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Methodological improvements of Resource Adequacy Assessments

Work package 3
Final Report

Approaches for economic assessments of power plants, storage facilities and flexibilities in the framework of Resource Adequacy Assessment

Study on behalf of the
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Approaches for economic assessments of power plants, storage facilities and flexibilities in the framework of Resource Adequacy Assessments

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List of Abbreviations

ACER	European Union Agency for the Cooperation of Energy Regulators
AS	Ancillary Services
BM	Balancing Mechanism
CAPEX	Capital Expenditure
CBA	Cost Benefit Analysis
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
CM	Capacity Mechanism
CONE	Cost of New Entry
CPF	Carbon price floor
CRM	Capacity Remuneration Mechanism
CWE	Central Western Europe
CY	Climate years
DSM	Demand-Side-Management
DSO	Distribution System Operator

DSR	Demand-Side-Response
EENS	Expected energy not served
ED	Economic Dispatch
EMEA	Europe, Middle East, and Africa
ENTSO-E	European Network of Transmission System Operators
EOM	Energy only market
ERAA	European Resource Adequacy Assessment
ERCOT	Electric Reliability Council of Texas
EV	Electric vehicle
EVA	Economic Viability Assessment
FBMC	Flow-Based Market Coupling
HP	Heat Pumps
IEM	Internal Energy Market
LOLE	Loss of load expectation
MAF	Mid-Term Adequacy Forecast
MCD	Monte-Carlo drawings
(EU) MS	(EU) Member State(s)
NGO	Non-governmental organisation
NPV	Net present value
NRAA	National Resource Adequacy Assessment
NTC	Net Transfer Capacity
OCGT	Open Cycle Gas Turbine
O&M	Operation and maintenance
PECD	Pan-European Climate Database
PJM	PJM Interconnection LLC (PJM)
PtH	Power-to-Heat
PV	Photovoltaic
RAA	Resource Adequacy Assessment
RD	Redispatch
RS	Reliability Standards
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
VOLL	Value of Lost Load
WACC	Weighted Average Cost of Capital

Executive Summary

The objective of this report is to review and assess the methodological options for applying the Economic Viability Assessment (EVA). In particular, the reviewed options should focus on reflecting a realistic approach to model market participants' decisions for investment and retirement of capacity resources under market conditions, in line with the current scientific and practical standards and reflecting the ongoing discussions on the implementation of economic assessments in Resource Adequacy Assessments (RAA) across Europe.

An important objective of the RAA is to inform political decision-makers whether it can be expected that a given reliability standard will be met through market-based drivers or whether specific additional measures may be necessary, such as the introduction of capacity markets to incentivise maintaining the existing and developing new capacity.
In this context, it is important that the capacity assumptions used in the RAA are consistent with the expected decisions of market participants regarding the investment, retirement, and mothballing decisions for the assets they operate. The additional step termed Economic Viability Assessment should ensure the economic plausibility of the capacities used in the Resource Adequacy Assessment. An EVA shall provide an endogenous assessment of the economic decisions of operators of each capacity resource and target year to maintain, retire, mothball, extend or new-build capacities.

Costs and revenues are used in a converging process to assess the economic viability of assets. Generally, the economic dispatch computation of the RAA serves as an input to the EVA to determine variable costs and revenues in the energy-only market (EOM), that is, the variable fuel and O&M costs and revenues associated with the operation in the wholesale markets and the markets for Ancillary Services (AS) and Balancing Mechanisms (BM). Next, the EOM perspective is extended with fixed costs and other revenues to determine if the decision to enter or to exit the capacity is economically viable and thus whether the capacity should be considered in the RAA. In total, the sources of revenues relevant for the EVA are the revenues from wholesale markets, from ancillary services and balancing markets, from capacity markets where they exist, from subsidies and lastly, from other sources. On the other side, the sources for costs relevant for the EVA are the costs for fuel and variable O&M, as well as for fixed O&M and, where applicable, the costs of (re-)investment.

As part of this project, a series of workshops were held where the methodological options for an EVA were discussed with market participants and academic experts. In particular, a key topic discussed during the workshops with market participants in July 2021 was how economic viability is actually evaluated by investors and operators of various types of capacity. The workshop has revealed a number of specificities of the market participants' decisions to enter or exit capacity in the market both in the current conditions and in anticipation of the EU-wide implementation of the market reforms within the Electricity regulation. In particular, this discussion has highlighted a striking difference in the drivers of the entry and exist decisions between the conventional thermal baseload plants and flexibility operators, such as peakload power plants, DSR and storage.

- For conventional baseload plants, the decision to enter or exit is mostly driven by the wholesale market as the main source of revenue. Typically, market participants apply conservative approaches to assess the ancillary services revenues, but on the other hand, capacity mechanisms can be a key driver for market entries. Investment decisions consider a rather long timeframe and conventional baseload plants operators have a risk averse approach in assessing forward scenarios for the entry/exit decisions.

- Flexibility resources, such as peakload power plants, storage and DSR, stack revenues from as many markets as possible. Each MW and MWh needs to be sold to combine market revenues, such as from balancing markets or other ancillary services. Capacity mechanisms can be crucial as well. Today balancing markets are the most important source of their revenue, but at higher storage and DSR capacities these markets might become saturated, and the importance of wholesale market revenues could increase with more volatile market prices. Flexibility entry/exist decisions are very sensitive to regulation and specific market design parameters. One could expect that investors relying on such a more uncertain income would have higher hurdle rates than those of the more risk-adverse investors. However, as compared to conventional baseload capacity, DSR and storage can be mobilised at lower investment cost and much faster. Hence, investors in such capacity have a different risk profile and are often more risk-seeking than risk-averse.

As a second key topic in the workshops, the two distinct options to perform EVA were discussed, which the ERAA-methodology as approved by ACER presents in Article 6 para 2:

- **Economic Viability Assessment of individual capacity resources (individual EVA approach).** The first option is to assess the economic viability of individual assets in the literal sense by performing an explicit assessment of revenues and costs by asset. In this case the revenues of the capacity resources are directly assessed and stacked across the revenues from the wholesale market, ancillary services, revenues from outside of the electricity sector and subsidies, and, where applicable, the revenues from capacity mechanisms. The entry, exit and mothballing decisions are then assessed for each capacity resource based on the estimated revenues and costs and accounting for the risk.

- **Economic Viability Assessment through overall system cost minimisation (cost minimisation EVA approach)**. The second option is to take a system instead of asset perspective, where the EVA will be implemented based on a minimisation of total system costs. In this case, the entry and exit decisions are assessed simultaneously for all capacity resources, all bidding zones and account for substitutional effects between capacity resources and bidding zones, by minimising the discounted costs of investment and operation of the entire power system.

The differences of the two approaches result in different strengths and weaknesses when they are introduced in practice. In principle, the two approaches would likely be able to yield the same result when using the same inputs, if unlimited computational capacity was available. The relative strengths and weaknesses of the two approaches only manifest because they tend to allocate the available computational capacity to different elements of the EVA:

- The individual EVA focuses explicitly on an accurate estimation of the individual costs and revenues, making sure the economic dispatch model used for the price estimation properly accounts for the generation constraints and calibrating the results on the historical market and price outcomes. However, the complexity on the investment element of the model may require simplifications regarding interdependencies between resource types, markets and regions.
- The cost minimisation approach, in turn, allows for considering all interactions and combinations of entering and exiting capacity types across all bidding zones considered in the assessment. However, it may require simplifications e.g. of the chronology and intertemporal unit commitment constraints.

A combination of the two approaches could provide a potential solution to the computational limitations of each of the approaches, as was suggested by the academic workshop participants. In particular, the capacity equilibrium resulting from the cost minimisation EVA could be used as a starting point for the viability assessment of the EVA of capacity resources.

Another important element of an EVA is the consistency between the EVA and RAA that needs to be achieved on the adequacy indicators. That is, despite being focused on the simulation of market participants' investment and retirement decisions, the EVA also provides an estimate of the loss of load expectation (LOLE), i.e., situations where supply is insufficient to meet demand albeit relying on a simplified modelling approach as compared to the RAA. Nevertheless, the outcomes of the EVA in terms of the LOLE need to be broadly consistent with those of the RAA.
The overall objective of the EVA is to ensure that the RAA assesses the potential forward adequacy development of the system based on the economically driven assumptions of possible expected capacity in the future. Since the purpose of the RAA is to inform about whether the system in the medium term of 10 years can reach its economically optimal Reliability Standard or whether it would need interventions (e.g. capacity mechanisms), it is important that the chosen EVA approach reflects the actual and future market conditions in an appropriate way.

It has to be noted, that the results of any EVA will have its limits, especially regarding the consideration of rare and/or unpredictable risks. The extreme situation in the energy markets that has been developing in Europe in 2022 driven by the Russian invasion in Ukraine is a good example for such risks that are difficult to predict but that may nevertheless have a significant impact on the EVA and the RAA. We refer the readers to the report under WP5 Extreme Events (as well as WP4 Climate Change) of the present project for more information on the accounting for extreme events and climate change in the RAA.

1. Introduction

This report presents an evaluation of approaches for Economic Viability Assessments (EVA) of power plants, storage facilities and flexibilities in the framework of resource adequacy assessments.
Until recently, Resource Adequacy Assessments (RAA) were largely based on exogenous assumptions for the future evolution of installed generation capacities and other available flexibility resources. This made the results of RAA very sensitive to the exogenous mix assumptions and scenarios and to the extent to which these mix scenarios are economically viable or represent under- or over-capacity assumptions.
An ideal EVA methodology should allow to endogenously estimate a realistic evolution of the generation and demand-side capacity mix driven by the combination of market, regulatory and policy frameworks (e.g. design of the spot and balancing markets, design of the ancillary services and the presence of capacity mechanisms, policies and regulation supporting RES and/or driving the phase-out of technologies, e.g. coal and nuclear). Such dynamic modelling of the mix provides an invaluable input to the RAA.
The objective of this report is to review and assess the methodological options for applying the EVA. In particular, the reviewed options should focus on reflecting a realistic approach to model market participants' decisions for investment and retirement of capacity resources under market conditions, in line with the current scientific and practical standards and reflecting the ongoing discussions on the implementation of economic assessments in RAA across Europe.
An important part of this project was a series of workshops on the methodologies of the EVA with industry and academic experts held in 2021 and 2022. The outcomes of the workshops contributed to the findings of this report.

It has to be noted, however, that the results of any EVA will have its limits, especially regarding the consideration of rare and/or unpredictable risks. The extreme situation in the energy markets that has been developing in Europe in 2022 driven by the Russian invasion in Ukraine is a good example for such risks that are difficult to predict but that may nevertheless have a significant impact on the EVA and the RAA. We refer the readers to the report under WP5 Extreme Events (as well as WP4 Climate Change) of the present project for more information on the accounting for extreme events and climate change in the RAA.

The report is structured as follows:

- First, we provide a theoretical background of the Economic Viability Assessment approaches and the main options.
- Second, we present practical implementation details of the Economic Viability Assessment options.
- Finally, we conclude with a summary of the main challenges and options when implementing Economic Viability Assessment in practice.

2. Theoretical background for EVA

In the following subsections we will first comprehensively introduce the role of the EVA within the RAA and its methodology according to the current ENTSO-E methodology for the ERAA as approved by ACER. We will then provide an overview of the economic background for the EVA by discussing the economic drivers for market entry, exit and mothballing. This subsection is followed by an in-depth discussion of the two different options the ENTSO-E methodology offers to perform the EVA. The last subsection concludes this chapter.

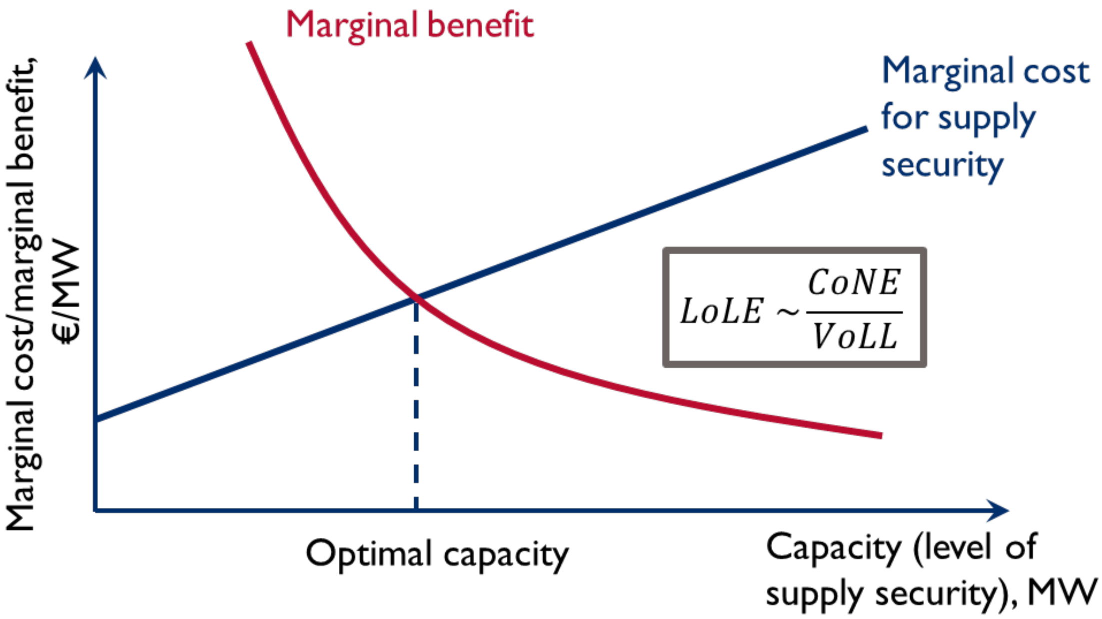
2.1 Role of the EVA within the RAA

European power markets are undergoing major changes and increasing shares of fluctuating generation from wind and solar not only impact the demand for technologies providing resource adequacy, but equally alter the market conditions these technologies are subjected to. Declining wholesale prices triggered by renewable generation with low or zero marginal costs, also referred to as the merit-order effect, put pressure on the profitability of conventional thermal plants and challenge their model to recover capital costs in energy-only markets. At the same time, new options to guarantee resource adequacy, such as demand-side response (including new technologies such as electrolysers or heat pumps) or storage, with more complex business models arise that must be included into adequacy assessments. Furthermore, the constraints on the transmission network infrastructure between the bidding zones make these changes non-uniform across Europe and induce differences in the adequacy situations between the bidding zones.
The evolution of the electricity system may create uncertainties, especially political ones, inhibiting investment signals to reach the theoretically optimal level of system adequacy (Reliability Standard). The RAA accompanied by the EVA intends to assess the expected level of investment and retirement and the resulting level of adequacy.
Below we discuss the role of the EVA in the context of the Reliability Standard and Resource Adequacy Assessment and formulate the criteria for the EVA.

2.1.1 Reliability Standard

The recent Electricity Regulation 2019/943 requires the Member States to set the theoretical economically optimal Reliability Standard in terms of a Loss of Load Expectation (LOLE) target. The theoretical optimal level of security of supply is determined by the point at which the incremental cost of capacity insuring customers against demand curtailment is equal to the incremental benefit to customers of avoiding load curtailment. Therefore, the Reliability Standard reflects a simplified economic optimisation between the marginal cost of a new capacity resource, given by the annualised investment cost or the Cost of New Entry (CONE), and the marginal cost reduction of Expected Energy Non-Served (EENS), given by the product of the expected average number of the loss of load hours (LOLE) and the estimated Value of the Loss of Load (VOLL). The Reliability Standard defined as the LOLE target will then be set as a ratio between the CONE and VOLL (Figure 1).
A detailed methodology for setting the Reliability Standard, as well as the estimation of the Value of Loss of Load and the Cost of New Entry was developed by ENTSO-E and approved by ACER in 2020 (ACER, 2020).

Figure 1: Economic equilibrium determining the Reliability Standard



Source: Own display

2.1.2 Possible reasons for deviations from the Reliability Standard

Under a number of simplifying assumptions, the theoretical economically optimal Reliability Standard determined by the LOLE target based on the values of VOLL and CONE would be naturally achieved. In an isolated market and in a long-term market equilibrium, a rational investor would build the peaking technology as long as its expected margin determined by the market price reaching VOLL during the scarcity periods of LOLE exceeds the investment cost of CONE.

However, in the real world, as well as in realistic electricity market modelling assessments, accounting for the interconnected bidding zones[1] and possible market imperfections the capacity entry/exit may deviate from the theoretically optimal level of capacity resulting in the system states deviating from the RS.

While interconnected bidding zones are a central element of the European IEM, possible market imperfections may be considered when conducting a RAA. According to Article 20 of Regulation 2019/943 on the elements of implementation plans for market reforms, those market imperfections may include:

- regulatory distortions,
- technical bidding limits,
- too low interconnection and grid capacity,
- obstacles for self-generation, energy storage, demand-side measures, and energy efficiency,
- Missing of cost-efficient and market-based procurement of balancing and ancillary service, and
- regulated prices.

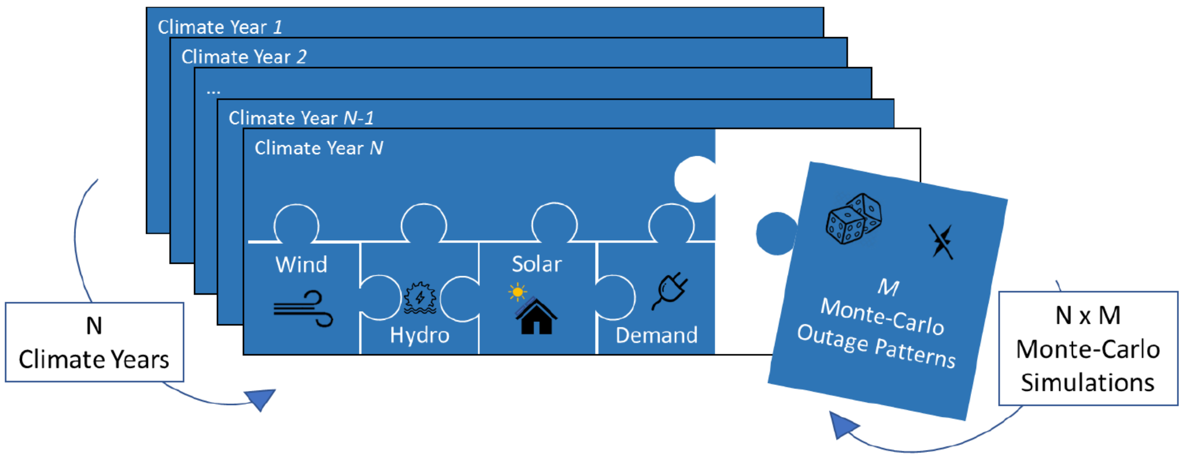
[1] In an interconnected system, possible variation of the CONE and VOLL across the bidding zones may cause the deviation from the Reliability Standard in a given bidding zone, other things being equal.

