The ABCs of RTOs

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April 20, 2016

Housekeeping

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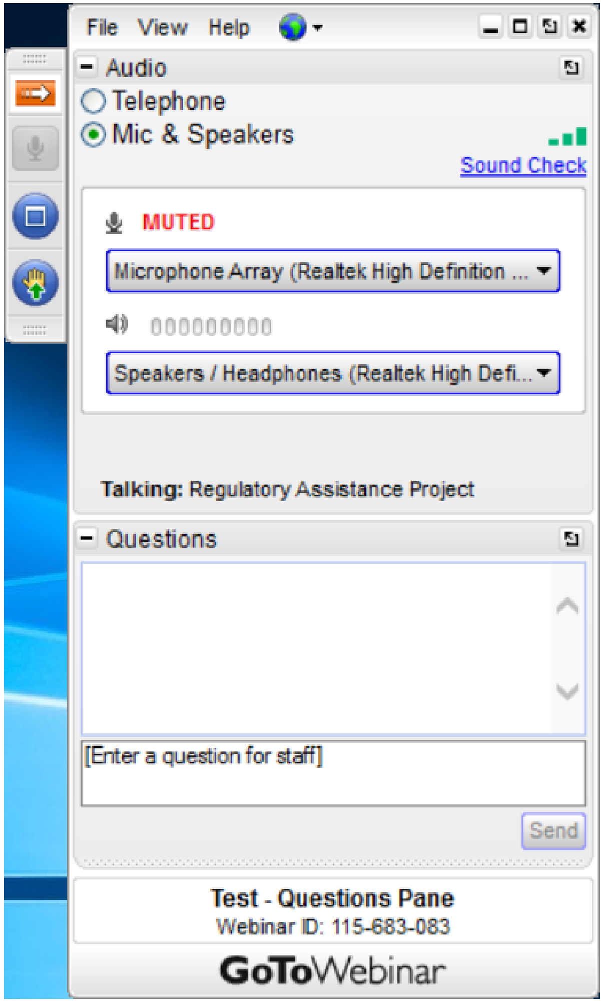

Our Experts

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Presentation Overview

- Nature and Purpose of Regional Transmission Organizations (RTOs)
- Key RTO Functions and Benefits
- Evolution of the Electricity Grid
- Overview of Least-cost Generation Dispatch and the Formation of Market Clearing Prices
- Economic Benefits of RTOs
- Emissions Effects of Least-cost Dispatch and Interconnected Systems like RTOs
- Implications for Clean Power Plan (CPP) Planning
- Recommendations

Nature and Purpose of RTOs

- What is a Regional Transmission Organization (RTO)?
- What do RTOs do?
- How can RTOs assist with CPP planning, reliability assessments, etc.?

Examples: MISO Generation Dispatch and Reliability Region

Generation Capacity

178,396 MW (market)

192,802 MW (reliability)

Historic Peak Load (July 20, 2011)

127,125 MW (market)

131,181 MW (reliability)

65,800 miles of transmission

15 States

1 Canadian Province

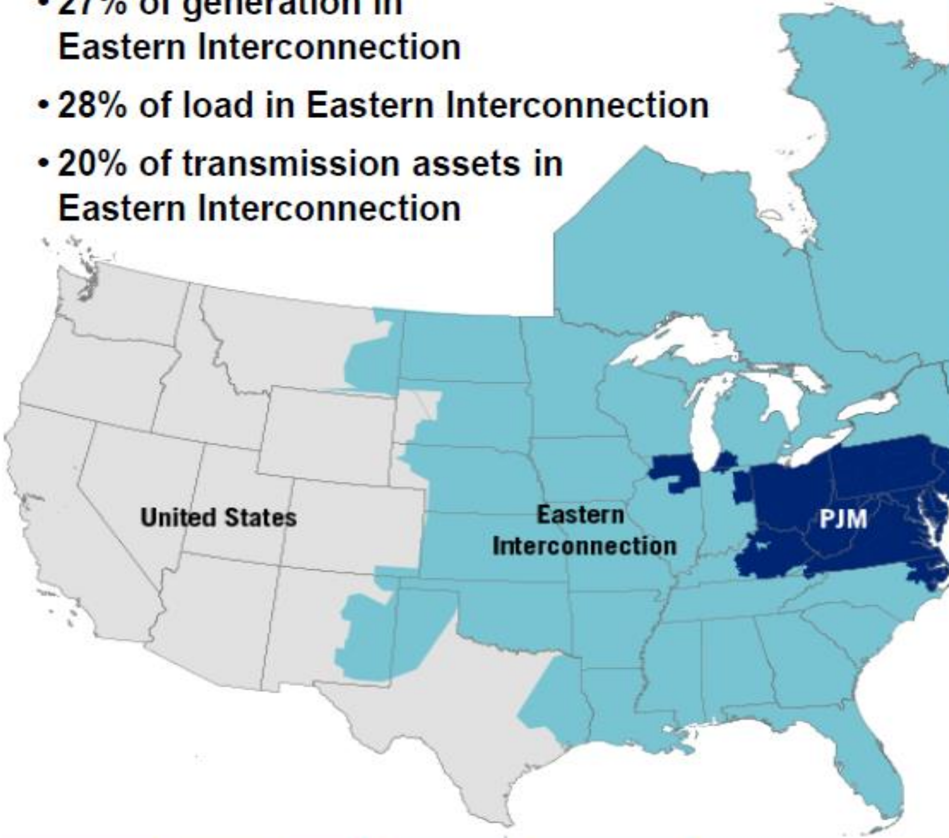
City of New Orleans

Examples: PJM Generation Dispatch and Reliability Region

pjm

PJM as Part of the Eastern Interconnection

- **27% of generation in Eastern Interconnection**
- **28% of load in Eastern Interconnection**
- **20% of transmission assets in Eastern Interconnection**

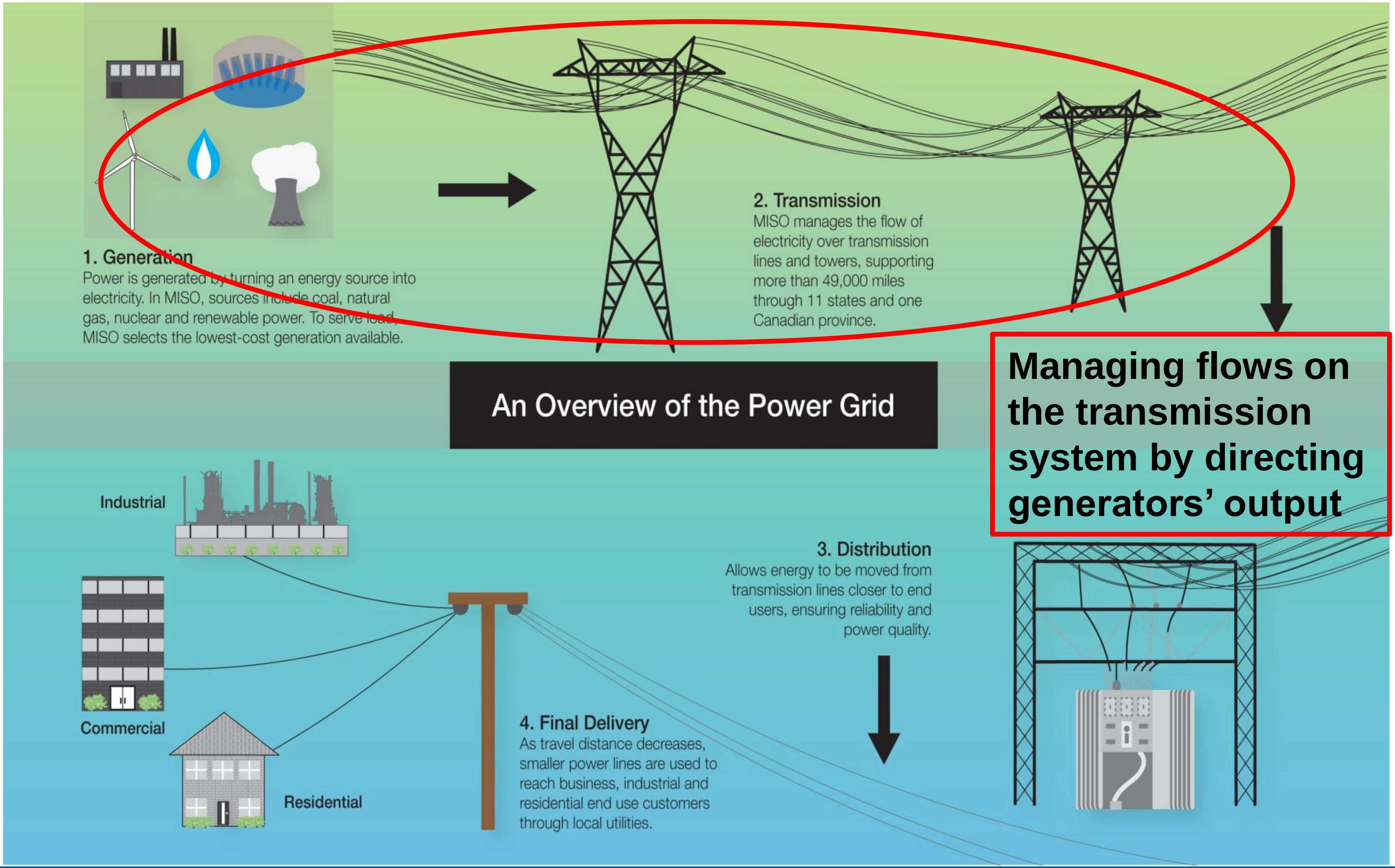


KEY STATISTICS	
PJM member companies	850+
millions of people served	61
peak load in megawatts	165,492
MWs of generating capacity	185,600
miles of transmission lines	62,556
2013 GWh of annual energy	832,331
generation sources	1,365
square miles of territory	243,417
area served	13 states+DC
externally facing tie lines	191

