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Impact Assessment

Market-wide Half-Hourly Settlement: Final Impact Assessment

Division:	Consumers & Markets	**Type of measure:**	Codes/Retail Competition measures
Team:	Settlement Reform	**Type of IA:**	Qualified under Section 5A UA 2000
Associated documents:	Decision Document and Full Business Case	**Contact for enquiries:**	HalfHourlySettlement@ofgem.gov.uk
Coverage:	Full		

The energy system is undergoing fundamental change, driven by the need to decarbonise energy supplies and by technological innovation. At the same time, electricity demand is expected to increase. Managing the transition in a flexible way that minimises costs requires changes to market and regulatory arrangements.

Market-wide half-hourly settlement **(MHHS)** is a vital enabler of flexibility. It builds on changes to require half-hourly settlement **(HHS)** for medium to large non-domestic consumers and to facilitate elective HHS for domestic and smaller non-domestic consumers. MHHS will send accurate signals to suppliers about the cost of serving their customers throughout each day. This will place incentives on suppliers to offer new tariffs and products that encourage more flexible use of energy and help consumers to lower their bills. Making best use of existing infrastructure should reduce the need for future generation and network investment. This will help decarbonise the sector cost-effectively, which will benefit all consumers and wider society.

This Final Impact Assessment **(IA)** sets out the impacts that can be expected from our chosen option for implementing MHHS. The Final IA is the central part of the Economic Case for introducing MHHS and it should be read in conjunction with the Full Business Case and associated Decision Document, which we have also published today.

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Summary: rationale for intervention and options

What is the problem?

Electricity settlement takes place every half hour. Most domestic and small non-domestic electricity customers have not had meters that can record half-hourly (**HH**) consumption, so for settlement purposes their consumption is estimated for each half hour. This is done by assigning these customers to one of four profile classes that are used to estimate a profile of consumption over time and to allocate the total energy used to each half-hour period.

This arrangement does not expose suppliers to variations in the consumption patterns of their own customers or to the true cost of supplying their customers throughout the day. So far, therefore, suppliers and other retailers have not been fully incentivised to innovate by offering smart tariffs and/or other products that help customers to shift consumption from peak periods. Yet retailers have a crucial role in fostering behaviour change in homes and businesses by developing and marketing compelling and trustworthy products and services that make it easy for consumers to use energy more efficiently.

Without substantial load shifting over time, there will need to be significant and costly investment in generation and network assets to meet rising peak demand. This would increase the costs of integrating low-carbon, intermittent generation and new sources of demand, such as electric vehicles. Based on experience to date and the evidence we have about stakeholders' future plans under the elective half-hourly settlement (**HHS**) arrangements, we do not expect the existing regime to deliver the tariff and product innovation that will be required to encourage customer load shifting on a scale or at a pace that would ease pressure significantly on the electricity system.

Current settlement arrangements are also inefficient. The reconciliation process is lengthy and market participants have to hold enough credit cover to meet their potential liabilities. Costs associated with these inefficiencies are likely to be passed onto customers.

Why is Ofgem intervention necessary?

The evidence suggests that the elective HHS arrangements will not deliver load shifting on a scale that will produce system-wide benefits. Consequently, there is a need to mandate HHS across the smaller non-domestic and the domestic electricity market. Introducing market-wide half-hourly settlement (**MHHS**) requires significant regulatory change. Past experience of major reform programmes suggests that strong incentives will need to be placed on industry to ensure that it can be delivered efficiently. As set out in the Full Business Case and in our consultation document on programme implementation principles[1], we expect to establish a range of governance and other requirements on parties to secure streamlined decision-making and to ensure that all parties progress in line with programme requirements and plans. We will develop our plans in the light of responses to that consultation and via a further consultation on implementation and governance arrangements.

What are the policy objectives and intended effects, including the effect on Ofgem's Strategic Outcomes?

The strategic objective is to minimise the overall cost to current and future consumers of moving to a net zero carbon electricity system while maintaining security of supply and system efficiency. Within that, the aim of the settlement reform project is to develop settlement arrangements that incentivise all energy suppliers and other retailers to encourage behaviour that contributes to a more cost-effective electricity system.

As set out in our Decarbonisation Action Plan, we will ensure that those who cannot provide flexibility are not unduly disadvantaged. As set out in our Forward Work Programme 2021/22, we will deliver a future retail market with innovative new products that, for example, enables consumers to benefit from the flexibility they can provide, while ensuring that protections are in place for all. We are currently developing our future of retail Strategic Change Programme, focusing on areas of greatest potential consumer detriment or opportunity, with a high-level objective (amongst others) of an energy transition that works for all energy consumers, harnessing innovation and flexibility, with effective protection for consumers. MHHS is a vital factor in securing this transition at lowest cost.

These objectives align with our principal objective[2] to protect the interests of existing and future consumers, our strategic narrative[3] until 2023, our Decarbonisation Programme Action Plan[4] and our Forward Work Programme 2021/22.[5]

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[1] For details see our consultation on programme implementation principles, January 2021.
[2] See 'Powers and duties of GEMA' on the Ofgem website.
[3] See Ofgem's strategic narrative for 2019-23, July 2019.
[4] See Ofgem's Decarbonisation Programme Action Plan, February 2020.
[5] See Ofgem's Forward Work Programme 2021/22, March 2021.

What are the policy options that have been considered, including any alternatives to regulation?

In our earlier Business Case documents we identified a range of potential policy options for achieving the objectives of the settlement reform programme. We appraised them using a mix of qualitative and quantitative assessment.[6] In the Draft Impact Assessment (**IA**) we then considered three main options for settlement reform in detail.

The first option was to rely solely on the elective HHS arrangements (the counterfactual, option 1). The second was to introduce MHHS based on the Design Working Group's (**DWG's**) recommended Target Operating Model (**TOM**) for all Meter Point Administration Numbers (**MPANs**) with a transition period of approximately 4 years up to the end of 2024. We said that we preferred this option. The third option was to introduce MHHS based on the DWG's recommended TOM for import-related MPANs only with a transition period of approximately 5 years up to the end of 2025.

In the Draft IA, we said that the elective arrangements (option 1) would not deliver sufficient levels of load shifting to meet our objectives for the project. Based on all the evidence we have seen, this remains our view.

In the Draft IA, we expressed the view that option 3 would unnecessarily delay the benefits of MHHS for import-related MPANs and – by excluding export MPANs from the scope of MHHS – would obviously preclude any benefits that would arise from settling all export-related MPANs on a HH basis.

In the Draft IA we also said that it would not be practicable to try to complete the transition to MHHS on a shorter timeframe, for example within a 3-year period. A key consideration was that industry resources would be fully committed to delivering faster switching by the end of 2021. In the Draft IA, we noted that, at the time of our analysis, a transition period of about 4 years was realistic with appropriate programme governance. We also took the view that settlement reform should seek to capture benefits relating to HHS for export as well as import MPANS. Accordingly, the Draft IA set out that Ofgem preferred option 2.

[6] See project objectives and assessment options, Strategic Outline Case and Outline Business Case.

Our chosen option justification

We have considered stakeholder views very carefully in deciding upon our chosen option. Almost all respondents agreed that MHHS should apply to export-related MPANs as well as to import-related MPANs, and that the transition period should be the same for all MPANs. Our chosen option fully reflects this feedback. However, respondents were divided on whether the transition period should be about 4 years or whether - in light of the inherent complexity of the transition to MHHS, competing demands on limited industry resources, and the unpredictable effects of Covid-19 – a longer transition period might be required to ensure that the new arrangements will be robust and implemented effectively. After considering all the representations made to us, and the report of our consultants, we have decided that the transition to MHHS should take place over a period of 4 years and 6 months starting in April 2021 and finishing in October 2025.

We consider that this timeframe achieves the best possible balance between delivering the benefits of MHHS as soon as possible and ensuring that the new arrangements (including central settlement systems) are robust. This timeframe still represents a challenge, but we consider it likely to be realistic and achievable with appropriate programme governance.

We believe that our chosen option for MHHS will place powerful new incentives on industry parties to offer a range of innovative products and services to consumers and thereby encourage substantial load shifting. This will in turn deliver significant consumer and societal benefits.

As noted above, our Draft IA preferred option was based on the DWG's TOM. The Association of Independent Meter and Data Agents (**AIMDA**), and another stakeholder, subsequently proposed alternative TOMs. We have assessed these proposals against a range of factors, including efficiency and cost effectiveness, the potential for flexibility, data quality benefits for settlement, and competition benefits. On the basis of that assessment, we have decided that it would be proportionate and beneficial overall to implement MHHS based on the DWG's TOM. For full details of our decision, and the assessment and reasoning for it, see our Decision Document.

Related documents

Alongside this Final IA, we have today published a Decision Document setting out our conclusions to the questions on which we consulted last year. In particular, the Decision Document confirms our position in relation to:

- the TOM, including data aggregation arrangements
- proposed changes to the settlement timetable
- settlement arrangements for export-related MPANs
- the length of the transition to the new settlement arrangements, including in light of stakeholder views on potential Covid-19 impacts, and
- data access and privacy issues and associated consumer messaging approaches.

It also contains a list of acronyms and a glossary of terms used in our MHHS documents.

The Final IA is a key economic component of the Business Case for MHHS. We have today published the Full Business Case (**FBC**) which is the third and final iteration of the Business Case. The FBC supports our final decision on when and how MHHS will be introduced. We will shortly be consulting on implementation and governance arrangements. Our FBC, amongst other things, gives an indication of our proposals in this area.[7]

We set out our plans for the MHHS programme governance arrangements in January 2021.[8] In this consultation we sought views on whether we had properly identified the challenges and risks, and appropriate mitigations, associated with industry-led implementation. We will consult on more detailed governance arrangements shortly.

Chosen option - Monetised Impacts (£m)

Business Impact Target Qualifying Provision	N/A
Business Impact Target (EANDCB)	N/A

We expect this policy measure to enhance competition between suppliers and other retailers in the provision of innovative products and services that lead to consumer behaviour change. In its 2016 Energy Market Review findings, the Competition and Markets Authority (**CMA**) found that "the absence of a firm plan for moving to half-hourly

[7] See the Ofgem website for access to all the MHHS documents published on 20 April 2021.
[8] See our consultation on programme implementation principles, January 2021.

settlement for domestic electricity customers is a feature of the market for domestic and small and medium-sized enterprises (**SMEs**) retail electricity supply in Great Britain that gives rise to an adverse effect on competition through the distortion of suppliers' incentives to encourage their customers to change their consumption profile, which overall reduces the efficiency, and therefore the competitiveness, of domestic and microbusiness retail electricity supply."[9]

Our chosen option effectively remedies this adverse effect on competition. Therefore, in line with Government guidance, we classify it as a non-qualifying regulatory provision. We rely mainly on administrative exclusion D ("Deliver or replicate better competition-based outcomes in markets characterised by market power: Pro-competition document").[10]

<table>
<tr><td>Expected range of net benefit to GB consumers[11]</td><td>£1,559m-£4,509m</td></tr>
<tr><td>Expected range of wider benefits for society[12]</td><td>£659m-£3,009m</td></tr>
<tr><td colspan="2">The net benefits relative to the counterfactual are presented in this table in Net Present Value terms (NPV), in 2018 calendar year prices, rounded to the nearest £m. The net benefits cover the period 2021 to 2045. NPV is calculated using 2018 as the base year. Figures calculated in this way are labelled as such throughout this document.

Cost/benefit figures in this IA are in 2019 prices unless stated otherwise (as, for example, with the net benefits described above). The quantified benefits in section 4 are rounded to the nearest £50m but the quantified costs in section 3 and the quantified net consumer benefits in section 6 are rounded to the nearest £0.1m. Therefore, some totals may not correspond with the sum of the separate figures.</td></tr>
</table>

[9] See paragraph 187 on page 44 of the CMA's Energy Market Investigation Final Report, June 2016.
[10] See page 33 of BEIS's Better Regulation Framework Interim Guidance, March 2020.
[11] The net benefit to GB consumers refers to the modelled benefits to consumers and the monetised direct costs. It is calculated by subtracting the monetised direct costs from the modelled consumer benefits (consumer surplus).
[12] The wider net benefits/costs for society refers to the net benefit to GB consumers plus other quantified impacts for society (ie, the impact on producers (generators), environmental tax revenue, unpriced carbon and interconnectors). This is calculated by subtracting the monetised direct costs from the modelled welfare benefits. By way of comparison, in our Outline Business Case published in August 2018, the headline benefits figures referred to the modelled welfare benefits and did not capture the monetised direct costs, which were quoted separately.

Chosen option - Hard to Monetise Impacts

The monetised figures do not represent the full benefits to consumers. We expect that our chosen option will achieve further benefits from stimulating both greater competition and innovation. Better quality and more frequent settlement data for both imported and exported volumes, combined with greater administrative efficiency, should encourage non-traditional players with disruptive business models to enter the market and compete with existing suppliers. This new entry, together with new price signals, should also stimulate an innovative response from those already in the market. A faster settlement timetable means suppliers would need less collateral to cover their potential settlement liabilities. This should reduce barriers to new entry.

The resulting innovation in energy services and products should improve outcomes for consumers. For example, MHHS is expected to accelerate the growth of new energy 'tariff-only' propositions, third party managed energy services involving smart controls, bundled 'asset and tariff' offerings managed by the consumer or on their behalf; and offer consumers new ways to provide flexibility to the energy system such as peer-to-peer (**P2P**) trading and grid balancing services.

Making non-aggregated data available to central settlement systems will make aggregation for settlement more flexible and future proof. Making non-aggregated data available to industry in a manner compliant with the relevant data protection rules should also stimulate innovation in value-added services, as well as other new business models (for instance, flexibility offerings such as demand-side response (**DSR**) and P2P trading, as well as opening up the market to allow parties to provide better tariff comparisons and potential use by third party intermediaries (**TPIs**)). Finally, making the data available to academics and policy-makers, in a manner compliant with data protection rules (for instance, appropriately aggregated and/or anonymised), should improve understanding and public policy-making in the future. We have not monetised these benefits as it is hard to value innovations, and the barriers to them, that are presently unknown.

We also cannot monetise the cost to consumers of taking up new product and service choices such as smart appliances. If take up is lower than we expect, this would reduce the value of the benefits that are realised from MHHS. We have, however, sought to monetise the costs to suppliers of offering HHS-enabled products such as Time of Use (**ToU**) tariffs and presented this as a cost sensitivity.

Key assumptions/sensitivities/risks

We have considered several potential risks relating to MHHS. Broadly, these cover

- **transitional risks** while the industry prepares for and implements MHHS, including interdependencies with other programmes that could affect the quality and speed of delivery
- **ongoing post-implementation risks**, such as
  - consumer concern about sharing HH consumption data
  - low uptake of smart tariffs (such as ToU tariffs) and
  - the potential distributional impacts that may arise if the take up of such tariffs is widespread.

The scale of benefits that can be achieved from MHHS depends on successful rollout of smart meters, the levels of data available for settlement, and the market and consumer response. We have adopted mechanisms to test whether our chosen option will deliver net benefits to consumers under a range of plausible assumptions and scenarios. There is, in particular, significant uncertainty about the level of load shifting that is feasible. To reflect this uncertainty, we have used a relatively wide assumption range.

Will the policy be reviewed?	**If applicable, set review date:**
Existing industry governance processes will remain in place to provide ongoing monitoring of the quality of supplier performance under MHHS. We will monitor opt-out rates during the transition period to ensure that the data sharing framework remains appropriate. Once the new settlement arrangements have come into force, we envisage routine monitoring of load shifting trends and opt-out rates. We will as necessary review the data access arrangements to ensure that they subsequently remain appropriate.	This and other information will as necessary inform a review of the data access arrangements and help us to determine whether they remain proportionate and consistent with delivering the objectives of settlement reform. We expect to carry out a review after a period of time once the system is up and running. We will undertake the review when we feel we have sufficient evidence to do so.

Is this proposal in scope of the Public Sector Equality Duty?	**Yes**

Summary: the counterfactual, the Draft IA preferred option and our Chosen Option

This table compares the qualitative impacts of retaining the elective HHS framework, the preferred option from our Draft IA, and the option for MHHS that we have chosen to pursue.

Summary of options	Main effects on consumer outcomes	Benefits	Costs	Key considerations (Risks, assumptions, distributional impacts etc.)
Existing 'elective' HHS (the counter factual)	Status quo. Slow progress towards greater flexibility and decarbonisation	Status quo	Status quo	Likely that only less peaky consumers will be settled HH. Likelihood of only limited increases in competition and of inefficient network and generation spending
April 2020 Preferred option – MHHS for import and export with a transition period of about 4 years up to the end of 2024	New products and services, with improved quality and convenience for consumers. Downward price pressure as system cost savings passed on to consumers. Higher load shifting. Faster decarbonisation	Better demand forecasting. Lower balancing costs. Reduced collateral needs. Maximises new entry and innovation	We expect that firms will pass programme and delivery costs through to consumers	More accurate consumption data spurs innovation
Our chosen option - MHHS for import and export with a transition period of 4 years and 6 months from April 2021 to October 2025	**New products and services, with improved quality and convenience for consumers. Downward price pressure as system cost savings passed on to consumers. Higher load shifting. Much faster decarbonisation than under the elective HHS regime (albeit the benefits are delayed by 10 months compared with the April 2020 preferred option)**	**Better demand forecasting. Lower balancing costs. Reduced collateral needs. Maximises new entry and innovation**	**We expect that firms will pass programme and delivery costs through to consumers**	**The longer transition period represents our best informed expectation of what can realistically be delivered by the industry. It is intended to ensure that the new settlement arrangements are robust. Access to more accurate consumption data spurs innovation**

In preparing this IA we have had regard to the Better Regulation Framework Principles which, amongst other things, state that an IA should be developed transparently, and should concisely and consistently summarise the quantitative and qualitative impacts of the options we have considered. In doing so, we may on occasion refer the reader back to options (such as the import-only version of MHHS) that we considered in the Draft IA published in April 2020.

Associated documents

- Ahmad Faruqui and Sanem Sergici, Arcturus: International Evidence on Dynamic Pricing (July 2013)
- Baringa, Electricity System Analysis – future system benefits from selected DSR scenarios (August 2012)
- Carbon Trust and Imperial College London, An analysis of electricity system flexibility for Great Britain (November 2016)
- Centre for Sustainable Energy, Beyond average consumption - Development of a framework for assessing impact of policy proposals on different consumer groups (June 2014)
- CEPA for Ofgem, Distributional Impacts of Time of Use Tariffs (July 2017)
- Competition and Markets Authority, Energy market investigation final report (June 2016)
- Department for Business, Energy and Industrial Strategy, Non-domestic Smart Energy Management Innovation Competition (November 2020)
- Department for Business, Energy & Industrial Strategy, Better Regulation Framework Guidance (March 2020)
- Department for Business, Energy and Industrial Strategy Updated short-term traded carbon values used for UK policy appraisal 2017 (January 2018)
- Department for Business, Energy and Industrial Strategy, Hinkley Point C: Value for Money Assessment (June 2017)
- Department for Business, Energy and Industrial Strategy, Smart meter roll-out: cost-benefit analysis 2019 (September 2019)
- Department for Business, Energy and Industrial Strategy, Updated energy and emissions projections: 2018 (April 2019)
- Department for Business, Energy and Industrial Strategy, UPDATED SHORT-TERM TRADED CARBON VALUES: Used for UK Public Policy Appraisal (January 2018)
- Department for Energy and Climate Change, DECC Dynamic Dispatch Model (May 2012)
- Department for Transport, National Travel Survey (July 2019)
- Department for Transport, The Road to Zero: Next steps towards cleaner road transport and delivering our Industrial Strategy (July 2018)
- Dr Timur Yunusov and Dr Jacopo Torriti - University of Reading, Distributional effects of Time of Use tariffs based on smart meter electricity demand and time use activities. Energy Policy (submitted)
- EA Technology, Assessing the Impact of Low Carbon Technologies on Great Britain's Power Distribution Networks (July 2012)

- Elexon, Change of Measurement Class and Change of Profile Class (June 2019)
- Energy Systems Catapult, Smart Systems and Heat: Phase 2 – Summary of Key Insights (March 2019)
- Frontier Economics with support from LCP and Sustainability First, Future potential for DSR in GB (October 2015)
- HM Treasury, Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal (April 2019)
- HM Treasury, The Green Book: Central Government Guidance on Appraisal and Evaluation (2020)
- Octopus, Agile Octopus: A consumer-led shift to a low carbon future (September 2018)
- Ofgem, Consumer Survey 2019: Tracking data and insights into future energy solutions (February 2020)
- Ofgem, Consumer Vulnerability Strategy 2025 (October 2019)
- Ofgem, Decision on the Initial Project Assessment of the FAB Link, IFA2 and Viking Link interconnectors (July 2015)
- Ofgem, Decision on the Initial Project Assessment of the GridLink, NeuConnect and NorthConnect interconnectors (January 2018)
- Ofgem/PWC, Energy consumers’ experiences and perceptions of smart time of use tariffs (October 2020)
- Ofgem, Market-wide Settlement Reform: Outline Business Case (August 2018)
- Ofgem, Ofgem decarbonisation programme action plan (February 2020)
- Ofgem, Ofgem’s regulatory stances (December 2016)
- Ofgem, Our powers and duties (July 2013)
- Ofgem, Our strategic narrative for 2019-23 (July 2019)
- Ofgem, Our strategy for regulating the future energy system (August 2017)
- Ofgem, State of the energy market 2019 Report (November 2019)
- Smart Energy GB, Consumer appetite to buy energy through a lifestyle service company (March 2018)
- The Brattle Group and UCL for Citizens Advice, The Value of TOU Tariffs in Great Britain: Insights for Decision-makers (July 2017)
- UK Power Networks, Low Carbon London (March 2015)
- US Department of Energy, Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies (November 2016).

1. Problem under consideration

Section summary

In this section we describe the problems with the current settlement arrangements, set out why we need to intervene, and state our project objectives in doing so.

1.1. Energy suppliers purchase most of their electricity in advance based on their forecasted estimates of what they expect their customers to use in half-hour (**HH**) periods through the day. The difference in each HH period between the volumes of electricity purchased by suppliers to cover their needs, and the volumes their customers are assumed to have used, are identified, reconciled and paid for through the settlement system.

1.2. Consumers have traditionally been settled against an estimated profile of their consumption in each HH period. There are currently four estimated profiles - called Profile Classes (**PC**). These apply to domestic and smaller non-domestic consumers. Estimated, non-half-hourly (**NHH**) arrangements have operated for domestic and small non-domestic consumers since the electricity supply market in Great Britain was opened to competition in 1998.

1.3. Arrangements for cost-effectively settling domestic and small non-domestic consumers using actual HH consumption data (rather than estimates) were put in place in 2017 on an elective (voluntary) basis. Half-hourly settlement (**HHS**) on a mandatory basis has been in place since 1 April 2017 for medium to large non-domestic consumers. The NHH arrangements that preceded this had operated since 1 April 1994.

1.4. Smart meters are being rolled out to domestic and small non-domestic consumers. This will enable the recording of actual consumption in each HH period. However, until smart meters and market-wide half-hourly settlement (**MHHS**) are in place, suppliers will - unless they have elected to adopt HHS - continue to forecast the energy requirements needed to meet their customers’ consumption based on estimates and standard NHH load profiles rather than their customers’ actual usage data.

Rationale for intervention

1.5. This reliance on estimates means suppliers are not exposed to any variations in consumption patterns and, therefore, to the true cost of supplying their customers throughout the day. Suppliers and other retailers consequently have little incentive to innovate by offering smart tariffs and/or other products (such as batteries) that enable more flexible use of energy leading to a reduction in generation and network demand at expensive peak periods.

1.6. Suppliers may opt to introduce HHS and new products through elective HHS. However, without exposing suppliers to the cost of supply of all of their customers in each HH period, we are unlikely to see these products develop to an extent that will bring significant system-level benefits or at a speed that will help the UK achieve its net zero commitments. We expressed this view in the Outline Business Case (**OBC**) and evidence from suppliers in our subsequent Request for Information (**RFI**) supported it. As at November 2020, less than 1% of metering points were settled under the elective arrangements (registered as HH sub-100kW domestic).

1.7. Increases in intermittent generation, rising electricity demand and the development of new technologies will further increase the need for flexibility to ensure we make the best use of the energy system and keep consumer bills as low as possible. Part of this involves consumption patterns evolving to ease pressures on the grid, utilising the potential new products and innovation that we expect to be introduced as a result of MHHS. Without this, there would likely need to be significant and costly investment in network and generation assets to manage peak demand. The costs of integrating low carbon, intermittent generation and new sources of demand like electric vehicles (**EVs**), would be higher.

1.8. MHHS is a key enabler for increasing flexibility in the system, and for many parts of the BEIS/Ofgem smart system and flexibility plan. According to analysis in the Government's 2020 Energy White Paper, moving to a smarter, more flexible energy system could save the UK up to £12 billion per annum by 2050 (in 2012 prices).[13]

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[13] See Energy White Paper 'Powering Our Net Zero Future' and Modelling 2050 electricity system analysis.

1.9. The current settlement arrangements do not capitalise on the potential for smart meters to bring efficiency gains. Without smart meters, market participants forecast their purchasing requirements based on profile data rather than HH consumption data. Market participants are also uncertain about their liabilities to each other because of the length of time taken to reconcile settlement volumes fully (up to 28 months). This can mean market participants are uncertain of their financial position for a long time, and must hold collateral for about one month. These inefficient costs may be passed to consumers. Reducing settlement collateral requirements should reduce entry barriers.[14]

1.10. The smart meter rollout presents an opportunity to introduce HHS on a market-wide basis. This can then facilitate several benefits to consumers:

- greater innovation and competition in the energy market
- the right environment for system efficiency gains through demand-side response
- improved supplier forecasting of customer demand should lower suppliers' wholesale costs, which can be passed on to consumers, and
- making the settlement process itself more efficient, thus reducing costs.

Project objectives

1.11. The strategic objective is to deliver the Government's and Ofgem's objectives in a cost-effective manner, minimising the overall cost to current and future consumers of moving to a net zero carbon electricity system while maintaining security of supply and system efficiency. We will do this by minimising the need for infrastructure investment and facilitating more efficient use of generation and network assets.

[14] When a supplier fails, certain costs can be mutualised across other suppliers. While this helps to ensure that the failed supplier's customer credit balances are protected, and that the integrity of government schemes is maintained, we want to reduce the wider impact that supplier failure has on other suppliers and consumers. Part of this means taking action to ensure the cost mutualisation arrangements do not encourage inefficient entry or expansion of poorly-prepared suppliers. As part of our Supplier Licensing Review, we have taken steps to improve supplier standards of financial resilience without presenting any undue barriers to entry, innovation or expansion. A reduction in settlement collateral requirements would further reduce any such remaining barriers that existed.

1.12. Within that, the aim of the settlement reform project is to develop settlement arrangements that incentivise all energy suppliers and other retailers to encourage behaviour that contributes to a more cost-effective electricity system. We will do this by establishing new settlement arrangements that:

- link future retailers' costs to their customers' actual consumption throughout the day
- encourage new and disruptive business models via settlement arrangements that facilitate competition in new areas, leading to product and service innovation – for example, storage and automation and/or pricing – that encourages more flexible use of energy in ways that reduce consumers' bills and their carbon footprint.

1.13. Ofgem has a role to play in ensuring that the conditions are in place for innovative products and services to emerge and for consumers to be suitably protected when using them. We set out in our Decarbonisation Programme Action Plan[15] that we would ensure that those who cannot provide flexibility are not unduly disadvantaged.

1.14. As stated in our Forward Work Programme 2021/22, Ofgem aims to enable a future retail market that can deliver the technological and behavioural changes needed to support decarbonisation at lowest cost, while ensuring the interests of consumers remain protected.[16] MHHS is a key enabler of this. We are currently developing our future of retail Strategic Change Programme, focusing on areas of greatest potential consumer detriment or opportunity, with a high-level objective (amongst others) of an energy transition that works for all energy consumers, harnessing innovation and flexibility, with effective protection for consumers. We expect to begin this Strategic Change Programme in the summer.

1.15. These objectives align with:

- Ofgem's principal objective to protect the interests of existing and future consumers,
- our strategic narrative until 2023,
- our Decarbonisation Action Plan, and
- our Forward Work Programme 2021/22.

[15] See Ofgem's Decarbonisation Programme Action Plan.
[16] See Ofgem's Forward Work Programme 2021/22.

2. Approach to the Impact Assessment

Section summary

In this section we briefly describe the main features of our chosen option and explain how it differs from the preferred option set out in the Draft Impact Assessment (**IA**). This section provides a qualitative assessment of the impact of the chosen option as compared with the counterfactual of retaining the elective half-hourly settlement (**HHS**) arrangements. Section 3 then provides a quantitative comparison of these options.

Our Draft IA preferred option was based on the Design Working Group's (**DWG's**) Target Operating Model (**TOM**). The Association of Independent Meter and Data Agents (**AIMDA**), and another stakeholder, subsequently proposed alternative TOMs. We have decided to implement market-wide half-hourly settlement (**MHHS**) based on the DWG's TOM. For full details of our decision, and the assessment and reasoning for it, see our Decision Document.

As set out in our Decision Document, we have decided not to pursue an import-only version of settlement reform. Those interested in understanding the potential impacts of an import-only MHHS should refer to the third option that we explored in the Draft IA. We do not include information about that option in this document.

