NEA System Cost Analysis for Integrated Low-Carbon Electricity Systems

A Guide for Stakeholders and Policymakers



BETTER POLICIES FOR BETTER LIVES

NUCLEAR ENERGY AGENCY

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1. The challenge of electricity sector transformation and how NEA system costs analysis can contribute to mastering it

The imperative to reduce carbon emissions is profoundly transforming the electricity and energy systems of Organisation for Economic Co-operation and Development (OECD) and Nuclear Energy Agency (NEA) countries. This sets in motion a number of interrelated developments that challenge traditional understandings of the way energy systems work. These changes also require a reappraisal of established notions of costs at the level of the integrated electricity system. Different technologies with comparable costs at the level of the individual plant can thus have very different effects on the total costs of a system. This impacts the strategic decision-making of energy policymakers with regard to the energy mix. It relates, in particular, to optimising the trade-offs between dispatchable low-carbon sources of electricity, such as nuclear energy or hydroelectricity, and variable sources, such as wind and solar photovoltaic (PV), that will be the backbone of future low-carbon electricity systems.

Among the different factors driving the changes under way, four play a particularly important role:

1. Perhaps the most important among these, is the increasing share of wind and solar PV in total electricity generation. Their variability requires either dedicated back-up capacity or additional flexibility on the demand side.
2. Driving the transformation of electricity and energy systems is the high capital intensity of low-carbon technologies. This holds for renewable sources such as onshore and offshore wind as well as solar PV as much as for nuclear energy or hydroelectricity. It also holds for energy efficiency measures, electric vehicles or hydrogen production. Reaching ambitious net zero emission objectives thus requires re-thinking the electricity sector. This impacts risk profiles and the costs of capital, but also brings an increasing share of exogenously determined must-run generation and a declining importance of competitive dispatch according to variable costs.
3. Technical and behavioural changes are also an important factor affecting the electricity and energy sectors. Information gathering of retail consumption, the remote operability of electrical equipment, modern batteries and advanced network electronics all allow for better management of volatile generation and consumption patterns. On the other hand, new modes of electricity consumption create both new challenges and opportunities, such as the charging and discharging of electric vehicles that, depending during which hours it takes place, may complicate or facilitate the establishment of a demand and supply balance.
4. Closely related to the previous point is the increasing electrification of energy consumption, also referred to as sector coupling. In order to further reduce greenhouse gas emissions, fossil fuel consumption in sectors such as transport, mobility, heating or industry are planned to be progressively substituted by carbon-free electricity. Co-generation and the use of hydrogen for process heat or as an energy vector are additional areas.

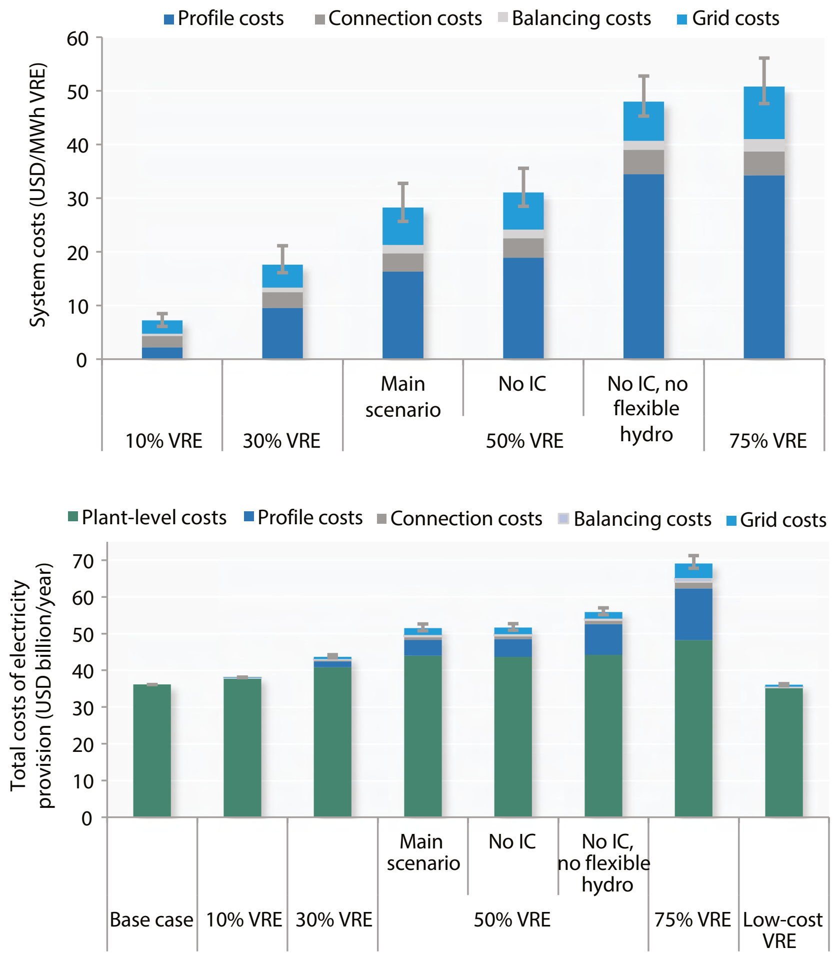
Together, these changes establish one fundamental fact: the role, impact and cost implications of individual technologies can no longer be understood in isolation. Understanding contemporary electricity systems requires the consistent adoption of a system approach. In order to assist policymakers in coming to terms with this new reality, the OECD Nuclear Energy Agency (NEA) developed its system cost analysis. Two reports, *Nuclear Energy and Renewables: System Effects in Low-Carbon Electricity Systems* (NEA, 2012) and *The Costs of Decarbonisation: System Costs with High Shares of Nuclear and Renewables* (NEA, 2019) set out the theory and analysed the cost implications of different shares of variable renewables (VRE) such as wind and solar PV in electricity systems operating under a strict carbon constraint of 50 gCO_2 per kWh. Since then, the NEA has modelled the implications of achieving Switzerland's net zero emission objective by complementing its hydroelectric resources either with a mix of solar PV and wind or with nuclear energy (NEA, 2022). The contribution of nuclear energy was further differentiated according to whether it resulted from the long-term operations of Switzerland's two youngest nuclear power plants or from yet to be constructed nuclear power plants. Both options resulted in a significant cost decrease due to the availability of round-the-clock, carbon-free electricity.

The present guide aims at providing a succinct synthesis of what is NEA system cost analysis and how it can help energy experts and policymakers to gain additional insights about the cost implications of different strategic choices when designing future electricity and energy systems operating under stringent carbon constraints. The purpose of this guide is to provide a first overview of what kind of results system cost analysis can provide and which questions may be asked in order to develop or test certain policy proposal of relevance. In fact, the full value of a system cost analysis will only reveal itself if based on an iterative dialogue between the NEA and the individual member country.

In its system cost work, the Agency employs its own in-house NEA Power System Mode (POSY) model, a state-of-the-art mixed integer linear programming model to develop detailed policy-relevant scenarios of different policy choices and to investigate their cost implications. As any modelling activity, system cost analysis can be undertaken at different levels of completeness and sophistication. Developing policy-relevant scenarios in collaboration with member countries requires, ideally, a fully calibrated model, fine-grained multi-year data, as well as coherent assumptions about costs and the availability of different low-carbon technologies and flexibility resources in order to develop, in collaboration with member countries, convincing and policy-relevant scenarios. Once all of these elements are optimally combined, NEA system cost analysis can become a highly valuable tool to inform and advance energy policy discussions about how to achieve ambitious carbon objectives in the most cost-effective manner.

Figure 1. Total system costs and costs per MWh for different shares of wind and solar PV

(USD/MWh, identical demand and carbon constraint of 50 gCO_2 per MWh)



Source: NEA (2019).

In preparing its analyses, the NEA works routinely with a wide range of stakeholders in government, industry and academia. Naturally, the Agency is also in contact with established energy modelling teams in member countries. Some of these teams have modelling resources, primarily used for preparing energy forecasts, comparable to those of the NEA. The unique element that distinguishes the NEA contribution in this discussion is the independence and credibility of an international organisation whose work is peer reviewed by the delegates of its member countries. Based on decades of experience interacting with both modellers and energy policymakers, the NEA also possesses a unique understanding of how to make the results obtained from integrated energy models relevant to the specific policy discussions ongoing in different member countries about the course of their energy transformation.

A key challenge in system cost analysis is to relate scenario results to relevant cost metrics and to allocate overall costs to particular elements of the model, such as individual technology options, behavioural patterns or policy objectives under carbon constraints of different stringencies. The starting point for such breakdowns will always be the complete costs of an electricity or an energy system required to satisfy given levels of demand at all times under an exogenous set of policy assumptions. A frequently applied technique is to then compare two least-cost equilibria distinguished only by differences in the numerical value of one single parameter, for instance the relative share of nuclear energy and variable renewables. The cost difference can then be allocated to the changed parameter. NEA system cost analysis is thus particularly useful for comparing the costs of different generation mixes to attain long-term policy objectives in terms of carbon emission reductions. Figure 1 shows results for a given electricity system, whose identical demand and carbon constraint are satisfied by different low-carbon generation mixes with different shares of nuclear energy and variable renewables such as wind and solar PV.

Working with optimised least-cost equilibria also distinguishes NEA system cost analysis from other assessments of system costs or system contributions such as the IEA VaLCOE metric. The latter, beginning from a non-equilibrium constellation, indicates how different technologies would move the system closer or further away from equilibrium. That said, NEA system cost analysis is not confined to any specific least cost equilibrium. The highly flexible mixed integer linear programming POSY model can adopt any number of conditions and constraints corresponding to real-world electricity systems.

