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Electrification of Heat and the Impact on the Scottish Electricity System

Commissioned by ClimateXChange / Scottish Government

Sample outputs, methodology and assumptions

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Project overview

INTRODUCTION

There are a number of opportunities that could arise from progress in decarbonising electricity supply, and using low carbon energy sources to displace conventional heating and transport fuels. However, there are a number of factors which will influence the extent of the impact of this approach on the whole energy system.

The peaks and troughs in heat demand, both within a day and across the seasons, are far greater than the variations in electrical demand, and create a challenge for electricity generating assets which, in the absence of storage, may be underutilised for long periods.

A higher penetration of electrical heating may also require additional investment in low (or lower) carbon generation sources to meet this additional demand. This introduces a complex short and long-term dynamic, where short-term increases in load may be met by increased (higher carbon) thermal output prior to the system adapting to this change in demand.

Electrification of heating can also place further pressure on the network infrastructure required to deliver the additional power to demand centres. There are potential impacts on the high voltage transmission network, particularly if the background generation is located in different geographical zones within the GB system, but there is likely to be a substantial impact on the distribution network, particularly if electrification is rolled out in localised clusters.

The Scottish Government would like a greater understanding of:

- where these thresholds for network upgrades might be triggered,
- how they interact with a greater penetration of distributed generation, and
- how this might impact future regulated price controls governing network development.

In addition, the **Scottish Government require a user-friendly tool that demonstrates the aggregate electric heating demand changes and its constraints on the grid out to 2050**. The aggregate demand changes will be aligned to the input requirements for the Scottish Government Electricity Dispatch Model, to allow a more detailed system wide impact to be undertaken. The model should also be consistent with, and be able to support the use of, the Whole System Energy Model for Scotland currently being developed from a UK TIMES basis.

PROJECT TEAM

Delta Energy & Environment – Michael Brown, Jon Slowe, Dina Darshini, Valts Grintals, Andrew Turton

Smarter Grid Solutions – Graham Ault, Laura Kane

Chiltern Power – John Scott

Executive summary (1/4)
Peak electric demand in Scotland (2016 – 2050)

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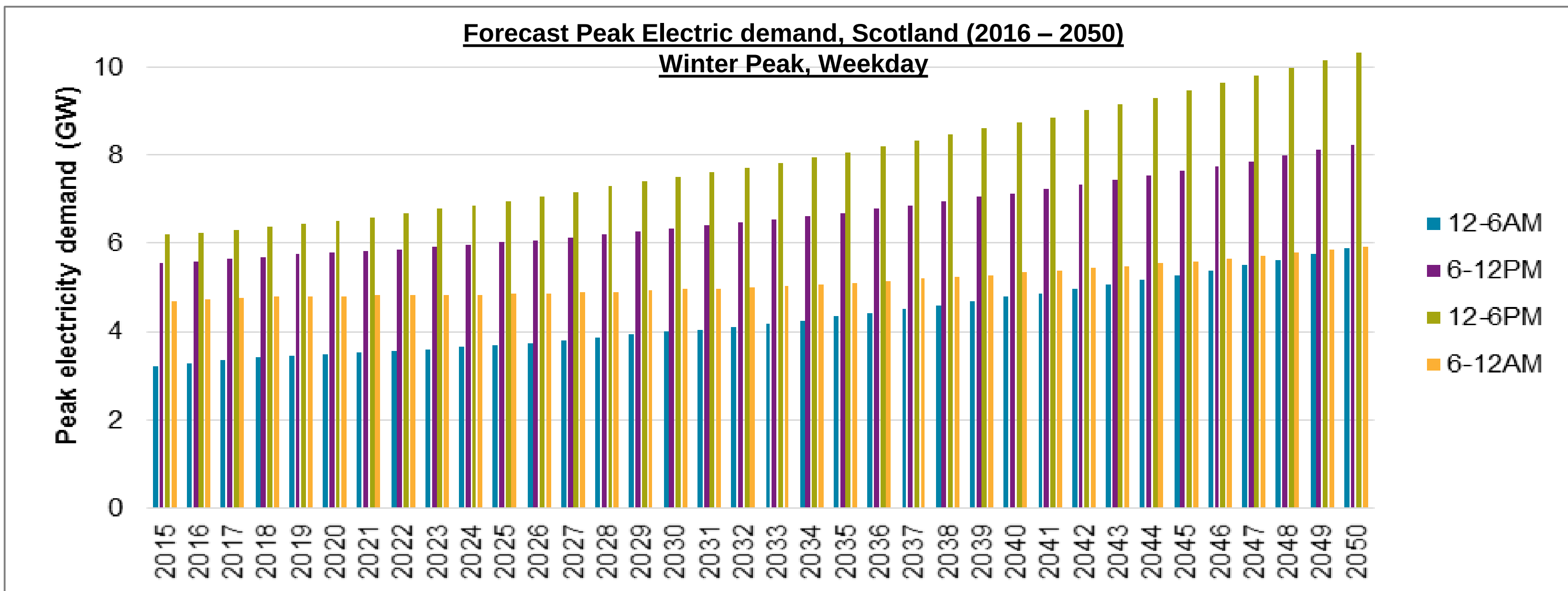
Overview:

- By 2050, peak electricity demand in Scotland on a peak winter weekday is estimated to exceed 10 GW depending on the assumption of the increasing uptake of electric-based heating technologies such as heat pumps especially in the residential and commercial sector. This is an 66% increase of 4 GW from a base case (current) of 6 GW peak electricity demand.
- With the displacement of electric heaters for heat pumps, the peak in the **12-6 AM** time block reduces in relation to the other peaks. Less electricity is consumed overnight and is reallocated to later time blocks, especially the **12-6 PM** time block (after 4.30 PM in preparation for occupants to come back from work / school; and while commercial and industrial sectors are still within working hours).
- The increase in peak demand by 2050 is observed despite district heating schemes being installed to meet 7.4TWh of Scotland's heating demand by 2050 (up from the current 0.3 TWh) and offsetting some individual electric-based central heating, and despite efficiency improvements made e.g. better insulation levels in newbuilds, demolitions of poorly insulated buildings, improvements in industrial process efficiencies, etc.
- **The outputs contained in the report refer to our reference scenario, deemed as the most plausible at the time of writing. It is important to note that there is a high level of uncertainty about future heat policy as well as other factors affecting the heating market. Further scenarios incorporating different assumptions for incentives and regulation; different energy prices; faster or slow technology cost reduction and performance improvement; customer attitudes; and heating industry investment could be run to explore sensitivities.**



Executive summary (2/4)
Electrification of heat Reference scenario – high level description

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Reference scenario:

Below, we provide a short summary of the key factors that shape and influence our reference scenario. Please note that this is one plausible scenario which has not been designed to be a projection or preferred scenario. Rather, the aim of this scenario is to provide insight into one plausible evolution of the sector, and is used to calibrate and test the overall model operation.

Policy and energy prices

'Electrification of heat' ambition remains, but is delayed

- Renewable Heat Incentive reduces gradually in the next few years to 2020, and disappears completely by 2026. However we simulate further incentives by reductions in the electricity price for electric heating.
- New build regulations do not tighten until 2021/22, at which point air-source HPs become the base case in off-gas dwellings.
- Insulation in retrofit is the 'low cost' option that policy makers focus on for savings energy and reducing carbon emissions.
- 2020 renewable and carbon targets are missed or just about met. Commitment to hitting 2050 targets remains, but are only met close to 2050.
- Gas CHP provides annual carbon savings through to 2030 under DECC's central grid decarbonisation trajectory assumptions, after which additional CHP leads to net increase in annual emissions. First time installations of industrial CHP assumed to be near zero after 2030 – mainly replacement market.
- Electricity prices rise at faster rate than gas prices. By 2050, electricity prices on average 28% higher than 2015 prices.

Technology

Slow growth in heat pump and CHP sales results in gradual cost reductions

- Heat pump manufacturer and boiler makers continue to offer HP solutions and gradually add hybrids to their portfolio.
- Fully installed prices still fall quickly in the short term as installer skill improves, but more slowly in the longer term as uptake post 2020 is low.
- Efficiency still gradually improves for heat pumps and CHP due to technology performance improvements coming from Asia / Germany, and as system design, insulation levels of buildings and lower temperature heat distribution systems become more common.
- Industrial HP technology advancement to handle medium temperature process heat by 2040.

Customers and installers

Customer awareness for low carbon heating remains low initially, with installers continuing to focus on conventional heating systems for some time

- No real change in customer awareness and attitude until 2020 at which point building regulations help drive the awareness and trust in heat pump technology.
- Customer confidence for 'low carbon' remains low following a sharp reduction in FiT for PV and a small reduction in the RHI in 2016.
- Installers and heating industry remain cautious about investment in training to install heat pump and CHP technologies, and continue to focus on offering conventional heating systems until 2020 - 2025.

Industry 'push'

Appliance manufacturers and energy suppliers slow to invest in the low carbon heating market

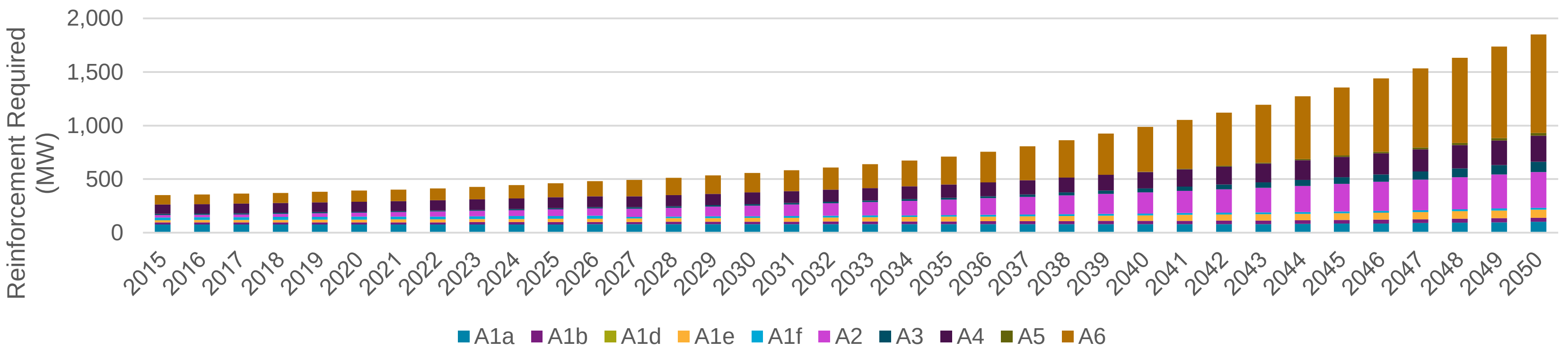
- Conventional heating manufacturers don't invest in upskilling installers and driving heat pump sales for several years.
- Heat pump manufacturers continue to introduce more products to the UK, but are more cautious about the opportunity in the UK market following revisions in the RHI.
- Energy suppliers invest in innovative heat business models such as selling heat-as-a-service. Electricity suppliers introduce heat pump electricity tariffs post 2030 to help stimulate uptake of HPs.

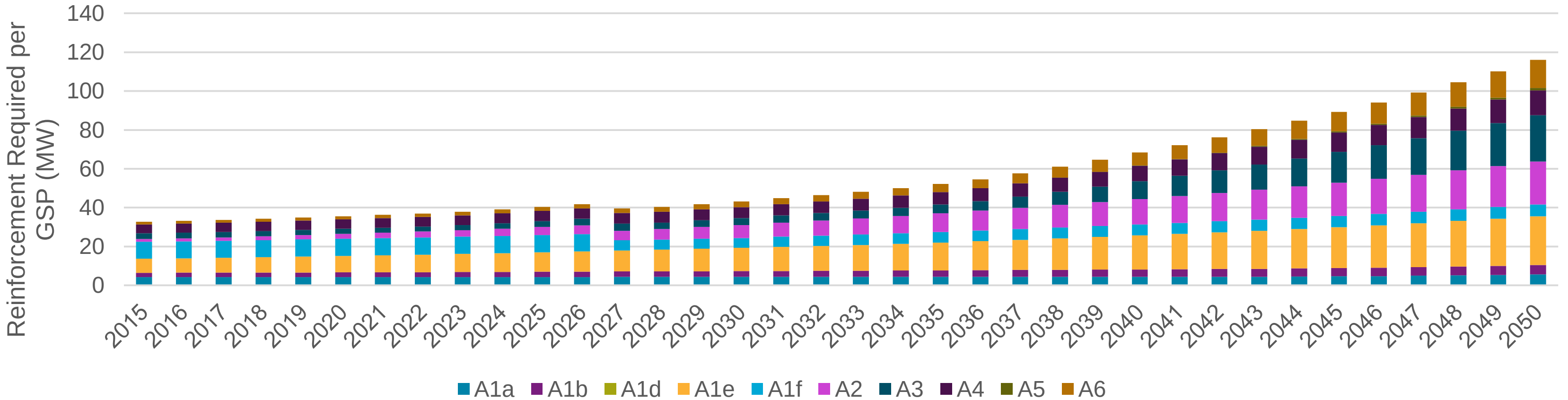
Smarter Grid Solution's Electricity Network Capacity model is divided into 11 zones [A1a – A6) in order to align the model with the Transmission Dispatch model currently used by the Scottish Government. See slide 94 on how the National Grid ETYS Transmission System Boundaries (B0 –B6) align with the A1a – A6 regions.

Executive summary (3/4)
Reinforcement requirements per region

Overview:

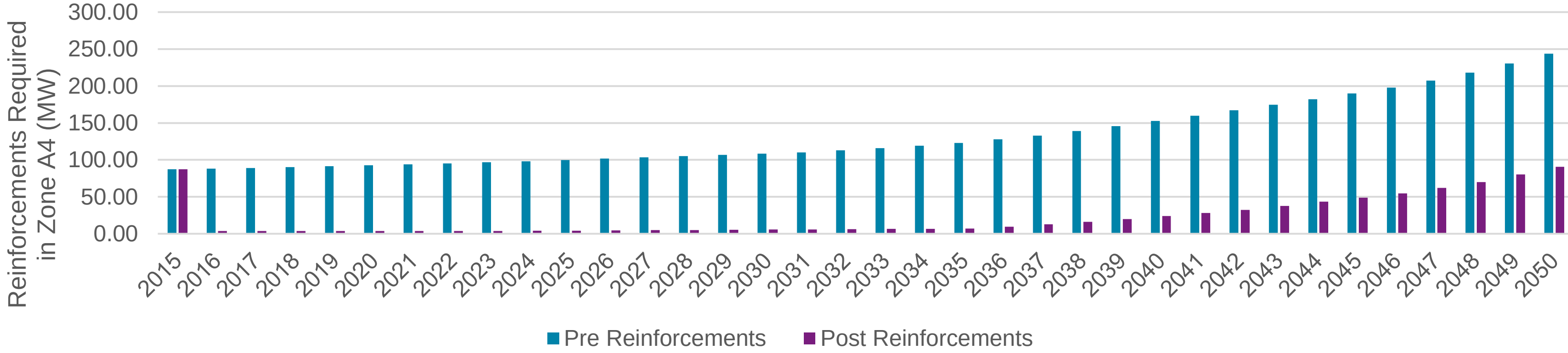
- By 2050 and based on the loads provided by Delta-ee reference scenario, there will be substantial reinforcements required across Scotland as a result of increase in electrical heat demand.
- From 2035 onwards, the rate of change in number of reinforcements required increases significantly. This may be counteracted in part by increase in the use of storage technology and growth in distributed generation. Failing that, it is prudent that DNOs consider significant network upgrades within the next price control period (RIIO-ED2) to cope with this significant increase in electrical heating demand.
- Of all the regions, A6 has the biggest increase in reinforcement overall (see slide 94 for breakdown of regions).
- A1e and A1f have the greatest reinforcement required per GSP – These zones cover Skye and Harris. The reinforcements are greatest here because the network is composed of either single transformer GSPs, or GSPs with relatively small N-1 capacity. With increasing demand in the area, this will lead to significant reinforcement requirements. The thermal limits of the subsea cables which link these GSPs to the mainland will also play a limiting factor on future increases in demand or generation.





Executive Summary (4/4)
Reinforcement costs and options

Overview:
- Using the A4 network region as an example, the potential reinforcement costs and options are shown below.



Type	Reinforcement Option	GSP to apply reinforcement to	Additional Capacity	Cost	Enabler Costs	Year Applied	New N (MW)	New N-1 (MW)
Conventional	New Transformer – Ground Mounted	Dunbeath	80%	£ 519,600.00		2016	27.00	13.50
Conventional	New Transformer – Ground Mounted	Sloy	80%	£ 519,600.00		2016	180.00	90.00
Conventional	Minor Reinforcement Works	Rannoch	100%	£ 623,520.00		2016	140.00	80.00
Conventional	New Transformer – Pole Mounted	St Fillans	80%	£ 5,800.00		2016	27.00	13.50
Conventional	Major Reinforcement works	Milton of Craigie	500%	£ 2,598,000.00		2016	720.00	360.00
Smart	Active Network Management - Dynamic Network Reconfiguration	Abernethy	10%	£ 53,553.00	£ 34,264.00	2032	132.00	66.00
Smart	RTTR (For Tx)	Lyndhurst	10%	£ 3,000.00	£ 5,711.00	2037	132.00	66.00

LV Upgrades (Applies only to conventional upgrades)

No of Conventional GSPs upgrades	5
Upgrades to 11kV Transformers per GSP	£ 22,344
Cable upgrades per GSP	£ 15,167,565
Total Cost of LV Upgrades	£ 75,949,545

Total Cost of 33kV Upgrades	£ 4,363,048
Cost of Wider Reinforcement	£ 75,949,545
Total cost of reinforcement	**£ 80,312,593**

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Introduction to Delta-ee's electric heating demand model (1/2)

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Overview:

We have calculated electric heating demands (and in the case of CHP, production) across four time blocks on an average peak winter weekday based on Delta-ee's reference scenario of technology deployment up to 2050, and detailed knowledge of technology performance variations with ambient temperature. The key output of this exercise is the aggregated winter peak load profiles segmented by end-user type, year, and region (B0-B6 as per the GB Transmission System Boundaries, ETYS zones). The outputs of Delta-ee's electric heating demand model are directly fed into Smarter Grid Solution's electricity network capacity model (described in slide 10 and from slide 83 onwards).

Excel spreadsheet tool – v1

Drop-down menu

- **END-USER** – Residential / Commercial / Industrial
- **YEAR** – 2015 – 2050
- **REGION** – Zone B0 – B6

		Peak Load profile				Peak Load profile			
Technology	**Technology uptake**	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM
ASHP	N	kW	kW	kW	kW				
GSHP	N	.	.	.	.				
Electric heaters	N	.	.	.	.				
Hybrids	N	.	.	.	.	N x kW			
Micro-CHP	N	.	.	.	.				
Fuel Cell (CHP)	N	kW	kW	kW	kW				
						Column total = MW additional electric heating demand per year, for region			

The v1 model does not cover diversity / co-incidence factors – e.g. what proportion of ASHPs will be operating at the same in a particular time block? Will these be at the same time as when the Micro-CHP runs? For now, all the peaks are additive.

DesignBuilder SOFTWARE

Inputs into technology uptake forecast = building stock, on/off-gas, technology payback periods, technology operational performance, energy prices, policy incentives, building regulations, technical fit, soft factors (e.g. customer awareness, installer attitude, etc.), suitable applications (space heating, hot water, process heat), etc.

Inputs into peak load profile = building physics modelling and process heating demand simulations to build thermal and spatial properties of different building / industrial types, and simulate the operation of different heating systems at different outdoor temperatures.

Introduction to Delta-ee electric heating demand model (2/2)
Configurable assumptions by users

1

DISTRICT HEATING

Drop-down menu

REGIONS		2015	2016-2020	2021-2030	2031-2040	2041-2050
	Residential	%	%	%	%	%
	Commercial	%	%	%	%	%
	Industrial	%	%	%	%	%

Zone B0 – B6

Impact on peak electric heat demand forecasts

– District heating can offset electric heating. Therefore if % on DH is increased, there is a further reduction in electric heating demand

If a DH scheme is assumed to be fuelled by electric-based heating systems such as large HPs, SGS will take account of this in their electricity network capacity model.

2

BUILDING STOCK THERMAL DEMAND EFFICIENCY IMPROVEMENTS

Drop-down menu

YEAR	% Efficiency improvements due to NEWBUILDS	% Efficiency improvements due to RENNOVATIONS	% Efficiency improvements due to DEMOLITIONS	=	% NET Reduction in thermal demand from buildings

2015 - 2050

Impact on peak electric heat demand forecasts

– If NET % is increased, reduction in electric heating demand

3

PEAK SHAVING SOLUTIONS AND LOAD SHAPE ALTERING MECHANISMS
(thermal storage, demand response, time-of-use tariffs)

Drop-down menu

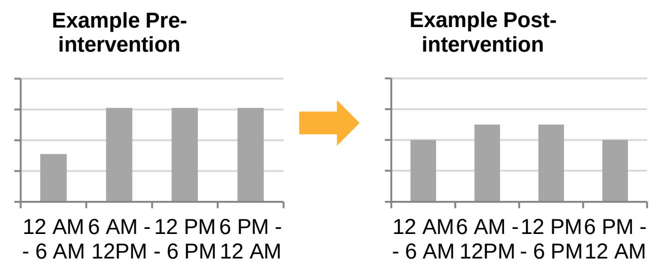
YEAR BANDS	Technology	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM
	ASHP	%	%	%	%
	GSHP	%	%	%	%
	Electric heaters	%	%	%	%
	Hybrids	%	%	%	%
	Micro-CHP	%	%	%	%
	Fuel Cell (CHP)	%	%	%	%

2016 – 2020 / 2021 – 2030 / ..

Describes the reduction in peak demand for each time period. For example, if user believes that peak shaving solutions (e.g. thermal storage) will be able to reduce peak electric heating demand in certain time blocks by X% - cells can be changed.

Impact on peak electric heat demand forecasts

– / +

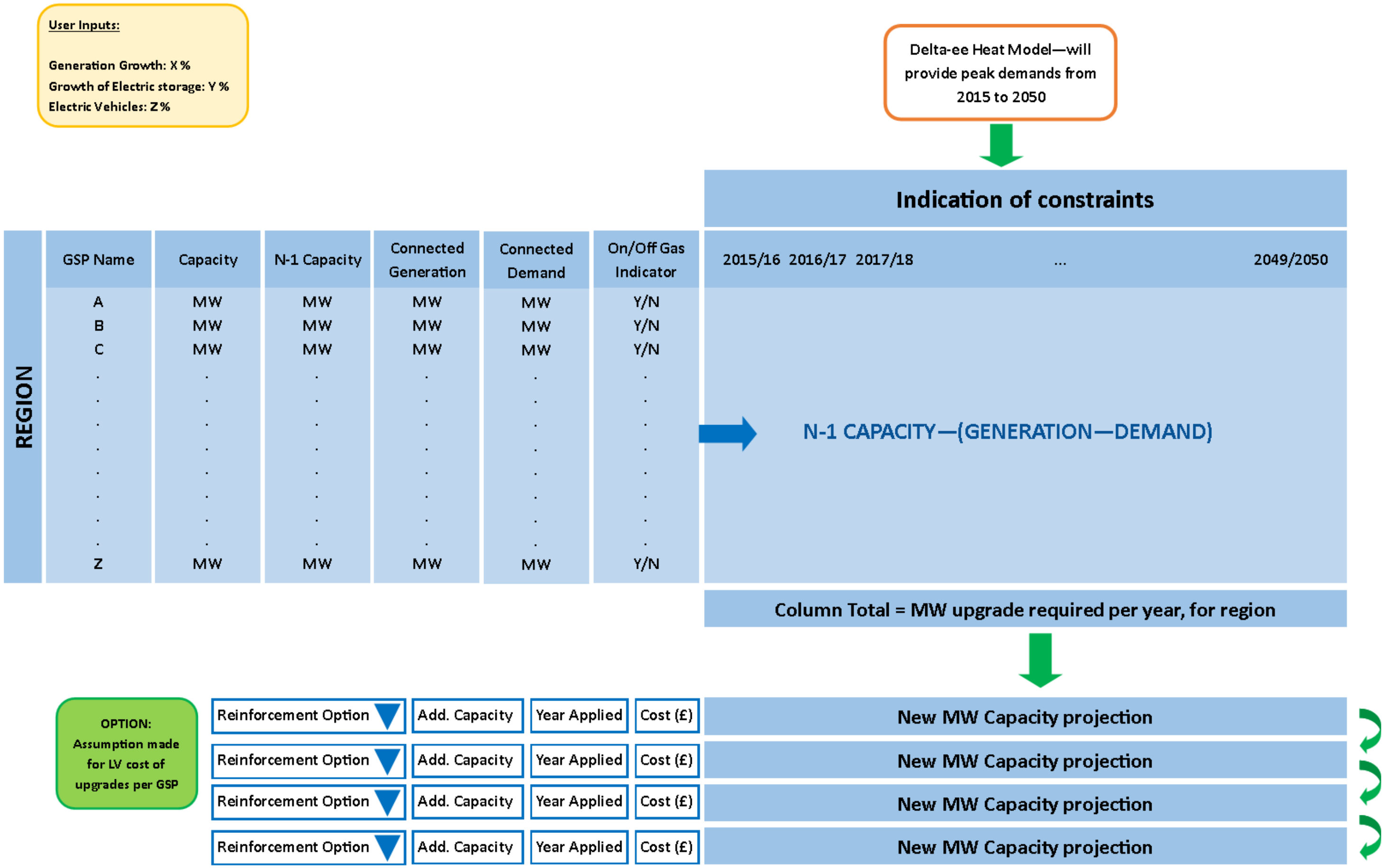


Introduction to Smarter Grid Solution's electricity network capacity model

smarter grid solutions

Overview:

The model is constructed using publicly available information from Long Term Development Statements (LTDS) for the network elements, and the published TRANSFORM data on network reinforcements. This model will take the peak demands from the Delta-ee model and project this on to the network model. The key output of this part of the model will be the identification of future network constraints, and the cost of potential reinforcements to relieve these constraints. The model focuses on 33kV level information with assumptions made with regard to 11kV and LV level upgrades.



Final model deliverable – merged Delta-ee and SGS model
Additional potential functionality of model

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Both Delta-ee and SGS' models are merged to form the main deliverable of this project (with an accompanying user manual).

Electric heating demand model + ***Electricity network capacity model*** = ***Electrification of Heat and Electricity Network Capacity Model: Scotland***

RECOMMENDATIONS FOR FUTURE RESEARCH AND REVISIONS TO MODEL

Whilst this model captures network characteristics relevant and appropriate to the objective of assessing network capacity and cost implications of electrical heating, there is a limit to what is practical within the scope of this project and the information made available. It is not possible to capture the complexity of a large power system accurately through a high level electrical modelling approach of the type implemented in the Scotland Electricity Network Capacity Modelling tool.

Topics discussed in the report, but not explicitly modelled include:

- Demand profiles of other commercial premises (universities, schools, hotels, restaurants, etc.) due to varied peak demand behaviour.
- Detailed time-series of hourly demand for every GSP in Scotland for e.g. the past three years (having chosen a representative "winter peak day") to form geographic-specific electricity demand baseline.
- Thermal storage, demand response, and dynamic time-of-use tariffs.
- Thermal loading in circuits (the model is based on substation capacity).
- Detailed voltage issues (the model addresses electricity flow capacity rather than related system voltage issues).
- Voltage capacity and limits of circuits and transformers (related to point above but with further technical issues related to technical voltage limitations of equipment).
- Details of low voltage transformers and circuits (i.e. anything below 11kV).

Future revisions to the model could be created to provide the following calculations:

- **Half-hourly or hourly time bands to understand peak electric heating demand. By using 4 broad time bands, we are unable to model diversity factors which would lower total estimated peak demand.**
- Greater granularity on spatial distribution of residential, commercial, and industrial sites across Scotland (permission to gain full access of the Scotland Heat Map and Scottish Assessors data).
- Linking of policy, energy price, soft factors, etc. variables directly to the technology uptake column in Delta-ee's electric heating demand model. This allows the user of the tool to automatically change technology uptake forecasts as and when changes happen.
- Details of substation constraints at LV level should appropriate network data be obtained.
- Details of circuit constraints based on existing detailed power system analysis techniques.
- Costs for LV network upgrades, as provided in the published TRANSFORM model data.

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Residential Heating technologies

Forecast uptake and assumptions behind reference scenario

Note: The forecasts refer to annual heating technology sales (not accumulated installed base of heating technologies). This includes sales of electric-based technologies directly replacing electric-based technologies in the existing building stock.

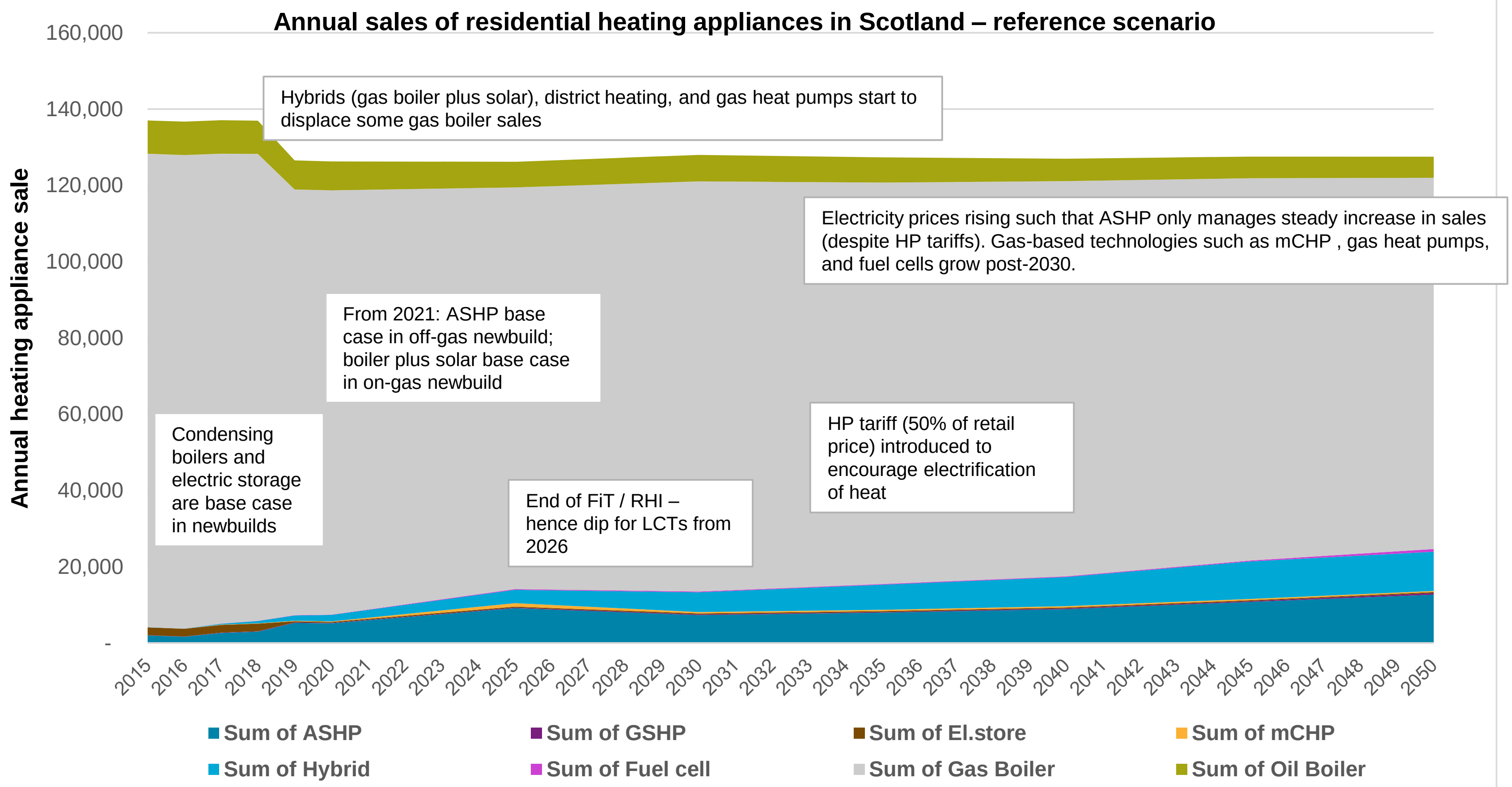
In the model - when estimating the impact heating technology uptake will have on peak electric heating demand out to 2050, we only consider technologies installed that are adding additional load demand (e.g. first time installations in newbuilds, replacement of a non-electric-based heating technology with an electric-based heating technology, etc.).

Forecast for annual sales of residential heating appliances (1/2)

Delta-ee view:

Below, we show the reference scenario for uptake of:

- Electric-based heating appliances such as air source heat pumps (ASHP), ground source heat pumps (GSHP), electric heaters, hybrids (condensing boiler plus heat pumps);
- Low carbon gas-based appliances such as micro-CHP (internal or Stirling engine) and fuel cell micro-CHP.
- Counterfactuals to the above such as gas and oil boilers and electric heating.



