An Introduction to Grid Services

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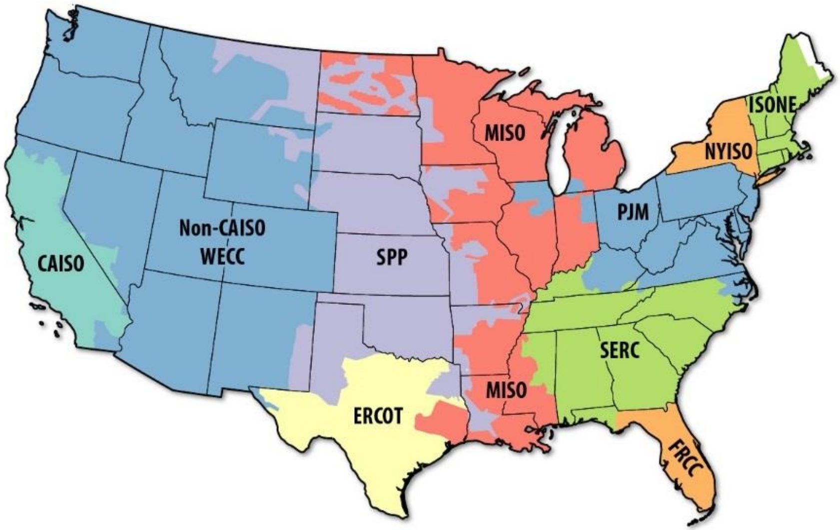
ESIG

Geographical Scope and Regions Analyzed

Market Regions	Estimated Electric Demand (TWh / % of U.S.)	Estimated Population (million / % of Total)
CAISO	228 / 6%	30 / 9%
PJM	759 / 19%	65 / 20%
ERCOT	357 / 9%	23 / 7%
ISO-NE	121 / 3%	14.5 / 4%
NYISO	157 / 4%	19.5 / 6%
MISO	656 / 16%	48 / 15%
SPP	246 / 6%	18 / 6%
Regulated Regions		
Non-CAISO WECC	654 / 16%	52 / 16%
FRCC	231 / 6%	16 / 5%
SERC	673 / 16%	39.4 /12%

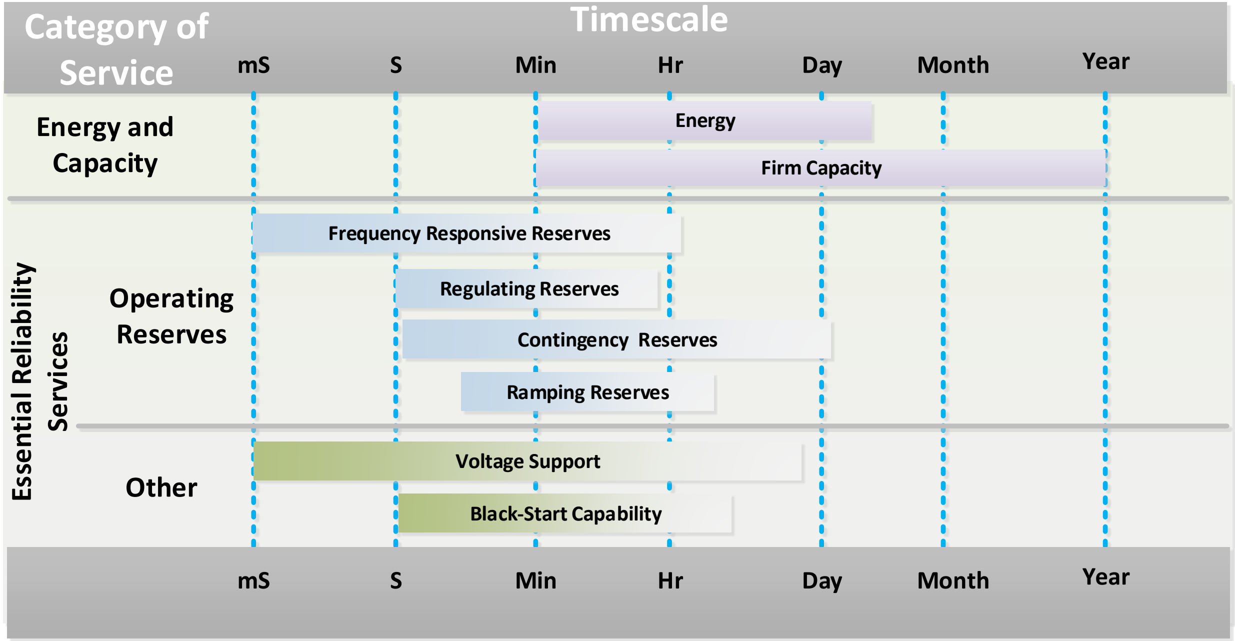


Current Grid Services

- Energy and Capacity
- Operating Reserves
- Other Essential Reliability Services
- Relative Total System Costs

Current Grid Services

- We separate energy and capacity services into one category and group the remaining services into a general essential reliability service (ERS) category.
- ERSs are further subdivided into operating reserves and other ERSs.