Rapidly changing electricity systems subjected to stringent carbon constraints can pose challenges to stakeholders and policymakers at the conceptual level – even before the necessary societal discussion processes are fully under way. In this context, system cost analysis can help answer a series of relevant questions. Examples of possible questions are given below. Many others can be imagined:

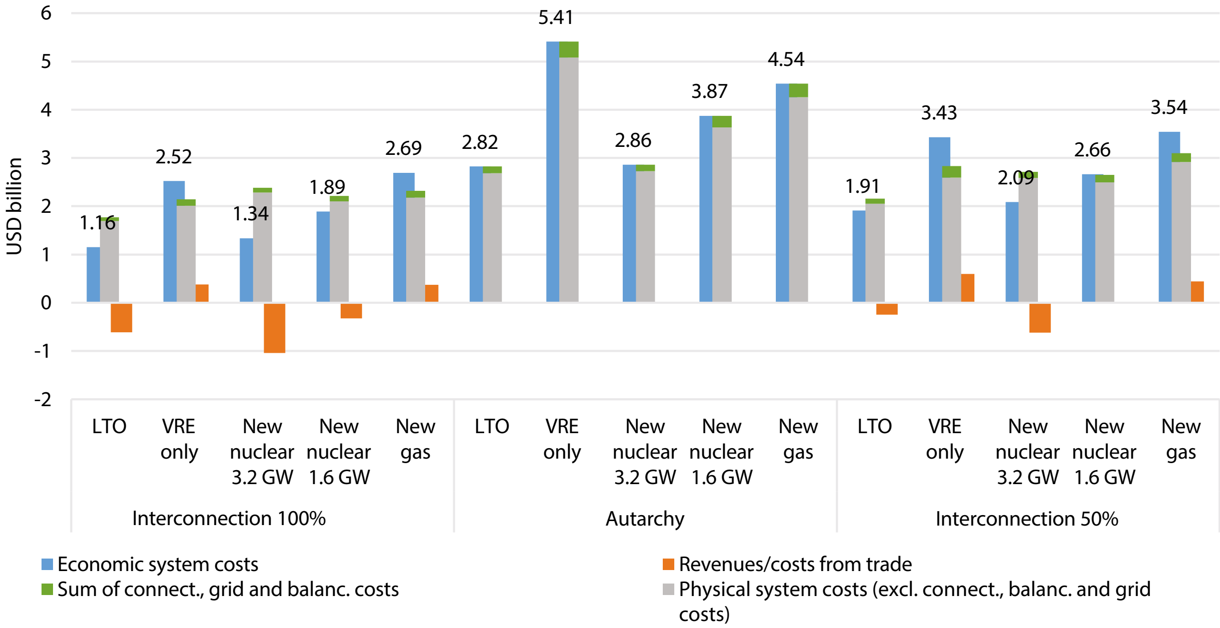
- What are the economic costs of attaining a given carbon emission target such as net zero with different low-carbon generation mixes?
- If carbon emission targets are coupled with targets for the deployment of variable renewables such as wind and solar PV, what is the impact of such targets on the capacity mix, the generation mix and the load factors or remaining dispatchable low-carbon generators?
- How does the market value of the electricity produced by wind and solar PV decline as their capacity and share in generation increases?
- What are the costs and benefits of deploying additional flexibility resources such as batteries, demand response, flexible back-up or additional interconnections?
- What is the level, volatility and structure of electricity prices, including hours with zero or negative prices? What is the likely impact on the cost of capital of such volatility?

To obtain meaningful results that can help support political decision-making, it is often useful to employ NEA system cost analysis to produce clearly differentiated scenarios that highlight the implications of the strategic policy choices specific to each country. An example of this is provided by the results of the 2022 NEA study assessing the system costs of different scenarios to achieve net zero emissions in Switzerland by 2050 (see Figure 2). Each of the fifteen different scenarios combines a specific mix of generation capacity with a given level of interconnection capacity for electricity trading. In this case, results do not come in the form of an additional cost per MWh of solar PV or wind capacity but in the form of a total cost figure for a fully fleshed out scenario, including a careful representation of Switzerland's important hydroelectricity capacity and a series of flexibility options.[1]

NEA system cost analysis thus combines rigour at the methodological level and flexibility at the level of formulating policy-relevant scenarios that aims to provide a useful decision-making tool for decision makers in the energy sector. System cost analysis is also one of the most exciting conceptual advances in energy economics in recent years. It is an effective tool for understanding the costs associated with different strategic choices in the energy field to achieve ambitious carbon targets while maintaining high levels of security of electricity and energy supply. As discussed in further detail in Section 3, any results of system cost modelling will be most relevant if the modelling process is accompanied by frequent and systematic consultation with a wide range of stakeholders in the member country concerned.

Figure 2. Total system costs of different net zero scenarios in Switzerland

(USD/MWh, identical demand and net zero carbon constraint for all scenarios)



Note: The Swiss study compares 5 scenarios for three different levels of electricity interconnections, 100% of current levels, autarchy and 50%. Each time the LTO scenario with current nuclear power plants has the lowest annual costs. The New Nuclear scenarios come next. The VRE only (solar PV, wind and hydro) and the New gas (price for CO_2 emissions from combustion at 100 USD/tCO_2) scenarios have the highest annual costs.

Source: NEA (2022).

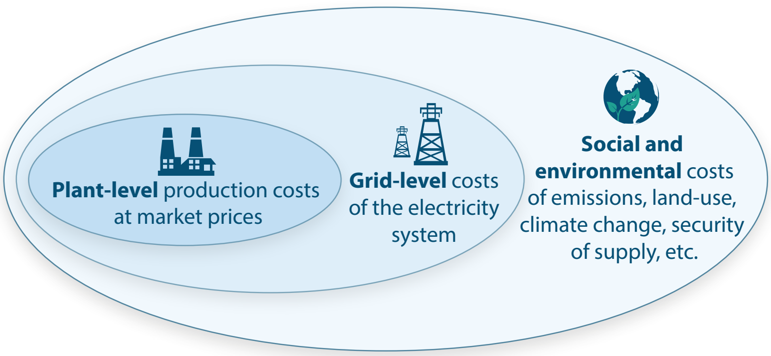
1. The real (net of inflation) cost of capital in this report was assumed to be 5 per cent. Recent increases in nominal rates would not change real rates decisively. In any case, even higher real costs of capital would primarily increase absolute numbers. Since, with the exception of the New Gas scenario, all scenarios rely on very capital-intensive technologies such as hydroelectricity, nuclear, wind and solar PV, different capital cost assumptions would not change their relative rank order.

2. Understanding system costs

System costs arise in all grid-based electricity systems and are caused by all technologies. However, they gained substantially heightened relevance with the advent of large amounts of wind and solar PV capacity. The latter's variability and uncertainty introduces significant costs at the level of the system as a whole, over and above their own costs at the level of the plant. These added costs are referred to as system costs. In order to distinguish such additional system costs from the costs of the system as a whole, the latter are often referred to as total system costs. Total system costs are thus the total economic costs of satisfying a given electricity demand at all times. These are not externalities or social costs (see also Box 1) but real monetary costs that somebody needs to pay. Regardless of the distinction between system costs as the added costs of satisfying a given demand with variable sources and total system costs, the key insight behind the system costs concept is that the technical characteristics of different technologies substantially impact the performance of the overall electricity systems beyond the impacts at the individual plant. This holds both for the structure and cost of electricity generation, as well as at the outlay and cost of the physical transmission and distribution grid.

While system costs have existed since the advent of electricity grids at the end of the 19th century – think of the risk of technical failures or outages, the cooling needs of nuclear or coal plants or changes in the grid-outlay due to the unit size of certain technologies – they have only been identified as a separate cost category in the second decade of the 21st century due to the work of the NEA and others. As a concept, system costs are thus a truly new cost category, distinct from the two broad cost categories with which energy economists customarily work: the costs of generating electricity at the individual plant and the full costs of electricity generation (see Figure 3). The latter category would include all external and social costs of electricity generation and provision reflecting the fact that electricity is often considered, at least partially, a public or a merit good. Even as a private good, it has important impacts on other public goods such as the environment or a secure energy supply.

Figure 3. Major cost categories in electricity systems

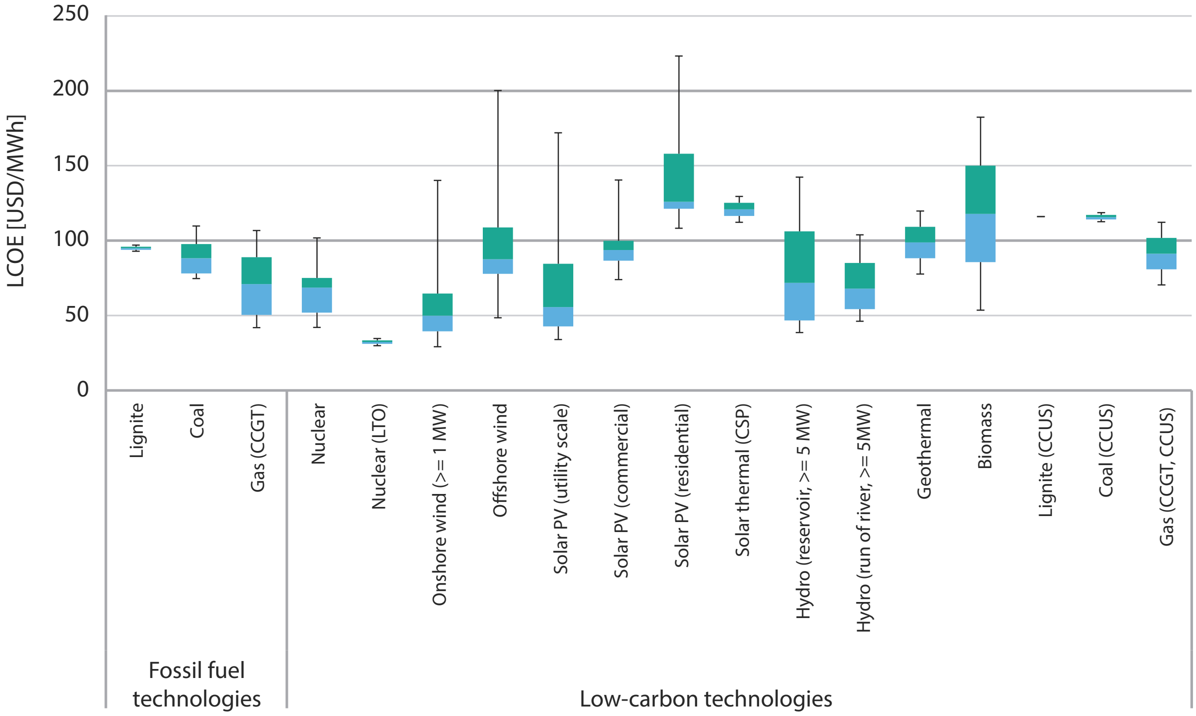


Source: Adapted from NEA (2012).

Considering system costs provides a more complete picture of the true costs of strategic energy policy choices than the widely used traditional cost accounting metric, the levelised cost of electricity (LCOE). Introduced in the regulated electricity systems of the 1960s, the LCOE provided a relatively simple, transparent and intuitive tool to compare the per MWh costs of baseload generation technologies, typically coal, gas, nuclear energy and run-of-river hydroelectricity. By compounding or discounting all lifetime costs for capital, operations and fuel to the date of commissioning and dividing their sum by the total discounted lifetime revenues, regulators had a handy gauge for the costs of each technology per unit of output, typically one MWh of electricity. For comparability, usually identical load factors and discount rates were employed across technologies, but, if required, varying rates and factors could be accommodated. Handily, the resulting per MWh costs corresponded precisely to the fixed tariff required by a utility to cover its costs including the regulated return on capital.

The LCOE methodology was initially challenged by the advent of liberalised electricity markets in the 1980s and 1990s. Changing markets, risk profiles and business models called into question the relevance of comparing different technologies in the same manner that was practised in regulated markets. And yet, the methodology survived because it continued to provide a simple intuitive reference and starting point for more complex calculations that an individual investor would undertake considering market conditions, price dynamics and financial risks. The LCOE methodology also suited a policymaker or social planner interested in a first understanding of the comparative resource costs for different technology rather than individual profit maximisation. In fact, the NEA continues to publish together with its sister agency, the International Energy Agency (IEA), the *Projected Costs of Generating Electricity* every five years – an overview of the LCOE costs of different technologies (see Figure 4).

Figure 4. Ranges for the LCOE of different electricity generation technologies at a 7% discount rate



Note: Light and dark blue rectangles indicate ranges for the second and third quartiles of data points obtained.
Source: IEA/NEA (2020).

LCOE, as an expression of plant-level production costs, remains an integral part of total system costs. The latter continue to result, of course, from the plant-level outlays on capital, fuel, operations and maintenance and so on of different technologies. Yet what changes in system costs are the interactions between different technologies to satisfy a given demand profile. A key lever transmitting these interactions are the reciprocal impacts on load factors and the overall capacity requirements of the system.

