TRANSMISSION NETWORK CONGESTION

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TRANSMISSION NETWORK CONGESTION

- Why do we care?
  - Higher generating costs as low-cost generation is "constrained off"
  - Stressed networks are less reliable
- Why does congestion emerge?
  - Thermal/physical limits on lines and transformers
  - Engineering reliability and contingency criteria (N-1, N-2, etc.)
    - How are these engineering criteria defined?
    - How do they relate to economic valuations of lost load (VOLL), priced-based demand response, rolling blackouts, and network collapse?
- How to allocate "scarce" transmission capacity with competitive G sector?
  - Alternatives to central dispatch by vertically integrated utilities
  - Non-price rationing hierarchies (intra- and inter-control area TLR protocols) with tariff-based transmission service contracts
  - Security constrained bid-based dispatch (nodal pricing) plus financial transmission rights (FTR)
  - Tradeable cost-based physical transmission rights between defined zones or "flow gates"
- How do we stimulate investment in new transmission capacity?
  - Reliability rules
  - Congestion cost reduction
  - Market power mitigation
  - Regulated transmission investment
  - Merchant transmission investment
  - Hybrid models

TRANSMISSION CONGESTION

G_1 $C_1 = C_1(q_1)$

Cheapgen

K

$q_1 = K$

$C_1' < C_2'$

$$p_1^* = C_1'(K)$$
$$p_2^* = C_2'(D(p_2^* - K)) > p_1^*$$
$$q_1 = K$$
$$D(p_2^*) = q_1 + q_2 = K + q_2$$
$$\boldsymbol{\eta^*} = p_2^* - p_1^*$$

Deargen

G_2 $Q = q_1 + q_2 = D(p_2)$ Load

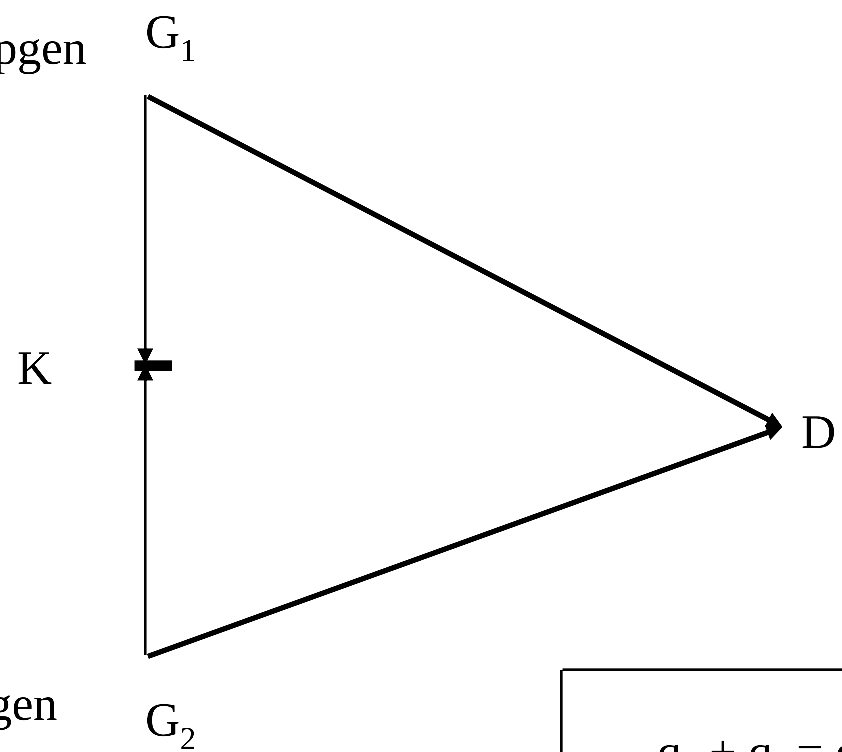
$C_2 = C_2(q_2)$

Joskow-Tirole

TRANSMISSION CONGESTION WITH LOOP FLOW

Node 1: Cheapgen

Cost: $C_1(q_1)$



$C_1' < C_2'$

Node 3: Consumption

$q_3 = D(p_3)$

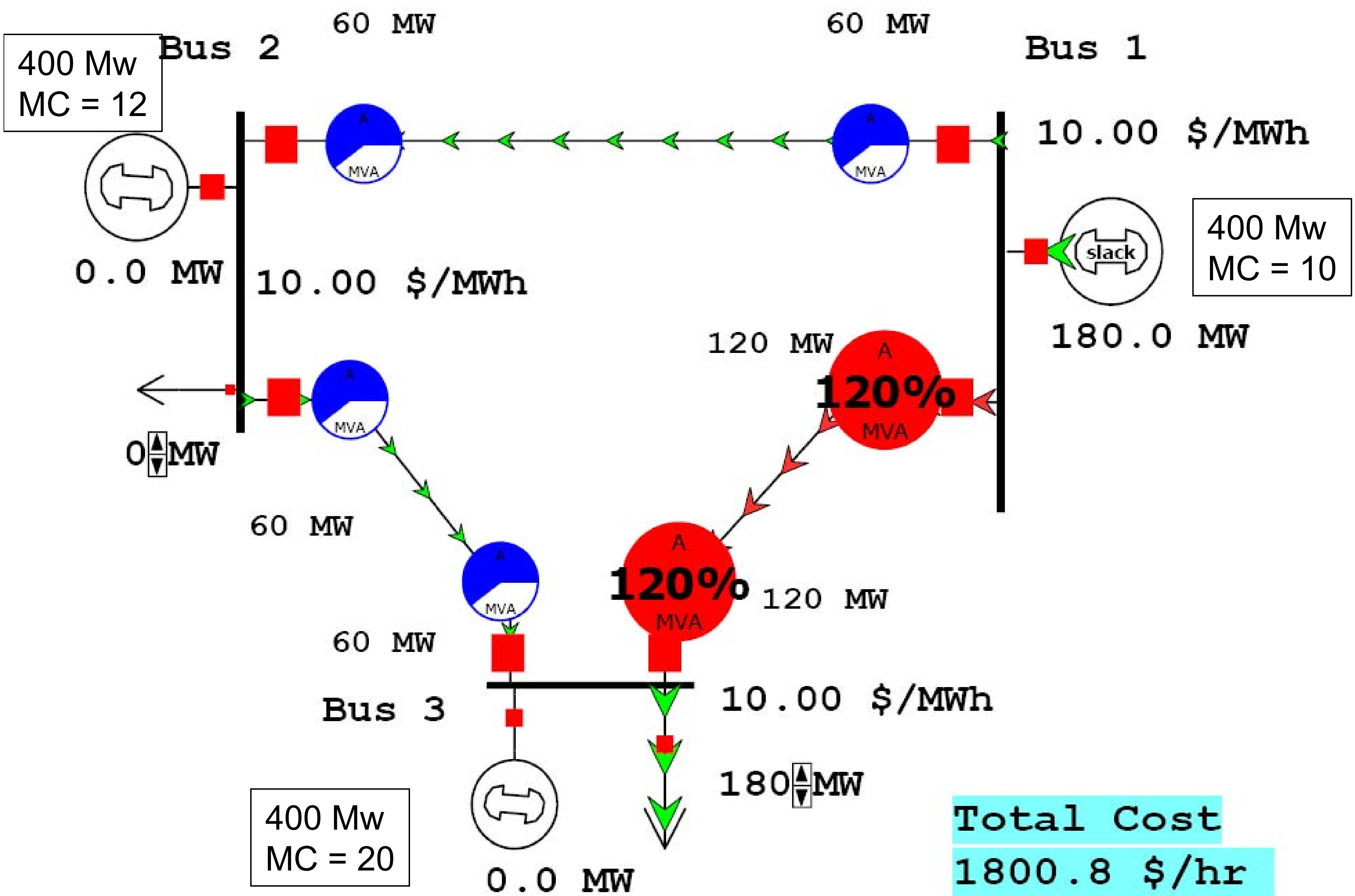
$p_3 = P(q_3)$

Node 2: Deargen

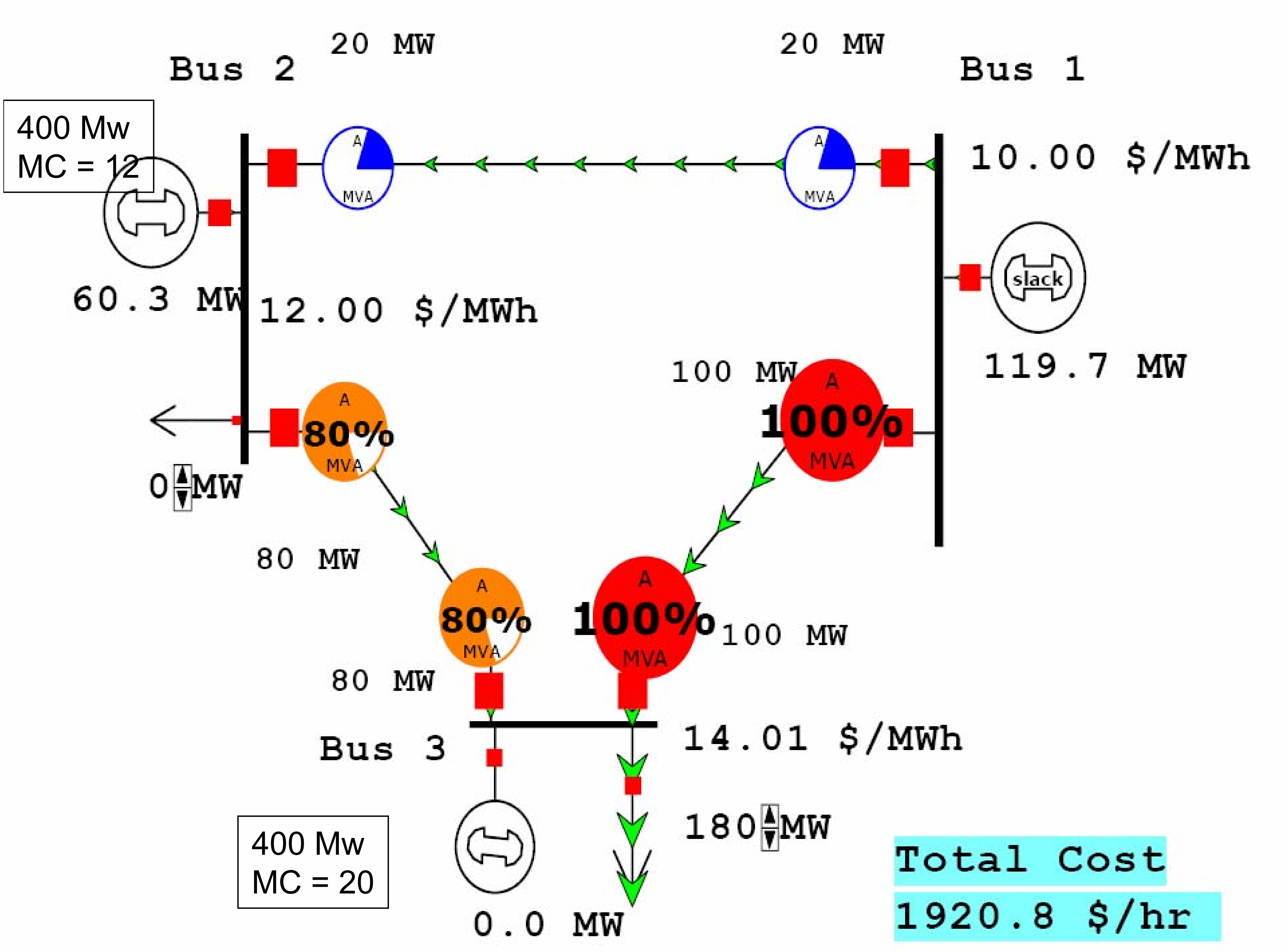
Cost: $C_2(q_2)$

$$q_1 + q_2 = q_3$$
$$1/3(q_1 - q_2) \leq K$$
$$p_1 = p_3 - \eta/3$$
$$p_2 = p_3 + \eta/3$$
$$p_3 = (p_1+p_2)/2$$
$$p_1 = C_1'(q_1) = C_1'(q_2 + 3K)$$
$$p_2 = 2P(2q_2 + 3K) - p_1$$

