Reliability Analyses in Resource Adequacy Assessments

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Reliability Concepts Outline

- Reliability Concepts
  - – Basic reliability concepts
    - Defining a loss-of-load event
    - System security
  - – Various reliability indices
  - – Reliability Criterion
    - Days per year,
    - Hours per year
    - Un-served MWh per year
    - Average outage duration
    - Maximum magnitude
  - – Westinghouse Capacity Model
    - Load distributions
    - Resource distributions

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Reliability Concepts Outline

- Reliability Concepts (continued)
  - Calculation of Loss of Load indices
    - Effect of adding / removing generating resources
    - Effect of adding / removing demand resources
    - Less dependable resources (Higher EFOR)
    - More dependable resources (Low EFOR)
  - Calculation of Installed Capability Requirements (ICR)
    - Concept of Additional Load Carrying Capability (ALCC)
    - Issue with ALCC representation of additional load skewness
  - Expansion and Proxy Units

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Reliability Concepts Outline

- Reliability Concepts (continued)
  - MARS Reliability Model
    - Load models
      - Matching the Westinghouse distributions for total New England
      - Expanding to RSP subarea loads
    - Monte Carlo technique
  - Calculation of total tie benefits
    - Current tie benefit protocol
    - Previous tie benefit methodologies
    - Effect of Emergency Operating Procedures on tie benefits
  - Larger footprint reliability models
    - Inclusion of PJM and Ontario
    - Large footprint issues

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Reliability Concepts Outline

- Tie Benefit Allocation
  - Allocation to specific interconnections
  - Allocation of benefits to specific ties
- Internal constraints
  - Internal to New England
    - Local Reliability Adequacy (LRA)
    - Maximum Capacity Limit (MCL)
  - Bringing an area to criterion
- "As-Is" vs. "At-Criterion"
- External Capacity Contracts
  - Current process
  - Tie Line Reliability Adjustment (TLRA) [Not covered]

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Reliability Concepts Outline

- Reliability Concepts (continued)
  - Other Issues
    - Maintenance requirements
    - Wind capacity value [Not covered]
    - Availability at time of peak
  - Risk Profile Concepts

Reliability Studies 101

Reliability Studies

- Reliability studies are based on probabilistic assessments
  - Probabilistic assessments are translated into adequacy metrics
    - Percent reserve margins
    - Percent capacity margins
    - Amount of resources needed
    - Maximum peak load that can be served
  - Probabilistic assessments assume
    - Some factors are correlated
      - All areas / regions see the same heat wave at the same time
      - A resource outage can be correlated to an interface rating change
      - Seasonal derating
    - Many reliability risks are random and independent (stochastic)
      - One resource outage does not affect the outage of another resource

Probabilities In Reliability Studies

- For every hour, of every day, the probability of insufficient resources to serve load can be quantified
  - For most hours this probability is (virtually) zero
  - For some hours, the probability is non-zero and has a contribution
  - Basic metric is “Loss of Load Probability” or “LOLP”
    - Given a load distribution and a supply distribution
      - LOLP is the probability of insufficient resources to serve load
      - There are no “measurement units” associated with a probability
      - “Measurement units” are “per period,” “per event” or “per coin flip,” etc.
- Operational errors are not considered (perfect foresight)
  - All resources are assumed to be available if they are not “broken”
  - All resources are assumed to be committed in a timely manner
  - No resources are unavailable due to higher than expected loads
  - All transmission elements are in service (with only N-1 considered)

“Expectations” In Reliability Studies

- Reliability Index is “Loss of Load Expectation” or “LOLE”
  - LOLP is calculated for each time period
    - Peak load of the day, or
    - Each hour (including the peak hour)
  - Time period used depends on desired reliability index
    - Every hour
    - Every contiguous event (i.e. possibly more than one per day)
    - Every daily peak (i.e. a day is limited to one Loss of Load event)
  - Summation of the LOLPs over a specified period of time
    - 5-day-week, 7-day-week, month, season, year or ten-years
    - Gives an **“expectation”** of how many occurrences could be experienced over a period of time
  - Index value is influenced (somewhat) by model mathematics

LOLE Reliability Indices

- Loss of Load Expectation (LOLE)
  - Has wide acceptance in electric power industry
  - Various techniques for calculation of reliability
  - Same distributions in different techniques will give similar results
- Review shows that a LOLE index of 0.1 days per year
  - Resembles an acceptable threshold for unreliability
  - The risk has grown from *"unlikely to happen"* to *"you know … a shortage could actually occur"*
- Acceptability of LOLE index is based on stakeholder involvement
- Emergence of "convenient" demand resource technologies allows customers to chose their level of reliability

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LOLE Fundamentalists

- Some people like to go back to the seminal, or fundamental, papers that
  - First applied probability to power system adequacy, and
  - Introduced the 0.1 days per year loss of load expectation

Calabrese, Giuseppe, "Generating Reserve Capacity Determined by the Probability Method," American Institute of Electrical Engineers, Transactions of the , vol.66, no.1, pp.1439-1450, Jan. 1947
URL: http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=5059596&isnumber=5059393

Calabrese, G., "Determination of Reserve Capacity by the Probability Method," American Institute of Electrical Engineers, Transactions of the , vol.69, no.2, pp.1681-1689, Jan. 1950
URL: http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=5060354&isnumber=5060205

Calabrese, G., "Determination of Reserve Capacity by the Probability Method Effect of Interconnections," American Institute of Electrical Engineers, Transactions of the , vol.70, no.1, pp.1018-1020, July 1951
URL: http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=5060518&isnumber=5060359

Other Probabilistic Indices

- Loss of Load Hours (LOLH)
  - The expected number of hours when shortages would occur
  - LOLH (hours/year) ***is not*** LOLE (days/year) times 24
    - 0.1 days / year * 24 hours / day = 2.4 hours per year
      - Would happen only if peak occurred in each of the 24 hours of the day
      - New England's LOLH would be about 0.3 to 0.5 hours per year
- Loss of Energy Expectation (LOEE or EUE)
  - Measure of how many MWhs would be lost in each hour times the probability of shortage (used for comparing load shape changes)
- Frequency & Duration (F&D)
  - Indication of how frequently outages would occur and how long they might last (used for comparing load shape changes)
- Loss of Reserve Expectation (LORE)
  - Indication of how often emergency operations would be required

Reliability Assessment

- Two broad approaches to reliability assessment
  - Loss of Load Expectation (LOLE)
  - Frequency and Duration (F&D)
- F&D
  - Requires additional data: generally unavailable
  - Concentration of risk in summer makes “frequency” measurement less meaningful
  - Daily load shapes make “duration” measurement less insightful
- A “bad day” is a “bad day” whether 1 or 6 hours

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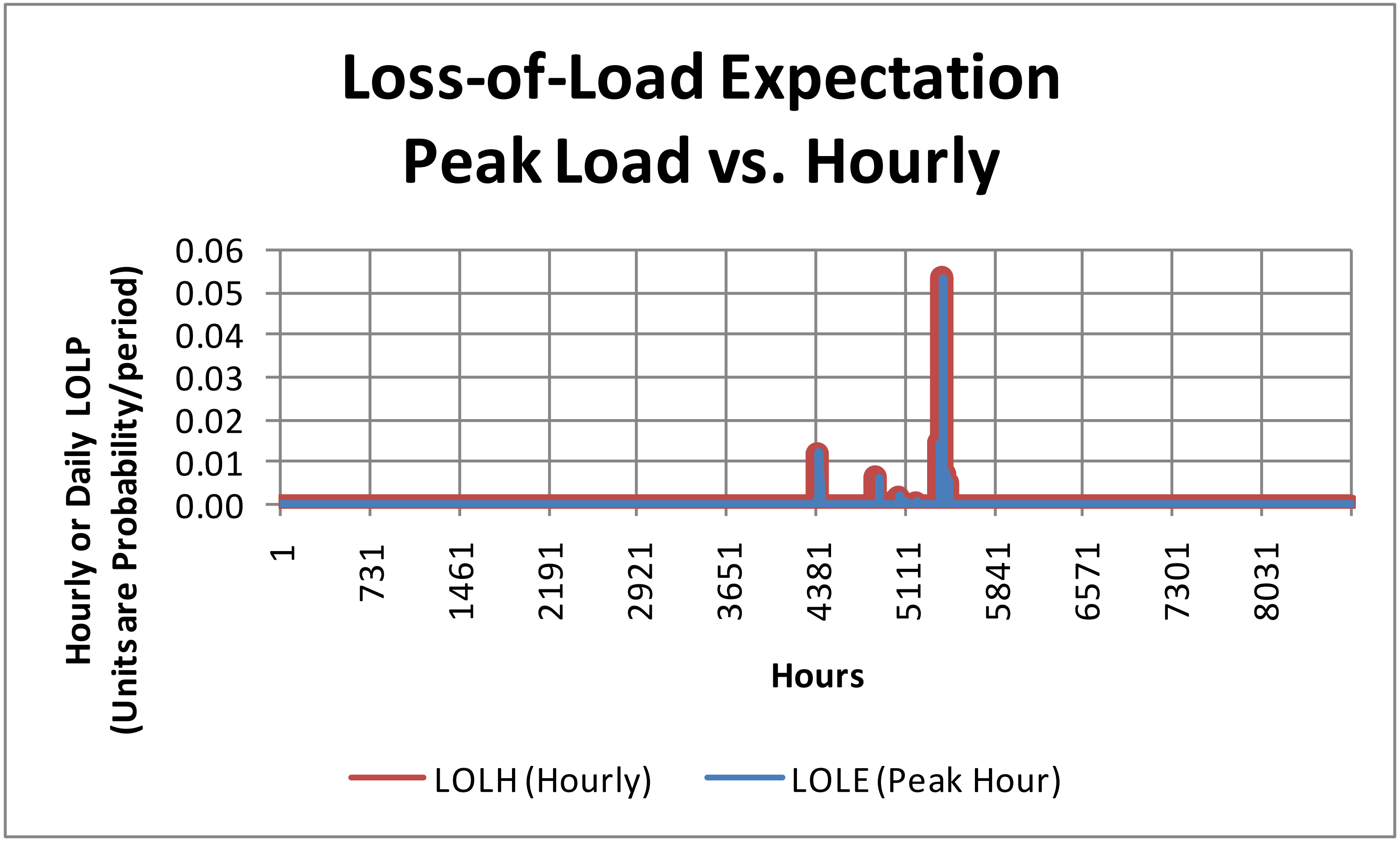
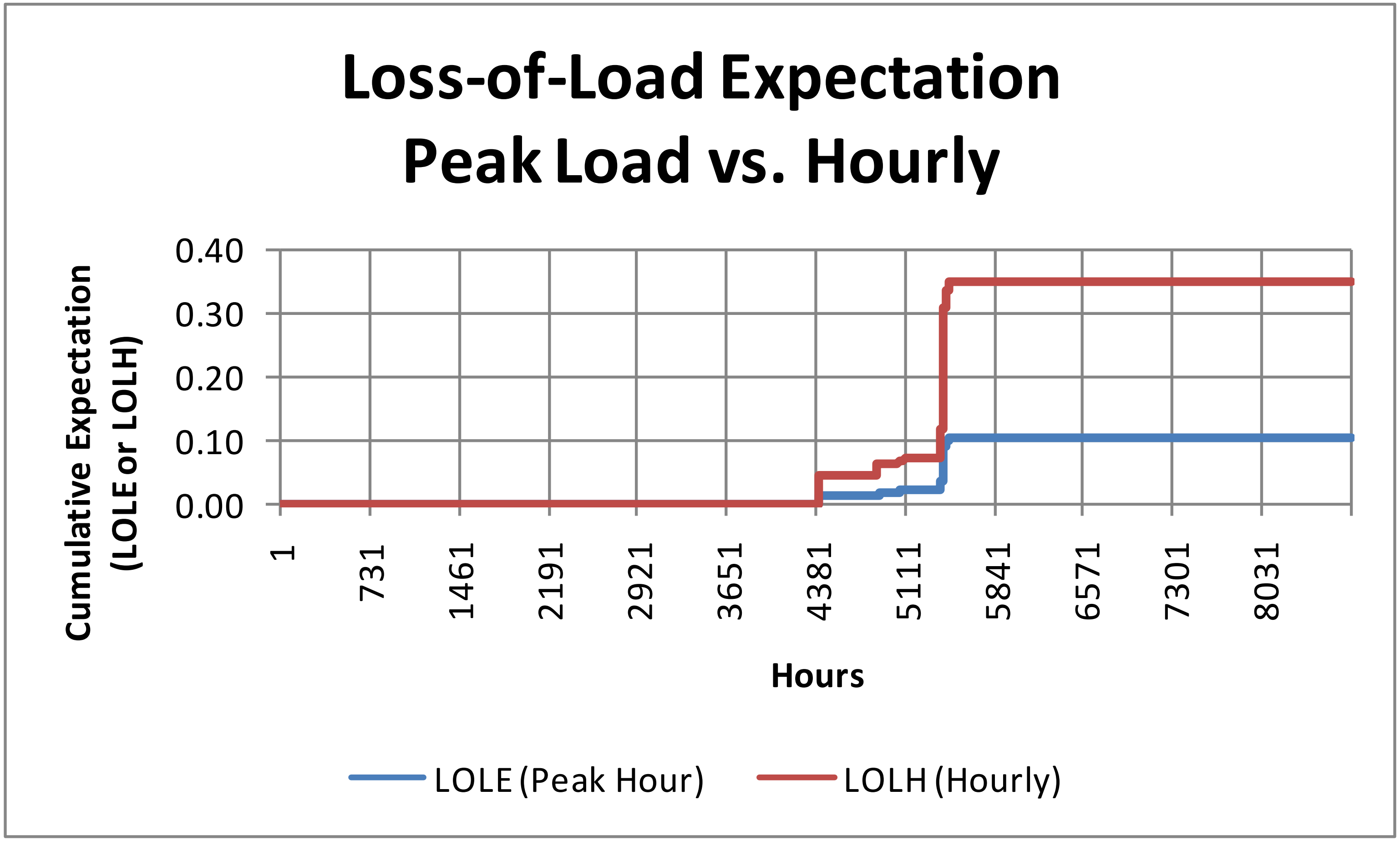
Loss of Load Probability / Period (LOLP)



Note: "Peak Hour" LOLP is the maximum hourly value within the preceding 24 hours and is added at hour 24

Illustration of Annual "Expectations"



Relative Equivalence of Indices

- Expressing reliability with different measurement units does not provide additional information about the reliability of the system
  - "Measurement units" may not describe "different aspects" of reliability
  - Indices expressed using "different terms" may highlight secondary effects
- A parallel for "measurement units" can be made to a person's height
  - The height of the presenter can be stated in different ways.
    - 6 feet tall
    - 72 inches tall
    - 182 centimeters tall
    - 18 hands tall (as used in measuring horses)
    - 0.001136 miles tall
- Indices can reflect "different aspects" for more information
  - Total height
  - Total height and weight
  - Total height, weight and shoe size

Why Use Probabilities

- Other techniques provide little quantification of risk
  - Percent reserve margin
  - Deterministic criterion
    - Largest unit rule
    - Largest unit and half of second largest unit rule
  - Historically, these techniques were suitable for
    - Small, isolated utilities
    - With ever-larger units being added
    - In the 1950's and 1960's these techniques were augmented by, and then replaced by probability techniques
- Probability techniques address the question:
  - What is the risk of insufficient resources to serve peak loads
  - Allows performance of different generators to be compared against a common standard

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Reliability Risk Measurements

- Single bus resource adequacy assessment
  - Measures Generation adequacy; and
  - Load Response Program (LRP) adequacy
- Constrained Multi-Region assessment
  - Includes regional component with inter-area Transmission risk
- Constrained Multi-Area assessment
  - Includes some amount of internal transmission constraints
  - Includes locational component w/o additional T&D risk
- Composite reliability assessment
  - Generation and LRP adequacy risks plus
  - Transmission and Distribution risks
  - "Delivered-to-the-customer-terminal" reliability

Customer Delivery Risk Factors

- Inclusion of additional risk factors (eg. T&D) change the magnitude of the reliability index
  - More risk factors means higher risk of problems
  - Observed, historical sub-area unreliability not usually a resource adequacy problem
    - Transmission outages
    - Uncommitted generators
    - Localized “common mode” generator failures
  - Additional risk factors (T&D) would increase the acceptable criterion
- If resource adequacy is the issue, LOLE index should be uniform across areas

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Inter-Regional Indices

- Historically, transmission constraints have been included only between NPCC regions
  - Tie line capability is based on an all-lines in service (N-1) limit with worst contingency
    - Each area in isolation is less reliable than 0.1 days/year
    - Interconnection improves reliability of both regions
- Criterion is meet when all regions are interconnected and at 0.1 days/year

Applicability of LOLE Index

- Index of 0.1 days/year applied to large interconnected regions with transmission
- IS a measure of resource adequacy
- IS NOT a composite reliability assessment
  - Generation and LRP adequacy and
  - Transmission and Distribution adequacy
    - Accurate and comprehensive T&D reliability data is not available
  - "Delivered-to-the-customer" reliability

Reliability Measurement

- Observation of past reliability
  - Rarely do events demonstrate unreliability
  - Regions are usually above reliability criterion
  - Review of “close” calls
    - Implementation of OP-4 events: regional / local
    - Call on emergency assistance from neighbors
    - These are the signature of impending unreliability
  - Analysis of past performance can provide insights into future unreliability
    - Identification of factors that could be a source of additional risks
    - Risk profile studies

LOLE Criterion for Resource Adequacy

- This development of the LOLE index considers:
  - Possible levels of peak loads due to weather variations
  - Impact of assumed generating unit performance
  - Load and capacity relief obtainable (Through the use of ISO NE Operating Procedure No. 4 - Action During a Capacity Deficiency)
- Loss of Load Expectation (LOLE) index
  - A day with any loss-of-load counts only once
    - Does not describe how many hours load is interrupted
    - Two possible events in a single day
      - i.e. an outage at noon, then recovery, then an evening outage
      - Counts as only one day with loss-of-load
  - Does not quantify how many MW are interrupted
  - Does not quantify the number of MWhs interrupted

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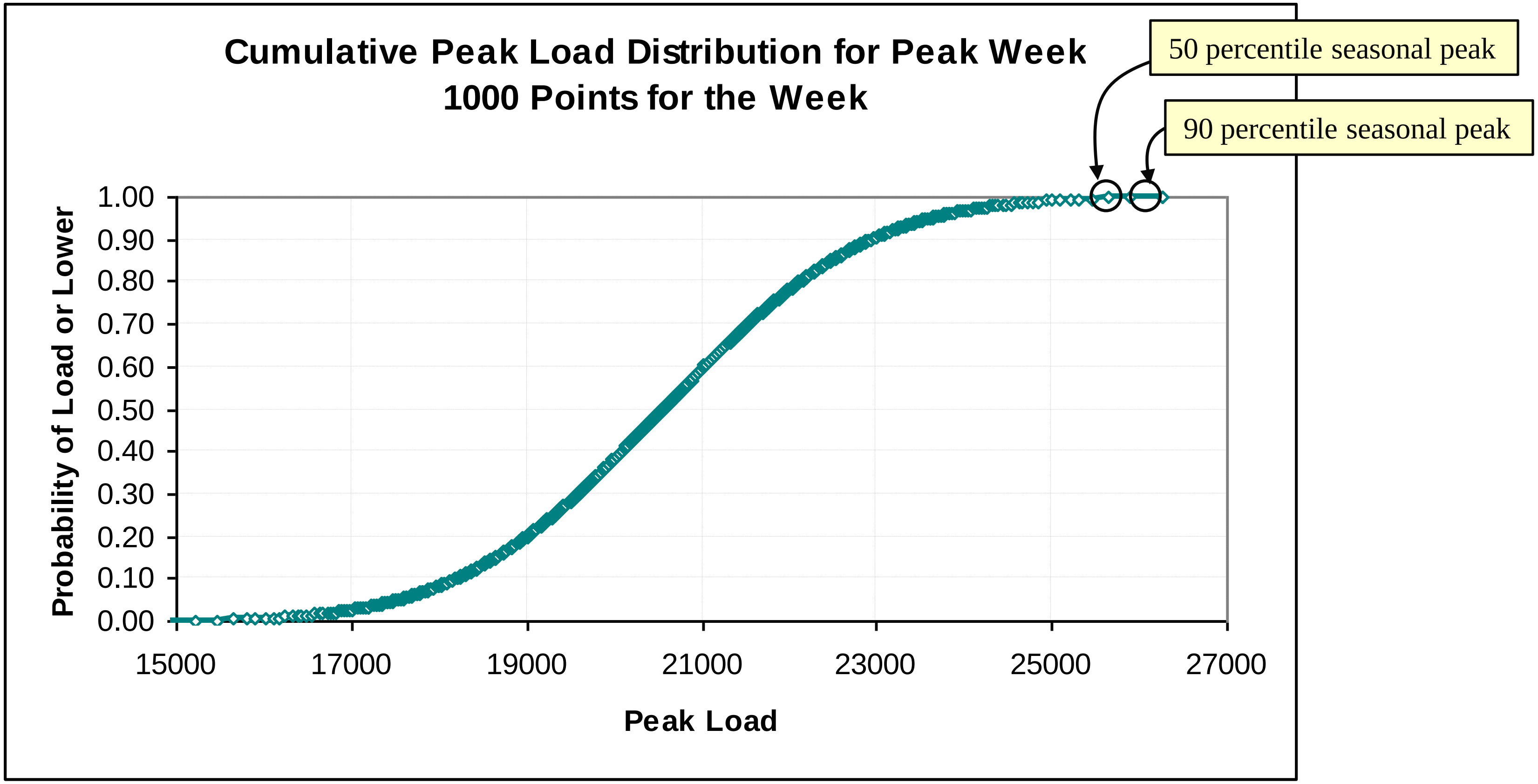
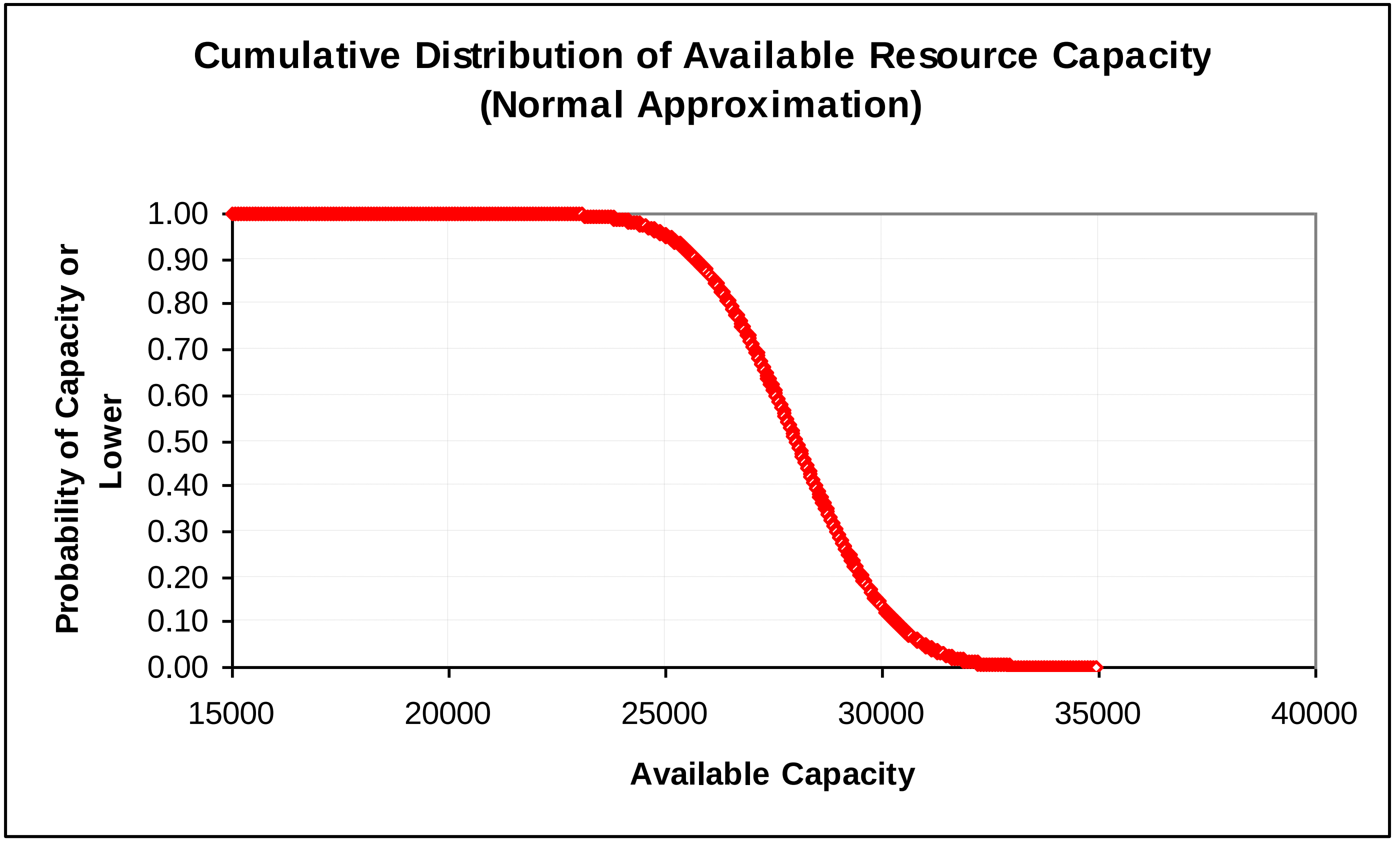
Models

- All reliability models address the same fundamental question: what is the “probabilistic” difference between
  - Load Distribution
  - Resource Distribution
- “Convolution” to determine probability of loads being higher than available resources
- Differences between models include:
  - Differences in mathematical solution technique (not the resulting answer)
  - Different factors that can be included
  - Different flexibility to represent correlations / actions

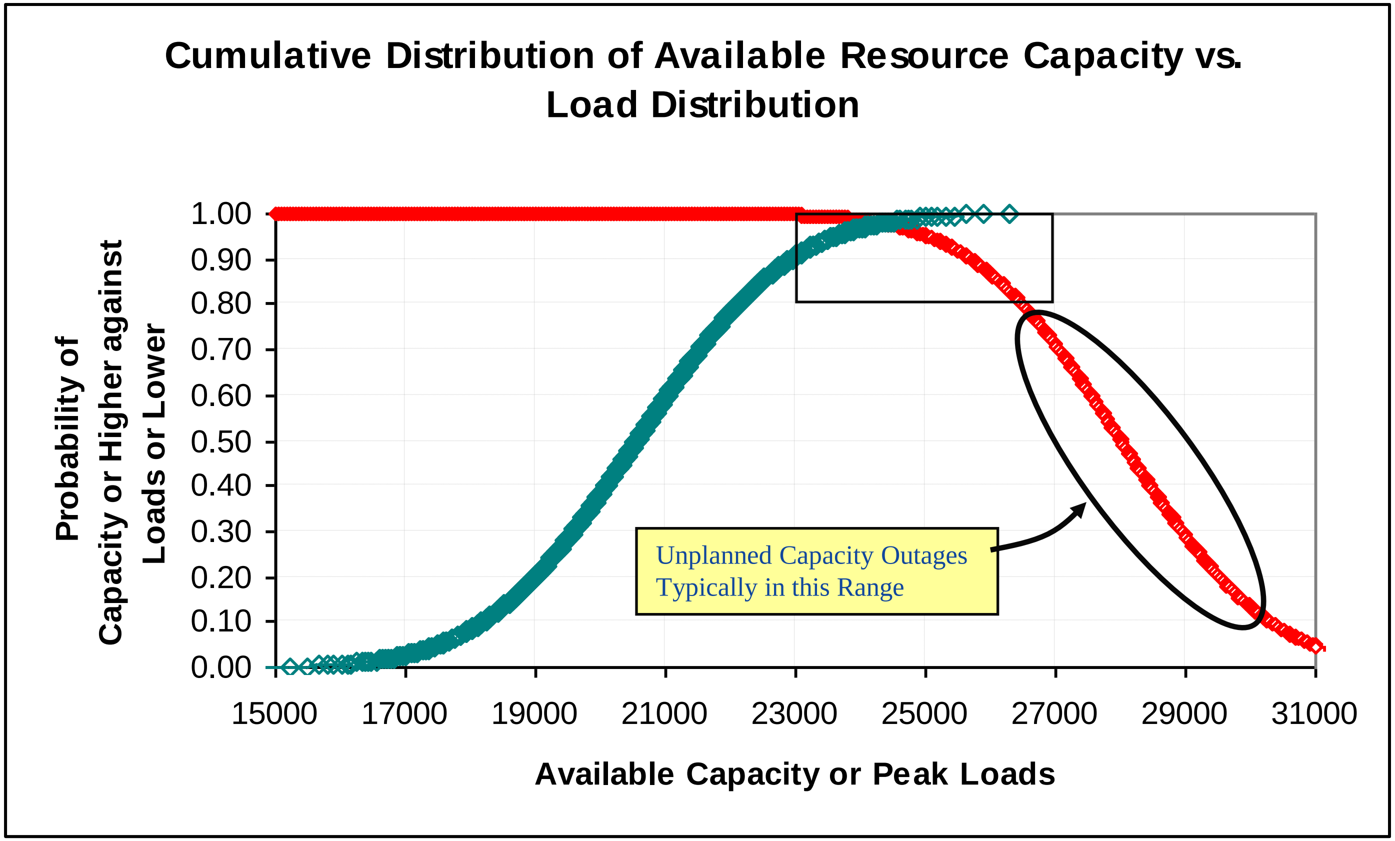
Distribution of Daily Peak Load



Distribution of Resources

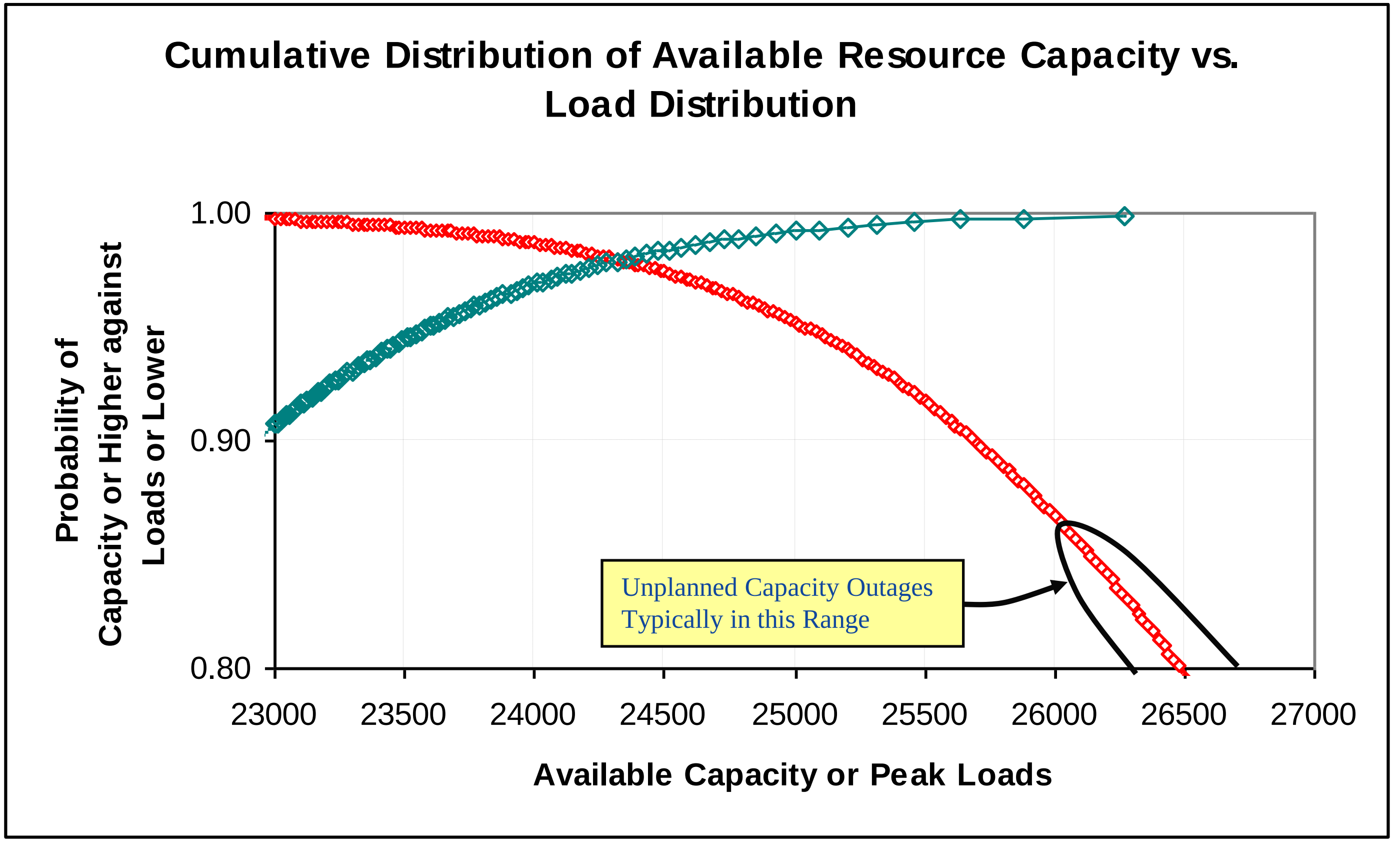


Resource and Load Distributions



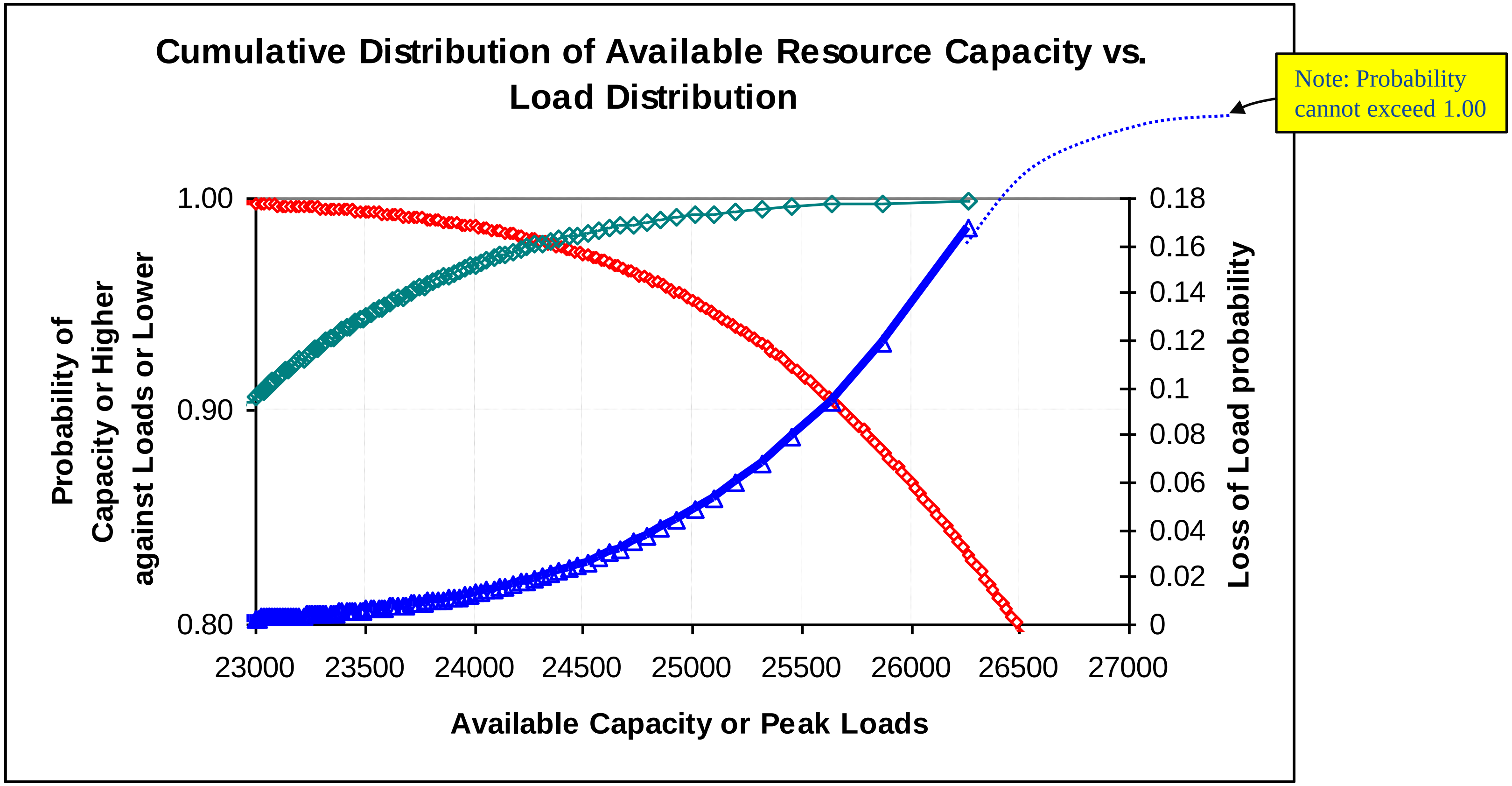
Note: Assuming no scheduled maintenance for resources during the peak load week

Resource and Load Distributions (zoom)



Note: LOLP is combination ("convolution") of loads higher than available capacity

Convolution of Distributions: LOLP



Notes: Each discrete load point has 1/1000th probability

Load and Capacity distributions represent 5 weekdays

LOLE for week is 0.16 probability * 5 days/week = 0.8 days/week

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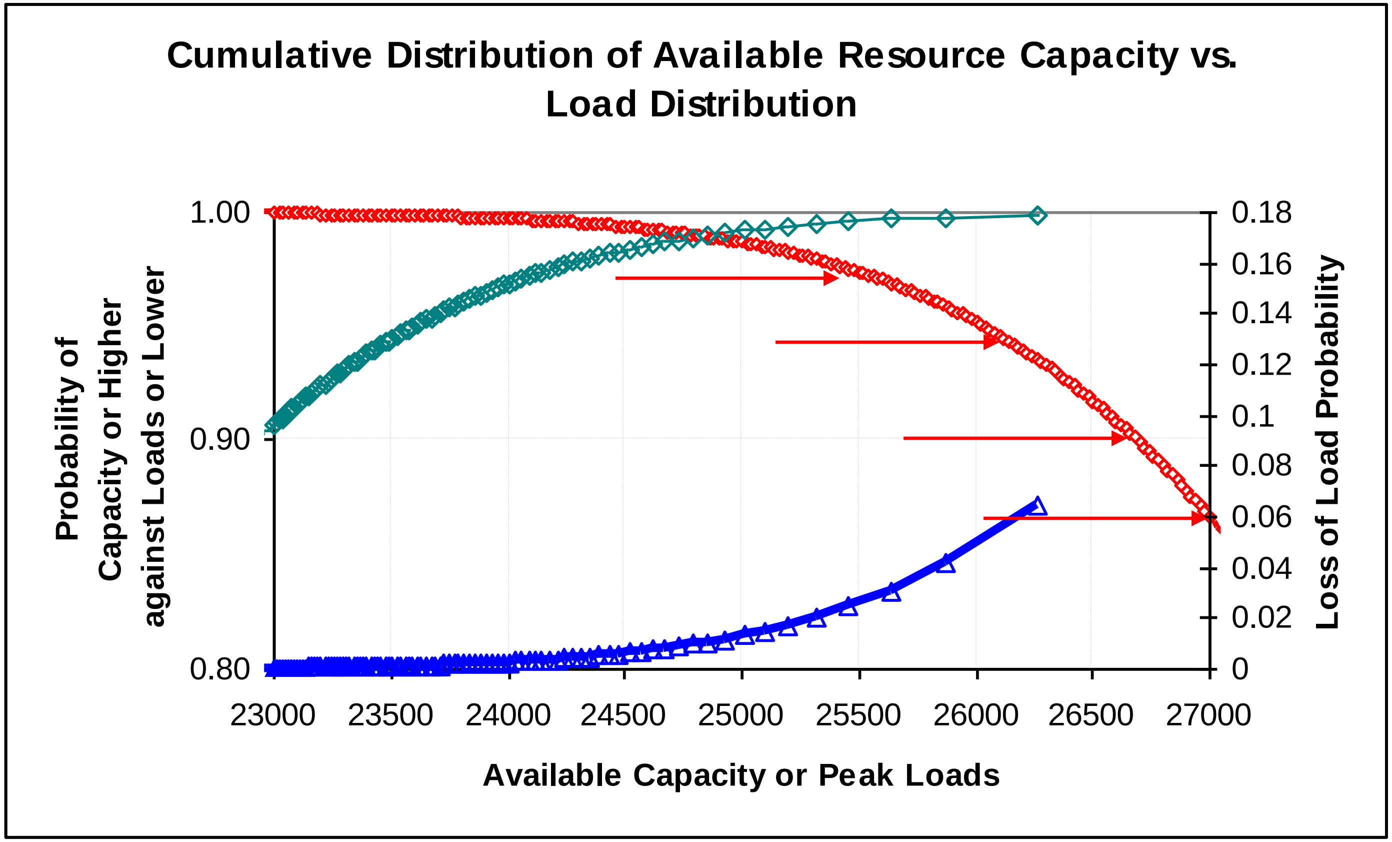
Additional Capacity Reduces LOLP



Notes: The addition of 1000 MW of resources reduces the LOLP from 0.16 to 0.06

The System … Has Been Changing

- NEPOOL has used the concept of Objective Capability for three decades
  - Objective Capability (ICR) has been renamed
    - Installed Capability Requirement (ICR)
    - No significant change
  - Thirty years ago New England was winter peaking
  - No significant interconnections to NB or HQ
  - Promise of nuclear energy looked bright
  - Load growth in 7 percent per year range
- Now strongly summer peaking
  - Many other characteristics are different

ISO New England Planning Criterion

- Installed Capacity Requirement (ICR) is the amount of available resources that New England needs to meet the ISO-NE / NPCC resource planning reliability criterion
- The reliability criterion requires that the expected frequency of interrupting firm customer loads, due to insufficient resources, be no more than once in ten years
  - This is the familiar Loss of Load Expectation (LOLE) criterion of 0.1 days with interruptions per year
    - More stringent than “one interruption in 10 years”
    - Because you can’t say: “in ten years we will be really reliable, so don’t worry about the poor reliability next year!”
- This one day in 10 years LOLE criterion is generally accepted as threshold for resource adequacy

Much of this was extracted from: http://www.iso-ne.com/committees/comm_wkgrps/othr/icsp/mtrls/2005/sep272005/technical_session_on_Westinghouse.ppt

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What is Installed Capability Requirement?