Ultimately, it was the advent of variable renewable energies (VRE) such as wind and solar PV that imposed the necessity for a broader cost metric. While all technologies always had some costs that were unaccounted for in standard LCOE calculations, their relatively low level allowed these costs to be absorbed by transmission network operators and utilities as part of routine operations. Table 1 below provides an overview of the estimated system costs of different technologies at penetration rates of 10% and 30% for the French electricity system.

Table 1. Grid-level system costs for different technologies in France (USD/MWh)

Technology	Nuclear		Coal		Gas		Onshore wind		Offshore wind		Solar	
Penetration level	*10%*	*30%*	*10%*	*30%*	*10%*	*30%*	*10%*	*30%*	*10%*	*30%*	*10%*	*30%*
Total plant level costs	**72.23**		**85.66**		**87.30**		**110.76**		**143.20**		**551.17**	
Back-up, profile or adequacy costs	0.00	0.00	0.33	0.33	0.00	0.00	34.24	36.48	34.24	36.48	47.21	48.16
Balancing costs	0.28	0.27	0.00	0.00	0.00	0.00	1.90	5.01	1.90	5.01	1.90	5.01
Grid connection	1.78	1.78	0.93	0.93	0.54	0.54	6.93	6.93	18.64	18.64	19.60	19.60
Grid reinforcement and extension	0.00	0.00	0.00	0.00	0.00	0.00	3.50	3.50	2.15	2.15	5.41	5.41
Total grid level costs	**2.07**	**2.05**	**1.26**	**1.26**	**0.54**	**0.54**	**46.56**	**51.91**	**56.93**	**62.27**	**74.12**	**78.17**

Source: Adapted from NEA (2012).

The numbers indicate that the variability, uncertainty and location requirements of wind and solar PV impose system costs in terms of back-up requirements, balancing and network development are at least one magnitude larger than those of other technologies. As different technologies provide different services, in particular different levels of continuity of generation, their output imposes different overall costs at the level of the system that differ from plan-level LCOE. This early and simple modelling effort also points towards an important fact since regularly confirmed in other studies, namely that system costs change, sometimes significantly, with a technology's share in electricity generation. In particular, when the penetration of wind and solar PV progresses beyond single digits, restricting cost assessments to plant-level LCOE provides a severely incomplete picture.

The main components of system costs

The largest system costs of wind and solar PV relate to their variability and the resulting need for dispatchable back-up or other added flexibility provision from sources such as demand response, electric storage or interconnections. No matter the amount of solar PV capacity installed, dispatchable capacity is required to supply electricity at night. In the language of system cost analysis, these costs are referred to as profile costs. In addition to profile costs, there are also balancing costs, due to the uncertainty rather than the variability of renewable electricity generation, connection costs as well as grid costs in the form of added outlays for transport and distribution, which are also significantly larger for distributed renewables. These four cost categories are presented in a slightly more complete manner in the following:

- **Profile costs** refer to the increase in the cost at the level of the overall system to satisfy a given demand profile due to the variability of VRE output. Profile costs are thus at the heart of the notion of system effects. The variability of VRE generation require back-up capacity for the hours when wind and solar PV generation is reduced or absent. This back-up capacity has the same fixed capital cost as in traditional systems but is now running a lower number of hours. This increases both total outlays in capital costs as well as average costs of dispatchable generators, which shows up in terms increased overall costs to meet a given demand pattern. A different way of looking at the profile costs of VRE is to consider that the electricity generation of wind or solar PV is concentrated during a limited number of hours with favourable meteorological conditions. This auto-correlation of wind and solar PV generation decreases the value for the system of each additional unit of capacity. Hours, in which not enough renewable load is available, alternate with hours in which variable renewables produce too much electricity and have to be curtailed, which increases the average costs of VRE as well as the profile costs of the system.
- **Balancing costs** are related to increased requirements for ensuring system stability with the help of operating reserves due to uncertainty in power generation that may stem from unforeseen plant outages or generation forecasting errors. The frequency and magnitude of forecasting errors have increased considerably with the advent of wind and solar PV. While forecasting their output has significantly improved, there remains an intrinsic risk of sudden generation shortfalls, a risk that is aptly captured in the image of a cloud passing before the sun. Balancing takes the form

of cycling costs, which means a dispatchable plant operates at less than full capacity, so that it can ramp up quickly in case of need. Such cycling is costly because plants are operated at less than the economically optimal capacity. In the case of dispatchable plants, the amount and cost of operating reserves are generally indicated in terms of the capacity of the largest individual unit (the N-1 rule) connected to the grid. In the case of wind and solar PV plants, their balancing costs are related to the uncertainty of their combined output due to forecasting errors. The cost of responding to the latter depends heavily of the share of VRE generation in the overall mix (see Table 2). Pre-announced ramps or scheduled outages would instead not count towards balancing costs, but would show up in profile costs.

Table 2. Estimates for grid and balancing costs (USD/MWh)

	Penetration level (%)	Grid costs	Balancing costs
Wind	<10%	3	1.0
	10% to 30%	5	2.0
	30% to 50%	8	4.0
	50% to 75%	11	6.0
Solar PV	<10%	1	0.5
	10% to 30%	2	1.0
	30% to 50%	4	1.0
	50% to 75%	7	1.5

Source: NEA (2022), adapted from NEA (2019).

- **Grid costs** are the additional costs required to accommodate the particularities of different power generation options on the transmission and distribution grid due to its size or location. All generation plants technologies can certain siting constraints. For example, large-scale nuclear power plants are preferred to be located near sources of cooling water, wind farms require regions with high wind potential, and solar PV plants depend on areas with high solar irradiation. In addition, due to their smaller per unit sizes, the latter have larger requirements for land-use and the development of the distribution grid. However, there exist considerable differences not only between individual countries but also within given technology categories. Residential, commercial or utility-size solar PV, for instance, differ in terms of the impacts on transmission and distribution grids. The estimates provided in Table 2 that are based on expert opinion should thus only be considered as indicative for industrialised countries. More research in this area would be highly valuable.

  Given such locational constraints, new interconnections may need to be built (grid extension) or the capacity of existing transmission infrastructure (grid reinforcement) must be increased to carry electricity generated far from load centres to consumers. Transmission losses also increase when electricity must be moved across sizeable distances. In some cases, a high penetration of distributed solar PV also requires additional investment in the distribution network to cope with increasing reverse power flows when local demand is insufficient to consume the electricity generated. Quantitative estimates of grid costs are often characterised by large variations, depending on the characteristics of individual systems, different penetration levels of VREs analysed, the inclusion of distribution costs as well as specific methodological assumptions.

- **Connection costs** represent the cost of linking a power plant to the nearest connection point of power grid. These are real costs at the level of the electricity system and can be considerable – for instance in the case of offshore wind. However, the allocation of these costs can vary from country to country. In some cases, connection costs are born by the project developer and should hence be included in the capital costs that form part of LCOE calculations. Checking the precise composition of LCOE calculations is thus particularly important in the case of connection costs. In other cases, however, the legislator has decided to socialise connection costs, which are then borne by consumers in the form of higher network tariffs in their electricity bill. Allocation thus does not change the level of total system costs. It does, however, change whether costs are already internalised in the private cost-benefit analysis of entrepreneurs or whether they remain outside their calculations thus potentially leading to sub-optimal over-investment. The per MW connection costs used in recent NEA work are indicated in Table 3. Again, connection costs vary also among nominally identical technologies and the estimates provided should only serve for first orientation for a generic industrialised country. Determining connection costs also remains an area where further research is necessary to take the specificities of different countries and different technologies fully into account.

Table 3. Connection costs (USD/MW/year, 5% of capital investment costs)

Open cycle gas turbine	1 919	**Hydro run-of-the-river**	7 685
Combined-cycle gas turbine	2 911	**Hydro reservoir**	7 930
Nuclear new build	12 382	**Hydro pump storage**	6 792
Wind	5 243	**Battery**	2 332
Solar PV	3 548		

Source: NEA (2022), adapted from NEA (2019).

The four categories of system costs discussed above are the most important economically and are thus included in most advanced system cost studies. However, they do not cover all costs that distinguish one technology from another. For instance, the heavy rotating mass of thermal power plants with large steam turbines provides inertia, a critical service that facilitates maintaining a stable frequency on transmission and distribution networks. In VRE dominated systems, it is thus more difficult to maintain stable frequencies on transmission and distribution networks. Advanced electronics can create synthetic inertia, albeit at an added cost.

Possibly even more important, but very difficult to quantify, is the technical wear and tear that systems with high shares of variable sources impose on dispatchable capacity. The latter are now required to ramp up and down faster and far more often, possibly also to shut down and to start-up again repeatedly. This is an issue in for gas- and coal-fired power generation as well as for nuclear in countries such as Belgium, France or Germany where plants engage in load-following.

Although the concept of system effects is relatively new, a rich and varied literature has built up quickly given the importance of the subjects. Among major studies, one may mention the work done by the NEA and the IEA (NEA, 2012, 2019 and 2022; IEA, 2014), the wind and solar PV integration study undertaken by Agora Energiewende (2015), the European-level study by French utility EDF (Silva and Burtin, 2015), the study on future power systems in Belgium by the University of Leuven (Delarue et al., 2016), and work done by the Imperial College London in the United Kingdom (Strbac et al., 2015 and 2016) and by the Massachusetts Institute of Technology in the United States (MIT, 2019) as well as several studies published by Hirth and Ueckerdt (Hirth, 2013, 2016a and 2016b; Ueckerdt et al., 2013). A more recent study is Byrom et al. (2021).

As a result of this broad and exciting research system cost analysis is in the process of going mainstream. As the impacts of the variability of increasing wind and solar PV capacity are better understood and integrated into the algorithms of models with at least hourly resolution, system cost modelling is becoming part of general electricity and energy system modelling. Comparing low-carbon scenarios with higher or lower shares of variable sources will *ceteris paribus* always indicate higher or lower costs for satisfying a given demand profile regardless of whether such a comparison is referred to as system cost modelling, energy system modelling or least-cost optimisation. However, in all of these cases, this requires a realistic representation and a good understanding of the characteristics and performance of different generation sources and flexibility options. Section 3 indicates the key elements required for such analysis.

