District Heating Feasibility

Phase 2: Network Development and Financial Modelling

FINAL REPORT

16th February 2018

Prepared for:

London Borough of Merton

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REVISION SCHEDULE

Rev	Date	Details	Prepared by	Reviewed by	Approved by
1	27/9/17	Draft Issue	Alban Leiper Senior Engineer Eleni Vogiatzi Engineer	Luke Aldred Principal Engineer	Channa Karunaratne Associate
2	16/02/18	Final Issue	Alban Leiper Senior Engineer Eleni Vogiatzi Engineer	Luke Aldred Principal Engineer	Channa Karunaratne Associate

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Notation

Abbreviation	Meaning
CAPEX	Capital Expenditure
CHP	Combined Heat and Power
CIBSE	Chartered Institute of Building Services Engineers
CO_2	Carbon Dioxide
CWSW	Colliers Wood and South Wimbledon
D	Diversity factor
DC	District Cooling
BEIS	Department of Business, Energy and Industrial Strategy (formerly DECC – see below)
DE	District Energy
DEC	Display Energy Certificate
DECC	Department of Energy and Climate Change
DHN	District Heating Network
DHW	Domestic Hot water
DNO	District Network Operator
DPD	Detailed Project Development
DSM	Dynamic Simulation Modelling
EC	Energy Centre
EfW	Energy from Waste
EPC	Energy Performance Certificate
ERF	Energy Recovery Facility
ESCO	Energy Services Company
FEE	Fabric Energy Efficiency
GIA	Gross Internal Area
GLA	Greater London Authority
GT	Grant Thornton

Abbreviation	Meaning
HNCoP	Heat networks Code of Practice
HNDU	Heat Network Delivery Unit
HNIP	Heat Network Investment Project
IRR	Internal Rate of Return
kWe	Kilowatt electric
kWth	Kilowatt thermal
LBM	London Borough of Merton
MTCML	Morden Town Centre and Morden Leisure Centre
NOx	Nitrogen Dioxide
NPV	Net Present Value
OPEX	Operational Expenditure
PPA	Power Purchase Agreement
PWLB	Public Works Loan Board
RHI	Renewable Heat Incentive
SAP	Standard Assessment Procedure
SCR	Selective Catalytic Reduction
SDEN	Sutton District Energy Network
SDLT	Stamp Duty Land Tax
SPV	Special Purpose Vehicle
SWBA	South Wimbledon Business Association
TfL	Transport for London
TM	Technical Memorandum
UEL	Useful Economic Life
UKPN	United Kingdom Power Networks
VOA	Valuation Office Agency

Executive Summary

District Heating (DH) can provide low cost energy to the residents and businesses in Merton, whilst delivering increased energy security, carbon savings and other environmental benefits. District Heating provides heat, which is generated in an Energy Centre (EC), to identified buildings in the area through the distribution of hot water in buried pipework.

This report is the second of two reports detailing the findings of an investigation into the feasibility of DH in the London Borough of Merton and should be read in conjunction with the Phase 1 report[1].

Phase 1 Summary

Phase 1 mapped the (relevant) existing and future heating, cooling and electrical demands and supplies in the borough. Only the demands of public and commercial buildings with significant energy consumption were reviewed, as smaller loads are less viable for connection to a district heating network. The mapping of heat supplies focussed on industrial waste heat, heat recovery from substations, energy from waste plants, existing gas fired combined heat and power (CHP) plant and heat that could be sourced from Merton's surface water (e.g. rivers).

The study concluded with two opportunity areas for district heating in the borough: Colliers Wood and South Wimbledon (CWSW) and Morden Town Centre and Leisure Centre (MTCML). Energy masterplanning for these two areas then sought to: prioritise buildings for connection; define how heat would be generated; determine pipework routes; evaluate Energy Centre (EC) locations; and develop capital costs.

The resultant CWSW network was based around a gas CHP solution with back up boilers housed in an energy centre located in the proposed High Path Estate development. In MTCML, a gas CHP based solution with back up boiler provision was also proposed, with the EC intended to be located in the car park adjacent to the Merton Civic Centre.

Phase 2 Summary

This report describes the design development and business case analysis of both network opportunities. Stakeholder engagement and site surveys assessed the buildings considered for connection, as well as other key assumptions such as EC location, the distribution of electricity generated by the CHP engines, proposed pipework routes and the appetite for connection of new developments.

[1] Phase 1: Heat Mapping and Energy Masterplanning report, final issue dated 11th January 2017.

EC layouts, plant sizing, pipework diameters and lengths, network operating temperatures and assessing the utilities connection requirements were all developed.

Detailed technical operating parameters for each network were established. Hourly heat and electrical demand profiles for each building were estimated and amalgamated. In line with the CIBSE Code of Practice for Heat Networks (CP1), estimates were made for parameters such as network heat losses, EC ancillary electrical requirements and CHP and boiler operating characteristics. These parameters form the backbone of the bespoke techno-economic model (TEM).

Capital cost estimates were made. Work was undertaken to assess what residents and businesses are currently paying for heat and electricity in Merton. These figures were used as a ceiling to ensure customers would realise a saving by connecting to the network. The associated revenues from the sale of heat and electricity, alongside CAPEX, REPEX (replacement expenditure) and OPEX values were consolidated into the TEMs.

The networks then underwent more detailed financial modelling (carried out by Grant Thornton). The outputs from the TEM were used to forecast a return for both Private and Public Sector investors. The internal rate of return (IRR) and net present value (NPV) were modelled for a number of network scenarios, in order to understand the economic robustness of the projects. The types of funding that might be available for a DH scheme in Merton were also identified, and a number of project sensitivities were explored.

CWSW network results

The proposed gas (CHP and boiler) fired district heating CWSW network was modelled to deliver 15,852MWh of heating, with a peak demand of 10.9MW. 75% of the heat demand would be met by the CHP, (a pre-requisite for State aid compliance). The network includes a 715m^2 EC located on the High Path Estate, with 4km of district heating pipework serving predominantly privately owned commercial and residential properties in the area. The study has included engagement with Clarion Housing Group (formerly Circle Group), the developers of the High Path Estate, who have been supportive of the plans detailed in this report and have not ruled out hosting the EC.

The wider DH network is proposed to operate at conventional temperatures of 95°C flow and 65°C return, with a dedicated lower temperature network for the High Path Estate. This would future-proof part of the network for lower carbon technologies such as heat pumps sourced from the nearby River Wandle or from London Underground ventilation shafts.

The phasing of the High Path Estate and the private ownership of the buildings on the network means that much of the network's heat demand is not realised until a number of years after construction. This is damaging to cash flow and increases the investment risk.

The CWSW network was shown to make a net carbon emission saving until 2035. Thereafter the model suggests that network will start to emit more carbon than the business as usual case due to the expected decarbonisaton of the electricity grid. Carbon saving projections are based on BEIS future carbon emissions factor projections for CHP.

Customers in Morden Industrial Estate have shown interest in purchasing electricity from the DEN. This would improve the revenues generated due to the higher price at which electricity can be sold to private customers compared to wholesale export to the grid. Due to the uncertainty of supplying the Morden Industrial Estate with electricity, the modelling has assumed that a proportion of the electricity generated by the CHP can be sold to the private heat customers on the network (rather than exported to the grid). Electrical demand modelling has been undertaken, and the amount of electricity sold privately has been calculated to be 54% of the total amount generated. This approach to the analysis means that the calculated network returns are conservative estimates and could be improved by increasing the amount of electricity sold privately. The results of the *base case* of the CWSW network are provided in Table 0-1.

Table 0-1: Summary of CWSW financial results

Scenario	A – Base Case
Technology	Gas CHP & Boilers
CAPEX (real)	£15.2m
Project IRR (Real, 40 year)	6.01%
Investor IRR (Nominal, 40 year)	7.69%
Investor NPV (Nominal , 40 year)	£3.97m
Project viable based on projections?	No

Whilst the base case was not shown to be attractive, scenarios which were found to bring the CWSW network to a more commercially viable proposition are as follows:

- Scenario C – this considers the impact of a CAPEX grant of 30% and generates an investor IRR of 9.92%
- Scenario D – this increases the heat price by 5% (relative to the assumed 10% discount on the price of heat offered to customers over their current tariff) and generates an investor IRR of 8.08%
- Scenario F – this increases the electricity price by 5% (relative to the assumed 10% discount on the price of electricity offered to customers over their current tariff) and generates an investor IRR of 7.94%.

MTCML network results

The proposed gas (CHP and boiler) fired DH network in MTCML provides heating to the Merton Civic Centre, the proposed Morden Town Centre development, the new Morden Leisure Centre, and Thames Valley College. The modelled peak heat demand of the network is 8.3MW, and 11,359MWh of heat is provided annually, of which 75% is met by CHP engines (a pre-requisite for State aid compliance). 1.5km of pipework is proposed to distribute low temperature heat (75°C flow, 45°C return) around the network[2], with a dedicated higher temperature supply for the Merton Civic Centre.

The 706m^2 energy centre is proposed to be located in the car park to the rear of the Merton Civic Centre; exploiting space currently used for plant where possible. Plant is proposed to be installed in two phases to meet the network demand as it increases over time.

Like the CWSW network, carbon savings of the MTCML network are significantly reduced beyond 2035 due to predicted grid decarbonisation.

Engagement with Transport for London (TfL) was undertaken to assess their appetite for purchasing generated electricity. At the meeting TfL confirmed they would be interested if the relevant substations were in place to make this possible. This needs further verification. As such, and for the purposes of the modelling, it is assumed that electricity is sold privately to customers on the network with the remainder exported to the grid. This has been calculated as 55% of the electricity generated. The results of the base case of the MTCML network are provided in Table 0-2. As with the CWSW network, the financial performance of the network could be improved with capital grant funding, or by increasing the revenues generated from the sale of heat or electricity.

Table 0-2: Summary of MTCML financial results

Scenario	A – Base Case
Technology	Gas CHP & Boilers
CAPEX (real)	£9.2m
Project IRR (Real, 40 year)	9.55%
Investor IRR (Nominal, 40 year)	9.59%
Investor NPV (Nominal, 40 year)	£5.12m
Project viable based on projections?	Likely, providing the working capital position can be resolved

[2] Subject to confirmation that Thames Valley College buildings can accept a 75°C flow temperature.

Key Risks

If LBM choose to pursue either network, it shall need to secure the energy centre sites at the earliest opportunity.

There is a risk that some of the customers identified for connection will either not be interested in connection, or technically unviable (for example due to the use of an incompatible heating/hot water system). In particular, operators of the identified existing private buildings must be engaged with as early as possible. Full buildings audits must be carried out to assess technical viability.

The ability to operate the MTCML network at lower operating temperatures is dependent on the design of the buildings and their suitability for accepting lower supply temperatures than conventional. LBM should engage with Thames Valley College at the earliest opportunity to ascertain the ability to supply heat at 75°C to their building(s). Furthermore, planning conditions should be imposed on the developers of the Morden Town Centre and Morden Leisure Centre developments to ensure that buildings are designed with heating supply temperatures of 75°C or lower.

Developers of future buildings such as that of the High Path Estate and the Morden Town Centre development should be consulted and made aware of any planning conditions that might affect them with regard to the district energy system in the area.

The importance of maximising the sale of electricity to private customers, as opposed to selling it to the grid, was highlighted in Phase 1. The higher revenues realised through private sales increases financial returns of the networks. Where possible, all electricity generated should be sold privately; it is generally preferable to supply electricity to a small number of large consumers rather than several small consumers.

The council must work to ensure that the proposed network serves to improve air quality in the local area when compared to the business as usual case. Detailed air dispersion modelling is necessary to show both the business as usual case and the proposed scheme effects.

Recommendations and next steps

Both the CWSW and MTCML areas present viable network opportunities for DH in Merton.

The CWSW network was shown to be viable mainly under the capital grant scenarios, i.e. LBM would need to secure additional funding on top of what could be obtained from investors. Schemes such as the UK Government's HNIP fund may be applicable and should be explored. Although the High Path Estate was not modelled as a standalone network, it is likely that a DH network to serve this development alone would be viable. Furthermore, such a strategy for the High Path Estate would align well with the Mayor of London's new London Plan. Detailed project development in the CWSW area could be led by Clarion Housing Group (formerly Circle) and could focus more specifically on the High Path Estate.

The MTCML network presents a better opportunity for DH in Merton, providing good investor returns and being future proofed for low carbon technologies in the future. LBM has a degree of control and influence over the Morden Town Centre scheme and as such can condition the developers to ensure that the design of buildings is carried out in a way that enables connection to DH. The town centre development has not been modelled as a standalone network, but its own district heating scheme is likely be found to be viable for a development of this type and scale, regardless of whether the wider network is pursued. LBM should take care to ensure that further work aligns with the phasing of the Morden Town Centre development.

The next phase of assessment (detailed project development – DPD) should seek to develop the findings of this study. HNDU funding may be available to assist with this work. This DPD phase should:

- assess delivery vehicle options and risk appetite
- add technical development to designs, including investigation into air quality aspects
- form a better understanding of commercial arrangements including bespoke negotiation with customers (and possible soft market engagement)
- prepare an Outline Business Case (OBC)
- prepare a bid for HNIP funding

Stakeholder engagement will be key - with new developers and owners/operators of the existing buildings proposed for connection; engagement internally within LBM - to secure areas necessary for hosting ECs and routes for pipework (planning and highways); engagement within the LBM finance and environmental teams - to discuss the benefits and risks associated with the schemes, and to identify if there are any opportunities for additional funding.

1. Introduction

1.1 Background to study

This study investigates the feasibility of district energy in the London Borough of Merton (LBM). The aim is to provide low cost energy and increased energy security to residents and businesses in the area, whilst also delivering carbon emissions savings and environmental benefits.

This report is the second of two reports and should be read in conjunction with the *Phase 1: Heat Mapping and Energy Masterplanning* report, January 2017.

1.2 Phase 1 overview

Phase 1 started by mapping all the heating, cooling and electrical requirements of key buildings in the borough. Demands were mapped in GIS, alongside suitable sources of waste or low grade heat in the area.

Two key opportunity areas for district heating were then investigated further:

- Colliers Wood and South Wimbledon (CWSW); and
- Morden Town Centre and Morden Leisure Centre (MTCML).

The key aspects for DH feasibility were accounted for:

- existing and future public and private buildings in the area and an assessment of their viability for connection;
- heat generation technologies that would be suitable;
- existing or future sources of heat;
- energy centre locations; and
- key barriers to district energy (DE) implementation such as railways, major roads, rivers and existing utilities.

Gas-fuelled Combined Heat and Power (CHP) was found to be the most viable heat generation technology based on technical, economic, environmental and local factors. A number of network scenarios were modelled for both areas to find the best performing technical, environmental and financial solution.

1.3 Phase 1 key findings and next steps

Due to a lack of information available on certain buildings on the MTCML network at the time of writing the Phase 1 report, the network opportunities in CWSW were found to perform much better financially. Now that this information is available with more certainty for the MTCML network (scale and type of development), results for the MTCML network are much improved compared to the Phase 1 findings.

Due to the predicted future decarbonisation of the UK's electricity supply, gas CHP was only shown to provide carbon emission savings up to c.2032 (based on DECC (now BEIS) bespoke CHP emissions factors[3]). As such, gas CHP is considered a viable low-carbon technology for use initially and can provide the network operator with attractive enough returns on investment to warrant the capital outlay for the heat network. CHP engines are generally expected to have an operating life of 80,000 – 100,000 hours (expected to deliver approximately 12-15 years of operation); thereafter, a replacement primary heat source will need to be found, in order to continue to provide low carbon heating to customer buildings.

The network operator must keep abreast of developments in terms of carbon emissions associated with grid electricity consumption, and periodically assess the low-carbon performance of different heat generation technologies, especially when the first generation CHP engines reach the end of their useful life after 12-15 years of operation.

The financial and technical modelling showed that networks are particularly sensitive to the amount of generated electricity which is sold to private customers in the area, as opposed to exported back into the grid. Maximising private sales is paramount, as revenues generated from private sales are much higher than those generated through export to the electricity grid.

Finding appropriate and interested private wire customers is therefore an essential part of district heating network development and an area for investigation under Phase 2.

Following the full review of Phase 1 findings by both the council and the HNDU, it was confirmed that the study could process into its second Phase, as described in this report.

[3] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/446512/Emissions_Factors_for_Electricity_Displaced_by_Gas_CHP.xlsx accessed 20th July 2016

2. Methodology

2.1 Overview

Phase 2 of the study is split into two key phases. Phase 2.1 aims to verify the network opportunities identified in Phase 1:

- Verification of the building list on each network, including full review of internal floor areas and benchmarked energy use
- Sense checking the areas for buildings that may have been missed previously
- Confirmation that buildings are located correctly on the maps
- Reviewing the proposed network routes and energy centre locations
- Carrying out site surveys to review pipework routes and non-intrusive building audits
- Stakeholder engagement

Phase 2.2 then develops the designs of the network opportunities and subjects them to detailed technical and financial modelling. The following key items are addressed or provided:

- Network schematics
- Indicative energy centre layouts
- Plant sizing
- Pipework sizing schedules
- Hourly heat profiling of network heat demands based on building type and operation
- Connection and installation phasing
- Technical modelling of network performance
- Detailed financial performance modelling carried out by sub-consultants Grant Thornton

This report, the associated drawings and the financial model (developed by Grant Thornton (GT) form the key deliverables of Phase 2 of the study. The final findings were presented to a range of stakeholders on 3rd October 2017.

2.2 Technical parameters

High level technical parameters identified in Phase 1 of this project were subjected to scrutiny and refined further under Phases 2.1 and 2.2. Table 2-1 shows the project technical parameters and their level of development under each phase of this study.

Table 2-1: Summary of technical parameters developed under project phases

	Phase 1	Phases 2.1 & 2.2
Energy Demand	Identified opportunity areas and suitable customers. Annual demand assessment for buildings identified to be suitable.	Building list subjected to scrutiny and refined. Annual energy demand figures checked and verified where possible. Hourly profiling of annual energy demands (both heat and electricity)
Energy Supply	AECOM assessed multiple options for energy centre locations and discussed the suitability of each site with the council. One location for each network opportunity was identified as the preferred location.	Site surveys carried out to investigate proposed energy centre locations. Detailed plant sizing carried out based on hourly profiling of network loads. Energy centre layouts and schematics produced based on plant schedules. Cost certainty added through energy size refinement.
Energy Distribution	High level network routes were developed based on maps of the area.	Site surveys were carried out to investigate the proposed network routes. Additional routes were identified and options reappraised based on cost effectiveness for the network. Detailed pipe sizing and hydraulic analysis carried out to provide pipework schedules for added cost certainty. Private wire electricity network opportunities were investigated further and modelled.
Energy Operation	Design principals were discussed on energy operation in terms of: · Interfaces and Hydraulic Separation; · Operation temperature.	Network operation temperatures better defined.

2.3 Economic parameters

Table 2-2: Summary of economic parameters developed under project phases

	Phase 1	Phases 2.1 & 2.2
Techno-economic modelling	High level techno-economic modelling was carried out to provide: capital cost estimates, IRR and NPV values for a range of network scenarios in each opportunity area.	Further granularity was added to the techno-economic model to account for: · Phasing of building connections and plant installation based on further development details made available; · Updated plant schedules and associated costs based on hourly network demand profiles · Energy centre costs based on layouts · Pipework costs based on detailed pipe-sizing assessments
Detailed financial modelling	None	Detailed financial modelling as carried out by Grant Thornton. Modelling accounts for: · Cost (CAPEX and OPEX) and revenue assumptions · Projected cashflows for projects · NPV and IRR forecasts · Discussion of funding options

3. Stakeholder engagement and surveys

3.1 Meetings and workshops

The meetings undertaken as part of Phase 2.1 and 2.2 of this study are summarised in Table 3-1.

Table 3-1: Phase 2 meetings and stakeholder engagement

Date	Description	Outcomes
24/2/17	Phase 2 .1 Inception meeting	Updated details on future buildings Transport for London (TfL) contact discussed
29/2/17	South Wimbledon Business Area (Morden Industrial Estate) engagement meeting	Awareness of scheme raised; limited questionnaires about customers' energy use returned.
17/3/17	Monthly progress meeting	AECOM set up on Merton energy data monitoring platforms Half hourly energy data for Civic Centre obtained
11/5/17	Phase 2.1 Wrap up meeting	Finalised building list
19/5/17	Phase 2.2 Inception meeting	GT briefed on project to date by AECOM and client team.
7/6/17	Future Merton team engagement meeting	GT given steer on likely procurement vehicles pursued by Merton in relation to heat networks. This feeds into detailed financial modelling.
13/7/17	Financial modelling workshop	GT presented overview of Financial Modelling, LBM provided feedback of approach
21/7/17	TfL engagement meeting	Understood TfL's appetite for purchasing electricity via a private wire, and explored vent shafts in the vicinity of networks explored
23/8/17	High Path Estate developer meeting	Reviewed the status of the High Path Estate development with developers Clarion Group. Presented findings and sought buy in to our recommendations
3/10/17	Final presentation	Key stakeholders engaged via a presentation of the final outcomes of the project

3.2 Site visits

The site surveys carried out as part of Phase 2.1 are described in Table 3-2.

Table 3-2: Phase 2 site surveys

Date	Description	Outcomes
24/2/2017	Network survey – MTCML	Revised building list Revised pipework routes
17/3/2017	Network survey – CWSW	Revised building list Revised pipework routes

4. Colliers Wood and South Wimbledon (CWSW Network)

This section summarises the technical development of the first of the two networks detailed in this study, the Colliers Wood and South Wimbledon (CWSW) Network. It focusses on the energy demand, distribution and supply on the network.

4.1 Energy demand

The buildings identified in Phase 1 of this study for the CWSW network have been refined and verified for inclusion in the network. Site surveys to visually assess buildings and pipework routes were used to determine whether buildings are suitable for connection and to ensure that the routes proposed are viable.

As a result of this work, a number of buildings have been omitted or added, and the pipework routes redesigned accordingly. This section addresses some of the factors that have influenced these changes, and should be read in conjunction with Appendix A, which details the findings of each building originally included.

4.1.1. Morden Industrial Estate

The Morden Industrial Estate (operated by the South Wimbledon Business Area (SWBA)) was originally considered for connection to the CWSW network. It consists of a wide variety of facilities including warehouse storage, a bakery, process plants, vehicle service centres, an industrial-scale laundrette and commercial offices.

Previously, the heat load of the industrial estate had been estimated by applying the relevant benchmark for each building type to the area breakdown schedule. However, due to the nature of many of the buildings surveyed, it is expected that this method overestimated the amount of heat that could be supplied by district heating. Table 4-1 shows how the heat load of the Morden Industrial Area has been adjusted to only allow for buildings that are eligible for connection.

The reduction in heat demand from previous calculations of c. 70% makes the already poorly performing Morden Industrial Estate even less attractive for connection. As such, the area shall be removed from further investigation as a heat load.

However, there will be a large electrical demand from many of the units, arising from the industrial processes and equipment. This could be an opportunity to sell the electricity being produced by the CHPs privately to third parties. The area will be retained in the study as a private wire customer opportunity for the sale of electricity. It is noted, however, that the longevity of any private wire arrangements is a risk with such tenants, who may only be on short term leases.

Table 4-1: Morden Industrial Area building type Schedule

Building Type	Area, m^2	Gas Consumption, MWh/annum	Eligible for connection (Yes/No)
Vacant	38,477	0	No
Warehouse office	47,194	1,017	No
General office	92,122	1,986	Yes
Logistics	14,427	363	No
Workshop	121,870	3,940	No
Retail warehouse shop	62,089	1,896	No
Unknown	12,772	505	No
Storage facility	3,985	115	No
Clinic or health centre	5,687	204	Yes
Large food store	23,150	437	No
Redevelopment site	624	25	No
Dry sports and leisure facilities	1,497	88	Yes
Adult Education Centre	1,131	24	Yes
Studio office	8,079	174	Yes
Restaurant	9,428	627	Yes
Places of religious worship	1,275	24	No
Entertainment Hall	1,131	85	Yes
Total	444,938	11,510	-
Total eligible for connection	119,075	3,189	-

4.1.2. Final building list and demand summary

Sites which are made up of numerous small buildings such as All Saints Boiler Houses and the Merton Abbey Mills commercial buildings are likely to introduce additional cost and difficulties during connection to the network due to the sparse nature of the buildings. Due to this, buildings with these properties have now been omitted from the network.

Hudson, March and May Court have been removed as they are likely to have been demolished by the time of the network's implementation; the High Path Estate development is due to replace these buildings.

Additional buildings have also been added: Independence House and the Nuffield Health Centre. They were identified along the proposed route but not previously captured. Table 4-2 shows the updated building list for the CWSW network.

Table 4-2: Updated CWSW network building list

	Name	Class	Ownership	Building Type	Floor area (m^2)	No. units	Assumed Year of Connection	Elec consumption (MWh p.a.)	Heat consumption (MWh p.a.)	DH applicable Space Heating (SH) Peak, kW	DH applicable Hot Water (DHW) Peak kW	Total Peak heating, kW	Source
1	111-127 The Broadway	Unknown	Private	Future	-	-	-	-	-	-	-	-	-
2	153-161 The Broadway	Hotel	Private	Under planning	5,952	-	2025	625	472	0	155	155	Planning application, AECOM Model. Zero SH peak as planning application states ASHP to supply SH, so DH not supplying SH load in this case.
3	Highlands House	Unknown	Private	Future	-	-	-	-	-	-	-	-	-
4	Viscount point	Residential	Private	Existing	4,875	65	2030	278	355	155	247	402	London Heat Map
5	Antoinette Hotel	Hotel	Private	Existing	1,200	-	2020	126	317	73	31	104	Previously London Heat map, updated to TM46 due to high figures
6	Polka Theatre	Entertainment Hall	Private	Existing	400	-	2020	60	134	31	3	35	TM46
7	Wimbledon Leisure Centre	Health club	LBM	Existing	5,526	-	2020	918	1,003	385	96	481	London Heat Map
8	Wimbledon YMCA	Unknown	Private	Future	-	-	-	-	-	-	-	-	
9	Broadway House	General office	Private	Existing	12,700	-	2020	625	578	773	116	889	London Heat Map
10	Virgin Active Health Club	Health club	Private	Existing	3,768	-	2035	603	1,326	262	66	328	TM46
11	High Path Estate Phase 1	Residential	Private	Under planning	36,250	483	2025	471	2,336	1,153	820	1,972	AECOM Model
11	High Path Estate Phase 2	Residential	Private	Under planning	36,250	483	2030	471	2,336	1,153	820	1,972	AECOM Model
11	High Path Estate Phase 3	Residential	Private	Under planning	36,250	483	2035	471	2,336	1,153	820	1,972	AECOM Model
12	The Old Lamp Works	Residential	Private	Future	3,029	43	2020	39	195	96	192	288	TM46
13	Merton Abbey Primary School	School	LBM	Existing	1,254	-	2025	50	183	98	11	109	London Heat Map
14	Merton Abbey Mills	Residential	Private	Existing	9,383	50	2040	160	704	298	210	508	TM46
15	Vista House	Residential	Private	Existing	4,875	65	2020	317	406	155	247	402	London Heat Map
16	Prospect House	Residential	Private	Existing	4,125	55	2020	268	343	131	222	354	London Heat Map
17	Independence House	Residential	Private	Existing	3,000	40	2020	195	249	95	184	280	London Heat Map
18	Premier Inn	Hotel	Private	Existing	2,599	-	2025	273	686	158	68	226	TM46
19	Nuffield Health Centre	Health club	Private	Existing	5,379	-	2025	861	1,893	374	94	468	TM46
Total				-	-	-	-	6,812	15,852			10,946	

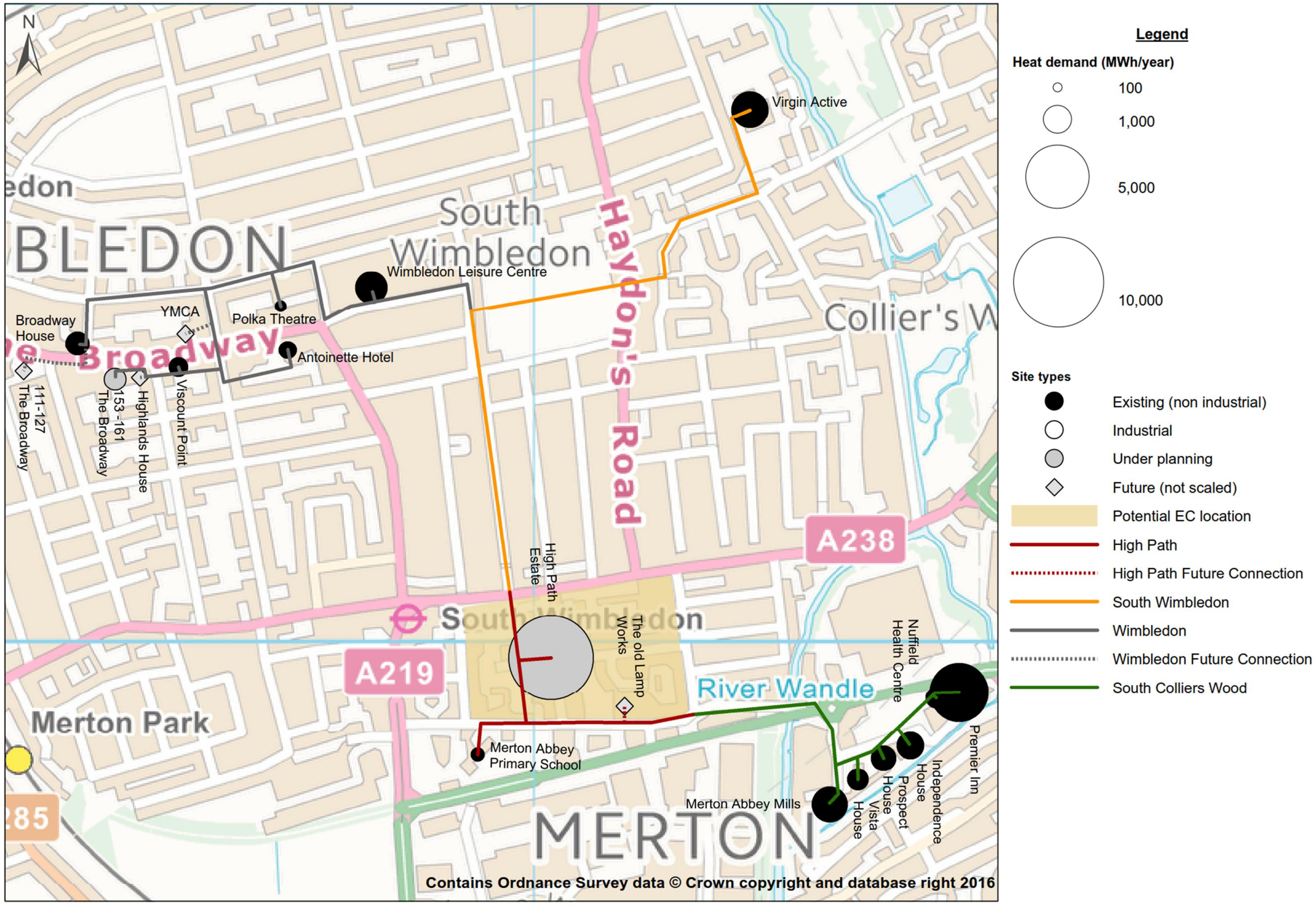

Figure 4-1: Updated CWSW buildings and network routing

4.1.3. Load profiling

The annual loads given in Table 4-2 were categorised by building class (residential, hotel, general office etc.), summed for each class, and subjected to AECOM's in house heat and electricity load profiling tool. This tool uses assumptions on the usage of these building types during both weekdays and weekends to split the annual heat use into 8,760 hourly loads (representing each hour of the year). All profiles for the different building classes were then summed together to give an overall hourly network demand profile which is to be met by the energy centre (plus an assumed annual network loss of 10%, as per good practice guidance in the CIBSE Heat Network Code of Practice[4]). Diversification was applied to residential DHW loads in line with the Code of Practice. Refer to Appendix C for the CWSW load profiles.

The resultant network hourly profile was then fed into the Merton techno-economic model, which sizes the required CHP engine and associated thermal store to ensure that over 75% of the thermal demand is met by the CHP engine if possible. The proposed energy centre technical parameters are set out in Section 4.3.4. An assumed turndown of 50% is assumed for engines; the CHP optimisation results recommend 2no. engines, giving an effective turndown of CHP heat to 25%. This raises CHP run hours and allows more of the heat demand to be met by the CHP plant.

A similar approach is used for the benchmarked electricity demands of buildings, allowing detailed analysis on the performance of a private wire electricity network implemented to serve the buildings on the network.

4.1.4. Energy flow breakdown

The network energy flow breakdown is provided in Table 4-3. The table assumes that there is a private wire electricity network serving all the buildings on the district heating network. The amount used 'on-site' is calculated based on the hourly CHP electricity output profile generated by the profiling tool, and the electrical demand profile of the private wire network; the degree to which the demand and supply curves overlap indicates how much electricity can be exported to these customer buildings in real time (i.e. without the use of storage facilities).

The table identifies the fact that in order to avoid exporting electricity to the grid (and the associated lower revenues), further private customers beyond the buildings identified in this report could be secured.

[4] CP1: Heat networks: Code of Practice for the UK; CIBSE; 2015

Table 4-3: CWSW gas CHP network energy flow

Parameter		Energy, MWh/annum
Heat	Network heat demand	15,852
	Heat losses	1,585
	Energy Centre total heat output	17,437
	CHP heat delivered	75%
Electricity	Network buildings electricity demand	6,812
	Ancillary electrical demand	341
	Energy centre CHP electricity generation	10,680
	Private wire electricity supplied to buildings/private wire customer	5,814
Gas	Energy centre gas consumption	34,565

4.2 Energy distribution

4.2.1. CWSW surveyed routes

Barriers to the installation of pipework on the routes suggested were investigated on the survey as summarised in Table 4-4.

Table 4-4: Physical barriers to route installation

Cluster	Barriers to route installation
High Path Estate	Exact route is TBC and will depend on Energy Centre (EC) location, development phasing and design. There did not appear to be any significant barriers to pipework installation in the area.
South Colliers Wood	A possible crossing point of the River Wandle has been identified, which may require the pipework to run uninsulated for the distance of the crossing, due to the roadway appearing to have a limited depth. This is still a risk however, as the amount of existing utilities currently routed within the road may cause difficulties in routing DH pipework and therefore prevent the crossing.
Central Colliers Wood	Connection from South Colliers Wood will be very difficult, as crossing the major roundabout will require an elevation change. The alternative route would be to follow the River Wandle north, however due to having to cross the river to reach the loads, this also represents a difficult route. Furthermore, there are perceived difficulties associated with connecting to Brown and Root House. As such this leg of the network will be omitted from future investigation. See Appendix A.
Wimbledon	There do not appear to be any major obstructions along the route in the Wimbledon area, other than needing to cross over The Broadway in order to serve the loads on the south side of the road. Further investigation of existing utilities buried in the road will indicate where best to make this crossing.
South Wimbledon	There do not appear to be any major obstructions along the route in the South Wimbledon area, other than needing to cross over Haydon's Road. Further investigation of existing utilities buried in the road will indicate where best to make this crossing.
Morden Industrial Area	There do not appear to be any major obstructions along the route in the Morden Industrial area, other than needing to cross over a major road; the A24. Further investigation of existing utilities buried in the road will indicate where best to make this crossing.

4.2.2. CWSW revised network maps

The revised network map, accounting for the changes to the building list detailed in Section 4.1 and the route omission as described in Table 4-4, is given in Figure 4-1 (see previous pages).

4.2.3. Secondary side ownership and operation

For existing buildings, it is assumed that the secondary side distribution of heat is retained under the operation of the building owner/operator. For existing residential blocks, this means that heat will be sold at a commercial rate to the building operator, and they will distribute and meter the individual dwellings as usual (assuming there is a communal heating system in place already).

For new residential developments (in this case the High Path estate), it is assumed that a communal heating system is the business as usual equivalent alternative to being connected to a wider heating network. There are two options for the district network operator:

1. Sell heat at the point of interchange between primary and secondary network. Heat would be sold as though to a commercial customer, and that customer (typically another ESCo) would redistribute the heat to residents and deal with the metering and billing of tenants. For the network operator, this has the advantage of removing the debt risk associated with having a large number of private residential customers and the significantly uplifted metering and billing requirements for the network. However, the unit price that heat would be sold at is lower, so the financial returns achievable are lower.
2. The network operator can pay for the installation and take ownership of the secondary side network, and sell heat to individual residential customers. This adds risks around metering and billing, but allows heat to be sold at the higher residential tariff. The network operator has to also ensure that the secondary side systems are built to a satisfactory standard, through engagement with the developer, and even with the production of network specifications.

For the purposes of this study, it is assumed that Option 2 is pursued for the operation of the secondary networks, due to the enhanced financial performance of this option.

Currently there is not enough information for detailed route planning within the High Path Estate development, as designs are only at c. RIBA 1 level. As such, detailed costing and route planning of the secondary networks for High Path Estate are not possible. An indicative uplift on pipework costs of 20% is used to estimate the secondary side costs of the High Path Estate.

4.2.4. Network temperatures

The network temperatures will be defined by the heating temperature requirements of the buildings on the network. Whilst new buildings can, and should, be designed to allow for lower, more efficient heating supply temperatures, older building stock typically relies on a flow temperature of 82°C, with a return of 71°C. Minimising district heating return temperatures is an essential aspect of ensuring efficient system operation (since an increase in the supply and return temperatures reduces the volumetric flow rate required of the system, thereby reducing the amount of pumping power required for distribution). However, district heating return temperatures are limited by the design of the customer buildings, such that a conventional 82/71°C secondary side distribution system would need a district heating network flow temperature of 90°C and a return temperature of around 75°C.

In most cases, buildings designed to 82/71°C will provide lower *return* temperatures with some minor control changes. However, reducing the flow temperature below the intended level can be difficult without expensive upgrades to heat emitters, such as radiators, and often means that heating demands cannot be met at peak periods. Outside peak heating times, heating temperatures can be reduced.

Determining the network temperatures requires an in depth look at the requirements of the buildings on the network. Whilst this study has not allowed for building audits to determine heating temperatures exactly, it has been assumed that existing buildings will be capable of (on average) being heated with 82/60°C secondary side heating temperatures, whilst any new developments will be required by the council to be designed to allow for 62/40°C heating supply temperatures.

Of the total annual network heat consumption of 15,852MWh, the CWSW network is split almost equally between loads that require more conventional heating supply temperatures, and those that can be designed to be lower. In order to meet the demands of the various buildings on the network, there are a few technical solutions that can be employed as shown in Table 4-5.

Table 4-5: Network temperature options

Flow/Return temperatures	Technical solution/commentary
75/45°C VLTHW	Retain boilers in existing buildings to meet higher temperature requirements Allows lower temperature distribution, but does not remove the requirement for boiler maintenance on existing buildings. Customers less likely to connect.
95/65°C LTHW	Step down temperatures at building connection points where required. Removes need to retain existing plant, but does not future proof network for lower temperature heat generation
95/65°C LTHW for wider network 75/45°C VLTHW dedicated supply to High Path Estate	Distribute heat at higher temperature to wider network, with dedicated lower temperature supply to High Path Estate. This allows existing boiler plant to be decommissioned, but future proofs some of the load for lower temperature heat generation, e.g. from heat pumps.

AECOM recommends that the wider network is designed for higher temperatures (flow and return temperatures of 95°C and 65°C respectively), but that there is a dedicated lower temperature network for the High Path Estate alone, with a temperature step-down heat exchanger located in the energy centre in the High Path Estate to give a flow temperature of 75°C and a return temperature of 45°C.

Table 4-6: Assumed secondary heating temperatures in network buildings

	Name	Class	Building Type	Assumed heating supply temperature, F/R	Heat consumption (MWh p.a.)
1	111-127 The Broadway	Unknown	Future	62/40	-
2	153-161 The Broadway	Hotel	Under planning	62/40	472
3	Highlands House	Unknown	Future	62/40	-
4	Viscount point	Residential	Existing	82/60	355
5	Antoinette Hotel	Hotel	Existing	82/60	317
6	Polka Theatre	Entertainment Hall	Existing	82/60	134
7	Wimbledon Leisure Centre	Health club	Existing	82/60	1,003
8	Wimbledon YMCA	Unknown	Future	62/40	-
9	Broadway House	General office	Existing	82/60	578
10	Virgin Active Health Club	Health club	Existing	82/60	1,326
11	High Path Estate Phase 1	Residential	Under planning	62/40	2,336
11	High Path Estate Phase 2	Residential	Under planning	62/40	2,336
11	High Path Estate Phase 3	Residential	Under planning	62/40	2,336
12	The Old Lamp Works	Residential	Future	62/40	195
13	Merton Abbey Primary School	School	Existing	82/60	183
14	Merton Abbey Mills	Residential	Existing	82/60	704
15	Vista House	Residential	Existing	82/60	406
16	Prospect House	Residential	Existing	82/60	343
17	Independence House	Residential	Existing	82/60	249
18	Premier Inn	Hotel	Existing	82/60	686
19	Nuffield Health Centre	Health club	Existing	82/60	1,893
Total			-		15,852

4.2.5. Pipework sizing and schedule

The pipework sizing and cost breakdown schedule for the CWSW network is provided in Table 4-7. The total pipework length is 4,045m at a total cost of £5,339,000. Costs do not include 'on-costs' at this stage, i.e. overheads, prelims, fees, legal costs and contingency. These are added later.

4.2.6.Electricity distribution

As identified in Phase 1, schemes were shown to be most financially viable if all electricity generated was sold privately, rather than exported to the grid. This is due to the relative higher price obtained by selling electricity to local private customers (the sale price of which would be around 90% of retail power prices) when compared with exporting it back to the grid (which would be achieved at wholesale power prices, around 50% of the retail price).

Selling the electricity privately requires the installation of a private network that distributes electricity to customers from the energy centre. Electricity customers can be the same as heat customers, or they might be other large electricity consumers in the area.

It is preferable to identify one single large electricity consumer in the area that can purchase all generated electricity. At the stakeholder engagement meeting with the South Wimbledon Business Association (SWBA), a number of businesses were present that are located in the Morden Industrial Estate. There was interest and enthusiasm at the suggestion of purchasing cheaper power. However, it is a risky assumption to make that all power would be sold privately via the SWBA.

It is recommended that LBM pursues this route as a priority, as it will maximise the returns of the network. However, a more conservative approach has been taken for the purposes of this report and modelling:

- **a private wire network is installed that is the same length (in m) as the pipework route identified;**
- **physically remove the connected buildings from their current DNO supply, and provide 100% of their electrical peak and annual demand via the private wire network**
- **appropriate costs have been assigned to the private wire network**
- **peak capacity electrical supply is brought in to the energy centre. This would be blended with the power generation from the CHP and the electrical HV power distributed via the private wire system to the connected buildings**
- **the electricity demand of buildings on the network is met by the CHP engines, when the demand is equal or less than the generated power. Any additional power requirements are supplied via the new EC DNO connection ;**
- **when generation exceeds demand, electricity is exported to the grid; and**
- **it is not anticipated that any DNO asset ownership could be transferred (procured) to the DH project, therefore dedicated new assets would be constructed (cableways and sub-stations) for the sole use of the private wire system and their associated electrical customers.**

In order to deliver this solution a number of further design development is required but more critically, the commercialisation stage of the project needs to progressed to assess the willingness of the proposed buildings to leave their current DNO supply and move to a private wire supply. The technical and commercial solution may be optimised if a DNO became a project stakeholder and assisted in the development of the project. AECOM have made a financial allowance for the proposed private wire solution, based on a capacity of power sale being made, but this remains at risk until prospective customers agree to switch supplier.

This solution is also at risk from future loss of electrical load scenarios if customers choose to change suppliers. Power purchase agreements for up to 25 years should be sought as part of the commercialisation phase of the project. The network operator should also be wary of changes to the electricity market and regulations that may affect the sale of electricity privately.

