NEWTON ENERGY GROUP

Locational Assessment of Resource Adequacy and Co-optimization of Generation and Transmission Expansion

Aleksandr Rudkevich
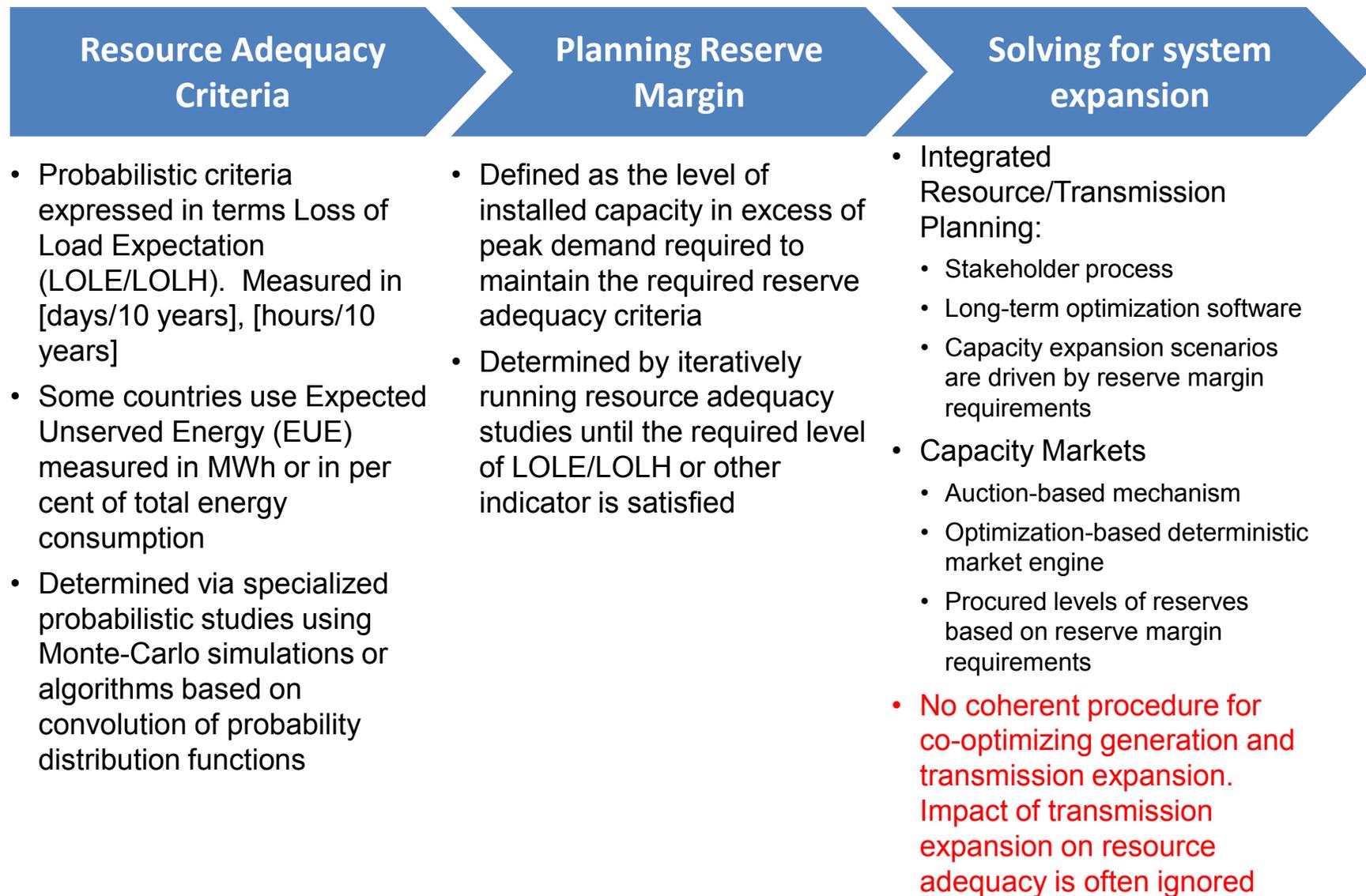Newton Energy Group
Newton, MA

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Presentation outline

- Capacity expansion problem
- Locational resource adequacy
- Toward capacity market for co-optimization of generation and transmission

High Level Schematic of the System Expansion Planning Process

Resource Adequacy Criteria	Planning Reserve Margin	Solving for system expansion

Resource Adequacy Criteria

- Probabilistic criteria expressed in terms Loss of Load Expectation (LOLE/LOLH). Measured in [days/10 years], [hours/10 years]
- Some countries use Expected Unserved Energy (EUE) measured in MWh or in per cent of total energy consumption
- Determined via specialized probabilistic studies using Monte-Carlo simulations or algorithms based on convolution of probability distribution functions

Planning Reserve Margin

- Defined as the level of installed capacity in excess of peak demand required to maintain the required reserve adequacy criteria
- Determined by iteratively running resource adequacy studies until the required level of LOLE/LOLH or other indicator is satisfied

Solving for system expansion

- Integrated Resource/Transmission Planning:
  - Stakeholder process
  - Long-term optimization software
  - Capacity expansion scenarios are driven by reserve margin requirements
- Capacity Markets
  - Auction-based mechanism
  - Optimization-based deterministic market engine
  - Procured levels of reserves based on reserve margin requirements
- No coherent procedure for co-optimizing generation and transmission expansion. Impact of transmission expansion on resource adequacy is often ignored

Capacity expansion approaches

	IRP/ITP	Capacity market
Resource options	Stakeholder inputs	Offered by market participants
Future economic and market assumptions	Stakeholder inputs (demand forecast, fuel prices, regulatory policy, cost of capital, etc.)	Combination of stakeholder inputs (demand forecast) and assumptions embedded in participants' offers (fuel prices, regulatory policy, cost of capital)
Cost allocation mechanism	Regulatory policy	Market prices
Risk allocation	Borne by ratepayers	Shared among ratepayers and investors
Algorithms/software	Complex co-optimization of investment and operating costs	Relatively simple optimization of investment costs

How to co-optimize generation and transmission expansion?

	IRP/ITP	Capacity market
Transmission expansion options	Stakeholder inputs	Offered by market participants
Future economic and market assumptions	Stakeholder inputs (demand forecast, fuel prices, regulatory policy, cost of capital, etc.)	Combination of stakeholder inputs (demand forecast) and assumptions embedded in participants' offers (fuel prices, regulatory policy, cost of capital)
Cost allocation mechanism	Regulatory policy	Market prices
Risk allocation	Borne by ratepayers	Shared among ratepayers and investors
Algorithms/software	Very complex: stochastic co-optimization of investment and operating costs	Stochastic co-optimization of investment costs only

Stochastic optimization is crucial for co-optimization of generation and transmission expansion

- In face of constrained transmission, resource adequacy assessment is locational

- Resource adequacy assessment is a probabilistic problem which cannot be solved when transmission topology is a decision variable

