Electricity System Analysis – future system benefits from selected DSR scenarios

Final report pack

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Contents

Introduction

Introduction

- Redpoint Energy and Element Energy have been commissioned by DECC to undertake modelling on the potential benefits of Demand Side Response (DSR) from domestic customers and Small and Medium Enterprises (SME) over the medium term to 2030.

- We expect these results to inform DECC's consideration of how the DSR resource potential is best deployed within the electricity system, in terms of avoiding distribution network investment and/or providing balancing services at the wider system level.

- All the scenarios in this study assume substantive electrification of heat and transport, in line with DECC's ambition scenarios. However, it should be noted that there are no current firm policies that address the existing market barriers and consumer resistance that may pre-empt this electrification from occurring. Likewise, assumptions on the uptake of DSR tariffs in the domestic and SME sectors rely on policy and market development to tackle consumer resistance and potential market barriers.

Aim & scope of study

- The aim of our work is to evaluate benefits from both a distribution network and wider system perspective against a number of background scenarios and different DSR tariffs.
- We have assessed the benefits of DSR in terms of avoided distribution network investment, avoided generation investment and avoided operational generation costs.
- We limit the scope of this study to DSR for domestic and SME demand.
- Potential for DSR in the domestic sector is larger than in the SME sector, and so only the domestic sector is fully modelled using a GB electricity market model.
- The technical potential of DSR for the SME sector is explored at a high level.

Potential DSR benefits overview

- The assessment of the potential benefits of domestic DSR includes three key components:
  1. Operational cost savings in terms of variable generation costs (fuel, carbon emissions, variable O&M)
  2. Avoided peak generation (OCGT) investment costs arising from reductions in peak demand
  3. Avoided DNO reinforcement investment costs arising from reductions in peak demand

- The potential benefits from domestic DSR are obtained by shifting the load profile, rather than by reducing overall electricity consumption.

- The DNO and generation benefits are assumed to be additive in this analysis, since the same modelled reduction in peak demand underpins the assessment of avoided DNO reinforcement and peak generation investment costs.

DSR – mechanisms assessed

There are a number of mechanisms to achieve demand side response. These include price-based schemes, where variations in the tariff are used to influence consumer consumption patterns and incentive-based schemes where consumers are financially incentivised to give over load control to the supplier, DNO or 3rd party.

- The forms of DSR considered in this study are static time of use tariffs (SToU), Critical Peak Pricing (CPP) and direct load control (LC). The impact of DSR is compared against a business-as-usual (BAU) baseline (no additional DSR*).
- **SToU (price-based)** – Different unit prices are defined for different blocks of time across the day. The rates reflect the average price of generating and delivering power during those periods and would include a peak rate at the time of peak demand. The time of the peak tariff may vary seasonally, but would be pre-defined in advance for an extended period, e.g. for the year.
- **CPP (price-based)** – A pre-specified high tariff is applied for usage during periods designated by the supplier as critical peak periods. The rate will typically be much higher than the non-peak tariff, e.g. a four or five times multiple, but will only be applied on a limited number of days/hours per year. The consumers will typically receive limited notice of the critical peak period, e.g. one day-ahead. In this study it has been assumed that the critical peak period is super-imposed on a SToU tariff and can be applied on 30 days of the year, for a 3 hour peak period.
- **LC (incentive based)** – Equipment is installed in the consumer's home or premises to enable the operator (e.g. supplier or DNO) to remotely control the operation of electrical equipment to respond to the needs of the system. Two variants of load control have been considered – load control available on a limited number of days (LC1) and load control available every day (LC2).

** The BAU profile is based in Elexon profile coefficients and so includes the impact of existing time of use tariffs (e.g. Economy 7)*

Methodology

Scenarios considered

20 scenarios are modelled fully, covering a range of DSR tariffs and demand assumptions

- Full system-wide modelling has been performed for 5 DSR tariff scenarios:
  - BAU (Business As Usual)
  - SToU (Static Time of Use)
  - LC1 (Load Control 1, applied on 30 peak days per year)
  - LC2 (Load Control 2, applied on all days in year)
  - CPP (Critical Peak Pricing)

  Note – LC1 back calculated from LC2 results

- For each DSR tariff scenario 4 demand / electrification scenarios have been assumed:
  - Low
  - Central
  - High
  - High Heat Pump (a sensitivity with different heat pump assumptions to High)

- In early years we do not model all scenarios, due to a lack of differences between them.

- Further sensitivities are performed to study the effect of changing Time of Use window, and uplift to SRMC based prices *.

** Wholesale electricity prices for the core scenarios were modelled based on system SRMC (short-run marginal costs), with no price uplift applied (in practice, market prices typically exceed SRMC levels at times of peak demand and tight capacity margins, contributing to the recovery of generators' fixed and capital costs).*

Matrix of scenarios

DSR	Demand	2015	2020	2025	2030
Business as Usual	Low			L-BAU	L-BAU
	Central	C-BAU	C-BAU	C-BAU	C-BAU
	High			H-BAU	H-BAU
	Heat Pump High			HHP-BAU	HHP-BAU
Static Time of Use	Low			L-SToU	L-SToU
	Central	C-SToU	C-SToU	C-SToU	C-SToU
	High			H-SToU	H-SToU
	Heat Pump High			HHP-SToU	HHP-SToU
Load Control 1	Low			L-LC1	L-LC1
	Central		C-LC1	C-LC1	C-LC1
	High			H-LC1	H-LC1
	Heat Pump High			HHP-LC1	HHP-LC1
Load Control 2	Low			L-LC2	L-LC2
	Central		C-LC2	C-LC2	C-LC2
	High			H-LC2	H-LC2
	Heat Pump High			HHP-LC2	HHP-LC2
Critical Peak Pricing	Low			L-CPP	L-CPP
	Central		C-CPP	C-CPP	C-CPP
	High			H-CPP	H-CPP
	Heat Pump High			HHP-CPP	HHP-CPP

Modelling methodology (1)

- Growth in electricity demand and changes to the shape of the demand profile due to the increasing use of technologies such as heat pumps and electric vehicles have been modelled to 2030. The demand model is based on:
  - A GB housing stock model including 10 distinct house types. The stock model includes regionally specific variations based on English, Scottish and Welsh Housing Condition Surveys
  - Domestic and SME electricity demand profile derived using Elexon profile coefficients.
  - Bottom-up modelling of heat pump uptake in the domestic stock based on consumer willingness-to-pay analysis (calibrated to DECC heat pump uptake projections).
  - Modelling of the domestic heat pump demand profile based on analysis of heating demand data recorded through the Carbon Trust's micro-CHP field trials.
  - Electric vehicle charging profile modelling for domestic, work and public charging points based on analysis of DFT trip statistics.
  - Bottom-up modelling of domestic appliance use based on national time of use survey statistics and appliance specifications.

- Imperial College supported the assessment of DNO reinforcement costs under each demand profile.
  - The Imperial model identifies the necessary network reinforcements at LV and HV to meet the peak demands, following the principles of Engineering Recommendation P2/6.
  - The costs of the network reinforcements are then assessed on the basis of the Distribution Price Control Review 5 (DPCR5) cost appendix (published by OFGEM and used as the basis of distribution network operator network investment planning).

Modelling methodology (2)

- We deployed an established power system simulation tool, PLEXOS, to model the operation of the wider GB electricity system at the transmission and generation level, as follows:
  - Over 450 generating units in GB, together with a simplified representation of interconnected markets.
  - Plant dynamics (e.g. minimum run times), part load heat rates (thermal efficiency by output level) and start costs incorporated for thermal plant.
  - Regional onshore and offshore hourly wind load profiles.
  - Full 365*24 hour modelling using daily simulation steps, with outages and emission limits optimised on an annual basis.
  - BAU and SToU domestic load profiles taken from the demand model, but flexible domestic demand under LC2 and CPP tariffs optimised within the PLEXOS model.

- The objective function in the system dispatch model is to minimise system-wide costs, rather than minimising prices or maximising DSR benefits for individual suppliers.

Modelling methodology (3)

- Potential savings in the peak generation requirement associated with DSR-led reductions in peak demand were estimated by considering the avoided capital and fixed costs of new OCGT investment, assuming a target de-rated capacity margin of 10%. This methodology was applied consistently across all scenarios and sensitivities, although in a limited number of cases, the implied reduction in peak generation capacity due to DSR exceeded the OCGT build available to displace.
  - E.g. the avoided peak generation capacity in a DSR scenario may exceed the overall new OCGT build in the BAU case, *or* new OCGT capacity may be required earlier in the modelling horizon before potentially being displaced in later years as the DSR uptake increases.
  - In these cases, the DSR modelling implied the potential to displace other new or existing generation plants besides new OCGT capacity, but we did not consider the differential in avoided costs from new OCGTs.

- The peak demand changes underlying the OCGT cost savings were consistent with those used to assess the potential savings in DNO reinforcement costs.
  - Peak demand reductions under SToU relative to BAU tariffs were assessed using the bottom-up demand model.
  - Further peak demand reductions under LC and CPP tariffs were assessed using the power system model.
  - Peak demand reductions were also modelled for LC and CPP tariffs using the bottom-up demand model, but were found to be no greater than those observed with the power system model, implying that the same peak demand savings could be applied to the DNO reinforcement and generation investment analysis.

- The DNO and generation benefits are therefore assumed to be additive (i.e. given that these benefits arise from the same modelled reduction in peak demand).

DSR – uptake scenarios

- Three scenarios for the uptake of DSR in the domestic sector have been developed – Low, Central and High.

- In each of the scenarios for uptake of DSR it is assumed that households that have a smart meter and take up a potentially smart technology (heat pump, EV or smart appliance) also take up some form of DSR.

% of households that take-up DSR	2015	2020	2025	2030
Low	8%	22%	25%	31%
Central	8%	23%	34%	48%
High	8%	24%	40%	64%

- SToU is the basic form of DSR that households are assumed to take up. In the LC and CPP cases, households are assumed to shift from SToU to LC or CPP over time, such that there is a mix of types of DSR through the stock (i.e. SToU and LC or SToU and CPP). Low, Central and High DSR uptake scenarios occur with Low, Central and High demand scenarios respectively.

- The percentage of the housing stock that take up LC or CPP in each scenario is tabulated below:

% of households that take-up advanced DSR		2015	2020	2025	2030
LC	Low	0%	2%	3%	4%
	Central	0%	2%	4%	6%
	High	0%	4%	8%	12%
CPP	Low	0%	2%	6%	9%
	Central	0%	3%	10%	16%
	High	0%	3%	12%	19%

Note that these are percentages of the overall housing stock. The remaining households that have taken up DSR are assumed to be responding to a SToU tariff.

DSR – consumer responsiveness

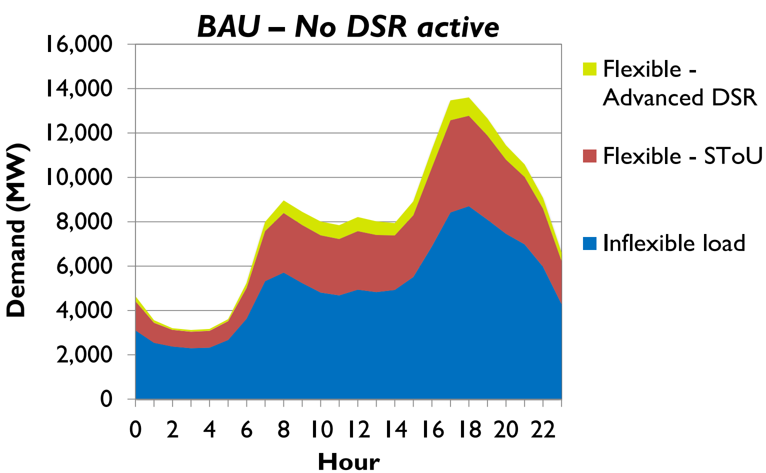
- In addition to the rate of uptake of DSR and the rate of uptake of potentially flexible demand, the further factor that will dictate the benefits of DSR is the effectiveness of the DSR measures at changing patterns of electricity consumption. The assumptions regarding the rate at which participating households respond are presented below, and discussed in more detail on slide 50.