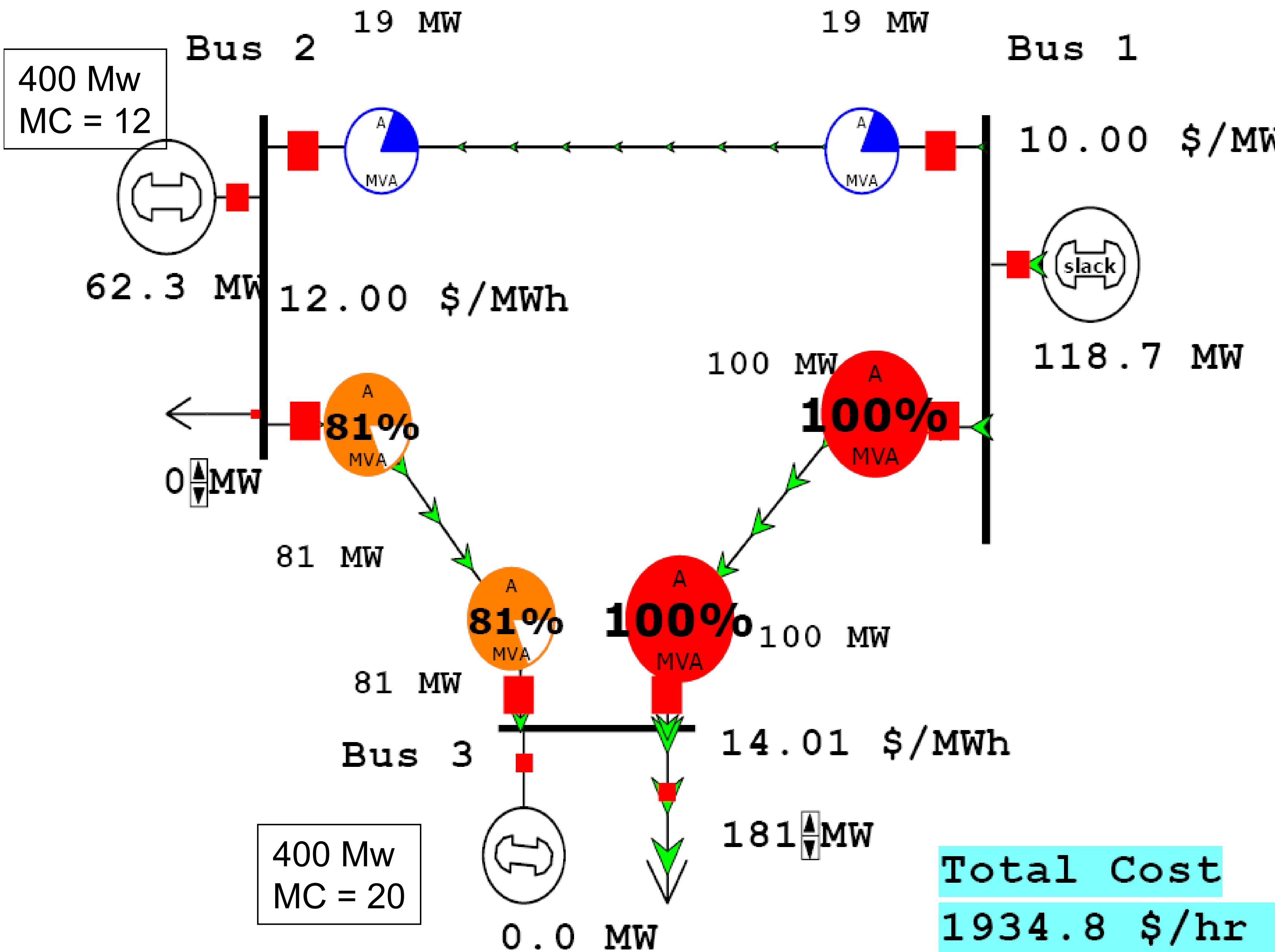
Joskow-Tirole



400 Mw
MC = 12
Bus 2
60 MW
60 MW
Bus 1
10.00 $/MWh
MVA
MVA
slack
400 Mw
MC = 10
0.0 MW
10.00 $/MWh
180.0 MW
120 MW
120%
MVA
0 MW
60 MW
120%
MVA
120 MW
60 MW
Bus 3
10.00 $/MWh
180 MW
400 Mw
MC = 20
0.0 MW
Total Cost
1800.8 $/hr

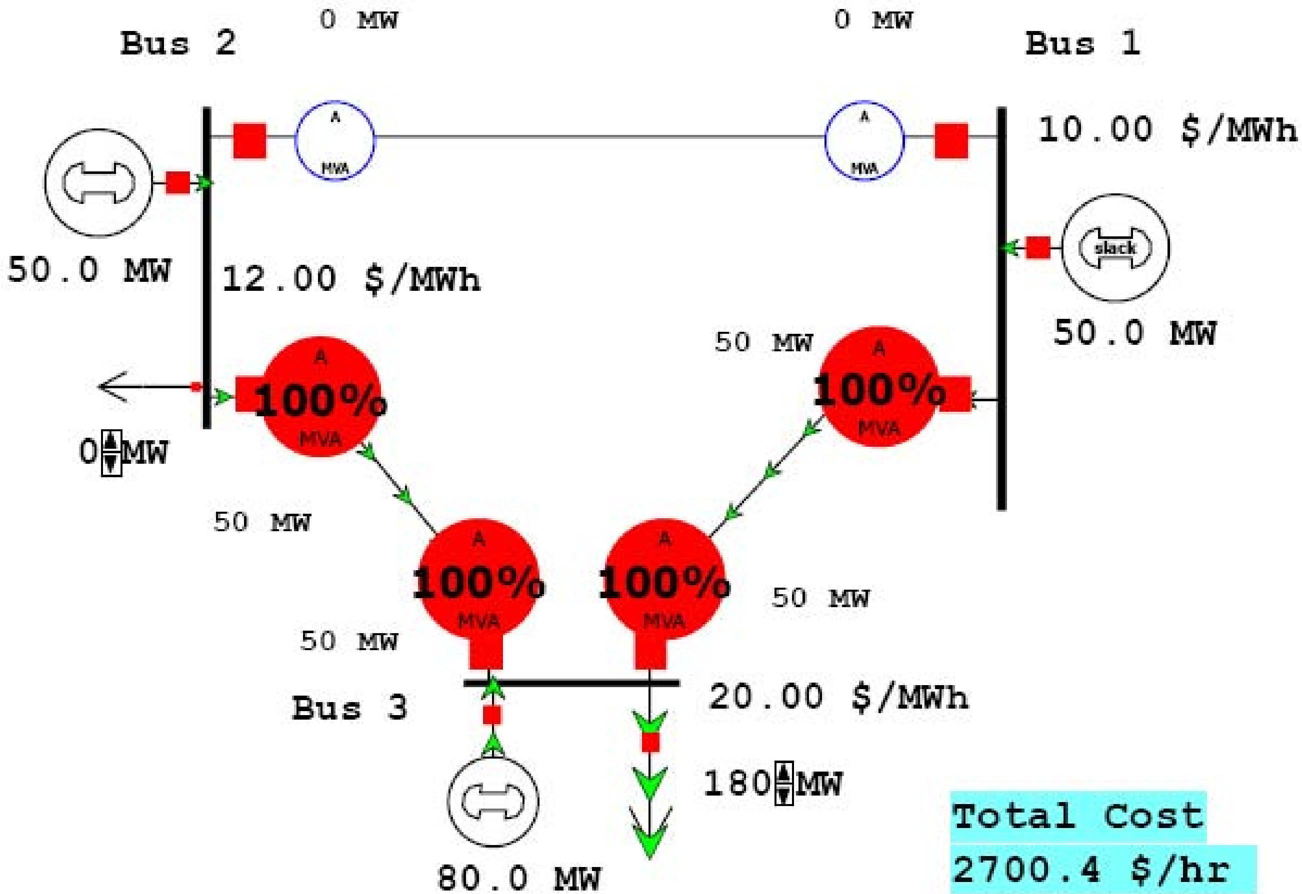


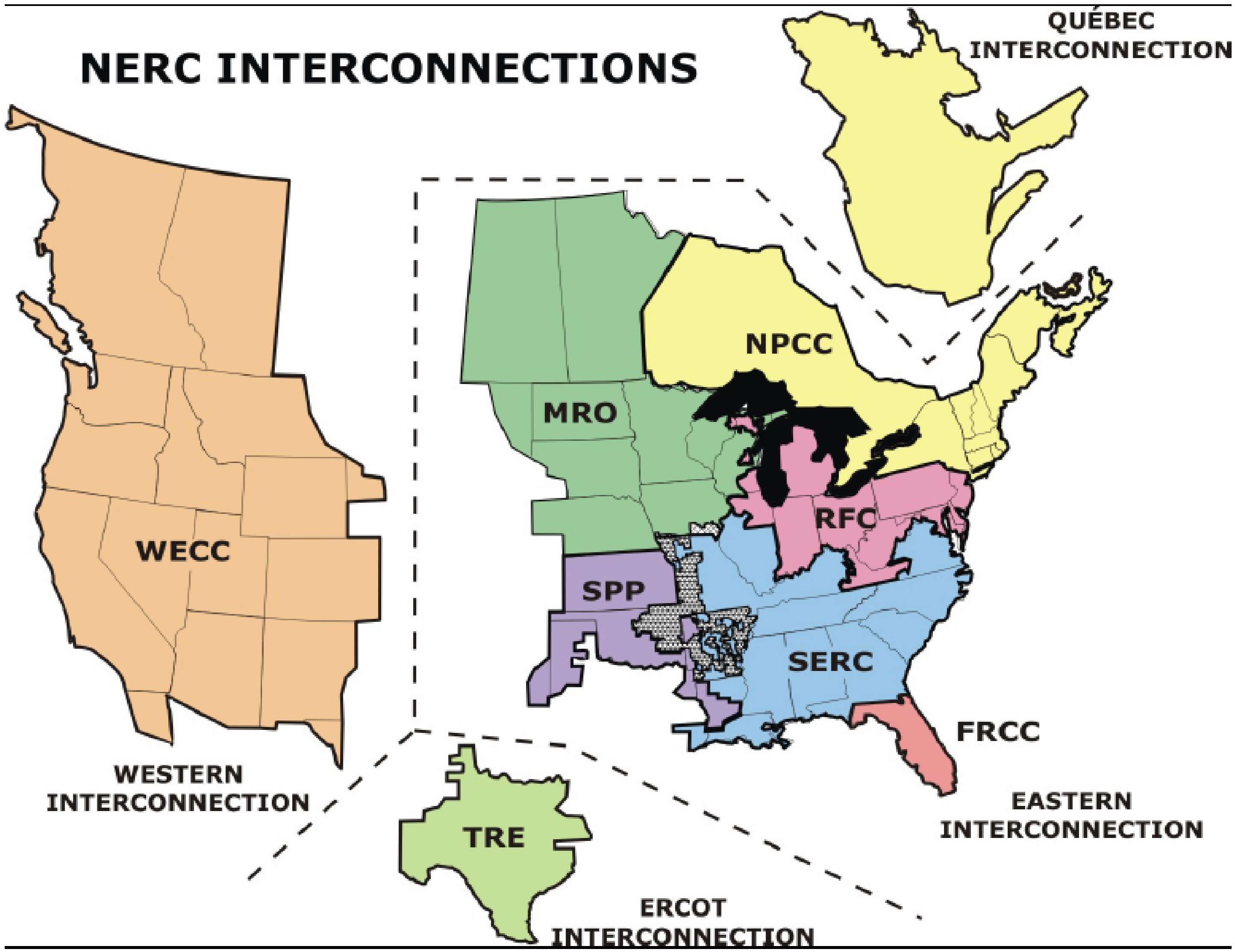
Bus 2
20 MW
20 MW
Bus 1
400 Mw
MC = 12
10.00 $/MWh
60.3 MW
12.00 $/MWh
slack
119.7 MW
100 MW
80%
100%
0 MW
80 MW
80%
100%
100 MW
80 MW
Bus 3
14.01 $/MWh
180 MW
400 Mw
MC = 20
0.0 MW
Total Cost
1920.8 $/hr


