Marginal Losses Implementation Training

Winter and Spring 2007

Version 1

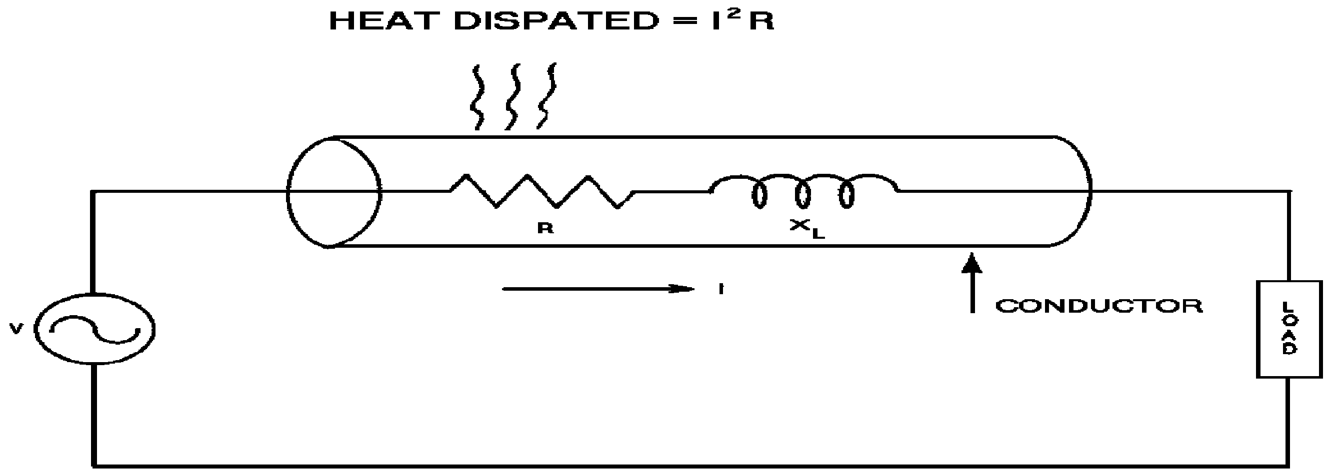
- Explain the factors impacting Transmission MW losses
- Describe changes to the LMP calculation as a result of the implementation of Marginal Losses
- Review the possible impacts on generation dispatch as a result of marginal losses
- Analyze the impact of Marginal Losses on Market Settlement through the use of business examples
- Discuss PJM Application and process changes as a result of Marginal Loss implementation

- Transmission Losses Definition
- Marginal Loss Calculation
- Loss Surplus Allocation
- Business Examples
- Load Carve-Out Process Changes
- Settlements Changes
- PJM Application Changes
- Next Steps

Transmission Losses Definition

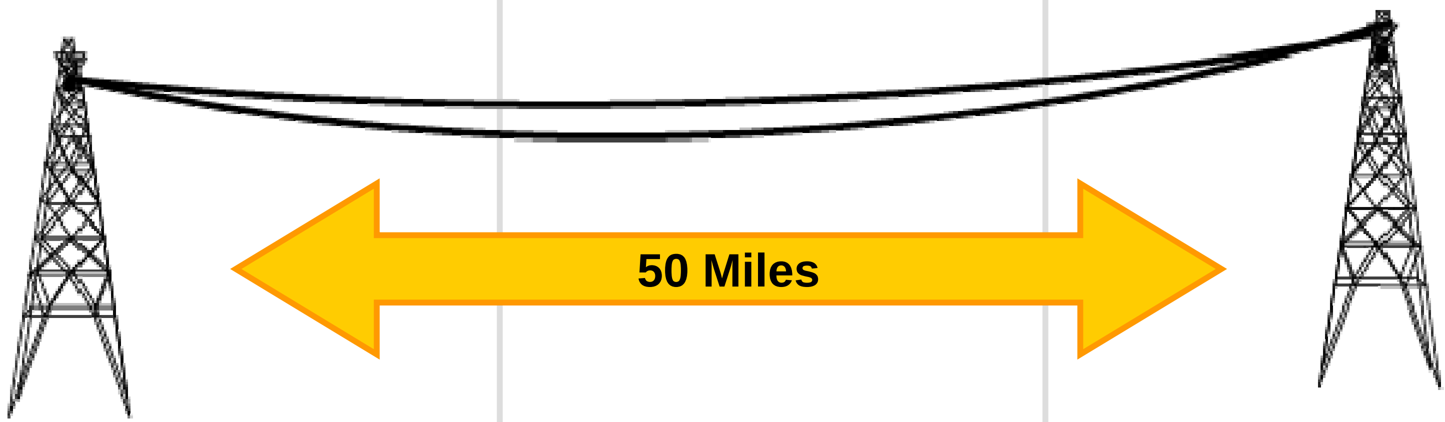
Version 1

- Real Power (MW) Losses
  - Power flow converted to heat in transmission equipment
  - Heat produced by current (I) flowing through resistance (R)
  - Losses equal to I^2R
  - Heat loss sets the “thermal rating” of equipment



- Real Power (MW) Losses
  - Increase with line length
    - Increased R
  - Increase with increased current flow (I)
  - Increase at lower voltages
    - Higher currents

Power = Current * Voltage



Power In: 100 MW

Voltage In: 235 KV

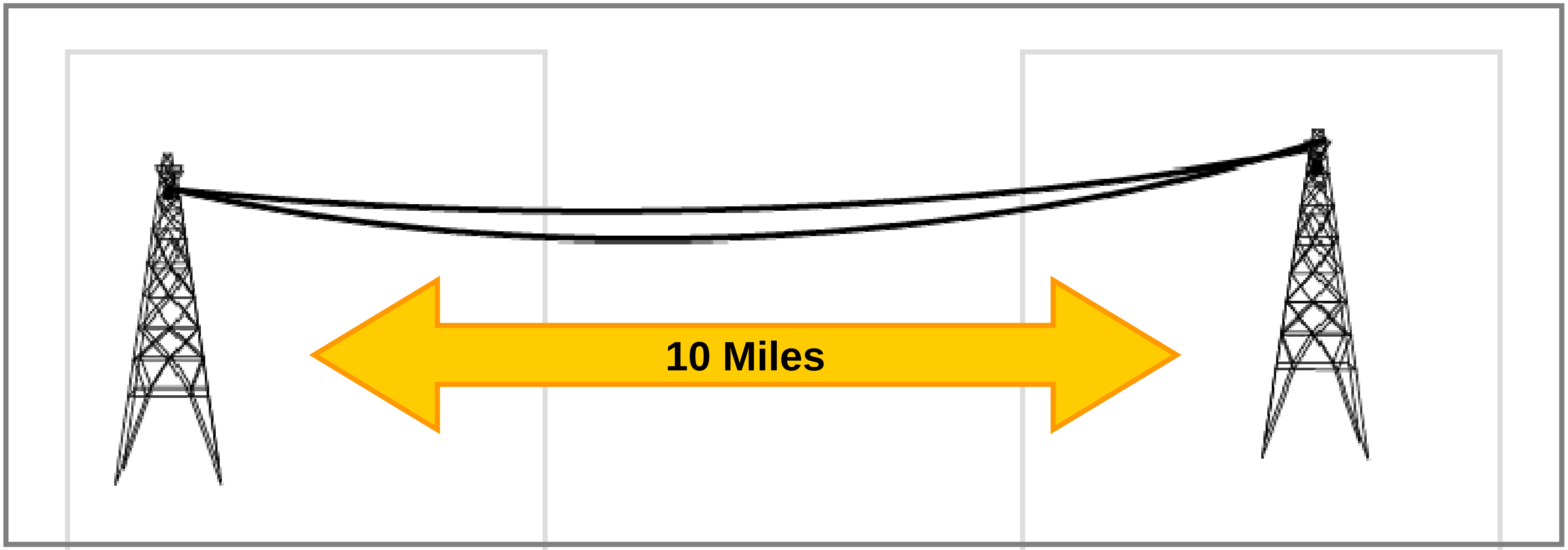
Current In: 425.53 A

Power Out: 90.946 MW

Power Loss: 9.054 MW

Voltage out: 213.72 KV

Current Out: 425.53 A



Power In: 100 MW

Voltage In: 235 KV

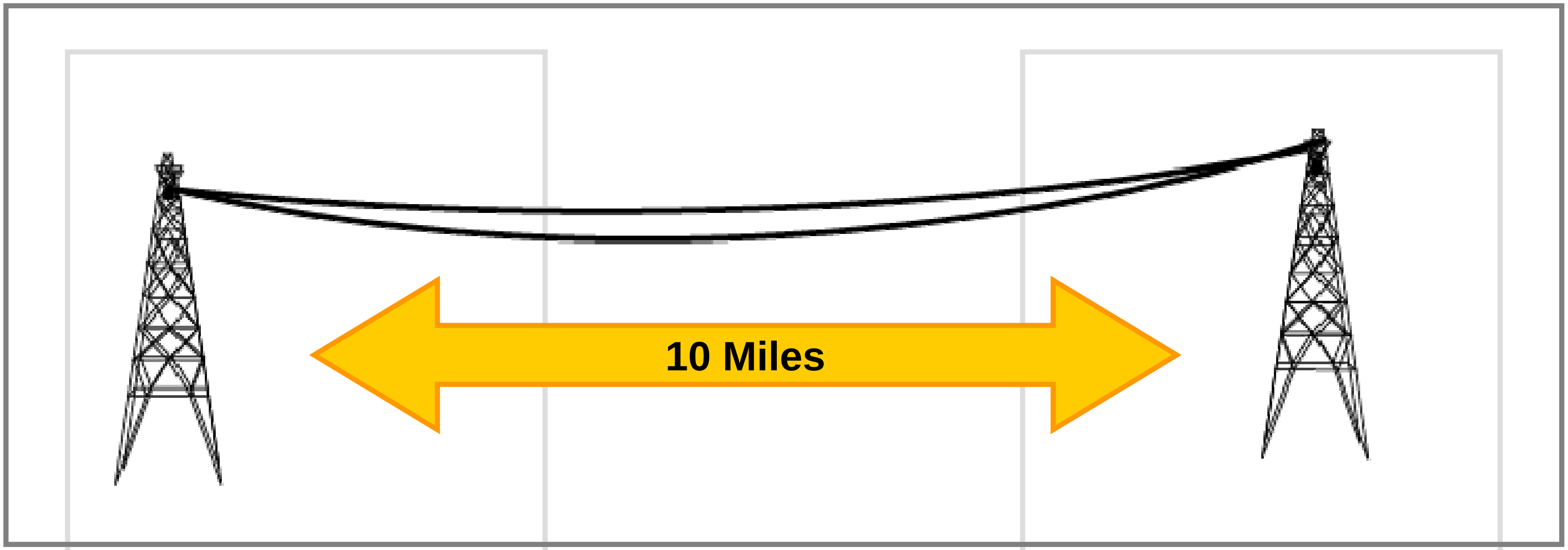
Current In: 425.53 A

Power Out: 98.2 MW

Power Loss: 1.8 MW

Voltage out: 230.74 KV

Current Out: 425.53 A



Power In: 100 MW

Voltage In: 525 KV

Current In: 190.47 A

Power Out: 99.637 MW

Power Loss: 0.363 MW

Voltage out: 523.09 KV

Current Out: 190.47 A

- Generation dispatch currently does not take into account the economic effect of losses
  - Results in inefficient dispatch
  - Must produce more MWs resulting in higher prices
- Including losses in dispatch can result in substantial cost savings through reduced *energy* and *congestion* costs
  - PJM studies have estimated savings of $100 million / year
- Total RTO losses on peak days can exceed 3,600 MW/hour

- Point-to-Point Transmission Losses
  – Day-Ahead Loss charges
  – Balancing Loss charges
  – Loss credits
- Network customers pay losses through PJM Interchange Energy Market
  – Delivered energy = load plus losses

Point-to-Point Transmission Losses Charge – Prior to Implementation of Marginal Losses

Day-Ahead Charge

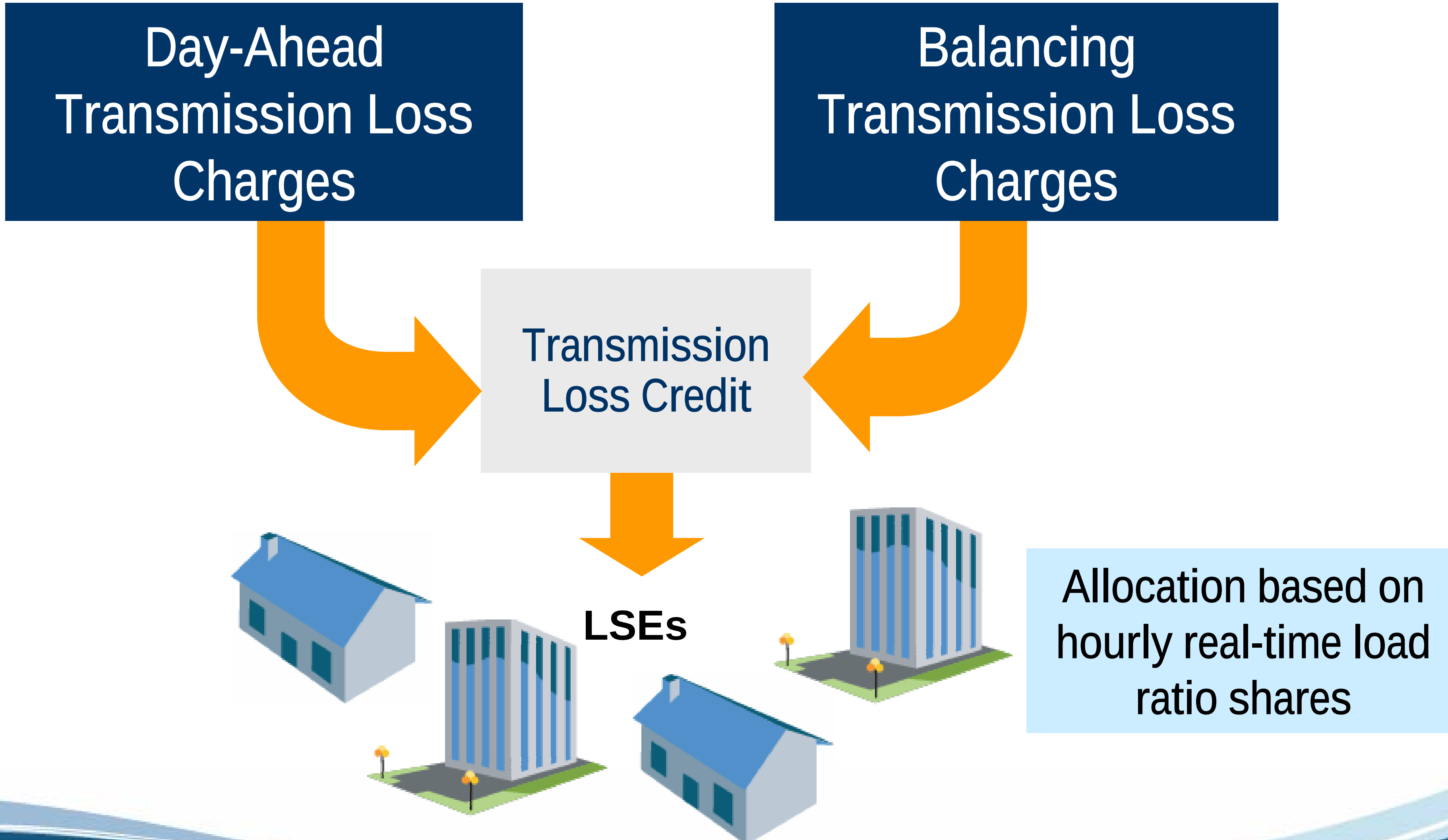
- Product of:
  - transaction MWh
  - pre-determined loss factors
  - day-ahead PJM "load" weighted-average LMP

Balancing Charge

- Product of:
  - transaction MWh deviation
  - pre-determined loss factors
  - real-time load weighted-average LMP for all load busses in PJM