Table 4-7: CWSW Pipework sizing and cost breakdown

Pipework size	Total (m)	Trench £/m pipe (S2)	Trench £/m civils for Hard Dig (S2)	Year 0 Trench £/m pipe (S2)	Year 0 Trench £/m civils for Hard Dig (S2)	Flow pipework Capex (Inc Civils), £'000s	Return pipework Capex (Exc Civils), £'000s	Heat Loss (W/m)	Heat Loss (MWh)	Velocity (m/s)	Maximum heat capacity (kW)	Internal Diameter (mm)
DN25 (33mm)	55	225	290	248	320	31	14	14.0	7	0.85	52	25
DN32 (42mm)	278	243	315	268	348	171	74	15.1	37	0.85	86	32
DN40 (48mm)	66	273	325	301	359	43	20	17.0	10	0.85	134	40
DN50 (60mm)	863	287	337	316	372	594	273	18.9	143	0.85	210	50
DN65 (76mm)	132	313	362	345	400	98	46	21.2	25	0.9	375	65
DN80 (89mm)	221	330	406	365	448	180	81	22.5	44	1	631	80
DN100 (114mm)	614	386	468	426	517	579	261	23.4	126	1.2	1,184	100
DN125 (139mm)	1513	432	525	477	580	1,599	722	26.5	352	1.4	2,158	125
DN150 (168mm)	252	481	593	532	655	299	134	30.4	67	1.6	3,551	150
DN 200 (219mm)	0	516	687	569	759	0	0	36.0	0	1.9	7,497	200
DN 250	0	661	690	729	762	0	0	34.8	0	2.2	13,563	250
DN 300	51	705	695	779	767	79	40	39.5	18	2.5	22,195	300
DN 350	0	839	715	926	789	0	0	37.9	0	2.5	30,209	350
DN400	0	928	770	1025	850	0	0	39.4	0	2.5	39,457	400
DN450	0	993	800	1096	883	0	0	39.2	0	2.5	49,938	450
DN500	0	1,444	850	1595	938	0	0	38.3	0	2.5	61,652	500
Total	4,045					3,674	1,665		827			

4.3 Energy supply

4.3.1. CWSW surveyed heat sources

River Wandle

This river, and its proximity to the new High Path Estate development, would be suitable to support a water source heat pump, supplying heat to the new development. The heat pump could satisfy the base load of a low temperature network or could form a standalone system serving a single building.

Underground Vent Shafts

A key outcome of the TfL engagement meeting held on 21st July 2017 was that a vent shaft is present in close proximity to the High Path Estate. However, TfL indicated that the best opportunities for utilising waste heat from the London Underground were in the city centre, where temperatures were much higher. The closest station to High Path Estate is South Wimbledon, a Zone 4 station on the outskirts of London close to the end of the Northern Line.

4.3.2. CWSW surveyed energy centre locations

The energy centre location for the CWSW is a risk item that needs further investigation. It is currently proposed that the EC be located within the High Path Development, but this needs confirmation from the developers and would be subject to unknown way-leaves or land costs to be borne by the network operator. Planning can assist in this area by conditioning the developer to allow for the additional required space. To give an idea of scale, the High Path Estate makes up around 54% of the peak load requirements of the network, so an energy centre sized to meet 100% of the network demand would be around twice the size of that required to satisfy the new development alone.

There may be potential for an energy centre to be located in the Morden Industrial Area if it is not possible to locate it in the High Path area, as there are a number of derelict plots of land on which an energy centre could be situated. A benefit for this would be not discharging emissions in close proximity to a residential area, as would be the case in the High Path area.

4.3.3. CWSW energy centre design

Energy centre concept designs have been developed (Appendix F), accounting for the following features:

- sufficient built area to house resilient peak load thermal capacity (N+1);
- sufficient built area to house all associated plant, equipment, ancillaries and welfare space to enable the operation of a large scale district energy scheme;
- no allowance for educational tour or visitors areas at present;
- an external compound area assigned for gas fired reciprocating CHP plant;

4.3.4. Network plant breakdown and operating parameters

Key technical parameters of the CWSW network are provided in Table 4-8. Plant sizes shown in this report supersede those given in the Phase 1 report, as detail added as part of this phase of the study has refined plant sizing figures. EC boilers are assumed to supply 100% of the network load, i.e. no boilers are assumed to be retained in any of the connected buildings. It is assumed that building plant rooms do not have space to accommodate both plates and boilers, and as such existing boilers would be decommissioned prior to connection to network. Buildings are only assumed to connect when existing boilers reach the end of their useful life.

Table 4-8: CWSW key plant breakdown and technical assumptions

Parameter		Value
Energy Centre	Boiler plant room area, m^2	506
	CHP plant room area, m^2	210
	Total area, m^2	716
Boiler	Phase 1 capacity, kWth	10,000
	Phase 2 capacity, kWth	4,000
	Total boiler capacity, kWth	14,000
	Efficiency	90%
	% heat demand met by boilers	25%
	Fuel	Gas
CHP	Phase 1 capacity, kWth	1,120
	Phase 2 capacity, kWth	1,120
	Total CHP capacity, kWth	2,240
	Total CHP capacity, kWe	2,000
	Electrical efficiency	37%
	Thermal efficiency	42%
	Gross efficiency	79%
	% heat demand met by CHP	75%
	Fuel	Gas
Thermal Storage	Total volume, m^3	60
	Change in temperature, dT, K	30
	Discharge capacity, kW	340
Parasitic loads/losses	Ancillary equipment electrical use	5%
	Network heat losses	10%

4.3.5. Network phasing and plant resilience

Based on the development of the network heat load as shown in Figure 4-2, it is proposed that there is a two phase installation of heat generation plant to meet the network demand. The boiler plant will serve the N+1 resilience requirements; CHP capacity does not contribute to resilience capacity due to engine maintenance down time requirements.

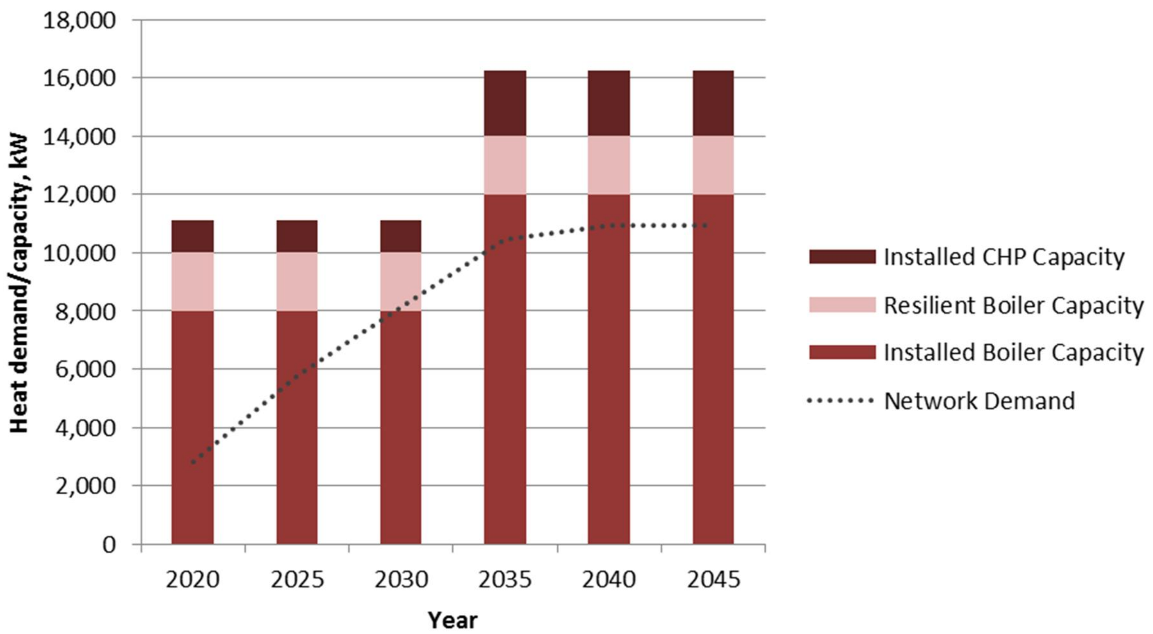

Figure 4-2: CWSW network and plant phasing details

4.3.6. Utilities

Gas

The energy centre will require at least a medium pressure gas supply. An intermediate pressure supply has been identified to run along Station Road and up Abbey Road (see Appendix H). The exact location of the EC within the High Path Estate is yet unknown, but due to the proximity of this main, an extension of 100m has been assumed at a cost of £50/m.

A further one-off cost allowance for gas connections of £15,000/MW of installed capacity has been allowed for in the CAPEX plan.

Electricity

The costs of electrical utility works for the network are assumed to lie mostly with the High Path Estate developer. This is due to the likely requirement of the installation of a new substation as part of the wider development. The costs of this new substation would be borne by the developers. The energy centre CHP plant would then connect into this substation, allowing export of additional power not distributed via the private wire network back to the grid. An assumed 100m length of buried HV cable has been assumed in the cost plan.

Private wire electrical network costs are accounted for separately.

4.3.7. Other Considerations

Air Quality

The air quality in Merton is a key focus for LBM. Replacing a building's existing boiler with district heating fed by gas CHP and boilers can improve air quality with due care and attention. Detailed air dispersion modelling is necessary at a later stage of design to confirm this. The following key aspects of system design are necessary to ensure air quality demands can be met:

- The use of Selective Catalytic Converters (SCR) on CHP engines and boiler plant
- Emitting flue gasses at the highest point possible

If these design points are achieved, the proposed district heating network should improve the air quality against the business as usual case.

The proposed low temperature network future proofs the scheme for the anticipated move away from combustion-based heating technologies and into electrically led solutions. This is important for air quality as when the grid becomes increasingly decarbonised, the air quality implications of using electricity are reduced.

Flue Arrangement

The necessary flue height will be an output of the air dispersion model. It is recommended that the energy centre location is chosen to be next to a high rise building such that a flue arrangement can be selected that makes use of the existing height of buildings around it to enable effective flue dispersion, rather than requiring a separate structure.

5. Morden Town Centre and Morden Leisure Centre (MTCML) network

5.1 Energy demand

The buildings included in the MTCML network in Phase 1 of this study have undergone scrutiny through either site surveys or investigation into planning details. Certain buildings have been omitted from the network and others added, where previously they have not been captured. This section addresses some of the factors that have influenced these changes, and should be read in conjunction with Appendix B, which details the findings of each building originally included.

5.1.1. Abbotsbury Triangle and Morden Station Development

Phase 1 of this study showed the Abbotsbury Triangle and the Morden Station developments as separate items. New information made available as part of Phase 2 means that both developments will be consolidated into a single heat load, supplied from a central Energy Centre. Further granularity on the schedule of buildings included in this development has also been provided, with the numbers in the building list updated accordingly.

Pipework for the supply of heat around the development is assumed to be a cost element of the development itself, and will not be included in the cost estimates of the district energy network. DH pipework is assumed to terminate in the development's dedicated energy centre, where a heat exchanger will be used to hydraulically separate the district network from the development's dedicated heating distribution network.

5.1.2. Other developments under planning

York Close Car Park is now omitted as it is unlikely to go ahead. The redevelopment of the Mosque on London Road is now captured and included as a future possible connection.

5.1.3. Final building list and demand summary

Based on the information gathered on the site surveys, the building list has been revised and confirmed, as per Table 5-2.

5.1.4. Load Profiling

See Section 4.1.3 for details on the methodology used in heat profiling, and 0 for the MTCML heat profiles generated.

5.1.5. Energy flow breakdown

The network energy flow breakdown is provided in Table 5-1. As in Section 4.1.4, the table assumes there is a private wire electricity network serving all the buildings on the district heating network. Further private customers beyond the buildings identified in this report must be secured in order to ensure financial viability of the network.

Table 5-1: MTCML gas CHP network energy flow

Parameter		Energy, MWh/annum
Heat	Network heat demand	11,359
	Heat losses	1,136
	Energy Centre total heat output	12,495
	Energy Centre CHP heat delivered	75%
Electricity	Network buildings electricity demand	5,205
	Ancillary electrical demand	260
	Energy centre CHP electricity generation	7,581
	Private wire electricity supplied to buildings	4,151
Gas	Energy centre gas consumption	24,666

Table 5-2: Updated MTCML network buildings list

	Cluster	Name	Class	Ownership	Building Type	Number of units	Floor area (m^2)	Assumed Plant Installation Year	Elec consumption (MWh p.a.)	Heat consumption (MWh p.a.)	Space Heating (SH) Peak, kW	Hot Water (DHW) Peak kW	Peak heating, kW	Source of energy data
1	Morden Town Centre	Morden Town Centre Development	Residential	Private	Under planning	1,070	66,870	2025	869	4,308	2,126	1,906	4,032	AECOM Model
			Retail	Private	Under planning	-	8,400	2025	671	329	756	84	840	
			Hotel	Private	Under planning	-	5,150	2025	330	1,197	314	134	448	
2	Morden Town Centre	York Close Car Park	Unknown	Private	Future	-	-	-	-	-	-	-	-	-
3	Morden Town Centre	Merton Civic Centre	General Office	LBM	Existing	-	18,718	2011	1,816	1,797	1,140	170	1,310	Previously over-estimated by London Heat Map, now updated to TM46
4	Morden Leisure Centre	Merton campus of South Thames College	University	Private	Existing	-	15,083	2000	1,207	2,896	787	525	1,312	London Heat Map
5	Morden Leisure Centre	Morden Park Swimming Pool	Health Club	LBM	Under planning	-	4,187	2025	312	833	291	73	364	AECOM Model
Total			-		-	-	-	-	5,205	11,359	-	-	8,307	-

5.2 Energy distribution

5.2.1.MTCML surveyed routes

The MTCML network is comprised of two key areas: Morden Town Centre and the Morden Leisure Centre area. These areas are separated by a dual-line railway which presents a significant barrier to pipework routing. The route identified in Phase 1 of this study involved crossing the railway and joining both areas via London Road, the A24 (a dual carriage-way), which runs beneath the railway (see Figure 5-1). This pipework run represents a significant cost element of the proposed network due to the necessary road closures and existing buried services.

Figure 5-1: Phase 1 proposed pipework railway crossing (buried under London road)

As part of this phase of the study and as a result of the site survey, alternative, cheaper pipework routes have been identified. These routes look at both the possibility of taking pipework under an alternative railway bridge and also through parts of Morden Park. In all cases, a significant proportion of the pipework is proposed to be laid in the park, i.e. buried in 'soft dig' conditions which are cheaper than 'hard dig' alternatives.

Figure 5-2: Phase 2 alternative proposed pipework railway crossing (buried under Links Avenue)

Five routes have been tabled for comparison, as shown in the map representation in Figure 5-33. Each route has been costed to allow comparison between options, as shown in Table 5-3.

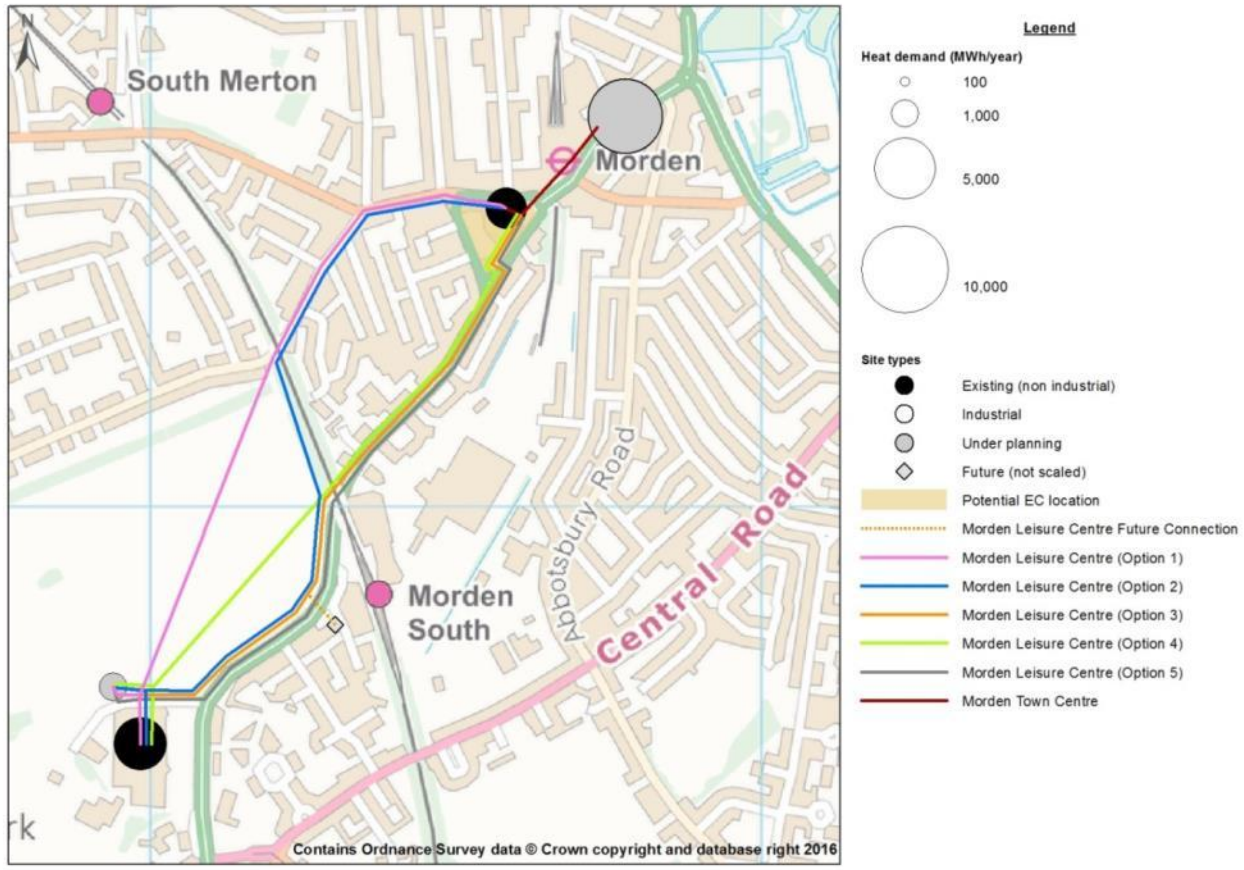

Figure 5-3: MTCML pipework route options

Table 5-3: MTCML pipework options comparison

Option	Description	Total Pipework Length (m)	Hard Dig Length (m)	Soft Dig Length (m)	Price, £'000s	Equivalent cost metric, £/m
1	Links Ave. bridge, direct through park	1,462	814	648	1,875	1,282
2	Links Ave. bridge, park perimeter	1,612	814	798	2,041	1,266
3	London Rd. bridge, park perimeter	1,467	897	570	1,901	1,296
4	London Rd. bridge, direct through park	1,344	897	447	1,764	1,313
5	London Rd. only	1,524	1,474	50	2,113	1,386

Options 1 and 4, which propose pipework is routed directly through the park, provide the shortest options. However, these options are discounted on the basis that the park may be relevelled in the future to provide sports facilities and that it would be better if pipework was routed around the park (meeting: Merton Civic Centre, 11th May 2017).

Routing the pipework along London road is preferable as it reduces overall pipework length and would allow future connection of the Mosque. However the road is owned by TfL so wayleaves and consents to use the road for pipework may add costs which have not been accounted for. See the Risk Register in Appendix K.

Option 3 is chosen as the preferable route as it uses the perimeter of the park, exploiting greater cost reductions due to soft dig, as well as the shorter London Road option. In the event of London Road being over-congested with services or expensive to obtain the rights to use it, Option 2 is the next best option. Due care and consideration of the trees around the perimeter of the park will be necessary during the design of this pipework route in later stages. Appropriate spacing must be given so as not to cause any damage to roots during trench installation.

5.2.2. MTCML revised network maps

The revised network map, accounting for the changes to the building list detailed in Section 5.1 and the chosen route as described in section 5.2.1, is given in Figure 5-4.

5.2.3. Secondary side ownership and operation

See section 4.2.3 for details on the approach to the treatment of building secondary side systems, for both existing and future buildings on the MTCML network.

5.2.4. Network temperatures

As discussed in Section 4.2.3, the network temperature will be a function of the requirements of the connected buildings. The MTCML network is made up of buildings of varying age and in varying stages of development. North of the energy centre (i.e. the Morden Town Centre redevelopment) is future planned development capable of accepting lower supply temperatures.

The Merton Civic Centre is an existing building likely to require a more conventional 82°C supply temperature. The south of the network comprises of the new Leisure Centre and the existing South Thames College. The college may have convective heat loads for heating large internal spaces and as such may be suited to lower network temperatures. A full building audit is necessary to determine this. The leisure centre could be designed for lower supply temperatures.

The Energy Centre is proposed to be located in the Merton Civic Centre. As such, if the South Thames College is capable of taking lower supply temperatures, then a full low temperature network (75/45) would be proposed, with a dedicated 95/65 feed to the Civic Centre only. Network temperatures are assumed to be constant throughout the year. Seasonal temperature variation could be explored to reduce supply temperatures in the summer, once temperature requirements of connected buildings are ascertained.

5.2.5. Pipework sizing and schedule

The breakdown of pipework sizes and costs for Option 3 is provided in Table 5-4. The combined cost of the flow and return pipework, with all related civils works for Option 3 is £1,901,000.

Provided the temperature difference between the flow and return pipework remains at 30K, this pipework sizing will remain the same regardless of the supply temperature.

5.2.6. Electricity distribution

At the meeting on 21st July 2017, TfL confirmed that they would be open to purchasing cheaper electricity from smaller generators if the Morden Station contains the necessary substation equipment. At the time of writing TfL were yet to confirm whether this is the case.

TfL are a large consumer of electricity and have their own 11kV network. As such they do not pay DUoS charges, but do pay to maintain their own network. Due to their high consumption, they pay very low unit costs for electricity, making them a less attractive customer for private wire electricity sales as the price per unit that could be achievable would be lower than sales to smaller consumers. There is a risk that the electricity sale price achievable could be reduced during the commercialisation and heads of terms development of a Power Purchase Agreement with TfL. Pursuing this option is therefore reported as a commercial risk.

The alternative solution (modelled here) is to take over the supply of electricity to all buildings on the network via a private wire, where generated power is sold to customers when there is demand for it, or exported back to the grid when there is not. Surplus power requirements for buildings will be met via the energy centre; see Section 4.2.6 for a full description of the methodology employed.

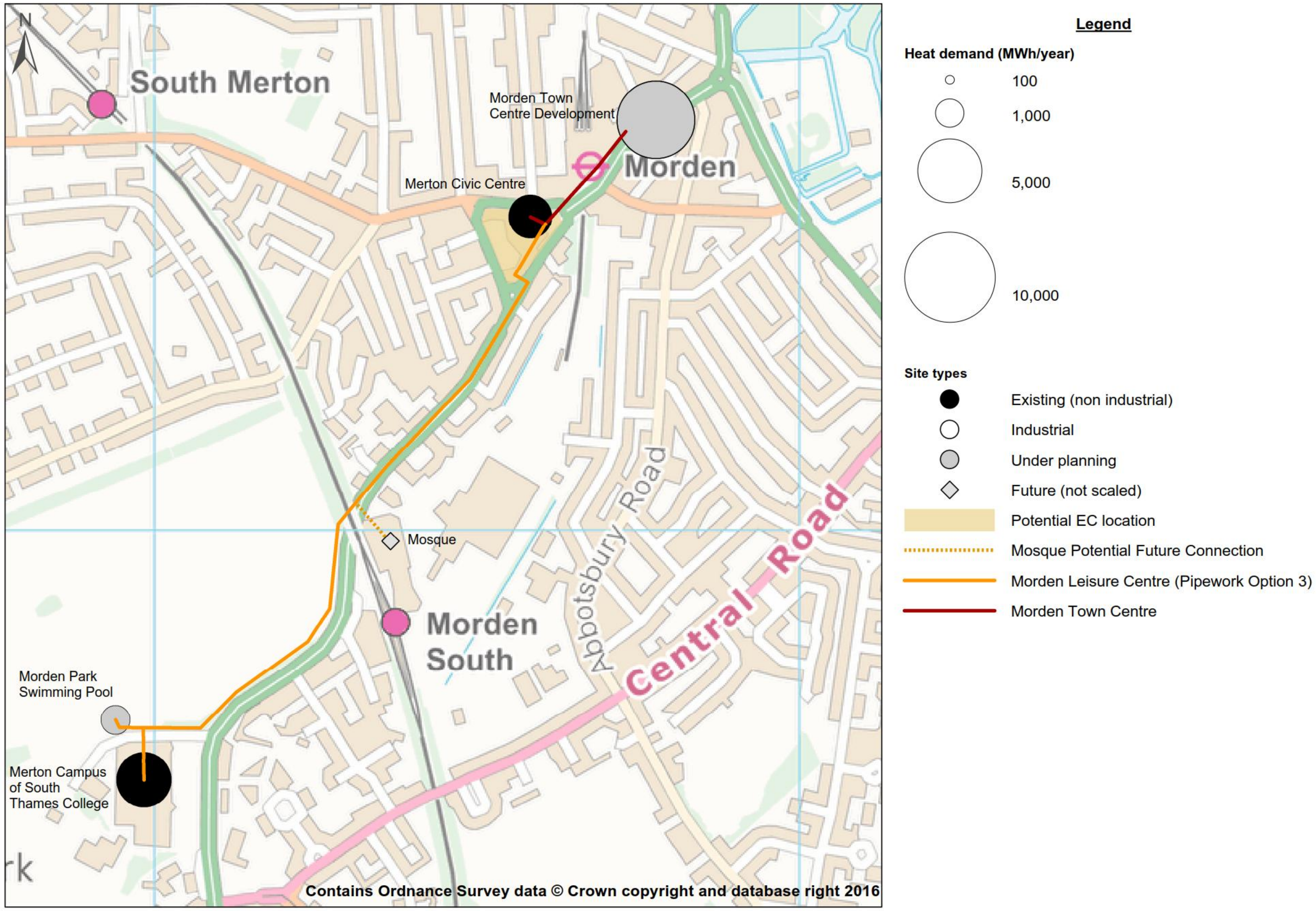

Figure 5-4: Updated MTCML buildings and network routing

Table 5-4: MTCML pipework Option 3 sizing and cost breakdown

Pipe size	Total (m)	Hard dig (m)	Soft dig (m)	Trench £/m pipe (S2)	Trench £/m civils for Hard Dig (S1)	Trench £/m civils for Soft Dig (S1)	Year 0 Trench £/m pipe (S2)	Year 0 Trench £/m civils for Hard Dig	Trench £/m civils for Soft Dig	Flow pipework Capex (Inc Civils), £'000s	Return pipework Capex (Exc Civils), £'000s	Velocity (m/s)	Max heat capacity (kW)	Internal Diameter (mm)
DN25 (33mm)	-	-	-	225	290	150	248	320	166	-	-	0.9	52	25
DN32 (42mm)	-	-	-	243	315	175	268	348	193	-	-	0.9	86	32
DN40 (48mm)	-	-	-	273	325	200	301	359	221	-	-	0.9	134	40
DN50 (60mm)	50	-	50	287	337	205	316	372	226	27	16	0.9	210	50
DN65 (76mm)	-	-	-	313	362	215	345	400	237	-	-	0.9	375	65
DN80 (89mm)	-	-	-	330	406	225	365	448	248	-	-	1.0	631	80
DN100 (114mm)	1,202	682	520	386	468	235	426	517	259	998	511	1.2	1,184	100
DN125 (139mm)	189	189	-	432	525	242	477	580	267	200	90	1.4	2,158	125
DN150 (168mm)	-	-	-	481	593	250	532	655	276	-	-	1.6	3,551	150
DN 200 (219mm)	-	-	-	516	687	275	569	759	304	-	-	1.9	7,497	200
DN 250	26	26	-	661	690	295	729	762	326	39	19	2.2	13,563	250
DN 300	-	-	-	705	695	300	779	767	331	-	-	2.5	22,195	300
DN 350	-	-	-	839	715	350	926	789	386	-	-	2.5	30,209	350
DN400	-	-	-	928	770	400	1,025	850	442	-	-	2.5	39,457	400
DN450	-	-	-	993	800	450	1,096	883	497	-	-	2.5	49,938	450
DN500	-	-	-	1,444	850	500	1,595	938	552	-	-	2.5	61,652	500
Total	1,467	897	570							1,264	637			

5.3 Energy supply

5.3.1. MTCML surveyed heat supplies

No London Underground ventilation shafts were identified on the site survey. TfL confirmed that there were no relevant vent shafts in the vicinity at the meeting on 21st July.

5.3.2. MTCML surveyed energy centre locations

The Energy Centre for the MTCML network was proposed to be located on the grounds of the Merton Civic Centre. There is already an electrically led, 210kWe CHP and a 200kWth absorption chiller plant room and associated heat rejection plant located on the 2nd floor roof of the building along London Road (exact footprint unknown, but estimated to be in the region of 200 - 300m^2), and a separate 130m^2 boiler plant room and a 50m^2 back up fuel storage room located in the basement of the Civic Centre. See Figure 5-5 and Figure 5-6.

Figure 5-5: The Merton Civic Centre EC requirements

The CHP and chiller plant is around 6 years old, meaning it might have life left in it by the time the district network is operational. As the system is currently set up to be electrically led, this means that some heat is rejected. It is proposed that in future this wasted heat is fed into the network if possible.

Boiler plant at the civic centre dates from 1962, and as such should be decommissioned.

It is proposed that a single, new, dedicated energy centre is built to support the district heating network, located within the Civic Centre site boundary as shown in Figure 5-5. Since it is unlikely that there is sufficient space available in the existing plant areas on site, a new area must be identified. A proportion of the car park, estimated at around 700m^2 in total, could be reappropriated to host the energy centre, if this is acceptable by LBM. No direct revenue is currently generated for LBM from the car park, but it is understood that it is used by other tenants in the building and that reappropriating its use would have an indirect knock on impact. This is therefore reported as a risk to proposals, as highlighted in the Risk Register (Appendix K).

Figure 5-6: The rear car park of the Merton Civic Centre

If the Merton Civic Centre is unable to host the Energy Centre, LBM shall have to secure the relevant area for the energy centre within the proposed Morden Town Centre development.

5.3.3. MTCML energy centre design

Energy centre concept designs have been developed for the MTCML network as described in Section 4.3.3. The MTCML indicative energy centre layout is provided in Appendix G. The key plant sizing breakdowns as a result of the technical modelling of the MTCML network are given in Table 5-5. Plant sizes listed in this report surpass those given in the Phase 1 report due to the additional layers of detail added as part of this phase, in particular phasing and hourly load profiling aspects. EC boilers are assumed to supply 100% of the network load, i.e. no boilers are retained in any of the connected buildings. It is assumed that building plant rooms do not have space to accommodate both plates and boilers. Buildings are only assumed to connect when existing boilers reach the end of their useful life.

Table 5-5: MTCML key plant breakdown and technical assumptions

Parameter		Value
Energy Centre	Boiler plant room area, m^2	495
	CHP plant room area, m^2	211
	Total area, m^2	706
Boiler	Phase 1 capacity, kWth	8,000
	Phase 2 capacity, kWth	2,000
	Total boiler capacity, kWth	10,000
	Efficiency	90%
	% heat demand met by boilers	25%
	Fuel	Gas
CHP	Phase 1 capacity, kWth	1,792
	Total CHP capacity, kWth	1,792
	Total CHP capacity, kWe	1,600
	Electrical efficiency	37%
	Thermal efficiency	42%
	Gross efficiency	79%
	% heat met by CHP	75%
	Fuel	Gas
Thermal storage	Total volume, m^3	60
	Change in temperature, dT, K	30
	Discharge capacity, kW	340
Parasitic loads/losses	Ancillary equipment electrical use	5%
	Network heat losses	10%

5.3.4. Network phasing

Based on the development of the network heat load, as shown in Figure 5-7, it is proposed that there is a two phase installation of heat generation plant to meet the network demand as it grows over time.

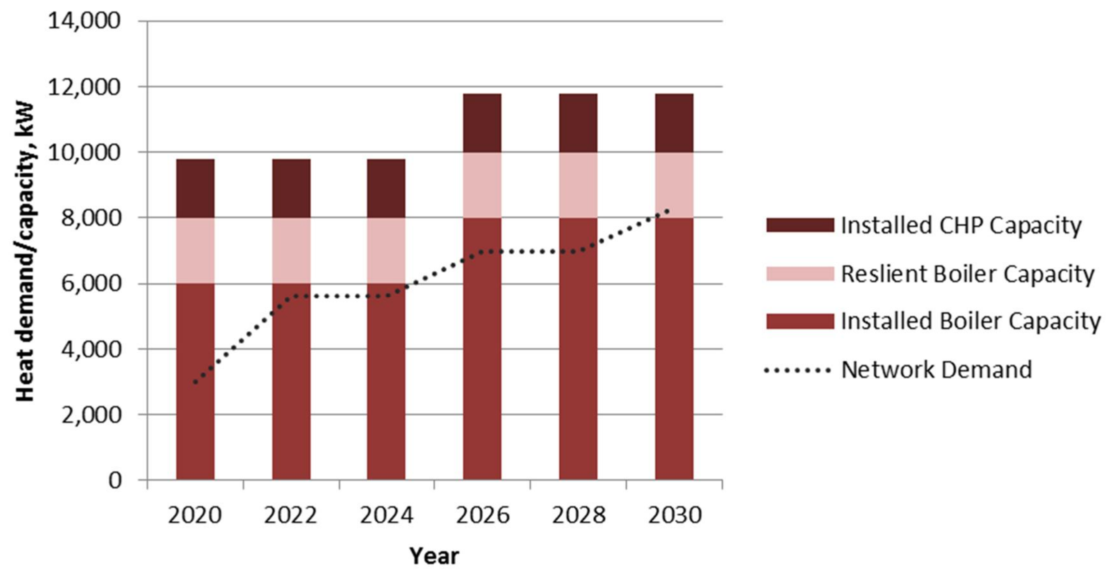

Figure 5-7: MTCML network and plant phasing details

5.3.5. Utilities

Gas

The energy centre will require at least a medium pressure gas supply. An intermediate pressure gas main (i.e. higher pressure than an MP main) can be found on the junction between St Helier Avenue and Boxley Road. See Appendix I for details. This would result in approximately a 500m extension of this medium pressure main to reach the energy centre at the Merton Civic Centre.

A cost allowance for gas connections of £15,000/MW of installed capacity has been allowed for in the CAPEX plan. A further £500/m has been allowed for the mains extensions works.

Electricity

The costs of electrical utility works for the network are associated with the installation of High Voltage electrical cable between the energy centre and the nearest HV substation. Due to the extent of the utility works that will be required during the construction of the Morden Town Centre development, it is highly likely that a new HV electrical substation will be installed on the development site. The costs of this new substation would be borne by the developers. The energy centre CHP plant would then connect into this substation, allowing export of additional power not distributed via the private wire network back to the grid. An assumed 200m length of buried HV cable has been assumed in the cost plan.

The cost of the private wire electrical network to serve the customers on the network is accounted for separately.

5.3.6.Other Considerations

Air Quality

Like the CWSW network, it is recommended that the MTCML energy centre design allows for:

- The use of Selective Catalytic Converters (SCR) on CHP engines and boiler plant
- Emitting flue gasses at the highest point possible

See section 4.3.7 for further details.

Flue Arrangement

The energy centre flues are proposed to run up the side of the Merton Civic Centre, such that flue gasses are emitted at the top of the building, i.e. above the 14th storey. This will likely be tall enough to ensure effective flue dispersion. However, a detailed air dispersion modeling study should be undertaken to assess the effectiveness of this strategy.

6. Carbon emissions and future strategy

The impact of DH network operation on area-wide carbon emissions is a major consideration in assessing its feasibility. Scheme carbon savings depend on the input fuel and the associated carbon factors of the grid electricity which is being offset by the CHP-generated electricity. Emissions associated with the combustion of natural gas are assumed to be constant over the lifetime of the project, where the emission factor used is 0.184 kgCO_2(e)/kWh, based on UK Government GHG Conversion Factors 2016. Electricity carbon factors are taken from the BEIS bespoke CHP emissions factors[5] spreadsheet for electricity displaced by gas CHP, as shown in the Figure 6-1 below.

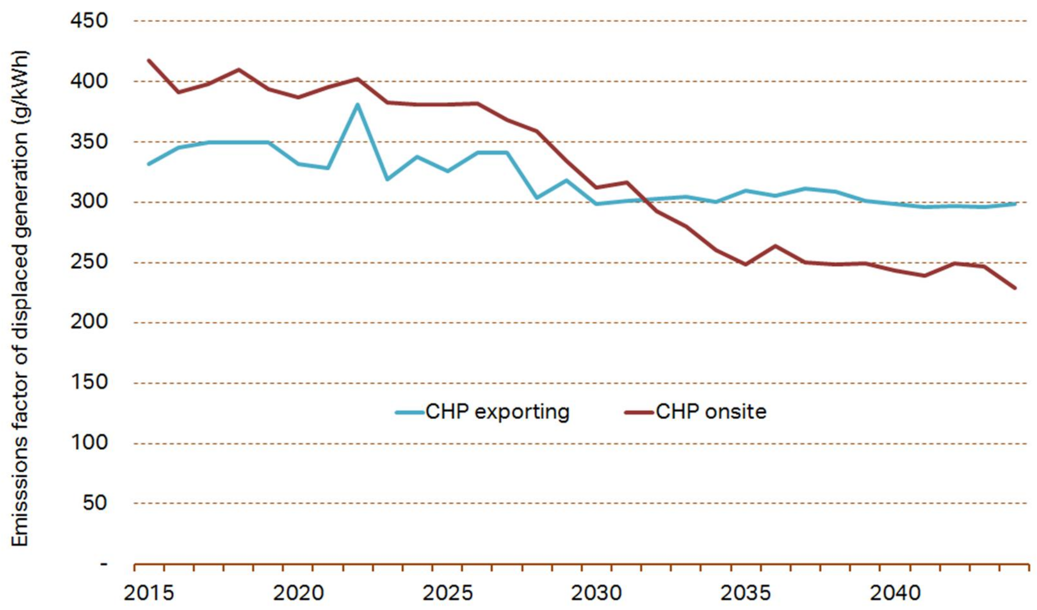

Figure 6-1 Bespoke marginal emissions factor for electricity displaced by gas CHP (gCO2(e)/kWh) (BEIS)

Figure 6-1 demonstrates that the emissions factor for electricity displaced by local CHP generation differs depending on whether the electricity is used on site, or exported back to the grid. Exported electricity is said to offset more carbon intensive sources of electricity on the grid so provides a net saving consistently; electricity generated and used on site is said to be more carbon intensive than the equivalent grid electricity (especially in the future as the grid decarbonises).

There may be scope to investigate the use of batteries to enhance the carbon emission performance of gas CHP, whereby engines are run when the grid is 'dirty' and batteries are charged ahead of use during times when the grid is 'clean'.

6.1 CWSW network carbon emissions

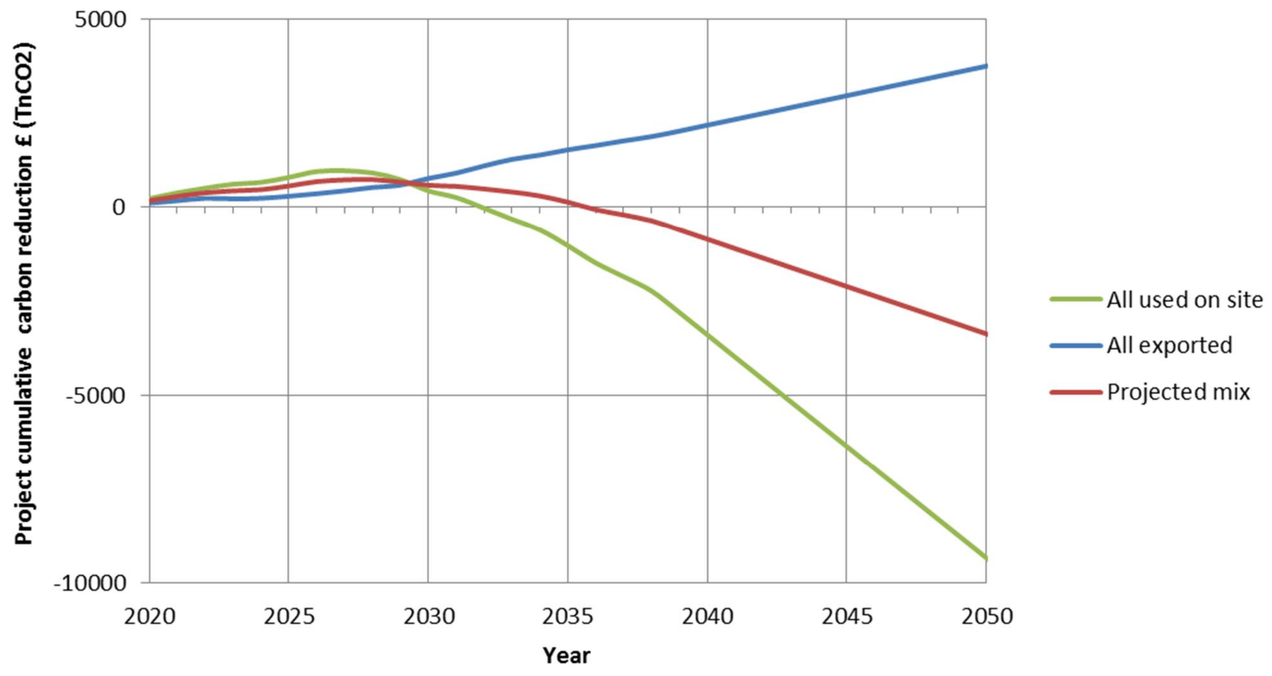

Figure 6-2 CWSW network cumulative carbon savings for different power generation uses

The carbon savings of the projects a highly dependent on how the electricity is used. The 'All used on site' case reflects the situation whereby all electricity is sold privately to a private customer (in this case the customers of the heat network). So although this situation represents the best case financially, it also offers the worst case in terms of carbon.

The modelled private wire network with some export (i.e. 'Projected mix' curve) sits between the two, and is shown to provide a net carbon benefit until around 2035.

[5] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/446512/Emissions_Factors_for_Electricity_Displaced_by_Gas_CHP.xlsx accessed 20th July 2016

6.2 MTCML network carbon emissions

Similarly, Figure 6-3 shows that the MTCML network will offer carbon savings between the years 2019 and 2035, if the electricity is part used on site, part exported as modelled as part of this report.

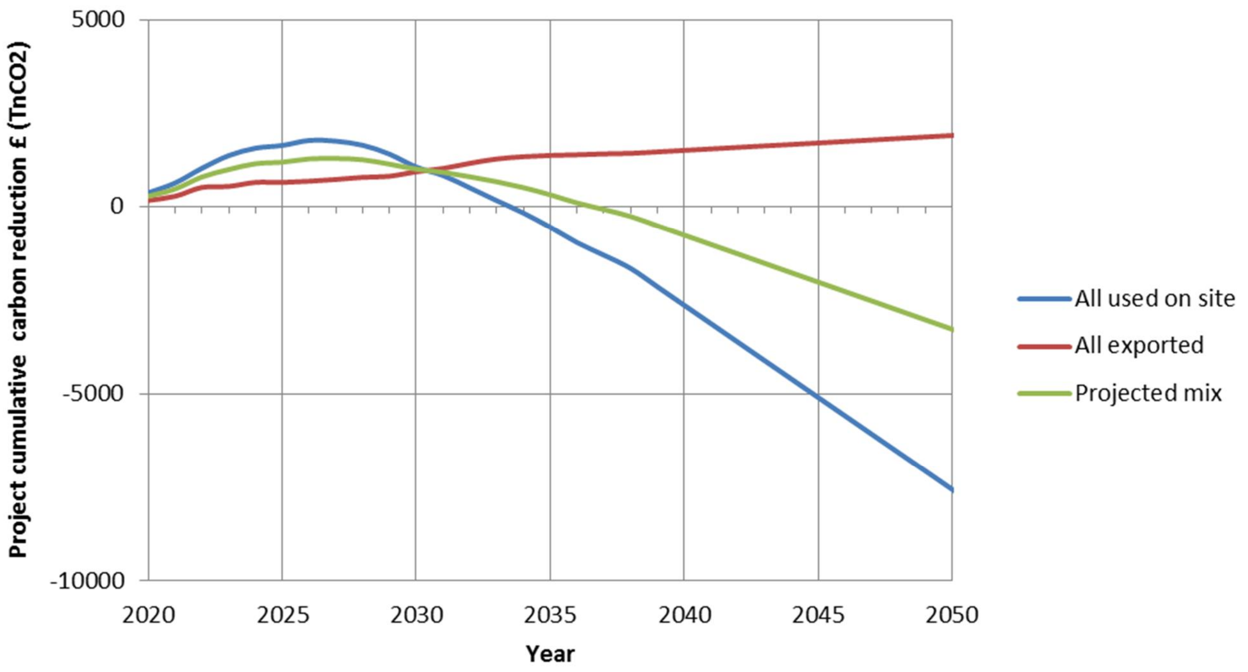

Figure 6-3 MTCML network cumulative carbon savings over the life-time of the project

6.3 Retaining existing plant

It is assumed in the modelling that boiler plant in existing buildings is not retained. This is because it is unlikely that there would be space in plant rooms for both plate heat exchangers and boilers. The age of boiler plant in existing buildings has been estimated and the model assumes buildings connect when this plant reaches the end of its useful life (i.e. after 25 years operation).

