

Agenda Item 3.0

PSPC Meeting 276

April 22, 2010

# New England Regional System Plan (RSP10)

## Representative Future Locational Forward Reserve Requirements in SWCT, Connecticut and NEMA/Boston Reserve Zones

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April 22, 2010

# Purpose

- Review the results, and the methodology and study assumptions used to develop long term representative Locational Forward Reserve Market (LFRM) requirements
  - Reserve Zones:
    - SWCT
    - Connecticut (also referred to as Greater Connecticut)
    - NEMA/Boston
  - Study Period:
    - 2011 – 2014 (both summer and winter seasons)
  - Study Assumptions:
    - Latest historical data used for developing most current seasonal LFRM requirements from market results
    - 2010 CELT report

# Special Note

- This forecast of representative future LFRM requirements is for information purposes only
  - THESE ARE NOT THE VALUES THAT WILL BE PROCURED IN THE MARKET.
- Actual market requirements will be calculated prior to each procurement period according to Section III 9.2.3 of Market Rule 1.

# Operating Reserve Requirements Background

- One of ISO New England's missions is to operate the grid in a reliable manner, ensuring that adequate real-time operating-reserve capacity is available to respond to system contingencies. Typical contingencies considered:
  - Loss of a supply source, such as a generator or,
  - Loss of a transmission element, such as a 345 kV transmission line
  - In certain circumstance, loss of multiple elements, such as two lines, a line and a generator, or several generators in a station that are vulnerable to a common-mode failure

# Operating Reserve Requirements Background (Cont.)

- Reliability standards, criteria, and procedures require the New England power system be planned and operated to protect and recover from specific types of network.
  - NERC Standard BAL-002-0 Disturbance Control Performance
    - <http://www.nerc.com/files/BAL-002-0.pdf>
  - NPCC Criteria A6, Operating Reserve Criteria
    - <http://www.npcc.org/documents/regStandards/Criteria.aspx>
  - ISO New England Operating Procedure 8, Operating Reserve and Automatic Generation Control
    - [http://www.iso-ne.com/rules\\_proceeds/operating/isone/op8/index.html](http://www.iso-ne.com/rules_proceeds/operating/isone/op8/index.html)
  - ISO New England Operating Procedure No. 19, Transmission Operations
    - [http://www.iso-ne.com/rules\\_proceeds/operating/isone/op19/op19\\_rto\\_final.pdf](http://www.iso-ne.com/rules_proceeds/operating/isone/op19/op19_rto_final.pdf)
- Useful reference on operating reserve requirements
  - ISO New England Operating Reserves White Paper
    - [http://www.iso-ne.com/pubs/whtpprs/operating\\_reserves\\_white\\_paper.pdf](http://www.iso-ne.com/pubs/whtpprs/operating_reserves_white_paper.pdf)

# LFRM Overview

- Locational Forward Reserve Market requirements reflect the amount of 30-minute reserves required to meet the ***local 2nd contingency under normal operating conditions***, taking into account the amount of reserve support that can be imported across the interfaces into the import constrained locations (External Reserve Support, or ERS).
- Depending on system conditions -- the configuration of the interface, the largest generator on-line, loads, and the total resources on-line in the area -- the local 2nd contingency will be either a line or a generator(s).
- The requirements for the Locational Forward Reserve Market are currently derived from an analysis of historical requirements data.
  - a rolling, two year historical data of daily peak hour operational requirements for each Reserve Zone for like periods (summer or winter)
  - The requirements are modified, as required, to reflect changes in the configuration of the transmission system or addition/retirement of major generating resources.

# Calculation of LFRM Requirement

- For the peak hour of each weekday and for each Reserve Zone, the daily Locational Reserve Requirement (dLRR) is first calculated.
  - dLRR is the amount of 30-minute contingency response, given the available transfer capability on the interface, that must be physically located within the import-constrained area to ensure recovery from the loss of the 2<sup>nd</sup> contingency.
  - a calculated value based on several data elements of the system.
- These daily peak hour operating requirements are aggregated into a frequency distribution. The MW value at the 95<sup>th</sup> percentile of the distribution establishes the LFRM requirement for each Reserve Zone.

# Calculation of dLRR

(a) The Second Contingency in each Reserve Zone is calculated as

$$2^{\text{nd}} \text{ Gen} = \text{Limit}_{N-1} - \text{Limit}_{N-2, \text{ Gen}} + \text{CONTG} - 30\text{ACT}$$

$$2^{\text{nd}} \text{ Line} = \text{Limit}_{N-1} - \text{Limit}_{N-2, \text{ Line}} - 30\text{ACT}$$

(b) The External Reserve Support (ERS) is calculated as follows

$$\text{ERS} = \text{Limit}_{N-1} - (\text{Load} - \text{Gen})$$

(c) The daily Locational Reserve Requirement (dLRR) equals

$$\text{dLRR} = \text{MAX}(2^{\text{nd}} \text{ Gen}, 2^{\text{nd}} \text{ Line}) - \text{ERS}$$

Where,

- LOAD = Forecast daily peak load;
- GEN = Minimum capacity commitments required for 1<sup>st</sup> contingency coverage from day ahead;
- CONTG = Second generation contingency;
- $\text{Limit}_{N-1}$  = First contingency interface limit;
- $\text{Limit}_{N-2, \text{ Gen}}$  = Second generation contingency interface limit;
- $\text{Limit}_{N-2, \text{ Line}}$  = Second line contingency interface limit;
- 30ACT = Non-generation based 30 minute actions, e.g., certain OP4 actions, load swap, Transmission Owner authorized load shedding.

