Decision support models in electric power systems

Generation reliability

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Topic objectives

- To understand
  - Why reliability must be studied
  - Where does reliability appear
  - How to assess the reliability
  - What is a probabilistic production cost model (PPC) by analytical simulation
  - How unit output is computed
  - How to compute some generation stochastic reliability measures

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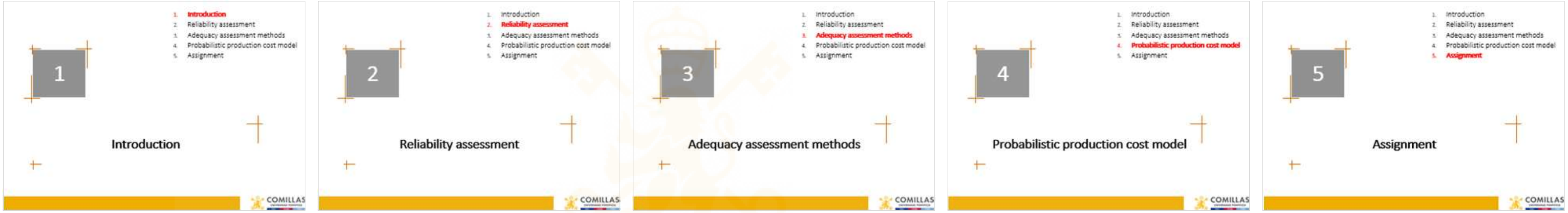

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1. Introduction
2. Reliability assessment
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4. Probabilistic production cost model
5. Assignment

1

Introduction

References

- Billinton, R. and Li, W. *Reliability Assessment of Electric Power Systems Using Monte Carlo Methods,* Springer, 2013.
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  - Good references about electric system reliability
  - Scope and insight that exceeds this presentation
- [IAEA, 84] "Chapter 7. Generating System Reliability", *Expansion planning for electrical generating systems, A guidebook.* International Atomic Energy Agency Technical report No 241. Vienna, Austria, 1984.

  (http://www-pub.iaea.org/MTCD/publications/PDF/TRS1/TRS241_Web.pdf)
  - Original source of part of this presentation
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- Vardi, J. and Avi-Itzhak, B. *Electric energy generation. Economics, reliability and rates.* The MIT Press, 1981.

Maintenance scheduling

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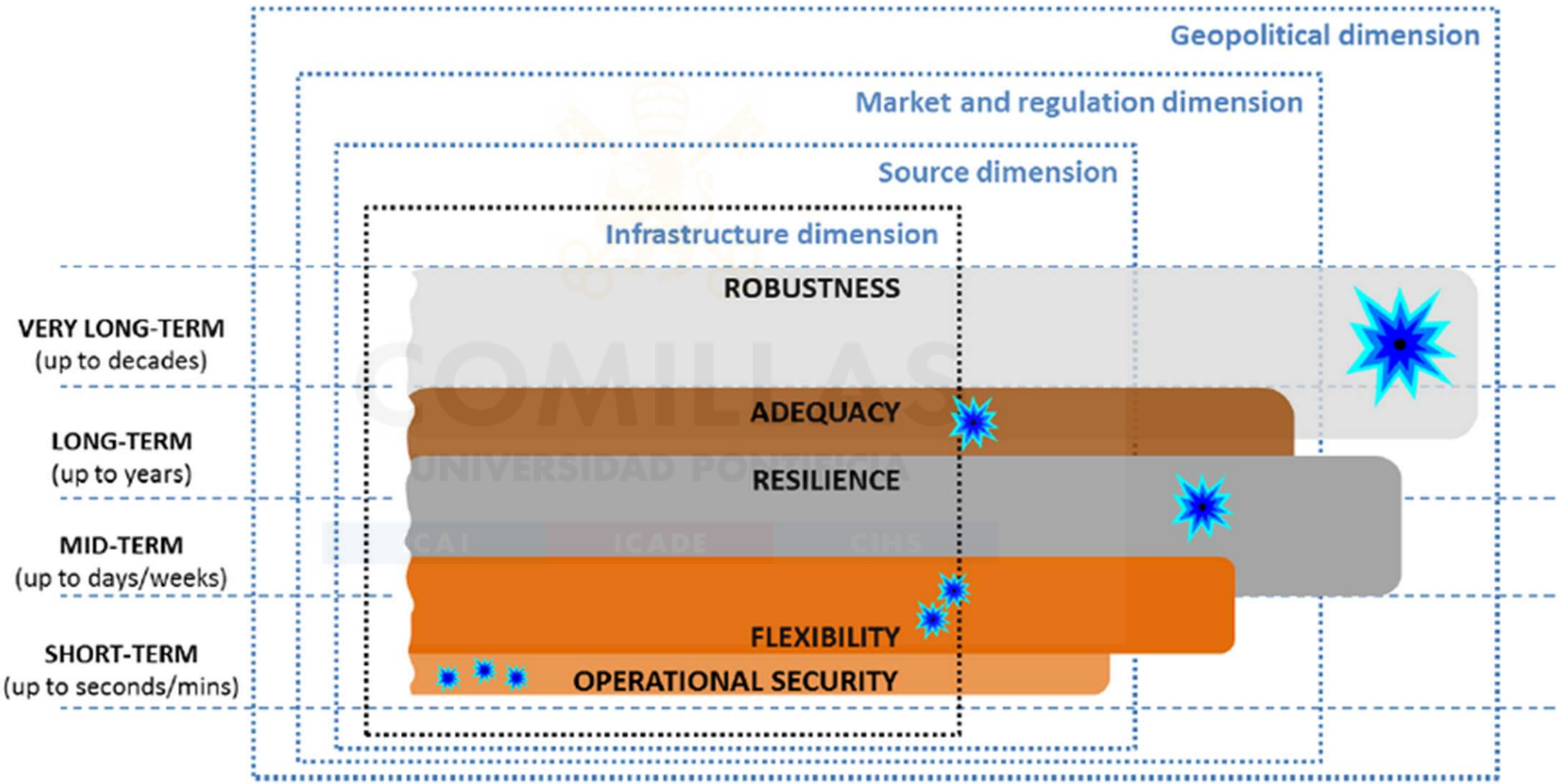
- L. Muñoz and A. Ramos *Goal programming approach to maintenance scheduling of generating units in large scale power systems* IEEE Transactions on Power Systems 14 (3): 1021-1027 Aug 1999 10.1109/59.780915

What is reliability?

- Adequacy (long-term)
  - The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements [ENTSO-E]
- Firmness (medium-term)
  - Firmness requires that enough supply infrastructure is available when needed and mainly depends on the operation planning activities of the already installed capacity: maintenance schedules, reservoir management, etc.
- Security (short-term)
  - The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements [ENTSO-E]

Electricity security



https://ses.jrc.ec.europa.eu/electricity-security

Reliability in electricity markets

- Currently, in electric markets, nobody speaks about the reliability
- We talk about
  - Long-term capacity payments (price set centrally)
  - Capacity markets (volume set centrally)
  - Reliability options (the unit receives money to be available in critical periods, those with a market price above a certain threshold)
  - Long-term reserve contracting
- However, all these topics are very closely related to reliability (adequacy)

L. Söder et al. *Review of wind generation within adequacy calculations and capacity markets for different power systems* Renewable & Sustainable Energy Reviews 119, March 2020 10.1016j.rser.2019.109540

Reliability targets and capacity markets

Area	Reliability Target	Capacity market	Capacity market horizon
Sweden	High reliability with reasonable cost	Strategic reserve	Tender for one year at the time
Great Britain	3 h LOLE/year	Centralized, with required capacity auctioned off in a transparent manner with 'pay as clear' auctions	Two auctions - 4 years and 1 year ahead of the delivery year
France	LOLE = 3 h	Decentralized Capacity market (obligation on suppliers)	Regular auctions, beginning 4 years ahead the delivery year.
Ireland	LOLE = 8 h	Two-part auction with unconstrained (pay as clear) and constrained (pay as bid) mechanisms	Two auctions - 4 years and 1 year ahead of the delivery year
US-PJM	One day, on average, every 10 years	Capacity Market	One Base Residual Auction and three Incremental Auctions per delivery year.
US-ERCOT	13.75% target reliability margin	None	N/A
Finland	High reliability with reasonable cost	Strategic reserve	Tender every three years
Portugal	LOLE = 5 h	Strategic reserve[a]	Long term (CAE/CMECs)/annual (auction)
Spain	Firm capacity = 110% of peak load	Targeted capacity payment	Investment incentive: first 10 years of operation; Availability incentive: annual payment
Norway	"Goal of secure power supply"	Seasonal and weekly reserve options "RKOM"	N/A
Denmark	"Keep a high reliability"	Time limited Strategic reserve in future is possible for Eastern Denmark network	N/A
Belgium	LOLE 3 h/year and 20 h for a once in 20 year	Strategic reserve	Tender for one year at the time with updated reserves volumes based adequacy assessment executed by the TSO
Germany	No reliability target	Capacity reserve, standby reserve, grid reserve	No market, regulated by theFederal Network Agency
Italy	LOLE defined by the Italian Ministry of Economic Development	Central-buyer market-wide mechanism, where reliability options are traded	Delivery period: 1 year for the main auctions, then monthly products can be traded in a secondary market.
Netherlands	LOLE = 4 h	None	N.A.

[a] In Portugal is in a transition phase and still exist earlier long-term capacity payments mechanisms.

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Reliability assessment

Reliability assessment

- Reliability index
  - Parameter that measures a particular aspect of the reliability of an electric system
    - We are going to consider only generation
- The most relevant aspects being assessed by reliability indexes are:
  - Duration of failures
  - Incidence of failures
  - Number or frequency of failures
- There is no index able to assess the total reliability, including all the aspects

Reliability criterion in Generation Expansion Planning

- Reliability is a crucial aspect of long-term generation expansion planning studies
  - The more installed capacity, the more reliability

1. Reliability criterion
   - Reliability standard or maximum value allowed for a reliability index for any expansion plan of an electric system
     - Constraint in the optimization problem
2. Cost associated with a reliability index in the design process of an electric system
   - Included in objective function as the cost of the not served electricity
3. In multiobjective optimization, reliability indexes are potential objective functions

Reliability criterion in Generation Expansion Planning

Minimize:

$\sum$ Operation costs + Investment costs

Subject to:

- Load supply
- Reliability index < maximum reliability index

Minimize:

$\sum$ Operation costs + Investment costs

+ Costs associated with not served energy

Subject to:

- Load supply

Minimize:

Objective function #1: $\sum$ Operation costs + Investment costs

Objective function #2: Reliability index

Subject to:

- Load supply

Reliability indexes classification

- Deterministic
  - Reflect the average behavior of the supply continuity
  - Do not consider stochasticity in the operation
  - Very frequently used
    - Intuitive
    - Simple to determine
    - Require few data to compute them
  - Easy comparison among systems
- Probabilistic
  - Do consider stochasticity in the operation
    - Unit failures
    - Load uncertainty
    - Hydro inflows
  - Offer more information of better quality than the deterministic indexes

Deterministic reliability indexes (i)

- Reserve Margin (*RM*):
  - Excess of generation capacity available to satisfy the yearly load demand

$$RM\left(MW\right) = Available\ generation\ -\ Maximum\ demand$$

$$RM\left(pu\right) = \frac{Available\ generation\ -\ Maximum\ demand}{Maximum\ demand}$$

  - The main characteristic is simplicity
    - Intuitive, easy to compute
    - Limited because it does not consider water reserves, sizes, or technologies

Deterministic reliability indexes (ii)

- Largest Unit (*LU*):
  - Potential unavailability of the largest unit
  - Beat the *RM* because it considers unit sizes

$$LU\left(pu\right) = \frac{RM\left(MW\right)}{\text{Largest unit power}}$$

$LU > 1 \rightarrow$ we can loss the largest unit

$LU < 1 \rightarrow$ if we loss the largest unit $\rightarrow$ not served energy

- Dry year:
  - Used in hydro-dominated systems
  - Criterion more than index
    - In the driest year (or drier year series) demand must be satisfied (deterministically)

Deterministic reliability indexes (iii)

- Generation system and load
  - Installed thermal power: 10000 MW
  - Installed hydropower: 3000 MW
  - Maximum forecasted load: 11500 MW
  - Largest unit: 1000 MW
  - Maximum hydropower in a dry year: 1300 MW
- Deterministic indexes

RM(*GW*)=(10+3-11.5)=1.5 GW → *excess of* 1.5 GW

RM(*pu*)=(10+3-11.5)/11.5=0.13 → *excess of* 13 % *of maximum load*

LU(*pu*)=(10+3-11.5)/1=1.5 → *excess of* 1.5 *largest unit*

Deterministic reliability indexes (iv)

- Deterministic reliability indexes in a dry year

  $RM(pu)=(10+1.3-11.5)/11.5=-0.017$ → *lack of -1.7 % of maximum load*

  $LU(pu)=(10+1.3-11.5)/1=-0.2$ → *lack of 20 % of the largest unit*

  → *In a hydrothermal system, things change in a dry year*

- Power needed for a reliability criterion *RM* > 2 GW

  $RM(MW)=(10+3+P_{NEW}-11.5)=2$ GW → $P_{NEW}= 0.5$ GW

- Power needed for a reliability criterion *RM* > 2 GW in a dry year

  $RM(MW)=(10+1.3+P_{NEW}-11.5)=2$ GW → $P_{NEW}= 2.2$ GW

Probabilistic reliability indexes: *LOLP* and *LOLE* (i)

- Loss Of Load Probability (*LOLP*):
  - According to the name, should be defined as the probability of being unable to satisfy all the power with the available generation
  - However, it usually is measured in the number of hours or days in a year with insufficient generation. For example, 0.1 day/year
- To avoid this double and ambiguous definition, Billinton defines the Loss Of Load Expectation (*LOLE*):
  - Number of days (hours) in a year that we expect not to satisfy the demand with the available generation

$$LOLP = \frac{LOLE}{365\ days \quad o \quad 8760\ hours}$$

Probabilistic reliability indexes: *LOLP* and *LOLE* (ii)

- The most frequently used reliability indexes
- No information regarding:
  - Duration and frequency of failures
  - Incidence of loss of load
- *LOLP* or *LOLE* can be calculated with the following:
  - Not to serve the 365 daily load peaks in a year
  - Not to serve the 8760 hourly loads in a year
- For the same system, *LOLP* values obtained are greater for the first case
  - Example: loss of load in just the maximum demand hour

$$LOLP_N = \frac{LOLE}{N}$$

$$LOLP_{365} = \frac{1}{365} > LOLP_{8760} = \frac{1}{8760}$$

Probabilistic reliability indexes: *LOLP* and *LOLE* (iii)

- Generation system and load
  - Unit 1:
    - Output: 1000 MW
    - Equivalent Forced Outage Rate (*EFOR*): 0.05 (5%)
  - Unit 2:
    - Output: 900 MW
    - Equivalent Forced Outage Rate (*EFOR*): 0.04 (4%)
  - Forecast maximum load:
    - Case A: 1100 MW
    - Case B: 800 MW
- *LOLP* case A: there will be a loss of load for any unit failure

$$LOLP_A = 0.05 + 0.04 - 0.04 \cdot 0.05 = 0.088\ (8.8\%)$$

- *LOLP* case B: there will be a loss of load only when both units fail

$$LOLP_B = 0.05 \cdot 0.04 = 0.002\ (0.2\%)$$

- *LOLP* > 0, because there is always a probability, and it can be very small, of failing all the units

Probabilistic reliability indexes : *LOEE* and *LOEP* (iv)

- Frequently used indexes, especially in systems with limited primary energy, such as hydrothermal ones
- Better than *LOLP* and *LOLE* because they consider the incidence of loss of load as not served energy
  - *LOLP* measures the probability of not serving demand. However, *LOLP* does not say anything about how much energy can be supplied
- Loss Of Energy Expectation (*LOEE*), widely known as Expected Energy Not Served (*EENS*) (Expected Unserved Energy EUE):
  - It is defined as energy expected not to be supplied in a year by generation unavailability or by lack of primary energy
- Loss Of Energy Probability (*LOEP*):
  - It is defined as the probability of not supplying a kWh with the available generation
  - As it is expressed in per unit, it allows comparing systems of different size

$$LOEP = \frac{EENS}{Total\ load}$$

Probabilistic reliability indexes: *POPM* and *XLOL* (v)

- eXpected Loss Of Load (*XLOL*) in MW:
  - Power we expect not to supply once the failure has occurred
  - It is also called eXpected Load Not Supplied (*XLNS*)

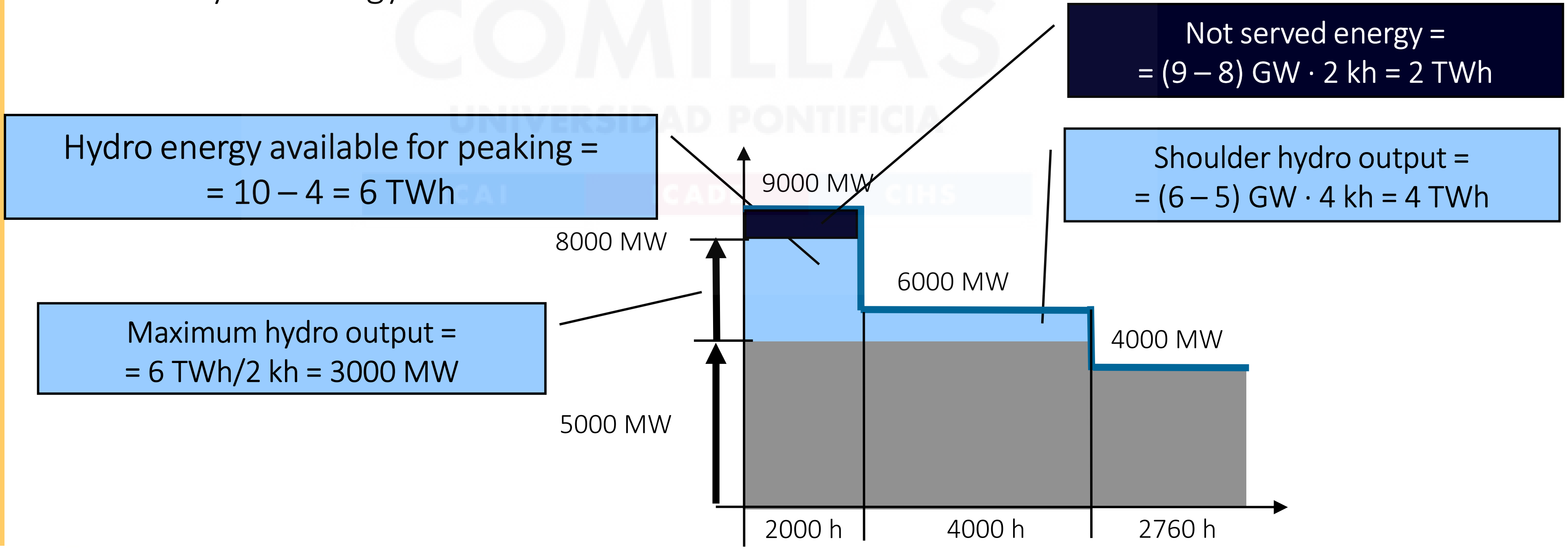
$$XLOL = \frac{EENS\ (MWh)}{LOLE\ (hours)} = \frac{EENS\ (MWh)}{LOLP \cdot 8760\ hours}$$

- Probability Of Positive Margin (*POPM*):
  - It is defined as the probability of satisfying the demand in the maximum yearly demand hour with the available generation
  - It is a probability of success

$$LOLP_N \leq 1 - POPM = LOLP_1$$

Probabilistic reliability indexes: *LOEE*, *LOEP* and *XLOL* (example 1)

- Generation system and demand
  - Peak: 2000 hours at 9000 MW (18 TWh)
  - Shoulder: 4000 hours at 6000 MW (24 TWh)
  - Off-peak: 2760 hours at 4000 MW (11.04 TWh)
  - Thermal capacity: 5000 MW (*EFOR*=0)
  - Hydro capacity: 5000 MW (*EFOR*=0)
  - Hydro energy: 10000 GWh



Probabilistic reliability indexes: *LOEE*, *LOEP* and *XLOL* (example 2)

- Reliability indexes

RM(*MW*)=(5+5-9)=1 GW → *excess of 1 GW*

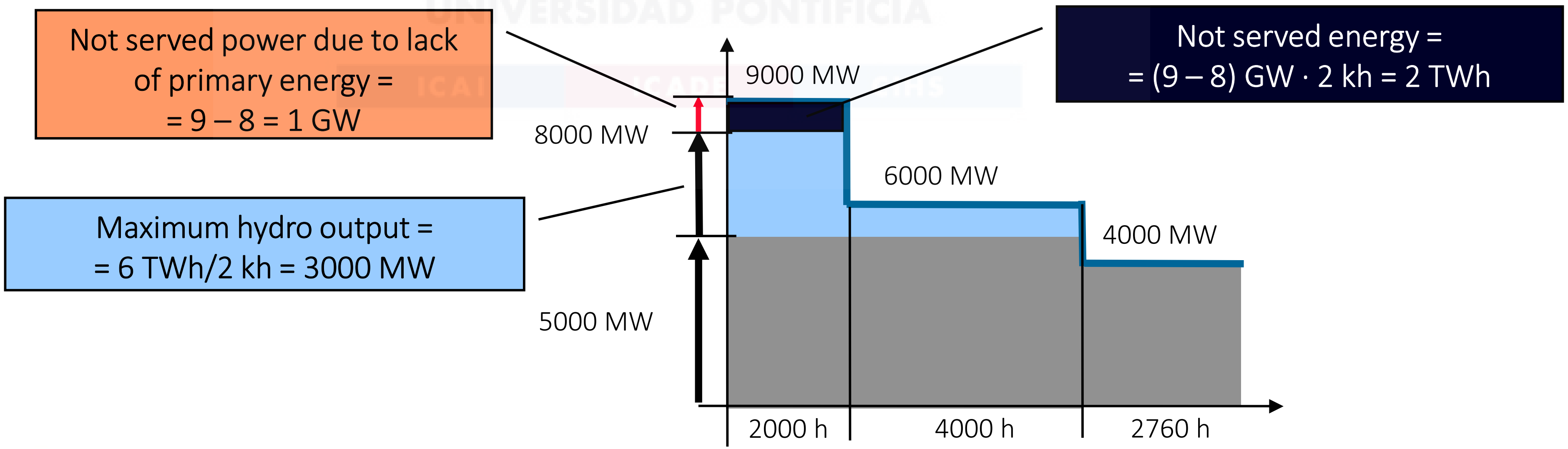
LOLE(*hours*)= 2000 hours → *lack of generation for 2000 hours*

