes
ROS	TMSR	Yes
	TMNSR	Yes
	TMOR	Yes
SWCT RCPF		
CT RCPF		
NEMA/Boston RCPF		
System	TMSR RCPF	
	Total 10 RCPF	
	Total 30 RCPF	Yes

TMSR, TMNSR, and TMOR from all Resources + **Reserve from total 30-minute RCPF Resource** >= **System total 30-minute Reserve Requirement**

Meeting Locational Reserve Requirement
Conceptual Illustration



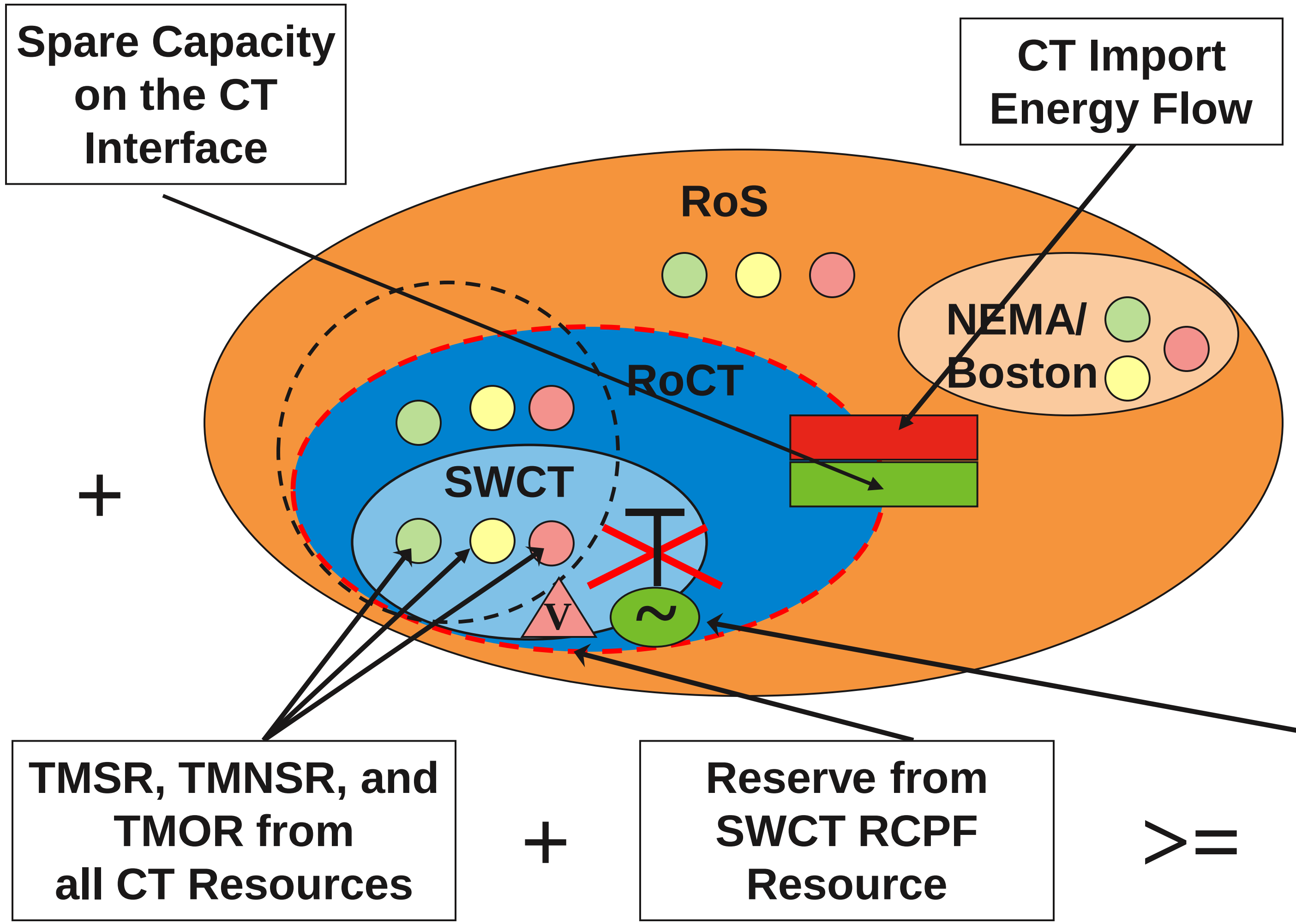
Meeting SWCT Reserve Requirement System Level Constraint



Resources \ Constraints		SWCT System
SWCT	TMSR	Yes
	TMNSR	Yes
	TMOR	Yes
RoCT	TMSR	Yes
	TMNSR	Yes
	TMOR	Yes
NEMA/ Boston	TMSR	Yes
	TMNSR	Yes
	TMOR	Yes
ROS	TMSR	Yes
	TMNSR	Yes
	TMOR	Yes
SWCT RCPF		Yes
CT RCPF		
NEMA/Boston RCPF		
System	TMSR RCPF	
	Total 10 RCPF	
	Total 30 RCPF	

TMSR, TMNSR, and TMOR from all Resources + **Reserve from SWCT RCPF Resource** >= **SWCT Reserve Requirement**

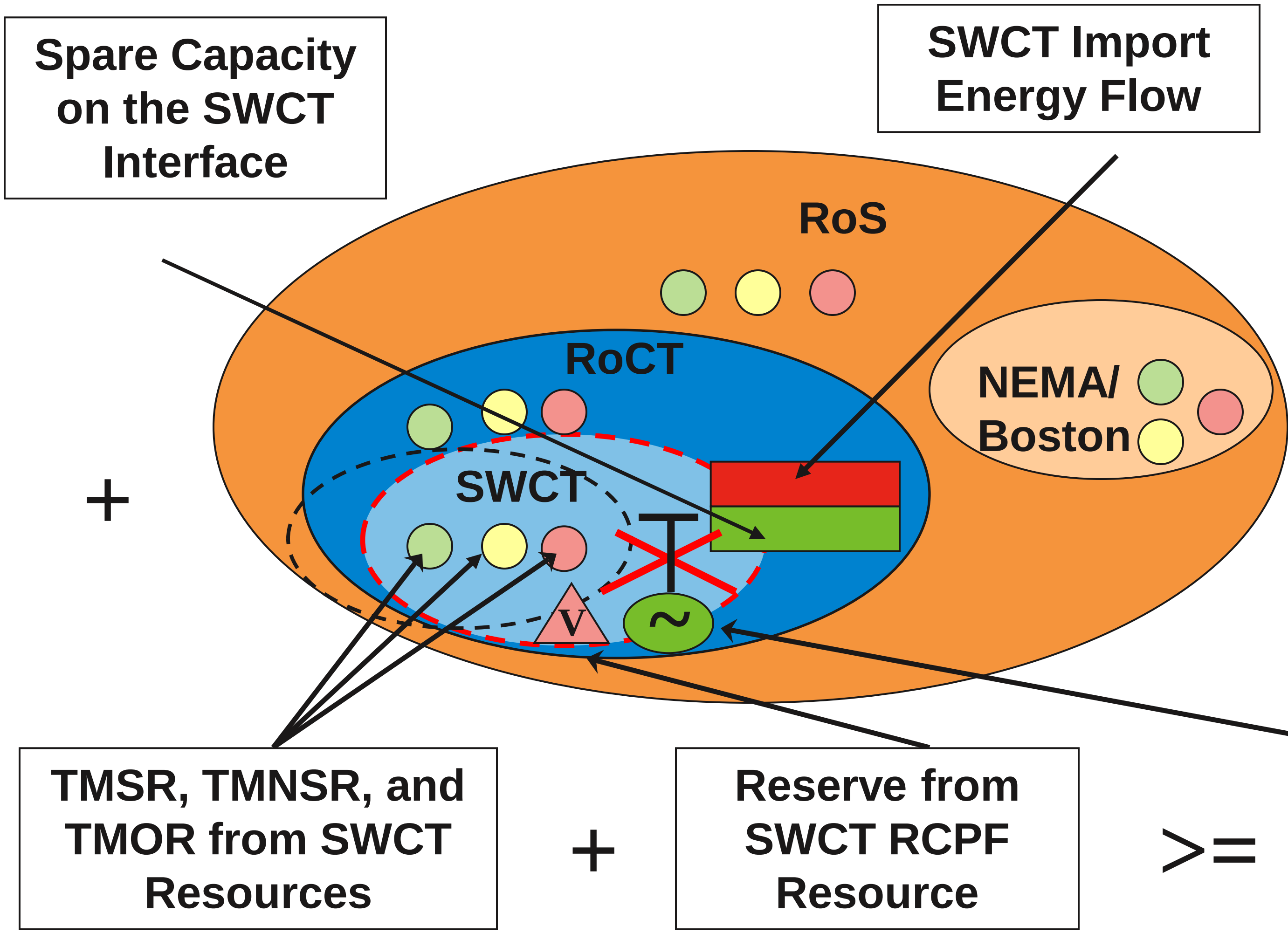
Meeting SWCT Reserve Requirement
CT Import Constraint



Resources \ Constraints		SWCT CT Import
SWCT	TMSR	Yes
	TMNSR	Yes
	TMOR	Yes
RoCT	TMSR	Yes
	TMNSR	Yes
	TMOR	Yes
NEMA/ Boston	TMSR	
	TMNSR	
	TMOR	
ROS	TMSR	
	TMNSR	
	TMOR	
SWCT RCPF		Yes
CT RCPF		
NEMA/Boston RCPF		
SWCT ISC		
CT ISC		Yes
NEMA/Boston ISC		

Meeting SWCT Reserve Requirement

SWCT Import Constraint



Resources \ Constraints		SWCT: SWCT Import
SWCT	TMSR	Yes
	TMNSR	Yes
	TMOR	Yes
RoCT	TMSR	
	TMNSR	
	TMOR	
NEMA/ Boston	TMSR	
	TMNSR	
	TMOR	
ROS	TMSR	
	TMNSR	
	TMOR	
SWCT RCPF		Yes
CT RCPF		
NEMA/Boston RCPF		
SWCT ISC		Yes
CT ISC		
NEMA/Boston ISC		

Meeting Reserve Requirements Summary

Constraints / Resources		SWCT Reserve Requirement			CT Reserve Requirement		NEMA/Boston Reserve Requirement		System Reserve Requirements		
		System	CT Import	SWCT Import	System	CT Import	System	Boston Import	TMSR	Total 10	Total 30
SWCT	TMSR	Yes	Yes	Yes	Yes	Yes	Yes		Yes	Yes	Yes
	TMNSR	Yes	Yes	Yes	Yes	Yes	Yes			Yes	Yes
	TMOR	Yes	Yes	Yes	Yes	Yes	Yes				Yes
RoCT	TMSR	Yes	Yes		Yes	Yes	Yes		Yes	Yes	Yes
	TMNSR	Yes	Yes		Yes	Yes	Yes			Yes	Yes
	TMOR	Yes	Yes		Yes	Yes	Yes				Yes
NEMA/ Boston	TMSR	Yes			Yes		Yes	Yes	Yes	Yes	Yes
	TMNSR	Yes			Yes		Yes	Yes		Yes	Yes
	TMOR	Yes			Yes		Yes	Yes			Yes
ROS	TMSR	Yes			Yes		Yes		Yes	Yes	Yes
	TMNSR	Yes			Yes		Yes			Yes	Yes
	TMOR	Yes			Yes		Yes				Yes
SWCT RCPF		Yes	Yes	Yes							
CT RCPF					Yes	Yes					
NEMA/Boston RCPF							Yes	Yes			
System	TMSR RCPF								Yes		
	Total 10 RCPF									Yes	
	Total 30 RCPF										Yes
SWCT ISC				Yes							
CT ISC			Yes			Yes					
NEMA/Boston ISC								Yes			

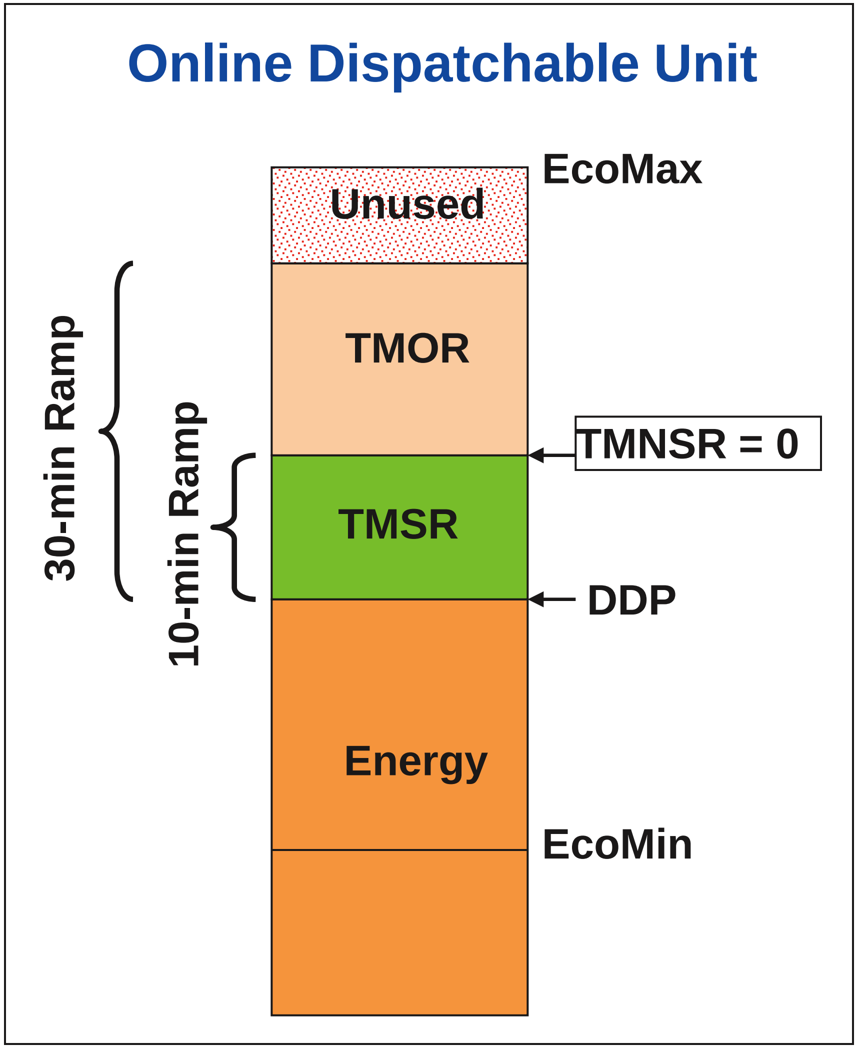
Yes: If a resource participates in meeting a reserve constraint.