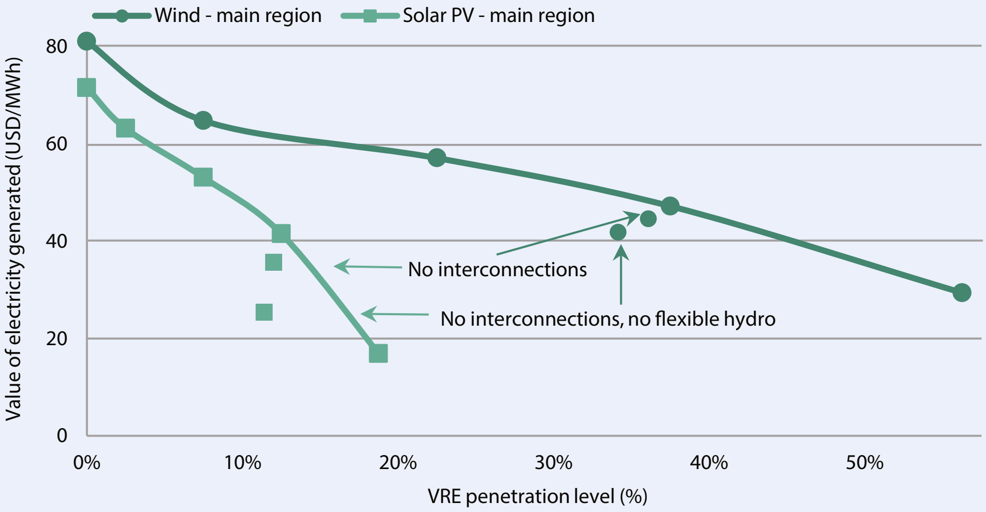
When analysing system costs, it must also always be kept in mind that they are highly country- and system-dependent. Key determinants are the structure of demand and its correlation with wind and solar PV generation, the availability of flexible resources in the form of hydro storage, batteries or demand response and the level of interconnections with neighbouring systems. This is precisely the reason why NEA system cost modelling is always carefully adapted to the precise characteristics of the national or regional system to be analysed.

Box 1. Do the system effects of variable renewables constitute an external cost?

System costs can be a conceptually challenging phenomenon. One question that is repeatedly asked in this context is whether system costs and, in particular, the profile costs generated by variable wind and solar PV generation constitute an uninternalised externality or a social cost akin, for instance, to the impact of airborne pollution and thus require corrective measures.

The short answer to this question is "no, as long as government does not resort to financing the deployment of wind and solar PV capacity with out-of-market measures such as feed-in-tariffs." The point is subtle. The definition of an externality implies that those affected by it have no means to transmit the impact on their utility to those who cause it. True, variable renewables (VRE) such as wind and solar PV create a need for costly storage or back-up and reduce the load factor of dispatchable technologies, indicating that their contribution to covering the needs of the electricity system is limited. However, a competitive electricity market will feed precisely this message back to renewable generators themselves in the form of lower prices for their electricity. To understand this, one needs to consider that the non-availability of wind and solar PV during certain hours is compensated by their excess production during other hours. In other words, their generation is concentrated in a subset of hours. During those operating hours, however, the average price is lower than the average price calculated over the totality of hours. This decline of the revenues of wind and solar PV producers depends on their share in the generation mix and can be estimated with some precision, see Figure 5. The effect is particularly strong for solar PV as its generation is concentrated during an even smaller subset of hours than wind generation.

Figure 5. The declining average market value of VRE as their share increases



Source: NEA (2019).

Technically speaking, profile costs constitute a "pecuniary externality", comparable to the entry of a new competitor, and not a "technical externality", comparable to pollution. The former, in principle, does not require corrective measures – except, of course, if the mediating market mechanism is overridden by governments themselves. The usual means to do so is by financing VRE generation out of the market, for instance, through feed-in tariffs. In any case, the calculation of total system costs in NEA (2019), and NEA (2022), as well as in other system cost studies are independent of the precise answer to this conceptual question. These studies show consistently that the current level of onshore wind and solar PV deployed in OECD countries and a fortiori their future target levels are already beyond the optimal cost-minimising point. For policymaking purposes, it is ultimately indifferent whether the resulting surplus costs are qualified as an economic inefficiency due to governments overriding market outcomes or as an uninternalised externality. From an economic point of view, inefficiently high levels of intermittent generation capacity should be returned towards optimal levels in either case.

3. Resource requirements for system cost studies

In the past ten years, methodological advances, and technological progress in computing power and modelling software have allowed mixed-integer linear programming (MILP) models to emerge as a new key tool for analysing the costs of integrated electricity systems. Since decentralised profit optimisation will lead to results identical to those of centralised cost minimisation, these models are equally applicable in systems with perfectly competitive electricity markets and regulated systems. As they minimise the combined costs of investment and dispatch to satisfy a given demand pattern, typically with an hourly resolution over one year, all the information contained in traditional LCOE analysis, including an appropriate discount rate, is also included in these models. However, their innovation is that they not only construct, subject to the exogenous constraints defined by energy and climate policies, an optimal generation mix, but they also provide hourly optimised least-cost dispatch. In other words, the system interactions between variable technologies, dispatchable baseload providers and flexibility providers, including storage, demand response and hydrogen production are fully included.

While the costs of doing comprehensive system cost studies have come down considerably, they remain non-negligible. Among the resources required, one can distinguish three major categories: computing hardware and software; required data, human and institutional capital. The overall costs for hardware and software are relatively limited at the level of even mid-sized institutions. The effort and cost to obtain the full set of data for the costs and performance of different technologies as well as, at least, hourly data for demand, fatal production and prices at interconnection points can vary enormously. They depend on the ambition and detail of the study as well as on the informational infrastructure of the country or the region for which the study is undertaken. In some countries, the annual time-series required for a solid study are available from different public sources. In others, they have to be obtained from private providers or have to be constructed by roundabout measures from alternative sources.

The greatest cost in energy systems modelling is the human resource requirements to develop the model, calibrate it to the specificities of the country and its energy sector, define the scenarios most relevant to ongoing energy policy debates and to engage in the iterative process between the NEA and the member country that aligns all the different elements. The advantage of undertaking a system cost study through the NEA and its POSY model, rather than an alternative research institution, resides in this process. Combining technical competence with an understanding of the musts, wants and conceptual frameworks of different stakeholders is what ultimately adds value. In those instances, a coherent modelling effort can become a highly useful tool to assist in decision-making or an instrument to help structure ongoing debates in a given country.

Hardware, software and human resource requirements for a national system costs analysis

Hardware requirements are limited to a mid-level personal computer with a Euro cost in the lower four digits. The POSY model exists, which means that the greater parts of the development costs have been amortised. It is available as an open source file at https://git.oecd-nea.org/posy/posy. Of course, each project will require specific new developments and, perhaps, extensions, but the model as such does not require any new outlays in terms of licensing costs or similar. However, serious modelling capable of repeated runs at sufficiently high speeds requires a commercial solver. Licences for solvers such as Gurobi or CPLEX typically cost between USD 10k and 20k per year. While not a prohibitive cost, this is significantly more than pure hardware. Alternatively, a number of free, open-source solvers are available online. However, the difference in their performance compared with commercial solvers is notable.

In terms of human resources, a full-time modeller will be required for the duration of the project. In addition, they will require the support of a senior expert on the strategic design of such studies during one quarter or half of the time of the project.

The POSY power system model

POSY is the NEA model for evaluating the system costs of electric power systems. For this purpose, investment in new electricity generation capacity and power dispatch on an hourly basis are assessed, while minimising the costs of the power system. Both linear and mixed-integer linear programming can be used. POSY optimises the total cost of electricity system for a given year while ensuring balance between electricity supply and demand. POSY is written in the Julia programming language, and uses the JuMP package for mathematical optimisation (Dunning, 2017).

The strength of linear optimisation models such as POSY is that they minimise the total costs of a system by *simultaneously* optimising decisions of long-term investment in different technologies and their short-term utilisation (dispatch). Optimised investment according to the constraint of continuously supplying an exogenously set demand curve is also referred to as "capacity expansion". The operational decisions to modify the power output by switching on or off different electricity generators or flexibility providers according to their marginal variable cost are referred to as "unit commitment". In most models, these decisions are supposed to be at the hourly level. Finer temporal resolutions are possible, for instance, if the behaviour of balancing markets is of interest, but this, of course, requires greater modelling resources.

The timeframe over which optimisation takes place is usually one year. This captures the important seasonal changes in demand and supply and, usually, also some hours of very peak demand, which ultimately determine the size of the system. However, especially in systems with a large share of renewable energies, there can be important inter-annual differences – especially for wind and solar production. The judicious application of modelling strategies, choice of year, average or min-max values, etc. can help to mitigate the impact of such differences. A standard run of the electricity system model thus optimises over 8 760 time slots, the number of hours in a single year.

POSY minimises costs over a set of technologies, including flexibility providers on the supply and the demand side, with different fixed and variable costs as well as a number of technical constraints (see below). The annualised fixed costs, including both investment and fixed operations and maintenance costs, as well as the variable costs of all technologies are then summed over the total number of hours to establish the total economic system costs. Fixed costs or investment costs result from the overnight costs for a specific construction time, financing costs and decommissioning costs. These costs are annualised according to the load factor, the expected lifetime and a prior agreed upon discount rate that reflects the cost of capital. The choice of the discount rate, identical for all technologies, can be crucial in determining the competitiveness between highly capital-intensive low-carbon technologies such as wind, solar PV, hydro, geothermal, nuclear energy or even fossil generation with carbon capture and storage (CCUS) on the one hand and less capital-intensive fossil fuel-based technologies such as coal or gas without carbon abatement on the other.

In interconnected electricity systems, the revenues and costs from electricity trading with a country's neighbours are further added to the total system costs. The structure of the algorithm used by POSY to minimise total system costs is indicated in the following equation where *TECH* is the set of technologies, DR is voluntary demand response and *VOLL* is the value of lost load during hours of involuntary demand curtailment. All cost values are positive, except for *Trade* which can deliver negative values during those hours when export revenues exceed import costs:

$$min \sum_{i=1}^{8760} \left(\sum_{j=1}^{TECH} \left(c_j^{INV} + c_j^{Fixed\ OM} + c_{ji}^{Var.\ OM} + c_{ji}^{Fuel} + c_{ji}^{Waste} + c_{ji}^{Carbon} \right) + c_i^{DR} + c_i^{VOLL} + c_i^{Trade} \right)$$

Including the revenues and costs from electricity trading also poses the question of whether commercial or physical cross-border flows should be taken into account. As an economic model aiming at cost minimisation, POSY takes into account only commercial flows of electricity. Physical flows regularly diverge as they follow the laws of Kirchhoff, which says that differences in voltage in an electrical system must sum to zero, i.e. that electric current will always flow from a node with a higher voltage to a node with a lower voltage. Even if bilaterally contracted, electric current can flow through third countries or even cross bilateral borders several times (loop flows). This leads to differences between the nominal interconnection capacity and the actual capacity available for commercial exchanges, but is routinely take into account. Table 4 below provides an overview of the technologies considered by the model.

Table 4. Selected components of an electricity system modelled in POSY

Technology type	Description	Examples
Dispatchable	Generation can be ramped up or down in function of the electricity price. Fossil fuel technologies may be included with or without CCUS, or both.	Nuclear energy*; CCGT; OCGT; biomass; CHP; coal
"Must run"	Generation is predictable in advance but does not react to market prices, typical for baseload mode.	Nuclear energy*; hydro run-of river; geothermal; waste incinerators
Variable	Generation depends on factors outside the electricity system, typically the weather.	Solar PV; onshore wind; offshore wind
Storage	Flexibility providing facilities that discharge electricity during certain hours and rely either on nature or on the electricity system to charge during other hours.	Hydro pump storage; hydro reservoirs; batteries
Hydrogen (H_2) electrolysis	H_2 is generated through electrolysis by using electricity; as this can be scheduled discontinuously in function of prices, electrolysis provides flexibility.	PEM electrolysers
Demand response (DR)	Voluntary demand response reduces or postpones consumption in function of prices. Involuntary demand response, disconnecting consumers, has high costs.	Voluntary DR; involuntary DR (scarcity hours)
Interconnections	POSY models trade with neighbouring countries based on least-cost dispatch. Import and exports volumes are provided for each time step.	Contracted imports and exports
Transportation and distribution	This category can bear additional components such as transmission losses, and primary and secondary reserves.	Fixed costs per MWh

* Technically, nuclear energy is always dispatchable in the limits of its technical ramping abilities. However, regulatory provisions in a wide range of countries do not allow for ramping beyond what is required for frequency control. In those cases, nuclear energy becomes *de facto* a must-run technology.

