FULLY COSTED
From Silos to Whole System
FULLY COSTED SYSTEM

FROM SILOS TO WHOLE SYSTEM

AMBITION: Drive greater and more efficient optimisation of whole system costs, unlocking the value in demand and flexibility assets while delivering customer benefits through spreading the financial joy.

TODAY: Silos still dominate with whole system costings rare. Cost impacts from one actor are passed onto others with few penalties or sanctions. Demand assets are still marginalised in terms of support, regulation and market design.

Recommendations: From Silos to Whole System

1. **Fully Costed Decision Making**: Policy, regulation and market design must accommodate the full system impacts ensuring that costs or impacts are not passed from one silo to another.
2. **Audit of Fully Costed System**: Whole System NAO Audit of policy, regulation and regulated assets.
3. **Levelised Cost of Energy no longer Fit-for-Purpose**: LCOE is too blunt an instrument to be useful in valuing or costing the system.
4. **Demand is Equal to Supply**: All policy and regulation and regulated assets must consider demand actions and assets equal to supply assets.
5. **Capturing Value Avoided Costs**: By adopting whole system costings it is possible to make decisions and capture the real value of avoided costs.
6. **More Data and Analysis**: The metrics in this report start analysing the value of whole system optimisation but our analysis has shown that there are still a lot of data gaps.
Fully Costed and Fully Valued

With fragmented responsibilities, siloed regulation and technology-based policy making, the whole system costs and carbon are at best nodded to and at worst not accounted for at all.

For example:
- Despite the success of the CfD in unlocking investment, this scheme does not consider the balancing costs or network constraints.
- Generation assets are not being blended with storage assets.
- There are duplications of actions taken by different system actors within the system. In the future this will become much more prevalent if not addressed.

Full system metrics do exist but it is not evident that they are used throughout all policy and regulatory decision making.

ETI and Frontier Economics identified the variable components of whole system costings, revealing the costs but also the associated benefits that need to be considered, and this is the basis of our new metrics.

The Components of Whole Electricity System Costs

- **Technology direct costs**
  - Capital and operational costs associated with the incremental technology.

- **Capacity adequacy impacts**
  - To the extent existing capacity can be retired, or new capacity forgone to ensure the same level of security of supply and carbon intensity as the counterfactual, there is a cost saving to the system.

- **Balancing costs**
  - If the incremental capacity impacts on the uncertainty of supply, it will affect how generators in the rest of the system are called on to help support system stability by altering their output. It will also affect the extent to which they need to be prepared to do so at short notice, potentially affecting their staffing, fuel, and/or maintenance costs.

- **Network impacts**
  - The incremental technology may require investments to reinforce or extend the existing grid, and changes to power flow may increase or decrease power losses due to transmission and distribution. It is also possible that technologies can free up headroom on the grid, creating network benefits.

- **Displaced generation impacts**
  - Outputs from the incremental technology can displace higher marginal cost generation, producing variable cost savings, e.g. fuel, carbon. The scale of this is diminished if generators in the rest of the system operate less efficiently, or the incremental technology is curtailed. This category includes the impact on variable costs of ensuring that the same carbon intensity is maintained.

Source: Frontier
Recommendation 1: Fully Costed Decision Making

All policy, regulation and market development need to account for full system costs not least those that are picked up by consumers through misalignments in the design of the market. There are too many regulatory frameworks that do not require the actors to be responsible for the whole and total system costs and these need to be reviewed.

Recommendation 2: Whole System NAO Audit and Assessment

The National Audit Office should be given responsibility to look at total system value every five years while Ofgem and BEIS should appoint a small but independent team to audit all decisions for their full system cost benefits.

New Metrics: The Missing Value of Demand

Demand and flexibility actions have not been effectively valued or costed within the system. This report has undertaken research that “crowds in” demand actions into the full cost and value of the system and unlocks a new competitive force within the sector – supply versus demand.

While there are many metrics available to understand the investment case for the deployment of specific producing technologies, there are few comparative metrics that measure the value that evaluate demand side “competitors”. Procurement choices have competed different types of generation by focusing on the LCOE calculations. The generation of energy, however, is only one part of the cost and other system and distribution costs are rising with a greater impact on the overall system costs.

New Research Unlocking Whole System Cost and Saving

ReCosting Energy has commissioned new research, providing a methodology to compare the value of all actions on the system, while also explicitly valuing and comparing several different demand assets and actions.

If the energy system is designed in a way that allows all assets, both demand and supply side, to receive their full value to the system, this will help ensure the optimal mixture of technologies is deployed.

Drawing on the work that Frontier Economics, ETI and LCP have done already on the fully costed “supply” part of the market, we asked Frontier Economics, LCP and the BEIS Dynamic Dispatch Model (DDM) team to run their model with demand side actions, energy efficiency, and storage of all sizes, equally compared with traditional supply options.

Our research has shown that comparisons are possible and necessary and has focussed on quantifying the value of technologies per MWh of energy they produce or avoid.

Implications for Policy & Regulation

- Reveals the value of demand side assets and storage
- Calls for policy, regulation and monopoly actors to give a new prominence to these assets and actions
- Indicates that we do not reward demand and flexibility assets and actions appropriately
- Creates a new value of “avoided cost” to the whole system
What the research has shown us

Many thanks to LCP, Frontier Economics and BEIS’s DDM team for conducting what we think is the very first comparison between whole system analysis of demand assets and actions equally and equivalently compared with generation options.

Comparing the outcomes from a Levelised Cost of Electricity and a Whole Electricity System Cost analysis including for the first time demand assets equally compared to generation assets

Moving from LCOE to Whole Electricity System Cost

To go from LCOE to Whole Electricity System Cost (WESC) requires adding on the additional costs and benefits attributable to a technology on the wider system. The graph below shows the impact on total system costs of adding a sufficient amount of a technology that will produce or avoid the requirement for 1MWh of electricity. Negative values indicate a technology that, when added to the system, reduces costs.

Source: @Challenging Ideas: ReCosting Energy
Displaced generation costs, system impact of a class of technologies.

Capacity adequacy costs

Total WSC

These example figures should not be interpreted as "generic" estimates of the whole system impact of a class of technologies. Whole system impacts are dependent on the wider electricity system and when technologies are assumed to be built.

The following graph includes an illustrative component for distribution network benefits. This accounts for the way that demand-side technologies may be able to reduce reinforcement costs on the networks.

Source: Frontier

Whole Electricity System Costs, excluding distribution network benefits

Whole Electricity System Costs, including distribution network benefits

These example figures should not be interpreted as "generic" estimates of the whole system impact of a class of technologies. Whole system impacts are dependent on the wider electricity system and when technologies are assumed to be built.
Key Findings: Whole System Value comparing Demand and Generation Assets

- **Value for Money:** Demand side measures can provide better value than generation technologies.
- **Whole System Benefit:** More demand side measures can reduce overall system costs.
- **Value of Renewable Generation and Storage:** Renewable generation and larger scale storage also show a reduction in whole system costs from an LCOE analysis.
- **Network Benefits:** In areas of constrained capacity these demand side and storage technologies have an increased value.
- **Avoided Costs:** Many of the actions and assets analysed show a real “avoided cost” which needs to be captured.