- Co-optimization of generation and transmission may not be properly accomplished without embedding resource adequacy assessment into the co-optimization process
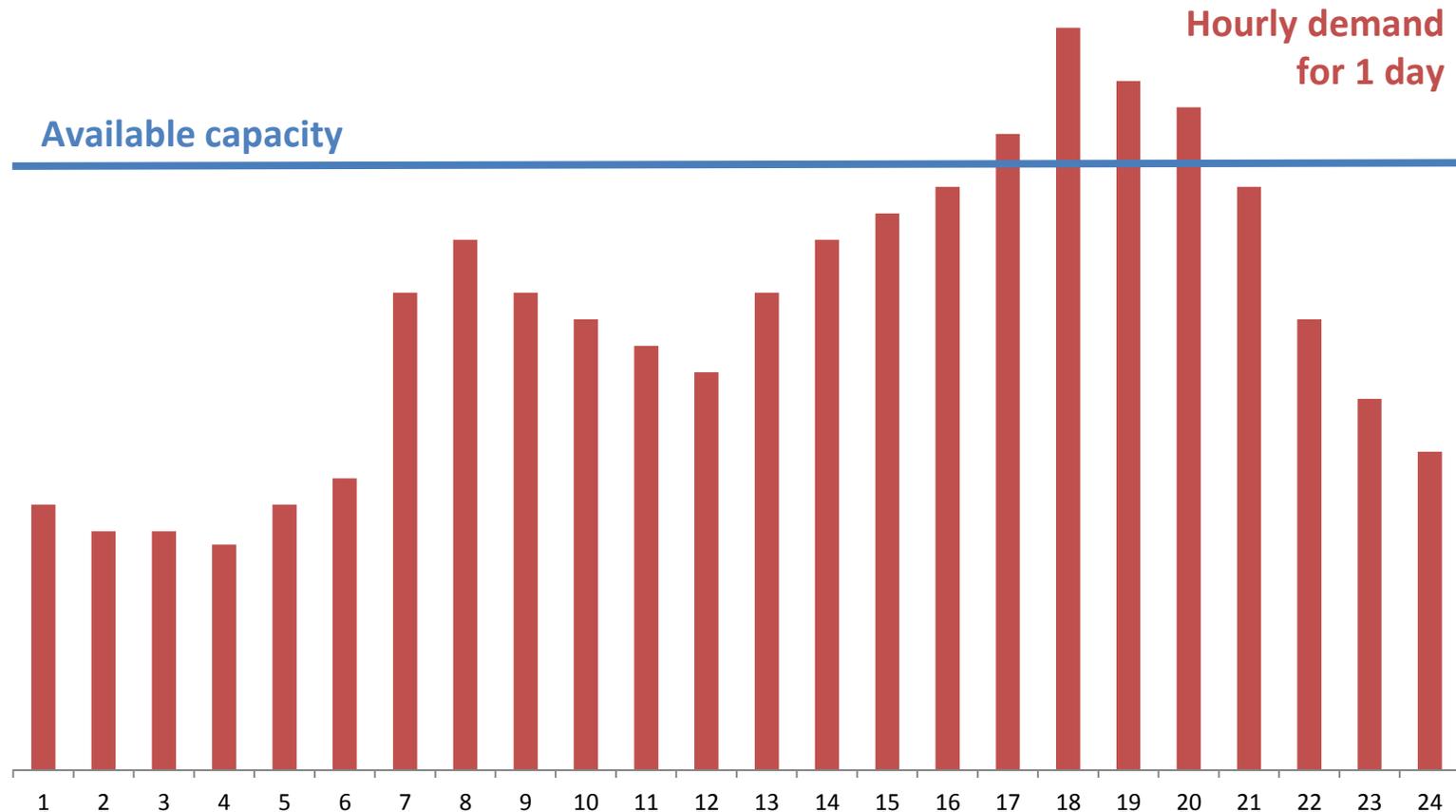
Resource Adequacy is measured by probabilistic criteria

- Resource adequacy criteria express *the expected frequency, expected duration* and/or *expected magnitude* of possible capacity deficiency (loss of load)

- Expected number of days per year of loss of load a.k.a. Loss of Load Expectation, **LOLE**) [days/yr]. 1 day in 10 years – US, Canada

- Expected number of hours per year of loss of load a.k.a.(Loss of Load Hours, **LOLH**) [hrs/yr]

- Expected value of unserved load in MWh/yr or % of annual energy use (**EUE**, **RUE –** other abbreviations **EENS, LOEE**)

Example: a contribution of supply deficiency scenario to LOLE and LOLH. Contribution to LOLE = 1 day; to LOLH = 4 hours
LOLE = 1 day in 10 yrs ←→ LOLH = 4 hrs in 10 years, not 24 hrs

Available capacity

Hourly demand for 1 day

1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

There is no known justification for 1 day in 10 years

- The concept of probabilistic criteria of power system reliability goes back to works of:
  - W.J. Lyman "Fundamental Considerations in Preparing Master System Plan" (1933)
  - P.E. Benner "The use of theory of probability to determine spare capacity" (1934)
  - S.M. Dean "Considerations involved in making system investment decisions for improved service reliability" (1938)
  - G. Calabrese "Generating reserve capability determined by the probability method" (1947)
- Cannot point to a single study providing a rationale for 1 day in 10 years. However, this criteria appears in the 1965 FERC blackout report
- "Industry experience has helped 1 day in 10 years evolve to become an accepted criteria, globally" [Henry Chao et al.]
- The theoretical approach that could lead to the LOLE justification has long been known (see for example S. Stoft, "Power Systems Economics")

The total cost approach to determining the optimal level of installed capacity


At optimum the marginal cost of reserves must equal marginal damage caused by unserved load

Optimal level of reserves

- - - Capacity cost

- - - Damage due to unserved load

—— Total costs

Cost

Reserve margin

0   0.2   0.4   0.6   0.8   1   1.2   1.4   1.6   1.8   2
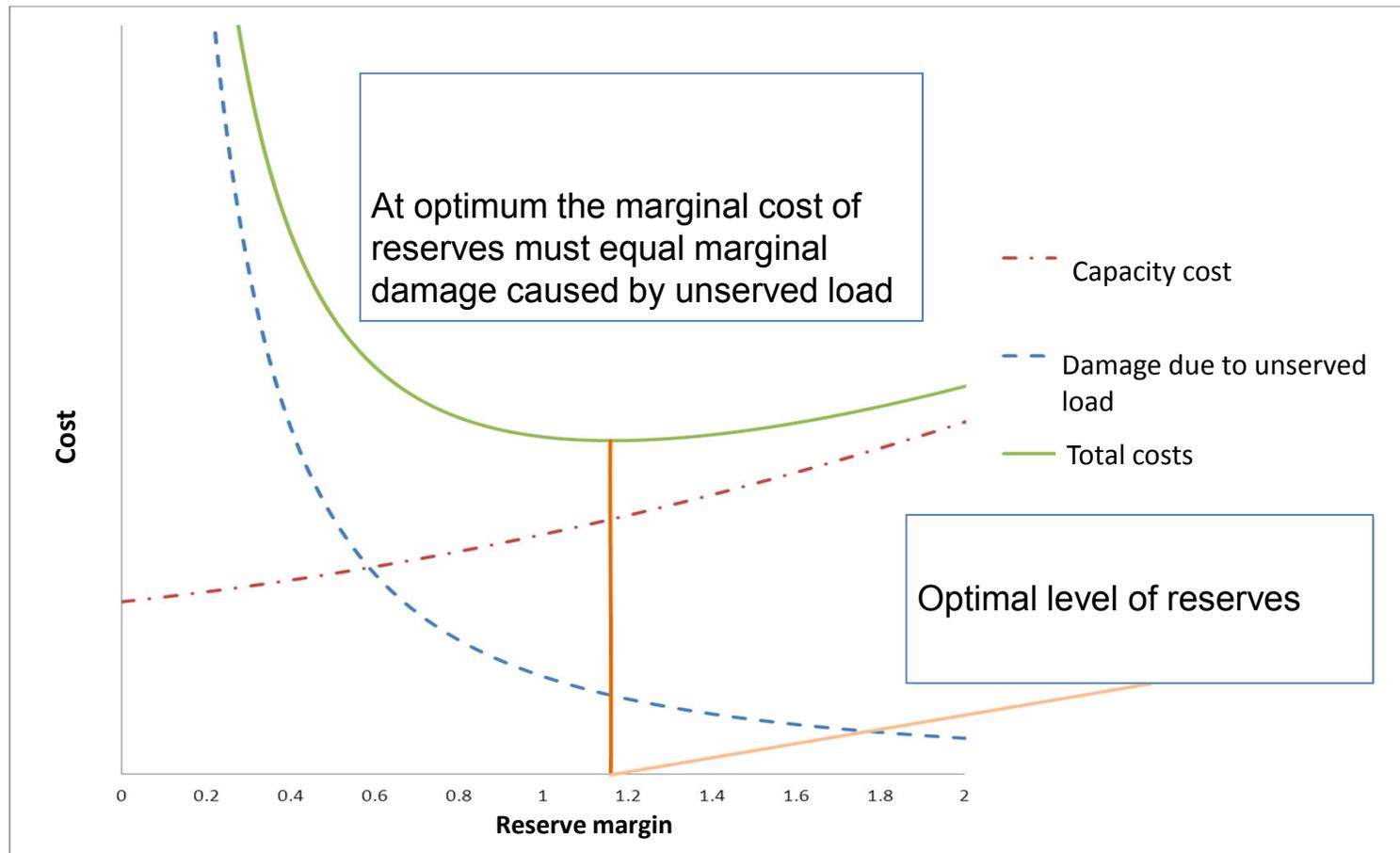
In a concentrated system (no Tx constraints) this problem is in fact reduced to minimization of one function of one variable. The challenge is in defining this function