# Developing Representative Future LFRM Requirement

# Uncertainty of Future Reserve Requirements

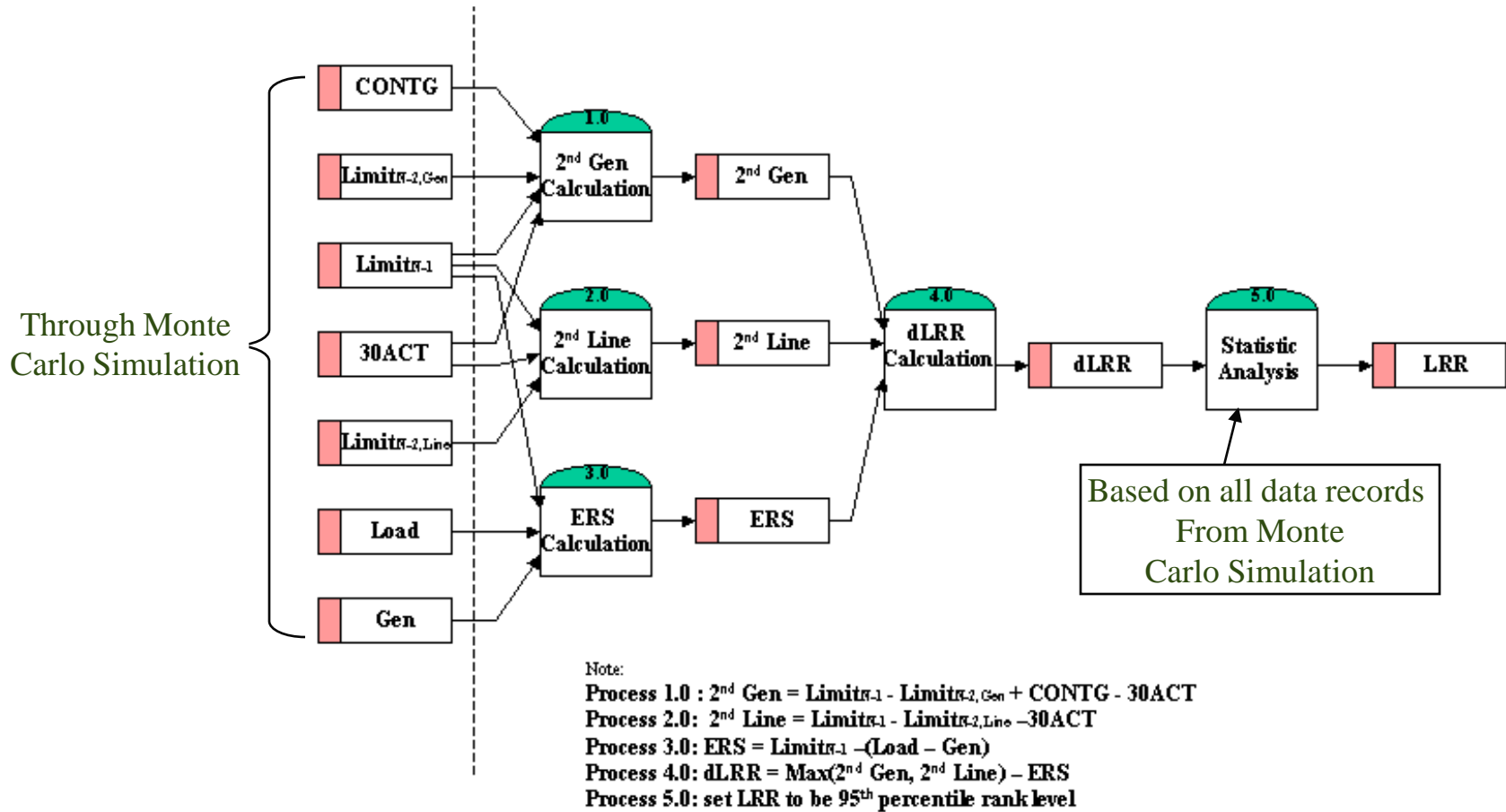
- Factors that would impact 2<sup>nd</sup> contingency
  - System condition/topology changes that result in interface limit changes, e.g.
    - New lines in-service
    - Outages (generator and line contingency, maintenance, etc.)
  - Largest generation contingency changes, e.g.
    - Uprate
    - Retirement/deactivation
- Factors effecting the external reserve support
  - Future load level
    - Demand resource impact
  - Generation dispatch pattern
    - Addition/retirement of base-load unit

# Future Reserve Requirement Projection Through Simulation

- Future reserve requirement for each Reserve Zone can be evaluated through probabilistic simulations that generate a series of possible system conditions for future periods
  - Historical system conditions are used to develop the probability distribution for each input variable and their correlations for the simulation
    - Daily peak load
    - Local online generation
    - Largest generation contingency
    - Interface limits ( $\text{Limit}_{N-1}$ ,  $\text{Limit}_{N-2, \text{Gen}}$ , and  $\text{Limit}_{N-2, \text{Line}}$ )
  - Adjustments are made to these historical distributions to better reflect future system conditions, e.g.
    - Load scaled up/down to forecast values
    - Interface limits changed based on projected system topology
    - Local generation adjusted for addition/retirement of units and the impacts of DR
  - Sensitivity scenarios are used to capture some future uncertainty, e.g.
    - Higher than expected load growth
    - In-service date of transmission upgrades
- Some operational constraints and interdependency may not be adequately captured in this type of simulation.