There may be scope for investigating retaining existing plant on the network if the above listed assumptions are found to be incorrect. In the Merton Civic Centre, boiler plant dates from 1962 and as such should not be retained. However, CHP and absorption chiller plant is only 6 years old, so there may be scope for retaining this (at least until the end of its useful life, after c/ 12 years of operation).

6.4 Future plant replacement

Carbon emissions results are highly dependent on the projected decarbonisation rate of the electricity supply in the UK, so it is advised that LBM maintain engagement with the carbon emissions factors of different fuels or technologies in the future to ensure that the network can continue to deliver environmental benefits.

The CHP engines could be replaced with like-for-like systems at the end of their 12-15 year useful life. Should the current BEIS projections of grid carbonisation be borne out, it is anticipated that other technologies would be appropriate for the long-term provision of thermal generation. The most appropriate are discussed in the following subsection.

However, should decarbonisation of the grid not occur at the rate which is projected by BEIS, it is likely that CHP will still play an important role in reducing CO_2 emissions, and may still be the most appropriate long-term technology for thermal generation on the proposed network.

In future, CHP may only be able to provide carbon savings for short periods of the year, i.e. during times of peak electricity demand, when the grid is at its most carbon intensive. The role of CHP in the low carbon grid may therefore change from baseload to peak. This may affect revenues in future. See Risk Register in Appendix K.

6.4.1. Waste heat

No high temperature waste heat opportunities were identified in Merton as part of this study. In the event of new sources of heat becoming available in the future, these should be pursued as a matter of priority for feeding the networks in future.

Low grade heat recovery from the London Underground ventilation shaft in South Wimbledon could be a possibility, but due to the shaft being located outside of Central London, it is considered to be a low opportunity by TfL, due to the lower temperatures experienced in the often deeper and more frequently used tunnels in Central London (meeting at TfL offices, 21st July 2017).

6.4.1. Energy from Waste

In the event of the construction of a new EfW plant in Merton, or the extension into Merton of heat networks from EfW facilities in neighbouring boroughs (e.g. Sutton), this would be a key priority for future heat supply.

Given the LBM commitment to air quality, it is expected that EfW facilities will become harder to implement in the future.

6.4.2.Heat Pumps

Air or ground source heat pumps could be utilised in future, potentially offering a very reliable low-carbon source of heat once decarbonisation of grid electricity is achieved.

Both types of heat pumps require large amounts of space for the collection of the low grade heat. In the case of an air source heat pump this would be in the form of large fans; ground source heat pumps require the installation of underground pipework.

The use of heat pumps in future would be especially suited to the MTCML network as it is proposed that this network is operated at flow and return temperatures of 75/45. This reduced flow temperature would enhance the heat pump coefficient of performance, improving cost and carbon savings.

6.4.3.Other Tech

Other technology options for consideration when the initial CHP engines reach the end of their operational life in the future include fuel cells and biomass. While fuel cell technology offers a potential long term solution, it can only be considered low carbon if it uses low carbon sourced hydrogen as its fuel (currently fuel cells use natural gas to synthesise hydrogen for use as a fuel, the synthesising process also producing carbon dioxide emissions). Future cost improvements (fuel cells are typically 2 – 3 times the capital cost of comparably sized gas CHP units), together with steps to create a hydrogen economy (including hydrogen distribution infrastructure), will be required to enable fuel cells to be considered a viable technology.

Biomass technology does offer significant opportunities for low carbon heat. Whilst the technology is reasonably mature and is in use across the country, their more extensive adoption is inhibited by air quality standards in urban areas. Biomass systems would need to improve significantly on their emissions of particulate matter (PM) and NOx emissions in order to be able to provide thermal generation services to the proposed networks in Merton.

Additionally, it is possible that the gas mains network, that currently supplies natural gas, will be developed in the future to supply biogas. Biogas contains the same hydrocarbon fractions as contained in natural gas, except that it is synthesised through the use of biological processes rather than extracted from mineral deposits. Since its synthesis and use in combustion occurs over short time periods, it is considered a carbon neutral fuel; as such it is possible that the use of biogas will increase considerably in coming years as a response to limit carbon emissions.

The use of biogas in mains gas infrastructure will significantly increase the potential use of CHP in the future, as a response to reducing carbon emissions.

6.4.4.Proposed future assumptions

Given the constraints identified with the above options, it is considered prudent that all the above options are re-evaluated during operation of the network. CHP plant is likely to require replacement after around 12-15 years of operation, providing a good opportunity for substituting the gas CHP engines for another, more relevant technology.

If gas CHP is replaced, the network operator will need to retain the capacity to continue delivering electricity to customers on the network. This could be mitigated through the replacement of gas CHP with biomass CHP, or through engagement with the DNO to ensure the relevant electricity supplies are in place ahead of the changeover.

There is the potential that the rate of the grid decarbonisation will be lower than BEIS forecast. As a result, the carbon savings delivered by the gas CHP in a long term could be still significant. Due to the number of unknown parameters and future dependencies, the model assumes a like-for-like replacement.

6.5 Future network expansion

All currently planned future development/redevelopment in Merton identified has been captured in this report. However, in the future there may be proposals for developments in close proximity to the network that could connect. The London Plan heating hierarchy would condition these developments to connect to the network.

It is recommended that, during more detailed design development, Merton stipulates that the network is future proofed for further heat loads. This could be achieved by specifying the correct pipe sizing to allow for expansion, and by installing capped pipes at strategic locations on the network where expansion may occur.

No dedicated future expansion provision has been made in the proposed Energy Centre or network. Development could be accommodated by increasing the boiler selection capacity and increasing the CHP run time. This has a small impact to the proposed project capex and would be a cost effective method of connecting any new buildings if they are located near the proposed heat network. The pipework sizing charts provided in Appendix L would allow for a c. 20% increase in heat load without having a significantly adverse effect on pumping power. Furthermore, return temperatures could be dropped in future to increase network capacity without resizing plant/pipework.

7. Economic assessment and financial modelling

7.1 Financial modelling introduction

Based on the network solutions proposed by AECOM, Grant Thornton have developed financial models (the Financial Models) to project the cashflows (including income statement and balance sheet), for the projects using various assumptions to illustrate a number of different scenarios. Two separate Financial Models have been prepared, one for MTCML and another for CWSW.

The purpose of the Financial Models is to give an indication of the potential financial viability of the projects based on assumptions about the costs (capital and operational) and revenues of the projects provided largely by the technical advisors, AECOM. The AECOM TEM models the technical performance of the network, developing energy flows and fuel inputs, the CAPEX and OPEX values of networks and project cash flows, as well as other network benefits such as carbon savings. The outputs of the AECOM models are then developed and added to in the Grant Thornton Financial Models, adding additional layers of detail such as tax and financing costs.

The Financial Models have been used to forecast a return for both Public and Private Sector investors. The measure of the return is the Investor IRR or the Net Present Value (NPV), the measure used being dependent on the scenario being considered. Measuring the returns is necessary to help understand the economic robustness of the project. The Investor IRR assesses the value of the returns of each project, taking in to account all tax implications, debt and/or equity paid in to an entity by the investor, interest received on any debt and dividends received. The NPV represents the current value of future cashflows based on a particular discount rate.

In addition to providing an indication of the financial returns, as part of the process to develop the Financial Models, the types of funding that might be available were explored.

A 'Base Case' scenario for each Project is included representing the prudent likely outcome. A number of variations on these Base Cases have been modelled to assess the viability of the projects. Development of the Techno-Economic Model into a Financial Model enables:

- Stress testing of the key input variables for the projects
- Identification of the key commercial outputs of the scenarios and how it may be funded
- Informing the discussion and debate about the preferred approach

In preparing the Base Cases, it has been assumed that the delivery model used for the generation and distribution of heat and power is a Special Purpose Vehicle (SPV) (one for each Project), established specifically for the purpose of the Project.

It should be noted that there are alternative options that could be explored to deliver the Projects, for example utilising an in-house delivery approach. Different approaches have their own strengths and weaknesses and should either project progress to commercialisation, it is recommended to give further thought to the delivery structure, including obtaining appropriate commercial and legal advice. For the purposes of Phase 2.2, we have utilised an SPV approach.

These SPV's are owned through an equity shareholding by the Council, with debt funding also provided by the Council. Any operational surpluses are distributed back to the Council in the form of dividends, after making an allowance for a minimum level of cash reserves. It is understood that the Council is familiar with this commercial model given they are currently setting up a Housing Development Company.

7.1.1. Project timing and commencement

Table 7-1 describes the timeframe applicable to the construction and the commencement of operations for the projects. The project cash flows have been considered over a period of 50 years from commencement of operation of the heat network. The Financial Models have the ability to assess the project over a shorter or longer timeframe. Regardless of the technological solution selected, the timings of the individual phases do not alter within the Financial Models and are based on the timetable detailed in the relevant Techno-Economic Model.

Table 7-1: Project timings

Project	Network Construction Start Date	Initial Network Phase Heat and Electricity distribution Start Date
MTCML	2019	2020
CWSW	2019	2020

The construction phase of the MTCML project is set to run from 2019 to 2030. The construction phase of the CWSW project is proposed over 2019 to 2041. This phased approach results in increasing heat and electricity revenues for the schemes as an increasing number of customers are connected to the relevant heat network.

7.2 Indexing and discounting

7.2.1.Indexation

As specified by the Heat Network Delivery Unit (HNDU) guidance, the Techno-Economic Model has been developed on a 'real' basis i.e. revenues and costs are expressed in constant current prices excluding the impact of inflation.

In developing the outputs of the Techno-Economic Model in to a Financial Model a commercial structure was applied which includes the cost of financing the capital expenditure in the network. These costs, as well as operating costs and revenues, are all uplifted by an assumed level of inflation, using indices applicable to the relevant cost / revenue.

The Financial Model uses a price base date of 1 April 2017. Table 7-2 below sets out the assumptions used to forecast nominal prices i.e. actual prices payable at the time including the inflation / indexation assumptions.

Table 7-2: Indexing assumptions

Index	Assumed to be	Applied to
RPIx	Based on Office for Budget Responsibilities projections to 31 March 2022, then 2.5% after this date	All CAPEX/OPEX items except fuels (see below)
Commercial IAG Grid Natural Gas Trend	Variable based on Government projections + RPIx	Gas purchased to power the CHP units/ boilers
IAG Grid Electricity Trend	Variable based on Government projections + RPIx	· Electricity sold via private wire · Electricity sold to the grid
IAG Gas Trend	Variable based on Government projections + RPIx	· Variable aspects of residential and commercial heat sales

7.2.2.Discount rate

In line with HMT Green Book, the net present value calculation uses discounting at a rate of 3.5% on real (unindexed) values to represent social time preference for years to 1 to 30, and 3% thereafter.

The discount rates are used to calculate the NPV of the project cashflows generated over the project life. The NPV is a best practice approach in assessing the investment decision in a long-term project.

7.3 Scenarios

7.3.1.Modelled project scenario and variations on base case

Table 7-3 below sets out the modelling. Both the MTCML and the CWSW projects have the same modelled scenarios.

Table 7-3: Scenarios tested

Scenario	Description
A (Base Case)	The network develops an energy centre using Gas CHP engines for its main source of heat; back-up boiler systems are also installed. Electricity is sold via private wire directly to network customers where possible, and any surplus is sold to the grid. The customers are a mixture of Public and Private sector customers, with connections to the network phased on the completion of development and commissioning of the different sites getting connected to the network, over a period from 2020 to 2030.
B	As Scenario A, however 30% of required capital funding is in the form of Private Sector debt.
C	As Scenario A, however 30% of the required capital spend is obtained from grant funding. The funding is used to finance purchase assets in the 2019-20 build period with a Useful Economic Life (UEL) of 14 or 25 years. The value of the grant is amortised over the asset life. Applying the grant to shorter life assets brings forward the income into the Income and Expenditure Account thereby improving the financial performance of the SPV.
D & E	As Scenario A, with heat sales price varied +/-5%.
F & G	As Scenario A, with electricity sales price varied +/-5%.
H & I	As Scenario A, with CAPEX costs varied +/- 30%. Capital Expenditure represents a significant source of outflow for the SPV. A resilience to a movement in these costs, particularly in an adverse direction, is representative of a stronger scheme. It also provides some rigour to the RIBA 2 standards adopted at this stage of modelling, which recognises the possibility of a degree of variance between the assessed costs and actual once further detailed planning is undertaken. BEIS have previously communicated 30% as a suitable value to be used in running this sensitivity.
J	As Scenario A, with required loan drawdowns given an 'end-of-project annuity period (to ensure all loan repayments have occurred by the end of the project life).
K & L	As Scenario A, with Project term changed from 50 years to 25 or 30 years, respectively

Scenario	Description
M & N	As Scenario A, with operating expenses varied +/-10%.
O	As Scenario A, with an increased coupon rate of +2% on Public Sector Debt. This means that the Public Sector lends in to the SPV at 6.78%, rather than the 4.78% seen under the Base Case.
P	As Scenario A, with a change made to indexing, such that revenues and costs are only subject to RPIx, with the impact of the IAG Gas and Electricity curves removed from all pricing.

7.3.2. Counterfactual scenario

In addition to the modelled project scenarios, a counterfactual scenario for each network has been prepared. The purpose of the counterfactual is to assess the value for money of the proposed heat network against a calculated 'Business as Usual' scenario, i.e. where buildings are heated with conventional gas boilers only.

The Counterfactual utilises expected future heat and electricity demands based on current technological configurations, and applies assumptions around future gas pricing, and fixed asset replacements for the existing technological solution on a consistent basis. Costs for fixed asset replacements are incurred as forecast in accordance with lifecycle expectations. No financing costs are assumed for these capital costs, with an assumption made that these are purchased from the relevant customers own available cash flows.

The Counterfactual therefore compiles the costs of heat and electricity delivery to the proposed customer base on the same basis as the project network (for example the dates at which heat demand is created), including gas purchase cost, electricity purchase costs, operating (maintenance) expenses and capital expenditure costs. Energy flows and all pricing assumptions are derived from the Techno-Economic Model. Indexation assumptions are applied on a basis consistent with the assumptions used in the Financial Model.

The Counterfactual costs are compared against the cost for customers of the proposed heat network by assessing the NPV of heat and electricity revenues generated by the heat network (representing the cost to the customers of the heat network) and comparing this to the counterfactual NPV. Where the NPV of the revenues to the heat network i.e. cost to the customers of the heat network is lower than the NPV of the Counterfactual cost, this represents a cost saving to the end users of the proposed network.

The results for each network are shown in their respective sections of this report.

7.4 Capital expenditure (CAPEX)

7.4.1. Summary of capital expenditure in the heat networks

Table 7-4 below shows the details of the capital expenditure associated with the different aspects of the proposed heat network Scenario A. Professional fees are estimated at 5% and legal fees at 2.5%. The design of networks has been developed to RIBA Stage 2; costs are accurate to -15% and +30%.

Table 7-4: Scenario A – Heat network costs

CAPEX (Real)	CWSW (£m)	MTCML (£m)
Buildings		
Energy Centre (excl. land costs and/or wayleaves)	0.74	0.72
Thermal Generation		
Connections	0.52	0.39
Pipework, HEX and Pumps	1.19	0.85
CHP Engines and private wire	2.32	2.14
Storage and conversion costs	0.06	0.06
Boilers and ancillaries, incl flues and ventilation	2.77	1.78
Network Distribution		
Pipework, Hex and Pumps	6.65	2.65
Other		
Professional and Legal Fees	0.92	0.60
Total (Real)	15.17	9.19
Total (Nominal) @ RPI	17.31	10.10

7.4.2. Description of capital expenditure elements of the network

CWSW network

<u>Network Costs</u>

Developing the network incurs capital costs of approximately £15.2m. The primary costs driving the network capital expenditure are:

- pipework trench costs of c.£6.2m and a Useful Economic Life (UEL) of 40 years (included within the total of £6.6m for Pipework, HEX and Pumps);
- the CHP engine costs of the network of c.£2.3m (included within the CHP Engines and private wire costs) and a UEL of 13 years; and
- Boilers, flues, ventilation, water treatment, controls and electrical costs of c.£2.8m and a UEL of 25-30 years.

This expenditure is shown proportionally in Figure 7-2. The outer ring groups expenditure into Management, Building, Thermal Generation and Network Distribution costs respectively, with the inner circle showing the line item breakdown of these categories.

<u>Capital Expenditure Profile</u>

Figure 7-1 below sets out the capital expenditure profile for the Base Case.

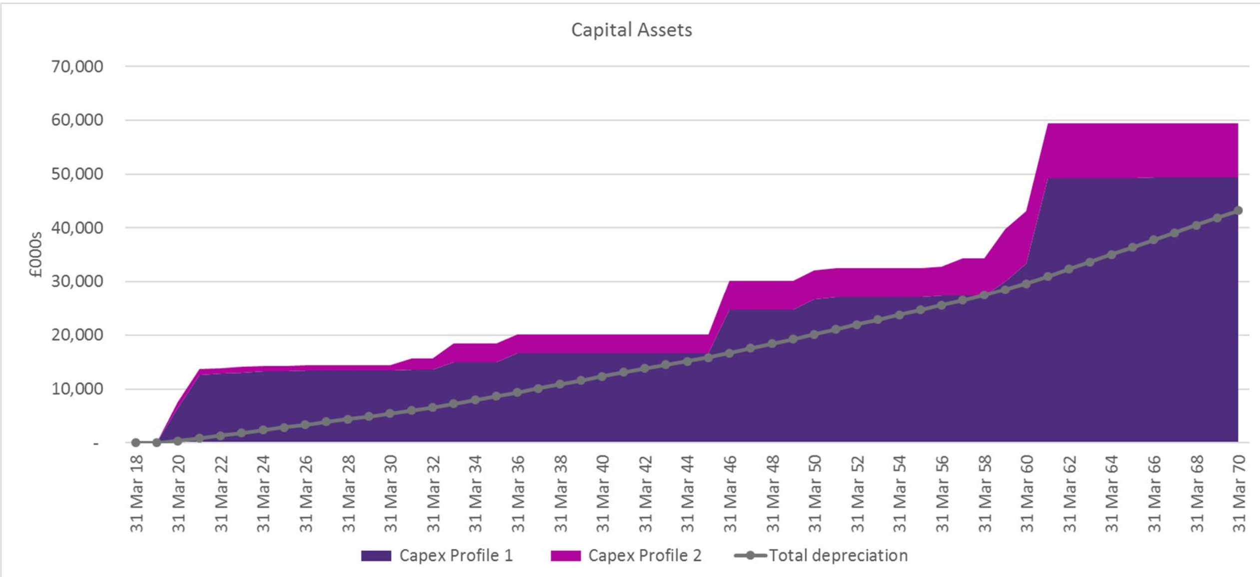

Figure 7-1: CWSW network capital expenditure for Scenario A

The 'steps' later on in the project life reflect the refresh of assets which are nearing the end of their UELs. As such, at the end of the project term, these assets are not fully depreciated, and therefore have a net book value in the financial statements. Under the Base Case, these assets have a depreciated value of £16.24m. We have not performed a separate assessment on whether these assets could be realised by the SPV, or whether they could be sold as part of the SPV on a 'going concern' basis to a new operator. Consequently, the value of these assets is not reflected in the project returns.

The UEL of the '25 year' and '50 year' assets purchased in the first period of network development have each been extended by one additional year. This ensures the Financial Model reflects that there will be no refresh costs associated with these assets in the final year of the scheme's operation.

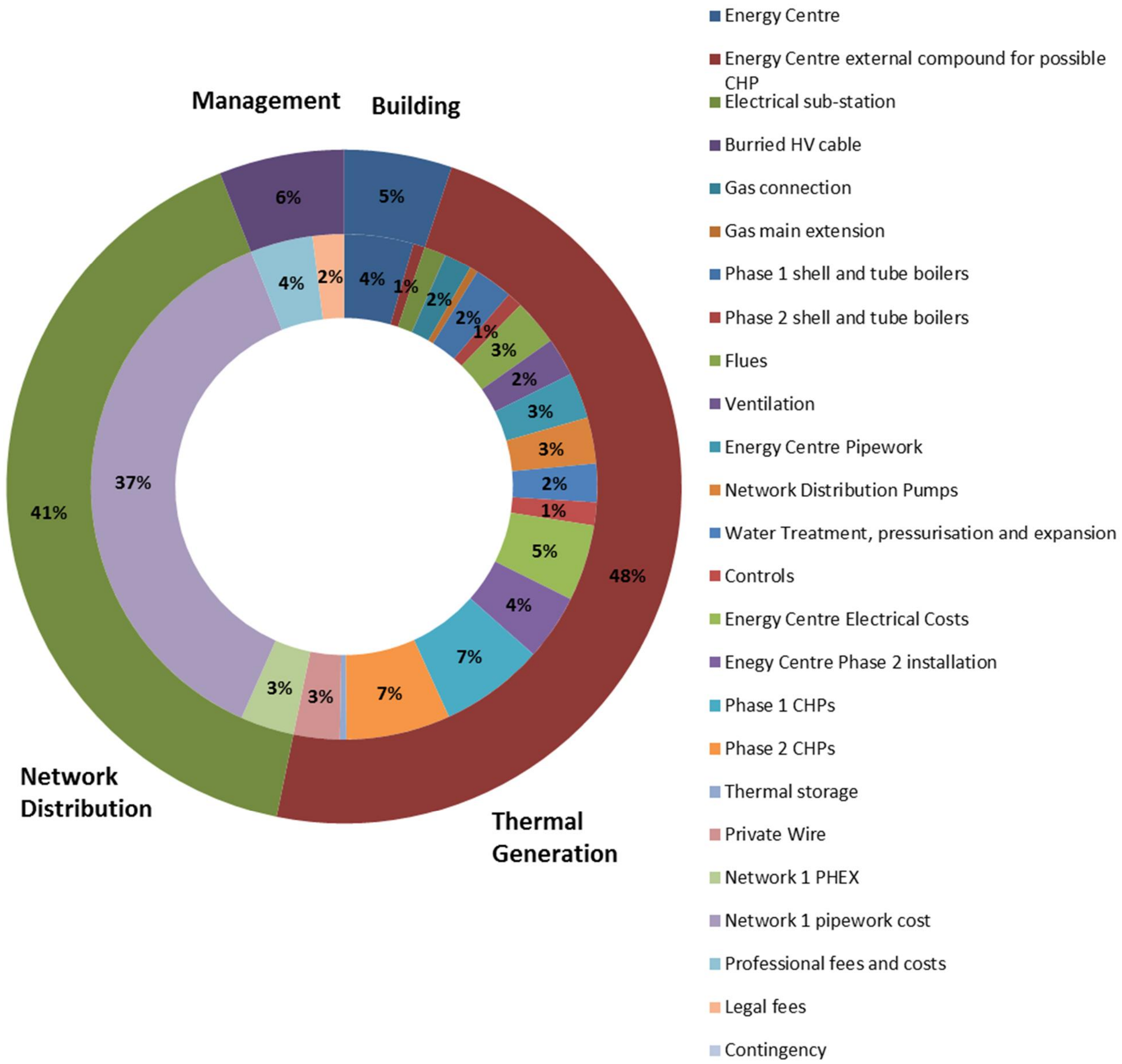

Figure 7-2: CWSW network CAPEX cost breakdown

MTCML network

Network Costs

Developing the network incurs capital costs of approximately £9.2m. The primary costs driving the network capital expenditure are the shell and tube boilers and associated equipment, with a cost of c.£1.8m and a UEL of 25-30 years, and the CHP engine costs of the network of c.£2.14m (included within the CHP engines and private wire cost), with a UEL of 14 years. This expenditure is shown proportionally in Figure 7-4. As before, the outer ring groups expenditure by category, with the inner circle showing the line item breakdown.

Capital Expenditure Profile

Figure 7-3 sets out the capital expenditure profile for the Base Case.

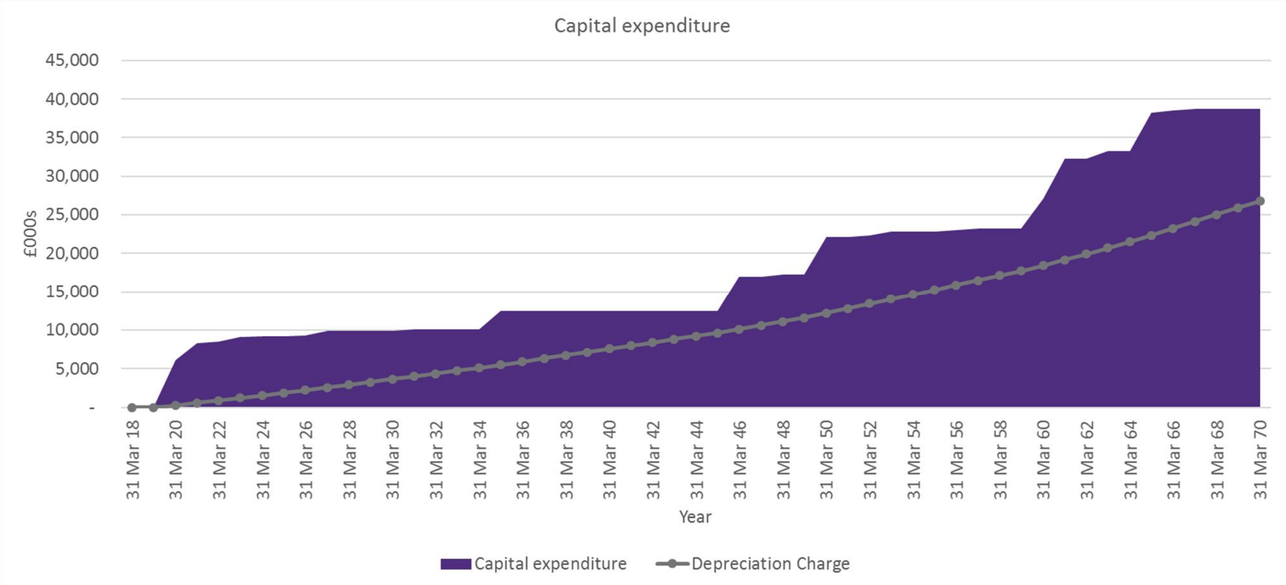

Figure 7-3: MTCML network capital expenditure for Scenario A

The 'steps' later on in the project life reflect the refresh of assets which are nearing the end of their UELs. As such, at the end of the project term, these assets are not fully depreciated, and therefore have a net book value in the financial statements. Under the Base Case, these assets have a depreciated value of £11.95m. We have not performed a separate assessment on whether these assets could be realised by the SPV, or whether they could be sold as part of the SPV on a 'going concern' basis to a new operator. Consequently, the value of these assets is not reflected in the project returns.

It should be noted that the UEL of the '14 year', '25 year', and '50 year' assets purchased in the first period of network development have each been extended by one additional year. Extending the UEL for these assets by one year ensures the Financial Model reflects that there will be no refresh costs associated with these assets in the final year of the schemes operation – something which represents an unrealistic position. This method results in the deprecation being slightly understated; however this should have no material effect on the output of the Financial Model.

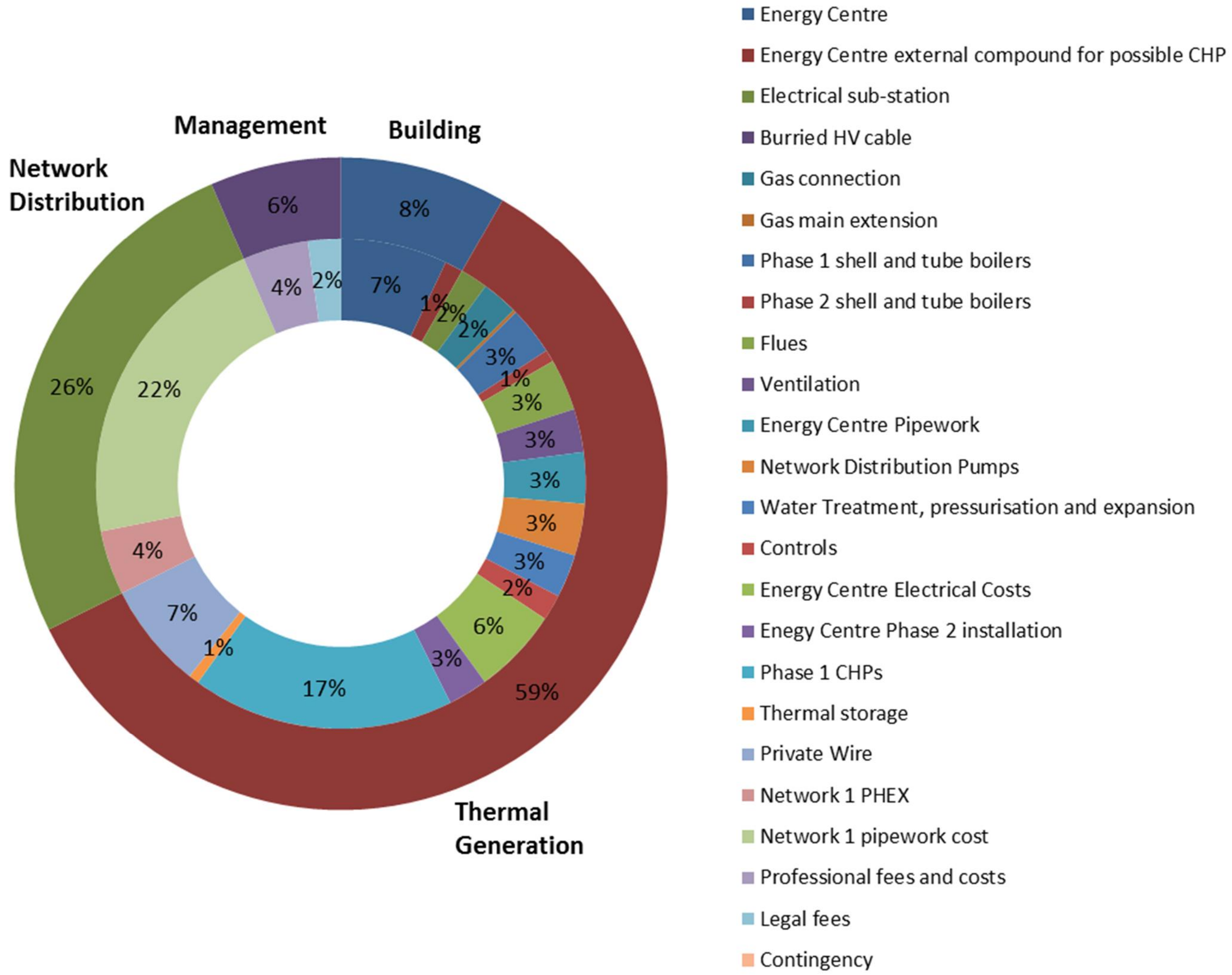

Figure 7-4: MTCML network CAPEX cost breakdown

7.5 Operational expenditure (OPEX)

The costs of operating the heat networks comprise of both fixed and variable costs. The figures detailed in this section show the forecast operating costs (in nominal terms) over the life of the Base Case. Due to the fixed inflation assumption applied to operating costs there is a steady increase in costs as per the figures below over the life of the project. The larger step increases indicate where additional loads are added to the networks.

7.5.1. CWSW network

Figure 7-5 shows the details of the operating costs for the Colliers Wood & South Wimbledon project.

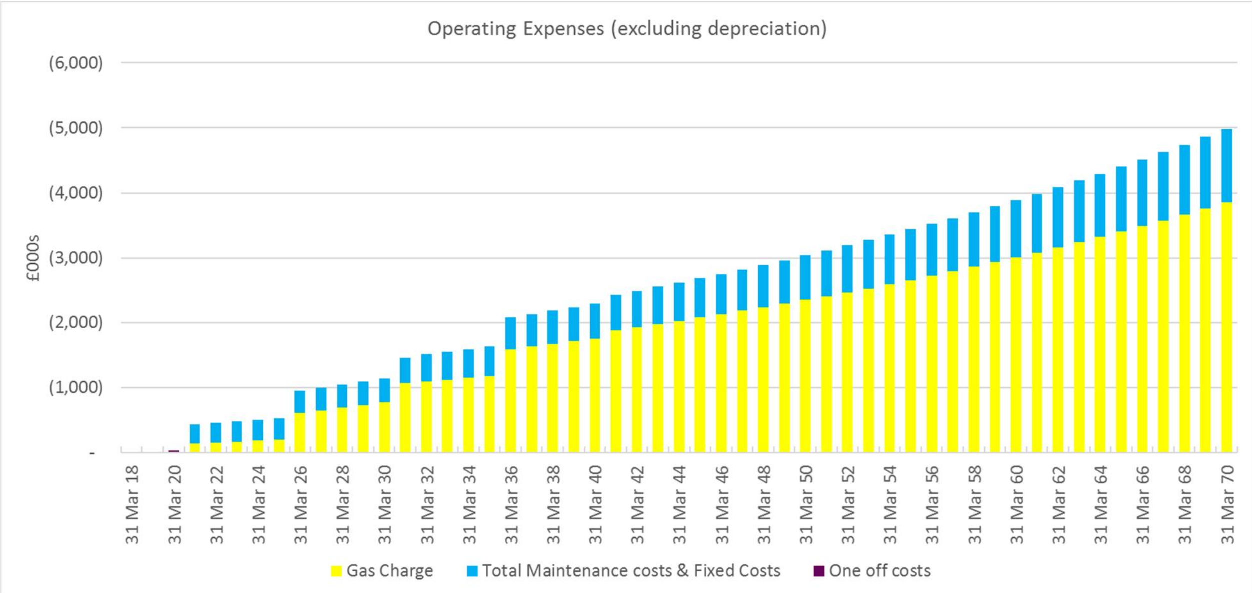

Figure 7-5: CWSW network OPEX expenditure (nominal) for Scenario A

Table 7-5 sets the total nominal operating costs for Scenario A (Base Case) over the project term and the assumptions that have formed the basis for these projections including assumptions as regards indices applicable for the cost items.

The gas prices used are BEIS historical figures, where *"the average price for each size of consumer is obtained by dividing the total quantity of purchases, for each fuel, into their total value. Prices shown are fully delivered prices, including all elements except VAT and Climate Change Levy."*

Table 7-5: CWSW network total operating costs (nominal) for Scenario A

Scenario A	Cost (£m)	Assumptions
Gas Charge	100.81	Gas purchase costs at £0.01561/kWh[6] indexed at the Commercial IAG Grid Gas Trend + RPIx over the project life.
Maintenance costs	24.18	Maintenance profile varies based on network set-up and technological solution adopted. Indexed at RPIx over the life of the project
Fixed costs	8.09	Audit Fees: £10,000/annum Admin Fees:£15,000/annum Insurance Fees: £50,000/annum All indexed at RPIx over the life of the project
One-off costs (fixed)	0.04	SPV Set up Costs of £35,000 Indexed at RPIx to commencement of project
Total OPEX	133.12	

7.5.2. MTCML network

Figure 7-6 shows the details of the annual operating costs for the MTCML project.

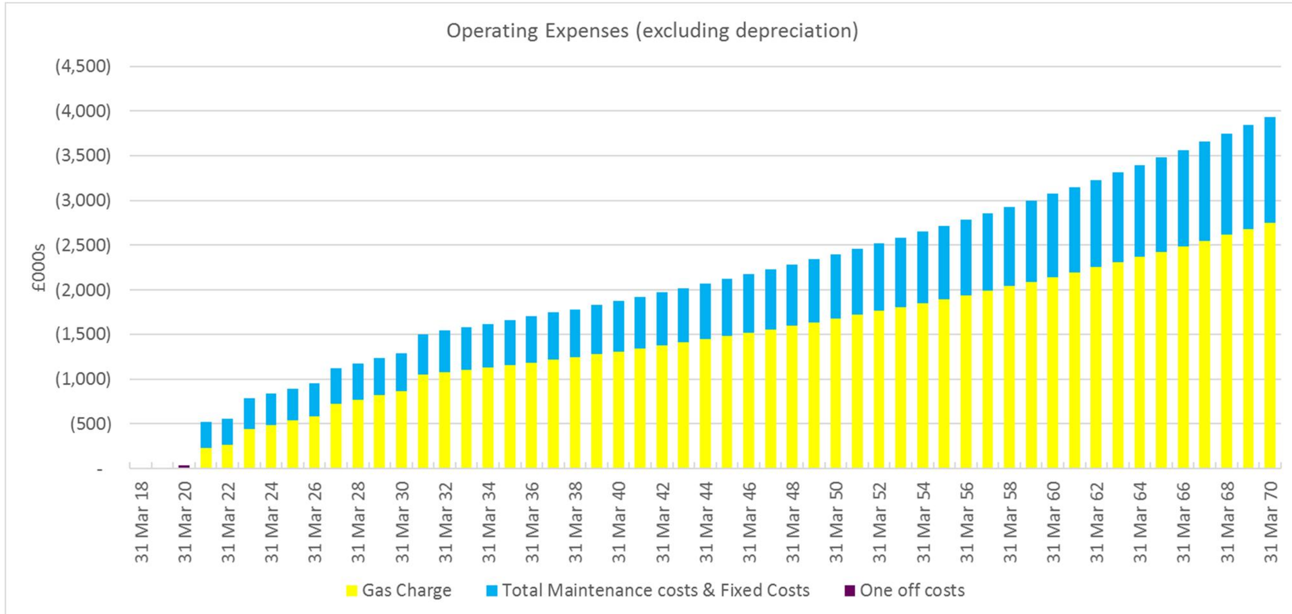

Figure 7-6: MTCML network OPEX expenditure (nominal) for Scenario A

[6] Based on the historical gas trend figure from Table 3.4.1 for Large customers, including CCL. https://www.gov.uk/government/statistical-data-sets/gas-and-electricity-prices-in-the-non-domestic-sector

Table 7-6 sets the total nominal operating costs for Scenario A (Base Case) over the project term and the assumptions that have formed the basis for these projections including assumptions as regards indices applicable for the cost items.

Table 7-6: MTCML network total operating costs (nominal) for Scenario A

Scenario A	Cost (£m)	Assumptions
Gas Charge	76.41	Gas purchase costs at £0.01561/kWh indexed at the Commercial IAG Grid Gas Trend + RPIx over the project life.
Maintenance costs	26.13	Maintenance profile varies based on network set-up and technological solution adopted. Indexed at RPIx over the life of the project
Fixed costs	8.09	Audit Fees: £10,000/annum Admin Fees:£15,000/annum Insurance Fees: £50,000/annum All indexed at RPIx over the life of the project
One-off costs (fixed)	0.04	SPV Set up Costs of £35,000 Indexed at RPIx to commencement of project
Total OPEX	110.67	

7.6 Revenue

Revenues for the network operators are generated from charges for residential and commercial heat as well as electricity income for private sales to customers and export to the grid.

7.6.1. CWSW network

Figure 7-7 shows the Base Case CWSW forecast revenues in nominal terms. As with the Morden Town Centre & Morden Leisure Centre Project, the forecasts show that heat and electricity income is split approximately 65/35.

In addition to the smooth increase in revenues once the network reaches full capacity, there are stepped changes in the early years. Whilst the pipework and the initial capital expenditure is undertaken over a specific period in two phases, the connection of loads takes longer and is over a greater number of phases (see Section 4.3.5). This gives issues with cashflow, as large capital expenditures at the outset of the project do not begin to generate revenues until later.

To demonstrate this, Figure 7-7 sets out the total energy capacity of the network once it is fully connected. The network connections are based on the expected developments and availability of energy off-take. Of particular note are the connection fees as these are received at particular point as shown in the graph. This is because it is assumed that these are contractually secured and received at the time of a customer signing up to the network.

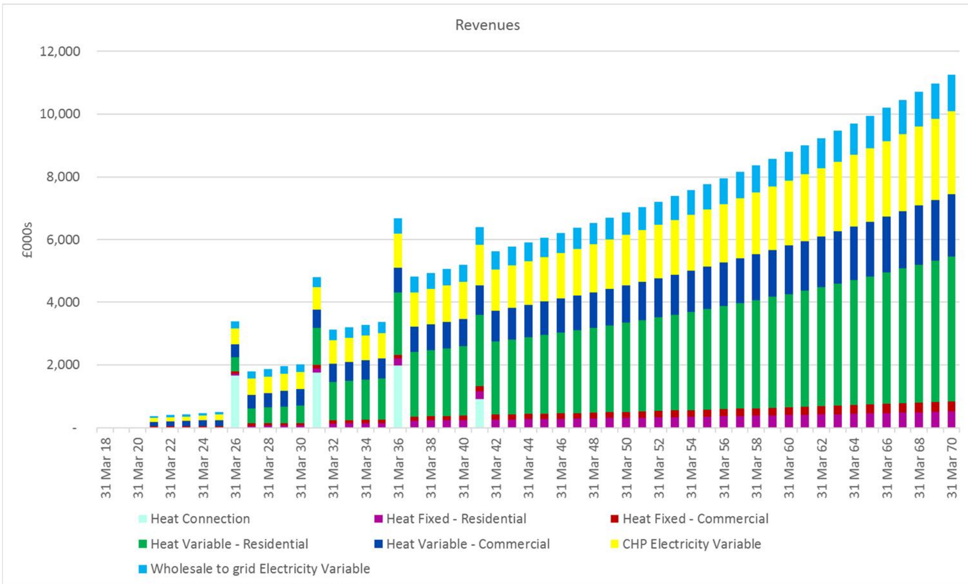

Figure 7-7: CWSW network- revenues generated (nominal) for Scenario A

7.6.2. MTCML network

Figure 7-8 below shows the forecast revenues for the Base Case (in nominal terms) over the project term. The forecasts show that heat and electricity income is split approximately 65/35.

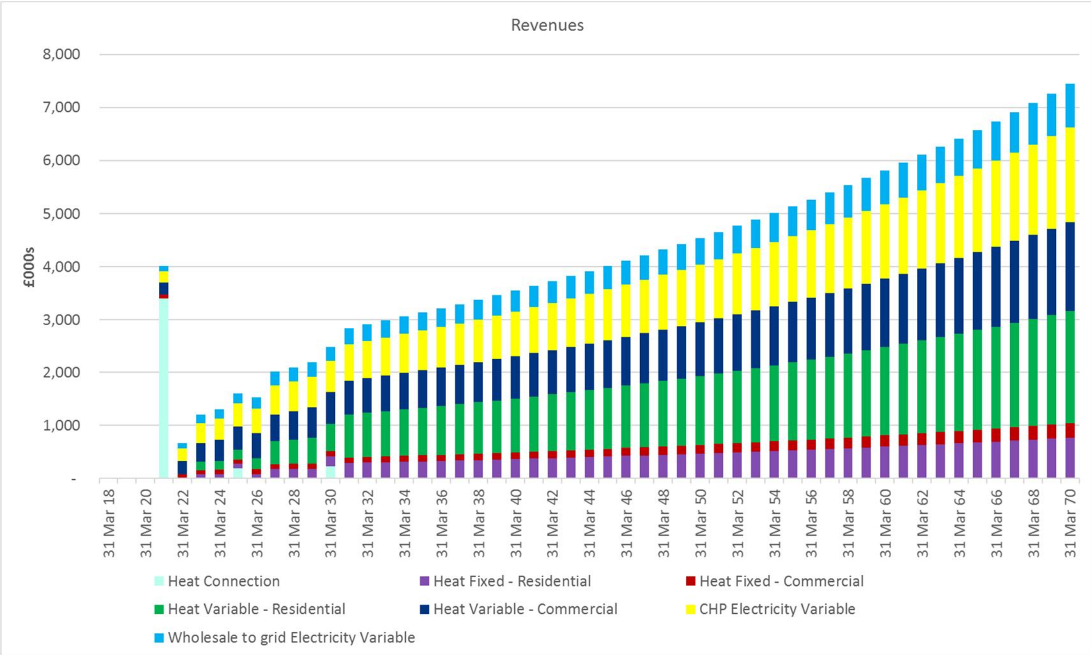

Figure 7-8: MTCML network- revenues generated (nominal) for Scenario A

The graph demonstrates that in addition to the smooth increase in revenues once the network reaches full capacity, there are stepped changes during the earlier years of the project, reflected by the phased connection of loads during implementation of the network.

