Valuing Capacity for Resources with Energy Limitations – Preliminary Independent Assessment

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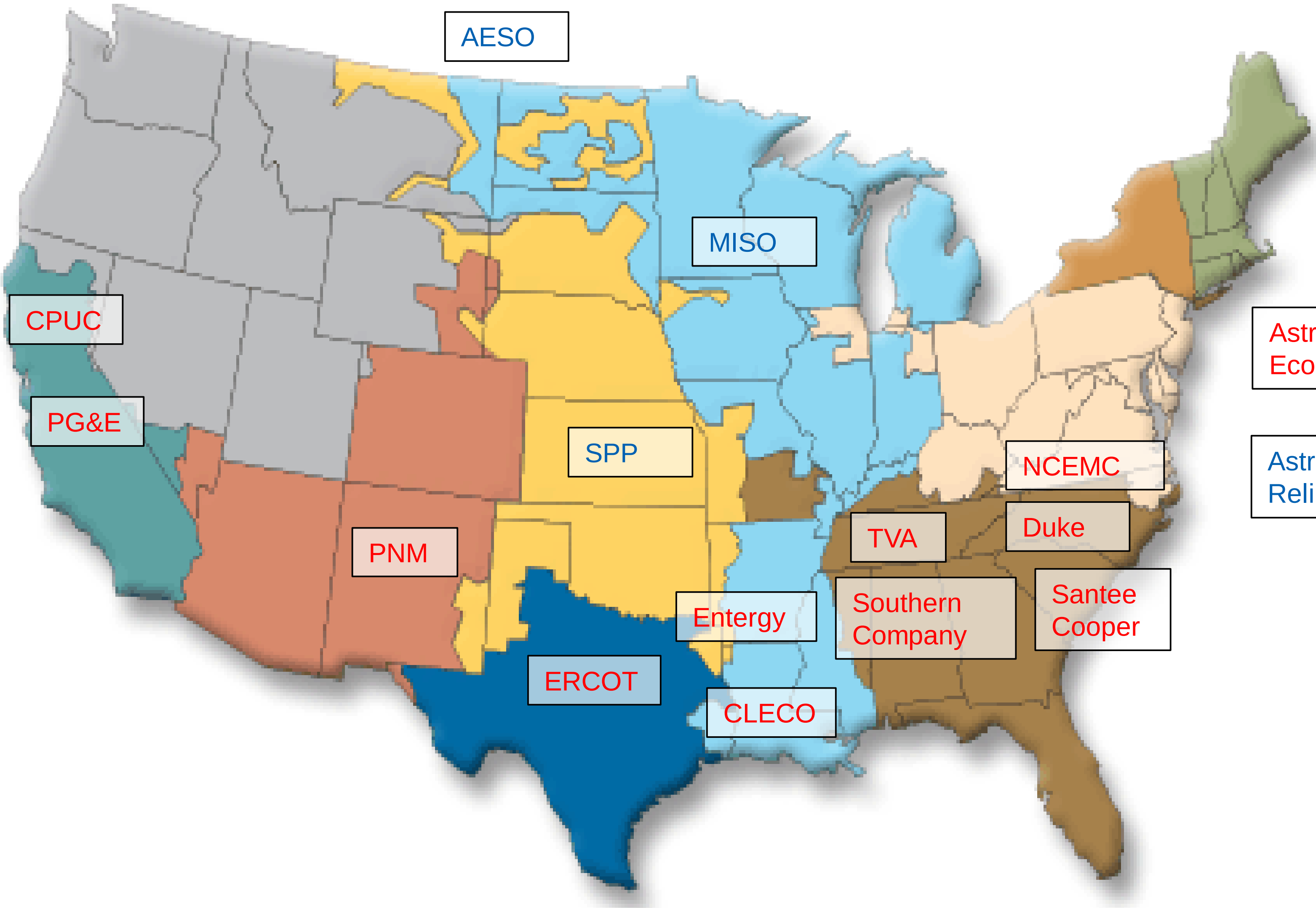
Overview

- **Astrapé was hired by NY-BEST to perform energy limited capacity valuation analysis**
- **Astrapé presented framework and load analysis on 12/18.**
- **Presentation agenda:**
  - Review SERVM framework
  - Review preliminary results and drivers
  - Next steps

Astrapé Resource Adequacy Clients



Astrapé Clients – Economic/Physical

Astrapé Clients –Physical Reliability

SERVM Framework

- **Capture Uncertainty in the Following Variables**
  - Weather (38 years of weather history)
    - Impact on Load and Resources (hydro, wind, PV, temp derates on thermal resources)
  - Economic Load Forecast Error (distribution of 5 points)
  - Unit Outage Modeling (100s of iterations)
- **Multi-Area Modeling – Pipe and Bubble Representation**
- **Total Base Case Scenario Breakdown**

38 **Weather Years** (Equal Probability)	x	**5** **LFE Points** (Associated Probabilities)	=	**190** **Load Scenarios** (Associated Probabilities)
190 **Load Scenarios**	x	**100** **Unit Outage Draws**	=	**19,000** **8760 Hour Simulations**

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Incorporating Weather Uncertainty for Load

1. Develop Load/Weather Relationship

- Collect Recent Hourly Loads
- Collect Recent Weather Data
- Normalize to Single Base Year
- Train using Neural Network Software