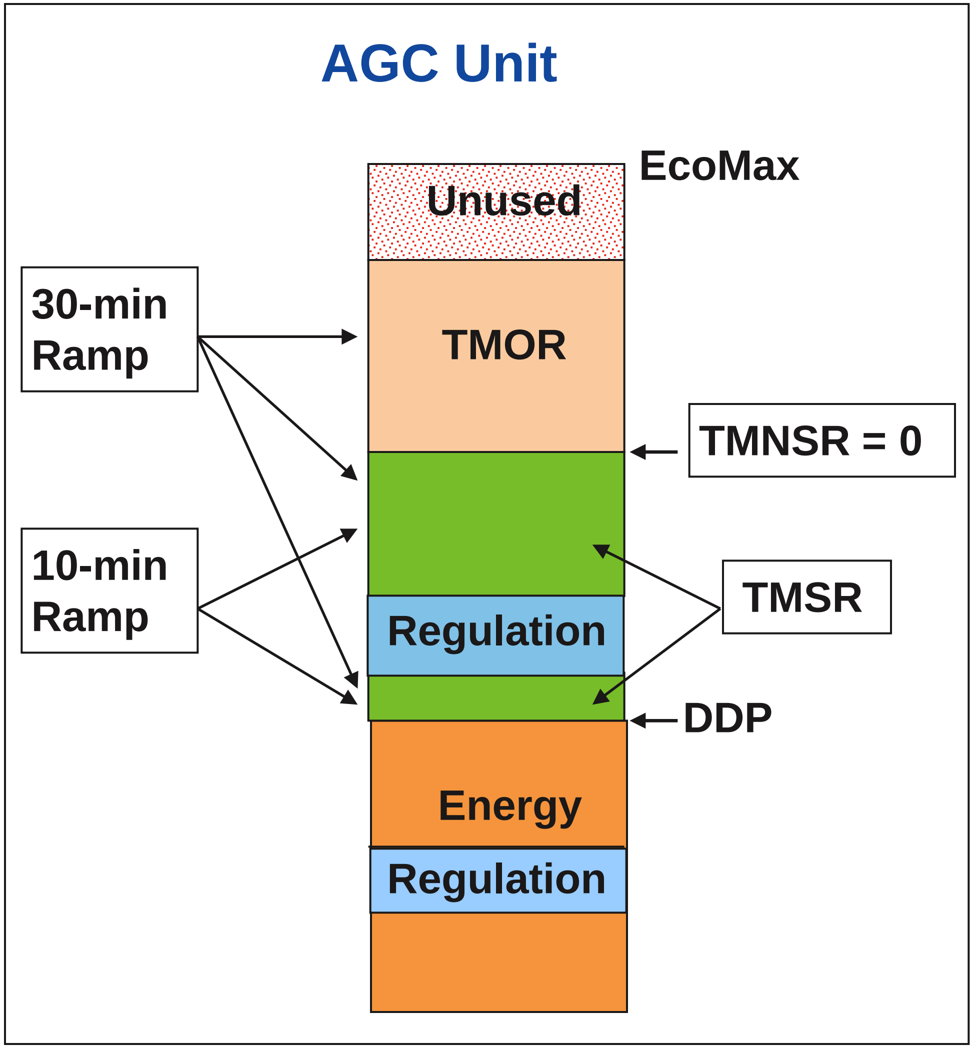
Example: Meeting SWCT Reserve Requirement

Reserve Constraints / Resources MW			SWCT Reserve Requirement		
			System	CT Import	SWCT Import
SWCT	TMSR	50	50	50	50
	TMNSR	50	50	50	50
	TMOR	50	50	50	50
RoCT	TMSR	100	100	100	
	TMNSR	100	100	100	
	TMOR	100	100	100	
NEMA/ Boston	TMSR	100	100		
	TMNSR	100	100		
	TMOR	100	100		
ROS	TMSR	500	500		
	TMNSR	500	500		
	TMOR	500	500		
SWCT TMOR RCPF		0	0	0	0
SWCT ISC		320			320
CT ISC		100		100	
Total Reserve Available			2250	550	470
Reserve Requirement			500	500	500

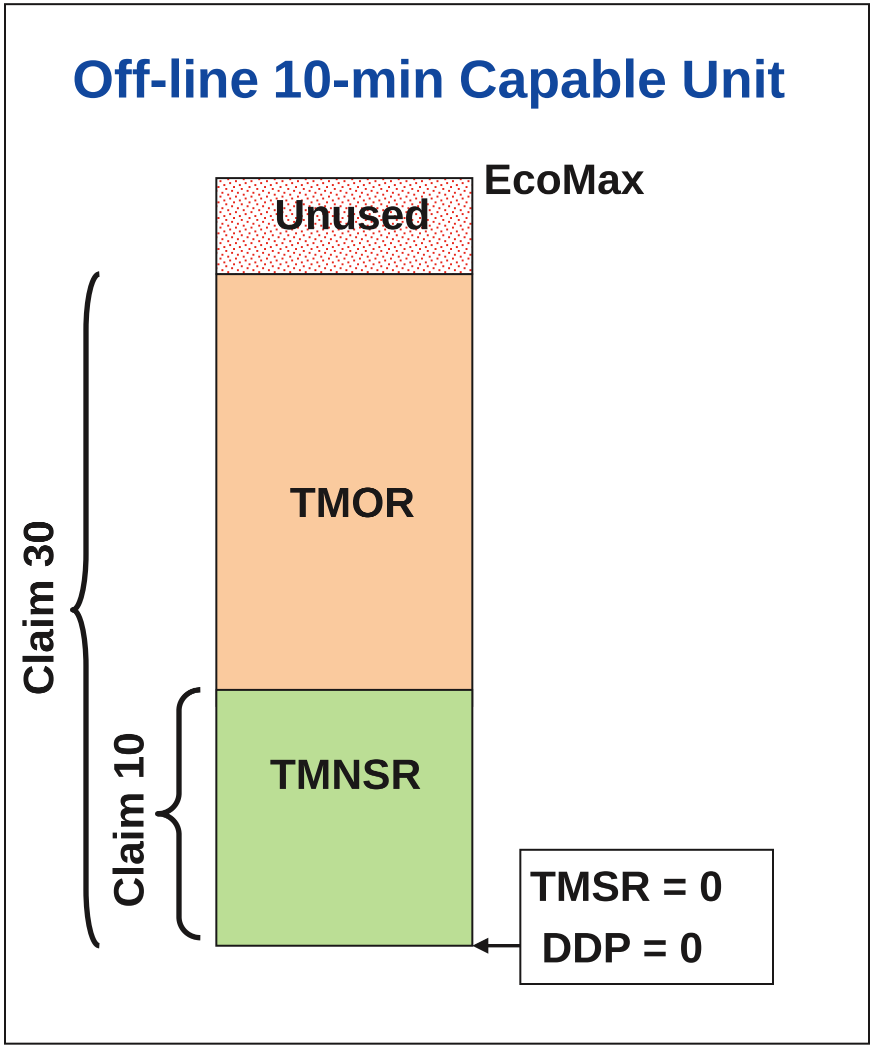
ISC = Interface Spare Capacity

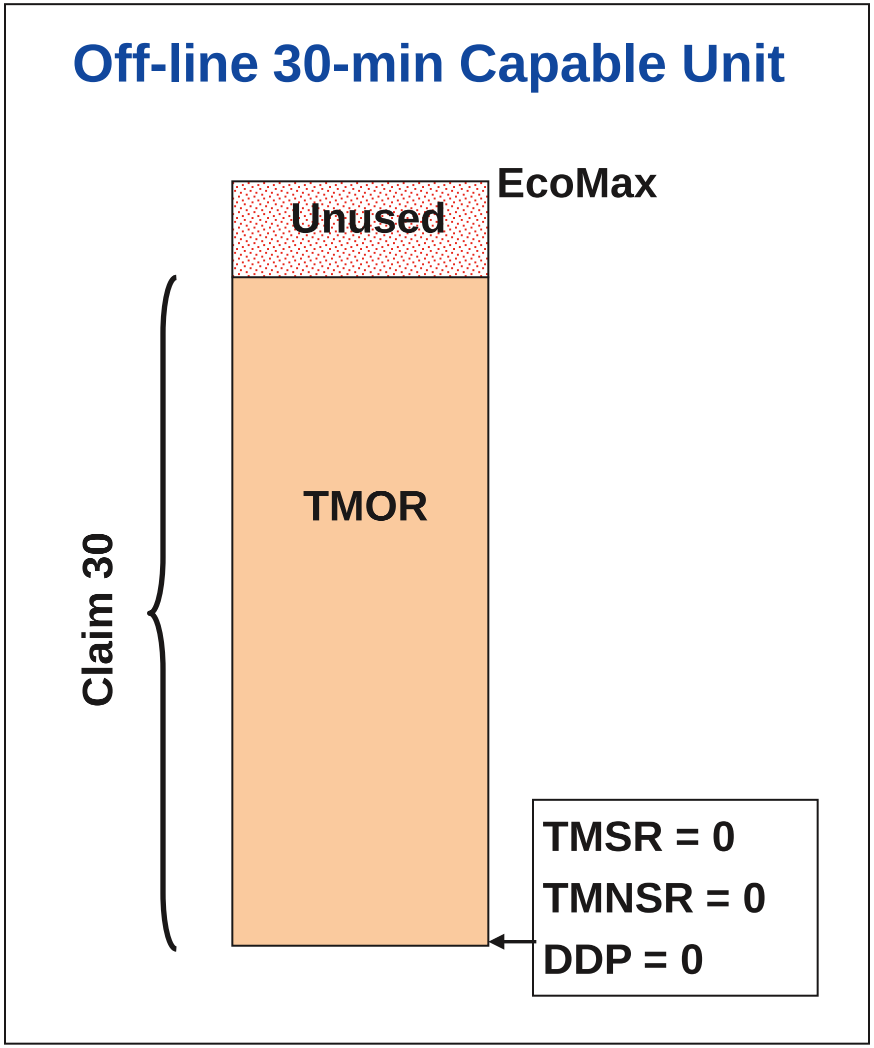
Reserve Designation -- Online Units





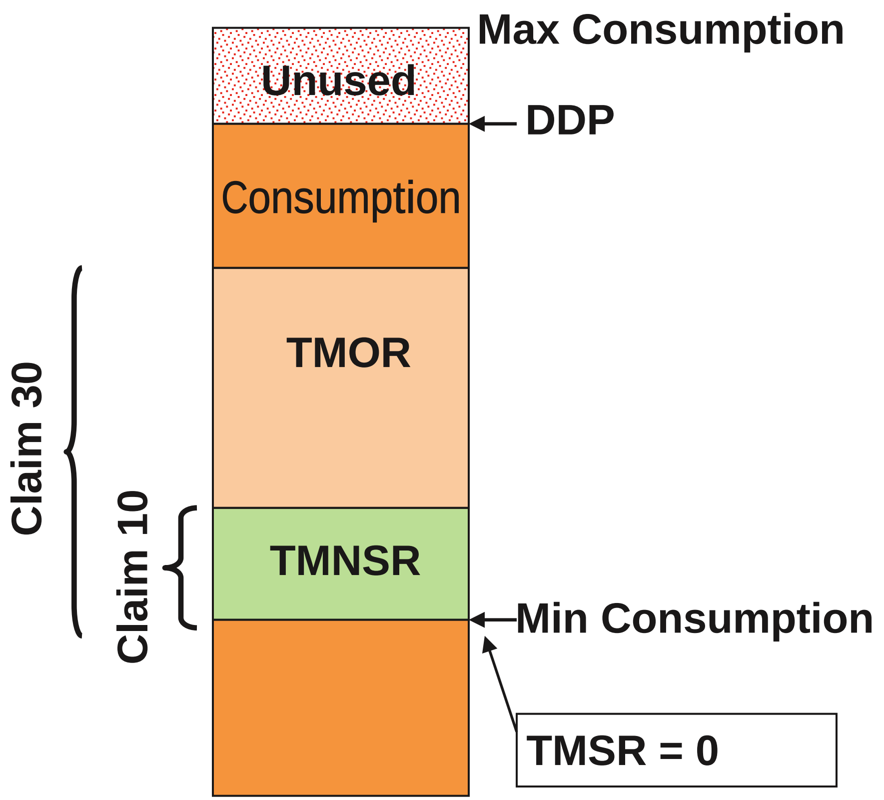
Reserve Designation -- Off-line Units



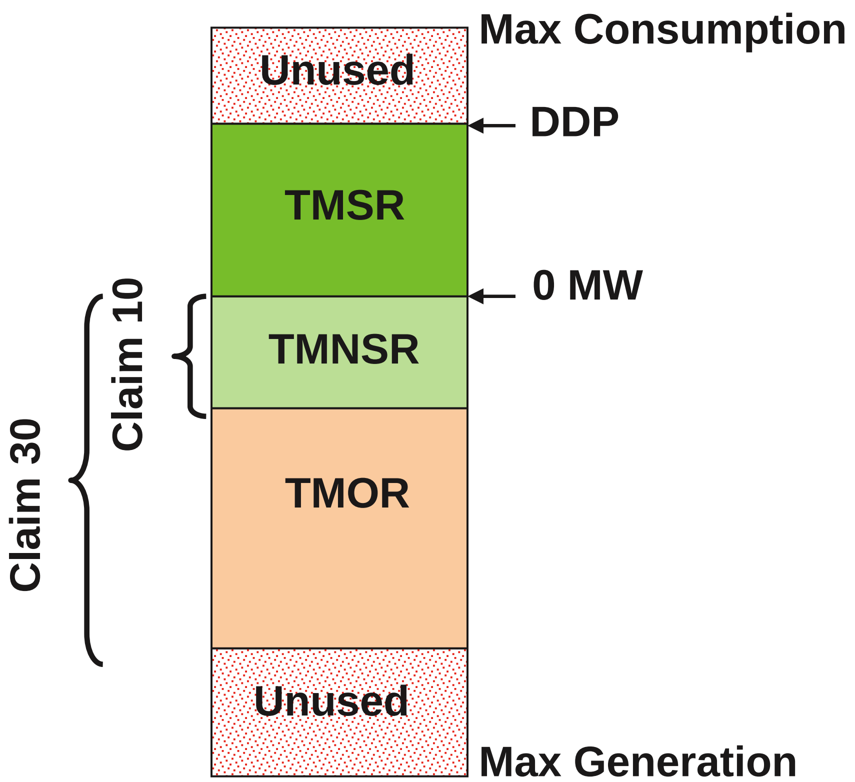


Reserve Designation --
Asset Related Demand

Dispatchable ARD



Dispatchable Pump



Market Clearing Prices and Properties

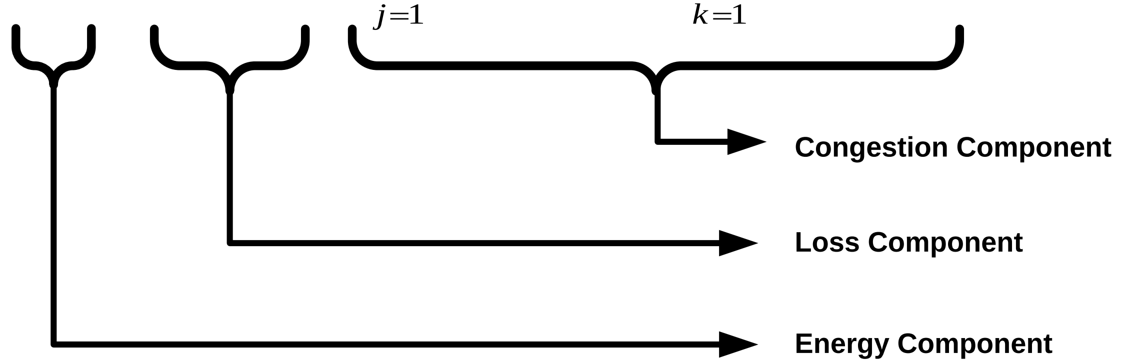
Energy-Reserve Co-optimization

- Objective is to minimize the total cost (equivalent to social welfare maximization).
- Subject to the following constraints:
  - Energy Balance
  - System Wide Reserve Constraints
  - Local Reserve Constraints
  - Transmission Constraints
  - Resource Level Constraints (joint capacity, ramp, regulation, and reserve capacity, etc.)
- Co-optimization Results are:
  - Desired Dispatch Point (DDP) and LMP
  - Reserve Designations and RMCP

Real-Time Locational Marginal Price Calculation

- LMP can be calculated using shadow prices as the following (α_k is the shadow price of an import constraint for a local reserve contingency event).
- Although the energy price is coupled with reserve price through shadow prices, there is no separate reserve component in LMP.

$$LMP_i = \lambda - LF_i \cdot \lambda + [\sum_{j=1}^{J} (S_{ij} \cdot \mu_j) - \sum_{k=1}^{K} (S_{ik} \cdot \alpha_k)]$$



Reserve Market Clearing Price (RMCP)

- RMCP is the maximum cost reduction caused by an increment of reserve supply at a location while respecting all related constraints.
- RMCP can be calculated using shadow prices of system and local reserve constraints.

