Proposed Changes to Improve ERCOT System Operations

Presented to:

**PUCT Workshop on Market Design Alternatives**

June 8, 2005

ERCOT System Operations

- Present prioritized list of changes included in May 4th filing
    - ERCOT currently operates reliably.
    - Proposed changes would allow ERCOT to more efficiently manage system operations and reinforce system reliability.
    - List does not consider cost of system implementation.

- Overview of ERCOT Market Model
- Proposed Changes
  - Current Operational Challenge
  - Example / Supporting Analysis
  - Description of Proposed Change
  - Benefits of Proposed Change
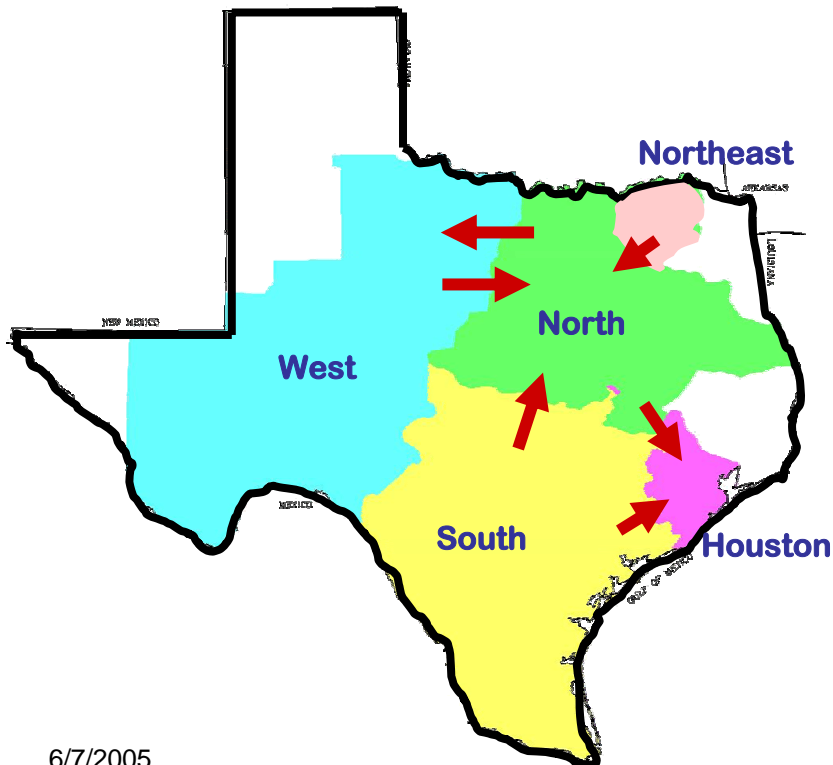 - Current Actions Underway

- Portfolio scheduling and bidding by zone
- 5 wholesale pricing points (congestion zones)
- 6 CSCs for inter-zonal congestion management

Northeast

North

West

South

Houston
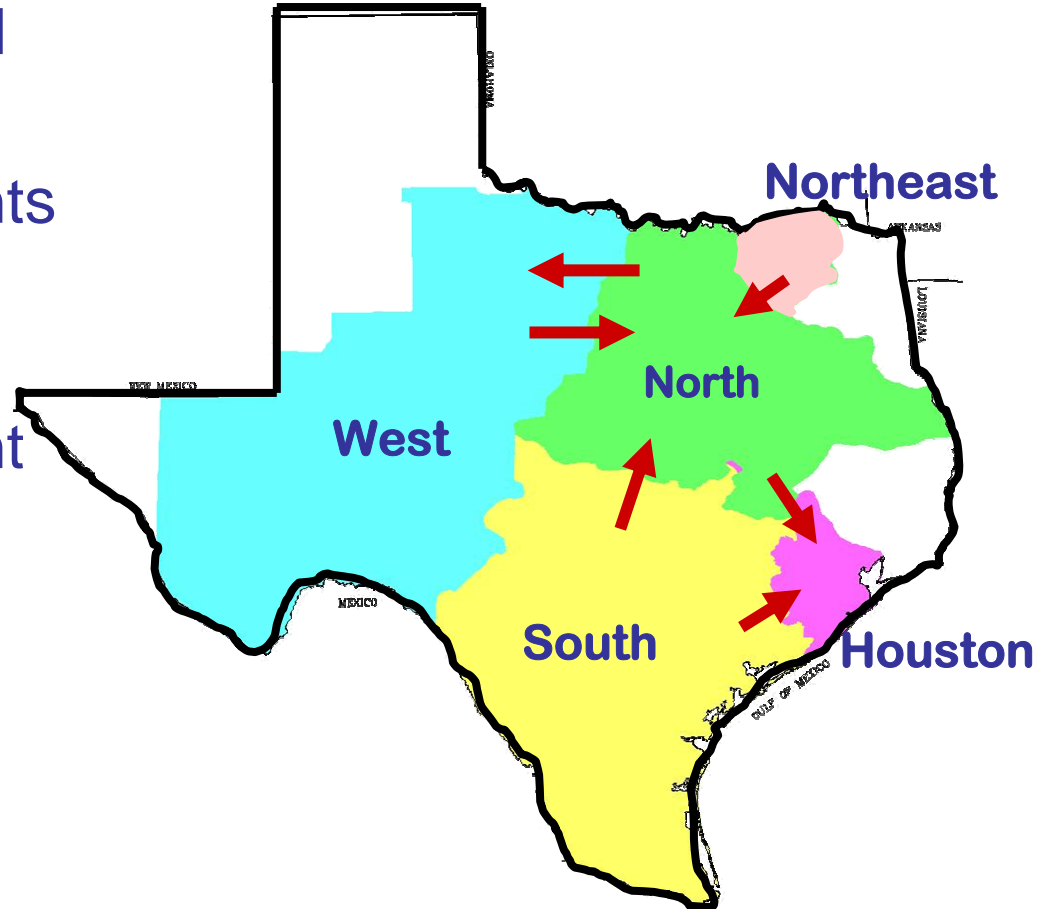
→ **CSC**
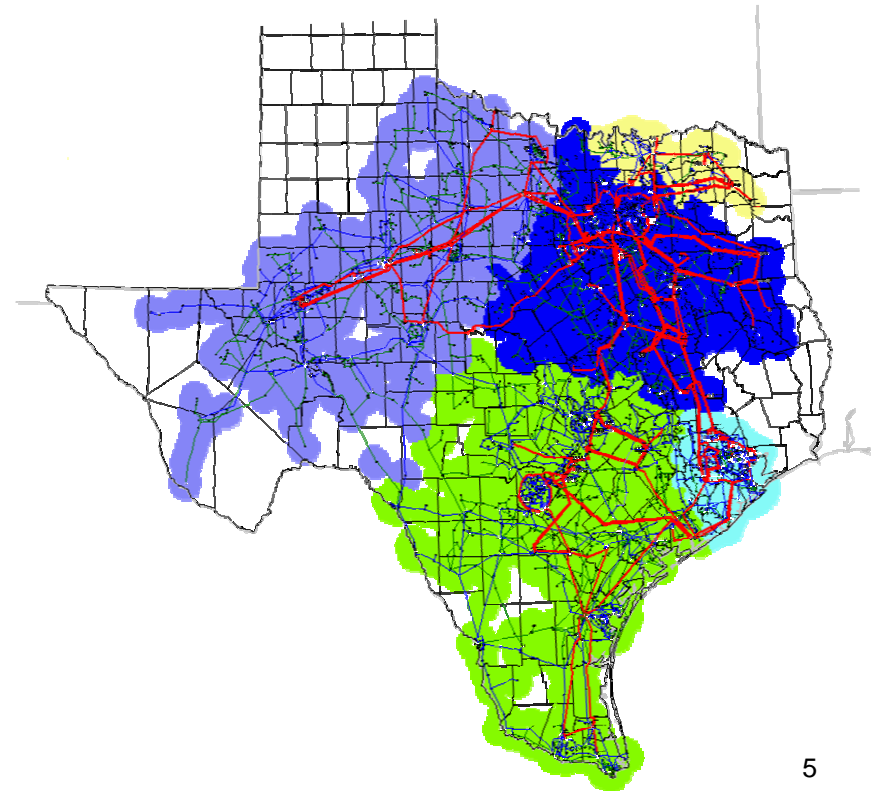**(Commercially Significant Constraint)**

Zonal Congestion

- Congestion between zones (CSC)
- Managed with Portfolio Balancing Energy deployments by zone

Local Congestion

- Congestion other than CSC
- Managed with local Balancing Energy deployments by Resource

1. **Utilize Resource-specific scheduling, bidding and deployment**

2. **Utilize Resource-specific ramp rates in dispatch**

3. **Utilize Resource-specific shift factors**

4. **Develop financial incentives for participants to follow schedules and instructions**

5. **Develop scheduling rules and/or market mechanisms to mitigate effects of block schedules**

6. **Develop mechanism to ensure deliverability of Ancillary Services**

7. **Increase observability of the transmission system**

8. **Issue dispatch instructions every five minutes**

9. **Assign local congestion costs directly**

10. **Implement a more robust Day Ahead unit commitment process**

- Difficult to manage congestion due to difference between Market model and Physical model
  - **Market:** ERCOT Market calculates flow on a transmission line using simplified inputs.
  - **Physical:** Physical flow depends on detailed inputs.
  - ➤ Difference between market-calculated flow and physical flow results in over or under issuance of energy deployments.

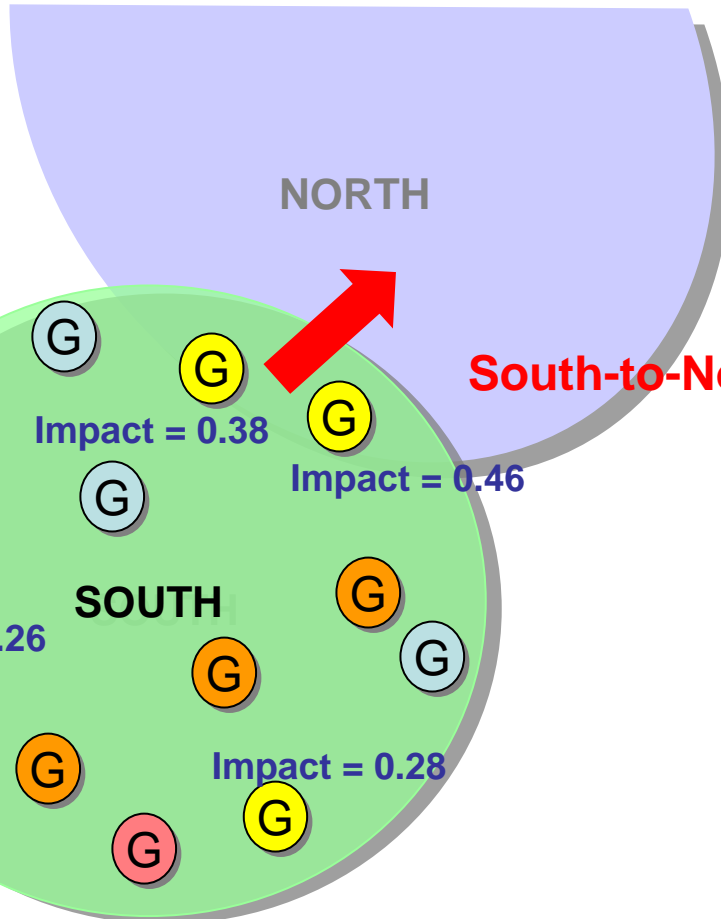- QSE with 4 units (G) in the South zone

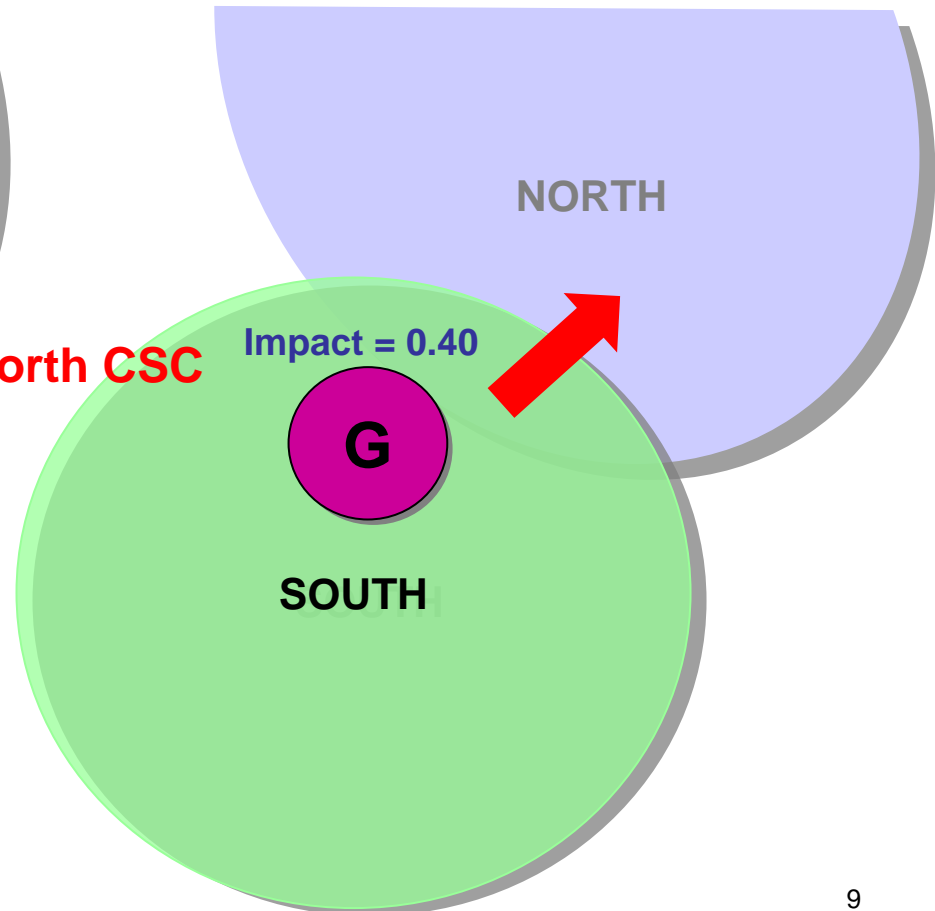**Physical**   **Market**

NORTH

South-to-North CSC

NORTH

SOUTH

SOUTH
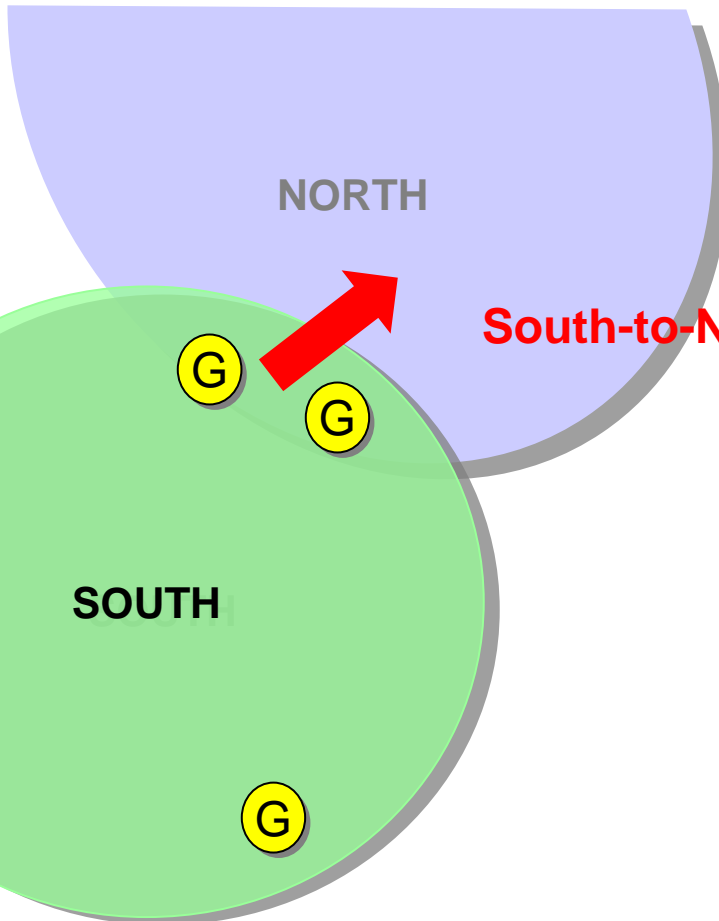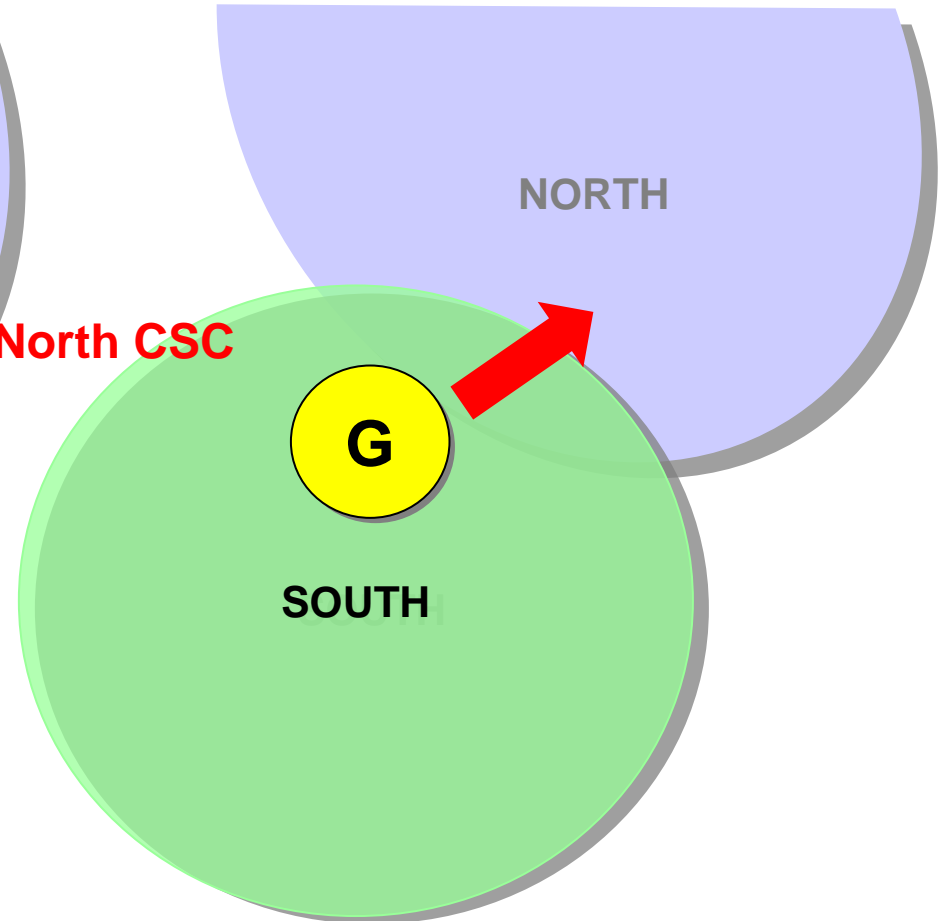
- Each unit has an impact on the energy flow across the CSC. In ERCOT Market model, these impacts are averaged across <u>all</u> units.