400 Mw
MC = 12
Bus 2
19 MW
19 MW
Bus 1
10.00 $/MWh
62.3 MW
12.00 $/MWh
slack
118.7 MW
100 MW
100%
MVA
81%
MVA
0 MW
81 MW
81%
100%
100 MW
81 MW
14.01 $/MWh
Bus 3
181 MW
400 Mw
MC = 20
0.0 MW
Total Cost
1934.8 $/hr

RELIABILITY AND CONTINGENCY CRITERIA

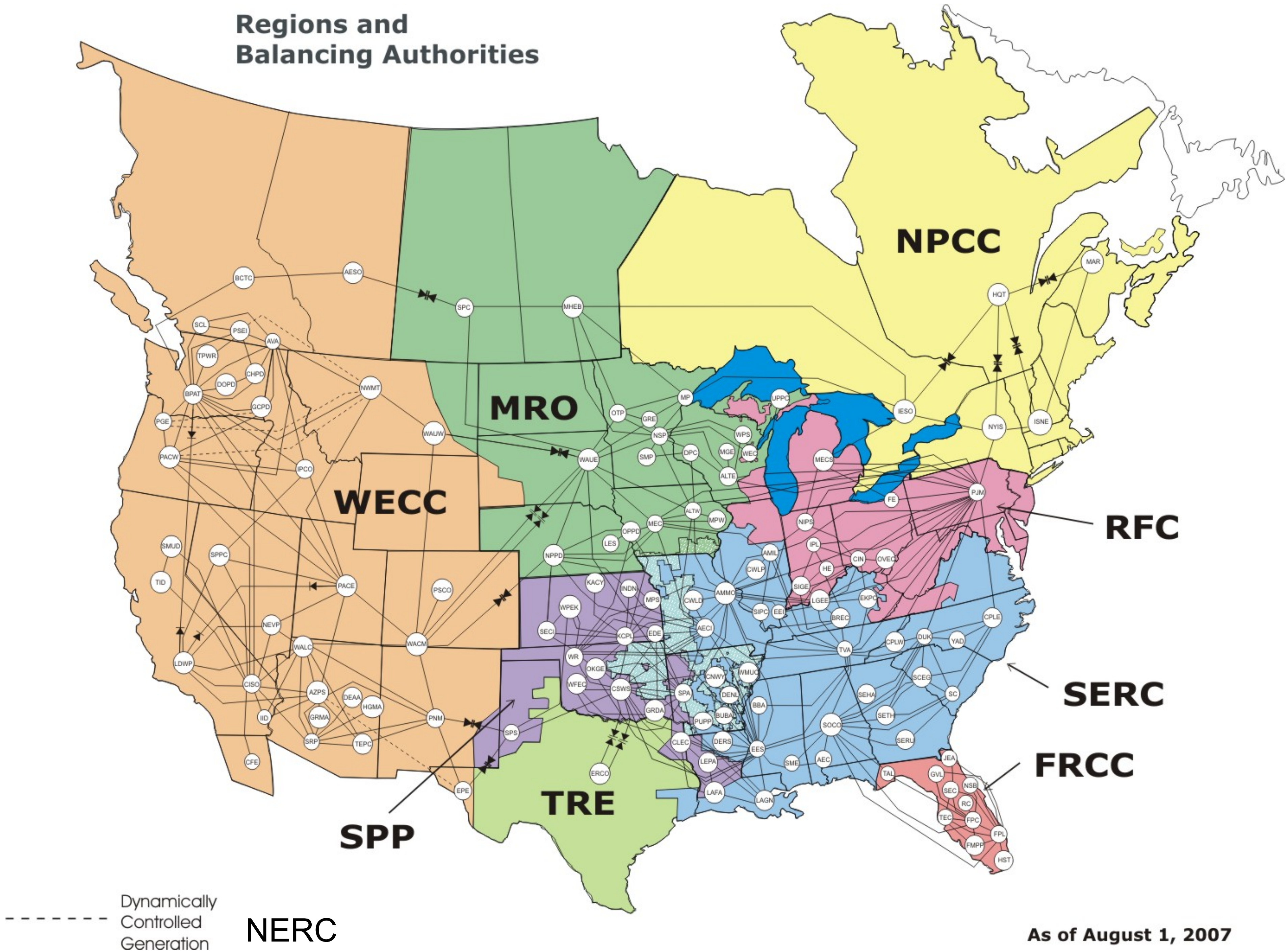
- Transmission capacity is rarely limited by thermal constraints on facilities
- Limits are typically a consequence of applying engineering reliability and contingency criteria
  - These criteria are not simple
  - They are based on a large number of assumptions about system conditions on many transmission links, generating stations and interconnected control areas
  - They can vary widely with system conditions and weather conditions
  - They can be affected by the installation of enhanced real time monitoring equipment
  - They are affected by the status of remedial action plans, information transfer and communication speeds
  - They give the system operator a lot of discretion
- These reliability and contingency criteria have been carried over from the old world of (many) regulated vertically integrated monopoly control area operators
  - There has been little evaluation of the economic rational or economic effects of these criteria
  - They affect wholesale market prices for energy


Bus 2
0 MW
0 MW
Bus 1
10.00 $/MWh
50.0 MW
12.00 $/MWh
50 MW
100%
100%
50.0 MW
0 MW
50 MW
100%
100%
50 MW
50 MW
Bus 3
20.00 $/MWh
180 MW
Total Cost
2700.4 $/hr
80.0 MW



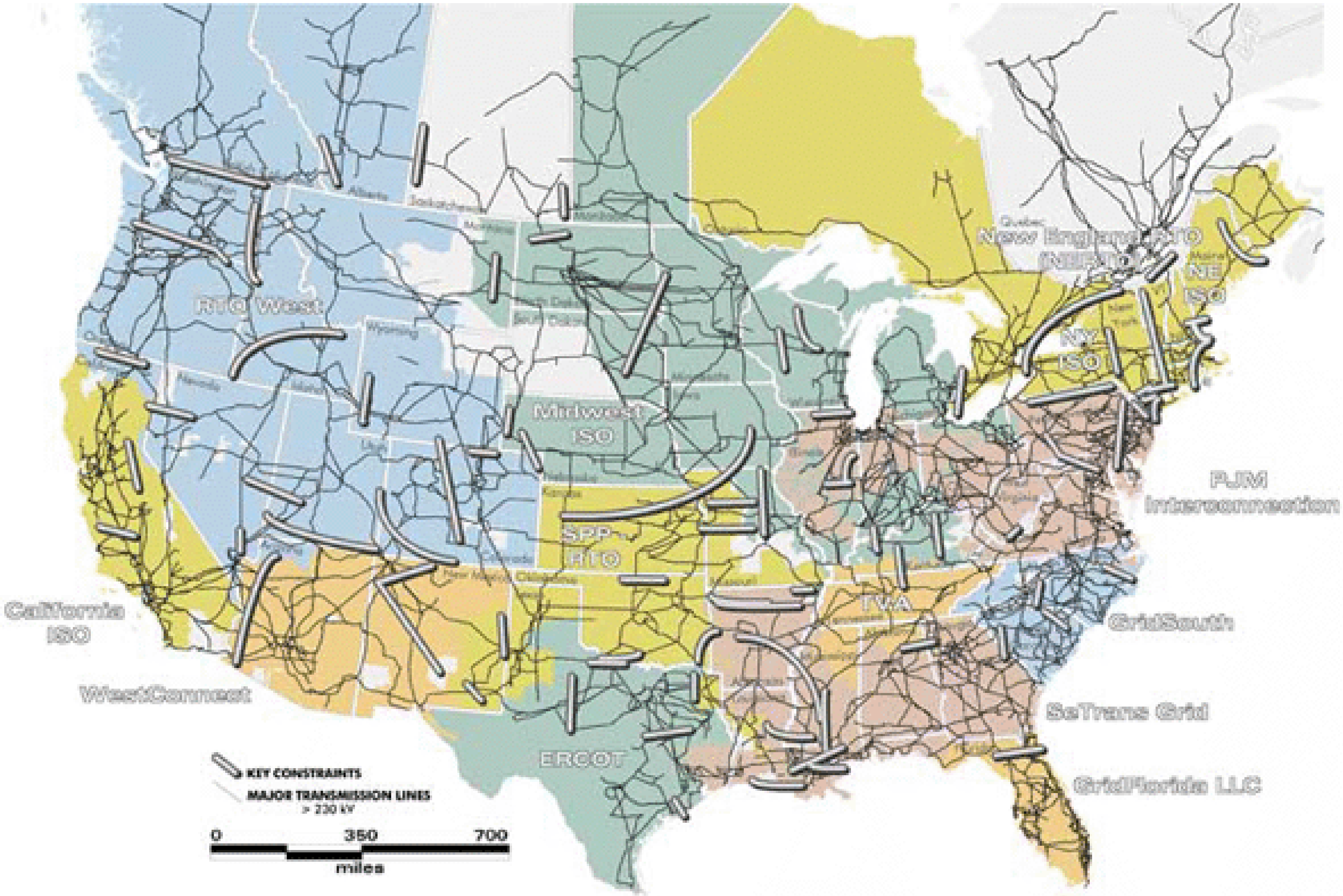
NERC INTERCONNECTIONS
QUÉBEC
INTERCONNECTION
NPCC
MRO
RFC
WECC
SPP
SERC
FRCC
TRE
WESTERN
INTERCONNECTION
EASTERN
INTERCONNECTION
ERCOT
INTERCONNECTION