2020 Estimated Regional Capacity Requirements

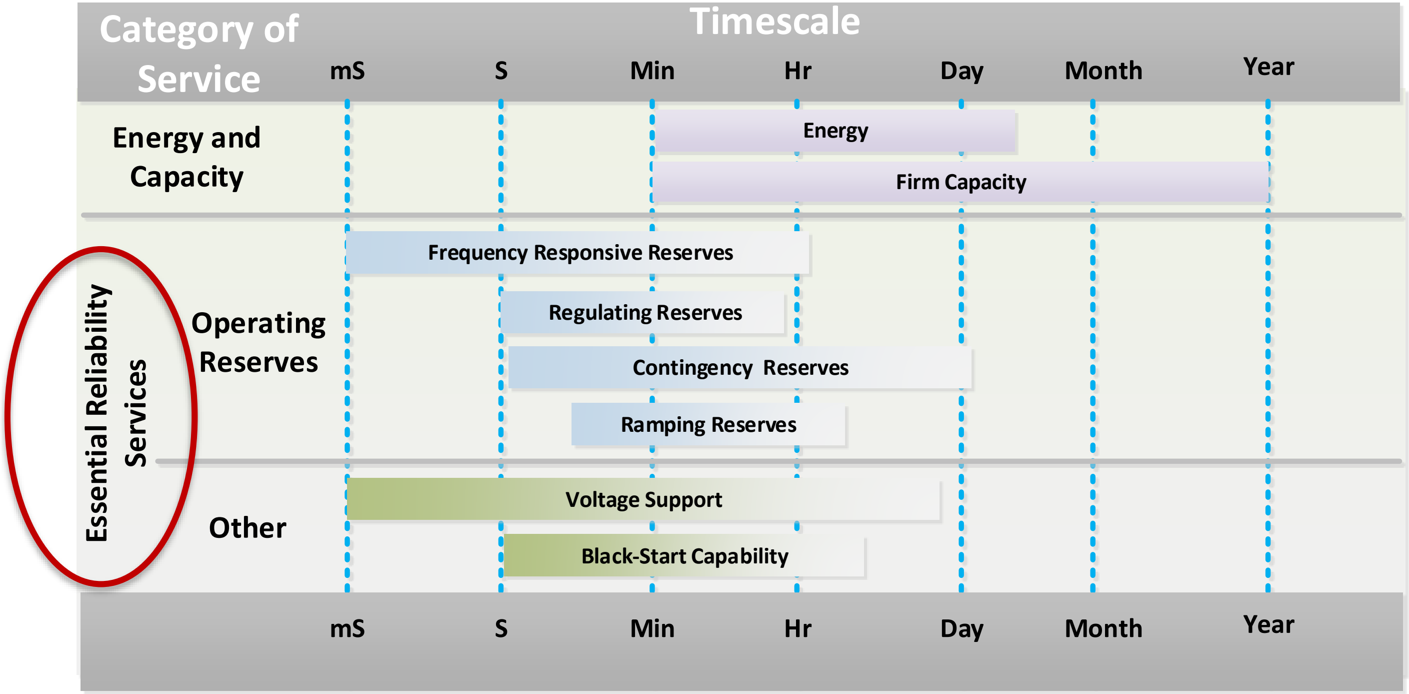
Region	2020 Estimated Peak Demand (GW)[a]	NERC Estimated Reference Margin Level (%)[b]	2020 Estimated Total Peak Capacity Requirement (GW)	2020 Estimated Reserve Margin (%)
Market Regions				
CAISO	53.6	16.14	62.3	20.6
PJM	147.5	16.60	172.0	28.0
ERCOT	73.7	13.75	83.5	18.0
ISO-NE	26.3	16.90	30.3	23.8
NYISO	32.1	15.00	36.9	25.0
MISO	121.4	15.80	140.6	19.4
SPP	52.5	12.00	58.8	28.9
Regulated Regions				
Non-CAISO WECC	110.0	range of 14.17 to 16.38	136.0	23.7 (range of 22.6 to 27.7)
FRCC	45.8	15.00	52.7	22.5
SERC	131.2	15.00	150.9	23.1

All U.S. regions are expected to have adequate generation capacity to meet peak demand in the near future.

Energy and Capacity Costs and Prices

Region	Average Energy Price ($/MWh)		Capacity Market Price ($/kW-month)	
	2016	2017	16/17	17/18
Market Regions				
CAISO	$33.1	$33.3	N/A	
PJM	$29.68	$30.85	$1.81	$3.66
ERCOT	$24.62	$28.25	NA	
ISO-NE	$31.74	$35.23	$3.15	$7.03
NYISO	$31.32	$34.62	Summer: $1.73 Winter: $5.77	Summer: $1.25 Winter: $6.49
MISO	$26.80	$29.46	NA	
SPP	$22.43	$23.43	NA	

Essential Reliability Services



- Often referred to as ancillary services
- Inconsistent terminology – Be careful!

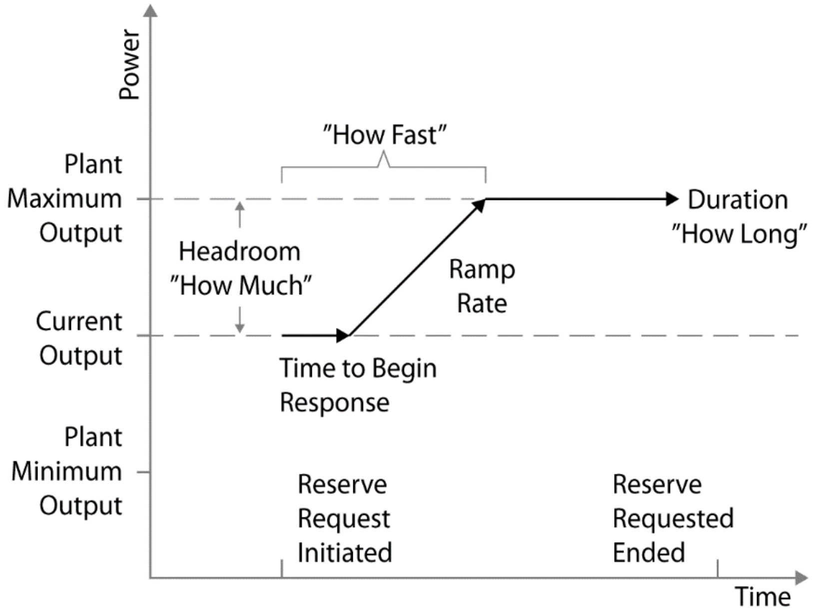
Operating Reserves

Defined as the capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection.

Distinctions can be characterized by three factors:

- **How much**
- **How fast**
- **How long**

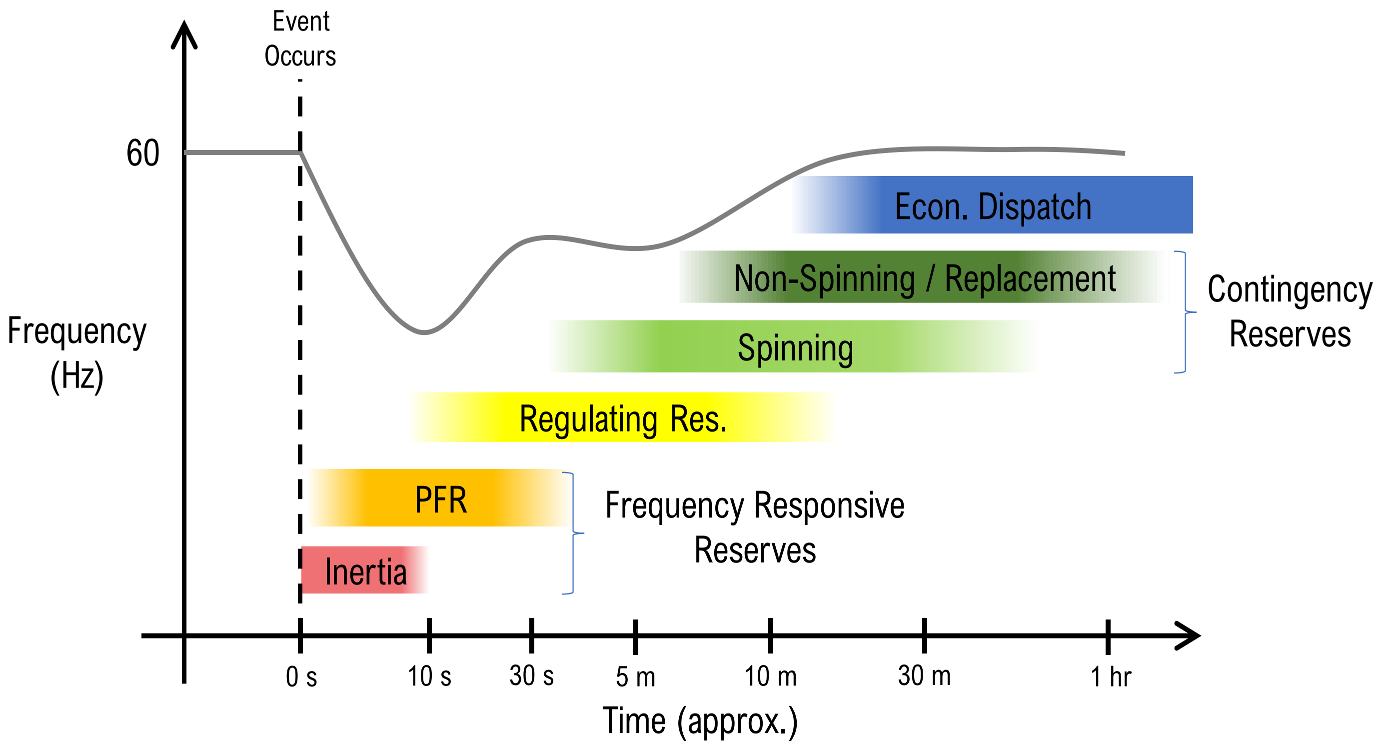
There are no uniform definitions for various operating reserve products.