Reserve Price Calculation

Constraint Shadow Price

Constraints / Locations		SWCT Reserve Requirement			CT Reserve Requirement		NEMA/Boston Reserve Requirement		System Reserve Requirements			RMCP ($/MWh)
		System	CT Import	SWCT Import	System	CT Import	System	Boston Import	TMSR	Total 10	Total 30	
		$1	$2	$3	$4	$5	$6	$7	$8	$9	$10	
SWCT	TMSR	1	1	1	1	1	1		1	1	1	48
	TMNSR	1	1	1	1	1	1			1	1	40
	TMOR	1	1	1	1	1	1				1	31
RoCT	TMSR	1	1		1	1	1		1	1	1	45
	TMNSR	1	1		1	1	1			1	1	37
	TMOR	1	1		1	1	1				1	28
NEMA/Boston	TMSR	1			1		1	1	1	1	1	45
	TMNSR	1			1		1	1		1	1	37
	TMOR	1			1		1	1			1	28
ROS	TMSR	1			1		1		1	1	1	38
	TMNSR	1			1		1			1	1	30
	TMOR	1			1		1				1	21

Resource Participation Factor

$RMCP_{SWCT}^{TMSR} =$

$1 \times 1 + 1 \times 2 + 1 \times 3 + 1 \times 4 + 1 \times 5 + 1 \times 6 + 0 \times 7 + 1 \times 8 + 1 \times 9 + 1 \times 10 = \$48/MWh$

Maximum RMCP Value in Theory

RCPFs

Constraints / Locations		SWCT Reserve Requirement			CT Reserve Requirement		NEMA/Boston Reserve Requirement		System Reserve Requirements			RMCP ($/MWh)
		System	CT Import	SWCT Import	System	CT Import	System	Boston Import	TMSR	Total 10	Total 30	
		$250	**$0**	**$0**	**$250**	**$0**	**$250**	**$0**	**$50**	**$850**	**$100**	
SWCT	TMSR	1	1	1	1	1	1		1	1	1	**1750**
	TMNSR	1	1	1	1	1	1			1	1	**1700**
	TMOR	1	1	1	1	1	1				1	**850**
RoCT	TMSR	1	1		1	1	1		1	1	1	**1750**
	TMNSR	1	1		1	1	1			1	1	**1700**
	TMOR	1	1		1	1	1				1	**850**
NEMA/ Boston	TMSR	1			1		1	1	1	1	1	**1750**
	TMNSR	1			1		1	1		1	1	**1700**
	TMOR	1			1		1	1			1	**850**
ROS	TMSR	1			1		1		1	1	1	**1750**
	TMNSR	1			1		1			1	1	**1700**
	TMOR	1			1		1				1	**850**

The sum of all shadow prices of reserve constraints for a local Reserve Zone cannot exceed its RCPF value: $250/MWh.

Note that we have roughly 3^{10} or 59,049 different constraint binding statuses.

Real-Time Reserve Price Cascading

- At the same location, TMSR price is always higher than or equal to TMNSR price; TMNSR price is always higher than or equal to TMOR price.
- For any Reserve product:
  - Its RMCP at SWCT is always higher than or equal to its price at CT (RoCT);
  - Its RMCP at CT (RoCT) is always higher than or equal to its price at RoS; and
  - Its RMCP at NEMA/Boston is always higher than or equal to its price at RoS.

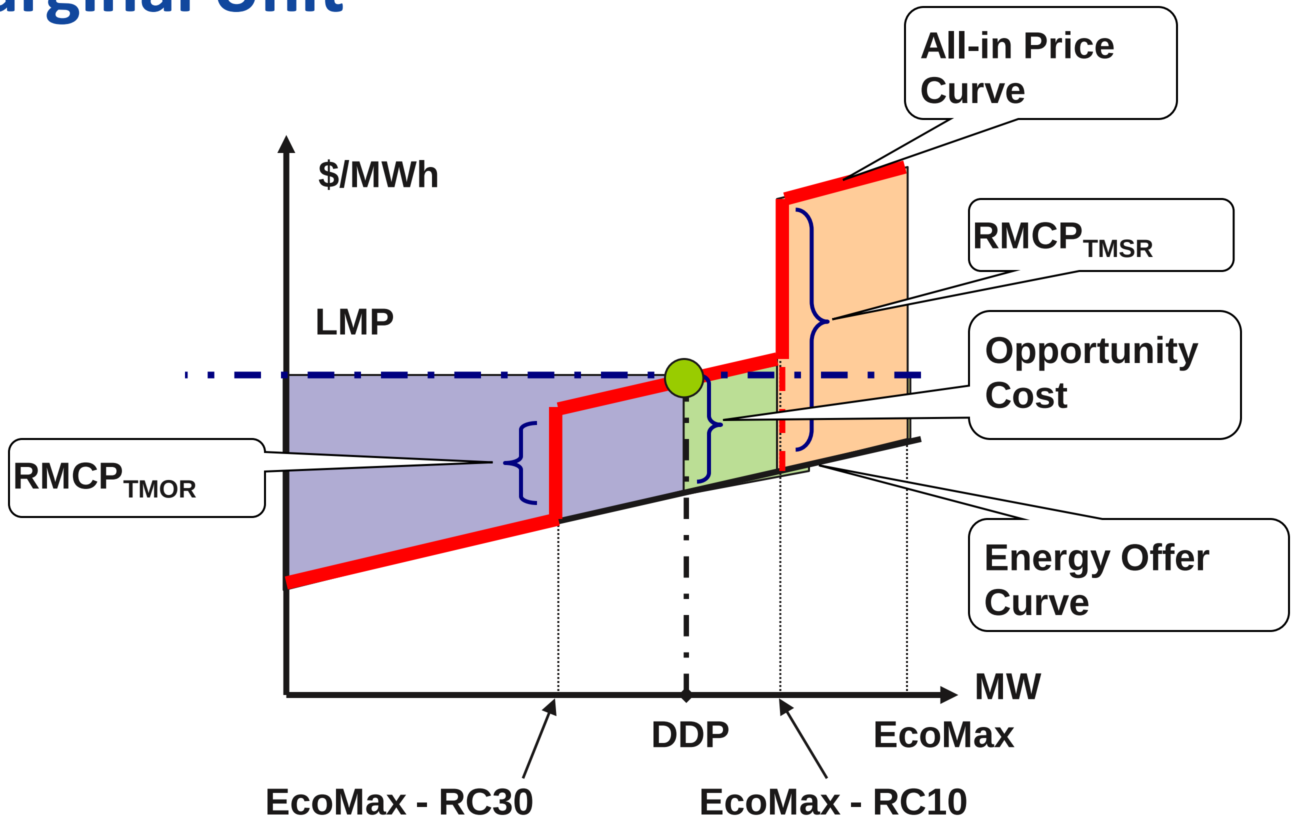
Understanding Energy and Reserve Prices and Designations

Generator's Profit Maximization
Under Energy-Reserve Co-optimization

- Under a perfectly competitive market, a generating resource will make its production decision based on the total profit maximization from both energy and reserve markets.
- The profit maximization strategy drives a generator to produce at a level where its marginal all-in cost (including both energy and opportunity cost for reserves) equals the market clearing price at its location.
- After energy and reserve co-optimization, each dispatchable generating resource is in one of the following conditions:
  - Marginal: set energy or reserve prices
  - Upward Constrained
  - Downward Constrained

Understanding Market Clearing Results

A Marginal Unit

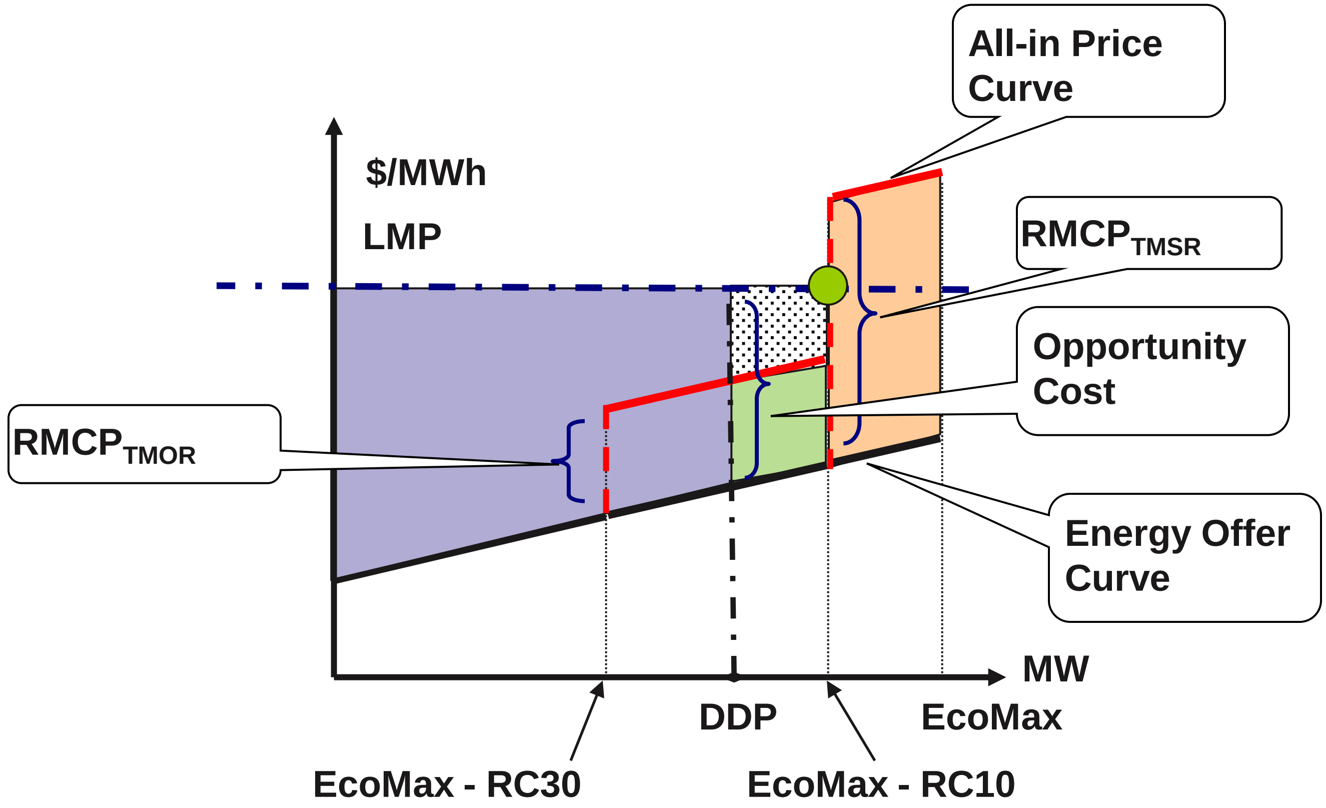


RC10: 10-min Capability RC30: 30-min Capability

Marginal: All-in Price at DDP = LMP or

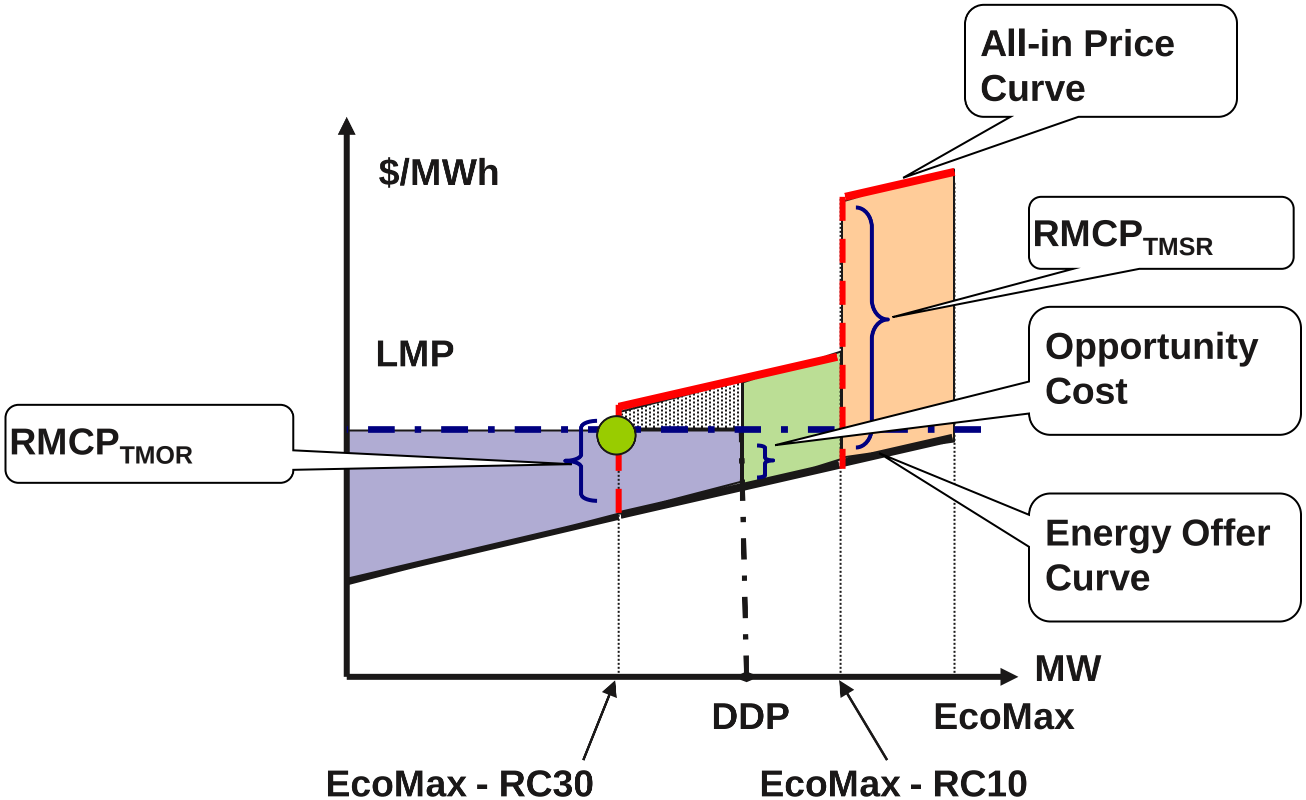
Opportunity Cost (OC) at DDP (LMP - Offer Price at DDP) = RMCP