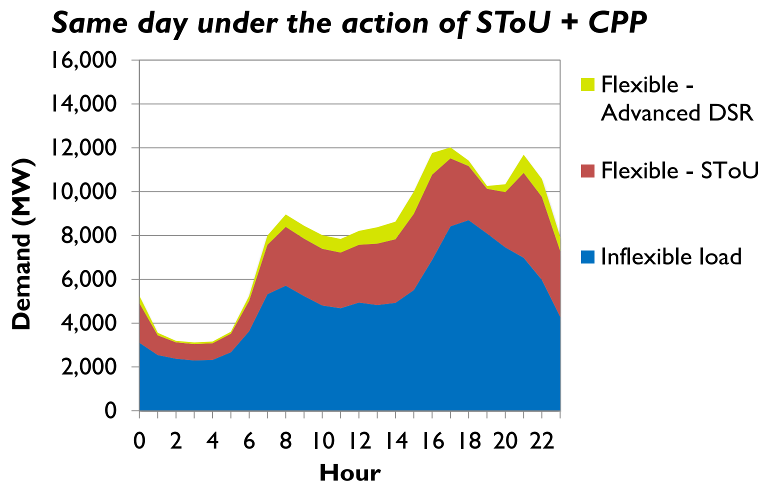
DSR	Responsive load	Demand shifted in response to tariff			
		2015	2020	2025	2030
SToU	Normal appliances	5%	10%	15%	20%
	HP / EV / SA	10%	20%	30%	40%
CPP	HP / EV / SA	30%	40%	50%	60%
LC	HP / EV / SA	100%	100%	100%	100%

Note that the percentages tabulated are the percentage reduction of the responsive load among those households that have taken up the particular type of DSR.

DSR – impact on the demand profile

<u>**Daily domestic demand profile**</u>





Note that the profiles above are based on the forecast load in the South of England and South Wales in 2030 under a High technology uptake scenario.

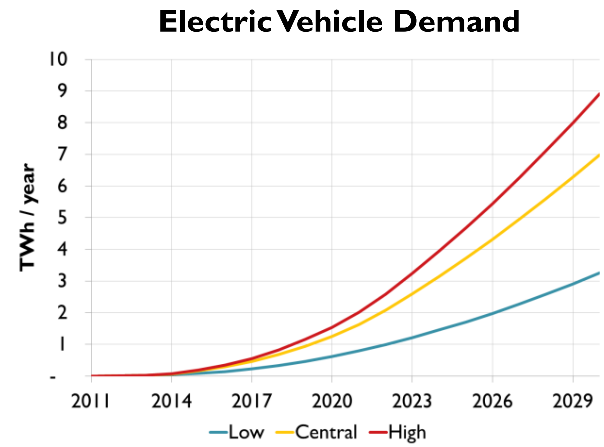
- The following loads have been designated as potentially flexible:
  - Heat pumps with storage
  - Electric vehicle charging
  - Smart Appliances
  - Non-smart cold (freezers only) & wet appliances*
- The amount of flexible load is determined by assumptions regarding the uptake of these technologies and further assumptions regarding the uptake of DSR by consumers. Consumers that take up a heat pump, electric vehicle or smart appliances are assumed to also take up some form of DSR.
- The load profile under the action of DSR (lower chart) is then generated on the basis of further assumptions regarding the amount of the flexible load that consumers shift during a DSR event.
- In the case of SToU, the peak tariff is assumed to apply during the evening peak (5pm to 8pm). In the case of LC and CPP, it is assumed that the flexible load can be optimised throughout the day (subject to technical constraints on flexibility, such as the duration of heat storage).

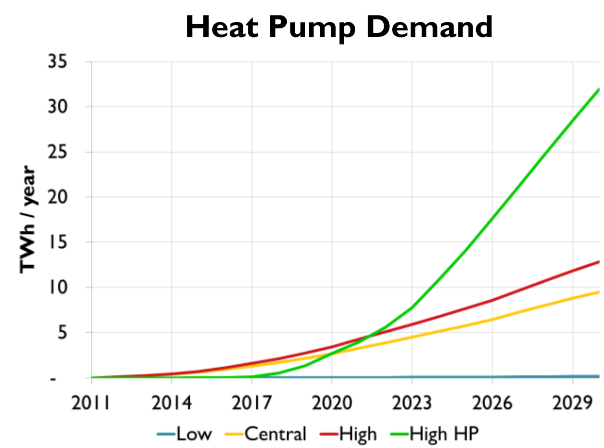
* *Non-smart appliances are assumed to respond to SToU only, e.g. using timer switches*

Demand scenarios

We present the results from three demand scenarios (Low, Central, High) and a heat pump sensitivity (High HP)

- Total system demand varies between scenarios, primarily driven by different assumptions on the uptake of electric vehicles (EVs) and heat pumps (HPs)
- EV uptake is based on DfT data
- Annual EV demand is calculated using average daily mileage and efficiency figures applied to each uptake projection
- HP uptake for Low, Central and High demand scenarios agrees with DECC figures for 2030, with smooth growth in preceding years starting in 2012
- Annual HP demand is calculated using average daily thermal demand and efficiency applied to each uptake projection
- The Heat pump 'High HP' sensitivity assumes uptake agreeing with DECC figures in all years 2012-2030, with little uptake before 2015
- A number of other HP assumptions are changed in this sensitivity, including: increasing the average HP unit size; keeping performance (COP) fixed at 2011 levels; and setting HPs' annual load factor to 20%





System modelling assumptions

Our assumptions are broadly consistent with those underpinning DECC's EMR analysis and Carbon Plan

- DECC Central commodity price projections are used in all cases.
- DECC Central carbon price projections are used in all cases, with Carbon Price Floor policy option applied to GB generators.
- A balanced GB generation mix is assumed, based on previous Redpoint modelling to support DECC's EMR analysis, and updated to reflect the higher demand in this study (due to different assumptions on electrification and energy efficiency policy baseline).
- Generation capacity is developed according to a 'least cost' approach whereby the most cost-efficient technologies are built first, subject to meeting a carbon intensity target of ~100g/kWh in 2030, and a derated capacity margin of above 10% in all years and scenarios.
- Due to varying demand, the capacity mix also varies between scenarios, with gas CCS, CCGT, and OCGT providing the differences in capacity.
- Transmission constraints based on National Grid's 'Gone Green' scenario assumptions.

Key results – domestic sector

Introduction

- The key benefits we present for domestic DSR are:
  - Savings in generation operational costs
  - Avoided OCGT investment costs
  - Avoided DNO reinforcement costs

- Avoided OCGT investment and DNO reinforcement costs are annuitised to enable direct comparison with the operational cost savings
  - WACC: 6.2% [OCGT], 4% [DNO]; Lifetime: 20years [OCGT], 50years [DNO] *

- Results are first presented on an aggregated basis to facilitate scenario comparison, before considering each scenario and then each key benefit in turn.

- Further benefits are then explored:
  - CO2 emissions, Transmission constraints, Wholesale prices, Benefits per meter

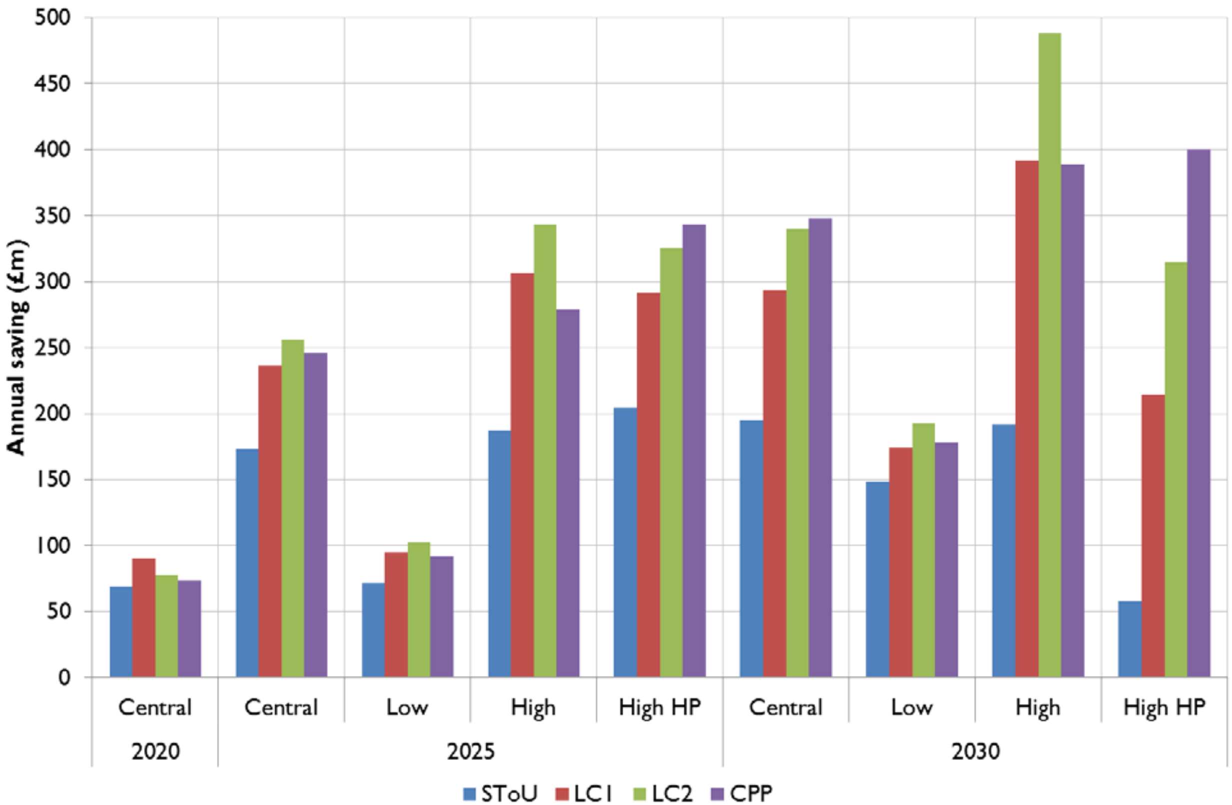
- All costs and savings are presented in real 2011 terms, and not discounted.

**OCGT WACC and lifetime assumptions consistent with DECC EMR analysis, DNO assumptions based on Ofgem Distribution Price Control Review*

Modelled benefits
Scenario comparison

REDPOINT Baringa elementenergy

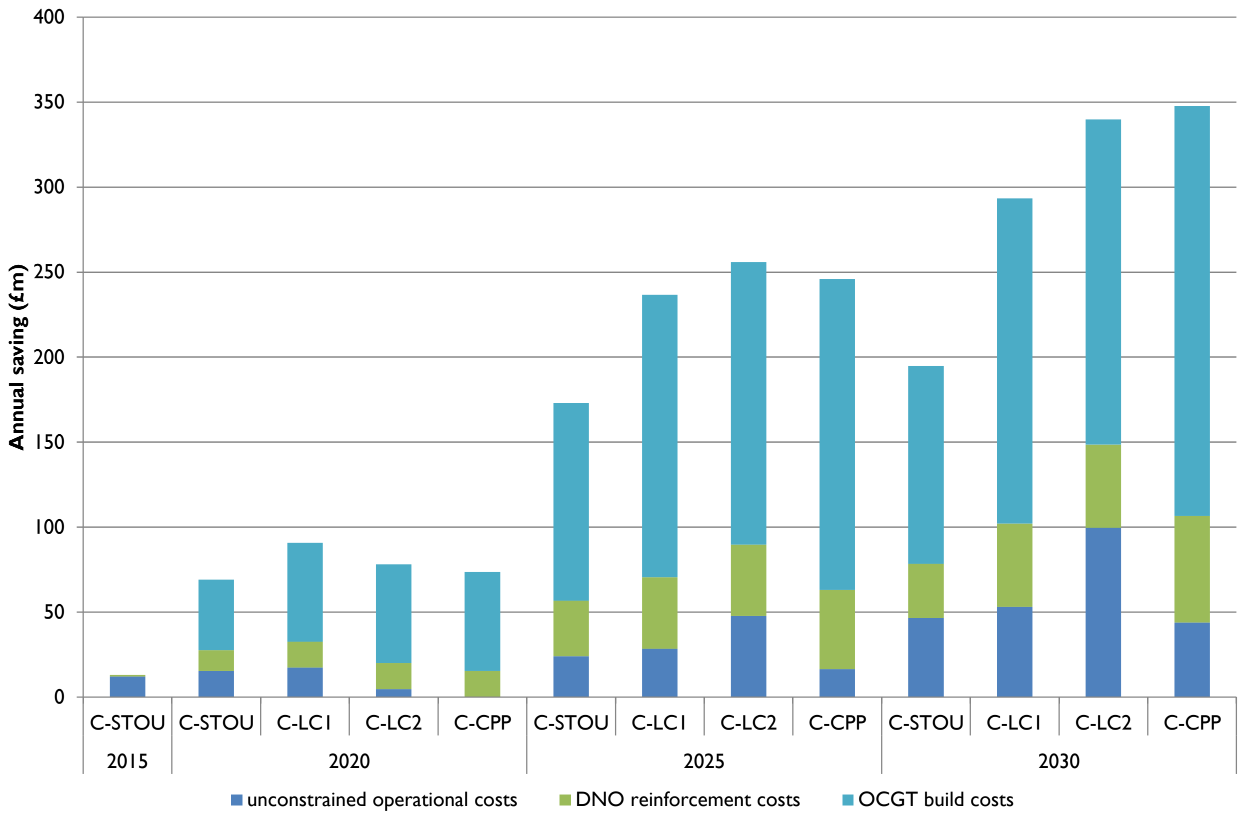
Annual DSR savings relative to the BAU baseline approach £500m by 2030 in the best case



- The potential DSR benefits increase over time, due to the assumed increase in flexible loads (primarily heat pumps and EVs)
- The DSR benefits in a given year increase with flexible demand (assumed penetration of heat pumps, EVs, smart appliances) and with the uptake of more dynamic DSR tariffs (LC, CPP).
- The dynamic DSR tariffs begin to show material incremental benefits over SToU by 2025 under the Central and High scenarios.
- The following slides show the composition of DSR savings in each demand scenario.