Source: Adapted from NEA (2022).

Standard linear programming models minimise the costs of the electricity system subject to a supply as well as to a carbon constraint by using algorithms in which the cost function is linear and the constraints are specified using only linear equalities and inequalities. The model will compute the share in generation of each technology disregarding any technical or operational constraints. This share can be smoothly varied to any desired level of capacity at any given hour.

POSY, however, is part of a category of models that are called mixed integer linear programming (MILP) models. Such models use algorithms, in which variables can be constrained to take an integer value, e.g. a technology can only run at full capacity or not at all, or it can only be called upon if it runs for at least four hours. The MILP formulation such allows to integrate the technical constraints of different technologies on the supply side or behavioural constraints on the demand side. Obviously, this makes for more complex problems but also for a much higher degree of realism by integrating defining features such as ramping constraints, start-up costs, minimum up and down times, must-run conditions, avoiding simultaneous charging and discharging for storage units, hourly and annual constraints on demand response (see Table 5). The capacity of individual solar PV, wind, run-of-the-river hydro or gas plants is usually small enough to justify the hypothesis of a one single continuous decision variable. Larger thermal units such as nuclear or residual coal plants with or without carbon capture, utilisation and storage (CCUS), however, require to be modelled individually in a process called unit clustering.

Providing a realistic picture of unit commitment is possible only with MILP models. This holds particularly true for systems with high shares of variable generation sources such as wind and solar

PV that strongly depend on the flexibility of the surrounding system. Disregarding the technical constraints of the dispatchable technologies required to complement the VRE will substantially underestimate the resulting system costs. Naturally, also the mathematical challenge and resolution times grow with the number of constraints as the number of possible combinations with on/off integer constraints and the resulting options for capacity expansion and unit commitment for each time step of the year increase exponentially.

Table 5. Example of technical constraints modelled in POSY

Constraint	Brief description
Commitment	• Only built units can be committed: $0 \leq u_{i,t} \leq x_i$ • Starting and shutting down constraint: $u_{i,t} - u_{i,t-1} = v_{i,t} - w_{i,t}$
Link between power above minimum and commitment	Power above minimum is determined by commitment, as well as startup and shutdown capabilities: $$0 \leq p_{i,t} \leq (\bar{P}_i - \underline{P}_i)u_{i,t} + (SU_i - \underline{P}_i)v_{i,t} - (\bar{P}_i - SD_i)w_{i,t+1}$$
Intermittent production	The production is equal to the production profile multiplied by the installed capacity: $\hat{p}_{i,t} = V_{i,t}x_i$
Fast dispatchable technologies production	$\hat{p}_{i,t} = \underline{P}_i\left(u_{i,t} + v_{i,t+1}\right) + p_{i,t}$
Slow dispatchable technologies production (case with linear, gradual startup/shutdown)	$p_{i,t} = startup(i,t) + up(i,t) + shutdown(i,t)$ With: $startup(i,t) = SU_i \sum_{h=2}^{SUD_i}\left(\frac{h-1}{SUD_i} v_{i,(t-h+SUD_i+2)}\right)$ $up(i,t) = \underline{P}_i\left(u_{i,t} + v_{i,t+1} - w_{i,t+1}\right) + p_{i,t}$ $shutdown(i,t) = SD_i \sum_{h=1}^{SDD_i}\left(\frac{SDD_i+1-h}{SDD_i} w_{t-h+2}\right)$
Storage	• Avoiding charging and discharging at the same time: $\forall \omega, s, t$ $\hat{c}_{\omega st} \leq (1-\gamma_{\omega st}) * (X_s^0 + \overline{X_s})$ and $\hat{e}_{\omega st} \leq \gamma_{\omega st} * (X_s^0 + \overline{X_s})$ • Definition of storage inventory $\forall \omega, s, t \quad \phi_{\omega st} = \phi_{\omega st-1} + \hat{c}_{\omega st} - \hat{e}_{\omega st}$
Demand response	• Hourly maximum of demand response: $DR_{i,t} \leq \overline{DR}_i^h$: • Yearly maximum of demand response: $\sum_{t\in T} DR_{i,t} \leq \overline{DR}_i^y$
Production and demand balance (supply constraint)	The sum of the total power output (including storage technologies), demand response and net imports must be equal at the total demand (incl. transmission losses, storage charging and H_2 production) and the production curtailment at each time step: $$\forall t, \quad \hat{p}_t + DR_t + IC_t = D_t + C_t$$

Source: Adapted from NEA (2022).

Data requirements and calibration

Undertaking a system cost analysis with the POSY model requires substantial economic and technical data. However, the overall amount is not unreasonable and in many countries much of the required data is either publicly available or can be sourced from system and network operators, government departments and research institutes. So far, no confidentiality issues have been observed in system cost work. While each system cost study differs in terms of a country's requirements, selected scenarios and technical detail, a minimum set of required data would include:

- The installed capacity of all technologies that are determined exogenously (brownfield);
- Hourly electricity demand (MW);
- Hourly wind and solar PV generation profiles (MW);
- Hourly generation profiles for hydropower (MW);
- Net interconnection capacity (ATC) as well as hourly exports and imports of electricity (MW); this may refer to national interconnections as well as to relevant regional interconnections;
- Hourly price series in neighbouring countries;

- The discount rate indicating the cost of capital; the latter may be identical for all technologies or may differ between technologies in function of their risk and access to financing;
- For all power generation technologies including battery storage, hydrogen production and carbon capture and storage (if applicable):
  - Investment cost (USD/MW installed, annualised, so [USD/MW/y]);
  - Fixed annual operation and maintenance (O&M) cost (USD/MW/y);
  - Variable operation and maintenance (O&M) cost (USD/MWh);
  - Power plant efficiency (%);
  - Maximum possible load factors (%);
  - Ramping ability of different dispatchable technologies (%/min);
  - Minimum uptimes or downtimes of different technologies;
  - Performance and costs of different storage technologies;
  - Cost of demand response;
  - Value of lost load (VOLL) (USD/MWh).
- Energy commodities:
  - Prices for all fuels (USD/GJ);
  - Carbon content of all fuels (kg CO_2/GJ), according to IPCC (2008);
  - If applicable, CO_2 price (USD/ton CO_2)

If certain costs should not be available for a given country, data gaps can be plugged with robust generic data derived, for instance, from comparable countries or from the NEA's own sources. The NEA, for instance, publishes every five years together with its sister agency, the International Energy Agency (IEA), the *Projected Costs of Generating Electricity,* which provides country-by-country estimates of the cost parameters indicated above for a wide range of technologies deployed in OECD countries. The latest NEA system cost study for Switzerland (NEA, 2022) combined generic data from IEA/NEA (2020) with country-specific data that was provided specifically for the study from local sources. Each study thus relies on a specifically prepared data set. Table 6 below reproduces the cost data used in NEA (2022) and may serve as an example for the overall format of asset of technology-specific cost data as well as for some easily verifiable data points that can be used for reference or control.

Once all the required data is assembled and even before the actual modelling of future scenario takes place, the model will need to be calibrated to the electricity and energy system under study. In this process, the model will be adapted and fed with appropriate data so that it is able to reproduce the hourly time series of at least one year for which real-world data is available. Comparing the output of the model with the historic time series provides an indication to which extent POSY captures the specificities of a country's electricity and energy sector. This is a subtle iterative process until the outputs of different technologies, their constraints as well as electricity prices, match their empirical counterparts reasonably well.

In a first step, just combining different time series is unlikely to result in such a match. Convergence will eventually be triggered by the adjustment of different technical constraints, the variable costs of different technologies the addition of further brownfield assumptions, i.e. additional exogenously provided constraints and, perhaps, tweaking the algorithm itself. Brownfield assumptions (historically determined binding constraints) include also the generation profiles of must-run installations such as waste incinerators or run-of-river hydroelectric plants. The hydrological dynamics of large hydroelectric reservoirs can also affect outcomes. A case in point is the modelling of nuclear energy. In some countries, nuclear reactors follow electricity demand and its generation is thus an output of the optimisation algorithm of the model. In others, it is operated in a strict baseload, must-run, mode and is hence an input. In both cases, outages for refuelling must be appropriately taken into account.

Once the model actually reproduces hour for hour the historic structure of supply in a given year with reasonable accuracy, POSY can be assumed to work and react roughly like the system under study. At this point, it is possible to start varying major policy-dependent assumptions such as carbon constraints, renewable targets or share of nuclear energy that will define the different scenarios of which the total system costs, price volatility, technical challenges and so forth are of interest for ongoing energy policy debates.

Table 6. Sample cost assumptions for generating technologies and flexibility providers in Switzerland

Technology	Fixed costs					Variable costs			
	Duration	Decom. cost**	Over-night cost*	Annual investm. cost (@5%)*	Fixed annual O&M	Variable O&M	Fuel cost	Carbon cost	Waste cost**
	Years	% of OC	USD per kW	USD per MW/y	USD per MW/y	USD per MWh	USD per MWh	USD per MWh	USD per MWh
Nuclear energy new build	60	15%	4 013	247 632	106 180	0	7	0	2.33
Nuclear energy LTO	20	15%	550	46 672	96 202	0	7	0	2.33
Onshore wind	25	5%	1 458	104 852	38 000	0	0	0	0
Solar PV	25	5%	1 000	70 952	25 000	0	0	0	0
Hydro – river	80	5%	3 012	153 701	42 500	0	0	0	0
Hydro – reservoir	80	5%	3 108	158 600	20 000	0	0	0	0
Hydro – pump storage	80	5%	2 662	135 841	20 000	0	0	0	0
Gas – OCGT	30	5%	590	38 380	14 599	5.56	138	55	0
Gas – CCGT	30	5%	895	58 221	26 024	3.50	85	34	0
Waste incinerators	40	5%	2 433	101 266	17 148	3.92	0	0	0
CHP	40	5%	2 951	223 436	17 451	3.50	0	0	0
Battery storage	15	5%	484	46 630	9 001	0	0	0	0
Hydrogen***	20	5%	500	40 121	1 204	0	70	0	0
Demand response	-	-	0	0	0	300	0	0	0
Load shedding	-	-	0	0	0	10 000	0	0	0

Notes: * Overnight costs include contingency payments of 15% for nuclear new build and 5% for all other technologies including nuclear LTO. Investment costs are annualised taking into account the years of construction.

** Decommissioning and waste costs have been included according to the conventions adopted in the joint IEA/NEA study of the *Projected Costs of Generating Electricity: 2020 Edition*.

*** Hydrogen fuel costs depend on the electricity generation mix, current figure for illustration only.

Source: Adapted from NEA (2022).

