Technology Collaboration Programme
by IEA

IEAGHG Technical Report
2020-11
September 2020

Beyond LCOE: Value of Technologies in Different Generation and Grid Scenarios

IEA GREENHOUSE GAS R&D PROGRAMME

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ACKNOWLEDGEMENTS AND CITATIONS

This report describes research sponsored by IEAGHG. This report was prepared by: Imperial College Consultants UK .

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The report should be cited in literature as follows:

'IEAGHG, "Beyond LCOE: Value of technologies in different generation and grid scenarios", 2020-11, September 2020.'

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BEYOND LCOE: VALUE OF TECHNOLOGIES IN DIFFERENT GENERATION AND GRID SCENARIOS

Key Messages

- This study is aimed at exploring and proposing an alternative concept to the levelised cost of electricity (LCOE), one that can be used to generate a transparent, intuitive and comprehensive approach with which to compare the evolving impact of technologies within an electricity system – rather than simply providing direct technology-technology comparison.
- LCOE is attractive as a metric for comparing power generation technologies; it is simple to calculate and provides messages that the energy community, whether technologists, project developers or policy makers, can relate to and apply in their decision making. With these attributes, the LCOE concept has become the dominant approach.
- However, LCOE suffers from well-documented weaknesses and is widely regarded as being poorly suited to the heterogeneous electricity grid of the 21st century. The energy community has been aware of its shortcomings since the early 1990s, with several alternatives having been proposed. Examples of these include the US EIA's 'Levelized Avoided Cost of Electricity' and the IEA's 'Value Adjusted LCOE'. While many of the alternatives proposed are excellent, no one method has emerged as being a clear preference to LCOE; they variously suffer from computational complexity, large data requirements or lack of transparency.
- In addition to providing energy and capacity services, a range of ancillary services are required by the grid. Ancillary services evaluated during the analysis for this study, include those provided by large-scale, synchronous thermal power stations (hydro, nuclear and fossil fuel):
  - Maintaining system frequency (inertia, primary, secondary, and tertiary reserves);
  - Maintaining system voltage; and
  - Restarting the system after black-out.
- If large-scale, synchronous, fossil-fuelled thermal plants were phased out, the availability of ancillary services that are inherently provided by those technologies becomes limited. In such a scenario, the value of these ancillary services would increase considerably.
- Of all the services that each technology provides to the system, modelling undertaken for this study indicates that the provision of firm capacity (MW) and energy (MWh) services are the most crucial.
- Early in the study, a new concept, the 'Levelised Cost of Electricity Service' (or 'LCES'), was developed. While demonstrating great promised for comparing the impact of technologies within an electricity system – it addresses both thermal and iRES technologies, satisfies important ancillary services and covers short and long-term time horizons – the LCES suffered from the same downsides as other concepts before it. With its computational complexity and significant data needs, LCES would be unlikely to replace LCOE as the metric of choice.

- However, an existing concept which assesses the capacity and the energy services of different technologies is the screening curve. While this represents a well-established method to compare thermal generation technologies, it is not suitable for the evaluation of intermittent renewable energy sources (iRES) and storage technologies.
- But this limitation can be overcome. Incorporating the effective capacity factors[1] of the technologies in the curve can reflect the capacity and energy services provided by iRES.
- Storage technologies can also be incorporated in the approach by limiting their maximum hours of discharge to the curtailed hours of the electricity source (to represent the time the technology needs to charge) and to the maximum hours of operation (which corresponds to the time needed to charge and discharge).
- Applying these rules allows the screening curve approach to be used to evaluate the capacity and energy value of dispatchable and non-dispatchable power generation technologies, as well as energy storage technologies.
- This is an accessible approach to evaluate the impact of arbitrary levels of all power generation technologies on the total system cost. The proposed concept can also be used to estimate the level of economic deployment of technologies considered and to determine the optimal role the technologies can play.
- Although the optimal energy share of iRES can be significant, the role of dispatchable plants remains critical in the system to meet the electricity demand.
- This study proposes the modified screening curve concept as an alternative concept to LCOE[2]. It shows that iRES have significant value by providing energy/fuel savings for the electricity system, with dispatchable technologies having critical value by supplying capacity for security of supply.

Background to the study

In December 2015, a global consensus was achieved on the ambition to limit anthropogenic climate warming to "well below 2°C" and to pursue efforts towards 1.5°C. The Paris Agreement was formally ratified the following year. Working towards the aims of the Agreement will require ambitious decarbonisation targets to be adopted within the energy industry. With this in mind, the power sector must play its part and CCS will be key to this endeavour. Energy modelling has routinely underlined the need for power CCS to have an integral place in the global portfolio of technologies to be deployed if global temperature increases are to be capped and the worst impacts of climate change avoided. Uptake to date, however, has been disappointing. Of the 21 CCS projects presently operating in eight countries, just two are in the power sector. The cost of CCS has often been presented as a significant contributory factor to the lack of uptake of the technology.

Since its introduction in the second half of the 20th century, the concept of levelised cost of electricity (LCOE) has become ubiquitous in the evaluation and comparison of power generation technologies. LCOE is a readily accessible metric, which evaluates the cost per kWh of

[1] The "effective capacity factor" is the ratio of the total useful energy delivered by a technology over a period to the total energy it could generate if it had been continuously operated at the rated capacity over that same period.
[2] While the data requirements and computational complexity for evaluating LCOE and the modified SC are essentially the same, the modified SC does not replace the more detailed analysis needed to develop a more precise assessment of the 'value' of each asset, reserve requirements, etc., but is an improvement to simply using the LCOE. The study did not set out to develop an alternative to sophisticated modelling but, rather, to think about potential alternatives to LCOE.

electricity produced by an asset over its lifetime. Significantly, LCOE focuses exclusively on the cost of electricity produced from a given asset, or set of assets, but neglects to address the provision, or otherwise, of so-called ancillary services which are vital for the reliable operation of an electricity grid. While this simplification was entirely appropriate for the electricity system of the 20th century, dominated at it was by thermal technologies (fossil fuels, nuclear and hydro), it falls well short as a metric to compare technologies in a system to provide net-zero emissions by the mid-21st century.

With the increased focus on non-fossil sources of energy, the shortcomings of the LCOE metric became apparent, and by the early 1990s, alternatives were being proposed. One of the earliest alternatives was the development of an approach based on system value (SV). Instead of focusing on the cost of an individual technology, the SV measures the change in total system cost avoided that results from the deployment of a technology, taking into account the individual cost of the technology, alternative technologies and the optimal role the technology can play in the system. While the SV approach was not widely adopted, the increasing focus on efforts to mitigate climate change and the rapidly increasing deployment of iRES, have led to discussions on alternative metrics to LCOE being resumed. In this context, it has been recognised that, while the SV approach is significantly more comprehensive than the LCOE approach, the computational complexity is significantly greater. To-date, even though several less complex alternatives have been proposed, LCOE, with its inherent simplicity, has remained the leading metric for the evaluation of power generation technologies.

Scope of Work

At present, LCOE is widely accepted as the industry norm. The main objective of the study is to explore the potential for a new concept that balances completeness and ease of use, one that can be used to generate a transparent, intuitive and comprehensive approach with which to compare the evolving impact of technologies within an electricity system.

This involves:

- Exploring the portfolio of ancillary services that a given electricity grid requires;
- Reviewing and evaluating the various alternatives to LCOE that have been proposed;
- Identifying the key characteristics of an alternative metric that might realistically serve to replace or augment LCOE; and, finally
- Developing a new concept for evaluating power generation technologies that fulfil these criteria.

The study uses the Electricity Systems Optimisation (ESO) framework developed at Imperial College London to quantify the value of a technology and provision of its services. By coupling detailed engineering and electricity market models, the framework provides a bottom-up assessment of the impacts (e.g. system cost and operability) of individual technology deployment into the energy system.

Findings of the Study

The results of the review of ancillary services provision by power generation technologies are presented in Figure 1. It is clear that only a small subset of power generation technologies provide all ancillary services, with important gaps associated particularly with iRES technologies.

Technology	Frequency				Voltage		System Restart	Reserve Capacity		
	Inertia	Primary Response	Secondary Response	Tertiary Response	System Strength	Reactive Power	Black start	Regulating Reserve	Contingency Reserve	Load Following Reserve
Nuclear	O			O	O	O	O		O	O
Bio	O	O	O	O	O	O	O	O	O	O
OCGT	O	O	O	O	O	O	O	O	O	O
CCGT	O	O	O	O	O	O	O	O	O	O
Coal-CCS	O	O	O	O	O	O	O	O	O	O
CCGT-CCS	O	O	O	O	O	O	O	O	O	O
BECCS	O	O	O	O	O	O	O	O	O	O
Wind turbine	O	O	O	O		O		O	O	O
Solar		O	O	O		O		O	O	O
Pumped Hydro Storage	O	O	O	O	O	O	O	O	O	O
Battery		O	O	O		O	O	O	O	O

O	The technology can provide the service
O	The technology can provide the service but might be limited by the energy availability and economic-environmental aspects
O	The technology can technically provide the service but providing this service may not be beneficial for the plant (*i.e.,* iRES and Nuclear tend to operate at full capacity or availability)

Figure 1: *Availability of ancillary services by power technology*[3]*, which shows a non-uniform provision of these services across all technologies.*

To serve as a viable alternative to LCOE, any new metric must preserve as far as possible the intuitive and accessible nature of the LCOE approach, avoiding the need for complex computational tools. However, as with the original SV approach, any alternative to LCOE must be able to reflect the impact of the deployment of a marginal quantity of a given technology on the overall system cost and performance. Implicit in this statement is the requirement for an element of system design to be incorporated in any new approach.

Key to the development of a readily accessible metric is robustly discriminating between those grid services that are more valuable, and retaining them, and discarding those which are less valuable. To this end, the ESO model's framework was extended to include an explicit description of all the ancillary services listed in Figure 1.

The new tool, ESO-ANCIL, was used to quantify the value of a given ancillary service to the grid. It was concluded that, while all services were important, the provision of firm capacity and power generation were most valuable. This has the additional implication that, for electricity systems that are increasingly incorporating additional iRES capacity, the creation of a capacity market may well be something to consider. Consequently, a new screening curve-based approach (SC) was proposed that would account for the value of both capacity and power. In line with the requirement for simplicity, the proposed screening curve method is compared against LCOE in Table 1.

[3] Note that the table provides a binary response i.e. the technology either provides the service or it doesn't. In practice, the case may not be as clear cut – the technology may actually only *partially* provide some of the services listed. This would be the case, e.g. for wind and solar.

Table 1: *Comparison between an LCOE approach and the proposed screening curve method*

Data Requirement	LCOE	Screening Curve
Capital cost	√	√
Fixed O&M	√	√
Variable O&M	√	√
Load duration curve	–	√
Technology availability	√	√
Hourly iRES availability	–	√
Analytical solution	√	√
Suitable for systems analysis	–	√

The table shows there to be an additional data requirement for the screening curve method compared with the LCOE approach. However, these data are generally readily available. Importantly, both methods are entirely analytical, and do not require complex models or numerical methods to solve.

The data requirements and computational complexity for evaluating LCOE and the SC are not too dissimilar. The additional requirement imposed by the SC is simply that one evaluates *all* technologies within a given system rather than making a simple comparison between, say, "Technology A" and "Technology B". Using the proposed SC method, one can rapidly and readily evaluate the role and value of given power generation technology within a given electricity system.

To provide confidence in the SC concept, it is compared with ESO-ANCIL, which takes into account the whole range of electricity system services required by the grid, the results of which are illustrated in Figure 2.

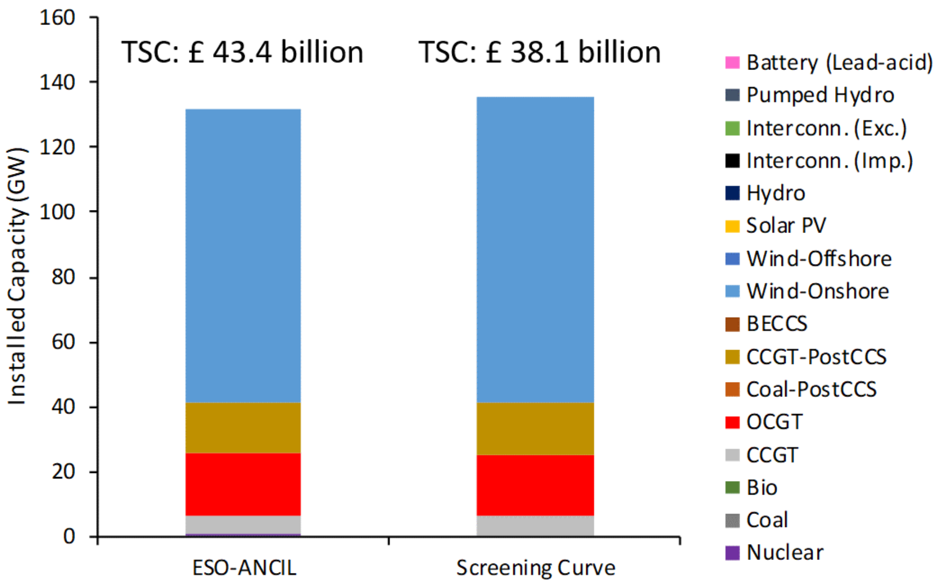

Figure 2: *Power generation screening curve validation against ESO-ANCIL.*

Clearly, the SC approach validates well in terms of system structure. It also provides a reliable description of the number of hours per year for which a given technology will be used. In other words, it provides insight into the likely capacity factor that each technology might achieve. Given that this is one of the key input parameters to the LCOE calculation, there are clear synergies between the new SC approach and the conventional LCOE approach. The discrepancy in calculated cost between the ESO-ANCIL and SC calculations arises from the absence of dynamics in the SC approach. As the SC calculation does not account for the costs associated with part load operation and start-up/shut-down cycles, developing a method to approximate this within the SC formulation is a potential avenue for future work.

However, in light of the computational simplicity, limited data requirements, transparency of this approach and a relatively small error in terms of the system structure, this modified screening curve concept is proposed as a new alternative to LCOE.

The new SC approach allows for the rapid evaluation of the value of a given technology in a whole-systems context. It appears to be a natural extension of the conventional LCOE approach, retaining simplicity and accessibility, whilst considerably adding to the depth of systems insight that can be achieved.

Expert Review Comments

A review was undertaken by a number of international experts. The draft report was well received, with reviewers commenting in detail on its content. Reviewers raised a number of questions, identified issues requiring further clarification and recommended areas where content might be rearranged for better flow. All matters raised by reviewers were addressed by the authors, with amendments made and explanations added to the final text.

Conclusions

The main objective of the study was to explore the potential for a new concept that balances completeness and ease of use, one that can be used to generate a transparent, intuitive and comprehensive approach with which to compare the evolving impact of technologies within an electricity system.

In addition to providing energy and capacity services, a range of ancillary services required by the grid were evaluated. The ancillary services evaluated were:

i) Ability to maintain system frequency (inertia, primary, secondary, and tertiary reserves),
ii) Ability to maintain system voltage, and
iii) Ability to restart the system after black-out.

Key results from the study were as follows:

- Owing to its accessibility and intuitive nature, the LCOE concept is the dominant approach for comparing power generation technologies. However, it suffers from well-documented weaknesses, and is widely regarded as being poorly suited to the heterogeneous electricity grid of the 21st century.

- Whilst the LCOE concept remains dominant, the community has been aware of its shortcomings since the early 1990s, with several alternatives having been proposed. Whilst many of these alternatives are excellent, no one method has emerged as being a clear preference to LCOE, variously suffering from computational complexity, large data requirements or lack of transparency.

- If large-scale, synchronous, fossil-fuelled thermal plants were phased out, the availability of ancillary services that are inherently provided by those technologies becomes limited. Consequently, the value of these ancillary services would increase considerably. Of all services that each technology provides to the system, capacity (MW) and energy (MWh) services are shown to be most critical.
- An existing concept that assesses the capacity and the energy services of different technologies is the screening curve. Whilst this represents a well-established method to compare thermal generation technologies, it is not suitable for the evaluation of iRES and storage technologies.
- This limitation can be overcome by incorporating the effective capacity factors of the technologies in the curve, which would reflect the capacity and energy services provided by iRES.
- Storage technologies can also be incorporated in the approach by limiting their maximum hours of discharge to the curtailed hours of the electricity source (to represent the time the technology needs to charge), and to the maximum hours of operation (emulates time needed to charge and discharge).
- Applying those rules allows the screening curve approach to be used to evaluate the capacity and energy value of dispatchable and non-dispatchable power generation, as well as energy storage technologies.
- This is an accessible approach to evaluate the impact of arbitrary levels of all power generation technologies on the total system cost. The proposed concept can also be used to estimate the level of economic deployment of technologies considered and to determine the optimal role the technologies can play.
- Although the optimal energy share of iRES can be significant, the role of dispatchable plants remains critical in the system to meet the electricity demand.
- The modified screening curve concept proposed in this study shows that iRES have significant value by providing energy/fuel savings for the electricity system, with dispatchable technologies having critical value by supplying firm capacity for security of supply.

This study offers an alternative concept that can be used to generate a transparent, intuitive and comprehensive approach with which to compare the evolving impact of technologies within an electricity system – rather than simply providing a direct comparison between technologies.

Recommendations

Given LCOEs well-documented weaknesses for application to the 21st century electricity grid, its lack of adequacy in identifying technologies for the optimal generating mix, alternatives to the LCOE have long been a target. The use of a modified screening curve approach, while not professing to supplant more complex analysis, has shown itself to be an excellent approach to compare the relative value and evolving impact of technologies within an electricity system. Disseminating this work to a wider audience will be a priority.

Suggestions for further work

Screening curves can provide an excellent first-order approximation of the optimal generating mix, assessing how often each technology will run based on its marginal operating cost. The means to include intermittent renewable energy sources and energy storage extends their application significantly. They do not, however, account for the costs associated with part load operation, ramping, minimum turndown and start-up/shut-down cycles. Developing a method to approximate these processes within the SC formulation provides a potential avenue for future investigation.

Beyond LCOE: Value of technologies in different generation and grid scenarios

FINAL REPORT

by

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International Energy Agency Greenhouse Gas R&D Programme,

London, March 2020

Executive Summary

Since its introduction in the second half of the 20^{th} century, the concept of "levelised cost of electricity" (LCOE) has become ubiquitous in the evaluation and comparison of power generation technologies. LCOE is a readily accessible metric which evaluates the cost per kWh of electricity produced by an asset over its lifetime. Importantly, LCOE focuses exclusively on the cost of electricity produced from a given asset, or set of assets, but neglects to describe the provision, or otherwise, of so-called ancillary services which are vital for the reliable operation of an electricity grid. This simplification was entirely appropriate for the electricity system of the 20^{th} century, composed, as it was, of an effectively homogeneous set of technologies, all of whom provided essentially the same set of ancillary services. As a consequence, the explicit monetisation of ancillary services was not required.

However, the volatility in energy prices that was associated with the "oil crisis" in 1973 and "energy crisis" in 1979, associated with the Yom Kippur war and the Iranian Revolution, respectively, and the subsequent "oil glut" in the 1980s spurred interest in energy technologies that were less exposed to the price volatility of fossil fuels. This led to an increased focus on nuclear, wind, solar, hydro, and tidal power. With increased focus on non-fossil sources of energy, the shortcomings of the LCOE metric became apparent, and by the early 1990s, alternatives were being proposed. One of the earliest alternatives was the development of a system value (SV)-based approach by Bouzguenda and Rahman in 1993. This work evaluated the economic and operational impact on energy cost associated with the deployment of large amounts of solar and wind power in a given electricity system. Here, instead of focusing on the cost of an individual technology, SV measures the change in total system cost avoided upon the deployment of a technology, taking into account the individual cost of the technology, alternative technologies, and the optimal role the technology can play in the system.

