2025 Forecasting & Markets Workshop

NASHVILLE, TN

Tutorial: System Operations in the US and Europe

System and Market Operations Tutorial

Erik Ela, Yonghong Chen, Jean Gillain

ESIG Market Design and Meteorology Workshop

Nashville, TN

June 24, 2025

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ENERGY SYSTEMS INTEGRATION GROUP

Tutorial Agenda

- Introduction and Objectives
- Global Electricity Market Structures
- Operational and Market Procedures and Timelines
- Forecast Integration
- Grid Services
- Forward looking: How will grid operations change in the future?

Today's Instructors

Erik Ela

Director, ESIG

Yonghong Chen

Chief Scientist, NREL

Jean Gillain

European Market Special, N-SIDE

Tutorial Objectives

Market Structures and Designs

- Understanding some of the basic differences across U.S. regions and also across N.A and Europe.

Operational Scheduling Practices

- How do System and Market Operators schedule supply resources at different timeframes.

Use of Forecasts in Power System Applications

- Clear understanding of where forecasts are used today and where they are starting to be used going forward

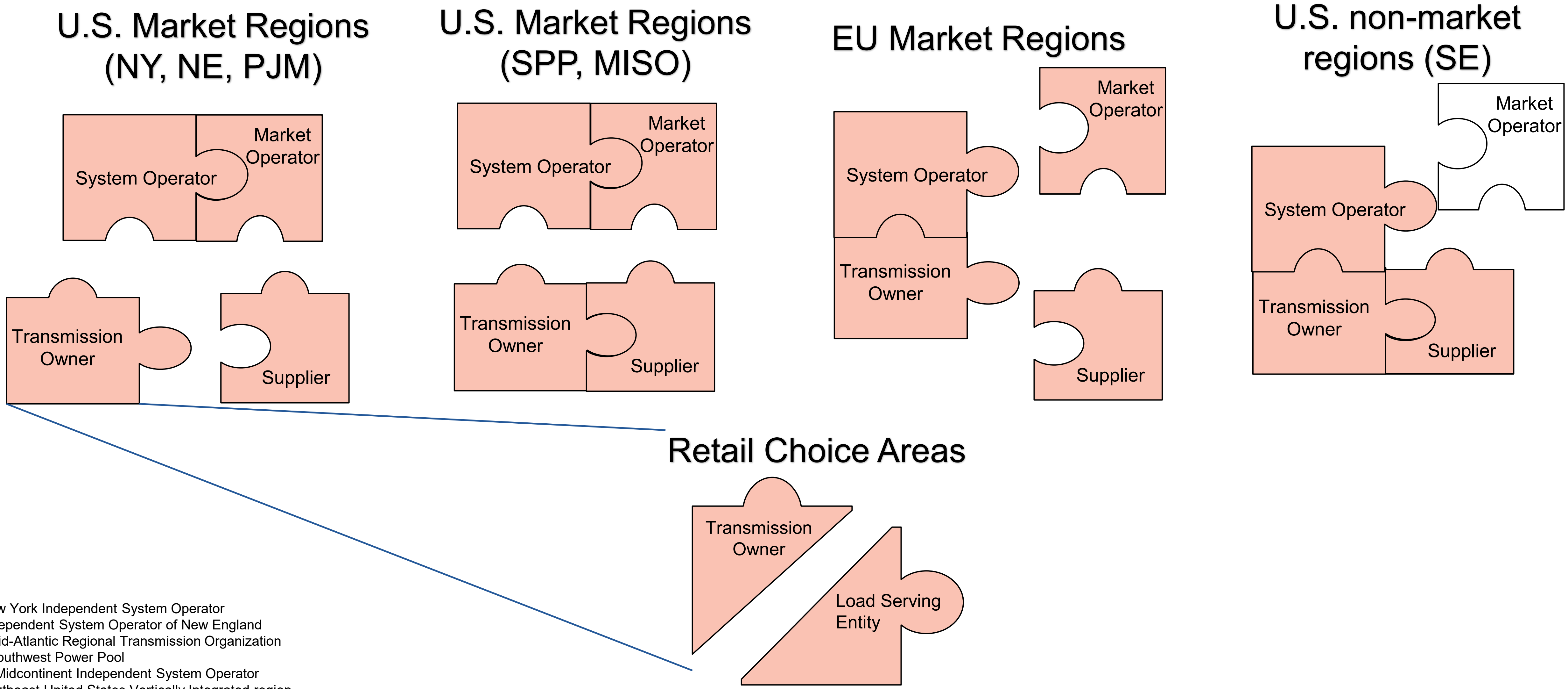
Operational Grid Services

- Understanding of the types of grid services across N.A. and E.U. and how they differ in what and who is providing them.

Forward-looking evolution

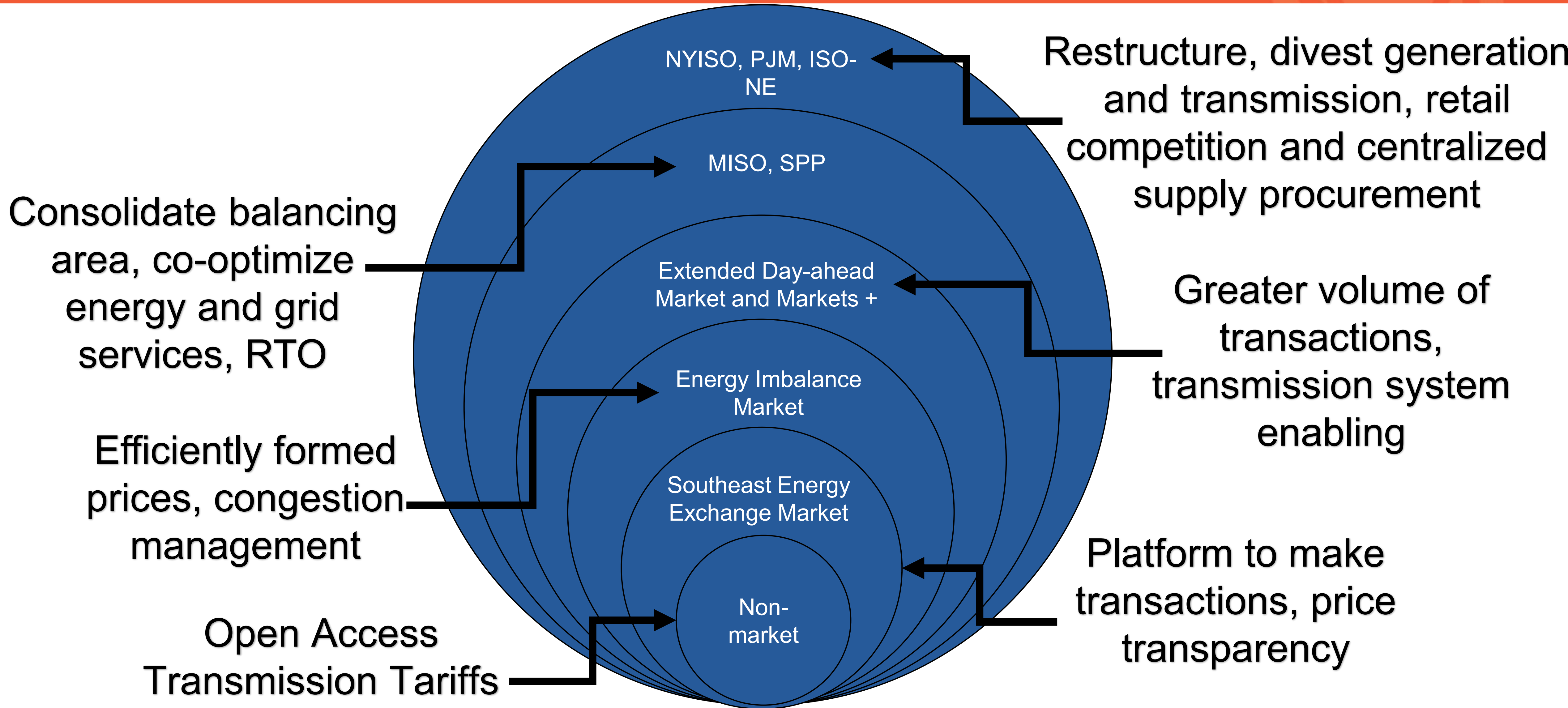
- What are the ways in which we might expect operations and markets to change in the future? What are the most important evolutions that are being discussed and starting to be implemented?

Market Structure and Responsibility Makeup



NY: New York Independent System Operator
NE: Independent System Operator of New England
PJM: Mid-Atlantic Regional Transmission Organization
SPP: Southwest Power Pool
MISO: Midcontinent Independent System Operator
SE: Southeast United States Vertically Integrated region

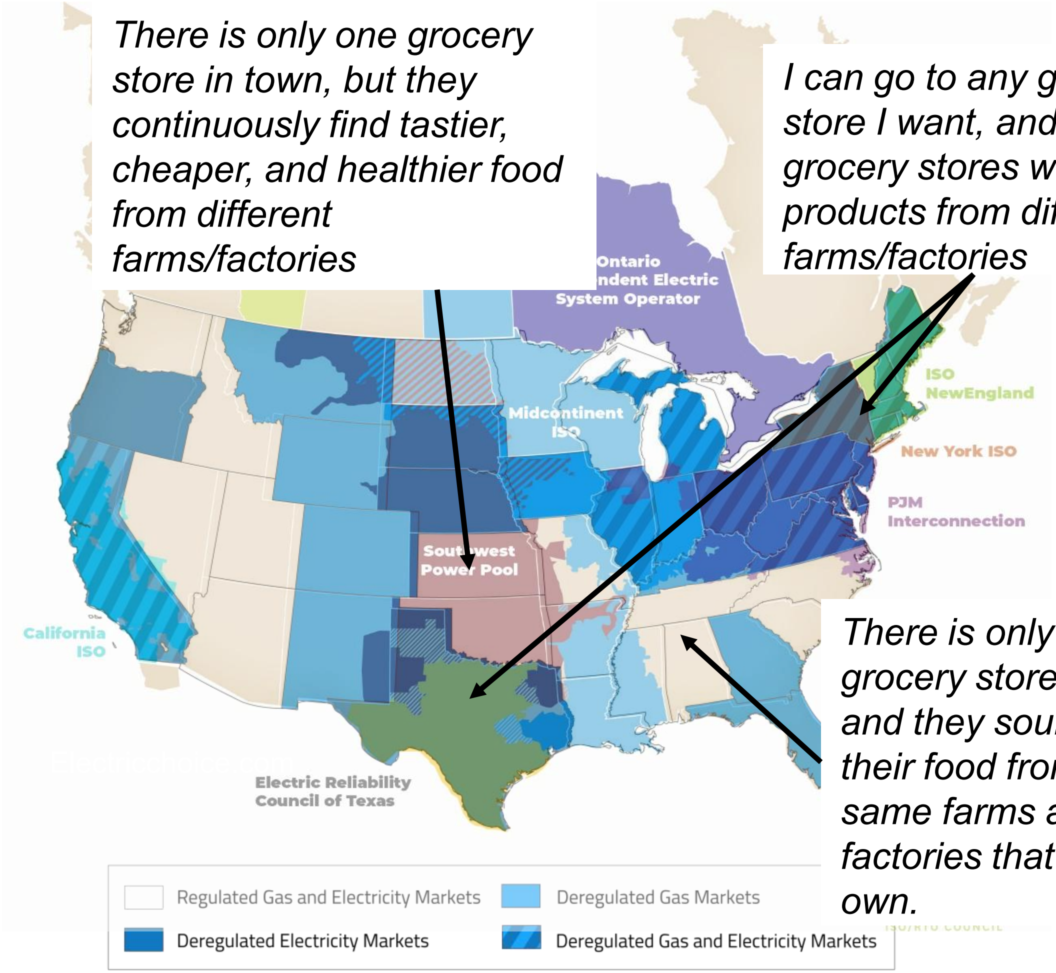
Complex properties of U.S. electricity markets



U.S. Retail Electricity Markets

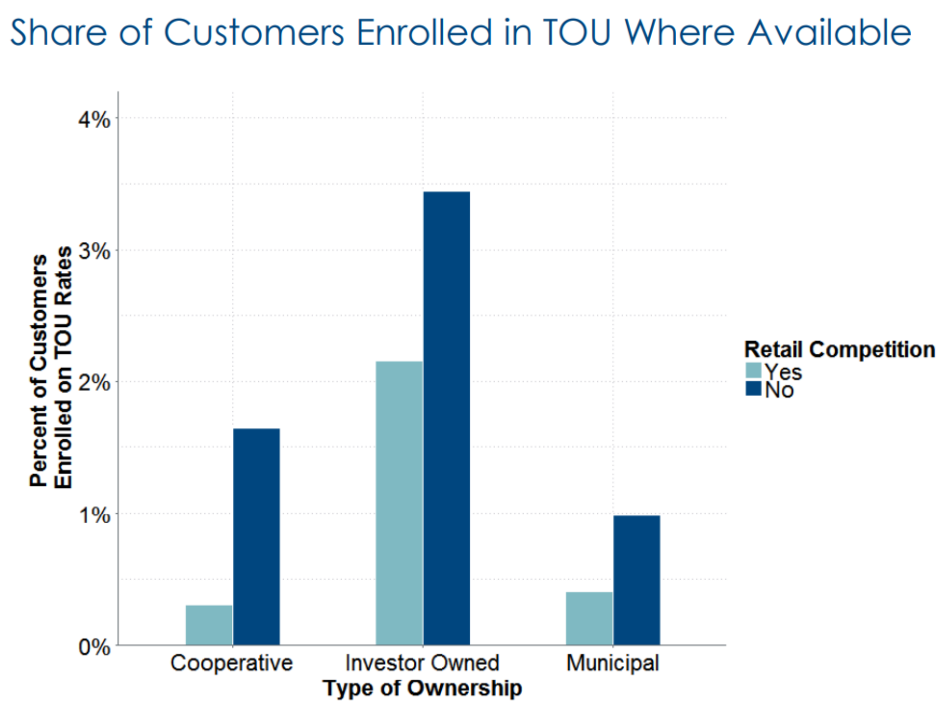
There is only one grocery store in town, but they continuously find tastier, cheaper, and healthier food from different farms/factories

I can go to any grocery store I want, and the grocery stores will have products from different farms/factories



There is only one grocery store in town, and they source all their food from the same farms and factories that they own.

Retail rates are regulated by **state** utility commissions or other local retail regulatory authorities



https://www.brattle.com/wp-content/uploads/2021/05/17904_a_survey_of_residential_time-of-use_tou_rates.pdf

Difference of Transmission system operators and Power Exchanges in EU

Feature/Role	Power Exchanges (PXs) / NEMOs	Transmission System Operators (TSOs)
Primary Focus	**Commercial trading,** price discovery, and market efficiency	**Physical security, stability, and reliability of the grid** (keeping the lights on)
What they handle	Bids and offers for **electricity** (energy volume)	Physical electricity flows, frequency, voltage, and system imbalances
Revenue	**Transaction fees** from market participants	Often from **grid access charges** (tariffs on electricity transported)
Timeframes	**Day-ahead, Intraday** (and sometimes longer-term products)	**Real-time operation, day-ahead**, and long-term grid planning
Key Cooperation	Market Coupling Operators (MCOs) for cross-border price coupling (e.g., PCR, SIDC)	ENTSO-E, regional operational centers (e.g., for balancing platforms like IGCC, MARI, PICASSO)

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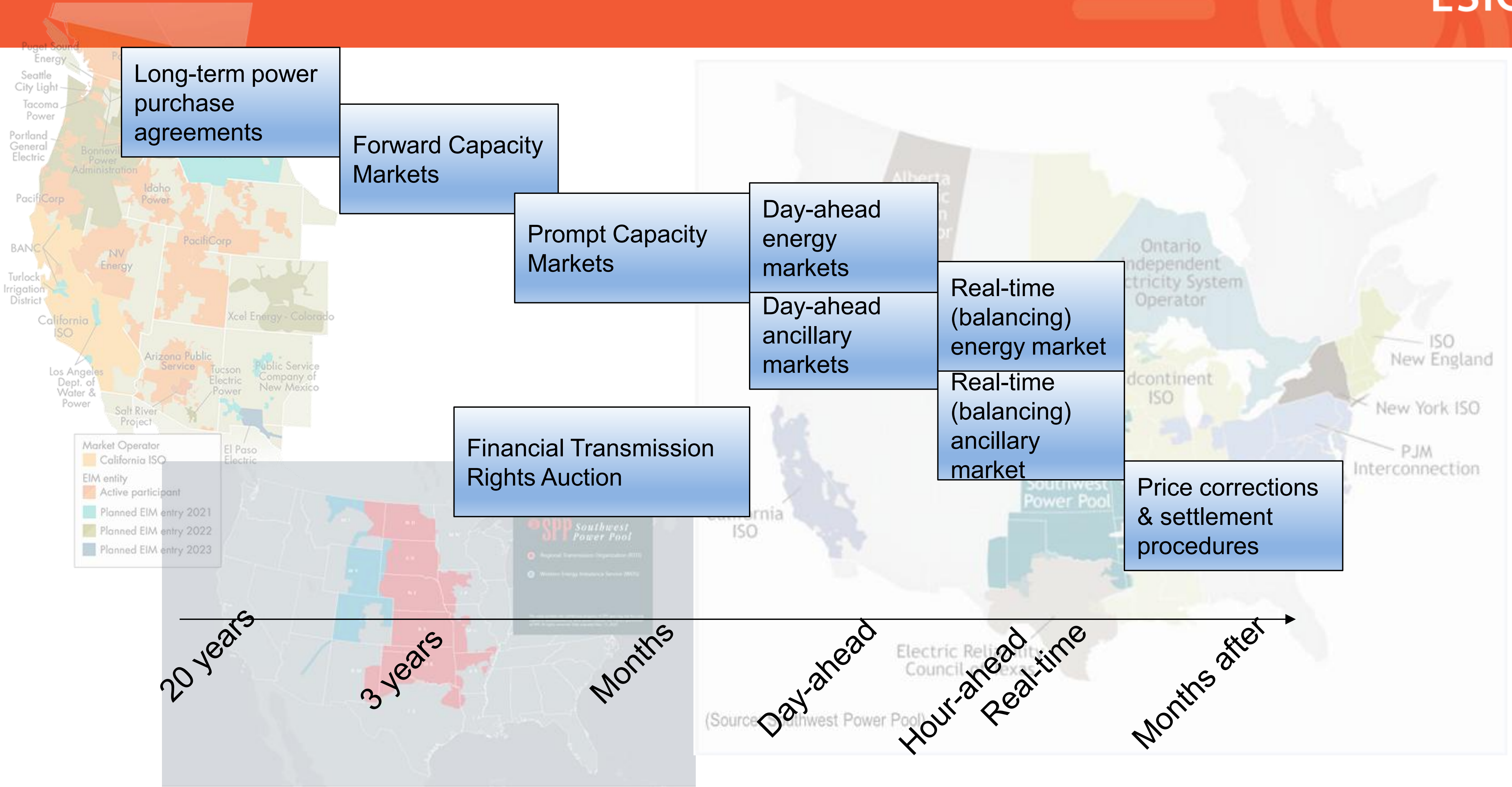
Today's Electricity Market Timelines – U.S.



Today's Electricity Market Timelines – Europe

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Forwards- FCA – FTRs and PTRs → Single Day ahead coupling SDAC → Single intraday coupling → Imbalance netting &Balancing platforms

- Over the counter: PPAs, CFDs
- Financial transmission rights
- Physical transmission rights
- Balancing capacity products can also be long term

- Available capacities published
- 12:00 gate closure
- Hourly clearing prices and market results announced

- Market Closures on previous day
- Market throughout day of

- Frequency containment reserve
- Frequency restoration reserve (automatic or manual)
- Replacement reserve

SDAC (Single Day-Ahead Coupling): the European electricity market covers 26 countries

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1 single algorithm
26 countries
10-years anniversary in 2024
SDAC traded volume in 2023: **1696 TWh**
Average welfare per session: **10.9 B €**

N-SIDE

Transmission System Operators (TSOs):

50Hertz Transmission, ADMIE, Amprion, APG, AST, ČEPS, Creos, EirGrid, Elering, ELES, ELIA, Energinet, ESO, Fingrid, HOPS, Litgrid, MAVIR, PSE, REE, REN, RTE, SEPS, SONI, Statnett, Svenska Kraftnät, TenneT DE, TenneT NL, Terna, Transelectrica, and TransnetBW.

Nominated Electricity Market Operators (NEMOs):

BSP, CROPEX, SEMOpx (EirGrid and SONI), EPEX, EXAA, GME, HEnEx, HUPX, IBEX, Nasdaq, Nord Pool, OMIE, OKTE, OPCOM, OTE, and TGE.

Source: [All NEMO committee - Newsletter April 2024]

U.S. electricity market design

Independent Market Operators do not own transmission

Nodal pricing for suppliers

Security-constrained centralized commitment and **5-minute** centralized dispatch

Day-ahead and real-time markets for energy and ancillary services

Three-part offers, partially convexified prices, make-whole payments

Technology-specific participation models

Co-optimized active power short-term ancillary service markets

Certain financial markets run by ISO (locational hedging and day-ahead convergence)

Reserve shortage pricing

U.S. electricity market design (unique across ISOs)

- Spot or forward capacity markets
- Demand Response participation (and retail rules)
- Clean Energy Policies (due to state regulation)
- Mitigation Procedures
- Individual Resource or Scheduling coordinators
- Intra-day scheduling Processes
- Short-term flexibility products
- Extended sloped operating reserve demand curves
- Performance Penalties

European market design

Transmission system operators own the grid elements

Zonal pricing

Spot day-ahead market with 60min MTU

Separated Day-ahead and intraday auctions for energy and ancillary services

Portfollio bidding including simple curves, blocks

Pay-as-clear with no Paradoxically accepted orders

European Balancing activation market

Complex Governance: NRA & ACER

European market design (unique across countries)

- Bidding products
- National/ regional balancing capacity market
- Clean Energy Policies (due to country regulation)
- Power exchanges
- Number of bidding zones and regions
- Redispatch methods
- Capacity remuneration mechanism
- Capacity calculation methods (ATC/Flow-based)

Questions

- General variety in U.S. electricity market structure
- Overview of key markets in the U.S. and in Europe
- Common design features across all U.S. Markets
- Common design features across all European Markets
- Unique features not common across these markets

Operational Scheduling and Market Timelines

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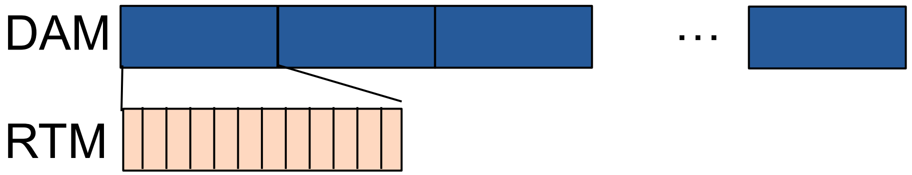
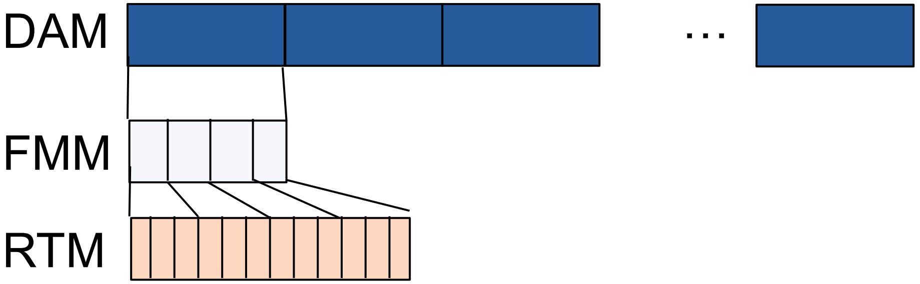
Settlements in Electricity Markets

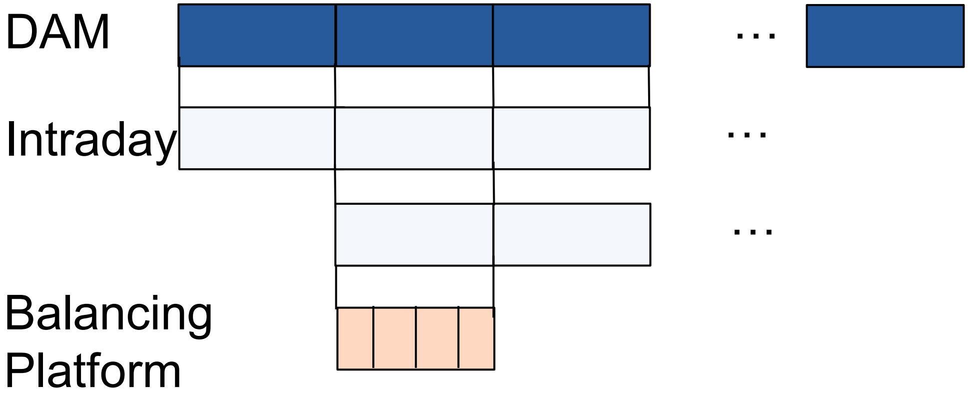
Most U.S. Markets



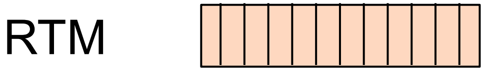
CAISO Market



European Market



Australian National Electricity Market



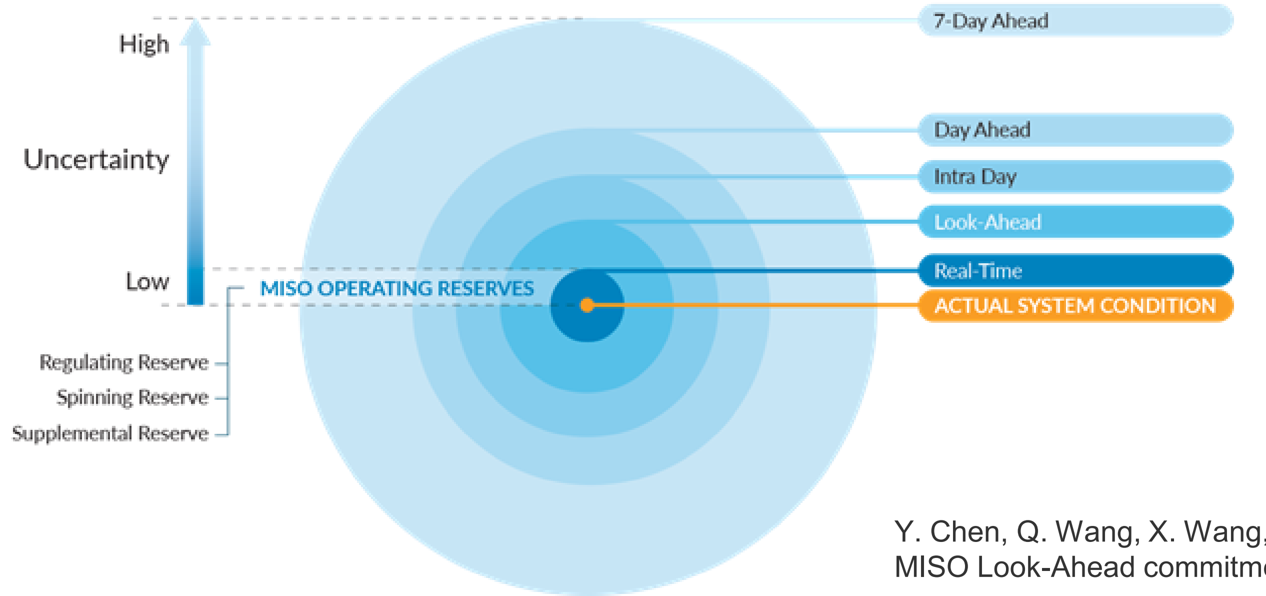
Korean Power Market

DAM: Day Ahead Market
RTM: Real Time Market
FMM: Fifteen Minute Market

Managing Uncertainty

Long-term planning horizon

- **Member resource adequacy plans and state policies**
- **RTOs/ISOs**
  - transmission expansion, generation interconnection
  - Resource adequacy
    - Capacity auction (1 or 3 years forward)
    - Planning reserve margin to meet reliability target
    - Capacity accreditation to reflect resource contributions



Operations

Market products
- Energy
- Operating reserves (5–10 min)
- Flexible ramp product (10 min)
- 30-min, 1-h products, etc.