4. Successful energy scenario building

The primary purpose of system cost analysis is to compare the overall costs and structural characteristics of different low-carbon scenarios in order to provide a coherent overview and assist in the formulation and selection of societal and political choices in the energy field. In order to arrive at scenarios that can inform and structure ongoing discussion in a meaningful manner, these scenarios need to be defined and refined by stakeholders and experts at the beginning of the modelling effort as well as all throughout the modelling process itself. The first point is obvious, stakeholders and partners in a system cost project need to have at least a general idea of the strategic policy choices facing a region, a country or a group of countries.

The second point may be less obvious but is no less important. Energy system modelling is as much an art or an artisanal effort as a science. In order to obtain pertinent results, an iterative process needs to be engaged that adapts each scenario until it corresponds fully to the explicit as well as implicit policy questions and assumptions that different stakeholders formulate with respect to an energy future that by definition is yet unwritten. This goes beyond the relative shares of variable renewables and nuclear energy, which inevitably will loom large in any comparison of the system costs of different generation mixes. Implicit assumptions that structure future electricity and energy systems may include the cost of batteries, the degree of electrification of the transport, heating and industrial sectors, changes in consumer behaviour and hence the structure of electricity demand, the increased or decreased integration with neighbouring countries, the impacts of climate change on the availability and performance of different technologies, in particular hydroelectricity, and so forth. Even if these assumptions are not fully spelled out or left open, they can be decisive. Not choosing is also a choice.

Depending on a country's electricity and energy system and the share of electricity generated by variable renewables any one of these assumptions can have a significant impact on any given scenario. If an assumption is particularly important and the results policy relevant, different variants of a single scenario will have to be developed. More often than not however, the preferences of stakeholders regarding the different issues only emerge during the iterations of the process of scenario modelling. The latter is not unlike the process of calibrating the original model described earlier. During the calibration effort, however, the modeller enriches the model with existing real-world features. These may not have been obvious at first sight, but the information does exist somewhere and just needs to be identified and codified for the purposes of the model.

Yet once the effort moves from model calibration to scenario building, future "facts" and "features" need to be determined. As indicated, the latter are not available in the form of a coherent set of assumptions. Identifying and honing them so that they become both policy-relevant and logically consistent, which is often not a trivial challenge, inevitably requires a comprehensive effort. This includes carefully reviewing detailed scenario results, understanding possible drivers, discussing and preparing new model runs in order to initiate the same process at the next level. Putting this iterative process in place and moderating it, coupled with advanced modelling expertise and a state of the art model, is where resides the principal value added of undertaking energy system cost modelling with the NEA.

Drivers of system cost scenarios

This section provides examples and first indications of what to pay attention to when choosing and, at a later stage, refining energy system scenarios It thus describes the most important drivers of the results of energy system analysis, both with regards to the total system costs of each scenario and its structural features such as ramping requirements, price volatility or the technical and economic impact on dispatchable generators.

Put in the simplest terms, scenario results are determined by three different categories of inputs – the plant level costs of different technologies, the correlation of renewable generation with demand and the availability and cost of flexibility resources. Each one of the three categories is briefly presented in the following.

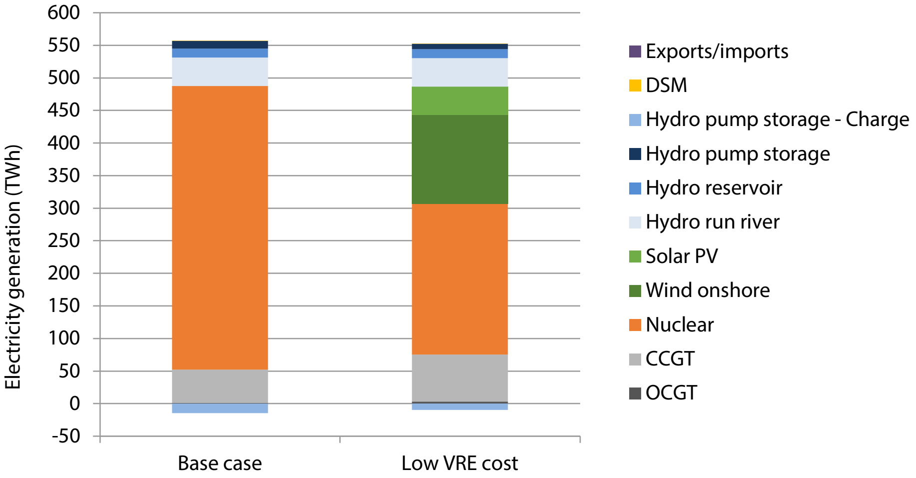
Plant-level costs

The inclusion of plant-level costs measured in terms of the levelised costs of electricity (LCOE) may come as some surprise as system cost analysis is often presented as surpassing LCOE accounting and making it obsolete. This is, of course, half-true. LCOE analysis on its own provides only a subset of relevant cost information and can be seriously misleading. Grid-level system costs constitute after all real monetary costs measured in dollars and cents that directly affect, in proportions depending on the regulatory arrangements specific to each country, the costs of generators, taxpayers and electricity consumers. Given that different technologies generate system costs in starkly differing measures it is thus necessary to complement LCOE values with information about system costs. This is, of course, the *raison d'être* of system cost analysis.

However, the relative plant-level costs of different technologies remain an important argument in the minimisation of the economic costs of attaining energy policy objectives such as a carbon emission reduction targets. As indicated in Table 6 plant-level costs are a function of overnight costs, construction times, the discount rates as well as the various components of variable costs, in particular fuel and carbon costs as well as an annual fixed costs for operations and maintenance. Despite their vastly differing system impacts, different low-carbon technologies such as nuclear, wind and solar PV, as well as hydroelectricity also continue to entertain a frank competition on costs, which include their not only construction and operations but also decommissioning and waste management.

Minimising the overall costs of an electricity and energy system thus means optimising the trade-off between plant-level costs and system costs. This shown by Figure 6. The left-hand column indicates an optimised system in which nuclear (in orange) does not only produce few system effects but is also the most cost-effective low-carbon source of electricity in terms of LCOE. Linear programming model such as POSY will choose to cover system needs primarily with nuclear power and the system, in this case, does not include any variable renewable energy sources such as wind and solar PV, but does include hydroelectricity. Private investors in a competitive electricity market would have made their investment decisions in a manner that would have achieved precisely the same outcome.

Figure 6. The trade-off between plant-level generation costs and system costs*



Note: * In the system represented by the left-hand column, nuclear has both lower system costs and lower LCOE costs than either wind or solar PV. In the system represented by the right-hand column, nuclear still has lower system costs but wind and solar PV both have lower LCOE costs. Both columns show results of system-wide cost minimisation.

Source: Based on NEA (2019).

The situation is more complex when looking at the right-hand column, which indicates an optimised system in which nuclear (in orange) still produces few system effects but wind and solar PV have now lower plant-level costs in terms of LCOE. The system achieving the lowest total system costs contains now significant parts of both variable renewables and nuclear energy. Again, private decision making and investment in competitive electricity markets would have arrived at the same outcome.

How can this be? Most observers are used to think about the competitiveness of generation in binary terms, the least-cost choice is constituted either by one or the other technology. Not so in system cost analysis, where the system costs of a technology are not constant per MWh but *increase* with the share of that technology in the generation mix. This underlies the arbitrage between plant-level costs and system costs in Figure 6. Below a certain threshold of their share in the generation mix, wind and solar PV, if they have indeed lower LCOE, will be the least cost-choice for generating low-carbon electricity. The model and, in a competitive market, investors will thus select wind and solar PV. However, as their shares increase, also their system costs increase. At a certain point, their increasing system costs will have exhausted the cost advantage in terms of LCOE and nuclear energy now become at the system level the least cost option to generate low-carbon electricity.

One of the most surprising features of system cost analysis, at least for those new to the subject, is that private investors in a competitive electricity market would make precisely the same choices, and would not select only the technology with the lowest plant-level production costs. In order to understand this, one needs to return to the reasoning outlined in Box 1 that the non-availability of variable wind and solar PV during certain hours, which is at the heart of their profile costs at the system level is compensated by their excess production during other hours. During those hours when all wind turbines or solar PV plants produce together, electricity prices will be lower than the average electricity price. In other words, the fact that VRE capacity regularly produces at the "wrong" hours when their contribution is least required not only penalises the owners of dispatchable plants whose load carrying hours are reduced but also the renewable generators themselves, whose prices are structurally lower than the prices obtained, for instance, by round-the-clock baseload generators. Again, this autocorrelation or self-cannibalisation effect increases with the share of variable sources in the generation mix. Once more, also private profit maximisation driven by market prices will converge towards the same least cost result as linear optimisation models such as POSY.

The final point of the least-cost trade-off between variable renewables and dispatchable low-carbon generators will depend on a country's specificities such as the correlation between renewable production and demand or its flexibility resources (see below). The principle of a trade-off between plant-level costs and system costs however is general. It also contains a powerful policy message: in the absence of the large-scale availability of low cost storage, least cost constellations of decarbonised electricity systems will include sizeable shares of both variable generators such as wind and solar PV and dispatchable generators such as nuclear energy or hydroelectricity in the generation mix. As long as technologies with comparatively lower plant-level costs are also the ones that causing the system costs, the binary logic of fully relying either on one or the other no longer applies in the integrated low-carbon systems of the future.

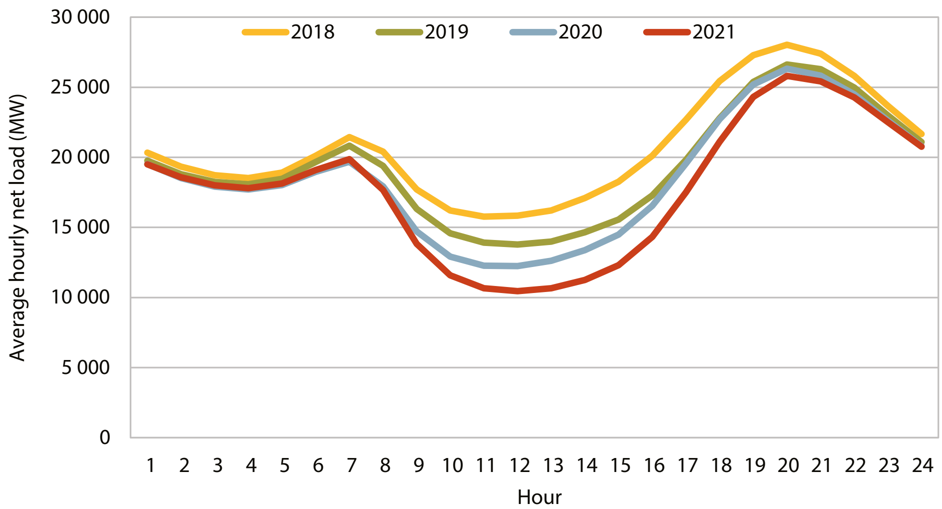
The correlation of renewable generation with demand at different levels of capacity

This is a key point. It is quite obvious that the comparatively low load factors of solar PV or wind are an important cause of the need for dispatchable low-carbon back-up or other sources of flexibility provision and hence the resulting increase in system costs. It is less obvious, yet equally important, how well the output of variable renewables is correlated with electricity demand. The latter varies according to the year, the season, the day and, importantly, according to the hour of the day. Consumption is lower at night and in most industrialised countries displays a smaller peak at around noon and a peak with maximum demand at around seven o'clock at night, when factories and offices are still operating but residential consumers and perhaps street-lighting are already beginning to consume electricity.