However, whilst the SV approach provided a more comprehensive measure of technology competitiveness, it was not widely adopted. One potential reason was that the deployment levels of intermittent renewable energy sources (iRES) in the 1990s and early 2000s were insufficient to motivate a change from the familiar and well-understood LCOE. More recently, with increasing focus on efforts to mitigate climate change, electricity grids around the world have been characterised by rapidly increasing deployment of iRES. As a consequence, discussions regarding alternative metrics to LCOE have resumed.

In this context, it has been recognised that, whilst the SV approach is significantly more comprehensive than the LCOE approach, the computational complexity associated with the evaluation of SV is significantly greater than that of LCOE. This has led to the proposition of several simpler alternatives, including: system LCOE, Levelised Avoided Cost of Electricity, technology χ value of energy storage, and intermittent renewables LCOE with firming capacity, and value adjusted levelised cost of electricity (VALCOE). However, despite these numerous contributions, LCOE remains the preeminent metric for the evaluation of power generation technologies.

The purpose of this study, therefore, is to enumerate and explain the portfolio of ancillary services that a given electricity grid requires, to review and evaluate the various alternatives to LCOE that have been proposed, and consequently to identify the key characteristics of an alternative metric that might realistically serve as an alternative to LCOE, and finally to develop a new concept for evaluating power generation technologies that fulfill these criteria.

The results of the review of ancillary services provision by power generation technologies are presented in Figure 1. As can be observed, only a small subset of power generation technologies provide all ancillary services, with important gaps particularly associated with iRES technologies. It is recognised that, in order to serve as a viable alternative to LCOE, any new metric must preserve as far as possible the intuitive and accessible nature of the LCOE approach, avoiding the need for complex computational tools. However, in line with the original SV approach, any alternative to LCOE must be able to take the impact of the deployment of a marginal quantity of a given technology on the overall system cost and performance. Implicit in this statement is the requirement that there be an element of system design incorporated in this new approach.

Technology	Frequency				Voltage		System Restart	Reserve Capacity		
	Inertia	Primary Response	Secondary Response	Tertiary Response	System Strength	Reactive Power	Black start	Regulating Reserve	Contingency Reserve	Load Following Reserve
Nuclear	$\color{green}{\text{O}}$			$\color{red}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$		$\color{red}{\text{O}}$	$\color{red}{\text{O}}$
Bio	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$
OCGT	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{orange}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{orange}{\text{O}}$	$\color{green}{\text{O}}$	$\color{orange}{\text{O}}$
CCGT	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$
Coal-CCS	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$
CCGT-CCS	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$
BECCS	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$
Wind turbine	$\color{green}{\text{O}}$	$\color{red}{\text{O}}$	$\color{red}{\text{O}}$	$\color{red}{\text{O}}$		$\color{green}{\text{O}}$		$\color{red}{\text{O}}$	$\color{red}{\text{O}}$	$\color{red}{\text{O}}$
Solar		$\color{red}{\text{O}}$	$\color{red}{\text{O}}$	$\color{red}{\text{O}}$		$\color{green}{\text{O}}$		$\color{red}{\text{O}}$	$\color{red}{\text{O}}$	$\color{red}{\text{O}}$
Pumped Hydro Storage	$\color{green}{\text{O}}$	$\color{orange}{\text{O}}$	$\color{orange}{\text{O}}$	$\color{orange}{\text{O}}$	$\color{green}{\text{O}}$	$\color{green}{\text{O}}$	$\color{orange}{\text{O}}$	$\color{orange}{\text{O}}$	$\color{orange}{\text{O}}$	$\color{orange}{\text{O}}$
Battery		$\color{orange}{\text{O}}$	$\color{orange}{\text{O}}$	$\color{orange}{\text{O}}$		$\color{green}{\text{O}}$	$\color{orange}{\text{O}}$	$\color{orange}{\text{O}}$	$\color{orange}{\text{O}}$	$\color{orange}{\text{O}}$

$\color{green}{\text{O}}$	The technology can provide the service
$\color{orange}{\text{O}}$	The technology can provide the service but might be limited by the energy availability and economic-environmental aspects
$\color{red}{\text{O}}$	The technology can technically provide the service but providing this service may not be beneficial for the plant (*i.e.,* iRES and Nuclear tend to operate at full capacity or availability)

Figure 1: Availability of ancillary services by power technology. It can be observed that there is a non-uniform provision of these services across all technologies.

Key to the development of a readily accessible metric is robustly discriminating between those grid services which are most valuable, and retaining them, and discarding those which are less valuable.

To this end, we extended the Electricity Systems Optimisation (ESO) framework to include an explicit description of all the ancillary services enumerated in Figure 1. In this report, this new tool is hereafter referred to as ESO-ANCIL, and has been used to quantify the value of a given ancillary service to the grid.

This study revealed an interesting interplay between the various technologies, however, we concluded that, whilst all services are important, the provision of firm capacity and power generation were most valuable. This has the additional implication that, for electricity systems which are increasingly incorporating additional iRES capacity, the creation of a capacity market may well be something to consider. Consequently, we proposed a new screening curve-based approach (SC) which can account for the value of both capacity and power. In line with the aforementioned requirement for simplicity, the proposed screening curve method is compared against LCOE in Table 1.

Table 1: Comparison between LCOE approach and proposed screening curve method. As can be observed, there is some additional data required for the screening curve method relative to the LCOE. However, these data are generally readily available. Importantly, both methods are entirely analytical, and do not require complex models or numerical methods to solve.

Data Requirement	**LCOE**	**Screening Curve**
Capital cost	✓	✓
Fixed O&M	✓	✓
Variable O&M	✓	✓
Load duration curve	✗	✓
Tech availability	✓	✓
Hourly iRES availability	✗	✓
Analytical solution	✓	✓
Suitable for systems analysis	✗	✓

As can be observed, the data requirements and computational complexity for evaluating LCOE and the SC are essentially identical. The additional requirement imposed by the SC is simply that one evaluates *all* technologies within a given system, as opposed to making the simplifying comparison between "Technology A" and "Technology B". Thus, using the proposed SC method, one can rapidly and readily evaluate the role and value of given power generation technology within a given electricity system.

In order to provide confidence in the SC concept, it is compared with ESO-ANCIL, which takes into account the whole range of electricity system services required by the grid, the results of which are illustrated in Figure 2.

As can be observed, the SC approach validates well in terms of system structure. It also provides a reliable description of the number of hours per year for which a given technology will be used. In other words, it provides insight into the likely capacity factor that each technology might achieve. Given that this is one of the key input parameters to the LCOE calculation, there are clear synergies between the new SC approach and the conventional LCOE approach. The discrepancy in calculated cost that can be observed between the ESO-ANCIL and SC calculations arise from the absence of dynamics in the SC approach. As the SC calculation does not account for the costs associated with part load operation and start-up/shut-down cycles, and thus developing a method to approximate this within the SC formulation is a potential avenue for future work.

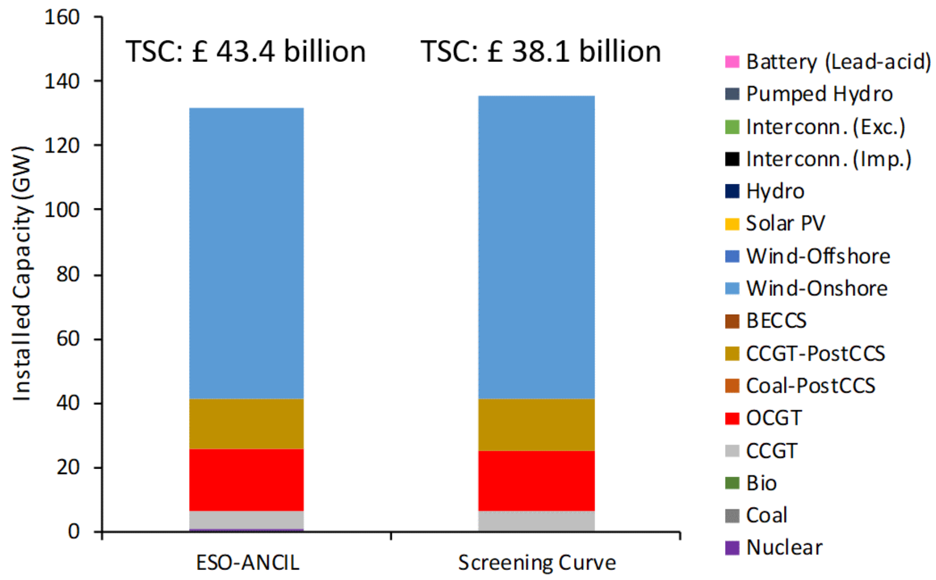

Figure 2: Power generation screening curve validation against ESO-ANCIL.

However, in light of the computational simplicity, limited data requirements, transparency of this approach, and a relatively small error in term of the system structure, we would propose this modified screening curve concept as a new alternative to LCOE.

The new SC approach allows for the rapid evaluation of the value of a given technology in a whole-systems context. It appears to be a natural extension of the conventional LCOE approach, retaining simplicity and accessibility, whilst considerably adding to the depth of systems insight that can be achieved.

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Chapter 1

Introduction

Electricity system design in the 21st century faces the challenge of providing affordable, reliable, and sustainable energy [1]. In line with this, the conference of the parties twenty-first session (the COP21) in Paris agreed to cap the global average temperature increase below 2°C above pre-industrial levels and to encourage efforts towards a 1.5°C limit [2]. As a result, the energy landscape is rapidly changing from a system dominated by large, synchronous, fossil fuelled power generation to a more diverse one, characterised by increasing penetration of intermittent renewable energy sources (iRES).

Compared to conventional thermal power generation technologies, which can provide dispatchable power whenever needed by the system, iRES strongly depends on the availability of its energy sources, *e.g.,* wind, solar irradiance, etc., which do not always match demand. Therefore, large deployment of iRES introduces new complexity in terms of balancing the power supply and demand whilst maintaining the system's service quality. As a result, ensuring grid stability/reliability via the provision of ancillary services becomes increasingly important.

In the 20th century electricity system, ancillary services were provided by all assets connected to the grid and, therefore, were not explicitly valued. In this context, levelised cost of electricity (LCOE) represented an intuitive and readily available metric to evaluate the competitiveness of power generation technologies with a sufficient level of accuracy. However, with the transition to a low/zero carbon paradigm and the growing penetration of heterogeneous generation resources in the energy system, LCOE can no longer describe the performance of individual power generation technologies in an adequate manner. As such, a new metric able to comprehensively value all services provided by power generation assets is required, and not only valuing energy service as the LCOE does.

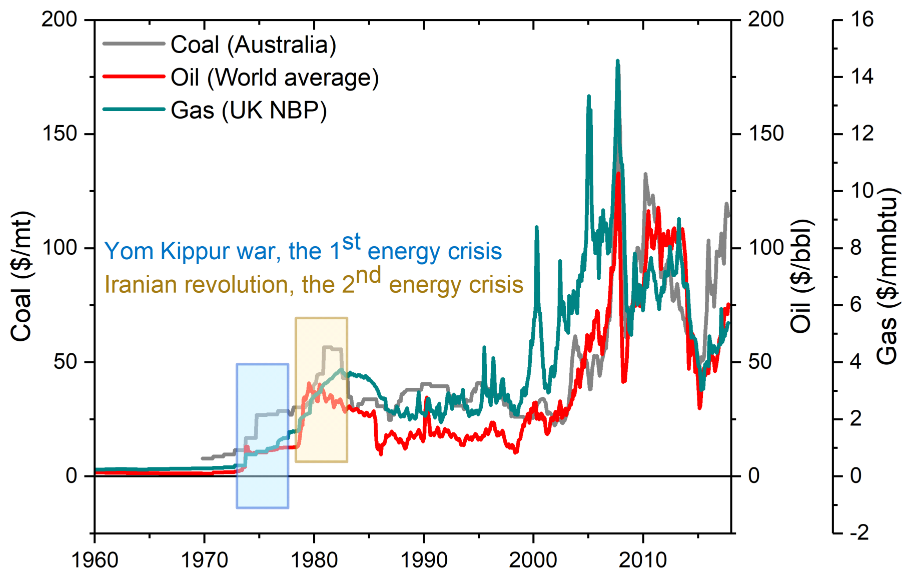
The purpose of this study is, therefore, i) to provide insight into the role of power generation technologies in the electricity system, ii) to compare LCOE to existing metrics that estimate the value of power generation technologies, and iii) to propose a new comprehensive metric that captures the key services and the value of energy technology within the energy system.

1.1 The origin of levelised cost of electricity (LCOE)

Until the early-1970s, the power system was highly homogeneous and dominated by fossil-based and hydro–power generation technologies [3]. In that period, the net present value (NPV) analysis was the primary method used for the economic evaluation of those plants on the basis of 'typical year' assumptions. Implicit in this approach was the premise that fossil fuel prices were non-volatile [4]. However, in 1973, the OPEC oil embargo to the United States (US) during the Yom Kippur war, led to skyrocketing oil prices (Figure 1.1) followed by the increase of coal and natural gas prices; thus, raising concerns of fuel price escalation.

In the same era, scientists and engineers had already been discussing the potential for alternative energy technologies, namely new reactor technologies for nuclear [5, 6], wind turbines [7], solar thermal [8], and photovoltaics [9]. The combination of an energy crisis and the PURPA Act promoted the development of technologies insulated from the effects of volatile fuel prices, *i.e.*, renewable energy technologies and nuclear power.

Comparing the economics of fossil thermal plants and nuclear plants was eased by the fact that their scales and operational natures are quite similar. The problem arose when comparing those dispatchable thermal technologies with significantly smaller scale intermittent renewable energy technologies, such as wind and solar power. To tackle this issue, scientists and engineers at that time adopted an NPV analysis approach to calculate the total life-cycle cost of electricity (TLC) [10], which explicitly accounts for the escalation of fuel prices.



***Note**:*
All prices are in nominal US$. The data is adapted from World Bank, 2018; BP, 2018

Figure 1.1: Fuel price historical data. As can be seen here, the increasing volatility of fuel prices was a key factor in initiating the search for an alternative to LCOE.

Total life-cycle cost (TLC) includes the cost of owning, operating, and maintaining an asset through the course of the asset's life span or the investors' period of interest. This quantity can be calculated using the following formula:

$$TLC = \sum_{t=1}^{T} \frac{C_t}{(1+r)^t} = \sum_{t=1}^{T} \frac{I_t + M_t + F_t}{(1+r)^t} \tag{1.1}$$

Where:

C	:	total annual cost
I	:	annualised capital cost in year t
M	:	maintenance cost in year t
F	:	fuel and variable costs in year t
r	:	discount rate
t	:	time period in the analysis

The TLC is then normalised on the basis of lifetime electricity production to eliminate the effect of scale. This final number is what we now refer to as LCOE [10–12].

$$TLC = \sum_{t=1}^{T} \frac{E_t \times LCOE}{(1+r)^t} \tag{1.2}$$

or

$$LCOE = \frac{\sum_{t=1}^{T} \frac{I_t+M_t+F_t}{(1+r)^t}}{\sum_{t=1}^{T} \frac{E_t}{(1+r)^t}} \tag{1.3}$$

with E_t is energy output in year t.

By the time of the second energy crisis following the 1979 Iranian revolution, the least cost approach became the dominant approach for capacity expansion planning of electricity systems.

Owing to the homogeneity of the grid in the past and concerns mainly around increases to fossil fuel prices, it was unnecessary to emphasise the other services a technology can offer other than the energy/electricity generation service. In this context, LCOE was a perfectly adequate metric.

In the 21st century, however, the costs of ensuring grid stability and meeting environmental targets are becoming more important. Thus, the LCOE is no longer an adequate metric, considering also the heterogeneity of services provided by the new portfolio of technologies.

With the rise in dissatisfaction with LCOE, there have been a number of attempts to provide alternatives, including technology system value [13–15], system LCOE [16], the levelised avoided cost of electricity (LACE) [17], technology χ value [18], intermittent renewables LCOE with firming capacity [19], and value adjusted LCOE [20]. With the exception of LACE, these alternatives describe the snapshot value of the technology in a particular year. However, looking at the history of the LCOE, its success was actually driven by its ability to capture the present and future 'value' of the electricity generation, as a function of fuel prices. Specifically, the key features contributing to the success of LCOE include:

1. A simple description of the role of a technology, *i.e.*, baseload, load following, and peaking capacities;

2. The ability to capture lifetime cost of technology, not just a single year snapshot;
3. The possibility to provide insights into the lifetime competitiveness of a technology;
4. The possibility to account for the evolving value of the input parameters during the technology lifetime, *e.g.* the increasing fuel or carbon prices;
5. The use of the same units as the price of electricity, *e.g.*, $/kWh, promoting acceptability to a wide range of stakeholders, from policy makers to end users.

However, the same aspects which constituted strengths in the 20th century, manifest as drawbacks in the 21st century:

1. LCOE explicitly values energy cost homogeneously without considering the temporal value of the energy service.
2. The metric cannot account for, or value, other system services, *i.e.*, ancillary, flexibility, and dispatchable services.
3. In the 21st century, the role of technology is unique for each system, and is likely to evolve over time. The a priori assumption of fixed roles can lead to misleading conclusions.
4. LCOE measures the cost of generating electricity without discounting the amount of electricity curtailed, particularly for intermittent renewable energy sources (iRES).

Learning from the success of LCOE, we can aim to develop a metric which:

1. Is capable of capturing the project lifetime cost, or value, as opposed to a single year snapshot;
2. Accounts for grid stabilisation;
3. Captures the various roles or services different technologies can offer for system optimisation;
4. Considers only key services, thus maintains the intuitiveness of LCOE.

1.2 Project Objective

The objective of this study is to develop a new concept and metric(s) that balance information comprehensiveness and ease of use, as an alternative to LCOE. In order to achieve this objective, we structure the work as follows:

1. Understand the evolution of grid service requirements,
2. Evaluate LCOE and existing alternatives,
3. Develop alternative concepts to LCOE,
4. Develop a new analytical metric.

This concept should be able to evaluate the competitiveness of a technology by taking into account all services it can provide to the grid and its interaction with other technologies in the grid. Traditionally, such concepts, *e.g.,* system value (SV), can only be evaluated using a sophisticated model, which reduces its accessibility. To avoid this outcome, any new metric must necessarily have an analytical solution. We therefore begin the study by identifying key energy system services.

Though all services to the grid are important, careful analysis is essential to quantify the significance of the service in the system, thus to reduce the number of the aforementioned "system value" concepts. The parameters emerging from the qualitative literature review are subsequently quantified using the Electricity System Optimisation with detailed Ancillary Services (ESO-ANCILS) framework. This framework builds upon the original ESO framework [21–23], which couples detailed engineering and electricity market models to provide a bottom-up analysis of the cost and the value of making power generation technology available to the electricity system. Within this approach, the value of a technology can be articulated as the combined value of the individual services provided to the system, such that, the technology value is the sum of its services' value to the grid. The framework is developed in a mixed-integer linear optimisation model which is formulated and modelled in GAMS 25.0.3 [24] and solved with the optimiser CPLEX 12.3. Pre-processing steps, such as data clustering and profiling is executed in the R environment [25]. A schematic of how the different software and modelling platforms integrate is provided in section 1.3.2.

The outputs from ESO-ANCILS are used to identify and select the most valuable services to be included in the proposed alternative concept and metric. This approach can significantly reduce the metric complexity while minimising the error, which is an inherent consequence of the simplification made. It is recognised that simplified metrics will not have the same level of accuracy as those calculated from detailed and advanced models. Therefore, this proposed method is intended to inform the general audience and address issues around LCOE no longer being an adequate measure of power generation technology competitiveness. No technology can be a silver bullet to deliver all services cost effectively. Furthermore, a generic solution cannot be derived from any single metric as different systems have distinctive characteristics and needs. Therefore, an alternative concept and metric are proposed in this study.

1.3 Approach and Methodology

This project uses the Electricity Systems Optimisation (ESO) framework [21–23] to quantify the value of a technology and provision of its services. By coupling detailed engineering and electricity market models, the framework provides a bottom-up assessment of the impacts (*e.g.* system cost and operability) of individual technology deployment into the energy system. The core of the technology valuation algorithm is a mixed-integer linear optimisation model, which is formulated and modelled in GAMS 25.0.3 [24] and solved with the optimiser CPLEX 12.3. Pre-processing steps, such as data clustering and profiling are executed in the R environment [25]. A high-level description of the model is presented in section 1.3.1, and a schematic of how the different software and modelling platforms integrate is provided in section 1.3.2.

