MISO Energy and Ancillary Services Co-optimization

ERCOT RTC Lessons Learned engagement

Sep. 24, 2019

Purpose & Key Takeaways

Purpose: Discuss MISO experiences with Real-Time Energy & Ancillary Services Co-optimization

Key Takeaways:

- MISO implemented Energy and Ancillary Services co-optimization in 2009
- $75 million investment at the time and provides at least $60 million annual return
- Important lessons learned include Ramp Sharing to address frequent price spikes

MISO Market Structure – *Bid-based Day-Ahead market and Real-Time Market with reliability commitments*

MISO Markets

Day-Ahead Market
- Bid-based day-ahead market using security constrained unit commitment and economic dispatch (SCUC & SCED)

Reliability Commitments
- SCUC-based reliability commitment processes to ensure that sufficient generation will be online to meet forecast real-time requirements

Real-Time Market
- Bid-based real-time security constrained economic dispatch

Financial Transmission Rights
Capacity Market

Locational Marginal Pricing

Offers based on Physical Realities
- Offers include start-up cost, no-load cost, incremental energy cost, reserve offer costs, as well as operating parameters

Locational Marginal Pricing (LMP)
- Marginal cost of serving an infinitesimal change of load at a node
- Includes commitment costs by ELMP

Marginal Clearing Price (MCP)
- Marginal cost to meet reserve requirements including reserve offer costs and opportunity costs
- Operating Reserve Demand Curves during reserve shortages

MISO Market Design – *Develop transparent market prices, facilitate market participation and least cost services*

Featured by:

- Nodal network representation
- Energy & Reserve co-optimization
- Efficient Scarcity Pricing
- Market-based approach to integrate renewables and incentivize flexibility
- Transparent pricing including eligibility of demand response

Market Launch
- Nodal network model
- Hourly Offer Updates
- 2005

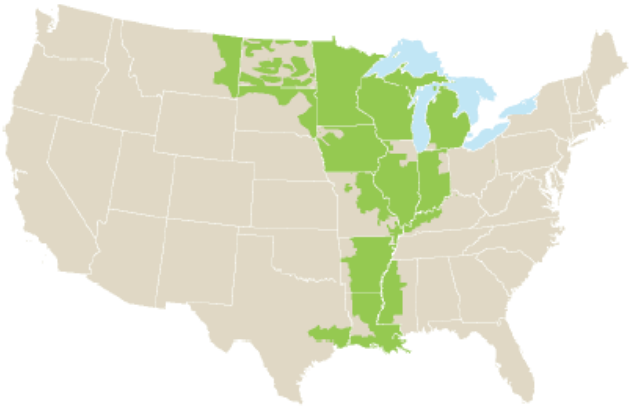
Energy Ancillary Co-optimization
- Operating Reserve Demand Curves
- 2009

Uplift Allocation; Dispatchable Intermittent Resources; Regulation Mileage
- 2011-2013

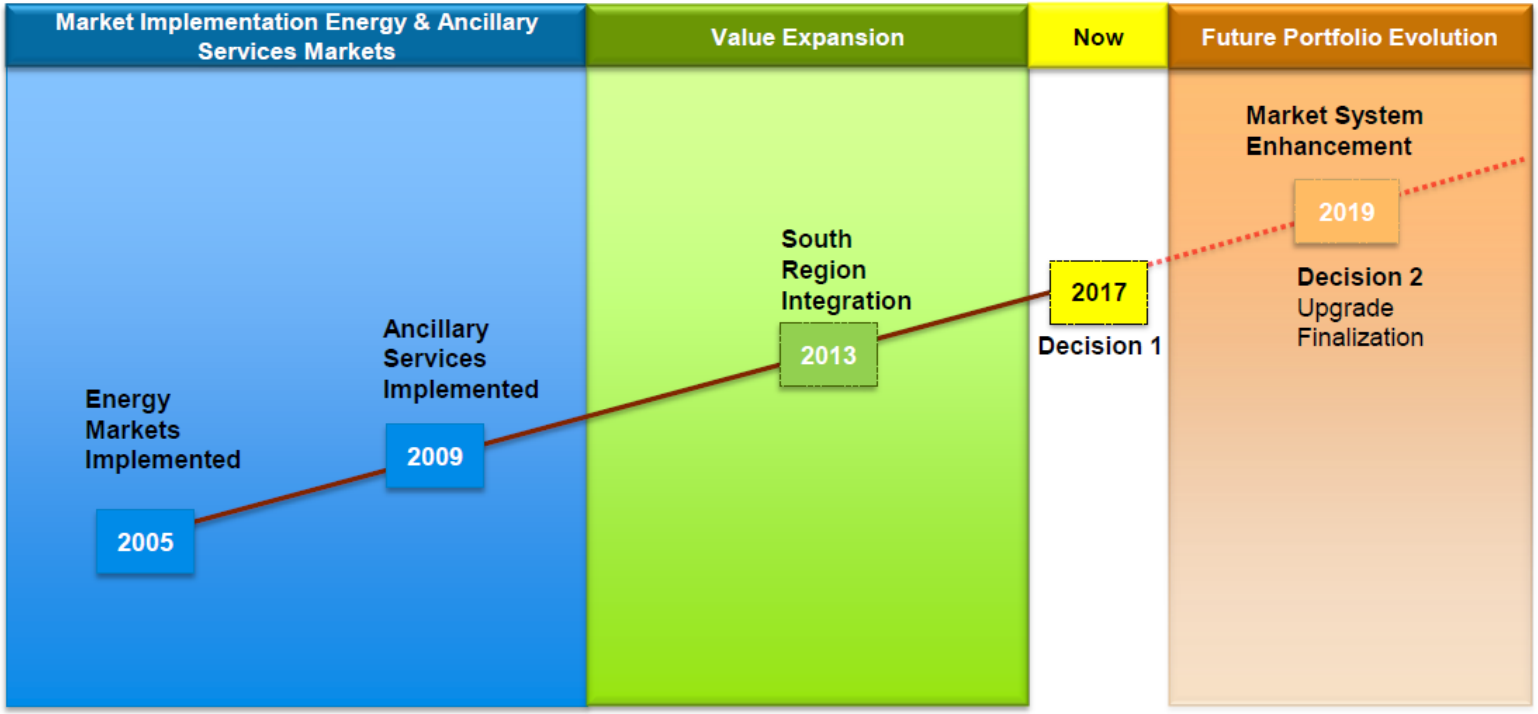
Market Vision and Roadmap, Sub-Regional Power Balance Constraint
- 2014