LOLP(*pu*)=2000/8760=0.22 → *rationing 22 % of the time*

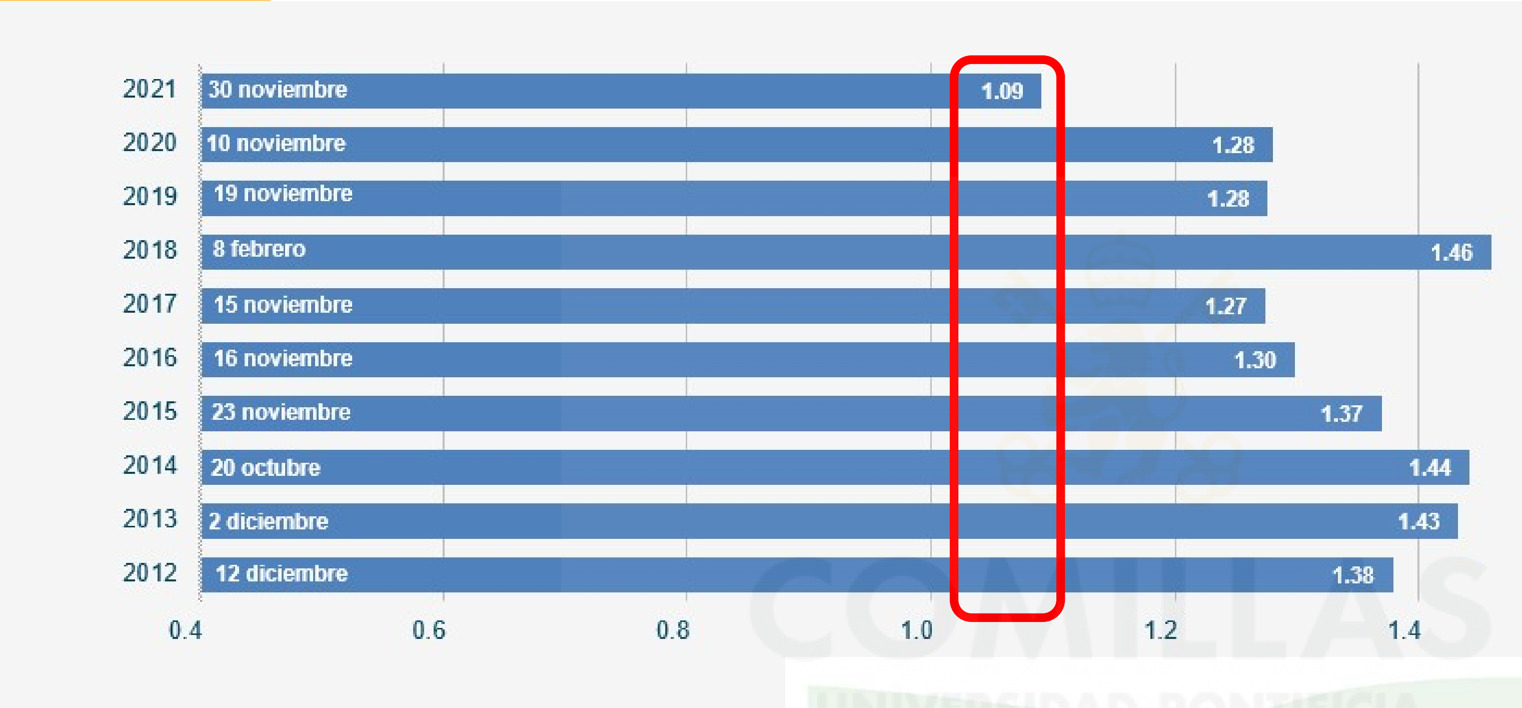
EENS(*GWh*)= 2000 GWh → *lack of primary energy*

LOEP(*pu*)=2 TWh/(2·9+4·6+2.76·4)TWh=0.0377 → *LOEP = 3.77 %*

XLOL(*GW*)= 2 TWh/2 kh = 1 GW → *lack of 1 GW when rationing*



Reserve margin (RM) of the Spanish system



ICmin = Min (Pd/Ps)

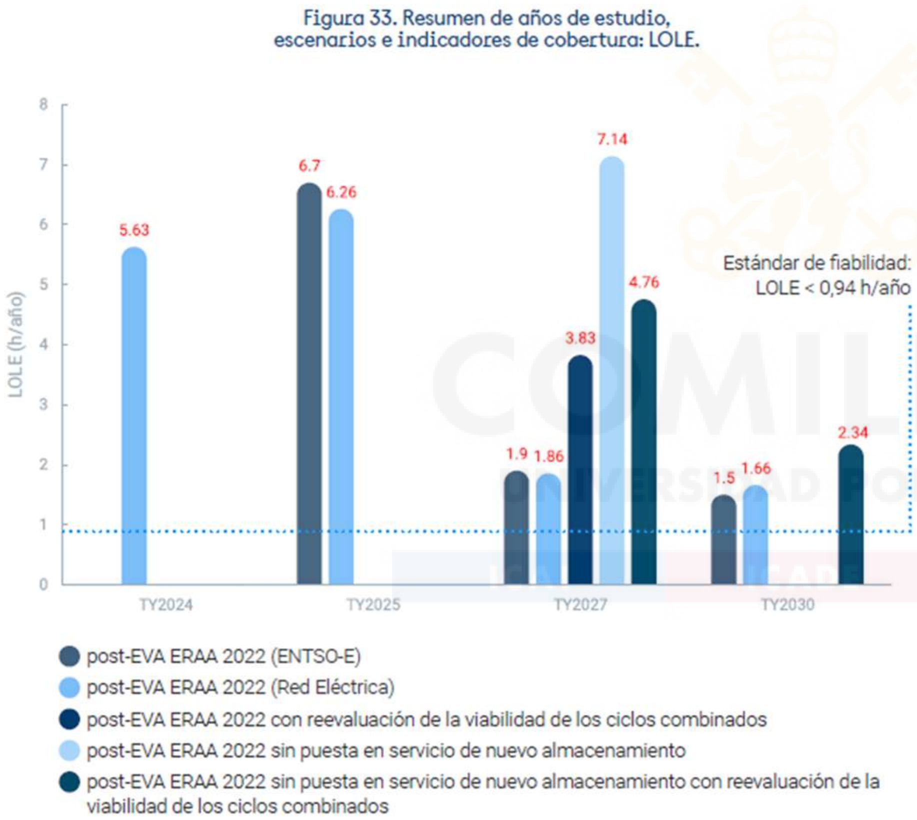
ICmin: Índice de cobertura mínimo.

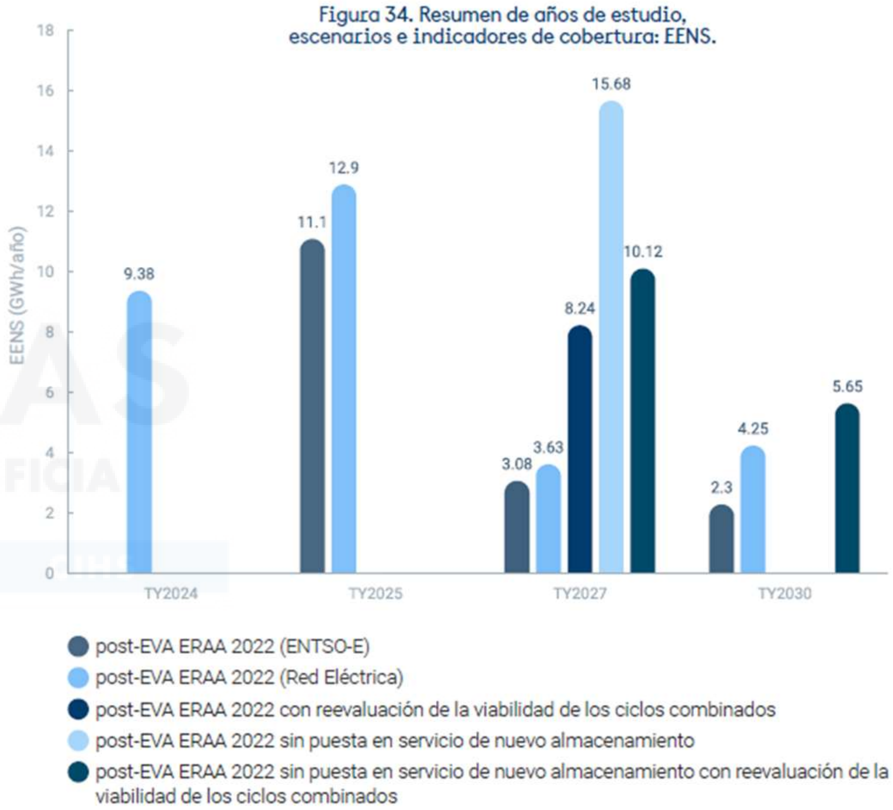
Pd: Potencia disponible en el sistema.

Ps: Punta de potencia demandada al sistema.

Source: REE

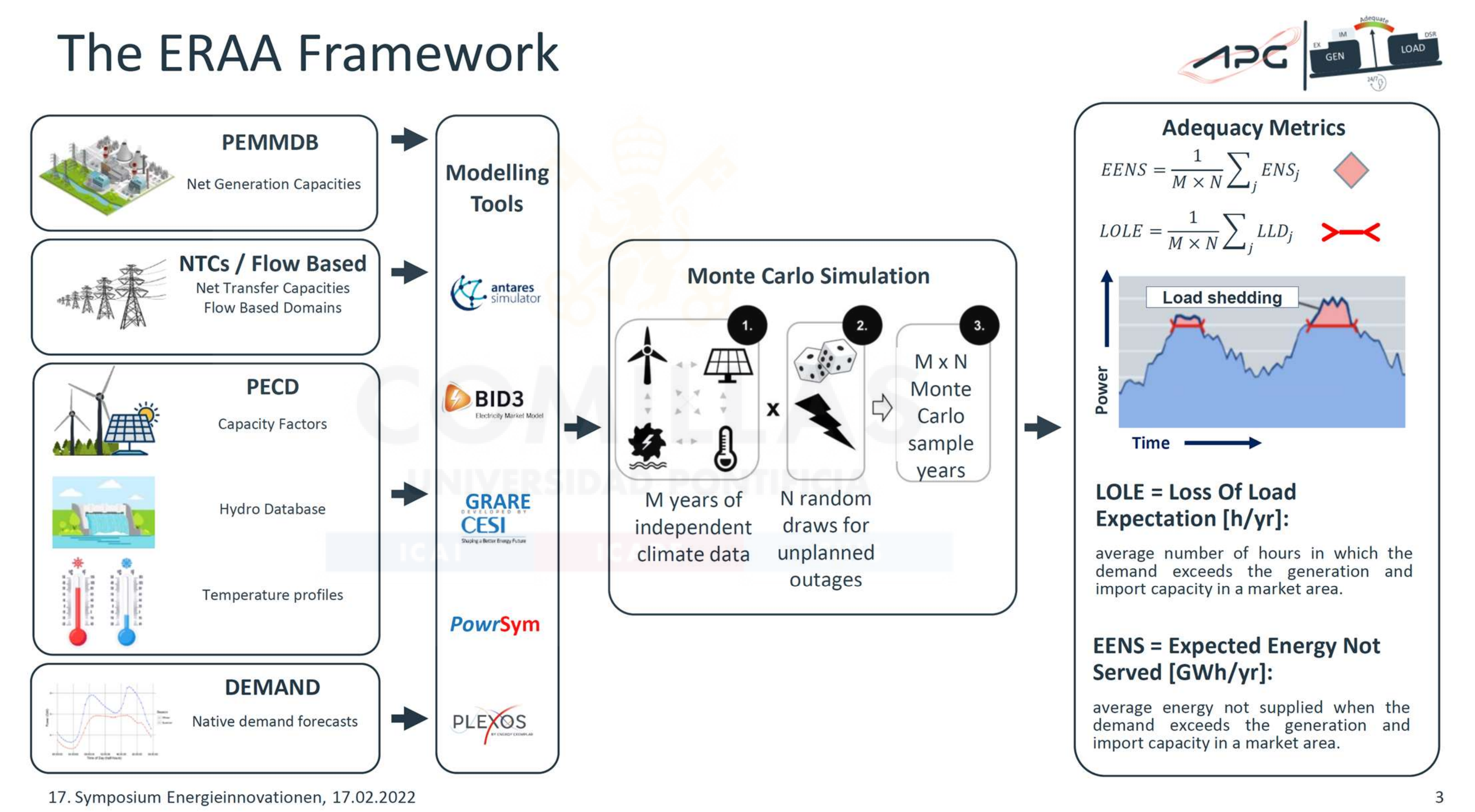
LOLE and EENS of the Spanish system 2024-2030



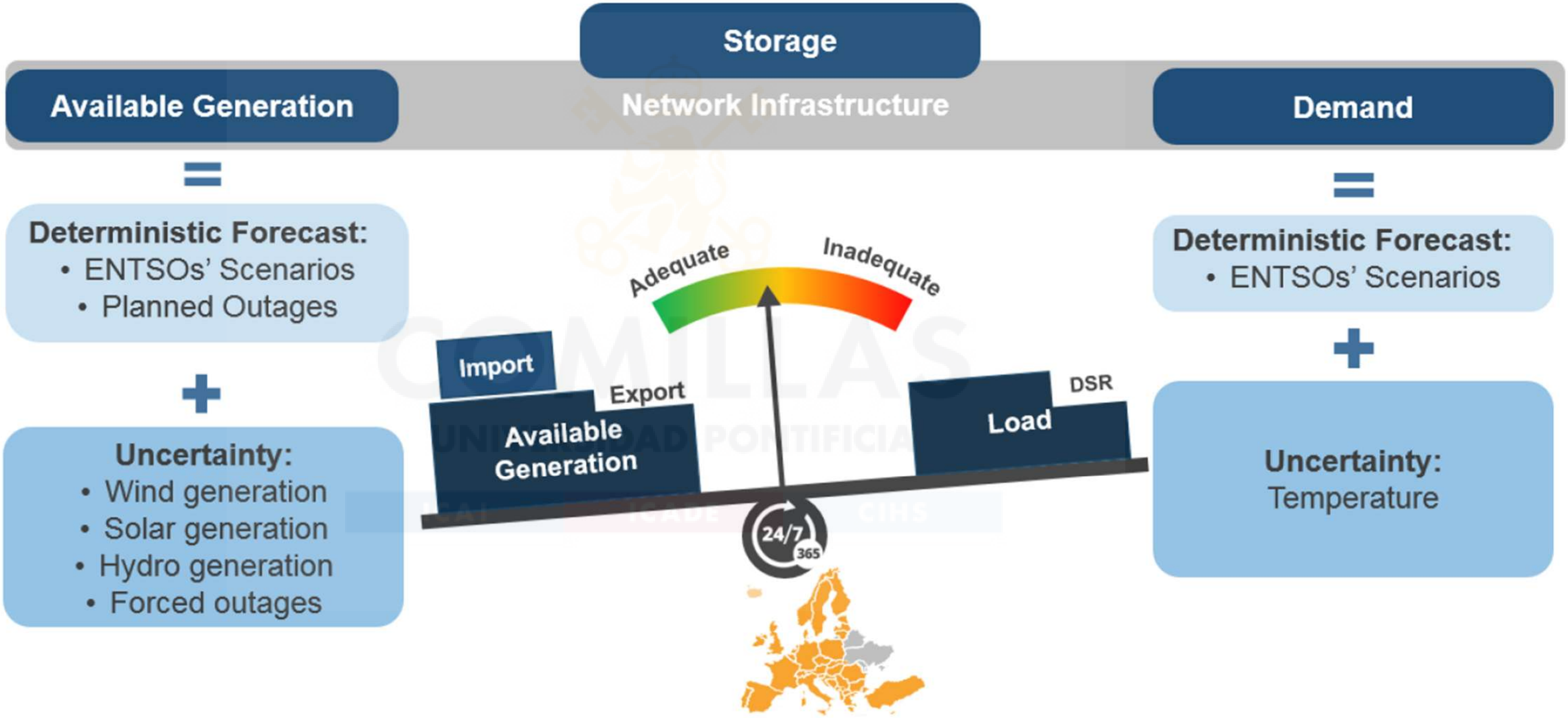


REE "Análisis nacional de cobertura del Sistema Eléctrico Peninsular Español" Octubre 2023
https://www.ree.es/sites/default/files/01_ACTIVIDADES/Documentos/informe_os_nov23.pdf

European Resource Adequacy Assessment (ERAA) 2023. Framework



European Resource Adequacy Assessment (ERAA) 2023. Methodological approach



European Resource Adequacy Assessment (ERAA) 2023

(https://www.entsoe.eu/outlooks/eraa/2023/)

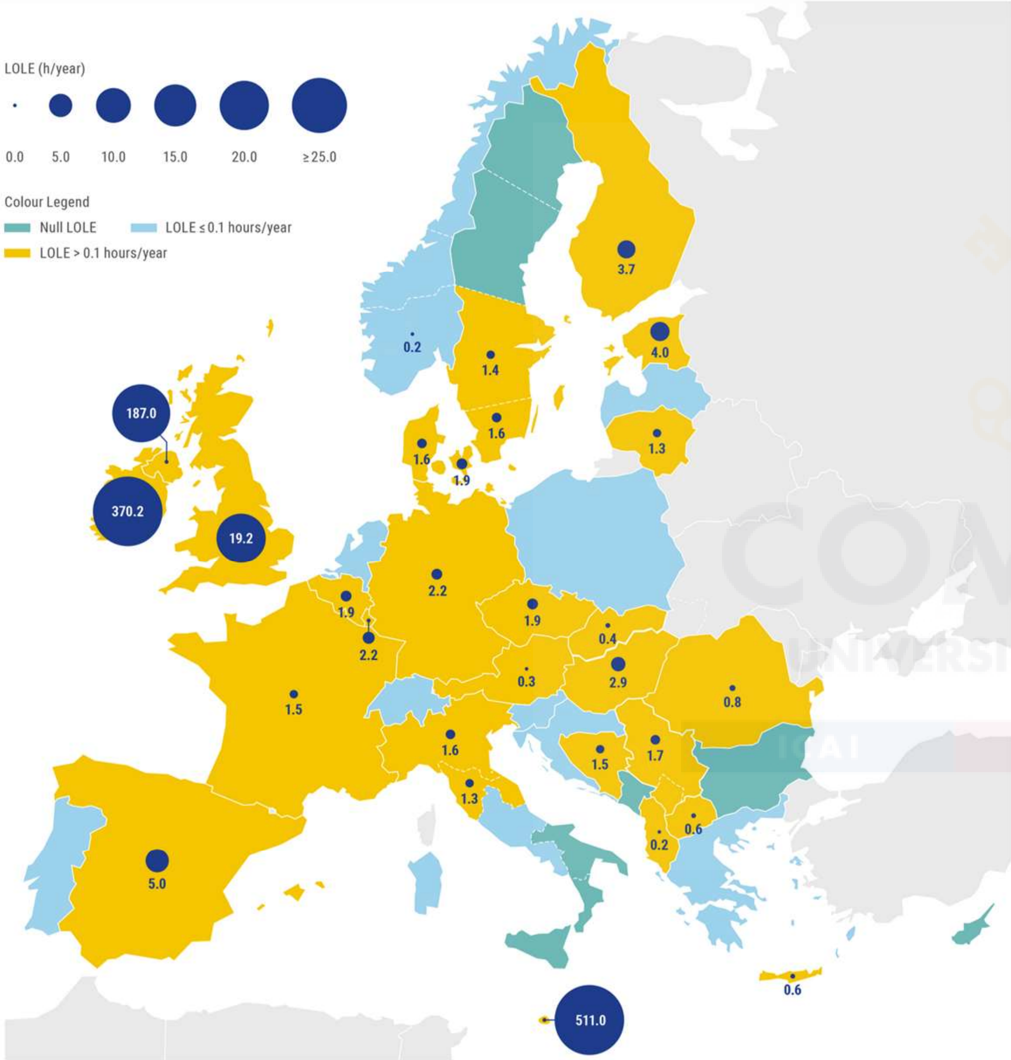


Figure 3: LOLE values in 2025* (Scenario A – Central Reference)

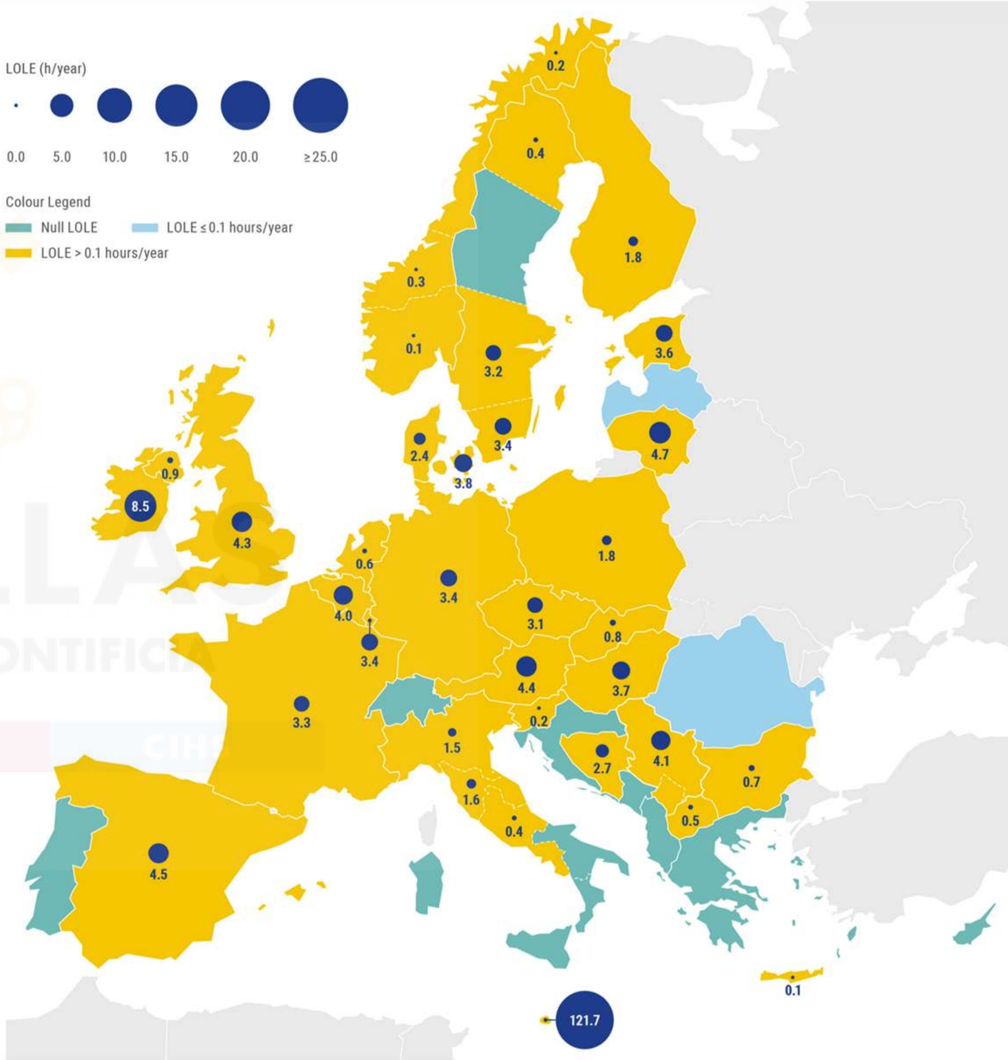
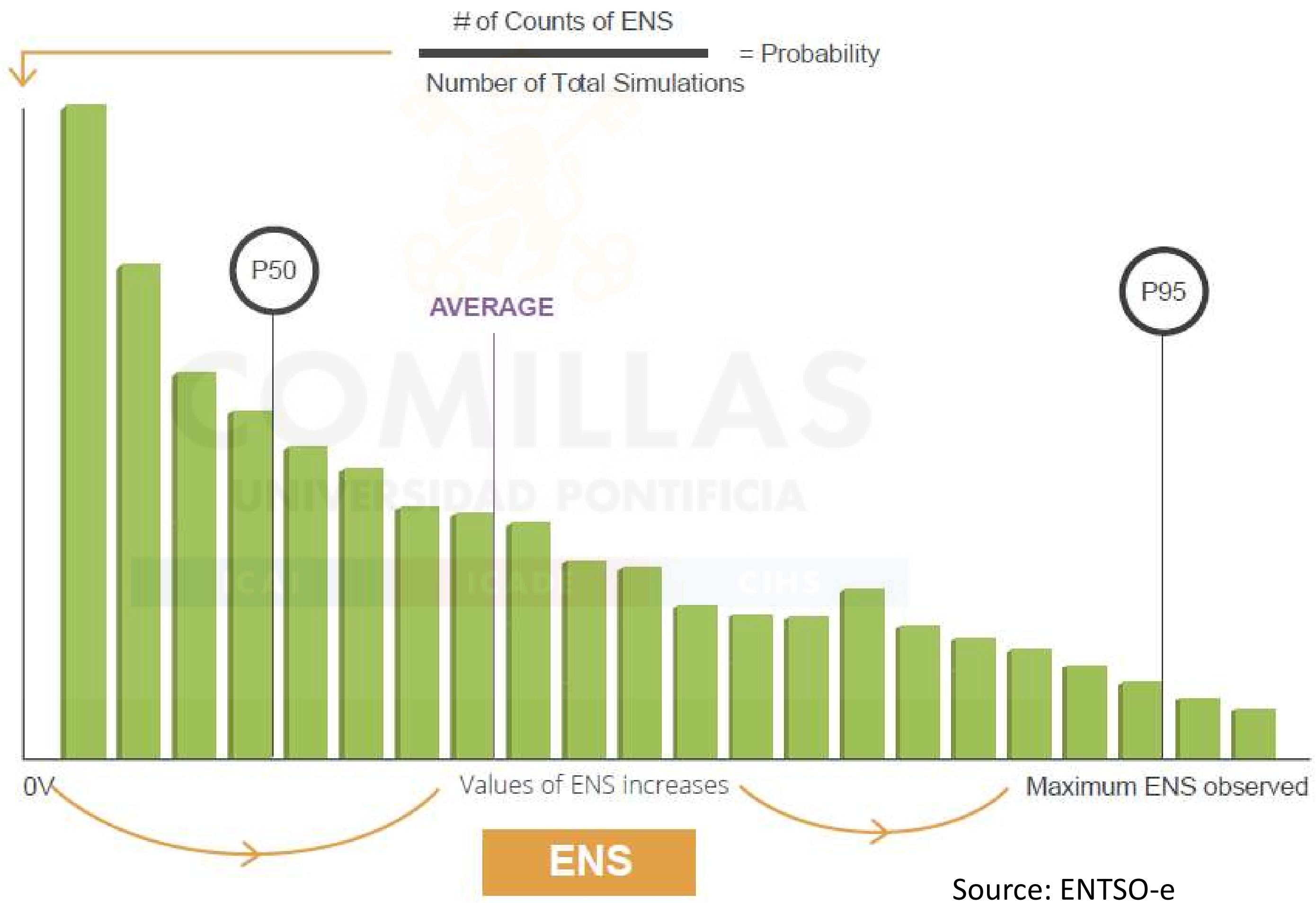