2. Apply Relationship to Create Synthetic Shapes

- Collect 1980-2017 Temperature

3. Scale Loads from Base Year to Future Study Year

4. Simulate Study Year with Each Shape

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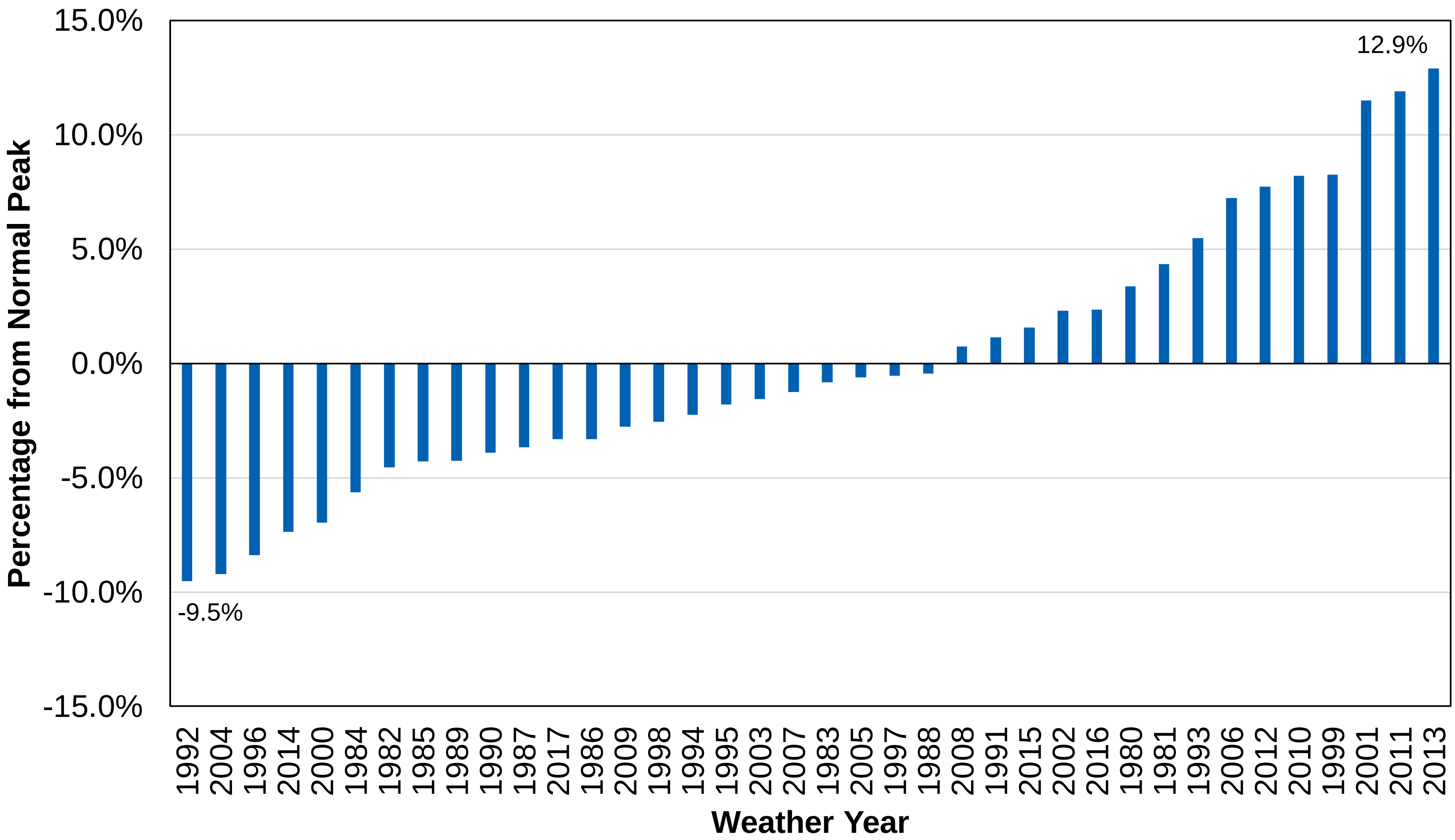
Peak Load Variability by Weather Year