ELMP, Ramp Capability Product, Emergency Pricing, M2M, CTS, 5min Settlement
- 2015-2018

Resource Availability and Needs, Energy Storage, Short-term Reserve, DER, …
- 2019 and beyond



Energy & AS co-optimization is one of the most significant investments in MISO history: $75 million



(In millions)	2005 Energy Market Implementation	2009 Ancillary Services Implemented	2013-2014 South Region Integration	2017-2024 Market System Enhancement
Technology Investment	$245	$75	$30	$130 (plus 25% contingency that includes vendor alternatives)

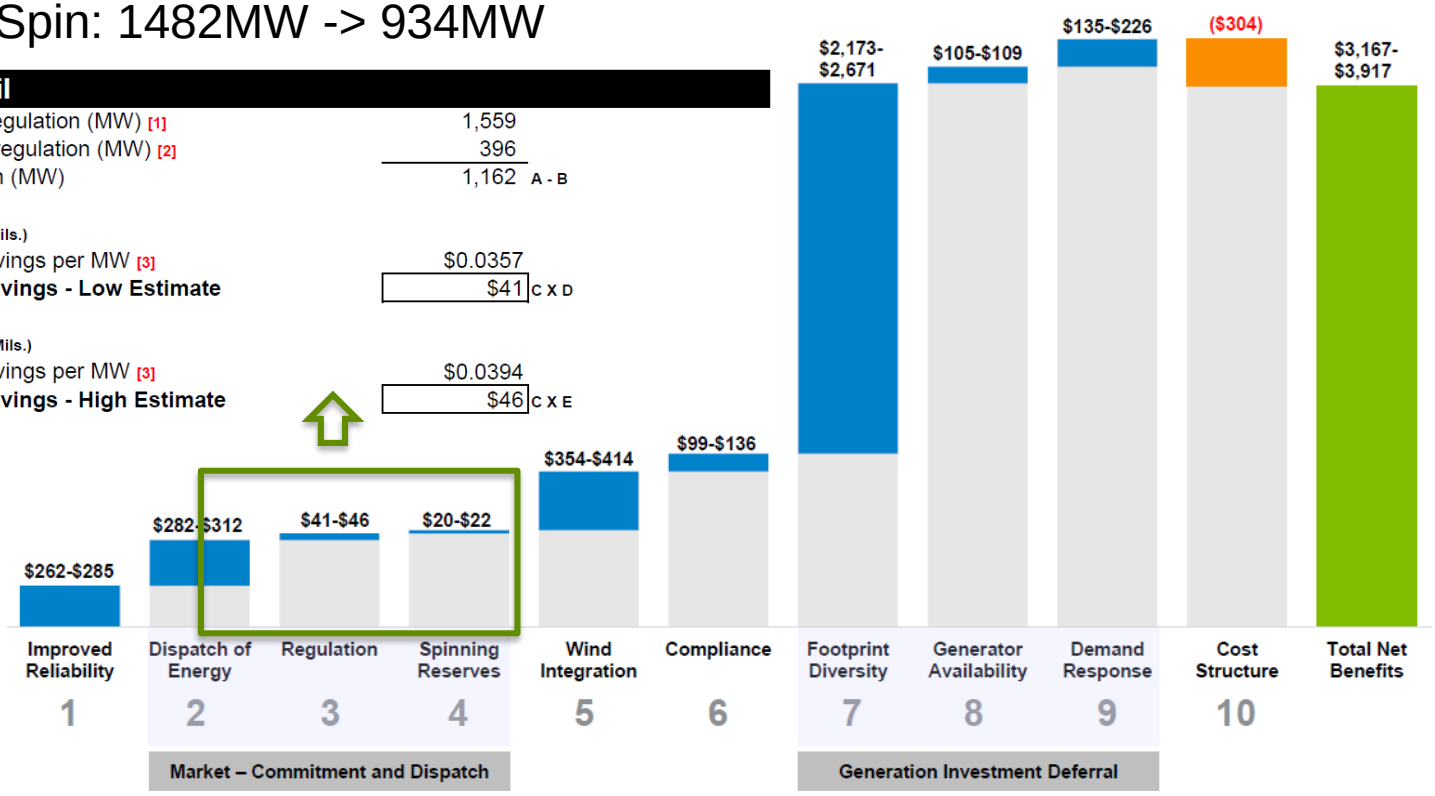
Note: numbers are not adjusted for inflation

Provides at least $60million yearly return

- More efficient commitment and dispatch of energy and reserves
- Reduced Regulation and Spinning reserve requirements
  - Regulation: 1159MW -> 396MW
  - Spin: 1482MW -> 934MW

Calculation Detail

A	Pre-ASM average regulation (MW) [1]	1,559	
B	Post-ASM average regulation (MW) [2]	396	
C	Regulation reduction (MW)	1,162	A - B
	Low Estimate ($ in Mils.)		
D	Production costs savings per MW [3]	$0.0357	
	Production cost savings - Low Estimate	$41	C X D
	High Estimate ($ in Mils.)		
E	Production costs savings per MW [3]	$0.0394	
	Production cost savings - High Estimate	$46	C X E