Understanding Market Clearing Results
An Upward Constrained Unit



Upward Constrained : All-in Price at DDP < LMP
or OC at DDP > RMCP

Understanding Market Clearing Results
A Downward Constrained Unit



Downward Constrained : All-in Price at DDP > LMP or OC at DDP < RMCP

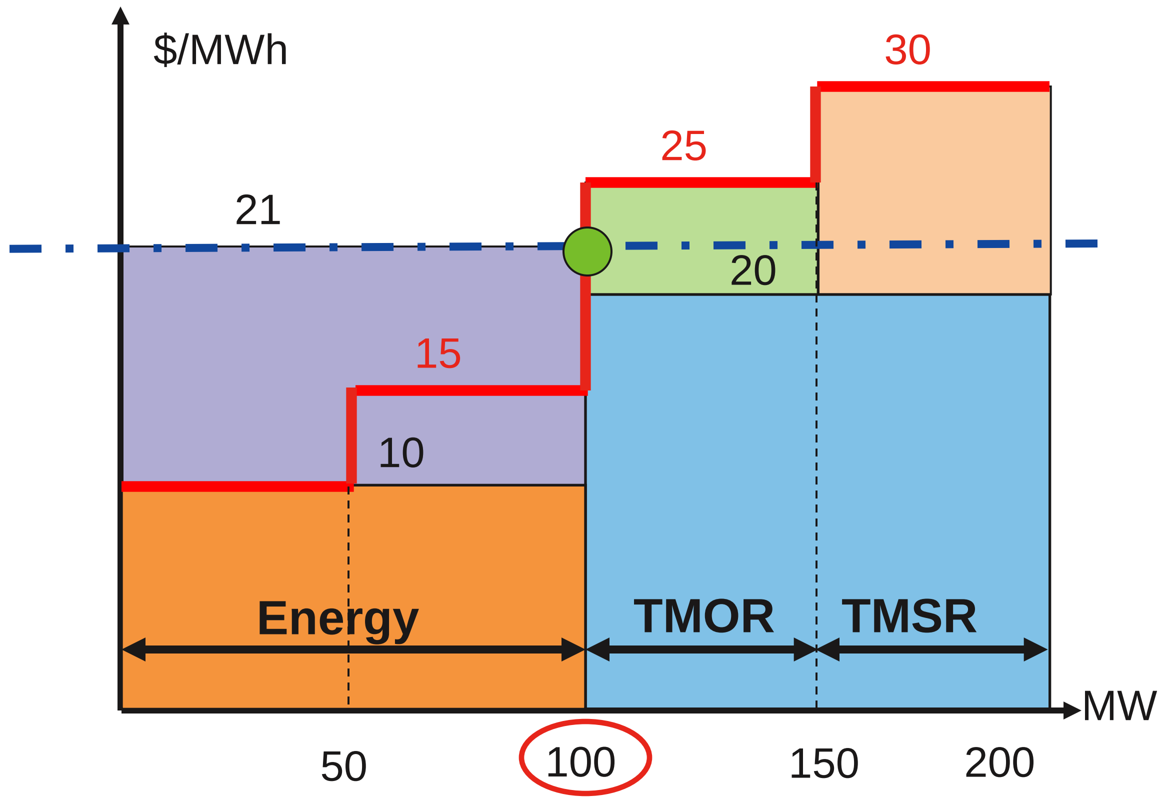
Question 2

- An online generator's bids are the following
  - 10-min ramping capability : 50 MW
  - 30-min ramping capability: 150 MW
  - EcoMax : 200 MW
  - EcoMin: 0 MW
- Given market clearing prices, how should it allocate energy and reserve to achieve the maximum profit under the perfectly competitive market?

Offer Curve	
MW	Price
100	$10/MWh
100	$20/MWh

Products	Price
Energy	$21/MWh
TMSR	$10/MWh
TMNSR	$8/MWh
TMOR	$5/MWh

Question 2 (cont.)



Energy Profit = (21 - 10) x 100 = $1,100

TMSR Profit = 10 x 50 = $500 **TMNSR Profit = 8 x 0 = $0** **TMOR Profit = 5 x 50 = $250**

Total Profit = $1,850

Demand's Benefit Maximization
Under Energy-Reserve Co-optimization

- Under the perfectly competitive market, the benefit maximization strategy drives a demand to consume at a level where its marginal all-in (including the opportunity cost for reserves) benefit equals the market clearing price at its location.

- After the energy and reserve co-optimization, a dispatchable demand is in one of the following conditions:
  - Marginal: set energy or reserve prices
  - Upward Constrained
  - Downward Constrained

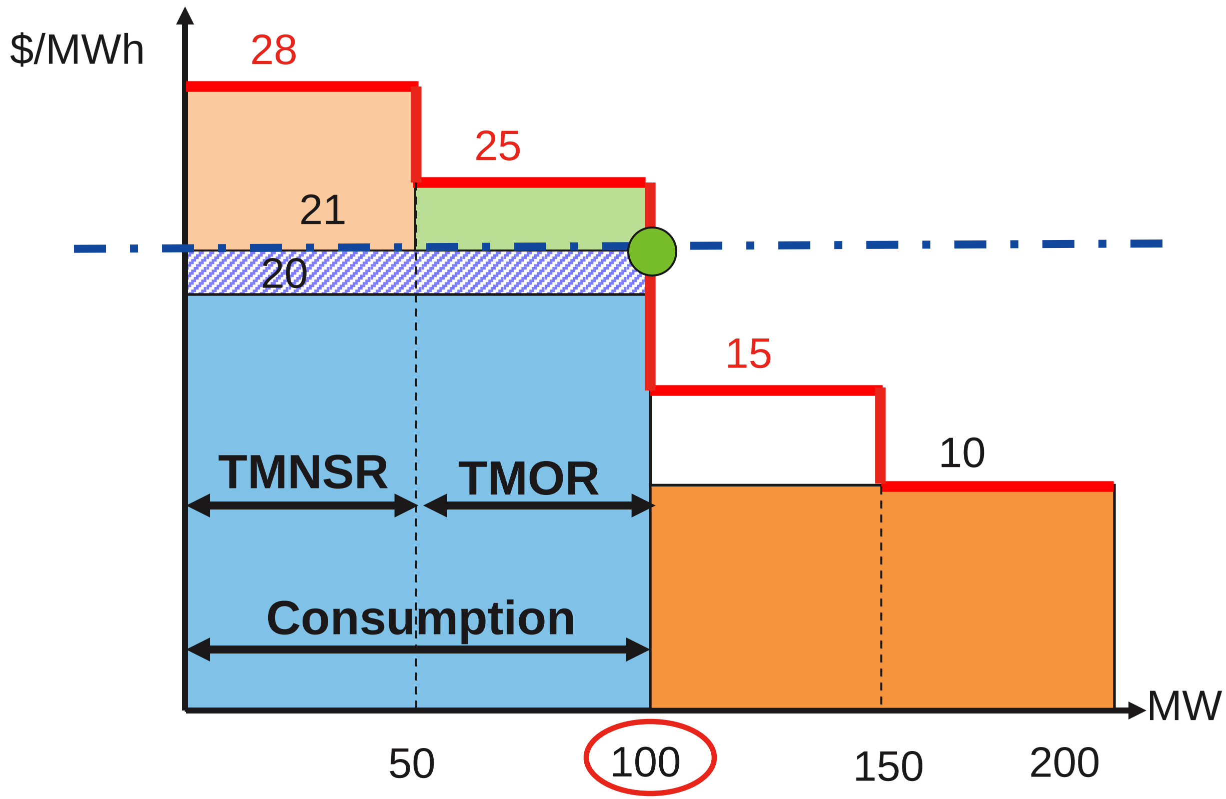
Question 3

- An online dispatchable ARD bids are the following
  - Claim 10: 50 MW
  - Claim 30: 150 MW
  - Max Consumption: 200 MW
  - Min Consumption: 0 MW
- Given market clearing prices, how should it allocate consumption and reserve to achieve the maximum saving under the perfectly competitive market?

Bid Curve	
MW	Price
100	$20/MWh
100	$10/MWh

Products	Price
Energy	$21/MWh
TMSR	$10/MWh
TMNSR	$8/MWh
TMOR	$5/MWh

Question 3 (cont.)



Energy Saving = (20 - 21) * 100 = -$100

TMSR Profit = 0 * 10 = $0　**TMNSR Profit = 8 * 50 = $400**　**TMOR Profit = 5 * 50 = $250**

Total Saving = $550

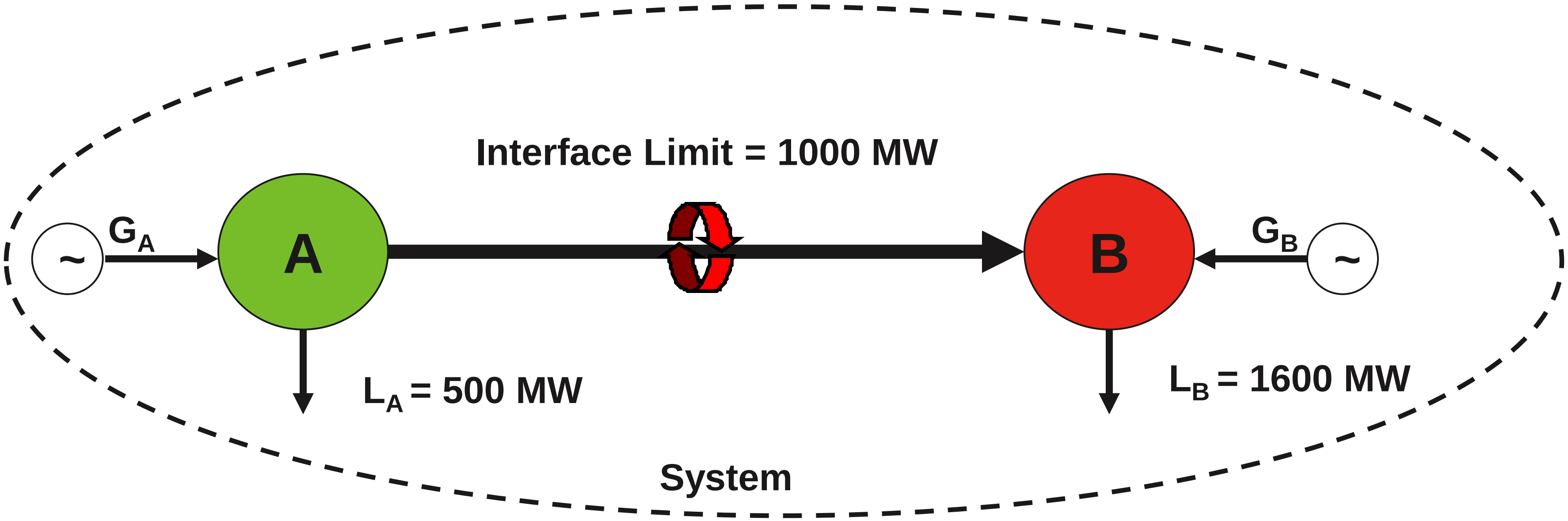
Examples with System Reserve Requirements Only

Normal Scenario (Base Case)

Case Objective

- When the system has plenty of reserves, we will have the following:
  - Co-optimized dispatch results and energy prices (LMPs) are the same as those obtained from the energy-only dispatch.
  - RMCP becomes zero.
  - All available reserves from qualified resources are designated.

Input



Generator	EcoMin (MW)	EcoMax (MW)	Offer Price ($/MWh)	RampMax (MW)
A	0	1800	25	500
B	0	900	20	800

Reserve Zone	Reserve Requirement (MW)	RCPF ($/MWh)
System	450	50

Notations

- Power or Energy Supply:
  - Generator A: P_A Generator B: P_B
- Load or Energy Demand:
  - Zone A: L_A Zone B: L_B
- Reserve Supply:
  - Generator A: R_A Generator B: R_B
  - System RCPF Reserve: R_{SYS}
  - Local RCPF Reserve: R_L
- Reserve Requirement:
  - System: Q_{SYS} Local: Q_L
- Offer Price
  - Generator A: C_A Generator B: C_B
  - System RCPF: C_{SYS} Local RCPF: C_L

Optimization in Summary

Objective: To minimize total cost

Min $[P_A \times C_A + P_B \times C_B + R_{SYS} \times C_{SYS}]$

Subject to:

I. Energy Balance

$\lambda: P_A + P_B = L_A + L_B$

II. System Reserve Constraint

$\alpha: R_A + R_B + R_{SYS} \geq Q_{SYS}$

III. Transmission Constraint

$\mu : (L_B - P_B) \leq 1000$

IV. Resource Level Constraints

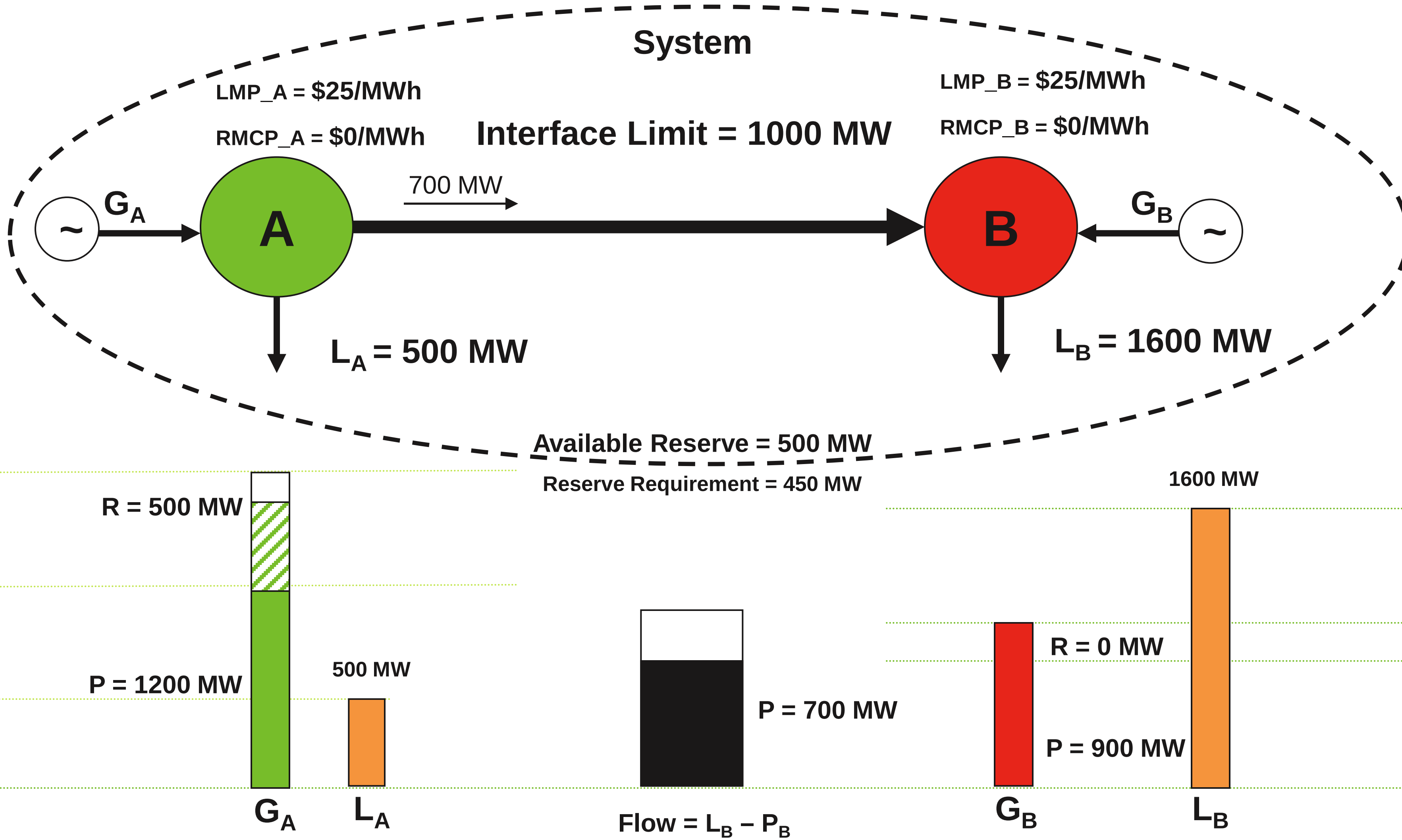
Shadow Prices

- *Shadow price* of Constraint I (to meet total energy demand) is the minimum total cost increase per incremental change of the (total fixed) energy demand.
- *Shadow price* of Constraint II (to meet System reserve requirement) is the minimum total cost increase per incremental change of the (fixed) reserve demand.
- *Shadow price* of Constraint III (for Interface limit) is the minimum total cost change per incremental change of the Interface limit.