Separate loss factors for on-peak (3%) and off-peak periods (2.5%)

Point-to-Point Transmission Losses Credit – Prior to Implementation of Marginal Losses



- MW Losses are caused by current (I) flowing through resistance (R)
- Losses increase with:
  - Lower voltage
  - Longer lines
  - Higher current
- Not factoring losses into the economic dispatch leads to a less than optimal generation dispatch

Marginal Loss Calculation

Version 1

- Transmission Losses Definition
- Marginal Loss Calculation
- Loss Surplus Allocation
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- Incremental Cost for each unit

  $\Delta C / \Delta P$ (where C is unit cost and P is the MW Power)

- Unit Cost (total)

  $C_T = C_1(P_1) + C_2(P_2) + \ldots + C_n(P_n)$

- Power Balance

  $P_1 + P_2 + \ldots + P_n = P_T$

Ignoring congestion, the economic dispatch which minimizes cost is when all units operate at the same incremental cost, λ

$$\lambda = \frac{\Delta C_1}{\Delta P_1} = \frac{\Delta C_2}{\Delta P_2} = \cdots = \frac{\Delta C_n}{\Delta P_n}$$

- P_R = Power Received by Customers
- P_L = Transmission Line Losses
- $P_T = P_R + P_L$
- Power Balance (ignoring interchange)

  $P_1 + P_2 + \ldots + P_n = P_R + P_L$
- Unit Cost (total)

  $C_T = C_1(P_1) + C_2(P_2) + \ldots + C_n(P_n)$

The Economic Dispatch still minimizes cost but we need a means to include the effect of losses

- Express Losses, P_L, as a function of generation

  $P_L = P_L(P_1, P_2, \ldots, P_n)$
- As individual generators change, the amount of losses will either increase (+) or decrease (-)
- The Incremental Loss for Bus i is the change in system losses due to a change in generation at Bus i

$$\frac{\Delta P_L}{\Delta P_i} = \frac{\text{Change in Losses}}{\text{Change in Unit MW Output}}$$

- The Incremental Loss for bus i is used to calculate a factor that can be used to include the effect of losses in the dispatch
- This factor is called the Loss Penalty Factor, or *Penalty Factor*

$$Pf_i = \frac{1}{\left(1 - \frac{\Delta P_L}{\Delta P_i}\right)}$$

- The Penalty Factors modify the incremental cost of each generator so as to include the effects of losses
- Penalty factors applied to each and every location
  - Including generation, load, virtual transaction

- If an increase in generation results in an **increase** in losses then:
  – Penalty factor is *greater* than 1
  – Units offer curve is adjusted higher
    - Unit offer curve is multiplied by penalty factor
    - <u>Unit looks *less* attractive to dispatch</u>

$$0 < \frac{\Delta P_L}{\Delta P_i} < 1$$

$$Pf_i = \frac{1}{\left(1 - \frac{\Delta P_L}{\Delta P_i}\right)} > 1.0$$

- If an increase in generation results in a **decrease** in losses then:
  - Penalty factor is less than 1
  - Units offer curve is adjusted lower
    - Unit offer curve is multiplied by penalty factor
    - Unit looks *more* attractive to dispatch
    - Total LMP would still at least equal unit's original offer

$$0 > \frac{\Delta P_L}{\Delta P_i} > -1$$

$$Pf_i = \frac{1}{\left(1 - \frac{\Delta P_L}{\Delta P_i}\right)} < 1.0$$

- Penalty Factors will also impact LMP
  - Penalty factor < 1 leads to *higher* LMP (decreases losses)
  - Penalty factor > 1 leads to *lower* LMP (increases losses)

LMPs will vary by location even in unconstrained operations

LMP = Generation Marginal Cost + Transmission Congestion Cost + Cost of Marginal Losses

Cost of Marginal Losses:

$$\text{Generation Marginal Cost} * \left[\frac{1}{Pf} - 1 \right]$$

LMP Components

LMP = System Energy Price + Congestion Price + Loss Price

- System Energy Price
  - Represents optimal dispatch ignoring congestion and losses
  - Same price for every bus in PJM
  - Used to price Spot Market Interchange
    - Spot Market buyer pays system energy price
    - Spot Market seller is paid system energy price
  - Calculated both in day ahead and real time

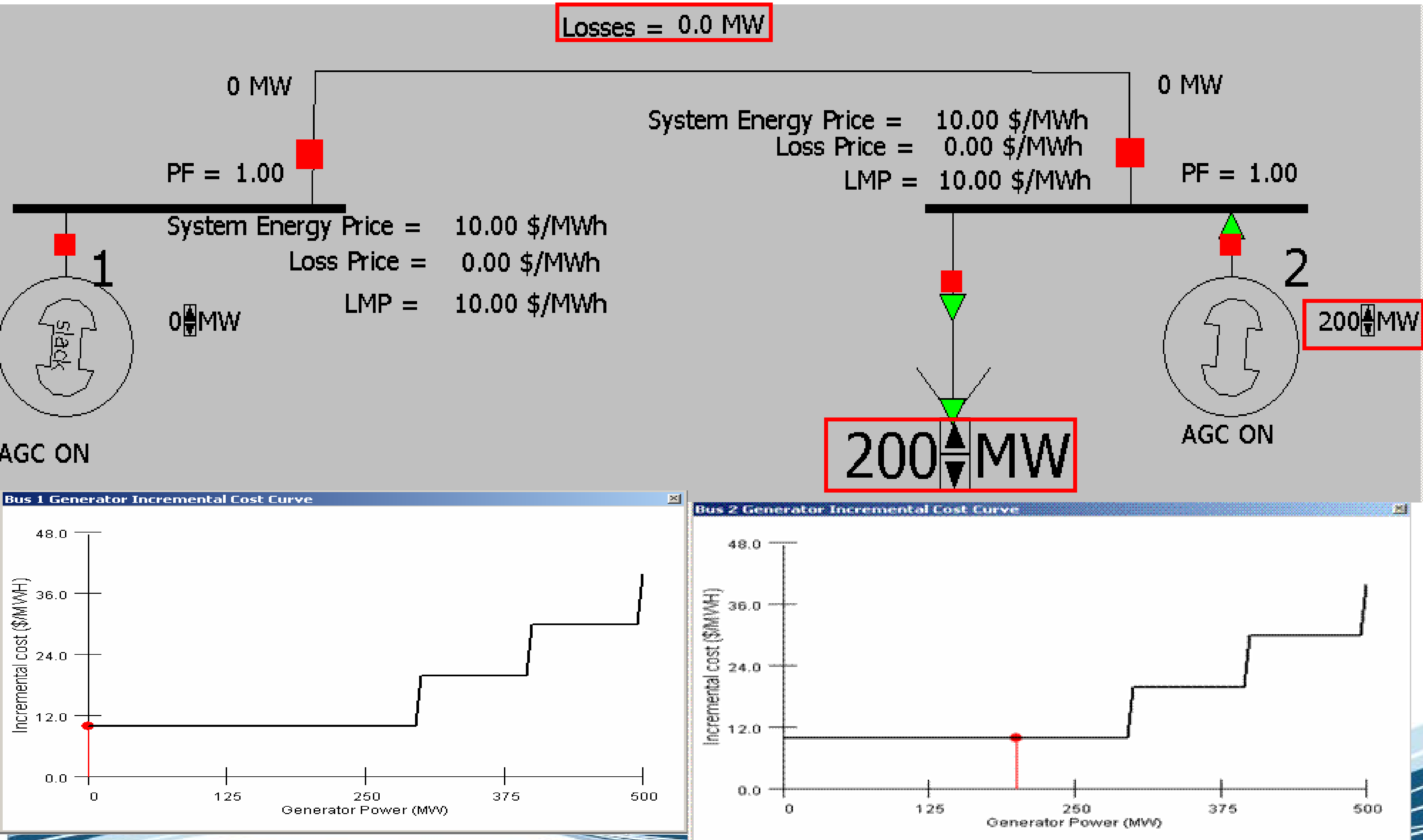
LMP = System Energy Price + Congestion Price + Loss Price

- Congestion Price
  - Represents price of congestion for binding constraints
    - Calculated using cost of marginal units controlling constraints and sensitivity factors on each bus
    - No change in this calculation
  - Will be zero if no constraints
    - Will vary by location if system is constrained
  - Used to price explicit and implicit congestion (Locational Net Congestion Bill)
    - Load pays Congestion Price
    - Generation is paid Congestion Price
    - Congestion revenues allocated as hourly credits to FTR holders
  - Calculated both in day ahead and real time

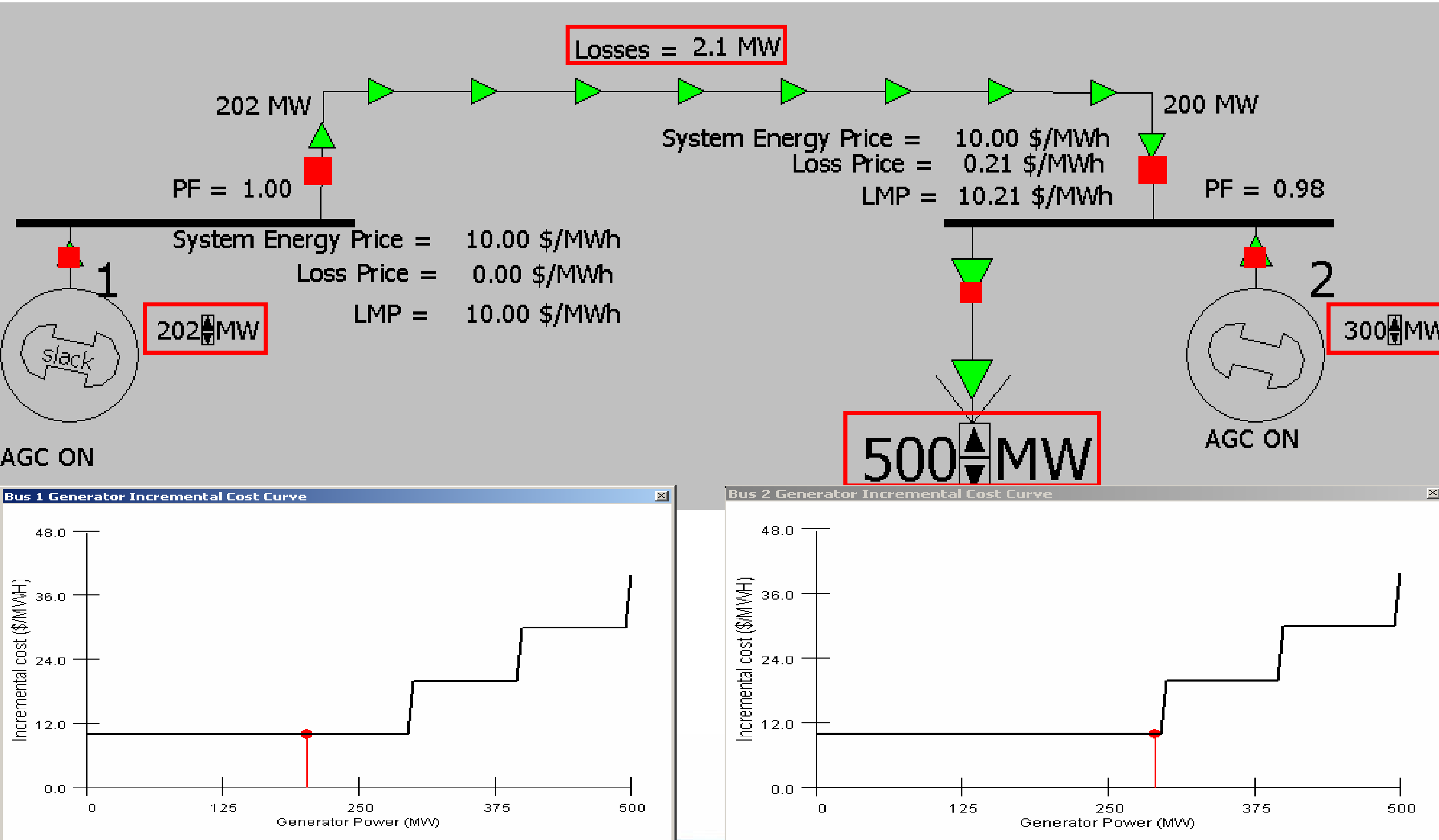
LMP = System Energy Price + Congestion Price + Loss Price

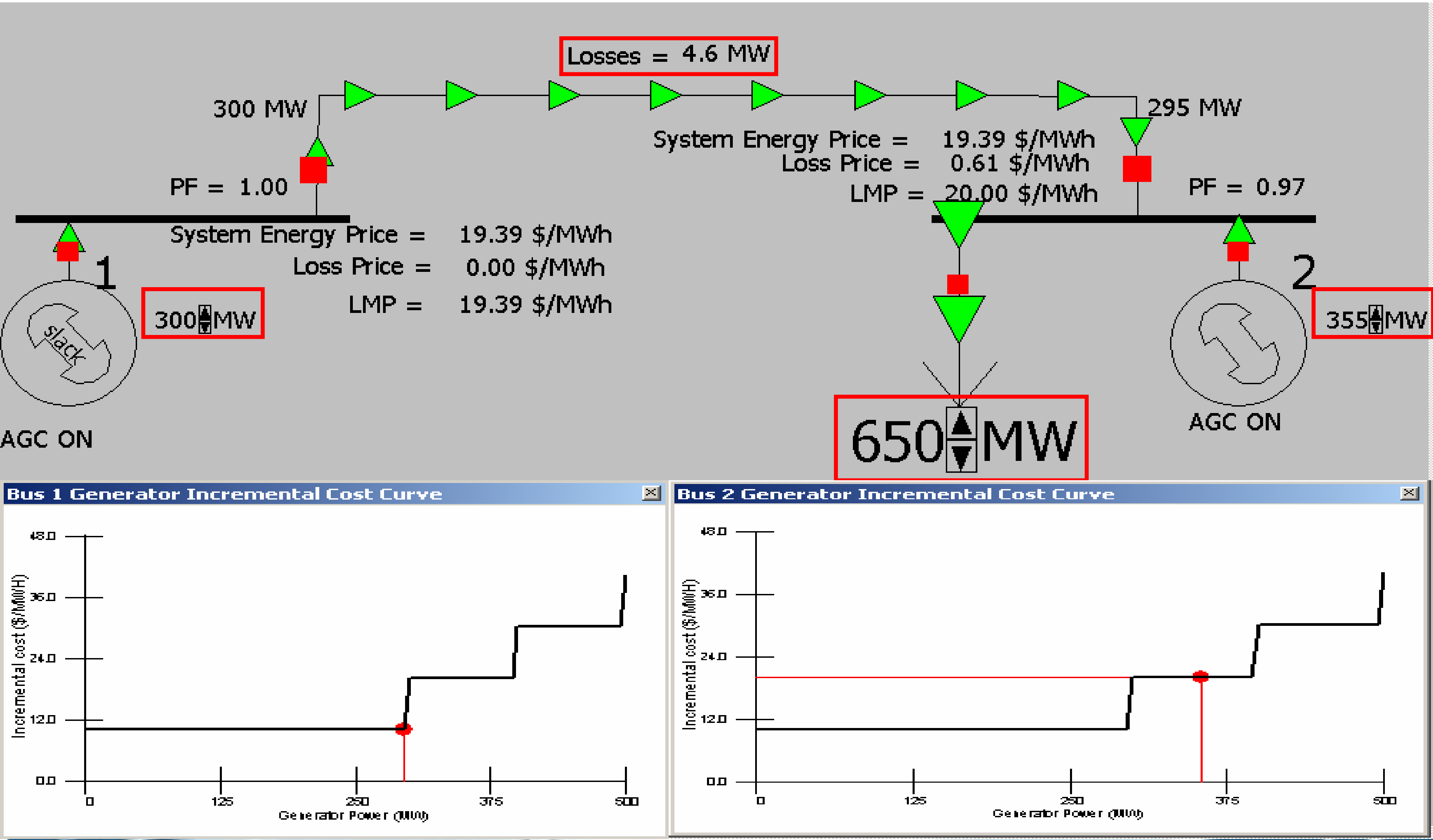
- Loss Price
  - Represents price of marginal losses
    - Calculated using penalty factors as previously described
  - Will vary by location
  - Used to price explicit and implicit losses (Locational Net Loss Bill)
    - Load pays the Loss Price
    - Generation is paid the Loss Price
    - Loss revenues are allocated based on load + exports ratio share
  - Calculated both in day-ahead and real-time

