

Power System Economics and Market Modeling



M2: Optimal Power Flow



2001 South First Street
Champaign, Illinois 61820
+1 (217) 384.6330

support@powerworld.com
<http://www.powerworld.com>

PowerWorld Simulator OPF and Locational Marginal Prices



- This Section will:
 - Provide background on Optimal Power Flow (OPF) Problem
 - Show how OPF is implemented in PowerWorld Simulator OPF
 - Demonstrate how Simulator OPF can be used to solve small and large problems
 - Provide hands-on Simulator OPF examples
 - Talk about splitting the cost at a bus into Energy, Losses, and Congestion
 - Demonstrate OPF results/visualization on a large system

Optimal Power Flow Overview



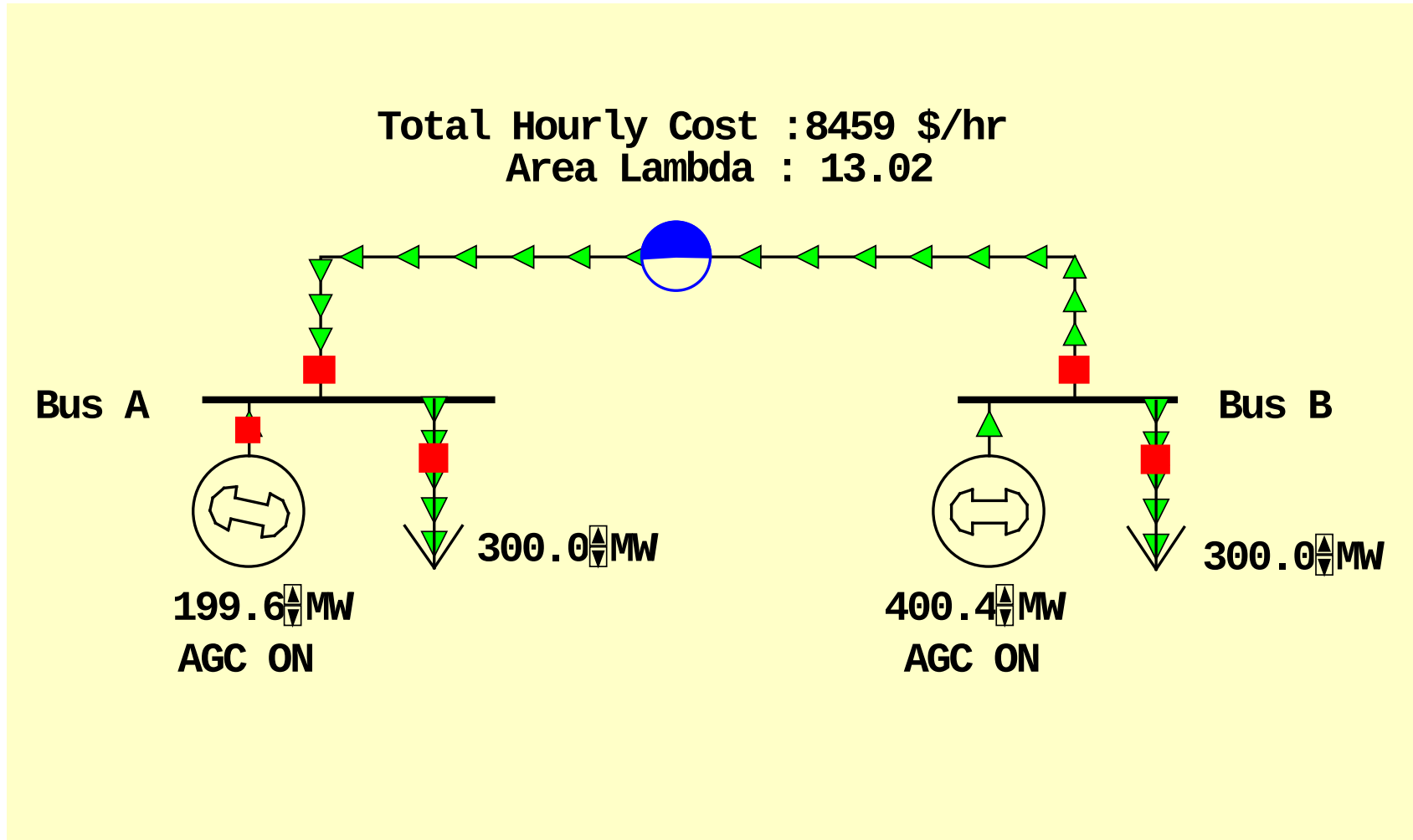
- The goal of an optimal power flow (OPF) is to determine the “best” way to instantaneously operate a power system.
- Usually “best” = minimizing operating cost.
- OPF considers the impact of the transmission system
- We’ll introduce OPF initially ignoring the transmission system

“Ideal” Power Market - No Transmission System Constraints



- Ideal power market is analogous to a lake. Generators supply energy to lake and loads remove energy.
- Ideal power market has no transmission constraints
- Single marginal cost associated with enforcing the constraint that supply = demand
 - buy from the least cost unit that is not at a limit
 - this price is the marginal cost

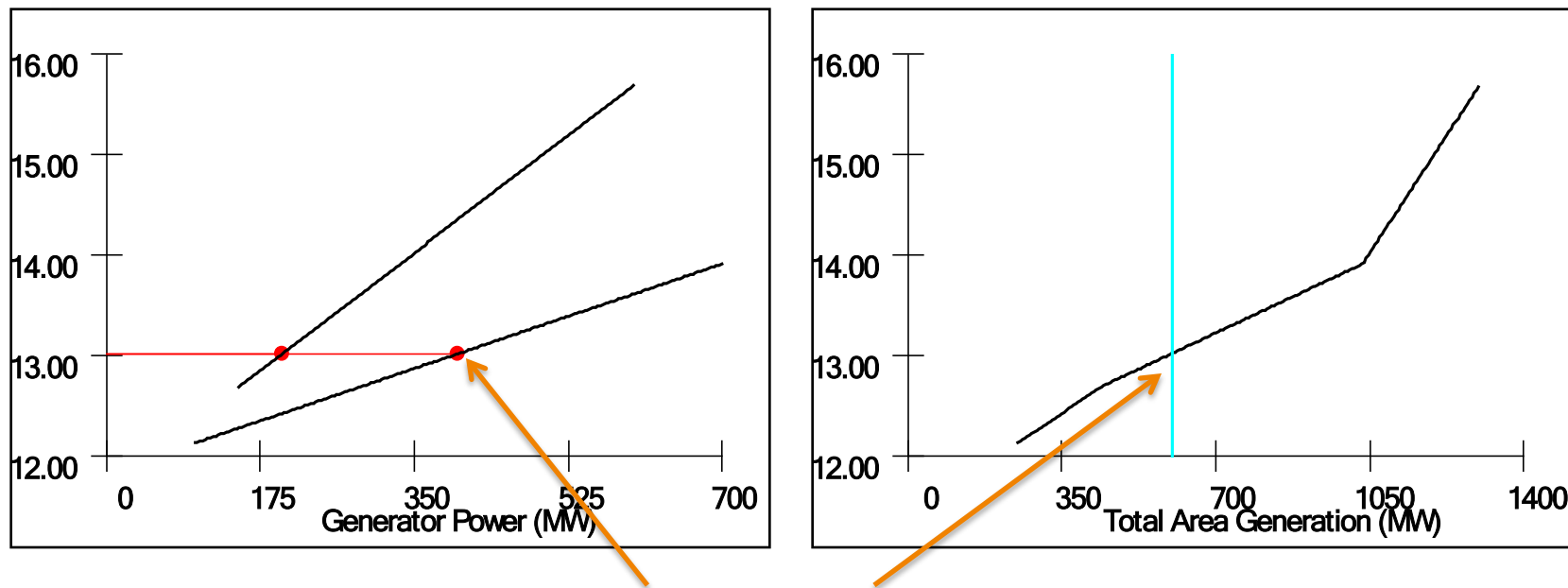
Two Bus Example



Market Marginal Cost is Determined from Net Gen Costs

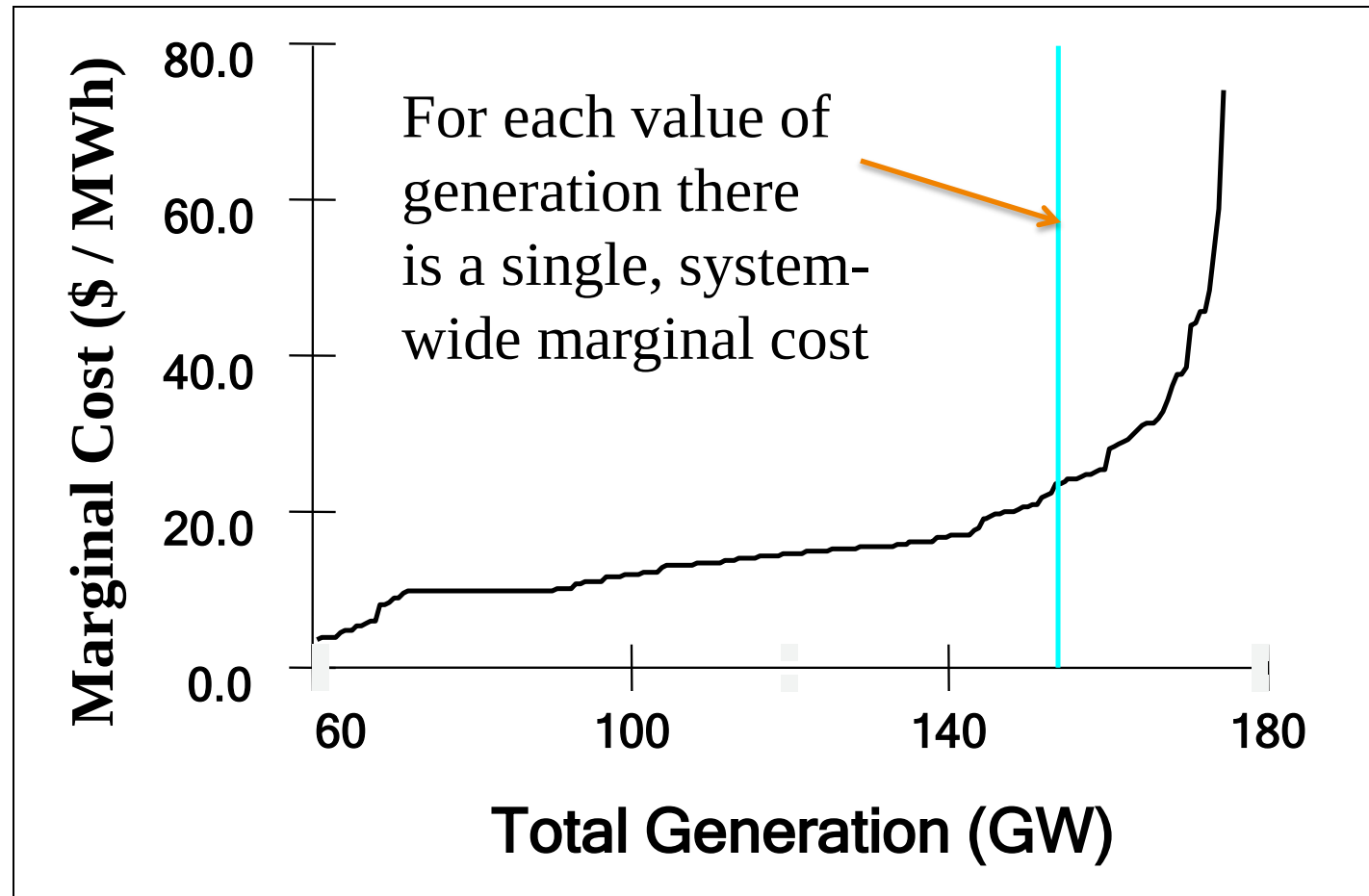


- Below are graphs associated with this two-bus system. The graph on the left shows the marginal cost for each of the generators. The graph on the right shows the system supply curve, assuming the system is optimally dispatched.



Current generator operating point

Variation in Marginal Cost for Northeast U.S.



Real Power Market



- Different operating regions impose constraints -- total demand in region must equal total supply
- Transmission system imposes constraints on the market
- Marginal costs become localized
- Requires solution by an optimal power flow

Optimal Power Flow (OPF)



- Minimize cost function, such as operating cost, taking into account realistic equality and inequality constraints
- Equality constraints
 - Bus real and reactive power balance
 - Generator voltage setpoints
 - Area MW interchange
 - Transmission line/transformer/interface flow limits

Optimal Power Flow (OPF)



- Inequality constraints
 - Transmission line/transformer/interface flow limits
 - Generator MW limits
 - Generator reactive power capability curves
 - Bus voltage magnitudes (not yet implemented in Simulator OPF)
- Available Controls
 - Generator MW outputs
 - Load MW demands
 - Phase shifters
 - Area Transactions

OPF Solution Methods



- Non-linear approach using Newton's method
 - Handles marginal losses well, but is relatively slow and has problems determining binding constraints
- Linear Programming (LP)
 - Fast and efficient in determining binding constraints, but has difficulty with marginal losses

Primal LP OPF Solution Algorithm



- Solution iterates between
 - Solving a full ac power flow solution
 - Enforces real/reactive power balance at each bus
 - Enforces generator reactive limits
 - System controls are assumed fixed
 - Takes into account non-linearities
 - solving a primal LP
 - Changes system controls to enforce linearized constraints while minimizing cost (or control change)

LP Solution



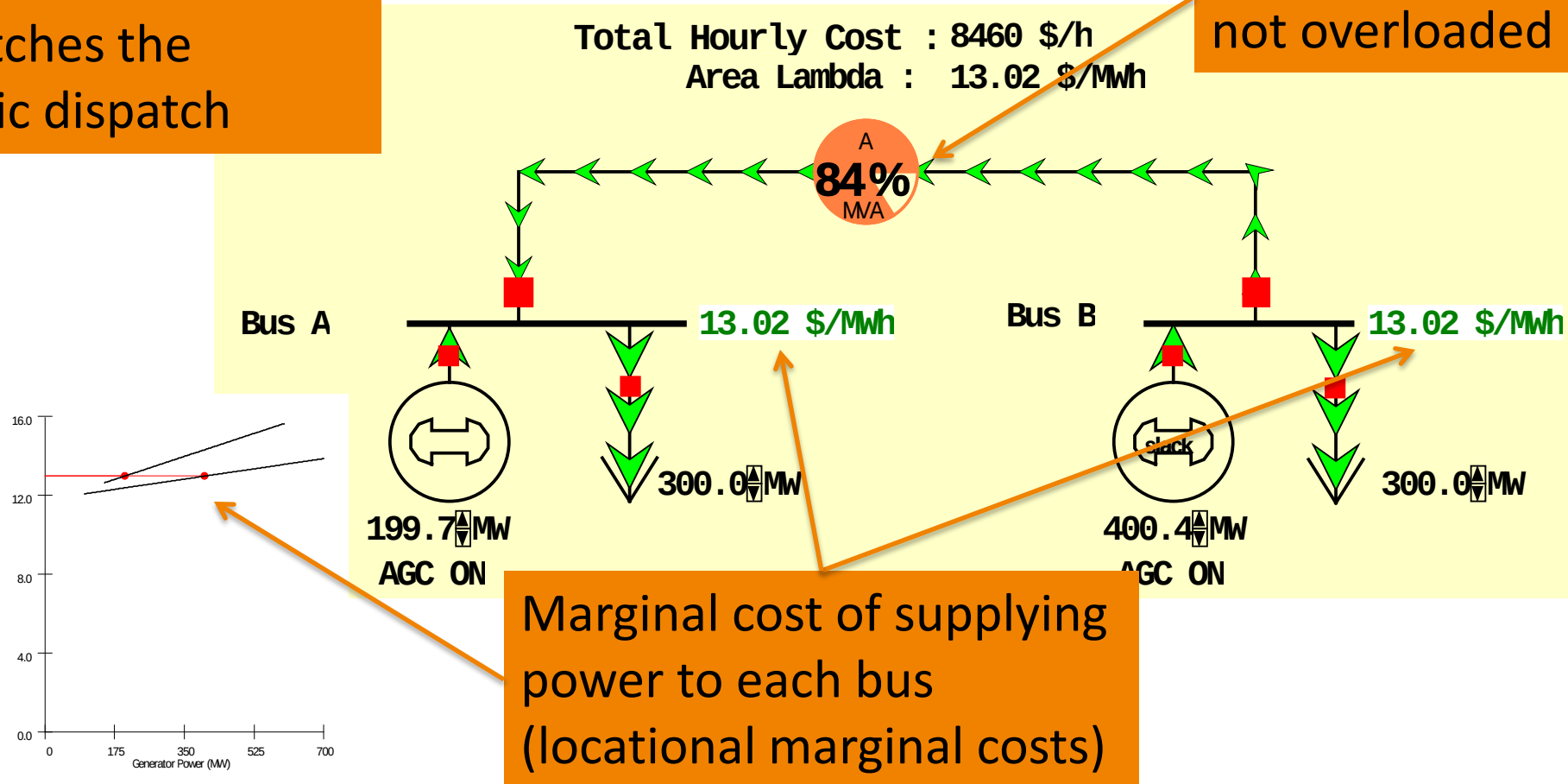
- Problem is setup to be initially feasible through the use of slack variables
 - Slack variables have high marginal costs; LP algorithm will remove them if at all possible
- Slack variables are used to enforce
 - Area/super area MW constraints
 - MVA line/transformer constraints
 - MW interface constraints