1.3.1 Overview of the ESO framework

The formulation of ESO is presented in detail in Appendix A, while key assumptions, constraints and input data are presented below.

Objective function

The objective function used throughout this study is the aggregated total system cost (TSC) over the period. This parameter is defined in equation 3c.1, and is a combination of capital, fixed, and variable operating costs.

Input data

Key input data for the analysis include the costs, efficiencies, and performance values of each power generation technology in the portfolio.

In specifying technology costs and economic assumptions, an essential requirement is to adopt a consistent costing approach, which ensures that the different technologies compete against each other on an equitable basis.

Thus, for individual technology costs, efficiencies, and performance data, we adopt the 2016 report from the Department for Business, Energy and Industrial Strategy (BEIS) in the UK [26], which provides a consistent and transparent costing methodology to support the input data adopted in the analysis (Table 1.1).

Table 1.1: Economic parameters for individual generation technologies used in this study.

Tech	**CAPEX**	**Fixed O&M**	**Variable OPEX**	**Start-up cost**	**OPEX No Load**
	£/kW	£/kW	£/MWh	£/unit.start	£/h
Nuclear	4,363	85.1	3	4,000,000	3,510
Coal	1,440	40	2	198,500	3,360
Biomass	3,040	60	2.5	198,500	3,153
CCGT	525	15	2	79,500	2,225
OCGT	344	15	5	3,770	89
Coal-PostCCS	3,600	95	2.8	250,145	4,229
CCGT-PostCCS	1,838	40	2.8	79,500	2,357
BECCS	4,300	90	10	250,145	4,229
Wind-Onshore	1,480	30	5	0	0
Wind-Offshore	2,916	45	3	0	0
Photovoltaic	800	10	0	0	0
Lead Acid Battery	1,800	15	3	0	0

CCGT = combined cycle gas turbine, OCGT = open cycle gas turbine
PostCCS = post-combustion CCS, BECCS = bioenergy with CCS

Table 1.2: Technical parameters of technology, where P_{min} and P_{max} are the minimum and maximum power output, respectively.

Tech	**P_{min}**	**P_{max}**	**Cap. Credit**	**Inertia**	**Efficiency**	**Capacity**	**Life-time**
	% cap.	% cap.	% cap.	s	%	MW	yrs
Nuclear	75	80	80	7	37	600	50
Coal	30	88	88	6	42	500	40
Biomass	30	88	88	6	42	500	40
CCGT	50	87	87	6	57	750	40
OCGT	10	94	94	6	40	100	40
Coal-PostCCS	30	80	80	6	34	500	40
CCGT-PostCCS	30	80	80	6	50	750	40
BECCS	30	85	85	6	32	500	40
Wind-Onshore	0	100	40	2	100	20	30
Wind-Offshore	0	100	53	2	100	50	30
Photovoltaic	0	100	12	0	100	10	30
Hydro	10	100	50	3	81	300	60
Pumped Hydro	10	100	50	3	0	300	60
Lead Acid Battery	0	100	50	0	89	100	10

Modelling assumptions and constraints

The following modelling assumptions and constraints have been adopted in the analysis:

1. **Security constraints:** We account for system reserve and inertia requirements to ensure reliable operation. Reserve requirements are included as a fraction of peak demand in addition to a proportion of the intermittent capacity online at every time period, t, to dynamically secure the largest firm and intermittent unit against failure.
2. **Environmental unit commitment (UC):** The formulation includes the CO_2 emission rates of the power generating technologies as well as an overall systems emission target.
3. **Detailed operation UC:** We introduce a coherent mode-wise operation of all technologies. Power output, emissions, costs, *etc.* varies between

these modes.

4. **Simultaneous design of the electricity system and unit-wise scheduling:** We formulate the model such that the optimal number of installed units per power generating technology is determined in each time-step together with their respective operational time plan. The available number of power generating units is an integer decision variable to the optimiser.
5. **Coherent and comprehensive technology representation:** All types of power generating technologies, thermal and intermittent renewable technologies, are represented in a consistent fashion. The modularity of the formulation enables extension of the number and type of available technologies.

1.3.2 Model structure and interfaces

This work relies on three software tools: Excel as the data carrier, R for data preprocessing, and GAMS for the actual modelling and solving of the optimisation program. Figure 1.2 visualises how the choice of scenario influences the solution procedure and where information is transferred. The upper right hand side of the scheme lists the parameters that have to be defined for each scenario. Additional parameters, provided in table A.1, can be perturbed in any model run.

The hourly electricity demand profile is selected according to the scenario year. The hourly data set for one year of the UK's electricity demand and availability of onshore wind, offshore wind, and solar power (4 dimensions) is transferred to the R clustering script. Here, the (8760, 4) sized data set, *i.e.*, year of 8760 hours by 4 dimensions, is clustered, profiled, and consequently reduced in size to a $((k+1)\cdot 24$, 4) data set. As a result of the clustering, which is described in detail in Appendix B, we obtain information about the weight of the individual clusters as a part of the entire data set.

The time-dependent and time-independent data is then fed into the GAMS optimisation framework. The mixed-integer linear program (MILP) is rigorously solved to determine the optimal electricity system design, operation, *etc.*, subject to the constraints outlined in Appendix A. The data output from GAMS is then transferred back to the Excel interface for post-processing and archiving.

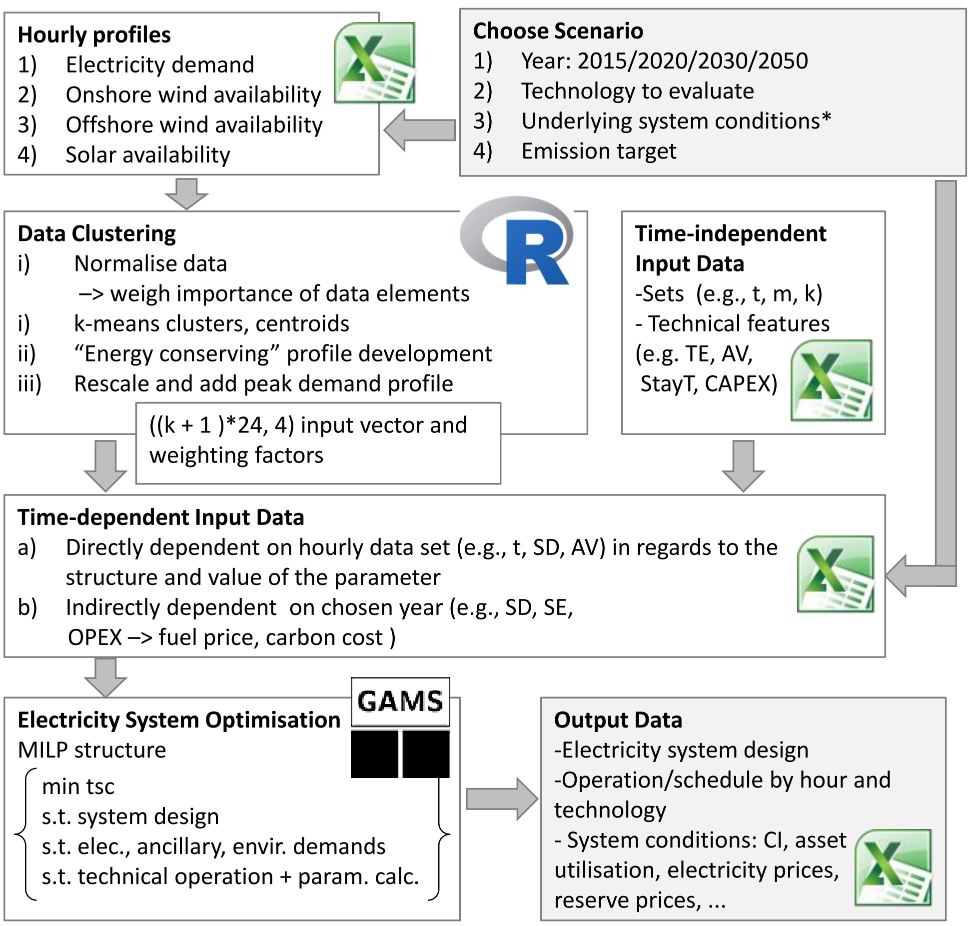


Figure 1.2: Model integration and solution process for the ESO framework. The final data output is followed by post-processing steps to retrieve the relevant information for analysis and visualisation.

Chapter 2

The evolution of the electricity grid

The power system is facing fundamental changes in both supply and demand technologies. On the supply side, there is a shift from large-scale, centralised, synchronous generators to light-weight generators and variable resources. On the demand side, there is a growing number of distributed and variable generation resources, requiring back up from the transmission system when additional supply is needed [27].

In this new grid paradigm, entities that used to be exclusively consumers now require the grid to be able to purchase, or otherwise accommodate, the excess power which they produce. The result is a system that requires much more flexibility, with the ability to dynamically optimise grid operations in short time frames. This paradigm blurs the boundary between 'producer' and 'consumer', with the consumer evolving to become a 'prosumer' [27–30].

As the producer-consumer boundary becomes less clear, managing supply and demand becomes more challenging, and grid reliability is threatened. To minimise this threat, and avoid system-wide failure, the grid had grown from multiple, small distributed markets to larger, integrated system (*e.g.*, national or regional scale), thus circumscribing the sub-system failure in each market and preventing its spread to the entire system [27].

On the other hand, as the consumer becomes a prosumer, the load profile observed by the large-scale producer is influenced by consumer demand as well as their own electricity production. As a result, the traditional load profile evolves to the so-called "duck curve" profile [27] (see Figure 2.1), leading to an increased requirement of ancillary services to ensure system reliability and stability of supply.

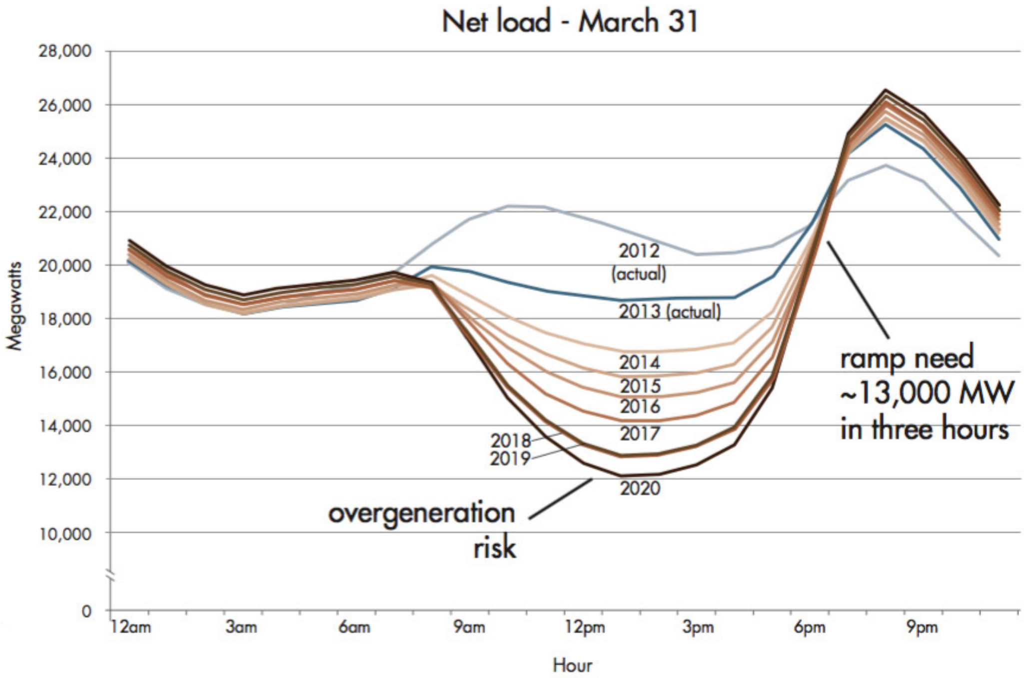


Figure 2.1: Illustration of the "duck curve" seen by power generators as the net result of power demand and self-generation by consumers in California (source: NREL [31]). As consumers generate electricity, mainly through solar PV, for their own consumption and for the grid, the load profile experienced by the system operator evolves, requiring the power producer to significantly lower their generation during the day and increase ramp up capability to meet the demand during the peak period.

2.1 Ancillary services for the grid

In addition to the primary electricity service required by consumers (*i.e.*, active power), ancillary services are key to ensuring the reliability and quality of the services delivered to consumers. Generally, ancillary services can be classified into 4 categories [32–40] as follows:

- Maintaining system frequency,
- Maintaining system voltage,

- Restarting the system, and
- Reserve capacity.

In this following text, ancillary services and mechanisms to maintain the system's reliability and service quality requirements are discussed.

2.1.1 Maintaining system frequency

System frequency is a quality aspect that needs to be maintained by the grid. In a power system, frequency disturbance is primarily caused by an imbalance between power supply and demand. This phenomena is explained by the Swing equation [41] as shown below:

$$\omega_m \mathcal{J} \frac{d\omega_m}{dt} = P_m - P_e \tag{2.1}$$

Where:

ω_m	: mechanical angular velocity
$\mathcal{J}$	: inertia
t	: time
P_m	: mechanical power acting on the rotor
P_e	: electrical power acting on the rotor

Because $\omega_m = \frac{\omega_e}{p}$, then:

$$\frac{2}{p}\omega_m \mathcal{J} \frac{d\omega_e}{dt} = P_m - P_e \leftrightarrow 2\frac{2}{p\omega_m}\left(\frac{1}{2}{\omega_m}^2 \mathcal{J}\right)\frac{d\omega_e}{dt} = P_m - P_e \tag{2.2}$$

$$\frac{2}{\omega_e}\left(\frac{1}{2}{\omega_m}^2 \mathcal{J}\right)\frac{d\omega_e}{dt} = P_m - P_e \tag{2.3}$$

Where:

ω_e	: electrical angular velocity
p	: number of poles

The mechanical and electrical power acting on the rotor is equal to electricity supply and demand. As such, when supply is equal to demand, rotor angular speed does not change. During disturbances, the angular velocity of the rotor will change but not deviate significantly from the nominal values. Hence, equations below can be derived:

$$H = \frac{1}{2}{\omega_m}^2 \mathcal{J} \tag{2.4}$$

$$\frac{2H}{\omega_e}\frac{d\omega_e}{dt} = S - D \tag{2.5}$$

$$\omega = 2\pi f \tag{2.6}$$

$$\frac{df}{dt} = (S - D)\frac{f_0}{2H} \tag{2.7}$$

Where:

ω_0	: initial angular velocity
S	: power supply
D	: power demand
f	: frequency
H	: inertial energy stored
$\frac{df}{dt}$	: rate of change of frequency ($RoCoF$)

Ancillary services required to maintain the system frequency can be classified into system inertia, primary, secondary, and tertiary responses.

System inertia

When power supply, S, is not equal to demand, D, the rotational speed of synchronous machines changes, either decelerating if $S < D$ or accelerating when $S > D$, thus altering the system frequency [32,38]. The level of the acceleration or deceleration of the synchronous machines' rotational speed is determined by the system inertia. As described by equation 2.7, the rate of change of frequency ($RoCoF$) is inversely proportional to system inertia. Consequently, the greater the inertia of a system, the slower its frequency will deviate when the power supply and demand are imbalanced. This immediate response from system inertia is critical for the system reliability as it allows some time for primary response assets to offset the imbalance.

System inertia is provided by power generation or energy storage assets equipped with rotating mass, *e.g.*, turbine. This service is inherently provided by thermal plants and hydro-power or pumped-hydro. However, in slowing down $RoCoF$, iRES may provide an additional service aimed to mimic the effect provided by inertial response, referred to as synthetic inertia. In contrast with inertia, which releases the turbine's momentum to make up S to restore generation and load balance in the system, synthetic inertia provides controlled active power and releases the contribution from a unit that is proportional to the $RoCoF$ [42, 43].

System control for synthetic inertia requires delay time to measure the system's deviation and to distinguish the deviation from the temporary local disturbances. As such, despite its capability of slowing down the $RoCoF$, synthetic inertia cannot be treated in the same way as system inertia in terms of immediate response capability following an imbalance [43]. Although synthetic inertia may contribute in slowing down the $RoCoF$, it can not provide an alternative to inertia from synchronous devices to prevent grid collapse.

Primary response

When the system's power supply and demand is imbalanced, the system inertia can only lower the $RoCoF$. The system's frequency, however, will keep decreasing or increasing until the balance between supply and demand has been brought back so that $RoCoF = 0\ Hz/s$ (see equation 2.7). As the system can only tolerate a small frequency excursion, the balance needs to be promptly restored *via* primary response. Typically, an imbalance must be restored by the primary response a few seconds after the fault and sustained for a further 30 s [44] (20 s in the case of the UK [45]) before the secondary response takes place. If the system frequency deviates beyond the tolerable range, it can trigger power station trips, which can eventually lead to blackouts. The response from primary assets should be maintained for approximately 15 minutes to allow secondary response assets to come online and replace this capacity. When the balance is restored by the primary response, the system frequency will be temporarily contained at the present level (*i.e.*, not at its nominal set point). Due to the grid capacity limit, response from primary reserve should be provided evenly throughout the grid nodes to avoid overloading the grid.

Owing to rapid response requirements, primary response is traditionally provided by open cycle gas turbines (OCGT), as they can be turned on and synchronised quickly, or by assets already operating and synchronised with head-room capacity. Assets providing this service usually need to have a low capital expenditure to lower the cost of providing response capacity.

Similar to the conventional thermal plants, iRES can also provide primary response, particularly when the grid frequency increases. Here, iRES power output can be promptly reduced to balance generation and load. By operating below its availability factor, iRES is also capable of responding to frequency drop, *i.e.*, when generation is less than the load, however, this inflicts a significant financial loss to the plant [46].

Aside from power generation technologies, electricity storage can also provide this service. Similar to iRES, however, the disadvantages of using electricity storage for primary response are i) the full reliance on the availability of stored electricity and ii) the economic sensitivity to the utilisation rate.

Secondary response

Using primary response assets to balance the system necessarily depletes the system of these assets, which increases the vulnerability of the system to further imbalances. Inadequate supply of these services therefore decreases resilience to cascading imbalance. To maintain system reliability, primary response capacity has to be restored with larger, but slower, sources of secondary response [44] (see Figure 2.2). Balancing the supply and demand using secondary response is also a way to restore the frequency contained by primary response to its nominal set point [44, 47]. Similar to the primary response, the secondary response needs to be followed by a permanent replacement within minutes, up to a few hours, [44, 45, 47] to restore the system resiliency.

Both primary and secondary responses are aimed to provide emergency response to system generation and load imbalance. While primary response acts exclusively for a very short period, albeit a critical one, secondary response assets are required to operate for a longer period, as their service needs to be provided in a more reliable manner. As such, exclusively relying on technologies with intermittent availability may put the supply security of the system at risk, while imposing significant economic damage to plants.

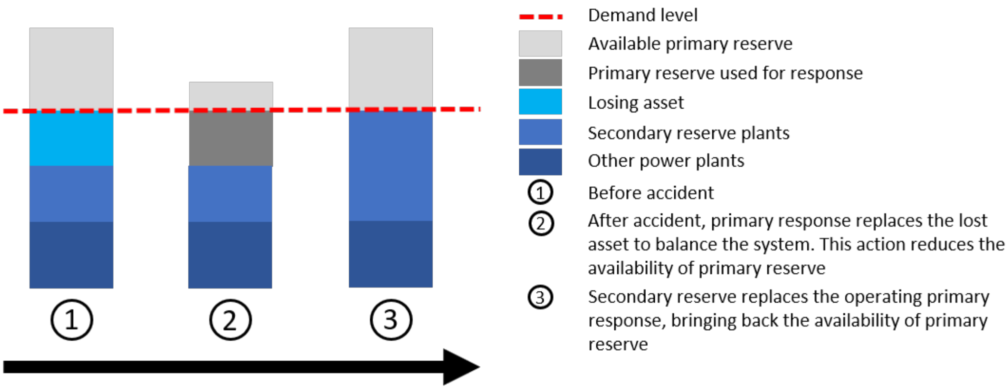


Figure 2.2: Primary and secondary response mechanisms for containing the system's frequency.