2.1.3 Resource Adequacy Assessment and Economic Viability Assessment

A RAA is an important analysis allowing to assess whether the future expected resources are sufficient to meet the demand. The RAA estimates the indicators of adequacy, such as the average number of hours in which a country's electricity demand cannot be met by the own available resources or imports via interconnectors (LOLE) and the associated Expected Energy not Served (EENS) expressed in GWh per year over the forward period up to 10 years.
The results of the RAA in terms of LOLE are compared with the LOLE target defining the Reliability Standard to assess whether in the medium-term period of 10 years adequacy concerns may appear which may potentially require interventions.

The RAA uses Monte Carlo Simulations to simulate each target year several times with different random inputs to obtain a large sample of results deriving from possible future states of the system. The random inputs are climate profiles and random outage events derived from available statistics and climate data. The objective of such simulations is to obtain a robust estimate of the adequacy indicators given a set of assumptions.

Figure 2. Construction of Monte Carlo sample years



Source: (ENTSO-E, 2021)

An important objective of the RAA is to inform and substantiate policy decisions, such as whether capacity mechanisms should be introduced to support maintaining the existing and developing new capacity, in case the RAA indicates a structural adequacy issue.
In this context, it is important that the capacity assumptions used in the RAA are consistent with the expected decisions of market participants regarding the investment, retirement, and mothballing decisions for the assets they operate. This consistency is provided by an EVA, which is an additional step to ensure the economic plausibility of the capacities used in the RAA. An EVA shall provide an endogenous assessment of the economic decisions of operators of each capacity resource and target year to maintain, retire, mothball, extend or new-build capacities.

Under the recent Electricity Regulation 2019/943, the European Resource Adequacy Assessment is required to contain an EVA. The European RAA methodology was developed by ENTSO-E and amended and approved by ACER on 02.10.2020.[2]

2.1.4 Criteria for the EVA

The Economic Viability Assessment is a quite complex model and as it is often the case with complex models, its usefulness depends on a number of methodological choices among the available options. Such choices are quite often imposed by the limited computational resources, which require to make certain simplifications. In the report we will aim to highlight the two main considerations that in our view should inform the methodological choices and the best allocation of the computational resources:

- How closely the resulting model reflects the entry/exit decisions taken by market participants;
- To what extent the chosen implementation approach is consistent with the overall objective of the RAA.

2.2 ENTSO-E methodology for EVA as approved by ACER

The EU Electricity Market Regulation 2019/943 for RAA stresses the importance of the Economic Viability Assessment, stipulating in Article 23 para 5 lit. b) *"The European resource adequacy assessment shall be based on a transparent methodology which shall ensure the assessment is based on an appropriate central reference scenario of projected demand and supply, including an* ***economic assessment of the likelihood of retirement, mothballing and new build of generation assets****…"*. Accordingly, Article 6 of ENTSO-E's methodology for the ERAA approved by ACER provides a general framework for performing economic viability assessments (EVA) (ACER, 2020).

2.2.1 Objective and scope of the EVA

According to Article 6 para 1 of ENTSO-E's methodology for the ERAA, the purpose of the EVA is to analyse the chances of either existing assets (generation, storage, demand response) being retired permanently or mothballed temporarily, new assets being build or relevant measures relating to the consumption of electricity, such as energy efficiency or demand-side management, being developed.

ENTSO-E's methodology as approved by ACER states that for each group of relevant assets, each modelled bidding zone and each year considered in the ERAA, the EVA should compare the expected market revenues against the costs in order to assess if the provision of capacity is economically viable (Article 6 para 4). The total revenues considered for the EVA are composed of revenues from different sources. These include revenues from wholesale electricity markets, revenues from participating in markets for ancillary services, and revenues from outside the electricity market, for example in case of combined generation of

[2] ACER (2020), Decision No 24/2020 of the European Union Agency for the Cooperation of Energy Regulators of 2 October 2020 on the methodology for the European resource adequacy assessment. https://documents.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2024-2020%20on%20ERAA.pdf

heat and power. Furthermore, revenues from political instruments, such as subsidies, or participation in capacity markets must be included as well.

Just like the RAA, the EVA is performed for each of the next ten years. Additionally, the EVA should also account for the expected costs and revenues beyond the studied time frame. Unlike adequacy assessment in the RAA, economic viability cannot be assessed for each year separately, but depends on the sum of revenues and costs across all years, even years that are beyond the scope of the RAA, but within the economic lifetime of an asset. For years outside of the RAA scope, but within the economic lifetime, the methodology permits to compute revenues based on forward prices in Article 6 para 9. According to Article 6 para 16 asset lifetimes beyond the years of the RAA can also be considered by depreciating the CAPEX using the Weighted Average Cost of Capital (WACC).

The regulatory boundaries of the power market must also be considered beyond direct subsidies or capacity markets as they affect revenues and market capacities. Such regulations include the zonal configuration of electricity markets, mandated phase-outs of certain technologies, for instance coal or nuclear power, or on the other hand expansion targets, for instance for renewable energy. For countries and bidding zones where capacity mechanisms already exist to enforce a certain reliability standard, the EVA with and without a capacity market should be performed as a check if the mechanism is actually necessary to achieve an adequate amount of capacity or not.

Another key point of the EVA mentioned in the ENTSO-E's methodology approved by ACER is to incorporate the risk perspective of investors into the analysis. Profitability of investments depends on several factors that are subject to considerable uncertainty. First and foremost, market revenues are uncertain, because electricity prices on the one hand and commodity prices on the other hand can fluctuate substantially. Other factors subject to uncertainty include the level of demand or fluctuations of renewable generation. Investors consider these risks when deciding on investments and hedge their investments against volatility and price spikes, which typically incur additional costs. Article 6 para 15 of the ENTSO-E methodology states that the effect of this risk management can be included in the EVA.

2.2.2 EVA and RAA scenarios

The EVA is embedded in the RAA that analyses the development of resource adequacy in the European power system for each of the next ten years. According to Article 3 of the ENTSO-E methodology, computation of the relevant indicators LOLE and EENS must build on a scenario framework that varies the level and structure of demand, the available power plant fleet, and the interconnection between regions. A mandatory reference scenario should be built on the projections of national TSOs.

The adequacy indicators are computed for each of these scenarios using an economic dispatch (ED) model that simulates the European power market by minimising operational costs of satisfying the assumed demand using the available power plant capacities.

Since the purpose of the EVA is to ensure the economic plausibility of the power plants capacities assumed, the input assumptions of the RAA must be adjusted according to the results of the EVA: economically not viable capacity that is currently in the market is removed, while viable, but mothballed capacity re-enters the market. Likewise, additional investment into new capacity or into extending the lifetime of existing capacity increase the available capacity, where profitable.

Due to their close connection, respective scenario assumptions for the RAA must also be applied in the EVA. However, Article 3 paragraph 4 of the ENTSO-E methodology states that the EVA is only mandatory for the reference scenario. Generally, consistency with the RAA is a priority of the EVA to ensure its accuracy. This consistency can be evaluated by comparing results of the dispatch simulations performed for the chosen EVA method and the RAA itself. We address these consistency issues in Section 3 below.

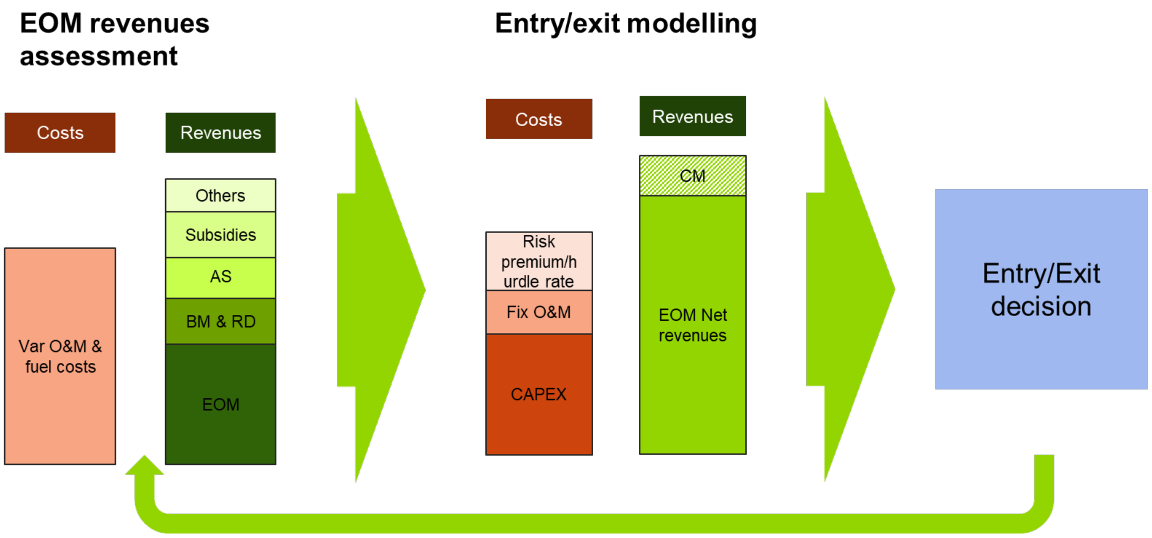
2.3 Main elements of the EVA

The two principal elements of the EVA are stacking a) the costs of operation, and if applicable investment, on the one hand and b) the revenues from operating the asset on the other hand. According to the ENTSO-E methodology, these steps are carried out for each type of technology, each target year, and each bidding zone considered in the overarching RAA.

Figure 3 illustrates how costs and revenues are used in a converging process to assess the economic capacities to be considered in the RAA. Generally, the economic dispatch computation of the RAA serves as an input to the EVA to determine costs and revenues in the energy-only market (EOM), that is, the variable fuel and O&M costs and revenues associated with the operation in the wholesale markets and the markets for Ancillary Services (AS) and Balancing Mechanisms (BM). Next, the EOM perspective is extended with costs and revenues to determine if the decision to enter or to exit the capacity is economic and whether the capacity should be considered in the RAA. The sources of revenues relevant for the EVA are categorized in the ACER's approved methodology as follows: Revenues from wholesale markets, from ancillary service and balancing markets, from capacity markets, from subsidies and lastly, from other sources.

Since costs and revenues constitute the key elements of the EVA, they are discussed at greater length in the following sections. We conclude with a discussion of revenue streams for different technologies.

Figure 3: Converging process of EVA



Note: The following abbreviations are used in this graph: Ancillary Services (AS), Balancing Mechanism (BM), Redispatch (RD), Energy only Market (EOM), operation and maintenance (O&M), and Capacity Mechanism (CM).
Source: Own display

2.3.1 Overview of the cost elements

Costs of assets can be grouped into four distinct categories: variable costs, annual fixed costs, CAPEX - all as introduced in ENTSO-E's methodology on CONE (short for cost of new entry) and mentioned in WP1 - and risk premia or hurdle rates (ACER, 2020).

Variable costs vary with generation and according to the comprehensive definition in Article 16 para 2 of ENTSO-E's methodology on CONE include: fuels costs depending on the asset's efficiency and expected fuel prices, CO_2 costs depending on the asset's emission factor and the expected emission prices, and other costs related to generation, for instance for handling of by-products (e.g. ashes) or for consumable materials (e.g. water). For DSR assets, variable costs are related to the cost of activation. Lastly, variable costs also include all taxes or levies imposed on variable generation.

Typically, the economic dispatch would result in scheduling the capacity to generate when its revenues from the energy and ancillary services markets exceed the variable costs. The revenues from such operation net of variable costs is referred to as EOM net revenues in Figure 3 Figure 3 above.
The net EOM revenues together with any other revenues received by the capacity regardless of the volume of production (e.g. capacity mechanism revenues) are then compared to the annual fixed costs to determine the entry or exit decision (we address in more details in Section 3 the dynamic dimension of the entry and exit decisions).

Annual fixed costs do not vary with generation output and are costs associated with keeping the asset capable to operate. According to Article 13 para 4 of ENTSO-E's methodology on CONE, annual fixed costs include labour costs, fixed maintenance and repair costs, insurance and asset management costs, transaction and control costs, fixed electricity transmission and distribution charges, or compensation costs, for instance for environmental reasons or to local residents. For DSR assets, the costs of compensating the underlying demand are considered annual fixed costs too.

CAPEX refers to **cap**ital **ex**penditures incurred only once during the construction or before the asset's commissioning. In Article 13 para 3 these expenditures are grouped into costs incurred by the contractor, like labour and material costs of construction, costs on the owner's side, costs for project development, financing, licenses and permits, or costs of land, and other upfront costs, for example for environmental or local resident compensation.

Capital expenditures can also relate to additional investments to prolong the lifetime of an asset. These costs are relevant to determine market entry of new capacity or a capacity upgrade. For the decisions about if existing assets exiting or re-entering the market, these costs are sunk and must not be considered. Since it CAPEX includes the financing costs, the these CAPEX depends on the type of investor, but also on the asset itself and its lifetime.

The risk premium or hurdle rate both reflect how the asset's economic performance across its lifetime is subject to uncertainty. The risk premium approach prices in the risk aversion of the investor and reflects the costs of hedging this risk. Alternatively, the hurdle rate reflects capital costs plus a hurdle premium to again price in risk aversion and can equally be interpreted as a threshold that the expected internal rate of return (IRR) of the asset needs to exceed to be economically viable.

2.3.2 Revenues from wholesale markets

Wholesale market revenues can be earned in several markets that can be differentiated by the time the trade takes place before its actual delivery (year-ahead, month-ahead, day-ahead, intraday, etc.) and the physical or financial nature of the trade.

Three key timeframes for the wholesale electricity markets are:

- **Forward markets**. Forward markets allow participants to trade energy in advance of delivery. In Europe, forward energy can be exchanged for yearly, quarterly, monthly, and weekly delivery blocks. Yearly products are typically available up to three years before delivery.[3] Forward trading happens both through market platforms and through over the counter (OTC) agreements between market players. Typical products are baseload and peak, but a number of other products may exist and be defined in bilateral transactions.

- **Day ahead market**. This is considered a reference market in Europe. The day-ahead market is operated through a blind auction which takes place once every day for all hours of the following day. The clearing of the market is determined by the optimisation algorithm Euphemia that is set to maximise the trade value in the region over 25 European countries accounting for the available transmission network constraints capacity across bidding zones (which may include both NTC-based and Flow-based market coupling). The clearing price in the day-ahead market is determined in each country's bidding zone as the as-bid value of the incremental energy delivered in the zone for a given hour. The clearing price is paid to all accepted sell bids and is paid by all accepted buy bids. Prices are limited by a technical bidding limit set between -500€/MWh and 3 000€/MWh. By the time of the release of this report, the technical bidding limit will likely be increased to 4 000€/MWh, resulting from the price events in

[3] Products with delivery period longer than 3 years may be available in the over-the counter trades and on some power exchanges but typically have low liquidity.

France in April 2022.[4] In addition to simple price-volume pairs, market players can represent the dynamic constraints of their generation portfolio through block bids, e.g. bids that span several hours with identical or different volumes (classic blocks or profiled blocks) and which have to be either entirely accepted or entirely rejected.

- **Intraday market**. Electricity can be traded any time after the closure of the day ahead market and up to several minutes before delivery (depending on the country). The European Single Intraday Coupling covers 21 European countries and features harmonised technical bidding limits set between -9,999.99 €/MWh and +9,999.99 €/MWh. While day-ahead trades are cleared in one single auction with the last accepted bid setting the price for all transactions, the intraday trading is performed on a continuous basis with transactions completed once the submitted offer is matched with a suitable pair. The intraday market allows for a high level of flexibility and market participants can use it to balance their positions closer to real time, but these markets may feature a higher price volatility and lower liquidity, entailing an increased risk for market participants (again, depending on the country).

In the day-ahead and intraday markets, the power price is set based on the demand and supply equilibrium and defined by the marginal offer that under the assumption of a competitive market represents the short-run marginal cost of the marginal unit. In the forward market, power prices represent an expectation of the future day-ahead prices.

2.3.3 Revenues from ancillary service and balancing markets

The main purpose of ancillary service and balancing markets is to quickly resolve unexpected misbalances of supply and demand and provide system services to the TSOs. Although market participants balance their positions in day-ahead and intraday markets, errors in RES forecasts, demand forecasts or last-minute forced outages of generation or transmission capacity can happen creating system imbalances. To prevent such system imbalances and maintain the grid's frequency at 50 Hz, European TSOs use flexible power reserves, with different response, called the frequency reserves. Four types of reserves are often distinguished and used consecutively in Europe:[5]

- The **frequency containment reserve** (FCR) (also called primary control reserve or R1) is used to stabilize the European frequency after the occurrence of an event leading to a frequency deviation. The FCR service properties are defined on a national level as well as on an EU level through the regional FCR cooperation;

- **Automatic Frequency Restoration Reserve** (aFRR) (also called secondary control reserve or R2) is used to bring frequency back to its nominal value and is automatically activated by TSOs. The resources providing aFRR need to be able to provide activation energy in the interval between 0 and 15 minutes.

- **Manual frequency restoration reserve** (mFRR) (also called tertiary control reserve or R3) is used to rebuild reserve capacities after aFRR has been activated. It is manually required by TSOs in proportion with actual needs. The activation of mFRR reserved capacity occurs within 15 minutes.