Two Bus Example - No Constraints

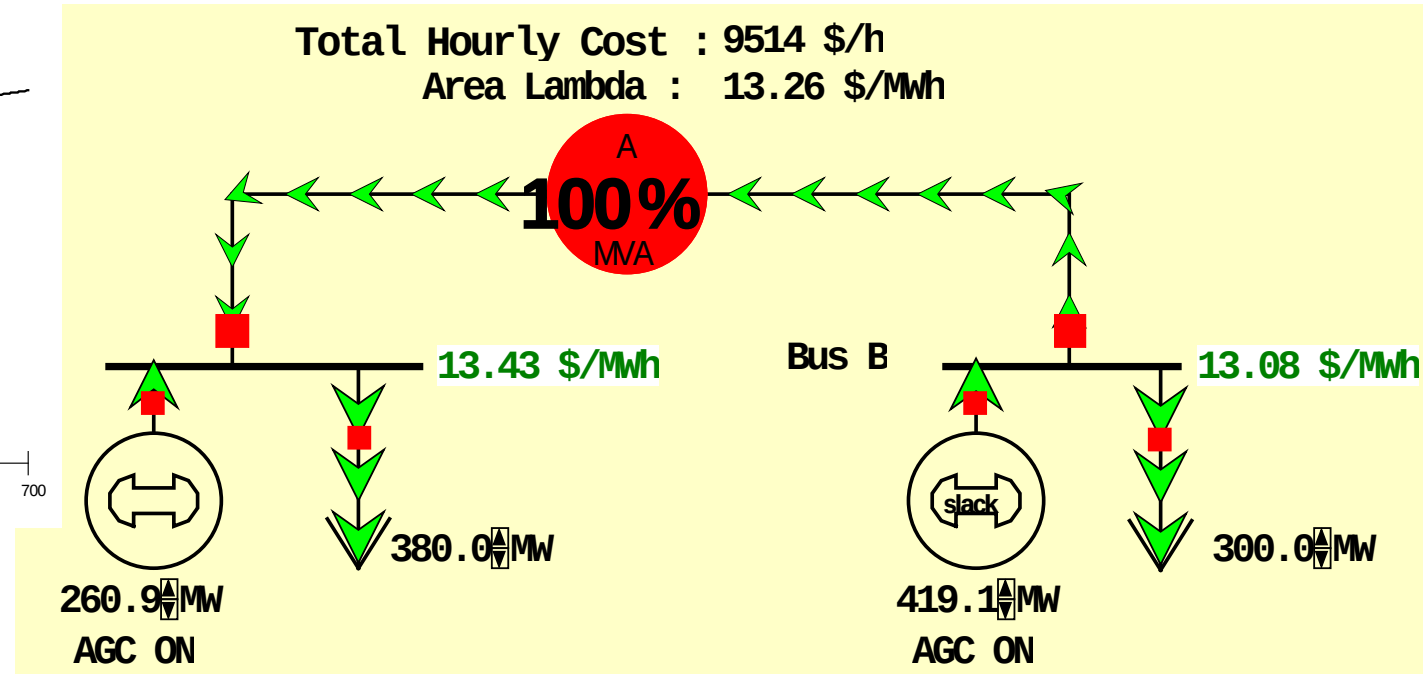
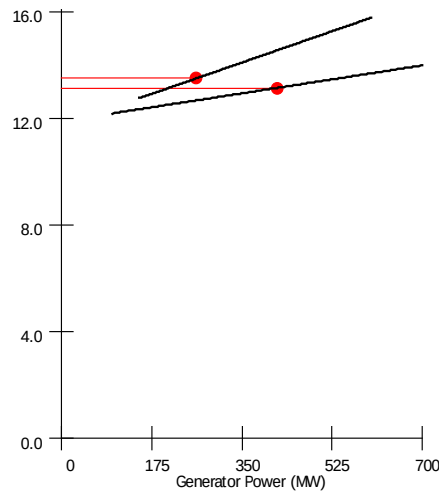


With no overloads the OPF matches the economic dispatch

Transmission line is not overloaded



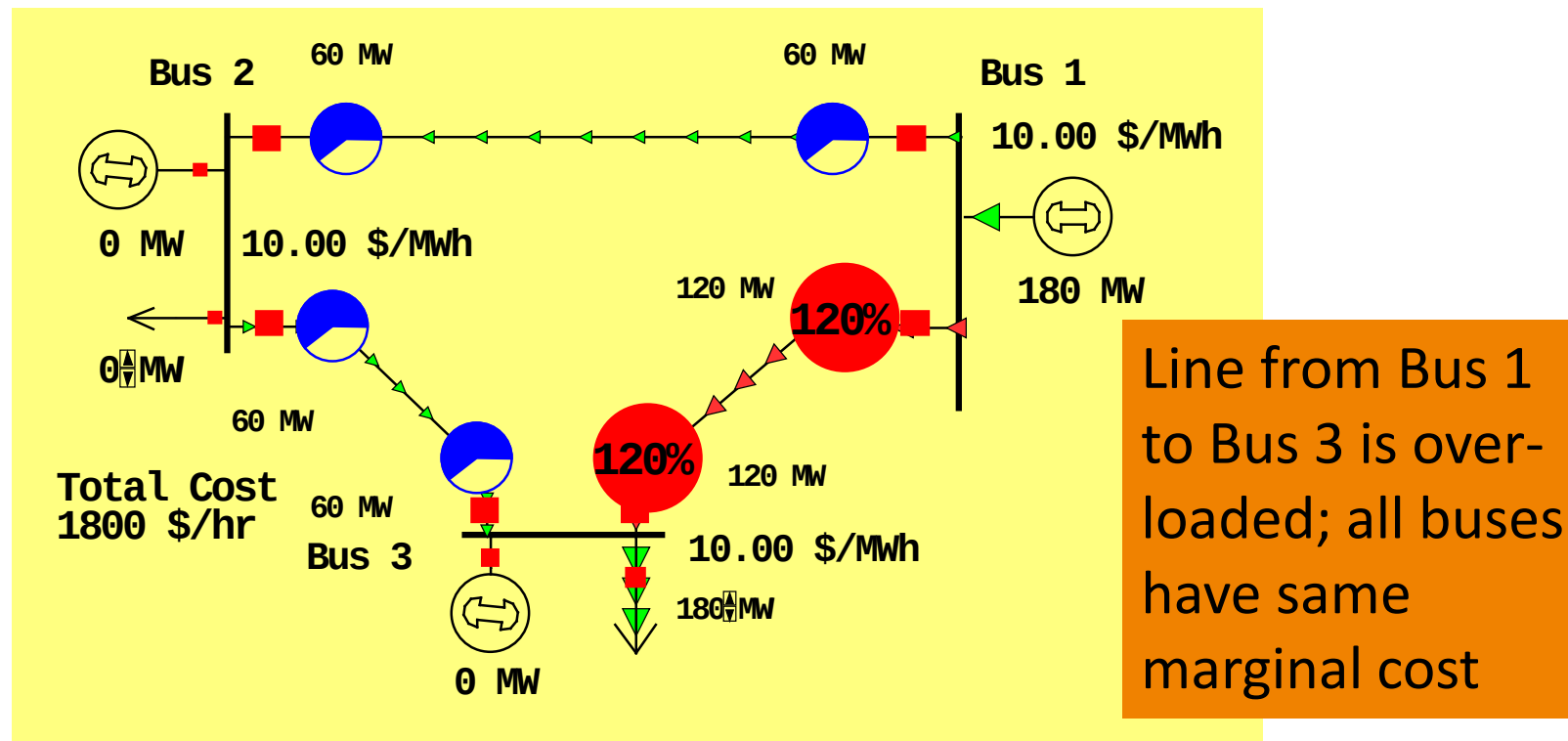
Two Bus Example with Constrained Line



With the line loaded to its limit, additional load at Bus A must be supplied locally, causing the marginal costs to diverge.

Hands-on: Three Bus Case

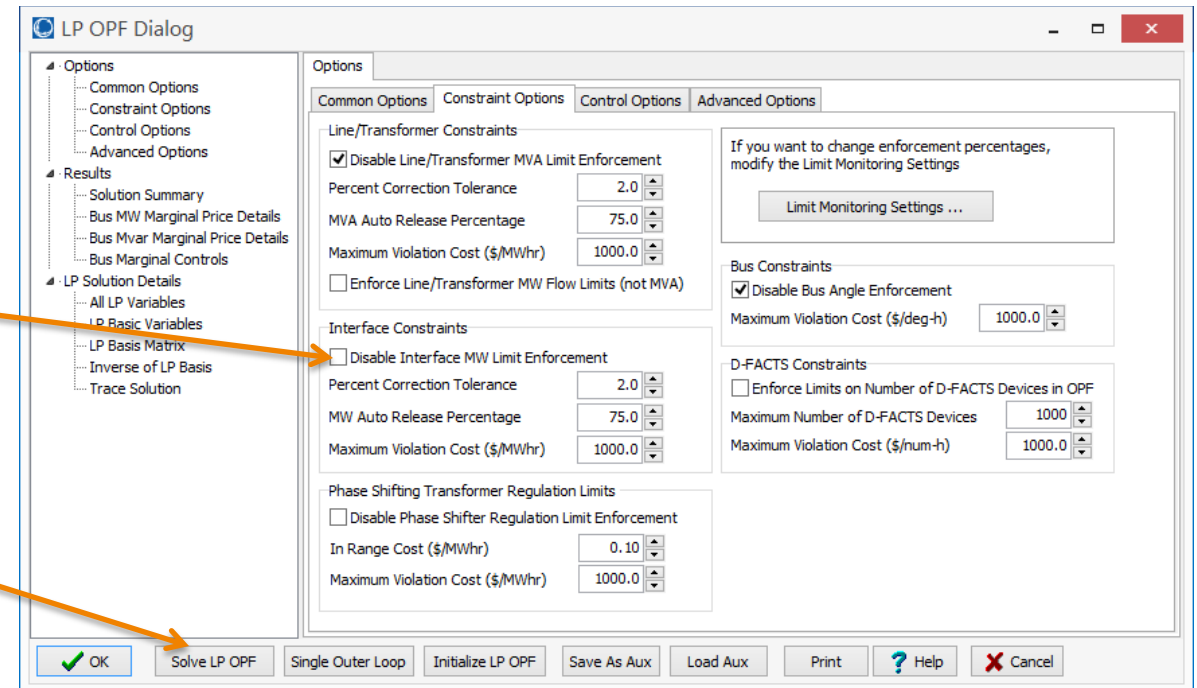
- Load B3LP case. In Run Mode go to the **Add Ons** ribbon tab. In the **Optimal Power Flow** ribbon group select **Primal LP** to solve the case. (Initially line limits are not enforced.)



Hands-on: Three Bus Case



- To enforce line limits:
 - From the OPF ribbon group, Select **OPF Options and Results** to view the main options dialog
 - Select **Constraint Options Tab**
 - Uncheck **Disable Line/Transformer MVA Limit Enforcement**
 - Click **Solve LP OPF**



Three Bus (B3) Example



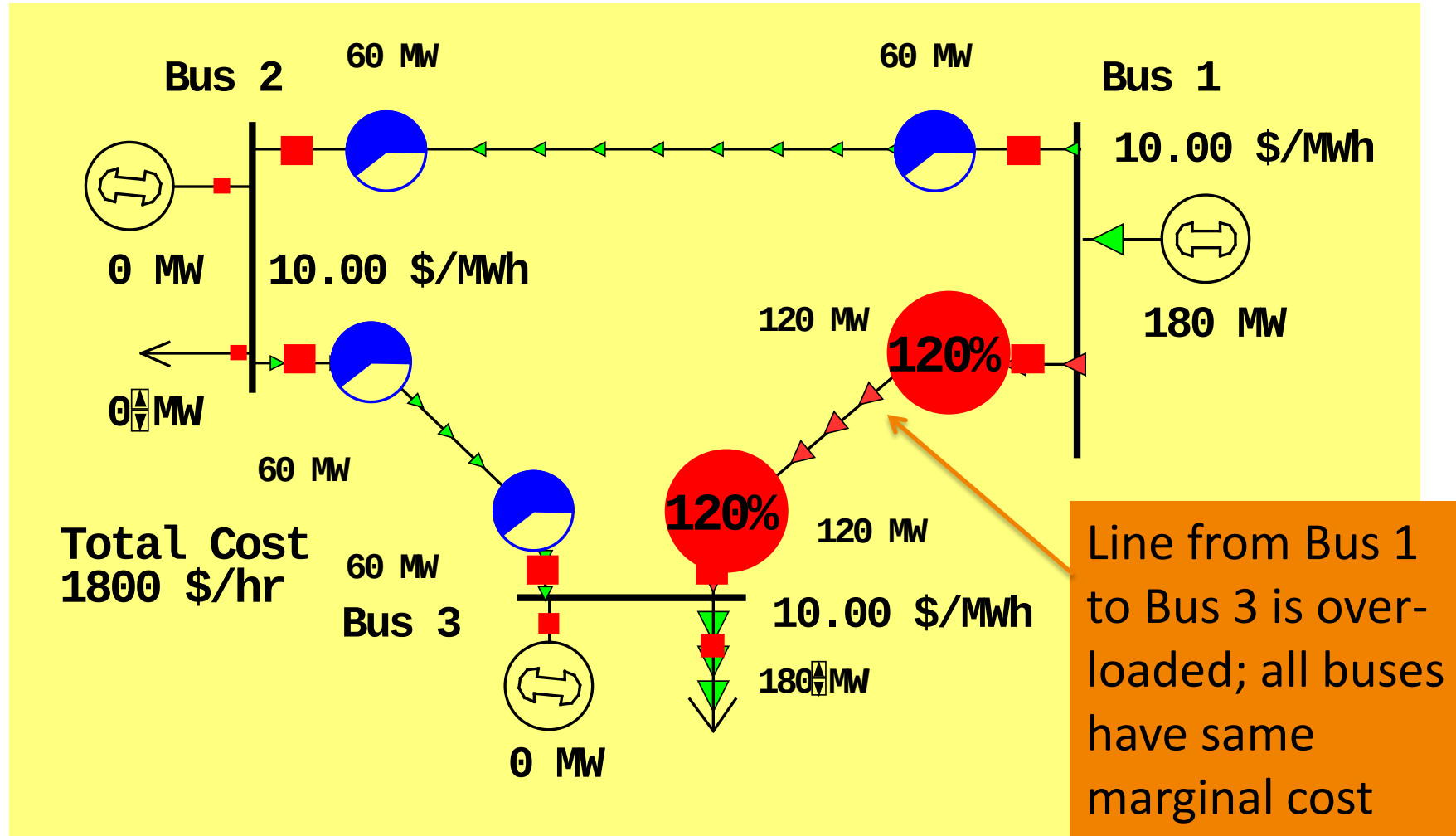
- Consider a three bus case (bus 1 is system slack), with all buses connected through 0.1 pu reactance lines, each with a 100 MVA limit
- Let the generator marginal costs be
 - Bus 1: 10 \$ / MWhr; Range = 0 to 400 MW
 - Bus 2: 12 \$ / MWhr; Range = 0 to 400 MW
 - Bus 3: 20 \$ / MWhr; Range = 0 to 400 MW
- Assume a single 180 MW load at bus 3

Solving the LP OPF



- All LP OPF commands are accessed from the LP OPF menu item.
- Before solving, we first need to specify what constraints to enforce
 - Select **OPF Case Info** → **OPF Areas** to turn on area constraint; set **AGC Status** to OPF
 - Initially we'll disable line MVA enforcement
 - Select **OPF Case Info** → **Options and Results** and go to the **Constraint Options** tab
 - Check **Disable Line/Transformer MVA Limit Enforcement**