Tertiary response/replacement reserve

The aim of the tertiary response is to maintain the supply-demand balance for a longer period. Whilst the purpose of the primary and secondary response capacity is to temporarily balance the system and to bring the frequency back to normal, tertiary response capacity is intended to 'permanently' replace the power loses that cause the imbalance [44, 45, 47].

The role of system inertia, primary, secondary, and tertiary responses in maintaining the system's frequency is illustrated in Figure 2.3.

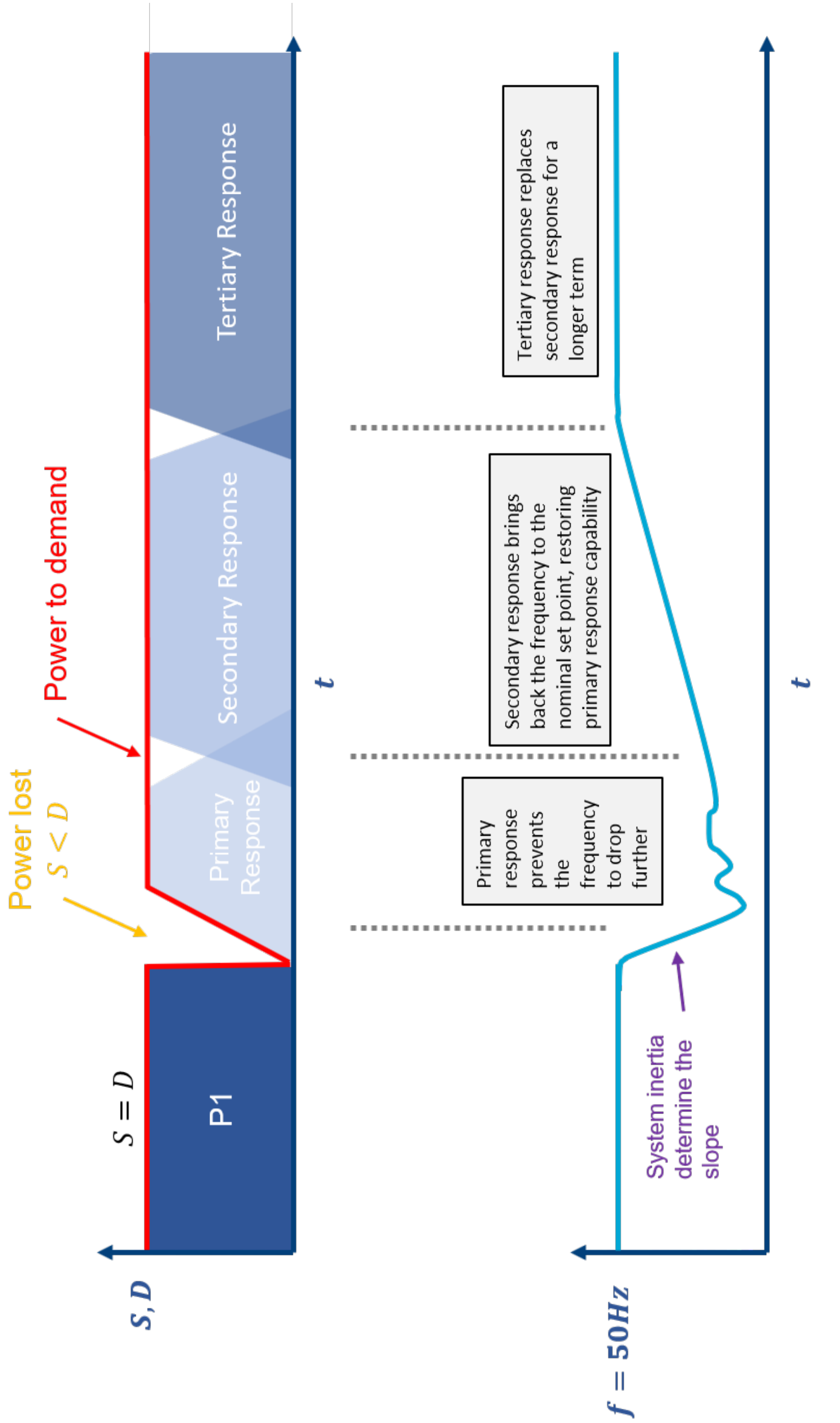


Figure 2.3: Illustration of frequency response mechanism.

2.1.2 Maintaining system voltage

Voltage stability generally refers to the capability of the system to maintain steady voltages during normal operating conditions after being subjected to a disturbance [48]. To maintain system's voltage stable, ancillary services required by the grid can be classified into system strength and voltage control.

System strength

While system inertia contributes to the capability of the system to maintain stable frequency during the supply-demand fluctuation, system strength relates to the ability of the system to maintain stable voltage levels. System strength is expressed as short circuit level (SCL) and measured in kA [43]. Similar to the system inertia, a minimum level of SCL needs to be maintained in order to maintain the quality of electricity supply which, in turn, relates to securing the system capability to supply the electricity demand. Currently, the main contributors of SCL are large scale synchronous generators [43]. Accordingly, if more non-synchronous generations connected to the grid and the synchronous ones operate less often, the level of system's SCL declines and the system becomes weaker and vulnerable to any imbalance [49]. System strength is a local characteristic [43]. Unlike other services, $e.g.$, inertia, frequency control, and voltage control, the distance SCL can propagate is very limited. Therefore, with the declining capacity of synchronous generation, maintaining system strength becomes more challenging.

Voltage control

To maintain system voltage, power generation has to be able to supply, or absorb, reactive power to or from the grid. Transporting reactive power through long transmission lines is highly inefficient, and therefore requires increased generation of reactive power. In addition to that, transporting reactive power through transmission networks reduce the efficiency of the network. The system capacity 'reads' apparent power, composed of active and reactive power as shown in Figure 2.4; this means that the amount of active power that can be produced by the generator and transported by transmission line is smaller. To effectively maintain an adequate amount of reactive power in the grid, whilst maximising the use of grid capacity to transmit active power, the generation and consumption of reactive power must be done locally [48].

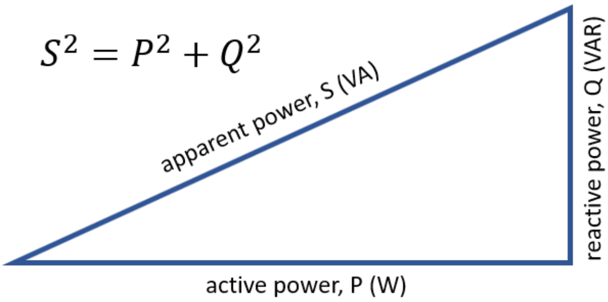


Figure 2.4: Illustration of apparent power, active power, and reactive power to maintain system voltage.

In order to maintain the desired level of reactive power, assets are required to not only generate reactive power (lagging) for the grid, but also absorb it (leading) when the level is too high. These capabilities are particularly important when the demand for power is low and the network assets generate reactive power [48, 50, 51]. In many systems, mandatory reactive power capability is 0.85 p.f. leading to 0.85 p.f. lagging [52, 53], where p.f. is the "Power Factor" and is defined by the quotient of active and apparent power. As illustrated in Figure 2.5, the maximum and minimum outputs of power generation are recognised as the boundaries – characterised by zone B in Figure 2.5. Assets providing the service beyond this requirement (zone A in Figure 2.5) may receive an additional remuneration [54]. However, operating at zone A also means that their ability to provide active power (P) is lowered (see Figure 2.4).

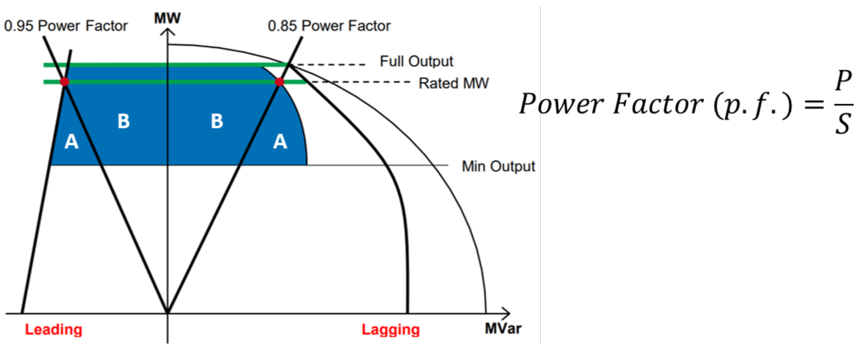


Figure 2.5: Illustration of reactive power capability chart from National Grid [52]

2.1.3 Restarting the system

Restarting the system from a total or partial shutdown, followed by a substantial supply deficit can be done through 'Black Start'. Assets providing this service must be able to restart the system within 2 hours, without using external support and may need to maintain their availability for several days up to one week. During the restarting process, the need for reliable power is higher than times of normal conditions. Any sources with uncertain performance or capability are thus to be avoided [37, 38, 40].

2.1.4 Reserve capacity

Whilst in other sectors, energy supply and demand can be balanced over a certain period of time, the supply in the power sector needs to meet the demand at the exact moment the demand signal is received. To avoid system failure and to secure the security of supply for the fluctuating power demand, capacity is reserved and dedicated to anticipate any sudden demand increases in the system. Depending on the temporal scale of demand fluctuations, and the nature of these fluctuations (*e.g.,* for anticipated fluctuations, or for an emergency response), reserve capacity can be categorised into regulating reserve, load following reserve and contingency reserve.

Regulating reserve

The electricity system is a highly dynamic environment, with demand changing not only on an hourly basis, but also on a minute-by-minute basis. This demand is typically met by using "spinning assets" [33,36–38,40], as illustrated in Figure 2.6. This capacity is referred to as regulating reserve.

Load following reserve

During normal operation, demand fluctuations on a minute-to-minute scale tend to be small and can be handled using already spinning assets within their operational limit. Conversely, demand variation on an hour-to-hour basis can be significant, and the system needs to follow the load pattern throughout the day.

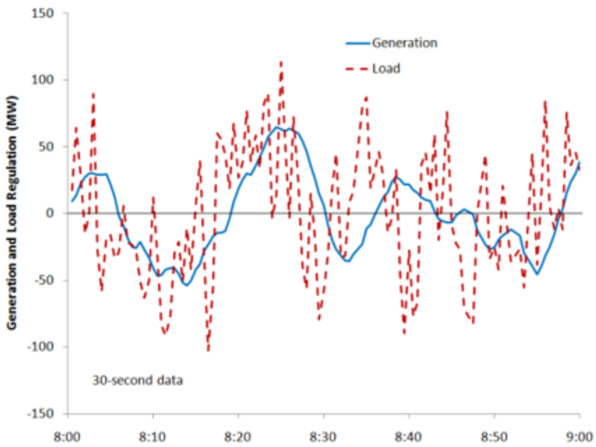


Figure 2.6: Illustration of regulating reserve as a balancing mechanism for short-term demand fluctuation from NREL [33].

Consequently, some additional assets should be reserved to satisfy the anticipated load pattern throughout the day and year [33, 36–38, 40].

Contingency reserve

Regulating and load following reserves are dedicated to the *anticipated* demand fluctuations. In contrast, contingency reserve refers to the capacity used to respond to an atypical event arising from a large supply-demand imbalance, usually due to a loss of a large generator. Services for frequency control are subsets of this reserve. Due to the fortuitous nature of these events, and because it is not economical to have assets operating exclusively in "standby" mode, contingency capacity is typically provided by existing operating assets (*e.g.*, primary and secondary responses can be satisfied by regulating reserve, and load following reserve can be used to provide tertiary response) [33, 36–38, 40] or assets for peak load.

2.2 Power generation service provision

As can be intuited from the foregoing text, the electricity system requires a broad suite of ancillary services, which cannot be provided by all technologies. Figure 2.7 presents a breakdown of which ancillary services are provided by different power generating technologies [40].

Importantly, dispatchable thermal power plants, such as CCGT, can provide all ancillary services, with limitations imposed by economics, not physics. For example, Nuclear can also provide all types of capacity reserve for the system. However, as nuclear technology typically has a large capital cost and very low operating cost, it is usually considered more appropriate to operate the technology in a baseload manner. Hence, there is usually not much head-room left for the technology to provide reserve capacity for the system.

	Frequency				Voltage		System Restart	Reserve Capacity		
Technology	Inertia	Primary Response	Secondary Response	Tertiary Response	System Strength	Reactive Power	Black start	Regulating Reserve	Contingency Reserve	Load Following Reserve
Nuclear	O (green)			O (red)	O (green)	O (green)	O (green)		O (red)	O (red)
Bio	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)
OCGT	O (green)	O (green)	O (green)	O (orange)	O (green)	O (green)	O (green)	O (orange)	O (green)	O (orange)
CCGT	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)
Coal-CCS	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)
CCGT-CCS	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)
BECCS	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)	O (green)
Wind turbine	O (green)	O (red)	O (red)	O (red)		O (green)		O (red)	O (red)	O (red)
Solar		O (red)	O (red)	O (red)		O (green)		O (red)	O (red)	O (red)
Pumped Hydro Storage	O (green)	O (orange)	O (orange)	O (orange)	O (green)	O (green)	O (orange)	O (orange)	O (orange)	O (orange)
Battery		O (orange)	O (orange)	O (orange)		O (green)	O (orange)	O (orange)	O (orange)	O (orange)

O (green)	The technology can provide the service
O (orange)	The technology can provide the service but might be limited by the energy availability and economic-environmental aspects
O (red)	The technology can technically provide the service but providing this service may not be beneficial for the plant (*i.e.,* iRES and Nuclear tend to operate at full capacity or availability)

Figure 2.7: Ancillary services provision by each power technology.

It can also be observed from Figure 2.7 that technologies with rotating equipment, such as a turbine (*i.e.*, excluding solar power or battery storage), can provide inertia for maintaining system frequency. To maintain reactive power, however, the literature [40] indicates that all technology can provide this reactive power for the system.

In the event of a blackout, the system is required to implement a "black start" procedure. This procedure requires assets that can provide electricity to the system with *high reliability* and, therefore, assets with intermittent availability are not suitable. It is also required that black start assets have the ability to turn on within 2 hours upon activation. Although old solid fuel-based technologies tend to have a long start up time, new technologies are capable of quick start ups, allowing them to participate in providing the black start service [55, 56].

Chapter 3

Metrics for valuing power generation technologies

The following section present an overview of the existing alternatives to LCOE [13–20], and discusses their strengths and weaknesses in this context.

1. Technology system value (TSV)
2. System LCOE (sLCOE)
3. Levelised avoided cost of electricity (LACE)
4. Technology χ value
5. Intermittent renewables LCOE with firming capacity
6. Value adjusted LCOE (VALCOE)

3.1 Technology system value (TSV)

As early as 1993, the shortcomings of LCOE started to emerge, leading to the introduction of the "technology system value" concept [13]. The metric uses electricity systems modelling, in contrast to technology-specific calculations, to comprehensively describe the impact of deploying a given technology on system performance. Here, the value of a technology is defined as the reduction of total system cost (TSC) following the deployment of a given technology [13–15] as a function of electricity generated. Such an approach is among the earliest contributions that describe the relationship between the value of a technology and its deployment rate; the optimal technology penetration can be described as the penetration level beyond which the marginal value becomes zero.

$$SV_p = \frac{TSC_{p=0} - TSC_p}{P} \tag{3.1}$$

or

$$SV_e = \frac{TSC_{e=0} - TSC_e}{E} \tag{3.2}$$

Where:

$SV_{p/e}$	: technology system value at the level of installed capacity (p) or generation (e)
TSC	: total system cost
P	: technology capacity added/deployed
E	: electricity generated by technology

Although the concept uses a relatively simple calculation and leads to a intuitive metric, the whole calculation process requires complex system modelling and hence, the metric becomes less accessible. Moreover, this metric, as it was originally defined, does not explicitly capture the value of a technology for its entire lifetime. This might represent a shortcoming when dealing with evolving energy systems, where structure and composition are projected to significantly change over the coming decades.

3.2 System LCOE (sLCOE)

A defining characteristic of intermittent renewable energy sources (iRES) is its ability to provide power at near-zero marginal cost. This means that, in the context of a economic dispatch market, iRES are typically dispatched ahead of other technologies, leaving the remaining electricity demand as residual load (see Figure 3.1). Consequently, high levels of iRES penetration can significantly reduce the utilisation of other assets whilst increasing the need for system balancing services. In this context, sLCOE aims to adjust the LCOE value of iRES via the system integration cost [16]. The system LCOE ($sLCOE$) of a technology is calculated using equation 3.3 below.

$$sLCOE = LCOE + \Delta \tag{3.3}$$

Where Δ is the relationship between the cost of integration, C_{int}, and the amount of electricity generated by intermittent renewables, E_{iRES}, (equation 3.4).

$$\Delta = \frac{d}{dE_{iRES}} C_{int} \tag{3.4}$$

This metric defines the cost of iRES integration as the additional cost incurred by dispatchable plants owing to iRES deployment within the system, including profile and balancing costs. Here, profile cost is defined as the additional cost per MWh generation due to the under-utilization of thermal plants as a result of the increasing share of iRES. Balancing cost represent the additional costs arising from increased start-up/shut-down cycles, as these costs are difficult to calculate, they have been empirically derived from literature. This concept is defined by equation 3.5 and is illustrated in Figure 3.1.

$$C_{int,profile} = \frac{E_{res}}{E_{tot}} C_{tot,0} \tag{3.5}$$

sLCOE offers a transparent and easy-to-use metric, and provides a better representation of the value of a given technology compared to the LCOE. This metric also retains features of the LCOE, as it adopts a unique value to compare technologies against. Although this makes the metric intuitive, the role each technology plays in the system remains poorly described.

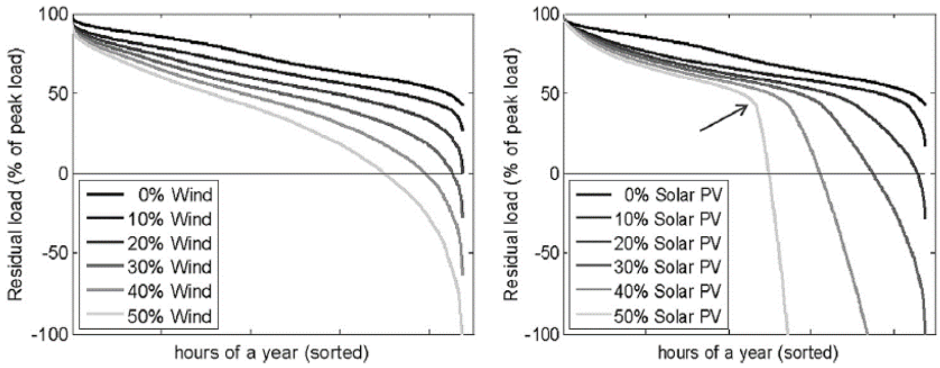


Figure 3.1: Illustration of residual load for sLCOE calculation from Ueckerdt *et al.*, [16]. Using this data, profile cost as part of the cost of iRES integration can be calculated using equation 3.5.

3.3 Levelised avoided cost of electricity (LACE)

Levelised avoided cost of electricity quantifies the value of a technology based on the potential profit the technology can obtain from selling energy and capacity to the system. As can be seen in equation 3.6, this metric also includes the value of capacity in addition to the energy value.

$$LACE = \frac{\sum_{y=1}^{Y} \Delta_{c,y} t_y + P_{cr} C_p}{E} \tag{3.6}$$

Where:

y : time period within a year
$\Delta_{c,y}$: marginal generation price at time period y
t_y : number of hours within time period y
C_p : capacity payment
P_{cr} : capacity credit
E : annual electricity generation

Designed to complement LCOE, this metric can be used to indicate whether the technology can provide value to the system or not, and should be used in combination with LCOE, as the value discrepancies between the two metrics represent the technology net value (NV). As such, a technology is said to provide value to the system if the net value is positive, *i.e.*, LACE is greater than LCOE [17].