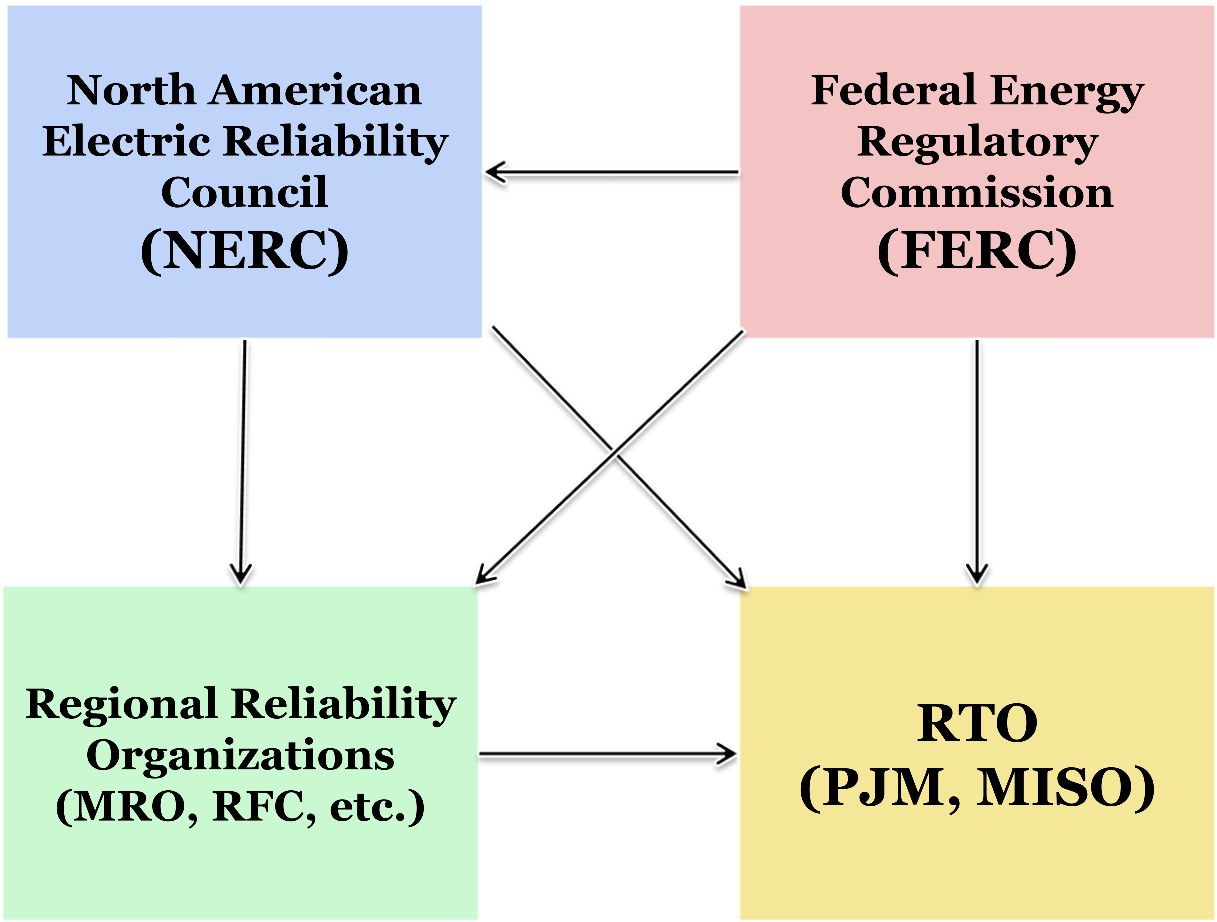
21% of U.S. GDP produced in PJM

As of 1/1/2014

The RTO's Role in the Electricity System



Who Oversees RTOs?

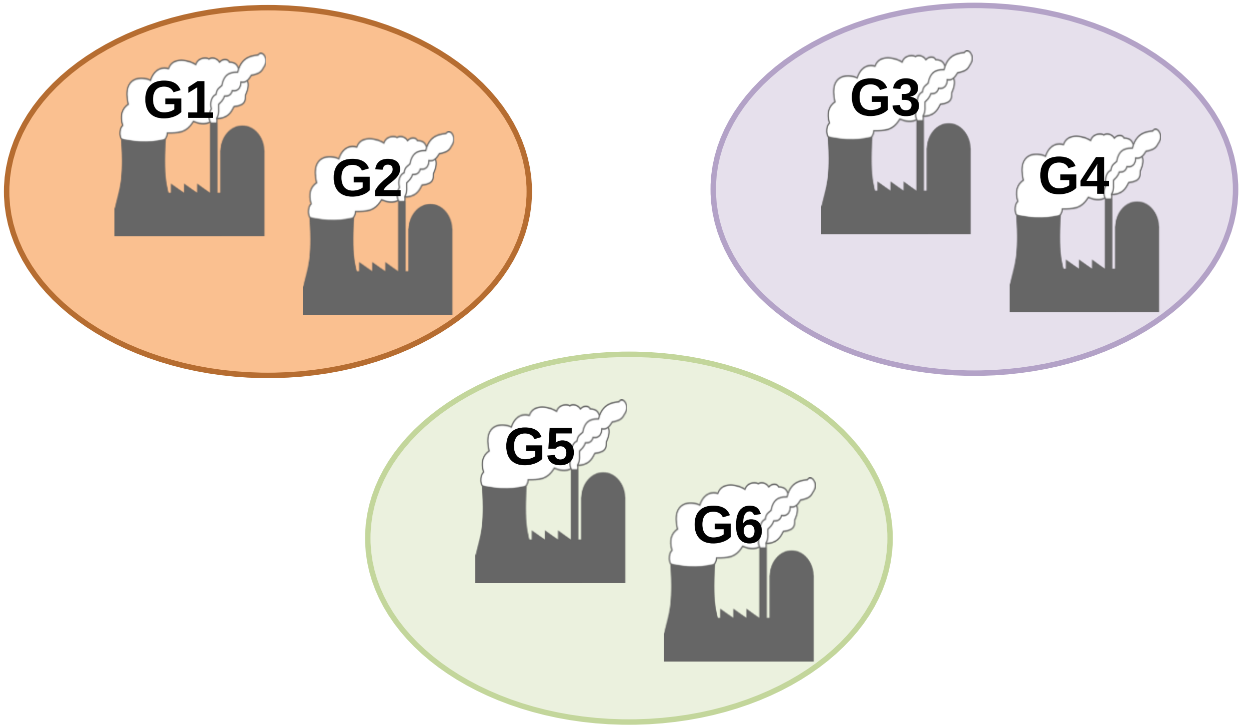


Key RTO Functions and Benefits

What RTOs Do	Implications
Provide transmission system access	Equal and non-discriminatory access
Platform for wholesale energy markets	Facilitate markets, investment, and regulatory initiatives
Perform market operations	Lower cost dispatch, system management
Coordinate reliability	Improved regional reliability
Coordinate regional planning	Integrated system planning

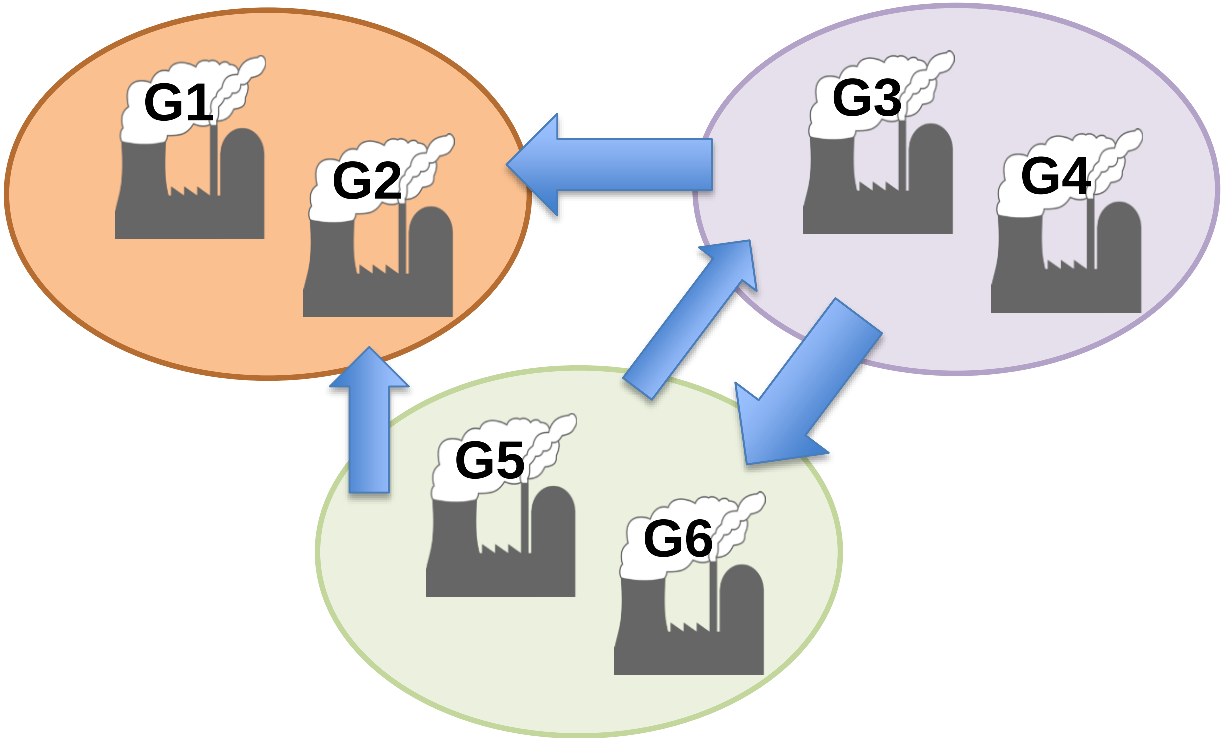
Evolution of the Grid: In the Beginning…