Figure 4: LOLE values in 2028 (Scenario A – Central Reference)

Mid-Term Adequacy Forecast (MAF) 2018. ENS distribution

(https://www.entsoe.eu/outlooks/maf/Pages/default.aspx)

https://www.entsoe.eu/Documents/SDC%20documents/MAF/MAF_2018_Methodology_and_Detailed_Results.pdf



Source: ENTSO-e

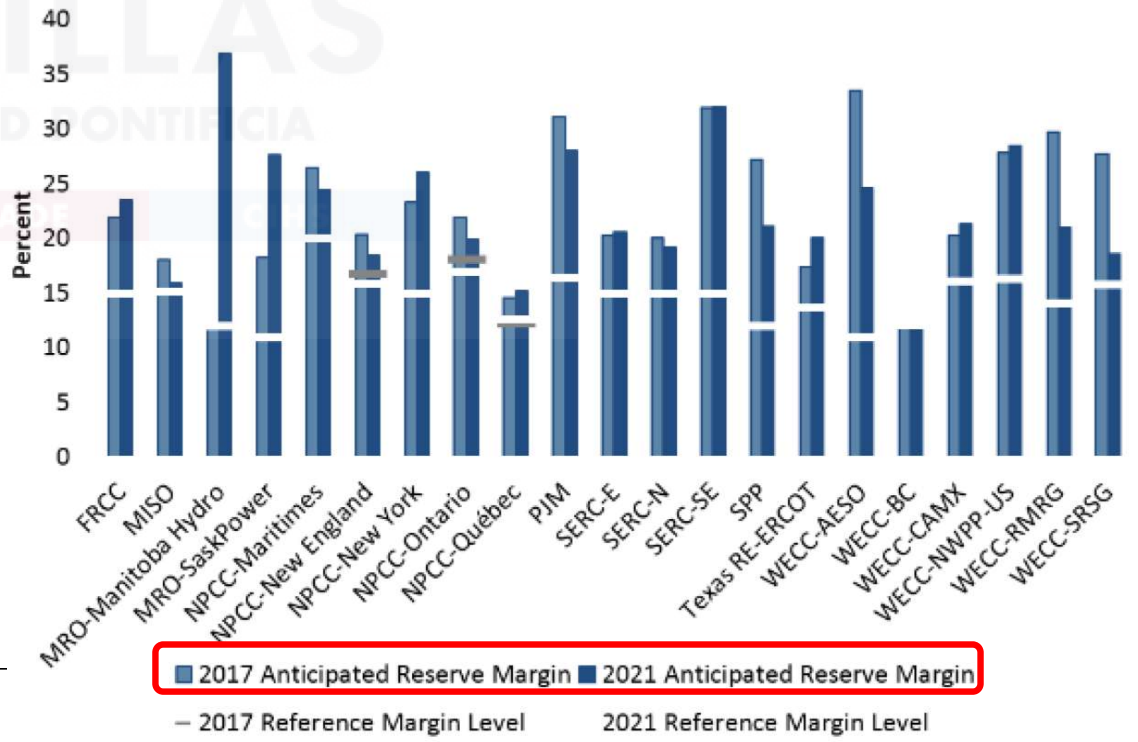
Capacity Markets (CM) in UK

https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-market-reform/capacity-market-cm-rules

- Auction to procure generation capacity 4 years ahead to be delivered
- Auction run annually with a single clearing price for all the capacity
- DR, storage, and interconnection eligible to participate
  - No newly built large-scale gas power plants. Old coal power plants longer than expected
  - 4 GW of small-scale diesel and gas engines, 500 MW of batteries (1 h of storage)
- New condition: 4 hours of sustained production

North American Electric Reliability Corporation (NERC)

- The Reliability Assessment and Performance Analysis program assesses, measures, and investigates historical trends and future projections to improve bulk power system reliability.
  - Long-Term Reliability Assessments annually assess the adequacy of the Bulk Electric System in the USA and Canada over ten years.
  - Summer and Winter analyses



Source: State of Reliability 2017 Report
http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.pdf

Resource Adequacy (EPRI)

Resource Adequacy

Decarbonization efforts are expected to drive fundamental change in electricity supply with significantly higher levels of variable and energy-limited resources and decreasing levels of dispatchable synchronous generation. A lower emission electricity sector will also be foundational for decarbonizing other energy sectors through electrifying segments of the transport, buildings, and industry sectors. With more of the energy economy dependent on the electricity sector, the reliability and resiliency of the supply of electricity will need to increase to meet societal expectations.

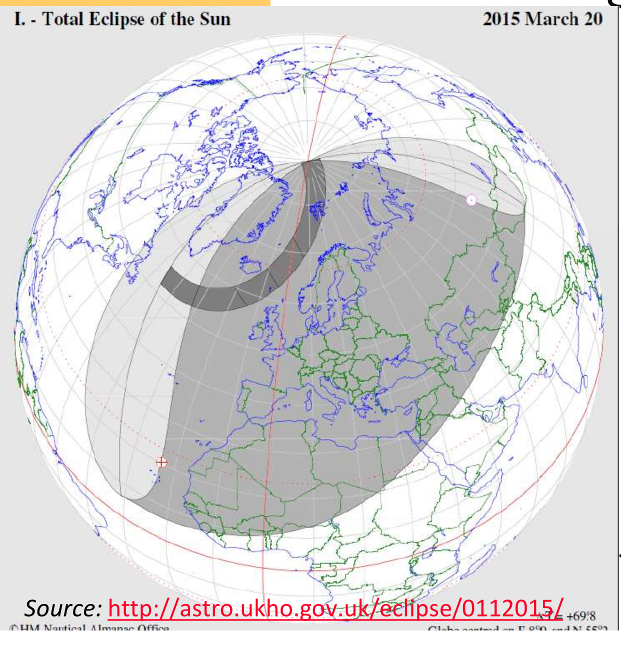
The initiative is focused on four key areas:

- **Developing metrics, criteria, and scenarios** to assess risk and guide investment decisions;
- **Creating models and data** to characterize how system resources perform under all operating conditions;
- **Accelerating the development of resource adequacy assessment tools** to advance new solutions benefiting society; and
- **Demonstrating the value of new approaches** through "real world" applications across diverse regions to guide employment of new processes.

https://www.epri.com/resource-adequacy

Resilience

- Ability of the electric system to cope with highly adverse conditions associated with climate and a combination of system contingencies whose probability of occurrence is above a certain threshold level.
- For example, temperatures increase to extreme values (hot waves in summer and cold waves in winter), decreasing water availability, storm events, low wind speeds, and cloudy weather over large areas, etc.



Source: http://astro.ukho.gov.uk/eclipse/0112015/

EPRI *Exploring the Impacts of Extreme Events, Natural Gas Fuel and Other Contingencies on Resource Adequacy* Jan 2021 https://www.epri.com/research/summary/000000003002019300

N. Abi-Samra *Power Grid Resiliency for Adverse Conditions* Artech House, 2017

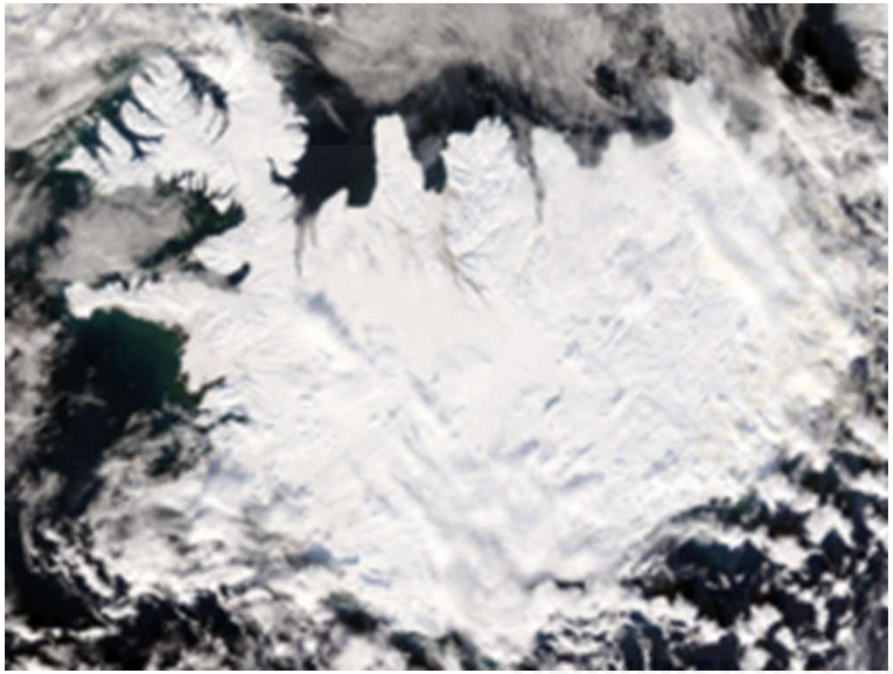
Y. Wang, Ch. Chen, J. Wang, and R. Baldick *Research on Resilience of Power Systems Under Natural Disasters-A Review* IEEE Transactions on Power Systems, 31 (2), 1604-1613, Mar 2016 10.1109/TPWRS.2015.2429656

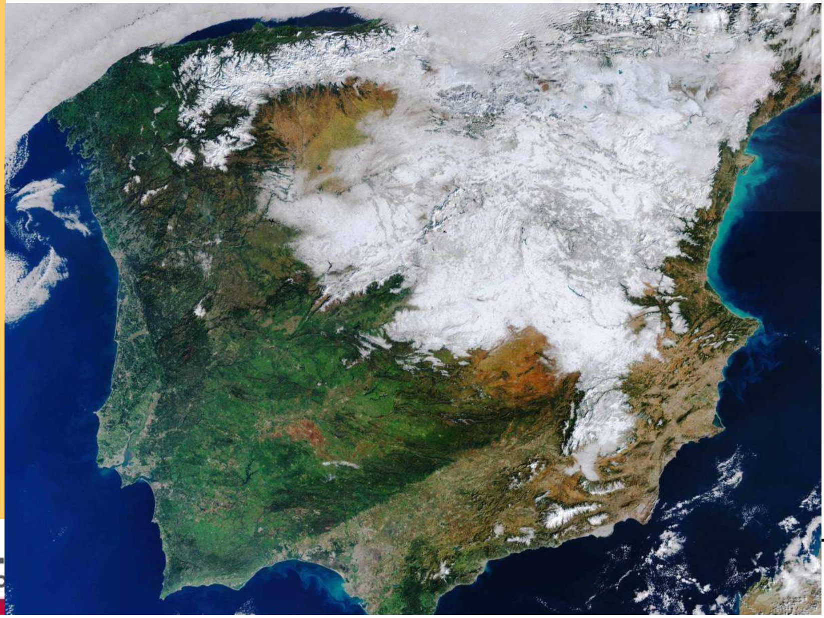
31 January 2011

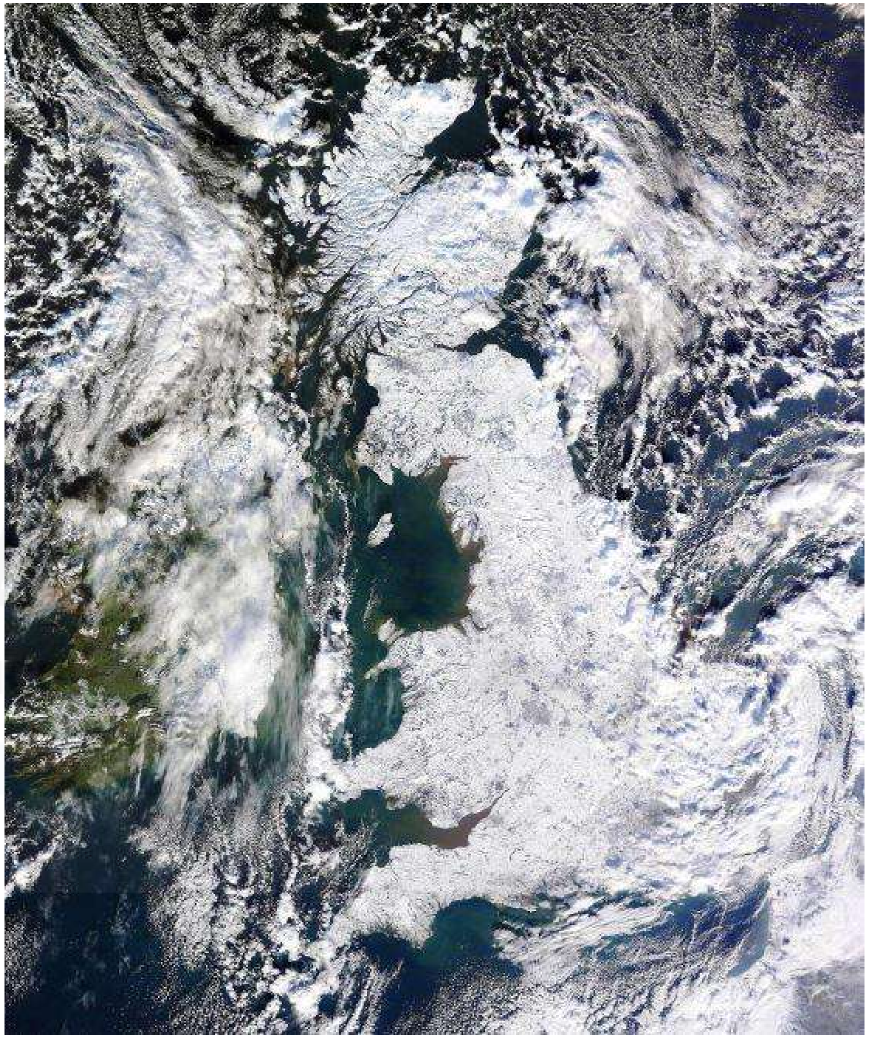
READi Insights: Extreme Heat Events and Impacts to the Electric System

https://www.epri.com/research/products/000000003002025522

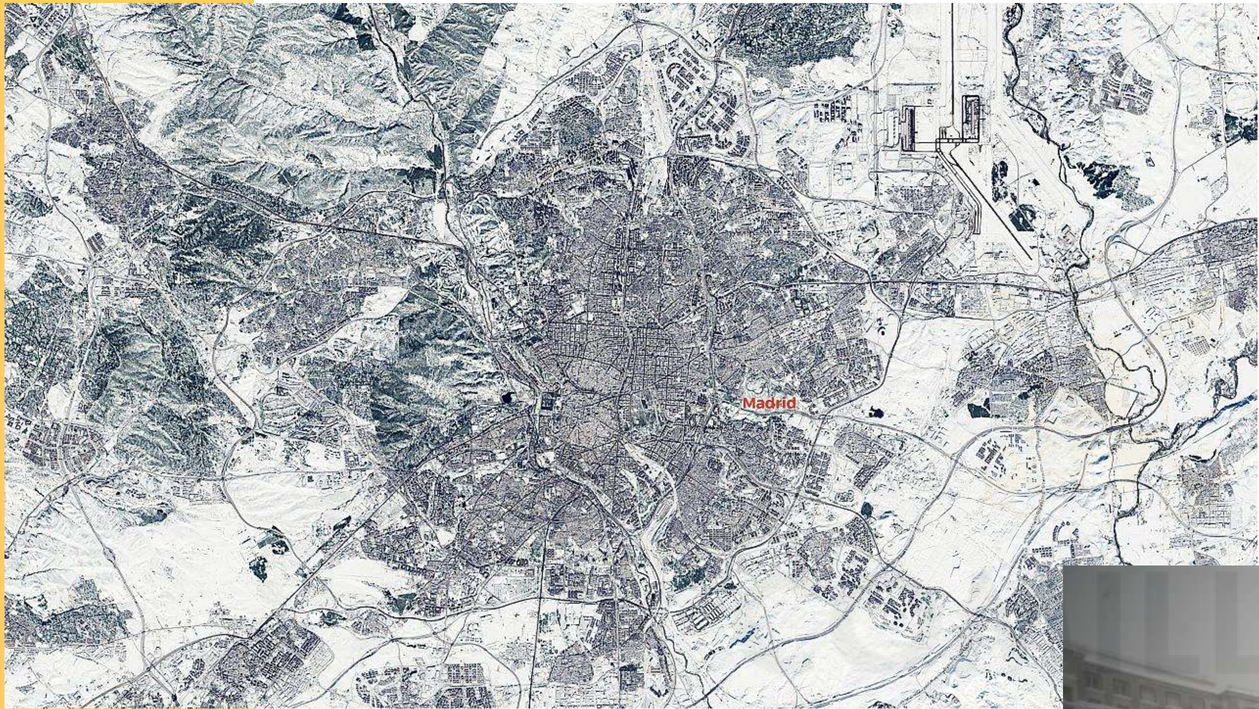
Iceland, Spain, and UK covered by snow







Madrid was covered by Filomena snowstorm. January 9th, 2021



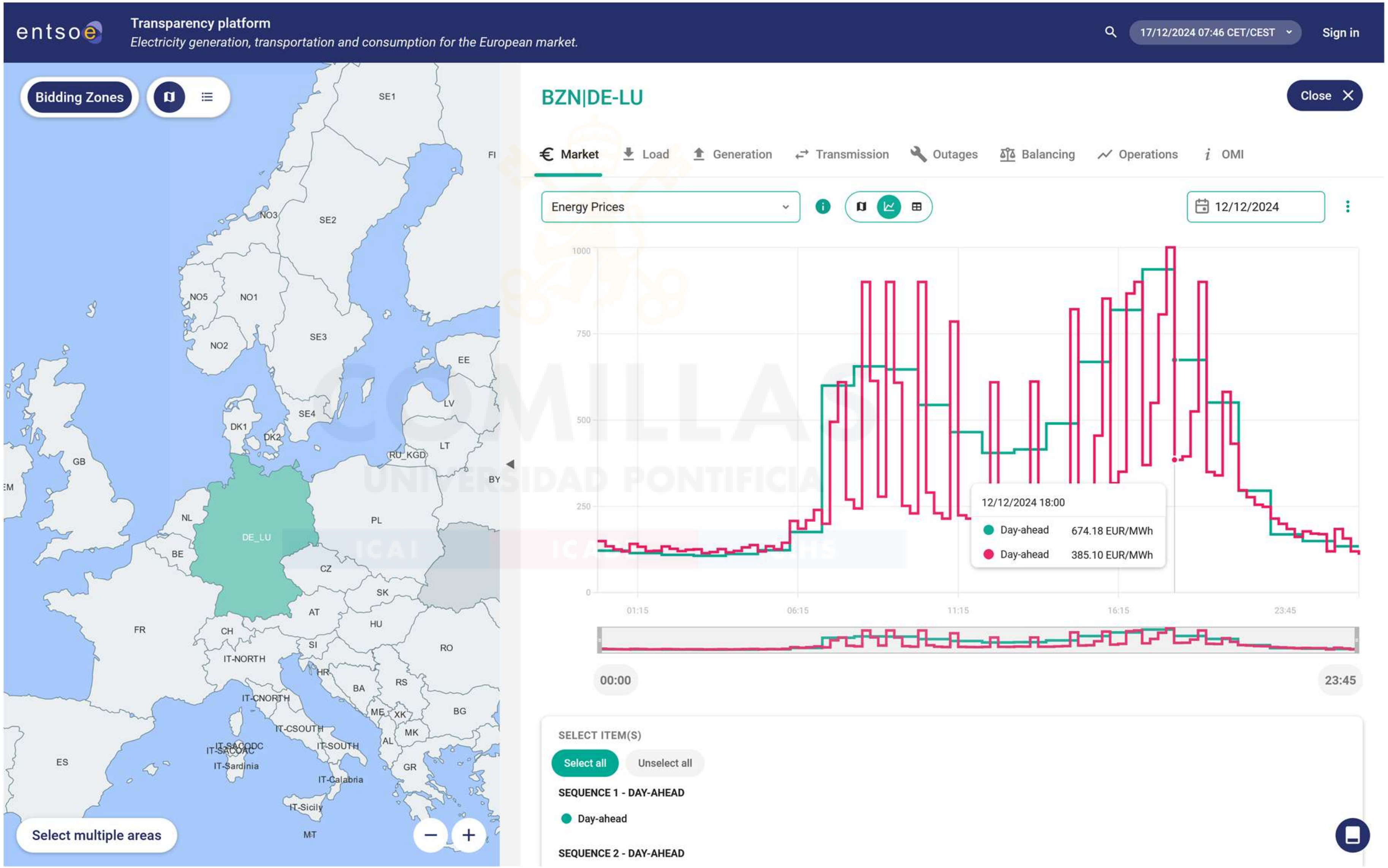
Only Happens Once
Every Fifty Years!!!