MISO co-optimizes energy and ancillary services in Day-Ahead and Real-Time markets

Market Clearing through Co-optimization

Energy

Regulating Reserve
Capacity held by a frequency responsive resource for the purpose of providing Regulating Reserve Deployment in both up/down direction

Spinning reserve
A specified percentage of Contingency Reserve that must be synchronized to the System and converted to Energy within Deployment Period

Supplemental reserve
Contingency Reserve not considered Spinning

Short-term reserve (*developing*)
Capacity held to meet system, regional, local needs

Ramp Capability Product

Priority

Prices Reflective of Marginal Cost or Value

Market Clearing Prices
Marginal costs to serve zonal/market-wide reserve requirements; deliverability cost is being captured as the model advances to account for transmission limits

Operating Reserve Demand Curves
The value demand side placed on the reserve base on its reliability impact, e.g., value of expected loss of load; value increases as shortage worsens to reflect the higher reliability risks

Operating Reserve Substitution
A higher quality reserve an serve the requirement of a lower quality reserve; the price of the higher quality reserve is thus higher or at lease equal to the lower quality reserve

Note: Non-market services not co-optimized: Reactive power supply and voltage control (transmission settlement), Blackstart service (transmission settlement), Primary frequency response (no compensated).

Reserve eligibility based on resource types

	Energy	Regulation Reserve	Spinning Reserve	Supplemental Reserve	Ramp Product	Capacity
Generator	Y*	Y*	Y*	Y*	Y*	Y*
DRR-I	Y*	N	Y*	Y*	N	Y*
DRR-II	Y*	Y*	Y*	Y*	Y*	Y*
SER	N	Y*	N	N	N	N
EAR	Y*	Y*	Y*	Y*	Y*	Y*
DIR	Y*	N	N	N	Y*	Y*

- DRR: Demand Response Resource
- SER: Stored Energy Resource
- EAR: External Asynchronies Resource
- DIR: Dispatchable Intermittent Resource

- Reserves must be supplied by Qualified Resources, and are subject to offer status and commitment status
- With Enhanced Combined Cycle modeling, resources can specify when transitioning or duct firing and cannot provide reserves
- Reserves cleared from Demand Response cannot exceed 40%; Individual Resources are limited to 20% of Reserve Requirements

Resources can specify their reserve offers by using multiple offer parameters

- Resources can submit reserve availability offer

Product	Offer Cap	Offer Floor
Energy	$2000/MWh*	-$500/MWh
Regulation Reserve	$500/MWh	0
Contingency Reserve	$100/MWh	0

  - Reserve volumes are capped by ramp rate over response times
- Other offer parameters include
  - Reserve qualification and dispatch status
  - Regulation Maximum and Minimum limits
  - Maximum of Supplemental Reserve
- Resources can self-schedule reserves
- No virtual offers for Ancillary Services

Note: FERC Order 831. To be effective on December 01, 2019

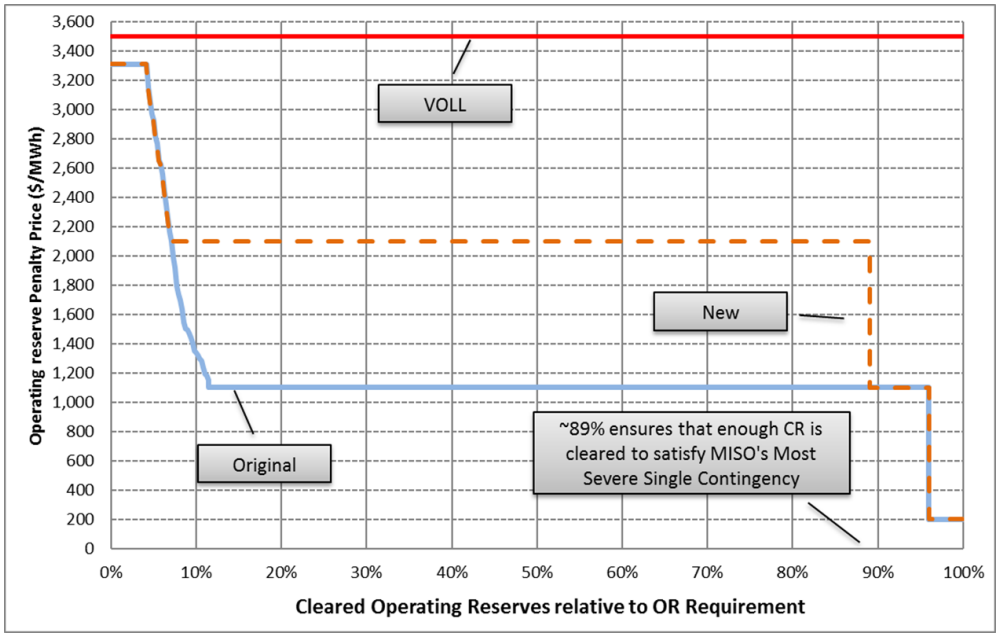
Operating Reserve Demand Curves*

- Cascading operating reserve requirements have three associated market-wide demand curves
  - Operating Reserve Demand Curve
  - Regulating and Spinning Reserve Demand Curve
  - Regulating Reserve Demand Curve

  (See Appendix)

Operating Reserve Demand Curve

- A sloped and stepped curve
- Based on VOLL and the estimated probability of loss of load
- VOLL is currently set at $3,500/MWh