- Installed Capability Requirement (ICR) is the amount of capacity that New England needs to operate the system such that the risk of interruption of firm customer loads due to insufficient resources is no more than one day in ten years

- Installed Capability Requirement does not mean
  - That ***emergency actions*** will not occur more than one day in ten years
  - That there will be zero loss of load events

“Loss of Load” Events

What is a "Loss of Load" Event

- Interrupting firm customer load … of course!
- But when would firm load be interrupted?
  - No reserves remain and another contingency has just occurred
  - No reserves remain and pre-contingency load shedding activated
- Large footprint reliability models
  - What is the meaning of "No reserves remain"
  - How far away can operating reserves be helpful?

Activating Involuntary Load Shedding

- No reserves remain / contingency has just occurred
  - Operator intervention to begin manual load shedding
    - Operators must act and see if the system reacts as expected
    - Next contingency could possibly create cascading conditions
    - Contingency could be in the operator's area or a neighboring area
  - Hold breath and hope that relay schemes will operate correctly
    - Under Voltage Load Shedding (UVLS)
    - Under Frequency Load Shedding (UFLS)
    - Relay based automatic "islanding" may be disruptive
- No reserves remain: use pre-contingency load shedding
  - Helps ensures that the system will remain in control of operators
  - Risk of second-guessing by regulators
  - NERC's enforceable procedures may require this

Implementing “Loss of Load” outages

- UFLS and/or UVLS
  - It seems unlikely that operators will rely on Under-Frequency Load Shed (UFLS) or Under-Voltage Load Shed (UVLS) to handle the next loss a large resource
  - Outcome may not always be predictable
- NERC likely to take a dim view of operating the system very close to automatic protection limits
- Automatic protection systems are designed to protect equipment and not to provide supervisory control

Proposed guidelines for a “Loss-of-Load”

- NERC Generation and Transmission Reliability Modeling Task Force (G&TRPMTF) is proposing the following guidelines for NERC required analyses.

Calculation of “load loss”

i. Emergency operating procedures such as voltage reduction or public appeals are load loss. These are considered as firm load interrupted for the purpose of a uniform calculation of metrics.
ii. Document the Interconnection’s method of allocating load loss when one or more Metric Reporting Areas (MRAs) have surplus power and several MRAs have shortages. Include in this documentation the Interconnection’s method of modeling Reserve Sharing Groups.
iii. Document whether reducing the Spinning Reserve portion of Operating Reserves below the minimum requirement of the Balancing Authority is or is not considered a load loss (i.e., will a BA, after exhausting all purchase opportunities, shed firm load to maintain its spinning reserve requirement?)

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Westinghouse Capacity Model

Annual ICR Process

- Process
  - The ICR is established by ISO New England annually
    - One year ahead during the transition period
    - Up to three years into the future for FCM
    - In the distant past, the process included multiple year projections
  - Developed through a stakeholder process that includes regulators
    - Power Supply Planning Committee – reviews assumptions and develops ICR scenario(s) for Reliability Committee consideration
    - Reliability Committee reviews the ICR scenario(s) and votes a recommendation(s) to the Participants Committee
    - Participants Committee
      - reviews the recommended ICR value
      - Votes to support or not support the recommended ICR
  - ICR is filed with FERC after the Participants Committee vote

IC Requirements Process - Mechanics

- Westinghouse/ABB Capacity Model Program is used to calculate ICR
  - Sensitivities observed by running various cases
  - Generally one of the cases is adopted for establishing ICR
- Assumptions are reviewed during the annual update
  - Loads
  - Capacity resource characteristics
    - Maintenance estimator
    - Forced outage estimator
  - Resource additions and retirements
  - Load and Resource relief available through OP-4 actions (including Tie Benefits)

IC Requirements Process – Tools

- Westinghouse/ABB Capacity Model Program
  - It is a “Single Area” program
    - Single area refers to the assumption that there is adequate transmission to deliver energy where and when it is needed
    - All loads and generators assumed to be connected to a single bus
    - Maintenance scheduled to minimize LOLE throughout the year
  - Uses mathematical (i.e. “closed form”) technique for solution
  - Probabilistic calculations to capture the random nature of loads and resource availability
    - Determines the probabilities of different amounts of unavailable capacity on the system as a result of resource forced outages
    - Mathematics gets very complex if any transmission is included

IC Requirements Process – Tools

- Multi-area MARS model could be used
  - MARS is a "Multi-Area" program
    - Multi-area refers to the assumption that transmission constraints may impede delivery of energy to where and when it is needed
    - Loads and generators can be assumed to be connected to different parts of the system
  - MARS model uses different technique to "do the math" than Westinghouse/ABB
    - Uses "Monte-Carlo" sampling instead of "closed form" solutions
    - Exactly the same inputs would produce exactly the same results
      - Load distributions
      - Resource distributions
    - "Monte-Carlo" models can include more constraints than analytical "closed form" models because states are known

IC Requirements Process – Excluded Factors

- Major factors not considered in ICR calculations:
  - Common mode failures of resources
  - Catastrophic long-term resource outages
  - Delays in resource additions or retirements
  - Energy / fuel limited resources
    - Energy / fuel supply
    - Fuel delivery issues
  - Uncertainty in assumptions for forced outage rate statistics
  - Intra-hour load excursions
  - Internal transmission constraints or transmission forced outages
  - Effects of ambient air temperatures above 90^{o}F on combustion turbine technologies
  - Effect of air and water environmental restrictions
  - Number of days that will actually incur a loss of load

Load Model Used in IC Requirements

- Uses distributions of daily peak loads for each week, explicitly taking into account weather uncertainty
  - Westinghouse load model is developed for
    - Non-holiday weekday peaks
    - Excludes weekend peaks
  - Assumes weekend peak contribution to system risk is negligible
    - Weekend peaks are much lower that weekday peaks
    - Risk of not having enough installed capacity is “much” lower
    - Weekend operational issues may reduce flexibility of the system
      - Resource maintenance
      - Transmission maintenance
      - More units on reserve shutdown (i.e. not needed)

Loads Model Development

- Loads represented by distributions of weekday peak loads
  - Represents daily peak loads only, not all hours
  - 52 weekly distributions for each year
  - Based on historical weather distributions from the last 3 decades
- These distributions are the key inputs in reliability studies
  - Projected monthly and seasonal peak loads
    - Are specific points on these load distribution curves
    - Specific points are useful as guideposts
      - 50/50 summer peak load is one point on composite distribution
      - 90/10 summer peak load is another point on composite distribution
  - Shape of load distributions affect the reliability calculations
  - Statistical parameters for the distributions are used to characterize the load levels with the probability of their occurrence

Peak Load Distribution Development

- For each of the 52 weeks of the forecast year
  - A distribution of 1000 possible peak load points are developed
    - Weather uncertainty is the primary uncertainty considered
    - Seasonal trends in composition of load (heating / cooling / other)
  - Distribution of raw peak load data
  - Raw peak load points approximated by a continuous distribution
    - Parameters estimated for three moments of the distribution:
      - Mean
      - Standard deviation
      - Skewness (fat / skinny tails)
    - Skewness is needed to capture the frequency of highest daily peak loads accurately as shown in next few slides
- The following distributions are illustrative and not for a specific year

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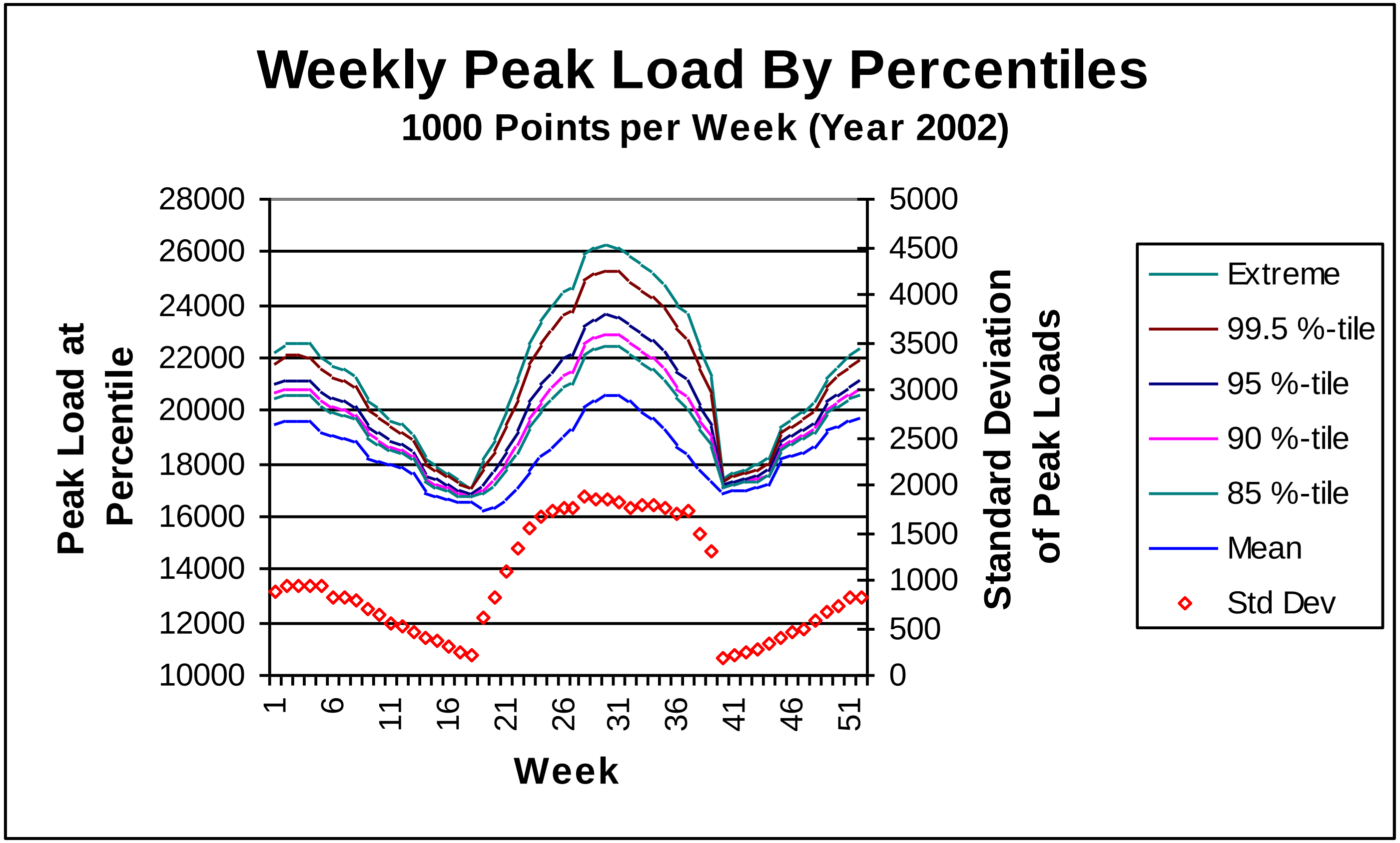
Illustration of Load Distributions



Note: Extreme peak loads shown have a very low probability of occurrence

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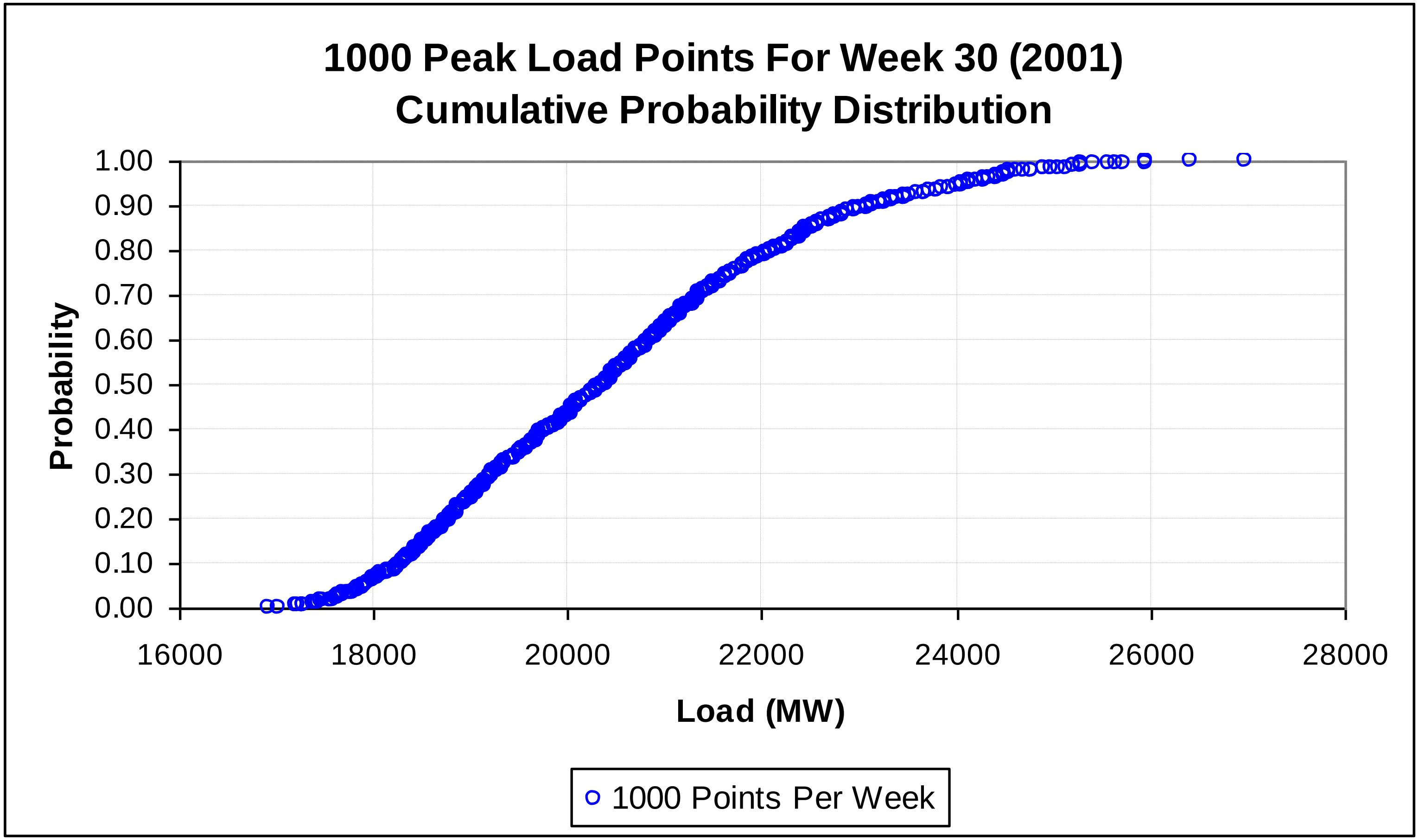
Reliability Calculation Details

Distribution of Raw Data for One Week



Note: Distribution represents 5 weekdays

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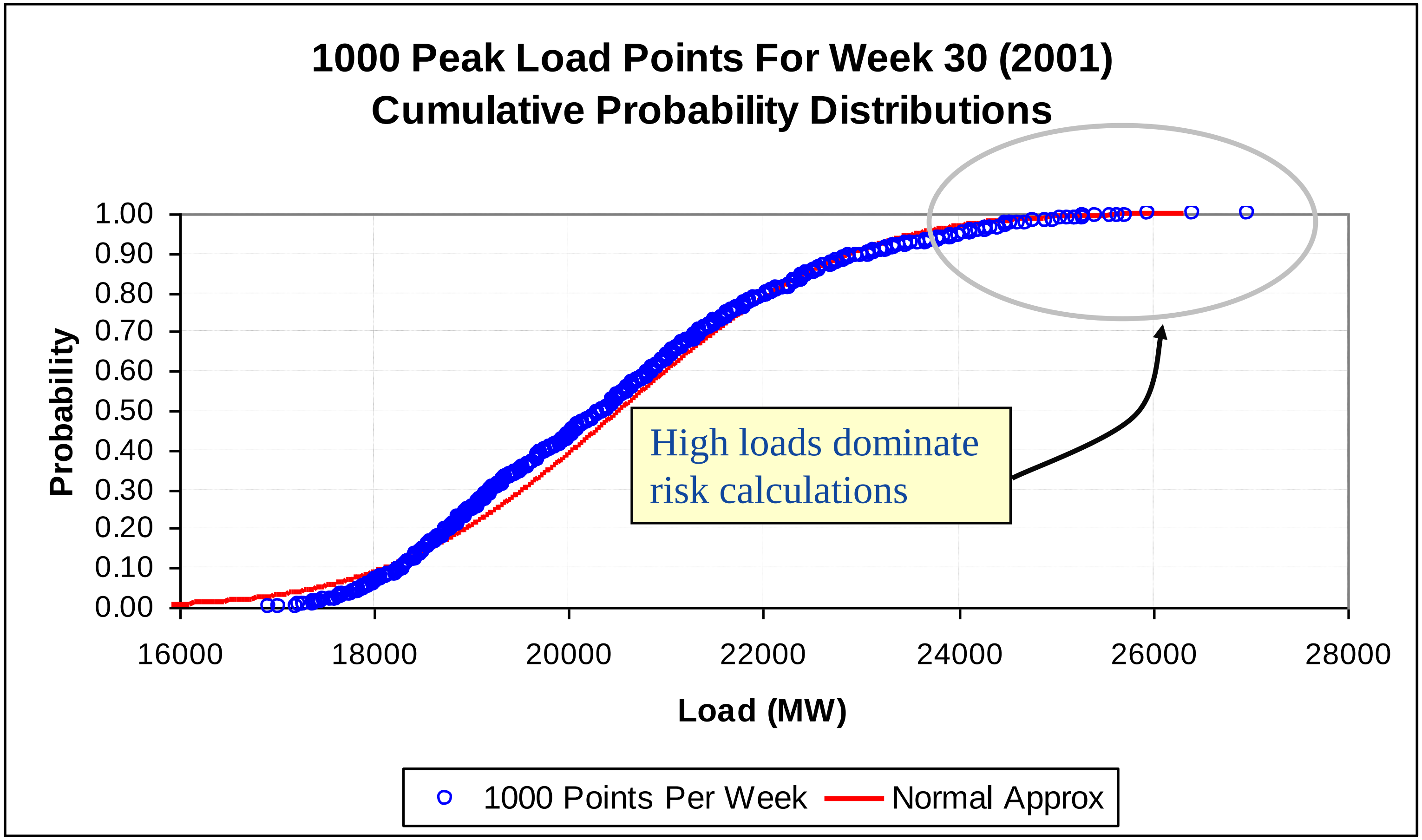
Normal Approximation is "Generally Good"



Note: Distribution represents 5 weekdays

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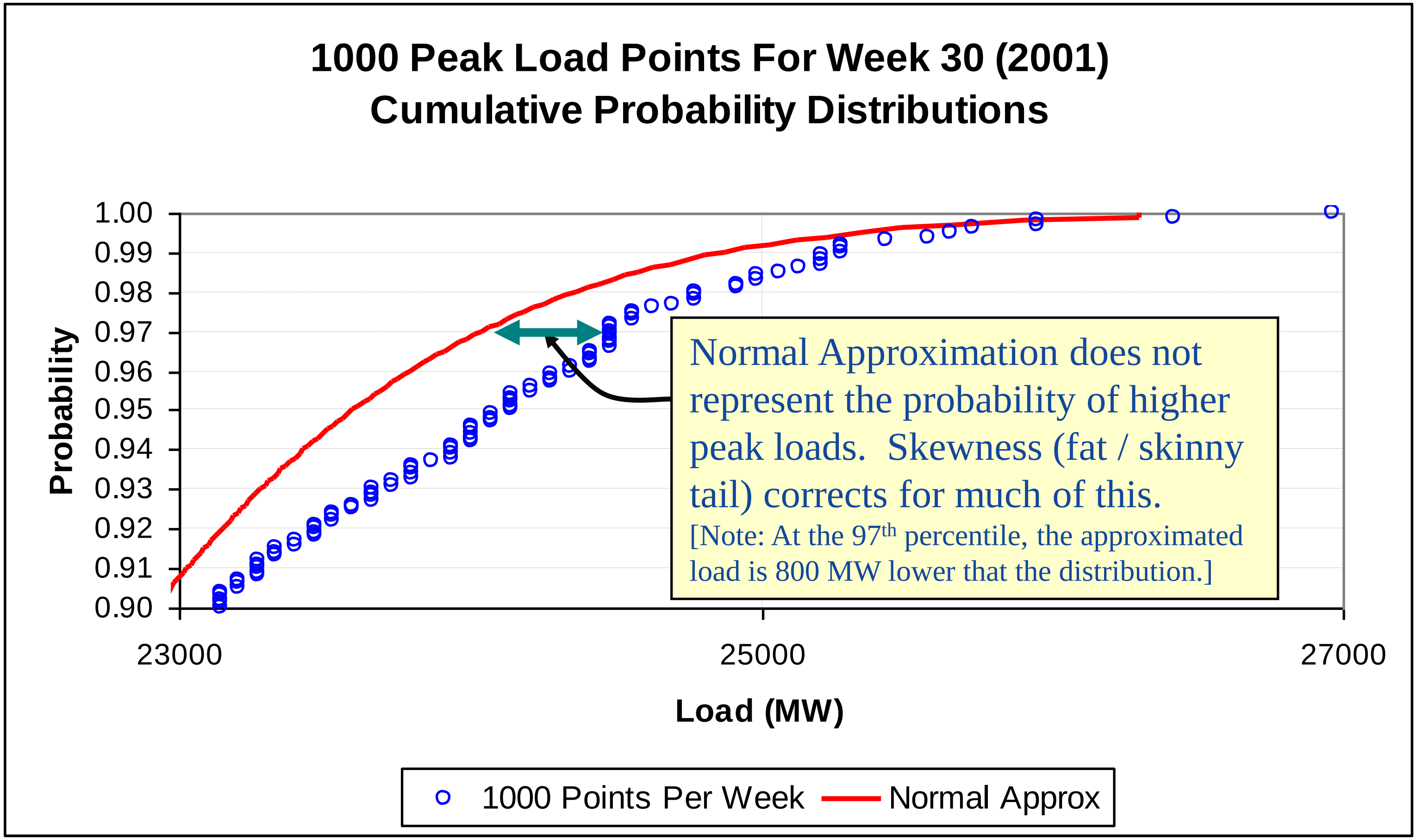
"Generally Good" Neglects the Upper Tail



Note: Distribution represents 5 weekdays

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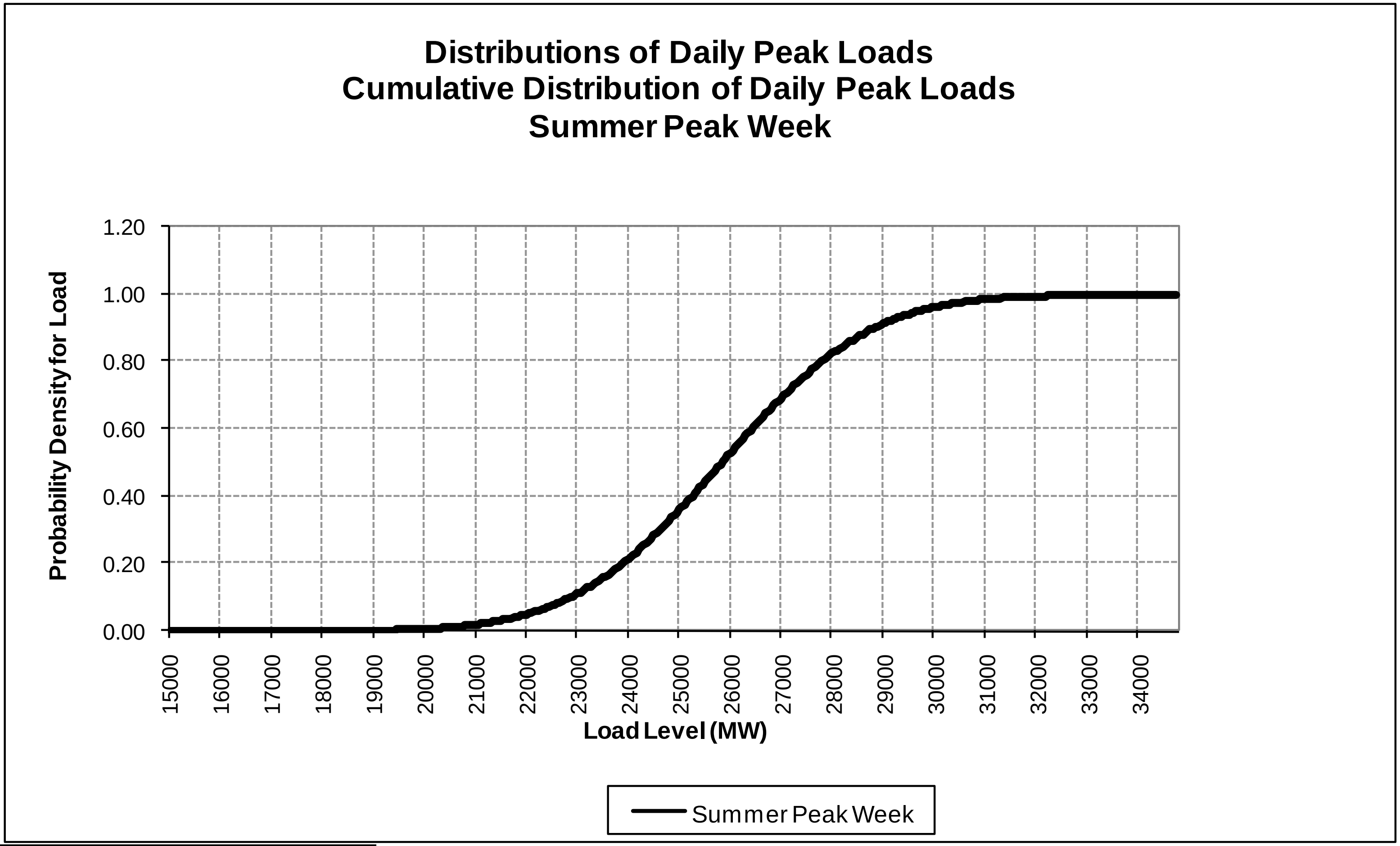
Cumulative Daily Peak Distribution For Highest Summer Week



Note: Distribution represents 5 weekdays

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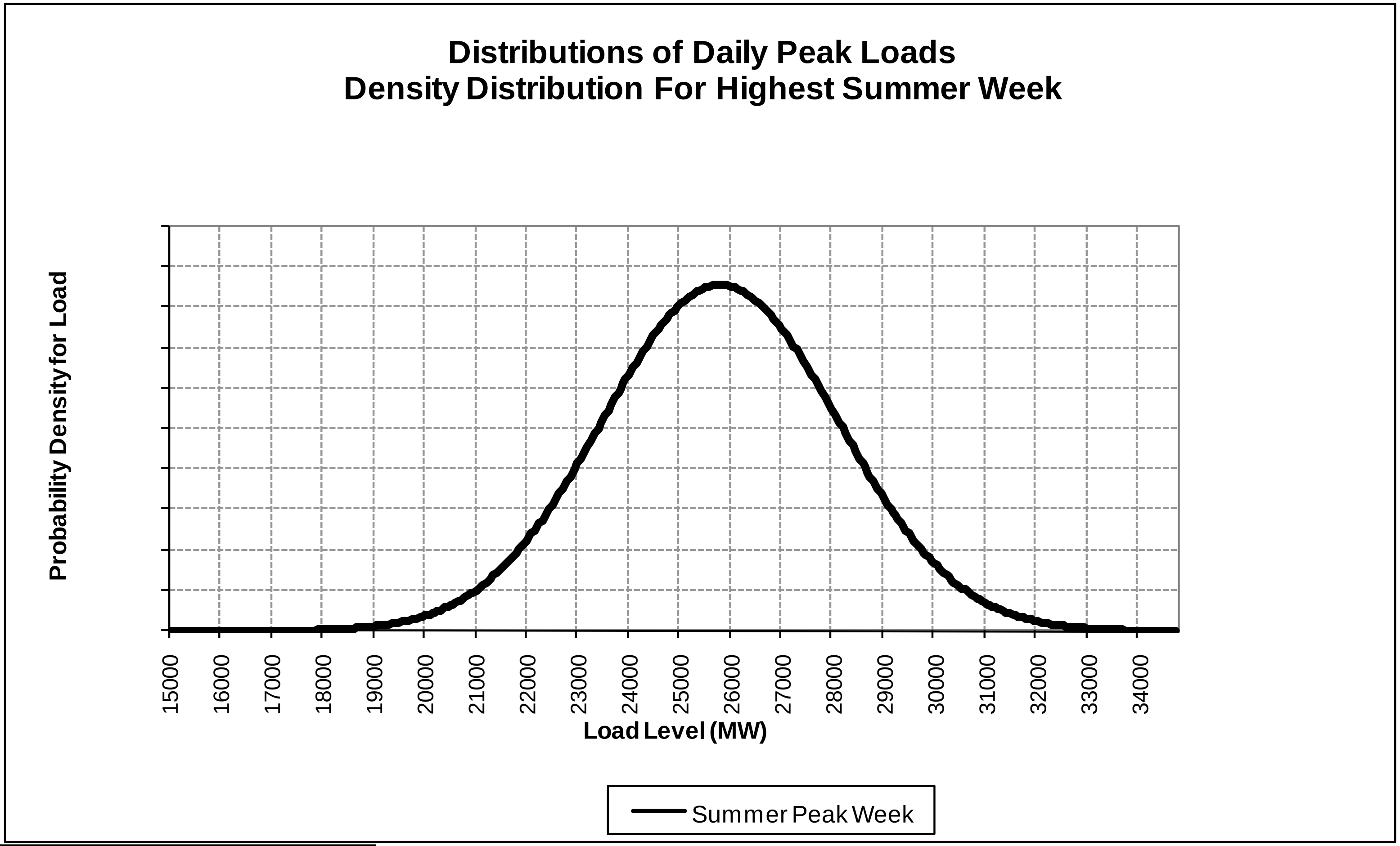
Daily Peak Density Distribution for Highest Summer Week



Note: Distribution represents 5 weekdays

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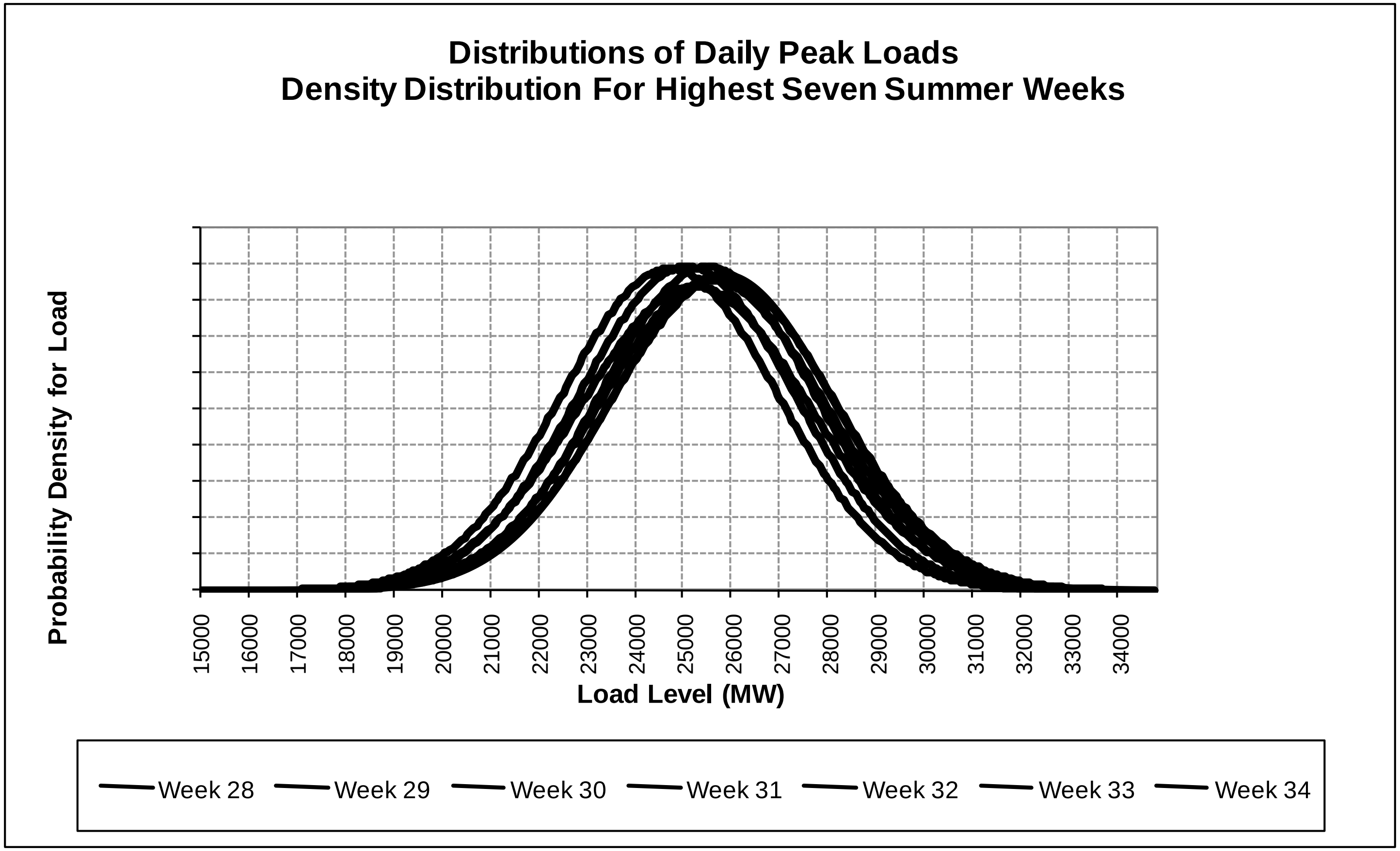
Daily Peak Density Distribution For Highest Seven Summer Weeks



Note: Each distribution represents 5 weekdays

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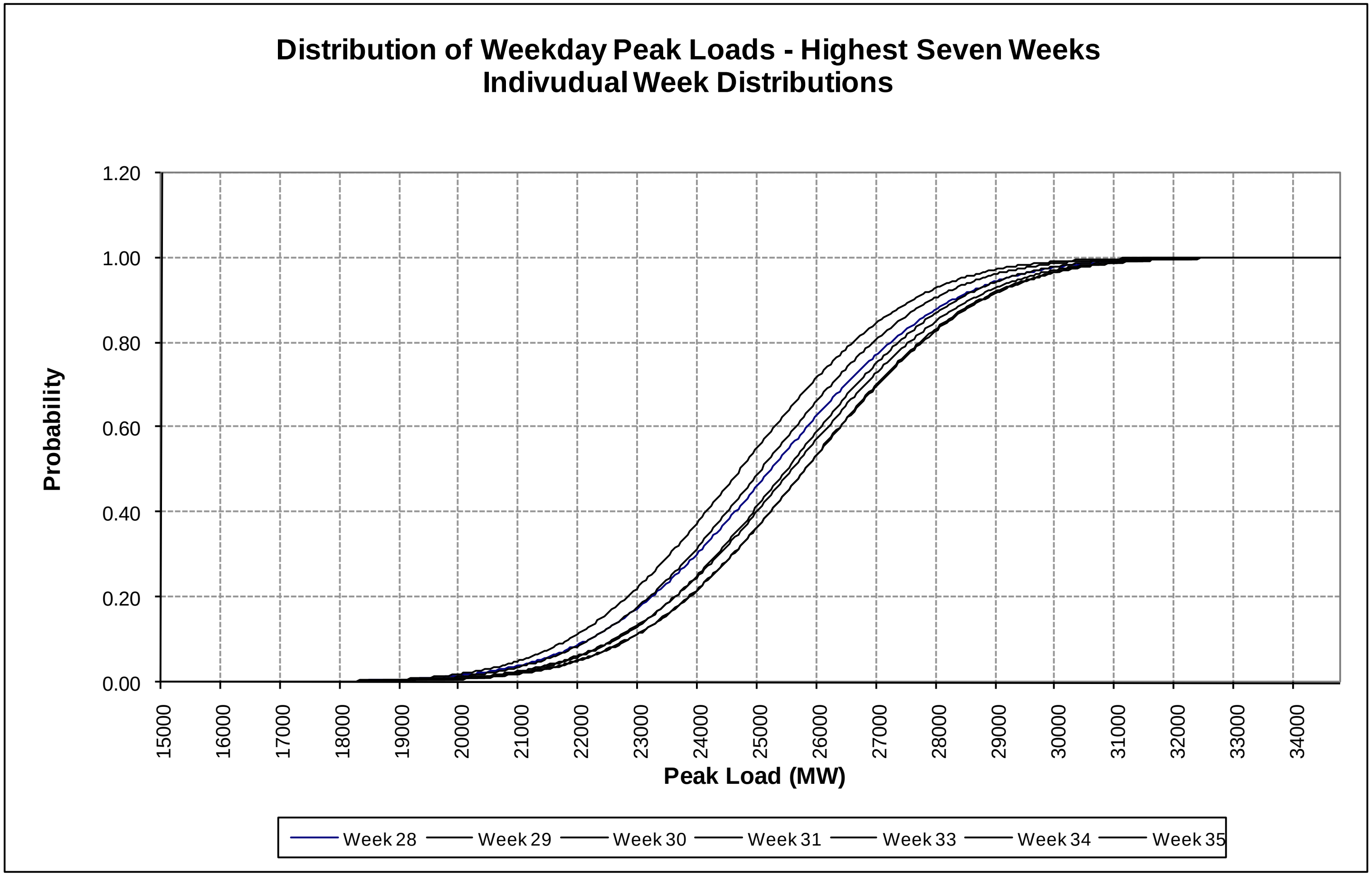
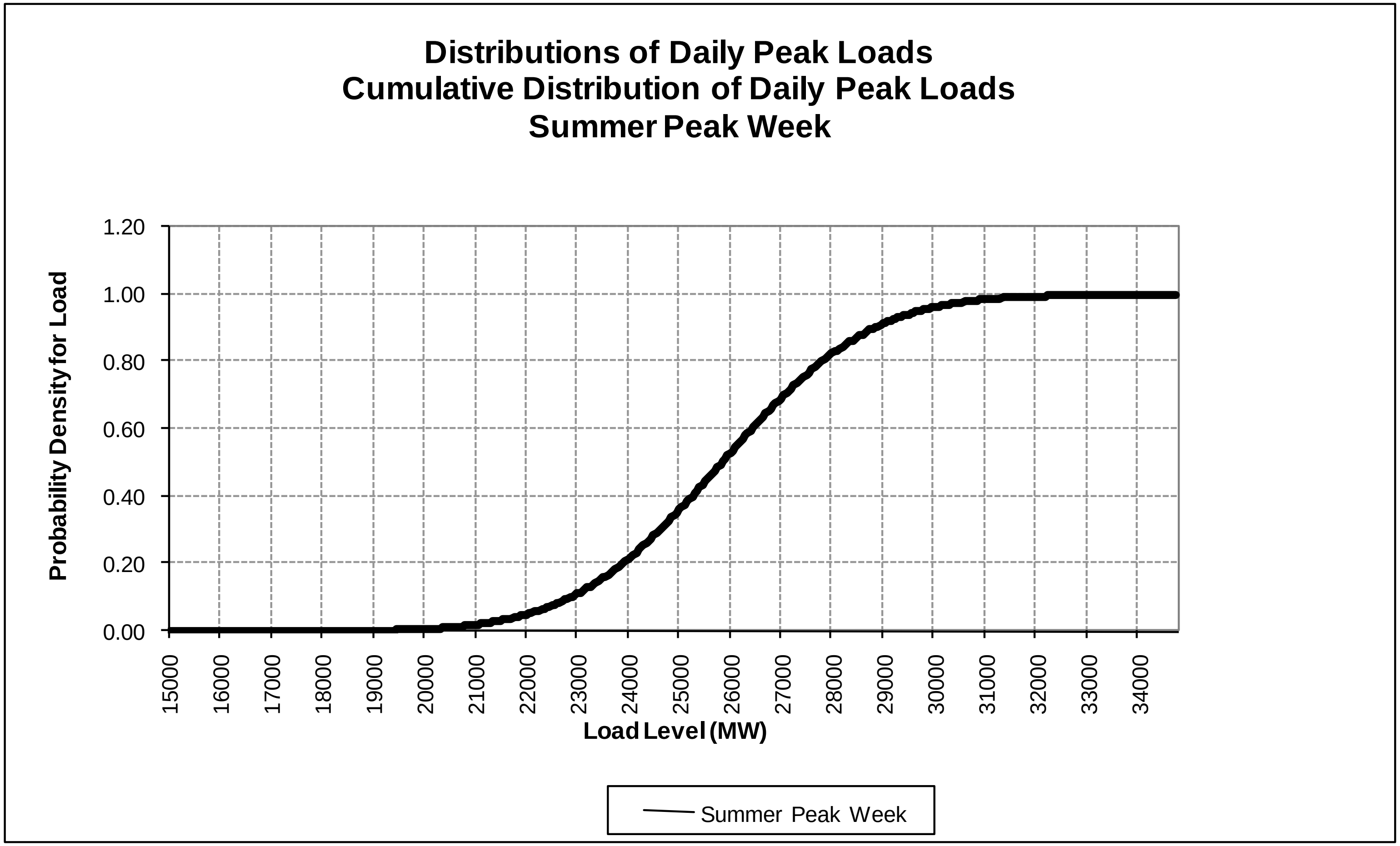
Cumulative Daily Peak Distribution For Highest Seven Summer Weeks