Market Clearing Prices Formulation

Constraints	Shadow Prices ($/MWh)	LMP_A ($/MWh)	LMP_B ($/MWh)	RMCP_A ($/MWh)	RMCP_B ($/MWh)
I. Energy Balance	λ	1	1		
II. System Reserve Requirement	$\alpha \geq 0$			1	1
III. Transmission Constraint	$\mu \leq 0$		-1		
Market Clearing Prices		λ	$\lambda - \mu$	α	α

Market Clearing Result Summary



Market Clearing Prices Calculation

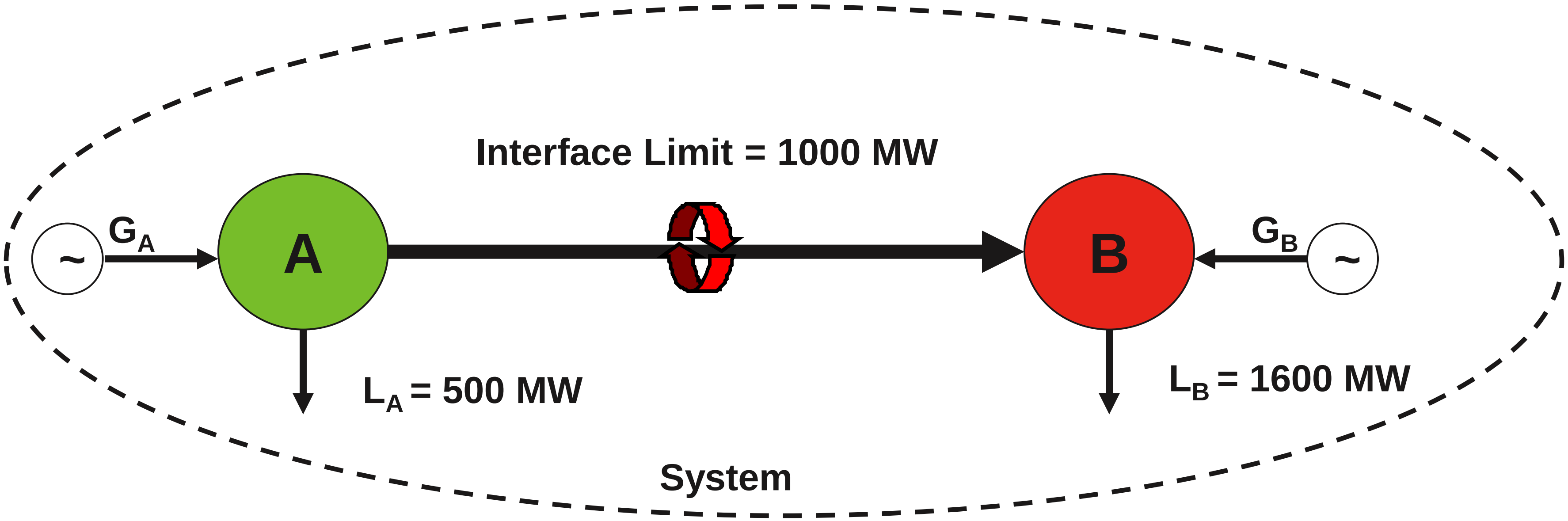
Constraints	Shadow Prices ($/MWh)	LMP_A ($/MWh)	LMP_B ($/MWh)	RMCP_A ($/MWh)	RMCP_B ($/MWh)
I. Energy Balance	25	1	1		
II. System Reserve Requirement	0			1	1
III. Transmission Constraint	0		-1		
Market Clearing Prices		25	25	0	0

Re-dispatch Scenario

Case Objective

- Reserves can be procured through re-dispatch (dispatch down inexpensive unit to create reserve and dispatch up ramp limited expensive one to pick up energy).
- The highest re-dispatch cost or opportunity cost will set the RMCP.
  - In this example, a $25/MWh unit is dispatched up and the $20/MWh unit is dispatched down. The re-dispatch cost (25 - 20) of $5/MWh becomes the Reserve Market Clearing Price.

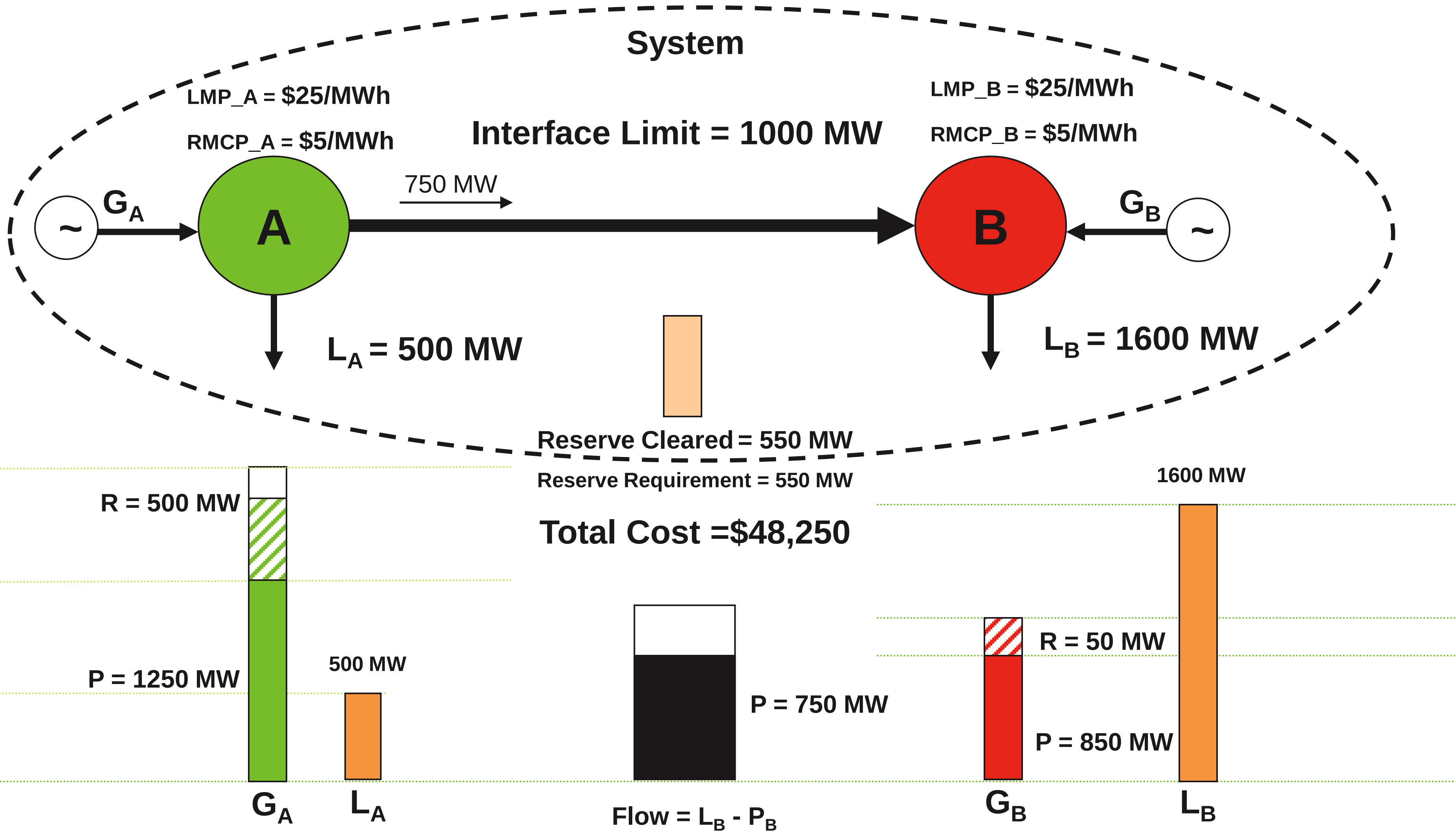
Input



Generator	EcoMin (MW)	EcoMax (MW)	Offer Price ($/MWh)	RampMax (MW)
A	0	1800	25	500
B	0	900	20	800

Reserve Zone	Reserve Requirement (MW)	RCPF ($/MWh)
System	550	50

Market Clearing Result Summary



Market Clearing Prices

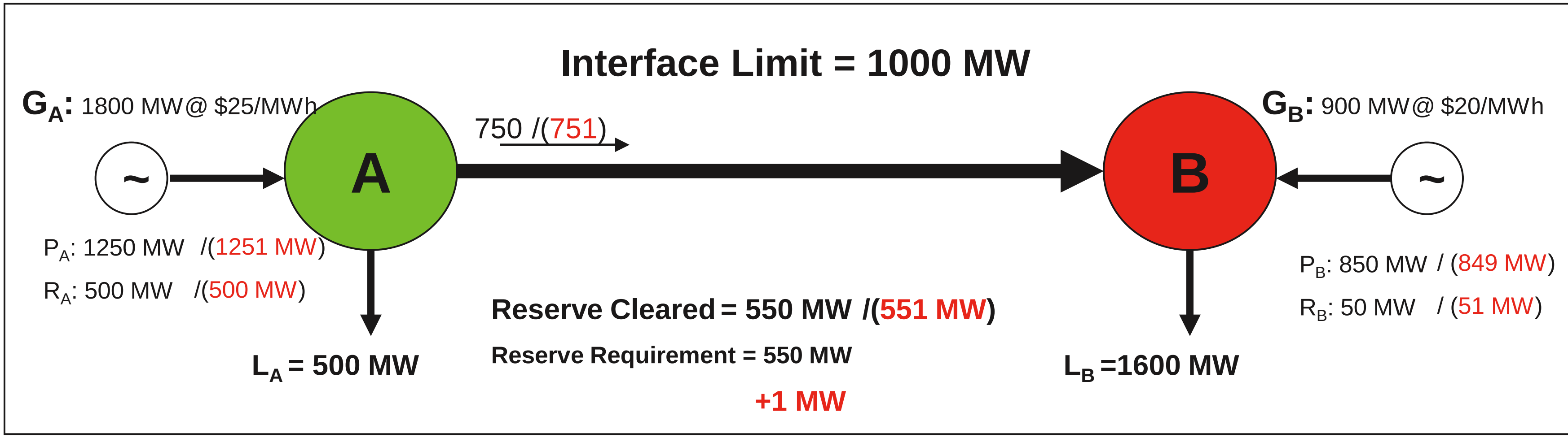
Constraints	Shadow Prices ($/MWh)	LMP_A ($/MWh)	LMP_B ($/MWh)	RMCP_A ($/MWh)	RMCP_B ($/MWh)
I. Energy Balance	25	1	1		
II. System Reserve Requirement	5			1	1
III. Transmission Constraint	0		-1		
Market Clearing Prices		25	25	5	5

Note: A is the reference bus/zone.

LMP_B = Sum of Related Shadow Prices = (25) x (1) + 0 x (-1) = $25/MWh

Shadow Price

Reserve Constraint



$R_A + R_B + R_{SYS} \geq Q_{SYS} + 1$

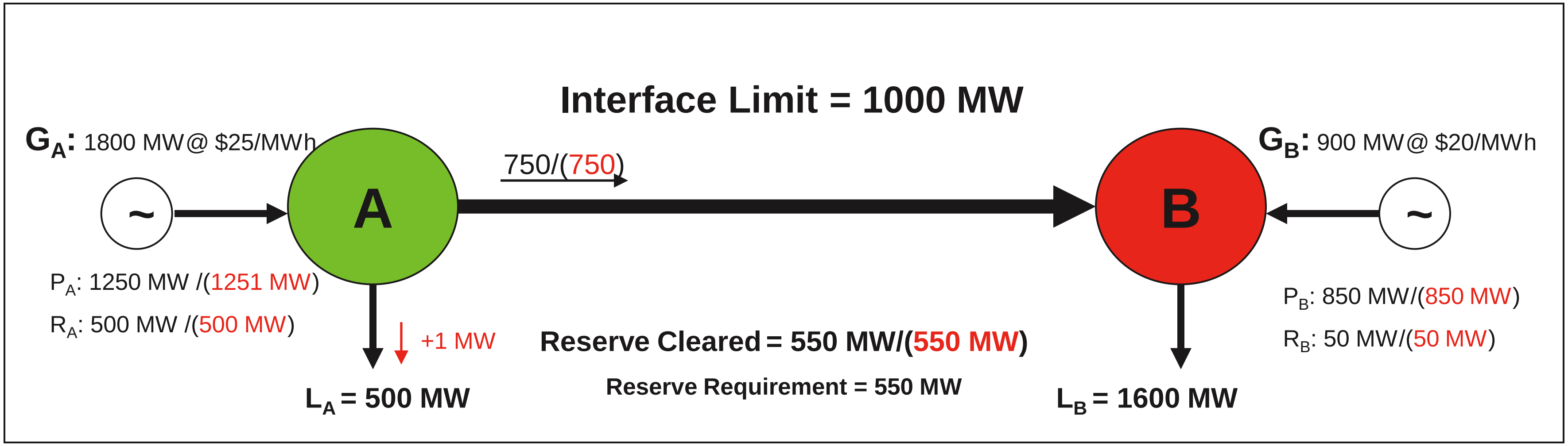
Base Case Total Cost = 1250 x 25 + 850 x 20 = $48,250

New Total Cost = [1251 x 25 + 849 x 20] = $48,255

Incremental Total Cost = New Total Cost - Base Case Total Cost =
$48,255 - $48,250 = **$5**

Shadow Price = Incremental Total Cost / Incremental Reserve Requirement = 5 / 1 = $5 / MWh

Locational Marginal Price Calculation by Definition



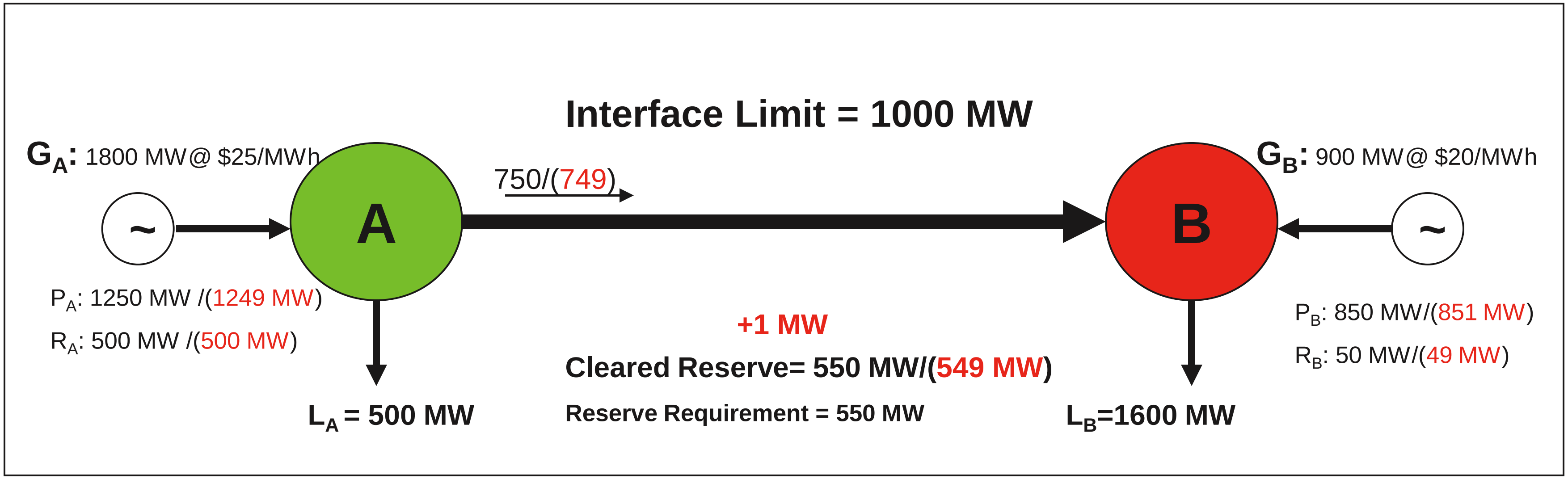
In order to serve the next MW of Load at A, should one more MW of energy come from Generator A or B?