Each utility system served its own geography, and generated to meet its own load as if it were an island



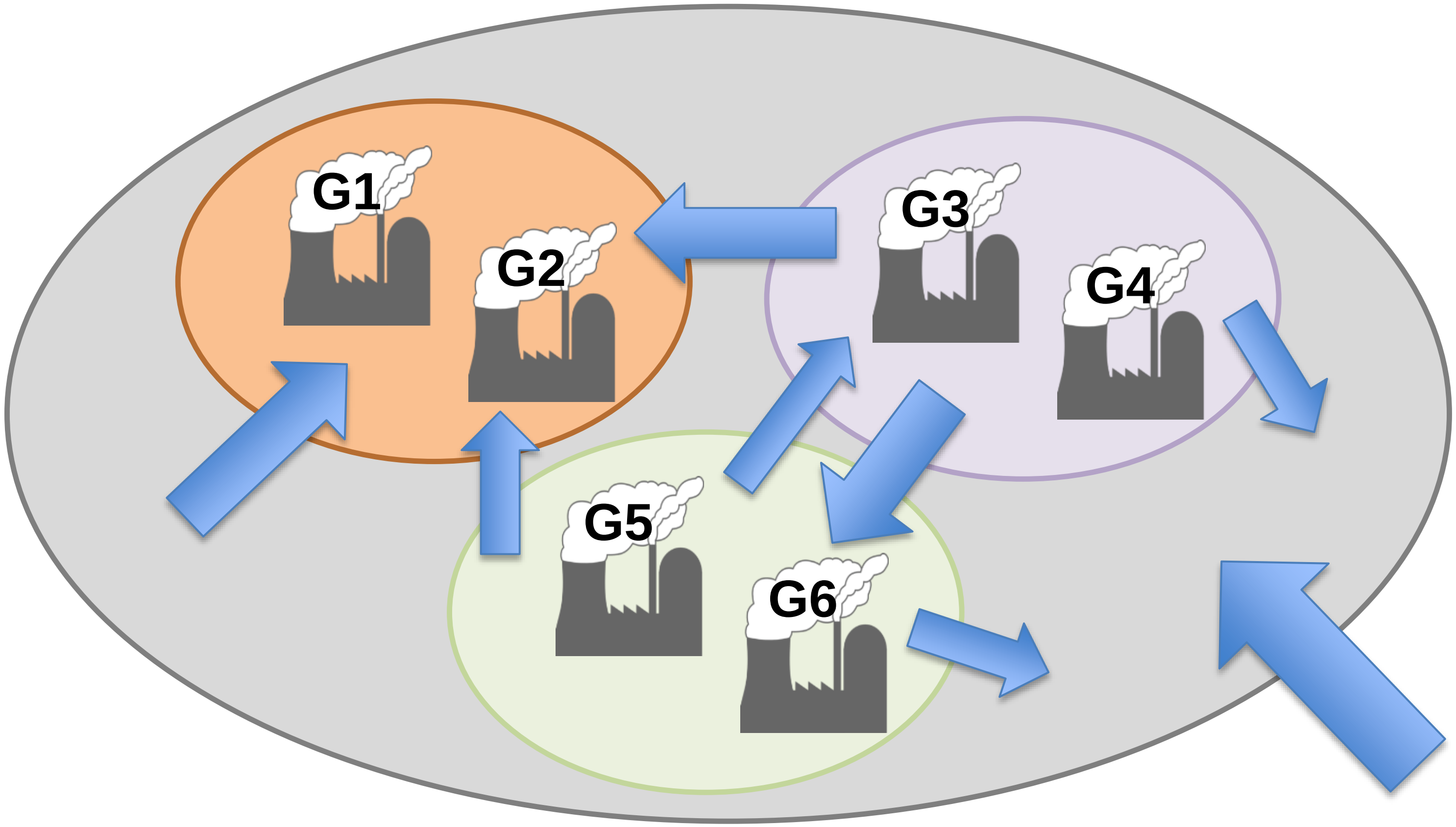
Evolution of the Grid: Systems Began to Share

Interconnected systems with bilateral power-sharing arrangements to reduce costs and enhance reliability…but still operated as separate systems



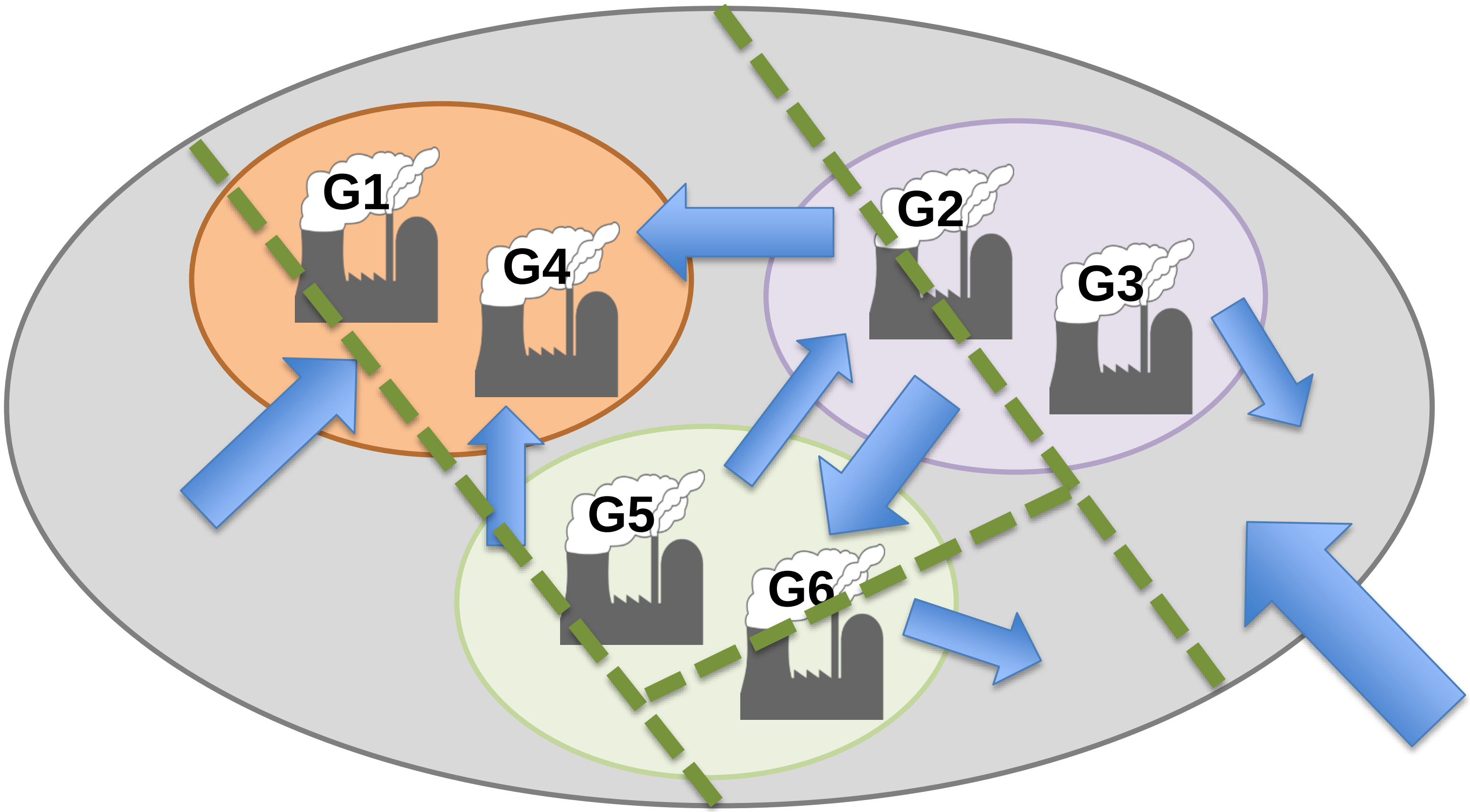
Evolution of the Grid: Systems Formed "Pools"

Utility systems entered into power-pooling arrangements and operated as one system