B3 with Line Limits NOT Enforced



Line Limit Enforcement



- Previous LP tableau was

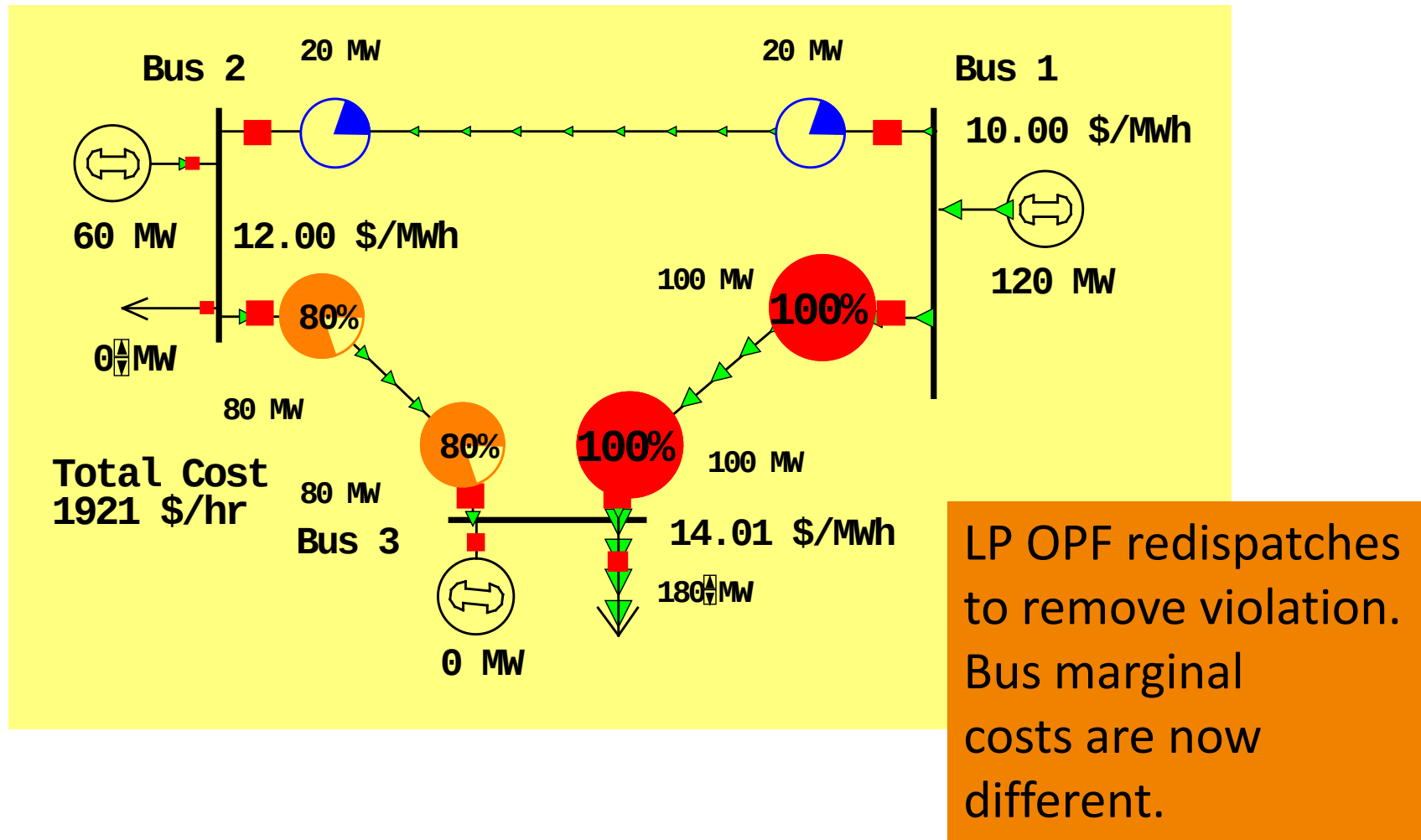
PG1	PG2	PG3	S1	b
1.00	1.00	1.00	1.00	0.00

- Line limit tableau is

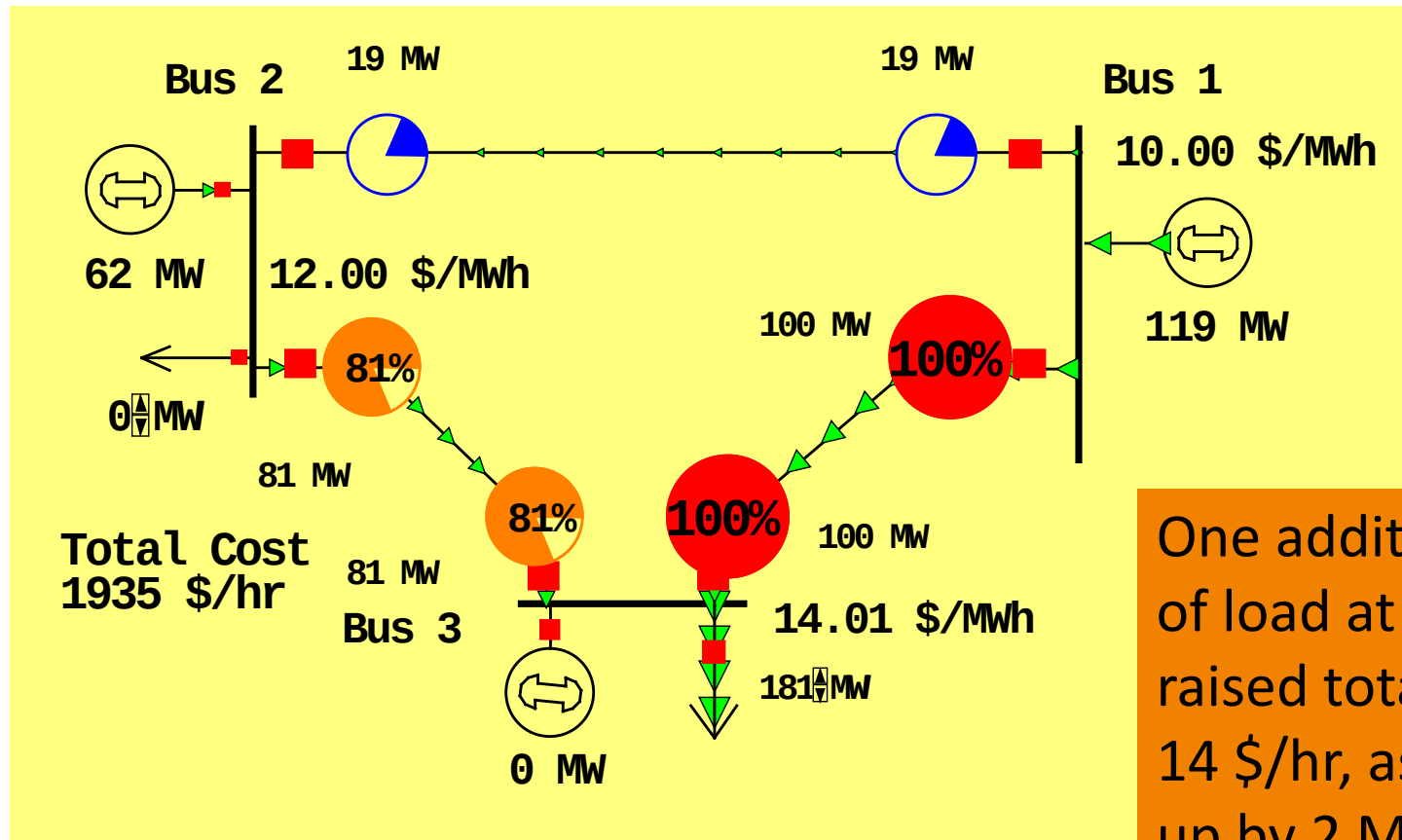
PG1	PG2	PG3	S1	S2	b
1.00	1.0	1.00	1.00	0.00	0.00
0.00	-0.33	-0.66	0.00	1.00	-0.20

- First row is from enforcing area constraint
- Second row is from enforcing the line flow MVA constraint

B3 with Line Limits Enforced



Verify Bus 3 Marginal Cost



One additional MW of load at bus 3 raised total cost by 14 \$/hr, as G2 went up by 2 MW and G1 went down by 1MW

Why is bus 3 LMP = \$14 /MWh



- All lines have equal impedance. Power flow in a simple network distributes inversely to impedance of path.
 - For bus 1 to supply 1 MW to bus 3, 2/3 MW would take direct path from 1 to 3, while 1/3 MW would “loop around” from 1 to 2 to 3.
 - Likewise, for bus 2 to supply 1 MW to bus 3, 2/3 MW would go from 2 to 3, while 1/3 MW would go from 2 to 1 to 3.

Why is bus 3 LMP = \$ 14 / MWh?



- With the line from 1 to 3 limited, no additional power flows are allowed on it.
- To supply 1 more MW to bus 3 we need
$$Pg1 + Pg2 = 1 \text{ MW}$$
$$2/3 Pg1 + 1/3 Pg2 = 0; \text{ (no more flow on 1-3)}$$
- Solving requires we up $Pg2$ by 2 MW and drop $Pg1$ by 1 MW -- a net increase of \$14.

Marginal Cost of Enforcing Constraints



- Similarly to the bus marginal cost, you can also calculate the marginal cost of enforcing a line constraint
- For a transmission line, this represents the amount of system savings which could be achieved if the MVA rating was increased by 1.0 MVA.

MVA Marginal Cost



- Choose **OPF Case Info** → **OPF Lines and Transformers** to bring up the OPF Constraint Records dialog
- Look at the column “MVA Marginal Cost”

The screenshot shows the 'OPF Constraints Records' dialog box with the 'Branch' tab selected. The 'Lines/Transformers' sub-tab is active, displaying a table of constraints. An orange arrow points to the 'MVA Marg. Cost' column, which has a value of 6.0 for the selected line.

	From Number	From Name	From Area Name	To Number	To Name	To Area Name	Circuit	Monitor	Max MVA	% of MVA Limit (Max)	Lim MVA	MVA Marg. Cost	Constraint Status
1	1	1	Home	2	2	Home	1	YES	19.8	19.8	100.0		
2	1	1	Home	3	3	Home	1	YES	100.0	100.0	100.0	6.0	Binding
3	2	2	Home	3	3	Home	1	YES	80.2	80.2	100.0		

Why is MVA Marginal Cost \$6/MVAhr



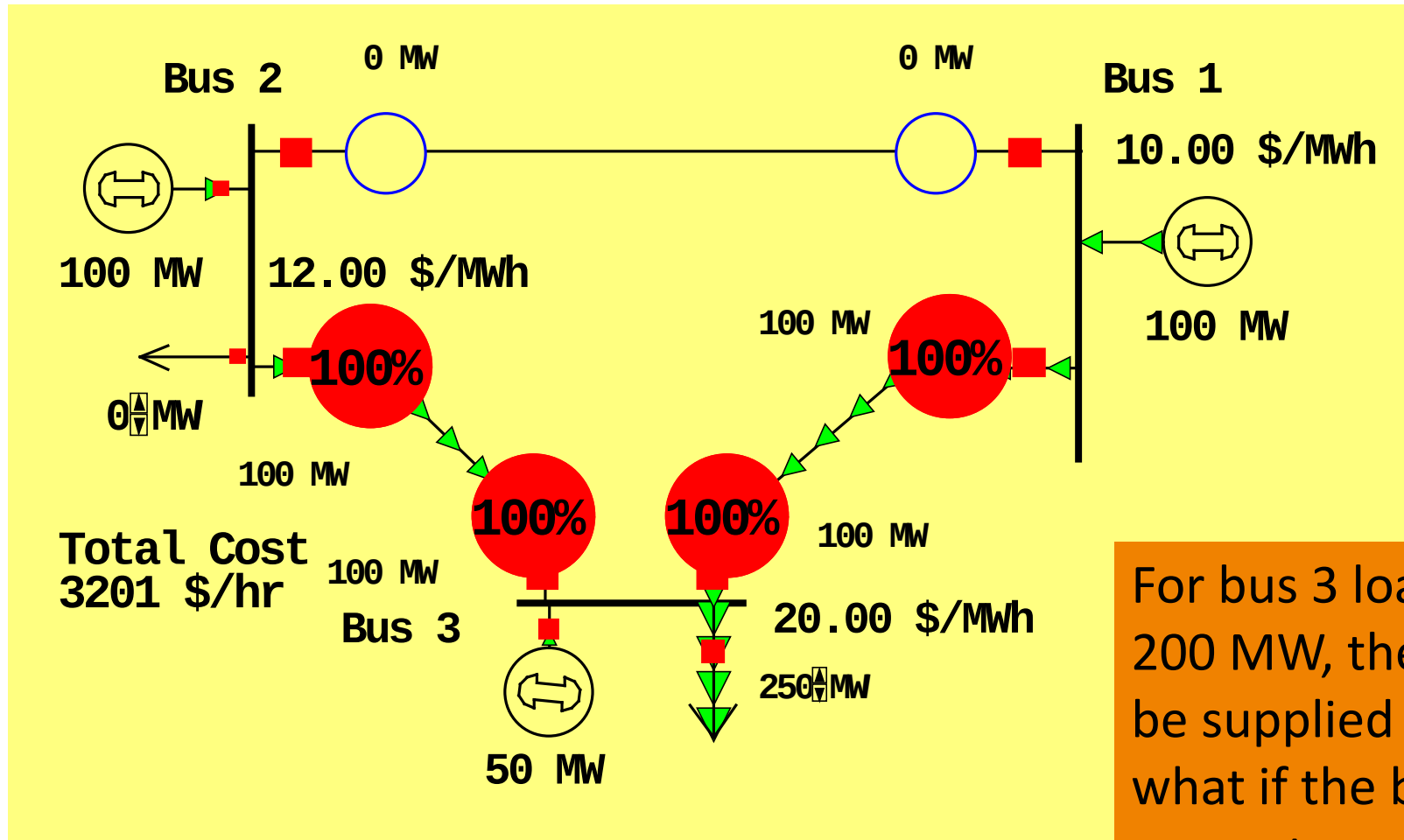
- If we allow 1 more MVA to flow on the line from 1 to 3, then this allows us to redispatch as follows

$$Pg1 + Pg2 = 0 \text{ MW}$$

$$2/3 Pg1 + 1/3 Pg2 = 1; \text{ (no more flow on 1-3)}$$

- Solving requires we drop Pg2 by 3 MW and increase Pg1 by 3 MW -- a net savings of \$6

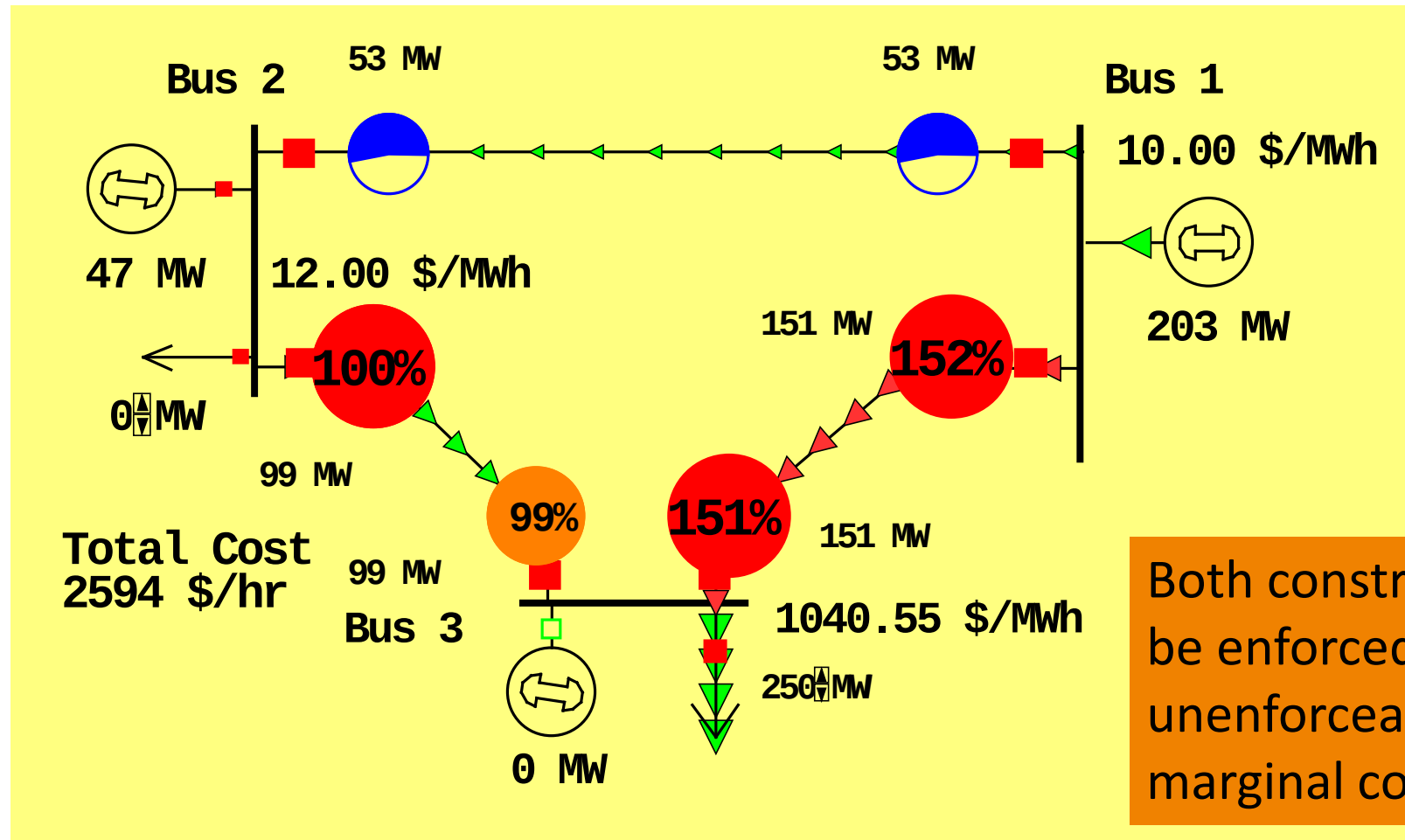
Both lines into Bus 3 Congested



For bus 3 loads above 200 MW, the load must be supplied locally. Then what if the bus 3 generator opens?