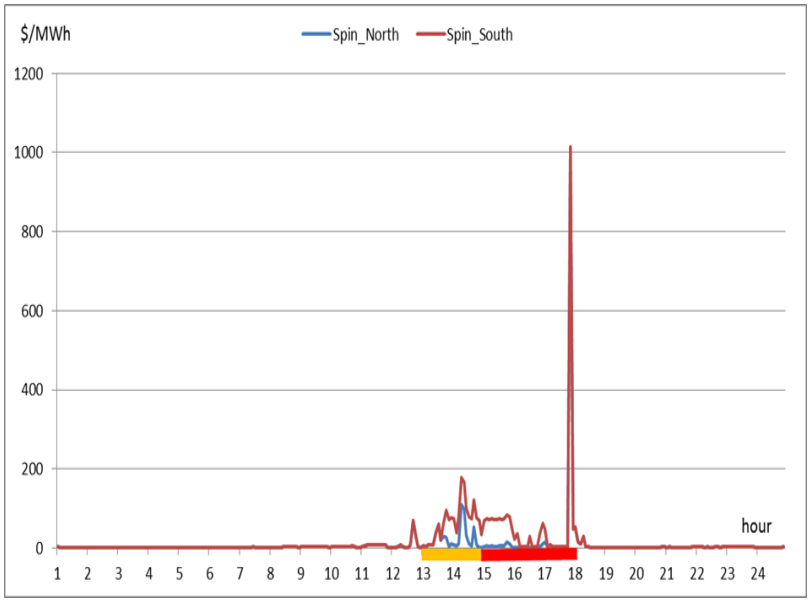


Reference: Schedule 28, BPM 002

Reserve Procurement Enhancement is enforced to ensure zonal reserve deliverability

- Original design was to establish minimum zonal reserve requirements and demand curves
  - Offline study may deviate from actual conditions and static requirements resulted in inefficient reserve clearing
- Retired zonal reserve requirements in 2018 and now uses Reserve Procurement Enhancement (RPE)
  - Restrict post reserve deployment flow from exceeding transmission limits
  - Zonal reserve requirements dynamically determined through co-optimization
- Result in zonal reserve prices

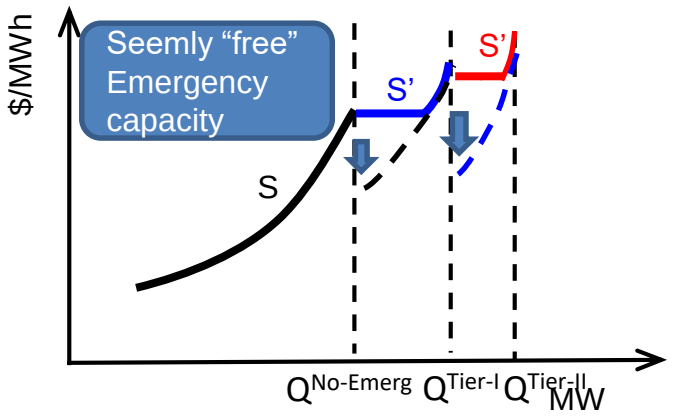
RPE binding on South-North Transfer Limit on Sep. 15, 2018

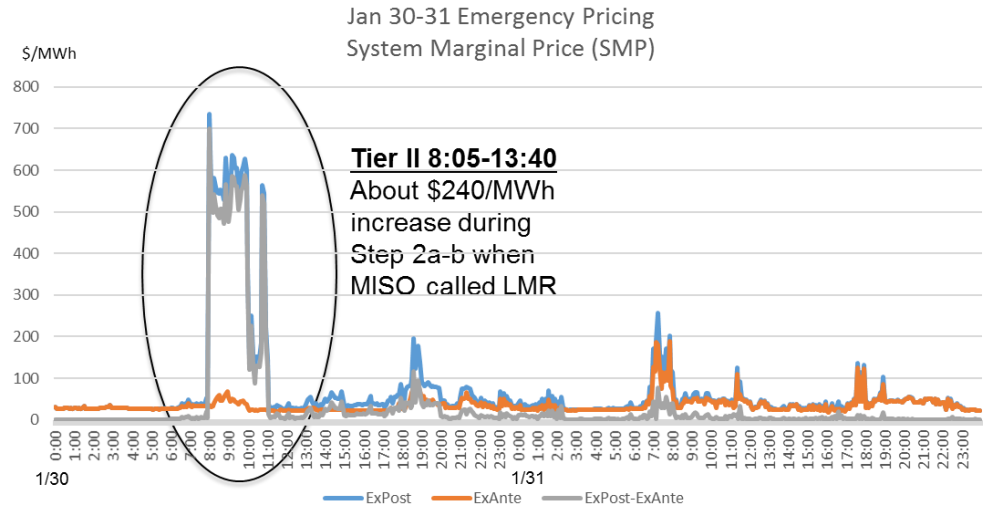


Note: Tariff 39.2.1A

Emergency Pricing assigns Proxy Offer and allow Emergency Resources to set prices

- Prevent uneconomic price suppression at capacity shortages
- Establish Emergency Offer Floors as the highest available economic and/or emergency offers in the affected areas
- Assign proxy offers to Emergency Resources such as Load Modifying Resources (see Appendix)
- Allow these resources to set prices by using ELMP logic





Most important lesson learned: **Ramp sharing** *(A little thing makes a big difference)*

- Frequent Price spikes were observed during parallel operations
  - Price volatility
  - Reliability risks due to insufficient reserves cleared
  - Resource foregone profits with trapped energy by ramp, …
- How should ramp be allocated?
  - Allocate among energy movement and all reserve deployments
  - Allocate among energy movement and regulation deployment
  - …

$$Energy + Reg + 0.5\,Spin \leq 5min * Ramp$$

- **Ramp sharing**
  - The same ramp capability is shared among energy and reserves
  - Reserve requirements are scaled up to account for ramp sharing

$$\Delta Energy \leq 5min * Ramp$$
$$Reg \leq 5min * Ramp$$
$$Spin \leq 10min * Ramp$$