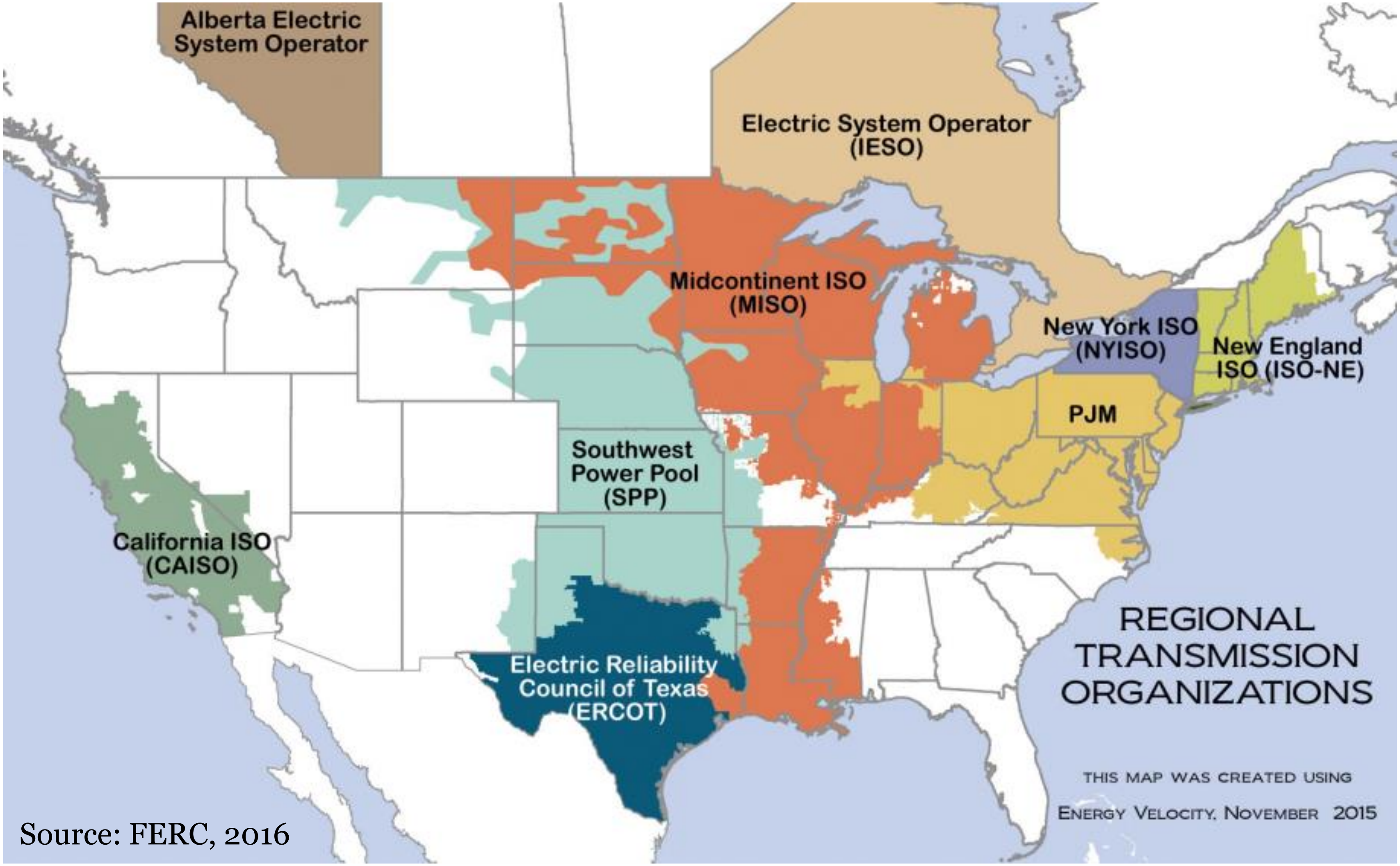


Evolution of the Grid:
From Power Pools to ISOs/RTOs

Even tighter coordination of operations to the benefit of all, even across state borders



US RTOs Today



Source: FERC, 2016

Questions?

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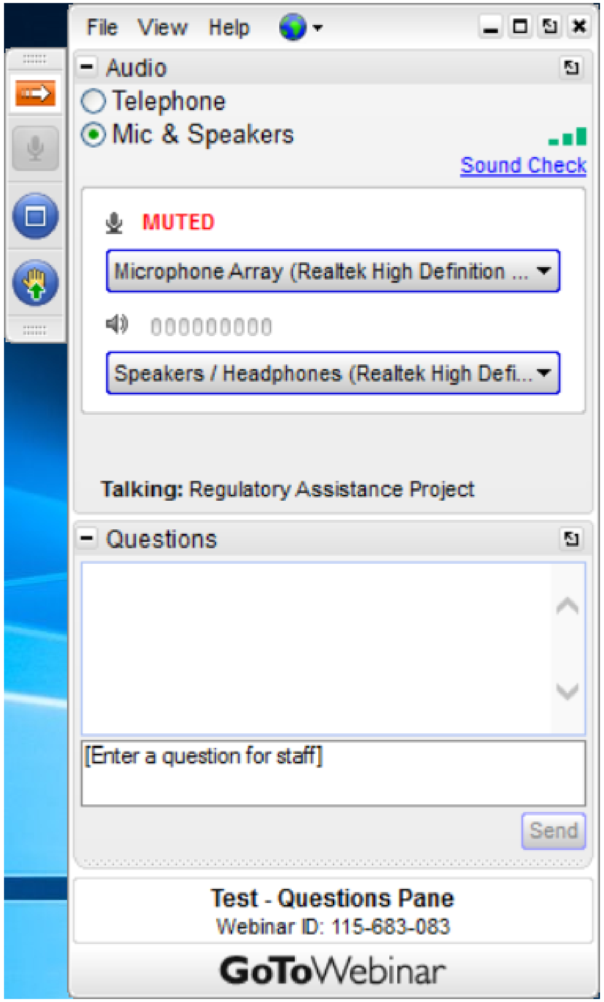
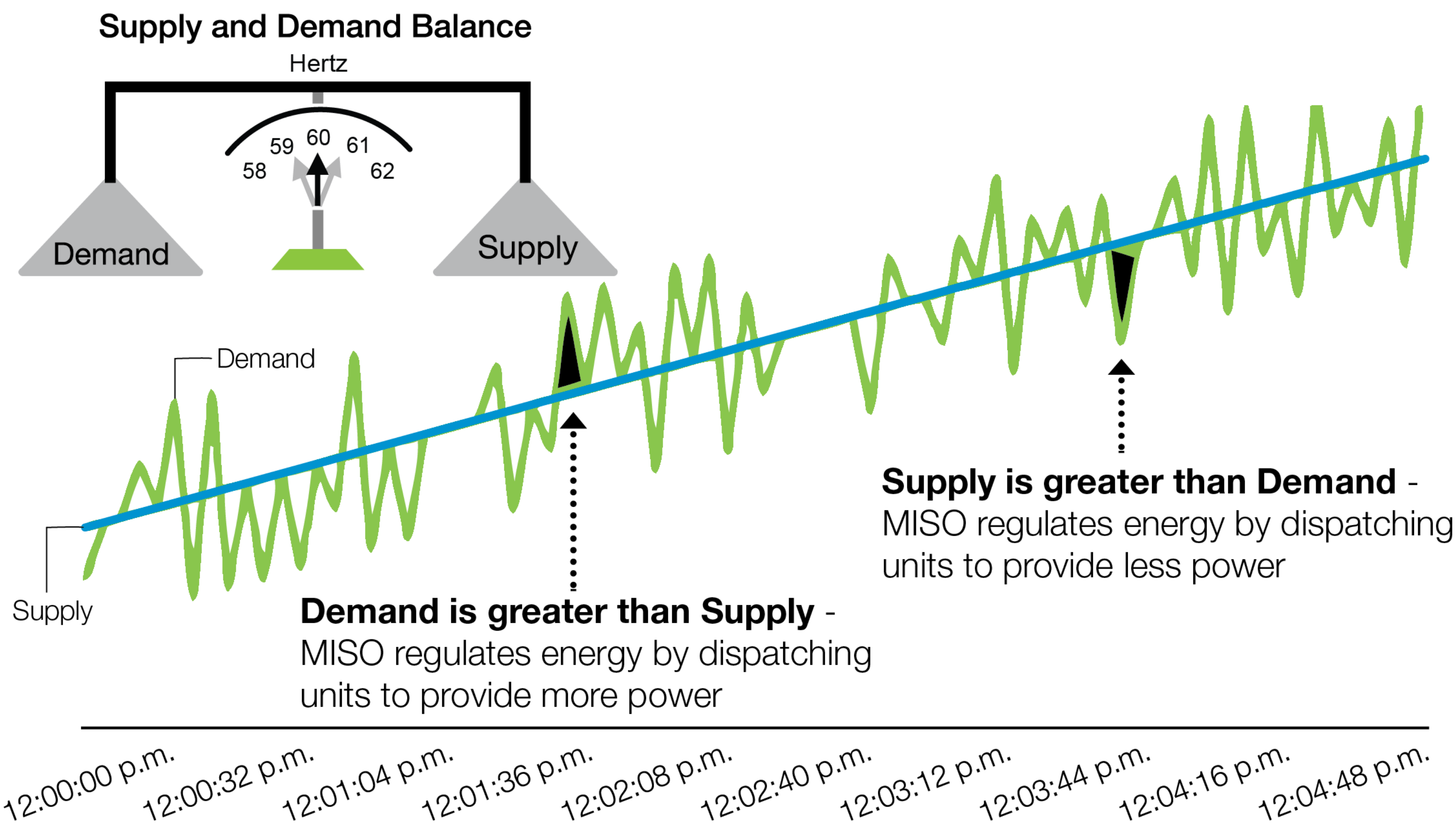