Physical

Market

South-to-North CSC

NORTH

Impact = 0.38

Impact = 0.46

Impact = 0.26

SOUTH

Impact = 0.28

Impact = 0.40

G

NORTH

SOUTH
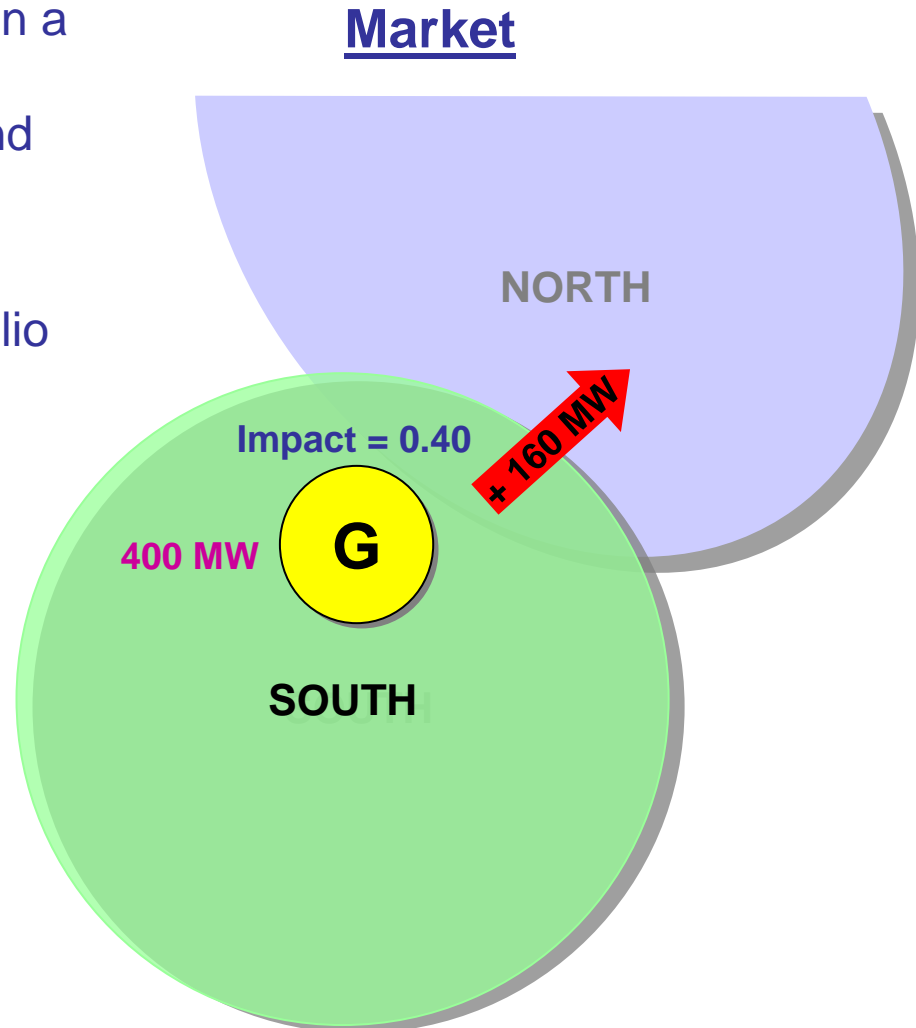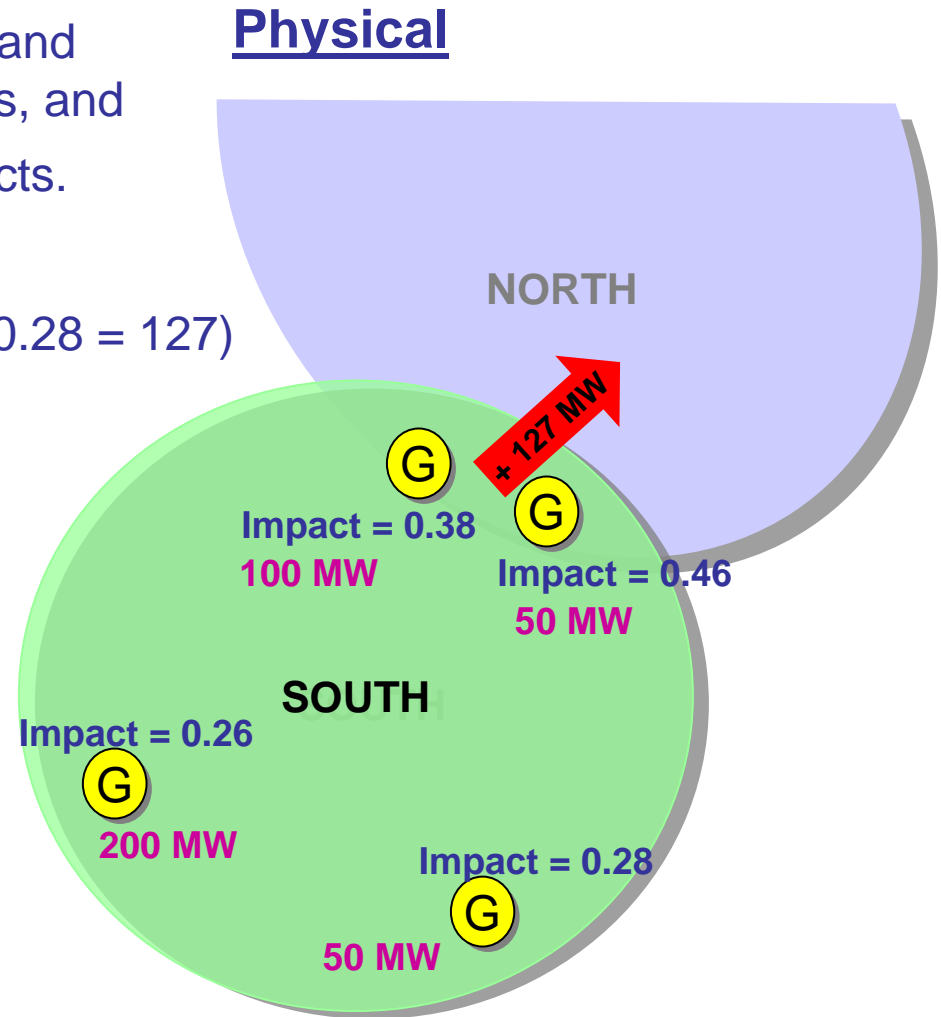
- ERCOT Market calculates the flow on a CSC based on QSEs portfolio schedules, portfolio deployments, and the averaged impact.

- So, if the QSE's schedule and portfolio deployments total 400 MW, its contribution to flow on the CSC is assumed to be160 MW.

  (400 * 0.40 = 160).

<u>Market</u>

NORTH

Impact = 0.40

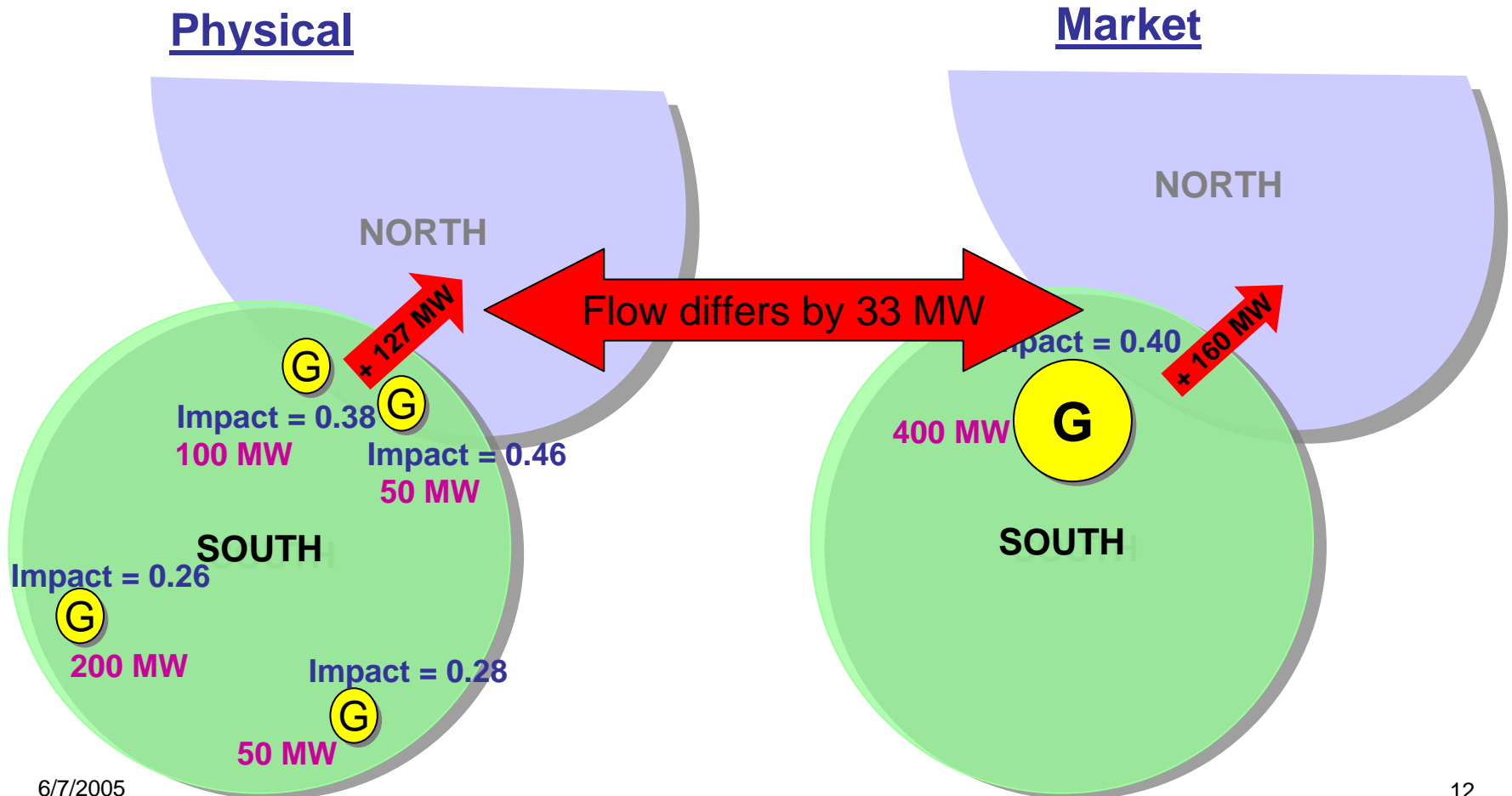**+ 160 MW**

400 MW

G

SOUTH

- Physical flow on CSC depends on:
  - How QSE divides its schedule and deployments among Resources, and
  - the Resources' individual impacts.

In example, flow = 127 MW
(100*0.38 + 50*0.46 + 200*0.26 + 50*0.28 = 127)

Flow can range from 104 to 184 MW depending on Resource allocation.

Physical

NORTH

+ 127 MW

G
Impact = 0.38
100 MW

G
Impact = 0.46
50 MW

SOUTH

Impact = 0.26
G
200 MW

Impact = 0.28
G
50 MW

- Physical model and Market model are <u>not</u> the same.