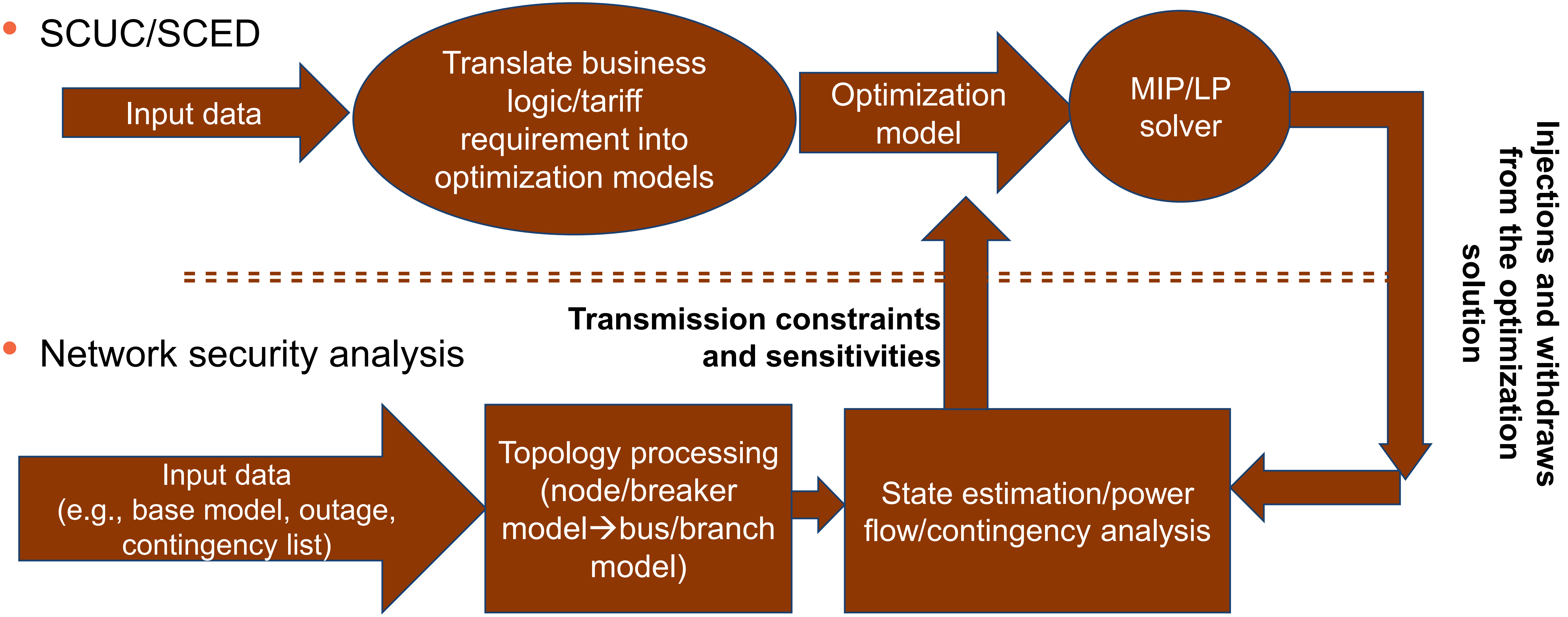
Operational process/tools
- Multistage commitment
- Multiple scenarios
- Margin
- Offsets

Out of market actions

Y. Chen, Q. Wang, X. Wang, and Y. Guan. 2014. "Applying robust optimization to MISO Look-Ahead commitment." IEEE PES General Meeting, National Harbor, MD.

Typical US Market Clearing System

- SCUC/SCED
- Network security analysis



SCUC: security constrained unit commitment
SCED: security constrained economic dispatch
MIP: mixed integer programming
LP: linear programming

Day Ahead Security-Constrained Unit Commitment

Security-constrained unit commitment

- Minimize production cost + violation penalty
  - Resource constraints
  - Transmission flow constraints
  - Power balance constraints
  - Reserve requirement constraints

(Resource constraints:)
- Time coupling on intertemporal constraints
- Mostly decoupled by resources (or resource groups).

(Transmission flow, power balance and reserve requirement constraints:)
- Coupling systemwide or zonal constraints within each interval
- No time coupling.

Network security analysis: identify transmission constraints

- Base case (Midcontinent Independent System Operator [MISO]: 45,000-bus network)
- North American Electric Reliability Corporation (NERC) requires N-1 security
  - Flow to be within limit under any N-1 line or generation contingencies
  - Security under other contingencies (operational guides)
- Real world: nonlinear alternating-current (AC) power flow model

DA Market Clearing Variables and Constraints

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Supply

- Generation offers (e.g., MISO about 1,400 generators)
- Transactions imported from external areas (dispatchable or fixed)
- Virtual suppliers (dispatchable)

Demand

- Load (dispatchable or fixed)
- Transactions exported to external areas
- Virtual demands (dispatchable)

Transmission constraints

- Pre-selected watchlist constraints (e.g., 7,000 for all intervals for large ISOs)
- Iterate with network security analysis for additional violations

Resource Constraints

- Traditional thermal generator constraints
  - Startup states
  - Minimum up time, minimum down time, state-transition logic, maximum up time
  - Capacity and ramping constraints
  - Maximum number of starts and maximum energy per day
  - Reserve commitment and reserve capacity
- Configuration-based combined cycle
  - Additional constraints on configuration transition
- Storage
  - State-of-charge energy limits: temporal dependent

Operational Uncertainty Management

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Direct input uncertainties

- Load forecast
- Wind forecast
- Solar forecast
- Generation availability
- Fuel assurance
- Net scheduled interchange

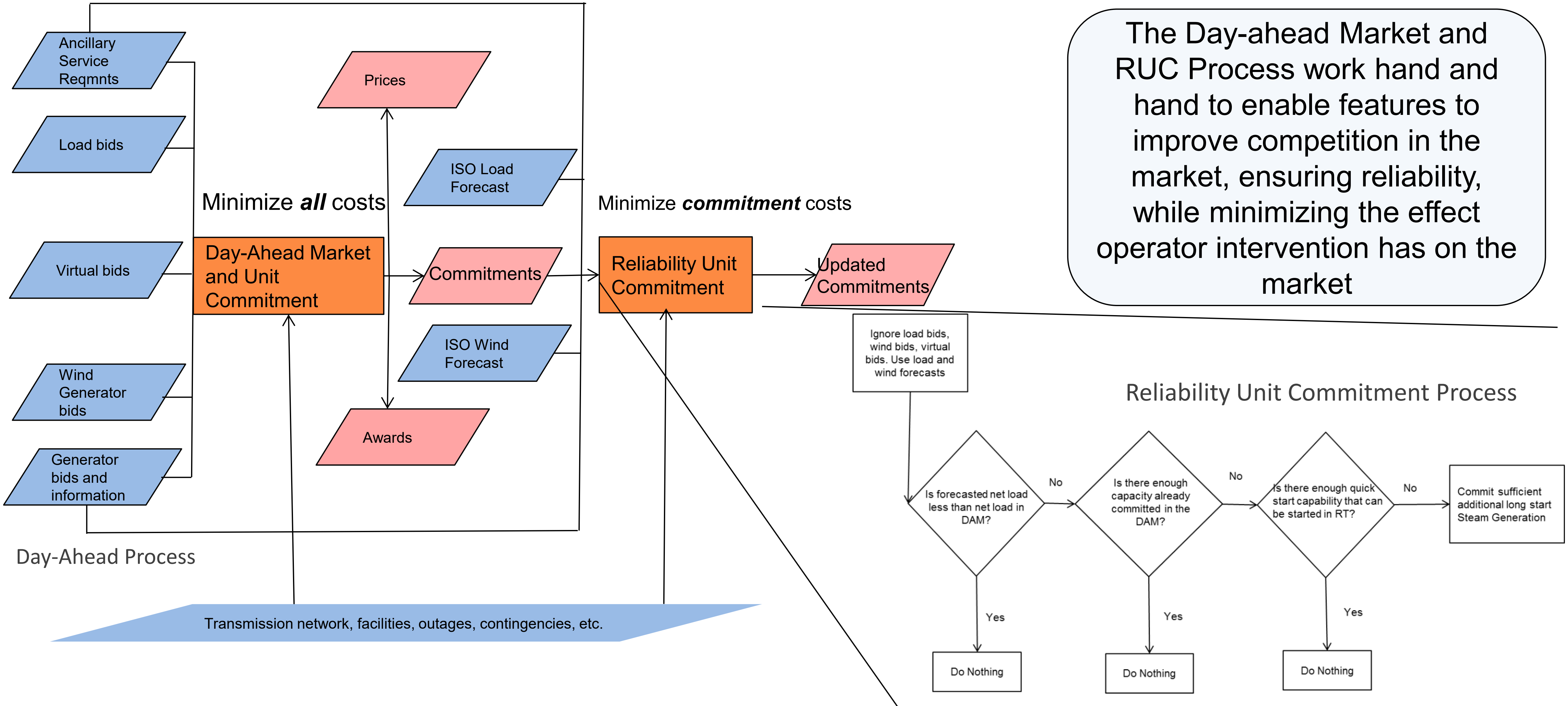
Derivative uncertainties

- Transmission congestion
- Responses from participants and operators

- Increased uncertainties on individual components
  - Uncertainties from load, wind and solar forecasts
    - Weather-dependent resources and more frequent extreme weather events
    - Distributed energy resources
  - Uncertainty on thermal resource availability
    - Interdependence with other infrastructure (e.g., gas)
  - Uncertainty on interchange
  - Loss of weather-dependent resources may have much larger impact than N-1/G-1
  - Transmission congestion may cause high stranded capacity
- Aggregate uncertainty is even more challenging to quantify

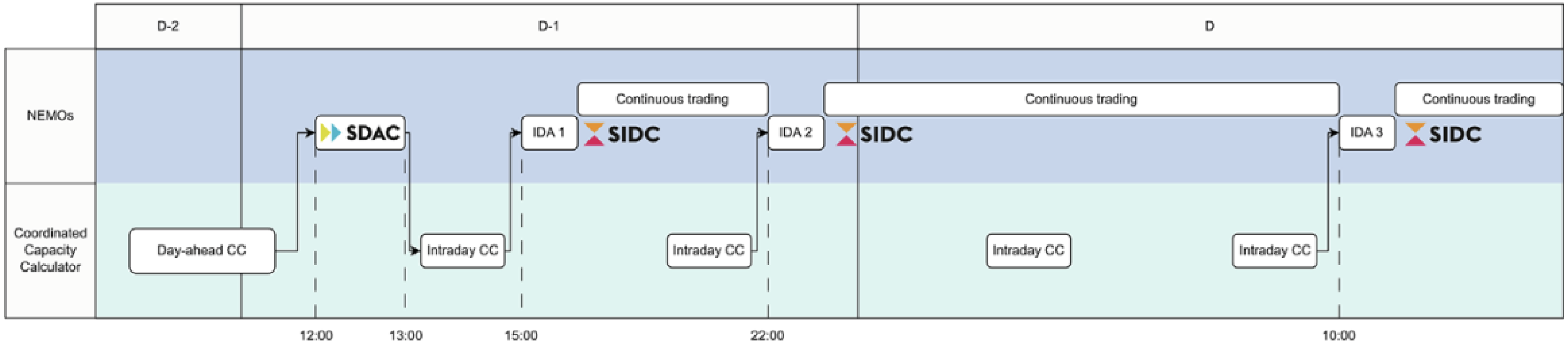
U.S. Day-Ahead Commitment Process

The Day-ahead Market and RUC Process work hand and hand to enable features to improve competition in the market, ensuring reliability, while minimizing the effect operator intervention has on the market



Questions

A closer look at the market power operations in EU in day-ahead



- **DA (Day-Ahead)** – closes at **12:00 D-1**
  - ~30% of market share
  - Sets the price reference
- **IDAs (Intraday Auctions)** – at **15:00**, **22:00 (D-1)** and **10:00 (D)**
  - Efficient cross-zonal allocation
  - Provide price signals & congestion rents
- **XBID (Continuous Trading)** – runs all day
  - First come, first served
  - No price signals or congestion rents

Source: European Electricity Market Coupling

Auction-based versus Continuous trading

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Auction

- Market participants submit their bids (volume, price, etc.) to their NEMOs
- After Gate Closure, all orders are considered in a single optimisation algorithm, together with the capacity and topology
- Auction provides
  - Optimized cross-border capacity allocation, and congestion rents
  - Unique Market Price per bidding zone and time unit

SDAC

SIDC IDA

Continuous Trading

- No common auctioning, and no unique market price
- Until Gate Closure, any bid can be matched with another order if
  - they are price compatible and
  - if there exist a route to transport the energy between bidding zones
- Capacity is allocated "first come, first served" and is not priced
- No congestion rent and no bidding zone price

SIDC XBID

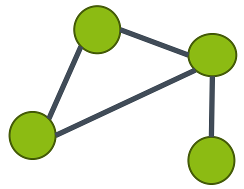
The Euphemia Market Coupling algorithm

INPUTS

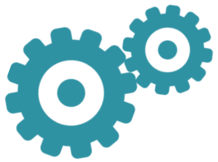
Market data

- Hourly orders
- Block orders
- Parent-child orders
- Exclusive group orders
- Flexible block orders
- PUN orders
- Scalable complex orders
- MIC orders
- Load gradient orders

Network data



- Bidding areas
- Network topology
- ATC constraints
- Flow-based constraints
- Net position ramping
- Line ramping
- Balance constraints
- Transmission tariffs
- Loss coefficients

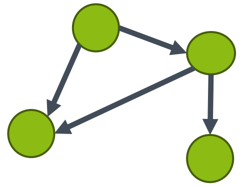


The EUPHEMIA algorithm

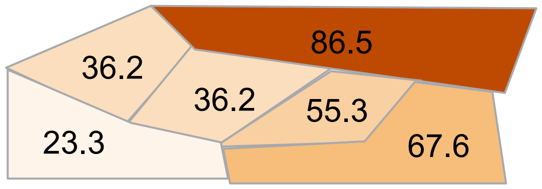
OUTPUTS

Executed Volumes (MWh)

Network flows (MW)



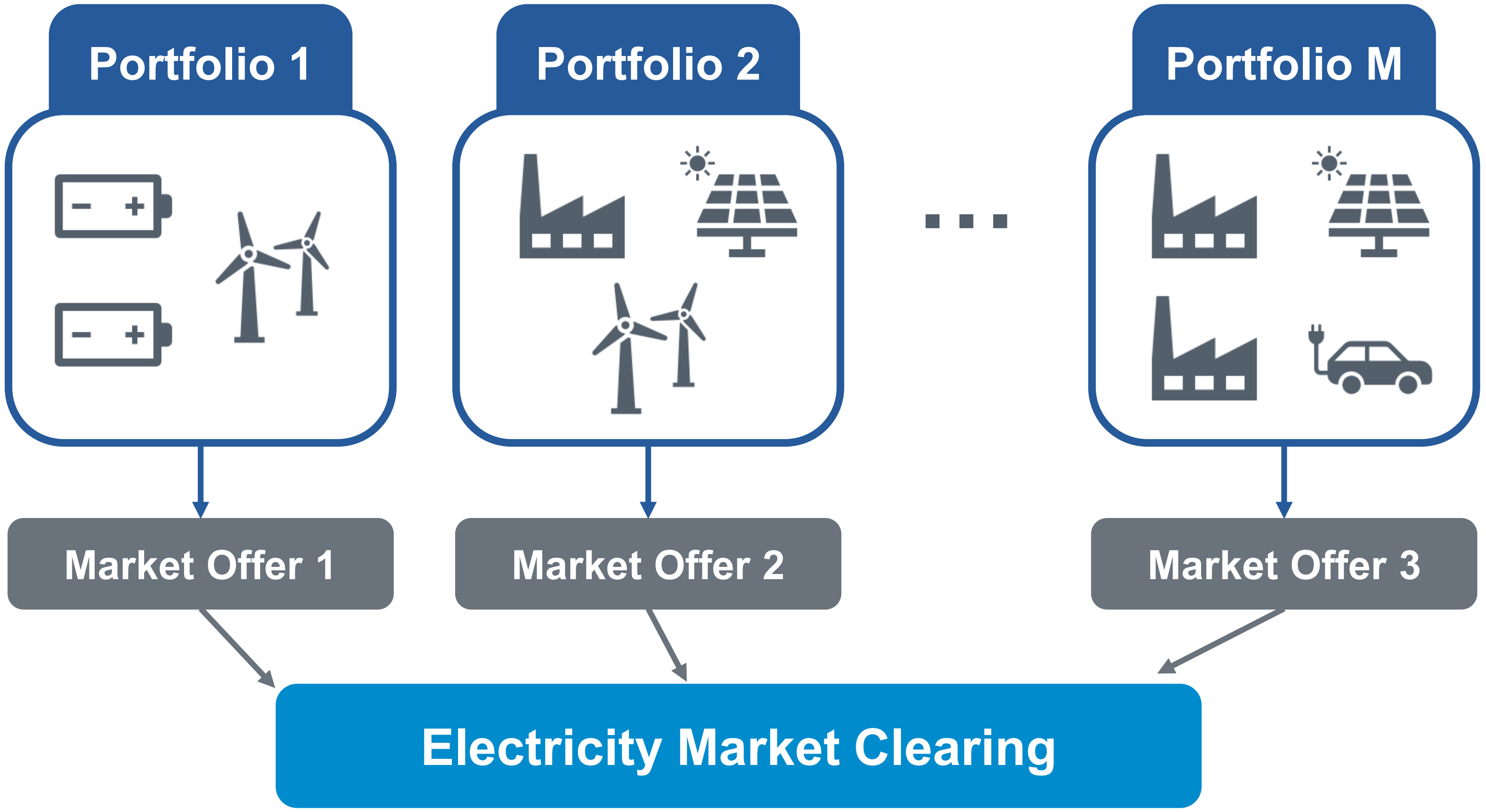
Market Prices (€/MWh)



Euphemia takes Market and Network data and returns market prices, executed volumes, and network flows

*The EUPHEMIA algorithm is owned by PCR, Price Coupling of Regions

The EU market uses portfollio bidding strutcture



Portfolio-based design

- Portfolios are **aggregation of resources** which are represented through a **unique market offer** in an electricity market.
- In practice:
  - **Aggregated offers** are constructed by portfolio owners
  - **Electricity market clears** and acceptance/rejection decisions of offers are provided to portfolio owners
  - Portfolio owners **disaggregate** the market outcomes
  - **Setpoints** are announced to the system operator **after** day-ahead but before real-time

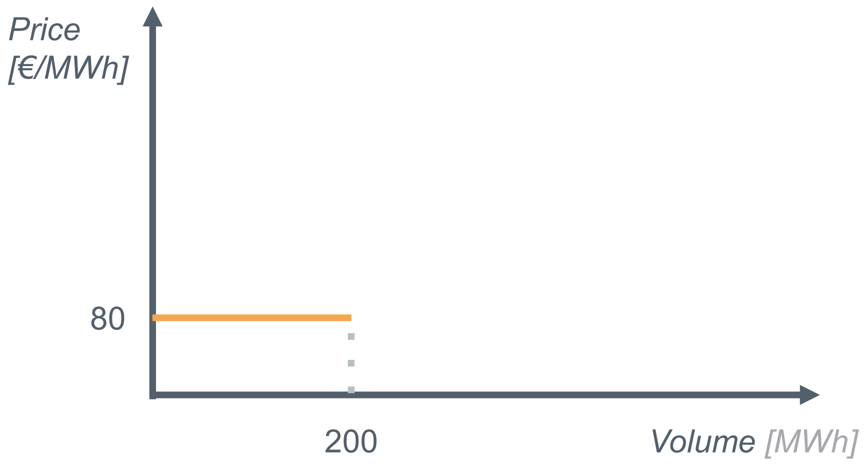
EUPHEMIA Bidding Products

Hourly orders

Block orders

Parent-child orders

Scalable complex orders



The simplest type of order, defined by:

- Quantity
- Price
- Time period
- Bidding zone
- Buy/Sell

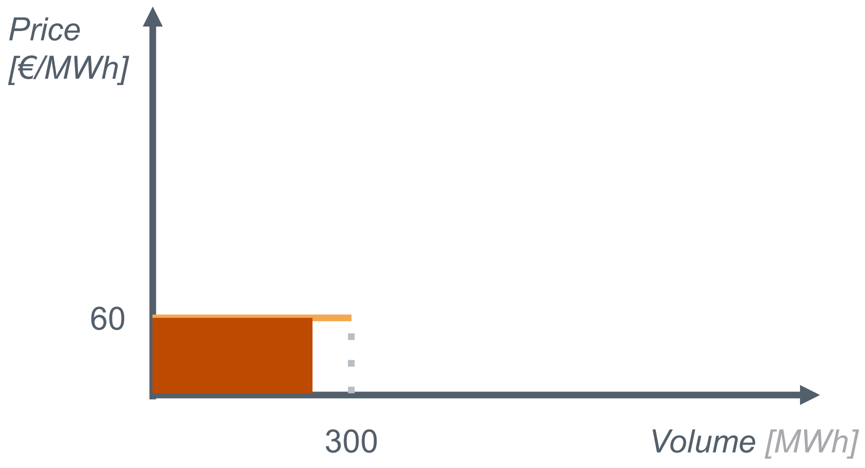
EUPHEMIA Bidding Products

Hourly orders

Block orders

Parent-child orders

Scalable complex orders

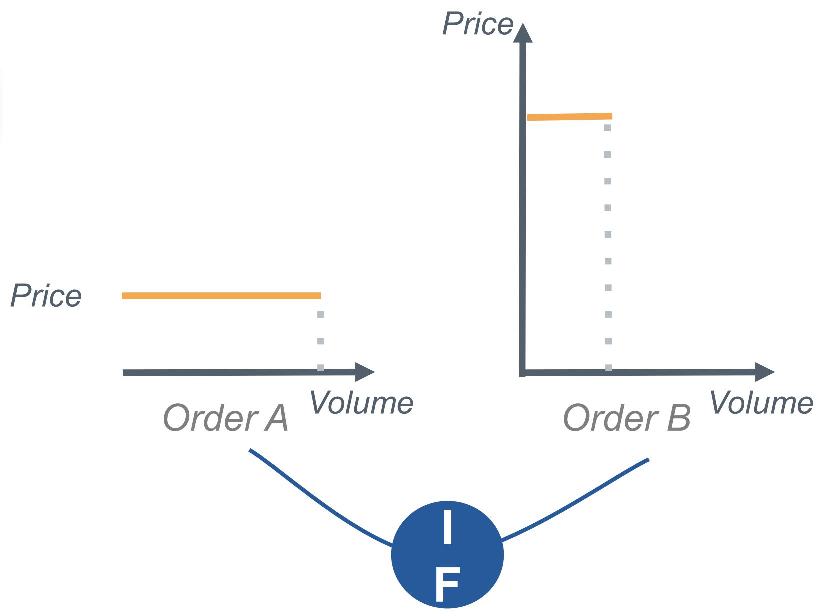


Block order definition

- Indivisible order
- Quantities
- price, time period, bidding zone
- Minimum acceptance ratio, e.g. 80%
- Possibly spanning over several time periods
- Can be used to represent nuclear power plants or thermal with specific link constraints.