7.6.3. Counterfactual heat prices

The counterfactual heat price is what customers on the heat network currently pay for heat. This depends on whether they are residential or commercial customers, and is made up of the cost of their fuel consumption (i.e. the variable charges) and the cost of operating their heating system (maintenance costs and standing charges). Heat tariffs for network customers are then based on the counterfactual costs, to ensure that customers will realise a saving by connecting to the network,

The counterfactual costs used in the modelling are shown in Table 7-7. The adjusted non variable charges of the counterfactual heat price differs between the two areas because it is based on a building by building basis, assuming a fixed charge per unit for residential, and per kW for commercial. When this fixed charge is adjusted to a variable rate it is affected by how much heat each unit is consuming. In the case of the MTCML network, the residential units are generally newer and therefore consume less heat. As such the counterfactual fixed costs per unit adjusted on a per kWh basis are higher.

Table 7-7: Year 1 counterfactual heat price breakdown

	Scenario A	CWSW	MTCML
Residential	Assumed replacement costs per unit	1,600	1,600
	Number of units	1,350	1,070
	Replacement cycle	20	20
	Annual standing charge[7]	£91.25	£91.25
	Annual maintenance[8]	£192.00	£192.00
	Adjusted non variable charges	6.4p/kWh	9.0p/kWh
	Gas price	3.6p/kWh	3.6p/kWh
	Boiler efficiency	86%	86%
	Variable charges per kWh	4.2p/kWh	4.2p/kWh
	Total counterfactual cost	10.6p/kWh	13.2p/kWh
Commercial	Assumed replacement costs per kW	£250/kW	£250/kW
	Replacement cycle	20	20
	Commercial maintenance costs	£4/kW	£4/kW
	Adjusted non variable charges	1.1p/kWh	2.4p/kWh
	Gas price	2.1p/kWh	2.1p/kWh
	Boiler efficiency	86%	86%
	Variable charges per kWh	2.5p/kWh	2.5p/kWh
	Total counterfactual cost	3.6p/kWh	4.9p/kWh

[7] Uswitch check of EDF standard variable
[8] British Gas Home Care: One boiler only with no excess

7.6.4. Heat network fixed charges

Fixed Charges are generally set to cover the minimum running costs of the scheme. This gives comfort to the operator (and funder) of the financial viability of the scheme. A common complaint made by customers is that Fixed Charges are too high, and therefore a commercial decision should be taken as to whether the full extent of fixed costs should be included in this element of the charge. The higher the element of Fixed Charge, the lower the demand risk is, i.e. variability in income subject to demand.

For the purposes of the TEM and Financial Models, fixed charges are based on the peak demand of the connected load. Residential tariffs are only applied to new residential developments, where the network operator is assumed to own and operate the secondary networks of the new developments. For existing residential blocks, the commercial tariffs are applied as it is assumed that heat is sold to the landlord, who then distributes the heat to residents as usual. Metering and billing costs for residential properties have also been included, to ensure that savings to customers can be delivered. Rates for fixed charges have been taken from those applied to the Olympic Park DH scheme. Variable rates are then adjusted to ensure heat tariffs will deliver savings to customers against the Merton specific counterfactual case.

Table 7-8: Fixed elements of heat price

	Scenario A	Price
Residential	Fixed charges	£23.45/kW
	Metering and billing costs	£105.02 per dwelling per annum
Commercial	Fixed charges	£17.07/kW
	Metering and billing costs	Assumed negligible due to reduced number of customers in comparison to residential customers

7.6.5. Network variable charges

Heat networks typically charge for heat via a Fixed Charge plus a Variable Charge, similar to most electricity or gas supply contracts. A third method – a ‘Flat Charge’ approach is no longer permissible under the Heat Network (Metering and Billing) Regulations 2014 unless it is not technically possible and economically justified to implement metering and charging based on actual consumption.

The variable charge is often set to cover the marginal costs of supplying heat to the customer, e.g. fuel costs and efficiency losses. Variable charges for each network have been adjusted to ensure that customers make a saving of 10% by connecting to the network; hence they are different between the two networks. Heat prices are then indexed based on the IAG Gas Trend +RPIx rate over the life of the project.

Table 7-9: Fixed elements of heat price

		CWSW	MTCML
Residential	Variable rate	6.45p/kWh	7.1p/kWh
	Reduction on counterfactual	90%	90%
	Equivalent network heat price per kWh	9.5p/kWh	11.9p/kWh
	Reduction on counterfactual heat price	10%	10%
Commercial	Variable rate	2.24p/kWh	3.4p/kWh
	Reduction on counterfactual	90%	90%
	Equivalent network heat price per kWh	3.2p/kWh	4.4p/kWh
	Reduction on counterfactual heat price	10%	10%

7.6.6. Connection charges

A connection charge is a one-off contribution towards the capital cost of initiating a connection to the heat network. The connection charge is often set to cover:

- The capital outlay required for connection to the scheme
- An amount not more than the cost which would be incurred for connection to/installation of an alternative heat source
- Planning Authority requirements

For the purposes of the Financial Modelling, connection charges of 50% of the counterfactual costs have been assumed. For existing buildings, the counterfactual is based on a £250/kW cost of boiler replacement. For the two large new developments (High Path Estate and the Morden Town Centre development), the counterfactual is based on a gas CHP DH network at a cost of £1000/kW.

7.6.7. Electricity Income

The electricity generated by the CHP engines of the SPVs can be sold via a Power Purchase Agreement (PPA). PPAs can be agreed with private wire customers or Energy companies / aggregators via the National Grid. PPAs can be structured to have either a fixed or variable price and can be over a short or long term. A PPA offering lower but guaranteed revenues over the long term may be considered preferable to a shorter agreement that could potentially deliver higher but less certain revenues.

The power would be delivered to customers by private wire, a distribution network operated outside of the transmission and distribution licences. As a result, electricity can be sold from generator to a user via this network often without the need to be licenced and without being bound by transmission and distribution codes. The private wire setup requires an initial capital expenditure (e.g. for laying cabling), but allows the achievement of higher income as a result of achieving an electricity sale price close to the retail rate.

The CWSW network, assume an electricity sales price of £0.0934/kWh (95% of the counterfactual price[9]) over private wire indexed using the IAG Grid Electricity trend + RPIx rate over the life of the project. In contrast, the MTCML network assumes an electricity sales price of £0.0885/kwh (90% of the counterfactual price, also indexed using the IAG Grid Electricity trend + RPIx rate over the life of the project.

The SPVs are also able to generate revenue from wholesale electricity sales. A sales price of £0.0492/kWh has been assumed, indexed using the IAG Electricity trend + RPIx rate over the life of the project. This is based on a value of 50% of the counterfactual price.

In calculating electricity income, possible additional income streams, e.g. ancillary services or embedded benefits have been omitted. These were considered however, given there is no certainty around, for example, embedded benefits, the decision was taken to pursue a prudent approach and exclude these from the base case financial modelling. These reflect potential upsides to the Projects however, that would be likely to improve the returns position of the schemes.

7.7 Tax

At this stage, high-level corporation tax assumptions have been adopted and greater clarity on structures and tax positions would be needed to have specific tax assumptions, including:

- Periodic tax calculations on taxable profits, whereas in practice this would reflect the company accounting periods and associated corporation tax payments. This is a prudent assumption as, given the customer mix of the network, it is likely the SPV will be subject to corporation tax;
- An assumption that the majority (90%) of capital expenditure will qualify for capital allowances and the Financial Model reflects a single pool with a main pool rate of 18%. For the avoidance of doubt, no assessment has been undertaken as regard eligibility for capital allowances, additionally, no assessment has been made of enhanced capital allowances for CHP assets;
- An assumption that there is no other disallowed expenditure and transactions, including financing costs, which are on an arms-length basis;
- That VAT is applicable on all income and expenditure flows at the standard rate of 20% and that VAT is also reclaimed on all capital expenditure;
- No allowance for any Stamp Duty Land Tax (SDLT) charges that may arise in the event of property transactions; and
- No assumptions have been included for any Community Infrastructure Levy (CIL) that may arise.

We have also not considered the possibility of setting up the SPV as a Distribution Company (DISCO) to allow it to benefit from Enterprise Investment Scheme (EIS) relief. We understand that this is still an emerging area at present, under exploration by a number of investors seeking returns through investments that not only provide financial returns but also qualify for tax relief. However, given the significant requirements around a project being eligible for EIS relief, legal and professional advice would be required to ensure the structuring of the SPV was in a manner that complied with HMRC requirements and guidelines. No such modelling or consultation has been undertaken at this stage.

It is recommended to obtain detailed tax advice as the project develops and there is greater clarity on contractual structures and commercial issues.

7.8 Funding and project cashflows

The Base Case, for both projects, is predicated on the use of Public Sector funds (in the form of both debt and equity) to meet the initial Capex requirements, as this is usually the cheapest form of finance available - unless grant funding is available. This section sets out some of the issues relating to the use of Public Sector funds (e.g. State Aid compliance). However, first the cashflows that will require financing from the Public Sector's perspective are analysed.

7.8.1. Understanding the project cashflows from the public sector's perspective

The capital expenditure of the project is not just the initial outlay but also major lifecycle replacement and refresh that is required to maintain the network, as not all components have similar useful lives. Furthermore, the initial outlay is phased to meet the construction and load connection timetable.

7.8.2. CWSW public sector cashflows

As with the MTCML Project, capital expenditure occurs at various points over the project life. Full details of the profile are in the Financial Model 'C_Capex' sheet.

As the Public Sector investment is in the form of debt and pin-point equity, repayments on the debt (principal and interest) commence once the network is operational. Dividends on the equity are back ended to when the debt has been largely repaid and restrictions on dividend payments arising from availability of profits and/or cash are likely to have been removed. Due to the long project term, the way future expenditure is funded needs to be considered. It may be possible to model options around the debt term and payment of dividends to free cash that could be retained in a lifecycle reserve that negates the need for additional borrowing, as currently assumed, when major lifecycle expenditure is required.

[9] https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

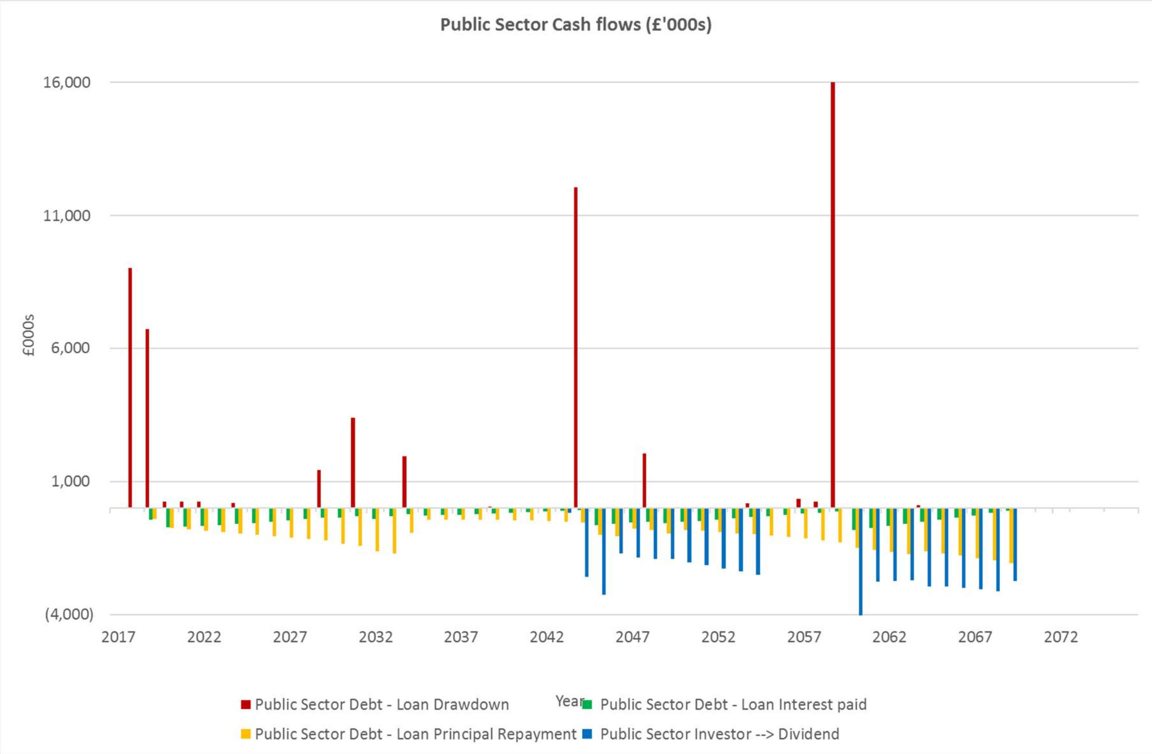

Figure 7-9: CWSW Public Sector Cashflows for Scenario A

The figure below is the cumulative cash position from the Public Sector's perspective. As is evident there is significant capital expenditure in 2045. The overall cash position becomes positive on a number of occasions but is sustained without going negative from 2044 onwards. Due to the additional borrowing arising whilst the original debt is being repaid a clear payback period for the initial outlay can only be determined by separately modelling the project without future capital expenditure.

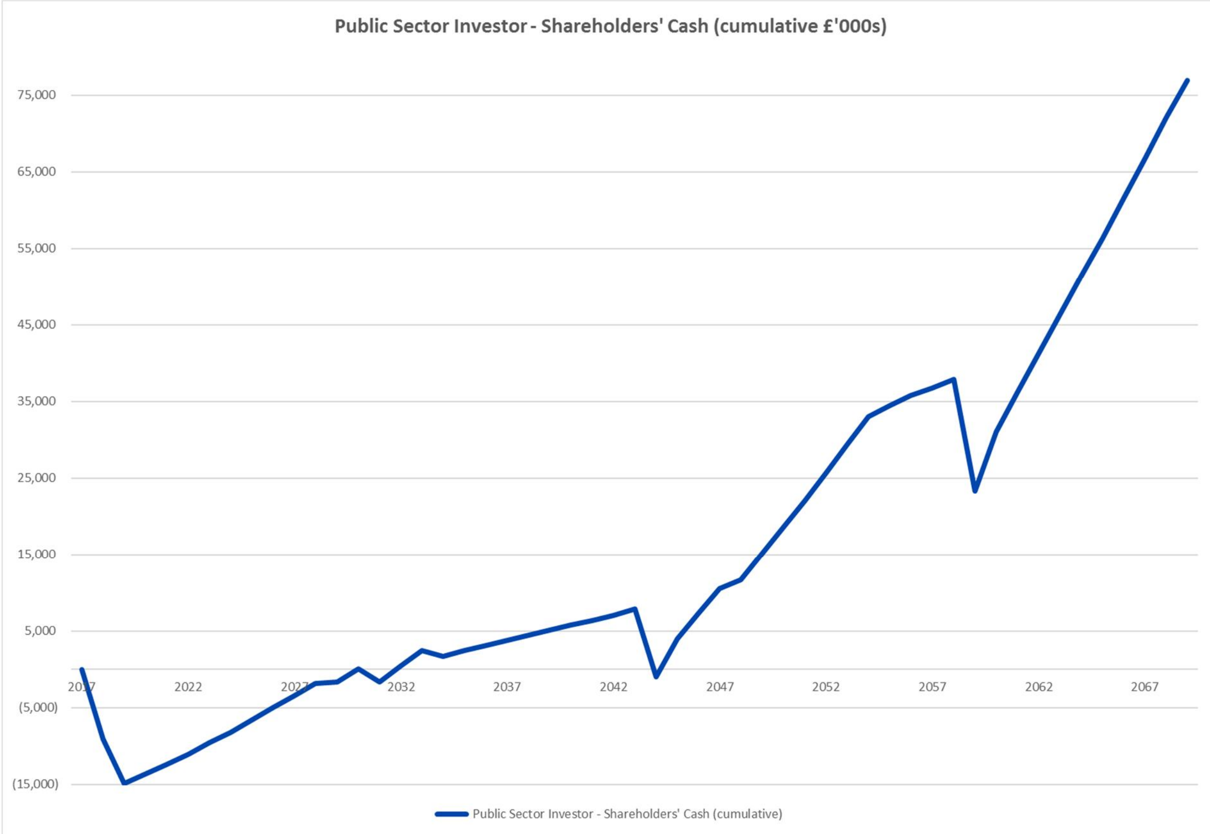

Figure 7-10: CWSW Public Sector Investor – Shareholders' Cash (Cumulative) for Scenario A

7.8.3. MTCML public sector cashflows

As shown by the figure below, which reflects nominal outflows, the capital expenditure (Public Sector – Loan Drawdown) occurs at various points over the project life with the initial expenditure occurring largely in the first five years but major lifecycle expense being incurred in 2047, 2058, 2059 and 2063. Full details of the profile are in the Financial Model 'C_Capex' sheet.

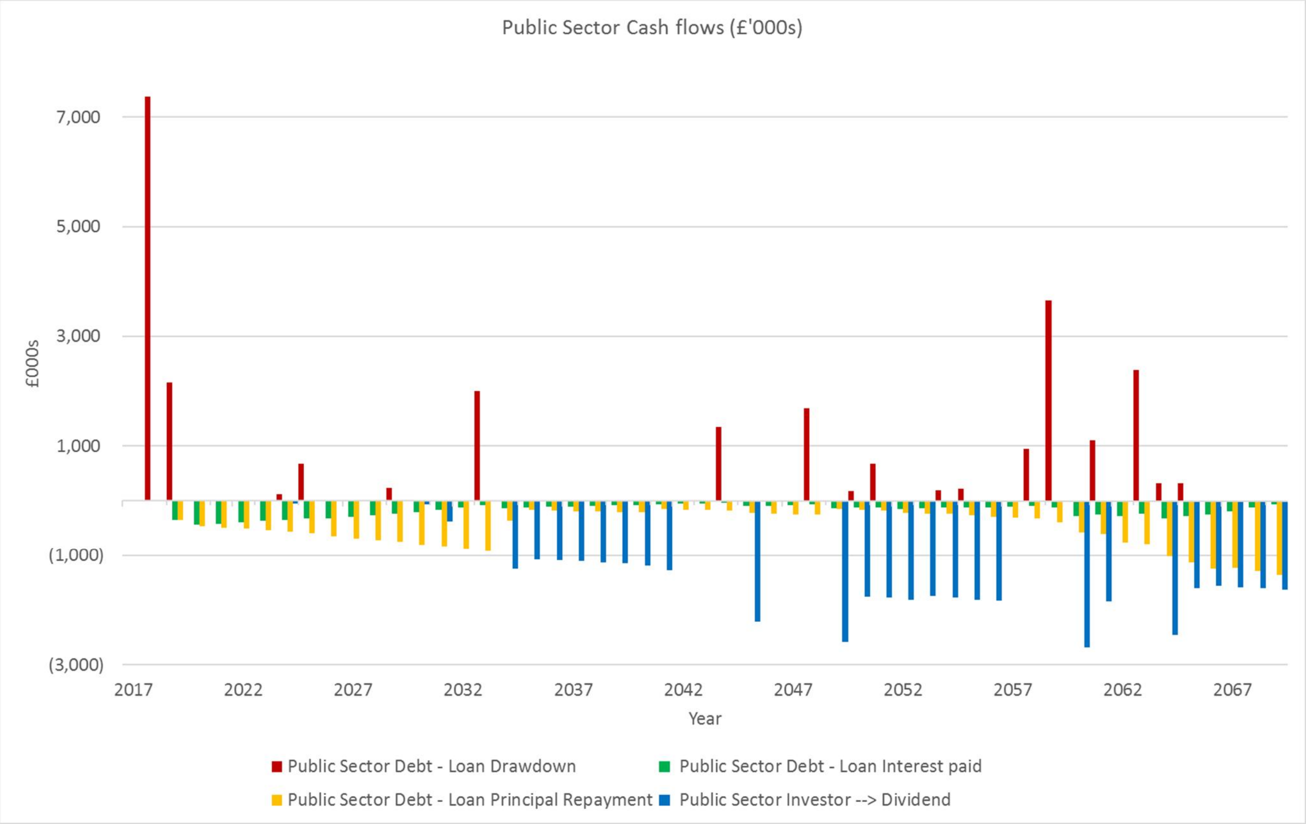

Figure 7-11: MTCML Public Sector Cashflows for Scenario A

Since the Public Sector investment is in the form of debt and equity, repayments on the debt (principal and interest) commence once the network is operational. Dividends on the equity are back ended to when the debt has been largely repaid and restrictions on dividend payments arising from availability of profits and/or cash are likely to have been removed. Due to the long project term, the way future expenditure is funded needs to be considered. It may be possible to model further options around the debt term and payment of dividends to free cash that could be retained in a lifecycle reserve that negates the need for additional borrowing, as currently assumed, when major lifecycle expenditure is required.

Set out below is the cumulative cash position from the Public Sector's perspective. The overall cash position becomes positive in 2030/31. Due to the additional borrowing arising whilst the initial debt is being repaid, there are periods (as shown from the dips in the graph) where there are decreases in the cumulative shareholder cash position coinciding with the lifecycle expenditure requirements mentioned above.

Figure 7-12: MTCML Public Sector Investor – Shareholders' Cash (Cumulative) for Scenario A

7.8.4. Grant funding

The funding available for the projects will need to be considered in light of the procurement route and the final agreed structure of any SPV. By far the most cost effective funding would be one that does not incur any interest. This may be through capital contributions (e.g. capital injections from the project sponsors) or grant funding. Grant funds which may be available to the project include HNDU development funding and the HNIP (Heat Networks Investment Project), albeit that will be subject to finalisation of how future HNIP funds are to be deployed. The HNIP programme is a government established scheme to provide £320m of capital support to heat network projects.

We anticipate that the Public Sector will be looking to bid for a HNIP grant for this project, should such funding be available. The key financial criteria for bidding for these funds for new heat networks during the pilot phase was:

> *"... this [criteria] applies to projects that cannot go ahead without support as the project financials (such as Internal Rate of Return), whilst positive, are not attractive enough to secure funding. The funding gap in this case is the capital contribution required to take the IRR without HNIP funding up to the hurdle rate IRR of the equity investors. It is expected that applicants will have explored all other reasonable sources of funding prior to applying for the scheme and will be required to provide evidence to demonstrate this."*

There are likely to be many funding criteria that must be met by schemes in order to be eligible for HNIP funding; these are yet to be announced. However they are likely to include a requirement for CHP schemes to have 75% of heat delivered by the CHP; requirements that are met by both networks modelled herein.

To show the potential effect grant funding could have on the project, Scenario C was developed for each project in the relevant Financial Model, in which 30% of the Capex is financed by grant funding. At Tables Table 7-10 and Table 7-11 the impact on the Public Sector IRR can be seen.

Given the financial positions of the Base Cases and the forecast cash positions of the Project, it is likely an argument can be made to secure such funding in order to improve the position of the project. Note that awards of HNIP funding at the pilot phase averaged around 30% of the capital expenditure of the scheme.

7.8.5. Public sector funding and state aid compliance

Local authorities generally have access to borrowing at lower costs of finance than the private sector, for example via the Public Works Loan Board (PWLB), Salix interest free loans, and internal resources. Where local authorities are lending into a project, State Aid requirements must be considered and regulations may necessitate the imposition of a floor on the interest rates that can be charged.

Interest rate charged in Financial Model

To calculate the required rate to meet State Aid regulations the European Commission Interest Base Rates[10] were used to identify the effective interest rate for the most recent time period. The effective interest rate is 0.78%. Then, via reference to State Aid requirements and exemptions[11] a margin of 400 basis points was applied – the minimum margin required for lending to an entity with no trading history and therefore considered to be higher risk compared to an established entity with an evidential trading history. This sets a minimum interest rate for lending from a Public Sector entity to an arm's length SPV of 4.78%. As a result, a lending rate of 4.78% has been set for all scenarios, which assume lending is provided by the Public Sector.

In the Financial Models, the SPV is assumed to require an injection of debt for all capital expenditure requirements once cash reserves have been utilised. This then has interest charged at a rate of 4.78%, and is repaid over a fixed term annuity of 15 years. Where a drawdown is required within the final 15 years of the project, the annuity term is reduced such that the debt is repaid by the end of the project term.

Public Works Loan Board rates

When considering whether to invest in the project, the Public Sector should compare the Public Sector Investor IRR (the Public Sector Investor IRR is different to the Project IRR in that it takes in to account the financing structure of the SPV, including the cost of debt and the value of any dividends paid) to the rate at which it can access capital. In the majority of instances this would be from the PWLB.

The current prudential borrowing rates are as described in Figure 7-13 (based on access to a new PWLB Annuity), and range between 1.04% - 2.80%, depending on the period of borrowing. The Council will need to determine its current level of Prudential Borrowing and its limits on borrowing in order to understand the scope for further borrowing. Borrowing rates for a 15 year annuity are in the region of 1.85%. This would indicate that the Public Sector is capable of lending to the SPV at a rate greater than its own cost of borrowing.

The returns shown on the Base Case represent the returns to an investor lending to the SPV at a 4.78% coupon rate, receiving interest payments on the investment balances, as well as dividend receipts on free cash flows to derive an overall return. They do not take account of the investor's own cost of borrowing. An investor in either project would need to consider if the returns offered by the Project to cover their own cost of borrowing, meet their own required hurdle rates, as a well as any other investment specific requirements, which fall out with the scope of identifying the indicative returns of the Projects.

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[10] http://ec.europa.eu/competition/state_aid/legislation/base_rates2017_07_en.pdf

[11] http://www.bigsocietycapital.com/sites/default/files/State%20Aid%20Information%20-%20January%202017.pdf

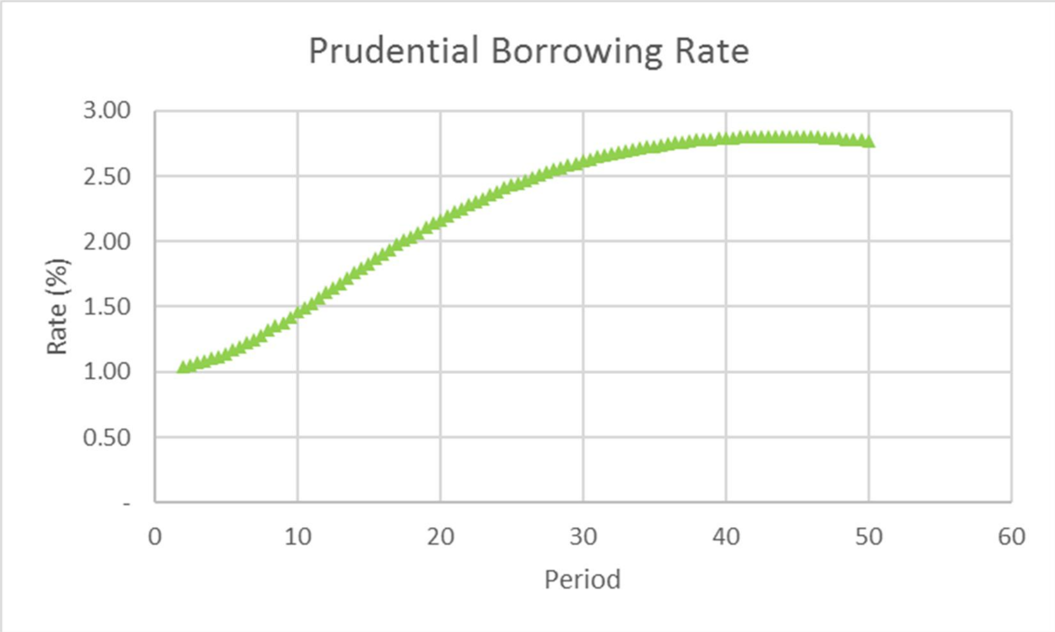


Figure 7-13: PWLB Rates

7.8.6. Project finance options

Commercial Project Finance may also be available where it is possible to demonstrate to funders that project revenues will comfortably service the debt. Such funding may be available against the strength of the forecast project cashflows with limited recourse against the borrowers. However, this is likely to be difficult and challenging considering the degree of risk that a funder would be willing and able to bear in relation to the underlying assets. Project finance may involve an element of both equity and debt holding within an SPV. This type of funding usually requires a considerable anchor heat load and guarantees from an entity with strong covenant strength.

With respect to the proposed Colliers Wood & South Wimbledon Project, the proposed customer mix means it is likely there is not sufficient anchor load in place to support this type of funding, although this may be possible if the health clubs and the leisure centre are able to commit.

For the MTCML project, given the nature of much of this heat network, there is a potential that the South Thames College and Merton Civic Centre could provide sufficient anchor load in place to support this type of funding. This would be even stronger if the 'Morden Town Centre Development' site in the Techno-Economic Model could be leveraged as an anchor load, however, the possibility of this is not yet clear.

Option B for each project was prepared to assess the impact of utilising banks as a source of project finance. This scenario reflects the effects on the project if 30% of the financing is in the form of Private Sector debt with an assumed interest rate of 7%. As the Public Sector, retaining 70% of the responsibility for financing the construction of the network and therefore is bearing the majority of the risk. 7% is considered to be a reasonable proxy for a commercial interest rate. If this option were explored further, market testing with potential financers would be required to more fully understand the expected returns.

Private Sector investment post-construction is often cheaper than during the construction phase (generally considered to be the most risky phase of a project). Using Public Sector finance to fund the construction phase followed by a Private Sector refinancing could be explored releasing the Public Sector capital would represent a financially attractive funding solution albeit with greater risk for the Council. For the purposes of the option below, all required debt drawdowns are assumed to be split 70:30 between the Public/Private Sector as and when such drawdowns are required with no front loading of Public Sector financing.

Table 7-10: CWSW network impact of Private Sector Finance

Scenario	Public Sector Interest Paid (£m)	Public Sector Investor IRR	Private Sector Interest Paid (£m)	Private Sector Investor IRR
A	20.76	7.69%	-	-
B	15.54	7.85%	12.99	7.00%
Variance	5.22	0.16%	12.99	7.00%

Table 7-11: MTCML network impact of Private Sector Finance

Scenario	Public Sector Interest Paid (£m)	Public Sector Investor IRR	Private Sector Interest Paid (£m)	Private Sector Investor IRR
A	9.20	9.59%	-	-
B	6.79	10.28%	4.56	7.00%
Variance	2.39	0.69%	4.56	7.00%

7.9 Financial model output – CWSW

7.9.1.Overview

In this section 7.9, we look at the details of the financial outcomes and analysis of CWSW scheme. The Base Case represents the scenario that is most likely to occur however, due the various factors that affect the financial performance of the project, a number of scenarios and sensitivities are undertaken.

- ***Section 7.9.2 Project and Investor Returns Analysis***
  We analyse the returns of the project and the returns to the investors in the project. The returns measured using IRRs and NPVs are an indicator of the financial viability of the project and the financial attractiveness of the project from an investor perspective. Also highlighted is the overdraft requirement (funding need arising from changes in operational cashflows) and depending on the quantum this may need to be addressed via alternative funding options.

- ***Section 7.9.3 Project Returns under different project lengths***
  We analyse the project returns under different project lengths to understand the impact on the project returns from a change in the project timeline.

- ***Section 7.9.4 Sensitivities***
  The purpose of the scenario and sensitivity analysis is to identify the outcomes should key variables be changed and identify factors that are critical to the project. The various scenarios set out are not indicative or suggestive of an expectation or likelihood of occurrence but can highlight key aspects to consider in negotiation of terms etc. As an example the indexation scenario highlights why tariff prices should be linked to indices reflecting energy prices and not general inflation.

- ***Section 7.9.5 Results of the Counterfactual***
  The counterfactual provides an indication of the costs under a business as usual scenario. Comparison of these projected costs against the projected costs of the project provide an estimate of the financial benefit or otherwise to the customers of the project.

7.9.2.Project and Investor Returns analysis

Table 7-12 below describes the IRR for both the Project and for an investor in the Project, as well as the NPV of the Project and the NPV to investors in the Project.

- Project IRR/NPV – These values are based on the key outputs of the Project. They present the performance of the Project, but do not include the impacts of corporation tax and financing assumptions on the project (for example the manner in which capital expenditure is funded, levels of returns required on debt funding, and the dividend policy adopted
- Investor IRR/NPV – These values take the Project IRR/NPV and overlays the impact of tax and financing assumptions placed on to the Project. There generated indicative values are specific to each investor, and depend on their levels of investment in the project and the timing and quantum of any returns received on investment made.

Table 7-12: CWSW network, 40 year IRR and NPV Summary

Scenario	Project metrics				Investor metrics			
	Project IRR (pre-tax/finance) (Real)	Project IRR (pre-tax/finance) (Nominal)	Project NPV (pre-tax/finance) (Nominal) £m	Maximum Overdraft Required £m	Public Sector Investor IRR	Public Sector Investor NPV £m	Private Sector Investor IRR	Private Sector Investor NPV £m
A: Base Case	6.01%	8.70%	10.04	16.54	7.69%	3.97	-	-
Variation on Base Case								
B: 30% private debt	6.01%	8.70%	10.04	14.54	7.85%	3.53	7.00%	0.51
C: 30% CAPEX grant	6.01%	8.70%	10.04	6.40	9.92%	8.48	-	-
D: +5% heat price	6.34%	9.05%	11.67	15.49	8.08%	5.19	-	-
E: -5% heat price	5.65%	8.34%	8.42	17.59	7.25%	2.74	-	-
F: +5% electricity price	6.22%	8.93%	11.05	15.75	7.94%	4.74	-	-
G: -5% electricity price	5.78%	8.47%	9.04	17.33	7.42%	3.20	-	-
H: +30% CAPEX costs	4.16%	6.81%	3.24	28.04	4.78%	(2.54)	-	-
I: -30% CAPEX costs	8.56%	11.33%	16.85	7.21	10.31	9.90	-	-
J: loans paid over annuity period to end of project	6.01%	8.70%	10.04	3.65	7.16%	3.64	-	-
M: +10% Opex costs	5.82%	8.51%	9.27	17.48	7.47%	3.34	-	-
N: -10% Opex costs	6.19%	8.90%	10.82	15.60	7.90%	4.60	-	-
O: Public Sector Debt 6.78%	6.01%	8.70%	10.04	23.01	7.85%	3.62	-	-
P: RPIx indexation	3.21%	5.83%	(0.64)	99.09	4.78%	(1.96)	-	-

Table 7-12 shows the IRR and NPV of the project and the Investor IRR & NPV under a number of scenarios. This is over a 50-year period based on a discount rate of 3.5% real (6.0875% nominal). It is worth noting that according to BEIS (formerly DECC), the IRRs for the portfolio of heat network projects it is supporting vary between 0% - 15%, with the majority ranging between 5% and 9%. Scenario A's Project IRR of 8.70% is therefore near the top end of the range of returns expected from the majority of projects.

Project analysis

An increase of 30% in the capital costs, Scenario H, results in the project being unable to repay its debt and Scenario P highlights the impact on the Scheme from changes in gas and electricity gas prices assumptions. Due to the large up-front costs of the Scheme (i.e. principally for capital expenditure), it takes a significant period for a return on investment to be achieved. Increases in revenues above RPIx are required for this to be achieved, as the greater returns of the Project come later in the Project life. The removal of the gas and electricity curves from the model pricing means the Project becomes unviable, and unable to meet its obligations.

All scenarios, with the exception of Scenario H, have a positive NPV. All scenarios prepared require a level of overdraft (with an assumed interest rate of 8.0%) to fund operational cashflow shortfalls. Should the Project progress to the commercialisation phase, an alternative approach to working capital requirements could be considered, for example through the use of a shareholder loan or a premium on share capital in establishing the SPV. These options should be explored in tandem with more detailed monthly financial modelling of the cash position. However, for the purposes of the feasibility modelling at this Phase 2.2, an overdraft facility was considered to be an appropriate approach to meeting the working capital requirements.

Investor Returns analysis

The project offers rates of return that are mid-range for a CHP project. The project has been assessed from the Public Sector's perspective however; the Council may consider involving a Private Sector lender although given the indicative returns of the project, Private Sector interest is likely to be low.

Scenario C, involving a 30% capital funding grant presents the most commercially viable solution, assuming such funding could be obtained as it generates the highest Investor IRR all of scenarios (where the capital expenditure is not amended).

As capital expenditure makes up a significant proportion of the costs of the project, changes in capital costs can have a large impact on the project NPV – an increase or decrease in capital requirements affects the financing costs of the project in addition to the costs of asset purchase. A reduction in capital requirements due to the use of grant funding of 30% increases the returns of the project by 2.62%. This also delivers a strengthened cash position for the SPV, such that it is able to pay out dividends in each year after 2036 (with the exception of those years where cash is held to meet upcoming capital expenditure requirements).

Altering the debt term also affects the returns. The base assumption on the debt term (Scenario A) is 15 years. If the debt were repaid over the project term (Scenario J) the returns from the project will be lower.

The cost of borrowing in the model under all scenarios except Scenario O is 4.78%. If the returns are 4.78%, this indicates that the Project is unable to achieve positive cash flows over the Project life as the Project can only meet the cost of borrowing.

7.9.3. Project Returns under different Project lengths (Scenarios K&L)

The base assumption in relation to project length is 50 years. Amending the project length to a 25 and 30-year appraisal period for Scenario A reduces the levels of returns as set out in Table 7-13. However, there are sufficient returns available such that, with an overdraft facility, the Project can be in a cash-positive position in the final year of operation.

Note that, under the 25 and 30-year scenarios, as with the Base Case, the life of relevant assets has been extended by an additional year to ensure there is no asset refresh in the final year of the scheme operation.

Table 7-13: CWSW network different project lengths

Scenarios K&L Length	Project IRR (pre-tax/finance) (Nominal)	Project NPV (pre-tax/finance) (Nominal)	Maximum Overdraft Required	Closing Cash Balance
50 years	8.70%	10.04m	16.54m	-
30 years	7.35%	3.00m	16.54m	-
25 years	6.89%	1.65m	16.65m	-

As with the Base Case, the fixed assets of the SPV are not fully depreciated at the end of the project term and have a net book value in the financial statements. The net book value is £9.28m and £3.84m under a 30-year and 25-year project length respectively. We have not performed a separate assessment on whether these assets could be realised by the SPV, or whether they could be sold as part of the SPV on a 'going concern' basis to a new operator. The value of these assets is therefore, not taken into account when calculating the project returns.

7.9.4. Sensitivities

Throughout this section, in addition to the Base Case (Scenario A) results, we have presented the results of various sensitivities that have been prepared to assess the resilience of the Base Case to changes in the assumptions underpinning the Project. The various sensitivities considered are:

7.9.4.1. Capital Expenditure (Scenario H & I)

We have assessed a +/- 30% sensitivity on the capital expenditure assuming the same spend profile for the expenditure. The impact of changes in capital expenditure is significant with the Investor IRR ranging between 4.78% and 10.31%. These sensitivities have indicated that a significant increase of the capital costs leaves the Project in a financially unattractive position, as the returns of the Project are limited to interest on debt and a significant negative NPV position. This reflects the importance of careful analysis of the capital expenditure required and regular monitoring of the costs of the Project. As expected, a reduction in capital costs boosts the returns of the Project. Greater analysis including optimism bias is undertaken during the development of the outline business case to refine the capital expenditure estimate.

7.9.4.2. Operating Expenditure (Scenario M & N)

We have applied a +/- 10% sensitivity to the annual operating costs of the Project, including the annual maintenance costs and the annual fixed costs of the Project. The impact of changes in operating expenditure are not significant and result in the Investor IRR changing by around 0.20% for a 10% change in opex. While this sensitivity increases or decreases the returns of the Project accordingly, the impacts are not significant enough to influence an assessment of whether the Project is a financially attractive investment. An increase in the annual operating costs increases the maximum overdraft required – in both sensitivities, the level of overdraft required likely reflects an unreasonable commercial position. In any situation, the owners of the SPV will need to consider carefully the working capital requirements of the SPV and how these are to be met.

7.9.4.3. Cost of capital (Scenario B, C & O)

In preparing the Base Case, we have assumed a coupon rate for Public Sector debt of 4.78%, calculated by reference to State Aid requirements and exemptions. As a sensitivity, we have assessed the impact of increasing the coupon rate to 6.78%. The result is an improvement in the returns to the Public Sector on its investment in the SPV so are upside scenarios. An increase in the coupon rate improves the return in the early years of the Project.

We have also prepared an alternative funding position sensitivity, where the SPV obtains 30% funding from the Private Sector, with debt provided at a coupon rate of 7%. This results in an improved position for the Public Sector due to a reduction in the funding requirements.

7.9.4.4. Energy sales prices (Scenario D, E, F & G)

We have prepared sensitivities of +/- 5% on both the heat and electricity sales of the SPV. Heat revenue to the SPV comprises of a connection fee, a fixed fee and a variable fee. The sensitivity has been run on the variable heat sales only, as we would anticipate that connection and fixed revenues would be contractually secured when new customers join the network.

Electricity revenues in the financial model are entirely variable and comprise of both sales to customers and sales to the grid. The 5% increase/decrease is applied to the base price for selling to those customers.

The Project is sufficiently resilient to these sensitivities, heat price and electricity price changes of 5% change the Investor IRR by around 0.40% and 0.25% respectively. As such, the decision as whether to proceed with the Project is unlikely to be affected by these results.

7.9.4.5. Model timeframe (Scenario K&L)

The Base Case of the Project assumes a 50-year timeline. Alternative sensitivities have been prepared assessing the Project under 30 and 25-year time lines. These are set out in table 7.12. While the returns under these project lives are still positive, the NPV is significantly reduced, as much of the returns of the SPV are realised later in the Project life, when the SPV has little in the way of ongoing spend to achieve its returns.

7.9.4.6. Indexation (Scenario P)

Revenues and costs relating to heat and electricity are indexed using the relevant projections on future fuel and electricity prices. The purpose of the inflation scenario is assess the impact on the SPV should inflation differ from projections. Using RPIx as an index rather than the projections on fuel and electricity prices result in a net reduction in project revenues and an increasing overdraft position. This is because revenues have a greater exposure to inflation compared to costs. This highlights the importance of ensuring that when heat tariff pricing is negotiated the indexation mechanism agreed is appropriate and not linked to a RPIx only index as an energy index more accurately reflects the changes in energy prices compared to a general price index (*also see section on counterfactual*).

7.9.4.7. Conclusion on sensitivities

There are two scenarios that forecast a negative NPV and therefore inadequate returns. These scenarios relate to an increase in the capex of 30% and the use of general inflation for indexation rather than an energy linked index i.e. using an index that reflects general price changes rather than one that reflects the movement in prices in the energy market. The project is relatively robust as the other scenarios show positive NPVs and returns that are similar to the base case position.

7.9.5. Results of counterfactual

The NPV of the heat network and the Counterfactual (taking account of CAPEX and OPEX) are set out in the table below. Please refer to section 7.3.2 which provides further detail on the manner by which the counterfactual values have been calculated.

Table 7-14: CWSW network – Financial benefit of Project

Description	Network NPV £m
Counterfactual heat cost	37.03
Counterfactual electricity cost	14.65
Counterfactual cost	51.68
Cost of heat for network customers	40.12
Cost of electricity for network customers	13.92
Total cost for network customers	54.11
Financial benefit of project in comparison to counterfactual	(2.43)

As per Table 7-14, the proposed heat network projects additional cost of c£2.43m that could be incurred by the users of the network. The existence of excess costs suggests that proceeding with the network does not make financial sense from the perspective of network customers.

The reason for the divergence between the counterfactual costs and the heat network costs are due to the difference between the split of standing and variable charges between the two cases. As different aspects of the cost base (e.g. commodities) change prices at different speeds, the relative costs will diverge over time. In the TEM, different indexation is applied to the various components. Whist the starting heat price represents a 10% discount, when indexation is applied the timing of the capital expenditure, and the impact of the IAG curves applied to the variable components can result in prices escalating at different rates.

