Programme Area: Nuclear

Project: System Requirements for Alternative Nuclear Technologies

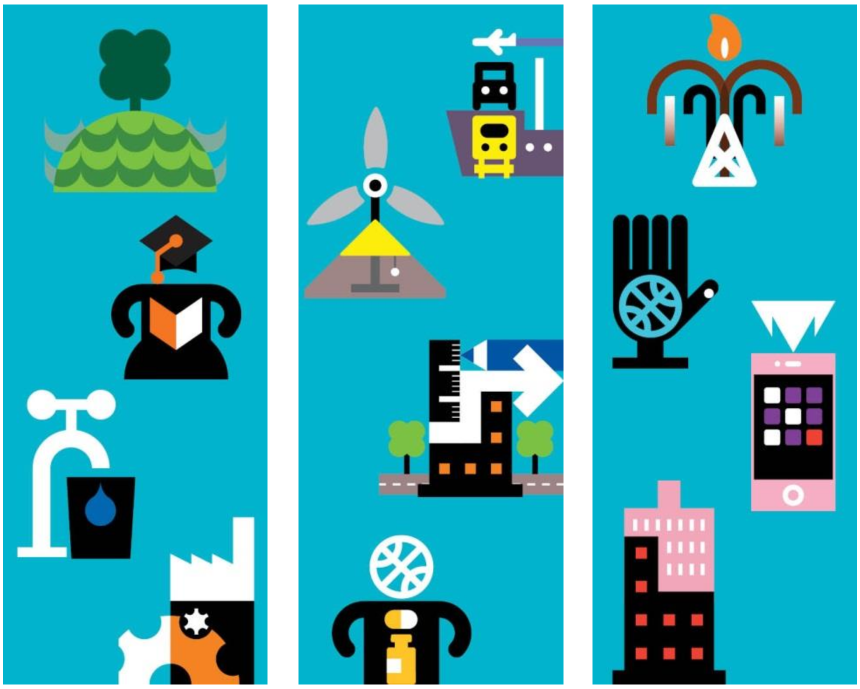
Title: Technical assessment of SMR heat extraction for district heat networks

Abstract:

Small Modular Nuclear Reactors (SMRs) are generally defined as nuclear reactors with a maximum electrical output below 300MWe. They are considered to have characteristics that are distinct from conventional large reactors and proponents claim that SMRs could offer a number of benefits to the UK's future energy system, including the reliable provision of low-carbon electricity and heat, lower financing costs, and the opening up of additional sites closer to demand. At the present time however, there are still significant uncertainties relating to the cost, performance and deployment timetables of SMR technologies. It is concluded that SMR heat supply could be a significant benefit to both plant economics and the decarbonisation of the UK's energy supply. The cost of designing and building SMR plants ready to supply future DH networks is relatively small, but the benefits are potentially large. This report may have relevance for organisations considering the potential deployment of SMRs into a future UK low carbon energy systems.

Context:

The purpose of the System Requirements for Alternative Nuclear Technologies project was to capture the high level technical performance characteristics and business-case parameters of small thermal plants, which will be of value to the potential future of the UK's energy system. The project included small nuclear reactors, enabling comparison with other small-scale plants, such as those powered by bio-mass. The project outputs will help enable the subsequent contrast of a range of specific technologies.



System Requirements For Alternative Nuclear Technologies (Phase 3)

Technical assessment of SMR heat extraction for district heat networks

September 2016

Energy Technologies Institute

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Contents

Executive Summary

Small Modular Nuclear Reactors (SMRs) are generally defined as nuclear reactors with a maximum electrical output below $300MW_e$. They are considered to have characteristics that are distinct from conventional large reactors and proponents claim that SMRs could offer a number of benefits to the UK's future energy system, including the reliable provision of low-carbon electricity and heat, lower financing costs, and the opening up of additional sites closer to demand. At the present time however, there are still significant uncertainties relating to the cost, performance and deployment timetables of SMR technologies.

This is the background context for the System Requirements for Alternative Nuclear Technologies (ANT) project, commissioned by the Energy Technologies Institute (ETI).

ANT project purpose

The overall purpose of the ANT project was to frame the UK energy system requirements for a small generic nuclear power plant with an output of up to $300MW_e$. Mott MacDonald was appointed by the ETI to undertake this work, which was carried out in 3 phases between September 2014 and March 2016.

Phases 1 and 2 involved a wide-range of tasks aimed at understanding the role that SMRs could play in the UK's future energy system and defining the functional and economic parameters for SMRs to fulfil this role. This work, which was completed in August 2015, covered a range of disciplines and topics including energy markets and economics, nuclear engineering, district heat (DH) network development and operation, power plant delivery, environmental impact and infrastructure financing. It was underpinned by a number of high-level engineering assumptions about the costs and performance of a generic SMR module and steam cycle. These assumptions were based on Mott MacDonald's experience of thermal steam cycles with heat offtake such as desalination. Consideration of issues relating to public acceptability was outside the scope of the project. Mott MacDonald appointed Rolls Royce as subcontractor for Phases 1 and 2 of the project, to provide specialist input relating to nuclear engineering.

The Project Summary Report for Phases 1 and 2 is available on the ETI website at: www.eti.co.uk/wp-content/uploads/2015/10/ANT-Summary-Report-with-Peer-Review.pdf.

Owing to the significance of the Phase 1 and 2 findings the ETI retained Mott MacDonald to undertake Phase 3. The objective of Phase 3 was to validate the assumptions and expand the findings of our earlier work by undertaking more detailed engineering analysis. This analysis involved using proprietary industry standard software packages to undertake thermo-dynamic modelling of SMR plant steam cycles and cost modelling of plant equipment. This report represents the culmination of our Phase 3 work.

Phases 1 and 2: the importance of low-carbon heat

A key conclusion from Phases 1 and 2 is that SMRs have the potential to operate as Combined Heat and Power (CHP) plants providing low-carbon heat to city-scale DH networks in the future, with the additional revenues from heat sales improving SMR plant economics. This conclusion is based on the starting assumptions (defined by the ETI) that unabated gas will need to be phased out by mid-century in order for the UK to meet its decarbonisation targets, and that large-scale DH networks will be required to cost effectively decarbonise heat in densely populated urban areas.

The analysis for Phases 1 and 2 was underpinned by a number of engineering assumptions about the costs and performance of a generic SMR module and steam cycle. These assumptions were developed by the project team based on engineering judgement and were subject to an external peer review process. We did not undertake detailed engineering investigations or thermo-dynamic modelling at this stage, or use any data associated with specific SMR designs.

Phase 3 objectives

Given the significance of the Phase 1 and 2 findings, Phase 3 aimed to validate our earlier assumptions and expand our earlier conclusions by focussing on two overarching areas:

The first area was the technical and economic viability of extracting heat from SMRs for supplying DH networks. In particular, we considered whether the efficiency and size of an SMR module has a significant impact on heat extraction. We sought to understand whether heat extraction requires fundamental changes to SMR steam cycle design or can be accommodated relatively easily with only minor incremental alterations. This is important given the requirement for SMRs to be standardised modules deployable in a range of contexts.

The second area was the flexibility of SMR plants to adapt to changing environmental conditions. SMRs offer the prospect of opening up a more diverse range of sites than large reactors, including inland sites close to rivers or lakes. However climate change could mean that more frequent and severe periods of drought restrict the amount of water available for extraction from these sources. The ability to switch SMR plants to cooling methods that require less water could be an important factor in managing long term risks to unconstrained plant operation and revenue generation.

The specific Phase 3 objectives were:

- Investigate the technically viability of extracting heat from the steam cycle of Light Water Reactor (LWR) based SMR plants to feed large-scale DH networks;
- Determine the extent of change required to SMR plant steam cycles to enable flexible heat extraction alongside flexible electricity generation;
- Determine whether the economic case for SMR heat extraction set out in Phases 1 and 2 is affected by the updated cost and performance assumptions resulting from this more detailed investigation;
- Assess whether the size and steam cycle thermal efficiency of a given SMR design is likely to materially affect the overall performance or economic case of a CHP SMR plant;
- Investigate a range of SMR plant cooling system options with varying water demands and determine whether these are likely to have a significant impact on plant performance;
- Understand the international precedents for nuclear powered DH networks and other large-scale thermal CHP plants feeding DH networks.

Approach

The engineering and cost modelling undertaken to achieve these objectives involved the use of a number of well-established proprietary industry standard software packages. These included Thermoflex (to model and analyse steam cycle heat balances and design SMR steam cycles), Plant Engineering and

Construction Estimator (PEACE) (for cost modelling of the equipment within the power plant boundary) and Advanced Flow Technology (AFT) Fathom (to calculate pressure drop and flow distribution in our DH network modelling).

Our approach involved the following principal tasks:

1. *Indicative SMR plant steam cycles* – This task used Thermoflex to develop indicative steam cycles for two notional 'electricity-only' SMR plants. The first plant assumes a small 50MW$_e$ SMR module with a relatively low thermal efficiency (~31%), referred to as 'Plant A'. The second plant assumes a larger 180MW$_e$ module with a higher thermal efficiency (~34%), referred to as 'Plant B'. The steam cycles designed for plants A and B have been designed to match some key features and performance characteristics with the information that technology developers NuScale and mPower have put into the public domain on their respective SMR designs. To do this, we reviewed publicly available non-proprietary information and designed the benchmark performance of our indicative steam cycle models to reflect the stated performance of these modules.
2. *Large-scale DH networks* – This task explored potential end-user requirements, operational parameters and heat losses of future city-scale DH networks. It involved developing a comprehensive software model of a representative DH network and working back from end-user requirements to define the steam extraction and heat supply temperatures required from a CHP SMR plant. This was necessary to design and fix the hardware configuration of the CHP steam cycle models in subsequent tasks.
3. *Design & performance of SMR heat extraction* – This task used Thermoflex to modify the electricity-only steam cycles developed in Task 1 to enable heat extraction to supply DH networks at a range of reactor loads. The modelling results provided key performance metrics (such as plant electrical derating during heat extraction) across different operational modes, allowing a comparison to be made between Plants A and B.
4. *Cooling system options* – This task assessed the viability and impact of alternative cooling methods should the solution assumed in the base case (Evaporative Cooling Tower (ECT)) become insufficient due to future water abstraction restrictions. The main alternative considered was use of an Air Cooled Condenser (ACC). We explored the impact of an ACC on plant configuration, equipment, performance, efficiency and operations.
5. *Cost assessment* – This task developed broad cost estimates for the incremental Capital expenditure (CAPEX) and Operational expenditure (OPEX) associated with CHP SMR plants compared to electricity only plants. This involved consideration of costs inside the plant boundary (such as equipment for steam extraction) and outside the boundary (such as buried DH pipe costs not associated with other types of thermal CHP plant). Cost comparisons were made between Plants A and B and between the different cooling options considered.
6. *Economic assessment of CHP SMRs* – This task revisited the economic case for SMR heat supply from Phases 1 and 2 of the ANT project. The economic model used previously was updated with cost and performance inputs obtained from the Phase 3 work. By generating a new set of economic metrics (Internal Rate of Return (IRR) and Levelised Cost of Electricity (LCOE)) we have drawn comparisons between Plants A and B.

7. *International review of nuclear CHP experience* – This involved a literature review and interviews to identify examples of nuclear and relevant non-nuclear CHP plants around the world. The purpose was to understand the precedents that exist for using nuclear heat in DH networks and identify relevant technical and operational lessons.

Conclusions

The engineering and cost modelling undertaken in Phase 3 of the ANT project validates the main finding of Phases 1 and 2 that SMRs could play an important role in the UK's future energy system by operating as Combined Heat and Power plants providing low-carbon heat to city-scale District Heating networks.

Extracting heat from the steam cycles of Light Water Reactor type SMR plants is technically feasible and relatively easy to implement. The indicative steam cycle solutions we developed can provide heat and power, simultaneously and independently. Furthermore, whilst our analysis has resulted in some amendments to our earlier assumptions regarding CHP plant performance and cost, these changes do not alter the central finding of our economic analysis that heat sales have the potential to significantly improve the economic attractiveness of SMR plants. This is because the costs of modifying an SMR steam cycle to allow for heat extraction are relatively small, whilst the revenues from heat sales are potentially large.

We also investigated whether or not the design philosophy adopted by SMR vendors – namely the size and efficiency of SMR module – makes a significant difference to the cost and performance of heat extraction. We conclude that it does not. The variations in cost and performance between our two indicative steam cycles were found to be minor.

As a result of these findings, and based on the ETI's energy system modelling that shows a potentially significant role for SMRs in the UK's future energy system, it will be important that any SMR design selected for regulatory assessment in the UK via the Generic Design Assessment (GDA) process is capable of heat supply. ***The evidence strongly suggests that should SMRs be deployed in the UK they should be configured 'CHP ready', even if they are initially required to supply electricity only***. 'CHP readiness' can be delivered for a small incremental cost (~£10/kW$_e$) and would ensure that SMR plants are ready for a subsequent upgrade to allow heat extraction to supply DH networks. If a First-of-a-Kind (FOAK) SMR is deployed in the UK, CHP readiness should be considered even if it cannot be demonstrated due to a lack of infrastructure/heat demand, to allow full demonstration of the concept.

We also suggest that consideration is given to ensuring that an SMR design entered into the UK licensing process is capable of other cogeneration applications suited to international markets, such as desalination. Whilst such applications were outside the scope of the ANT project, ensuring that a UK licensed SMR design is flexible enough to meet international requirements may be a material factor in achieving the economic case for SMRs, which rests on cost reductions driven by the factory production of large numbers of identical components.

If the UK does embark on a strategy for decarbonising heat that involves the use of nuclear powered DH networks, it will not be without precedent. Our review of relevant international examples indicates that the use of a nuclear reactor as a CHP plant is a proven and viable technological partnership which has been successfully used by a number of countries for many decades, including Switzerland and Russia. In addition, large city-scale non-nuclear DH networks such as Warsaw, Copenhagen and Helsinki have provided reliable heating to 100,000's of people for many decades.

Finally we conclude that plant cooling technologies that use very little water (such as an ACC) are technically feasible and could be retrofitted to existing SMR plants that were initially built with only Mechanical Draught ECTs. Such hybrid solutions have the advantage of exploiting the higher steam cycle efficiency of the ECT during times of sufficient water, and of being able to continue operating with the ACC when water is scarce.[1]

This finding is important because a number of potential SMR sites identified in the Power Plant Siting Study (PPSS) are inland. If more frequent and severe droughts in the future result in restrictions on water abstraction rates from inland water sources then the ability to switch SMR plants to cooling methods that require less water could be an important factor supporting long-term deployment and building in resilience to a changing climate.

Depending on SMR location and potential future water constraints (i.e. not coastal or rivers locations where extraction is a small percentage of the total flow), we suggest that consideration is given to the potential risk of constrained plant operation/ loss of revenue, and how this could be mitigated by building the SMR plant 'ACC ready'. This would involve little additional cost but require a larger site and a steam cycle configuration with space for subsequent modification.

By validating the findings of Phases 1 and 2 of the ANT project, we conclude that SMR heat supply could be a significant benefit to both plant economics and the decarbonisation of the UK's energy supply. The cost of designing and building SMR plants ready to supply future DH networks is relatively small, but the benefits are potentially large. This report may have relevance for organisations considering the potential deployment of SMRs into a future UK low carbon energy systems.

[1] These hybrid solutions assumed cooling water would still be available for safe reactor shutdown.

1 Introduction

Small Modular Nuclear Reactors (SMRs) are defined by the International Atomic Energy Agency as advanced nuclear power reactors with a maximum electrical output below $300MW_e$. They are considered to have characteristics that distinguish them from conventional large reactors, such as modular design with pre-fabrication in offsite factories and the potential for multiple reactors to be deployed together at the same site to form larger power plants. Many SMRs are also being designed as 'integral' units, where all key primary system components are integrated within a single pressure vessel and surrounded by a containment structure. A number of countries and companies are at different stages in the development of SMR technology.

If the technology is successfully developed, proponents claim that SMRs have the potential to offer a number of benefits to the UK's future energy system. These include the reliable provision of low-carbon electricity and heat, flexible deployment and the opening up of new sites closer to demand. There could also be economic benefits to countries that establish themselves at the forefront of technology development and export. But despite this potential, there are currently significant uncertainties relating to the future costs and performance of SMR technologies and the suitability of different designs for the UK, as well as market and investor uncertainty.

1.1 System Requirements for Alternative Nuclear Technologies project

As a result, the System Requirements for Alternative Nuclear Technologies (ANT) Project was commissioned by the Energy Technologies Institute (ETI) and undertaken in three phases between September 2014 and March 2016. The overall purpose of the ANT project was to frame the UK energy system requirements for a small generic nuclear power plant with an output of up to $300MW_e$. Mott MacDonald was appointed by the ETI to undertake this work.

Phases 1 and 2 involved a wide-range of tasks aimed at understanding the role that SMRs could play in the UK's future energy system and defining the functional and economic parameters for SMRs to fulfil this role. This work, which was completed in August 2015, covered a range of disciplines and topics including energy markets and economics, nuclear engineering, district heat (DH) network development and operation, power plant delivery, environmental impact and infrastructure financing. It was underpinned by a number of high-level engineering assumptions about the costs and performance of a generic SMR module and steam cycle. These assumptions were based on Mott MacDonald's experience of thermal steam cycles with heat offtake such as desalination. Consideration of issues relating to public acceptability and the Generic Design Assessment (GDA) process was outside the scope of the project. Mott MacDonald appointed Rolls Royce as subcontractor for Phases 1 and 2 of the project, to provide specialist input relating to nuclear engineering.

An overview of the Phase 1 and 2 scope and findings is provided below, with more detail given in Appendix A. At the time of writing, the Project Summary Report for Phases 1 and 2 is also available on the ETI website at: www.eti.co.uk/wp-content/uploads/2015/10/ANT-Summary-Report-with-Peer-Review.pdf.

Owing to the significance of the Phase 1 and 2 findings the ETI retained Mott MacDonald to undertake Phase 3. The objective of Phase 3 was to validate the assumptions and expand the findings of our earlier work by undertaking further engineering and cost analysis. This analysis involved using proprietary industry standard software packages to undertake thermo-dynamic modelling of SMR plant steam cycles and cost modelling of plant equipment. This report represents the culmination of our Phase 3 work.

1.2 Phases 1 and 2

Phases 1 and 2 involved a Functional Requirements workstream and a Business Case workstream. Each workstream was made up of a number of tasks defined by the ETI.

The Functional Requirements workstream focussed on determining what SMRs will need to do from a technical perspective to be of value to the UK's future energy system. Some of the tasks were aimed at understanding what SMRs might realistically offer in terms of energy services, commercial readiness and long-term deployment rates. Other tasks explored the needs of the energy system, such as low-carbon heat for DH network energisation, technology capable of being located on a diverse range of sites close to demand, and the compatibility of nuclear power plant fuel cycles with existing infrastructure. These pieces of analysis fed into the development of key SMR technical requirements.

The Business Case workstream focussed primarily on what SMRs will need to achieve from an economic perspective to be of value to the UK's future energy system. The main component was the economic appraisal, which served two functions. First, and most important for the ANT project, it estimated broad 'target costs' for SMRs – i.e. the *maximum* amount an SMR power plant could cost whilst still delivering commercial rates of return to investors under future market conditions. Second, and less important for the ANT project, the appraisal developed an indicative scenario for actual SMR costs by making high-level estimates of future CAPEX and OPEX for Light Water Reactor (LWR) type SMRs and how these might reduce over time. This scenario was compared with target costs to provide an initial view on the relative viability of different SMR service offerings, e.g. 'electricity-only SMR plant versus a Combined Heat and Power (CHP) SMR plant.

The conclusions of these two workstreams were presented in the Phases 1 and 2 Project Summary Report referenced above. A key conclusion was that SMRs have the potential to operate as CHP plants providing low-carbon heat to city-scale DH networks in the future, with the additional revenues from heat sales improving SMR plant economics. This conclusion is based on the starting assumptions (defined by the ETI) that unabated gas will need to be phased out by mid-century in order for the UK to meet its decarbonisation targets, and that large-scale DH networks will be required to cost effectively decarbonise heat in densely populated urban areas.

The analysis for Phases 1 and 2 was underpinned by a number of engineering assumptions about the costs and performance of a generic SMR module and steam cycle. These assumptions were developed by the project team, based on the combined experience of Mott MacDonald and Rolls Royce personnel. These assumptions were subject to an external peer review process that involved input from the Politecnico di Milano University, leading academics in the field of SMR economics, and the consultancy firm Atkins. We did not undertake any detailed engineering investigation or thermo-dynamic modelling at this stage, or use performance and cost data associated with any specific SMR designs.

Our Phase 1 and 2 work also concluded that it is likely to be feasible for a small number of standardised SMR modules and plug-in systems to be configured at the site level to provide a range of energy services. This implies that the same core plant design could be deployed to provide (only) electricity at some sites and adapted to provide CHP at other sites. This conclusion is important because standardised modules are considered a prerequisite for realising the economics benefits of factory production and standardised processes that SMRs could offer.

1.3 Phase 3 objectives

Due to the significance of the Phase 1 and 2 findings, the ETI retained Mott MacDonald to undertake further engineering investigations into the potential role of SMRs in the UK's future energy system. This third phase of work (Phase 3) is the subject of this report. Its overall purpose is to validate and expand the findings of ANT project by focusing on two overarching areas:

The first area is the technical and economic viability of extracting heat from SMRs for supplying DH networks. In particular, we consider whether the efficiency and size of an SMR module has a significant impact on heat extraction. We also seek to understand whether heat extraction requires fundamental changes to SMR steam cycle design or can be accommodated relatively easily with only minor incremental alterations. This is important given the requirement for SMRs to be standardised modules deployable in a range of contexts.

The second area is the flexibility of SMR plants to adapt to changing environmental and regulatory conditions in the future. SMRs offer the prospect of opening up a more diverse range of sites than large reactors, including inland sites close to rivers or lakes. However the timescales associated with SMR deployment (alongside projected climatic changes) mean that drought or other drivers could restrict the amount of water available for extraction from these sources. The ability to switch SMR plants to cooling methods that require less water could therefore be an important factor supporting long-term deployment.

The specific Phase 3 objectives are:

- Investigate the technically viability of extracting heat from the steam cycle of LWR based SMR plants to feed large-scale DH networks;
- Determine the extent of change required to SMR plant steam cycles to enable flexible heat extraction alongside flexible electricity generation;
- Determine whether the economic case for SMR heat extraction set out in Phases 1 and 2 is affected by the updated cost and performance assumptions resulting from this more detailed investigation;
- Assess whether the size and steam cycle thermal efficiency of a given SMR design is likely to materially affect the overall performance or economic case of a CHP SMR plant;
- Investigate a range of SMR plant cooling system options with varying water demands and determine whether these are likely to have a significant impact on plant performance;
- Understand the international precedents for nuclear powered DH networks and other large-scale thermal CHP plants feeding DH networks.

It is intended that the conclusions from this Phase 3 work will be available to update the ETI's portfolio of project knowledge in relation to the deployment of nuclear technologies within a UK low carbon energy system. It is anticipated that this may be of value to the ETI's members.

1.4 Phase 3 scope

The scope of work for Phase 3 involved the following principal tasks:

1. ***Indicative SMR plant steam cycles*** – This task used thermodynamic modelling software to develop indicative steam cycles for two notional 'electricity-only' SMR plants. The first plant assumes a small 50MW_e SMR module with a relatively low thermal efficiency (~31%), referred to throughout the report as 'Plant A'. The second plant assumes a larger 180MW_e module with a higher thermal efficiency (~34%), referred to as 'Plant B'. We have designed steam system cycles for plants A and B so they have some key common features and performance characteristics with the information that NuScale and mPower have put into the public domain on their respective SMR designs. To do this, we reviewed publicly available non-proprietary information and designed the benchmark performance of our indicative steam cycle models to reflect the stated performance of these modules as closely as reasonably possible.

2. ***Large-scale DH networks*** – This task explored potential end-user requirements, operational parameters and heat losses of future city-scale DH networks. It involved developing a comprehensive software model of a representative DH network and working back from end-user requirements to define the steam extraction and heat supply temperatures required from a CHP SMR plant. This was necessary to design and fix the hardware configuration of the CHP steam cycle models used in subsequent tasks.