EUPHEMIA Bidding Products

- Hourly orders
- Block orders
- **Parent-child orders**
- Scalable complex orders



Parent-Child order definition

- ➢ Quantity, price, time period, bidding zone
- ➢ Child order can be executed only if parent order is executed
- ➢ Can be used to represent storage, ramping constraints in thermal power plants.

EUPHEMIA Bidding Products

- Hourly orders
- Block orders
- Parent-child orders
- **Scalable complex orders**

Scalable Complex order definition

- Quantity, price, time period, bidding zone
- A fixed cost independent of the activation level
- A Minimum acceptance volume per hour
- Ramp conditions
- **Can be out-of-the-money for some hours as long as in-the-money for the whole day**

Also require the use of a **binary variable**

Introduced as a more scalable version of the Minimum Income Condition order used in the Iberic Peninsula and in Ireland

Closer to US-design, only used in Spain, Italy and Ireland.

Questions

Seams Management

	Europe		United States	
	Coupling	Clearing Model	Coupling	Clearing Model
Day ahead	Multi-region >900 GW	Zonal aggregated	Limited	Nodal within each RTO (up to ~180 GW)
Intra-day	Multi-region >900 GW	Zonal aggregated	Limited	Nodal within each RTO (up to ~180 GW)
Real time	No		Some level of coordinated transaction or market-to-market congestion management	Nodal within each RTO (up to ~180 GW)
Pros	>900-GW coupling to optimize transferring across large region		Each RTO achieves high efficiency on power balance, congestion management, and reserve procurement	
Cons	Congestion management challenges with zonal clearing		Expanding nodal clearing to multi-RTO has jurisdictional and computational challenges	

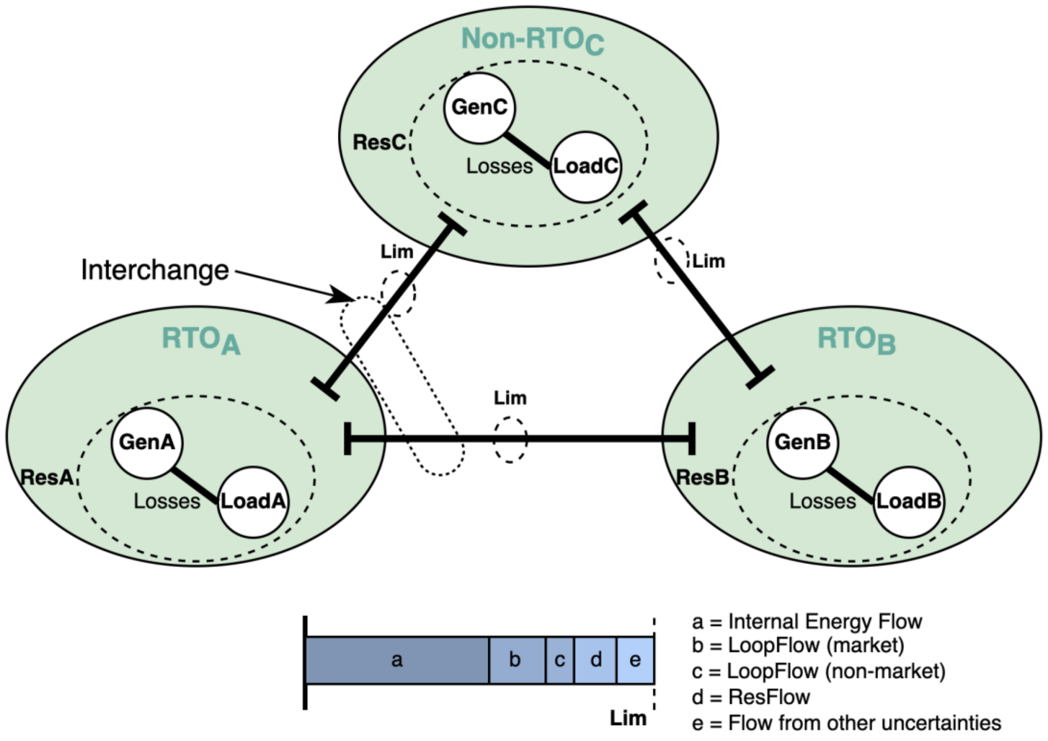
Interregional Coordination

Balancing authority: power balance

- Gen + Interchange = Load + Losses
- Reserve ≥ Reserve Requirement

Reliability coordination: congestion management*

- Flow from energy: a + b + c ≤ Limit
- Flow with reserve and margin: a + b + c + d + e ≤ Limit



Example methods to manage various components:

Interchange	Interchange optimization, coordinated transaction scheduling, etc.
a	Security-constrained unit commitment and economic dispatch
b	M2M coordination on congestion relief with external RTOs
c	NERC transmission loading relief
d and e	Transmission reliability margin (e.g., 2%)

* Also responsible for other reliability services such as managing voltage and reactive power.

Coordinated Transaction Scheduling

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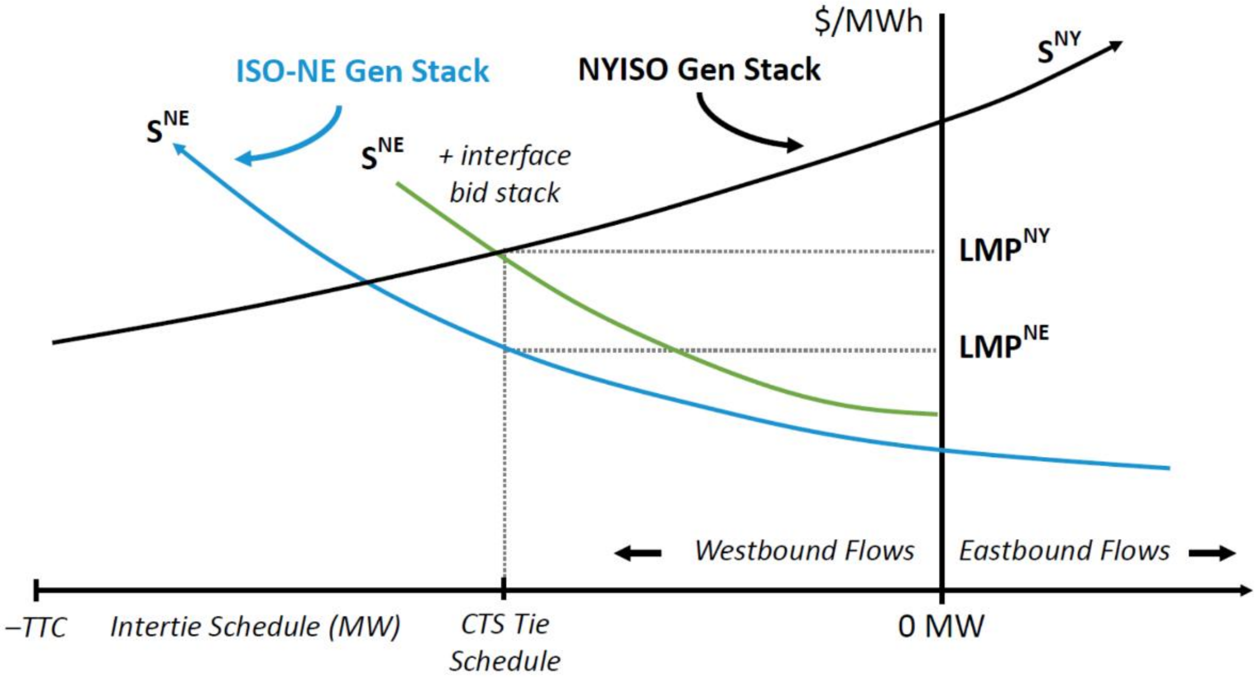
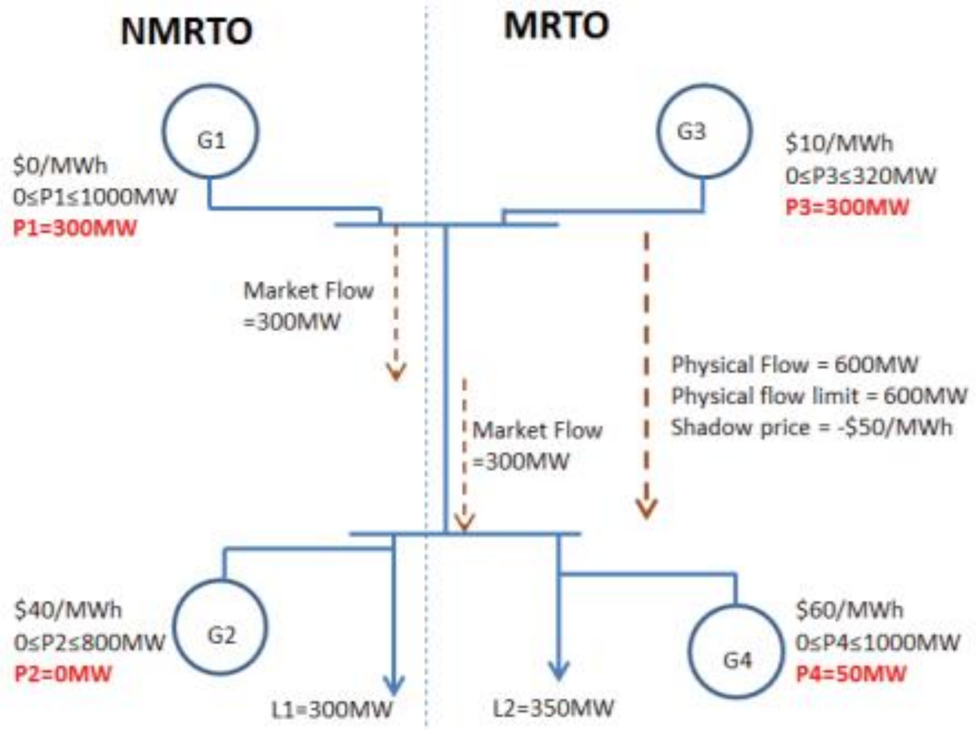
- ISO New England (ISO-NE) calculates its supply curve and sends to New York ISO (NYISO)
- NYISO applies ISO-NE supply curve and clears transaction bids
- Cleared transactions can close the price gaps between the two ISOs



ISO-NE. 2015. "Coordinated Transactions Scheduling (CTS) Training." www.iso-ne.com/static-assets/documents/2015/09/iso-ne_cts_training_20150921.pdf.

M2M Congestion Management

- Practice between MISO/PJM, MISO/SPP
- Monitoring RTO can request relief from non-monitoring RTO
  - Request relief amount
  - Exchange shadow price
  - Achieve flow and shadow price convergence



Redispatch cost:
$40 – $0 = $40/MWh

<

Redispatch cost:
$60 – $10 = $50/MWh

Request more relief from non-monitoring RTO

Y. Chen, Y. Jiang, and T. Mallinger, 2017. "Address Power Swing Issue Under Market to Market Flow Control Coordination." 2017 IEEE Power & Energy Society General Meeting, Chicago, IL.

Questions

Forecasting in Power System Applications

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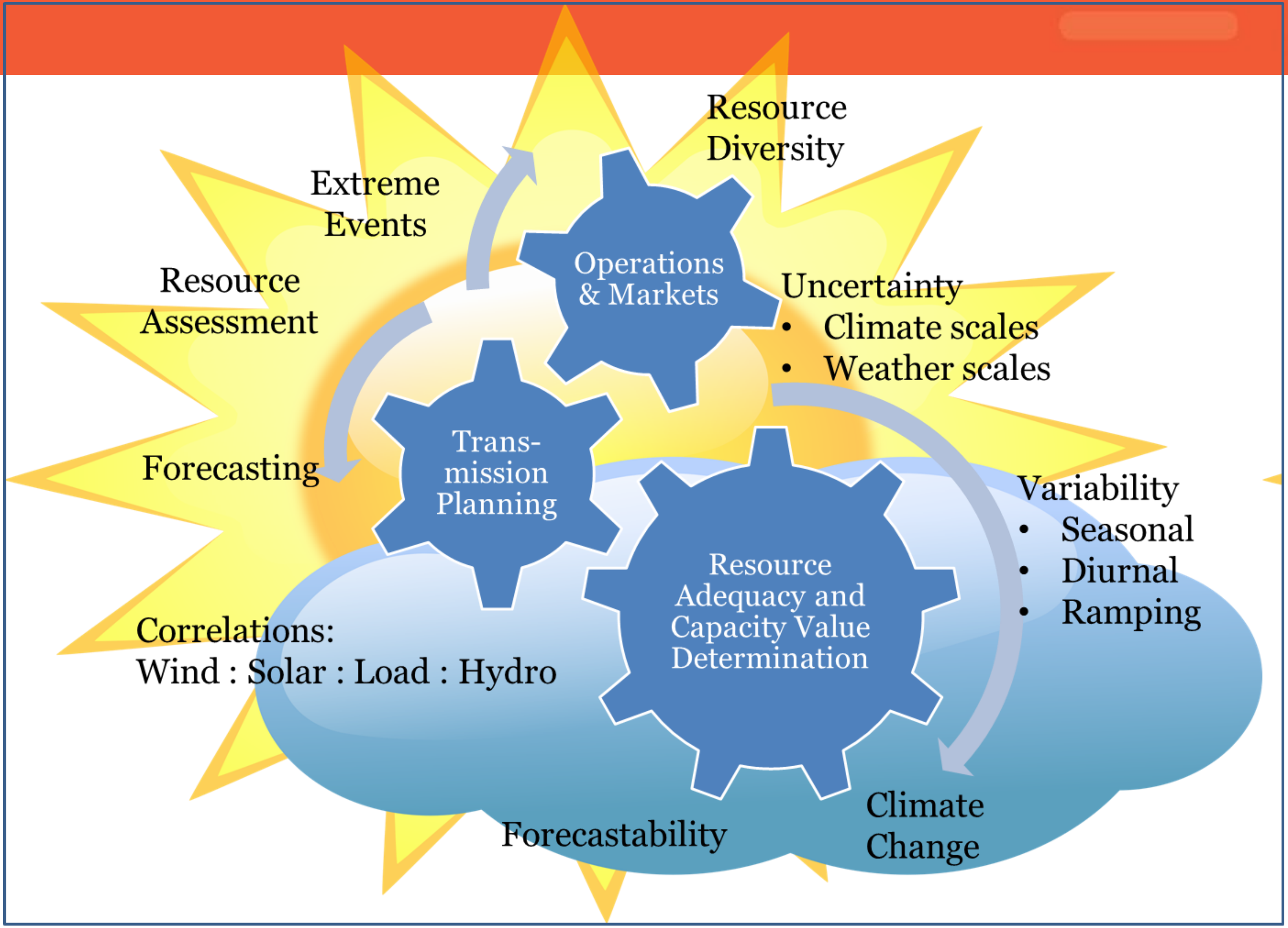
Use of Meteorology in Operations and Planning



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Sharply Focused
Understanding Renewable Resources

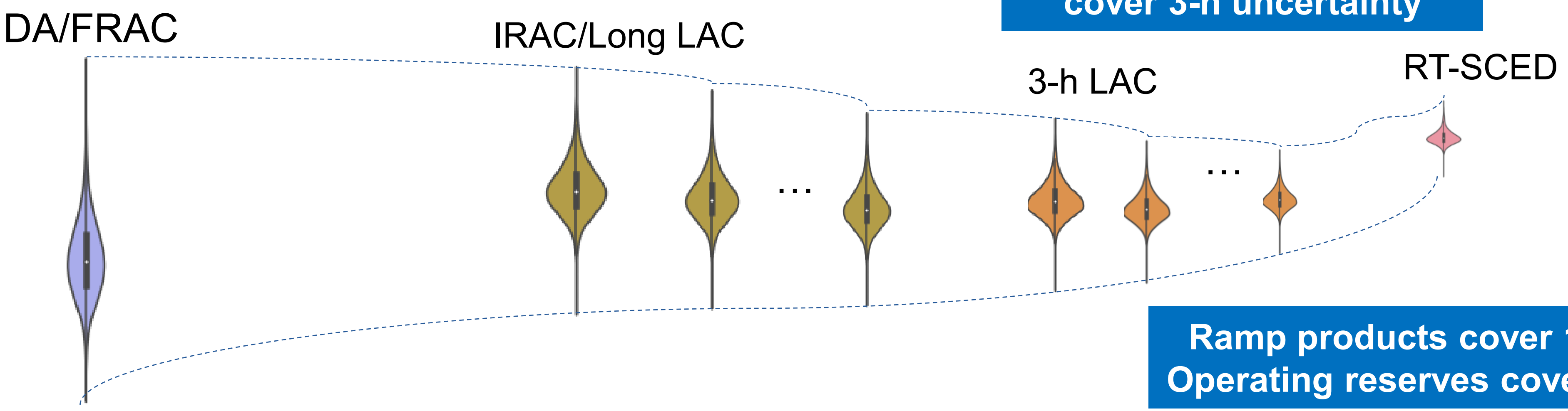
Market Products and Processes for Operational Uncertainty Management

Operational uncertainty management

- Multistage clearing process with multiple scenarios
- Ancillary service products and operational margins
- Decision for current stage and options for future stages.

FRAC margins (4 h online and offline) to hold options for intraday

Short-term reserve to cover 3-h uncertainty



Ramp products cover 10–30 min
Operating reserves cover 0–10 min

Nazif Faqiry, Arezou Ghesmati, Yonghong Chen, and Bernard Knueven. 2023. “Market Simulation Tools and Uncertainty Quantification Methods to Support Operational Uncertainty Management.” FERC Technical Conference, June 27, 2023. www.ferc.gov/media/arezou-ghesmati-midcontinent-iso-carmel.

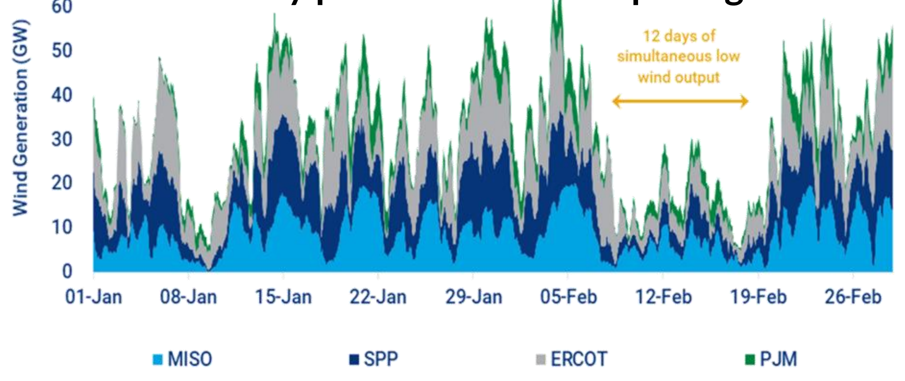
DA: day ahead, FRAC: forward reliability commitment
IRAC: intra-day reliability commitment, LAC: look ahead commitment
RT-SCED: real time security constrained economic dispatch

Operational Challenges

- Current energy and ancillary service markets may not provide sufficient price signals for resources with certain important attributes
- Capacity markets: 1 or 3 years forward
  - Limited consideration of some important reliability attributes
- For any of the future portfolios, how to ensure essential reliability attributes for reliable operations?
  - Availability, fuel assurance, flexibility, long-duration energy, voltage stability, primary frequency response, etc.

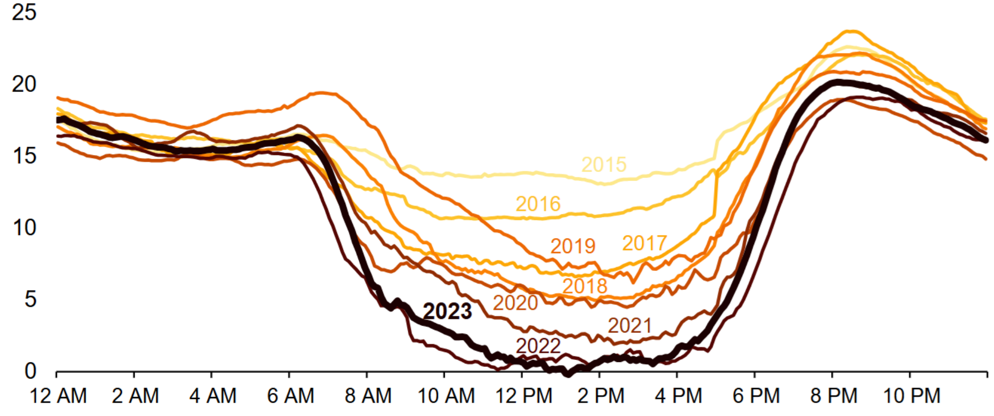
MISO. 2022. "System Attributes Stakeholder Workshop." RASC-2022-1. Sept. 21, 2022. cdn.misoenergy.org/20220921%20System%20Attributes%20Workshop%20Presentation626391.pdf.

During Winter Storm Uri, wind output was low for a 12-day period across multiple regions



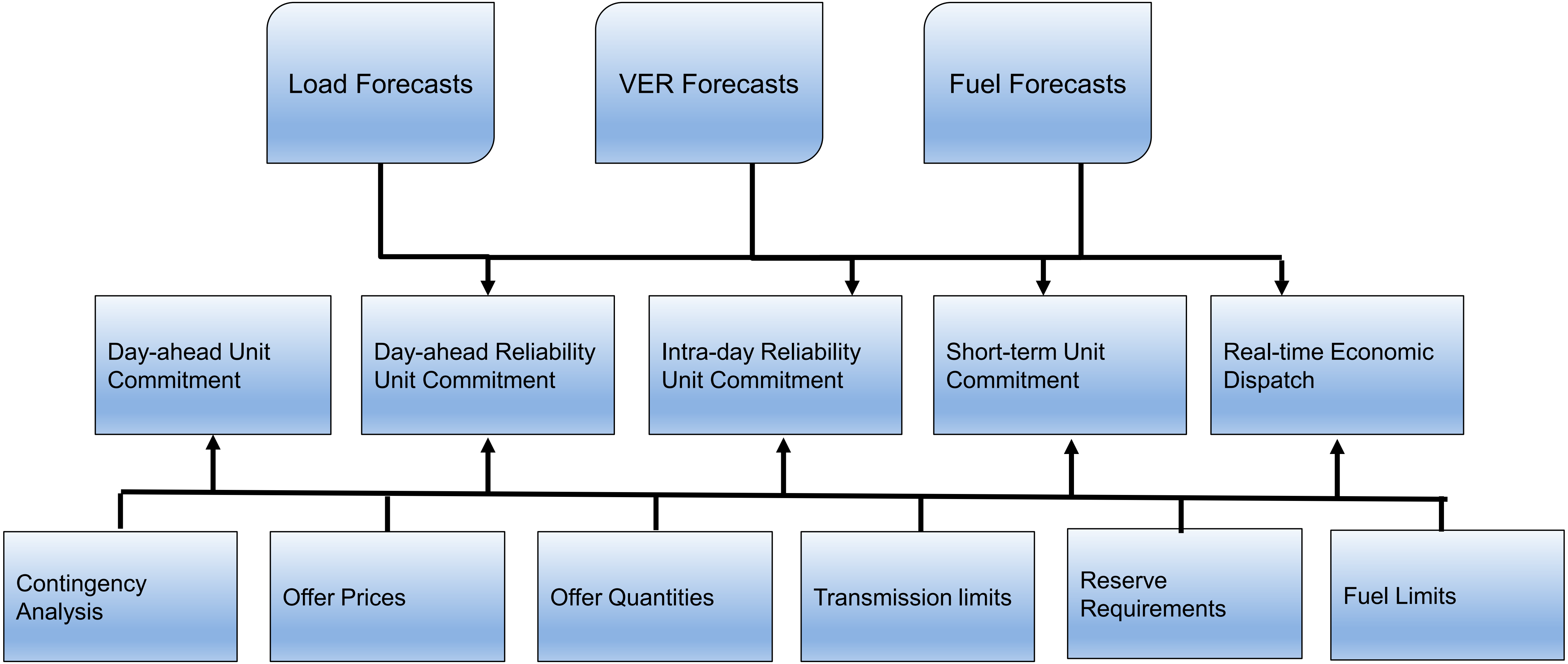
Source: Wood Mackenzie, ERCOT, MISO, SPP, PJM

California's duck curve is getting deeper
CAISO lowest net load day each spring (March–May, 2015–2023), gigawatts