What Sets the Size of Reserve Requirements?

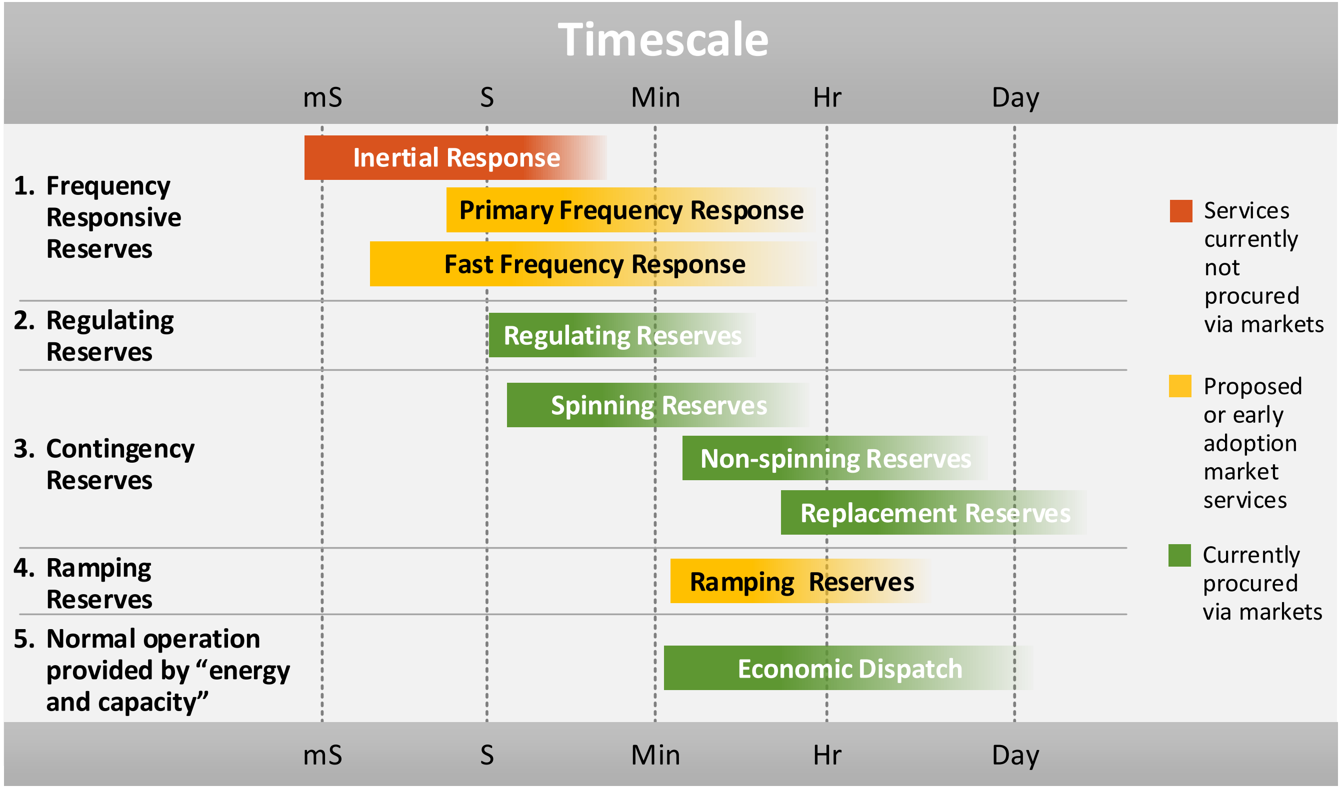
- **Events – Largest contingency (this has nothing to do with wind or solar)**
- **Normal uncertainty – This is from VG and load.**

Timescales of a Contingency Event

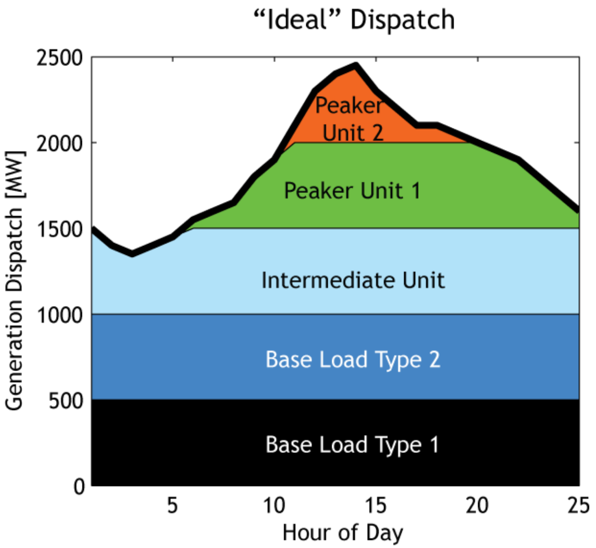


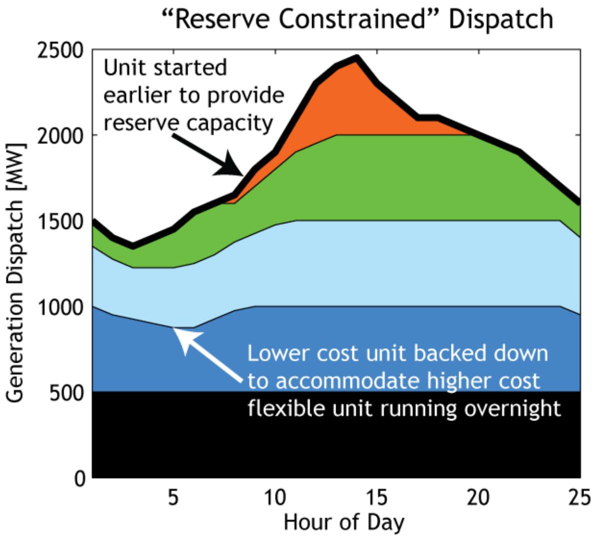
Resources with different technical characteristics are deployed at different times; typically, they are deployed in order of response speed, from very fast to slow (and with corresponding costs that range from more to less expensive).