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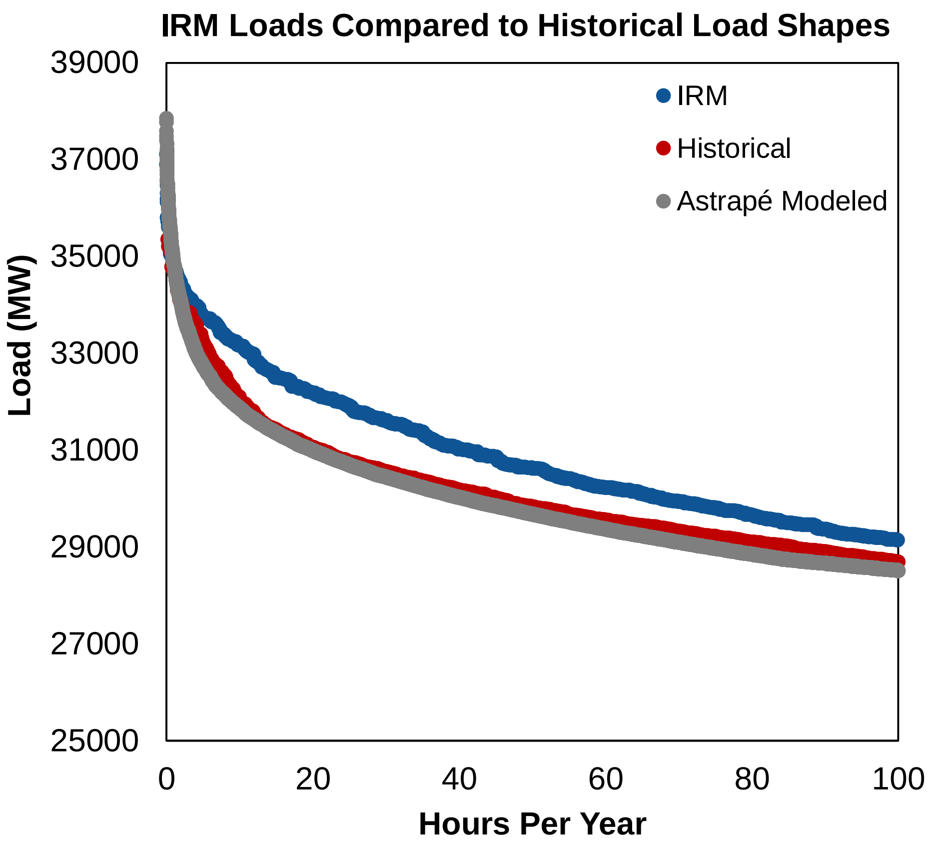
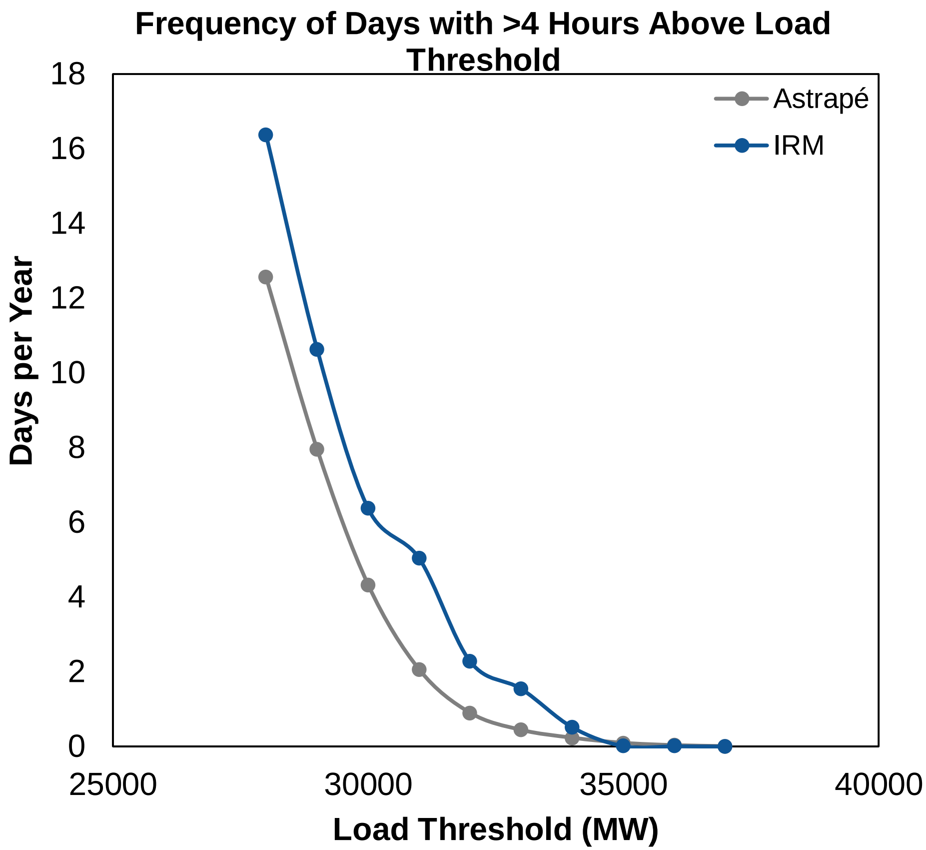
Effect of Load Scaling for Uncertainty





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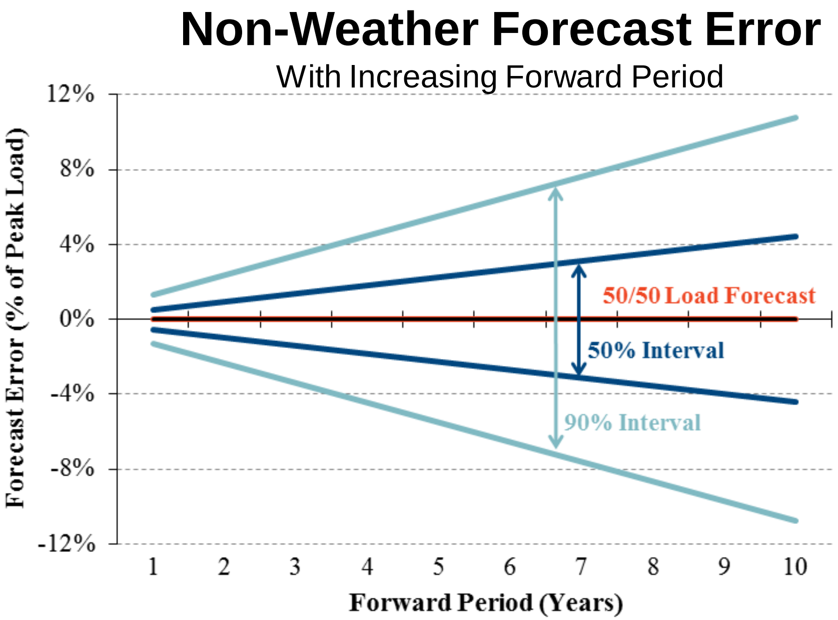
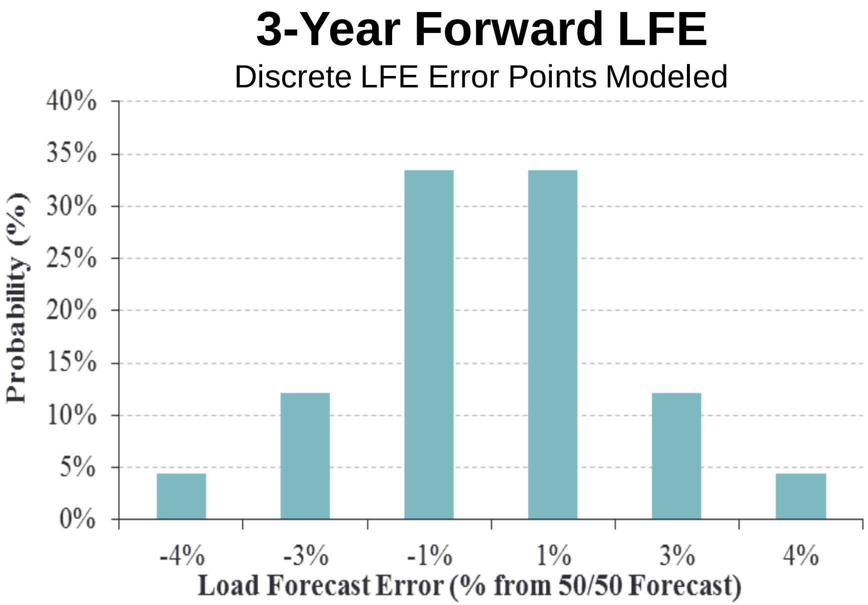
Load Forecast Uncertainty and Forward Period