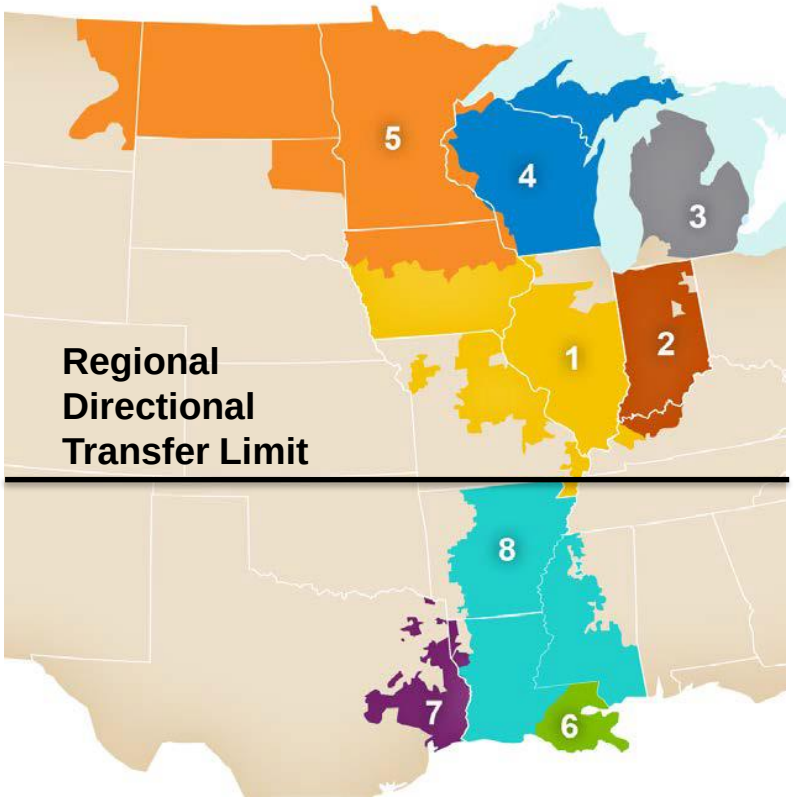
Other noteworthy

- Make-Whole Payments and cost allocation
  - Day-Ahead Margin Assurance Payment (DAMAP) to preserve eroded DA margin by following RT dispatch
  - To the extent there is price separation between reserve zones, cost is allocated by zone where it is incurred*
- Market Education
  - With co-optimization, market clearing results may not be straightforward and RTO should help market participants to understand market outcomes
- Operation actions
  - Operation actions may be involved and should be reduced with market and system enhancements

Reference: Schedules 3, 5 and 6

MISO continues to improve its co-optimization to adapt to the evolving generation fleet

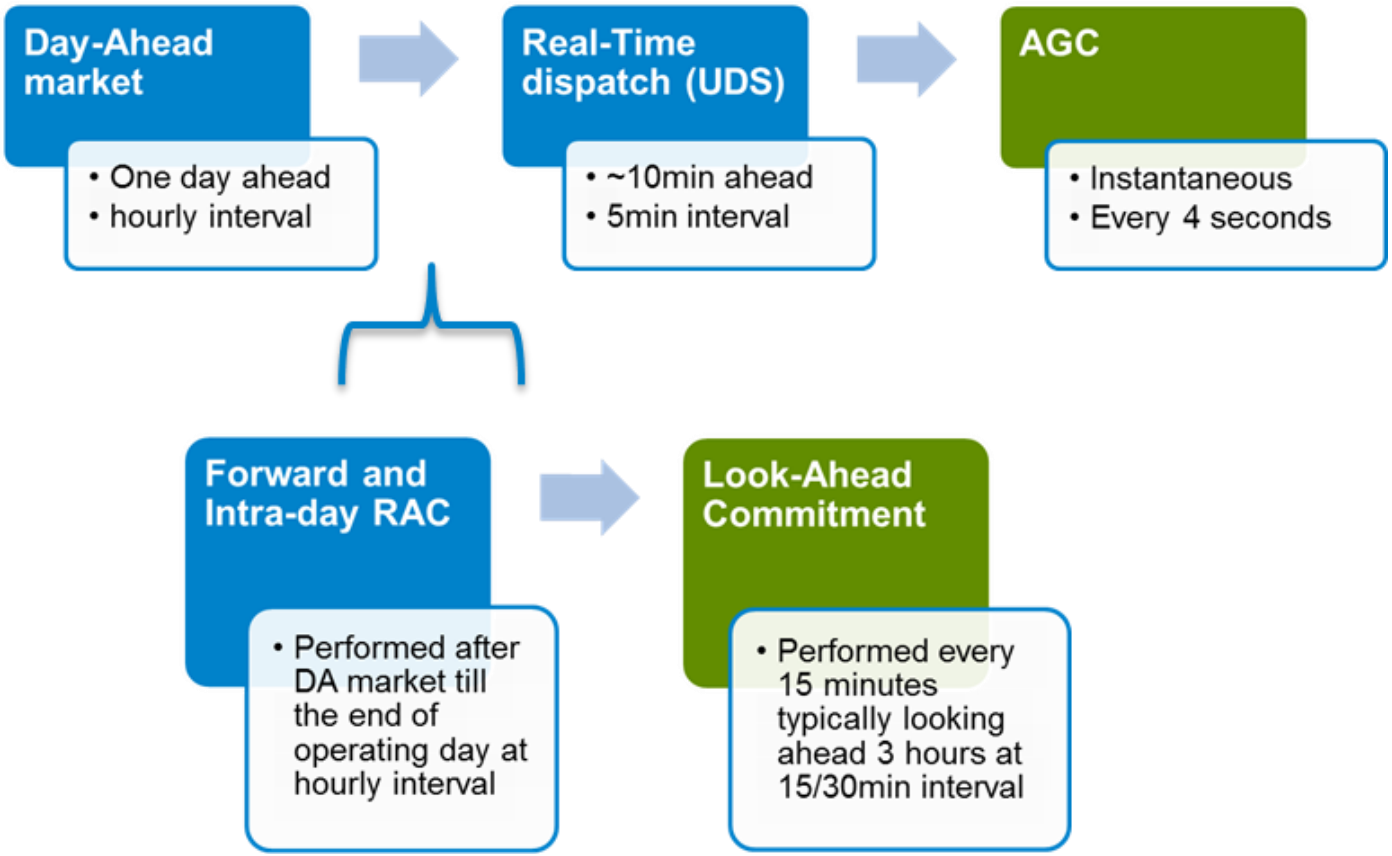
- Reserve deliverability
  - Regional flow management
  - Reserve post-deployment constraint demand curves
- Develop and/or explore new products
  - Fast First AGC
  - Short-Term Reserve
- Holistic review of price formation
  - Operating Reserve Demand Curves and VOLL
  - Emergency Pricing