Timescales of Operating Reserve Requirements



Why Do Reserves Incur Costs?





This is messy.

Market prices are largely variable costs. This is referred to as "opportunity costs" in wholesale markets. Also "movement costs" for some services.

Tariffs in regulated regions are largely priced on a capacity basis

Frequency-Responsive Reserve Requirements

Frequency-responsive reserves traditionally consist of two services:

- Inertial response
- PFR
- Fast Frequency Response (discussed later)
- Neither inertial response nor PFR is a market product in any ISO/RTO market*

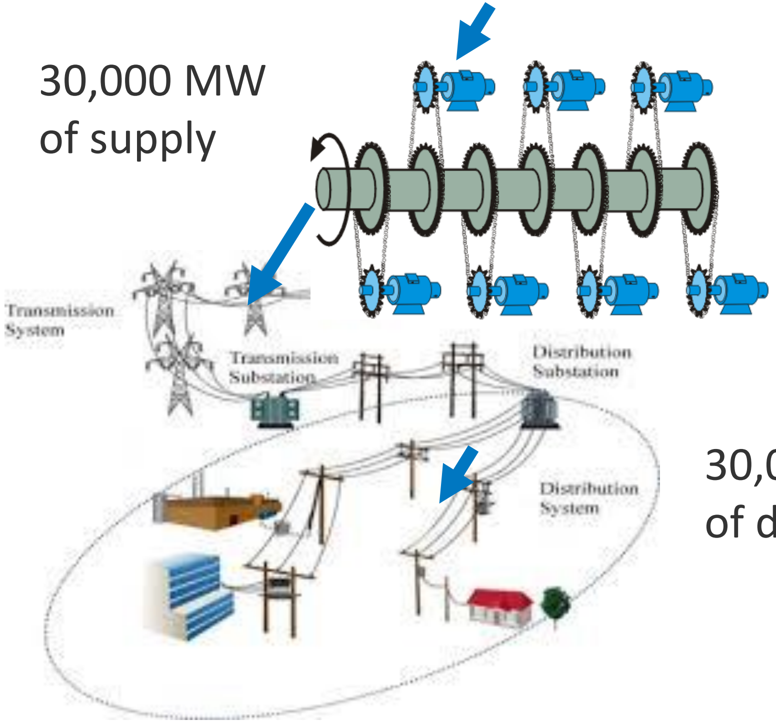
Inertial Response

- Unlike all the other reserve products and more complicated (but the first responder, so we have to start here)
- No “headroom” component of inertial response
  - The amount of inertia that can be provided by a generator is independent of instantaneous power output

Inertial Response - Steady State Operation

Thirty 1,000 MW Generators.

30,000 MW of supply

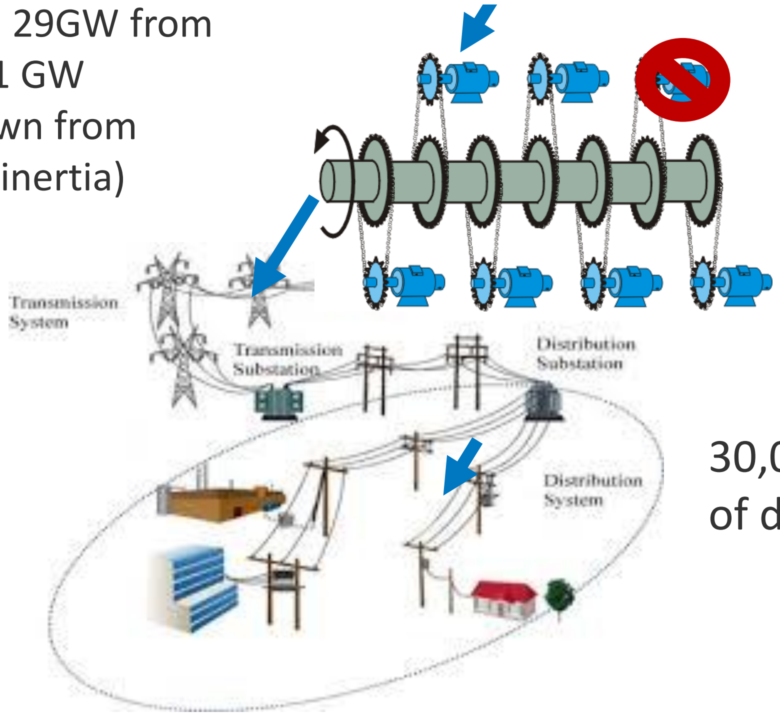


30,000 MW of demand

Inertial Response - Immediately after a Fault

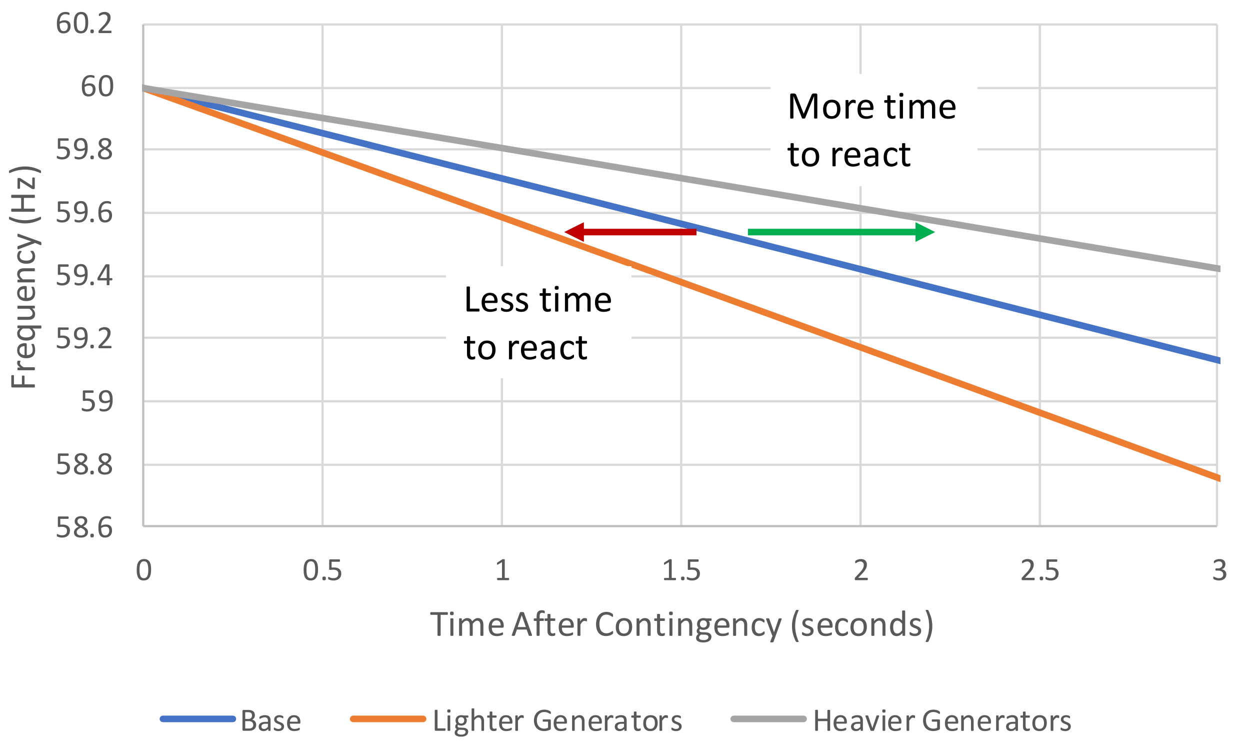
Twenty-nine 1,000 MW Generators. Each injecting 1,000 MW of power plus extracting 34 MW of stored kinetic energy