Case with G3 Opened

Unenforceable Constraints



Unenforceable Constraint Costs



- Is this solution Valid? Not really.
- If a constraint cannot be enforced due to insufficient controls, the slack variable associated with enforcing that constraint *cannot* be removed from the LP basis
 - marginal cost depends upon the arbitrary cost of the slack variable
 - this value is specified in the Maximum Violation Cost field on the LP OPF, Options dialog.

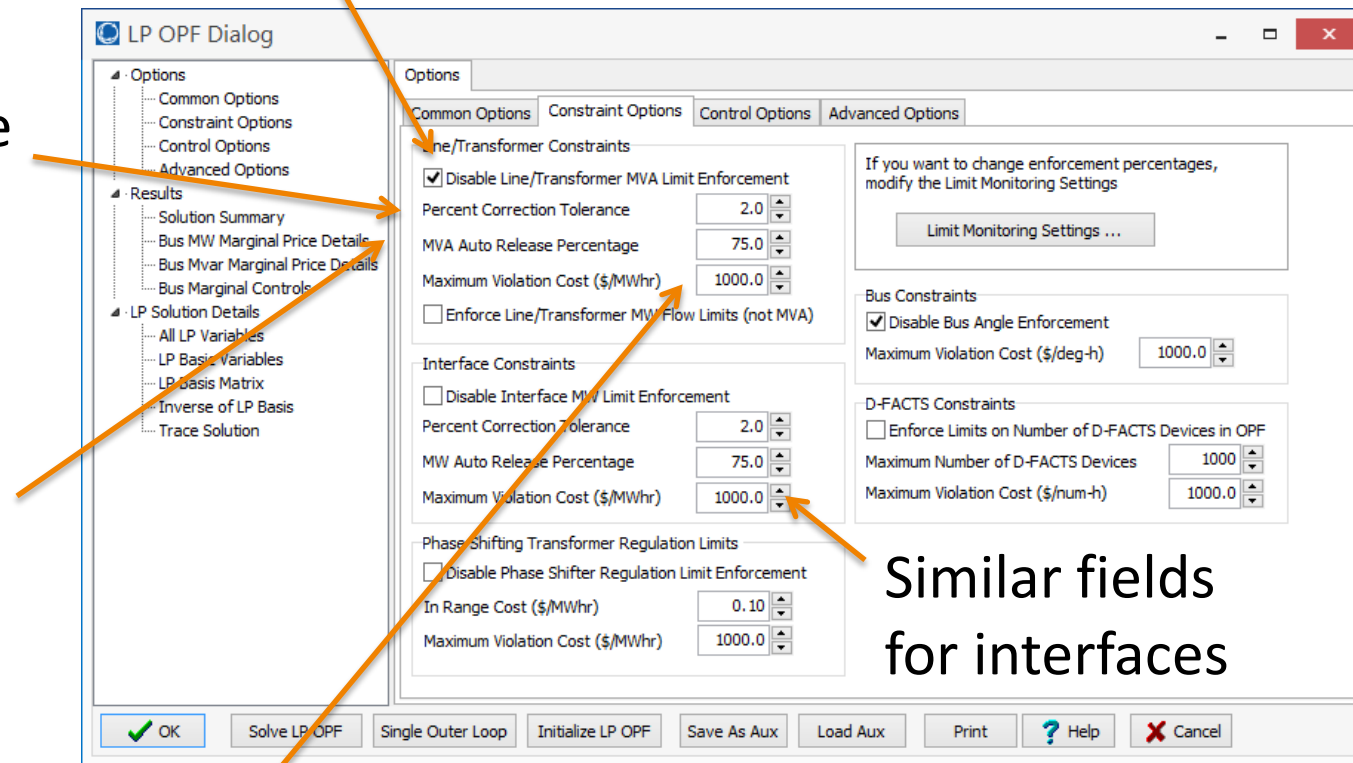
LP OPF Dialog, Options: Constraint Options



Disables enforcement of
Line constraints

Enforcement tolerance
deadband; needed because
of system non- linearities

Previously-binding line
constraints with loadings
above this value remain in
tableau



Cost of unenforceable line violations

Why report Unenforceable Violations?

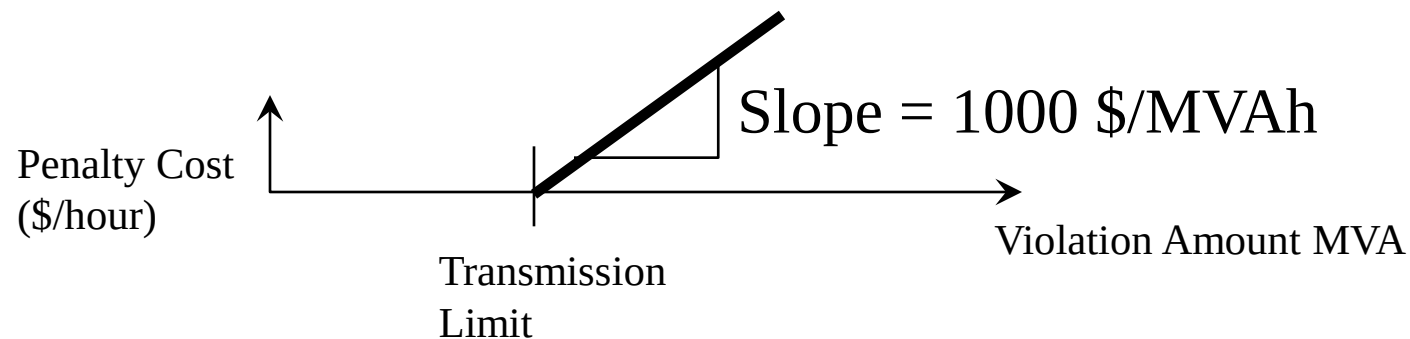


- Simulator tries its best to remove the line violations.
- High marginal prices will point you toward the line violations which are causing the system to be invalid.
- What should you do?
 - Look for generators that are in/out of service near the constraint
 - Look to see if it's a load or generator pocket without enough transmission
 - Model demand response through load benefit curves
 - Consider ignoring the line limit or increasing its rating
 - Apply piecewise-linear limit cost to violations

What does the Maximum Violation Cost for a Constraint represent?



- You can think of it as a *penalty function*
 - The “cost” of violating the constraint is equal to 1000 \$/hour for each MVA that the line is overloaded
 - Therefore if Simulator’s OPF determines that it would cost more to enforce the constraint, then it will just “pay” this cost and overload the constraint
 - The penalty function would have the following form

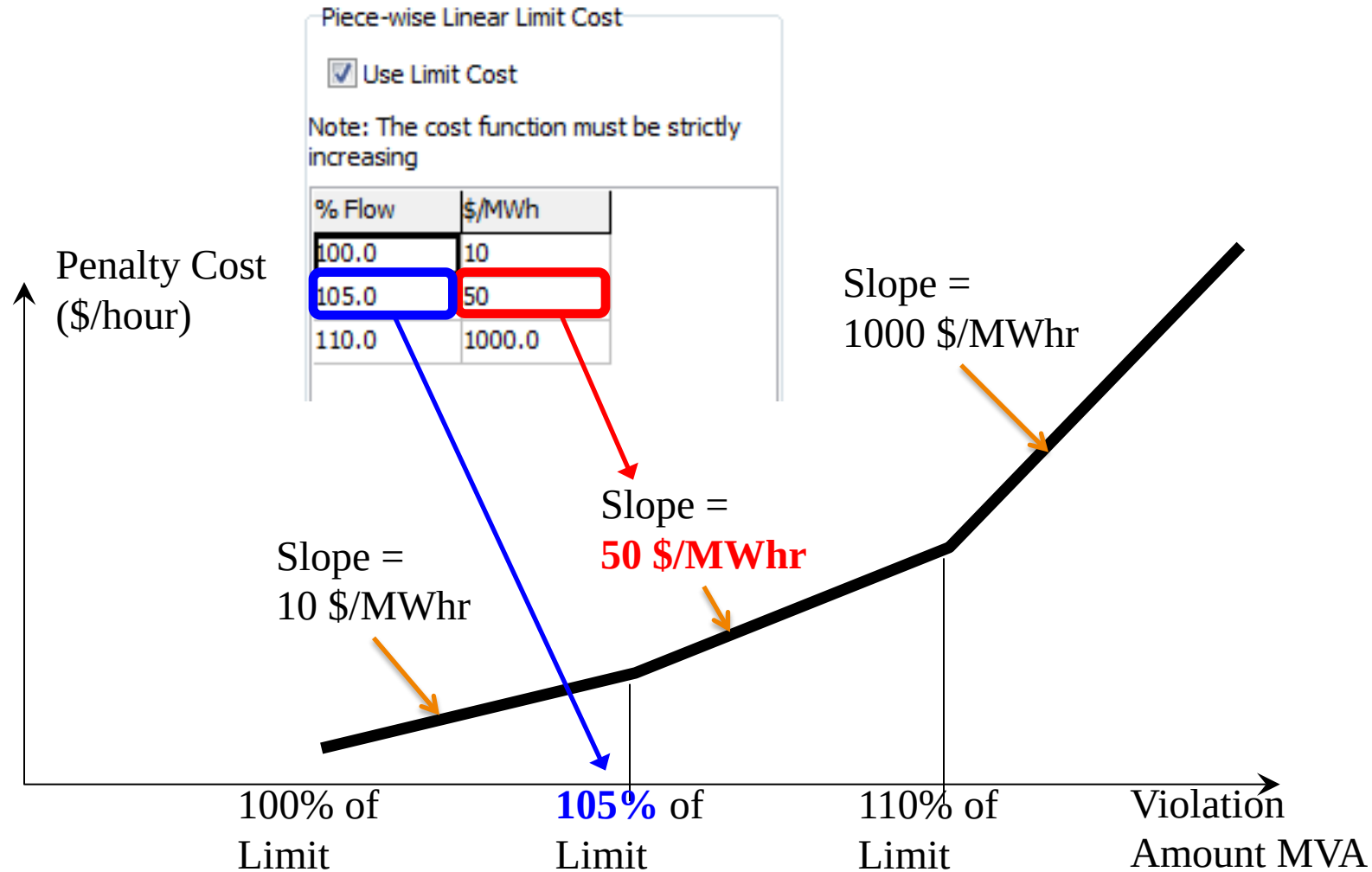


Specifying a Piece-wise Limit Cost with the Limit Groups



- Each Limit Group can specify a piece-wise limit cost which will then override the maximum violation cost specified in the OPF
 - Go to the **Tools** ribbon tab and select the **Limit Monitoring Settings** button.
 - Go to the Modify/Create Limit Groups tab
 - Right-click on your limit group and choose Show Dialog.
 - On the right side of this dialog, you may define the limit cost
- This allows for a more complex *penalty function* as shown on next slide
 - This allows the OPF to “dispatch” the amount of overload similar to a generator dispatch

Specifying a Piece-wise Limit Cost with the Limit Groups



OPF Line/Transformer MVA Constraints Display



Model Explorer: Branches

Explore Fields

- Owners
- Substations
- Super Areas
- Tielines between Areas
- Tielines between Zones
- Transfer Directions
- Zones
- Solution Details
- Case Information and Auxiliary
- Contingency Analysis
- Fault Analysis
- Optimal Power Flow
 - Bids
 - Reserve Requirements
 - Results
 - Areas
 - Branches
 - Buses
 - DC Lines
 - Generators
 - Interfaces
 - Loads

Open New Explorer

OPF Constraints Records

Filter Advanced Branch Find... Remove

Line/Transformer Constraints

- ☐ Disable Line/Transformer MVA Limit Enforcement
- Percent Correction Tolerance 2.0
- ☐ Only Show Limit Violations
- ☒ Only Areas with Line MVA Enforcement
- ☐ Use Area/Zone Filters
- ☐ Enforce Line/Transformer MW Flow Limits (not MVA)

Interface Constraints

- ☐ Disable Interface MW Limit Enforcement
- Percent Correction Tolerance 2.0
- ☐ Only Show Limit Violations
- ☐ Use Area/Zone Filters
- Note: These settings also apply to Nomogram Interfaces

Monitor/Enforce Contingent Interface Elements

- ☒ Never
- ☐ Power Flow/OPF but not CA/SCOPF
- ☐ All Applications including CA/SCOPF

☒ Do not enforce limits on radials lines and buses Limit Monitoring Settings ... If you want to change enforcement percentages, modify the Limit Monitoring Settings

Lines/Transformers Interfaces Nomogram Interfaces

	From Number	From Name	From Area Name	To Number	To Name	To Area Name	Circuit	Monitor	Max MVA	% of MVA Limit (Max)	Lim MVA	MVA Marg. Cost	Constraint Status
1	1	1	Home	2	2	Home	1	YES	52.6	100.0	100.0	1000.0	Unenforceable
2	1	1	Home	3	3	Home	1	YES	152.2	152.2	100.0	1008.3	Binding
3	2	2	Home	3	3	Home	1	YES	100.0	100.0	100.0	1008.3	Binding

Search Search Now Options

Line loadings

Set to specify enforcement of individual lines

Marginal costs are non-zero only for lines that are active constraints

Indicates if line is unenforceable

Demand Response/Load Benefit



- Constraints influenced by load pockets can often be relieved if load is interrupted or curtailed
- Load benefit models can be applied to model price-sensitive loads or loads that have contractual obligations to reduce during congestion or at certain price points (e.g. Large Flexible Loads)
- Required settings to use this feature with OPF
 - The OPF Option *Disable All Load MW Controls* = NO (unchecked on LP OPF Dialog)
 - Area that load belongs to has *Load MW Dispatch* = YES
 - Load uses a piecewise linear benefit model and *AGC* = YES

LP OPF Dialog, Options: Common Options



Uncheck to
Enable Load
Demand
Response

The screenshot shows the 'LP OPF Dialog' window with the 'Options' tab selected. The 'Common Options' sub-tab is active. In the 'LP Control Variables' section, the checkbox 'Disable All Load MW Controls' is highlighted with an orange box. An orange arrow points from the text 'Uncheck to Enable Load Demand Response' to this checkbox. Other options include 'Objective Function' (Minimum Cost selected), 'LP Options' (Maximum Number of LP Iterations: 30), and 'LP Solution Details' (All LP Variables, LP Basic Variables, LP Basis Matrix, Inverse of LP Basis, Trace Solution).