Questions?

Appendix

MISO markets and processes



UDS: Unit Dispatch System; AGC: Automatic Generation Control; RAC: Reliability Assessment Commitment

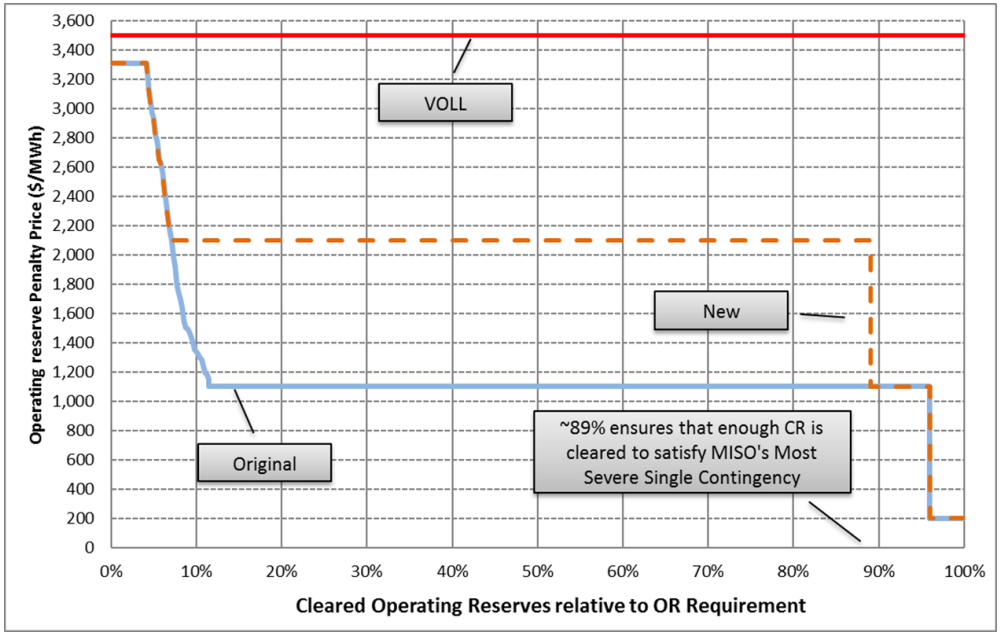
Historical requirements and prices

Product	Response Time	Requirement	Average Price
Regulation Reserve	5min	About 300 MW ~ 500 MW Requirement set to comply with NERC Standard (BAL-001-2)	$11/MWh
Contingency Reserve (Spinning and Supplemental)	10min	About 2,000 MW (at least 40% spin) MISO and Manitoba Hydro form a Contingency Reserve Sharing Group and have set the requirements based on Most Severe Single Contingency and largest total combined loss; MISO shares 1,850 MW with 40% or 740 MW Spin and 1,110 MW Supplemental; We clear Spin between 900 MW (non-ramping hours) and 1100 MW (ramping hours) MW to ensure we have rampable Spin due to ramp sharing in MISO's Unit Dispatch System	Spin: $4/MWh Supp: $1.5/MWh
Ramp Capability	10min	About 0 MW ~ 2,000 MW Requirements vary by interval based on expected net load changes plus uncertainties such as load or wind forecast errors	Up Ramp: $0.25/MWh; Dn Ramp: 0

Market-Wide Operating Reserve Demand Curve

- A sloped and stepped curve
- Based on VOLL and the estimated probability of loss of load
- VOLL is currently set at $3,500/MWh

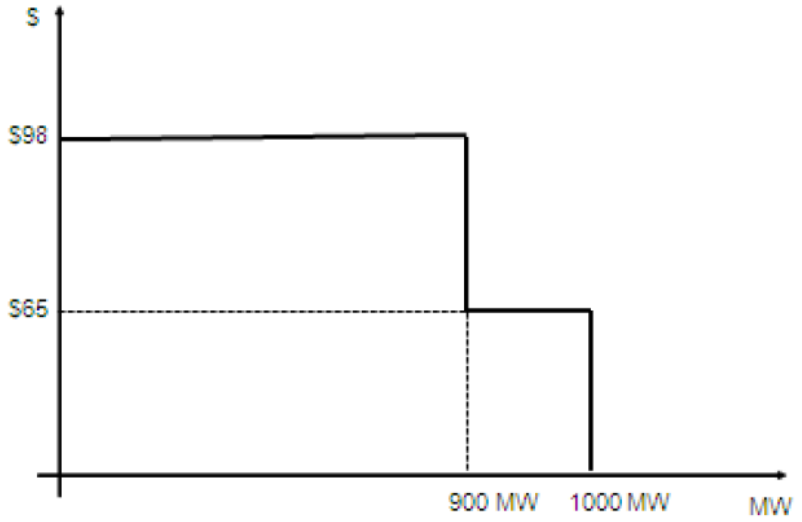
Cleared Reserve Level (CRL)	Price ($/MWh)
Req > CRL ≥ 96% Req	$200
96% Req > CRL > 4%	max{VOLL*prob loss load, Offer caps}
CRL ≤ 4%Req	VOLL- Reg demand curve