Options presented in this Final IA

2.1. In this document we present our estimates of the impact of three policy options. These are:

- retaining the elective HHS arrangements (the counterfactual)
- introducing MHHS based on the DWG's recommended TOM for all MPANs with a transition period of approximately 4 years ending at end-2024 (the preferred option from the Draft IA)
- introducing MHHS based on the DWG's recommended TOM for all MPANs with a transition period of 4 years and 6 months from April 2021 to October 2025 (our chosen option).

Key changes to the Draft IA

2.2. The chosen option for MHHS is, apart from the transition period, the same as the preferred option from the Draft IA. We have decided to introduce MHHS on the basis of the Target Operating Model recommended by the Design Working Group in 2019. Non-aggregated HH consumption data will be made available to central settlement systems.[17] Suppliers will have daily access, via the Data Communications Company (**DCC**), to a day's worth of data from every smart meter. There will be a faster, more efficient settlement timetable. Export-related MPANs will be within the scope of these reforms. There will be a two-phase transitional period involving systems design, development and testing and then 13 months for migration.

2.3. The difference between our chosen option and the preferred option in the Draft IA is the length of the two-phase transition period. In the preferred option from the Draft IA, the transition period would in total have lasted for about 4 years. The initial phase, to develop and test new systems and processes, would have lasted for about 3 years – in our analysis, beginning in January 2021 and running to the end of 2023. The migration phase would have followed and lasted for 1 year – in our analysis, to the end of 2024.

2.4. In the option we have chosen, the transition period will last for 4 years and 6 months. The development and testing phase will begin in April 2021. The migration phase will then run for 13 months and finish in October 2025.[18] (As noted in the Management Case of the Full Business Case (**FBC**), we intend that changes to the transition plan can be considered and made via the programme governance arrangements. Any changes to the length of the transition plan proposed will have to be approved through the programme governance set up to deliver MHHS. We propose to establish a threshold of 3 months beyond which any changes to the length of the plan would be subject to Ofgem approval and we would look carefully

[17] The advantages and disadvantages of making non-aggregated HH data available to central settlement systems are discussed in section 4 of the Draft IA consultation document and section 2 of the MHHS Decision Document. The decision on where and how the non-aggregated data is to be held has not yet been made. The data could be held in a single central hub or in multiple stores.
[18] For more details about the transition period see section 7 of the Draft IA consultation document.

at the costs and benefits of any such proposed change. Further details will be set out in our forthcoming consultation on implementation and governance arrangements.)

Other options: Export-related MPANs

2.5. As noted above, the Final IA does not include an assessment of the impact of an import-only version of MHHS. The great majority of stakeholders agreed with the view we expressed in the consultation on the Draft IA that it would not be in the interests of consumers to exclude export-related MPANs from the scope of the reforms. Thus, we do not consider it proportionate to present the option here and refer interested parties to the Draft IA for our estimation of its potential impact.

Other options: Alternative Target Operating Model

2.6. We have also carefully considered representations from the Association of Independent Meter and Data Agents (**AIMDA**) in relation to an alternative Target Operating Model to that recommended by the DWG. The alternative TOM proposed by AIMDA shares many elements of the DWG's TOM but one key difference is AIMDA's proposal that for settlement purposes, consumption data is only transferred in aggregated form. However, data would be accessible in non-aggregated or different configurations by central settlement systems for particular settlement purposes or by other interested parties.

2.7. We have examined the advantages and disadvantages of the AIMDA proposal, and of a further proposal from another stakeholder. As noted above, we have assessed these proposals against a range of factors, including efficiency and cost effectiveness, the potential for flexibility, data quality benefits for settlement, and competition benefits. On the basis of that assessment, we have decided that it would be proportionate and beneficial overall to implement MHHS based on the DWG's TOM. For full details of our decision, and the assessment and reasoning for it, see our Decision Document.

Consumer consent to sharing half-hourly (HH) consumption data

2.8. Under the existing framework as set out in the Supply Licence Conditions (**SLCs**), domestic consumers must provide opt-in consent for their HH data to be processed for settlement and forecasting purposes. Whilst daily data can be processed by default from these customers, they may opt out to monthly resolution, unless the data is required for a regulated purpose.[19]

2.9. Under MHHS the party responsible for settlement will have a legal requirement to collect HH data from domestic consumers for settlement purposes, unless the consumer opts out. In the Draft IA consultation, we proposed that daily resolution data should be collected for these purposes from these opted-out domestic consumers. However, we also recognised that those domestic consumers who had their smart meters fitted before the new MHHS data sharing framework enters into force did so under the existing framework that included the right to opt out to monthly resolution of data collection for these purposes. We therefore sought evidence to understand whether it was proportionate to require daily resolution data to be collected for these purposes from this subset of domestic consumers under MHHS.

2.10. In light of the responses received, we set out two policy decisions in our accompanying Decision Document relating to domestic customers :

1) There will be a legal obligation on the party responsible for settlement to collect data at daily granularity from domestic "new system customers" who have opted out of HH data collection for settlement and forecasting purposes.[20]

2) The granularity of data to be processed for "old system customers" will be in line with the existing framework.[21]

2.11. We believe that this data sharing framework appropriately balances consumer privacy considerations with the need to ensure that as much high-resolution data as possible is entered into the settlement system to contribute to achieving the benefits

[19] Such as in order to provide an accurate bill, and to investigate suspected theft and/or fraud.
[20] "New system customers" refer to those consumers who had their smart/advanced meters installed, or decided to change supplier/contract, after the new framework entered into force.
[21] "Old system customers" refer to those consumers who had their smart/advanced meters installed before the new framework enters into force, and have not decided to change supplier or contract since.

of the reforms. Further details on next steps for the implementation of the MHHS data sharing framework are set out in our April 2020 open letter to stakeholders.[22]

2.12. We also take this opportunity to remind stakeholders that parties in possession of personal data must comply with data protection law, including the General Data Protection Regulation (Regulation (EU) 2016/679) as retained in domestic law following the UK's withdrawal from the European Union ("**UK GDPR**").

MHHS compared to elective HHS

2.13. In the Outline Business Case (**OBC**), we said that supplier incentives under the elective arrangements were unlikely to be strong enough to facilitate a transformational shift in consumption patterns.[23] We cited the following reasons:

- information asymmetries allow suppliers to 'cherry pick' the customers they try to influence, particularly in a market with significant levels of customer disengagement
- suppliers would incur significant upfront costs in changing IT systems and operations
- suppliers would be exposed to new risks (for example, in forecasting customer demand accurately without Profile Classes, and whether customers would take-up any new products and services) and this could deter innovation, and
- not all the benefits of HHS flow directly to suppliers, which makes the incentives on suppliers to introduce HHS weak relative to the potential benefits for consumers, and justifies a market-wide approach.

2.14. Achieving the higher end of the potential benefits presented in the Final IA would likely require a critical mass of consumers being HH settled, for Time of Use (**ToU**) products and other innovations to be commonplace and for consumers to shift their consumption from peak periods as a result. In reaching a conclusion about whether this could happen without MHHS, we have considered recent developments in the

[22] For more details see the open letter.
[23] The CMA also expressed this view in its Energy Market Report 2016.

elective market and suppliers' responses both to our 2019 Request for Information (**RFI**) and to the consultation on the Draft IA.

2.15. Elective HHS enables those firms wanting to be early movers and innovators in this market to develop new products and services.[24] However, as at November 2020 less than 1% of domestic metering points were registered as HH sub-100kW domestic. Of the suppliers that responded to our RFI in 2019 and Draft IA consultation in 2020, only a small number said they were offering tariffs facilitated by HHS. No other supplier that responded said that they would develop HHS-facilitated tariffs in the short term. A small number of suppliers said they would consider developing these tariffs in the future if long-term elective HHS were to continue under BAU, but only if there were a commercial case for these products (for example, if there were an increase in consumers demanding ToU tariffs). No other supplier that responded said they would develop HHS-facilitated tariffs without Ofgem making a formal decision to introduce MHHS.

2.16. One supplier said MHHS would remove barriers to further innovation that exist under the elective arrangements, including an absence of industry-wide gain/loss processes for half-hourly settled customers, the need to switch customers from non-half-hourly settlement (**NHHS**) to HHS and a lack of effective performance oversight, as well as allowing suppliers to benefit from economies of scale when offering smart tariffs. They thought that these efficiency gains from cheaper operational costs and economies of scale were needed to allow suppliers to offer smart tariffs to a wider customer base. The supplier suggested there should be guidance for suppliers and agents and new, bespoke governance processes.

2.17. To be clear, though, the supplier does not regard these improvements as a substitute for MHHS. We agree. Improvements to the elective process would not address the main barrier to innovation, which is that suppliers do not face accurate signals about the cost of serving their customers throughout the day. MHHS is necessary to remove that barrier.

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[24] For example, Bulb Energy has partnered with EDMI Limited to undertake a trial of a smart Electric Vehicle charging load management service with funding from BEIS. Phase 2 of the trial ran in 2020.

2.18. That said, Ofgem will be looking at whether there are barriers to the use of elective, what they are, and what could be done to remove them so as to bring forward some of the benefits of HHS before MHHS comes into force.

2.19. Several suppliers noted that consumer demand would drive their product innovation. We consider that consumer demand for innovative products is likely to be higher under MHHS than under the elective arrangements. One supplier noted the importance of changes under the Electricity network access and forward-looking charges Significant Code Review (**SCR**) in determining the direction of their product innovation.

2.20. We conclude that elective HHS will deliver insufficient load shifting to produce the scale of system-level benefits we seek. Without MHHS it is unlikely that the disengaged (or less engaged) would be given a chance to reduce peak time demands via Time of Use tariffs, smart appliances and battery storage. Similarly, MHHS is expected to facilitate some of the options that are under consideration in the Electricity network access and forward-looking charges SCR.

2.21. Finally, there are process and efficiency reasons for introducing MHHS rather than relying on incrementally increasing HHS uptake under the elective arrangements. A number of the direct benefits, such as shorter settlement timeframes and removing the profiling arrangements, can only be realised with a significant number of HH-settled customers. MHHS would avoid having to run half-hourly and non-half-hourly settlement systems concurrently. Similarly, MHHS avoids any potential unintended consequences where customers change between HHS and NHHS systems.

2.22. This qualitative assessment strongly suggests that MHHS is the best way to deliver the project objectives. The following sections evaluate the costs and benefits of our chosen option and present comparisons, where appropriate, with the counterfactual and with the preferred option in the Draft IA.

3. Monetised direct costs

Section summary

In this section we set out our analysis of the monetised direct costs of introducing market-wide half-hourly settlement (**MHHS**) under our chosen option as compared with retaining the existing elective arrangements.

Based on responses to the Request for Information (**RFI**), the consultation on the Draft IA and other evidence from stakeholders, we have estimated the costs under our chosen option that could be borne by industry participants, including suppliers, supplier agents, the DCC, Elexon, distribution network businesses, the Electricity System Operator and the Low Carbon Contracts Company.

At the end of the section we summarise the total direct costs of our chosen option and, acknowledging the uncertainty involved, present a table of cost ranges. We also compare the aggregate total costs of our chosen option with the preferred option published in the Draft IA.

Approach to assessing direct industry costs

3.1. Industry will incur costs in implementing and operating MHHS. We have classified these costs as transitional costs, which relate to the investment needed to implement the changes, or ongoing costs for operating the new settlement arrangements over and above 'business as usual' operating costs. The costs will vary for each market participant.[25]

3.2. Transitional costs include the following:

[25] While we expect industry to incur an overall net cost, these are likely to be distributed unevenly between individual participants. In some areas, we expect industry costs to reduce against the counterfactual. For example, savings can be expected to arise from improved forecasting of customer demand, and from changes to the settlement timetable. These benefits are incorporated within the overall costs reported in this section.

- upgrades to existing industry participants' IT capabilities so that they are able to interact as necessary with the new Target Operating Model (**TOM**), including the costs of migrating Meter Point Administration Numbers (**MPANs**) to the new settlement arrangements
- costs arising during and immediately after the migration period to monitor the new arrangements in live operation and deal with unexpected problems experienced after the end of migration[26] to the new settlement arrangements (excluding programme costs)
- programme costs (central delivery assurance, detailed programme design and engagement costs, including for Ofgem).

3.3. Ongoing costs include the following:

- operation of the TOM
- costs for industry participants to maintain and operate their new IT arrangements, including maintaining an acceptable level of IT resilience
- changes to staffing requirements to manage the new settlement processes
- any reduction in costs due to increased efficiency in the required processes.

3.4. We have not included, as part of the central estimate of costs, the costs of suppliers developing, marketing and billing for new products and services after MHHS comes into effect. That is because the introduction of MHHS does not automatically require these costs to be incurred. However, we have considered some of these costs as part of a sensitivity analysis, and note that these extra costs might be necessary to achieve the higher end of the potential benefits.

Accounting for uncertainty

3.5. We recognise that MHHS will impose significant costs on the industry. We have made extensive efforts to ensure that we understand these costs, and their drivers, as well as we can. Where the costs have been difficult to obtain or verify we have adopted a consciously cautious approach to ensure that we are, as far as possible, mitigating the risk of underestimating these. For example, where it was not possible to get

[26] This is the point by which all MPANs must be settled under the TOM.

quantitative data from particular stakeholders, we sought to fill in the gaps by estimating the costs using data from similar stakeholders. Finally, in line with Green Book guidance, we have made some adjustments to the costs to correct for potential optimism bias that might have been present in the costs reported to us. We summarise our approach at paragraph 3.101 and in the accompanying table.

3.6. We acknowledge the difficulty for industry participants of calculating the exact costs of implementing MHHS at this stage of TOM development. To take account of this, we invited stakeholders to qualify their quantitative responses to the RFI using an uncertainty margin, which we could then use to calculate a cost range that could be compared with our central estimate of costs. We present our cost range analysis at the end of this section of the IA.

Present Value (PV) calculations

3.7. In line with Green Book guidance,[27] we have calculated the PV by applying a 3.5% discount rate to real values (using GDP deflator to remove inflation effects). We have used the year 2018 as the base year to calculate real prices to ensure comparability with the figures published in our Outline Business Case (**OBC**) for MHHS. All values are discounted to 2018. Unless otherwise stated, we have applied the same methodology to both costs and benefits.

3.8. We have taken the following approach to investment periods to calculate the total costs in PV terms. Transitional costs (one-off costs) are divided equally across the transition period (except when we had information that allowed us to attribute costs to specific years). Under the chosen option, the transition period of 4 years and 6 months means transitional costs are accounted for over the period April 2021 to October 2025. Ongoing costs - new Business As Usual (**BAU**) costs - start after the migration phase is finished and are accounted for over a 20-year period. Under the chosen option this period is November 2025 to December 2045. All costs are discounted using the above methodology.

[27] HM Treasury, The Green Book: Central Government Guidance on Appraisal and Evaluation (2020).

3.9. The length of the transition period is the key difference between the chosen option and our Draft IA preferred option. It will affect the duration of the transitional costs and when we should start computing annual ongoing costs (new BAU costs). It will therefore affect the total costs (in PV terms). To ensure comparability between the different options, those costs (in PV terms) are always calculated for 2021-2045.

3.10. Under the preferred option in the Draft IA the transition period of 4 years would mean that annual ongoing costs start in 2025, almost a year earlier than under the chosen option. We show how total costs change between the two options in table 9 at the end of this section.

Suppliers

Our Chosen Option – MHHS for import and export Meter Point Administration Numbers (MPANs) with a transition period of 4 years and 6 months

3.11. The table below summarises the estimated net costs[28] of our chosen option for suppliers (central estimate). It includes adjustments to account for those suppliers that did not respond to our RFI and adjustments we have made to some supplier responses. For example, to account for the suppliers from which we did not receive data or only partial data, we sought to estimate the cost of MHHS per MPAN for the different sectors of the market and for different categories of cost, and uplifted the costs accordingly.

3.12. In some cases, suppliers reported costs that we did not consider to be attributable to MHHS (for example the cost of developing new products enabled by MHHS). We did not include these costs in the central estimate. However, the costs that could be necessary to achieve the higher end of the benefits are shown in table 8 below. Where we proposed to adjust or disallow costs, we informed the relevant stakeholder.

[28] We describe the total costs in this section as net costs because stakeholders reported costs and costs savings. The total costs are the net of these.

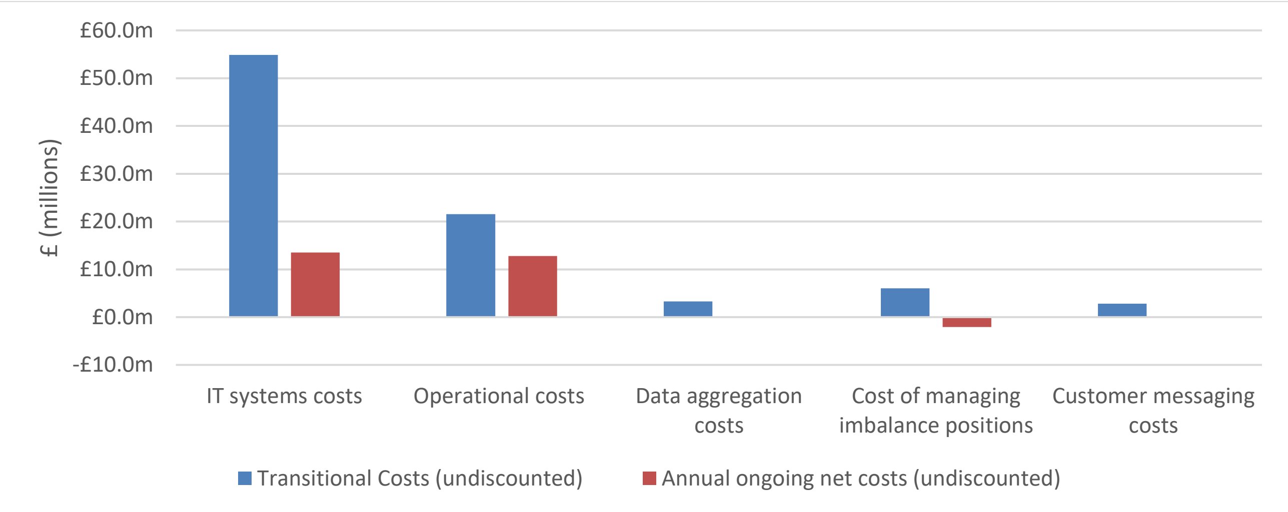
3.13. We have included some costs incurred by software providers that provide settlement-related services to suppliers.[29] The data is presented as a total and as a cost breakdown by categories of costs. In estimating supplier costs, we took appropriate account of recent corporate transactions in the sector.

Table 1: Estimated net direct costs for suppliers of our chosen option (£ millions)

Types of cost	Transitional costs (undiscounted, £2019)	Annual ongoing net costs (undiscounted, £2019)	Total net costs (2021-2045), 2018 PV
IT systems	£54.9m	£13.5m	
Operational	£21.5m	£12.8m	
Data aggregation	£3.3m	£0.0m[30]	
Managing imbalances	£6.0m	-£2.1m	
Customer messaging	£2.8m	£0.0m	
Total costs	**£88.5m**	**£24.2m**	**£341.5m**

3.14. The figure below shows the undiscounted cost breakdown of our chosen option.

Figure 1: Undiscounted net direct costs for suppliers of our chosen option (£ millions)



[29] As with the data from suppliers, some adjustments were required to account for those software providers that did not respond to our RFI.
[30] The ongoing costs of aggregating HH data have been accounted for within Elexon's ongoing costs.

3.15. For all MHHS options, suppliers would need to invest in new IT systems and/or upgrade existing IT systems to interact with the new central settlement system and TOM services. Operational costs would increase, mainly due to the increase in the complexity of the consumption data that suppliers would need to manage. Under any option, suppliers would incur costs in managing imbalance positions and in customer messaging (given the need to inform customers about their data sharing options).

3.16. On the other hand, suppliers should make cost savings as a result of having more detailed consumption data and improvements in energy consumption forecasting (which would, for example, reduce the exposure to imbalance costs).

3.17. There was considerable difference between suppliers on their cost drivers. This depended on factors such as the flexibility and cost of amending existing systems, design decisions, and different levels of efficiency in implementing and operating new processes. However, we outline below some general trends about cost drivers.

Transitional costs

3.18. The main cost driver is upgrading existing and/or buying new IT systems so as to operate under the new settlement arrangements. Supplier responses varied as to which IT processes would need substantial investment. Some suppliers cited costs relating to the removal of profiling activities and change of measurement class of non-half-hourly (**NHH**) MPANs. Others emphasised the costs relating to collecting and processing metering data. A few highlighted costs arising from changes to demand forecasting activity.

3.19. Transitional operational costs were the second biggest cost category, though less than half the total for IT costs. Supplier responses again varied considerably, for example in relation to balancing costs. The two most costly processes were managing customer contract communications and demand forecasting.

Annual ongoing costs

3.20. In aggregate, reported IT and operational ongoing costs were almost the same. However, this masks significant differences among larger suppliers about which category of costs would be larger. Some suppliers expected to make net operational savings.

3.21. The main drivers of ongoing IT costs are collecting, transferring and holding HH consumption data, and demand forecasting activities. The main drivers of ongoing operational costs are transferring and processing HH metering data, and managing customers' contract communications. Some suppliers reported expected net cost savings from demand forecasting activities due to the improvement of forecasting tools using more granular consumption data. However, they noted higher uncertainty around the expected cost savings compared to the expected costs.

3.22. Respondents did not anticipate any net ongoing costs for balancing, customer messaging or meeting environmental scheme obligations. Some expected net ongoing savings from balancing costs due to more accurate consumption data.

3.23. Some suppliers with 'in-house' agents[31] cited an increase in ongoing costs as a result of our proposed changes to the settlement timetable.[32] These costs related mainly to making more frequent manual meter reads where a consumer is not on a smart meter and because of an assumed requirement for more timely fault resolution. We expect the Balancing and Settlement Code Performance Assurance Framework (**BSC PAF**), when assessing risk and deploying performance assurance techniques, to set performance targets taking into account factors such as (but not limited to) the number of traditional meters remaining, dependency on DCC performance and a reasonable level of meter faults. In its response to the consultation on the Draft IA, Elexon stated that it had a similar expectation.

3.24. Accordingly, we have not accepted all the cost increases estimated in this area by suppliers with in-house agents. Most suppliers did not provide evidence about the impact of making non-aggregated data available to central settlement systems. Those that did (mainly those with in-house agents) thought that the ongoing costs of such a model would be similar to those experienced in the market today.

[31] Agents can carry out certain settlement-related functions on behalf of suppliers, including data collection, data aggregation and meter operation.
[32] Our settlement timetable proposals were described in section 5 of the consultation document and decisions relating to those proposals are set out in the Decision Document also published today.

3.25. We did not receive quantitative evidence about the ongoing costs that could be incurred by software providers that provide settlement-related services to suppliers. We did, though, speak to some software providers during the preparation of this IA and those conversations have informed our approach to estimating these costs. In light of this, we have included some ongoing annual costs in the low millions in the total costs.

Export MPANs

3.26. The vast majority of respondents to the RFI and the consultation on the Draft IA stated that MHHS should apply to export-related MPANs and should be implemented over the same time period as MHHS for import-related MPANs.

3.27. In response to our RFI, three large suppliers said the costs of settling export MPANs half-hourly would either be the same or very similar to the per MPAN costs of MHHS for imports. One larger supplier said that its systems for export metering were largely manual. Two other suppliers said they could not quantify the impact of settling export MPANs on a HH basis because they did not offer export tariffs at the time of the RFI (which closed before the Smart Export Guarantee launched on January 1 2020).

3.28. Based on the RFI responses we received, we estimate that implementing MHHS for export MPANs will impose transition costs of £4.15 million on suppliers. However, a small number of suppliers that responded to the RFI reported ongoing costs or savings, leading to estimated overall savings of £200,000 per annum, attributable to factors including improved forecasting. We did not receive many responses from smaller suppliers but expect that many currently either have manual processes for export or do not serve export customers.

3.29. Under the Smart Export Guarantee (**SEG**), suppliers with over 150,000 domestic customers have been required to offer export tariffs since January 2020 for specific onsite renewable generation technologies up to 5MW, or up to 50kW for Micro Combined Heat and Power.[33] The launch of the SEG should mean that many more

[33] For more information on our website see Smart Export Guarantee.

export MPANs are registered before MHHS comes into effect. In response to our RFI, two suppliers said that because of this it would be reasonable to introduce MHHS for export MPANs at the same time as for import MPANs. Three large suppliers said that there would likely be savings if we brought in MHHS for import and export at the same time. Several other suppliers reported that the relative implementation timings for import and export would have little or no impact on their transitional or ongoing costs. However, one smaller supplier said that, as they believe they would need a separate system for export MPANs, it would be helpful to introduce MHHS for export 2 years after import MPANs.

3.30. The responses to the consultation on the Draft IA provided no new evidence that would change our estimation of the costs and benefits of including export related MPANs. However, some raised concerns about how MHHS for export would interact with the SEG and FITs schemes. We discuss this in the Decision Document.

Transition period

3.31. In our RFI, we asked suppliers to assume an overall transition period of 4 years, based on 3 years to implement the TOM and 1 year to migrate MPANs. We asked how their costs might change assuming a 3- and a 5-year transition period instead. The majority of suppliers that responded to the RFI did not identify significant differences in costs whether the transition period lasted 3, 4 or 5 years. However, some suppliers were concerned about a potential lack of dedicated resources while the industry was seeking to implement faster switching.

3.32. These suppliers said that a rapid transitional period could increase costs on suppliers as a result of having to procure additional resources to handle the extra work in 2020 and 2021. One supplier suggested that a 3-year transition could increase implementation costs by as much as 25% compared to a transition period of 4 years. Without additional resources, a rapid transition over 3 or 3½ years could affect the design quality and overall robustness of the new settlement arrangements.

3.33. Two suppliers said that a transition to MHHS over 5 years might allow other industry changes to be bedded in, and so make the transition more straightforward. One other supplier expressed concern about resource availability in the short term but said a 5-year transition period would significantly increase uncertainty. For this supplier a 4-year period would strike the right balance.

3.34. After considering the RFI responses, we consulted on a preferred transition period of about 4 years. As noted above, we have carefully considered industry feedback about the transition period and have decided that MHHS should be implemented over a period of 4 years and 6 months. For full details see our Decision Document.

Independent supplier agents

Our chosen option – MHHS for import and export MPANs with a transition period of 4 years and 6 months

3.35. The table below summarises estimated net costs of implementing our chosen MHHS option for independent[34] supplier agents. Under our chosen option (and the preferred option from our Draft IA), supplier agent functions would shift from the current ones of meter operator, data collector and data aggregator to new ones of metering and data service provider. Aggregation for the purposes of settlement would no longer occur outside central settlement systems. Instead, non-aggregated data would be made available to central settlement systems for the purposes of calculating the settlement imbalance.

3.36. We have not received costs from all independent supplier agents in the market. In order to derive an approximate set of costs for all the independent supplier agents in the market, we have applied a 25% increase to the IT and operational costs reported to us. We believe this approach is conservative and may even overstate the costs to a small extent. For more details see paragraph 9.16 of the Decision Document.

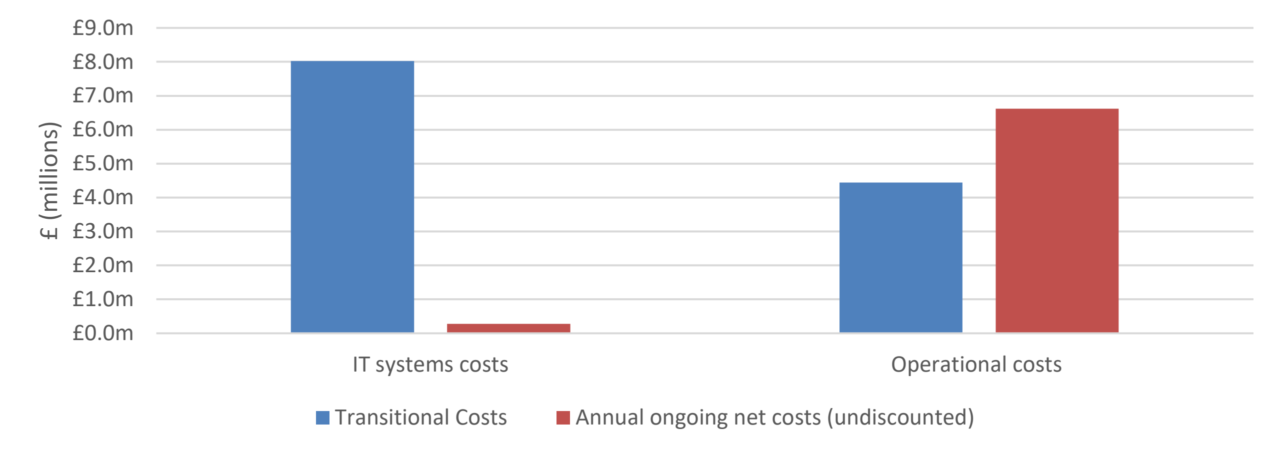
Table 2: Estimated net direct costs for independent supplier agents of our chosen option (£ millions)

Costs of MHHS	Transitional Costs (undiscounted, £2019)	Annual ongoing net costs (undiscounted, £2019)	Total net costs (2021-2045), 2018 PV
IT systems costs	£8.0m	£0.3m	
Operational costs	£4.4m	£6.6m	
Total costs	£12.5m	£6.9m	£86.7m

[34] 'In-house' supplier agent costs are covered under the supplier costs section.