3. ***Design & performance of SMR heat extraction*** – This task used thermodynamic modelling software to 'upgrade' the electricity-only steam cycles developed in Task 1 to enable heat extraction to supply DH networks at a range of reactor loads. The modelling results provided key performance metrics (such as plant electrical derating during heat extraction) across different operational modes, allowing a comparison to be made between the two notional SMR plants (Plants A and B). The outputs of this task also provide an indication of the extent of changes required to allow heat extraction from SMR steam cycles.

4. ***Cooling system options*** – This task assessed the viability and impact of alternative cooling methods should the solution assumed in the base case (Evaporative Cooling Tower (ECT)) become inadequate at a given site due to future restrictions on water availability. The main alternative considered was use of an Air Cooled Condensers (ACC). We explored the impact an ACC would have on plant configuration, equipment, performance, efficiency and operations. We also considered, but in less detail, the alternatives of fin fan coolers and the long distance piping of seawater to inland plants from coasts and estuaries.

5. ***Cost assessment*** – This task developed broad cost estimates for the incremental Capital Expenditure (CAPEX) and Operational Expenditure (OPEX) associated with CHP SMR plants compared to electricity only plants. This involved consideration of costs inside the plant boundary (such as equipment for steam extraction) and outside the boundary (such as buried DH pipe costs not associated with other types of thermal CHP plant). Cost comparisons were made between Plants A and B and between the different cooling options considered.

6. ***Economic assessment of CHP SMRs*** – This task revisited the economic case for SMR heat supply from Phases 1 and 2 of the ANT project. The economic model used previously was updated with cost and performance inputs obtained from the Phase 3 work. By generating a new set of economic metrics (Internal Rate of Return (IRR) and Levelised Cost of Electricity (LCOE)) we have drawn comparisons between Plants A and B.

7. ***International review of nuclear CHP experience*** – This task involved a literature review to identify examples of nuclear and relevant non-nuclear CHP plants around the world. The purpose was to understand the precedents that exist for using nuclear heat in DH networks and identify any relevant technical and operational lessons for SMR plants. This was supported with targeted interviews.

Further detail on the methodologies used for these tasks is provided in the relevant sections of this report.

1.5 Modelling software

Much of the work carried out in Phase 3 required use of the following well established industry software packages:

- Thermoflex - this package was used to model and analyse steam cycle heat balances and to design SMR steam cycles;
- Plant Engineering and Construction Estimator (PEACE) - this plant engineering and cost estimation tool was used for cost modelling of the equipment within the power plant boundary;
- AFT Fathom - this fluid dynamic simulation software is used to calculate pressure drop and flow distribution in liquid piping systems, and was used here for the DH network modelling;
- Revit - this design software is used to provide 3D design and visualisation of potential buildings by utilising the programmes site planning functionality. It was used here for 3D plant layout designs;
- Microstation - to create the 3D models and diagrams for DH network tunnelling.

1.6 Assumptions

The analysis covered here required making a number of assumptions across a range of areas, including DH network parameters, SMR module performance and steam cycle design. Wherever possible these assumptions were based on credible public domain sources, referenced throughout this report.

For example we used publicly available non-proprietary information published by NuScale and mPower when developing our notional SMR steam cycles for Plants A and B, and then confirmed these as credible through our own modelling. Where such information was not available or credible, we drew on the expertise from across Mott MacDonald to make assumptions which were then agreed with the ETI. In other instances (e.g. some DH network parameters), information was directly provided by the ETI based on work being undertaken elsewhere.

More detail on specific assumptions is provided in the relevant parts of this report.

1.7 Key definitions

District heating refers to a system of centralised heat generation that is distributed to customers (households, business and industry) via a network of pipes and a transport medium (steam or water). DH systems can operate at both large and small scales, from city-wide networks such as those found in Copenhagen and Helsinki to local networks serving single large buildings or urban developments.

Benefits of DH networks include:

- The provision of reliable and cost effective heat where domestic gas supplies/boilers are not available and other fuels are expensive or dirty;
- The avoidance of the need for individual fuel supplies and combustion exhausts from individual dwellings;
- The potential for efficient use of energy by using mostly waste heat from thermal power plants or other sources;
- The potential to use low-carbon sources of heat.

CHP generation is an approach that can achieve high efficiencies and lowered emissions for the utilisation of a fuel source. Most nuclear power stations in the world achieve quite low thermal efficiencies with only around one third of core reactor heat turned into electricity. The remaining energy is usually expelled as waste heat into adjacent water sources, meaning there is the potential for these plants to be used for cogenerating heat as well as power.

1.8 Report structure

This Phase 3 report provides a detailed overview of all work undertaken for Phase 3. The structure of the report is provided in Table 1.1 below, along with the key questions addressed in each section.

Table 1.1: ANT Phase 3 report structure

Section	Scope	Key questions addressed
Executive Summary		
1. Introduction		
2. Indicative steam cycles for electricity-only plants	Steam cycle for Plant A Steam cycle for Plant B Full and part load performance	What would steam cycles for electricity-only SMR plants look like?
3. Large-scale DH networks	DH network layout End-user characteristics Piping parameters Results of modelling	What heat supply requirements could future large-scale DH networks place on SMR plants?
4. SMR heat extraction	Heat extraction solutions for CHP SMRs CHP performance in different operational modes Comparison between two notional SMR plants 'CHP readiness' Indicative plant layouts & equipment lists	How could plant steam cycles be modified to allow heat extraction for DH networks in a range of different flexible operational modes? How does the size and efficiency of an SMR module impact the performance of a CHP plant? How do the Phase 3 performance metrics compare with assumptions made in ANT phases 1 and 2?
5. Cooling system options	Mechanical draught Evaporative Cooling Towers (ECTs) (with water supply from a nearby river) Air cooled condensers (ACCs) Mechanical draught ECTs (with seawater supply) Dry cooling towers	What are the alternative cooling methods to mechanical draught ECTs? What would be the impact on performance of using air cooled condensers?
6. Cost assessment	CAPEX increment for CHP SMRs CAPEX increment for air cooled condenser CAPEX for heat mains (outside plant boundary) OPEX increment	What is the cost increment for CHP SMR plants compared to power only SMR plants? What is the impact of the cooling system on costs? How much will the heat mains between plant and DH network cost?
7. Economics of CHP SMRs and alternative plant cooling systems	Phases 1 and 2 economic appraisal CHP SMRs revisited Alternative plant cooling systems	Do the updated cost and performance figures from the above analysis affect the economic case for CHP SMRs set out in Phases 1 and 2? Is there a material difference in the economic case of SMRs of different sizes and efficiencies? What is the impact of an ACC?
8. Global review of nuclear and large-scale CHP	Large-scale DH networks worldwide Nuclear powered CHP: examples and lessons	What are the relevant international examples of large-scale DH and nuclear powered CHP? What technical and operational issues have large CHP plants encountered elsewhere and what relevant lessons can be drawn for SMRs?
9. Conclusions	Summary of key findings Implications for wider work into SMRs	What are the key findings in terms of the technical and economic viability of SMR heat extraction? Does the size and efficiency of an SMR have a material effect on cost and performance? Do the Phase 3 findings support the idea that standardised SMR modules can be deployed in a diverse range of contexts to provide a range of energy services in changing environmental conditions?

Source: Mott MacDonald

2 Electricity-only SMR steam cycles

We used proprietary thermo-dynamic modelling software (Thermoflex) to develop indicative steam cycles for two notional electricity-only LWR SMR plants (i.e. not designed for heat extraction). The steam cycle for Plant A assumed a small SMR module (50MW_e) with a relatively low thermal efficiency of 31% approximating to the technical and performance characteristics of NuScale technology. The steam cycle for Plant B assumed a larger SMR module (180MW_e) with a higher thermal efficiency of just under 34% approximating to the technical and performance characteristics of mPower technology.

The purpose of this work was to develop two credible functional SMR steam cycle models that have been benchmarked to confirm they provide reasonable representations of different SMR technologies. These models were subsequently used as a basis to consider the modifications required under the study scope – i.e. to allow for heat extraction (Section 4).

2.1 Steam cycle parameter assumptions

To develop indicative steam cycles for Plants A and B, wherever possible we used assumptions derived from credible non-proprietary information in the public domain. Where such information was not available, we made our own assumptions and agreed these with the ETI. The assumptions used are shown in Table 2.1 below.

The performance of Plants A and B was modelled using the following indicative UK inland ambient condition assumptions: 12°C dry ambient temperature, 60% relative humidity and 1.01 bara ambient pressure.

Table 2.1 Assumptions used to develop steam cycle models

Item	Plant A (approximation of NuScale)		Plant B (approximation of mPower)	
	NuScale public domain information	**Mott MacDonald assumptions / comments**	**mPower public domain information**	**Mott MacDonald assumptions / comments**
Configuration	No reheat		The steam cycle includes a moisture separator/reheater	
Gross power output	50MW$_e$		180 MW$_e$ (water cooled) 155 MW$_e$ (air cooled)	mPower quotes a gross power output of 155MW$_e$ for an air cooled plant. Based on our experience, we would expect a derating for air cooled plant to be less than the one quoted by mPower (except if the plant operates in severe ambient conditions).
Net power output	47.5MW$_e$, equivalent to an auxiliary load of 4.5% of gross power	Based on NuScale's stated output of 570MW$_e$ net for 12 modules.	None	An output from the model was that the auxiliary load would be 4.9% of the gross power, and a net power of 171.7MW$_e$.
Thermal efficiency (gross heat to gross power)	31.25%	Based on NuScale's stated thermal power rating for core reactor of 160MW$_{th}$ and gross electrical output of 50MW$_e$.	33.96%	Based on mPower's stated thermal power rating for core reactor of 530MW$_{th}$ and gross electrical output of 180MW$_e$.
Initial steam conditions Pressure Temperature Flowrate	100% core output: 500psia/34.5bara 580F/304.4°C 535,000lb/hr/67.4kg/s 20% core output: 640psia/41.4bara 550°F/287.8°C	Steam flow rate at 20% has been estimated via modelling. In terms of the shape of the performance profile between 20% and 100% reactor thermal output: • We assumed that the temperature of the initial steam reduces with core reactor output in a linear relationship. • We assumed that the pressure of the initial steam has a square law relationship with core reactor output. • Validation of these assumptions is contained within the report sections below provided in Section 2.2 below.	100% output 571F/299°C at 825 psia/57 bara Part load output Not available Shape of curves between minimum-100% have not been provided	Reactor performance at minimum load and part load is not provided. We estimated the inlet steam pressure and temperature at part load for mPower by assuming that the inlet steam pressure (and temperature) at part load for mPower technology decreases (and increases) at the same rate assumed for NuScale technology.
Cooling medium type	None	The NuScale steam cycle performance figures are based on an ECT.	None	We assumed the mPower steam cycle will use an ECT.
ECTs performance	None	A cooling water temperature approach of 5°C to the wet bulb temperature and a condenser temperature rise of 12°C was assumed. Reducing the cooling water temperature difference	None	The same assumptions were made regarding the performance of ECTs for both NuScale and mPower SMR technology.

Item	Plant A (approximation of NuScale)		Plant B (approximation of mPower)	
		between the cold water leaving the tower and the wet bulb temperature of the air will require a large contact area between the cooling water and the ambient air in the tower, increasing both the size and cost of the cooling tower. Reducing the temperature rise through the condenser requires a larger cooling water flow rate and hence larger and more expensive pumps and pipes, as well as greater pump power consumption.		
Condensing pressure		Assumed to be 0.07 bara.		Assumed to be 0.07 bara.
Feed heating stages	Three	NuScale steam cycle performance figures suggest three feed heating stages.	Four (one High Pressure (HP) feedwater heater, one deaerator, two Low Pressure (LP) feedwater heaters)	
Feedwater Temperature /pressure	100% core output: 300°F/148°C 600psia/41.4bara 20% core output: 200°F/93°C	We have estimated feedwater extraction points (pressure, temperature, flowrate) in order to have the highest steam cycle efficiency and to deliver the feedwater temperature stated by NuScale.	100% core output 414 F/212°C 2.12 Mlbm/hr = 267.1 kg/s 295 °C Part load output: Not available	We estimated feedwater extraction points (pressure, temperature, flowrate) in order to have the highest steam cycle efficiency and to deliver the feedwater temperature stated by mPower.
Steam Turbine (ST) isentropic efficiency	None	We have assumed a ST isentropic efficiency of 90% based on our experience of ST units of a similar size.	None	It is expected that the mPower ST will have an isentropic efficiency higher than NuScale due its larger size.
Moisture separator reheater	Not applicable	The NuScale information available in the public domain shows no reheating stage.	The mPower concept includes a moisture separator reheating with live steam extraction	It was assumed that the moisture removal equipment has an efficiency of 90% and the reheater has a Terminal Temperature Difference of 5°C.

Source: Mott MacDonald

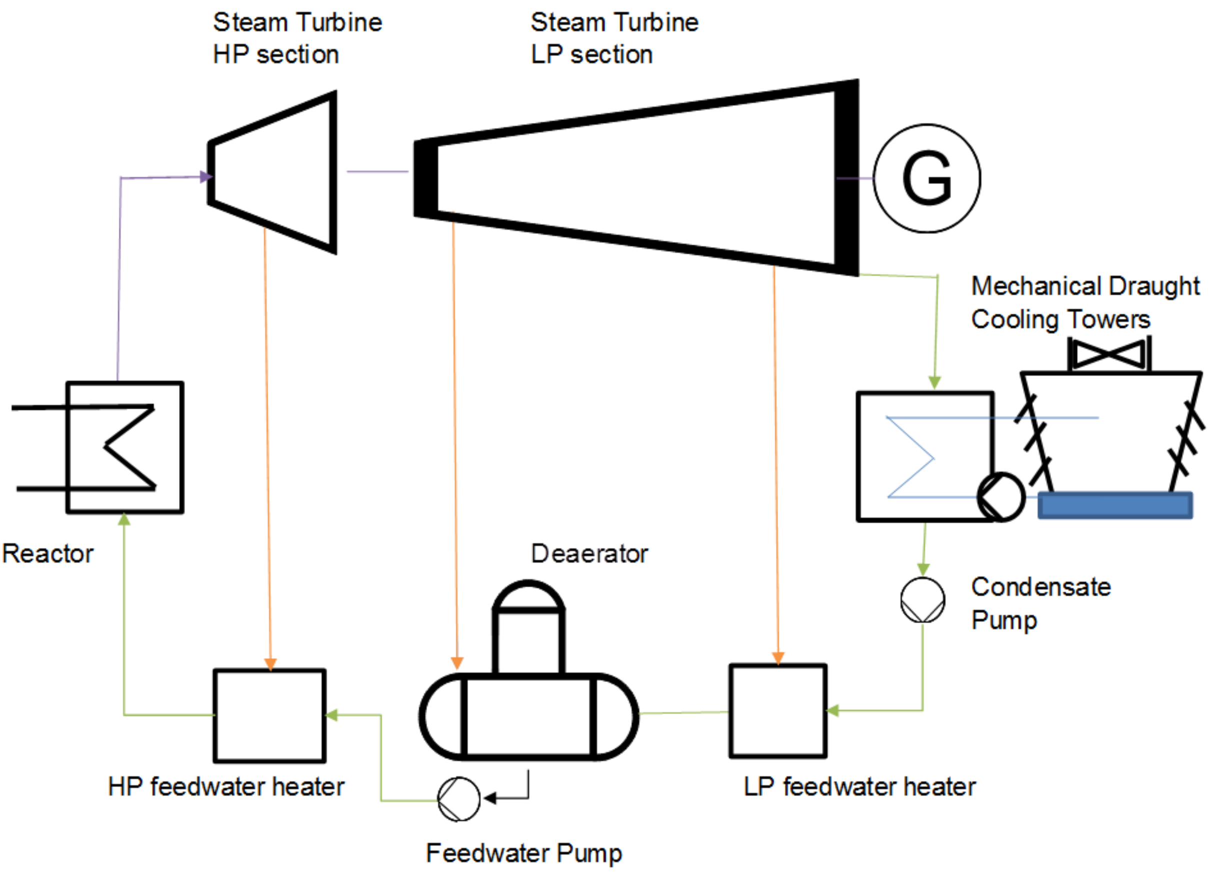
The main publicly available sources of information on the NuScale and mPower SMR technologies are provided in Appendix B. This information was used to identify where assumptions needed to be made to develop the base case SMR steam cycle models.

2.2 Plant A steam cycle

The steam cycle for Plant A (shown in Figure 2.1) was designed with three feed heating stages, based on publicly available information on the NuScale steam cycle. This provides a feedwater temperature of 148°C at full reactor load. Steam generated by the reactor is expanded in a condensing non-reheat steam turbine. The steam turbine (ST) has three extraction points which feed a high pressure (HP) feedwater heater, an intermediate pressure (IP) feedwater heater (also called a deaerator) and a low pressure (LP) feedwater heater. We estimated feedwater extraction point parameters (i.e. pressure, temperature, flowrate) to achieve the highest steam cycle efficiency and deliver the feedwater temperature stated by NuScale.

As suggested in NuScale's documentation, warm water from the condenser is cooled in Evaporative Cooling Towers (ECTs). We have assumed that the make-up water to replace water lost in the cooling towers (due to drift, evaporation and blowdown) will be extracted from a nearby river.

Figure 2.1: Indicative steam cycle for Plant A (electricity only)



Source: Mott MacDonald

2.2.1 Plant A performance at full and minimum reactor load

Table 2.2 shows the performance parameters of Plant A (electricity only) at 100% and 20% reactor outputs, based on our modelling results. Heat and mass balances are provided in Appendix C.

Table 2.2: Performance parameters of Plant A (electricity only) at 100% and 20% reactor loads

	100% reactor load	20% reactor load
Feedwater temperature (°C)	148	96
Gross power at generator terminals (MW_e)	50	6.7
Auxiliary Load (MW_e)	2.4	1.1
Auxiliary Load (% of gross power)	4.7%	17.17%
Net Power (MW_e)	47.7	5.6
Quality of steam at ST exhaust	82.9%	89.7%
Heat input (MW_{th})	159.5	31.8
Gross Electrical Efficiency	31.4%	21.1%
Net Electrical Efficiency	29.9%	17.5%

Source: Mott MacDonald

At 100% reactor load our modelling of Plant A produces:
- A gross power of 50MW_e which matches the figure quoted by NuScale;
- An auxiliary load of 4.7% of gross power output which is line with the figure of 4.5% of gross power output quoted by NuScale;
- A gross electrical efficiency of 31.4% compared to 31.25% quoted by NuScale. Our model's slightly higher figure is explained by the reactor thermal output calculated by Thermoflex (159.5MW_{th} producing steam from 148°C to 304.4°C at 34.5bara compared to NuScale's stated 160MW_{th} reactor output). This difference and its effect on subsequent analysis is considered negligible.

At 20% reactor load our modelling of Plant A produces:
- A feedwater temperature of 96°C, close to the value of 93°C stated by NuScale;
- A gross power of 6.7MW_e for a gross electrical efficiency of 21.1%.

In general there is a close correlation obtained between our modelling outputs for Plant A and the performance figures presented by NuScale in their documentation.

2.2.2 Part load performance profile of reactor steam generator

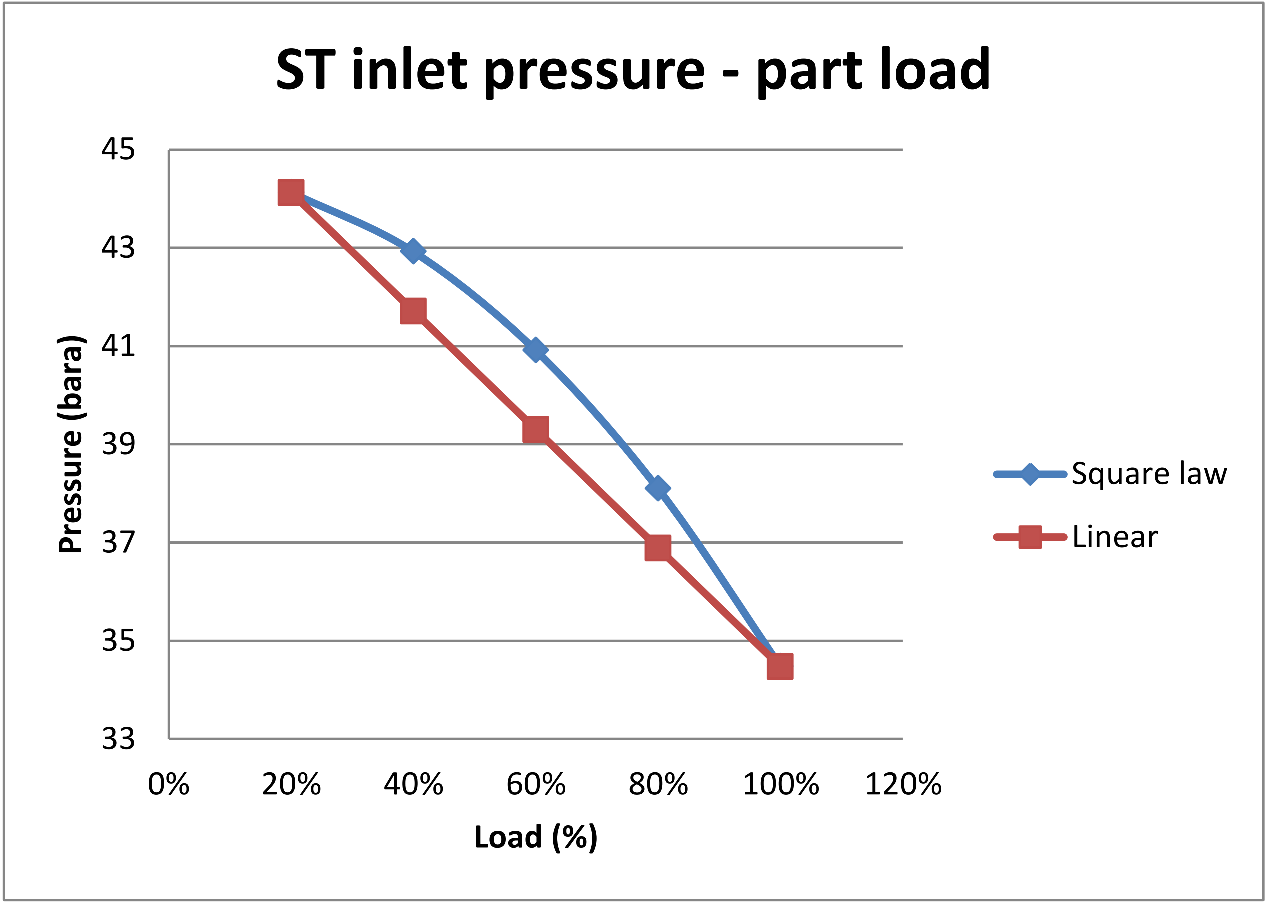
The shape of the performance profile curve between 20% and 100% reactor thermal output, and how performance changes as temperature and pressure changes, is not provided in NuScale's public domain literature.

Typically for a constant mass flow, an increase in heat load will increase the outlet temperature proportionally. Therefore it was assumed that an increase in reactor output will increase the temperature of the initial steam in a linear relationship. In terms of pressure drop, the relation with heat input is less obvious. To determine whether the shape of the profile is important in the context of heat extraction, we analysed the reactor steam generator performance profile between the two known operating points (20% and 100% reactor output) for the following sets of pressure drop assumptions:

- Linear pressure drop through the steam generator;
- Square law increasing pressure drop through the steam generator.

These two assumption sets are illustrated in Figure 2.2.