NERC


Regions and
Balancing Authorities
NPCC
MRO
WECC
RFC
SERC
FRCC
TRE
SPP
Dynamically
Controlled
Generation
As of August 1, 2007

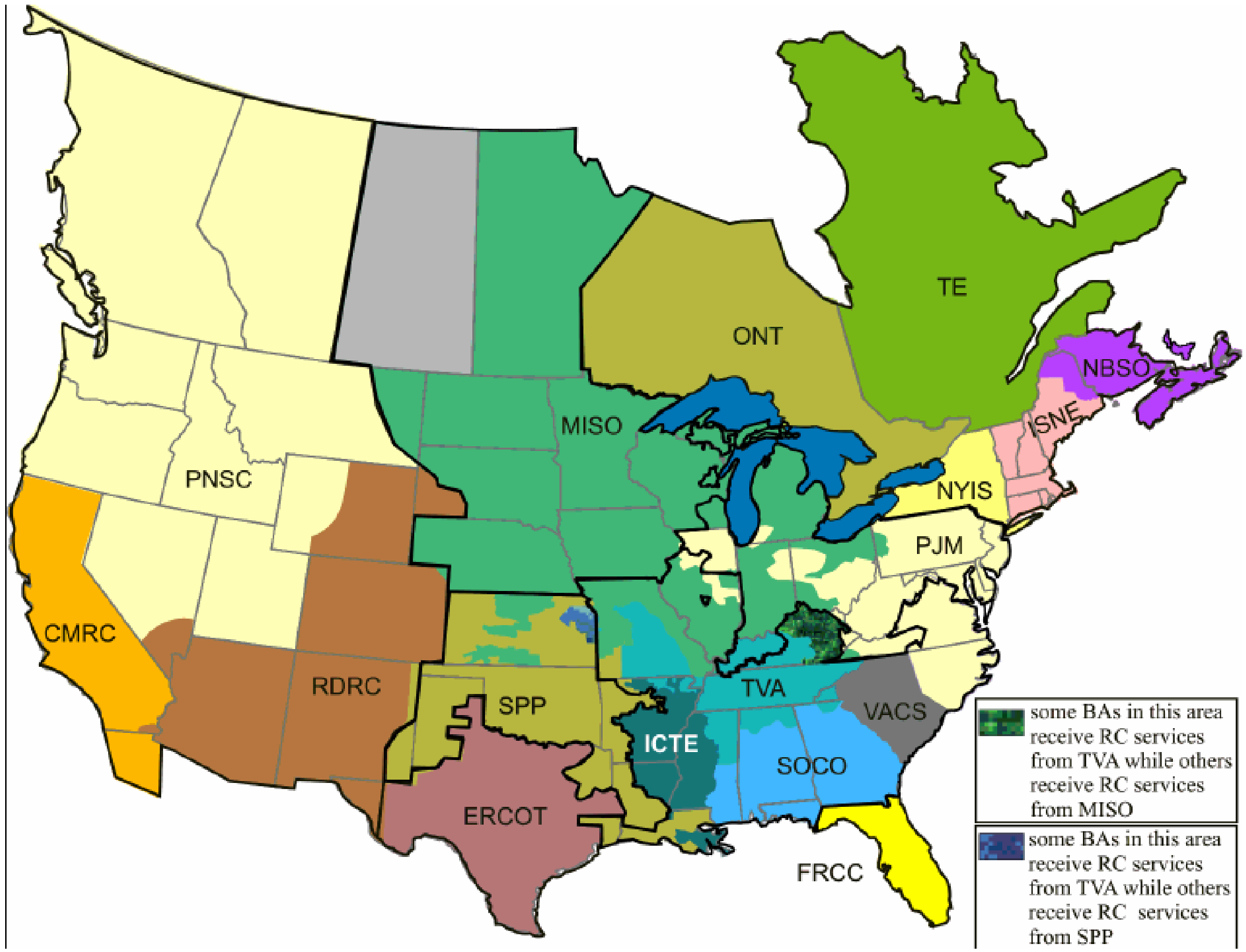
NERC

MAJOR U.S. CONGESTED INTERFACES



Source: Platts

Security Coordinators



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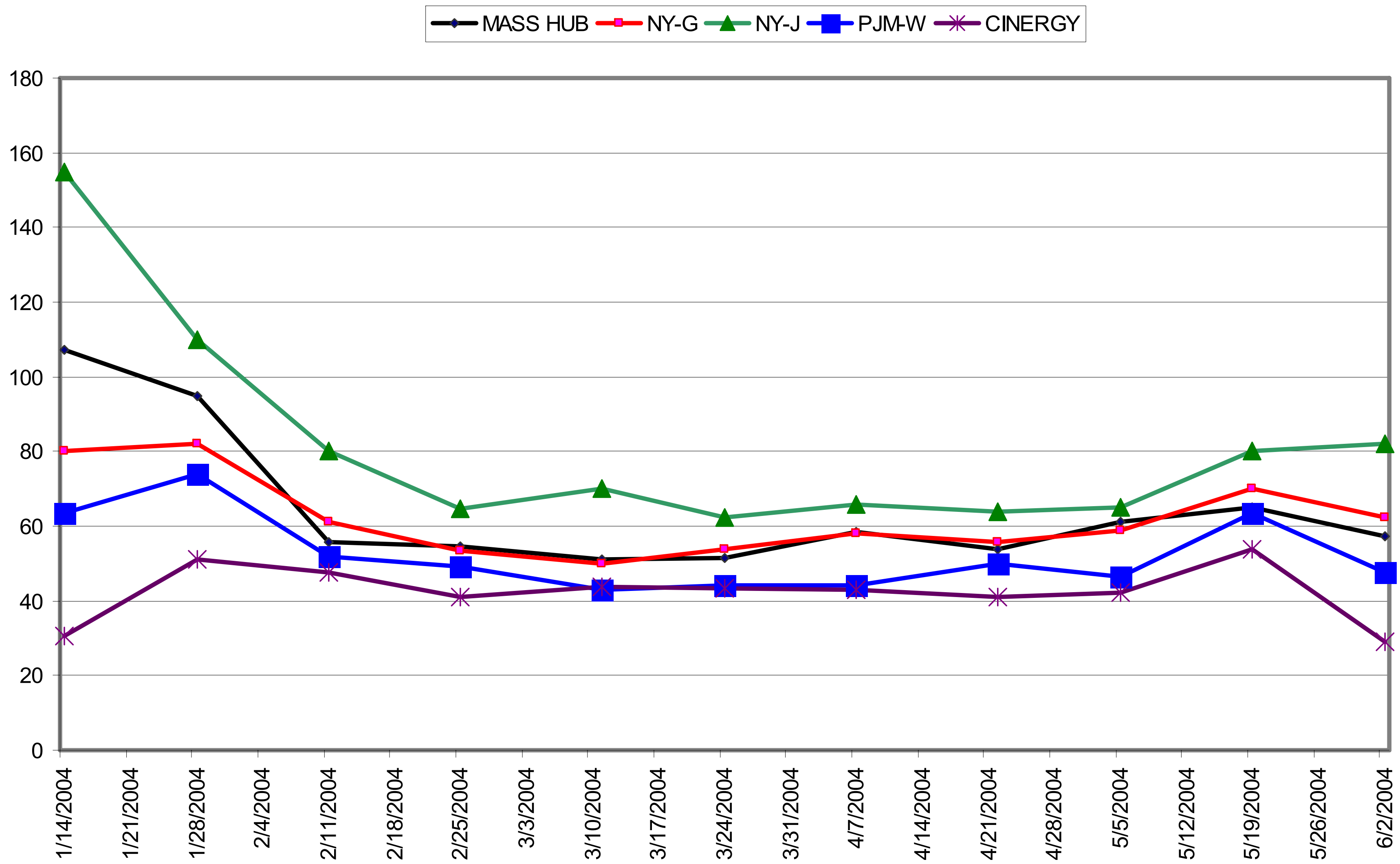
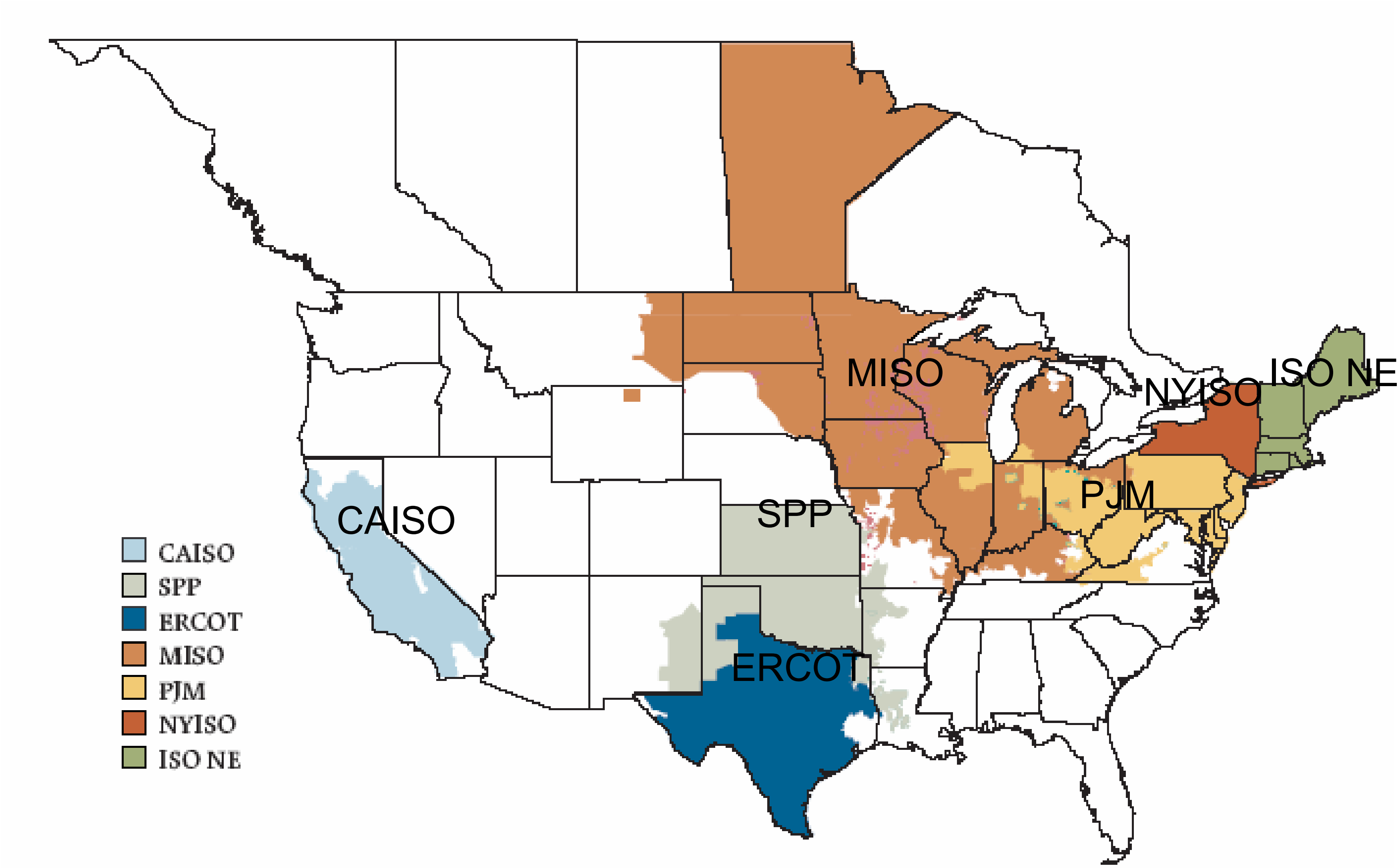
DAY-AHEAD PEAK WHOLESALE ENERGY PRICES (2004) $/MWH



CONGESTION MANAGEMENT IN THE U.S.