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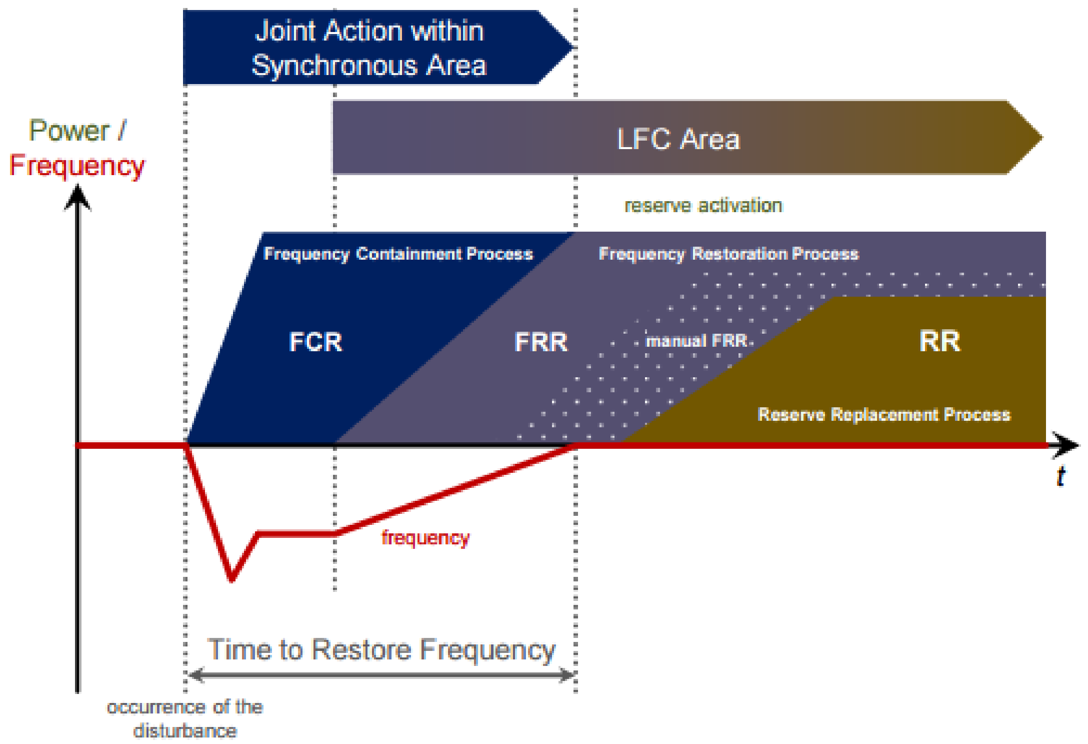
[4] Moestue, H. (2022, April 4). EU power bourses to hike price cap after French spike. *Montel.* https://www.montelnews.com/news/1310833/eu-power-bourses-to-hike-price-cap-after-french-spike-

[5] According to the EU electricity market directive, Ancillary Services also cover non-frequency ancillary services (such as inertia, black start, voltage control, etc), which may also be procured in a market-based way.

- The **Replacement Regulation** (RR) replaces the activated FRR and/or supports the FRR activation by activation of RR. However, this type of reserve is only being used in a number of European countries. The Reserve Replacement Process is implemented by the disturbed LFC Area.

Figure 4: Frequency reserves used in Europe



Source: SEM Committee (2013)

The procurement of these reserves features two steps:

- Reservation: The capacity that is capable of providing a specific reserve is contracted in advance in a yearly, monthly, weekly or a daily auction. The formats, settlements and the timeframe of the auctions vary greatly among European countries.
- Activation: The reserves that are both contracted in advance and otherwise available can be activated after the gate closure time of the intraday market. The current EU framework is developing towards several platforms for exchanging balancing energy across borders, namely: FCR cooperation (primary regulation) started with German TSOs since 2007, extended to neighbouring TSOs in 2014 onwards and currently, 10 TSOs are considering to assess the FCR Cooperation. The platforms for cooperation on aFRR - Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO) - and mFRR - Manually Activated Reserves Initiative (MARI) - were initiated in 2017 and about to be approved. Finally, Trans European Replacement Reserves Exchange (TERRE) for RR reserves is the European implementation project for exchanging replacement reserves initiated in 2013 and launched on 6 January 2020.

Revenues from wholesale and balancing markets together constitute the EOM revenues and within the EVA are computed for future scenarios.

2.3.4 Revenues from capacity markets

Capacity markets are measures to address potential adequacy issues by providing a separate revenue stream to some or all capacity resources that are deemed necessary to meet a given reliability standard.

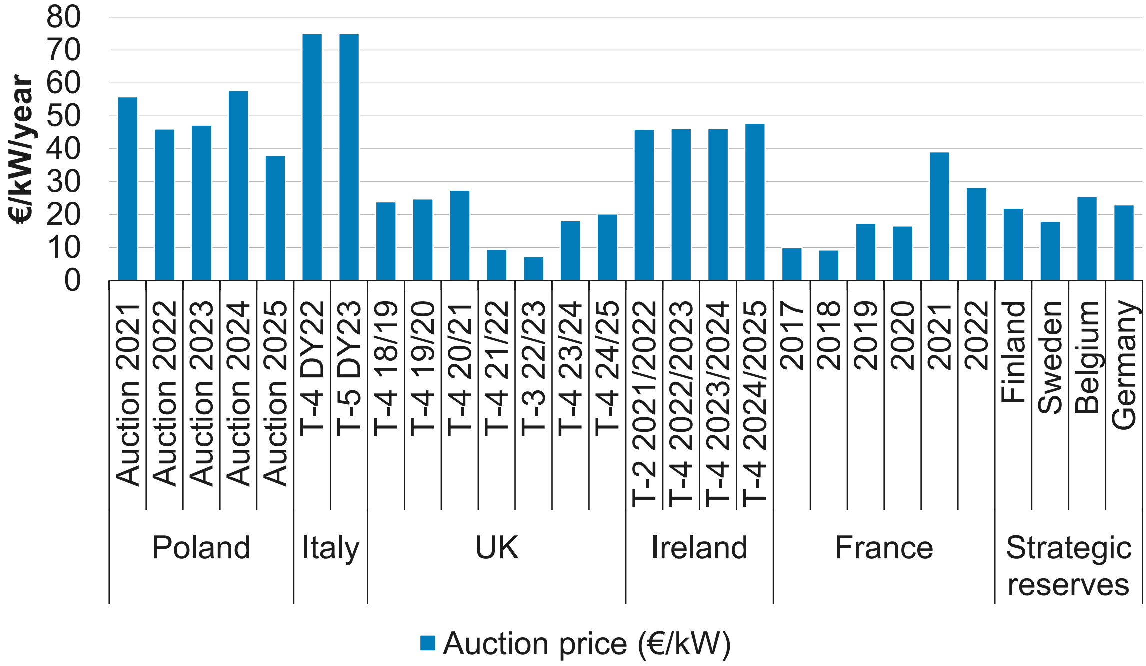
According to the Electricity Regulation 2019/943, two high-level design types are eligible for approval by the European Commission:

- **Strategic reserve.** In a strategic reserve mechanism, the top up capacity is contracted and then held in reserve outside the market. It is only activated when the market is expected to not clear. Typically, strategic reserves aim to keep existing capacity available to the system.
- **A market-wide CRM.** In a market-wide CRM, the total amount of required capacity is set centrally, and then procured either through a central bidding process in which potential capacity providers compete so that the market determines the price, or through a decentralised obligation placed on electricity suppliers to contract with capacity providers. In both cases, the price of capacity is determined by the supply and demand equilibrium. Typically, such a CRM aims to address the adequacy concerns that do not have a short-term nature and cannot be addressed by maintaining the existing capacity and/or require new investment.

The revenues received by the capacity resources through capacity mechanisms vary significantly across the European markets that have introduced such mechanisms, as shown in Figure 5 below. The clearing capacity prices vary greatly across the recent capacity auctions depending on system conditions and the CRM design. The price may depend on:

- Capacity adequacy situation and whether the adequacy target can be met with existing capacity or whether refurbished or new capacity is needed (e.g. new coal capacity cleared in both auctions in Poland);
- The fixed O&M cost of the existing capacity required for adequacy (e.g. relatively high in Ireland);
- The expected margins earned by the capacity in the energy and ancillary service markets (likely high in GB and France);
- Bid caps for the existing capacity (Irish cap being higher than GB and a possibility to derogate lead to a higher price). Italian capacity auction allows clearing at separate prices for existing and new capacity.

Figure 5: Prices in recent CRM auctions



Source: Own display based on data from national CRM sources

2.3.5 Revenues outside of the electricity sector

The revenues obtained by capacity operators in the markets described above may be complemented by other revenue streams, such as revenues outside of electricity markets, for instance revenues from selling hydrogen for electrolyzers.

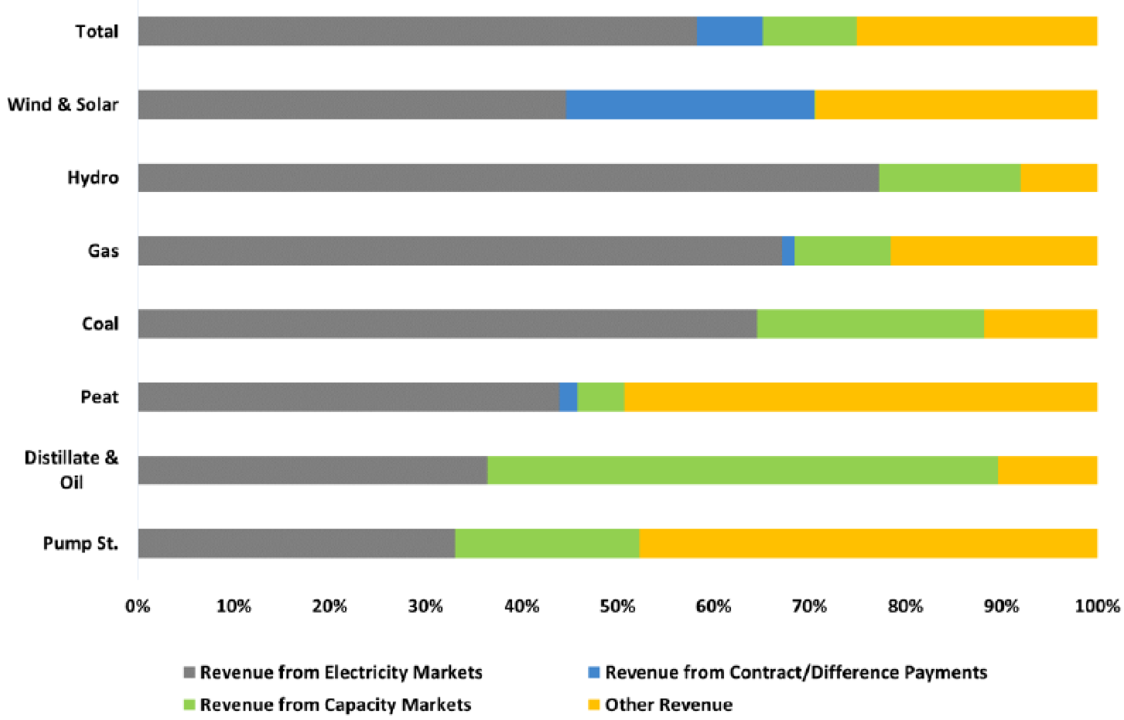
For conventional generators, revenues outside of the power sector are most relevant for **combined heat and power (CHP) units**, also called co-generation units, which simultaneously generate electricity and steam for industrial processes and/or heat for district heating. CHP units can deliver pure electrical (often referred to as ‘condense mode’), power and heat (referred to as ‘CHP mode’), and pure heat (usually by its ancillary boiler).

Another source of income can be governmental subsidies. Subsidies for power and heat production typically include tax expenditures (exemptions and reductions, tax allowances, tax credits and others), direct transfers (grants, soft loans) and indirect transfers (feed-in tariffs, feed-in premiums, renewable energy quotas, tradeable certificates, and others). Typically, subsidies are granted for renewable energies in the form of feed-in premium, grants, or quotas. In some countries, also DSR receives subsidies, which is practically a payment for allowing the regulator to curtail industrial consumers when needed.

2.3.6 Composition of revenue streams and drivers for entry/exit decisions

Figure 6 show the composition of revenues for different assets in Ireland 2019 and illustrates how revenue sources greatly depend on the type of assets. For most conventional power plants, the wholesale market constitutes the main source of revenue. In the case of Ireland, for peat also other revenues, presumably from heat sales, constitute a large share of revenues as well. Oil power plants generate their major share of revenue in the capacity market since they cannot compete on the wholesale market due to their high variable costs. The subsidization of wind and solar by is reflected by their revenue from contracts for difference, which is the deployed support scheme for renewables in Ireland.

Figure 6: Sources of revenue as % of total by generation fuel source in 2019, Ireland



Source: SEM-21-052 Generator Financial Performance Report FY2019

The revenue structure for most assets greatly depends on the regulatory framework and is also difficult to classify. In the example of Ireland, pumped storage for example earned revenues from temporal arbitrage on wholesale markets and on the capacity market, but the largest revenue stream comes from other sources, presumably the ancillary services and balancing markets.

Regardless of technology, the operator's decisions to enter or exit the market are driven by the expected revenues. However, the source and structure of revenues driving these decisions greatly depend on the respective asset.
As part of this project, a series of workshops were held where the methodologies of the EVA were discussed with the market participants and academic experts. In particular, a key topic discussed during the workshops with the market participants in July 2021 was how economic viability is actually evaluated by investors and operators of various types of capacity.
The workshops conducted as part of this study have revealed a number of specificities of the market participants' decisions to enter or exit capacity in the market both in the current conditions and in anticipation of the EU-wide implementation of the market reforms within the Electricity Market Regulation 2019/943. In particular, this discussion has highlighted a striking difference in the drivers of the entry and exit decisions between the conventional thermal plants and flexibility operators, such as DSR and storage. There are further differences within these two categories, e.g. between baseload and peak-load conventional plants as well as between storage and DSR.

For conventional power plants (especially baseload), the decision to enter or exit is mostly driven by the wholesale market as the main source of revenue. Typically, market participants apply conservative approaches to assess the ancillary services revenues, but on the other hand capacity mechanisms – where they exist – can be a driver of market entries as well.

Since the economic lifetime of such power plants is long and investment costs are high (typically, for both baseload and peak-load power plants), investment decisions consider a rather long timeframe. Market regulation affecting the price dynamics during the scarcity periods (price limitations through explicit or implicit technical bidding limits) or, on the contrary, specific mechanisms ensuring scarcity pricing also have an impact on revenues and entry/exit incentives.

A decisive question is therefore to what degree investors consider rare scarcity events that will provide substantial revenues but are difficult to anticipate due to their rarity. Here, the structure of revenues and costs greatly differs between baseload and peak-load power plants. For instance, revenues from the wholesale market for baseload power plants depend on average prices, while peak-load plants are more sensitive to the peak-load pricing and thus the frequency of scarcity events.

This comes along with different hedging methods that further reflect the difference among the conventional power plants: Baseload power plants, like nuclear, coal or sometimes CCGT if they operate as baseload, can be hedged in the forward markets, while peak-load power plants, such as older and less efficient CCGT or OCGT may require more sophisticated hedging approaches or will be predominantly marketed at the spot markets. However, practitioners participating in the workshop agreed that such hedging options are not critical in determining entry or exit decisions. They have also considered that the scope of natural hedges provided by vertically integrated portfolio and hedging available through forward market are limited. Eventually, the entry and exit decisions of conventional capacities are made based on fundamental modelling of diversified scenarios. An entry decision needs to be justified by a solid business case in the central scenario rather than on relying on extreme scenarios.

Hence, for baseload power plants a form of risk aversion approach may be applied in assessing forward scenarios for the entry/exit decisions. In this case, it could be argued that scarcity events may not trigger investments in such facilities in the EVA. Nevertheless, even a risk averse investor can deploy hedging strategies to include the expected scarcity rents into his calculation which would increase investment in peak-load capacities.

In turn, according to the practitioners a different picture can be drawn for investors for flexibility and peak-load assets, such as storage or aggregators of DSR resources. They seem to consider peak-load pricing during scarcity events in their business cases, as these resources are typically characterised by low investment but high variable costs. For those actors the risk that expected price spikes will not occur is limited due to their costs structures and it comes along with the chance of high return on investment, if the expected price spikes will occur.

For storage systems like batteries, wholesale revenues would rather depend on price volatility than on the overall price level. This also applies to some forms of DSR, but at the same time opportunity costs of market entry or exit greatly differ for storage and DSR or other flexible consumers, like e-mobility, heat pumps, and electrolysers.

Furthermore, stacking of revenues from as many markets as possible is also very important for storage and DSR. Each MW and MWh needs to be sold to combine market revenues, such as from balancing markets or other ancillary services. In case of electrolysers, demand from the hydrogen market need to be taken into account. Capacity mechanisms are crucial as well, where they exist. Today, balancing markets are the most important source of their revenue, but at higher DSR capacities these markets might become saturated and the importance of wholesale market revenues could increase. Similarly, the importance of wholesale market revenues for storage and DSR may grow with their increasing intraday or seasonal price volatility driven mainly by the increasing shares of variable RES.

Flexibility entry/exit decisions are very sensitive to regulation and specific market design parameters. The absence of simple and efficient ancillary services markets and balancing responsibility is a barrier to flexibility development (Lago, Poplavskaya, Suryanarayana, & De Schutter, 2021). Specific market design parameters, such as reservoir size, network tariffs and derating factors make a big impact and are the reason of difference in volume of batteries in Germany and UK vs e.g. France and Belgium. Flexibility development also highly depends on explicit and implicit subsidies. Especially for DSR, market access is the most important driver of economic viability, impacted both by entry barriers as well as potential revenue streams such as interruptibility schemes or CRMs.

Also, the timeframe considered when assessing profitability can be much shorter, either because technical lifetimes are shorter, for instance of battery storage, or investment cost are negligible, for instance in case of some aggregated DSR. These circumstances seem to lead to hurdle rates which are not necessarily higher than those of more risk averse investors for conventional power plants.