Physical

Market

NORTH

NORTH

Flow differs by 33 MW

+ 127 MW

+ 160 MW

Impact = 0.40

400 MW

G

Impact = 0.38
100 MW

G

Impact = 0.46
50 MW

SOUTH

SOUTH

Impact = 0.26

G

200 MW

Impact = 0.28

G

50 MW

Distribution of Resource-specific Generation Shift Factors by Zone
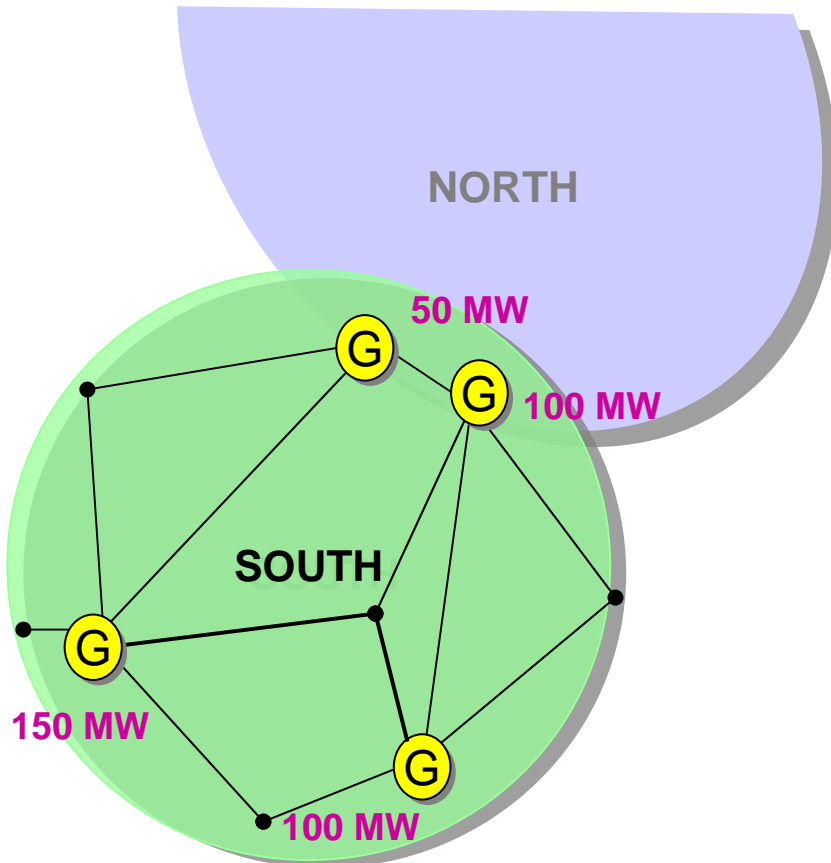## South-to-North CSC 2004[1]
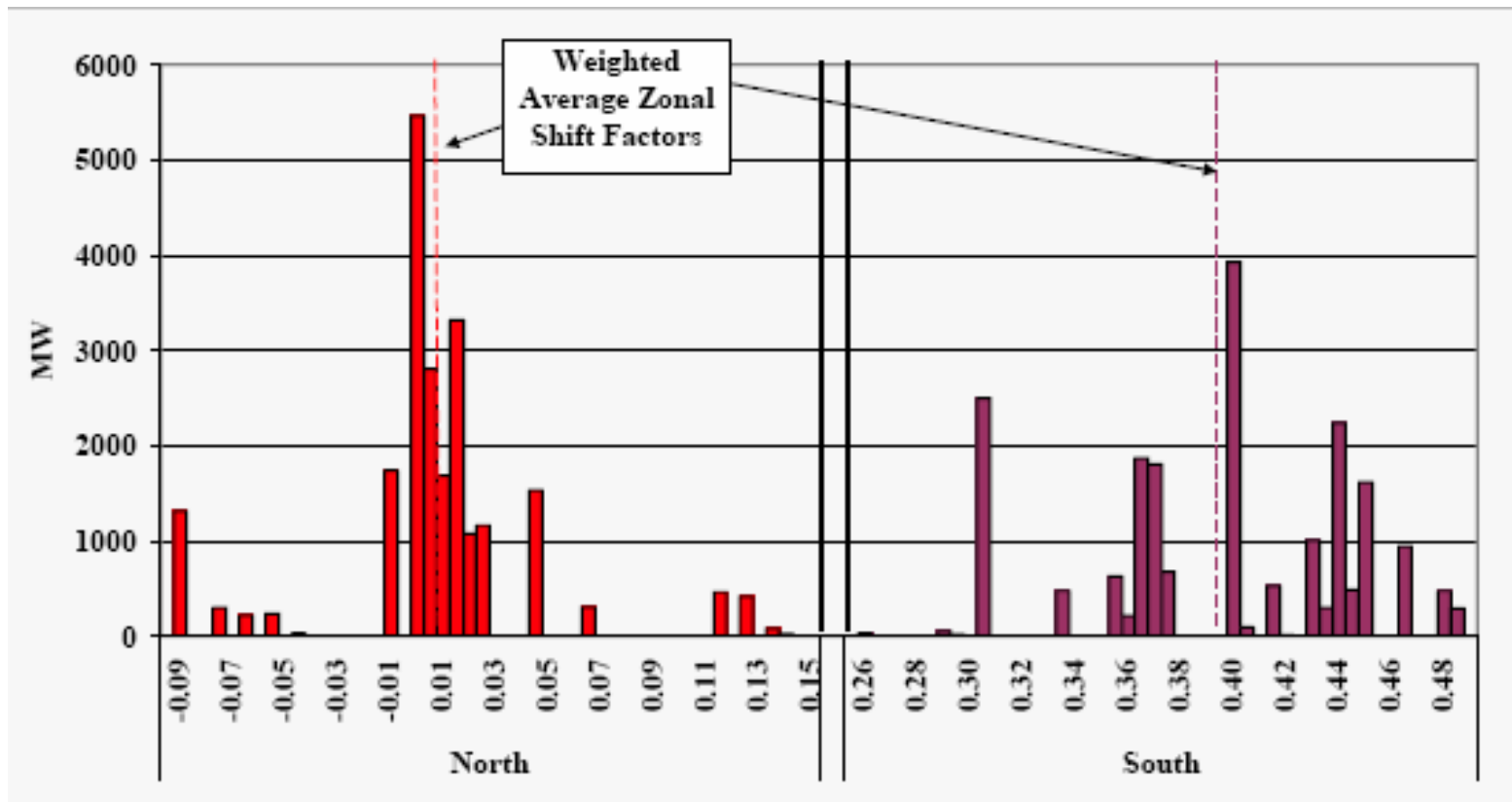
[1] Potomac Economics, LTD. 2004 Assessment of the Operation of the ERCOT Wholesale Electricity Markets. November 2004: 44.
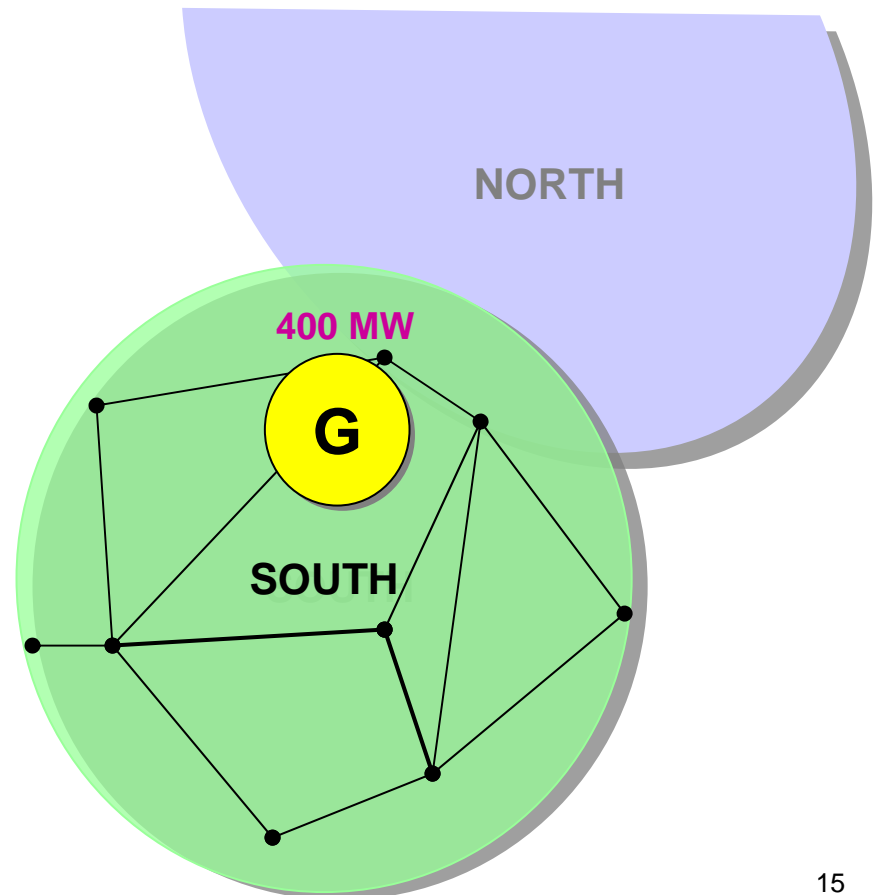
- Congestion may not be managed as expected due to portfolio scheduling and deployment.
  - QSEs have flexibility in deployment of Resources.
    - Resources that are most effective may not be used at all.
    - ERCOT must guess how QSEs will use their Resources.
    - To the extent ERCOT's guess is wrong, additional Out-of-Merit deployments are required to manage remaining congestion.
  - Congestion Management is effective over time, but not as fast or efficient as it could be.

- QSE's schedule + Balancing Energy deployments = 400 MW
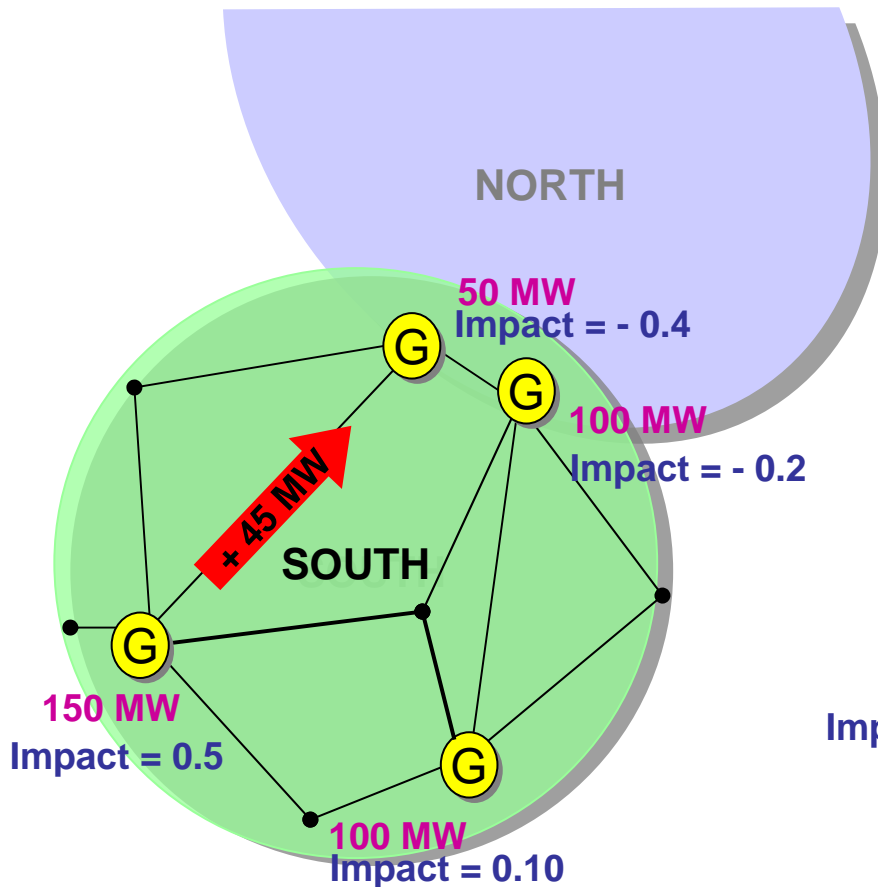- QSE divides 400 MW across its Resources at its discretion.

Actual

Market

NORTH

50 MW

100 MW

SOUTH

150 MW

100 MW

NORTH

400 MW

G

SOUTH

- Flow on a line is calculated using the Resources' MW output and impact.

Actual

Market

NORTH

50 MW
Impact = - 0.4

100 MW
Impact = - 0.2

+ 45 MW

SOUTH

150 MW

Impact = 0.5

100 MW
Impact = 0.10

NORTH

?
Impact = - 0.4

?
Impact = - 0.2

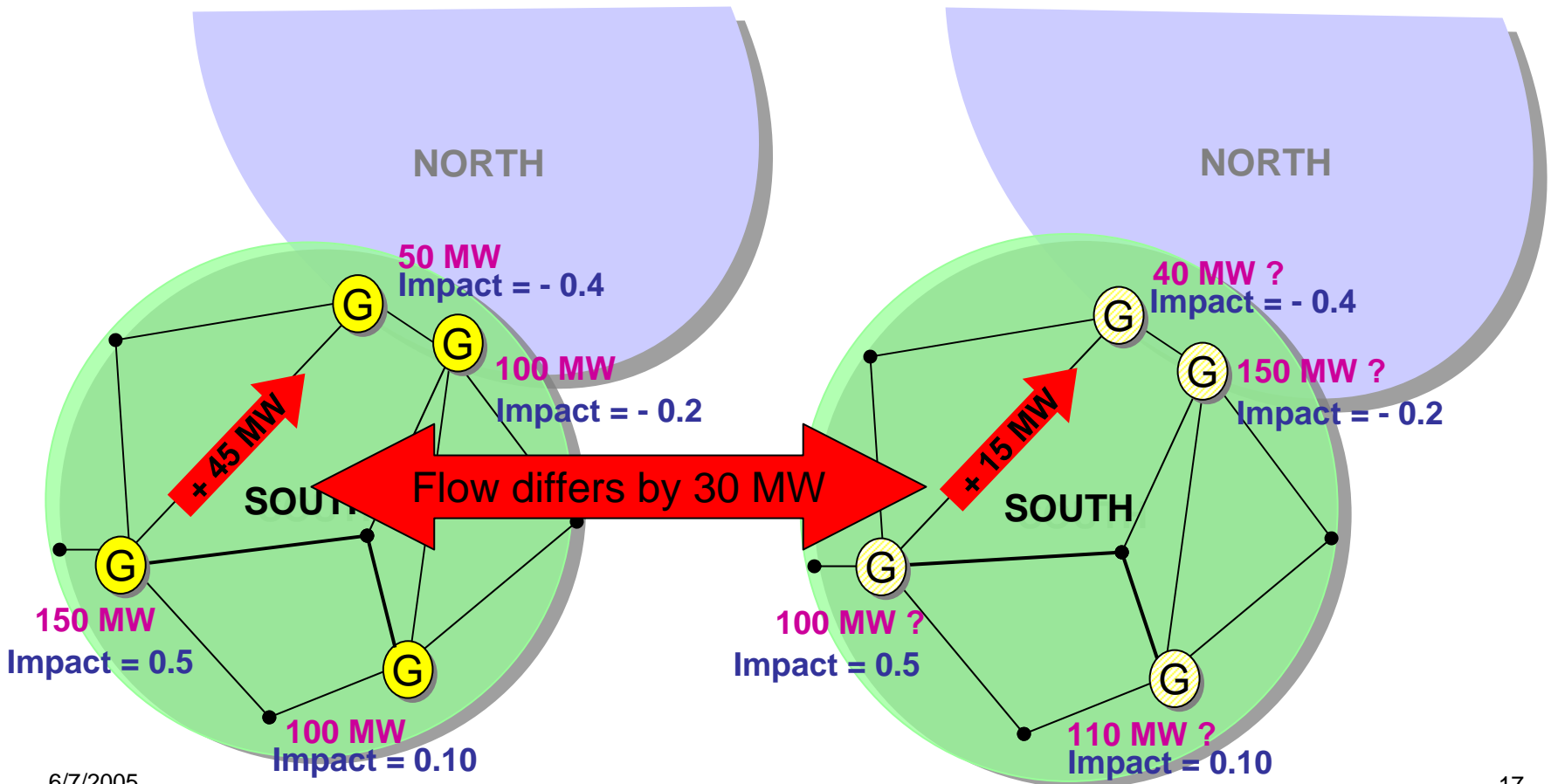SOUTH

?
Impact = 0.5

?
Impact = 0.10
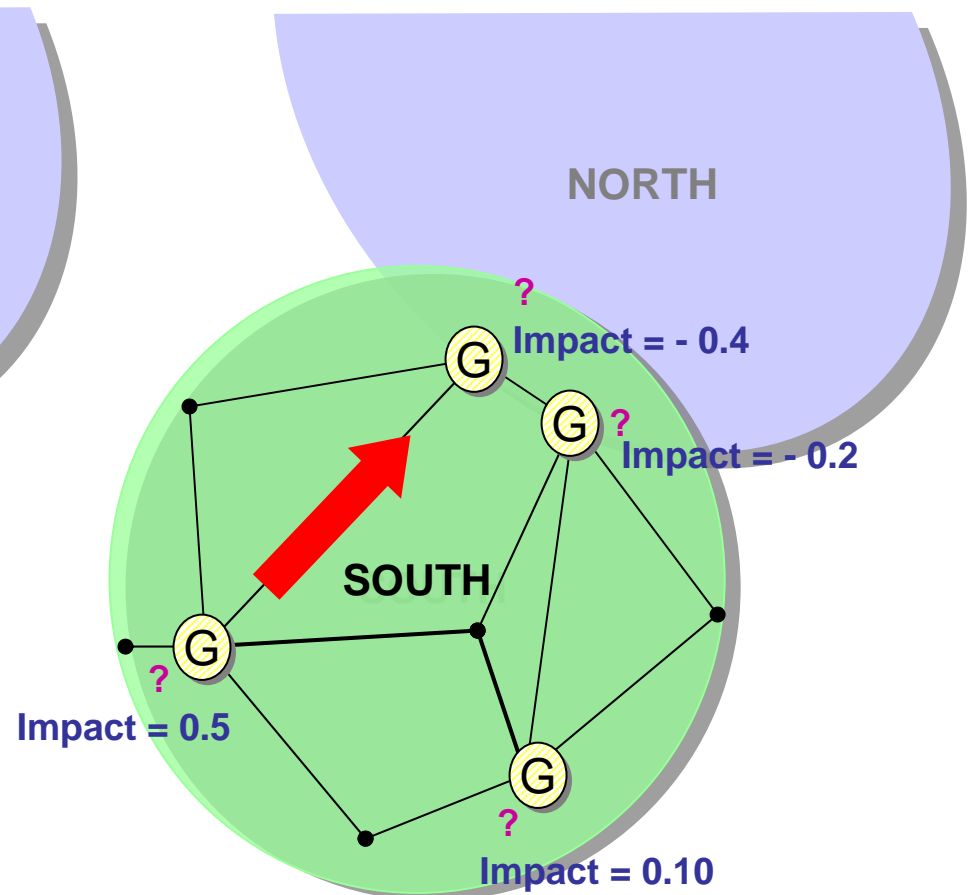
- To manage Local Congestion without Resource-specific schedules and bids, ERCOT Market system estimates MW output of each unit.

Actual

Market

NORTH

NORTH

50 MW
Impact = - 0.4

100 MW
Impact = - 0.2

+ 45 MW

SOUTH

150 MW
Impact = 0.5

100 MW
Impact = 0.10

40 MW ?
Impact = - 0.4

150 MW ?
Impact = - 0.2

+ 15 MW

SOUTH

100 MW ?
Impact = 0.5

110 MW ?
**Impact = 0.10**

Flow differs by 30 MW

- Congestion may not be managed as expected due to portfolio ramp rates.
  - Market system uses portfolio ramp rate to deploy Balancing Energy.
    - Portfolio ramp rate may not accurately reflect Resources' capabilities.
  - Market system gives Resource-specific deployments limited by portfolio ramp rate.
    - Individual Resource may not be capable of following deployment <u>OR</u>
    - ERCOT restricted in its deployment based on portfolio ramp rate.

- ERCOT asks Unit G2 to move **30 MW** using **Portfolio** ramp rate of 3 MW/min.