LP OPF Dialog

Options

Common Options Constraint Options Control Options Advanced Options

Objective Function

☒ Minimum Cost

☐ Minimum Control Change

☐ Include OPF Reserve Requirements

☐ Use a Single Control for Up/Down Regulation

LP Control Variables

☐ Disable All Phase Shifter Controls

☐ Disable All Generator MW Controls

☐ Disable All Load MW Controls

☐ Disable Area-to-Area MW Transaction Controls

☐ Disable DC Transmission Line MW Controls

☒ Disable D-FACTS Controls

LP Options

Maximum Number of LP Iterations: 30

☐ Treat Maximum LP Iteration Solutions as Valid

Phase Shifter Cost (\$ / degree): 0.100000

☒ Calculate Bus Marginal Cost of Reactive Power

☒ Save Full OPF Results in PWB File

☐ Do Detailed LP Logging (i.e., Each Pivot)

☐ Start with Last Valid OPF Solution

☒ Include only online devices in Injection Group calculation

D-FACTS Cost (\$ / per unit X): 0.010000

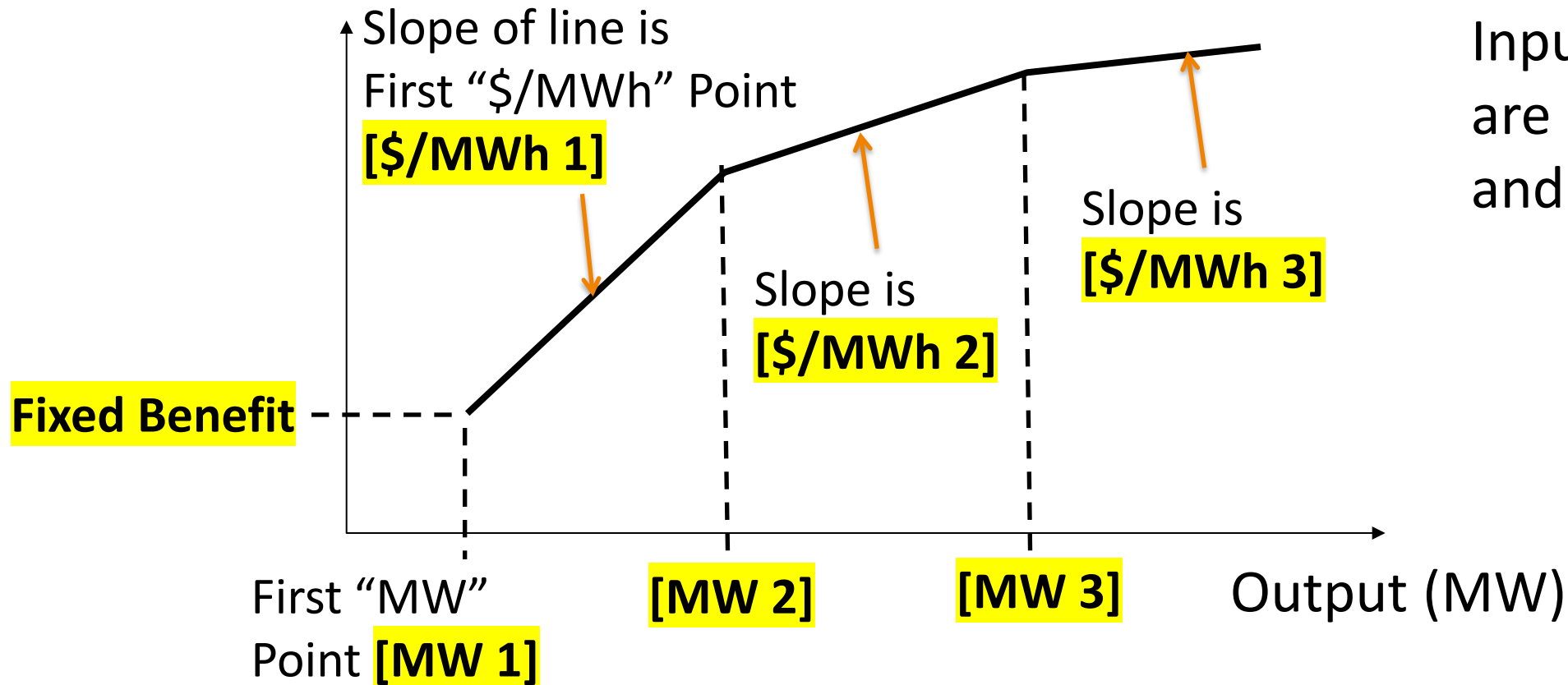
☐ Balance Marginally Similar Controls

OK Solve LP OPF Single Outer Loop Initialize LP OPF Save As Aux Load Aux Print Res Help Cancel

Piecewise Linear Load Benefit Input

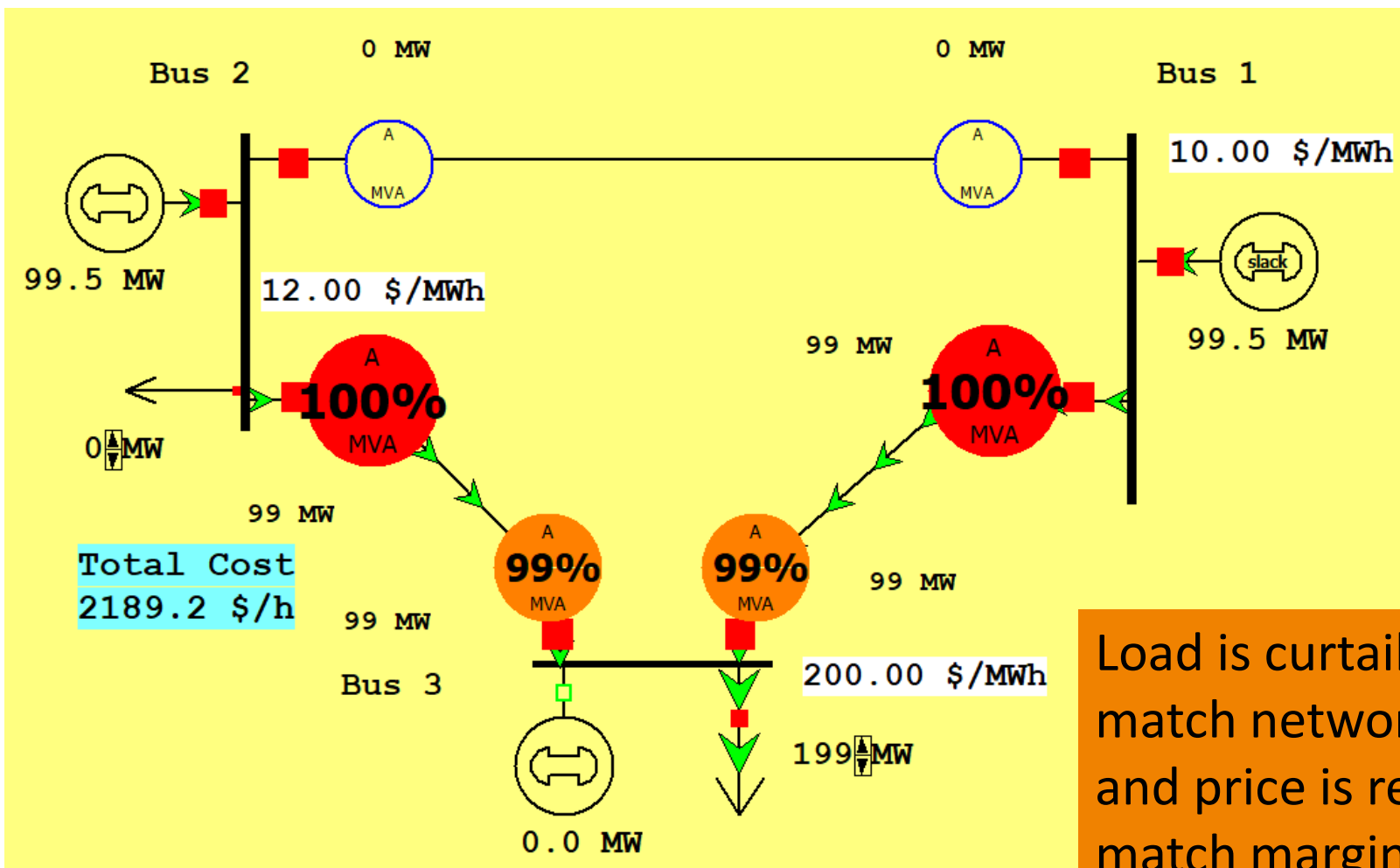


Piecewise Linear Benefit Curve (units = \$/h)



Input variables are highlighted and bold

Case with G3 Opened and Benefit Model for Load 3 1



Load Dialog

Load Information OPF Load Dispatch Custom Stability GIC

Benefit Model OPF Reserve Bids

Benefit Model

☐ None

☒ Piecewise Linear

MW Control

Min. MW Output: 0.000

Max. MW Output: 250.000

☒ Available for AGC

Fixed Benefit (\$/hr): 0.00

Piece-wise Linear Benefit Curve

Note: The benefit function must be strictly decreasing.

MW	\$/MWh
0.0	10000.00
50.0000	1000.00
100.000	800.000
150.000	200.000
200.000	0.0000

Load is curtailed to match network capacity and price is reduced to match marginal benefit

LP OPF Dialog, Options:

Common Options



- Objective Functions:
 - Minimum Costs (includes generator costs and also load benefits if specified)
 - Minimum Control Change (move the smallest amount of generation and/or load)
- LP Control Variables can be disabled globally
 - Phase Shifters, Generator MW, Loads MW, Area Transactions, DC Line MW, D-FACTS
- Maximum Number of LP Iterations
- Phase Shifter Cost (\$/degree) and D-FACTS Cost (\$/pu X)
 - The cost of moving the phase shifter or changing reactance of D-FACTS device. Normally these are left at defaults (close to zero.)

LP OPF Dialog, Options: Common Options



- Calculate Bus Marginal Cost of Reactive Power
- Save Full OPF Results in PWB file
- Do Detailed Logging (i.e., each pivot)
- Start with Last Valid OPF Solution

LP OPF Dialog, Options:

Control Options



LP OPF Dialog

Options

- Options
 - Common Options
 - Constraint Options
 - Control Options
 - Advanced Options
- Results
 - Solution Summary
 - Bus MW Marginal Price Details
 - Bus Mvar Marginal Price Details
 - Bus Marginal Controls
- LP Solution Details
 - All LP Variables
 - LP Basic Variables
 - LP Basis Matrix
 - Inverse of LP Basis
 - Trace Solution

Options

Common Options | Constraint Options | **Control Options** | Advanced Options

Fast Start Generator Options

- ☒ Allow Commitment of Fast Start Generators
- ☐ Allow Decommitment of Fast Start Generators
- Round to On Percentage of Min Limit: 2.0

Modeling Generators without Piecewise Linear Cost Curves

Generator Cost Models

- ☐ Ignore them
- ☒ Change to Specified Points per Curve
- ☐ Change to Specified MWs per Segment

Total Points per Cost Curve: 5

MWs per Cost Curve Segment: 10.0

☐ Save Existing Piecewise Linear Cost Curves

Modeling of OPF Areas/Superareas

During the Initial OPF Power Flow Solution

- ☐ No Area Control
- ☒ Participation Factor Control (recommended)
- ☐ Economic Dispatch Control
- ☐ Area Slack Bus Control

During Stand-Alone Power Flow Solutions

- ☐ No Area Control
- ☒ Participation Factor Control (recommended)
- ☐ Economic Dispatch Control
- ☐ Area Slack Bus Control

☒ Treat Area/Superarea MW Constraints as unenforceable even when the ACE is less than the AGC Tolerance (default is checked)

OK Solve LP OPF Single Outer Loop Initialize LP OPF Save As Aux Load Aux Print ? Help X Cancel

LP OPF Dialog, Options: Control Options



- Fast Start Generators
 - For generators with the column **Fast Start** set to *YES*, these check boxes determine if the generators are allowed to be turned on and/or off
- Modeling of OPF Areas/Super Areas
 - During the Initial OPF Power Flow Solution
 - At the start of an OPF solution, a solved power flow solution must be determined. Areas which are on OPF will use this.
 - Participation Factor is recommended
 - During Stand-Alone Power Flow Solutions
 - When solving a normal Power Flow Solution, this specifies how areas which are on OPF control will be solved.
 - Participation Factor is recommended

LP OPF Dialog, Options: Control Options



- Modeling Generators Without Piecewise Linear Cost Curves
 - Ignore Them (generators with cubic models are ignored)
 - Change to Specified Points Per Curve
 - Modify Total Points per Cost Curve as appropriate
 - Change to Specified MWs per Segment
 - Modify MWs per Cost Curve Segment
- Save Existing Piecewise Linear Cost Curves
 - If unchecked then existing piecewise linear curves are overwritten

LP OPF Dialog, Options: Control Options



- Treat Area/Superarea MW Constraints as unenforceable even when the ACE is less than the AGC Tolerance
 - Default is that this option is checked
 - When checked, area/superarea constraints are unenforceable when the ACE is not zero
 - When unchecked, area/superarea constraints are considered enforceable if the ACE is less than the AGC Tolerance

Modeling Generator Costs



- Generator costs are modeled with either a cubic cost or piecewise linear cost function

Cost model is specified on the generator dialog, **Costs** tab

Generator Options

Bus Number: 1, Bus Name: One, ID: 1, Area Name: Top, Labels: no labels

Fuel Type: Unknown, Unit Type: LIN (Unknown)

Costs tab selected

Cost Model: ☒ Piecewise Linear

Unit Fuel Cost (\$/MBtu): 2.040

Variable O&M (\$/MWh): 0.000

Fixed Costs (costs at zero MW output):

Fuel Cost Independent Value (\$/hr): 0.00

Fuel Cost Dependent Value (Mbtu/hr): 373.50

Piece-wise Linear Cost Curve

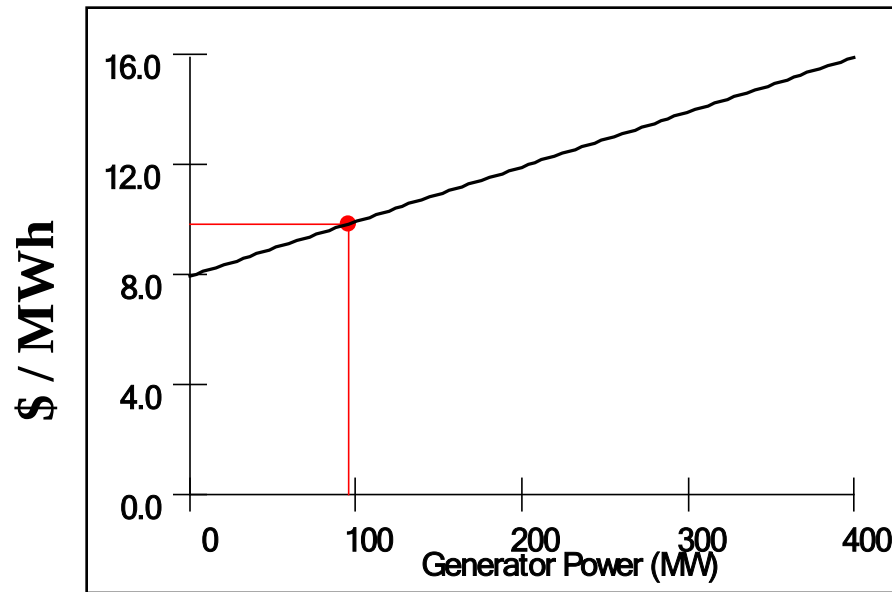
Note: The cost function must be strictly increasing.

MW	\$/MWh
100.0	16.34
200.0	16.87
300.0	17.40

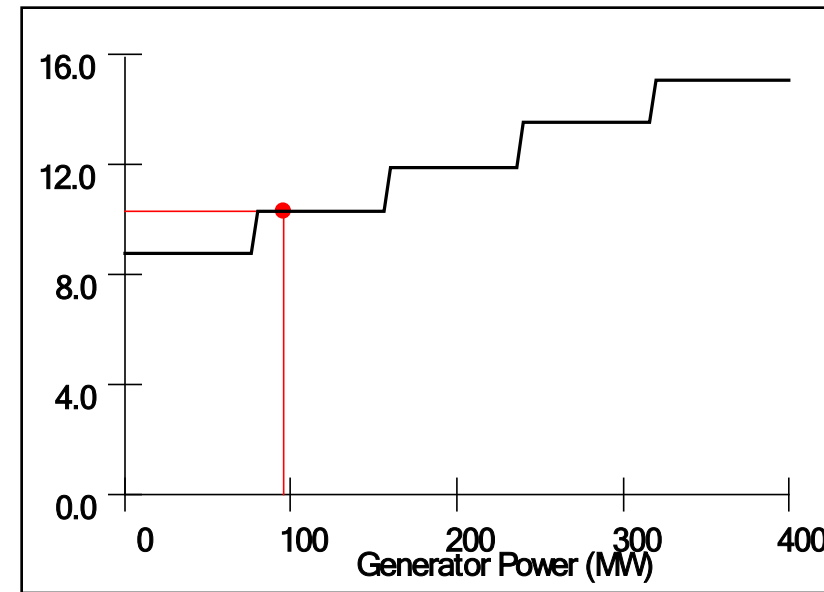
Fixed costs are now entered in fields to left and apply to both cubic and piecewise linear models.

The LP OPF **requires** a piecewise linear model. (It's called a *linear* program for a reason.) Therefore any existing cubic models are automatically converted to piecewise linear before the solution, and then converted back afterward.

Comparison of Cubic and Piecewise Linear Marginal Cost Curves



Continuous generator
marginal cost curve



Piecewise linear generator marginal
cost curve with five segments

This conversion may affect the final cost. Using more segments better approximates the original curve, but may take longer to solve.