Source: Copernicus

Drought at Southeast of England

The driest in the last 256 years

German day-ahead hourly prices soared to an 18-year high of EUR 936.28/MWh (2024-12-11) [Dunkelflaute]



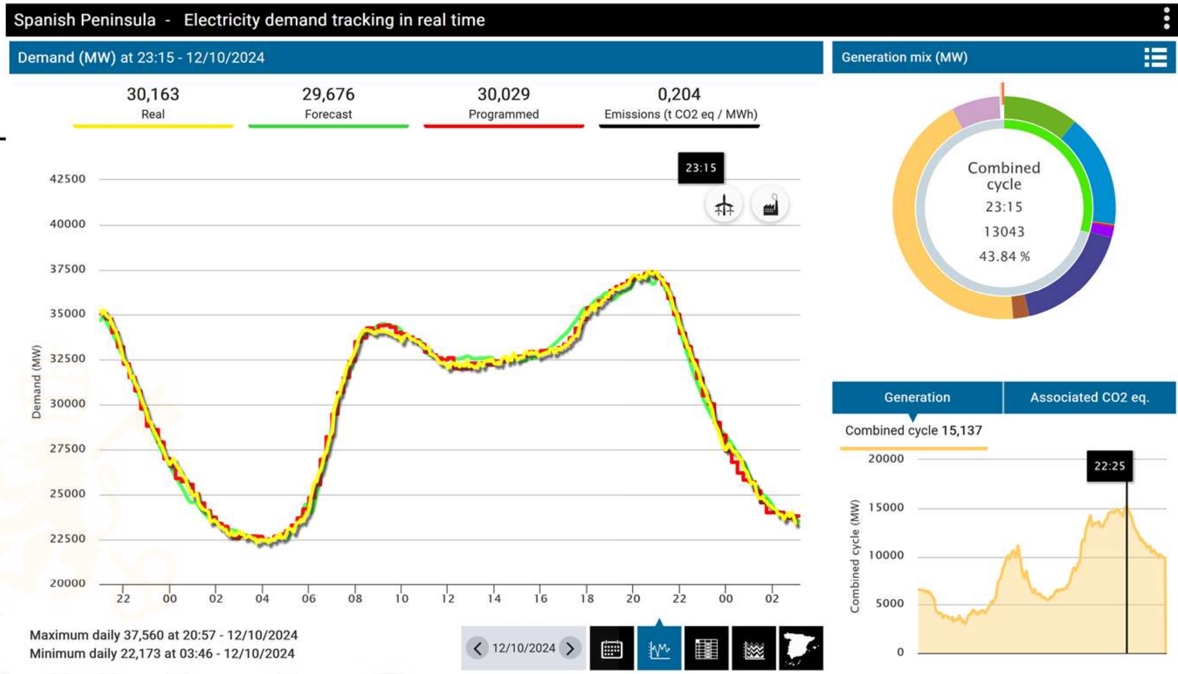
Spain (2024-12-10)

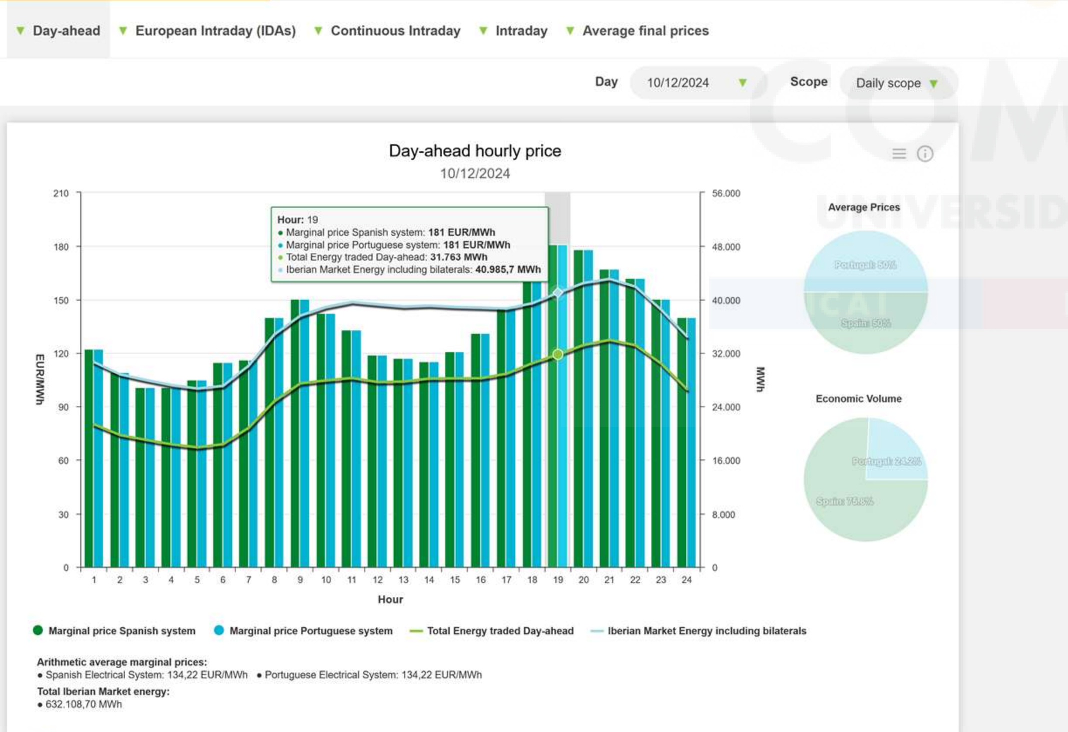
Nuclear: 5000 MW

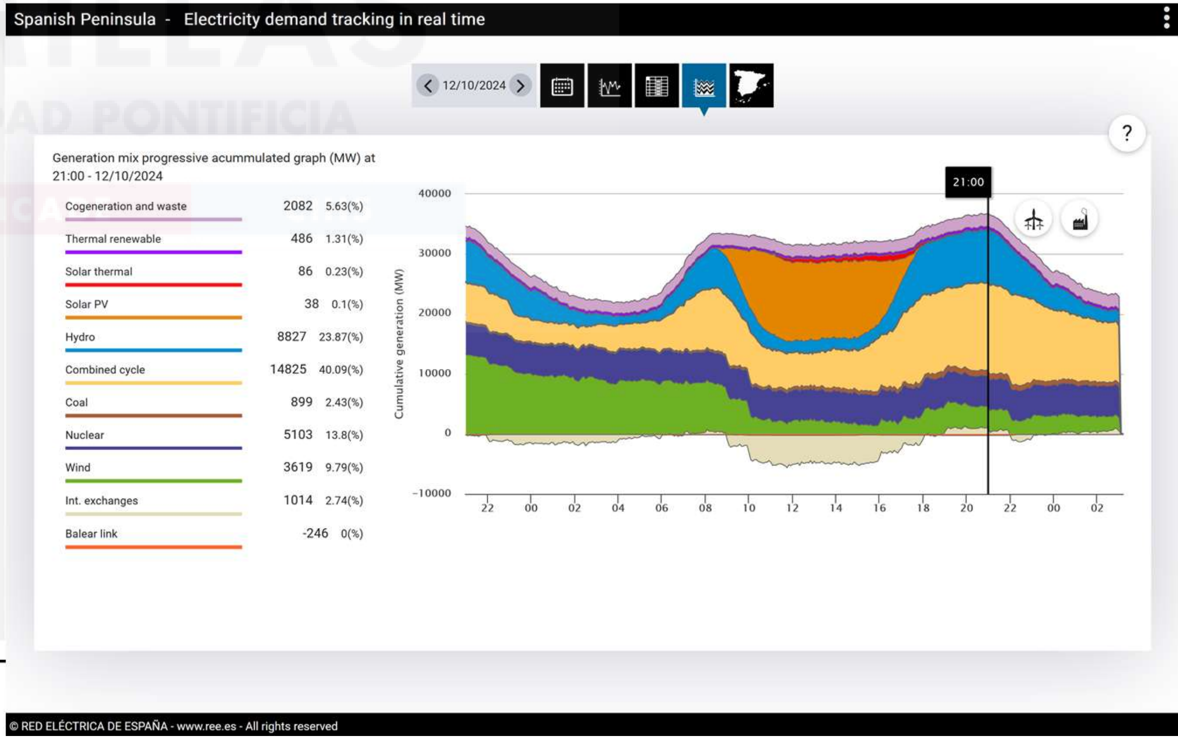
CCGT: 15000 MW

Demand response: 500 MW

Market price: 181 €/MWh



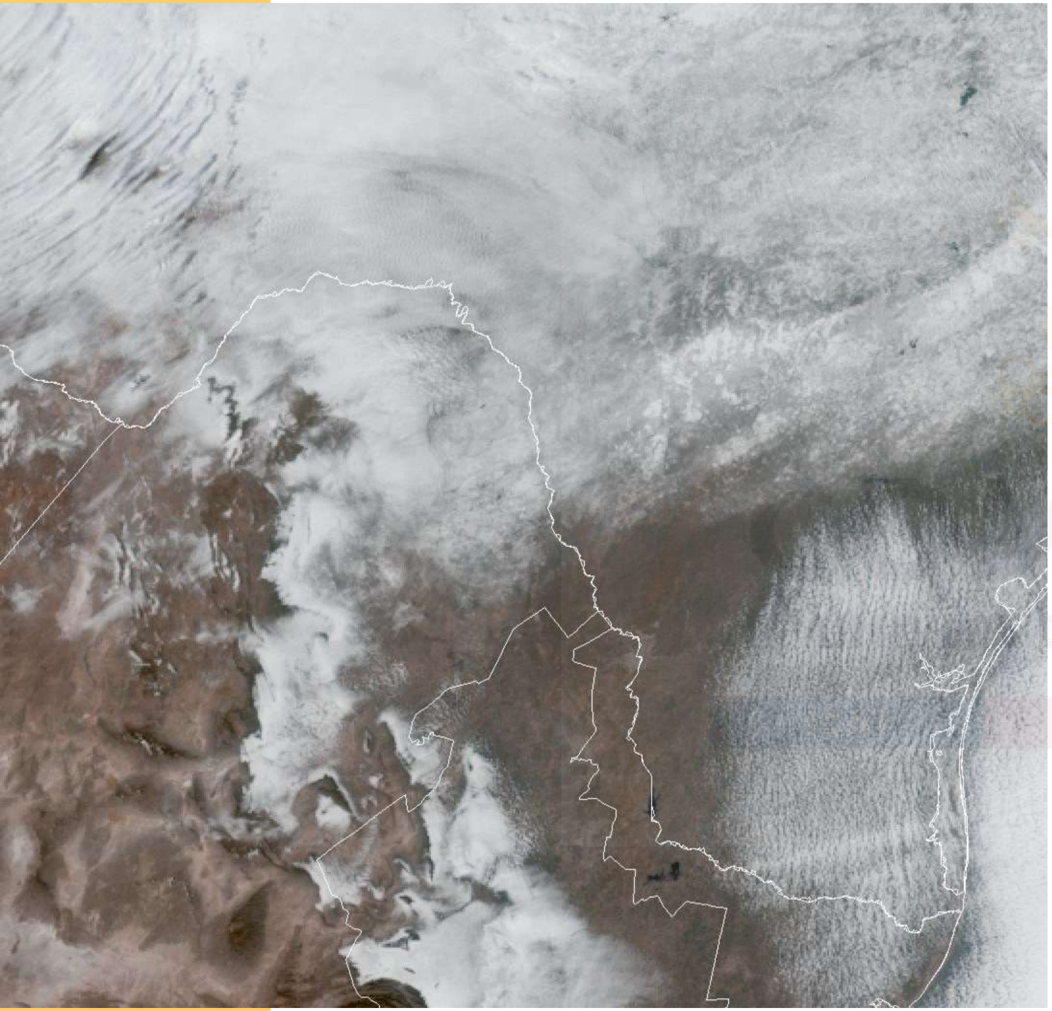




Drought at Lake Powell, Colorado River (Arizona, Utah, USA)

2017 2022

Winter storm in Texas (February 15, 2021)



Texas power outages bring Austin city data center offline

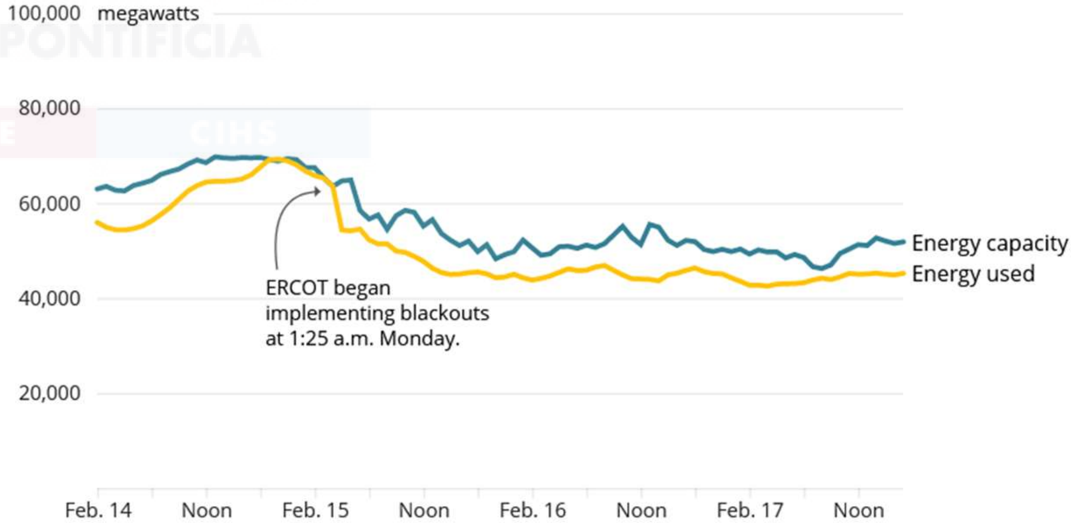
As well as leaving thousands without power amid freezing temperatures

February 16, 2021 By: Sebastian Moss Be the first to comment

Widespread rolling power outages across Texas took down Austin's city data center.

Local utility Austin Energy is believed to have left around 200,000 customers without power during a brutal winter storm impacting every county in Texas.

Statewide, more than two million were left without power on Monday, as temperatures dropped as low as -7.6°F (-22°C). Governor Greg Abbott has issued a disaster declaration, while The White House has issued its own federal emergency declaration for Texas.



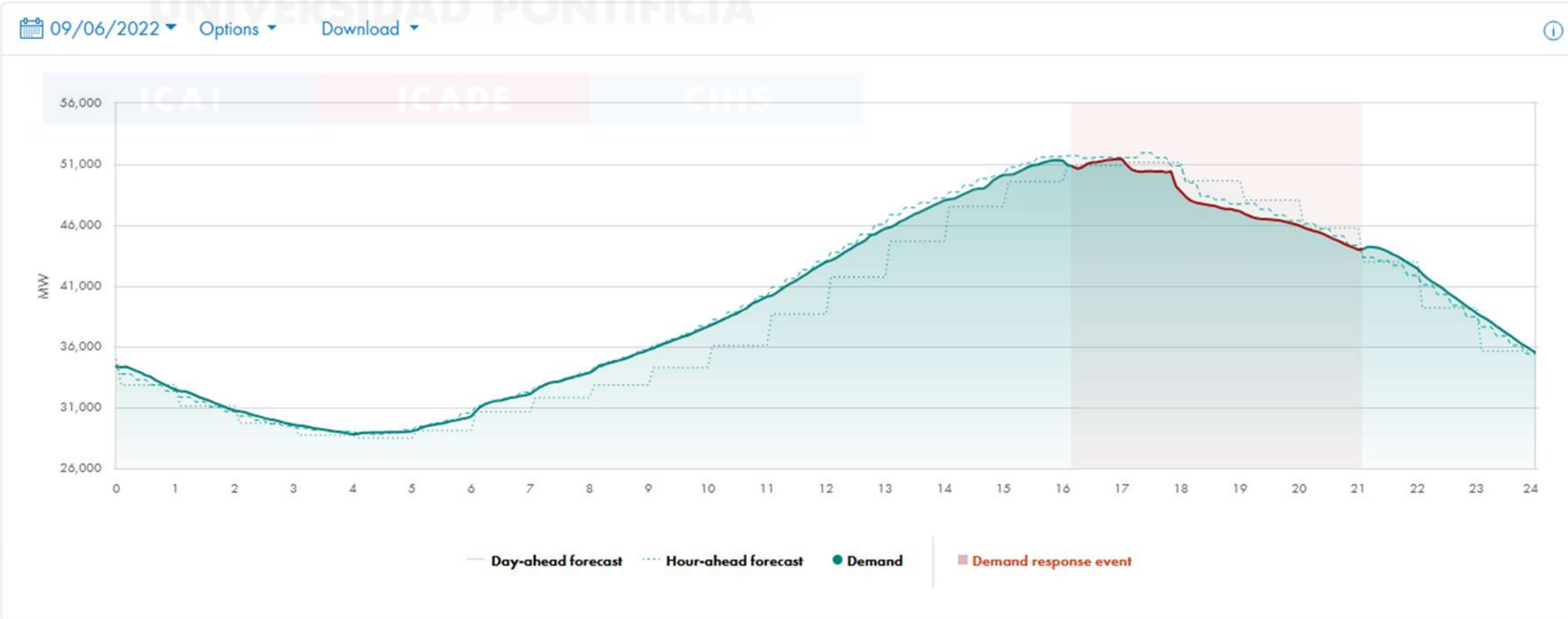
Note: Energy capacity excludes offline power sources that could be brought online.
Source: Electric Reliability Council of Texas
Credit: Mandi Cai

ERCOT Sheds Load as Extreme Cold Forces Generators Offline; MISO, SPP Brace for Worsening System Conditions

Resource adequacy in CAISO

*Note: Values for the 7th day of the day-ahead forecasts will complete by 9:30 PT.

http://www.caiso.com/TodaysOutlook/Pages/default.aspx



1. Introduction
2. Reliability assessment
3. Adequacy assessment methods
4. Probabilistic production cost model
5. Assignment

3

Adequacy assessment methods

Generation capacity adequacy assessment methods
(https://pascua.iit.comillas.edu/aramos/StarGenLite_PPCM.zip)

1. State Table
   - Exact
   - Impossible to use for large-scale systems

2. Monte Carlo (MC) Simulation
   - Allows computing not only mean values but their distributions
   - Sequential or non-sequential

3. Probabilistic Production Cost (PPC) Model
   - Very quick analytical technique

Reliability measures by a State Table

- Generation system and load
  - Unit 1:
    - Output: 1000 MW
    - *EFOR*: 0.05 (5%)
  - Unit 2:
    - Output: 900 MW
    - *EFOR*: 0.04 (4%)
  - Forecasted maximum load:
    - Case A: 1100 MW

State	Available capacity	Probability	*PNS*
11	1900	0.912	0
10	1000	0.038	100
01	900	0.048	200
00	0	0.002	1100

- Reliability measures
  - *LOLP* = 0.088
  - *EENS* = 15.6 MW

Reliability measures by Monte Carlo Simulation

- For each sample
  - Obtain generator availability
  - Dispatch available units to supply demand
  - Determine if this sample has *PNS* and its quantity

- Compute *LOLP* and *EENS*

$$LOLP = \frac{\#\ of\ samples\ with\ PNS}{\#\ of\ samples}$$

$$EENS = \frac{Total\ PNS}{\#\ of\ samples}$$

Estimation

- Sample mean

$$\overline{X}(n) = \hat{\mu} = \frac{\sum_{i=1}^{n} x_i}{n}$$

- Sample variance

$$S^2(n) = \hat{\sigma}^2 = \frac{\sum_{i=1}^{n} (x_i - \overline{X}(n))^2}{n-1}$$

- Variance of the mean

$$\dot{v}ar\left[\overline{X}(n)\right] = \frac{S^2(n)}{n} = \frac{\sum_{i=1}^{n} (x_i - \overline{X}(n))^2}{n(n-1)}$$

- Confidence interval of the mean

$$\left(\overline{X}(n) - t_{n-1,\alpha/2}\sqrt{\frac{S^2(n)}{n}}, \overline{X}(n) + t_{n-1,\alpha/2}\sqrt{\frac{S^2(n)}{n}}\right)$$

Standard error (SE)

- Coefficient of variation (CV)

$$c_v = \frac{\sqrt{\frac{S^2(n)}{n}}}{\overline{X}(n)}$$

$$t_{1000-1,1\%/2} = 2.581 \qquad t_{1000-1,5\%/2} = 1.962$$

In Excel, look for *Data > Data Analysis > Descriptive Statistics* to compute these values

Note that the Confidence level statistic in Excel corresponds to the half-width of the confidence interval

Estimating the average number by Monte Carlo

- We want to estimate the mean value of the facets of a dice by sampling

	Samples				
	10	30	50	500	1000
Mean	3.20	3.60	3.28	3.40	3.47
Standard Deviation	1.75	1.73	1.59	1.69	1.75
Standard Error	0.55	0.32	0.23	0.08	0.06
Lower Bound 99 %	1.40	2.73	2.68	3.20	3.32
Upper Bound 99 %	5.00	4.47	3.88	3.60	3.61
Coeff. of Variation	0.18	0.11	0.09	0.02	0.02

Small example

- An electric system has 2 generators with a failure probability of 0.1
- The system fails if at least one of the units is failed
- Determine the system reliability by Monte Carlo simulation
- Determine the number of samples needed to achieve a half-width of 2 % with a confidence level of 95 %

LOLP: exact computation and Monte Carlo simulation

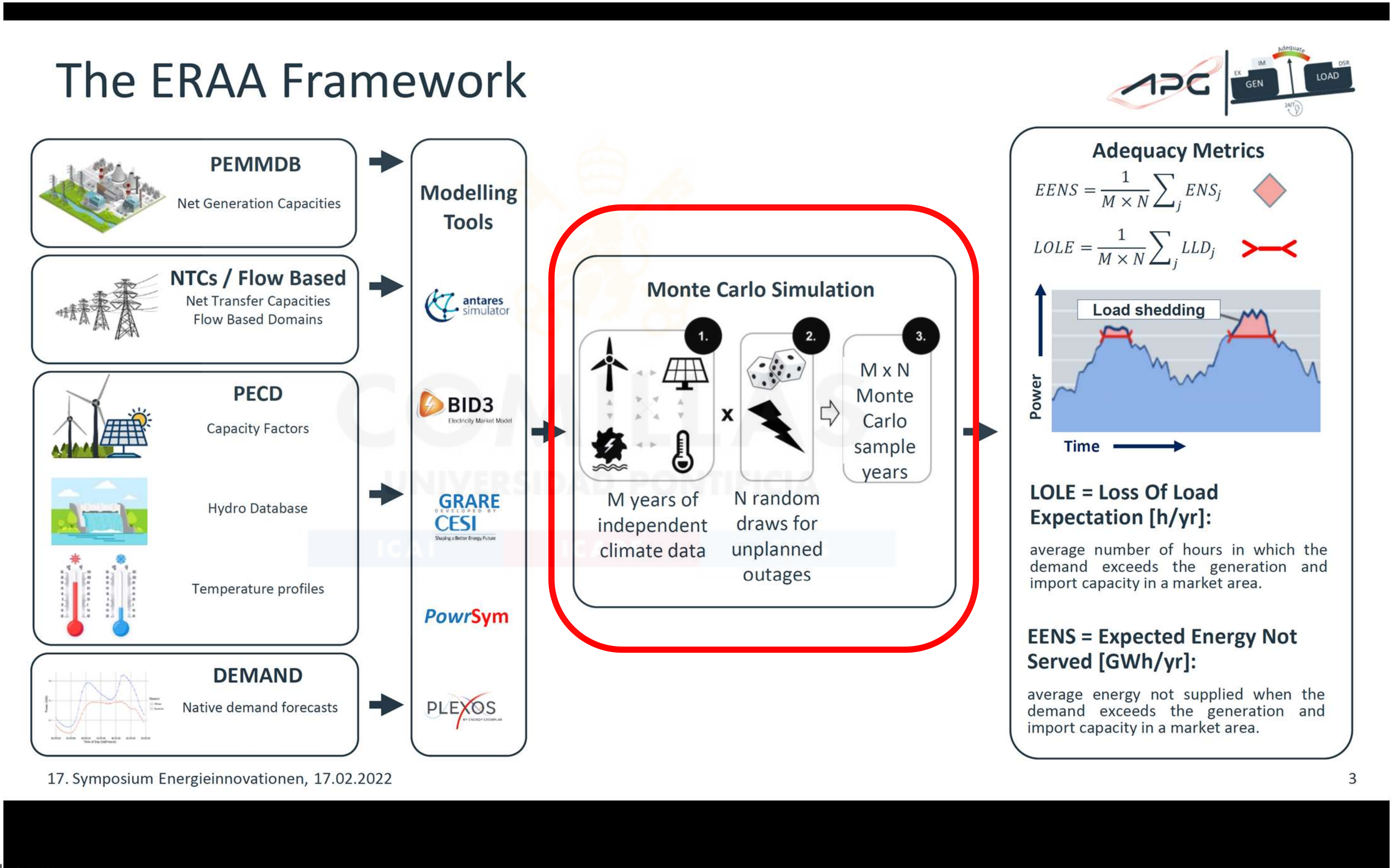
- State table: Case *p*=0.9
  - Mean: 0.81
  - Variance of the r.v.: 0.1539
  - Coefficient of variation of the r.v.: 0.484322
- State table: Case *p*=0.95
  - Mean: 0.9025
  - Variance of the r.v.: 0.08799375
  - Coefficient of variation of the r.v.: 0.328684
- MC: 2000 samples

p=0.9		**p=0.95**	
media	0.802000	media	0.905500
varianza	0.158875	varianza	0.085613
var media	0.000079	var media	0.000043
coef var	0.496997	coef var	0.323132