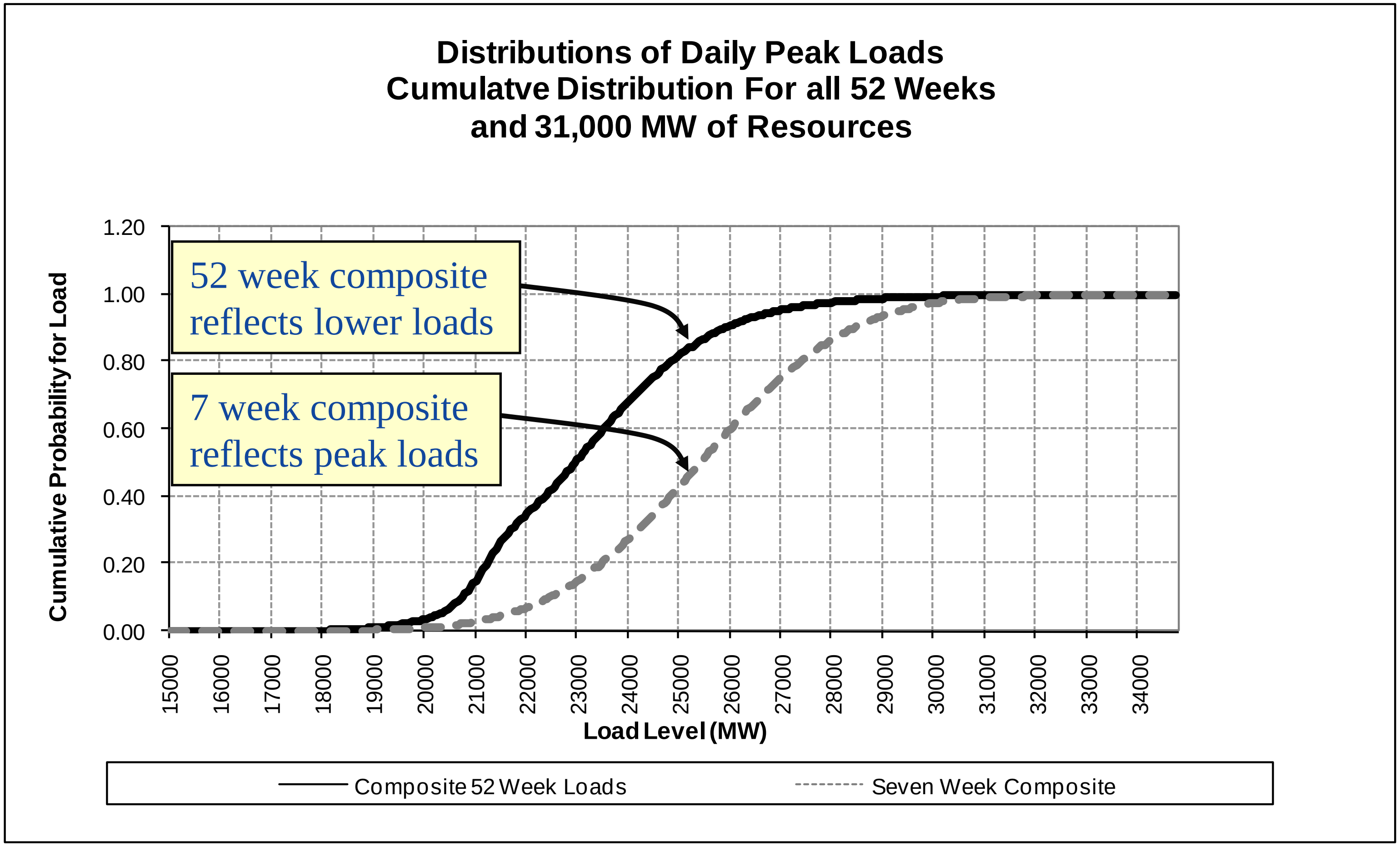
Note: Each distribution represents 5 weekdays

Cumulative Daily Peak Distribution For Highest Seven Summer Weeks



Note: This load distribution represents 35 weekdays

Effect of Including all 52 Weeks



Note: Seven week distribution represents 35 weekdays
52 week distribution represents 260 weekdays

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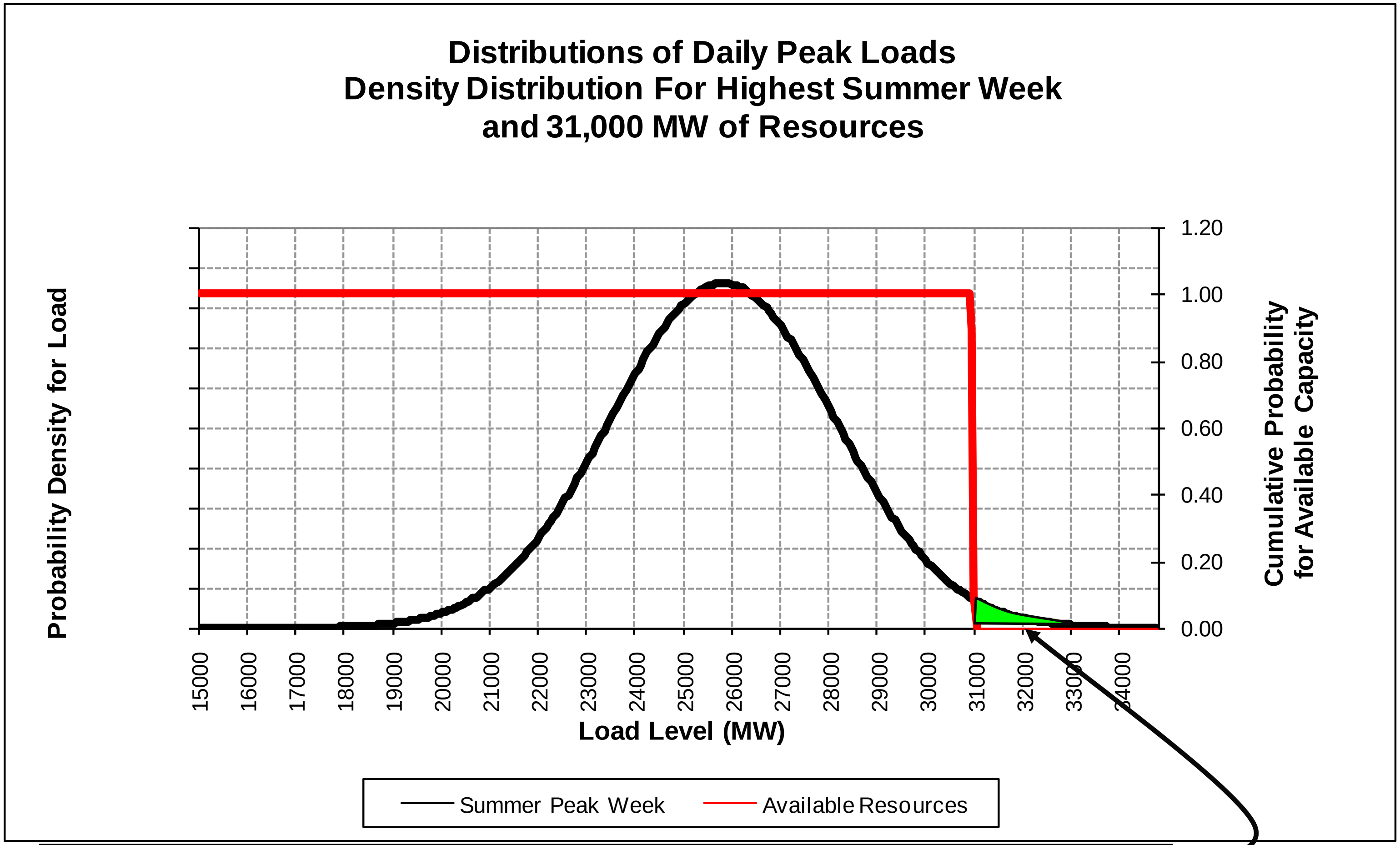
Illustrating LOLP

- LOLP is the cornerstone of probabilistic reliability studies
- Reliability studies compare differences between
  - Loads to be served and
  - Available resources (e.g. not on forced or scheduled outages)
- If resources were perfectly available when needed
  - Whenever loads are less than installed resources
    - Then: no "Loss Of Load" (i.e. no contribution to LOLP)
  - Whenever loads are more than installed resources
    - Then: a "Loss of Load" occurs (i.e. contribution to LOLP)
- Following examples
  - Assumes 31,000 MW of perfectly reliable resources
  - Resource uncertainty will be incorporated in later slides

LOLP With 31,000 MW of Resources



Loss of Load Probability: when loads greater than available resources

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LOLP and LOLE Calculations

- Probability of loads exceeding available capacity
  - Probability of loads in excess of 31,000 MW
  - 0.01293 probability (area under the curve above 31,000 MW)
- If the load distribution represents 1 day then:
  - The "expectation" that load would exceed available resources would be 0.01293 for that one day
    - Restating this would be 0.01293 "*expected outage events per day"*
    - Identical days have the same probability value
- If the load distribution represented five weekdays
  - The "expectation" would be the same for each of the five days
  - The "expectation" would be five times or 0.06463 *expected outage events per week*
  - Risk in other weeks would evaluated separately

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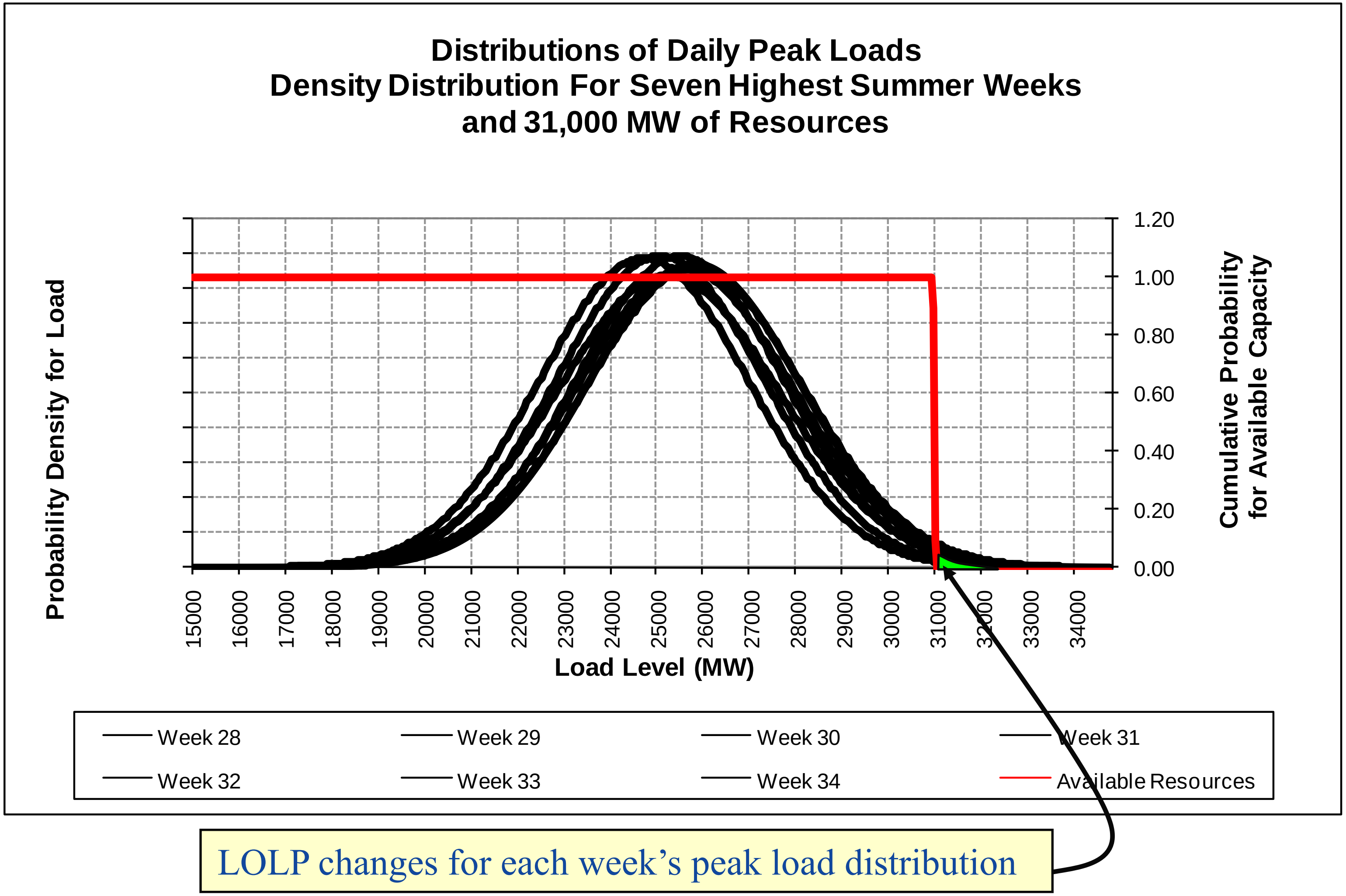
Seven Critical Weeks of Peak Loads



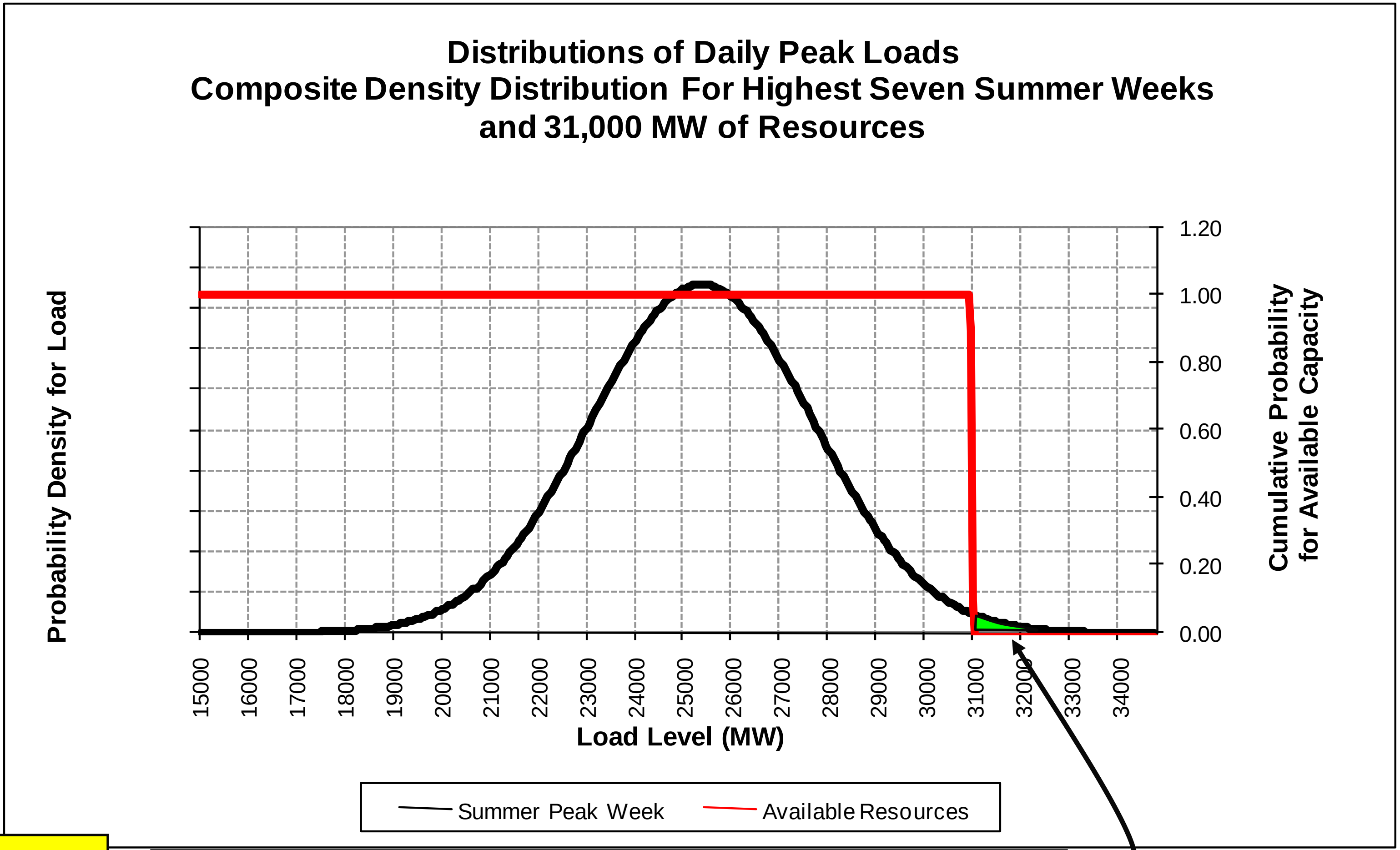
LOLE Reliability Index for Seven Weeks

- Loss of Load Probabilities vary for each week depending on the level of the loads.
  - Each week represents five weekdays
  - Loss of load expectation equals LOLP times number of days

	Loss of Load Probability (LOLP)	Loss of Load Expectation (LOLE) Expected outage events per week
Week 28	0.00783	0.03913
Week 29	0.01028	0.05139
Week 30	0.01293	0.06463
Week 31	0.01174	0.05870
Week 32	0.00687	0.03433
Week 33	0.00403	0.02014
Week 34	0.00263	0.01316
Total		0.26831

  - With 31,000 MW of resources and the seven peak load weeks:
    - We have a LOLE of 0.26831 outage events per summer
    - If these were the only weeks with significant LOLP then reliability index would be 0.26831 expected outage events per year (or LOLE)

Single Distribution Can Represent the 35 Days



Note: This distribution represents 35 weekdays

LOLP for seven week composite distribution is 0.00804

Note: 0.00804 x 35 days/ period = 0.2814 days/period

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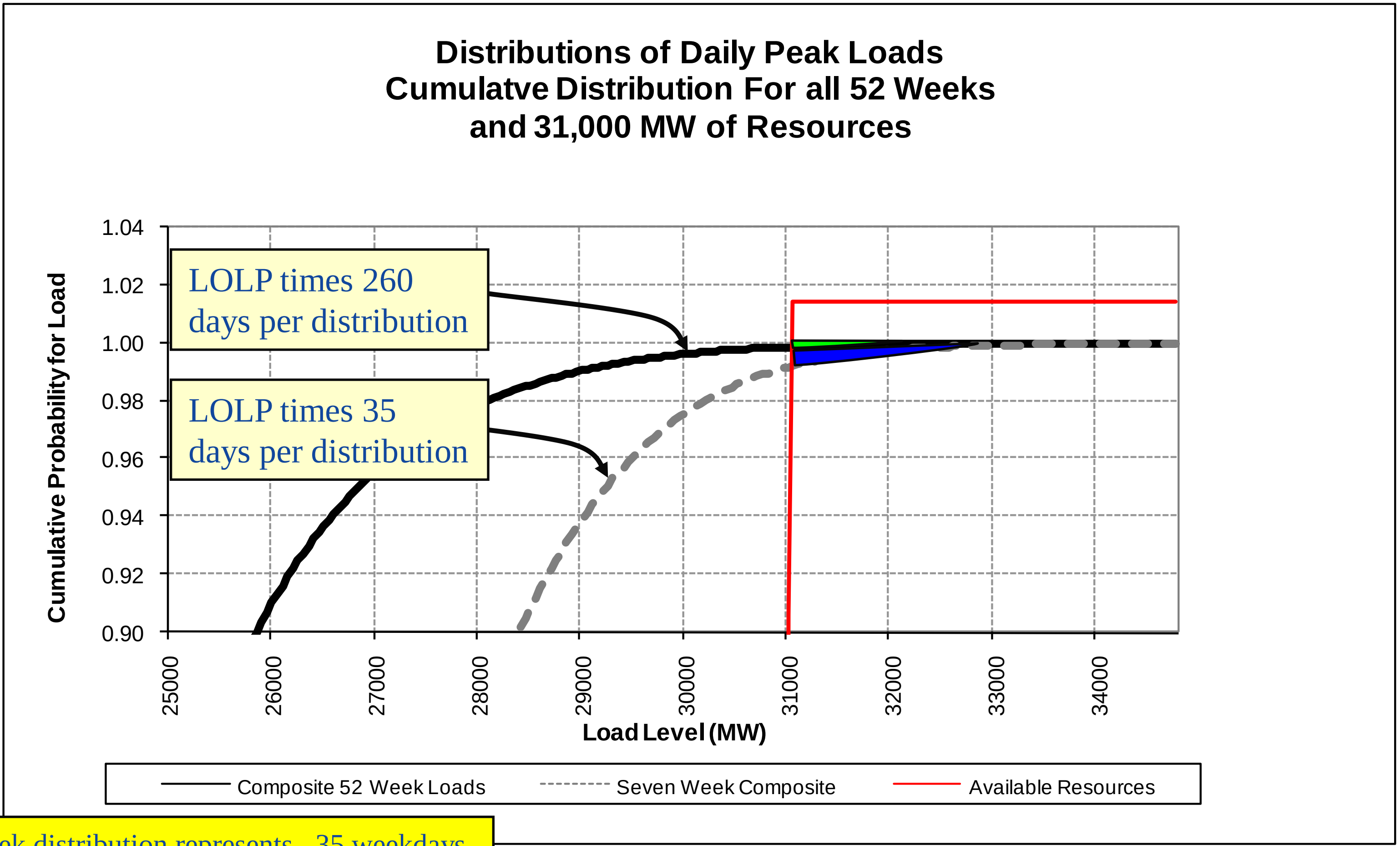
Equivalent LOLE When Adjusted for Days



Note: Seven week distribution represents 35 weekdays
52 week distribution represents 260 weekdays

Note: 0.00804 x 35 days/ period = 0.2814 days/period
0.00110 x 260 days/ year = 0.2860 days/ year

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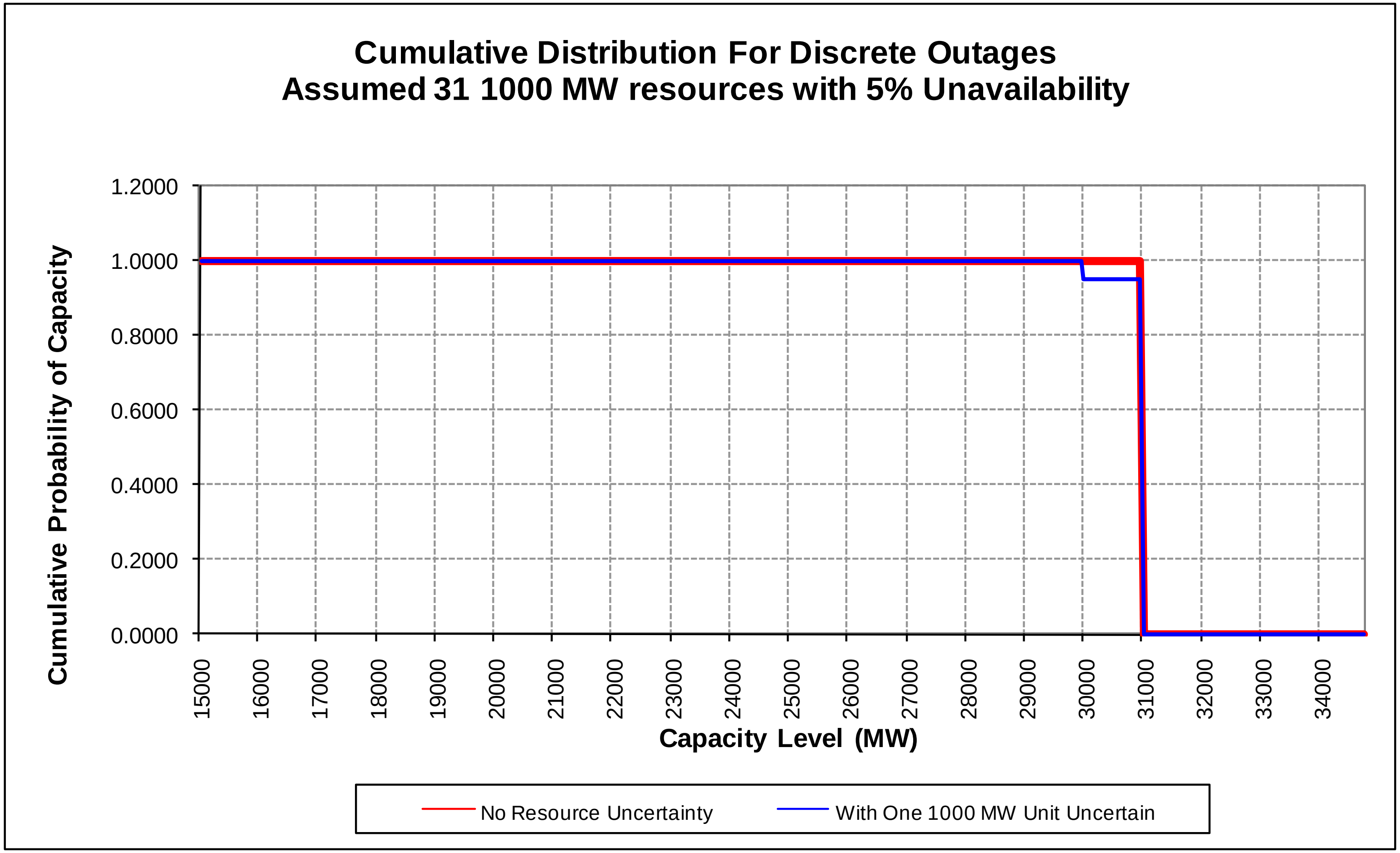
Effect of Resource Unavailability

- Previous examples assumed that
  - There were 31,000 MW available
  - Perfectly reliable capacity
  - LOLE was only the area to the right of 31,000 MW
- However, real capacity is not perfectly reliable
  - In a large system:
    - All of the resources are never 100% available
    - All of the resources are never completely broken
    - Amount of resources available can be described as a distribution
  - The LOLP calculation becomes more complicated
    - No longer a vertical line
    - Now a cumulative distribution

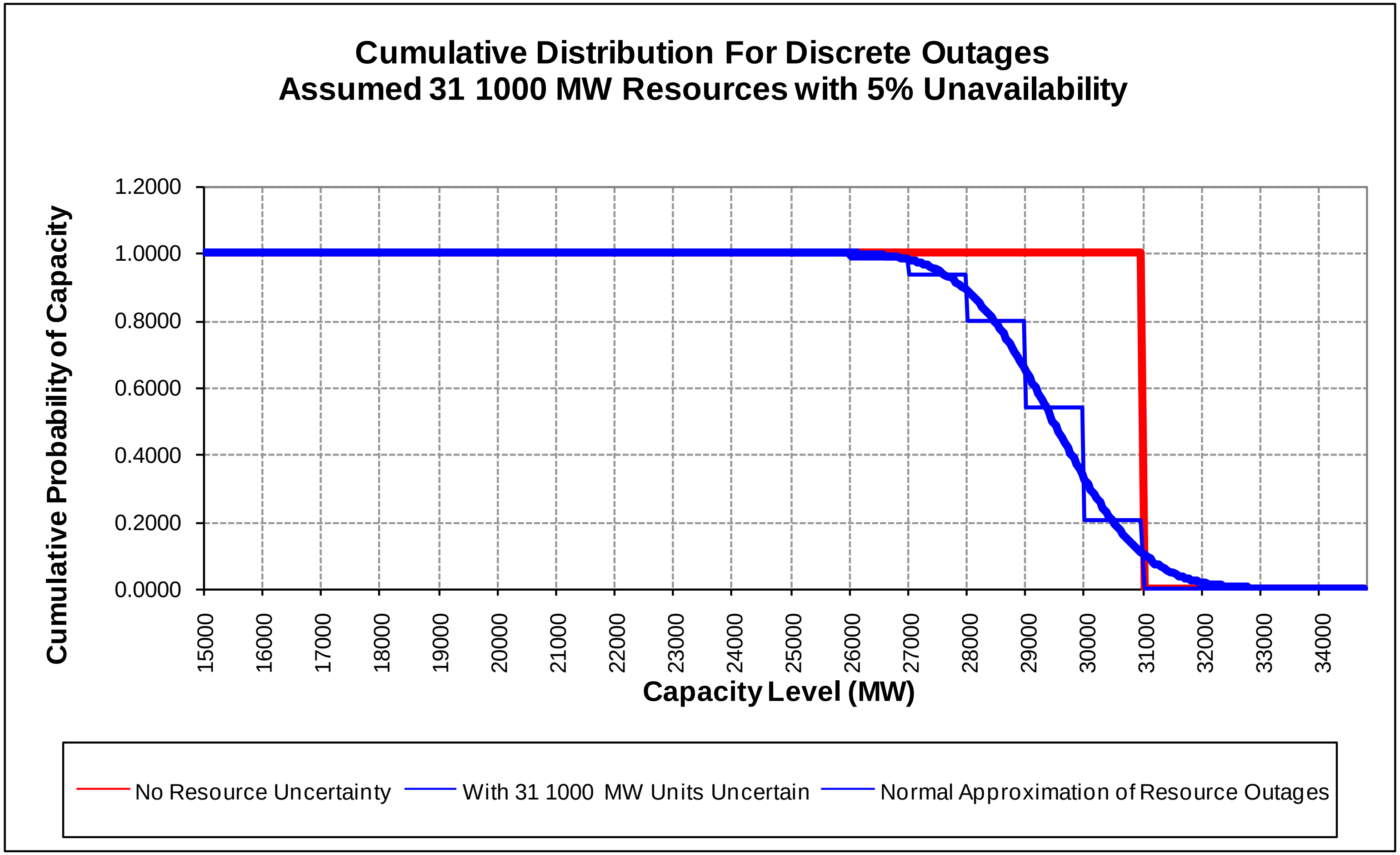
Resource Unavailability Distribution

- Following slides show how resource unavailability is represented in a probabilistic analysis
  - Each resource has a probability of outage
  - Whenever any unit is unavailable, total available resources are reduced
- When the risk of discrete units possibly being on outage are considered, a stair-step distribution will result
  - This example assumes the 31,000 MW is comprised of:
    - Thirty one 1000 MW units
    - Unavailability rate is 5 percent
- Normal approximation is shown for these outages
  - Not a good representation for only 31 large resources
  - Used here for illustrative purposes only

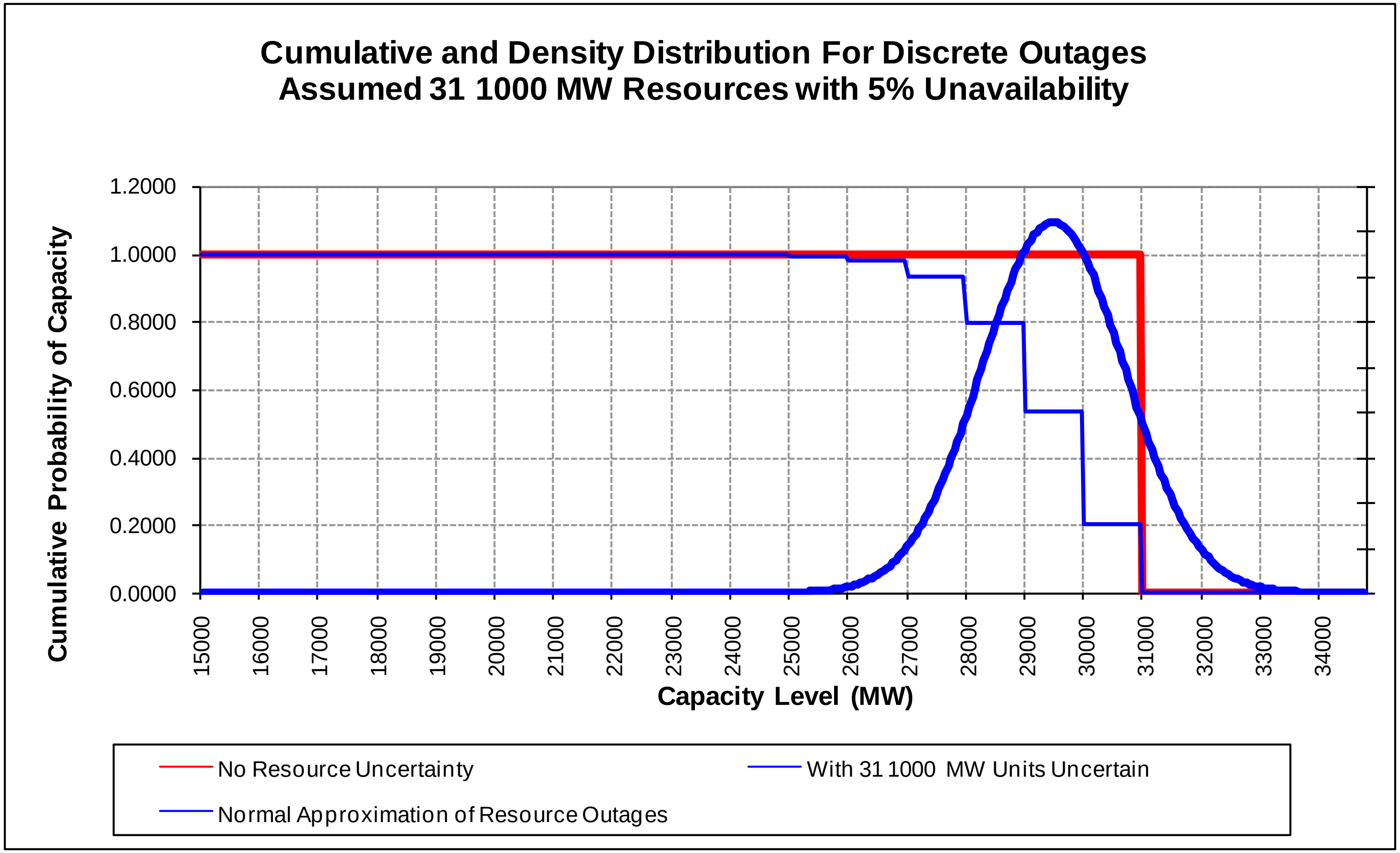
Perfect Capacity vs. One Resource with Uncertainty (1000 MW out of 31000 MW)



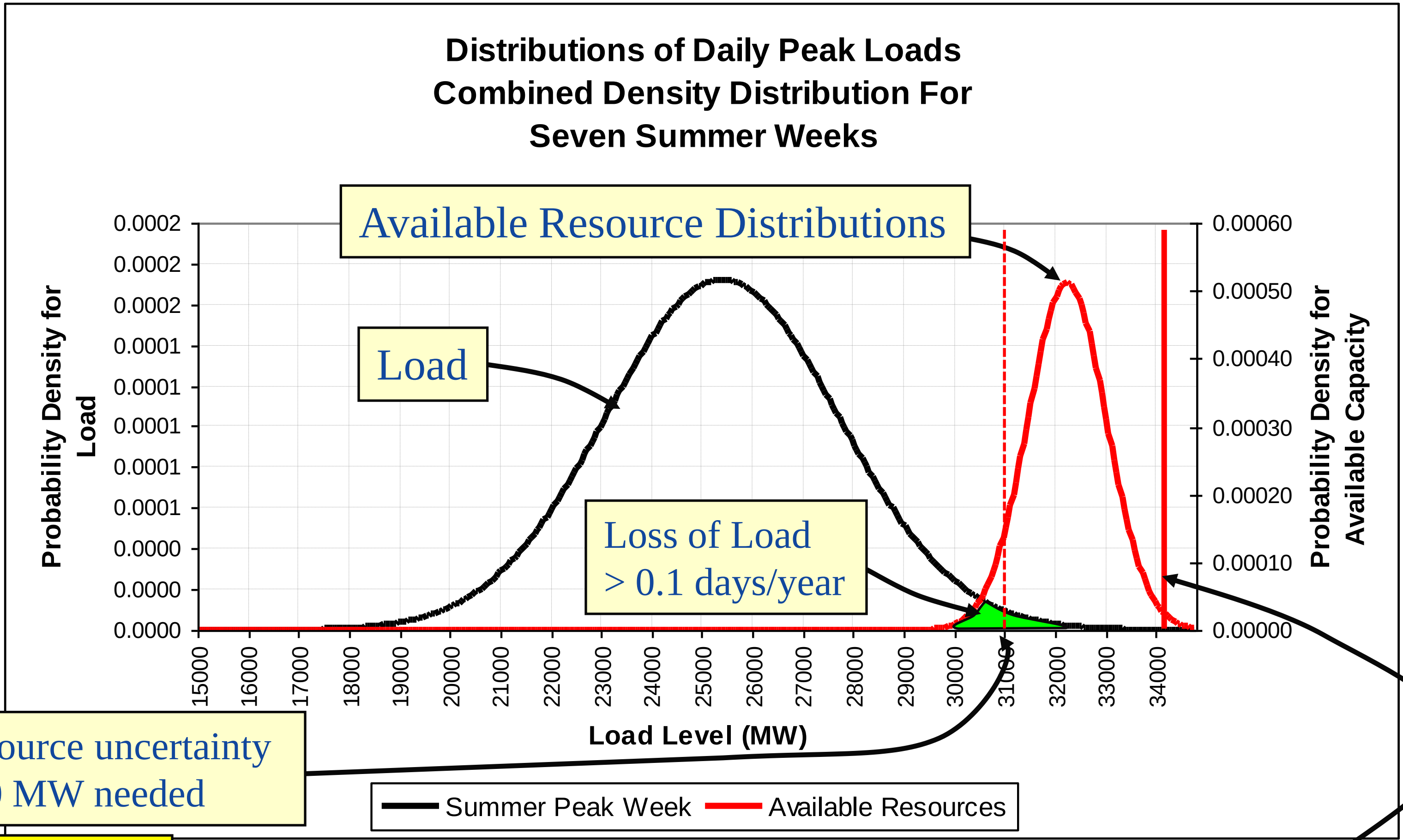
Normal Approximation of Capacity Outages



Density Distribution of Capacity Outages



Availability Capacity Density Distribution



With no resource uncertainty only 31,000 MW needed

Note: This load distribution represents 35 weekdays

With uncertainty, more resources than 31,000 MW are needed

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Effect of Resources with Different EFOR

- EFOR is a statistic that describes the probability of finding a resource in a state
  - Available or
  - Unavailable
- With 100 percent available resources (EFOR = 0%)
  - "Fewer" resources needed to meet peak loads with a given LOLE
- With 70 percent available resources (EFOR = 30%)
  - "More" resources needed to meet peak loads with a given LOLE
- With a variety of resources with different EFOR statistics
  - Each resource's contribution to meeting peaks can be quantified
    - Removing any resource will mean that the peak load that could be served, at a given LOLE, must decrease
    - Can be expressed in terms of MW effect on 'supportable' peak load

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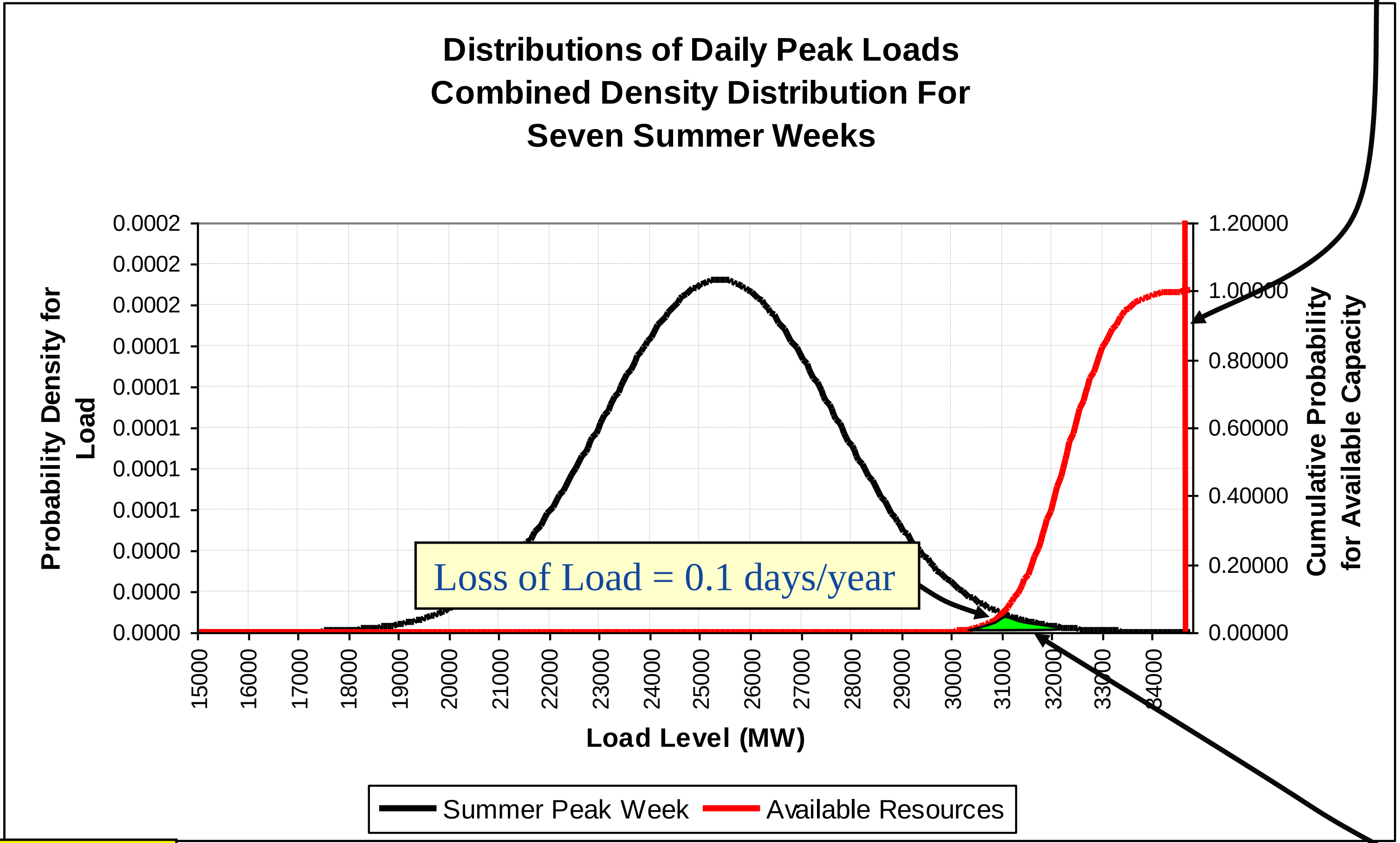
Available Capacity Cumulative Distribution