3.37. Figure 2 below breaks down the undiscounted costs for independent supplier agents.

Figure 2: Undiscounted net direct costs for independent supplier agents of our chosen option for MHHS (£ millions)



3.38. There was general agreement among supplier agent responses about the main ongoing cost drivers: these related to the operational costs of processing and validating meter data, and collecting, storing and transferring that data. Supplier agents also noted (alongside suppliers with in-house agents) that shortening the settlement timetable would increase meter reading costs as agents adopt more intensive dialling and/or site visit practices. As we have already said, we expect the BSC PAF, when assessing risk and deploying performance assurance techniques, to set performance targets taking into account factors (but not limited to) such as the number of traditional meters remaining, dependency on DCC performance and a reasonable level of meter faults. In its response to the consultation on the Draft IA, Elexon stated that it had a similar expectation.

3.39. The main transitional costs relate to IT system changes in order to handle the increased data and communications required.

3.40. Under our chosen option for MHHS, supplier agents would have to make non-aggregated data available to central settlement systems. This can be expected to have an impact on supplier agent revenues, as they currently carry out the data aggregation role. We received limited quantitative information on the impact on revenues from most respondents. However, we have not included this in the ongoing costs for these options as the loss of revenue to supplier agents does not result in an additional cost to consumers.

3.41. We do not therefore propose to include the future and potential future supplier agents' lost revenues in the total policy costs. However, we have included some transitional costs of stopping the data aggregation services (such as the cost of renegotiating existing contracts).

3.42. If aggregation for settlement purposes were to continue to occur at the supplier agent level, supplier agents thought data aggregation costs would be similar to the costs of aggregating data today, but that there may be a small one off cost to upgrade the hardware. They thought the costs of transferring data, in comparison to options 2 and 3, would be lower as the data would be aggregated prior to being transferred to central settlement systems.

3.43. As noted above, we have decided that non-aggregated data should be made available to central settlement systems. We set out our reasons for the decision in section 2 of the Decision Document.[35] For more information about the economic impact of this on supplier agents, see section 3 of the consultation document.

Export MPANs and the transition period

3.44. Supplier agents who responded to the RFI said that their systems could already handle export MPANs so the only additional costs for introducing MHHS for export MPANs would be the costs associated with serving the additional metering points.

3.45. All the supplier agents that responded to the RFI stated that the duration of the transitional period would have no impact on their operational costs. Most supplier agents took a similar view in relation to transitional costs.

3.46. For further information about our decision in relation to export MPANs and the MHHS transition period see our Decision Document.

[35] See the Decision Document (this links to all the MHHS documents published on 20 April 2021).

Data Communications Company

Our chosen option - MHHS for import and export MPANs with a transition period of 4 years and 6 months

3.47. The Data Communications Company (**DCC**) maintains the national infrastructure that connects smart meters to industry users such as suppliers and network operators, under licence.

3.48. SMETS2 meters are enrolled onto the DCC's national communications network when installed and commissioned. SMETS1 meters use separate communications and data services which have been procured by individual energy suppliers. The DCC is required to develop a communications service for at least 99% of the SMETS1 population and enrolment of SMETS1 meters into the national network has begun. These SMETS1 meters are being enrolled remotely, without the consumer needing to take any action. Licence conditions require that suppliers take 'all reasonable steps' to enrol SMETS1 meters within 12 months of being able to do so, and to replace any unenrolled SMETS1 meters with SMETS2 meters by the end of 2021.[36]

3.49. In our RFI from 2019 we asked the DCC to estimate the cost of two scenarios for data retrieval from smart meters under MHHS:

1 - Retrieving one day of HH metering data, daily, from every smart meter, and
2 - Retrieving one month of HH metering data, daily, from 1 in 30 smart meters.

3.50. The DCC provided costs for scenario 1. The DCC's view, which we reported in the Draft IA, was that scenario 2 would cost at least twice as much as scenario 1. This is because it would require the localised delivery of large volumes of data, create an inefficient distribution of load and so require extra investment to manage (for example more localised large volume uplinks). This remains the DCC's view.

3.51. The DCC also felt scenario 2 would be less practical in that pulling a month's worth of data would be more likely to increase the failure rate of service requests, which

[36] Electricity supply standard licence condition 54.4 to 54.7.

would in turn result in more service requests being required to retrieve the data. Again, this remains the DCC's view. We have not received any evidence or recommendations to the contrary from other stakeholders. Consequently, in this Final IA, we have used an updated set of costs from the DCC for scenario 1. These costs assume that any new services supported by the TOM, such as vehicle-to-grid services and peer-to-peer trading, have their data requirements met by the MHHS service and do not result in additional load being placed on the DCC's systems.

3.52. In the Draft IA we noted that the DCC had provided a high level estimate of the net costs for implementing MHHS over 4 years in the general region of £10 million. In the light of further discussions with the DCC, we have updated these costs, which are now in the general region of £20 million. The costs include both direct programme resource costs and additional necessary incremental costs associated with retrieving one day of HH metering data, daily, from every smart meter (scenario 1 above). These costs also include estimated costs relating to export MPANS.

3.53. The one-off transitional costs include those associated with implementing the necessary architectural changes, responding to any changes to industry specifications and upgrading the communications hub firmware. The DCC estimated that these costs would be absorbed over an 18-month period. The ongoing annual costs (which the DCC estimates to be in the hundreds of thousands of pounds) reflect the additional costs necessary to operate the new infrastructure. These costs have been slightly amended from the Draft IA, where we estimated them to be in the low millions of pounds.

3.54. The DCC has stated that it can deliver the changes required within two years, though costs associated with programme overheads could increase accordingly if longer delivery timescales than this were to be required. It is noted that a Smart Energy Code (**SEC**) modification will also be required alongside any DCC changes.

3.55. The DCC has told us that the costs per meter will be higher for SMETS1 than for SMETS2 meters because these devices require a different processing approach than SMETS2 meters. This extra cost was not included in our draft IA. The DCC is considering how best to minimise the SMETS1-related costs of introducing MHHS.[37] We have included all the costs reported by the DCC in our central estimate of costs.

3.56. The DCC is still evolving the high-level design that has driven these cost estimates, and has said that as the industry requirements become firmer, so will the costs. However, we expect the DCC to develop appropriate solutions to deliver MHHS in a cost-effective way. All costs incurred by the DCC, including those for MHHS, will be scrutinised through the annual price control assessment. We expect the DCC to ensure all costs incurred are economic and efficient, seeking out ways to drive costs down over the programme to ensure value for money.

Elexon

Our chosen option - MHHS for import and export MPANs with a transition period of 4 years and 6 months

3.57. These paragraphs (up to 3.64) relate only to Elexon's costs as the operator of the central settlement system. They do not relate to Elexon's programme management costs, which are discussed later in this section.

3.58. Elexon estimates that it would face some transitional costs (in the low to mid millions of pounds) but these would be balanced by ongoing annual cost savings, leading to potential net cost savings overall.

3.59. The main cost drivers identified by Elexon are the one-off development costs for the IT system and process changes required to implement the new TOM services, as well as the one-off costs of decommissioning the existing NHH services.

3.60. For ongoing costs, Elexon believed there will be an ongoing net benefit of decommissioning the NHH services (processes as well as systems) and replacing them with the new TOM services. Elexon also identified potential cost savings which might arise from the removal of NHH services, such as no longer being required to send Market Domain Data and profiling data through the Data Transfer Network

[37] For more information on this issue see section 4 of our Decision Document.

(**DTN**). This would significantly reduce Elexon's DTN traffic volumes. Elexon also identified cost savings because the current HH agents and systems are less costly to assure/audit compared with the NHH agents and systems.

3.61. The most significant potential ongoing cost increase identified by Elexon would arise if there were a need to extend the technical assurance service for non-smart meters (with current transformers) or advanced meters. However, Elexon believed it was unlikely that this would be required.[38]

3.62. If aggregation continued to take place outside the Balancing and Settlement Code (**BSC**) central systems, Elexon believed there would be little cost difference compared to the preferred TOM. The design of the load shaping service as part of the TOM would require central systems to process large amounts of meter point level HH data so as to create the load shapes. There would, therefore, be no significant cost saving from storing less data if data were to be aggregated outside central systems for settlement. In addition, other industry changes, notably BSC Modification Proposals P344 (Project TERRE) and P375 (behind the Meter) mean BSC systems will need to be able to process meter point level data regardless of where data is aggregated for settlement purposes.

Export MPANs and the transition period

3.63. In relation to its own systems, Elexon does not believe there would be any operational difference between MHHS for import and export MPANs. Elexon has told us that its systems would not, therefore, require significant additional changes if we decide to mandate HHS for export.

3.64. Elexon believes it will take approximately two years to design, build and carry out pre-integration testing for the required changes to BSC central settlement systems. Elexon believes that it will be in a position to start this process at the point that the AWG has made its recommendations. Elexon does not believe any cost savings would arise from taking longer than two years to complete its new central settlement

[38] The Retail Code Consolidation SCR recently consulted on whether to move metering assurance, including technical assurance, to the Retail Energy Code from the BSC. More information can be found on [the Ofgem website.]

system. However, Elexon notes that a longer transition period would delay the benefits of MHHS and would potentially increase the transition costs if there were further support of industry testing with participants and service providers.

Distribution Network Operators

Our chosen option - MHHS for import and export MPANs with a transition period of 4 years and 6 months

3.65. The table below summarises the estimated net costs for Distribution Network Operators (**DNOs**) and Independent Distribution Network Operators (**IDNOs**).

Table 3: Estimated net direct costs for DNO/IDNOs of our chosen MHHS option (£ millions)

Costs of MHHS	Transitional Costs (undiscounted, £2019)	Annual ongoing net costs (undiscounted, £2019)	Total net costs (2021-2045), 2018 PV
Operational costs: Export	£1.3m	£0.1m	
IT costs and other operational costs	£0.6m	£0.0m	
Total costs	**£1.9m**	**£0.1m**	**£2.1m**

3.66. We have been told by DNOs and IDNOs that their main cost drivers are one-off costs relating to registering export MPANs for customers that do not currently have one and changes to the DURABILL and Metering Point Registration System provided by St. Clements (which would be shared amongst all DNOs and IDNOs). The transitional costs associated with registering export MPANs are £1.2m, accompanied by £50,000 of ongoing costs associated with the increased volume of export MPAN registrations. Separately, we have also been told that costs will likely be incurred for the modification of associated downstream and upstream systems as well as costs associated with programme engagement and testing. We have not been provided any quantitative values for this.

3.67. We did not receive much quantitative information from IDNOs but they identified similar cost drivers as DNOs. The costs to IDNO of changes to the DURABILL and

Metering Point Registration System have been accounted for, but we have not been able to account for the costs to IDNOs of registering export MPANs.

3.68. Many network operators felt they did not have enough information to provide costs for Unmetered Supply (**UMS**)[39] customers, and raised concerns about the costs to NHH UMS customers of moving to HH regimes. One area of concern was the frequency of inventory updates required. Currently, HH UMS customers update their inventories monthly with the network operator and NHH UMS customers update their inventories annually. One network operator estimated that if its entire UMS portfolio were to move to monthly inventory updates that would cost in the region of tens of thousands of pounds per annum.

3.69. Network operators also raised concerns about charges that could potentially be levied on small UMS customers if they were to be settled half-hourly. Currently, half-hourly data for HH UMS customers is created by their meter administrators. This is a relatively manual process that requires significant interaction with the customer. One meter administrator estimates that the customer is charged thousands of pounds per annum for this service.

3.70. For NHH unmetered customers, unmetered supplies operators and data aggregators apply similar profiling processes as for metered customers to their supplier's data. One meter administrator estimates that the data aggregator charges the supplier an annual fee in the region of 10s of pounds per MPAN for this service. If current NHH unmetered supply customers were to be charged under the current HH regime, network operators suggest that these charges could be significantly more than their total energy bill. We do not believe that monthly inventory updates or the current half-hourly data aggregators' (**HHDAs**) charging regime would be proportionate for smaller UMS customers.

3.71. There is currently a Distribution Connection and Use of System Agreement (**DCUSA**) modification DCP 375 at the consultation stage that is looking at amendments to the

[39] An Unmetered Supply is any electronic equipment that draws a current and is connected to the Distribution Network without a meter recording its energy consumption. UMS inventories are lists of equipment and running patterns associated with a UMS connection.

unmetered supplies national terms of connection, including a provision that seeks to change the obligations for inventory updates for all UMS customers so that updates are required when there is a change, and if there is no change an annual confirmation of no change.[40] If DCP375 is approved, it could mean that there is no change to inventory update obligations on current NHH customers with stable inventories when MHHS is implemented.

3.72. We agree with stakeholders about the need for further detail about the MHHS cost impact on unmetered customers so this can be understood better and addressed appropriately, as industry develops the further detail of the TOM. We expect industry to ensure that its solution to the treatment of unmetered customers is proportionate and addresses the potential cost impact.

Export MPANs and the transition period

3.73. Including export-related MPANs in MHHS will impose some costs on DNOs and IDNOs. Based on the evidence that we have received, DNOs and IDNOs would incur £1.2m of transitional costs and about £50,000 of ongoing costs associated with increased export MPAN registration.

3.74. Most network operators believed that the length of the transition period would not affect their costs. Some DNOs said that suppliers would need to provide them with the information required to register export MPANs in a timely manner and that this would be the main influence on how long network operators needed to implement the changes required for MHHS.

Data transfer costs

3.75. ElectraLink currently provides the data communication infrastructure necessary to facilitate electricity retail settlement. ElectraLink does this through the Data Transfer Service (**DTS**), part of the Energy Market Data Hub (**EMDH**).

[40] More information on DCP 375 can be found on the DCUSA website.

Our chosen option – MHHS for import and export MPANs with a transition period of 4 years and 6 months

3.76. MHHS will significantly increase the volume of settlement-related data traffic that will be exchanged between parties within the system. ElectraLink estimates that monthly data traffic could increase by approximately 2,600 GB (over 100 times the volume of half-hourly (**HH**) data currently being processed) if all MPANs in the market were settled half-hourly. Any data transfer network must be able to accommodate that extra traffic securely and cost effectively.

3.77. Under MHHS, one option could be to expand ElectraLink's existing DTS communications network as market participants are already connected to it. ElectraLink believes that the DTS platform is suitably scalable to enable it to accommodate the extra data traffic cost-effectively and with minimal disruption to industry.

3.78. We have not decided which communications solution should be used to transfer data under the TOM. Here, we cite the estimated costs to ElectraLink of using its communications network in order to indicate the magnitude of costs that may be involved. There are other possible solutions to consider. The AWG will consider the logical requirements for transferring data under the TOM and consider options accordingly. Cost-effectiveness and data security will be important considerations and therefore we expect any communications solution should be in the same order of magnitude as the ElectraLink costs.

3.79. We will be consulting shortly on our proposals for the implementation and governance arrangements, including our proposals for key principles on when decisions would be made by Ofgem.[41] However, until these new arrangements are in place, Ofgem will continue to make decisions (including on the AWG's recommendation) under the current SCR governance framework.

3.80. The new framework will be designed to ensure the decisions are non-discriminatory and that potential conflicts of interest are properly addressed. We expect that where

[41] See the Management Case of the FBC for an outline of our proposals.

decisions reach a threshold for Ofgem intervention, they will be taken by Ofgem. One of the key principles we are consulting on is whether a proposal would materially increase the costs over and above those identified in this IA. In considering whether to approve a proposal, we would expect to take into account an assessment of costs and benefits.

3.81. We have estimated the net incremental costs for ElectraLink of MHHS under our chosen option as less than £10 million by 2045 (2018 PV). For context, the current ElectraLink DTS for all NHH and HH market processes including switching, metering and settlement costs industry approximately £7m per year. This highlights the fact that most of the underlying system costs are largely fixed, due to a replatforming of the EMDH in 2020 to meet the demands of HHS.

3.82. The incremental increase in costs relative to the status quo is due to the need to add additional data storage, additional load balancing capability to manage traffic peaks, and additional communication capacity. However, these costs would be recovered through DTS charges levied on the users of the service.

3.83. These costs have been captured in the costs reported to us by other parties, notably suppliers and supplier agents. In fact, we think the costs reported by other parties in relation to the transfer of data slightly overestimate the total costs for ElectraLink. Therefore, to avoid double counting, we have not included the direct costs to ElectraLink in the total costs.

3.84. ElectraLink noted in its RFI and consultation response that the operational costs of implementation would not vary across different transitional periods. ElectraLink also noted that there would be no additional costs to the users of its DTS if export were included or not.

Electricity System Operator

Our chosen option - MHHS for import and export MPANs with a transition period of 4 years and 6 months

3.85. The ESO said it could incur costs as a result of removal of NHH methodologies, which could impact on charging and billing systems and on other IT solutions and associated business processes. The potential impact will become clearer as the Code Change and Development Group continues its work. The ESO has estimated that the overall IT cost estimates for implementing the changes across systems is in the low millions of pounds. The ESO has indicated that these costs would not vary with the implementation period or whether or not export is included in MHHS.

3.86. The ESO also said that costs could arise if it had to make changes to gits charging and billing system as a result of Ofgem's Electricity network access and forward-looking charges Significant Code Review (**SCR**), which may be enabled by our MHHS decision. These changes would be necessary, said the ESO, if Ofgem required Elexon to change the frequency and format of data that it sends to them for calculating charges. The ESO has not been able to provide any estimates in relation to these potential costs.

Other Code administrators

3.87. We have not received much quantified information about any additional costs that could be incurred by other code administrators, as a result of any decision to introduce MHHS.

3.88. We believe some costs will be incurred by the code administrators impacted by changes (such as the code administrators for the Distribution Connection and Use of System Agreements (**DCUSA**), the Smart Energy Code and the Master Registration Agreement) but we think these costs would be minimal. For example, ElectraLink, the code administrator for the DCUSA, has stated that it would incur one-off costs associated with legal text changes to the DCUSA. Some of these would be absorbed in ElectraLink's business as usual change processes, whilst some may require extra funding. We included an estimate for the extra funding in our sensitivity analysis.

Low Carbon Contracts Company

3.89. The Low Carbon Contracts Company (**LCCC**) is a private limited company wholly owned by BEIS. It was created to assist in the delivery of the government's Electricity Market Reform programme.[42] Its main role is to oversee the participation of low carbon generators within the Contracts for Difference process. This involves

[42] For more details see Electricity Market Reform programme.

managing the contracts themselves and administering the levy on suppliers that funds the payments to generators.

Our chosen option - MHHS for import and export MPANs with a transition period of 4 years and 6 months

3.90. The LCCC said it would incur some one-off costs as a result of MHHS, due mainly to the need to change processes if the settlement timetable is shortened as proposed. The LCCC also said it would incur no incremental ongoing costs.

3.91. The LCCC provided two transitional cost estimates. These were:

- Estimate 1 – LCCC systems require development to align with the new 4-month Final Reconciliation (**RF**) settlement timetable. No data changes are required. The LCCC estimated the costs to be in the low hundreds of thousands of pounds.
- Estimate 2 – Assumes a requirement to create and handle a separate settlement timetable, and some changes being required to data associated with delivery. The LCCC estimated the costs to be in the high hundreds of thousands of pounds.

Programme costs

Programme costs, including programme management arrangements

3.92. We define programme costs as the additional costs to industry of participating in and providing robust programme management and governance to ensure the successful, effective and timely implementation of MHHS. They include the resourcing and procurement of a central Programme Management Operation (**PMO**), a Programme Party Coordinator function, a Systems Integrator function and an Independent Assurance function and they take into account the ramp up and ramp down periods in the early and latter stages of the transition.

3.93. Elexon has provided programme management cost estimates for the implementation phase of MHHS. For our central cost estimate, we have adjusted these costs by 10% to take account of potential optimism bias. We therefore expect them to be in the order of £90m over six years (in 2020 prices).

3.94. This is higher than the estimate in the Draft IA. The increase arises for three reasons: first, our decision to adopt a slightly longer transition period for the programme; second, the adjustments we have made to correct for potential optimism bias in the costs reported to us; and, third, because we inadvertently omitted certain programme management cost drivers from our assessment in the Draft IA. These cost drivers relate mainly to the System Integrator and Independent Assurance functions. They have now been included in our assessment.

3.95. Most programme management costs will be incurred during the implementation phase. However, there could be costs connected with resolving issues after full transition. We recognise that, if there were to be a significant problem at implementation, the consequences could be far reaching and costly for industry and consumers. We are aware of these potential impacts. The delivery and assurance arrangements that we intend to put in place are commensurate with this risk (see the Decision Document and FBC for details).

Ofgem costs

3.96. Ofgem will incur transitional costs relating to the resources required to support the programme in the role of Sponsor throughout the transition, including an extra one-year ramp down period. We estimate these costs to be £1.6m (in 2020 prices).

Summary of direct costs

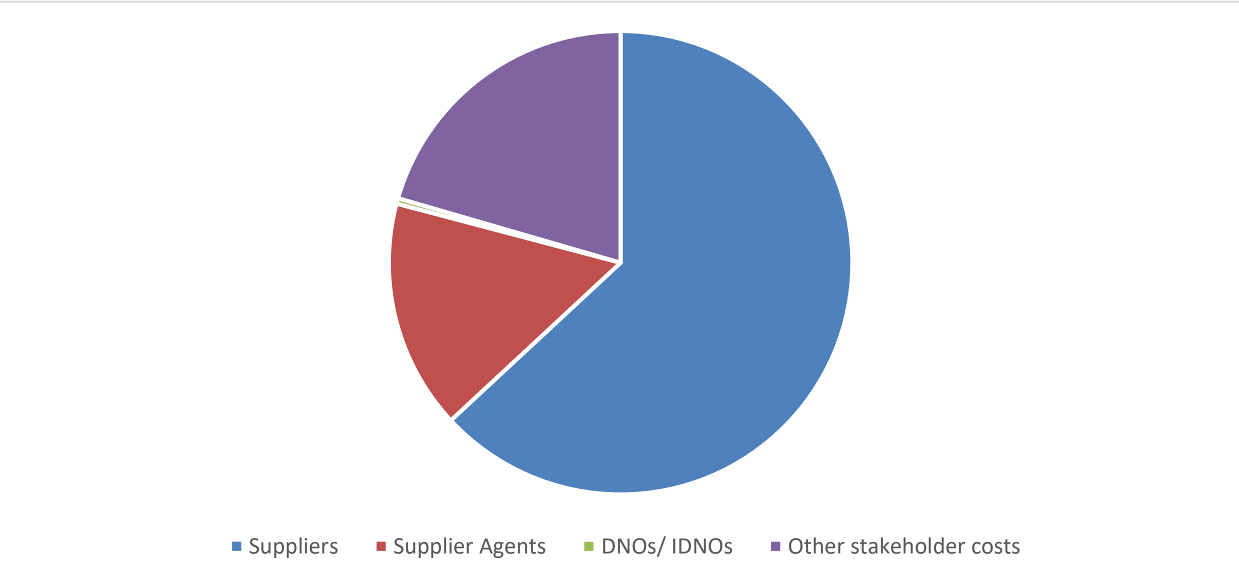
Our chosen option - MHHS for import and export MPANs with a transition period of 4 years and 6 months

3.97. The tables and figures below summarise the estimated costs that each type of market participant would incur under our chosen option for MHHS.

Table 4 Estimated net direct costs by stakeholder type in our chosen option (£ millions)

Stakeholder type	Transitional costs (£2019, undiscounted)	Annual ongoing net costs (£2019, undiscounted)	Total net costs (2021-2045), 2018 PV
Suppliers	£88.5m	£24.2m	£341.5m
Supplier Agents	£12.5m	£6.9m	£86.7m
DNOs/ IDNOs	£1.9m	£0.1m	£2.1m
Other stakeholders[43]	£128.2m	£1m	£111.0m
Total costs	**£230.9m**	**£32.1m**	**£541.3m**

Figure 3: Proportion of estimated net direct costs by stakeholder type under our chosen option for MHHS

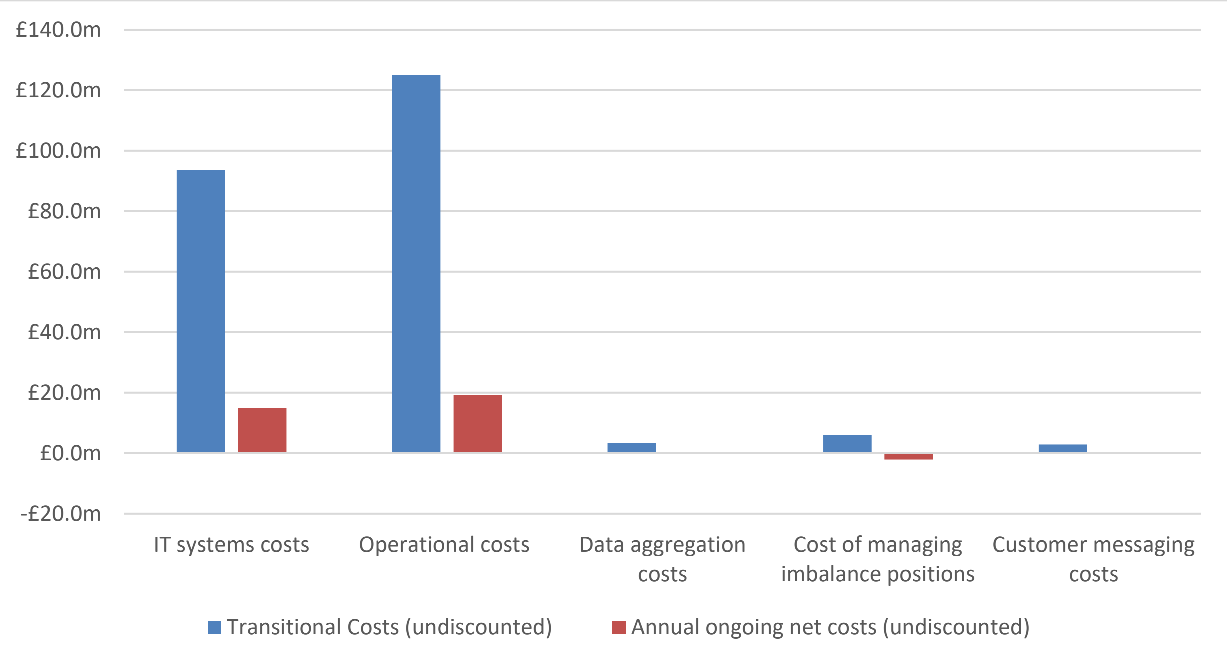


[43] The 'other stakeholder' row includes costs for the DCC, Elexon, ElectraLink, the ESO, the LCCC and Ofgem (including programme delivery and post-implementation costs).

Table 5: Estimated net direct costs by cost type under our chosen option for MHHS (£ millions)

Costs of MHHS	Transitional Costs (£2019, undiscounted)	Annual ongoing net costs (£2019, undiscounted)	Total net costs (2021-2045), 2018 PV
IT systems	£93.6m	£14.9m	
Operational	£125.3m	£19.3m	
Data aggregation	£3.3m	£0.0m	
Managing imbalances	£6.0m	-£2.1m	
Customer messaging	£2.8m	£0.0m	
Total	**£230.9m**	**£32.1m**	**£541.3m**

Figure 4: Estimated net direct costs (undiscounted) by cost type under our chosen option for MHHS



Cost ranges

3.98. As noted at the beginning of this section, we asked stakeholders to qualify their quantitative responses to the RFI using a +/- uncertainty margin. We have used this information, together with other sources of information that we considered to be relevant to capture the full potential scale of costs, to build a cost range. In particular, the cost range captures:

- the uncertainty margin reported by stakeholders through the RFI and through subsequent engagement
- different level of optimism bias (see paragraph 3.101 for more detail), and
- some costs of increasing frequency of meter reads, when these were reported by suppliers (see paragraph 3.102 below for more detail).

3.99. We consider the central cost to be our best estimate of costs. The cost range shows the level of uncertainty industry faces when trying to cost accurately the changes required for MHHS.

3.100. Table 6 below sets out the range of costs we have developed. We have used this range to develop the potential net impacts for consumers shown in section 6.

Table 6: Estimated net direct cost range, based on cost uncertainty (£ millions)

Cost range	Total transitional costs (£2019, undiscounted)	Total annual ongoing net costs (£2019, undiscounted)	Total costs (2021-2045), 2018 PV
High	£309.2m	£43.0m	£731.1m
Central	**£230.9m**	**£32.1m**	**£541.3m**
Low	£199.8m	£21.9m	£407.5m

Optimism bias

3.101. As noted above, and in line with Green Book guidance,[44] we have adjusted certain costs reported to us to account for the possibility that they might prove to be too optimistic. Table 7 shows the optimism bias adjustments, or range of adjustments, that we have made in each category of costs. Essentially, our approach has been to apply moderate adjustments to the central cost estimate and larger adjustments to the high cost estimate but none to the low cost estimate, since that is effectively a best case cost scenario.

[44] HM Treasury, The Green Book: Central Government Guidance on Appraisal and Evaluation (2020).

Table 7 Optimism bias adjustments to the cost estimates

Cost categories	Optimism bias %, central cost estimate	Optimism bias %, high cost estimate	Notes
Programme costs (Dec 2019-March 2021)	0%	0%	Known costs
Programme costs (from April 2021)	10%	20%	See footnote [45]
Ofgem costs	0%	50%	See footnote [46]
Other stakeholders' IT costs	0%-50%	0%-200%	See footnote[47]

Excluded costs

3.102. We have excluded certain reported costs from these cost ranges on the basis that they do not appear reasonable to us. In particular, we do not propose to include the costs provided by suppliers of reading traditional meters every month. This is because, as noted earlier, we expect that the BSC PAF will amongst other things take into account the extent of smart meter penetration and make appropriate adjustments to targets if necessary. In its response to the consultation on the Draft IA, Elexon stated that it had a similar expectation. On the other hand, we have included in our central estimate some costs of reading traditional meters every three months and we have included a 50% uncertainty for those costs in the high range. We believe this is a proportionate and conservative approach to these costs.