An advantage of LACE is that it is an intuitive extension to LCOE. In addition to including more services, LACE recognises the temporal value of electricity services *via* period slicing y. Nevertheless, the metric does not account for the deployment levels of technology as in the case of other metrics such as sLCOE and TSV. Although the concept does not require users to use complicated equations, the temporal price parameter used in the calculation ($\Delta_{c,y}$) may require input from sophisticated electricity models to obtain the value.

3.4 Technology χ value for energy storage

The penetration of iRES in electricity systems has been rapidly increasing following the cost reduction of the technology (*i.e.*, technology cost learning). The capability of the technology to generate electricity, however, is constrained by the availability of the energy source (*e.g.*, solar irradiance). In order for iRES to be capable of supplying electricity on demand, electricity storage is needed. As this can incur significant additional capital cost for the system, the selection of the most adequate storage technology is a key challenge, especially given the wide range of technology characteristics, *e.g.*, power and energy capacity. To allow comparison between different electricity storage technologies, the χ value has been proposed [18]. This is a dimensionless number where the value of a technology is defined as the ratio of annual system revenue to annual system cost as shown in equation 3.7 below.

$$\chi = \frac{R_{total}}{CRF\ \left(C_{gen} + \dot{E}_{max}\left(C^{storage}_{power} + h\ C^{storage}_{energy}\right)\right)} \tag{3.7}$$

Where:

χ	: power generation + storage technology value
R_{total}	: revenue total
CRF	: capital recovery factor

C_{gen} : overnight capital expenditure of power generation
$\dot{E}_{max}$: storage peak power
$C^{storage}_{power}$: power-based overnight capital expenditure of storage
h : duration
$C^{storage}_{energy}$: power-based overnight capital expenditure of storage

It can be seen from equation 3.7 that this concept adopts a cost-benefit ratio analysis, where technology value is directly proportional to the χ value, making the metric intuitive, simple, and transparent. The equation also shows that the metric takes into account the temporal value of an energy service in the system, which is a key consideration in the 21st century grid.

Despite its ability to take into account the temporal value of electricity, the χ concept requires hourly electricity price data, which may not be readily available. Moreover, to maximise R_{total} is a relatively complex system modelling task. These requirements make the concept less immediately accessible than at first glance. Further, this concept is only applicable for relatively low levels of iRES penetration, where iRES plants are "price takers" as the system cannot capture the change in system characteristics owing to the changing system portfolio.

3.5 Intermittent renewables LCOE with firming capacity

One of the major drawbacks of iRES compared to thermal power plants is its dependency on its energy source availability. To allow direct comparison between technologies, a new concept has been recently proposed by Lovegrove *et al.*, [19], which attempts to recognise the distinguishing operational characteristics of iRES and dispatchable thermal plants by making the capacity of iRES firm through coupling it with energy storage. Using this approach, iRES-storage and dispatchable thermal technologies can be 'fairly' compared. A key advantage of this concept is that it uses the LCOE costing approach, thus avoiding the need for complex modelling while preserving the features of LCOE. Similarly to LCOE, this approach cannot describe the interaction between technologies in the system. Additionally, bearing in mind, to design a least cost system, not every technology is required to have all features and roles needed by the system. Therefore, this approach may be overly prescriptive from a system perspective.

3.6 Value adjusted LCOE (VALCOE)

Similarly to LACE, the value adjusted LCOE (VALCOE) attempts to resolve the drawbacks of LCOE by quantifying the value of a technology based on a more comprehensive set of electricity services, as opposed to exclusively energy. LACE is a separate "value" metric to complement the LCOE, whereas VALCOE is a "net" LCOE after value adjustment using energy, capacity, and flexibility services [20], and is described in equation 3.8 below.

$$VALCOE_x = LCOE_x + \left[E_x - \overline{E}\right] + \left[C_x - \overline{C}\right] + \left[F_x - \overline{F}\right] \tag{3.8}$$

Where:

E : value of energy
$\overline{E}$: average value of energy of the system
C : value of capacity
$\overline{C}$: average value of capacity of the system
F : value of flexibility
$\overline{F}$: average value of flexibility of the system
x : technology

In VALCOE, the value of energy services offered by a given technology x is calculated using equations 3.9–3.11 below.

$$E_x\left(\frac{\$}{MWh}\right) = \frac{\sum_h^{8760}\left[WholesalePrice_h\left(\frac{\$}{MWh}\right) \times Output_{x,h}\ (MW)\right]}{\sum_h^{8760} Output_{x,h}\ (MWh)} \tag{3.9}$$

$$C_x\left(\frac{\$}{MWh}\right) = \frac{CapacityCredit_x(\%) \times CapacityValue\left(\frac{\$}{MW}\right)}{CapacityFactor_x \times 8760h} \tag{3.10}$$

$$F_x\left(\frac{\$}{MWh}\right) = \frac{FlexibilityMultiplier_x(\%) \times FlexibilityValue\left(\frac{\$}{MW}\right)}{CapacityFactor_x \times 8760h} \tag{3.11}$$

As can be seen from the equations above, VALCOE preserves the intuitiveness of LCOE and dimensionality of LACE. The metric also covers a broader range of values of system services, *i.e.*, energy (temporal), capacity and flexibility offered by all technologies. However, as the concept does not account for the interaction between technologies, it cannot capture the diminishing marginal value of a technology with increasing level of deployment. In addition to that, to obtain average value of energy, capacity, and flexibility in the system, a complex model is typically required.

Chapter 4

Conceptual development of a new metric

The different roles and services power generation technologies can offer to the power system was already being recognised even in the LCOE era. However, the success of the LCOE, as discussed in Chapter 1, was driven by its emphasise on energy service being the most valuable service in the 20^{th} century grid, instead of considering all the services in its calculation. This allows simple formulation of the metric so that it can be widely accepted. In this study, we adopt the same approach in order to develop a new set of concept and metric as an alternative to the LCOE, which balances the comprehensiveness and ease-of-use. Firstly, we quantify the value of each service using the Electricity System Optimisation (ESO) framework. Secondly, the results from evaluating system service value using ESO are used to identify the most valuable services and technologies that have the most technology system value. Finally, we proposed a new alternative concept and metric to the LCOE based on the most valuable services identified in step 2. Several existing approaches to quantify the value of electricity service are discussed in section 4.1 below.

4.1 Approaches to valuing electricity services

As the electricity system evolves, the traditional dominance of conventional thermal plants is likely to reduce, with commensurate reduction in the availability of associated ancillary services. This implies that the more explicit valuation of these services may be required. This is not a task for which the conventional LCOE metric is well-suited, and the objective of this study is to propose a new concept that is both practical and able to fairly approximate the value of power generation.

4.1.1 Risk valuation

This method quantifies risk as the product of probability and severity.

$$Risk = Probability \times Severity \tag{4.1}$$

Where the probability is determined based on the service reserve margin, and severity is usually measured as the value of lost load (VoLL) [36, 57].

4.1.2 Ancillary service marginal cost or marginal price (ASMC/ASMP)

The price of electricity in liberalised markets is usually determined on a marginal cost basis, and many electricity markets remunerate the provision of ancillary services in the same way [36, 58, 59]. As such, when the system is served by mostly thermal plants, the price of ancillary services are zero, *i.e.*, similar to the 20$^{\text{th}}$ century grid. On the other hand, when electricity from iRES dominates the system, thermal plants are offered a new revenue stream from the ancillary services market.

4.2 Quantifying the value of electricity system services

Every power generation technology is unique, and provides a discrete set of services at different costs. For example, nuclear can provide electricity at a very low short run marginal cost, whilst OCGT provides the same service at an appreciably greater marginal cost, making nuclear a preferred option for the provision of baseload power. However, for other services, *e.g.*, primary response capacity, owing to its relatively low capital cost, OCGT offers a cost effective option. In this section, we present a comprehensive approach to value individual grid services and assess the role played by power generation and energy storage technologies within the electricity grid.

To achieve this, we implement the ancillary service marginal cost (ASMC) approach, described in section 4.1.2, within the ESO framework. This concept is further unpacked in the following text. Initially, the marginal supply cost of a given service when all technologies (*i.e.*, Techs 1 – 5 in this example) are available is illustrated in Figure 4.1. Here, the dashed red line specifies the quantity of a given service required by the electricity grid. Hence, the marginal cost of providing that service at that level is given by $\dot{C}_1$.

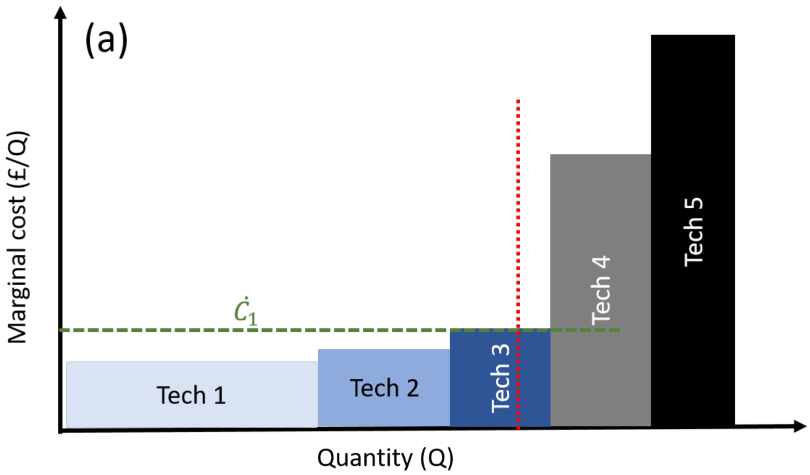


Figure 4.1: Service marginal cost when Tech 3 is (a) made available. Figure 4.2 (b) shows Tech 3 being excluded from the assets disposal. Graph 4.3 (c) illustrates service system value as service avoided cost.

Figure 4.2 illustrates the impact of excluding a given technology from the system – in this example, we exclude Tech 3. As a result, Tech 4 – hitherto not part of the merit order – now supplies the grid service, but at a significantly higher marginal cost of $\dot{C}_2$.

As illustrated in Figure 4.3, removing Tech 3 from the system has the service avoided cost, which is the product of the capacity removed and the price advantage, *i.e.*, $\Delta Q \Delta \dot{C}$.

Under the ASMC approach, this marginal cost ($\Delta Q \Delta \dot{C}$) is therefore the value provided by Tech 3, recognising that this can vary on an hour-by-hour basis, in

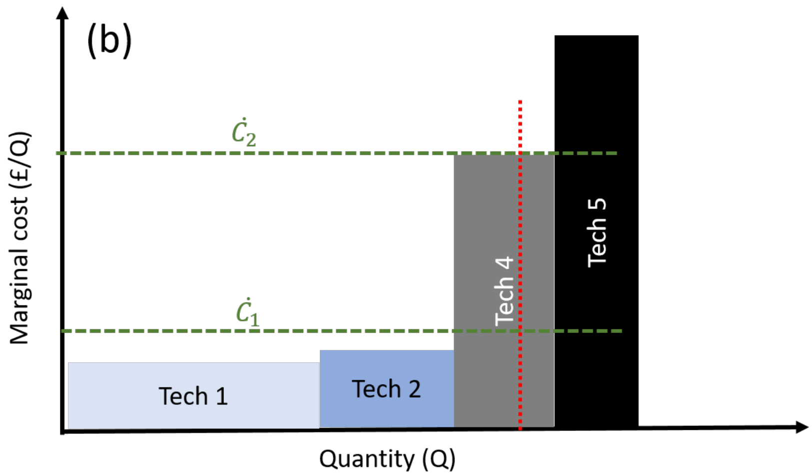


Figure 4.2: Service marginal cost when Tech 3 is excluded from the assets disposal.

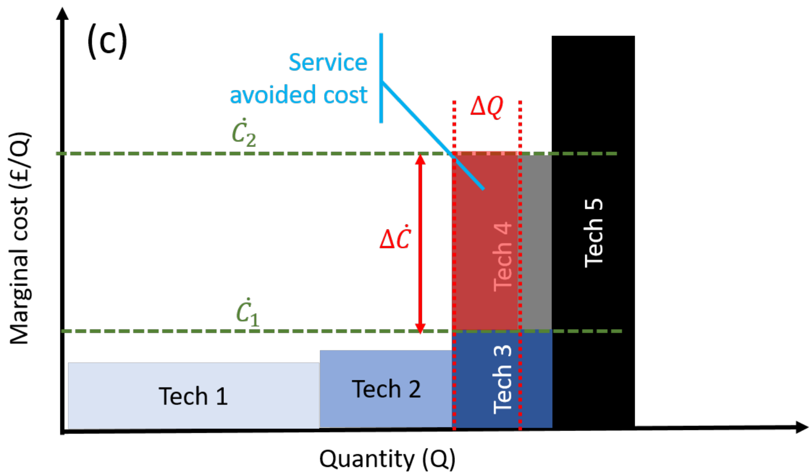


Figure 4.3: Service system value reflected as a service avoided cost.

line with demand and availability of technologies.

Importantly, owing to grid reserve requirements leading to the deployment of overcapacity, the hour-by-hour marginal value of specific services (*e.g.*, inertia, primary, secondary, and tertiary responses) tends to be relatively low for many hours when these services are relatively abundant. Conversely, the marginal value becomes relatively high for the few hours when these services become scarce. It is also important to quantify the way in which dispatchable technologies, *e.g.*, CCGT with CCS, provide value by allowing the flexible scheduling of other technologies, thereby minimising the total system cost. Consequently, we use the so-called "service system value approach", defined as the reduction of service cost as the technology is made available, which may provide inertia, primary, secondary, and tertiary response [13–15].

Using this approach, the value of each specific service and the overall net value of a given technology is quantified, as illustrated by the example for CCGT-CCS in Figure 4.4. Two key points can be discerned here. First, it identifies the "economic limit of deployment" of the modelled system, *i.e.*, 54 GW in this example. Beyond this point, further installed capacity of this technology to the system imposes a cost.

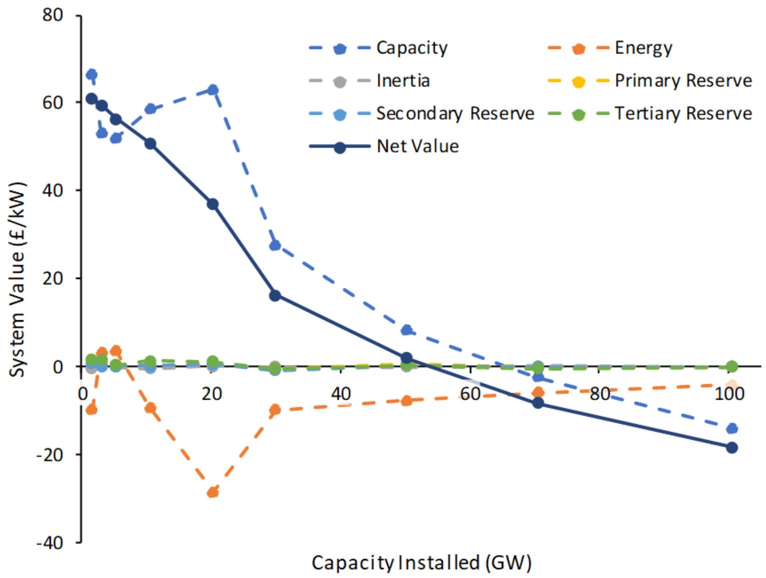


Figure 4.4: Service value breakdown of CCGT-CCS in the UK's 2050 electricity system. The graph shows that capacity and energy services are the most significant services that determine the net value of the technology in the system.

Second, it can be observed that the value of the ancillary services provided by a given technology depends on what is being displaced. Between 0 and 5 GW, CCGT-CCS displaces OCGT capacity, and although the system value of CCGT-CCS capacity drops, the system value of energy services increases. This observation can be explained by noting that whilst the capital cost of CCGT-CCS is greater than that of OCGT, the marginal cost of electricity is reduced. Similar reasoning can be deployed for the remainder of the figure.

One key conclusion from this analysis is that the key contributors to system value are capacity and energy. For a first approximation, ancillary services such as inertia and reserve can be excluded at this level of analysis. This conclusion was tested for the deployment of wind, solar, and CCGT-CCS technologies, and found to be robust.

4.3 Power generation screening curve

As discussed in section 4.2, whilst all services are valuable, the provision of energy and capacity were consistently found to be the most valuable. In this section, we propose to use this conclusion as a basis for the development of a new approach to value power generation technologies, whilst remaining cognisant of the insights derived from the literature review presented earlier in this report, *i.e.*, the importance of including the effect of the composition of the broader system, ensure tractability, and transparency.

To this end, we start by considering another approach for the optimal design of electricity systems – the power generation screening curve. This concept is simple to use, and is capable of recognising different roles of technologies in the system, *i.e.*, baseload, intermediate load, load following, and peak load generations, and how these roles change and evolve with system design.

The screening curve model describes each technology with a linear equation. The y-axis intercept is defined by the annual cost of owning and operating a given power generation technology, *i.e.*, the fixed costs of annualised capital cost, fixed operating cost, and maintenance costs, whilst the slope is given by the sum of variable operating costs and fuel costs. Hence, the annual cost increases with the increasing number of operating hours. This principle is expressed by equation 4.2.

$$\begin{aligned} Annual\ Cost = CAPEX\ \times\ CRF\ +\ Fixed\ OPEX \\ +\ Variable\ OPEX \times\ Full\ load\ hours \end{aligned} \tag{4.2}$$

This approach is illustrated for a system without intermittent renewables in Figure 4.5. Nuclear power is characterised by high fixed cost, but very low operating cost. Conversely, OCGT has very low fixed cost and high operating costs. Thus, the screening curve can intuitively inform us that nuclear and OCGT are best used as baseload and peak-load power generation technologies, respectively. As shown in the figure, at a high capacity factor (*i.e.*, large number of operating hours), nuclear can provide the lowest annual cost, whereas OCGT provides the lowest cost at a very low capacity factor. The most cost effective technology varies as a function of capacity factor. This feature of the screening curve can be used to optimise capacity mix given the load duration curve of the power system – a readily accessible piece of information.

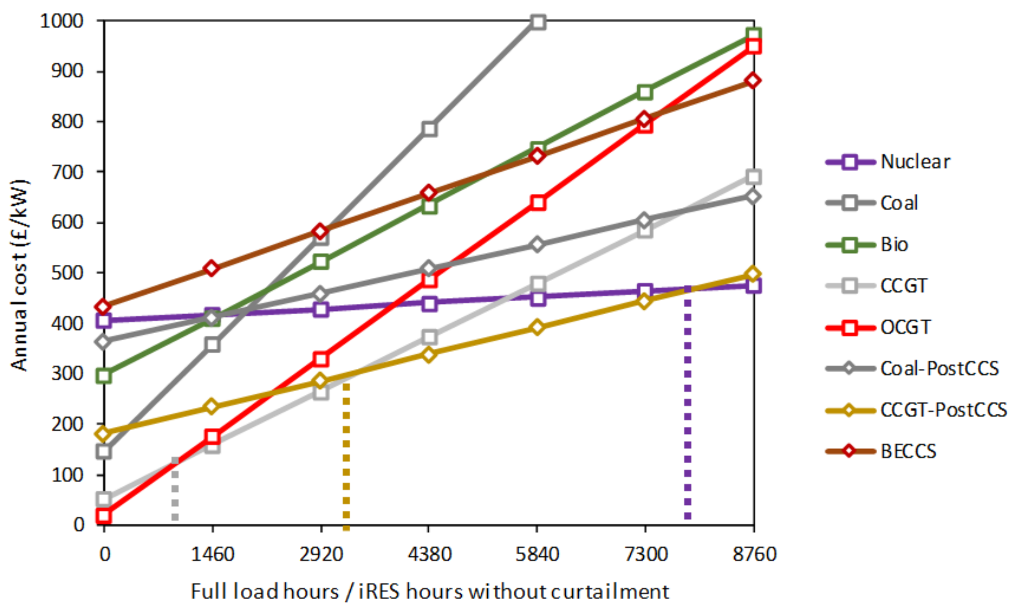


Figure 4.5: Illustration of a conventional screening curve used for comparing dispatchable thermal technologies. In a system without renewables, the role of power generation can be classified into four categories: 1) baseload, 2) intermediate load, 3) load following, and 4) peak load.