Installed capacity requirements should be determined economically based on a balance between the cost of adding new and maintaining existing capacity and damage caused by unserved demand

- Cost of adding/maintaining capacity – this is known as missing money, lack of revenues from the markets for energy and ancillary services generators need to stay online (existing) or be built (new)
- Marginal damage due to unserved energy is the derivative of the damage function often approximated as VOLL x [marginal unserved energy]
- VOLL – value of lost load
- Marginal unserved energy = LOLH (see next slide)
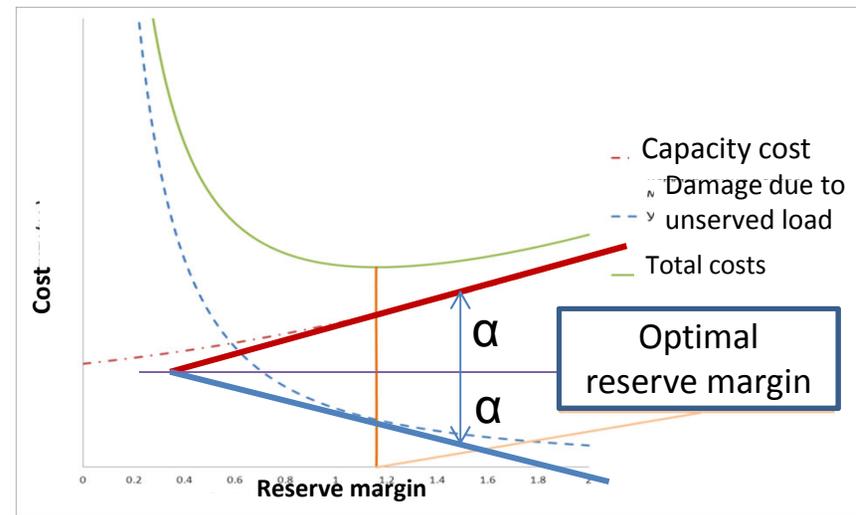
At optimum, marginal cost of capacity equals marginal damage due to unserved energy

Marginal unserved energy equals LOLH (in an unconstrained system)

Generalized load = Load + capacity on outage

Unserved energy

Installed capacity + 1 kW UCAP

Reduction in unserved energy due to increased reserves

Installed capacity

Generalized load duration curve

Loss of Load Hours (LOLH)

8760
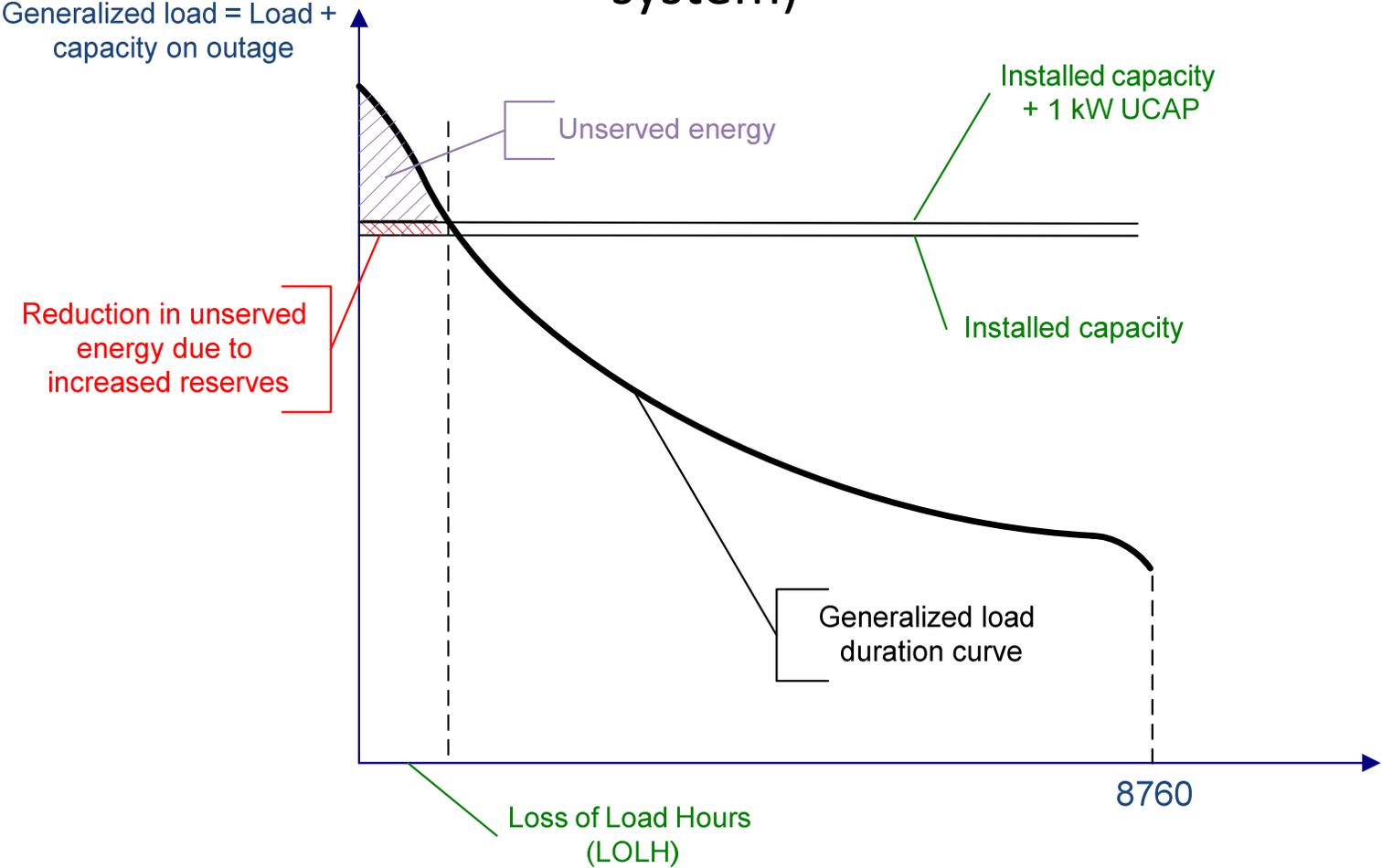
Marginal unserved energy = [reduction in unserved energy]/[1 kW]
= [1 kW X LOLH]]/[1 kW] = LOLH

Economic justification for the LOLH criterion (for an unconstrained system)

$$MCC = VOLL \times LOLH \quad \Rightarrow \quad LOLH = \frac{MCC}{VOLL}$$

$LOLH$ – loss of load hours

MCC – Marginal cost of adding or keeping capacity online

$VOLL$ – Value of Lost Load

Example:

$VOLL$ = $10/kWh

MCC = $90/kW-yr

$LOLH$ = 9 hrs/year

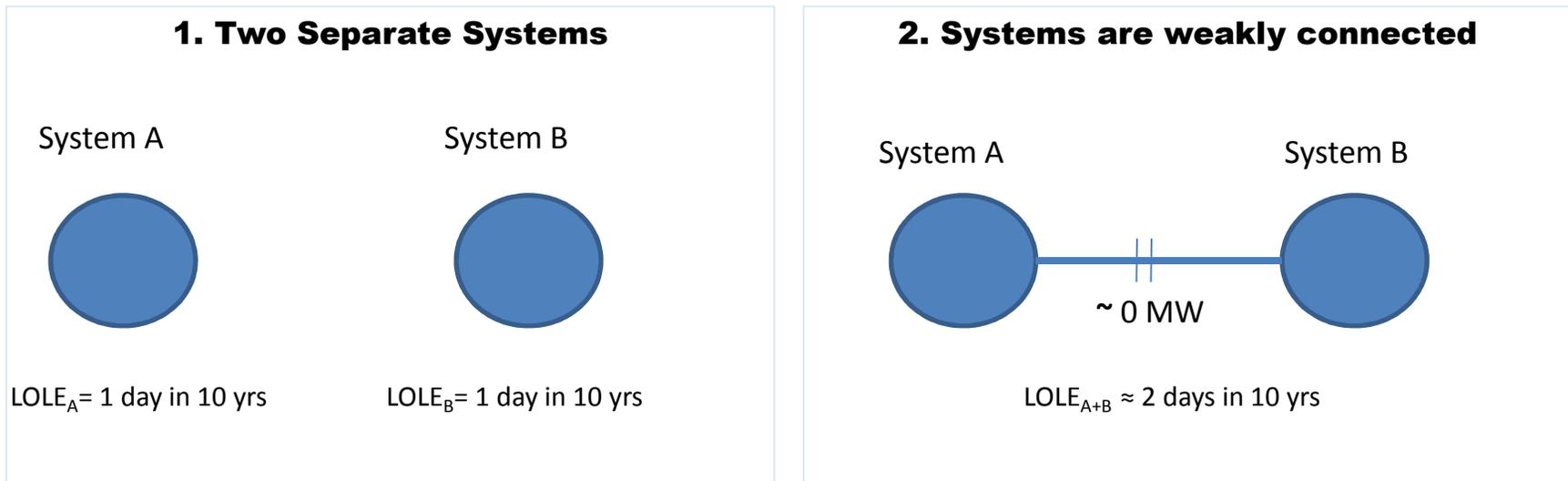1 day in 10 years = 0.36 hrs/year would be justified by VOLL of $250.00/kWh
(Must be careful in making comparisons across systems. The answer very much depends among other things on how the loss of load is defined in a particular system. For example, in NY, 1 day in 10 years is achievable after all EOPs are applied. Before EOPs, LOLE could be close to 80 days in 10 years)

LOLH/LOLE criteria may not be applied to transmission constrained systems.
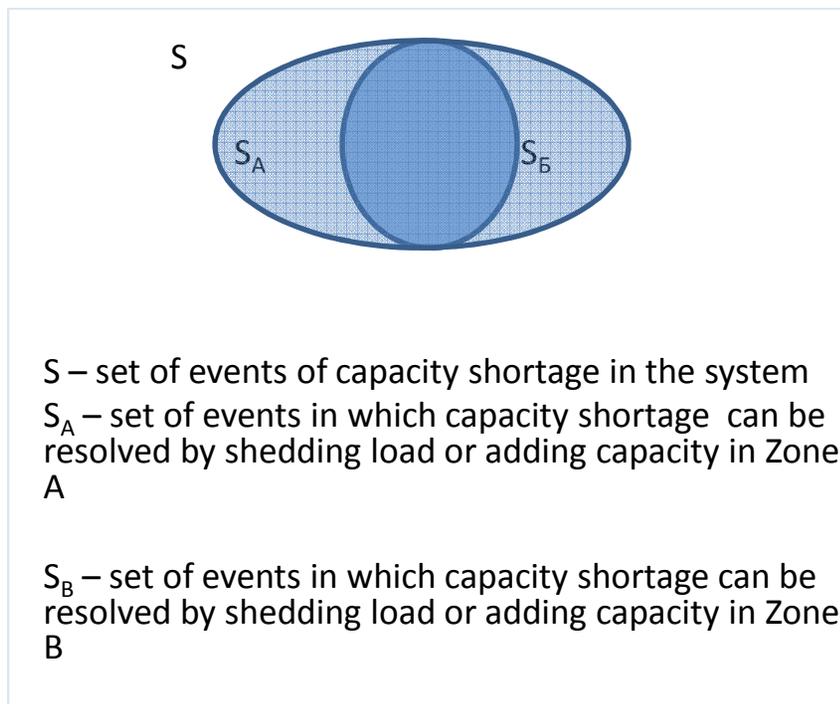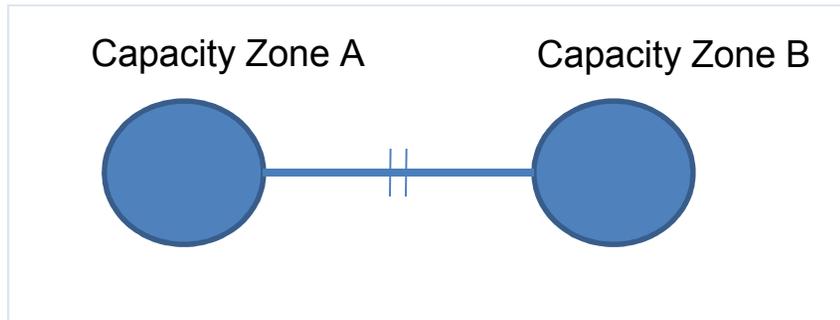## Lazebnik's Paradox

❑ **LOLH reflects the average frequency of the loss of load in the system as a whole**

❑ **But LOLH for the system with transmission constraints no longer reflects marginal unserved energy or marginal damage**

❑ **LOLH provides no signal on the location of needed capacity**

❑ **Setting adequacy criteria in terms of LOLH for the system yields paradoxical results**

1. Two Separate Systems

System A   System B

$LOLE_A$ = 1 day in 10 yrs $LOLE_B$ = 1 day in 10 yrs

2. Systems are weakly connected

System A   System B

~ 0 MW

$LOLE_{A+B}$ ≈ 2 days in 10 yrs

In the second case the frequency of interruption of individual end users is practically the same as in the first case but the LOLE no longer meets the 1 day in 10 years standard. In the first case, no investments are necessary. In the second case, new reserves must be added to meet the 1 day in 10 years criterion

Based on the Total Cost Criteria investment decisions should be driven by indicators of marginal damage or marginal unserved energy

Capacity Zone A   Capacity Zone B

S

S_A $S_Б$

S – set of events of capacity shortage in the system
S_A – set of events in which capacity shortage can be resolved by shedding load or adding capacity in Zone A

S_B – set of events in which capacity shortage can be resolved by shedding load or adding capacity in Zone B

In the absence of transmission constraints

**LOLH (hours/yr) = P [S] x 8760 = $\partial EUE/\partial L$,
P [S] – probability of all events in S
Optimal capacity addition rule:**

**LOLH x MCC= $\partial EUE/\partial L$ x VOLL = MCC
MCC– annualized capacity cost**

In a constrained system LOLH does not drive the optimal capacity addition rule:

Optimal capacity addition rule for Zone A
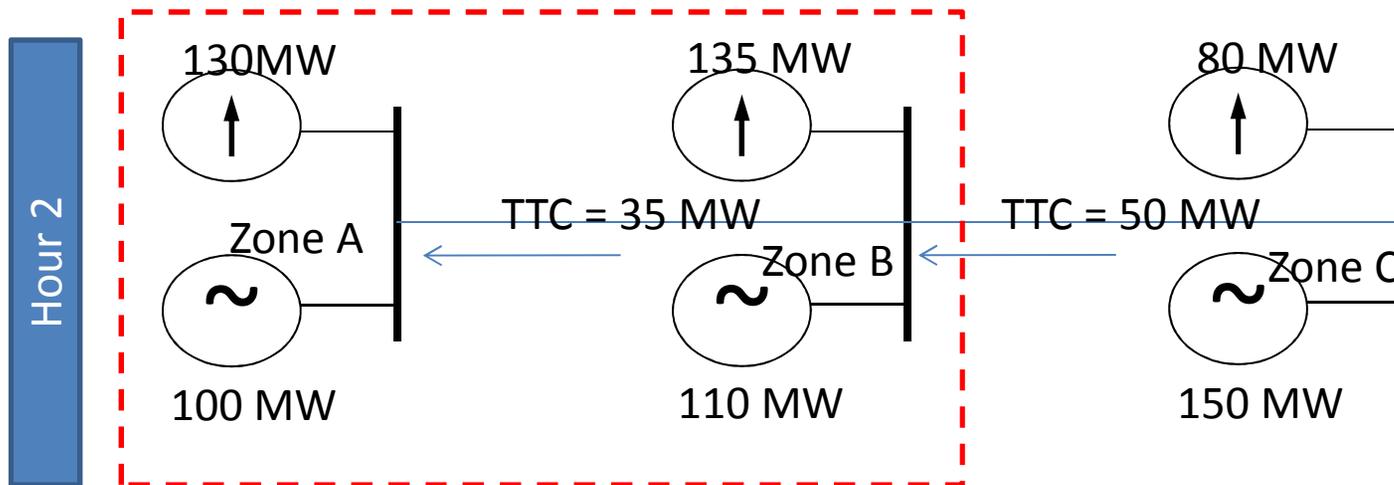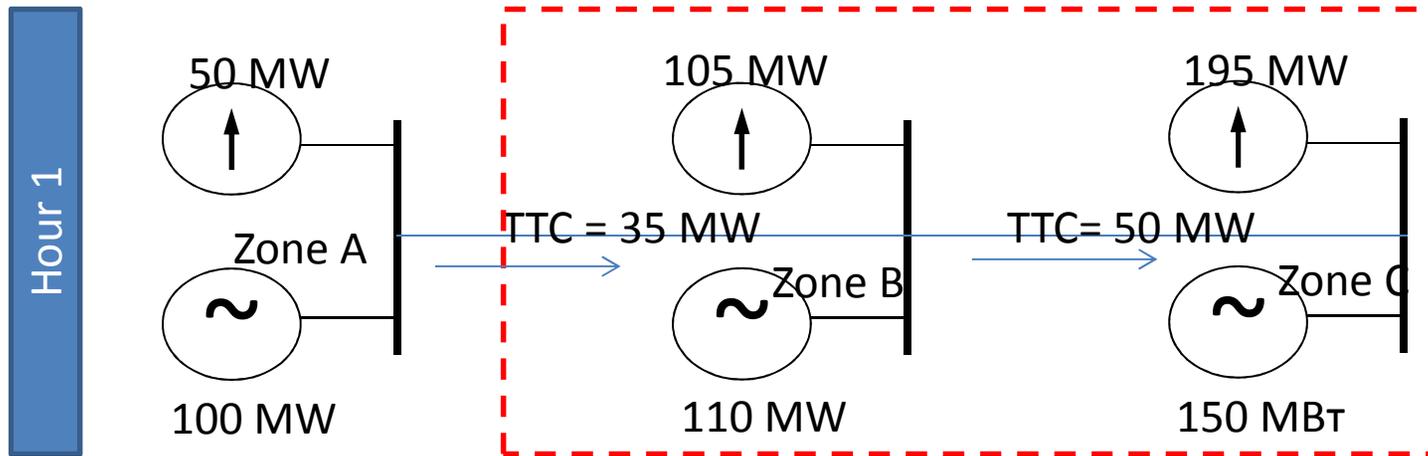**$\partial EUE/\partial L_A$ x VOLL = MCC$_A$**

Optimal capacity addition rule for Zone B
$\partial EUE/\partial L_B$ x VOLL = MCC$_B$

The right indicators are $\partial EUE/\partial L_A$ and $\partial EUE/\partial L_B$

A 3-zone System Example of a Capacity Deficient System. Available capacity (360 MW)) exceeds demand (345-350 MW) but transmission constraints cause deficiency
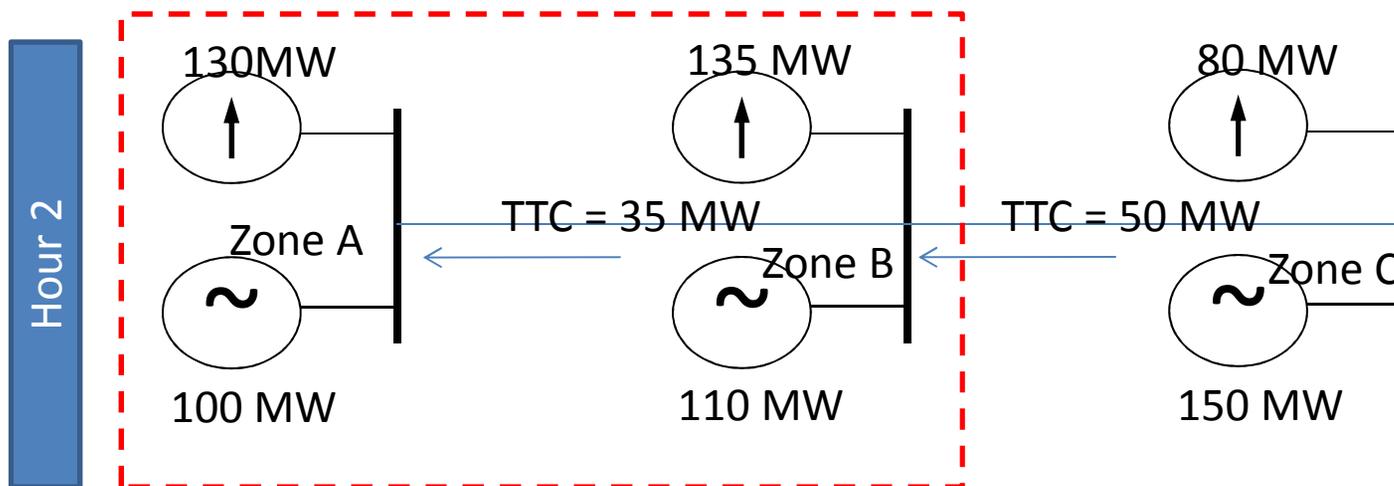
Hour 1

50 MW

Zone A

100 MW

TTC = 35 MW

105 MW

Zone B

110 MW

TTC= 50 MW

195 MW

Zone C

150 МВт

Hour 2

130MW

Zone A

100 MW

TTC = 35 MW

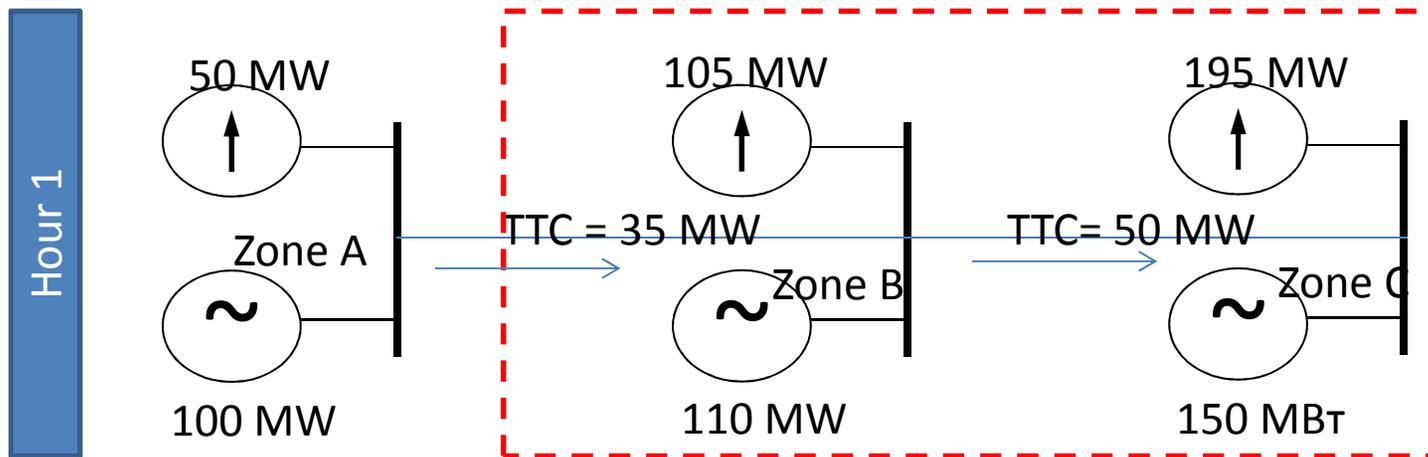135 MW

Zone B

110 MW

TTC = 50 MW

80 MW

Zone C

150 MW

Constrained system: marginal unserved energy and Marginal LOLH

- Consider a transmission constrained bulk power system divided into zones. Assume the system is deficient. At a given moment in time under a given probabilistic scenario a zone will be called *marginally deficient* if reducing demand <u>in that zone</u> reduces the total level of unserved load in <u>the system</u>.