Market-Wide Regulation & Spinning Reserve Demand Curve

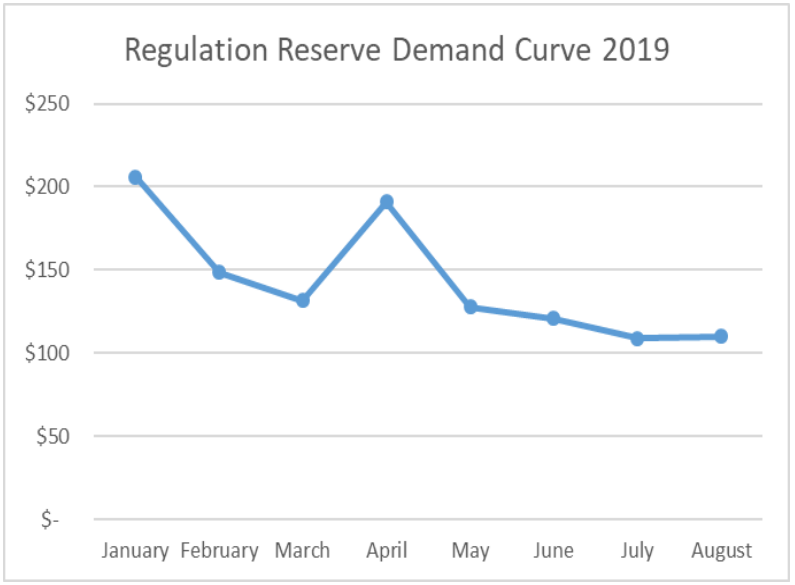
- A two stepped curve
- Represent the reliability value when contingency reserve is not short but the spinning portion (40%) is short

Cleared Reserve Level (CRL)	Price ($/MWh)
Req > CRL ≥ 90% Req	$65
CRL < 90% Req	$98

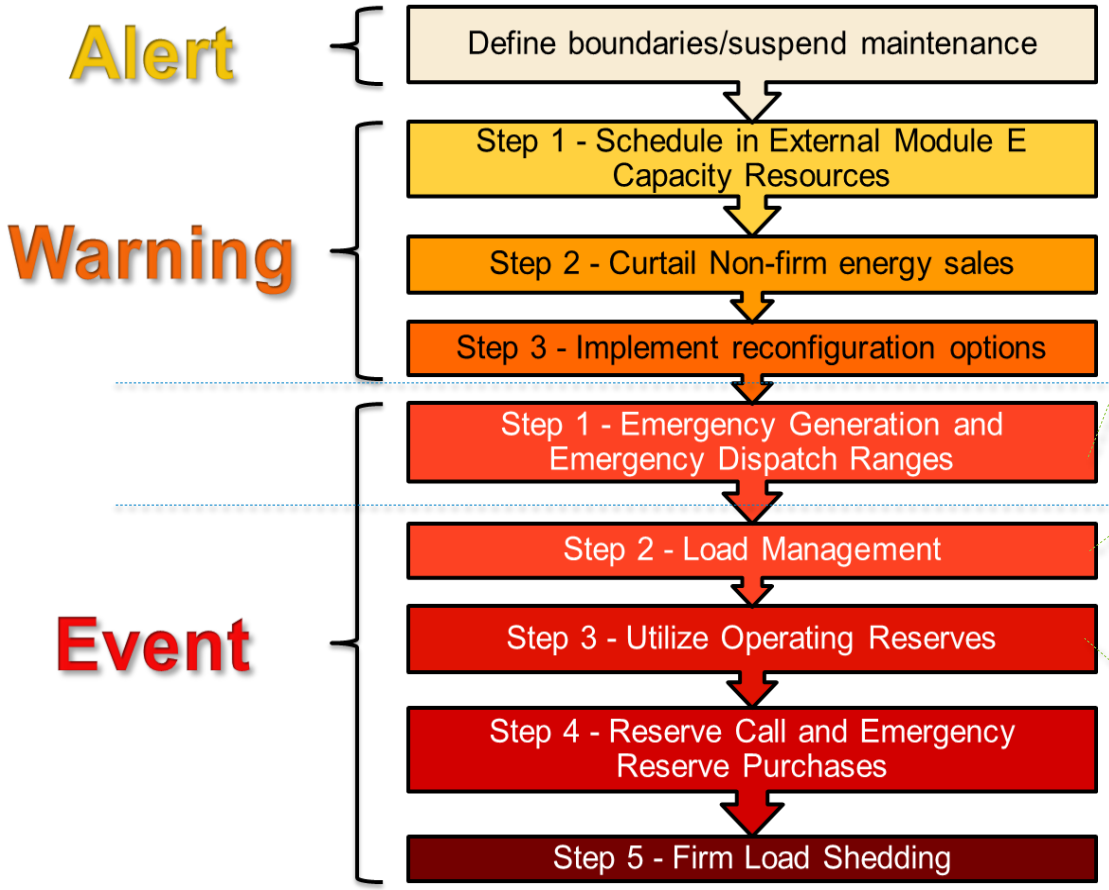


Market-Wide Regulation Reserve Demand Curve

- Demand curve value set monthly
  - Average cost of committing and running a peaking unit
  - Determined using a gas price index and annual proxy heat rate
  - No less than Contingency Reserve Offer Cap ($100)