Forecast for annual sales of residential heating appliances (2/2)

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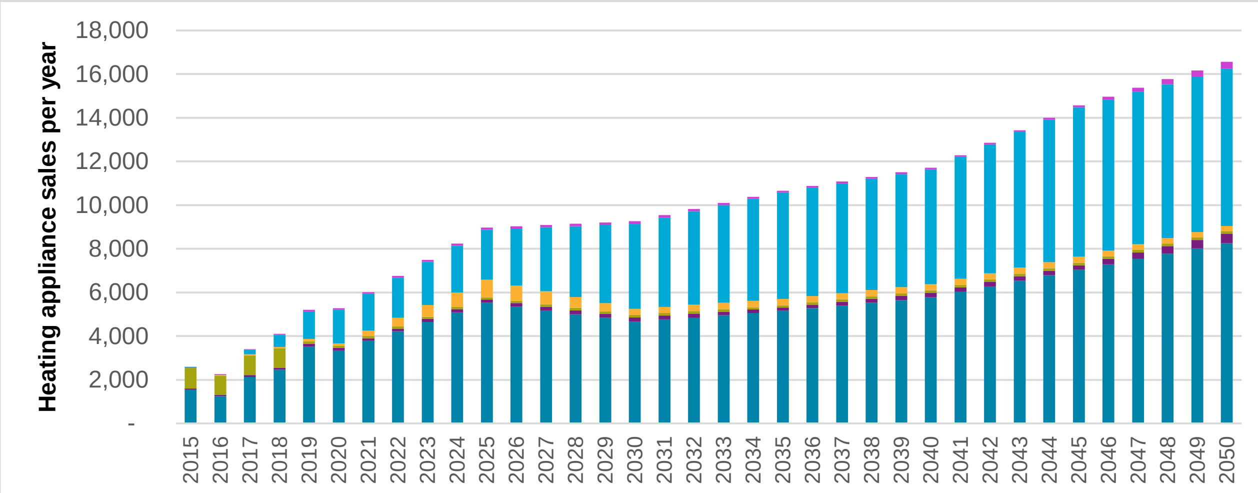
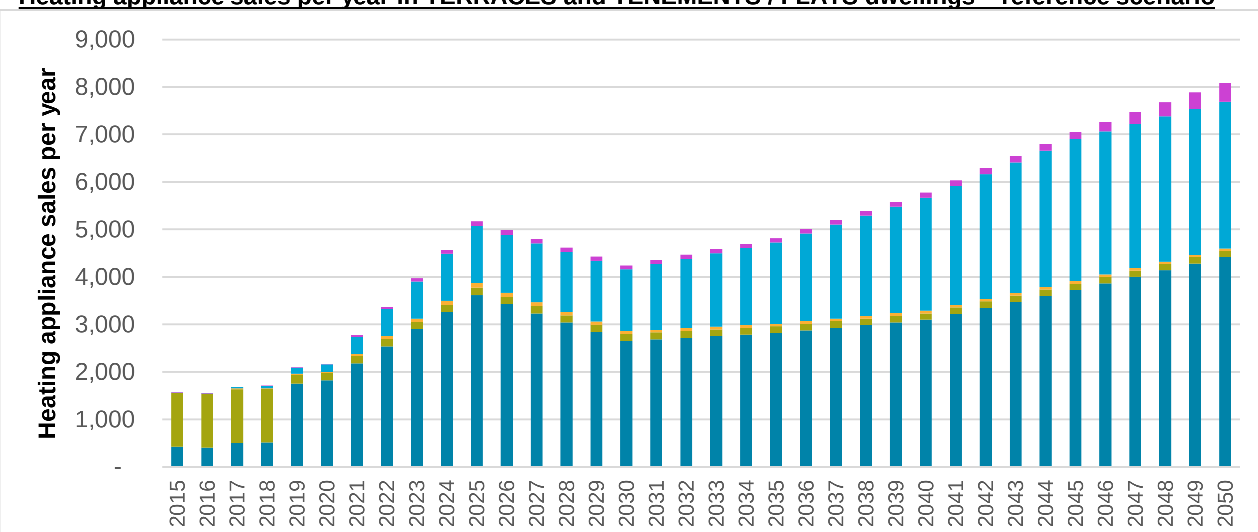
Heating appliance sales per year in DETACHED and SEMI-DETACHED dwellings – reference scenario



Heating appliance sales per year in TERRACES and TENEMENTS / FLATS dwellings – reference scenario



FUEL CELLS

- Strong potential for cost reduction post-2025 as global fuel cell market helps drive installed costs down in the UK – greater uptake nearer to 2050.

HYBRIDS

- Hybrids are a low cost alternative to boilers, having the lowest additional costs of competing technologies. Biggest opportunity for hybrids will be in smaller on-gas segments.

MICRO-CHP

- mCHP performs best in larger thermal demand properties - where it generates more electricity and its payback becomes more competitive with hybrids and ASHPs. In smaller properties, it struggles to compete due to longer paybacks.

ELECTRIC HEATERS

- Electric heater annual sales significantly displaced by ASHPs and some district heating.

GSHP

- Due to space constraints, GSHPs have higher penetration in larger property types only.

ASHP

- With the introduction of the RHI, ASHPs will generate additional revenue for customers of £100s per year. This reduces payback periods for off-gas segments to 5 – 10 years in 2015, raising the appeal of ASHPs. HP tariff from 2026 propels ASHP sales even further.

High level breakdown of the Scottish housing stock used within Delta-ee’s housing stock model

Overview of the housing stock segmentation for Scotland

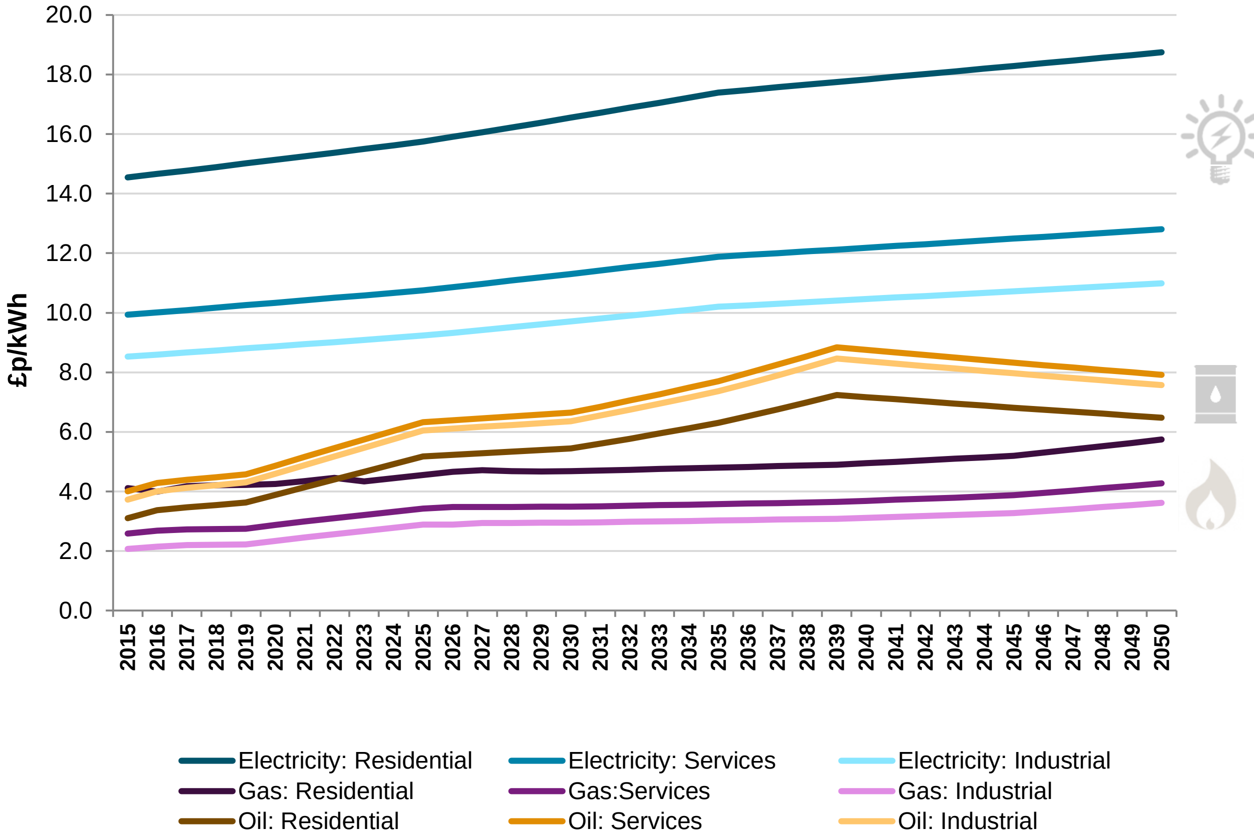
- We have segmented the Scottish housing stock by the **property type** (we have excluded caravans and temporary dwellings) and by central heating **fuel type** for each of the seven regions.
- Overall, Scotland has the following breakdown of property types: 22% Detached; 23% Semi-Detached; 19% Terraced; and 37% Tenements/ Flats. There is a high proportion of tenements in the B6 region which consists of high-density urban areas such as Edinburgh and Glasgow.
- Most of Scotland’s housing stock is on-gas properties [74% gas-based central heating; 13% electric; 6% oil; and 7% using other fuel types]. However, the B0 region which consists of Orkney Islands and a part of the Highlands differs from this national average [electric, oil, and other non-gas fuel types make up 71% of central heating system types in B0].

	DETACHED	SEMI-DETACHED	TERRACED	TENEMENTS / FLATS	Gas	Elec.	Oil	Others
B0	~ 27,400 Properties	~ 16,900 Properties	~ 8,800 Properties	~ 7,400 Properties	29%	27%	27%	17%
B1	~ 36,100 Properties	~ 23,700 Properties	~ 13,200 Properties	~ 9,900 Properties	46%	19%	22%	13%
B2	~ 69,800 Properties	~ 57,700 Properties	~ 31,900 Properties	~ 68,600 Properties	64%	15%	13%	8%
B3	~ 14,300 Properties	~ 8,600 Properties	~ 5,100 Properties	~ 11,900 Properties	44%	27%	14%	15%
B4	~ 74,000 Properties	~ 71,400 Properties	~ 46,800 Properties	~ 97,300 Properties	70%	17%	6%	7%
B5	~ 66,100 Properties	~ 78,600 Properties	~ 63,200 Properties	~ 89,000 Properties	86%	8%	2%	4%
B6	~ 223,800 Properties	~ 278,800 Properties	~ 269,600 Properties	~ 578,000 Properties	79%	12%	3%	6%

(house icon) = 10,000 properties

Energy prices – current prices and high level view on change in prices to 2050

Scotland retail energy prices (£p / kWh)



Notes:

- *The forecast above is based on a combination of DECC reference scenario and Delta-ee analysis.*
- *Residential prices include VAT. This is at the reduced rate (5%) for heating fuels.*
- *Industry and services prices do not include VAT.*
- *Oil prices include petroleum duties.*
- *Other non-residential fuels include the climate change levy. Industrial prices allow for the average impact of Climate Change Agreement (CCA) rebates and Good Quality Combined Heat and Power (GQCHP) exemptions.*

Factors influencing forecast:

Electricity:

- Electricity prices may rise steadily to 2025 due to a number of factors [one aspect is green subsidies (supporting PV and wind uptake) which are paid for via increased taxes on electricity bills].
- As coal plants come offline in the second half of the decade, it is possible that less efficient gas plants that have recently been mothballed could come back online. This will put more upward pressure on electricity prices.
- So will the extra payments supporting the EMR (Electricity Market Reform) – and new 'Contracts for Differences' which provide guaranteed revenue for low carbon generators; and the 'Capacity Market' which supports investment in peak generation and demand response.
- The recent oil price reduction might slow the rate of this rise, but prices will continue to grow.
- Electrification of heat and grid upgrades places steady upward pressure on prices post-2030.

Oil:

- By 2050, oil prices to have doubled from current levels and then fall as demand reduces, geo-political disruptions to supply occur, and exploration efforts decline due to low oil prices between 2014-2025.

Gas:

- Europe is currently awash with gas supply.
- As demand for gas across Europe gradually increases, we are likely to see a slight upward pressure on prices post-2025. However, demand growth is partly offset by building supply, with possible new LNG and shale gas developments at the end of the decade.
- Post-2030 grid upgrades to support green gas and a hydrogen economy might push gas prices up.

Fully installed costs of residential heating technologies: current & future

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Definition of fully installed costs:
Includes the heating appliance, any auxiliary equipment, and labour (installation) costs. This is the final amount that the average customer pays for an installed system. All prices below are expressed in GBP (£). Subsidies are not included. The (possible) rise in VAT for low carbon technologies from 5% to 20% is not reflected in the table below – this is because we have assumed that this is absorbed by manufacturers or installers (which will incur shrinking margins) and not passed on to the final customer.

Fully installed cost for **conventional** heating systems **(boilers)**

Prices include the cost of a chimney & a hot water storage tank	2015	2020	2025	2030	2050
Non condensing gas boiler (30kW)	2,650	No longer allowed	No longer allowed	No longer allowed	No longer allowed
Condensing gas boiler (30kW)	2,650	2,650	2,650	2,650	2,650
Non-condensing oil boiler	3,100	No longer allowed	No longer allowed	No longer allowed	No longer allowed
Condensing oil boiler	3,100	3,100	3,100	3,100	3,100
The above prices include the cost & installation of e.g. radiators, cylinders, a hot water storage tank , etc.	*1,000 – 1,500*	*1,000 – 1,500*	*1,000 – 1,500*	*1,000 – 1,500*	*1,000 – 1,500*

Fully installed costs for **conventiona**l **electric heaters**

Values are in £ / year	2015	2020	2025	2030	2050
Electric storage heaters	3,150	3,150	3,150	3,150	3,150

Fully installed cost for <u>**electrically**</u> **driven heat pumps &** <u>**gas**</u> **driven heat pumps**

Values are in £ / year	2015	2020	2025	2030	2050
ASHP monoblock (air – water) (8 – 10 kW)	9,500	8,250	7,000	6,000	5,000
ASHP split (air – water) (8 – 10 kW)	8,520	7,375	6000	5,000	4,500
GSHP Borehole (14 – 16 kW)	14,333	13,916	13,500	12,500	11,500
GSHP Trench (14 – 16 kW)	12,833	12,416	12,000	11,000	10,000
Gas driven heat pump (8 – 10 kW)	10,000	9,000	7,500	6,500	5,500

Fully installed cost for **hybrid heat pumps ('boiler plus ASHP')**

Values are in £ / year	2015	2020	2025	2030	2050
Hybrid heat pump gas boiler high capacity (8kW ASHP plus ~20 kW boiler)	8,166	7,333	6,500	5,800	5,000
Hybrid heat pump gas boiler low capacity (4kW ASHP plus ~20 kW boiler)	5,857	5,500	4,500	4,000	3,500
Hybrid heat pump oil boiler high capacity (8kW ASHP plus ~20 kW boiler)	14,666	13,833	13,000	12,000	11,000
Hybrid heat pump oil boiler low capacity (4kW ASHP plus ~20 kW boiler)	7,000	6,375	5,750	5,000	4,500

Fully installed cost for **micro CHP (engine based and fuel cell)**

Values are in £ / year	2015	2020	2025	2030	2050
Micro-CHP – gas, Stirling engine (1 kWe)	10,083	7,791	5,500	5,000	4,800
Micro-CHP – gas, internal combustion engine (1 kWe)	12,000	8,750	5,500	5,000	4,800
Fuel cell, PEM (Proton exchange membrane) (1 kWe)	18,000	13,000	8,000	7,000	6,000

GSHPs will typically be installed in larger dwellings (e.g. detached properties) with higher thermal demands and space for ground loops, and therefore we display a larger thermal capacity system in the table above. For ASHPs, we believe these will typically be installed in mid – smaller thermal demand properties and therefore use smaller capacity systems. Note – for both systems, we scale the size of the system (and therefore the installed price) up and down depending on the thermal demand of the dwelling it is being installed in.

Annual maintenance costs of residential heating technologies: current & future

Definition of annual maintenance costs:
Includes the annual (labour) maintenance of the heating system and auxiliary equipment, replacement of parts under warranty, etc. This does not include other operational costs such as fuel prices. All prices below are expressed in GBP (£). Subsidies are not included.

Typical maintenance costs for **conventional** heating systems **(boilers)**

Values are in £ / year	2015	2020	2025	2030	2050
Non condensing gas boiler (30kW)	75	75	75	75	75
Condensing gas boiler (30kW)	75	75	75	75	75
Non-condensing oil boiler	100	100	100	100	100
Condensing oil boiler	100	100	100	100	100

Typical maintenance costs for **conventiona**l **electric heaters**

Values are in £ / year	2015	2020	2025	2030	2050
Electric storage heaters	25	25	25	25	25

Typical maintenance costs for **electrically driven heat pumps & gas driven heat pumps**

Values are in £ / year	2015	2020	2025	2030	2050
ASHP monoblock (air – water) (8 – 10 kW)	71	60	50	50	50
ASHP split (air – water) (8 – 10 kW)	92	71	50	50	50
GSHP Borehole (14 – 16 kW)	96	85	75	75	75
GSHP Trench (14 – 16 kW)	96	85	75	75	75
Gas driven heat pump (8 – 10 kW)	150	100	75	60	60

Typical maintenance costs for **hybrid heat pumps (‘boiler plus ASHP’)**

Values are in £ / year	2015	2020	2025	2030	2050
Hybrid heat pump gas boiler high capacity (8kW ASHP plus ~20 kW boiler)	117	96	75	75	75
Hybrid heat pump gas boiler low capacity (4kW ASHP plus ~20 kW boiler)	117	96	75	75	75
Hybrid heat pump oil boiler high capacity (8kW ASHP plus ~20 kW boiler)	138	106	75	75	75
Hybrid heat pump oil boiler low capacity (4kW ASHP plus ~20 kW boiler)	117	96	75	75	75

Typical maintenance costs for **micro CHP (engine based and fuel cell)**

Values are in £ / year	2015	2020	2025	2030	2050
Micro-CHP – gas, Stirling engine (1 kWe)	138	106	75	75	75
Micro-CHP – gas, internal combustion engine (1 kWe)	400	358	300	250	250
Fuel cell, PEM (Proton exchange membrane) (1 kWe)	500	300	200	100	100

Technology performance of residential heating technologies: current & future

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Definition of performance measures:
Thermal and electrical efficiencies are higher heating values (HHV).
'SPF' = seasonal performance factor. This is the average thermal efficiency (COP for heat pumps) achieved by the heating appliance over the course of the year.

SPF for **conventional** heating systems **(boilers)**

Overall thermal efficiency (%)	2015	2020	2025	2030	2050
Non condensing gas boiler (30kW)	75	No longer allowed	No longer allowed	No longer allowed	No longer allowed
Condensing gas boiler (30kW)	84	84	84	86	88
Non-condensing oil boiler	80	No longer allowed	No longer allowed	No longer allowed	No longer allowed
Condensing oil boiler	84	84	84	84	84

SPF for **conventional electric heaters**

Overall thermal efficiency (%)	2015	2020	2025	2030	2050
Electric storage heaters	100	100	100	100	100

SPF for **electrically driven heat pumps & gas driven heat pumps**

SPF for space heating & hot water production	2015	2020	2025	2030	2050
Space heating efficiencies					
ASHP monoblock (8 – 10 kW) [apply the same values to the heat pump part of hybrid heat pumps]	2.93	3.02	3.10	3.20	3.40
ASHP split (8 – 10 kW) [apply the same values to the heat pump part of hybrid heat pumps]	2.74	2.84	2.95	3.05	3.25
GSHP Borehole (14 – 16 kW)	3.25	3.37	3.50	3.60	3.80
GSHP Trench (14 – 16 kW)	3.25	3.37	3.50	3.60	3.80
Gas driven heat pump (8 – 10 kW)	1.25	1.30	1.45	1.55	1.75
Hot water production efficiency					
ASHP monoblock (8 – 10 kW) [apply the same values to the heat pump part of hybrid heat pumps]	2.43	2.51	2.60	2.70	2.80
ASHP split (8 – 10 kW) [apply the same values to the heat pump part of hybrid heat pumps]	2.24	2.34	2.45	2.55	2.65
GSHP Borehole (14 – 16 kW)	2.61	2.66	2.70	2.80	2.90
GSHP Trench (14 – 16 kW)	2.61	2.66	2.70	2.80	2.90
Gas driven heat pump (8 – 10 kW)	1.25	1.30	1.45	1.55	1.75

SPF for **micro CHP (engine based and fuel cell)**

Overall thermal efficiencies and electrical efficiencies (%)	2015	2020	2025	2030	2050
Thermal efficiency					
Micro-CHP – gas, Stirling engine (1 kWe)	75	75	75	73.5	73
Micro-CHP – gas, internal combustion engine (1 kWe)	64	63	62	59	56
Fuel cell, PEM (Proton exchange membrane) (1 kWe)	55	54	52	49	46
Electrical efficiency					
Micro-CHP – gas, Stirling engine (1 kWe)	14	15	16	16	17
Micro-CHP – gas, internal combustion engine (1 kWe)	26	28	30	32	35
Fuel cell, PEM (Proton exchange membrane) (1 kWe)	35	38	40	42	45

Policy incentives for residential heating technologies (FiT, RHI, and export tariff levels): current & future

Definition of policy incentives:

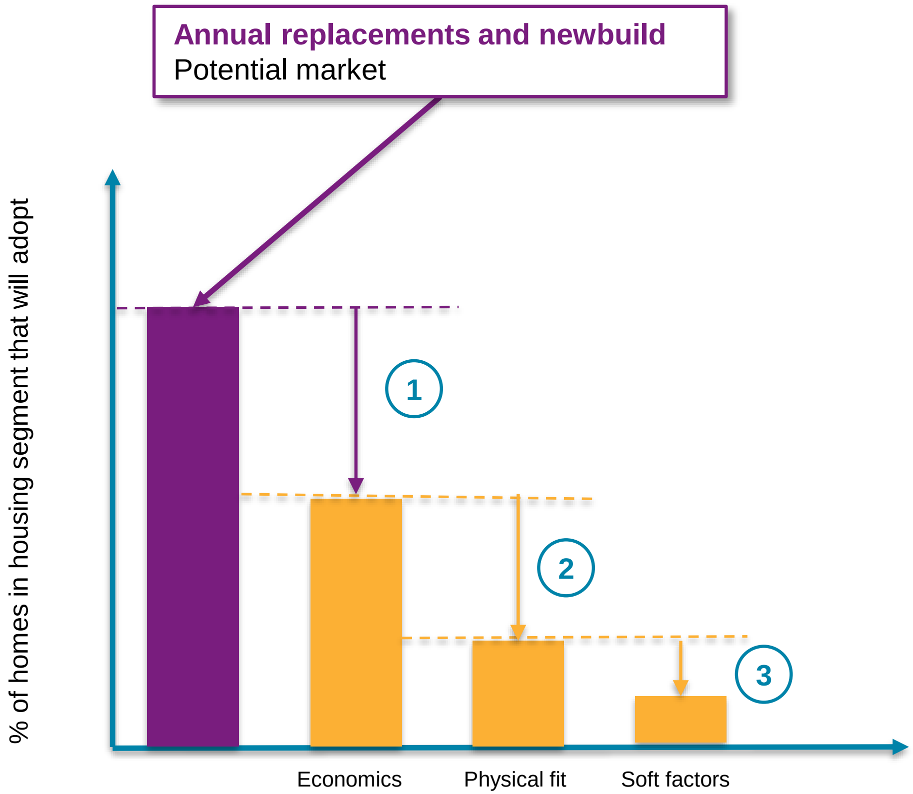
- **Feed-in-Tariff (FiT):** The UK Feed-in Tariff scheme was introduced in 2010 to reward generation and export of PV / small wind / micro-CHP. It rewards generation irrespective of whether the electricity produced is fed onto the grid or not.
- **Export tariff:** The export tariff is a bonus payment for every kWh of surplus electricity a system exports to the electricity grid.
- **Renewable Heat Incentive (RHI):** The UK domestic Renewable Heat Incentive supports renewable household heat, with payments per kWh of renewable heat produced.

Technology	Comments on central scenario assumptions	2015 incentives	2020 incentives	2025 incentives	2030 incentives	2050 incentives
ASHP	Strong government focus on this technology.	RHI: 7.4p / kWh	RHI: 6.5p / kWh	RHI: 5.7p / kWh	HP tariff: Level uncertain. We estimate 50% of retail rate	No longer available
GSHP	Strong government focus on this technology.	RHI: 19.1p / kWh	RHI: 14.7p / kWh	RHI: 11.4p / kWh	HP tariff: Level uncertain. We estimate 50% of retail rate	No longer available
Hybrid	UK government starting to become more confident on this technology – strong support expected.	RHI: 7.4p / kWh for heat pump output	RHI: 6.5p / kWh for heat pump output	RHI: 5.7p / kWh for heat pump output	HP tariff: Level uncertain. We estimate 50% of retail rate	No longer available
Gas heat pump	UK government modelling shows strong economic opportunity – likely to be supported, but level of support uncertain.	Not available	RHI: Level uncertain We estimate 2p / kWh	RHI: Level uncertain We estimate 2p / kWh	Uncertain *(new subsidy mechanism to meet targets?)*	No longer available
Micro CHP	FiT currently available, but little government confidence or support – long term support uncertain & likely to decline after 2020.	FiT: 12.9 p / kWh Export tariff: 4.6 p / kWh	FiT: 12.9 p / kWh Export tariff: 4.6 p / kWh	FiT: 8p / kWh Export tariff: 4.6 p / kWh	Uncertain *(new subsidy mechanism to meet targets?)*	No longer available

Residential customer uptake: Methodology (1/4)

Customer uptake for one technology depends on economics, physical fit and 'soft factors'
If one of these criteria is not appealing, the customer is likely to turn to other technologies and ultimately to 'typical boilers' (gas/electrical/oil/LPG)

CUSTOMER UPTAKE METHODOLOGY – ECONOMICS, PHYSICAL FIT AND SOFT FACTORS



1. **Economics** is used as the first filter – as the primary decision factor for a majority of customers is the cost of technology. If the economics are very poor, only innovators will take up a technology

2. **Physical fit** is used as the second filter as some technologies will be automatically ruled out or have lesser uptake if it is difficult to install

3. **Soft factors** are the final filter – customers' preferences and other factors that impact decision making. Technology aesthetics, time to install, disruption etc.

Residential customer uptake: Methodology (2/4)
Economics: Customer uptake versus payback & upfront cost

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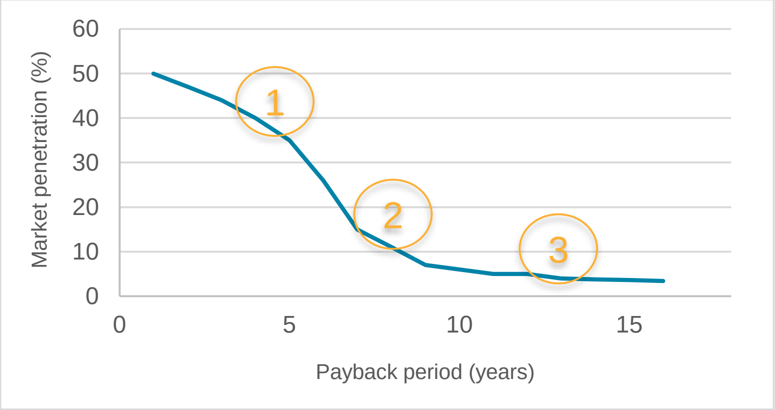
UK customers are most sensitive to upfront costs:

The upfront cost of a new heating system will always be the biggest barrier for customers considering investing in a low carbon heating system. The vast majority of UK customers today want a low cost, easy boiler replacement, and are not willing to pay more than the price of a like-for like replacement boiler. A payback of less than 5 years is expected on 'new' low carbon technologies.

ANTICIPATED MARKET PENETRATION OF LOW CARBON HEATING APPLIANCES VERSUS PAYBACK FOR UK CUSTOMERS

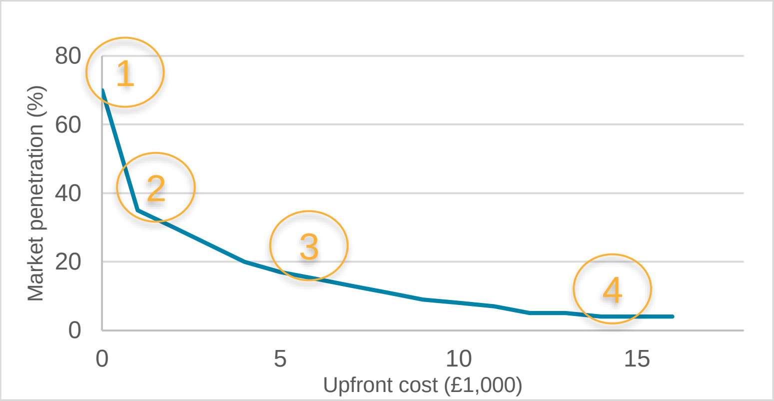


1 – 30-40% of customers state that the payback period must be less than 5 years if there were to consider investing.

2 – The average length of time that a home owner stays in the same property is ~7 years in the UK. Very few people are therefore interested in low carbon technologies with longer payback as they are not thinking that far ahead. A payback of less than 7 years is when customer interest in low carbon technologies begins to grow.

3 – Only 5% of customers would be willing to invest in low carbon heating appliances when the payback period is over 10 years.

ANTICIPATED MARKET PENETRATION OF LOW CARBON HEATING APPLIANCES VERSUS UPFRONT COST FOR UK CUSTOMERS



1 – Customers are cautious and 'fear' new technologies – in the UK there will always be some inertia to moving away from trusted heating technologies. A small proportion of customers will not switch away from their current heating system (even if a more efficient system was offered for free).

2 – 30-40% of UK customers would consider investing in low carbon heating systems if the additional upfront costs are low (<£1,000 more than a boiler). Most customers will continue to opt for a 'typical boiler' if this is the cheapest replacement solution,

3 – Despite ambitions to be 'greener', customers are not willing to pay for it – once the cost of heating system is more than £3,000 – 4,000 more than a boiler, less than 20% of customers will consider investing.

4 – A small proportion of UK customers are willing to pay significant amounts of money to become independent of energy suppliers and to lower their energy bills. An estimated 5% of the market would consider investing in low carbon heating systems with high upfront cost.

Residential customer uptake: Methodology (3/4)
Physical fit: Suitability of different types of heating technologies

	DETACHED	SEMI-DETACHED (individual system)	TERRACED (individual system)	TENEMENTS / FLATS (individual system)
ASHP monoblock	*Perfect*	*Perfect*	*Moderate*	*Ex difficult*
ASHP split	*Perfect*	*Perfect*	*Moderate*	*Ex difficult*
Electric storage heater	*Perfect*	*Perfect*	*Perfect*	*Perfect*
Gas boiler high efficiency	*Perfect*	*Perfect*	*Perfect*	*Perfect*
GSHP Borehole	*Good*	*Difficult*	*Zero*	*Zero*
GSHP Trench	*Difficult*	*Ex difficult*	*Zero*	*Zero*
Hybrid heat pump gas boiler high capacity	*Perfect*	*Good*	*Difficult*	*Ex difficult*
Hybrid heat pump gas boiler low capacity	*Perfect*	*Good*	*Difficult*	*Ex difficult*
Hybrid heat pump oil boiler high capacity	*Perfect*	*Good*	*Difficult*	*Ex difficult*
Hybrid heat pump oil boiler low capacity	*Perfect*	*Good*	*Difficult*	*Ex difficult*
Micro-CHP engine - gas ICE	*Good*	*Good*	*Difficult*	*Zero*
Micro-CHP engine - gas stirling	*Good*	*Good*	*Difficult*	*Zero*
Oil boiler high efficiency	*Perfect*	*Perfect*	*Perfect*	*Perfect*

In the table below, we map on to the **chosen representative house types (pre-selected for this project)** where electric heaters, hybrids, and heat pump technologies are likely to be applicable. Note: Newbuilds can be designed to accommodate certain technologies.

Factors that influence the suitability of different types of heat pumps for different house types:

1. Available **space inside the dwelling** for hot water tanks and internal units.
2. Available **space outside the dwelling** for external units or for ground loops.
3. Availability of **gas connection** – a gas connection is required for hybrid heat pumps with a gas boiler to be deployed.
4. The **density of housing**. Rural vs urban locations can be used as a proxy for the density of housing.

	ASHP	GSHP	Hybrid	Electric
Detached, post-1982, off-gas rural, BC EPC, family, average size 144m²	✓	✓		
Semi-detached, 1945-64, on-gas urban, DE EPC, pensioner couple, average size 90m²	?		✓	
Terraced, 1965-82, on-gas urban, DE EPC, adult couple, average size 84m²	?		?	
Tenement / flat, pre-1919, on-gas urban, DE EPC, adult couple, average size 68m²				✓

Residential customer uptake: Methodology (4/4)
Soft factors: Customer appeal assumptions

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If one of these factors is low, the whole customer appeal will be low.
Within Delta-ee's "technology uptake" forecast tool, customer appeal is different for every technology and the 'typical boilers' have the highest uptake. It is not different from one segment to another.

SOFT FACTORS - METHODOLOGY

1	CUSTOMER FAMILIARITY / TRUST	**Customer familiarity and trust** towards the technology. Have there been horror stories? And what have been the consequences? Is the technology crucial? (e.g. If PV is not working, the property can still be warm and still has electricity – If an ASHP is not working, the house is cold)
2	GOVERNMENT COMMITMENT	**Government commitment** reflects the technologies that are being pushed by the government and the confidence that customers will have in the incentives remaining / being as generous.
3	MARKET PUSH	**Market push** is mostly the role that utilities and suppliers play to create or to push the market for a technology.
4	INSTALLER ATTITUDE	**Installer attitude** is a combination of installer capability of installing the technology and the general product offering (maintenance, servicing, warranties, etc.)
5	CUSTOMER AWARENESS	**Customer awareness** of the technology

KEY NARRATIVE BEHIND REFERENCE SCENARIO (SEE NEXT SLIDE AS WELL ON CUSTOMER AND INSTALLER ATTITUDES)

'Electrification of heat' ambition remains, but is delayed

- Renewable Heat Incentive reduces gradually in the next few years to 2020, and disappears completely by 2026.
- New build regulations do not tighten until 2021/22, at which point ASHPs become the base case in off-gas dwellings.
- Insulation in retrofit is the 'low cost' option that policy makers focus on for savings energy and reducing carbon emissions.
- 2020 renewable energy and carbon targets are missed or just about met. Commitment to hitting 2050 targets remains, but are only met close to 2050.
- Customer confidence in policy / incentives for 'low carbon' remains low following a sharp reduction in FiT for PV and a small reduction in the RHI in 2016.

Appliance manufacturers gradually add new product to their portfolios by 2020, with electricity suppliers getting more active post 2020

- Boiler manufacturers are slow to add new heat pump products to their portfolio (except for Ideal via Atlantic), especially after the poor uptake of hybrid heat pumps experienced in 2014/15.
- Heat pump manufacturers continue to introduce more products to the UK, but are more cautious about the opportunity in the UK market following revisions in the RHI.
- Electricity suppliers introduce heat pump electricity tariffs post 2020 to help stimulate uptake of HPs.

Soft factors: Customer appeal assumptions
Understanding customers and installers

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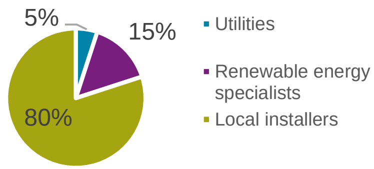
Installers

There are large numbers of very small installation companies

Typically, these companies have 1-4 employees and can be the local plumbers.

NUMBER OF INSTALLATION COMPANIES BY COMPANY TYPE

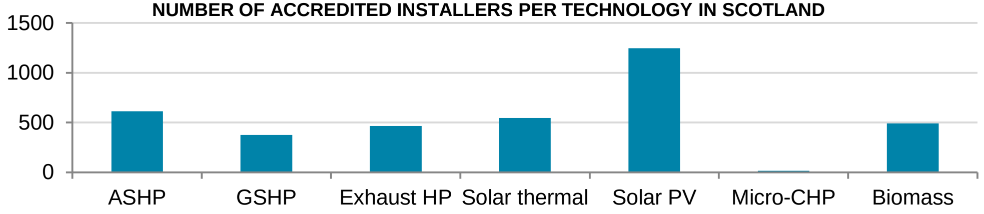


Most Scottish heating installers are 'conservative' when it comes to new technologies

The MCS (Microgeneration Certification Scheme) is a 'quality passport' for installers for low carbon technologies. It ensures that the installer has been trained, and has quality control procedures in place.

- Few installers skilled in technologies other than PV, ASHP and solar thermal.