# Locational Reserve Requirements Forecast Data Flow Diagram

Forecasted  
daily peak hour data

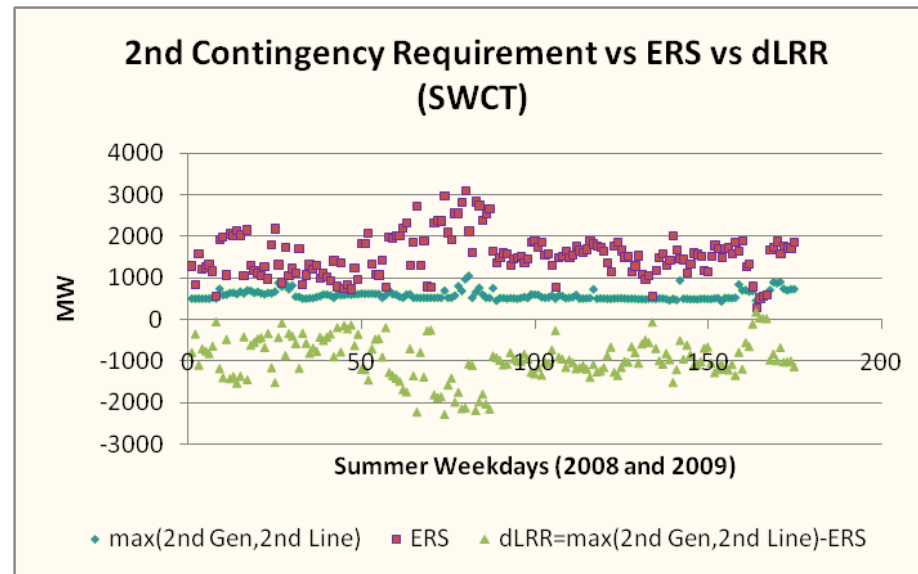
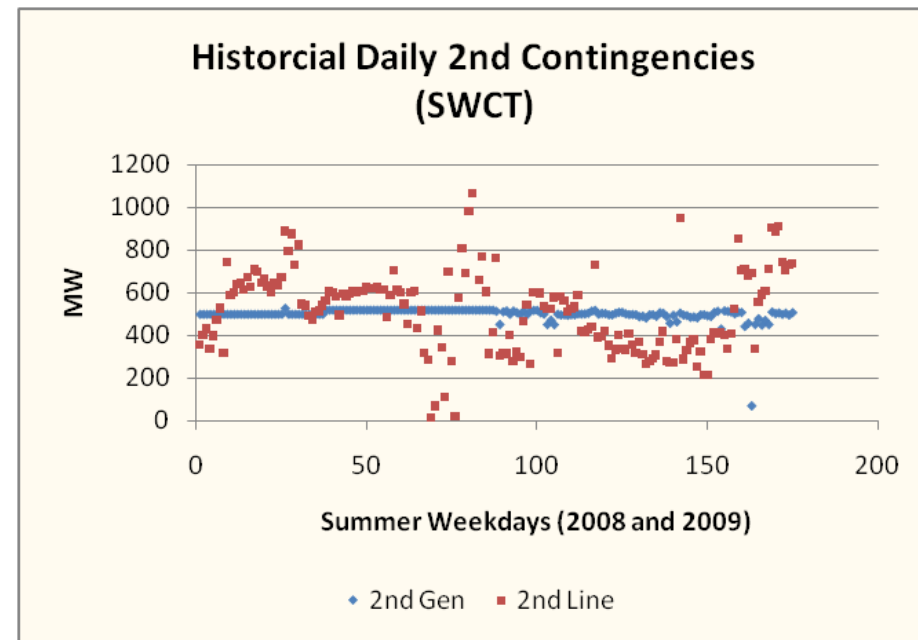


# Simulation Procedure to Generate dLRR data

- After input variables randomly sampled
  - Process 1.0
    - $2\text{nd Gen} = \text{Limit}_{N-1} - \text{Limit}_{N-2, \text{Gen}} + \text{CONTG} - 30\text{ACT}$ .
  - Process 2.0
    - $2\text{nd Line} = \text{Limit}_{N-1} - \text{Limit}_{N-2, \text{Line}} - 30\text{ACT}$ .
  - Process 3.0
    - $\text{ERS} = \text{Limit}_{N-1} - (\text{Load} - \text{Gen})$ .
  - Process 4.0
    - $\text{dLRR} = \text{Max}(2\text{nd Gen}, 2\text{nd Line}) - \text{ERS}$ .
- After completion of simulation (thousands of iterations)
  - Process 5.0
    - Form frequency distribution of dLRR, and set LRR to 95<sup>th</sup> percentile of the distribution.