Based on the screening curve presented in Figure 4.5, the lowest annual cost is provided by certain technologies for a given number of operating hours:

- Nuclear operated >8000 hours,
- CCS between 3000 and 8000 hours,
- CCGT between 1000 and 3000 hours,
- OCGT less than 1000 hours.

Hence, the optimal capacity for each technology in the system can be determined using the load duration curve (Figure 4.6).

Despite its ability to distinguish between the different roles of dispatchable thermal plants, a traditional screening curve cannot evaluate the value of intermittent renewable power generators and energy storage. Therefore, we adapt the screening curve model by building upon Ueckerdt's work [16], and treat intermittent

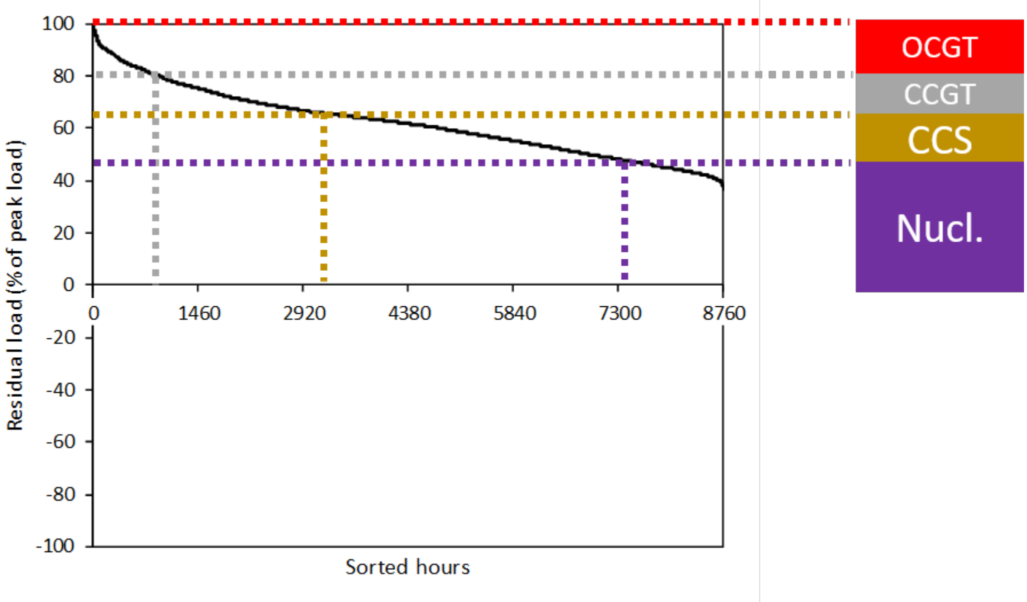


Figure 4.6: Illustration of conventional load duration curve used for comparing dispatchable thermal technologies. Using the optimal full load hours range from Figure 4.5, optimal capacity for each technology can be determined.

renewable power generators and energy storage as a "load reducer", which is defined as any technology with a near-zero marginal cost, thus it is dispatched ahead of other technologies (coal, CCGT, OCGT, nuclear, etc.) in the power generation supply curve. This approach deliberately disregards the "economic level of deployment" concept, *e.g.*, the impact of increasing curtailment rate at higher iRES penetration levels. This is important as it thus allows us to evaluate the impact of imposed levels of technology deployment, as is often articulated by "renewable portfolio standards".

Therefore, once the technology is installed, the consequence is a reduction in power demand of the load curve, leaving the remaining demand – the residual load – to be met by the other technologies.

In the next section, we outline a set of rules in applying the screening curve analysis to different types of technologies, namely dispatchable power plants, intermittent renewable energy sources, and energy storage technologies.

Dispatchable thermal plants

Dispatchable thermal plants are treated in the conventional manner, as outlined above, and associated costs are calculated using equation 4.3.

$$\begin{aligned} Annual\ Cost_{dispatchable} = {} & CAPEX\ \times\ CRF\ +\ Fixed\ OPEX \\ & +\ Variable\ OPEX \times\ Full\ load\ hours \end{aligned} \tag{4.3}$$

Non-dispatchable iRES

In order to assess iRES on an equivalent basis to dispatchable thermal technologies, its annualised cost needs to be divided by its capacity factor, and the potential for curtailment must to be explicitly accounted for. Here we propose to achieve this *via* the definition of an "effective capacity factor", *i.e.*, the ratio or the total useful energy can be delivered by a technology over a period to the total energy it can generate if the technology is continuously operated at the rated capacity. This approach for the iRES annual cost calculation can be expressed with equations 4.4 and 4.5 as follows:

$$\begin{aligned} Annual\ Cost_{iRES} = {} & CAPEX\ \times\ \frac{CRF}{CF \times \frac{ECF}{CF}}\ +\ Fixed\ OPEX \\ & +\ Variable\ OPEX \times\ Hours\ without\ curtailment \end{aligned} \tag{4.4}$$

$$\begin{aligned} Annual\ Cost_{iRES} = {} & CAPEX\ \times\ \frac{CRF}{ECF}\ +\ Fixed\ OPEX \\ & +\ Variable\ OPEX \times\ Hours\ without\ curtailment \end{aligned} \tag{4.5}$$

where CRF is capital recovery factor, CF is the availability factor or capacity factor without curtailment, and ECF is the effective capacity factor after curtailment is accounted for. Although the "actual" annual cost of iRES doesn't change with its deployment, this approach allows the description of the evolving "perceived" annual cost of iRES as the same technology is increasingly deployed within a given system. Specifically, whilst the capital cost of a given technology is constant, but, owing to increasing curtailment, the "effective capacity factor" (ECF) decreases, thus increasing system costs.

Electricity storage

Electricity storage is, in some ways, a dispatchable source of power, but requires electricity from other technologies to operate. It also requires time to charge, and assuming charging and discharging rates are equal, its maximum load duration is half a full year. In addition to this constraint, its maximum load duration is also limited by the quantity of curtailed generation, which is reduced by the round-trip efficiency of the technology. Thus, the annualised cost of energy storage is given by:

$$\begin{aligned} Annual\ Cost_{storage} = {} & CAPEX\ \times\ CRF\ +\ Fixed\,OPEX \\ & +\ Variable\ OPEX \times\ Full\ load\ hours \end{aligned} \tag{4.6}$$

where variable $OPEX$ for storage includes both its inherent variable $OPEX$ and the associated charging cost, *i.e.*, the cost of electricity required to charge it. In the interest of simplicity, we assume curtailed electricity to be available at negligible cost. Of course, this may not be true, with abundant arbitrage opportunities in practice.

Figure 4.7 illustrates a thought experiment using this concept with onshore wind as an exemplar iRES technology.

In this example, nuclear power emerges as the most cost effective option for baseload operation to operate all the year. At a reduced number of operating hours, *i.e.*, between approximately 3500 and 7300 hours, CCGT-CCS provides the lowest annual costs, and when fewer than 1000 hours are available, OCGT is the most cost effective technology. Figure 4.7 also shows that when curtailment is not an issue, onshore wind electricity is the most cost effective source of power. As curtailment increases, *i.e.*, the number of operating hours are reduced, the cost of onshore wind increases accordingly. In this example, onshore wind remains the cheapest option until operating hours are less than 5900 hours.

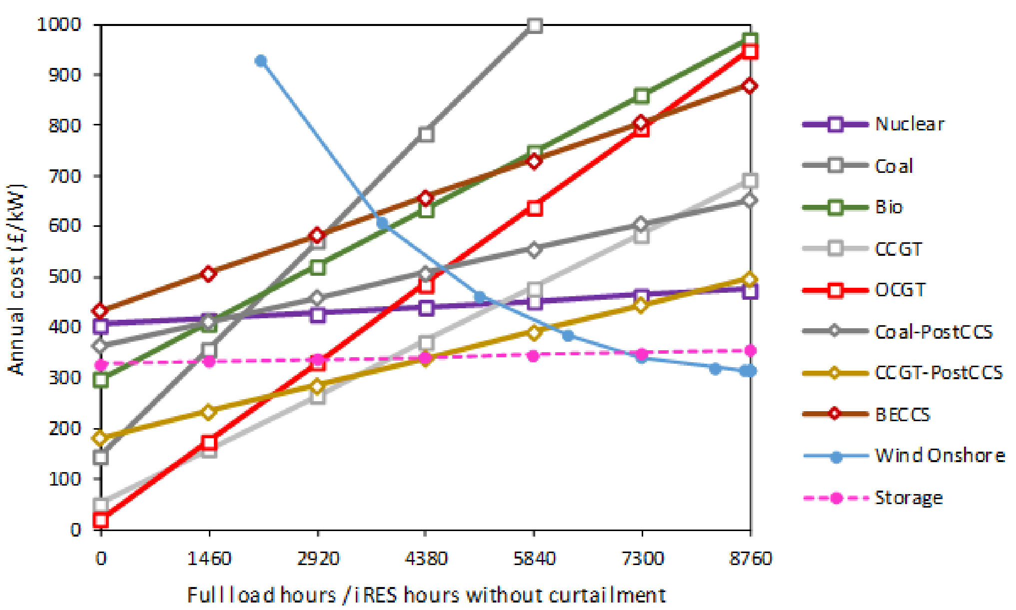


Figure 4.7: Illustration of screening curve evaluation of power generation and technologies under a central carbon price.

Applying this finding to the UK's load duration curve, 5900 hours of onshore wind energy corresponds to 63% of electricity demand. In reading Figure 4.8, it is important to recall that, owing to the requirement for sufficient charging time, energy storage technology is limited to 4380 hours. Therefore in this example, there is direct competition between CCGT-CCS and energy storage.

Providing 63% of the UK's demand requires the installation of onshore wind capacity equivalent to 173% of peak load demand. In addition to this iRES capacity, the system still requires firm capacity to meet the residual load. As shown in Figure 4.7, CCGT-PostCCS can deliver the lowest annual cost of electricity when the full load hours is between 3480 and 5960 hours. This hours of operation range corresponds to 30% of the peak load capacity. Figure 4.8 also indicates that the optimal role of unabated CCGT will be to provide load following capacity that operates between 950 and 3480 hours, whereas the role of OCGT remains peak load capacity. Interestingly, a system with high penetration of onshore wind does not require baseload technology because the maximum full load hours in the residual load is relatively too short for baseload operation. Consequently, technologies with high fixed cost but low variable cost typically used for baseload capacity, such as nuclear, become less competitive.

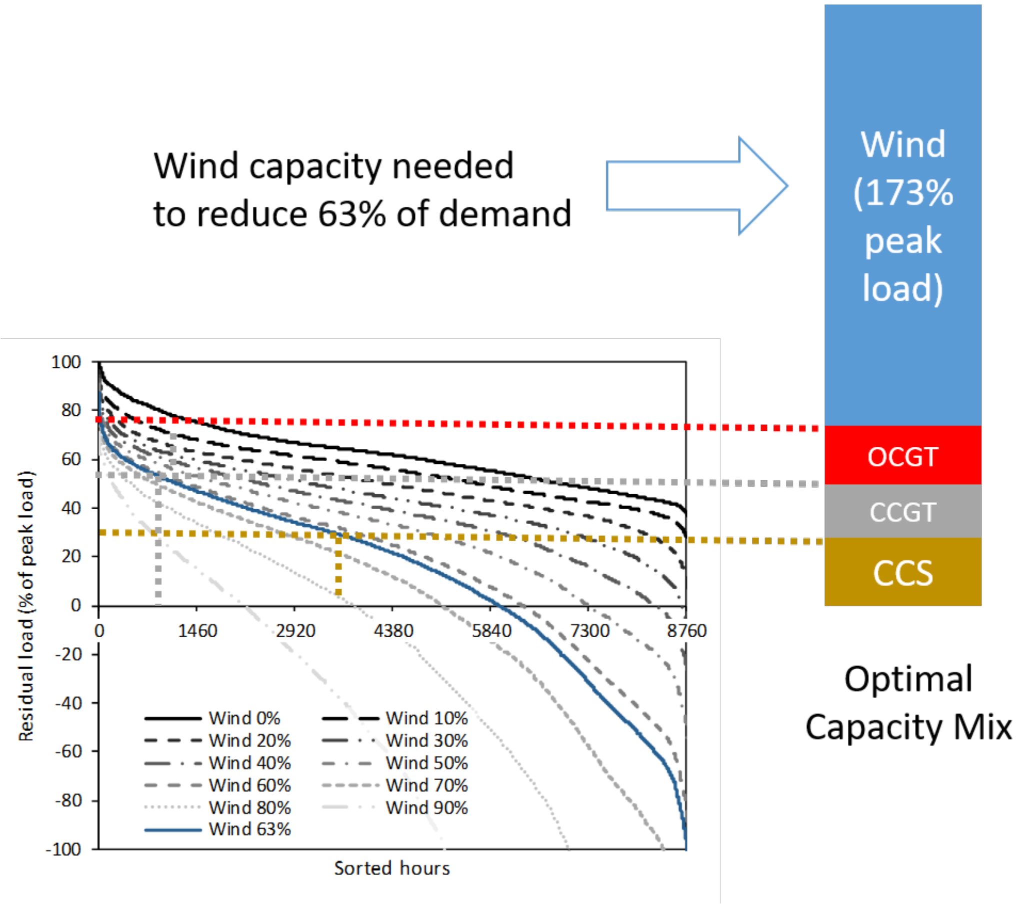


Figure 4.8: Screening curve of UK power system under onshore wind penetration. As can be seen in the graph, the optimal electricity share from onshore wind is 63%, according to screening curve concept. This share of electricity corresponds to 173% of peak load of onshore wind installed capacity

As can be intuited, changing the price of carbon emissions will impact the relative merit order of the other thermal technologies. For instance, when the price of emitting CO_2 is low or zero, CCS technologies are less cost effective than their unabated counterparts. However, at no point did a competition between CCS technologies and renewable technologies become apparent. The dispatch of near zero marginal cost renewable generation was always prioritised in the system, until this was reduced by curtailment.

Further investigation revealed that the competitive full load hours and hours without curtailment of dispatchable thermal technologies (*i.e.*, OCGT, CCGT, and CCGT-CCS), and onshore wind, are relatively inelastic to the carbon price imposed to the system. For example, the primary role of OCGT is to provide peak load capacity for the system, and therefore, the temporal value of this capacity is consistently greater than the variable cost to generate electricity for a very short duration. The value proposition of onshore wind is also inelastic as its cost is primarily influenced by curtailment rate, which is a consequence of the mismatch between its availability and demand. In other words, this serves to further contradict any suggestion of a competition between renewable energy technologies and CCS.

The results of our study using the proposed screening curve concept indicates that the system cost of iRES increases exponentially with deployment owing to curtailment. This will in turn affect their system-value proposition relative to other technologies. Evaluating this concept in the context of onshore wind, offshore wind, and solar PV penetration in the UK's power system shows that iRES has the potential to provide significant value to the electricity system through avoided fuel costs. This is in agreement with results presented previously [60]. However, heavily relying on iRES to provide security of supply for the system proves to be costly owing to a mismatch between iRES availability and electricity demand. Hence, optimal capacity mix analysis using the screening curve concept shows that the value of dispatchable thermal capacity for the system remains high.

In this approach, a key piece of input data is the load duration curve. However, this curve is very likely to evolve with time, in line with, for example, increasing electrification of domestic heating and transport.

Owing to its intermittency, a high penetration of iRES will increase the number of hours with electricity over-supply. Subsequently, this significantly reduces the hours of residual load, effectively eliminating the requirement for baseload capacity.

In order to validate the accuracy of the proposed concept, a similar calculation is performed using ESO-ANCIL, which takes into account the whole range of electricity system services required by the grid. Here, the capacity mix between ESO-ANCIL and the proposed concept are compared. Calculated using the screening curve, the optimal capacity for the onshore wind, CCGT-PostCCS, CCGT, and OCGT is 176%, 30%, 12%, and 35% of the peak load demand, which is equivalent to 94.5 GW, 16.1 GW, 6.4 GW, and 18.8 GW, respectively. In contrast, the results with ESO-ANCIL indicates that the capacity mix also includes one unit of nuclear power plant in the system. The capacity mix obtained from ESO-ANCIL is composed of 0.6 GW of Nuclear, 6 GW of CCGT, 19.4 GW of OCGT, 15.6 GW of CCGT-PostCCS, and 90.2 GW of onshore wind. Although the power generation screening curve can value energy and capacity services, the requirements of system inertia and reserve capacity are not explicitly taken into account. Therefore, the optimal capacity for thermal plants, primarily OCGT and Nuclear, is slightly underestimated. Here, the total system cost (TSC) from ESO-ANCIL is slightly more than the TSC from the screening curve. This is due to ESO-ANCIL taking into account a broader range of technology costs compared to the screening curve, *e.g.*, start up and no load costs. Additionally, ESO-ANCIL is constrained by plants scheduling, and it is a mixed integer linear optimisation compared to the fully linear power generation screening curve.

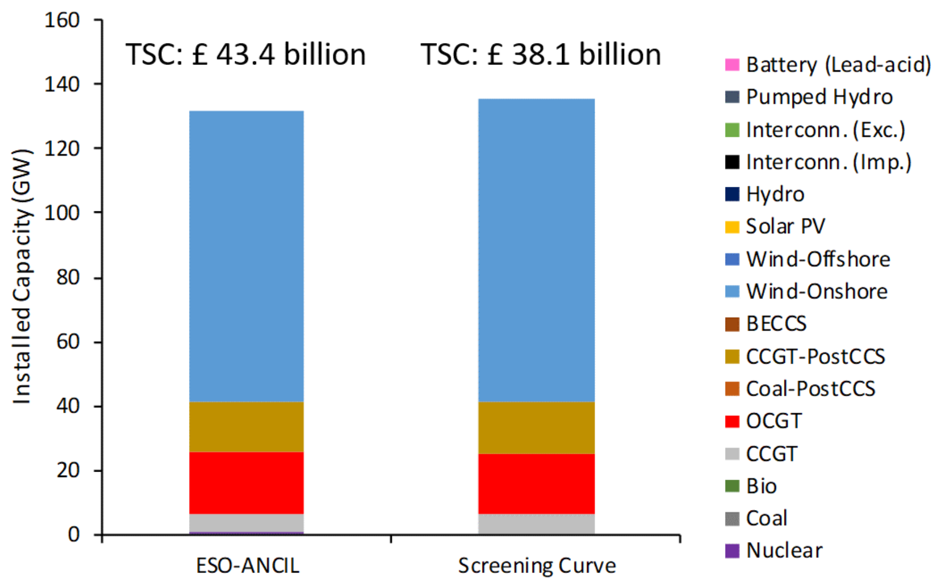


Figure 4.9: Validation of the power generation screening curve against the ESO-ANCIL model.

Although the TSC error is relatively considerable (14%), in light of the computational simplicity, limited data requirements, transparency of the approach, and a relatively small error in term of the system structure, we would propose this modified screening curve concept as a new alternative to LCOE.

Chapter 5

Conclusions

The objective of this study is to evaluate the various concepts that have been proposed as alternatives to LCOE, and to explore the potential for a new concept that balances completeness and ease of use as an alternative to LCOE.