NUMBER OF ACCREDITED INSTALLERS PER TECHNOLOGY IN SCOTLAND



Key uncertainties

- How quickly will installers get 'trained up' in new technologies
- Once trained in a 'new' technology, how effectively will installers 'upsell' the technology to customers? Or how much will they wait for customers to ask for the technology?

Registered Social Landlords

RSLs represent around 23% of the Scottish existing stock.

Their main driver for installing microgeneration is to reduce the fuel poverty for their tenants. A technology with high cost savings will be favoured.

The key barrier to RSLs is the upfront costs of the technology as they have a limited budget for their stock.

Payback is often not an issue for them as long as it pays back eventually.

Homeowners

Comprising 58% of the Scottish housing stock, most homeowners replace their heating system in two ways:

- *Distressed purchase* – their boiler breaks down, often in winter, and the customer needs to install a new system as quickly as possible
- *Procrastinators* – they know their boiler is close to failure, and eventually replace it.

Most UK homeowners have traditionally had very low awareness of the brand and type of boiler they install – relying on the installer to specify the product. They are very much cost driven. Research has shown that any extra cost above a conventional boiler is a very hard sell, and the vast majority of customers expect any extra investment to payback within 3-5 years.

Key uncertainties

- The proportion of homeowners that make more considered, researched 'investments' in their heating system, and how quickly this grows
- The response of homeowners to installer or other 'recommendations' on a lower carbon technology

Housing developers

Housing developers represent ~60% of the new build stock.

Their main driver for installing microgen is the building regulations: They will do it only if they have to. They will generally select the lowest cost route to meeting the regulations.

Their choice of heating is mostly related to the upfront cost of the technology. They try to build the property as cheap as possible and maximise sales value. Developers can be concerned that aesthetics of microgeneration technologies can negatively affect potential buyers.

Housing developers are generally well aware of the technologies in the market.

Key uncertainties

- Very few – housing developers will focus on the lowest cost, simplest to install technology. They will want to avoid technologies that have complexity / potential for mistakes in installation, and that customers might think complex or unattractive.
- No evidence so far that customers will pay more for a home with an efficient heating system. Unlikely to change significantly.

Commercial Heating technologies

Forecast uptake and assumptions behind reference scenario

Note: The forecasts refer to annual heating technology sales (not accumulated installed base of heating technologies). This includes sales of electric-based technologies directly replacing electric-based technologies in the existing building stock.

In the model - when estimating the impact heating technology uptake will have on peak electric heating demand out to 2050, we only consider technologies installed that are adding additional load demand (e.g. first time installations in newbuilds, replacement of a non-electric-based heating technology with an electric-based heating technology, etc.).

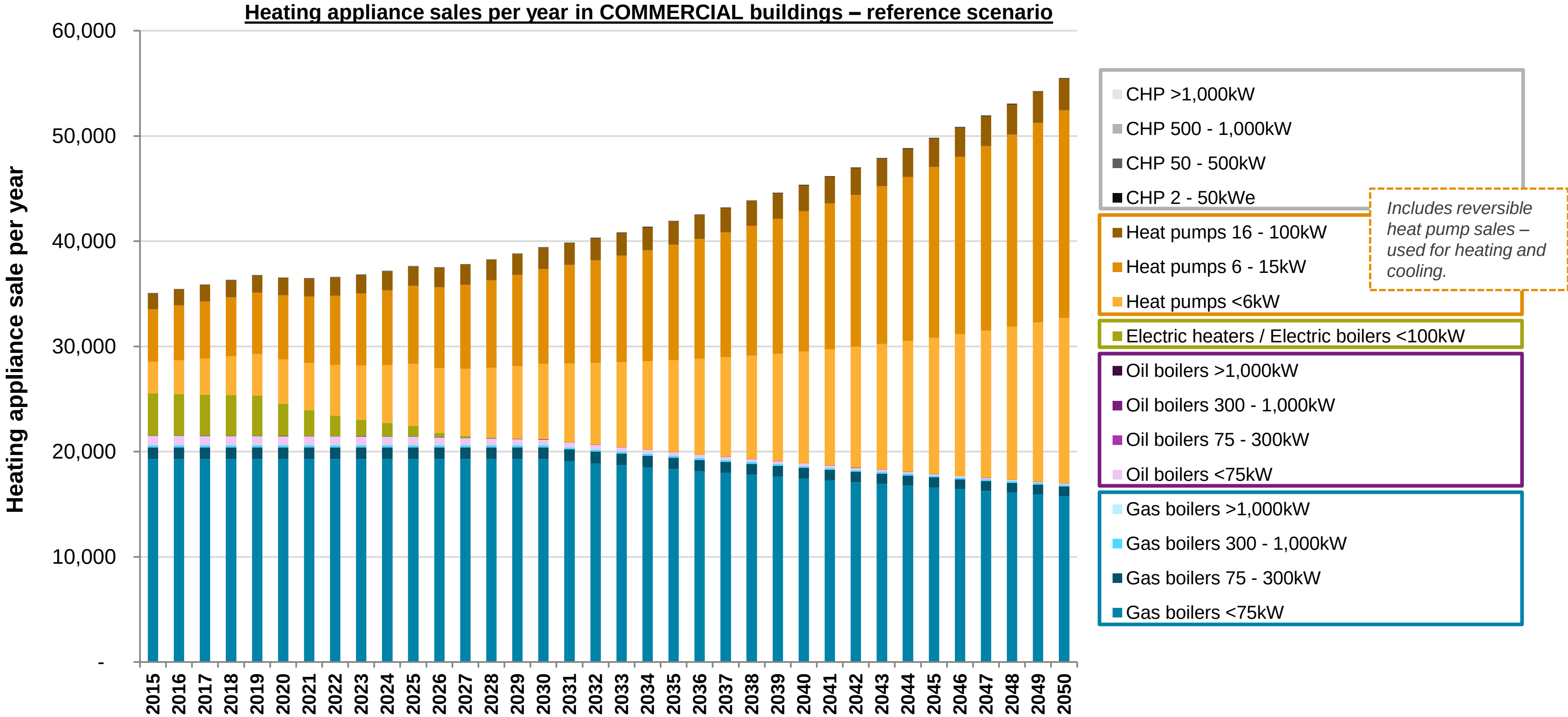
Forecast for annual sales of commercial heating appliances (1/2)

Delta-ee view:

Below, we show the reference scenario for uptake (unit sales) of:

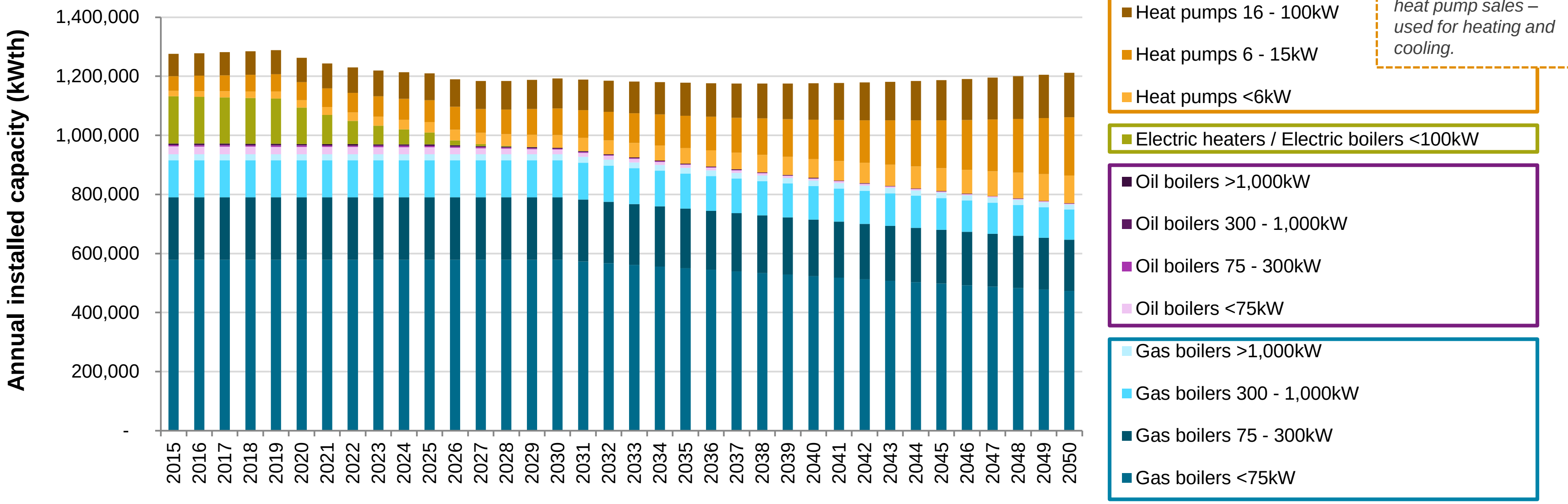
- Electric-based heating appliances such as air source heat pumps, ground source heat pumps (jointly categorised as Heat pumps), electric heaters and electric boilers
- Low carbon gas-based appliances such as CHP (internal combustion engine).
- Counterfactuals to the above such as gas and oil boilers. In many cases in the commercial sector, boilers will still be installed alongside other technologies (rather than a direct counterfactual)

We have **segmented this by heating appliance capacity size as this varies substantially in the commercial sector and multiple-unit installations are common. In the next slide we show how this translates into annual installed capacity (kWth).**

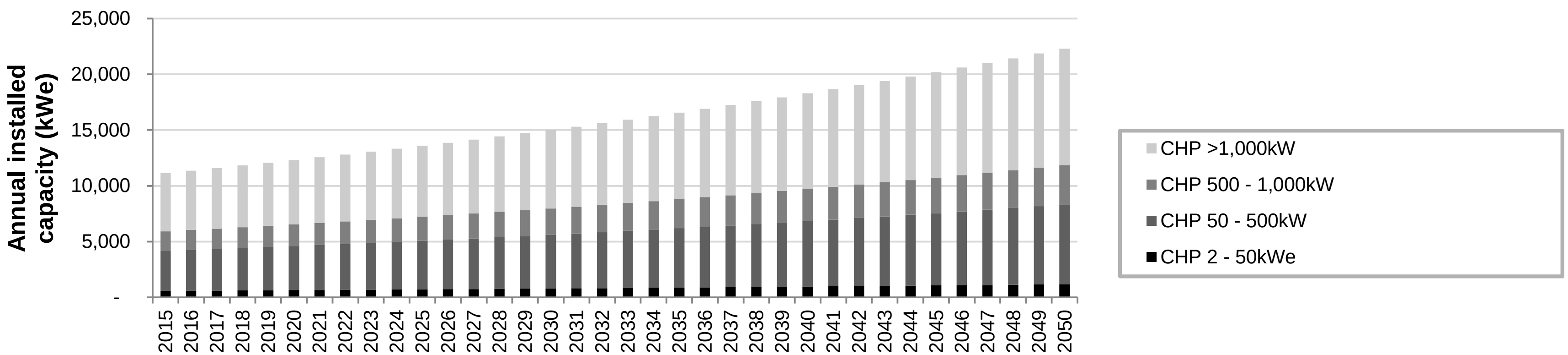


Forecast for annual sales of commercial heating appliances (2/2)

Annual installed *thermal* capacity in COMMERCIAL buildings – reference scenario



Annual installed *electrical* capacity (CHP) in COMMERCIAL buildings – reference scenario



High level breakdown of the Scottish commercial building stock used within Delta-ee's building stock model

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Overview of the commercial stock segmentation for Scotland

- We have segmented the Scottish commercial building stock by the **business type** and by **size of premise (floor area, m²)** for each of the seven regions.
- Overall, we estimate Scotland's total floor area of commercial buildings (~ 87,000,000 m²) is segmented as follows: 35% = hospitals and care facilities; 16% = shops; 12% offices; 36% = others. Hence, for the purpose of this research project, we have chosen to focus our peak load profile modelling on offices, shops, and the healthcare sector.
- Most of Scotland's commercial building stock is urban on-gas properties [>80% gas-based central heating].

Number of commercial premises per region

	OFFICES			SHOPS			HOSPITALS AND CARE FACILTIES			OTHERS		
	< 1,000 m²	1,000 – 10,000 m²	> 10,000m²	< 1,000 m²	1,000 – 10,000 m²	> 10,000m²	< 1,000 m²	1,000 – 10,000 m²	> 10,000m²	< 1,000 m²	1,000 – 10,000 m²	> 10,000m²
B0	972	51	-	1,523	80	-	100	96	2	5,399	671	2
B1	1,121	59	-	1,894	100	-	116	108	3	5,694	725	3
B2	3,698	195	-	4,353	229	-	268	233	119	7,896	1,166	119
B3	570	30	-	1,216	64	-	78	65	1	4,550	562	1
B4	4,115	217	-	6,568	346	-	300	304	83	9,030	1,382	83
B5	3,764	198	-	5,760	303	-	395	245	88	5,400	975	88
B6	23,538	1,239	-	29,222	1,538	-	1,413	1,399	582	26,070	4,840	582

System costs and efficiencies of commercial heating technologies: current & future

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Definition of costs and efficiencies:
Capital expenditure (CAPEX): Includes the heating appliance, any auxiliary equipment, and labour (installation) costs. This is the final amount that the average customer pays for an installed system.
Operating expenditure (OPEX): Includes the annual (labour) maintenance of the heating system and auxiliary equipment, replacement of parts under warranty, etc. This does not include other operational costs such as fuel prices.
All prices below are expressed in GBP (£). Subsidies are not included.
Efficiencies: Thermal and electrical efficiencies are higher heating values (HHV). The seasonal performance factor for heat pumps is the average thermal efficiency achieved by the heating appliance over the course of the year.

CAPEX for heating systems

Values are in £ / MWh	2015	2020	2025	2030	2050
Gas boiler	35.6	35.6	35.6	35.6	35.6
Oil boiler	65.2	65.2	65.2	65.2	65.2
Electric heating	120.9	120.9	120.9	120.9	120.9
ASHP	186.0	176.7	167.9	159.5	143.5
GSHP	299.2	284.2	261.5	238.0	214.2
CHP (internal combustion engine)	150.5	143.1	136.1	129.4	124.4

OPEX for heating systems

Values are in £ / MWh	2015	2020	2025	2030	2050
Gas boiler	2.81	2.81	2.81	2.81	2.81
Oil boiler	2.04	2.04	2.04	2.04	2.04
Electric heating	2.38	2.38	2.38	2.38	2.38
ASHP	0.58	0.55	0.52	0.50	0.45
GSHP	1.18	1.12	1.03	0.94	0.84
CHP (internal combustion engine)	6.15	5.84	5.56	5.28	5.08

Efficiency and seasonal performance factors of heating systems

Overall efficiency (%)	2015	2020	2025	2030	2050
Thermal efficiency					
Gas boiler	92%	92%	92%	92%	92%
Oil boiler	87%	87%	87%	87%	87%
Electric heating	100%	100%	100%	100%	100%
ASHP	240%	250%	260%	270%	280%
GSHP	260%	270%	280%	290%	300%
CHP (internal combustion engine)	50%	50%	50%	50%	50%
Electrical efficiency					
CHP (internal combustion engine)	36%	36%	36%	36%	36%

Policy incentives for commercial heating technologies (ND-RHI and export tariff levels): current & future

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Definition of policy incentives:

- **Non-Domestic Renewable Heat Incentive (RHI):** The UK domestic Renewable Heat Incentive supports renewable non-domestic heat, with payments per kWh of renewable heat produced.
- **Export tariff:** The export tariff is a bonus payment for every kWh of surplus electricity a system exports to the electricity grid.

Technology	Comments on central scenario assumptions	2015 incentives	2020 incentives	2025 incentives	2030 incentives	2050 incentives
ASHP	Strong government focus on this technology.	RHI: 2.54p / kWh	RHI: 2.2p / kWh	RHI: 1.9p / kWh	HP tariff: Level uncertain. We estimate 50% of retail rate	No longer available
GSHP	Strong government focus on this technology.	RHI: 8.84p / kWh (Tier 1); 2.64p / kWh (Tier 2)	RHI: 7.75p / kWh (Tier 1); 2.31p / kWh (Tier 2)	RHI: 6.79p / kWh (Tier 1); 2.02p / kWh (Tier 2)	HP tariff: Level uncertain. We estimate 50% of retail rate	No longer available
Hybrid	UK government starting to become more confident on this technology – strong support expected.	RHI: 2.54p / kWh for heat pump output	RHI: 2.2p / kWh for heat pump output	RHI: 1.9p / kWh for heat pump output	HP tariff: Level uncertain. We estimate 50% of retail rate	No longer available
Gas heat pump	UK government modelling shows strong economic opportunity – likely to be supported, but level of support uncertain.	Not available	RHI: Level uncertain We estimate 1p / kWh	RHI: Level uncertain We estimate 0.9p / kWh	Uncertain *(new subsidy mechanism to meet targets?)*	No longer available
CHP (fossil-fuelled)	RHI, FiT, and CfD (Contracts for Difference) available for biogas and biomass-based CHP. Little government support for fossil-fuelled CHP.	Export tariff: 4.6 p / kWh	Export tariff: 4.6 p / kWh	Export tariff: 4.6 p / kWh	Uncertain *(new subsidy mechanism to meet targets?)*	No longer available

Policy incentives for commercial heating technologies (ECA and CRC): current & future

Definition of policy incentives:

- **Enhanced Capital Allowances:** Companies can write off the cost of qualifying energy-saving new plants or machinery against the business's taxable profits in the financial year the purchase was made.
- **Carbon Reduction Commitment:** is a mandatory carbon emissions reporting and pricing scheme to cover large public and private sector organisations in the UK that use more than 6,000MWh per year of electricity and have at least one half-hourly meter settled on the half-hourly electricity market. In the 2016 Spring budget, the government announced that CRC payments will be replaced in a revenue-neutral way with a corresponding increase in the Climate Change Levy from April 2019.

Level of support / incentive

	2015	2020	2025	2030	2050
Enhanced Capital Allowances	100% tax relief	100% tax relief	75% tax relief	50% tax relief	No longer available
Carbon Reduction Commitment	£16.0 / tonne of CO^2 eq.	£17.2 / tonne of CO^2 eq.	No longer available	No longer available	No longer available

Customer uptake assumptions – public vs. private sector decision-making process

Overview:

- Heating system purchases are sometimes distressed purchases with larger organisations going to tender while smaller companies will likely get several quotes. However many organisations will include replacement systems as planned maintenance or refurbishment works.
- **Attractive payback periods for the private sector tend to be lower than the public sector (2-3 years, with an acceptable threshold of 3-5 years).**
- Apart from SMEs (Small and Medium Enterprises), most non-domestic end-users tend to outsource heating / cooling system procurement to Facility Management firms, EPCs (Engineering, Procurement, and Construction companies), or ESCOs (Energy Services companies).
- Registered social landlords (of large housing associations and local authorities) will use a contractor to bulk-buy heating products for one housing development or mass renovation project in order to get low prices. The contractor may approach a wholesaler or the manufacturer.

Public sector	Private sector
• The public sector tends to be more receptive to outsourcing energy related activities. • As several issues are combined in the investment/outsourcing decision in the public sector [energy cost; carbon reduction targets; maintenance; funding new infrastructure] the acceptable payback period of LCTs and renewable heating is extended to maybe 5-7 years compared to private sector of 3-5 years. • This generally allows a lower acceptable ROI for the public sector end client with an average of 6-8% but higher in private, average 10-12% [for individual contracts these ranges may well overlap reflecting the specific circumstances]. • Public sector also tends to accept a wider 'basket of measures' in order to achieve the highest CO_2 saving probably as they have harsher carbon reduction targets. This is again reflected in the acceptable payback / ROI rates.	• Private sector have higher turnover rates when it comes to technology / service providers, i.e. prefer not to be committed to one supplier of 'outsourced services' for a long period of time. • Private sector tends to have shorter contract duration due to the higher credit risk in the long run. Also the amortization time constraints are different to the public sector. • Private sector more interested in compliance at current time – important for technology / service providers to bring wider benefit to client – not just energy, but also operational cost reduction, reduced compliance costs etc. • Private sector focused on one-technology solutions through initial contract to keep contract as short as possible in the perceived fast moving technology market.

Industrial Heating technologies

Forecast uptake and assumptions behind reference scenario

Note: The forecasts refer to annual heating technology sales (not accumulated installed base of heating technologies).

In the model - when estimating the impact heating technology uptake will have on peak electric heating demand out to 2050, we only consider technologies installed that are adding additional load demand.

Forecast for annual sales of industrial heating appliances

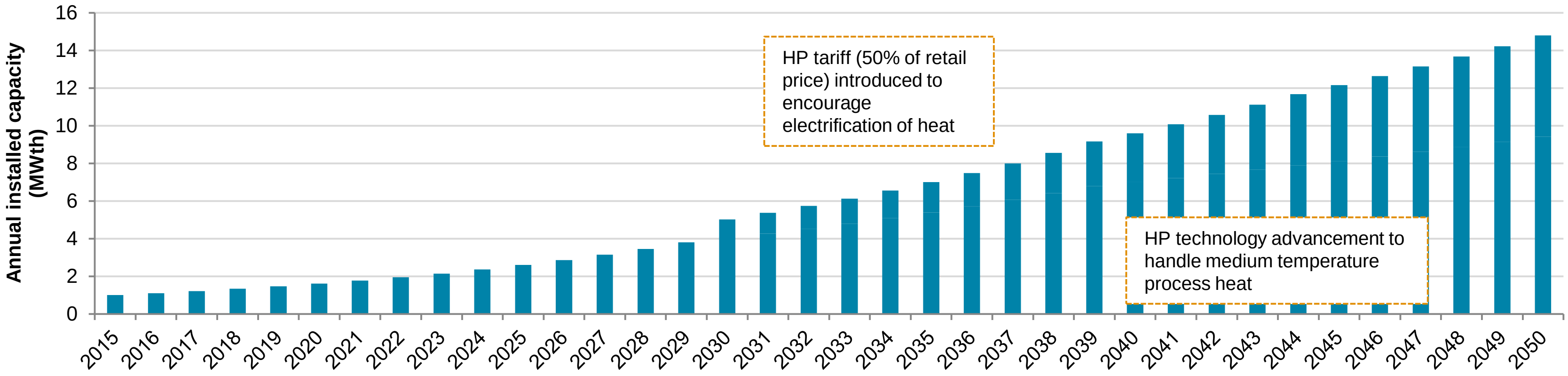
Delta-ee view:

Below, we show the reference scenario for uptake (annual sales) of:

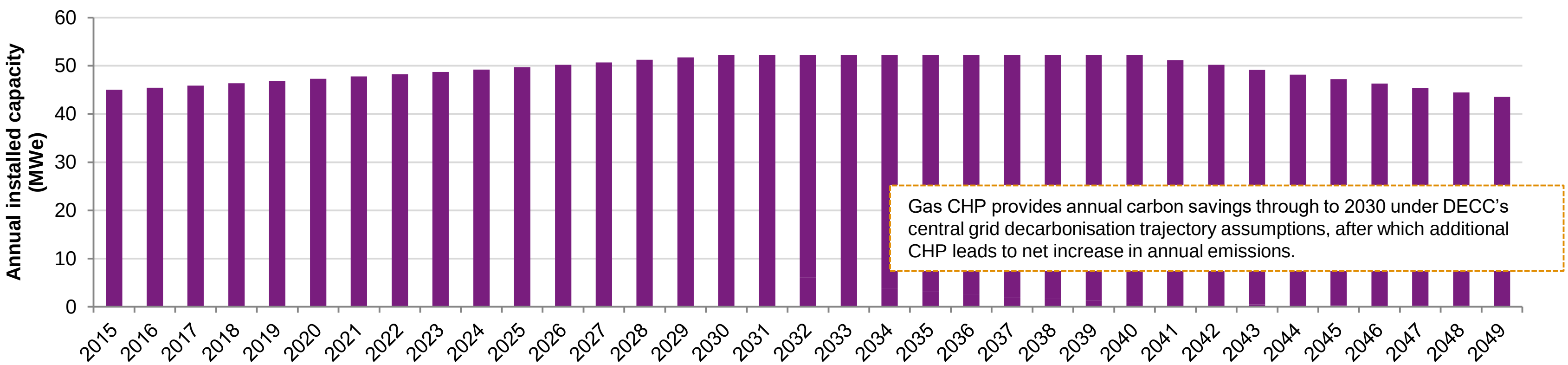
- Heat pumps (typically 100 – 400 kW capacity systems)
- CHP - internal combustion engine and turbine) (typically larger than 500kWe up to 10s of MWe capacity systems)

Just as in the commercial sector, the heating appliance capacity size varies substantially and multiple-unit installations are common per scheme. Therefore, we present annual sales in capacity (MWth and MWe) rather than in units.

Annual installed *thermal* capacity (Heat Pumps) in INDUSTRIAL sites – reference scenario



Annual installed *electrical* capacity (CHP) in INDUSTRIAL sites – reference scenario



Industrial heating demand

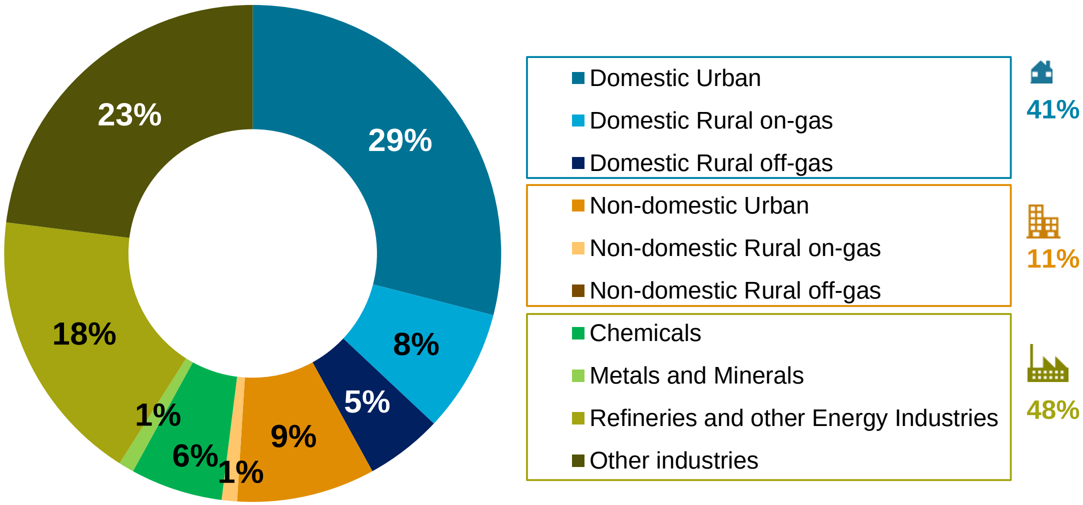
Delta-ee view:
The industrial sector accounts for nearly half of Scotland's non-electric heat demand. For the purpose of this project, we have focused our research on the electrification of heat in the:

- food and drinks sector
- paper and pulp sector

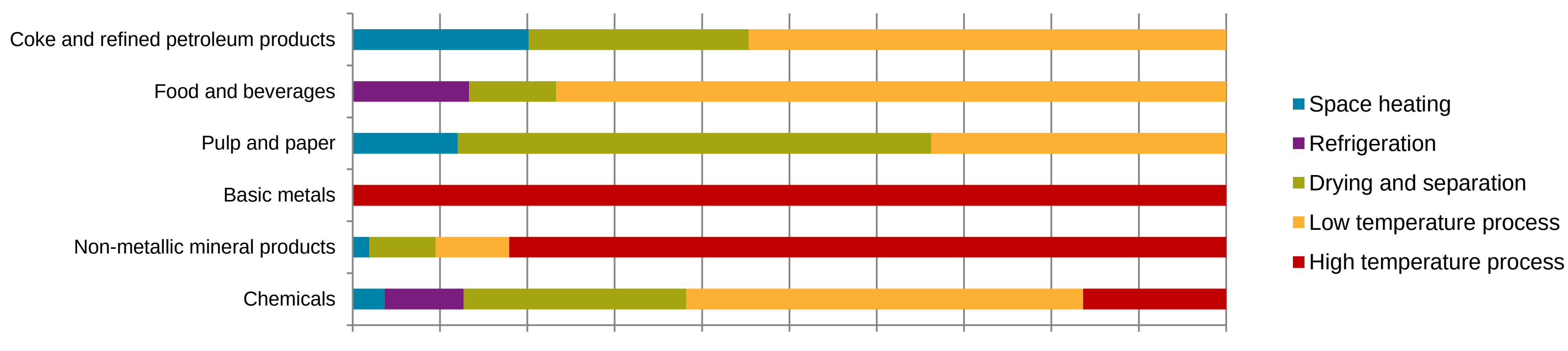
Compared to other sectors, **the food and drink sector has a large part of its heat demand at fairly low temperatures and this could enable these sectors to shift towards electrification more easily**. **The paper and pulp industry provides ideal operational conditions for industrial heat pumps, with processes that are typically continuous (e.g. drying, dewatering, ink removal), and which generate waste heat streams which can be utilised by heat pumps.**

For other sectors, using electricity as their energy source is possible at higher temperatures but equipment (e.g. electric kilns) is not developed at scale and lower efficiencies can result compared to using other fuels. Electricity price projections relative to counterfactual fuels (e.g. gas and solid fuels) will be a key consideration in any investment decision. The coke and refined petroleum products sector will use solid fuel or other petroleum products and is unlikely to switch to other fuel sources.

Scottish Non-electric Heat Energy Consumption Baseline (2010)



Heat demand in Industrial sites by Sector and Application



High level breakdown of the Scottish industrial sites used within Delta-ee's industrial site model

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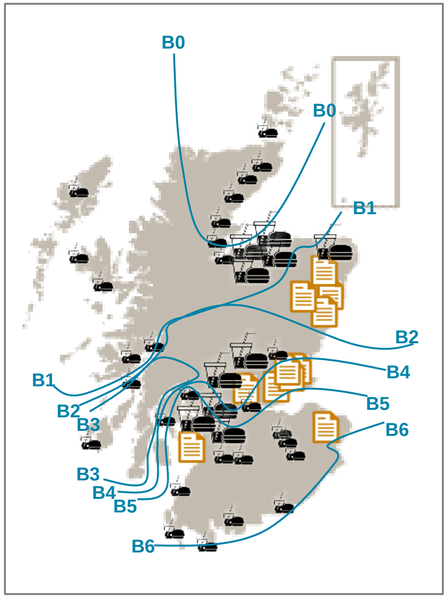
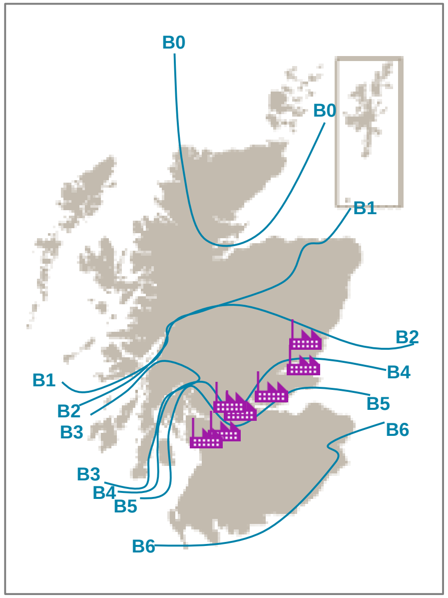
Overview of the industrial site segmentation for Scotland

- We have based our segmentation of industrial sites per region based on data from the Scottish Assessors database of number of non-domestic premises per local authority. We singled out three segments [quarries / mines; petrochemicals; and industrial sites (including factories and warehouses)] which did not fall into the commercial sector building stock analysis in slide 30.
- The table below only details the number of premises, but not the size of premises. Assumptions are made on the heat load for each site.
- This is supplemented by the CHP Development Map and Scotland Heat Map which provides spatial distribution data on the consumption of heating throughout UK and Scotland respectively.
- To derive the technical potential of industrial heating demand able to be met by industrial heat pumps and CHP, we also analyse current market penetration rates in Europe across key industrial sectors and applications (see next two slides).



Paper and pulp
Food and beverages (dairies, breweries, distilleries, food processing, etc.)



Heat intensive industrial sites

Number of premises

	QUARRIES / MINES	PETROCHEMICALS	INDUSTRIAL SITES (including FACTORIES / WAREHOUSES)	Industrial heat demand (TWh) per region
B0	59	12	1,887	~ 1.0 TWh
B1	66	14	2,351	~ 2.7 TWh
B2	237	21	5,492	~ 3.5 TWh
B3	37	13	1,143	~ 0.2 TWh
B4	67	16	6,064	~ 5.4 TWh
B5	50	25	5,264	~ 5.3 TWh
B6	153	35	25,143	~ 20.2 TWh

Note: The total industrial heat demand in a region can be heavily skewed by a small number of premises. E.g. Grangemouth refinery in Falkirk (Falkirk is split across B4 and B5).

Current Industrial Heat Pump use in Europe - by industrial sector

Overview:

- HP implementation in Europe is currently **most widespread in the Food & Drink sector** – as a result of the wide range of potential applications for IHPs in key sub-sectors such as dairies, food processing, distilling and brewing.
- Heat pumps can – and are - used for a wide range of applications in industry, including: heating, ventilation, air-conditioning, hot water, drying, dehumidification, concentration. We explore applications more on the following slide.
- **Almost all installations use mechanical vapour compression (MVC) heat pumps today**, so it is a well-proven technology – **as we move to 2020 we expect to see increasing use of alternatives such as absorption** [see Appendix ii for an introduction to industrial heat pump technologies].

Industry sectors where heat pumps are currently installed in Europe, applications found on the market, and the typical IHP technology used.

Sector	Applications	Common HP Technology used
Chemicals (incl. refining & petrochemicals)	Distillation (separation) of petrochemicals	Mechanical vapour compression (open-cycle)
	Concentration of liquid streams and waste heat recovery with heat sink temperatures from 80°C to 100°C	Mechanical vapour compression (open-cycle)
	High temperature purification and clean superheated steam generation with heat sink temperatures from 100°C to 150°C	Mechanical vapour compression (open-cycle)
Pharmaceuticals	Process water heating	Mechanical vapour compression (closed-cycle)
Paper & Printing	Space Heating	Mechanical vapour compression (open-cycle)
	Drying, black liquor processing and waste heat recovery with heat sink temperatures from 80°C to 100°C	Mechanical vapour compression (open-cycle)
	Superheated steam generation for process water heating use with heat sink temperatures from 100°C to 150°C	Mechanical vapour compression (closed-cycle)
	Flash steam recovery	Thermocompression (open-cycle)
	Lumber & paper drying & dehumidification with heat sink temperatures from 80°C to 100°C	Mechanical compression (closed-cycle)
Food & Drinks	Space heating and hot water production	Mechanical vapour compression (open-cycle)
	Concentration of liquids & sterilisation (e.g. waste alcohol, milk, sugar solutions), drying and waste heat recovery with heat sink temperatures from 80°C to 100°C	Mechanical vapor compression, and thermocompression (open-cycle); mechanical compression+absorption
	Cooling & refrigeration	Mechanical compression & absorption (closed-cycle)
	High temperature purification and superheated steam generation with heat sink temperatures from 100°C to 150°C for process water heating	Mechanical compression (closed-cycle)
Iron & Steel	Space heating	Mechanical compression & absorption (closed-cycle)
	Machine oil cooling + quenching tank cooling	Mechanical compression & absorption (closed-cycle)
Clay products	Drying	Mechanical compression (closed-cycle)
District Heating	Large-scale heating	Mechanical compression & absorption (closed-cycle)
General	Space heating of factories	Mechanical compression (closed-cycle)

Current Industrial Heat Pump use in Europe - by application

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Applications for heat pumps in industry: Heat pumps are multi-functional and can often meet these varied demands simultaneously

- The primary current applications for HPs in industry involve the **production of hot (and cold) water** (e.g. for process cleaning and machine cooling respectively), in addition to **space heating (& cooling), drying** and the **concentration of liquid solutions** (e.g. for brewing, distillation and chemical production processes).
- The application which may have the most untapped potential, is **heat pumps used for drying** – there are a wide range of drying applications for which IHP are so far not used significantly. This has been due to a historical lack of specialist suppliers of such technology (several are now emerging), and low awareness of the potential to use HPs for drying. **Drying can be one of the most energy intensive industry demands, so there is significant savings potential**.