30,000 MW of supply. 29GW from active injections, and 1 GW automatically withdrawn from stored kinetic energy (inertia)

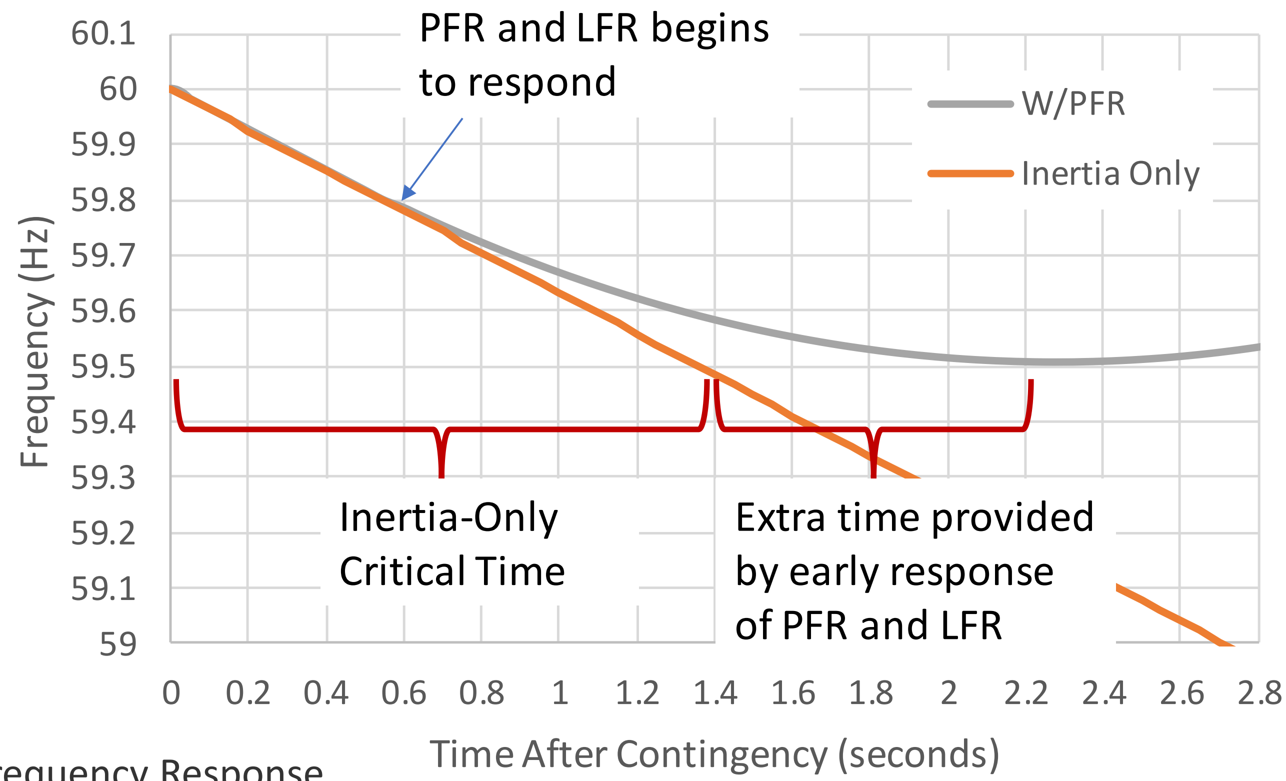


30,000 MW of demand

Inertial Response – It's All About Time



Inertial Response – Critical Inertia



PFR – Primary Frequency Response

LFR - Load Frequency Response

Inertial Response

- Critical Inertia requirement is measured in energy—how much energy can be injected rapidly into the system
  - Often measured in GW-seconds
- ERCOT is actively studying the amount of critical inertia needed and making changes to ensure needed to maintain frequency stability via FFR and other mechanisms
- Challenges in EI and WI are significantly less and there is no immediate need for additional real inertia

- Paul's opinion – outside ERCOT this whole issue is probably getting more attention than it deserves