Modelled benefits
Central demand

Annual system balancing and DNO savings of up to £350m relative to the BAU case in 2030



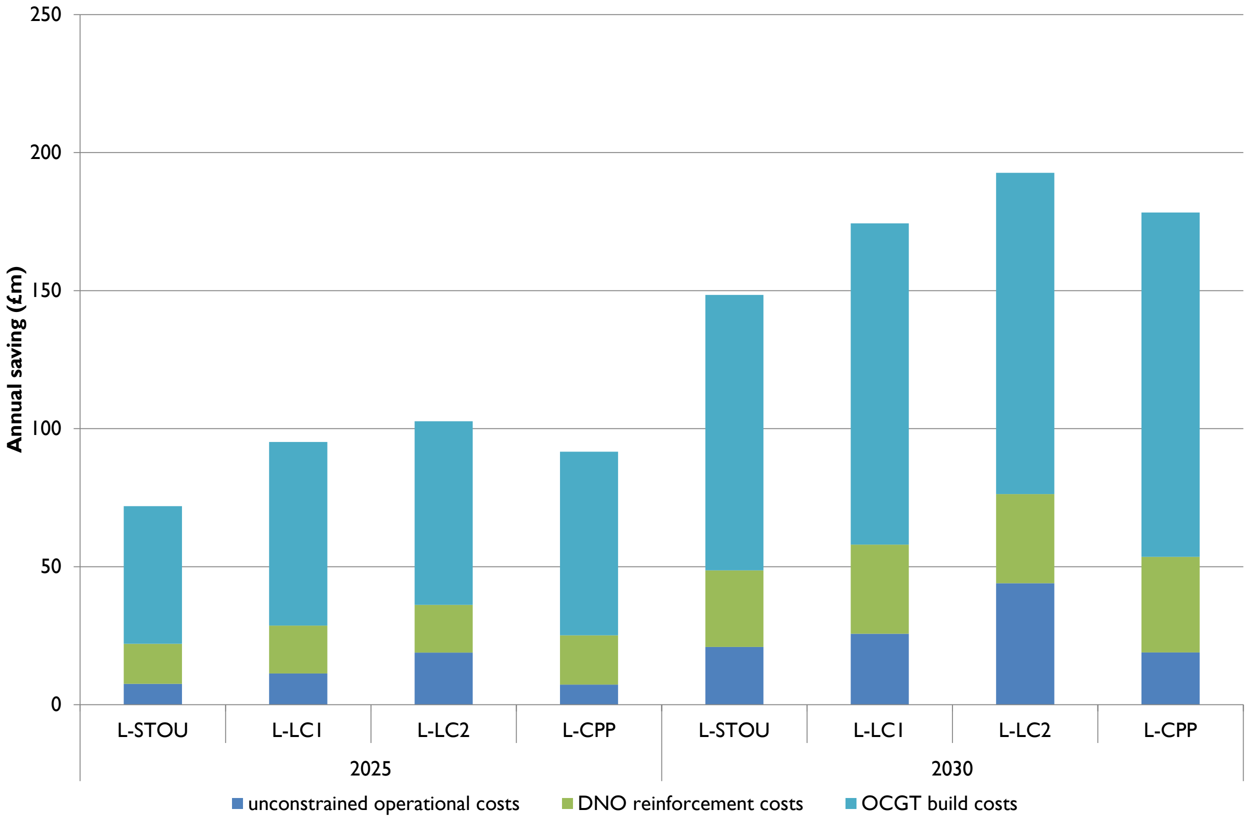
- From a system balancing perspective, the most significant DSR savings are the avoided capital and fixed costs of peak generation capacity (OCGTs), plus operational savings in unconstrained* generation costs.
- The largest operational savings are seen in the LC2 DSR case, which offers the potential for year round savings in unconstrained generation costs (while the LC1 and CPP cases are limited to 30 days per year).
- CPP is assumed to have a higher uptake than LC1/LC2 and this is why it has the largest overall savings by 2030 due to greater reductions in peak demand, OCGT and DNO reinforcement costs.

Note that the generation cost savings presented here are taken from 'unconstrained' system modelling runs, which exclude transmission and reserve constraints. Our 'constrained' modelling runs did not show significant variations between DSR scenarios over and above the 'unconstrained' results.

Modelled benefits

Low demand

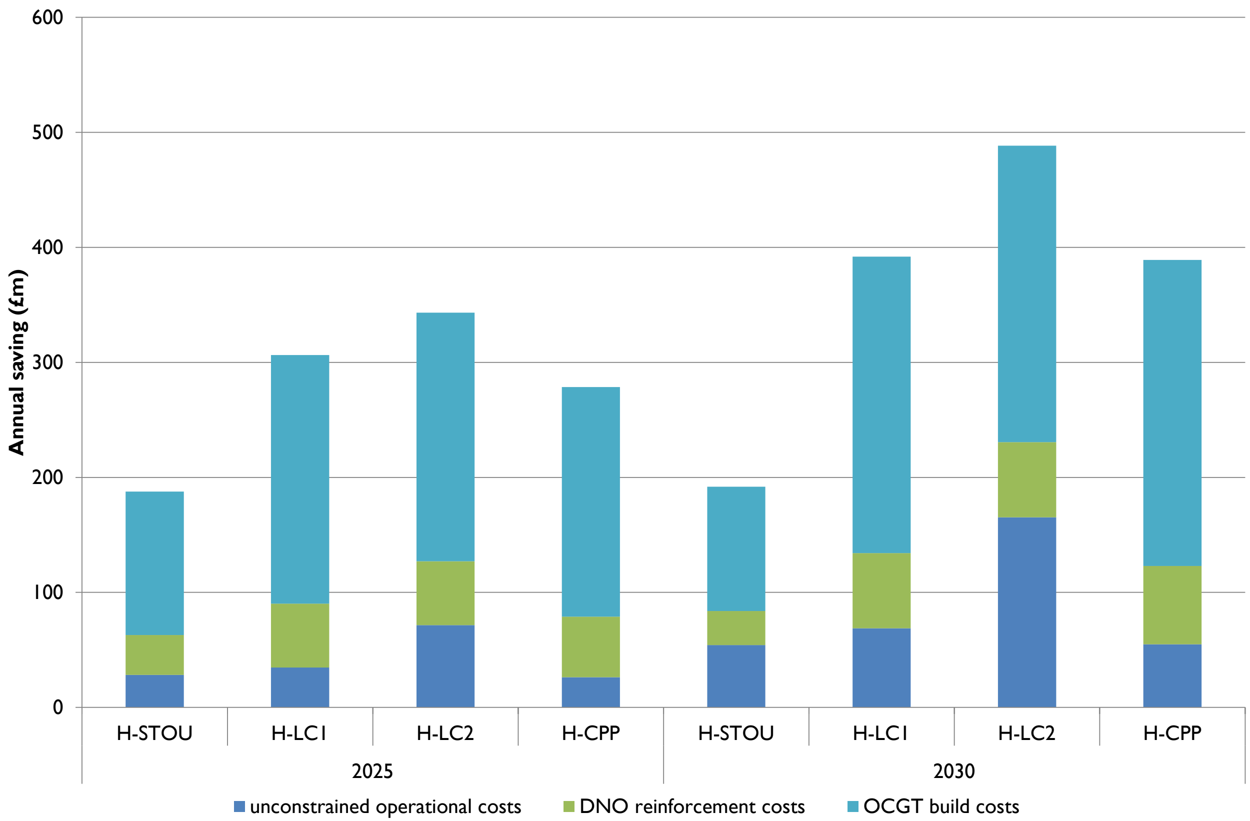
Lower levels of flexible demand in the Low scenario reduce the potential DSR savings



- Low uptake of EVs and heat pumps results in lower demand and lower potential flexibility.
- Higher overall benefits under LC2 rather than CPP, with year-round operational cost savings under LC2 offsetting the greater avoided investment cost savings (OCGTs, DNO reinforcement) under CPP.

Modelled benefits
High demand

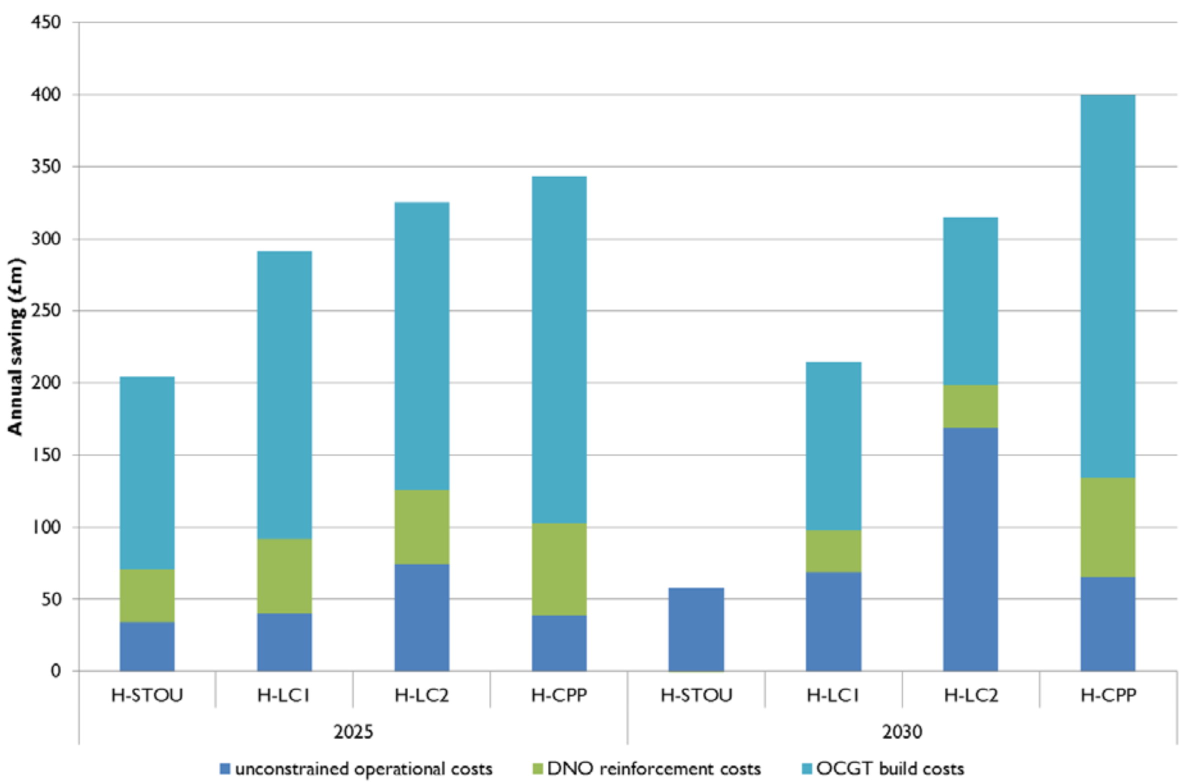
There is greater potential for load shifting and cost savings in the high demand scenarios.