Application category	Examples of specific application in industry	Extent to which IHPs used for this application in Europe	
Space Heating	• Space heating / temperature regulation of e.g. office spaces & warehouses across a *wide range of industrial sectors* • Climate control for e.g. storage of antibiotics cultures in the *pharmaceuticals sector,* pasteurization in the *dairy sector*	● (green)	**Many IHPs installed used for space heating** (estimate >30% of European installations)
Hot water	• Washing of bottles in *breweries, distillers, wineries, dairies* • Washing factory surface areas in e.g. *food processing sector, abattoirs, dairies* and a *wide range of other industrial sectors* • Defrosting frozen food products in the *food processing sector* • Process water heating in the *pharmaceuticals sector* • Sanitary hot water for use in offices, canteens etc across a *wide range of industrial sectors*	● (green)	**Many IHPs installed used for producing hot water for washing** (estimate >30% of European installations)
Cooling	• Air conditioning of e.g. office spaces, warehouses across a *wide range of industrial sectors* • Maintaining temperatures for e.g. storage of antibiotics cultures in the *pharmaceuticals sector,* greenhouses in the *agricultural sector* • Refrigeration of milk & other products in the *dairy sector* and *food & drinks sector* • Process cooling such as machine oil cooling in the *iron & steel sector*	● (green)	**Many IHPs installed used for space cooling & cold water** (estimate >30% of European installations)
Concentration	• Distillation in the *drinks sector* • Liquids concentration & sterilisation in the *food sector* • Refining in the *chemicals sector*	● (amber)	**Growing use of IHPs** (~10-20% of European installations)
Dehumidification	• Humidity / climate control in e.g. *pharmaceuticals production, chemicals* • Climate control in greenhouses in the *agricultural sector*	● (amber)	**Growing use of IHPs** (~10-20% of European installations)
Drying	• Drying milk for production of milk powder in the *dairy sector* • Drying fruit & vegetables in the *food sector* • Drying malt in the *brewing sector* • Drying wood / paper in the *lumber / pulp & paper sectors* • Drying clay in *the production of bricks, tiles & ceramic products*	● (red)	**Some IHPs used for drying but this is still a niche market** (likely <5% of European installations)
Desalination	• Purification of water contaminated by particular processes across a *range of industries* • Desalination of brackish water for use in processes across a *range of industries*	● (red)	**Some IHPs used but a niche market** (likely <5% of European installations)

Other industrial heating applications using electricity

Heating type	Example applications
Resistive and infrared heating	Production micro electronic switching circuit Electrolytic smelting Electroslag re-melting Graphitising of green carbon Electric glass melting Electrode boiler Heating of food
Induction heating	Melting of metals Electric glass melting Welding Brazing Surface treatment
High frequency heating	Welding of plastic Several applications in food industry (drying, tempering, pasteurisation) Several applications in textile industry (drying, preheating, tissue treatment, fixation of dyes) Drying applications in paper and cardboard industry
Microwave heating	Several applications in food industry (drying, pasteurisation, sterilisation, vacuum dehydration) Several applications in rubber industry (preheating before extrusion, rubber vulcanisation, resin polymerisation) Several applications in chemical industry (vacuum drying, sterilisation, microwave assisted chemical reactions) Sintering of ceramics
Arc furnaces	Steel recycling

Industrial CHP technologies and key industrial sectors

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Overview:

- According to DUKES 2015 data (Digest of UK Energy Statistics), the total installed capacity of Good Quality-qualified CHP in UK was 6.1 GWe in 2014. Scotland constitutes 8.8% of this CHP capacity with roughly 0.5 GWe. [Note: In reality, there are more CHP schemes in UK / Scotland than accounted for in the figure above or below, as some schemes do not register or are only partially Good-Quality qualified].
- Most UK CHP capacity is industrial, supplying process steam (93.5% of heat from CHP). A smaller, but expanding, proportion of heat supplied by CHP (5.3%) is in the form of 'Low Temperature Hot Water' at 75-95°C for space and water heating. Heat recovered from gas turbine exhaust heat, and supplied as hot air at up to 550°C, and hot oil at around 160°C make up the remaining heat supplied by CHP.

SIZE OF SCHEME	TYPICAL TECHNOLOGY	GRADE OF HEAT
Fossil fuel CHP		
<10 MWe	Reciprocating engine. Heat, supplied as hot water, recovered from engine cooling system	75 – 95 ^{0} C hot water
10 – 50 MWe	Simple cycle gas turbine. Heat, supplied as steam, recovered from turbine exhaust	350 – 450 ^{o} C steam at up to 60 bar
> 50 MWe	Combined cycle gas turbine. Heat supplied as steam, extracted from steam turbine	350 – 450 ^{o} C steam at up to 60 bar
Renewable CHP		
<10 MWe	Bioliquid reciprocating engine. Heat, supplied as hot water, recovered from engine cooling system	75 – 95 ^{0} C hot water
> 10 MWe	Solid biomass steam turbine. Heat, supplied as steam, extracted from steam turbine.	120 – 450 ^{o} C steam at up to 60 bar

Scotland-specific overview:

The DUKES CHP data is broken down by region and by economic sector below. We will use this to inform our forecasts for the types of industrial sectors in Scotland that form the main replacement market sectors and where there is still untapped potential.

	Number of schemes	Electrical capacity (MWe)	Heat capacity (MWth)	Electricity generated (GWh)	Heat generated (GWh)	Load factor (%)
Scotland [2015]	132	538	2,859	2,487	8,811	57.8%
UK [2015]	2,066	6,118	22,539	20,281	43,306	51.5%

Iron, steel and non-ferrous metals	Chemicals	Oil refineries and oil & gas terminals	Paper, publishing and printing	Food, beverages and tobacco	Metal products, machinery, and equipment	Mineral products	Other industrial sectors	Non-industrial sectors
0%	16%	57%	14%	4%	0%	0%	5%	4%

Economic proposition for industrial heating technologies in Europe

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Overview:
From a direct economic comparison, it can be seen that based on CAPEX/OPEX from known case-studies, **heat pumps appear to have a have lower annual operational cost than CHP** (even including electricity savings from in-house generation) and **gas boilers**. Furthermore, the **current low price of gas** in Europe results in an especially low comparative OPEX for **gas absorption heat pumps**, whilst **MVC** heat pumps become **less competitive with rising electricity prices**. However, it should be noted that this is **based on** the CAPEX and OPEX **data available from known case studies**, with the **range of costs likely to vary substantially** for a given technology from project to project and industry to industry.

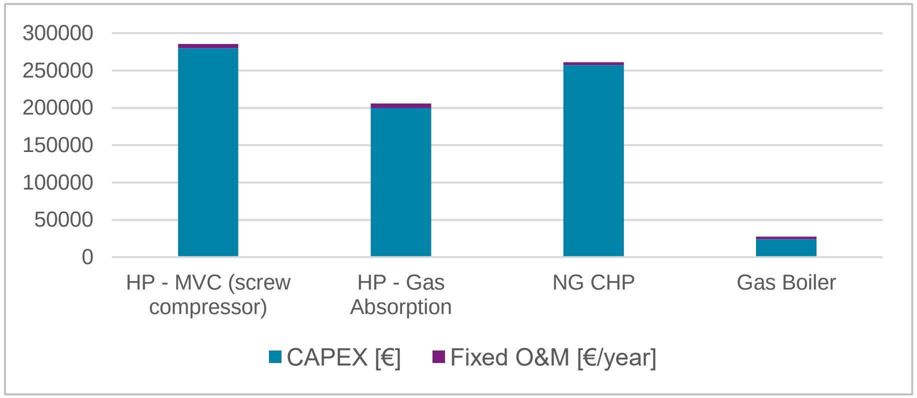
IHP cost comparison scenario for an average system

- In order to provide a better understanding of how the economics of IHPs compared to current industrial heating alternatives, a basic, **direct economic comparison** of the technologies was completed (see figures to the right).
- The installed systems were based on a **thermal demand of 400 kW** (current industry average for IHPs), with the assumed CAPEX, OPEX and fuel costs provided in the two tables below.
- The top figure on the right breaks down the total capital costs (**CAPEX**) (including designed, ancillary systems & installations), and annual yearly costs. From this direct comparison, **IHPs** can be seen to be **cost competitive with CHP** (for an average installation), but much more expensive than a gas boiler.
- The bottom figure on the right breaks down the annual variable costs including fuel (**OPEX**). This figure breaks down **OPEX by country**, due to the differences in **electricity and gas prices** between Germany, the UK and Italy.

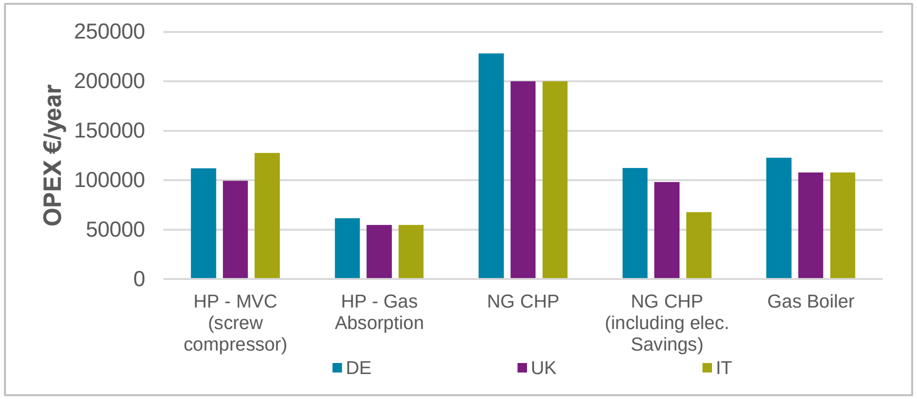
Technology	Efficiency	CAPEX [€/kW$_{th}$]	O&M [€/MWh$_{th}$]
MVC HP	400%	700	2
Gas Absorption HP	200%	500	2
CHP	88% (50% heat; 38% electricity)	900 (elec. capacity)	1.4
Gas Boiler	94%	60	1.2

Note: OPEX & CAPEX costs based on European industry averages

CAPEX and Fixed O&M Costs by Industrial Heating Technology



Comparison of Annual O&M Costs and Fuel Costs by Industrial Heating Technology



System costs and applications of industrial heating technologies

Industrial heat pumps capable of meeting widest range of needs

- The **difficulty in directly comparing** the heating technology options currently available in industry is that the applications for which they can be used varies dramatically. This makes a direct comparison of capital expenditure (CAPEX) and fixed operation & maintenance (Fixed O&M) costs difficult.
- The ability for **heat pumps to meet a wide variety of heating needs** (see table below), means that in reality a heat pump should not be directly competing with the cost of a CHP or gas boiler system. That is, the cost of the additional systems which it is replacing, e.g. additional drying circuits, chillers for cooling, etc., should ideally be included in any calculation. This is in the same way that the savings from electricity produced and used in-house by a CHP system would be taken into economic consideration.

Comparison of range of application for heating solutions currently used in industry

	Space Heating	Sanitary Hot Water	Process Heat	Cooling	Additional Functions e.g. drying, concentration	Electricity Production	Economics
HEAT PUMP	✓	✓	Up to 100°C ✓ By 2040: up to 200ºC	✓	✓	✗	Can replace multiple technologies for different applications with heat pumps (e.g. no need for separate heating and cooling system), potentially bringing down upfront costs and running costs where installed in optimum way. Added value proposition of additional functionalities which traditional systems cannot provide.
CHP	✓	✓	✓	✗ (unless CCHP)	✗	✓	Main additional benefit is electricity production i.e. electricity savings improve overall system running costs.
GAS BOILER	✓	✓	✗	✗	✗	✗	Lowest CAPEX but highest OPEX system.

Table of contents

Residential Demand profiles

Building physics model approach and assumptions behind reference scenario

Assumptions behind Delta-ee's peak electric heating demand modelling

Overview:

- The table below indicates the assumptions used in Delta-ee's peak load behaviour modelling of the seven selected technologies across four time blocks on a winter's day in Scotland.
- The purpose of this commissioned piece of research is to understand **peak behaviour** rather than average behaviour (in the next two slides we show the difference in load shapes between the "peak" and "average" winter).
- In the case of hybrid heat pumps – we have chosen the "worst case scenario" peak behaviour whereby the heat pump is allowed continued operation despite the very cold weather. Typically, between outside temperatures of say -5 C to 8 C, the boiler usually operates only when the heat pump cannot maintain target flow temperatures. Beyond certain outside temperatures (more than -5 C) , the heat pump is typically restricted to limit inefficient operation in very cold weather [see example in slide 49]

Peak Load Behaviour					
Technology	Source	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM
Electric Storage Heating	*Charge*	100%	100%	0%	100%
	Boost	0%	0%	0%	50%
	DHW	100%	0%	0%	100%
ASHP (Low Temperature, LT)	*Heat Pump*	100%	100%	100%	100%
	In-line	0%	100%	100%	100%
AHSP (High temperature, HT)	*Heat Pump*	100%	100%	100%	100%
	In-line	0%	100%	100%	100%
Hybrid (LT) ASHP	*Heat Pump*	100%	100%	100%	100%
GSHP (LT)	*Heat Pump*	100%	100%	100%	100%
	In-line	0%	100%	100%	100%
ICE mCHP	*Generation*	100%	100%	100%	100%
FC mCHP	*Generation*	100%	100%	100%	100%

See Appendix i for definition of high and low temperature heat pumps.

Example load profiles for heat pumps: High temperature ASHP in a semi detached dwelling (3 days)

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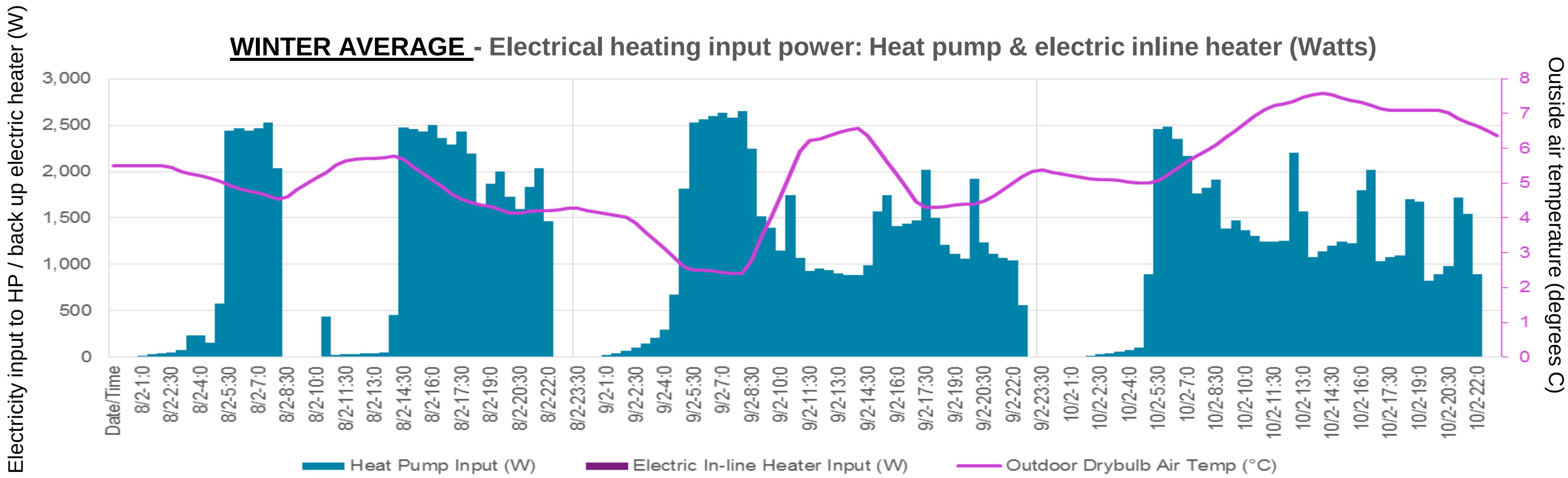
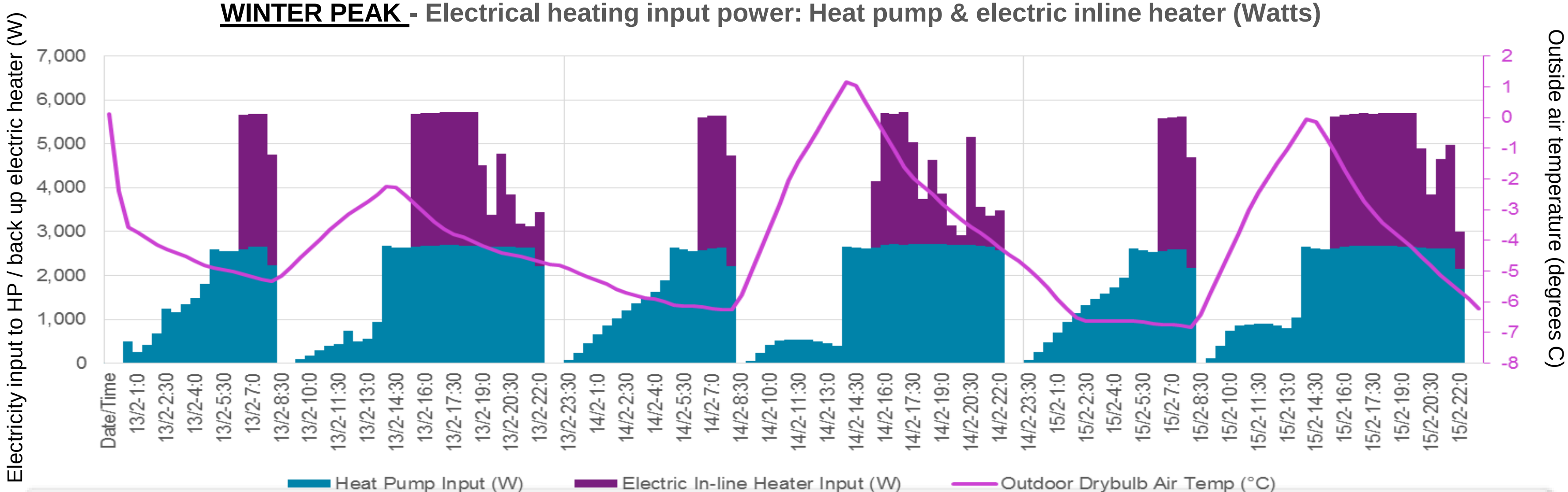
WINTER AVERAGE - Electrical heating input power: Heat pump & electric inline heater (Watts)



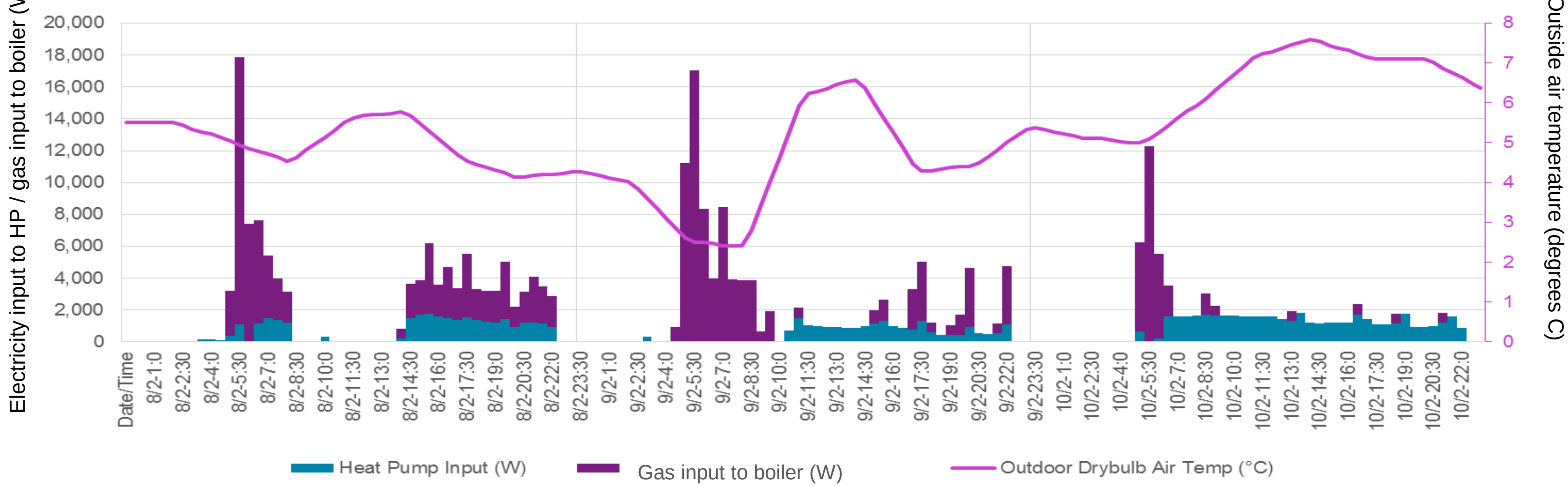
WINTER PEAK - Electrical heating input power: Heat pump & electric inline heater (Watts)



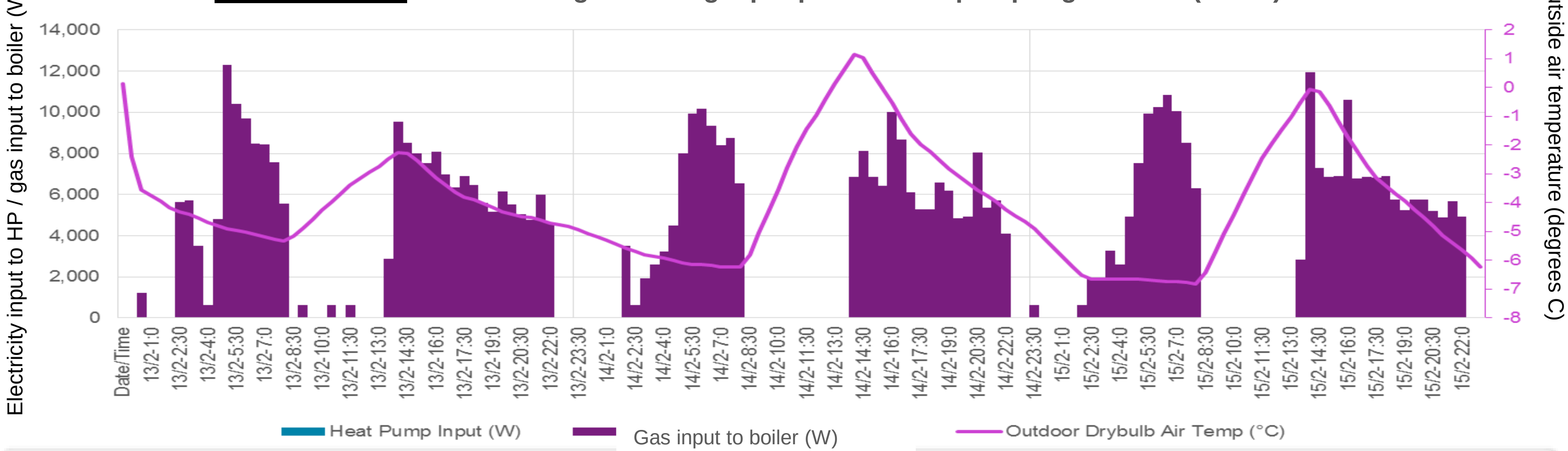
In extreme winter conditions, the gas boiler takes over full supply of heat (as demonstrated in the second diagram). But, for this project we have chosen the “worst case scenario” peak behaviour whereby the heat pump is allowed continued operation despite the very cold weather.

Example load profiles for heat pumps: Hybrid heat pump in a semi detached dwelling (3 days)

WINTER AVERAGE - Electrical & gas heating input power: Heat pump & gas boiler (Watts)



WINTER PEAK - Electrical & gas heating input power: Heat pump & gas boiler (Watts)



Assumptions behind Delta-ee's peak electric heating demand modelling

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For the purpose of this project, we have selected four "representative" house types to study in greater detail (selected after analysing data from the Scottish House Conditions Survey 2013):

- ***Detached, post-1982, BC EPC, average size 140 -145m²***
- ***Semi-detached, 1945-64, DE EPC, average size 90m²***
- ***Terraced, 1965-82, DE EPC, average size 80-90m²***
- ***Tenement, pre-1919, DE EPC, average size 60-70m²***

The table below lists the peak electric heating demand (and generation) per technology per "representative" dwelling type based on the capacity of the heating system (heat source / mCHP sizing) needed to meet the dwelling's thermal demand and the heating system's efficiency (HP CoP). This is modelled through Design Builder software.

		Heat Source / mCHP Sizing (kW)				HP CoP			
Technology	Source	Tenement	Terrace	Semi-Detached	Detached	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM
Electric Storage Heating	*Charge*	6.6	11	14.3	22				
	Boost	3	5	6.5	10				
	DHW	3	6	6	6				
ASHP (LT)	*Heat Pump*		5	6.5	10	1.7	2.1	2.1	2.1
	In-line		3	3	3				
AHSP (HT)	*Heat Pump*		5	6.5	10	1.5	1.8	1.8	1.8
	In-line		3	3	3				
Hybrid (LT) ASHP	*Heat Pump*		4	5	8	1.7	2.2	2.2	2
GSHP (LT)	*Heat Pump*		5	6.5	10	2.5	2.5	2.5	2.5
	In-line		3	3	3				
ICE mCHP	*Generation*		-1	-1	-1				
FC mCHP	*Generation*		-1	-1	-1				

CoP of HP is less because temperature differential between outside and indoor temperature is large, hence HP works less efficiently.

PEAK ELECTRIC HEATING DEMAND (AND GENERATION) - kW

Tenement (mid-floor, mid-row)				
Technology	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM
Electric Storage Heating	9.6	6.6	0.0	11.1
ASHP (LT)				
AHSP (HT)				
Hybrid LT ASHP				
GSHP (LT)				
ICE mCHP				
FC mCHP				

Terrace				
Technology	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM
Electric Storage Heating	17.0	11.0	0.0	19.5
ASHP (LT)	2.4	5.4	5.4	5.4
AHSP (HT)	2.8	5.8	5.8	5.8
Hybrid LT ASHP	2.0	2.0	2.0	2.0
GSHP (LT)	2.0	5.0	5.0	5.0
ICE mCHP	-1.00	-1.00	-1.00	-1.00
FC mCHP	-1.00	-1.00	-1.00	-1.00

Semi-Detached				
Technology	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM
Electric Storage Heating	20.3	14.3	0.0	23.6
ASHP (LT)	3.1	6.1	6.1	6.1
AHSP (HT)	3.6	6.6	6.6	6.6
Hybrid LT ASHP	2.5	2.5	2.5	2.5
GSHP (LT)	2.6	5.6	5.6	5.6
ICE mCHP	-1.00	-1.00	-1.00	-1.00
FC mCHP	-1.00	-1.00	-1.00	-1.00

Detached				
Technology	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM
Electric Storage Heating	28.0	22.0	0.0	33.0
ASHP (LT)	4.8	7.8	7.8	7.8
AHSP (HT)	5.6	8.6	8.6	8.6
Hybrid LT ASHP	4.0	4.0	4.0	4.0
GSHP (LT)	4.0	7.0	7.0	7.0
ICE mCHP	-1.00	-1.00	-1.00	-1.00
FC mCHP	-1.00	-1.00	-1.00	-1.00

Sensitivities to consider (for future scenario-building)

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Sensitivities					
Technology	Source	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM
Electric Storage Heating	*Charge*	Lower / higher heat capacity = lower / higher charge power	e	Potential for afternoon re-charge under ToU tariff?	Assume charge starts 11pm - if starts at midnight, ZERO demand in this period
	Boost	None - assume no boost as ESH has charged	None - pre-heat & mornign heatign period was supplied from stored heat	Assumed that there is enough stored heat to maintina high heat transfer rate in ealry evening, and hence no boost	f
	DHW	None - assume DHW tank charges using off-peak	g	Assumed that extra DHW input required due to evening usage after 6pm - if this usage is before 6pm, would expect DHW input to shift to 12-6pm period	
ASHP (LT)	*Heat Pump*	a & i	h & i	l & j	h & i
	In-line	None - assume no in-line usage - longer pre-heat instead	k	k	k
AHSP (HT)	*Heat Pump*	a & i	h & i	l & j	h & i
	In-line	None - assume no in-line usage - longer pre-heat instead	k	k	k
Hybrid (LT) ASHP	*Heat Pump*	a & b & i	h & i	l & j	h & i
GSHP (LT)	*Heat Pump*	a & i	h & i	l & j	h & i
	In-line	None - assume no in-line usage - longer pre-heat instead	k	k	k
ICE mCHP	*Generation*	c	l	l	l
FC mCHP	*Generation*	d	l	l	l

Common Sensitivities

a) If morning timeclock is much later, then there may be ZERO pre-heat usage before 6am, however there would still be some setback heating (likely to reach 50-100% demand, depending on diversity of room demand, and type of room level control).

b) On very cold days, hybrid controller would use boiler instead of heat pump, so HP load would be ZERO.

c) If morning timeclock is much later, then there may be no requirement for pre-heat usage before 6am, so ICE mCHP generation would drop to ZERO.

d) If morning timeclock is much later, then there may be no requirement for pre-heat usage before 6am, so FC generation would drop to minimum modulation step (0.25kW).

e) Assumed charging 11pm-7am - if charge periods change or very low charge required (due to milder day), then no charge after 6am.

f) Assumed that stored heat diminishes in zones at different rates, and that coincidence of boost heater usage across rooms is medium.

g) Assumed that stored DHW is enough for morning usage - highly concentrated demand may require additional heat to be added in morning.

h) None: HP will maintain peak output for sustained period in winter during morning and evening heating periods.

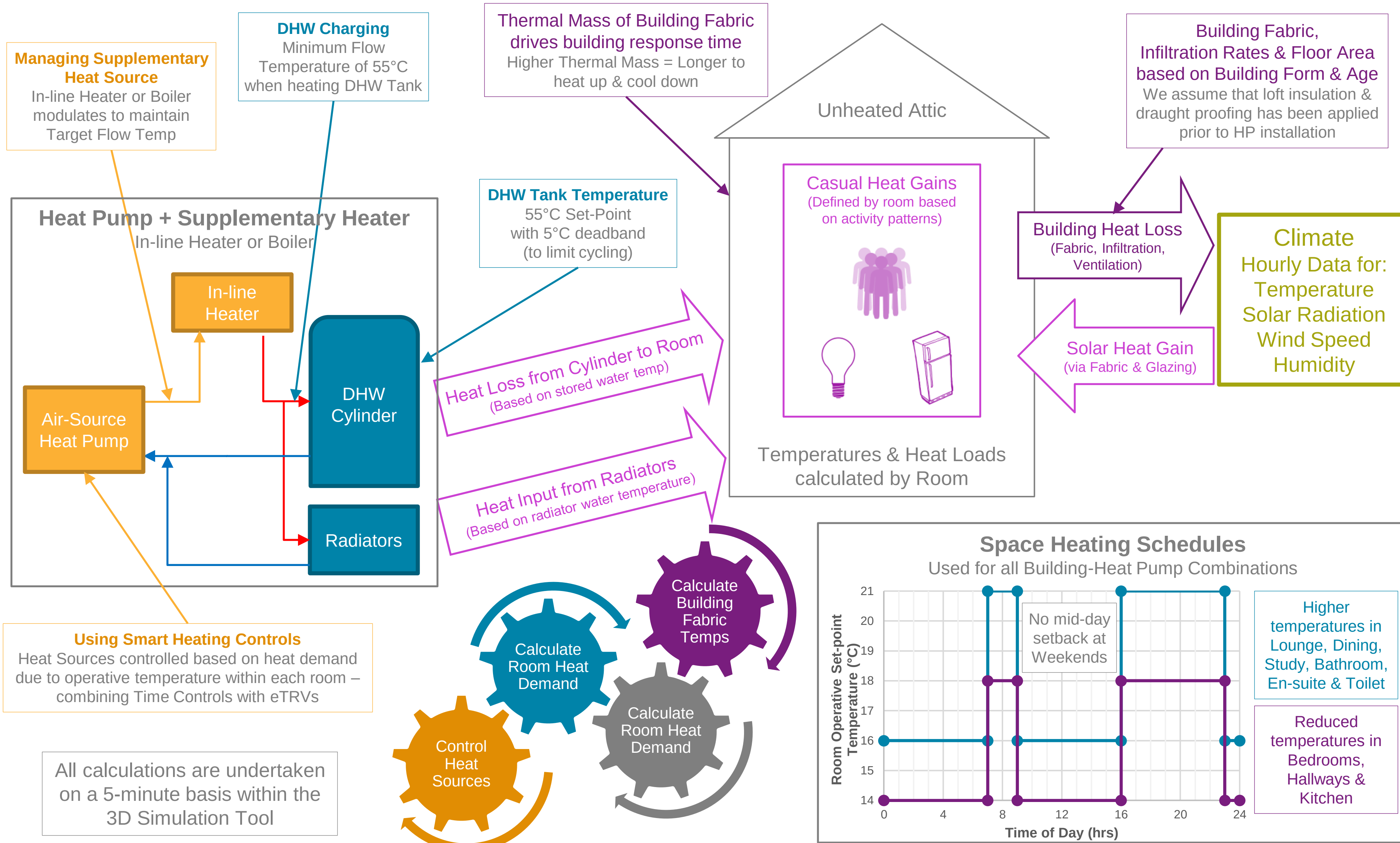
i) Consider changes to HP CoP, driven by technology, and impact of external temperature on source temperature and required flow temperature (due to weather compensation controls).

j) Assumed that evening heating period starts before 6pm, and that pre-heat starts well before 6pm - if evening heating period starts well after 6pm, then there may be no pre-heat or comfort period before 6pm - however, there would still be some setback heating.

k) In-line heater usage during comfort periods - if comfort periods are adjusted, then in-line heater usage could shift.

l) Expect mCHP to reach maximum output during comfort periods in winter.