These findings and this analysis also reinforces the key recommendations in the section “From Socialising Risk to Owning Risk”, that highlights the need for businesses to manage their own whole systems risks and associated costs.

An EV van example

**THE VALUE OF AN EV VAN TO THE SYSTEM**
An electric van could deliver up to £500 per year value to the system through displaced generation costs, capacity adequacy value, balancing opportunities and reduced distribution network reinforcement costs.

**THE VALUE TO THE OWNER OF THE VAN**
The owner of the van would be able to capture these benefits, through fully cost-reflective prices for energy and network access, and be able to participate in the Capacity Market.
Some of the assumptions of how demand assets could perform are conservative, and with greater automation, increased price signals and locational pricing the impact of demand assets will increase.

<table>
<thead>
<tr>
<th>Technology</th>
<th>Description</th>
<th>Capital costs</th>
<th>Feed O&amp;M costs</th>
<th>Variable costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>DSR – EV residential off street</td>
<td>20% of demand in the period between 6pm and 10pm can be shifted later by up to 8 hours.</td>
<td>N/A – It is assumed that once an EV is purchased, there are no additional costs in enabling it to undertake DSR.</td>
<td>N/A – It is assumed that once an EV is purchased, there are no additional costs in undertaking DSR.</td>
<td>N/A. While there will be a cost associated with charging the battery at a later period, this will be modelled as part of the “dispatched generation cost”</td>
</tr>
<tr>
<td>DSR – EV depot</td>
<td>20% of demand in the period between 6pm and 10pm can be shifted later by up to 8 hours.</td>
<td>N/A. While there will be a cost associated with charging the battery at a later period, this will be modelled as part of the “dispatched generation cost”.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>DSR – HP domestic</td>
<td>2% of peak demand can be shifted by up to 23 hours earlier (based on 20% of properties having heat storage).</td>
<td>N/A – It is assumed that once a HP is purchased, there are no additional costs in enabling it to undertake DSR.</td>
<td>N/A – It is assumed that once a HP is purchased, there are no additional costs in enabling it to undertake DSR.</td>
<td>N/A. While there will be a cost associated with charging the battery at a later period, this will be modelled as part of the “dispatched generation cost”</td>
</tr>
<tr>
<td>DSR – other non-domestic</td>
<td>Demand can be shifted backwards or forwards by up to 4 hours.</td>
<td>£14/kW.</td>
<td>N/A</td>
<td>N/A – It is assumed that the DSR can be carried out in a way that does not inconvenience the consumer</td>
</tr>
<tr>
<td>DSR – other non-domestic</td>
<td>Demand can be shifted backwards or forwards by up to 2 hours.</td>
<td>£305/kW.</td>
<td>N/A</td>
<td></td>
</tr>
<tr>
<td>Li-ion battery DNO T1</td>
<td>DNO batteries with 1 hour duration.</td>
<td>£800/kW</td>
<td>£10/kW</td>
<td>N/A – It is assumed that the DSR can be carried out in a way that does not inconvenience the consumer</td>
</tr>
<tr>
<td>Li-ion battery DNO T2/T3</td>
<td>DNO batteries with 4 hour duration.</td>
<td>£1,370/kW</td>
<td>£150/kW</td>
<td>N/A – It is assumed that the DSR can be carried out in a way that does not inconvenience the consumer</td>
</tr>
<tr>
<td>Efficiency – domestic LEDs</td>
<td>Modelled as a percentage reduction in energy use.</td>
<td>£39/kW</td>
<td>N/A</td>
<td>N/A</td>
</tr>
</tbody>
</table>

(1) DSR cost based on average of ‘high’ and ‘low’ 2030 scenarios from p74 of Carbon Trust and Imperial (2016), An Analysis of electricity system flexibility for Great Britain
(2) All figures for Li-Ion batteries are shown as a discounted cost per kW over the lifetime of the battery. For example, the capital costs will first have been annuitised at a hurdle rate, and then discounted back at the 3.5% social discount rate
(3) Based on an illustrative estimate of £15/MWh/year from BEIS. This was based on the use of LED bulbs. We converted this to £/kW using the load factor within the DDM. We have also scaled the cost up to account for the way that the DDM assumes that energy efficiency measures will last for 30 years, while the cost input is based on an intervention that only lasts 10 years.
Recommendations from the Research

**Recommendation 3: Levelised Cost of Electricity is no Longer an Effective Metric of Cost or Value**

Levelised cost of electricity is no longer, or maybe never has ever been, an effective measure of valuing whole system costs and should not be utilised in decision making or as a metric of value for support mechanisms such as the Contracts for Difference. This mis-costing of the system is becoming more and more of a distortion as system costs rise and commodity costs reduce.

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**TODAY: LEVELISED COST**

**TOMORROW: WHOLE SYSTEM COSTS**

Revealing different outcomes for all forms of demand and flexibility assets and generation assets, showing LCOE is not able to reflect the overall value or cost to the system.

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**WHOLE SYSTEM COSTING METHODOLOGY EXISTS**

It is now about deploying whole system methodology to inform decision making, where possible ensuring the incentives faced by market actors reflect the whole system costs and benefits. However, it does require more work on the nature and operational characteristics of different demand actions and assets, as well as how to compare the value of assets that primarily provide energy against those that primarily provide capacity.
Recommendation 4: All Assets and Options Must be Considered Equal

We believe that including demand side assets and actions as a mainstream actor is crucial in driving greater value from the system, informing choices, and designing support mechanisms. By creating equality it will open up investment in storage and generation blending, flexibility, customers assets and permanent demand reduction (energy efficiency).

Extraordinarily the Capacity Market “does not have rewarding flexibility” as an objective, which seems like a big gap in its ability to reward the multiple routes to delivering capacity.

Recommendation 5: Value the Avoided Cost of Energy

This work creates a value for Avoided Cost of Energy – requiring less total energy, managing peak not meeting peak, sweating assets efficiently and delivering energy efficiency. The Avoided Cost of Energy needs to become much more central as we move forward if we are to avoid ‘milk lakes’, increased system costs and under-utilised assets.

We currently neither quantify nor pass on the value of avoided costs in the current system effectively. Through the comparative metrics developed, there is the opportunity to attribute the avoided cost of energy to those that assist the system to avoid increasing generation assets, balancing charges not incurred, distribution costs not required and overall capacity increased. We further develop the project’s analysis to show how this value can be attributed effectively to reward assets and actions throughout the system.

This avoided cost is only realised through Whole System Modelling revealing that value often sits between the current silos. Costing the whole system and taking decisions on the basis of whole system efficiency is crucial if this “productivity” gain is to be captured.