35,000 MW Minimum Installed Resources



Note: This load distribution represents 35 weekdays

LOLP for seven week composite distribution and cumulative capacity

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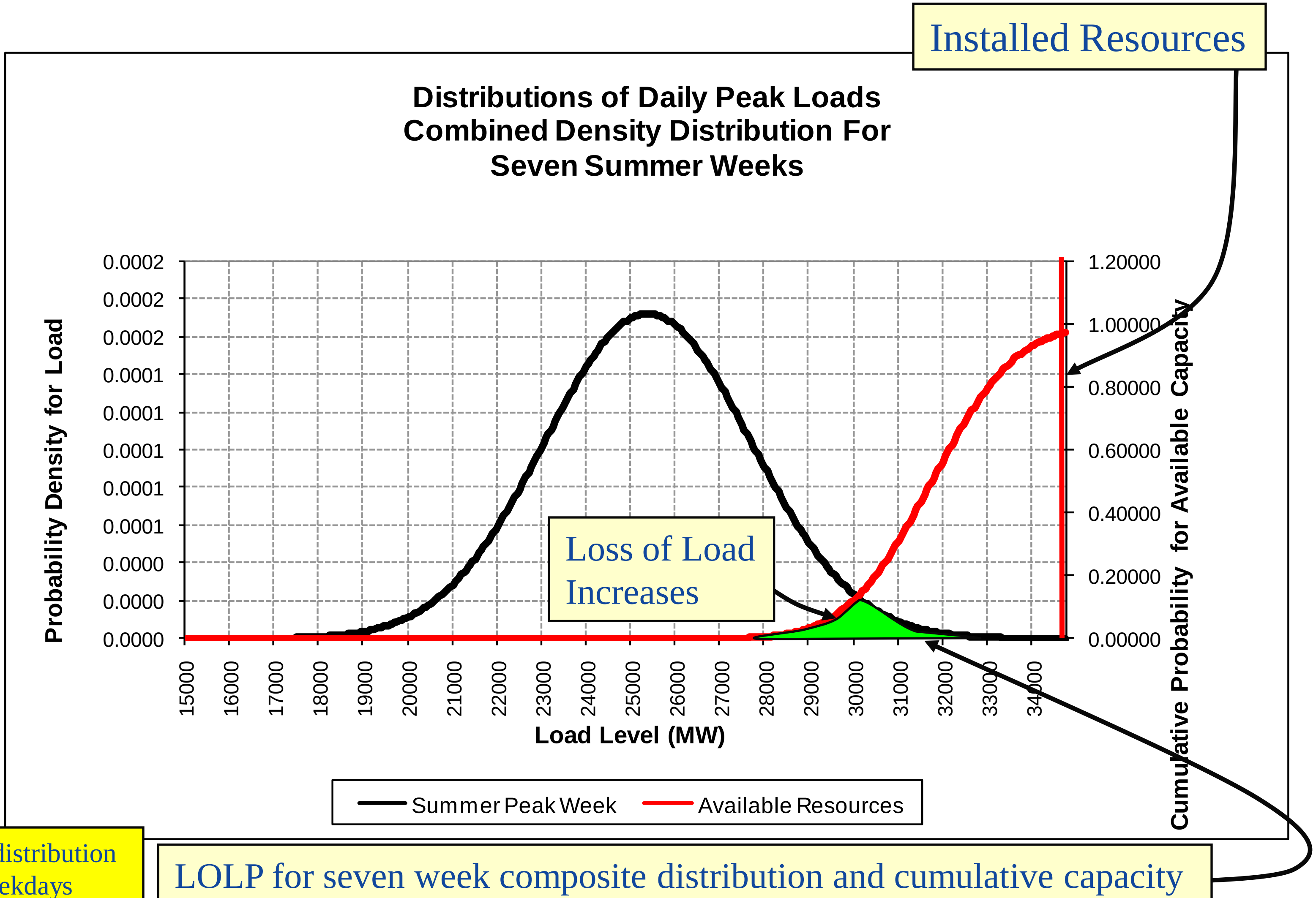
Effect of Base Resources with High EFOR

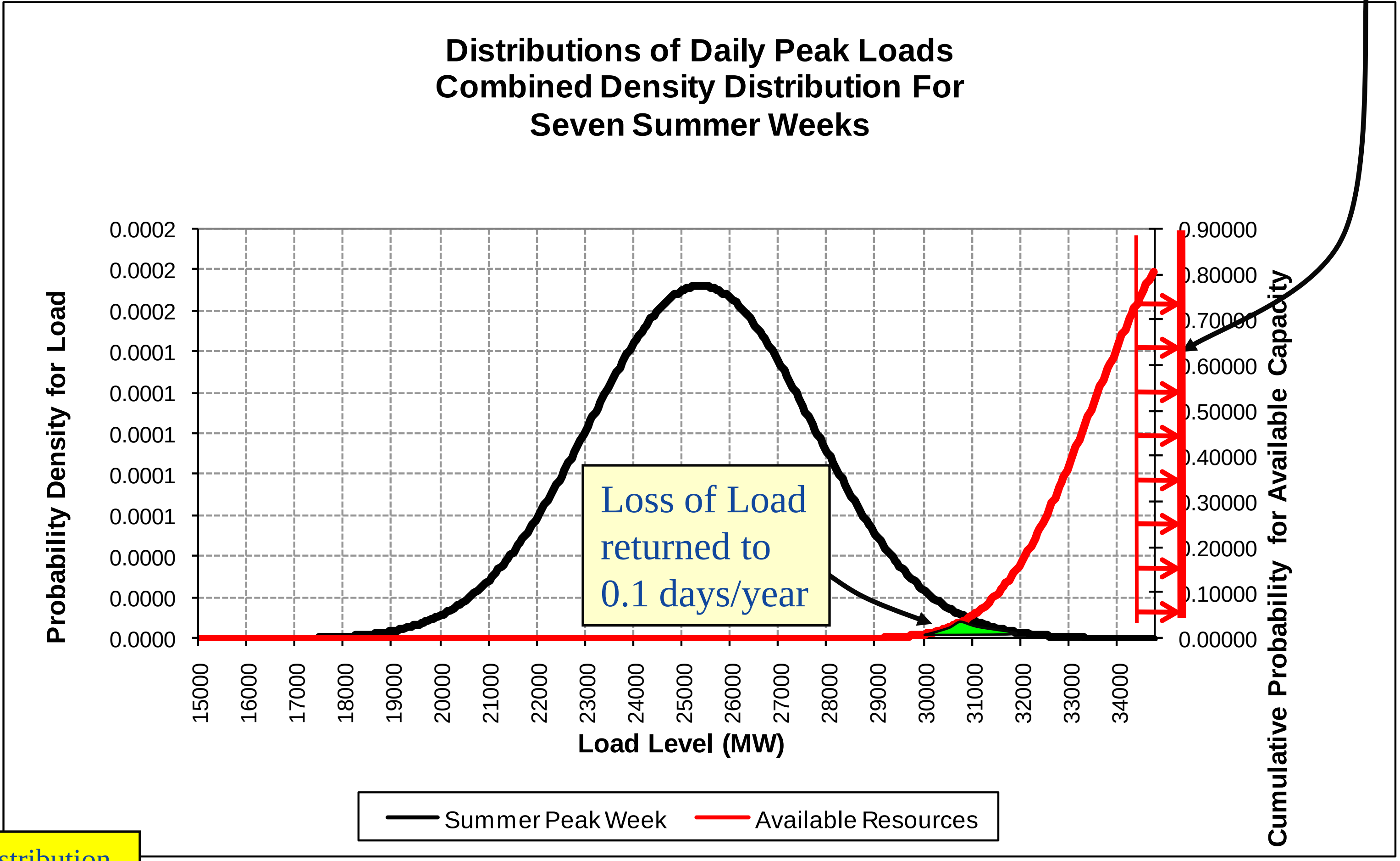


Note: This load distribution represents 35 weekdays

LOLP for seven week composite distribution and cumulative capacity

Adding Resources Returns Risk to Target

Adjusted Minimum Installed Resources



Note: This load distribution represents 35 weekdays

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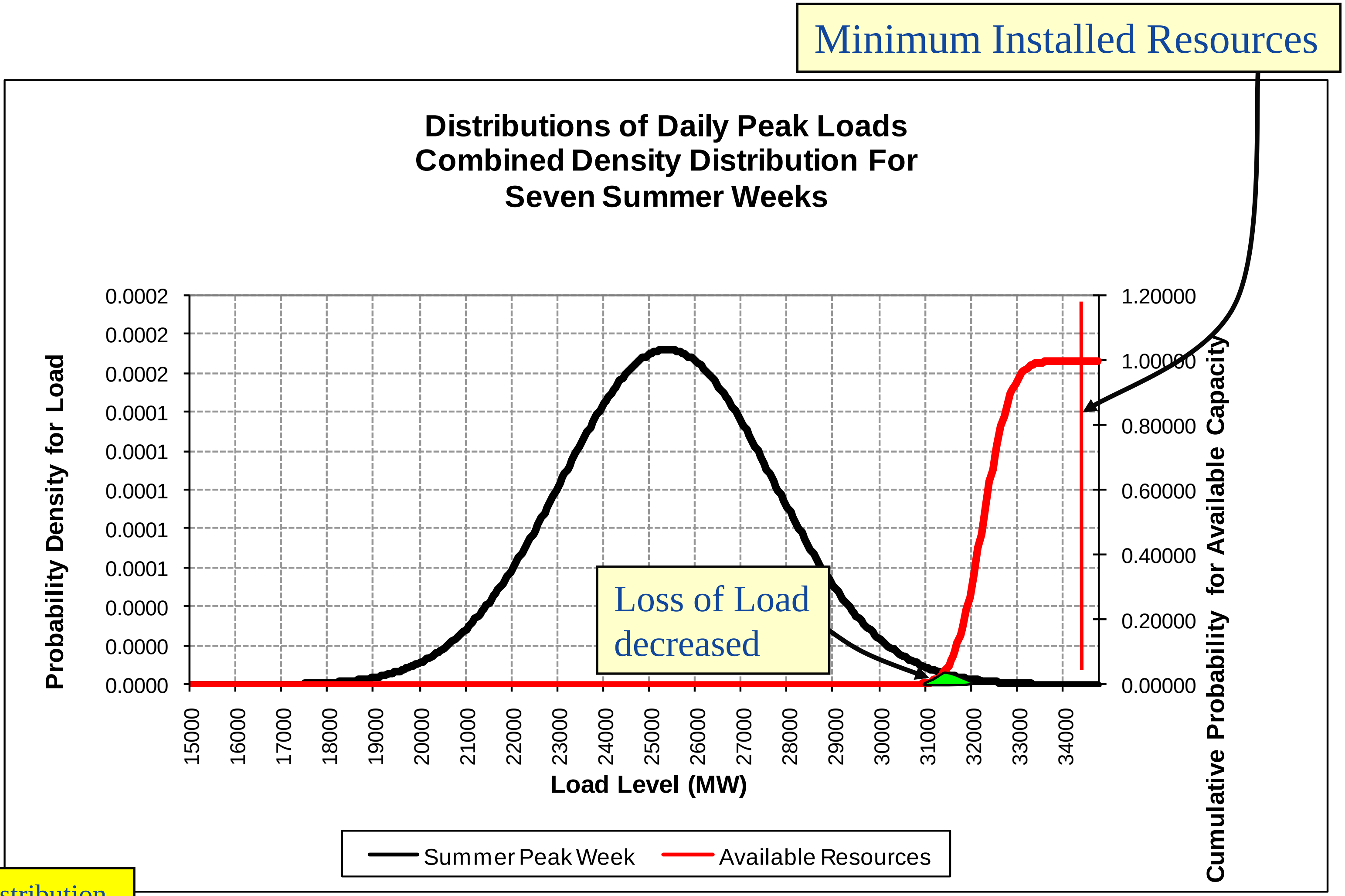
Effect of Base Resources with Low EFOR



Note: This load distribution represents 35 weekdays

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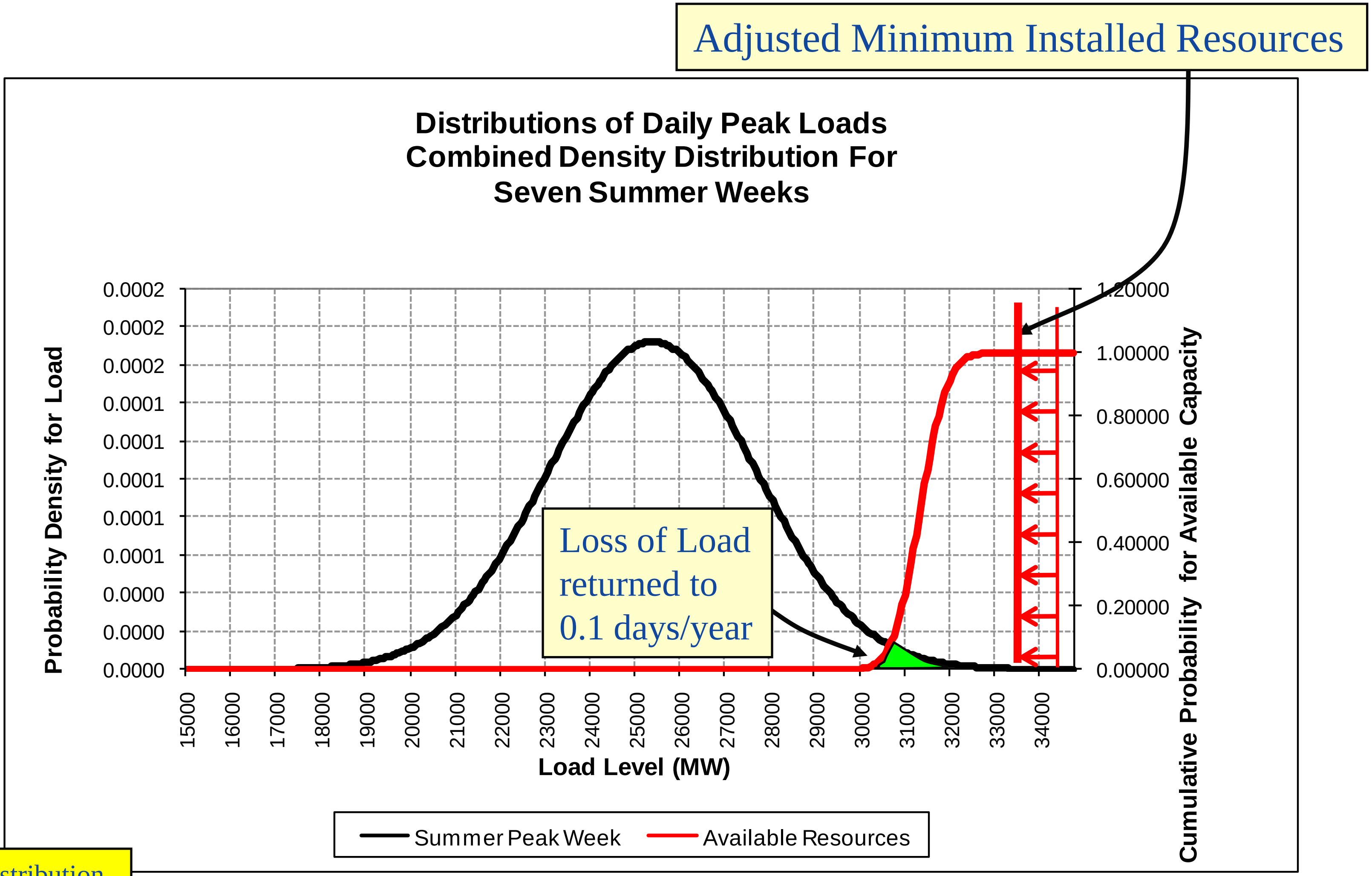
Removing Resources Returns Risk to Target



Note: This load distribution represents 35 weekdays

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Calculating ICR Using the Formula

Resources Included in ICR Calculation

- Iron in the ground within New England
  - Energy limited hydro resources
  - Intermittent energy wind resources
- Demand Resources within New England
  - Passive DR
  - Active DR
- Capacity purchases from external areas
- Load/Capacity Relief from OP4 Emergency Operating Procedures
  - Tie benefits
  - Voltage reductions
  - Erosion of operating reserve
  - Emergency Generation DR

Key Westinghouse Model Outputs

- The key Westinghouse Model output is LOLE
  - All of New England
  - All resources can serve all loads
- The other key Westinghouse Model output is:
  - Additional Load Carrying Capability (ALCC)
  - Quantifies
    - How much higher / lower the loads could be
    - For the system to just meet the LOLE criterion
  - ALCC is used in the ICR formula

Additional Load Carrying Capability

- ALCC
  - If the ALCC is positive
    - System has surplus installed resources to meet the criterion
  - If the ALCC is negative
    - The system is short of installed capacity to meet the criterion
    - The LOLE would be higher than 1 day in 10 years
    - Resources would need to be added to the system (proxy units)
  - If the ALCC is zero
    - Then the installed resource is exactly at the right level
- ALCC avoids removing specific resources when the system is surplus
  - Removing a different set of specific resources would give a different ICR

ICR Formula

Development of the NEPOOL Installed Capacity Requirement (ICR) formula without the Hydro Quebec Interconnection Credit Adjustment.

Define *APk* = *Annual Peak Load*

TB = *Tie Benefits*

OP4 = *OP4 Load Relief other than Tie Benefits*

CCR = *Claimed Credible Resources = Sum of all supply resources except TB and OP4*

Cap = *Total Modeled Capacity = Sum of all supply resources = CCR + TB + OP4*

R = *Reserve Margin at 0.1 days per year*

$R_{As\text{-}Is}$ = *Reserve Margin with all Claimed Credible Resources (CCR)*

ALCC = *Additional Load Carrying Capability,* ΔL *, (from the Reliability Model)*

ICR = Installed Capability Requirement

Define the Reserve Margin at 0.1 days per year LOLE

$$R = \frac{ICR}{APk} - 1$$

The actual reserve margin, which may provide a higher or lower LOLE than the target is defined in terms of the resources that are claimed for capacity (CCR).

$$R_{As-Is} == \left(\frac{CCR}{Apk}\right) - 1$$

ICR Formula (continued)

The total amount of capacity modeled to get the "As-Is" LOLE includes Tie Benefits and other OP4

$$Cap = CCR + TB + OP4$$

Including this in the reserve margin equation

$$R_{As-Is} == \left(\frac{Cap - TB - OP4}{Apk} \right) - 1$$

To equate the Target Reserve Margin, "R" equation with the "As-Is" reserve margin, "$R_{As\text{-}Is}$" an adjustment to the peak load is used (ALCC)

$$R = \frac{ICR}{APk} - 1 = \left(\frac{Cap - TB - OP4}{Apk + ALCC} \right) - 1$$

Simplifying, we get:

$$\frac{ICR}{APk} = \left(\frac{Cap - TB - OP4}{Apk + ALCC} \right)$$

Rearranging the terms we get the familiar equation

$$ICR = Apk \left(\frac{Cap - TB - OP4}{Apk + ALCC} \right)$$

$$ICR = \left(\frac{Cap - TB - OP4}{1 + \frac{ALCC}{APk}} \right)$$

Proxy Units

Effect of Unit Availability Assumptions

- The minimum ICR is a function of the aggregate
  - Load distributions
  - Resource sizes
  - Resource EFOR
  - Assumption of independence of outages
- Addition of a "low EFOR" resource
  - Will decrease ICR
  - Will need fewer MW installed to get the same LOLE
- Addition of a "high EFOR" resource
  - Will increase ICR
  - Will need more MW installed to get the same LOLE
- ICR uses a specific equation to calculate a MW value

ICR Tradeoff Framework

- One MW of neutral resource adjustment capacity
  - Worth 1.00 MW of typical capacity
  - Zero change in ICR
- One MW of perfect capacity
  - Worth approximately 1.10 MW of typical capacity
  - 0.10 MW reduction in ICR
- One MW of poorly performing resource
  - Could be worth (something like) only 0.80 MW of typical capacity
  - ICR would increase by some amount
    - Depends upon size and forced outage rates

Firm Adjustments

- Perfect capacity (zero EFOR)
  - Affects only the mean of the capacity outage distribution
  - Does not affect the standard deviation or skewness
  - Because it affects only the mean, it can be positive or negative
  - Equates to a firm (absolutely certain) load reduction in aggregate demand
- Firm load reduction
  - There are no limits to the number of activations (i.e. interrupts)
  - Always activates as requested
  - Activates at its capacity value with no allowance for failure
- Firm (certain) adjustments are worth more from reliability perspective than typical resources (with uncertainty)

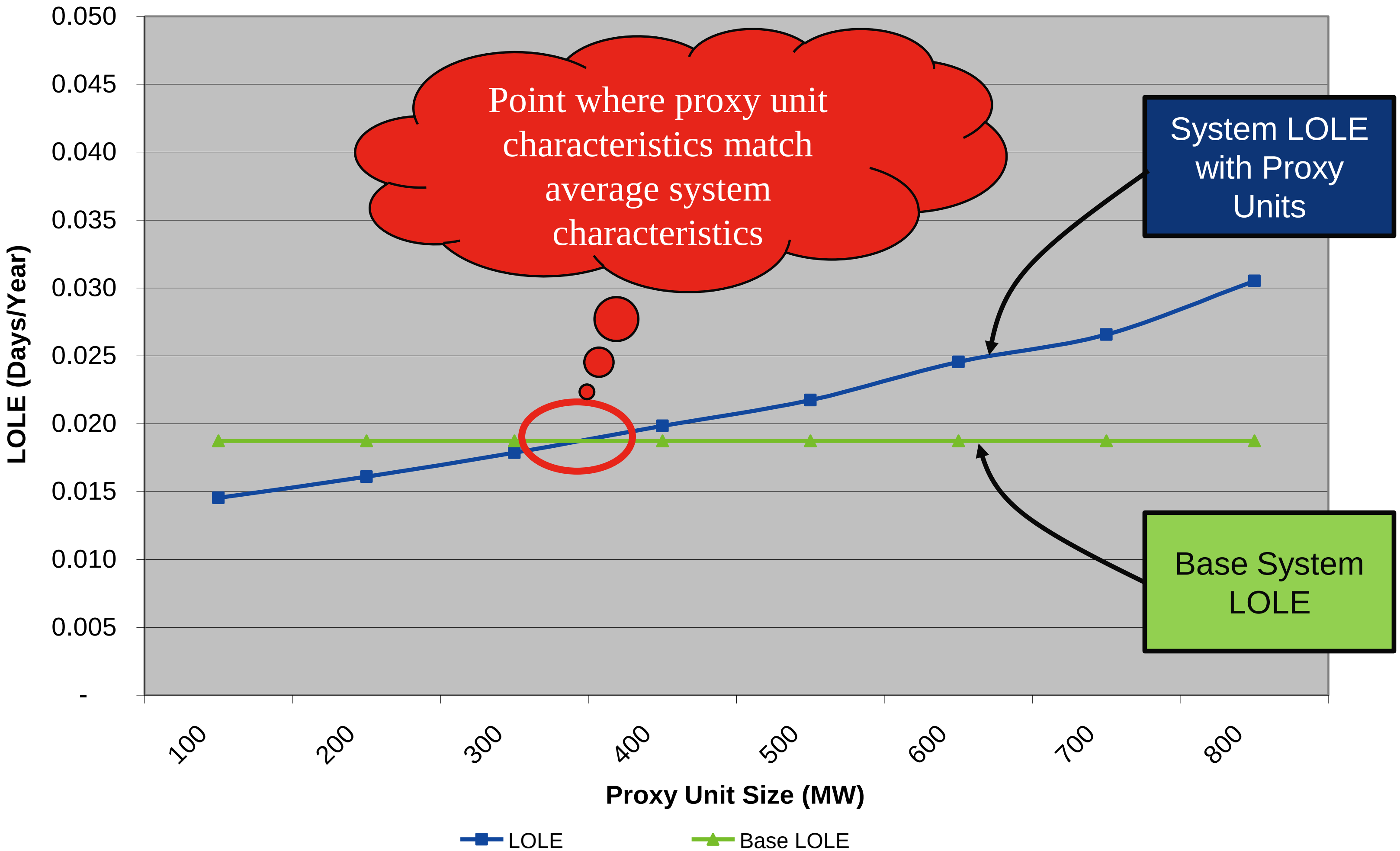
Neutral Adjustments

- “Proxy unit” is effectively neutral to the ICR calculations
  - Calibrated so that it will not affect ICR value
  - Based on average availability statistics for all of New England’s Resources
    - EFOR of 5.54 percent
    - Scheduled maintenance of 5 weeks
  - Added to New England’s resources if a future year is deficient
  - Practical proxy problem
    - Proxy units can be added
    - But … they can’t be removed (because they are not in the data)
- An alternative “neutral” adjustment is to raise peak loads
  - Increase load just enough to attain 0.1 days/year LOLE
  - Called “Additional Load Carrying Capability” (ALCC)

Determining Proxy Unit Size

- Proxy units are determined using average system characteristics and LOLE calculations
  - Using average availability characteristics for New England
    - 5.54% EFORd
    - 5 weeks of maintenance
  - Replace all units in New England with proxy units
    - Adjust capacity ratings until initial LOLE is calculated
    - Results using RSP06 assumptions shown on following slide
  - Replacing all system capacity with proxy units leaves LOLE unchanged

Proxy Unit Results for 2006 RSP System



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Proxy Unit Results for 2006 RSP System

- Results illustrate that a proxy unit for the 2006 RSP system is:
  - 350 MW
  - 5.54% EFORd
  - 5 weeks of maintenance

Other Assumptions

ISO New England Preliminary EFORd Review

- Investigation of availability statistics was undertaken
  - Reconnaissance investigation to begin discussing this issue
  - Six summers since start of SMD markets: 2003 through 2008
  - Top five peak load days were selected for each summer season
  - Sample set of 30 peak load hours used in making distributions
    - The actual availability performance of generating resources
    - Then compared to an approximation using the EFORd statistic
  - EFORd parameter is used in the calculation of ICR
- As part of the Forward Capacity Market (FCM)
  - A proposed sampling of resource availability based on only shortage hours is envisioned
  - Expected to better align the planning statistics with actual performance when capability is needed

Resource Availability Estimators

- LOLE studies based on stochastic parameters
  - Resource forced outage estimator is the most significant
  - EFORd is the most widely used parameter estimator
    - It is an “all hours not on economic reserve shutdown” estimator
    - It is not, specifically, an EFOR at time of peak load / system stress
  - A distribution of expected outages can be created from EFORd data as follows

$$\sigma = \sqrt{(n) * (MW_i) * (MW_i) * (EFORd_i) * (1 - EFORd_i)}$$

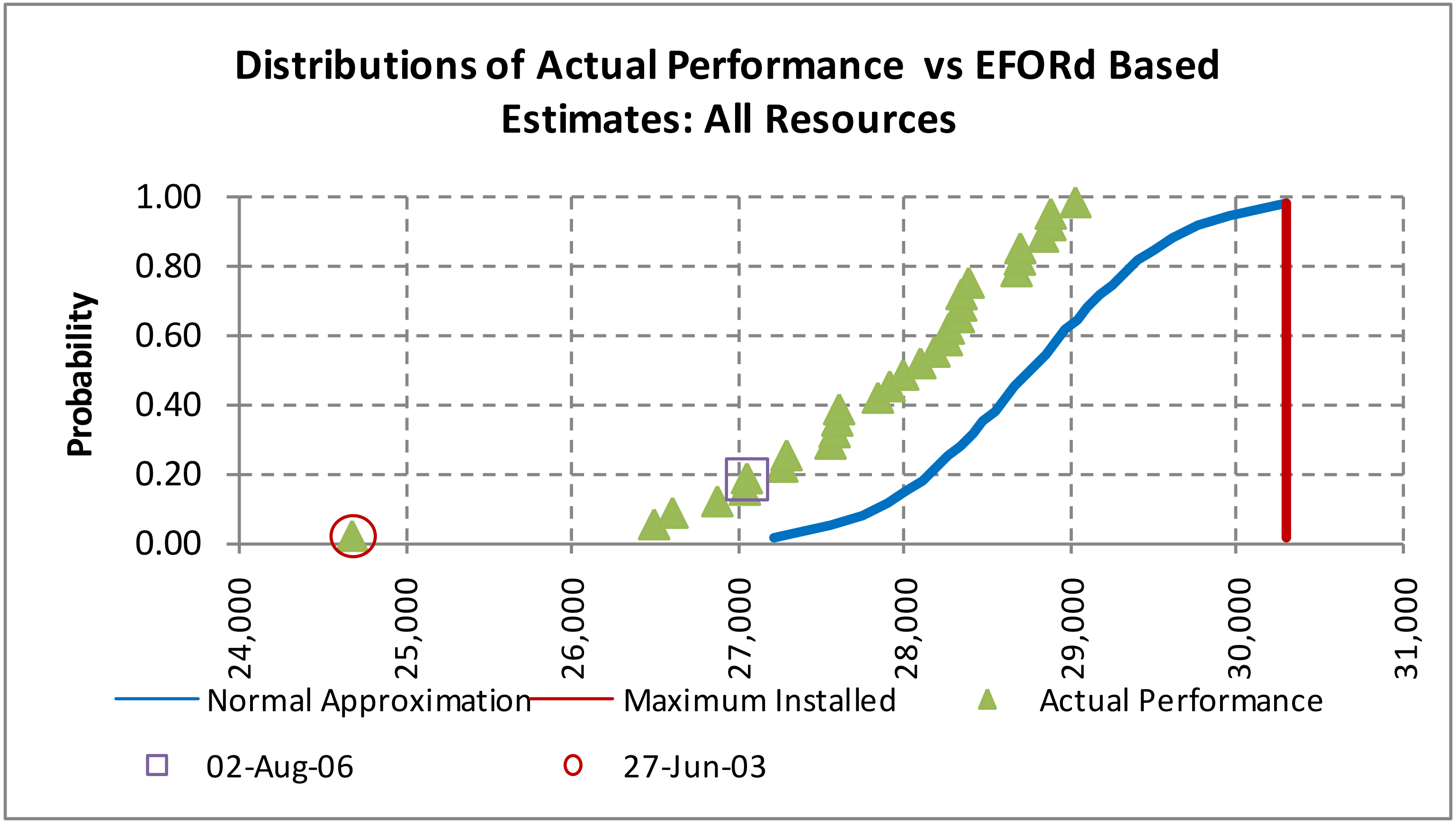
$$MeanMW = (MW_i) * (EFORd_i)$$

ISO New England Statistics

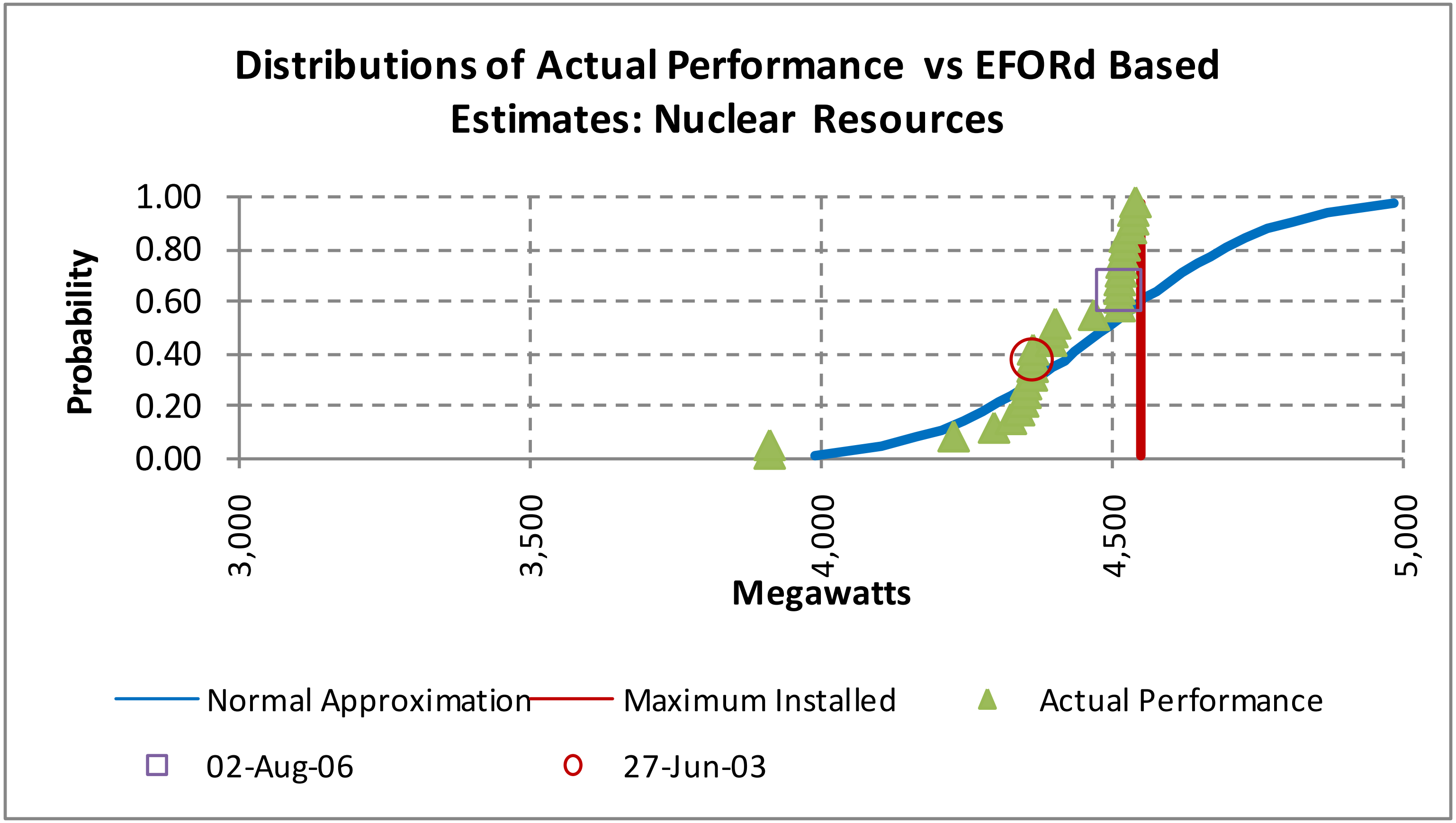
- Preliminary review of historical data suggests:
  - Actual performance tends to be less than EFORd suggests
  - Comparison of mean statistic indicates
    - Total of 907 MW lower
    - About 3 percent of capacity
- Some resources bid in capacity above seasonal rating
  - Capability above seasonal ratings neglected
  - Need to better understand the incentives for under/over rating

Comparison of Mean Parameter (MW)			
Technology	EFORd Based	Operational Data	Difference
Combined Cycle	10420.2	10015.4	404.8
Combustion Turbines	1731.4	1765.6	-34.2
Fossil	8955.8	8791.0	164.7
Diesel	46.2	41.8	4.4
Hydro	3116.5	2837.6	278.9
Nuclear	4487.3	4398.4	88.9
Total	28757.3	27849.7	907.6