System configurations being simulated in the Building Physics model:
Heat Load Simulation Methodology



System configurations being simulated in the Building Physics model:
Low- & High-Temperature All-Electric Heat Pump Installations

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Heat Pump Capacity
Sized as 95-100% of building's design heat load

5kW or 6.5kW Heat Output

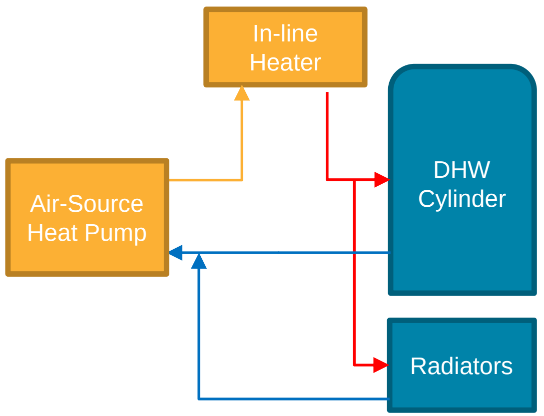
0% to 100% modulation range

In-line Heater Capacity
Acting as supplementary heater – NOT a full backup for HP

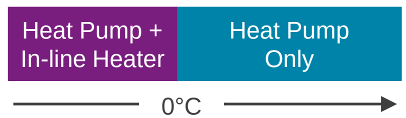
3kW Heat Output

0% to 100% Modulation Range

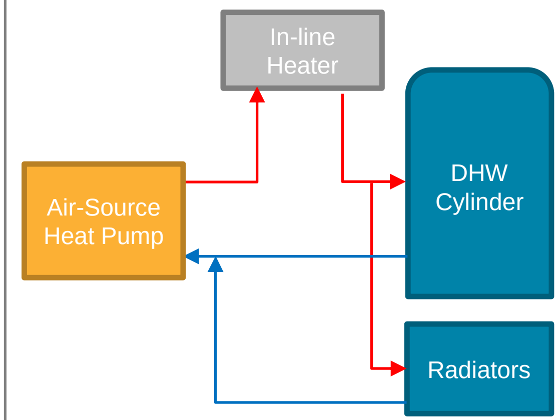
Heat Pump + In-line Heater Mode
In-line Heater modulates to meet target flow temp



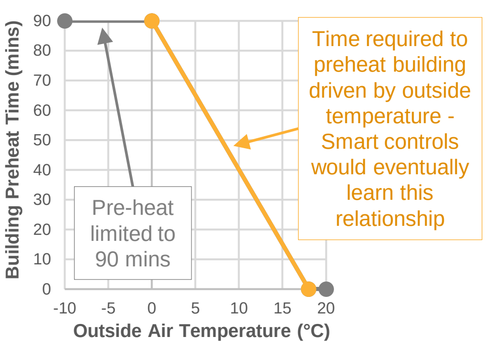
Selecting Operating Mode
Low- & High-Temperature Heat Pumps



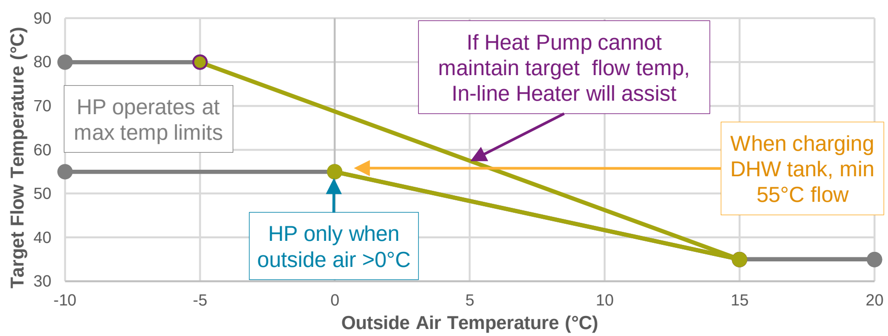
Heat Pump Only Mode
In-line Heater is unused



Optimised Start
HP Preheats building without In-line Heater



Weather Compensation
Non-Hybrid HPs use a single Target Flow Temp for Space Heating & HP



Common Control Logic
Applied to all Heat Pumps Types

- **DHW Charging:** Minimum Flow Temperature of 55°C
- **Optimised Start:** Building Pre-heating time between 0 & 90 minutes, calculated morning & afternoon based on outside air temp
- **Space Heating Schedules**: Defined for weekdays & weekend
- **Space Heating Set-points**: Defined per room, with Comfort 18°C or 21°C and Set-back = 14°C or 16°C
- **DHW Tank Set-point:** 55°C, with 5°C deadband (to limit cycling)

System configurations being simulated in the Building Physics model: *Hybrid Heat Pump Installations*

Heat Pump Capacity
Hybrid Heat Pumps are smaller than all-electric alternatives

5kW or 8kW Heat Output

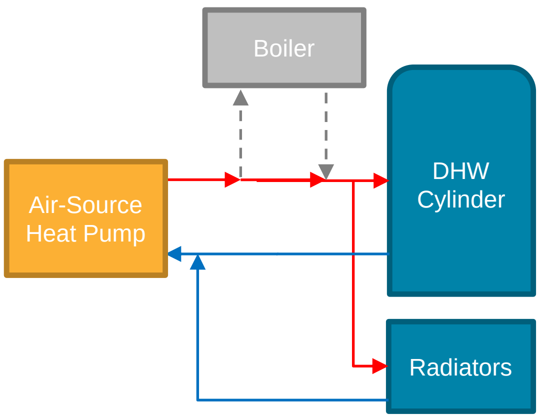
0% to 100% Modulation Range

Boiler Capacity
Based on existing boiler capacity

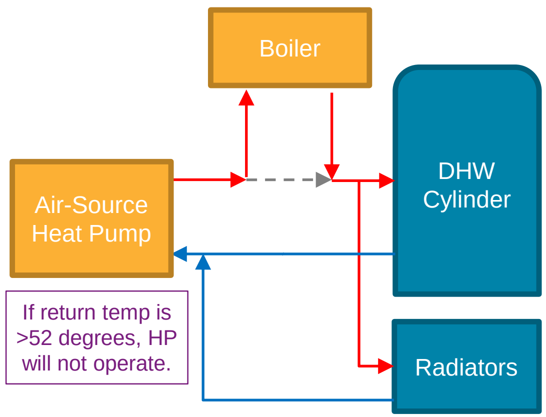
12kW to 18kW Heat Output

25% to 100% Modulation Range

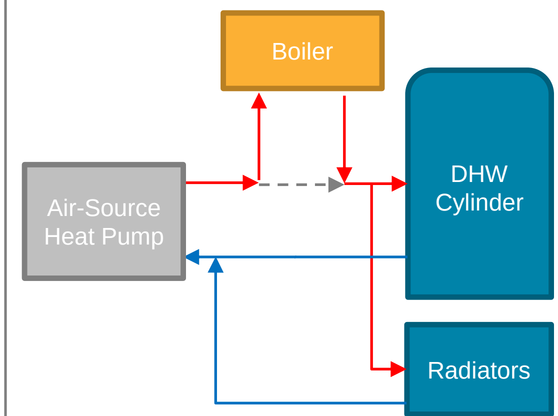
Heat Pump Only Mode
Boiler not in circuit



Heat Pump + Boiler Mode
Both Heat Pump & Boiler in circuit



Boiler Only Mode
HP is switched off



Selecting Operating Mode
Hybrid Heat Pumps

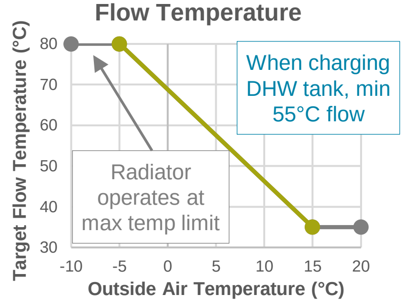
Mode	Outside Temperature
Heat Pump Only	>8°C
Heat Pump + Boiler	-5°C to 8°C
Boiler Only	< -5°C

Boiler operates only when Heat Pump cannot maintain Target Flow Temperature

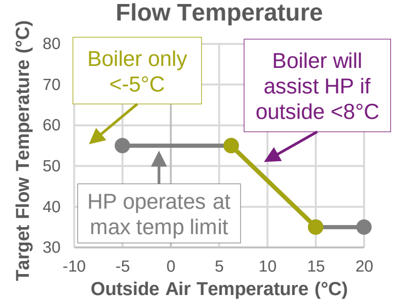
Heat Pump restricted to limit inefficient operation in very cold weather

Weather Compensation
Hybrid Heat Pumps require 2 levels of control

Space Heating Target Flow Temperature



Heat Pump Target Flow Temperature



Common Control Logic
Applied to all Heat Pumps Types

- **DHW Charging:** Minimum Flow Temperature of 55°C
- **Optimised Start:** Building Pre-heating time between 0 & 90 minutes, calculated morning & afternoon based on outside air temp
- **Space Heating Schedules**: Defined for weekdays & weekend
- **Space Heating Set-points**: Defined per room, with Comfort 18°C or 21°C and Set-back = 14°C or 16°C
- **DHW Tank Set-point:** 55°C, with 5°C deadband (to limit cycling)

System configurations being simulated in the Building Physics model: Smart Electric Storage Heaters (ESH) Installations

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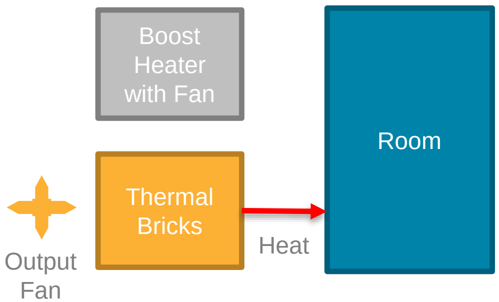
Storage Heater Charging	2.2kW Heat Input	16kWh Heat Capacity	No Modulation
Storage Heater Output	1kW Heat Output	ON or OFF No Modulation	
Boost Heater Capacity Heats room air directly	1kW Heat Output	0% to 100% Modulation Range	

Storage Heater Sizing Methodology
Based on the relative sizes provided above, storage heaters will be sized on a zone-by-zone basis to meet design heat load (99% of hours per year are warmer than temperate, x°C)

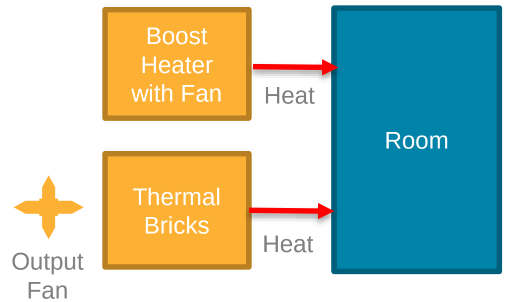
Stored Heat Output Mode

Output Fan modulates to maintain room temperature set-point



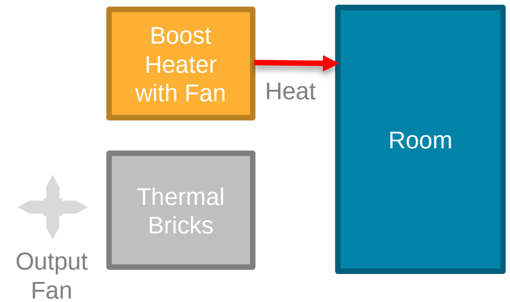
Stored Heat Output + Boost Heater

Output Fan at full capacity, so Boost Heater modulates to maintain room temperature set-point



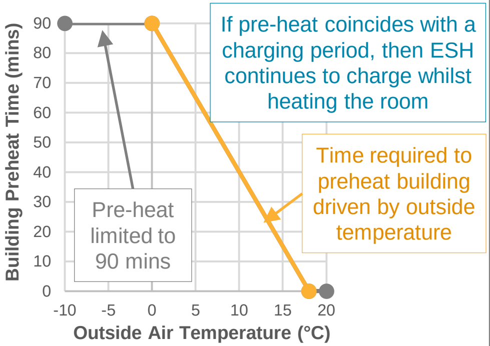
Boost Heater Only Mode

Thermal bricks are discharged, so Boost Heater modulates to maintain room temperature set-point



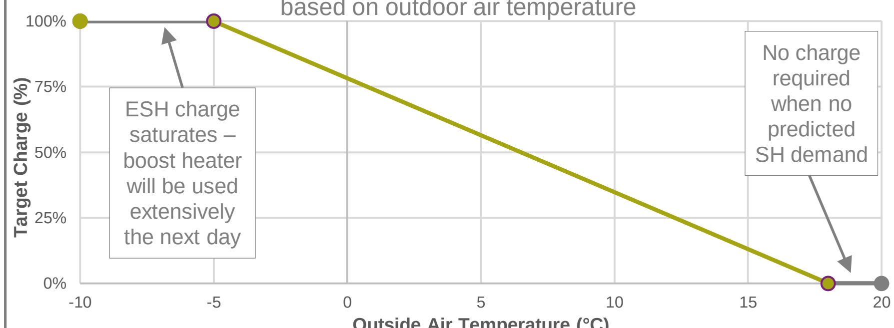
Optimised Start

HP Preheats building without Boost Heater



Weather Compensated Charge Control

Required charge of Storage Heater (average brick temperature) is calculated based on outdoor air temperature



Selecting Operating Mode

For Smart Storage Heater Output

Heating Mode	Operating Mode
Set-Back	Stored Heat Output Only
Pre-Heat	Stored Heat Output Only

Comfort	IF State of Charge <1% THEN
	Boost Heater Only
	ELSEIF
	(Room SP–Actual) > 2°C THEN
	Stored Heat Output + Boost
	ELSE
	Stored Heat Only

Commercial Demand profiles

Building physics model approach and assumptions behind reference scenario

Assumptions behind Delta-ee's peak electric heating demand modelling

Overview:

- The table below indicates the assumptions used in Delta-ee's peak load behaviour modelling of the selected technologies across four time blocks on a winter's day in Scotland. Based on the commercial building stock segmentation as detailed in slide 30, the peak load behaviour has been modelled in three segment types – supermarkets, offices, and hospitals. An "others" category has also been created which is the average of the modelled three segments.
- To derive "representative" peak electric heating demand (and generation) [see next two slides] small (<1,000m^2), medium (1,000 – 10,000m^2) and large (>10,000m^2) premises are distinguished as these require different capacities of heating systems. The peak load behaviour is assumed to be the same across all premise sizes for offices, supermarkets and others. It is assumed that large hospitals (eg. large campus hospital with 24 hour operation) have different behaviour from small healthcare facilities, and that CHP technologies are the chosen option over heat pumps.

SUPERMARKET [note: we have used supermarket demand profiles as the representative profile for the "shops" category]

		Peak Load Behaviour			
Technology	*Source*	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM
ASHP	*Heat Pump*	100%	100%	100%	100%
	DHW	100%	0%	0%	0%
GSHP	*Heat Pump*	100%	100%	100%	100%
	DHW	100%	0%	0%	0%
ICE CHP	*Generation*	100%	100%	100%	100%
FC CHP	*Generation*	100%	100%	100%	100%

OFFICE

		Peak Load Behaviour			
Technology	*Source*	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM
ASHP	*Heat Pump*	100%	100%	100%	25%
	DHW	100%	0%	100%	0%
GSHP	*Heat Pump*	100%	100%	100%	25%
	DHW	100%	0%	100%	0%
ICE CHP	*Generation*	100%	100%	100%	0%
FC CHP	*Generation*	100%	100%	100%	25%

SMALL COMMUNITY HOSPITAL

		Peak Load Behaviour			
Technology	*Source*	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM
ASHP	*Heat Pump*	100%	100%	100%	100%
	DHW	0%	0%	0%	0%
GSHP	*Heat Pump*	100%	100%	100%	100%
	DHW	0%	0%	0%	0%
ICE CHP	*Generation*	100%	100%	100%	100%
FC CHP	*Generation*	100%	100%	100%	100%

LARGE CAMPUS HOSPITAL

		Peak Load Behaviour			
Technology	*Source*	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM
ICE CHP	*Generation*	100%	100%	100%	100%
FC CHP	*Generation*	100%	100%	100%	100%

Thermal demand (kWh/m^2) largely based on CIBSE TM46 2008, weather-corrected for Scotland

Assumptions behind Delta-ee's peak electric heating demand modelling and sensitivities to consider - EXAMPLES

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SUPERMARKET (2,500 m^2 floor area; 190 kWh / m^2 thermal demand)

			HP CoP				Peak load (kW)				Sensitivities					
Technology	Source	Heat Source / CHP Sizing	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM		Source	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM
ASHP (LT)	Heat Pump	158	1.7	2.1	2.1	2.1	105	75	75	75	ASHP (LT)	Heat Pump	b & c	b & c	b & c	b & c
	DHW	12										DHW	a	a	a	a
AHSP (HT)	Heat Pump	158	2.5	2.5	2.5	2.5	75	63	63	63	AHSP (HT)	Heat Pump	b & c	b & c	b & c	b & c
	DHW	12										DHW	a	a	a	a
ICE CHP	Generation	-125					-125	-125	-125	-125	ICE CHP	Generation	d	d	d	d
FC CHP	Generation	-150					-150	-150	-150	-150	FC CHP	Generation	d	d	d	d

Common Supermarket Sensitivities

a: Assumed that stored DHW is enough for all day - highly concentrated demand may require additional heat to be added later in the day.
b: None: HP will maintain peak output for sustained period in winter during pre-heat, morning, afternoon and evening heating periods.
c: Consider changes to HP CoP, driven by technology, and impact of external temperature on source temp and required flow temp (due to weather compensation controls).
d: Expect continuous CHP output during occupation & preheat periods throughout winter, until store is closed.

OFFICE (150 m^2 floor area; 134 kWh / m^2 thermal demand)

			HP CoP				Peak load (kW)				Sensitivities					
Technology	Source	Heat Source / CHP Sizing	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM		Source	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM
ASHP (LT)	Heat Pump	209	1.7	2.1	2.1	2.1	138	100	115	25	ASHP (LT)	Heat Pump	l & k	n & k	n & k	m & k
	DHW	15										DHW	q	q	q	q
AHSP (HT)	Heat Pump	209	2.5	2.5	2.5	2.5	99	84	99	21	AHSP (HT)	Heat Pump	l & k	n & k	n & k	m & k
	DHW	15										DHW	q	q	q	q
ICE CHP	Generation	-80					-80	-80	-80	0	ICE CHP	Generation	l	n	n	o
FC CHP	Generation	-100					-100	-100	-100	-25	FC CHP	Generation	l	n	n	p

Common Office Sensitivities

k: Consider changes to HP CoP, driven by technology, and impact of external temperature on source temp and required flow temp (due to weather compensation controls).
l: Based on pre-heat prior to 8am occupation.
m: Assumed Space Heating setback, with diversity across zones.
n: Comfort period required full output.
o: Assumed ICE CHP is not cycled on for short setback operation, particularly as electric demand is low.
p: Assumed FC CHP is not ramped up from minimum modulation on for short setback operation, particularly as electric demand is low.
q: DHW immersion heater used primarily overnight (off peak), with some additional charge in afternoon due to high usage - afternoon charge could be avoided with large DHW storage cylinders.

Thermal demand (kWh/m^2) largely based on CIBSE TM46 2008, weather-corrected for Scotland

Assumptions behind Delta-ee's peak electric heating demand modelling and sensitivities to consider - EXAMPLES

DELTA Energy & Environment

SMALL COMMUNITY HOSPITAL (500 m^2 floor area; 350 kWh / m^2 thermal demand)

			HP CoP				Peak load (kW)				Sensitivities					
Technology	Source	Heat Source / CHP Sizing	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM		Source	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM
ASHP (LT)	Heat Pump	180	1.7	2.1	2.1	2.1	106	86	86	86	ASHP (LT)	Heat Pump	w & x	w & x	w & x	w & x
	DHW	18										DHW	v	v	v	v
AHSP (HT)	Heat Pump	180	2.5	2.5	2.5	2.5	72	72	72	72	AHSP (HT)	Heat Pump	w & x	w & x	w & x	w & x
	DHW	18										DHW	v	v	v	v
ICE CHP	Generation	-75					-75	-75	-75	-75	ICE CHP	Generation	y	y	y	y
FC CHP	Generation	-90					-90	-90	-90	-90	FC CHP	Generation	y	y	y	y

Common Small Community Hospital Sensitivities

v: Assume DHW demand is met by HP & CHP - although on extreme winters day DHW immersion heater usage may be required

w: Consider changes to HP CoP, driven by technology, and impact of external temperature on source temp and required flow temp (due to weather compensation controls)

x: Continuous heat pump use due to 24/7 operation in portions of the community hospital.

y: Expect optimal sizing of CHP to result in undersizing vs heat demand in winter period. Continuous heat demand for 24/7 operation, especially as over-night heat may be used to re-charge large DHW calorifiers (large storage tanks)

LARGE CAMPUS HOSPITAL (20,000 m^2 floor area; 350 kWh / m^2 thermal demand)

			HP CoP				Peak load (kW)				Sensitivities					
Technology	Source	Heat Source / CHP Sizing	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM		Source	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM
ICE CHP	Generation	-1,200					-1,200	-1,200	-1,200	-1,200	ICE CHP	Generation	z	z	z	z
FC CHP	Generation	-1,440					-1,440	-1,440	-1,440	-1,440	FC CHP	Generation	z	z	z	z

Common Large Hospital Campus Sensitivities

z: Expect optimal sizing of CHP to result in undersizing vs heat demand in winter period. Continuous heat demand for 24/7 operation.

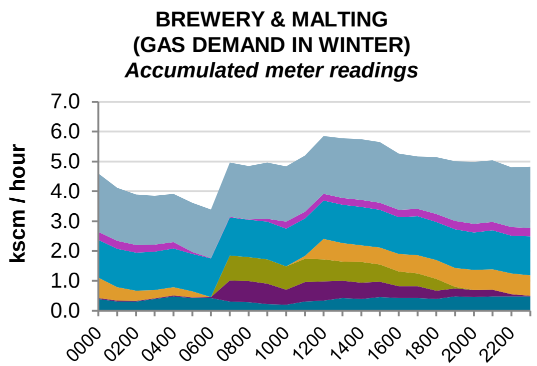
Industrial Demand profiles

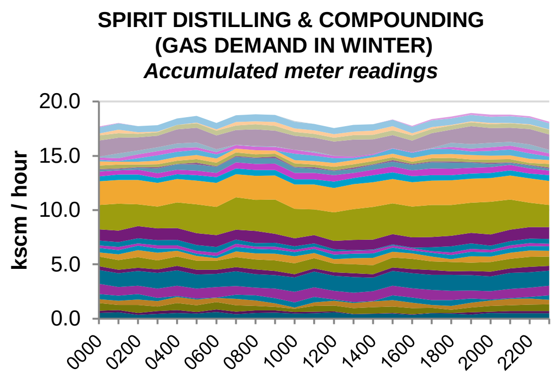
Assumptions behind reference scenario

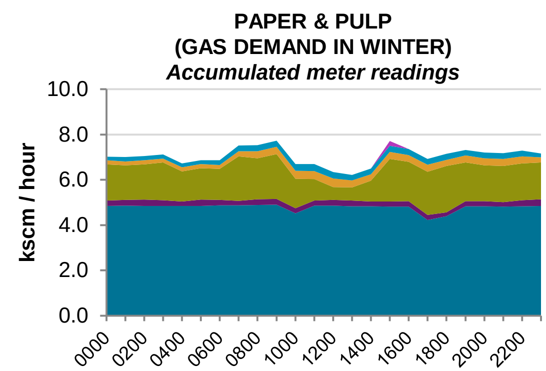
Gas demand in industrial sites – proxy for thermal demand

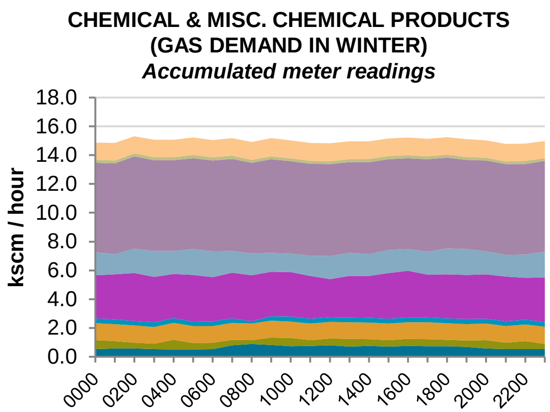
Overview:
Delta-ee reviewed 100 gas daily metered readings (average winter weekday) of industrial sites across Scotland. Each meter reading represents an individual meter point, some of which will relate to the same industrial site but different meters. All flows are expressed in thousand of standard cubic meters (kscm/h). **In general, gas (heat) demand is consistent throughout the day**. Some industries, such as breweries have clearer peaks during the day. In the next slide, we break down the gas (heat) demand of two industry types into estimates of half hourly process heat demand and space heating / hot water profiles.

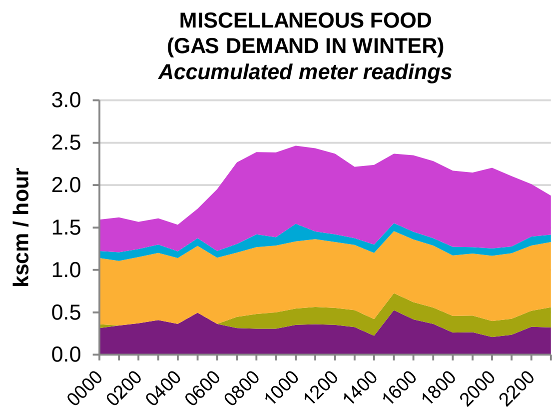
Full list of industries analysed: agriculture & horticulture; water supply; steel tubs; extraction of stone, clay, sand and gravel; glass containers, other glass products; basic organic chemicals; synthetic resins and plastic materials; chemicals; adhesive file, cloth, and foil; ferrous metal foundries; fabricated constructional steel work; food, drink, and tobacco processing; mechanical, marine, and precision engineering; electronic consumer goods and electronics; slaughterhouses; animal by-product processing; preparation of milk and milk products; fish processing; bread and flour confectionary; cocoa, chocolate, and sugar confectionary; miscellaneous foods; spirit distilling and compounding; brewing and malting; woollen & worsted industries; carpets, rugs, and matting; miscellaneous textiles; manufacturing of semi-furnished wood products; paper and pulp; rubber tyres and inner tubes; plastics; other manufacturing. The different colours below represent different meter reading profiles.

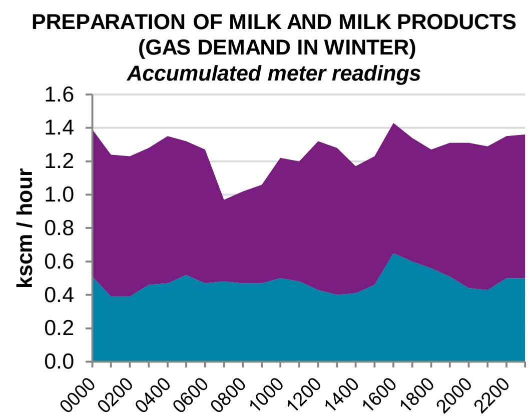








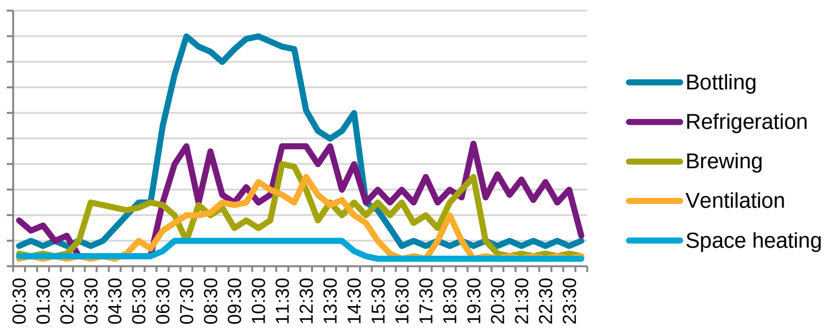




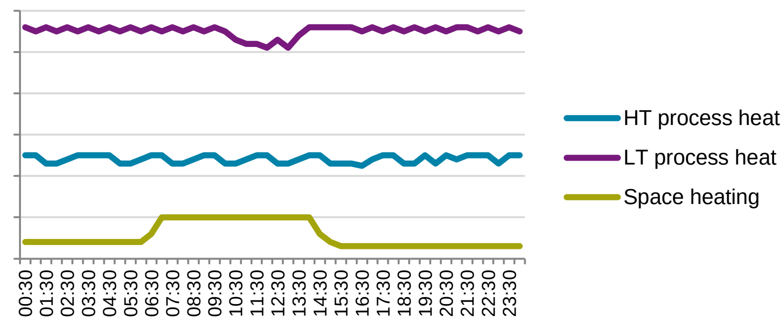
Breaking down individual industrial process heat and non-process heat demands

Overview:
The daily heating needs (half-hourly demand profile) of industrial sites is contingent on the size of the industrial site and the activities within it (e.g. process heat-intensive, 24-hour operations, etc.). Below we show illustrative examples of the difference between a “theoretical” small brewery and large chemicals and pharmaceuticals industrial site.

SMALL BREWERY: DAILY HEAT NEEDS



LARGE CHEMICALS AND PHARMACEUTICALS: DAILY HEAT NEEDS



Overview:
To derive the peak load demand (or generation) for this project, Delta-ee has assumed that the heat pump and CHP has been sized for base-load operation.

Calculation:

- Peak Heat Load = Average Heat Demand per industrial site / Full Load Equivalent Hours:
  10 GWh/yr / 7,000 hours/yr = 1.43 MW
- Using the assumption that the minimum baseload = 70% of peak, the base load heat demand = 1.43MW * 70% = 1MW
- So, for example, to meet 1 MW of baseload heating demand, one (or multiple units) heat pump at its peak will draw anywhere between 476 – 556 kW of electricity (depending on the CoP).

		Peak load behaviour				HP CoP				Peak load (kW)			
Technology	Source	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM	12 AM – 6 AM	6 AM – 12 PM	12 PM – 6PM	6PM – 12 AM
Heat Pump	Electric Demand	100%	100%	100%	100%	1.8	2	2.1	1.9	556	500	476	526

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Electricity demand baseline setting

Time-series of load-demands at each grid supply point (GSP, which is an electrical sub-station which connects a distribution system to a transmission system) are not available in the public domain. The GSPs provide a finite number of nodes for the assessment of both the geographically-specific demands (B0-B6) for electricity.

The electricity demand baseline setting within this study would ideally have used time-series of hourly demand for every GSP in Scotland for e.g. the past three years (having chosen a representative “winter peak day”). However, this amount of data would have been excessively large for convenient handling and goes beyond the scope of the project.

Comparison of known individual GSP demand profiles suggest that time-series data from one GSP cannot be applied directly to another GSP if the only correlating information is the maximum demand.

Furthermore, Scottish distribution network operators (SSE and SP) are unable to break these hourly demand for every GSP into residential, commercial, industrial and other demands.

Estimates of current (2014) electricity demand – winter peak
Methodology (1/2)

Based on a sample of profiled metered consumption* (which is then aggregated to represent the 3 sectors in Scotland: Residential; Commercial; and Industrial) shown in Figure 1 – we identify the individual (half-hourly) peak demand across the four time blocks of a day for each sector, as per Figure 2. When added together, this would give us a system demand profile for Scotland as in Figure 3, with peak demand per time block (Figure 4). This includes all uses of electricity (appliances, lighting, heating, cooling, etc.).

***Exelon load profiling data , BRE report on peak electricity demand in the UK, various other sources.**

Figure 1: Daily demand profiles by sector – winter weekday

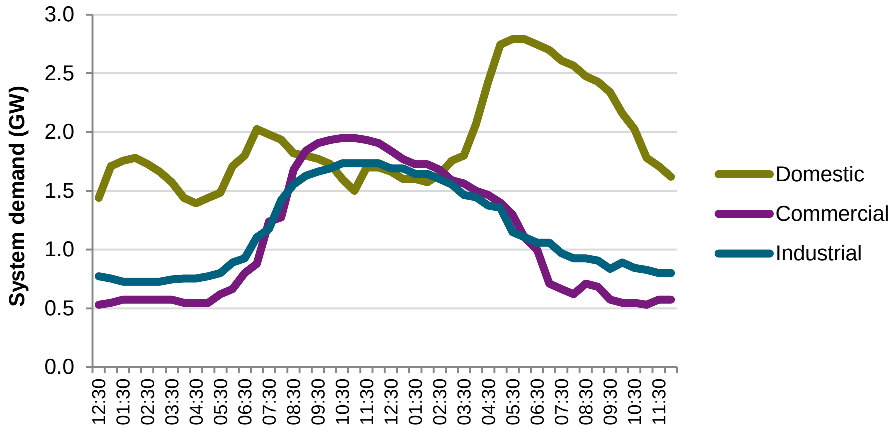


Figure 2: Peak daily demand profiles by sector – winter weekday [12-6am ; 6-12pm ; 12-6pm ; 6-12am]

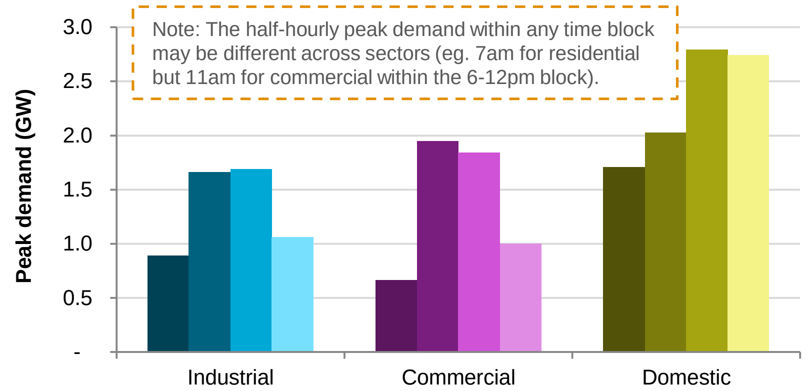
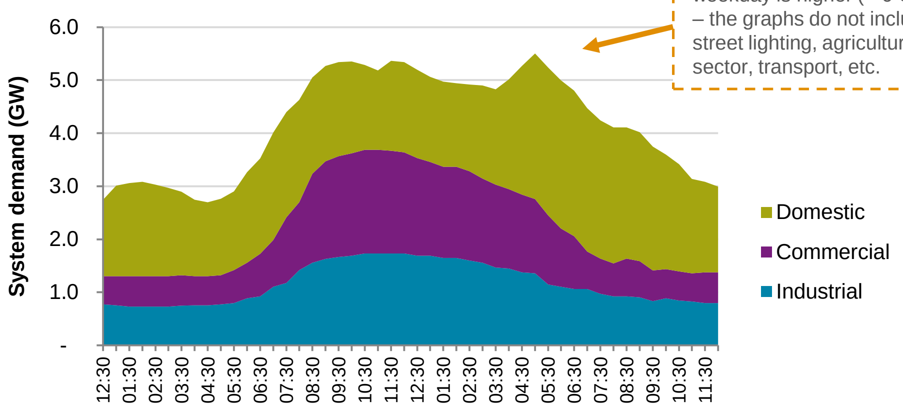
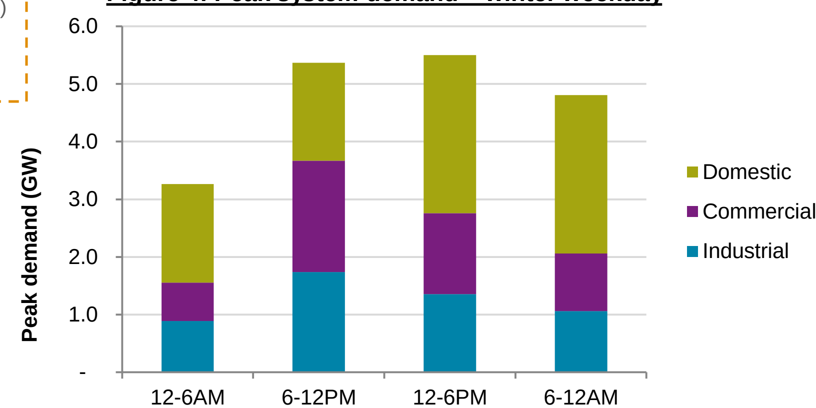


Figure 3: Daily system demand – winter weekday



Note: Actual peak electricity demand on a winter weekday is higher (~ 6 GW) – the graphs do not include street lighting, agriculture sector, transport, etc.