Emergency Operating Procedure



Event - Step 1:
a) Commit AME
b) Implement Emergency Max Limits
c) Declare NERC Energy Emergency Alert (EEA) 1 - All available non-emergency resources in use

Event – Step 2:
a) Declare NERC EEA 2 - Load Mgmt procedures in effect
b) I**mplement LMR (BTMG & DR)** & Load Management Measures (LMM) – Stage 1
c) **Commit Emergency Demand Response (EDR)**
d) Implement Emergency Energy Purchases

Event - Step 3:
a) Utilize Operating Reserves
b) Instruct load reduction of Load Management Measures (LMM) – Stage 2

Day-Ahead Margin Assurance Payment to ensure adequate market incentives

- Under two-market settlement, RT price volatility may cause resources to be dispatched differently and lose DA profit
  - Resources could offer less flexibility to lock their DA position
- Co-optimization across multi-products may increase the likelihood of DA/RT scheduling differences
- MISO has Day-Ahead Margin Assurance Payment (DAMAP) to preserve DA margin eroded by following RT dispatch

DA Profit – RT profit

Make up the difference between DA profit and RT profit

$$\text{Min } \{0, \text{Sum}_{\text{energy,reserves}}[\text{RT Price} \times (\text{RT MW} - \text{DA MW}) - (\int_0^{\text{RTMW}} \text{Cost} - \int_0^{\text{DAMW}} \text{Cost})]\}$$

Education is important as prices and market clearing results are not straightforward

- RTO: Help market participants to understand market outcomes
  - Why prices are not like any of the offers?
  - Why I am not cleared at EconMax when energy price is higher that my offer? …
- Market participants: Have confidence in co-optimization

A simple Example without transmission

Unit	EconMin	EconMax	ramprate	Energy	Spin
	MW	MW	MW/min	$/MWh	$/MWh
A	10	100	5	15	1
B	10	50	1	20	2
C	0	10	1	30	5

Load	110MW
SpinRequirem	20MW

Unit MW	Energy	Spin
A	90	10
B	20	10
C	0	0
price $/MWh	20	6

Set by Unit A:
Offer Cost ($1/MWh) + Opportunity cost ($20/MWh - $15/MWh)

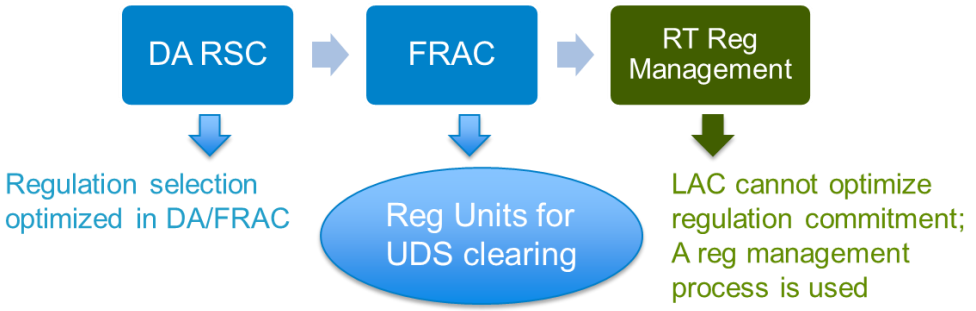
Operation actions are being reduced with Market and System Enhancements

Examples of Operation Actions

- Disqualify resources from reserve clearing
- Regulation Management
  - Regulation clearing is limited to “REG-committed” resources due to different operational limits*
  - The limited pool may be short to provide regulation as system conditions change

Add units on Regulation while not stranding capacity

- Regulation selection is typically on an hourly basis
- Inappropriate selection could reduce operating capacity and cause uplift



*Note: reg capacity ≤ econ capacity; bi-directional ramp ≤ up/dn ramp

Enhanced Combined Cycle (ECC) allows more accurate offers and efficient operations

- Three levels of offer parameters modelled under ECC
  - Resource level
  - Configuration level
  - Component level

Participant can specify reserve qualification status as “Not-qualified” for the Duct-Burner configuration

Participant can specify Transition Time
- RT: Not clear reserves when transitioning
- LAC/RAC/DA: Not clear if transition time ≥ Eligibility Cutoff (half of the interval)

	AllOff	1X1-A	1X1-B	2X1	2X1-DB	3X1	3X1-DB
AllOff	1	valid	valid	valid	invalid		
1X1-A	10min/0min/$0	1	invalid	30min/10min/$900	invalid		
1X1-B	10min/0min/$0	invalid	1	30min/10min/$900	invalid		
2X1	10min/0min/$0	10min/10min/$0	10min/10min/$0	1	10min/0min/$50		
2X1-DB	invalid	invalid	invalid	10min/10min/$0	1		
3X1							
3X1-DB							

	when start from alloff				
Configuration name	COLDSTARTUPCOST	INTERSTARTUPCOST	HOTSTARTUPCOST	HOTTOCOLDTIME(h)	HOTTOINTERTIME(h)
1X1-A	1500	1000	500	10	4
1X1-B	1500	1000	500	10	4
2X1	2500	2000	700	12	6
2X1-DB	N/A (invalid to start from Alloff)				
3X1	3500	3000	900	12	6
3X1-DB	N/A (invalid to start from Alloff)				
Alloff					

INDIVIDUAL UNIT NAME	MINDOWNTIME(h)	MINUPTIME(h)	MAXRUNTIME(h)
CT1	8	5	N/A
CT2	8	5	N/A
CT3	8	5	N/A
ST	12	10	N/A
DB	2	2	N/A

https://www.misoenergy.org/stakeholder-engagement/committees/enhanced-combined-cycle-task-team-ecctt/