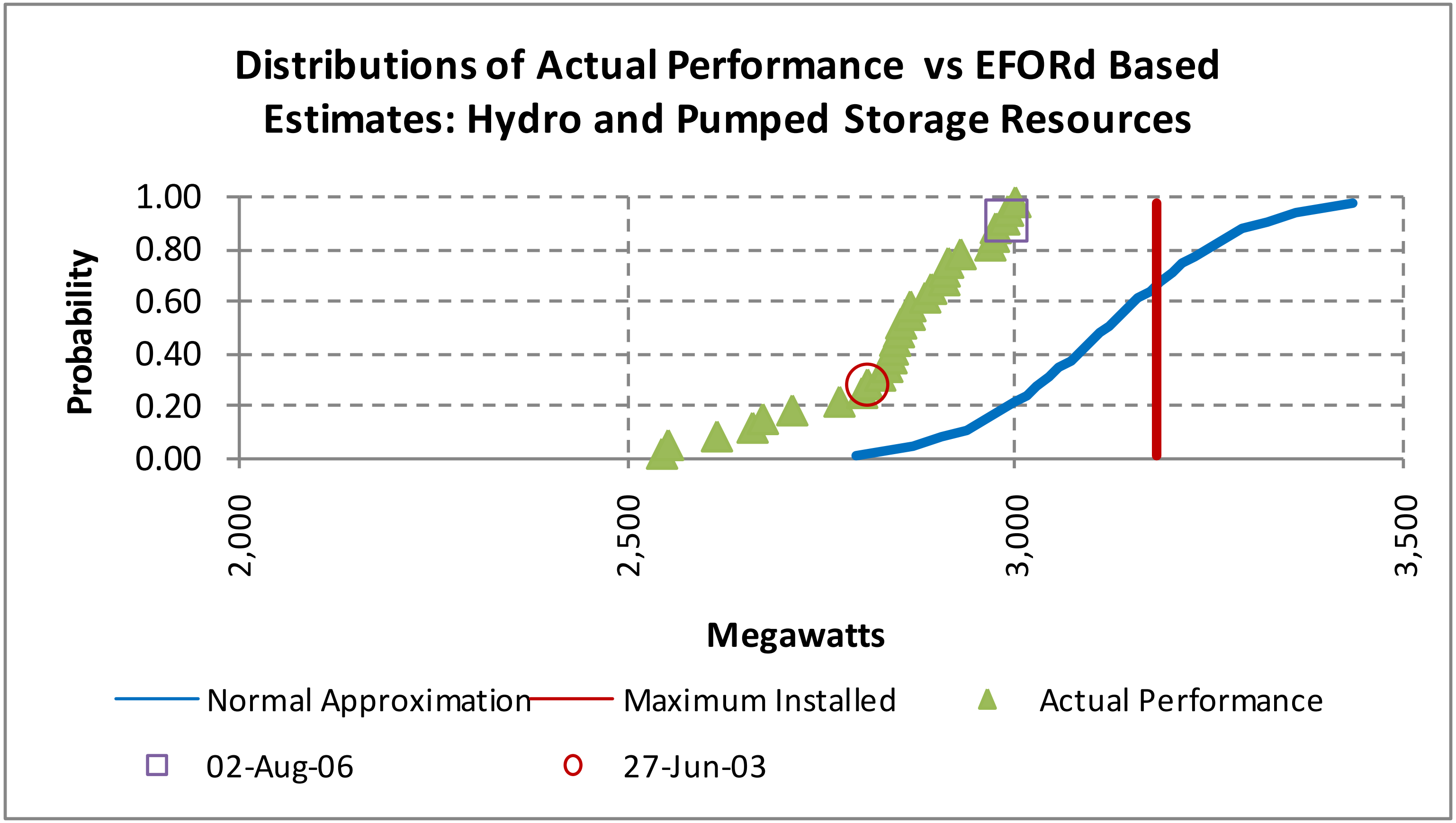
Distribution Comparison: All Resources



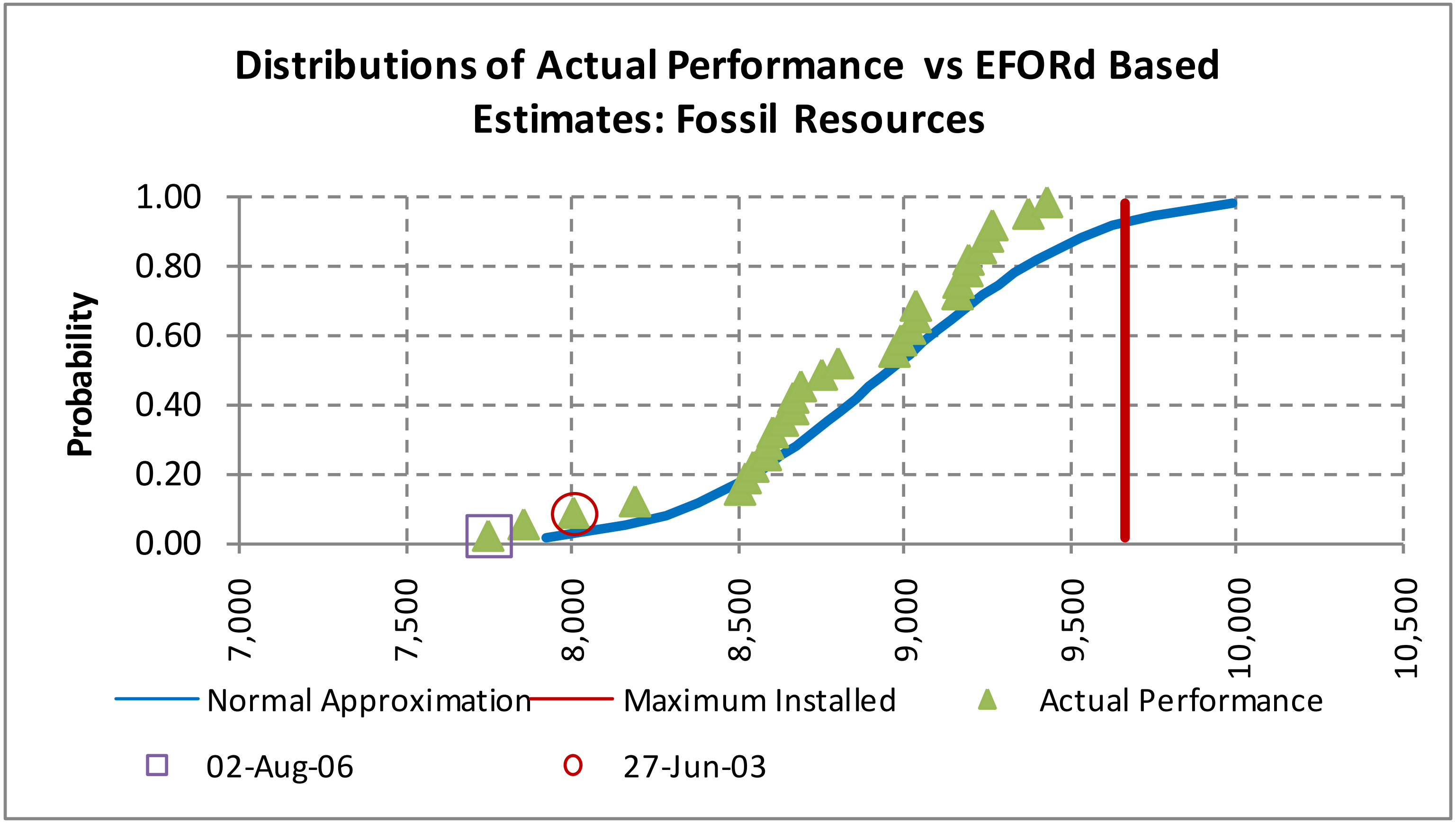
Distribution Comparison: Nuclear



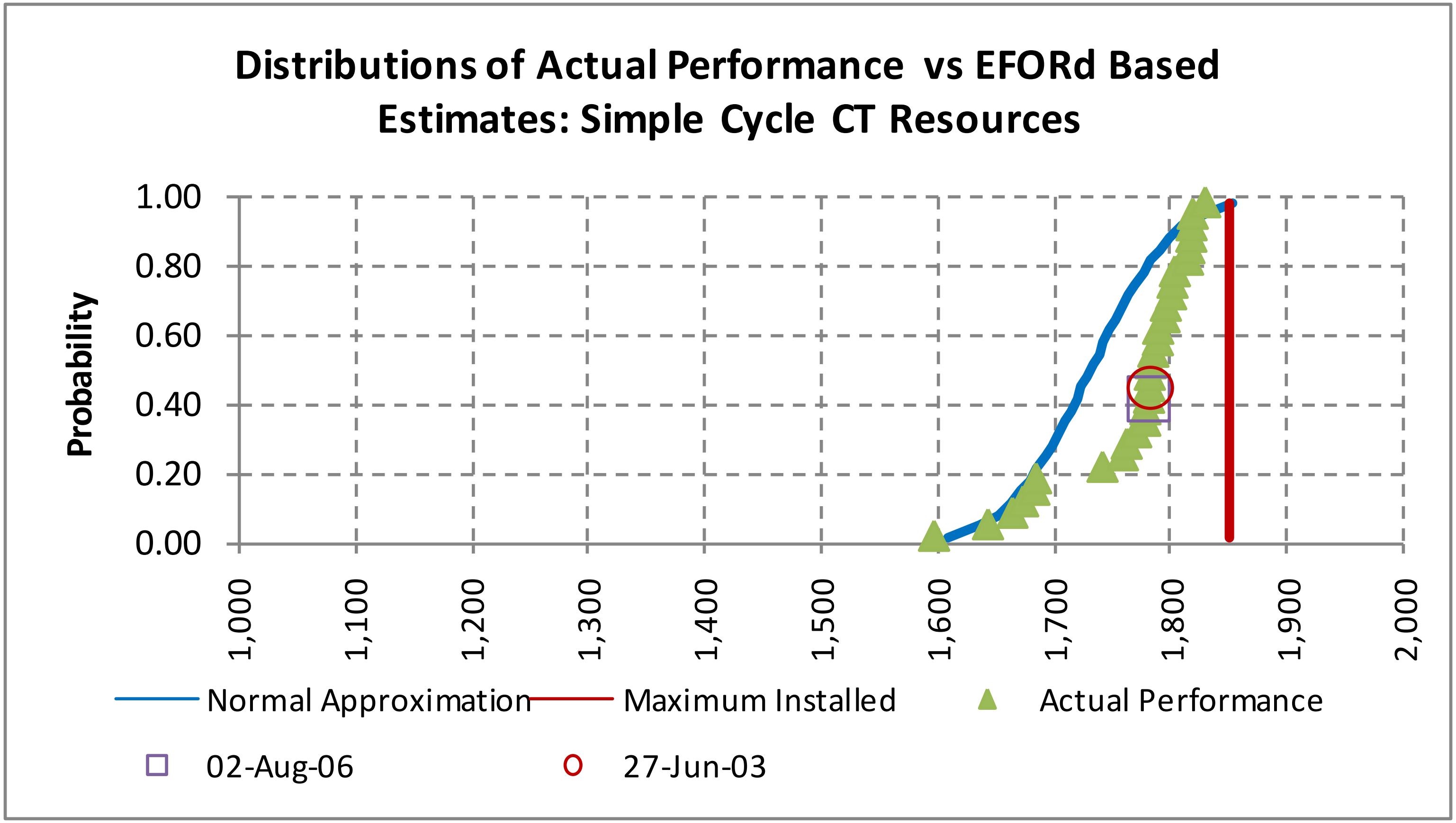
Distribution Comparison: Hydro and PS



Distribution Comparison: Fossil



Distribution Comparison: Simple Cycle CT



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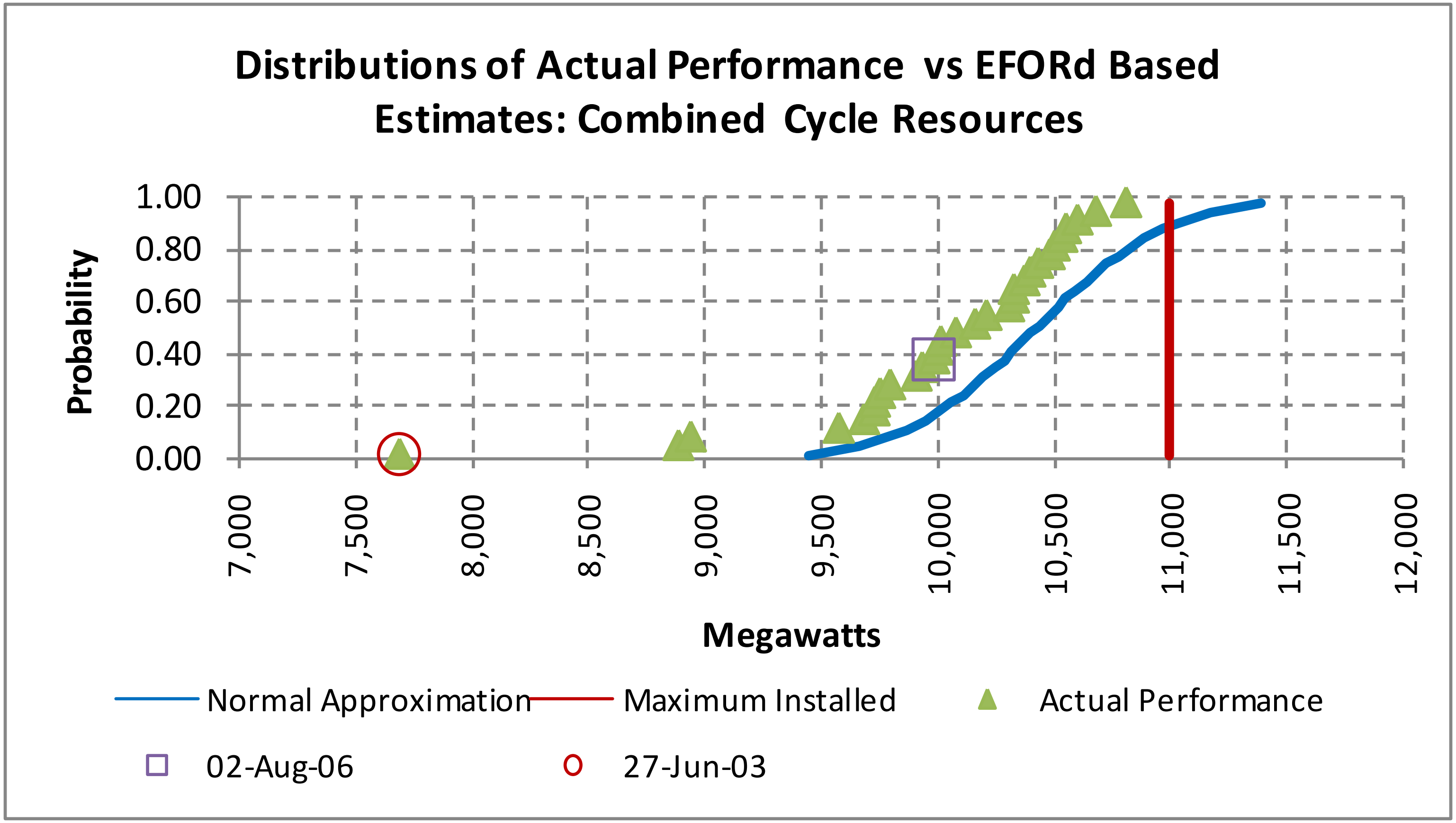
Distribution Comparison: Combined Cycle`



Parametric Changes for Sensitivity Analysis

Routine ICR Sensitivity Cases

- Each year, during the ICR process, sensitivities are routinely performed
  - Effect of the change in load forecast and profiles
  - Effect of the change in resource availability
  - Combinations of changes
  - All other minor changes
- Composite effects
  - Following sensitivities show
    - Effect of resource EFOR adjustments decrease ICR by 120 MW
    - Effect of load forecast and profiles increase ICR by 421 MW
    - Combined EFOR and load changes
      - Where 295 MW ~= 301 MW = 421 MW – 120 MW

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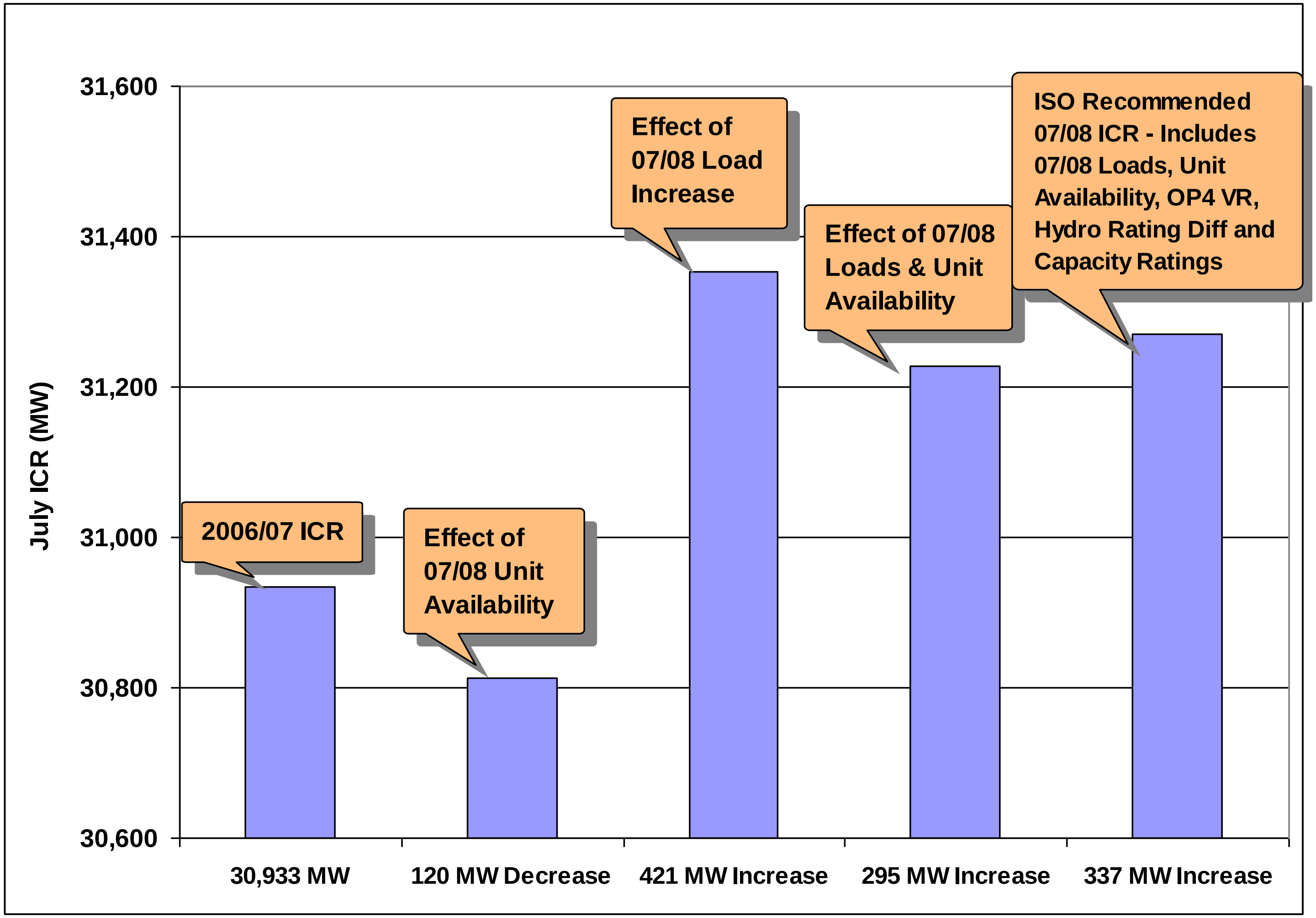
Sensitivities for 2007/08 ICR Presentation



MARS Model

Westinghouse vs. MARS

- Both models create load and capacity distributions as shown in prior slides
  - Calculation techniques are very different
    - Monte-Carlo can handle complex inter-relationships
    - Closed form mathematics becomes too complex
  - Effect is the same
- Concurrent use of both models provides greater insight into the problem under study

MARS Calculations

- Monte-Carlo means thousands of replications
  - Each replication is
    - A specific system state with
      - Specific units either available or failed
      - Loads in each area at specific levels
      - Transmission flows approaching, or at, limits
    - A single point of the curve
  - Many, many, many replications needed to quantify low probability events such as LOLE
    - Assume 10 equally stressed summer peak load days
    - Each day could experience 100 failures in a 10,000 replication simulation for system 0.1 days per year
    - Expectation is: 1000 loss-of-load days in 10,000 years
  - At 0.1 days/year only peak hour is significant

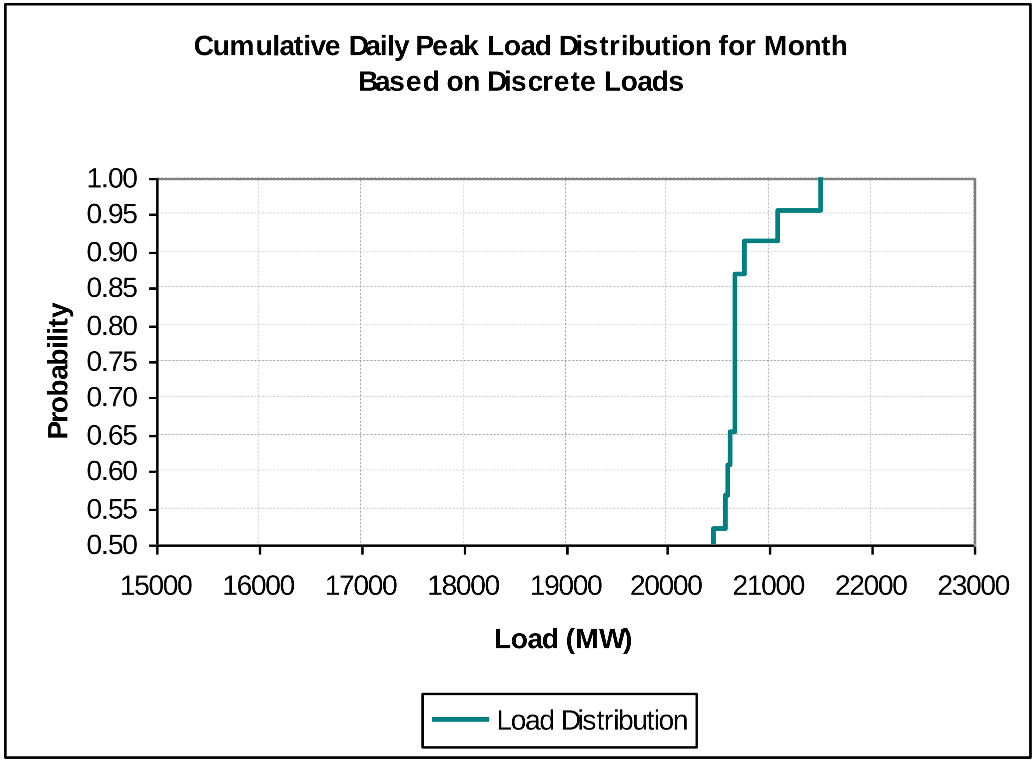
Sequential Monte-Carlo

- MARS runs all 8760 hours/year chronologically
- Significant resource outages could occur at moderate loads and cause a loss of load
  - In 10,000 replications the effect of a non-peak load loss of load is miniscule and below any concern
  - May be only a concern for a Frequency and Duration index
- Hourly loss of load analysis shows

  0.10 days/year LOLE ~= 0.35 hours/year LOLH

Discrete Weekday Peak Loads

- Probability of each load step is 1/21*



* For a month with 21 weekdays

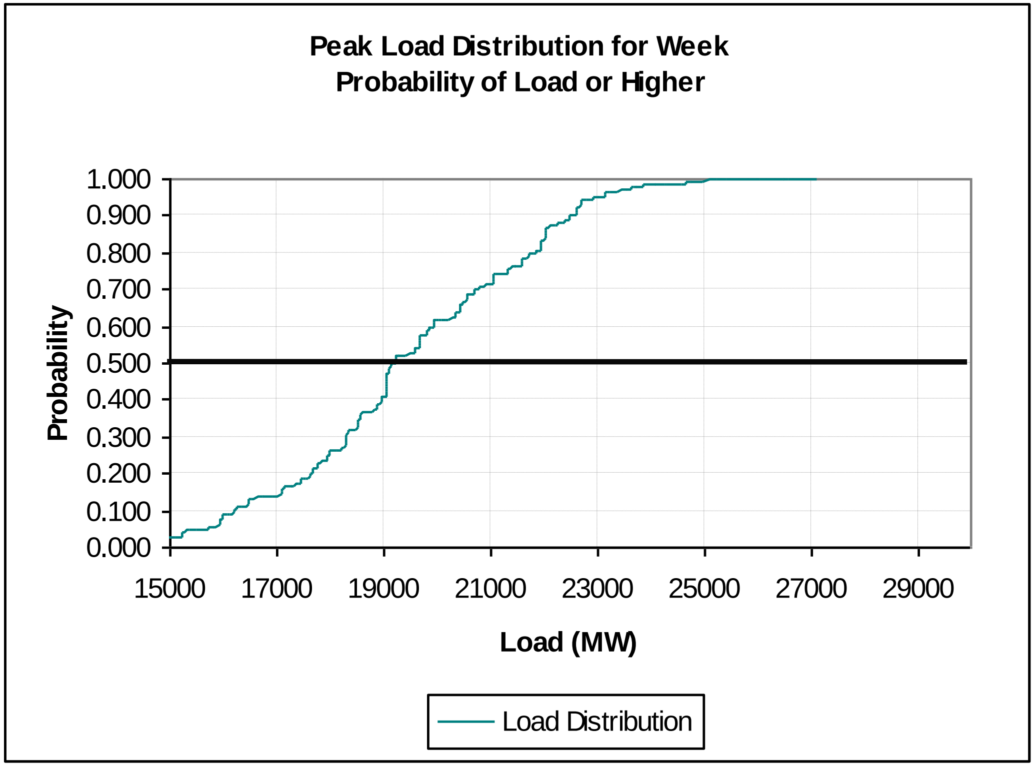
Load Forecast Uncertainty Multipliers

- Used to stretch series of discrete weekday peak loads into “Westinghouse” weekly distribution of peak load.
- Programmatic development of multiplier/probability pairs
  - Eleven pairs
  - Based on least squares fit
  - Each month is has unique set
  - Symmetry not mandated
  - Match tail of Westinghouse loads
- Critical to benchmarking
- No “fudge factor” employed

Steps	Weighting	LFU Multipliers
1	0.01	1.062
2	0.02	1.049
3	0.05	1.027
4	0.10	0.995
5	0.15	0.992
6	0.01	0.978
7	0.15	0.978
8	0.02	0.975
9	0.05	0.973
10	0.10	0.965
11	0.34	0.940
Sum	1.00	

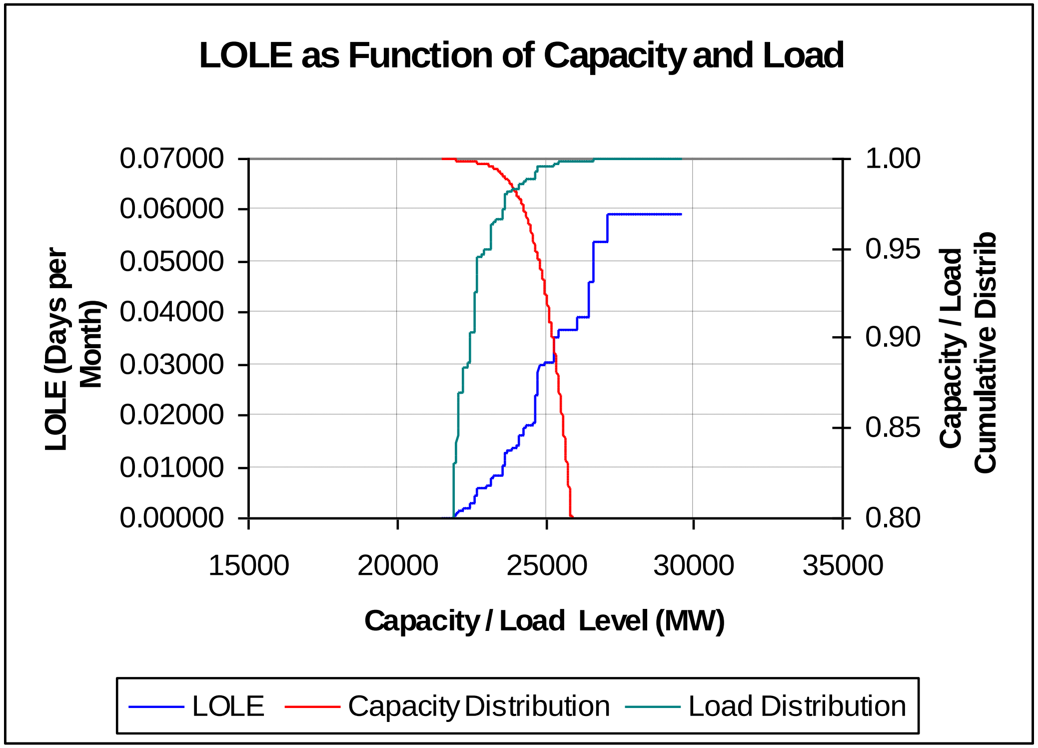
Distribution of Weekday Peak Loads

- Distribution of loads influenced by LFU multipliers



Interaction of Loads, Capacity, LOLE

- LOLE is calculated by the convolution of capacity and load distributions*



* The distribution of capacity margin (i.e., capacity minus load) is produced by the convolution of capacity distribution and load distribution. LOLP is the probability of all negative capacity margin states (i.e., capacity margin < 0 = reserve margin). The LOLE is the LOLP multiplied by the length of study period represented by the distributions.

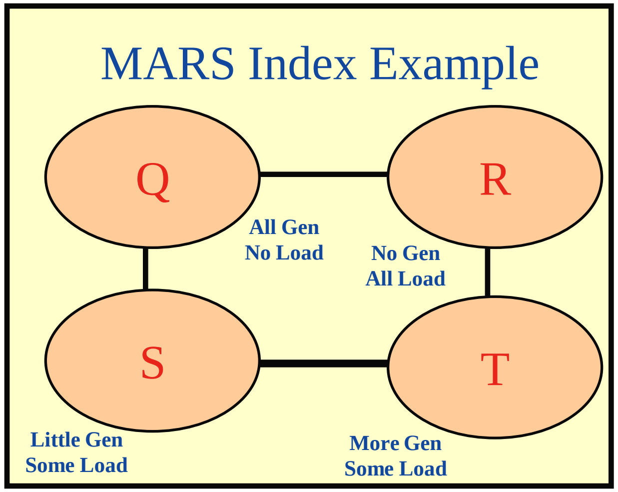
The MARS LOLE Index

MARS LOLE Index Characteristics

- LOLE index characteristics are important
- MARS control area level LOLE indices to be used
  - Control area indices based on individual sub-area LOLE indices
  - Union of LOLE events across all sub-areas of a control area
- Sub-areas of a control area do not need to be contiguous
  - Non-contiguous sub-areas may have an impact
- Emergency operating procedure constraints ignored
  - Use NPCC CP-8 modeling assumptions
  - In actuality, benefits of some emergency operating procedures
    - Unlikely to be shared with other control areas
    - Operational issues may preempt ability to share
    - May result in minor increases in control area capacity requirements
- External control area assistance order may have impact

Understanding the MARS Index

- Four sub-areas with no constraints
  - One sub-area has only generation
  - One sub-area has only load
  - Two sub-areas have balance of both



Sub Area	Iter 1	Iter 2	Iter 3	Iter 4	Iter 5	Iter 6	Average
Resource							
Q	1100	1100	900	1100	700	900	
R	0	0	0	0	0	0	
S	350	450	510	450	510	490	
T	549	355	549	450	549	549	
Load							
Q	0	0	0	0	0	0	
R	1000	1000	1000	1000	1000	1000	
S	500	500	500	500	500	500	
T	500	500	500	500	500	500	
Surplus MW	-1	-95	-41	0	-241	-61	
Pool LOLE	Yes	Yes	Yes	No	Yes	Yes	
Pool LOLE 'Hit'	1	1	1	0	1	1	0.83
Q LOLE 'Hit'	0	0	0	0	0	0	0.00
R LOLE 'Hit'	1	1	1	0	1	1	0.83
S LOLE 'Hit'	1	1	0	0	0	1	0.50
T LOLE 'Hit'	0	1	0	0	0	0	0.17

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MARS Sub-Area LOLE Index Characteristics

- Control area wide considerations
  - If control area has sufficient resources
    - It will satisfy its own loads first
    - Before providing assistance to other control areas
- Generation only sub-area (no load) always has zero LOLE
- For a sub-area that has only load and no generation
  - LOLE 'hit' will occur whenever there is a control area wide shortage
  - LOLE 'hit' will NOT occur if another part of the control area is short and this sub-area is "export" constrained to the "short" area
- For a sub-area with BOTH load and resources
  - LOLE 'hit' will occur whenever there is a control area wide shortage and the sub-area is deficient in that shortage hour
  - LOLE 'hit' will NOT occur if the area is initially not in shortage

MARS Combined Control Area Indices

- When New England has 0.100 days/year LOLE ***and*** New York has 0.100 days/year LOLE
  - Union of LOLE events for both control areas is 0.162 days/year
    - This is true even in absence of binding transmission constraints
    - Due to MARS index definition
      - Why should New England get an LOLE 'hit' when New York is short
      - Why should New York get an LOLE 'hit' when New England is short
      - No load loss sharing between control areas (each area is responsible)
  - If modeled as a single combined large control area (NPCC-US)
    - LOLE for combined area would be approximately 0.162 days/year
      - Even without binding transmission constraints
      - LOLE would now be shared internally within large control area
    - LOLE for both control areas could be brought to 0.100 days/year
      - But the areas need more capacity to improve combined reliability
      - Flexibility in locating capacity in either area absent sub-criterion

MARS Contract Modeling

- MARS can represent contracts between control areas
  - Define originating sub-area
  - Define destination sub-area
  - Designate a transmission interface link as the contract path
- Removal / Transfer reduction of contract path
  - Contract flow has priority rights on contract path link
  - Uses as much transmission capacity as necessary
  - Contract still flows if transmission link is deleted
    - Firm load increase in originating sub-area
    - Firm resource increase in destination sub-area
    - Similar to a firm increase or decrease in ‘native’ capacity
- Contracting allows for improving reliability in one area vis-à-vis another area

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Local Resource Adequacy and Maximum Capacity Limit for FCA

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Locational Requirement Methodology

- Local Resource Adequacy (LRA)
  - Connecticut
  - NEMA/BOSTON
  - Local Resource Adequacy (LRA) is the minimum amount of capacity that must be electrically located within an import-constrained Load Zone to meet the Installed Capacity Requirement (ICR)
- Maximum Capacity Limit (MCL) for Maine
  - Maximum Capacity Limit (MCL) is the maximum amount of capacity that can be procured in an export-constrained Load Zone to meet the ICR

Common Steps for LRA and MCL

- Model the Load Zone under study vs. the rest of the NE Control Area using the GE MARS simulation model
  - Reflect load and resources electrically connected to them, including external Control Area support from tie benefits
  - Model the transmission interface constraint between the Load Zone under study and the rest of the New England
  - Add proxy units that are required in the New England to meet the resource adequacy planning criterion of 0.1 days/year LOLE
  - If the system LOLE with proxy units added is less than 0.1 days/year
    - Firm load is added (or unforced capacity is subtracted)
    - Ensure New England system LOLE equals 0.1 days/year

Additional Steps for Calculating LRA

- Beginning with the New England system at 0.1 days/year
  - Adjust the firm load within the Load Zone under study
    - Until the LOLE of the NE Control Area LOLE reaches 0.105 days / year
    - As firm load is added to the Load Zone under study, an equal amount of firm load is removed from (or added to) the rest of the NE Control Area
- Note that New England’s share of tie benefits from New York, New Brunswick and Quebec are considered pre-existing at their respective interconnection points

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Methodology for Calculating Local Resource Adequacy (Cont.)

Calculate the LRA for the import-constrained Load Zone in accordance with the following formula:

LRA_z = $Resources_z$ + Proxy $Units_z$ – (Proxy Units $Adjustment_z$/ (1-FOR_z)) – (Firm Load $Adjustment_z$/ (1-FOR_z))

in which,

- LRA_z = MW of Local Resource Adequacy for Load Zone Z
- $Resources_z$ = MW of resources electrically located within the Load Zone Z, including Import Capacity Resource on the import-constrained side of the interface, if any
- Proxy $Units_z$ = MW of proxy unit additions in the Load Zone Z
- Proxy Units $Adjustment_z$ = MW of firm load added to (or unforced capacity subtracted from) Load Zone Z until the system LOLE equals 0.1 days/year
- Firm Load $Adjustment_z$ = MW of firm load added (or subtracted) within the Load Zone Z to make the LOLE of the NE Control Area equal to 0.105 days per year,
- FOR_z = Capacity weighted average of the forced outage rate modeled for all resources within the Load Zone Z, including any proxy unit additions to the Load Zone Z

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Methodology for Calculating Maximum Capacity Limit (Cont.)

Calculate the MCL for the export-constrained Load Zone Y in accordance with the following formula:

$\text{Maximum Capacity Limit}_{Y} = \text{ICR} – \text{LRA}_{\text{RestofNewEngland}}$

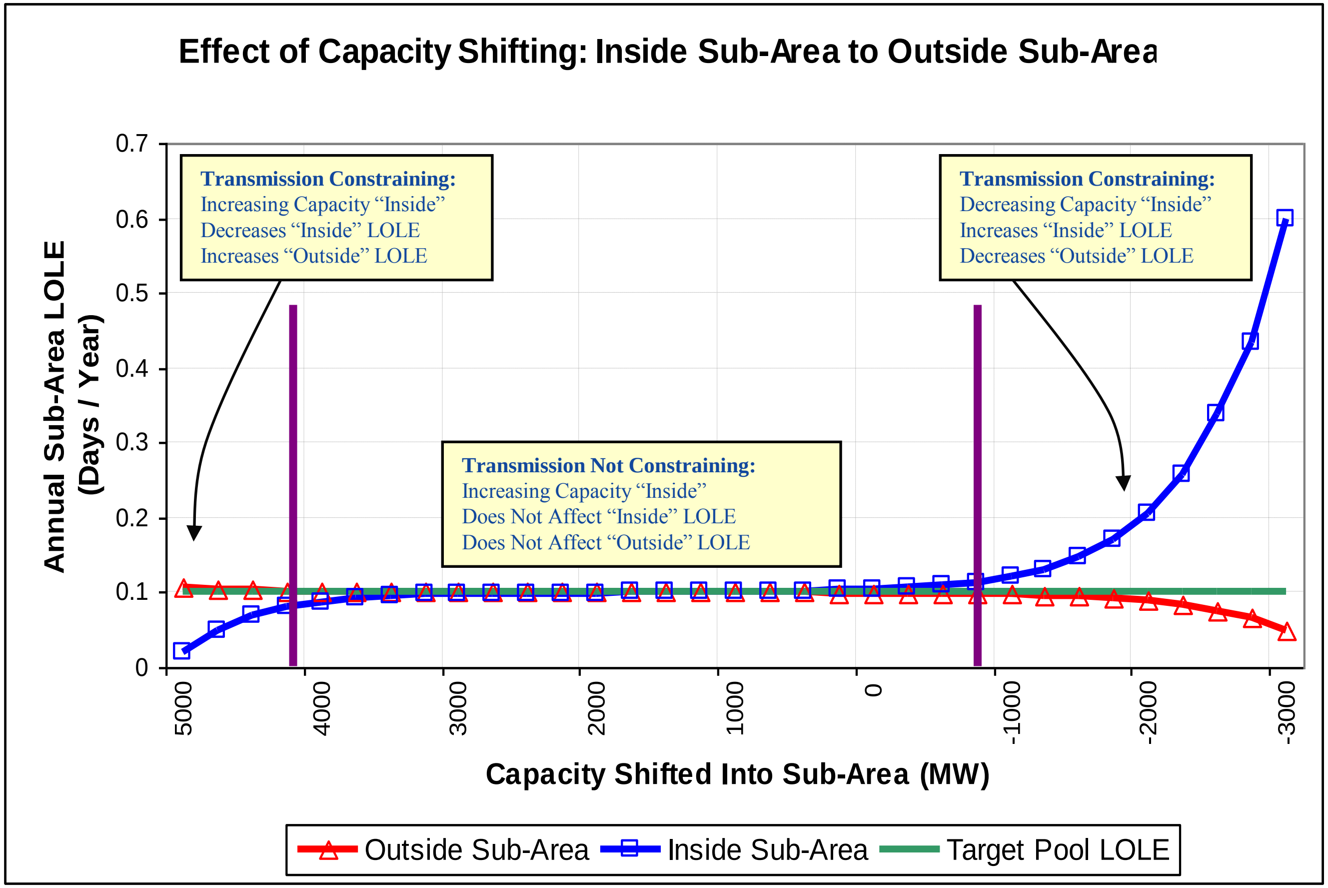
In which,

- Maximum Capacity Limit_{Y} = Maximum amount of resources, including import Capacity Resources on the export-constrained side of the interface, if any that can be procured in the export-constrained Load Zone Y under study to meet the ICR.
- ICR = MW of Installed Capacity Requirement for the NE Control Area
- $\text{LRA}_{\text{RestofNewEngland}}$ = MW of Local Resource Adequacy for the rest of the NE Control Area, which for the purposes of this calculation is treated as an import-constrained region. $\text{LRA}_{\text{RestofNewEngland}}$ is determined in accordance with the methodology presented in prior slides.

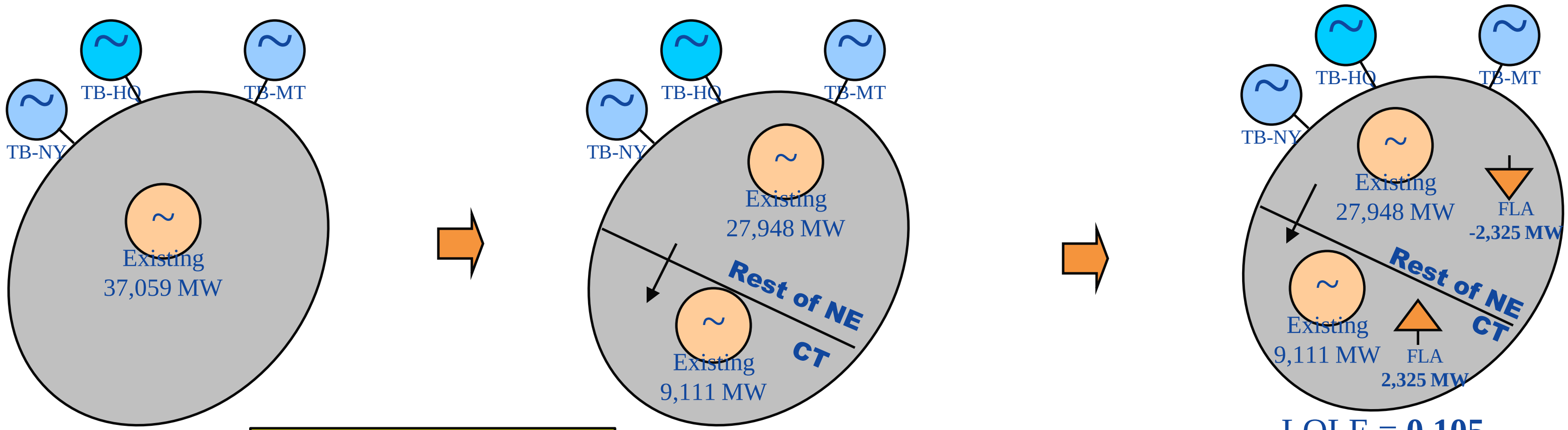
Reliability Calculation Methodology

- Approach shown here is applicable to both
  - New England wide Installed Capacity Requirements (ICR), and
  - Locational Capacity Requirements (LRA and MCL)
- Loads
  - Total New England loads are developed as shown
  - Loads for sub areas are
    - Approximately a percentage of the total load
    - Percentage changes by month
- Calculations are identical
  - Question addressed by the calculation is:
    - What is the MINIMUM (or MAXIMUM) of capacity that is required IN THE AREA UNDER STUDY to satisfy the reliability criterion, GIVEN the risks and constraints that have been modeled

Target Amount of Capacity in a Zone



Calculation Procedure
– LRA for Connecticut



LOLE = 0.001 | LOLE will now be brought to 0.100 days/year | LOLE = 0.001 | LOLE = **0.105**

System LOLE < 0.1 with existing resources modeled, proxy units are NOT needed, and no Proxy Units Adjustment (PUAz) is required.

Model the transmission interface between CT and Rest of NE. System LOLE remains at 0.001. Because LOLE is less than 0.105, Firm Load Adjustment (FLAz) will be made.

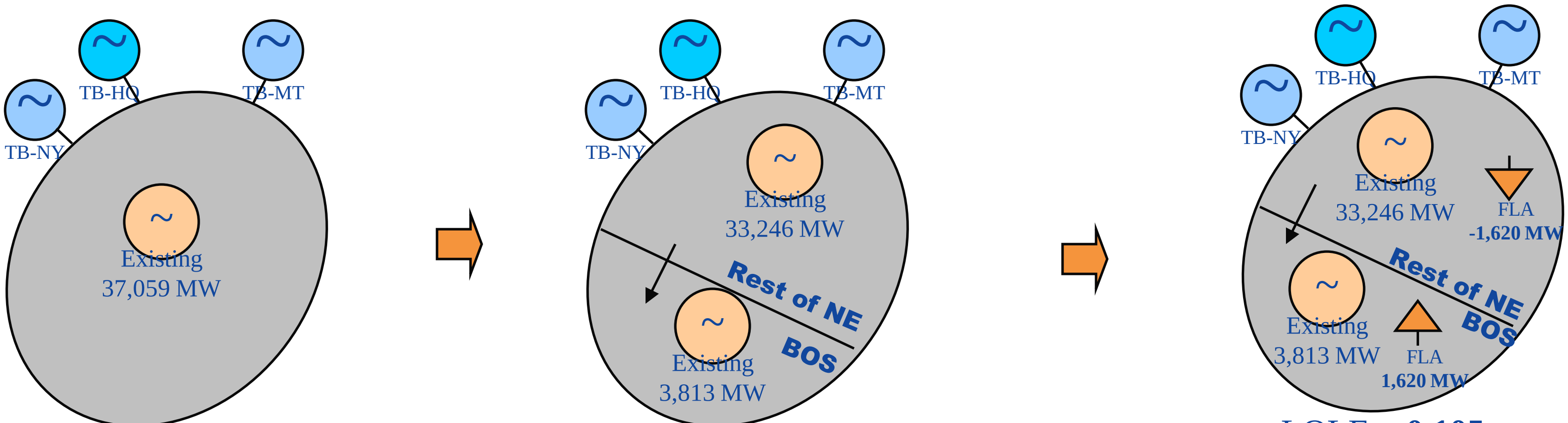
After **adding 2,325 MW** load to CT and **subtracting 2,325 MW** from Rest of NE, system LOLE reaches 0.105. LRA for CT is then determined as

$$LRA_z = Resources_z + Proxy\ Units_z - (PUA_z / (1 - FOR_z)) - (FLA_z / (1 - FOR_z))$$
$$= 9{,}111 + 0 - 0 /(1 - 0.0592) - 2{,}325/(1 - 0.0592)$$
$$= 6{,}640\ MW$$

Note:
PUAz is the Proxy Units Adjustment
FLAz is Firm Load Adjustment

Based on FCA 3 for 2012/13

Calculation Procedure
– LRA for NEMA/BOSTON



LOLE = 0.001 | LOLE will now be brought to 0.100 days/year | LOLE = 0.001 | LOLE = **0.105**

System LOLE < 0.1 with existing resources modeled, proxy units are NOT needed, and no Proxy Units Adjustment (PUAz) is required.

Model the transmission interface between NEMA/BOSTON and Rest of NE. System LOLE remains at 0.001. Because LOLE is less than 0.105, Firm Load Adjustment (FLAz) will be made.

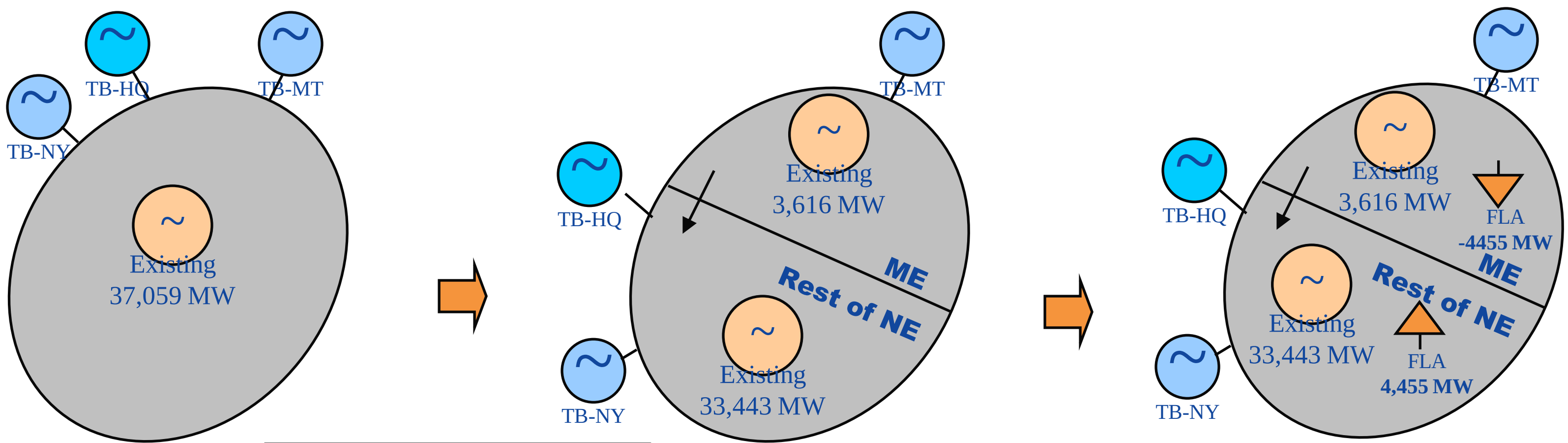
After **adding 1,620 MW** load to NEMA/BOSTON and **subtracting 1,620 MW** from Rest of NE, system LOLE reaches 0.105. LRA for NEMA/BOSTON is then determined as

LRAz = Resources$_z$
+ Proxy Units$_z$
– (PUAz/ (1 – FORz))
– (FLAz/ (1 – FORz))
= 3,813 + 0 – 0 /(1 – 0.0970)
– 1,620/(1 – 0.0970)
= 2,019 MW

Note:
PUAz is the Proxy Units Adjustment
FLAz is Firm Load Adjustment

Based on FCA 3 for 2012/13

Calculation Procedure
– MCL for Maine



LOLE = 0.001 | LOLE will now be brought to 0.100 days/year | LOLE = 0.001 | LOLE = **0.105**

System LOLE < 0.1 with existing resources modeled, proxy units are NOT needed, and no Proxy Units Adjustment (PUAz) is required.