Figure 4: Peak system demand – winter weekday



Peak electricity demand per region – winter weekday *Methodology (2/2)*

Magnitude of demand per region: Based on National Grid's sub-national electricity consumption datasets (electricity sales, GWh) – we have used the ratio per local authority to form our estimates of peak demand per region (B0-B6). Total electricity consumption includes domestic (economy 7 and standard) and non-domestic.
Shape of demand profile per region: The profiles are then adjusted to take account of the ratio between domestic and non-domestic electricity consumption (which alters the shape of the aggregated demand profile). For example, in Zone B3, domestic consumers consume ~51% of electricity sales while non-domestic consumers consume ~49%. Conversely, in Zone B2 domestic consumers consume 39% and non-domestic consumers consume ~61% of electricity sales.

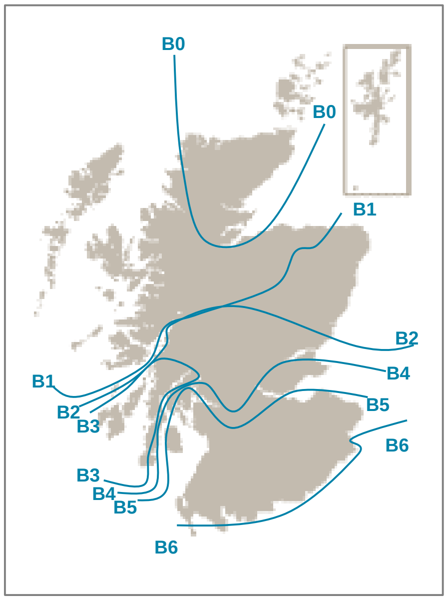
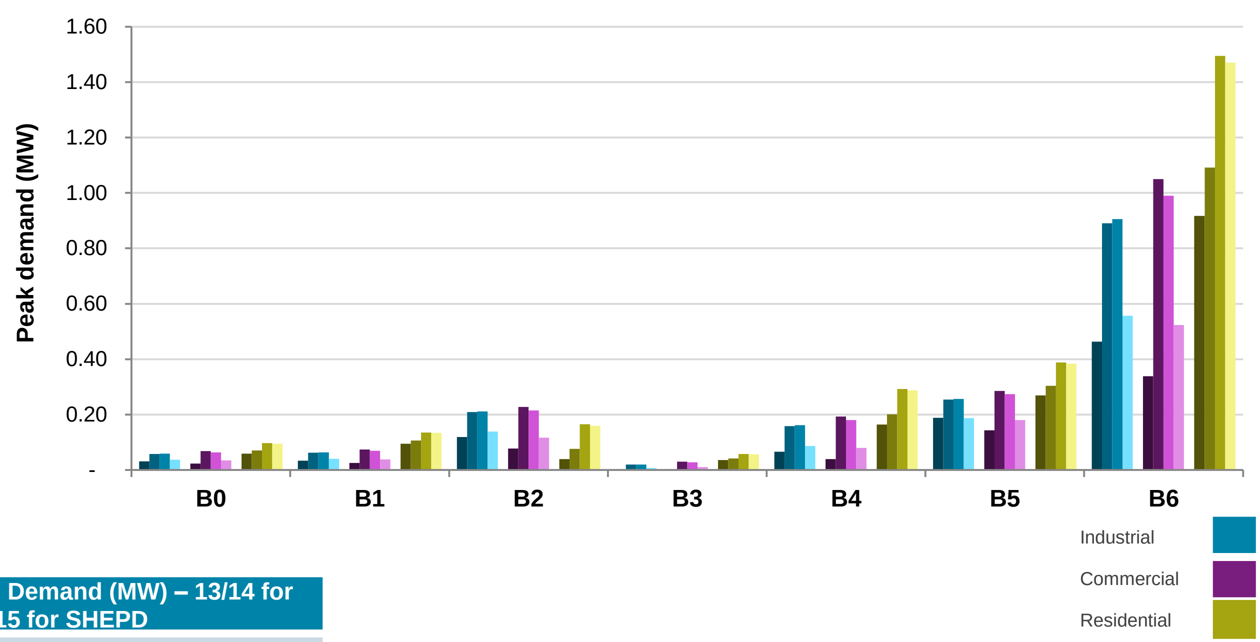


Figure 5: Peak system demand per region – winter weekday



Boundary	Distribution Connected Demand (MW) – 13/14 for SPEN, 14/15 for SHEPD
B0	126
B1	471
B2	541
B3	66
B4	507
B5	1067
B6	3,152
Shetland	42

We then cross-check the numbers produced in the graph above with actual Distribution Connected Demand (MW). In general, the share of demand across the boundaries is similar to the chart above – with B6 having the largest demands. All values were extracted from the LTDS (Long Term Development Statement) and ETYS (Electricity Ten Year Statement) and are based on connection applications – so the connection could be for 20MW but in reality there is only 10MW connected at the present time, with potential of more connections in the future.

Non-heat electricity load growth assumptions per region

Overview:

- Upon consultation with Scottish Power Energy Networks (SPEN) and Scottish and Southern Energy (SSE), the two electricity distribution network operators of Scotland – we have **assumed the base case peak electricity demand per region will remain constant up to 2050**. This means that the additional peak electric heating demand (minus CHP electricity generation) due to increased uptake of electric-based heating technologies is added on top of the base case winter peak figure.
- The reason for constant non-heat electricity demand is due to the forecast increase in demand (e.g. growth in electricity-consuming appliance purchases in line with GDP growth) being offset with a decrease in demand (e.g. efficiency improvements of appliances).
- The scope of both v1 models (Delta-ee's Electric Heat Demand model and SGS's electricity network capacity model) **excludes the impact of Electric Vehicles** on non-heat electricity load growth.
- It is not possible to capture the complexity of a large power system accurately through a high level electrical modelling approach of the type implemented in the Scotland Electricity Network Capacity Modelling tool. While the combination of both models captures network characteristics relevant and appropriate to the objective of assessing network capacity and cost implications of electrical heating, there is a limit to what is practical within the scope of this project and the information made available.

Forecast winter peak electric demand per region [B0-B6] – 2015 – 2050

Inputs into Smarter Grid Solution’s electrical system model

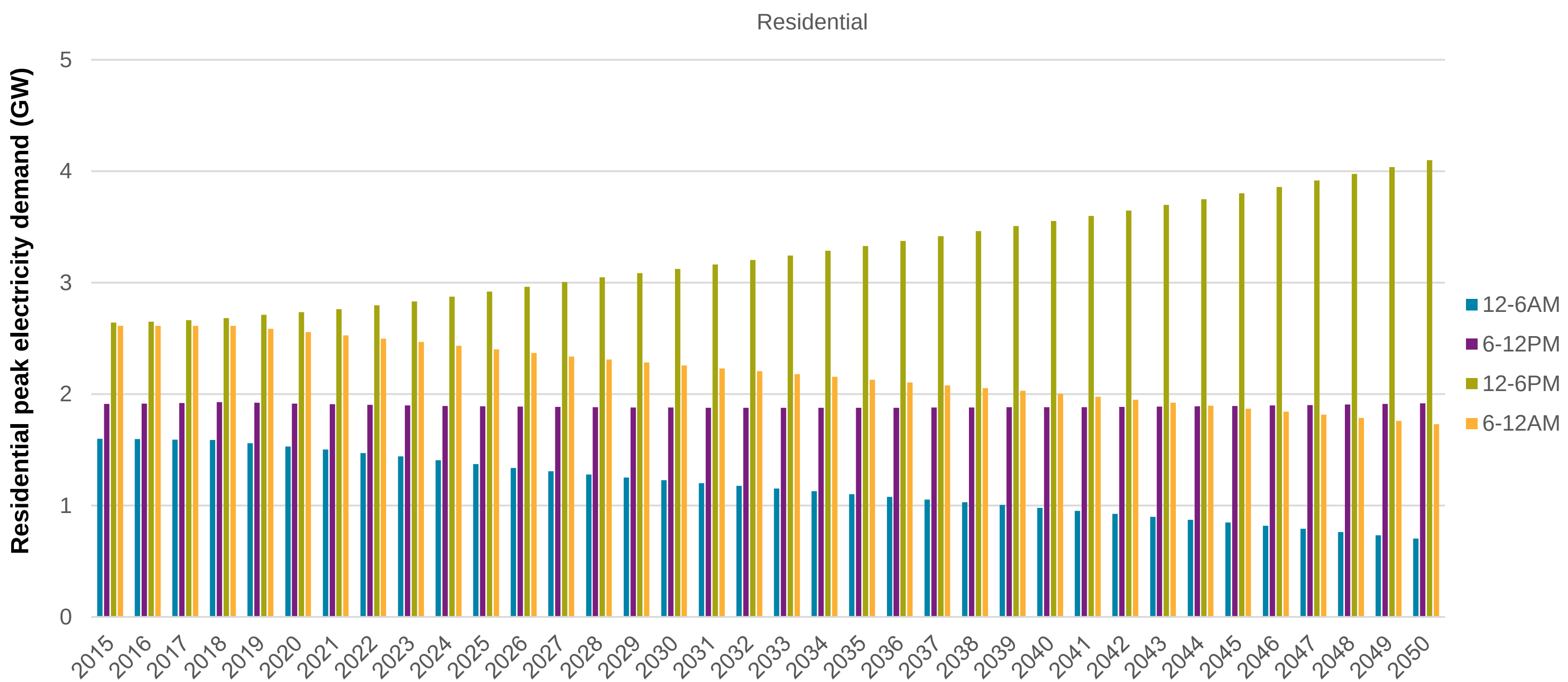
RESIDENTIAL: Peak electricity demand (including additional electric heating demand)

Overview:

- By 2050, residential peak electricity demand on a peak winter weekday may reach 4.1 GW (base case electricity demand plus additional electric heating demand) due to the increasing uptake of electric-based heating technologies in homes. This is an increase of 2.6 GW.
- Over the period to 2050, the replacement of storage heating with HPs results in a reduction in night time peaks, in particular for the **12-6 AM** time block. There is a significant increase (about 50%) increase in peak for the **12-6 PM** time block (after 4.30 PM in preparation for occupants to come back from work / school).

Note: The peak demands below do not take into account peak shaving solutions or the introduction of dynamic time-of-use pricing.

Forecast Peak Electric demand, Scotland (2016 – 2050)



COMMERCIAL: Peak electricity demand (including additional electric heating demand)

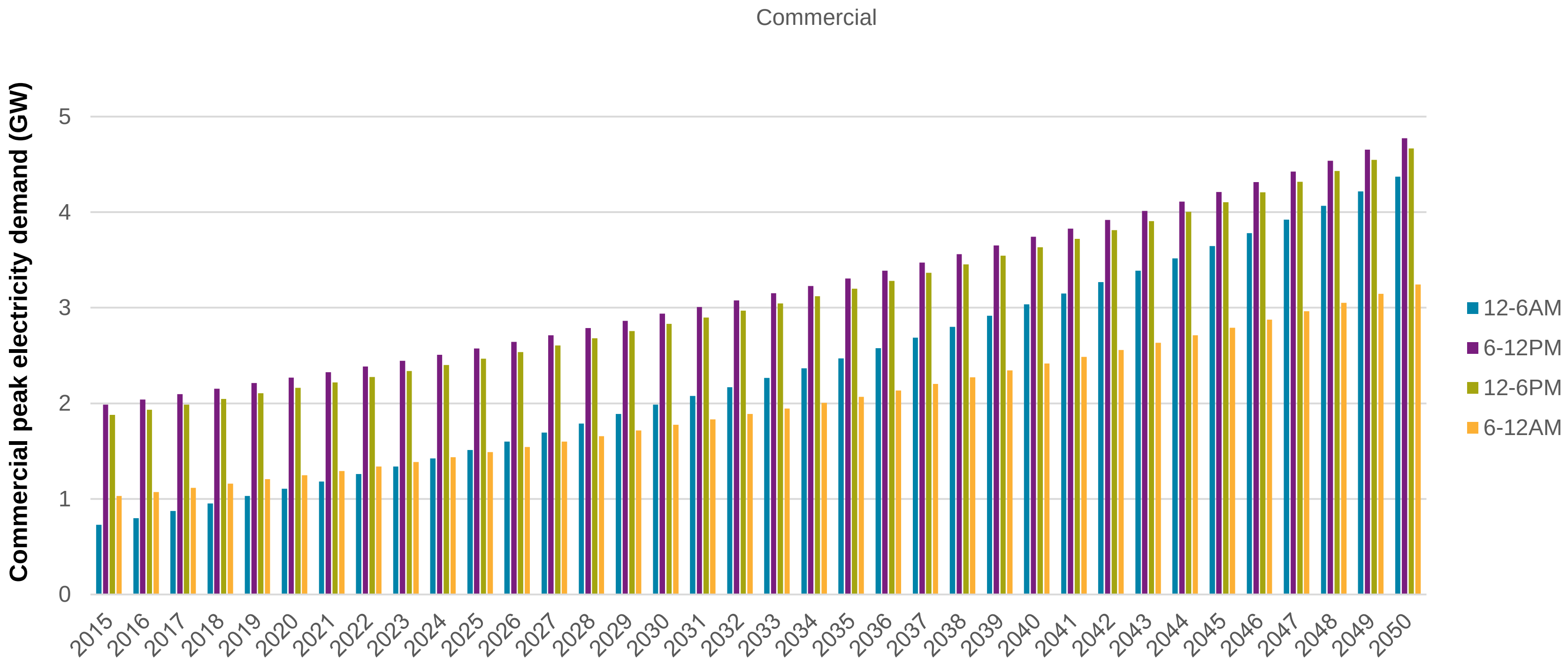
DELTA Energy & Environment

Overview:

- By 2050, commercial peak electricity demand on a peak winter weekday may reach 4.6 GW (base case electricity demand plus additional electric heating demand) due to the increasing uptake of electric-based heating technologies in commercial premises such as offices, supermarkets, and others. This is an increase of 2.7 GW.
- Over the period to 2050, there is an increase in peaks across all four time bands, especially the **12-6AM** time block (more than double by 2050). This is because (unlike in the residential sector where there is a substantial offset of electric heaters with heat pumps), the starting base of heating technologies in the commercial sector does not include much electric storage heaters which would have caused a higher starting peak for the 12-6AM time band nor direct electric heaters which would have caused higher starting peaks across other time bands as well. Hence, electrification in the commercial sector will very likely always increase peak demand.

Note: The peak demands below do not take into account peak shaving solutions or the introduction of dynamic time-of-use pricing.

Forecast Peak Electric demand, Scotland (2016 – 2050)



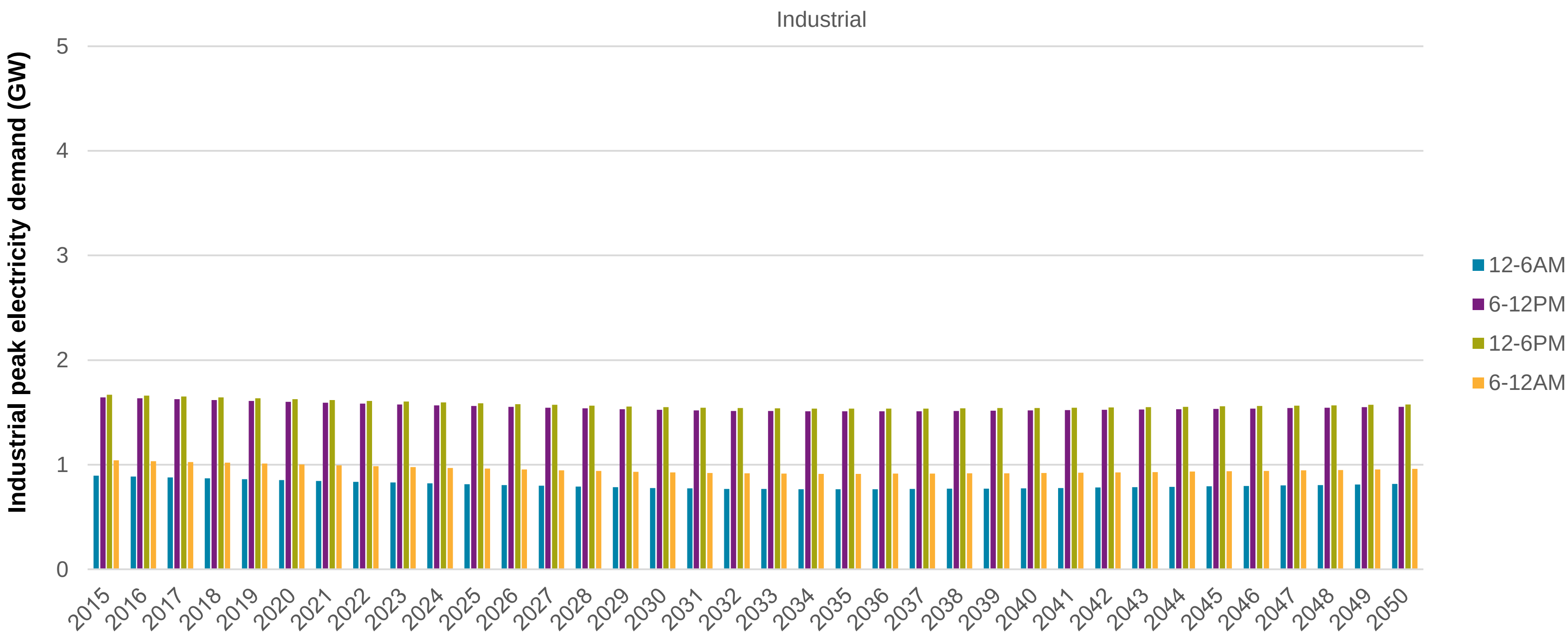
INDUSTRIAL: Peak electricity demand (including additional electric heating demand)

Overview:

- By 2050, industrial peak electricity demand on a peak winter weekday may stay relatively constant at around 1.6 GW (base case electricity demand plus additional electric heating demand) due to the growth in heat pumps being offset by replacement of some direct electric technologies, and increase in CHP generation.

Note: The peak demands below do not take into account peak shaving solutions or the introduction of dynamic time-of-use pricing.

Forecast Peak Electric demand, Scotland (2016 – 2050)



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District Heating

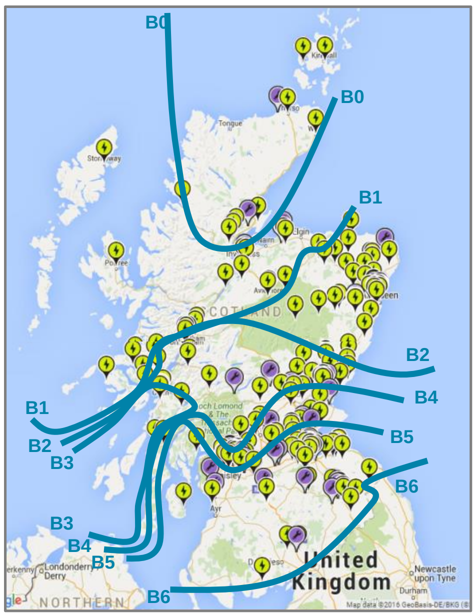
Assumptions behind reference scenario

District Heating

Overview:

- In Delta-ee's reference scenario, we have assumed the **Scottish Government's ambition is met - to achieve 1.5 TWh of Scotland's heat demand being delivered by district or communal heating and to have 40,000 homes connected by 2020** (as set out in it's Heat Policy Statement). **By 2050, we assume 7.4 TWh being met by DH.**
- The Delta-ee electric heating demand model is indifferent to the generating technology (e.g. medium scale CHP, secondary heat, geothermal heat, energy from waste heat, etc.) – as the model focuses more on the reduction of demand for individual heating technologies as a result of DH.

Existing district heating schemes (2015) ~ 1% of Scotland's heat demand



Operational DH project
In development DH project

To see sizes of schemes, please refer to HNP Projects Map

- Small schemes (<45kW)
- Medium schemes (45kW - <1MW)
- Large schemes (>1MW)

Assumed split between sectors – Scotland's heat demand met by district heating

	2016-2020	2021-2030	2031-2040	2041-2050
Residential	0.5 TWh	0.8 TWh	1.4 TWh	2.5 TWh
Commercial	0.5 TWh	0.8 TWh	1.4 TWh	2.5 TWh
Industrial	0.5 TWh	0.8 TWh	1.4 TWh	2.5 TWh
TOTAL	***1.5 TWh***	***2.6 TWh***	***4.3 TWh***	***7.4 TWh***

Assumed number of dwellings connected to a district heating scheme, per region

	2016-2020	2021-2030	2031-2040	2041-2050
B0	1,031	2,406	3,781	5,156
B1	1,413	3,298	5,182	7,067
B2	3,884	9,062	14,241	19,419
B3	681	1,588	2,496	3,403
B4	4,932	11,507	18,083	24,659
B5	5,058	11,802	18,546	25,289
B6	23,001	53,670	84,339	115,007
SCOTLAND	***40,000***	***93,333***	***146,667***	***200,000***

We have assumed the following split for residential DH connections:

- 20% semi-detached
- 40% terraces
- 40% tenements/ flats.

And the average thermal demand of the existing residential stock:

- 17MWh / year (semi-detached)
- 13MWh / year (terraces)
- 10MWh / year (tenements/flats)

SCOTLAND: Peak electricity demand (including additional electric heating demand) – if no additional DH schemes were added

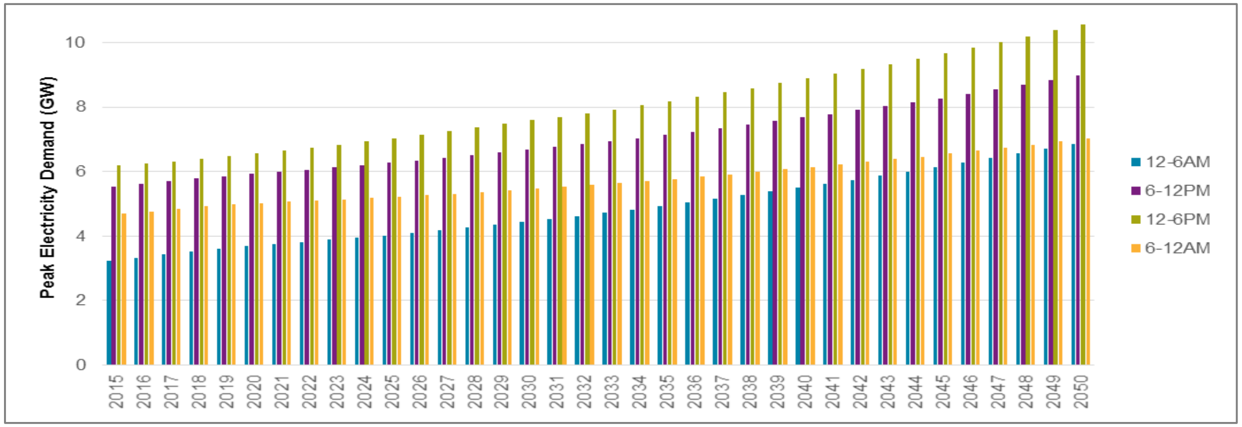
Energy & Environment

Overview:

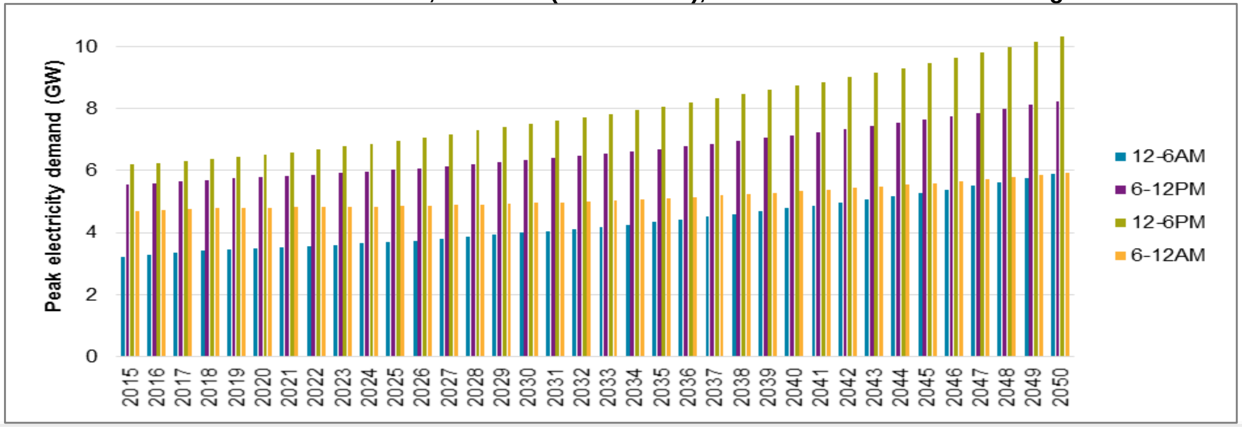
- The total estimated capacity of district heating schemes in operation in Scotland is nearly 100 MWth, delivering roughly 0.3 TWh of Scotland's heat demand. In general, district heating is normally better suited to built-up areas with high heat demand densities (housing estates and campus sites such as universities, large hospital sites and industrial complexes), though there are a few existing small scale schemes in off-gas grid areas.
- The extension of district heating schemes to provide 7.4 TWh of Scotland's heat demand by 2050 compared to just 0.3 TWh has little impact on peak electric heating demand (eg. 0.2 GW peak reduction in the 12-6 PM time block). This is despite the assumption that a large proportion* of district heating connections will replace individual electric heating technologies in the existing building stock (retrofit).

*Displacement rate calculation differs per region (due to differences in existing stock on electric heating).

Forecast Peak Electric demand, Scotland (2016 – 2050), with no additional District Heating schemes



Forecast Peak Electric demand, Scotland (2016 – 2050), with additional District Heating schemes



Building stock / thermal demand efficiency improvements

Assumptions behind reference scenario

Building stock / thermal demand efficiency improvements

Overview:

- Based on the Heat Policy Statement, the Scottish Government sets out its heat hierarchy, firstly reducing the need for heat for example through better insulated buildings; secondly by ensuring an efficient heat supply, such as development of the district heating sector and the use of unused excess heat through heat recovery, and lastly through the effective use of renewable or low carbon heat sources. The Statement places energy efficiency at the heart of the approach that the Scottish Government will take to decarbonising the whole energy system, by designating energy efficiency as a National Infrastructure Priority. One mechanism of this will be Scotland's Energy Efficiency Programme (SEEP), which will provide an offer of support to all buildings in Scotland – domestic and non-domestic – to improve their energy efficiency rating.

- In Delta-ee's reference scenario, we have assumed the following:

	Net impact on overall peak electric heating demand
Residential	
Newbuild : ~15,000 new dwellings per year Demolitions : ~2,000 demolitions per year Based on historic trends (average of the past 3 years) per local authority.	⬆
50% thermal demand efficiency improvement in each newbuild compared to base case existing stock (2014)	⬇
Assuming 10% of demolished dwellings are electric off-gas grid properties.	⬇
Renovation rate : ~1% of existing stock undertakes efficiency (10% thermal demand reduction) improvements	⬇
HP technology efficiency (COP) increases over time (as detailed in slide 20)	⬇
Commercial	
Net newbuild (*minus demolitions*) : +0.5% of number of premises in base case existing stock (2014) per year	⬆
10-20% heat demand reduction in commercial premises where new electric heating technologies or CHP are installed from 2015 onwards per year compared to base case existing stock (2014) due to efficiency improvements (net effect of newbuilds, rennovations, and demolitions).	⬇
HP technology efficiency (COP) increases over time (as detailed in slide 31)	⬇
Industrial	
5% heat demand reduction in industrial sites where new electric heating technologies or CHP are installed from 2015 onwards per year compared to base case existing stock (2014) due to efficiency improvements .	⬇

Peak shaving solutions and load shape-altering mechanisms

Note: no peak shaving solutions and load shape-altering mechanisms are assumed in the previous slides showing peak electric demand outputs. This is a stand-alone section in this slideset which demonstrates how the accompanying model includes this over-arching variable and Delta-ee commentary on thermal storage technologies.

Source: Extract from ENWL's "Managing the future network impact of electrification of heat" project

Peak shaving solutions and load shape-altering mechanisms

Overview:

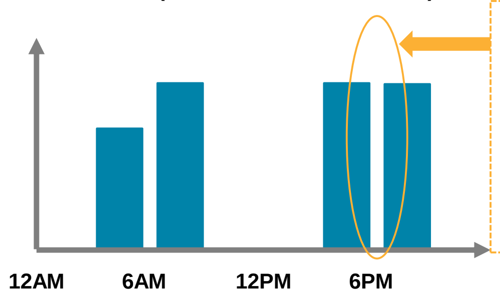
The load profiles used in Delta-ee's model and shown in previous slides are thermally-led peaks (except in the case of electric storage heaters which make use of the Economy 7 tariff overnight) – which means it generally follows building occupancy levels and process operations.

However,:

- Players in the electricity value chain (electricity suppliers and the system operator) may begin to influence the operation of electric heating and heat pumps to optimise the operation of the wider electricity system (e.g. influencing electricity demand to maximise the use of low cost electricity). This 'optimisation' will be based on national, rather than local, price signals.
- 'Optimisation' of heat pump operation at the system level could actually increase the stresses that heat pump load causes at the DNO level (e.g. if price signals shift / encourage heat pump load to increase at peak load times), making the challenge for Scottish Power and SSE even higher.
- In slide 81, we highlight how dynamic time-of-use pricing can lead to higher peaks in the absence of peak-shaving solutions such as thermal storage.

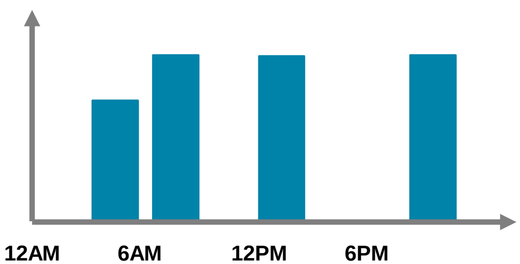
SIMPLIFIED EXPLANATION OF THE PROBLEM – ECONOMY 10 TARIFF SCENARIO

RESIDENTIAL HEAT PUMP LOAD PROFILE
(Peak across 4 time bands)



Despite the residential peak heat pump load profile on a winter peak day having three peaks, the 5-7PM peak is the peak that system balancers will be interested in as electricity demand is highest at a system demand level at this time (considering residential, commercial, and industrial together; and all electricity uses including appliances, lighting, heating ,etc.)

RESIDENTIAL HEAT PUMP LOAD PROFILE OPTIMISED FOR ECONOMY 10 TARIFF
(Peak across 4 time bands)



Theoretically, even by making use of Economy 10 tariffs (assumed off-peak periods of 12am-5am, 1pm-4pm, 8pm-10pm), this could lead to new peaks being formed at the start of off-peak periods (in this case at 1pm and 8pm) if the low-tariff periods are assumed to be the same across Scotland / UK. These peaks are related to the loss in consumption diversity as devices whose demand has been postponed during the high-tariff periods all activated at the same time. This problem is only evident where Economy 10 tariffs are widely adopted and delayed loads are significant.

Assuming heat pumps undertaking demand-shifting measures have access to 180 litres of hot water thermal storage (with negligible heat loss), 2-3kWh of thermal demand can be satisfied from a fully charged store which is roughly half of the thermal demand between 5-7pm in the coldest months.

The example above is based on the results from Element Energy's modelling which simulate heat pumps charging thermal storage to capacity in low-tariff periods, and discharging the thermal storage during peak periods. Only when thermal demand cannot be satisfied by the thermal storage do the heat pumps operate during peak periods. When modelling time-of-use tariffs such as Economy 10 (in which the evening high-tariff period begins at 4pm), they found that typical hot water cylinders can satisfy much of the demand during 4-5pm, but have insufficient thermal energy to shift a significant amount of electricity demand from the 6-7pm peak to later times.

Possible timeline assumptions

Overview:

- At the time of writing, it is impossible to determine the net impact of dynamic time-of-use tariffs and wider adoption of thermal storage technologies on Scotland's peak electric heating demand leading out to 2050. In general, Delta-ee would assume that more smoothening of (sector-specific) load profiles may happen from 2021 onwards with the completion of smart meter roll-outs, introduction of dynamic time-of-use tariffs, growing number of Demand Response Aggregators, wider adoption of thermal storage technologies, and intelligent control systems increasingly being integrated into heating technologies.
- The user of the Delta-ee electric heat demand tool will be able to modify the default percentages presented below as and when more concrete evidence of all the above start emerging.

DYNAMIC ELECTRICITY PRICING

2020 — 2030 — 2040 — 2050

- Economy 7 tariff in place
- UK-wide smart meter roll-out complete
- Voluntary Dynamic Time-of-Use tariffs introduced
- Greater engagement across Scotland with ToU tariffs
- Greater share of wind generation as part of Scotland's Renewable Energy plan

Intelligent control systems for Low Carbon Technologies (LCTs) and renewable heating technologies may replace the need for Thermal Energy Storage as they help to match heat generation to heat demand, and provide some flexibility for timing of heat production. But overall we see intelligent controls driving thermal storage applications as, together with thermal storage, they will help to maximise flexibility and matching of heat generation and heat demand.