- Non-weather load forecast error increases with forward period
- Each weather shape simulated with each LFE and associated probabilities





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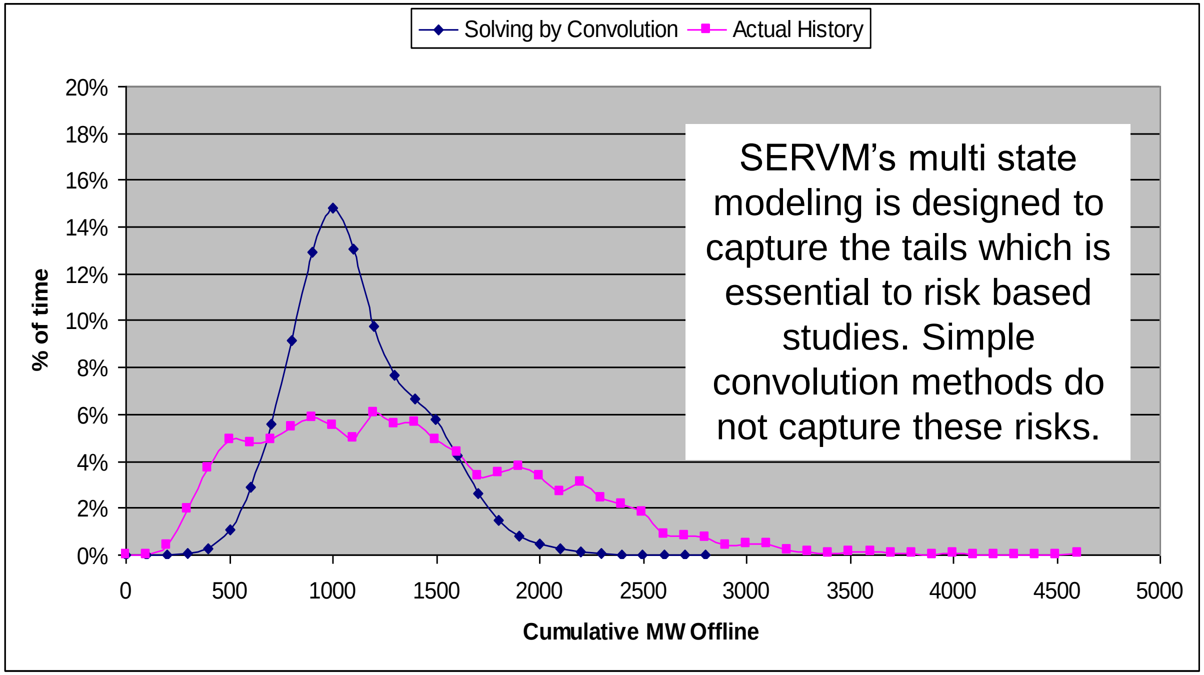
Unit Outage Modeling

- **Full Outages**
  - Time to Repair
  - Time to Failure
- **Partial Outages**
  - Time to Repair
  - Time to Failure
  - Derate Percentage
- **Startup Failures**
- **Maintenance Outages**
- **Planned Outages**
- **Created Based on Historical GADS Data**

- Multi State Frequency and Duration Modeling vs Convolution



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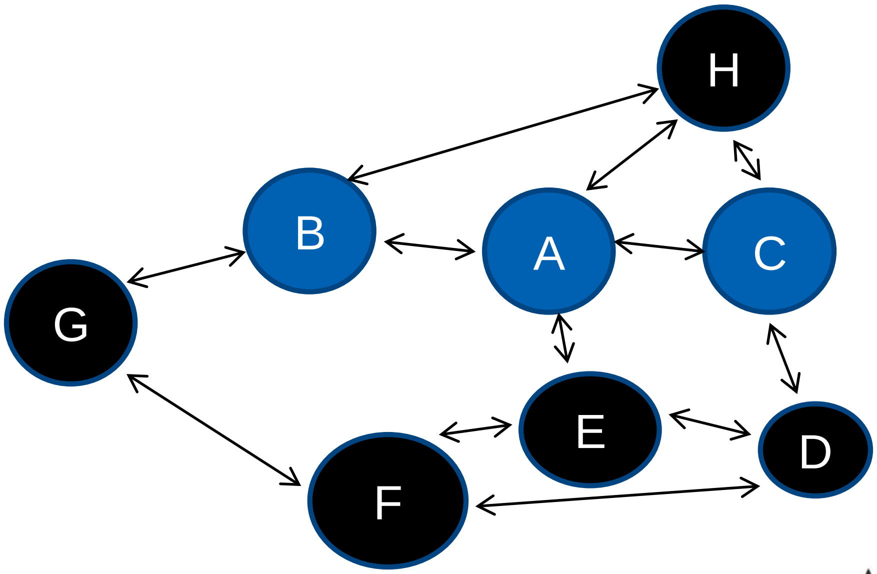
Multi-Area Modeling