- Nodal Pricing Areas
  - New England
  - New York
  - PJM
  - MISO
  - California (next year)
  - Texas (Zonal/flowgates → nodal)
- Rest of U.S.
  - Tariff-based transmission service with limited trading
  - No congestion pricing
  - Administrative rationing of scarce capacity

ISO/RTOs in the United States 2006



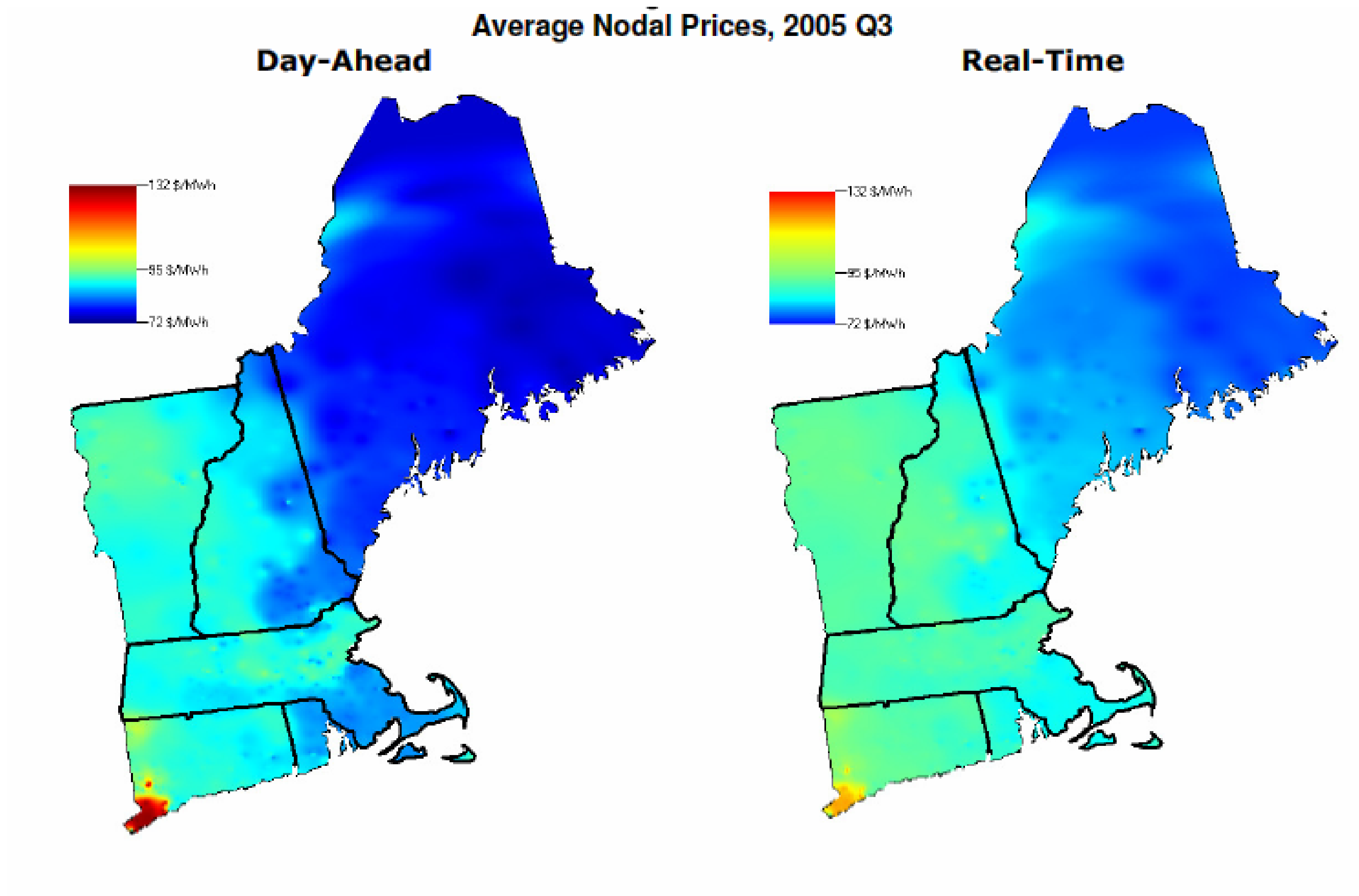
Source: State of the Markets Report 2004, FERC Office of Market Oversight and Investigations (2005, page 53).

Table 8: RTO Market Characteristics in 2006

■ Existing　□ Projected　◆ Cost-Based　● Other

Services Provided	ISO-NE	NYISO	PJM	MISO	SPP	ERCOT	CAISO
Bilateral transactions	■	■	■	■	■	■	■
Active online physical trading	■		■	■		■	■
Active online financial trading	■	■	■	■			■
Real-time energy market	■	■ [1]	■	■	■ [2]	■	■
Locational energy price	■	■	■	■	■	■	■
Hourly energy price	■	■	■	■	■	■	■
Congestion price	■	■	■	■	■	■	■
Losses price	■	■	□ 07 [3]	■	■ [4]	■	■ [5]
Day-ahead energy market	■	■ [1]	■	■		□ 09	□ 08
Locational energy price	■	■	■	■		□ 09	□ 08
Hourly energy price	■	■	■	■		□ 09 [6]	□ 08
Congestion price	■	■	■	■		□ 09	■ [7]
Losses price	■	■	□ 07 [3]	■			□ 08
Ancillary services market	■	■	■	□ 08	◆	■	■
Regulation service market	■	■	◆ [8]	◆	◆	■	■
Operating reserves market	■	■	■ [9]	◆ [10]	◆	■	■
Reactive power market	● [11]	● [12]	◆	◆	◆	◆	◆
Black start market		◆	◆	◆	◆	● [13]	◆
Financial transmission rights	■	■	■	■		■	■ [7]
Capacity market	■ [14]	■	■			● [15]	◆ [16]
Regional transmission scheduling	■	■	■	■	■	■	■
Regional economic dispatch	■	■	■	■	■	■ [17]	■ [17]
Regional transmission planning	■	■	■	■	■	■	■
Regional interconnection process	■	■	■	■	■	■	■
Independent market monitor	■	■	■	■	■	■	■
Mitigation	■	■	■	■	■		■

Source: FERC *2006 State of the Markets Report*



Average Nodal Prices, 2005 Q3
Day-Ahead
Real-Time
132 $/MWh
95 $/MWh
72 $/MWh
132 $/MWh
95 $/MWh
72 $/MWh

ISO-NE (2006)

NODAL PRICING MODEL

- The nodal pricing models now work reasonably well in the Eastern ISOs from both economic dispatch and reliability perspectives
- NE, NY and PJM now include marginal losses in prices
- Congestion is managed economically and least bid-cost dispatch is achieved
- Nodal prices provide a good indication of congestion costs (except during scarcity conditions)
- Day-ahead and real-time prices are well arbitraged in an expected value sense
- Market power and gaming are more transparent than with other systems
- Coordination between ISOs is improving
  - PJM internalized through expansion and joint operating agreements with MISO
- California and Texas are moving to nodal pricing due to problems with zonal models

NON-PRICE RATIONALING

Priority of Interchange Transactions

3.1.1. Interchange Transaction curtailment priority shall be determined by the Transmission Service reserved over the constrained facility(ies) as follows:

Transmission Service Priorities

Priority 0. Next-hour Market Service — NX*

Priority 1. Service over secondary receipt and delivery points — NS

Priority 2. Non-Firm Point-to-Point Hourly Service — NH

Priority 3. Non-Firm Point-to-Point Daily Service — ND

Priority 4. Non-Firm Point-to-Point Weekly Service — NW

Priority 5. Non-Firm Point-to-Point Monthly Service — NM

Priority 6. Network Integration Transmission Service from sources not designated as network resources — NN

Priority 7. Firm Point-to-Point Transmission Service — F and Network Integration Transmission Service from Designated Resources — FN

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Example

This example is based on the premise that a transaction should be curtailed in proportion to its Transfer Distribution Factor on the Constraints. Its effect on the interface is a combination of its size in MW and its effect based on its distribution factor.

Column	**Description**
1. Initial Transaction	Interchange Transaction before the TLR Procedure is implemented.
2. Distribution Factor	Proportional effect of the Transaction over the constrained interface due to the physical arrangement and impedance of the transmission system.
3. Impact on the Interface	Result of multiplying the Transaction MW by the distribution factor. This yields the MW that flow through the constrained interface from the Transaction. Performing this calculation for each Transaction yields the total flow through the constrained interface from all the Interchange Transactions. In this case, 760 MW.
4. Impact Weighting Factor	"Normalization" of the total of the Distribution Factors in Column 2. Calculated by dividing the Distribution Factor for each Transaction by the total of the Distribution Factors.
5. Weighted Maximum Interface Reduction	Multiplying the Impact on the Interface from each Transaction by its Impact Weighting Factor yields a new proportion that is a combination of the MW Impact on the Interface and the Distribution Factor.
6. Interface Reduction	Multiplying the amount needed to reduce the flow over the constrained interface (280 MW) by the normalization of the Weighted Maximum Interface Reduction yields the actual MW reduction that each Transaction must *contribute* to achieve the total reduction.
7. Transaction Reduction	Now divide by the Distribution Factor to see how much the Transaction must be reduced to yield the result calculated in Column 7. Note that the reductions for the first two Interchange Transactions (A-D (1) and A-D (2) are in proportion to their size since their distribution factors are equal.
8. New Transaction Amount	Subtracting the Transaction Reduction from the Initial Transaction yields the New Transaction Amount.
9. Adjusted Impact on Interface	A check to ensure the new constrained interface MW flow has been reduced to the target amount.