The US Energy Information Department has been exploring the Levelised Avoided Cost of Energy (LACE) and has created some metrics but this doesn’t include demand side actions or assets.
Recommendation 6: More Data and Analysis Required

This project was only able to quantify and compare all technology options for the increase in a 1 MW of energy. However, there are several other value pots that need to be quantified and we recommend that this work is done as part of the wider BEIS and industry flexibility planning.

While this project has shown that demand side assets and actions deliver a value to the system, it has also revealed the very sparse knowledge and data around demand assets and actions costs and their characteristics.

Conclusion

These metrics make the case that demand and generation should be compared equally and provide policy and regulation new tools to optimise the system more efficiently. It also requires focus on the interaction between demand and supply, moving customers from being on the side lines to being central to delivering an optimised, efficient and modern energy system – with value and benefits flowing in their direction.

This value will be further realised by half-hourly settlements and technology based services that will be in a position to capture the value and reward the actions and assets.

This is the start of fully optimising the system, driving more from less, and is at the heart of our overarching principle of optimisation not consumption.

RESEARCH AND MODELLING PROJECTS

There is a need for greater modelling of demand, measured against whole system costs. It might require, as we start this optimisation journey, giving different assets an allocated value so that we can initially standardise the “base case”, developing into more nuanced values as we see how assets perform and what new assets come onto the system. This will also be accelerated by greater digitalisation of assets and much more granular information flows.

FRONTIER ECONOMICS SAYS

“This exercise has highlighted the relative paucity of data on the costs and benefits of demand-side measures... to consider demand-side measures alongside generation, a more systematic collation of this data along the lines of what is available for generation will be required.”

2 The Levelised Avoided Cost of Electricity (LACE) represents that power plant’s value to the grid. A generator’s avoided cost reflects the costs that would be incurred to provide the electricity displaced, by a new generation project as an estimate of the revenue available to the plant. As with LCOE, these revenues are converted to a level stream of payments over the plant’s assumed financial lifetime.
MODELLING WHOLE SYSTEM COSTS OF DEMAND-SIDE TECHNOLOGIES

Analysis carried out for the ReCosting Energy project

27 November 2020
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EXECUTIVE SUMMARY

The ReCosting Energy project has been examining how the GB energy sector may need to be transformed to meet the opportunities and challenges of net zero. This requires an understanding of the extent to which demand-side activities could add value to the system and whether the regulatory and market landscape needs to be changed to unlock this value.

Generation technologies are often compared on the basis of the “Levelised Cost of Electricity” (LCOE), a metric that summarises the lifetime cost per MWh generated. This can be extended to a “Whole Electricity System Cost” (WESC), which incorporates the wider impacts of a generator on the electricity system. The WESC can enable comparisons of the value that different types of generation add to the system (although no single metric can fully capture the optimal mixture of different technologies).\(^1\)

We were therefore commissioned to calculate a set of example WESCs for demand-side technologies. This exercise is worthwhile since:

- it can determine whether it is possible to compare demand-side technologies to generation technologies using these types of metric, and what issues may need to be overcome; and
- the figures, while intended as examples which will not reflect all types of demand-side technologies or all future energy system scenarios, can show whether there is the potential for demand-side measures to be more cost effective than supply-side investment, and identify the circumstances where this would be more likely.

We carried out modelling to estimate the WESC for a variety of representative demand-side technologies, as well as various forms of generation.

Figure 1 summarises the results: The blue line indicates how much additional cost would be incurred on the electricity system if a sufficient amount of each technology was built to produce\(^2\) 1MWh over its lifetime. Negative values indicate a technology that, when added to the system, reduces costs. These figures relate to technologies added to the system in 2025.

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\(^1\) Such an exercise requires optimising the least-cost way of building and dispatching plants to meet demand. While outside the scope of this work, the types of data required for the WESC metric shown here are also the key inputs for such an optimisation.

\(^2\) For DSR and storage technologies, this refers to the gross electrical energy output or avoided while shifting or discharging, and does not include the associated energy requirement for “catching up” on demand shifting or charging storage.
Our analysis shows that it is possible to compare demand-side and generation technologies alongside one another. Some of the examples of demand-side technologies we have modelled provide a greater benefit to the system per MWh than generation. This is primarily driven by their investment costs: We have assumed a zero or low cost for some forms of DSR and domestic energy efficiency measures, and as a result they constitute a lower cost form of "generation" than even low-cost plants such as wind and solar. If the potential benefits to local distribution networks are accounted for, even more forms of demand-side action may become cost-effective for the system as a whole.

The benefits to the system can be material. For example, the whole system benefits of carrying out DSR to shift the charging of an electric van might be worth up to £500 per van per year if the van is in a location requiring distribution network reinforcement.\(^3\) If such benefits flowed through to consumers, they could incentivise such demand-side actions. In some cases this may require regulatory changes (such as widespread half-hourly settlement).

This exercise has also highlighted the relative paucity of data on the costs and benefits of demand-side measures. If policymakers are to consider demand-side measures alongside generation, then a more systematic collation of this data (along the lines of what is available for generation) will be required.

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\(^3\) The benefit would be around £84 without such gains on the distribution network.
1 INTRODUCTION

The ReCosting Energy project has been examining how the GB energy sector may need to be transformed to meet the opportunities and challenges of net zero. This requires an understanding of the extent to which demand-side activities could add value to the system and whether the regulatory and market landscape needs to be changed to unlock this value. To do this, it is first necessary to compare demand-side activities, such as DSR, storage, and energy efficiency, on a like-for-like basis with generation assets.

Different electricity generation technologies are frequently compared in terms of the Levelised Cost of Electricity (LCOE), a simple metric focusing on the costs of building and running an asset. Whole Electricity System Costs (WESCs) have also been developed to extend the LCOE to cover the wider impacts of generation technologies on the whole system. The project therefore commissioned Frontier to calculate a set of example WESCs for demand-side technologies. This exercise is useful since:

- it can determine whether it is possible to compare demand-side technologies to generation technologies using these types of metric, and what issues may need to be overcome; and
- the figures, while intended as examples which will not reflect all types of demand-side technologies or all future energy system scenarios, can show whether there is the potential for demand-side measures to be more cost effective than supply-side investment, and identify the circumstances where this would be more likely.

The rest of this annex is structured as follows.

- First, we describe the way in which the LCOE is calculated for generation technologies. We explain how it can be extended to a more WESC metric, and how this should be interpreted.

- We then set out the methodology used to model whole system impacts alongside some of the main assumptions made for the demand-side technologies we are modelling.

- The results section presents both levelised costs and whole system costs for demand-side technologies, alongside generation technologies.

- We present two worked examples that show how the figures can be interpreted.

- Finally, we set out the main conclusions from this analysis.
2 WHAT ARE WHOLE SYSTEM IMPACTS AND HOW CAN THEY BE INTERPRETED

In this section we briefly describe the Levelised Cost of Electricity (LCOE) metric, and how this can be extended to estimate a Whole Electricity System Cost (WESC).