- Unit G2 can only move **10 MW** based on its **Resource** ramp rate of 1 MW/min.
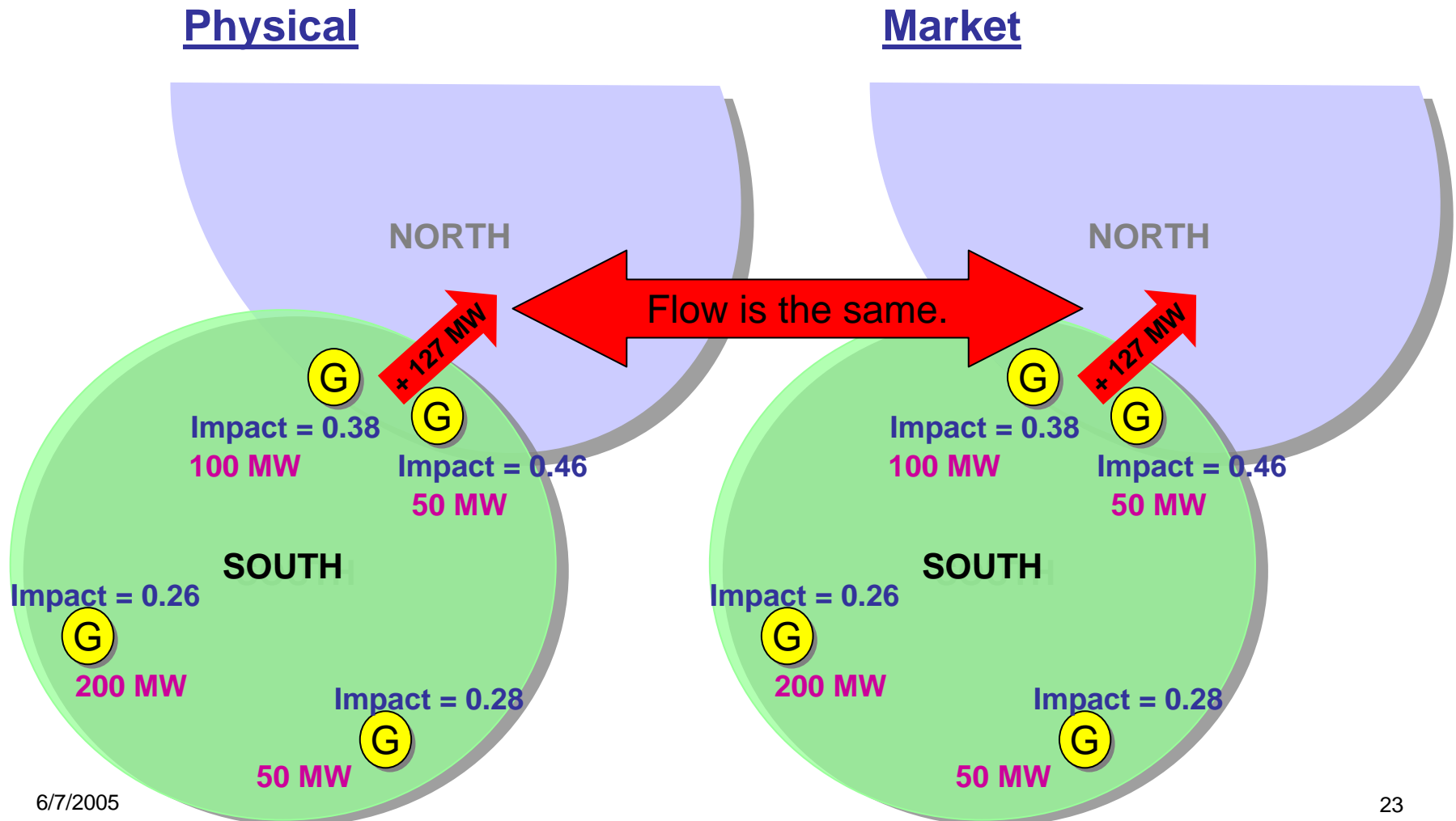
Physical
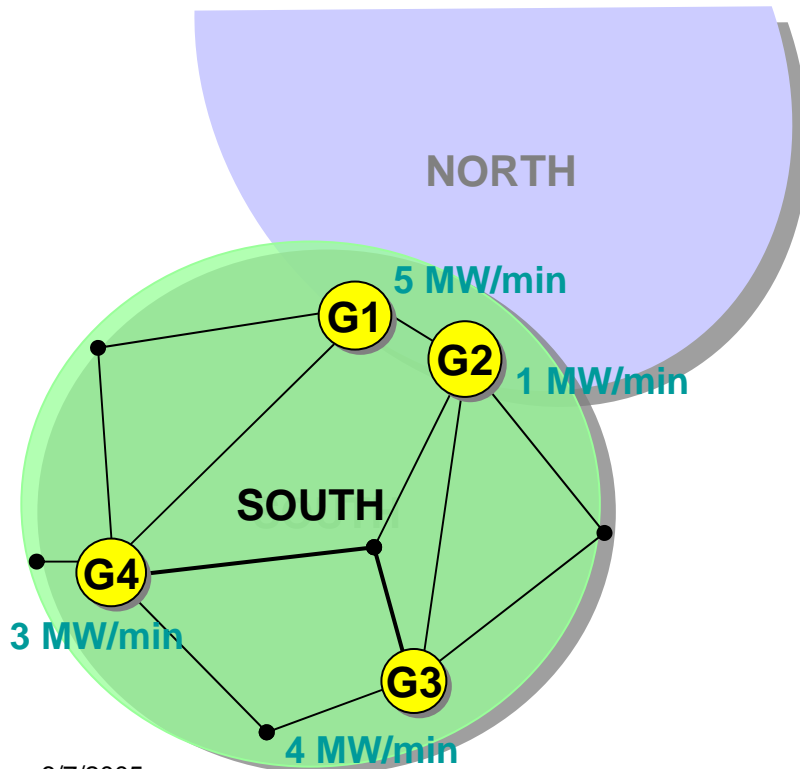
Market
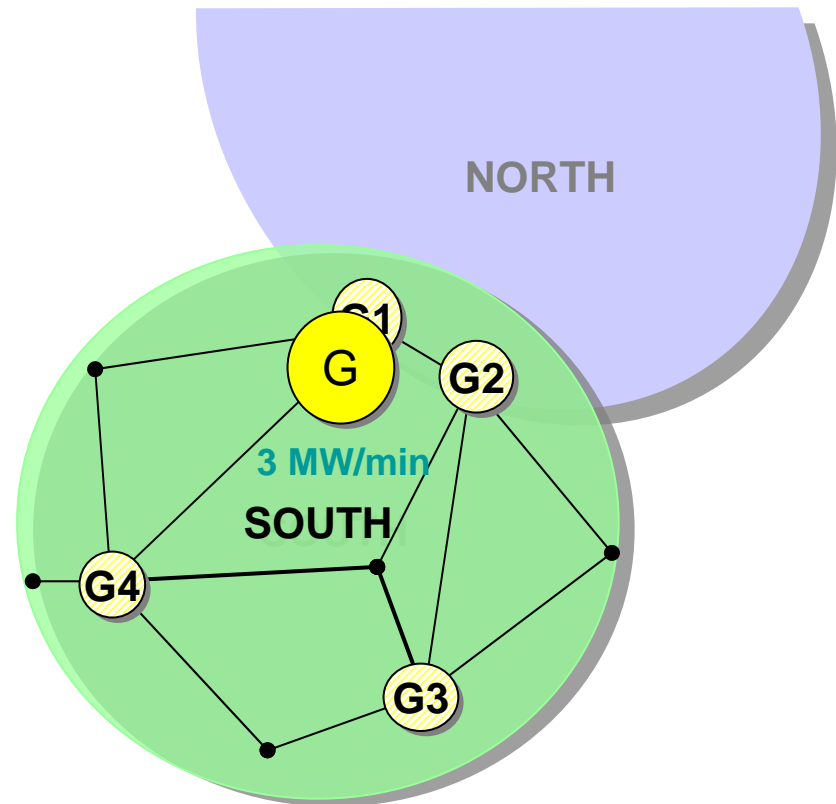
- Potomac Economics cited similar operational challenges in their report, *2004 Assessment of the Operation of the ERCOT Wholesale Electricity Markets*:

  - "The differences between the actual resource-specific shift factors and the zonal average shift factors result in inefficient congestion management and inaccurate zonal prices" (p.49).

  - Effect on congestion depends on which Resource responds to the portfolio deployment.

    - Study showed current market model required 30 to 60% more energy to solve congestion than would be required using Resource-specific data (p.64).

- Receive schedules and bids at Resource level instead of Portfolio level

- Send all deployments at Resource level

- Use Resource-specific ramp rates

- Use Resource-specific shift factors

- **By using Resource-specific data,**
  - Physical model and Market model are the same.
    - Market system could accurately calculate flow on transmission lines using Resource-specific schedules and impacts
  - Increased accuracy and efficiency in congestion management.
    - Resource-specific deployments and impacts ensure most efficient Resources used to manage both Zonal and Local Congestion.
    - Use of Resource-specific ramp rate ensures Resource's ability to follow deployment.
  - Stronger link between Operations and Settlements.

- ERCOT Market System would calculate the flow on a line based on Resource's schedule, deployments, and impact.
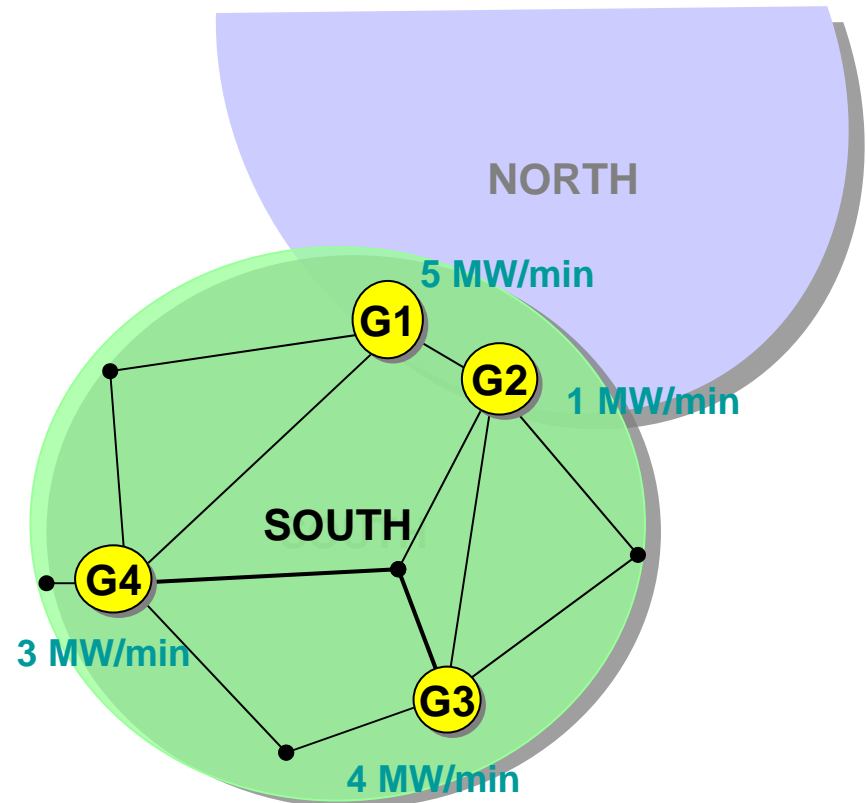

Physical

Market

NORTH

NORTH

Flow is the same.

+ 127 MW

+ 127 MW

Impact = 0.38
100 MW

Impact = 0.46
50 MW

Impact = 0.38
100 MW

Impact = 0.46
50 MW

SOUTH

SOUTH

Impact = 0.26

Impact = 0.26

200 MW

200 MW

Impact = 0.28

Impact = 0.28

50 MW

50 MW

6/7/2005

23

- ERCOT deploys Unit G2 to move **10 MW** based on its **Resource** ramp rate of 1 MW/min.

- Unit G2 can move as expected.
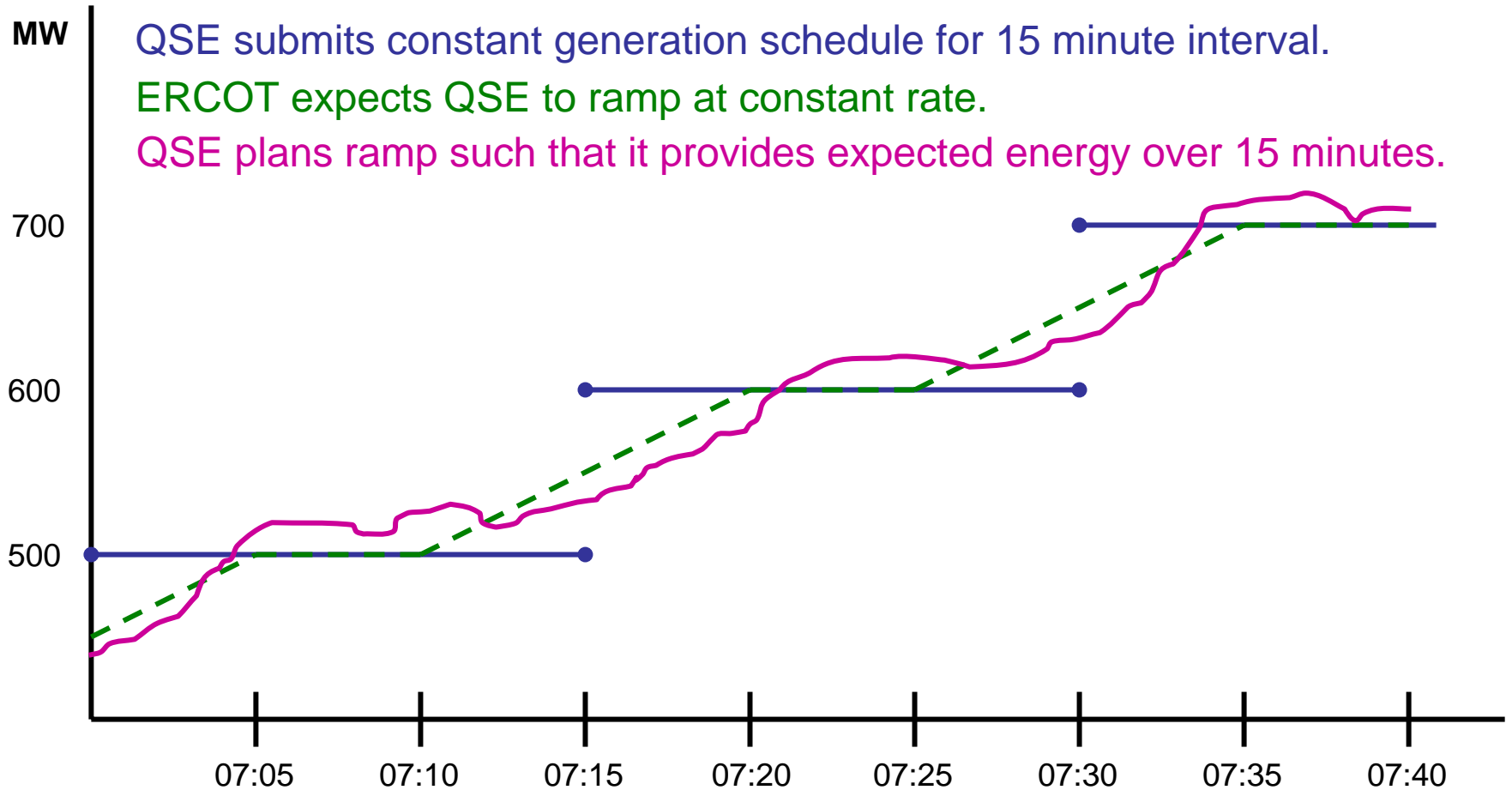
Physical
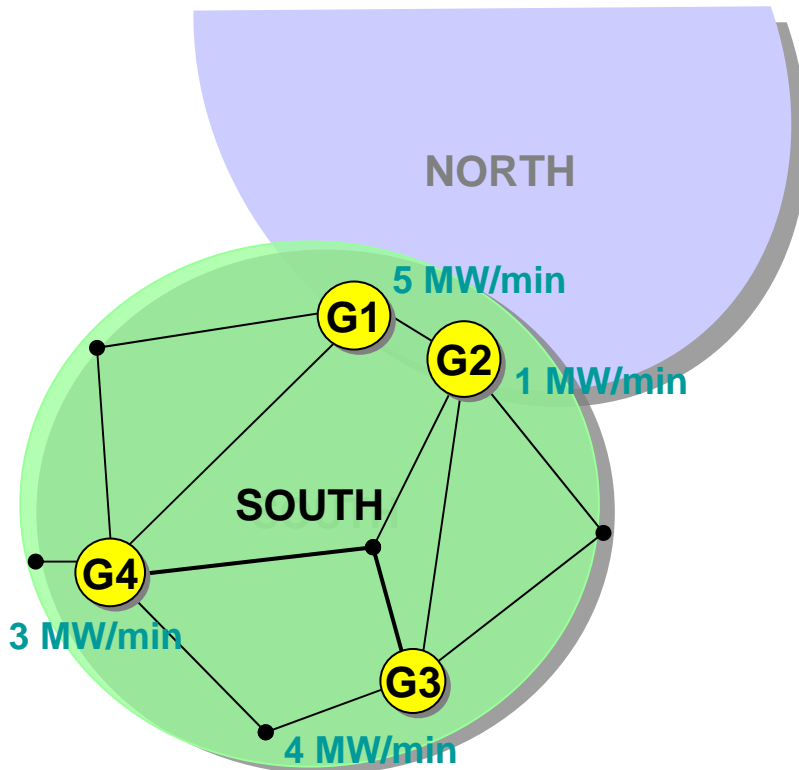
Market

- Responding to Potomac's short-term recommendations to improve current model:
  - Improve the process for designating zones and revising CSC definitions to minimize the effects of the simplifying zonal assumptions. Current Status: Protocol Revision (PRR 589) drafted and approved by PRS in April. Approved by TAC. Board review in June.

  - Modify the calculation methodology of the zonal average shift factor to exclude generation whose output is generally fixed (e.g., nuclear units). Current Status: Protocol Revision (PRR 592) drafted and approved by PRS in May. Approved by TAC. Board review in June.

  - Provide ERCOT the operational flexibility to temporarily modify the definition of a CSC associated with topology changes. Current Status: Protocol Revision (PRR 587) drafted and approved by PRS in April. Approved by TAC. Board review in June.