- Greater potential for load shifting than other core demand scenarios, due to high uptake of potentially flexible heat pumps and EVs.
- Highest overall savings under LC2, reaching £488m in 2030.
- As the level of flexible domestic demand increases, the potential to shift the domestic peak is limited by the increasing overlap with the slightly earlier peak in non-domestic load. This caps the potential investment cost savings (OCGTs, DNO reinforcement) under CPP relative to LC and SToU, despite the assumed higher uptake of the tariff.

Modelled benefits
High demand HP sensitivity

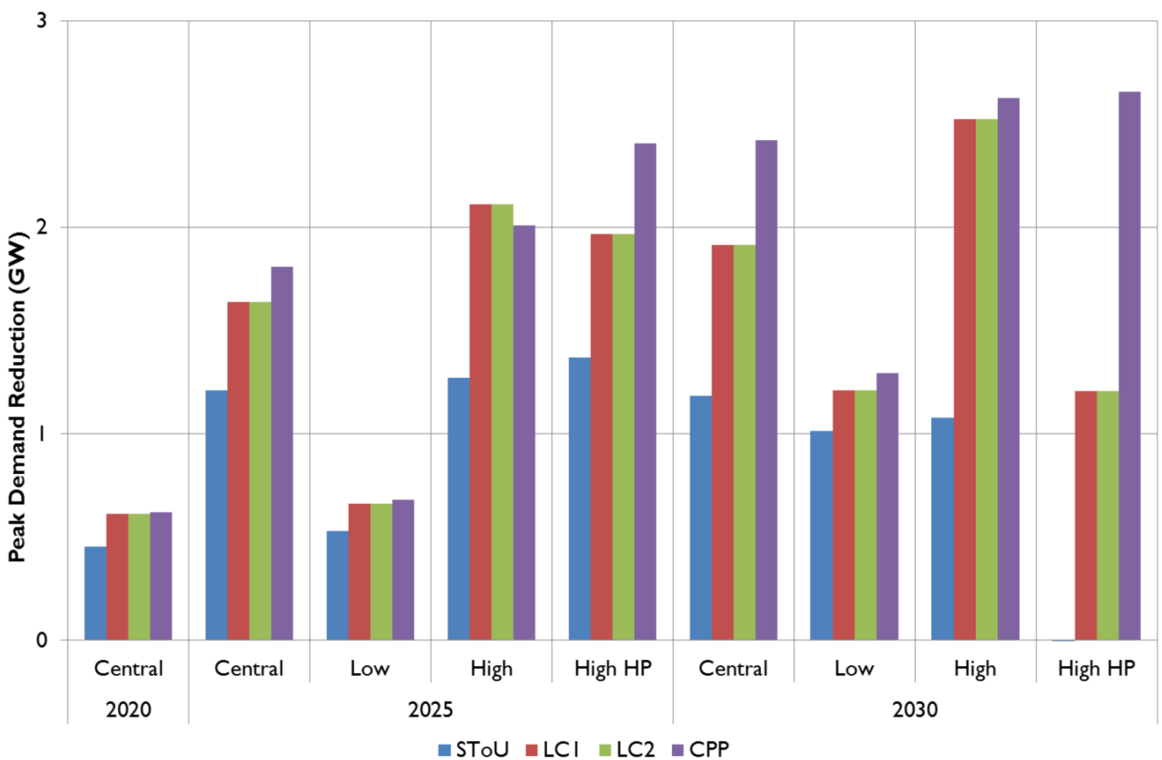
Relative to the core scenarios, the HP Sensitivities show similar savings under H-CPP and reduced savings under H-LC2 (despite the higher levels of heat pump load)



- As in the core scenarios, the more dynamic tariffs (LC1, LC2, CPP) demonstrate a large potential cost saving.
- The High demand scenarios provide potentially larger savings with higher heat pump uptake, but the coincidence between shifted domestic and non-domestic peaks can reduce or eliminate peak demand savings, as shown in 2030 High SToU vs BAU; discussed further on slide 37.
- These results illustrate the importance of the choice of the domestic peak demand tariff window on the system wide demand peak.
- The assumed limited storage potential of heat pumps restricts the capability for further load shifting.

Peak demand reduction

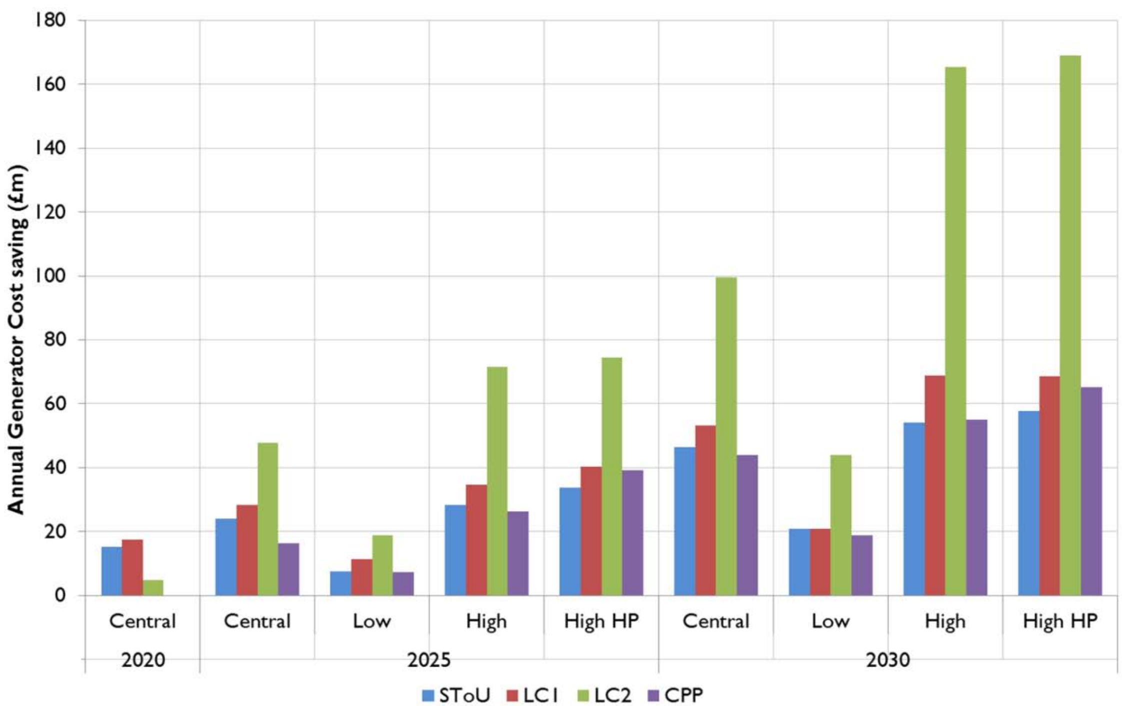
Peak demand is reduced by up to 2.5GW through use of DSR and flexible demand



- Peak demand is reduced by shifting flexible load away from peak periods
- Higher demand scenarios show increased potential for peak demand reductions
- Critical Peak Pricing tariff gives the largest peak demand reductions
- Peak demand reductions will result in lower distribution network reinforcement costs and lower OCGT investment costs

Generation operational cost impacts

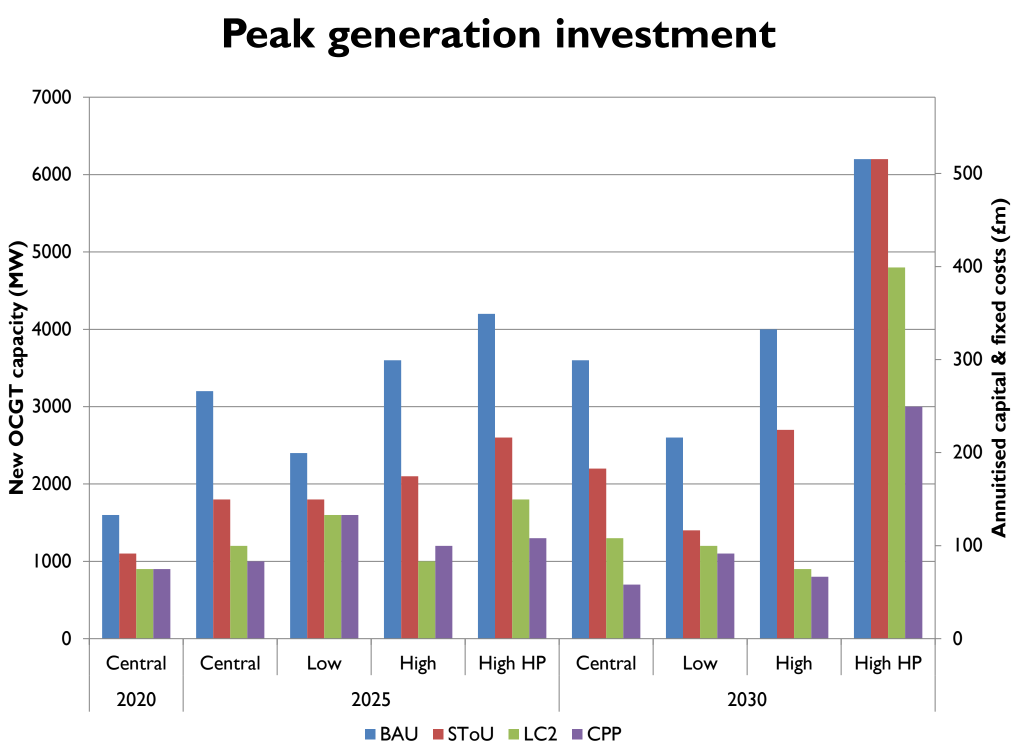
Generator operational costs savings observed of up to £170m, due to flatter demand profile and resulting reduction in peaking plant usage



- Generator operational costs include the price of fuel and carbon, variable Operation & Maintenance (VO&M), and start costs.
- The use of DSR to shift load from peak periods results in a flatter demand profile with fewer plant starts and better use of base load plant.
- All DSR tariffs show benefit over BaU.
- LC1 and CPP show limited increase in benefit over SToU due to increased DSR flexibility applying on 30 days per annum only. These tariffs focus on peak reduction rather then operational savings.
- LC2 shows large increase in benefit over LC1 and CPP due to increased DSR flexibility and resulting flatter demand profile applying on every day of year.
- Largest benefit over BaU found in 2030 High HP LC2 scenario - £170m per annum.

OCGT investment impacts

Significant cost savings could be achieved under static and dynamic DSR regimes by reducing peak demand and avoiding investment in peaking plant.



- The greatest peak demand reductions have been observed under High and High HP demand scenarios as there is greater potential for load shifting.
- In particular, CPP has been found to reduce peak demand to a greater extent compared to the LC1/LC2 options due to a higher assumed DSR uptake.
- We have estimated the avoided peak generation investment and fixed operating costs associated with DSR-led reductions in peak demand (assuming new OCGT capacity is displaced and a target de-rated capacity margin of 10%).
- Under the most beneficial scenarios (CPP under High Demand and the High HP sensitivity), this analysis suggests 3.2GW of OCGTs could be avoided in 2030, resulting in annual savings of approximately £266m.
- However, the full 2030 savings under CPP may not be attainable due to the respective time profiles of OCGT investment and DSR deployment. As shown in the chart, the requirement for new OCGT capacity is higher in 2025 than 2030 under the CPP tariff*, e.g. 1200 MW in 2025 High scenario, falling to 800 MW in 2030.