Marginal Loss Example

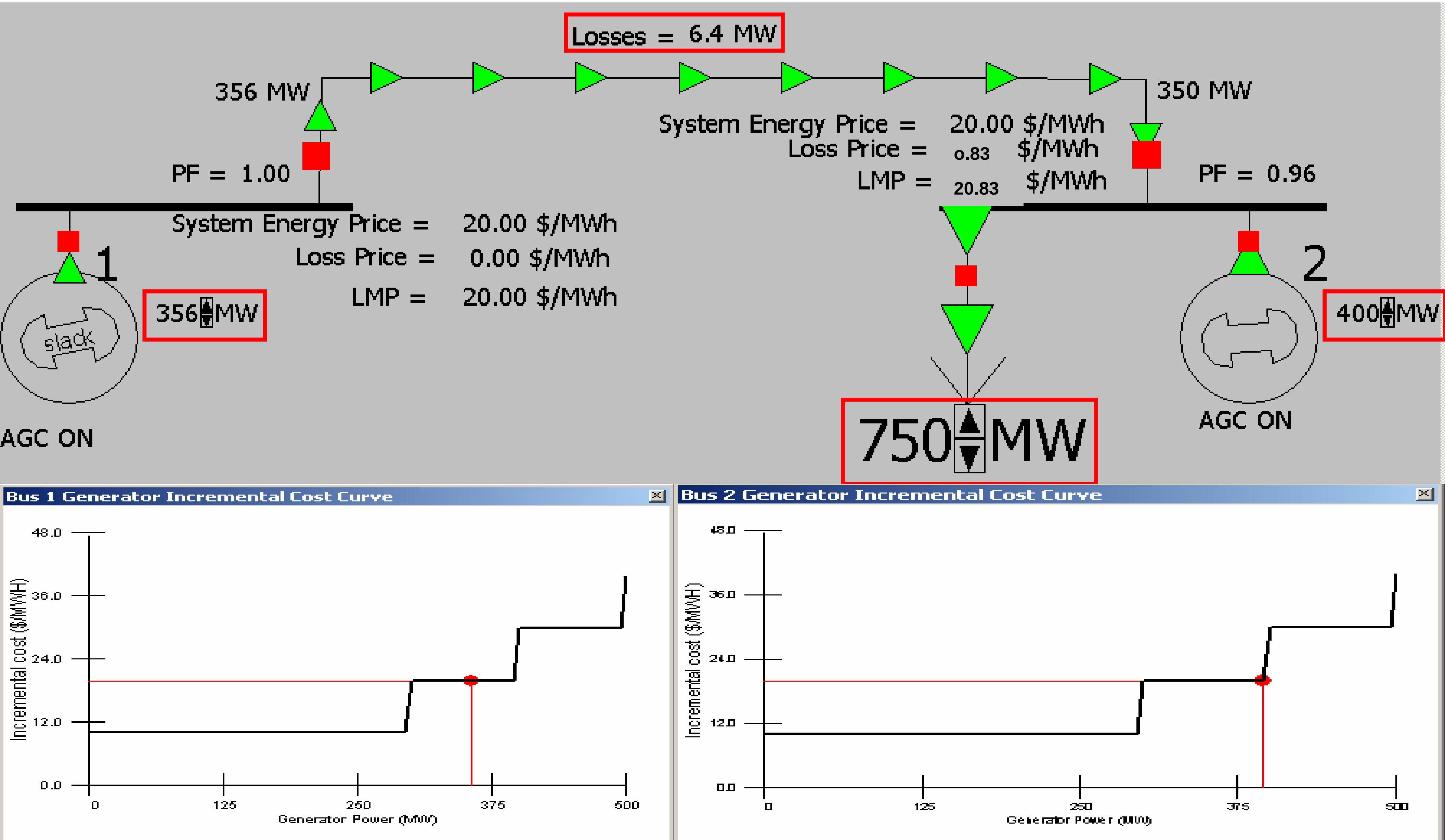


Marginal Loss Example




Losses = 4.6 MW
300 MW
295 MW
PF = 1.00
PF = 0.97
System Energy Price = 19.39 $/MWh
Loss Price = 0.61 $/MWh
LMP = 20.00 $/MWh
System Energy Price = 19.39 $/MWh
Loss Price = 0.00 $/MWh
LMP = 19.39 $/MWh
1
2
slack
300 MW
355 MW
650 MW
AGC ON
AGC ON
Bus 1 Generator Incremental Cost Curve
Bus 2 Generator Incremental Cost Curve
Incremental cost ($/MWH)
Generator Power (MW)
0.0
12.0
24.0
36.0
48.0
0
125
250
375
500

Marginal Loss Example



- Penalty factors are calculated based on transmission characteristics, generation levels and load levels
- PJM will utilize a Distributed Loss Reference for Marginal Loss implementation
- Distributed Loss Reference uses the “center” of load as the reference point
  - Electrical center of load
  - Shifts with load
    - Moves with State Estimator calculation
  - Minimizes
    - Error caused by the linearization of the loss model
    - Un-hedgeable loss component

- Penalty factors are calculated for each bus based on effect of an injection at that bus on total system losses.
- Penalty factors are used to modify the incremental cost of each generator to include the impact of losses
- LMPs will include the effect of marginal losses and will vary across PJM even in unconstrained situations
- LMP will be shown as three components:
  - System Energy Price
  - Loss Price
  - Congestion Price

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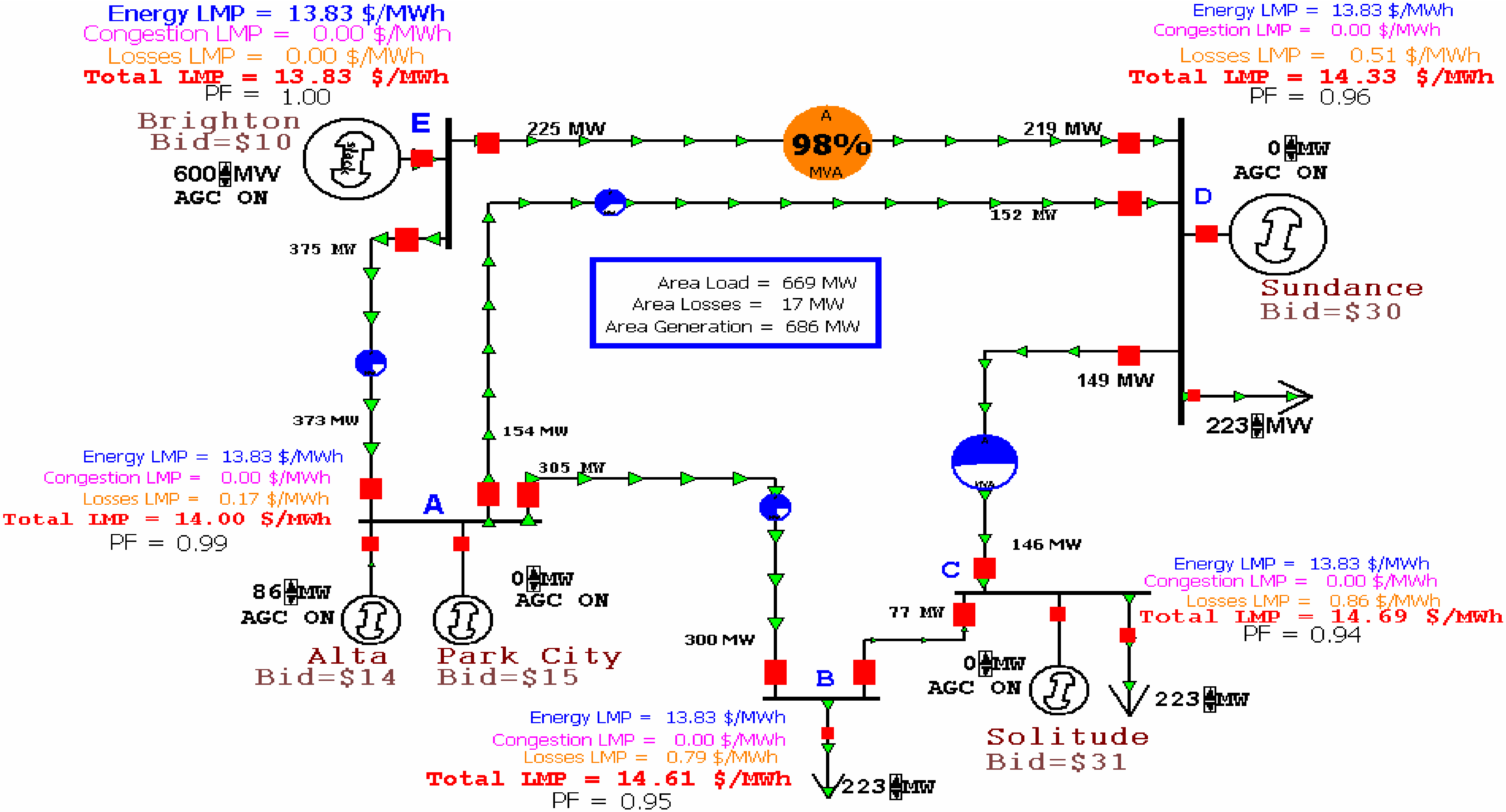
- Money collected from Marginal Losses will be approximately twice that collected from average losses
- More money collected from load than is paid to generation
  - Results in a loss surplus
    - Estimated to be about $35,000-$55,000 per hour
      - $308-$485 million per year
  - Distributed to Transmission Users based on load + exports ratio shares

- Loss surplus is allocated to Transmission Users

$$\text{Loss Credit} = \text{Total Loss Surplus (\$)} * \left(\frac{\text{Customer total MWh of energy delivered to load + exports}}{\text{Total PJM MWh of energy delivered to load + exports}} \right)$$

Loss Surplus - Example



Load Bus	MWh	Loss Price + System Energy Price	Load Charges
B	223	$14.61	$3258.03
C	223	$14.69	$3275.87
D	223	$14.33	$3195.59
			$9729.49

PJM collects $9729.49 in energy + loss charges from load

Generator	Bus	MWh	Loss Price + System Energy Price	Generator Payments
Brighton	E	600	$13.83	$8298
Alta	A	86	$14.00	$1204
Park City	A	0	$14.00	$0
Solitude	C	0	$14.69	$0
Sundance	D	0	$14.33	$0
				$9502

PJM pays $9502 in energy + loss credits to generation

Surplus of $227.49 is the Loss Revenues

Loss Surplus Allocation

Load Bus	MWh	LSE	Loss Surplus Allocation
B	223	ABC	(223/669)($227.49) = $75.83
C	223	XYZ	(446/669)($227.49) = $151.66
D	223		
	669		$227.49

- Implementation of Marginal Losses results in a surplus of loss charges collected
- This surplus is allocated to Transmission Users based on load plus exports ratio shares

Business Examples

Version 1

- Transmission Losses Definition
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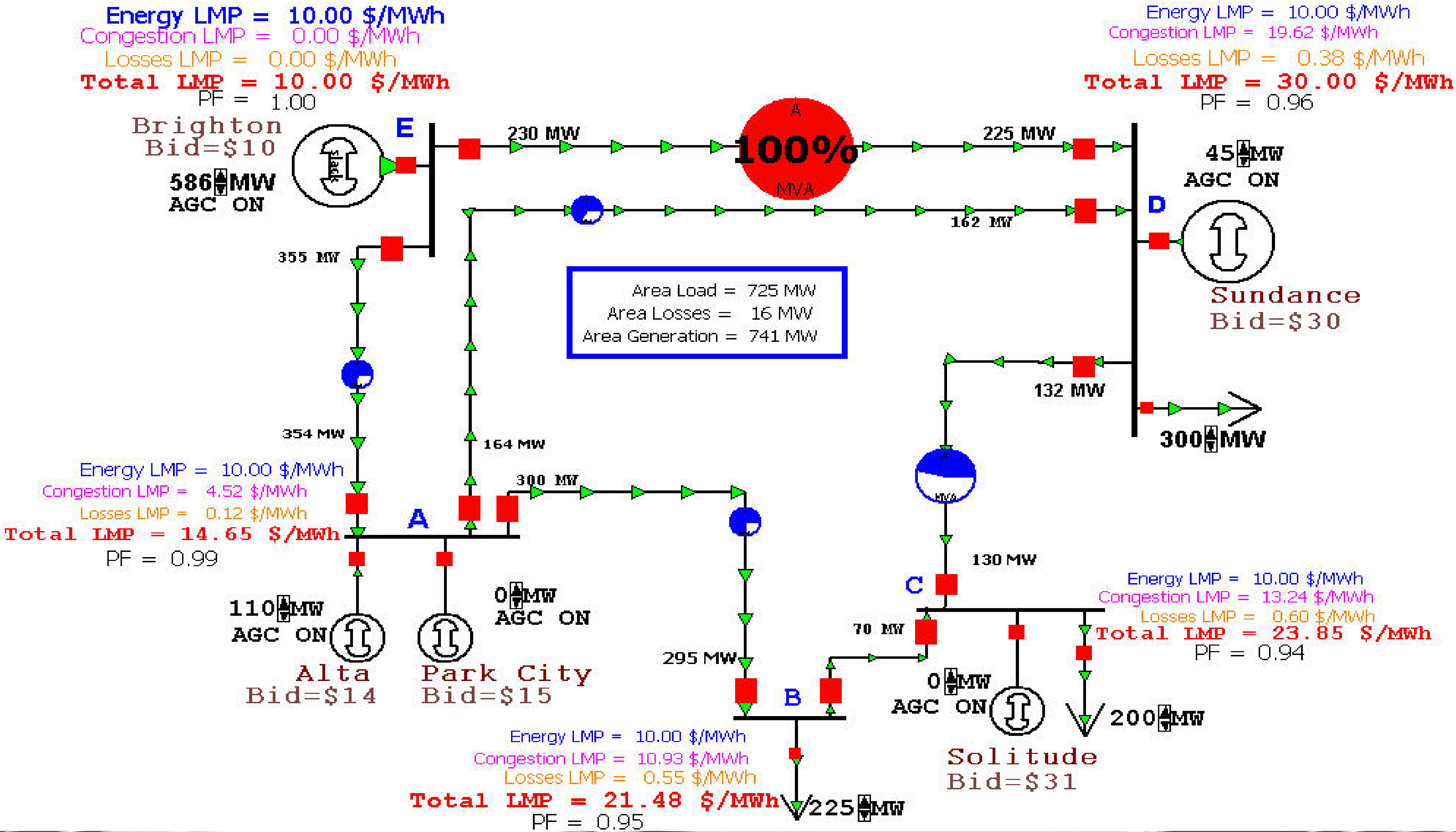
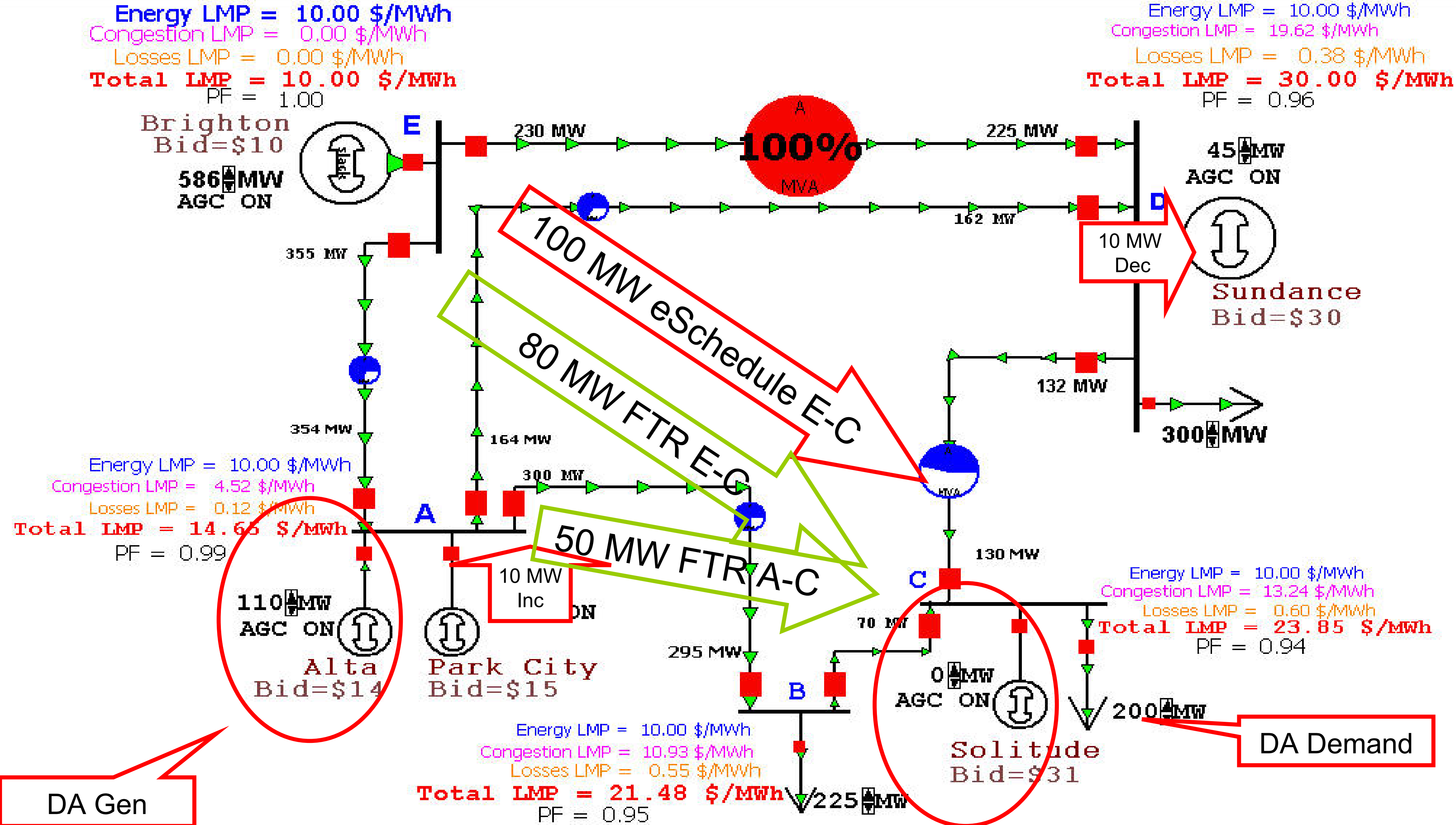
- The following example will illustrate the calculations for:
  - Spot Market Energy (DA and Balancing)
  - Implicit Congestion (DA and Balancing)
  - Implicit Losses (DA and Balancing)
  - Explicit Congestion (DA and Balancing)
  - Explicit Losses (DA and Balancing)
  - FTR Target Allocations