2.1 Levelised costs

Electricity generation technologies have widely varying cost structures, with a different mixture of initial capital costs, fixed running costs, and variable running costs (such as fuel), which depend on the electrical energy produced. For example:

- an open-cycle gas turbine (OCGT) has relatively low construction and maintenance costs, but since it consumes a large amount of fuel (and emits a large amount of carbon) it has high variable costs;
- a wind turbine has no fuel costs, but a high capital expenditure; and
- a nuclear power plant has relatively high capex and fixed costs, low variable costs and a significant decommissioning cost at the end of the plant’s lifetime.

The Levelised Cost of Electricity (LCOE) metric summarises all of these different costs on a simple £/MWh basis. It is calculated as the discounted sum of all lifetime costs of a generator, divided by the discounted sum of electrical energy generated over its lifetime.

BEIS regularly publishes LCOE cost estimates of various generation technologies, and its latest report describes in more detail how they are calculated. However, as that report states, “...the simplicity of the measure means that there are factors which are not considered, including a technology’s impact on the wider system given the timing, location and other characteristics of its generation.”

“Whole system cost” metrics have therefore been developed to take account of some of these other factors, and allow the cost-effectiveness of different technologies to be compared on a more like-for-like basis.

2.2 Whole system costs

Technologies with the same LCOE have the same “direct” costs, but may have very different impacts on the power system. For example, consider two generators that have the same LCOE, but where one can be dispatched flexibly, and one produces electricity intermittently. All else equal, the flexible generator may add more value to the system (i.e. lead to a greater reduction in the costs of operating the system) since:

- if it can be relied upon to produce electricity during the system peak, it can reduce the amount of capacity that needs to be kept on standby;

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4 BEIS (2020), Electricity Generation Costs 2020
if its output can be rapidly increased or decreased it may reduce the costs of balancing the system (i.e. keeping electrical demand and supply equal to one another); and

if it can be dispatched when electricity prices are highest, it will displace forms of generation with higher variable costs.

A Whole Electricity System Cost (WESC) metric takes these wider impacts on the power system\(^5\) into account.

One way of calculating such a metric is to simulate the operation of the electricity system, both without and with a quantity of the generation technology under consideration. Once the generator is added, the system is allowed to re-optimise (for example, a small amount of another type of generation may be able to be retired). The change in total system costs for each year can then be calculated, discounted, and divided by the discounted output of the generator that is being assessed.

The WESC metric is therefore equal to the LCOE, plus a variety of whole system impacts. One way of categorising these costs, described in our previous work for DECC\(^6\) and the Energy Technologies Institute,\(^7\) is described in Figure 2. BEIS has adopted this type of framework to calculate what it terms “enhanced levelised costs” \(^8\).

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\(^5\) The WESC does not consider impacts beyond this (e.g. on the transport, gas, or heating systems). For example, it is possible that the use of DSR could reduce ownership costs of heat pumps and electric vehicles, leading to greater take-up of these assets and benefits elsewhere in the system. As this impact is beyond the power system, it is not quantified as part of the WESC.

\(^6\) Frontier (2016), *Whole power system impacts of electricity generation technologies*

\(^7\) Frontier (2018), *A framework for assessing the value for money of electricity technologies*

\(^8\) BEIS (2020)
The additional categories of cost described in Figure 2 are not directly incurred by the owners of generators. This may suggest that they are externalities (i.e. costs and benefits not faced by the producer). However this is not necessarily the case. For example, at least some generators may be able to obtain revenue streams corresponding to:

- capacity adequacy costs from the capacity market;
- balancing costs from the balancing services market;
- network costs from a combination of avoiding network charges such as TNUoS; and
- displaced generation costs from the wholesale energy market.

The WESC metric takes into account some of the factors overlooked by the LCOE, and in that sense allows different technologies to be compared on a more “level playing field”. However, reducing the many different characteristics of generators down to a single metric will inevitably lose much detail. The following section describes how WESCs can be interpreted.

Figure 2   The components of Whole Electricity System Costs

<table>
<thead>
<tr>
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<td>If the incremental capacity impacts on the uncertainty of supply, it will affect how generators in the rest of the system are called on to help support system stability by altering their output. It will also affect the extent to which they need to be prepared to do so at short notice, potentially affecting their staffing, fuel, and/or maintenance costs.</td>
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<td>The incremental technology may require investments to reinforce or extend the existing grid, and changes to power flow may increase or decrease power losses due to transmission and distribution. It is also possible that technologies can free up headroom on the grid, creating network benefits.</td>
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<td>Outputs from the incremental technology can displace higher marginal cost generation, producing variable cost savings, e.g. fuel, carbon. The scale of this is diminished if generators in the rest of the system operate less efficiently, or the incremental technology is curtailed. This category includes the impact on variable costs of ensuring that the same carbon intensity is maintained.</td>
</tr>
</tbody>
</table>

Source: Frontier
Modelling whole system costs of demand-side technologies

2.3 Interpreting whole system costs

The results of any WESC analysis will be highly dependent on the baseline system under consideration. For example, if a system already has a large amount of flexibility, adding intermittent generation may appear more beneficial compared with a situation where there was a lower amount of flexibility.

For a given system, the metric estimates the impact on whole system costs of an investment in additional generation. The sign of the metric can therefore show whether or not investment in a particular technology is beneficial from the point of view of the system as a whole.

As set out in Frontier (2016): *If all externalities were appropriately priced (e.g. carbon) into the costs of building and running the power system, and therefore included in the estimation of the various impacts, then generation capacity with a positive whole system impact would increase the costs of the system overall and, consequently, ought not to be built, on the basis of power system costs alone. Conversely, where the whole system impact implies a net reduction in total costs, the associated capacity ought to be built.*

Therefore, from the point of view of the specific system under consideration, technologies with negative WESCs are more beneficial than those with positive WESCs. However, great care must be taken when comparing technologies where the WESCs are of the same sign: A technology with a lower WESC is not necessarily better value for money than a technology with a higher WESC of the same sign.

The WESC is constructed as a cost per MWh and therefore answers a specific question: *If a generator has to be built that can produce 1MWh of output over its lifetime, what is the least costly option?* However there are other equally valid questions that could be asked. For example: *If a generator has to be built which can supply 1kW of firm capacity during the system peak, what is the least costly option?* That question could be answered with a variant of the WESC which divides the total system cost by the derated capacity provided by the generator, rather than its energy.9

Both of these are valid questions for a system planner to answer. However, the generator that is most cost-effective at providing 1MWh of energy may not be the most cost-effective at providing capacity. For example, a solar plant may be able to provide cheap energy, but adds very little (if anything) to capacity adequacy. It cannot therefore be said that the generator with the lowest WESC is the “best” type of generation overall.

We could try to avoid these issues by asking: *Per pound invested, which technology provides the greatest value to the system?* However this is only useful for the very specific case where there is a strict limit on the amount of money that can be invested. Such a metric will tend to favour technologies with low initial investment costs, even if they have high running costs, and may not be optimal for the system as a whole in the long run.