- Pipe and Bubble Representation with import and export constraints
- Constraints can be constants, distributions, tied to load level, or input by month
- Ties can be modeled with random outages
- Areas will share resources based on economic pricing and physical constraints
- Load/Wind/Hydro diversity is embedded in each region's input data



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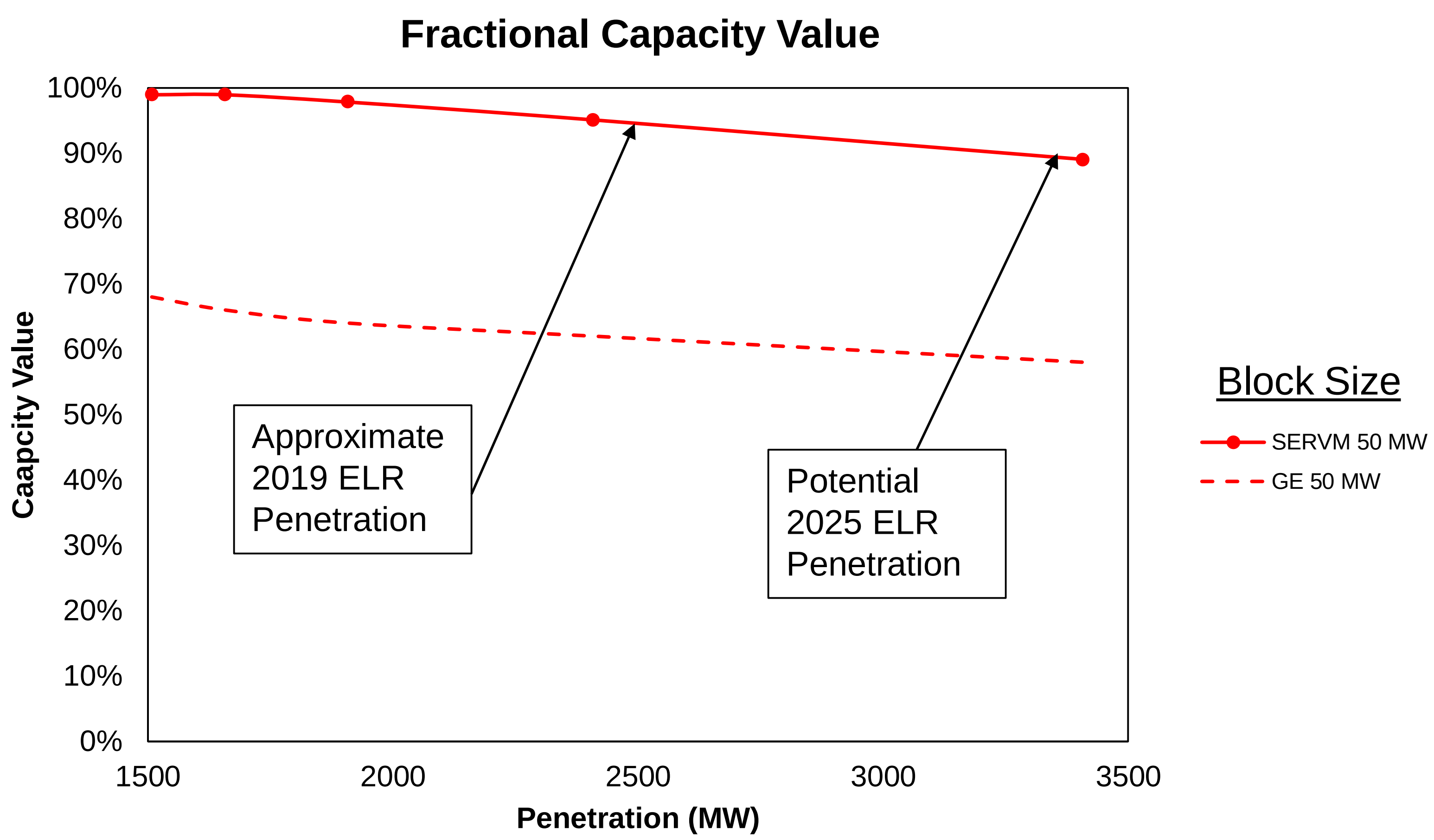
Energy Limited Duration Approach

- **Study Steps**
  - Model all loads and resources in NYCA, ISO-NE, PJM, IESO, HQ
    - Include existing PSH with constraints in NYCA
    - Include energy limited resources (DR and PSH) in neighboring regions
  - Calibrate reliability in NYCA and neighboring regions to 0.1 LOLE
  - Add energy limited capacity
  - Remove perfect (no duration limit and no forced outage rate) conventional capacity until NYCA reliability again meets 0.1 LOLE
  - Fractional capacity value = Perfect capacity removed / energy limited capacity added

Key Assumptions

- Simulated at criterion for NYCA and neighbors
- Reserves fully exhausted before shedding firm load
- Capacity value instead of ELCC
- Energy limited resources compared to perfect capacity
- Endogenous simulations
- 2019 resource mix
- Existing pumped storage hydro always modeled with 8-hour duration
- Magnitude of each portfolio directly comparable to GE portfolios, although composition is different due to PSH treatment.