The heat tariff structure will determine whether the customer or the supplier takes on the risk of divergence. The actual tariff structure will be negotiated during the commercialisation phase of the project, and will depend on each customer's appetite for risk, understanding of future price predictions and expectations around the split between the fixed and variable elements of their heat tariff. The risk allocation attempts to favour the customer, but in the analysis a residual risk remains that Value for Money will not be achieved. The impact of the risk allocation is around +/- 0.4% IRR as shown by scenarios D & E.

Careful consideration should therefore be given to the assumptions made in assessing the heat network and the decision making process underpinning any decisions to proceed with development of the network. Financial benefit for customers of the scheme could be generated by further reducing the heat tariff price (electricity prices assumed for customer are based on the market price for electricity with a 10% discount), however this would further reduce the returns from the scheme.

7.10 Financial model output - MTCML

7.10.1. Overview

In this section 7.10, we look at the details of the financial outcomes and analysis of MTCML scheme. The Base Case represents the scenario that is most likely to occur however, due the various factors that affect the financial performance of the project, a number of scenarios and sensitivities are undertaken.

- *Section 7.10.2 Project and Investor Returns analysis*
  We analyse the returns of the project and the returns to the investors in the project. The returns measured using IRRs and NPVs are an indicator of the financial viability of the project and the financial attractiveness of the project from an investor perspective. Also highlighted is the overdraft requirement (funding need arising from changes in operational cashflows) and depending on the quantum this may need to be addressed via alternative funding options.

- *Section 7.10.3 Project Returns under different project lengths*
  We analyse the project returns under different project lengths to understand the impact on the project returns from a change in the project timeline.

- *Section 7.10.4 Sensitivities*
  The purpose of the scenario and sensitivity analysis is to identify the outcomes should key variables be changed and identify factors that are critical to the project. The various scenarios set out are not indicative or suggestive of an expectation or likelihood of occurrence but can highlight key aspects to consider in negotiation of terms etc. As an example the indexation scenario highlights why tariff prices should be linked to indices reflecting energy prices and not general inflation.

- *Section 7.10.5 Results of the Counterfactual*
  The counterfactual provides an indication of the costs under a business as usual scenario. Comparison of these projected costs against the projected costs of the project provide an estimate of the financial benefit or otherwise to the customers of the project.

7.10.2. Project and Investor Returns analysis

Table 7-15 below describes the IRR for both the projects and for an investor in the project, as well as the NPV of the project and the NPV to investors in the project.

- Project IRR/NPV – These values are based on the key outputs of the project. They present the performance of the project, but does not include the impacts of corporation tax and financing assumptions on the project (for example the manner in which capital expenditure is funded, levels of returns required on debt funding, and the dividend policy adopted)

- **Investor IRR/NPV – These values take the project IRR/NPV and overlays the impact of tax and financing assumptions placed on to the Project. Their generated indicative values are specific to each investor, and depend on their levels of investment in the project and the timing and quantum of any returns received on investment made.**

Table 7-15: MTCML network, 40 year IRR and NPV summary

Scenario	Project metrics				Investor metrics			
	Project IRR (pre-tax/finance) (Real)	Project IRR (pre-tax/finance) (Nominal)	Project NPV (pre-tax/finance) (Nominal) £m	Maximum Overdraft Required £m	Public Sector Investor IRR	Public Sector Investor NPV £m	Private Sector Investor IRR	Private Sector Investor NPV £m
A: Base Case	9.55%	12.38%	9.59	0.46	9.59%	5.12	-	-
	Variation on Base Case							
B: 30% private debt	9.55%	12.38%	9.59	0.55	10.28%	5.08	7.00%	0.19
C: 30% CAPEX grant	9.55%	12.38%	9.59	0.08	11.86%	6.90	-	-
D: +5% heat price	10.09%	12.94%	10.72	0.28	9.99%	5.95	-	-
E: -5% heat price	8.99%	11.80%	8.46	0.75	9.18%	4.40	-	-
F: +5% electricity price	9.99%	12.84%	10.43	0.28	9.90%	5.75	-	-
G: -5% electricity price	9.10%	11.92%	8.75	0.73	9.27%	4.60	-	-
H: +30% CAPEX costs	6.19%	8.92%	5.24	4.85	7.21%	1.72	-	-
I: -30% CAPEX costs	15.86%	18.90%	13.94	0.04	13.03%	8.40	-	-
J: loans over annuity period to end of project	9.55%	12.38%	9.59	-	8.61%	4.34	-	-
M: +10% Opex costs	9.08%	11.89%	8.76	0.79	9.28%	4.61	-	-
N: -10% Opex costs	10.02%	12.87%	10.42	0.28	9.91%	5.74	-	-
O: Public Sector Debt 6.78%	9.55%	12.38%	9.60	2.04	9.94%	5.41	-	-
P: RPIx Only	5.95%	8.67%	3.12	3.64	6.72%	0.66	-	-

Table 7-15 shows the IRR and the NPV of the project and the Investor IRR and NPV under a number of scenarios. This is over a 50-year period based on a discount rate of 3.5% real (6.0875% nominal). It is worth noting that according to BEIS (formerly DECC), the IRRs for the portfolio of heat network projects it is supporting vary between 0% - 15%, but with the majority ranging between 5% - 9%. Scenario A's Project IRR of 12.38% is above the range of returns expected from the majority of projects.

Project analysis

A number of the scenarios despite having a positive NPV, require a level of overdraft (with an assumed interest rate of 8.0%) to fund operational cashflow shortfalls. Should the Project progress to the commercialisation phase, an alternative approach to working capital requirements could be considered, for example through the use of a shareholder loan or a premium on share capital in establishing the SPV. These options should be explored in tandem with more detailed monthly financial modelling of the cash position. However, for the feasibility modelling at this Phase 2.2, an overdraft facility was considered to be an appropriate approach to meeting the working capital requirements.

Investor Returns analysis

It is evident that the project offers strong rates of return. Although the project has been assessed from the Public Sector's perspective, the Council could consider Private Sector debt. Given the indicative returns of the project, further discussion will be required with the Private Sector as to whether this level of return is acceptable. The returns may be attractive enough to draw investments from pension funds.

Scenario C, involving a 30% capital funding grant presents the most commercially viable solution, assuming such funding could be obtained as it generates the highest Investor IRR all of scenarios (where the capital expenditure is not amended).

Scenario analysis shows that the project is more sensitive to fluctuations in the heat sales price than it is to electricity, this is because heat sales are projected to make up more than half (65%) of the revenues for the project. Since capital expenditure makes up a significant proportion of the costs of the project, changes in capital costs can have a large impact on the project NPV – an increase or decrease in capital requirements affects the financing costs of the project in addition to the costs of asset purchase. A reduction in capital requirements due to the use of grant funding of 30% increases the returns from the project by 3.44%.

Altering the debt term also affects the returns. The base assumption on the debt term (Scenario A) is 15 years. If the debt were repaid over the project term (Scenario J) the returns from the project will be lower (although lending over such a term is unlikely anyway).

7.10.3. Project Returns under different project lengths (Scenarios K&L)

The base assumption in relation to project length is 50 years. Amending the project length to a 25 and 30-year appraisal period for Scenario A reduces the levels of returns as set out in Table 7-16. However, the returns are still high and the overdraft requirement does not change.

Note that, under the 25 and 30-year scenarios, as with the Base Case, the life of relevant assets has been extended by an additional year to ensure there is no asset refresh in the final year of the scheme operation.

Table 7-16: MTCML network different project lengths

Scenarios K&L Length	Project IRR (pre-tax/finance) (Nominal)	Project NPV (pre-tax/finance) (Nominal)	Maximum Overdraft Required	Closing Cash Balance
50 years	12.38%	9.59m	0.46m	-
30 years	11.59%	5.64m	0.46m	-
25 years	11.54%	5.34m	0.46m	-

As with the Base Case, the fixed assets of the SPV are not fully depreciated at the end of the project term and have a net book value in the financial statements. The net book value is £7.30m and £2.23m under a 30-year and 25-year project length respectively. We have not performed a separate assessment on whether these assets could be realised by the SPV, or whether they could be sold as part of the SPV on a 'going concern' basis to a new operator. The value of these assets is therefore, not taken into account when calculating the project returns.

7.10.4. Sensitivities

Throughout this section, in addition to the Base Case (Scenario A) results, we have presented the results of various sensitivities that have been prepared to assess the resilience of the Base Case to changes in the assumptions underpinning the Project. The various sensitivities considered are:

7.10.4.1. Capital Expenditure (Scenario H & I)

We have assessed a +/- 30% sensitivity on the capital expenditure assuming the same spend profile for the expenditure. The impact of changes in capital expenditure are significant with the Investor IRR ranging between 7.21% and 13.03% however also demonstrate the robustness of the project as the return remain healthy even in the downside sensitivity. These sensitivities have indicated that a significant increase of the capital costs, while reducing the returns of the Project, still leaves the Project showing strong positive returns. However, the significant additional debt results in an overdraft of c.£5m, which, given its quantum, would likely need to be met by working capital funding from the Public Sector. This reflects the importance of careful analysis of the capital expenditure required and regular monitoring of the costs of the Project. As expected, a reduction in capital costs improves the returns of the Project. Greater analysis including optimism bias is undertaken during the development of the outline business case to further refine capital expenditure estimate.

7.10.4.2. Operating Expenditure (Scenario M & N)

We have applied a simple +/- 10% sensitivity to the annual operating costs of the Project, including the annual maintenance costs and the annual fixed costs of the Project. While this sensitivity increases or decreases the returns of the Project accordingly, they are not significant enough (a 10% change in opex changes the Investor IRR's by around 0.30%) to influence an assessment of whether the project is a financially attractive investment. An increase in the annual operating costs will also increase the maximum overdraft required. In any situation, the owners of the SPV will need to consider carefully the working capital requirements of the SPV and how these are to be met.

7.10.4.3. Cost of capital (Scenario B, C & O)

In preparing the Base Case, we have assumed a coupon rate for Public Sector debt of 4.78%, calculated by reference to State Aid requirements and exemptions. As a sensitivity, we have assessed the impact of increasing the coupon rate to 6.78%. The result is an improvement in the returns to the Public Sector on its investment in the SPV so are upside scenarios. This is due to two reasons. An increase in the coupon rate improves the return in the early years of the Project and in later years, results in a slight decrease in the taxable profits of the Project, resulting in a slightly reduced level of tax 'leakage' from the SPV.

We have also prepared an alternative funding position sensitivity, where the SPV obtains 30% funding form the Private Sector, with debt provided at a coupon rate of 7%. This results in an improved position for the Public Sector due to a reduction in the funding requirements.

7.10.4.4. Energy sales prices (Scenario D, E, F & G)

We have prepared sensitivities of +/- 5% on both the heat and electricity sales of the SPV. Heat revenue to the SPV comprises of a connection fee, a fixed fee and a variable fee. The sensitivity has been run on the variable heat sales only, as we would anticipate that connection and fixed revenues would be contractually secured when new customers join the network.

Electricity revenues in the financial model are entirely variable and comprise of both sales to customers and sales to the grid, the 5% increase/decrease is applied to the base price for selling to those customers.

The Project is sufficiently resilient to these sensitivities, heat price and electricity price changes of 5% change the Investor IRR by around 0.40% and 0.30% respectively. The Project is sufficiently robust that the Project remains an attractive proposition under any of these sensitivities.

7.10.4.5. Model timeframe (Scenario K&L)

The Base Case of the Project assumes a 50-year timeline. Alternative sensitivities have been prepared assessing the Project under 30 and 25-year time lines. These results are set out in table 7.17. While the returns under these project lives are still positive, the NPV is significantly reduced, as much of the returns of the SPV are realised later in the Project life, when the SPV has little in the way of ongoing spend to achieve its returns.

7.10.4.6. Indexation (Scenario P)

Revenues and costs relating to heat and electricity are indexed using the relevant projections on future fuel and electricity prices. The purpose of the inflation scenario is assess the impact on the SPV should inflation differ from projections. Using RPIx as an index rather than the projections on fuel and electricity prices results in a net reduction in project revenues and the need for a higher overdraft. This is because revenues have a greater exposure to inflation compared to costs. This highlights the importance of ensuring that when heat tariff pricing is negotiated the indexation mechanism agreed is appropriate and not linked to a RPIx only index as an energy index more accurately reflects the changes in energy prices compared to a general price index.

7.10.4.7. Conclusion on sensitivities

The project is robust as all scenarios show positive NPVs and returns. The returns drop below 9% in three scenarios. These scenarios relate to an increase in the capex of 30%, the use of general inflation for indexation rather than an energy linked index i.e. using an index that reflects general price changes rather than one that reflects the movement in prices in the energy market and repayment of debt over the project term.

7.10.5. Results of counterfactual

The NPV of the heat network and the Counterfactual (taking account of CAPEX and OPEX) are set out in the table below. Please refer to section 7.3.2 which provides further detail on the manner by which the counterfactual values have been calculated.

Table 7-17: MTCML network– Financial benefit of Project

Description	Network NPV £m
Counterfactual heat cost	33.42
Counterfactual electricity cost	12.81
Counterfactual cost	46.23
Cost of heat for network customers	32.48
Cost of electricity for network customers	11.53
Total cost for network customers	44.01
Financial benefit of project in comparison to counterfactual	2.22

As can be seen per Table 7-17, the proposed heat network represents a financial benefit of c£2.2m, representing potential savings that could be made by the users of the network. The existence of savings suggests that proceeding with the network makes financial sense from the perspective of network customers. See Section 7.9.5 for more discussion on Value for Money.

8. Risk assessment and management

A full risk register is provided in Appendix K. Some of the key risks found for each network are further explored in this section.

8.1 EC location and cost

If LBM chooses to pursue either network further, it shall need to secure the areas for the energy centre locations at the earliest opportunity. Failure to confirm the spaces identified in this report would necessitate alternative locations to be sought, for example:

- CWSW: within the Merton Industrial Estate
- MTCML: an area within the proposed Morden Town Centre developments, through planning conditions

Engagement with developers where necessary is vital to ensure areas are earmarked for energy centre location early on in the masterplanning phases. The costs of land for EC location should also be investigated – modelling has not accounted for land costs.

8.2 Building connections

There is a risk that some of the buildings identified for connection to the networks will either not be interested in connection, or technically unviable. Some customers may only be prepared to sign shorter heat supply agreements. In particular, operators of the identified existing private buildings must be engaged with as early on in the network development as possible. Full buildings audits must be carried out to assess technical viability.

Developers of future buildings such as that of the High Path Estate and the Morden Town Centre development must be consulted on connection and made aware of any planning conditions that will affect them, but which are necessary for the development of the network.

For any council owned buildings (for example the Merton Civic Centre), facilities managers and relevant stakeholders must be engaged with early on in the process.

8.3 Network temperature and future proofing

The MTCML network was identified as a low temperature network with flow/return temperatures of 75/45°C, and a dedicated 95/65°C supply to the Merton Civic Centre, due to the EC's proximity to that building.

The ability to install the network with lower operating temperatures is dependent on the design of the buildings on the network and their eligibility for accepting lower supply temperatures than would be conventionally designed for.

LBM should engage with the Thames Valley College at the earliest opportunity to ascertain the ability to supply heat at 75°C. Furthermore, planning conditions should be imposed on the developers of the Morden Town Centre and Morden Leisure Centre developments to ensure that buildings are designed with heating supply temperatures of 75°C. Networks are assumed to adopt the secondary side distribution of heat within new developments. The network operator will need to control quality of such systems.

8.4 Private wire electricity sales

The importance of maximising the sale of electricity to private customers, as opposed to selling it to the grid, was highlighted in Phase 1. The higher revenues realised through private sales increases financial returns of the networks. Where possible, all electricity generated should be sold privately; this requires the identification of a single large electricity consumer in the vicinity of the network who will buy the power.

The modelling carried out as part of this study identified that approximately half the electricity generated could be sold to the buildings on the network. However this requires the network operator to take over the supply of all electricity to the customers through the private wire network. In other words, customers would be physically removed from their current DNO supply, and connected via the energy centre. This assumption remains a risk until prospective customers agree to switch supplier.

During the commercialisation phases of the project this process must be given due attention early in the process to secure the private sale of sufficient electricity to back up financial performance of the network.

8.5 Policy/regulations updates

There is a risk that updates to policies or regulations (such as building regulations) may erode the case for the use of CHP. In the case of the MTCML network, this risk is mitigated by the proposal to use a lower heating supply temperature, such that the use of heat pumps in future would be possible.

LBM must keep abreast of changes to policies and regulations, to ensure that the technology used to replace gas CHP (if applicable) meets requirements. Any changes to the electricity market may also affect financial performance of networks.

8.6 Air quality

The council must work to ensure that the proposed network serves to improve air quality in the local area when compared to the business as usual case. Detailed air dispersion modelling is necessary to show both the BAU and the proposed scheme effects.

9. Conclusions

The study herein investigates the technical and financial feasibility of district heating in the London Borough of Merton. It builds on the results of previous phases to focus on the following network opportunities:

- Colliers Wood and South Wimbledon (CWSW); and
- Morden Town Centre and Morden Leisure Centre (MTCML).

The design of each network has been further developed in this phase of the study, with detailed financial modelling carried out to assess the performance of each network. This section highlights the key findings of Phase 2.2.

9.1 CWSW network

The network proposed in the CWSW area is a gas CHP and gas boiler supplied district heating network with around 4km of buried pipework serving a range of predominantly privately owned commercial and residential buildings. The total calculated heat consumption of the network is 15,852MWh, with a peak heating demand of 10.9MW. 75% of the heat demand is met by the CHP, making the network eligible for HNIP funding, a UK government grant programme for capital investment in heat networks.

The CWSW network is proposed to be a high temperature network (flow and return temperatures of 95°C and 65°C respectively) with a dedicated lower temperature network for the High Path Estate alone. Full hydraulic pipe sizing has been carried out. No opportunities for soft dig trenching were identified for the network, and whilst pipework has been routed down quieter roads where possible, installation of pipework will be challenging.

The network centres on the High Path Estate, a large new development in South Wimbledon, where it is proposed that the 716m^2 energy centre could be located. This study has included engagement with the developers of the estate, Circle Housing Group. They support the fact that district heating is a strong possibility for the delivery of energy on their site and have not ruled out locating the energy centre there.

The number of privately operated existing buildings on the network means that many loads may not connect to the network for some time. Furthermore, the phased nature of the construction of the High Path Estate adds to the difficulties around phasing of the construction of the network.

The installation of the heat generation plant is proposed to be in two phases to align with the development of the network heat load. The Energy Centre area and thermal capacity is summarised in the table below.

Table 9-1: Energy Centre key plant breakdown – CWSW

Items	Parameter	CWSW
Network	Thermal demand, MW	10.9
Energy Centre	Total area, m^2	716
Gas Boiler	Phase 1 capacity, kWth	10,000
	Phase 2 capacity, kWth	4,000
	Total boiler capacity, kWth	14,000
CHP	Phase 1 capacity, kWth	1,120
	Phase 2 capacity, kWth	1,120
	Total CHP capacity, kWth	2,240
	Total CHP capacity, kWe	2,000
Thermal Storage	Total volume, m^3	60

The use of the electricity generated by the CHP engines requires confirmation. Customers in the Merton Industrial Estate have been engaged and are open to purchasing cheaper power via a private wire. This needs confirmation and further investigation – ideally a single customer can be identified that would buy all generated electricity.

Modelling this situation would show the best possible financial performance of the network, as generated revenue would be highest. Since it is not a certainty that all power can be sold privately, the network has been modelled with the assumption that the buildings on the network also buy electricity, with the remainder sold to the grid at the lower wholesale price. As such, modelled results are conservative estimates.

9.1.1. Carbon

The CWSW network was shown to make a net carbon emission saving until 2035. Thereafter the network will start to emit more carbon than the business as usual case due to the expected decarbonisaton of the electricity grid. Carbon saving projections are based on BEIS future carbon emissions factor projections for CHP.

To secure long-term savings, an alternative heat source (i.e. heat recovery or heat pumps) could replace CHP at the end of its 12-15 year useful life. However, due to constraints associated with the installation of the proposed alternative solutions and the degree of sensitivity associated with the assumed rate of grid decarbonisation on the anticipated carbon emissions savings, it is suggested that re-evaluation of suitable future technologies will be undertaken in the future in order to implement the most viable option.

9.1.2. Financial Modelling Results

Based on current assumptions, the CWSW scheme appears less viable when compared to the MTCML scheme. Whilst it may potentially be viable financially with grant funding support, it does not present a value for money solution for customers and does not seem to have sufficient current anchor loads although the health and leisure centres may present opportunities.

Scenario C (the scenario with a 30% grant, e.g. from HNIP funding, see Section 7.3) represents the most commercially viable solution.

The Base Case for this project shows a Public Sector Investor IRR of 6.19% - towards the lower end of the range of IRRs for this type of project. It also has a high level of overdraft throughout the project life that is unlikely to be commercially obtainable. The financial metrics, based on a 50 year project, with a 15-year annuity term for injections of debt funding are:

Table 9-2: - CWSW network -Base Case Outputs for Scenario A

Scenario	A – Base Case
Technology	Gas CHP & Boilers
Project IRR (Real, 40 year)	6.01%
Investor IRR (40 year)	7.69%
Investor NPV (40 year)	£3.97m
Project viable based on projections?	No

In order to seek to bring this project to a commercially viable proposition, under the funding structure assumed, there are a number of approaches that can be used to improve the commercial viability:

- Scenario C – this considers the impact of a CAPEX grant of 30% and generates an investor IRR of 9.92%
- Scenario D – this increases the heat price by 5% and generates an investor IRR of 8.08%
- Scenario F – this increases the electricity price by 5% and generates an investor IRR of 7.94%
- Scenario N – reducing the OPEX costs by 10% increases the investor IRR to 7.90%

Of the above, a capital grant of 30%, for example through obtaining HNDU funding, could significantly improve the projected financial performance of the project. Under Scenario C, the modelled outputs of the Project are:

Table 9-3: CWSW – network –30% CAPEX Grant Outputs for Scenario C

Scenario	C - 30% CAPEX Grant scenario
Technology	Gas CHP & Boilers
Project IRR (Real, 40 year)	6.01%
Investor IRR	9.92%
Investor NPV	£8.48m
Project viable based on projections?	Potentially

The cost and sources of funding will be key to the deliverability of the project, as demonstrated by the indicative potential viability through obtaining capital grant funding and the Council should consider any internal resources available as well as the ability to draw down from the PWLB. Any capital injections or grant funding obtainable would have a significantly positive impact on project viability.

However, it should be noted that, under the currently modelled assumptions, the Project does not indicate a Value for Money position for the customers (for heat purchases). This would indicate that there would be no financial incentive for customers to switch to the proposed Heat Network from their current heat solution. However, there is the potential to achieve a reduction in power costs.

9.2 MTCML network

The MTCML network is a gas boiler and gas CHP fed district heating network in Morden Town Centre with a total pipework length of around 1.5km. Buildings on the network include the Merton Civic Centre and the Morden Town Centre development, with pipework running south to serve the proposed Merton Leisure Centre and the existing Thames Valley College buildings. The total heat consumption on the network is 11,359MWh, with a peak heating demand of 8.3MW. Detailed hourly load profiling and CHP modelling shows that 75% of the heat demand is met by the CHP.

The network is proposed to be a full low temperature network (75/45) with a dedicated 95/65 feed to the Civic Centre only, subject to confirmation that the Thames Valley College buildings can accept the proposed heating supply temperature. A comparison of pipework routes showed that the most suitable route is around the perimeter of Morden Park, providing 570m of cheaper soft dig pipework trenching.

The 706m^2 energy centre is proposed to be located in the car park to the rear of the Merton Civic Centre, exploiting space currently used for plant where possible. Plant is proposed to be installed in two phases to meet the network demand as it changes over time, as shown in Table 9-4.

Table 9-4: Energy Centre key plant breakdown – MTCML

Items	Parameter	MTCML
Network	Thermal demand, MW	8.3
Energy Centre	Total area, m^2	706
Gas Boiler	Phase 1 capacity, kWth	8,000
	Phase 2 capacity, kWth	2,000
	Total boiler capacity, kWth	10,000
CHP	Phase 1 capacity, kWth	1,792
	Phase 2 capacity, kWth	-
	Total CHP capacity, kWth	1,792
	Total CHP capacity, kWe	1,600
Thermal Storage	Total volume, m^3	60

At a meeting with TfL on 21st July, it was confirmed that TfL would consider purchasing power at a cheaper rate through Morden underground centre, if the relevant substations were in place to make this possible. At the time of writing they have not confirmed this.

Similarly to the CWSW network, the MTCML network has been modelled with the assumption that the power generated will be sold privately to the buildings on the network, with surplus electricity sold back to the grid. As such the results highlighted in this report represent conservative estimates for financial performance, if the TfL option is successful.

9.2.1. Carbon

The MTCML network was shown to save carbon over the alternative gas boiler solution until c.2036. Thereafter, based on BEIS future carbon emissions factor projections for CHP, the proposed network will not provide a saving due to the expected decarbonisaton of the electricity grid.

The proposed low operating temperature ensures that the network will be configured appropriately to enable future replacement of combustion based technologies with lower carbon, electrical based technologies like heat pumps, if this is found to be appropriate and economical after around 12-15 years of operation (i.e. at the end of the life of the first phase of CHP install).

9.2.2. Financial Modelling Results

The MTCML scheme presents an option that should be taken to the commercialisation phase. This is because the Base Case:

- has investor returns that are attractive to the public and potentially to the private sector;
- presents a value for money solution for customers; and
- benefits from potential public sector anchor loads from South Thames College and Merton Civic Centre.

However the Base Case requires a significant overdraft (c£6m) which is unlikely to be available commercially. Further work to improve the cashflow position of the project is therefore required – this could be undertaken through changing the loan repayment profile.

A further way of improving the position is set out in Scenario C where it assumed that the project receives grant funding of 30% of initial CAPEX.

The Base Case scenario has a Public Sector Investor IRR of 7.00% that is broadly in the middle of the range of IRRs for this type of project. It also has a high level of overdraft throughout the project life that is unlikely to be commercially obtainable. The financial metrics, based on a 50-year project, with a 15-year annuity term for injections of debt funding are:

Table 9-5: MTCML network -Base Case Outputs for Scenario A

Scenario	A – Base Case
Technology	Gas CHP & Boilers
Project IRR (Real, 40 year)	9.55%
Investor IRR (40 year)	9.59%
Investor NPV (40 year)	£5.12m
Project viable based on projections?	Likely, providing the working capital position can be resolved

The Base Case (Scenario A) requires a level of overdraft (with an assumed interest rate of 8.0%) to fund operational cashflow shortfalls. Should the Project progress to the commercialisation phase, an alternative approach to working capital requirements could be considered, for example through the use of a shareholder loan or a premium on share capital in establishing the SPV.

However, under the funding structure assumed, there are a number of approaches that can be used to improve the commercial viability of the scheme:

- Scenario C – this considers the impact of a CAPEX grant of 30% and generates an investor IRR of 11.86%
- Scenario D – this increases the heat price by 5% and generates an investor IRR of 9.99%

The cost and sources of funding will be key to the deliverability of the project, as demonstrated by the indicative potential viability through obtaining capital grant funding and the Council should consider any internal resources available as well as the ability to draw down from the PWLB. Any capital injections or grant funding obtainable would have a significantly positive impact on project viability.

Of the modelled scenarios, Scenario C shows the most commercially viable solution, giving the following outputs:

Table 9-6: MTCML network –30% CAPEX Grant Outputs for Scenario C

Scenario	C - 30% CAPEX Grant scenario
Technology	Gas CHP & Boilers
Project IRR	9.55%
Investor IRR	11.86%
Investor NPV	£6.90m
Project viable based on projections?	Yes

If suitable grant funding can be obtained, and if capital expenditure costs could be reduced, this would present an opportunity for the Project to be considered viable and pursued further.

Notably, the results of the Counterfactual analysis show that the project presents Value for Money for the identified customers of the heat network – even when assessed against the outputs of the Base Case. This suggests that customers could be convinced to sign up to the new heat network as there would be a tangible financial benefit for doing so, even without consideration of the social and environmental benefits.

9.3 Recommendations

Certain scenarios of both networks have been shown to be viable; LBM should seek to decide whether to advance with both networks into the next phase of the study, or to concentrate on one. Of the two, the viable scenario of the MTCML network gives highest returns. The MTCML network also:

- brings benefit to the council through connection of the Merton Civic Centre
- is a less challenging installation in terms of pipework, and includes significant ‘soft dig’ trenching that reduces installation costs
- has heat loads that are projected to connect quicker than the CWSW network, improving revenues and cash flow
- provides investor returns are more attractive to the public and potentially to the private sector

The cost and sources of funding will be the key to the deliverability of the project.

9.4 Next steps

LBM can apply for funding from the HNDU for ‘Early Commercialisation’ of projects, the final phase of the HNDU process. The costs of this will depend on the scope of the commercialisation undertaken and whether LBM wants to pursue both opportunities detailed here, or to focus only on one. The next stage of works will aim to develop:

- customer commercial agreements
- heat supply contracts
- necessary land purchase and land access arrangements
- tariff structure for customer contracts
- further development of financial model and business case and associated commercial advice costs where necessary.

AECOM recommends that LBM focusses on the following actions in the next phase of development:

- Making stakeholders aware of the result of this study

  The financial analysis has also shown that the new development sites will be vital to the viability of the network. We would therefore strongly recommend that the results of this study are shared with the prospective developers so that they are aware that this project is being considered and understand the importance of their sites.

- Undertake further discussions within LBM on the proposed Energy Centre location

  The identified Energy Centre location was selected with a high level comparative analysis on some key issues, such as proximity to heat demands, space availability and utility connections. As part of this study an indicative Energy Centre building has been proposed and we would recommend that the Council reviews the suitability of this site, with inputs from the planning department, asset management and finance departments as well as relevant local Councilors.

- Hold discussions with LBM and other associated bodies on the proposed network route

  A network route has been proposed by this study and it is recommended that this is reviewed by the Council and any other relevant bodies to review the approach that has been proposed and identify any opportunities or constraints that further development of this project would need to be aware of.

- Consider sources of funding to support the project

It is recommended that some internal discussions are held to understand the opportunity and appetite for capital funding as well as work to investigate potential grant funding.

Appendix A. CWSW Site survey building assessment

Table A-1: CWSW network buildings survey notes (green – included, red – omitted)

<table>
<tr><th>No.</th><th>Building</th><th>Building Photo</th><th>Building Class</th><th>Stage</th><th>Survey notes</th></tr>
<tr><td>1</td><td>Hudson Court</td><td rowspan="3"></td><td rowspan="3">Residential</td><td rowspan="3">Existing</td><td rowspan="3">3no. similar high-rise residential buildings, due to be demolished and replaced by the new High Path Estate Development (Building no. 5). These buildings have now been removed from the building list for this network.</td></tr>
<tr><td>2</td><td>Marsh Court</td></tr>
<tr><td>3</td><td>May Court</td></tr>
<tr><td>4</td><td>Merton Abbey Primary School</td><td>
</td><td>School</td><td>Existing</td><td>Assumed to have centralised plant – needs surveying to be confirmed. Retained in this phase of the study.</td></tr>
<tr><td>5</td><td>High Path Estate</td><td>[NO PHOTO]</td><td>Residential</td><td>Under Planning</td><td>Not surveyed</td></tr>
</table>

No.	Building	Building Photo	Building Class	Stage	Survey notes
6	The Old Lamp Works	[NO PHOTO]	TBC	Future	Not surveyed
7	All Saints Boiler Houses: Tintern Close/Woburn Close	[NO PHOTO]	Residential	Existing	This development consists of individual terraced houses, which would each require a connection to the network. This increases the length of pipework and costs associated with the installation due to the number of required connection points, thereby greatly increasing the costs associated with connection. As such this entry will be omitted from further phases of this study.
8	Connolly Leather Works	[NO PHOTO]	Residential	Existing	Ex-industrial building converted to residential apartments. It was not clear from an external visual assessment whether or not the building has centralised plant, or if each apartment has its own boiler. Currently assumed for connection.
9	Virgin Active, Health Club, Battle Close		Health club	Existing	Large health club building representing a good candidate for connection to the heat network. The building appears to have been built in the last 0-10 years so would likely not want to connect until current plant is up for renewal.
10	Antoinette Hotel		Hotel	Existing	Medium sized hotel likely to have centralised plant with wet heating distribution system. Plant assumed to be old and ready for replacement as soon as the network is installed.

No.	Building	Building Photo	Building Class	Stage	Survey notes
11	Broadway House, The Broadway & 2-14 Stanley Road		Mixed use	Existing	Commercial office building, likely to have centralised plant with wet heating distribution system. Retained in study.
12	Police Station, 15-23 Queen's Road	[NO PHOTO]	Emergency services	Existing	This building is likely to have centralised plant with a wet heating distribution system, and as such is retained in this study.
13	Polka Theatre, 238-244 The Broadway		Entertainment Hall	Existing	Relatively small building, with a small heat demand, however if the boilers installed are nearing the end of their life expectancy this is still a viable connection as the network is due to pass the building anyway.

No.	Building	Building Photo	Building Class	Stage	Survey notes
14	Viscount Point		Residential	Existing	Large residential block, likely to have centralised plant and assumed to be eligible for connection.
15	Wimbledon Leisure Centre, Latimer Road		Leisure centre	Existing	Leisure centre and gym, likely to have centralised plant.
16	YMCA, 200 The Broadway		Hotel	Future	Current building is due to be demolished; new scheme is under development and has not submitted a planning application. The new development is likely to consist of a YMCA hostel, private residential apartment block and leisure and community centre.

No.	Building	Building Photo	Building Class	Stage	Survey notes
17	153-161 The Broadway		Hotel	Under Planning	Currently an old office building, with planning granted to become a 176 bedroom Premier Inn hotel with a restaurant on the ground floor. Due to contain a micro-CHP unit of 19.2kWe and 36.1kWth. Not started on site, assumed year of completion 2020. Since planning permission has been granted already, it will be difficult to persuade developers to connect to a possible future DH scheme and it is likely that dedicated heat generation plant will be installed for the building. Therefore connection only likely
18	Highlands House, 165-171 The Broadway		TBC	Future	Future identified development site - not surveyed as no further information on future building class/type available. Retained in study for future connection.
19	Merton Abbey Mills		Residential	Existing	Approximately 50 newly built dwellings. These may be individually heated electrically, but if not, it is likely that there is centralised plant within each building. Retained in the study.

No.	Building	Building Photo	Building Class	Stage	Survey notes
20	Merton Abbey Mills, Watermill Way, Colliers Wood		Mixed use	Existing	Multiple restaurants, commercial and industrial buildings. Number of old buildings, low likelihood of centralised plant, high connection costs, many vacant buildings. These building have therefore been wirthdrawn from the study.
21	Premier Inn		Hotel	Existing	Large hotel, including a large Nuffield Health Leisure Centre, which had not previously been captured by the study. Gross internal floor areas of both the hotel and now the leisure centre have been updated accordingly.
22	Flat 1 2 Chapter Way London		Residential	Existing	Large residential development, consisting of three main buildings. These are most likely to have centralised plant in each building and this building is assumed to be eligible for connection. A further block was identified that had not been previously captured. These two buildings are now listed as Prospect, Vista and Independence House in the updated building list.
23	Flat 1 4 Chapter way London				

No.	Building	Building Photo	Building Class	Stage	Survey notes
24	Morden Industrial Area (SWBA)		Industrial	Existing	Refer to Section 4.1.1 for more details
25	Brown & Root House		Mixed use	Under Planning	High-rise mixed use building, predominately residential. Consists of the main block, and a new extension to the rear which is currently under construction. Previous difficulties experienced with the developer indicate that it may be an onerous process to persuade them to connect to the network.
26	Holiday Inn Express		Hotel	Existing	Omitted due to location – very expensive pipework route required to serve this single building.
27	Land at Corner of Baltic Close & High Street	[NO PHOTO]	TBC	Future	Not surveyed – no further information available on planning portal

	Crossing	Crossing photo	Survey notes
1	South Colliers Wood River Wandle bridge	 	There are two bridges at the same location. The first (top picture) is only used for parking but does not look like the structure has the relevant depth to house insulated pipe. It may be possible to lay uninsulated pipework for just the width of the bridge. There may be issues there with uninsulated pipes in close proximity to HV cables or water mains. The other bridge (seen in the lower photo as the section of elevated road) is a busier road which may have further cost implications to lay pipework within. Above ground pipework may also be possible where the two bridges meet (i.e. behind the parked cars in the lower photo). A specialist survey will be necessary to identify whether pipework could make this crossing,.

2	Central Colliers Wood junction	 	The junction between South Colliers Wood and Central Colliers Wood (A24 and A236) comprises a section of elevated road that is around 400m in length. It is expected that finding a route for the pipework across the junction would be prohibitively expensive as a result of the elevation.

Appendix B. MTCML Site survey building assessment

Table B-1: CWSW network buildings survey notes (green – retained, red – omitted)

No.	Building	Building Photo	Building Class	Stage	Survey notes
1	Crown Lane Studio	[NO PHOTO]	Entertainment Hall	Existing	Previously incorrect floor area, actual size of building is much smaller than previously assessed. Removed from study.
2	Merton Civic Centre		General Office	Existing	Existing CHP and absorption plant is around 6 years old. Boiler plant is at end of its useful life – boilers date from the 60s. CHP could be retained for feed in to network. Boilers to be decommissioned.
3	The Crown	[NO PHOTO]	Mixed use	Existing	Heat load reassessed to be smaller than previously understood. Revised load below threshold for connection. Building removed from list.
4	Abbotsbury Triangle site	[NO PHOTO]	Mixed use	Under Planning	Not surveyed – future development under planning retained in study. Figures updated and consolidated into single, overall Morden Town Centre Development
5	Morden Road Clinic	[NO PHOTO]	TBC	Future	Not surveyed – future development site under planning now consolidated into single 'Morden Station Development'
6	Morden Station Offices and retail units (Morden Station)	[NO PHOTO]	Mixed use	Under Planning	Not surveyed – future development site under planning now consolidated into single 'Morden Station Development'
7	York Close Car Park	[NO PHOTO]	TBC	Future	Not surveyed – future development site retained in study, no further information available
8	Morden Station staff car park (Morden Station)	[NO PHOTO]	TBC	Future	Not surveyed – future development site under planning now consolidated into single 'Morden Town Centre Development'
9	Morden Park Swimming Pool	[NO PHOTO]	Swimming pool	Under planning	Not surveyed – future development under planning

No.	Building	Building Photo	Building Class	Stage	Survey notes
10	Travelodge		Hotel	Existing	Existing hotel likely to have centralised heat generation plant. Removed from study due to previous AECOM experience with customer and lack of appetite for connection.
11	Merton campus of South Thames College		University	Existing	Existing large education building, likely to include centralised heat generation plant. Eligible for connection to DH, retained in study.