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9 The same issue applies to the LCOE. This is explained in BEIS (2020): a pound per derated kW measure is a more suitable way of comparing the costs of peaking plant than the LCOE.
In general, there is no single least cost type of generation, and a well-functioning system will require a mixture of complementary technologies. For example, intermittent generation on its own cannot meet peak demand in a cost-effective way, but can when combined with flexible sources of generation or storage. *A single metric such as the WESC cannot take account of such relationships.* Instead, a more complex model is required that optimises the overall least-cost mixture of technologies subject to various constraints (such as meeting demand in every hour).\(^{10}\)

Despite these complexities, we consider that the WESC is still a useful metric since:

- the sign of the WESC indicates whether, for the scenario under consideration, a technology will add or reduce costs; and
- a comparison of WESCs may be valid between technologies that all have a relatively high load factor (where their role in providing energy is important).

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\(^{10}\) One example of such a model is the Energy Systems Catapult’s ESME model. This is a whole-system optimisation model which goes beyond the power sector to include markets such as heat and transport. ESME is capable of trading-off investment in generation against activities such as energy efficiency.
3 MODELLING METHODOLOGY AND ASSUMPTIONS

In this section, we first describe the model that has been used to estimate example WESCs for generation and demand-side technologies. We then set out the key inputs, including those that relate to the specific demand-side technologies that have been assessed.

3.1 Model methodology

As we described above, WESCs can be estimated by simulating the cost of running the power system both with and without an extra generator (or demand-side technology) added.

The modelling we report in this Annex has been carried out using BEIS’s Dynamic Dispatch Model (DDM). This power system model is capable of simulating the GB electricity system, including the behaviour of investors, and the dispatch of generation to meet demand. It also includes functionality to calculate the different components of WESC.

For this work, the DDM was set up with a scenario\(^\text{11}\) that represents a reasonable view of how the GB power system may evolve in the future, to act as a baseline for the estimation of whole system costs. However it is not intended to act as a forecast of the future power system, and so is not reported here.

The DDM simulates whole system impact on a marginal basis (i.e. it considers the impact of a very small additional unit of generation). The £/MWh results produced from the model therefore cannot be applied to very large increments of capacity. In general, as more and more of a particular technology is added to the system, each additional unit will reduce system costs by less (or increase them by more). This is because different forms of generation are complementary to one another, and there will be fewer gains from adding a technology that is already very widely adopted.\(^\text{12}\)

It is necessary to specify the year when the additional capacity is added. We used 2025 – this is consistent with our earlier work for the ETI, and is reflective of when investments that are committed now may come onto the system.

We have built a very simple model to extract these figures from the DDM and calculate a WESC. This is a simplified version of the calculations used for our 2018 work for the ETI.\(^\text{13}\) The main simplifications are as follows.

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\(^\text{11}\) The scenarios provided to us included variants with different levels of demand and flexibility. For the purpose of this report, we only present results for one scenario (with “central” flexibility and “high” demand). This is since the other scenarios available to us represent a relatively narrow range of possible configurations of the system, and might suggest (misleadingly) that the WESC results are not sensitive to the assumed baseline system.

\(^\text{12}\) For example, if there is a very high amount of wind generation on the system, there will be less value to adding more. This is since the output of the wind generators will be correlated, and will increasingly need to be curtailed in periods when it is too high.

\(^\text{13}\) Frontier (2018), A framework for assessing the value for money of electricity technologies
The DDM uses hurdle rates to calculate the financing costs of different technologies. A technology that is seen as more risky will have a higher hurdle rate, will attract higher financing costs and will (all else equal) have a higher levelised cost and whole system cost. However the risk faced by a technology depends on both its intrinsic risk as well as the regulatory framework. For example, generators eligible for CfDs will face a lower level of risk than those exposed to the wholesale market, and will therefore have a lower hurdle rate. In our 2018 modelling, we carried out an adjustment to hurdle rates to try to better reflect the intrinsic properties of each technology (rather than the policy regime that applied to them) to place them on a level playing field. This adjustment has not been carried out for the modelling presented here.

When a technology is added that can reliably provide 1MW of power during the peak hours of the year, it will allow 1MW of another technology to be retired (or not built) while maintaining the same security of supply. The DDM captures this as a “capacity adequacy” benefit. However while this includes the avoided technology-own costs, the DDM does not presently capture the “second-round” effects of removing that technology (such as changes in balancing or network cost). We have not calculated the impact of this effect on WESC.

The WESC, like the LCOE, is expressed on a pounds per MWh generated basis. There is therefore a need to define what we mean by “generation” for DSR, storage and energy efficiency.

- For energy efficiency, this “generation” represents the overall reduction in electrical energy consumption caused by the efficiency measures. This concept is frequently referred to as “negawatts”.

- For storage, it represents the gross electrical energy provided to the system during periods when the batteries are discharged.
  - The batteries will also need to be charged, consuming additional electrical energy from the wider system. We treat this as a cost of the gross electrical energy provided, which in the model is reflected by a positive contribution to the “displaced generation” cost figure.
  - The battery will tend to discharge when power prices are high, and charge when they are low. This difference in power prices leads to the battery having a negative displaced generation cost overall: The value of electricity released will be higher than the value of electricity consumed.

- For DSR, “generation” refers to the gross reduction in energy when demand is reduced or shifted. If demand is shifted to other hours, this increase will be costed in the same way as a battery charging.

For the purposes of this modelling, we have not presented the transmission network reinforcement costs provided by the DDM. These costs will be very specific to where on the network the additional generation is added, and the DDM has not been populated with locations for the DSR, storage and energy efficiency technologies.

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14 We do not have such rates for the DSR and energy efficiency technologies and so assume that any capital costs are paid up-front.
As the DSR, storage and energy efficiency technologies will be embedded on the distribution networks, there may be additional benefits from using them to reduce the need for reinforcement on those networks. These benefits will also be extremely localised. On areas of the distribution network where there are no constraints there may be no such benefits, while in areas where the use of DSR, storage or energy efficiency can avert reinforcement, the benefits could be very high. To illustrate the possible magnitude of these benefits, we have used a benefit of £17 per kW per year\(^\text{15}\) for technologies that have the potential to reduce peak demand on the distribution networks.

### 3.2 Model inputs

The DDM has been populated with examples of different demand-side technologies (DSR, energy efficiency, and storage). Figure 3 below provides a high-level summary of their nature and costs.

There are many different forms of DSR, energy efficiency, and storage, each with their own characteristics and costs. The examples used in this modelling should not be interpreted as being representative of all forms of demand-side technologies.\(^\text{16}\) For DSR these costs relate to the incremental costs of carrying out DSR using an existing asset (such as a heat pump or electric vehicle) rather than the cost of the asset itself. A consumer purchasing a vehicle will do so primarily due to the benefits in terms of increased mobility, safety, comfort etc. Similarly, a consumer purchasing a heat pump will do so for reasons unconnected to the use of the heat pump for DSR. The whole system impacts we are modelling relate to the electricity system, but not the wider markets for transport, heat etc. Therefore we include neither the costs nor the benefits of the underlying assets themselves.