Figure 2.2: Potential assumptions for part load reactor steam generator performance profile



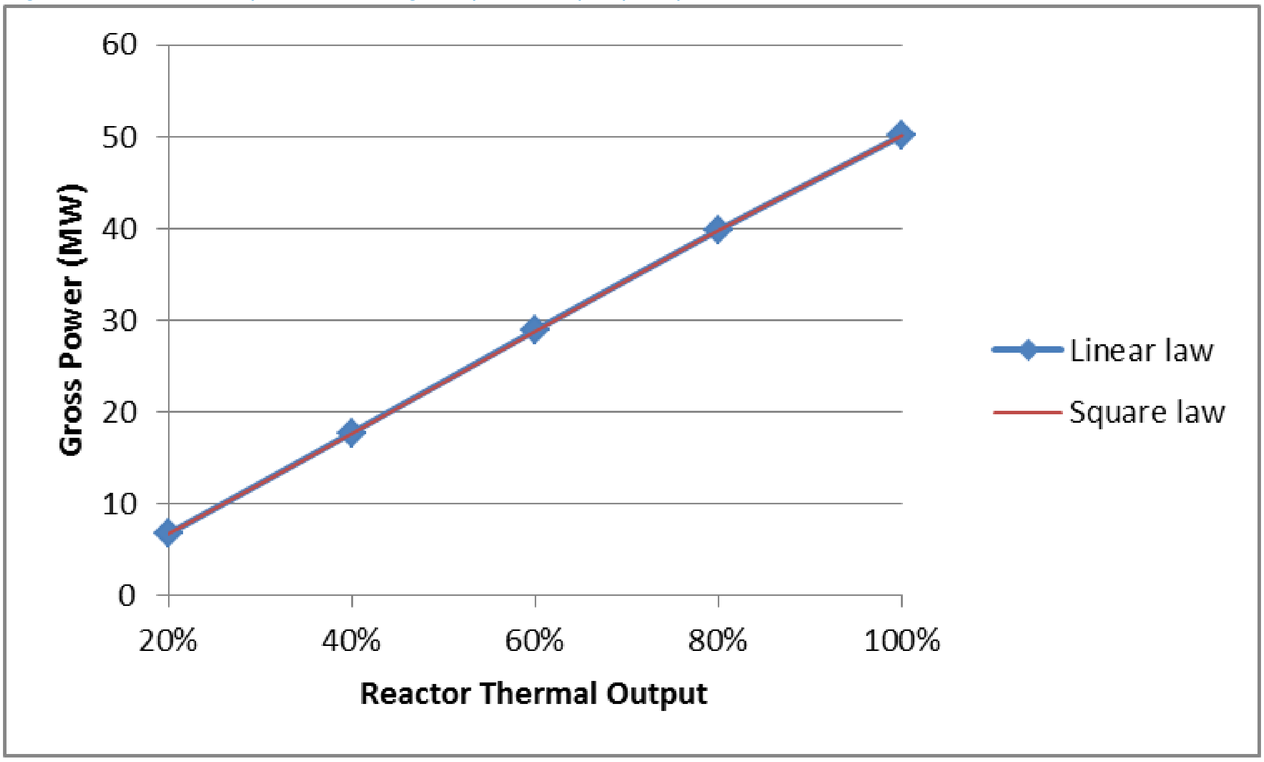
Source: Mott MacDonald

We tested the two assumptions sets at three intermediate operating points:

- 40% reactor thermal output;
- 60% reactor thermal output;
- 80% reactor thermal output.

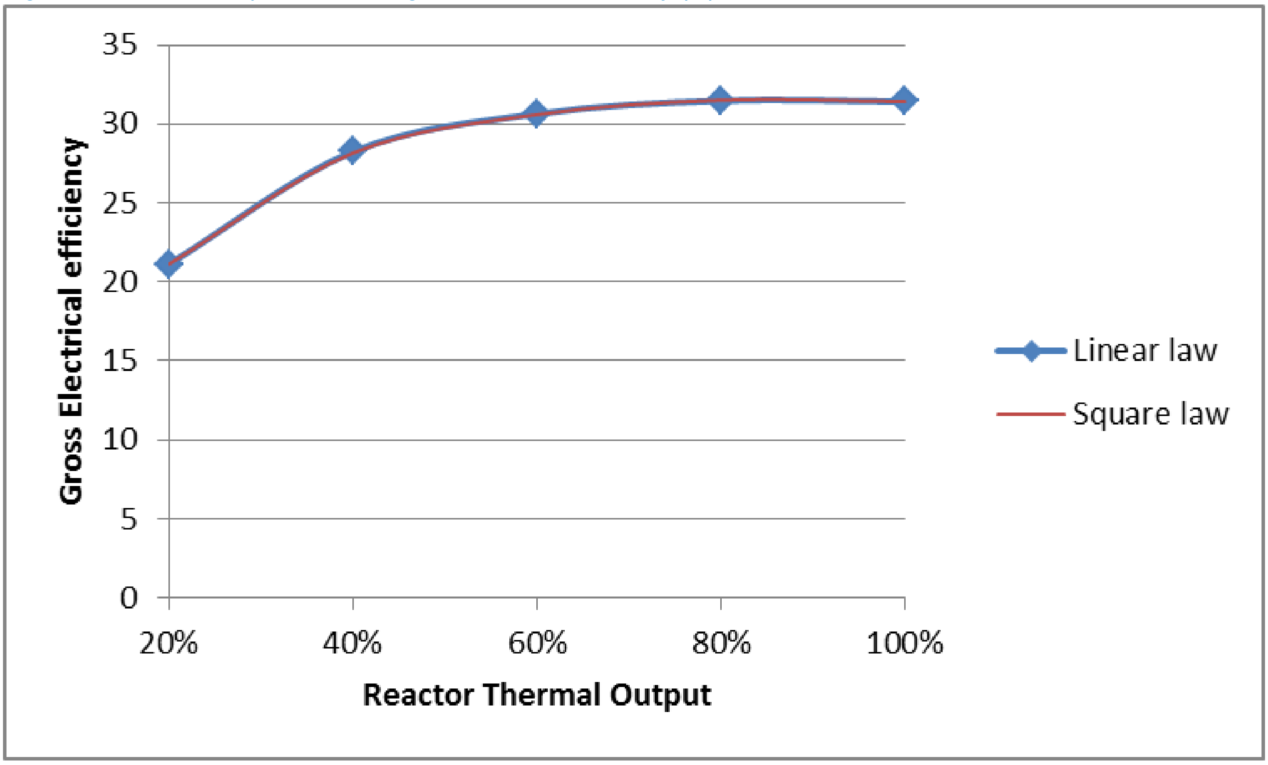
The results are shown in Figure 2.3 and Figure 2.4. They show that the gross electrical efficiency and gross power output for linear and square law pressure drop assumptions are so similar that they appear to overlap. This suggests there are minimal differences in thermal and power output behaviour between the two sets of pressure drop assumptions. Overall, we consider the square law pressure drop assumption to be more rational, and have used this as the basis for our part load modelling of Plants A and B.

Figure 2.3: Part load performance - gross power output (MW_e)



Source: Mott MacDonald

Figure 2.4: Part load performance - gross electrical efficiency (%)



Source: Mott MacDonald

The full results for the part load modelling of Plant A are shown in Table 2.3.

Table 2.3: Plant A (electricity only) - Performance from 20% to 100% reactor load

		Full Power				Part Load
Reactor Output		**100%**	**80%**	**60%**	**40%**	**20%**
	MW_{th}	159.73	126.31	94.07	62.61	31.81
Live steam						
Temperature	degC	304.4	300	296	292	288
Pressure	bara	34.5	38	41	43	44
Flow	kg/s	67.5	53.1	39.2	25.7	12.7
Feedwater						
Temperature	degC	148	139.5	129.5	116.3	96
Performance						
Gross Power Output	MW_e	50	40	29	18	6.7
Gross electric efficiency		31.38%	31.51%	30.59%	28.15%	21.14%
Net electric power	MW_e	48	38	27	16	6
Net electric efficiency		29.90%	29.87%	28.72%	25.84%	17.51%
Auxiliary load (% of gross power)		4.71%	5.19%	6.12%	8.24%	115.48%

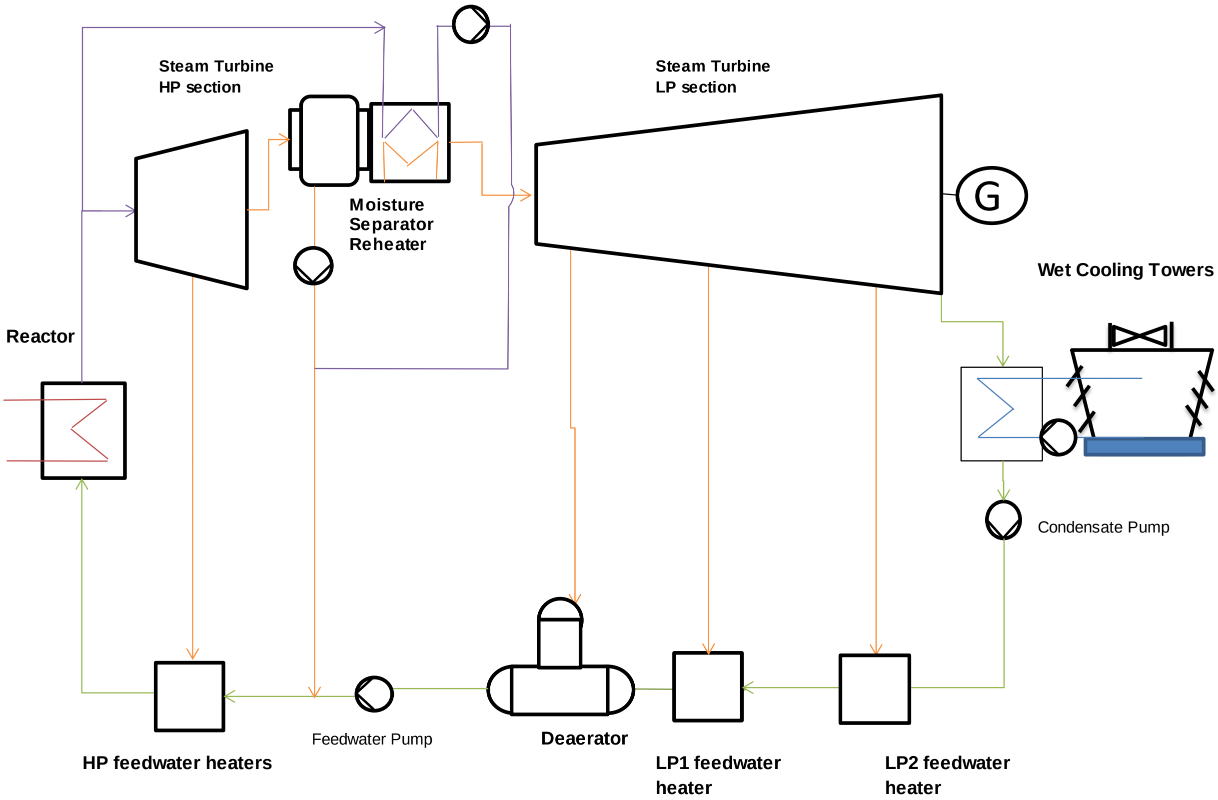
Source: Mott MacDonald

2.3 Plant B steam cycle

The steam cycle for Plant B has been designed to include a fourth feed heating stage, providing a feedwater temperature of 212°C at full reactor load. A Moisture Separator Reheater (MSR) is also included – a feature which is not part of the Plant A steam cycle. The MSR removes moisture from the HP turbine exhaust steam in order to protect the LP turbine from erosion and damage. After moisture removal, the MSR reheats the dry steam by condensing extraction and/or live steam before the reheated steam is admitted to the LP turbine. The MSR can contain one or two stages of reheat – typically using live steam as the heating system for the former and live steam as well as extraction steam for the latter.

We have assumed that reheating is carried out in one stage by condensing live steam as heating steam. As shown in our modelling results in Table 2.4, the moisture content of the steam at the end of the steam turbine is within our expectations and does not justify a second stage of reheat.

Figure 2.5: Indicative steam cycle for Plant B (electricity only)



Source: Mott MacDonald

Overall, the higher steam cycle efficiency of Plant B is achieved by the combination of:

- Reactor production of live steam at a higher pressure (57bara/299°C versus 34.5bara/304.4°C for Plant A);
- A larger and more efficient steam turbine (180 MW_e gross versus 50MW_e gross for Plant A);
- The addition of a MSR, located between the HP and LP steam turbine sections.

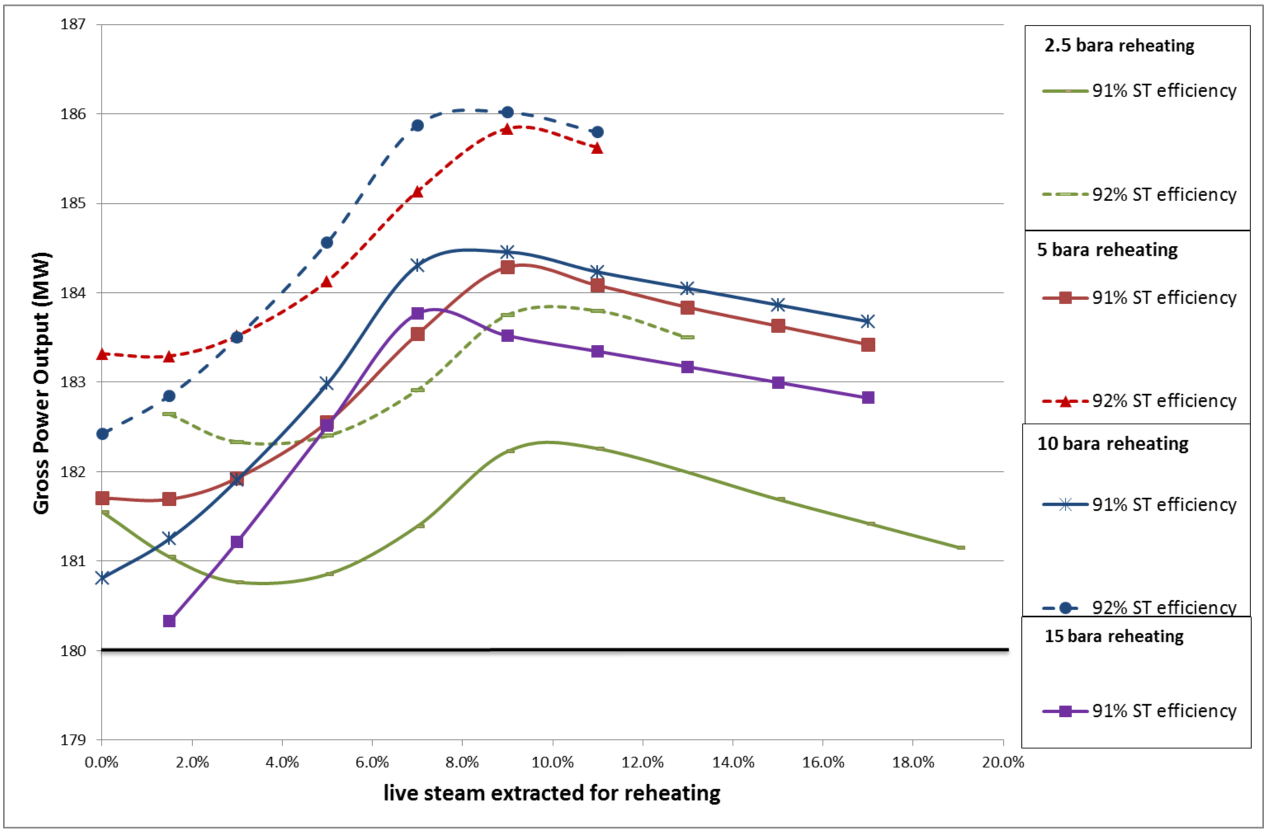
2.3.1 Replicating mPower's stated performance

Developing the electricity only steam cycle shown in Figure 2.5 involved an iterative modelling process using Thermoflex. By varying design parameters of the steam cycle (ST efficiency, level of reheating pressure and quantity of live steam extracted for reheating) and MSR, our model achieved a level of performance broadly in line with mPower's stated levels. This analysis was not needed for Plant A because the NuScale steam cycle is less complicated and does not include an MSR.

Figure 2.6 below summarises the thermal modelling results obtained when key steam cycle parameters are varied. It shows the indicative gross power output Plant B at:

- 91% and 92% ST efficiency;
- Four pressure levels of reheating (2.5bara, 5 bara, 10bara and 15 bara);
- Different level of live steam extracted for reheating.

Figure 2.6: Gross power output for Plant B under varying steam cycle parameters



Source: Mott MacDonald

Figure 2.6 also shows that extracting more live steam for reheating purpose first increases the gross power output before reaching a peak. The reheating reduces the steam moisture content and increases the efficiency of the ST sections located after the reheater. After reaching a peak, extracting more live steam reduces the gross power output because at this point live steam used for reheating is not available to generate electrical power in LP ST sections.

Figure 2.6 shows that mPower's stated gross power output of 180MW_e is exceeded with a 91% and 92% ST efficiency at any level of live steam extracted and at any considered reheating pressure. Due to lack of publically available information, we used engineering judgement to select the following combination of parameters for the Plant B base case: 91% ST efficiency, 5bara reheating pressure and 5% of live steam extraction.

2.3.2 Plant B performance at full load

Table 2.4 shows the performance parameters of Plant B (electricity only) at 100% reactor output, based on our modelling results. The heat and mass balance is provided in Appendix C.

Table 2.4: Performance parameters of Plant B (electricity only) at 100% reactor load

	100% reactor load
Feedwater temperature (°C)	212
Gross power at generator terminals (MW_e)	182.4
Auxiliary Load (MW_e)	9.0
Auxiliary Load (% of gross power)	4.9%
Net Power (MW_e)	173.4
Quality of steam at ST exhaust	89%
Heat input (MW_{th})	530
Gross Electrical Efficiency	34.4%
Net Electrical Efficiency	32.7%

Source: Mott MacDonald

At 100% reactor load our modelling of Plant A produces:

- A gross power of 182MW_e which is slightly higher than the figure quoted by NuScale;
- A gross electrical efficiency of 34.4% which is slightly higher than the figure quoted by NuScale.

Overall, our Plant B thermal model is a close approximation to the outputs and the performance figures presented by mPower in their published documentation. The difference in terms of gross power output between our modelling and mPower's stated performance can be explained by the assumption of a constant ST efficiency across through the different ST stages. It should be noted that in reality the ST efficiency is likely to differ from the HP section and LP section. However our assumption of a constant ST efficiency across the ST stages is considered reasonable for the purpose of this study.

The moisture content of the steam at the end of ST is within our expectations and does not justify a second stage of reheat.

2.3.3 Plant B performance at part load

The full results for the part load modelling of Plant B are shown in Table 2.5.

Table 2.5: Plant B - Performance in electrical only mode from 20% to 100% reactor load

		Full Power	Part Load	Part Load	Part Load	Part Load
Reactor Output		100%	80%	60%	40%	20%
	MW_{th}	529.8	423.9	317.9	211.9	105.9
Live steam						
Temperature	degC	299.4	295.3	291.2	287.1	283
Pressure	bara	56.9	62.9	67.5	70.9	72.8
Flow	kg/s	267	213.3	158.6	103.7	49.02
Feedwater						
Temperature	degC	213	203	190	172	144
Performance						
Gross Power Output	MW_e	182	142	101	63	25
Gross electric efficiency		34.43%	33.59%	31.75%	29.55%	23.58%
Net electric power	MW_e	173	134	95	57	21
Net electric efficiency		32.73%	31.71%	29.74%	27.03%	19.63%

Source: Mott MacDonald

2.4 Summary

Using thermo-dynamic modelling, we developed two indicative SMR plant steam cycles that are able to closely approximate the stated performance parameters of NuScale and mPower technologies. These plant steam cycles represent a small relatively low efficiency SMR technology producing electricity only (Plant A) and a larger, higher efficiency SMR technology producing electricity only (Plant B). These indicative plants are used as the basis for the heat extraction analysis presented in the rest of this report.

3 Large-scale district heat networks

To determine the required steam extraction temperature from the CHP plant, we developed a representative model of a notional future DH network and worked ‘back’ from the desired end-user temperature to determine the plant steam cycle requirements. We used AFT Fathom software to calculate pressure drop and flow distribution in liquid piping systems and to explore DH network heat losses. To do this, we made a number of assumptions about the operational parameters of future large-scale DH networks based on information provided by the ETI. These assumptions are detailed below.

The main output of this task – the CHP plant steam extraction temperature – was a key input for the heat extraction modelling which is outlined in Section 4.

3.1 DH network and end user characteristics

For the DH network to be modelled, a number of assumptions were provided by the ETI during the initial stages of the project. These are outlined below in Table 3.1.

Table 3.1: Assumptions and information provided by ETI for DH network and end user characteristics

Item	Info received from ETI	Assumption used in modelling
Delivery temperature to end users (defined as domestic or commercial dwelling)	80°C	Hot water will need to reach end-users in the distribution network at 80°C (not in the building internal piping but in the feed to last heat exchanger).
Full load return temperature from the end users	60°C	Water will be returned at 60°C (from the end-user heat exchanger to the distribution network).
Number of heat exchanges between long distance mains (from SMR to edge of city centre) and end users	Validated during the initial stages of the project	Three exchangers required: One between long-distance heat main and city-wide transmission network One between the city-wide network and the local neighbourhood/street scale distribution network. One between the local distribution network and the end-user dwelling (this is the heat exchanger that would be fed from the distribution network with the 80C water noted above).
Delta T across each heat exchanger	5°C	Confirmed, with a hot water supply.
Control strategy	Validated during the initial stages of the project	We assume a control strategy that maintains a constant return temperature with a varying flow rate.
Distance of plant from DH network	30km	30km

Source: ETI

3.2 DH scheme layout

Based on the assumptions above, several online sources were reviewed to determine a likely potential layout for a city-wide DH scheme. The International Energy Agency (IEA) has conducted a comparison of distributed CHP/DH with large-scale CHP/DH and concluded that:

"The higher energy efficiencies and lower capital costs of large-scale [heat providers] have been shown to more than offset the costs of developing the large-scale district heating network."

IEA - Comparison of distributed CHP/DH with large-scale CHP/DH

The recommended layout based on the IEA's work is a large thermal CHP plant outside the city boundary feeding a ring main and booster pumps to provide heat to end users in the city. This layout is considered a suitable basis for a representative model of a future DH network energised by a CHP SMR plant located up to 30km away from the DH network (as detailed above in Section 3.1).

3.3 DH network model

The assumptions in Table 3.1 were used to create an AFT Fathom process pressure drop and heat loss model for a notional city-scale DH network.

The DH network was sized based on the maximum steam extraction for six Type A steam cycle units, approximating a power island capable of producing 300MW$_e$ gross. Determining the steam extraction temperature was an iterative process as changing the maximum heat extraction changed DH flow rates, altering the heat loss profile in the pipes and therefore changing the required steam extraction temperature. This work was therefore run in parallel to the heat extraction modelling to determine the final heat extraction results outlined in the next section (Section 4).

3.4 Piping parameters

3.4.1 Flow rates

Our model assumes (as per Table 3.1) that there will be a 20°C temperature difference between the supply and return water to the end user. Using the heat available from the power plant and the cooling water delta temperature allows the calculation of the DH flow rates, using the following formula.

$$\dot{m} = \frac{P}{h_2 - h_1}$$

Where:

$\dot{m}$ is the DH mass flow in kg/s

P is the heat available from the power plant in kW

h_x is the enthalpy of the water at the inlet (h_1) and outlet (h_2) of the heat exchanger

The heat loss and pressure drop results from this calculation were used to calculate the flow rate in the long distance main pipe.

3.4.2 Pipe sizing

Based on recommendations in the Department of the Environment, Transport and the Regions (DETR) good practice guide 234, the use of CHP piping needs to conform to BS EN 253:2009[2]. Based on the required temperatures of the suggested system, the British Standard indicates that reasonable design pressures and pipe lifetimes can be expected.

Due to the flowrates, multiples of the largest size of pipework available in this standard would be required for the main pipe from the reactor to the city. If suitable numbers of the reactors are to be installed, it may be feasible to create a bespoke pipe specification for a larger pipe diameter. The cost of bespoke pipes would be difficult to estimate and therefore have not been considered within the scope of this study.

A transport fluid velocity of 2.5m/s was assumed as this provided a good balance between pressure drop, pipe cross sectional area and heat loss. This resulted in cross sectional areas larger than DN1200 (1.2m diameter), the largest pipe available that conforms to BS EN 253. Therefore, multiple parallel pipes were run within the model. Further modelling to investigate the optimal balance the cost of installed piping, pumping power and heat losses was not undertaken in the present study.