Electricity Supply and Demand is Balanced Moment to Moment



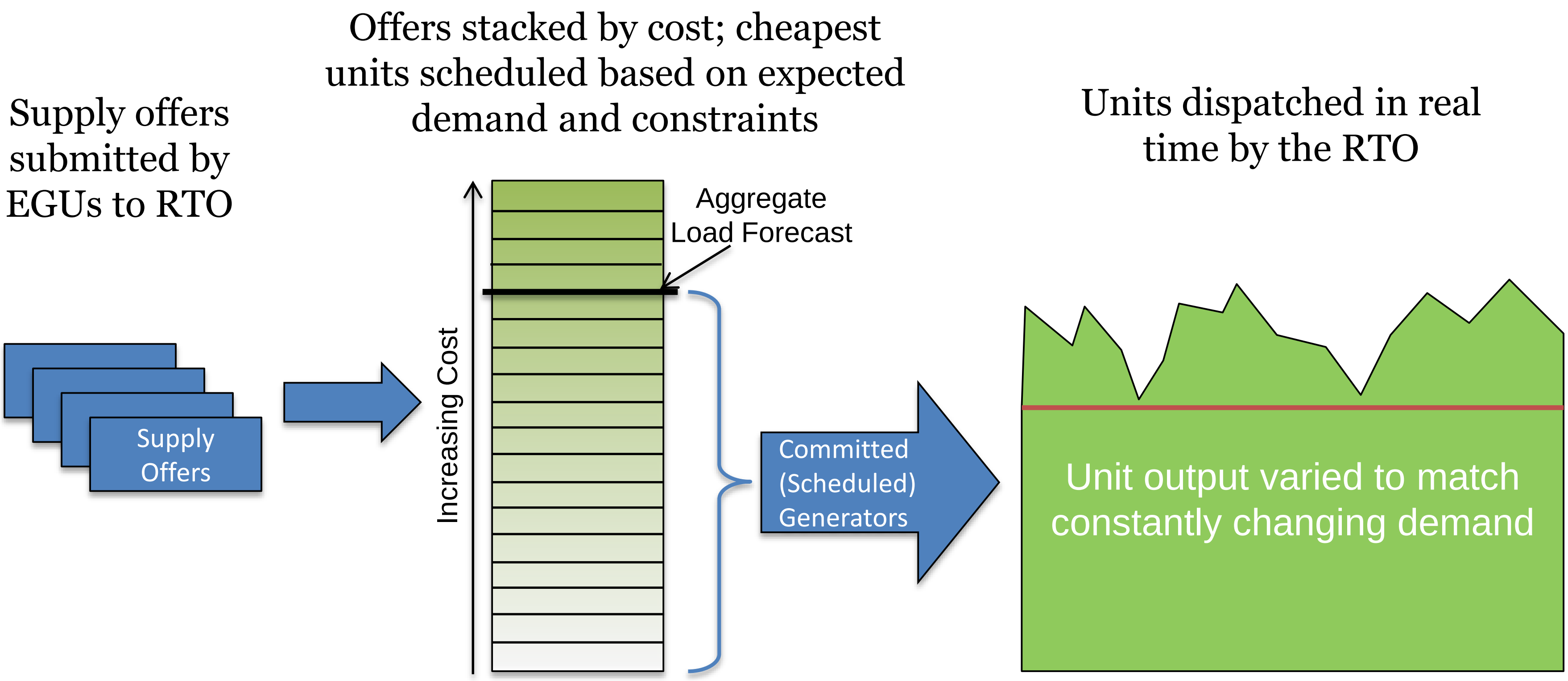
RTOs Operate via Least-Cost Dispatch, Respecting Generation, Transmission, and Regulatory Constraints

- Such constraints can include:
  - Balance of supply and demand
  - Physical limits of transmission facilities
  - Reserves and other reliability requirements
  - Power quality requirements (e.g., voltage levels, frequency)
  - Generators' schedules (e.g., maintenance outages)
  - Emissions limitations or hours-of-operation constraints
  - Other physical, regulatory, or market requirements

"Offers to Supply" from Generators Underpin Least-Cost Dispatch and System Operation

- Utilities seek to dispatch their systems at least cost
- Applies to vertically integrated utilities as well as organized markets
- What goes into generators' offers?
  - Fuel
  - Variable O&M
  - Emissions Costs

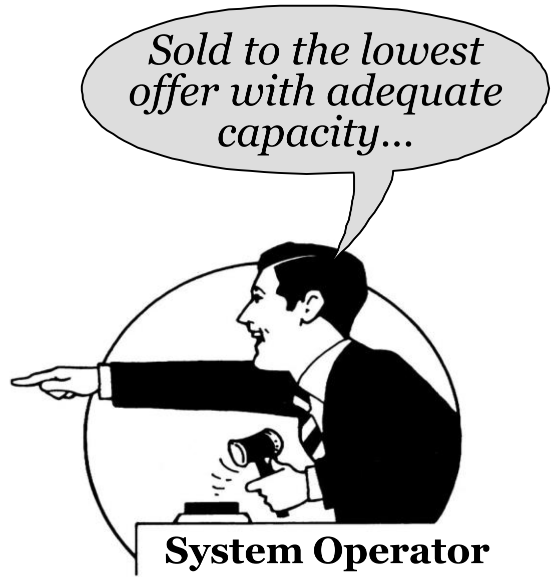
Overview of Generation Dispatch



Least-Cost Dispatch (via "Dispatch Stack") Minimizes Production Cost

Load: 499 MWs

Generator C **Capacity:** **200 MWs** **Bid: $20/MWh**	**Not Dispatched**
Generator B **Capacity:** **200 MWs** **Bid: $15/MWh**	**199 MWs** **@ $15**
Generator A **Capacity:** **300 MWs** **Bid: $10/MWh**	**300 MWs** **@ $10**



Production cost: ((300x$10) + (199x$15)) = **$5,985**

Using Gen C would only increase production cost, because its offer is higher than Gen A or B.

The "Market Clearing Price" is the Cost of the Last MW Generated (called the "Marginal Cost")

Load: 499 MWs

Generator C **Capacity:** **200 MWs** **Bid: $20/MWh**	**Not Dispatched**
Generator B **Capacity:** **200 MWs** **Bid: $15/MWh**	**199 MWs** **@ $15**
Generator A **Capacity:** **300 MWs** **Bid: $10/MWh**	**300 MWs** **@ $10**

Cost (Offer) of Marginal Unit (the last one dispatched) = $15/MWh
therefore
Market Clearing Price = $15/MWh

ALL generators receive the Market Clearing Price
therefore
Market Cost =
(499 MWh x $15/MWh) = **$7,485**

Load: 499 MWs

Payments by Load (Customers) to Generators

Generator C **Capacity:** **200 MWs** **Bid: $20/MWh**	**Not Dispatched**
Generator B **Capacity:** **200 MWs** **Bid: $15/MWh**	**199 MWs** **@ $15**
Generator A **Capacity:** **300 MWs** **Bid: $10/MWh**	**300 MWs** **@ $10**

All energy is transacted at the market clearing price.