- For each zone we can determined the expected number of hours it will be marginally deficient. Consider this indicator as an analog of LOLH and denoted as $MLOLH_z$.

- For each zone we can also define the marginal expected unserved energy ($MEUE_z$) as a reduction in unserved energy in the system in response to a small reduction in load (or increase in unforced capacity) in that zone

- **$MEUE_z$ and $MLOLH_z$ are economicallys justified locational criteria of resource adequacy**

- As in the unconstrained system, <u>for each zone z</u> the identity holds *)

$$MLOLH_z = MEUE_z$$

- The LOLH for the system as a whole may be significantly higher than MLOLH for each zone. We argue that the standard should be set for the MLOLH by zone. If 0.36 hours per year is considered acceptable and this standard is satisfied in terms of MLOLH for each zone, the entire system meets resource adequacy requirements. At the same time the LOLH for the system will be much higher than 0.36 hours per year, but from the economic standpoint this is irrelevant!

*) this identity is true only if the system is modeled as a transportation system in the absence of KVL

Marginal deficiency sends the right locational signal. Zone B is marginally deficient in both hours while zone A and Zone B are marginally deficient in 1 hour each.

Hour 1

50 MW

105 MW

195 MW

Zone A

TTC = 35 MW

TTC= 50 MW

Zone B

Zone C

100 MW

110 MW

150 МВт

Hour 2

130MW

135 MW

80 MW

Zone A

TTC = 35 MW

TTC = 50 MW

Zone B

Zone C

100 MW

110 MW

150 MW

Adding 1 MW in zone B will reduce unserved energy by 2 MWh. Adding 1 MW at A or C will reduced unserved energy by 1 MWh only.

Locational thresholds for MLOLH (assuming the same VOLL everywhere)

$$MCC_z = VOLL \times MLOLH_z$$

$$MLOLH_z = \frac{MCC_z}{VOLL}$$

$MLOLH_z$ – mean number of hours over which zone z is marginally deficient

MCC_z – marginal cost of adding or keeping capacity online in zone z

$VOLL$ – value of lost load

Example:
$VOLL$ = $10/kWh
MCC_z = $90/kW-year
$MLOLH_z$ = 9 hours/year in each zone

Assuming constant system-wide VOLL, higher MCC implies higher MLOLH. This does not mean that consumers in that zone will be interrupted more frequently. It only means that capacity in that zone is more often needed to resolve deficiency in the system.

Setting locational capacity requirements

- MLOLH at each location is a function of installed capacity in <u>all zones</u>

- To find optimal installed capacity requirements, it is necessary to solve a system of simultaneous equations

$$MLOLH_z(\text{UCAP}_1, \ldots, \text{UCAP}_n) = MLOLH_{z0}$$
$$z = 1, 2, \ldots, n$$

- The level of unforced capacity in each zone depends on unforced capacity in other zones <u>and on transfer capabilities of transmission connections between zones</u>

Transmission vs. Generation
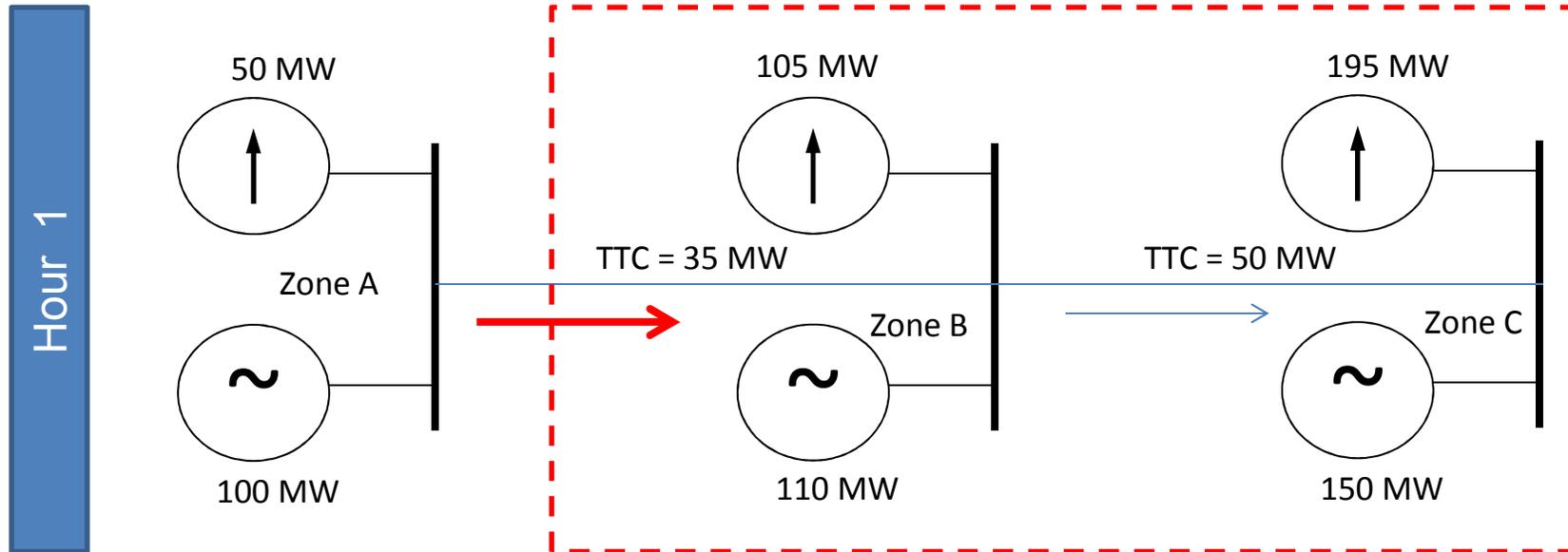
- When importing zone is marginally deficient but the transmission is constrained, we call this transmission connection *reliability limiting* (this is determined by shadow prices in the problem of reliability dispatch, not by imposing arbitrary deficiency allocation rules)
- A 1 MW increase in the TTC of the connections from A to B reduces unserved energy by 1 MWh (the same effect as increasing capacity in zones B or C by 1 MW)
- *RLH(A→B)* – expected number of hours the connection is reliability limiting in the direction from A to B

Transmission vs. Generation (cont'd)

A 1 MW increase in the TTC of the connection in both directions yields the same reliability effect as building X_z of UCAP in zone z or X_w of UCAP in zone w where

$$X_z = \frac{BRLH_{wz}}{MLOLH_z} \qquad X_w = \frac{BRLH_{wz}}{MLOLH_w} \qquad BRLH_{wz} = RLH_{w \rightarrow z} + RLH_{z \rightarrow w}$$

Resource Adequacy Indicators of Transmission Connections

- *RLH and BRLH* -- directional and bi-directional expected number of reliability limiting hours, respectively
- Important property (in absence of KVL)

$$RLH_{w->z} - RLH_{z->w} = MLOLH_z - MLOLH_w$$

- If MLOLH in two neighboring zones are equal, the connection between these two zones must be reliability limiting in each direction with the same frequency
- The reliability effect of transmission is <u>not</u> determined by the difference in the frequency of marginal deficiency between two neighboring zones. It is determined by *BRLH*
- The reliability *value* of transmission is <u>not</u> determined by the difference in capacity prices between two neighboring zones. It is much higher than that difference!
- Current capacity markets fail to capture the reliability value of transmission!