OPF Case Information Displays



- Several Case Information Displays exist for use with the OPF
 - OPF Areas
 - OPF Buses
 - OPF DC Lines
 - OPF Generators
 - OPF Interfaces
 - OPF Load Records
 - OPF Lines and Transformers
 - OPF Nomograms
 - OPF Phase Shifters
 - OPF Super Areas
 - OPF Transactions
 - OPF Zones
- To provide a good example of these displays, go to the **Application Menu** and choose **Open Case** and reopen the b7flatlp.pwb example case

OPF Area Records Display: Special Fields



- Controls Types that are available
 - XF Phase – specifies if phase-shifters are available
 - Load MW Dispatch – specifies if load can be moved
 - DC Line MW – specifies if DC MW setpoint can be moved
- Constraint Types which should be enforced
 - Branch MVA – should branch limits be enforced
 - Interface MW – should interface limits be enforced (this will also apply to nomogram interfaces)
- Include Marg. Losses
 - Specifies if marginal losses are used in the OPF

The screenshot shows the 'Model Explorer: Areas' window with the 'OPF Area Records' tab selected. The table displays the following data:

Area Num	Area Name	AGC Status	XF Phase	Branch MVA	Interface MW	Load MW Dispatch	DC Line MW Control	Include Marg. Losses	MW Marg. Ave	Cost	MW Marg St.Dev.
1	1 Top	OPF	YES	YES	YES	NO	YES	NO		13.87	
2	2 Left	OPF	YES	YES	YES	NO	YES	NO		17.60	
3	3 Right	OPF	YES	YES	YES	NO	YES	NO		21.80	

OPF Gen Records Display: Special Fields



- Fast Start
 - Should the generator be available for being turned on/off by the OPF
- OPF MW Control (*YES, NO, or If Agcable*)
 - Should the generator be made available for OPF dispatch
- IC for OPF
 - The incremental cost of the generator used by the OPF (may be different than actual IC for cubic cost curve generators)
- Initial MW, Cost
 - The output and cost at the start of the OPF solution
- Delta MW, Cost
 - The change in the output and cost for the last OPF solution

	Number of Bus	Name of Bus	ID	Area Name of Gen	AGC	Fast Start	OPF MW Control	Gen MW	Cost \$/Hr (generation only)	MW Marg. Cost of Bus	IC for OPF	Initial MW	Initial Cost	Delta MW	Delta Cost
1	1	1	1	Top	YES	NO	If Agcable	95.5	1600.46	13.00	13.00	0.0	0.00	95.5	1600.46
2	2	2	1	Top	YES	NO	If Agcable	150.0	2653.60	14.25	15.00	0.0	0.00	150.0	2653.60
3	4	4	1	Top	YES	NO	If Agcable	106.5	2020.27	14.00	14.00	0.0	0.00	106.5	2020.27
4	6	6	1	Left	YES	NO	If Agcable	250.0	5057.05	17.60	17.60	0.0	0.00	250.0	5057.05
5	7	7	1	Right	YES	NO	If Agcable	200.2	4721.67	21.80	21.80	0.0	0.00	200.2	4721.67

OPF Super Area Records Display: Special Fields



- Control Types and Constraint Types continue to be governed by the settings by Area
- Include Marg. Losses must be specified with the Super Area
- AGC Status
 - Remember that when a Super Area is set to an AGC status, this overrides the areas inside it.

	Super Area	AGC Status	Use Area PF	Num Areas	Include Marg. Losses	Gen MW	Load MW	Tot Sched MW	ACE MW	Lambda	Loss MW	ED use PF
1	TheSA	OPF	NO	3	NO	803.52	800.00	0.00	0.00	20.60	3.52	YES

Cost of Energy, Losses and Congestion

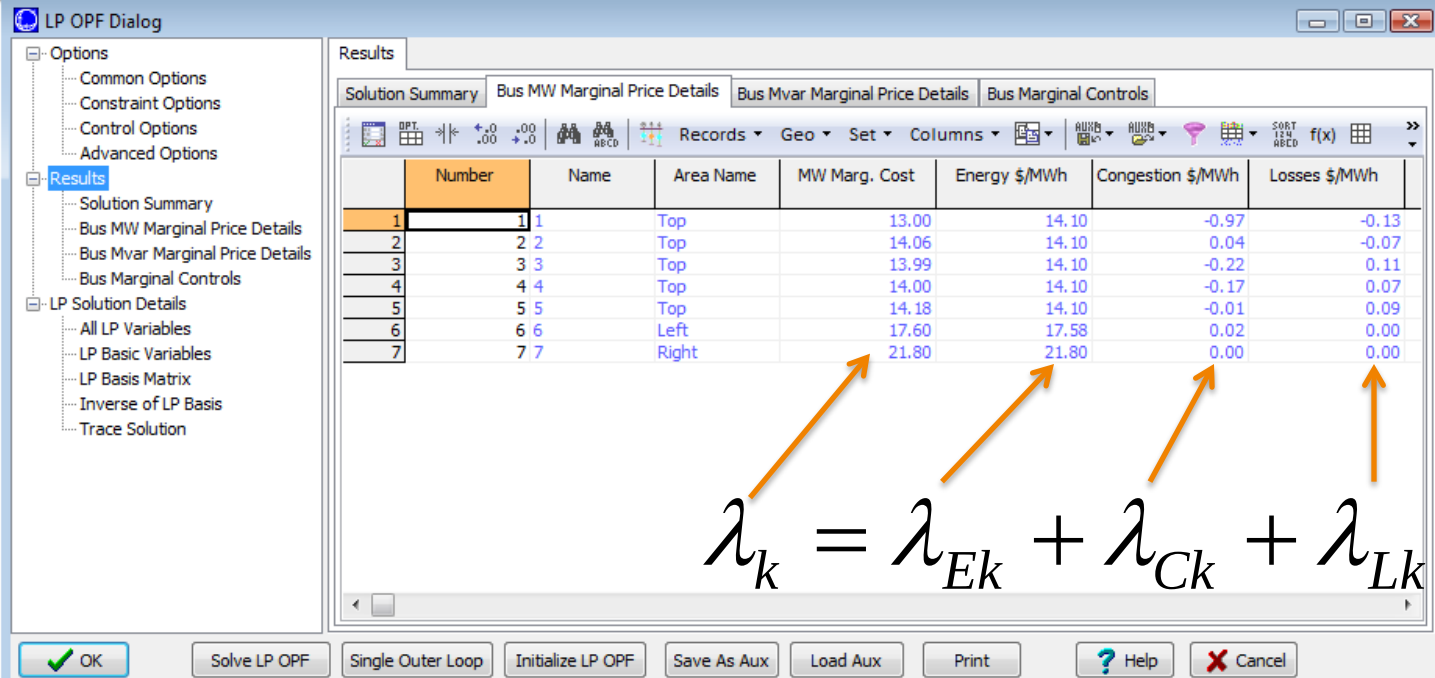


- Some ISO documents refer to the cost components of energy, losses, and congestion
- Go to the **Add Ons** ribbon tab and select **OPF Case Info → OPF Areas**
 - Toggle **Include Marg. Losses** column of each area to YES
- Choose **OPF Case Info → Primal LP** to resolve.
- Now choose **OPF Case Info → OPF Options and Results**
 - Go to the **Results → Bus MW Marginal Price Details** page
 - Here you will find columns for the MW Marg Cost, Energy, Congestion and Losses

Cost of Energy, Losses and Congestion



- The only value that is truly unique for an OPF solution is the total MW Marginal Cost λ_k
- The cost of Energy, Losses, and Congestion are dependent on the *reference* for Energy and Losses



The screenshot shows the 'Results' tab of the 'LP OPF Dialog' window. It contains a table with columns: Number, Name, Area Name, MW Marg. Cost, Energy \$/MWh, Congestion \$/MWh, and Losses \$/MWh. The table lists 7 buses. Below the table, the equation $\lambda_k = \lambda_{Ek} + \lambda_{Ck} + \lambda_{Lk}$ is displayed, with orange arrows pointing from the terms to the corresponding columns in the table: λ_{Ek} points to Energy \$/MWh, λ_{Ck} points to Congestion \$/MWh, and λ_{Lk} points to Losses \$/MWh.

	Number	Name	Area Name	MW Marg. Cost	Energy \$/MWh	Congestion \$/MWh	Losses \$/MWh
1	1	1	Top	13.00	14.10	-0.97	-0.13
2	2	2	Top	14.06	14.10	0.04	-0.07
3	3	3	Top	13.99	14.10	-0.22	0.11
4	4	4	Top	14.00	14.10	-0.17	0.07
5	5	5	Top	14.18	14.10	-0.01	0.09
6	6	6	Left	17.60	17.58	0.02	0.00
7	7	7	Right	21.80	21.80	0.00	0.00

$\lambda_k = \lambda_{Ek} + \lambda_{Ck} + \lambda_{Lk}$

Cost of Energy, Loss, and Congestion Reference



- These references must be specified by the region being dispatched: either an area or super area
 - This is for areas, so choose **OPF Case Info → OPF Areas**
 - Right-click on Area Top and choose show Dialog
 - Go to the OPF Tab and you will see a section of this dialog which is shown below.
 - Similar settings can be found on the Super Area dialog

Cost of Energy, Loss, and Congestion Reference

☒ Existing loss sensitivities directly

☐ Area's Bus' Loads

☐ Injection Group

☐ Specific Bus

Cost of Energy



- The cost of energy at every bus in the area (or super area) is set to the same value
- The calculation of this value is based upon the specified reference
 - **Existing loss sensitivities directly**: Cost of energy at every bus is equal to the cost of enforcing the area constraint for the area containing the bus, and the formula given above is not used
 - **Area's Bus' Loads**: Weighting factor is the load at each bus in the area
 - **Injection Group**: Weighting factor is the participation factor of the points in the injection group
 - **Specific Bus**: Weighting factor is 1 for the specified bus and zero for every other bus in the area
- The loss sensitivity at each bus is also determined from the same specified reference

$$\lambda_{Ek} = \frac{\sum_{n \in N} \left(\frac{\alpha_n \lambda_n}{1 - \tilde{L}_n} \right)}{\sum_{n \in N} \left(\frac{\alpha_n}{1 - \tilde{L}_n} \right)}$$

λ_n : marginal cost at bus n
 α_n : weighting factor at bus n
 $\tilde{L}_n$: loss sensitivity at bus n

Cost of Losses



- Loss sensitivity must be calculated relative to the specified reference
 - **Existing loss sensitivities directly**: The sensitivity contained in each bus' Loss MW Sens field
 - **Area's Bus' Loads or Injection Group**: Simulator converts the loss sensitivities to a reference of having injections at each bus absorbed at a distributed set of buses defined by the Area's buses weighted by load, or the injection group buses
 - **Specific Bus**: Simulator converts the loss sensitivities to a reference of having injections at each bus absorbed by the specific bus
- The cost of losses at each bus is then equal to the negative of the product of the loss sensitivity times the cost of energy.

$$\lambda_{Lk} = -\tilde{L}_k \lambda_{Ek}$$

Cost of Congestion



- The cost of congestion is simply the amount of the MW Marginal Cost which is leftover.

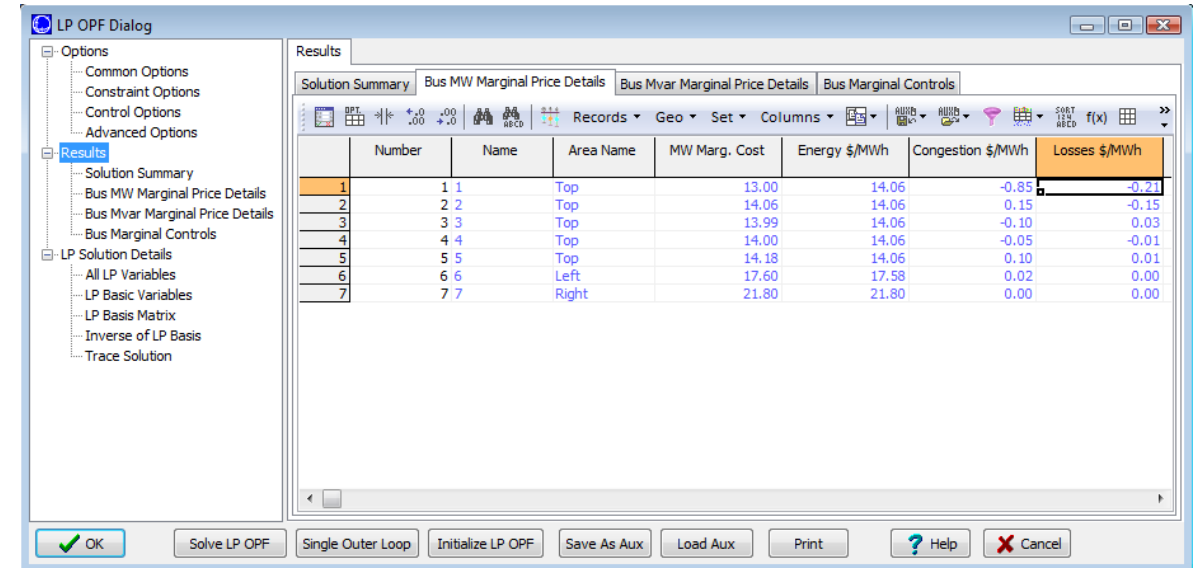
$$\lambda_{Ck} = \lambda_k - \lambda_{Ek} - \lambda_{Lk}$$

- Note: splitting this amount into pieces is completely dependent on how you choose the references

Example with Different References



- Go to the Area Dialog for Area TOP (1)
- Change the references for Area Top to use the Area's Bus' Loads for the reference.
- Choose **Add Ons** → **Primal LP** to resolve
- Compare results to previous ones and you will notice
 - MW Marg. Cost has not changed
 - Energy, Congestion, and Losses are all different



LP OPF Dialog

Results

Solution Summary | Bus MW Marginal Price Details | Bus Mvar Marginal Price Details | Bus Marginal Controls

	Number	Name	Area Name	MW Marg. Cost	Energy \$/MWh	Congestion \$/MWh	Losses \$/MWh
1	1	1	Top	13.00	14.06	-0.85	-0.21
2	2	2	Top	14.06	14.06	0.15	-0.15
3	3	3	Top	13.99	14.06	-0.10	0.03
4	4	4	Top	14.00	14.06	-0.05	-0.01
5	5	5	Top	14.18	14.06	0.10	0.01
6	6	6	Left	17.60	17.58	0.02	0.00
7	7	7	Right	21.80	21.80	0.00	0.00

OK Solve LP OPF Single Outer Loop Initialize LP OPF Save As Aux Load Aux Print ? Help X Cancel

Super Areas



- Super areas are a record structure used to hold a set of areas
- By using super areas, a number of areas can be dispatched as though they were a single area
- For a super area to be used in the OPF, its AGC Status field must be *OPF*

Hands-on: Seven bus case



- Load the B7FlatLP case. Try to duplicate the results from the previous two slides.
- What are the marginal costs of enforcing the line constraints? How do the system costs change if the line constraints are relaxed (i.e., not enforced)? For example, try solving without enforcing line 1 to 2.

Hands-on: Seven Bus Case



- Modify the cost model for the generator at bus one.
 - How does changing from piece-wise linear to cubic affect the final solution?
 - How do the generation conversion parameters on the option dialog affect the results?
- Try re-solving the case with different lines removed from service.