However, even though these synthetic conclusions for the individual technology classes could be derived in the course of the workshops, they should be taken with caution, accounting for the large variation of situations within each technology class. The workshops also revealed that the drivers for market entry and exit are diverse and greatly depend on the specific type of asset considered and also individual circumstances for each single asset.

2.4 Articulation between the two EVA options

In Article 6 para 2, the ENTSO-E methodology offers two distinct options to perform EVAs:

- **Economic Viability Assessment of individual capacity resources (individual EVA approach).** The first option is to assess the economic viability of individual assets in the literal sense by performing an explicit assessment of revenues and costs by asset. In this case the revenues of the capacity resources are directly assessed and stacked across the revenues from the wholesale market, ancillary services, revenues from outside of the electricity sector, subsidies, and revenues from capacity mechanisms. The entry, exit and mothballing decisions are then assessed for each capacity resource based on the estimated revenues and costs and accounting for the risk.

- **Economic Viability Assessment through overall system cost minimisation (cost minimisation EVA approach)**. The second option takes a system instead of asset perspective based on the assumption of a perfectly competitive market, with the aim of minimising total system costs. In this case, the entry and exit decisions are assessed simultaneously for all capacity resources, all bidding zones and account for substitutional effects between capacity resource types and bidding zones, by minimising the discounted costs of investment and operation of the entire power system.

These two options are introduced and compared in greater detail in this section.

2.4.1 Examples of the two EVA options considered in the ACER's approved methodology

For the purpose of the first option, cumulative revenues from all markets are estimated assuming the markets are competitive and compared against total costs to determine, which assets exit and enter the market or can expected to be subject to further investments. For this calculation, expected revenues from the wholesale market and ancillary service and balancing markets should be based on the results of the economic dispatch modelling performed as part of the RAA. In addition, calculation of revenues must account for the regulatory framework, such as subsidies, and may consider the influence of risk management. The adequacy assessments in the Elia report "Adequacy and Flexibility Study for Belgium 2022 -– 2032" or in the TenneT reporting "Monitoring Leveringszekerheid 2021" provide exemplary applications of this EVA methodology (Elia, 2021; TenneT, 2021).

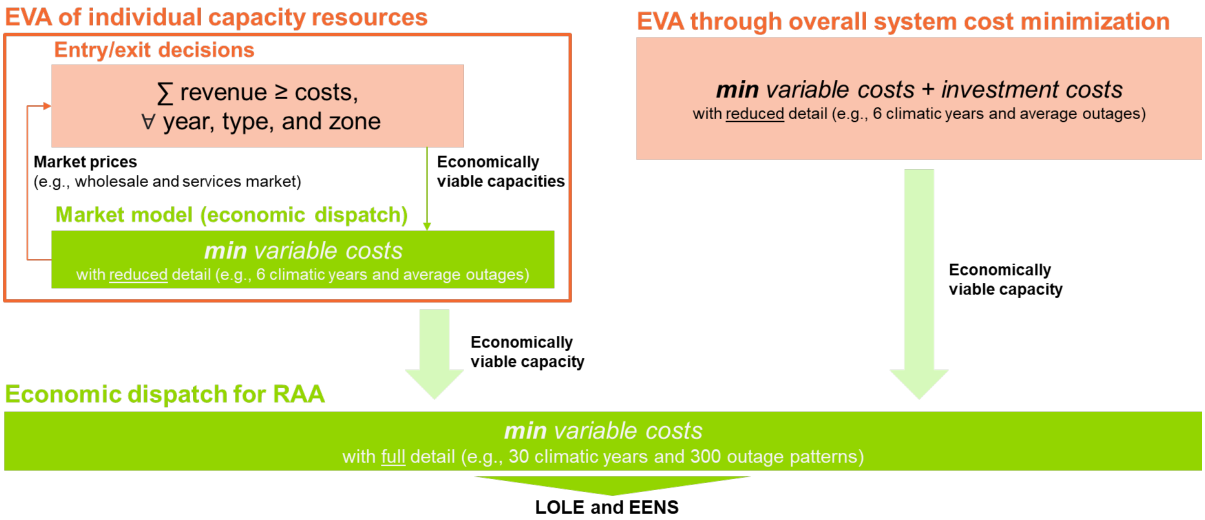
As an alternative, the economic viability can be assessed using an optimisation of the system from the point of view of an ideal and benevolent centralized planner, whose objective is the maximisation of the net social welfare, which corresponds to minimising generation costs, if the demand of the end consumers could be considered inelastic. Such an assumption is generally reasonable, since the approach typically incorporates DSR not as a price-elastic consumer, but as storage technology subject to additional operational restrictions or a highly expensive peak-load technology. In economic terms, the underlying assumptions of the optimisation approach corresponds to a perfectly competitive market. Following this interpretation, capacities are considered consistent with economic viability, if they result from the optimisation model. For instance, the method is used in an adequacy report prepared on behalf of the German Ministry of economic affairs and climate action, as well in the recent ENTSO-E European Resource Adequacy assessment (BMWK, 2021; ENTSO-E, 2021).

The computational complexity of the optimisation model greatly depends on the level of technical detail represented by the model, for instance, if the need of ancillary and balancing services in included. The ENTSO-E methodology approved by ACER states that applied model should include an accurate representation of storage and DSR, grid constraints, reserve requirements, and regulatory constraints, such as capacity markets, the phase-out of technologies, for instance coal or nuclear plants, a mandated increase of capacities, or any other relevant policies.

2.4.2 The different approaches of the two EVA options

The central difference between individual EVA and cost minimisation EVA is how they coordinate the modelling of the market operations and entry/exit decisions, as illustrated in Figure 7 below.

Figure 7: Procedure for both EVA options



Source: Own display

The **individual EVA** checks the economic viability of each type of asset in each bidding zone separately based on the modelled revenues across different markets. The market revenues are modelled using the economic dispatch models that assess the market prices as a marginal cost of the production of energy (or an ancillary service, or capacity).
The economic dispatch model assessing the market revenues needs to be supplemented by the assessment of economic viability and the modelling of entry/exit decisions through a "soft" integration. That is, for each asset that is part of the EVA analysis (existing or a candidate for new entry), the market revenues modelled over the modelling timeframe should be compared with the variable and fixed costs to model the entry/exit decision or to check if the previous assumption on such decision remains economically viable.

In case the individual EVA requires a change in the capacity assumed in the initial economic dispatch, an iterative process is required, where the economic viability is assessed based on prices from the economic dispatch and the capacity assumptions are adjusted several times until convergence on the capacity assumptions. This process can take substantial time and may require some simplifications, for example terminating the process as soon as the remaining differences between the EVA and economic dispatch are sufficiently small. It is also conceivable to reduce the number of sample years for the Monte Carlo analysis of the economic dispatch model that is used for the EVA, while using a detailed economic dispatch model for RAA to assess the LOLE and EENS (Elia, 2021).

In the overall **cost minimisation EVA** on the other hand, dispatch and investment are not linked in a "soft" way that requires iterations but, being part of the same model, are integrated very tightly through a joint optimisation. As a result, convergence between investment and dispatch models occurs automatically accounting for the impact of all assets in all regions simultaneously to achieve a stable capacity equilibrium (i.e., a proven optimal solution of the modelling problem). However, such automatic and comprehensive convergence on capacity may be computationally intensive as well, and thus may require some simplifications of the model as discussed in detail in Section 3 below.

2.4.3 Characteristics of the two approaches

The characteristics of the two approaches result in different strengths and weaknesses when they are introduced in practice. It should be noted that if unlimited computational capacity was available, the two approaches would likely be able to yield the same result when using the same inputs. The relative strengths and weaknesses of the two approaches only manifest because they tend to allocate the limited available computational capacity to different elements of the EVA. We highlight several such elements below and summarise them in Table 1.

Table 1: Characteristics of two EVA methods

	Economic viability assessment of individual capacity resources	**Minimisation of the overall system cost**
Simulation of market revenues	Focus on market revenues and decisions to enter/exit from the point of view of capacity providers – aims to estimate revenues with high precision	Considers the system from the central planner perspective, potentially simplifying the calculation of the revenue streams
Peak load pricing	Peak-load pricing occurs when the demand sets the price at the DSR activation level, VOLL or the technical bidding limit in case it is lower than VOLL	Peak load pricing appears during scarcity situations at the level necessary to recover fixed cost of economically efficient new investments
Entry/exit decisions	May be limited in a) how many investment/retirement options are tested; and b) considering interdependencies between bidding zones	Allows an exhaustive testing of potential investment/retirement options across all modelled BZ simultaneously

Simulation of market revenues

In principle, both methods rely on modelling the wholesale and balancing markets, either explicitly estimating prices and revenues in case of the individual EVA approach or through an integrated modelling solution of dispatch and investments in case of the cost minimisation EVA approach. For example, both methods could account for the trade-offs between participation in ancillary services (capacity reservation) and possible revenues forgone from unsold energy. However, an accurate estimation of the market revenues requires allocating significant computational resources to the economic dispatch model:

- As discussed in detail in Section 3 below, the individual EVA can be focused explicitly to achieve accurate estimation of the prices, making sure the economic dispatch model used for the price estimation properly accounts for the generation constraints and calibrating the results on the historical market and price outcomes.
- The cost minimisation EVA, in turn, requires usually a higher level of simplification for the dispatch, due to the complexity on the investment element of the model, which may involve simplifications of the chronology and intertemporal unit commitment constraints. For instance, reduction of the temporal granularity or relaxation of the unit-commitment constraints are often required, which may affect the accuracy of modelling wholesale and balancing markets.

In the workshops held in March 2022, some participants stated that the individual EVA may be closer to the investor's perspective, simulating the investor's decisions on entry/exit based on the projected market revenues and costs. In their point of view, this allows the individual EVA approach to be more accurate in assessing the investment decision from an investors point of view. Other participants stated, that an EVA relying solely on the wholesale prices estimation based on short-run marginal costs and not reflecting peak load pricing may underestimate wholesale revenues in the individual capacity approach (cf. next sub-section).

Peak-load pricing

Both approaches allow addressing the situations of scarcity when supply is exhausted, and the demand sets the price. During such scarcity situations demand can be represented either by the activation price of the DSR or by the willingness to pay for the load curtailment (Value of Loss of Load or VOLL).

- In the individual EVA, the peak-load pricing occurs when the demand sets the price at the DSR activation level, VOLL or the technical bidding limit in case it is lower than VOLL. As a result of the iterations between the market and the investment modelling, the frequency and the magnitude of such prices becomes aligned with the marginal cost of additional investment.
- In the cost minimisation approach, peak-load pricing will appear in the model during such situations at the level that is necessary to recover fixed cost of economically efficient new investments.

In principle, and assuming the same inputs and conditions are implemented, both approaches should result in the same level and frequency of the peak-load prices. In practice, the peak-load price estimated through the cost minimisation EVA may be below the VOLL or technical bidding limits in case such lower price level is sufficient for fixed cost recovery. Some participants of the academic workshop held in May 2022 stated that regardless of the EVA approach, it is critical to ensure the consistency between the investment costs and the electricity prices in terms of peak-load pricing, which enables refinancing of investments and typically takes place when supply is exhausted (inelastic) and thus the elastic part of demand is setting the price during scarcity situations. Some participants noticed that in case the individual EVA approach does not explicitly address the scarcity pricing, this may lead to underestimating electricity market prices and thus the economic viability of resources, while the cost minimisation EVA is reflecting this metric inherently.

Entry/exit decisions

The allocation of the available computational capacity could affect the accuracy of the modelling of entry and exit decisions between the two EVA approaches:

- The “soft” iterative process of the **individual EVA** approach may need to focus the modelling of the entry/exit decisions on specific countries or regions. Although in theory, the number of different combinations of investment and retirements are not limited, in practice, the number of options depends on the computational effort and resulting number of iterations. As a result, different combinations of investment and retirements cannot be tested exhaustively, especially when the assessment includes more than one region. Indeed, under this approach, it may be difficult to assess the impact of one asset in one region entering or exiting the market on the economic viability of assets in other countries or regions. These effects could indeed be non-negligible since substantial cannibalization effects can occur in (coupled) power markets. For instance, profitability of a peak-load power plant will be highly sensitive to the number of scarcity events, which might greatly decrease, if only a small amount of additional capacity enters the market in the neighbouring country.

- The **cost minimisation EVA** has the advantage of endogenously considering all interactions and combinations of entering and exiting capacities across all bidding zones considered in the assessment. In that sense, the cost minimisation EVA can be theoretically understood to be more systematic in accounting for candidates for retirement and investment across BZs, making this choice internally in the optimization problem.

Participants of the academic workshop in March 2022 have also pointed out that the differences between the two EVA options are much driven by the computational limitations which require to make modelling simplifications that may impact the outcomes of the two approaches differently. They have also suggested potential benefits of combining the two approaches, for example by using the capacity equilibrium resulting from the cost minimisation EVA as the starting point for the viability assessment of the EVA of capacity resources.
In practice, this would require the following steps:

- implementing both approaches in a consistent way (i.e. using the same modelling inputs and, ideally, modelling platforms),
- running the optimal capacity expansion model first, applying the cost minimisation EVA with possible necessary simplifications of the dispatch and market models to obtain the initial decision on the entry and exit of different resource types across all bidding zones, and
- using the capacity assumptions obtained from the previous step as a starting point, implement the individual EVA, by running the detailed dispatch and market models and verify the viability of individual resources. If necessary, this may involve adjustments and iterations of the entry/exit decisions to achieve convergence based on the modelling of the entry/exit decisions of individual resources.

3. Practical implementation of the EVA

After having introduced the theoretical foundations for EVA in the previous section, this chapter focuses on its practical implementation. The focus here is on the models for economic dispatch and capacity expansion and how they reflect the revenues relevant for both options to perform the EVA. The first subsection provides the basic mathematical formulation for these models and describes the iterative process for the individual EVA with greater depth. The second subsection builds on this, explaining how the different types of revenues discussed in section 2.3 can be obtained from a model. The last two subsections discuss the representation of risk within the respective methodologies and discuss computational challenges of the practical implementation.

3.1 Implementation process

3.1.1 Mathematical model formulation

The economic dispatch and the capacity expansion model for the cost minimisation minimization EVA are mathematical optimisation problems of similar structure. To keep computational complexity manageable, these problems are typically formulated as linear problems. This structure will be introduced based on an exemplary formulation of an expansion model for the EVA through overall system cost minimisation in equations 1 to 8 (Göke & Kendziorski, 2022). Afterwards, we will discuss in what way an economic dispatch model deviates from this formulation.

$$\min \quad InvCost + VarCost \tag{1}$$

$$s.t. \quad \sum_{i\in I} Gen_{t,r,i} + St^{out}_{t,r,i} - St^{in}_{t,r,i} + \sum_{r'\in N(r)} Exc_{r,r'} = dem_{t,r} \quad \forall t \in T, r \in R \tag{2}$$

$$St^{lvl}_{t-1,r,i} + St^{in}_{t,r,i} - St^{out}_{t,r,i} = St^{lvl}_{t,r,i} \quad \forall t \in T, r \in R, i \in I_{st} \tag{3}$$

$$Gen_{t,r,i} \leq cf_{t,r,i} \cdot Capa^{gen}_{r,i} \quad \forall t \in T, r \in R, i \in I_{gen} \tag{4}$$

$$St^{out}_{t,r,i} + St^{in}_{t,r,i} \leq Capa^{st}_{r,i} \quad \forall t \in T, r \in R, i \in I_{st} \tag{5}$$

$$St^{lvl}_{t,r,i} \leq Capa^{lvl}_{r,i} \quad \forall t \in T, r \in R, i \in I_{st} \tag{6}$$

$$-ntc_{r,r'} \leq Exc_{r,r'} \leq ntc_{r,r'} \quad \forall r \in R, r' \in N(r) \tag{7}$$

$$\sum_{t\in T, r\in R, i\in I} (Gen_{t,r,i} + St^{out}_{t,r,i}) \cdot varCost_{t,r,i} = VarCost \tag{8}$$

$$\sum_{r\in R, i\in I} Capa_{r,i} \cdot ann_{r,i} = InvCost \tag{9}$$

$$Gen_{t,r,i} \geq 0, St^{out/in/lvl}_{t,r,i} \geq 0, Capa_{r,i} \geq 0$$

Generally, all elements of model equations can be distinguished into variables and parameter. Variables are endogenous to the model and are determined as part of the optimisation; parameters are exogenous and must be defined before the optimisation. To make them easier to distinguish, in the equations above variables are capitalized while parameters are written with a small letter.

The first equation states the objective of the entire optimisation problem, which is to minimise the sum of investment and variable costs. The optimisation is constrained by the equations 2 to 9 that aim to represent the technological constraints of the power system.

Most importantly, the energy balance in the second equations enforces that supply equals demand at each time-step t and in each considered region r. Supply includes generation, discharging and charging summed over all considered types of assets i and the import or exports summed over all connected regions r'. Demand on the right-hand side is a parameter reflecting the electricity demand that must be met.

The storage balance in equation 3 connects the variables for charging and discharging to the storage level by setting the level at time-step t to the level of the previous time-step $t-1$. DR assets are typically represented by the representation of storages with additional terms not discussed with greater detail here (Zerrahn & Schill, 2015; Göransson, Goop, Unger, Odenberger, & Johnsson, 2014).

Equation 4 to 6 ensure that the amount of generated, charged, discharged, and stored energy for all types of assets does not exceed their installed capacities. For generation, the installed capacities must be corrected with a capacity factor that reflects the share of capacity available for generation at time-step t in region r, e.g. the availability profiles for wind or solar generators. Since the aim of the model for the EVA is to determine entry, exit and mothballing decisions, the asset capacities are endogenous variables in this model. The exchange of electricity between regions in both directions is constrained in equation 8 by the available NTCs capacities, which are exogenously assumed in this example.

Lastly, equations 9 and 10 define the costs to be minimised. Specific variable costs are a parameter that corresponds to variable costs as defined in the CONE methodology (see section 2.3.1). Total variable costs are obtained by multiplying with energy quantities and summing over all types of assets i and regions r. Total investments costs are computed analogously, but with capacities and annualized investment costs instead.