- MC: 20000 samples

p=0.9		**p=0.95**	
media	0.809200	media	0.904950
varianza	0.154403	varianza	0.086020
var media	0.000008	var media	0.000004
coef var	0.485593	coef var	0.324097

ERAA Framework



Mid-Term Adequacy Forecast (MAF) 2018
EENS convergence

https://www.entsoe.eu/Documents/SDC%20documents/MAF/MAF_2018_Methodology_and_Detailed_Results.pdf

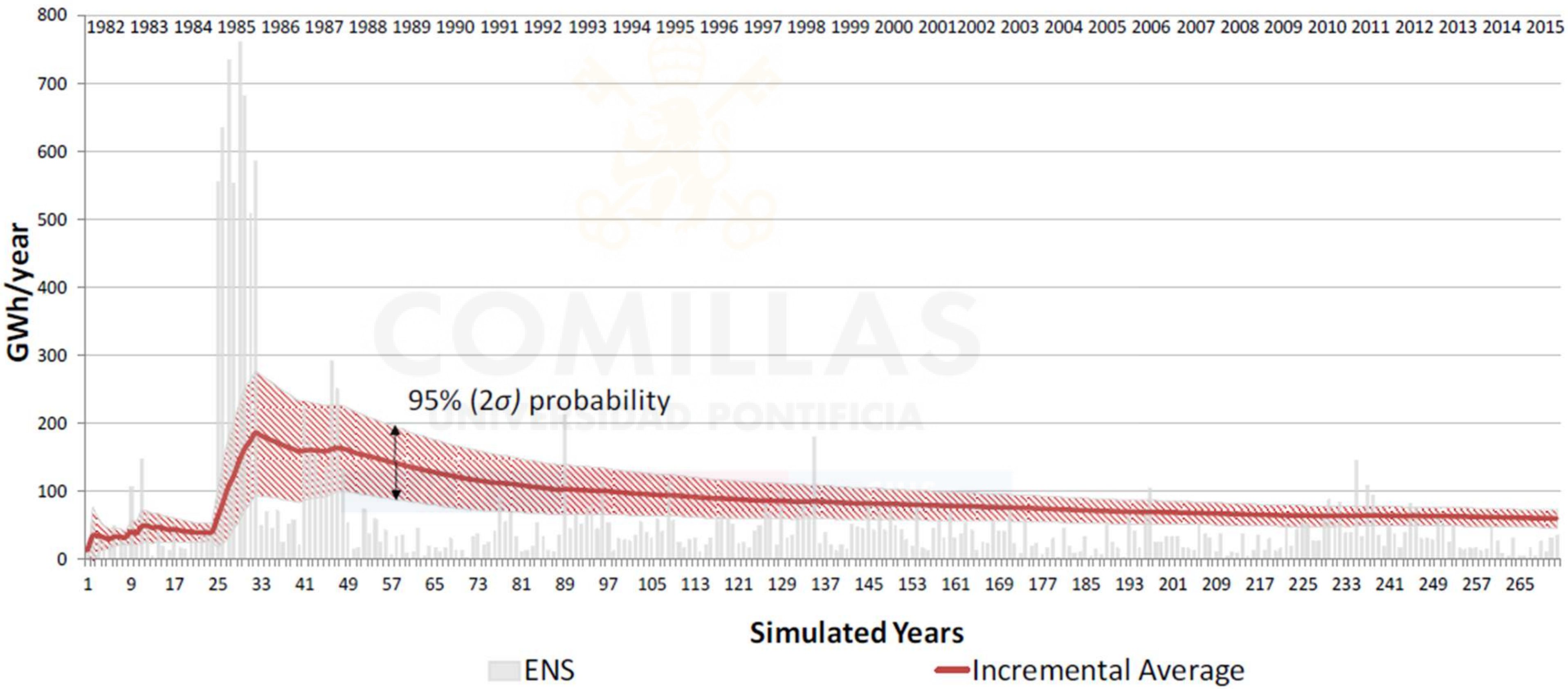
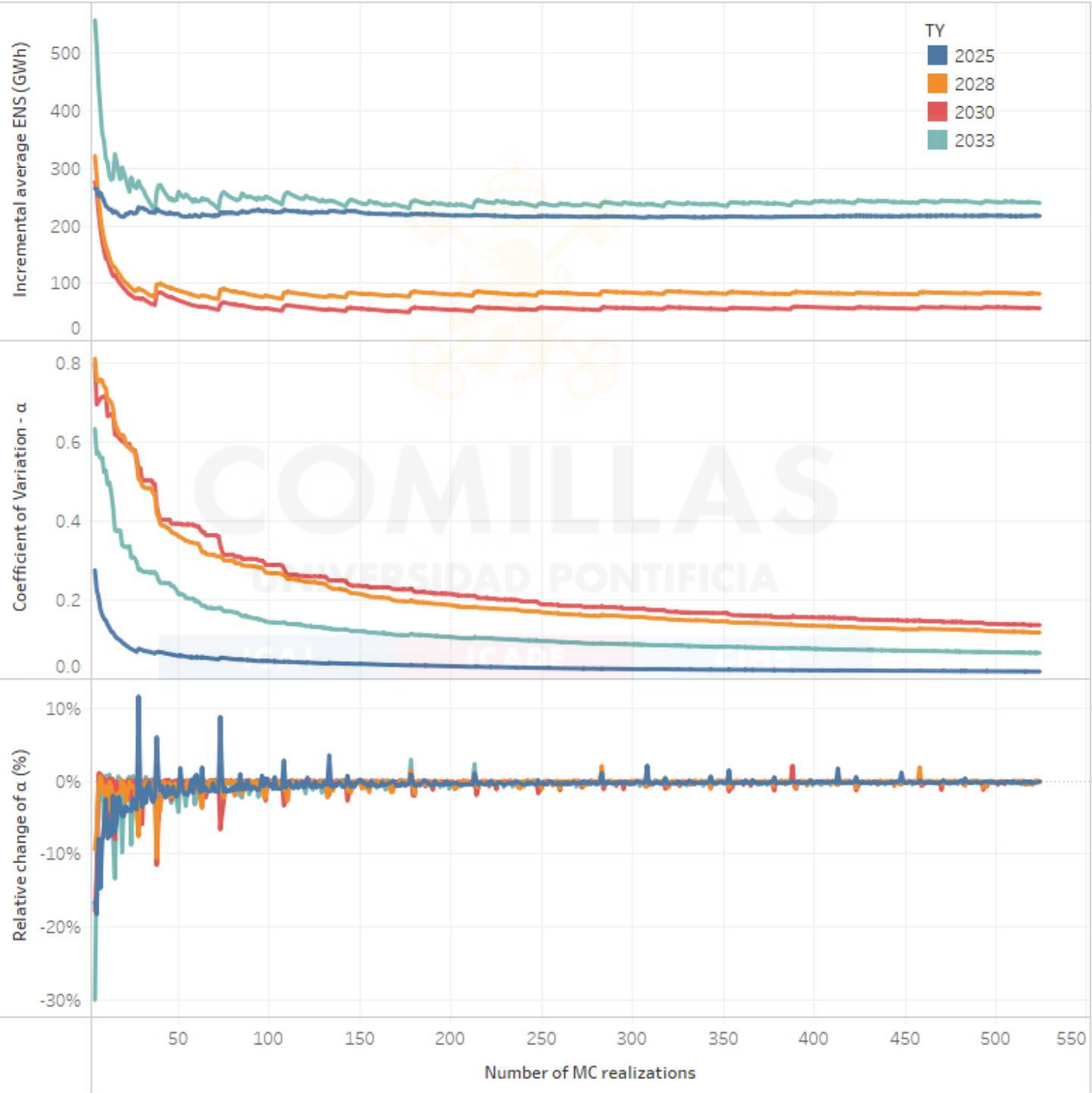


Figure 5: Example of EENS convergence over a number of Monte Carlo simulations

ERAA 2023. Incremental average ENS, Coefficient of variation α and relative change of α evolution (Scenario A)



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Probabilistic production cost model

Probabilistic Production Cost (PPC) model

- Electric demand and
- Unit available capacity are independent random variables

PPC Model by Analytical Simulation

- Unit expected output
- System reliability measures
  - Loss of load probability *LOLP*
  - Expected energy not served *EENS*
  - Loss of energy probability *LOEP*

Statistical basic concepts

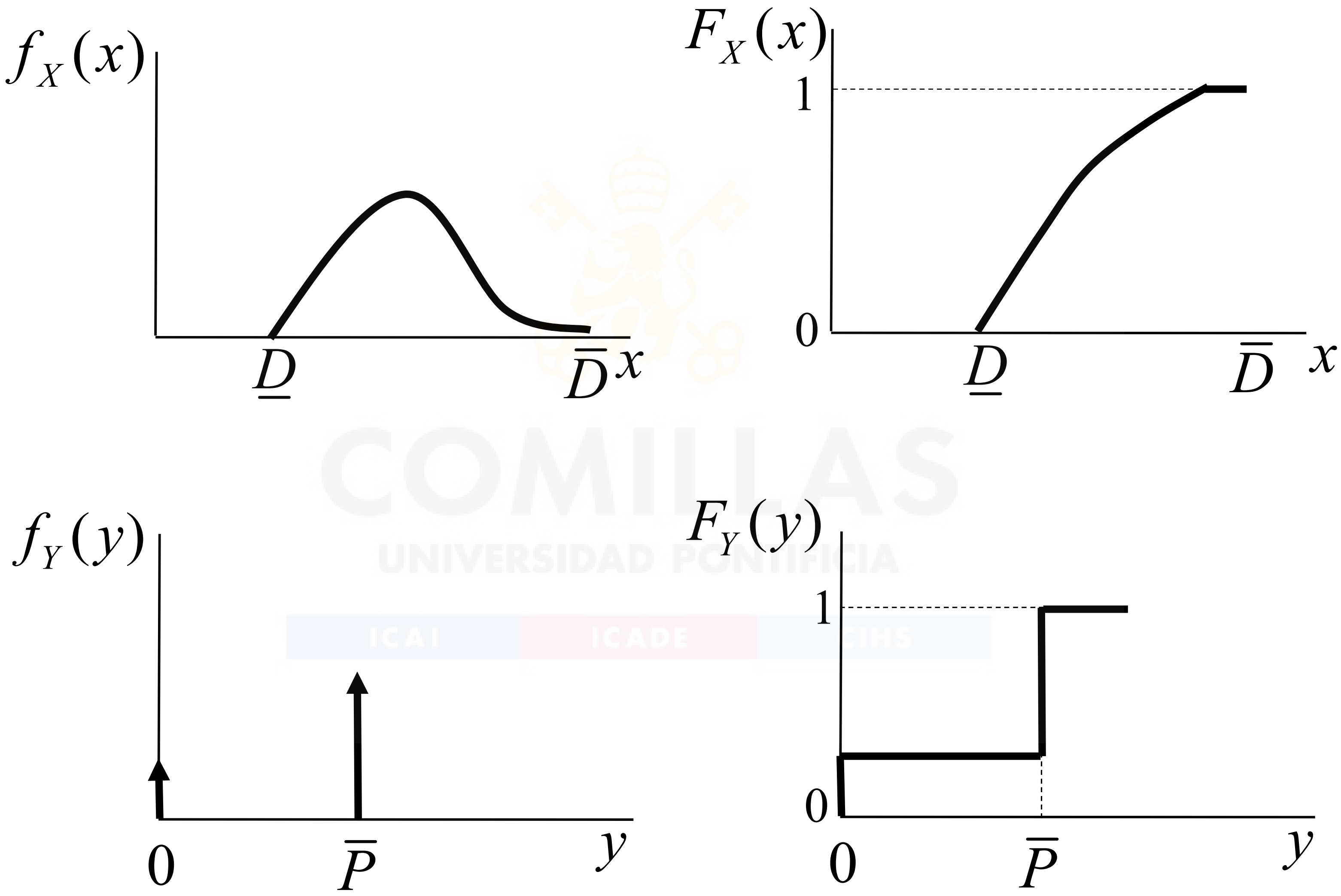
- Let X a random variable
- Probability density function (*PDF*) $f_X(x)$
  - Probability that the variable belongs to an infinitesimal interval

$$f_X(x) = P[x < X < x + dx]/dx$$

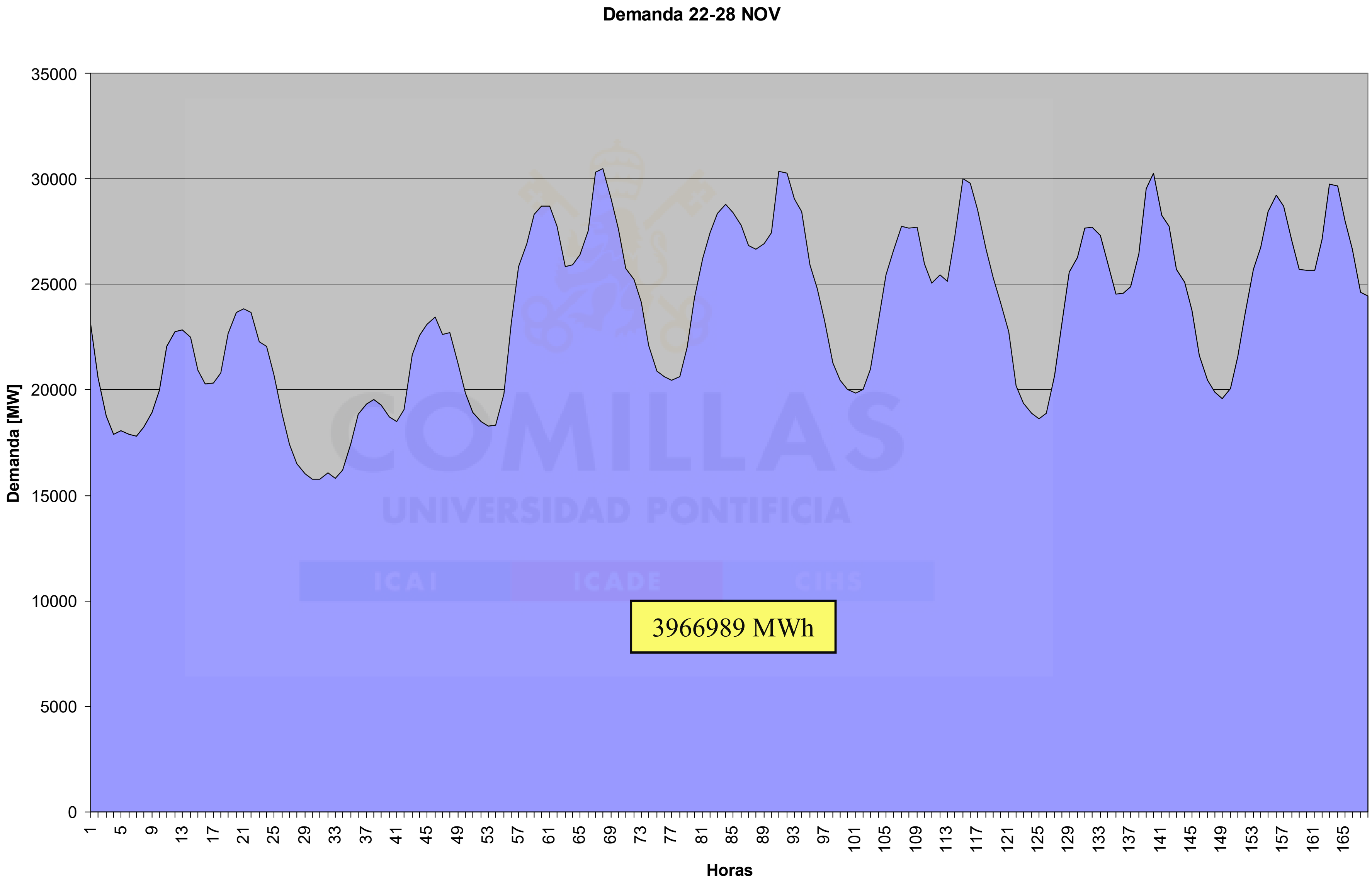
- Cumulative distribution function (*CDF*) $F_X(x)$
  - Probability that the variable is lower or equal to a specific value