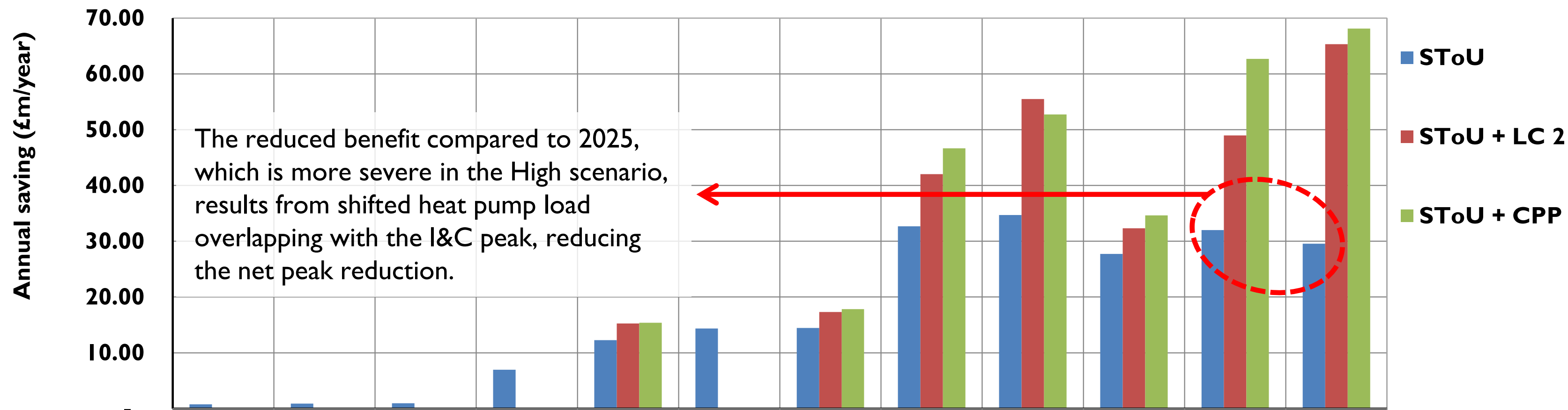
**If there is a requirement to build OCGT in 2025 this sunk investment cost cannot be recovered in 2030. However, it may still be possible to displace other capacity, e.g. existing OCGT, noting that this would be at a different £ / kW rate to that assumed for new build OCGT.*

DNO impacts – core scenarios

All DSR cases result in lower distribution network reinforcement costs compared to the Business as Usual reference in each uptake scenario (Low, Central and High)

- A reduction in network investment saving is seen in the SToU case after 2025 in both Central and High scenarios. This is a result of flexible heat pump load being shifted to before the peak window (5 – 8pm) where it overlaps with the I&C load, reducing the overall peak reduction. The effect is greater in the High scenario as more load is shifted.

Distribution network - Annual saving in network investment



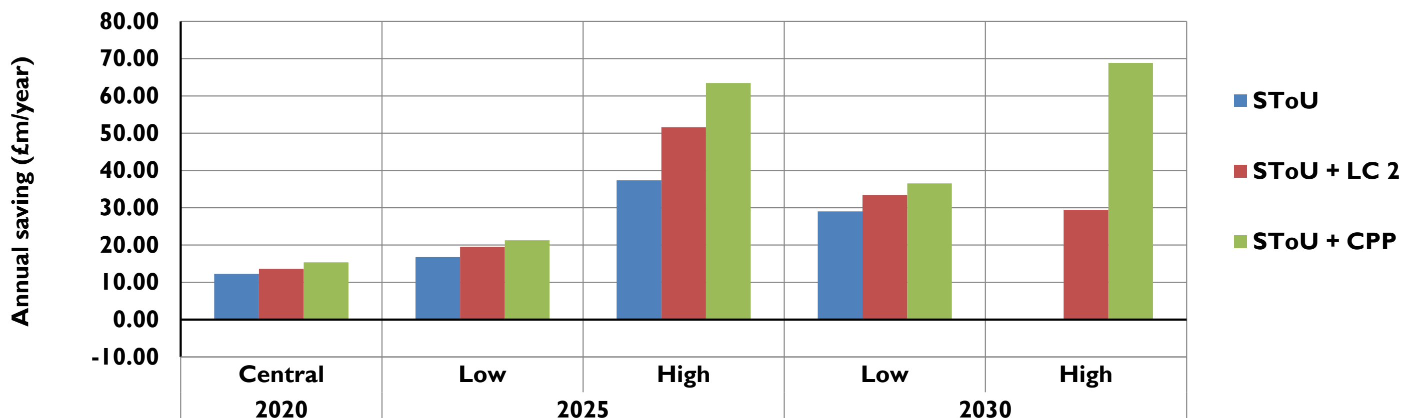
		2015 Low	2015 Central	2015 High	2020 Low	2020 Central	2020 High	2025 Low	2025 Central	2025 High	2030 Low	2030 Central	2030 High
Annualised capital saving (£m/year)	SToU	0.76	0.90	0.95	6.98	12.27	14.36	14.46	32.67	34.71	27.74	31.99	29.56
	SToU + LC 2	-	-	-	-	15.24	-	17.30	42.01	55.49	32.31	48.98	65.31
	SToU + CPP	-	-	-	-	15.38	-	17.84	46.67	52.73	34.64	62.68	68.11
Reduction on BAU	SToU	1%	1%	1%	4%	6%	6%	5%	9%	9%	8%	7%	6%
	SToU + LC 2	-	-	-	-	7%	-	6%	12%	14%	9%	11%	13%
	SToU + CPP	-	-	-	-	7%	-	6%	13%	13%	10%	14%	14%

DNO impacts – heat pump sensitivities

Under the increased heat pump load assumptions (High HP sensitivity scenario), the impact of the shifted heat pump load coinciding with the I&C peak load before the 5-8pm window is more severe.

- In the case of SToU alone, the peak reduction benefit has been negated by 2030 and a reduced benefit is seen under load control in the high scenario. The CPP case still delivers an increasing benefit, as the effect is masked by a greater overall availability of flexible load.
- Under the current SToU DSR assumptions (critically the 5-8pm window) and assumptions on heat pump flexibility (3 hour store), the impact of increasing flexible heat pump load is to the detriment of overall peak reduction on the distribution network.
- DNOs plan their investment well in advance, e.g. at the beginning of an 8-year price control period. While DSR in the domestic sector does offer a benefit in reduced network investment, the uncertainty in the scale of benefit creates a challenge for long-term investment planning.

Distribution network - Annual saving in network investment



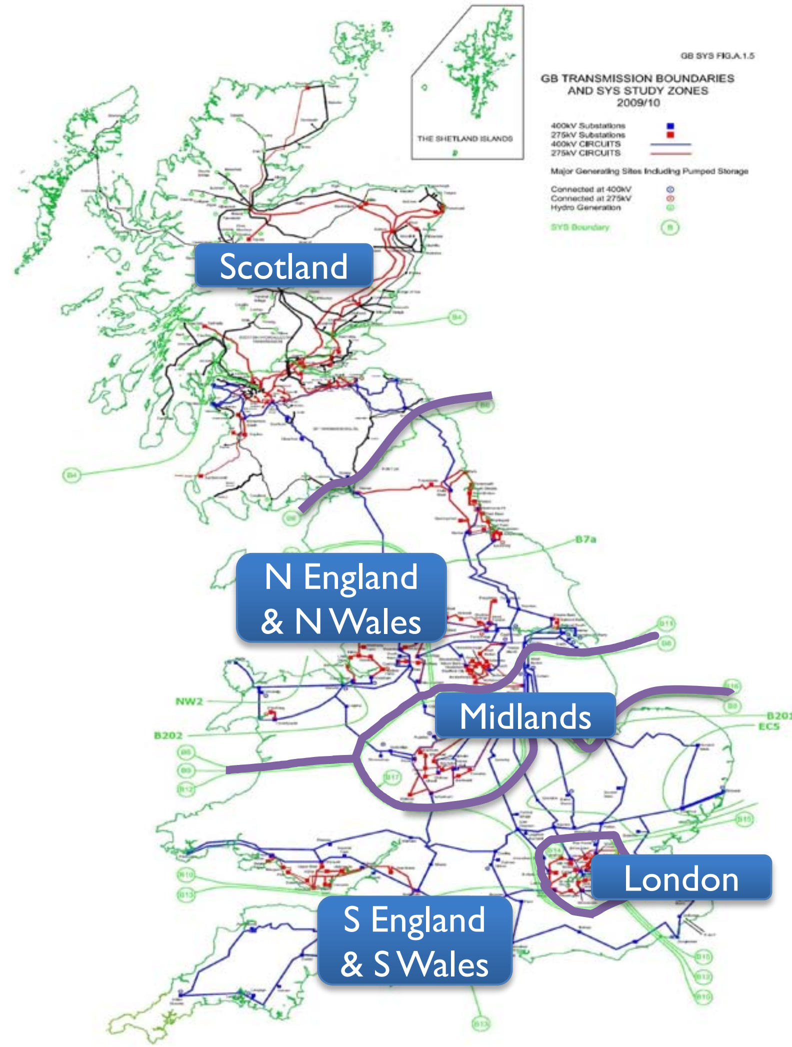
		Central 2020	Low 2025	High 2025	Low 2030	High 2030
Annualised capital saving (£m/year)	SToU	12.27	16.77	37.38	29.02	-0.13
	SToU + LC 2	13.61	19.55	51.62	33.45	29.45
	SToU + CPP	15.36	21.29	63.49	36.55	68.86
Reduction on BAU	SToU	6%	5%	8%	8%	0%
	SToU + LC 2	6%	6%	11%	9%	4%
	SToU + CPP	7%	7%	14%	10%	10%

Carbon impacts

- DSR can reduce carbon emissions as load is shifted to periods with less carbon intensive plant at the margin.
- By 2030, the modelling results show modest reductions in emissions moving from BAU to SToU and the dynamic DSR tariffs, with the lowest emissions seen under the year-round LC2 DSR tariff. The reduction in 2030 emissions under LC2 (relative to BAU) ranges from 0.4mt (Low) to 1.2mt (High).
- The cost of CO2 is included in the generator operational costs shown on previous slides
  - This accounts for approximately half of the operational cost savings seen under LC2 in 2030 High demand scenario (£90m / £165m)

Transmission impacts

- DSR appeared to have a very limited impact on constraint costs at the level of geographic resolution modelled in the study.
- This may be a function of the generation mix assumed – with a higher proportion of intermittent renewables constraint costs and associated DSR induced cost savings may increase.



Wholesale price impacts

- Wholesale electricity prices for the core scenarios were modelled based on system SRMC (short-run marginal costs), with no price uplift applied (in practice, market prices typically exceed SRMC levels at times of peak demand and tight capacity margins, contributing to the recovery of generators' fixed and capital costs). These results showed no material differences in annual average prices across the different DSR scenarios. The flexible load shifted from peak to offpeak periods was not significant enough to make a noticeable change in annual average system wide prices, though an individual consumer on a DSR tariff would benefit from shifting load away from high price periods to low price periods.
- In practice suppliers and consumers engaging in DSR would be expected to benefit from avoiding the uplift component of wholesale prices above SRMC levels at peak times, and avoiding the peak demand components of transmission and distribution charges.
- A sensitivity incorporating price uplift above SRMC levels (as a function of capacity margin) was modelled for the High scenarios in 2030. This showed the system load-weighted average price falling under the DSR tariffs, with the LC2 price averaging 70.2 £/MWh relative to 71.5 £/MWh in BAU. By including uplift, the difference in price between peak and offpeak periods is high enough that the effect of DSR is noticeable at a system level. Annual wholesale purchase cost savings (as seen by suppliers) for consumers on DSR tariffs ranged from £7 (SToU) to £34 (LC2) per household on the respective DSR tariffs when uplift was modelled.

Benefits per meter

The potential power sector cost savings can also be shown on a per domestic meter basis. For illustrative purposes, the figures below assume 100% passback of all cost savings to domestic consumers (and are based on the modelled cost savings rather than wholesale price changes)

- If power sector cost savings (operational, DNO reinforcement, and OCGT build costs) are equally shared amongst all domestic consumers, annual savings of the order of £10 per household are seen in 2025 and 2030.
- These savings are higher in high demand scenarios and with increasing flexibility of DSR tariffs, ranging in 2030 from £5 (Low, SToU) to £16 (High, LC2) per household.
- If power sector cost savings are passed back to only those customers on particular DSR tariffs, greater savings are seen by these customers.
- These targeted savings can be of the order of £50 per household per year for the dynamic DSR tariffs; the highest saving is seen by customers on LC2 tariff, £90 per household per year in the High 2030 scenario. This saving is only seen by customers specifically on the LC2 tariff, not SToU customers in the LC2 scenarios.
- Targeted savings for consumers on SToU tariffs are much lower, of the order of £15 per household

Key drivers

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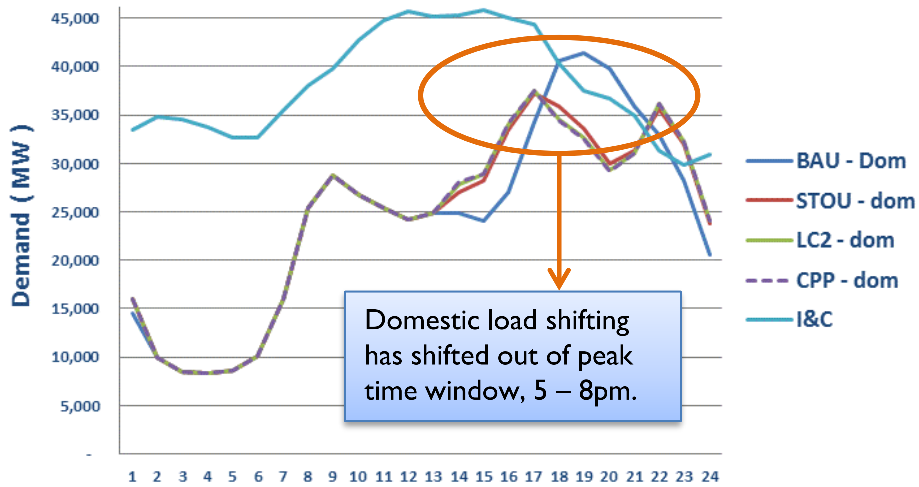
- The most significant potential savings from the deployment of domestic DSR have been found to arise from reductions in peak demand leading to avoided investment costs in generation capacity and DNO reinforcement.