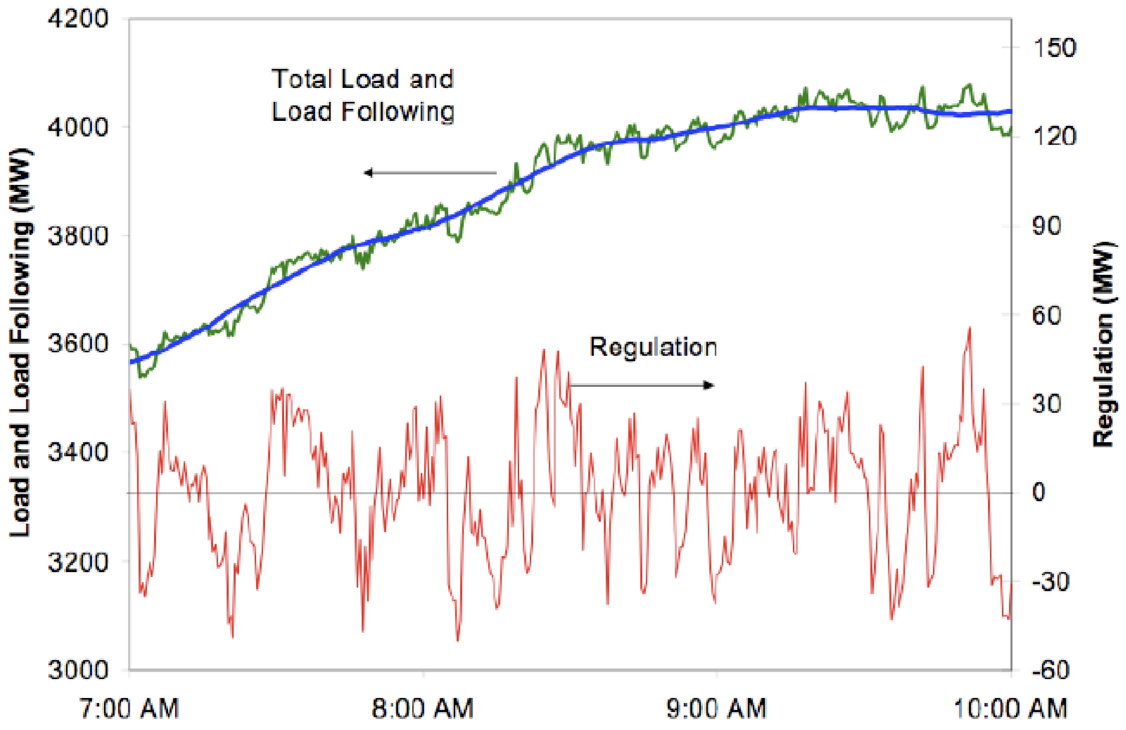
Primary Frequency (Governor) Response

Interconnection	Region	Freq. Response Ob. (MW/0.1Hz)	Max. Delta Freq. (Hz)[b]	Requirement (MW / % of Peak Demand)
ERCOT	ERCOT	381	0.405	1,543 / 2.2%
Western	Western Total	858	0.28	2,402 / 1.5%
	CAISO	196.5		550 / 1.1%
	Non-CAISO	661.5		1,852 / 1.7%
Eastern	Eastern Total	1015	0.42	4,263 / 0.8%[c]
	FRCC	76.2		320 / 0.7%
	SERC	303.6		1,275 / 1.0%
	NYISO	49.9		210 / 0.7%
	PJM	258.3		1,085 / 0.7%
	ISO-NE	38.3		161 / 0.7%
	MISO	210		882 / 0.7%

NERC minimum recommended standards for PFR

Regulating Reserve Requirements and Costs

- Regulating reserves are a market product in each ISO/RTO
- Most technically demanding in terms of response rate and the need for nearly continual ramping of the plant providing this service
- Typically the most costly of the reserve services



Regulating Reserve Requirements and Costs

Market Regions	Average Regulation Requirement (% of Peak Demand / MW)	2017 Average Price ($/MW-hr)
CAISO	Regulation Up: 0.64% / 320 Regulation Down: 0.72% / 360	Regulation Up: $12.13 Regulation Down: $7.69
PJM	Off-peak: 0.36% / 525 On-peak: 0.55% / 800	$16.78[d]
ERCOT	Regulation Up: 0.48% / 318 Regulation Down: 0.42% / 295	Regulation Up: $8.76 Regulation Down: $7.48
ISO-NE	0.25% / 60	$29.23
NYISO	0.73% / 217	$10.28
MISO	0.35% 425	$9.74
SPP	Regulation Up: 0.92% / 470 Regulation Down: 0.63% / 325[m]	Regulation Up: $8.20 Regulation Down: $6.60
Regulated Regions[o]	(% of Peak Demand / Estimated Region Requirement in MW)	Tariff ($/kW-month / $/MW-hr)
Non-CAISO WECC (proxy utility: APS)	1.17% / 1,240	$7.41/$10.29
FRCC (proxy utility: Florida Power & Light)	1.35% / 629	$4.8/$6.67
SERC (proxy utility: Southern Company)	1.15% / 1,477	$4.2/$5.83
National	0.90% / 6,000 MW	$11.24

Spinning Contingency Reserves

Market Regions	Spinning Requirement (% of Peak Demand / MW)	2017 Average Price ($/MW-hr)
CAISO	1.60% / 800 MW[a]	$10.13[b]
PJM	1.03% / 1,504.8 MW[c]	$3.73[d]
ERCOT	3.76% / 2,616.8 MW[e]	$9.77[f]
ISO-NE	3.75% / 900 MW[g]	$2.96[h]
NYISO	2.20% / 655 MW[i]	$5.00[j]
MISO	0.61% / 740 MW[k]	$2.94[l]
SPP	1.14% / 585 MW[m]	$5.25[n]
Regulated Regions	(% of Peak Demand) / Estimated Region Requirement	Tariff ($/kW-month / $/MW-hr)
Non-CAISO WECC (Arizona Public Service)	1.50% / 1590	$6.26 / $8.69
FRCC (Florida Power & Light)	0.43% / 200	$5.16 / $7.17
SERC (Southern Company)	2.00% / 2,568	$4.2 / $5.83
National	1.58% / 12,160	$6.15

The actual quantity procured is typically greater than regulation requirements, but the price is typically lower due to the infrequent ramping requirements.

Non-Spinning Contingency Reserves

The procurement for non-spinning reserves is typically similar to that of spinning reserves (because non-spinning typically replace spinning). They have the lowest technical requirements in terms of response rate and are therefore typically the least expensive of the market reserve products.

Market Regions	Non-Spinning Requirement (% of Peak Demand / MW)	2017 Average Price ($/MW-hr)
CAISO	1.60% / 800 MW[a]	$3.09[b]
PJM	1.03% / 1,053.2 MW[c]	$2.11[d]
ERCOT	2.21% / 1,534.5 MW[e]	$3.18[f]
ISO-NE	10-minute total : 5.98% / 1435 MW 30-minute : 3.33% / 800 MW[g]	10-minute non-spinning: $0.89 30-minute : $0.82[h]
NYISO	10-minute total : 4.41% / 1310 MW 30-minute reserve: 8.82% / 2620 MW[i]	10-minute non-spinning: $4.18 30-minute component: $4.01[j]
MISO	0.92% / 1,110 MW[k]	$1.14[l]
SPP	1.43% / 730 MW[m]	<$1[n]
Regulated Regions	(% of Peak Demand)/ Estimated Region Requirement	Tariff ($/kW-month / $/MW-hr)
Non-CAISO WECC (APS)	1.50% / 1,590	$0.97 / $1.35
FRCC (FP&L)	1.31% / 527	$4.83 / $6.71
SERC (Southern Company)	2.00% / 2,568	$4.20 / $5.83
National	1.98% / 14,768	$2.92