$$F_X(x) = P[X \leq x] = \int_{-\infty}^{x} f_X(x)dx$$

Continuous and discrete random variables

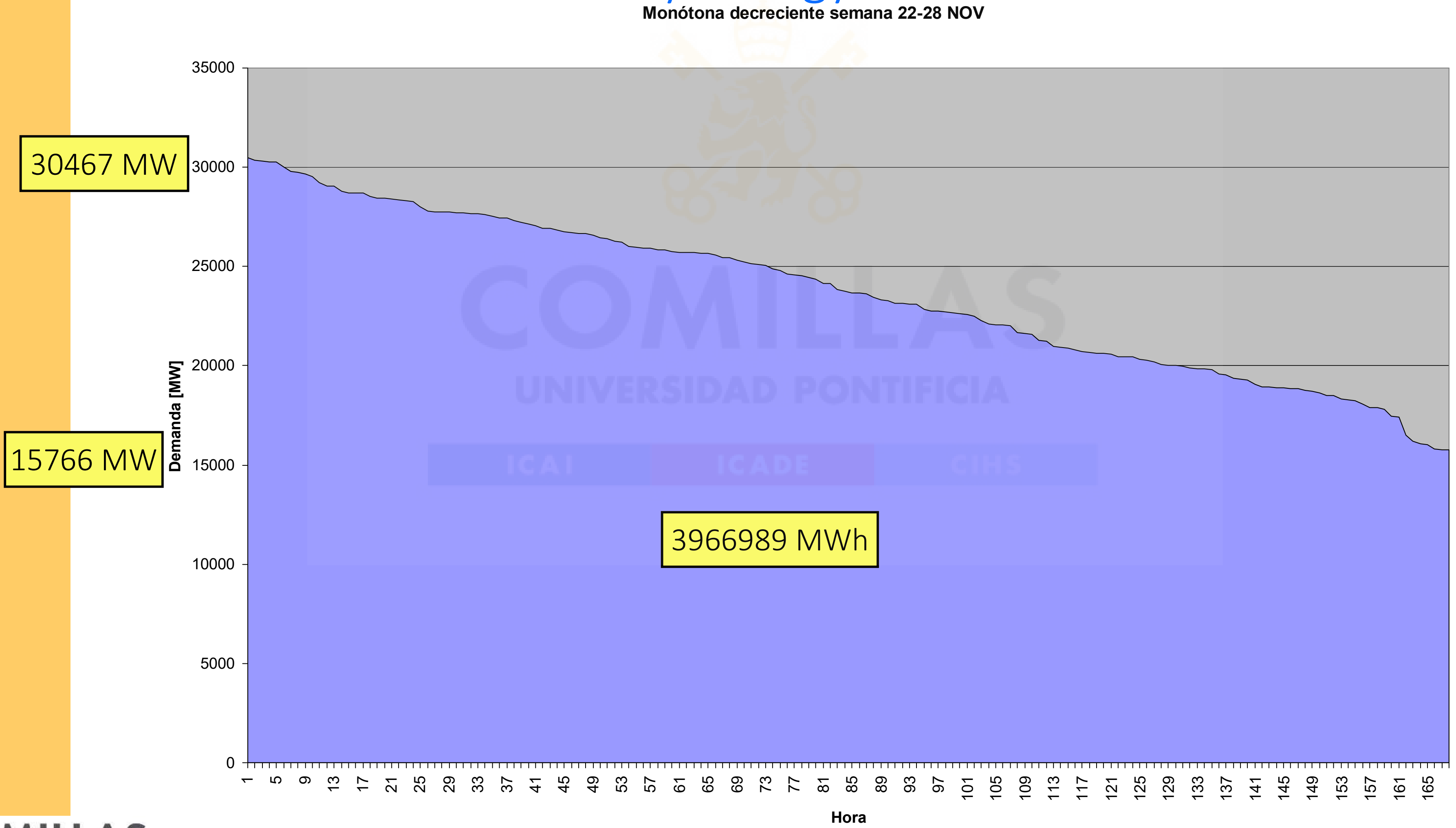


Weekly demand



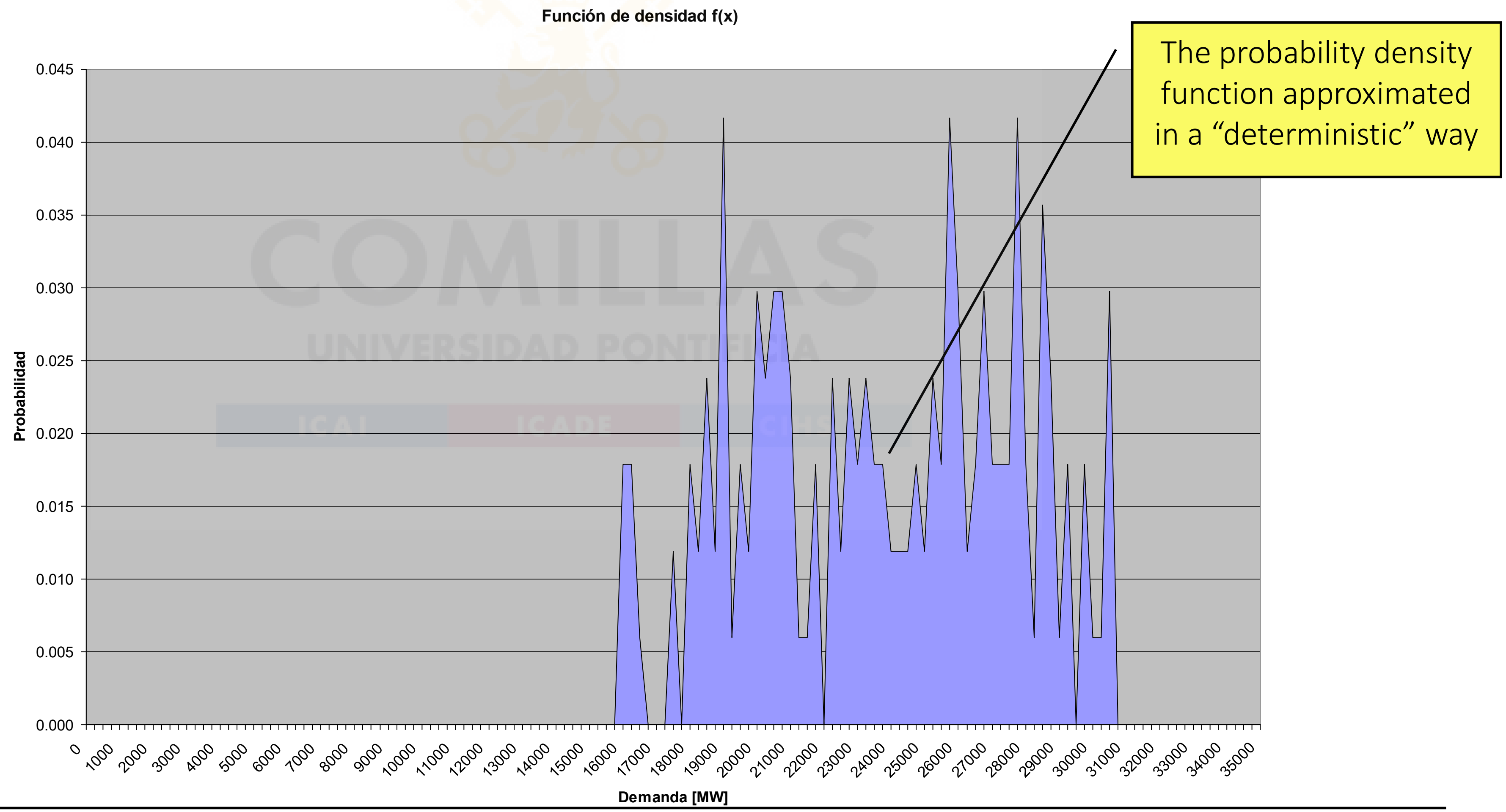
Load-duration curve

– Decreasing ordering of the 168 demand values
– Area = total weekly energy



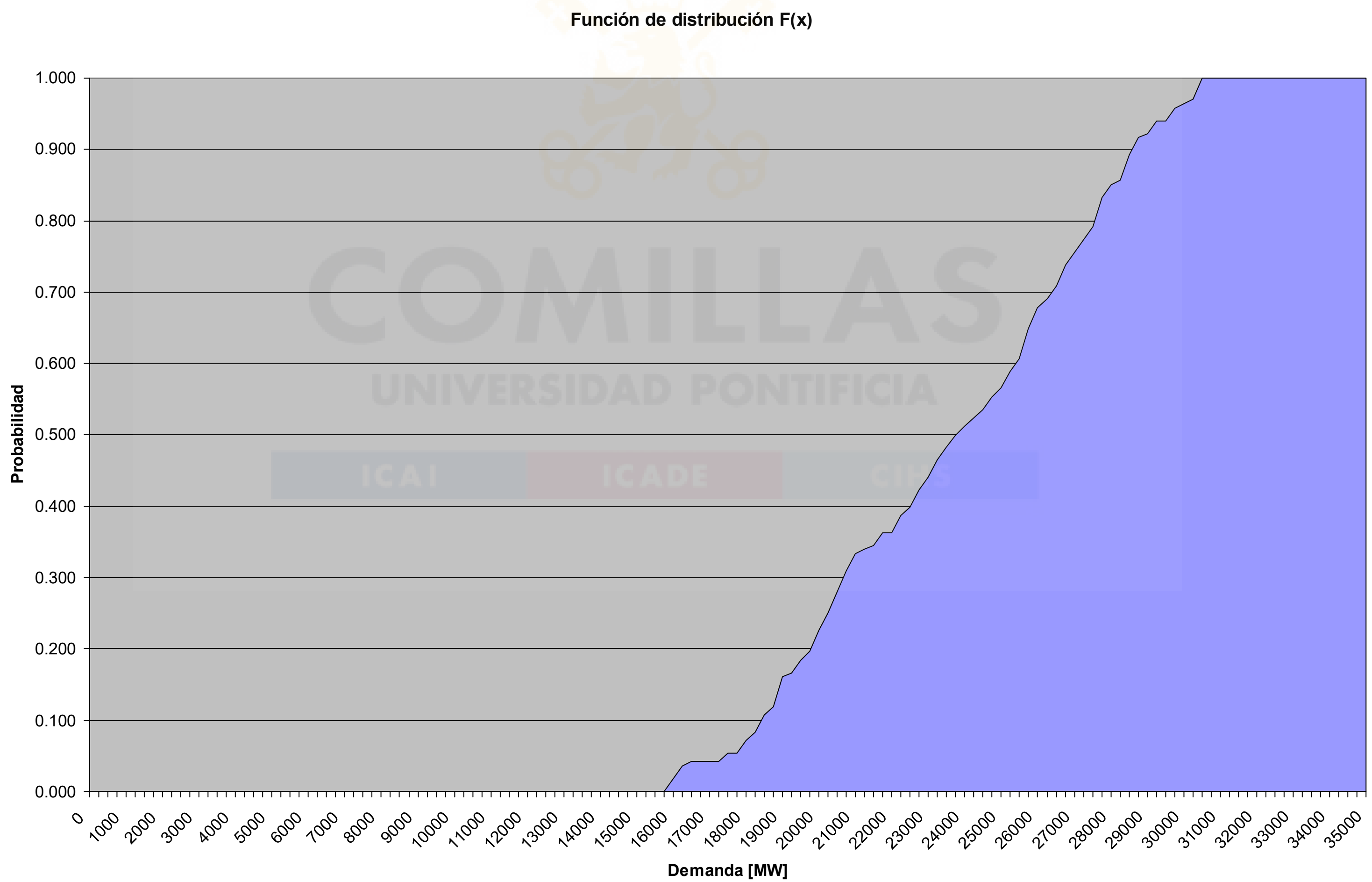
Demand probability density function

– Probability of the demand is equal to a specific value $f(x)$
– Obtained from load forecasts for this week



Demand cumulative distribution function (CDF)

– Probability of the demand is ≤ to a certain value $F_X(x)$
– Obtained accumulating the probability density function $f_X(x)$

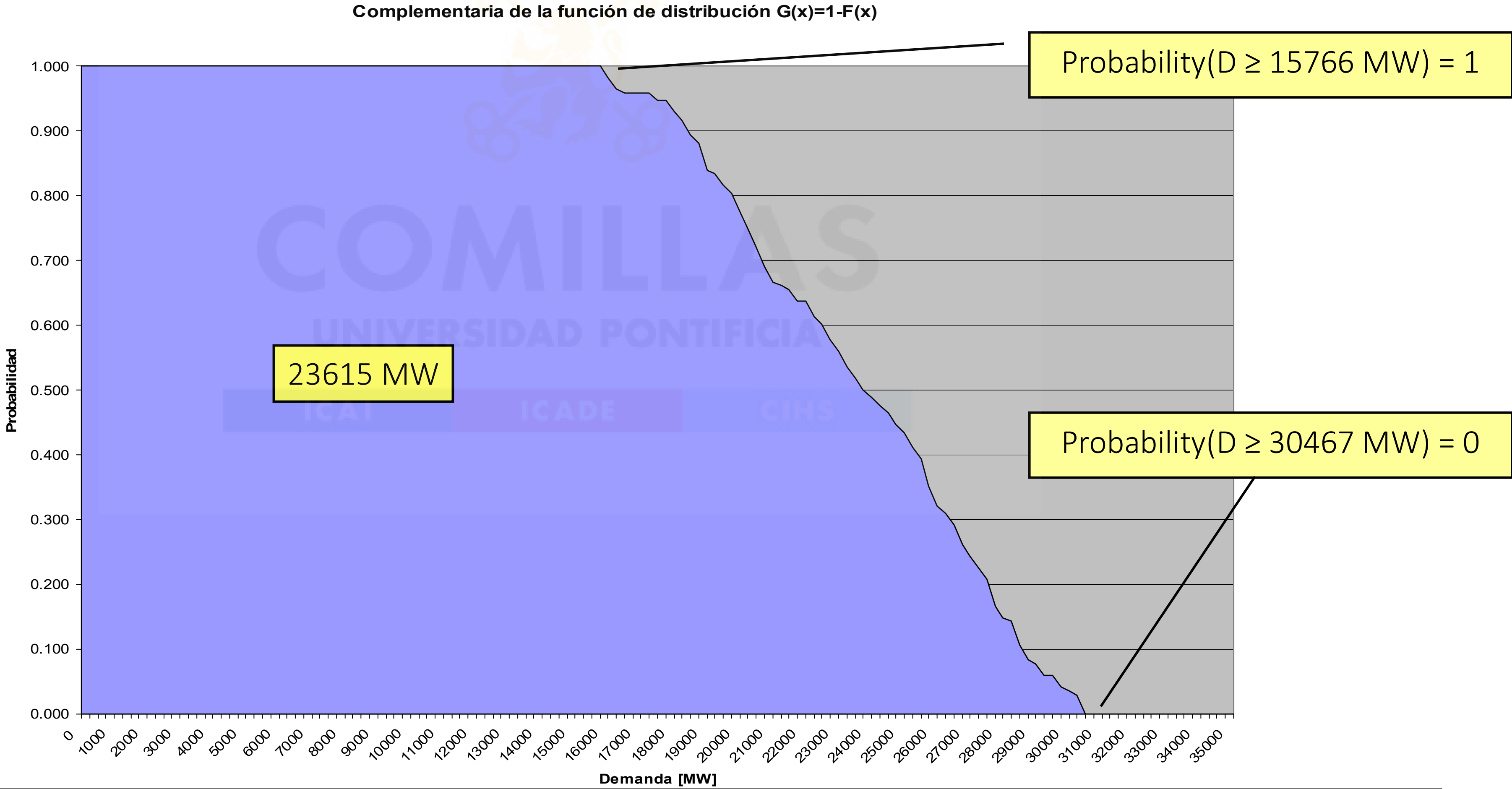


Complementary cumulative distribution function (*CCDF*) (also called Load-Duration Curve LDC)

– Probability of the demand is ≥ to a certain value

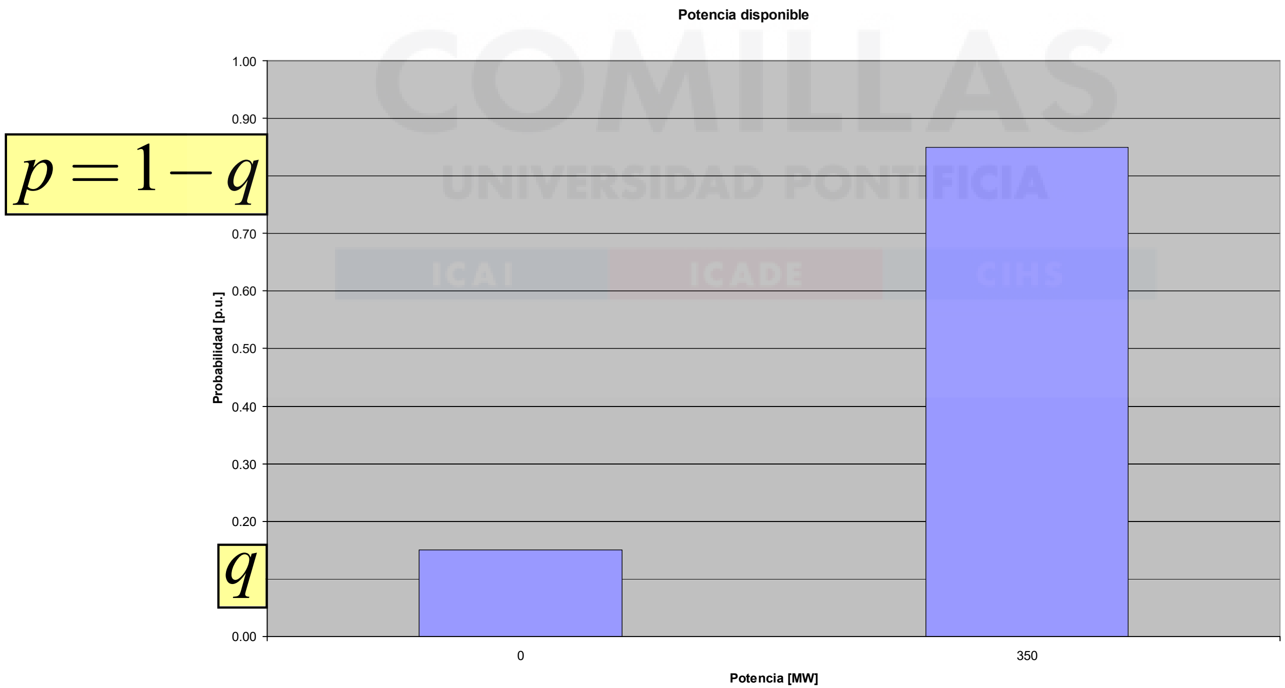
$$G_X(x) = 1 - F_X(x)$$

– Total weekly energy = area · week duration



Probability density function of the unit available capacity

- Random variable with Bernoulli distribution
  - A unit can only be into two possible states (available or unavailable)
  - q unit failure probability. Available capacity = 0
  - $p = 1 - q$ unit operation probability. Available capacity = rated capacity



Unit dispatch

- Thermal units are dispatched in single loading order by increasing variable cost:
  - Nuclear, brown lignite, black lignite, imported coal, domestic coal, gas, oil, etc.
- It does NOT consider minimum load or start-ups of the units
- Hydroelectric units are dispatched where they produce their available energy (unregulated flows)
- Unit failures are supposed to be independent among them and independent of the demand uncertainty
- It does NOT exist inter-period relations

Common cause failure

P. Fairley, Nuclear Shutdowns Put Belgians and Britons on Blackout Alert, IEEE Spectrum, Sep 2014

Ultrasound inspection of the reactor pressure vessels at the utility's Doel power station near Antwerp revealed previously unrecognized defects at its 1,000-megawatt reactor #3. Prior tests looked only for aging of the welds between a pressure vessel's steel plates, but this time broader inspections at Doel 3 detected thousands of tiny cracks in the plates themselves. The cracks were most likely created when the plates were originally forged.

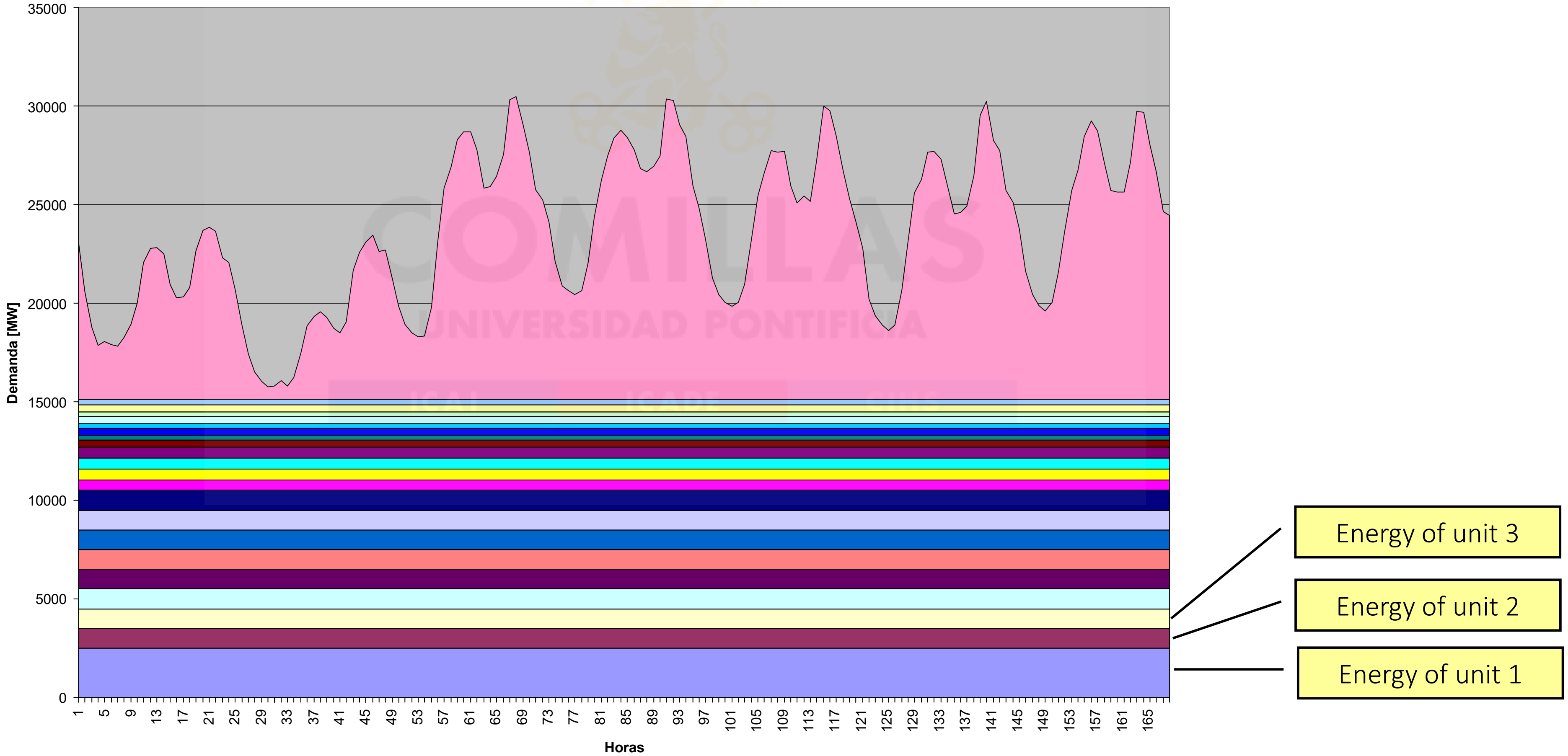
L. Buchsbaum, *France's Nuclear Storm: Many Power Plants Down Due to Quality Concerns*, Power, Nov 2016

World Nuclear News, *Five French units to undergo steam generator checks*, Oct 2016

In June, the Autorité de Sûreté Nucléaire said it had identified 18 French nuclear power reactors operated by EDF - of both 900 MWe and 1450 MWe capacity - whose steam generators could contain high carbon concentrations.

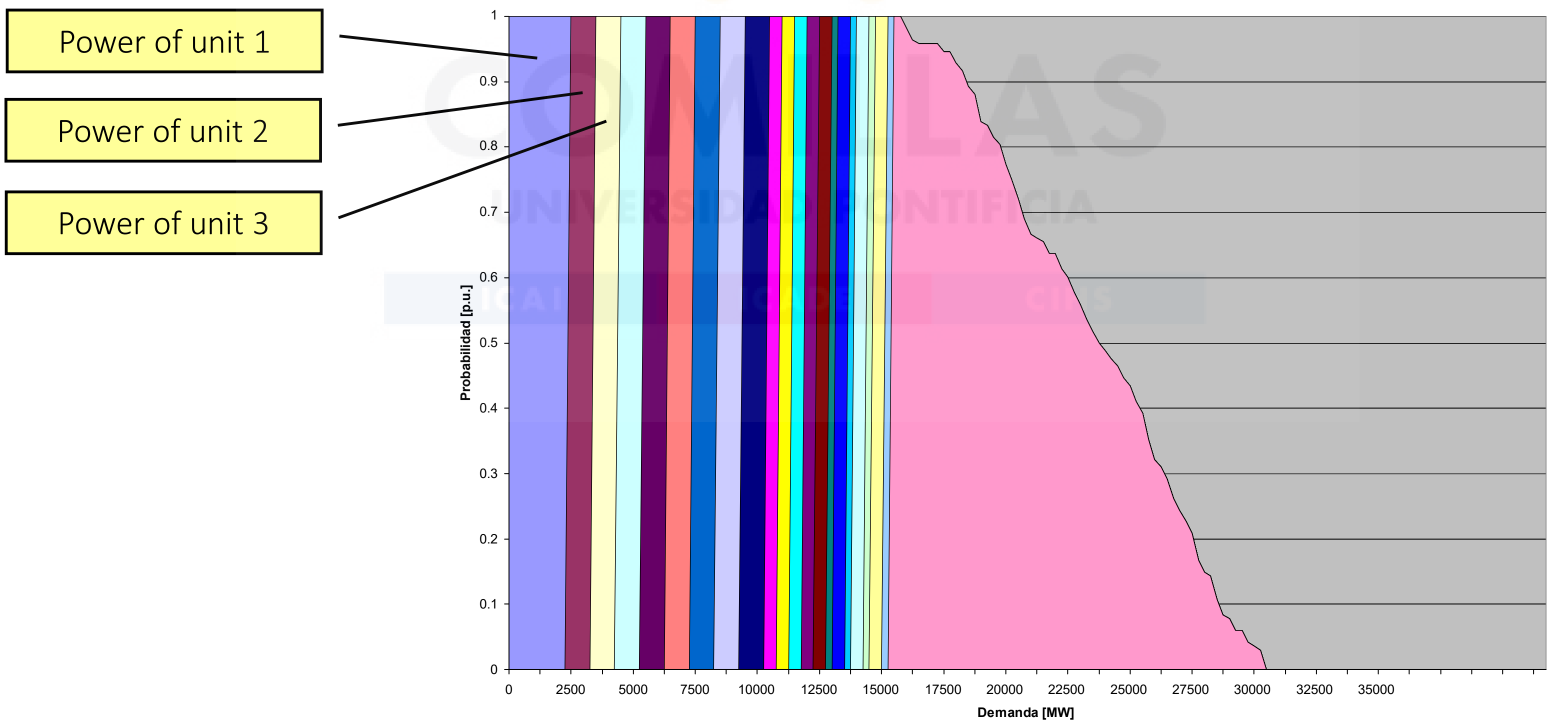
Dispatch WITHOUT thermal units' failure (i)

- Thermal units are dispatched from the bottom up (in a pile) under the load curve
- Energy output = curve area



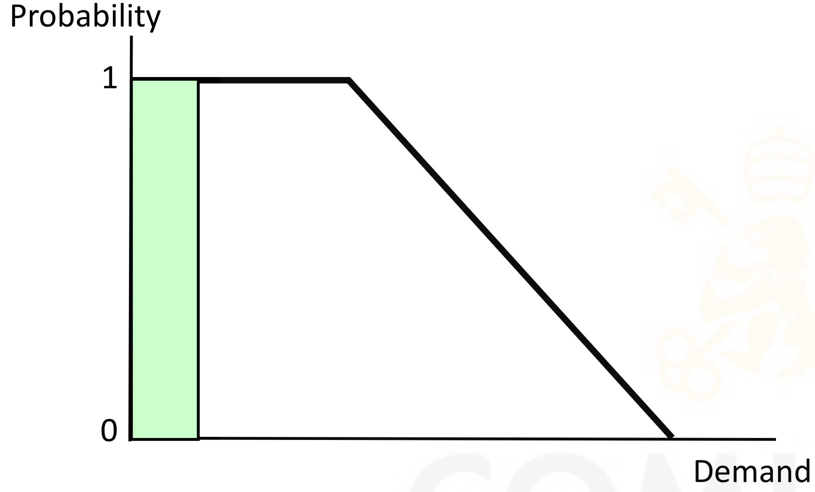
Dispatch WITHOUT thermal units' failure (ii)

- Thermal units are dispatched from left to right under the complementary cumulative distribution function (CCDF) curve
- Energy output = area · period duration



Dispatch WITH thermal unit failure (i)

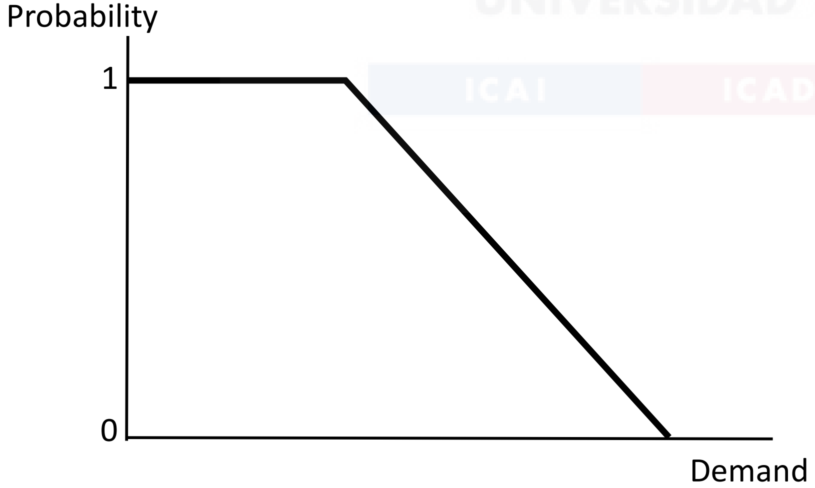
Unit does NOT fail, with probability $\boldsymbol{p = 1 - q}$



Expected energy output of the unit =

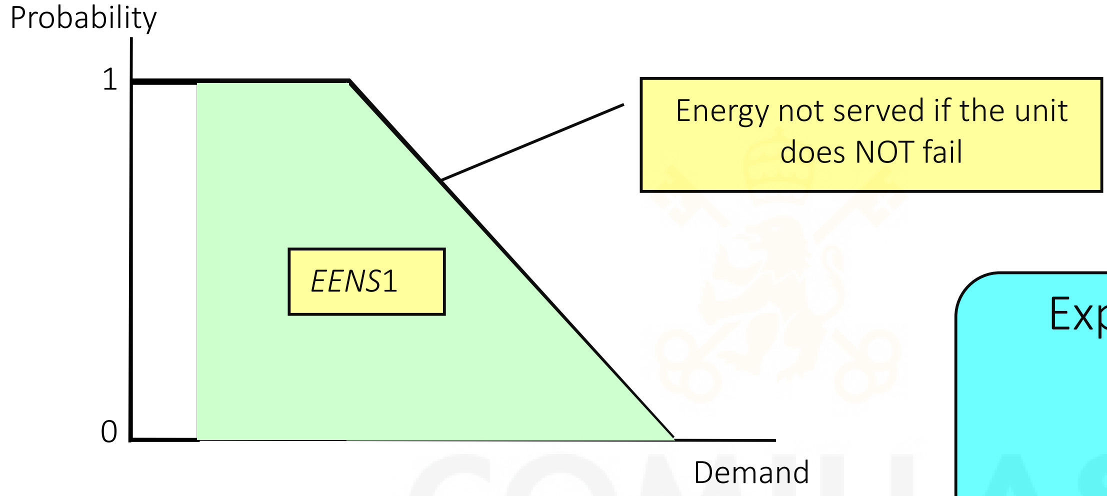
area · duration · probability

Unit fails, with probability $\boldsymbol{q}$



Dispatch WITH thermal unit failure (ii)