Source: https://www.eia.gov/todayinenergy/detail.php?id=56880

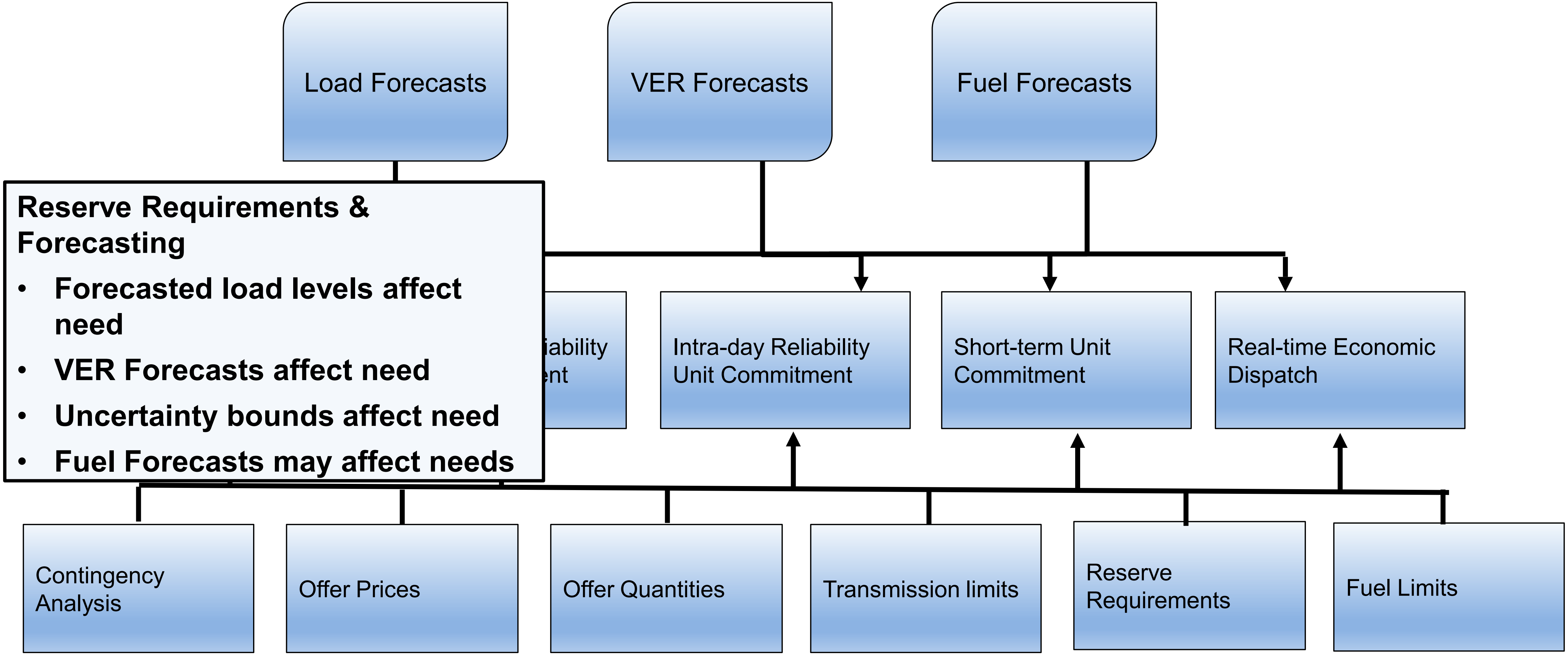
Forecasting Applications



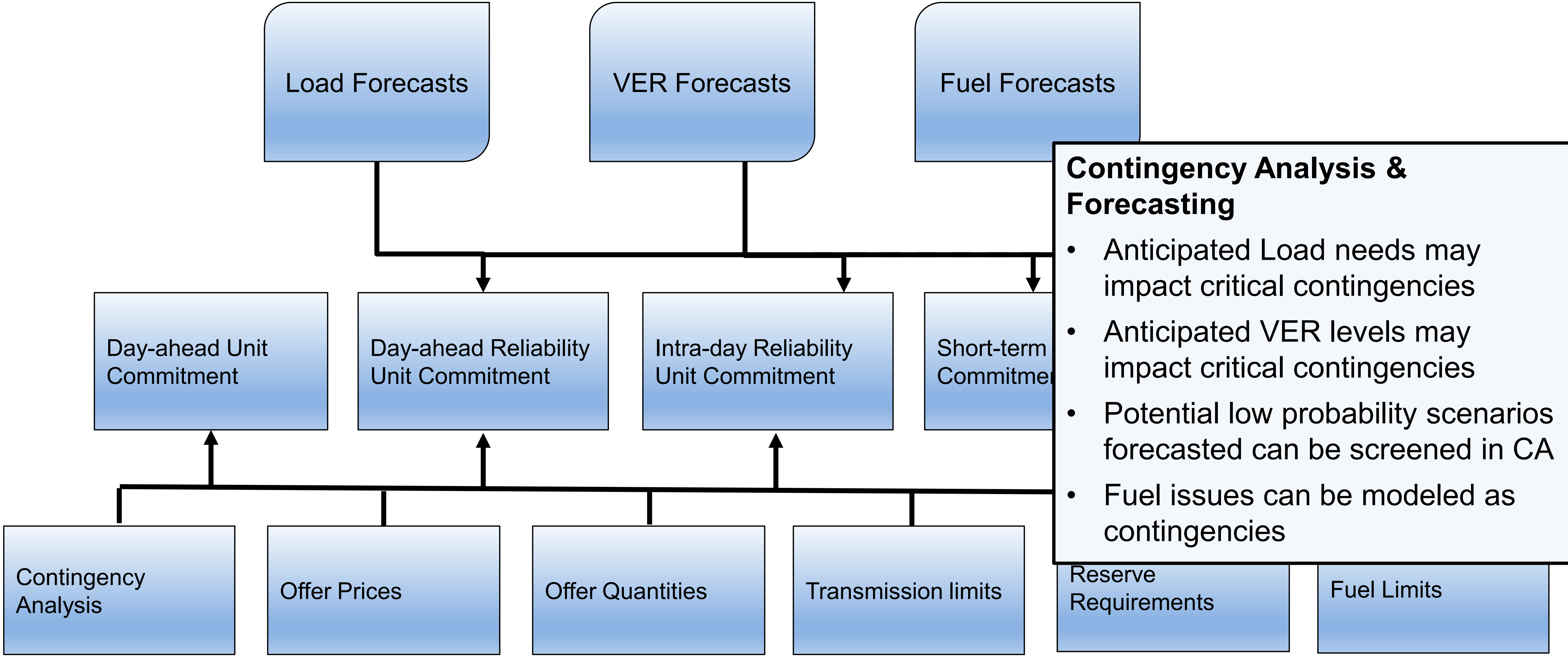
Forecasting Applications

Reserve Requirements & Forecasting

- **Forecasted load levels affect need**
- **VER Forecasts affect need**
- **Uncertainty bounds affect need**
- **Fuel Forecasts may affect needs**



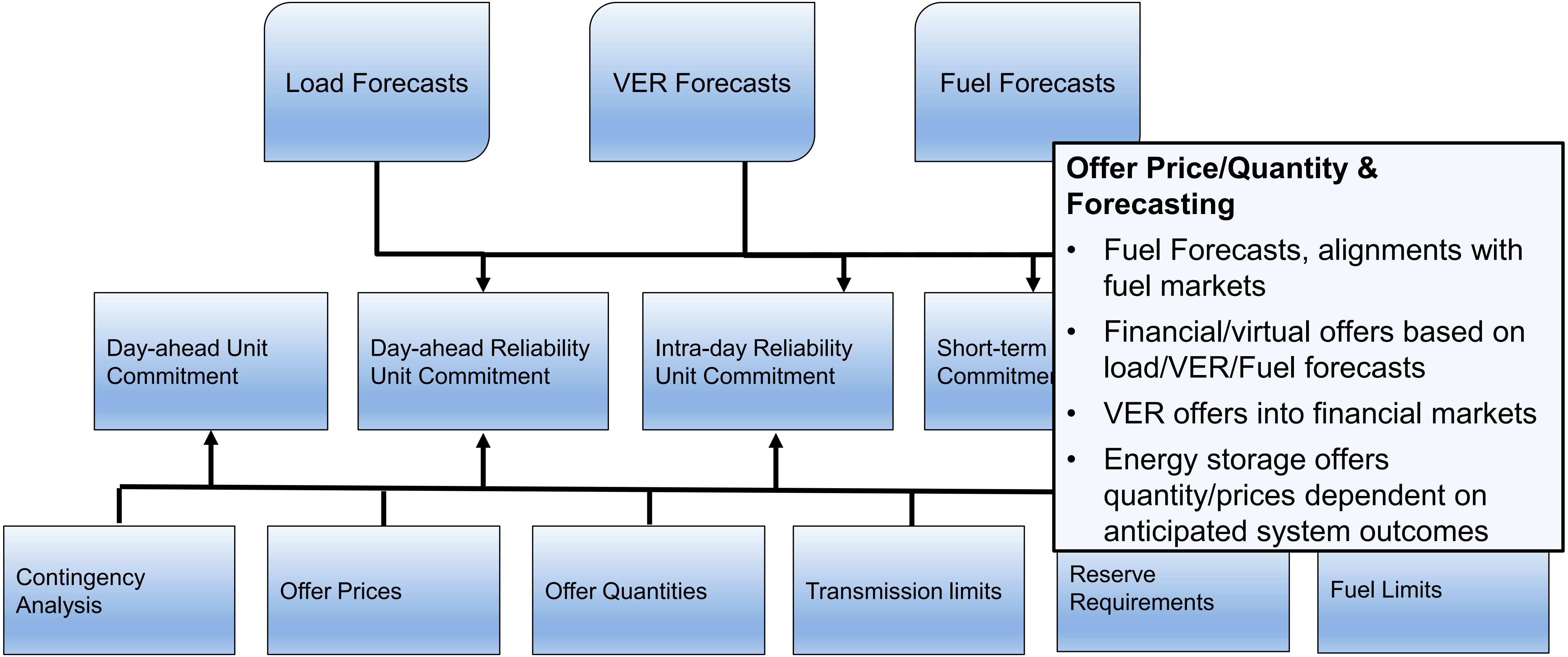
Forecasting Applications



Contingency Analysis & Forecasting

- Anticipated Load needs may impact critical contingencies
- Anticipated VER levels may impact critical contingencies
- Potential low probability scenarios forecasted can be screened in CA
- Fuel issues can be modeled as contingencies

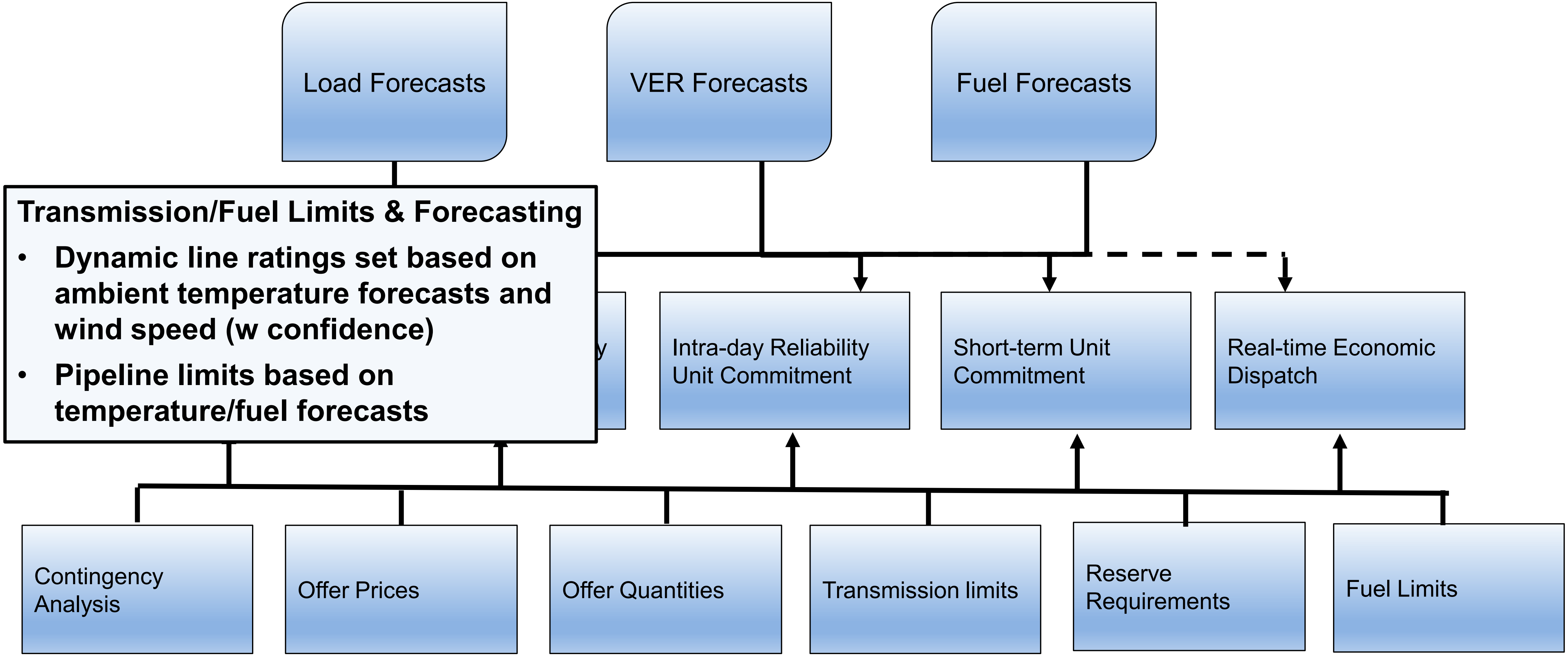
Forecasting Applications



Offer Price/Quantity & Forecasting

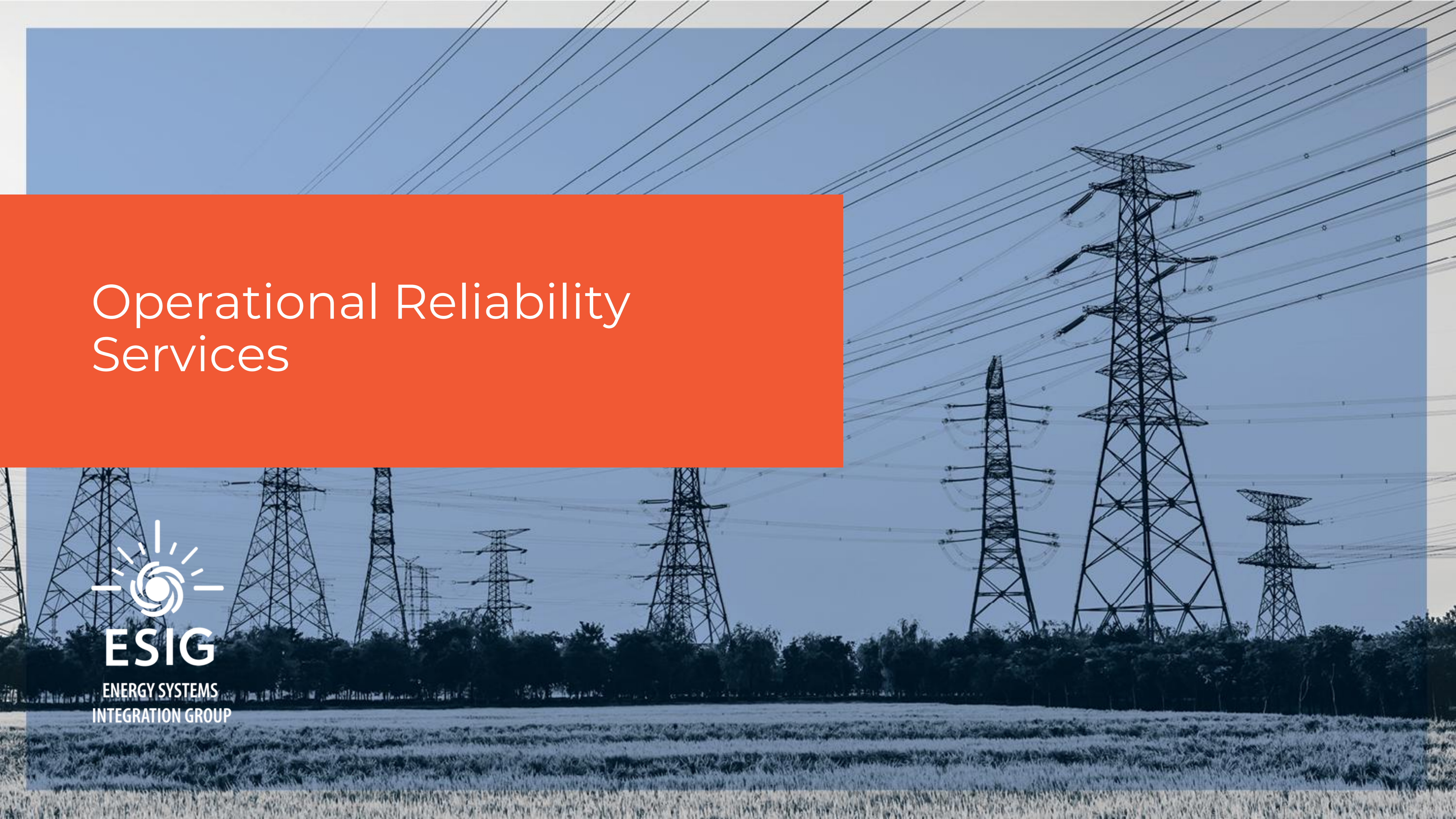
- Fuel Forecasts, alignments with fuel markets
- Financial/virtual offers based on load/VER/Fuel forecasts
- VER offers into financial markets
- Energy storage offers quantity/prices dependent on anticipated system outcomes

Forecasting Applications

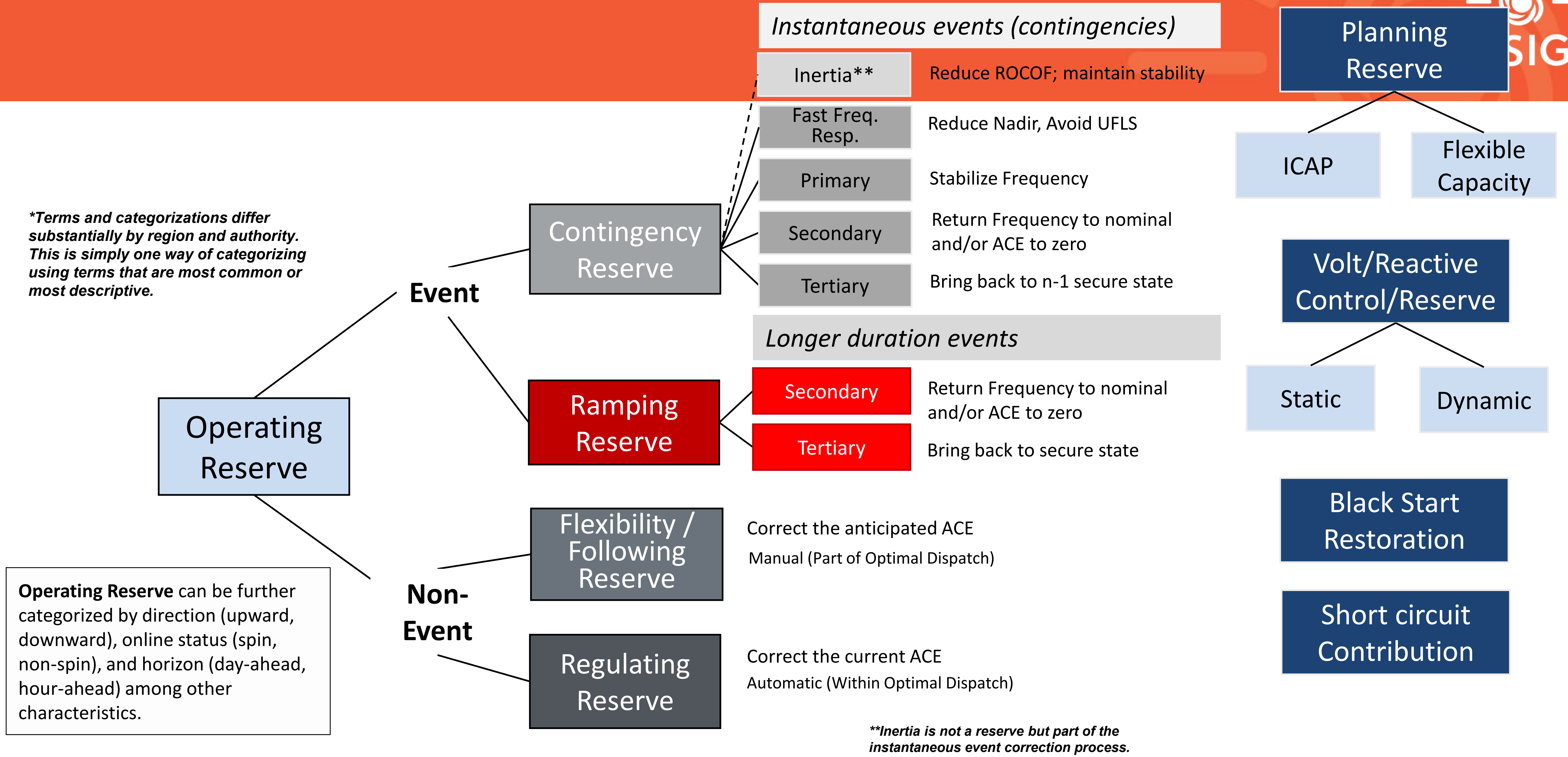


Questions

Operational Reliability Services

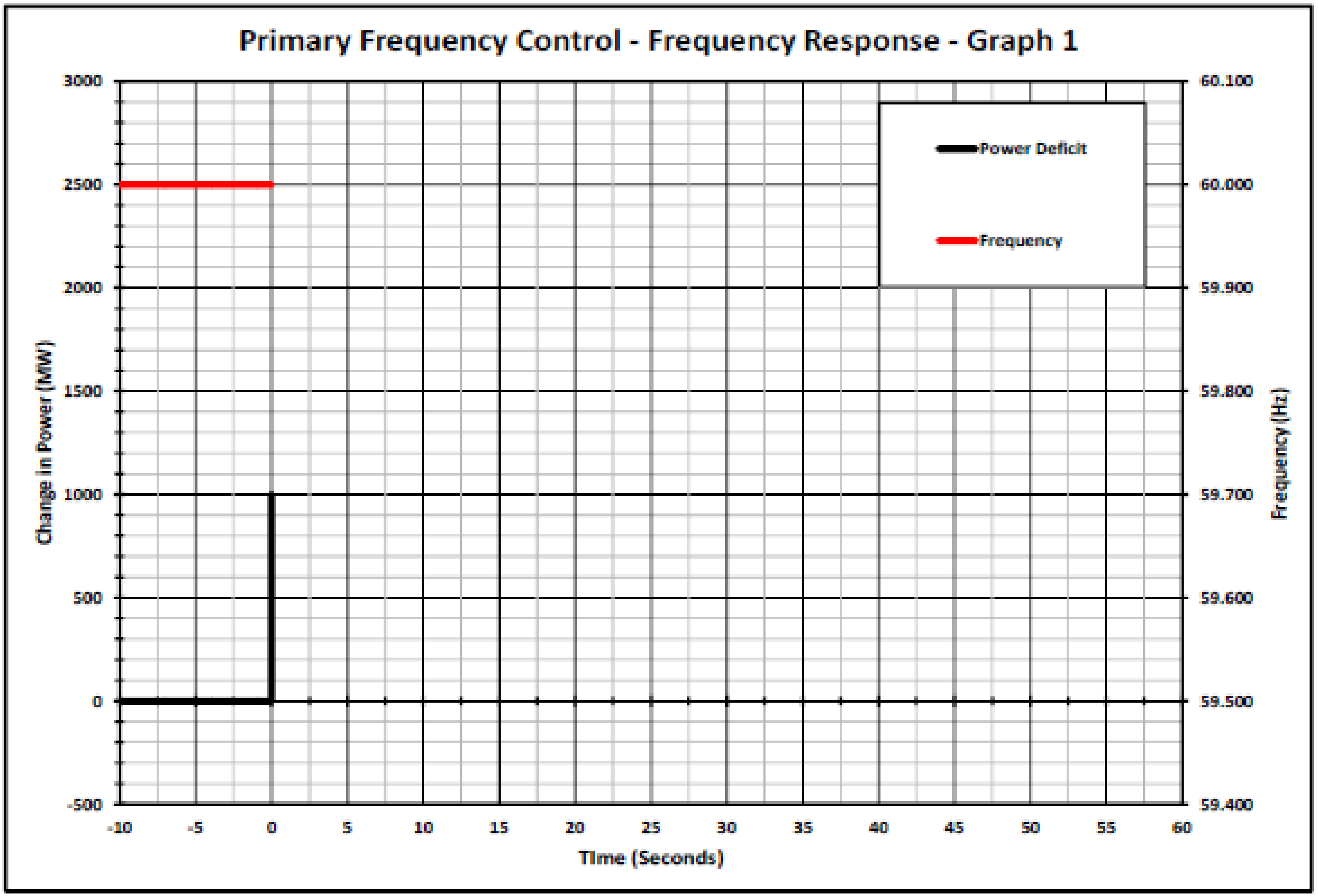


Ancillary Services (Bulk Power System)



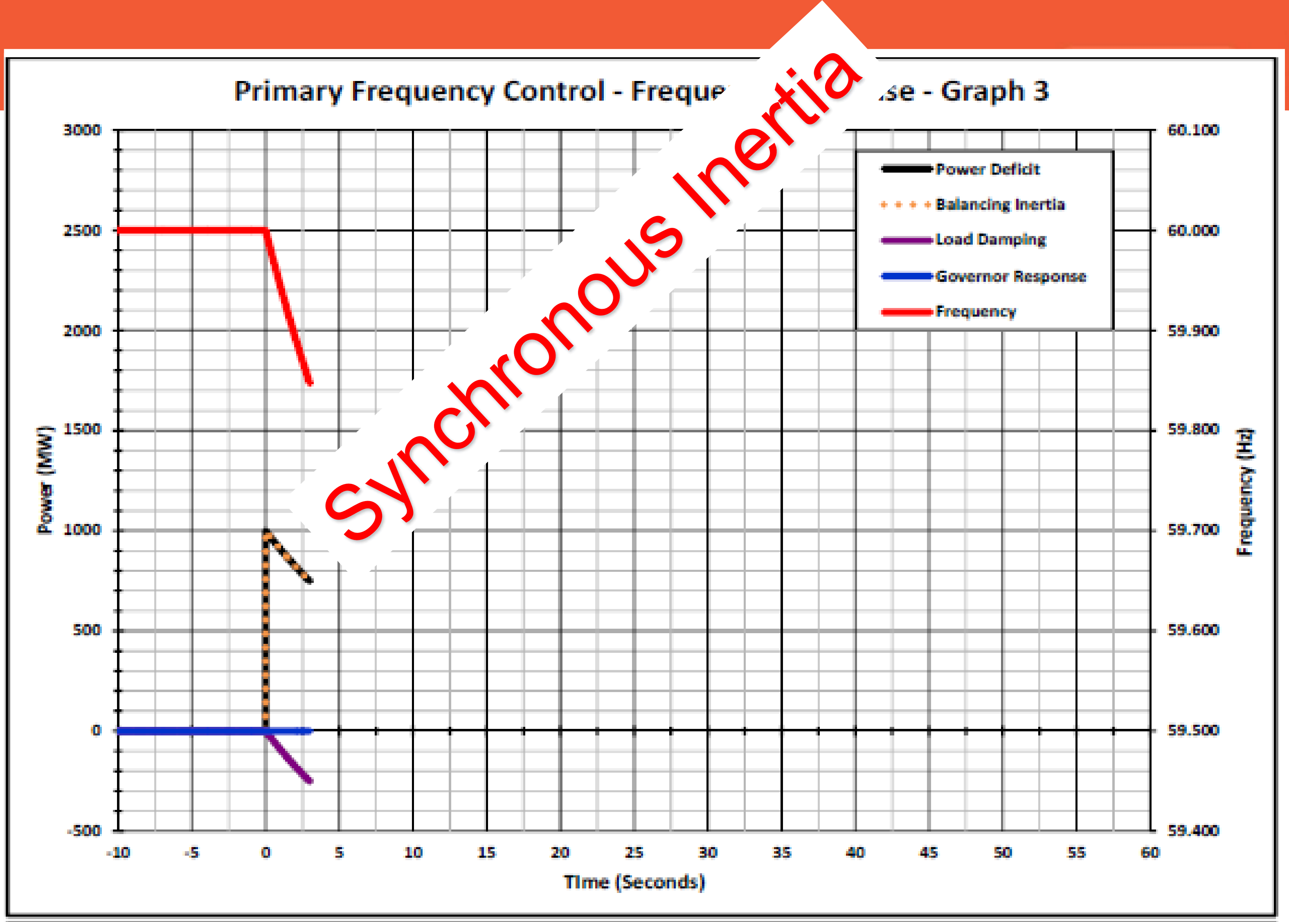
Adapted from Ela et al., *An Enhanced Dynamic Reserve Method for Balancing Areas*, EPRI, Palo Alto, CA: 2017. 3002010941.