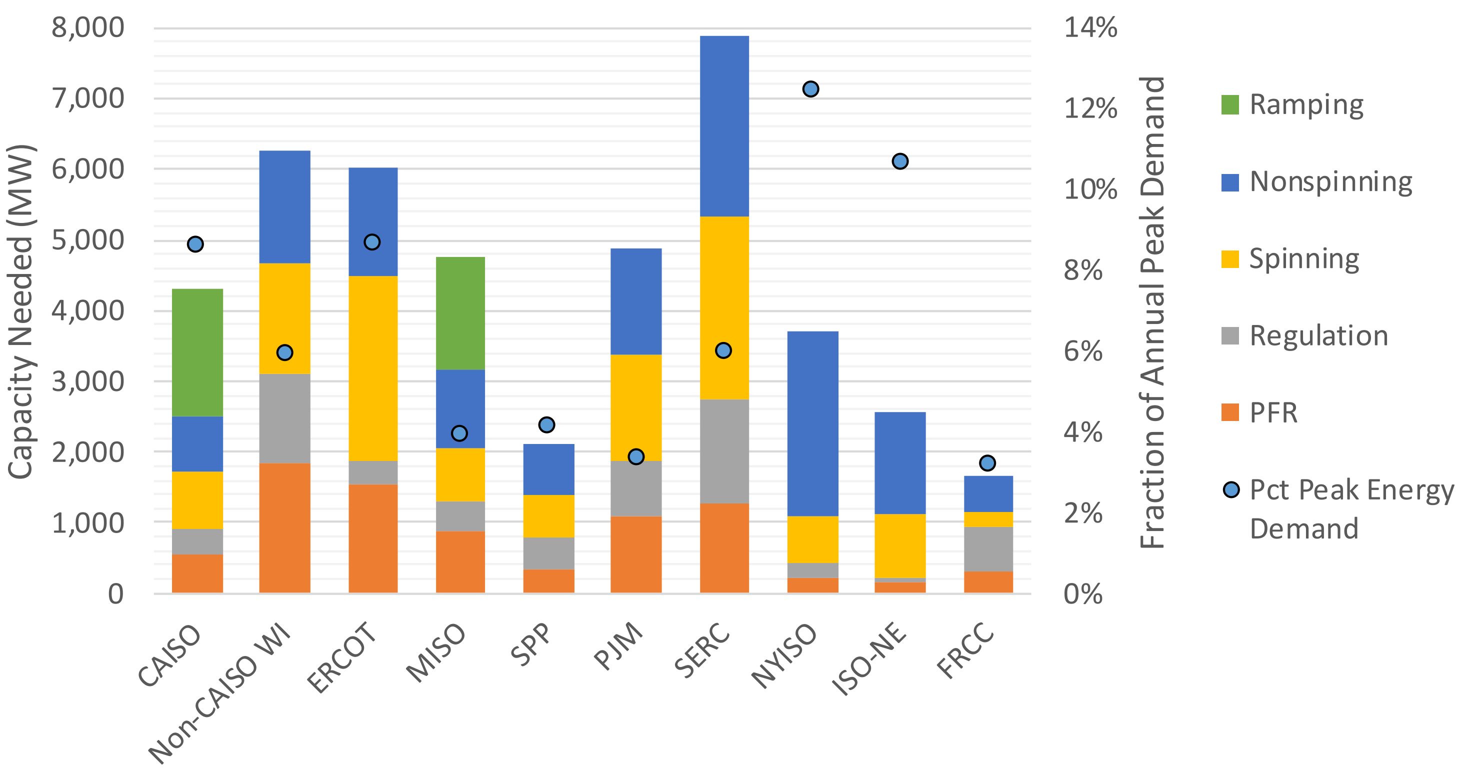
Ramping Reserve Requirements

Ramping (Flexibility) Requirements by Region

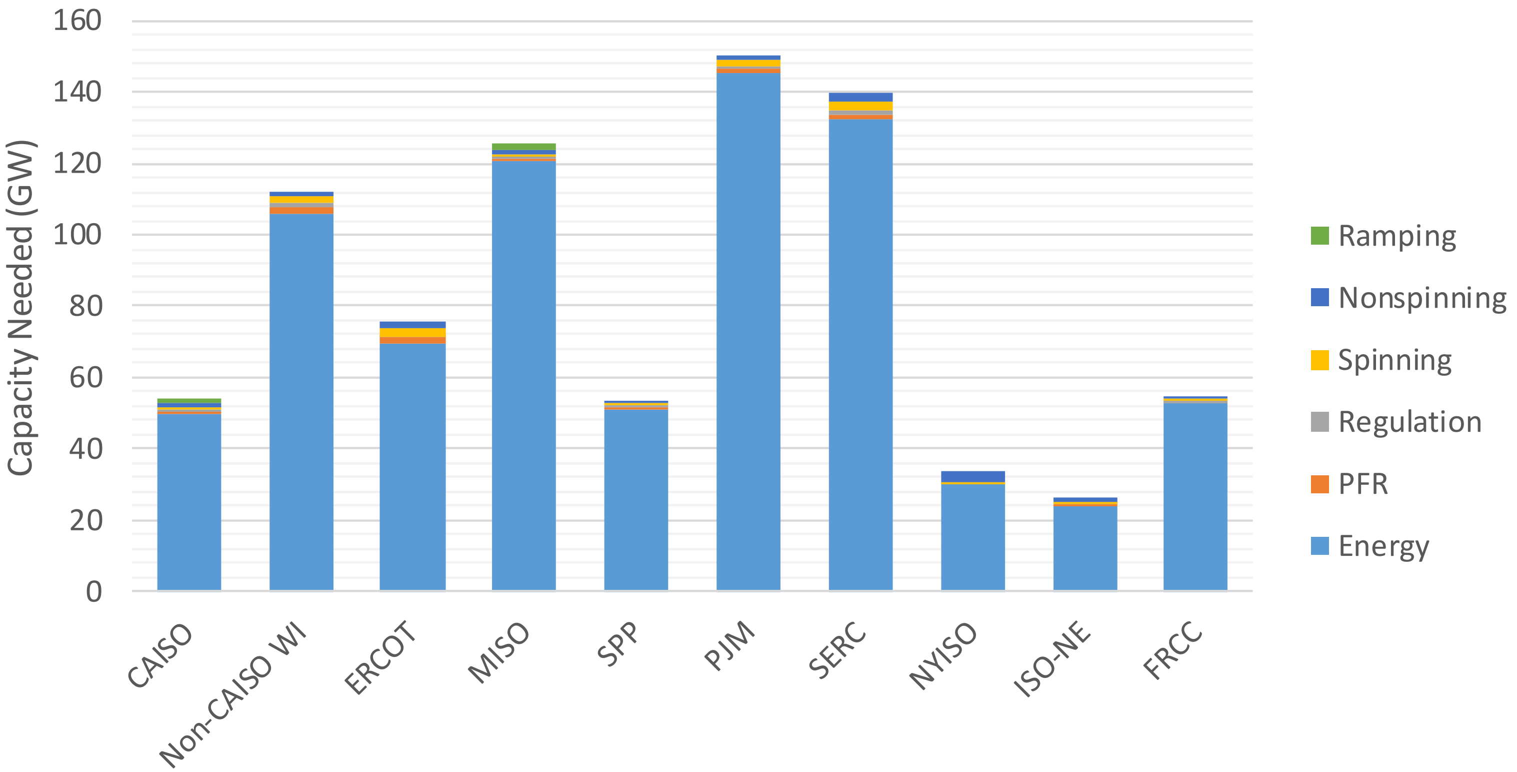
Region	Requirement
CAISO	• Maximum flexible ramp up and down requirements are defined as the 2.5% and the 97.5% percentile of net load change • Uncertainty threshold: ○ For the system in the 15-minute market: -1,200 MW in the downward direction and 1,800 MW in the upward direction; ○ For the system in the 5-minute market: -300 MW and 500 MW in the downward and upward direction[a]
MISO	• Depends on the sum of the forecasted change in net load and an additional amount of ramp up/down (575 MW for now) • Highest hourly average real-time ramp-up requirement: 1,554 MW • Highest hourly average real-time ramp-down requirement: 1,614 MW[b]

These reserves are an emerging product with limited market data for analysis.