therefore

Payment by Load = Market Cost = (499 MWh x $15/MWh) = **$7,485**

Gen A revenue: (300 x $15) = $4,500
Gen B revenue: (199 x $15) = $2,985

Load Increase by 2 MW => Requires Higher-Cost Generation to Serve Load

Generator C
Capacity:
200 MWs
Bid: $20/MWh

1 MW
@ $20

Generator B
Capacity:
200 MWs
Bid: $15/MWh

200 MWs
@ $15

Generator A
Capacity:
300 MWs
Bid: $10/MWh

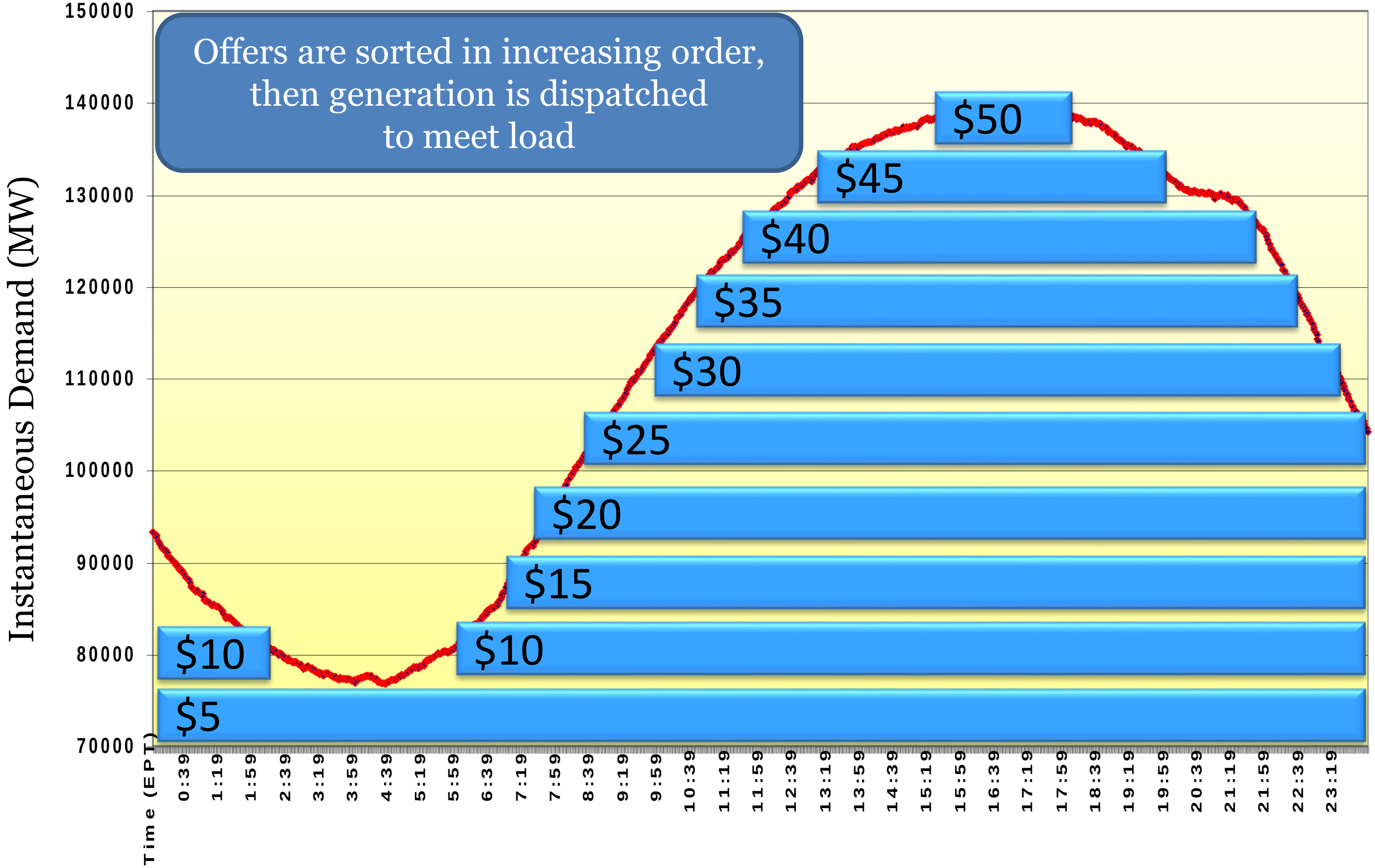
300 MWs
@ $10

Market Clearing Price now= **$20**/MWh.
Production cost is only marginally higher ((300x$10)+(200x$15)+(1x$20)) = **$6,020** *(only $35 more)*

But Payment by Load now =
(501 MWh x $20/MWh) = **$10,020** *($2,515 more)*

Gen A Revenue = 300 MWh x $20/MWh = $6,000
Gen B Revenue = 200 MWh x $20/MWh = $4,000
Gen C Revenue = 1 MWh x $20/MWh = $20

Matching Supply to Demand Over the Day

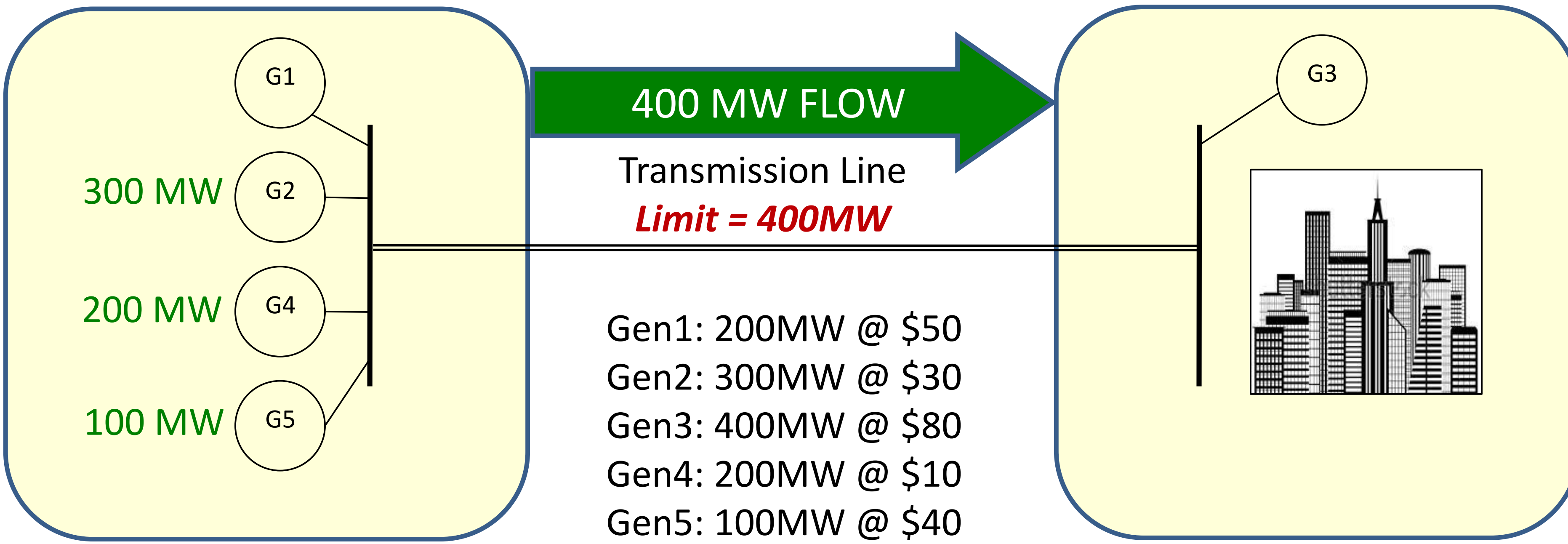


Generation Dispatch Over Multiple Areas (1)

(e.g., Two states in an RTO)