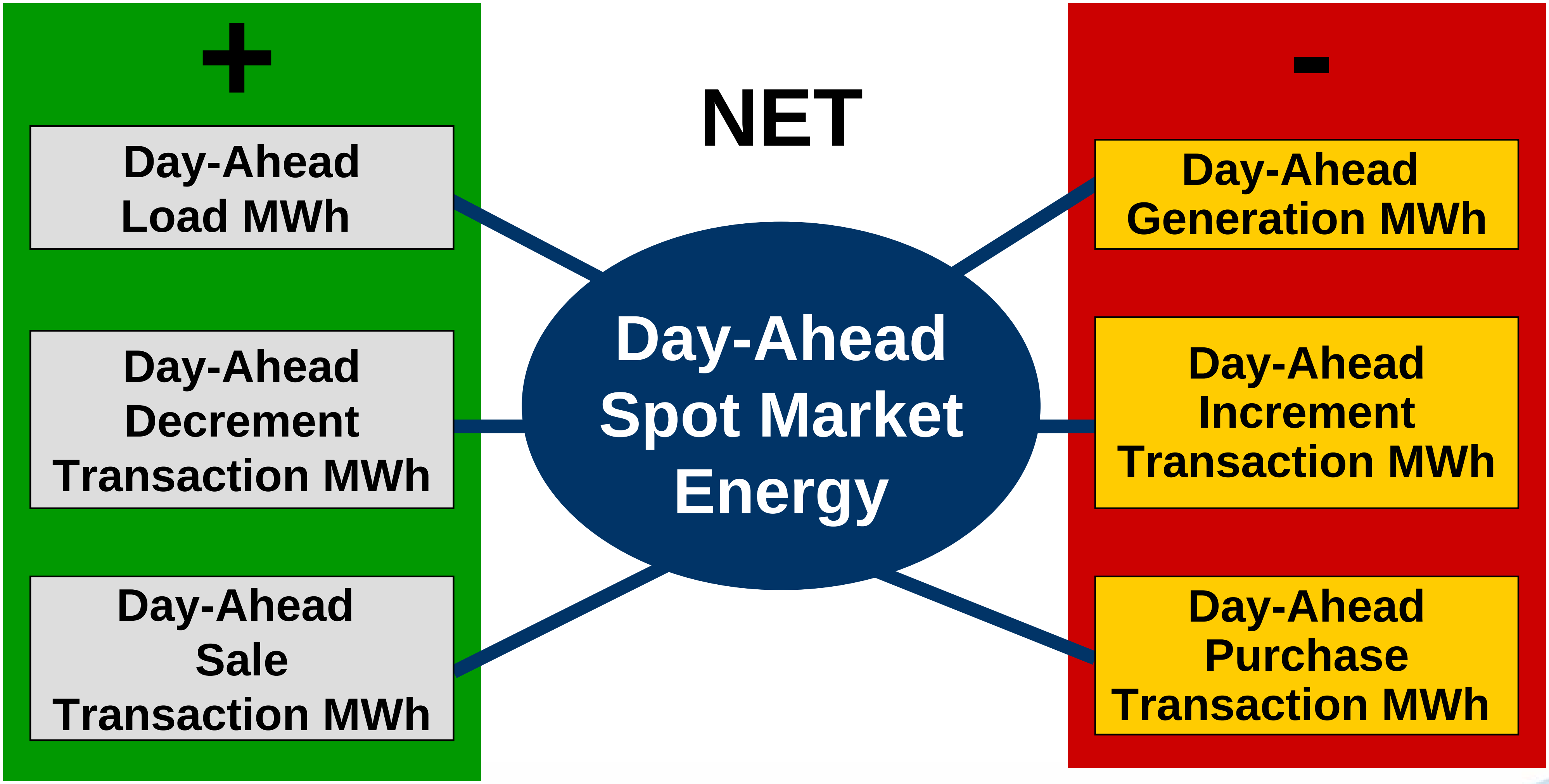

Energy LMP = 10.00 $/MWh
Congestion LMP = 0.00 $/MWh
Losses LMP = 0.00 $/MWh
Total LMP = 10.00 $/MWh
PF = 1.00
Brighton
Bid=$10
586 MW
AGC ON
E
230 MW
100%
MVA
225 MW
Energy LMP = 10.00 $/MWh
Congestion LMP = 19.62 $/MWh
Losses LMP = 0.38 $/MWh
Total LMP = 30.00 $/MWh
PF = 0.96
45 MW
AGC ON
D
162 MW
Sundance
Bid=$30
355 MW
Area Load = 725 MW
Area Losses = 16 MW
Area Generation = 741 MW
132 MW
300 MW
354 MW
164 MW
Energy LMP = 10.00 $/MWh
Congestion LMP = 4.52 $/MWh
Losses LMP = 0.12 $/MWh
Total LMP = 14.65 $/MWh
PF = 0.99
A
300 MW
130 MW
C
Energy LMP = 10.00 $/MWh
Congestion LMP = 13.24 $/MWh
Losses LMP = 0.60 $/MWh
Total LMP = 23.85 $/MWh
PF = 0.94
110 MW
AGC ON
0 MW
AGC ON
Alta
Bid=$14
Park City
Bid=$15
70 MW
295 MW
B
0 MW
AGC ON
200 MW
Solitude
Bid=$31
Energy LMP = 10.00 $/MWh
Congestion LMP = 10.93 $/MWh
Losses LMP = 0.55 $/MWh
Total LMP = 21.48 $/MWh
PF = 0.95
225 MW

- Participant ABC is engaged in the following activities:
  - Virtual trading (Inc/Dec)
    - Inc bus A; Dec bus D
  - Generation Owner
    - Alta, Solitude
  - Load Serving Entity
    - Day-ahead Demand at bus C
  - Internal Bilateral Transaction
    - Bus E to Bus C
  - FTR holder
    - Bus E to Bus C
    - Bus A to Bus C



Energy LMP = 10.00 $/MWh
Congestion LMP = 0.00 $/MWh
Losses LMP = 0.00 $/MWh
Total LMP = 10.00 $/MWh
PF = 1.00
Brighton
Bid=$10
586 MW
AGC ON
E
230 MW
100%
MVA
225 MW
Energy LMP = 10.00 $/MWh
Congestion LMP = 19.62 $/MWh
Losses LMP = 0.38 $/MWh
Total LMP = 30.00 $/MWh
PF = 0.96
45 MW
AGC ON
D
162 MW
10 MW
Dec
Sundance
Bid=$30
355 MW
100 MW eSchedule E-C
80 MW FTR E-C
50 MW FTR A-C
132 MW
300 MW
354 MW
164 MW
Energy LMP = 10.00 $/MWh
Congestion LMP = 4.52 $/MWh
Losses LMP = 0.12 $/MWh
Total LMP = 14.65 $/MWh
PF = 0.99
300 MW
A
110 MW
AGC ON
Alta
Bid=$14
10 MW
Inc
Park City
Bid=$15
295 MW
B
130 MW
C
70 MW
Energy LMP = 10.00 $/MWh
Congestion LMP = 13.24 $/MWh
Losses LMP = 0.60 $/MWh
Total LMP = 23.85 $/MWh
PF = 0.94
0 MW
AGC ON
Solitude
Bid=$31
200 MW
DA Demand
Energy LMP = 10.00 $/MWh
Congestion LMP = 10.93 $/MWh
Losses LMP = 0.55 $/MWh
Total LMP = 21.48 $/MWh
PF = 0.95
225 MW
DA Gen

Day-Ahead Spot Market Energy Calculation



Buyer Charges → Day-Ahead System Energy Price

Seller Charges (negative) → Day-Ahead System Energy Price

System Energy Price will be the same for all participants.

Business Example – Day-Ahead Spot Market Energy

Energy Market Withdrawals	Energy Market Injections
200 MW (DA Demand)	100 MW (eSchedule purchase)
10 MW (Decrement Bid)	110 MW (Alta day-ahead schedule)
	10 MW (Increment Offer)
	0 MW (Solitude day-ahead schedule)
210 MW	220 MW

210 MW – 220 MW = -10 MW * $10.00 = -$100 charge

(Note that charge is negative)

Day-Ahead System Energy Price

Calculation of Locational Net Congestion Bill (Implicit Congestion)

Locational Net Congestion Bill is the difference in congestion prices between a participant's energy market withdrawals and injections

Net Congestion Bill:

Congestion Withdrawal Charges - Congestion Injection Credits

Congestion Withdrawal Charges*:

Load: Load Bus MWh x *Congestion Price* at Load Bus

Energy Sales: Sale MWh x *Congestion Price* at Source

Decrement Bids: Dec Bid MWh x *Congestion Price* at Bus

Congestion Injection Credits*:

Generation: Gen Bus MWh x *Congestion Price at* Gen Bus

Energy Purchases: Purchase MWh x *Congestion Price* at Sink

Increment Offers: Offer Bid MWh x *Congestion Price* at Bus

** deviations are used for balancing market calculations*

Business Example – Day-Ahead Implicit Congestion

Congestion Withdrawal Charges	Congestion Injection Credits
200 MW (DA Demand) * $13.24 = $2648	100 MW (eSchedule purchase) * $13.24 = $1324
10 MW (Decrement Bid) * $19.62 = $196.20	110 MW (Alta DA schedule) * $4.52 = $497.20
	10 MW (Increment Offer) * $4.52 = $45.2
	0 MW (Solitude DA schedule) * $13.24 = $0
$2844.20	$1866.40

$2844.20 - $1866.40 = $977.80 charge

Prices are day-ahead congestion prices at corresponding locations.

Locational Net Loss Bill is the difference in loss prices between a participant's energy market withdrawals and injections

Net Loss Bill:

Loss Withdrawal Charges – Loss Injection Credits

Loss Withdrawal Charges*:

Load: Load Bus MWh x *Loss Price* at Load Bus

Energy Sales: Sale MWh x *Loss Price* at Source

Decrement Bids: Dec Bid MWh x *Loss Price* at Bus

Loss Injection Credits*:

Generation: Gen Bus MWh x *Loss Price* at Gen Bus

Energy Purchases: Purchase MWh x *Loss Price* at Sink

Increment Offers: Inc Offer MWh x *Loss Price* at Bus

** deviations are used for balancing market calculations*

Loss Withdrawal Charges	Loss Injection Credits
200 MW (DA Demand) * $0.60 = $120	100 MW (eSchedule purchase) * $0.60 = $60
10 MW (Decrement Bid) * $0.38 = $3.80	110 MW (Alta DA schedule) * $0.12 = $13.20
	10 MW (Increment Offer) * $0.12 = $1.20
	0 MW (Solitude DA schedule) * $0.60 = $0
$123.80	$74.40

$123.80 - $74.40 = $49.40 charge

Prices are day-ahead loss prices at corresponding locations.