Appendix C. CWSW Load Profiles

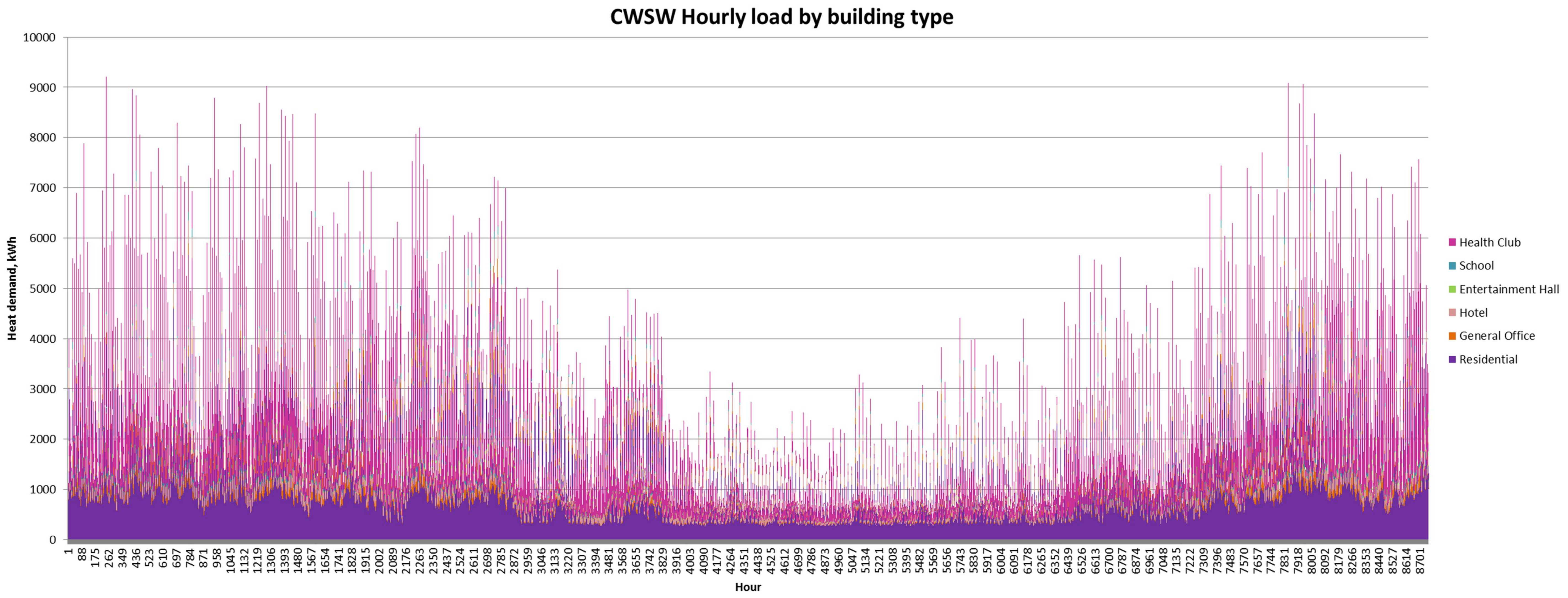


Figure C-1: CWSW hourly annual heat load profile (generated by AECOM in house profiling tool)

Figure C-2: CWSW Typical winter weekly heat demand

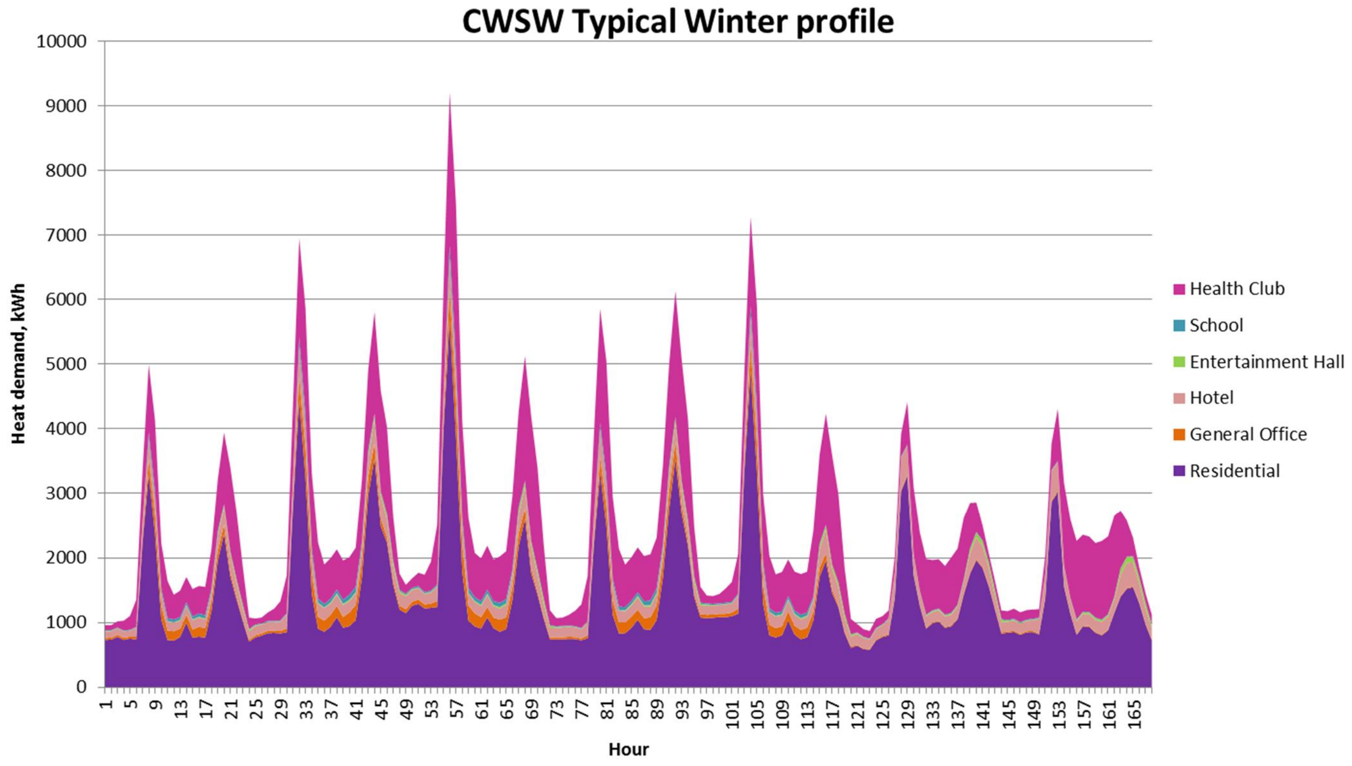
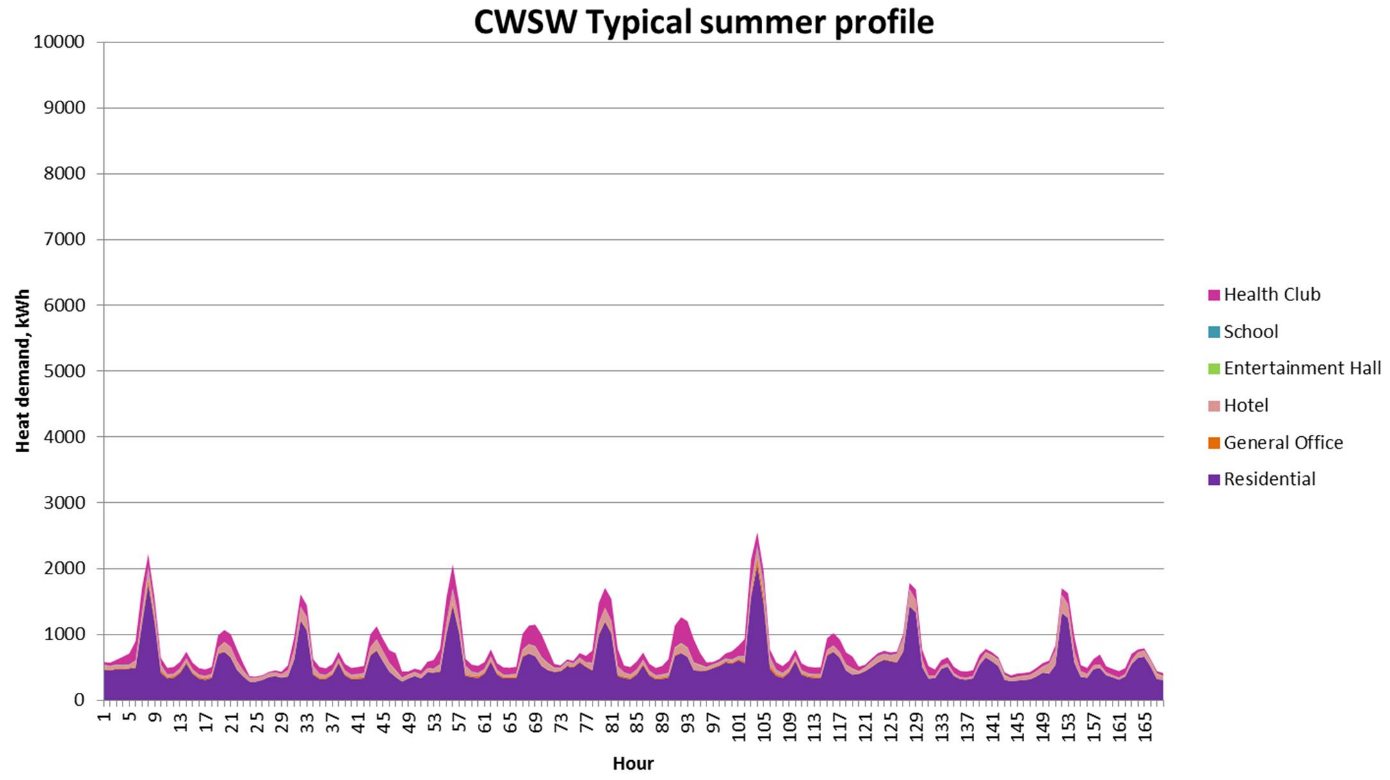


Figure C-3: Typical summer weekly heat demand



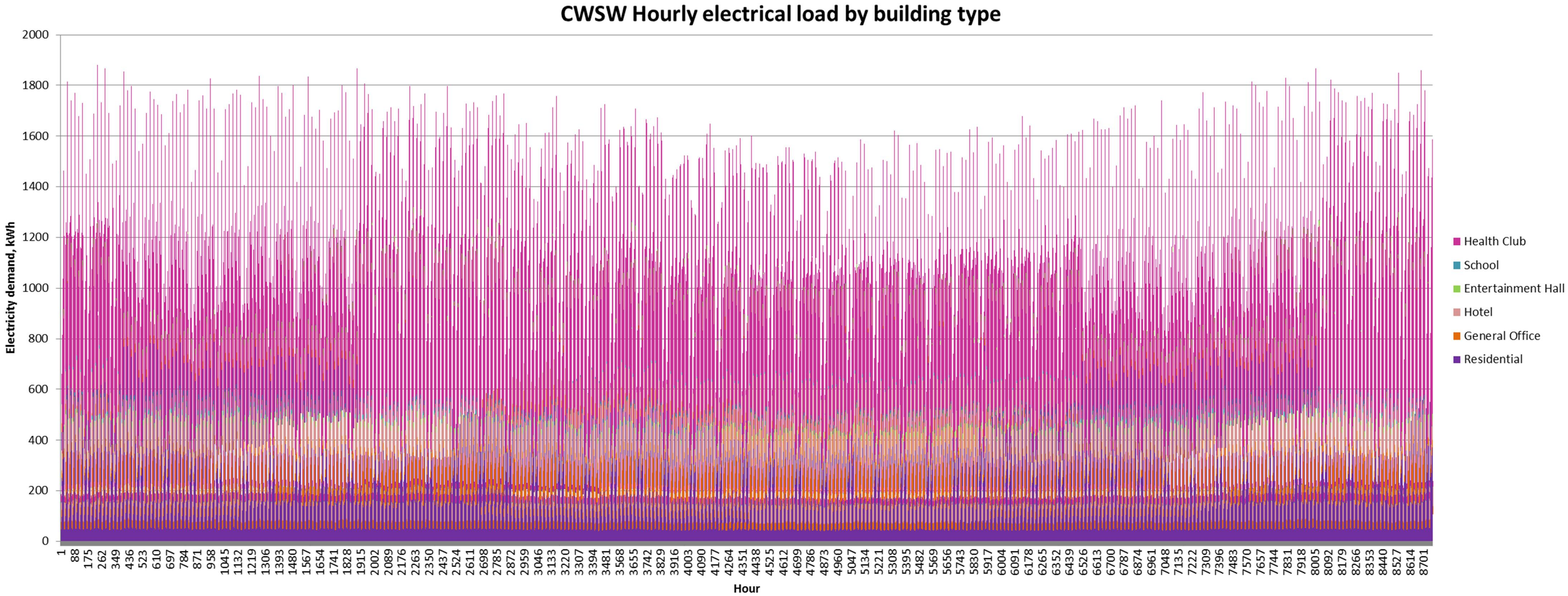


Figure C-4: CWSW hourly annual electricity load profile (generated by AECOM in house profiling tool)

Figure C-5: CWSW Typical winter weekly electricity demand

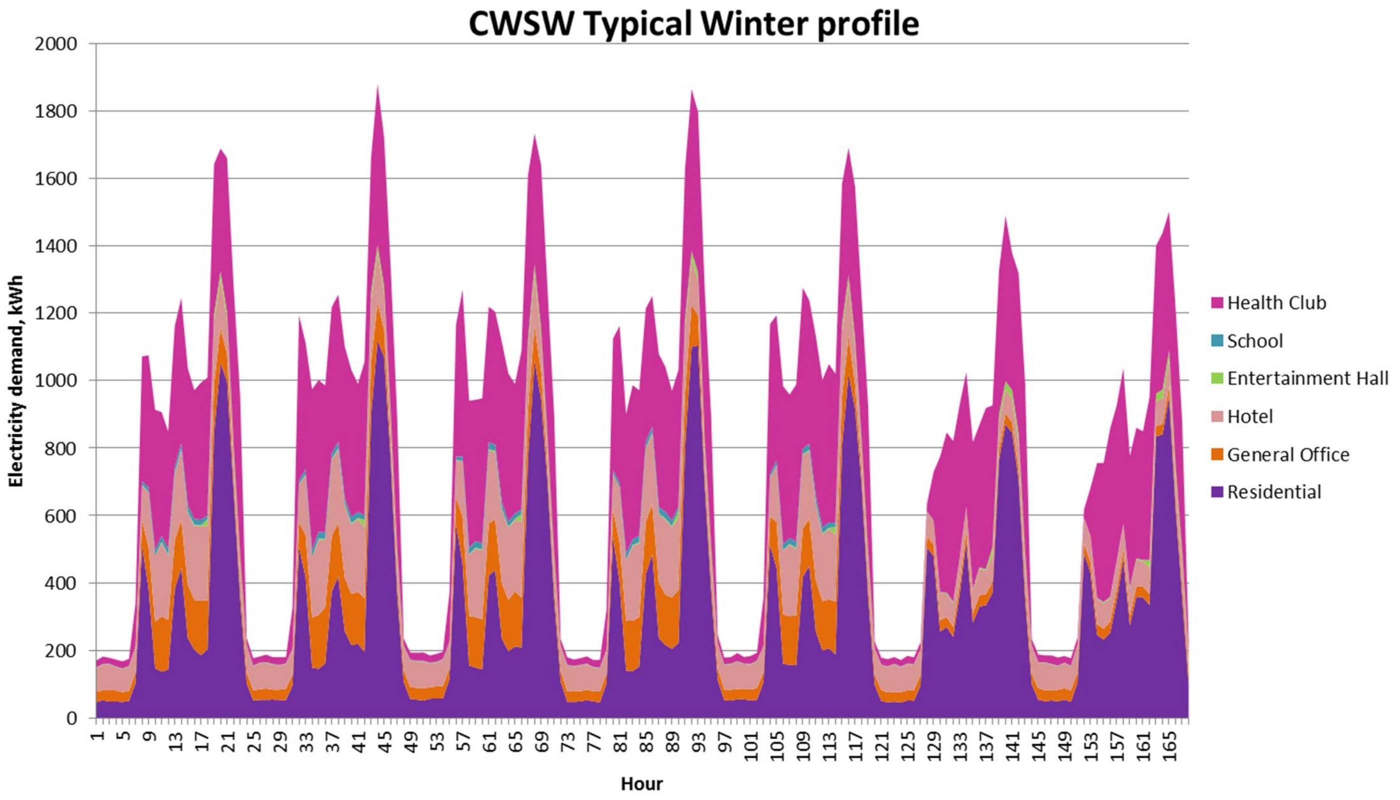
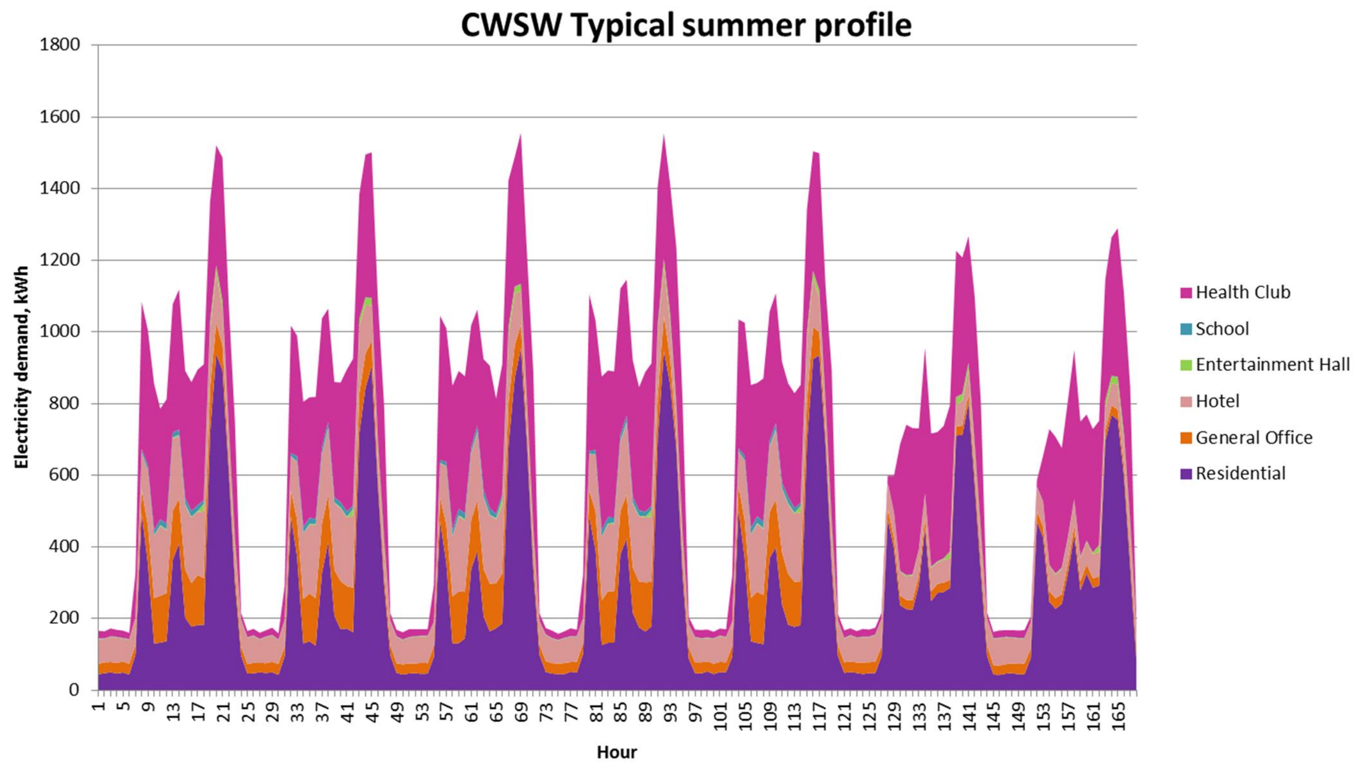


Figure C-6: Typical summer weekly heat demand



Appendix D. MTCML Load Profiles

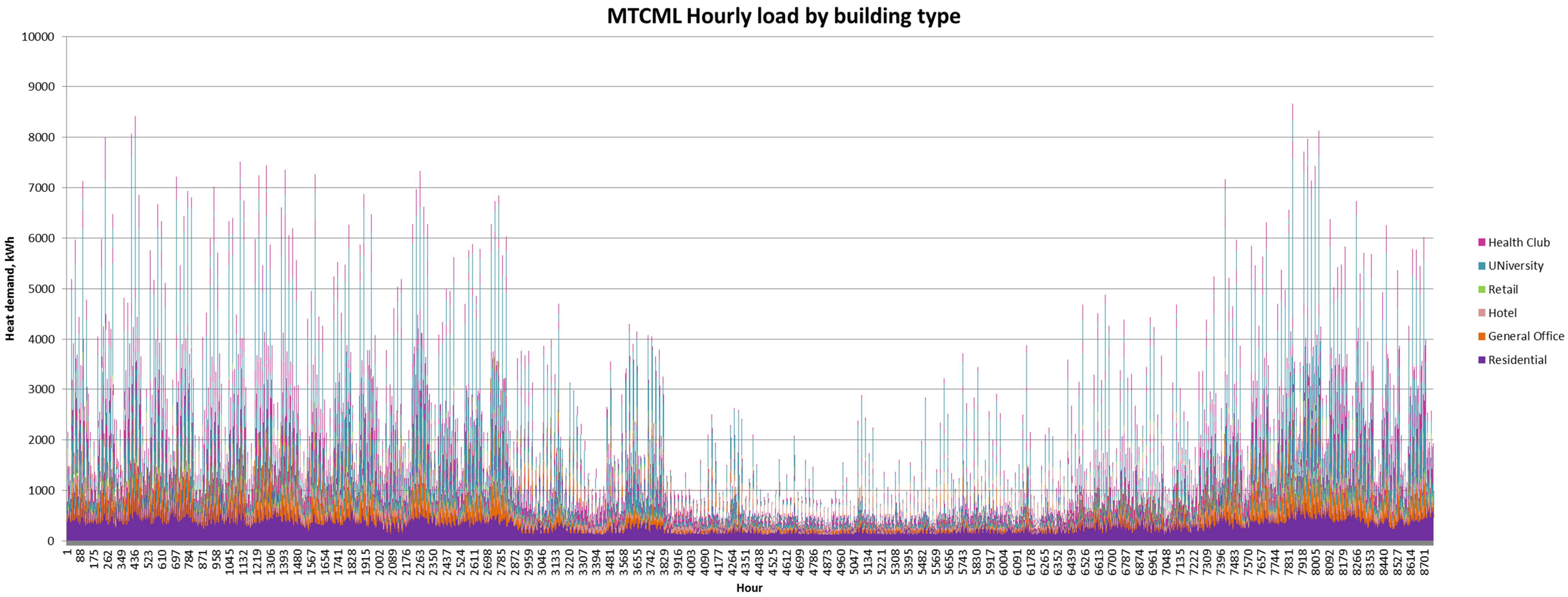


Figure D-1: MTCML hourly annual heat load profile (generated by AECOM in house profiling tool)

Figure D-2: Typical winter weekly heat demand

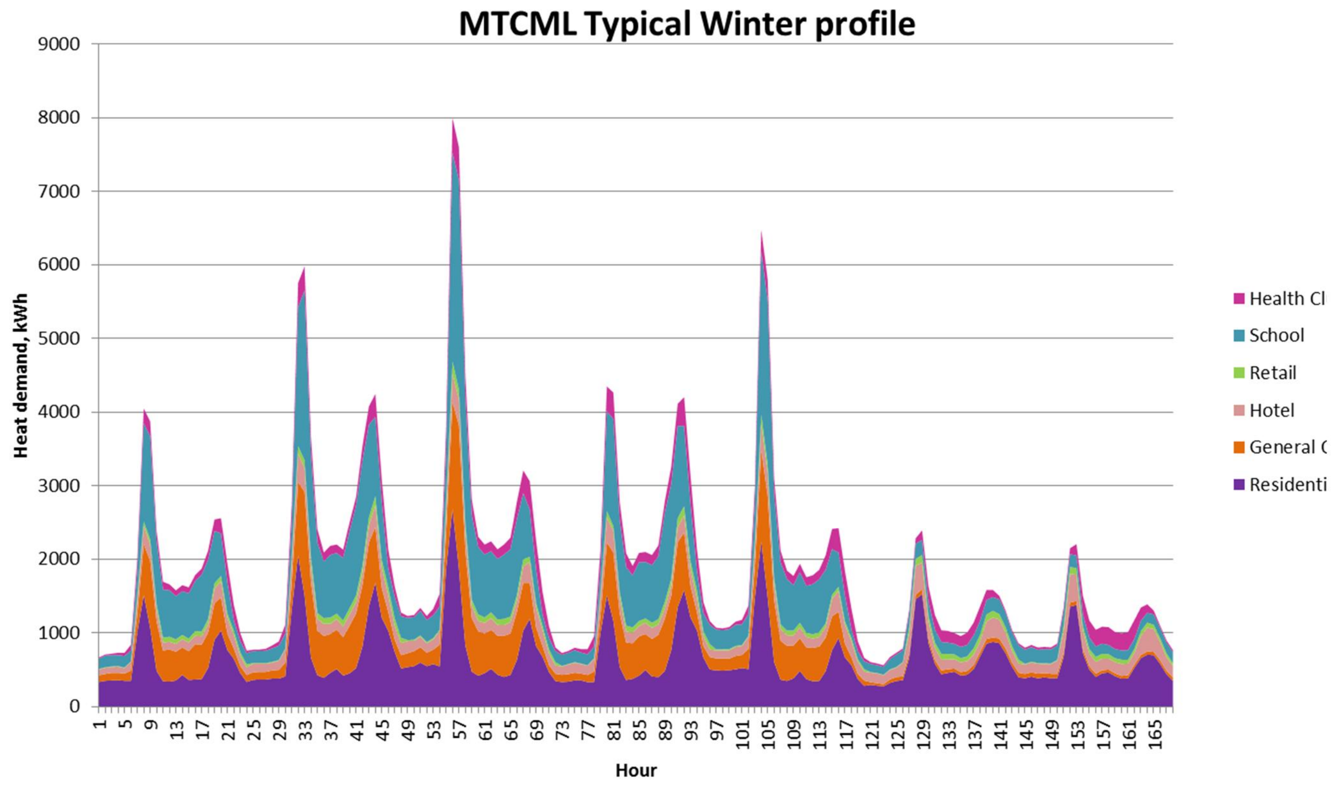
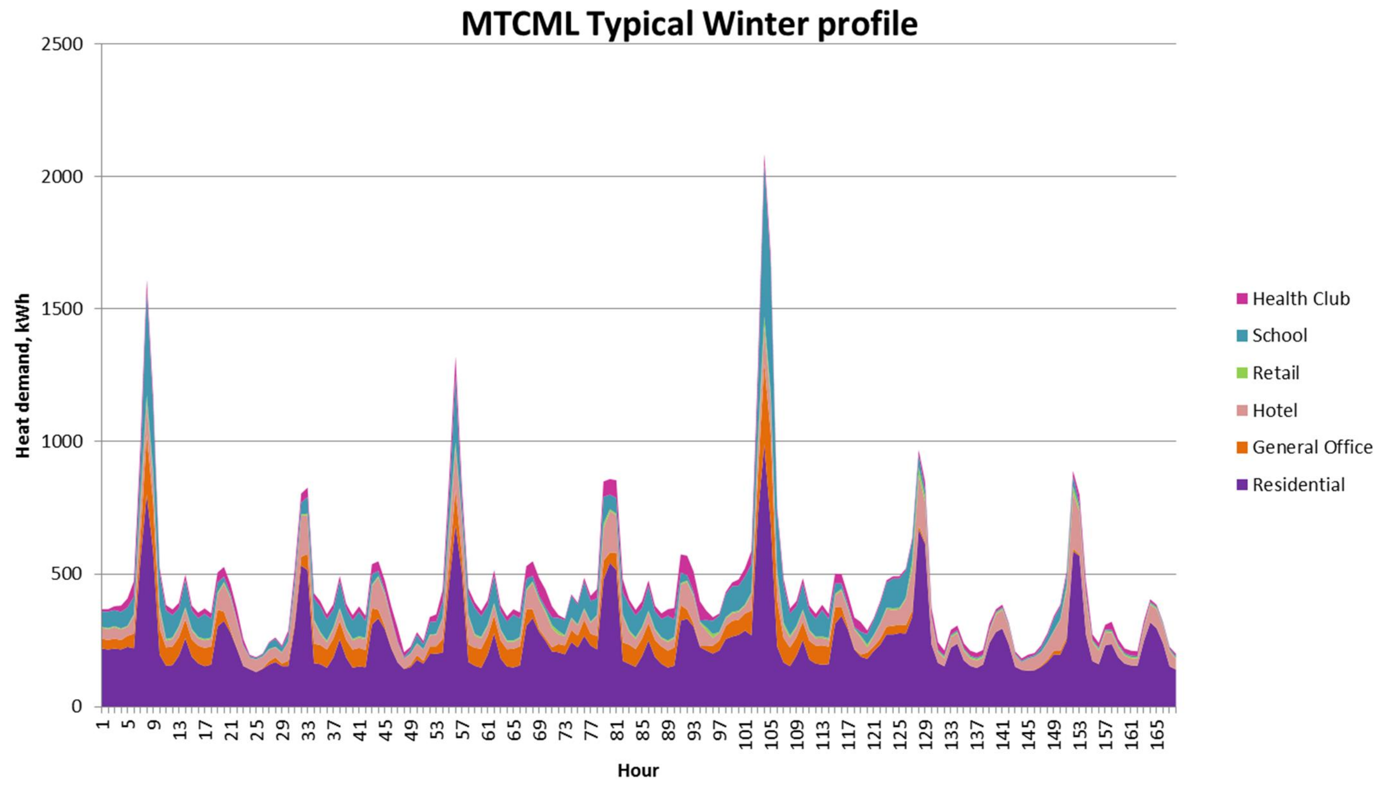


Figure D-3: Typical summer weekly heat demand



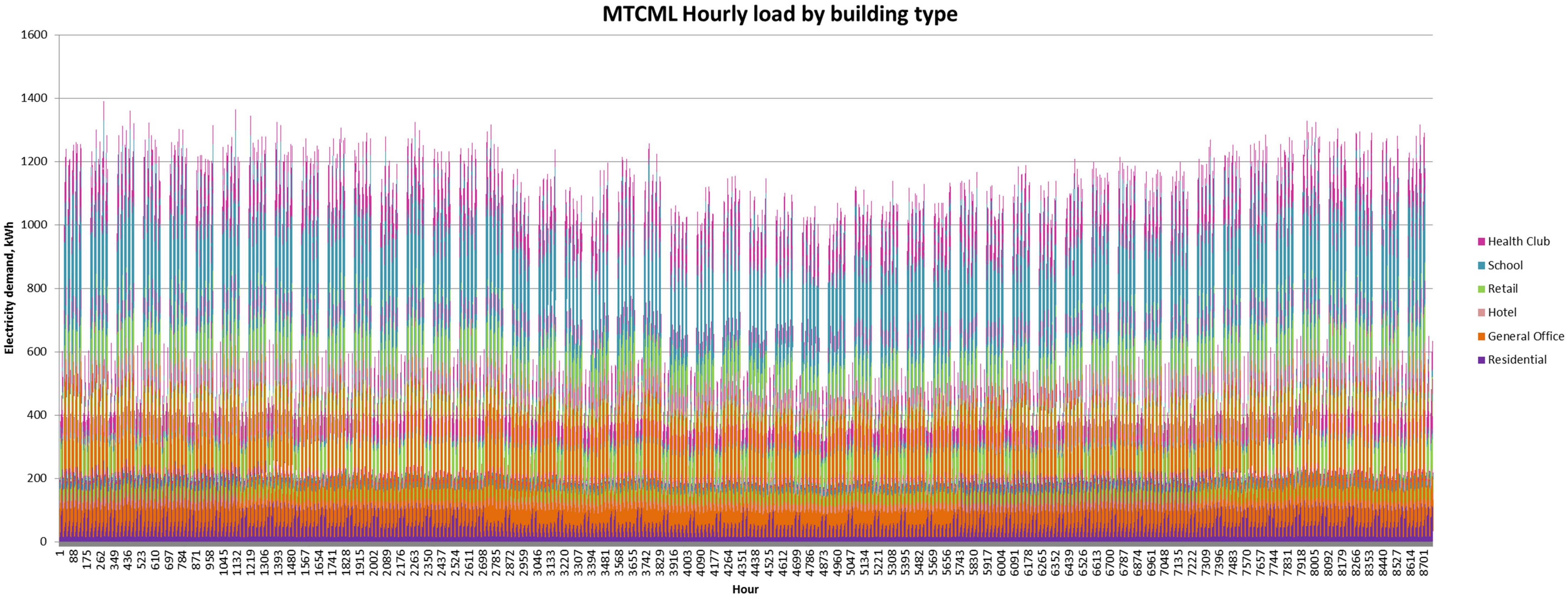


Figure D-4: MTCML hourly annual electrical load profile (generated by AECOM in house profiling tool)

Figure D-5: Typical winter weekly elec demand

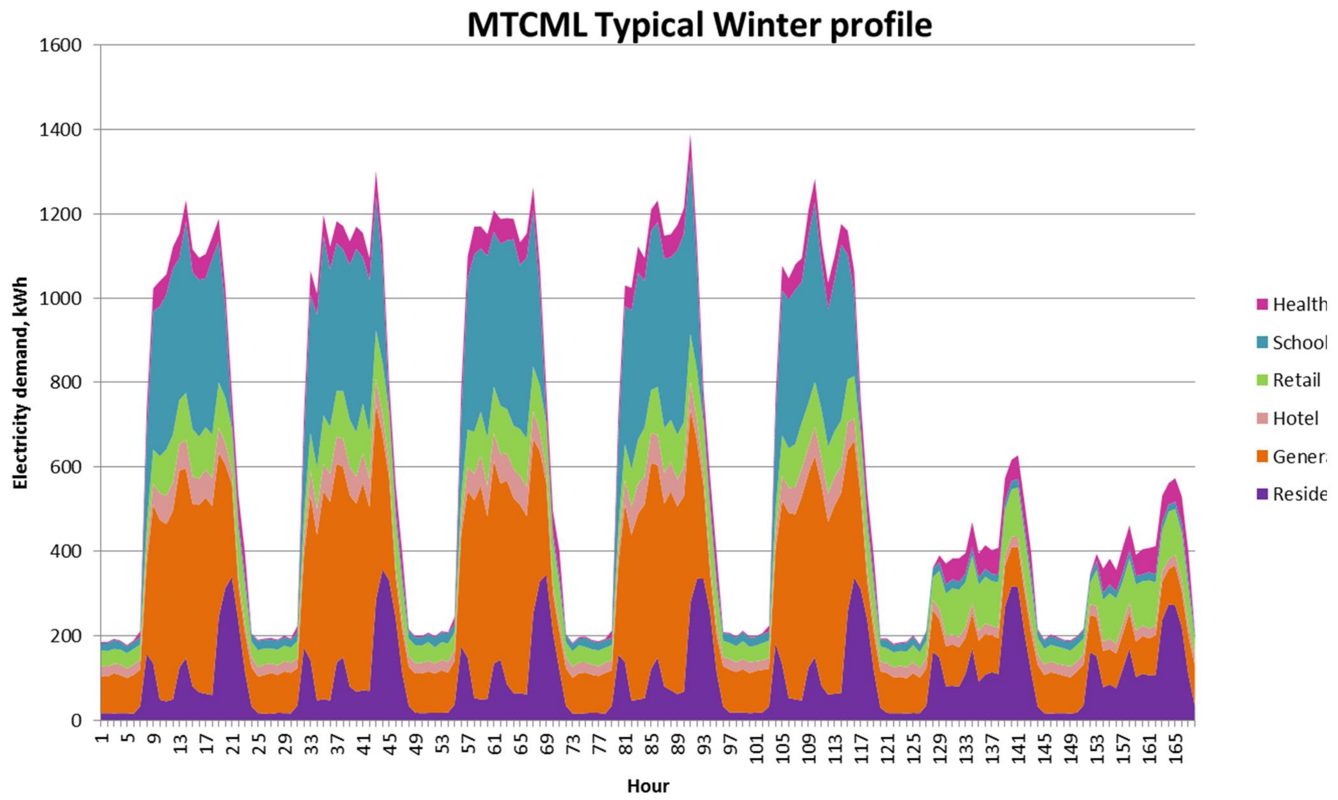
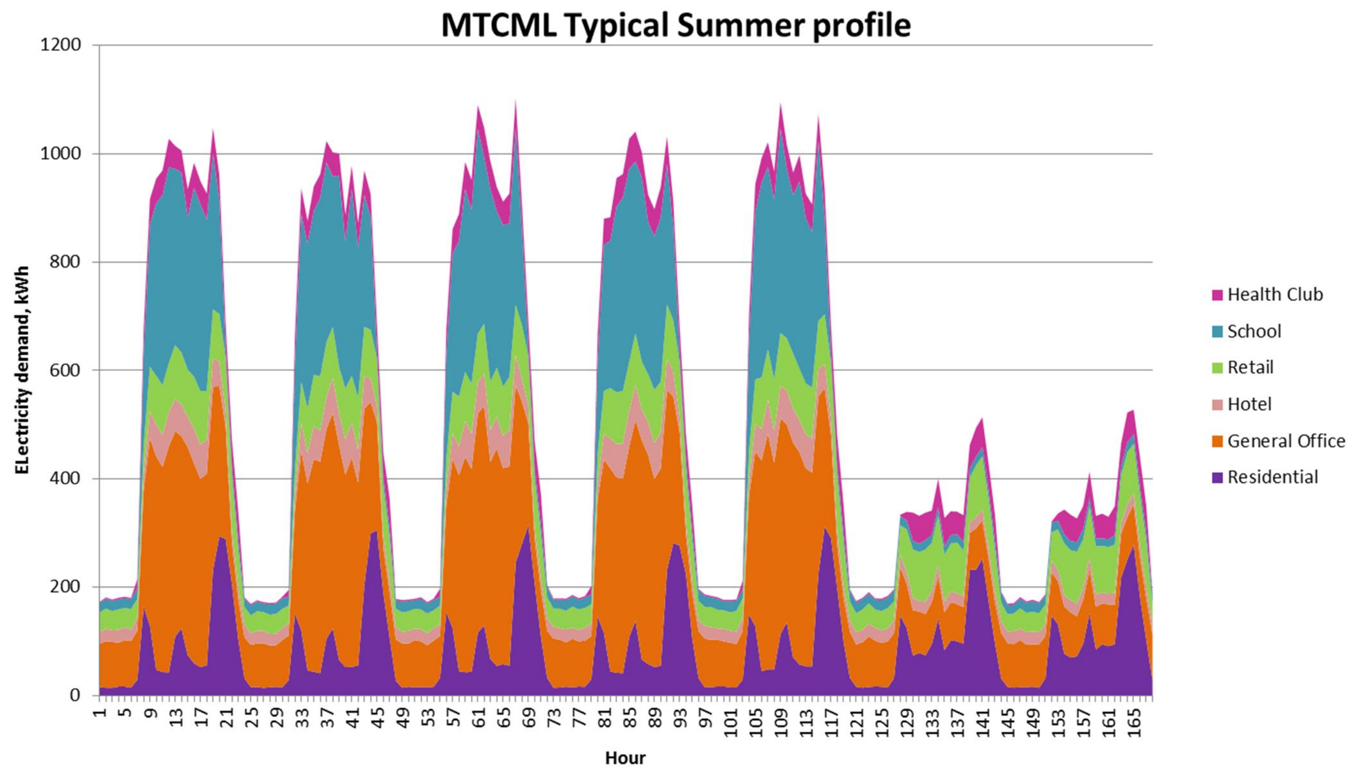


Figure D-6: Typical summer weekly heat demand



Appendix E. Techno-economic modelling assumptions

Introduction

A full techno-economic model has been developed from first principles. This section details the assumptions made during this assessment.

Plant sizing

Gas fired reciprocating engines have been modelled to supply low carbon heat to the networks. The engines assessed have the following characteristics;

- High heat value efficiency – 79%
- Heat to power ratio 1.1:1
- Electrical output – 11kV rating
- Re-starts – limited in design to maximum of 2 in any 24 hour period
- Turn down – 50%

All gas CHPs were modelled as operating on a thermally led basis connected to the electrical grid (i.e. not operating in island mode). Engines are sized using AECOM's in house specialist CHP sizing and optimisation tool. This assessment selects the most appropriate engine size and number based on the hourly load profiles given in Appendix C & D. Based on this assessment and the assumptions detailed above, 2no. 800 kWe engines were selected for MTCML, and 2no. 1,000kWe engines selected for CWSW.

With 2no. engines and 50% turndown per engine, the effective turndown for CHP plant is 25%. This allows CHP plant to operate more efficiently, providing more of the overall heat demand and raising the CHP run hours.

An analysis was undertaken to quantify the effects of increasing the thermal storage tank size from 60m³. Increasing the tank size to 100m³ increased the IRR by 0.1%; Increasing the tanks size to 250m³ resulted in a lower IRR as the additional capital cost of the larger tank(s) was not justified by the small operational benefits. 60m³ was selected as the most appropriate thermal storage size for both networks.

Boilers were sized to meet the full network peak demand, with N+1 resiliency. Load duration curves for both networks are given in Figures E-1 and E-2. The selected CHP engine size supplies 75% of the total network heat demand, in line with HNIP funding requirements.

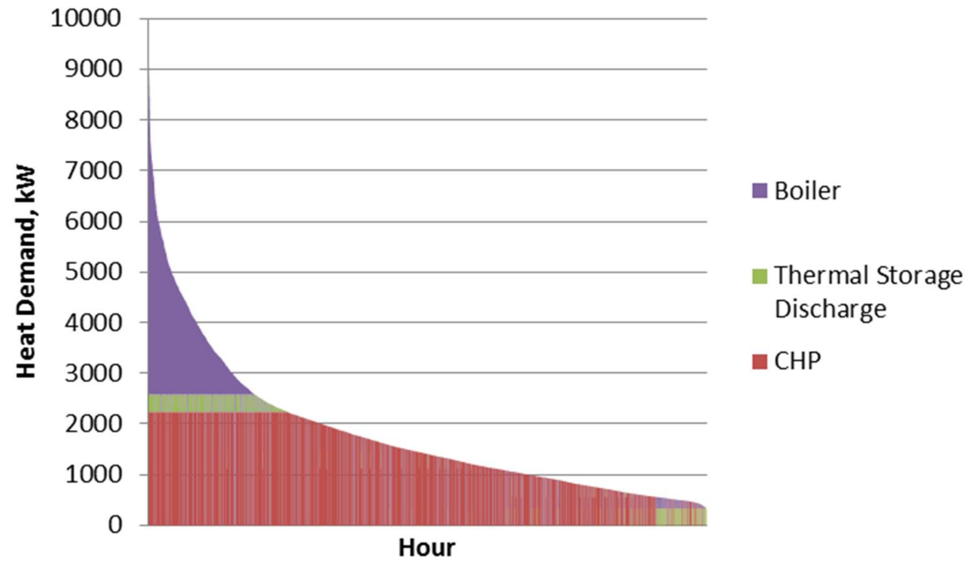


Figure E-1 CWSW load duration curves

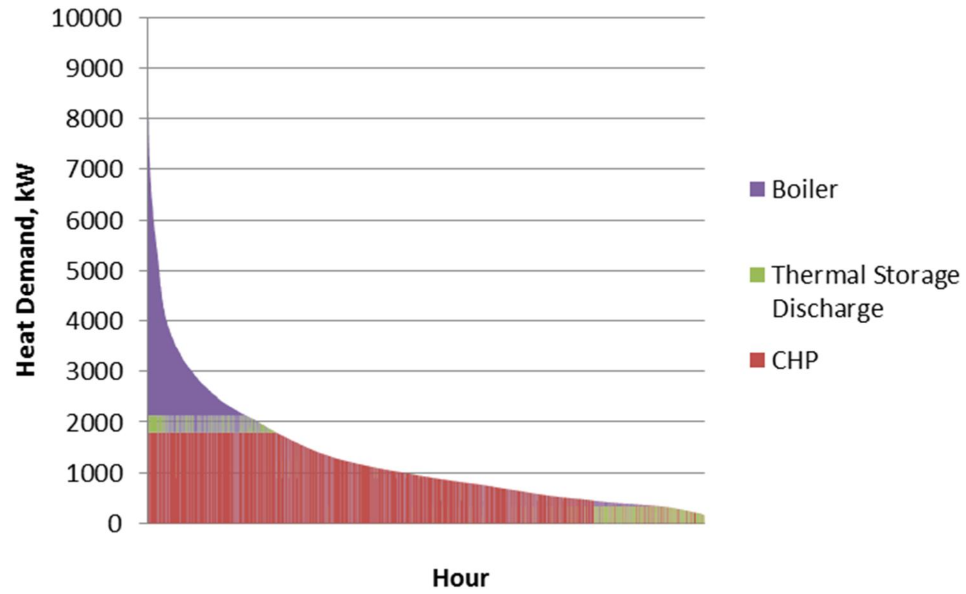


Figure E-2 MTCML load duration curves

CAPEX Assumptions

Values are derived from AECOM experience and suitable industry standards (such as SPONS), which have been back checked with contractors during the tender stages of other DH projects to ensure that values are up to date and accurate.

The key assumptions made in the estimation of the capital costs (CAPEX) of each network option are given below. The model updates the CAPEX values to reflect the user-selected parameters, for example whether a given building is included in the calculations.

The breakdown of CAPEX assumptions for networks is provided in Table E-2. Certain items do not apply to all networks, for example items specific to CHP or heat recovery.

A large element of network costs is associated with the distribution of heat. In particular, in scenarios which include large numbers of new residential developments, distribution costs are even higher. The business as usual case for new developments in London is assumed to be gas fired CHP based district heating. The network operator is assumed to pay for the up-front costs of heat distribution within new developments, as well as the operation of these aspects throughout the lifetime of the project. A certain amount of this cost can be recovered through connection charges.

Table E-1: CAPEX metric assumptions (applied where relevant)

CAPEX item	Metric	Based on
Energy Centre:		
Energy Centre Construction (new)	£1,250/m^2	This value reflects an EC building with aesthetic/architectural finish.
Energy Centre external compound (new)	£500/m^2	This value reflects an external compound for housing the CHP engines
Energy Centre Phase 2 installation	£150/kW	Phase 2 boiler capacity
Heat Generation Systems:		
Gas CHP engines	£950/kWe	CHP thermal output capacity
Thermal storage systems	£1,000/m^3	Total volume of required thermal storage vessels
Boilers	£35/kW	Boiler thermal capacity
Ancillary equipment (incl. flues; ventilation; distribution pumps; energy centre electrical costs and pipework; water treatment; pressurisation and expansion; and BMS/Controls)	£205/kW	Boiler thermal capacity
Electrical Ancillaries:		
Sub-station including private HV transformers, HV switch room, LV switch gear, connection cost	£100,000	One off cost, subject to G59 application of local HV infrastructure upgrade requirements. Significant risk item – see Risk Register in Appendix K
Buried HV cable	£55/m	HV cable length
Private wire	£420/m	DH pipework length (i.e. private wire
Gas Systems:		
Gas Connection	£15,000/MW	Boiler and CHP thermal capacity
Extension of gas main	£370/m	Assumed trench length of 200m
External works:		
New development connection costs	Nominal 20% uplift on total pipework cost	No further information available on layout of proposed new developments and likely pipework routes/lengths
DH pipework	Varies depending on soft/hard dig. CWSW: £1,326/m MTCML: £1,296/m	Pipework length for each network option (average, to account for a mixture of hard dig and soft dig trenching)
Customer heat exchanger	£32/kW	Undiversified heat load
Other Costs/Fees:		
Professional fees	5.0%	Of sub-total

CAPEX item	Metric	Based on
Legal fees	2.5%	Of sub-total

Asset replacement cycles

The following assumptions have been made on the required replacement cycles of plant and equipment on the basis that a like-for-like replacement will be sought throughout the network lifespan. All other plant and equipment is assumed to last beyond the project lifetime. Plant replacement at the end of the lifespan is assumed to be accounted for an additional CAPEX cost items when required.

Table E-2: Asset replacement assumptions

Technology/asset	Replacement cycle	Replacement year
EC boilers, incl. ancillary equipment	Every 25 years	2049 (install 2019)
Gas CHP	Every 80,000 hours operation	Approximately 12 - 13 years after initial installation
Heat exchangers	Every 25 years	2045 (install 2020)
Pipework	Every 50 years	2070 (install 2020)
Gas connection/ Extension	Every 30 years	2049 (install 2019)

OPEX Assumptions

Fuel Costs

Fuel unit prices for gas and electricity are based on energy price analysis published by the Department for Business, Energy & Industrial Strategy (BEIS). Domestic values are specific to regions; those published for the East Midlands have been used for the current study.

Year 1 prices are based on the average values over the last two years. The price of the fuel varies based on the quantity of heat and electricity purchased. The larger the quantity of fuel purchased, the lower the fuel price. This means that the network operator will be able to buy fuel at a lower cost than customers in the area are currently paying.

The price for gas and electricity used by the model is presented in the table below. Networks which consume more gas pay less per unit due to the lower tariffs associated with higher consumption.