\(^\text{15}\) This was the indicative ceiling price for DSR calculated as part of Norther PowerGrid’s Customer-Led Network Revolution Project – see CLNR (2015), Customer-Led Network Revolution Project Closedown Report p14

\(^\text{16}\) As an example of the uncertainty in these costs, the source we use for domestic DSR costs has a range from £43/kW to £984/kW – the inputs below use the middle of this range.
<table>
<thead>
<tr>
<th>Technology</th>
<th>Description</th>
<th>Capital costs</th>
<th>Fixed O&amp;M costs</th>
<th>Variable costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>DSR – EV residential on street</td>
<td>20% of demand in the period between 4pm and 10pm can be shifted later by up to 8 hours.</td>
<td>N/A – it is assumed that once an EV is purchased, there are no additional costs in enabling it to undertake DSR.</td>
<td>N/A – it is assumed that once an EV is purchased, there are no additional costs in using it to undertake DSR.</td>
<td>N/A. While there will be a cost associated with charging the battery at a later period, this will be modelled as part of the “displaced generation cost”.</td>
</tr>
<tr>
<td>DSR – EV residential off street</td>
<td>70% of demand in the period between 4pm and 10pm can be shifted later by up to 8 hours.</td>
<td>N/A – it is assumed that once an EV is purchased, there are no additional costs in enabling it to undertake DSR.</td>
<td>N/A – it is assumed that once an EV is purchased, there are no additional costs in using it to undertake DSR.</td>
<td>N/A. While there will be a cost associated with charging the battery at a later period, this will be modelled as part of the “displaced generation cost”.</td>
</tr>
<tr>
<td>DSR – EV depot</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>DSR – HP domestic</td>
<td>2% of peak demand can be shifted by up to 23 hours earlier (based on 20% of properties having heat storage).</td>
<td>N/A – it is assumed that once a HP is purchased, there are no additional costs in enabling it to undertake DSR.</td>
<td>N/A – it is assumed that once a HP is purchased, there are no additional costs in using it to undertake DSR.</td>
<td>N/A. While there will be a cost associated with running the heat pump earlier, this will be modelled as part of the “displaced generation cost”.</td>
</tr>
<tr>
<td>DSR – HP non-domestic</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>DSR – other domestic</td>
<td>Demand can be shifted backwards or forwards by up to 4 hours.</td>
<td>£514/kW (^{17})</td>
<td>N/A.</td>
<td>N/A. It is assumed that the DSR can be carried out in a way that does not inconvenience the consumer.</td>
</tr>
<tr>
<td>DSR – other non domestic</td>
<td>Demand can be shifted backwards or forwards by up to 2 hours.</td>
<td>£300/kW.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Li-ion battery DNO T1</td>
<td>DNO batteries with 1 hour duration.</td>
<td>£500/kW (^{18})</td>
<td>£80/kW</td>
<td>N/A. While there will be a cost associated with charging the battery at a later period, this will be modelled as part of the “displaced generation cost”.</td>
</tr>
<tr>
<td>Li-ion battery DNO T2/T3</td>
<td>DNO batteries with 4 hour duration.</td>
<td>£1,170/kW</td>
<td>£190/kW</td>
<td></td>
</tr>
<tr>
<td>Efficiency – domestic LEDs</td>
<td>Modelled as a percentage reduction in energy use.</td>
<td>£593/kW (^{19})</td>
<td>N/A</td>
<td>N/A.</td>
</tr>
</tbody>
</table>

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\(^{17}\) DSR costs based on average of “high” and “low” 2030 scenarios from p74 of Carbon Trust and Imperial (2016). An analysis of electricity system flexibility for Great Britain

\(^{18}\) All figures for Li-ion batteries are shown as a discounted cost per kW over the lifetime of the battery. For example, the capital costs will first have been annuitized at a hurdle rate, and then discounted back at the 3.5% social discount rate.

\(^{19}\) Based on an illustrative estimate of £15/MWh/year from BEIS. This was based on the use of LED bulbs. We converted this to £/kW using the load factor within the DDM. We have also scaled the cost up to account for the way that the DDM assumes that energy efficiency measures will last for 30 years, while the cost input is based on an intervention that only lasts 10 years.
4 MODEL RESULTS

Since the WESC is an extension of the LCOE, we first calculate the LCOE for each modelled technology, before adding on the other components of WESC.

4.1 Example LCOE estimates

Figure 4 presents the LCOE estimates, and splits them into fixed costs (including both capex and fixed operating costs) and variable costs. Figures above £300/MWh (for technologies with extremely low load factors) have been truncated.

These example figures should not be interpreted as “generic” estimates of the whole system impact of a class of technologies. Whole system impacts are dependent on the wider electricity system and when technologies are assumed to be built.

Source: Frontier

The purpose of this analysis has not been to produce a set of generation LCOE figures. The figures above will be particular to the specific scenario we have assessed, and should not be used as the source for other analysis. However they are broadly in line with the costs reported in BEIS (2020) for plants commissioning in 2025.

20 Unlike many LCOE estimates, this modelling uses simulated load factors for flexible technologies, rather than the maximum potential generation net of availability. The LCOE estimates above will therefore be particularly sensitive to how frequently each type of plant is simulated as being dispatched.
When comparing the LCOE of the demand-side technologies to the generation technologies, four groups of technologies stand out:

- **DSR for heat pumps and electric vehicles.** As described in Figure 3, the assumptions used for this modelling include no costs for enabling or carrying out DSR for these assets. These technologies therefore have a levelised cost of zero.

- **Energy efficiency measures.** The domestic and non-domestic energy efficiency measures are assumed to have some fixed costs. However, on a simple £/MWh basis, these costs are lower than the forms of generation technologies considered.

- **Li-Ion batteries.** The batteries have levelised costs at the high end of the generation technologies. This is also before the cost of the energy used to charge the batteries is accounted for (which in the model is considered as part of displaced generation costs).

- **“Other” forms of DSR.** The “other” DSR measures have levelised costs that are above all generation technologies except OCGTs. This reflects the extremely low load factor modelled for these measures (which is equivalent to DSR being carried out for around 20 hours in the year).

### 4.2 Example WESC estimates

The simple levelised cost measure does not include the wider system impact of the technologies. For example, although the “other” DSR does not release a large amount of energy onto the system, if it does so during times of peak demand then it may have a disproportionately high capacity adequacy benefit. We have therefore added on the other components of WESC.

Figure 5 plots the resulting WESC estimates. Each component of the whole system impact is shown as a separate bar. The sum of these is the overall whole system impact, which is shown by the light blue line. These can be interpreted as the change in total electricity system cost if a sufficient amount of a technology is added to produce a lifetime output of 1MWh (and the rest of the system is allowed to adjust in response).

This graph does not include any potential distribution network benefits as these are likely to be highly localised and will not apply in all areas (they are quantified in Figure 6 below).