# Historical Summer Data - SWCT

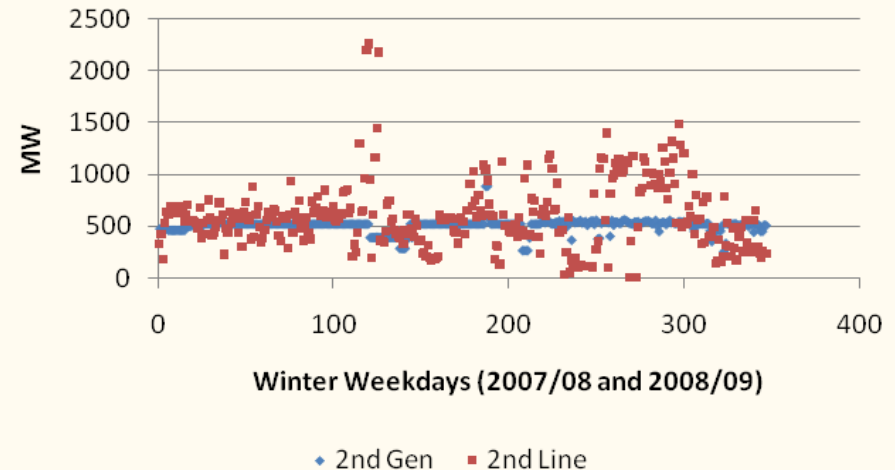
- 2<sup>nd</sup> contingency is a line or a generator with almost equal frequency
- 2<sup>nd</sup> Gen is relatively constant
- 2<sup>nd</sup> Line is volatile, and the magnitude can be much higher than 2<sup>nd</sup> Gen
- No reserve requirement for the zone for most days as adequate external reserve support can be obtained



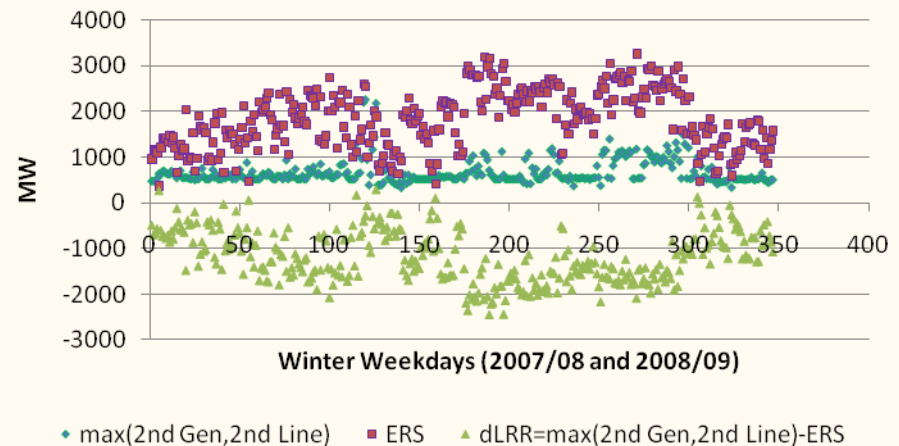
# Historical Winter Data - SWCT

- 2<sup>nd</sup> contingency is a line or a generator with almost equal frequency
- 2<sup>nd</sup> Gen is relatively constant
- 2<sup>nd</sup> Line is volatile, and the magnitude can be much higher than 2<sup>nd</sup> Gen
- No reserve requirement for the zone for most of the days as adequate external reserve support can be obtained

### Historical Daily 2nd Contingencies (SWCT)



### 2nd Contingency Requirement vs ERS vs dLRR (SWCT)



# Simulation Assumptions and Scenarios

## - SWCT

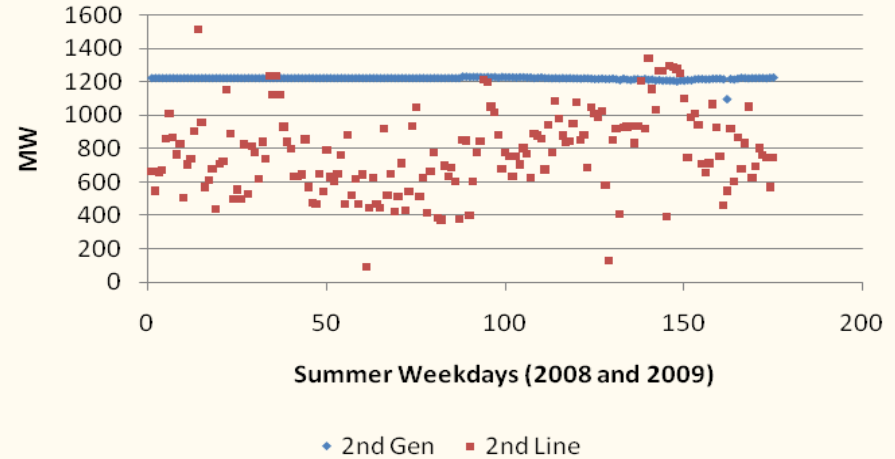
- 2<sup>nd</sup> Generation Contingency
  - Loss of Milford 1 and 2 (520 MW)
  - Assumed constant
- 2<sup>nd</sup> Line Contingency
  - Assumed constant at planning limits
    - N-1 Limit = 3,200 MW;      N-1-1 Limit = 2,300 MW
  - Also assumed to follow historical distribution as a sensitivity scenario
    - N-1 and N-1-1 Limits change dynamically with system conditions
- 30ACT
  - 10% (not to exceed 500 MW) of post 2<sup>nd</sup> contingency load shed for line-line condition.
- Loads
  - Passive DR is used to reduce load (values per 2010 CELT)
    - Summer: 94 MW (2010); 147 MW (2011); 187 MW (2012); 188 MW(2013,2014)
    - Winter: 89 MW (2010/11); 142 MW (2011/12); 182 MW (2012/13,2013/14,2014/15)
  - Both reference and high load forecast are used