- Comparison of the modelling results over time, across demand scenarios, and between DSR tariffs illustrates that the key drivers of domestic DSR benefits are the growth in flexible loads (e.g. assumed penetration of heat pumps, EVs, smart appliances) and consumer uptake of DSR.
  - For a given background of flexible domestic load, the realised DSR potential is a function of both the uptake of DSR tariffs and the level of consumer responsiveness once on a DSR tariff.
  - The largest potential reductions in peak demand are seen under the CPP tariff, which is assumed to have a higher uptake than LC, albeit with a lower degree of responsiveness by consumers on the tariff.

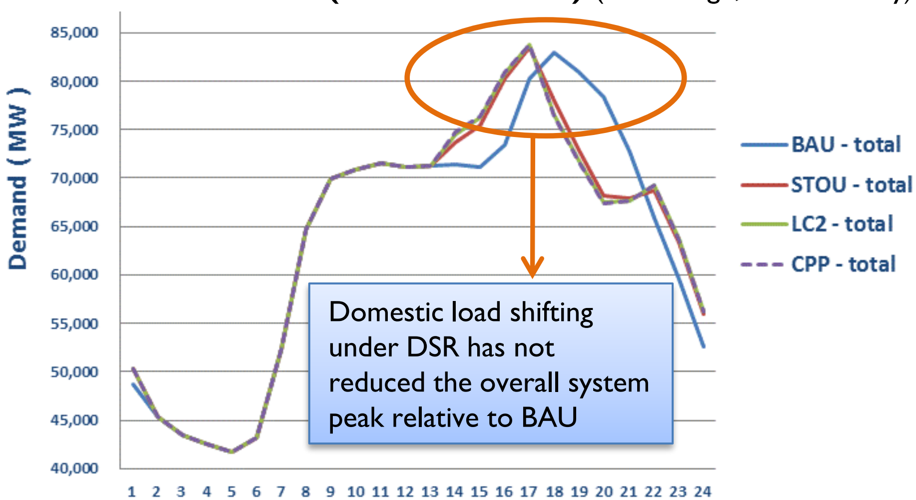
- Higher flexible demand generally leads to higher benefits, but the potential for peak demand reduction via DSR load shifting is limited by the increasing overlap with the non-domestic load peak at high penetrations of flexible domestic load (particularly heat pumps).
  - The interaction between domestic and non-domestic load peaks is illustrated in the following slides by a sensitivity on the DSR peak window definition.

Peak demand: effect of shifting domestic-load onto I&C peak

Un-combined demand (domestic + I&C) *(2030 High, HP sensitivity)*



Combined demand (domestic + I&C) *(2030 High, HP sensitivity)*



- The model assumes that the flexible heat pump load is 'shifted' before the peak time window (5 – 8pm) and can be shifted by a period of 3 hours (assumed to be the average duration of thermal stores).
- In other words, the model assumes that heat pumps will operate to top-up their thermal stores just before the peak time - where the load overlaps with the maximum of the I&C load;
- At higher levels of flexible heat pump load (as in the central and high HP sensitivity scenarios) the addition of shifted heat pump load to the I&C load begins to **reverse** the peak reduction.
- For very large HP load penetrations (as pictured in this slide) the overlap *increases* the total system peak (greater diversity in the shifted heat pump load due to variability in the size of domestic storage tanks may mitigate this effect to a certain extent).
- The modelling has demonstrated that the impact on peak demand is highly sensitive to the selection of peak window. The impact of altering the peak period on the DSR benefits is explored in the following slides.

Impact of altering the Time of Use period on the overall demand peak

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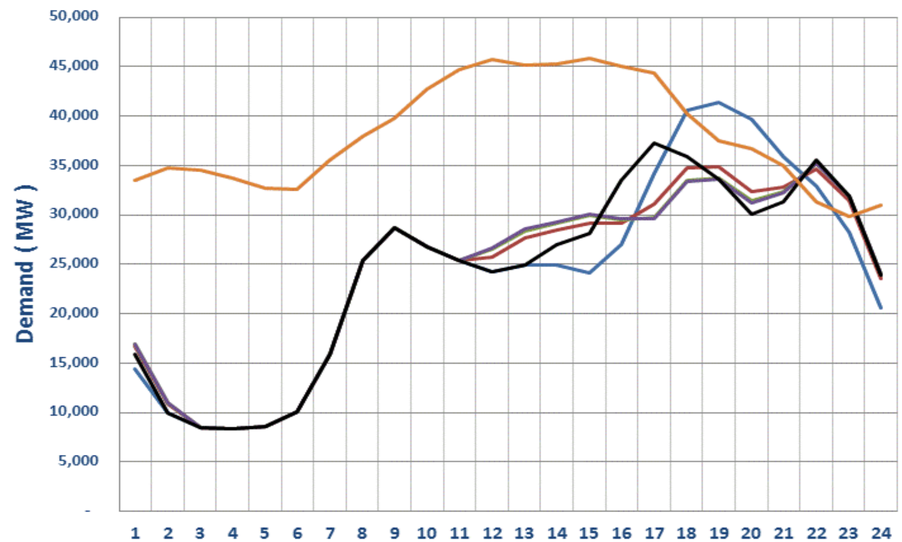
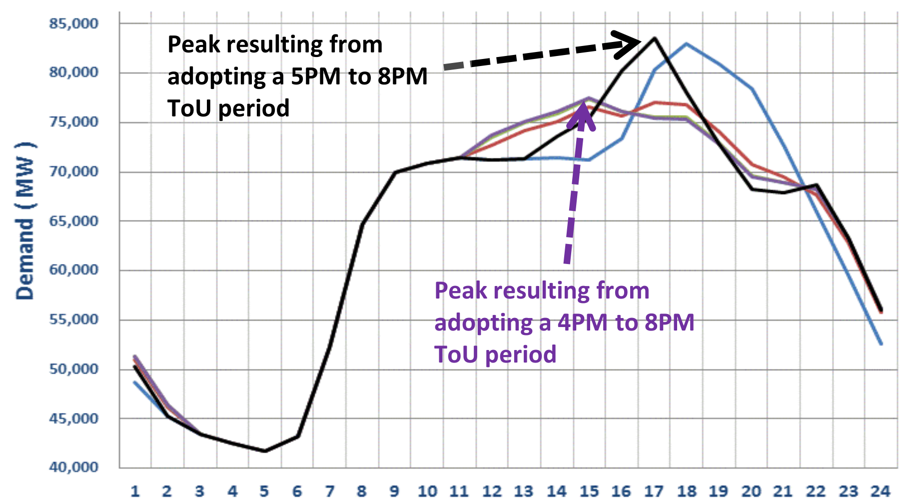
- Analysis of impact on overall peak of shifting the peak pricing period to begin at 4pm instead of 5pm is shown in the profiles;
- Bringing the peak period forward by one hour significantly increases the peak reduction for all DSR cases.
- The peak pricing period is assumed to end at the same time (8pm). Note that a shifting of the ending time has no noticeable effects on the overall peak reduction;
- Results are shown for 2030 High scenario, based on the heat pump sensitivity assumptions.



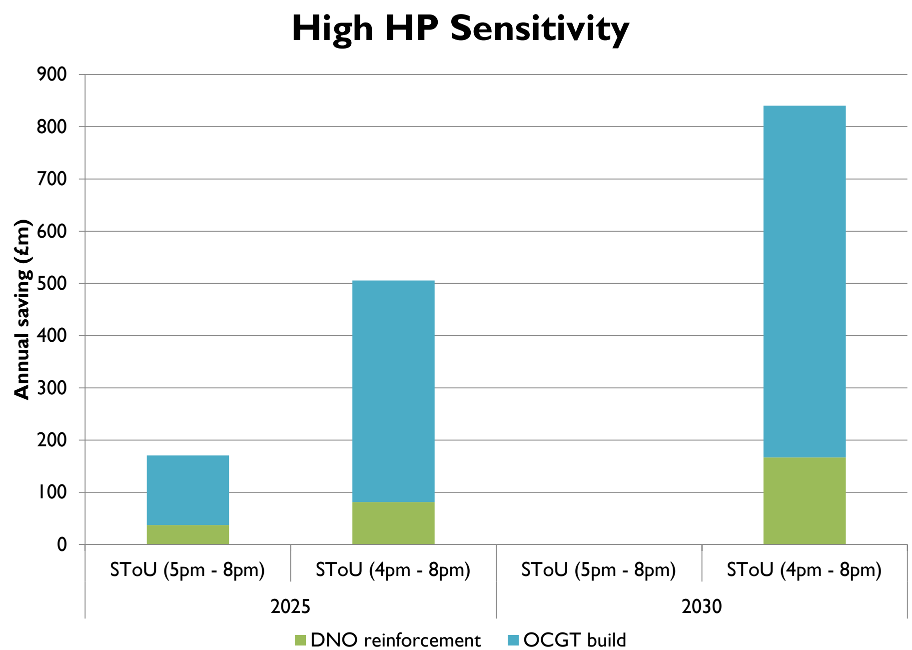
Un-combined demand (domestic + I&C)



Combined demand (domestic + I&C)

Impact of altering the ToU period on the potential DSR benefits

- The increased peak demand reduction observed with the alternative ToU pricing period enables higher potential DSR benefits.
- Avoided distribution and generation investment costs (DNO reinforcement, OCGT build) have been estimated for the SToU High HP sensitivity applying the alternative ToU period (4pm to 8pm).
- Note the generation investment savings shown here are based on the capital and fixed costs of new OCGTs, but the implied reduction in new OCGT capacity exceeds the total OCGT build in the BAU case. This suggests the potential to displace other new or existing generation plants in addition to new OCGT, but we have not considered how the annuitised costs of other plant would differ from new OCGT (ie all displaced generation is assumed to be of the same cost as new OCGTs).
- Potential benefits have not been modelled for the dynamic DSR tariffs (LC, CPP) with the alternative ToU period but would be expected to be at least as high as those estimated for the SToU tariff (with the same caveat as above on displacing peak generation capacity beyond new OCGTs).



High HP sensitivity	2025		2030	
	SToU (5pm - 8pm)	SToU (4pm - 8pm)	SToU (5pm - 8pm)	SToU (4pm - 8pm)
DNO reinforcement	37	81	0	167
OCGT build	133	424	0	673
Investment savings	**170**	**505**	**0**	**840**

Conclusions on sensitivity to Time of Use period selection

- The peak load analysis, distribution network investment analysis and window period sensitivity have shown that the reinforcement cost savings accessible by the DSR measures investigated are highly sensitive to:
  - The coincidence between the 'shifted' domestic profiles and the I&C load ('overlaps');
  - The amount of flexible heat pump load assumed in the system ('HP penetration');
  - The underlying assumption of shifting the HP with storage load earlier (i.e. before the peak period) and assuming a 3 hour autonomy of the storage tank (i.e. tanks are recharged within 3 hours before the ToU period start); and
  - The timing of the ToU window.

- All these elements are correlated:
  - The definition of the most suitable ToU window needs to be based on both the domestic and I&C demand profile, such that possible 'overlap' effects generated by the shifting of the largest flexible loads – most notably, heat pumps with storage – can be taken into account.