Although equations 1 to 9 outline the model used for cost minimisation EVA, the structure of the economic dispatch model used to obtain inputs like wholesale prices for the individual EVA is very similar. In this case, only variable costs are optimised, and capacities are not a variable, but must be defined exogenously.

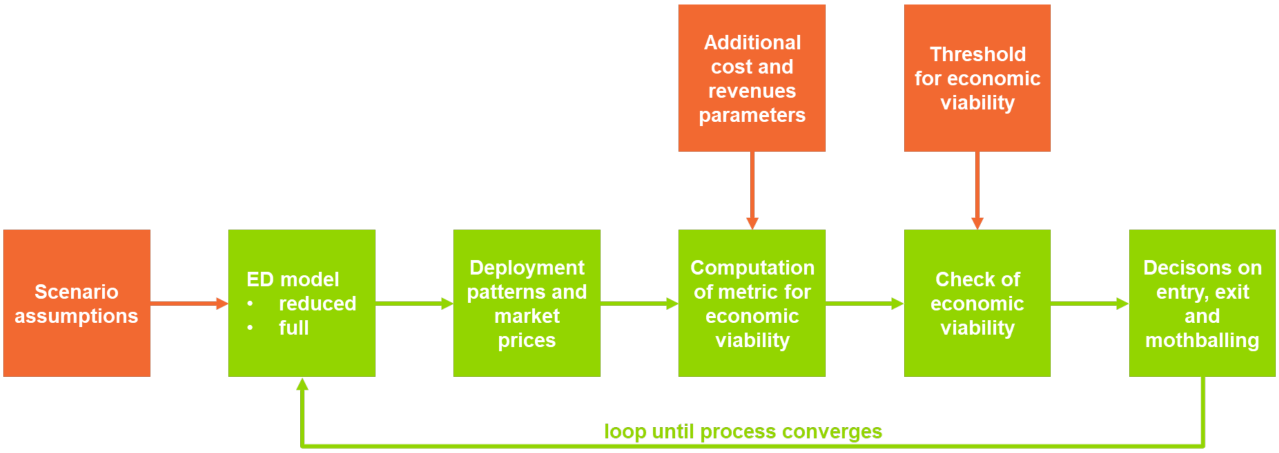
It should also be noted that for illustration purposes, the introduced mathematical formulation is stylized. Especially in the economic dispatch model, practical implementations will be more detailed, for instance representation of power exchange might not be limited to NTCs but consider physical flows instead. In addition, further elements, like balancing and ancillary services, can be included too, as we will discuss in the following section.

3.1.2 Iteration for entry/exit decisions in the individual EVA

The individual EVA does not only consist of the ED model, but instead involves an iterative investment process integrating the ED model as described in section 2.4. In this section, we will practically discuss how this iterative process can be designed.

An overview of the iterative process is provided in Figure 8 where orange boxes indicate input assumptions to the process while the green elements describe the process itself. Input assumptions include the relevant assumptions of the underlying scenarios used for the RAA, for instance fuel prices, demand projects but also a starting set of capacities. These capacities must be grouped into sensible categories based on technology, ageage, and the respective type of decision, for instance mothballing of hard coal power between 20 and 25 years of age, because in the subsequent iteration, economic viability can only be assessed jointly for all capacities within the same category.

Figure 8: Iterative process for EVA of individual capacity resources



Source: Own display based on Elia 2021

In the first iteration, the ED model is solved for this starting set of capacities to determine market prices and generation patterns. As a result, this step captures the interaction of different capacities in the market and how they impact revenues, for example how revenues of peak-load capacities are impacted by a change in base-load capacity. In theory, this step could use the full ED model applied for the adequacy assessment of the RAA, which includes a broad range of Monte Carlo to cover different demand, generationgeneration, and outages patterns. In practice however, this approach is not viable, because running the ED model at this level of detail is highly time-consuming and running it for each iteration of the EVA does not appear practical. An alternative is to run a reduced ED model that is sufficient to assess economic viability but would be insufficient for adequacy assessment. The Elia report for example runs the ED model with 200 of 597 Monte Carlo years in the first iteration and then applies k-medoid clustering to identify typical periods in terms of revenue generation to further reduce the model in subsequent iterations. After a predefined number of iterations, the detail is increased again to 200 Monte Carlo years and a new set of typical clusters is selected to ensure the reduced model is still consistent and can provide accurate results.

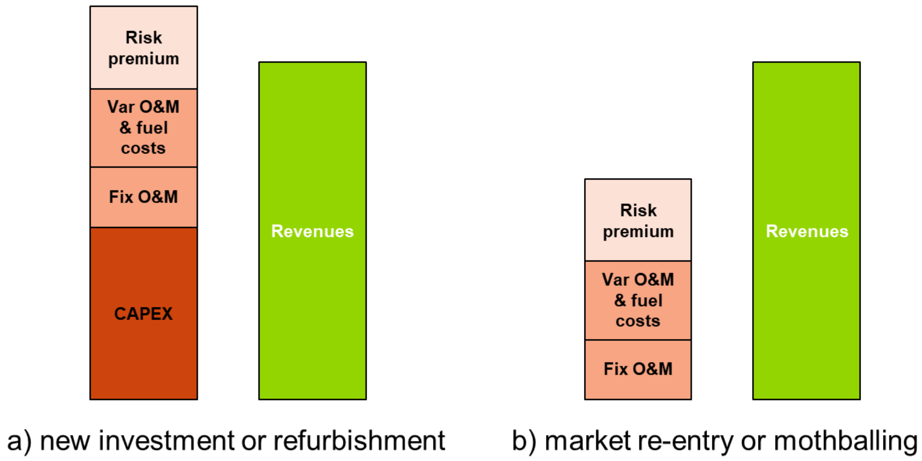
Afterwards the results of the economic dispatch model are used to determine the revenues from the wholesale and balancing markets for each capacity category. Since the ED model will not cover each year within the economic lifetime but might end earlier and work with 2- or 5-year steps, revenues for the missing years are extra- or interpolated. Additional revenues from subsidies or other markets, like capacity markets or district heating, are accounted for separately not based on results of the economic dispatch model. Section 3.2 provides an in-depth explanation on how different revenue streams are either based on results of the ED model or are computed otherwise. As discussed in section 2.3.6, the composition of these revenues will greatly depend on the category, for instance DSR or storage will rely much more on revenues from balancing markets than baseload plants. Besides quantitative parameters, the computation of revenues will also require assumptions on regulation regarding participation in balancing or capacity markets, because they will heavily determine the amount of revenues DSR, or storage can earn in these markets.

Next, these revenues and additional assumptions on costs of the capacity are combined to compute a metric for the economic viability of each capacity category and this metric is compared to a pre-defined threshold to decide, if capacities of a certain category are economically viable or not. Common metrics for this purpose are the net-present value (NPV) or the internal rate of return (IRR) with the latter being used in the Elia adequacy study, but in theory also more sophisticated risk-based metrics are conceivable as discussed in section 3.3. The NPV is computed according to the formula below where r_t and c_t provide costs and revenues in specific year *t*, C_{fix} provides the investment costs and i gives the specific interest rate. For a given interest rate, a project can be considered viable, if the NPV is greater zero. Alternatively, the formula can be solved for the interest rate and solved assuming a NPV value of zero. In this case, the project is economically viable, if the actual interest rate exceeds the computed internal interest rate.

$$NPV = \sum_{t=1}^{T} \frac{r_t - c_t}{(1+i)^t} - C_{fix}$$

The costs and revenues to be included into the assessment of economic viability depend on the type of asset and on the decision being investigated. As discussed in section 2.5, for DSR the "economic lifetime" meaning the timeframe T to be considered when computing revenues can be rather short, because investment costs only play a minor role compared to fixed costs that are necessary to reimburse participating consumers. Also, costs to be considered depend on the available options of investing in a new asset or keeping an existing asset in operation. As shown in Figure 9 new investments, or similarly the refurbishment of existing assets, must consider CAPEX or investment costs when assessing economic viability. On the other hand, investment costs are sunk and do not need to be considered when assessing re-commissioning or mothballing of existing capacities.

Figure 9: Cases for decision on market entry or exit



Source: Own display

After determining the economic viability for all categories, capacities must be adjusted accordingly for the next iteration. The main purpose of this adjustment is to achieve quick convergence between the market simulation based on the ED and the assessment of economic viability, meaning that all operating capacities should be profitable, but that additional investments or re-entry to the market would not. The ENTSO-E methodology does not provide any specific guidance on how to achieve this convergence, but the Elia report puts forward a specific approach: First all capacity categories are sorted in ascending order based on the computed IRR and then the capacity of the most profitable ones is increase by a fixed amount. Vice versa, the capacity of the most unprofitable categories is reduced. Not adjusting all capacities at once appears practical, because changing some capacities can be sufficient to achieve an economic viable setup for all, since capacities heavily interact in the market. To sort the categories rather by IRR than NPV appears appropriate as well, because IRR is a relative metric that avoids a bias induced by the total magnitude of costs and revenues for a certain category. Finally, the iteration process might run into situations, where results oscillate between two different solutions. In this case, the Elia report proposes to just use the one solution of the two with higher overall revenues for assets operators. In the academic literature alternative and more complex algorithms to ensure the economic viability for a set of capacities based on results of a dispatch model are provided (Göke & Madlener, 2022).

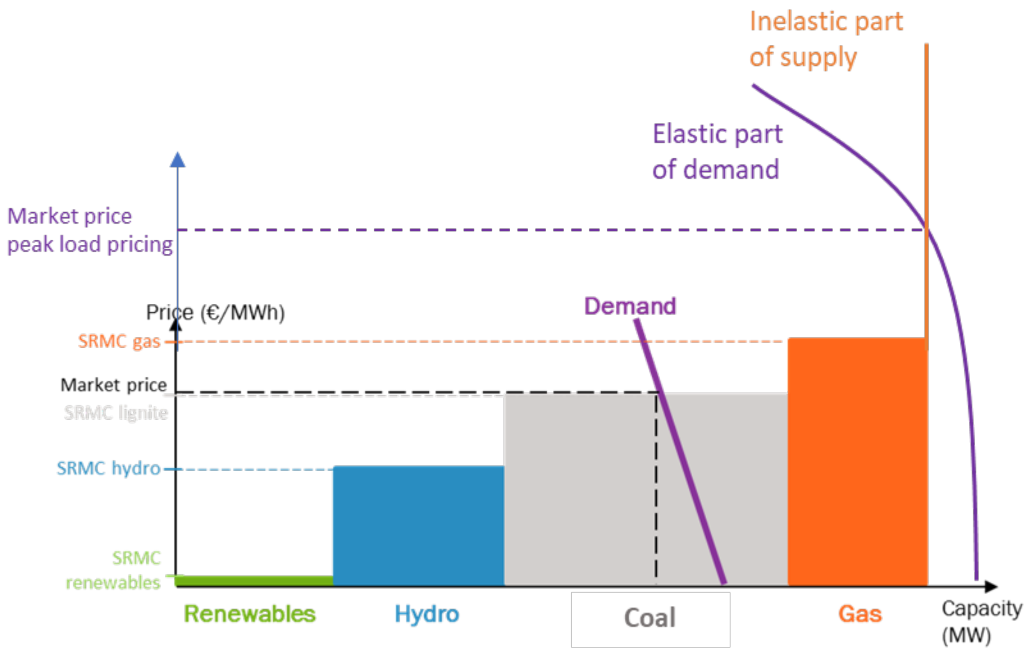
3.2 Representation of revenue streams

Many of the revenues relevant for the EVA are determined based on model results. For the individual EVA, revenues from wholesale and balancing markets are based on prices and asset operation computed in the economic dispatch model. The cost minimisation EVA accounts for all revenue streams by including them into the capacity expansion model. In this section, we discuss how models are practically deployed and extended for both methods to account for the different streams of revenue.

3.2.1 Wholesale market

Wholesale market revenues are generally based on the computed cost minimising dispatch. This model assesses the wholesale electricity price based on the marginal value of energy that corresponds to the shadow price of the energy balance in equation 2 in the previous section. This reflects how in the market generation decisions are based on short run marginal costs (SRMC), plants with lower short-run marginal costs are dispatched first, and power prices are then computed based on the costs of the marginal producing unit (Figure 10). In case of the cost minimisation EVA no explicit prices must be extracted from the model and the internal representation of these market mechanics is sufficient.

Figure 10: Illustration of the SRMC merit order and peak load pricing principles



Source: Own display

Such estimation of electricity prices based on the marginal cost is realistic as long as the capacity margin above the demand is sufficiently high and there is high competition between generators to serve the demand. Assuming fully competitive power markets under current market rules implies that (i) generation decisions are based on hourly merit-order dispatch based on marginal cost of production of the different power plants, (ii) power plant operators bid their short run marginal cost (SRMC) based on unsubsidized fuel price and unsubsidized variable operation and maintenance cost, and (iii) wholesale power price would be subject to the wholesale power technical bidding limit that was until recently set at 3 000€/MWh, but as discussed in 3.2.4 below, has recently increased to 4 000€/MWh. Whenever generation or DSR capacity is not sufficient to meet the demand, the scarcity pricing should be accounted for by applying the technical bidding limit during such scarcity periods, where demand curtailment determines the price.

During scarcity periods where supply is exhausted (inelastic), so called peak load pricing takes place, where elastic part of the demand sets the price (see Figure 10). During such situations demand is willing to pay until up to the VOLL to avoid a loss of load, which enables refinancing of investment costs for new build resources. In the individual EVA approach, as a result of the iterations between the market and the investment modelling, the frequency and the magnitude of such prices becomes aligned with the marginal cost of additional investment. In the cost minimisation EVA, peak load pricing will appear in the model during such situations at the level that is necessary to recover fixed cost of economically efficient new investments. In principle, and assuming the same inputs and conditions are implemented, both approaches should result in the same level and frequency of the peak-load prices. In practice, the peak-load price estimated through the cost minimisation may be below the VOLL or technical bidding limit in case such lower price level is sufficient for fixed cost recovery.

For the application in the interconnected European system, the dispatch model must cover the European countries. Often countries beyond this geographic scope are modelled at an aggregated level (Figure 11). Even more regional models can be developed addressing generation with a high level of detail in the region of interest and the countries and market zones beyond the main perimeter. To obtain market prices for each market zones, models use the zonal transmission network representation that matches with the price zones currently implemented in Europe and the commercial transmission boundaries.

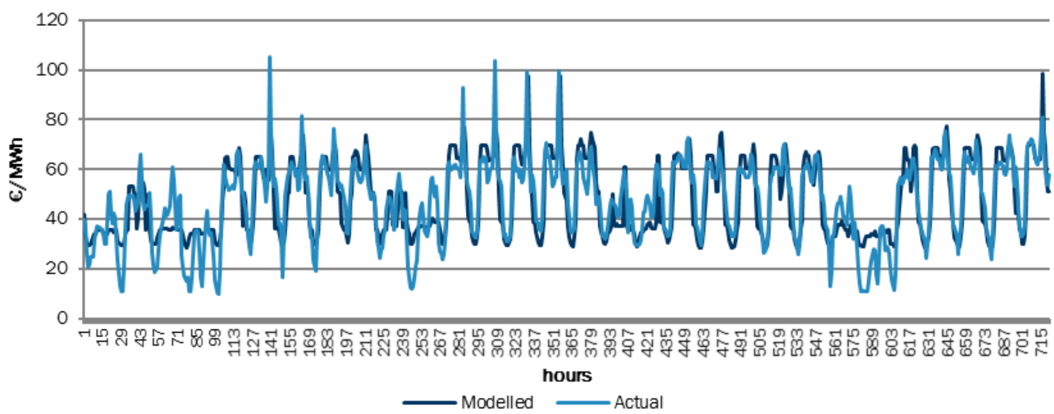
Figure 11: Geographic scope of the model

Source: Own display

To make price estimates more accurate, the economic dispatch model often is extended to account for additional technical constraints of thermal and hydro capacity. For example, the economic dispatch can account for the thermal unit commitment constraints, such as the minimum stable limit, the start-up costs, the minimum run time, the minimum down time, and the ramping rates (Tejada-Arango, Morales-España, Wogrin, & Centeno, 2020).

The wholesale dispatch model may need to be calibrated to ensure that its price and revenue forecast is accurate. For this purpose, before using the market model for assessment of future wholesale market revenues, the model needs to be run on the historical input data of demand, commodity and CO_2 prices and available generation. The outcomes of the model in terms of generation, transmission flows and prices are then compared with the historical data and parameters of the model are fine-tuned to ensure that the model correctly calculates the historical market outcomes (Figure 12). We note that in addition to the backtesting of the "normal" periods, it is important to ensure accuracy of the model in simulating the wholesale prices during scarcity situations, where demand sets the price above the short run marginal costs. Such backtesting could be difficult because due to historical excess capacity and low DSR participation those situations with prices reaching possibly up to the VOLL or the technical bidding limit remain rare.

Figure 12: Example for the back-casting calibration – FR hourly prices, November 2012



Source: Own display

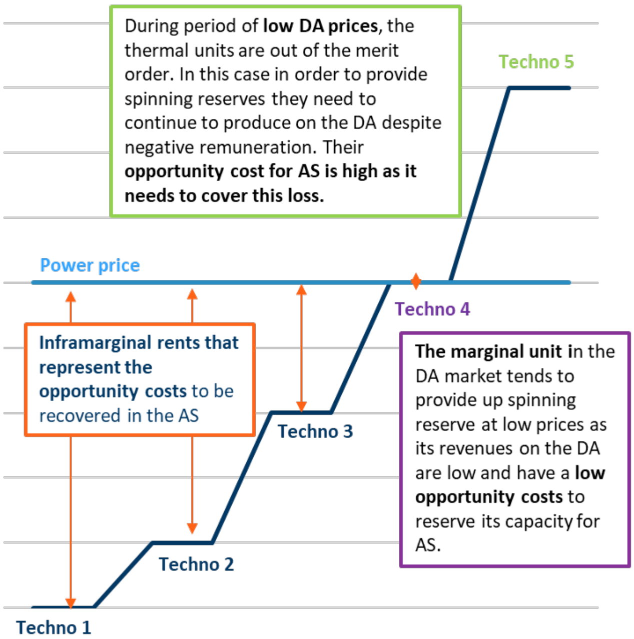
Wholesale prices based on shadow variables from the ED model will always reflect the marginal costs of the next-expensive unit not being deployed. To account for scarcity prices that exceed the marginal costs of the most expensive power plant, either a corresponding DSR technology can be added to a model to the extent the DSR volume is available or the current technical bidding limit in the market reflecting the practical value of demand curtailment. If regulation on scarcity prices is more complex and higher prices can already occur when a small share of peak-load capacity has not been utilized, shadow variables will not reflect this and will require post-processing to reflect wholesale prices.