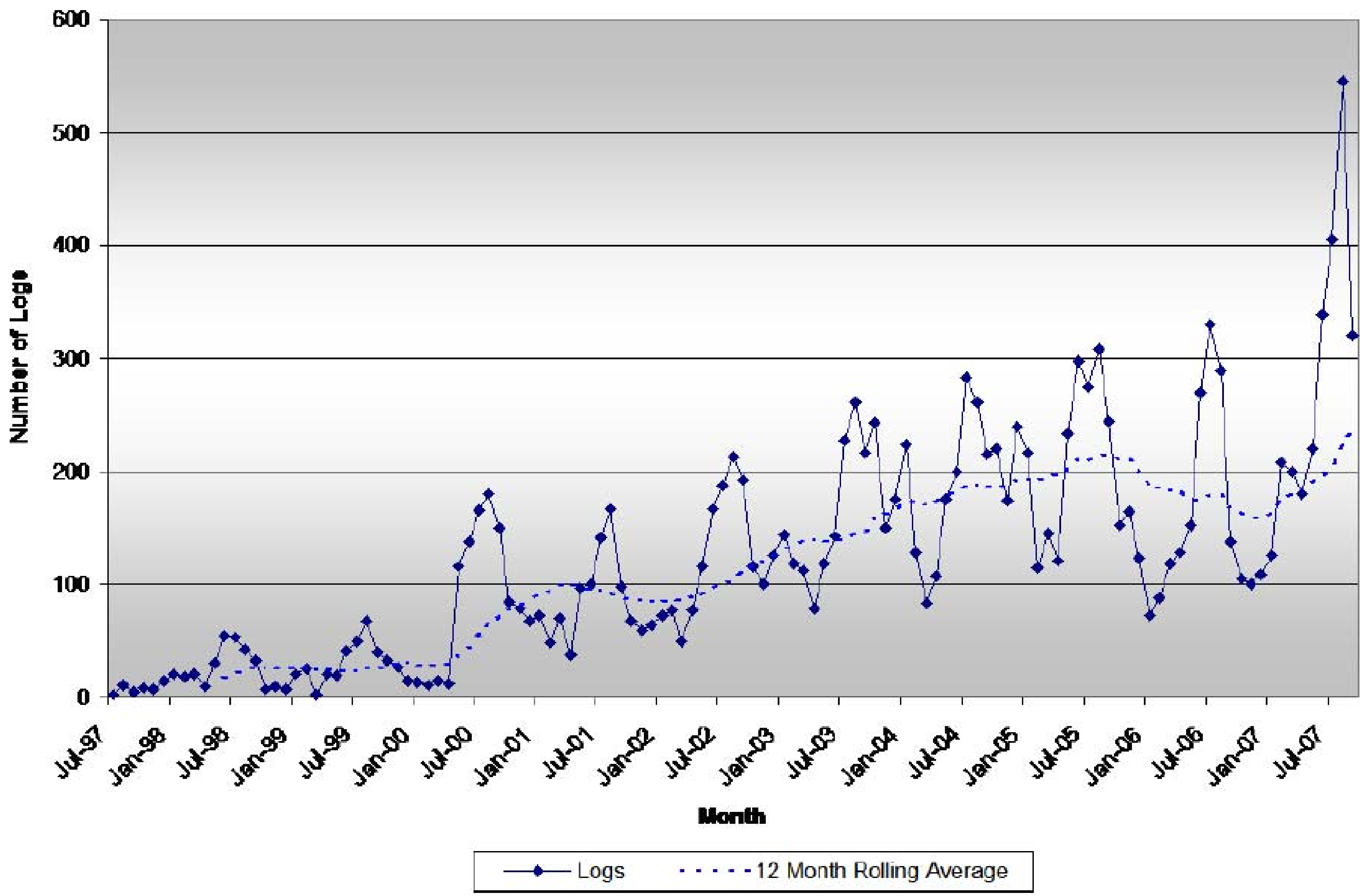
Example 2

Flow to maintain on Facility	800 MW
Expected flow next hour from Transactions using Point-to-Point Transmission Service	950 MW
Contribution from flow next hour from service to Network customers and Native Load	50 MW
Expected Net flow next hour on Facility	1000 MW
Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation	1000 MW – 800 MW = 200 MW
Amount to enter into IDC for Transactions using Point-to-Point Transmission Service	950 MW – 200 MW = 750 MW

Example 3

Flow to maintain on Facility	800 MW
Expected flow next hour from Transactions using Point-to-Point Transmission Service	950 MW
Contribution from flow next hour from service to Network customers and Native Load	-200 MW
Expected Net flow next hour on Facility	750 MW
Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation	750 MW – 800 MW = -50 MW None are held

Total Number of TLR Logs Reported by Month
Same Data as Chart01 - Different View



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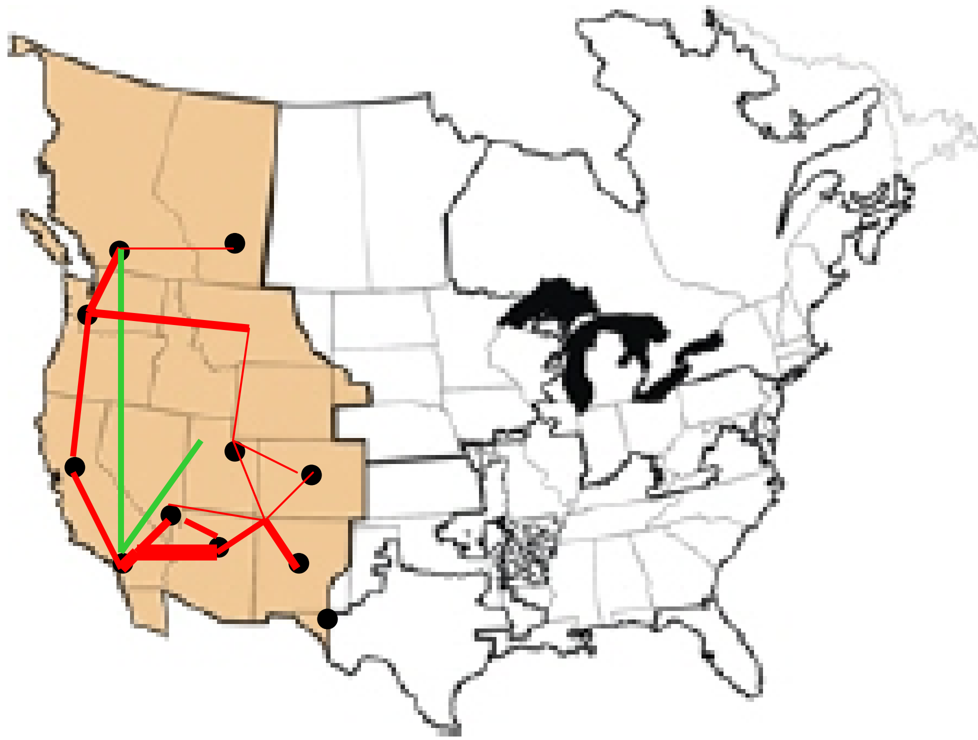
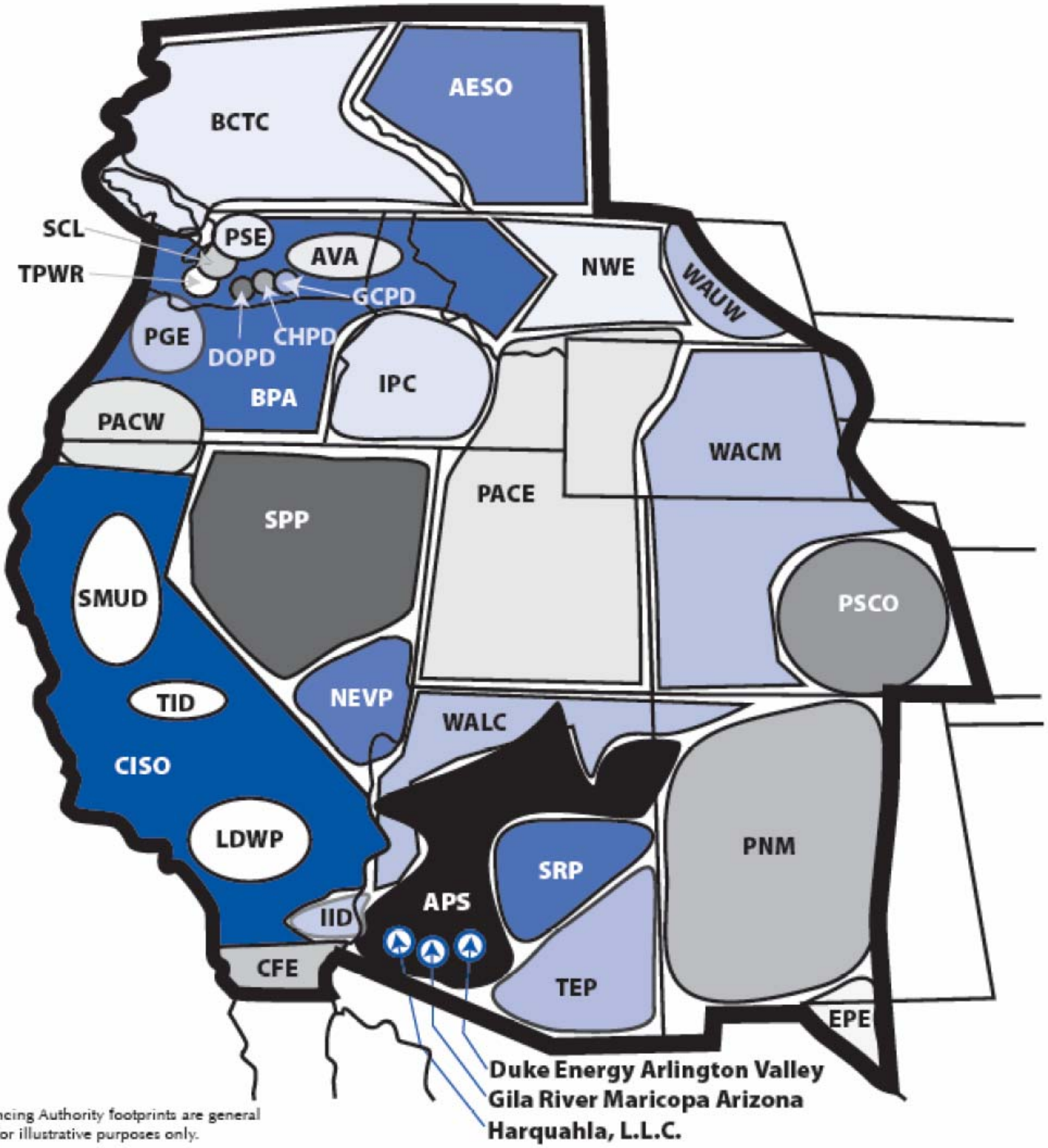
NON-PRICE RATIONING

- Works reasonably well from a reliability perspective as long as there is good communication between SOs, between SOs and generators and generators follow instructions
- Redispatch is not necessarily efficient because it is not based on hour-ahead costs of redispatch
- TLRs continue to increase
- Continuing arguments about whether redispatch was “fair” and consistent with contracts
  - This problem is exacerbated when SO also owns generating capacity on the network
- Cost and price of congestion is not transparent