We have evaluated a range of ancillary services required by the grid to i) maintain system frequency (inertia, primary, secondary, and tertiary reserves), ii) maintain system voltage, and iii) to restart the system after black-out, in addition to providing energy and capacity services. The key results of this project are summarised here:

- Owing to its accessibility and intuitiveness, the levelised cost of electricity (LCOE) concept is the dominant approach for comparing power generation technologies. However, it suffers from well-documented weaknesses, and is widely regarded as being poorly suited for the hetrogeneous electricity grid of the 21^{st} century.
- Whilst the LCOE concept remains dominant, the community has been aware of its shortcommings since the early 1990s, with several alternatives having been proposed. Whilst many of these alternatives are excellent, no one method has emerged as being a clear preference to LCOE, variously suffering from computational complexity, large data requirements, or lack of transparency.
- If large-scale, synchronous, fossil-fuelled thermal plants are phased out, the availability of ancillary services that were inherently provided by those technologies becomes limited. Consequently, the value of these ancillary services increases considerably. Among all services that each technology

provides to the system, capacity and energy services become crucial.

- An existing concept which assesses the capacity and the energy services of different technologies is the screening curve. Whilst this represents a well-established method to compare thermal generation technologies, it is not suitable for the evaluation of iRES and storage technologies.
- This limitation can be overcome by incorporating the effective capacity factors of the technologies in the curve, which would reflect the capacity and energy services provided by iRES.
- Storage technologies can also be incorporated in the approach by limiting their maximum hours of discharge to the curtailed hours of the electricity source (to represent the time the technology needs to charge), and to the maximum hours of operation (emulates time needed to charge and discharge).
- Applying those rules allows the screening curve approach to be used to evaluate the capacity and energy value of dispatchable and non-dispatchable power generation, as well as energy storage technologies.
- This is an accessible approach to evaluate the impact of arbitrary levels of all power generation technologies on the total system cost. The proposed concept can also be used to estimate the level of economic deployment of technologies considered, and to determine the optimal role the technologies can play.
- Although the optimal energy share of iRES can be significant, the role of dispatchable plants remains critical in the system to meet the electricity demand.
- The modified screening curve concept proposed in this study shows that iRES have significant value by providing energy/fuel savings for the electricity system, with dispatchable technologies also having critical value by supplying capacity for security of supply.

This study thus provides an alternative concept which can be used to generate a transparent, intuitive, and comprehensive approach with which to compare the evolving impact of technologies within an electricity system – rather than simply provide direct technology-wise comparison.

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Appendix A

Model Assumptions, Constraints, and Formulation

1. Security constraint: We account for system reserve and inertia requirements to ensure reliable operation. Reserve requirements are included as a fraction of peak demand in addition to a proportion of the intermittent capacity online at every time period, t, to dynamically secure the largest firm and intermittent unit against failure.
2. Environmental unit commitment (UC): The formulation includes the CO_2 emission rates of the power generating technologies as well as an overall systems emission target.
3. Detailed operation UC: We introduce a coherent mode-wise operation of all technologies. Power output, emissions, costs, *etc.* varies between these modes.
4. Simultaneous design of the electricity system and unit-wise scheduling: We formulate the model such that the optimal number of installed units per power generating technology is determined as well as their respective operational time plan. The available number of power generating units is an integer decision variable to the optimiser.
5. Coherent technology representation: All types of power generating technologies, thermal and intermittent renewable technologies, are represented in a consistent fashion. The modularity of the formulation enables extension of the number and type of available technologies.

Type	Symbol	Unit	Description
Sets	i,j	-	technologies, $i \in I = \{1,...,I_{end}\}$, with alias j
	t	h	time periods, $t \in T = \{1,...,T_{end}\}$
	m,m'	-	modes of operation, $m \in M = \{off, su, inc\}$, with alias m'
	k	h	set of all possible stay times, $k \in K = \{1,...,max\{StayT(i,m,m')\}\}$
	ic	-	subset of I, $ic \subseteq I$, conventional technologies
	ir	-	subset of I, $ir \subseteq I$, renewable technologies, or such without modal operation
	$Trans(m,m')$	-	possible transitions from mode m to m', 1 if transition allowed, 0 else
	$ForbidT(m,m')$	-	forbidden transitions for mode m to m', 1 if transition forbidden, 0 else
Parameter	$Num(i)$	-	number of available units of technology i
	$Des(i)$	MW/unit	nominal capacity per unit of technology i
	$TE(i,m,*)$	diff.	mode-dependent features of technology i, where * is
where * is	"$Pmin$"	%-MW	minimum power output
	"RP"	%-MW	reserve potential
	"IP"	%-MW	inertia potential
	"Ems"	t_{CO_2}/MWh	emission rate
	$AV(i,m,t)$	%-MW	availability factor of technology i in mode m at time step t
	$StayT(i,m,m')$	h	minimum stay time of technology i in mode m' after transition from mode m to m'
	$CAPEX(i)$	$/unit	annualised investment costs of technology i

	$OPEX(i,m)$	diff.	operational costs of technology i in mode m, in \$/MWh for $m = \{inc\}$, in \$/unit for $m = \{su\}$
	$OPEXNL(i)$	\$/MWh	fixed operational costs of technology i when operating in any mode
	$SD(t)$	MWh	system electricity demand at time period t
	$WF(t)$	-	weighing factor for clustered data at time period t
	PL	MW	peak load over time horizon T
	RM	%-MW	reserve margin
	WR	%-MW	reserve buffer for wind power generation
	$SI(t)$	MW.s	system inertia demand at time step t
	SE	t_{CO_2}	system emission target
Variables	$d(i$	-	number of units of technology i designed/installed
Integer	$n(i,m,t)$	-	number of units of technology i in mode m at time period t
	$z(i,m,m',t)$	-	number of units of technology i switching from mode m to m' at time t
Binary	$x(i,t)$	-	1, if at least one unit of technology i is not in mode "off" at time t
Positive	$p(i,m,t)$	MWh	power output of technology i in mode m as time period t
	$r(i,m,t)$	MW	reserve capacity provided by technology i in mode m at time period t
	$e(i,m,t)$	t_{CO_2}/MWh	emissions caused by technology i at time period t
	tsc	\$	total system cost, subsequently corrected from penalty term $M\,x(i,m)$, where M is a large number

The objective function (3c.1) represents the annual total system cost tsc granularly subdivided by cost factors and operational modes. We differentiate between "no load" costs (\$/h), which occur for any power plant that is online, the incremental costs for providing power output or spinning reserve (\$/MWh), and start-up costs (\$/unit).

Due to the different units of operation costs, the $OPEX(i,m)$ term is split and multiplied by the respective decision variable. The hourly operational increments are multiplied by the vector $WF(t)$ which contains the weighting factors as derived from the data clustering in Appendix B. Hence, the obtained total system cost tsc are scaled back to represent annual construction cost and one year of operation.

$$
\begin{aligned}
min\ tsc = & \sum_{i \in I} CAPEX(i)\, d(i)\, Des(i) && \text{(A.1)}\\
&+ \sum_{\substack{i \in I, m=\{su\},\\ m'=\{off\}, t \in T}} (OPEX(i,m) n(i,m,t)/StayT(i,m',m))\, WF(t) \\
&+ \sum_{\substack{i \in I, m=\{inc\},\\ t \in T}} OPEX(i,m)\, p(i,\textit{inc},t)\, WF(t) \\
&+ \sum_{\substack{i \in I, m \in \{su,inc\},\\ t \in T}} OPEXNL(i)\, n(i,m,t)\, WF(t) && \text{(3c.1)}
\end{aligned}
$$

The design constraint (3c.2) limits the number of units of technology i to be installed (designed: $d(i)$) by the upper bound $Num(i)$. Equation (3c.3) ensures that each units of technology i is in a mode m (*off*, *su*: start-up, *inc*: incremental (running)) at each time period t.

$$0 \leq d(i) \leq Num(i) \qquad \forall i \qquad \text{(3c.2)}$$

$$\sum_{m \in M} n(i,m,t) = d(i) \qquad \forall i,t \qquad \text{(3c.3)}$$

System-wide constraints (3c.4)-(3c.6) include power balances, which ensure sufficient electricity supply, reserve, and inertia requirements in the system at every time period t. Reserve is provided as measured by a predefined reserve margin RM, a percentage of peak load demand $PL = max_t SD(t)$ plus a percentage of intermittent power output, denoted as "wind reserve" WR.

System inertia requirements are met if enough units with "inertia potential" $TE(i,m,\textit{IP})$ are online. All units which are online can provide inertia to the extent of their "inertia potential", $IP(i)$. Intermittent power generators have very little or no inertia potential. Constraint (3c.7) sets the environmental target for the electricity system by limiting the sum of emissions of all units i in every mode m at all time periods t by an emissions target SE.

The dual variable for the power balance (3c.4) represent marginal electricity price; dual variable for the reserve balance (3c.5) the marginal price for reserve.

$$\sum_{i\in I, m\in M} p(i,m,t) = SD(t) \qquad \forall t \qquad (3c.4)$$

$$\sum_{i\in I, m\in M} r(i,m,t) \geq PL\,RM + \sum_{ir,m} p(ir,m,t)\,WR \qquad \forall t \qquad (3c.5)$$

$$\sum_{i\in I, m\in M} n(i,m,t)\,Des(i)\,TE(i,m,\mathit{IP}) \geq SI(t) \qquad \forall t \qquad (3c.6)$$

$$\sum_{i\in I, m\in M, t\in T} e(i,m,t)\,WF(t) \leq SE \qquad (3c.7)$$

Unit specific constraints define the detailed operation as to comply with the technical abilities of each type of technology. Constraint (3c.8) sets the overall output level (power and reserve) for the generating technologies i by their installed capacity level and availability matrix $AV(i,m,t)$. Inequalities (3c.9) and (3c.10) define the upper and lower bounds of power output. With the mode dependent availability matrix $AV(i,m,mt)$, we define the hourly available level of onshore wind, offshore wind, and solar power output. For the conventional power plants, we can demonstrate part-load behaviour by defining a different maximum power output in the start-up mode.

$$\sum_{m\in M} p(i,m,t) + r(i,m,t) \leq \sum_{m\in M} n(i,m,t)\,Des(i)\,AV(i,m,t) \quad \forall i,t \quad (3c.8)$$

$$p(i,m,t) \geq n(i,m,t)\,Des(i)\,TE(i,m,\mathit{Pmin})\,AV(i,m,t) \quad \forall ic,m,t \qquad (3c.9)$$

$$p(i,m,t) + r(i,m,t) \leq n(i,m,t)\,Des(i)\,AV(i,m,t) \quad \forall i,m,t \qquad (3c.10)$$

The provision of spinning reserve service is further constrained according to the mode-dependent "reserve potential" $TE(i,m,\mathit{RP})$ matrix, which prohibits reserve offer in the *off* and *su* mode and assigns the possible amount of capacity provided for the *inc* modes. An exception are power plants that are able to start-up very quickly and are therefore eligible to offer reserve while being off. The only type of power plant that falls into this category and is considered in this model are

OCGT power plants.

For intermittent renewable power generators, we exclude the possibility of exclusive reserve provision in the $TE(i{,}m{,}\mathit{RP})$ matrix according to the current state of technology development. Nevertheless, it should be noted that the model presented here is easily adjustable, if through technological advancement, the provision of capacity reserve service for intermittent power technologies becomes feasible.

$$r(i{,}m{,}t) \leq (n(i{,}m{,}t)\, Des(i)\, AV(i{,}m{,}t) - p(i{,}m{,}t))\, TE(i{,}m{,}\mathit{RP}) \quad \forall i{,}m{,}t \tag{3c.11}$$

The operation of the intermittent power generators $ir \subset I$ is modelled with fewer operational modes. If wind speeds are sufficient and power output is possible, there is no start-up behaviour in wind power plants, unlike thermal power plants. Hence, constraint (3c.12) disables intermittent power generators from being in the *su* mode.

$$n(ir{,}m{,}t) = 0 \qquad \forall i{,}m = \{su\}{,}t \tag{3c.12}$$

A set of integer constraints determines the optimal operational behaviour for the different units of the conventional technology type ($ic \subset I$). Equations (3c.13) and (3c.14) defines the switching between the operational modes as well as the region of allowed mode transitions by the set $Trans(m{,}m')$ and its inverse $ForbidTrans(m{,}m')$.

Inequality (3c.15) ensures that units stay in the operational mode m' for a minimum amount of time according to the set $StayT(i{,}m{,}m')$ after transitioning from mode m to m'. The number of units $n(i{,}m'{,}t)$ in mode m' has to be greater or equal than the number of units that switched into mode m', $z(i{,}m{,}m'{,}t)$, for the minimum stay time.

$$n(ic,m,t) - n(ic,m,t-1) = \sum_{m'} z(ic,m',m,t) - \sum_{m'} z(ic,m,m',t) \qquad (3c.13)$$

$$\forall ic,t,m$$

$$z(ic,m,m',t) = 0 \qquad \forall ic,m \in ForbidT(m,m'),t \qquad (3c.14)$$

$$n(ic,m',t) \geq \sum_{k=t-StayT(ic,m,m')+1}^{t} z(ic,m,m',k) \qquad (3c.15)$$

$$\forall ic,t,m \in Trans(m,m')$$

Constraint (3c.16) determines the carbon emissions associated with each power generating technology i by operation in mode m in each time period t.

$$e(i,m,t) = TE(i,m,\mathit{Ems})\,(p(i,m,t) + r(i,m,t)) \qquad \forall i,t,m \qquad (3c.16)$$

The objective function (3c.1) and constraints (3c.2)-(3c.16) define the final model formulation, which provides the basis for the analyses and results presented in the main body of this study. The optimisation problem is formulated as MILP, modelled in GAMS 23.7.3 and solved with CPLEX 12.3. We define a set of additional parameters to analyse and investigate the system behaviour and characteristics. In particular, the costs for electricity and reserve provision are the dual variables (the shadow price) of the electricity balance (3c.4) and reserve constraint (3c.5). The function $marginal()$ here refers to the mathematically marginal value of the respective constraint.

Type	Symbol	Unit	Description
Parameter	tse	t_{CO_2}	total system emission
	$MEP(t)$	\$/MWh	marginal electricity price
	$MRP(t)$	\$/MW	marginal reserve price
	$RL(t)$	MW	reserve level at time t
	CI	t_{CO_2}/MWh	system carbon intensity
	$CD(i)$	GW	chosen design of technologies
	$Util(i)$	%-capacity	utilisation of technologies

$$tse = \sum_{i,m,t} e(i,m,t)\, WF(t) \tag{A.1}$$

$$MEP(t) = marginal(ElecDem(t)) \tag{A.2}$$

$$MRP(t) = marginal(ResDem(t)) \tag{A.3}$$

$$RL(t) = PL\, RM + \sum_{ir,m,t} p(ir,m,t)\, WR \tag{A.4}$$

$$CI = tse / \sum_{i,m,t} (p(i,m,t) + r(i,m,t))\, WF(t) \tag{A.5}$$

$$CD(i) = d(i)\, Des(i)/10^3 \tag{A.6}$$

if $d(i) \geq 0$:

$$Util(i) = \sum_{m,t} p(i,m,t)\, WF(t)/8760/\,(d(i)\, Des(i)) \tag{A.7}$$

Appendix B

Clustering of Input Data

In order to reduce computational effort and to increase solution speed when solving our MILP energy systems model, we have adapted a data clustering technique to reduce the hourly granular data of electricity demand, wind power, and solar power availability to a manageable size, *i.e.*, so solution time of the MILP is less than one hour. We apply the k-means data clustering method, which is based on assigning raw data into k clusters such that the Euclidean distance between the data points in the clusters and the cluster mean (or centroid) is minimal [61]. Each cluster is assigned a specific weighting factor based on the number of data that is represented by the cluster. A cluster containing a large number of data points will have a high weight, whereas a cluster containing very few data points will have a low weight. The weighting factor is subsequently used to rescale the final calculations as to preserve the original data structure. The model formulation in section A includes the weighting factor, $WF(t)$, obtained in this manner.

In a next step, hourly profiles have to be assigned to each individual data cluster. Typically, the chosen profile for a cluster k is represented by its average value, its mean, or a randomly chosen profile belonging to the respective cluster. Each technique has its individual advantages and drawbacks; often this is a trade-off between representing the full range of values in the cluster while maintaining a realistic data structure without smoothing or perturbing effects. We have developed a profiling method which preserves the average value (*i.e.*, energy, in the case of electricity demand) of the clustered data as well as the realistic profile pattern. The "energy preserving" profiling method chooses a specific profile from the data subset in each cluster k such that the energy demand across this profile is closest to the energy demand of the mean of this cluster. Subsequently, other hourly granular data such as solar power availability are dealt with in a similar fashion.

Figure B.1 gives examples of clustered data for electricity demand, onshore wind, offshore wind, and solar power availability across the UK.

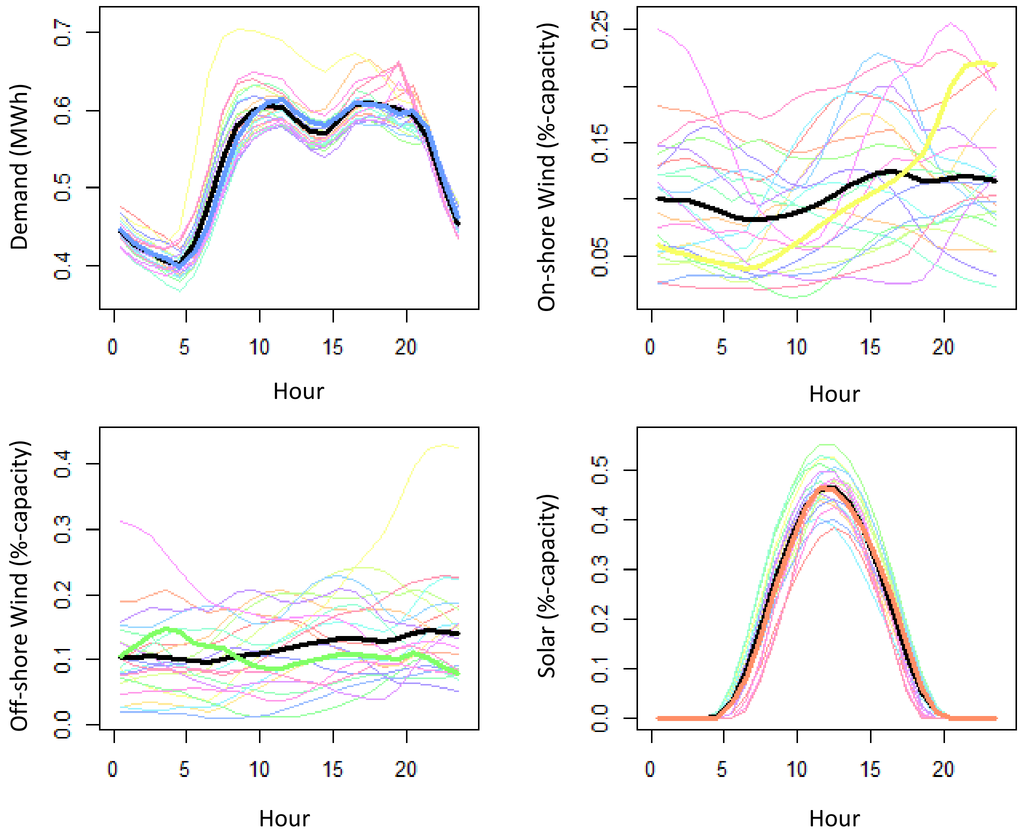

Figure B.1: Example of 4-dimensional data space, in electricity demand, onshore wind, offshore wind, and solar availability, assigned to the same cluster. The thin colourful lines represent all profiles that were clustered into cluster 11. The thick black line represents the mean of the cluster, and the thick coloured lines (*e.g.*, blue, yellow, green or orange) are the specific profile chosen to comply with the "energy preserving" profiling method.

Applying the aforementioned "energy preserving" profiling method to the individual days, we obtain k clusters similar to the presented profiles and reduce the data space from 8760 hours per year to 480 (=20 $\cdot$ 24) time steps if $k = 20$. Figure B.2 visualises the k clusters with the respective profile for the four cohesive data sets. In order to ensure that the data sequence (daily profile) containing the peak demand is included in the reduced data set, we add the peak day with a weighting factor of 1 to the k obtained clusters, resulting in $((k+1)\cdot$ 24 =) 504 time steps. We find that a number of $k = 21$ clusters achieves a good trade-off between accuracy and computational tractability. The error between clustered and the full data set amounts on average to 0.6 % for system-level values, and to 4 % for technology-specific values.