THERMAL STORAGE

2020 — 2030 — 2040 — 2050

- Existing stock of hot water tanks and electric storage heaters
- Continued uptake of combination (or "combi") boilers in the UK and the accompanying move away from hot water storage cylinders.
- In the residential and small commercial sector, sales of hot water cylinders would increase and new products such as PCM (Phase Change Materials) gain traction – alongside higher uptake of heat pumps.
- The number of district heating schemes will grow further and the majority of new schemes will most likely use water based TTES (Tank Thermal Energy Storage).
- Stricter building regulations requiring more energy efficient technologies to be used in new builds and existing buildings would increase the uptake of LCTs and renewable heating technologies. Furthermore, it could also encourage the installation of underground thermal storage such as BTES (Borehole Thermal Energy Storage) or ATES (Aquifer Thermal Energy Storage) for improving performance of heating and cooling in large buildings.

With many newer residential houses using combi boilers, no space for thermal storage is incorporated into the design of the buildings. Therefore, this may potentially rule out the future potential for these houses to be retrofitted with renewable heating technologies requiring heat storage.

This growth scenario assumes the emergence of strong time-of-use prices for end-customers (or for other players in the electricity value chain). Different types of customers would be rewarded for shifting demand away from peak electricity demand periods – or for generating during times of peak electricity demand. Thermal Energy Storage together with intelligent controls and effective system integration enable production of heat from electricity, or CHP, to exploit these price signals.
The underlying rationale for improved electricity price signals that can be exploited with TES would be high levels of renewable energy generation. Upstream price signals, such as balancing services or network operator incentives emerge and a growing number of aggregators and demand response players monetise flexibility from distributed assets.

NOTE: Please see Appendix Iil for full list of considered Thermal storage technologies.

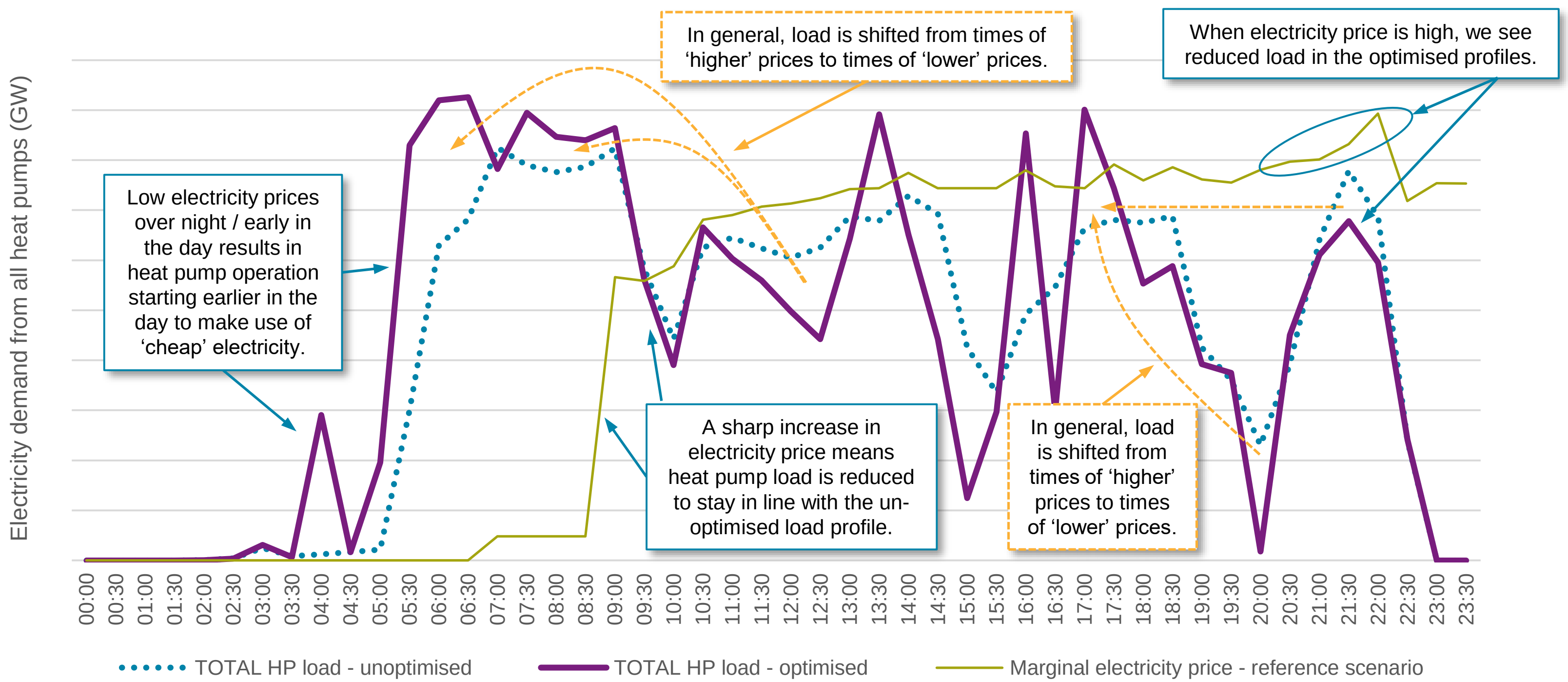
Source: Extract from ENWL's "Managing the future network impact of electrification of heat" Delta-ee project

Theoretical impact of the 'optimisation' of all heat pumps at the National level due to dynamic time-of-use tariffs

Impact of 'optimisation' on the overall electricity demand from ALL heat pumps in the installed base in 2050.

- In the chart below, we illustrate a "theoretical" total electricity demand from ALL heat pumps over one day on UK's network in 2050, both before and after 'optimisation'. We also plot the price of electricity from marginal generation plant (the key driver of optimisation) over the course on one day to illustrate the impact that electricity price has on the operation of heat pumps.
- **After 'optimisation', when the operation of all heat pumps is influenced to maximise the use of lower cost electricity, we see the maximum load increasing by 10 – 15%.** Considering only the evening heating period (16:00 – 23:00), when peak electricity demand on UK's network currently occurs, we see the maximum load increasing from at 21:30 in the chart below to being at 17:00 in the chart below. This is 15% increase in electricity demand during 'peak demand' times resulting from the optimisation of heat pump operation.
- Note – the chart below illustrate just one day, during an **'average' winter** week.
- Typically, during **'average' winter** days, 'optimisation' results in a small increase in both load from ASHPs and hybrids, typically **adding 5 – 15% onto the maximum load** from all heat pumps.
- On **'1 in 20' winter** days however, we can see a much more significant impact due to hybrid heat pumps (which usually do not operate during very cold spells) switching on, and from the back up electric heaters of ASHPs occasionally switching on. This can result in the **maximum load increasing typically by 15 – 25%.**

Electricity load from ALL heat pumps - before and after 'optimisation



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Definition of LV, HV and EHV network voltage levels

Overview:
EHV across the UK and Europe and it is therefore necessary to clarify these definitions. Scottish Power defines it as follows:
The distribution system is configured in a number of standard running arrangements and operates at 33kV and 22kV(EHV), 11kV and 6.6kV(HV) and 400 volts and 230 volts (LV), providing supply to the connection point of all remaining customers for industrial, commercial and domestic purposes.

TRANSFORM defines the voltage levels in the cost tables as follows:

- LV = Distribution (HV/LV) Transformer
- HV = Primary (EHV/HV) Transformer
- EHV = Grid (EHV) Transformer

Therefore, when looking at reinforcement costs options, the LV option will be selected in most cases, with HV options application for the smart solutions in some cases.

VOLTAGE LEVEL	Scottish Network		TRANSFORM
132kV	Transmission	EHV	EHV
33kV	Distribution	EHV	HV
11kV	Distribution	HV	LV
400V	Distribution	LV	-

LOW VOLTAGE (LV) STUDY

The Scottish Government has enquired about the feasibility of obtaining network information and conducting analysis at low voltage level. This information is not readily available from the DNOs in the same way that HV and EHV data is available. In order to access this LV network information, system planners are required to extract this information from detailed network diagrams. This can be a lengthy process, and there is a charge associated with doing so.
A number of studies of LV networks have been carried out under Low Carbon Network Fund1 projects in the UK and these are used to gain insight into LV network capacity issues.

The Flexible Urban Networks project by UK Power Networks (UKPN) investigates the use of power electronic devices to enable deferral of reinforcement and facilitate the connection of low carbon technologies and distributed generation in urban areas, meshing existing networks which are not meshed and by removing boundaries within existing meshed networks.

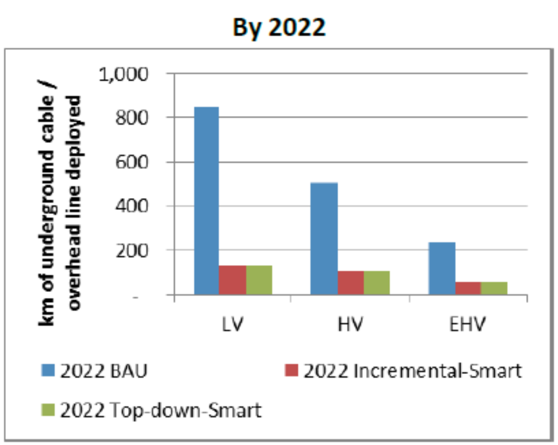
UKPN has also studied low voltage connection low carbon technologies (LCT) as part of the Low Carbon London innovation project2. Working with Imperial College London, part of the project looks at the impact of UK policy encouraging the deployment of heat pumps and PV generation on the low voltage network. An example network was selected from the suite of Engineering Instrumentation Zones (EIZs) which form part of UK Power Networks' London network and whose detailed topologies were assembled by the Low Carbon London project. This network was then used as a test case. The selected network has one of the highest percentages of domestic customers of the EIZs, as this is the type of network most affected by the introduction of both technologies. Different levels of penetration are assessed for their impact on daily peak load.
We proposed to use this information to help inform the level of LV upgrades required, and cost of these upgrades, based on the number of upgrades at HV level. A full explanation of how this is assumed in the model is provided in Slides 101-102.

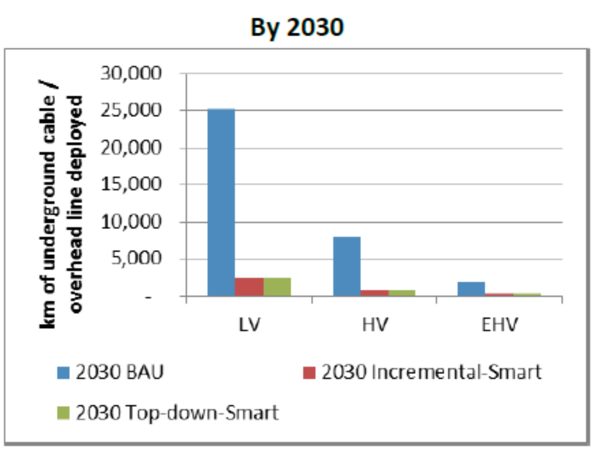
Conclusions from Smart Grid Forum TRANSFORM and DS2030 programmes

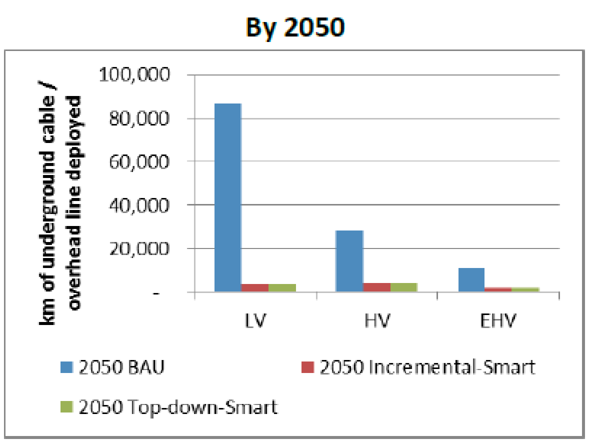
TRANSFORM programme

- The TRANSFORM Model (developed by EA Technology as part of the Smart Grid Forum's WS3 work), is a techno-economic model for the evaluation of distribution network operators (DNOs) investment options to address future network issues resulting from LCT projections.
- As part of the study, representative networks were developed. This provided reference network models on which to analyse changes in demand and generation, and the impact of numerous reinforcements and smart technologies.
- LV network feeders were separated into 19 types of feeder, with geographical areas ranging from Central Business Districts, suburban streets to rural farmsteads or small holdings. For each feeder, EA Technology defines length, rating, customers connected, and load. All LV network feeders are considered to be radial. DNOs were approached by EA Technology to determine standard feeder loads and combinations of basic house types associated with each of the 19 feeder types. This is similar to the work being undertaken by Delta-ee to quantify the types of demand across Scotland. It is noted in the TRANSFORM report that it is difficult to obtain detailed information from DNOs regarding LV network data. Assumptions and engineering judgement is required.
- The results from the TRANSFORM model suggested that a large number of smart deployments would be required at LV level for future changes in demand and generation. A mix of both conventional and smart solutions are required at all voltage levels.
- Under existing/normal 'Business as Usual' methods of network development, the only capacity reinforcement options are new circuits or transformers. By using 'smart' reinforcements, there is a significant reduction in the number of new circuits and transformers required as illustrated in the figures below.

Figure: TRANSFORM modelling summary showing the differences in the amount (km) of underground cable and overhead lines required for deployment under the three investment strategies.







Overview:

- The Distribution System 2030 (DS2030) project follows on from the TRANSFORM report, and provides more detail and discussion of what a future distribution network might look like (in terms of assets, connected devices, solutions, architecture, etc.), and how it may be operated.
- The scope of the DS2030 Project was to undertake detailed electrical power system analyses of the electricity system from the present up to 2030, with particular focus on the distribution networks, their design and, critically, their operation. The approach to this analysis, agreed with the Smart Grid Forum WS7 committee, was to study a small number of networks in depth, which were deemed to be typical of the types of low voltage networks across the UK.
- The DS2030 studies developed and utilised four Base Networks covering a range of typical distribution network types, specifically Urban, Rural, ScottishPower Manweb Interconnected and Central London. Future uptake of larger generation and Low Carbon Technologies (LCTs), specifically Electric Vehicles (EVs), Heat Pumps (HPs) and Photovoltaic generation (PVs), were considered in the form of two Scenarios developed to stress the networks in different ways. DS2030 Scenario 1 is dominated more by demand and DS2030 Scenario 2 considers connection of greater generation capacity, accompanied by lower uptake in demand. Sensitivity analysis was undertaken as appropriate throughout the studies working from the DECC/National Grid based LCT scenarios.
- For the low voltage networks, changes in demand and generation impact on the 4 network types in different ways. For example, in the rural network example, the connection of large generation had a negative effect on available capacity i.e. upgrades were required. In urban networks, the installation of generation would has a positive effect on available capacity, as it offsets the increase in demand from other low carbon technologies.
- Looking to the longer term, it was found that smart technologies cannot solve network capacity issues alone. Simulations revealed overloads of up to 70%, which smart solutions can only relieve around 10% on their own. Traditional reinforcement is required to alleviate significant and persistent overloading. Smart solutions provide added flexibility and are an option cost in the interim.
- A summary of simulation results looking at thermal issues are provided in Table 2 below. DS2030 Scenario 1 is dominated more by demand and DS2030 Scenario 2 considers connection of greater generation capacity, accompanied by lower uptake in demand. Sensitivity analysis was undertaken as appropriate throughout the studies.

Table 1: Simulated thermal issues identified in the Base Networks by 2034

Voltage (kV)	Condition	Urban	Rural
33	Intact	✓	✗ limited numbers of circuits overloaded
	N-1	✗ limited sections overloaded	✗ limited sections overloaded
trans-formers	Intact	✓	✓
	N-1	✗ few transformers overloaded	✗ few transformers overloaded
11 / 6	Intact	✗ limited sections overloaded	✓
	N-1	✗ significant sections overloaded	✓
trans-formers	Intact	✗ many transformers overloaded	✗ few transformers overloaded
LV	Intact	✓	✓

Key:

- no issues for any condition	✓ - indicates no issues for condition
- issues during N-1 contingencies only	✗ - indicates issues for condition as elaborated
- issues for system intact (and contingencies)	

Continue on next slide..

DS2030 programme

Continued…

- Another area of consideration is voltage and reactive power limitations. If generation connects in certain areas of the LV network, there may be voltage rise issues on the LV network.
- The DS2030 studies provided some specific learning on the benefits of applying smart solutions to distribution systems, in particular variations in the extent of the benefits available in networks with different characteristics e.g. meshed, radial, urban, rural, etc.
- The DS2030 studies have concluded based on a typical LV network and using aggregated LCT demand profiles, there would be satisfactory network operation.

Table 2: Summary of Study Results Voltage Issues (2034, no reinforcement, N-1 Contingencies)

Voltage	Issue	Base Network	
		Urban	Rural
11(6.6)kV	Undervoltage	✗ extensive undervoltage issues	✓
	Overvoltage	✓	✗ extensive overvoltages
LV	Undervoltage	✗ undervoltage issues with connections in excess of Scenarios 1 & 2	✗ undervoltage issues with connections in excess of Scenarios 1 & 2 when fed by upstream primary with set point of 1pu
	Overvoltage	✗ Overvoltage issues with connections in excess of Scenarios 1 & 2	✗ Extensive issues when supplied by primary with set point of 1.03pu. Overvoltage issues with connections in excess of Scenarios 1 & 2 when fed by upstream primary with set point of 1pu

Key:

- no issues for any condition	✓ - indicates no issues for condition
- issues during N-1 contingencies only	✗ - indicates issues for condition as elaborated
- issues for system intact (and contingencies)	

Application of TRANSFORM and DS2030 outcomes to Scotland Electricity Network Capacity Model

COMPARISON OF THE TRANSFORM AND DS2030 STUDIES

The DS2030 study concludes that traditional reinforcement is required in combination with smart solutions, depending on the network characteristics and demands, and concurs with TRANSFORM conclusions. DS2030 has shown that some smart solutions are likely to provide different benefits than assumed in TRANSFORM and that they will be more suited to networks with specific characteristics rather than all types.

- TRANSFORM indicated that the most investment and the greatest number of deployments would be associated with LV solutions, highlighting that many future issues are expected to be associated with the LV network including 11/0.433 kV transformers.
- The DS2030 studies considering a typical LV network and using aggregated LCT demand profiles showed satisfactory network operation, and that heat pump and EV volumes beyond the scenarios studied in the project could be accommodated without network changes. Higher levels of PV generation were shown to be accommodated by changing the fixed tap position of the upstream transformer, for example 11/0.433 kV. Sensitivity studies showed that if LV demand or generation exceed the assumed scenario uptake levels in parts of the network, for example due to clustering, then voltages may become unacceptable and other LV voltage solutions may be required.
- It is likely that the disparities in study findings could be explained by differences in the levels of clustering in TRANSFORM, the assumed initial capacity headroom margin and associated statistical distributions.

APPLICATION OF TRANSFORM AND DS2030 OUTCOMES TO SCOTLAND ELECTRICITY NETWORK CAPACITY MODEL

To account for upgrades in the LV network required for electric heating uptake in Scotland, a percentage increase in cost will be added to each Grid Supply Point (GSP) based on assumptions regarding the volume of LV network in each area. LV network upgrades options and costs are available from the TRANSFORM report, and assumptions have been clarified during workshop discussions with SPEN and SSEPD with regards to the length of lines, and typical number of LV transformers in urban and rural regions.

The following assumptions have been made regarding LV networks in Scotland, and the predicted network upgrade costs.

- Costs are provided in TRANSFORM for LV reinforcement options, which equates to 11 kV level in Scottish distribution networks. In order to quantify costs for Scottish LV networks (400 V and below), the ratio of HV to LV TRANSFORM costs will be used.
- The number of LV transformers in each region will be estimated based on the ratio of HV to EHV transformers in Scottish distribution networks (11 kV to 33 kV)

More details of these and other modelling assumptions are provided in Slides 101-102

Scotland Electricity Network Capacity Model

SCOTLAND ELECTRICITY NETWORK CAPACITY MODEL

The Scotland Electricity Network Capacity Model takes the demands created by Delta-ee, and generates information regarding the required capacity upgrades for GSPs across Scotland. It allows the users to generate a number of future energy scenarios including growth in generation, growth of EV, storage and the impact of large loads from district heating systems. A summary of the model is as follows:

- Assesses electricity network capacity issues with future energy scenarios
- Provides nodal capacity headroom
- Includes all grid and primary substations
- Considers intact and contingent network conditions
- Provides inputs for growth of microgeneration, demand growth, electric heat, etc
- Includes estimated capacity and costs for circuits and LV networks to provide holistic view of capacity and reinforcement requirements.

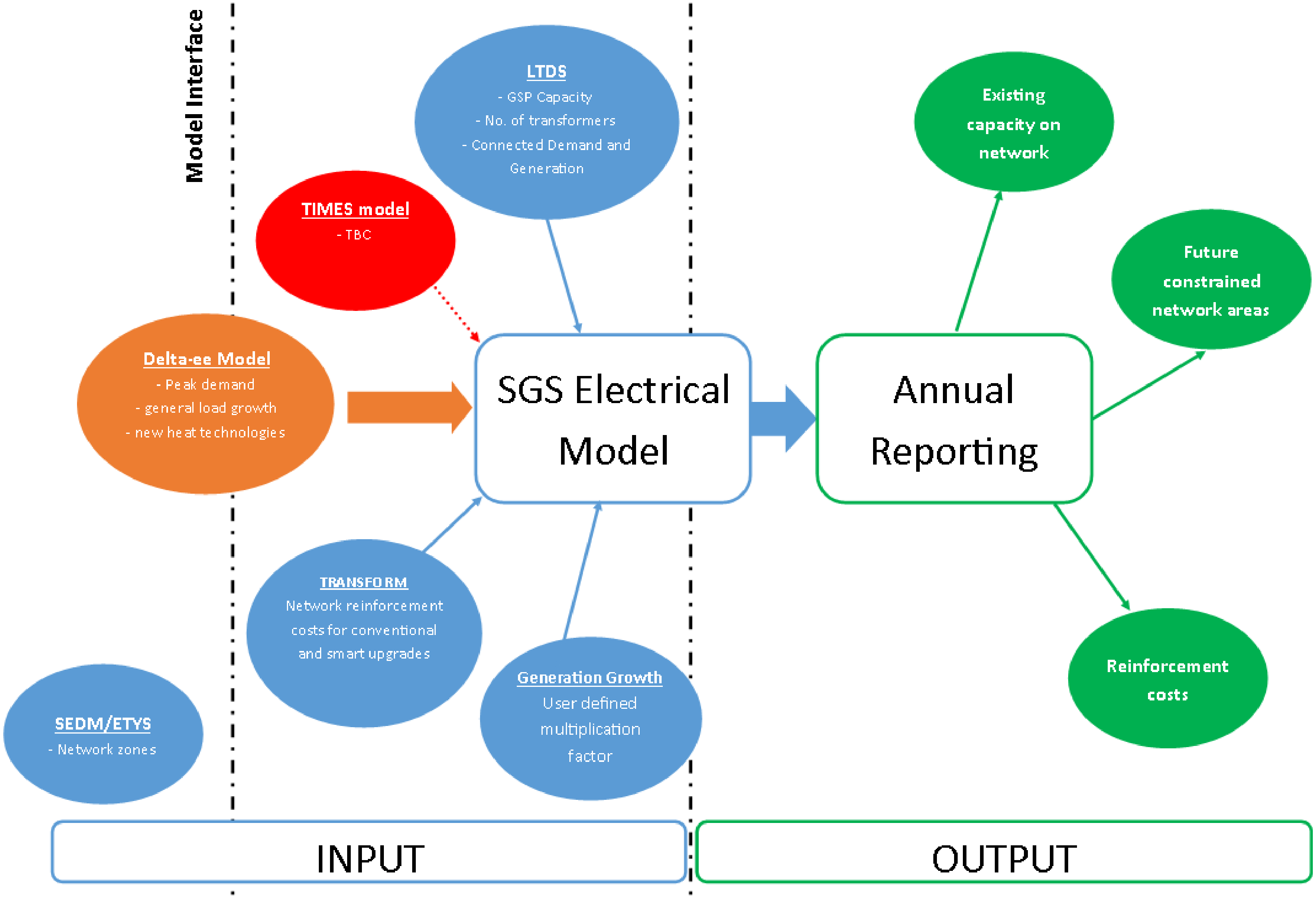
SCOTLAND ELECTRICITY NETWORK CAPACITY MODELLING METHODOLOGY

The aim of the project is to develop a straightforward, high-level but appropriately detailed, user friendly model that is configurable by the user to allow the model to be adapted over time and remain a useful tool and resource for the Scottish Government.

Therefore, Microsoft Excel is used as the basis for the Scotland Electricity Network Capacity Modelling tool. Microsoft Excel is used globally for processing data, and can be easily configured by users. The tool will be configurable for future changes and adaptations to the model. In order to prevent errors arising when using the model, calculation spreadsheets will be locked, and the user only able to change input data and add to reference data.
The calculations are relatively straightforward with the complexities embedded and locked to ensure that the right input data is captured, checked and arranged in relevant worksheets to allow the spreadsheet to process data and provide output reports.

A schematic showing the inputs and outputs of the electrical model is shown in the next slide.

Schematic of Smarter Grid Solution's Electricity Network Capacity model



Scope of the Model

It is not possible to capture the complexity of a large power system accurately through a high level electrical modelling approach of the type implemented in the Scotland Electricity Network Capacity Modelling tool. While this model captures network characteristics relevant and appropriate to the objective of assessing network capacity and cost implications of electrical heating, there is a limit to what is practical within the scope of this project and the information made available. The model includes:

The model includes:

- Thermal (MVA) capacity of Primary substation transformers in Scotland (i.e. 33/11 kV level);
- Volume (in MW) of actual connected demand and generation as of 2014 (to the most recent available information);
- Costs of reinforcements to increase thermal capacity of transformers (based on the TRANSFORM model and validated with Scottish DNOs);
- The ability to identify and quantify constrained GSPs in each network region.

Topics discussed in the report, but not explicitly modelled include:

- Thermal loading in circuits (the model is based on substation capacity only);
- Detailed voltage issues (the model addresses electricity flow capacity rather than related system voltage issues);
- Voltage capacity and limits of circuits and transformers (related to the point above but with further issues related to technical voltage limitations of equipment);
- Details of low voltage transformers and circuits (i.e. anything below 11 kV).

Future revisions to the model could be created to provide the following calculations:

- Details of substation constraints at LV level should appropriate network data be obtained;
- Details of circuit constraints based on existing detailed power system analysis techniques;
- Costs for LV network upgrades, as provided in the published TRANSFORM model data.

Key metrics in the Scotland electricity network capacity model

The following metrics are required for each region in the electrical model.

Metric	Type of data	Source
Capacity of each substation in the region, and connected generation and demand	Network data	DNO Long Term Development Statements and GBSO Electricity Ten Year Statement
Demand = peak + general load growth + new heat technologies	Demand based on heat technologies in use in given scenario and demand growth as determined by the user. This is assumed to be 0% in the base case.	Delta-ee Heat Model
Gas Network Indicator	Identify if substations supply areas where the gas network is available i.e. indicate if electric heating is likely to be in use.	Visual comparison of Scottish Gas Network map to electricity network schematic.
Generation growth factor	% growth factor for generation for projected future reports	User Input, this can be based on future policy plans, or be similar to National Grid Future Energy Scenario assumptions
Cost of conventional network reinforcements	Annualised TOTEX based on assumed asset life cost of standard network upgrades that can release additional capacity on the network for growing demand.	Published Smart Grid Forum/ WS3 TRANSFORM modelling data and RIIO-ED1 unit cost data.
Cost of smart grid network reinforcements	TOTEX cost of smart grid technology upgrades that can release additional capacity on the network for growing demand. This cost will include the cost of 'Smart Grid Enablers' which are required before smart solutions are rolled out.	Published Smart Grid Forum/ WS3 TRANSFORM modelling data
Network Geographical location	Reference points for the location of the substations. Each substation might have multiple associations (e.g. B6, Linmill GSP, South Lanarkshire LA area, etc) however it is expected the main grouping will be by Transmission Zones (See slide 94.)	Electricity Ten Year Statement, and Scottish Electricity Dispatch Model documentation

Introduction to the design of Smarter Grid Solution's electric system model

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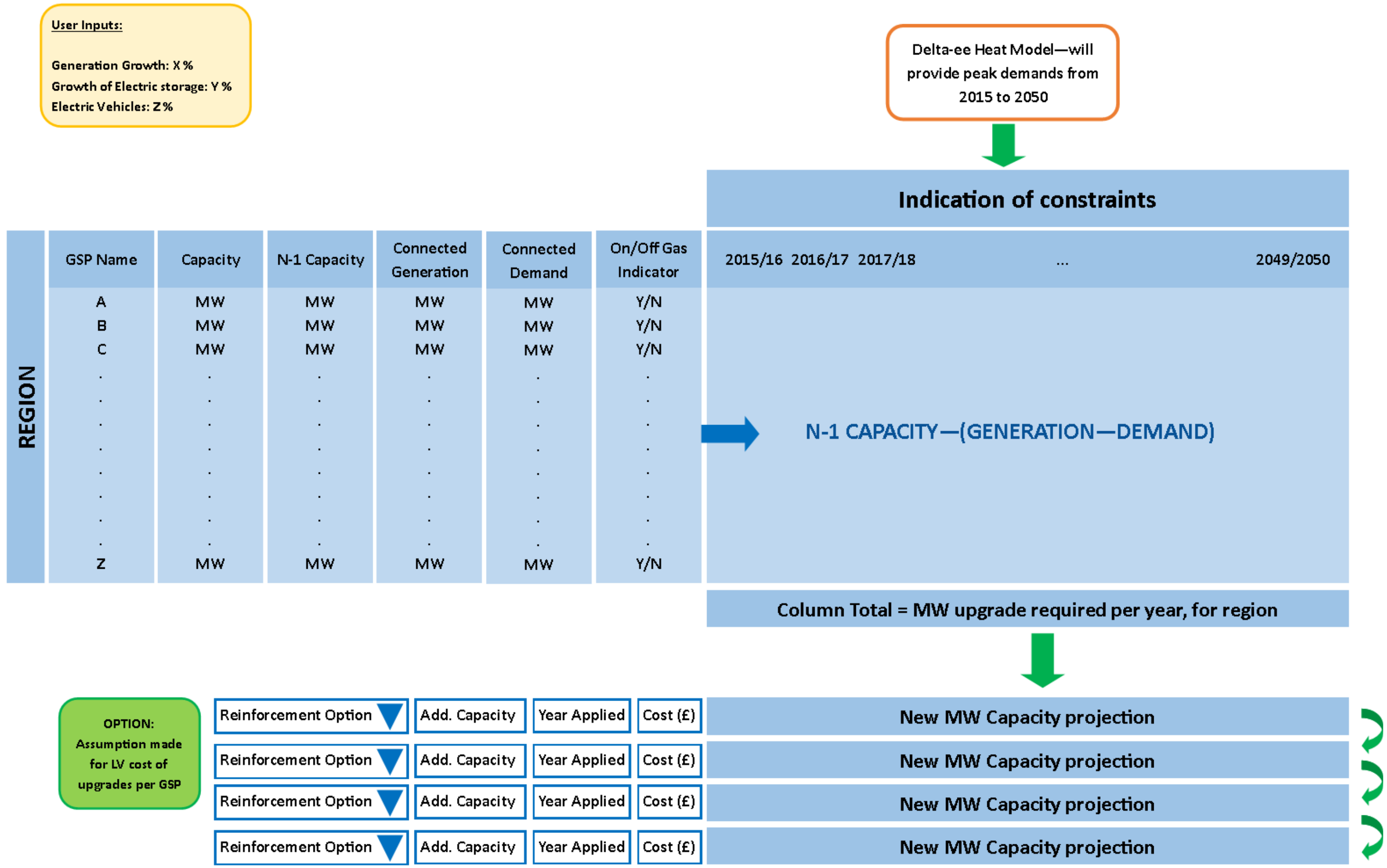
Overview:

The model is constructed using publicly available information from LTDS documents for the network elements, and the published TRANSFORM data on network reinforcements. This model will take the peak demands from the Delta-ee model and project this on to the network model. The key output of this part of the model will be the identification of future network constraints, and the cost of potential reinforcements to relieve these constraints. The model focuses on 33kV level information with assumptions made with regard to 11kV and LV level upgrades.



Baseline Metrics

Overview:
These metrics have been extracted from publicly available information, published by the Distribution Network Operators as part of their license conditions.

GSP Capacity (Intact and N-1)
The sum total of the capacities of all transformers at each GSP was calculated, then the capacity of the largest transformer was subtracted from that, to give a worst-case N-1 capacity.

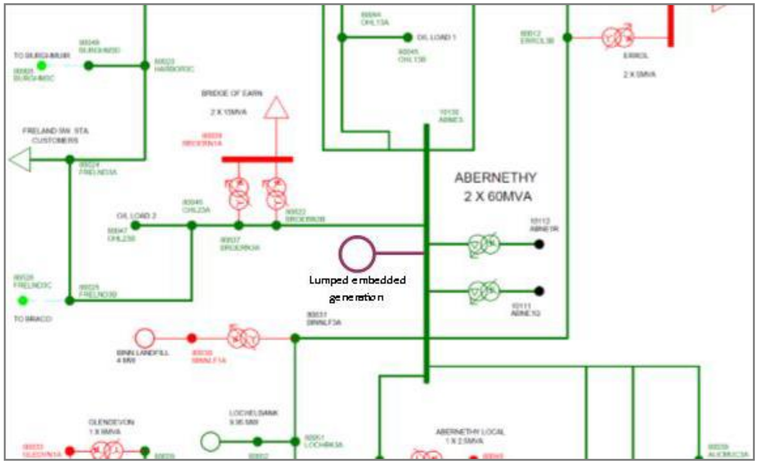
Demand Levels
Connected demands were extracted from the LTDSs. This is used to calculate the share of demand across the network zones.

Connected Generation
Capacity of connection generation. This has been broken down into the following categories
Distribution connected:

- Wind
- Other (consisting of PV, Waste, Biomass & Energy Crops, Tidal & Wave and CHP)

The generation data was sourced from the LTDSs. These generation capacities include the total volume of generation that is currently connected, or is contracted to connect. Where a primary substation was not provided, it is assumed that the generation is connected at the 33 kV side of the GSP.

Figure : Extract for SHEPD LTDS of the Abernethy 33kV system. All connected and contracted generation has been assumed to connect at the 33kV side of the GSP unless otherwise stated in the LTDS.



Model Regions

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Overview:
The Scotland Electricity Network Capacity model is divided into 11 zones in order to align the model with the Transmission Dispatch model currently used by the Scottish Government. Each region contains a number of residential, commercial and industrial loads. The regions are based on the Transmission System Boundaries, which can be found in the Electricity Ten Year Statement.