Generator A is more expensive at $25. Generator B is less expensive at $20. However, one more MW from B to serve energy will reduce one MW of reserve supply from B, resulting in a violation of reserve constraint since A's reserve capability has been fully utilized. The Reserve shortage penalty or RCPF is $50, which is greater than the cost difference between A and B ($25 - $20 = $5). Overall, to dispatch one MW more from A to serve the next MW of Load at A is the optimal (or least expensive) solution.

The total cost increase = 25 x 1 = $25

LMP_A = Total Cost Increase / Fixed Demand Increment at A = 25/1 = $25/MWh

Reserve Market Clearing Price
Calculation by Definition



How will the system respond to the introduction of an additional MW of reserve supply?

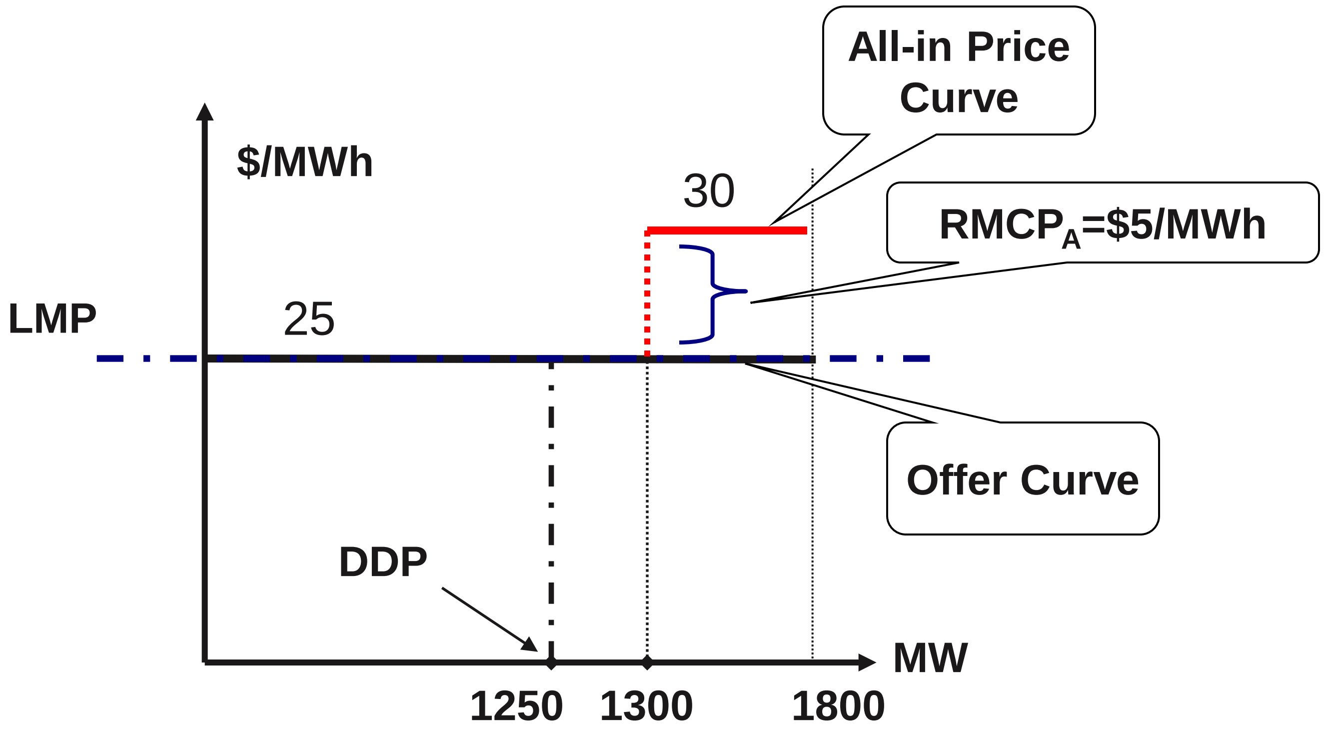
Generator A is more expensive @ $25 and will reduce its generation output by 1 MW.

Generator B is less expensive. It will increase output by 1 MW and reduce reserve supply by 1 MW, while keeping the total reserve supply (including the introduced reserve supply) unchanged at 550 MW.

The total cost reduction = 25 x 1 - 20 x 1 = $5

RMCP_A = Total Cost Reduction/Reserve Supply Increment at A = 5/1 = $5/MWh

Generator A's Profit Maximization



Should Generator A follow its dispatch instruction?

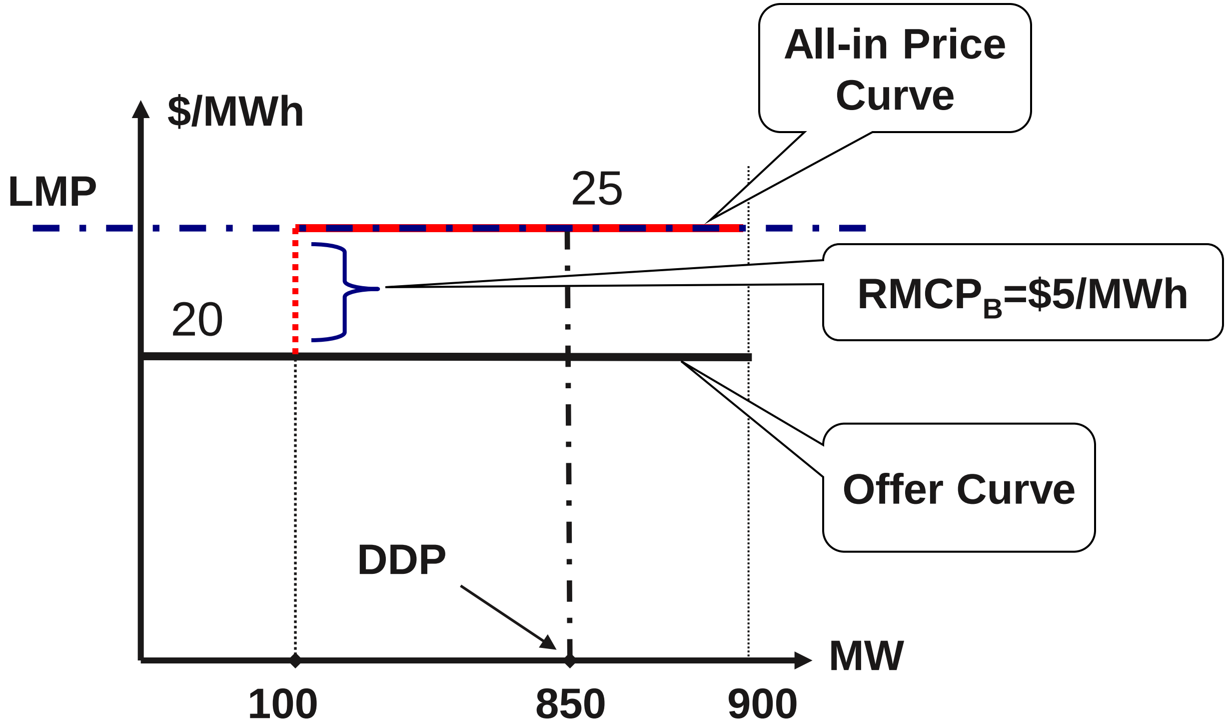
Energy Profit = (LMP - Offer Price) x Energy MW = (25 - 25) x 1250 = $0

Reserve Profit = RMCP x Reserve MW = 5 x 500 = $2,500

Total Energy and Reserve Profit = 0 + 2500 = $2,500 ← Maximum Profit

All-in Price at DDP ($25/MWh) = LMP ($25/MWh) ← Marginal Unit

Generator B's Profit Maximization



Should Generator B follow its dispatch instruction?

Energy Profit = (LMP - Offer Price) x Energy MW = (25 - 20) x 850 = $4,250

Reserve Profit = RMCP x Reserve MW = 5 x 50 = $250

Total Energy and Reserve Profit = 4250 + 250 = $4,500 ← The Maximum Profit

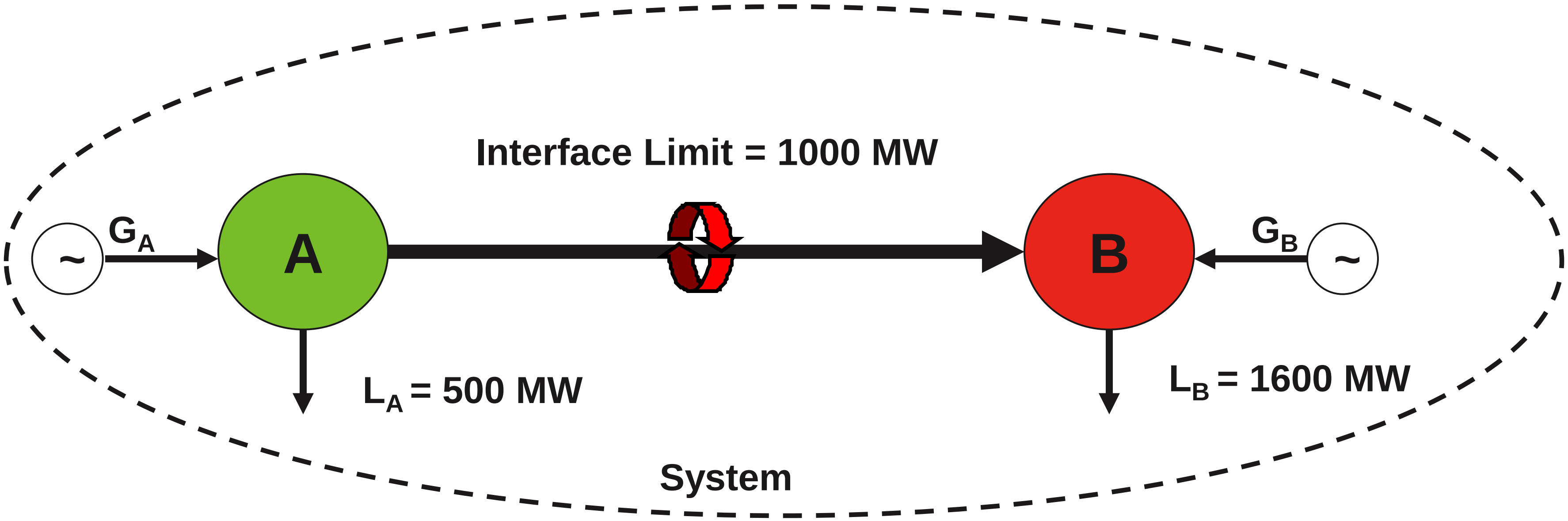
All-in Price at DDP ($25/MWh) = LMP ($25/MWh) ← Marginal Unit

Physical Reserve Shortage Scenario

Case Objective

- When the system has enough ramping capability, but not enough capacity to meet the total energy and reserve requirement, we will have:
  - Reserve shortage condition with the reserve price set to the RCPF. Reserve price is $50/MWh in this example.
  - RCPF value inflated energy price due to the energy-reserve coupling effect. In this example, the energy price is (20 + 50) or $70/MWh.

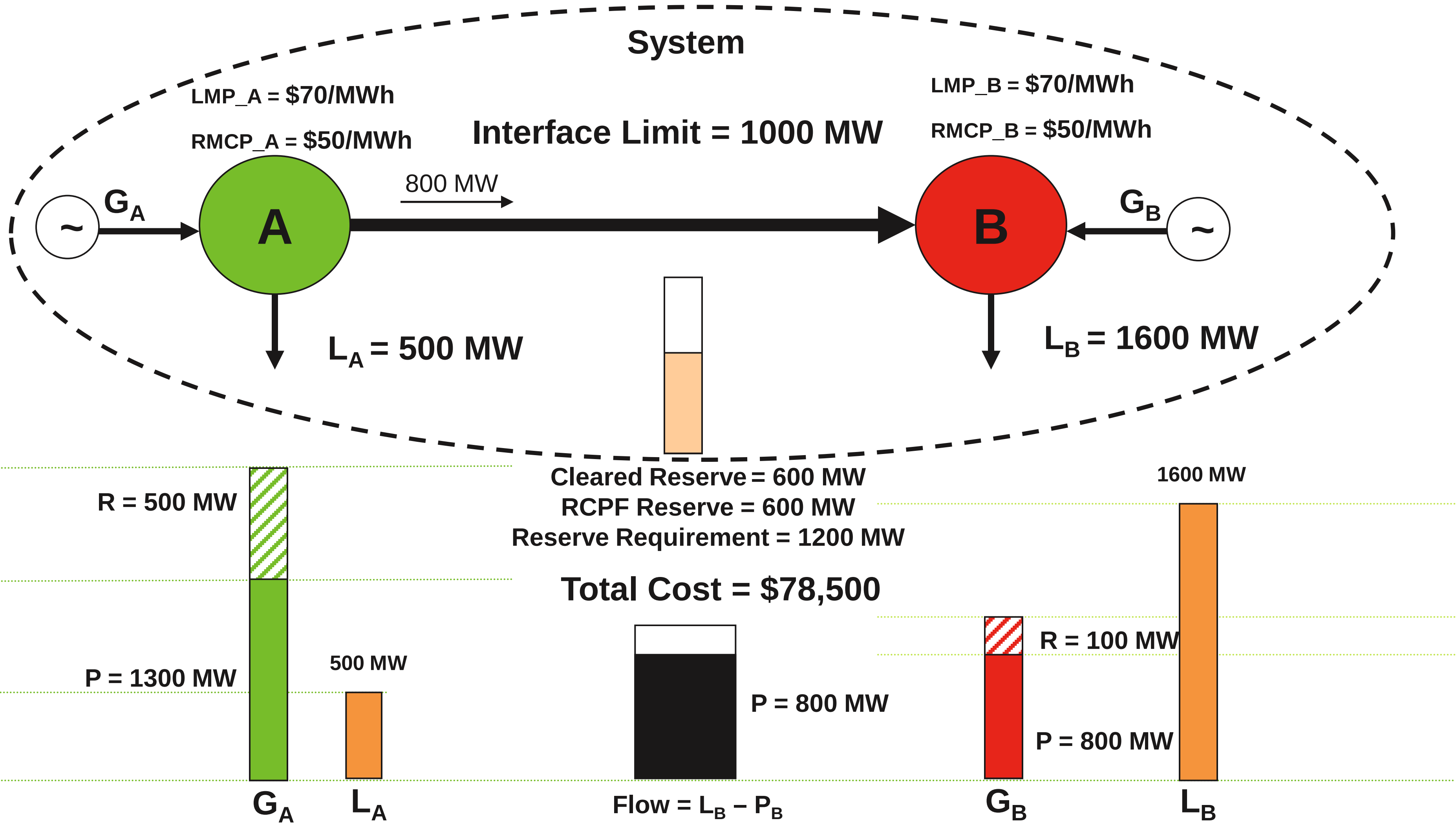
Input



Generator	EcoMin (MW)	EcoMax (MW)	Offer Price ($/MWh)	RampMax (MW)
A	0	1800	25	500
B	0	900	20	800