Frequency Control

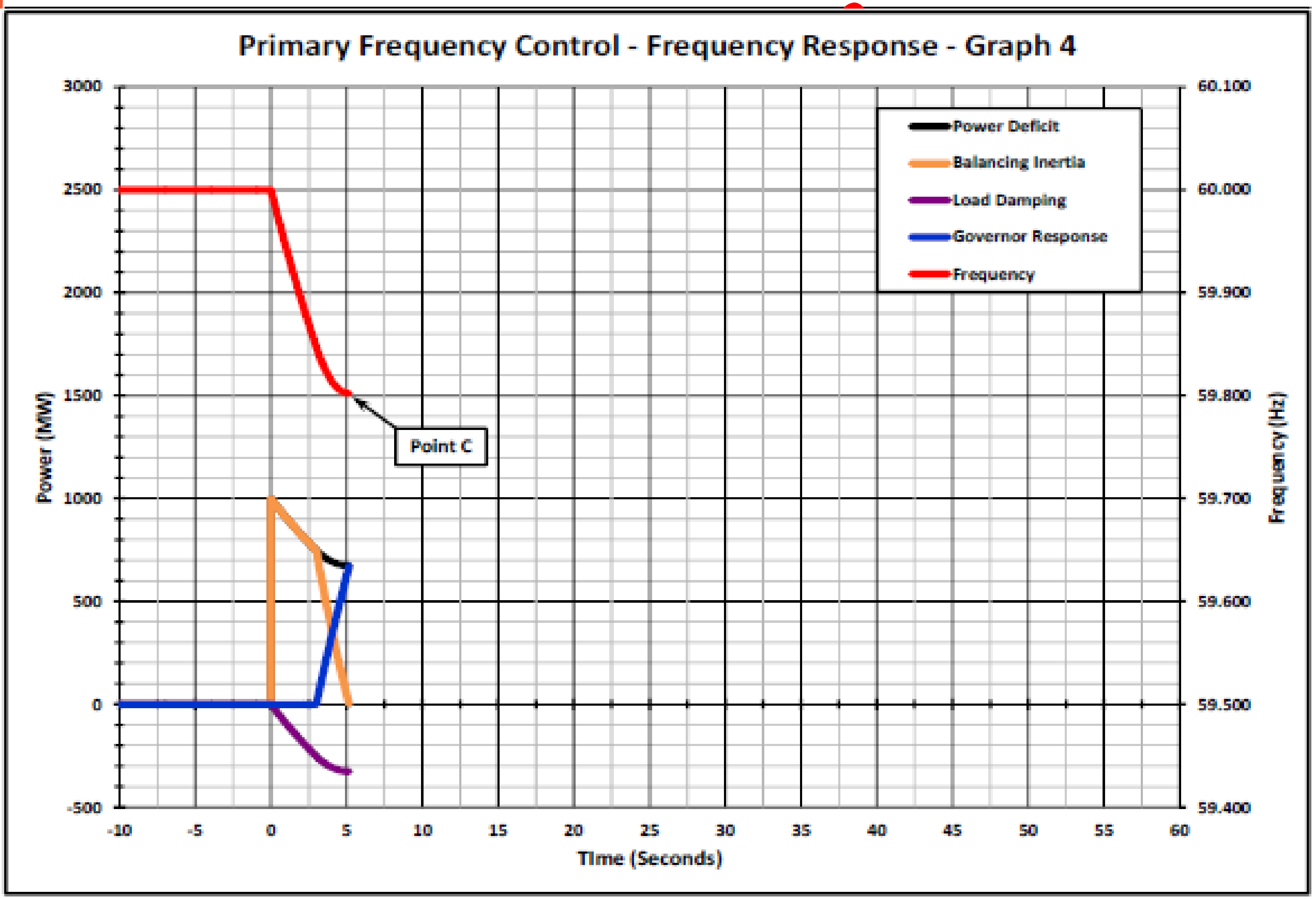


Citation

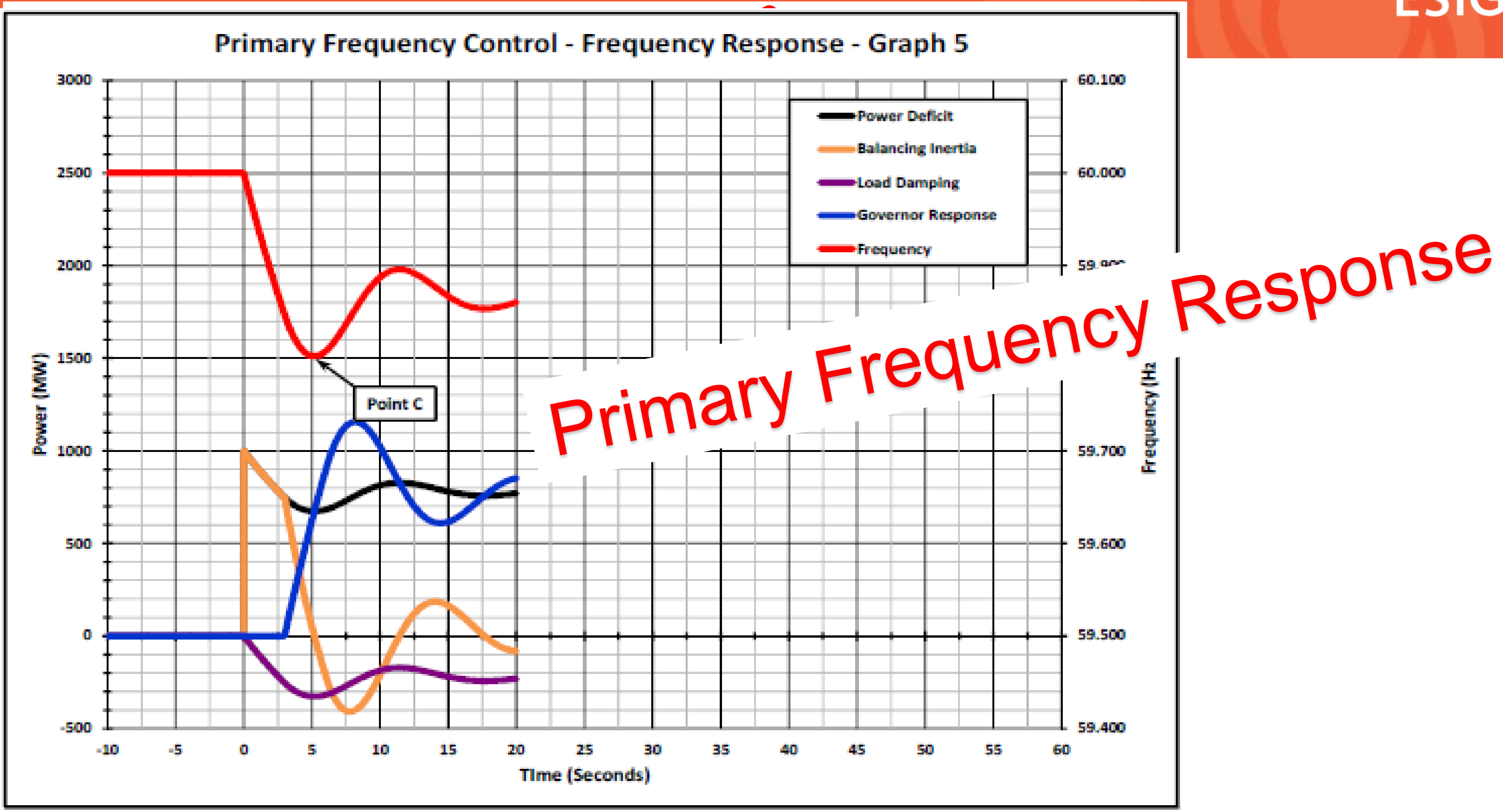
Frequency Control



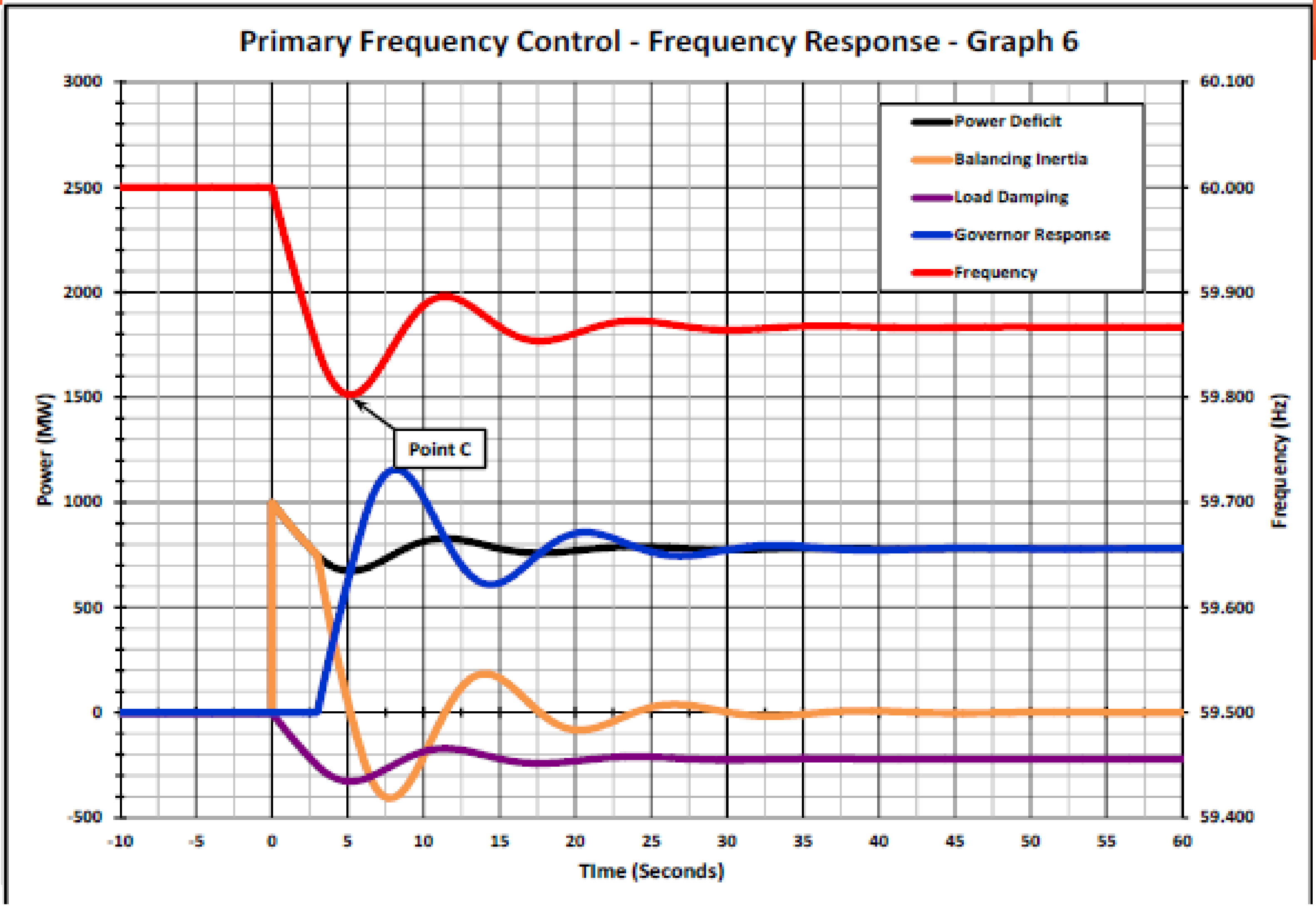
Frequency Control



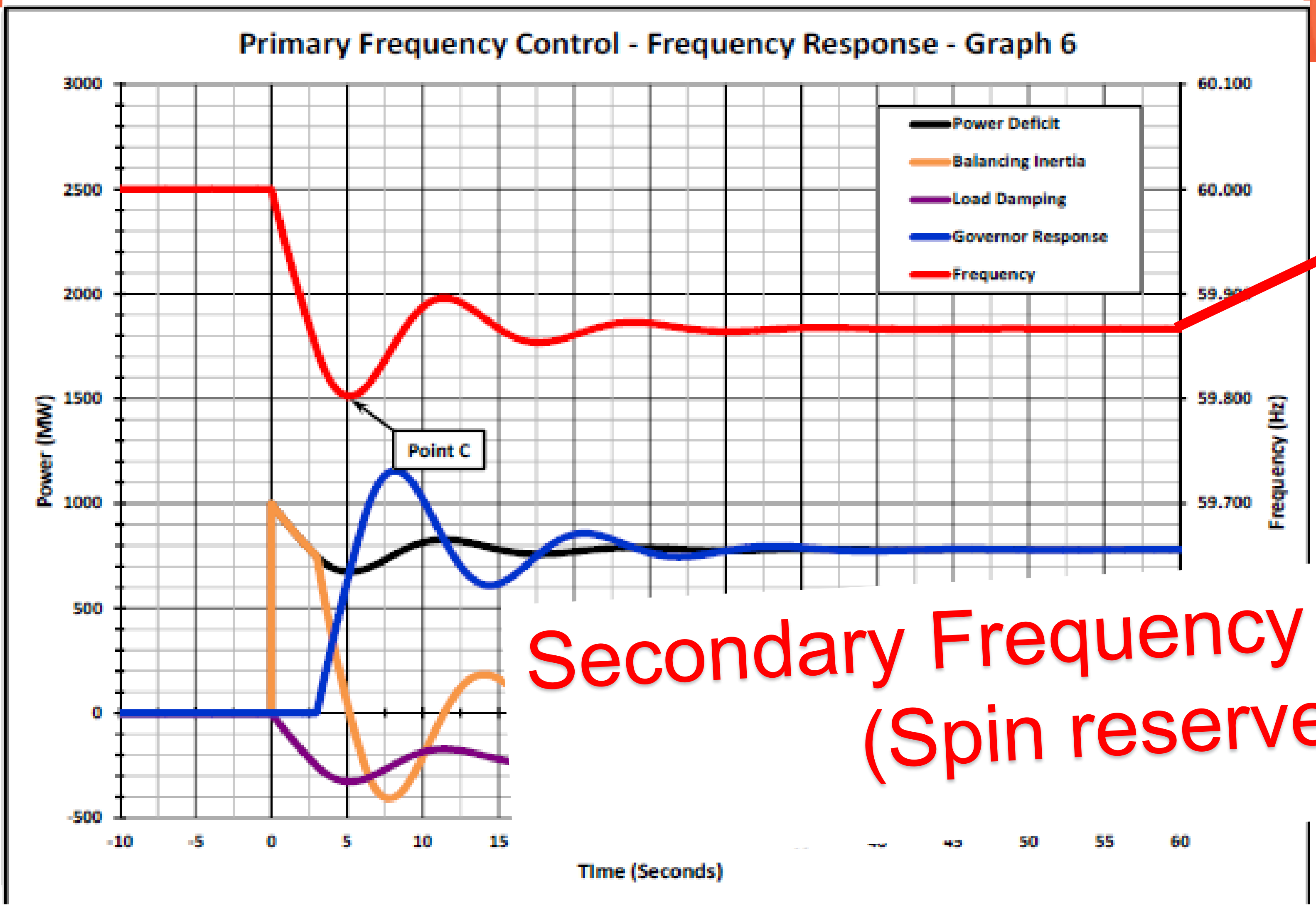
Frequency Control



Frequency Control



Frequency Control



Secondary Frequency Response
(Spin reserve)

Primary Frequency Response (PFR) vs. Regulation

ESIG

Primary Frequency Response

- PFR is proportional to frequency deviation and stabilizes frequency, but does not correct frequency deviation
- Corrects imbalances across interconnection
- Autonomous local control
- Typically for large contingency events
- Requirement through frequency response obligation (FRO)
- U.S. resource capability requirement; markets absent

Regulation

- Regulation brings ACE to zero, which due to frequency bias, also corrects frequency deviation
- Only corrects for imbalances within area
- Through AGC, as directed by system operator
- Used in a continuous basis with a much lower dead band
- Performance through CPS1 and BAAL
- No individual resource requirement; markets common across all regions

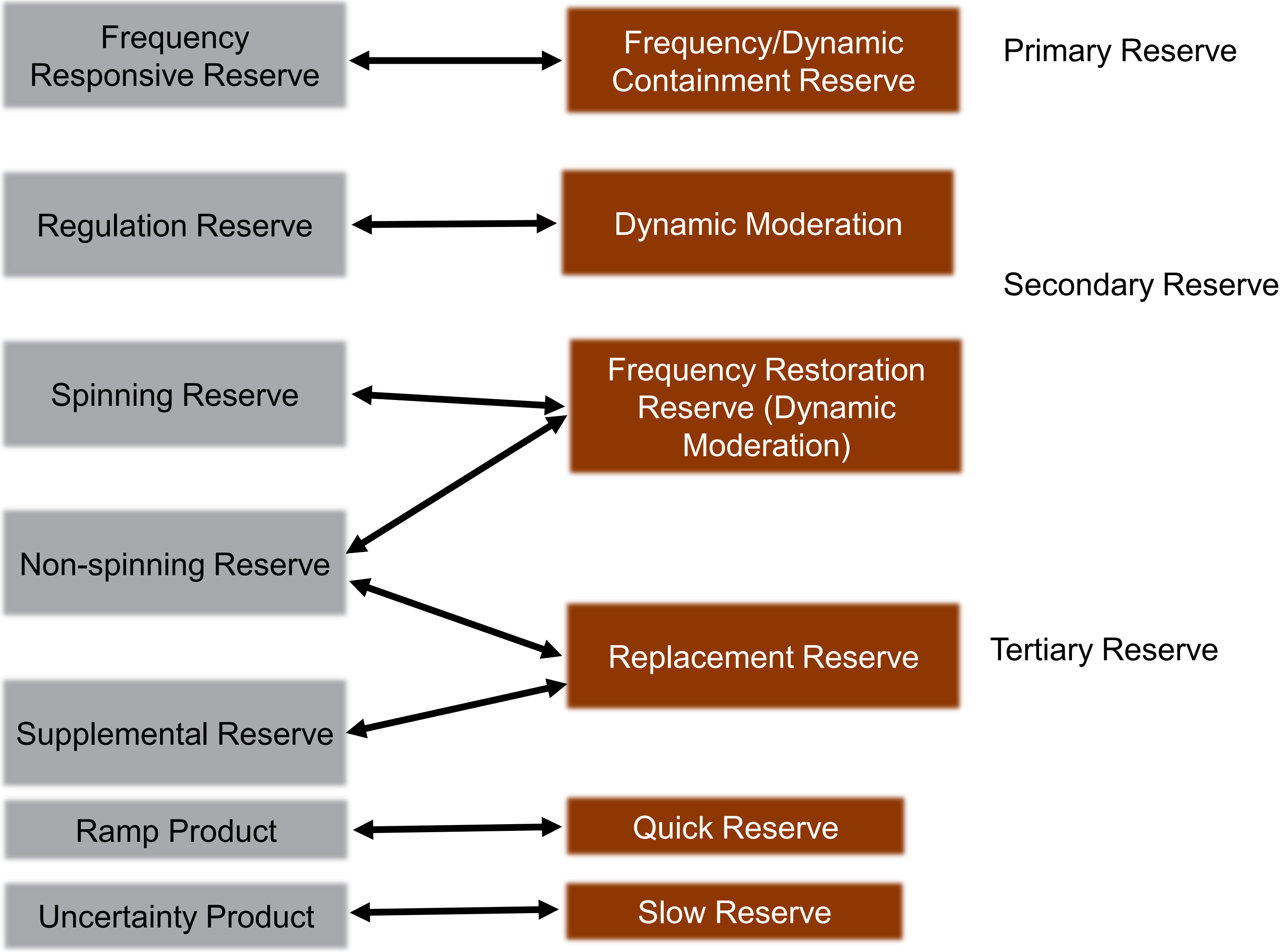
Regulation ensures that it does not counter what the area should be providing of PFR through frequency bias

Relevant NERC Resource Demand Balancing (BAL) Standards

ESIG

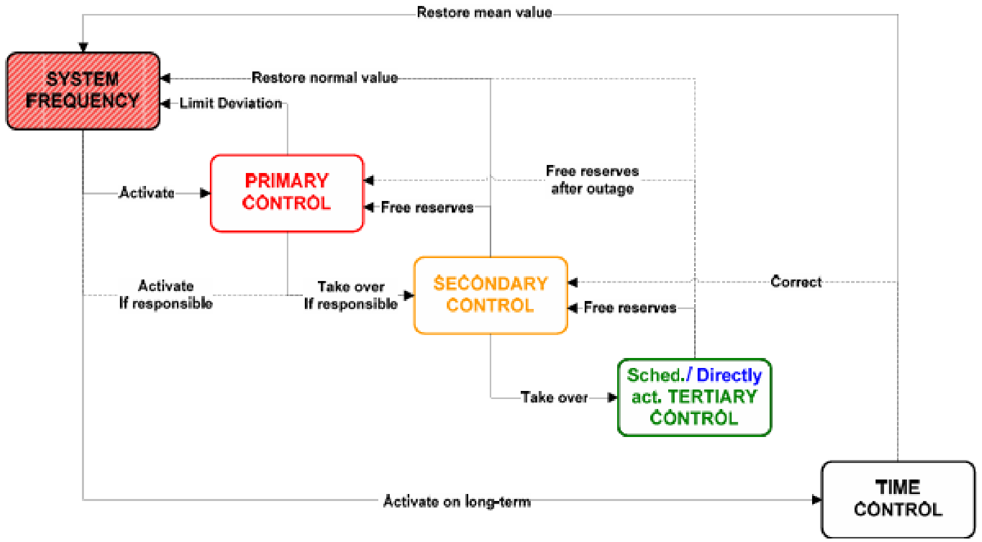
- **BAL-001-2**: Balancing Authority's must comply with Control Performance Standard 1 (CPS1 – 12-month average of how much BA may negatively impact frequency with its ACE) and the Balancing Authority ACE Limit (BAAL - a frequency-dependent limit that ACE may not exceed for greater than 30 clock minutes). **Impact: Regulating Reserve**
- **BAL-002-3**: The Disturbance Control Standard (DCS) includes recovery of ACE to pre-disturbance level within 15-minutes, and a requirement of contingency reserve that is greater or equal to the largest contingency. **Impact: Contingency (Secondary) Reserve**
- **BAL-003-2**: The Frequency Response Obligation (FRO) requires a minimum amount of frequency response for balancing areas, and specific requirements for frequency bias that is used in the ACE equation **Impact: Contingency (Primary) Reserve**
- Some regional entities (e.g., **NPCC Directory #5**) may require additional reserve products. **Impact: Contingency (Tertiary) Reserve**
- Ramp and Uncertainty Products are typically **applied in markets** and not based on reliability standards. **Impact: Contingency (Tertiary) Reserve**