# Historical Summer Data

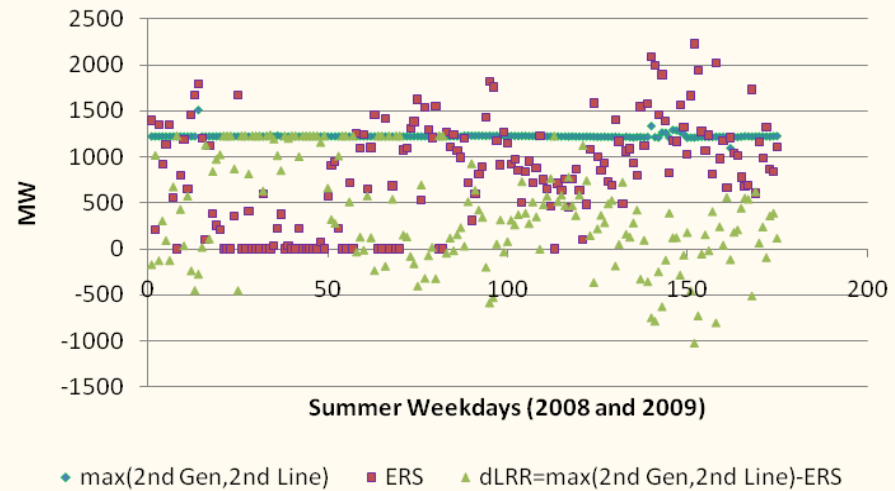
## - CT

- 2<sup>nd</sup> contingency is mostly a generator, and relatively constant
- Certain amount of zonal reserve is required for most days
- Reserve requirements can be as high as the 2<sup>nd</sup> contingency requirement for some days
  - Import capability has been used up for N-1 coverage, no room for external reserve support
  - RMR commitments have typically been made during these hours
- Lower zonal reserve requirements observed in 2009 as compared to 2008
  - Higher N-1 limits observed in 2009
  - Slightly lower loads in 2009

### Historical Daily 2nd Contingencies (CT)



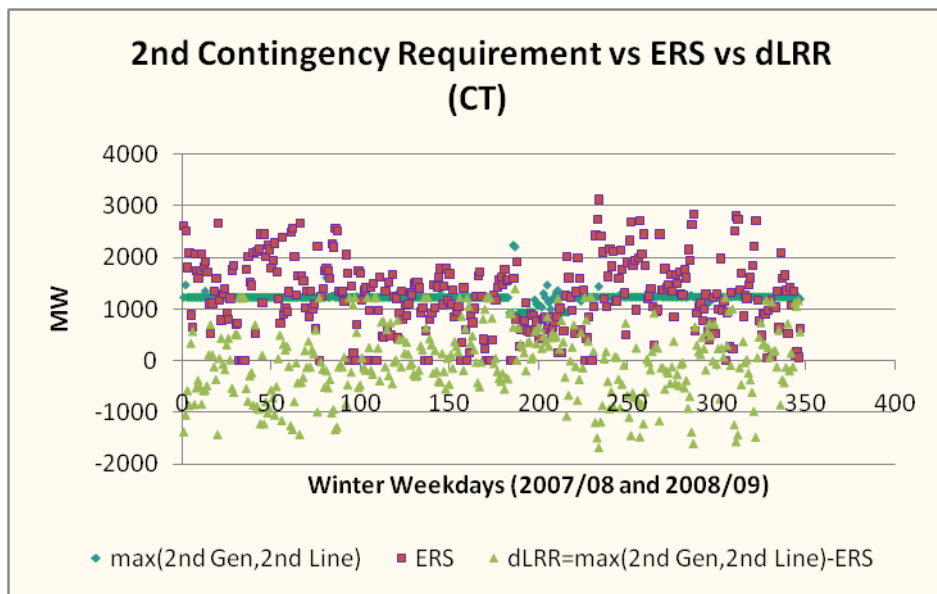
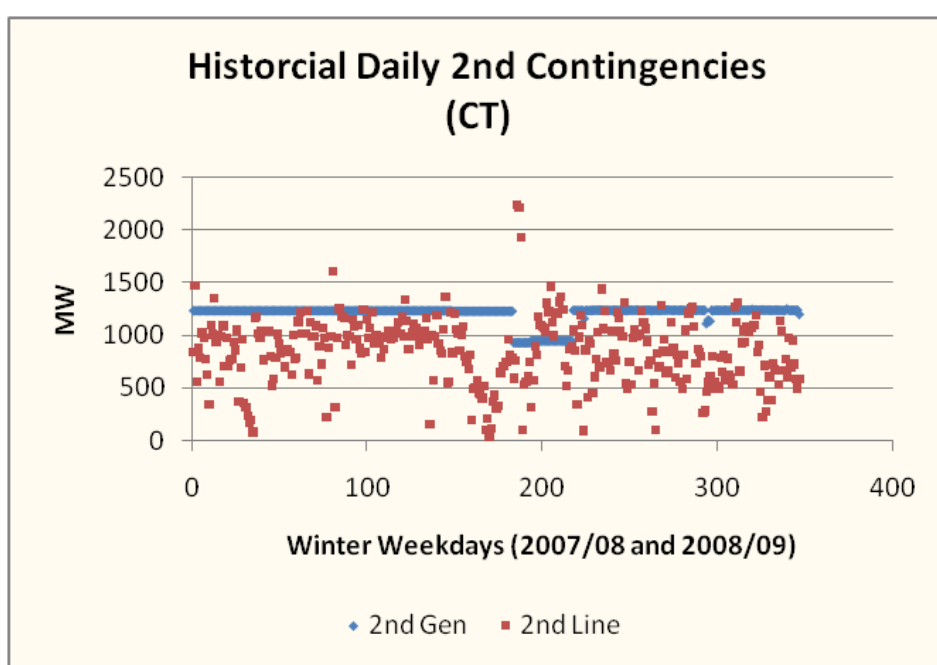
### 2nd Contingency Requirement vs ERS vs dLRR (CT)