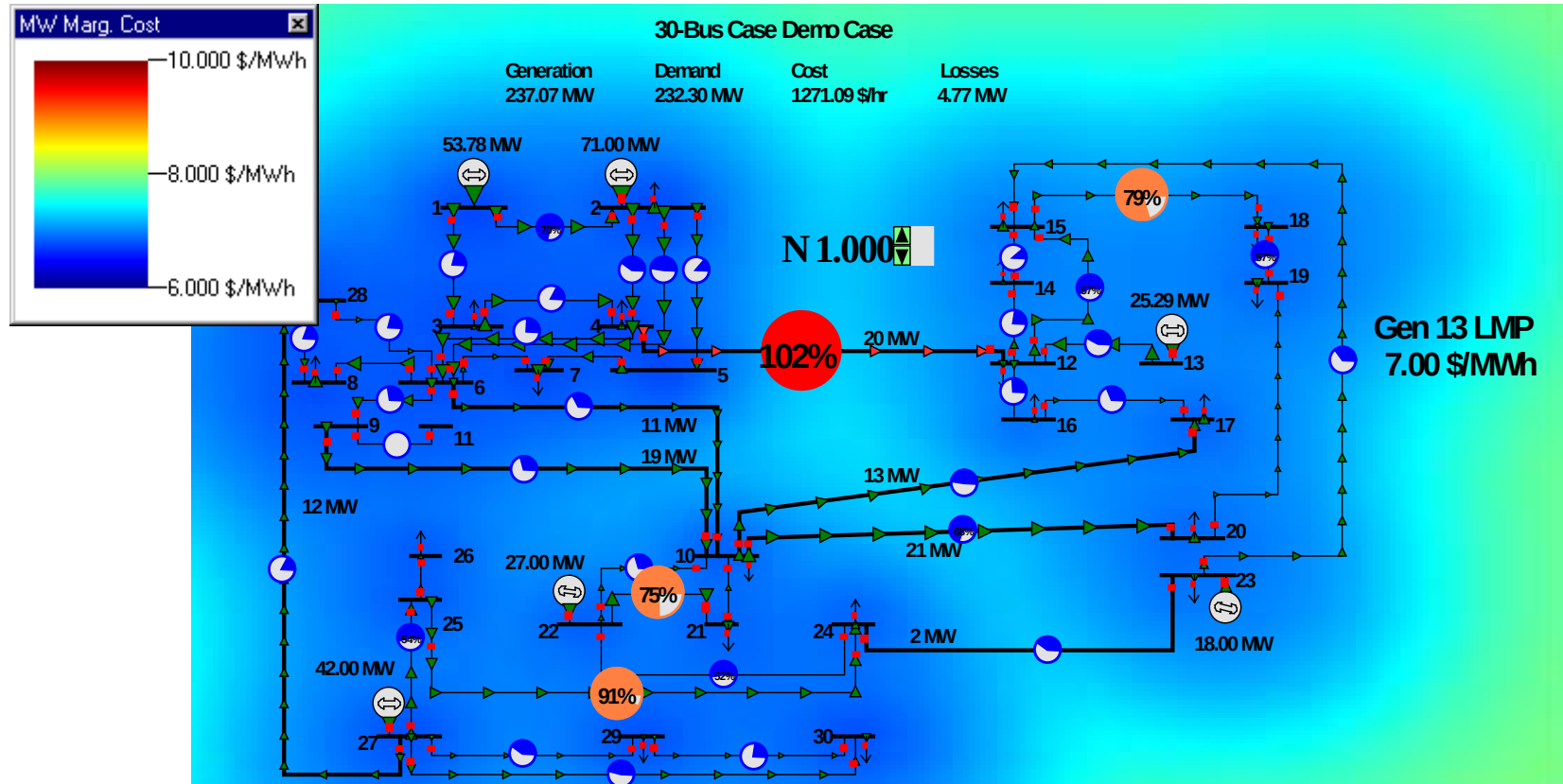


Some more Examples



- The remainder of these slides will present some further examples
 - Using the OPF to perform profit maximization
 - Using the OPF on a very large system

LP Application: Profit Maximization on 30 Bus System



The next slides illustrate how the OPF can be used to study the impact of bids on profit. Assume bus 13 generator has a true marginal cost of \$ 7 / MWh.



Profit Maximization



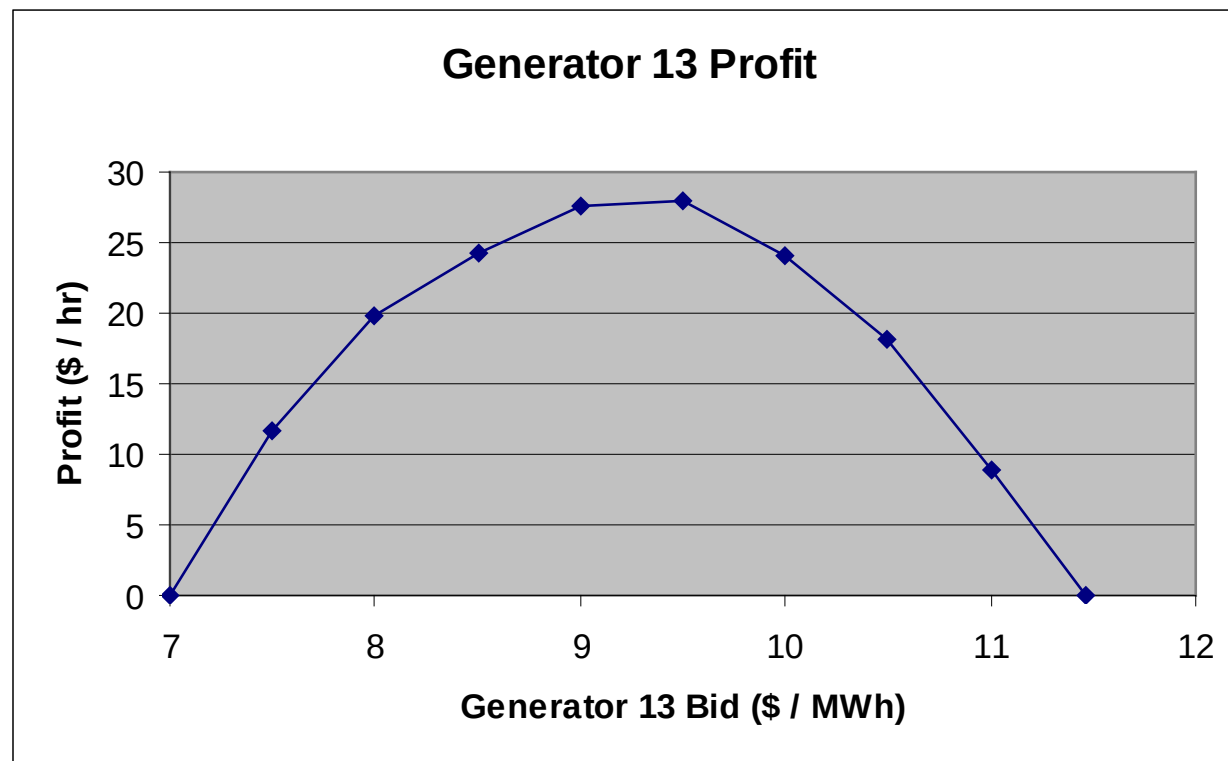
- If the bus 13 generator were paid the multiple of its bus LMP and its output, its profit would be:

$$\text{Profit} = \text{LMP} * \text{MW} - 7 * \text{MW}$$

- What should the generator bid to maximize its profit? This problem can be solved using the OPF with different assumed generator costs.



Profit Maximization



Generator 13's best response is to bid about \$ 9.5 / MWh



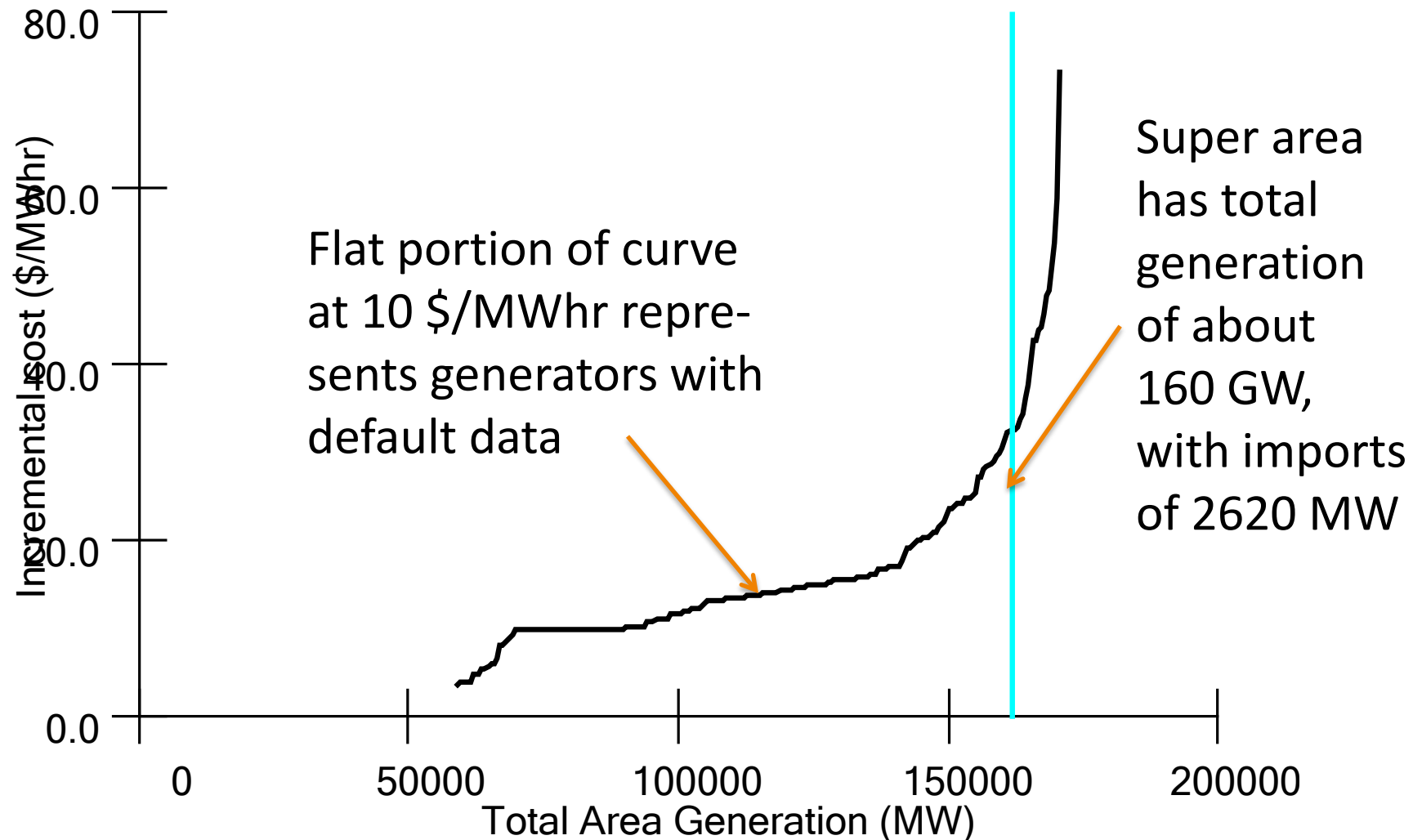
Application of LP OPF to a Large System



- Next case is based upon the FERC Form 715 1997 Summer Peak case filed by NEPOOL
 - Case has 9270 buses and 2506 generators, representing a significant portion of the Eastern Interconnect transmission and generation
 - Estimated cost data for most generators in NEPOOL, NYPP, PJM, and ECAR
 - These regions were modeled as a super area
 - Results developed by joint project between PowerWorld and U.S. Energy Information Administration



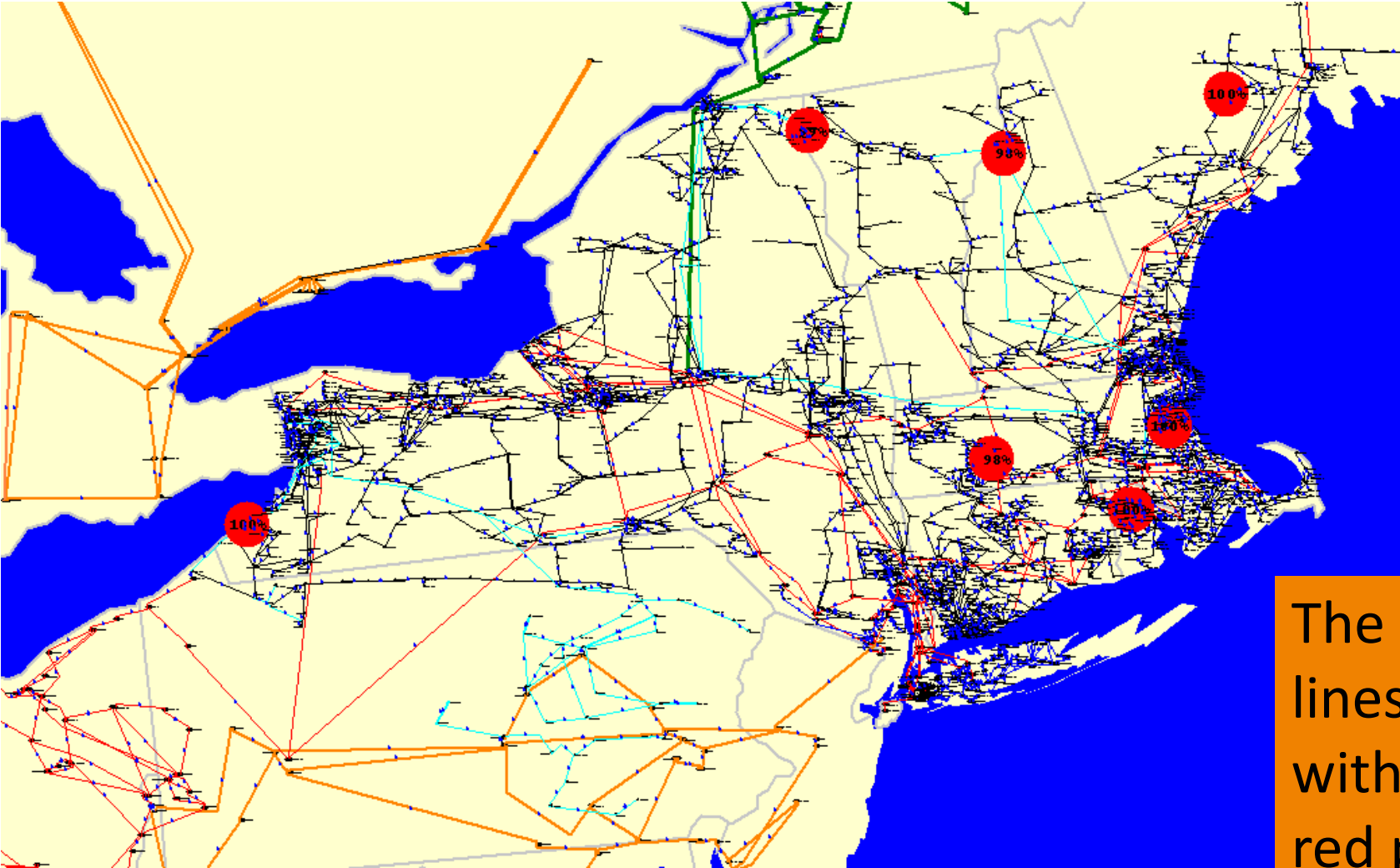
NEPOOL/NYPP/PJM/ECAR Supply Curve



Case HEV Transmission



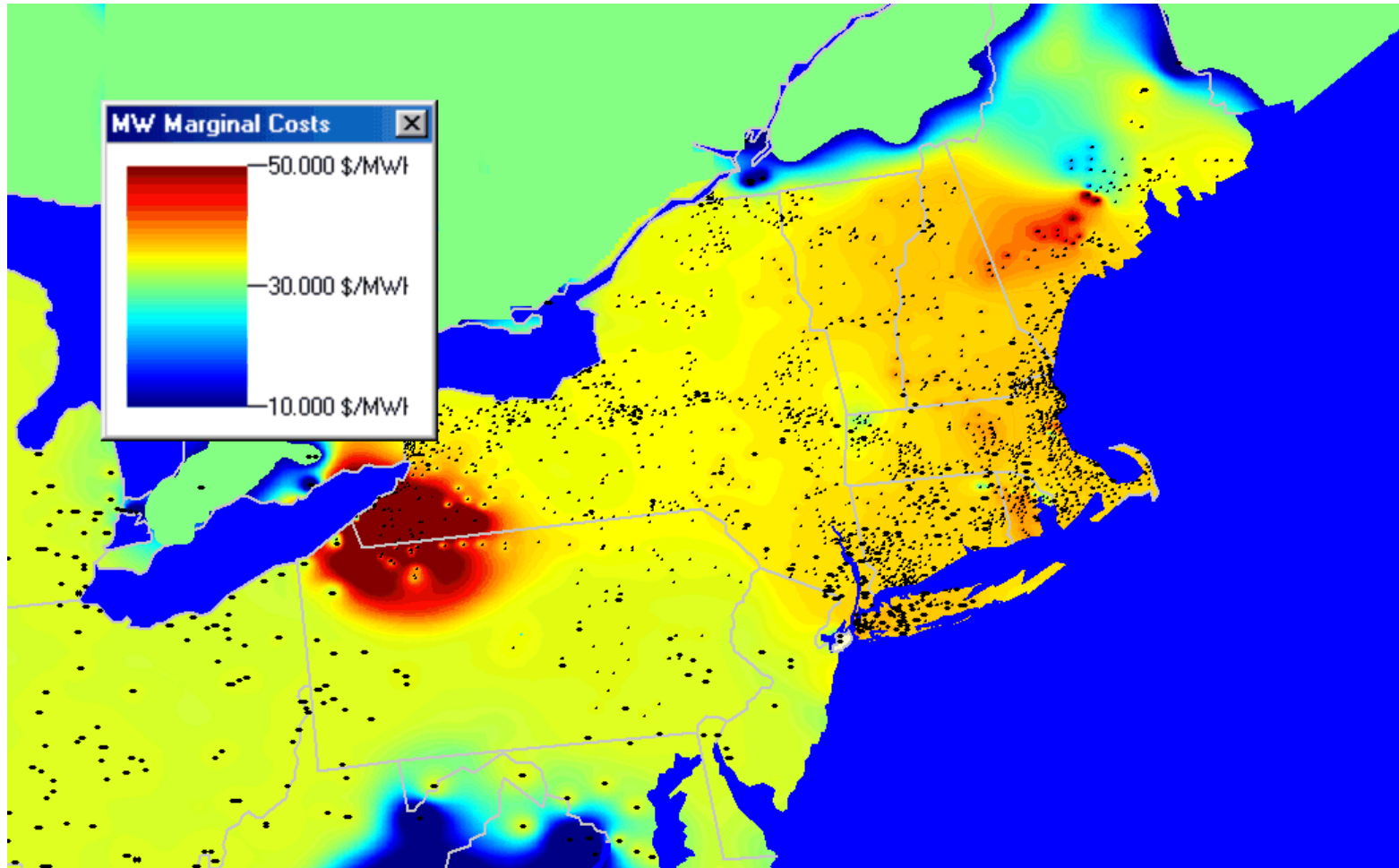
NYPP/NEPOOL Lower Voltage Transmission - Optimal Solution