3.103. We have looked at the potential costs of offering new HHS-enabled products (such as Time of Use tariffs) in the market. For example, some suppliers have told us that

[45] We have applied the lower end of the recommended optimism bias values in the Green Book, given the level of detail of these costs, as appropriate for the Full Business Case stage.
[46] We have applied optimism bias towards the lower end of the recommended values in the Green Book for the high cost estimate, and 0 for the central cost estimate. This is to reflect that these costs are detailed and based on existing budget provisions.
[47] This row refers to the 'other stakeholders' category as described in table 4 above. We have applied optimism bias towards the higher end of the recommended values in the Green Book for the high cost estimate (with one exception) and towards the lower end for the central case. This is to reflect that these costs are reasonably detailed, have been updated or received since the publication of the Outline Business Case (and in some cases recently updated). We have taken a conservative approach, particularly with our higher cost estimate.

they would need to update their billing systems to be ToU compatible. This investment is not required by our chosen option for MHHS and so we have not included it in our central estimate of costs or in the cost ranges shown in table 6 above.[48] However, we acknowledge that some of these costs might have to be incurred in order to realise the full potential of the estimated benefits.

3.104. The table below shows the total estimated costs of offering HHS-enabled products and how those costs would increase the central cost estimate.

Table 8 Estimated net direct costs of offering HHS products (£ millions)

	Total one-off costs (undiscounted)	Total ongoing net costs (undiscounted)	Total net costs (2021-2045), 2018 PV
Central cost estimate	£230.9m	£32.1m	£541.3m
Extra costs of offering HHS products	£17.0m	£3.0m	£47.3m
Central cost estimate plus estimated additional costs of offering HHS products	**£247.9m**	**£35.1m**	**£588.5m**

Export MPANs

3.105. Based on the evidence we have received, including export MPANs within the scope of MHHS would increase the costs of implementation, though not substantially (especially when the potential benefits are taken into account). Export-related transitional costs for suppliers and DNOs are estimated to total around £5.4m. DNOs would incur ongoing costs of about £50,000 associated with the increased volume of export registrations. Most of the costs stakeholders identified relate to registering and settling export MPANs rather than specifically settling them half-hourly. Elexon confirmed that its systems can already accommodate export MPANs.

[48] Some costs of offering ToU tariffs have been included.

3.106. As noted above, the SEG should prompt the registration of many more export-related MPANs before any transition to MHHS is completed. This should enable a steady flow of registrations over the next few years and reduce the impact of having the same transition period for all MPANs. Bringing in MHHS for import and export MPANs at the same time could realise cost savings for suppliers. That said, we expect that some smaller suppliers currently have manual processes for dealing with export-related MPANs or do not serve export customers.

3.107. We received some feedback to the consultation on the Draft IA raising concerns about progress with SEG being not fast enough and a number of issues regarding MPANs and the SEG and FIT schemes. In particular, concerns that the processes were not in place to support data collection, swapping out meters and issuing export MPANs. We discuss these issues in section 4 of our Decision Document.

3.108. These costs should be set against the loss of the annual net ongoing cost savings we expect to arise from including export MPANs within MHHS. We expect these cost savings to arise from improved network management, more accurate settlement and better supplier forecasting. Moreover, we expect a range of benefits we cannot quantify arising from increased competition, innovation and consumer engagement due to the development of new and innovative tariffs in this sector of the market (see sections 4 and 5).

Transitional period

3.109. Most RFI respondents said costs would be similar with a 4- or 5-year transition. Some suppliers, and one supplier agent, said a 3-year transition could increase costs as a result of having to procure additional resources to handle the extra work during 2020 and 2021. Without these extra resources, we were told that a rapid transition period could affect the design quality and overall robustness of the new settlement arrangements.

3.110. We commissioned PWC to look more closely at the transition period, to engage with a variety of industry stakeholders, and to make recommendations to Ofgem. Our chosen option reflects this and includes a transition period of 4 years and 6 months.

3.111. In table 9 below, we present an estimate of the total costs (in 2018 PV terms) under our chosen option. To calculate these costs, we have assumed no cost increase or reduction due to the longer implementation period, and divided transitional costs equally across the transitional period of 4 years and 6 months from April 2021 to October 2025 (except as regards some programme costs for which we have estimated an increase in transitional costs to account for the longer transition period, or when stakeholders have attributed costs to specific years of the implementation period). Ongoing costs are accounted for over the period November 2025-December 2045.

Difference between our chosen option and our preferred option in the draft IA

3.112. The table below shows the difference in total costs between the Chosen Option and our Preferred Option as set out in in our Draft IA. We estimate that the total costs of the Chosen Option in 2018 PV terms are about £49m higher than the costs that we attributed to the Preferred Option in our Draft IA over the period 2021-2045. However, the total costs of the two options are not directly comparable because, as noted above, in the Draft IA we omitted certain programme management cost drivers from the cost attribution and we did not make any adjustments for optimism bias.

3.113. The apparent increase in costs in our Chosen Option is mostly due to the new programme management cost estimate in this IA. However, the net increase in costs is mitigated by the longer transition period under the Chosen Option. This is because the longer transition period means the ongoing costs (new BAU) start to be realised 10 months later, so we are accounting for almost one less year of ongoing costs.

Table 9: Estimated net direct cost comparison of our chosen option and the Draft IA preferred option (£ millions)

Costs MHHS – comparison	Transitional costs (£2019, undiscounted)	Annual ongoing net costs (£2019, undiscounted)	Total net costs (2021-2045), 2018 PV
Chosen Option	£230.9m	£32.1m	£541.3m
Preferred Option draft IA	£142.7m	£31.8m	£492.5m
Cost difference	**£88.3m**	**£0.4m**	**£48.7m**

4. Monetised direct benefits

Section summary

This section sets out our estimation of the monetised direct benefits of market-wide half-hourly settlement (**MHHS**). We have used a GB power market model - the Dynamic Dispatch Model (**DDM**) - to calculate these benefits.

We begin by outlining the range of benefits that we have sought to quantify. We explain the methodology and assumptions behind our analysis and describe the load shifting and fossil fuel price scenarios that we have considered. We then discuss the interactions between MHHS and the Targeted Charging Review (**TCR**) and the Access and Forward Looking Charging Reform and set out our approach to calculating and attributing benefits across these closely related projects.

We then set out the results of our DDM analysis, which estimates very significant benefits from MHHS. We include an estimate of potential carbon emissions savings. We have also used BEIS's Distribution Networks Model (**DNM**) as a sensitivity analysis to capture potential benefits at the distribution network level. In response to comments on the Draft IA, we have added a sensitivity analysis to estimate the benefits of MHHS assuming no load shifting by small non-domestic consumers.

Finally, using evidence from our Request for Information, we sought as far as possible to quantify the direct benefits of better demand forecasting and a more efficient settlement process. Other significant benefits such as the effect on competition, innovation and customer outcomes cannot be quantified and/or attributed solely to MHHS. They are covered in section 5 on unquantified benefits.

Benefits covered in this section

4.1. In this section we estimate the direct quantifiable benefits of MHHS. This includes the benefits from different levels of load shifting by domestic and small non-domestic consumers[49] under certain scenarios. This analysis seeks to capture benefits such as:

- generation and network investment savings through better use of existing assets (note the model we used does not fully capture all the potential benefits: see the subsection below on the limitations of the DDM in relation to network costs)
- operational savings as load shifting reduces the need to operate generation assets at peak times
- the carbon emissions saved because the lower demand can be satisfied with less polluting generators, and
- the benefits from more accurate forecasting and matching of supply and demand, resulting in a reduction in the residual imbalance that the Electricity System Operator (**ESO**) needs to resolve, and therefore the costs of doing so.

Benefits from load shifting

4.2. A core objective of the energy transformation is to promote a decarbonised system by supporting the development and use of renewable generation and by lowering demand at peak times relative to what it would otherwise be, thereby minimising the need for infrastructure investment. MHHS is a critical enabler of this.

4.3. We have sought to quantify the impact of a shift in consumption as a result of changes to the settlement arrangements using the DDM, a GB power market model.[50] The following paragraphs explain the methodology and assumptions that underpin our use of this model.

Modelling methodology

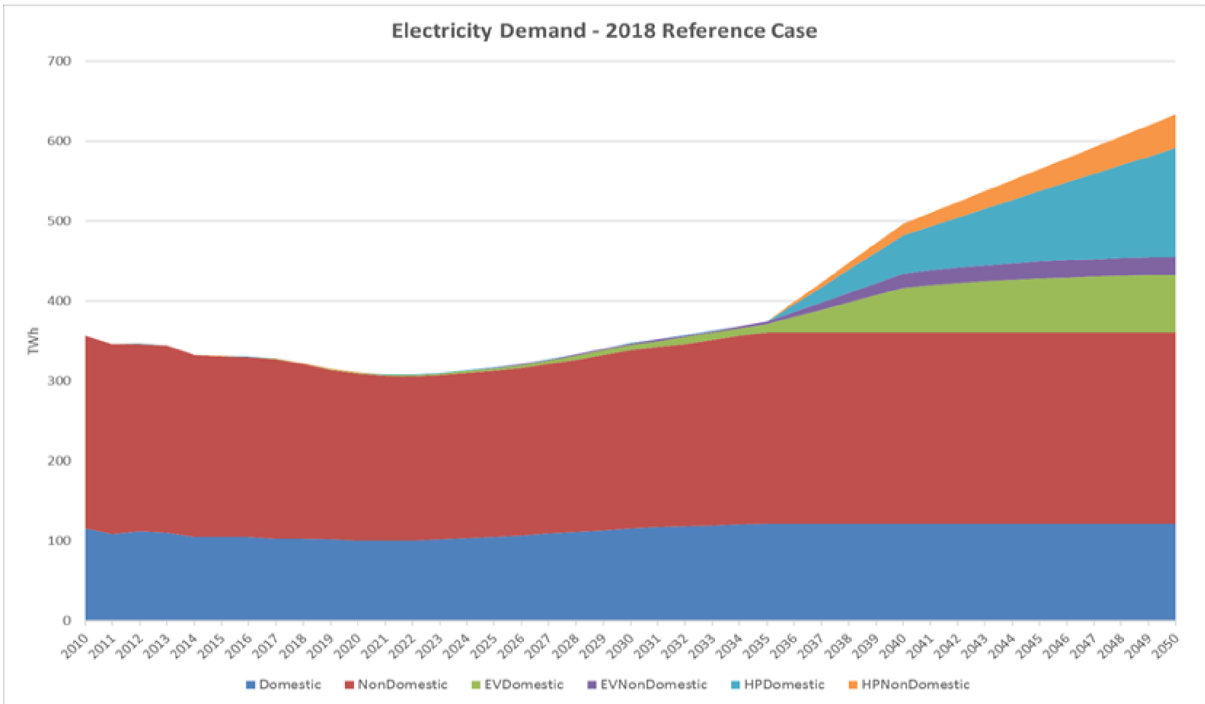
4.4. The DDM analyses electricity dispatch decisions from GB power generators and investment decisions in generating capacity from 2010 to 2050. It can show the impact of policy decisions on generation, capacity, costs, prices, security of supply

[49] The scope of the project covers consumers in profile classes 1 to 4. However, the DDM has certain limitations on how it can distinguish between small non-domestic (classes 3 and 4) and other non-domestic (classes 5 to 8) demand. The model limitations are discussed in more detail below.
[50] For more information about how the model works see Dynamic Dispatch Model.

and carbon emissions. The DDM has been used for a number of key policy decisions such as the 2019 updated smart meter rollout cost-benefit analysis and the Hinkley Point C value for money assessment. The DDM has been used for this analysis on the basis of a set of assumptions determined by Ofgem, in a number of different scenarios. We describe these below.

4.5. The DDM models the electricity wholesale market and investment in new plant. To model the market, the model calculates the short run marginal cost of every generation plant for each half-hourly (**HH**) period across each sample day using assumptions input by the user. For example, the figure 5 below shows a breakdown of the assumed demand levels in the model based on BEIS's 2018 Reference Case.[51] From this, it constructs the merit order of supply, which is then matched to demand, entered as an input, to derive the equilibrium wholesale market price.

Figure 5: Electricity demand (in TWh) by source of demand assumed in the model



Note: the data behind this chart is shown in table 27 in appendix 3 of this document.

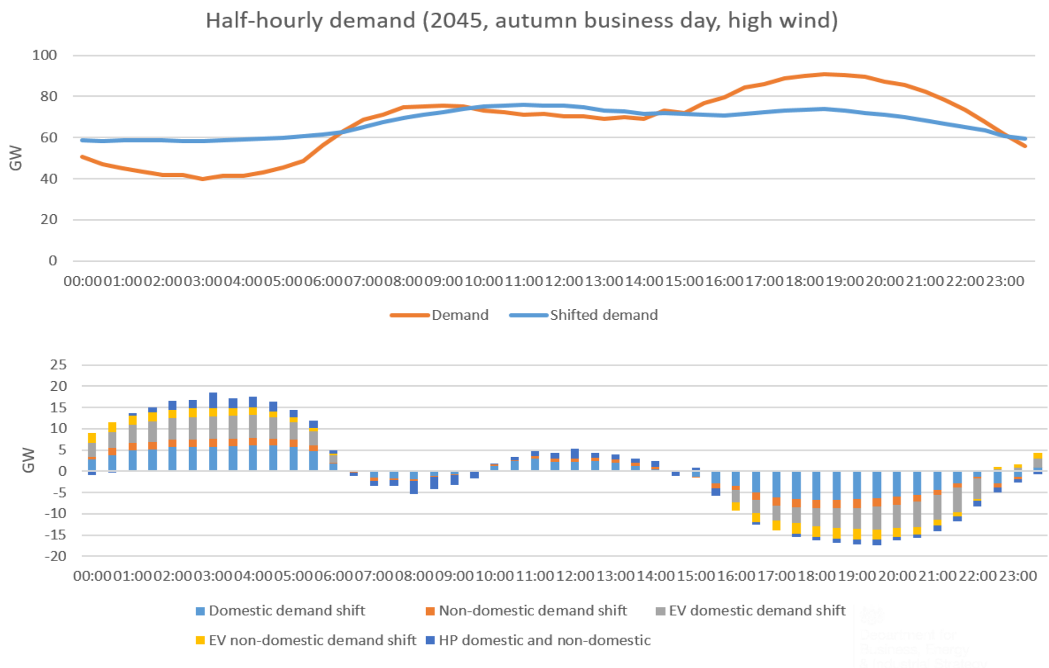
[51] BEIS has now published its 2019 Reference Case. Therefore, these values are not the latest figures (both in aggregate and at individual demand-type level). See BEIS's Updated Energy and Emissions Projections 2019, December 2020.

4.6. Daily demand is allocated between the HH periods that make up a day by the model using demand load curves. This is repeated for the DDM's 22 sample days. The load shifting constraint is applied to give an estimate of how much load can be shifted from each HH period. This shiftable load is then reallocated between HH periods.

4.7. Shifting between periods is constrained by a limit on the number of hours by which demand can be shifted. This is entered as an assumption by the user. HH periods are ordered by the level of demand: the HH periods with the lowest demand are shifted to first. For each period to which demand is shifted, the demand-side response (**DSR**) technologies that could shift demand to that period are ordered by the amount of demand they could shift: the DSR technology that can shift the least to that period is shifted first.

4.8. Figure 6 below shows how demand is shifted both at the aggregated level and by technology for a sample day (2045, autumn business day, high wind, high shift central fossil fuel (**CFF**) scenario). Please note that this shows the impact of all DSR assumptions and not only the DSR attributable to MHHS. In particular, the shifting of heat pump demand, and a small proportion of the domestic EV demand, is not attributable to the policy (as shown in the load shifting assumptions for the factual and counterfactual, tables 12 and 13).

Figure 6: Half-hourly demand in GW for a sample day (2045, autumn business day, high wind)



Note: the data behind this chart is shown in table 28 in appendix 3 of this document.

4.9. As noted above, the DDM also models the investment in new plants. Generation investment decisions in the model are based on generators' projected revenue and cash flows, allowing us to estimate the impacts and changes in the generation mix. Revenues are based on rational expectations of future market prices up to 15 years ahead. The generator that is projected to be the most profitable is built first. The process is then repeated, taking into account the existence of the new generator in subsequent investment decisions. The model adds generators until no new generator is profitable. Applying this mechanism, the model estimated changes in generation capacity as a result of the assumed levels of load shifting from 2025 to 2045.

4.10. For the high load shifting scenario (under the CFF scenario), the model estimated a significant decrease in unabated gas capacity, and an increase in renewable energy sources (**RES**), particularly offshore wind. For the low load shifting scenario (under the CFF scenario) the model showed very little change in generation capacity apart for battery capacity at the network level. In both scenarios the modelling showed reduction in the latter. This is because increase in demand flexibility leads to lower need for battery storage, other things being equal.

4.11. It is therefore worth stressing that the results show the impact of the MHHS policy considered in isolation, and therefore, they do not show the total possible change in generation capacity in the future, as the energy system moves towards greater flexibility and relies on multiple flexibility sources. For example, we expect the installed capacity of battery storage at the network level to increase in the future. However, a greater level of demand flexibility means that less battery capacity may be needed than it would otherwise be the case.

Scenarios and sensitivities

4.12. Predicting electricity system outcomes, such as the potential level of load shifting facilitated by MHHS, is extremely challenging because of the uncertainty about technological, market and behavioural factors that influence those outcomes. Given the high level of uncertainty, we have taken the following scenario-based approach:

- Load shifting scenarios: these scenarios identify a range of possible load-shifting outcomes under each of the policy options, by specifying a likely upper and lower bound to the possible load shifting outcomes (discussed in the subsection below on modelling assumptions)

- Electricity system scenarios: these identify different potential pathways for the future development of the electricity system. We have used two such scenarios:

    - a Central fossil fuel (**CFF**) price scenario which is consistent with BEIS's annually updated Reference Case scenario (2018 figures). This is the main projection in BEIS' Energy and Emissions Projections.[52] It is based on central projections for the key drivers of energy emissions, such as fossil fuel prices, GDP and population. This is our base case.
    - a low fossil fuel (**LFF**) price scenario, in which less value is associated with flexible demand, which we expect to be indicative of the likely lower bound for overall expected system benefits of load shifting. However, this scenario leads to more fossil fuel generation capacity and fewer renewables. We regard this as unlikely given that public policy will be

[52] See BEIS's Updated energy and emissions projections: 2018, April 2019.

increasingly geared towards delivering the UK's net zero commitments. We therefore present it in this IA as a sensitivity analysis only.

4.13. It is worth noting that these scenarios do not assume a pathway to net zero by 2050. Given the strategic role we think MHHS will play in supporting the transition to a net zero carbon electricity system, we think that the right analytical approach is to test the value of the reform against a counterfactual that reflects current policies only[53], rather than using a counterfactual that assumes that net zero targets will be achieved. For example, all the net zero pathways in National Grid's Future Energy Scenarios 2020 Report[54] assume a level of Time-of-Use (**ToU**) tariff uptake by 2035 that we do not think is achievable without MHHS in place. However, for completeness, we tested a high carbon value scenario, more in line with the carbon costs we can expect under a net zero pathway, as a sensitivity analysis (sensitivity analyses are discussed below).

4.14. Recent modelling from BEIS[55] supporting the Energy White Paper (December 2020[56]) suggested that the benefits of system flexibility under a net zero scenario are high, in the region of £12bn per year in 2050 in the high demand scenario without hydrogen. It should be pointed out, however, that there are significant differences between this analysis and the one we carried out for this IA, which means that the analyses are not directly comparable. For example, the definition of flexibility is wider in the former, including interconnectors and network-level battery storage, whereas we focused on DSR by domestic and smaller non-domestic consumers. BEIS's study did not provide benefit estimates for DSR only. In any case, BEIS's analysis shows that system flexibility has a high value under a scenario with a high proportion of renewable generation, and we consider that MHHS is essential to supporting system flexibility in the future.

[53] The UK has made significant progress in decarbonising the economy, however, significant challenges remain if we are to continue on the path to meet our 2050 net zero goals. Ofgem is working closely with the Government industry and wider stakeholders to help the UK make the transition to net zero at the lowest cost to consumers. Ofgem's Forward Work Programme 2021/22 sets out key strategic programmes to help deliver this transition.
[54] See Future Energy Scenarios documents.
[55] See page 12 of Modelling 2050 electricity system analysis.
[56] See BEIS's Energy White Paper 'Powering Our Net Zero Future'.

4.15. We have tested the following additional sensitivities:

- reducing the load shifting window, this shows the change in the modelled benefits when the restrictions on how the demand is shifted away from the peak and across the day are changed (as discussed in paragraphs 4.55-4.57)
- the benefits of load shifting on the distribution networks using the DNM, which is discussed in a subsection below on modelling distribution network level benefits,
- the benefits of MHHS assuming no load shifting from small non-domestic consumers (benefits from domestic consumers only), and
- a high carbon value scenario showing how the impacts (cost savings from reduction in carbon emissions) would change under a scenario where carbon emissions have a higher cost. This is discussed in a subsection below on carbon emissions.

4.16. Table 10 below summarises the scenarios used in the analysis.

Table 10 - Scenarios used in the DDM modelling

Electricity system scenarios	Load shifting scenarios	Scenarios	Sensitivity test
Central fossil fuel (CFF) prices	Low load shifting	Scenario 1	Reducing the load shifting window
			Including distribution networks benefits
			Benefits from domestic consumers only
			High carbon cost
	High load shifting	Scenario 2	Reducing the load shifting window
			Including distribution networks benefits
			Benefits from domestic consumers only
			High carbon cost
Low fossil fuel (LFF) prices	Low load shifting	Sensitivity analysis only	LFF – Low load shifting
	High load shifting	Sensitivity analysis only	LFF – High load shifting

Model inputs

4.17. The DDM takes economic, climate, policy, generation and demand variables as external inputs. BEIS defines these inputs in its baseline modelling scenarios. This includes the fossil fuel prices used in the CFF and LFF price scenarios. In our modelling we used the fossil fuel price estimates from the Government's 2018 Energy and Emissions Projections document.[57]

4.18. In our modelling, the factual (essentially the chosen option but with some small variations[58]) and the counterfactual (the status quo, option 1 in the Draft IA) in each scenario were distinguished by the fact that they took different values for the load-shifting constraint: the maximum proportion of demand that can be shifted from any half hour of the day to another. We explain the effect of our load shifting assumptions on the DDM below, and in appendix 2.

Model outputs

4.19. The outputs from the DDM include the expected changes in welfare, consumer surplus and producer surplus resulting from the policy, as well as carbon costs. These outputs are constituted as follows:

- change in welfare is the sum of changes in carbon costs, generation costs, capital costs, system costs, unserved energy, interconnectors, and unpriced carbon[59]
- change in consumer surplus is the sum of changes in the wholesale price, low carbon payments, capacity payments and unserved energy, and
- change in producer surplus is the sum of changes in the wholesale price, low carbon price support, capacity payments, and producer costs.

4.20. The model also calculates changes in environmental tax revenue between the factual and the counterfactual.

4.21. Generation costs and capital costs together encapsulate the variable, operating and construction costs of generation. System costs are transmission network costs,

[57] See BEIS's Updated Energy and Emissions Projections 2018.
[58] As explained in paragraph 4.22, the benefits have been modelled for the period 2025-2045. However, the longer transition period of the chosen option means that the benefits will in fact start to be realised from towards the end of 2025. We have adjusted the benefits modelled in this section to reflect appropriately the actual transition period of the chosen option.
[59] Change in welfare can also be expressed as the sum of the change in consumer surplus, producer surplus, environmental tax, unpriced carbon (societal benefit) and GB interconnector surplus.

consisting of Transmission Network Use of System, Balancing Services Use of System and inertia costs. Distribution network costs are not included in the DDM's outputs, so we have used BEIS's Distribution Networks Model as a sensitivity to capture these potential benefits. Those results are set out in the subsection below on modelling distribution network level benefits.

Modelling assumptions

4.22. The modelling period we chose for the analysis was from 2025 to 2045. This reflects the long-term nature of the chain of benefits. We specified the load shifting constraint as a 'straight line' progression from the value at 2025 to a maximum value during the modelled time period up to 2045. However, under the chosen option, we expect the benefits of MHHS to start flowing from late 2025 (rather than from the start of 2025 as would have been the case with preferred option in the Draft IA).

4.23. The outputs of the model shown in this section are for the period 2025-2045. However, to calculate the net impacts on consumers, we have made a conservative adjustment to the benefits modelled by the DDM so that the benefits are for the period 2026-2045. We discuss the impact on the benefits of these adjustments in paragraphs 4.75 and 4.76 and in table 18 at the end of this section.

4.24. There is significant uncertainty about how much demand will be shiftable in the future. Among other things, this depends on the tariffs offered by suppliers, the availability of technologies for shifting load automatically, price signals, and consumers' response to price signals. Instead of estimating each of these variables to inform an estimate of potential load shifting, we have estimated a range of values for load shifting from a review of research and trials that look at load shifting in response to price signals. We looked at two key parameters for determining the extent of load shifting: the take-up of smart tariffs and the level of load shifting by customers on smart tariffs, as a percentage of peak reduction.

4.25. The overall level of load shifting away from the system peak can be calculated as the product of these two parameters:

System load shifting = proportion of customers with a smart tariff × percent of demand shifted at peak by customers with a smart tariff

4.26. Drawing upon existing academic literature, we identified a range of estimates for each parameter. Combining both parameters, we estimated a range for potential load shifting. Table 11 below shows the value of each parameter.[60]

Table 11: Estimated system peak demand shifting attributable to MHHS

	% of consumers on smart tariffs (A)	% of peak demand shifted per consumer (average) (B)	% of system peak demand shift (A)x(B)
Upper bound 2025	20%	30%	**6%**
Upper bound 2045	60%	50%	**30%**
Lower bound 2025	10%	10%	**1%**
Lower bound 2045	30%	20%	**6%**

4.27. The load shifting constraints for domestic and non-domestic demand, including electric vehicle (**EV**) and heat pump demand, are specified separately in the model. It is worth noting, however, that following the approach described above, we estimated the overall level of load shifting attributable to MHHS for the aggregated demand. Given the requirements of the model, we had to specify the level of load shifting separately for each source of demand. For transparency, this is shown in tables 12, 13 and 14 below. This means that the breakdown of the load shifting assumptions by source of demand is an attribution intended to achieve specific value of aggregate demand shift, and that these assumptions should not be considered in isolation. We assigned the same level of load shifting constraint for domestic and non-domestic heat pump demand in the counterfactual and the factual (option 2), which means that the DDM results capture no benefits from increased heat pump flexibility. Assuming that MHHS will not increase load shifting from heat pumps is a conservative approach.

4.28. Table 12 below shows the final level of load shifting in each load shifting scenario. This is shown as an increase on the baseline load shifting level in the counterfactual. The resulting level of load shifting for domestic EVs is slightly higher than for

[60] Table 25 in appendix 2 gives more information on the sources behind each parameter.

domestic demand and non-domestic EV demand. This reflects the assumption that there would be some level of load shifting for domestic EVs under the counterfactual. However, as noted above, the level of load shifting attributable to MHHS is the same for domestic and EV demand.

4.29. Tables 13 and 14 respectively show the load shifting attributable to MHHS and the baseline in the counterfactual.

Table 12: Load shifting assumptions (% of peak load), low and high load shifting scenarios

Assumptions	Load shifting scenarios	Year	Domestic demand, non-domestic EV demand	Domestic EV demand	Domestic/non-domestic heat pump demand[61]
% of total demand during peak hours that can be shifted	Low load shifting	2025	1%	2%	90%
		2045	6%	14%	90%
	High load shifting	2025	6%	7%	90%
		2045	30%	38%	90%

Table 13: Load shifting increase under MHHS relative to the counterfactual

Assumptions	Load shifting scenarios	Year	Domestic demand, non-domestic EV demand	Domestic EV demand	Domestic/non-domestic heat pump demand
% of total demand during peak hours that can be shifted	Low load shifting	2025	1%	1%	0%
		2045	6%	6%	0%
	High load shifting	2025	6%	6%	0%
		2045	30%	30%	0%

[61] The same level of load shifting was assumed in the factual and in the counterfactual. Load from heat pumps was only allowed to shift by one hour (one-hour shifting window).

Table 14: Load shifting (% of peak load) in the counterfactual

Assumptions	Load shifting scenario	Year	Domestic demand, non-domestic EV demand	Domestic EV demand[62]	Domestic/non-domestic heat pump demand[63]
% of total demand during peak hours that can be shifted	Counterfactual	2025	0%	1%	90%
		2045	0%	8%	90%

4.30. We have assumed an 8-hour window in which demand in any half-hour is allowed to shift (either up to 4 hours earlier or up to 4 hours later). We believe that this is a good approximation of small users' ability to offer flexibility across different technologies. We have tested the implications of this assumption through two sensitivity tests that restrict the shifting window to 4 hours and 2 hours.