Total Reserve Requirements



Total Energy and Reserve Requirements



Other Essential Reliability Services

- There are a number of other ERSs; two of the most important are:
  - **Black-start**
    - Used for system restoration
  - **Voltage support**
    - Provides reactive power to maintain proper voltages
- A significant difference from other services is that these are typically acquired on a cost-of-service basis

Relative Total System Costs

- Vast majority of generation-related costs are associated with the provision of energy and capacity

2017 ISO-NE Market Settlements Summary

	Billing ($ Million)	Percentage
Energy markets total	4,522	49.50%
Forward capacity market payments	2,244	24.56%
Regional network service	2,163	23.68%
Reserve markets total	70	0.77%
Net commitment-period compensation	52	0.57%
Regulation market	32	0.35%
Financial transmission rights (FTRs)	20	0.22%
Black-start	12	0.13%
Volt-ampere-reactive capacity cost	20	0.22%
Demand-response payments	1	0.01%
Total	$9,136	100.00%

2017 PJM Market Settlements Summary

	Billing ($ Million)	Percentage
Energy market	21,087	52.49%
Capacity	9,103	22.66%
Transmission	8,739	21.75%
Scheduling	366	0.91%
Reactive services	309	0.77%
Regulation market	104	0.26%
Black-start	72	0.18%
Operating reserves	68	0.17%
Synchronized reserve market	49	0.12%
Day-ahead scheduling reserve market	34	0.08%
Other	241	0.60%
Total	$40,172	100.00%

Provision of Grid Services from Wind and Solar

- Energy and Capacity
- Operating Reserves
- Other Essential Reliability Services

Energy and Capacity

- Most ISO/RTOs and large utilities with substantial wind deployments have performed capacity credit analysis of wind.

- Capacity credit analysis of solar is also ongoing

- The following table demonstrates that for nearly all regions of the United States, a capacity credit of significantly less than 50% is applied to wind, with capacity credits well under 20% applied in many cases.

Energy and Capacity

Capacity Credit by Market Region

Region	Capacity Credit
Market Regions	
CAISO[a]	Summer values of about 27%.
PJM[b]	Initially applies 13% of nameplate; after three years of operation, historic performance over seasonal peak periods determine unit's capacity credit.
ERCOT[b]	Based on average historical availability during the highest 20 seasonal peak load hours for each season (2009–2016). Values recalculated after each season with new historical data. Current contribution: 58% coastal and 14% noncoastal (summer); 35% coastal and 20% noncoastal (winter).
ISO-NE[b]	Summer values average to approximately 13.2% of nameplate rating.
NYISO[c]	Onshore: summer 10%; winter 30% Offshore: 38%
MISO[d]	
2016	15.6%
2017	15.6%
2018	15.2%
SPP	5% assumed for first three years if the load-serving entity (LSE) chooses not to perform the net capability calculation during the first 3 years of operation, after which the net capability calculations are applied by selecting the appropriate monthly MW values corresponding to the LSE's peak load month for each season.
Regulated Regions	
Non-CAISO WECC	Varies. For example, Xcel Colorado uses 16%.[e] Portland General Electric uses 5%–15% for wind resources located in the Pacific Northwest.[f]
FRCC	Not applicable.
SERC	Varies.

Operating Reserves from Wind and Solar

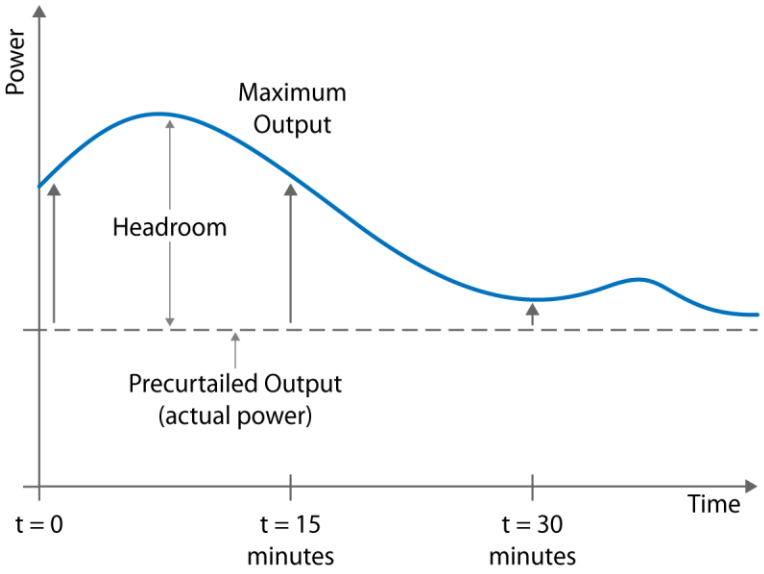
- Wind and solar were once considered a non-dispatchable “must-take” resource without the ability to provide reserves
- Now recognized that the output of wind and solar can be accurately controlled (up to the amount allowed by weather)

Parameter	Thermal/Hydro	Wind
Dispatch Range (“how much”)	Min to max, min is typically 25% to 50% of max[a]	0 to max, where maximum output is variable (limited by current wind speed)
Ramp Rate (“how fast”)	Start time ranges from several minutes to hours. Ramp rate when online ranges from about 1%/min to 5%/min	Ramp rate greater than 5%/second[c]
Availability of Output (“how long”)	Typically unconstrained with fuel availability	Contingent on wind resource, which has increased unpredictability with duration

Operating Reserves

While the need for pre-curtailment is an economic factor, an important technical factor is ensuring that headroom will remain available for the response time needed.

Impact of variable output on the ability of wind or solar to provide upward reserve services



Terminological Issues…

- "Fast frequency response" (FFR) has emerged as a preferred term that captures the ability of non-synchronous generators to rapidly inject real power into a grid upon sensing a change in frequency. Also applies to loads.

Conventional Synchronous Generator	Wind (Previous Terms)	Wind (Current Terms)
Inertia	Synthetic inertia (derived from kinetic energy)	FFR (derived from kinetic energy) or "Inertia based frequency response"
PFR	PFR from pre-curtailment	PFR or FFR (from pre-curtailment)

Summary – Grid Services from Wind and PV

Service	Market Procured and Compensated Service?	Wind and Solar Can Technically Provide? (Weather Dependent)	Wind and Solar Currently Provides in U.S.?	Requires Pre-Curtailment for Wind and PV to Provide?
Capacity	Y	Y	Y	N
Energy	Y	Y	Y	N
Physical Inertial Response	N	No	N/A	N/A
Fast Frequency Response	N – proposals only	Y	Limited	Yes, except wind can draw from stored inertia)
Primary Frequency Response	Very early stage	Y	Limited	Y
Regulating Reserves	Y	Y	Limited	Y
Contingency – Spinning	Y	Y	Limited	Y
Contingency – Non-spinning	Y	Y	No	Y
Contingency – Replacement	Y	Maybe	No	Y
Ramping Reserves	Y (some locations)	Y	Limited	Y
Voltage Support	Y – cost of Service	Y^{c} – location dependent	Limited	N
Black-Start	Y – cost of Service	Unclear, location dependent	No	N

That’s All…

Read the full report:
https://www.nrel.gov/docs/fy19osti/72578.pdf

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