- Protocol Revision (PRR 476) to implement Resource-specific ramp rates approved by TAC. Current Status: ERCOT performing feasibility study.
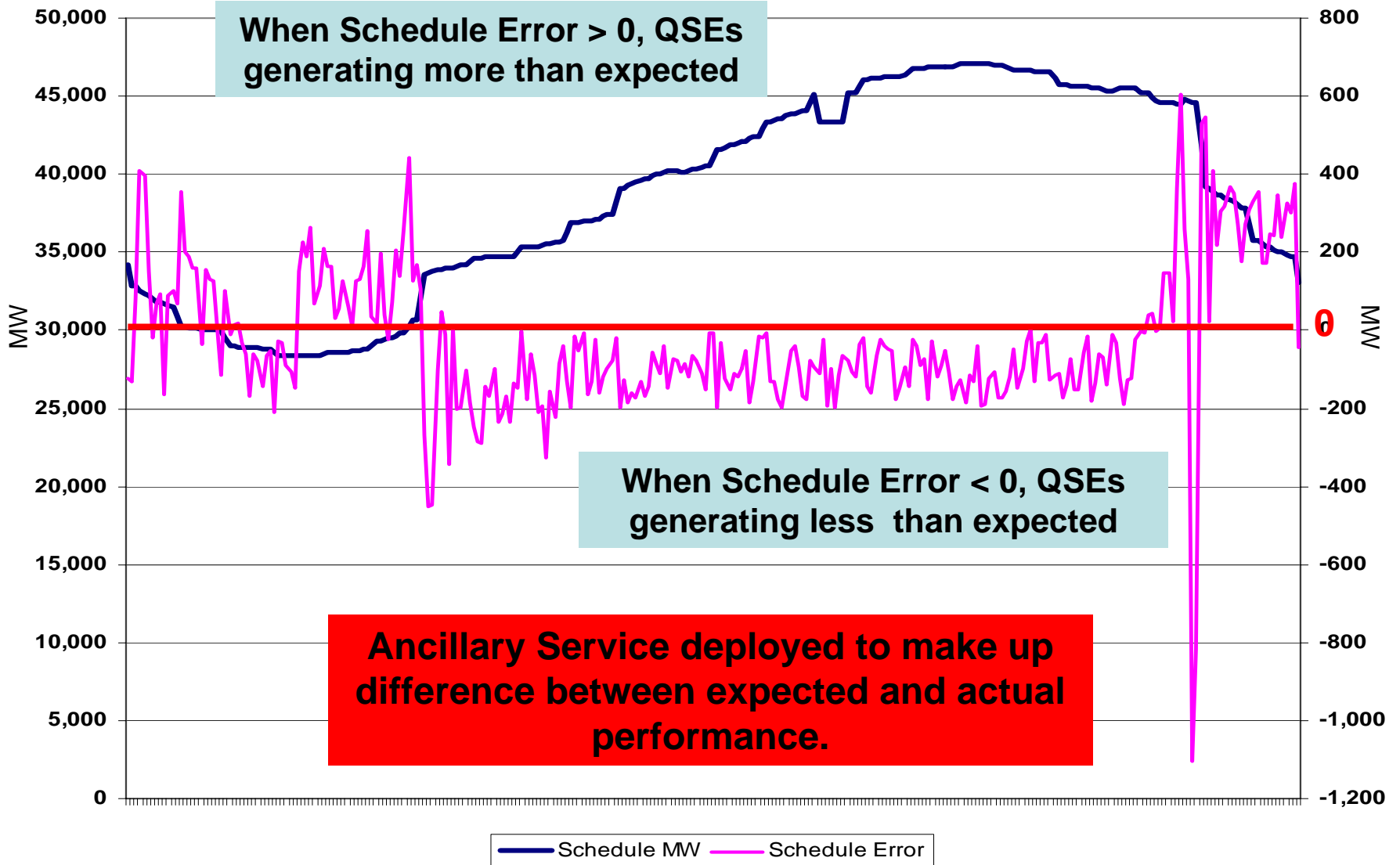
➢ None of the above addresses the core problems.

1. **Utilize Resource-specific scheduling, bidding and deployment**

2. **Utilize Resource-specific ramp rates in dispatch**

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4. **Develop financial incentives for participants to follow schedules and instructions**

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6. **Develop mechanism to ensure deliverability of Ancillary Services**

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10. **Implement a more robust Day Ahead unit commitment process**

- The ERCOT control system is based on expectation that QSEs will follow schedules and deployments.

- Difficult to maintain frequency and manage congestion when QSEs don't perform as expected.

  – ERCOT must deploy Ancillary Services.

  – ERCOT must use Out-of-Merit deployments.

  – Cost of these services assigned to Loads.

- Current Settlement charge is designed to prevent price chasing, not to encourage good frequency control practices.

QSE submits constant generation schedule for 15 minute interval.
ERCOT expects QSE to ramp at constant rate.
QSE plans ramp such that it provides expected energy over 15 minutes.

4. Develop performance incentives for QSEs
Example of Operational Challenge

- Potomac Economics reported that <u>majority</u> of QSEs

  - *under-generate* during the afternoon

  - *over-generate* during the early morning and evening.[2]

Average SCE for Large and Small QSEs January to September 2004
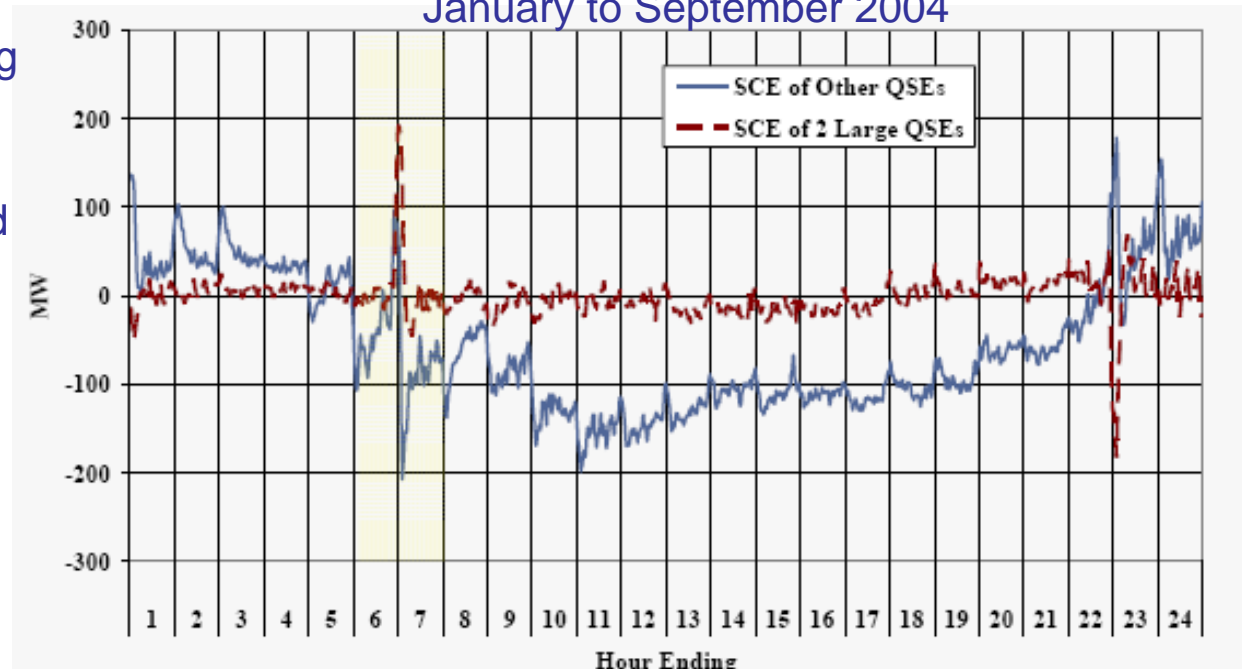
[2] Potomac Economics, LTD. <u>2004 Assessment of the Operation of the ERCOT Wholesale Electricity Markets.</u> November 2004: 121.

- Add settlement methodology to incent QSEs to follow their schedules and deployments.

- Change would provide financial incentive for QSEs to meet expectations.

  - Improved system control

    - Frequency

    - Congestion Management

  - Less Ancillary Service Deployment and Procurement

    - Less cost to Loads

- Protocol Revision drafted to partially allocate cost of Regulation deployment to QSEs with schedule error.
    - PRR 586 (SCE Performance and Regulation Cost Re-Allocation)
   - Under discussion by stakeholders.

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6/7/2005

- Challenge to maintain system frequency during large schedule changes
  - Some QSEs schedule energy that cannot be provided using expected linear ramp.
    - Risk: If a large unit trips while frequency is low, the likelihood that firm load will be shed is greatly increased.

- Balancing Energy deployments are a challenge because Operator needs to compensate for additional QSE schedule error.

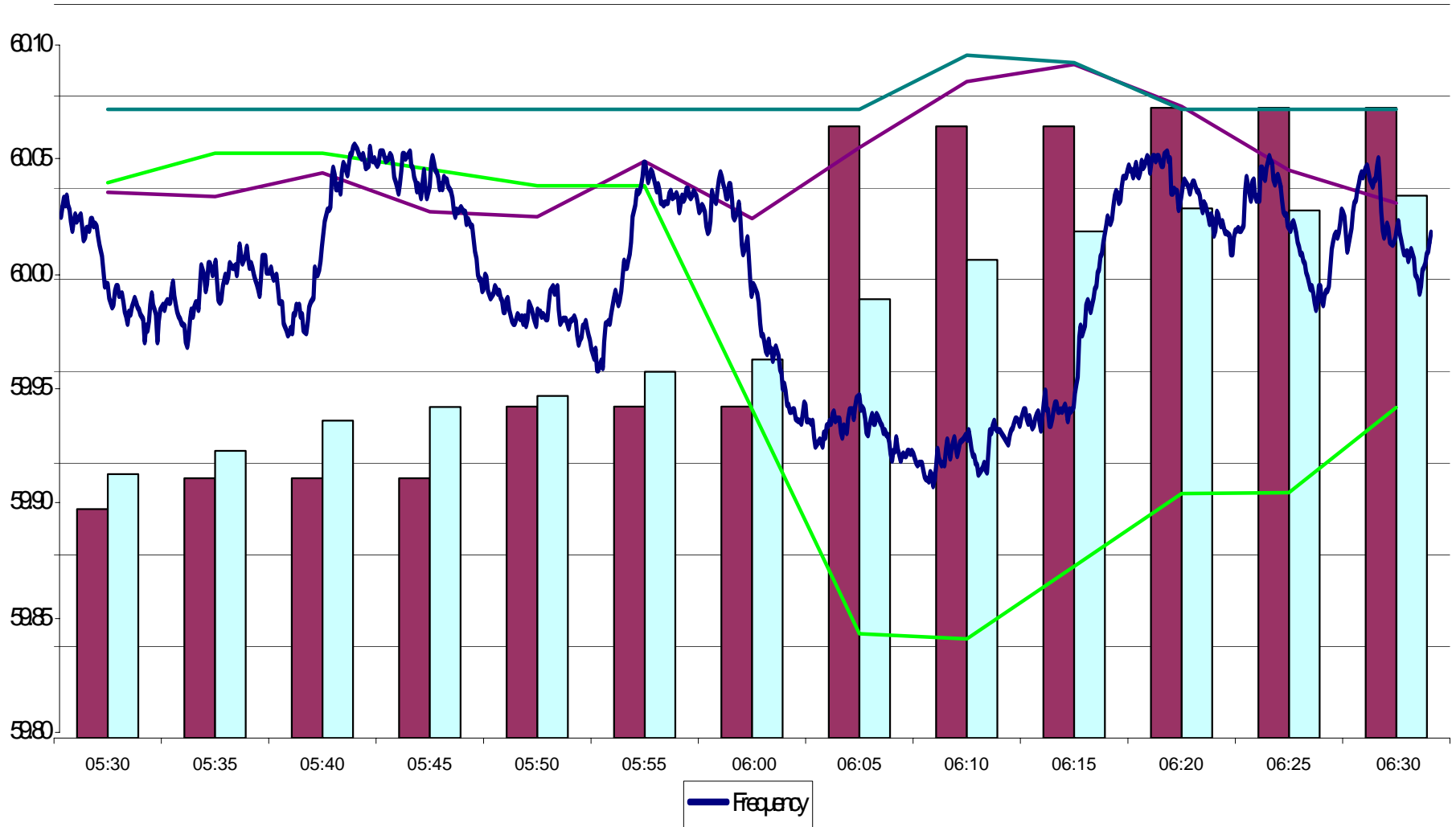- Significant amounts of Ancillary Services required to maintain frequency
  - Cost is assigned to Loads.

Generation Schedule v. Load: 05/24/2005 05:30 – 06:30

Legend: ■ Gen Sched □ Load
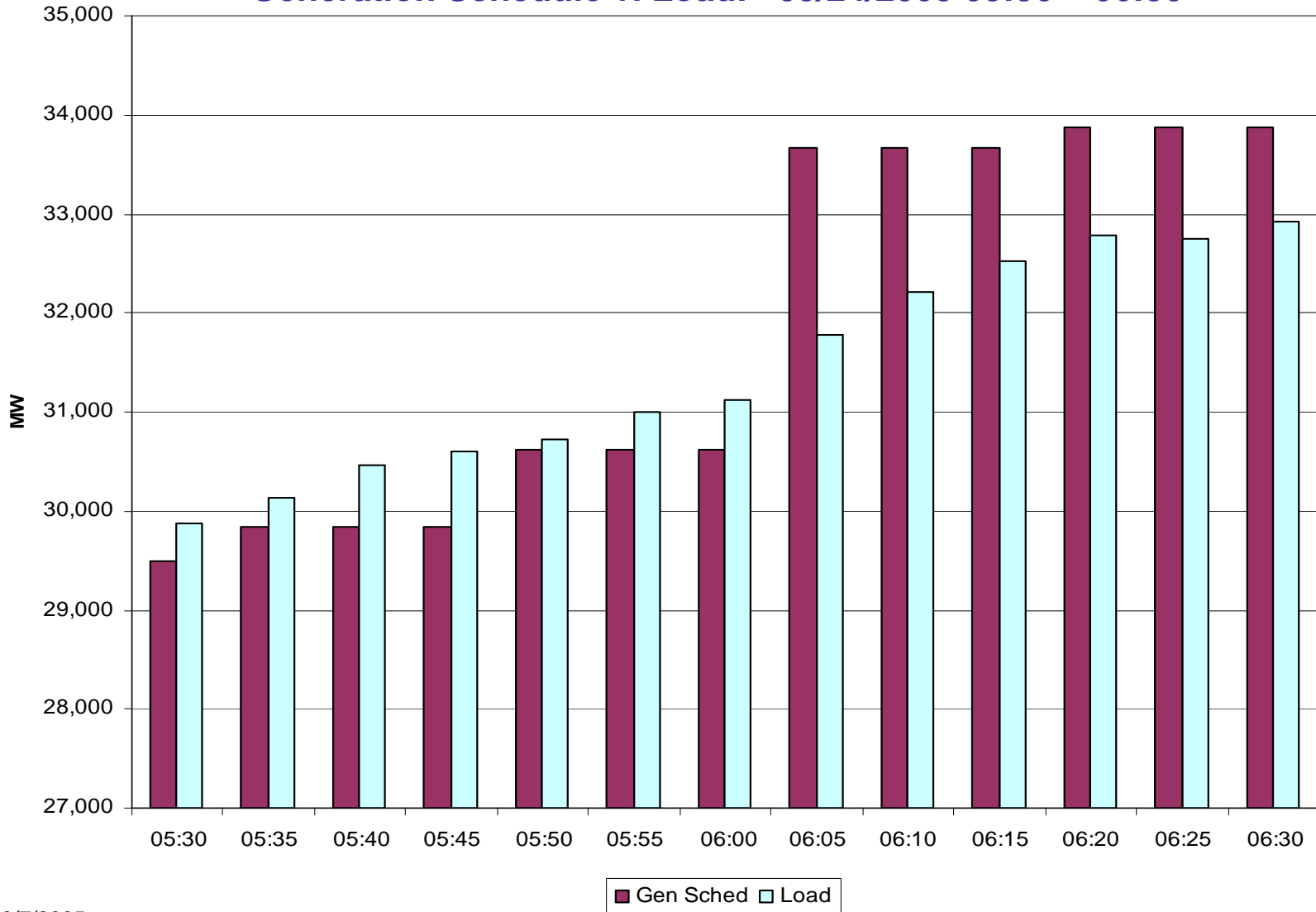
Generation Schedule, Load, and AS Deployments :   05/24/2005 05:30 – 06:30
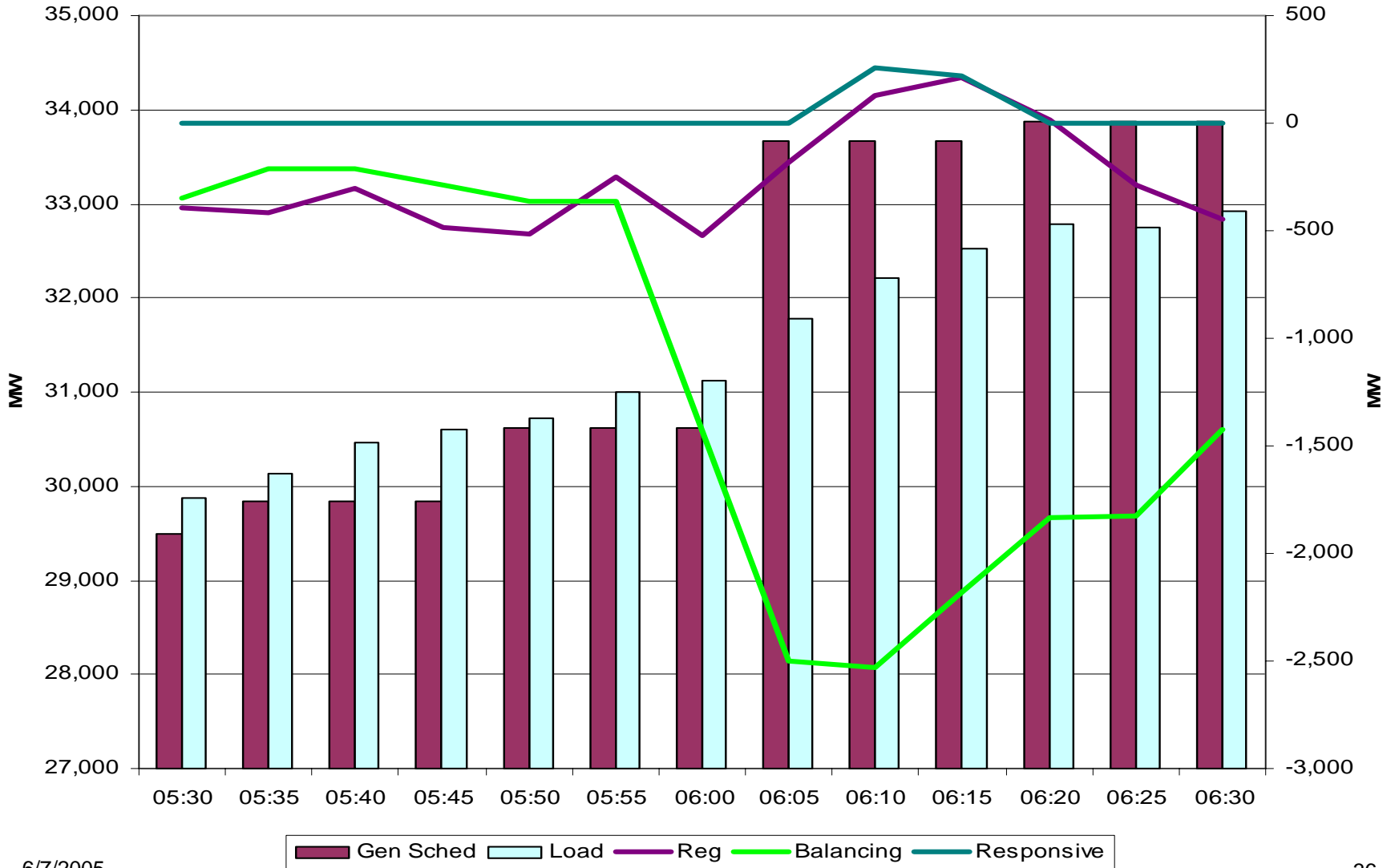
## Frequency :   05/24/2005 05:30 – 06:30

- Increased possibility of failing NERC standards.
    - ERCOT normally fails Control Performance Standard 1 (CPS1) metric for the hour endings 0700 and 2300, but passes in other hours, resulting in an overall passing score.
    - ERCOT historically has not met the CPS2 metric since market opening, but has been granted an exemption.
    - There is movement at NERC to replace CPS2 with a tougher standard which ERCOT probably would not pass. ERCOT's argument for exemption from CPS2 would not apply to this proposed standard.