Within each region, details of substations associated with each GSP from 33 kV down to 11 kV are provided in the Excel spreadsheet model. Assumptions of how to treat upgrades below 11 kV level are described in Slide 101-102. The key metrics listed for each substation are provided in slide 91

Figure 1: National Grid ETYS Transmission System Boundaries

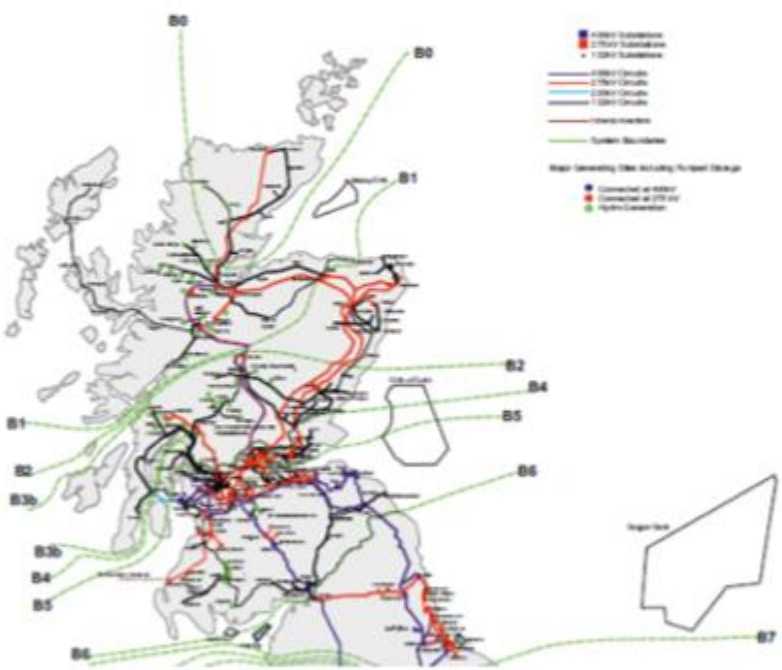
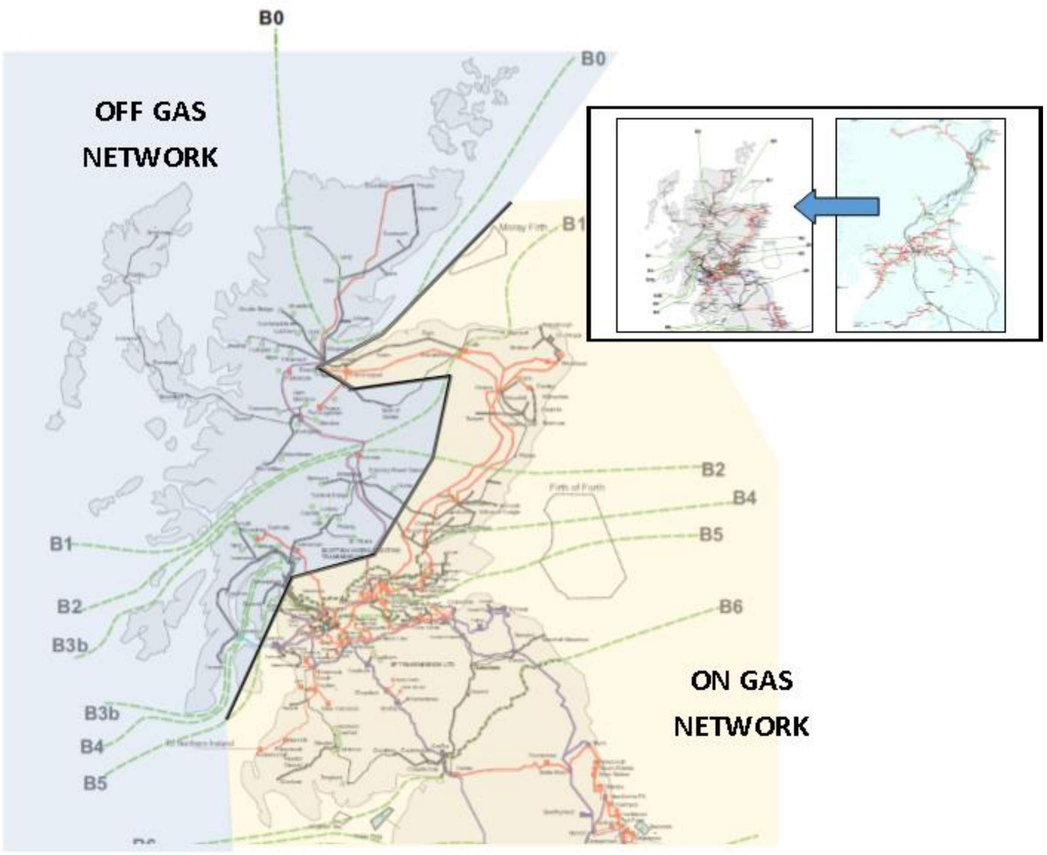


Figure 2: Scottish Government defined regions

On or Off Gas Grid - assumptions

Overview:
GSPs are identified as being ON or OFF the gas network by visually comparing the Scottish Gas Network map to the GB Transmission System Map. A diagram of this is show in the Figure below. By comparing the electricity network infrastructure with the gas network infrastructure, it is possible to identify if GSPs are either on or off the gas grid, and therefore whether heat demand currently relies on fuel oil or electric heating or whether natural gas (piped) heating is likely.

Figure: National Grid Transmission Boundaries overlaid with the Gas Network to allow estimation of which GSPs were either on or off the gas network.



P2/6 Security Standards

Overview:
Engineering Recommendation P2/6 outlines the rules regarding Security of Supply. It is used as a guide to system planning by network operators. P2/6 determines the level of redundancy required for different levels of connected demand and generation. This information allows the model to make assumptions about what network reinforcements are required for different electrical demand levels at each substation.

Extract from Table 1 of Engineering Recommendation P2/6

Range of Group Demand	Minimum demand to be met after a certain time period during a First Circuit Outage (fault or planned)	How this is applied in the model	P2/6 Limit in Model
≤ 1 MW	In repair time	GSP is unconstrained so long as transformer has sufficient capacity to meet demand under normal operating conditions	0
> 1 MW and ≤ 12 MW	Within 3hrs: Group demand – 1MW Group Demand to be met within repair time	The load (total demand – 1 MW) must be met follow the loss of the largest transformer on the circuit e.g. N-1 capacity.	Demand – 1 MW
> 12 MW and ≤ 60 MW	Within 15 mins: Smaller of Group Demand – 12MW or 2/3 Group Demand Within 3hrs: Group Demand	The load must be met follow the loss of the largest transformer on the circuit e.g. N-1 capacity.	Min(Demand – 12 MW, 2/3 * Demand)
> 60 MW and ≤ 300 MW	Immediately: Group Demand – 20 MW Within 3hrs: Group Demand	A loss of supply not exceeding 60 s is considered as immediate restoration. In terms of the ScotGov model, this means the load (total demand – 20MW) must be met follow the loss of the largest transformer on the circuit e.g. N-1 capacity.	Demand – 20 MW
> 300 MW and ≤ 1500 MW	Immediately: Group Demand	The load must be met follow the loss of the largest transformer on the circuit e.g. N-1 capacity.	Demand

It should be noted that there is currently a review of P2/6 on-going at the time of writing this report. Any changes to P2/6 are still some way into the future. Should significant changes to P2/6 occur in the future, the model user will be able to update the standards in the table. Should a more complex or probabilistic method of defining security standards be the outcome of the P2/6 review then development of an updated version of the model may be required (but this is expected to be some years away yet).

Reinforcement options (TRANSFORM model, EA technology)

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Overview:
There are a wide range of reinforcement options published in Appendix 1.0 of the TRANSFORM report, shown in the Table below.

In the TRANSFORM study, **some representative solutions were not selected as being the best solution**. These included:

- Storage – due to the high cost
- Generation Constraint Management and Network Support – due to insufficient granularity of individual circuits. Unlikely at LV due to the size of generation connected.
- Switched Capacitors – high costs when compared with other technologies. This is based on a small number of real projects.

Popular smart solutions included:

- Active Network Management – Dynamic Network Reconfiguration
- D-FACTS
- Permanent Meshing of Networks
- Real Time Thermal Ratings

New transformers, major and minor works were selected from the conventional solutions options.

Reinforcement options from TRANSFORM Report

Smart Solutions	Conventional Solutions	Smart Enabler
• Active Network Management - Dynamic Network Reconfiguration • D_FACTS • DSR • Electrical Energy Storage • Embedded DC Networks • EAVC • Fault Current Limiters • Generator Constraint Management • Generator Providing Network Support e.g. Operating in PV Mode • Local smart EV Charging infrastructure • Permanent Meshing of Networks • Real Time Thermal Ratings • Switched Capacitors • Temporary Meshing	• Split feeder • New Split Feeder • New Transformer • Minor Works • Major Works	• Communications & Control Platforms between variant solutions • DNO to DSR aggregator enablers • Network Measurement Devices • DCC to DNO Communications platforms • Phase imbalance measurement • Weather/ambient tempt data • Design Tools • Protection and Remote Control

An enabler is a component part of a solution, but one that is not, in itself, able to provide headroom benefits. They are typically associated with monitoring, communications or control systems.

Reinforcement options (used in Smarter Grid Solution's model)

Overview:
A selection of solutions for study in this model are listed below. They were selected due to their ability to boost capacity at the transformer. The TRANSFORM document will be used as a reference, and the user of the model will be able to change and add in upgrade options to the model in future, should it be required or desired. The cost of smart enablers is added to the overall smart solution costs once the first smart solution is required in a GSP area (and is then enabled for other smart solutions).

Costs in the TRANSFORM report are provided in a group basis i.e. the cost are calculated on a per feeder basis so the TOTEX is split across the number of feeders served. The model does not provide the number of feeders for the cost calculation. Therefore, in order to determine the cost of a GSP upgrade, per transformer, some costs are used from the DNO charging reporting documents to the regulator – RIIO-ED1 and DCPR5.

Reinforcement options selected for Scottish Government model

Smart Solutions	Conventional Solutions
• Active Network Management - Dynamic Network Reconfiguration • D-FACTS • STATCOM • Demand Side Response • Electrical Energy Storage • Local smart EV Charging infrastructure • Permanent Meshing of Networks • Real Time Thermal Ratings • Temporary Meshing	• New Transformer • Minor Works • Major Works

Derived Metrics

P2/6 Constraint Capacity
This is defined in line with P2/6 recommendations, see Slide 96 for details.

Security Level Constraint
A GSP is considered to be ‘constrained’ if either its Maximum Net Import level or its Maximum Net Export level exceeds its calculated worst-case security level capacity. This is as follows:

- For exporting GSPs, it is considered constrained if export is greater than 2/3 of intact capacity.
- For importing, GSPs, it is considered constrained if import is greater than 90% of N-1 capacity.

Final Constraint
The P2/6 and security level constraints are compared and the worst case constraint is used to calculated the required reinforcement. The result is given in MW.

Impact of Upgrades
Conventional and smart grid technologies can be used to increase the available capacity on the electricity network. The impact of technologies can be assessed using data published in the TRANSFORM report. These will be compared to standard reinforcement upgrades i.e. building more wires or increasing the size of a transformer.
For the reinforcement calculation in the model, when reinforcement is applied, the percentage increase in capacity is applied to the fully intact capacity. The number of transformers is assumed to stay the same. However, for the N-1 calculation, if this was originally 0 i.e. there was only a single transformer, it is assumed that the number of transformers will increase and the N-1 capacity is now half of the intact capacity.
For example, a GSP has a single transformer with 15 MVA capacity. Major reinforcements are applied, which will increase the capacity by 80%. The N and N-1 capacities are shown in below.

(MVA)	BEFORE	AFTER
Fully Intact (N)	15	27
Outage (N-1)	0	13.5

Cost of reinforcements
The costs of traditional reinforcements are extracted from publicly available information in DNO business plans i.e. RIIO-ED1 and the published TRANSFORM model data.
In terms of smart reinforcements, a selection of potential smart grid options will be created based on the TRANSFORM model. This list will include the most likely smart grid reinforcement options for Scotland. The cost information from the TRANSFORM model is publicly available information, and therefore model users can calculate reinforcement costs from other smart grid reinforcement options in the future if they desire.

User Inputs and model outputs

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Generation Availability factors
These values are the capacity factors of connected generation. The user has the ability to enter a capacity factor for wind generation, and all other renewable generation.

Lumped Demands
The user can add lumped demands to the model, which allows representation of larger, discrete district heating demand increases. The user can select the GSP to apply the large demand to, and the year in which to apply it. This should be used to match with any district heating assumptions made in the Delta-ee section of the modelling.

Use of Electrical Storage
This input requires a starting capacity assumption, with a multiplier or percentage growth/contraction value to account for electrical storage devices. It is assumed that the storage device will be used to provide additional capacity at peak demand time periods.

Growth of Electric Vehicles
This input requires a starting capacity assumption, with a multiplier or percentage growth/contraction value to account for electric vehicle devices. It is assumed that EV demand will be applied at peak times. This is a worst-case assumption however the focus of this model is not on the growth of EV, but on the impact of heating technology on electrical demand. This assumption is in line with DS 2030 results which show that households with heat pumps and electric vehicles have a higher impact on the network than households without.

Generation Growth Factors
The growth (or contraction) of Demand and Generation is based on user input values. This allows the user to tailor the level of generation growth in different regions.
The user has the ability to apply growth to generation in each year, and for each region.

OUTPUTS

The model will process the input data within the excel spreadsheet tool, and produce a table of annual reporting values from 2015 through to 2050. These reports will be produced for each region of the Scottish electricity network, and will provide the following information

- Capacity of each substation
- Identification of constrained GSPs
- Volume of capacity upgrades required at each GSP
- Costs for reinforcements (including both traditional and smart grids)

Assumptions

Accounting for LV upgrades per GSP

A review of other LV network studies is provided in Slides 83-85. Based on this review, it is assumed that LV upgrades can be captured as an additional cost for each 33 kV GSP upgrade.

Costs are provided in TRANSFORM for LV reinforcement options, which equates to 11 kV level in Scottish distribution networks. In order to quantify costs for Scottish LV level (400 V and below), the ratio of HV to LV TRANSFORM costs will be used.

This can be assessed against the 11 kV transformer information provided in the LTDS for SHEPD and SPEN. The number of 11 kV substations behind each 33 kV GSP will be counted for each region e.g. a region with a high number of substations, will incur a higher reinforcement cost. The total number of 11 kV/LV transformers in SHEPD network is provided in Slide 102. For the SPEN network, the ratio of 11 kV to 33 kV will be used to calculate the number of LV to 11 kV transformers.

Accounting for Voltage Issues

The model does not have the capacity to analyse in voltage levels in any depth. It can be assumed that when a transformer is upgraded for thermal issues, it will provide additional voltage capacity.

Assumptions

smarter grid solutions

Cable Reinforcements

Both SHEPD and SPEN publish information on the length of cable and line at each voltage level on the network. Based on published unit cost information, and pro rata distribution of cable per GSP and assumption can be made regarding the cost of cable and line upgrades in each region.

SSE

SHEPD

Voltage		Unit	Volume
33 kV	Overhead Line	km	5,468
	Cable	km	1,119
	Transformers	33/11 kV and 33 kV /LV	2,117
11 kV	Overhead Line	km	21,819
	Cable	km	5,110
	Transformers	11 kV/LV ground and pole mounted	53,125
Low Voltage	Overhead Line	km	4,121
	Cable	km	10268

SP ENERGY NETWORKS

SPEN

Voltage Level	Line Length	
	Overhead Line	Underground Cable
11kV	14,053	12,402
33kV	2,661	2,996

Reinforcement Costs

Based on the assumptions outlined above, and the costs provided in TRANSFORM and DPCR5 (Distribution Price Control Review), the follow sections set out how the reinforcement costs are applied in the model, and how LV and 11 kV network reinforcements are accounted for.

Network Configuration

The model will provide network information for 33 kV level of the network. In order to quantify the reinforcements required at LV level, the distance of cable in each region must be determined. This is based on the number of 11 kV transformers in a region, and then the total cable length from LTDS is shared proportionally across the network operator area (See the previous slide). There is no LV cable length defined for SPEN. It is assumed that Region A5 and A6 have similar cable lengths to Region A4.

A summary of the number of GSPs, 11kV transformers and length of LV cable is provided in the Table of the left. A breakdown of 11 kV transformers and LV cable per GSP is shown in the table on the right.

Summary of number of GSPs, 11 kV transformers and length of LV cable.

Region	Network Owner	No of GSP (33 kV)	No of 11 kV Transformers	Length of LV Cable (km)
A1a	SHEPD	18	114	4030
A1b	SHEPD	8	38	1343
A1d	SHEPD	1	13	460
A1e	SHEPD	3	28	990
A1f	SHEPD	3	13	460
A2	SHEPD	15	62	2192
A3	SHEPD	4	38	1343
A4	SHEPD	19	101	3571
A5	SPEN	22	121	3571
A6	SPEN	63	320	3571

Breakdown of 11 kV transformers and LV cable per GSP

Region	No of 11 kV Transformers	Length of LV Cable (km)
A1a	6.33	223.89
A1b	4.75	167.88
A1d	13.00	460.00
A1e	9.33	330.00
A1f	4.33	153.33
A2	4.13	146.13
A3	9.50	335.75
A4	5.32	187.95
A5	5.50	162.32
A6	5.08	56.68
All	67.27	2223.93

Conventional Reinforcements

The costs for conventional reinforcements are taken from DCPR5 unit cost information. While costs for conventional network upgrades are provided in the TRANSFORM report, they are provided on a per feeder basis, meaning that the cost of installing, for example, a primary transformer is smeared across the number of feeders that the transformer supplies. Details of the number of feeders are not provided in the cost summary table and therefore it is not possible to calculate the 'per transformer' cost. DCPR5 provides CAPEX costs, and in line with TRANSFORM, no OPEX costs are considered.

The conventional reinforcement costs are shown below for Scottish 33 kV, 11 kV and cable upgrades at LV level.

Table: Summary of number of GSPs, 11 kV transformers and length of LV cable.

Reinforcement Option	33 kV	11 kV	LV	Additional Capacity
New Transformer – Pole Mounted	£5,800	£4,200		80%
New Transformer – Ground Mounted	£519,600	£13,300		80%
Replacement Line (per km)			£80,700	-
Major Reinforcement Works	£2,598,000			500%
Minor Reinforcement Works	£623,520			100%

Smart Reinforcements

The costs for smart reinforcements are taken from the TRANSFORM report. Included in the cost of the smart upgrade, is the TOTEX of the ‘smart enabler’. It is assumed that smart solutions are not applied at LV or 11 kV level but gain the benefits of having the smart reinforcement being installed at higher voltage levels.

Table: Summary of Smart Reinforcements provided in the model, with associated costs and capacity improvements

Smart Reinforcement	Enabler	Enabler Costs	33 kV	Additional Capacity
Active Network Management - Dynamic Network Reconfiguration	Advanced control systems RMUs fitted with activators	£34,264	£53,553	10%
D_FACTS			£102,842	4%
STATCOM			£152,842	5%
DNO to central business district DSR			£12,258	0%
Electrical Energy Storage - Small (50 kW; 100 kWh)	Advanced Control Communications to and from devices	£18,274	£251,421	10%
HV connected EES (Small -1.5 MW, 3 MWh)	Advanced Control Communications to and from devices	£18,274	£3,403,553	0%
HV connected EES (Medium -2.5 MW, 5 MWh)	Advanced Control Communications to and from devices	£18,274	£3,803,553	0%
HV connected EES (Large -3 MW, 6 MWh)	Advanced Control Communications to and from devices	£18,274	£4,203,553	0%
Local smart EV Charging infrastructure			£18,553	0%
Permanent Meshing of Networks (Suburban)			£101,421	15%
Permanent Meshing of Networks (Urban)			£21,421	0%
RTTR (For Tx)	Weather Monitoring	£5,711	£3,000	10%
Temporary Meshing	Advanced control systems	£17,132	£27,106	8%

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Appendix i
High level description of the different heat pumps considered in this study

Heat pumps (HP) use physical principles in order to move (or "pump") energy from a place with a lower temperature level, e.g. from the outside air, to somewhere with a higher temperature level, e.g. the flow temperature required in a heating system. The types of heat pumps which have been considered in this study are summarised below.

Type of heat pump	Description
Air-source heat pump, low temperature	▶ An air-source heat pump uses electricity and energy from the outside air in order to supply heat to a building. ▶ The seasonal conversion efficiency of electricity to useful heat is around 250-300% in the UK, as the heat pump extracts 1.5 - 2 units of energy from the outside air for every unit of electricity it consumes. ▶ This is subject to seasonal changes, as the outside temperature affects the heat pump's ability to extract energy. The higher the outside temperature, the more energy the heat pump can extract per unit of electricity it consumes. Daily efficiencies will therefore vary. ▶ A **low temperature heat pump** as defined in this project **reaches flow temperatures of 55°C** (this is the temperature of the water leaving the heat pump, which feeds the space heating & hot water circuits). The key element for the heat pump's efficiency is the difference between the heat source (in this case the outside air) and the flow temperature it has to achieve. Buildings requiring lower flow temperatures (for example: well insulated buildings & new builds) will therefore achieve higher seasonal conversion efficiencies.
Air-source HP, high temperature	▶ High temperature air-source heat pumps have the same key functionalities as low temperature versions. ▶ The main difference to a low-temperature air-source heat pump is that high temperature heat pumps can achieve higher flow temperatures of up to 80°C and are optimised to doing so. ▶ Their seasonal efficiencies (if required to run at these high temperatures) will nevertheless be lower than those of low temperature systems.
Hybrid air-source heat pump	▶ Hybrid air-source heat pumps are a combination of a low temperature air source heat pump with a fossil fuel boiler (gas or oil), which is controlled by a single, intelligent controller. ▶ The main advantage of hybrid heat pumps is that the controller allows the heating system to switch between fuel sources (i.e. to use the boiler, or the heat pump, or both parts) based on the efficiency of the system under current circumstances (e.g. outdoor temperature, flow temperature, etc.). This can be combined with other information, such as energy prices or noise level, to optimise the operation of the system as a whole. ▶ In general this will mean that the boiler will take over from the heat pump during very cold periods (when the efficiency of the heat pump part falls).
Ground source heat pump	▶ Similar to air-source heat pumps, ground source heat pumps use electricity to make renewable energy, in this case from the ground, using either vertical boreholes or a horizontal collector. ▶ From a depth of 10-15 meters the temperature of the ground is stable at around 10°C throughout the year. Due to this higher and more stable source temperature, a ground-source heat pumps are more efficient than air source heat pumps. ▶ Ground source heat pumps are, due to the high costs linked to developing the ground source, more expensive than air source heat pumps

Appendix ii
Introduction – Industrial Heat Pump Technology Options (1/2)

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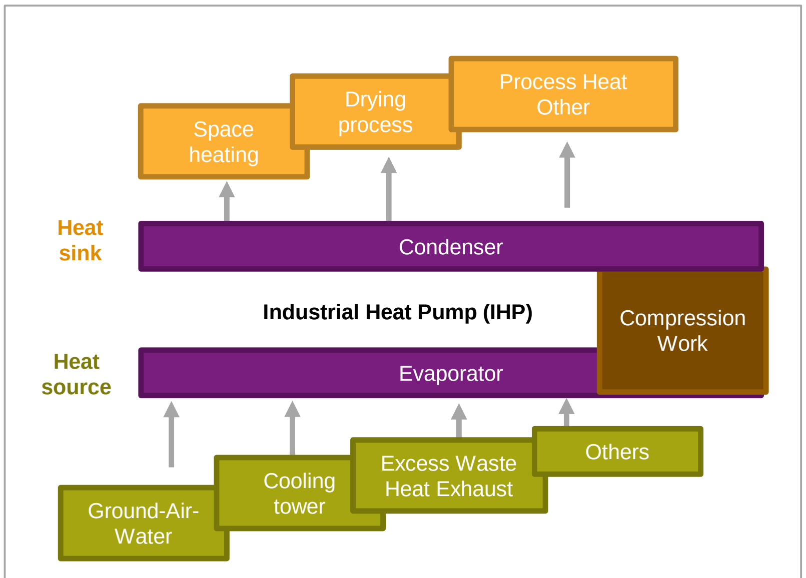
Overview:
Heat pump types can be grouped according to different categories, all of which influence their operating parameters (e.g. source and sink temperatures), and ultimately their potential application in industry. There is a wider range of options than for domestic scale heat pumps, as seen to the right – with waste heat, steam and process heat all potential sources or sinks. **Mechanical compression heat pumps are the most commonly installed in industry today, as one of the older and most familiar technologies, and lower price compared to alternatives.**

WAYS TO CATEGORISE HEAT PUMP TYPES:

By energy source	By energy sink	By what drives the heat pump cycle	By heat pump concept
Water Ground Air Waste heat Process heat Stored heat from solar thermal/other source?	Water Air Steam	Gas Electricity Waste heat	Engine Absorption Adsorption Open and closed cycle mechanical vapour compression

HEAT SOURCES AND HEAT SINKS FOR INDUSTRIAL HEAT PUMPS



COMPRESSION CYCLE CONCEPT

Compression work in IHPs is usually done through:

- **Mechanical compression** Systems divided into
  - *Mechanical Vapour Compression - usually a closed cycle using refrigerant,* using various compressor types e.g. scroll (typically <100 kW output), reciprocating (<500 kW), screw (< 5MW) or turbo (>5 MW) compressor.
  - *Mechanical Vapour Recompression (usually an open cycle using process fluid itself, typically using roots blowers, centrifugal compressors etc)*
- **Thermal compression** (e.g. an absorption / adsorption cycle)
- **A hybrid compression / absorption cycle**

WHAT DRIVES THE COMPRESSION CYCLE

Usually driven by electric motor or gas engine (usually internal combustion engine)

Driven by gas or waste heat

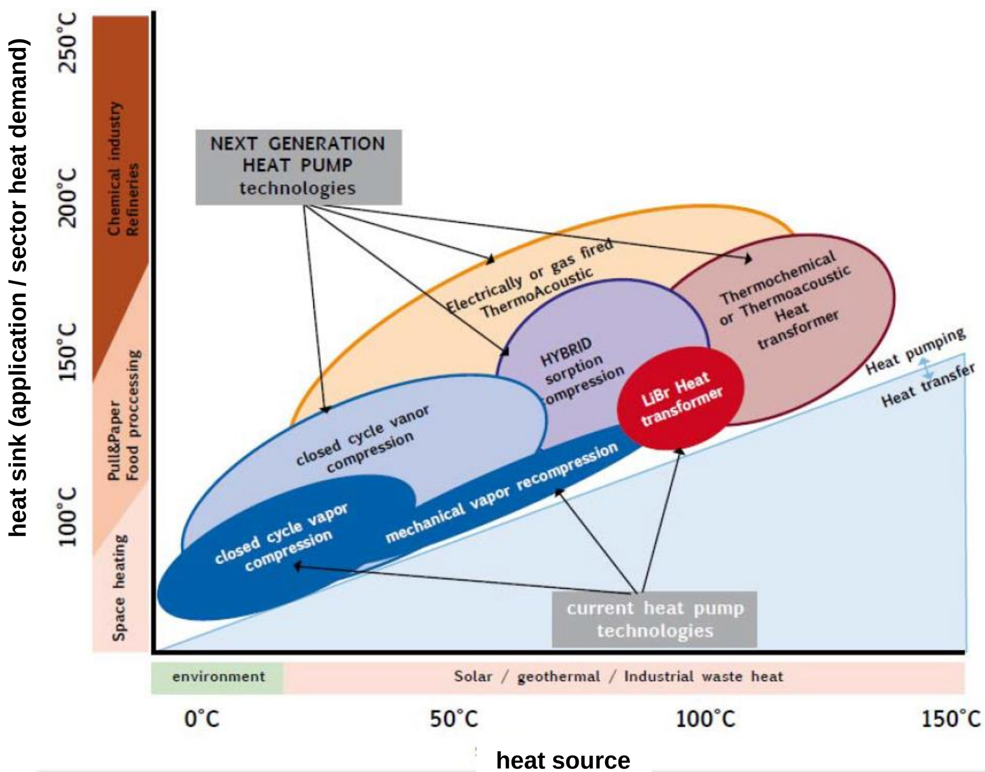
Driven by a combination

Appendix ii
Introduction – Industrial Heat Pump Technology Options (2/2)

Here we introduce the existing IHP technology concepts and expectations for their development. **A wide range of applications are already applicable to IHPs**, and **new innovation is widening the range of industry applications towards 2020 and beyond**.

Industrial Heat pump concepts and their operating temperatures

The source temperature available for the heat pump, and the heat demand (heat sink) are the key factors determining which type of heat pump can be used in a particular application and industrial sector. The diagram below illustrates different heat pump concepts existing on the market and under development, and their respective ranges of heat source and heat demand (sink).



Dominant currently available technologies:

Current HP technology is limited to temperature output of approximately 100°C and source temperature input of below 100°C.

Name	Concept	Source Temp.	Sink Temp.
Closed cycle vapour compression	Uses mechanical compression of a working fluid (refrigerant) to achieve temperature lift.	~0-45°C	<~100°C
Mechanical vapour recompression (open cycle)	Uses a mechanical compressor to increase the pressure of waste vapour – working fluid is vapour (water).	~40-100°C	<~120°C
LiBr heat transformer	Absorption system, waste heat or steam driven	~100°C	<~150°C

Heat pump technologies under development:

The main focus of technology R&D is on widening the operating parameters of IHPs so that they can use higher source temperatures, and meet demand for higher temperatures. On-going work includes:

- "Standard" HP technologies as described above (vapour compression) with new working fluids (may be available by 2020).
- Hybrid sorption / compression heat pumps (may be available by 2020)
- Thermochemical / Thermoacoustic heat pumps (concepts till to be proved – timelines less certain)

Source: Kleefkens, O & Spoelstra, S, 2014, IEA HP Conference Montreal proceedings

Appendix iii
Summary of key Thermal Energy Storage technologies

Type of TES	Description	Energy input	Key application areas	System efficiency	Market status (TRL) in 2015
Tank thermal energy storage (TTES)	Tank systems usually storing hot water, but molten salts and heat transfer oils have also been used extensively (depending on temperature required).	All conventional and renewable heating systems (boilers, CHP, heat pumps, biomass, solar thermal).	**Domestic** = Intraday **Non-Domestic** = Intraday and Inter seasonal **District Heating** = Intraday and Interseasonal	50-90%	9
Pit thermal energy storage (PTES)	Shallow pits dug in the ground, which are then lined and filled with gravel and / or water for energy storage.	Larger solar thermal installations, as PTES is most beneficial at scale (plus interaction with other heat inputs for district heating).	**Domestic** = Interseasonal (only for apartment blocks or mini communal heating) **District Heating** = Interseasonal	Up to 80%	6-8
Borehole thermal energy storage (BTES)	Regularly spaced vertical holes are drilled into the ground, with heat exchangers inserted to transfer heat to and from the ground.	Solar thermal, ground source heat pump for extraction, potentially CHP, gas turbines, waste heat.	**Domestic** = Interseasonal **Non-Domestic** = Inter seasonal **District Heating** = Interseasonal	6-54% (Efficiency commonly increases the longer system is in operation)	6-8
Aquifer thermal energy storage (ATES)	Open-loop system utilising natural underground water-bearing permeable layers from which groundwater is extracted.	Ground source heat pump, waste heat, CHP.	**Domestic** = Interseasonal (only in mulit-family homes / blocks of apartments) **District Heating** = Interseasonal	70-90%	5-8
Phase change materials (PCM)	Using organic or inorganic compounds to store energy in the form of heat in the material's change of phase (usually from solid to liquid, but also from liquid to gas).	All conventional and renewable heating systems (boilers, CHP, heat pumps, biomass, solar thermal), solar PV.	**Domestic** = Intraday **Non-Domestic** = Intraday **District Heating** = Intraday	75-90%	5-8
Thermochemical heat storage	Reversible chemical reactions to store large quantities of heat in a compact volume.	Most likely industrial heat, but theoretically variety of heat sources.	**Non-Domestic** = Intraday and Interseasonal **District Heating** = Intraday and Interseasonal	Potentially very high (up to 100%), but in practice so far low.	1-5

The European Commission (2013; Horizon 2020 work programme) has defined 9 Technology Readiness Levels (TRL). For the purpose of providing a basis for the comparison of market status we have adopted the Commission's definitions, as found in the Horizon 2020 Work Programme 2014-2015 - General Annex G:
TRL 1 – basic principles observed
TRL 2 – technology concept formulated
TRL 3 – experimental proof of concept
TRL 4 – technology validated in lab
TRL 5 – technology validated in relevant environment (industrially relevant environment in the case of key enabling technologies)
TRL 6 – technology demonstrated in relevant environment (industrially relevant environment in the case of key enabling technologies)
TRL 7 – system prototype demonstration in operational environment
TRL 8 – system complete and qualified
TRL 9 – actual system proven in operational environment (competitive manufacturing in the case of key enabling technologies; or in space)

Appendix iii
Cost assumptions of thermal energy storage technologies

DELTA Energy & Environment

Overview:

Cost estimates for TES can range from below 0.30 £/kWh for very large interseasonal applications to above 400 £/kWh for very small PCM stores. Generally costs progressively reduce as the size of the thermal store increases – meaning that the bigger the store the lower the cost (in terms of £/kWh or £/m³). Cost estimation can prove very difficult and uncertain depending on the TES technology evaluated, for each technology different methods can be adopted for calculating costs. Therefore, where possible this report includes a wide range of potential costs. The high level results are presented in the table below.

For operation and maintenance costs, there is limited data available. A study from Germany (Solites, 2012) evaluated a number of different TES projects for interseasonal heat storage and found that whilst there is very little monitored data, operating costs could be estimated to be around 0.25% of total investment cost and maintenance cost approximately 1%. Aside from the operation and maintenance of the actual thermal store, further costs for the overall integrated heating system need to be considered. Operation and maintenance of components such as heat pumps and auxiliary heat sources, may be relatively high and thus affect the cost performance of the overall solution.

Type of TES (heat storage)	District Heating	Non-domestic	Domestic	Cost reduction potential out to 2050
Tank thermal energy storage (TTES)	<1-150 £/kWh (highly dependent on size, e.g. some commercial systems may be similar size to domestic)		25 -180 £/kWh	***0 – 10%***
Pit thermal energy storage (PTES)	0.30-0.80 £/kWh	N/A	N/A	***10 – 20%***
Borehole thermal energy storage (BTES)	Potentially as low as 0.30 £/kWh (highly dependent on size, and method used for measuring heat retained in ground)			***10 – 20%***
Aquifer thermal energy storage (ATES)	600-1000 £/kW (note ATES size commonly expressed as maximum heating rate for heat being extracted from well not the energy stored in aquifer)		N/A	***10 – 20%***
Phase change materials (PCM)	Unlikely to be used		250-400 £/kWh (potentially as low as 50 £/kWh for large applications)	***20 – 30%***
Thermochemical heat storage	Potentially very cost effective, but at current state of research very cost intensive and not ready or economical for commercialisation.			***20 – 30%***

ATES costs are provided in £/kW, as the aquifer provides a natural storage medium the boundaries of the store are difficult to define. The purpose of ATES is to increase the efficiency of heating and cooling, thus the more meaningful metric used for cost comparison is kW rather than kWh, as this expresses the maximum rate at which energy can be extracted. When comparing costs in terms of m³ water equivalent ATES is very much competitive with other underground thermal storage technologies.

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