3.2.2 Ancillary service and balancing markets

The markets for the ancillary services and balancing capacity can be modelled by defining the supply and demand for such reserves, similar to the supply and demand for power in the energy balance. However, it must be kept in mind that all computation of revenues builds on exogenous, very critical assumptions regarding what kind of assets match prequalification conditions and have actually access to the market. Appendix 0 provides details on how balancing reserve requirements are determined in practice.

For market participants whose business model is based on the 'stacking up' of different revenues, such as ancillary services markets (frequency and non-frequency) and wholesale markets, the bidding strategy is based on the opportunity cost of not participating to another market as illustrated in Figure 13.

Figure 13: Cost of provision of ancillary services reserves



Source: Own display

To account for ancillary service and balancing markets within the individual EVA or the cost minimisation EVA, the basic formulation introduced in section 3.1 must be extended. This could be achieved by introducing a new balance that ensures supply for ancillary services matches demand.

For a stylized example of positive and negative reserve requirements, this is demonstrated in Equation 10 to 13 (Lorenz, 2017). Equation 10 and 11 introduce balances for positive and negative reserve, respectively. The left-hand side of these balances provides the supply of negative or positive reserve summed over all types of assets i. The right-hand side specifies the demand for reserves and consists of an exogenously assumed amount and additional demand depending on capacity of fluctuating renewable capacities in the system. Equation 12 replaces equation 4 of the problem formulation in section 3.1 and adds the amount of positive reserves provided to the capacity constraint limiting generation according to the installed capacities. Analogously, equation 13 ensures negative reserves provided by each technology cannot exceed actual generation.

$$\sum_{i \in I} Res_{t,r,i}^{pos} = dem_{t,r,i}^{pos} + \sum_{i \in I^{re}} Capa_{r,i} \cdot posReg_i \qquad \forall t \in T, r \in R \qquad (10)$$

$$\sum_{i \in I} Res_{t,r,i}^{neg} = dem_{t,r,i}^{neg} + \sum_{i \in I^{re}} Capa_{r,i} \cdot negReg_i \qquad \forall t \in T, r \in R \qquad (11)$$

$$Gen_{t,r,i} + Res_{t,r,i}^{pos} \leq cf_{t,r,i} \cdot Capa_{r,i}^{gen} \qquad \forall t \in T, r \in R, i \in I_{gen} \qquad (12)$$

$$Res_{t,r,i}^{neg} \leq Gen_{t,r,i} \qquad \forall t \in T, r \in R, i \in I_{gen} \quad (13)$$

For the individual EVA, the shadow prices of equations 10 and 11 provide the market prices for reserve requirements, analogously to the energy balance and wholesale prices. In case of the cost minimisation EVA, the prices need to be extracted, because capacity decisions are already internalized.

In the practical implementation, balancing services should ideally be further differentiated into FCR, aFRR, and mFRR and include the activation of energy as well. In addition, models can also be extended further to account for inertia and reactive power as well (Wogrin, Tejada-Arango, Delikaraoglou, & Botterud, 2020).

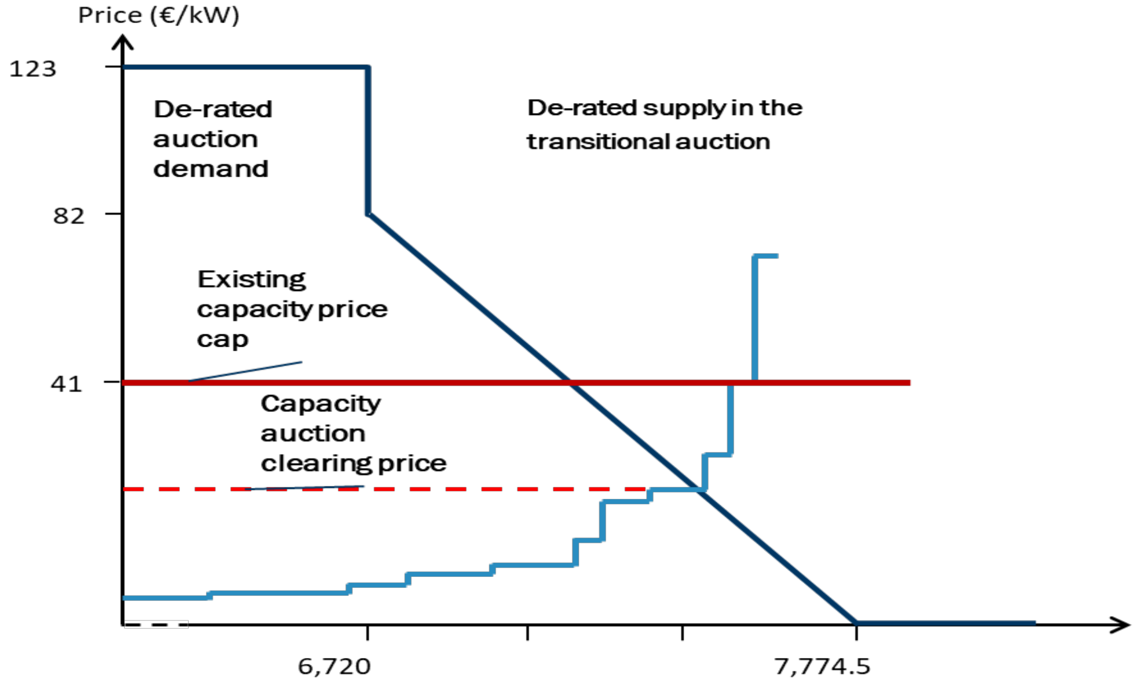
3.2.3 Capacity markets

Modelling of capacity markets aims to capture the equilibrium between capacity demand and supply, taking into account the details of the capacity market, such as the technical bidding limits for the existing capacity and for all capacity applied to address potential market power and the specific shape of the demand curve. It must be noted that revenues must build on exogenous and very critical assumptions regarding access to capacity markets for different technologies. Already existing capacity contracts must always be included in the EVA.

The volume of the demand curve in terms of de-rated capacity is usually determined by the Reliability Standard determined by the MS based on the country's estimated Value of Loss of Load, according to ENTSO-E's methodology[6] that the capacity market operator (a TSO) is planning to meet. The TSOs run models (based on adequacy assessment) to convert the Reliability Standard expressed in terms of an objective of the target average number of hours of Loss of Load Expectations (e.g. 3 or 8 hours) into a requirement for capacity in terms of derated capacity. The derated requirement for capacity as well as other parameters of demand and technical bidding limits are usually published by TSOs in advance of the auctions (Figure 14).

[6] ACER, October 2020, Methodology for calculating the value of lost load, the cost of new entry and the reliability standard

Figure 14: Example of supply and demand for capacity in the Irish capacity auction



Source: Own display

For the individual EVA, the consideration of a capacity market can add substantial complexity and includes two steps:

- First modelling the capacity market itself, and
- Second capturing how it interacts with the other revenue streams to determine entry/exit and mothballing decisions.

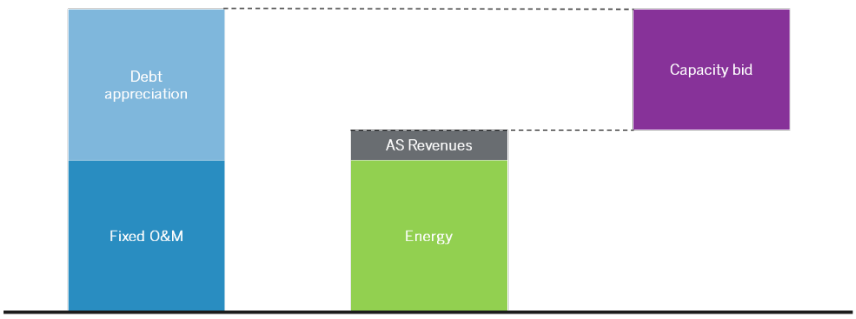
Modelling of the capacity market requires assessment of the net avoidable fixed cost of individual capacity operators defined as the avoidable fixed costs associated with making the capacity available over the delivery period of the capacity market net of the expected profits received in the energy and ancillary services markets.

The energy and ancillary services revenues are modelled as described above. The **net avoidable fixed costs** depend on each capacity unit's characteristics but also on whether a capacity unit is a new or an existing one. For the **existing units,** the avoidable cost of being a capacity resource is represented by:

- Fixed annual operating and maintenance expenses; and
- Debt depreciation (equity cost is assumed to be a sunk cost).

Figure 15 illustrates the balance between the net avoidable fixed costs and the expected net revenues (from energy and ancillary services), the gap representing a capacity bid of an existing unit recovering its net avoidable fixed cost.

Figure 15: Net avoidable cost of existing units



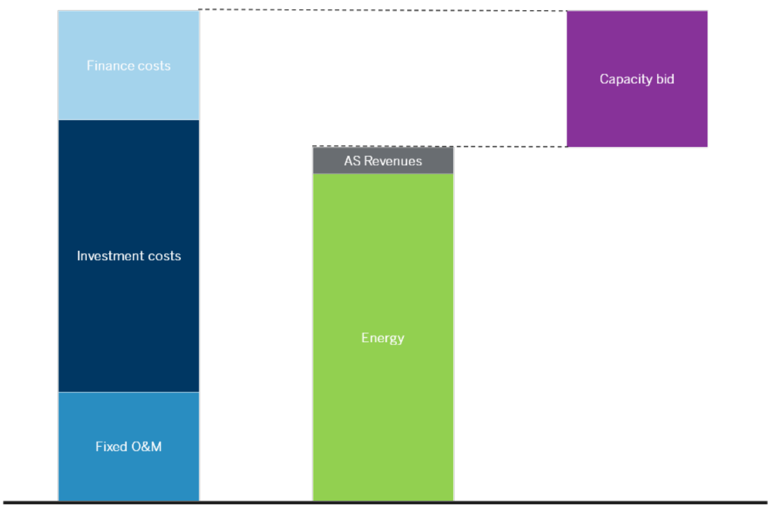
Source: Own display

For **new units,** the net avoidable cost of being a capacity resource is represented by:

- Fixed annual operating and maintenance expenses;
- Investment costs (annualised); and
- Financing costs.

Figure 16 illustrates the balance between the avoidable fixed costs and the expected net revenues (from energy and ancillary services), the gap representing a capacity bid of a new unit recovering its net avoidable cost.

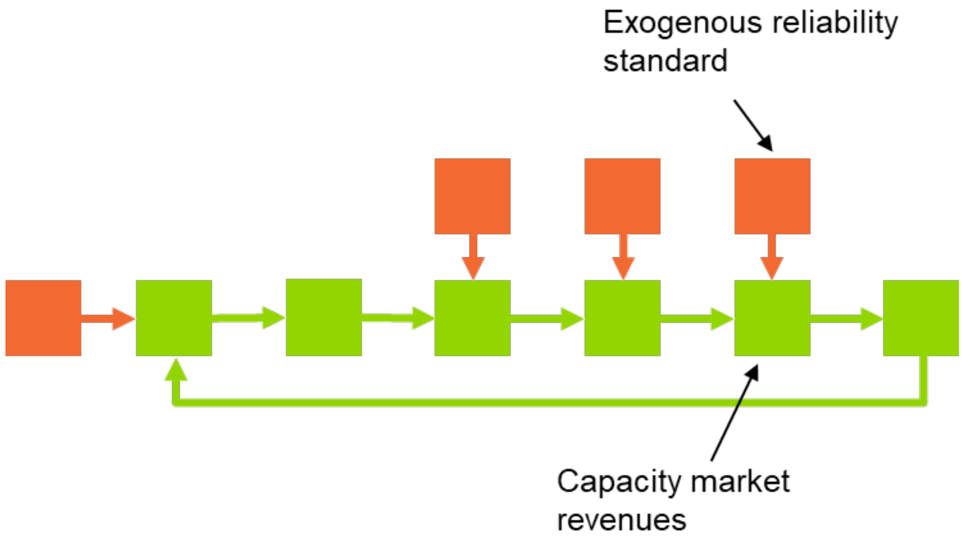
Figure 16: Net avoidable cost of new units



Source: Own display

After having assessed the revenues of the capacity resources as described above, the decision of the capacity operators to enter or exit in the market may need to be found by performing iterations looking for a convergence of the mix such that no further existing capacity is economic to exit, and no new capacity is economic to enter. This process extends the iteration of the individual EVA, which is already necessary in an „energy only“ scenario as shown in Figure 17 below.

Figure 17 Iteration process for investment/retirement decision with a CRM



Source: Own display, extension of Figure 8 describing the process without a CRM

In the cost minimisation EVA, the required capacity level can directly be enforced with a corresponding constraint as demonstrated in the equation below. The sum of all capacities from assets that qualify for the participation in capacity markets must at least amount the exogenously set level of capacity demand to meet the Reliability Standard.

$$\sum_{i \in I^{cm}} Capa_{r,i} \geq capaDem_r \qquad \forall\, r \in R \qquad (14)$$

Again, shadow prices of the equation do not need to be extracted, because all entry/exit decisions are already internalized in the cost minimisation EVA.

Alternatively, the cost minimisation EVA can also account for capacity markets by exogenously adding capacities on top of the results of the system cost minimisation until reliability standards are met. For instance, in the ERAA methodology it is described how in the case with a CRM computed capacities are tested with the detailed ED model ex-post. If the reliability standard is not met, iteratively first retired capacities are added and then new capacities are built.

3.2.4 Other revenues and regulation

The way revenues from non-electricity markets, subsidies and other kinds of regulation generating revenues greatly differs by revenue. As a result, these revenues can also be accounted for differently in the EVA and their implementation could also differ between the two EVA approaches. Below we discuss three potential elements of regulation:

- Heat sales,
- Subsidies, and
- Price caps and scarcity pricing.

Heat sales
Quite often the combined heat and power (CHP) receiving revenues for both producing electricity and for providing heat are considered out of the scope of the EVA. That is, since the

decisions to enter or exist for such capacity is not driven entirely by the electricity markets, this capacity is taken as given in a similar way with other policy-driven technologies, such as nuclear and renewables.

However, there are potential ways to address explicitly the revenues received by CHP from outside of the electricity market and to model the entry/exit of such capacity endogenously within the EVS.

The simplest way to account for heat sales in the individual EVA revenues is to assume a uniform heat price and include it in the overall computation. But since CHP capacities are often subsidized as well, CHP capacity is often considered as policy-driven capacity outside of the scope of the economic viability assessment. Some recent approaches model the combined electricity and heat revenues of the CHP capacity more accurately as it is done in the recent Elia's Adequacy and Flexibility Study. To assess the additional revenues from steam and heat generation, the **CHP-credit approach** (Fichtner, 2020) is applied in the last Elia's adequacy and flexibility study.

The CHP-credit approach considers a reduction of the variable costs of the CHP units for their dispatch decision in the electricity market. By reducing the variable cost at which the unit is dispatched, it increases the margin that such units would make (based on electricity market revenues and the decreased variable costs), which mimics the additional revenues CHPs would get from selling heat or steam.

The CHP credit approach is built upon the reasoning of opportunity costs, meaning if not provided by CHP the heat/steam/process needs to be generated by a gas boiler. The benefit in marginal cost for the CHP is therefore the opportunity cost (avoided cost) of generating the same amount of heat with a gas boiler. The avoided costs should use assumptions on boiler efficiency (e.g., 99%) and heat generated per MWh electric produced by the CHP (e.g., 1.5MWh_{th} /MWh_{el}). The CHP credit is calculated depending on the gas and carbon prices and subtracted from the CHP's marginal costs, which can then be directly used in modelling the expected revenues of CHPs. However, the calibration of the CHP-credit approach may be challenging in practice because the actual CHP revenues can vary greatly depending on the supplied process (e.g., steam generation, heat/steam profile required, and industrial process).

If CHP capacities are not considered as policy-driven capacity outside of the scope of the economic viability assessment, for the cost minimisation EVA the capacity expansion problem must be extended to consider heat requirements. The revenues received from a CHP operation are highly dependent on the value of heat and the annual operating hours of a plant. Operating hours of CHP are typically higher than a stand-alone technology which would otherwise be often used as peaking plants (e.g., OCGTs). One approach to consider required heat generation in the cost minimisation are must-run operating profiles, which may be interrupted by large scale PtH or gas boilers to avoid, that CHPs have to run at minimum capacity factor to supply heat or steam, even if power prices were lower than its marginal costs, i.e., operating at loss.

In addition, it is important to differentiate between two main types of CHP generators within the modelling:

1. Independent power producers for specific district heating requirements; and
2. External waste heat market participants.

We note that the economic viability and operation of the former type of CHP generator is more directly related to its variable costs and expected market revenues, whereas the latter type supplies heat/steam as a waste by-product of an industrial processes that jointly define the economic viability.

Subsidies
Subsidies also impact the economic viability of capacity resources. Subsidies for power and heat production typically include **tax expenditures** (exemptions and reductions, tax allowances, tax credits and others), **direct transfers** (grants, soft loans) and **indirect transfers** (feed-in tariffs, feed-in premiums, renewable energy quotas, tradeable certificates, and others).

Treatment of the expected revenues from subsidies in the EVA can be twofold (and this is irrespectively of the two EVA's options). The first states that when subsidies or support schemes are available, one can assume that they ensure that the installed capacity target is reached, and the EVA may not be performed in such cases for those technologies (ERAA methodology (Article 6, 9 (d))). Note also that there is no guarantee that the capacities receiving subsides today will receive them for all the target years assessed in a resource adequacy.