4.31. As a result of stakeholder feedback, we refined the assumptions that we used for the MHHS Outline Business Case (**OBC**) in the Draft IA. In particular, we worked with BEIS to avoid capturing benefits from larger non-domestic consumers and we slightly reduced the load shifting assumptions in the high load shifting scenario. We also included demand from EVs in the main analysis[64] and a new set of load shifting assumptions for EV demand. For the Final IA we have taken the same modelling assumptions for the base case, and included a new sensitivity analysis testing the impact on the benefits if we assume no load shifting from the small non-domestic consumers.

[62] The level of load shifting constraint for domestic EVs we have used in the counterfactual differs from BEIS's assumption in its Energy and Emissions Projections 2018.
[63] The same level of load shifting was assumed in the factual and in the counterfactual. Load from heat pumps was only allowed to shift by one hour (one-hour shifting window).
[64] In the OBC we included EV demand in the sensitivity analysis only. However, we thought this was significantly underestimating the project benefits.

4.32. We believe the modelling analysis is more robust as a result of these changes. That said, the DDM has certain limitations that are important to recognise. In particular, the DDM:

- accounts for network cost savings at the transmission level only, so omits distribution networks cost savings. Furthermore, it does not fully capture the benefits that load shifting could have for the transmission network. Notably, the model does not represent cost associated with reinforcing and maintaining the network in relation to load shifting, and location of new generation is not optimised to reduce MW-km costs. We have used the DNM to estimate the benefits from distribution networks cost savings and the results are shown as part of the sensitivity analysis below
- can allow both domestic and non-domestic load to shift, or only domestic load. However, the DDM does not distinguish within these categories and does not separate smaller non-domestic consumers (Profile Classes 3-4) from other sources of non-domestic load, such as non-domestic consumers covered by P272 (formerly Profile Classes 5-8) and 'traditional' half-hourly sites in Measurement Class C.[65] The scope of our project includes Profile Classes (**PC**) 1-4. To estimate the effects of load shifting by customers as a result of MHHS, we applied our load shifting assumptions to domestic demand and to a proportion[66] of non-domestic demand corresponding to PCs 3-4
- can also allow EV demand to shift separately from domestic and non-domestic demand. Based on our review of the evidence, we expect that there would be some EV demand shifting under elective HHS. This is reflected in our assumptions for the counterfactual. The potential EV demand load shifting in the scenarios is equal to the sum of potential EV demand load shifting under the counterfactual and potential domestic demand load shifting that we can attribute to MHHS under each scenario.

4.33. The output from the DDM model does not account for any costs to consumers of load shifting. These could be costs to purchase technological enablers such as smart

[65] GB metering systems are categorised by seven Measurement Classes. See Change of Measurement Class and Change of Profile Class, Elexon, June 2019.
[66] Consistent with assumptions in BEIS's Smart meter roll-out: cost-benefit analysis, September 2019.

appliances or batteries, or costs in understanding and responding to price signals in tariffs. Some of these costs could be mitigated to an extent if suppliers can offer new products and innovations that are simple for consumers to understand and engage with.

4.34. The figures from the modelling set out an indicative range of potential benefits, rather than specific estimates, in order to highlight the magnitude of potential benefits that can be achieved. These figures are supplemented in our qualitative assessment of the impacts of MHHS on competition and innovation in the market.

Interaction of MHHS with other policies

4.35. MHHS is an important part of Ofgem and BEIS's Smart Systems and Flexibility Plan, Ofgem's Decarbonisation Action Plan and our Forward Work Programme for 2021/22.[67] It is one of several Ofgem policies that is intended to promote electricity system flexibility. Like those other policies, MHHS will do this by sending cost-reflective signals to market participants about the cost of serving their customers throughout each day. This will place incentives on suppliers to offer new tariffs and products that encourage more flexible use of energy, potentially minimising inefficient investment in the energy system. MHHS will facilitate other policies by making it possible for suppliers to be charged based on the time period in which the energy was consumed.

4.36. MHHS interacts particularly closely with the Targeted Charging Review and the Electricity network access and forward-looking charging Significant Code Review. Given the close interactions, it is important to ensure as far as possible that the basis of the estimated benefits is clearly set out so that an informed assessment is made as to the anticipated impact of each project. We set out our approach to this below. Given the interactions between the projects and differences in the focus of

[67] Section 2 of our MHHS Draft IA consultation document sets out the strategic context for settlement reform and summarises key elements of our Decarbonisation Programme Action Plan. The Strategic Case section of the Full Business Case provides an update on the strategic context and on these key related aspects of our work.

their policy options and assessment, we would not recommend simply summing their estimated impacts in order to estimate their aggregate effects.

Targeted Charging Review

4.37. In November 2019, we published our Decision (and associated Direction) on the Targeted Charging Review (**TCR**) Significant Code Review.[68] The TCR reforms will introduce a series of fixed residual charges to address inefficient price signals which create harmful distortions in the market. This new charge structure will mean there is no variability in a customer's residual network charges throughout the day.

4.38. When the Decision is fully implemented, the costs of operating, maintaining and upgrading the electricity grid will be spread more fairly and, by reducing harmful distortions, will save consumers about £300m per year, with anticipated £4bn-£5bn consumer savings in total over the period to 2040. The Authority has approved a series of code modification proposals that implement various aspects of our Decision. Other code modifications intended to give effect to our TCR Decision have been proposed and are being considered. For further details see the Strategic Case section of the Full Business Case.

4.39. Some stakeholders have expressed the view that the TCR, by eliminating some time-based price signals, has reduced the benefits available from MHHS. Our view is that the signals removed by TCR were distortive and that the reforms will enable other markets to send more efficient signals. For example, we expect the TCR to lead to an increase in wholesale market prices during peak periods.

4.40. The benefits case for MHHS needs to be considered in the light of other policy developments taking place on the timescale of MHHS implementation as well – including Access and forward-looking charging reform (see below). These policies, along with the variation in wholesale costs and any other determinants of price variation, will have an impact on where on the scale, from the low load shifting to the high load shifting scenario the benefits will fall.

[68] See our TCR full decision document.

Access and forward-looking charging significant code review

4.41. In our Access and forward-looking charging significant code review (Access SCR) we are reviewing forward-looking network charges, with the aim of ensuring that electricity networks are used efficiently and flexibly, reflecting users' needs and allowing consumers to benefit from new technologies and services while avoiding unnecessary costs on energy bills in general. As noted in the Forward Work Programme 2021/22, Ofgem plans to consult on an early 'minded to' position in the spring. We will be feeding our initial findings into our work with BEIS on the new joint Smart Systems and Flexibility Plan (to be published later this spring).

4.42. A number of the reform options under consideration would build on MHHS, so some of the potential benefits of these reforms are dependent on the implementation of MHHS. Changes under the Access SCR could therefore contribute to the potential benefits which MHHS will enable, by encouraging network users to change their behaviour and so reducing network costs.

4.43. This MHHS impact assessment (**IA**) includes some benefits from consumption shifting and reducing network cost. Given the complexity of the interactions between MHHS and the Access SCR, it is challenging to separate fully the benefits arising from each of these policies. As such, our decisions on each programme of work will (to the extent practicable) consider the respective contributions that each policy is expected to bring to realising the anticipated benefits.

4.44. As explained above, the modelling of the benefits from MHHS considered a range of load shifting values. We recognise that in order to realise the benefits toward the upper end (or above) of the range of estimated benefits, new reforms that increase time-based price signals in the market (for example, some of the options considered under the Access SCR) are likely to be needed. We therefore consider that, when distinguishing the benefits of MHHS itself from those of other programmes enabled by MHHS, the conservative approach is to look at the low end of our modelled range. Some of the proposed access and forward-looking charging reforms could increase the benefits more towards the high estimate of the range, or potentially beyond.

4.45. As noted above, the DDM does not include distribution network-specific benefits. We have therefore also modelled the distribution network effects of MHHS. Our analysis suggests that increasing levels of load shifting would benefit the distribution network (see the subsection on modelling distribution network level benefits). However, given the interactions with the Access SCR, we consider distribution level benefits as part of our sensitivity analysis rather than as part of our central benefits case, in order to reduce the risk of double counting. In addition, the DDM is limited in its inclusion of transmission network-specific benefits, which reduces the potential for overlap with Access SCR benefits.

4.46. The Access SCR may also result in benefits from areas beyond the scope of those enabled by MHHS. Some of the options under the Access SCR, such as introducing charges for distribution connected generators, where they are driving costs, and charging zones within a DNO region, would impact on the economic incentives on generators or incentivise load shifting for larger demand customers, bringing about benefits that are not counted in the MHHS IA.[69]

System-wide load shifting benefits from 2025-2045

4.47. The output from the DDM modelling is set out in tables 14-15 (in £ millions rounded to the nearest £50 million). These results are presented in Present Value (**PV**) terms, discounted with 2018 as the base year and using 2018 real prices. We have used the Green Book discount rate to calculate PVs. This discount rate is set at 3.5% (in real terms) for the entire period of the analysis (2025-2045) in line with the Green Book guidance.[70]

4.48. The outputs are presented as change in welfare, which consist of carbon cost savings, generation, capital and network cost savings, balancing cost savings, unserved energy, interconnectors and unpriced carbon. Change in welfare can be broken down into:

- Consumer surplus – consisting of wholesale price reductions, low carbon and capacity payments, network costs, balancing costs and unserved energy
- Producer surplus – consisting of wholesale price reductions, low carbon and capacity payments and producer costs

[69] The MHHS IA only considers load shifting impacts for customers in profile classes 1-4. While the modelling for MHHS takes into account indirect effects on generators' incentives arising from different consumption patterns, it will not introduce policies that affect commercial generators directly.
[70] HM Treasury, The Green Book: Central Government Guidance on Appraisal and Evaluation (2020).

- Environmental tax
- Societal benefit – consisting of unpriced carbon (the difference between low carbon payments and the carbon appraisal value), and
- GB Interconnector surplus.

4.49. Some benefits to one group directly transfer into costs against another group, generating net zero benefits/costs. For example, capacity payments are a cost (negative) to consumers but a benefit (positive) of exactly the same amount for producers. Other outputs generate additional benefits/costs.

4.50. The outputs show a **welfare increase under both scenarios**, with system benefit that increases over time. This increase is driven mainly by benefits from generation costs savings in the high load shift scenario, capital[71] cost savings in the low load shift scenario, and interconnector flow savings in both scenarios.[72]

4.51. These interconnector cost savings make up a higher proportion of the welfare increase under the high load shift scenario. They outweigh an increase in transmission network costs. These costs increase because the increase in load shifting leads to a higher proportion of transmission-connected renewables in the capacity mix. In particular, the capacity of offshore wind increases, which has associated a higher network cost than other generation sources. The DDM also shows a decrease in the capacity of distribution connected storage, but this does not affect the network savings outputs as distribution network costs are not estimated in the DDM (however, it impacts the analysis in the DNM as less storage will be connected to the representative networks in the model).

[71] The DDM does not account for distribution network costs or cost savings, which would be additional to the figures presented in this analysis.
[72] Interconnector cost savings are explained by the fact that net imports decrease as the demand peaks are reduced, meaning less electricity is imported as demand can be met through cheaper domestic generation. Note that interconnectors that have been awarded a cap and floor regime have all been assessed through an Initial Project Assessment (**IPA**) and are considered to be likely in the interests of GB consumers (see our publications relating to the FAB Link, IFA2 and Viking Link interconnectors and to the GridLink, NeuConnect and NorthConnect interconnectors).

4.52. We ran the DNM[73] as a sensitivity analysis to investigate the effects of increased load shifting on distribution network costs. The distribution cost savings estimated by the DNM outweigh the transmission network cost increase estimated by the DDM. Carbon cost savings make a significant contribution in all scenarios, as better use is made of existing generation and new build plant has a lower carbon intensity.

4.53. There is a significant welfare transfer[74] from producers to consumers. This transfer is greater under the high load shifting scenarios than under the low ones. This comes from a reduction in wholesale prices during peak periods. Load shifting reduces peak demand, so the wholesale market clears at a lower price. Consumers therefore pay less for the energy purchased in those periods and producers receive less money for the energy they generate.

4.54. Under all scenarios, the results indicate potentially significant system-wide benefits from introducing MHHS.[75] The results also highlight the scale of the benefits that could be achieved by implementing policies that encourage flexibility across the electricity system. The potential welfare benefits under the base case across the two scenarios range from £1.2bn to £3.6bn PV by 2045 (in 2018 prices).[76] The wide range reflects the significant uncertainties about the energy system transition and the range of outcomes that are therefore possible. The results are presented in PV terms and rounded to the nearest £50 million.[77]

[73] Appendix 1 provides a brief summary of how the Distribution Networks Model (**DNM**) works.
[74] A welfare transfer does not generate additional benefits or costs, but redistributes benefits or costs from one group to another (producers to consumers or vice versa).
[75] As discussed at the beginning of section 4, this analysis takes account of different costs such as carbon costs, electricity generation costs or capital cost of new electricity generation assets, but not the costs discussed in section 3.
[76] As stated above, these welfare results are smaller than what we estimated for the OBC (2018 NPV £1.8bn-£5.4bn), reflecting our refinement of the model and load shifting parameters.
[77] Figures below £25m are represented as <£25m.

Table 15: Modelling output (benefits) - Scenario 1: low load shifting, Central Fossil Fuel (CFF) prices, £ millions, difference compared to the counterfactual

Cumulative, in £ millions, 2018 PV	Scenario 1: low load shifting, CFF prices		
Year	**2030**	**2040**	**2045**
Change in welfare	**200**	**750**	**1,200**
Carbon costs	<25	50	100
Generation costs	<25	<25	-150
Capital costs	100	400	450
Network costs	<25	50	50
Balancing costs	<25	-50	-50
Unserved energy	50	50	50
Interconnectors costs	<25	300	750
Unpriced carbon (appraisal value)	<25	<25	<25
Distributional analysis			
Change in consumer surplus	450	1,550	2,100
Change in producer (generator) surplus	-200	-600	-450
Change in Environmental Tax Revenue	<25	<25	<25
Change in Unpriced Carbon	<25	<25	<25
Change in GB Interconnector surplus	-50	-200	-400

Note: due to rounding, some totals may not correspond with the sum of the separate figures.

Table 16: Modelling output (benefits) - scenario 2: High load shifting, Central Fossil Fuel (CFF) prices, (£ millions), difference compared to the counterfactual

Cumulative, in £ millions, 2018 PV	Scenario 2: high load shifting, CFF prices		
Year	**2030**	**2040**	**2045**
Change in welfare	**500**	**2,000**	**3,600**
Carbon costs	100	500	1,000
Generation costs	550	750	500
Capital costs	100	-600	-950
Network costs	50	-550	-850

Balancing costs	<25	-50	-150
Unserved energy	<25	-50	-100
Interconnectors costs	-400	1,750	3,900
Unpriced carbon (appraisal value)	150	200	200
Distributional analysis			
Change in consumer surplus	350	2,650	5,050
Change in producer (generator) surplus	150	-350	-600
Change in Environmental Tax Revenue	<25	<25	<25
Change in Unpriced Carbon	150	200	200
Change in GB Interconnector surplus	-100	-550	-1,050

Note: due to rounding, some totals may not correspond with the sum of the separate figures.

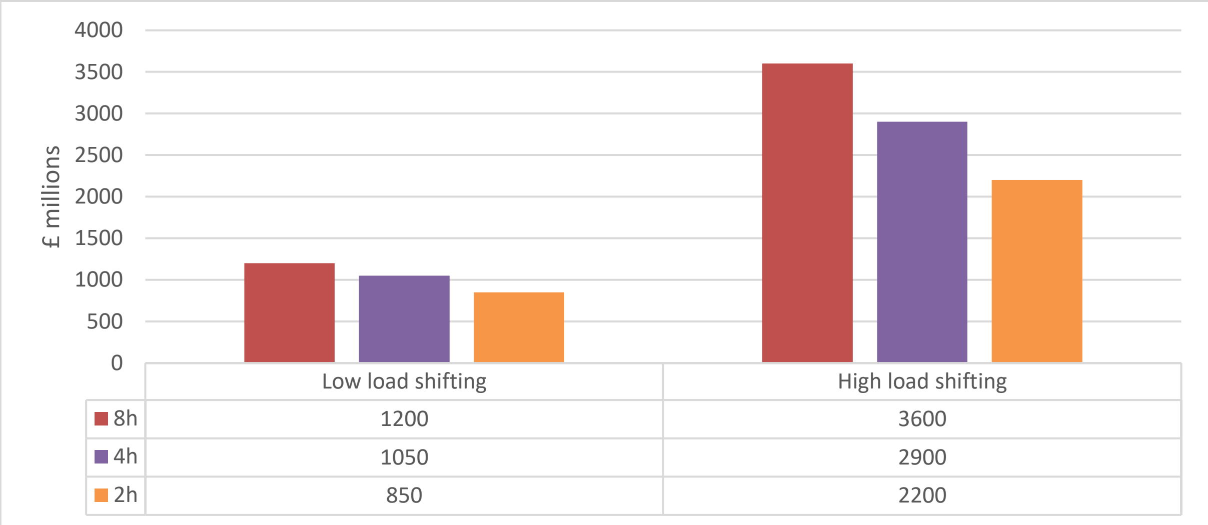
4.55. As noted in the modelling assumptions section at the beginning of this section, we have assumed an 8-hour window in which demand in any half-hour is allowed to shift (either up to 4 hours earlier or up to 4 hours later). We tested two additional shifting-window sensitivities across both scenarios:

- reducing the load shifting window from 8 hours to 4 hours
- reducing the load shifting window from 8 hours to 2 hours.

4.56. As expected, reducing the shifting window reduces the welfare benefits. This is true for both load shifting scenarios, with this effect becoming more pronounced with a smaller shifting window (though this effect varies across scenarios). Figure 5 shows the reduction in welfare compared to the baseline (8-hour shifting window).

4.57. An 8-hour shifting window, assuming an allowed shift of 4 hours each side of peak periods, aligns with several load shifting possibilities, such as shifting washing machine and dishwasher load, overnight charging or using domestic battery storage. While an 8-hour window therefore seems realistic, moving this to a 4-hour (2 hours either side of peak) or 2-hour (1 hour either side of peak) window allows us to consider how the benefits could change. We will examine the available evidence on this and use this to inform our understanding of the uncertainty associated with our modelling results.

Figure 7: Sensitivities – reducing the shifting window, cumulative benefits from 2025 to 2045, 2018 PV figures (8-hour window is the base case), £ millions



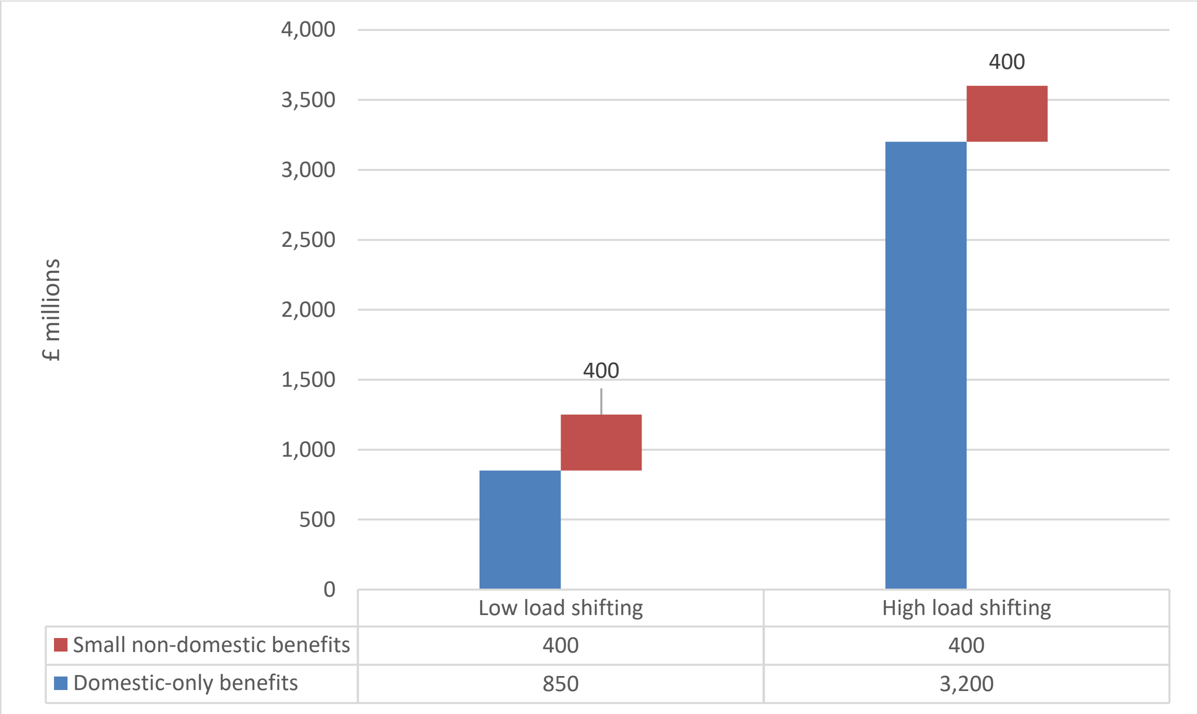
Sensitivity analyses

Load shifting by domestic consumers only

4.58. As noted at the beginning of this section, we have included a new sensitivity analysis testing the impact on the benefits if we assume no load shifting from the small non-domestic consumers. We do not think this is a credible scenario, as most of the dynamics that we expect would trigger domestic demand-side response also hold true for small-non domestic consumers. However, we recognise that there is less direct evidence to support our assumptions about load shifting from this sector of the market, and therefore, it was important to understand how much our benefits case was relying on it.

4.59. Figure 8 below shows the range of change in welfare across both the high and low load shifting scenarios when we assume load shifting from domestic consumers only. The analysis indicates a decrease in benefits, although relatively small compared to the benefits from domestic demand. In particular, the cumulative benefits by 2045 under the low load shifting scenario would be £850m and £3,200m (in 2018 PV) under the high load shifting scenario. This means a reduction of approximately £400m for both scenarios. Nevertheless, these benefits outweigh the total costs estimated in section 3.

Figure 8: Sensitivities – domestic-only benefits, cumulative benefits from 2025 to 2045, 2018 PV figures (base case includes benefits from domestic and small-non domestic load shifting), £ millions

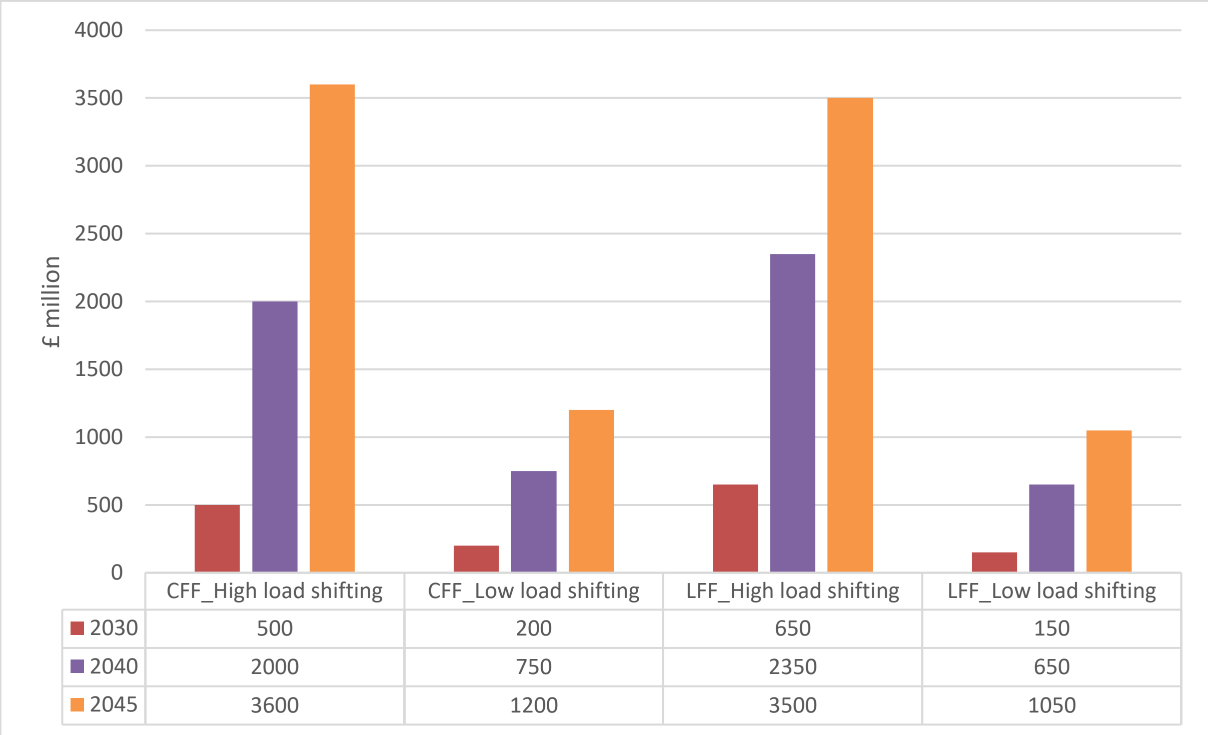


Electricity system scenarios

4.60. We have tested the sensitivity of the assessment to future fossil fuel prices using BEIS's LFF price scenario, in which less value is associated with flexible demand. We expect this to be indicative of the lower bound for overall expected system benefits of load shifting. However, this scenario leads to more fossil fuel generation capacity and fewer renewables. We regard this as unlikely given that public policy will be increasingly geared towards delivering the UK's net zero commitments. We have, therefore, included it only as a sensitivity test in this Final IA.

4.61. Figure 9 shows the range of benefits across both the high and low load shifting scenarios for both CFF and LFF scenarios. As expected, the scenario with lower fossil fuel prices reduces the benefits we can expect from higher flexibility in the system. However, the sensitivity analysis also shows that the change in benefits associated with fossil fuel prices is relatively small, especially when compared to the variation across the low load shifting scenarios.

Figure 9: Sensitivities – benefits under CFF and LFF scenarios, 2018 PV figures (CFF is the base case), £ millions



Distribution network level benefits

4.62. As noted above, the DDM does not capture distribution network cost savings. We have overcome this by using BEIS's DNM.[78] However, we have decided to present the DNM results as a sensitivity analysis to reduce the risk of double counting these benefits with our Access SCR.[79]

4.63. The DNM is a model of GB electricity distribution network costs from 2010 to 2050. It comprises two parts:

- a Power Flow Model (**PFM**) which uses representative networks to detect where the network becomes stressed and would be in need of reinforcement, and

[78] See appendix 1 for more information about how the DNM works.
[79] We discussed the interaction of MHHS with other Ofgem projects earlier in this section.

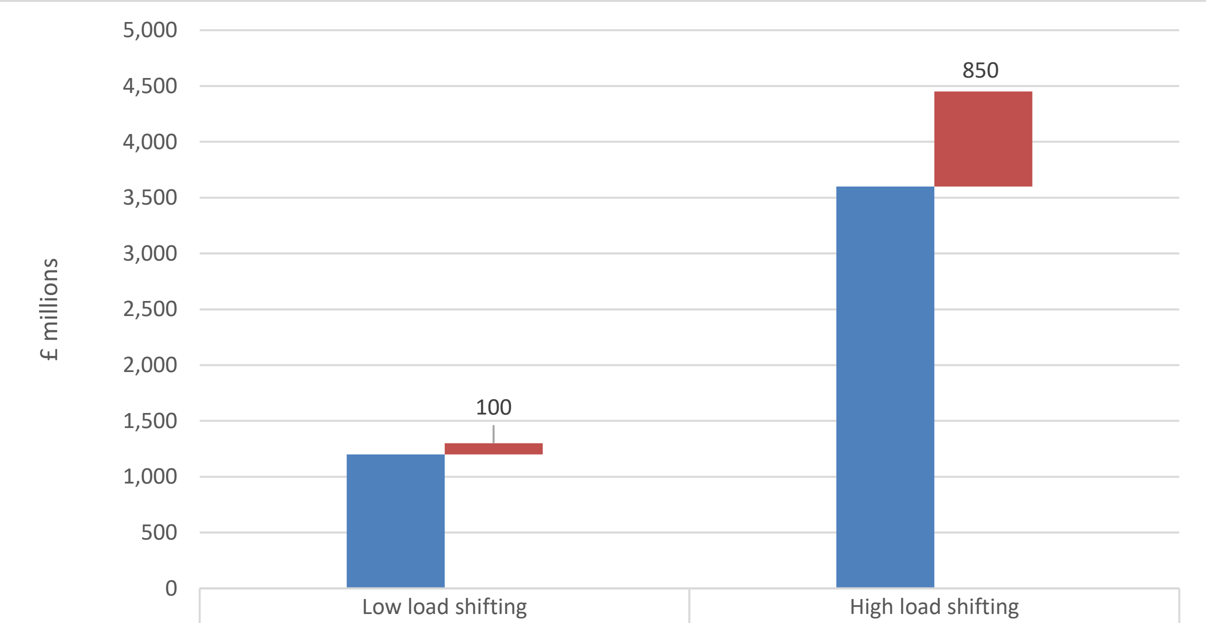
- An Investment Model (**IM**), which chooses the most cost-effective solutions to resolve the issues identified by the PFM, replicating the process that a DNO would go through when assessing a network.

4.64. Alongside assumptions on representative networks and investment solutions, the DNM takes DDM outputs as inputs, including the level of demand shifted. Therefore, the same load shifting assumptions and considerations as for the DDM results apply here. We tested this sensitivity using two scenarios: low load shifting under Central Fuel Fossil prices, and high load shifting under Central Fossil Fuel prices.

4.65. The DNM output shows an increase in change in welfare for both scenarios compared to the DDM results, increasing the total welfare benefits from approximately £1.2billion - £3.6billion to £1.3billion - £4.4billion (2018 PV) by 2045.