3.4.3 Pipe insulation

Insulation thicknesses for our model were determined from BS EN 253. Insulation constants used were as follows:

- Polyurethane insulation conductivity – 0.029W/mK;
- Polyethylene casing conductivity – 0.5W/mK;
- External convection coefficient – 30W/m^2K.

The external convection coefficient is pessimistic as this is equivalent to an air speed of 7m/s over the pipes.

2 BS EN 253:2009 +A1:2013 District heating pipes — Pre-insulated bonded pipe systems for directly buried hot water networks — Pipe assembly of steel service pipe, polyurethane thermal insulation and outer casing of polyethylene

3.4.4 Pipe lengths

We have assumed that future city-scale DH networks would need to have a minimum heat load density in order to be economically viable. We set this density threshold using one of the lowest currently known connected heat load densities found in Swedish DH networks (8kWhth/m^2/yr). This implied that a maximum city size with an 11.2km radius could be serviced by a 300MW$_e$/540MW$_{th}$ SMR CHP plant. The pipe lengths in the DH network were therefore calculated to service a DH network with an 11.2km radius. This area would contain ~380,000 homes, based on 2.2kWh/h average heat demand per home and 75% penetration. The work in Phases 1 and 2 found around 50 urban conurbations in Great Britain able to use the majority of the heat from a 100MW$_e$ SMR or larger. About half of these conurbations were able to use the majority of the heat from a 300MW$_e$ SMR or larger.

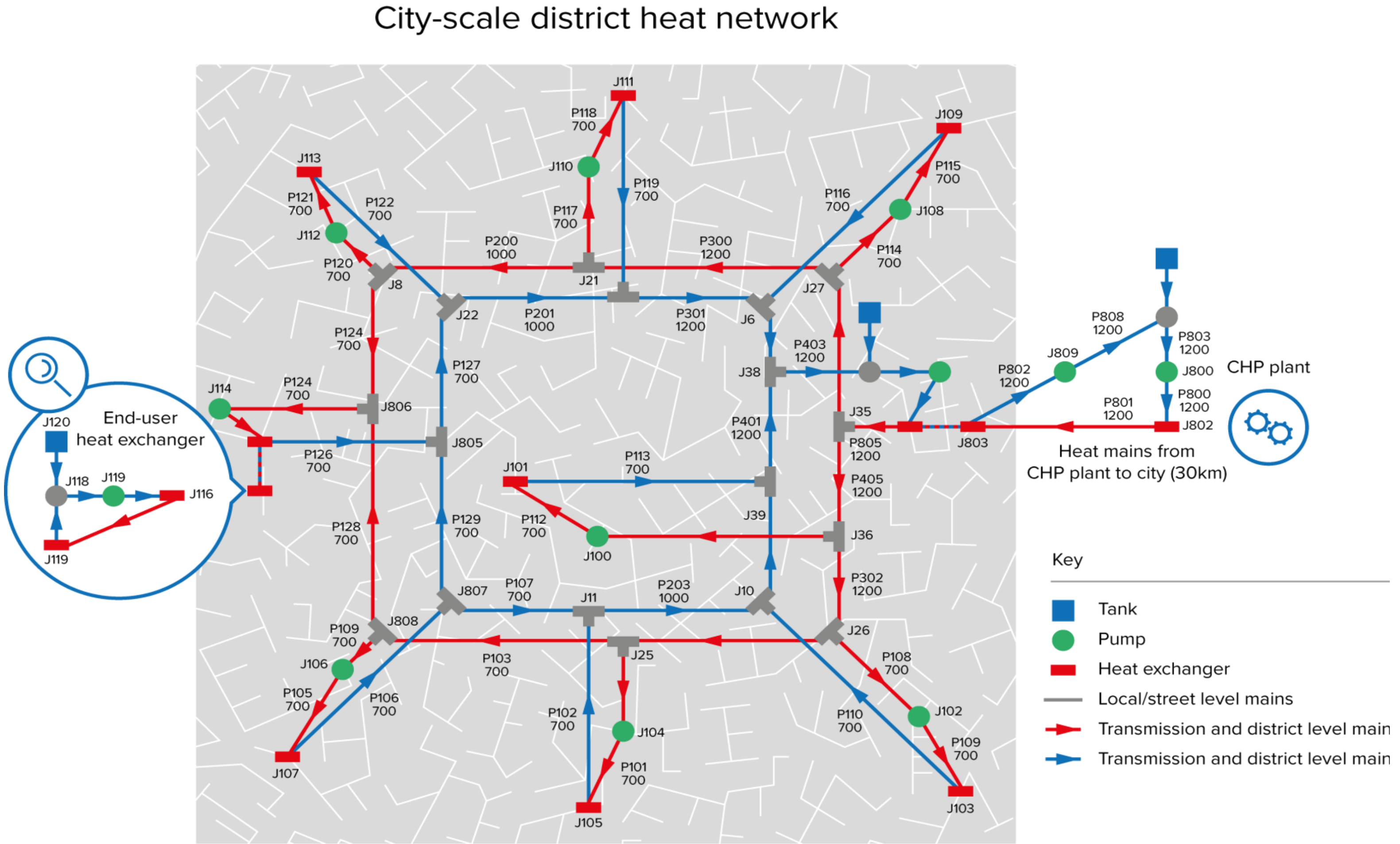
The length of the pipe from the CHP plant to the city was modelled at 30km as shown in Table 3.1; pipe routing would be site specific. We assumed that pipe expansion (thermal expansion) would be taken up with bellows, removing the need for large expansion loops and numerous elbows. We therefore assumed that there would be two 30° bends per km for all pipes in the network.

3.4.5 AFT pressure drop model

Figure 3.1 below shows the AFT Fathom model pipes and equipment based on the representative model of a city-scale DH network created for the ANT project, which assumes a conurbation over 350km^2 in size with around 380,000 homes. There are multiple tiers of heat mains infrastructure as recommended by the IEA.[3] The pump and heat exchanger in the top right of the Figure represent the DH pump and condenser, leading to the long-distance mains pipe. This leads to the city-wide distribution network via an intermediate heat exchanger. Eight booster pumps then feed local/street distribution heat exchangers, with an end-user heat exchanger represented on the left of Figure 3.1.

[3] IEA Annex VII Report 8 DHC-05.01 – A comparison of distributed CHP/DH with large scale CHP/DH

Figure 3.1: AFT Fathom DH network model based on a conurbation over 350km^2 in size with around 380,000 homes



Source: Mott MacDonald

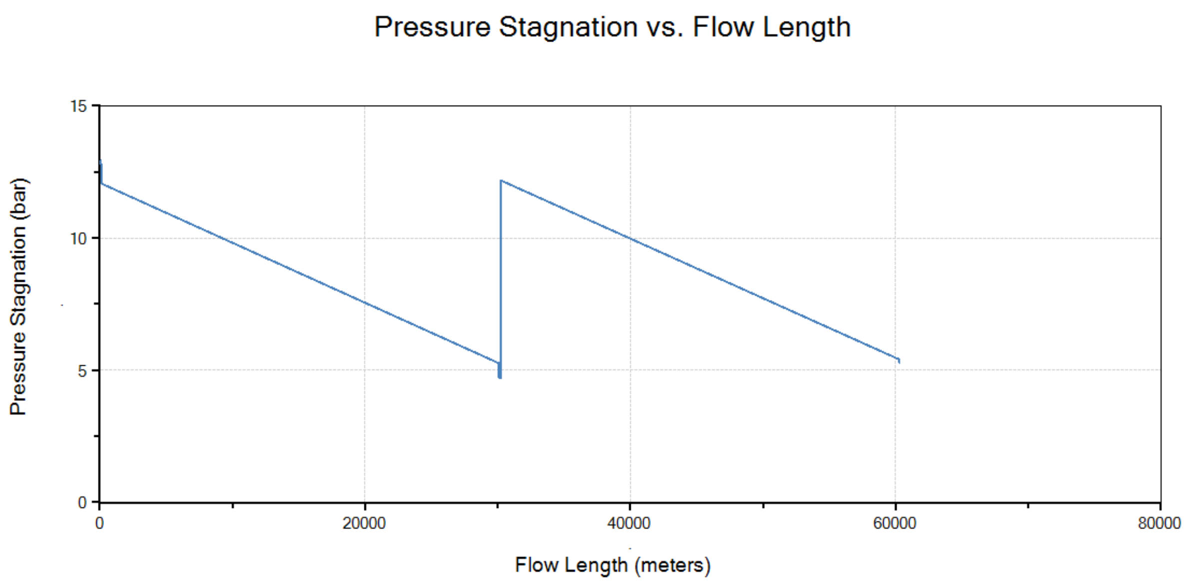
3.5 Modelling results

3.5.1 Pressure drops

Choosing a design velocity of 2.5m/s for the transport fluid resulted in a pressure that would exceed the design pressure of BS EN 253 pipework with a single pump, so a booster pump was added at the city wide distribution end of the long distance mains pipe. A booster pump removed the need for two tunnels each containing two pairs of DH pipework. Instead one tunnel containing three pairs of DH pipes could be used. The pressure profile through the long distance main is shown in Figure 3.2.

Minimum pressures at the pump inlets have also been kept relatively high to provide enough Net Positive Suction Head required to prevent pump cavitation. This ensures that if the heat exchanger leaks, the leakage flows towards the power plant and not towards the DH distribution ring main.

Figure 3.2: Long distance main pressure profile



Source: Mott MacDonald (AFT Fathom model)

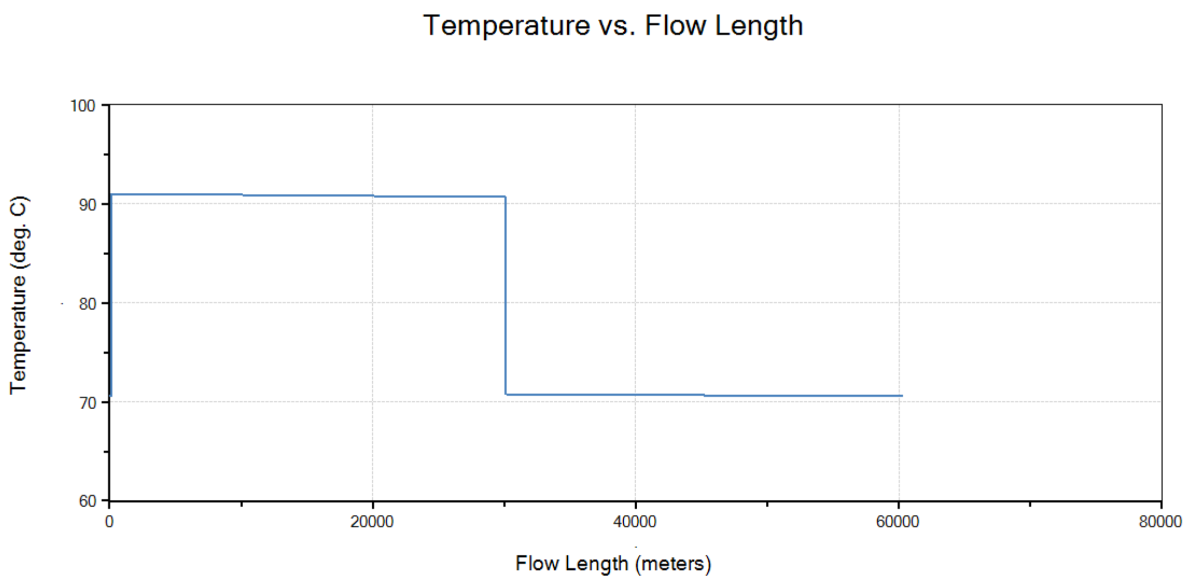
3.5.2 Heat and temperature losses

Heat losses were calculated using the physical properties of BS EN 253 pipework, using the assumption that the full length of the pipework are in tunnels with an ambient temperature of 12°C. This tunnel temperature is likely to be pessimistically low as the pipe heat losses are likely to raise the ambient temperature in the tunnel, but these assumptions were chosen as a conservative case given tunnel lengths and ventilation requirements are unknown. Modelling of tunnel ventilation during a subsequent Front End

Engineering Design (FEED) stage of the project could determine whether this temperature could be increased to reduce the heat loss in the tunnel.

Figure 3.3 shows that for the full flow case temperature drop through the high temperature long distance main is 0.30°C which equates to a heat loss of ~9.8MW_{th}. The temperature drop through the low temperature return long distance main is 0.22°C, which equates to a heat loss of ~7.4MW_{th}. Therefore the thermal loss in the long distance main connection with the DH network is ~2.6% of the total heat duty at full load.

Figure 3.3: Long distance main temperature profile



Source: Mott MacDonald (AFT Fathom model)

Our modelling indicates that heat losses would occur in the city wide distribution and local/street distribution networks. Heat exchanger duties are summarised below in Table 3.2.

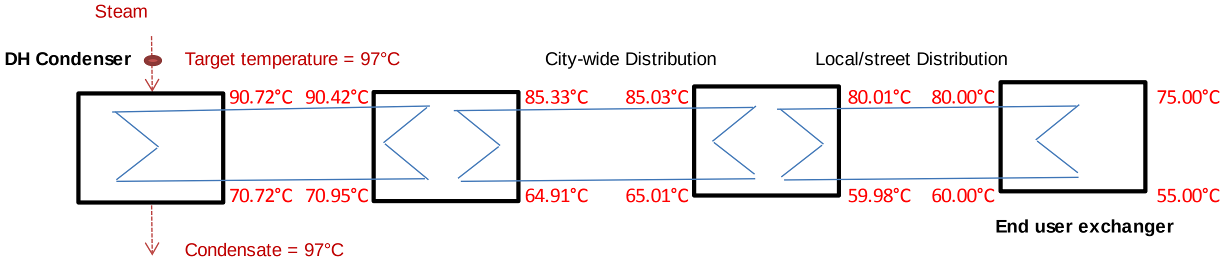
Table 3.2: Heat exchanger duties across the DH network showing heat losses between exchangers (MW_{th})

Heat exchanger	100% reactor output	80% reactor output	60% reactor output	40% reactor output	20% reactor output
DH condenser	657	507	366	227	87
City wide distribution	640	490	350	211	71
Heat exchangers outside scope of report					
Total at local/street distribution	632	482	342	203	62

Source: Mott MacDonald (AFT Fathom model)

Figure 3.4 shows the final full load temperatures of the DH pipework to achieve the end user temperatures defined in Table 3.1**Error! Reference source not found.**. This adds together the 5°C deltas at each of the heat exchangers and the heat losses in the DH pipework to show that a 97°C steam temperature at the DH condenser inlet is required for DH network heating to achieve an 80°C temperature at the end user.

Figure 3.4: DH Condenser – Target stream temperature



Source: Mott MacDonald

3.5.3 Pumping loads

For the sale of heat to be economical, the power requirements for the DH network should not be a significant proportion of the total power output of the SMR. The pump power for all load cases are therefore provided below in Table 3.3. All pumps were assumed to have an efficiency of 85%.

Table 3.3: DH network pump loads (kW_e)

Pump	100% reactor output	80% reactor output	60% reactor output	40% reactor output	20% reactor output
Long distance main pump	7,589.2	3,211.3	1,165.3	267.7	9.0
Pumps outside power plant boundary					
Long distance main booster pump	7,583.2	3,157.6	1,166.5	266.6	8.9
City wide distribution pump	1,613.9	1,235.9	682.4	145.0	0.8
Average city wide distribution booster pump	510.2	177.0	39.0	8.7	0.6
Local/street distribution pump	299.1	132.8	46.7	9.6	0.4
Total (note 1)	15,671.8	6,871.8	2,534.4	558.1	17.5

Note 1: Assuming x1 city wide distribution pump, x8 city wide distribution booster pumps and x8 local/street distribution pumps
Source: Mott MacDonald

The total power required to operate the DH pumps within the power plant boundary is ~7.6MW. This will be used in the net power calculations in Section 4.

3.6 Summary

Using AFT Fathom software, we created a representative pressure drop and heat loss model of a notional future large-scale DH network. By working back from the assumed end-user temperature of 80°C, we defined a requirement that steam would need to be extracted at 97°C from the steam cycle of a CHP SMR. This requirement is a necessary input assumption for scoping the hardware configuration of the CHP steam cycle in Section 4 of this report.

4 SMR heat extraction

As there is no publically available information for a CHP LWR SMR, all steam cycle models in this section have modified the Section 2 steam cycle models for a DH extraction with the lowest energy penalty. To modify the steam cycle models shown in Section 2 to allow for heat supply DH networks, we used the Thermoflex software and assessed different technical options for heat extraction across a range of plant operating modes. By doing this, we identified a viable technical solution which had the lowest efficiency penalty across a range of core reactor output loads. This information was used to select a hardware configuration of the CHP plant steam cycle and allowed comparison of the performance of Plants A and B against each other and against the generic performance assumptions used in ANT Phases 1 and 2.

A key input to this task was the assumption (derived from the work reported in Section 3) that in order to meet end-user requirements, steam would need to be extracted at 97°C from the steam cycle of a CHP SMR.

Two of the main performance metrics resulting from this analysis were the plant's electrical derating in CHP mode and heat to power ratio. These are defined in more detail below and both are key input values for the economic assessment presented in Section 7.

Thermoflex software was used to model the steam cycles and assess the level of energy penalty associated with steam extraction.

We also undertook spatial modelling to provide an indicative plant layout and 3D model of both Plant A and Plant B.

4.1 CHP operating modes

The CHP plant operating modes considered in our analysis were:

a) Power only, full load;
b) Power only, part load;
c) Full load power, Maximum heat (CHP base case);
d) Part load power, heat equal to corresponding power output;
e) Full load power, with heat output lower than the corresponding power output.

Additional operating modes are possible, where more heat is extracted by bypassing the steam turbine and reducing its electrical output. Such scenarios would have no impact on the steam cycles developed for the above operational modes, but would require relatively minor modifications to the HP steam circuit as shown in Appendix E. These operating scenarios have therefore not been explored further in this report.

All the steam cycles modelled in Section 4 have been modelled to achieve a flexible operating envelope bounded by the static operating modes outlined above. The steam cycles modelled are therefore capable of providing heat and power independently to match user/grid requirements.

4.2 Determining the steam extraction point

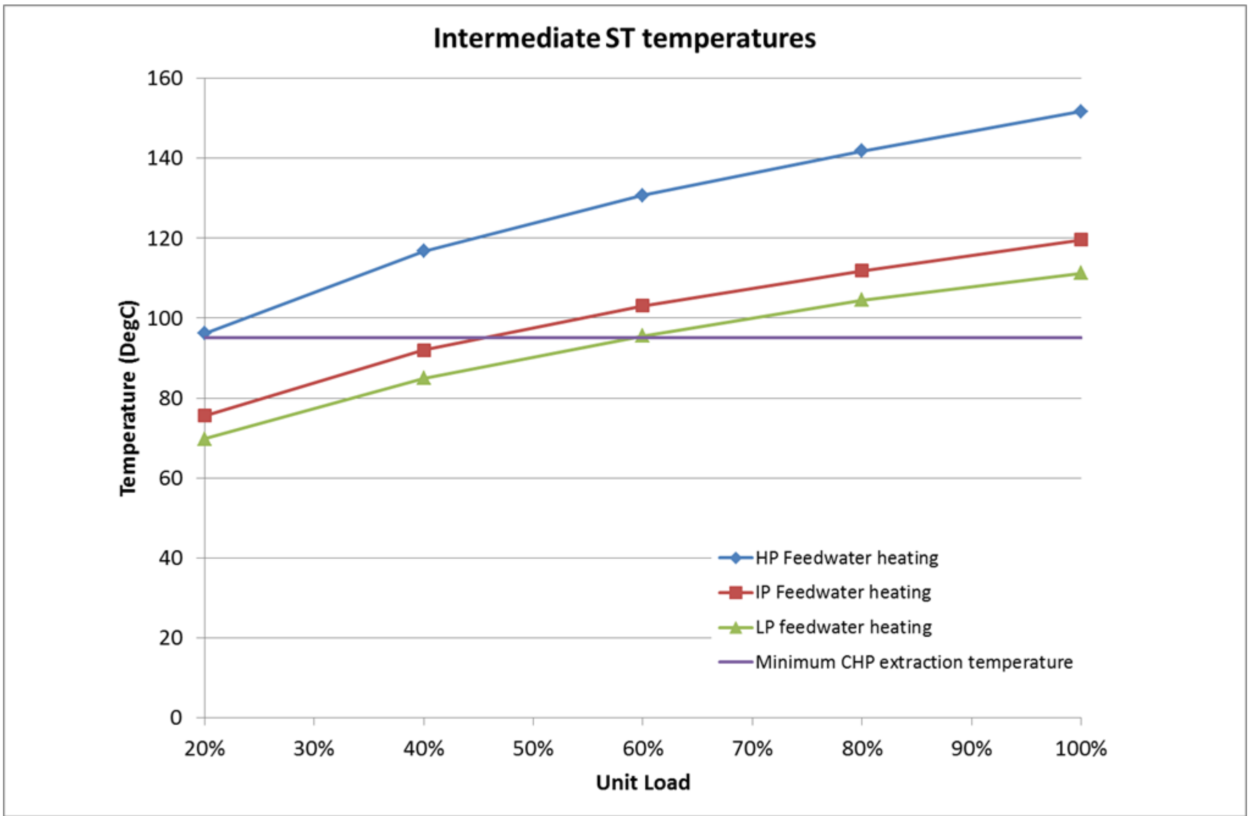
To determine the optimal steam extraction point to provide steam at 97°C across the five CHP operational modes, we modelled different technical options for the Plant A steam cycle. This included consideration of the tapping locations already available in the electricity-only steam cycle models, and then additional tapping locations in the steam cycle models.

4.2.1 Extracting at the tapping points available in the electricity-only steam cycle

The electricity-only steam cycle modelled in Section 2 for Plant A has three tapping points (which provide steam at 112°C, 120°C and 150°C at full reactor load). We investigated whether extracting steam at any of these available tapping points could provide 97°C steam across the range of reactor loads (20%-100%).

Figure 4.1 shows that reducing the reactor heat output results in significant reductions in tapping point steam temperatures.

Figure 4.1: Plant A - Steam temperature at the tapping points available in the electricity-only steam cycle



Source: Mott MacDonald

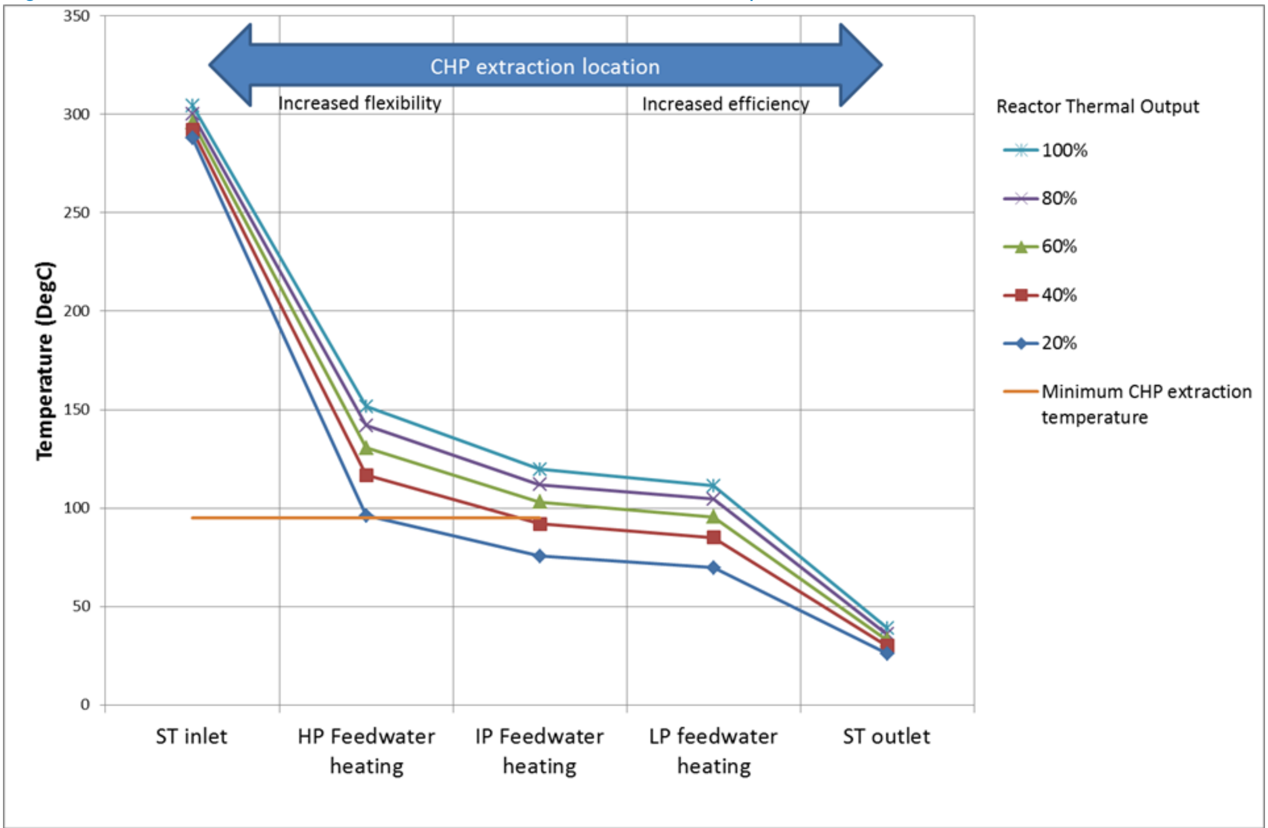
Temperature at the tapping points already available in the electricity-only steam cycle varies considerably when reactor output reduces. This means that if the most efficient tapping point is chosen for full load operation, the system will no longer be able to supply heat to the DH system at an adequate temperature once the reactor heat output falls much below full load. This shows there is a trade-off between high load efficiency and reactor output flexibility.