The second treatment considers the subsidies in an economic assessment. Some subsidies are more implicit than others. For example, biomass used for power and heat generation is not exposed to the CO_2 price because biomass is currently treated as carbon neutral[7] under the EU ETS. This missing cost for capacity resources using biomass may be considered explicitly as a subsidy supporting their economic viability. The use of biomass for district heating and CHP is quite significant especially in some European regions,[8] such as the Nordic countries. Energy tax exceptions for biomass may also be treated as a subsidy, but the absence of this "hidden" tax may be difficult to identify, similarly as R&D subsidies. Other mentioned subsidies, namely tax expenditures, direct and indirect transfers, may be more directly included in the economic assessment, but the economic viability of the capacity resources will then strongly dependent on the subsidy assumptions, such as their magnitude and duration.

An alternative approach in EVA can be to model the capacity resources' true costs and expected revenues **without subsides** to obtain an unbiased view on the possibly missing money which can then be addressed by policy instruments. Scenarios and sensitivity analyses can be also applied for varying assumptions on the costs and revenues of different technologies, which can also implicitly reflect policy incentives (subsidies). In the cost minimisation EVA subsidies could be reflected in the cost assumptions, in the individual EVA subsidies can be factored in directly.

Technical bidding limits and scarcity pricing
Technical bidding limits, i.e., a maximum energy price at which a modelled market can clear, are a key aspect of electricity market design, potentially affecting investment decisions. Until recently, the day-ahead technical bidding limit was set at 3 000 €/MWh, but automatic adjustment mechanisms are foreseen by Article 10 of the Electricity Market Regulation. For example, following a proposal by NEMOs (NEMO Comittee, 2020) when a price of 60% of the prevailing technical bidding limit is reached, the technical bidding limit increases by 1 000 €/MWh, increasing in theory up until the Value of Lost Load (VOLL). By the time of the release of this report, the technical bidding limit is expected to be increased to 5 000€/MWh following this principle, resulting from the price events in the Baltic region in August 2022, after the technical bidding limit has already been adjusted once to 4 000€/MWh after the price

[7] This is because it is assumed that the same amount of CO_2 was sequestered during the sustainable growth of the biomass as will be released when the biomass fuels are combusted.
[8] See study on biomass subsidies, e.g. http://trinomics.eu/wp-content/uploads/2019/11/Trinomics-EU-biomass-subsidies-final-report-28nov2019.pdf

events in France in April 2022.[9] VOLL levels are nationally set following an ENTSO-E methodology and typically vary between 10 000 and 20 000 €/MWh. According to ACER (2019) and in line with Art. 41 of the CACM guideline, the maximum and minimum clearing prices (for the single day-ahead coupling) shall take into account an estimation of VOLL as determined by the market participants' willingness to pay. The technical bidding limits will therefore be gradually increased reflecting VOLL, which can further differ by market places, i.e. day-ahead, intraday, or balancing and imbalance power markets.

Regulatory scarcity pricing is a relatively new regulatory approach under discussion in Europe (that was implemented in some markets of the USA in 2000s and 2010s, e.g. in ERCOT[10] and PJM[11]), which addresses the missing money problem via more precise valuation of reserve services. Scarcity pricing refers to the notion of increasing energy prices above the marginal cost of the marginal unit (a price adder) under conditions where the system is short on generation capacity. The theoretical justification of the approach is that it adjusts the real-time price of energy and reserve capacity such that the resulting dispatch of profit-maximizing generators would reproduce the optimal dispatch that would be obtained if the contribution of reserve capacity towards reducing the loss of load probability would be accounted for (Hogan, 2013). Scarcity pricing generates profits for generating resources that serve towards covering the capital costs of these units. Scarcity pricing is therefore essential for attracting investment in a market (flexible technologies and demand response).
Practical application of the regulatory scarcity pricing in the context of the EVA would imply that depending on the degree of scarcity, the wholesale prices can reach levels above the technical bidding limit, potentially reaching VOLL based on the assumptions of the specific parameters of the scarcity mechanism.

The effect of the technical bidding limits can be captured in both EVA approaches by implementing a slack variable setting the price of the demand constraint being not met. As mentioned above, the two EVA approaches address the peak load pricing differently: The cost minimisation EVA defines the peak load prices to ensure refinancing of investments during scarcity periods, while the individual EVA implies that this is achieved in the equilibrium between the dispatch and investment by setting the price at the technical bidding limit or VOLL during scarcity periods. Although both approaches should be expected to result in the same level of the peak-load prices, in practice, the peak-load estimated through the cost minimisation may be below the VOLL or technical bidding limit in case such lower price level is sufficient for fixed cost recovery.

3.3 Uncertainties and risk in the EVA

This chapter discusses what kind of uncertainties and risks the economic viability of assets is subjected to, how these risks relate to the risk assessment of the RAA, and the ways these risks can be accounted for in the methodology.

3.3.1 Critical uncertainties for the EVA

Investment decisions are difficult because they are sensitive to variables that are uncertain. Most of the risks relevant for the economic viability result from the markets the assets

[9] https://www.montelnews.com/news/1310833/eu-power-bourses-to-hike-price-cap-after-french-spike-

[10] ERCOT (Electric Reliability Council of Texas) is an American organization that operates Texas's electrical grid, the Texas Interconnection.

[11] PJM Interconnection LLC (PJM) is a regional transmission organization (RTO) in the United States. It is part of the Eastern Interconnection grid operating an electric transmission system serving all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

participate in, most importantly the electricity markets. Risks in these markets can be distinguished into a price risk reflecting the uncertainty of obtained prices and a volume risk reflecting the uncertainty of sold volumes. Both these risks are highly correlated and depend on entry or exit of other market participants, commodity prices, and the development of demand. For instance, market entry of renewables or reduced consumption due to an economic crisis will both reduce prices and the amount of electricity sold by thermal power plants. In addition, thermal power plants are subject to a price risk from commodity markets for fossil fuels or emission certificates.

On top of the market risk, there are substantial regulatory or political risks which are more difficult to quantify. For instance, a change of regulation in the ancillary and balancing markets could have a severe and unexpected effect on the revenue of market participants. Political risks can also greatly affect market participants that regulation is not aimed at directly. For instance, subsidies for renewable energies in many European countries greatly decreased wholesale prices and resulted in substantial reduction of revenues for thermal power plants. Other examples of political risks include regulation and compensation mechanisms related to the phase-out of fossil fuels, the configuration of market zones, or the introduction of capacity markets. Lastly, there are practical risks associated with the construction and operation of assets, for instance an unexpected delay in construction.

The consideration of risks is already a central component of the RAA where the EVA is a part of. To precisely estimate of resource adequacy, the RAA methodology provides detailed instructions on how to deploy a Monte-Carlo approach considering different climatic years and outage patterns and how to draft and test different scenarios of long-term system development. But although EVA shares several uncertainties with the RAA approach, the impact of these uncertainties between EVA and RAA can differ and some key uncertainties for the EVA are not relevant for the RAA at all. In the following, we will refer to these uncertainties as “asymmetric” and discuss them with greater detail.

Asymmetric uncertainties are important to discuss, because they are not a focus of the stochastic methods in the RAA, but still have considerable impact on the RAA and therefore ultimately on the EVA as well. The most important example for asymmetric uncertainties are commodity prices of thermal generators. Prices for fossil fuels and emission certificates can fluctuate substantially and the resulting uncertainty greatly affects entry and exist decisions by operators, but in the RAA these uncertainties play a minor role and might only be considered in different sensitivities, if at all.

3.3.2 Consideration of risks in the methodology

In the EVA, risk and uncertainty can be accounted for in different ways. The most straightforward way is to perform the EVA for the different scenarios of the RAA that reflect different pathways for the development of the overall system. This approach rather takes a macro perspective capable to account for key political and market risks but cannot capture the impact of rare scarcity events and is not very elaborated from a methodological perspective. Instead, the RAA and the EVA are simply performed independently for each scenario leading to different results regarding installed capacities and adequacy metrics. Accordingly, this approach does not capture the risk behaviour and mitigation strategies by investors and market participants.

Two more sophisticated methods to account for risks are already mandated in the EVA methodology. First, the EVA must consider the different Monte Carlo years also used for the adequacy assessment of the RAA. Although the purpose of these Monte Carlo years in the RAA is to capture adequacy risks, using them within the EVA can accurately account for market risks and most importantly scarcity events. Nevertheless, deploying the same number as Monte Carlo years with the same level of temporal detail as in the RAA is challenging for the EVA, as we will discuss in following section. The ERAA 2021 was criticized by ACER for not including sufficient Monte Carlo years, which would require a stochastic capacity expansion model (Backe, Skar, Granado, Turgut, & Tomasgard, 2022). The Elia report using EVA of individual capacity resources already deploys a higher but still reduced number of Monte Carlo scenarios to compute a distribution of market revenues.

Second, the EVA methodology mandates to use a differentiated Weighted Average Cost of Capital (WACC) that reflects the risk premium different investments are subject to. The WACC considers how investment risks impact financing costs. The higher the risk regarding the project profitability, the higher the expected return investors require. To compute the WACC, the expected returns of fund providers/investors are aggregated based on respective share in financing an investment. Different methods are conceivable to compute the WACC for adequacy studies:

- WACC can be determined either exogenously (via an independent study/benchmark) or endogenously to the adequacy study (e.g. risk and WACC premium assigned to investors computed based on the modelled revenue fluctuation), or with a hybrid approach combining both a base WACC determined exogenously with WACC premia determined endogenously;[12]
- WACC can be either asset-specific or normative, i.e. for a technology class (e.g. CCGT, OCGT etc.) and/or market operator type (Utility, IPP etc.).

The ERAA 2021 uses a uniform WACC for all regions based on a study specifically estimating the WACC for the Belgian market under certain conditions. In its review, ACER criticises this approach and states the WACC should reflect the different market conditions in European markets and therefore differ by country. In addition, the computation process must be made transparent.

The computed WACC can then be integrated in the respective EVA method. For the individual EVA, the WACC is used to compute the IRR or NPV that is used to determine the profitability of certain capacity categories and to decide on how to adjust their capacity in the next iteration as described in section 3.1.2. In the cost minimisation EVA, the WACC will be used to annualize the investment costs being part of the cost minimisation according to the formula below where i is the assumed WACC, n is the economic lifetime, and inv are the investment costs.

$$ann = invCost \frac{(1+i)^n \cdot i}{(1+i)^n - 1}$$

Finally, it is conceivable to deploy more advanced metrics to advance the representation of asymmetric risks that are critical for the EVA but not extensively covered in the RAA, for instance commodity prices. Different price developments here could be included into the Monte Carlo scenarios that currently only reflect climatic conditions and outage patterns. Correspondingly, the iterative adjustments of capacities in the EVA of individual capacity resources could be based on other risk metrics than IRR or NPV, for example value-at-risk or expected shortfall. However, further advancing risk metrics increases computational challenges in the EVA. In addition, it is questionable, if improving methods can lead to more precise results or will just create “over-sophistication”, meaning more complex but not more accurate methods. For instance, a key question of risk management by market participants is the rest of their portfolio, which cannot be reflected by the EVA.

12 See for instance RTE (2018). *Impact assessment of the French Capacity market*

3.4 Computational challenges and simplifications

Like any quantitative model, the methods for the EVA have to make certain simplifications to be computationally feasible. On the one hand, these concern rather theoretical aspects, like assuming that in the market capacities will develop in a cost minimising way, as discussed in section 2.4 of the theoretical section.

Beyond these theoretical assumptions, some practical simplifications are necessary to keep the computational complexity of models manageable. In particular the cost minimisation EVA will typically require simplifications not used in ED dispatch models. First, because capacity variables are part of the model and increase complexity. Second, because the scope cannot be limited to a single year but must cover the entire timeframe of the RAA and might even go beyond to account for the economic lifetime of assets. For the individual EVA this problem is not as pronounced, because the ED model can be solved separately for each year, while the cost minimisation EVA only performs one comprehensive optimisation. On the other hand, the individual EVA requires simplifications regarding the iteration process, due to limitations in exhaustively testing all investment possibilities in various technologies and across various bidding zones (i.e., no unique solution of the EVA model can be found or attested in the individual EVA).

In the following, we will discuss simplifications mostly applicable for both EVA methods regarding time-series reduction and unit commitment.

3.4.1 Monte Carlo climate years

Both EVA approaches share that they cannot deploy the full number of Monte Carlo years used for the adequacy assessment of the RAA, while at the same time must ultimately lead to results that cannot be inconsistent with the RAA. Such inconsistency between RAA and EVA was one of the reasons for ACER to reject the ERAA 2021 by ENTSO-E. In this case, the EVA was based on representative periods for a small number of climatic years and an average outage pattern opposed to a high number of Monte Carlo years. As a result, the computed values for the LOLE (i.e., investment signals due to scarcity prices) were found to be much smaller than the more accurate values computed by the ED model using all Monte Carlo years. This may lead to an underestimation of the viability of resources in the EVA and thus also their deployment as compared to the full probabilistic ED.

As discussed in section 3.1.2, the Elia report based on EVA of individual capacity resources uses a reduced number of time-steps for most iterations and only 200 Monte Carlo years. The number of time-steps is only increased in selective iterations to ensure consistency. A plausibility check within the report that tests final results with all time-steps and not 200 but all 597 Monte Carlo years proves accuracy. As a result, the approach is capable to achieve consistency regarding LOLE and EENS between the calculations performed for the EVA to determine capacity and the overall adequacy assessment of the RAA. Achieving such consistency is crucial, because inconsistency between LOLE and EENS implies that scarcity events are not accurately captured by the EVA. As a result, also results on economic viability will differ substantially since peak-load scarcity events account for a substantial share of revenue for peak-load plants.

The RAA applying cost minimisation EVA often uses a selection of representative climate years from several years of climatic data or a clustering of the climate years approach. Although ACER generally accepted to deploy some simplifications until the full compliance with the RAA-method due by 2024, final results were criticised for insufficient consistency with the ED model that suggests computation of capacities is biased since scarcity events are not fully reflected.[13] Another example is provided by the German RAA that applies the cost minimisation approach for ERA while simplifying using only 6 climate years.[14]

Some discrepancies of LOLE between EVA and ED due to non-avoidable simplifications in both approaches discussed may not be completely ruled out. Nevertheless, a high degree of consistency of the LOLE estimation between EVA and RAA should still be achieved.

3.4.2 Temporal granularity reduction

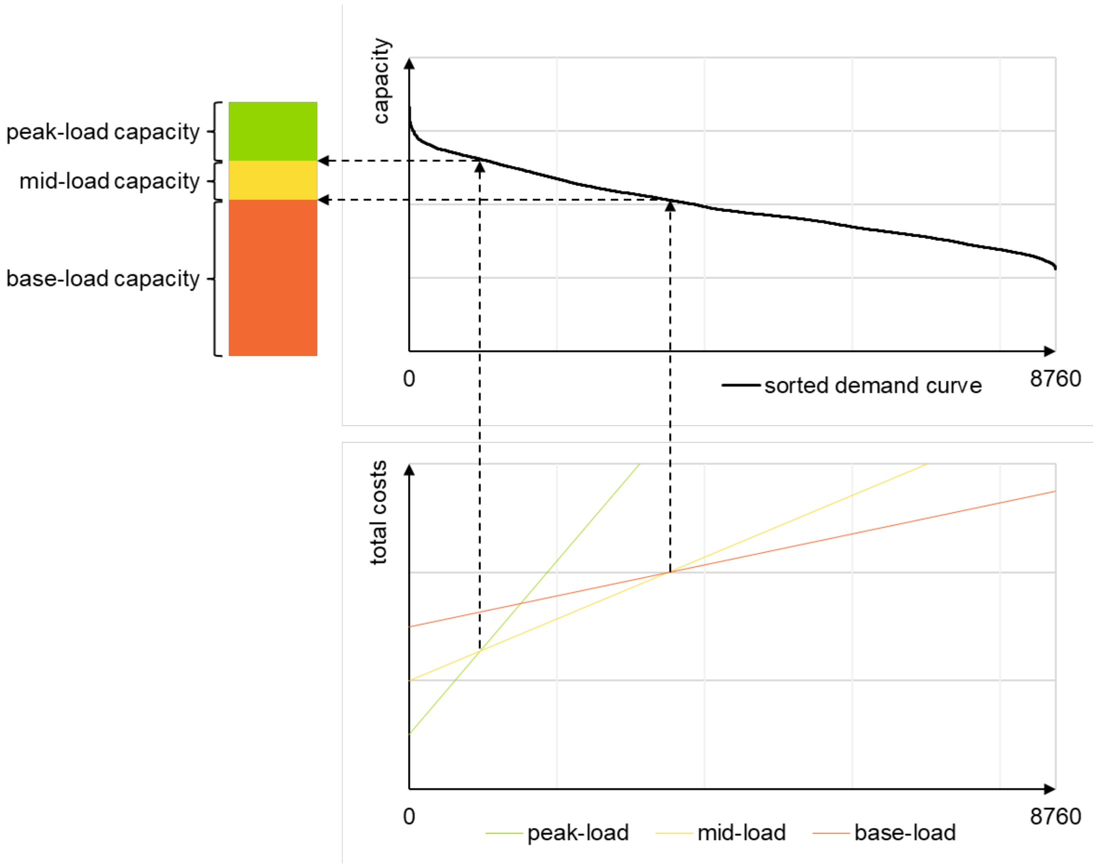
The academic literature provides different methods to reduce the temporal detail of ED models used for the individual EVA or capacity planning models used for the cost minimisation EVA.

The greatest simplification, only applied for capacity planning models, is to not include the full chronology of the load into the model and instead base capacity expansion on a simple load duration curve model. An example of the mechanics of such model is described in Figure 18 below. First total cost depending on the number of operating hours for different technologies are plotted in the lower graph. For each line, the intercept with the x-axis represents fixed investment costs even incurred without any operation and the slope reflects variable generation costs. Accordingly, the graph captures the trade-off between base-, mid- and peak-load technologies in terms of fixed and variable costs. For a given number of operating hours, the graph can be used to determine to cost-efficient technology for supply. This technology changes wherever lines intersect.