NERC ENTSO-E/UK Reserve Products Comparison



ENTSO-E Policy 1

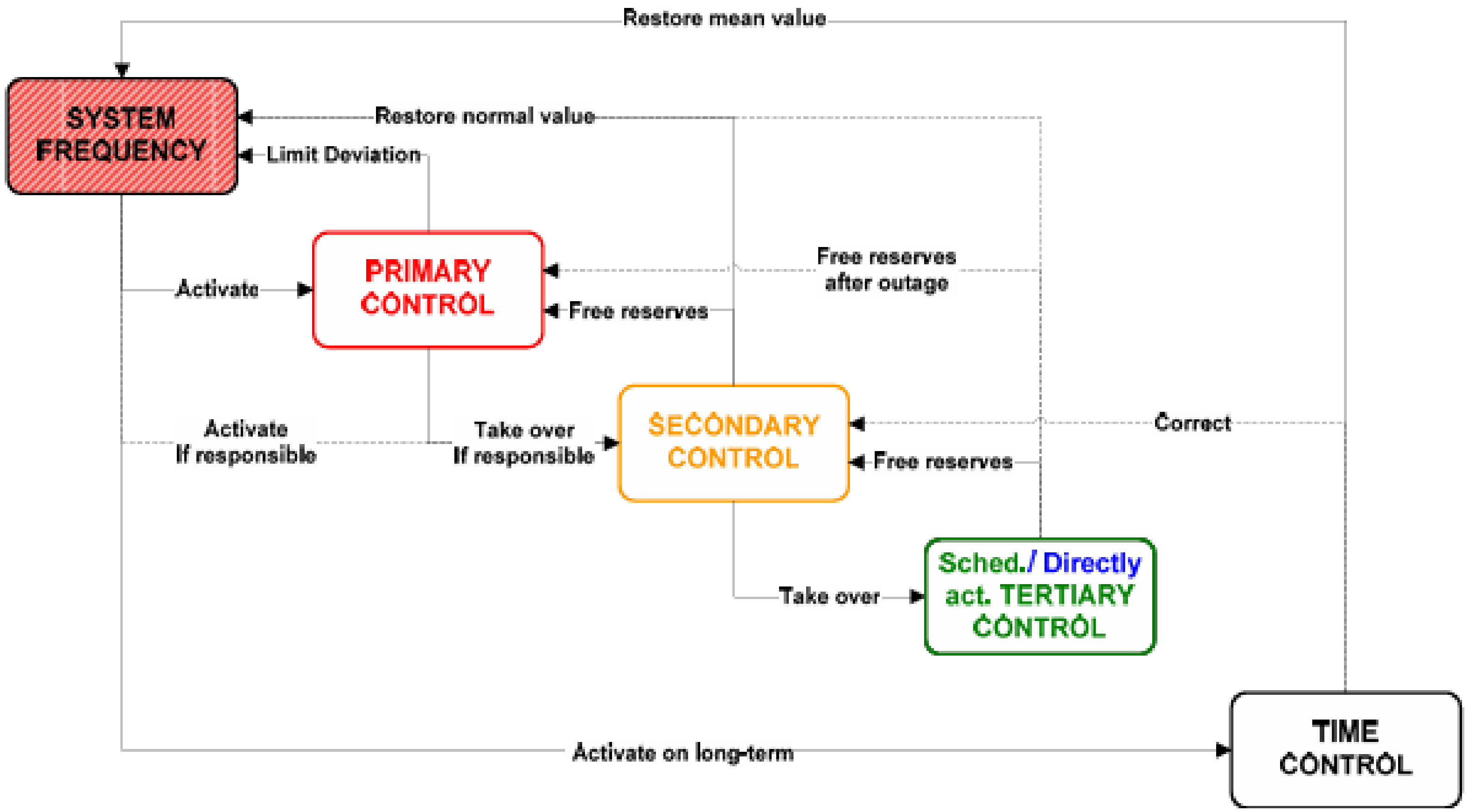
- **Primary Control**: About 3000 MW across the Continental European Synchronous Area, prorated for each TSO based on generation share. Max steady-state frequency deviation of 200 mHz and response requirement of 30 seconds (100% deployment).
  - Requirement based on meeting a once in 20 years probability event
  - More stringent response requirements exist in Ireland, Great Britain, and Northern Europe.



https://eepublicdownloads.entsoe.eu/clean-documents/pre2015/resources/LCFR/130628-NC_LFCR-Issue1.pdf

EU Reserves

- FCR
  - Large deviation
  - Fast and Rough
- aFRR
  - Bring back close to 50Hz
- mFRR
  - Release other reserve
  - Stabilize frequency



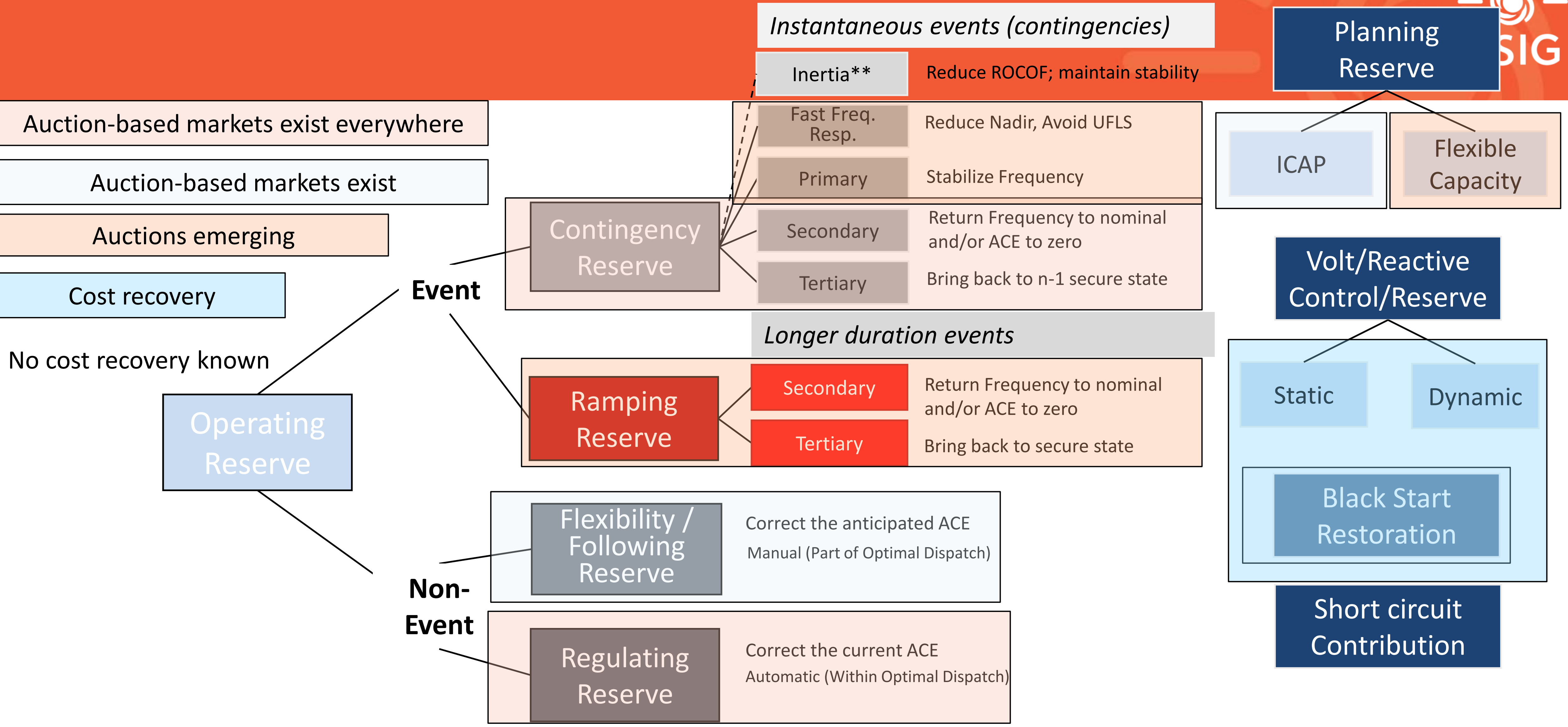
https://eepublicdownloads.entsoe.eu/clean-documents/pre2015/resources/LCFR/130628-NC_LFCR-Issue1.pdf

Questions

Ancillary Service Markets

ESIG
ENERGY SYSTEMS INTEGRATION GROUP

Ancillary Service Compensation in the United States



Inertia is not a reserve but part of the instantaneous event correction process.

Adapted from Ela et al., *An Enhanced Dynamic Reserve Method for Balancing Areas,* EPRI, Palo Alto, CA: 2017. 3002010941.

Ancillary Service Markets in the United States

- Two-Settlement
- Payments for capacity reserved not deployed reserve
- Co-optimization with energy and lost opportunity cost
- Pricing Hierarchy and Cascading
- Administrative Shortage Pricing
- Market Power mitigation
- Regulation pay for performance

Simultaneous Clearing

	Energy Cost	Capacity	Reserve Cost
Gen1	10 $/MWh	100 MW	1 $/MWh
Gen2	20 $/MWh	100 MW	5 $/MWh
Gen3	25 $/MWh	150 MW	15 $/MWh

Load = 250 MW	Reserve Requirement = 50 MW

Sequential

	Energy Schedule
Gen1	100 MW
Gen2	100 MW
Gen3	50 MW
Total	250 MW

Co-optimized

	Energy Schedule	Reserve
Gen1	100 MW	0 MW
Gen2	50 MW	50 MW
Gen3	100 MW	0 MW
Total	250 MW	50 MW

Lost opportunity Cost

ESIG

- Reflects one of the primary costs incurred to providing a reserve service
- Incentivize resource to provide most important service needed by SO
- Allows for scarcity prices to impact energy prices during critical time periods aligning prices with reliability

	Energy Cost	Capacity	Ramp Rate
Gen1	10 $/MWh	100 MW	1 MW/min
Gen2	20 $/MWh	100 MW	5 MW/min
Gen3	25 $/MWh	150 MW	8 MW/min

Load = 250 MW	Reserve Requirement = 50 MW, 5-minute response required

	Energy Schedule	Reserve
Gen1	100 MW	0 MW
Gen2	100 MW	0 MW
Gen3	50 MW	50 MW
Total	250 MW	50 MW

Lost opportunity Cost

- Reflects one of the primary costs incurred to providing a reserve service
- Incentivize resource to provide most important service needed by SO
- Allows for scarcity prices to impact energy prices during critical time periods aligning prices with reliability

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Gen2	20 $/MWh	100 MW	5 MW/min
Gen3	25 $/MWh	150 MW	8 MW/min

Load = 250 MW	Reserve Requirement = 50 MW, 5-minute response required

	Energy Schedule	Reserve
Gen1	100 MW	0 MW
Gen2	90 MW	10 MW
Gen3	60 MW	40 MW
Total	250 MW	50 MW

Energy Price = $25/MWh

Reserve Price = $5/MWh

Importance of Lost opportunity Cost

ESIG

- Reflects one of the primary costs incurred to providing a reserve service
- Incentivize resource to provide most important service needed by SO
- Allows for scarcity prices to impact energy prices during critical time periods aligning prices with reliability

	Energy Cost	Capacity	Ramp Rate
Gen1	10 $/MWh	100 MW	1 MW/min
Gen2	20 $/MWh	100 MW	5 MW/min
Gen3	25 $/MWh	100 MW	8 MW/min

Load = 250 MW	Reserve Requirement = 60 MW, 5-minute response required	Reserve shortage price = $1,000/MW-h

	Energy Schedule	Reserve	Cost
Gen1	100 MW	0 MW	$1,000
Gen2	90 MW	10 MW	$1,800
Gen3	60 MW	40 MW	$1,500
Penalty	--	10 MW	$10,000
Total	250 MW	60 MW	$14,300

Importance of Lost opportunity Cost

ESIG

- Reflects one of the primary costs incurred to providing a reserve service
- Incentivize resource to provide most important service
- Allows for scarcity prices during critical time periods aligning prices with reliability

	Energy Cost	Capacity	Ramp Rate
Gen1	10 $/MWh	100 MW	1 MW/min
Gen2	20 $/MWh	100 MW	5 MW/min
Gen3	25 $/MWh	100 MW	8 MW/min

Load = 250 MW	Reserve Requirement = 60 MW, 5-minute response required	Reserve shortage price = $1,000/MW-h

To calculate reserve price, add 1 MWh of reserve requirement and find the total cost difference

	Energy Schedule	Reserve	Cost
Gen1	100 MW	0 MW	$1,000
Gen2	90 MW	10 MW	$1,800
Gen3	60 MW	40 MW	$1,500
Penalty	--	10 MW	$10,000
Total	250 MW	60 MW	$14,300

Reserve Price = $1,000/MWh

	Energy Schedule	Reserve	Cost
Gen1	100 MW	0 MW	$1,000
Gen2	90 MW	10 MW	$1,800
Gen3	60 MW	40 MW	$1,500
Penalty	--	11 MW	$11,000
Total	250 MW	60 MW	$15,300

Importance of Lost opportunity Cost

- Reflects one of the primary costs incurred to providing a reserve service
- Incentivize resource to provide most important service
- Allows for scarcity prices during critical time periods aligning prices with reliability

	Energy Cost	Capacity	Ramp Rate
Gen1	10 $/MWh	100 MW	1 MW/min
Gen2	20 $/MWh	100 MW	5 MW/min
Gen3	25 $/MWh	100 MW	8 MW/min

Load = 250 MW	Reserve Requirement = 60 MW, 5-minute response required	Reserve shortage price = $1,000/MW-h

To calculate energy price, add 1 MWh of load demand and find the total cost difference

	Energy Schedule	Reserve	Cost
Gen1	100 MW	0 MW	$1,000
Gen2	90 MW	10 MW	$1,800
Gen3	60 MW	40 MW	$1,500
Penalty	--	10 MW	$10,000
Total	250 MW	60 MW	$14,300

Energy Price = $1,020/MWh

	Energy Schedule	Reserve	Cost
Gen1	100 MW	0 MW	$1,000
Gen2	91 MW	9 MW	$1,820
Gen3	60 MW	40 MW	$1,500
Penalty	--	11 MW	$11,000
Total	251 MW	60 MW	$15,320

Reserve Shortage Pricing

Outside of capacity markets or bilateral contracts, operating reserve shortage values are the predominant way that rent is collected for capital cost recovery and are critical design features in co-optimized energy and ancillary service markets

VOLL based

- Penalty value of the shortages are some derivative of the assumed value of lost load, sometimes multiplied by the probability of loss load

Supply action based

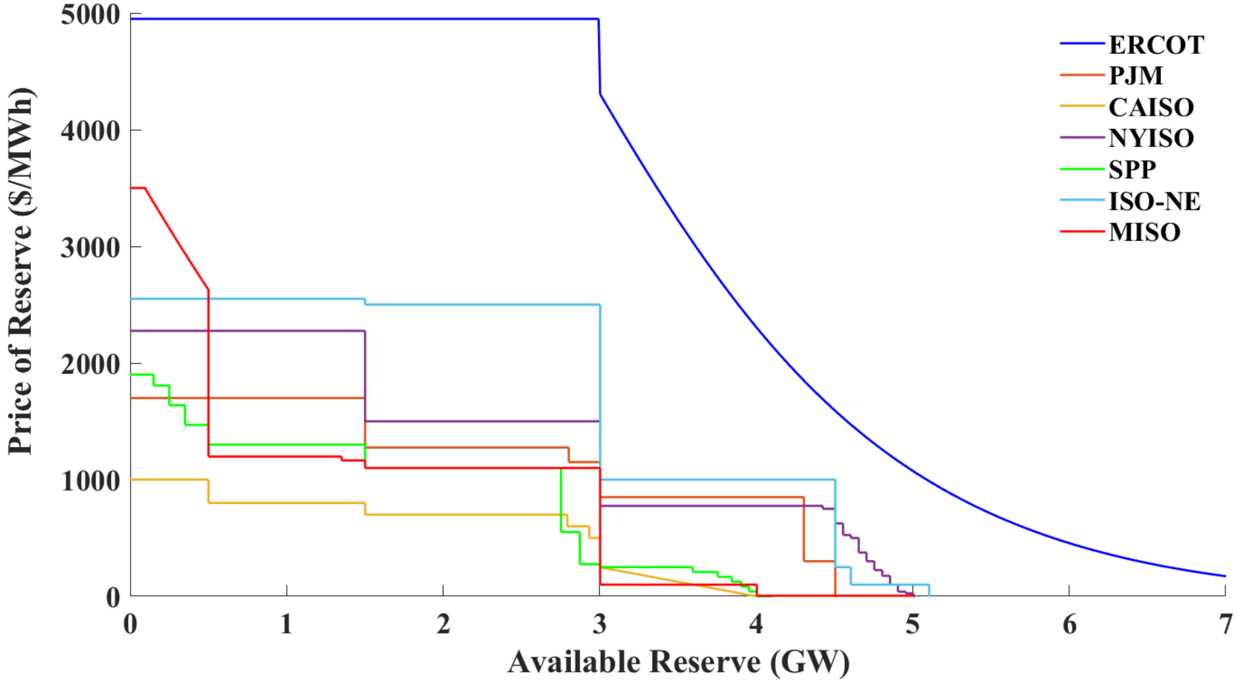
- Penalty value of shortage is based on avoiding the cost of the next action, usually committing a generator

Penalty based

- Penalty value of shortage is based on the reliability penalty incurred from violation of compliance or penalty from leaning on neighboring regions

Ranking

- Penalty value of multiple reserve products are based purely on a hierarchy so that the most valuable products are highest valued and least valuable are lowest

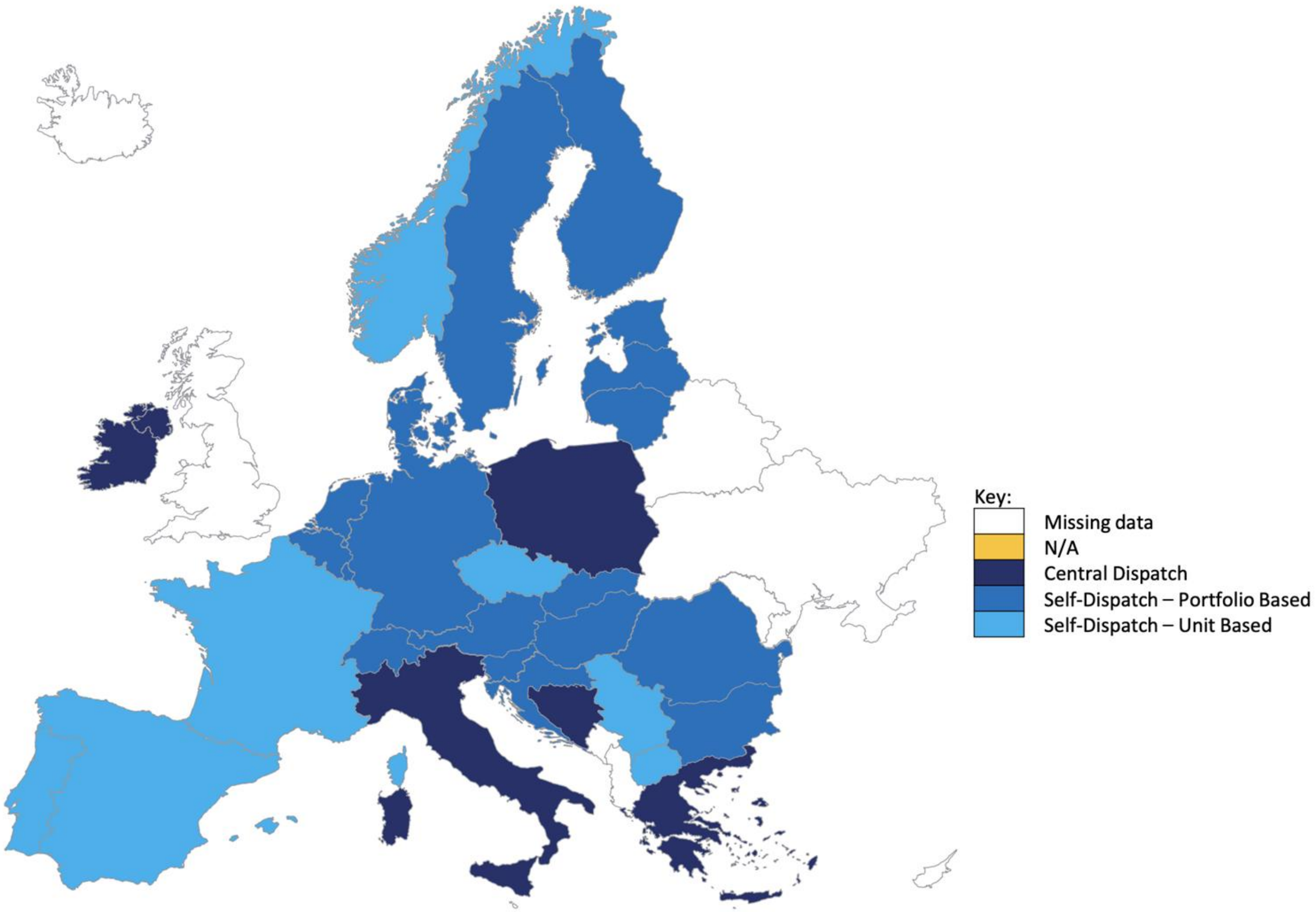


The use of multiple products creates a declining demand curve for reserve that provides higher value placed on procuring reserve as the system gets tighter.

Mehrtash, Hobbs, & Ela, "Reserve and Energy Scarcity Pricing in United States Power Markets: A Comparative Review of Principles and Practices" *Renewable and Sustainable Energy Reviews,* vol. 183 (2023).

Questions

Different balancing approaches across Europe



Source: Survey on Ancillary services procurement Balancing market design 2022

Types of Balancing Processes

Central Dispatch

A scheduling and dispatching model where the generation schedules and consumption schedules as well as dispatching of power generating facilities and demand facilities, in reference to dispatchable facilities, are determined by a TSO within the integrated scheduling process.

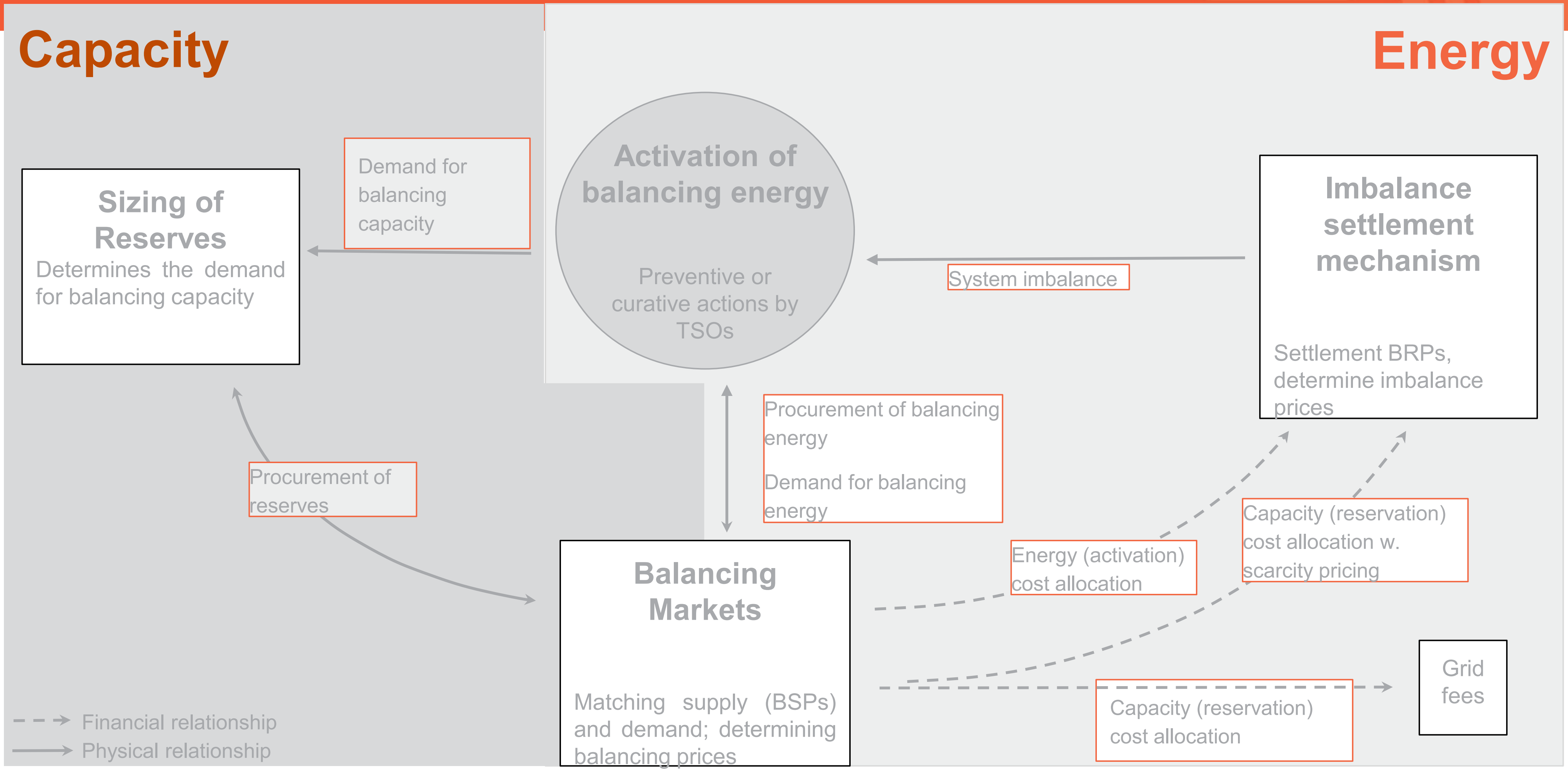
Self-Dispatch: Portfolio Based

Portfolio based means a scheduling and dispatching model where the aggregated generation schedules and consumption schedules as well as dispatching of power generating facilities and demand facilities are determined by the scheduling agents of those facilities.