Technologies have been ordered by this whole system impact. Technologies with lower figures will add fewer costs (or greater benefits) to the system for each MWh of energy they produce.
Modelling whole system costs of demand-side technologies

Figure 5  Example WESC, excluding distribution network benefits

While the addition of the other WESC components has changed the position of some technologies, they are still broadly in the same order: The low WESC of some of the demand-side technologies is therefore driven primarily by their low investment cost per MWh.

The majority of technologies under consideration, including all types of generation, have a positive WESC (i.e. adding them to the simulated system leads to an increase in total costs). This suggests that the scenario that is being simulated already has sufficient or excess capacity, and so adding more will lead to additional costs.

Two types of demand-side technologies do have a negative WESC, indicating that whole system costs can be reduced if they are added to the system.

- **The heat pump and EV DSR measures** all have extremely low (negative) whole system impacts. This is to be expected – as noted above, we have modelled these without any incremental costs, but they are still able to displace costs of generation and capacity elsewhere in the system. If costs were required to enable DSR and incentivise load-shifting, these would need to be taken into account.
Despite being associated with capital costs, **domestic energy efficiency measures** (represented here by the conversion of lighting to LED bulbs) reduce whole system costs.

As noted in section 2.3, comparing the value of this metric across different technologies with positive WESCs must be carried out with caution. This is because the use of a £/MWh metric only makes sense for technologies that are primarily being built to provide energy, rather than capacity. Since the “other” forms of DSR and OCGTs both have an extremely low factor, comparisons between these technologies and the others in the graph are unlikely to be valid.

Non-domestic energy efficiency and Li-Ion batteries also have relatively low load factors (between 5% and 20%), although these are in a more similar range to some generation technologies (solar, onshore wind, and CCGTs) and so may be more comparable. On this basis, the batteries and non-domestic energy efficiency measures we model do appear to be more expensive per MWh than many forms of generation. However, the results do not include the benefits from “stacking” these benefits alongside reduced distribution network reinforcement costs, which may be particularly significant for batteries.

The graph below adds in an illustrative size of these distribution network benefits. This assumes that the DSR, storage and energy efficiency technologies can be added to a section of the network that would otherwise require reinforcement to meet peak demand. These figures would not apply to installations of these technologies in areas where the network did not require reinforcement.
The addition of these benefits leads to an improvement for whole system impacts for all the DSR, storage and energy efficiency technologies, given that they are all on the distribution network. “Other non-domestic” DSR, is now shown as having a negative WESC (whereas without these benefits it adds costs to the system).
5 WORKED EXAMPLES

The £/MWh figures produced by the LCOE and WESC calculations allow different technologies to be compared on a like-for-like basis. However the concept of a MWh of DSR, storage, or energy efficiency can seem rather abstract. For example, it is not immediately clear from the graphs above what these results mean in terms of individual households or firms carrying out actions on the demand-side.

To make these figures more concrete, we have produced two simplified examples.

- The first considers what the £/MWh figures for depot-based EVs would mean for the owner of such an EV.
- The second uses the £/MWh figures to compare the impact of energy efficiency and new build CCGTs on the system.

5.1 Depot-based electric vehicles

Figure 7 summarises the components of WESC estimated by the model for depot-based electric vehicles (EVs).

**Figure 7  WESC components for depot-based electric vehicles**

<table>
<thead>
<tr>
<th>WESC component</th>
<th>Value per MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Technology own variable costs</td>
<td>£0/MWh</td>
</tr>
<tr>
<td>Technology own fixed costs</td>
<td>£0/MWh</td>
</tr>
<tr>
<td>Capacity adequacy costs</td>
<td>-£10/MWh</td>
</tr>
<tr>
<td>Balancing costs</td>
<td>-£0.01/MWh</td>
</tr>
<tr>
<td>Displaced generation costs</td>
<td>-£5/MWh</td>
</tr>
<tr>
<td>Distribution network costs</td>
<td>£75/MWh</td>
</tr>
</tbody>
</table>

Source: Frontier

To translate these figures into more intuitive terms we need to make a number of assumptions regarding the EV. These assumptions are illustrative and may not correspond exactly to the type of vehicle that is being modelled in the DDM.

- We assume that the vehicle is an electric van with a 37kWh battery, which is charged using a 22kW fast charger at the depot. The vehicle will therefore take roughly an hour and a half to fully charge.
- The van is assumed to be fully recharged (from empty to full) for five days a week, for 30 weeks of the year. Without any DSR, we assume that the van would be charged after working hours, at a time that would coincide with the system peak.
- The DSR acts to postpone the charging of the vehicle until after the system peak (for example to later at night).

These assumptions are illustrative and may not correspond exactly to the type of vehicle that is being modelled in the DDM.

Based on a VW Transporter electric - [https://www.parkers.co.uk/vans-pickups/volkswagen/transporter/2020-e-transporter-review/](https://www.parkers.co.uk/vans-pickups/volkswagen/transporter/2020-e-transporter-review/)

The figures in this example have been chosen to be realistic, while also providing the same load factor as used in our modelling.
The amount of energy that such DSR could shift is 37kWh per charge, or around 5.6MWh over the year (3.7kWh multiplied by 5 days and 30 weeks). The peak amount of power which the DSR could shift is 22kW, based on the capacity of the charger.

We can also use the assumptions to calculate that the load factor\(^{24}\) for the EV is approximately 3%. This is lower than all generation technologies in the model except OCGTs and illustrates how this form of DSR provides a relatively high peak power reduction, compared to the overall amount of energy it can shift.

Since we have estimated that a single EV can shift 5.6MWh per year, we can convert the WESC into a value per van that is enable per DSR:

**5.1.1 Technology own costs: £0 per van**

As described in Figure 3, we assumed that there are no material costs involved in carrying out this type of DSR and so the owner of the van does not incur any such costs.

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\(^{24}\) A load factor is the amount of energy that can be shifted, as a proportion of the energy that would be shifted if the technology operated at its maximum power throughout the year.

\(^{25}\) For example, a single van shifting its demand at peak will almost certainly reduce peak demand by a full 22kW. However if a million vans shift demand, peak demand may not shift by 22GW, as a different hour will likely become the peak.
5.1.2 Capacity adequacy benefits: £56 per van per year

By postponing the charging of the van during the system peak, overall peak demand on the system is reduced by 22kW. This means that 22kW of standby generation could be retired from the system (or not built in the first place), reducing overall costs.

In practice, 22kW is an extremely small amount of capacity compared to the size of a typical power plant (many hundreds of megawatts or more) and so it is unlikely that exactly 22kW of capacity could be retired — this figure simply represents the average expected reduction in capacity requirements.

The results of the modelling suggest that this cost saving is approximately £56 per year.

This benefit accrues to the whole system, but may not necessarily “flow down” to the owner of the van. For that to happen, there either needs to be a component of non-domestic bills that accurately reflects the capacity adequacy costs, or the van owner will need to be able to participate in the capacity market (e.g. through an aggregator).