The constrained lines are shown with the large red pie charts



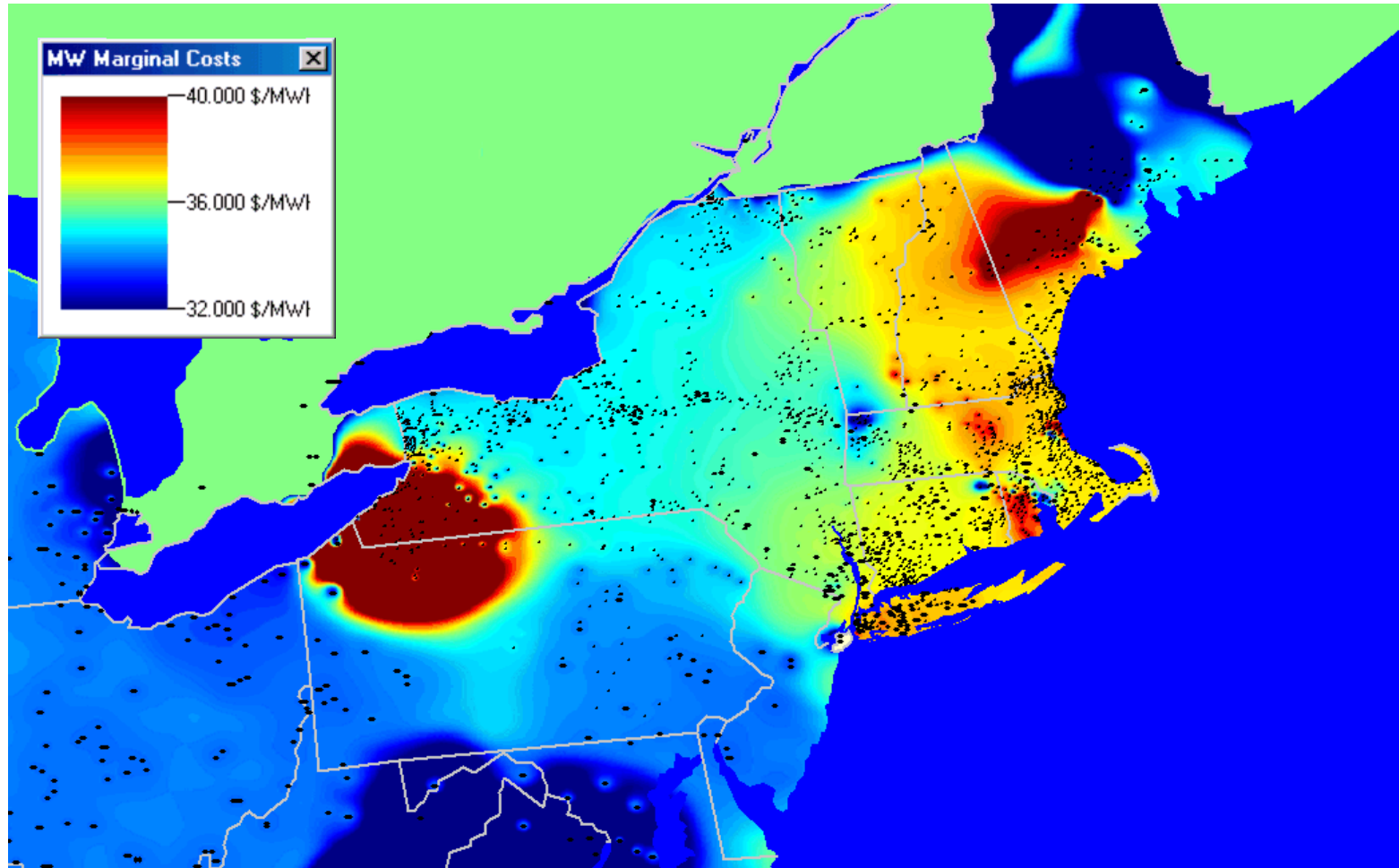
Bus Marginal Prices – Large Range



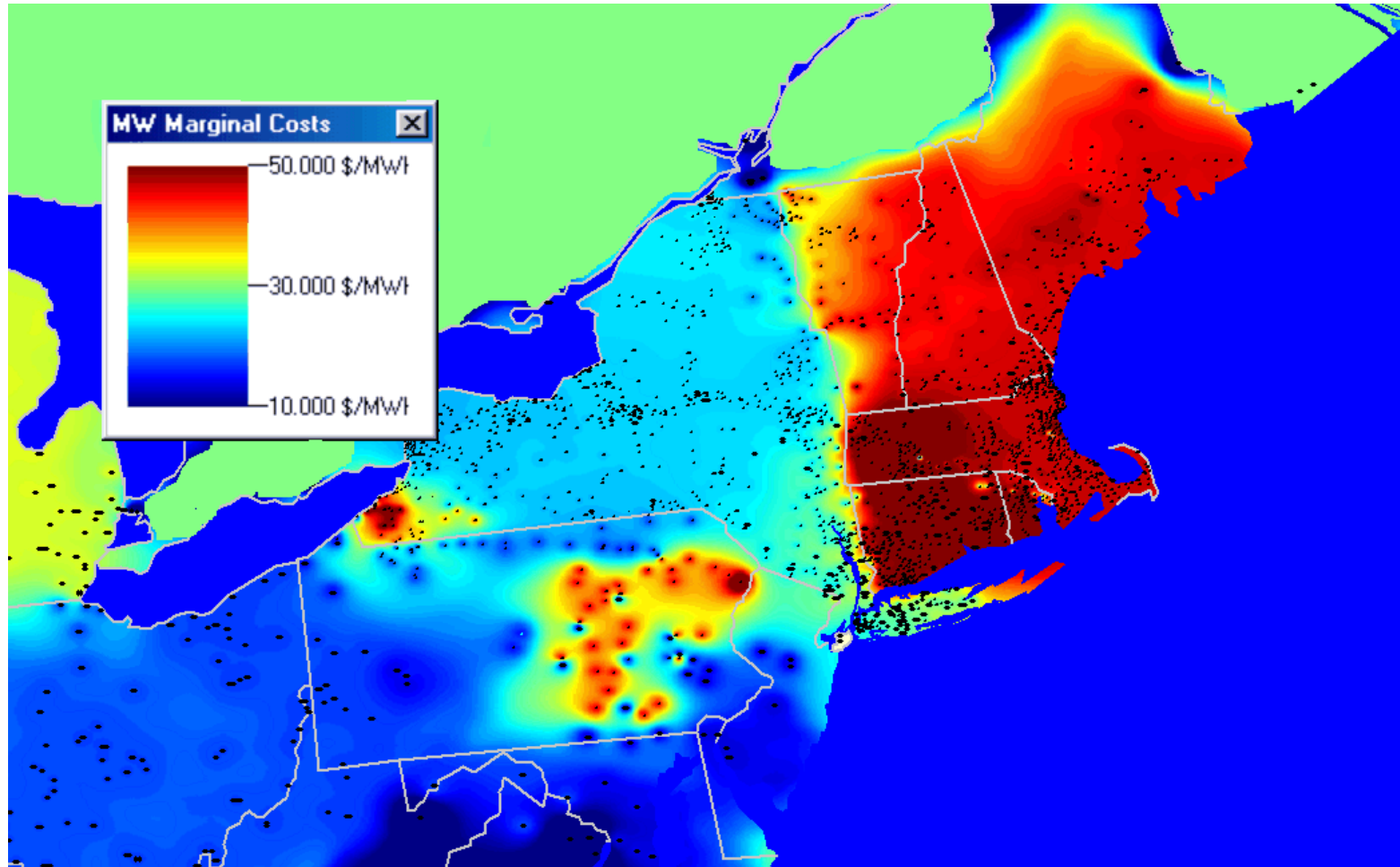
Total operating cost = \$ 4,445,990 / hr



Bus Marginal Prices - Narrow Range



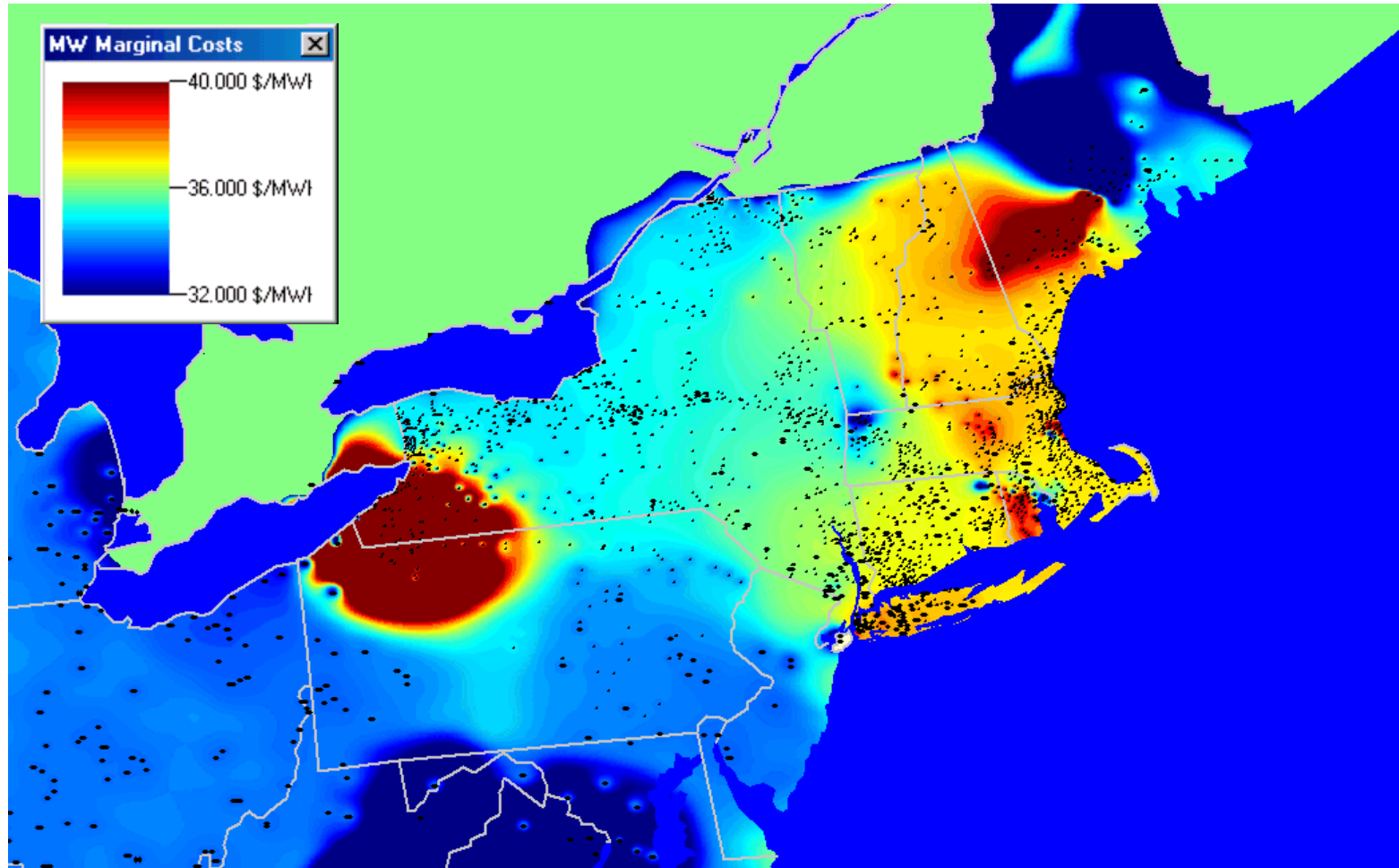
Bus Marginal Costs -- Individual Areas with Basecase Interchange



Total operating cost = \$4,494,170 / hr, an increase of \$48,170 / hr

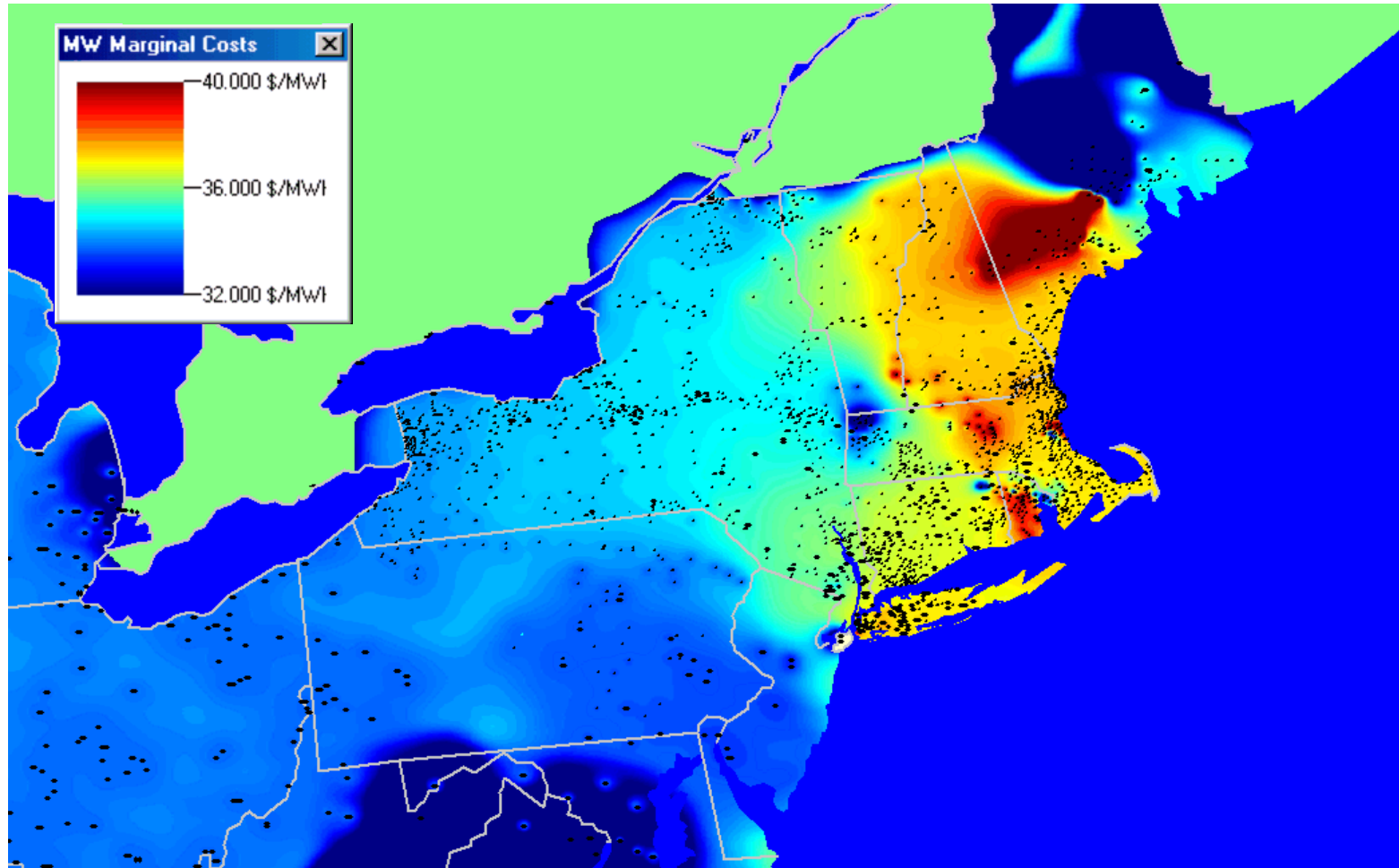
Superarea Case Again

85 MW Gen at 6642 is off



Superarea Case

85 MW Gen at 6642 is On



Slide Intentionally Left Blank