Model the transmission interface between Maine and Rest of NE. System LOLE remains at 0.001. Because LOLE is less than 0.105, Firm Load Adjustment (FLAz) will be made.

After **adding 4,455 MW** load to Rest of NE and **Subtracting 4,455 MW** from Maine, system LOLE reaches 0.105. LRA for Rest of NE is determined as

$LRA_{restofNewEngland}$ = $Resources_z$ + Proxy $Units_z$

– (PUA_z/ (1-FOR_z)) – (FLA_z/ (1 – FOR_z))

= 33,443 + 0 – 0 /(1 – 0.0591)

– 4,455/(1 – 0.0591)

= 28,708 MW

MCL for Maine is then determined as

MCL = ICR – $LRA_{RestofNewEngland}$

= 31,965 – 28,708

= 3,257 MW

Note:
PUAz is the Proxy Units Adjustment
FLAz is Firm Load Adjustment

Based on FCA 3 for 2012/13

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Tie Benefits Theory and Calculation

Tie Benefit Background

- NPCC reliability criterion states that:

  Each Area’s resources will be planned in such a manner that after due allowance for scheduled maintenance, forced and partial outages, interconnections with neighboring areas, and available operating procedures, the probability of disconnecting non-interruptible customers due to resource deficiency, on the average, will be no more than once every ten years.

- Part of this evaluation is:
  - Consideration of emergency assistance from external control areas
  - Adjusted for grandfathered contracts and estimated external capacity purchases

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Typical Tie Benefit Study Assumptions

- The General Electric Multi-Area Reliability Simulation (MARS) is used as the primary analytical tool for this analysis. The MARS model will include:
  - The most recent database updated for the latest assumptions.
  - All known generators and their associated MW ratings and transition rates.
  - The transfer limits of the transmission system between Zones and/or Areas in both directions.
  - Groupings of interface flows that would limit the total flows to less than the sum of the individual flows into or out of an area
  - The transition rates for the cable interfaces in NYISO
  - Daily peak loads for each of the zones and areas
  - Emergency operating procedures
  - All firm transactions between areas and zones
  - Generator maintenance schedules
  - Load forecast uncertainty

Models to Use for Tie Benefits

- Single area model
  - Single area models are not used to develop tie benefits
  - Single area models use inputs developed from multi-area models
  - Single area model used for Installed Capability Requirements
  - Appropriateness of single area model not relevant to tie benefit discussion
- Multiple area model
  - Consensus is that a multi area model is appropriate for quantifying external capacity assistance
    - External capacity assistance
      - Quantified in terms of firm capacity equivalent
      - For purposes of developing inputs for a single area model
  - If a multi area model were used for Installed Capability Requirement
    - There would be no tie benefit discussion
    - Effect would be internalized
    - Discussion would then shift to multi area modeling assumptions

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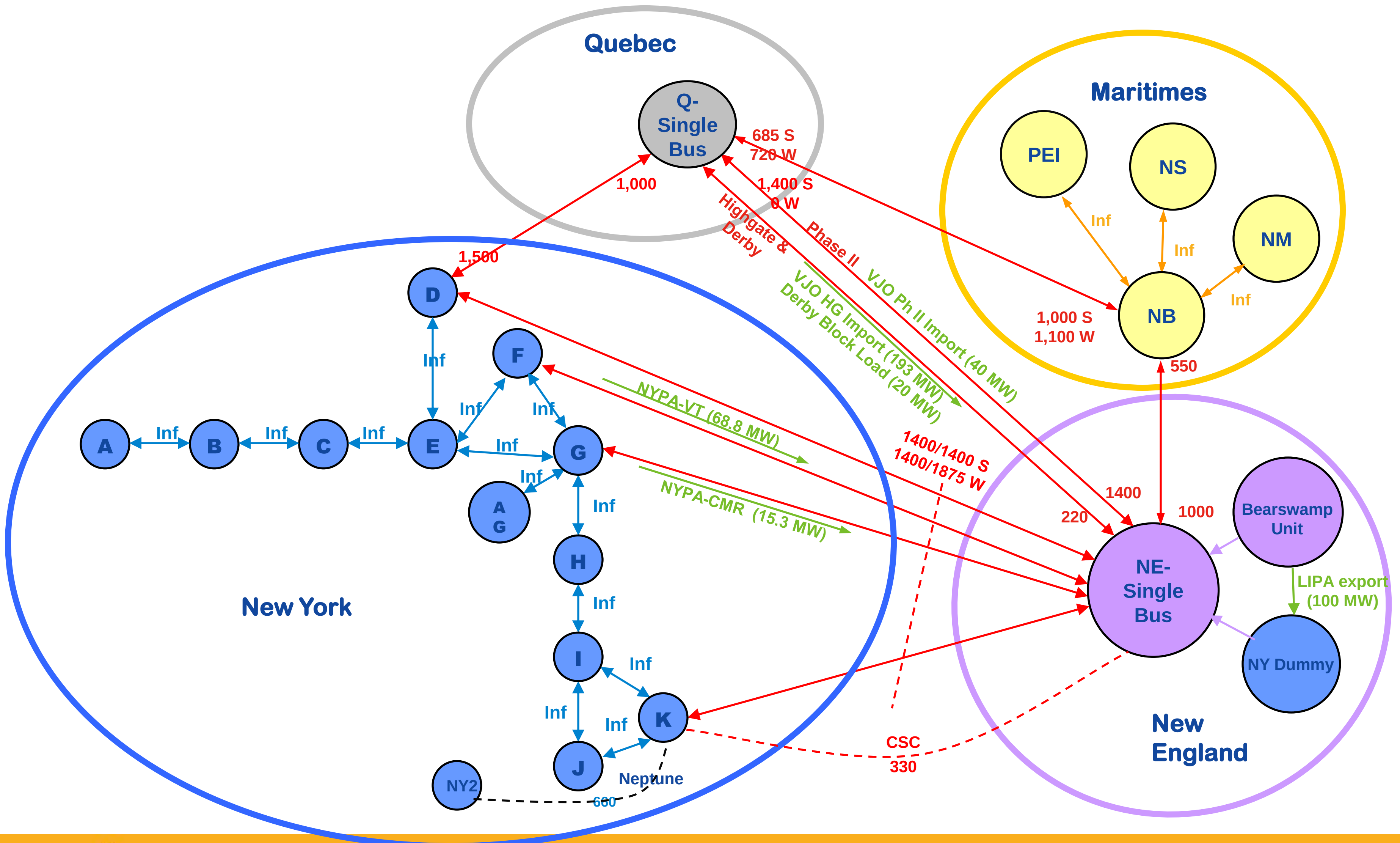
Study Assumptions
– Interconnection Diagram



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Typical Tie Benefit: Initial Case Set-up

- Initial reliability simulation will be run to achieve design reliability levels
  - The LOLE result will be compared to the LOLE criterion target of disconnecting firm load 0.1 days per year.
  - If the LOLE result is higher or lower than 0.1 days per year, MARS is re-run in an iterative process
    - Increasing/decreasing capacity in the zones or groups of zones
    - Defined by the critical import interfaces in order to attain the 0.1 LOLE
- The goal will be to:
  - Maximize the amount of capacity that can be removed within the control area to satisfy the LOLE reliability criterion
  - The MARS function table firm capacity adjustments will be used
    - Facilitate capacity shifts between regions
    - Avoid potential distortions associated with shifting of individual units

Scope: Establishing the Base Case

- The LOLE indices to be considered will be:
  - Considering internal transmission limits
    - NYISO
    - ISONE
    - Maritimes
    - Quebec
  - When these simultaneously attain 0.1 days per year with the minimum amounts of capacity this defines a base case

Tie Benefit Example: Study for Year 2012/13

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Basis for Tie Benefit Example

- Calculate Tie Benefit values from neighboring Control Areas to New England for the year 2012 using the current calculation methodology
  - To calculate the total Tie Benefit available to New England
  - To calculate the Tie Benefit associated with each neighboring Control Area
  - To determine the Tie Benefit associated with each neighboring Control Area
- Consistent with the assumptions used for 2012/13 ICR calculation, except:
  - Only grandfather imports are modeled
    - VJO import to reflect delist bids
    - 193 MW through Highgate
    - 20 MW through derby line
    - 40 MW through HQ phase II

Basis for Tie Benefit Example

- Calculate Tie Benefit values through probabilistic method
  - Using multi-area probabilistic simulation model, GE MARS
- Evaluate under "at criterion" conditions for all interconnected Areas
  - All Areas are brought to 0.1 days/year simultaneously while interconnected to each other
- Inter-Area transmission constraints are modeled, while internal constraints within each Area are eliminated by adding resources where needed
- Calculate the Tie Benefit contributions of each neighboring Areas in a consistent manner
  - If the sum of the tie benefits from the individual neighboring Areas is not equal to the total amount of tie benefits, then each of the neighboring Area's tie benefits will be adjusted based on the ratio of the individual Area tie benefit to the sum of the tie benefits

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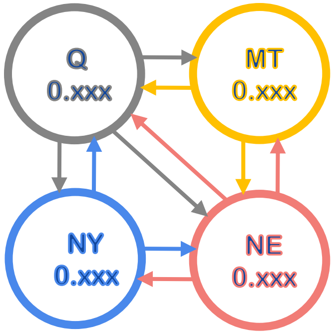
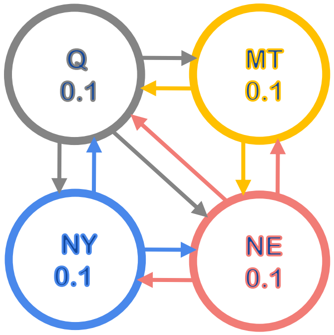
Example Methodology

– Calculation of Total Tie Benefits, TB_{Total}

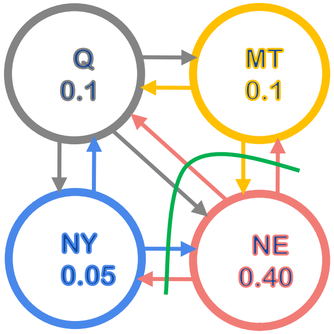
Step 1: Interconnect New England, Quebec, New York and Maritimes systems and calculate each Control Area's risk index ($LOLE_{interconnected}$).



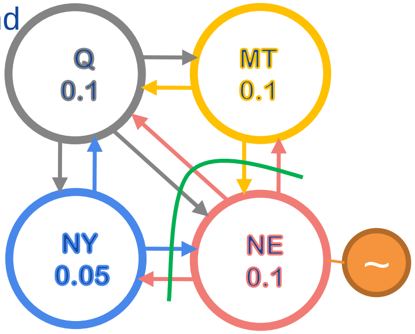
Step 2: Bring each Control Area's risk index to the 0.1 days/year level simultaneously, by adjusting the resources/load in each Control Areas.



Step 3: Reduce the total transfer capabilities of the interconnections from neighboring Areas to allow for only net firm capacity import, and calculate the New England risk index ($LOLE_{NE\text{-}w/oNY\&HQ\&MT}$). $LOLE_{NE\text{-}w/oNY\&HQ\&MT}$ > 0.1 days/year.



Step 4: Bring New England Control Area's risk index, $LOLE_{NE\text{-}w/oNY\&HQ\&MT}$, back to the 0.1 days/year, by adding unforced resources to New England



Step 5: The total tie benefits from neighboring Areas, TB_{Total} equals to the amount of resources added to New England in the Step 4.

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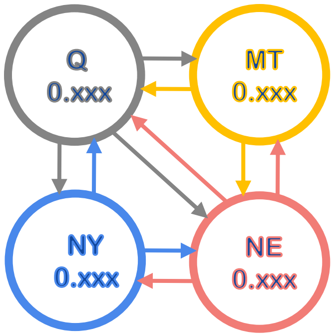
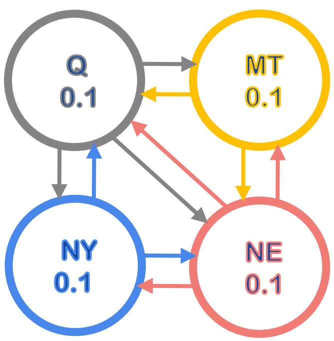
Example Methodology
– Calculation of New York Tie Benefit, TB_{Tie_NY}

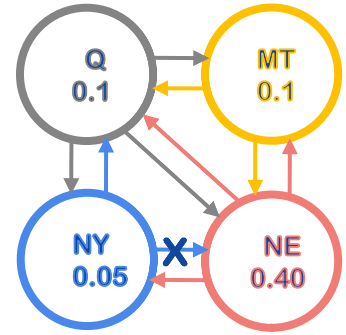
Step 1: Interconnect New England, Quebec, New York and Maritimes systems and calculate each Control Area's risk index ($LOLE_{interconnected}$).



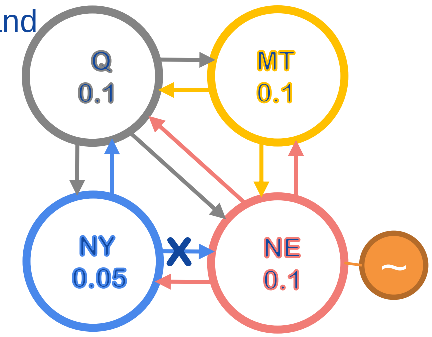
Step 2: Bring each Control Area's risk index to the 0.1 days/year level simultaneously, by adjusting the resources/load in each Control Areas.



Step 3: Reduce the transfer capabilities of the interconnections (All AC lines and Cross Sound Cable) from New York to New England to allow for only firm capacity import, and calculate the New England risk index ($LOLE_{NE\text{-}w/oNY}$). $LOLE_{NE\text{-}w/oNY}$ > 0.1 days/year.



Step 4: Bring New England Control Area's risk index, $LOLE_{NE\text{-}w/oNY}$, back to the 0.1 days/year, by adding unforced resources to New England



Step 5: The tie benefit contribution of the interconnections from New York to New England (TB_{Tie_NY}) equals to the amount of resources added to New England in the Step 4.

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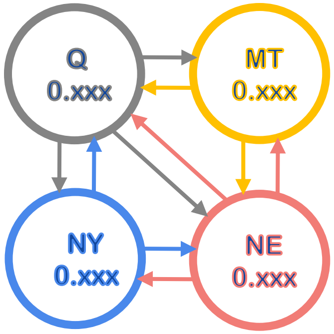
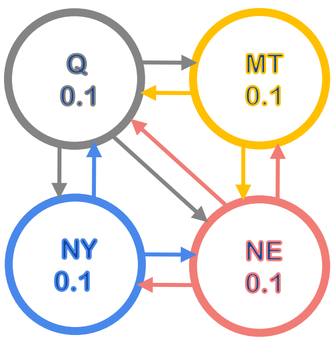
Example Methodology

– Calculation of Maritimes Tie Benefit, TB_{Tie_MT}

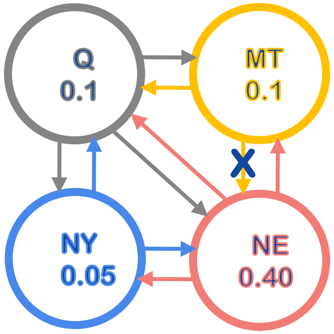
Step 1: Interconnect New England, Quebec, New York and Maritimes systems and calculate each Control Area's risk index ($LOLE_{interconnected}$).



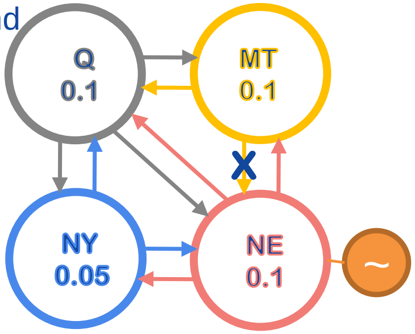
Step 2: Bring each Control Area's risk index to the 0.1 days/year level simultaneously, by adjusting the resources/load in each Control Areas.



Step 3: Reduce the transfer capabilities of the interconnections from Maritimes to New England to allow for only firm capacity import, and calculate the New England risk index ($LOLE_{NE\text{-}w/oMT}$). $LOLE_{NE\text{-}w/oMT}$ > 0.1 days/year.



Step 4: Bring New England Control Area's risk index, $LOLE_{NE\text{-}w/oMT}$, back to the 0.1 days/year, by adding unforced resources to New England



Step 5: The tie benefit contribution of the interconnections from Maritimes to New England (TB_{Tie_MT}) equals to the amount of resources added to New England in the Step 4.

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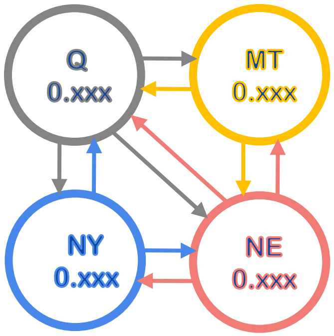
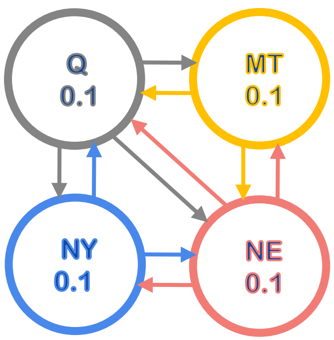
Example Methodology

– Calculation of Quebec Tie Benefit, TB_{Tie_Q}

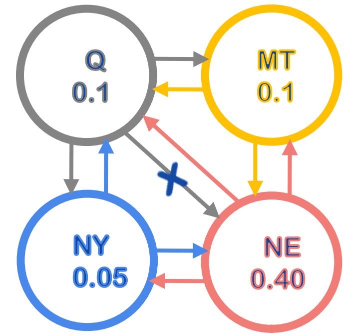
Step 1: Interconnect New England, Quebec, New York and Maritimes systems and calculate each Control Area's risk index ($LOLE_{interconnected}$).



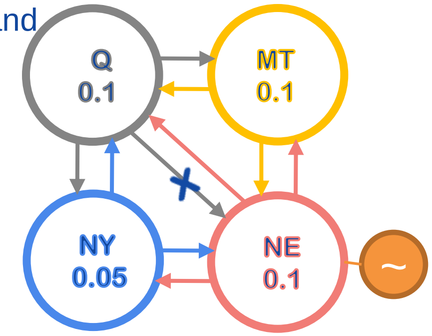
Step 2: Bring each Control Area's risk index to the 0.1 days/year level simultaneously, by adjusting the resources/load in each Control Areas.



Step 3: Reduce the transfer capabilities of the interconnections from Quebec to New England to allow for only firm capacity import, and calculate the New England risk index ($LOLE_{NE-w/oQ}$). $LOLE_{NE-w/oQ}$ > 0.1 days/year.



Step 4: Bring New England Control Area's risk index, $LOLE_{NE-w/oQ}$, back to the 0.1 days/year, by adding unforced resources to New England



Step 5: The tie benefit contribution of the interconnections from Quebec to New England (TB_{Tie_Q}) equals to the amount of resources added to New England in the Step 4.

Internal Constraints without Capacity Zones

- Modeled only one internal constraint within New England
  - Orrington South Interface limit assumed to be 1,200 MW
- Modeling the Orrington South Export constraint and sub-area load diversity, the results of the simulations are as follows:

Impact of Orrington South Export constraint on Tie Benefits (MW)

	Total TB	HQ	MT	NY
Without Internal Constraints	1560	788	657	115
with Orrington S. constraint only	1320	806	373	141

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Assumptions – Interconnected Systems

- Areas: New England, New York, Maritimes and Quebec
- Interconnection topology between systems and modeling techniques are consistent with NPCC studies
  - Reserve sharing among Areas
  - Emergency Operating Procedures (EOP) of each Area implemented after interconnection assistance
- Simplification to speed up calculation process without sacrificing calculation accuracy:
  - Subareas are aggregated to as few subareas as possible
  - EOP are aggregated to as few steps as possible

Example Results

- Total Tie Benefits from New York, Quebec and Maritimes
  TB_{Total} = 1665 MW

- Tie Benefit associated with New York
  TB_{Tie_NY} = 125 MW

- Tie Benefit associated with Maritimes
  TB_{Tie_MT} = 560 MW

- Tie Benefit associated with Quebec
  TB_{Tie_Q} = 845 MW

Allocation of Total Tie Benefit to Individual Neighboring Areas

- Since the sum of the tie benefits from the individual neighboring Areas is not equal to the total tie benefits calculated, each of the neighboring Area's tie benefits will be adjusted based on the ratio of the individual Area tie benefit to the sum of the tie benefits.
  - Adjusted New York Tie Benefit Contribution

    TB_{Tie_NY} = 1665 * 125 / (125 + 560 + 845) = 136 MW

  - Adjusted Maritimes Tie Benefit Contribution

    TB_{Tie_MT} = 1665 * 560 / (125 + 560 + 845) = 609 MW

  - Adjusted Quebec Tie Benefit Contribution

    TB_{Tie_Q} = 1665 * 845 / (125 + 560 + 845) = 920 MW

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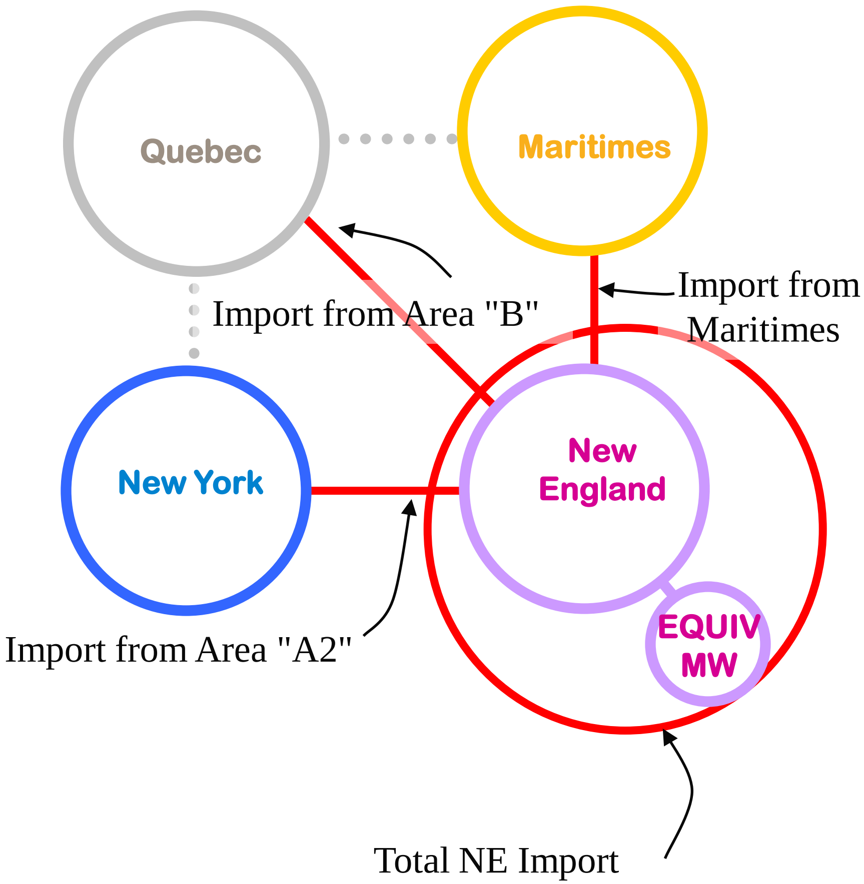
Sensitivity to NYISO EOP Assumptions

- A sensitivity scenario was performed to investigate the impact of the change in New York EOP assumptions on total tie benefits.

- Changing the EOP assumptions 2012/13 tie benefit study
  - To the value 2011/12 New York EOP assumptions
  - Total Tie Benefits for New England of 1,810 MW

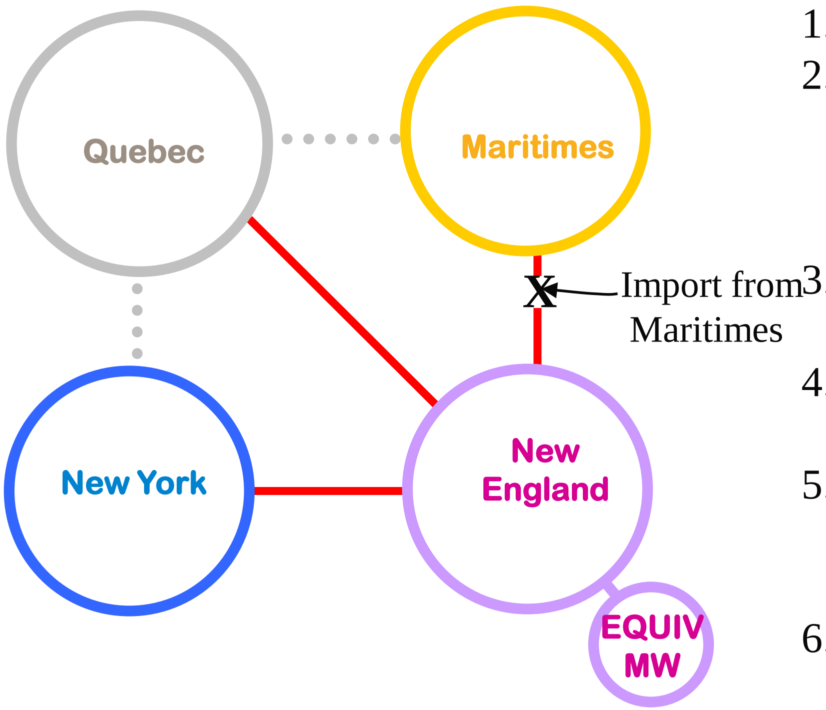
Total Interface Tie Benefits: Comparison of Current and 2003 Methodology

Current Approach: Total Tie Benefits



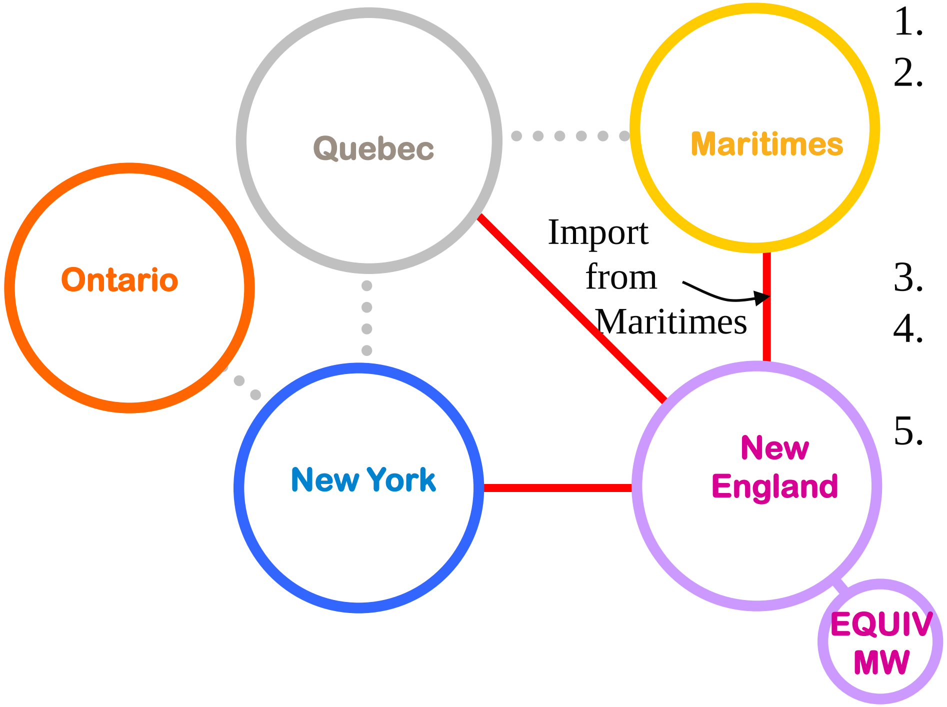
1. Connect all areas together
2. Bring NE to 0.1 d/y LOLE interconnected
   [Note: NE LOLE affected by Load Loss Sharing with New York resulting from sharing HQ and Maritimes tie benefits]
3. Limit transfer capability into New England to get "isolated" LOLE
4. Determine Equivalent TB (EQUIV) to return NE to 0.1 d/y
   [Note: Maritimes / Quebec capacity is still flowing across NE to help New York avoid shortages. This has no effect on NE because NE cannot import any TB from any area]

Current Approach: Individual Tie Benefits



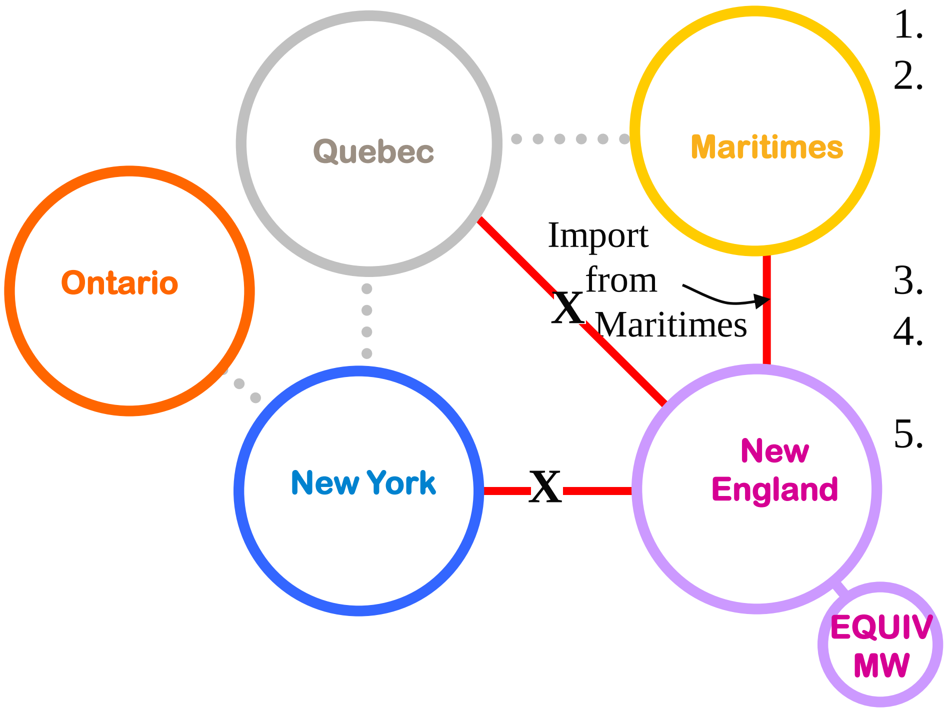
1. Connect All Areas Together
2. Bring NE to 0.1 d/y LOLE interconnected
   [Note: NE LOLE affected by Load Loss Sharing with New York resulting from sharing HQ and Maritimes tie benefits]
3. Cut each tie individually to obtain LOLE without an external area, such as Maritimes]
4. Determine Maritimes TB contribution to New England (EQUIV) to return NE to 0.1 d/y
5. Maritimes capacity can not help either NE or NY avoid joint shortages. The $EQUIV_{MR}$ is adjusted until New England LOLE brought to 0.1 d/y
6. [Note: This measures only NE benefit from Maritimes]
7. Repeat for other areas

2003 Approach – Total Tie Benefits



1. Connect All Areas Together
2. Bring NE to 0.1 d/y LOLE interconnected [Note: NE LOLE affected by Load Loss Sharing with New York resulting from sharing HQ and Maritimes tie benefits]
3. Isolate New England to get "isolated" LOLE
4. Determine equivalent Tie Benefits (EQUIV) to return NE to 0.1 d/y
5. No significant difference with current approach

2003 Approach - Individual Tie Benefits



1. Connect All Areas Together
2. Bring NE to 0.1 d/y LOLE interconnected [Note: NE LOLE affected by Load Loss Sharing with New York resulting from sharing HQ and Maritimes tie benefits]
3. Cut ALL ties to obtain isolated LOLE
4. Determine Maritimes Tie Benefits contribution to New England (EQUIV) to return NE to 0.1 d/y
5. Maritimes capacity CAN NOT help NY avoid joint shortages and NE captures all of the TB itself [Note: Both NE's share plus share when there had been joint outages due to insufficient tie benefits for NE and NY. This is fundamentally a larger amount of assistance than captured in the 2007 methodology. 2007 methodology captures only NE share of LOLE avoidance.]
6. Repeat for other interconnections

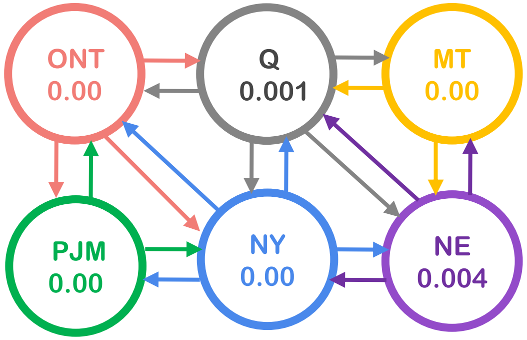
Modeling Additional Control Areas

Modeling Additional Control Areas

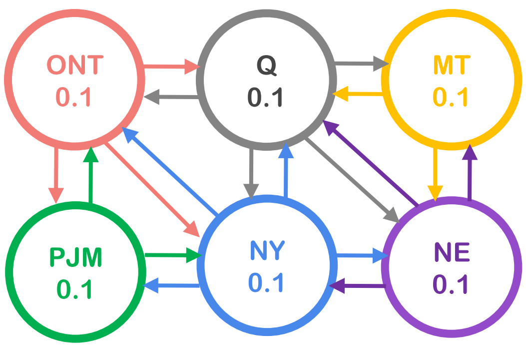
- Comparison of four vs. six area model
  - Four control areas of HQ, Maritimes, NE, and NY
  - Six control areas of HQ, Maritimes, NE, NY, Ontario and PJM
    - Assumptions/data for HQ, MT, NY and NE control areas are consistent with those for the tie benefit study for 2010 ARA3
    - Ontario and PJM are based on the latest NPCC CP8 study data
- Transmission
  - Inter-Area transmission constraints are modeled
  - Both simulations assumed no internal transmission constraints
    - Within New England
    - Within External areas (data not readily available)
  - Analysis based on “at-criterion” conditions for all control areas
  - Bring every area (interconnected) to .1 days/year simultaneously

Six-Area Tie Benefits Calculation

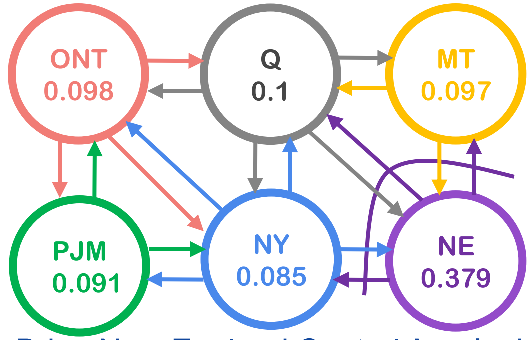
Step 1: Interconnect New England, Quebec, New York, Maritimes, PJM and Ontario systems, and calculate each Control Area's risk index ($LOLE_{interconnected}$).



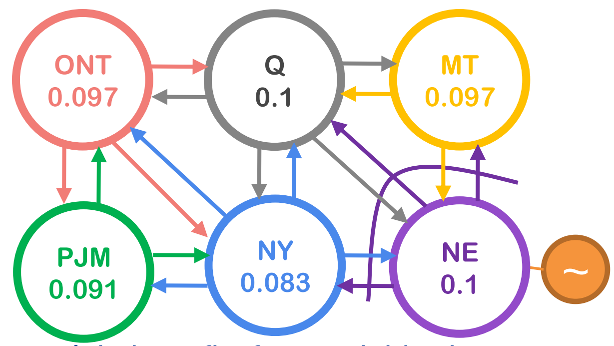
Step 2: Bring the all Control Area's risk index to the 0.1days/year level simultaneously, by adjusting the resource/load in each Control Areas.



Step 3: Reduce the total transfer capabilities of the interconnections from neighboring Areas to allow for only firm capacity import, and calculate the New England risk index ($LOLE_{NE\text{-}w/oExternalAreas}$). $LOLE_{NE\text{-}w/oExternalAreas}$ > 0.1 days/year.



Step 4: Bring New England Control Area's risk index, $LOLE_{NE\text{-}w/oExternalAreas}$, back to the 0.1 days/year, by adding unforced resources to New England.



Step 5: The total tie benefits from neighboring Areas, TB_{Total} equals to the amount of resources added to New England in the Step 4.