Table E-3: Fuel price assumptions

Gas Price (p/kWh)			Electricity Price (p/kWh)
Network Operator	Current tariff paid by customers		Network Operator[12]
	Commercial[13]	Residential[14]	
1.6	2.1	3.6	9.8

Please note that the prices above are fully delivered prices, including Climate Change Levy. However, they do not account for any uplift due to VAT.

Future fuel price projections

Trend projections of future energy prices are taken from the BEIS Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal[15]. Year 1 costs are taken as described above, with future prices indexed to the trends provided.

Within the Green Book tables, three bands of prices are given: High, Central and Low. For the purposes of the model, it is assumed that fuels increase in line with the Central prediction.

Figure F-1 shows the HM Treasury Green Book future fuel price projections, showing the Central scenario for electricity and gas. Whilst the trend of these projections have been used in the model, the projections made in the Green Book do not show any change to price beyond c. 2027, an unlikely scenario. This could pose a risk for the viability of the network and thus it has been registered as a risk item in Appendix K.

[12] QEP 3.4.1 and 3.4.2, https://www.gov.uk/government/statistical-data-sets/gas-and-electricity-prices-in-the-non-domestic-sector

[13] QEP 3.4.1 and 3.4.2 https://www.gov.uk/government/statistical-data-sets/gas-and-electricity-prices-in-the-non-domestic-sector

[14] QEP 2.3.3 https://www.gov.uk/government/statistical-data-sets/annual-domestic-energy-price-statistics

[15] https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

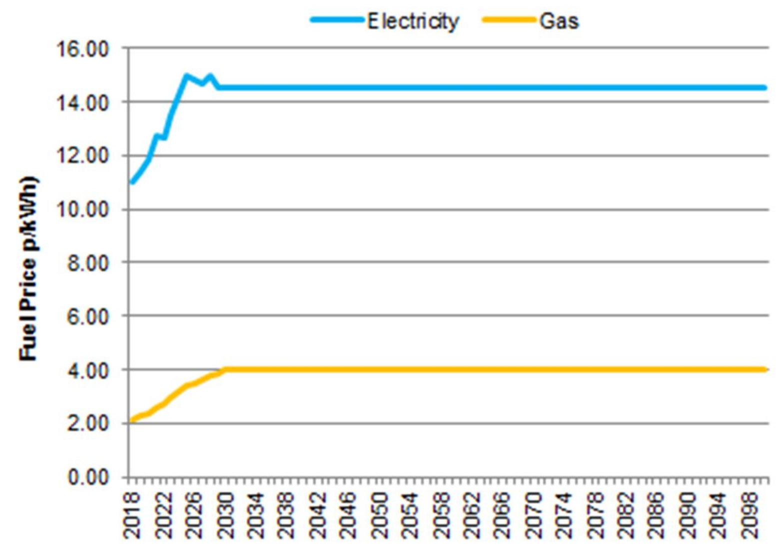


Figure E-1 HM Treasury Green Book future fuel price projections: central scenario

Maintenance Costs

Maintenance and staffing costs are assumed to be constant over the lifespan of the project. The figures given in Table E-4 are based on AECOM experience and recent quotes from contractors and developers.

Table E-4: OPEX assumptions

OPEX item	Metric	Based on
Energy Centre	2.5/m^2	EC footprint
Gas CHP	£0.010/kWh$_e$p.a.	CHP electricity generation
Energy centre boilers	£2.25/kW p.a.	Boiler thermal output capacity
Heat exchanger	£1.00/kW p.a.	Undiversified heat load
Pipework	1%	Pipework CAPEX
Private Cables	1%	CAPEX for Private Wire and DNO connection to the Energy Centre
Labour	£100,000p.a.	One full time employee incl. overheads

Revenue

Revenue will come from a number of sources, including direct charges for heat and fixed charges for operation (comparable to standing charges on conventional utility services). There will also be revenue from the sale of CHP-generated electricity, which may be available through sales to the grid or directly to electricity consumers. Revenues are also generated through connection charges, a one off cost to customers to connect to the network.

Counterfactual heat price

The counterfactual heat price is what customers on the heat network currently pay for heat, assuming heating is provided with a conventional gas boiler. This depends on whether they are residential or commercial customers, and is made up of the cost of their fuel consumption (i.e. the variable charges) and the cost of operating and maintaining their heating system (maintenance costs and standing charges). Heat tariffs for network customers are then based on the counterfactual costs, to ensure that customers will realise a saving by connecting to the network,

The counterfactual costs used in the modelling are shown in Table E-5. The adjusted non variable charges of the counterfactual heat price differ between areas because it is based on a building by building basis, assuming a fixed charge per unit for residential, and per kW for commercial. When this fixed charge is adjusted to a variable rate it is affected by how much heat each unit is consuming. Residential unit consumption values vary depending on the number of homes being proposed under each development.

Table E-5: Year 1 counterfactual heat price breakdown

	Scenario A	CWSW	MTCML
Residential	Assumed replacement costs per unit	1,600	1,600
	Number of units	1,350	1,070
	Replacement cycle	20	20
	Annual standing charge[16]	£91.25	£91.25
	Annual maintenance[17]	£192.00	£192.00
	Adjusted non variable charges	6.4p/kWh	9.0p/kWh
	Gas price	3.6p/kWh	3.6p/kWh
	Boiler efficiency	86%	86%
	Variable charges per kWh	4.2p/kWh	4.2p/kWh
	Total counterfactual cost	10.6p/kWh	13.2p/kWh
Commercial	Assumed replacement costs per kW	£250/kW	£250/kW
	Replacement cycle	20	20
	Commercial maintenance costs	£4/kW	£4/kW
	Adjusted non variable charges	1.1p/kWh	2.4p/kWh
	Gas price	2.1p/kWh	2.1p/kWh
	Boiler efficiency	86%	86%
	Variable charges per kWh	2.5p/kWh	2.5p/kWh
	Total counterfactual cost	3.6p/kWh	4.9p/kWh

[16] Uswitch check of EDF standard variable
[17] British Gas Home Care: One boiler only with no excess

Connection charges

A Connection Charge is a one off contribution towards the capital cost of initiating a customer's connection to the heat network. The connection charge could be designed to cover:

- The capital outlay required to contribute to the scheme
- An amount not more than the cost which would be incurred for connection to/installation of an alternative heat source
- An amount not more than the cost incurred of replacing existing plant for that building
- Planning Authority requirements

LBM may wish to consider if it has any funds available for injection into the scheme as a capital contribution or whether any of the potential customers to the schemes may be willing to pay a connection charge.

Connection charges for existing buildings have been assumed to be linked to the cost of replacing boiler plant, less a user-specified discount rate. The default values chosen for the results of the model are that plant is assumed to be replaced once over the 25 year lifespan of the network, and that the cost of this replacement is equal to £350/kW of the building's peak heating demand. For new developments, the counterfactual case is assumed to be gas fired CHP based district heating system, costed at £1,000/kW. A discount of 50% is then applied to the counterfactual costs so that customers realise a saving by connecting.

Heat Sale

Heat networks typically charge for heat via a Fixed Charge plus a Variable Charge (based on consumption), similar to most electricity or gas supply contracts. Some schemes charge using a Flat Charge, but this method of charging is no longer allowed under the Heat Network (Metering and Billing) Regulations 2014 unless it is not technically possible and economically justified to implement metering and charging based on actual consumption.

It has been assumed that heat demand does not fluctuate from year to year over the assessment period (except for the phased delivery of new buildings), i.e. no allowance is made for future developments, or redevelopment of existing buildings, beyond those captured by the energy mapping study herein.

Fixed/Standing Charge

Fixed charges are often set to cover the fixed costs or minimum running costs of the scheme. This gives comfort to the operator (and funder) of the financial viability of the scheme. A common complaint made by customers is that Fixed Charges are too high, and therefore a commercial decision should be taken as to whether the full extent of fixed costs should be included in the Fixed Charge. The higher the element of Fixed Charge relative to Variable Charge, the lower the risk to the operator, i.e. variability in income relative to demand.

Variable (unit) Charge

The variable charge is often set to cover the marginal costs of supplying heat to the customer, e.g. fuel costs and efficiency losses. It would also be expected that an element of profit would be included within the variable charge on a 'for-profit' project.

Modelled Charges

When setting heat charges, prices will need to be set low enough that they are competitive to attract customers to connect to the scheme (i.e. will need to be considered with respect to current heating costs). However, prices will need to be set high enough such that a satisfactory return on investment is met.

The model uses the counterfactual heat price as calculated in Table E-5 to inform the revenues generated by the scheme. A discount of 10% is applied to the counterfactual price such that value can be offered to customers. Model users can alter the discount rates to explore the limitations of what can be charged to customers in order to offer them a saving whilst also delivering an attractively high IRR.

Electricity Revenue

The proposed heat generation technology is CHP. The electricity generated by the CHP can either be sold privately or exported to the grid.

Revenue generated through the sale of electricity via private wire or a sleeving arrangement is dependent on the agreement with the customer. The prices will usually be linked to the prevailing retail price, such that the customer benefits from a reduction in its energy bills over what they would pay otherwise. The default values for the purposes of the results given in this report are that electricity is sold privately at a discount rate of 10% against the BEIS published statistical retail electricity price. The remaining electricity is assumed to be exported to the grid at a discount rate of 50% against the BEIS published statistical retail electricity price (which in recent years has been representative of the wholesale price).

Although private wire electricity distribution demands certain up front capital expenditure, the revenues generated are much higher than exporting to the grid. As such, the ratio of electricity generated which is sold via a private wire or sleeving arrangement to that which is exported at whole sale rates affects the commercial viability of the network significantly. As such, this is highlighted as a key risk item that should be subject to further investigation in subsequent studies. Whilst it is preferable to sell all generated electricity privately, AECOM recognises that this may not be technically feasible.

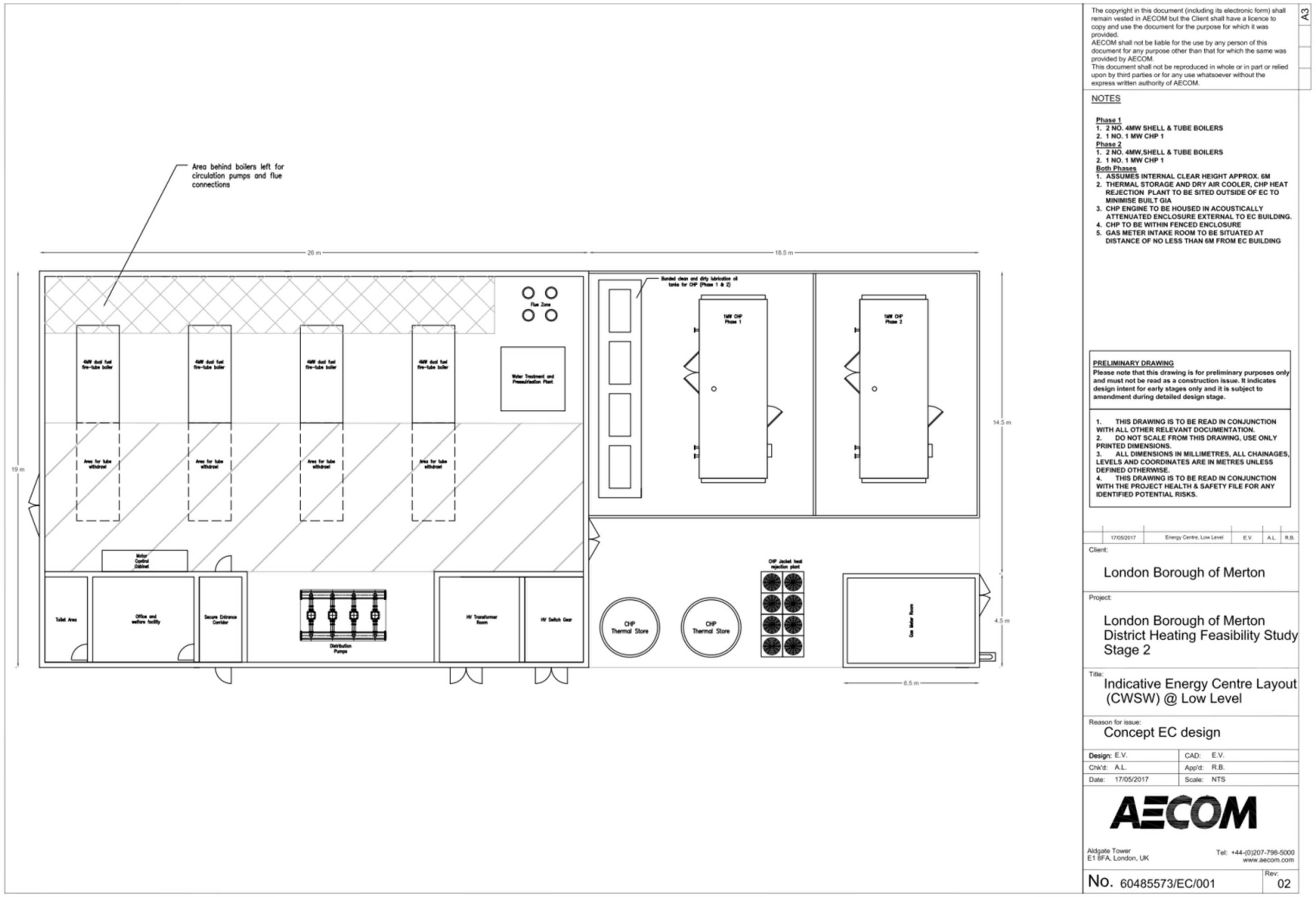
Default Parameters

The default values defining revenue that were chosen for the modelling as described in this section are summarised below.

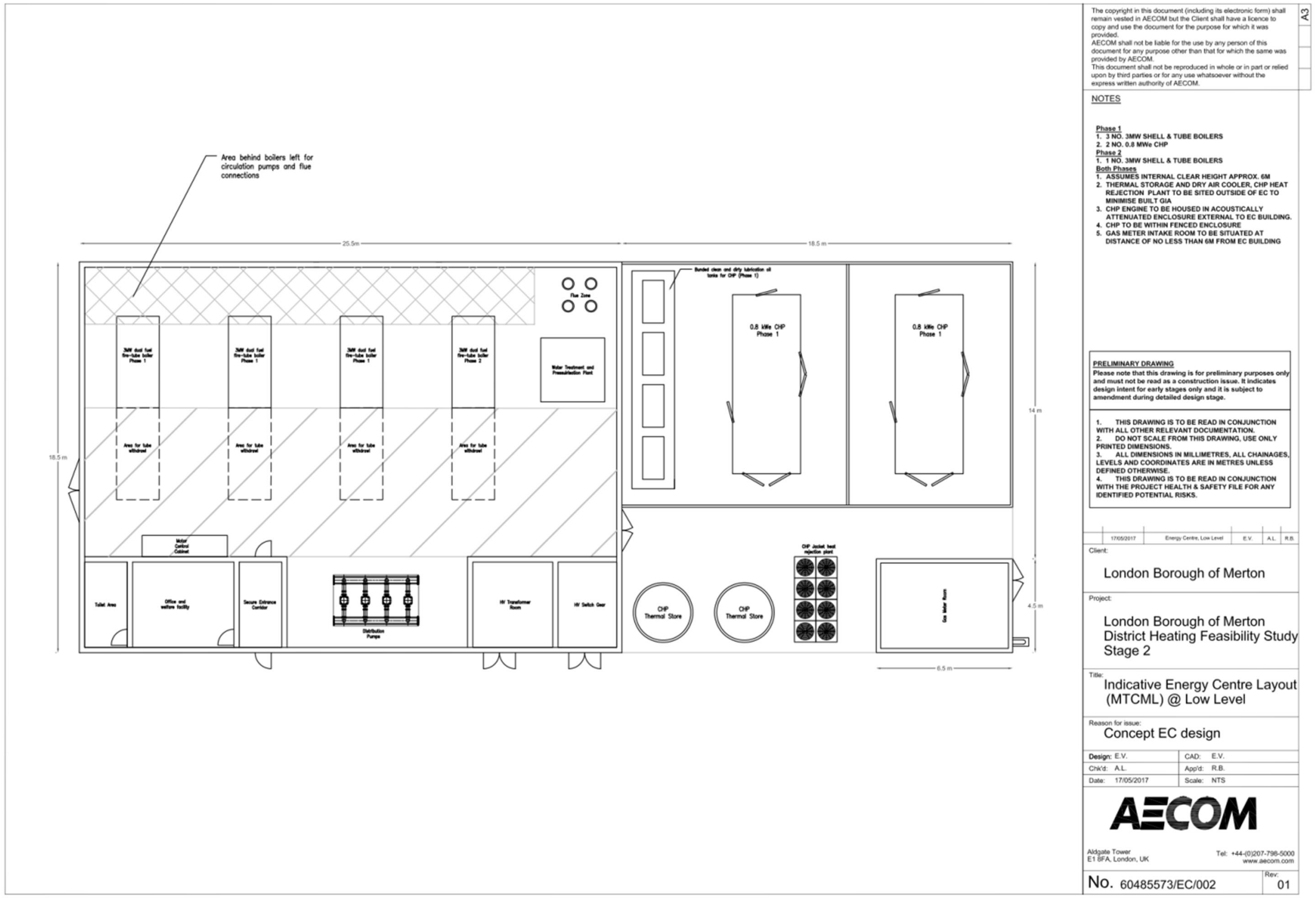
Table F-8: Default revenue parameters used within the model for analysis

Parameter	Value
First year of scheme operation	2020
CHP heat provision, % of total	At least 75%
Network distribution heat losses	15%
Electricity sold via private wire	To customers on the network
Private wire electricity discount rate against retail price	10%
Exported electricity discount rate against retail price (i.e. wholesale)	50%
Connection charge discount against counterfactual	50%
Heat sale discount against counterfactual heat price	10%
Discount rate	3.5%

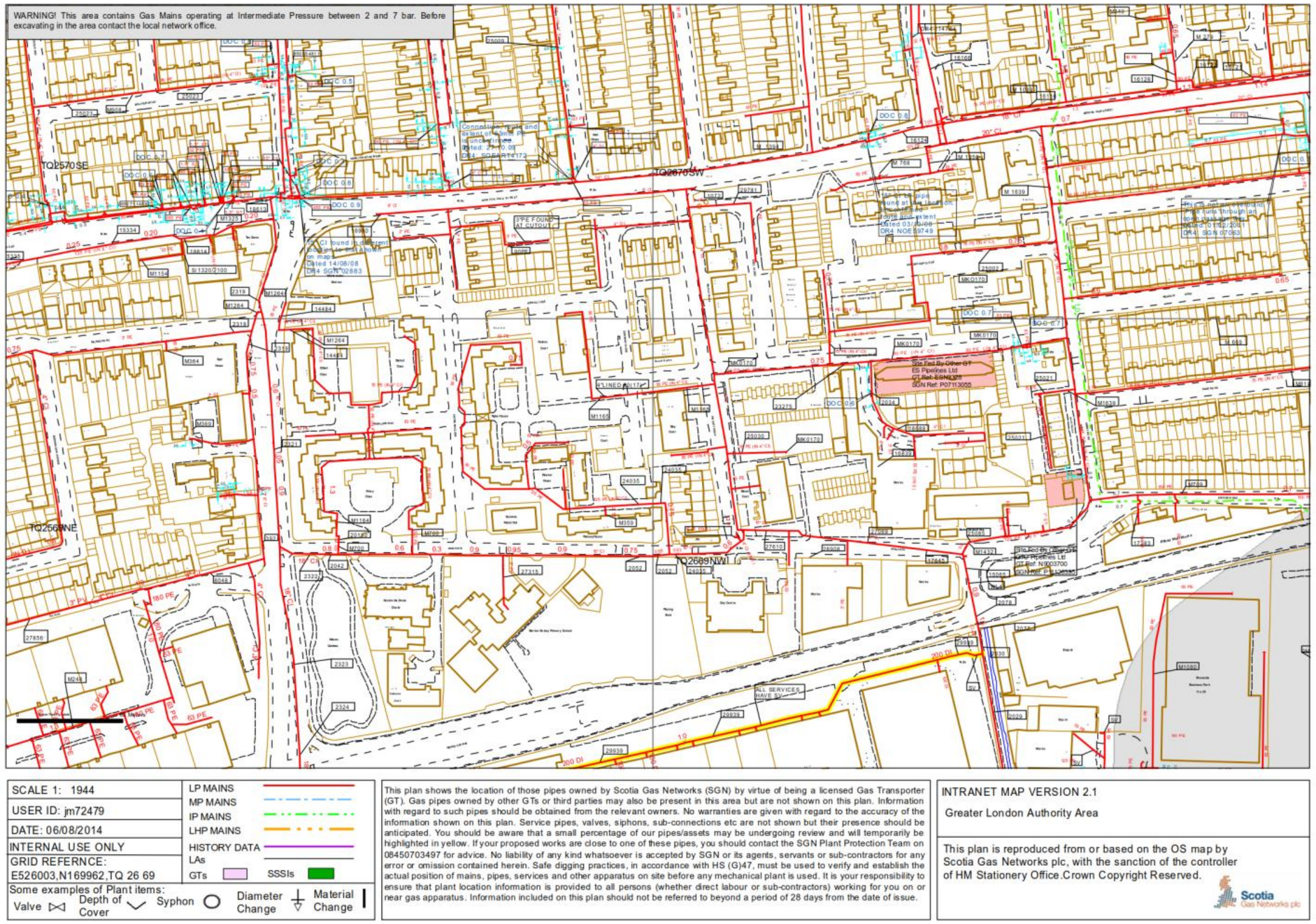
Appendix F. CWSW energy centre indicative layouts



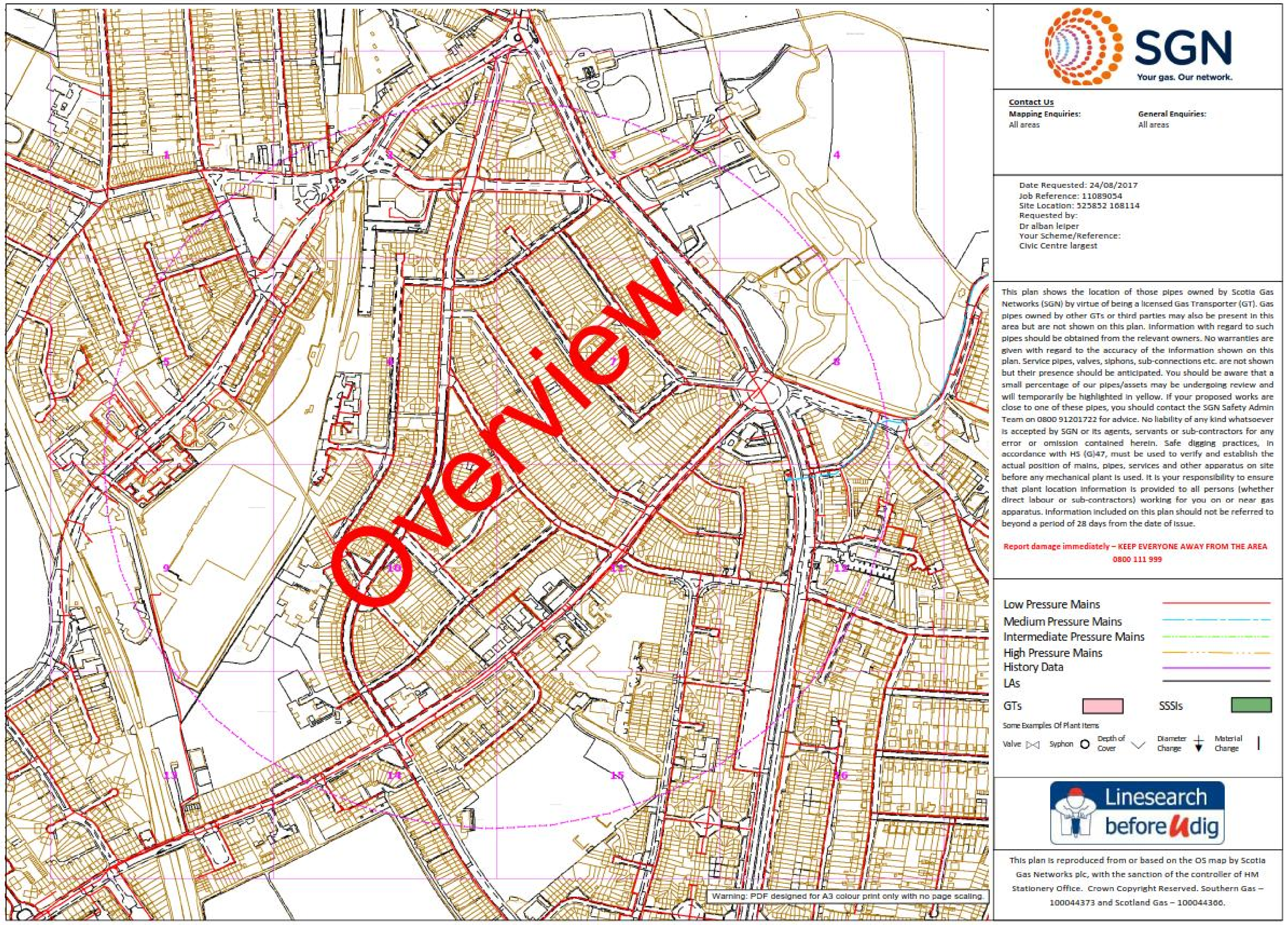
Appendix G. MTCML energy centre indicative layouts



Appendix H. CWSW Gas utilities



Appendix I. MTCML Gas utilities



Appendix J. Loan repayment schedules

Figure J-1: MTCML – Scenario A – Funded by loans made from the Council

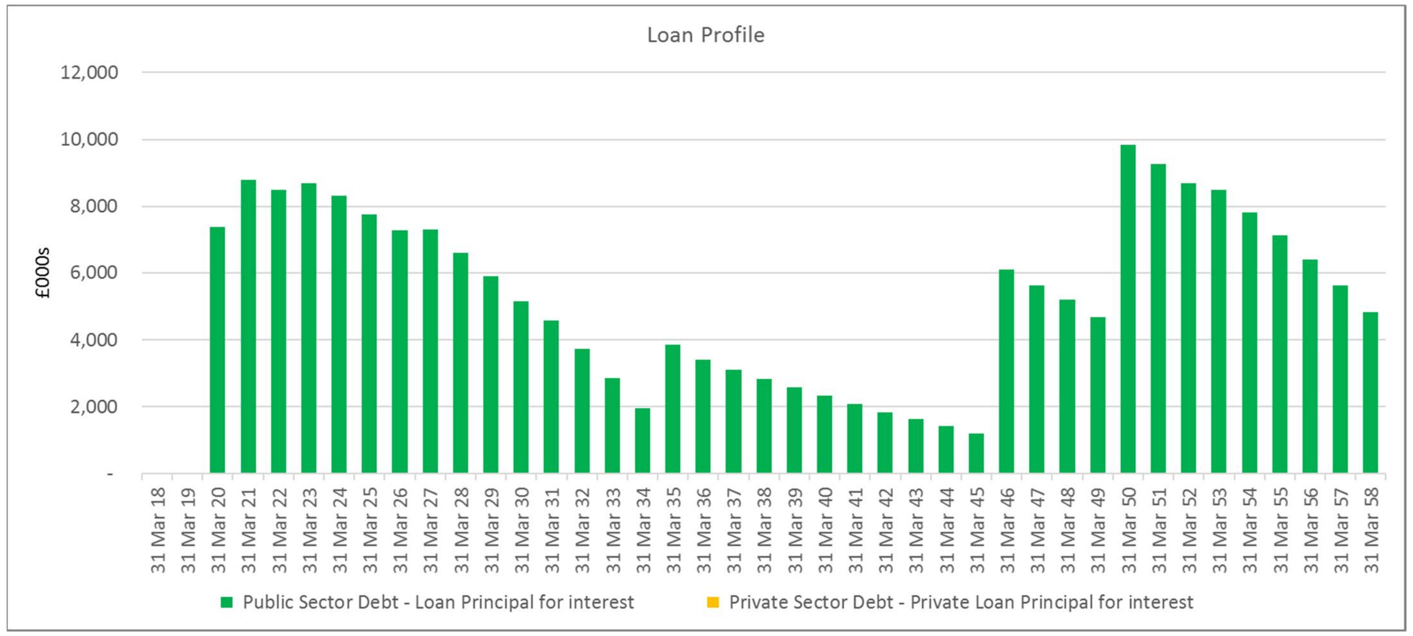


Figure J-2: MTCML – Scenario B – 30% of Loan provided by private finance

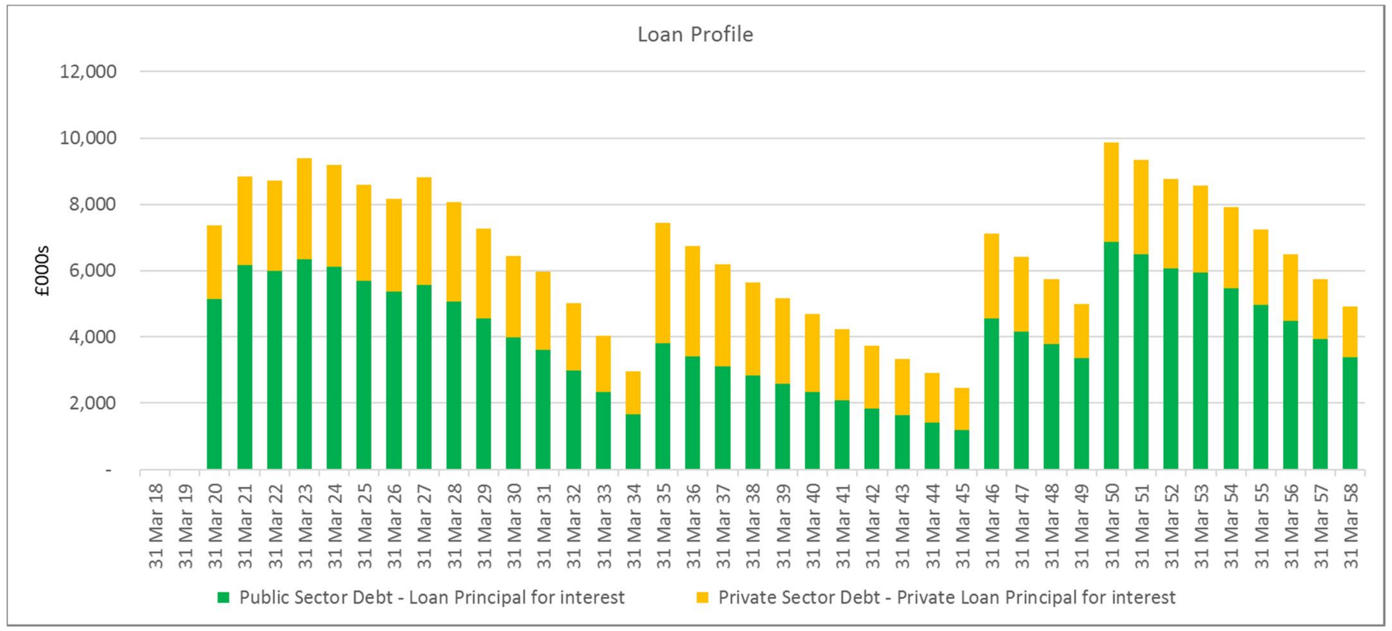


Figure J-3: MTCML – Scenario C – 30% CAPEX Grant

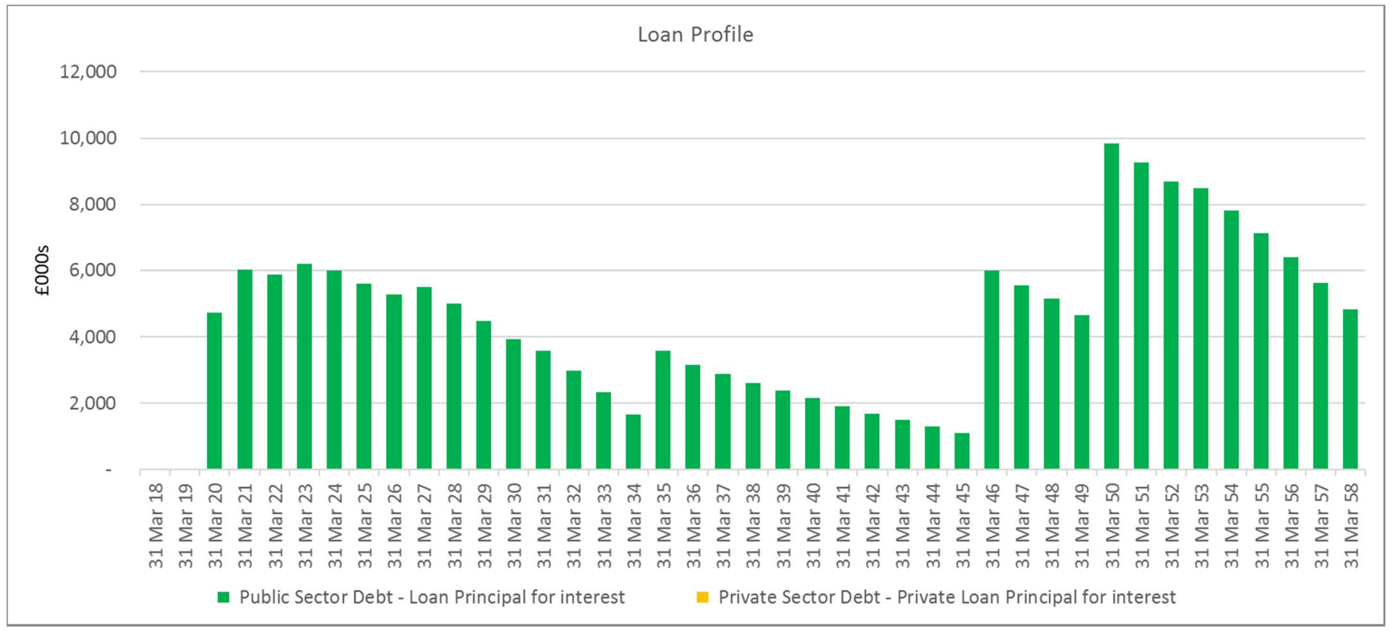


Figure J-4: MTCML - Scenario J – 50 Year loan annuity repayment

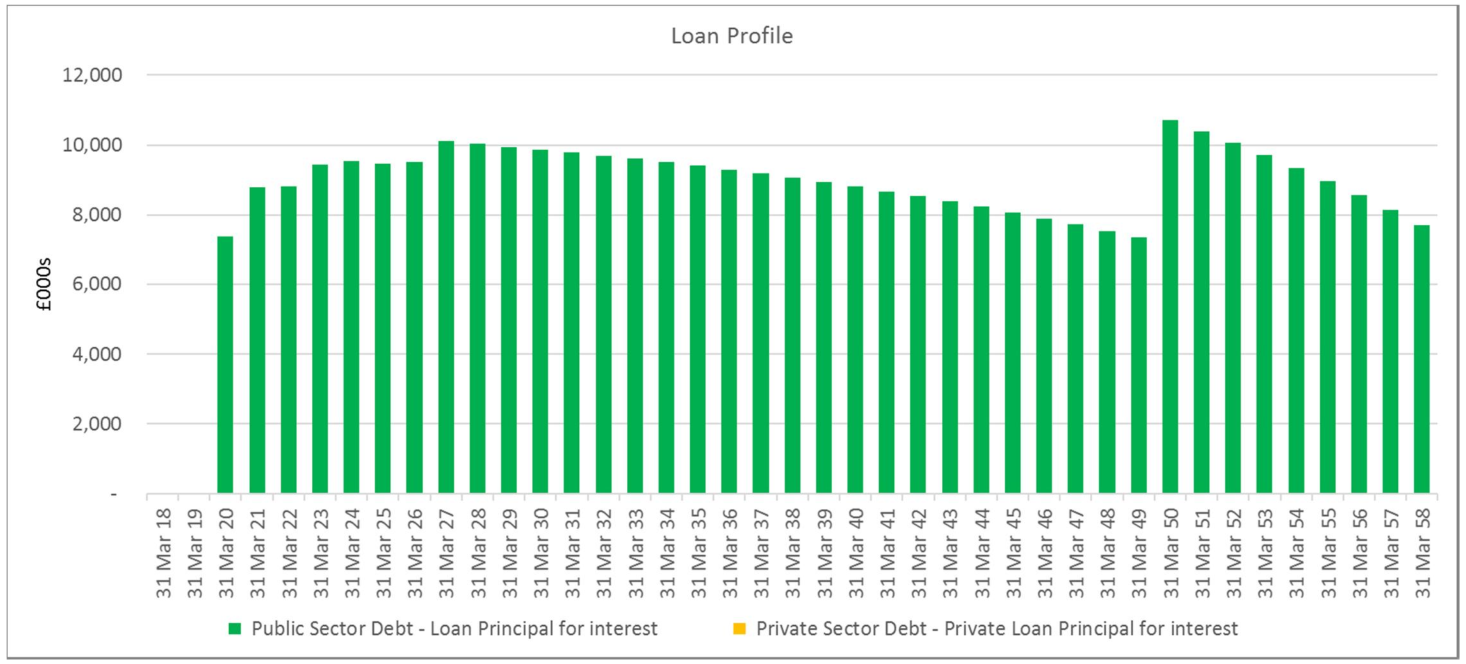


Figure J-5: CWSW – Scenario A – Funded by loans made from the Council

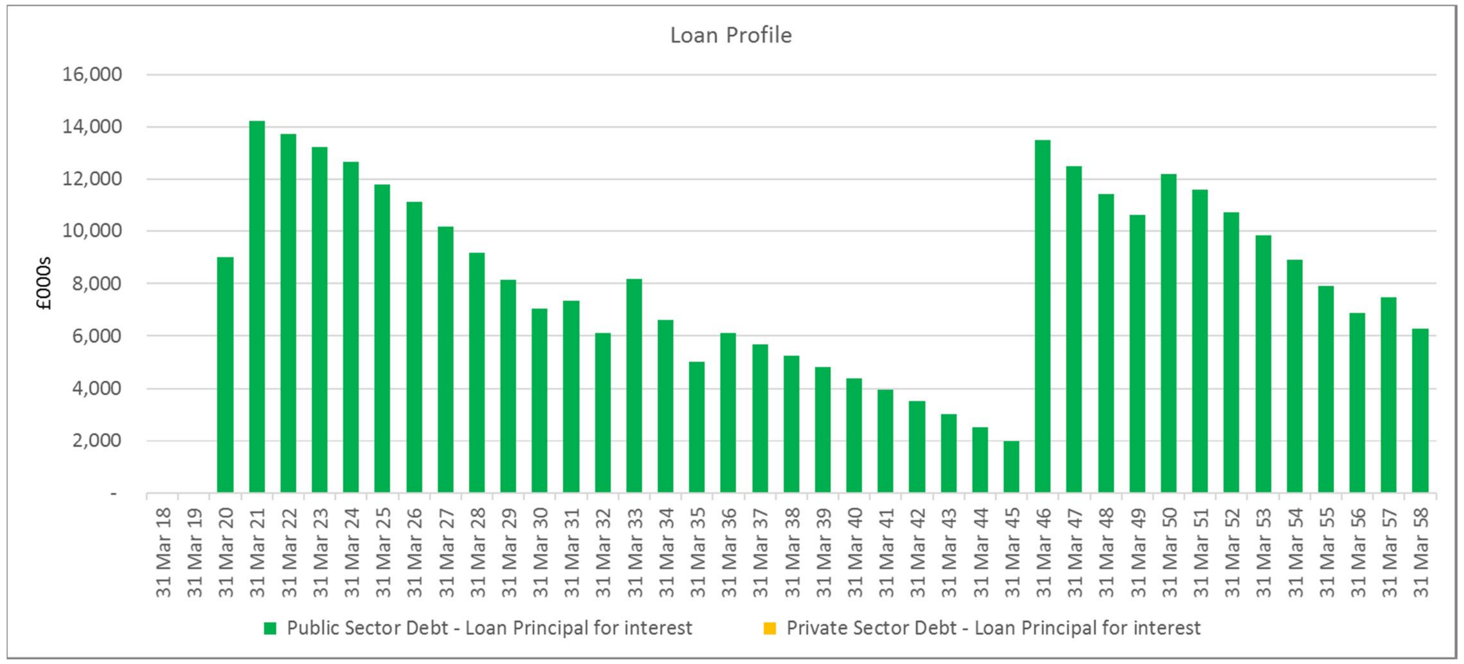


Figure J-6: CWSW – Scenario B – 30% of Loan provided by private finance

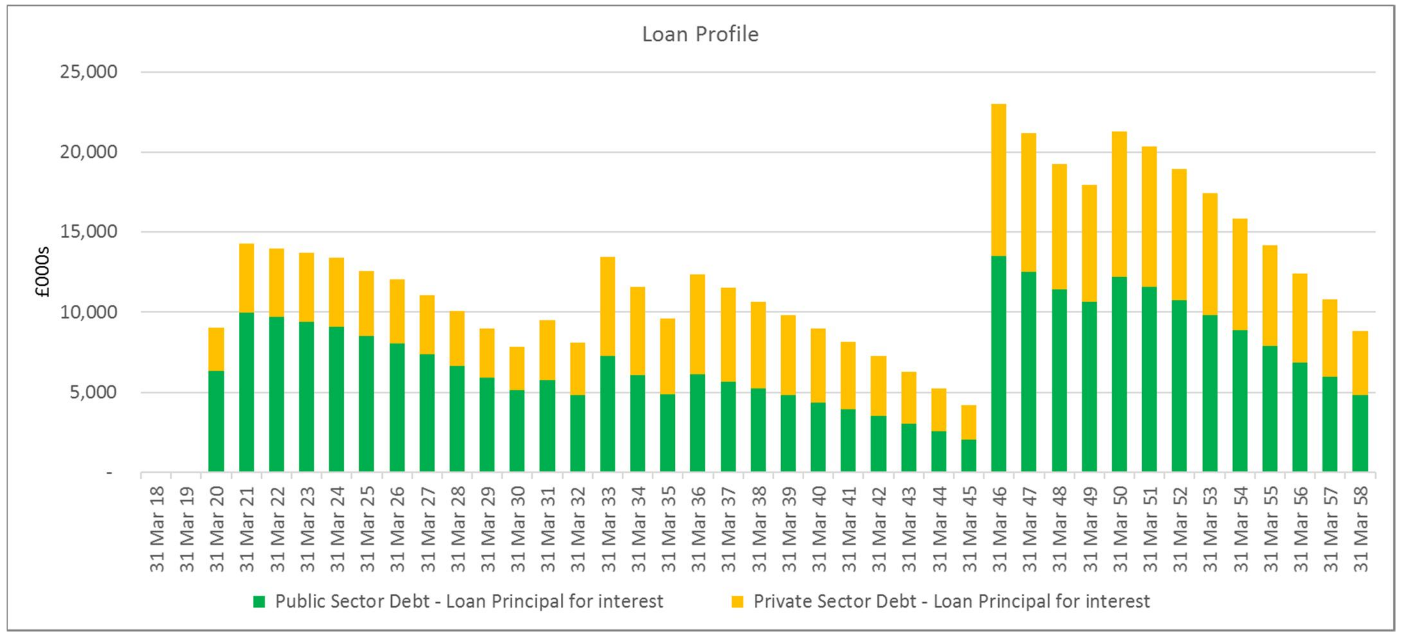


Figure J-7: CWSW – Scenario C – 30% CAPEX Grant

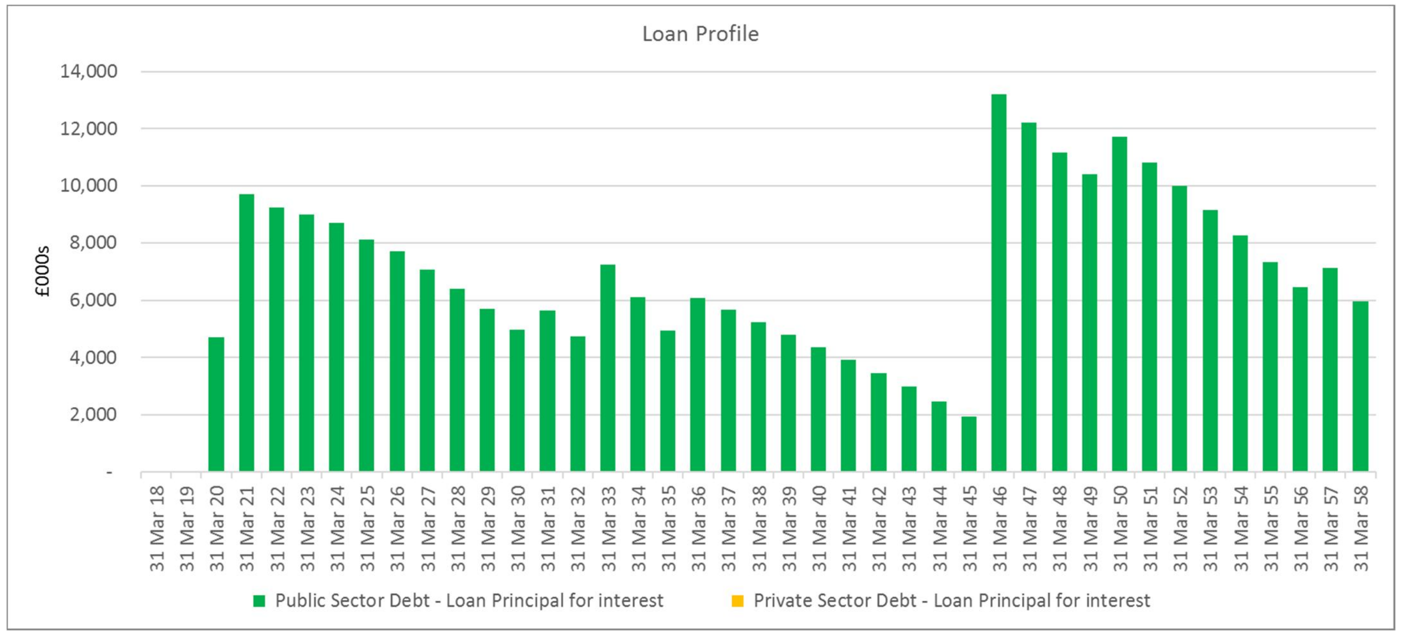
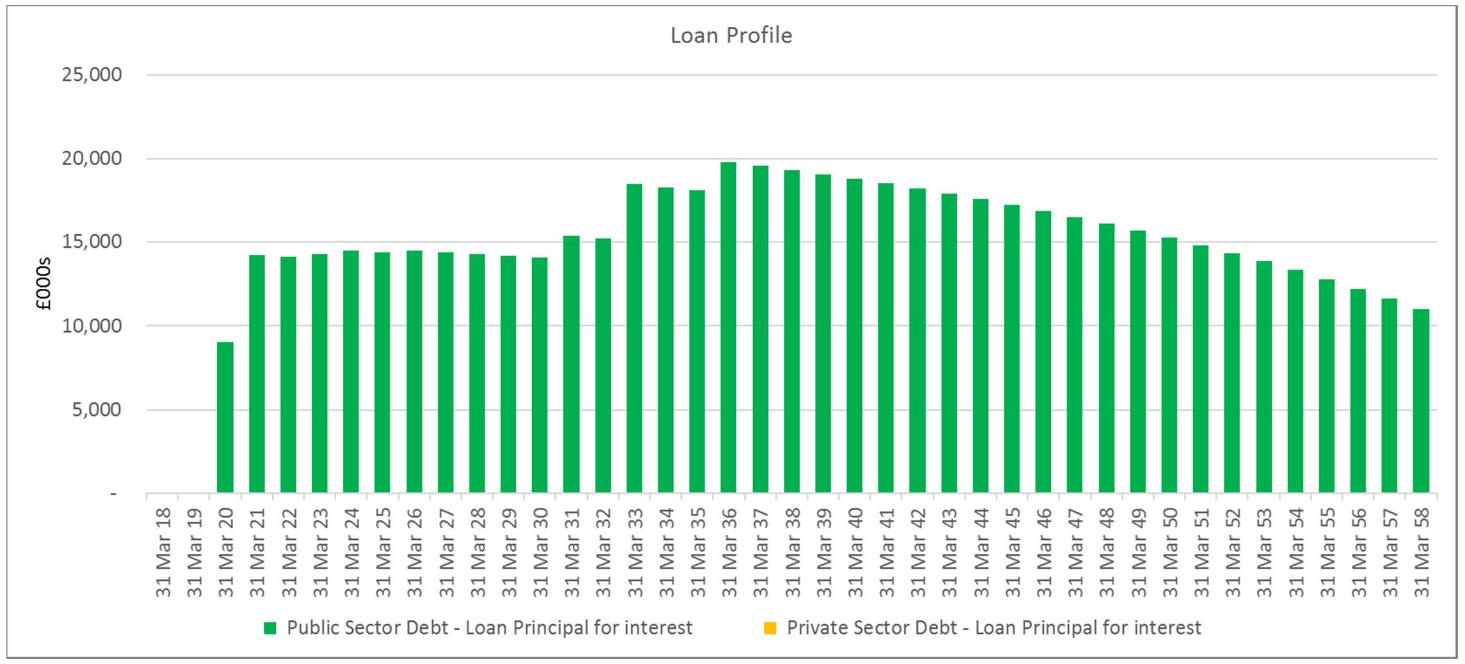