Steam conditions can be maintained above 97°C across the range of reactor loads only if the steam is extracted at the highest temperature tapping point. However this tapping point provides steam at an unnecessarily high temperature most of the time, leading to inefficient heat extraction with a correspondingly higher impact on power generation.

Figure 4.2 shows that extracting steam at low temperature (closer to the steam turbine outlet) will improve efficiency at the expense of flexibility, whilst extracting steam at higher temperature (closer to the steam turbine inlet) will improve flexibility at the expense of efficiency.

In conclusion, we do not consider using the tapping points already available in the electricity-only steam cycle as an adequate solution for heat extraction to supply a DH network.

Figure 4.2: Part Load Performance - Intermediate steam turbine temperature



Source: Mott MacDonald

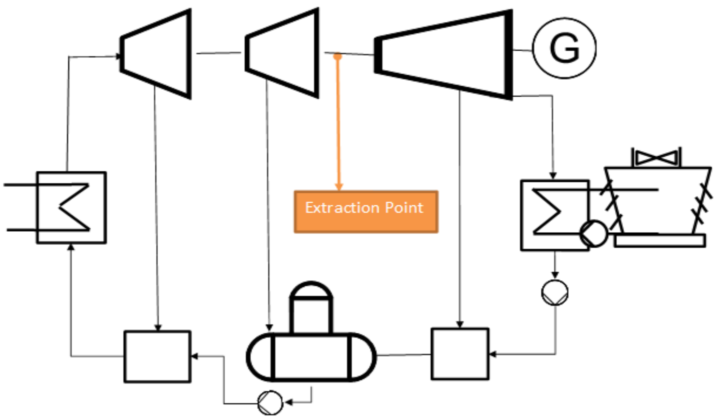
4.2.2 Extracting steam outside the electricity-only tapping points

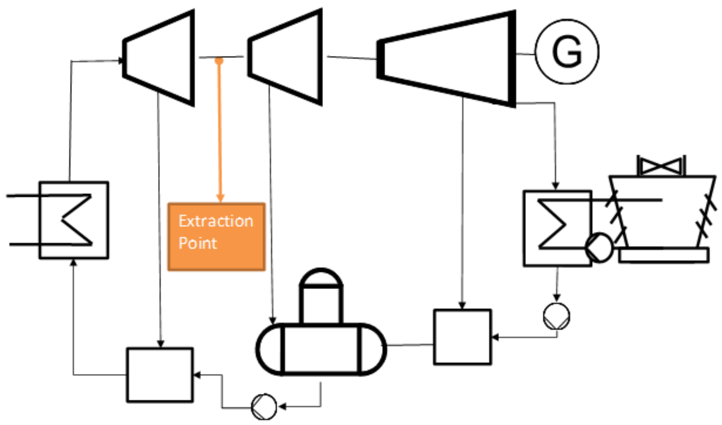
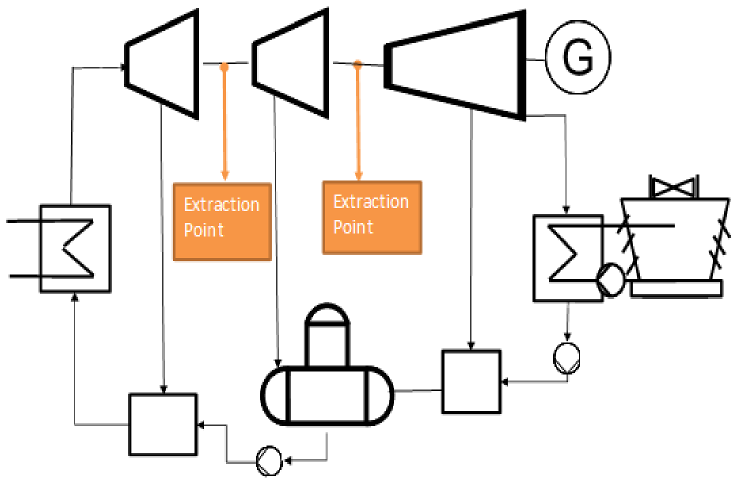
We identified six additional technical solutions to heat extraction. These are described in Table 4.1. For each solution the modifications required to the electricity-only steam cycle are represented in orange. The solutions each offer a different level of flexibility and efficiency. They can be classified in two main categories:

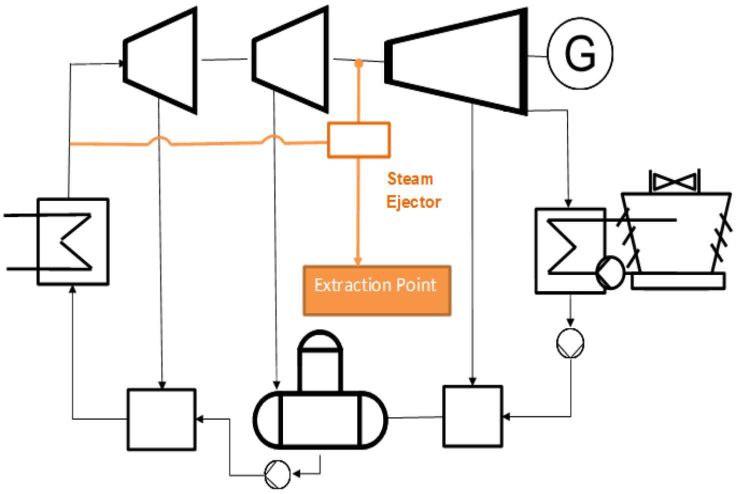
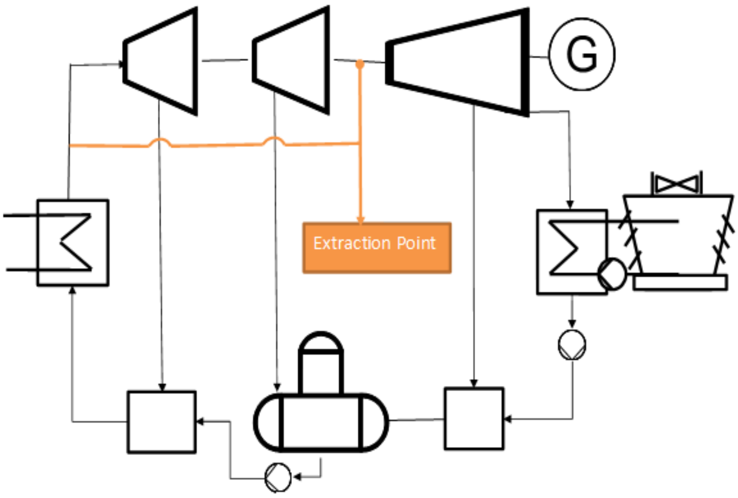
- Technical solutions with uncontrolled/un-throttled steam extraction;
- Technical solutions with controlled/throttled steam extraction.

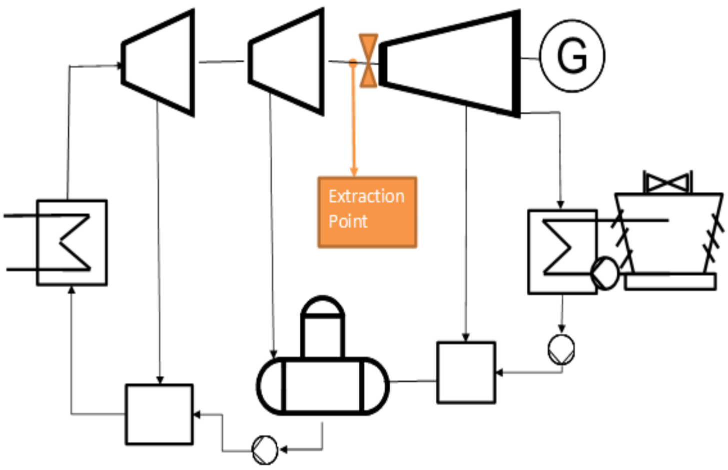
The difference between these two categories is that the technical solution with controlled steam extraction includes a valve immediately downstream of the extraction point.

Table 4.1: Potential Technical Solutions

Option	Description	Schematic
Technical Solutions with uncontrolled/un-throttled steam extraction		
Option 1	Constrain the reactor output operating flexibility so that it does not fall below a certain threshold – i.e. fix the lowest allowable reactor load, based on the ability to deliver good quality steam from an efficient tapping point (suggested to be between 50-70% reactor output)	

Option	Description	Schematic
Option 2	Target full reactor output operating flexibility (a large turndown range) by extracting heat at a point that provides the correct steam conditions at all loads but takes steam at an unnecessarily high temperature most of the time (leading to inefficient heat extraction).	
Option 3	Target full reactor output operating flexibility by designing a turbine with two large extraction points that switch depending on reactor load requirements. This would be both technically and operationally more complex than solution 2 but would result in a high heat extraction efficiency.	

Option	Description	Schematic
Option 4	Target full reactor output operating flexibility using HP live steam to provide the motive force for a steam ejector to "raise the quality" of the extracted steam. This would have efficiency penalties.	
Option 5	Target full reactor output operational flexibility with the use of a combination of extracted steam and supplementary heating with live HP steam. This is likely to be unacceptably inefficient.	

Option	Description	Schematic
Technical Solutions with controlled/throttled steam extraction		
Option 6	Target full reactor output operating flexibility via a controlled extraction (i.e. throttled inlets at the stages immediately downstream of the extraction point).	

Source: Mott MacDonald

4.2.3 Viability of six technical steam extraction solutions

Our analysis shows that at low DH demand with low levels of heat extraction, all technical solutions are capable of providing steam at a suitable extraction temperature.

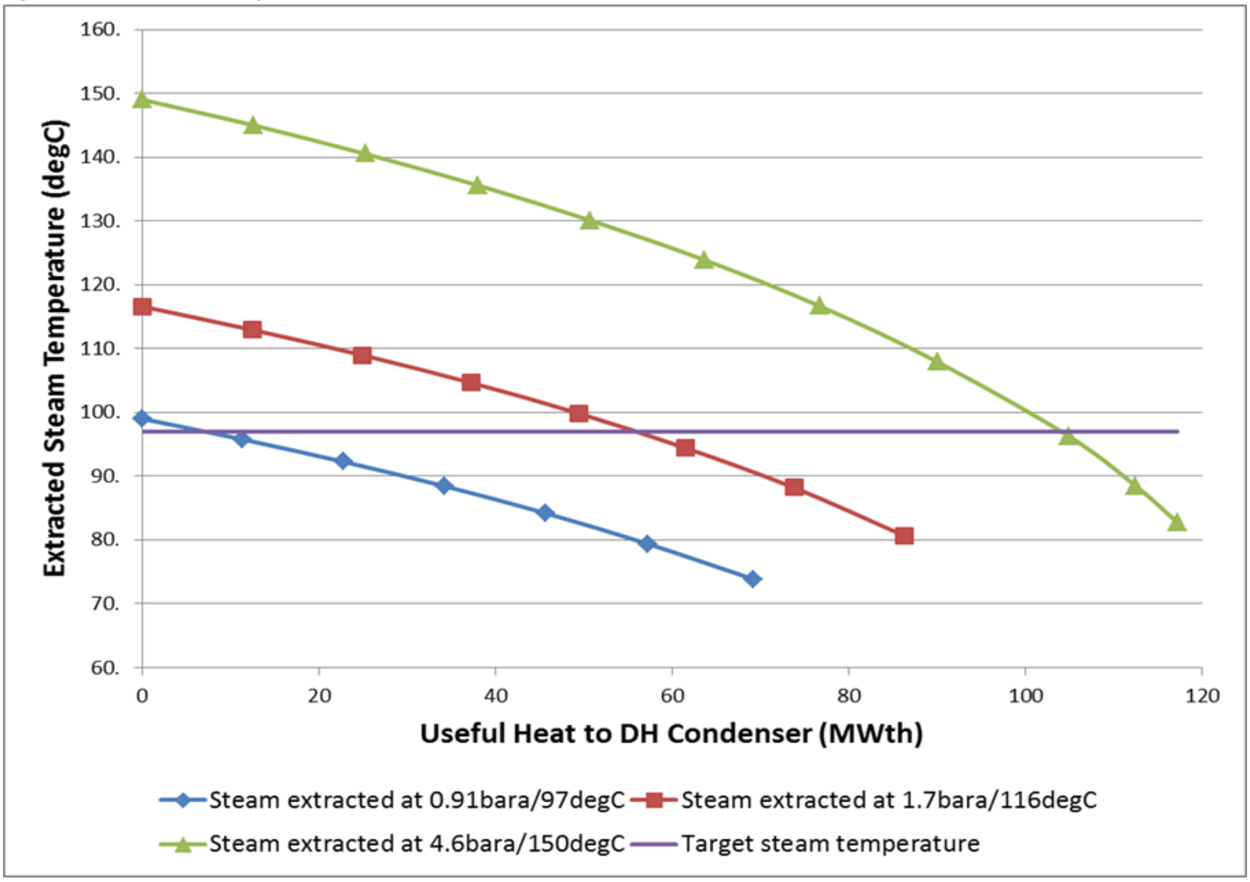
However at maximum heat extraction only two technical solutions are capable of maintaining a suitable extraction temperature over the whole reactor range:

- Option 2: extracting steam at unnecessarily high temperature (with a uncontrolled extraction);
- Option 6: extracting steam via controlled extraction.

To obtain this result we created a process design model for Plant A (assuming 100% reactor output) where steam could be extracted at three tapping points (low, medium and high temperature) via an uncontrolled extraction.

Figure 4.3 below shows how the temperature of the extracted steam at these tapping points reduces when heat extraction increases (at 100% reactor output).

Figure 4.3: Steam temperature variation without control of the steam extraction, at 100% reactor load



Source: Mott MacDonald

At low DH demand steam extraction is low and a substantial flow is passed through the last steam turbine stages. The steam temperature available at the three extraction points is sufficient to reach the 97°C target.

As the DH load increases more steam is required by the DH condenser, leaving less steam to expand through the last steam turbine stage. As the flow in the final steam turbine stage decreases, its inlet pressure falls, reducing the temperature of the steam available at the tapping point. Further increases in DH load cause the steam temperature at the tapping point to fall well below the target temperature.

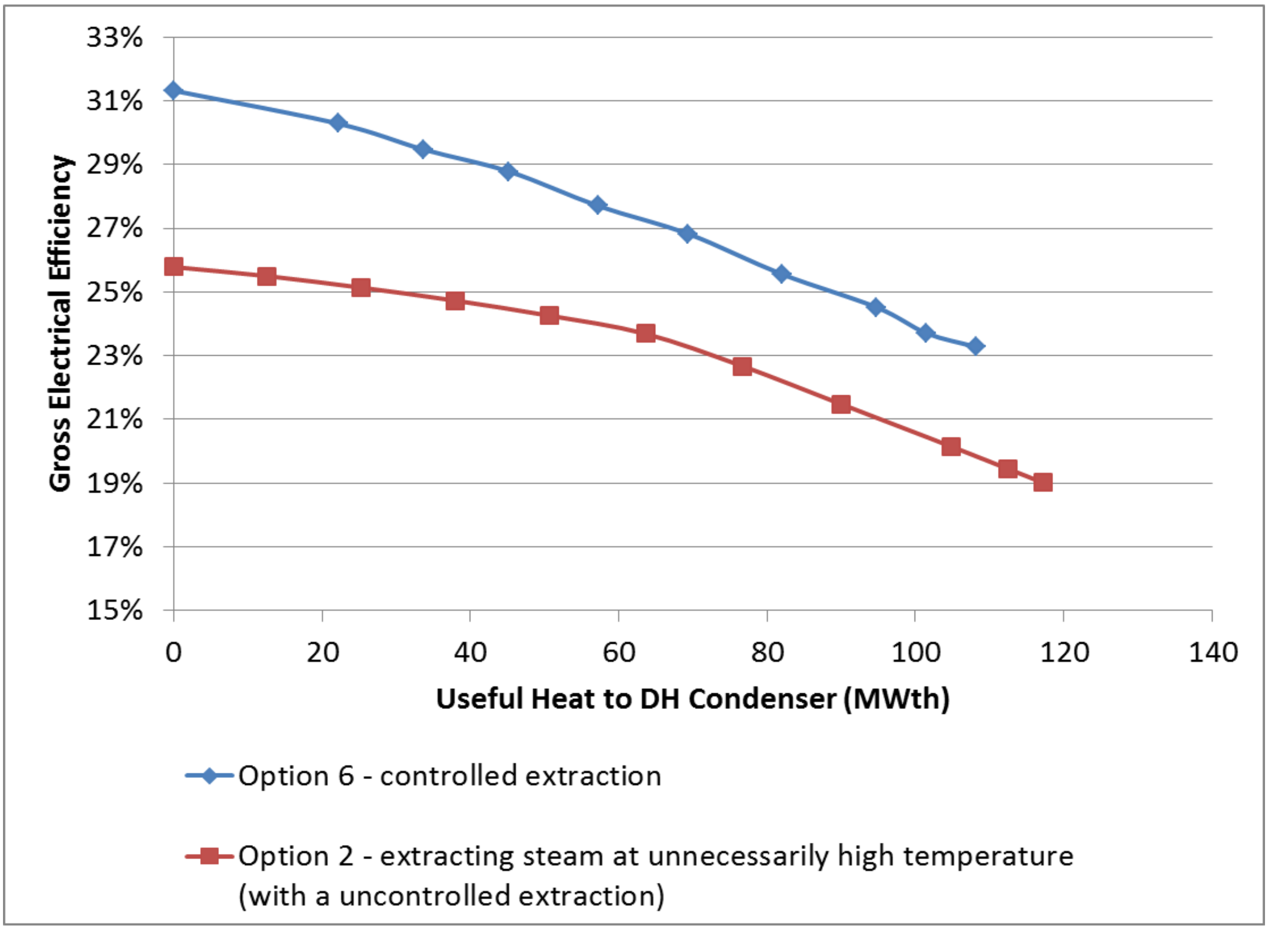
At greater DH load, the steam temperature at the tapping point can be prevented from falling below the target by a controlled extraction valve located immediately downstream of the extraction point.

4.2.4 Determining the preferred solution

The performance of the two solutions assessed as capable of supplying steam at an adequate temperature (Options 2 & 6) was tested over the full reactor output operating range and over the whole range of DH loads.

Figure 4.4 shows the gross electrical efficiency for both solutions at 100% reactor thermal output over a range of DH loads.

Figure 4.4: Gross Electrical Efficiency – Option 2 vs Option 6 (100% Reactor Thermal Output)



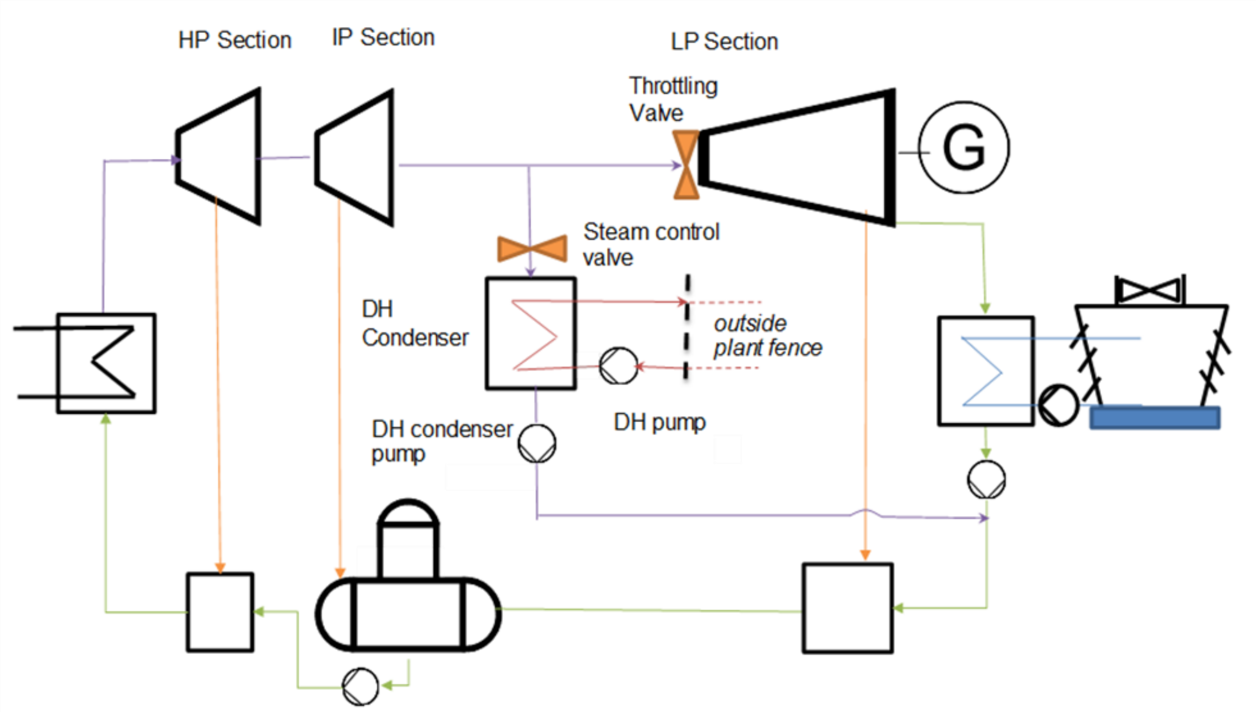
Source: Mott MacDonald

Figure 4.4 shows that Option 2 has a higher efficiency penalty than Option 6. Option 6 – which requires controlled steam extraction - was therefore selected for further consideration.

4.2.5 Selected technical option (Option 6) in detail

Figure 4.5 below shows in detail all of the additional equipment required within the plant boundary to achieve SMR heat extraction for DH.

Figure 4.5: Equipment schematic showing equipment within the plant boundary to achieve option 6



Source: Mott MacDonald

To extract the steam from between the IP and LP stages of the ST, a crossover is required with a throttling valve. This throttling valve maintains the upstream pressure to allow steam extraction across the ST load range. The steam control valve then controls the steam flow rate to match the DH demand. The steam is depressurised and de-superheated so that the saturated steam entering the DH condenser condenses transfers its energy to the water for the DH network. The steam condensate is then returned to an appropriate location in the steam/condensate cycle via the DH condensate pump. For a list of equipment sizes and weights, see Table 4.5 (page 53) and Table 4.6 (page 54) for Plant A and Plant B respectively.

4.2.6 Optimisation of the selected technical solution (Option 6)

To further optimise the preferred technical solution (Option 6), we created a process design model to investigate the location of the controlled extraction point that offers the lowest efficiency penalty over the full reactor output operating range. To do this we divided the steam turbine into 11 sections with ten potential tapping points, providing steam at temperatures ranging from 97 to 150°C.