Study Results

- Total tie benefits value based on 4-Area model and assuming “at criteria” conditions for external control areas

  TB_{Total}(4 Area) = 1,525 MW

- Total tie benefits value based on 6-Area model and assuming “at-criteria” conditions for external control areas

  TB_{Total}(6 Area) = 1,780 MW

- Difference is 255 MW

Modeling Additional Control Areas

- Observations
  - High computational effort
  - Marginal increase in tie benefits
    - PJM is an over 100,000 MW system
    - Ontario is an approximately 24,000 MW system
  - No direct emergency assistance agreement with Ontario or PJM
  - What about simultaneous assistance with MISO, Michigan etc.
  - Successful delivery of emergency power from PJM and Ontario
    - Through New York to the New England border is
      - unknown,
      - un-tested
    - Not subject to transmission planning protocols
      - No process to build to transmission to provide pass-through tie benefits between external areas

LOLE Modeling Concerns for Very Large Footprint Reliability Studies

Overview

- Significant interest exists in expanding the footprint of reliability studies
  - Assumptions for small footprint studies
    - May become less acceptable for large footprint studies
    - External risks become explicitly incorporated
    - Addition of / representation of risk factors suggests different criterion
      - More stringent criterion (Model says LOLE is 0.01 days/year):
        - Believe that assumptions do not include all relevant risks
        - Must have a more stringent criterion to account for the risks we didn't include
      - Less stringent criterion (Model says LOLE is 1.00 days/year):
        - Believe that assumptions leave additional flexibility that is not included
        - We know that un-modeled operating flexibility will make things better
  - This presentation will review some issues affecting very large footprint reliability studies

Key Issues

- Transmission Issues
  - Major interfaces
  - Ratings
  - Planning
- Resource availability under stressed conditions
- Operating Reserve
- What is a “Loss of Load” event
- Effect of system size
- Tie Benefits from a Very Large Footprint Reliability Model

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Transmission Issues

Transmission Issues

- Transmission interfaces are an important part of large footprint reliability studies
  - Effect of reliability studies that includes transmission is to identify:
    - Minimum amount of resources are needed to satisfy criterion
    - Where do the resources need to be located
    - What effect does a change in the interface limits have on where resources are needed
- Changes in an interface ratings may:
  - Enable a change in the location of:
    - A minimum amount of resources, or
    - A maximum amount of resources
  - Have no effect

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Transmission at Peak Load Conditions

- Transmission studies must assume certain resource availability patterns
  - At time of peak, when emergency energy must flow, a different (and specific) set of resources must actually support those flows
  - Availability of resources at time of peak may be worse than assumed in deliverability tests
    - Under emergency conditions, “higher” forced outages are “likely”
    - “Deliverability” tests satisfy internal loads without an overlay of emergency energy flows (i.e. “railroading” of emergency energy)
    - “Deliverability” tests are not designed to support emergency transfers to another balancing authority
  - Transmission limits at time of peak
    - Not all transmission elements will be in service at time of peak
    - Protection of all transmission elements, in real time, required

Transmission Limits

- Transmission planning protocols probably do not lead to infrastructure investment to support emergency energy flows to third parties
  - Focus is on internal transmission needs
    - CETO/CETL type process based largely on expected peak loads
    - May not factor in cross system flows of emergency energy that will place additional stresses on the transmission system
  - Inter-regional planning activities may identify projects that are beneficial to the wider region
- Emergency energy will be delivered if possible
  - On a “best efforts” basis
  - Violation of NERC operating criteria is not acceptable
  - Willingness of a remote system to put their system “at-risk” for another control area is questionable

Operating Reserve

Operating Reserve in Reliability Studies

- Reliability studies assume that all or most operating reserve can be eroded before a loss of load event occurs
- This assumption:
  - May be appropriate for a single, “small” control area
  - Assumption may be questionable for a “large” control area
  - Probably unreasonable for a large footprint reliability model
    - Operating Reserve is needed for contingencies that must be planned for
    - Operating Reserve may be “bottled-in”
      - Voltage / Reactive conditions may limit the “reach” of the operating reserve assistance
      - At high load and emergency conditions, and actual resources on-line availability actual transmission elements in service the I^2R and I^2X real and reactive losses may be significant

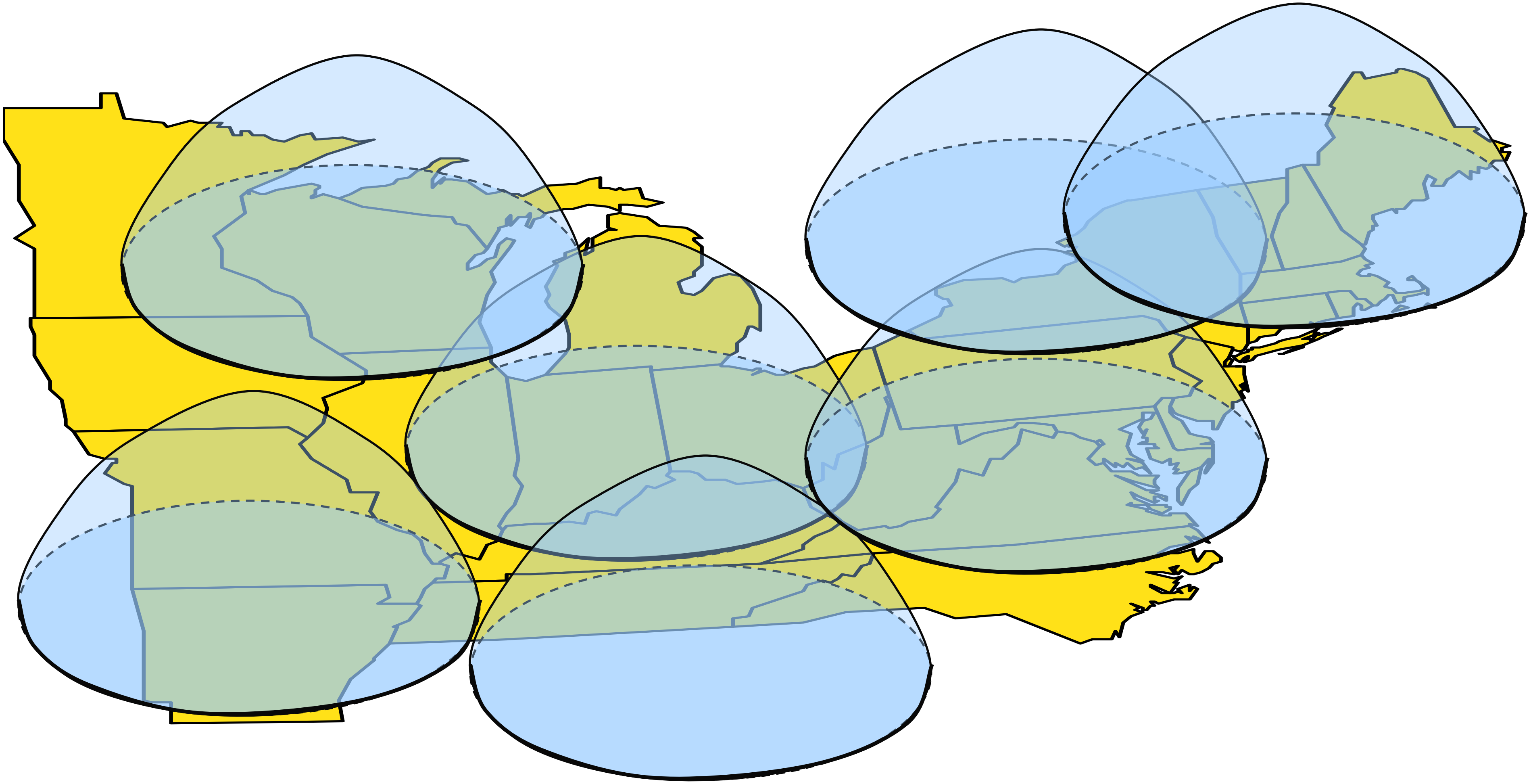
Modeling Minimum Operating Reserves

- Need to consider operating reserves across the region
  - In a single area model, it is reasonable to assume that neighboring areas will share their operating reserves
  - Operating Reserves must be geographically dispersed to protect ALL transmission assets
  - Ultimately the amount and method to include operating reserve is a subject of further discussion
- N-2 Interface ratings
  - N-2 interface ratings expect dispatchable 30 minute resources
  - Lack of resources in import constrained side may reduce operating flexibility

Operating Reserve Examples

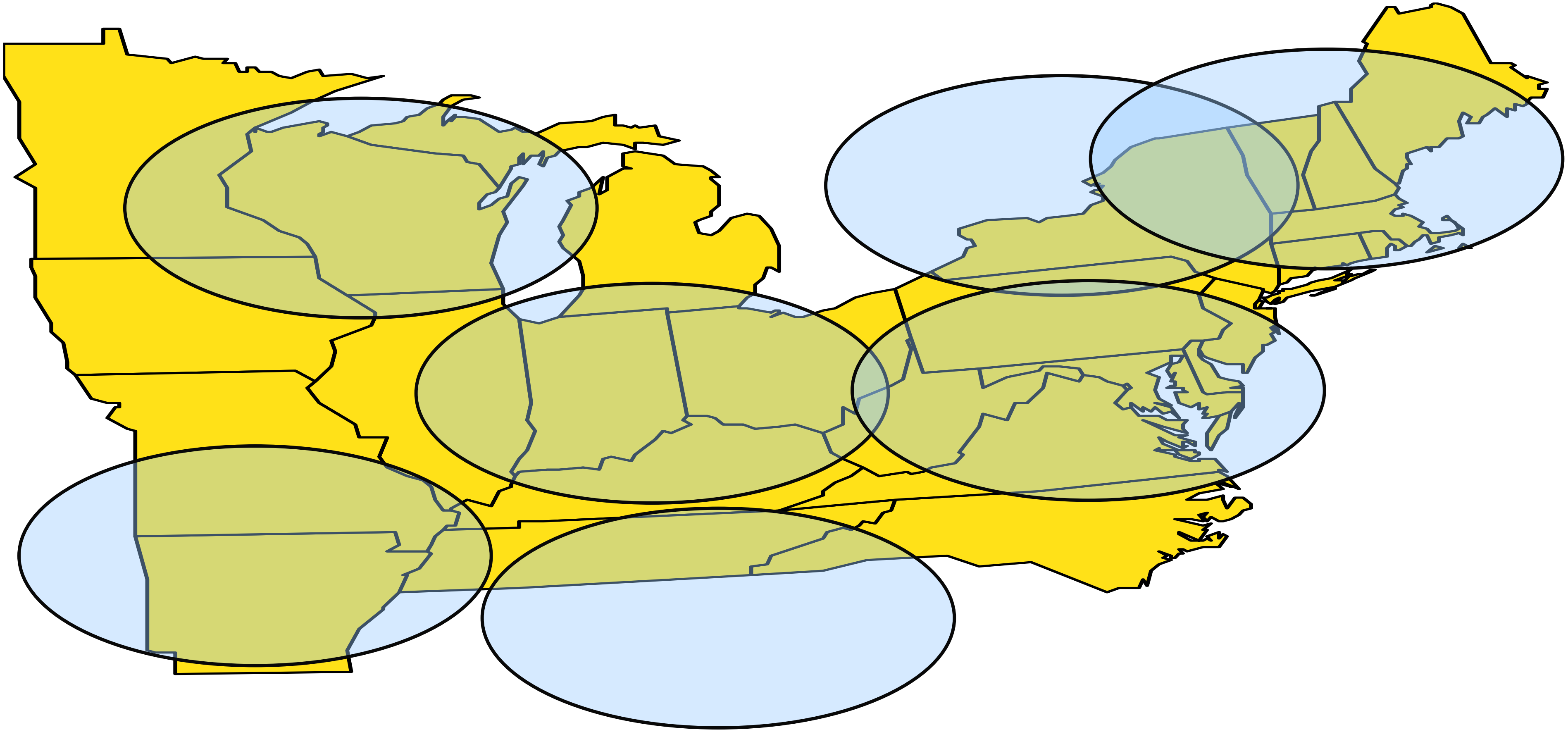
- Following graphics illustrate operating reserve
  - Case 1: All areas have adequate operating reserve
  - Case 2: All operating reserve has been eroded everywhere
    - Loss of another generator or increase in load would slow system frequency
    - Loss of a transmission element may create conditions for cascading transmission outages
  - Case 3: NE has reduced operating reserve, but NY has reserves
  - Case 4: NE has no operating reserve, but NY has reserves
  - Case 5: Both NE and NY have no operating reserve
  - Case 6: Interfaces that need to be protected
  - Case 7: Sub-area location of operating reserve (could be in the form of generators or dispatchable loads)

Operating Reserve Distributed Across All Areas



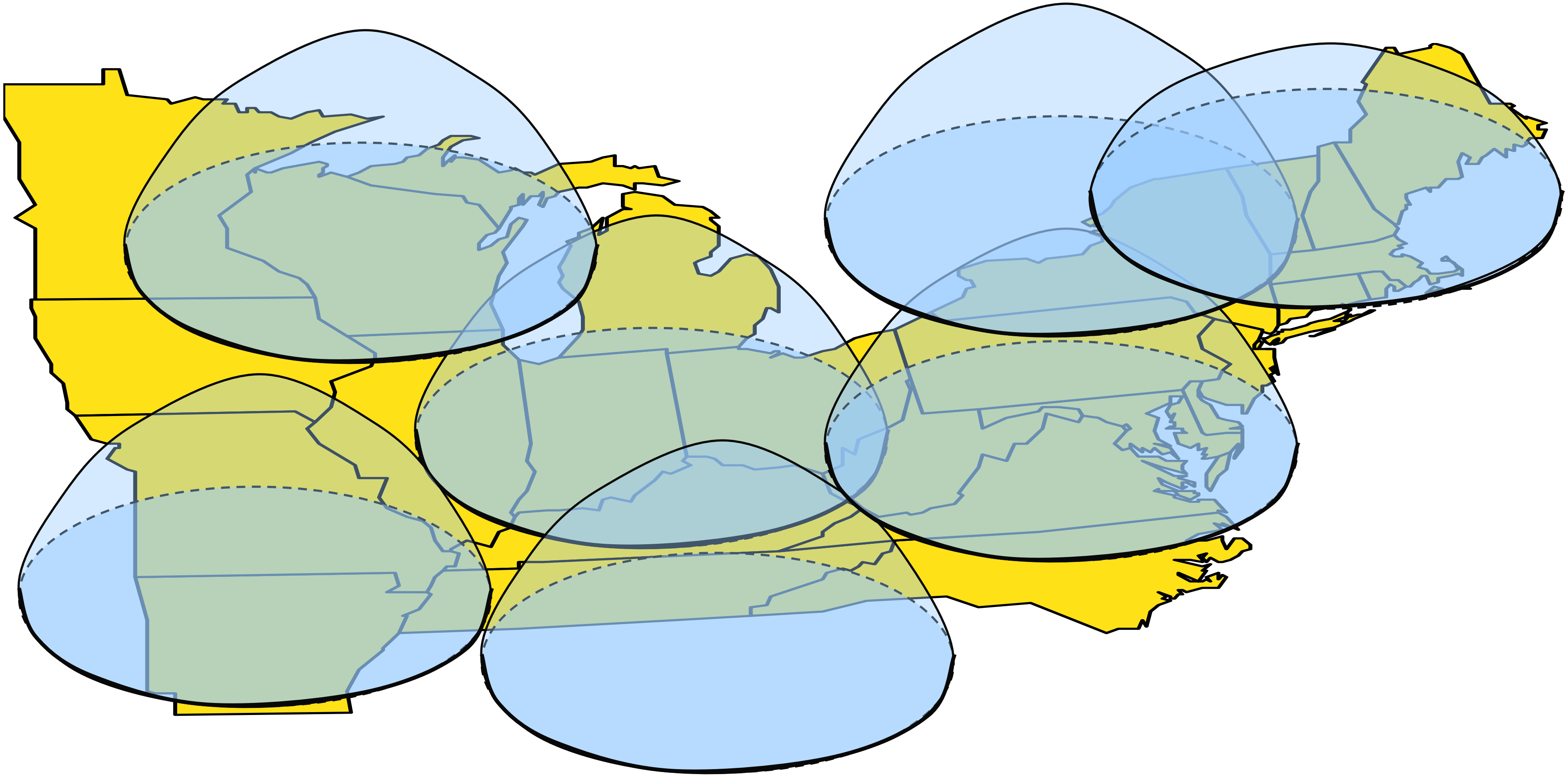
Case 1: All areas have adequate operating reserve

In LOLE Models All Areas Can Erode All Operating Reserve



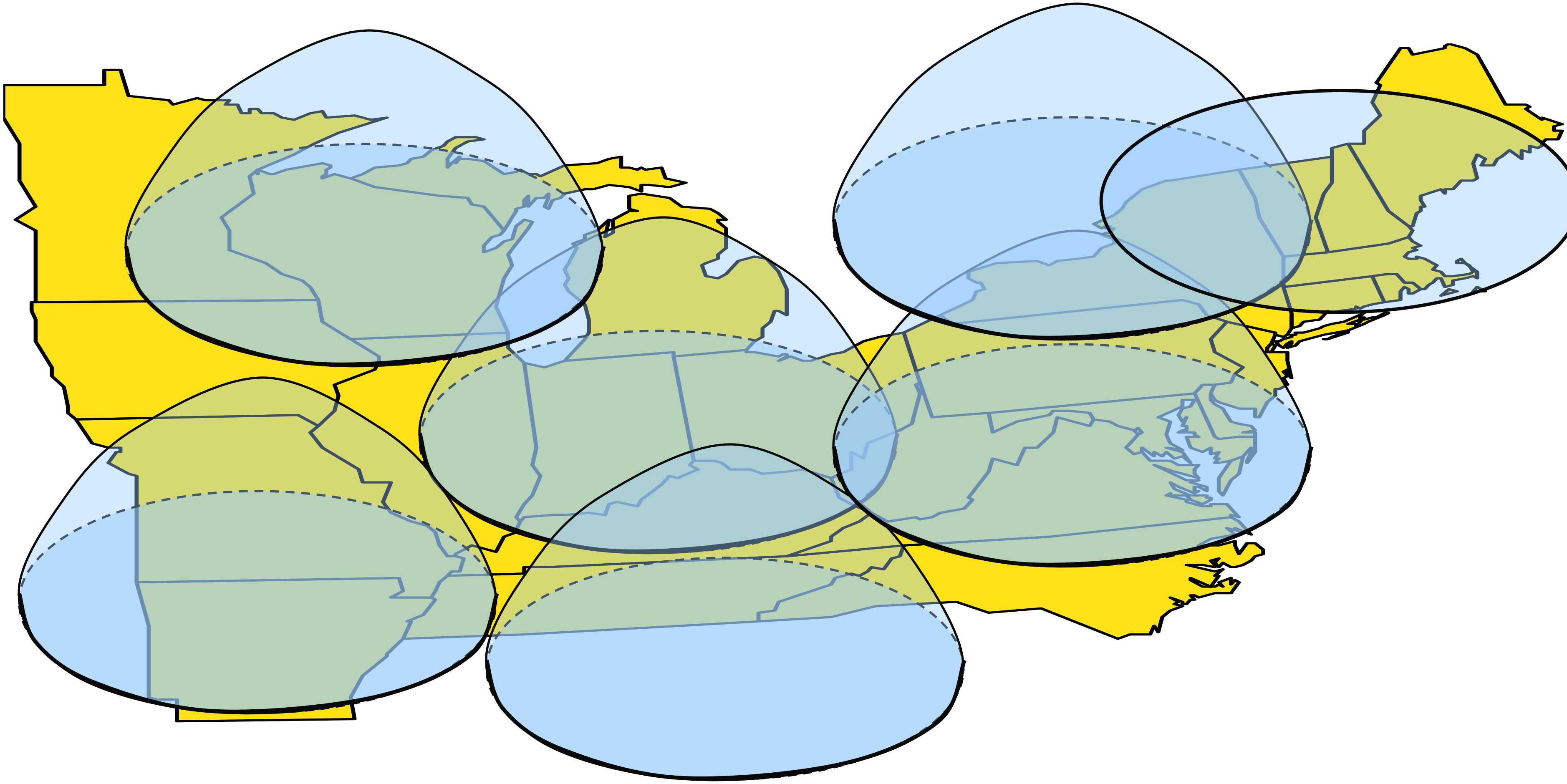
Case 2: All operating reserve has been eroded everywhere

New England Reduces Operating Reserve



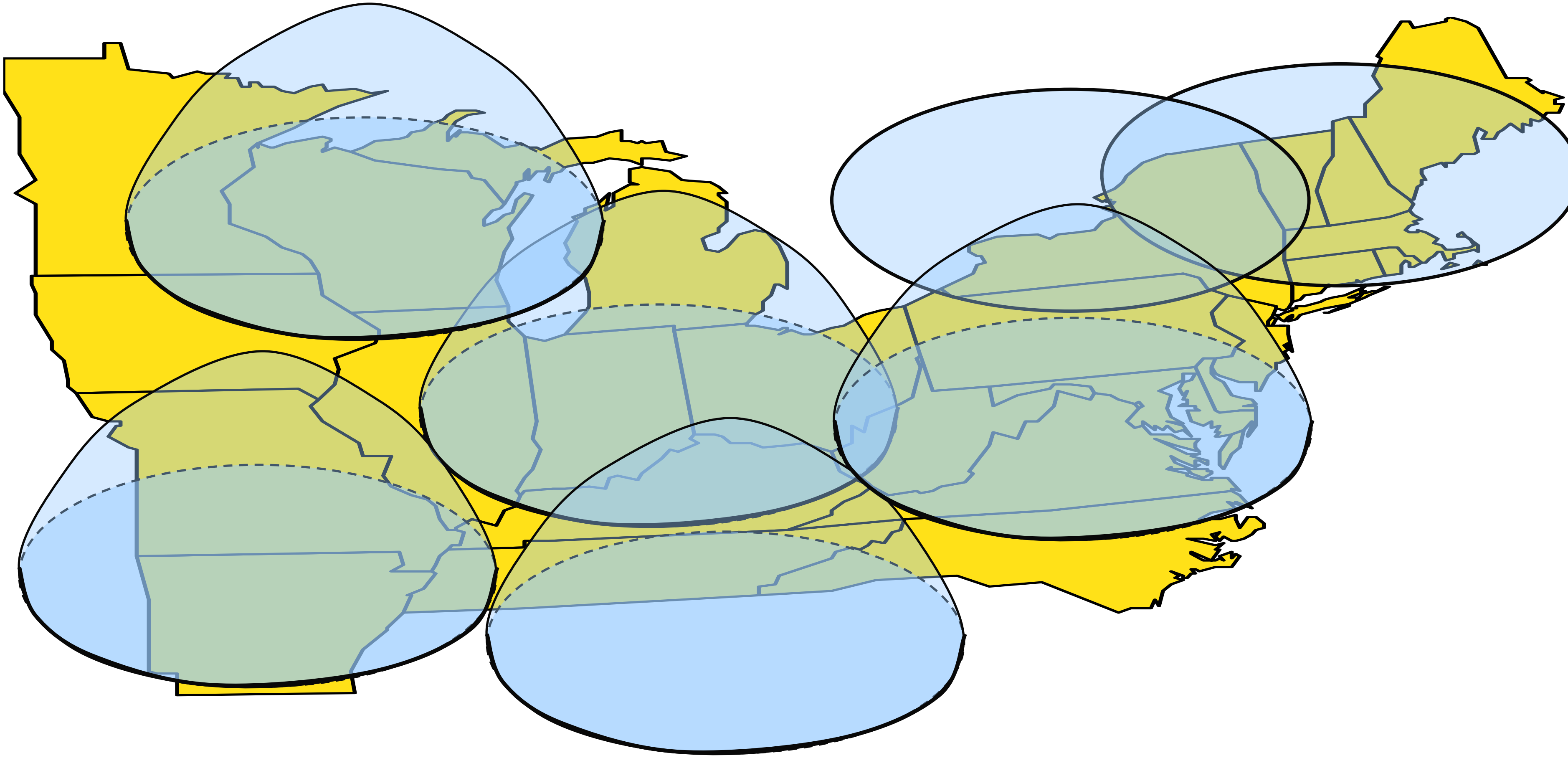
Case 3: NE has reduced operating reserve, but NY has reserves

New England Eliminates Operating Reserve



Case 4: NE has no operating reserve, but NY has reserves

NE and NY Eliminate Operating Reserve



Case 5: Both NE and NY have no operating reserve (looks risky for NE)

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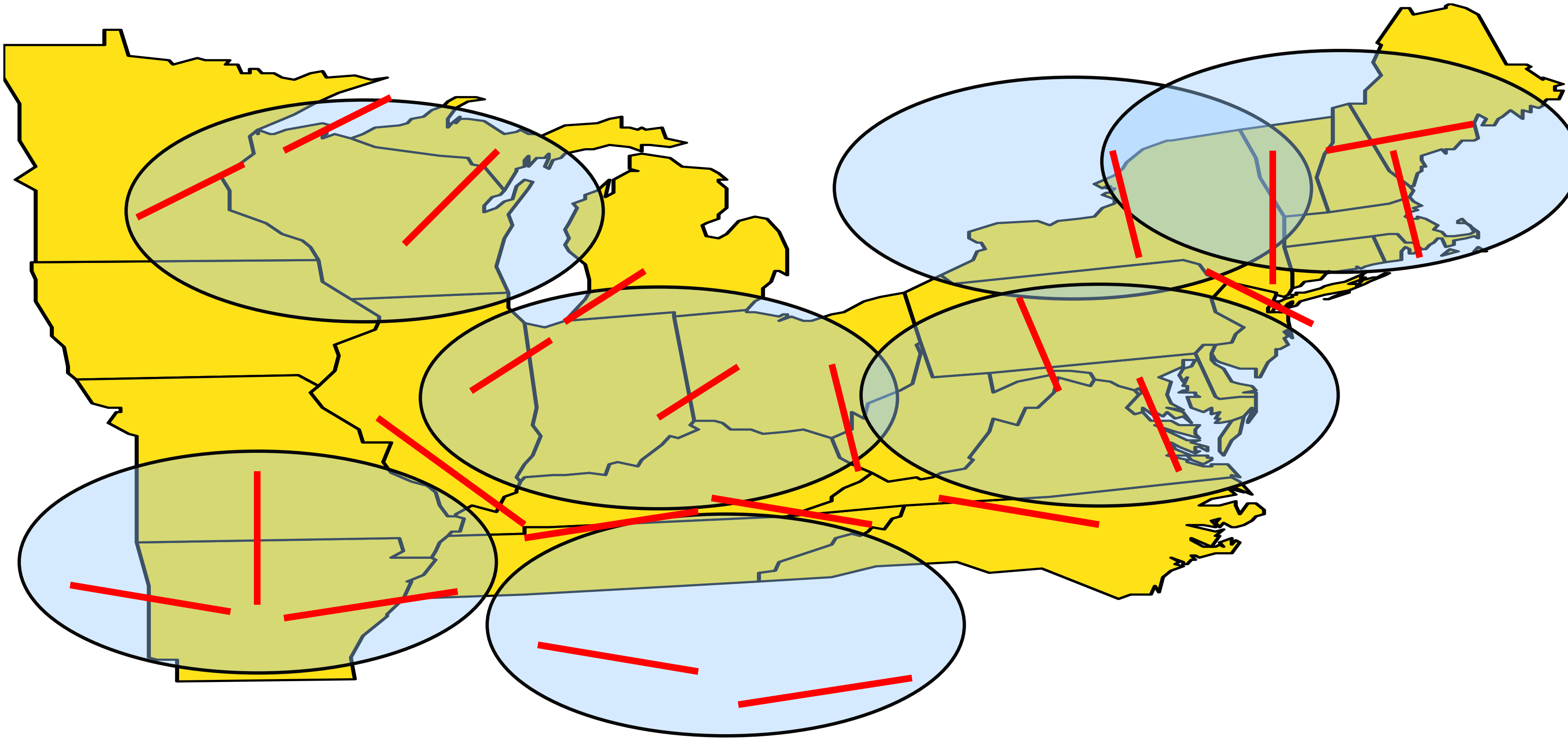
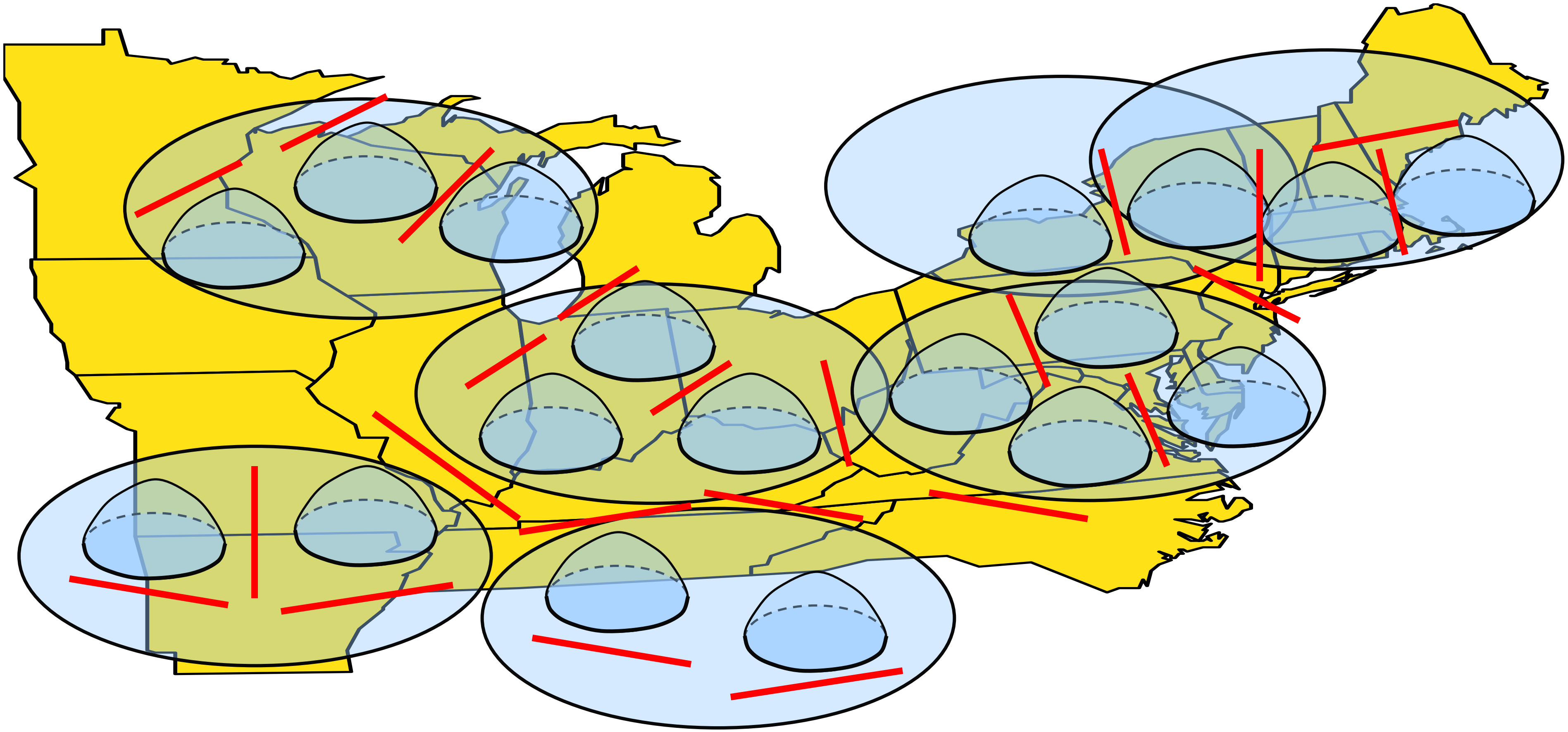
Critical Interfaces Need to be Protected



Case 6: Transmission Interfaces

Operating Reserves Needed to Protect Against Contingencies



Case 7: Operating Reserve needs to be held in specific areas

Tie Benefits from a Large Footprint Reliability Model

Large Footprint Reliability Model

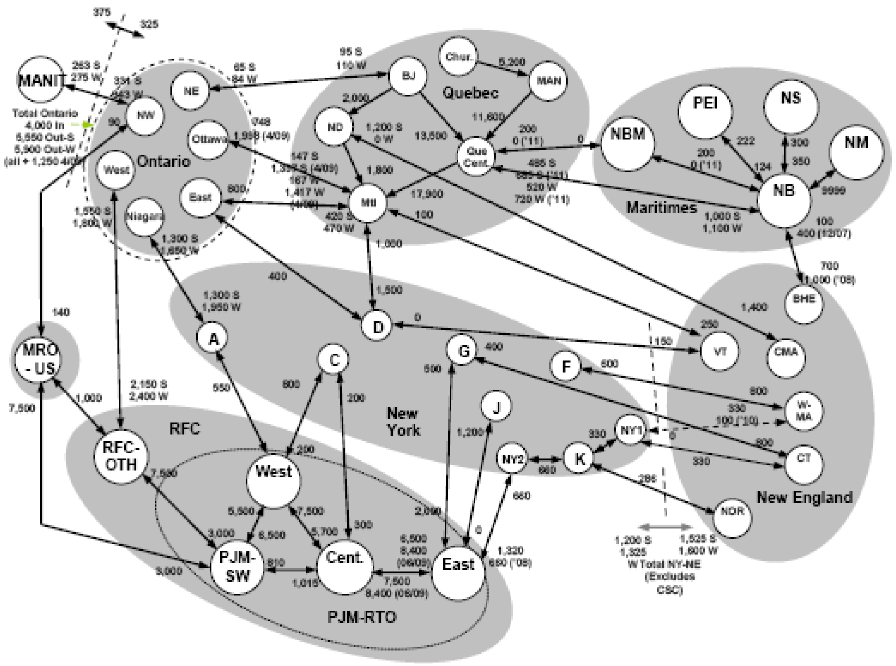
- CP-8 study originated to evaluate whether
  - NPCC areas are "over-relying on ties"
  - Effect of transmission constraints
- Results show large tie benefits
  - Assuming "At-Criterion"
  - Year 2009
  - Tie Benefits are a large fraction of import capability

	Import Capability (MW)	At-Criterion Tie Benefits (MW)	Percent of Import Capability
New England	4835	4110	0.850
New York	8640	3648	0.422
Ontario	5250	5245	0.999

- CP8 Tie Benefit Study tables suggest negative reserve margins
- Estimates of resulting reserve margins shown are not directly from the CP8 report

http://www.npcc.org/viewDoc.aspx?name=Final_CP-8_Tie_Benefit_Report_Nov_6.pdf&cat=pubAssis

CP8 Study Has a Large Footprint



Transfer Limits have Annual Ratings unless noted:

S – Summer Rating
W – Winter Rating

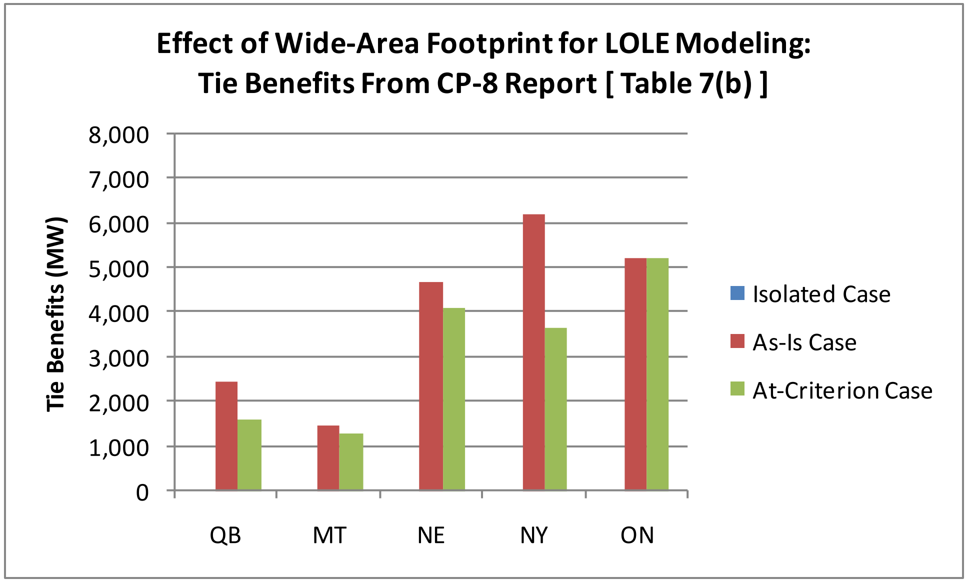
Figure 1 - Assumed NPCC Transfer Limits (MW)

http://www.npcc.org/viewDoc.aspx?name=Final_CP-8_Tie_Benefit_Report_Nov_6.pdf&cat=pubAssis

CP8 Study Tie Benefits

- Tie Benefits shown from the CP8 report for 2009
  - Isolate Tie Benefits are zero
  - “As-Is” and “At-Criterion” Tie Benefits are as shown

2009	Isolated Case	As-Is Case	At-Criterion Case
QB	0	2440	1618
MT	0	1491	1291
NE	0	4701	4110
NY	0	6203	3648
ON	0	5250	5245



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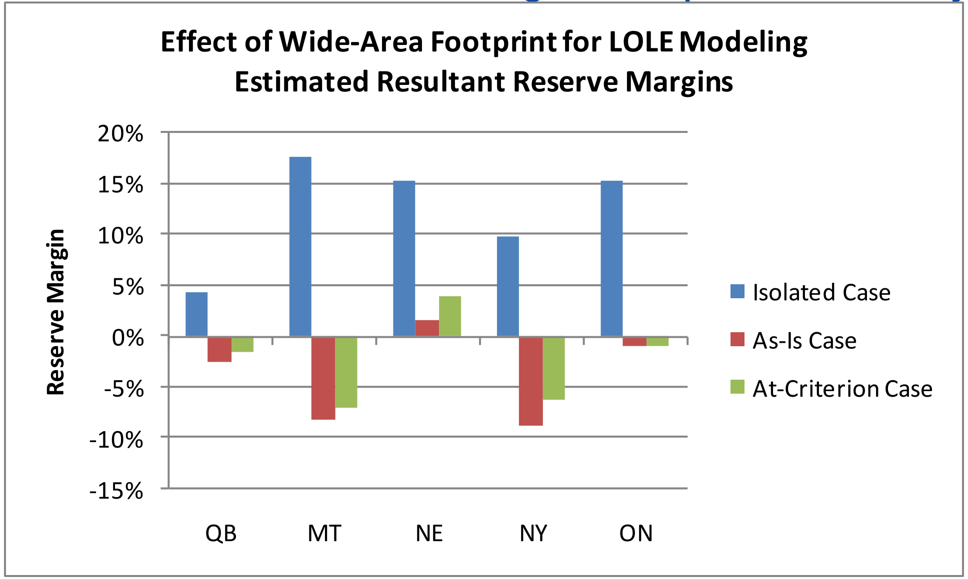
Estimated Resulting Reserve Margins

- Reserve margins not published in CP8 report
  - Estimates were made for total capacity under "At-Criterion"
  - Indicative Reserve Margins were calculated
    - Acceptable Reserve Margins are all negative except NE
    - Results suggest (to me) that some risk factors are not adequately factored in to this Large Footprint reliability analysis



Note: Reserve Margins shown are estimated and may not be these values

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Recommendations for Further Analysis in Very Large Footprint Models

- Need a reliability retrospective
  - Historical on-peak, resource availability
  - Transmission limits during actual peak load days
    - TADS* may be useful
    - TADS may not help understand transfer limits and concerns during peak hours
  - Location of operating reserve across the interconnection
    - Estimate of how much more energy resources could “securely” provide
    - Is the presence of “bottled-in” operating reserve quantifiable
    - If quantifiable, is it significant
  - Develop a “lessons learned” document with discussion of how to implement findings

* TADS is the NERC managed “Transmission Availability Data System” similar to GADS

Allocating Tie Benefits to Neighbors
Discussion of 2003 Study Methodology

2003 vs. 2007 Study Allocation Methods

- Questions were raised about the effect of using the 2003 allocation approach for New England's interconnections
  - Procedure used in the 2003 study
    - After isolation of New England
    - Determine effect of adding each interconnection in turn
    - Allocation metric based on improvement to New England's LOLE
  - Procedure used in the 2007 study
    - After interconnection of New England
    - Determine effect of cutting each interconnection in turn
    - Allocation metric based on degradation of New England's LOLE
- Alternative allocation procedures will be discussed here
  - Requested that Quebec be modeled as follows
    - Transmission fully committed to the benefit of New England
    - "Fully committed to New England" means either ICAP or "priority"

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2007 Study vs. 2003 Study

- Effect of internal constraints not considered
  - Local Resource Adequacy procedures developed since 2003
  - Assumed to alleviate effect of internal constraints
  - Rationale illustrated in a previous response
- Ontario not included in this retrospective
- 2007 did not calculate winter tie benefits
  - 2003 study provided calculations for winter
  - Focus is on annual allocation
    - Summer tie benefits used in ICR
    - Winter period not reviewed
      - Effect on ICR is negligible
      - May affect fuel diversity discussion
      - Vulnerability to fuel supply disruption

Allocation Metrics

- Total tie benefits can be allocated to interconnections using various metrics
  - The 2003 study developed allocation metrics based on:
    - Aggregate transfer capability to a neighboring control area, and
    - Only the interconnected area's resources
    - Neglecting pass through capacity support from other Control Areas
  - A sensitivity case to the 2003 study allocation metric
    - Aggregate transfer capability to a neighboring control area
    - Including pass through capacity support from other Control Areas
  - The 2007 study used a metric that
    - Quantified the effect of aggregate transfer capability to a neighboring control area
    - In the context of the dynamics of multi-area reliability model

Allocating Tie Benefits to Specific Ties

Methods for Allocating Tie Benefits to Individual Ties

- Current Method
  - Compares the New England LOLE difference between the scenario with all ties from an area interconnected and the scenario without one specific tie that is under investigation
  - Used this approach to calculate HQICC for 2013/14 Attempt to simulate NY CSC tie benefits failed to provide a quantifiable benefit under “at criteria” conditions.
  - May not capture tie line benefits below certain threshold for a control area

Policy Issues Relating to Individual Tie Line Tie Benefits Calculation

- The technical methodology will not resolve policy issues
- Policy decisions could influence technical methodology
- A few questions below just to get your thoughts started!!!
  - How should Control Area tie benefits contributions be allocated?
    - First come, first serve?
    - Equal rights?
- Who has overlapping interconnection impact rights?
- Transmission interconnections with minimum interconnection standards or existing resource?
- What about new resources, etc.?

Supporting Analysis to Evaluate Individual Tie Line Contributions

- Probabilistic analysis
  - Four control areas modeled: HQ, MT, NE and NY
    - Assumptions/data for all control areas are consistent with those for the tie benefit study for 2010 ARA3.
  - Inter-Area transmission constraints are modeled, while internal constraints within each Area are relaxed
    - The internal transmission constraints were not modeled to save simulation time. These methodologies can be applied with internal transmission constraints modeled.
  - All control areas are assumed “at criterion” conditions
    - Bring every area (interconnected) to .1 days/year simultaneously

Supporting Analysis to Evaluate Individual Tie Line Contributions

- The following individual tie(s) are used for tie benefit evaluation:
  - HQ Phase II
  - Maritimes
  - NY AC ties
  - NY DC tie
- A total of 16 interconnection states for four connections
  - Number of states equals n^2 for ‘n’ individual ties

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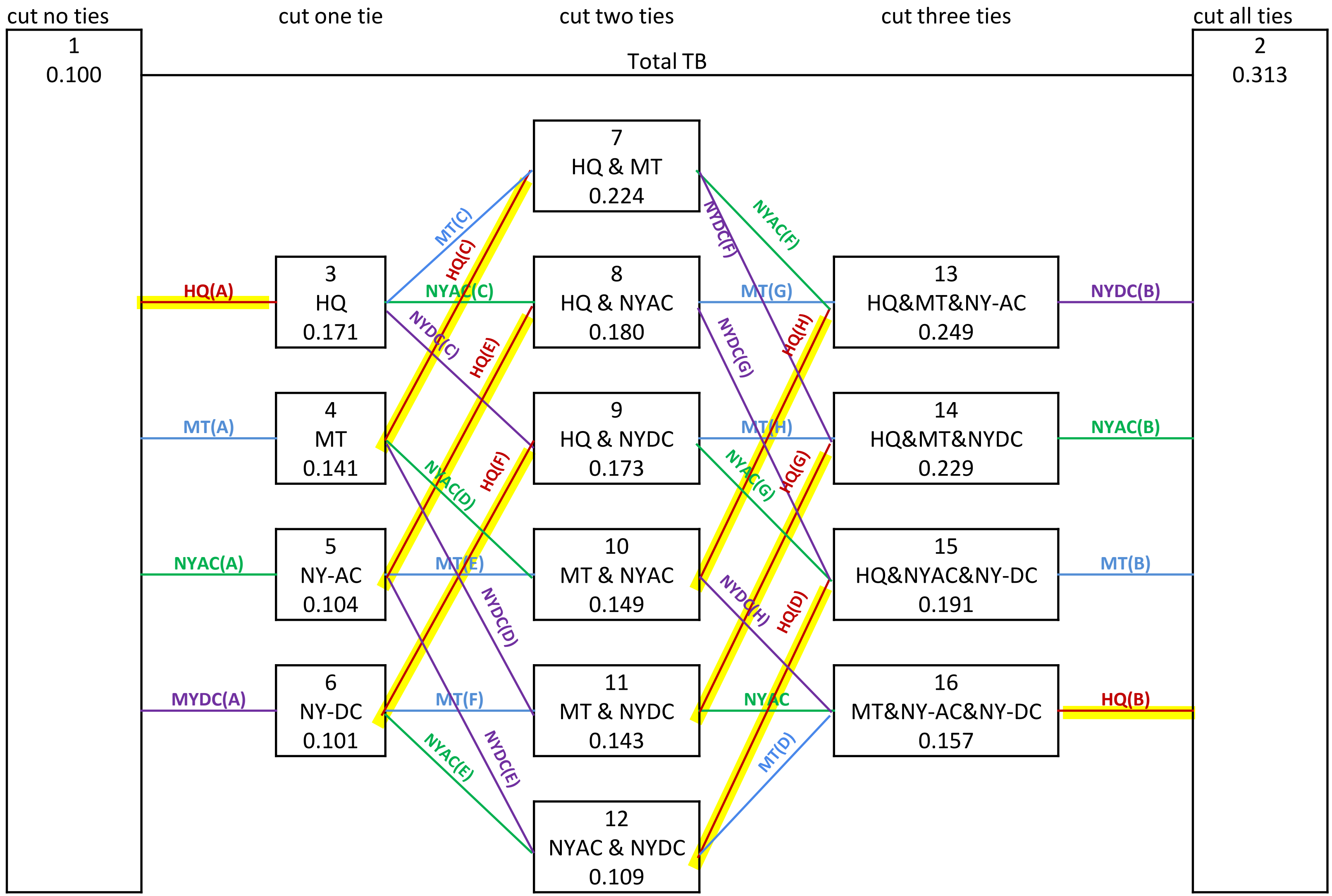
Relationship between Evaluation Scenarios (Cases Highlighted are for HQ Phase II Evaluation)



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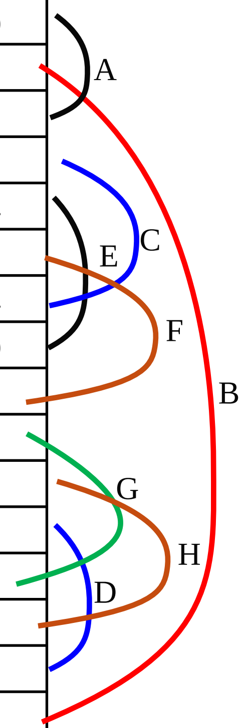
HQ-Phase II Tie Benefit Evaluation

		Interconnection Status				
Scenario	Discription	HQ-Phase II	Maritimes	NY-AC	NY-DC	LOLE
1	Cut None	√	√	√	√	0.100
2	Cut All	x	x	x	x	0.313
3	Cut HQ-Phase II	x	√	√	√	0.171
4	Cut Maritimes	√	x	√	√	0.141
5	Cut NY-AC	√	√	x	√	0.104
6	Cut NY-DC	√	√	√	x	0.101
7	Cut HQ-Phase II & Maritimes	x	x	√	√	0.224
8	Cut HQ-Phase II & NY-AC	x	√	x	√	0.180
9	Cut HQ-Phase II & NY-DC	x	√	√	x	0.173
10	Cut Maritimes & NY-AC	√	x	x	√	0.149
11	Cut Maritimes & NY-DC	√	x	√	x	0.143
12	Cut NY-AC & NY-DC	√	√	x	x	0.109
13	Cut HQ-Phase II & Maritimes & NY-AC	x	x	x	√	0.249
14	Cut HQ-Phase II & Maritimes & NY-DC	x	x	√	x	0.229
15	Cut HQ-Phase II & NY-AC & NY-DC	x	√	x	x	0.191
16	Cut Maritimes & NY-AC & NY-DC	√	x	x	x	0.157



- There are 8 scenarios (A-H) that can be used for evaluating HQ-Phase II tie benefit contribution.