Self-Dispatch: Unit based

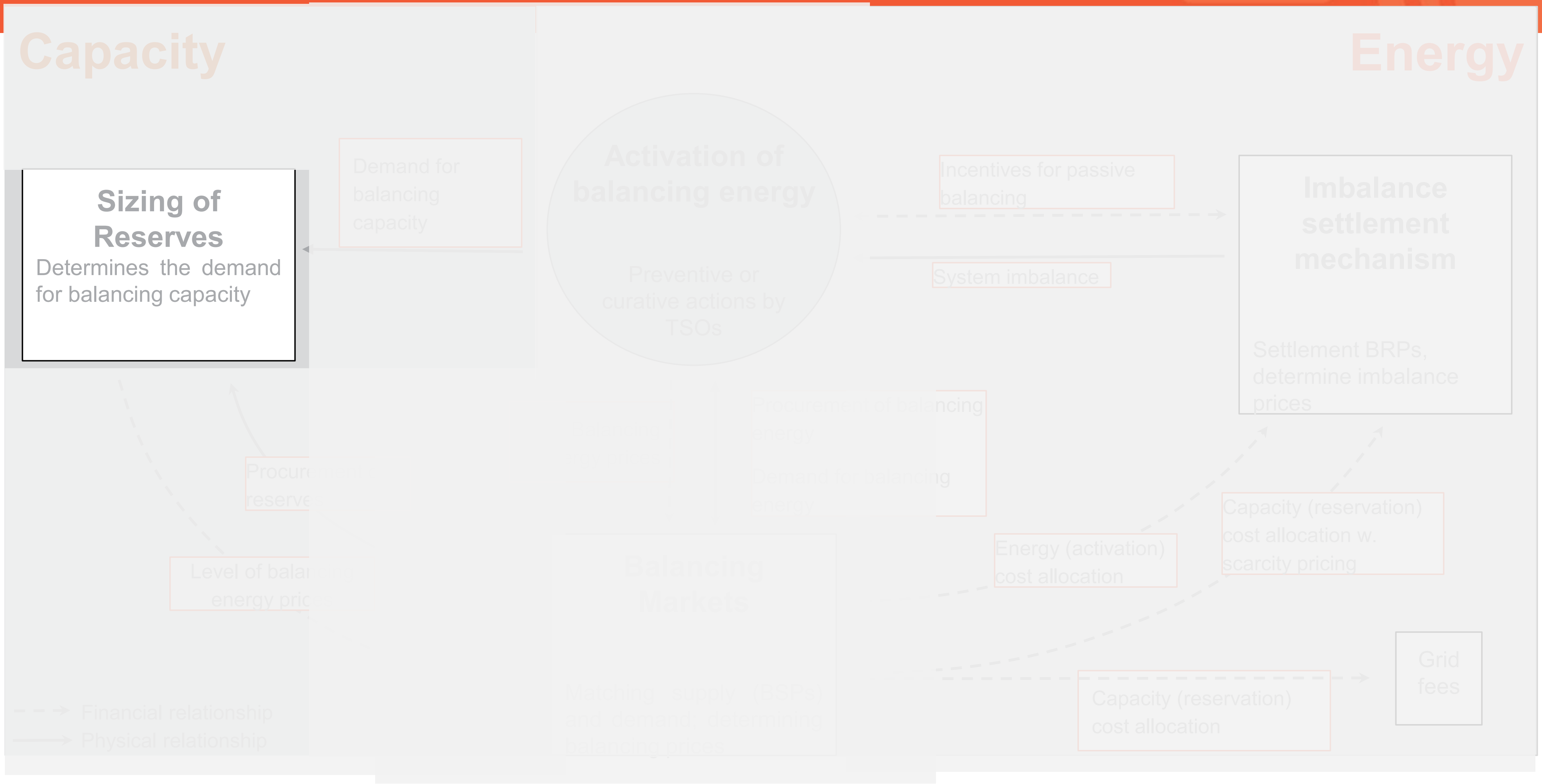
Unit based means a scheduling and dispatching model where power generating facilities and demand facilities follow their own generation schedules or consumption schedules.

The four building blocks of Balancing



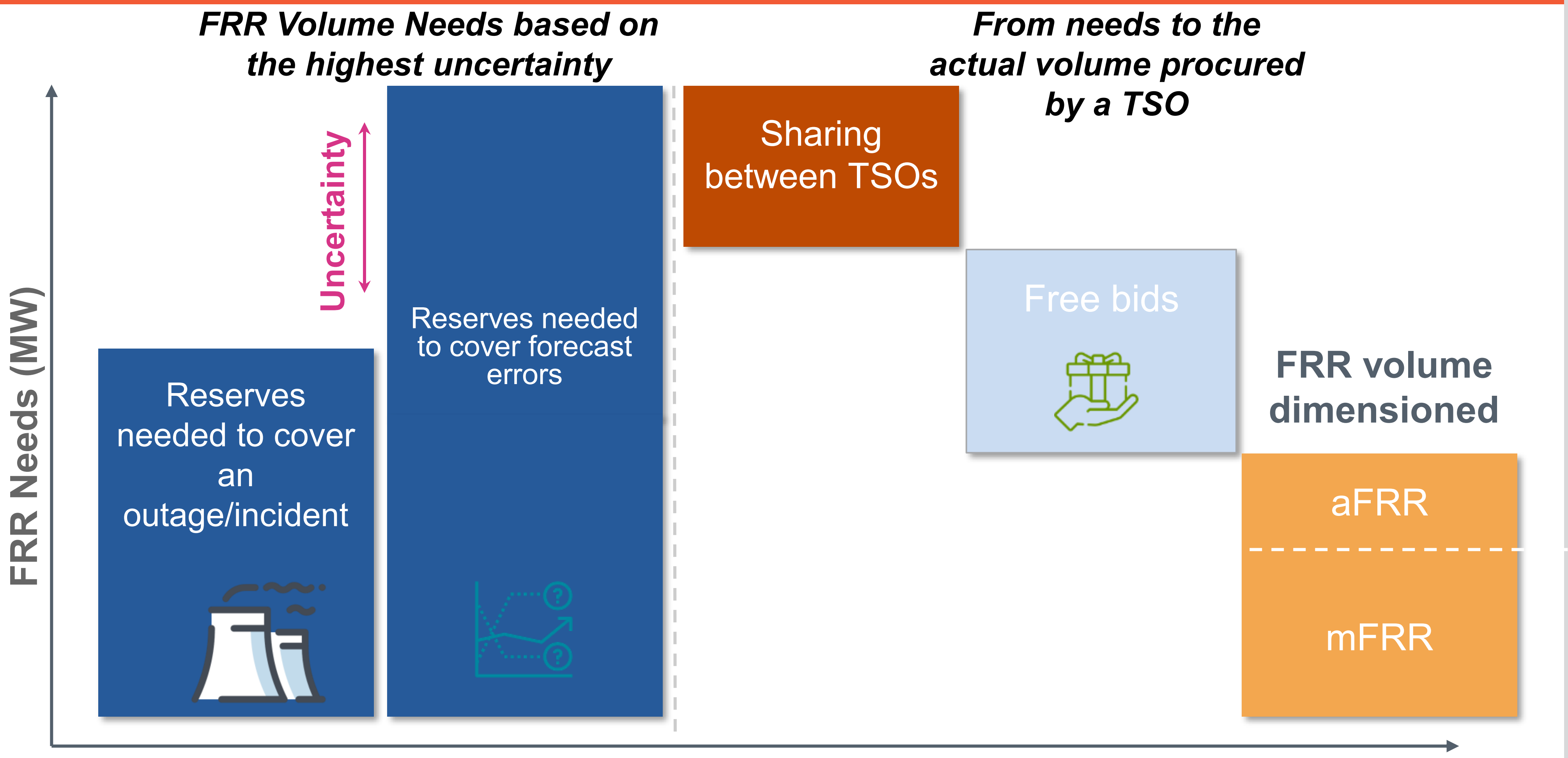
Adapted from: The EU Electricity Network Codes (2020 Ed.)

The four building blocks of Balancing in EU



Adapted from: The EU Electricity Network Codes (2020 Ed.)

Sizing of reserves for one LFC Area



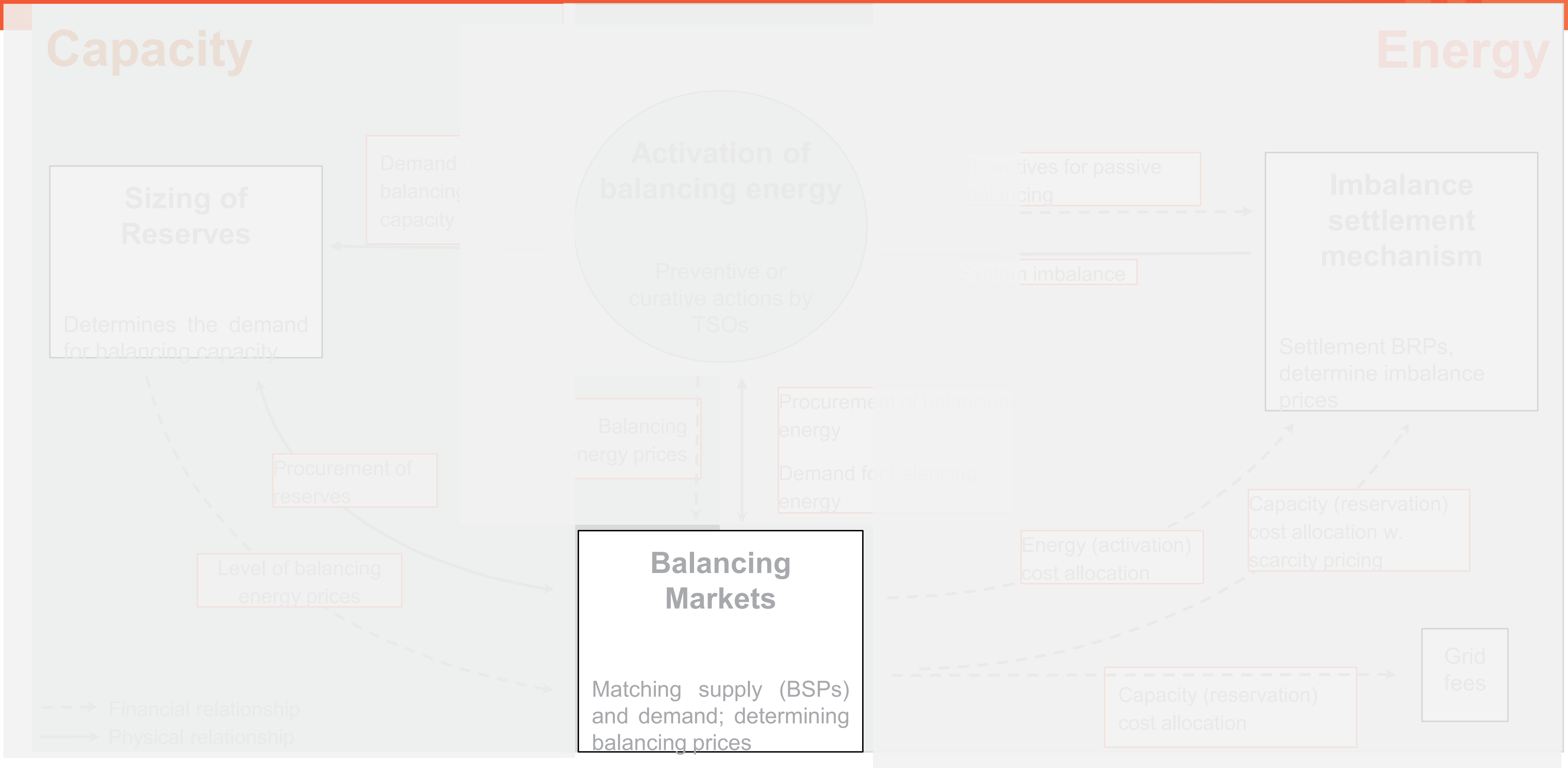
Elia-style

Elia disposes of reserve sharing agreements on mFRR with RTE, TENNET, AMPRION and NESO that facilitate the sharing of mFRR with neighbouring TSOs.

Free bids are submitted by market participants without a prior obligation with the TSO.

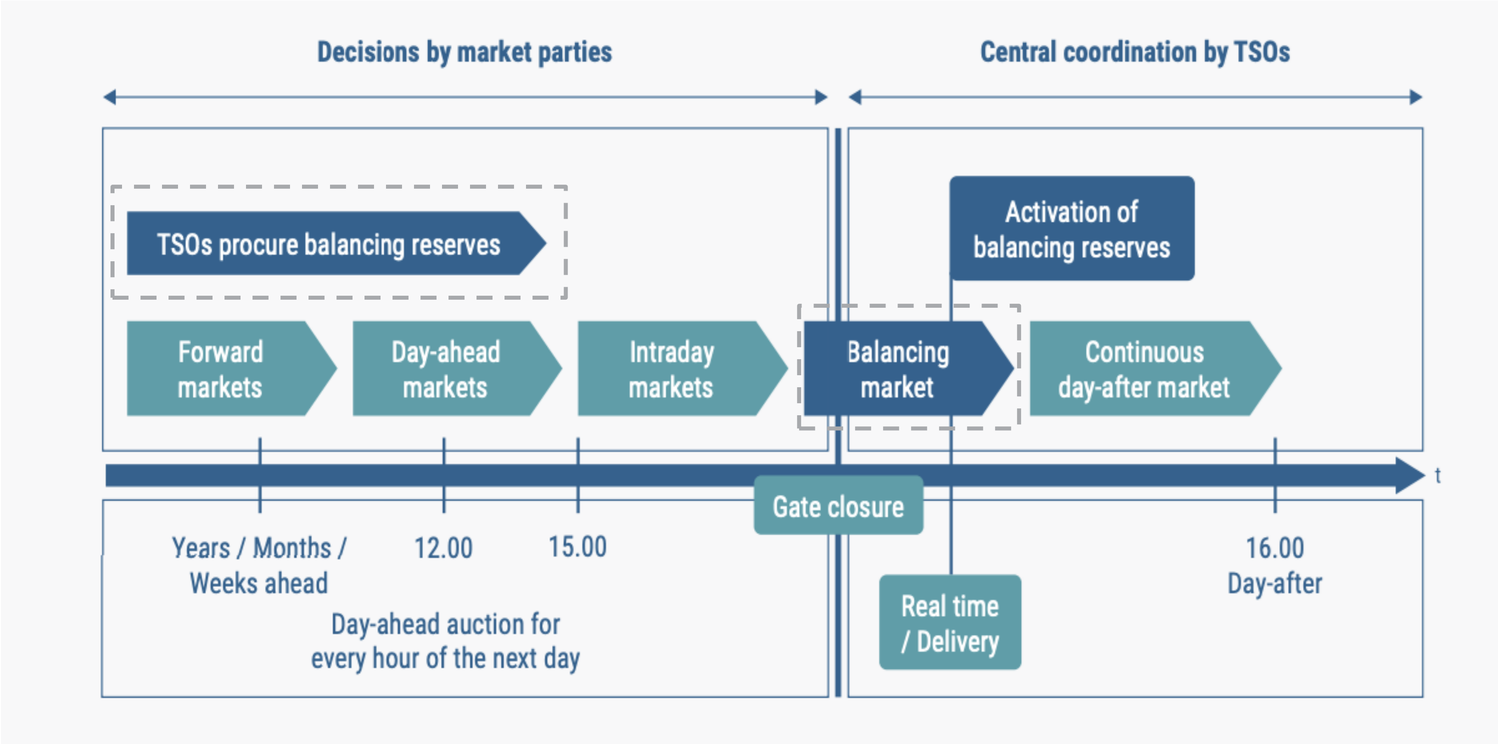
Final FRR volume dimensioned should contain a percentage of aFRR and mFRR.

The four building blocks of Balancing in EU



Adapted from: [The EU Electricity Network Codes (2020 Ed.)]

Timeline of operations: Balancing & Energy



Balancing <u>Capacity</u> Markets

Secure the minimum amount of assets able to provide balancing services to ensure sufficient balancing energy bids in real time.

All awarded assets receive a capacity remuneration.

Operated by the national TSOs

Balancing <u>Energy</u> Markets

Ensure efficient usage of available reserves (i.e. merit order based activation)

In these markets, they cover the aggregated imbalance caused by BRPs' deviations from their market positions (system imbalance).

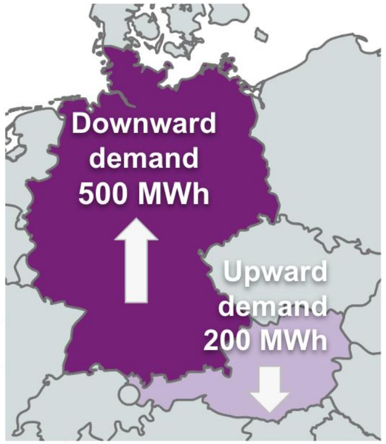
BSPs are dispatched based on their balancing energy bid, a price-quantity pair that represents the limit price at which they are willing to be activated and the maximum quantity that they can deliver.

Degrees of coordination: Activation of balancing

Autarky

No cooperation between TSOs.

Without coordination on the activation of demand for balancing energy

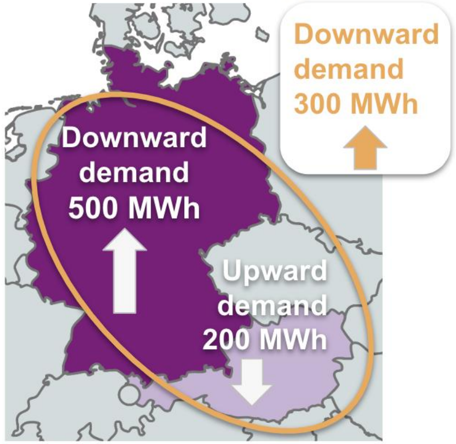


Imbalance netting

Coordination of imbalances to avoid inefficiencies.

Imbalance netting avoids counteracting activation of balancing energy in adjacent TSO zones.

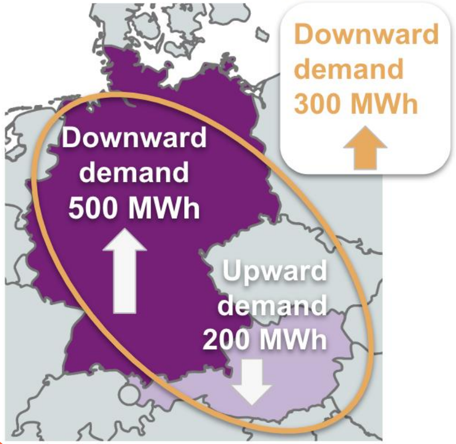
With coordination on the activation of demand for balancing energy

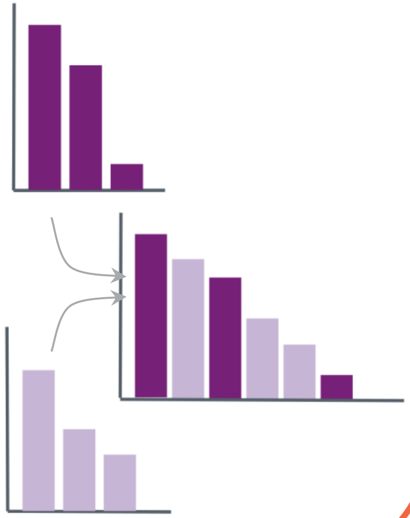


Exchange

Cooperating TSOs construct a **common merit order** of balancing energy bids and select the least-cost activation that meets the net imbalance of the joint TSO zone, given that sufficient CZC is available. This reduces activation costs.

With coordination on the activation of demand for balancing energy





The Platforms for the Exchange of Balancing Energy

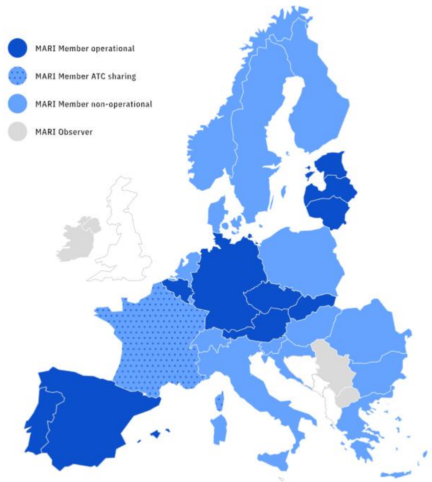
ESIG

IGCC

Avoiding the simultaneous activation of FRR in opposite directions (imbalance netting) through aFRR's AGC controllers