Business Example – Day-Ahead Explicit Congestion

Transaction MWh * [Day-Ahead *Congestion Price at Sink* - Day-Ahead *Congestion Price at* Source]

- Transmission customer pays congestion for external transactions
- Buyer pays congestion for internal transactions (network customer)

100 MW (eSchedule purchase) * ($13.24 - $0) = $1,324 charge

Business Example – Day-Ahead Explicit Losses

Transaction MWh * [Day-Ahead *Loss Price at Sink* - Day-Ahead *Loss Price* at Source]

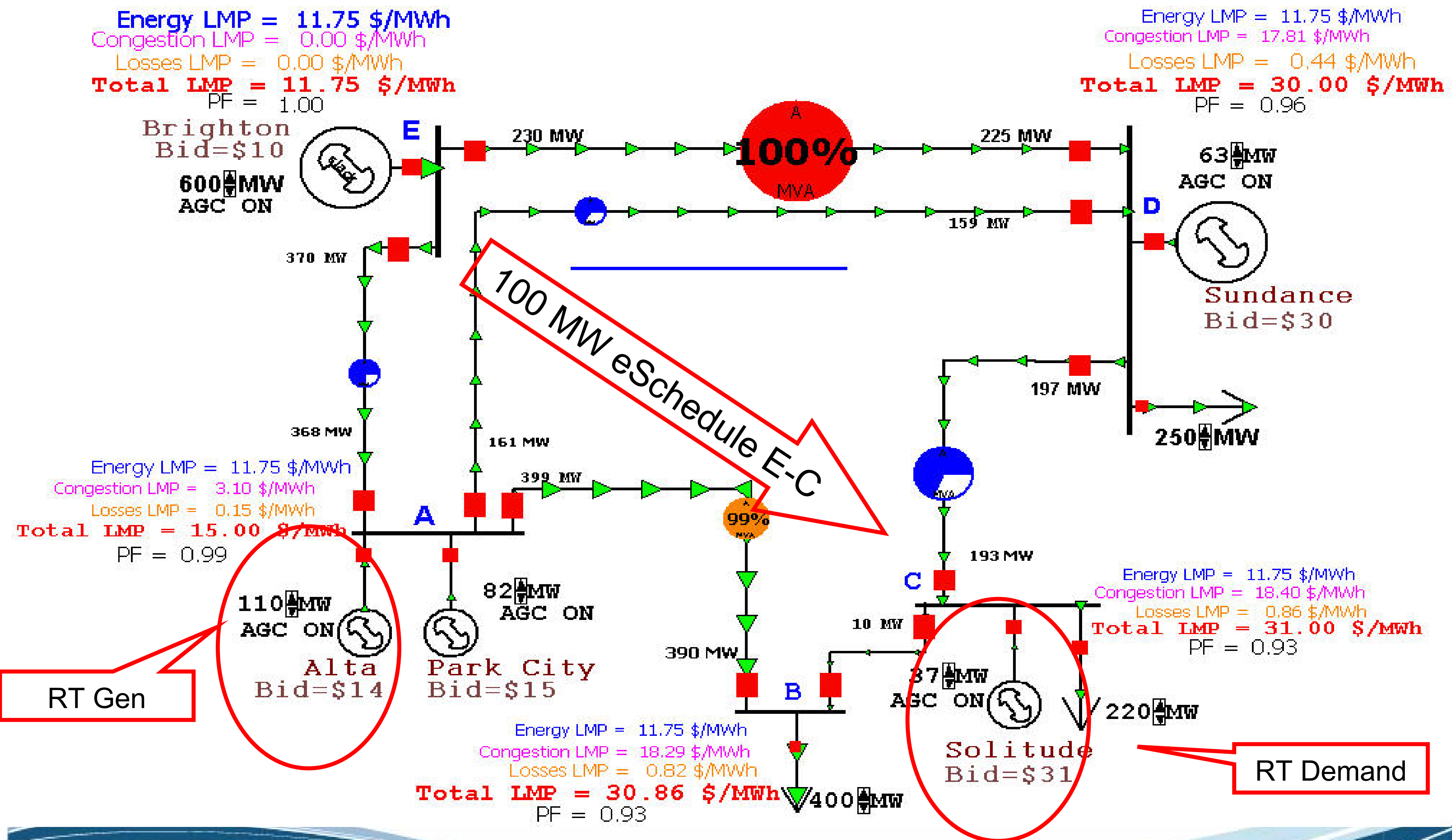
- Transmission customer pays losses for external transactions
- Buyer pays losses for internal transactions (network customer)

100 MW (eSchedule purchase) * ($0.60 - $0) = $60 charge

FTR Target Allocation = **FTR MW** * (Day-Ahead *Congestion Price at Sink* - Day-Ahead *Congestion Price at* Source)

FTR #1 Target Allocation = 80 MW ($13.24 - $0) = $1,059.20
FTR #2 Target Allocation = 50 MW ($13.24 - $4.52) = $436.00

Business Example – Balancing Market



Balancing Spot Market Charges = [Real-Time Net Interchange (MWh) - Day-Ahead Net Interchange (MWh)] * *Real-Time System Energy Price* ($/MWh)

- Charge amounts may be either positive (+) or negative (-), depending on the difference between Day-Ahead and Balancing Interchange MWh

Business Example – Balancing Spot Market Energy

Real-Time Energy Withdrawals	Real-Time Energy Injections
220 MW (RT Load excluding losses)	100 MW (eSchedule purchase)
	110 MW (Alta actual generation)
	37 MW (Solitude actual generation)
220 MW	247 MW

220 MW – 247 MW = -27 MW

Real-Time Net Interchange

-27 MW – (-10 MW) = -17 MW ($11.75) = -$199.75 charge

(Note that charge is negative)

Real-Time Net Interchange

Day-Ahead Net Interchange

Real-Time System Energy Price

Locational Net Congestion Bill is the difference in congestion prices between a participant's energy market withdrawals and injections

Net Congestion Bill:

Congestion Withdrawal Charges - Congestion Injection Credits

Congestion Withdrawal Charges*:

Load: Load Bus MWh x *Congestion Price* at Load Bus

Energy Sales: Sale MWh x *Congestion Price* at Source

Decrement Bids: Dec Bid MWh x *Congestion Price* at Bus

Congestion Injection Credits*:

Generation: Gen Bus MWh x *Congestion Price at* Gen Bus

Energy Purchases: Purchase MWh x *Congestion Price* at Sink

Increment Offers: Offer Bid MWh x *Congestion Price* at Bus

** deviations are used for balancing market calculations*

Business Example – Balancing Implicit Congestion

Congestion Withdrawal Charges	Congestion Injection Credits
(220 MW - 200 MW (Demand Dev)) * $18.40 = $368.00	(100 MW - 100 MW (eSchedule purch dev)) * $18.40 = $0
(0 MW - 10 MW (Decrement Dev)) * $17.81 = -$178.10	(110 MW - 110 MW (Alta deviation)) * $3.10 = $0
	(0 MW - 10 MW (Increment Dev)) * $3.10 = -$31.00
	(37 MW - 0 MW (Solitude deviation)) * $18.40 = $680.8
$190.00	$649.80

$190.00 - $649.80 = - $459.80 charge

Prices are real-time congestion price at corresponding locations.

Locational Net Loss Bill is the difference in loss prices between a participant's energy market withdrawals and injections

Net Loss Bill:

Loss Withdrawal Charges – Loss Injection Credits

Loss Withdrawal Charges*:

Load: Load Bus MWh x *Loss Price* at Load Bus

Energy Sales: Sale MWh x *Loss Price* at Source

Decrement Bids: Dec Bid MWh x *Loss Price* at Bus

Loss Injection Credits*:

Generation: Gen Bus MWh x *Loss Price* at Gen Bus

Energy Purchases: Purchase MWh x *Loss Price* at Sink

Increment Offers: Inc Offer MWh x *Loss Price* at Bus

** deviations are used for balancing market calculations*

Business Example – Balancing Implicit Losses

Loss Withdrawal Charges	Loss Injection Credits
(220 MW - 200 MW (Demand Dev)) * $0.86 = $17.20	(100 MW - 100 MW (eSchedule purch dev)) * $0.86 = $0
(0 MW - 10 MW (Decrement Dev)) * $0.44 = - $4.40	(110 MW - 110 MW (Alta deviation)) * $0.15 = $0
	(0 MW - 10 MW (Increment Dev)) * $0.15 = -$1.50
	(37 MW - 0 MW (Solitude deviation) * $0.86 = $31.82
$12.80	$30.32

$12.80 - $30.32 = - $17.52 charge

Prices are real-time congestion price at corresponding locations.

Balancing Explicit Congestion Charge

Transaction MWh Deviation * (Real-Time *Congestion Price at Sink* - Real-Time *Congestion Price at* Source)

- Transmission customer pays congestion for external transactions
- Buyer pays congestion for internal transactions (network customer)

0 MWh (eSchedule purchase deviation) * ($18.40 - $0) = $0

Transaction MWh Deviation * [Real-Time *Loss Price at Sink* - Real-Time *Loss Price* at Source]

- Transmission customer pays losses for external transactions
- Buyer pays losses for internal transactions (network customer)

0 MW (eSchedule purchase deviation) * ($0.86 - $0) = $0

Total System Loss Surplus = $123.31
(total for all participants)

Example Participant's Transmission Loss Credit =
($123.31) (220 MW/ 870 MW) = $31.18

Where: 220 MW is hourly real-time load at bus C (example participant) and 870 MW is total system load + zero exports

- Maps/MW Flow Program
- 2005 Annual simulation run (8760 hours)
  - Full transmission model (2004)
  - Production cost simulation using:
    - Production cost database built from RDI basecase (2002/2003 release)
    - Simulates security-constrained unit commitment and Economic Dispatch
    - Includes hourly load forecasts, generation outage schedules, etc

Simulation Results – Load Price

Zone	Change in Zonal Load Price Due to Loss Component ($/MWh) Loss Case – Base Case	Change in Zonal Load Price Due to Congestion Component ($/MWh) Loss Case – Base Case	Load Net Change
AECO	$2.21	-$2.37	-$0.16
AP	$0.23	-$0.24	-$0.01
BG&E	$1.41	-$2.74	-$1.33
DPL	$1.91	-$2.53	-$0.62
GPUE	$2.45	-$2.23	$0.22
GPUW	$1.30	-$1.43	-$0.13
PECO	$1.85	-$2.32	-$0.47
PPL	$1.76	-$2.04	-$0.28
PEPCO	$0.92	-$2.87	-$1.95
PSEG	$2.39	-$2.21	$0.18
RECO	$2.34	-$2.18	$0.16
AEP	-$0.69	$0.52	-$0.17
DP&L	-$0.54	$0.45	-$0.09
VP	$0.74	-$1.52	-$0.78
COM-ED	-$1.74	$1.06	-$0.68
DUQ	-$0.55	$0.41	-$0.14

Simulation Results – Generation Price

Zone	Change in Zonal Gen Price Due to Loss Component ($/MWh) Loss Case – Base Case	Change in Zonal Gen Price Due to Congestion Component ($/MWh) Loss Case – Base Case	Generation Net Change
AECO	$2.15	-$2.37	-$0.22
AP	$0.22	-$0.32	-$0.10
BG&E	$1.37	-$2.75	-$1.38
DPL	$1.85	-$2.53	-$0.68
GPUE	$2.39	-$2.24	$0.15
GPUW	$1.22	-$1.69	-$0.47
PECO	$1.79	-$2.36	-$0.57
PPL	$1.69	-$2.17	-$0.48
PEPCO	$0.90	-$2.69	-$1.79
PSEG	$2.30	-$2.20	$0.10
RECO	--	--	--
AEP	-$0.66	$0.52	-$0.14
DP&L	-$0.50	$0.45	-$0.05
VP	$0.72	-$1.13	-$0.41
COM-ED	-$1.68	$1.06	-$0.62
DUQ	-$0.54	$0.41	-$0.13

Summary of Net Changes

Zone	Load Net Change ($/MWh) Loss Case – Base Case	Gen Net Change ($/MWh) Loss Case – Base Case
AECO	-$0.16	-$0.22
AP	-$0.01	-$0.10
BG&E	-$1.33	-$1.38
DPL	-$0.62	-$0.68
GPUE	$0.22	$0.15
GPUW	-$0.13	-$0.47
PECO	-$0.47	-$0.57
PPL	-$0.28	-$0.48
PEPCO	-$1.95	-$1.79
PSEG	$0.18	$0.10
RECO	$0.16	--
AEP	-$0.17	-$0.14
DP&L	-$0.09	-$0.05
VP	-$0.78	-$0.41
COM-ED	-$0.68	-$0.62
DUQ	-$0.14	-$0.13

Marginal Loss Implementation - Summary

- **Spot Market Energy** charges (+/-) priced at the System Energy Price
- **Implicit Congestion** charges (+/-) calculated as a locational net congestion bill using the Congestion Price
- **Explicit Congestion** charges (+/-) calculated for transactions using the Congestion Price at source and sink
- **Implicit Loss** charges (+/-) calculated as a locational net loss bill using the Loss Price
- **Explicit Loss** charges (+/-) calculated for transactions using the Loss Price at source and sink

- **FTR Target Allocations** calculated as FTR MW times the difference between the day-ahead congestion prices at the FTR source/sink

- **Loss Surplus** is allocated as credits to Transmission Users based on hourly real-time load + exports ratio share

- Transmission Losses Definition
- Marginal Loss Calculation
- Loss Surplus Allocation
- Business Examples
- Load Carve-Out Process Changes
- Settlements Changes
- PJM Application Changes
- Next Steps

- Implementation of Marginal Losses creates potential for double counting of losses due to:
  - EDCs gross up the derived loads measured at individual retail meters to account for losses
    - Based on State-filed retail rates
  - PJM Settlement calculations being changed to account for losses using the marginal loss component of LMP
- Solution is to calculate the amount of losses that will be included in the LMP value and subtract it from the EDCs' total load values
  - Eliminates double counting potential
  - Consistent approach
  - Does not require filing new retail rates with States

- Loads will be reduced based on a *hourly* EDC Loss De-ration Factor
  - Determined by state-estimated losses
- For non-PJM Mid-Atlantic EDCs:

$$f_{loss} = Loss_{EDC\text{-}SE} \;/\; TL$$

f_{loss} = EDC loss de-ration factor
$Loss_{EDC\text{-}SE}$ = EDC hourly total state-estimated losses
TL = EDC total revenue-metered load (includes all losses)

- For PJM Mid-Atlantic EDCs:

$$f_{loss} = (Loss_{EDC\ non\text{-}500kV} + Loss_{500kV}) / (TL + Loss_{500kV})$$

f_{loss} = EDC loss de-ration factor
$Loss_{EDC\ non\text{-}500kV}$ = EDC total non-500 kV state-estimated losses
$Loss_{500kV}$ = EDC revenue-metered 500 kV loss allocation
TL = EDC total revenue-metered load (includes all losses)

Zonal Marginal Loss Factor - Example

1. EDC determines measured customer load and calculates "bottom-up" total load per existing State-filed procedures

$$Load_{\ metered} = 11.0\ MW$$
$$f_{EDC} = 0.0345$$

$$TL_{\ Bottom\text{-}up} = Load_{\ metered} \times (1 + f_{EDC})$$
$$= 11.0 \times 1.0345$$
$$= 11.3795$$

2. EDC submits this Total Load to PJM via eSchedules. Upon receipt, PJM will apply the EDC Loss De-ration Factor in order to de-rate the submitted load by the calculated value of marginal losses included in LMP.

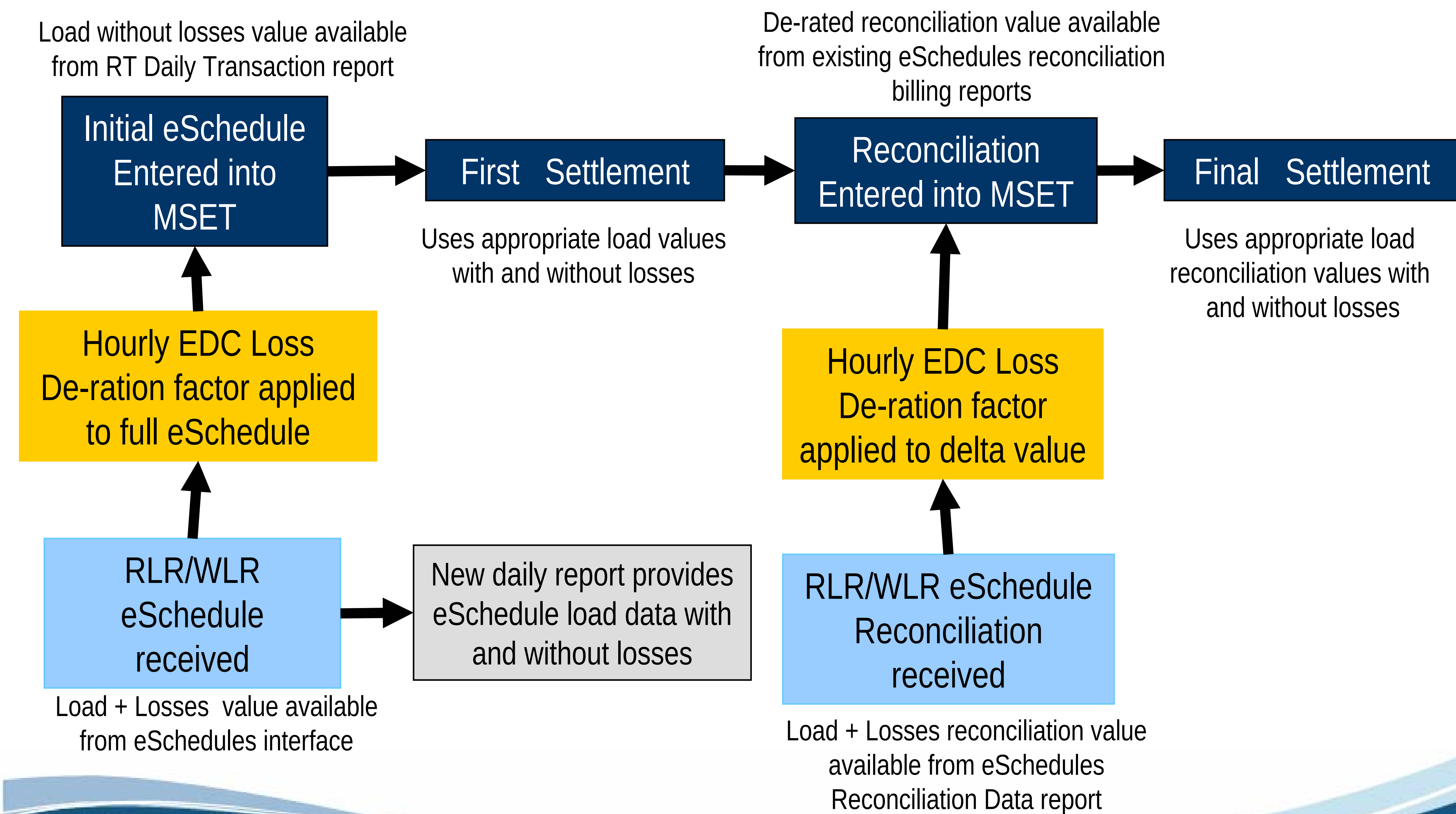
$$f_{loss} = 0.01255$$

$$Loss_{\ marginal} = f_{loss} \times TL_{bottom\text{-}up}$$
$$= 0.01255 \times 11.3795$$
$$= 0.1428$$

$$TL_{\ de\text{-}rated} = TL_{bottom\text{-}up} - Loss_{marginal}$$
$$= 11.3795 - 0.1428$$
$$= 11.2367$$