HQ-Phase II Tie Benefit	A	B	C	D	E	F	G	H	Average
	Current method	LIPA/2002 TB							
Scenarios Compared	1 vs 3	2 vs 16	4 vs 7	12 vs 15	5 vs 8	6 vs 9	10 vs 13	11 vs 14	
LOLE delta (days/year)	0.071	0.156	0.082	0.082	0.076	0.073	0.100	0.086	0.091
Equivalent Tie Benefit (MW)	795	880	660	835	820	805	680	660	767

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Maritimes Tie Benefit Evaluation

		Interconnection Status				
Scenario	Discription	HQ-Phase II	Maritimes	NY-AC	NY-DC	LOLE
1	Cut None	√	√	√	√	0.100
2	Cut All	x	x	x	x	0.313
3	Cut HQ-Phase II	x	√	√	√	0.171
4	Cut Maritimes	√	x	√	√	0.141
5	Cut NY-AC	√	√	x	√	0.104
6	Cut NY-DC	√	√	√	x	0.101
7	Cut HQ-Phase II & Maritimes	x	x	√	√	0.224
8	Cut HQ-Phase II & NY-AC	x	√	x	√	0.180
9	Cut HQ-Phase II & NY-DC	x	√	√	x	0.173
10	Cut Maritimes & NY-AC	√	x	x	√	0.149
11	Cut Maritimes & NY-DC	√	x	√	x	0.143
12	Cut NY-AC & NY-DC	√	√	x	x	0.109
13	Cut HQ-Phase II & Maritimes & NY-AC	x	x	x	√	0.249
14	Cut HQ-Phase II & Maritimes & NY-DC	x	x	√	x	0.229
15	Cut HQ-Phase II & NY-AC & NY-DC	x	√	x	x	0.191
16	Cut Maritimes & NY-AC & NY-DC	√	x	x	x	0.157

- There are 8 scenarios (A-H) that can be used for evaluating Maritimes tie benefit contribution.

Maritimes Tie Benefit	A	B	C	D	E	F	G	H	
	Current method	LIPA/2002 TB							Average
Scenarios Compared	1 vs 4	2 vs 15	3 vs 7	12 vs 16	5 vs 10	6 vs 11	8 vs 13	9 vs 14	
LOLE delta (days/year)	0.041	0.122	0.052	0.048	0.045	0.043	0.069	0.055	0.059
Equivalent Tie Benefit (MW)	510	620	385	535	530	520	425	370	487

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NY AC Tie Benefit Evaluation

		Interconnection Status				
Scenario	Discription	HQ-Phase II	Maritimes	NY-AC	NY-DC	LOLE
1	Cut None	√	√	√	√	0.100
2	Cut All	x	x	x	x	0.313
3	Cut HQ-Phase II	x	√	√	√	0.171
4	Cut Maritimes	√	x	√	√	0.141
5	Cut NY-AC	√	√	x	√	0.104
6	Cut NY-DC	√	√	√	x	0.101
7	Cut HQ-Phase II & Maritimes	x	x	√	√	0.224
8	Cut HQ-Phase II & NY-AC	x	√	x	√	0.180
9	Cut HQ-Phase II & NY-DC	x	√	√	x	0.173
10	Cut Maritimes & NY-AC	√	x	x	√	0.149
11	Cut Maritimes & NY-DC	√	x	√	x	0.143
12	Cut NY-AC & NY-DC	√	√	x	x	0.109
13	Cut HQ-Phase II & Maritimes & NY-AC	x	x	x	√	0.249
14	Cut HQ-Phase II & Maritimes & NY-DC	x	x	√	x	0.229
15	Cut HQ-Phase II & NY-AC & NY-DC	x	√	x	x	0.191
16	Cut Maritimes & NY-AC & NY-DC	√	x	x	x	0.157

- There are 8 scenarios (A-H) that can be used for evaluating NY AC tie benefit contribution.

NY AC Tie Benefit	A	B	C	D	E	F	G	H	Average
	Current method	LIPA/2002 TB							
Scenarios Compared	1 vs 5	2 vs 14	3 vs 8	4 vs 10	6 vs 12	7 vs 13	9 vs 15	11 vs 16	
LOLE delta (days/year)	0.005	0.084	0.009	0.008	0.008	0.026	0.018	0.014	0.021
Equivalent Tie Benefit (MW)	75	390	85	90	120	140	150	130	148

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NY DC Tie Benefit Evaluation

Scenario	Discription	HQ-Phase II	Maritimes	NY-AC	NY-DC	LOLE
		Interconnection Status				
1	Cut None	√	√	√	√	0.100
2	Cut All	x	x	x	x	0.313
3	Cut HQ-Phase II	x	√	√	√	0.171
4	Cut Maritimes	√	x	√	√	0.141
5	Cut NY-AC	√	√	x	√	0.104
6	Cut NY-DC	√	√	√	x	0.101
7	Cut HQ-Phase II & Maritimes	x	x	√	√	0.224
8	Cut HQ-Phase II & NY-AC	x	√	x	√	0.180
9	Cut HQ-Phase II & NY-DC	x	√	√	x	0.173
10	Cut Maritimes & NY-AC	√	x	x	√	0.149
11	Cut Maritimes & NY-DC	√	x	√	x	0.143
12	Cut NY-AC & NY-DC	√	√	x	x	0.109
13	Cut HQ-Phase II & Maritimes & NY-AC	x	x	x	√	0.249
14	Cut HQ-Phase II & Maritimes & NY-DC	x	x	√	x	0.229
15	Cut HQ-Phase II & NY-AC & NY-DC	x	√	x	x	0.191
16	Cut Maritimes & NY-AC & NY-DC	√	x	x	x	0.157

- There are 8 scenarios (A-H) that can be used for evaluating NY DC tie benefit contribution.

NY DC Tie Benefit	A	B	C	D	E	F	G	H	Average
	Current method	LIPA/2002 TB							
Scenarios Compared	1 vs 6	2 vs 13	3 vs 9	4 vs 11	5 vs 12	7 vs 14	8 vs 15	10 vs 16	
LOLE delta (days/year)	0.001	0.063	0.002	0.002	0.005	0.005	0.011	0.008	0.012
Equivalent Tie Benefit (MW)	15	280	25	25	65	35	90	75	76

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Using “At-criteria” or “As-is” Conditions for Calculating Tie Benefits in FCA / ARA

Supporting Analysis

- Four control areas model: HQ, MT, NE and NY
  - Assumptions/data for all control areas are consistent with those for the tie benefit study for 2010 ARA3
  - Inter-Area transmission constraints are modeled, while internal constraints within each Area are relaxed
- – Total benefits values are calculated and compared for two scenarios:
  - External control areas assumed “as-is” conditions, and New England assumed “at-criterion” conditions (same as tie benefits study for 2010 ARA3).
  - Both external control areas and New England assumed “at-criteria” conditions
    - – Bring every area (interconnected) to .1 days/year simultaneously

Using “At-criteria” or “As-is” Conditions for Calculating Tie Benefits

- Presented the results of simulations using 2010/11 “as-is” and “at-criteria” system conditions to the PSPC
  - 1,525 MW using “at criteria” system conditions
  - 3,415 MW using “as is” system conditions
- ISO-NE and PSPC found the results of tie benefit calculations for the 3rd ARA of 2010/11, using “as-is” system conditions, are too high for ICR calculations
  - Resulting reserve is 4.3%
  - Unsafe margin for system operations

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Operational Aspect Relating to ICR

- Whether the Installed Capacity Requirement relies on tie benefits that are calculated using “at criteria” or “as is” system conditions, ultimately one must answer the key question.

- Is the region setting the proper amount of ICR that would allow the system operators to operate the New England bulk power system according to all the reliability requirements posed by NPCC and NERC?

Risk Profile Analysis: Illustrating Various Amounts of Tie Benefits

A Quick Recap of OP 4

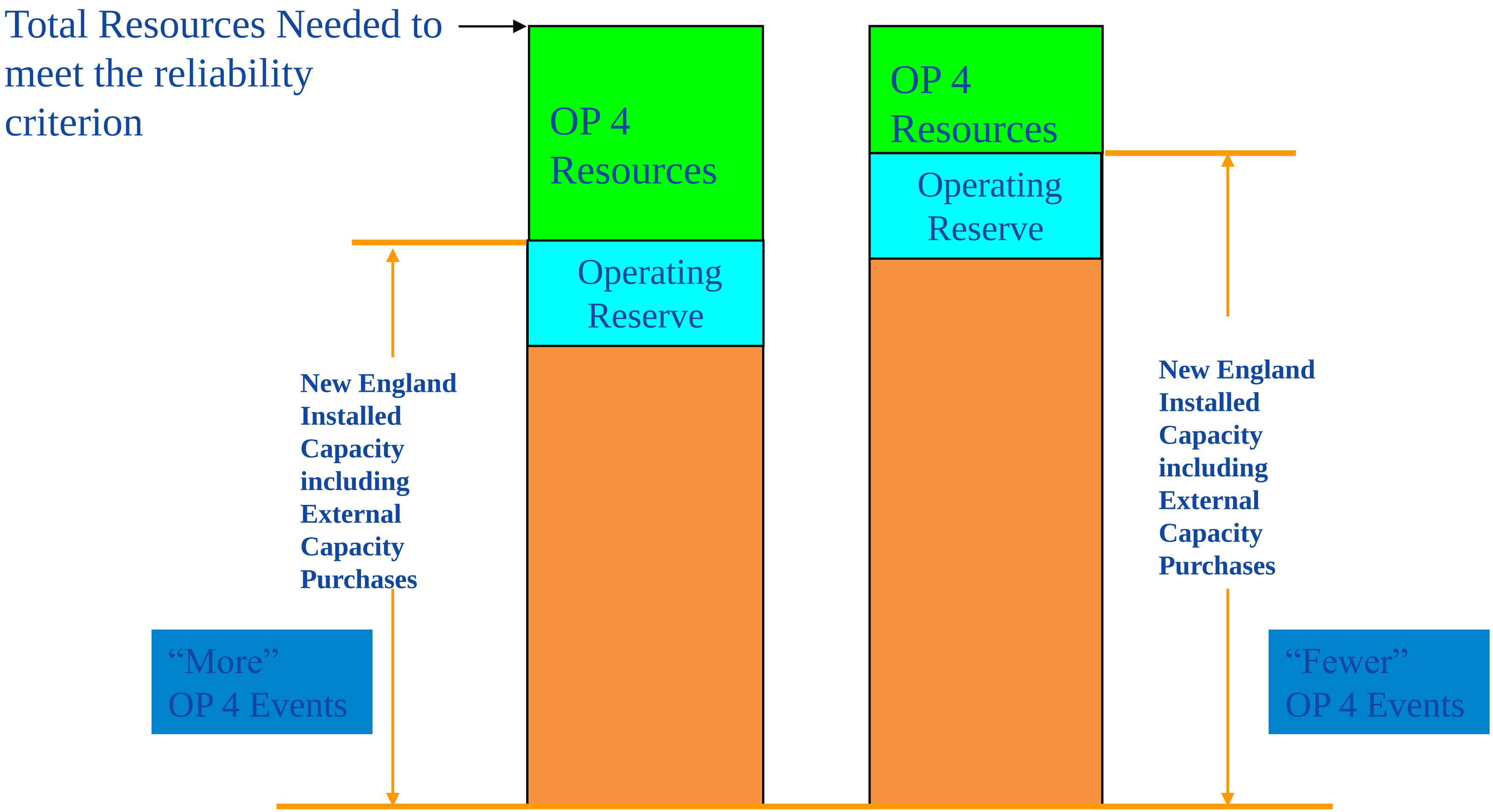
- Activation of OP-4 is a warning sign of insufficient resources
- Operating Procedure No. 4 - Action During a Capacity Deficiency (OP 4) is activated during or in anticipation of system or sub-region capacity deficiencies
  - Capacity deficiency – Available generating capacity expected to be insufficient to meet the load plus operating reserve
  - OP 4 actions either increase the generation supply
    - Reallocate resources from operating reserve to serving load
    - Reduce the load
- The load and capacity relief assumed obtainable from the OP 4 are treated as resources in meeting the once in 10 years disconnection of firm load resource planning reliability criterion
- OP 4 actions are allowed by NPCC planning criteria
- OP 4 documentation can be found on the ISO-NE website at:

  http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html

Relationship between ICR and Load and Capacity Relief from OP 4 Actions

- Installed Capacity Requirement (ICR) is the amount of installed capacity that
  - New England needs on a system-wide basis
  - to meet the 0.1 days/year LOLE resource adequacy criterion
  - while taking into account factors such as:
    - Load uncertainty due to weather
    - Generation forced and planned outages
    - Load and capacity relief from operating procedures
      - Load Response Programs (treated as OP 4 resource pre FCM)
      - Emergency assistance from surrounding Control Areas (tie benefits)
      - Voltage Reductions

OP 4 Resources and Total Resources Needed to meet Reliability Criterion



The Risk Profile Concept

- The once in 10 years disconnection of firm load criterion provides a single reliability metric
- Risk Profile concept quantifies the frequency with which OP 4 actions are likely to be implemented under a wide range of system conditions
- The concept was developed in 1974 to provide:
  - A detailed measurement of system reliability not provided by a single LOLE value
  - Illustration of the relationship between established operating procedures and system reliability
  - An explanation in terms of operating procedures that directly affect the public

Risk Profile Analyses

- Risk Profile concept quantifies the frequency with which OP 4 actions are likely to be implemented under assumed load and resource conditions
- Risk Profile is focused on resource adequacy
  - All resources assumed available if not forced or scheduled out
  - Operational constraints, such as unit start-times or minimum down times, are not modeled

Results of Prior Risk Profile Studies

- Risk Profile studies were conducted in 1974, 1981,1991, 1995 and 2001 at various load and capacity conditions:
  - Key results were presented in terms of Risk Profile “bands” or “ranges” across the span of years studied
    - Sensitive to estimates of the load relief obtainable from OP 4
    - When designed to meet a specific customer disconnection criterion expected frequency of an OP 4 action is a function of:
      - Expected relief obtained from that action as well as
      - All subsequent actions to be taken
      - The number of occurrences of any action is independent of the expected relief from any less severe OP 4 action

The 2009 Risk Profile Analysis

- This risk profile analysis is conducted using the load and capacity assumptions associated with the calculations of the 2012/2013 Installed Capacity Requirement to obtain the expected number of times New England may need to call on OP 4 actions to meet system load and reserve requirements at criterion.
  - Analysis looks at frequency and depth of OP 4 implementation
- New England system modeled as one-bus system
- New England system modeled "at-criterion" only
  - "At-Criterion" assumes that every year, system conditions will exist such that New England is exactly at it's resource planning criterion of 0.1 days/year LOLE

2009 Risk Profile Analysis – Scenarios

- Five tie benefits scenarios were simulated.
  - These scenarios covered the following tie benefits: 1,665 MW; 2,000 MW; 2,500 MW; 3,000 MW and 3,500 MW.
  - Simulations covered Capability Years 2012/13 through 2019/2020
  - Simulations conducted to obtain expected frequency to call:
    - OP 4
    - Tie benefits
    - Voltage reduction

Results of 2009 Risk Profile Analysis

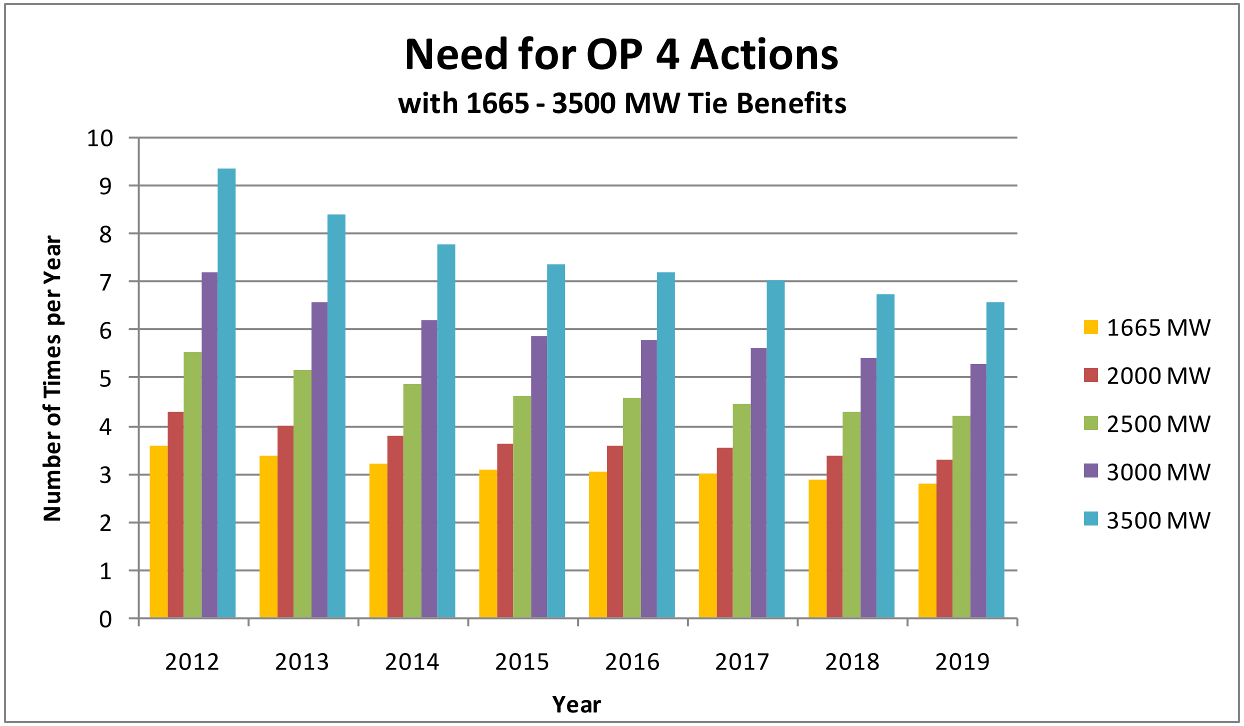
- Results of the 2009 Risk Profile Analysis are shown by year for the five tie benefits scenarios investigated

- OP 4 usage declines over time
  - OP 4 load relief MW are relatively constant while the total resources needed to meet the reliability criterion increases

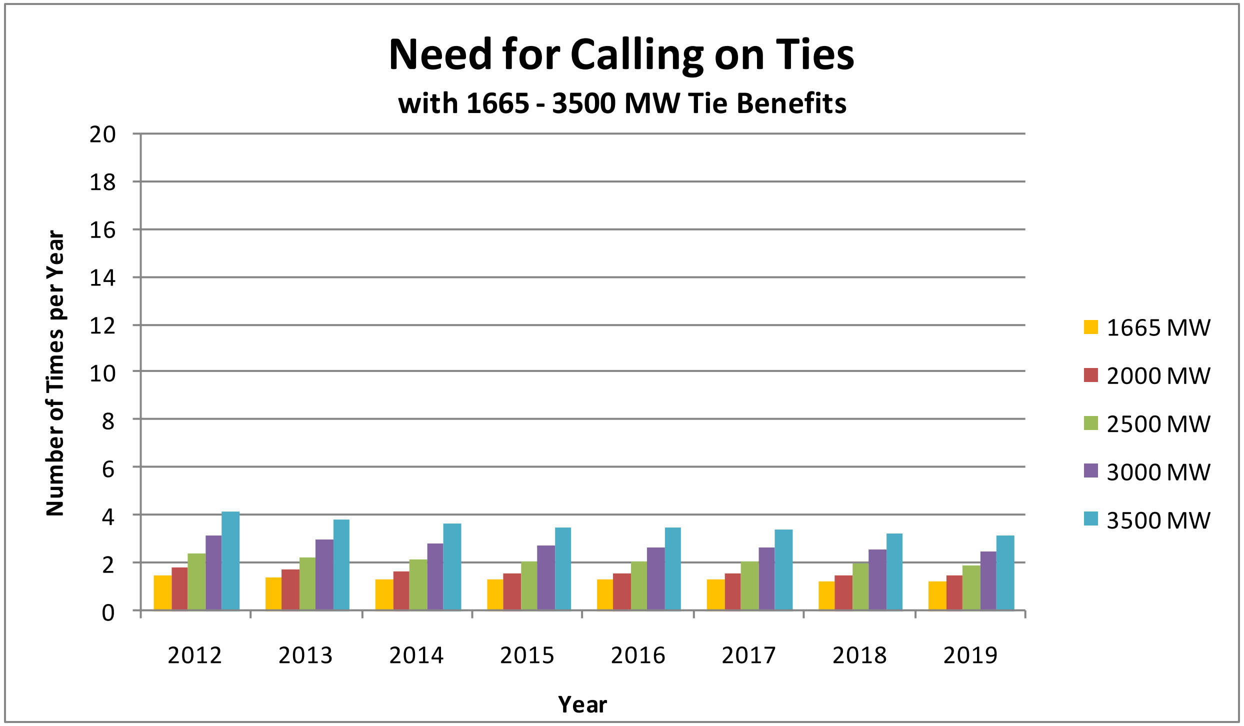
- The number of times various OP 4 Actions would be called are shown in the following slides:

Risk Profile Results – Need for OP 4

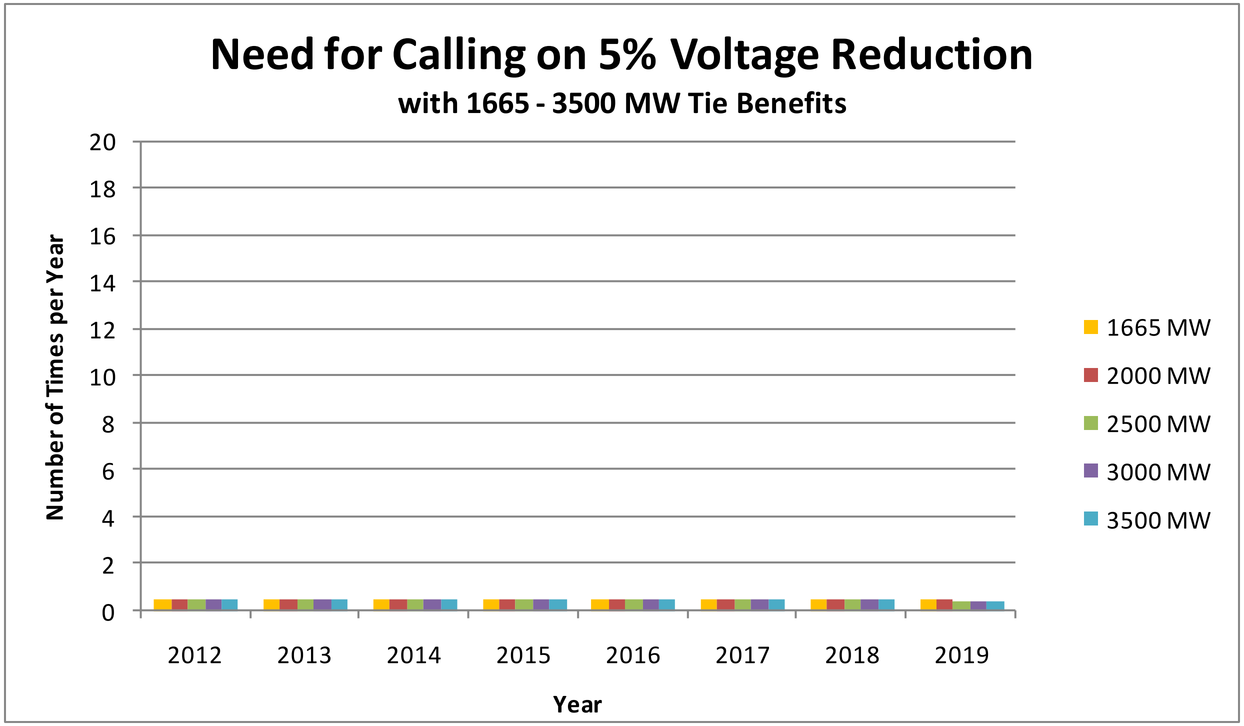
Assuming Various MW of Tie Benefits Relied on to Meet the 0.1 Days/Year LOLE Criterion



Risk Profile Results – Need for Tie Benefits Assuming Various MW of Tie Benefits Relied on to Meet the 0.1 Days/Year LOLE Criterion



Risk Profile Results – Need for Voltage Reduction Assuming Various MW of Tie Benefits Relied on to Meet the 0.1 Days/Year LOLE Criterion



System is brought to criteria for each tie benefits scenario…once the tie benefits are added back in to determine the calls on VR, the different scenarios effectively are the same system, so the results are all similar.

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Risk Profile Study Observations

- The more OP 4 load relief assumed as resources to meet the 0.1 days/year resource planning reliability criterion, the fewer generating and demand capacity resources are required
- As the percent of the OP 4 load relief used to meet the 0.1 days/year decreases, the total calls on OP 4 should decrease (all else being equal)
  - Conversely, the more OP 4 load relief used, the more calls on OP 4
- Based on the load and capacity relief assumed, the expected calls on OP 4 never exceed ten times per year

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Relationship between Operable Capacity Analysis and Probabilistic Capacity Analysis

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Objectives

- Given the **same set of resource mix**
  - Same MW and characteristics
  - Illustrate components of probabilistic and deterministic metrics
- **Difference Between Criterion and Capacity Margin Metric**
  - Probabilistic analysis sets criterion for resource adequacy
    - Firm load shedding,
    - No more than 0.1 days/year
  - Operational Capacity Analysis evaluates Pre-OP4 capacity margin
    - Positive margin is good
    - Negative margin illustrates

Conceptual ICR (LOLE) vs. Operational Capacity Analysis

Operation and Assessment Point	Variable	Probabilistic Analysis		Operational Capacity Analysis for Specific System Condition	
	[1] Load	a distribution		peak load (50/50 and 90/10)	28,160 (50/50) 30,110 (90/10)
	[2] Operating Reserve	deterministic	200	deterministic	2000
Load plus operating reserve	[3]=[1]+[2]	a distribution		deterministic	30,160 (50/50) 32,110 (90/10)
	[4] Resources used for both analysis	Generating resources plus DR (resources operating before OP4): total **ratings** = 29,375 MW			
	[5] Maintenance	not allowed in the model	0	assumed none	0
	[6] Forced outage	a distribution		historical average (i.e. expected value, no uncertainty)	2,100
Expected available pre-OP4 resources	[7]=[4]–[5]– 6]	a distribution			27,275
Operational Capacity Analysis Metric Showing Capacity Margin (surplus(+) or shortage(-)): [8] = [7] – [3]					**-2,885 (50/50)** **-4,835 (90/10)**
Begin OP4 Actions (excluding operating reserve)	[9] Deplete operating reserve	deterministic	0		
	[10] Voltage reduction	deterministic	651		
	[11] Tie Benefit	EFORd assumed	3,415		
Expected available resources before Firm Load Shedding	[12]=[7]+[9]+ 10]+[11]	a distribution			
Probabilistic Analysis Criterion Point (Firm Load Shedding): probability of firm load shedding, [13] = convolution of [3] and [12]		Expected value	**LOLE=0.1**		

Communicating Resource Adequacy

- Various ways of communicating resource adequacy
- Model results
  - Most definitive assessment
  - MARS or Westinghouse
  - Frequently viewed as a ‘blackbox” result that needs to be understood via sensitivity analysis
- Other approaches
  - “Operable capacity” illustration
    - Concept is easy to explain
    - Limited framework for considering nuance
  - Simplified probabilistic illustration
    - Concept is also relatively easy to explain
    - Simplified explanation of the inner workings of the “Model results”
    - Ability to explain and quantify nuance associated with reliability studies

Probabilistic vs. Deterministic Analysis

- Both are consistent viewed from similar perspective
  - Goal: Estimate maximum peak load that can be served
    - Start with the resources you need
    - Add other load relief and supplemental capacity
    - Subtract out unavailable capacity
    - Determine maximum amount of load that can be served
    - Compare to a peak load level representative of future conditions
  - Or … Estimate capacity needed to satisfy peak load
    - Process is reverse of previous concept
    - Start with peak loads
    - Add expected outages
    - Get total resources required including emergency procedures
    - Subtract out emergency procedures to get “iron in the ground or under contract”

Operable Capacity Analysis

- Operable Capacity (start at “Start” … end at “End”)
  - Start with minimum available capacity
    - Add OP4
    - Add 2000 MW of tie benefits
    - Get total resources
  - Calculate maximum load that can be served
    - Subtract allowance for operating reserve
    - Subtract expected outages
    - Result is close to 90/10 peak load (-64 MW)
  - Note that the 1785 MW adjustment to get to the 50/50 peak load is known from the peak load distribution
- See illustration on the next slide

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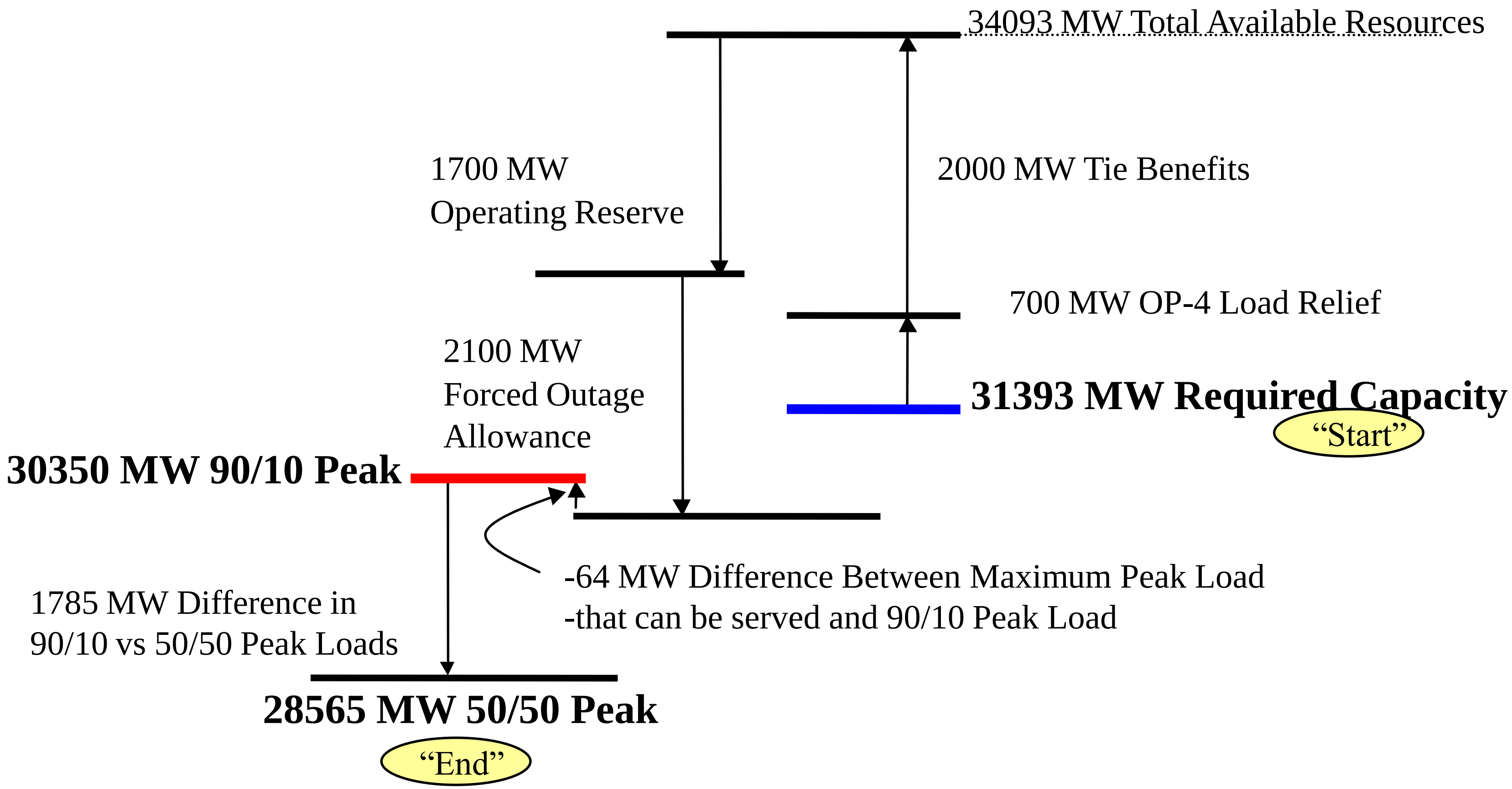
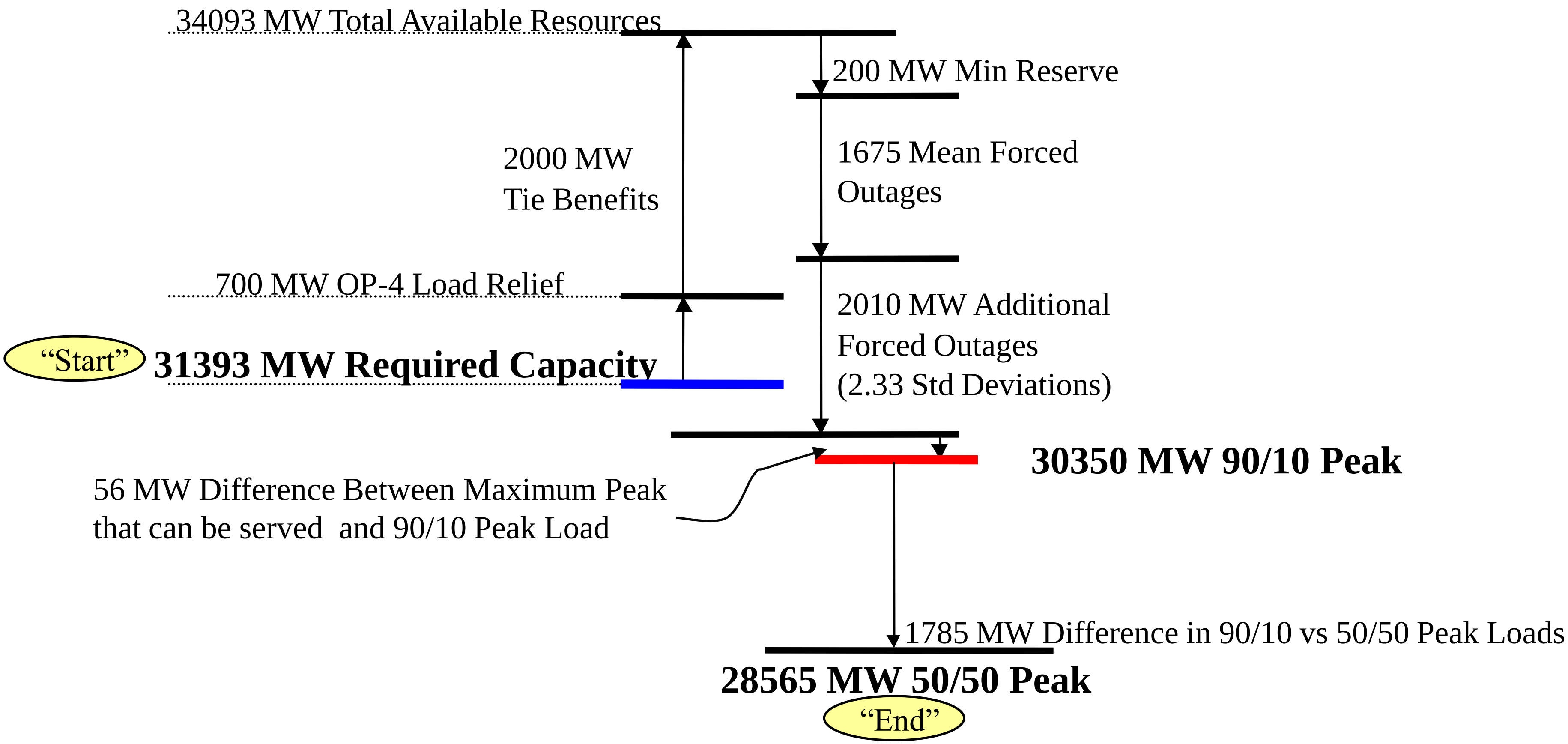
Operable Capacity Illustration



Simplified Probabilistic Capacity Analysis

- Operable Capacity (start at “Start” … end at “End”)
  - Start with available capacity
    - Add OP4
    - Add 2000 MW of tie benefits
    - Get total resources
  - Calculate maximum load that can be served
    - Subtract expected capacity on forced outages
    - Subtract 2.33 standard deviations of forced outages to account for 1 day in ten year extremes
    - Result is close to 90/10 peak load (56 MW)
  - Note that the 1785 MW adjustment to get to the 50/50 peak load is known from the peak load distribution
- See illustration on the next slide

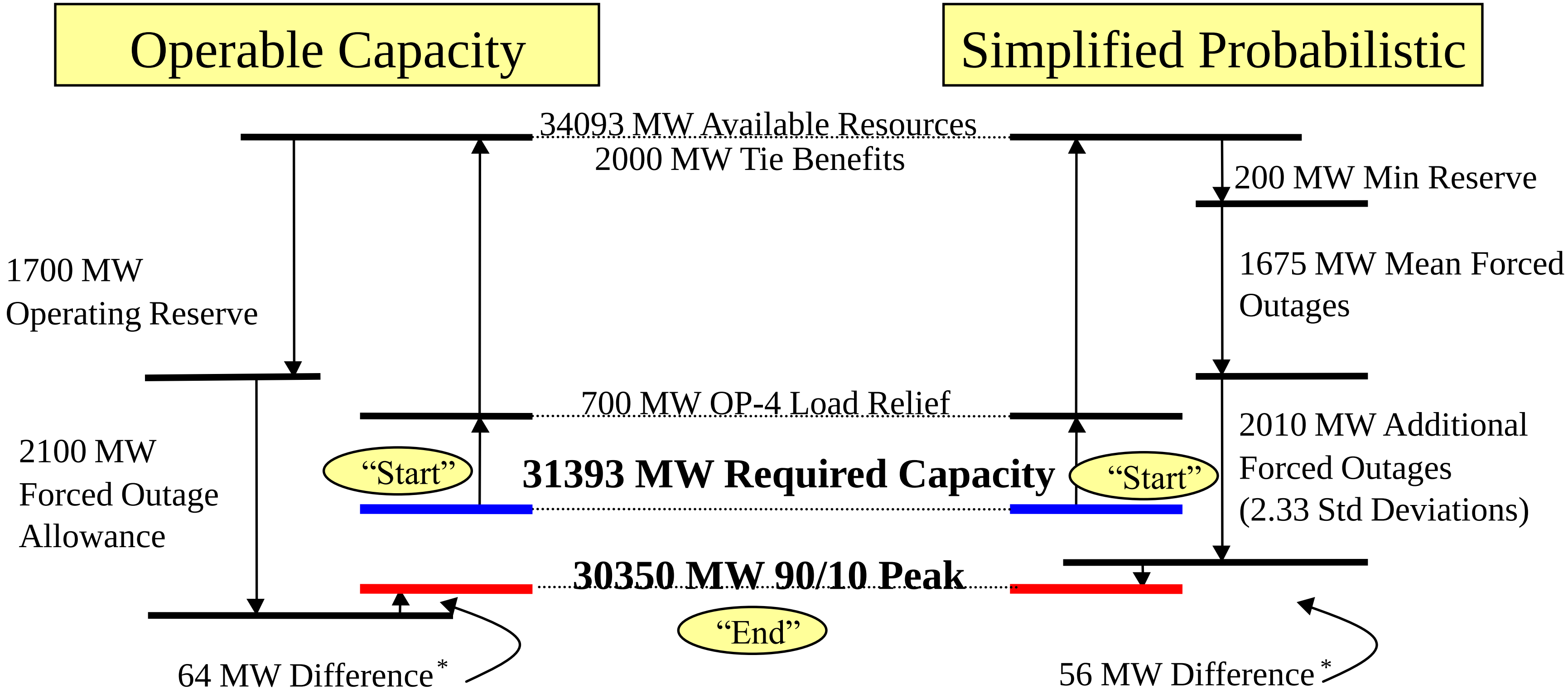
Probabilistic Capacity Illustration



Comparability of Approaches: Side by Side

- Either approach gives approximately the same relationship between the peak load and required capacity
  – Operable Capacity Approach
  – Simplified Probabilistic Capacity Analysis
- Can start with either
  – Peak load and then calculate required installed capacity, or
  – Available installed capacity and then calculate the maximum peak load
    - 90/10 peak or 50/50 peak
    - Difference is a fixed amount based on peak load distribution
    - Difference is 1785 MW in this example
- See illustration on the next slide for a side-by-side comparison

Side by Side Comparison



*Compared to 90/10 Peak Load

Observations

- Operable Capacity analysis is a simplified approximation for a probabilistic analysis
  - Total capacity is the same (installed, plus OP-4, plus tie benefits)
  - These calculations illustrate crude tradeoff concept

(Expected Outages) + (2.33 sigma Outages) + Minimum Operating Margin ~=
(Expected Operating Reserve) + (Expected Forced Outages)

- Operable capacity analysis provides very limited sensitivity analysis of the input
- May have value in more granular analysis of sub-areas such as TSAs

Questions?