Preliminary 4 Hour Duration Results



**All energy limited resource portfolios include 1408 MW of 8-hour PSH.*

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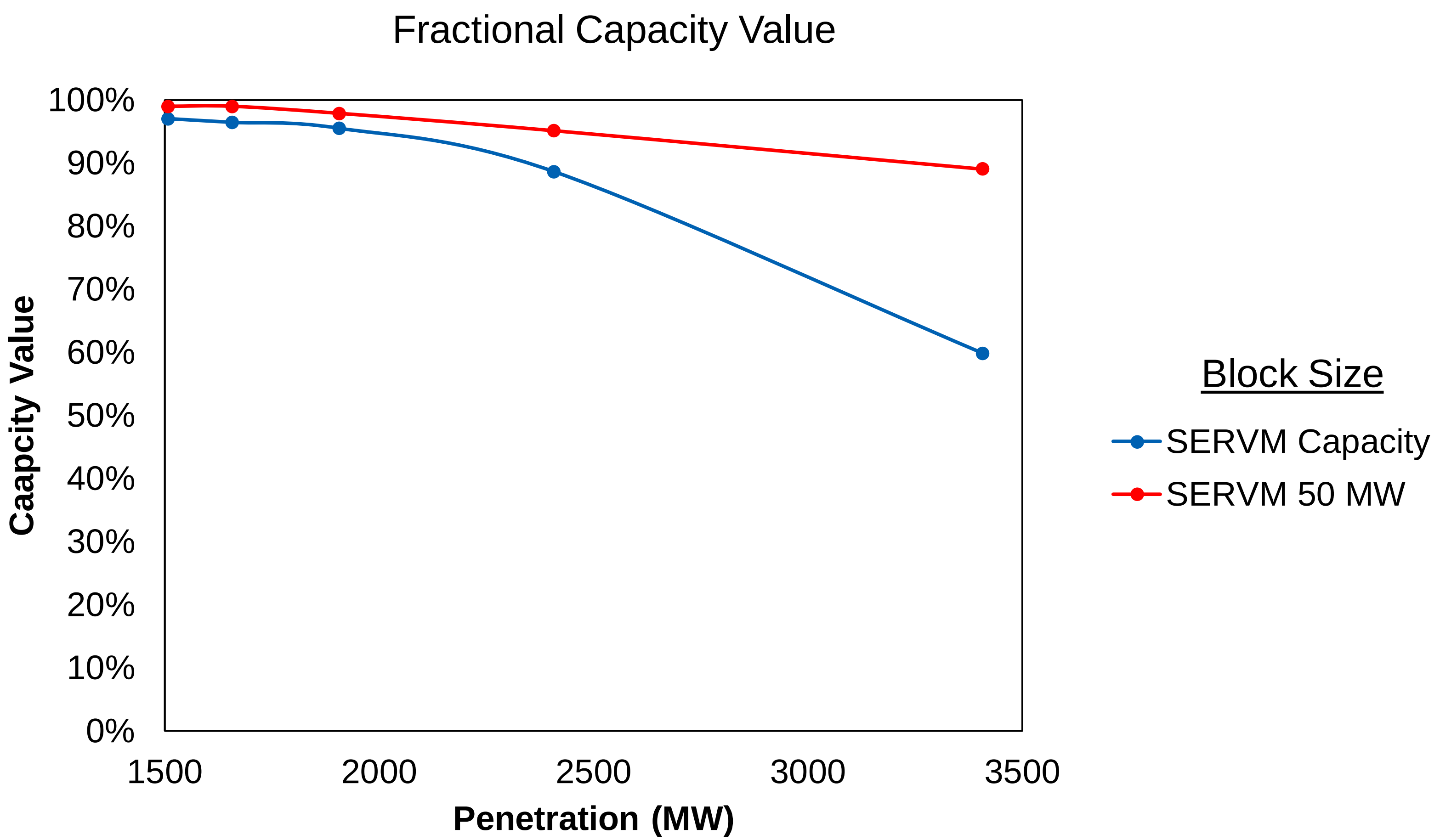
Preliminary 4 Hour Diversity Benefit