Area 1: Load = 200 MW

Area 2: Load = 400 MW



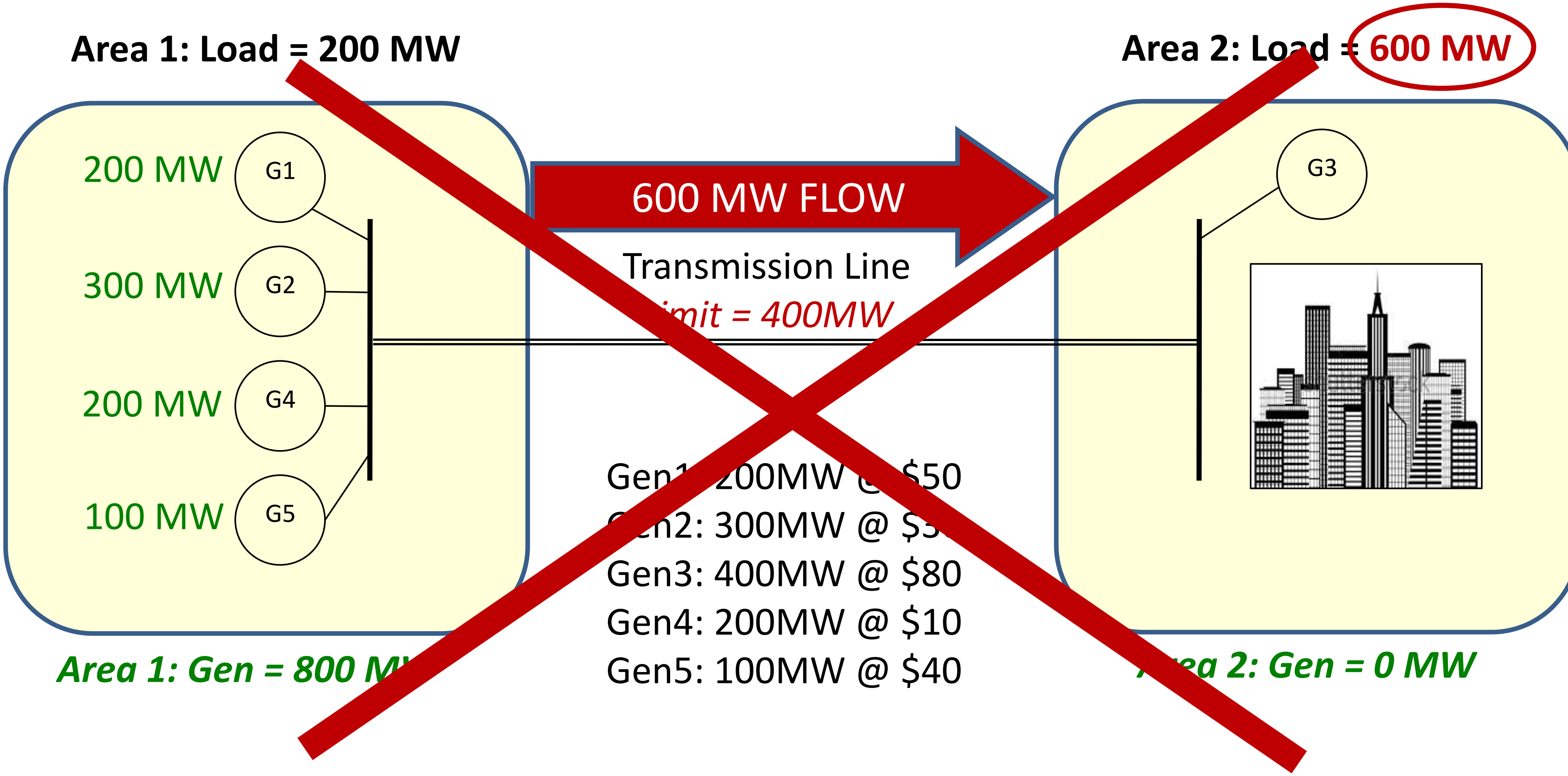
Area 1: Gen = 600 MW

Area 2: Gen = 0 MW

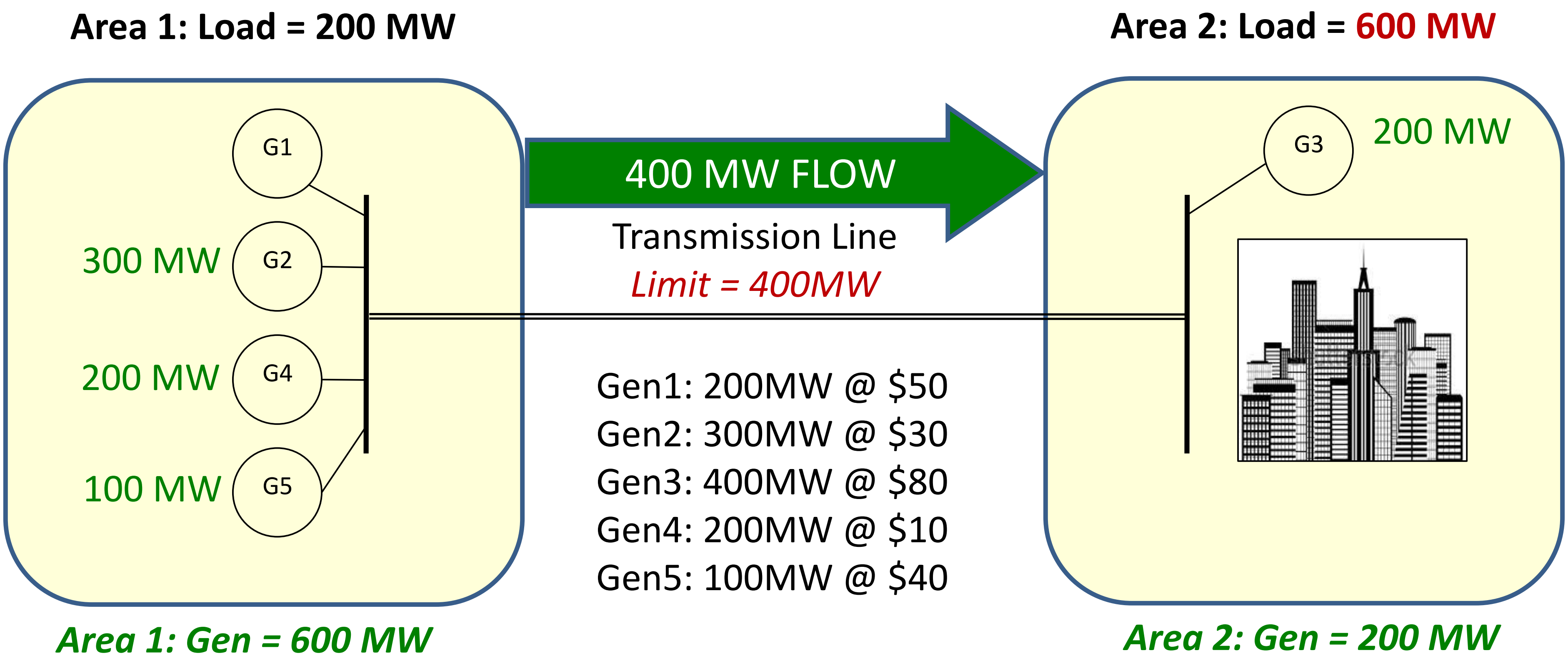
Market Clearing Price in both areas is $40/MWh
Payment by Load in Area 1 = $8,000
Payment by Load in Area 2 = $16,000

Gen 2 paid $12,000
Gen 4 paid $8,000
Gen 5 paid $4,000

Generation Dispatch Over Multiple Areas (2)



Generation Dispatch Over Multiple Areas (3)



Economic Benefit of RTO Interconnection (1)

Isolated Systems

System 1

Load: 500 MWs

System 1 Clearing Price = $15/MWh

Load payment = $7,500

Generator C Capacity: 200 MWs Bid: $18/MWh	0 MW @ $18
Generator B Capacity: 200 MWs Bid: $15/MWh	200 MWs @ $15
Generator A Capacity: 300 MWs Bid: $10/MWh	300 MWs @ $10

System 2

Load: 500 MWs

Generator F Capacity: 200 MWs Bid: $40/MWh	0 MW @ $40
Generator E Capacity: 300 MWs Bid: $25/MWh	200 MWs @ $25
Generator D Capacity: 300 MWs Bid: $12/MWh	300 MWs @ $12

System 2 Clearing Price = $25/MWh

Load payment = $12,500

Total Payment by Load Across Both Systems: $20,000

Economic Benefit of RTO Interconnection (2)

Interconnected Systems

System 1

Load: 500 MWs

Interconnected Clearing Price = $18/MWh

Load payment = $9,000

Generator	Capacity	Bid	Dispatch
Generator C	200 MWs	$18/MWh	200 MW @ $18
Generator B	200 MWs	$15/MWh	200 MWs @ $15
Generator A	300 MWs	$10/MWh	300 MWs @ $10

200 MW

System 2

Load: 500 MWs

Generator	Capacity	Bid	Dispatch
Generator F	200 MWs	$40/MWh	0 MW @ $40
Generator E	300 MWs	$25/MWh	0 MWs @ $25
Generator D	300 MWs	$12/MWh	300 MWs @ $12

Interconnected Clearing Price = $18/MWh

Load payment = $9,000

Total Payment by Load Across Both Systems: $18,000 (saving $2,000 or 10%)

Economic Benefit of RTO Interconnection (3)

Interconnected with **Reserve Capacity Sharing** (10%)

Joint Coincident Peak Load: 1,000 MWs

System 1

Peak Load:
560 MWs
(616 MW res)

System 1 NC Peak Clearing Price = $18/MWh

System 1 C Peak Clearing Price = $25/MWh

Generator C
Capacity:
200 MWs
Bid: $18/MWh

200 MW
@ $18

Generator B
Capacity:
200 MWs
Bid: $15/MWh

200 MWs
@ $15

Generator A
Capacity:
300 MWs
Bid: $10/MWh

300 MWs
@ $10

~~**nerato**~~
~~**Ca y:**~~
~~**20 Ws**~~
~~**Bi $40/ Wh**~~

0 MW
@ $40

Generator E
Capacity:
300 MWs
Bid: $25/MWh

100 MWs
@ $25

Generator D
Capacity:
300 MWs
Bid: $12/MWh

300 MWs
@ $12

System 2

Peak Load:
560 MWs
(616 MW res)

System 2 NC Peak Clearing Price = $**40**/MWh

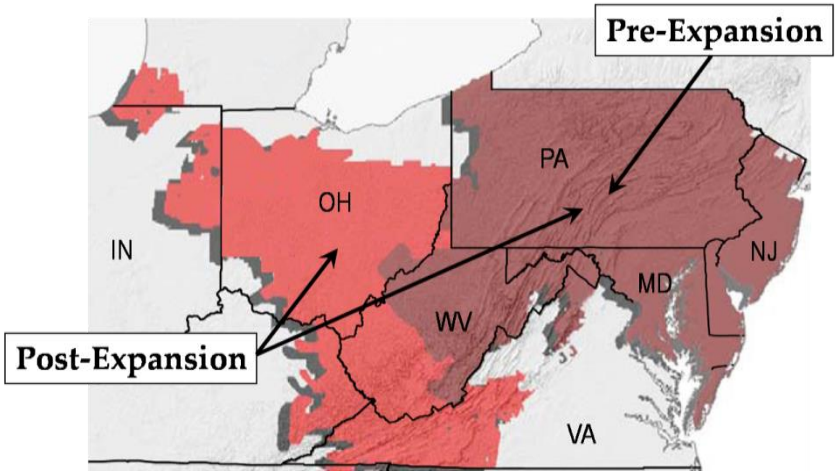
System 2 C Peak Clearing Price = $25/MWh

Reserve Sharing avoids need for Gen F.

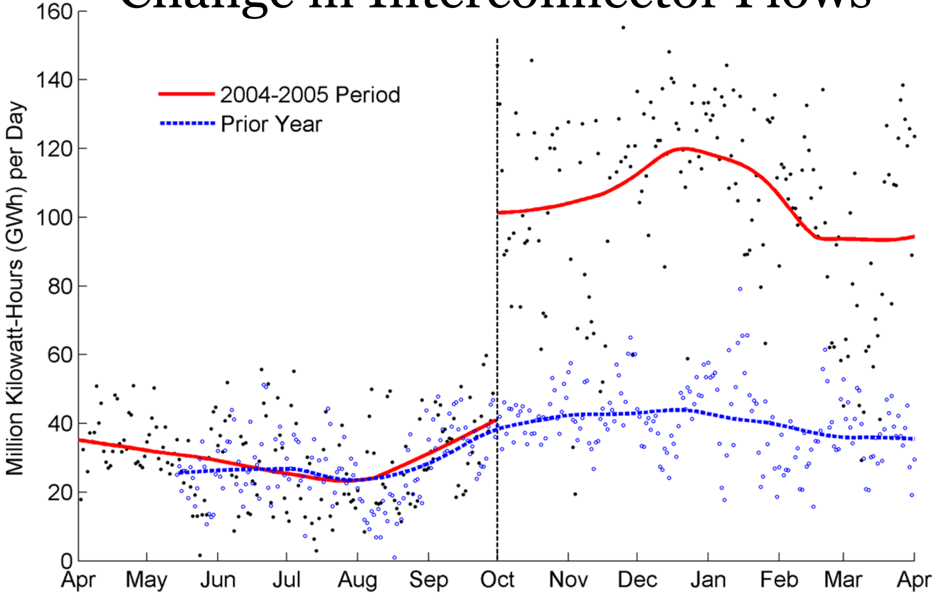
Peak + 10% = 1,100 MWs

Example: 2004 PJM Market Expansion

Integration of AEP, Dayton, and ComEd into the PJM Market



Change in Interconnector Flows



Key Conclusions:

- Incremental benefit = $180 Million annually; Net Present Value of $1.5B over 20 years
- Bilateral trading could only achieve 40% of the efficiency gains of centralized dispatch

Source: Erin T. Mansur and Matthew W. White, "Market Organization and Efficiency in Electricity Markets," March 31, 2009, Figure 2, pg 50, discussion draft, (available at http://bpp.wharton.upenn.edu/mawhite/).