- Unadjusted Load Reconciliation Value including all losses is submitted to eSchedules (for RLR and WLR eSchedules)
- PJM will apply hourly EDC Loss De-ration Factors to these schedules to de-rate them for losses
- Load Reconciliation MWh (not including losses) will be settled separately using each of the three components of real-time LMP
  - Energy reconciliation charges
  - Congestion reconciliation charges
  - Loss reconciliation charges
- Load Reconciliation MWh for Ancillary Service reconciliations will include or not include losses depending on the applicable settlement calculation for the particular ancillary service

Flow Diagram for Load eSchedules Loss De-Ration



Load MWh will now exclude Loss MWh (since load pays loss component of LMP)

- LSEs no longer hedge real-time losses in day-ahead demand bid
- LSEs' real-time load in energy market no longer includes loss MWh
- EDCs' zonal real-time load will be reduced by state-estimated losses
- PJM Mid-Atlantic 500 kV losses no longer allocated as load
- EDC Loss De-ration Factors will de-rate Retail Load Responsibility (RLR) and Wholesale Load Responsibility (WLR) eSchedules MWh

Zonal EDCs must still report load including losses, for:

- Network service peak loads (NSPLs)
- Capacity peak load contributions (PLCs)
- Load forecasting and zonal reserve requirements

eMTR load submission screen data will include losses

- De-rated loss adjustment and final de-rated load will be made available

- To prevent double-counting of losses, PJM will de-rate EDC and LSE load values to account for losses in the marginal loss calculation
  – Will not require changes to existing EDC/LSE processes
  – Participants will be able to see original and de-rated load values through eSchedules and eMTR
- Day-ahead Demand Bids should no longer include losses

- Transmission Losses Definition
- Marginal Loss Calculation
- Surplus Loss Allocation
- Business Examples
- Load Carve-Out Process Changes
- Settlements Changes
- PJM Application Changes
- Next Steps

- Prior to Marginal Losses Implementation
  - Point-to-point transmission customers are charged for transmission losses based on
    - Transaction MWh
    - PJM load-weighted average LMP
    - Loss factor (3% on-peak; 2½% off-peak)

- After Marginal Losses Implementation
  - This charge (and the associated credit allocation) will be *eliminated* since losses will be included in the LMPs
  - New line items for Transmission Loss charges and credits replace the existing line items

- Prior to Marginal Loss Implementation
  - Losses on PJM Mid-Atlantic 500 kV system allocated as load to PJM Mid-Atlantic EDCs
- After Marginal Loss Implementation
  - PJM Mid-Atlantic 500 kV losses will no longer be allocated as load
    - Losses now included in LMP calculation
    - EDC total real-time load will be reduced by state-estimator losses (and revenue-metered 500 kV losses, as applicable)

- Prior to June 1, 2007
  - Inadvertent Interchange energy allocated to EDCs only
    - EDC would further allocate to LSEs in their zone
    - Priced at PJM load-weighted-average LMP
- After June 1, 2007
  - Allocated as +/- charges *directly to all LSEs*
    - Based on real-time load ratio shares
    - Priced at the PJM load-weighted-average LMP
      - Total LMP (3 components)

Note: This change is unrelated to Marginal Losses, but being implemented at the same time. This change has been approved by FERC for a June 1, 2007 implementation.

- Prior to June 1, 2007
  - Monthly charges (+/-) to PJM fully-metered EDCs and generators for corrections to metered energy values
- After June 1, 2007
  - Meter correction charges to account for *external* tie meter errors
    - Allocated as +/- charges *directly to all LSEs*
      - Based on real-time load ratio shares
      - Priced at the PJM load-weighted-average LMP
        - » Total LMP (3 components)
  - Internal tie, generator, and PJM Mid-Atlantic 500 kV meter correction charges remain with applicable EDCs/Generators

Note: This change is unrelated to Marginal Losses, but being implemented at the same time. This change has been approved by FERC for a June 1, 2007 implementation.

“Load” for Market Settlements Billing Items

- Prior to Marginal Loss Implementation
  - Obligations/charges for all Ancillary Services was based on load plus losses

- After Marginal Loss Implementation
  - Some Ancillary Services charged based on “Load plus Losses” while others charged based on “Lossless Load”
  - In general:
    - Operating Agreement accounting uses “Lossless Load”
    - OATT accounting uses “Load plus Losses”
  - Terminology:
    - “Load” refers to “Lossless Load” unless specifically called out as “Load plus Losses” in the agreement language
  - Details on next few slides

"Load" for Network Transmission and Capacity Obligation

- Network Transmission Service
  - Charged based on Network Service Peak Loads (NSPLs)
    - Based on "Load plus Losses"

- Capacity Obligation
  - Based on Peak Load Contributions (PLCs)
    - Based on "Load plus Losses"

No Change

- The following Schedule 9 and 10 charges will be charged to “Load plus Losses” transmission use
  - Schedule 9-1
    - PJM Scheduling, System Control and Dispatch Service – Control Area Administration
  - Schedule 9-3
    - PJM Scheduling, System Control and Dispatch Service – Market Support
  - Schedule 9-FERC
    - FERC Annual Charge Recovery
  - Schedule 9-OPSI
    - Organization of PJM States, Inc. (OPSI)
  - Schedule 10-NERC
    - North American Electric Reliability Corporation (NERC)
  - Schedule 10-RFC
    - Reliability*First* Corporation

No Change

- Schedule 1A – Transmission Owner Scheduling, System Control and Dispatch Service
  - Charge to transmission use, where Network load is “Load plus Losses”

No Change

“Load” for Ancillary Services – Reactive Supply and Black Start

- Schedule 2 (Reactive Supply) and Schedule 6A (Black Start Service)
  - Charges allocated to point-to-point and network customers based on transmission usage
    - Network customer load is “Load plus Losses”

No Change

- LSE hourly Regulation Obligation based on real-time load ratio share of the total regulation MWh assigned that hour
  - Load for this calculation will be “Lossless Load”

Change

- LMP used in Regulation Market Clearing Price calculation will be total LMP

- PJM Synchronized Reserve Requirements differ by Synchronized Reserve Market Area
- LSE hourly Synchronized Reserve Obligation based on real-time load ratio share of the total synch reserve tier 2 MWh assigned that hour
  - Load for this calculation will be "Lossless Load"

Change

- LMP used in Synchronized Reserve Market Clearing Price calculation will be total LMP

"Load" for Ancillary Services – Day-Ahead Operating Reserve

- Day-Ahead Operating Reserve charges allocated to decrement bids, day-ahead exports and cleared day-ahead demand
  - Day-ahead demand assumed to be "Lossless Load"
    - LSEs no longer need to hedge real-time losses in day-ahead demand bid
- Day-Ahead Energy Market revenues for generator operating reserve credit calculation will utilize total LMP

Change

- Balancing Operating Reserve charges allocated to generation (not following dispatch), transaction, and load deviations
  - Load deviations based on “Lossless Load”
    - Compare real-time lossless load to cleared DA demand
- Balancing energy market revenues for generator operating reserve credit calculation will utilize total LMP

Change

"Load" for Ancillary Services – Synchronous Condensing Charge

- Synchronous Condensing Charge
  - Not for Synchronized Reserve nor Reactive Services
    - Allocated based on real-time load plus export shares
      - Load is real-time "Lossless Load"

Change

“Load” for Ancillary Services – Reactive Services

- Reactive Services Charge (not Schedule 2)
  - Charges for generators who alter their output to achieve greater reactive capability
    - Allocated separately for each zone based on real-time load ratio shares within applicable zone
      - Load is real-time “Lossless Load”

Change

“Load” for Demand Response

- Credits for day-ahead and real-time demand reductions
  - PJM will de-rate reduction (previously grossed up for losses) based on EDC Loss De-ration Factor
  - Therefore, credit based on “Lossless load”
- Charges allocated by zonal load ratio shares
  - Based on “Lossless load”

Change

“Load” for Market Settlements Billing Items - Summary

Billing Item Based on “Load + Losses”	Billing Item Based on “Lossless Load”
Network Transmission Service	Spot Market Energy (DA and Balancing)
Capacity Obligation	Congestion (DA and Balancing)
Schedule 1A- Trans Owner Scheduling, System Control and Dispatch	Regulation Obligation
Schedule 2 – Reactive	Synchronized Reserve Obligation
Schedule 6A – Black Start	DA Operating Reserve (DA Demand)
Schedule 9-1 PJM Control Area Administration	Balancing Operating Reserve (Load deviations)
Schedule 9-3 PJM Market Support	Synchronous Condensing (for load following and post-contingency operation)
Schedule 9-FERC Schedule 9-OPSI	Reactive Services (units reduced to provide more reactive power)
Schedule 10-NERC	Load Response
Schedule 10-RFC	Inadvertent Interchange

- New PJM Billing Line Items
  - Transmission Loss charges and credits
  - Transmission Loss Reconciliation charges and credits
  - Transmission Congestion Reconciliation charges
  - Inadvertent Interchange charges

- Terminated PJM Billing Line Items
  - Point-to-point Transmission Loss charges and credits
  - Point-to-point Transmission Loss Reconciliation credits
  - Spot Market Energy credits

- New PJM Settlement Reports
  - Transmission Loss Charge Summary
  - Explicit Losses Summary
  - Transmission Loss Credit Summary
  - Load eSchedules With and Without Losses
  - EDC Hourly Loss De-ration Factors
  - EDC Inadvertent Allocations
  - Inadvertent Interchange Charge Summary
  - Meter Correction Charge Summary
  - Meter Correction Allocation Charge Summary

Replace current point-to-point loss charge/credit reports

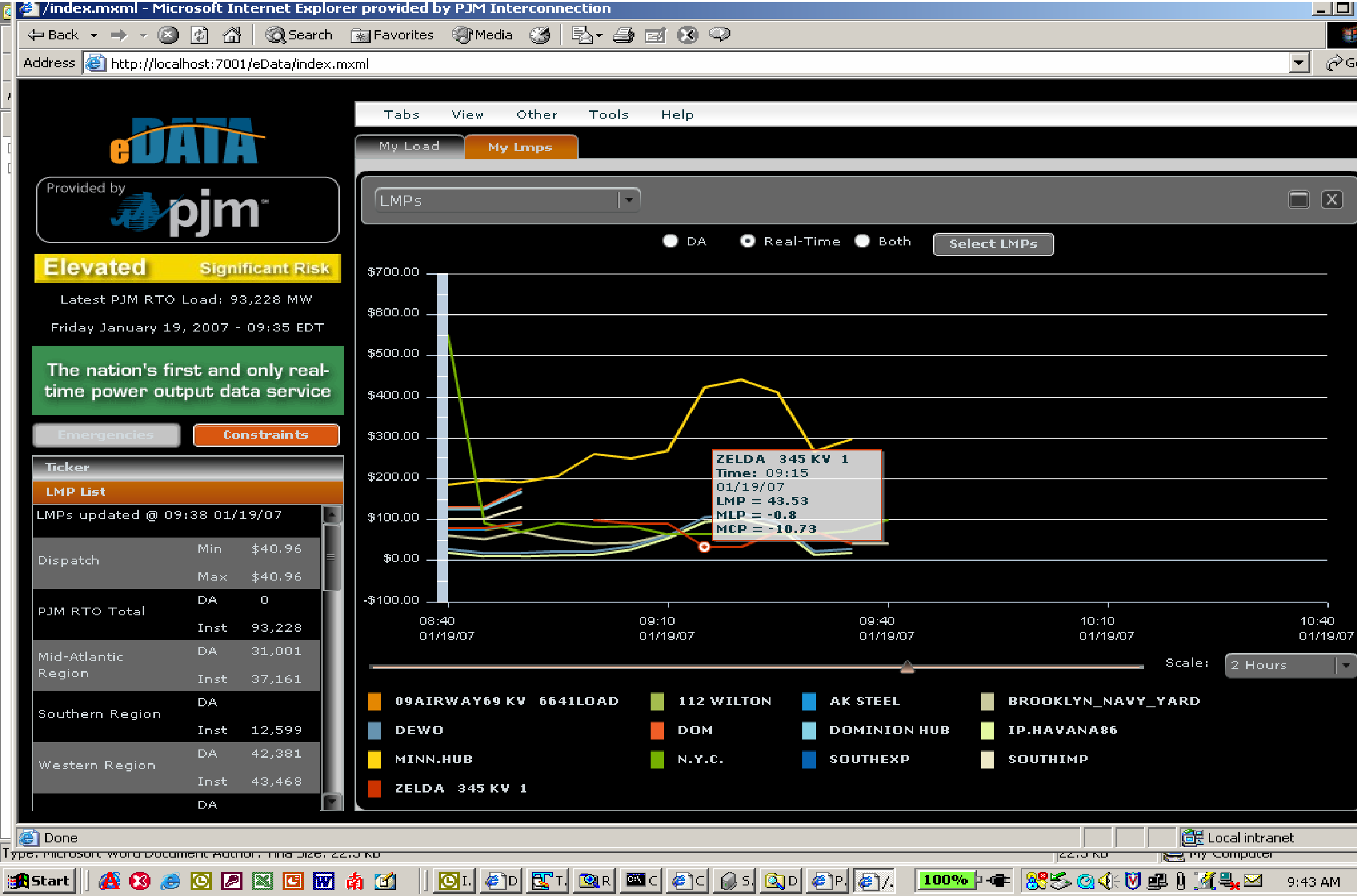
- Modified PJM Settlement Reports
  - Monthly LMP Postings (DA, RT, and FTR Zonal)
  - Daily Real-time Energy Transactions
  - Spot Market Energy Summary
  - Congestion Summary
  - Explicit Congestion Charges
  - FTR Target Allocations
  - Load Response Monthly Summary
  - Energy Congestion Losses Charges Reconciliation (was formerly just Energy Reconciliation)

- Transmission Losses Definition
- Marginal Loss Calculation
- Loss Surplus Allocation
- Business Examples
- Load Carve-Out Process Changes
- Settlements Changes
- PJM Application Changes
- Next Steps

eData	Posting Components of the LMP eDataFeed
eMKT	Posting Components of the LMP Change to Demand Bidding strategy. MINOR CHANGE TO MUI
eSchedule	EDC Load Carve-Out process impacts New/Modified Reports
eMTR	Load De-Ration procedure added and additional data displayed Meter Correction Charge reports moved to eSchedules
eFTR	Congestion Price will be used in the settlement calculation NO CHANGE to MUI
Load Response	Loss Value Definition NO CHANGE TO MUI
eCapacity	No Application Changes
EES	No Application Changes
eDART	No Application Changes
eGads	No Application Changes

- Provide means to display the marginal loss information by component
- eDataFeed will Include means to query PJM for marginal loss information (loss component of price)

eData – Test Screen Shot



- Include the marginal loss effect into the Day-Ahead formulation
- Add the posting of components of Day-Ahead LMPs to eMKT
  - Total LMP, Loss Price, Congestion Price
- Modifications to XML queries to download all three LMP components.