4.66. Figure 10 below illustrates these results.

Figure 10: Sensitivities - including the DNM results, 2018 PV figures cumulative benefits (2025-2045), central FFP, £ millions

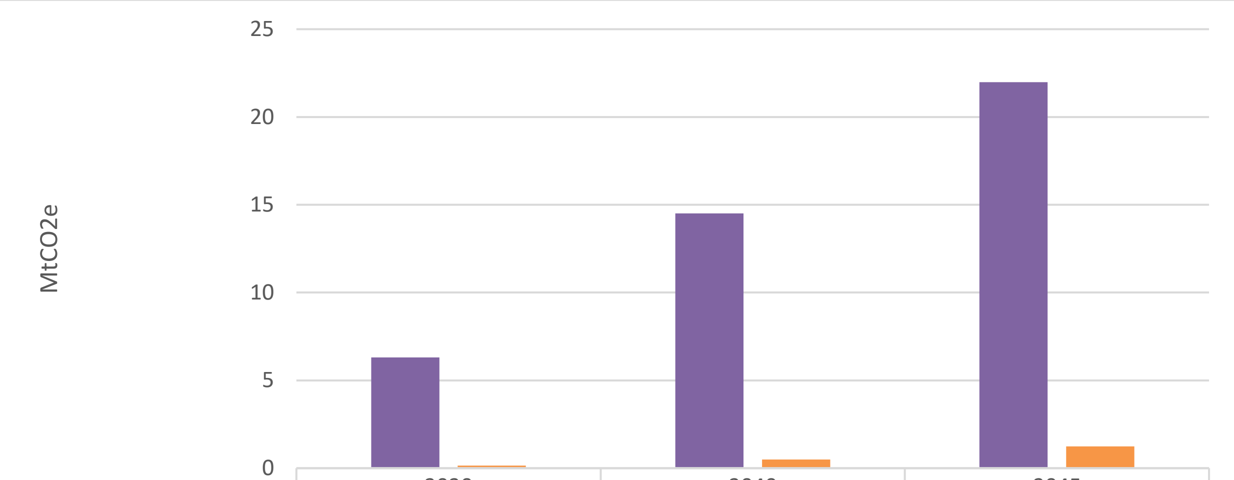


	Low load shifting	High load shifting
DNM results	100	850
DDM results	1,200	3,600

Carbon emissions under the main scenarios

4.67. We show the carbon emission savings calculated by the DDM model. Figure 11 below shows the CO_2 emissions (in $MtCO_2e$) for the CFF scenario.

Figure 11: Estimated emissions savings (MtCO2e) under the Central Fossil Fuel (CFF) Prices high and low load shifting scenarios, cumulative figures



	2030	2040	2045
CFF_High load Shifting	6.31	14.51	21.98
CFF_Low load Shifting	0.14	0.49	1.24

Carbon impacts

4.68. As noted earlier, the DDM can demonstrate the impact of policy decisions on carbon emissions. In particular, it produces two carbon emissions outputs that are included in the change in welfare analysis:

- Carbon Costs: the total carbon emissions for a given year are multiplied by the expected European Emissions Allowance (**EUA**) price in that year
- Unpriced Carbon: this quantifies the difference between the actual EUA carbon price and the societal value of carbon (defined by the appraisal value). This is treated as a cost.

4.69. The DDM results show a reduction in carbon costs driven by a reduction in carbon emissions under all scenarios by 2045 (including the scenarios in the sensitivity tests). This reduction in carbon emissions is due to the higher proportion of renewables in the generation mix facilitated by the reduction in peak consumption.

4.70. The table below shows the reduction in Carbon Costs and Unpriced Carbon costs under each scenario.

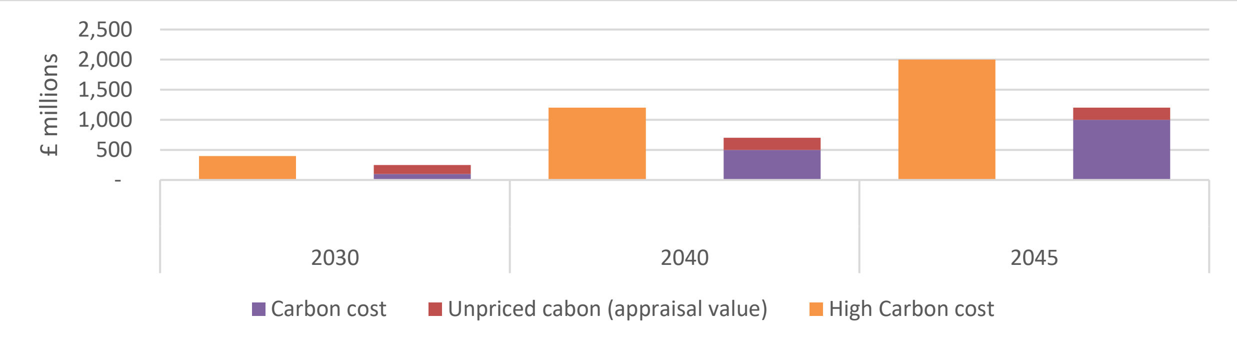
Table 17: Estimated carbon emissions savings (£ millions), 2018 PV figures, cumulative

Cumulative in £ millions, 2018 PV	All scenarios: total cost savings (carbon costs + unpriced carbon)		
Year	**2030**	**2040**	**2045**
High load shifting scenario - CFF	250	750	1,250
Low load shifting scenario - CFF	<25	50	100

4.71. We have conducted a high carbon value[80] sensitivity analysis, showing how the impacts (cost savings from reduction in carbon emissions) would change under a scenario where carbon emissions have a higher cost. This is particularly relevant as the net zero commitment is likely to have implications for carbon values in future.

4.72. Figure 12 below shows how the cost savings from carbon emissions (in £ millions) increase under the high carbon value scenario compared to the base case.[81]

Figure 12: Estimated costs savings (£ millions) from reduction in carbon emissions, high load shifting, CFF price scenario, 2018 PV figures, cumulative

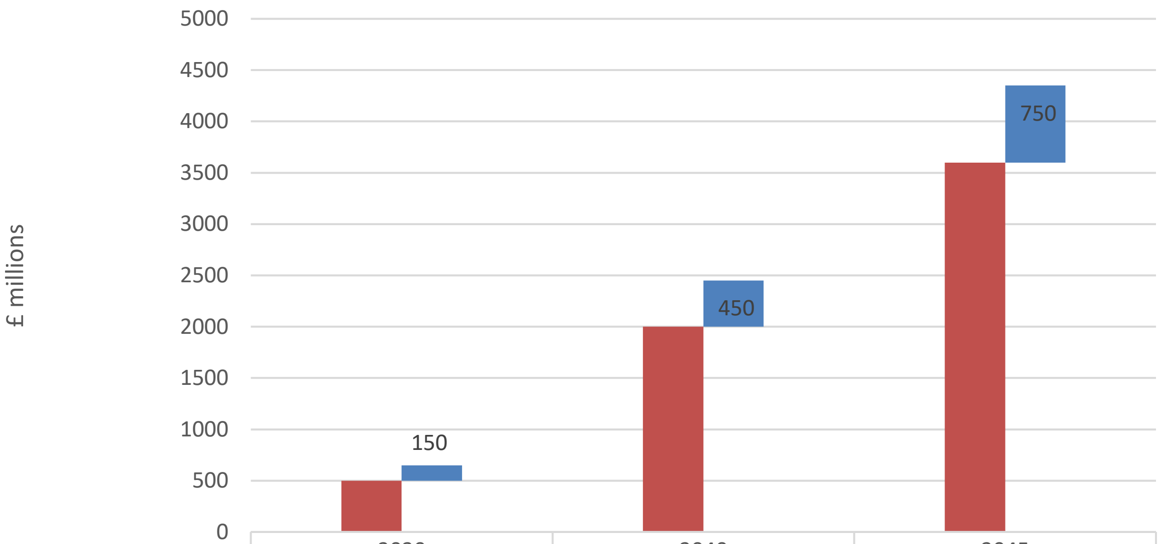


	2030	2040	2045
Unpriced carbon (appraisal value)	150	200	200
Carbon cost	100	500	1,000
High carbon cost	400	1,200	2,000

80 Based on BEIS's Updated Short-term Traded Carbon Values: Used for UK Public Policy Appraisal, January 2018.
81 As described in table 17, the total costs savings from carbon emissions in the base case are calculated as carbon costs and unpriced carbon.

4.73. Figure 13 below shows the increase in welfare when using the high carbon value scenario compared to the base case. This figure also shows the difference between Carbon Costs and Unpriced Carbon Costs. It is worth noting that most of the carbon impacts in the base case are already captured by the Carbon Costs, and therefore Unpriced Carbon costs are relatively small.[82]

Figure 13: Estimated cost savings (£ millions) from reduction in carbon emissions, high load shifting, CFF price scenario, 2018 PV figures, cumulative

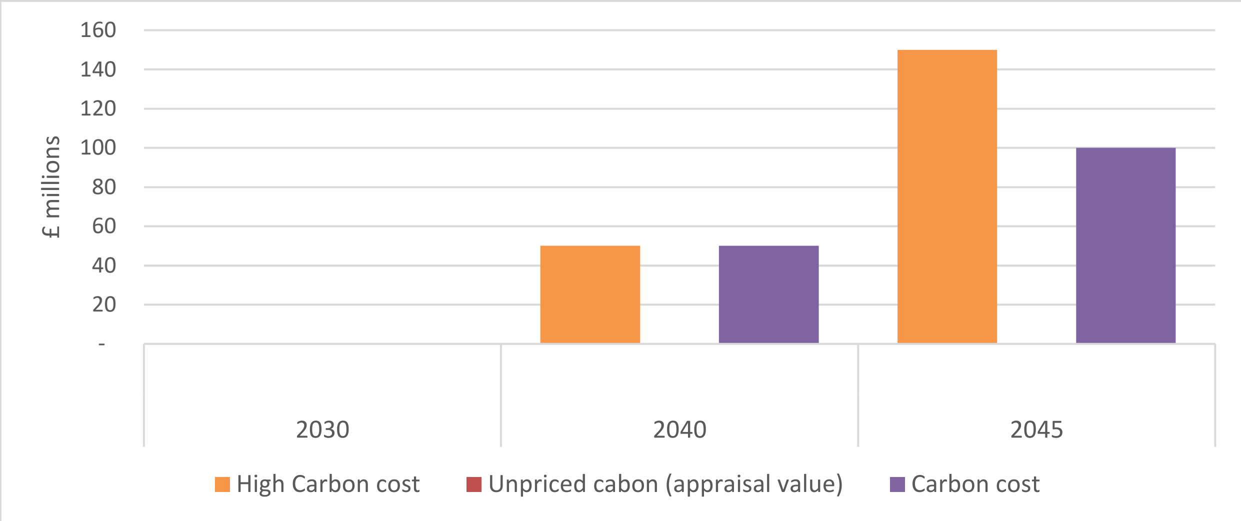


	2030	2040	2045
High carbon costs	150	450	750
Central Case benefits	500	2000	3600

4.74. Figures 14 and 15 describing the modelling outputs only show the Unpriced Carbon and Carbon Costs figures. Due to the rounding methodology, values below £50m are not shown in these figures.

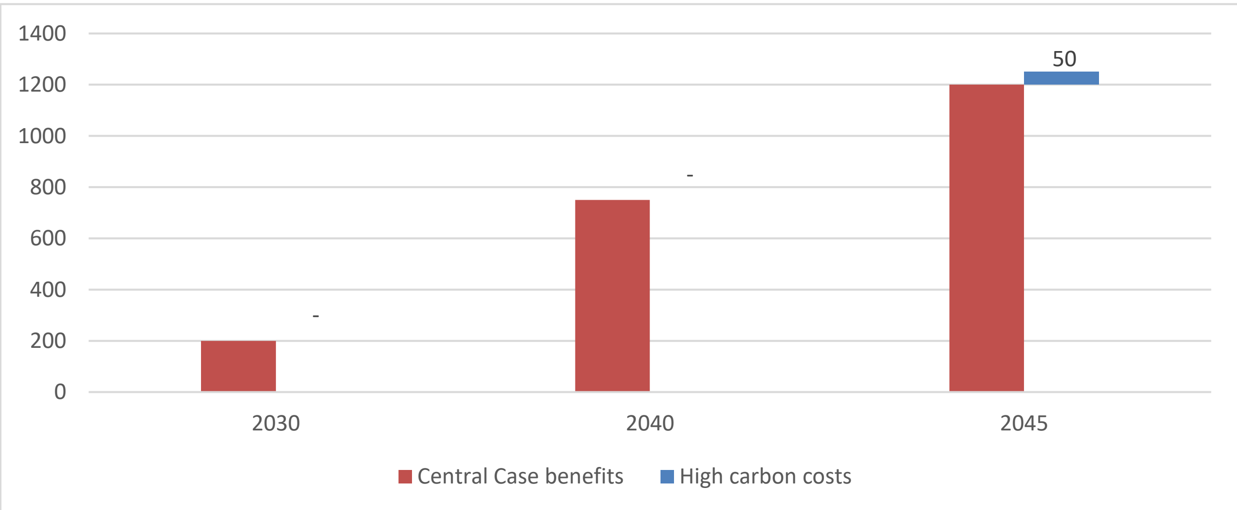
[82] We explain the difference between these figures at paragraph 4.68.

Figure 14: Estimated costs savings (£ millions) from reduction in carbon emissions, low load shifting, CFF price scenario, 2018 PV figures, cumulative



£m	2030	2040	2045
Carbon cost	<25	50	100
Unpriced carbon (appraisal value)	<25	<25	<25
High carbon cost	<25	50	150

Figure 15: Estimated cost savings (£ millions) from reduction in carbon emissions, low load shifting, CFF price scenario



£m	2030	2040	2045
High carbon cost	<25	<25	50
Central Case benefits	200	750	1200

System-wide benefits from load shifting for different implementation periods

4.75. As explained at the beginning of this chapter, the system-wide benefits discussed above were modelled for the period 2025-2045. However, our chosen option assumes a transition period of 4 years and 6 months. As a result of this longer transition period, we now expect the benefits of MHHS to start flowing in late 2025. We have adjusted the benefits from the model accordingly, taking a conservative approach, by calculating the benefits from the start of 2026.

4.76. The table below compares the benefits of MHHS under different transition periods, calculated using the DDM output. To aid the comparison, the benefits for both options are calculated out to 2045. It shows a relatively small impact for the change in welfare in the high load shifting scenario, and no noticeable change for the low load shifting scenario (once the figures are rounded to the nearest £50m).

Table 18: Estimated change in welfare benefits under different implementation periods, in 2018 PV, £ millions, cumulative by 2045

Cumulative in £ millions, 2018 PV	Different transition periods Change in welfare by 2045		
Transition period	4 years approx. as in the Draft IA preferred option (2025-2045)	4 years and 6 months as in our chosen option (2026-2045)	Difference
High load shifting scenario – CFF	£3,600m	£3,550m	-£50m
Low load shifting scenario – CFF	£1,200m	£1,200m	<£25m

Other quantified benefits not captured by the modelling

Benefits from including export-related MPANs in MHHS

4.77. In their Request for Information (**RFI**) and consultation responses, many suppliers agreed in principle that including export-related MPANs in MHHS would produce benefits. However, only a few suppliers submitted quantified estimates of the benefits. The benefits that were reported by industry participants through the RFI are captured in the total costs discussed in section 3 as cost savings. Given the continuing high level of uncertainty at this time, we have not sought to extrapolate across the sector using the figures those suppliers provided.

4.78. Some large suppliers told us that mandating settlement of export would bring more accurate settlement, and one mentioned that it would enable the alignment of settlements and payments for export. They added, however, that these benefits would depend on effective delivery of the Smart Export Guarantee (**SEG**).

4.79. Other suppliers mentioned ongoing benefits expected from improved forecasting. An independent supplier agreed that including export MPANs would bring forecasting benefits and said that it would also reduce risk because unsettled, exported energy would no longer be smeared across parties through the Grid Supply Point Group (**GSPG**) Correction Factor. Two suppliers, one large and one independent, stated that mandating settlement of export would give them the right incentive to offer innovative new tariffs and products.

4.80. Other large suppliers said longer-term benefits in relation to forecasting, balancing and innovation might be limited because of the relatively small size of the sub 30 kW export market. Those large suppliers said they could not quantify these benefits for this reason. Nevertheless, these benefits would not be possible if export-related MPANs were to be excluded from the scope of MHHS.

4.81. Including export-related MPANs in MHHS should improve system flexibility by enabling more accurate and granular price-signals to be sent to owners of small assets with export capacity. For example, these price signals can incentivise users to export or self-consume when the energy is most needed in the system. However, the modelled system-wide benefits discussed in this section do not capture this potential value of system flexibility.

4.82. This is because there is little evidence we could rely upon to quantify the impact it would have on the energy system. As noted above, the sub 30kw export market is relatively small, and we would expect the benefits to be correspondingly small compared to the total quantified benefits of MHHS. That said, widespread uptake of technologies such as Vehicle to Grid (**V2G**) or domestic battery storage could lead to significant benefits. We discuss how MHHS could incentivise innovations such as these in section 5 on non-monetised benefits.

Better matching of supply and demand reduces the cost of managing imbalance positions

4.83. Unmetered export volumes are spilled onto the distribution network system and this has some negative effects. It is reallocated to suppliers via the GSPG Correction process, potentially causing cross-subsidies. This spill has a significant impact on suppliers' ability to forecast and purchase energy accurately. We expect MHHS in the medium term will lead to more accurate forecasting and matching of supply and demand, reducing the imbalance costs faced by suppliers as well as the residual imbalance that the ESO needs to resolve, and therefore the costs of doing so.

4.84. We sought to quantify this through our RFI. Several suppliers said they would expect their ability to forecast to improve, and reported related cost savings amounting to £4.5m per year. We have reflected these cost savings in the total cost estimates reported in section 3 above. The ESO acknowledged that more accurate forecasting by suppliers (and better availability of data) could lead to a more balanced system and, therefore, potentially produce a relatively small reduction in the ESO's balancing costs. The ESO did not quantify any cost savings in its response because this would depend on the extent to which suppliers improve their ability to forecast.

Summary of monetised direct benefits

4.85. The table below sets out the total monetised direct benefits of our chosen option for MHHS. We discuss the net impact on consumers in section 6. As noted above, we have adjusted these benefits to reflect the longer transition period of the chosen option so that benefits start to realise in 2026, instead of 2025.

4.86. Therefore, the values in the table show cumulative benefits for the period 2026-2045 (instead of 2025-2045 as shown in the rest of this section). However, the impact of these adjustment is relatively small and, once the figures are rounded to the nearest £50m, only noticeable for the change in welfare in the high load shifting scenario. The other values remain unchanged. The net impact on consumers in section 6 are calculated using the adjusted values for the period 2026-2045.

Table 19: Monetised estimated direct benefits for our chosen option for MHHS, in 2018 PV, £ millions, cumulative (2026-2045)

Summary of monetised direct benefits - MHHS chosen option	2018 PV, £ millions, cumulative (2026-2045)
System-wide welfare benefits from load shifting	Scenario 1 (low load shifting) £1,200m
	Scenario 2 (high load shifting) £3,550m
Consumer benefits (consumer surplus) from load shifting	Scenario1 (low load shifting) £2,100m
	Scenario 2 (high load shifting) £5,050m
Benefits from including export-related MPANs	Mostly qualitative description
Better matching of supply and demand reduces the cost of managing imbalance positions	£49m (included as a cost saving in the monetised costs discussed in section 3)

4.87. Table 20 below summarises the different sensitivity tests discussed in this section. The sensitivities are calculated against a baseline for the period 2025-2045. Therefore, they are not adjusted for the longer transition period of the chosen option for MHHS. However, as noted above, this impact is minimal.

4.88. It is worth noting that even the lowest benefit sensitivity scenario (low load shifting scenario - 2h shifting window) shows substantial positive change in welfare (above the costs described in section 3), albeit by a significantly lower margin than our central estimate (Central Fossil Fuel prices – 8h shifting window).

Table 20: Summary of sensitivity analysis, shows change in welfare under the different sensitivity tests, in 2018 PV, £ millions, cumulative (2025-2045)

Sensitivities summary, 2018 PV, £ millions, cumulative by 2045	Sensitivity test	Scenario 1 (CFF, low load shifting)	Scenario 2 (CFF, high load shifting)
Baseline		£1,200m	£3,600m
Sensitivity - change in welfare	Low Fossil Fuel Prices	£1,050m	£3,500m
	4h shifting window	£1,050m	£2,900m
	2h shifting window	£850m	£2,200m
	Excluding non-domestic load shifting	£850m	£3,200m
	Including distribution network benefits	£1,300m	£4,450m
	Including high carbon costs	£1,250m	£4,350m

Table 21: Monetised direct benefits for the preferred option in Draft IA, in 2018 PV, £M, cumulative (2025-2045)

Summary of monetised direct benefits – preferred option in Draft IA	2018 PV, £ millions, cumulative by 2045
System-wide welfare benefits from load shifting	Scenario 1 (low load shifting) £1,200m
	Scenario 2 (high load shifting) £3,600m
Consumer benefits (consumer surplus) from load shifting	Scenario 1 (low load shifting) £2,100m
	Scenario 2 (high load shifting) £5,050m
Benefits from including export-related MPANs	Mostly qualitative description
Better matching of supply and demand reduces the cost of managing imbalance positions	£53m (included as a cost saving in the monetised costs discussed in section 3)

5. Non-monetised benefits

Section summary

In this section we identify other direct benefits that we expect market-wide half-hourly settlement (**MHHS**) to bring but which are hard to value. The benefits relate mainly to increased innovation, competition and consumer engagement.

We begin by outlining the broader work we are doing to facilitate the energy transition, and other market and technological developments that we expect to see. This is the context within which MHHS will operate. Using market signals and consumption data, MHHS will place incentives on existing and new market participants to develop and offer a much wider range of innovative products and services that enable consumers to shift their electricity use away from peak times. The scale of the benefits achieved will depend on the level of consumer take-up.

5.1. We expect that MHHS will, over the long term, deliver a variety of benefits that are hard to quantify. We base this expectation on a set of reasonable assumptions about the future development of the retail energy market and energy system, including the extent to which consumers will actually shift their consumption away from times of peak demand.

5.2. MHHS should facilitate innovation in products and services by existing and new market participants. This wider choice should directly benefit consumers. The scale of benefits depends on the extent to which consumers engage with any innovative offerings that emerge. We cannot predict that with certainty. However, our aim is to assist this transition by creating a smarter, more flexible energy system and a more competitive energy market, in particular through our work on:

- the smart meter rollout
- faster, more reliable switching
- modernising energy data
- Access and forward-looking charging reform, and
- the RIIO-2 network price controls.

5.3. Our Decarbonisation Action Plan set out our intentions in relation to these and other projects. For the latest position see Ofgem's Forward Work Programme 2021/22.[83] Alongside these regulatory changes, we expect broader market impacts to arise from significant and rapid technological change in the following areas:

- electrification of transport
- electrification and decarbonisation of heat
- increased renewable generation
- energy storage solutions, and
- demand-side response (**DSR**) grid services.

5.4. Clearly, the pace of the transition to a smarter, more flexible and low carbon energy system will depend partly on the affordability of flexibility solutions and partly on the ability and willingness of consumers to engage with them. Retailers will play a critical role in developing and marketing the products and services that encourage and make it easy for consumers to use energy efficiently.

5.5. Some consumers will be confident enough to take up smart Time of Use (**ToU**) tariffs, on the basis that the tariff fits their existing behaviour or because they can easily change their behaviour. Others may choose smart options that cause the least disruption to their existing routines, or may engage indirectly through automated or managed DSR solutions.[84] Prospective energy bill savings are likely to be a key driver of consumer decisions to engage.[85] The availability of smart tariff comparison tools in the future could help consumers engage and make decisions on taking up smart tariffs that suit their circumstances.[86]

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[83] See Ofgem's Decarbonisation Programme Action Plan and Forward Work Programme 2021/22.
[84] See the PwC research we commissioned (October 2020) about consumers' perceptions of smart ToU tariffs.
[85] The Ofgem Consumer Survey 2019 included some evidence about the level of prospective savings that consumers may need in order to load shift.
[86] BEIS will soon publish research with consumers gauging consumer reactions to a potential smart tariff price comparison tool, awareness of smart tariffs and interest in them. This follows BEIS's commissioning and funding of the Smarter Tariffs - Smarter Comparisons project, which aims to develop a prototype smart tariff comparison tool for customers with a SMETS2 smart meter.

Incentivising innovation

5.6. Under the existing elective settlement arrangements we have begun to see some innovative propositions. However, without access to the granular consumption data and the incentive of cost-reflective pricing, we think that innovation will not occur at the scale and pace necessary to meet the UK's net zero targets.

5.7. MHHS helps to remedy these deficiencies. It will incentivise suppliers to manage the actual costs of providing energy to their customers more efficiently.[87] By providing access to HH consumption data (in line with privacy rules), MHHS will greatly strengthen retailers' incentives to offer:

- new energy tariff-only propositions, such as new and increasingly complex ToU tariffs (for example static, dynamic, as well as critical peak and critical peak rebate pricing),
- new third party managed energy services based on an energy proposition, such as automated 'heat-as-a-service' or repurposing of existing non-smart heating using smart controls. These would allow the consumer to set a preferred level of comfort and convenience which is remotely managed to deliver heating efficiently and unlock any flexibility the consumer could offer,
- new bundled 'asset and tariff' offerings managed for the consumer by a third party or directly controlled by actively engaged consumers (such as an EV smart charging and tariff bundle or an import/export tariff included with the offer of a storage battery where the consumer may already have solar PV), and
- more niche offerings that could be targeted at local communities such as peer-to-peer (**P2P**), Virtual Power Plant (**VPP**), or DSR grid balancing services.

5.8. MHHS should, therefore, play a key role in supporting innovative offers that transform the energy system and retail energy market. We have noted that faster, more reliable switching could accelerate innovation in the energy market, encouraging more and varied competitive offerings to consumers. Digitalisation (sharing consumers' granular usage data with their consent) may also be a driver for consumers to find and switch to the right offering for them. Third parties offering

[87] For more detail see our Outline Business Case and section 2 of this document.

price comparison tools could provide a more comprehensive comparison service, taking into account the electrical appliances and other assets that a consumer owns and tailoring the service to the consumer's requirements.

Increasing competition

5.9. Market-wide settlement reform will support competition by reducing the overall costs of the settlement process, thereby removing barriers to entry for new market players. As noted earlier, this could be achieved through market players needing to post less collateral[88] with Elexon in the settlement process, or realising cost savings through more accurately forecasting demand.

5.10. In their responses to the consultation on the Draft IA, some supplier agents expressed the view that using non-aggregated data in central settlement systems would adversely impact competition. We do not agree – in fact, we consider our changes in this area to be pro-competitive because they will enable new innovations based on third-party access to data (in line with privacy rules) - and have set out our reasoning in section 2 of the Decision Document.

5.11. Exposing suppliers to the true cost of supply of their customers in every half hour period places incentives on them to encourage load shifting. This opens up an opportunity for suppliers to reduce the costs of serving their customer base, allowing those suppliers who take up this opportunity to potentially gain a competitive advantage over their competitors by offering new and innovative tariffs. Market-wide settlement reform can also enable new technologies and business models that capitalise on the new incentives placed on the market, facilitating and incentivising load shifting and therefore cost reduction.

5.12. The combination of lower entry barriers and the opportunities for cost reduction, together with the new technologies and products enabled by half-hourly settlement (**HHS**), could encourage both more market participation and increasingly innovative

[88] In our Supplier Licensing Review we have taken steps to ensure that the cost mutualisation arrangements do not encourage inefficient entry or expansion of poorly-prepared suppliers. As noted above, our aim is to improve supplier standards of financial resilience without presenting any undue barriers to entry, innovation or expansion. A reduction in settlement collateral requirements would further reduce any such remaining barriers that existed.

players to join, competing with incumbent participants. When combined with other Ofgem projects that are seeking to support competition and innovation in the market, such as the work on Access and forward-looking charging reform and removing barriers to innovation, MHHS could have a profound impact on the dynamics of the market by encouraging the design and marketing of innovative new products which help consumers realise the benefits of their flexibility.

5.13. These competition effects are challenging to predict and quantify, but should be recognised as an important consequence of the project that can deliver positive outcomes for consumers. This view was shared by the Competition and Markets Authority (**CMA**) in its 2016 Energy Market Investigation, which found that the current system of load profiling reduces the competitiveness of domestic retail electricity supply.[89]

Increasing consumer choice

5.14. We expect that MHHS will facilitate more consumer choice in a future energy market stimulated by innovation. We expect that new market participants with new business models will enter the market and compete with incumbent suppliers, who in turn would evolve their existing offerings or develop new offers in response. This process would increase choice for consumers and drive down prices relative to the counterfactual. We are already beginning to see an increase in choice through new smart ToU tariffs and aggregation services targeted particularly at those consumers with existing flexibility assets.

5.15. There could also be broad-based energy services where the tariff is part of a bigger 'bundle' that includes a flexibility asset. The growth potential of these offers may be linked to the willingness of consumers to make data available about their usage to providers. Consumers that opt out of sharing their granular energy data may have a more limited choice of products and services.