Economic surplus: 620 M€ in 2023

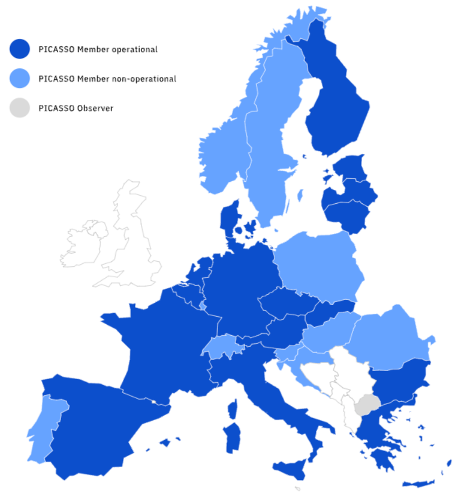
MARI



Exchange of mFRR activation via standard products

Economic surplus: 10 M€ in 2023

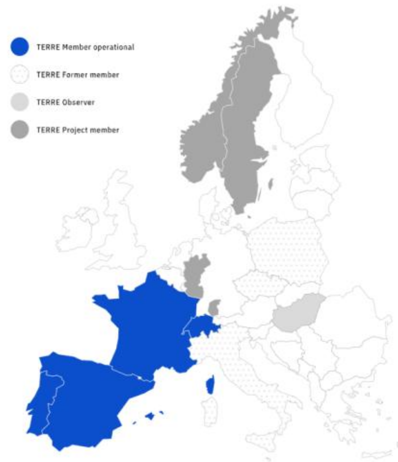
PICASSO



Exchange of aFRR activations via standard products

Economic surplus:135 M€ in 2023

TERRE

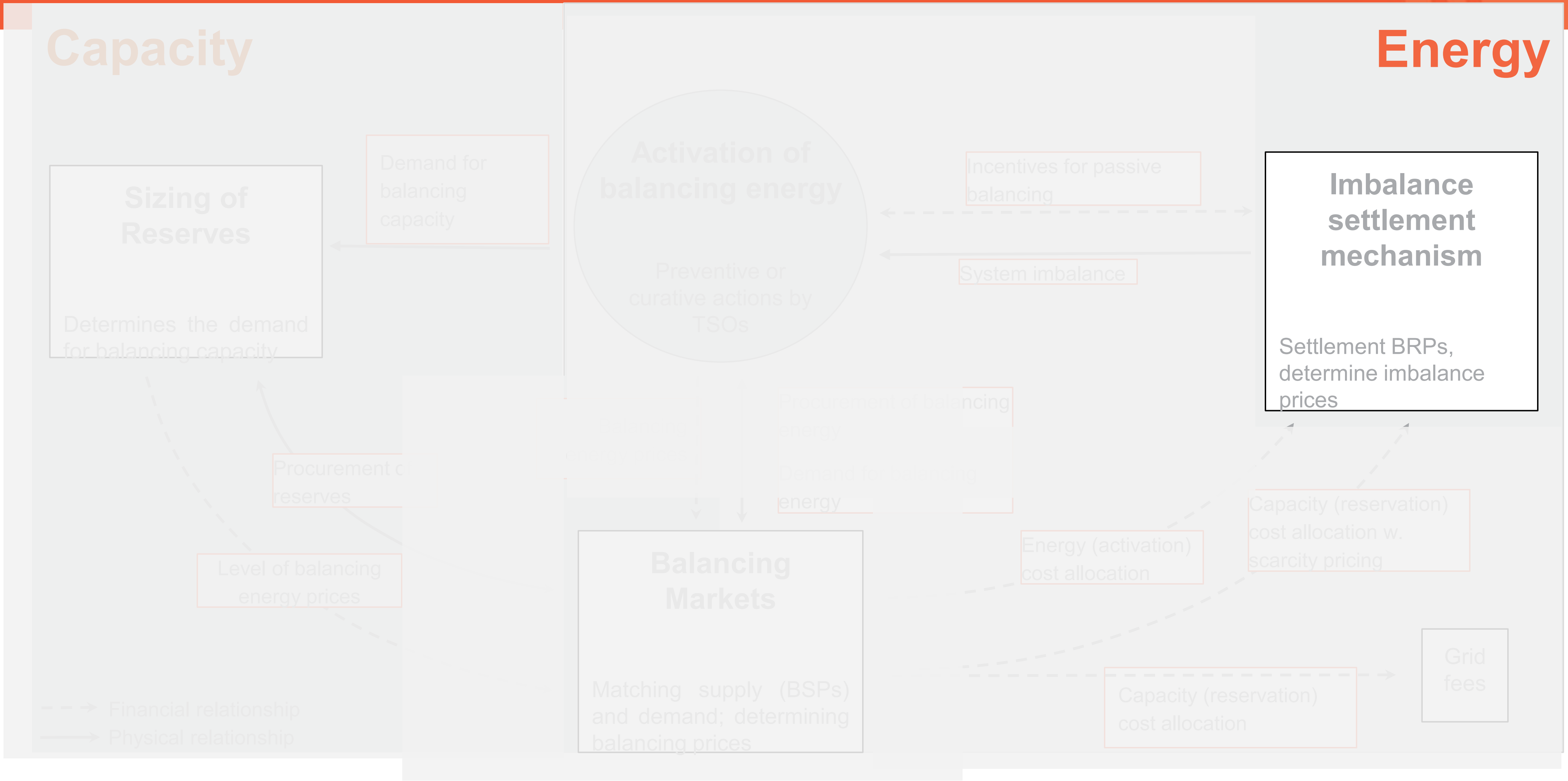


Exchange of RR activation via standard products

Economic surplus: 280 M€ in 2023

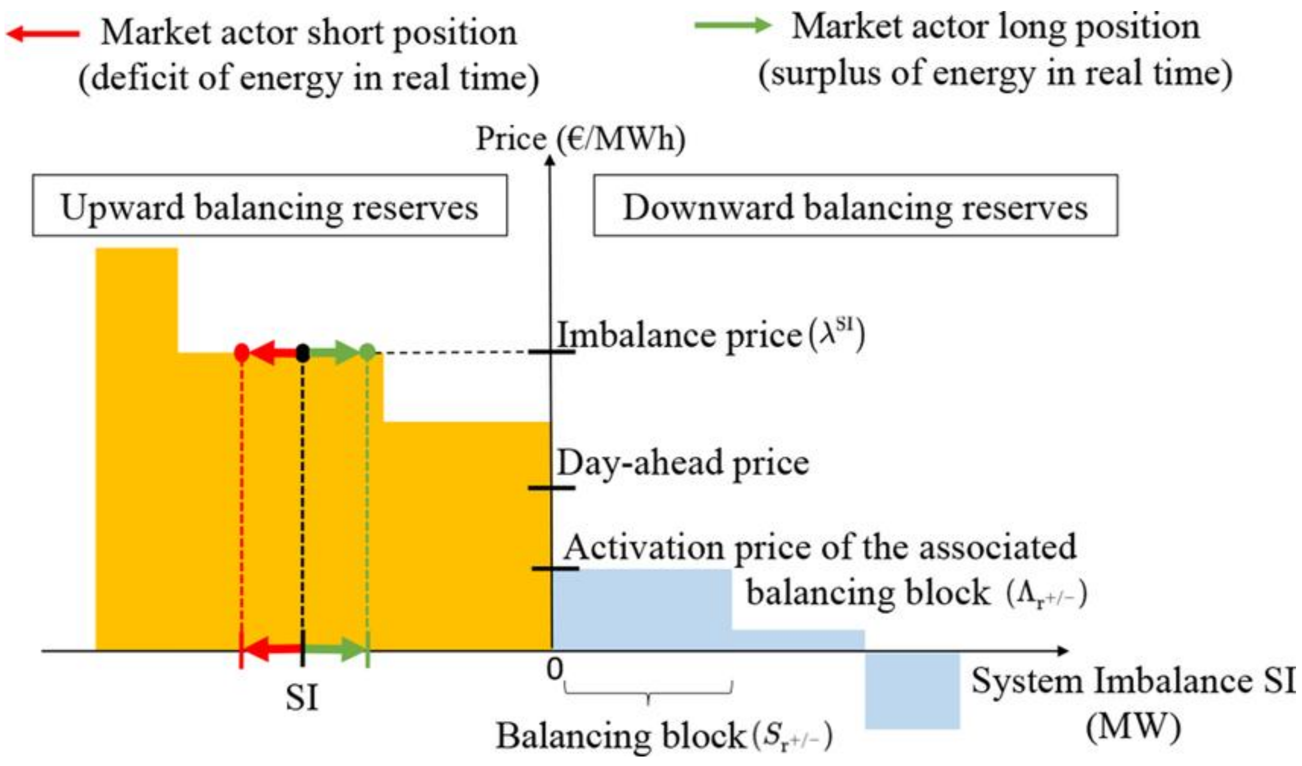
Eventually it will be merged with…

The four building blocks of Balancing



Adapted from: The EU Electricity Network Codes (2020 Ed.)

Imbalance Settlement Harmonization



ISH as a settling of the costs incurred by the deviations from BRPs' net positions

Calculation of Imbalance prices

- Single pricing applicable short and long positions (though possible exemptions)
- Min/Max based on the system imbalance or weighted average approach
- Main components
  - price(s) of satisfied demand for (specific and standardized) balancing energy
  - Activated balancing volumes (in case of weighted average approach)
  - Value Of Avoided Activation (VoAA)

Source: Methodology for the harmonisation of the main features of imbalance settlement & J. Bottieau et al

Questions

Going Forward

Where do we see these aspects changing in the future?

ESIG
ENERGY SYSTEMS
INTEGRATION GROUP

Operational Scheduling Changes and Initiatives

- Multi-day markets or guarantees (MISO, SPP)
- Renewable Dispatch Enhancements (MISO, PJM)
- 5-minute external transactions (NYISO, SPP)
- Energy Storage State of Charge Management (CAISO, ERCOT, others)
- Nodal Markets (IESO, AESO) Day-ahead market (IESO)
- Using Ambient Adjusted Transmission Ratings (FERC)

Ancillary Services Changes and Initiatives

- Dynamic Reserve Requirements (NYISO, CAISO, MISO)
- Introduction of Short/Long Ramp Products (CAISO, SPP, ISO-NE, NYISO, ERCOT)
- Reserve Deliverability Enhancements (NYISO, CAISO, SPP)
- Adding day-ahead or real-time AS markets (ISO-NE, ERCOT, CAISO)
- Expanded Operating Reserve Demand Curve (MISO, CAISO, PJM)
- Elimination of Voltage Support Payments (FERC)

Pricing Reform for Energy and Ancillary Services

ESIG

Supply-side non-convexity

- Locational marginal price (LMP) may not be able to cover total cost
- Convex hull pricing (CHP): incorporate fixed cost into pricing

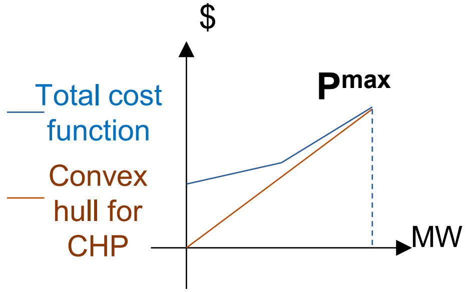
Supply-side emergency capacity

- Seemingly free and depressed prices
- Emergency pricing for better signal

Reserve values

- Demand side proxy for reliability.
- Signal for investment
- Dynamic reserve requirements and demand curves

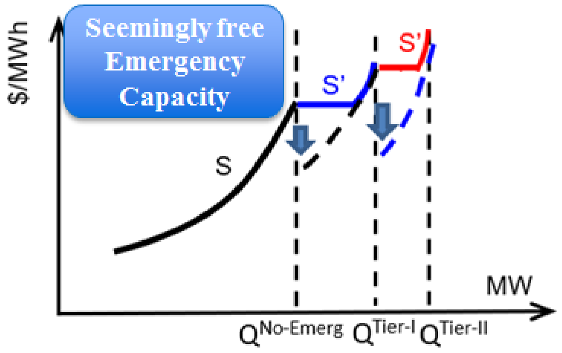
CHP: minimize uplift



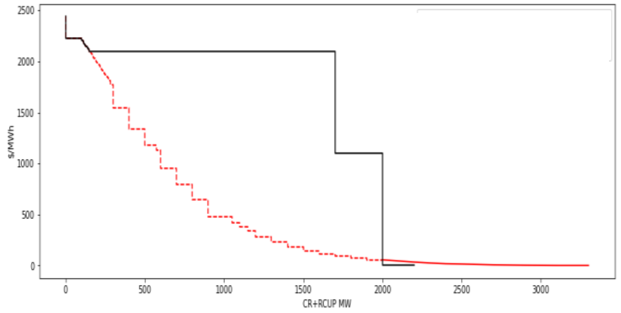
→ CHP is close to achieve incentive compatibility and revenue sufficiency in the short run

Emergency pricing

- Assign emergency offer to emergency capacity without offers.



ORDC
Operating reserve demand curve



Opportunities for Improvement on Existing Reserve Market Design

ESIG

Balancing authority: **power balance**

- Gen + Interchange = Load + Losses
- Reserve ≥ Reserve Requirement

Traditionally:

- Load uncertainty
- Largest contingency from base load generators

New challenges on total reserve requirements:

- Increased load uncertainty
- Resource availability uncertainty (e.g., fuel, intermittency)
- Large contingency associated with varying megawatt loss

- **Product design to address uncertainty in megawatts, megawatts per hour, and megawatt-hours.**
- **Reserve requirements—static or time varying?**
- **Reserve value (demand curve)?**
- **How to ensure reserve availability (performance)?**

Opportunities for Improvement on Existing Reserve Market Design

ESIG

Reliability coordination: congestion management*

- Energy Flow ≤ Limit
- Energy Flow – Contingency Flow + Reserve Deploy Flow ≤ Limit

- **Where to procure reserves?**
- **Which scenarios to consider?**
  - **Contingency events?**
  - **Transmission constraints?**
  - **Uncertainty events? Probabilistic distribution?**
  - **Reserve deployment assumption?**

*Reliability coordination is also responsible for other reliability services

Traditionally:

- Post-contingent flow violation addressed via RT-SCED
- Zonal reserve models are used to address:
  - Large zonal transfer issues
  - Load pockets' lack of fast-start resources

New issues on locational reserve requirements due to transmission congestions:

- Increased local load uncertainty
- Local resource capacity availability (e.g., fuel, intermittency)
- Large contingency associated with varying megawatt loss and import limits

Reserve Product Design

- Many developments at ISOs/RTOs to address flexibility and availability needs
- However, existing reserve product design may not provide enough incentives for availability in real time
  - ISO-NE day-ahead option product design to incentivize participants to make fuel arrangement[1]
  - Alternative solutions from capacity market:
    - MISO availability-based accreditation
    - PJM and ISO-NE pay for performance

[1] ISO-NE. 2020. *Energy Security Improvements: Creating Energy Options for New England*. Version 2.1. www.iso-ne.com/static-assets/documents/2020/04/esi-white-paper-final-with-cover-page-04152020.pdf.

Reserve Requirement: Static or Dynamic?

- ISOs move toward dynamic reserve requirements (e.g., MISO,[1] NYISO[2])
- Uncertainties include more time-varying components:
  - Forecast errors
  - Largest generation outputs may not be static
  - Resource-stranded capacity due to congestion
- NREL research with MISO:
  - Uncertainty quantification on forecast errors
  - Scenario generation
  - Stranded capacity uncertainty due to congestion
  - Stochastic optimization

[1] Y. Chen. 2023. "Addressing Uncertainties Through Improved Reserve Product Design." *IEEE Transactions on Power Systems* 38(4): 3911–3923.
[2] Matthew Musto, Kanchan Upadhyay, and Edward Lo. 2024. "Optimizing Energy and Reserve Schedules for Post-Contingency Scenarios: A Security Constrained Unit Commitment Approach." July 9, 2024, Washington, D.C. www.ferc.gov/media/presentation-optimising-energy-and-reserve-schedules-post-contingency-scenarios.

Reserve Deliverability

- ISOs move toward co-optimized post-reserve deployment flow based on generation shift factor impacts on transmission constraints
    - MISO operating reserves[1]
    - MISO short-term reserve[2]
    - California ISO (CAISO) nodal flexible ramping[3]
    - NYISO proposed nodal dynamic reserve[4]

[1] Y. Chen, P. Gribik, and J. Gardner. 2014. "Incorporating Post Zonal Reserve Deployment Transmission Constraints Into Energy and Ancillary Service Co-Optimization." *IEEE Transactions on Power Systems* 29(2): 537–549.

[2] F. Wang and Y. Chen. 2021. "Market Implications of Short-Term Reserve Deliverability Enhancement." *IEEE Transactions on Power Systems* 36(2): 1504–1514.

[3] Guillermo Bautista Alderete, George Angelidis, and Kun Zhao. 2023. "Operational Experience with Nodal Procurement of Flexible Ramping Product." FERC Technical Conference, June 2023. www.ferc.gov/media/guillermo-bautista-alderete-california-iso-folsom-ca.

[4] Matthew Musto, Kanchan Upadhyay, and Edward Lo. 2024. "Optimizing Energy and Reserve Schedules for Post-Contingency Scenarios: A Security Constrained Unit Commitment Approach." FERC Technical Conference, July 9, 2024. www.ferc.gov/media/presentation-optimising-energy-and-reserve-schedules-post-contingency-scenarios.

Reserve Procurement Coordination

- **Reserve sharing**
  - Existing resource sharing groups to jointly respond to the single largest contingency event
  - Future large events driven by HVDC development, uncertainty from wind and solar, etc.

- **Reserve deployment** impact on interregional transmission
  - Coordination on transmission capacity and reserve procurement location

- **Reserve product definition**
  - Development of consistent reserve product may be helpful for reserve sharing across seams

New Resource Integration

- Storage
  - Storage can provide all market products in most RTOs (FERC Order 841)
  - Storage optimization in market clearing
    - Multi-configuration pumped storage optimization
    - Tight state-of-charge formulation
    - Challenges with state of charge constraint under limited look ahead window

- Distributed energy resource and demand response
  - Participation model (FERC Order 2222)
  - Single node vs. multi-node aggregation
    - Transmission & distribution coordination.
  - Computational impact
  - Market process enhancement (e.g., benefit from more frequent offer update)

- Flow control devices
  - Interregional HVDC operation
  - How to improve the scheduling and coordination to maximize the value of transmission?

Who should optimize what?

- *Optimizing on the RTO side: more efficiency with global optimization; however, more market design computational complexity.*
- *Optimizing on the participant side: less impact on market design and computation; however, suboptimal solution and potential risk on both RTO and participants.*

Questions

A few selected SDAC challenges

15-min MTU go-live

Non Uniform Pricing

New Bidding products

Co-optimization of energy/balancing

The SDAC 15-min MTU go-live is planned for Q3 2025

15-min MTU go-live

This is a major change: trade will be allowed at 15-min, 30-min, and 60-min in and across all SDAC bidding zones, except Ireland (30’ and 60’)

Algorithm performance

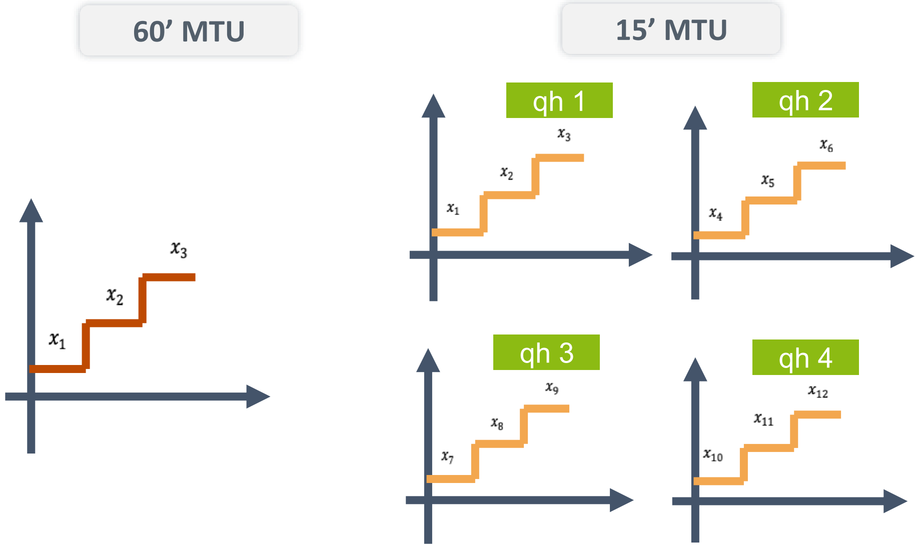
- 4-year R&D work performed by N-SIDE on Euphemia to enable the support of 15’ MTU (exponential complexity)

Product offering

- Curves and block offered at 15’, 30’ and 60’ time resolutions
- Possibility of paradoxical rejection of curves at coarser time resolution

Operational impact

- Time allocated to Euphemia increased from 17’ to 30’



Multi-time resolution

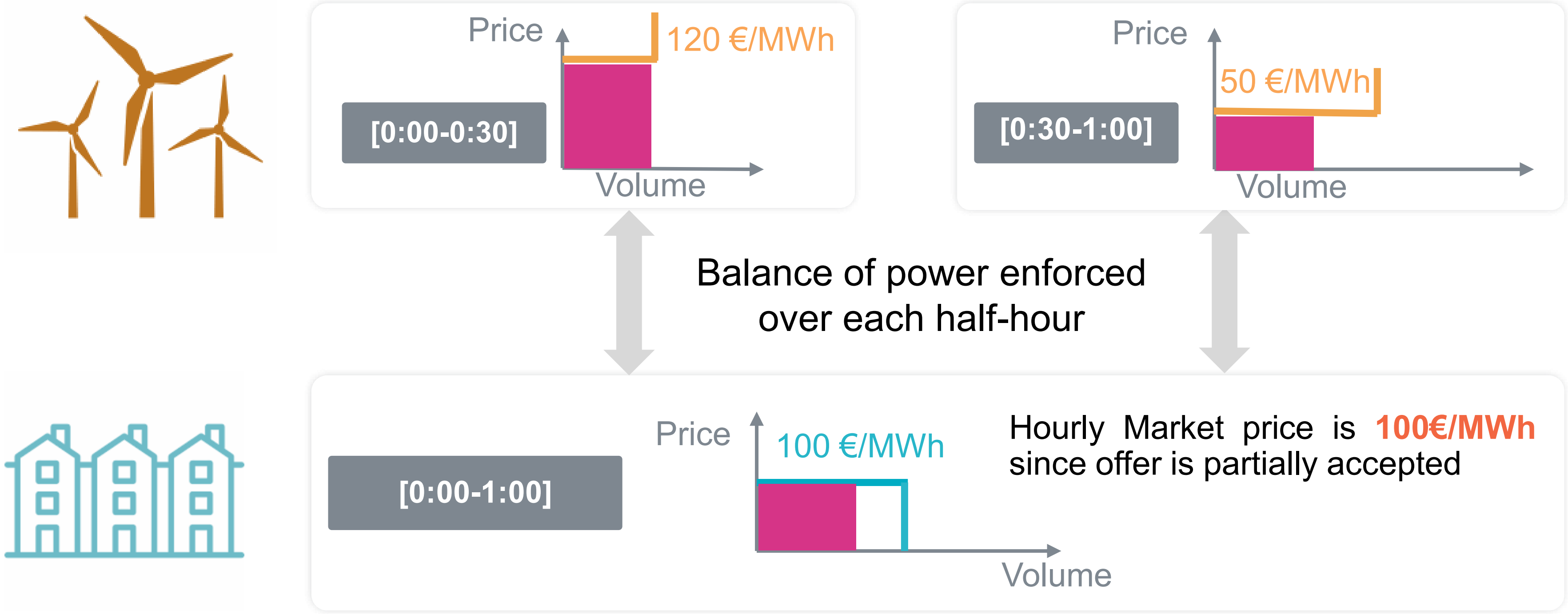
15-min MTU go-live

In this example, what should be the **market price of the whole hour?** (pay-as-clear scheme)

Multi-time resolution

15-min MTU go-live

Market price of half-hour 2 is **50€/MWh** since offer is partially accepted

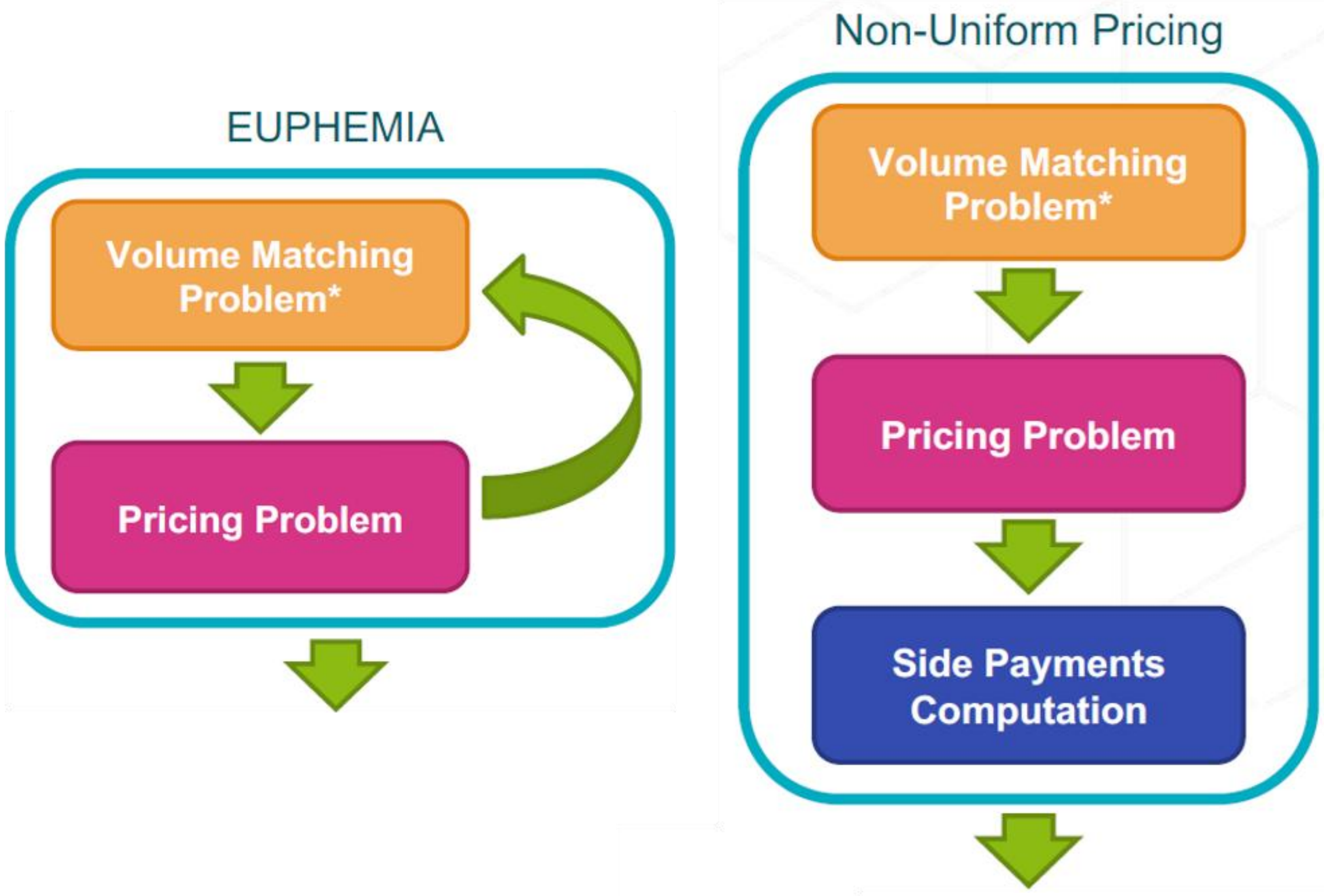


In this example, what should be the **market price of the first half-hour?** (pay-as-clear scheme)

Non Uniform Pricing

A possible way forward to improve algorithm scalability and auction welfare

Non Uniform Pricing



Rationale of Non-Uniform Pricing

- Current Euphemia implementation requires iteration between volume and price problem to account for the no-PAB condition
- Non-Uniform Pricing avoids this by decoupling the volume and price calculations into two independent steps

Advantages of Non-uniform Pricing

- Computationally more efficient
- Achieve more social welfare (assuming same orders)

Drawbacks of Non-uniform Pricing

- Need for organizing "side-payments" corresponding to the compensations paid to PAB.

Source: Market Coupling Consultative Group, 1st December 2022

New bidding products

Expressive bidding products

Efficient trading requires adapted bidding products

Example: Storage orders

- **Large industrial batteries and electric vehicles** could provide a lot of additional flexibility to electricity markets in the future, but **lack the right bidding products to properly reflect their short-term flexibility**
- **Tomorrow, storage orders could be an interesting new bidding product,** enabling storage technologies to arbitrage between periods and **reducing price differences across the day and thus peak prices**

Tutorial Wrap Up

ESIG
ENERGY SYSTEMS
INTEGRATION GROUP

Tutorial Objectives

Market Structures and Designs

- Understanding some of the basic differences across U.S. regions and also across N.A and Europe.

Operational Scheduling Practices

- How do System and Market Operators schedule supply resources at different timeframes.

Use of Forecasts in Power System Applications

- Clear understanding of where forecasts are used today and where they are starting to be used going forward

Operational Grid Services

- Understanding of the types of grid services across N.A. and E.U. and how they differ in what and who is providing them.

Forward-looking evolution

- What are the ways in which we might expect operations and markets to change in the future? What are the most important evolutions that are being discussed and starting to be implemented?

Questions

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