Unit does NOT fail, with probability $\boldsymbol{p = 1 - q}$

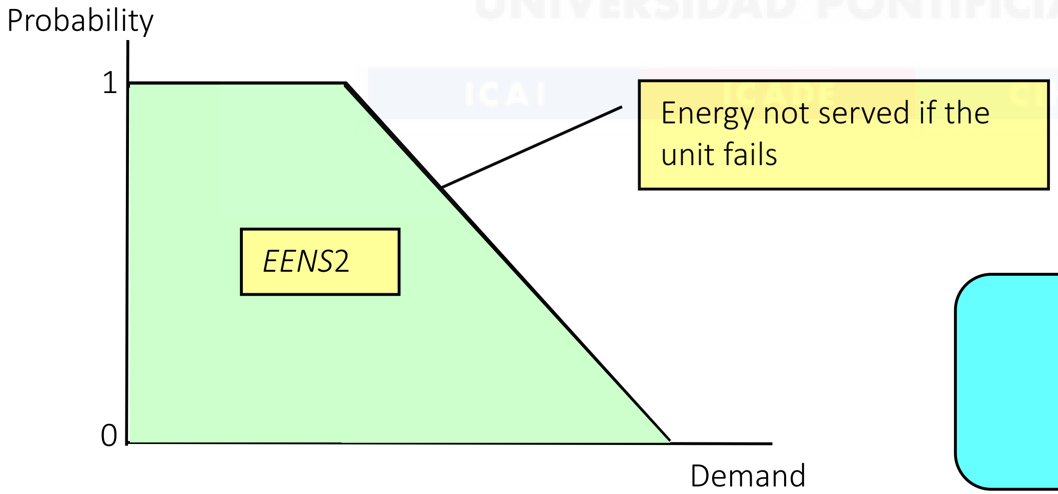


Expected energy output of the unit =

EENS before unit dispatch –

EENS after unit dispatch

Unit fails, with probability $\boldsymbol{q}$

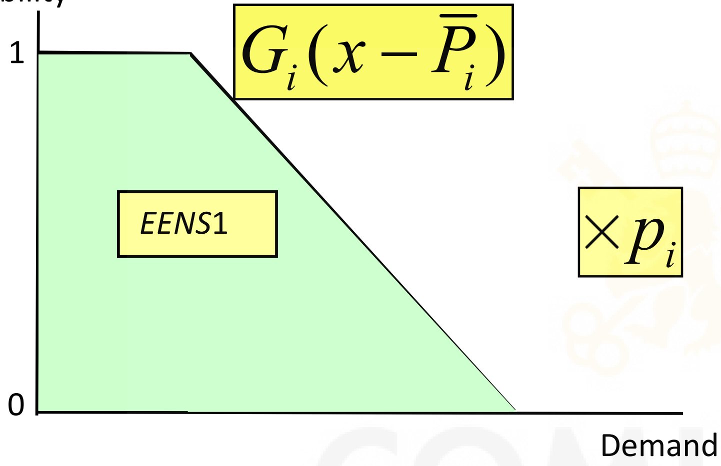


EENS after unit dispatch =

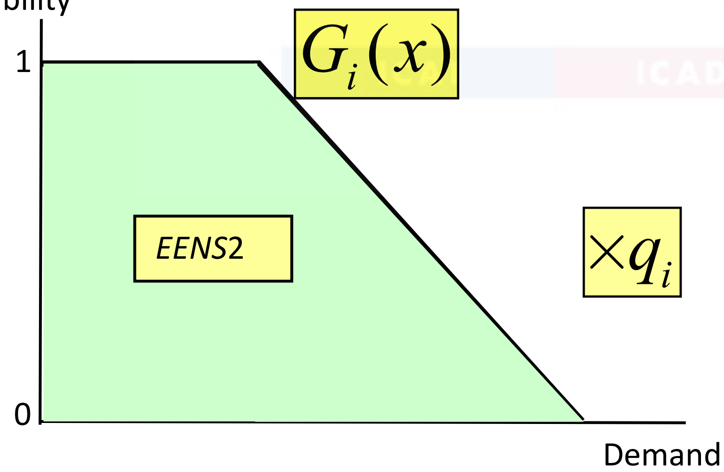
$(EENS1 \cdot p + EENS2 \cdot q) \cdot duration$

Thermal unit convolution (i)

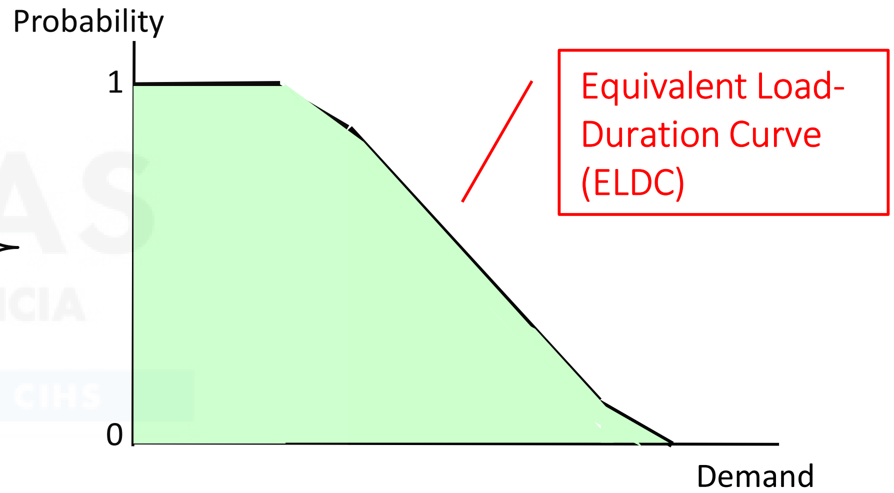
EENS if the unit i does NOT fail



EENS if the unit i fails



EENS after unit i dispatch



$$G_{i+1}(x) = p_i G_i(x-\bar{P}_i) + q_i G_i(x)$$

Thermal unit convolution (ii)

- Complementary cumulative distribution function (CCDF)

$$G_1(x) = G_X(x)$$

- Unit convolution $i = 1, \dots, N$

$$G_{i+1}(x) = p_i G_i(x - \overline{P}_i) + q_i G_i(x)$$

- Expected energy output for each thermal unit i

$$E_i = T \int_0^{\overline{D}} \left[G_i(x) - G_{i+1}(x) \right] dx$$

being T period duration and $\overline{D}$ the maximum demand

- Commitment hours of the unit

$$H_i = T \cdot G_i(0)$$

Dispatch of two units versus a single aggregated unit

- The dispatching result is NOT the same:
  - Two units with a specific failure probability that
  - Dispatching a single unit with a capacity equal to the sum of both and equivalent probability

Reliability measures (i)

- *EENS Expected energy not served*

$$EENS = E_{N+1} = T\int_0^{\bar{D}} G_{N+1}(x)dx$$

- *LOLP Loss of load probability*

$$LOLP = G_{N+1}(0)$$

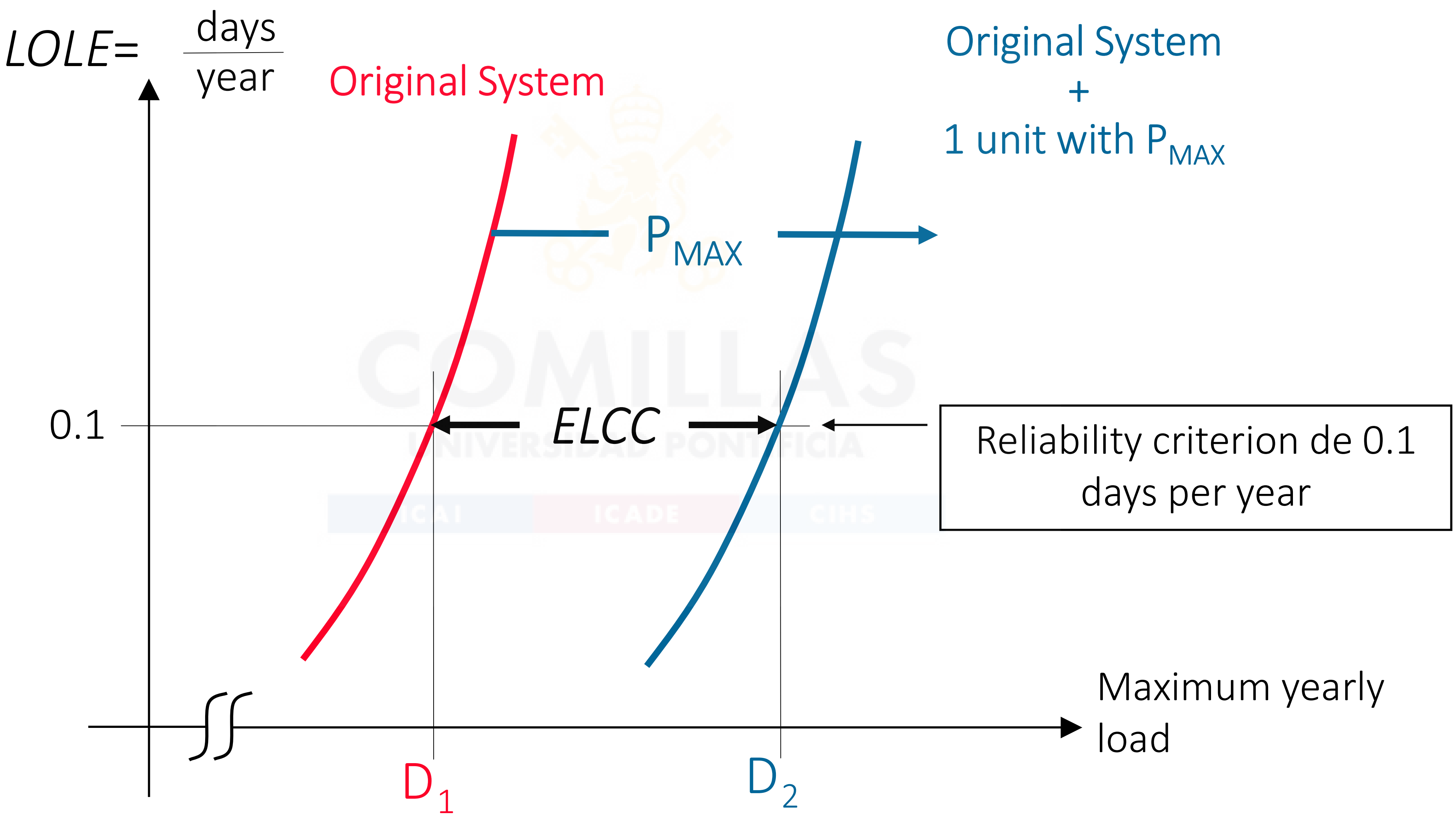
- *LOEP Loss of energy probability*

$$LOEP = \frac{EENS}{\int_0^{\bar{D}} G_1(x)dx}$$

Unit contribution to system reliability: *ELCC* and *FCE* (i)

- Effective load-carrying capability (*ELCC*)
  - Increment in maximum demand that can be covered by the system when adding a given unit, keeping constant a specific reliability index
  - Depends on the unit characteristics
    - Maximum output
    - Forced outage rate (*EFOR*), scheduled maintenance
    - Primary energy limits
  - One-year scope
  - Algorithm (for the decrement in maximum demand)
    - All the units of the system are dispatched
    - *LOLP* is determined
    - Deconvolution of a unit
    - Unit *ELCC* is determined

Unit contribution to system reliability: *ELCC* and *FCE* (ii)

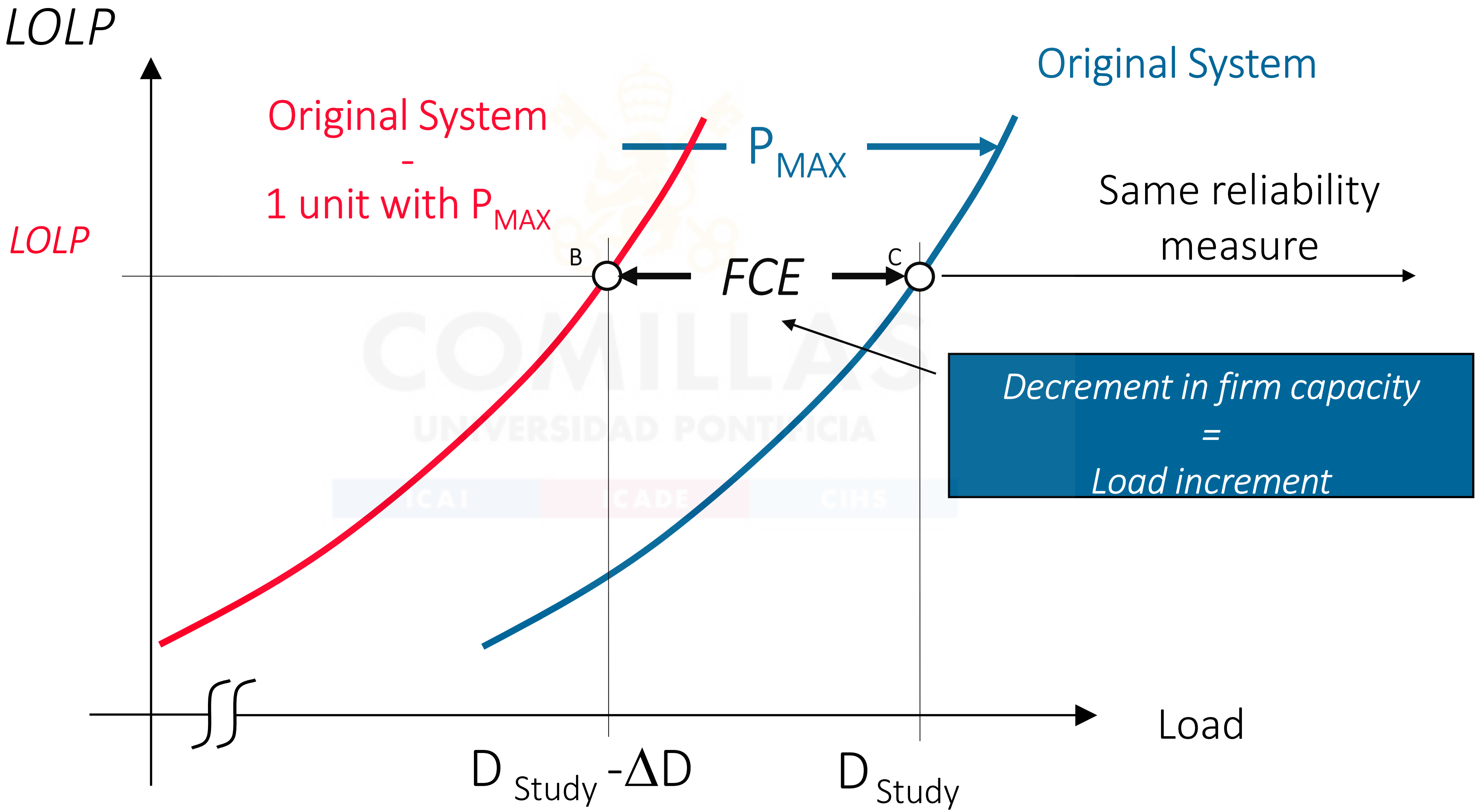


Unit contribution to system reliability: *ELCC* and *FCE* (iii)

- Firm Capacity Equivalent (*FCE*)
  - Like *ELCC*, it is computed considering only the demand of a given hour
  - Firm capacity is defined as the ideal unit always available
    - No outages, no maintenance
  - Given a generation system and a load, *FCE* is the power capacity with failure probability equal to 0, such as if substituted by the unit, gives the same system reliability measure

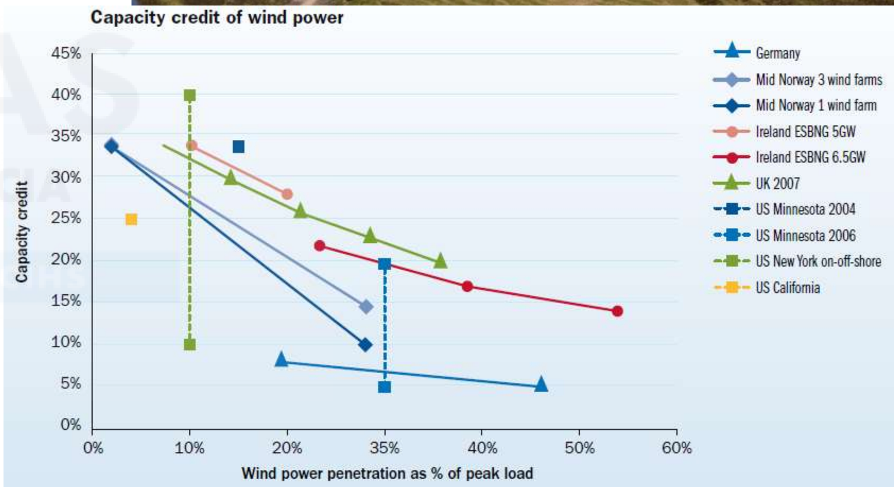
- *FCE* and *ELCC*
  - Define the (incremental or marginal) contribution to system reliability that each unit is reasonably able to provide
  - Define the maximum capacity each generating unit can offer or remunerate for.
  - Must be used to determine capacity payments by contributing to system reliability.

Unit contribution to system reliability: *ELCC* and *FCE* (iv)



Capacity credit of wind power

- Contribution of wind power to system adequacy.
- It is estimated by determining the capacity of conventional plants displaced by wind power while maintaining the same degree of system reliability, in other words, an unchanged probability of failure to meet the reliability criteria for the system.
- Alternatively, it is estimated by determining the additional load the system can carry when wind power is added, maintaining the same reliability level.



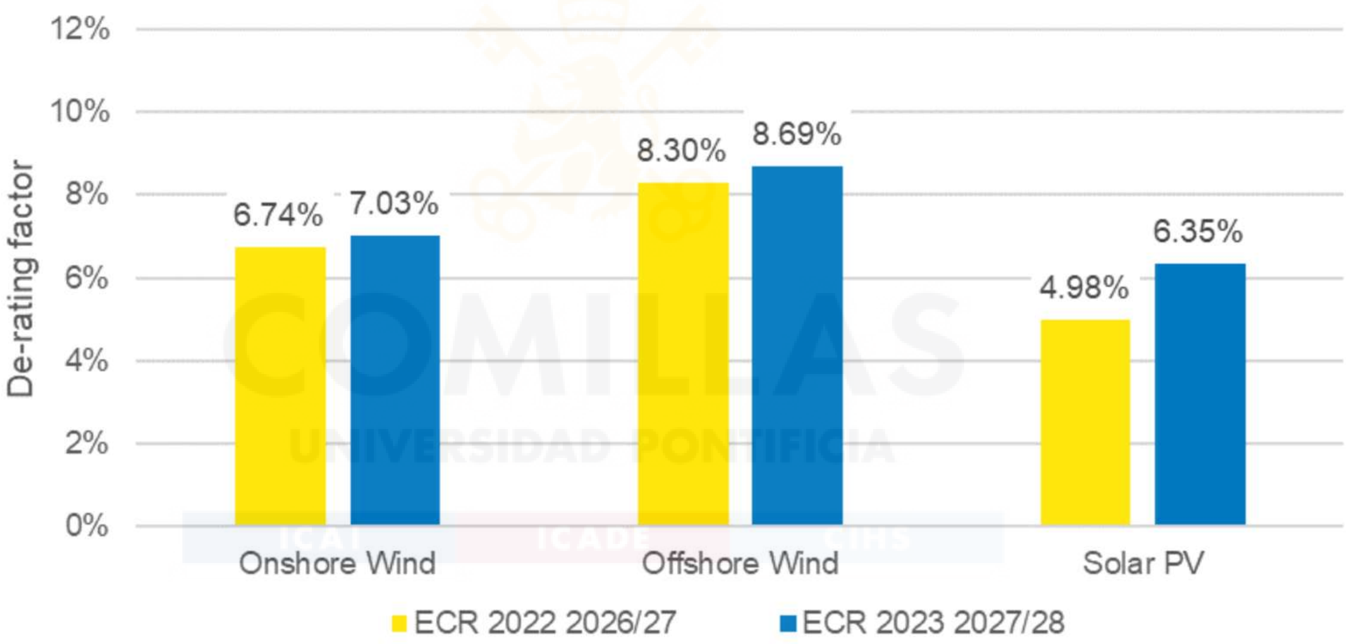
EWEA Powering Europe: wind energy and the electricity grid 2010
www.ewea.org/grids2010/fileadmin/documents/reports/grids_report.pdf

M. Amelin *Comparison of Capacity Credit Calculation Methods for Conventional Power Plants and Wind Power* IEEE Transaction on Power Systems, 24(2): 685-691 May 2009 10.1109/TPWRS.2009.2016493

NERC *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning* March 2011 http://www.nerc.com/files/ivgtf1-2.pdf

De-rating Factors for Conventional Plants, Storage and Renewables for Capacity Market Auctions in UK

Figure 25: De-rating factors for renewables T-4 comparison



Source: nationalgridESO. May 2023

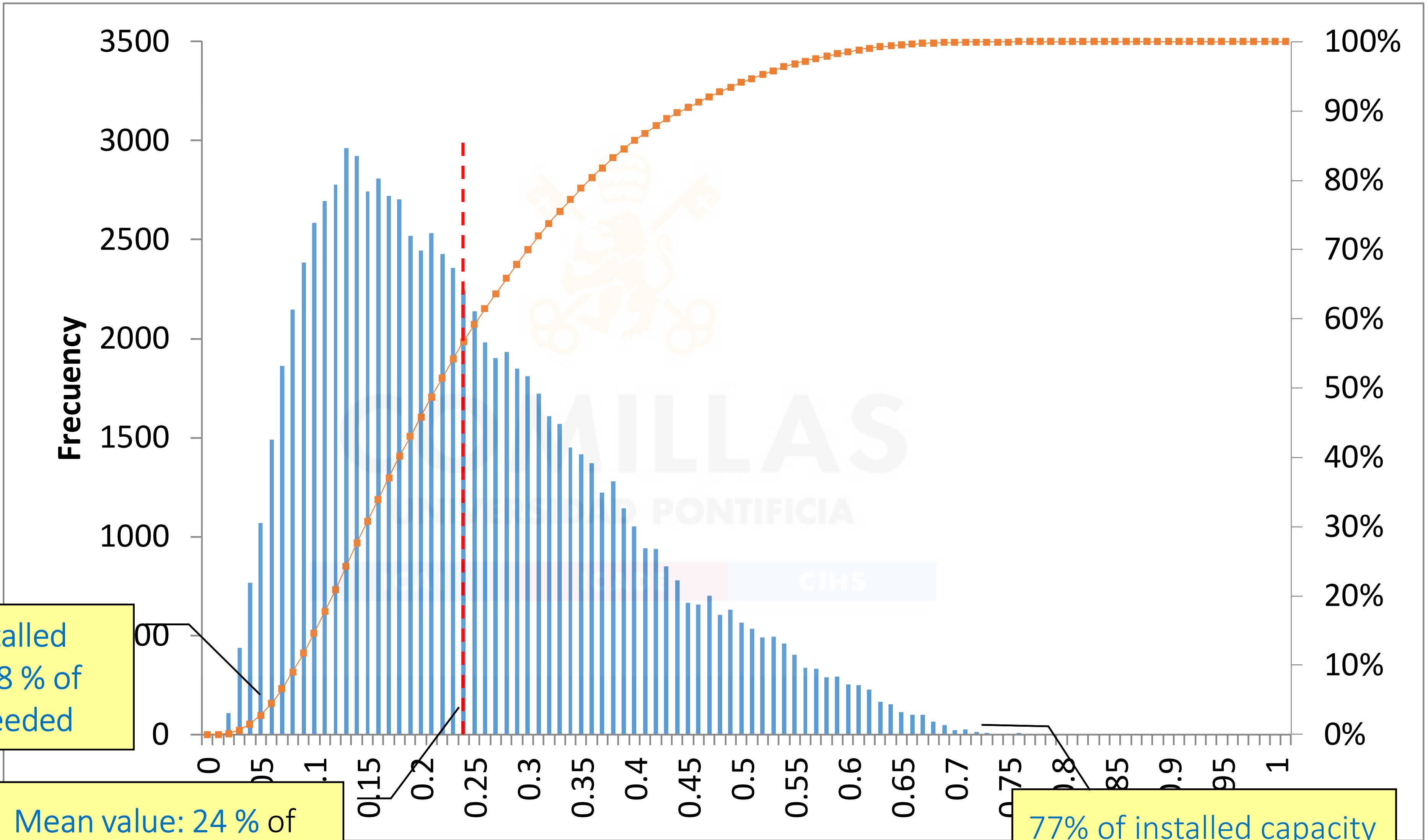
https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Electricity%20Capacity%20Report%202023.pdf

Wind generation in adequacy calculations and capacity markets

Area	Method for wind power capacity credit.	Has wind power an impact on the capacity market?	Is wind power paid for the capacity credit
Sweden	Probability of 90% of being exceeded = 9% of installed capacity	No: Wind power capacity credit is not considered concerning size of strategic reserve	No
Great Britain	Equivalent Firm Capacity based on Expected Unserved Energy as the statistical risk metric CM participant wind is paid marginal EFC, overall wind fleet is represented by total EFC	Yes – but as it is mostly ineligible for the CM due to most of the wind projects receiving subsidy, it mainly reduces the amount of capacity that needs to be procured from other supply sources via it's total EFC	CM participant wind is paid as per the marginal EFC. Remainder of the non-CM-participant wind gets subsidies from government schemes, which may include an element of the capacity value indirectly
France	Equivalence to perfect mean to respect LOLE = 3 h	Direct participation in capacity market (1 wind guarantee = 1 thermal guarantee = ...)	Yes (but reduces other remuneration from energy market - ie. "Contract for Difference")
Ireland	ELCC relative to LOLE target, within a least worst regrets approach	Yes, participation is permitted but voluntary, with low contribution at present	Yes, subject to voluntary participation, but non-performance strike price penalties
US-PJM	Three year average of capacity factor at peak load hours.	Yes	Yes
US-ERCOT	Ten year average of capacity factor at peak load hours in each season	N/A	No
Finland	Wind power included in the LOLE calculations as time series.	Can decrease the need for the strategic reserve.	No
Portugal	Combination of i) of 95% and 99% exceeding probability and ii) Wind power included in the LOLE calculations as time series.	Yes	No
Spain	Probability of 95% of being exceeded	No. Capacity payments are independent on wind firm capacity	No
Norway	Combination of power market and grid simulations	Indirectly (WP may impact the request for reserve options)	No
Denmark	Wind power included in the EUE, LOLE calculations as time series.	No	No
Belgium	Scenario based probabilistic assessment (Monte Carlo with hourly dispatch on 30 scenario years)	Indirectly (Adequacy assessment to determine volume of strategic reserves)	No
Germany	1% capacity credit	Indirect: due to the regional focus of installed wind power in the northern part, a grid reserve is needed for the southern part	No
Italy	Equivalent Firm Capacity based on LOLE taken as statistical risk metric	Direct participation to capacity market	Yes, if selected in the capacity auction
Netherlands	N.A.	N.A.	N.A.