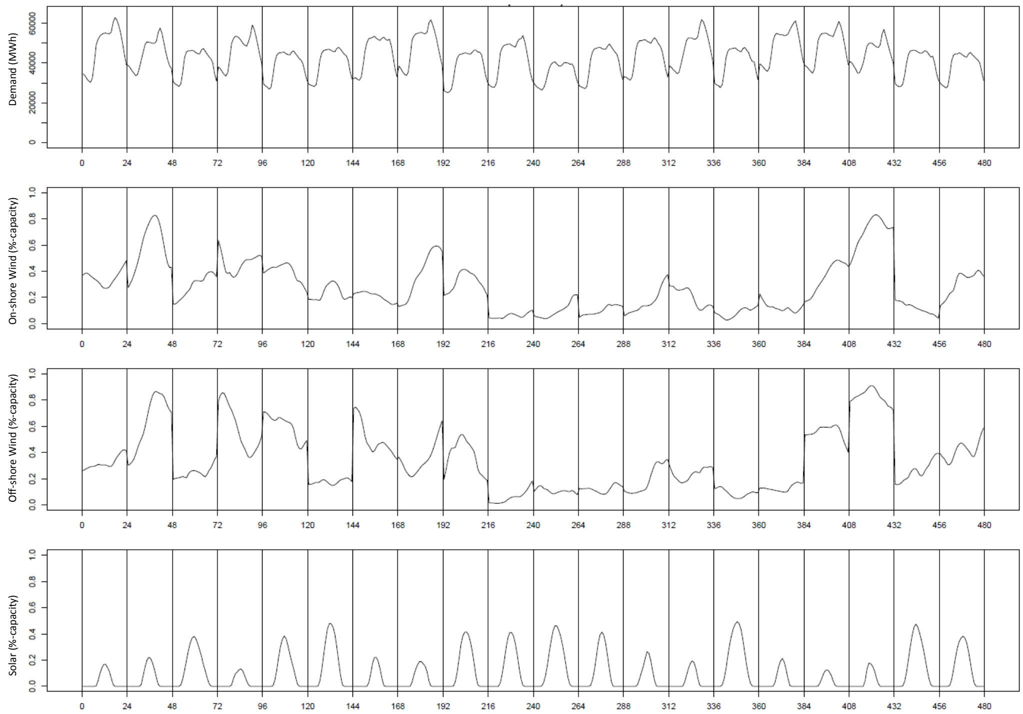

Figure B.2: Specific profiles according to the "energy preserving" profiling method for k clusters. The onshore and offshore wind profiles show most clearly the importance of preserving a realistic hourly pattern by applying the "energy preserving" profiling as opposed to using the cluster mean. The resulting smoothness of a mean-value profile would significantly misrepresent the behaviour of wind power plants and strongly underestimate operational challenges laying herein.

In the challenge to create data which is as realistic as possible using the minimum data space, the difficulty of smoothness occurs not only within the individual cluster (daily profiles), but also between the clusters, as they are connected in series without considering the potential "jump" between the last and first values of the consecutive clusters. The clustered data set which shows the largest value difference between two consecutive hours is the electricity demand profile at time periods 192 and 336 as shown in figure B.2. Here, the demand drops more than 10 GW in one hour, which does not necessarily occur in realistic electricity demand curves. In 2014 the largest difference in electric demand in hourly averaged data (derived from half hourly data provided by National Grid [62]) reached 4.8 GW. However, a smoothing of these unusually large data jumps, as proposed for example by Green and Staffell [61], exceeds the scope of this work. In fact, retaining the sharp drops in the demand data set allows us to study the power plants behaviour in such an occurrence. Since this report deals especially with the flexibility of individual power plants, as well as with the ability of entire power systems to react and adjust the operational schedule according to demand signals (as well as technical, economic, and environmental constraints), we deem the obtained data clusters and profiles to be suitable for the purposes of this work.

It is interesting to note that with the obtained profiling method we can allocate an order of importance to our raw data. Here for example, we apply the clustering to a 4-dimensional data set (demand, onshore wind, offshore wind, solar) simultaneously as to retain the hourly match between the data elements. Depending on the correlation of the numerical range of the data elements we can increase the importance of representation in the clusters. Including the demand vector with very high values ($\geq 10{,}000$) and while the remaining elements range in $[0, 1]$ would overstate the importance of the demand as the Euclidean distance for these vector elements has much larger weight. We chose to normalise all data to be in the same range of $[0, 1]$ as to equally weigh their importance. However, for some applications a different emphasis might be of interest.

Appendix C

Input Data

Table C.1: Economic parameters for individual generation technologies used in this study.

Tech	**CAPEX**	**Fixed O&M**	**Variable OPEX**	**Start-up cost**	**OPEX No Load**
	£/kW	£/kW	£/MWh	£/unit.start	£/h
Nuclear	4,363	85.1	3	4,000,000	3,510
Coal	1,440	40	2	198,500	3,360
Biomass	3,040	60	2.5	198,500	3,153
CCGT	525	15	2	79,500	2,225
OCGT	344	15	5	3,770	89
Coal-PostCCS	3,600	95	2.8	250,145	4,229
CCGT-PostCCS	1,838	40	2.8	79,500	2,357
BECCS	4,300	90	10	250,145	4,229
Wind-Onshore	1,480	30	5	0	0
Wind-Offshore	2,916	45	3	0	0
Photovoltaic	800	10	0	0	0
Lead Acid Battery	1,800	15	3	0	0

CCGT = combined cycle gas turbine, OCGT = open cycle gas turbine
PostCCS = post-combustion CCS, BECCS = bioenergy with CCS

Table C.2: Technical parameters of technology, where P_{min} and P_{max} are the minimum and maximum power output, respectively.

Tech	**P_{min}**	**P_{max}**	**Cap. Credit**	**Inertia**	**Efficiency**	**Capacity**	**Life-time**
	% cap.	% cap.	% cap.	s	%	MW	yrs
Nuclear	75	80	80	7	37	600	50
Coal	30	88	88	6	42	500	40
Biomass	30	88	88	6	42	500	40
CCGT	50	87	87	6	57	750	40
OCGT	10	94	94	6	40	100	40
Coal-PostCCS	30	80	80	6	34	500	40
CCGT-PostCCS	30	80	80	6	50	750	40
BECCS	30	85	85	6	32	500	40
Wind-Onshore	0	100	40	2	100	20	30
Wind-Offshore	0	100	53	2	100	50	30
Photovoltaic	0	100	12	0	100	10	30
Hydro	10	100	50	3	81	300	60
Pumped Hydro	10	100	50	3	0	300	60
Lead Acid Battery	0	100	50	0	89	100	10

Appendix D

Power System Analysis using the Screening Curve

In this section, the approach to optimise the capacity mix of a power system using the power system screening curve is introduced. In addition to power systems cost data , *i.e.*, capital expenditure, fixed and var. O&M, and fuel price, the screening curve methodology relies on data on hourly power demand and iRES hourly availability. Rather than being assumed implicitly, the technology capacity factor and the annual power output are derived from the screening curve. The approach relies on two key graphs: 1) the screening curve and 2) load duration curve.

D.1 Load duration curve

The load duration curve describes the relationship between generating capacity requirements and capacity utilization of a power system. To generate the curve, hourly power demand data for the entire year are sorted in descending order of magnitude. Fig D.2 offers an example of load duration curve based on UK's hourly demand data D.1.

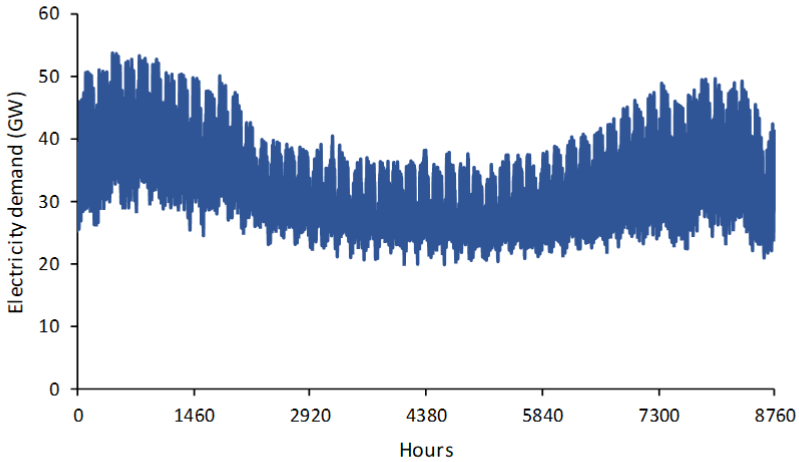

Figure D.1: Illustration of hourly demand data.

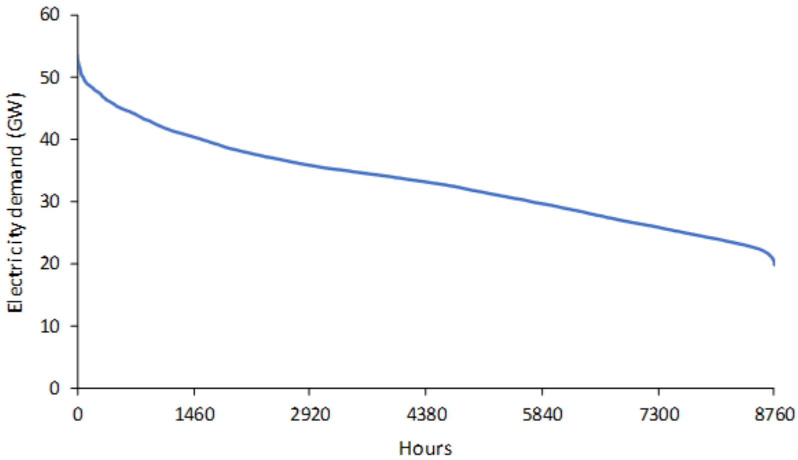

Figure D.2: Illustration of load duration curve.

In the screening curve approach, iRES is treated as a hypothetical load reducer technology due to its low variable cost. As such, iRES is assumed to be dispatched ahead of other technologies , thus leaving the load unmet by iRES generation as residual load. Residual load duration curves under different wind-onshore penetration shares, normalised using the system's peak demand, are shown in Fig D.3. As can be seen, for up to 40% of onshore wind penetration, the electricity generated from the technology can be fully accommodated by the demand. Here, the effective capacity factor of the technology is equal to its availability factor.

Beyond this penetration level, there will be some hours when the amount of electricity generated by onshore wind is exceeding the demand and, therefore, gets curtailed. In this case, the effective capacity factor is expressed as the ratio between power to demand over total power generation from onshore wind.

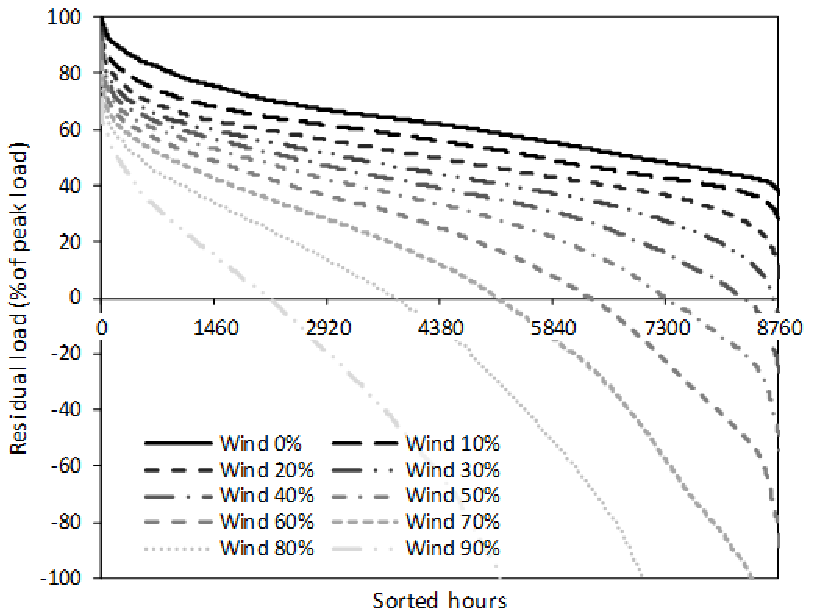

Figure D.3: Illustration of residual load duration curves under different wind penetrations.

D.2 Power technologies screening curve

The screening curve presents the annual cost to own and operate power technology as a function of number of full-load-hours of operation, for dispatchable and storage technologies, or hours without curtailment, for iRES. Equations used to calculate the annual cost for those technologies are discussed in Section 4.3 and are presented below for convenience:

Dispatchable thermal plants

$$\begin{aligned} Annual\ Cost_{dispatchable} = {} & CAPEX\ \times\ CRF\ +\ Fixed\ OPEX \\ & +\ Variable\ OPEX \times\ Full\ load\ hours \end{aligned} \tag{D.1}$$

iRES

$$Annual\ Cost_{iRES} = CAPEX\ \times \frac{CRF}{ECF}\ +\ Fixed\ OPEX \\ +\ Variable\ OPEX \times\ Hours\ without\ curtailment \tag{D.2}$$

Electricity storage

$$Annual\ Cost_{storage} = CAPEX\ \times\ CRF\ +\ Fixed\ OPEX \\ +\ Variable\ OPEX \times\ Full\ load\ hours \tag{D.3}$$

As can be seen from equations D.1 and D.3, capital expenditure and fixed opex represent the intersection of the annual cost curve with the y axis (at x equal to 0 hr) and the variable OPEX is the slope of the curve. For iRES, the "perceived" annual cost depends on the effective capacity factor. Using the equations above and data from Appendix C, the screening curve in Fig D.4 can be obtained.

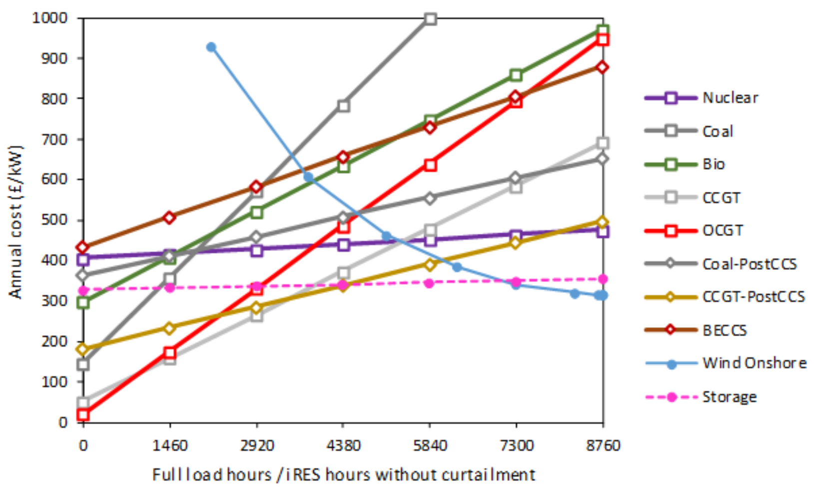

Figure D.4: Illustration of screening curve evaluation of power generation and technologies under a central carbon price.

D.3 System optimisation using the screening curve

The screening curve represents the annual cost of owning and operating power generation and storage technologies as a function of full load hours or hours without curtailment. As such, the approach helps to identify technologies providing the lowest annual costs under a range of operating hours. Thus, the optimal capacity mix in the system can by determined by combining the screening curve and the load duration curve charts.

A first step of the approach is the selection of the cheapest technology to be operated all the year, which will be dispatched ahead of other technologies. In the screening curve presented in Fig D.4, such role is assigned to onshore wind. Increasing the level of deployment of onshore wind increases the curtailment rate of the technology, reducing the number of hours the technology operates without being curtailed. As can be seen, onshore wind remains the cheapest technology until the number of hours without curtailment decreased to around 6000 hours. Using load duration curve in Fig D.3 and interpolation, it can be determined that the share of onshore wind, where the iRES hours without curtailment is equal to 5960 hours, is 63% of the annual demand (see Fig D.5).

At this level of penetration, the useful electricity generated by onshore wind is only 47% of the total electricity it can generate, i.e., the ratio of green coloured area and the total of green and red area in Fig D.5. Accordingly, effective capacity factor of the technology at the level of deployment is 13.6%. Therefore, the optimal capacity of onshore wind can be calculated using equation D.4.

$$\begin{aligned} P_{iRES,\ opt} &= \frac{E_{iRES,\ useful}}{8760 \times ECF} \\ &= \frac{SD_{Annual} \times Share_{iRES}}{8760 \times ECF} \end{aligned} \tag{D.4}$$

Using the equation above, ithe optimal capacity deployment of onshore wind is 176% of the peak demand.

Next to onshore wind, CCGT-PostCCS can provide the lowest cost from 3480 to 5960 hours. using the residual load duration curves at 63% wind penetration,

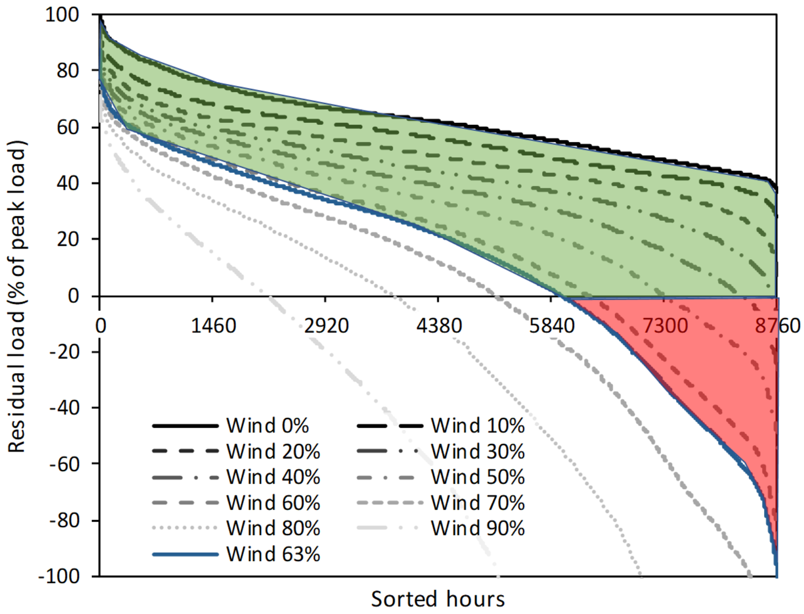

Figure D.5: Optimal residual load duration curve under wind penetration.

this correspond to 30% of peak load demand. CCGT offers the lowest cost to operate between 950 and 3480 hours, which intersects with residual loads equal to 30% and 52% or the peak load demand. Therefore, the optimal capacity for CCGT is 12% of the peak load. Finally, OCGT remains the cheapest technology to provide electricity during the peak load, with the number of full load hours less than 950 hours. This, corresponds to 35 GW of optimal capacity.

Given that the optimal capacity for the onshore wind, CCGT-PostCCS, CCGT, and OCGT is 176%, 30%, 12%, and 35% of the peak load demand, this is equal to 94.5 GW, 16.1 GW, 6.4 GW, 18.8 GW, respectively.

The screening curve provides information regarding the cost of owning and operating power technology under different hours of operation. Not only it allows user to optimise the system, but also the total system cost by summing up the total technology cost (TTC), as described in Eqs D.5-D.7. According to the equations provided below, the total system cost of the designed system is £ 38.1 billion.

$$TTC_i = \; P_{i,\; opt} \times \frac{AnnualCost_{t2} + AnnualCost_{t1}}{2} \qquad \forall \, i \neq iRES \quad \text{(D.5)}$$

$$TTC_{iRES} = \ P_{iRES,\ opt} \times AnnualCost_{t2} \qquad \forall\ i = iRES \tag{D.6}$$

$$TSC = \ \sum_{i}^{I}\ TTC_{i} \qquad \forall\ i \tag{D.7}$$

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