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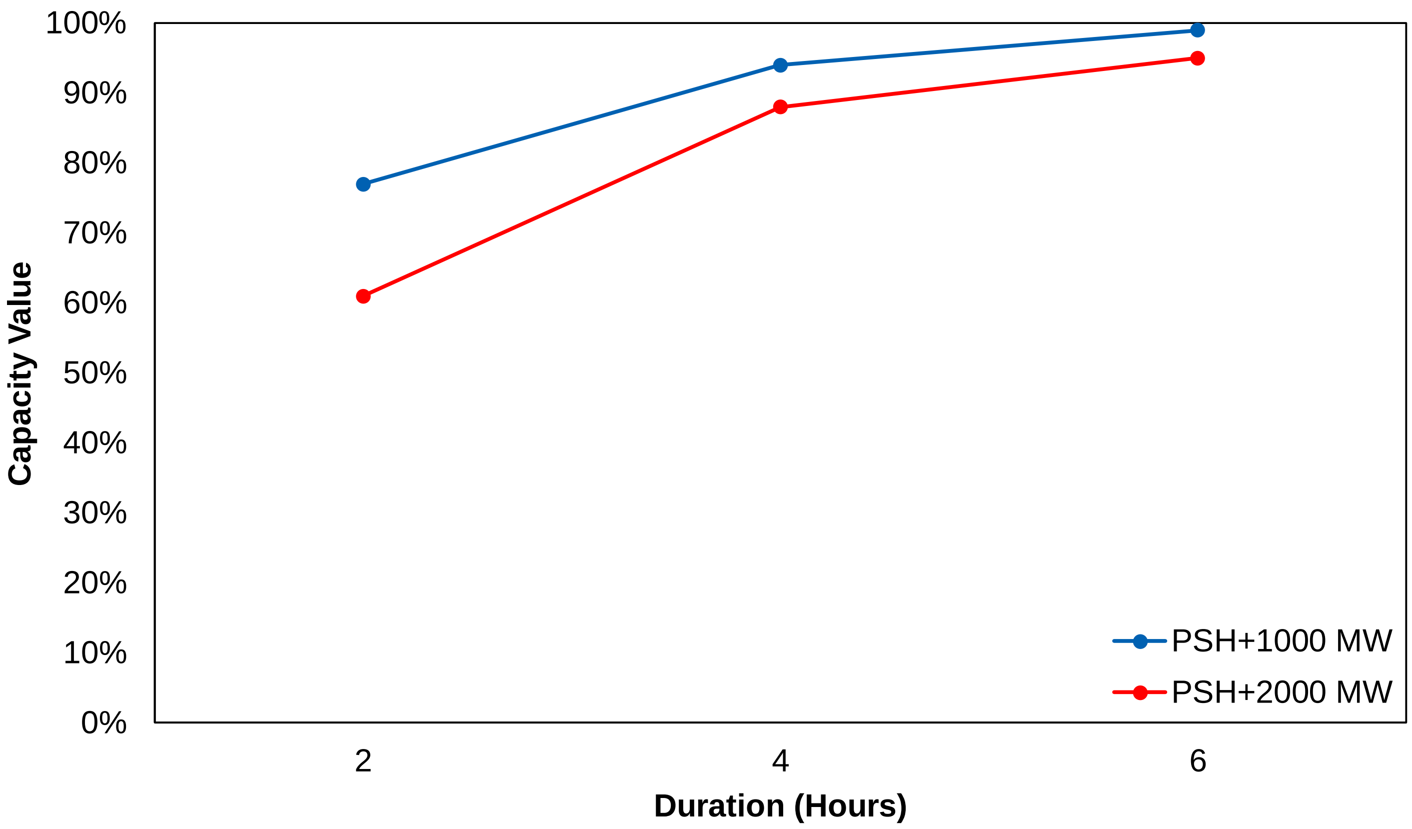
Preliminary 2 & 6 Hour Duration Results



**All energy limited resource portfolios include 1408 MW of 8-hour PSH.*

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Drivers of Differences from GE Study

- **Treatment of load uncertainty**
- **Diversity with neighbors; GE MARS study assumes no diversity**
- **Endogenous treatment of resource interactions**
- **Generator outage modeling**
- **Internal transmission constraints**

Regional Load Diversity

- **Regional load diversity is not realistic in the GE simulations**
  - Artificial correlation in 3 highest load days
- **Diversity results in higher shoulder period purchase availability, shortening the need for duration**

	Peak Load (MW)	Load Diversity (% below non-coincident 50/50 peak)	
	Non-Coincident Peak Load	**At System Coincident Peak**	**At NYISO Coincident Peak**
NYISO	36,427	-5.9%	0.0%
PJM	163,597	-0.9%	-3.8%
ISONE	26,762	-7.9%	-3.3%
IESO	24,404	-9.1%	-14.2%
System	291,297	0.0%	-2.3%

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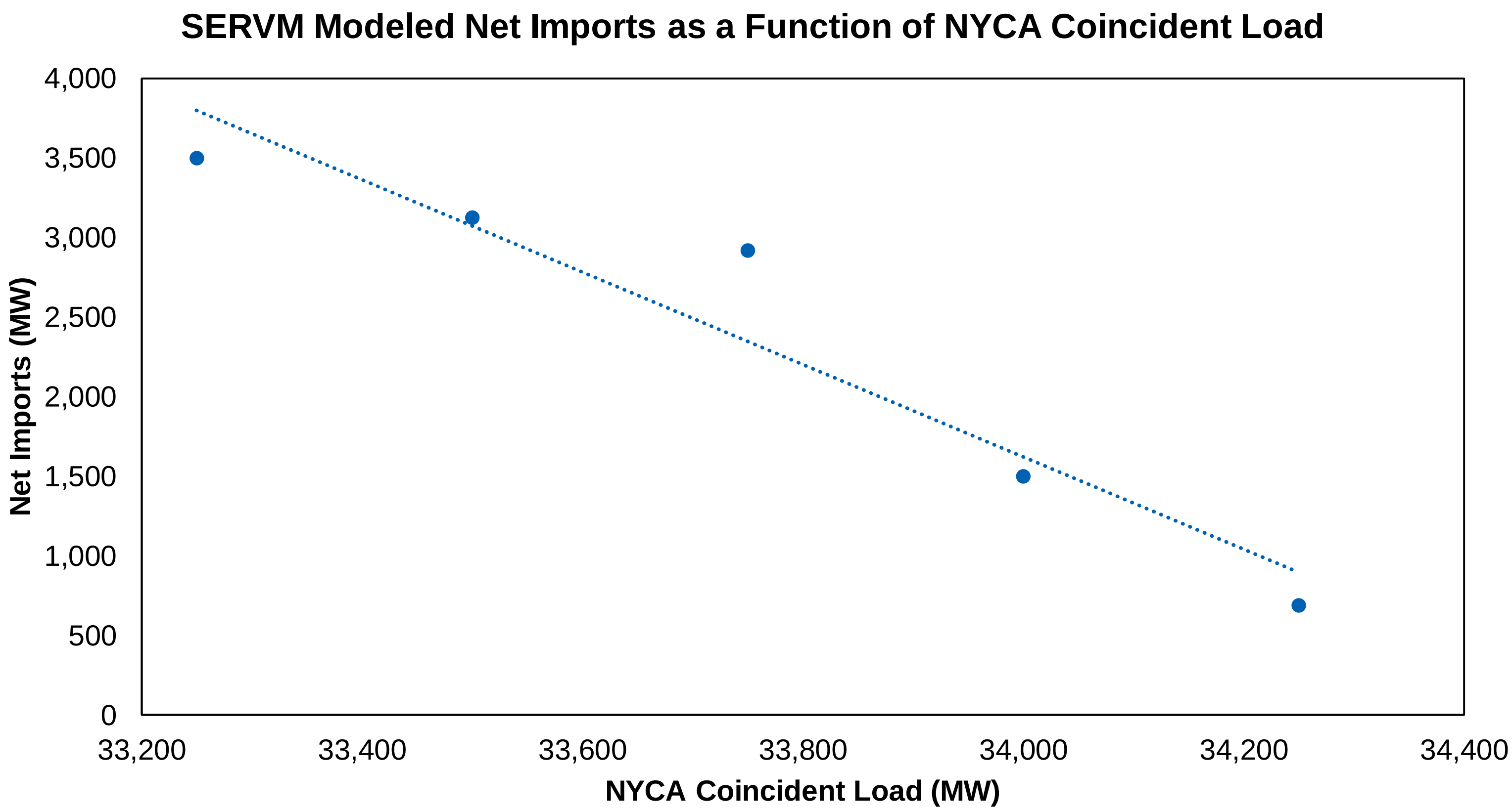
Imports by Load Level