Threshold levels for *BRLH*

Similarly to the way the thresholds are set for installed capacity, the total cost minimization principle leads to following thresholds for transmission reliability indicators:

$$BRLH0_{z,w} = \frac{MCT_{z,w}}{VOLL}$$

$MCT_{z,w}$ - annualized per unit cost of increasing TTC between zones z and w (capital costs <u>less savings in production costs realized in markets for energy and AS, an equivalent of "missing money" for transmission</u>)

If $BRLH_{z,w} > BRLH0_{z,w}$, then the generation expansion solution could be improved (would reduce total costs) by enforcing this transmission connection and avoiding some generation additions

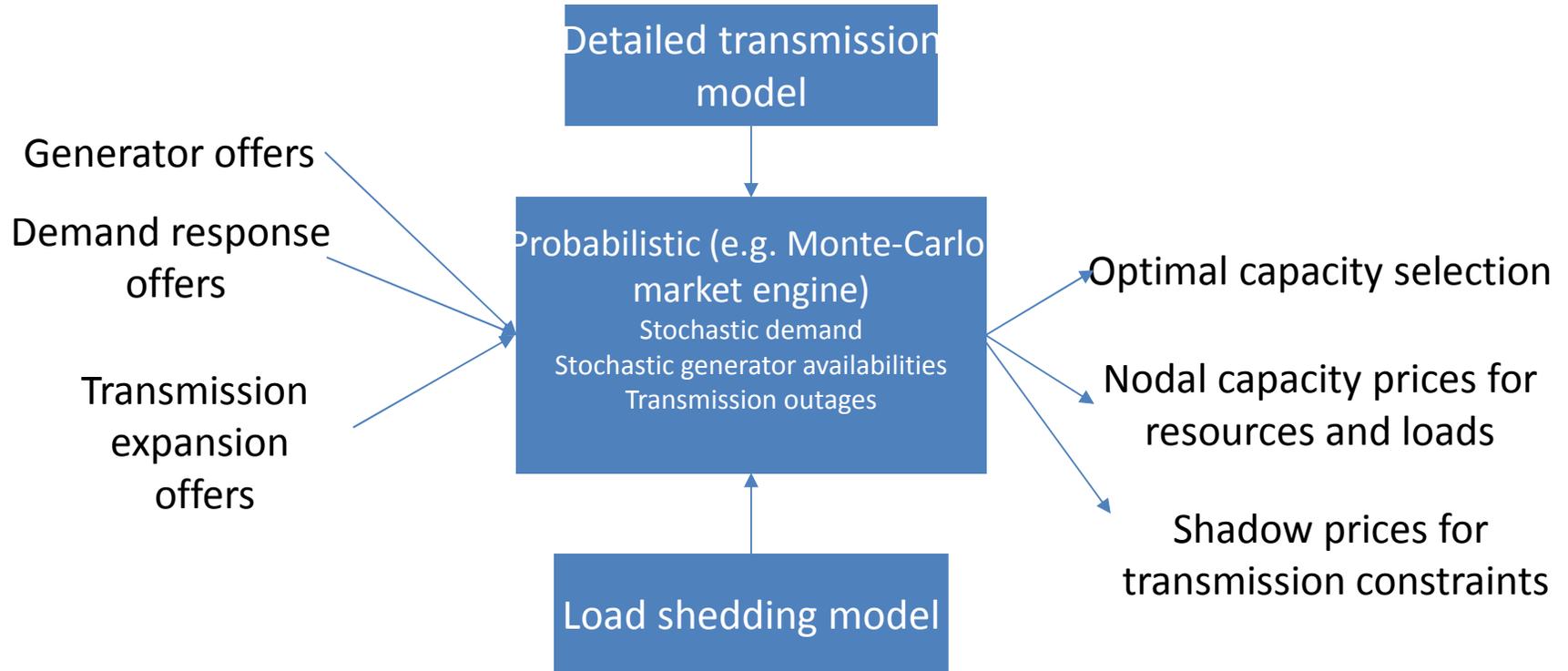# Proposed Co-Optimization Approach: Stochastic Reliability Pricing Model

- Market-based: optimal generation and transmission mix is selected through a capacity procurement auction conducted on a regular basis (e.g. annually)
- Planning horizon: one- or multi-year
- Footprint: an RTO but could be multiple RTOs
- Market engine:
  - Uses full transmission model and factors in security constraints;
  - Transmission expansion is treated as Topology Control
  - Models generator and transmission availability as stochastic processes;
  - Models demand as stochastic processes;
  - Does not require regional reserve margins as an input;
  - Explicitly incorporates expected value of unserved energy E(VUE) into the auctioneer's objective function
- Auction outcome:
  - Optimal selection of the resource and transmission mix
  - Locational capacity prices for resources
  - Locational capacity prices for loads
  - Market-based compensation for transmission expansion

Schematic of the Market Engine

Auctioneer's Objective Function: **min [**(Gen Cost @CRR) + (DR Cost @CRR) + (Tx Cost @ CRR) + **E**(VUE)**]**
Planning horizon: one- or multi-year

Detailed transmission model

Generator offers

Demand response offers

Transmission expansion offers

Probabilistic (e.g. Monte-Carlo market engine)
Stochastic demand
Stochastic generator availabilities
Transmission outages

Optimal capacity selection

Nodal capacity prices for resources and loads

Shadow prices for transmission constraints

Load shedding model
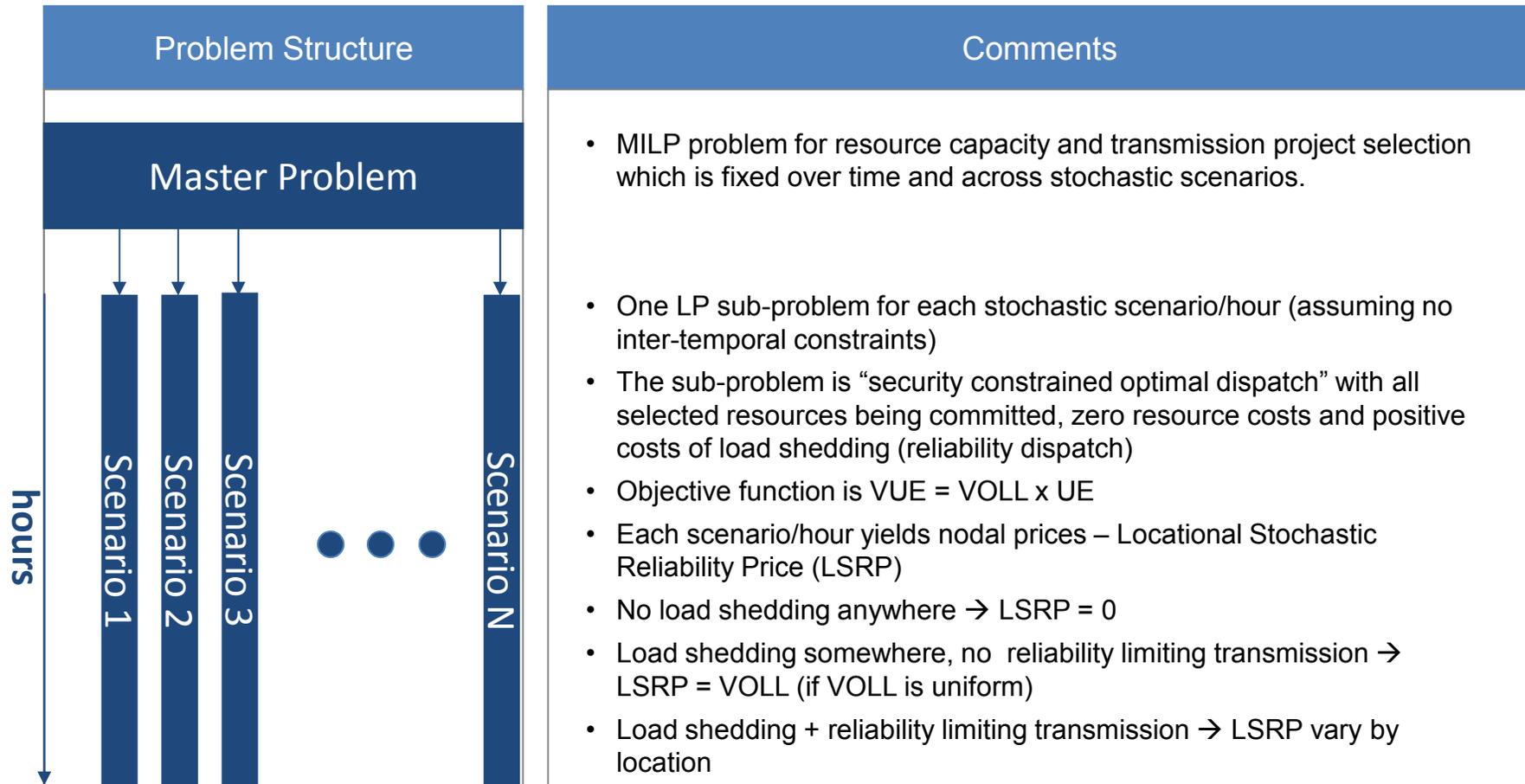
Market Engine Inputs

Input	Explanation/Source
Detailed transmission model (DC linearization)	Transmission topology which will be changing over planning horizon by incorporating transmission developers' offers (specific projects to include into the load flow model, offer prices)
Transmission outages	Based on historical statistics or engineering estimates
Generators offers	Price/quantity pairs: CRRs and installed capacity for existing and new capacities
Generator availability	Stochastic processes with parameters estimated per GADS
Stochastic demand	Stochastic variations around demand forecasts developed by LSEs or System Operator
DR offers	Price/quantity pairs: CRRs and levels of demand reduction below forward contracts to purchase power
Load shedding model	Locational levels of load shedding potential and associated VOLLs set administratively and/or specified by large buyers. Could be represented by locational VOLL curves

Auctioneer's Optimization Problem

Problem Structure	Comments

Problem Structure:

Master Problem

hours

Scenario 1 | Scenario 2 | Scenario 3 | • • • | Scenario N

Comments:

- MILP problem for resource capacity and transmission project selection which is fixed over time and across stochastic scenarios.