Reserve Zone	Reserve Requirement (MW)	RCPF ($/MWh)
System	1200 ↑	50

Market Clearing Result Summary



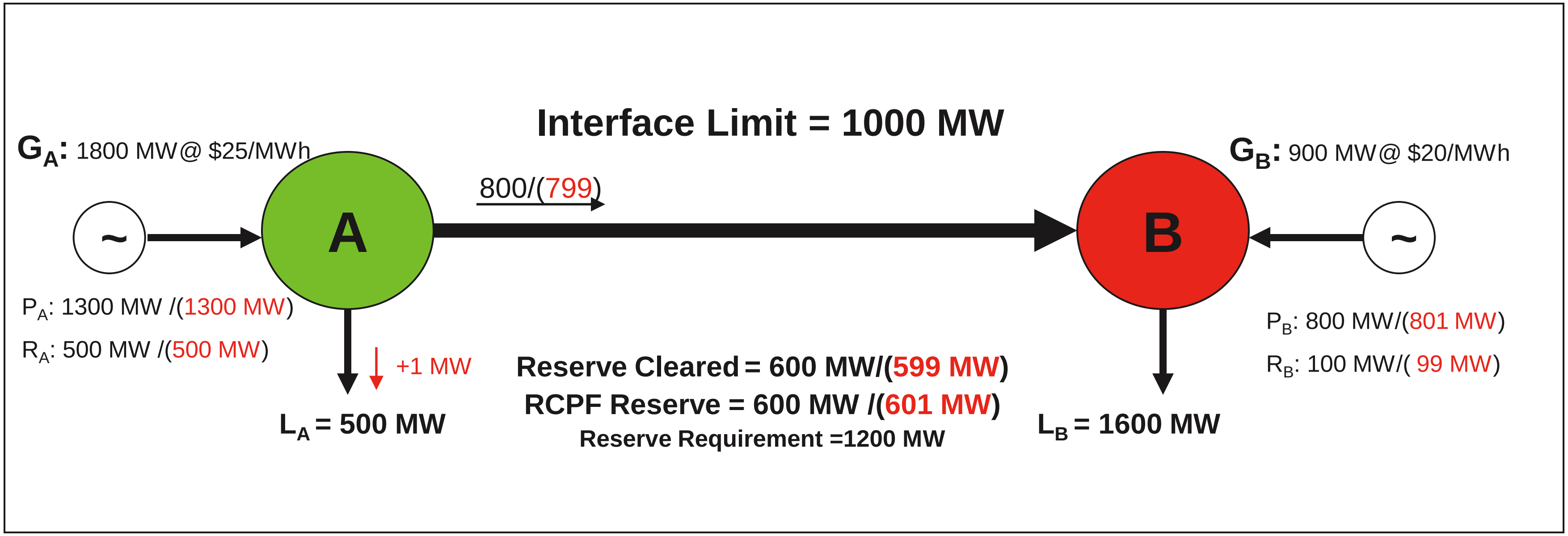
Market Clearing Prices

Constraints	Shadow Prices ($/MWh)	LMP_A ($/MWh)	LMP_B ($/MWh)	RMCP_A ($/MWh)	RMCP_B ($/MWh)
I. Energy Balance	70	1	1		
II. System Reserve Requirement	50			1	1
III. Transmission Constraint	0		-1		
Market Clearing Prices		70	70	50	50

Note: A is the reference bus/zone.

LMP_B = Sum of Related Shadow Prices = (70) x (1) + 0 x (-1) = $70/MWh

LMP Calculation at A



What is the best way for the system to respond to the increase of load at A?

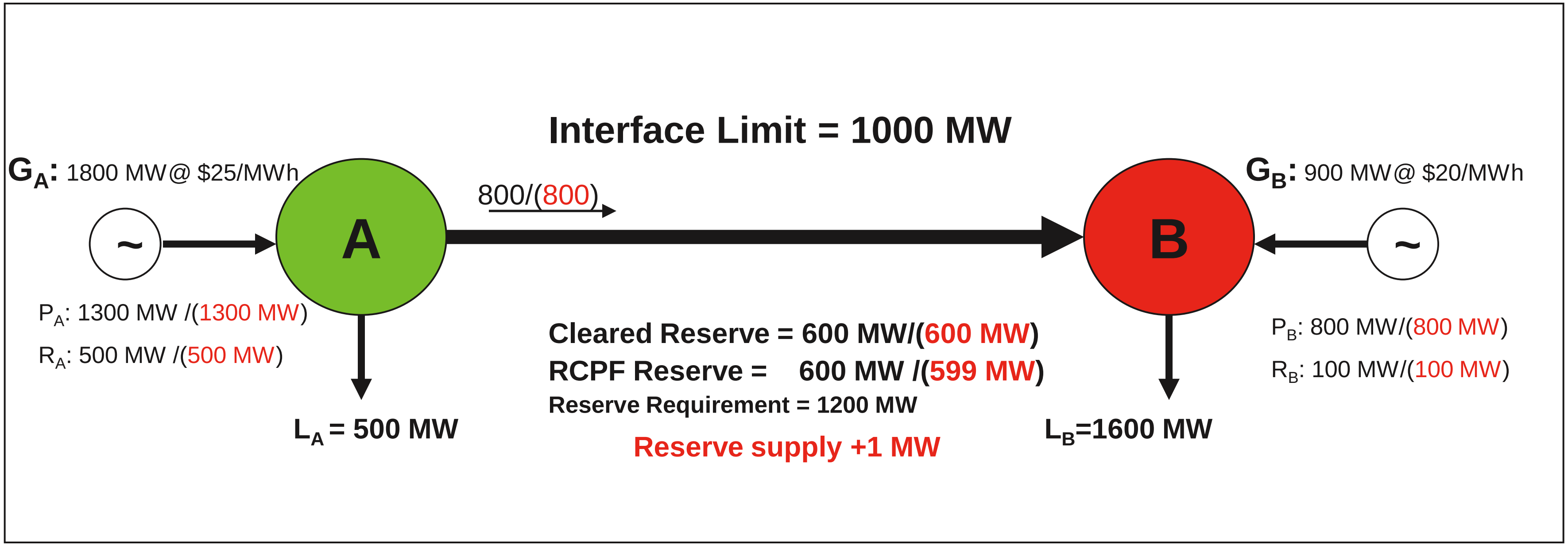
Generator B increases output by 1 MW and reduces its reserve supply by 1 MW.

The RCPF resource picks up the 1 MW reserve shortage created by generator B.

The total cost increase = 20 x 1 + 50 x 1= $70

LMP_A = Total Cost Increase / Fixed Demand Increment at A = 70/1 = $70/MWh

RMCP Calculation by Definition



How will the system respond to the introduction of an additional MW of reserve supply?

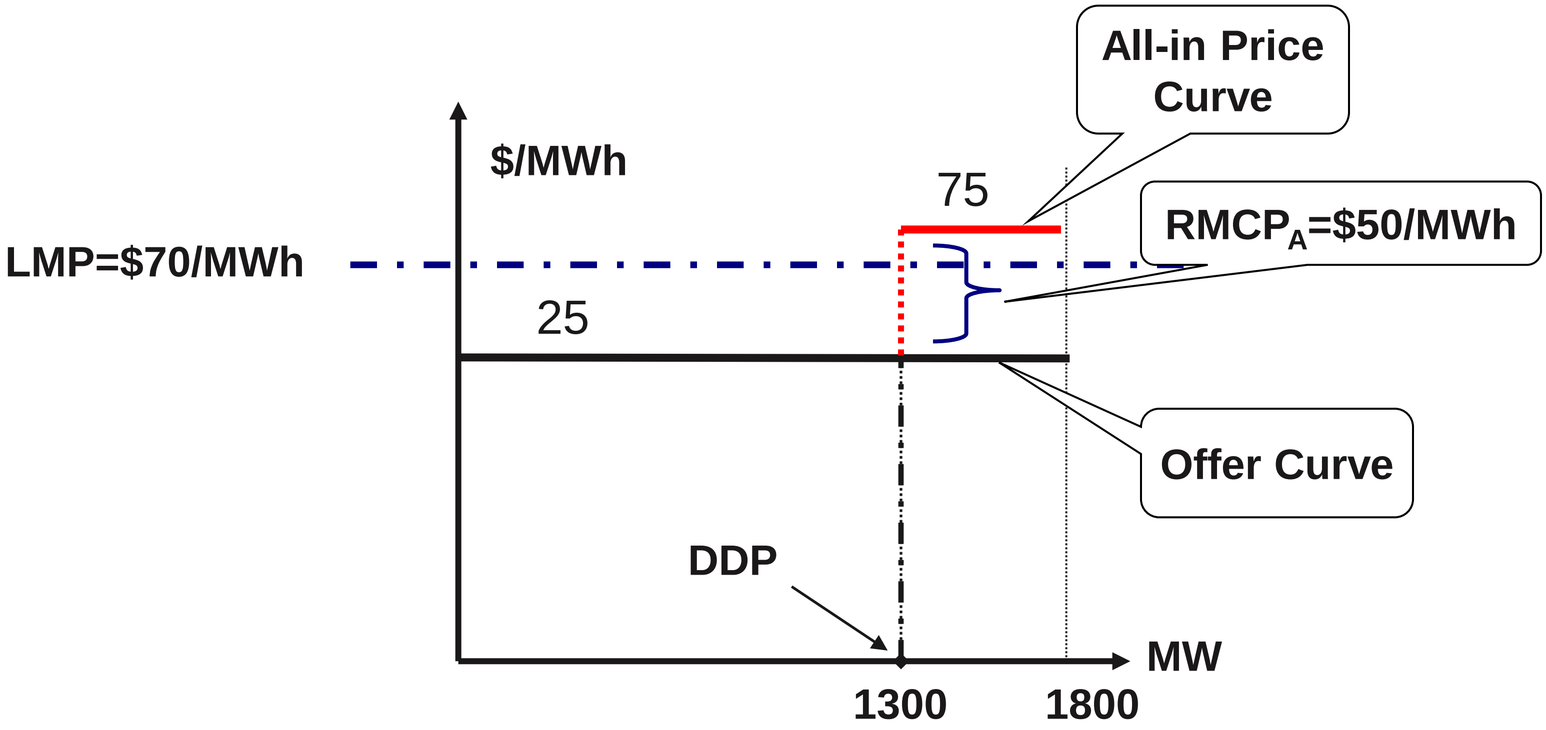
Both Generators A and B will remain unchanged.

The RCPF resource supplies 1 MW less reserve.

The total cost reduction = 50 x 1 = $50

RMCP_A = Total Cost Reduction/Reserve Supply Increment at A = 50/1 = $50/MWh

Generator A's Profit Maximization



Should Generator A follow its dispatch instruction?

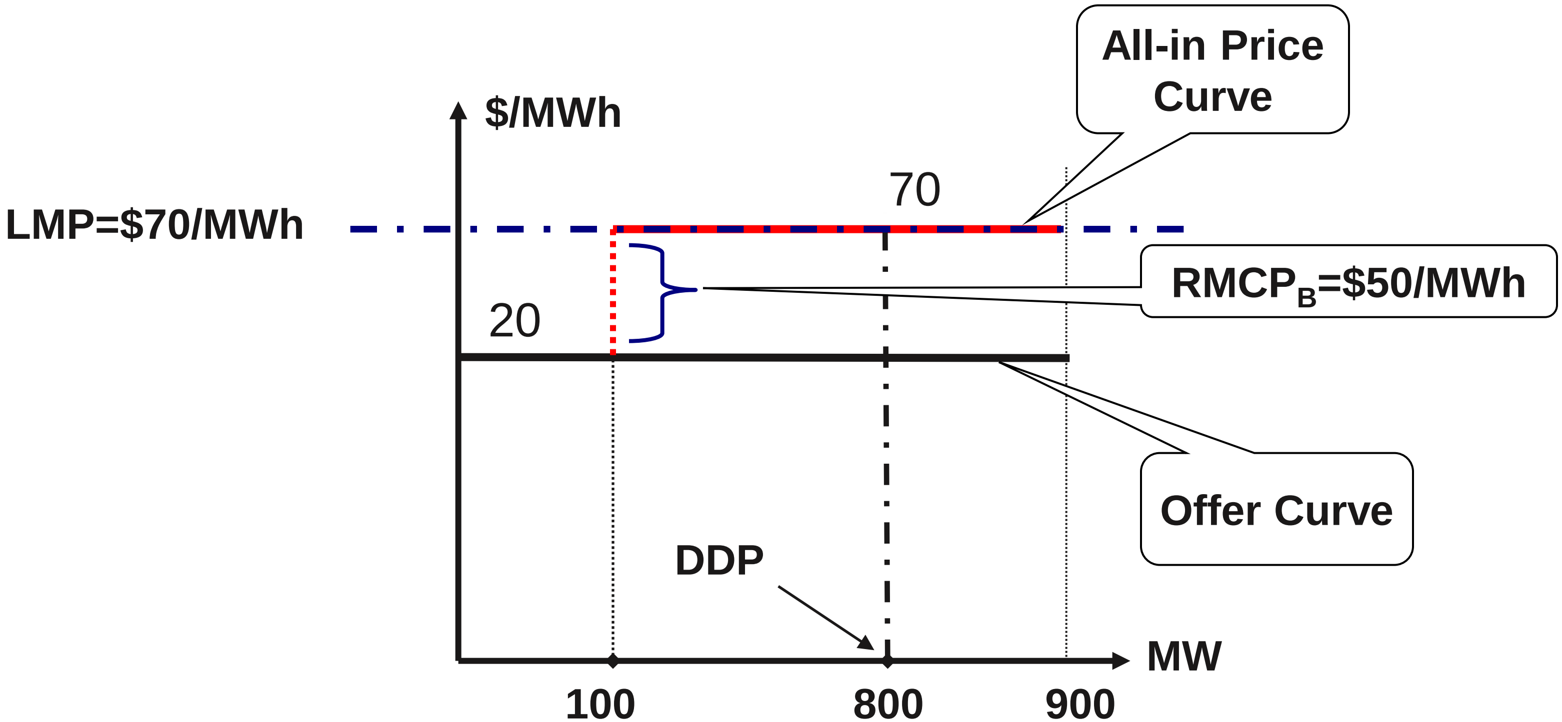
Energy Profit = (LMP - Offer Price) x Energy MW = (70 - 25) x 1300 = $58,500

Reserve Profit = RMCP x Reserve MW = 50 x 500 = $25,000

Total Energy and Reserve Profit = 58500 + 25000 = $83,500 ← Maximum Profit

All-in Price at DDP ($25/MWh or $75/MWh) ≠ LMP ($70/MWh) ← Non-Marginal Unit

Generator B's Profit Maximization



Should Generator B follow its dispatch instruction?