# Historical Winter Data

## - CT

- 2<sup>nd</sup> contingency is mostly a generator, and relatively constant
- Certain amount of zonal reserve is required for 50 percent of the days
- Reserve requirements can be as high as the 2<sup>nd</sup> contingency requirement for some days
  - Import capability has been used up for N-1 coverage, no room for external reserve support
  - RMR commitments have typically been made during these hours



# Simulation Assumptions and Scenarios

## - CT

- 2<sup>nd</sup> Generation Contingency
  - Loss of Millstone Unit 3 (1,230 MW)
  - Assumed constant
- Interface Limits
  - Assumed constant at planning limits
    - N-1 Limit = 2,500 MW; N-1-1 Limit = 1,300 MW
  - Also assumed to follow historical distribution as sensitivity scenarios
    - Two distributions investigated
      - based on last 2-yr historical data
      - based on 2009 historical data only
- 30ACT
  - 10% (not to exceed 500 MW) of post 2<sup>nd</sup> contingency load shed for line-line condition.

# Simulation Assumptions and Scenarios

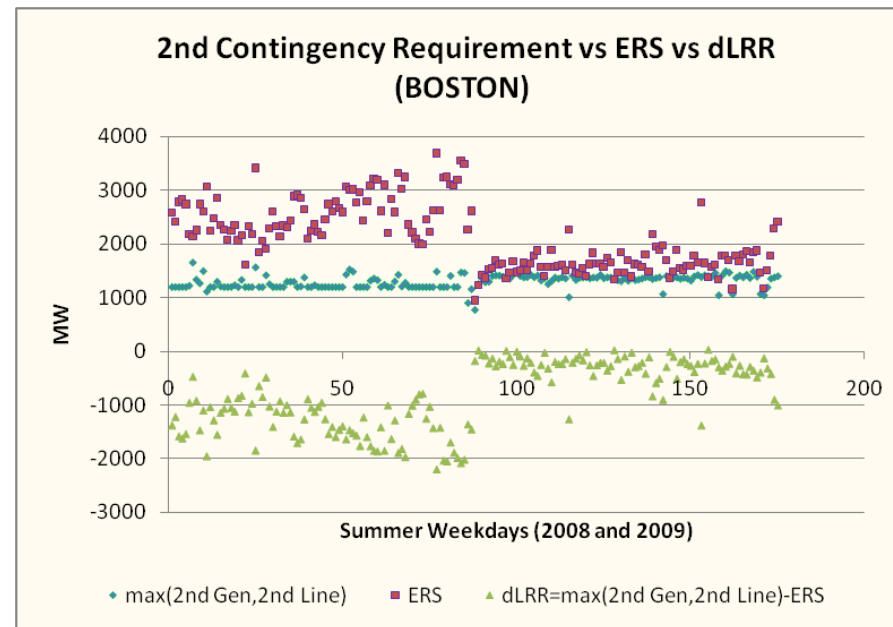
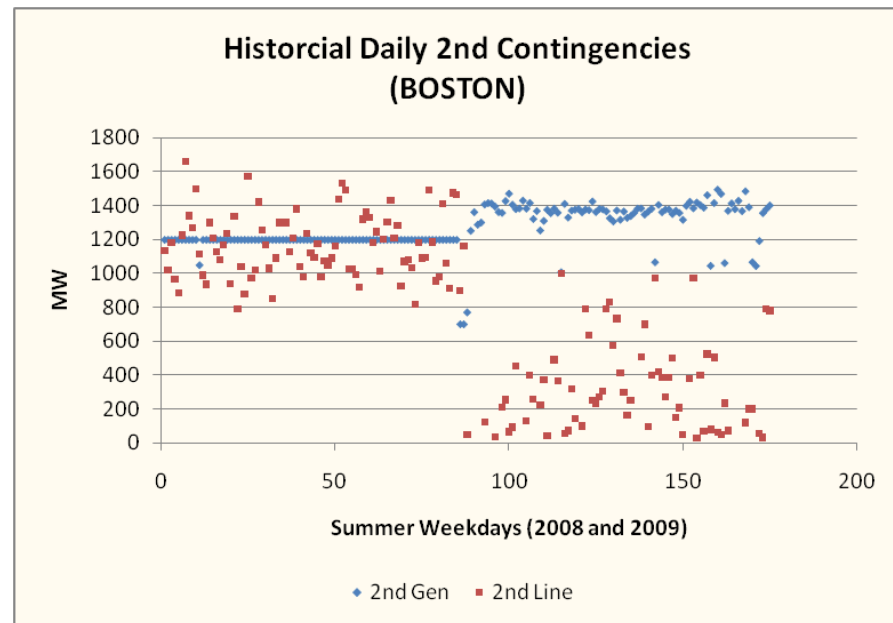
## - CT (cont.)