- One LP sub-problem for each stochastic scenario/hour (assuming no inter-temporal constraints)
- The sub-problem is "security constrained optimal dispatch" with all selected resources being committed, zero resource costs and positive costs of load shedding (reliability dispatch)
- Objective function is VUE = VOLL x UE
- Each scenario/hour yields nodal prices – Locational Stochastic Reliability Price (LSRP)
- No load shedding anywhere → LSRP = 0
- Load shedding somewhere, no reliability limiting transmission → LSRP = VOLL (if VOLL is uniform)
- Load shedding + reliability limiting transmission → LSRP vary by location

Resource Capacity Price (RCP)

$$RCP_j = \mathbf{E}\sum_t \bar{S}_j(t,\omega)\max\left(0, LSRP_j(t,\omega)\right) - \mathbf{E}\sum_t \underline{S}_j(t,\omega)\max\left(0, -LSRP_j(t,\omega)\right)$$

- Resource capacity price is the difference between the reliability value of the option to use 1 MW of capacity when it is needed and the reliability cost of the obligation to use 1 MW of capacity when it is not needed

$\bar{S}_j(t,\omega)$ and $\underline{S}_j(t,\omega)$

  - p.u. maximum resource availability and low bound operational limitation, respectively
- <u>Ultimately, the resource offer is</u>
    - Accepted fully if offer price is below RCP$_j$
    - Rejected fully if offer price is above RCP$_j$
    - Accepted partially (marginal) if offer price is equal to RCP$_j$
- In the auction settlement, resources are paid RCPs for each MW of accepted installed capacity

Load Capacity Prices (LCP) and the Overall Settlement

$$LCP_j = \mathbf{E}\sum_t LSRP_j(t,\omega)\left[\frac{L_j(t,\omega) - u_j(t,\omega)}{D_j}\right]$$

- Load payment depends on served load simulated in each scenario: *load pays for reliability only to the extent it is not interrupted at the time when others are*
- Depending on consumption patterns and/or level of interruption loads at the same location may pay different capacity prices
- Prices are defined per unit of projected peak demand
- Projected peaks are used as a billing determinants in the auction settlement

$$\sum_j D_j LCP_j = \sum_j X_j RCP_j + \text{ReliabilityRent}, \quad \text{ReliabilityRent} \geq 0$$

- Reliability rent equals the expected value of total reliability limited value of transmission constraints and is never negative
- The Auctioneer is never revenue deficient
- Reliability rent provides the fund to pay for transmission investments

Reliability Rent

- Reliability rent (RR) is the sumproduct of shadow prices for binding transmission constraints and constraint limits in each stochastic realization of reliability dispatch (similar to congestion rent in dispatch)

- Important:
$$\mathbf{E}(\sum_t RR) \gg RR[@\mathbf{E}(LCP)]$$

- Reliability value of transmission must be captured at each stochastic realization of reliability dispatch. It cannot be estimated from expected values of capacity prices

- Loads pay for transmission simply by paying locational capacity prices

- Transmission offers are formulaically compensated from RR and RR is sufficient to cover the costs of accepted transmission offers

How generation and transmission are paid for in this capacity market

MCC = $90/kW-yr

Z   MCT = $120/kW-yr   **w**

MCC = $90/kW-yr
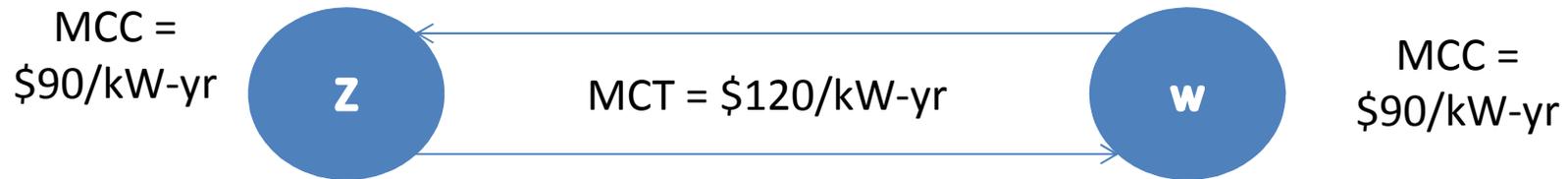
Assuming VOLL = $10/kWh, at optimum we have:

$MLOLHz = MLOLHw$ = 9 hrs/yr

$BRLHz,w$ = 12 hrs/yr

$RLHz,w = RLHw,z$ = 6 hrs/yr

(note that reducing transmission capacity by 1 kW saves $120/yr but requires to build 1 kW at *z* and 1 kW an *w* which is $180/yr)

The system will be in global shortage for 3 hrs/yr. In addition, individual zones are in local shortage for 6 hrs each

During 3 hrs of global shortage uniterrupted load = available generation. Load pays $10/kWh, generators collect $10/kWh, payments and receipts are in balance

During 6 hours of local shortage Uninterrupted load in Zone = Gen in Zone + TTC into zone. Load pays $10/kWh to Gen in Zone and $10/kWh in reliability rent to transmission providers. Payments and receipts are in balance

<u>Therefore</u>:

Loads pay $90/kW-yr, Generators collect $90/kW-yr and Transmission collects $120/kW-yr

Both generation and transmission expansions are fully paid for by loads through capacity prices!

Conclusions

- Resource adequacy criteria currently used in practice are not suitable for constrained power systems
- Presently used approaches likely lead to excessive reserve margins and suboptimal allocation of generation capacity between zones. Moreover, contribution of transmission to resource adequacy and tradeoffs between generation and transmission expansion are often overlooked
- More precise location-based indicators of resource adequacy in the form of MLOLH and BRLH should be applied in system planning and capacity market design
- In a "stand-alone" implementation, these locational resource adequacy indicators provide locational (decentralized) investment signals for generation and transmission developers
    - They are useful for centralized planning approaches
    - They are most suitable for the market driven system expansion environment
- Stochastic co-optimization of generation and transmission expansion based on total cost criterion ensure resource adequacy without the need to impose special reliability criteria
- Capacity market for generation and transmission utilizing stochastic optimization base market engine can provide:
    - market-based solution for co-optimization of generation and transmission investments;
    - Unambiguous price based mechanism for investment cost recovery without the need for special cost-allocation schemes
- Industry needs the tool which can do it
- Industry has to recognize this need and encourage the OR and software community to develop one

Additional Materials

- A.M. Rudkevich, A.I. Lazebnik, I.S. Sorokin, "A Nodal Capacity Market to Assure Resource Adequacy." IEEE Proceedings of the 45th Hawaii International Conference of System Sciences. January, 2012

- A.M. Rudkevich, A.I. Lazebnik, I.S. Sorokin, "Economically Justified Locational Criteria of the Security of Supply." Presented at the 9th International Conference on European Energy Markets, Florence, Italy, May 10-12, 2012

- A.M. Rudkevich, "A Nodal Capacity Market for Generation and Transmisson Investments." *In preparation*

Contact Information

Alex Rudkevich

Newton Energy Group

arudkevich@negll.com

Telephone: +1-617-340-9810 (office)

+1-617-417-6688 (mobile)