Imagine now a highly developed country with good sunshine especially during noontime that is beginning to install solar PV capacity. Imagine further that it uses electrically powered air conditioning to cool homes and offices. As it happens, these air conditioners will work hardest precisely over noontime when the sun is at its peak. However, this is precisely also the time when solar PV generation will be at its peak. In this state of affairs, only very little back-up will be required for the first few MW of solar PV capacity. The fact that solar PV will not generate at night or during evening peak hours is not a problem as long as air conditioning is turned lower during those hours. While this might sound very encouraging for variable renewable energy sources, three *caveats* are of order. First, only vary rarely solar PV or wind production is as nicely correlated with demand as in the stylised example above. Second, the effect only applies to the very first MW of variable capacity. As soon as PV capacity has reached the level of peak air-conditioning demand, the correlation breaks down (see Figure 7). Third, in many electricity systems the key issue is not hourly demand variations over the day, some of which could, at a cost, be mitigated by chemical batteries, but seasonal or inter-annual variations, where batteries are of little help due to their limited energy storage capabilities.

Figure 7, which shows the development of the net or residual load (demand minus generation from wind and solar PV), summarises both the benefits and the limits of the correlation of solar PV generation and demand in the case of California. Between 2017 and 2022, solar PV capacity grew from 10.2 GW to 15.1 GW. This increase leads to a decrease of dispatchable generation, the net load, during hours with strong solar generation around noon. The residual load curve thus displays an ever deeper concavity during hours with strong solar generation. This bowl-shaped concavity is sometimes referred to as the "duck's back" or, more recently, a "canyon". It should be noted that the values indicate annual averages for each hour. During particularly sunny days, net load can even turn negative. Dispatchable capacity, however, is still required for mornings and evening peak-hours. One day, chemical batteries might play a role here, but they are not yet economically attractive at large scale.

Figure 7. The California "Duck curve": Hourly average net load (2018-2021)*



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Source: CAISO (2022).

As indicated, California has quite favourable conditions for the use of solar PV, primarily because of bountiful sunshine and high demand for air conditioning during noon hours. In a country such as France, with less sunshine and a steep peak during evening hours due to electric heating, the impact on net load and the required ramps would be even stronger. In order to capture such impacts, system cost analysis needs to consider all 8 760 hours of the year in order to capture both daily and seasonal variations.

NEA modelling is also moving towards multi-year assessments for solar PV and wind generation since annual variability can be considerable. As first order-of-magnitude assumptions one may consider year-on-year differences up to 10% for solar PV and up to 20% for onshore wind. However, there are large differences between countries and these numbers are provided only for initial orientation. The bottom line is that the generation structure of VRE generation capacity, the structure of demand as well as their correlation, weighs heavily in the determination of the system costs of renewables as well as the total system costs.

The availability and cost of flexibility resources

There is general agreement that flexibility provision is an essential determinant of the system costs of the variability of wind and solar PV, and that investment in flexible resources is required to integrate their increasing capacity into the generation system. In function of their technical performance and costs, different technologies will be used to reply to different flexibility needs. The category of flexibility resources is a broad one. It can be defined as the set of all technical and behavioural levers that can be used to either increase supply or reduce demand in order to ensure the indispensable second-for-second balance between electricity supply and demand. This is necessary in response to the variability of wind and solar PV generation. In principle, this would include dispatchable baseload providers to the extent that nuclear reactors as well as coal- and gas-fired power plants are capable of load-following, i.e. they are capable of adjusting their output according to market conditions and system requirements.

In practice, dispatchable baseload provides, with the exception of open-cycle gas turbines (OCGT) are usually not categorised as flexibility resources, although they play an important role in ensuring adequate amounts of seasonal and inter-annual flexibility. Given their high capital costs, their business model must necessarily be to run as many hours as possible rather than to react occasionally to high prices or system stress. In other words, the term of flexibility resource is usually limited to technologies or kinds of behaviour such as demand response whose profitability does not depend on continuous power provision and for whom frequent up and down ramping is not only technically possible, but commercially attractive. This implies that flexibility providers have a cost-structure characterised by low fixed and high variable costs. That said, baseload power plants whether nuclear, coal or CCGT gas plants do, of course, contribute to the overall sustainability of the system, precisely because their output does not require to be complemented by other sources. Their large spinning turbines also provide the inertia that stabilises electricity systems at the physical level. In low-carbon system with net zero emissions based primarily on variable renewables these stabilising functions need to be provided by other means. Generating "synthetic inertia" is thus technically possible using advanced system electronics, albeit again at an added cost. Following NEA (2019), one can identify six different sub-categories of flexibility provision:

- **Flexibility from conventional power plants**: Conventional generation currently provides the majority of flexibility services in all OECD and NEA countries. As indicated, this concerns primarily technologies with low fixed costs such as OCGTs. Of course, flexible hydropower whether based on reservoirs or pump storage units is also a very important source of flexibility among dispatchable generators (the latter are occasionally also considered a form of non-chemical battery storage).
- **Electric energy storage**: Batteries are employed to shift energy demand from peak to off-peak periods, levelling the residual load. The most prevalent form of battery storage is currently constituted by chemical lithium-ion batteries capable of providing energy for up to six hours. In addition, new technologies such as compressed-air energy storage or fuel cells may one day offer additional options. Storage may one day also include the time-adjustable production of hydrogen (H_2) on the basis of electrolysis and its subsequent use as a vector of storage or generation either directly or by passing through an additional step of conversion into methane (CH_4).
- **Network development and cross-border interconnections**: The benefits of the division of labour increase with the size of the market. The larger and more diversified an electricity system is, the easier and less costly it is to find offsets on the demand or supply side for any given form of variability. For distribution networks the local integration of demand- and supply-side technologies to net out variations in virtual power plants, local energy markets, or smart grids can be an option.
- **Voluntary demand response (DR)**: Certain consumers, whether industrial, commercial and residential, can be incentivised to reduce their baseline consumption. This may avoid building expensive capacity to deal with peak consumption hours. Load shifting or peak shaving would just postpone consumption at a certain hour, load shedding would reduce it for good.
- **Involuntary demand response (scarcity)**: If a demand and supply mismatch cannot be resolved by any other means and system stability is endangered, the system operator can proceed to rolling blackouts such that different consumer groups are disconnected for a limited duration. This has high welfare costs and leads to "scarcity pricing" at the level of the value of lost load (VOLL) measured in the thousands of USD in the remainder of the market.
- **Operational flexibility from VRE (curtailment)**: There is debate whether the ability to disconnect variable renewables during hours of excess generation from the grid counts as a proper flexibility contribution as such as it only allows to *reduce* consumption during critical hours. Either way, such curtailment is critical for maintaining network stability.

The availability and cost of such flexibility resources is a key driver of the costs of electricity systems with significant shares of variable renewables. The cheaper the available flexibility options to compensate for the variability of wind and solar PV, the lower are the total system costs to cover a given demand structure. Section 5 provides modelling results from the POSY model where varying ratios of nuclear and variable generation under a net zero carbon constraints operate once in a context with high flexibility resources and once in a context with low flexibility resources. It is obvious that the contribution of nuclear energy as a dispatchable baseload provider is all the more valuable in systems with few flexibility resources. This is due to the fact that nuclear requires few flexibility resources of its own and that in those countries where nuclear load-following is practised, it effectively contributes to smooth out variations in the daily and weekly balance of demand and supply.

Supporters of an increasing deployment of wind and solar PV frequently claim that the widespread availability of flexibility resources will allow the accommodation of ever greater amounts of variable resources in the future. However, while such claims may be understandable in the context of developing alternative scenarios to influence energy policy debates, there is no automatic tendency towards such a scenario. Flexibility resources are often subject to decreasing returns to scale. Hydropower facilities are limited by geography, chemical batteries pose issues of costs and waste and demand response has limits in the opportunity costs for industrial and domestic consumers foregoing consumption.

Even more so than generation costs and the correlation between renewables generation and demand, the availability and cost of flexibility resources are driven by the country-specific conditions. Their impacts are compounded in future-oriented scenarios that require making assumptions about the deployment of electric vehicles, the introduction of co-generation, the production and use of hydrogen as well as, in general, increasing electrification of energy uses through sector coupling. All of the above can easily upset the ranking of the system costs of different scenarios operating under strong carbon constraints with high shares of variable renewables and nuclear energy.

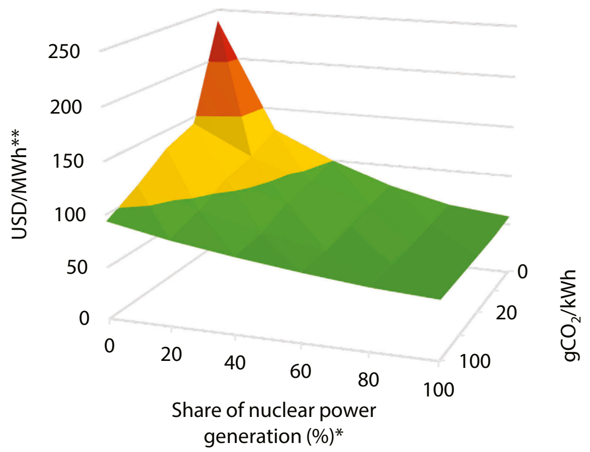
The decisive role played by these (not always obvious) determinants of system cost studies, generation costs, which demand correlation and flexibility resources and make the careful framing of forward-oriented scenarios as part of a dialogue between member country, stakeholders and the NEA modelling team so important. This is an iterative process of several repeated rounds of formulating assumptions and strategic policy objectives, intermediate scenario results and expert evaluation. Even the availability of a state-of–the-art model and access to detailed data sets cannot substitute for this process. It is only over time that in this manner analytically and politically sustainable scenarios begin to emerge that can legitimately aspire to play a relevant role in ongoing policy discussions.

5. The impacts of generation costs and the availability of flexibility resources: An illustrative system costs analysis

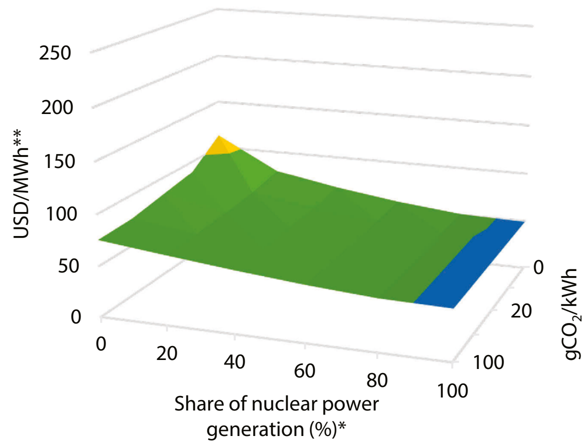
Results of a system cost analysis of a hypothetical country are contained in the four three-dimensional graphs in Figure 8. They illustrate how changing assumptions for two of the three categories driving results presented in the previous section – relative plant-level costs and the availability of flexibility resources – determine overall results. The four graphs combine two sets of contrasting plant-level cost assumptions with two sets of assumptions regarding the availability of flexibility resources.