- Loads
  - Passive DR is used to reduce load (values per 2010 CELT)
    - Summer: 94 MW (2010); 147 MW (2011); 187 MW (2012); 188 MW(2013,2014)
    - Winter: 89 MW (2010/11); 142 MW (2011/12); 182 MW (2012/13,2013/14,2014/15)
  - Both reference and high load forecast are used
- NEEWS
  - Projected earliest in-service timeline is 2014
  - Not modeled in the study for summer period
    - 1<sup>st</sup> summer period it may have impacts on is 2015, which is beyond study period of this analysis
  - Modeled as a sensitivity for 2014/15 winter period
    - May have impacts on the 2014/15 winter period if placed in-service by April 30, 2014 and meets the availability criterion
    - Interface limits with NEWWS: N-1 Limit = 3,600 MW; N-1-1 Limit = 2,500 MW
- Kleen unit
  - Not modeled in this year's analysis as more information is required on its projected in-service date

# Historical Summer Data

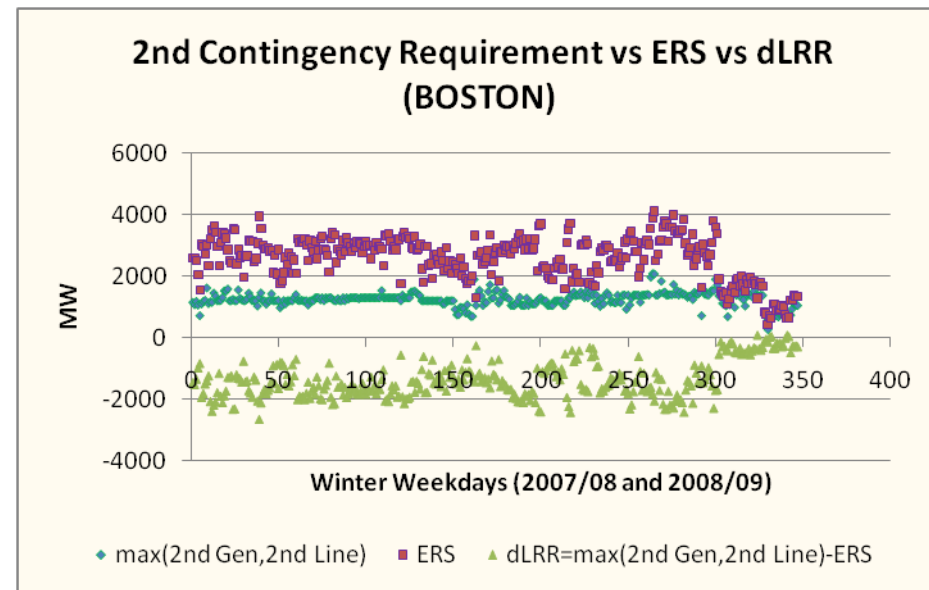
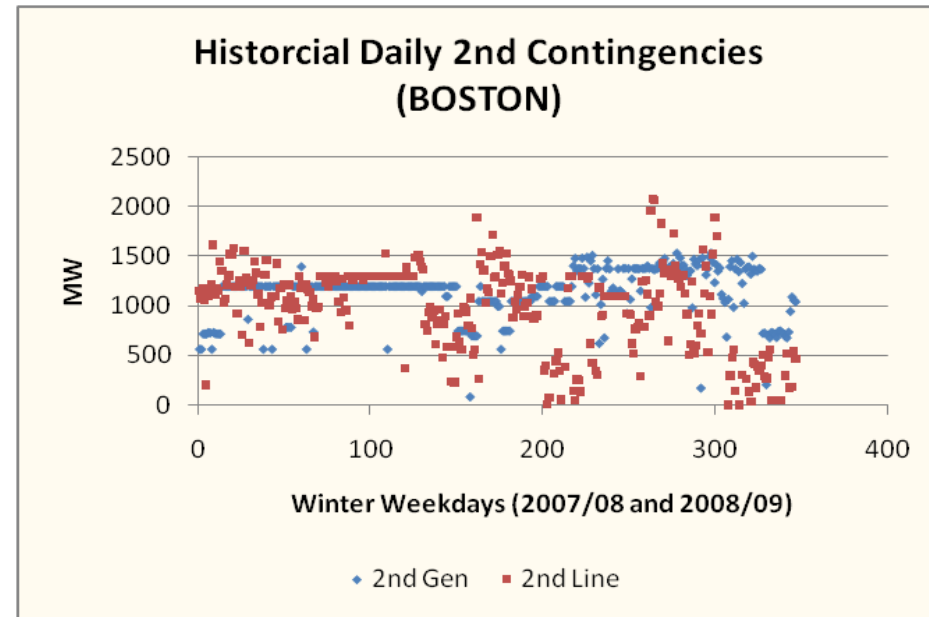
## - NEMA/BOSTON

- 2<sup>nd</sup> contingency is a line or a generator in 2008, and mostly a generator in 2009
- 2<sup>nd</sup> Gen is relatively constant, while 2<sup>nd</sup> Line is volatile
- No reserve requirement for the zone for most days as adequate external reserve support can be obtained
- Lower ERS in 2009, resulting in smaller margins to have a zonal requirement
  - Lower interface limits observed in 2009