Emissions Impacts of RTO Interconnection (1)

Individual States

State 1

Load: 500 MWs

State 1 CO_2 emissions:

(270 + 150 + 0)

= **420 tons**

Generator C
Capacity: 200 MWs
Bid: $18/MWh
CO_2: 1200 #/MWh

0 MWs @ $18

0 tons CO_2

Generator B
Capacity: 200 MWs
Bid: $15/MWh
CO_2: 1500 #/MWh

200 MWs @ $15

150 tons CO_2

Generator A
Capacity: 300 MWs
Bid: $10/MWh
CO_2: 1800 #/MWh

300 MWs @ $10

270 tons CO_2

State 2

Load: 500 MWs

Generator F
Capacity: 200 MWs
Bid: $40/MWh
CO_2: 900 #/MWh

0 MWs @ $40

0 tons CO_2

Generator E
Capacity: 300 MWs
Bid: $25/MWh
CO_2: 1100 #/MWh

200 MWs @ $25

110 tons CO_2

Generator D
Capacity: 300 MWs
Bid: $12/MWh
CO_2: 1500 #/MWh

300 MWs @ $12

225 tons CO_2

State 2 CO_2 emissions:

(225 + 110 + 0)

= **335 tons**

Total Emissions for Both States: 755 tons

Emissions Impacts of RTO Interconnection (2)

States Interconnected in an RTO

State 1

Load: 500 MWs

System 1
CO_2 emissions:
(270 +150+120)
= **540 tons**

Generator C Capacity: 200 MWs Bid: \$18/MWh CO_2: 1200 #/MWh	200 MWs @ \$18	120 tons CO_2
Generator B Capacity: 200 MWs Bid: \$15/MWh CO_2: 1500 #/MWh	200 MWs @ \$15	150 tons CO_2
Generator A Capacity: 300 MWs Bid: \$10/MWh CO_2: 1800 #/MWh	300 MWs @ \$10	270 tons CO_2

200 MW

State 2

Load: 500 MWs

Generator F Capacity: 200 MWs Bid: \$40/MWh CO_2: 900 #/MWh	0 MWs @ \$40	0 tons CO_2
Generator E Capacity: 300 MWs Bid: \$25/MWh CO_2: 1100 #/MWh	0 MWs @ \$25	0 tons CO_2
Generator D Capacity: 300 MWs Bid: \$12/MWh CO_2: 1500 #/MWh	300 MWs @ \$12	225 tons CO_2

System 2
CO_2 emissions:
(225 + 0 + 0)
= **225 tons**

Total Emissions for Both States: 765 tons (10 tons more), higher in State 1, lower in State 2

Emissions Impacts of RTO Interconnection (3)

States Interconnected in an RTO

State 1

Load: 500 MWs

Generator C Capacity: 200 MWs Bid: \$18/MWh CO_2: 800 #/MWh	200 MWs @ \$18	80 tons CO_2
Generator B Capacity: 200 MWs Bid: \$15/MWh CO_2: 1500 #/MWh	200 MWs @ \$15	150 tons CO_2
Generator A Capacity: 300 MWs Bid: \$10/MWh CO_2: 1800 #/MWh	300 MWs @ \$10	270 tons CO_2

System 1 CO_2 emissions:

(270 +150 +80)

=

500 tons

200 MW

State 2

Load: 500 MWs

Generator F Capacity: 200 MWs Bid: \$40/MWh CO_2: 900 #/MWh	0 MWs @ \$40	0 tons CO_2
Generator E Capacity: 300 MWs Bid: \$25/MWh CO_2: 1100 #/MWh	0 MWs @ \$25	0 tons CO_2
Generator D Capacity: 300 MWs Bid: \$12/MWh CO_2: 1500 #/MWh	300 MWs @ \$12	225 tons CO_2

System 2 CO2 emissions:

(225 + 0 + 0)

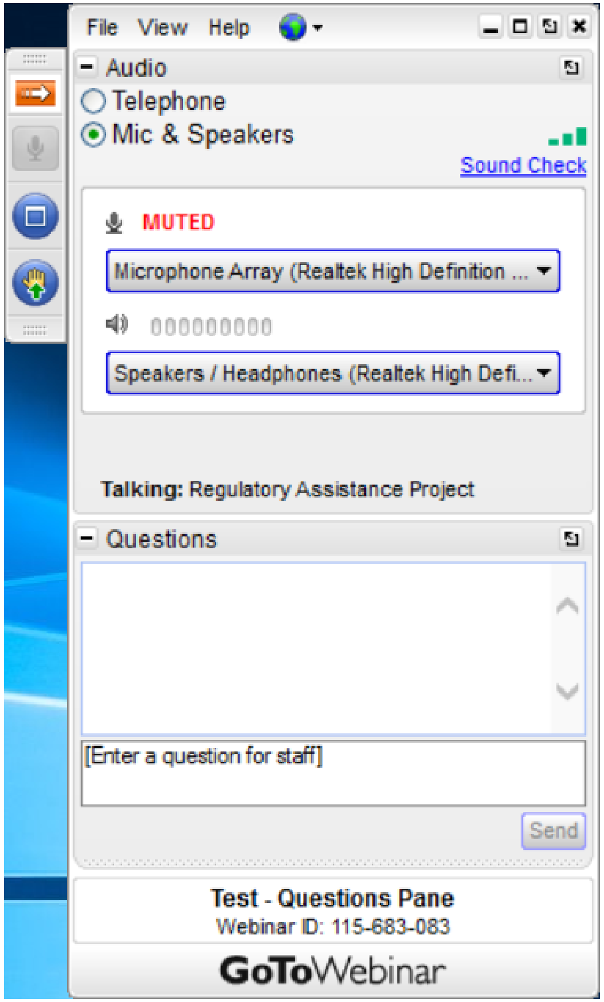
=

225 tons

Total Emissions for Both States: 725 tons (30 tons less overall than original case)

Questions?

Please send questions through the Questions pane



Implications for CPP Planning

- Regional markets dispatch EGUs on the basis of cost, providing economic and reliability benefits
- The Clean Power Plan will internalize carbon costs; this will affect a regional market's "economic merit order" (EGU dispatch order):
  - Generally, EGUs with higher emissions will be more costly to use
- Modifications to dispatch order may cause electricity generation and emissions to:
  - Occur in different amounts
  - Occur in different geographic locations (sometimes in different states)
- Decision-makers will need to determine:
  - Relative advantage of compliance plan structure & path (mass or rate)
  - Benefits of coordinating compliance plans with neighboring states
  - Multi-pollutant ramifications

Recommendations

- Communicate closely with RTO staff and other states in your RTO in developing your CPP plan
- States with multiple RTOs => additional burden, but planning dialogue still necessary
- Recognize and try to preserve economic and reliability benefits of regional coordination
- Fashion carbon policy that best preserves these attributes
- System modeling will likely be required
  - Can do state-only modeling with spreadsheets, but system modeling likely necessary for regions

Questions?

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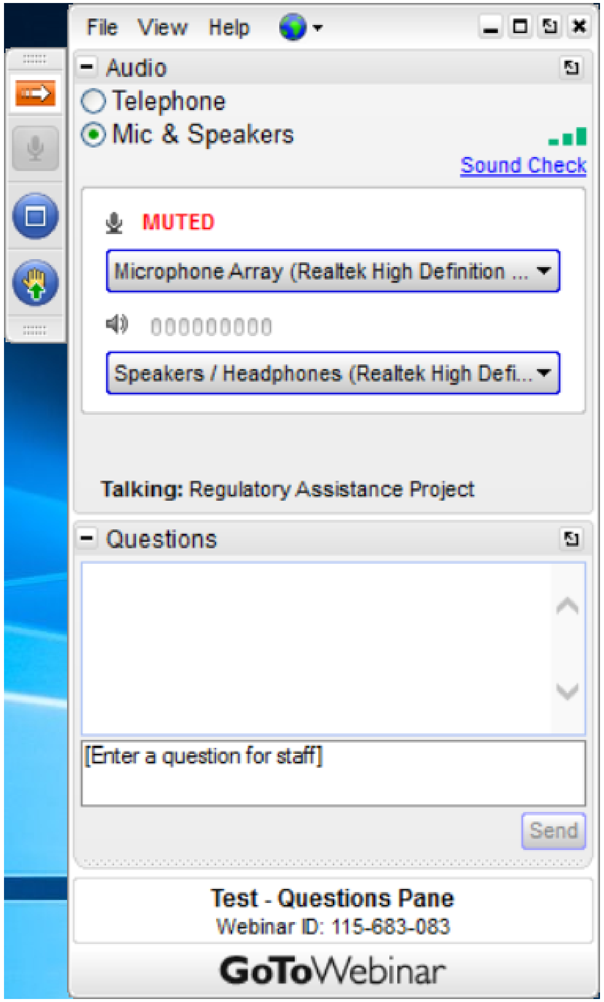

Conclusions

- RTOs run their respective regional grids to provide reliability and efficient system operations,
- RTOs provide and manage regional energy markets to minimize energy production costs,
- RTOs perform long-term transmission systems and market planning to ensure energy resource adequacy, and
- Regional coordination of RTOs suggests that both reliability and economic costs associated with CPP compliance may be most effectively addressed regionally.

Thank You for Your Time and Attention

About RAP

The Regulatory Assistance Project (RAP) is a global, non-profit team of experts focused on the long-term economic and environmental sustainability of the power sector. RAP has deep expertise in regulatory and market policies to:

- Promote economic efficiency
- Protect the environment
- Ensure system reliability
- Allocate system benefits fairly among all consumers

Learn more about RAP at www.raponline.org

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