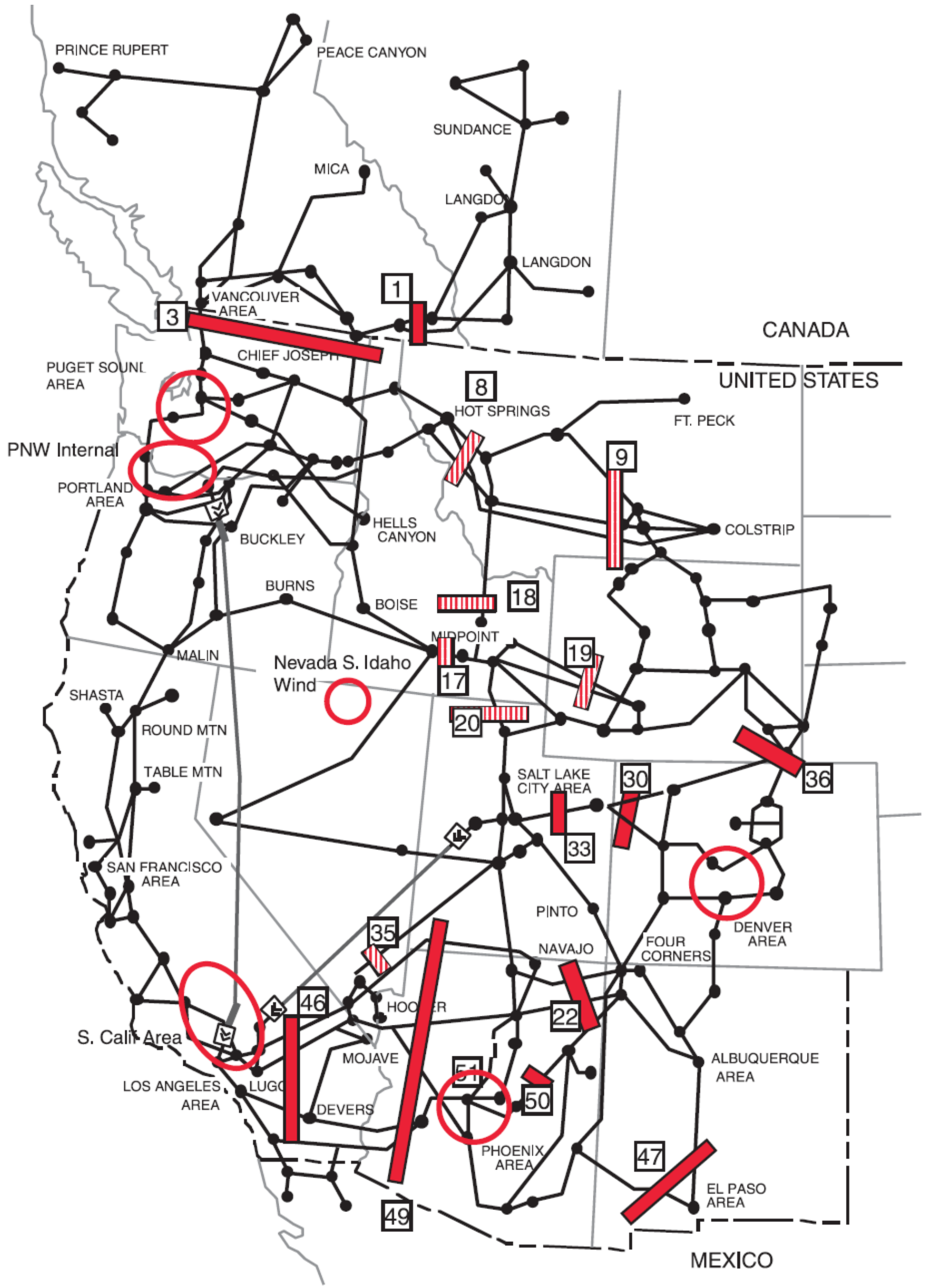
WECC



Adapted from NERC

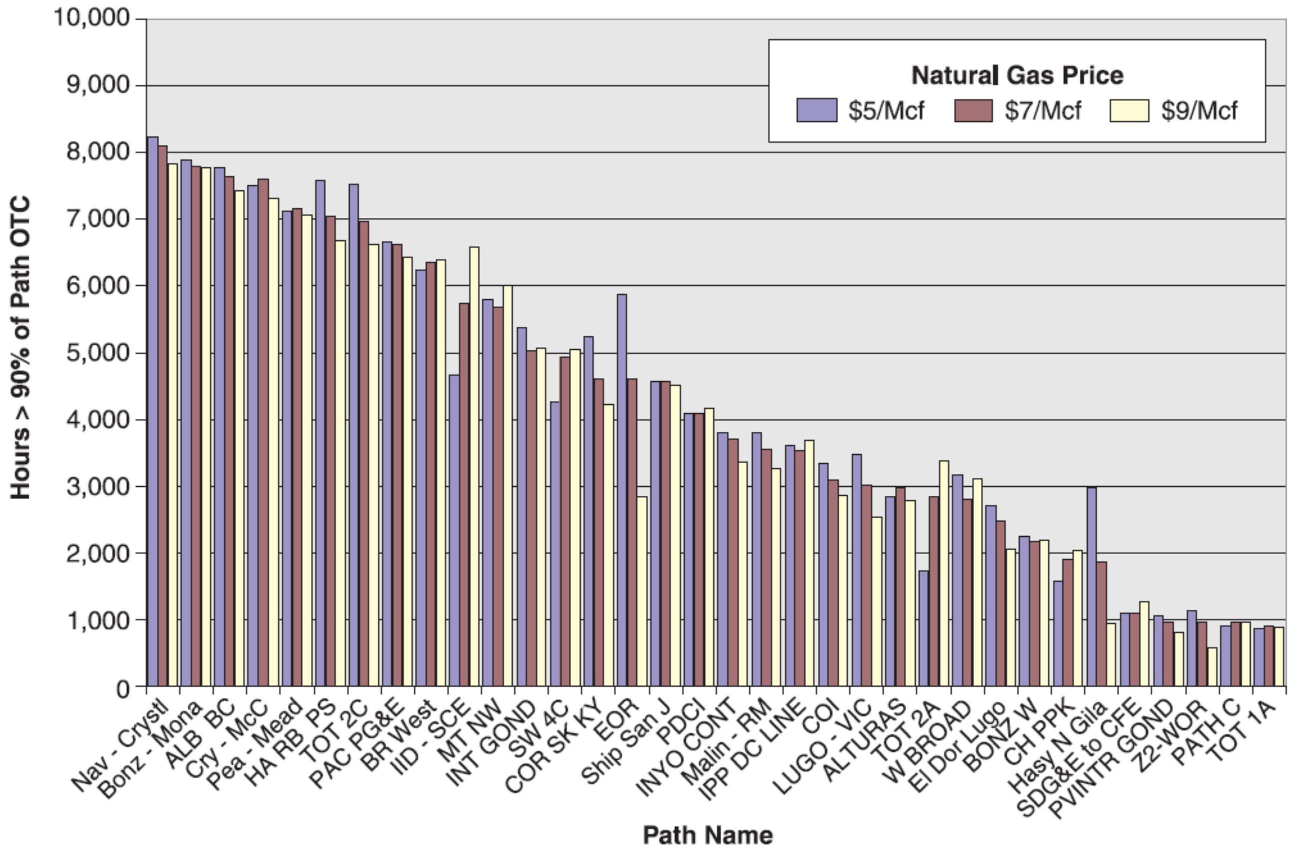


Balancing Authority footprints are general and for illustrative purposes only.


PRINCE RUPERT
PEACE CANYON
SUNDANCE
MICA
LANGDON
LANGDON
VANCOUVER AREA
1
3
CANADA
UNITED STATES
CHIEF JOSEPH
PUGET SOUND AREA
8
HOT SPRINGS
FT. PECK
9
PNW Internal
PORTLAND AREA
COLSTRIP
BUCKLEY
HELLS CANYON
BURNS
BOISE
18
MIDPOINT
MALIN
Nevada S. Idaho Wind
17
19
SHASTA
ROUND MTN
20
TABLE MTN
SALT LAKE CITY AREA
30
36
33
SAN FRANCISCO AREA
PINTO
DENVER AREA
35
NAVAJO
FOUR CORNERS
46
HOOVER
22
S. Calif Area
MOJAVE
ALBUQUERQUE AREA
LOS ANGELES AREA
LUGO
51
50
DEVERS
PHOENIX AREA
47
EL PASO AREA
49
MEXICO

DOE

Figure 4-4. Projected Congestion on Western Transmission Paths, 2008



U90 values at alternative natural gas prices.

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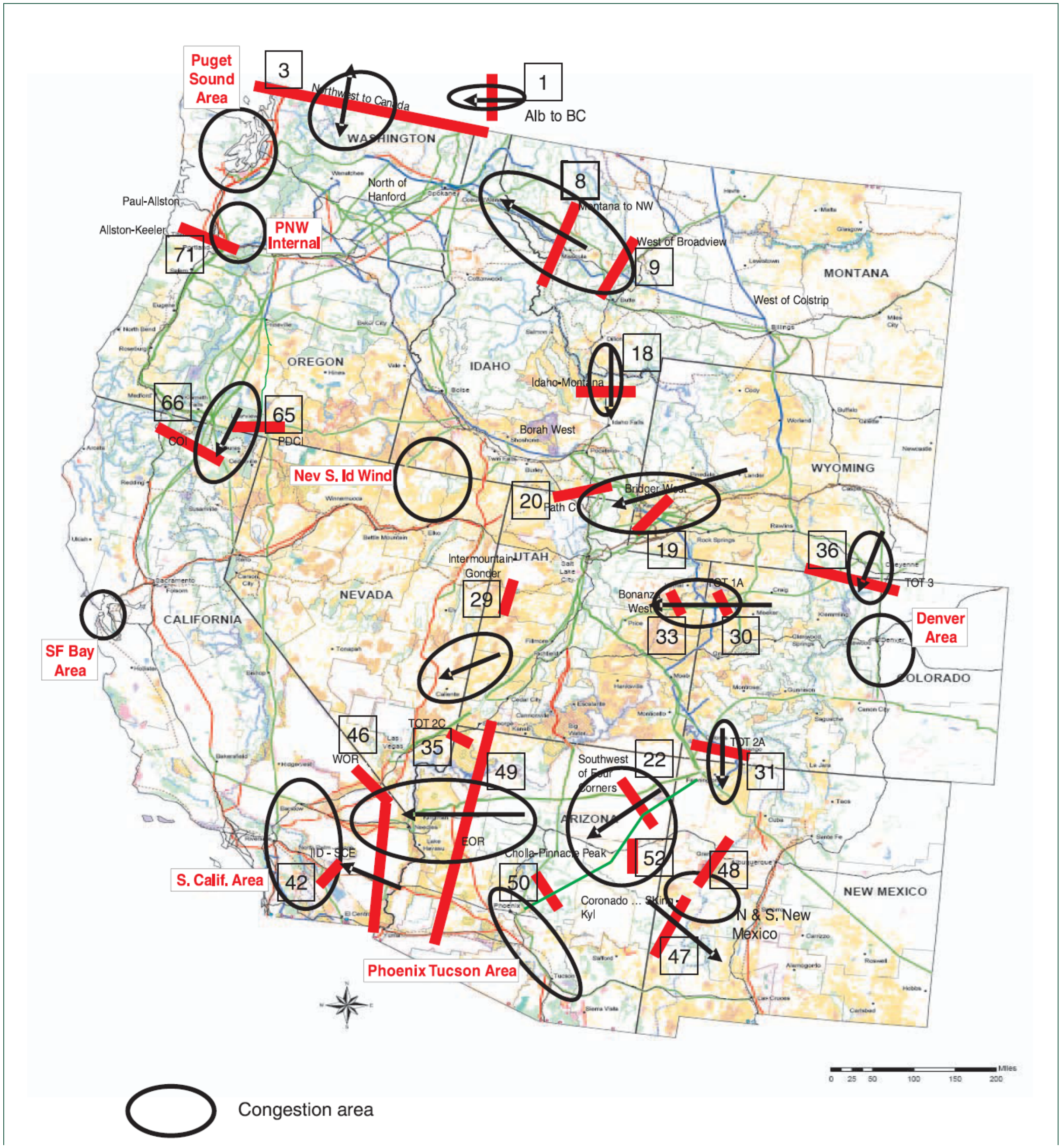
Figure 4-7. Existing and Projected Major Transmission Constraints in the Western Interconnection