CPS1 by Hour - April 2005
Passing Score >= 100
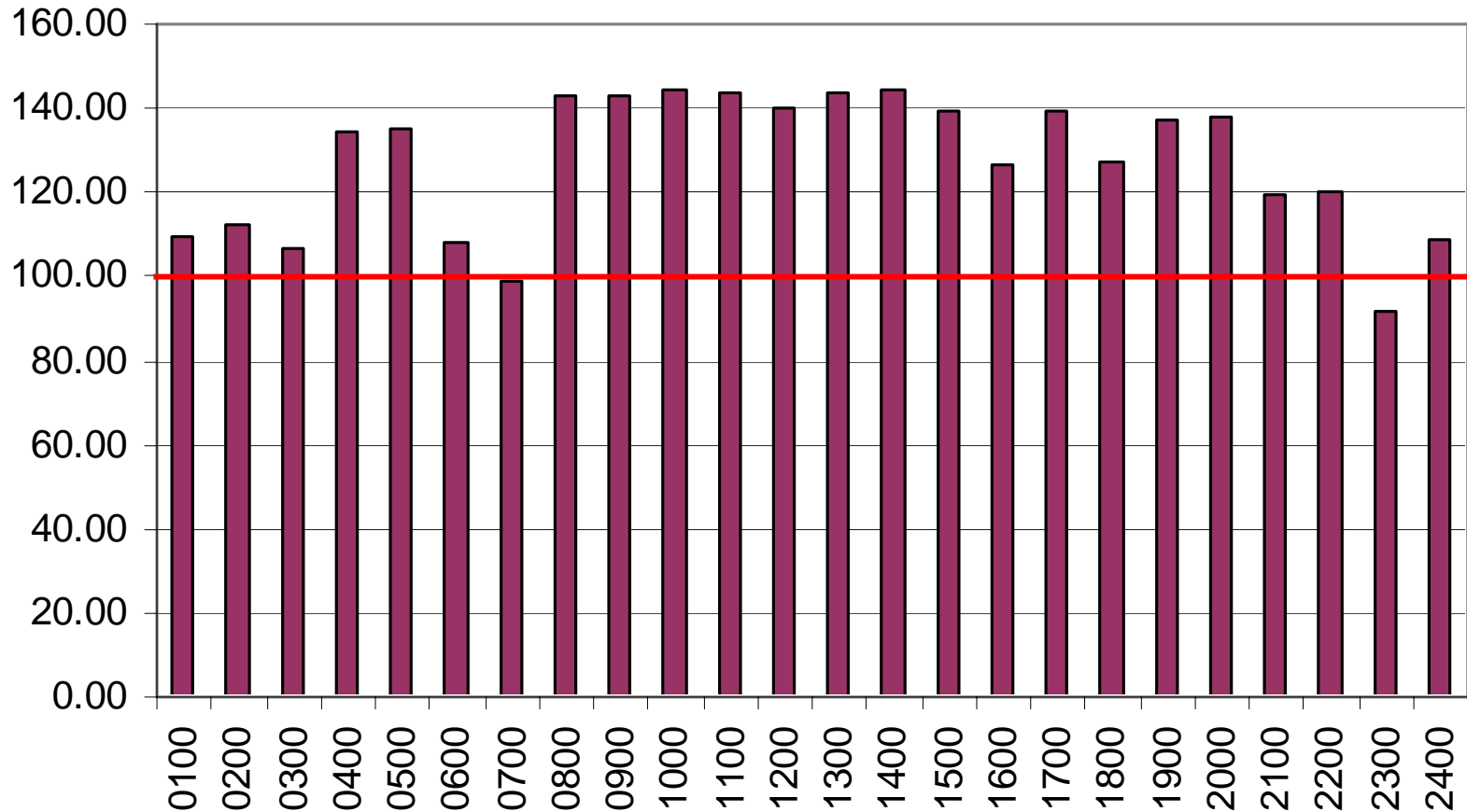
CPS2 by Hour - April 2005
Passing Score >= 90
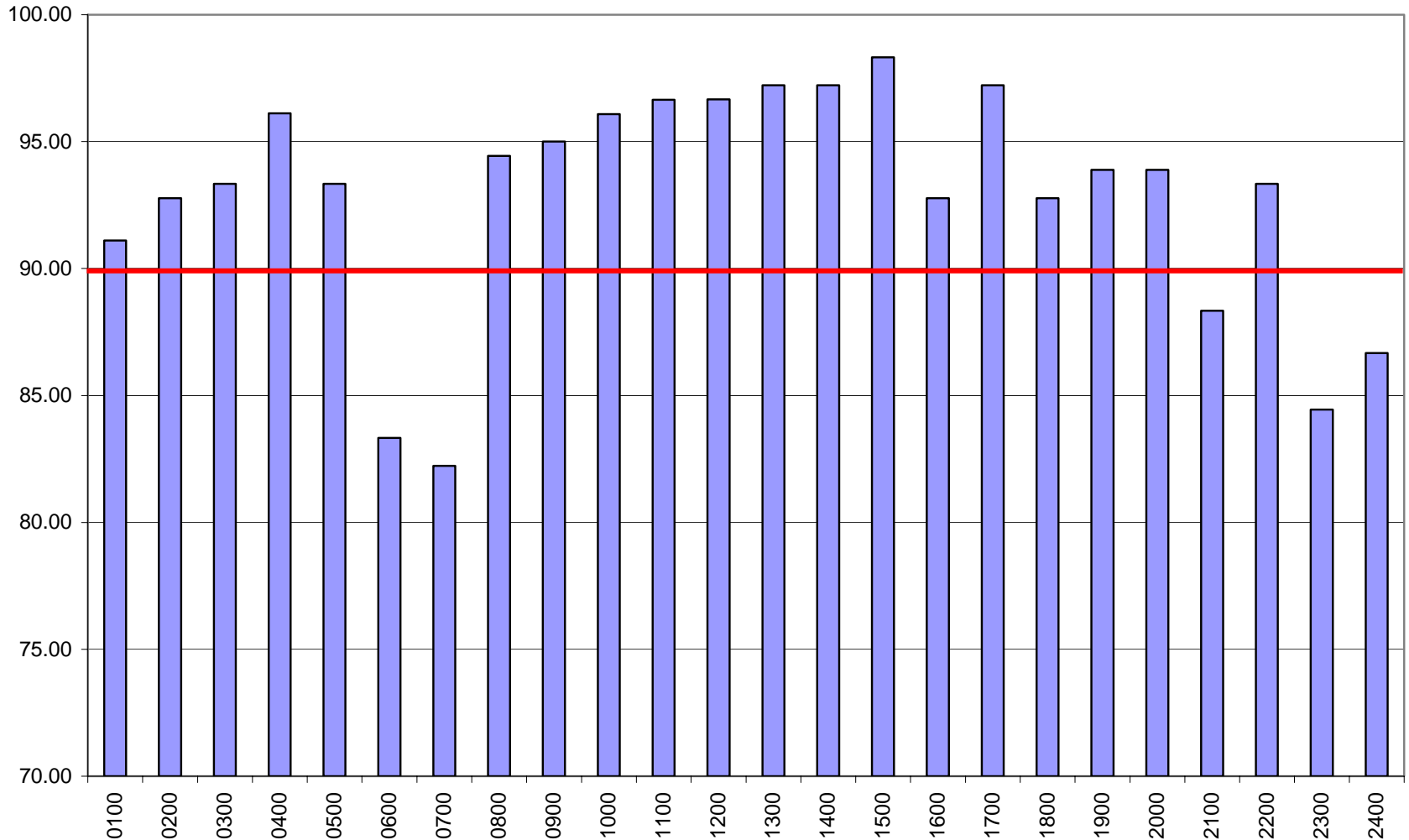
- Implement rule that limits magnitude of schedule changes
  - One option: a base power schedule change limitation, to be no larger than the largest projected load growth in ERCOT, perhaps times a multiplier

<u>and/or</u>

- Introduce additional market mechanisms
  - One option: Integrated Day Ahead market (security-constrained, financially binding)

- Enhanced reliability

  – Better frequency control = Less system risk

- Reduced cost of Ancillary Service deployment

  – Reduce deployment of large amounts of Ancillary Services for schedule changes.

- Successfully meet NERC criteria during all hours.

- Protocol Revision, PRR525 <u>(SCE Performance and Monitoring),</u> approved by Board on April 19.
  - Partial implementation on May 1.
  - Full implementation expected upon system implementation.
  - ➢ PRR 525 is a reporting mechanism and does not provide financial disincentive.

- Protocol Revision 586 <u>(SCE Performance and Regulation Cost Re-Allocation)</u> under discussion by stakeholders.

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- Ancillary Services are procured, but can't be delivered.
    - Ancillary Services are procured by portfolio.
    - Resources allocated by QSE to supply Ancillary Services may not be available.
        - Restricted due to Local Congestion
    - Some procured Ancillary Service capacity is not deliverable.
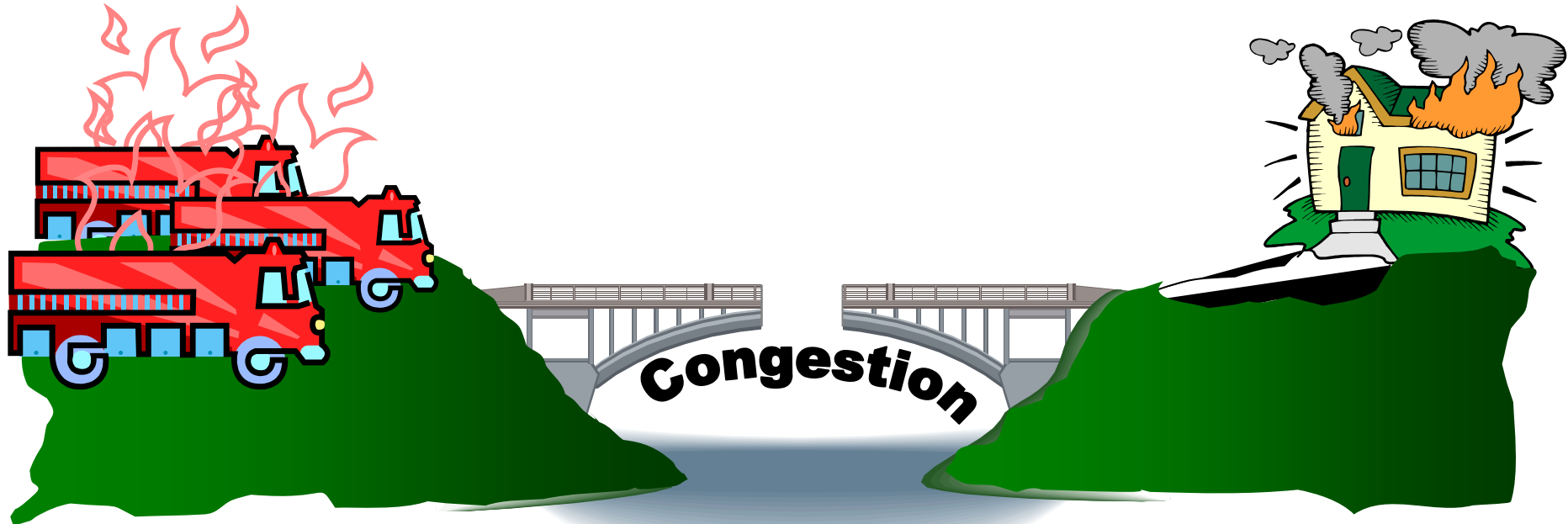
Congestion

Services procured, but can't respond to the problem.

- Description: Develop method to determine whether a QSE is able to deliver Ancillary Services
  - Take Resource location into consideration when procuring services.
  - Congestion Analysis would be an input to procurement process.

- Benefits:
  - Improve reliability
    - Ensures that services procured can be delivered when needed.
  - Prevent ERCOT from having to choose between transmission reliability and capacity reliability.

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- Telemetry serves as ERCOT's eyes.
  - Provides key measurements to assess system conditions.

- A location is <u>observable</u> if ERCOT receives adequate measurement to calculate flow and voltage.

- A measurement is <u>critical</u> when its loss causes an observable location to become unobservable.

- When a critical measurement is lost, ERCOT must estimate its measurements.

- Lack of observability poses challenge to Congestion Management.
  - ERCOT may relieve a problem which is illusionary.
  - Real problem may go unnoticed.

- Lack of observability increases risk of NERC violation.
  - NERC policies require use of analysis tools to adequately assess system conditions.
    - Inadequate situational awareness cited as one of the causes of the August 14th Northeast blackout.
    - ERCOT is not at similar risk of blackout as all of its 345kv lines are observable.

The simple diagram below shows a substation that is observable.
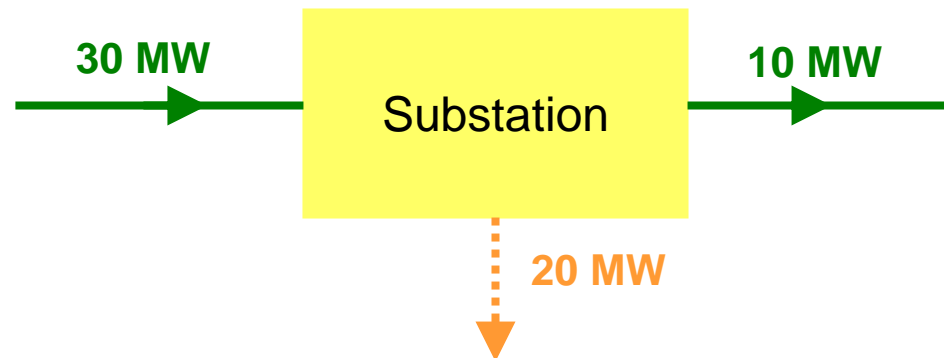
30 MW → **Substation** → **10 MW**