# Historical Winter Data - NEMA/BOSTON

- 2<sup>nd</sup> contingency is a line or a generator with slightly higher frequency being a generator
- Both 2<sup>nd</sup> Gen and 2<sup>nd</sup> Line contingency is relatively volatile
- No reserve requirement for the zone for most days as adequate external reserve support can be obtained



# Simulation Assumptions and Scenarios

## - NEMA/BOSTON

- 2<sup>nd</sup> Generation Contingency
  - Loss of Mystic 8 and 9 (1,400 MW)
  - Assumed both constant and to follow historical distribution
- 2<sup>nd</sup> Line Contingency
  - Assumed constant at planning limits
    - N-1 Limit = 4,900 MW;      N-1-1 Limit = 3,700 MW
  - Also assumed to follow historical distribution as a sensitivity
    - N-1 and N-1-1 Limits change dynamically with system conditions
- 30ACT
  - 400 MW of post 2<sup>nd</sup> contingency load shed for line-line condition.
- Loads
  - Passive DR is used to reduce load (values per 2010 CELT)
    - Summer: 109 MW (2010); 139 MW (2011); 210 MW (2012,2013,2014)
    - Winter: 107 MW (2010/11); 136 MW (2011/12); 207 MW (2012/13,2013/14,2014/15)
  - Both reference and high load forecast are used

# Simulation Results

Area/Improvement	Market Period <sup>(a)</sup>	Fast-Start Resources Offered into the Forward Reserve Auction (MW) <sup>(b)</sup>	Representative Future Locational Forward Reserve Market Requirements (MW)	
			Summer (Jun to Sep) <sup>(c)</sup>	Winter (Oct to May) <sup>(c)</sup>
Greater Southwest Connecticut <sup>(d)</sup>	2010	TBD(summer) 426(winter)	0 <sup>(e)</sup>	TBD
	2011		0	0
	2012		0	0
	2013		0	0
	2014		0	0
Greater Connecticut <sup>(f,g)</sup>	2010	TBD(summer) 1,170(winter) <sup>(h)</sup>	1,225 <sup>(e)</sup>	TBD
	2011		1,000 to 1,250	900 to 1,250
	2012		1,000 to 1,250	800 to 1,150
	2013		1,000 to 1,250	725 to 1,100
	2014		1,050 to 1,250	750 to 1,100 0 (w/NEEWS)
NEMA/BOSTON <sup>(g,i)</sup>	2010	TBD(summer) 34(winter)	0 <sup>(e)</sup>	TBD
	2011		0 to 100	0
	2012		0 to 125	0
	2013		0 to 125	0
	2014		0 to 150	0

\* TBD – values will be available by RSP10 publication

# Footnotes for Prior Table

- (a) The market period is from June 1 through May 31 of the following year.
- (b) These values are based on the megawatts of resources offered into the forward-reserve auction. The summer value is based on resources offered for the summer 2010 forward-reserve auction, and the winter value is based on resources offered for the winter 2009/2010 forward-reserve auction. A summary of the forward-reserve auction offers is available online at [http://www.iso-ne.com/markets/othrmkts\\_data/res\\_mkt/summ/2009/forward\\_reserve\\_auction\\_results.pdf](http://www.iso-ne.com/markets/othrmkts_data/res_mkt/summ/2009/forward_reserve_auction_results.pdf).
- (c) “Summer” means June through September of a capability year; “winter” means October of the associated capability year through May of the following year (e.g., the 2010 winter values are for October 2010 through May 2011). The representative values show a range to reflect load uncertainty.
- (d) The assumed N-1 and N-1-1 values to reflect transmission import limits into Greater Southwest Connecticut are 3,200 MW and 2,300 MW respectively.
- (e) These values are actual locational forward-reserve requirements. Requirements for future years are projected on the basis of assumed contingencies.
- (f) The assumed N-1 and N-1-1 values to reflect transmission import limits into Greater Connecticut are 2,500 MW and 1,300 MW respectively. Those limits are assumed to increase to 3,600 MW and 2,500 MW respectively in 2014 if the New England East–West Solution (NEEWS) project is placed in-service.
- (g) In some circumstances, when transmission contingencies are more severe than generation contingencies, shedding some load may be acceptable.
- (h) This value includes resources in Greater Southwest Connecticut. The amount offered to the Connecticut **summer 2009** locational forward 10-minute operating reserve (LFTMOR) auction was **597 MW**, and the amount offered to the winter 2009/2010 auction was 744 MW.
- (i) The assumed N-1 and N-1-1 values to reflect transmission import limits into Boston are 4,900 MW and 3,700 MW respectively. The operating-reserve values for NEMA/BOSTON would be lower without consideration of the common-mode failures of Mystic units #8 and #9 that were assumed to trip up to 1,400 MW because of exposure to a common failure of the fuel supply to the units.

# Software Used for Simulation

- Crystal Ball (Professional Edition)
  - Crystal Ball is an Excel based risk analysis, simulation and optimization software marketed by Decisioneering (a division of Oracle/Hyperion).
  - an add-in module to Microsoft Excel to provide an easy way to perform forecast simulations.
  - uses Monte Carlo simulation to generate a wide range of possible optimized outcomes in terms of the range of forecast outputs and their probabilities based on the input assumptions.
- <http://www.oracle.com/crystalball/index.html>

# Questions?