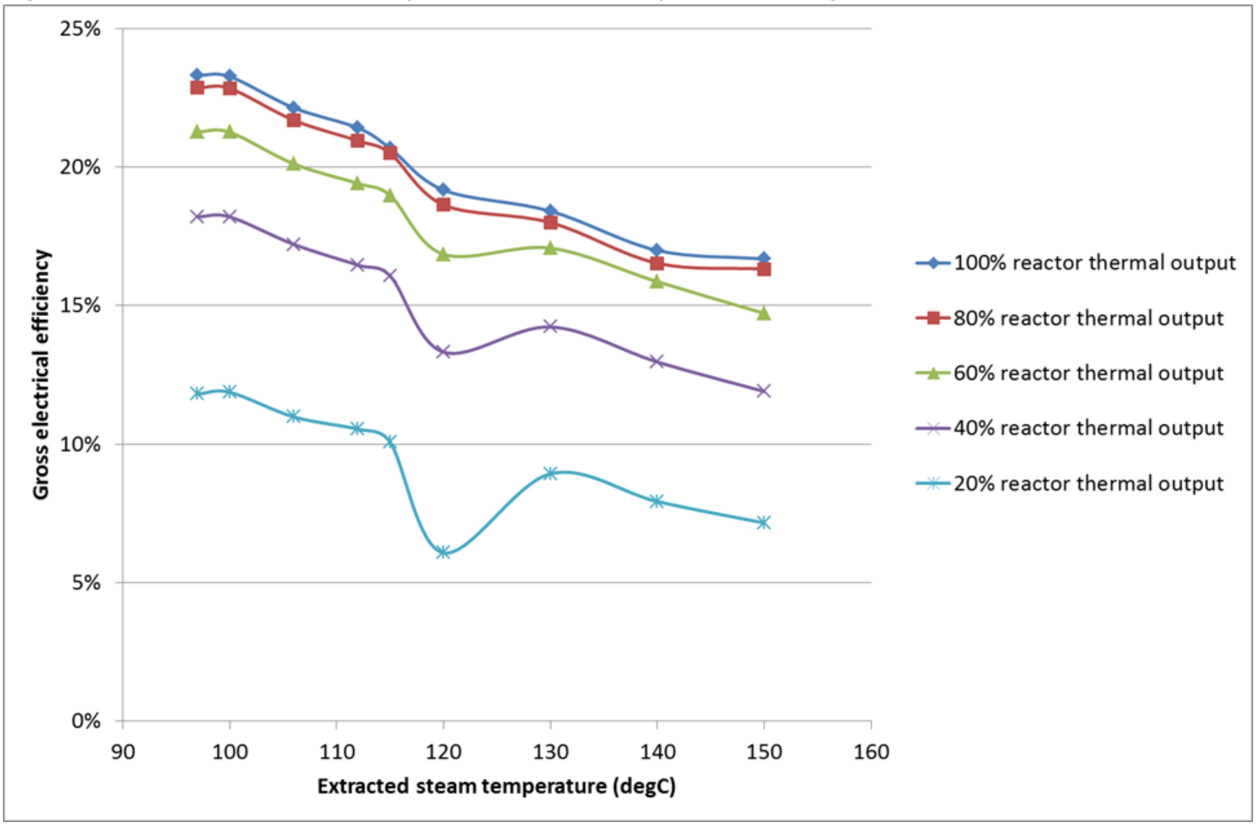
At 100% reactor output, steam is extracted for DH at the lowest pressure and temperature. At this tapping point, we assessed the maximum heat which can be extracted while maintaining minimum flow (10% of the full load steam flow) through the final stages of the ST. The tapping point was incrementally moved upstream (closer to the steam inlet for the ST). This increased the temperature and pressure of the extracted steam and so resulted in reduced steam mass flow rates to achieve the same heat supply to the DH network.

Secondly, the same methodology was employed for cases when the reactor operates at part load: extracting steam for DH at the lowest pressure/temperature and determining the maximum heat which can be extracted while maintaining 10% minimum flow through the ST. Again, the tapping point was incrementally moved upstream, achieving the same pressure and temperature increases and reduced steam mass flow for the same heat supply as before; the impacts on electrical efficiency were also assessed.

The modelling undertaken for Plant A suggests that a minimum of 5% of full load steam flow is required to be passed through the ST, at any load, to minimise exhaust losses. A minimum steam flow of 10% of the full load steam flow has been assumed to encompass a design margin.

Figure 4.6 shows the variation in gross electrical efficiency when the steam is extracted at ten different tapping points with a controlled extraction. Extracted steam temperatures on the x-axis of the graph represent the steam extraction temperatures at full load. These temperatures will reduce at part load, but were used to differentiate between the tapping locations.

Figure 4.6: Gross electrical efficiency for various reactor output levels, during maximum steam extraction



Source: Mott MacDonald

Figure 4.6 shows that extracting steam via a controlled extraction at one location where the steam temperature and pressure is the lowest offers the lowest efficiency penalty. In the case of the Plant A steam cycle, the tapping point will be located after the low feedwater heater and the ST exhaust (as shown in Figure 4.8).

With the Plant A CHP configuration, heat is extracted between the HP and LP turbine section. Our global review of existing and planned nuclear CHP projects (Section 8) shows that that this is typically the optimal steam extraction point used elsewhere.

In addition it should be noted that modest levels of heat extraction are possible without a control valve in the cross-over section (throttling), but at higher levels of steam extraction a controlled extraction configuration is required. This is a typical configuration in non-nuclear applications of many types.

Additional tappings from the LP section also allow further refinement of the system by ‘pre-heating’ the DH fluid in a way analogous to feed heating in a traditional steam cycle. We have not analysed this mechanism here (which could offer a small increase in cycle efficiency) because the incremental complexity cannot necessarily be justified for small steam turbines.

We have selected an extraction point where the steam temperature and pressure are the lowest. The maximum amount of steam it is possible to extract at this point is a percentage of the steam flowing through the LP turbine. It is possible, if deemed necessary, to supply more heat than this simple configuration allows by tapping steam from the HP main upstream of the steam turbine (as described in Appendix E). Whilst we have assumed this is not necessary in this report, it is a standard technique used elsewhere and could be adopted without any further modifications to the steam turbine.

4.2.7 Plant B steam cycle

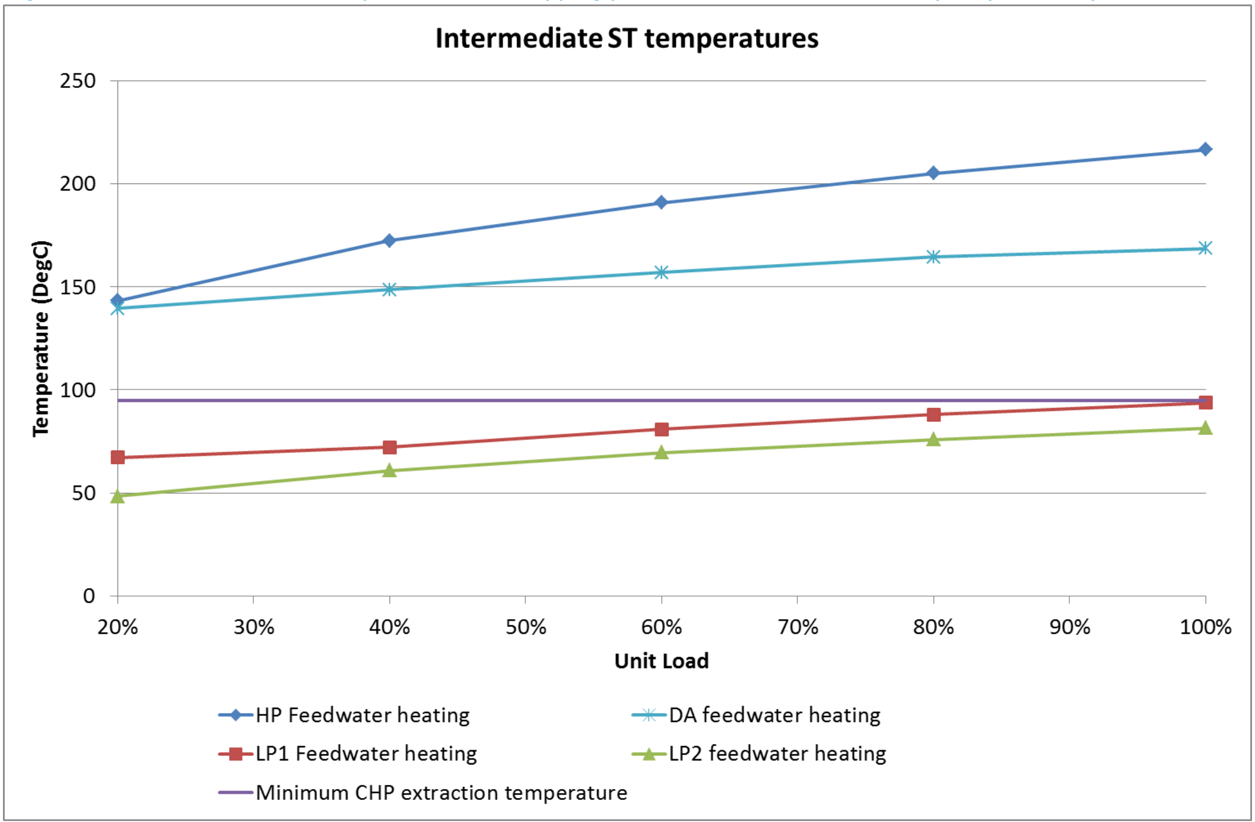
The above analysis to locate the steam extraction at the optimum location was based on the Plant A thermal model. However we also tested the key assumptions developed with that model on the Plant B thermal model.

In electricity-only mode, Plant B has four steam tapping points. Figure 4.7 below shows the variation in steam temperature at these four tapping points over the reactor load range.

These results confirm that:
- The temperature at the tapping points varies considerably when reactor output reduces;
- Steam can be maintained above 97°C over the range of reactor load only if the steam is extracted at the highest temperature tapping point.

These results confirm that the conclusions drawn from the analysis performed for the Plant A thermal model are also applicable to Plant B.

Figure 4.7: Plant B - Steam temperature at the tapping points available in the electricity-only steam cycle model



Source: Mott MacDonald

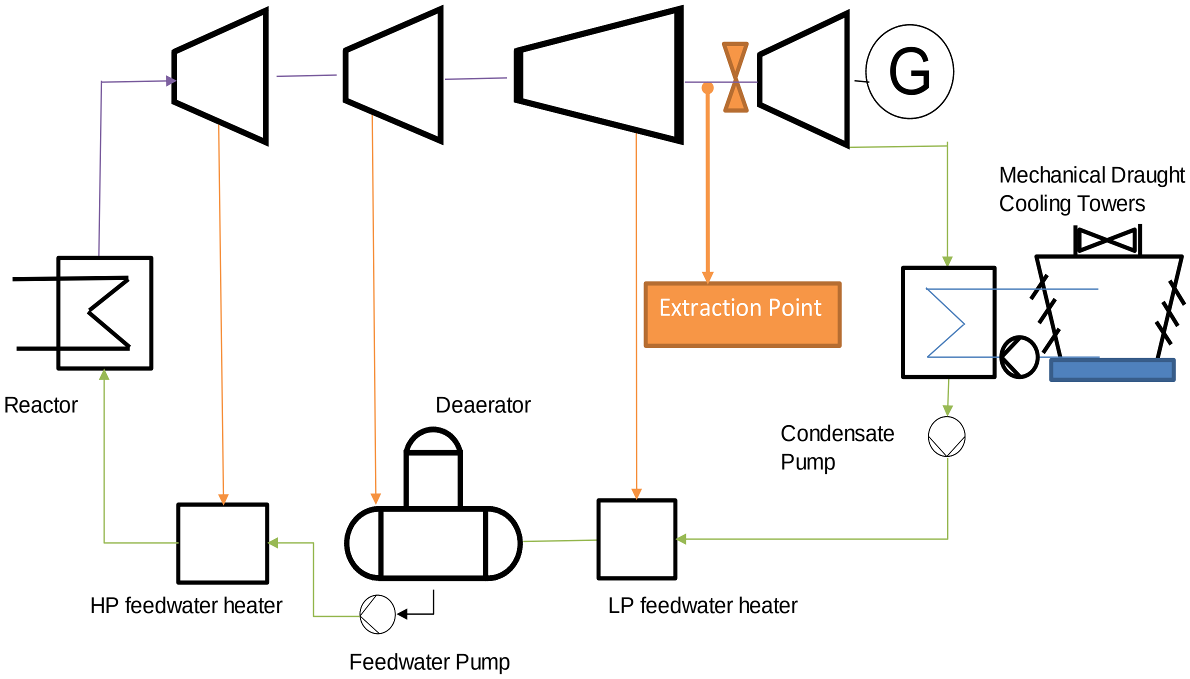
4.3 CHP steam cycles

The preferred technical solution (with a single controlled extract at the lowest pressure and temperature possible) provides a practical means of extracting most of the LP steam flow to supply heat to a DH network. This preferred technical solution offers the best overall performance without excessive complexity and corresponding capital cost.

This technical solution requires a simple modification to the standard Plant A or Plant B steam turbine (splitting the single casing design into a more traditional design with a cross-over between HP/IP and LP sections). This provides a practical means of extracting most of the LP steam flow to supply heat to a DH network.

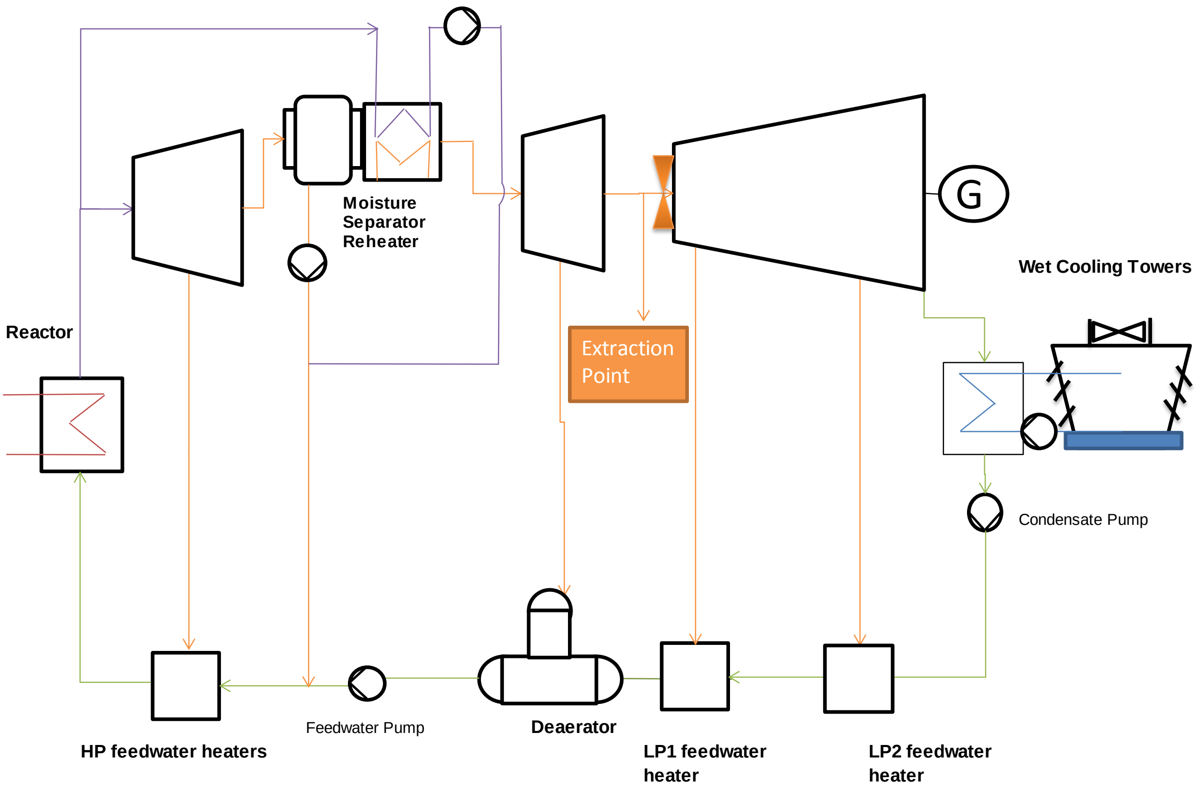
Figure 4.8 and Figure 4.9 below show this preferred solution for the Plant A and Plant B models respectively.

Figure 4.8: Indicative steam cycle for Plant A CHP SMR plant



Source: Mott MacDonald

Figure 4.9: Indicative steam cycle for Plant B CHP SMR plant



Source: Mott MacDonald

In order to provide steam at 97°C temperature over the full reactor operating range:

- The Plant A steam cycle model was modified by including a tapping point with a control valve between the extraction points feeding the LP pressure feedwater heater and ST exhaust;
- The Plant B steam cycle model was modified by including a tapping point with a control valve between the extraction points feeding the deaerator and the LP1 pressure feedwater heater.

These modifications to the SMR steam turbine have a negligible impact on the power only performance of the underlying steam cycle.

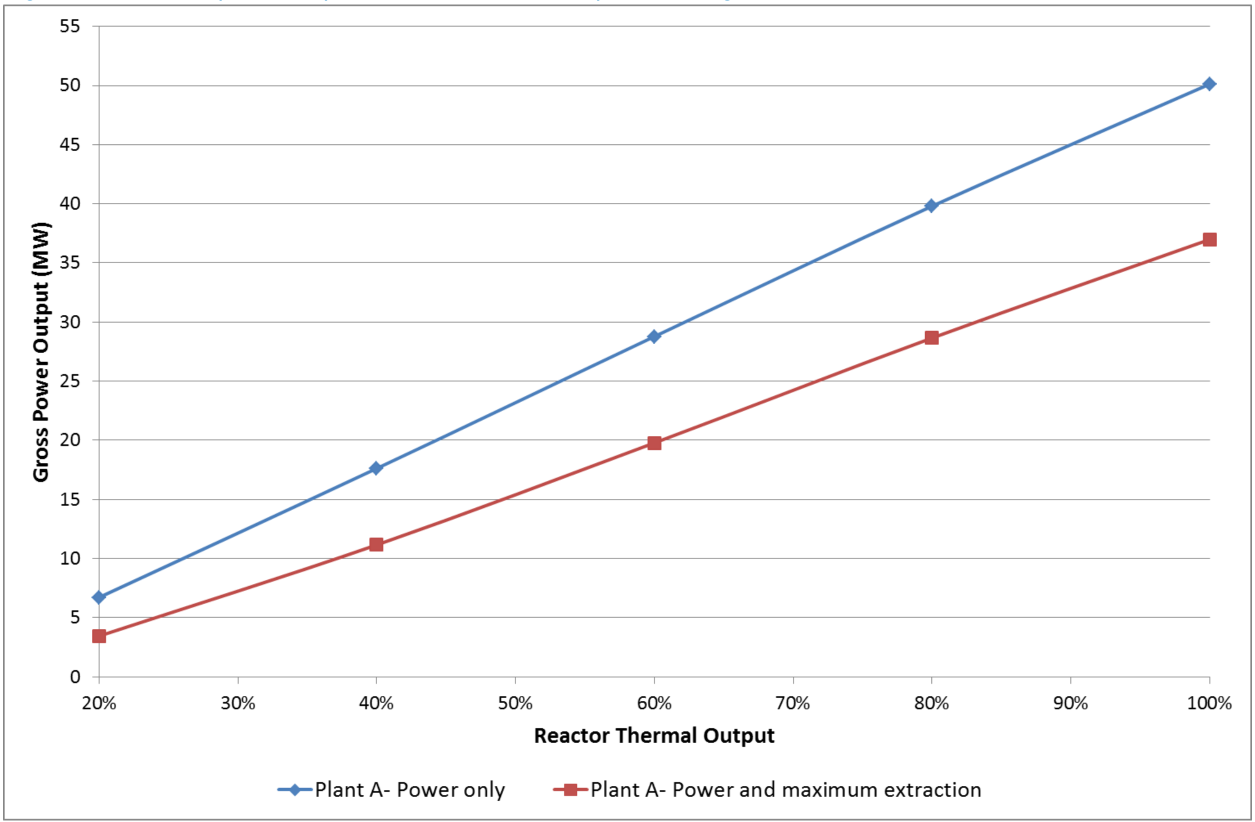
4.4 Performance across different CHP operational modes

The CHP SMR steam cycle configuration designed here allows a wide variety of operational modes, such as power only (full and part load), full power with full corresponding heat and variable power with variable heat.

4.4.1.1 Plant A operating envelope

Figure 4.10 shows the range of gross power outputs achievable over the steam extraction range for Plant A.

Figure 4.10: Gross power output vs reactor thermal output for a single Plant A based module



Source: Mott MacDonald

Table 4.1 summarises the performance of one SMR module based on Plant A technology at core reactor outputs ranging from 20% to 100%, in both electricity-only and CHP modes. The key performance results obtained are marked **in bold.**

The steam cycle design allows the extraction of any flow rate of steam irrespective of the reactor load, up to the maximum heat load values outlined in Table 4.1. Efficiencies are bounded by the values in Table 4.1.

The results show that given 100% reactor thermal output (160MW$_{th}$), the maximum power output in electricity-only mode is 50MW$_e$ gross. In maximum CHP mode the useful heat output for the DH mains is 109 MW$_{th}$ and the maximum power output is 37 MW$_e$ gross. This implies a derating in net power output of ~28.7% and a heat to power ratio of 2.23 (defined here as the ratio of maximum heat output in CHP mode to maximum power output in electricity only mode). At 20% reactor output, the electrical power output is reduced to around 6.7 MW_e gross (without steam extraction) and to 3.5 MW_e gross (with maximum heat extraction). At this level, the heat provided to the DH condenser falls to 14 MW_{th}.