- **Higher purchase availability at sub-peak hours shortens duration need**



Preliminary IRM Calibration

- **Each zone set to 50/50 2019 forecast**
- **Conventional generation moved within zones and internal constraints relaxed to achieve reliability parity across NYISO**
- **Conventional generation removed (CC/CT) until LOLE = 0.1**
- **Resulting IRM = 13.7%**
  - NYSRC ‘No internal NYCA transmission constraints’ sensitivity demonstrates 2.4% lower IRM = **14.4% RM**
  - SERVM likely sees more import benefit due to load diversity
- **Additional calibration to be performed**

Next Steps

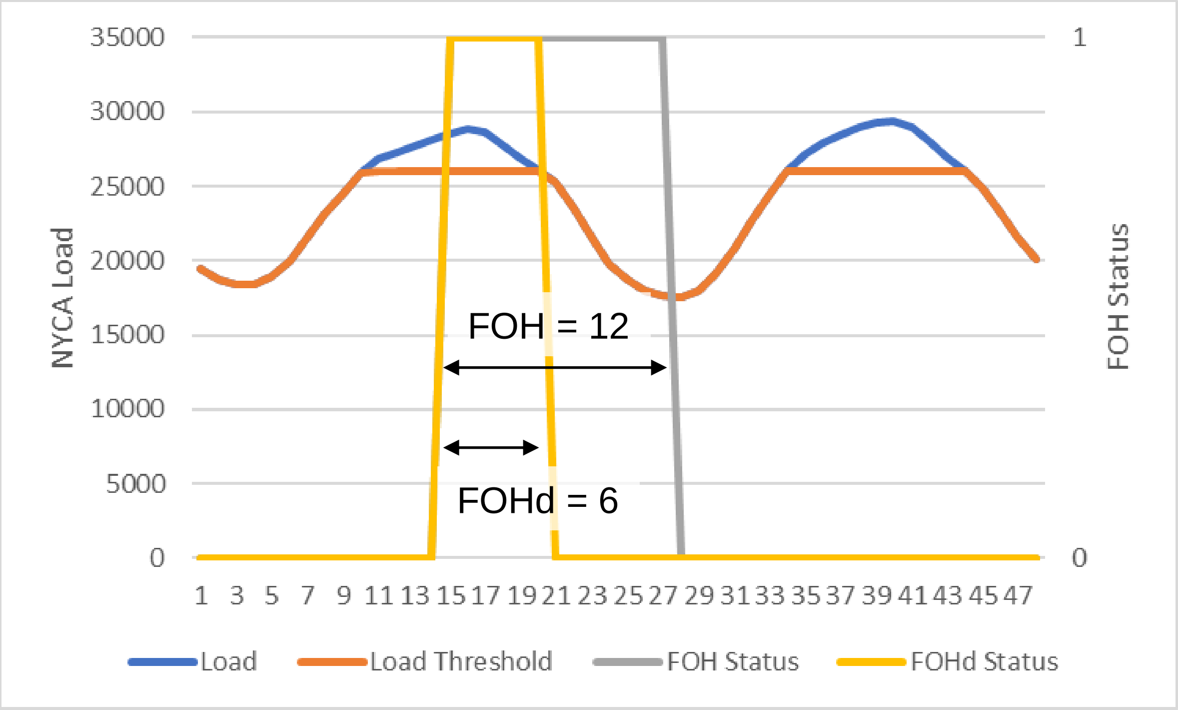
- Simulate additional duration, penetration, and resource mix scenarios.
- Simulate with IRM load profiles in SERVM with must-run dispatch
- 2-3 weeks for additional simulations and documentation

Appendix

EFOR vs EFORd

	NYCA
SERVM EFOR	12.9%
SERVM EFORd	7.2%

$FOHd =$ Hours forced out AND unit would have been operated



$$FOR = \frac{FOH}{FOH + SH}$$

$$FOR = \frac{12}{12+100} = 10.7\%$$

$$FORd = \frac{FOHd}{FOHd + SH}$$

$$FORd = \frac{6}{6+100} = 5.6\%$$

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