5.16. We expect that MHHS will facilitate innovation, new entry and greater choice of products and services. For many, this means opportunity - to get a better service,

[89] See the CMA's Energy Market Investigation Final Report (2016), page 591.

save money and help the environment. For others, particularly more vulnerable consumers, this will be more of a challenge and they may need extra support and protection.

5.17. As stated in our Forward Work Programme 2021/22, we will deliver a future retail market with innovative new retail products that, for example, enable consumers to benefit from the flexibility they can provide, while ensuring that protections are in place for all. We are developing our future of retail Strategic Change Programme with a high level objective (amongst others) of an energy transition that works for all energy consumers, harnessing innovation and flexibility, with effective protection for consumers. We expect to begin this Strategic Change Programme in the summer.

Fewer settlement errors and lower collateral requirements

5.18. Our proposals will promote a more accurate settlement process, with better quality data and fewer settlement errors. The settlement system will increasingly use data from smart meters, removing (or minimising) the need for estimation and the current profiling arrangements. However, as part of our RFI and consultation on the Draft IA we have not received any data that allow us to quantify this benefit.

5.19. We have decided to improve the efficiency of the settlement process by shortening the timeframes. This should reduce suppliers' exposure and the amount of collateral that suppliers must post in order to cover it. Reducing settlement collateral requirements should reduce entry barriers.[90]

[90] As noted above, in our Supplier Licensing Review we have taken steps to ensure that the cost mutualisation arrangements do not encourage inefficient entry or expansion of poorly-prepared suppliers. Our aim is to improve supplier standards of financial resilience without presenting any undue barriers to entry, innovation or expansion. A reduction in settlement collateral requirements would further reduce any such remaining barriers that existed.

6. Consumer impacts

Section summary

In this section, we bring together the quantitative and qualitative analysis from previous sections of the Impact Assessment (**IA**) in order to draw conclusions about the overall impact of our chosen option for market-wide half-hourly settlement (**MHHS**). We summarise the potential distributional impacts of MHHS amongst consumers, including rural consumers and consumers with protected characteristics under the Equality Act 2010. We also summarise the potential impact on small non-domestic consumers.

As stated in our Forward Work Programme (**FWP**) 2021/22, we will deliver a future retail market with innovative new retail products that, for example, enables consumers to benefit from the flexibility they can provide, while ensuring that protections are in place for all. We are developing our future of retail Strategic Change Programme with a high level objective (amongst others) of an energy transition that works for all energy consumers, harnessing innovation and flexibility, with effective protection for consumers. MHHS is vital for supporting that transition at lowest cost, and our chosen option will deliver significant benefits for GB energy consumers.

Net direct and indirect consumer impacts

6.1. The table below sets out the net position for consumers after taking account of monetised costs and benefits under our chosen option relative to the counterfactual. It makes clear that **MHHS under our chosen option is expected to have a significant net benefit for consumers compared with the counterfactual.**

Table 22: Summary of estimated net impacts under our chosen option, 2018 NPV, cumulative costs and benefits by 2045, £ millions

Summary of MHHS net benefits	Low Shifting (scenario 1)			High Shifting (scenario 2)		
Total monetised benefits for consumers	£2,100m			£5,050m		
	Costs - low case	Costs – central case	Costs - high case	Costs - low case	Costs – central case	Costs - High case
Total monetised costs	£407.5m	£541.3m	£731.1m	£407.5	£541.3m	£731.1m
Net Benefits of MHHS	£1,692.5m	**£1,558.7m**	£1,368.9	£4,642.5m	**£4,508.7m**	£4,318.9m

6.2. The table below compares the net impacts on consumers of our chosen option and the preferred option from our Draft IA.

Table 23: Net benefit comparison of our chosen option and the preferred option from the Draft IA, 2018 NPV, cumulative net benefits by 2045, £ millions

Comparison of net benefits to consumers	Low Load Shifting (scenario 1)	High Load Shifting (scenario 2)
Our chosen option	£1,558.7m	£4,508.7m
The previous preferred option (Draft IA, April 2020)	£1,607.5m	£4,557.5m
Difference in net quantified benefits	**£48.7m**	**£48.7m**
Non-monetised benefits	Both options bring benefits from settling export in terms of improved network management, more accurate settlement, better forecasting and through increased innovation, competition and consumer engagement (see sections 4 and 5 above). So far as non-monetised benefits are concerned, we do not expect significant differences between our chosen option and the preferred option on which we consulted.	

Distributional impacts on consumers

6.3. The preceding tables summarise the net impacts of the options we have considered for consumers in the aggregate. However, changes to the energy system facilitated by MHHS are likely to affect different consumers in different ways depending on their individual circumstances. We set out below the work that has been done to estimate the potential distributional impacts on different types of energy consumer. This includes rural and regional effects and impacts on consumers with protected characteristics under the Equality Act.

6.4. We have considered the distributional impacts on household energy bills of taking up specific Time of Use (**ToU**) tariffs, where electricity prices vary across the day, compared with remaining on 'flat' tariffs where the price paid is the same regardless of when the electricity is used. There is a risk that some customers might sign up to ToU tariffs even though they have little ability to shift consumption away from more expensive peak periods. There is also a risk that, if enough customers switch to ToU products, the customers left on flat tariffs will see their prices go up.

6.5. We will deliver a future retail market with innovative new retail products that, for example, enables consumers to benefit from the flexibility they can provide, while ensuring that protections are in place for all. As set out in our Forward Work Programme 2021/22, we will develop a future of retail Strategic Change Programme that has high level objectives that include fair energy prices, with or without the price cap, and a better deal for consumers in vulnerable circumstances.

Previous work on identifying MHHS distributional impacts

6.6. In the Outline Business Case (**OBC**), we referred to analysis we commissioned in 2016 from Cambridge Economic Policy Associates (**CEPA**) about distributional impacts across defined sociodemographic groups of consumers of them taking up static ToU tariffs compared to staying on flat tariffs.[91] MHHS will incentivise energy providers to offer consumers a variety of different types of 'smart' (static, dynamic

[91] See page 66 of the MHHS Outline Business Case as well as the full CEPA report (July 2017).

and real-time) ToU tariffs. CEPA assessed the distributional impacts using the datasets of domestic consumers that were involved in smart meter trials, using the ACORN classification to differentiate consumers by sociodemographic group.[92]

6.7. CEPA noted how different groups of consumers might respond to different motivations and incentives, such as achieving a certain defined level of bill savings. Most consumers across the different sociodemographic groups, including groups of consumers in vulnerable situations but excepting some of the most well-off groups, could make, on average, a modest bill saving (2% in the case of vulnerable consumer groups) by moving to a static ToU tariff compared with staying on a flat tariff. This took into account consumers' predicted demand response with a ToU tariff.[93] However, a wide range of positive and negative energy bill impacts within all of the groups was possible, regardless of whether consumers responded to ToU price signals or not (the dotted line bars in the figure below).[94]

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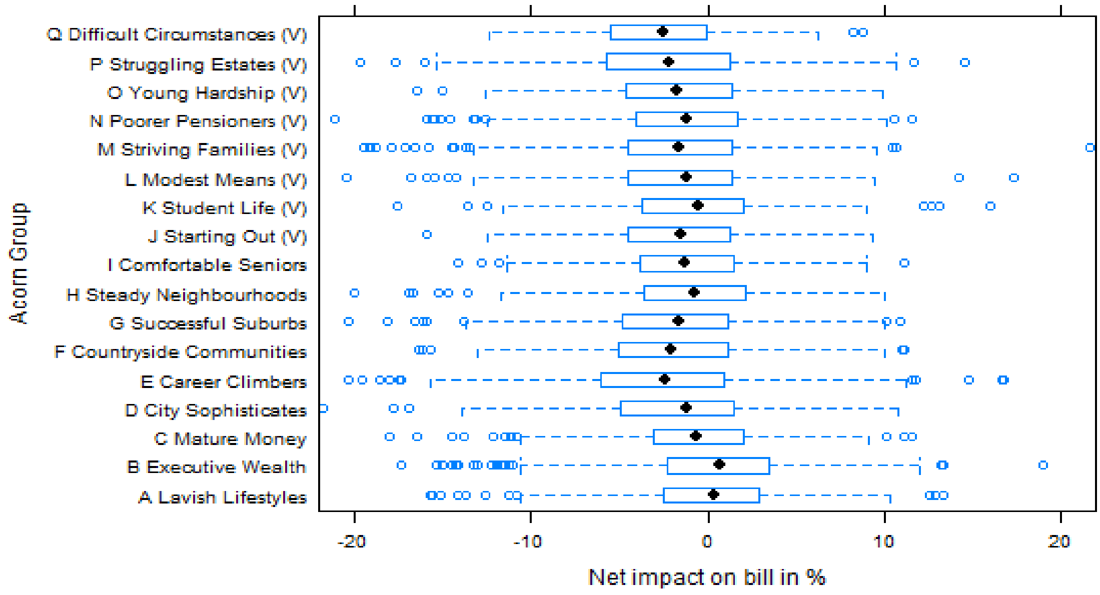
[92] ACORN is a powerful consumer classification tool that segments the UK's population by analysing demographic data, social factors, population and consumer behaviour to help provide an insight into different types of people.

[93] Specifically, CEPA designed their tariff scenarios to assume that if consumers do not change their consumption, the bill of the average customer will remain unchanged relative to what they would have paid under an existing flat tariff. Thereafter, building in consumers' predicted demand response accounts for the modest rise in average bills for the most well-off groups and a modest decrease in average bills for most lower income groups.

[94] See chapter 4 of the CEPA report.

Figure 16: Impact on bill in relative terms under static ToU reference tariff (% net impact compared to a flat tariff), assuming customers adjust consumption to tariff



Key: black dot shows the median, box shows the interquartile, bars show the 2nd to 98th percentiles, circles are outliers[95]

Linking with Ofgem's distributional impacts framework

6.8. Ofgem has updated our impact assessment guidance alongside which we published an analytical framework for assessing the potential distributional impacts of our policies on different types of consumers using a refreshed set of consumer archetypes.[96] We have considered, since we published the draft IA, whether there are more recent robust sources of data available to us in sufficient amounts to undertake further meaningful quantitative analysis of the distributional impacts for

[95] It is likely that the outliers are mostly not genuine outliers in their class. This is both because postcode-level social classification is being used, and because of the presence of other data difficulties. Rather the outliers are likely mostly made up of, in part, consumers unrepresentative of the social category attributed to the postcode, and, in part, data difficulties such as meter faults, theft, non-domestic use of electricity, etc. CEPA did not recommend any policy conclusions be based on an examination of outliers.
[96] See our updated Impact Assessment guidance and associated framework documents, May 2020.

different consumer groups (using the refreshed archetypes if possible) of the implementation of MHHS.

6.9. In our view, there is very limited usable evidence available to quantify the potential distributional impacts across specific consumer groups of implementing MHHS, and to assess whether consumers will respond to the flexibility options it may facilitate. A particular issue is the lack of new available daily consumption profile data for different consumer groups which we can model. At the time it was done, the CEPA analysis was useful in assessing potential impacts based on the half-hourly (**HH**) consumption data that was looked at, and the consumer classifications used to draw out the distributional effects, but the limitations in the datasets were recognised.[97]

6.10. Robust and meaningful distributional impacts analysis depends on how effectively consumers are categorised (into broad or narrowly defined groups) and the quality of the datasets available. Taking the analysis one step further would involve reaching an informed view of how consumers may respond to price signals and, as a result, their propensity to change behaviour and load shift. This could help us identify whether specific policy levers may prompt a greater or lesser response from consumers to help achieve a more efficient, flexible and low carbon energy system.

6.11. In the future it may be possible, using our refreshed archetypes, to look at the daily rather than the annual consumption profile for different groups of consumers, as well as looking at characteristics including age, disability, income level and the number of dependents. Using a richer, more detailed dataset, we could further improve the narrative about how policy may affect different consumer groups.

6.12. Currently, it is not possible for us to set out a complete quantifiable distributional impact analysis across the different categories of domestic consumers found in the

[97] These limitations (using London-only consumers from the Low Carbon London trial and excluding a higher proportion of vulnerable consumers) could have skewed the results obtained by CEPA. In a paper by Adam Hutchinson ('Residential Electricity Time-of-use Tariffs: A Welfare Analysis' in *Topics in Sustainable Energy: An Economic Analysis of Net Demand Volatility Management* (PhD thesis, University of Warwick), pp. 69-122 (2015)), using a smaller but more representative sample taken from the 2013 UK Household Electricity Survey, there were similar results to CEPA's analysis, showing that households would not be exposed to excessive bill changes if they moved onto a ToU tariff and did not change their consumption behaviour.

refreshed archetypes without a robust evidence base showing the flexibility of different consumer groups.[98] We have, however, carried out some additional distributional impact analysis, using the refreshed archetypes, to quantify the impacts of the system benefits that we can attribute to MHHS. The system benefits are discussed in section 4 above (which also contains more information on the assumptions underpinning, and the methodology used in calculating, those benefits).

6.13. For this analysis, we used BEIS's Average Prices and Bills Model[99] (**APBM**) to estimate how energy prices would change as a result of implementing MHHS. We then combined the changes in energy prices with the refreshed archetypes' energy consumption and income data to estimate bill savings (assuming consumers are on flat tariffs). The analysis shows the distributional impacts across different consumer types and the new consumer archetypes, indicating modest annual savings for all consumers. It is worth noting, however, that when these savings are considered over the 2026-2045 period and for the total number of households, the resulting value is very significant, in line with the system-wide benefits shown in section 4.

6.14. Table 24 below illustrates the distributional impact by consumer archetype, showing annual savings per household that range from £2 to £4 in the low load-shifting scenario and from £4 to £9 in the high load-shifting scenario, with small differences between consumer groups. Table 23 also shows the total annual savings (in £m) per archetype, resulting from applying the individual savings per household to the total number of households in each archetype.

6.15. It is worth noting that these are benefits that should be experienced by all consumers regardless of whether they engage at individual household level in DSR or not. It does not show, however, the potential impact for consumers who take up ToU tariffs. These impacts are shown in the CEPA analysis discussed above. Nor does it include the unquantified benefits we expect to arise from increased innovation and competition (as described in section 5 above).

[98] The refreshed archetypes apply typical annual consumption values for consumer types rather than a richer half hourly consumption dataset.
[99] The model estimates the different components of gas and electricity prices on a £/MWh basis to build up a bill: wholesale costs, network costs, supplier costs and margins, policy costs and VAT.

Table 24: Electricity bill savings by archetype group and headline statistics

Archetype	Low load shifting scenario: Electricity annual average savings per household (in £)	Low load shifting scenario: Electricity total annual savings (in £m)	High load shifting scenario: Electricity annual average savings per household (in £)	High load shifting scenario: Electricity total annual savings (in £m)
A1	£2	£5.47m	£5	£14.70m
A2	£3	£8.75m	£8	£23.50m
B3	£2	£8.22m	£6	£22.09m
B4	£2	£5.80m	£7	£15.56m
C5	£2	£3.01m	£4	£8.09m
D6	£2	£3.70m	£6	£9.93m
D7	£3	£3.04m	£7	£8.17m
E8	£2	£5.20m	£6	£13.97m
E9	£2	£6.04m	£5	£16.21m
F10	£4	£6.71m	£9	£18.01m
G11	£3	£4.84m	£9	£12.99m
H12	£2	£1.58m	£7	£4.25m
H13	£3	£1.72m	£9	£4.62m

Archetype	Numbers of hhlds	Heating fuel	Average hhld income BHC (GB avg: £34k)	Average hhld income AHC (GB avg: £29k)	Elec kWh (GB avg: 3,980)	Gas kWh (GB avg: 13,180)	Attributes (key words)
A1	2,761,000	Mains gas	£48,000	£40,900	3,250	9,650	High incomes, owner occupied, working age families, full time employment, low consumption, regular switchers.
A2	2,916,000	Mains gas	£54,600	£48,200	4,920	20,520	High incomes, owner occupied, middle aged adults, full time employment, big houses, very high consumption, solar PV installers, care for the environment.
B3	3,674,000	Mains gas	£28,600	£28,000	3,670	15,350	Average incomes, retired, owner occupied - no mortgage, lapsed switchers, late adopters.
B4	2,323,000	Mains gas	£40,600	£36,600	4,090	15,630	High incomes, owner occupied, part-type employed, high consumers, flexible lifestyles, environmental concerns.
C5	1,922,000	Mains gas	£15,200	£13,200	2,570	11,270	Very low incomes, single female adult pensioners, non-switchers, prepayment meters, disconnected (no internet or smart phones).
D6	1,547,000	Mains gas	£18,100	£13,600	3,920	12,340	Low income, disability, fuel debt, prepayment meter, disengaged, social housing, BME households, single parents.
D7	1,205,000	Mains gas	£34,000	£30,400	4,140	15,600	Middle aged to pensioners, full time work or retired, disability benefits, above average incomes, high consumers.
E8	2,356,000	Mains gas	£23,400	£16,200	3,620	11,950	Low income, younger households, part-time work or unemployed, private or social renters, disengaged non-switchers.
E9	3,093,000	Mains gas	£37,000	£29,700	3,200	10,440	High income, young renters, full time employments, private renters, early adopters, smart phones.
F10	1,912,000	Oil, Electric	£38,900	£35,400	5,750	0	Middle aged to pensioners, full time work or retired, owner occupied, higher incomes, oil heating, rural, RHI installers, late adopters.
G11	1,510,000	Electric, Oil	£30,200	£23,200	5,250	0	Younger couples or single adults, private renters, electric heating, employed, average incomes, early adopters, BME backgrounds, low levels of engagement.
H12	644,000	Electric, Oil	£14,500	£12,000	4,030	0	Elderly, single adults, very low income, medium electricity consumers, never-switched, disconnected, fuel debt.
H13	526,000	Electric, Oil	£22,000	£18,200	5,360	0	Off gas, low income, high electricity consumption, disability benefits, over 45s, low energy market engagement, late adopters.
All households	**26,390,000**		**£34,100**	**£29,400**	**3,980**	**13,630**	

Note: annual average savings per household (in £) are rounded to the nearest unit.

6.16. Recent work from Dr Timur Yunusov and Professor Jacopo Torriti of Reading University gives some indication of the potential impact of ToU tariffs on different family types, assuming no load shifting. The impacts vary significantly with the assumptions made about the nature of the ToU tariff.[100]

6.17. They found that, based on estimated intraday demand profiles for different family structures at different income levels, high-income couples without children would be the most adversely impacted (or least positively impacted) family group (in relation to the other family groups studied) if they chose to take up a ToU tariff and did not change their consumption pattern. Conversely, in relative terms, low income single parents are among the family groups who would benefit most (or lose least).

6.18. The paper noted some limitations to the analysis. In particular, the use of historical regional datasets where only households' smart meter data was available to use is insufficient to understand the distributional effects of ToU tariffs unless this data is also enriched by sociodemographic parameters, which are currently not contained in publicly available sources. To compensate for the lack of access to such data, the authors have sought to estimate synthetic consumption profiles using data from different sources, but this remains an approximation.

6.19. The gains and losses shown in Yunusov and Torriti's work would only apply if a customer in a particular group took up a ToU tariff and did not change consumption behaviour. In practice, we expect that those taking up a ToU tariff would usually do so either because they could benefit from it without changing their behaviour or because they believe that they could easily change their behaviour in order to benefit from it. Technologies like batteries (perhaps communal ones shared between apartments in a block of flats), smart appliances, or electric vehicles (**EVs**) equipped with smart chargers could increasingly help consumers to realise those benefits.[101]

[100] See Distributional effects of Time of Use tariffs based on smart meter electricity demand and time use activities, Energy Policy (submitted), co-authored by Dr Timur Yunusov and Professor Jacopo Torriti of Reading University (2020).
[101] Project Shift is a recent collaborative trial, funded by Ofgem, seeking to deepen understanding about the value and potential of low voltage flexibility, with a particular focus on smart charging solutions for domestic EV drivers. The Project Shift interim report was published in January 2021 with a final report due later in 2021.

Impacts on consumers living in remote rural areas

6.20. In remote rural areas, the cost of maintaining and operating the distribution networks may be higher than other areas. MHHS could facilitate innovative local solutions in remote communities. One possibility is self- or third party-managed energy storage alongside renewable generation (wind or solar PV) that offers a balancing service to the local grid - a Virtual Power Plant (**VPP**). This could produce demand–side response (**DSR**) and revenue generating opportunities.[102]

6.21. Remote communities could offer local DSR services, allowing them to sell excess electricity flexibly when the energy system needs it while retaining access to, and use of, the broader energy system to meet their demand when there is insufficient 'self-supply' from local renewable generation. Such services could contribute to a more efficient local energy system in remote rural areas. Trials are under way in the Orkney Islands and in Cornwall.[103]

6.22. In remote areas of northern Scotland, Wales and England, electricity is the main fuel for heating as well as for lighting. In off-gas grid areas, domestic consumers could be encouraged to take up electric smart heating solutions, such as heat pump installation by individual households and/or by local communities, controlled directly by them or as a third-party managed DSR solution. Such offers could be more energy efficient and 'greener' than connecting to the gas grid. However, there may be access and affordability challenges in relation to installing and paying for them.[104]

[102] There are numerous examples of DSR trials. One is the Core4Grid 'Hybrid Home' trial run by geo (Green Energy Options), EdF Energy and others. It is funded via BEIS's Innovative Domestic DSR Competition.

[103] See the Solo Energy case study. Solo Energy (now part of SMS plc) is offering some domestic consumers on Orkney a storage battery solution managed by them as part of a local DSR service (known as ReFLEX Orkney). See also Centrica's recently concluded trial offering local DSR services from domestic and non-domestic consumers with renewable generation capability, the Cornwall Local Energy initiative.

[104] There are examples of trials of 'heat as a service' concepts involving smart heating controlled through smartphone apps and smart thermostats which participating consumers have broadly supported as providing appropriate levels of comfort and which help them save on their energy costs. There is more information about one trial, the Smart Systems and Heat programme, which was managed and delivered by the Energy Systems Catapult in two phases and which could usefully apply to consumers in remote areas.

6.23. EVs offer consumers access to, and use of, a flexible asset. For those in remote areas, a key issue will be access to convenient EV charging points. Statistically, those living in remote areas with private transport need to travel greater distances.[105] Having a robust local energy system could help them. Smarter and more flexible energy grids may be required, for example by developing community-based energy solutions linked to renewable generation. Otherwise, significant infrastructure upgrades may be needed, and the need for such upgrades may vary across different regions.[106]

Impacts on small non-domestic consumers

6.24. We have set out elsewhere in this IA the load shifting assumptions we have used for small non-domestic consumers. In our decision document, we set out the views of a number of stakeholders who responded to the draft IA consultation who thought that our views on load shifting potentially overstate MHHS benefits. They highlighted how, in their view, these consumers are relatively inflexible energy users due to set business operating hours, are generally time poor and would have limited capacity to interact with load shifting messages. They also pointed to the range of consumers in this category being diverse in terms of size and sector, which makes an assessment of load shifting potential more difficult.

6.25. Our view is that some of these consumers will have the propensity to engage with solutions, such as innovative technologies like EVs and batteries, which offer them the ability to load shift. Our decision document also highlights a recent innovation competition funded by BEIS indicating that, for the sectors assessed (smaller retail, hospitality and schools), certain incentives can create opportunities for behaviour change leading to flexible energy use.[107] For example, tracking of energy usage by time of day was found to be a helpful feature.

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[105] See the most recent Department for Transport (DfT) statistics from the National Travel Survey (for England) showing that rural car use (by mileage per person) is significantly higher compared to urban car use.

[106] See, for example, the Electric A9 project, which is Transport Scotland's vision to increase the number of EV charging points across a key trunk road connecting rural to urban Scotland.

[107] See BEIS's Non-Domestic Smart Energy Management Innovation Competition (NDSEMIC) final report.

6.26. Results also suggested that the tailoring of tools and features to different organisational contexts was particularly beneficial in engaging non-domestic consumers. This provides some further evidence that these consumers could be incentivised to become flexible. However, we acknowledge that there are uncertainties in this area and our load shifting assumptions have therefore been suitably cautious by assuming a wide range of potential load shifting with a conservative lower-end. Furthermore, we have carried out a sensitivity analysis testing a scenario with no load shifting from the small non-domestic sector.[108] The analysis showed that, even in the absence of load shifting from this sector, the benefits of MHHS would outweigh the costs (although by a smaller margin). Ultimately, this approach balances caution with the emerging positive indications that load shifting holds potential for non-domestic consumers.

Regional impacts

6.27. We have no quantitative evidence that introducing MHHS would directly affect different parts of the country in significantly different ways. We have received no new evidence indicating that there could be differential regional impacts. Factors that we might expect to contribute to some variations across regions include:

- different working patterns and commuting times, leading to somewhat different peak consumption times,
- differing proportions of household types, since both the CEPA research and Yunusov and Torriti’s work suggest that, on average, the impact of ToU tariffs varies with household type, and
- differing network structures. MHHS could help reduce the need for costly network reinforcements. Any impacts may differ across regions, based on the scope for such reductions and strength of charging signals. Our work on Access and forward-looking charging reform is considering options which could increase the granularity of network charging signals.[109]

[108] See paragraphs 4.58 and 4.59 above.
[109] See the open letter on our shortlisted policy options for more detail.

Equality Act 2010 impacts

6.28. Changes facilitated by MHHS could have particular impacts on certain consumer groups falling within the definition of having 'protected characteristics'.[110] These protected characteristics include disability and age. Some consumers within these groups will feel better equipped to deal with the impacts than others (for example, if they are 'tech savvy', are happy to share data in return for a bill saving and can actively engage in a smarter, more flexible market).

6.29. Consistent with our Consumer Vulnerability Strategy (**CVS 2025**),[111] we want all consumers to share in these benefits and not be left behind. Some of the impacts associated with changes facilitated by MHHS may have more relevance for consumers with protected characteristics and require mitigating actions or further exploration in line with the CVS 2025:

- engagement with and understanding of energy usage and the ability to change behaviour – some stakeholders suggested to us that an independent source of advice to support these consumers in a more sophisticated energy market may be needed. We recognise that some consumers may struggle with digital tools such as smartphone apps, and could need additional support or specific tools to help them engage, understand their usage, and make informed choices about any flexibility they could offer and the right product choice for them. For example, depending on their circumstances, elderly consumers and people with disabilities may need more specific support from their energy provider than other consumers. This means providing appropriate advice, help and usable tools that assist these consumers' understanding,[112]

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[110] Ofgem has a statutory duty under the Equalities Act 2010 to have regard to the wider range of groups with protected characteristics so as to ensure the elimination of discrimination and advancing equality of opportunity for these groups.
[111] For more detail see Ofgem's Consumer Vulnerability Strategy 2025.
[112] Our Consumer Survey 2019 found that 55% of disabled consumers were disengaged from the market because they had not switched supplier or tariff or compared prices in the previous 12 months. This figure rose to 61% for financially constrained consumers (defined as consumers on a prepayment tariff, in arrears on their energy bills, or in receipt of means tested benefits). These consumers have relatively low levels of confidence in engaging with suppliers and lower levels of knowledge about the energy market. Our 2020 Consumer Survey (results to be published) indicates a broadly similar trend towards disengagement for these consumer groups.

- affordability and access issues – some of these consumers may have greater difficulty accessing certain flexibility products and services due to their cost and physical location. This may particularly affect certain consumers in social housing, on low incomes or those living in private rented accommodation where landlords must agree to install flexibility options such as smart appliances or storage batteries. Affordability concerns could be overcome by pooling resources, for example at community level. However, some consumers with protected characteristics may need more support to understand the implications for them,
- consumer protection issues – we expect MHHS to incentivise the development of a range of new products and services that encourage consumers to shift their energy consumption. Some of these offers – such as smart ToU tariffs or bundled flexibility options - may be relatively complex. Some consumers with protected characteristics may need more tailored support from their energy provider to engage with and benefit from these innovative offers.

Future of Retail Strategic Change Programme

6.30. As previously noted, Ofgem aims to enable a future retail market that can deliver the technological and behavioural changes needed to support decarbonisation at lowest cost, while ensuring that the interests of consumers remain protected. MHHS is a key enabler of this. We are currently developing our future of retail Strategic Change Programme, focusing on areas of greatest potential consumer detriment or opportunity, with the following high level objectives:

- an energy transition that works for all energy consumers, harnessing innovation and flexibility, with effective protection for consumers
- fair energy prices, with or without the price cap
- a better deal for consumers in vulnerable circumstances.

6.31. We expect to begin this Strategic Change Programme in the summer. Consumers will need to have confidence that they will be sufficiently protected in order to engage with new energy products or services. Consumers will also need to be confident about engaging with their energy provider when things go wrong and, if they remain dissatisfied, about using redress mechanisms to put things right.

6.32. For our part, we believe principles-based regulation is appropriate for regulating the new products and services that we expect MHHS to encourage. However, we will keep this under review if evidence emerges that any specific new protections may be needed. As set out in our Decarbonisation Programme Action Plan, we will ensure that consumers who cannot provide flexibility are not unduly disadvantaged.

7. Risks and assumptions, monitoring and evaluation

Section summary

In this section we describe the risks we have considered and the assumptions we have made in drawing up the options for market-wide half-hourly settlement (**MHHS**). We also set out how we propose to monitor and evaluate the new settlement arrangements. We ask stakeholders to bear this in mind in terms of the datasets that they keep.

Risks and assumptions

7.1. We have considered several potential risks relating to MHHS. Broadly, these cover:

- transitional risks while the industry prepares for and implements MHHS, including interdependencies with other programmes that could affect the quality and speed of delivery,
- ongoing post-implementation risks, such as:
    - consumer concern about sharing half-hourly (**HH** consumption data
    - low uptake of smart tariffs (such as Time of Use tariffs) and
    - the potential distributional impacts that may arise if the take-up of such tariffs is widespread.