Total LMP, Loss Price, Congestion Price

PJM eSuite - Microsoft Internet Explorer provided by PJM Interconnection

Address https://testweb.pjm.com/mui/index.htm

eSUITE — PJM - Valley Forge, Pa. 10:20EST — > Login > Upload > E-mail

(mm/dd/yyyy) Change Date

> CAM
> eCapacity
> eData
> EES
> eFTR
> eMKT
> eMTR
> eRPM
> eSchedules
> eSuite Messages
> Load Response
> MSRS
> OASIS

Non - eSuite Tools

> eDART
> eGADS
> eFuel
> Emerg. Procedures

Public
Generator
Demand
Admin

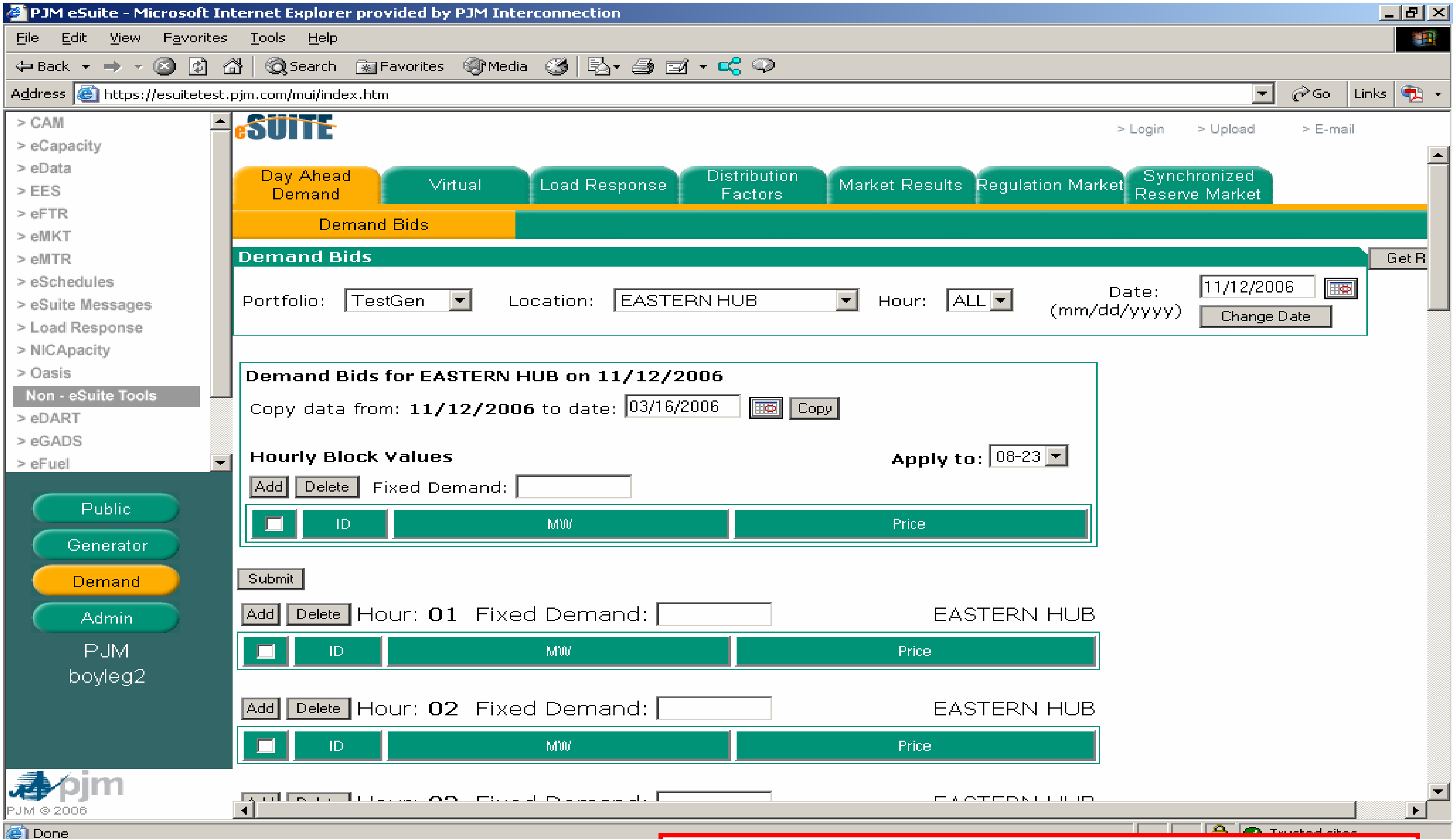
PJM
baizmantest

PJM © 2007

Day-Ahead Prices For: 01/10/2007

Location	1/13	2/14	3/15	4/16	5/17	6/18	7/19	8/20	9/21
AECO	23.56 0.99 0.00	23.33 0.95 0.00	23.03 0.92 0.00	23.35 0.93 0.00	24.32 1.01 0.00	28.05 1.29 0.32	46.38 2.22 3.35	54.51 2.49 0.48	46.77 2.10
	34.81 1.55 3.92	34.65 1.48 4.75	32.49 1.39 3.99	33.56 1.36 5.38	41.54 1.60 9.69	68.10 2.64 17.31	67.37 3.09 7.48	61.25 2.61 10.37	51.31 2.34
	1/13	2/14	3/15	4/16	5/17	6/18	7/19	8/20	9/21
AEP	22.50 -0.07 0.00	22.30 -0.08 0.00	22.07 -0.04 0.00	22.36 -0.06 0.00	23.21 -0.10 0.00	25.50 -0.14 -0.80	36.56 -0.17 -4.08	50.48 0.13 -1.19	44.82 0.15
	28.04 -0.13 -1.17	26.88 -0.15 -1.39	25.96 -0.14 -1.01	25.26 -0.16 -1.40	27.18 -0.25 -2.82	43.17 -0.15 -4.83	55.03 0.06 -1.83	45.71 -0.05 -2.51	39.76 -0.16
	1/13	2/14	3/15	4/16	5/17	6/18	7/19	8/20	9/21
APS	22.78 0.21 0.00	22.65 0.27 0.00	22.38 0.27 0.00	22.69 0.27 0.00	23.58 0.27 0.00	26.37 0.28 -0.35	39.15 0.37 -2.03	51.33 0.31 -0.52	44.97 0.30
	28.42 0.26 -1.18	27.21 0.21 -1.42	26.21 0.18 -1.08	25.47 0.14 -1.49	27.45 0.15 -2.95	43.25 0.21 -5.11	55.10 0.28 -1.98	45.81 0.26 -2.72	39.99 0.22
	1/13	2/14	3/15	4/16	5/17	6/18	7/19	8/20	9/21
BGE	22.69 0.12 0.00	22.51 0.13 0.00	22.24 0.13 0.00	22.55 0.13 0.00	23.45 0.14 0.00	27.99 0.20 1.35	47.02 0.29 5.92	53.88 0.31 2.03	44.93 0.26
	28.37 0.19 -1.16	27.17 0.17 -1.42	26.15 0.16 -1.12	25.43 0.14 -1.53	28.37 0.17 -2.05	43.16 0.26 -5.25	55.04 0.32 -2.08	45.69 0.27 -2.85	40.77 0.24
	1/13	2/14	3/15	4/16	5/17	6/18	7/19	8/20	9/21
COMED	22.31 -0.26 0.00	22.00 -0.38 0.00	21.74 -0.37 0.00	22.06 -0.37 0.01	22.87 -0.45 0.01	25.15 -0.45 -0.84	35.81 -0.70 -4.30	49.80 -0.48 -1.26	44.67 0.00
	28.06 -0.18 -1.10	27.16 -0.15 -1.11	26.06 -0.10 -0.95	25.41 -0.08 -1.33	27.41 -0.16 -2.68	45.26 0.24 -3.13	55.56 0.49 -1.73	46.11 0.21 -2.37	39.92 -0.09
	1/13	2/14	3/15	4/16	5/17	6/18	7/19	8/20	9/21
DAY	22.52 -0.05 0.00	22.32 -0.06 0.00	22.05 -0.06 0.00	22.36 -0.06 0.00	23.23 -0.08 0.00	25.46 -0.08 -0.90	36.15 -0.10 -4.56	50.14 -0.06 -1.34	44.63 -0.04
	28.14 -0.06 -1.14	26.99 -0.07 -1.36	26.06 -0.07 -0.98	25.38 -0.07 -1.37	27.39 -0.09 -2.77	43.37 -0.06 -4.72	54.99 -0.02 -1.79	45.76 -0.06 -2.45	39.87 -0.08
	1/13	2/14	3/15	4/16	5/17	6/18	7/19	8/20	9/21
DOM	23.40 0.83 0.00	23.37 0.99 0.00	23.07 0.96 0.00	23.46 1.04 0.00	24.52 1.21 0.00	29.07 1.55 1.08	47.46 2.00 4.65	55.61 2.45 1.62	46.49 1.82
	29.06 1.03 -1.31	27.79 0.93 -1.56	26.75 0.81 -1.17	25.90 0.70 -1.62	28.16 0.92 -3.01	43.90 1.26 -5.51	56.38 1.72 -2.14	46.90 1.57 -2.94	41.20 1.41
	1/13	2/14	3/15	4/16	5/17	6/18	7/19	8/20	9/21
DPL	22.77 0.20 0.00	22.57 0.19 0.00	22.29 0.18 0.00	22.61 0.19 0.00	23.52 0.21 0.00	27.10 0.28 0.38	45.07 0.48 3.78	52.59 0.48 0.57	45.05 0.38
	33.75 0.30 4.11	33.71 0.29 5.00	31.62 0.28 4.23	32.77 0.25 5.70	40.78 0.31 10.22	66.95 0.46 18.34	65.27 0.53 7.94	59.73 0.45 11.01	49.80 0.40
	1/13	2/14	3/15	4/16	5/17	6/18	7/19	8/20	9/21
DUQ	22.20 -0.37 0.00	22.00 -0.38 0.00	21.75 -0.36 0.00	22.02 -0.40 0.00	22.83 -0.48 0.00	24.37 -0.75 -1.32	32.86 -1.44 -6.51	48.06 -1.50 -1.98	43.43 -1.24
	27.39 -0.69 -1.26	26.29 -0.64 -1.49	25.46 -0.58 -1.07	24.74 -0.58 -1.50	26.40 -0.78 -3.07	41.59 -1.43 -5.13	53.24 -1.62 -1.94	44.15 -1.46 -2.66	38.38 -1.37
	1/13	2/14	3/15	4/16	5/17	6/18	7/19	8/20	9/21
JCPL	22.62 0.05 0.00	22.43 0.05 0.00	22.16 0.05 0.00	22.47 0.05 0.00	23.36 0.05 0.00	26.68 0.07 0.17	43.17 0.13 2.23	51.94 0.14 0.26	44.79 0.12
	33.10 0.10 3.66	32.82 0.09 4.31	30.78 0.08 3.59	31.59 0.07 4.70	38.79 0.08 8.46	62.61 0.14 14.32	63.07 0.16 6.11	56.81 0.14 8.40	47.86 0.12
	1/13	2/14	3/15	4/16	5/17	6/18	7/19	8/20	9/21
METED	22.65 0.08 0.00	22.45 0.07 0.00	22.19 0.08 0.00	22.50 0.08 0.00	23.39 0.08 0.00	26.91 0.11 0.36	42.91 0.19 1.91	52.31 0.22 0.55	44.84 0.17

Done — Trusted sites



No screen changes!
Demand bids should NOT reflect losses!

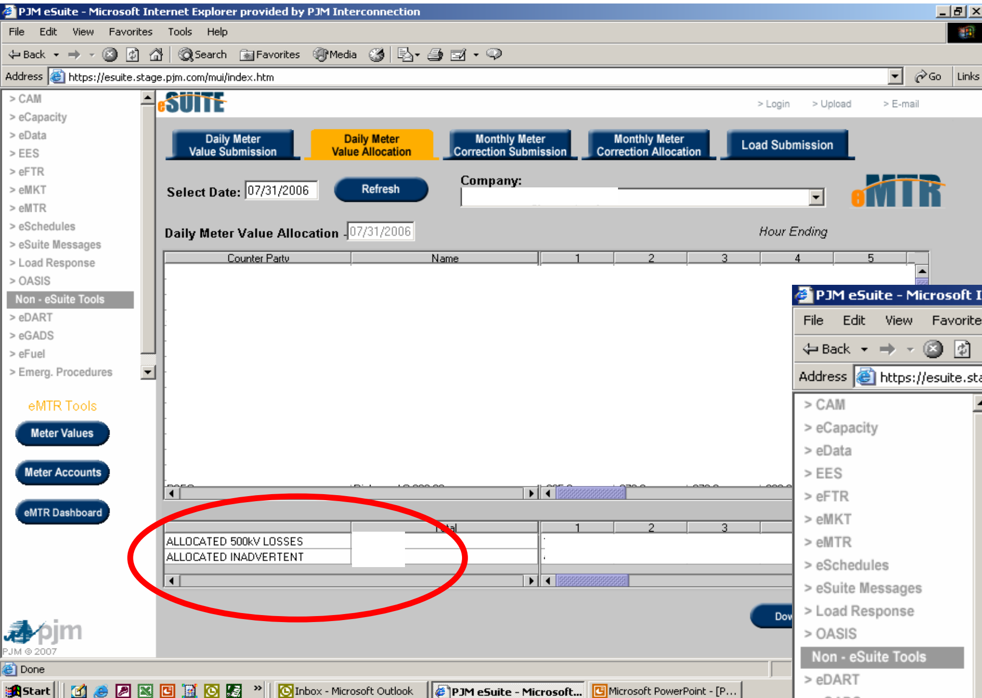
- Load Responsibility "load plus losses" data submitted in accordance with PJM eSchedules deadlines
  - "Lossless" load values will be determined by PJM using hourly EDC loss de-ration factors
  - EDCs may "carve-out" entire load to others same as today
  - eSchedule deadline changes being discussed by Market Settlements Working Group
- New report showing Load Responsibility eSchedule data with and without losses (under Interchange category)
- New report showing all EDCs' hourly loss de-ration factors (under Modeling Data)
- Other new and modified reports

- Create new procedure to calculate and store de-rated loss adjustment
- Add de-rated loss adjustment, load data (with and without losses), and applicable EDC loss de-ration factor to Load Submission screen
- Add EDC de-rated loss adjustment to Daily Meter Value Allocation screen