Figure 8. Total economic system costs as a function of the carbon constraint and share of nuclear power generation in scenarios with different VRE and nuclear power costs and flexibility levels

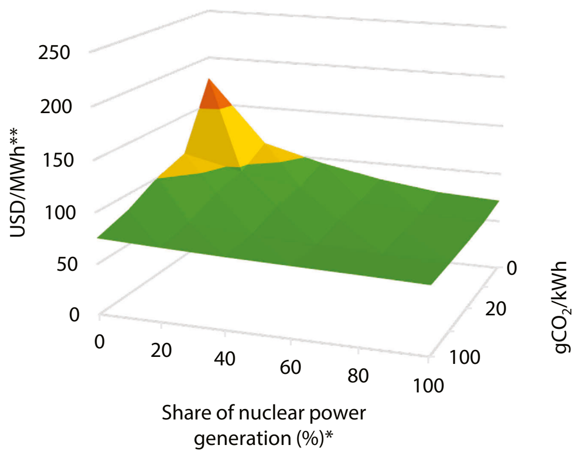
8.a High variable renewables/low nuclear costs and low flexibility



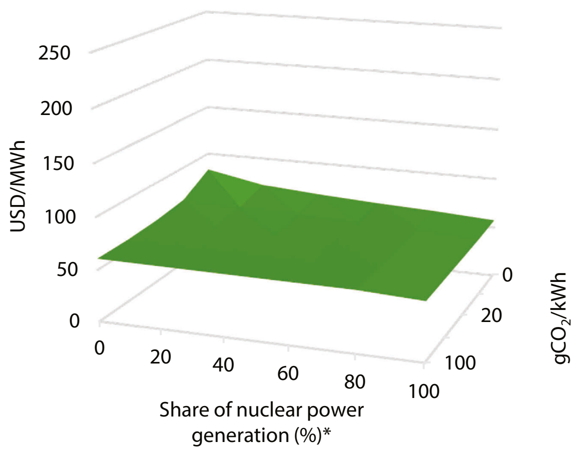
8.b High variable renewables/low nuclear costs and high flexibility



8.c Low variable renewables/high nuclear costs and low flexibility



8.d Low variable renewables/high nuclear costs and high flexibility



* Optimised least cost scenarios in function of given share nuclear power generation. ** Total economic system costs include Capex and Opex minus net export revenues. Balancing, connection, transmission and distribution costs are not considered. Discount rate = 5%.

The plant-level cost assumptions in Table 7 are thus combined first in a high renewable cost/low nuclear energy cost case (graphs 8a and 8b) and second in a low renewable cost/high nuclear energy cost case (graphs 8c and 8d). The two plant-level cost cases thus do not represent lower or higher costs for all technologies in a uniform manner but are designed to bring out differences in the costs of attaining certain carbon targets in different circumstances.

Table 7. "High" and "low" capital cost assumptions for nuclear energy and variable renewables*

Technology	Overnight cost (USD/kW)	Annual investment cost (USD/kW/y)
Solar PV utility scale – Low	500	35
Solar PV utility scale – High	1 000	71
Onshore wind – Low	1 000	71
Onshore wind – High	1 500	106
Offshore wind – Low	1 500	106
Offshore wind – High	3 000	213
Nuclear new build – Low	4 000	211
Nuclear new build – High	6 000	317

* For reasons of transparency, only capital costs were changed, while fuel as well as operations and maintenance costs were kept constant. Differences in low and high capital costs are designed to show their impacts on modelling outcomes not to provide new indications of capital costs themselves.

Crucial here are the *relative* costs between two sets of low-carbon technologies: nuclear energy and variable renewables sources consisting of onshore and offshore wind as well as solar PV. As can been seen by comparing graphs 8a and 8b with graphs 8c and 8d, a relative cost advantage of variable renewables lowers peak system costs more than the relative cost advantage for nuclear energy. The reason is that peak system costs are correlated with high shares of variable sources. As their costs decline, peak total system costs also decline. The opposite holds true for system constellations with a higher share of nuclear energy, where total system costs benefit from low nuclear energy costs. In other words, a high renewable/low nuclear cost case makes for a broader range and steeper increase in system costs as the share of nuclear energy recedes than a low renewables/high nuclear energy cost case.

The second pair of contrasting assumptions regards the availability of flexibility resources. Flexibility can be provided by a number of technical and behavioural options. The availability of interconnections for electricity trading, flexible hydropower, batteries, voluntary demand side management (DSM) and involuntary demand response (load shedding with prices at the value of lost load, VOLL) can all contribute to the variability and intermittency of renewables technologies. The full set of assumptions for a Low flexibility case and a High flexibility case are provided in Table 8.

Combining the assumptions of Tables 7 and 8 allows to compute the four graphs of Figure 8 for a mid-sized country with good interconnections and average wind and solar resources. The x-axis represents the share of nuclear power generation as a percentage of an optimal nuclear generation baseline, the remainder being supplied by wind and solar PV, hydropower and, to the extent that the carbon constraint is not zero, some residual gas-fired power generation. Each combination of relative variable renewables/nuclear power costs and flexibility assumptions, results in different shares of optimal nuclear power generation as a portion of total electricity production. Depending on the carbon constraint, the optimal share of nuclear ranges from 20-90% of total electricity generation, which makes it difficult to directly compare the four scenarios presented in Figure 8 for equal share of nuclear power. The y-axis indicates the carbon constraint in terms of gCO_2 per kWh. The z-axis indicates total system costs in terms of USD per MWh.

Based on the assumptions and parameters detailed in Table 7 and Table 8, the numerical results of this illustrative modelling exercise confirm what has been developed in qualitative terms in previous sections:

- A more severe carbon constraint always increases system costs.
- A higher share of variable renewables such as wind and solar PV always increases system costs. As a low-carbon resource and with hydro resources fixed, VRE substitute for nuclear energy to attain a given carbon constraint. Under a zero carbon constraint, system costs thus increase in the high variable renewables/low nuclear cost and low flexibility case from 95 USD/MWh to almost 240 USD/MWh when switching from nuclear to variable renewables.
- Aiming at attaining very ambitious carbon constraints (net zero) without any contribution of nuclear energy and with only variable renewables is exceedingly expensive. The cost minimising generation mix always contains some level of nuclear energy.
- As explained earlier, a high renewables/low nuclear energy cost case makes for a broader range and a steeper surface of total system costs.

Table 8. Capacity and cost of different flexibility options in the "High flexibility" and "Low flexibility" cases

Technology	Available capacity (GW)	Fixed overnight cost (USD/kW)	Variable cost (USD/MWh)
Interconnections – Low*	0 (autarchy)	0	0
Interconnections – High*	15.1 for imports 18.1 for exports	0	Import prices
Hydro (reservoir) – Low**	3	3 100	0
Hydro (reservoir) – High**	5	3 100	0
Hydro (pump storage) – Low**	0	2 500	0
Hydro (pump storage) – High**	5	2 500	0
Batteries (Li-ion) – Low**	40	1 600	0
Batteries (Li-ion) – High**	No limit	1 200	0
Voluntary demand response 1, 2, 3	5, 5, 10	0	100, 300, 500
Load shedding 1, 2, 3	10, 10, no limit	0	10 000, 15 000, 20 000

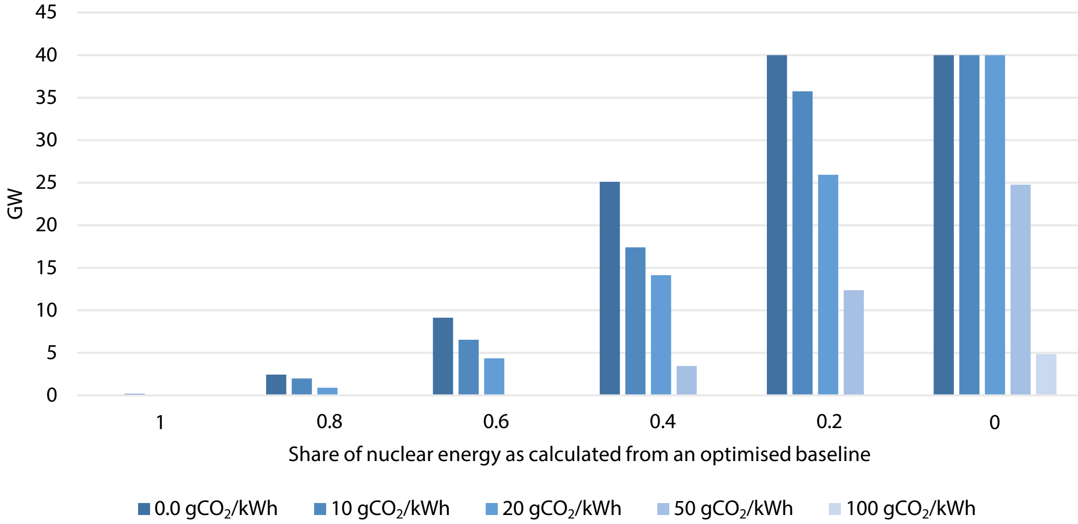
Notes: * In a full-fledged system cost study, the fixed overnight costs of interconnections would be part of grid costs. This illustrative case only considers generation costs. Variable costs are given by import prices. Receipts from electricity exports are deducted from total system costs.

** The variable costs of flexible hydro and chemical batteries are constituted by the intertemporal opportunity costs of not being able to use the stored energy at another hour. By minimising total system costs, POSY charges and uses available energy optimally. Indicating zero variable cost means that no additional technical costs arise.

The availability of flexibility resources crucially determines system costs at high shares of variable sources under stringent carbon constraints such as net zero. Peak system costs more than double when transitioning from high to low flexibility. In general, the availability of flexibility resources heavily influences costs in an electricity system with high shares of variable renewables. Flexibility needs primarily drive the overall system costs by increasing storage requirements in electricity systems, especially when high shares of variable renewables are present and dispatchable capacity is low. This effect is depicted in Figure 9.

At relatively low carbon constraints (e.g. 100 gCO_2/kWh), dispatchable gas capacity remains, which accounts for the minimal battery capacity expansion, even in the absence of nuclear power generation. However, as carbon constraints increase, forcing gas plants out of the system and prompting more variable renewable capacity deployment, battery storage needs begin to grow. This phenomenon is relatively moderate with dispatchable nuclear power but intensifies when this source of dispatchable power approaches zero at high carbon constraints. For example, a shift from 40% to 0% in nuclear power generation's share from the baseline results in a doubling of battery capacity, driving system costs up sharply.

Figure 9. Battery capacity as a function of the carbon constraint and the share of nuclear power generation in the high variable renewables/low nuclear cost and low flexibility scenario



It is not the purpose of this very succinct illustrative system cost analysis to draw any specific policy conclusions for a particular country or group of countries. Its purpose is rather to develop a first intuition of what kind of results system cost analysis can provide and which questions may be asked in order to develop or test certain policy proposal of relevance. As indicated throughout this guide, the full value of a system cost analysis will only reveal itself is based on an iterative dialogue between the NEA and the individual member country. A full NEA system cost analysis will require a fully calibrated model, fine-grained multi-year data, convincing and policy-relevant scenarios as well as coherent assumptions about costs and the availability of different low-carbon technologies and flexibility resources. Once these are all optimally combined, an NEA system cost analysis can become a highly valuable tool to inform and advance energy policy discussions about how to achieve ambitious carbon objectives in the most cost-effective manner.

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