Transitional period

7.2. The transition to MHHS will bring a resource-intensive period of system design, development and testing that will require committed engagement from many stakeholders. The project is running at the same time as other projects aiming to transform the retail market. We have been working to understand and address resource challenges arising from them. We have considered the extent of any resource overlaps especially in relation to implementing the new switching arrangements that are due to go live in summer 2022.

7.3. In the light of responses to the consultation document, and subsequent work carried out for us by PwC, we have decided that MHHS should be introduced with a transitional period of 4 years and 6 months. We will shortly be consulting on programme implementation and governance arrangements. These will place clear incentives on industry to introduce the new settlement arrangements on time and to a high standard.

Post-implementation

Estimating the benefits of MHHS

7.4. MHHS will enable the development and delivery of new products and services that should produce long lasting consumer and wider societal benefits. The scale of benefits that can be achieved depends on the successful rollout of smart meters, the levels of data available for settlement, and the resulting market and consumer response.

7.5. In response to the Draft Impact Assessment (**IA**), some stakeholders raised the possibility that smart meter penetration at the start of 2025 might be lower than originally anticipated and that this could affect the costs and benefits estimated in the IA. As explained more fully in our Decision Document, we expect that any potential impact from relatively low smart meter penetration would only be temporary and would merely delay some of the benefits.

7.6. In the long term, we consider that it would have no significant impact on the scale of benefits as suppliers respond to the ongoing economic incentives on them to innovate and offer new products and services. Even if smart meter penetration were to be lower than expected over the long term, the direct benefits to be realised from MHHS might fall towards the lower end of our range – but not below it. This is for two reasons. First, because we expect the main driver for uptake of Time of Use tariffs to be ownership of flexible, low carbon technology such as EVs, heat pumps and batteries rather than the rollout of smart meters per se. Second, because we took a consciously conservative approach to our lower bound scenario precisely to account for uncertainties such as the degree of smart meter coverage.

7.7. The scale of the benefits will in turn depend on factors such the state of competition in the market, the environment for innovation, and the value of flexibility stemming from wholesale price variations and other price signals in the market, for example those arising from the Electricity network access and forward-looking charging reforms and associated code modifications. The direction we take on each of these projects will affect the balance of signals that suppliers and consumers face, and influence the extent to which suppliers and other energy/service providers develop new products and services making use of customers' smart meter data, the take up rate of these offerings by consumers and how much they shift their usage from peak times.

7.8. As a result, there remains substantial uncertainty over the exact nature and scale of the impact of our reforms. Coupled with the challenges of taking a long term view, we have imperfect data on the costs to industry of delivering our reforms and significant uncertainty over future price developments. Given this uncertainty, we have adopted mechanisms to test the conclusion that our chosen option for MHHS will maximise net benefits for consumers under a range of plausible assumptions and scenarios. These mechanisms are:

- identifying ranges for monetised direct costs and benefits of our chosen option
- using a power market model to assess the potential benefits of a more flexible energy system enabled by MHHS, which quantifies the benefit of consumer load shifting under different scenarios and sensitivities,
- considering how best to assess non-monetised benefits, and
- engaging extensively with industry participants on the proposals.

Consumers opting-out of providing HH consumption data

7.9. The volume of granular data available for settlement will impact on the benefits that can be achieved. At present suppliers may collect data from their domestic customers at daily granularity by default, though the customer may opt out to monthly granularity, unless the data is required for a regulated purpose. We understand that opt-out rates under the current arrangements have been low, with a number of suppliers reporting single-digit percentages.

7.10. In determining an appropriate data sharing framework for settlement purposes, we have aimed to strike a balance between consumers' rights to privacy over their data and the system-wide benefits that we expect to result from the reforms if enough quality data is entered into the system. We think that, if too many consumers opted out to monthly resolution of data collection for settlement, the benefits of the reforms will be impacted.

7.11. We have set out that the party responsible for settlement will have a legal obligation to collect HH data for settlement purposes, unless the domestic consumer opts out of this processing.[113] Microbusiness customers will not be able to opt out. We have also set out that data collected for settlement purposes can also be used for forecasting. Where the domestic consumer does opt out, we have decided that daily resolution data should be collected for these purposes. We have also set out in our Decision Document that the granularity of data to be collected from existing or "old system" customers will be in line with the existing Data Access and Privacy Framework rules.[114]

7.12. Effective supplier messaging about the benefits of sharing data for settlement should further mitigate that risk. Consumers must be made aware of why their HH consumption data is required and the benefits that sharing it can bring, so that they can make an informed choice as to their data sharing preferences.

7.13. We think that, if the messaging is inadequate, inconsistent or confusing to consumers, opt-out rates will increase. We also recognise that settlement and forecasting are difficult concepts for suppliers to discuss with their customers. We therefore think there would be benefits to some form of central coordination to the messaging for consumers, and intend to work with industry to formulate clear and effective communications which can be consistently used across all consumers. Further details can be found in section 6 of our Decision Document.

Storing HH data securely

7.14. Under the Design Working Group's (**DWG**) preferred Target Operating Model (**TOM**), non-aggregated data would be made available to the Balancing and Settlement Code (**BSC**) central settlement systems for the purpose of calculating the settlement imbalance. However, the DWG's preferred TOM design has not set out where the non-aggregated data would be held or how it would be accessed. It could be held in multiple stores or in a single data hub.

[113] We set out our policy decisions on the MHHS access to data framework in our 2019 decision letter and provided further clarification on certain issues in our 2020 open letter.
[114] "Existing" or "old system customers" are defined as those who had their smart meters installed before the new framework enters into force, and have not changed supplier or contract since.

7.15. Any access to this data would be subject to privacy safeguards and would have to be in compliance with data protection legislation, including the General Data Protection Regulation (Regulation (EU) 2016/679) as retained in domestic law following the UK's withdrawal from the European Union ("**UK GDPR**"). There is general agreement within industry that there should be no gatekeepers to data and those that should, or want to, access that data (under the right security and governance controls) should be able to quickly and easily.

7.16. The Architecture Working Group (**AWG**)[115] is currently working on its recommendation for the most appropriate architectural solution to deliver the DWG's TOM (i.e. how data will be held and transported within that TOM model). The AWG will consult ahead of making a final recommendation. Once it has recommended a model, we will consider the proposed solution for transfer and storage of market-wide non-aggregated data. We will think about security and privacy issues, the TOM Design principles and the TOM development principles. These principles include ensuring that the system design does not act as a barrier for the potential future uses of data, for example, by facilitating third party access.[116]

7.17. We will be consulting shortly on our proposals for implementation and governance arrangements. However, until these new arrangements are in place, Ofgem will continue to make decisions (including on the AWG's recommendation) under the current Significant Code Review (**SCR**) governance framework. The new framework will be designed to ensure the decisions are non-discriminatory and that potential conflicts of interest are properly addressed. We expect that where decisions reach a threshold for Ofgem intervention, they will be taken by Ofgem.

Monitoring and evaluation

7.18. Introducing MHHS is a major undertaking that involves complex changes to IT systems and operating processes across the industry. As such, it requires careful and detailed planning and effective supervision. As set out in the Management Case of the Full Business Case, we will be consulting shortly on implementation and

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[115] For more detail see the Architecture Working Group webpage.
[116] For more detail see the TOM Development Principles.

governance arrangements to assure timely and high quality delivery. We will rely on those governance arrangements to ensure that all relevant parties meet their deliverables by the final deadline for migrating Meter Point Administration Numbers (**MPANs**) to the new settlement arrangements.

7.19. Ofgem will continue to rely on the existing Performance Assurance Framework to monitor ongoing settlement performance quality. Should experience of the new settlement arrangements suggest that improvements could be made, we will expect industry parties to pursue them in the usual way by raising code modification proposals.

7.20. We will monitor opt-out rates during the transition period to ensure that the data sharing framework remains appropriate. Once the new settlement arrangements have come into force, we envisage routine monitoring of load shifting trends and opt-out rates. We are still considering the precise scope of the information that we will want to gather and the frequency with which we will want to request it. Stakeholders will, however, appreciate the importance that we attach to maintaining good quality datasets in relation to consumer load shifting and opt-outs.

7.21. This and other information will as necessary inform a review of the data access arrangements and help us to determine whether they remain proportionate and consistent with delivering the objectives of settlement reform. We expect to carry out this review after a period of time once the system is up and running. We will undertake the review when we feel we have sufficient evidence to do so.

8. Appendices

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Appendix 1

Appendix 1: Modelling distribution network benefits

Distribution Networks Model (DNM)

1.1. Built in 2017-18, the DNM models the GB electricity distribution network costs from 2010 to 2050. It comprises a Power Flow Model (**PFM**) and an Investment Model (**IM**).

1.2. The DNM uses representative network archetypes based on actual existing distribution networks in Great Britain to calculate changes in reinforcement costs under different scenarios. It uses four representative "base networks" – a base urban network, a base rural network, a meshed/Manweb-type network and a London network. These base networks are used together with regional demand and loading data to create ten regional networks – reflecting South of England, North of England, Scotland, West Midlands & Wales and London.

1.3. The PFM utilises power flow algorithms to model electricity flows through these representative networks. The power flows directly depend on the scenario inputs specified by the user to estimate future network breaches and constraints (in the form of thermal or voltage constraints). These inputs consist of peak/minimum demand profiles, Distributed Generation (**DG**) profiles, and varying levels of DSR.

1.4. All these inputs are taken from the DDM, which is run separately. As DNOs are required (by the "N-1" reliability criterion) to reinforce their networks to cope with worst case network contingencies, the DNM similarly models worst-case scenarios for electricity network operators: a maximum (system peak) demand with minimum DG scenario, and a low demand maximum DG scenario.

1.5. The model possesses a list of solutions that can be used for network reinforcement to address the network constraints identified by the PFM. The IM uses a cost function and financial modelling to optimise solution selection by DNOs (looking at the total capital and operating expenditure) of installing all these solutions in the representative networks) in order to reinforce the networks. The DNM, therefore, replicates the process that a DNO would go through when assessing a network. The IM also allows for the modelling of different investment strategies and foresight assumptions.

1.6. The IM uses 'conventional' and 'smart' solutions to reinforce its representative networks. Conventional solutions consist of a variety of standard network reinforcement (overhead lines, underground cabling and the installation of pole or ground mounted transformers). Smart solutions consist of demand or generation constraint services, special voltage and thermal regulating instruments and active network management/network reconfiguration. Smart solutions can be turned on and off.

1.7. To calculate GB-wide costs, the outputs from the two models are upscaled based on predetermined 'scaling factors'. All the assumptions used to build the model are based on widely accepted industry standards (Smart Grid Forum WS3 & WS7).

Appendix 2

Appendix 2: Load shifting assumptions

1.1. Table 25 shows the range of estimates for the proportion of customers with a smart tariff and the percentage of demand shifted at peak by customers with a smart tariff, and the resulting estimate of the overall range for system load shifting that can be attributable to market-wide half-hourly settlement (**MHHS**). This range captures load shifting from low carbon technology users (such as electric vehicle users) and technological enablers (such as smart charges or battery storage), but excludes load shifting from heat pump users.

Table 25: Estimated system peak demand shifting attributable to MHHS (with sources and notes)

	% of consumers on smart tariffs (A)	% of peak demand shifted per consumer (average) (B)	% of system peak demand shift (A)x(B)
Upper bound 2025	20% Fell et al (2015)[117]	30% Trials: Octopus (2018)[118], CBS (2016)[119], Faruqui (2013)[120], Arcturus 2.0[121] and BEIS's Smart meter roll-out CBA (2019)[122]	**6%**
Upper bound 2045	60% Baringa (2012)[123] This figure is supported by new evidence on take-up of EVs and heat pumps (which were used as a proxy for take up of smart tariffs)	50% Baringa (2012): optimistic assumption based on high level of smart technology take-up like battery storage. FES 2020: two of the three net zero (NZ) scenarios assume	**30%**

[117] Public acceptability of domestic demand-side response in Great Britain: The role of automation and direct load.
[118] Octopus trial.
[119] Final Report on Customer Acceptance, Retention and Response to Time-Based Rates from the Consumer Behavior Studies (CBS).
[120] Faruqui and Sergici's (2013) Demand Response summary from 163 tariff pilots from US, Australia and France amongst others.
[121] Arcturus 2.0: A meta-analysis of time-varying Rates for Electricity (2017).
[122] Department for Business, Energy and Industrial Strategy, 'Smart meter roll out: cost benefit analysis 2019.'
[123] Baringa, 'Electricity System Analysis – future system benefits from selected DSR scenarios.'

	FES 2020[124]: all three FES scenarios that assume NZ objectives are met by 2050 assume at least 60% uptake of ToU tariffs by 2045 (ranging from 60% to 83%)	very high uptake of smart white good appliances by 2045. BEIS's Smart meter roll-out CBA (2019)	
Lower bound 2025	10% Baringa (2012), CBS (2016), Citizens Advice (2017)[125]: conservative assumption compared to the expected uptake of smart appliances such as EVs and heat pumps (used as a proxy for take up of TOU tariffs)	10% Baringa (2012), CBS (2016), CLNR[126], Arcturus 2.0[127]: conservative compared to Octopus and others' results. Consistent with little to no automation	**1%**
Lower bound 2045	30% Baringa (2012): conservative assumption compared to the expected uptake of smart appliances such as EVs and heat pumps (used as a proxy for take up of smart tariffs) FES 2020: this figure is conservative compared to the FES scenarios above.	20% Baringa (2012), Arcturus 2.0: conservative compared to Octopus (2018) results and others. Consistent with little automation	**6%**

1.2. We have decided not to include any additional load shifting from heat pumps in our chosen option for MHHS. This is a conservative measure that undervalues the benefits of MHHS. It also reflects the difficulty of calculating the potential of load shifting under MHHS compared to elective and the fact that heat pump users might have the highest incentive to take up Time of Use (**ToU**) tariffs even under the elective settlement arrangements. In response to comments on our Draft IA, we have carried out an extra sensitivity analysis that assumes no load shifting by small non-domestic consumers.

124 Future Energy Scenarios 2020 report (FES 2020), National Grid (2020).
125 UCL/Brattle for Citizens Advice: The Value of Time of Use Tariffs in Great Britain.
126 CLNR results summarised.
127 Arcturus 2.0: A meta-analysis of time-varying Rates for Electricity (2017).

Rationale for the counterfactual

1.3. The counterfactual is the baseline scenario against which the proposal for change is compared. In this case the counterfactual assumes that elective half-hourly settlement (**HHS**) arrangements are in place, instead of MHHS.

1.4. Estimating the level of load shifting under the counterfactual is not straightforward because little data about load shifting to date is available. Using the information available to us, we analysed the incentives on suppliers to develop and offer smart tariffs to different types of consumer, and for those consumers to take them up. We summarise our analysis of these incentives and show the resulting load shifting assumptions for the counterfactual below.

Table 26: Load shifting assumptions (% of peak load), low and high load shifting scenarios

Assumptions	Load shifting scenario	Year	Domestic demand, non-domestic EV demand	Domestic EV demand[128]	Domestic/non-domestic heat pump demand
% of total demand during peak hours that can be shifted	Counterfactual	2025	0%	1%	90%
		2045	0%	8%	90%

Incentives on suppliers

1.5. Elective half-hourly settlement (**HHS**) alone is unlikely to deliver the levels of half-hourly settled customers to achieve the scale of load shifting we seek, and a move to HHS on a market-wide basis is needed to place the right incentives on the market to deliver a significant level of load shifting. This view was shared by the Competition and Markets Authority (**CMA**) in its 2016 Energy Market Investigation, where it found that "elective half-

[128] The level of load shifting constraint for domestic EVs we have used in the counterfactual differs from BEIS's assumption in [2018 "Energy and Emissions Projections"].

hourly settlement is unlikely to be an effective substitute for full, mandatory half-hourly settlement. This is because under mandatory settlement, all suppliers bear the full costs that their customers impose on the electricity system". The CMA also highlighted concerns around cherry-picking, recognising that while elective HHS may enable individual suppliers to make cost savings, overall system costs would be unlikely to fall under elective HHS and the potential benefits of HHS would not be realised.

1.6. Without implementing HHS on a market-wide basis, there is only a limited incentive for suppliers to elect to half-hourly settle their customers, and therefore far less of an incentive to develop and offer new products and innovations to help customers shift their consumption away from peak periods. This limited incentive means the levels of HHS we expect to see under elective HHS will not be enough to realise load shifting of the scale necessary to deliver benefits to consumers from avoiding inefficient network and generation investment.

1.7. HHS also exposes suppliers to risks (as well as opportunities), which suppliers may well be unwilling to elect to take on. Firstly, the current profiling arrangements provide suppliers with a degree of protection against variability in customers' consumption patterns and predictability in terms of their forecast shape, and suppliers may not wish to take on the risks of moving to HHS, even if it would open new market opportunities. Secondly, there are risks around the level of take-up of the products and innovations enabled by HHS, which may deter some suppliers from being a first-mover in the market, or adopting HHS at all.

1.8. With elective HHS, we are far less likely to find solutions across the market that can bring forward the types of tariffs and innovations on a scale that will really influence the level of acceptance and adoption of these. Market-wide settlement reform will help in this regard, by exposing suppliers to a new incentive to help their customers to shift their consumption away from peak periods. This is supported by the responses both to our Request for Information (**RFI**) (2019) and to the consultation on the Draft IA.

Incentives on consumers

Domestic - relatively low users

1.9. Suppliers have had little incentive to offer demand-side response (**DSR**) products and consumers little incentive to take them up. We think that the potential for aggregated levels of load shifting of this sector of the market under elective is negligible (note that to achieve 1% of load shifting we would need 10% of take-up of smart tariffs and 10% of average peak reduction).

Domestic - high energy users/electric vehicle (EV) users

1.10. Significant load shifting could be achieved in this sector under the elective arrangements, particularly for EV users. Suppliers could decide to offer smart products (for example, because of competition and product differentiation dynamics) even if they are not exposed to the costs. However, suppliers could find ways of appealing to these users other than ToU tariffs. For example, they could offer cheaper rates for consuming above a certain volume of consumption.

1.11. We have calculated the level of load shifting in the counterfactual based on the information available to us, allowing for some increase over the period 2025-2045, as shown in table 26 above.

Domestic - high energy users – heat pump users

1.12. We have taken BEIS's assumption (2018 BEIS reference case) that demand from heat pumps is 90% shiftable but just by one hour, reflecting the higher incentive of these users to take up ToU tariffs even under elective. Note that our assumption is the same in the factual and in the counterfactual, which is a conservative approach, as explained above.

Domestic - high energy users – other electric heating

1.13. We have assumed very little to no flexibility from these users because it is very difficult to offer flexibility without enabling technology.

Non-domestic EV users

1.14. We have assumed that there is no load shifting from these users on the basis that vehicles used for business operations might be less flexible than for domestic use, or might need a higher incentive. This is in line with the level of load shifting from EV non-domestic demand in the 2018 BEIS reference case.

Small non-domestic consumers

1.15. Given the relative lack of consumer demand for ToU products to date, and the lack of incentive on suppliers proactively to develop them, we assume very little load shifting from these consumers under the elective arrangements. As noted above, in light of responses to the Draft IA we have carried a sensitivity analysis that assumes no load shifting from this sector even under our chosen option for MHHS.

Third party intermediaries and flexibility

1.16. In responding to the Draft IA, some stakeholders said that, in future, third party intermediaries (**TPIs**) might be able to drive demand side response (**DSR**) independently of the settlement arrangements. We acknowledge the high level of uncertainty we face when seeking to estimate the level of load shifting over the next 30 years, and that innovative technology and business models could develop in unexpected ways. This level of uncertainty is the reason why we have taken a wide range of load shifting assumptions (as shown in table 24 above), and a conservative approach in relation to heat pumps.

1.17. That said, to date, we are not aware of TPIs driving significant levels of flexibility from domestic and small-non domestic consumers at the scale needed to achieve the system-wide benefits described in this IA, or even whether TPIs would target peak reduction at all. Furthermore, we consider that there is a parallel between these products and the issue around elective HHS, in the sense that both products are likely to be offered to engaged consumers with potentially profitable consumption patterns. As in the case with elective HHS,[129] our position is that these consumers alone will not be enough to drive the level of load shifting we seek with this reform. In any case, it is clear to us that placing the right incentives on suppliers would result in a significant increase in system flexibility.

[129] For a discussion about elective HHS see section 2 above.

Appendix 3

Appendix 3: Data tables for charts 5 and 6

1.1. The tables below show the data behind figures 5 and 6 in section 4 of this document. Note that the demand in both tables is based on BEIS's 2018 Reference Case[130] and that table 28 shows the impact of all demand-side response (**DSR**) assumptions (not just the DSR attributable to MHHS). In particular, the shifting of heat pump demand, and a small proportion of the domestic EV demand, is not attributable to MHHS.

Table 27: Data for figure 5, 2018 reference case demand, TWh - long term projections

	Domestic	Non-domestic	EV domestic	EV non-domestic	HP domestic	HP non-domestic	Total
2019	101.3	212.7	0.4	0.1	0.3	0.1	315.0
2020	99.9	209.6	0.6	0.2	0.4	0.1	310.7
2021	99.6	207.3	0.9	0.3	0.4	0.1	308.5
2022	100.2	206.0	1.3	0.4	0.4	0.1	308.3
2023	101.8	205.7	1.7	0.5	0.4	0.1	310.2
2024	103.4	206.8	2.3	0.6	0.4	0.1	313.6
2025	105.2	207.5	3.0	0.8	0.4	0.1	317.1
2026	107.1	209.3	3.6	1.0	0.4	0.1	321.5
2027	109.1	212.0	4.3	1.2	0.4	0.1	327.1
2028	111.1	215.6	5.0	1.4	0.4	0.1	333.6
2029	113.1	219.4	5.7	1.6	0.4	0.1	340.4
2030	115.5	223.2	6.5	1.8	0.4	0.1	347.6
2031	116.8	225.8	7.3	2.1	0.4	0.1	352.5
2032	118.1	228.5	8.0	2.3	0.4	0.1	357.3
2033	119.1	232.5	8.7	2.5	0.4	0.1	363.3
2034	120.3	235.9	9.4	2.7	0.4	0.1	368.7
2035	121.4	239.5	10.0	2.9	0.3	0.1	374.4

[130] BEIS has now published its 2019 Reference Case. Therefore, these values are not the latest figures (both in aggregate and at individual demand-type level). See BEIS's Updated Energy and Emissions Projections 2019, December 2020.

	Domestic	Non-domestic	EV domestic	EV non-domestic	HP domestic	HP non-domestic	Total
2036	121.4	239.5	19.1	5.9	9.8	3.0	398.8
2037	121.4	239.5	28.2	8.9	19.3	6.0	423.3
2038	121.4	239.5	37.3	11.8	28.8	8.9	447.8
2039	121.4	239.5	46.4	14.8	38.3	11.8	472.3
2040	121.4	239.5	55.5	17.8	47.8	14.7	496.7
2041	121.4	239.5	58.5	18.7	55.2	17.0	510.4
2042	121.4	239.5	61.2	19.4	63.0	19.4	524.0
2043	121.4	239.5	63.5	20.1	71.2	21.9	537.6
2044	121.4	239.5	65.5	20.7	79.7	24.6	551.3
2045	121.4	239.5	67.1	21.1	88.5	27.3	564.9
2046	121.4	239.5	68.4	21.5	97.6	30.1	578.6
2047	121.4	239.5	69.6	21.8	106.9	33.0	592.2
2048	121.4	239.5	70.4	22.0	116.5	35.9	605.8
2049	121.4	239.5	71.2	22.2	126.2	38.9	619.5
2050	121.4	239.5	71.7	22.4	136.1	42.0	633.1

Table 28: Data for figure 6, High shift CFF, 2045 autumn business day, high wind, GW

Time of day	**00:00**	**00:30**	**01:00**	**01:30**	**02:00**	**02:30**	**03:00**
GW							
Demand	50.7	47.2	45.0	43.6	41.9	41.6	39.9
Shifted demand after policy	58.8	58.5	58.6	58.6	58.5	58.4	58.4
Domestic	2.7	3.8	5.0	5.2	5.6	5.7	5.8
Non-domestic	0.7	1.6	1.7	1.8	1.8	1.8	1.8
Electric Vehicle (EV) domestic	3.4	3.8	4.2	4.8	5.0	5.3	5.3
EV non-domestic	2.3	2.3	2.2	2.1	2.0	2.0	2.0
Heat Pump (HP) domestic	-0.8	-0.3	0.2	0.8	1.8	1.5	3.3
HP non-domestic	-0.2	0.0	0.3	0.4	0.4	0.4	0.4
Time of day	**03:30**	**04:00**	**04:30**	**05:00**	**05:30**	**06:00**	**06:30**
GW							
Demand	41.5	41.4	42.9	45.4	48.6	56.4	63.3
Shifted demand after policy	58.6	59.0	59.3	59.7	60.5	61.3	62.5
Domestic	5.9	6.0	6.0	5.8	4.7	1.8	0.3
Non-domestic	1.8	1.8	1.7	1.6	1.5	0.2	-0.3

EV domestic	5.3	5.5	4.9	4.1	3.1	1.8	0.0
EV non-domestic	1.8	1.8	1.5	1.2	0.9	0.5	0.0
HP domestic	2.0	1.9	1.6	1.4	1.7	0.7	-2.3
HP non-domestic	0.2	0.5	0.7	0.3	0.1	0.0	1.6
Time of day	**07:00**	**07:30**	**08:00**	**08:30**	**09:00**	**09:30**	**10:00**
GW							
Demand	68.6	71.1	74.8	75.2	75.7	75.2	73.3
Shifted demand after policy	65.2	67.7	69.4	71.0	72.5	73.8	75.0
Domestic	-1.5	-1.7	-1.8	-1.1	-0.8	0.0	1.2
Non-domestic	-0.7	-0.4	-0.5	-0.1	-0.2	0.2	0.5
EV domestic	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EV non-domestic	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HP domestic	-1.9	-1.7	-1.9	-2.0	-1.5	-1.0	-0.8
HP non-domestic	0.7	0.2	-1.2	-1.0	-0.7	-0.6	0.8
Example of shifted demand	**10:30**	**11:00**	**11:30**	**12:00**	**12:30**	**13:00**	**13:30**
GW							
Demand	72.2	71.2	71.4	70.2	70.5	69.3	70.0
Shifted demand after policy	75.5	75.9	75.7	75.5	74.8	73.3	72.9
Domestic	2.5	3.0	2.2	2.3	2.5	2.1	1.3
Non-domestic	0.1	0.5	0.7	0.7	0.8	0.8	0.7
EV domestic	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EV non-domestic	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HP domestic	0.1	1.0	1.2	2.2	0.6	0.7	0.9
HP non-domestic	0.7	0.2	0.2	0.1	0.5	0.3	-0.1
Time of day	**14:00**	**14:30**	**15:00**	**15:30**	**16:00**	**16:30**	**17:00**
GW							
Demand	69.2	73.1	72.0	76.8	79.7	84.3	85.8
Shifted demand after policy	71.6	72.1	71.5	71.0	70.6	71.7	72.2
Domestic	0.5	-0.1	-1.3	-2.9	-3.4	-5.0	-6.1
Non-domestic	0.6	0.1	-0.2	-1.1	-1.1	-1.8	-2.0
EV domestic	0.0	0.0	0.0	0.0	-2.9	-3.0	-3.4
EV non-domestic	0.0	0.0	0.0	0.0	-1.8	-2.1	-2.4
HP domestic	1.6	-0.8	1.0	-1.2	0.3	0.0	0.7
HP non-domestic	-0.3	-0.3	-0.1	-0.5	-0.3	-0.7	-0.4
Time of day	**17:30**	**18:00**	**18:30**	**19:00**	**19:30**	**20:00**	**20:30**
GW							

Demand	88.8	89.9	90.7	90.4	89.5	87.3	85.7
Shifted demand after policy	73.3	73.7	73.8	73.2	72.1	71.0	70.0
Domestic	-6.5	-6.7	-6.7	-6.6	-6.3	-6.0	-5.5
Non-domestic	-2.0	-2.0	-2.0	-2.0	-2.0	-1.9	-1.6
EV domestic	-3.7	-4.2	-4.7	-5.0	-5.4	-5.4	-5.9
EV non-domestic	-2.5	-2.6	-2.5	-2.5	-2.3	-2.1	-1.8
HP domestic	-0.5	-0.3	-0.2	-1.0	-1.2	-0.8	-0.8
HP non-domestic	-0.4	-0.5	-0.8	-0.2	-0.2	-0.1	-0.1
Time of day	**21:00**	**21:30**	**22:00**	**22:30**	**23:00**	**23:30**	
GW							
Demand	82.3	78.5	73.5	67.5	61.6	55.8	
Shifted demand after policy	68.3	66.7	65.3	63.6	60.6	59.4	
Domestic	-4.4	-2.9	-1.3	-2.8	-1.4	0.8	
Non-domestic	-1.3	-0.8	-0.2	-0.9	-0.5	0.2	
EV domestic	-5.7	-5.8	-4.9	0.5	0.9	2.0	
EV non-domestic	-1.4	-1.0	-0.4	0.5	0.8	1.5	
HP domestic	-1.2	-1.1	-1.4	-1.2	-0.8	-0.6	
HP non-domestic	-0.1	-0.1	0.1	0.0	0.0	-0.1	