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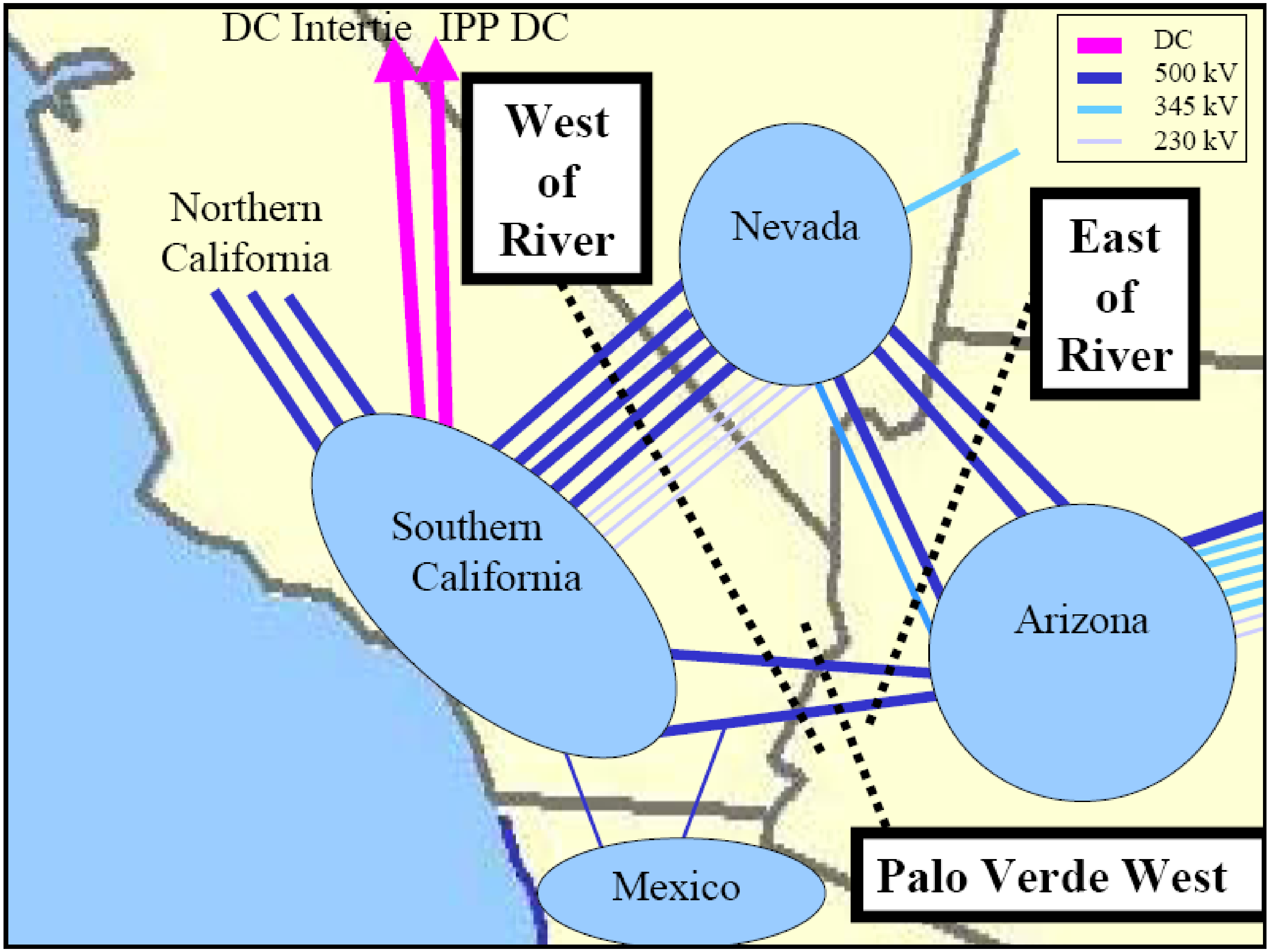
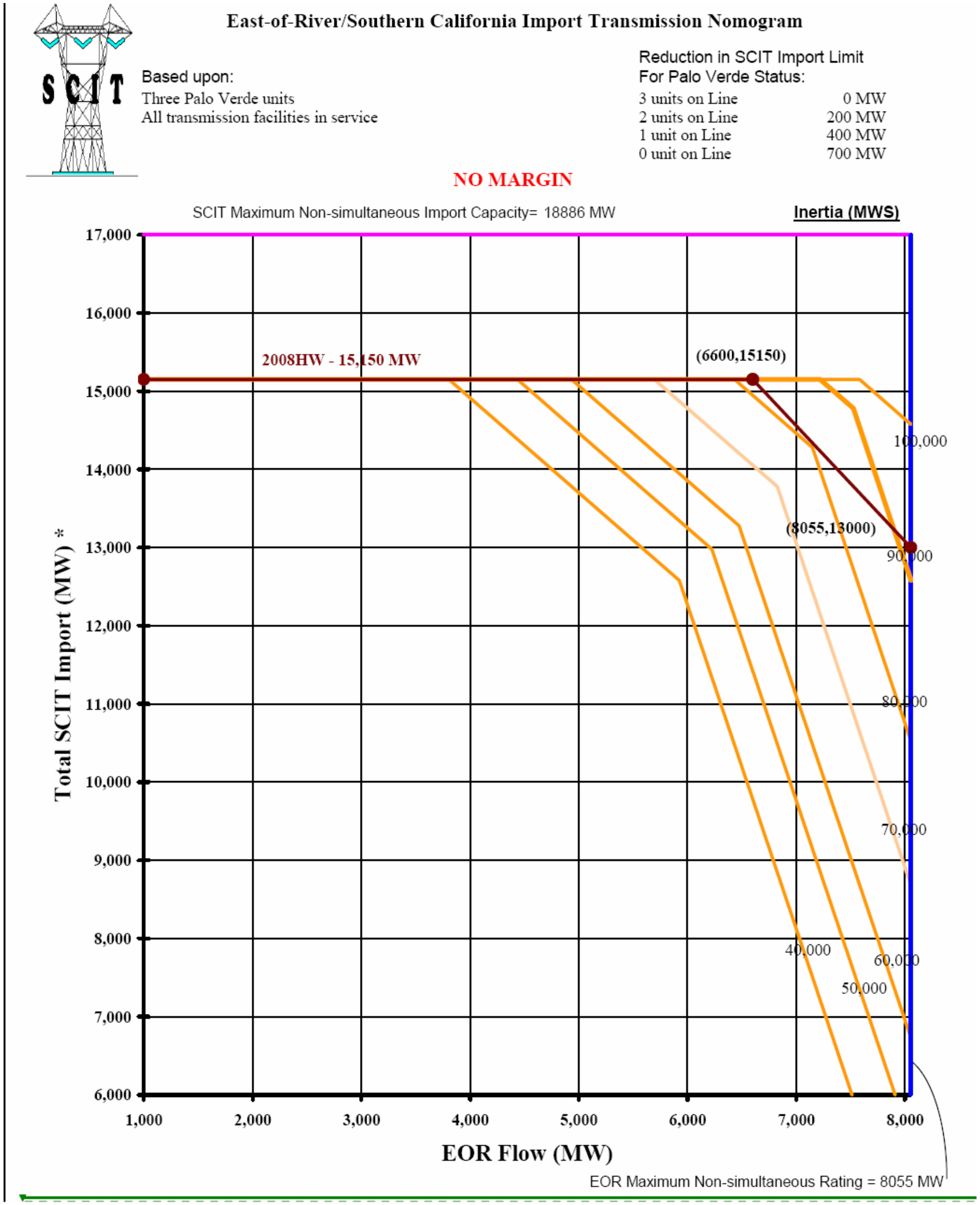

DC Intertie
IPP DC
DC
500 kV
345 kV
230 kV
West of River
Northern California
Nevada
East of River
Southern California
Arizona
Mexico
Palo Verde West

CAISO



East-of-River/Southern California Import Transmission Nomogram
SCIT
Based upon:
Three Palo Verde units
All transmission facilities in service
Reduction in SCIT Import Limit
For Palo Verde Status:
3 units on Line 0 MW
2 units on Line 200 MW
1 unit on Line 400 MW
0 unit on Line 700 MW
NO MARGIN
SCIT Maximum Non-simultaneous Import Capacity= 18886 MW
Inertia (MWS)
2008HW - 15,150 MW
(6600,15150)
(8055,13000)
100,000
90,000
80,000
70,000
60,000
50,000
40,000
Total SCIT Import (MW) *
EOR Flow (MW)
EOR Maximum Non-simultaneous Rating = 8055 MW

CAISO

Assumptions

- 2008 SSG-WI assumptions with increased renewables in California
- Path 49 Upgrades
  - Palo Verde-Devers #1 Series Capacitors Upgraded
  - Hassayampa-North Gila-Imperial Valley Series Capacitors Upgraded
  - 2nd Devers 500/230 kV Transformer added
  - SVC added at Devers
- Miguel-Mission 230 kV line added
- East of River limited to 8,055 MW
- West of River Unconstrained

Assumptions (continued)

- Palo Verde West limited to 3600 MW
- All 500 kV line ratings are respected
- Mohave out of service
- Mountainview, Palomar, and Otay Mesa in-service
- Additional renewables in California to meet Renewable Portfolio Standard of 20%

Sequence Studied

- Step 1: Add EOR 9000 project (Mead-Perkins and Navajo-Crystal Upgrade)
- Step 2: Add Moenkopi-Eldorado series capacitor upgrade
- Step 3: Add Palo Verde-Devers #2

CALIFORNIA ISO

California Independent
System Operator

EOR Path Rating Observations

- A 9,000 MW EOR rating appears to be an appropriate objective after the EOR 9000 project
- With the addition of the Moenkopi-Eldorado upgrade to the EOR 9000 project, a 9,500 MW EOR rating appears to be an appropriate objective
- With the addition of the PVD2 project, a 11,500 MW EOR rating appears to be an appropriate objective(a 2,000 MW increase)
- Qualification -- Achieving these path ratings may prove to be technically infeasible or uneconomic

TRANSMISSION INVESTMENT

- Driven by reliability criteria and economic opportunities to reduce congestion
  - These are not independent
  - Implementation of reliability criteria affect market prices
- Origins of engineering reliability criteria are opaque
  - Solutions to restore reliability criteria are complex and do not have unique solutions
  - Require interaction over entire synchronized network involving multiple SOs
- Not conducive to link-by-link merchant investments
- Regional planning and integrated assessment of reliability and economic criteria are essential
- Economic implications and justifications for reliability criteria need a fresh assessment