L. Söder et al. *Review of wind generation within adequacy calculations and capacity markets for different power systems* Renewable & Sustainable Energy Reviews 10.1016j.rser.2019.109540

Probability distribution $f(x)$ and $F(x)$ (2014-2023 hourly data)



5 % of installed capacity 98 % of being exceeded

Mean value: 24 % of installed capacity

77% of installed capacity never exceeded

Source: REE

Discrete convolution method

- An interval for specifying the complementary cumulative distribution function (for example, 10 MW)
- Thermal unit capacities must be multiple of this interval
- Shifts of the load-duration curve are an exact number of points

Small case (i)

Units' capacity have to be multiple of this number

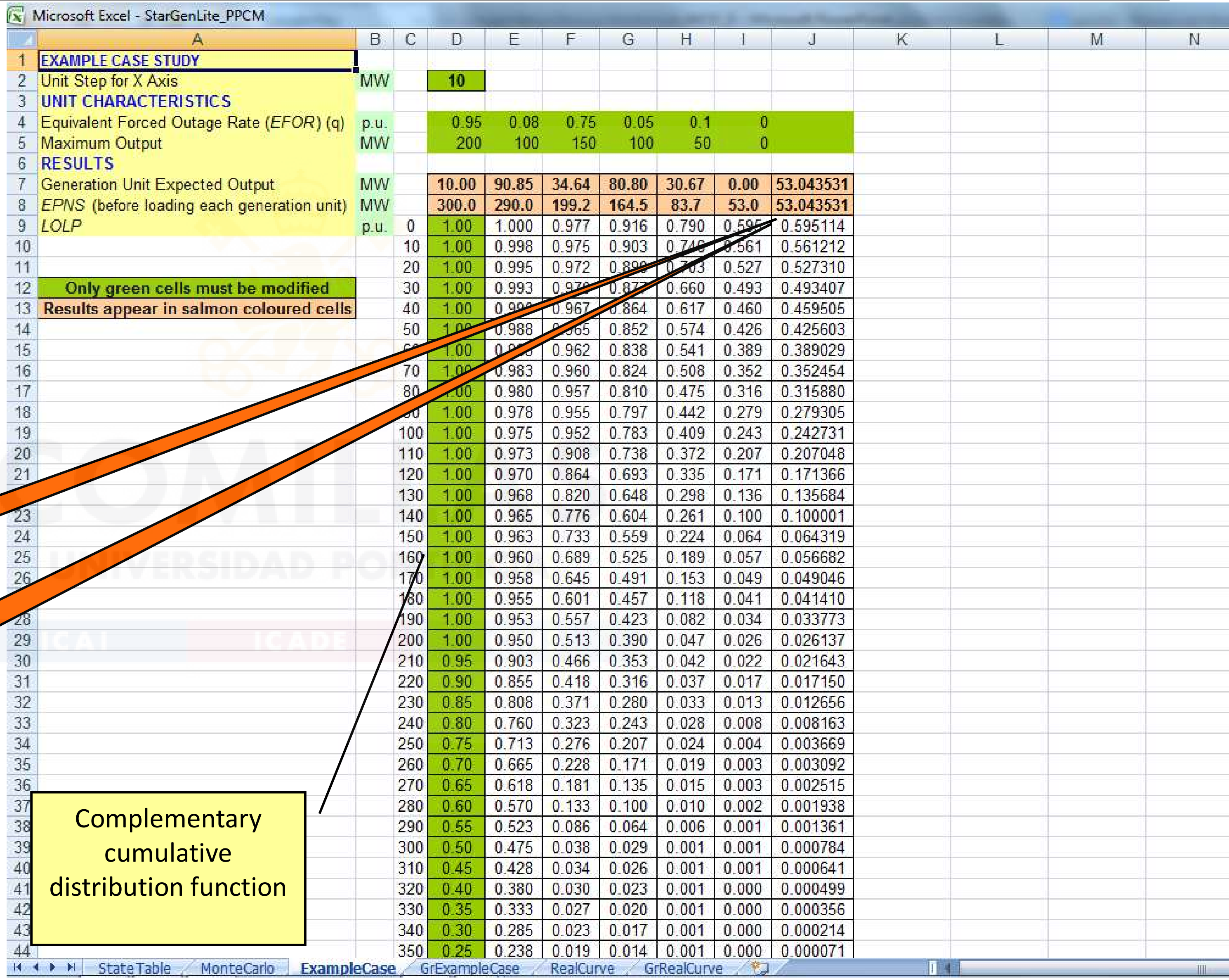
EENS before unit dispatch

LOLP before unit dispatch

EENS = 53 MW

LOLP = 0.595

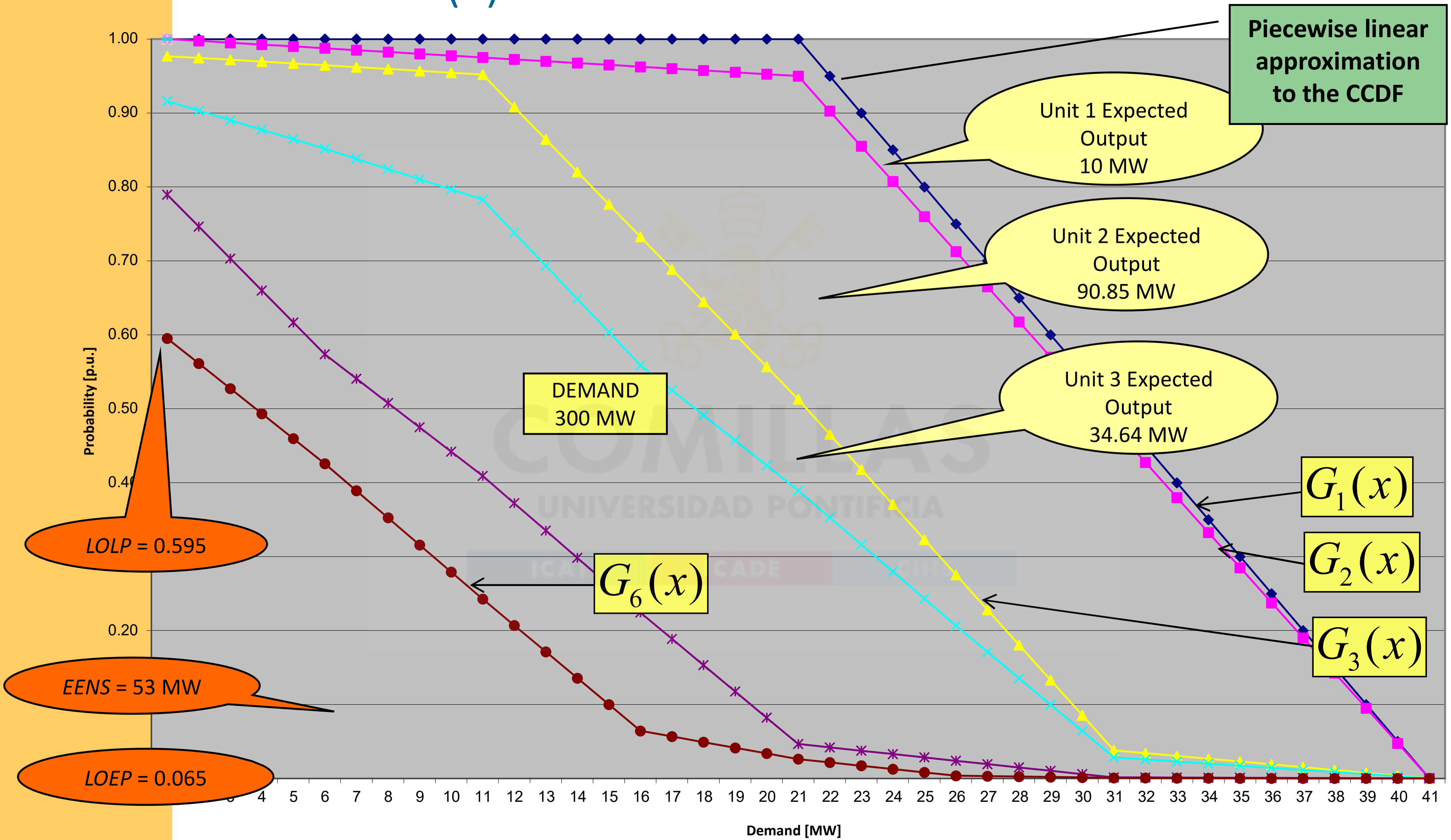
Complementary cumulative distribution function



Microsoft Excel - StarGenLite_PPCM

	A	B	C	D	E	F	G	H	I	J
1	EXAMPLE CASE STUDY									
2	Unit Step for X Axis	MW		10						
3	UNIT CHARACTERISTICS									
4	Equivalent Forced Outage Rate (*EFOR*) (q)	p.u.		0.95	0.08	0.75	0.05	0.1	0	
5	Maximum Output	MW		200	100	150	100	50	0	
6	RESULTS									
7	Generation Unit Expected Output	MW		10.00	90.85	34.64	80.80	30.67	0.00	53.043531
8	*EPNS* (before loading each generation unit)	MW		300.0	290.0	199.2	164.5	83.7	53.0	53.043531
9	*LOLP*	p.u.	0	1.00	1.000	0.977	0.916	0.790	0.595	0.595114
10			10	1.00	0.998	0.975	0.903	0.74[illegible]	0.561	0.561212
11			20	1.00	0.995	0.972	0.89[illegible]	[illegible]	0.527	0.527310
12	Only green cells must be modified		30	1.00	0.993	0.97[illegible]	0.87[illegible]	0.660	0.493	0.493407
13	Results appear in salmon coloured cells		40	1.00	0.99[illegible]	0.967	0.864	0.617	0.460	0.459505
14			50	1.00	0.988	[illegible]	0.852	0.574	0.426	0.425603
15			[illegible]	1.00	[illegible]	0.962	0.838	0.541	0.389	0.389029
16			70	1.00	0.983	0.960	0.824	0.508	0.352	0.352454
17			80	1.00	0.980	0.957	0.810	0.475	0.316	0.315880
18			[illegible]	1.00	0.978	0.955	0.797	0.442	0.279	0.279305
19			100	1.00	0.975	0.952	0.783	0.409	0.243	0.242731
20			110	1.00	0.973	0.908	0.738	0.372	0.207	0.207048
21			120	1.00	0.970	0.864	0.693	0.335	0.171	0.171366
[illegible]			130	1.00	0.968	0.820	0.648	0.298	0.136	0.135684
23			140	1.00	0.965	0.776	0.604	0.261	0.100	0.100001
24			150	1.00	0.963	0.733	0.559	0.224	0.064	0.064319
25			160	1.00	0.960	0.689	0.525	0.189	0.057	0.056682
26			170	1.00	0.958	0.645	0.491	0.153	0.049	0.049046
[illegible]			180	1.00	0.955	0.601	0.457	0.118	0.041	0.041410
28			190	1.00	0.953	0.557	0.423	0.082	0.034	0.033773
29			200	1.00	0.950	0.513	0.390	0.047	0.026	0.026137
30			210	0.95	0.903	0.466	0.353	0.042	0.022	0.021643
31			220	0.90	0.855	0.418	0.316	0.037	0.017	0.017150
32			230	0.85	0.808	0.371	0.280	0.033	0.013	0.012656
33			240	0.80	0.760	0.323	0.243	0.028	0.008	0.008163
34			250	0.75	0.713	0.276	0.207	0.024	0.004	0.003669
35			260	0.70	0.665	0.228	0.171	0.019	0.003	0.003092
36			270	0.65	0.618	0.181	0.135	0.015	0.003	0.002515
37			280	0.60	0.570	0.133	0.100	0.010	0.002	0.001938
38			290	0.55	0.523	0.086	0.064	0.006	0.001	0.001361
39			300	0.50	0.475	0.038	0.029	0.001	0.001	0.000784
40			310	0.45	0.428	0.034	0.026	0.001	0.001	0.000641
41			320	0.40	0.380	0.030	0.023	0.001	0.000	0.000499
42			330	0.35	0.333	0.027	0.020	0.001	0.000	0.000356
43			340	0.30	0.285	0.023	0.017	0.001	0.000	0.000214
44			350	0.25	0.238	0.019	0.014	0.001	0.000	0.000071

Small case (ii)

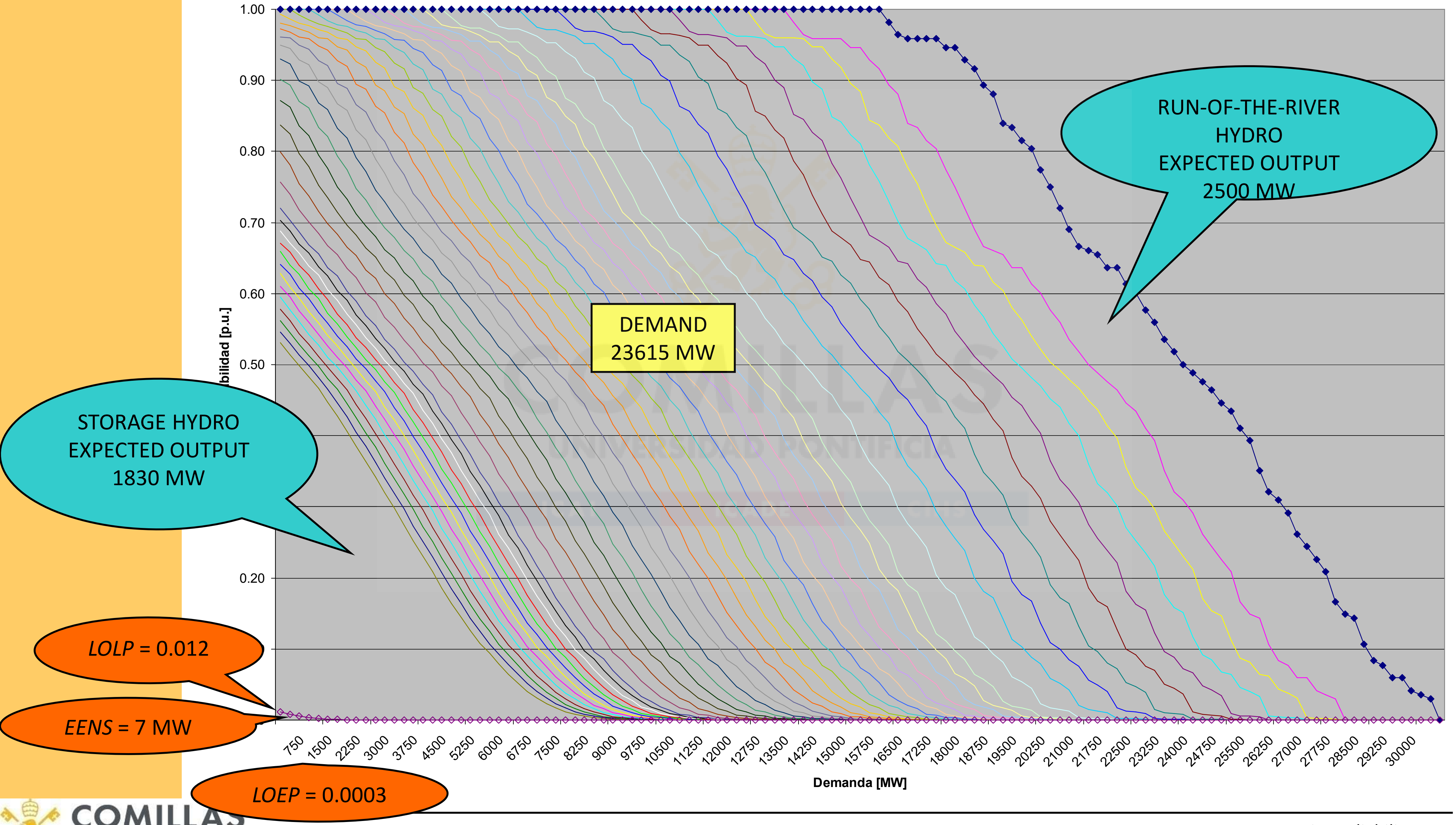


Real case (i)

- Interval size: 250 MW
- Maximum demand 30467 MW, minimum 15766 MW
- Installed capacity of thermal units 32000 MW

Nº of units	Capacity [MW]	*EFOR*
1 (~Run-Of-the-River)	2500	0
9	1000	0.05
20	500	0.05
12	250	0.05
1 (~Storage Hydro)	7500	0

Real case (ii)



1.00
0.90
0.80
0.70
0.60
0.50
0.20
bilidad [p.u.]
Demanda [MW]
750 1500 2250 3000 3750 4500 5250 6000 6750 7500 8250 9000 9750 10500 11250 12000 12750 13500 14250 15000 15750 16500 17250 18000 18750 19500 20250 21000 21750 22500 23250 24000 24750 25500 26250 27000 27750 28500 29250 30000
DEMAND 23615 MW
RUN-OF-THE-RIVER HYDRO EXPECTED OUTPUT 2500 MW
STORAGE HYDRO EXPECTED OUTPUT 1830 MW
LOLP = 0.012
EENS = 7 MW
LOEP = 0.0003

Dispatch of limited energy plants

- *LEP* (*limited energy plants*)
  - Thermal units with maximum fuel available (take-or-pay contracts)
  - Hydro units with limited unregulated flows
    - If they are dispatched first because their variable cost is 0, they will produce more energy than available
    - Unregulated flows are supposed to be deterministic (expected value)
    - They are dispatched at maximum capacity to minimize total variable costs (but which is their maximum capacity?)
- Algorithm
  - We try to dispatch the unit at every step until the energy produced by the *LEP* unit is lower than its available energy
  - Convolution invariance property: the sum of the energy produced by the thermal unit and the *LEP* unit is the same regardless of the order in which they are dispatched
  - Energy produced by the thermal unit is recalculated

Summary of a PPC model

- Advantages:
  - Demand and generation are independent random variables
  - Computation of units' output
  - Computation of reliability measures
  - Computation speed
- Disadvantages:
  - Single loading order (heuristically obtained)
  - No minimum load, no startup or shutdown
  - No extensions for electricity markets

1. Introduction
2. Reliability assessment
3. Adequacy assessment methods
4. Probabilistic production cost model
5. Assignment

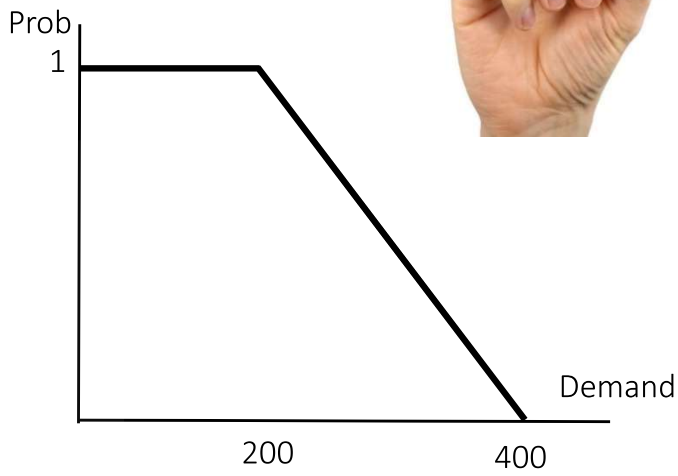
5

Assignment

Generation reliability homework

- Determine the expected unit output, *LOLP*, and *EENS* by using Monte Carlo simulation

- For this electric system
  - Load varies linearly (see figure) from 200 to 400 MW
  - Period duration 1000 h
  - Thermal generation dispatched by increasing variable cost
- This assignment is done individually
- Due date: Sunday, November 10
- Homework discussion: Monday, December 9



Capacity [MW]	EFOR [p.u.]	Variable cost [€/MWh]
230	0.07	50
210	0.04	65
180	0.09	45
150	0.06	75
80	0.10	110
70	0.20	120

Generation reliability homework

- Questions to address in the report (<2 pages, <1000 words)
  1. State table and PPC model give the same results for *LOLP* and *EENS* (2 pts)
  2. Estimate the number of samples of MC simulation needed to achieve approximately a 20 % half-width confidence interval in the *LOLP* with a confidence level of 95 % and determine the *LOLP* and *EENS* for this MC simulation (2 pts)
  3. Compute the expected energy produced by each generator with each one of the three methods (2 pts)
  4. Compute the expected total variable costs of the system with each of the three methods (1 pts)
  5. Substitute the biggest unit for two smaller ones with the same total capacity and the same EFOR and evaluate the effect on the reliability measures (3 pts)

Decision support models in electric power systems

Generation reliability

Prof. Andrés Ramos

https://pascua.iit.comillas.edu/aramos/Ramos_CV.htm

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