20 MW ↓

The diagram can be expanded to show a set of observable locations.
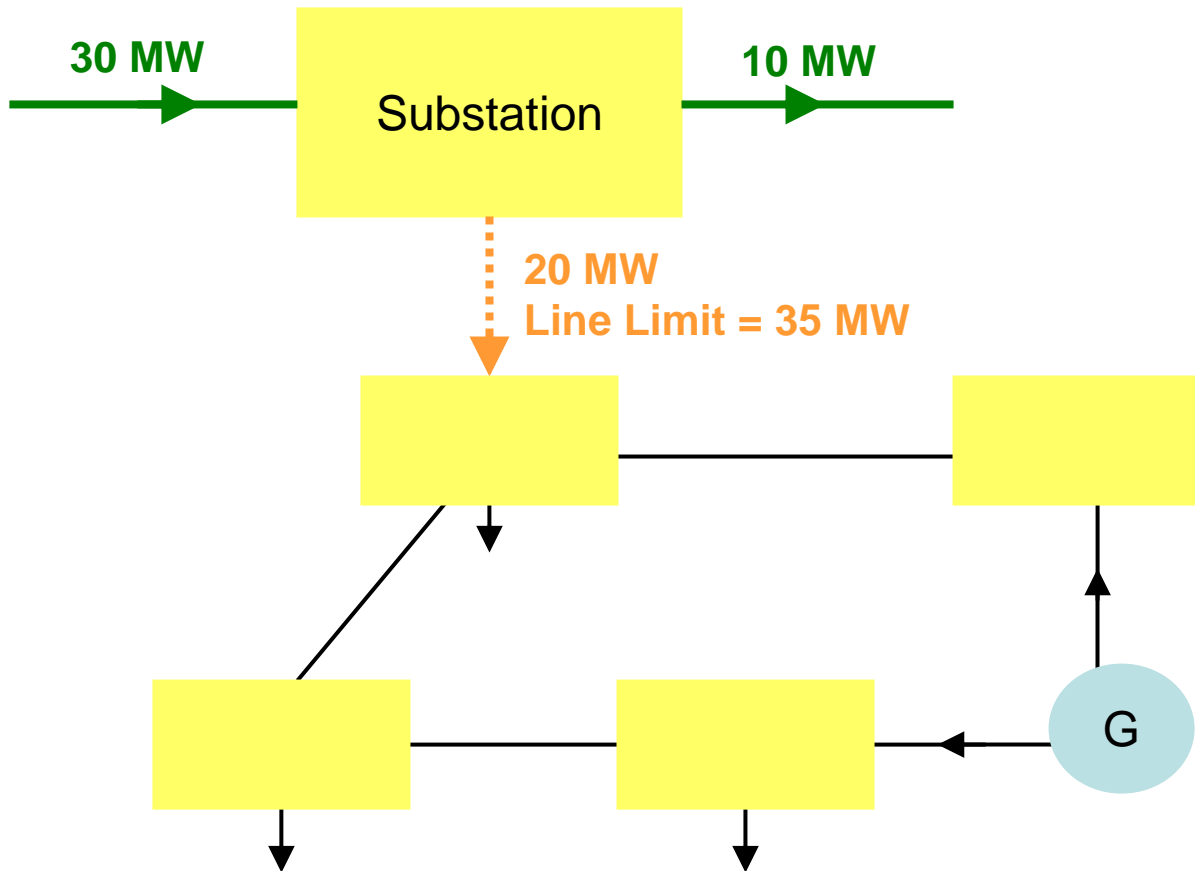
A loss of critical measurements can create a set of unobservable locations, or an unobservable island.
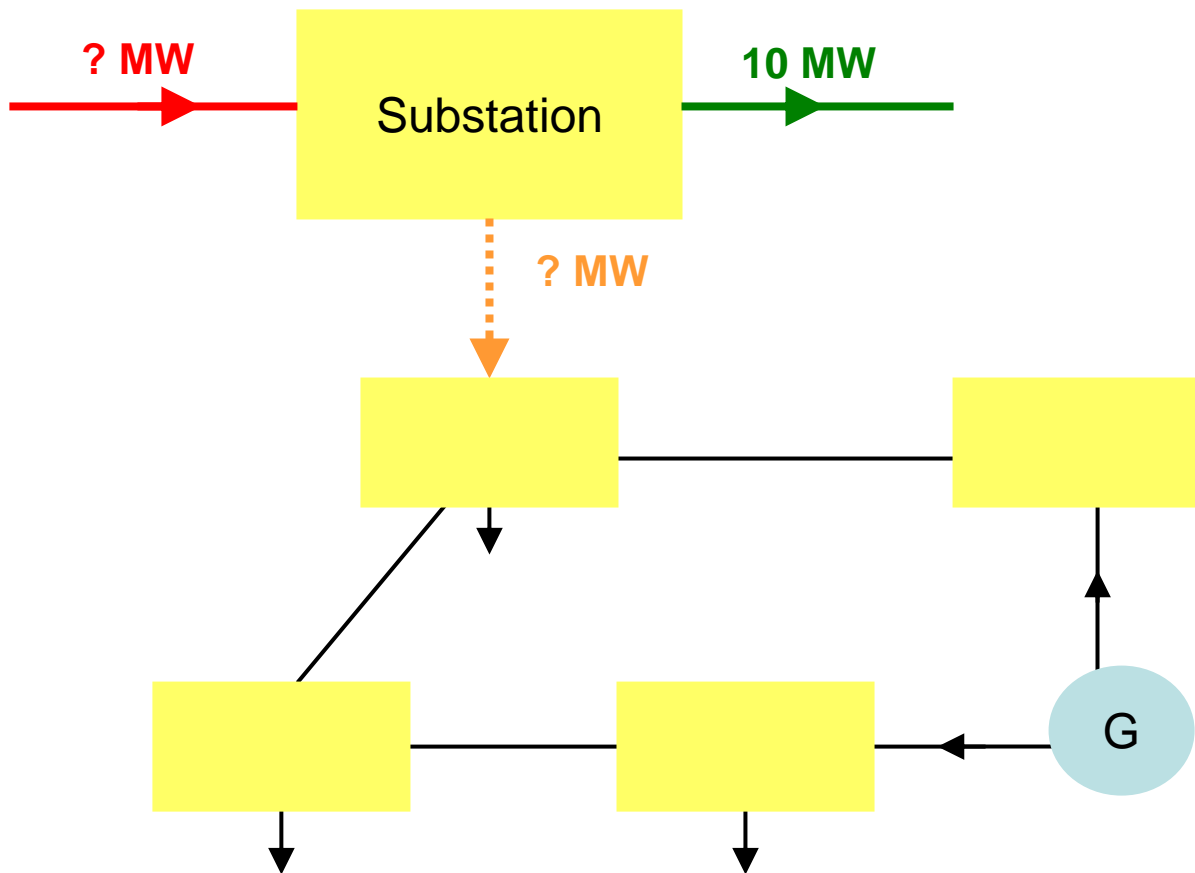
Due to the loss of telemetry, if the flow is estimated by ERCOT to be 50 MW, this results in imaginary problems. ERCOT will deploy energy to resolve the problem it believes exists.

50 MW   Substation   **10 MW**

40 MW
Line Limit = 35 MW

G
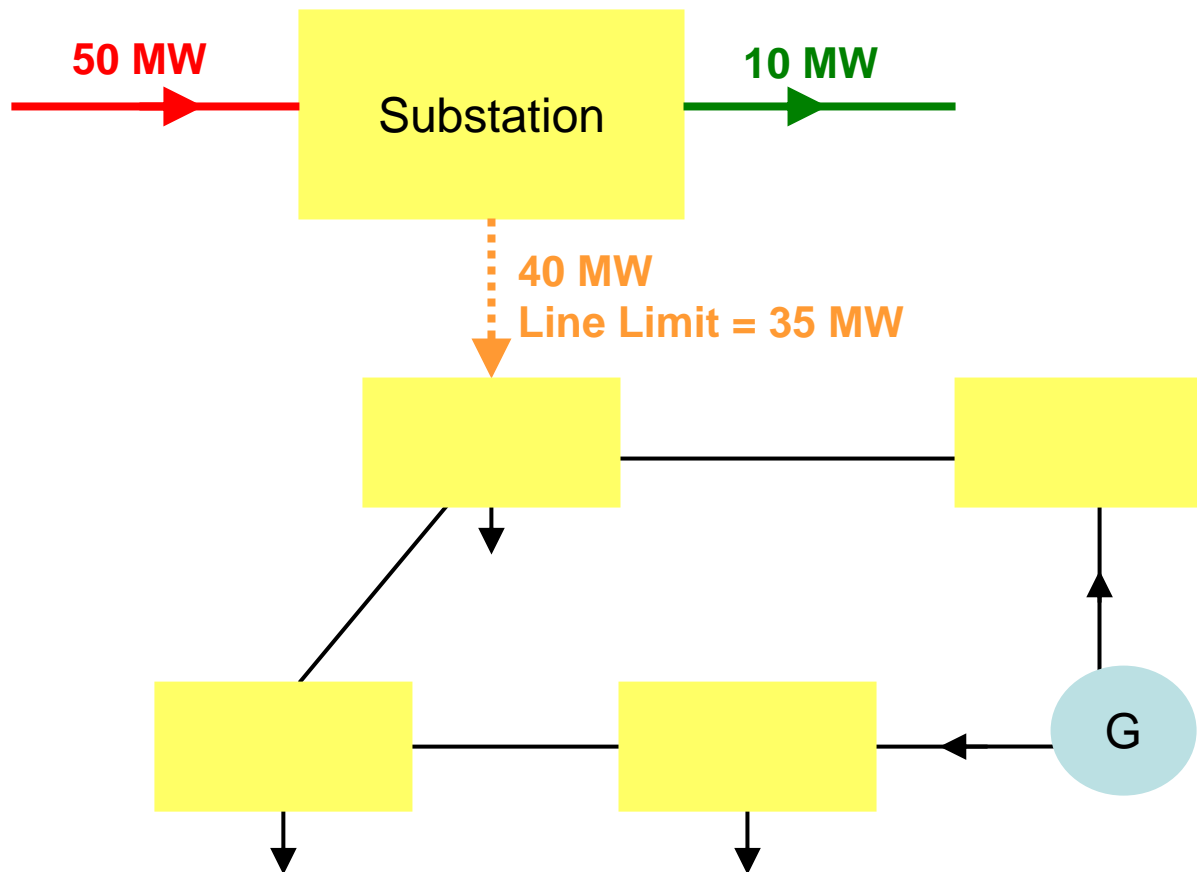
- Add telemetry to locations within ERCOT
  - Identify specific locations that would benefit from additional telemetry.
  - Reduce the number of critical measurements.

- Additional telemetry results in increased observability.
  - More accuracy in managing congestion
  - Less risk of equipment damage post contingency
  - Less risk of NERC violation

- Operating Guide Revision Request (OGRR) 163 drafted
  - Revision clarifies ERCOT's ability to require telemetry additions if reliability problem exists.
  - To be reviewed by stakeholders in June

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- Congestion Management is a challenge with current market timing.
    - Real-time market solves too far in the future.
        - ERCOT Market begins study for each 15-minute interval <u>13-minutes prior</u> to the start of the interval.
        - 28 total minutes between the time the study starts to the time the interval ends.
    - Significant changes can occur in Load and Generation patterns during these 28 minutes.
        - These changes are not accounted for in the study and resulting energy deployments.
        - Takes time to correct for any problems (e.g. unit trip)
        - Ancillary Services deployed to account for Load changes.

ERCOT solves for
09:00 interval.

09:00 Interval

28 Minutes

08:30

08:45

09:00
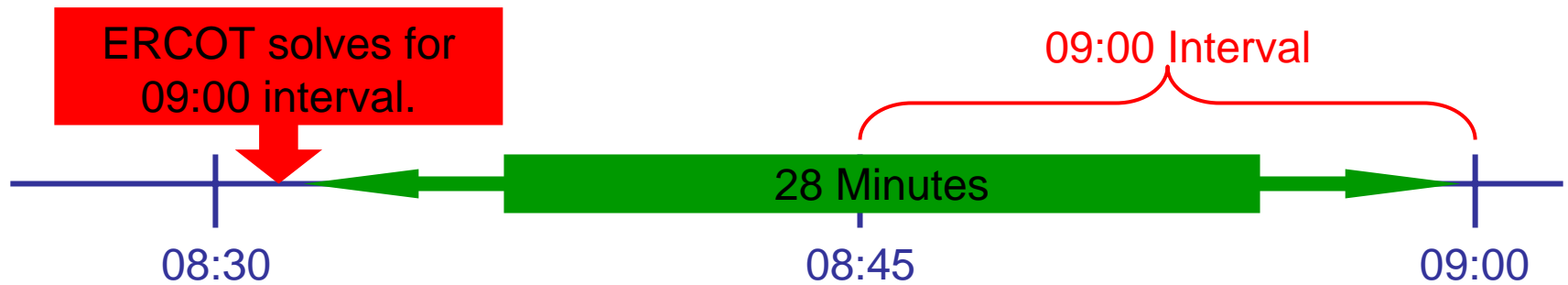
Actual Load v. Forecast Load: 15 minute intervals

6/7/2005
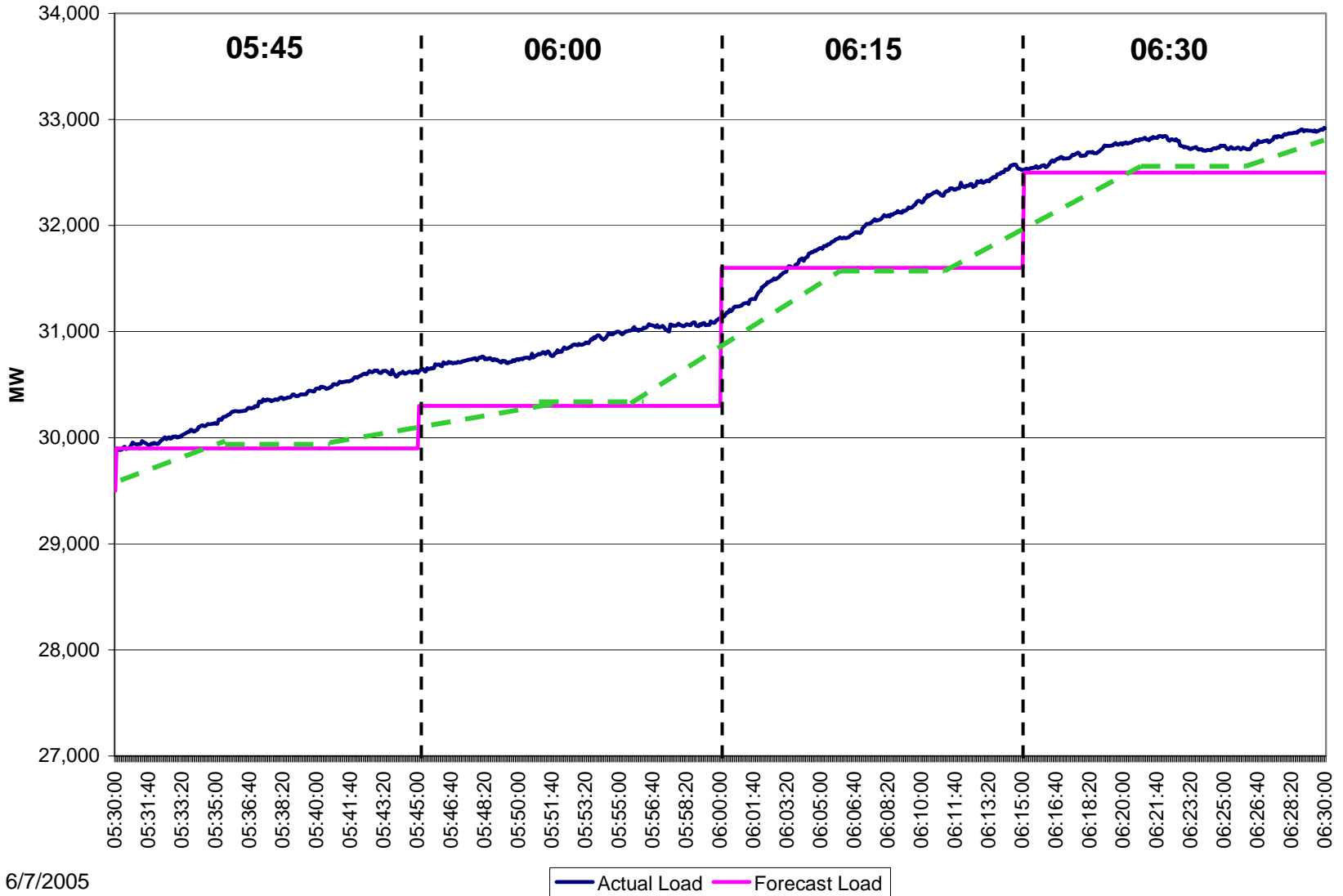
- Issue dispatch instructions for each <u>5</u> minute interval
  - 5 minute data could be aggregated into 15 minute data for Settlements

- Change improves congestion management by increasing accuracy of Real-time solution.
  - Study includes more up-to-date information
    - Increases ability to control frequency
    - Reduces need for Ancillary Service deployments
    - Reduces Out-of-Merit deployments
  - Able to correct problems quickly

Actual Load v. Forecast Load: 5 minute intervals

Legend: Actual Load — 15 Min Forecast Load — 5 min Forecast Load

6/7/2005
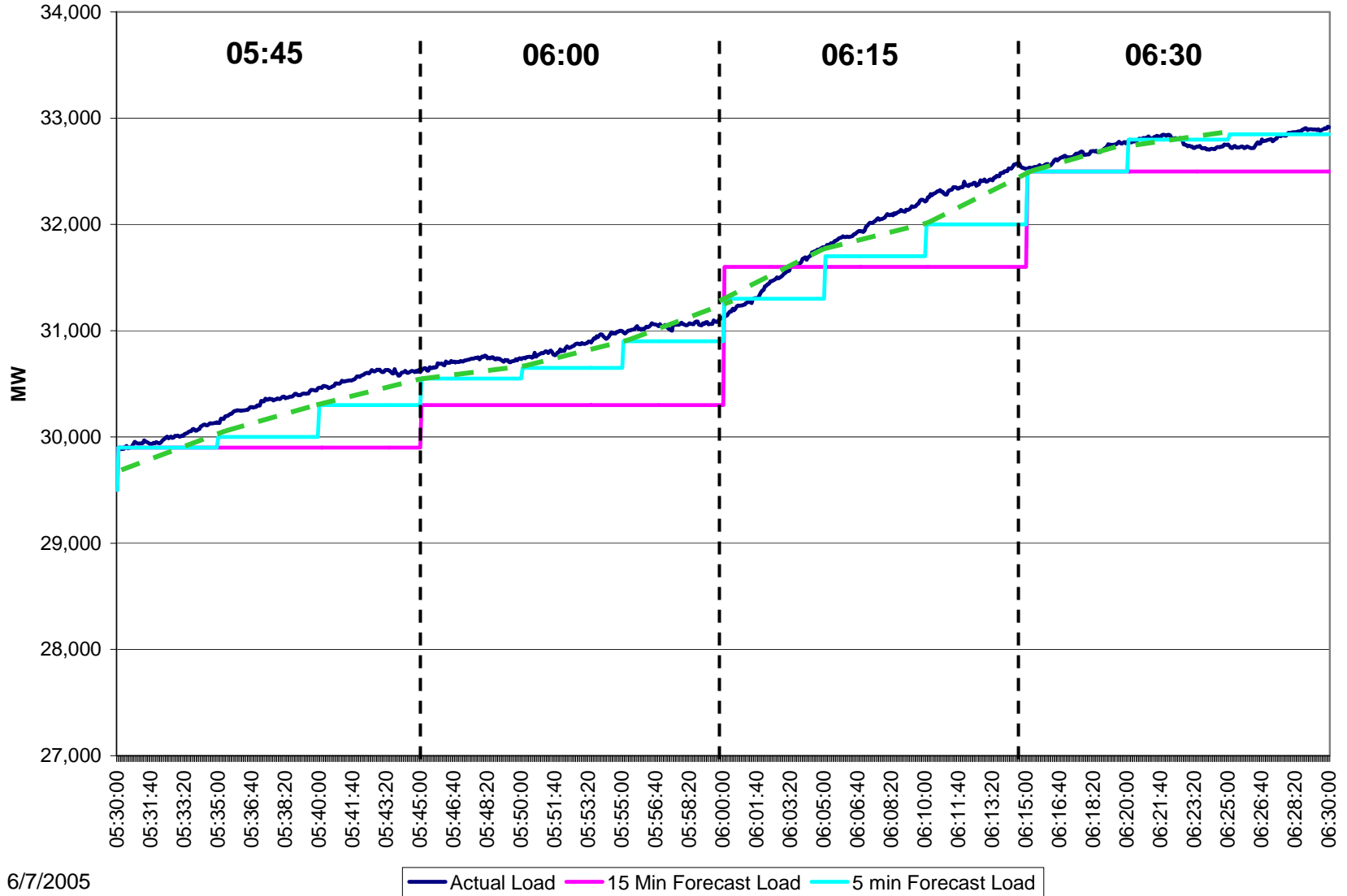
- Protocol Revision, <u>PRR 601 15 Minute Ramping for BES and Base Power Schedule</u>, submitted.
  - Modifies the ramping period from 10 minutes to 15 minutes.
  - Addresses Potomac Economics' recommendation to create a continuous ramp during the interval.