[13] „Overall, ACER considers that the level of simplifications of the EVA in the ERAA 2021 is not acceptable due to the considerable impacts it has on the results.“ Acer (2022), Decision on the European Resource Adequacy Assessment for 2021, Annex 1

[14] BWMi

Figure 18: Duration curve model to determine installed capacities



Source: Own display

To determine a cost-efficient combination of technologies satisfying demand, the total cost curves are paired with a duration curve of demand sorting hourly data over a year in descending order. To further reduce complexity this curve can also be approximated, for instance by a stepped curve. In the model, fluctuating renewables, like wind and solar, can only be considered exogenously by subtracting their hourly generation from demand, resulting in the so-called residual demand curve.

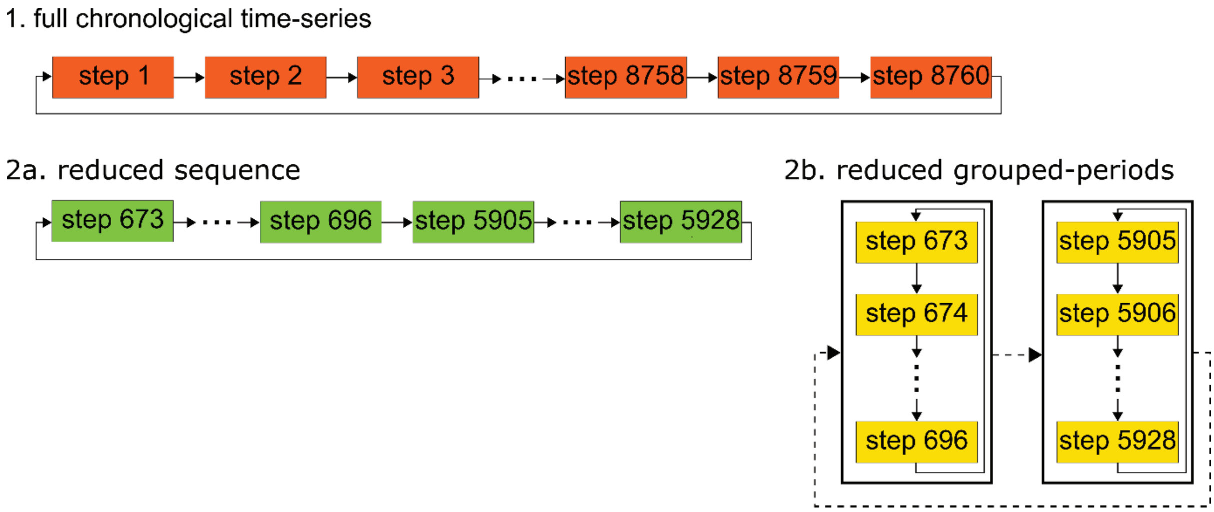
To ensure adequacy, the total sum of capacities must comply with maximum demand on the very left of the curve. In addition, the number of operating hours for peak-load capacities to be cost-efficient can be transferred into the upper graph and used to derive their capacities. The same process is repeated for mid- and base-load technologies to obtain all capacities.

Although highly efficient in terms of computation time, the approach is very simplistic. Capacities are solely based on the investment and variable costs of the respective technologies. Intertemporal effects of operation, like ramping restrictions or minimum offline time, cannot be represented. For the same reason, energy storage cannot be modelled either. More importantly, also interzonal effects cannot be captured, because the approach only works for a single market. Imports and exports to neighbouring markets restricted by line capacities are not accounted for. Correspondingly, academic research finds the method inferior to others in terms of accuracy (Nweke, Leanez, Drayton, & Kolhe, 2012). The method is not used in any of the existing EVA options and likely insufficient to achieve consistency with the detailed chronological time-series used for the resource adequacy assessment.

The next-best alternative is to not use a full year of chronological data, but to run models with a reduced subset of timesteps. This approach is applicable for both, the ED model used for the individual EVA and capacity planning models used for the cost minimisation EVA.

Fundamentally, two different methods illustrated in Figure 19 can be distinguished to represent a reduced time-series within a model (Göke & Kendziorski, 2022). For demonstration, we assume a "full" time-series includes all hours of a year in chronological order.
One way is to implement the reduced time-series the very same way, termed a reduced sequence. This approach facilitates the implementation of inter-temporal constraints, like storage levels, but will either impose a bias on short- or long-term.
Alternatively, the steps of the reduced time-series can be grouped into independent periods, for instance a week or a day. Inter-temporal constraints are than imposed independently for each grouped period. This approach is well suited, if intertemporal constraints only apply for a short duration, like minimum offline times of thermal power plants or battery storage (Pineda & Morales, 2018). If intertemporal constraints cover longer timespans, in case of seasonal storage for instance, the approach must be extended to track storage levels across several grouped periods (Kotzur, Markewitz, Robinius, & Stolten, 2018).

Figure 19: Methods to implement reduced time-series, based on Göke & Kendziorski, 2022



Source: (Göke & Kendziorski, 2022)

The question of how to select time-steps from the full time-series can be separated from the implementation discussed above. In the example presented in Figure 19, two representative days consisting of 24 hours are selected from the full time-series. Academic literature provides a wide range for selecting such time-steps (Hoffmann, Kotzur, Stolten, & Robinius, 2020). Alternatively, new representative time-steps can also be created synthetically (Doménech, Campos, & Villar, 2018).

Generally, the underestimation of lost-load when using reduced time-series is a common problem, but academic literature suggests two different ways to address this (Hoffmann;Kotzur;& Stolten, 2022)(Hoffmann, Kotzur, & Stolten, 2022). First, the temporal resolution of the reduced time-series can be increased. On the one hand, this approach is straight forward and will consistently improve the solution, but on the other it will obviously increase computational complexity of the problem and can easily lead to models becoming unsolvable. Second, the selection criteria for the time-steps of the reduced time-series can be improved, sometime specifically to account for extreme events leading to lost load (Teichgraeber, et al., 2020). While this approach will not increase computational complexity, it is not as effective and cannot be guaranteed to consistently improve results.

Both existing analyses of economic viability deploy time-series reduction in some way.

3.4.3 Unit commitment constraints

Detailed ED models will typically consider each unit of generation separately enabling them to account for complex operational constraints. In the following equations, the index i refers to a single unit and the binary variable $Opr_{t,i}$ reflects, if this unit is operating or not at a given time t. Consequently, the first equation imposes a lower limit on the utilization of the plant whenever it is operating reflecting restrictions of large thermal power plants. Similarly, the second constraint defines a minimum timespan the plant must remain offline once it has stopped operation once. Finally, the last two constraints limit the gradient of generation across time-steps to capture operational restrictions. Additionally, it is conceivable to further expand the listed equations, for instance to account for start-up costs of plants.

$$Gen_{t,i} \geq minGen_i \cdot Capa_i \cdot Opr_{t,i} \qquad \forall t \in T, i \in I_{gen}$$

$$\sum_{t\prime=t}^{t\prime - minOff_i + 1} (1 - Opr_{t\prime,i}) \geq minOff_i \cdot (Opr_{t+1,i} - Opr_{t,i}) \qquad \forall t \in T, i \in I_{gen}$$

$$Gen_{t-1,i} - Gen_{t,i} \leq gra_i \cdot Capa_i \qquad \forall t \in T, i \in I_{gen}$$

$$Gen_{t,i} - Gen_{t-1,i} \leq gra_i \cdot Capa_i \qquad \forall t \in T, i \in I_{gen}$$

$$Opr_{\boldsymbol{t,i}} \in \{0,1\}$$

In general, these unit commitment constraints are most relevant for large thermal assets, such as coal or gas power plants. However, since they introduce a binary constraint including them can greatly increase the computational complexity and solve time of any linear problem. Therefore, a common simplification is to aggregate all plants with similar characteristics, e.g. all old coal plants, into one comprehensive category i. These categories can be compared to categories ENTSO-E uses for other publications, like the TYNDP. Nevertheless, such aggregation if implemented within the EVA may create further inconsistency with the adequacy assessment in the RAA, which under the ENTSO-E's methodology requires unit-level detail. Aggregating capacities will neglect the constraints listed above. Omitting them will assume that the affected plants are perfectly flexible and neglect opportunity costs incurred by inflexibility. As a result, using these simplifications in either EVA method will underestimate market prices and is likely to impose a bias on results. The magnitude of that bias will greatly depend on the role of large and rather inflexible thermal plants in the modelled system.

4. Final conclusions on the EVA

This report has outlined all relevant costs and revenues that have to be applied in a converging process to assess the economic viability of assets. The economic dispatch modelling serves to determine variable costs and revenues in the energy-only market (EOM), that is, the variable fuel and O&M costs and revenues associated with the operation in the wholesale markets and the markets for Ancillary Services (AS) and Balancing Mechanisms (BM). Further, the EOM perspective is extended with fixed costs and other revenues to determine if the decision to enter or to exit the capacity is economically viable and thus whether the capacity should be considered in the RAA.

It became clear, that the Economic Viability Assessment is a quite complex model which intends to assess over a forward period of capacity technical lifetime a) the market operation and associated revenues and costs and b) the decisions to enter, exit or mothball capacity based on the fixed costs and the expected costs and revenues.

As it is often the case with complex models, the outcome of the EVA depends on a number of methodological choices among the available options. This report highlights that such choices are quite often imposed by the limited computational resources, which require to make certain simplifications.

Below we summarise the considerations that in our view should inform the methodological choices and the best allocation of the computational resources stemming from the discussions presented in the report.

First, one need to ensure that the EVA model reflects the entry/exit decisions being made by the market participants operating different capacity types, for which a number of requirements for the EVA implementation may have to be set:

- Reliance of different capacity resources on the revenues from various sources may require a detailed representation of the involved markets: wholesale and balancing markets, as well as capacity mechanisms, where they exist.
- The fact that market regulation and revenues outside markets can have significant impact on the entry/exit decisions require a careful application of these regulation in the EVA. In particular, the extent to which markets are not yet fully opened for DSR as well as the existence of explicit subsidies and support schemes for DSR and storage should be taken into account.
- Different types of capacity are subject to different economic considerations. As the discussions in the workshops have revealed, operators of baseload power plants may be more risk-averse and thus applying rather average electricity prices in their economic assessment. Peak-load power plants, as well as flexibility options such as DSR or storage, in turn, may be partly more risk-seeking, depending on their individual structure of costs and the expected refinancing times.
- The choice between the two EVA approaches (individual EVA vs cost minimisation EVA) may also be driven by this consideration. On the one hand, the individual EVA allows to explicitly account for the revenues across various markets and better reflects the investor's point of view, while being potentially limited regarding the design choices of investors and interdependencies across different resource types, markets and bidding zones. The EVA through cost minimisation, on the other hand, allows for a systemic perspective where all interdependencies in the system are reflected, while being potentially limited in considering different revenue streams for an individual investment. In both cases, the weaknesses could be somehow addressed by additional

modelling efforts. However, this would come at the cost of additional computational complexity, which might technically not be feasible.

- A combination of two approaches could provide a potential solution to the computational limitations of each of the approaches, as was suggested by the academic workshop participants. In particular, the capacity equilibrium resulting from the cost minimisation EVA could be used as a starting point for the viability assessment of the EVA of capacity resources.

Second, consideration of the realism of the EVA in modelling operators' entry/exit decisions does not always require model complexity. On the contrary, the discussion with the industry representatives during the workshops highlights the fact that the investment decisions are often driven by simplified views on the market, for example:

- Decisions to invest in conventional (in particular baseload) plants are often driven by a single base case scenario, potentially accompanied by a downside scenario. Such decisions do not necessarily consider a wide range of scenarios, accounting for the climate variation and the expected price spikes that can be produced in some specific climate conditions.
- The time horizon of the decisions to develop flexibility resources, such as DSR and storage, could be much shorter than the time horizon of the conventional plants, while at least for DSR and flexible consumption the share of investment costs is much smaller. This could justify simplification of the assessment of economic viability and not perform a long-term multi-year analysis for these assets.

Third, the EVA approach should focus on the overall objective to ensure that the RAA assesses the forward adequacy of the system based on the economically driven assumptions of the future expected capacity. Since the purpose of the RAA is to inform about whether the system in the medium term of 10 years can reach its economically optimal Reliability Standard or whether it would need interventions (e.g. capacity mechanisms), it is important that the chosen EVA approach reflects the actual and future market conditions over the full lifetime of an asset in an appropriate way.

Finally, an important element of the consistency between the EVA and RAA that needs to be achieved is on the adequacy indicators. That is, despite being focused on the simulation of market participants' investment and retirement decisions, the outcomes of the EVA in terms of the LOLE need to be broadly consistent with those of the RAA. For example, in case RAA results in a much higher LOLE than EVA, one may consider that EVA has underestimated the economic capacity and vice versa. Even though some discrepancies of LOLE between EVA and RAA can be justified by the risk attitude (e.g. risk aversion of some capacity types / operators and risk-taking attitude of other types / operators) and the fact that investment decision may not always be driven by rare high-price scarcity events, a strong degree of consistency between EVA and RAA should still be achieved.

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Appendix

Dimensioning of reserve requirements

The demand for reserves is defined by the combination of the expected forced outages of thermal plants and cross-border lines, the forecast errors from the load (errors between the forecast on the DA or after the ID and the realized to be covered by the reserves) and forecast errors from renewable (increase driven by increased RES capacity or decrease linked with learning curve of RES generation forecast).

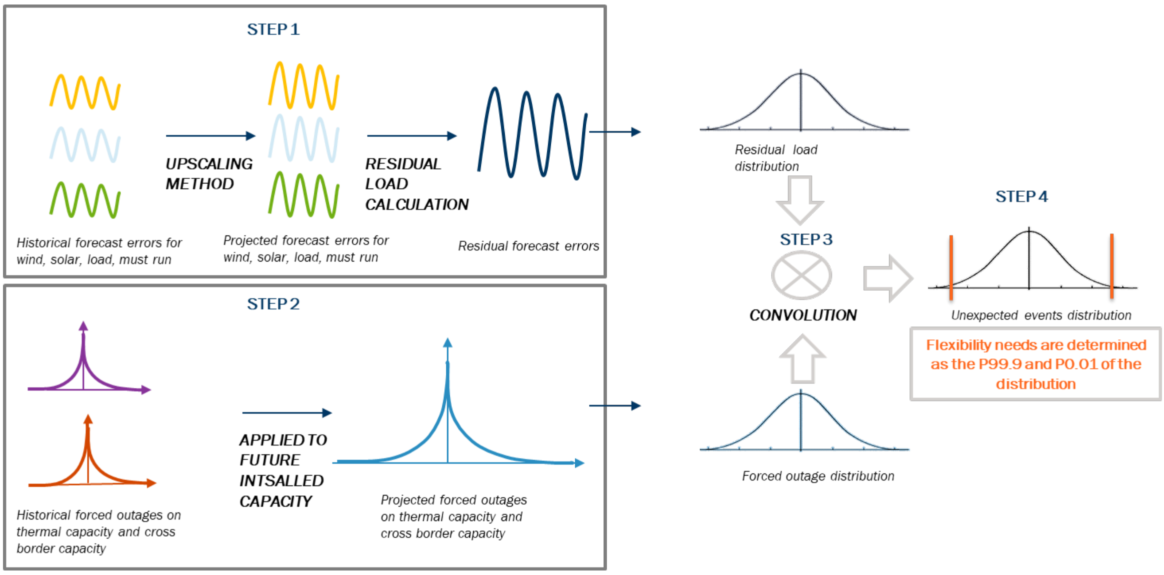
The overall need for flexibility can be defined in the following four steps (Figure 20):

- The **first step** consists in estimating the forecast errors for load, wind, solar and must-run generation for the periods day-ahead/last forecast (DA/LF) and last forecast/realized time (LF/RT). An upscaling methodology is used to increase these errors based on the growth of installed capacity and load. The projected data enables to calculate the residual load error, the distribution of error day-ahead/last forecast and last forecast/realized time and the variation (delta) of error LF/RT.

- The **second step** estimates the future forced outages for thermal capacity and for interconnections, based on historical forced outages of those assets.

- The **third step** consists in “merging” these unexpected events – residual load errors and forced outages – to assess the total flexibility needs for each period. This is done using a convolution product. The final distribution of each period represents the total unexpected events occurring over each period. The upward and downward flexibility needs for each period are defined as the P99.9 and P0.01 of this distribution

Figure 20: Overall need for flexibility



Source: Own display, based on (Elia, 2021)

Then, the need for flexibility that needs to be procured from the market is defined in the European balancing guidelines:

- **FCR dimensioning is defined as follows**:

- The reserve capacity for the synchronous area shall cover at least the reference incident, and for the CE and Nordics synchronous area, the TSO should have the right to define a probabilistic dimensioning approach with the aim of reducing the probability of insufficient FCR to below or equal to once in 20 years.

- The size of the reference incident is defined in the CE synchronous area to 3000MW. (This size is potentially subject to changes with new interconnections, additional large units)

- The size of the reference incident for the GB, IE/NI and Nordic synchronous area is equal to the largest imbalance that may result from defined potential outages.

- **aFRR and mFRR dimensioning** is less precisely defined by the European balancing guidelines, but the guidelines mention that:

    - TSOs should determine the reserve capacity based on historical records covering at least the time to restore frequency, and covering at least one full year;

    - TSOs should consider the size of a reference incident;

    - The reserve should be enough to cover the imbalances in 99% of the time.

Final definition of the demand for each type of reserve needs to be fine-tuned based on the national practice.

On the supply side, both electricity producers and customers (via demand response for instance) can theoretically participate to ancillary services markets. Their effective participation depends on:

- Technical requirements for the participation to the different reserves (activation time, delivery period, installed capacity, upward or downward direction),

- Economics consideration (possibility to participate to different markets) and regulation (prequalification requirements),

- Those considerations will in turn impact the bidding strategy in the ancillary services markets.