Figure J-8: CWSW – Scenario J – 50 Year loan annuity repayment



Appendix K. Risk Register

Ref.	Risk	Commentary	Risk: Probability	Risk: Impact	Risk: Severity	Suggested Risk Mitigation
R/01	Energy Centre location and cost	Energy centres are planned in the High Path Estate and behind the Merton Civic Centre. While there is space available in these locations, there are significant consents from stakeholders that must be secured in order to ensure the necessary areas are made available. Costs of obtaining/using land may be higher than expected.	Med.	High	High	1. Engage with stakeholders from the outset. Particularly within LBM (for Merton Civic Centre) and with Circle group (for High Path Estate), to ensure that they understand the implications of the energy centres 2. Provide details on Energy Centre design to stakeholders at the earliest opportunity to ensure they understand energy centre particulars 3. Seek explicit consent for locations at earliest opportunity 4. Impose planning conditions on High Path to host energy centre if necessary 5. Understand cost implications of land use as soon as possible
R/02	Customer satisfaction	Customer satisfaction and retention in Merton will depend to a large degree on having fair and equitable contracts. It is important that the service level for the heat supplied is defined as this will ultimately determine the design and hence the costs of delivering the heat.	Low	High	Med.	1. Engage with customers where education is required to communicate what a Heat Network is and how it operates 2. Provide reports on energy supply and use and bills that are clear and informative; 3. Develop communications with customers that meet customer expectations; 4. State levels of service provision and response times to reported failures: 5. Customers to meet agreed obligations. 6. Consider adoption of a Code of Conduct scheme such as Heat Trust 7. Adoption of agreed performance guarantees to be monitored and reviewed
R/03	Heat Tariff	Heat tariff may require change due to external influences, in order to remain attractive or compliant with future guidance	Low	High	Med.	1. Establish proposed heat tariff (fixed and variable element) and demonstrate current cost effectiveness against identified counterfactual 2. Conduct sensitivity analysis on future heat tariff rates based on risk identified within this document 3. Consider within sensitivity testing that future heat rate tariffs may be capped against identified metrics
R/04	Customer bad debt	The customer fails to pay on submitted bills and falls into Debt. This is especially risky in cases where the network operator is selling heat to many individual residential customers, as opposed to fewer commercial customers.	Med.	High	High	1. Establish whom holds debt risk within commercial structure 2. Identify possible level of debt risk 3. Conduct sensitivity analysis and establish level of debt that could be accommodated within the heat tariff 3. Develop revenue protection strategy that can be applied throughout the lifespan of the system 4. Establish suitable heat sale agreements. 5. Consider adoption of Heat Trust scheme.
R/05	Assessment of thermal loads	The peak heat demand drive capital costs as plant and network capacity increases. Oversized assets also lead to increased operational costs. The annual heat consumption determines the heat revenues to the scheme and, together with the daily and annual profiles of this consumption will determine the capacity of the low carbon plant which will supply the majority of the heat. Oversizing is more likely to occur than under sizing.	High	Med.	High	1. Establish peak and annual loads based on best available data as defined within Heat Networks Code of Practice. If potential loads are unknown, document assessment basis. 2. Conduct sensitivity analysis on the projected loads based on the level of certainty of projected loads being present and connecting 3. Establish likelihood of load being connected by engaging with responsible representative 4. Confirm projected loads with responsible representative; occupation rates, periods of occupation etc. 5. For existing residential buildings, the heat network provider will need to estimate peak and annual demands based on modelling or experience from supplying buildings of similar size and type, or where block boilers are used from fuel consumption data.

Ref.	Risk	Commentary	Risk: Probability	Risk: Impact	Risk: Severity	Suggested Risk Mitigation
R/06	Connection of thermal loads	The projected peak and annual thermal loads do not occur due to; development not progressing or customers do not connect	High	High	High	1. Engage with responsible representative/stakeholder/customer at an early stage of the project 2. Maintain dialogue until connection is made 3. Identify heat sale agreements with commercial information being made available 4. Ensure that the heat network offering is competitive with the counter factual 5. Use of planning system for new developments to include suitable designs/conditions/obligations
R/07	Realisation of thermal load	The projected thermal loads of connected customers fail to be realised.	High	Med.	High	1. Establish peak and annual loads based on best available data as defined within HNCoP. If potential loads are unknown, document assessment basis. 2. Conduct sensitivity analysis on the projected loads based on the level of certainty of projected loads being present and connecting 3. Establish likelihood of load being connected by engaging with responsible representative 4. Confirm projected loads with responsible representative; occupation rates, periods of occupation etc. 5. Develop heat sales agreements with consideration of guaranteed annual thermal energy purchase with a minimum connection duration
R/08	Change of connected thermal loads	Connected thermal loads change due to alteration of building usage, improvement in energy performance or connection termination	Low	High	Med.	1. Maintain dialogue with customer to identify potential for future change 2. Develop heat sales agreements with consideration of guaranteed annual thermal energy purchase with a minimum connection duration
R/09	Unsuitable operating temperatures	Operating temperatures are a key aspect of heat network design and will determine both the capital cost of the network and the heat losses and pumping energy. Designing for lower operating temperatures will result in higher efficiencies with some types of heat sources, e.g. heat pumps and steam turbine extraction.	Med.	High	High	An optimisation study shall be carried out to determine the operating temperatures for peak design conditions and how they vary with any given scheme as it will be impacted by the type of heat supply plant and the characteristics of the heat network. The designer has also to consider constraints such as the temperatures used for existing heating systems and the degree that these can be varied. Hence the requirements given below may not be valid in all cases and may be over-ruled by the conclusions of a detailed study for an individual scheme.
R/10	Heat losses	Losses (proportion of annual thermal energy lost in kWh or MWh) are often incorrect leading to inaccurate energy centre plant and financial planning. The HNCoP states a best practice of 10% annual thermal production is lost to below ground pipework (energy centre to building). The HNCoP states a best practice of 10% annual thermal loss of vertical and lateral pipework, up to and including the HIU.	Med.	Med.	Med.	Detailed assessment of below ground and above ground losses. Review of insulation applied, pipework diameter, length of pipe and operating temperatures.

Ref.	Risk	Commentary	Risk: Probability	Risk: Impact	Risk: Severity	Suggested Risk Mitigation
R/11	Combustion plant size	Losses (proportion of annual thermal energy lost in kWh or MWh) are often incorrect leading to inaccurate energy centre plant and financial planning. The HNCoP states a best practice of 10% annual thermal production is lost to below ground pipework (energy centre to building). The HNCoP states a best practice of 10% annual thermal loss of vertical and lateral pipework, up to and including the HIU.	Low	Med.	Med.	1. Identify and agree peak thermal loads assessment 2. Consider development of the peak thermal load if the system is to have phased completion 3. Identify thermal resilience strategy with specific consideration of boiler capacity and low carbon system capacity. Boilers at N+1 with CHP as supplementary heat (not considered in peak capacity) are common. 4. Review impact of capex inclusive of material, labour, maintenance as well as spatial impact
R/12	Heat controls	Heat controls result in poor operation of the system at generation, distribution and customer level. Key issues are optimisation of the system's resultant heat carbon factor and maintenance of flow and return temperatures.	Med.	Low	Med.	Appropriate generation, distribution (primary and secondary) and customer side controls should be designed, installed, commissioned and monitored. Employ suitable designers and operators and review proposals with Commissioning Manager. Ensure the systems are put in place, commissioned and operate as intended
R/13	Inefficient heat network routes, pipe sizes and reliability	The capital cost of the heat network is likely to be a major component of the project cost. The routes for the network will define the length, installation difficulty and hence cost.	Med.	High	High	The quality of materials, design, construction and operation of the heat network are important in determining the reliability of the system. An optimisation study shall be carried out under high standards to achieve: 1. Energy efficient heat network; 2. Low cost network - optimisation of routes and pipe sizing for minimum lifecycle cost; 3. Reliable network with a long life and low maintenance requirements; 4. Efficient heat distribution system within a multi-residential building; 5. Other buried utility coordination; 6. Geographical obstacle review; 7. Land ownership
R/14	Inappropriate building interface connection	A fundamental design choice is whether the buildings or dwellings are directly connected to the heat network (where the water in the network flows directly through the heating circuits of the building) or indirectly where a heat exchanger is used to provide a physical barrier to the water. The choice has an impact on cost and operating temperatures and pressures.	Low	High	Med.	1. A study shall be carried out to assess the costs and benefits of each connection methods at a building level and at an individual dwelling level; 2. Where indirect connection is used the heat exchanger shall be sized with an approach temperature (primary return (outlet) temperature – secondary return (inlet) temperature) of less than 5 °C; 3. Where boilers are being retained within the building for use at times of high demand the connection design shall ensure that the heat network heat supply is prioritised and the boilers used only when required to supplement this; 4. Large bodied strainers with fine mesh shall be specified to reduce the risk of dirt accumulating on valves and heat exchangers; 5. Control valves shall be two-port so that a variable volume control principle is established; 6. The design of plantrooms for the heat network interface substations shall provide sufficient space for maintenance access and for future replacement of equipment. It shall provide suitable power supplies including for use when carrying out maintenance, lighting, ventilation, water supply and drainage facilities.
R/15	Assessment of Environmental Impacts	The potential for negative environmental impacts that need to be considered, in particular there may be additional NOX and particulate emissions, increased noise and visual impact.	Med.	Med.	Med.	A more detailed evaluation of environmental impacts and benefits will be required at the design stage to support a planning application, to comply with legislation and to make the case for the project in terms of CO2 reductions.

Ref.	Risk	Commentary	Risk: Probability	Risk: Impact	Risk: Severity	Suggested Risk Mitigation
R/16	Air quality requirements	Optimism that emissions standards can be met with ease, without any flue scrubbing and emissions reduction technologies (which are costly)	Low	Med.	Med.	1. Assess local planning requirements in addition to any environmental permitting 2. Analyse plant flue gas performance 3. Develop mitigation strategy as required i.e. change plant or install flue treatment systems 4. Financially plan for proposed approach 5. Conduct appropriate flue gas/air quality assessment 6. Confirm final solution 7. Demonstrate operational performance when appropriate
R/17	Health and safety issues in construction, operation and maintenance	Reducing health and safety risks is of primary importance in any project. The health and safety of the general public during construction must be considered particularly as heat networks are often installed through publicly accessible areas.	High	High	High	1. The client body shall recognise their role and obligations under the CDM Regulations and register the project as one governed by the CDM Regulations prior to the start of the design process. 2. The designer has a key role to carry out a designer's risk assessment and then to mitigate these risks by taking appropriate design decisions. The requirements of the COSHH and DSEAR Regulations shall be taken into account in developing the design. Consider undertaking a HAZOP assessment
R/18	Poor performance of central plant	The principal rationale for any heat network is that heat can be produced at lower cost and with a lower carbon content at a central plant than at a building level. In particular certain heat sources are only feasible at scale (e.g. deep geothermal, energy from waste). The economic case for the heat network will depend on achieving the cost and environmental benefits at the central plant.	Med.	High	High	1. Designers will need to refer to detailed guidance on various aspects of central plant design as appropriate and identify a performance level 2. Monitor the operation of the central plant and to provide regular reports to the owner/developer so that a high standard of performance can be maintained. 3. Conduct sensitivity analysis based on the poor performance of the plant
R/19	Inadequate thermal energy supply	Failure to deliver the required amount of heat to each customer, critically at the times of peak demand.	Low	High	Med.	1. ensuring that each customer cannot take more than the design flow rate that has been set in the supply contract (typically defined as a kW supply rate at defined flow and return temperatures); 2. For residential properties, a hydraulic interface unit (HIU) is often used to provide a central control and metering point at each dwelling; 3. Commission cost effective, accurate and reliable heat meters in accordance with the Measuring Instruments Directive (MID) and shall be Class 2 accuracy; 4. Implement guaranteed performance standards within the contract
R/20	Thermal Connection Arrangements	Anchor load customers/developers can prove key to the financial success of a network. Failure to secure these connections can result in financial failure of the heat network	Med.	High	High	Discussions with key anchor load customers should be undertaken as early as possible in order to establish both the technical and the commercial viability of providing heat utilities to them. Time and resource should be itemised in the business plan to allow for these. Negotiations may be required in order to secure connections

Ref.	Risk	Commentary	Risk Probability	Risk Impact	Risk Severity	Suggested Risk Mitigation
R/21	Future fuel price variation	The price of heat would include fuel cost, standing charge, maintenance cost, etc. These cost are significant parts of Opex, variation of which will impact the revenue. If the spark gap (i.e. difference between gas and electricity) differs greatly from that predicted, this is a risk to CHP systems which are reliant on the cost of both fuels.	High	High	High	Conduct sensitivity analysis on projections of future fuel and electricity prices such as those published by the Inter-departmental Analysts Group (IAG), HM Treasury. Operator can help mitigate risk through use of future heat sale prices and linking to identified and agreed indices.
R/22	Change of regulation	Financial incentives and various funding scheme have significant impact on the case financial model.	Med.	High	High	Financial analysis based on both current regulations and potential policies under consultation.
R/23	Industry Regulation	The heat industry is not regulated by an external third party. Formation of external regulatory body will incur additional management costs	Med.	High	High	Whilst the industry is currently unregulated, there have been a number of motions that have been applied by central Government, independent trade groups and professional bodies to improve the base level quality of the industry. Future external regulation may still occur given the current and predicted state of the market. Conduct sensitivity analysis on the potential for increased management/governance costs in the future. Sensitivity should be higher if not already assessing costs associated with current schemes i.e. CHPQA, Heat Trust, Heat Network Regulations
R/24	Professional experience	Without the correct set of skills or experience within the delivery team, a potential project may face increased costs at any stage of the project.	Med.	High	High	1. Promoter role can include the review of project requirement's and develop a delivery team that covers the identified roles with sufficient expertise; 2. Ensure companies and individuals have sufficient experience by reviewing CVs, case studies, references and training; 3. Consider specifying project to be delivered under the requirements of a formal structure, such as the Heat Networks Code of Practice.
R/25	Fuel incomer requirement	Risk that gas main infrastructure near chosen scheme site is of sufficient pressures and kW capacity to service energy centre.	High	Med.	High	Energy centres often require significant gas main peak capacity and pressure which cannot always be readily provided locally from the existing in situ pipework. Early investigation of gas mains infrastructure recommended.

Ref.	Risk	Commentary	Risk: Probability	Risk: Impact	Risk: Severity	Suggested Risk Mitigation
R/26	Fuel incomers costs	Assumed that connection of gas network to Energy Centre is straightforward when it can be onerous and costly	Med.	Low	Med.	Early investigation of gas mains infrastructure recommended.
R/27	Water quality	Water treatment is sometimes not considered, impacting CAPEX and OPEX. Hard water means extensive water treatment is required to reduce mineral content of the water. Without water treatment, plant lifespans will be reduced which is unlikely to be considered in life-cycle costs.	Low	Med.	Med.	1. Level of water treatment required should be investigated early. 2. Water treatment plant to be identified along with Capex and Opex costs 3. Water quality to be maintained whilst the system is operational.
R/28	DNO electrical connection	Electric DNO fee to connect and export to grid is underestimated/ unknown at design stage (can often lead to huge one-off expense to connect for grid reinforcement works). Initial budget costs are often not tested soon enough within the project life cycle. Requirement to undertaken lengthy G59 application means it's often not done at early feasibility stages, which can lead to optimism on DNO connection cost/procedure. Occasionally, DNO infrastructure connection requirements/costs can halt a project completely.	High	High	High	Initial budget costs to be developed based on knowledge and experience of the local utilities. Identify changes in the current connection; increased import capacity (Heat Pumps) or ability to export (CHP) and amend price accordingly Seek quotations as soon as practically possible Identify key technical requirements are addressed within and quotations; security of supply, faults, capacity. Ensure cost of connection is contained within the business case and verified. Continue to engage with the market to ensure prices remain accurate and fit-for-purpose
R/29	Private wire customers	Schemes are more feasible if electricity is sold to private customers in the area that will consume electricity generated. The buildings identified on the network have been modelled to have a lower electricity consumption demand than the amount of electricity being generated by the scheme. As such, additional electricity customers should be identified to maximise financial returns on the network.	Med.	High	High	AECOM and LBM are working to identify large electrical customers in the area. For the CWSW area, the Morden Industrial Estate has expressed interest in purchasing power, but specific customers and availability for export are to be confirmed. Further engagement with the SWBA is required to engage these stakeholders. For the MTCML network, TfL have expressed interest, but further work is required to confirm this.
R/30	Electric export market	Electrical energy generated on-site, not evaluated suitability based on the perceived inability to connect to suitable loads, resulting in 100% export	Med.	Low	Med.	Local grid constraints to be assessed at Feasibility Stage. Identify opportunities to sell electricity to higher value connections. Conduct sensitivity analysis based on assumed average unit price per kWhe. As the project progresses, further mitigate risk and sensitivity by proving viability of connections and entering commercial negotiations with potential customers

Ref.	Risk	Commentary	Risk: Probability	Risk: Impact	Risk: Severity	Suggested Risk Mitigation
R/31	Electrical load available for sleeving/private wire	Sleeving/private wire end customer might not have the electric load requirement it is assumed to have or be willing to enter contract due to pre-existing electrical supply arrangements	Low	High	Med.	Early engagement with potential customers is required to establish the real electrical load available. Discussion around potential costs and willingness to enter contractor to be commenced at an early stage to de-risk item.
R/32	Sleeving/Private wire arrangements	Assumption of sleeving to end customers is assumed to be technically easy, requiring little or no upgrade to electrical infrastructure. Cost can directly impact maximum sale price per MWh.	Low	High	Med.	Capital costs to be identified, based on the level of design information available. Risk of price increased to be considered and appropriate contingency value put in place until risk designed out.
R/33	Electrical export	Parasitic loads, transmission losses and transformer inefficiency often under-estimated/ignored.	Med.	Med.	Med.	Assess potential parasitic loads and losses that could impact the quantity of electrical energy available for sale. Can reduce saleable electricity by up to 10%.
R/34	Electric revenue/private wire sales	Achievable sale price of electric often assumed to be too high (retail/wholesale). Assumed private wire electricity sales are dependent on identifying relevant and willing customers	Med.	High	High	Consider value of electricity used to generate heat and evaluate cost benefit of making loads parasitic Identify suitable electrical customers as early as possible. Assess mid-point sale price per kWh for each point of sale. Agree a lower price and a higher price to sensitivity analysis
R/35	Heat meters	Heat meters either not present, not installed properly or unable to transmit recorded information	Low	Low	Low	Suitable heat meters are to be installed in accordance with the relevant regulations and Heat Networks Code of Practice. The heat meter should be appropriate to the system design and installed in accordance with the manufacturer's requirements. Installed meters are to be commissioned and proven to operate over a continuing period of time, including data transmission. Meters will require on-going maintenance and possible recalibration, as identified during the planned maintenance process.

Ref.	Risk	Commentary	Risk: Probability	Risk: Impact	Risk: Severity	Suggested Risk Mitigation
R/36	Energy Centre size and cost metrics	No industry standard benchmark on physical size requirements, so often energy centres can be under-estimated. When at design stage, these errors can impact construction costs, cause programme delay and land use/developer availability. Furthermore, no industry standard benchmarks are available for construction/procurement costs (£/m2).	Med.	Med.	Med.	Limited information or specific published metrics available therefore assessment to consider plant size, movement and maintenance. Internal heights and location of heavy plant also to be considered.
R/37	Connection to external heat sources	Potential current/future requirements to connect to other external heat sources e.g. Energy from Waste plants. External heat sources will impact both peak and base load generation requirements for the heat network.	Low	High	Med.	1. Assess potential for current/future connections to external heat sources and their technical compatibility 2. Identify drivers that would lead to connection and the cost impact of the connection 3. Establish possible timescale in which a connection would be made 4. Review impact on peak thermal generation plant (possible redundancy) 5. Review impact on LZC plant due to reduced run hours 6. Review impact on plant area required
R/38	Connection to other DH networks	Potential current/future requirements to connect to other heat networks. External heat network will impact both peak and base load generation requirements for the heat network.	Med.	High	High	1. Assess potential for current/future connections to external heat networks and their technical compatibility 2. Identify drivers that would lead to connection and the cost impact of the connection 3. Establish possible timescale in which a connection would be made 4. Review impact on peak thermal generation plant (possible redundancy) 5. Review impact on LZC plant due to reduced run hours 6. Review impact on plant area required
R/39	DH pipework design	Pipe lengths often assumed to be too short than is necessary Installation of pipework is assumed to be straightforward, without the need to coordinate with utilities/highways which is rarely the case Pipework insulation performance overestimated, impacting energy losses and load on Energy Centre Inappropriate DeltaT can result in larger (increased capital and operational costs) Adverse design parameters can result in the shortening of the systems lifespan	Med.	High	High	Principles of network design (pipe sizing, DeltaTs, velocities, stress) should be based on agreed standards i.e. HNCoP and manufacturers recommendations. Networks should be designed for identified connected loads and documented allowance for any future expansion (increase in diversified peak capacity). Routes of pipework are to be established at any early stage with an identified allowance for additional pipework that has yet to be accounted for i.e. inaccuracy in routing and expansion loops. As the design progresses, routes detailed and confirmed, the additional allowance proportion should be reduced to zero.
R/40	DH pipework costs	Pipework costs often underestimated at early stages of the project until installation. Additional costs arise from the location of the pipework; soft dig, sub-urban, urban or central urban hard dig.	Med.	High	High	Establish lengths, sizes and routes at Feasibility stage and apply appropriate metrics dependant on dig type, location and obstacles Engage with manufacturers and installers to review and improve pricing accuracy when detail is available. This should be conducted as early as possible and prior to completion of the outline business case.

Ref.	Risk	Commentary	Risk: Probability	Risk: Impact	Risk: Severity	Suggested Risk Mitigation
R/41	DH pipework maintenance	Pipe failures are not accounted for. If they are accounted for, they are assumed to be easy to maintain. In reality, to fix a failed pipe is difficult, takes time and is costly - due to ground excavation works, welding costs etc. Servicing of loads from DH network will be interrupted, requiring a short-term servicing strategy to be put in place and temporary plant to be brought onto site - this is often unaccounted for.	Low	Med.	Med.	OPEX cost estimates for pipework failure/servicing should be allowed for in the economic model. Consider use of leak detection, water quality monitoring and extended warrantees
R/42	Secondary/Tertiary system compatibility (existing buildings)	Within existing buildings it can be assumed to be easy to convert/changeover secondary side systems to be compatible with network connection. Cost of ensuring technical compatibility to be considered In new build, how SH and DHW services are designed can have a significant impact on the capital costs and operating costs of the heat network. For example, achieving consistently low return temperatures will reduce capital costs for the network and thermal store, result in lower heat losses and pumping energy and in some cases reduce the cost of low carbon heat production.	High	High	High	1. Identify existing buildings that may wish to connect to the heat network 2. Estimate initial cost of connection based on anticipated supply arrangement 3. Confirm and validate operational parameters of the existing system 4. Confirm age and condition of existing/retained assets 5. Develop costs to reflect works to be undertaken and risk levels present i.e. re-commissioning of customer system from 82°C/71°C to 80°C/60°C flow and return temperatures.
R/43	Secondary/Tertiary system compatibility (new buildings)	How SH and DHW services are designed can have a significant impact on the capital costs and operating costs of the heat network. For example, achieving consistently low return temperatures will reduce capital costs for the network and thermal store, result in lower heat losses and pumping energy and in some cases reduce the cost of low carbon heat production.	High	High	High	1. Conduct specific design study to review the various options available for space heating and DHWS in relation to supply from heat networks.2. Implement agreed design, installation, commissioning standards and review their implementation3. Operator and Land Developers, or persons responsible for customer heat systems, to coordinate and ensure compatibility.
R/44	Secondary/Tertiary systems operation	Poor secondary/tertiary side operation can result in high return temperatures, corridor overheating and poor system performance	Med.	Low	Med.	1. Develop and agree a heat network design manual that covers design, installation, commissioning and operation. 2. Consider making technically measurable items contractually binding i.e. return temperatures during summer and low loads 3. Review operational interface if customer plant is being retained. 4. Ensure that the heat taken from the network is maximised, measured and monitored. Emphasis to be placed on measuring return temperatures to the network.
R/45	Secondary/Tertiary systems commissioning	Poor secondary/tertiary side commissioning can result in high return temperatures, corridor overheating and poor system performance	Med.	Med.	Med.	Potentially significant risk. Impact can be reduced by incentivising down stream system owners to optimise their systems, or by commissioning systems as part of the network (this would require associated costs to be included in the business case). Network operator may not wish to undertake downstream side systems.

Ref.	Risk	Commentary	Risk: Probability	Risk: Impact	Risk: Severity	Suggested Risk Mitigation
R/46	Planning consent and Way leave agreements	Planning process often not considered, or are assumed to be straightforward. Energy Centre building planning performance requirements often not considered. Assumption that wayleave consent for preferred pipework routing will be granted, meaning in reality the required pipework lengths may increase and/or target anchor heat loads may not be connectable.	Med.	High	High	Often overlooked. Early engagement with relevant bodies within local authority recommended (planning, highways etc.) to establish requirements for the energy centre, environmental performance and routing option viability. If above ground pipework (pipe bridges) are being considered, additional Planning engagement may be required. Way leaves agreement may take considerably longer than anticipated. If Local Authority delivered, this may mitigate risks around land use due to LA powers.
R/47	Carbon content of fuels	Future carbon content of electric offset is uncertain, potentially impacting future carbon tax abatement. Unknown carbon content of future fuel used in the Energy Centre, impacts the carbon content of electrical/heat export.	Med.	Med.	Med.	Whilst utility carbon content is projected to reduce, the exact reductions are unknown. Use of DECC projections is recommended for initial assessment and DECC CHP bespoke carbon factors.
R/48	Technology costs with maturity	Expectations of significant reductions in technology costs, particularly for technologies that currently are only marginally viable that may not have much scope for quick price reductions (e.g. platinum content fuel cells). Impacts the technologies that are considered in current studies.	Med.	Med.	Med.	Significant unknowns. Conservative estimates recommended. Review opportunities to future proof the heat network both technically and commercially. Consider heat network suitability for current alternative technologies that are not yet commercially viable.
R/49	Technology availability	Expectation that future technologies that replace CHP as the prime mover become available at scale, and are compatible with designed and installed network.	Med.	Low	Med.	Cost allowances should be made in the business case to allow technology changeover. Review opportunities to future proof the heat network both technically and commercially.
R/50	Future-proofing of the network	The approach taken to future-proofing of the network to accommodate potential future demand expansion is inadequate -(this concerns projects that haven't yet been considered and/or approved). Future development does not have the opportunity to connect due to the inadequate future-proofing, or its connection would make the scheme sub-optimal. Not accounting for future expansion, could lead to increased O+M or capital costs, or missed opportunities and future savings.	Med.	High	High	Development plans have been requested, to ensure best prediction for future. Any future new-builds to be obliged to connect to the scheme, with information to be provided to stakeholders (including contractors) as early as possible. Options to future proof design have been identified at feasibility stage. To be further considered at procurement stage and require contractor to future proof design e.g. through oversizing pipes, planning for nodal system. Consider potential contractual issues involved in connecting with other existing networks. Take into account future potential of new nearby developments. Must weigh up initial investment vs future impact/costs, but ensure no sacrificial plant, and existing scheme plant not oversized (to cater for future unconfirmed demand).

Ref.	Risk	Commentary	Risk: Probability	Risk: Impact	Risk: Severity	Suggested Risk Mitigation
R/51	Insufficient gas supply to the energy centre available.	May influence scheme size if fuel supply is limited	Med.	High	High	Ensure there is enough capacity - consult with National Grid. Could alter the CHP specification, to increase the electrical rating.
R/52	Failure to gain approvals/political sign-off	Programme delay or overall threat to connection	Med.	High	High	Ensure the clinical side of hospital approvals needed is kept informed of works needed, and can influence the construction schedule
R/53	Scheme fails to achieve an acceptable debt rate with customers	This would result in high charges for heat. High charges for heat would result in no (or insufficient) take-up of the scheme.	High	High	High	As only a small number of customers expected, an acceptable debt rate should emerge as a result of the feasibility and design process.
R/54	Economic performance insufficient	It cannot provide discounted heat sales and the marginal business case fails to attract investment, whether from the council or a third party. If the network cannot give an economic benefit over the status quo, it is unlikely to be adopted.	High	High	High	This is of lower risk where there is larger public sector involvement and likelihood of accepting a smaller heat price discount. If the case is marginal, the council may need to raise the capital for the development. Negotiation with potential customers will be needed based on feasibility results and options identified. If the scheme does not achieve the desired IRR then an emphasis on the 'bigger picture' may be required to attract customers. e.g. being part of the first phase of an expanding low carbon network.
R/55	Sub-optimal capital programme	Release/availability of funding drives phasing and impacts design decisions	High	High	High	Capture as much information as possible for the feasibility study. Communicate modelling assumptions and understanding regularly to check future plans are appropriately captured. Identify alternative funding sources.

Ref.	Risk	Commentary	Risk: Probability	Risk: Impact	Risk: Severity	Suggested Risk Mitigation
R/56	Uncertainty over capital cost	This can lead to funding issues. This could be, for instance, contractor costs increase. Reduced NPV or IRR for the scheme, or scheme is mothballed.	Med.	High	High	Costs to be reviewed through process. Further work will be needed at detailed design stage to determine capital costs. Specific items such as energy centre or distribution network costs need further negotiation.
R/57	Operation and maintenance costs of DH network	If the capital spend profile included for maintenance and cyclical plant replacement is too low, scheme will suffer from reduced returns and increased operational costs	Med.	High	High	The initial phase scheme proposals are for gas CHP which is a reliable and mature technology. Costs to be reviewed through process. Further work will be needed at detailed design stage to determine capital costs. Specific items such as O&M costs need further negotiation.
R/58	Cost of carbon and available subsidies.	If the cost of carbon emissions increases, this might result in reduced returns and increased operational costs	Med.	High	High	Costs to be reviewed through process, with any changes to Government policy and the utilities markets noted. Further work will be needed at detailed design stage to determine such costs.
R/59	Selection of sub-optimal procurement option	Lack of understanding of procurement options available may lead to selecting sub-optimal supply chain partner	Med.	High	High	Procurement workshops; soft market testing. Engage with potential procurement partners as early as possible.
R/60	Costs of metering and billing for heat sales with customers.	Impacts on scheme viability	Med.	Med.	Med.	Unlikely to be high with small number of customers involved. Review in future if network expands.
R/61	TRIAD and STOR model assumptions (which feed into energy cost/payment data) overly optimistic.	Actual financial performance worse than that modelled, resulting in lower returns.	Med.	Med.	Med.	Use existing site data, and also lessons learnt from previous projects. Use worst case assumptions. Undertake sensitivity analysis

Ref.	Risk	Commentary	Risk: Probability	Risk: Impact	Risk: Severity	Suggested Risk Mitigation
R/62	Assumptions about avoidance of carbon costs wrong	Impact on modelled financial performance, potentially resulting in lower returns.	Med.	Med.	Med.	Use existing site data, and also lessons learnt from previous projects. Use worst case assumptions. Undertake sensitivity analysis
R/63	The proposed scheme gas consumption is significantly increased	Insufficient network capacity may be available for a large increase in gas consumption.	Med.	Med.	Med.	Investigate network capacity and utility information.
R/64	Failure to manage stakeholder expectations	Stakeholders may pull out of agreement at an advanced stage. Uncertain scheme uptake would threaten the technical and economic viability of the scheme	Med.	High	High	Regular and clear contact with key stakeholders. Key customers are public sector which should reduce risk. Ongoing consultation and early negotiation of contract terms and signing of contract.
R/65	Proposed energy centre(s) building not big enough to accommodate required energy source in future (no spare space for expansion).	Missed potential to connect future development and concurrently improve performance of the proposed scheme.	Med.	High	High	If possible, building to be designed to be able to extend. Other site(s) may be needed for future expansion, and the team should continue to consider these alternative locations.
R/66	Inability to secure energy centre site for initial phase, inability to install CHP and associated kit in energy centre.	Increased cost or programme to locate energy centre	Med.	High	High	Potential energy centre sites to be identified and reviewed. Further analysis required including need to explore further with Planning and Legal. To engage with and try to sign up landowners to the scheme as early as possible. For future proofing, external CHP location to be considered resulting in potentially easier expansion.
R/67	Lack of integration with existing and planned future minor works (e.g. repair and replacement) or site activities that might disrupt DH scheme works.	Potential lost revenue, unnecessary costs or delayed programme	High	Med.	High	Consider key potential constraints. Coordinate works with existing projects, work with stakeholders to ensure aware of these. Stakeholder activity constraints may include busy periods/ events.

Ref.	Risk	Commentary	Risk: Probability	Risk: Impact	Risk: Severity	Suggested Risk Mitigation
R/68	Remaining life of existing plant may be good. Risk of 'sunk' costs to connect to heat network	Potential customers may be less likely to join up, or would want to get some use out of their existing plant or some costs recouped.	High	High	High	Will need to negotiate with customers on these points. Potential customers in private sector are likely to have new plant. Possibly the scheme might pay to adopt decentralised plant, or use temporary plant until the network is operational. Could let people connect as and when, but this impacts the financial case. Detailed engagement and contractual negotiations requried. Site survey undertaken has identified plant and will make allowances in the planned connection times to suite plant end of life unless agreed otherwise.
R/69	Ability to retain customers on longer term contracts.	Uncertain scheme uptake would threaten the sustained technical and economic viability of the scheme	Med.	High	High	Heat sales prices and contracts will need to be robust and attractive, and without break clauses. Draft Head of Terms to be developed under next stage and explored with stakeholders
R/70	Complex works access to the selected Energy Centre(s).	1. Delays to the programme schedule 2. Additional costs 3. Potential to be picked up by the media	Med.	High	High	Define costs (allow for high estimate) and works clearly, Early engagement with contractor and engagement with other stakeholders e.g. FM. 3. Soft testing
R/71	Programme delays at construction stage (e.g. due to getting approval for works in roads, delivery delays, requirements for limiting work timescales due to events or building requirements).	Cost and programme	Med.	Med.	Med.	Careful forward planning and management should be undertaken to manage and minimise delays. Detailed procurement programme to be presented with TC documents. If completion date is not met, buildings due to connect will need to be able to utilise their existing heat systems. Ensure programme not too tight and managed appropriately.
R/72	Risks which may impact on programme e.g. discovering asbestos or ground conditions	Cost, programme, technical and economic viability	High	High	High	Detailed surveys of each building to be undertaken where builders work is to be carried out, including asbestos survey, and GPR survey. Tio be undertaken in the next stage of design works

Ref.	Risk	Commentary	Risk: Probability	Risk: Impact	Risk: Severity	Suggested Risk Mitigation
R/73	Local political risk	Changes to council administrations results in lower priority for heat networks or even abandonments through removal of resource. Reduction in long-term scheme support	Med.	Med.	Med.	Continued engagement with the Council senior management is essential for the scheme to be given the resources and priority required. Reduce risk by contractually mandating this.
R/74	National political risk	Changes to national administration or strategy results in move away from heat networks, or powers which allow local authorities to develop and invest in heat networks. Reduction in available funding, incentives or difficulty in achieving planning for this strategy	Med.	Med.	Med.	This may place a greater emphasis on schemes being economically attractive for commercial investment. Engagement with national government required. Scheme to be optimised and future-proofed as far as possible to ensure long term viability.
R/75	Risk of obsolete components needing replacing over the lifetime of the scheme.	Increased replacement costs	Med.	Med.	Med.	Ensure spares will be available for long period.
R/76	Financial incentives and various funding schemes have significant impact on the financial model.	The financial case may change based on future regulation, negatively impacting the performance of the scheme.	Med.	High	High	Financial analysis based on both current regulations and potential policies under consultation.
R/77	No industry standard benchmark on physical size requirements	Often energy centres can be under-estimated. Furthermore, no industry standard benchmarks are available for construction/procurement costs (£/m2). When at design stage, these errors can impact construction costs, cause programme delay and land use/developer availability.	Med.	Med.	Med.	AECOM is developing budget costs based on data held within the organisation and submitting for Client review
R/78	Pipework routing along London Road	It is currently proposed to route pipework along London Road between Merton Civic Centre and the Morden Leisure Centre. This road is owned by TfL and the costs of wayleaves and consents from TfL to use the road have not been accounted for. There is a risk that these will increase the costs.	Med.	Med.	Med.	Engage with TfL early to assess costs of routing pipework along London Road. If costs are found to be prohibitevly high, AECOM suggest pursuing pipework Option 2 instead, which redirects pipework under the railway on Links Avenue.
R/79	Length of contracts customers are willing to agree to	The modelling assumes that customers are retained on the network for the lifetime of the project. Customers may not be willing to sign agreements that ensure this, meaning there is a risk they will disconnect in future	Med.	High	High	This is a risk to be addressed during commercialisation. Customers need to understand the benefits of connection, including technical, environmental and financial. This will be a key aspect of the contract negotiations. It is more of a risk for existing buildings, as new developments can be conditioned to connect by LBM.

Ref.	Risk	Commentary	Risk: Probability	Risk: Impact	Risk: Severity	Suggested Risk Mitigation
R/80	Trees in Morden Park prevent pipework to be installed in proposed location	The pipework route to the Morden Leisure Centre and Thames Valley College is proposed to lie just inside the park boundary next to London Road.	Med.	Med.	Med.	Carry out detailed assessment of trees and requirement for spacing between trees and pipework. If pipework cannot lie inside park boundary, relocate it to being buried under London Road.
R/81	LBM loss of car park spaces	LBM does not currently generate revenue from the car park by the Morden Civic Centre, however there may be consequences on current/future tenants	Med.	Low	Low	Engage with users of car parking spaces early to notify them of plans for EC location in the car park.
R/82	Role of CHP in the low carbon grid changes from baseload to peak	As the UK electricity grid decarbonises, the role of CHP may change from providing the base load heating demand to the peaks only, in order to reduce overall peak electricity requirements on the grid. This would affect revenues from sale of electricity	Med.	High	Med.	Focus on private wire customers to secure future revenues. Keep abreast of changes to regulations/policies. There may be future opportunities for different revenue types from providing power during times of peak demand
R/83	Length of heat or power purchase agreements	Some customers may only be willing to sign short agreements for the purchase of heat or electricity from network operator	Med.	Med.	Med.	Assess appetite for purchase agreements and length of contracts during commercialisation phase of study
R/84	Electricity market risks	Risk that the structure/policies/framework of the electricity market changes, putting the sale/export of electricity at risk, and associated revenues	Med.	Med.	Med.	Secure purchase power agreements for as long as possible with private customers, to avoid exporting power to the grid. Keep abreast of changes to regulations/policies and understand alternatives before any changes occur.
R/85	State aid risks	If LBM chooses to pursue state aid, there is a risk that the project is carried forward on the assumption that state aid is achievable, but that this is later found to be untrue.	Med.	High	Med.	LBM should work with the HNDU to understand the eligibility of both schemes for state aid, before proceeding on the assumption that they are.
R/86	Value of EC space	Risk that the value of EC space is higher than anticipated and has detrimental effect on network financial performance	Med.	High	Med.	LBM should engage internally around Morden Civic Centre Car Park and with Clarion Group around High Path Estate to understand value of EC space.

Appendix L. Pipework breakdown schedule

Provided separately as an excel spreadsheet.