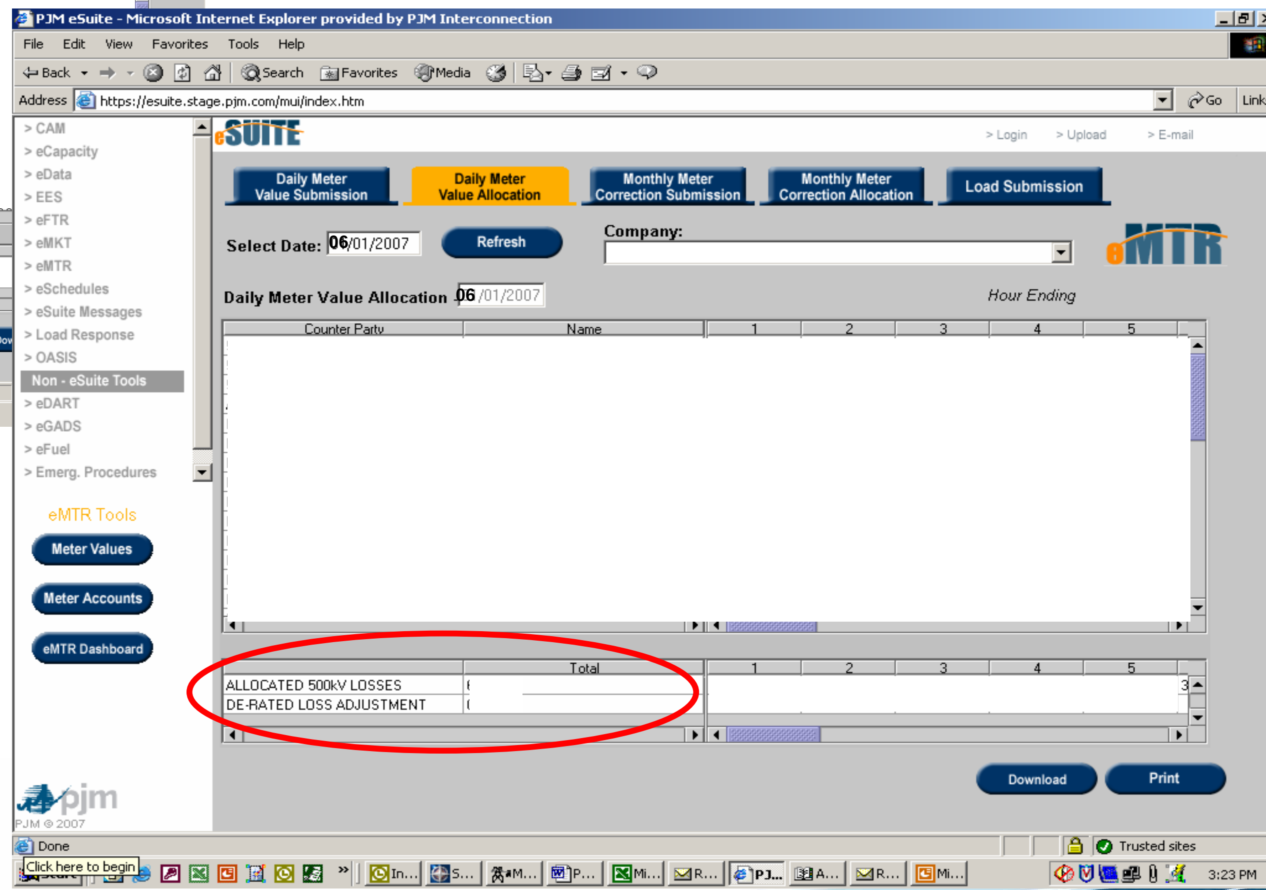
- Tie and generator meter data submitted in accordance with PJM eMTR deadlines
  - eMTR deadline changes being discussed by Market Settlements Working Group
- eMTR displays include the following additional hourly data available each day after the deadline:
  - PJM Mid-Atlantic EDC shares of 500 kV losses
  - EDC total “load with losses” values
  - EDC “de-rated loss adjustment” values
  - EDC total “load without losses” values
  - Hourly EDC “loss de-ration factors” (based on state-estimated losses)

eMTR Allocation Screen (for EDCs)

If the date selected is after the Marginal Losses implementation date, the Allocated Inadvertent row is replaced by De-rated Loss Adjustment.

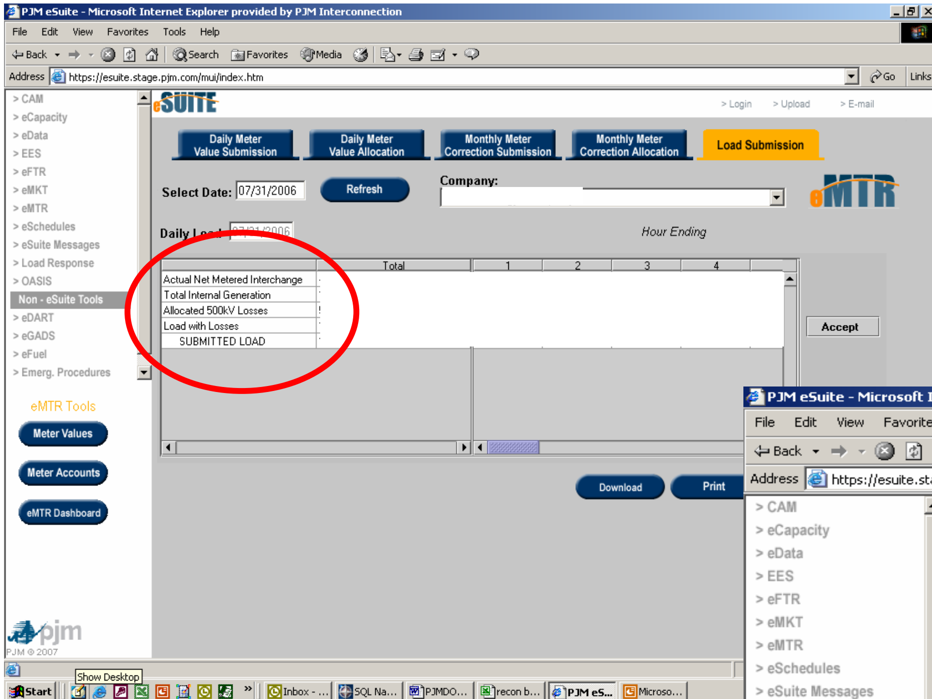


After 6/1/07

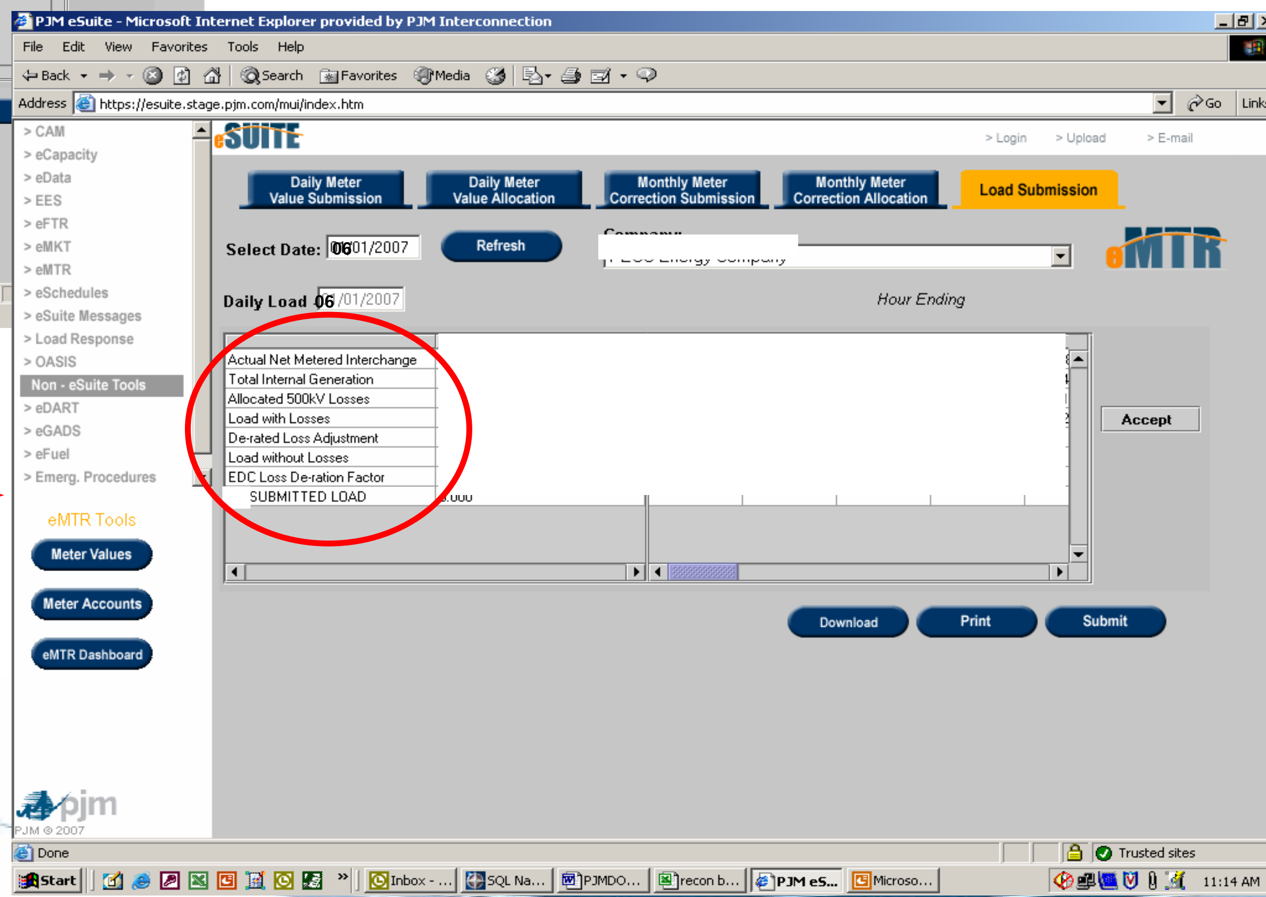


eMTR Load Submission Screen (for EDCs)

Calculated Load changes to Load with Losses and, if the date selected is after the Marginal Losses implementation date, De-rated Loss Adjustment, Load without Losses, and EDC Loss De-ration Factor are also shown.



After 6/1/07



- No changes to the user interface
- Congestion price will be used in settlements calculation for FTR Target Allocation
- Losses are not hedged by FTRs

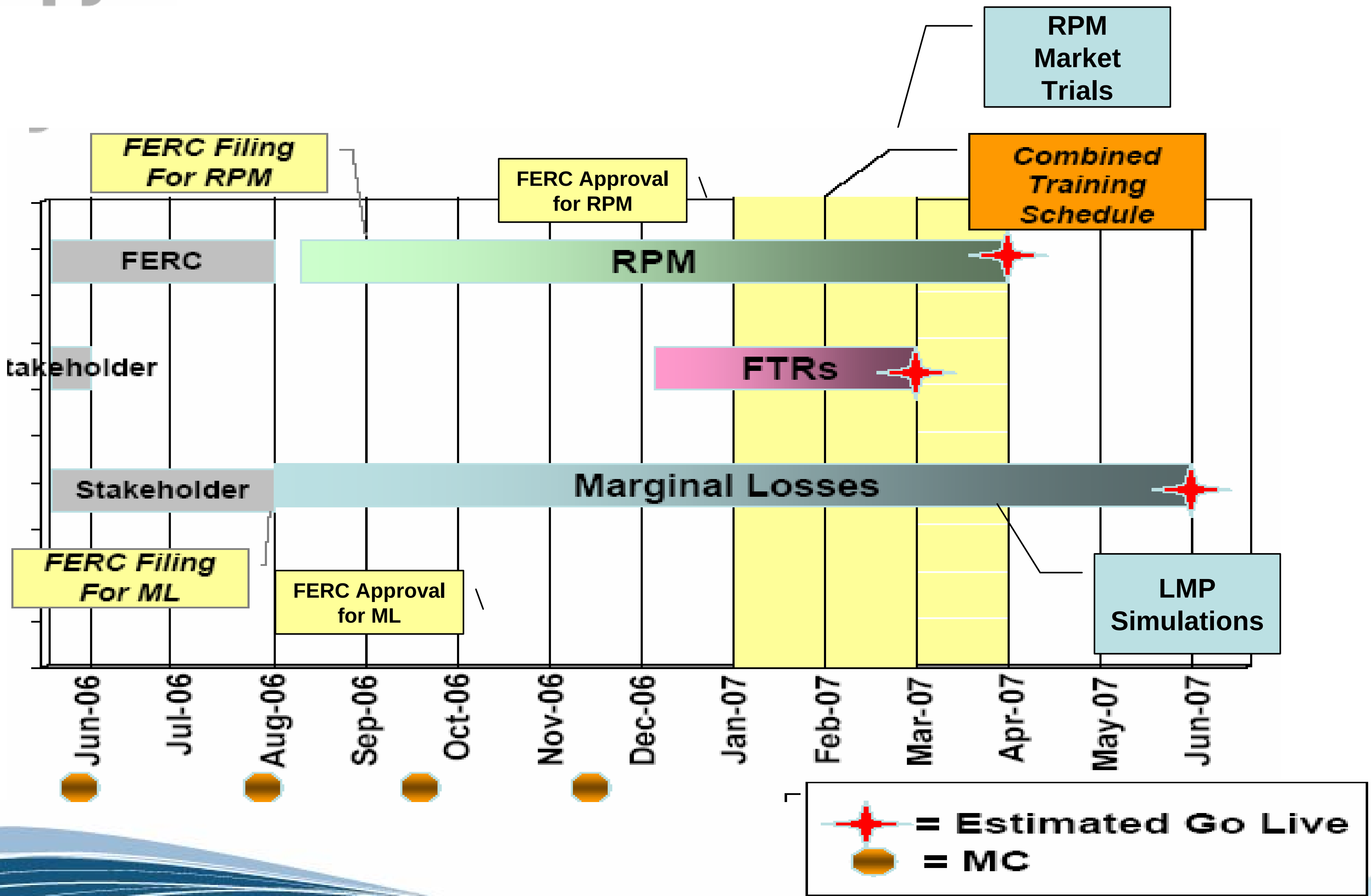
- No changes to the user interface
- Credits for day-ahead and real-time demand reductions
  - PJM will de-rate reduction (previously grossed up for losses) based on EDC Loss De-ration Factor
  - Credit based on “Lossless load”
- Charges allocated by zonal load ratio shares
  - Based on “Lossless load”

- No changes to the user interface
- Up-to congestion transactions continue to clear on the delta of total LMP
  - These look like "Up-to total price differences" transactions

- No major changes to application user interfaces
- LMP component breakdown will be available via eDATA, eDATAfeed and eMKT (Day-ahead)
- New and revised Market Settlement reports available via eSchedules
- Minor eMTR changes to show loss de-ration
- Day-ahead Demand Bids should not include losses following Marginal Loss implementation

- Transmission Losses Definition
- Marginal Loss Calculation
- Loss Surplus Allocation
- Business Examples
- Load Carve-Out Process Changes
- Settlements Changes
- PJM Application Changes
- Next Steps

Marginal Losses Implementation Timeline



- Documentation (ie Manuals, FAQs, and User Guides) will be ready and become available for review concurrent to the training schedule.
- Stakeholder review of the manuals at the PC, MIC, MRC, is expected to begin in February/March, 2007.
- Schedule Market Settlements Working Group Meetings in April & May, 2007 as readiness in addition to training sessions.

Combined Training Schedule

Session	City	Hotel	Dates	Course
In Person – Session I	King of Prussia	Crowne Plaza	Monday, February 12, 2007 Tuesday, February 13, 2007 Weds, February 14, 2007 Thurs, February 15, 2007	Annual FTR Auction Marginal Losses RPM (Full Day) RPM (Full Day)
Virtual – Session I			Tuesday, February 20, 2007 Weds, February 21, 2007 Thursday, February 22, 2007	Annual FTR Auction Marginal Losses RPM
In Person – Session II	Columbus	Hyatt Downtown	Monday, February 26, 2007 Tuesday, February 27, 2007 Weds, February 28, 2007 Thursday, March 1, 2007	Annual FTR Auction Marginal Losses RPM (Full Day) RPM (Full Day)
In Person	Houston	Marriot Intercont.	Tuesday, March 6, 2007 Weds, March 7, 2007	RPM (Full Day) RPM (Full Day)
In Person – Session III	Malvern	Desmond	Tuesday, March 13, 2007 Weds., March 14, 2007 Thursday, March 15, 2007	Marginal Losses RPM (Full Day) RPM (Full Day)
In Person – Session IV	Chicago	Hyatt	Monday, March 19, 2007 Tuesday, March 20, 2007	RPM Full Day) RPM (Full Day)
COMBO - Virtual Session II	PJM	Tech Center	Monday, March 26, 2007 Tuesday, March 27, 2007	Marginal Losses RPM

Agenda

- Transmission Losses Definition
- Marginal Loss Calculation
- Loss Surplus Allocation
- Business Examples
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- Settlements Changes
- PJM Application Changes
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