1. **Utilize Resource-specific scheduling, bidding and deployment**

2. **Utilize Resource-specific ramp rates in dispatch**

3. **Utilize Resource-specific shift factors**

4. **Develop financial incentives for participants to follow schedules and instructions**

5. **Develop scheduling rules and/or market mechanisms to mitigate effects of block schedules**

6. **Develop mechanism to ensure deliverability of Ancillary Services**

7. **Increase observability of the transmission system**

8. **Issue dispatch instructions every five minutes**

9. **Assign local congestion costs directly**

10. **Implement a more robust Day Ahead unit commitment process**

- Currently, Local Congestion costs are uplifted to Loads in ERCOT system based on load ratio share.
  - There is no financial incentive for QSEs to use Resources that help solve congestion.
  - QSEs are paid to curtail output in congested areas.

- Assume a QSE with the following portfolio:
  – 1000 MW of load
  – Gas units: 500 MW of capacity
  – Coal units: 1000 MW of capacity
- Assume transmission limit outside the coal station is 500 MW.
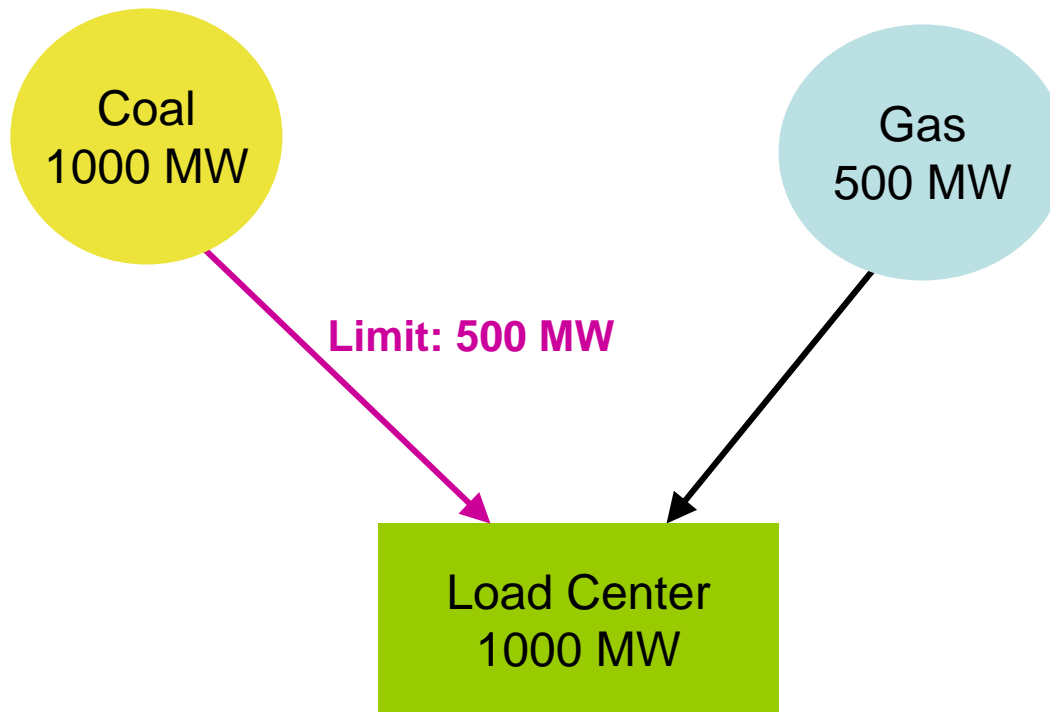
- Since congestion cost is uplifted, the QSE has the financial incentive to schedule all the 1000 MW from the Coal units.
- ERCOT will need to redispatch to decrease flow on the line.
- Cost of redispatch is uplifted.

Coal
1000 MW

Gas
0 MW

Flow = 1000 MW
Limit: 500 MW

Load Center
1000 MW
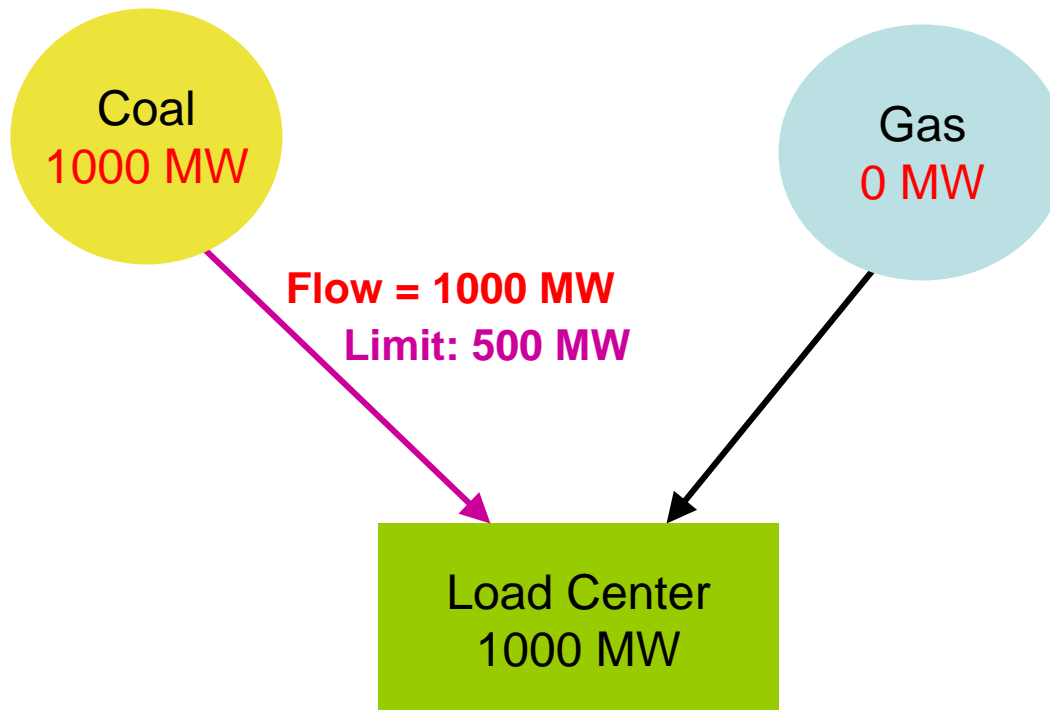
- When ERCOT market opened in 2001, Zonal Congestion costs were uplifted to Loads.
  - Large amount of South-to-North Zonal Congestion due to inter-zonal energy schedules from South zone.

- After Direct Assignment of Zonal Congestion cost in Feb.2002, scheduling behavior changed.
  - Scheduled energy from South-to-North CSC reduced significantly.
  - South-to-North Zonal Congestion decreased.

- With direct assignment of congestion cost, financial incentive exists for QSEs to use Resources that help resolve congestion.

  - Increased efficiency in congestion management
  - Reduction of congestion management activities

- When the congestion cost is directly assigned, the QSE has less financial incentive to schedule all the 1000 MW from the Coal units.

- QSE will assume cost if redispatch is required.

- As shown in this example, direct assignment can effectively reduce ISO congestion management activities.
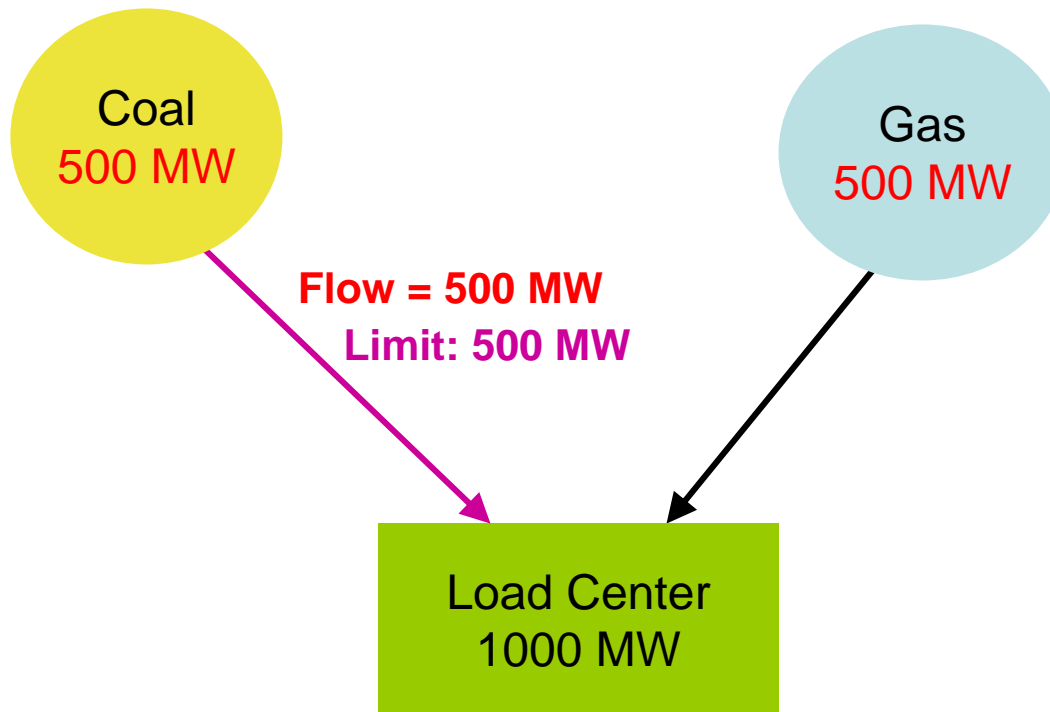
Coal
500 MW

Gas
500 MW

Flow = 500 MW
Limit: 500 MW

Load Center
1000 MW

1. **Utilize Resource-specific scheduling, bidding and deployment**

2. **Utilize Resource-specific ramp rates in dispatch**

3. **Utilize Resource-specific shift factors**

4. **Develop financial incentives for participants to follow schedules and instructions**

5. **Develop scheduling rules and/or market mechanisms to mitigate effects of block schedules**

6. **Develop mechanism to ensure deliverability of Ancillary Services**

7. **Increase observability of the transmission system**

8. **Issue dispatch instructions every five minutes**

9. **Assign local congestion costs directly**

10. **Implement a more robust Day Ahead unit commitment process**

- ERCOT currently uses Out-of-Merit Capacity (OOMC) to manage Day Ahead capacity issues.

  – Manual selection of Resources

  – Start-up and energy costs are not considered in selection

  – No market mechanism exists

- Implement an automatic Day Ahead unit commitment process
  - Considers available bids in procuring system-wide capacity
  - Considers start-up and energy costs in procuring local capacity
  - Considers time constraints (e.g., start-up time, minimum run time)

- Increases accuracy in assessing capacity needs
  – Improves reliability
  – Produces cost savings by procuring minimum capacity necessary
  – Partially allocates cost to loads that are short

- Provides market mechanism to meet capacity need
  – Procures capacity competitively at least cost

- Next major software release includes new Day Ahead unit commitment process
  - Provides necessary changes to overcome operational challenges
  - Release is currently scheduled later this year

- These 10 changes would allow ERCOT to better manage system operations.

- Primary benefits of these changes:
  - Synchronize Operations and Settlement
  - Align market incentives with reliability

➢ Efficient Operations support efficient Markets.

- Significant design and IT system changes required to fully implement changes.
  - Formal Cost / Benefit analysis should be performed.
  - Adequate time for system implementation should be allowed.

Comparison of Proposals: Summary

ERCOT Proposed Change	TNT Protocols	COCL	Patton Recs
1. Utilize Resource-specific scheduling, bidding, and deployment	●	●	○
2. Utilize Resource-specific ramp rates in dispatch.	●	◍	○
3. Utilize Resource-specific shift factors.	●	◍	◍
4. Develop financial incentives for participants to follow schedules and instructions.	◍	●	●
5. Develop scheduling rules to mitigate effects of block schedules.	◍	○	◍
6. Develop mechanism to ensure deliverability prior to procuring Ancillary Services.	○	○	○
7. Increase observability in the transmission system.	●	○	○
8. Issue dispatch instructions every 5 minutes.	●	●	○
9. Assign Local Congestion costs directly.	●	◍	○
10. Implement more robust Day Ahead unit commitment process	●	◍	○

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ERCOT Proposed Change	TNT Protocols
1. Utilize Resource-specific scheduling, bidding, and deployment	🟢 Fulfills.
2. Utilize Resource-specific ramp rates in dispatch.	🟢 Fulfills.
3. Utilize Resource-specific shift factors.	🟢 Fulfills.
4. Develop financial incentives for participants to follow schedules and instructions.	◐ Small penalty factor is included.
5. Develop scheduling rules to mitigate effects of block schedules.	◐ Does not specifically provide scheduling rules. Market structure resolves problem, however, by separating financial responsibility and physical responsibility. QSE provides binding bid but a non-binding schedule. ERCOT assesses operational need and meets need with submitted bids.
6. Develop mechanism to ensure deliverability prior to procuring Ancillary Services.	○ Does not address.
7. Increase observability in the transmission system.	🟢 Fulfills.
8. Issue dispatch instructions every 5 minutes.	🟢 Fulfills.
9. Assign Local Congestion costs directly.	🟢 Fulfills.
10. Implement more robust Day Ahead unit commitment process	🟢 Fulfills.

ERCOT Proposed Change		COCL Proposal
1. Utilize Resource-specific scheduling, bidding, and deployment	●	Fulfills.
2. Utilize Resource-specific ramp rates in dispatch.	◉	Does not specifically address ERCOT's change, but possible to implement with proposed framework.
3. Utilize Resource-specific shift factors.	◉	Addresses bus-level dispatch, but does not offer details on congestion clearing (zonal, local) and use of resource-specific shift factors.
4. Develop financial incentives for participants to follow schedules and instructions.	●	Fulfills.
5. Develop scheduling rules to mitigate effects of block schedules.	○	Does not address..
6. Develop mechanism to ensure deliverability prior to procuring Ancillary Services.	○	Does not address.
7. Increase observability in the transmission system.	○	Does not address.
8. Issue dispatch instructions every 5 minutes.	●	Fulfills.
9. Assign Local Congestion costs directly.	◉	Possible to implement with proposed framework, but no details given on settlement and use of bus price.
10. Implement more robust Day Ahead unit commitment process	◉	Does not specifically address commitment process, but does address Day Ahead Market and improved ERCOT dispatch.

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ERCOT Proposed Change	Patton Recommendations
1. Utilize Resource-specific scheduling, bidding, and deployment	○ Does not address.
2. Utilize Resource-specific ramp rates in dispatch.	○ Does not address.
3. Utilize Resource-specific shift factors.	⊜ Resource-specific shift factors not specifically addressed. Rec.3 offers minor improvement to calculation of zonal average shift factors.
4. Develop financial incentives for participants to follow schedules and instructions.	● Fulfilled by Rec.11
5. Develop scheduling rules to mitigate effects of block schedules.	⊜ Rec. 10 addresses but does not resolve.
6. Develop mechanism to ensure deliverability prior to procuring Ancillary Services.	○ Does not address.
7. Increase observability in the transmission system.	○ Does not address.
8. Issue dispatch instructions every 5 minutes.	○ Does not address.
9. Assign Local Congestion costs directly.	○ Does not address.
10. Implement more robust Day Ahead unit commitment process	○ Does not address.