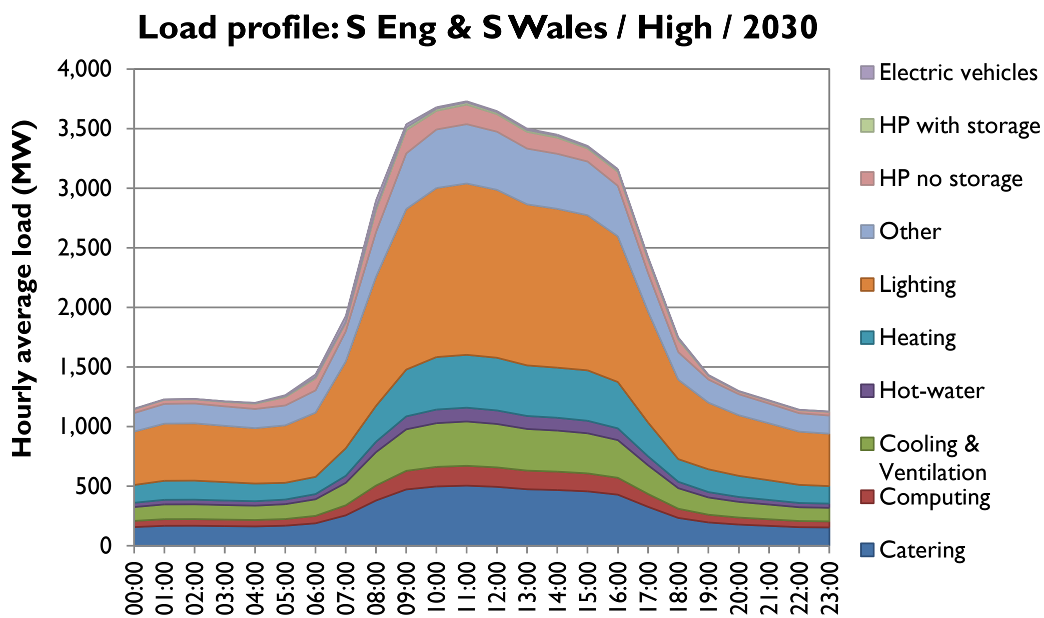
- Assuming that the system operator / DN operator(s) can define the most suitable ToU period according to the criteria as above, then the DSR measures seem to deliver an increasing cumulative saving compared to the BAU case.

- The analysis suggest that a DSR technique is most effective when:
  - A large amount of flexible load is available **and**
  - 'Correlation' (or overlaps) with non-domestic loads is minimised – i.e. by identifying the most suitable ToU windows over time and actively deciding how much load to shift case by case.

SME results

SME sector DSR – technical potential

- The technical potential for DSR in the SME sector has been assessed over the period to 2030 on the basis of an analysis of the composition of the load profile (i.e. by load type) and assumptions regarding the flexibility of those loads.
- The load composition (in 2030) and assumptions regarding flexibility are shown below:



Note that the profile is derived from Profile Coefficient data provided by Elexon for Profile Classes 3 & 4.

Load	Fraction of sector consumption	Degree of flexibility (within 3h period)
Electric vehicles*	0.5%	100%
HP no storage	4.1%	0%
HP with storage	0.5%	100%
Catering	14%	0%
Computing	4%	0%
Cooling & Ventilation	10%	33%
Hot water	3%	100%
Heating	12%	50%
Lighting	39%	0%
Other	13%	33%

** Note the EV load comprises company, fleet and private vehicles charged at work.*

- Based on the percentage flexibility assumptions by end-use, the average flexible load within a particular time period can be estimated.

SME sector DSR – technical potential

- The technical potential for the load-shifting in the peak 3-hour window is shown below for each year and by region (results are shown for the High heat pump uptake scenario).
- On the basis of the profile shape given by Elexon coefficients for profile classes 3 and 4, the peak period is from 10am to 1pm (this may not be consistent with the period over which DSR would be applied in practice, e.g. a ToU tariff, but is an upper bound on the potential).

Year	Technical potential for load reduction (MW)					
	Scotland	N Eng & N Wales	Midlands	London	S Eng & S wales	Total
2015	205	464	338	217	774	**1,999**
2020	205	464	338	217	774	**1,999**
2025	204	463	337	215	772	**1,992**
2030	207	470	342	218	783	**2,019**

- On the basis of the flexibility assumptions, the upper bound on the technical potential for load-shifting is around 2GW.
- The technical potential exhibits little variation over time, as only the heat pump and EV load varies. As the majority of heat pumps are assumed to be installed without storage (inflexible) and to an extent displace less efficient electrical heating (which has some flexibility), the flexible potential drops over time. This trend reverses between 2025 and 2030, when the rate of heat pump uptake with storage and electric vehicles increases.

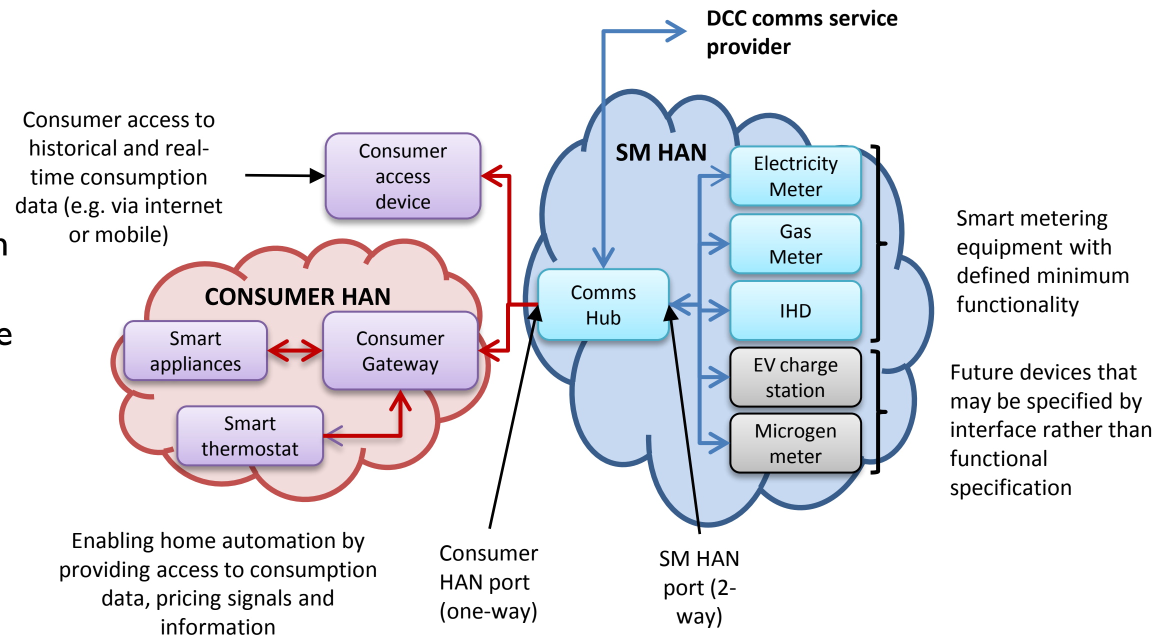
Impact of DSR in the SME sector

- The flexible load within a 3-hour peak period has been estimated to be approximately 20% of the total consumption in the period. This includes no assumption on the uptake of DSR within the SME sector or the extent of the response that participating organisations provide in practice.
- We have researched the impact of existing and past time of use pricing programs in the commercial sector in order to inform estimations of the range of uptake of the technical potential:
  - Experience of critical peak and real time pricing programs in the US have recorded reductions in peak period consumption of between 6 to 17% in the commercial sector, depending on the level of enabling technology provided in combination with the tariff (e.g. smart thermostats).
  - A recent trial of time of use pricing in the SME sector in Ireland recorded only a 0.3% reduction in peak period consumption in a limited trial of around 500 participants (the result was not found to be statistically significant).
- The higher levels of response have been recorded in day-ahead critical peak or real time pricing programs, with strong price incentives and use of enabling technologies such as smart thermostats. These higher responses have also been found in the US, where consumers are more aware of demand side response schemes and their benefits.
- Peak reductions of 25% to 50% of the technical potential (5% to 10% overall load reduction) may therefore be a reasonable expectation of the response in the GB market. This corresponds to an overall load reduction (nation-wide) of 500 MW to 1GW in 2030.
- Much of the technical potential is already present in the SME sector, hence an early introduction of DSR could provide benefits. An analysis of the impact of shifting the SME load on overall system peaks has not been performed. DSR mechanisms would need to be designed to avoid shifted load reinforcing peak loads in other sectors.

Smart device analysis

The smart metering system

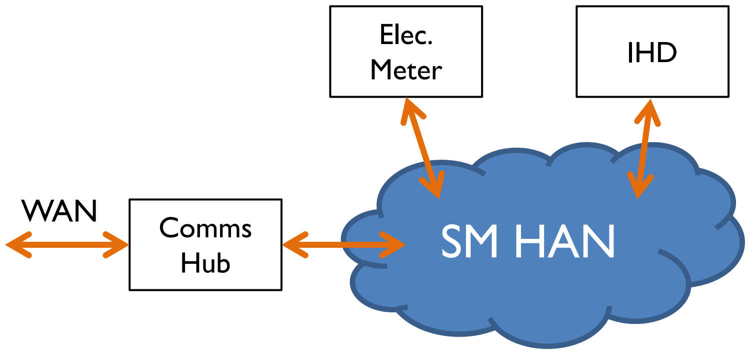
- The components of a potential smart household are shown schematically in the diagram.
- The extent of the smart system required will to some extent depend on the type of DSR it is intended to enable.
- Smart meters will be rolled-out in all homes with adequate functionality to enable SToU, CPP and load control, e.g. 2-way communication, multiple registers for ToUs and load management capability.
- A smart meter and In-home display (IHD) is adequate to enable a ToU, i.e. a visible signal to inform the occupants that the peak period is active. This requires intervention on behalf of the occupant and may limit effectiveness.



- Automated response of devices is likely to increase the effectiveness of tariffs. This requires load management via a Home Area Network (HAN) on the basis of a pricing signal. This could be achieved, for example, by smart plugs and a smart thermostat communicating with a communications hub.
- Direct load control requires two-way communication between the home and the energy supplier, DNO or 3rd party (the operator). This enables the availability of loads to be communicated to the operator and for the operator to remotely control operation.

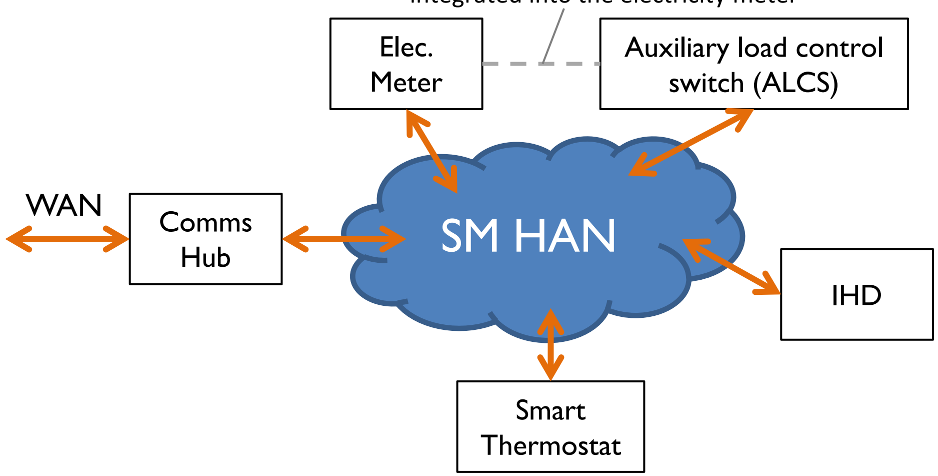
Smart home architectures

SToU / CPP with user intervention



- A smart home system consisting of a communications hub, smart meter and in-home display communicating via the smart meter HAN (SM HAN) is sufficient to enable a SToU or CPP tariff (indeed these tariffs can be operated without a smart metering system, e.g. by using SMS based communication).
- In this configuration, the consumer responds to the information regarding a peak or critical peak price period by manually reducing load.