Energy Profit = (LMP - Offer Price) x Energy MW = (70 - 20) x 800 = $40,000

Reserve Profit = RMCP x Reserve MW = 50 x 100 = $5,000

Total Energy and Reserve Profit = 40,000 + 5000 = $45,000 ← The Maximum Profit

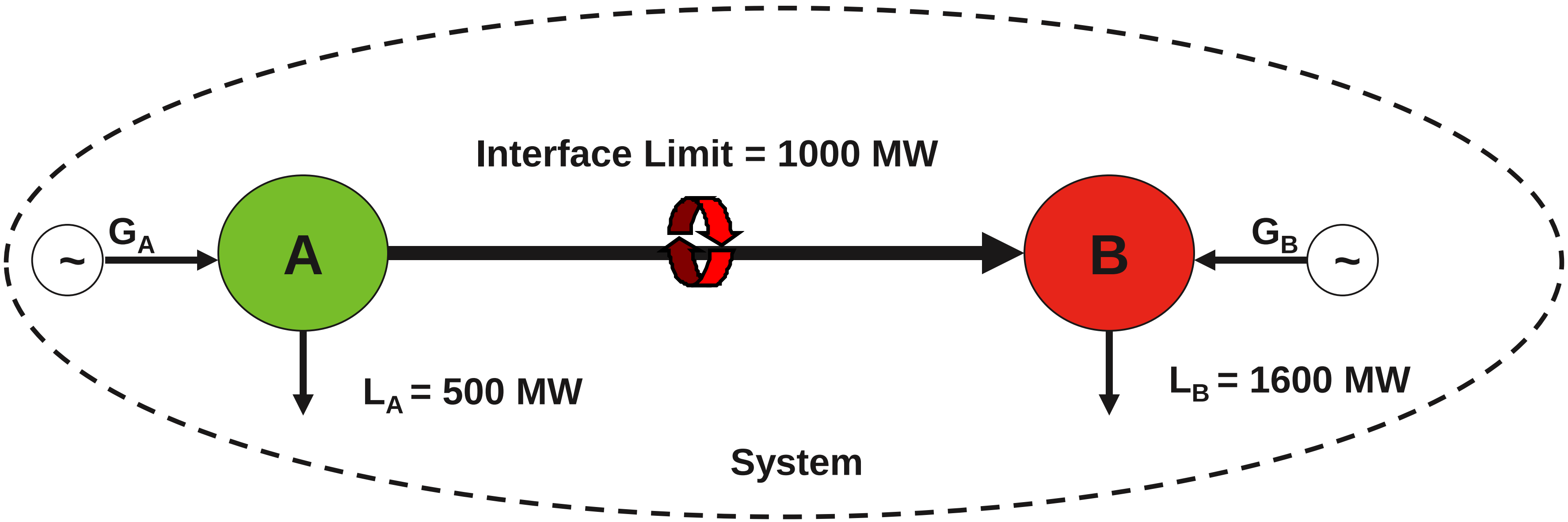
All-in Price at DDP ($70/MWh) = LMP ($70/MWh) ← Marginal Unit

Economic Reserve Shortage Scenario

Case Objective

- The system can be in an artificial reserve shortage condition when the cost of re-dispatch to procure reserve exceeds the value of the RCPF.
- In the example, the re-dispatch cost is (75 - 20) or $55/MWh, exceeding the RCPF value of $50/MWh.
- The reserve price is thus capped by $50/MWh.

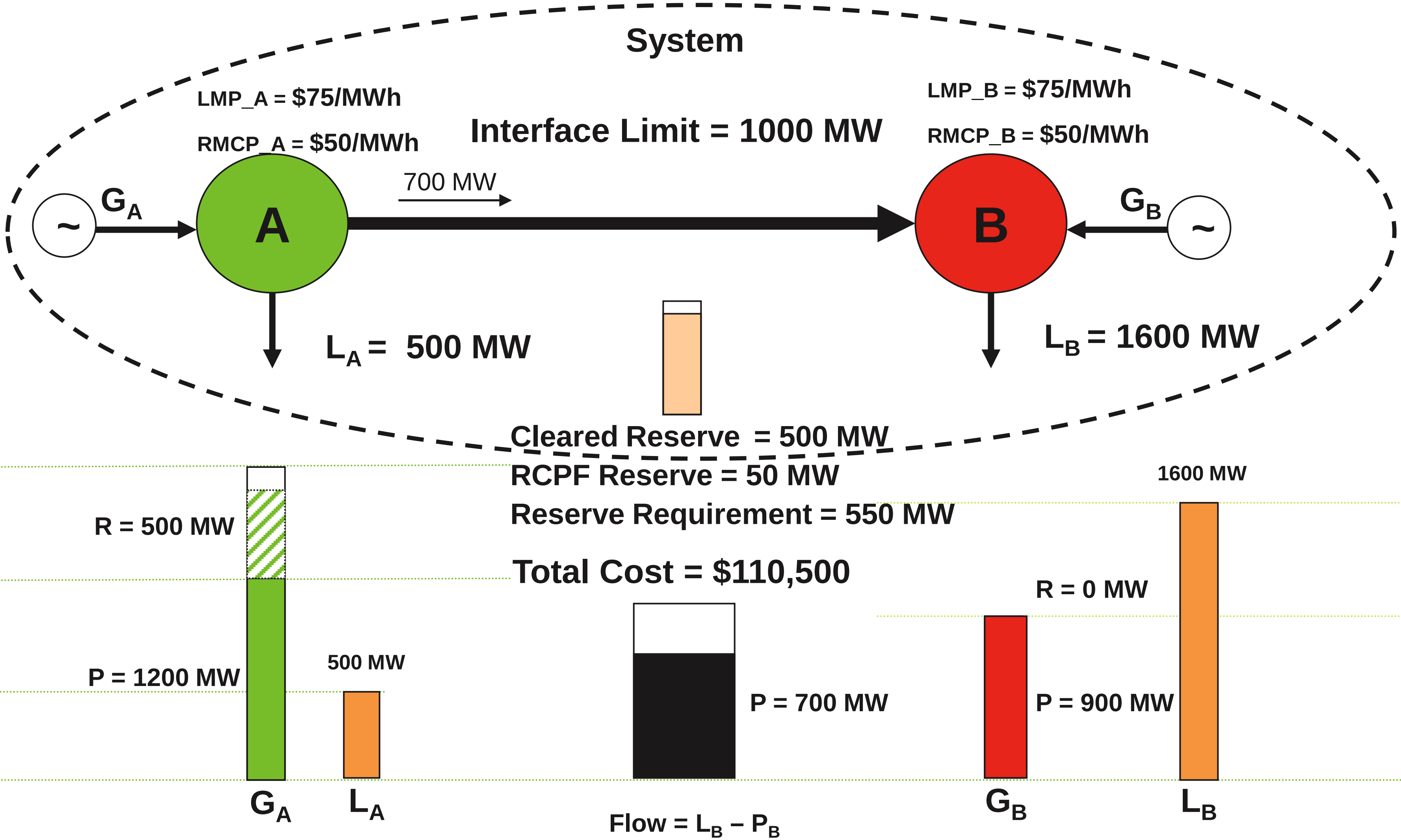
Input



Generator	EcoMin (MW)	EcoMax (MW)	Offer Price ($/MWh)	RampMax (MW)
A	0	1800	75	500
B	0	900	20	800

Reserve Zone	Reserve Requirement (MW)	RCPF ($/MWh)
System	550	50

Market Clearing Result Summary



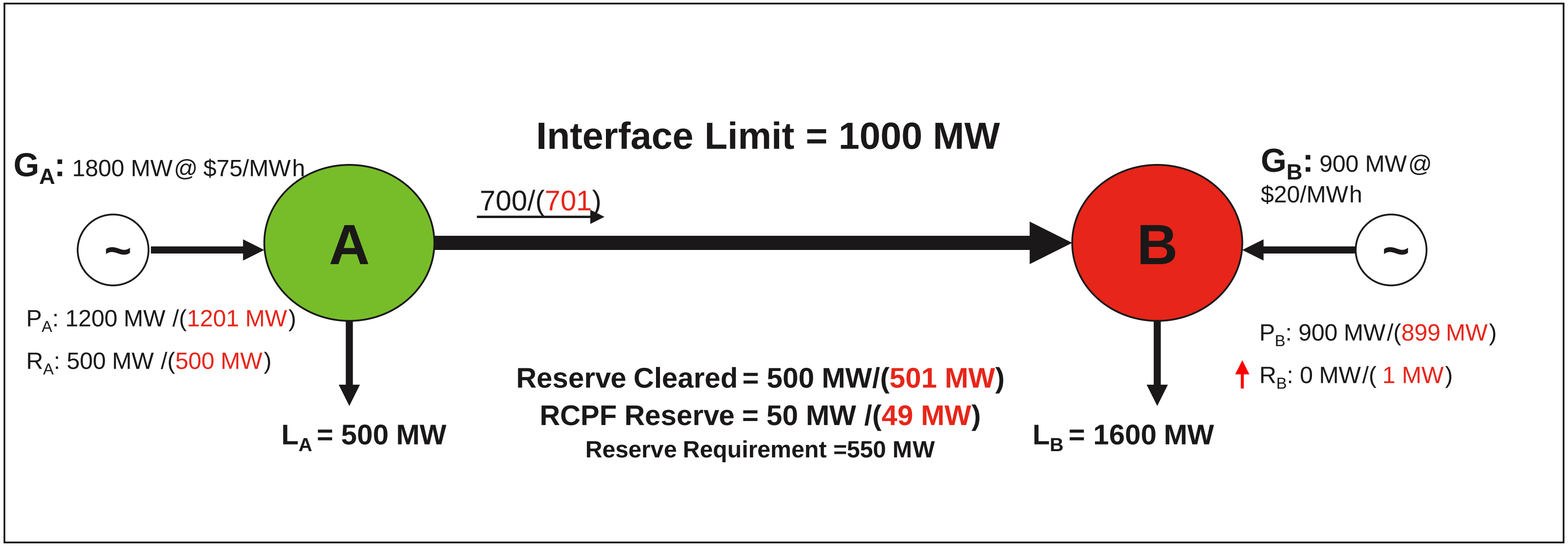
Market Clearing Prices

Constraints	Shadow Prices ($/MWh)	LMP_A ($/MWh)	LMP_B ($/MWh)	RMCP_A ($/MWh)	RMCP_B ($/MWh)
I. Energy Balance	75	1	1		
II. System Reserve Requirement	50			1	1
III. Transmission Constraint	0		-1		
Market Clearing Prices		75	75	50	50

Note: A is the reference bus/zone.

LMP_B = Sum of Related Shadow Prices = (75) x 1 + 0 x (-1) = $75/MWh

Why Not Re-dispatch?



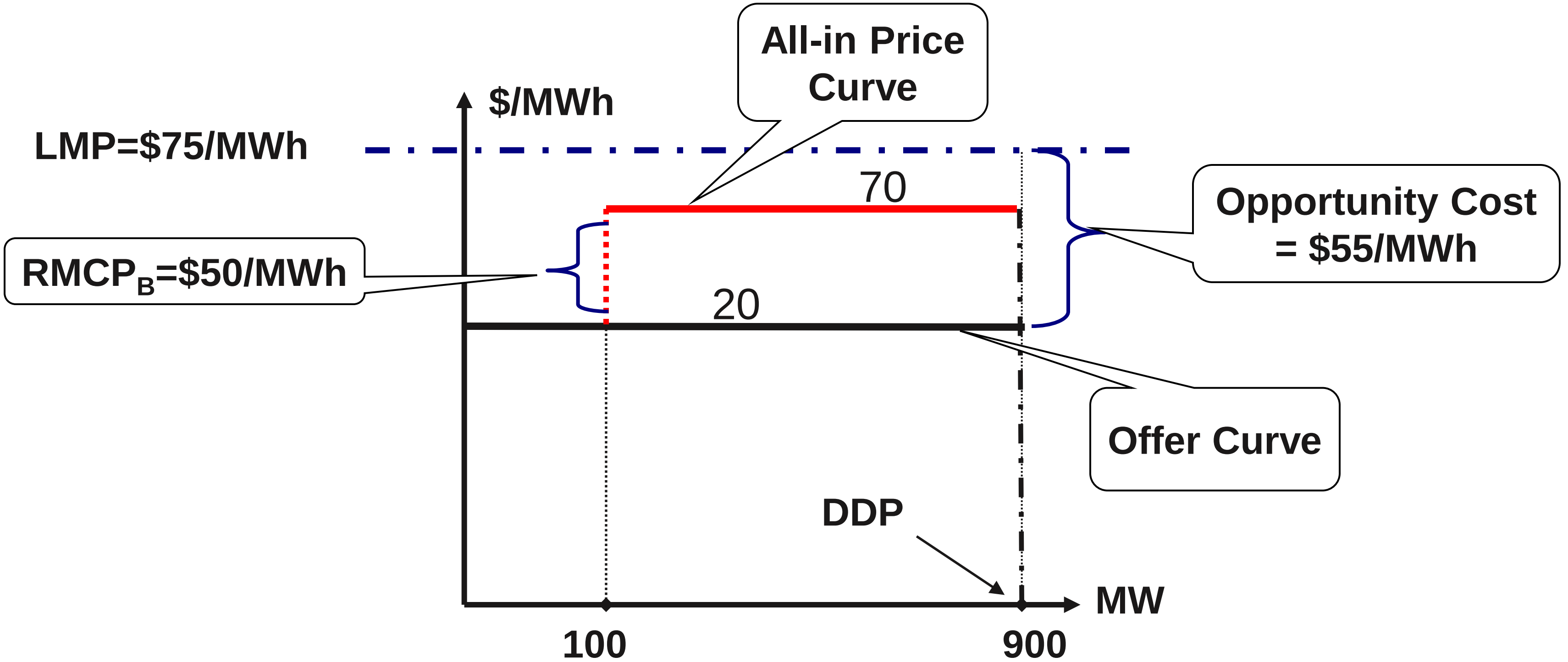
Why not create more reserve from Generator B?

To create 1 MW of reserve, Generator B with a cheaper energy offer $20 has to be backed down by 1 MW, and Generator A with $75 offer price picks up 1 MW. At the same time, RCPF resource can reduce 1 MW of reserve supply.

The total cost increase = 75 x 1 - 20 x 1 - 50 x 1= $5

It is not economic to re-dispatch in order to procure 1 more MW of reserve or reduce the total amount of reserve violation.

Why Not Re-dispatch? (cont.)



Following the dispatch instruction, Generator B maximizes its as-bid profit, $49,500 all from energy sale. Any Deviation from the DDP will reduce the as-bid profit of Generator B assuming the clearing prices do not change.

From reserve point view, its opportunity cost is 75 - 20 or $55/MWh, which is greater than RMCP ($50/MWh). It is uneconomic to clear Generator B's reserve.

Questions

Evaluations