5.1.3 Balancing benefits: 6p per van per year

The DSR carried out by the EV could in principle be used by the system operator to help balance supply and demand.

However, in our model results, the value of this benefit is very low. This may reflect the way in which the DSR is assumed to be carried out for a relatively small proportion of hours in the day, and will not be available to carry out balancing actions most of the time. This value might be higher for more flexible forms of DSR (such as the use of vehicle-to-grid).

5.1.4 Displaced generation benefits: £28 per van per year

Despite providing DSR, the van is still consuming the same amount of electrical energy per year that it did. However this will now be during times when demand is lower, and so when forms of generation with lower variable costs are operating. There will therefore be a net reduction in the variable costs of generation.

This cost saving is approximately £28 per year.

The van owner will obtain these benefits directly if they are billed for their energy usage in a way that reflects the varying wholesale cost of electricity across the day. This would require them to have both half-hourly settlement (which is currently mandatory only for larger consumers) and a tariff that reflects wholesale prices.

5.1.5 Distribution network reinforcement costs: £420 per van per year

If the local distribution network was near its maximum capacity, then the EV could provide a significant amount of additional value. This could take the form of a
contract to regularly carry out DSR to reduce peak loads, or an agreement to carry out DSR in the event of a fault on the network that reduces its capacity.

The value of such benefits will vary tremendously depending on the status of the local network (and may be zero if the network has ample capacity). We have assumed that the DSR is happening in an area where the network is near its maximum capacity, which, given our assumptions about its value, results in savings to the network operator of £420 per year.

For the van owner to obtain these benefits, they would either need to:

- face a fully cost-reflective distribution network use of system charge, which passes on the benefits of a local reduction in demand to their bills; or
- enter into a contract with the DNO to provide these services directly.

5.2 Non-domestic energy efficiency and solar

As we have emphasised throughout this annex, even with a measure like WESC it is difficult to compare technologies that provide very different services to the system. For example the same metric cannot be used to compare an OCGT (which primarily provides peak capacity) and a nuclear plant (which primarily provides baseload energy).

Such comparisons become more meaningful when technologies have a similar load factor. Within our model, non-domestic energy efficiency has a load factor of 12%, which is comparable to the load factor of solar (10%). Solar is a particularly cheap form of generation on a £/MWh basis, and like energy efficiency has high fixed costs and low variable costs. It is therefore informative to compare the two, as in Figure 9.

Figure 9 WESC components for solar and non-domestic efficiency

<table>
<thead>
<tr>
<th>WESC component</th>
<th>Large solar</th>
<th>Non-domestic efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Technology own variable costs</td>
<td>£0.0</td>
<td>£0.0</td>
</tr>
<tr>
<td>Technology own fixed costs</td>
<td>£42.2</td>
<td>£34.0</td>
</tr>
<tr>
<td>Capacity adequacy costs</td>
<td>-£0.2</td>
<td>-£2.1</td>
</tr>
<tr>
<td>Balancing costs</td>
<td>£0.8</td>
<td>£0.0</td>
</tr>
<tr>
<td>Displaced generation costs</td>
<td>-£27.6</td>
<td>-£31.5</td>
</tr>
<tr>
<td><strong>Total WESC</strong></td>
<td><strong>£15.3</strong></td>
<td><strong>£0.4</strong></td>
</tr>
</tbody>
</table>

Source: Frontier

Although both technologies would add costs to the system, “producing” 1MWh of electricity from non-domestic energy efficiency is estimated as being around £15 cheaper than from solar. This is due to a combination of factors.

- **Fixed costs**: Under the assumptions set out in Figure 3, the amount of non-domestic energy efficiency interventions required to save 1MWh are around £8 cheaper than building an equivalent amount of solar plant.

26 The “load factor” of energy efficiency is defined here as the total MWh reduction across the year, divided by the total reduction that would occur if the highest peak reduction was replicated across every hour of the year.
- **Capacity adequacy costs**: An amount of non-domestic energy efficiency interventions that saves 1MWh can reduce capacity adequacy costs by around £2, while solar is associated with very little saving. This is unsurprising: The efficiency savings will tend to reduce consumption whenever non-domestic customers are consuming electricity (which will include some consumption during the peak, which will be during winter evenings). By contrast, solar will produce very little power during the peak.

- **Balancing costs**: Non-domestic energy efficiency produces a predictable reduction in electricity requirements. It therefore does not contribute to imbalances. As it is inflexible, it can also not help mitigate imbalances caused by other technologies. By contrast, solar generation is intermittent, and in the model leads to higher imbalance costs.

- **Displaced generation costs**: Both solar and energy efficiency displace other forms of generation. However, solar will tend to displace most generation during summer days, when demand is lower and the marginal cost of generation higher. By contrast, the energy efficiency measures will reduce demand in a way which is more correlated to overall system demand. The generation displaced is therefore more costly.
6 CONCLUSIONS

We set out to answer two key questions with this analysis:

- First, whether it is possible at all to compare demand-side technologies on a like-for-like basis with generation; and
- second, whether demand-side technologies may (at least in some circumstances) be able to add more value to the system than generation technologies?

In both cases, the results have been positive.

This work has shown that it is possible to compare demand-side and generation technologies alongside one another. The WESC metric provides a useful benchmark with which to compare the contribution of different types of technologies, and can be applied as easily to demand-side actions as to more conventional generation technologies. No single metric can fully capture the complementary nature of different technologies – for example, how peaking and baseload technologies can work together as part of the system. However the £/MWh metric is particularly useful for comparing technologies with broadly similar roles providing energy to the system – as shown in the example comparing energy efficiency and solar generation.

Some of the examples of demand-side technologies we have modelled provide a greater benefit to the system per MWh than generation. This is primarily driven by their investment costs: We have assumed a zero or low cost for some forms of DSR and domestic energy efficiency measures, and as a result they constitute a lower cost form of “generation” than even low-cost plants such as wind and solar. If the potential benefits to local distribution networks are accounted for, even more forms of demand-side action may become cost-effective for the system as a whole.

However, this work has also highlighted barriers to unlocking this value.

Some forms of demand-side action may have significant benefits at the level of an individual asset. For example, we demonstrated how the whole system benefits of carrying out DSR to shift the charging of an electric van might be worth up to £500 per van per year. If these benefits flowed through to consumers, they could incentivise such demand-side actions to take place. However in some cases this may require regulatory changes (such as widespread half-hourly settlement) so consumers face the true costs and benefits of their actions on the system.

In addition, this exercise has highlighted the relative paucity of data on the costs and benefits of demand-side measures. Data on the costs of generation technologies is readily available – for example through BEIS’s regularly updated generation cost assumptions. Information on the costs of demand-side measures is generally harder to find in such a summarised form. This is understandable, as there is such a huge variety of demand-side measures, with very different characteristics. However, without this data, it will be difficult for policymakers and others to consider demand-side measures alongside generation (for example when running models to assess how the optimal energy system may look in the future).
Modelling whole system costs of demand-side technologies