Direct load control

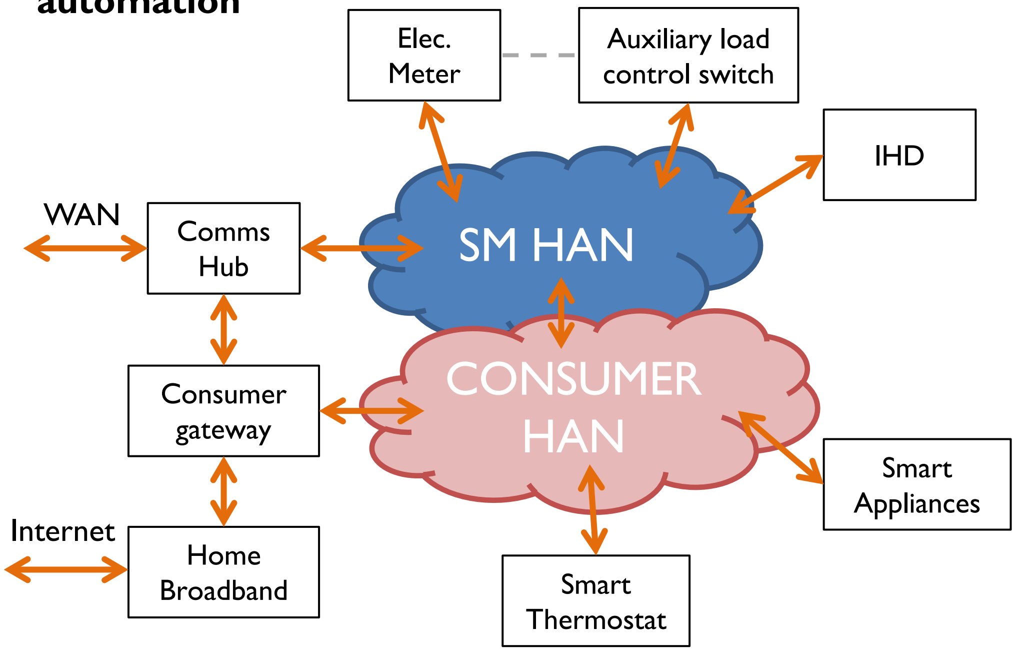


- The draft smart meter functional specification requires the SM HAN to support up to 8 devices* (including the elec and gas meters, comms hub and IHD). Direct load control will be enabled either by connection of a load control circuit directly to the smart electricity meter or, as shown in the diagram, by 2-way communication between the smart devices (auxiliary load control switches, thermostat etc.) and the energy supplier via the SM HAN / WAN. It is expected that only larger loads will be connected to the smart meter / SM-HAN, smaller appliances will require additional communications (see next slide). All devices on the SM-HAN will need to be approved.

**The number of devices has not yet been fixed*

Smart home architectures (2)

SToU / CPP or direct load control enabled by home automation



- In this configuration, the consumer response to the peak or critical peak tariff is enabled by a home automation system, i.e. smart thermostat and load control devices, that reduce load when the price exceeds a certain level.
- Consumers will interface with the Smart Metering System through an approved Gateway Device. This will provide a secure bridge between the SM HAN and other communications networks within the consumer's home (the Consumer HAN).
- The Gateway device will have access to data from the SM HAN e.g. energy usage, pricing, tariffs etc., enabling the loads on the Consumer HAN to respond to the information received by the smart meter.
- This system could automate the response to SToU / CPP tariffs and could also enable direct load control of devices on the Consumer HAN, provided that the approved consumer gateway can accept load control signals from the Comms Hub.

Smart system requirements for DSR

The additional smart devices (supplementary to the basic smart metering system) required to facilitate various kinds of DSR are summarised in the table below:

Smart metering system components	Additional requirements to enable DSR mechanisms			
	SToU	**CPP**	**SToU / CPP automated**	**Load control**
Smart meter & Comms Hub (SM-HAN)	Standard specification	Standard specification	An additional consumer gateway is required to provide the Consumer HAN (C-HAN). Appliance loads will sit on the C-HAN and respond to pricing signals. Large loads (e.g. heating and EVs) could sit on the SM-HAN, if approved devices.	Large loads such as water-heating or EVs could be controlled via a load control switch (activated by a signal). This could be an auxiliary switch integrated into the meter or a stand-alone switch on the SM-HAN. Smaller appliances are not expected to sit on the SM-HAN, hence a consumer gateway would be required to enable communication with these devices via the C-HAN.
IHD	Standard specification	Upgrade to enable day-ahead signalling of the CPP tariff.	Upgrade to enable day-ahead signalling of the CPP tariff.	Standard specification
Smart devices	Not required	Not required	Smart thermostat, load control switches and smart appliances required to communicate across the SM-HAN or C-HAN.	Smart thermostat, load control switches and smart appliances required to communicate across the SM-HAN or C-HAN.

The key additional requirements for automation of the response of domestic loads, particularly smaller appliance loads, are the consumer gateway required to establish the C-HAN and the smart appliances / load control switches (i.e. communication enabled).

Consumer response to Time Of Use pricing

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- The impact of time of use tariffs has been shown to be strongly dependent on the level of automation used to enable the response. For example:
  - Recent field trials of time of use tariffs in Ireland, together with provision of smart meters and electricity usage monitors found peak period energy use was on average reduced by around 9%.
  - A trial of CPP without any enabling technology in California found that peak period consumption was reduced by 14%, although it should be noted that this is in an area acutely aware of the problems of constraints in the electricity system.
  - US trials of CPP with enabling technologies such as smart thermostats and load control devices have recorded peak time usage reduction from 27% to 60 %. It should be noted that this reduction was partly related to air conditioning and pool pumps, loads that are not typical in the UK housing stock.
- The levels of response of flexible loads assumed in this analysis are shown in the table below:

DSR	Responsive load	Reduction of demand in peak period*			
		2015	2020	2025	2030
SToU	Normal appliances	5%	10%	15%	20%
	HP / EV / SA	10%	20%	30%	40%
CPP	HP / EV / SA	30%	40%	50%	60%
LC	HP / EV / SA	100%	100%	100%	100%

** Note that the reductions tabulated are the average response among the households participating with DSR (not reductions across the whole stock)*

- The response in normal appliance load is assumed to be delivered by consumer intervention.
- It is assumed that heat pumps, electric vehicles and smart appliances become part of an automated response system (via SM-HAN or C-HAN).
- Response is assumed to improve over time as consumers become more knowledgeable and accepting of time of use pricing.
- In the case of load control, a 100% rate of response of available loads is assumed (assumes no reliance on human behaviour, although in practice consumers may have an override).

Summary of home automation requirements

- This study is focussed on the benefits of DSR in the domestic and small commercial sector and not the costs associated with enabling the response. However, as discussed on the previous slide, an automated response to DSR signals is expected to be required to achieve the levels of response assumed in the study of benefits.
- The levels of response of EVs, heat pumps and smart appliances assumes automation rather than regular consumer intervention.
- Smart charging of EVs will require the home charging station to incorporate communication functionality enabling it to receive signals via the SM-HAN. Note that private vehicles charged at public stations could still be available for DSR, without the homeowner incurring this additional expense.
- The control of heat pumps, to respond to pricing signals and also deliver thermal comfort, is likely to require a smart thermostat.
- As smaller appliance loads such as washing machines and freezers are not expected to sit on the SM-HAN, a further communication device – a consumer gateway – will be required to enable response of these devices, in addition to the smart enabled appliances.

Home electric vehicle charging station – will require functionality to communicate with the smart meter (via the SM-HAN)

Smart thermostat to enable communication with heat pumps

Consumer gateway – required to establish the C-HAN and enable communication with appliances

Smart appliances, incorporating functionality to receive signals via the C-HAN and automate the response

Conclusions

Conclusions

- The most significant potential savings have been found to be associated with reducing investment in OCGT peaking plant and DNO reinforcement, as well as reduced operational generation costs, with overall annual domestic DSR benefits approaching £500m in 2030 in the best case (High scenario, LC2 DSR tariff), equivalent to around £90 per dynamic DSR household.

- The potential benefits are observed to increase over time (due to the assumed increase in flexible loads), with increased flexible demand (assumed penetration of heat pumps, EVs, smart appliances) and with the uptake of more dynamic DSR tariffs (LC, CPP).
  - The largest operational savings are seen in the LC2 DSR case, which offers the potential for year round savings in generation costs (whereas the LC1 and CPP cases are limited to 30 days per year).
  - The largest potential reductions in peak demand are seen under CPP, which is assumed to have a higher uptake than LC, and therefore shows a greater potential saving in OCGT and DNO reinforcement costs.
  - The dynamic DSR tariffs begin to show material incremental benefits over SToU by 2025 under the Central and High scenarios.

- With increasingly high penetrations of flexible domestic load (particularly heat pumps), the potential for peak demand reduction via DSR load shifting is limited by the increasing overlap with the non-domestic load peak. The modelling results are observed to be highly sensitive to the assumptions on heat pump penetration, dynamic tariff uptake, the DSR peak window definition and heat pump storage characteristics. By 2030, the highest DSR benefits are seen either under CPP or LC2, depending on the interaction between these key assumptions in each scenario.

Annex

Demand modelling – key assumptions(1)

Parameter	Assumption
Domestic demand growth	• Growth in line with DECC's UEP Central scenario. Household growth rates were also provided by DECC (consistent with UEP model)
Demand profile	• Based on Elexon profile coefficients (1 & 2 for domestic demand and 3 & 4 for small commercial)
Heat pump uptake scenarios	• Based on DECC scenarios
HP load profile & operating characteristics	• Load profiles based on thermal demand measurements in a range of dwelling types (Carbon Trust Micro-CHP field trials). • Heat pumps with storage assumed to have 3 hr peak demand storage capacity. • COP improvement over time from 2.5 to 4 for ASHP and 3.3 to 4.8 for GSHP (based on Design of the Renewable Heat Incentive (NERA for DECC, 2010)).
EV uptake scenarios	• Based on DfT scenarios
EV charging profile & operating characteristics	• Charging profiles based on analysis of DfT National Travel Survey trip statistics and assumption that vehicles are plugged in on arrival at destination (e.g. home, work) • EV battery characteristics (size and charging rate) agreed with DfT • Charging location, average mileage and vehicle efficiency provided by DECC / DfT. • Only the load associated with EVs charging 'at home' is considered in the calculation of flexible load available for demand side response ('at home' includes cars charged at the domestic premises and could also include an element of on-street charging, i.e. near the home. Private and company vehicles are included in the calculation). The load associated with EVs charged at work or at other public stations is included as an inflexible component of the non-domestic load.

Demand modelling – key assumptions(2)

Parameter	Assumption
Flexible / Smart appliances	• Wet and cold domestic appliances have been assumed to offer flexibility. The electricity demand attributed to these appliances has been based on DECC Energy Consumption in the UK Domestic data tables (2010 update). • Penetration of smart appliances is based on discussions with DECC and Loughborough University • Appliance load profile based on profiles generated by the University of Loughborough using a model based on national Time of Use statistics
Demand Side Response uptake	• DSR uptake projections are based on the assumption that consumers taking up electric vehicles, heat pumps and smart appliances would also take up such tariffs. • Low, Central and High scenarios for EV and HP uptake were provided by DECC. Between 30% to 64% of households are assumed to participate in DSR by 2030. • In DSR scenarios LC1 & LC2 (load control), up to 12% of households are assumed to participate by 2030. In the case of CPP, up to 19% of households participate by 2030
Demand side response impact	• Assumptions on the consumer response to price-based DSR have been based on published literature on existing or past DSR programs. • The response of heat pump, EV and smart appliance load is assumed to be via an enabling technology (e.g. smart thermostats and load control switches that communicate with the smart metering system and automate the response to price signals), with corresponding high rates of response (up to 60% in the case of CPP). • In the case of load control, it is assumed 100% of a household's flexible load can be shifted.

System modelling – key assumptions(1)

Parameter	Assumption
Commodity prices	• DECC Central commodity price projections were used in all scenarios and sensitivities.
Carbon prices	• DECC Central carbon price projections were used in all scenarios and sensitivities. • Carbon prices including the Carbon Price Floor (CPF) policy option reach £74.2/t in 2030. • Generic overseas generators used to model interconnector flows are not exposed to the CPF.
Generation mix	• The starting point for the generation capacity mix is a scenario modelled by Redpoint in 2011 to support DECC's EMR analysis. • The demand profile applied to the BAU scenario in this study is considerably higher than that applied to the previous EMR run (mainly because of different assumptions regarding policy savings and electrification of heating and transport). • We therefore had to allow some existing CCGT plant to retire later, and build some additional plant, with the aim being to reach a carbon intensity of ~100g/kWh in 2030. • We employed a 'least-cost' approach whereby the most cost-efficient generation technologies are built: in order, these are nuclear, onshore wind, gas CCS and small biomass. • We also ensured that de-rated capacity margins in the system remain above 10% throughout the modelling horizon across all scenarios modelled.
Transmission reinforcement	• Transmission boundary limits and reinforcements are based on National Grid's 'Gone Green' scenario assumptions, as published in the ELSI model (January 2012).