Mott MacDonald

Table 4.1: Plant A - Performance summary for a single 50MW$_e$ SMR module

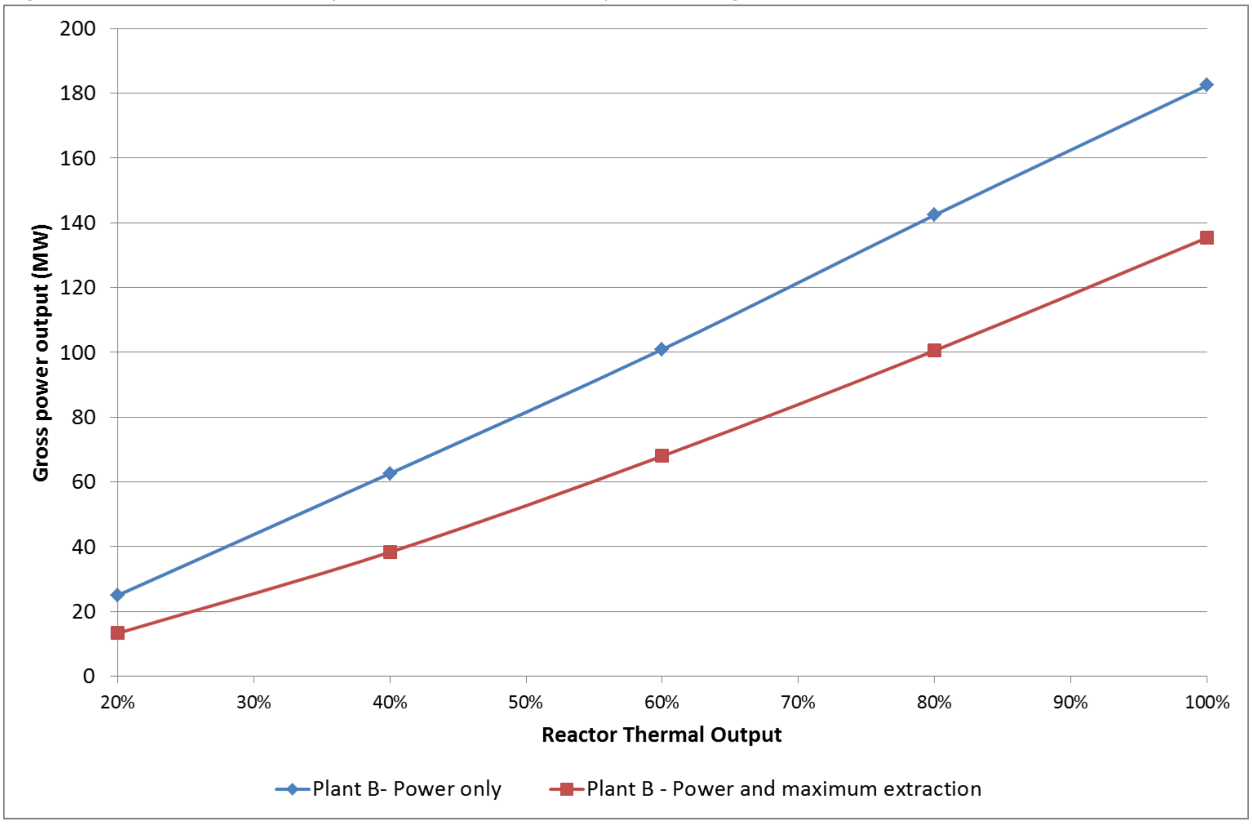
		Power Only					Power + Heat				
Reactor Output		**Full Power**	**Part Load**				**Full Power**	**Part Load**			
		100%	80%	60%	40%	20%	100%	80%	60%	40%	20%
	MW$_{th}$	159.7	126.3	94.0	62.6	31.8	159.6	126.0	93.7	62.1	31.2
Live steam											
Temperature	°C	304.4	300	296	292	288	304.4	300	296	292	288
Pressure	bara	34.5	38	41	43	44	34.5	38	41	43	44
Flow	kg/s	67.5	53.1	39.2	25.7	12.7	67.5	53.1	39.2	25.7	12.7
Feedwater											
Temperature	°C	148	139.5	129.5	116.3	96	148.2	140.8	131.7	120.6	107
ST											
Steam flow at LP exit	kg/s	54.4	43.3	32.5	21.8	11.2	5.4	5.4	5.4	5.4	5.4
Performance											
Gross Power	**MW$_e$**	**50**	**40**	**29**	**18**	**6.7**	**37.0**	**28.7**	**19.8**	**11.2**	**3.5**
Gross electric efficiency		**31.38%**	**31.51%**	**30.59%**	**28.15%**	**21.14%**	**23.17%**	**22.73%**	**21.12%**	**17.97%**	**11.08%**
Net Power (Note 1)	MW$_e$	**48**	**38**	**27**	**16**	**6**	**34.1**	**26.6**	**18.2**	**9.9**	**2.3**
Net Electric Efficiency		**29.90%**	**29.87%**	**28.72%**	**25.84%**	**17.51%**	**21.33%**	**21.09%**	**19.43%**	**15.89%**	**7.48%**
Gross Power derating							**26.2%**	**28.0%**	**31.2%**	**36.6%**	**48.6%**
Net Power derating							**28.7%**	**29.5%**	**32.6%**	**39.0%**	**58.1%**
Steam extraction											
Temperature	°C	97	97	97	97	97	97	97	97	97	97
Pressure	bara	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91
Flow	kg/s	0	0	0	0	0	54.47	42.26	30.25	18.26	6.26
Steam enthalpy	kJ/kg	N/A	N/A	N/A	N/A	N/A	2416.5	2406.4	2422.3	2474.6	2620.6
Condensate Enthalpy	kJ/kg	406.8	406.8	406.8	406.8	406.8	406.8	406.8	406.8	406.8	406.8
Heat load	MW$_{th}$	0	0	0	0	0	109.5	84.5	61.0	37.8	13.9

Note 1: Auxiliary load includes cooling tower fans and pumps, ST auxiliaries, feedwater pump, the condensate pump and long distance main booster pump.
Source: Mott MacDonald

4.4.1.2 Plant B operating envelope

Figure 4.11 shows the range of gross power outputs achievable over the steam extraction range for Plant B.

Figure 4.11: Gross Power Output vs reactor thermal output for a single Plant B based module



Source: Mott MacDonald modelling

Table 4.2 summarises the performance of one SMR module based on Plant B technology at core reactor outputs ranging from 20% to 100%, in both electricity-only mode and CHP modes. The key performance results obtained are marked **in bold**.

The steam cycle design allows the extraction of any flow rate of steam irrespective of the reactor load, up to the maximum heat load values outlined in Table 4.2. Efficiencies are bounded by the values in Table 4.2.

The results show that given 100% reactor thermal output ($530MW_{th}$), the maximum power output in electricity only mode is $182MW_e$ gross. In maximum CHP mode the useful heat output for the DH mains is $350MW_{th}$ and the maximum power output is $135MW_e$ gross. This implies a derating in net power output of ~28.3% and a heat to power ratio of 1.95 (defined here as the ratio of maximum heat output in CHP mode to maximum power output in electricity only mode). At 20% reactor output, the electrical power output is reduced to around 25MW$_e$ gross (without steam extraction) and to 13MW$_e$ gross (with maximum heat extraction). At this level, the heat provided to the DH condenser falls to 47MW$_{th}$.

Table 4.2: Plant B - Performance summary for a single 182MW$_e$ SMR module

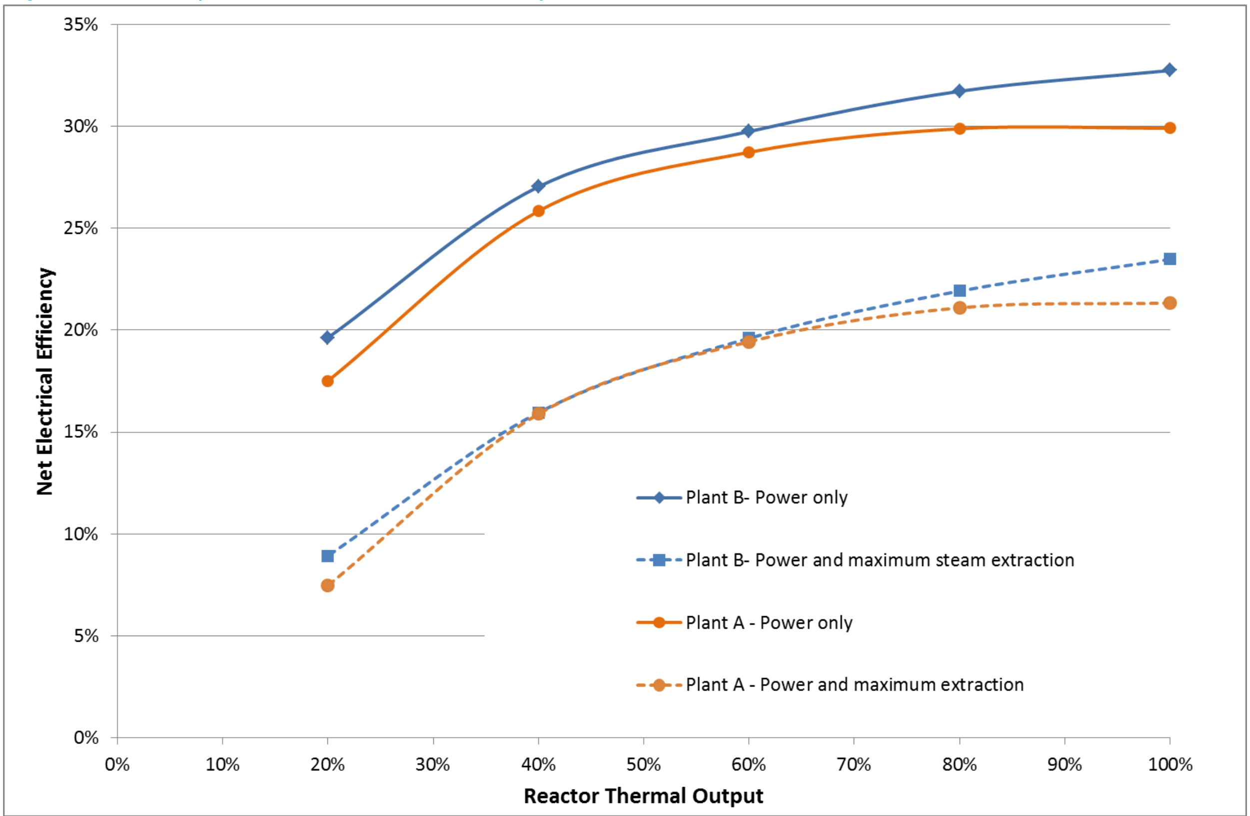
		Electricity only					CHP mode				
Reactor Output		**Full Power**	**Part Reactor Load**				**Full Power**	**Part Reactor Load**			
		100%	**80%**	**60%**	**40%**	**20%**	**100%**	**80%**	**60%**	**40%**	**20%**
	MW$_{th}$	530	424	318	212	106	530	424	318	212	106
Live steam											
Temperature	°C	299.4	295.3	291.2	287.1	283	299.4	295.3	291.2	287.1	283
Pressure	bara	56.9	62.9	67.5	70.9	72.8	56.9	62.9	67.5	70.9	72.8
Flow	kg/s	267	213.3	158.6	103.7	49.02	267	213.3	158.6	103.7	49.02
Feedwater											
Temperature	°C	213	203	190	172	144	212.7	203.	190.5	173.2	146.4
ST											
Steam flow at LP exit	kg/s	161.5	130.2	99.26	67.19	34.48	17.84	17.28	17.44	17.27	16.98
Performance											
Gross Power	**MW$_e$**	**182**	**142**	**101**	**63**	**25**	**135.4**	**100.5**	**68.0**	**38.3**	**13.3**
Gross electric efficiency		**34.43%**	**33.59%**	**31.75%**	**29.55%**	**23.58%**	**25.55%**	**23.74%**	**21.42%**	**18.13%**	**12.60%**
Net Power (Note 1)	**MW$_e$**	**173**	**134**	**95**	**57**	**21**	**124.3**	**92.8**	**62.2**	**33.7**	**9.4**
Net electric efficiency		**32.73%**	**31.71%**	**29.74%**	**27.03%**	**19.63%**	**23.47%**	**21.92%**	**19.60%**	**15.95%**	**8.93%**
Gross Power derating							**-25.8%**	**-29.4%**	**-32.6%**	**-38.8%**	**-46.8%**
Net Power derating							**-28.30%**	**-30.94%**	**-34.21%**	**-41.14%**	**-54.71%**
Steam extraction											
Temperature	°C	97	97	97	97	97	97	97	97	97	97
Pressure	bara	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91
Flow	kg/s	0	0	0	0	0	159.5	126.	91.18	56.55	20.63
Steam enthalpy	kJ/kg	N/A	N/A	N/A	N/A	N/A	2600.2	2623.1	2652.2	2671.2	2671.2
Condensate Enthalpy	kJ/kg	406.8	406.8	406.8	406.8	406.8	406.5	406.5	406.5	406.5	406.5
Heat load to DH condenser	**MW$_{th}$**	**0**	**0**	**0**	**0**	**0**	**350**	**279**	**205**	**128**	**47**

Note 1: Auxiliary load includes cooling tower fans and pumps, ST auxiliaries, feedwater pump, the condensate pump and long distance main booster pump.
Source: Mott MacDonald

4.5 Comparison between Plants A and B

In this section we compare the results from Plants A and B. Figure 4.12 compares the net electrical efficiency at different levels of core reactor output for both plants in electricity-only and CHP modes. The results are also summarised in Table 4.3.

Figure 4.12: Comparison of net electrical efficiency for Plants A & B



Source: Mott MacDonald

At 100% reactor output the difference in net electrical efficiency in electricity only mode is 2.8 percentage points (equivalent to an increase in heat rate by 9%). In maximum heat extraction mode it is 2.1 percentage points (equivalent to an increase in heat rate by 10%). In other words, the Plant B higher efficiency steam cycle (due in large part to the addition of the MSR) offers a modest increase in electrical efficiency, most notably when the reactor core output is 80% or above.

Table 4.3 summarises the key performance metrics (at full reactor output) between the two plants based on the modelling undertaken above.

Table 4.3: Comparison of key performance metrics at 100% reactor output

	Plant A	Plant B
Core reactor output (single module) – MW_{th}	159.5	530
Electricity only mode		
Gross power output in electricity only mode – MW_e	50	182
Net power output in electricity only mode - MW_e	47.8	173
Gross Electrical Efficiency - %	31.4%	34.4%
Net Electrical Efficiency - %	29.9%	32.7%
Maximum heat extraction		
Maximum heat supply to DH mains - MW_{th}	109.5	350
Maximum heat supply to city-wide distribution network - MW_{th}	106.5	340
Gross power output with full heat extraction – MW_e	37.0	135.4
Net power output in with full heat extraction – MW_e (1)	34.1	129
Gross Electrical Efficiency - %	23.2%	25.5%
Net Electrical Efficiency - %	21.3%	23.5%
Gross Power derating with full heat extraction	**26.2%**	**25.8%**
Net Power derating with full heat extraction	**28.7%**	**28.3%**
Heat to Power ratio	2.23	1.95

Note: (1) includes auxiliaries for DH pumps.
Source: Mott MacDonald

The Plant A and B modelled steam cycles are less efficient than the generic steam cycle efficiencies assumed in Phases 1 and 2 of the ANT project. Modelling undertaken in this report indicates that the reduction in power output for a given heat extraction is marginally (but not significantly) higher for Plants A and B than for the earlier assumed cycle.

The modelling shows that the derating of gross electrical output in full CHP mode (maximum heat extraction) would be 26.2% for Plant A (28.7% net) and 25.8% for the more efficient Plant B (28.3% net). This is to be expected because Plant B power generation at maximum extraction is higher than Plant A.

The heat to power ratio (ratio of maximum heat output to maximum net electrical output) is 2.23 for Plant A and 1.95 for Plant B. This ratio was estimated to be 1.8 for the generic steam cycle design in Phases 1 and 2. Our new higher ratio implies that a lower total amount of installed SMR capacity would be needed to meet the heat demand considered in our earlier Phase 1 and 2 work. In broad terms, the 1.8 heat to power ratio assumed in Phases 1 and 2 implied that 22.3GW_e SMR fleet capacity would be required to meet the identified heat demand. The higher Plant A heat to power ratio of 2.23 implies that a lower fleet electrical capacity of 18GW_e would be sufficient to meet the same heat load.

Plant A's heat to power ratio is higher than Plant B due to the lower gross efficiency of its steam cycle (31.4% versus 34.4%), meaning less of the available energy is being converted to electricity and more energy is available for heat. These ratios are based on thermal losses of 2.7% in the DH pipework (as calculated in Section 2).

Table 4.4 provides an energy flow breakdown for the two plants. The third and fourth columns show the results when the net power output of both plants is scaled to allow for a direct comparison on a like-for-like basis.

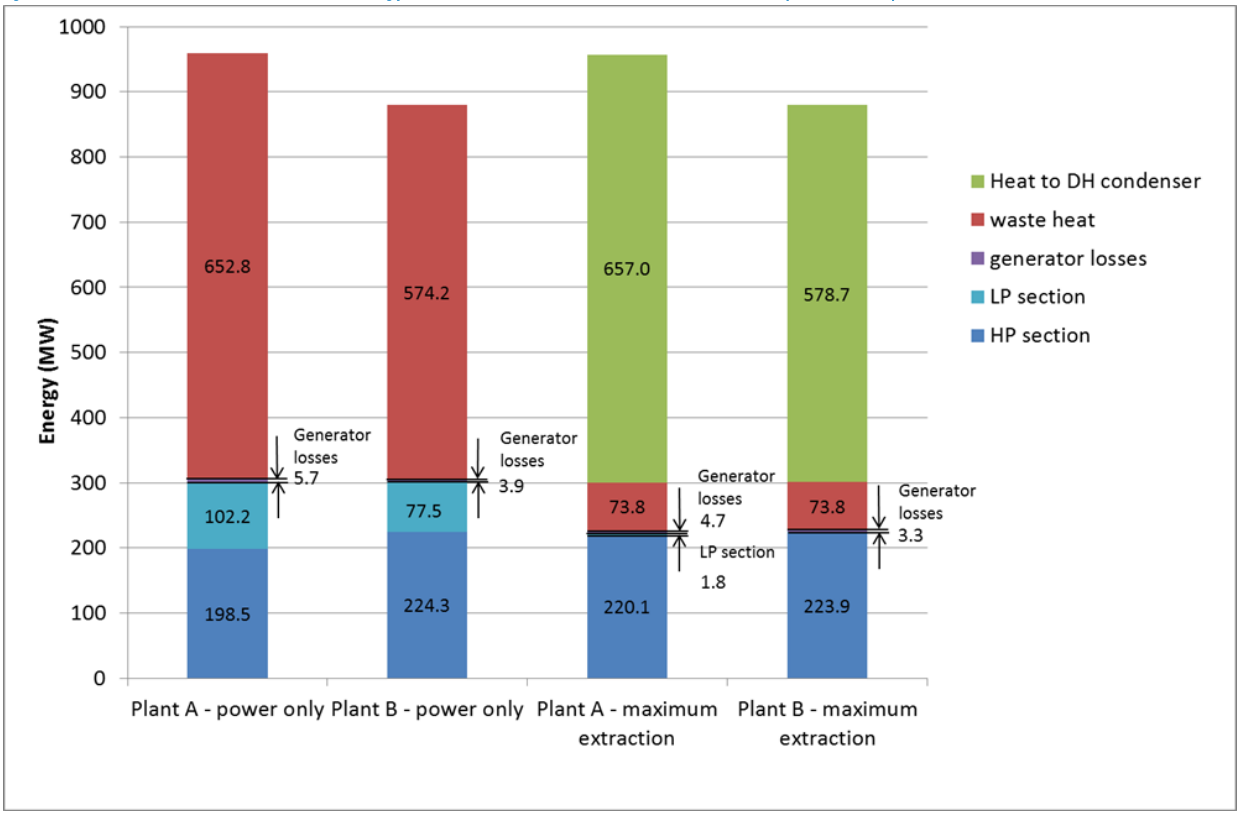
Table 4.4: Energy flow breakdown

	Plant A (single module)	Plant B (single module)	Plant B (same net power output as 6xPlant A modules)	Plant A (6 modules)	Difference
Reactor output (MW_{th})	159.5	530	881	957	+75 MW_{th}
Electricity only (full reactor output)					
Net power (MW_e)	47.8	173.4	286.9	286.9	0
DH pump (MW_e)	0	0	0	0	
Gross power (MW_e)	50.1	182.4	301.8	300.6	-1.2
HP section (MW_e)	33.1	135.6	224.3	198.5	-25.9
LP section (MW_e)	17.0	46.9	77.5	102.2	24.7
Heat to Condenser (MW_{th})	108.8	347.1	574.2	652.8	78.6
Generator Losses (MW_e)	0.9	2.3	3.9	5.7	1.8
Maximum heat extraction (full reactor output)					
Net power (MW_e)	35.6	128.9	213.3	213.7	+0.4
DH pump (MW_e)	1.3	4.6	7.6	7.6	0
Gross power (MW_e)	37.0	135.4	224.0	221.9	-2.0
HP section (MW_e)	36.7	135.3	223.9	220.1	-3.8
LP section (MW_e)	0.3	0.0	0.1	1.8	+1.7
Heat to Condenser (MW_{th})	12.3	44.6	73.8	73.8	0.0
Heat to DH Condenser (MW_{th})	109.5	349.8	578.7	657.0	78.3
Generator Losses (MW_e)	0.3	0.7	3.3	4.7	1.4

Source: Mott MacDonald

Figure 4.13 shows the energy balance information from Table 4.4. It shows the distribution of reactor thermal output for both Plants A & B in electricity-only mode and with maximum heat extraction.

Figure 4.13: Plant A vs Plant B Energy balance when scaled for the same power output



Source: Mott MacDonald

4.6 Indicative plant layouts and equipment lists

4.6.1 Equipment Size

4.6.1.1 Plant A

The equipment associated with one Plant A SMR module is listed in Table 4.5. Equipment weights and dimensions are an output of the PEACE costing model and are based on actual equipment duties.

Table 4.5: Plant A - Equipment list (per module)

Power plant					
Equipment	**Number**	**Capacity**	**Size**		**Weight (tonnes)**
			Length (m)	**Width (m)**	
Steam Turbine	1	$50MW_e$	7.3m	4.9m	116t
ST generator (including exciter)	1	58MVA	8.4m	3.1m	97.3t
Water cooled Condenser	1	$1887m^2$ effective surface area	8.8m	2.9m	66t (operating wet weight – excluding vacuum forces)
Mechanical draught cooling towers	1	2170kg/s of closed cooling water	13.5m per cell 5 cells	12.7m per cell 5 cells - 12.8m overall height	457t (wet operating weight excluding basin water)
Cooling water pump and motor	3 x 50%	16m pump pressure rise	1.4m	0.9m	Pump: 1.1t (each) Motor: 1.0t (each)
Feedwater pump and motor	3 x 50%	479m pump pressure rise	2.5m	0.9m	Pump: 1.0t (each) Motor: 0.9t (each)
Condensate pump and motor	3 x 50%	80m pump pressure rise	0.66m	1.0m	Pump: 0.4t (each) Motor: 0. t (each)
LP feedwater heater	1	$417m^2$ total external heat transfer area	13.4m	1.08m outer diameter	13.8t (operating wet weight)
HP feedwater heater	1	$160m^2$ total external heat transfer area	10.3m	0.8m outer diameter	5t (operating wet weight)
Deaerator	1	242.6t/h feedwater exit flow	7.7m	2.5m outer diameter - 5.3m overall height	12.2t dry
DH system					
Equipment	**Number**	**Capacity**	**Size**		**Weight (tonnes)**
DH condenser	2 x 50%		14.7m	1.9m outer diameter	35.5t dry 63.6 t total operating wet
DH pump (see note 1)	3 x 50%	173m pump pressure rise	5.3m	1.3m	Pump: 5.9t (each) Motor: 5.3t (each)
DH condensate pump	3 x 50%	54m pump pressure rise	1.0m	1.0m	Pump: 0.4t (each) Motor: 0.3t (each)

Note 1: Duty for all 6 reactors

Source: Mott MacDonald

4.6.1.2 Plant B

Table 4.6 below lists the equipment associated with one Plant B module. As above, equipment weights and dimensions are an output of our steam cycle thermal model and are based on the equipment duties.

Table 4.6: Plant B - Equipment list (per module)

Power plant					
Equipment	**Number**	**Capacity**	**Size**		**Weight (tonnes)**
			Length (m)	**Width (m)**	
Steam Turbine	1	$182MW_e$	20m	6.7m	432t
ST generator (including exciter)	1	213MVA	11.6m	3.8m	243t
Water cooled Condenser	1	6500 m^2 effective surface area	16.8m	4.0m	217t (operating wet weight – excluding vacuum forces)
Mechanical draught cooling towers	1	6747.5kg/s of closed cooling water	13.45m per cell 14 cells	14.12m per cell 14 cells – 13.2m overall height	1,550t (wet operating weight excluding basin water)
Cooling water pump and motor	3 x 50%	14m pump pressure rise	2.1m	2.1	Pump: 2.1t (each) Motor: 2.1t (each)
Feedwater pump and motor	3 x 50%	811m pump pressure rise	3.7m	1.34	Pump: 5.4t (each) Motor: 4.7t (each)
Condensate pump and motor	3 x 50%	148m pump pressure rise	1.5m	1.5 m	Pump: 1.1t (each) Motor: 1.1t (each)
LP1 feedwater heater	1	$789m^2$ total external heat transfer area	17.0m	1.3m outer diameter	26.94t (operating wet weight)
LP2 feedwater heater	1	$423m^2$ total external heat transfer area	13.6m	1.0m outer diameter	15.36t (operating wet weight)
HP feedwater heater	1	$916m^2$ total external heat transfer area	14.6m	1.5m outer diameter	36t (operating wet weight)
Deaerator	1	961t/h feedwater exit flow	12.3m	3.8m outer diameter – 7.1m overall height	40.5t dry
Reheater condensate pump	3 x 50%	210m pump pressure rise	1.5m	0.5m	Pump: 0.3t (each) Motor: 0.2t (each)
Pump for water extracted in moisture separator	3 x 50%	790m pump pressure rise	2.1m	0.75m	Pump: 0.7t (each) Motor: 0.6t (each)

DH system					
DH Equipment	Number	Capacity	Size		Weight (tonnes)
DH condenser	4 x 25%		15m	2.2m outer diameter	54.6t dry 69.3t total wet
DH pump (see note 1)	3 x50%	195m pump pressure rise	7.6m	1.9m	Pump: 24.0t (each) Motor: 21.9t (each)
DH condensate pump	3 x 50%	103m pump pressure rise	1.5 m	1.5m	Pump: 1.0t (each) Motor: 0.9t (each)

Note 1: Duty for all 6 reactors
Source: Mott MacDonald

4.6.2 Plant layout and 3D view

An SMR power plant is likely to consist of multiple power modules and a corresponding number of steam turbines deployed together at a single site. Sections 4.1 to 4.4 above were based on one module but for the illustrative 3D plant layouts and DH system designs in this section we have assumed:

- For Plant A, six modules together at a single site (totalling 300MW$_e$ gross capacity);
- For Plant B, two modules together at a single site (totalling 360MW$_e$ gross capacity).

This is intended to represent one possible size of SMR plant (broadly equivalent to the 300MW$_e$ generic plant assumed in Phases 1 and 2) but in reality future plants may be larger or smaller than this.

4.6.2.1 Plant A equipment layout

Using the equipment dimensions from Table 4.5 and typical equipment configurations from the thermal modelling software, a basic equipment layout has been created to show the potential extent of footprint modifications required to add CHP functionality to a six modules reactor power plant. This is shown in Appendix G.1.

4.6.2.2 Plant B equipment layout

A publically available mPower presentation shows a plant layout for four modules with an ACC. [4]

Using this layout and the equipment dimensions from Table 4.6, a basic equipment layout has been created to show the potential extent of footprint modifications required to add CHP functionality to a two module power plant. This is shown in Appendix G.2

The mPower presentation states that 2 modules will require a 457m x 305m plot and 14.6ha of space within an outer fence[5]. Our indicative layout (including CHP functionality and based on cooling towers) is

4 mPower (2010) ANS/DC Chapter Presentation (Presentation). T.J.Kim

5 mPower (2013) IAEA SMR Technical Meeting (Presentation). Robert Temple, Chengdu China, September 3 2013.

based on a 507m x 330m plot which equates to a total space requirement of 16.7ha, which closely resembles the mPower presentation.

4.7 'CHP readiness'

The thermodynamic modelling presented here suggests that it is technically feasible to extract heat from SMR plant steam cycles to supply large-scale DH networks. This would involve using proven technical approaches that are relatively easy to implement provided they are built in from the start or as long as the SMR steam cycles are designed to be 'CHP ready', meaning they could easily be upgraded to supply heat in the future. If early SMR plants are initially required to provide electricity only, we suggest that consideration is given to future-proofing these plants by requiring them to be 'CHP ready'. If electricity-only SMR plants are built without due consideration given to future heat supply there is a risk that the costs and complexities of a mid-life plant upgrade would be prohibitive.

4.7.1 Potential requirements of a CHP ready facility

A CHP ready facility would be an SMR plant initially built to provide electricity only, but one that can easily be retrofitted with CHP technology when the necessary regulatory, infrastructure and economic drivers are in place. The site chosen should be close enough to provide heat to a city or large town that has or will have in the future a DH network installed. Using the existing CCS readiness requirements as a guide, the potential requirements for a CHP Ready SMR facility are set out below.

The project developer should:

- Demonstrate that retrofitted CHP equipment can be connected to the existing equipment effectively and without an excessive outage period and that there will be sufficient space available to construct and safely operate additional CHP facilities.
- Include plant features that should be ***installed when the plant is built***:
  - A ST with a cross-over and room for a control valve to facilitate CHP steam offtake across the ST load range;
  - Civils and structures are designed for additional CHP equipment in existing buildings i.e. suitable location for CHP pumps considering NPSH requirements.
- Include the following ***additional space requirements*** should also be built into the plant:
  - Space for on-site CHP pipework;
  - Space for any additional pressure relief required due to addition of cross-over control valve;
  - Space for connection to integrate CHP heat exchanger condensate ;
  - Space available for all the CHP equipment with suitable space for maintenance of equipment;
  - Space for additional transformers, Motor Control Centre (MCC) and cabling or a suitably sized auxiliary power supply for the future CHP loads;
  - Space for additional Input/Output (I/O) for CHP control;
  - Space for CHP expansion tank (if on site);
  - Ability to extend site utilities to accommodate CHP equipment e.g. instrument air, lighting etc.;
  - Identify and leave clear realistic CHP pipeline or other route(s) to CHP users;

– Space to facilitate construction of the CHP, including contractor accommodation and laydown, while maintaining SMR operations.

4.7.2 Cost of CHP readiness

We estimate that the potential incremental specific CAPEX of CHP readiness is ~£10/kW$_e$. This is broken down in Table 4.7. It compares to a total 'inside the plant boundary' cost of an actual CHP upgrade of ~£92/kW$_e$ to £115/kW$_e$ (see Section 6.2 for more details).

Table 4.7 – Estimate of incremental specific CAPEX of CHP readiness

Equipment	Incremental specific CAPEX for 'CHP Readiness' (£/kW$_e$)
ST cross-over (Estimated 10% uplift on ST cost)	4.9
ST building (Estimated 15% uplift to ST building cost)	2.4
DH condenser civils	0.8
DH pump civils	1.5
DH condensate pump civils	0.1
Total - Owner's Cost	9.6

Source: Mott MacDonald

4.7.3 An international perspective

The ANT project is focussed on SMR requirements for the UK's future energy system. However it is important to recognise that there is a potentially large and diverse international market for SMR technologies, and that some of these markets could have requirements beyond the supply of electricity and heat for DH networks. For example, a recent paper by Locatelli et al (2015)[6] explored the potential for desalination and algae biofuel applications that use heat extracted from an SMR thermal cycle.

Given this potential, we suggest that further investigation may be warranted to determine whether the 'CHP ready' concept described above should be broadened to include a wider range of potential applications, not just DH heat supply. Such an approach would allow a standardised SMR plant design with potential for steam off-take for multiple applications to be taken through the GDA licensing process.[7]

Achieving GDA licensing for a standardised design with steam off-takes for multiple applications is important because the economic case for SMRs is underpinned by cost reductions driven by modularisation and the fabrication of standardised components using mass production techniques. Full realisation of these 'economies of multiples' is likely to require the production of a large number of identical units, which in turn will require a market of sufficient size to drive demand. Whilst it is outside the scope of

[6] Giorgio Locatelli, Sara Boarin, Francesco Pellegrino and Marco E. Ricotti - Load following with Small Modular Reactors (SMR): A real options analysis - Energy 80 (2015) 41-54

[7] This report only considers the technical solutions and costs associated with heat extraction for DH network supply. It does not consider any additional or alternate modifications that may be required for other heat offtake applications. These modifications may require a different solution to the one presented in this report.

the ANT project to investigate the level of market demand required to fully exploit the economies of multiples, it is clear that a single licensed SMR design that is flexible enough to access a variety of international markets will be in a stronger commercial position than a competing SMR design only capable of a limited range of applications.

4.8 Summary

Overall, based on the public domain information available as an input to this report, we conclude that it is likely to be both practical and technically feasible to adapt the proposed different SMR steam cycles to supply heat to large-scale DH networks. Our analysis suggests that this thermal integration can be done in such a way as to deliver a wide-range of CHP plant flexibility (varying levels of heat and power output) with minimal impacts on efficiency and operation in power only mode.

In addition, our thermodynamic modelling indicates that some key performance parameters for Plants A and B are different from the generic assumptions used in Phases 1 and 2. Whilst these differences do not impact the overall economic case for heat extraction from SMR plants (see Section 7), they could have an impact at the energy system level. In particular, the higher heat to power ratios that result from less efficient Plant A and B steam cycle models imply that a lower SMR fleet electrical capacity would be needed to meet a given heat demand. In Phases 1 and 2 we calculated that ~22.3GW_e[8] SMR fleet capacity would be required to meet the identified demand, based on an assumed heat to power ratio of 1.8. For comparison, this falls to ~18GW_e fleet capacity using the higher Plant A's heat to power ratio identified in this report.

8 There is a set of supporting assumptions and underpinning analysis behind this value. For a detailed understanding of the origin of this figure it is necessary to refer to the Phases 1 and 2 report.

5 Cooling system options

The base case SMR analysis has been performed assuming that the LWR SMR plants are built with Draught Mechanical Evaporative Cooling Towers (ECTs) as their primary cooling mechanism. However in the future it is conceivable that SMR plants located at inland sites may face an increasing risk of restrictions on abstraction from inland water sources due to extended periods of drought in a changing climate. To explore potential options for maintaining plant operation in these circumstances, we undertook a high-level assessment of alternative plant cooling systems, including their technical feasibility and impact on plant cost and performance.

The main alternative option which has been explored is the use of ACCs which do not require access to a water source. Our main scenario assumes a ‘hybrid’ cooling system, where a plant initially built with an ECT is subject to a mid-life upgrade to include an ACC *in addition* to its ECT. This hybrid system would involve both cooling technologies operating in tandem – the ECT during periods of water availability and the ACC during periods of scarcity. We do not consider the adequacy of an ACC as the ultimate heat sink for reactor safety during abnormal operations because this is outside the scope of the ANT Phase 3 project.

The other options explored (at a higher level of detail) include
- Sea water mechanical ECTs with long distance access to the coast;
- Dry cooling towers, also known as fin-fan cooling radiators.

Before presenting our investigation into these alternative cooling methods some background information on ECT technologies is provided.

This section is based on Plant A which provides a representative indication of impacts in the event of the ECT primary coolant source being constrained. This is considered reasonable since the options for cooling system applications are not expected to be dependent upon the deployed SMR technology type.

5.1 Base Case: Mechanical Draught ECTs

5.1.1 Outline process description

As shown in Figures 5.1 and 5.2, the configuration of a mechanical draught ECT contains a water-cooled condenser, a closed water circuit, and cooling towers where excess heat is released to the atmosphere by evaporation.

Warm cooling water from the condenser is cooled by evaporation while falling through a current of air in the cooling tower and coming to rest in the collecting basin below. The cooled water then circulates in a closed loop from the collecting basin back to the condenser.

5.1.2 Design

The design of ECTs can be either mechanical draught or natural draught.

Figure 5.1: Natural draught cooling tower

Source: Mott MacDonald

Figure 5.2: Mechanical draught cooling tower

Source: Mott MacDonald

Mechanical draught towers are currently the most common type of ECTs installed with power plants. In these towers, air flow through the tower is induced by a mechanical fan located on the top of the towers.

Natural draught cooling towers are sometimes installed in large power plants. Natural draught cooling towers, typically of reinforced concrete construction, rely on the buoyancy of the warm humid plume to naturally draw air upwards against the cooling water flow, saving auxiliary power consumed by fans. However, since the density difference between the warm plume and the ambient air is small, the tower needs to be tall to generate sufficient draught. Natural draught ECTs are typically limited to large plants (exceeding 500MW$_e$ capacity).

We do not consider natural draught ECTs as an alternative to mechanical draught evaporative heat exchangers because they are not recommended for sites where space is limited or where there are restrictions on the visual impact of the plant.

The optimum design of any ECT is site specific, however it should be noted that mechanical draught cooling towers offer greater modularity over natural draught cooling towers. The design of any natural draught cooling tower will require site specific design and construction, whereas multiple “off the shelf” mechanical draught cooling towers could be combined to achieve the required heat removal rates.

5.1.3 Water requirements

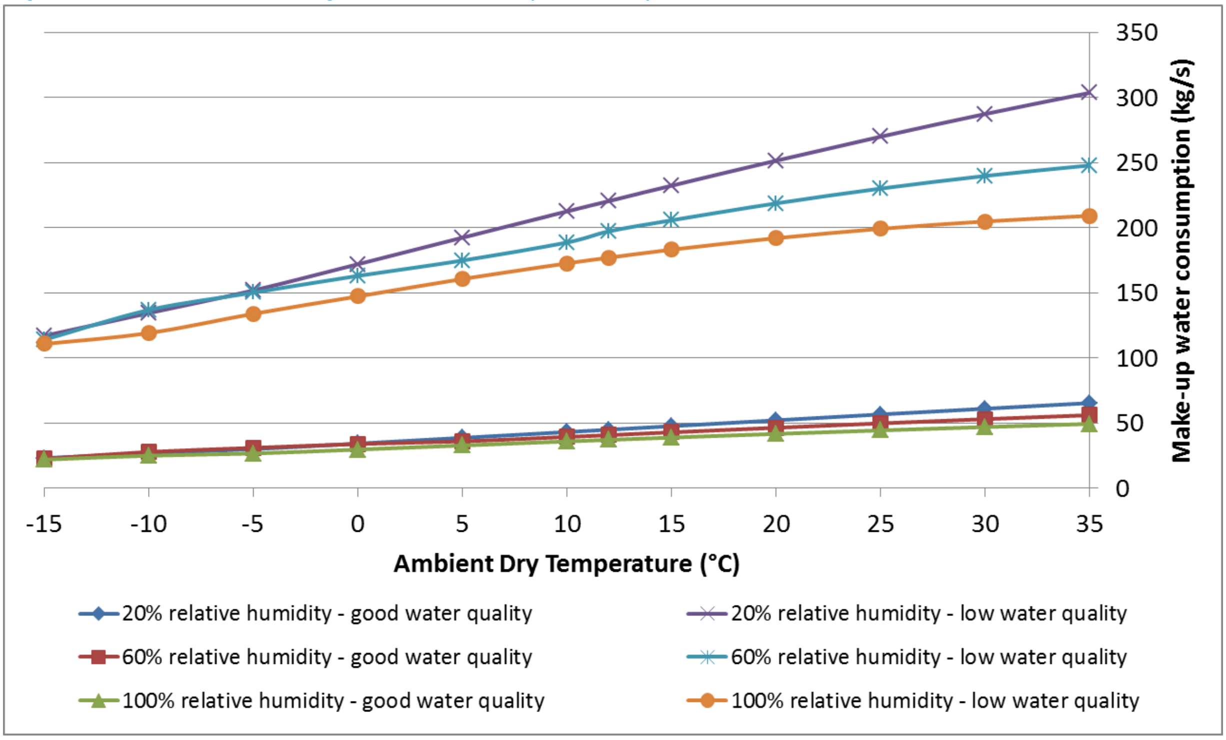
In Sections 2 and 4 we assumed the make-up water to replace water lost in the cooling towers due to drift, evaporation and blowdown, would be extracted from a nearby river.

The level of make-up water required by ECTs is dependent on:
- The evaporation rate, which depends on ambient conditions;
- The blowdown rate, which is selected based on the quality of the make-up water and impurities in the air. Generally, the blowdown could vary from 1% for very high quality make-up water to 20% of the recirculation rate for lower quality;
- The quantity of water lost through drift (i.e. water lost as liquid droplets entrained with the air). Typically the drift in modern cooling towers is expected to be minimum.

Figure 5.3 shows indicative maximum and minimum water requirements for one reactor over the ambient envelope when generating electricity only with the reactor output at 100%.

The water requirement for one module is expected to be around 20-65kg/s if river water is good quality or around 110-305kg/s for lower river water quality (e.g. brackish water or seawater).

Figure 5.3: Mechanical draught ECTs – Make-up water requirements for one 50MW$_e$ module



Note: (1) Excludes water demand for primary system, services, sanitation, steam cycle (other than cooling towers) and DH circuit treatment and make-up; (2) Assumes electricity-only SMR plant.

Source: Mott MacDonald

5.2 Option 1: Air Cooled Condenser

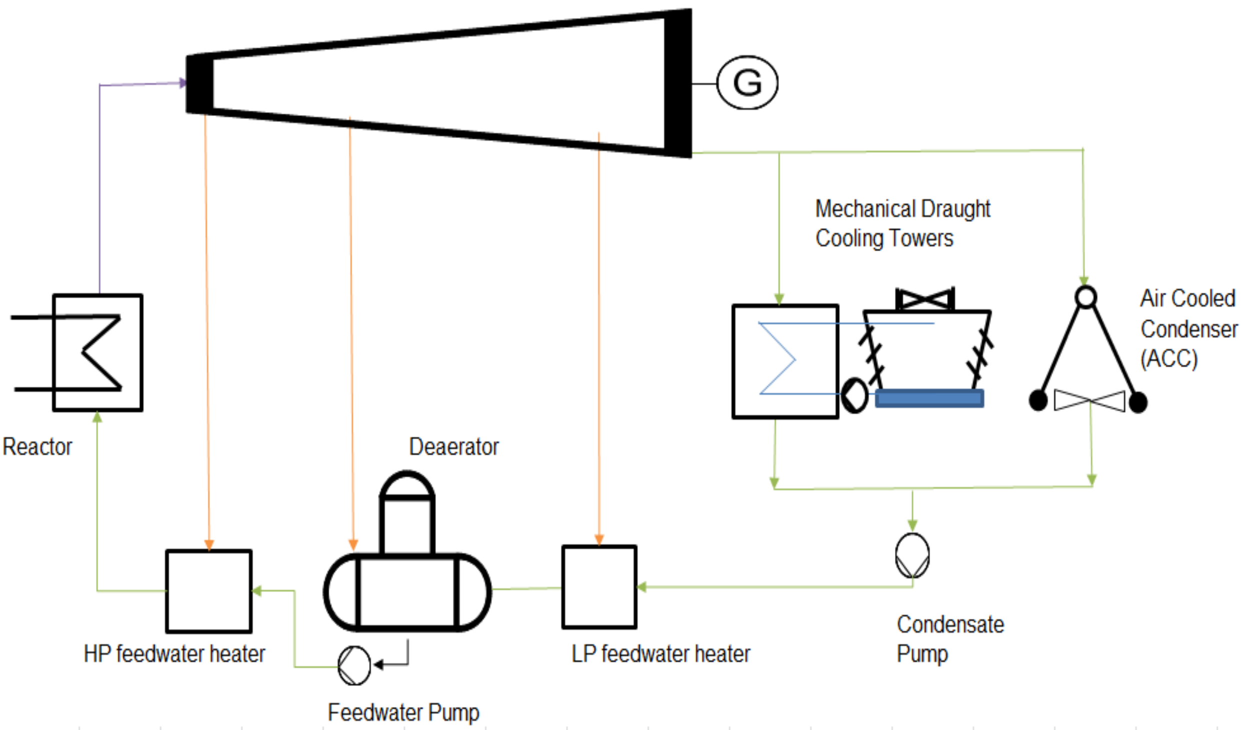
ACCs are common worldwide, with over 1,000 global uses at combined cycle power plants, biomass/ waste to energy plants, coal-fired plants and even a few solar plants. In 2015, the 1,020MW$_e$ Loviisa nuclear power plant in Finland was the first nuclear plant to install a back-up ACC (in case of seawater unavailability) after the technology was identified as a development target by the Finnish nuclear regulator, STUK, in response to the Fukushima accident in March 2011.

5.2.1 Outline process description

The ACC condenses turbine exhaust steam inside finned tubes which are externally cooled by ambient air (instead of sea or river water).

Figure 5.4 shows an indicative steam cycle model for Plant A with the hybrid cooling system comprising both an ECT and ACC.

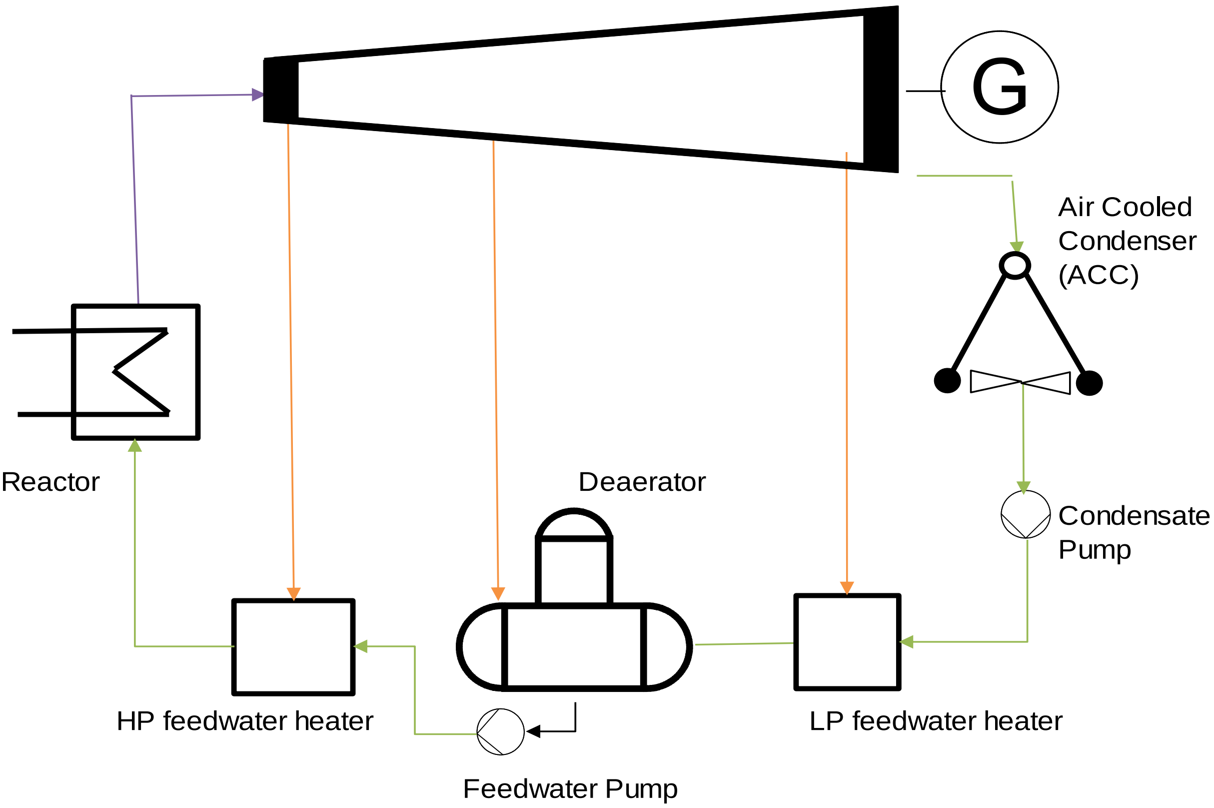
Figure 5.4: Steam cycle model for Plant A (single 50MW$_e$ module) with hybrid cooling system of an ECT and ACC



Source: Mott MacDonald

Figure 5.5 shows the Plant A steam cycle model with an ACC instead of mechanical draught cooling towers.

Figure 5.5: Steam circuit for Plant A (single 50MW$_e$ module) with an ACC only



Source: Mott MacDonald

5.2.2 Impact on plant performance

The relative performance of an ACC verses ECT will vary throughout the year due to changes in ambient conditions like temperature and humidity.

Base case SMR plant steam cycle models in Section 5 have been designed to operate optimally at 12°C dry ambient temperature, 60% relative humidity and 1.013bara. However we have also considered the impact of varying conditions with the ambient dry temperature at site varying from -15°C to +35°C, relative humidity from 20% to 100% and pressure ranging from 950 to 1050 mbar.

In the sections below we present the impact of different ambient conditions on a plant with an ACC and a plant with an ECT, in both electricity-only and CHP operating modes. The performance envelope of the hybrid cooling system is bounded by the ACC at the lower end and the ECT at the higher end during high ambient temperatures.

Due to the relatively low air-side heat transfer coefficients, the heat exchange area required by ACCs is high, increasing footprint and capital costs compared to the ECT option. In our analysis below, two sizes of ACC were considered:

- A configuration with a ful duty (unconstrained) ACC for projects where land and/or capital costs are unconstrained. In this case the plant with unconstrained ACC will maintain the gross power output below/at the design conditions, maximising plant efficiency;
- A configuration with smaller size (constrained) ACC involving a penalty in gross power output over the whole ambient conditions range. The plant owner may decide to install a smaller size ACC to limit the investment in capital cost or the SMR plant may be located in a relatively constrained site where the available space is not sufficient to accommodate a full duty ACC.

A constrained ACC has been considered to determine the energy efficiency penalty of retrofitting an SMR at some time in the future when it was not originally designed and built with sufficient space for ACCs. This scenario will help determine if a plant should be built ‘ACC ready’ to reduce the risk of becoming a stranded asset. See Section 5.2.7 for more details on ACC readiness.

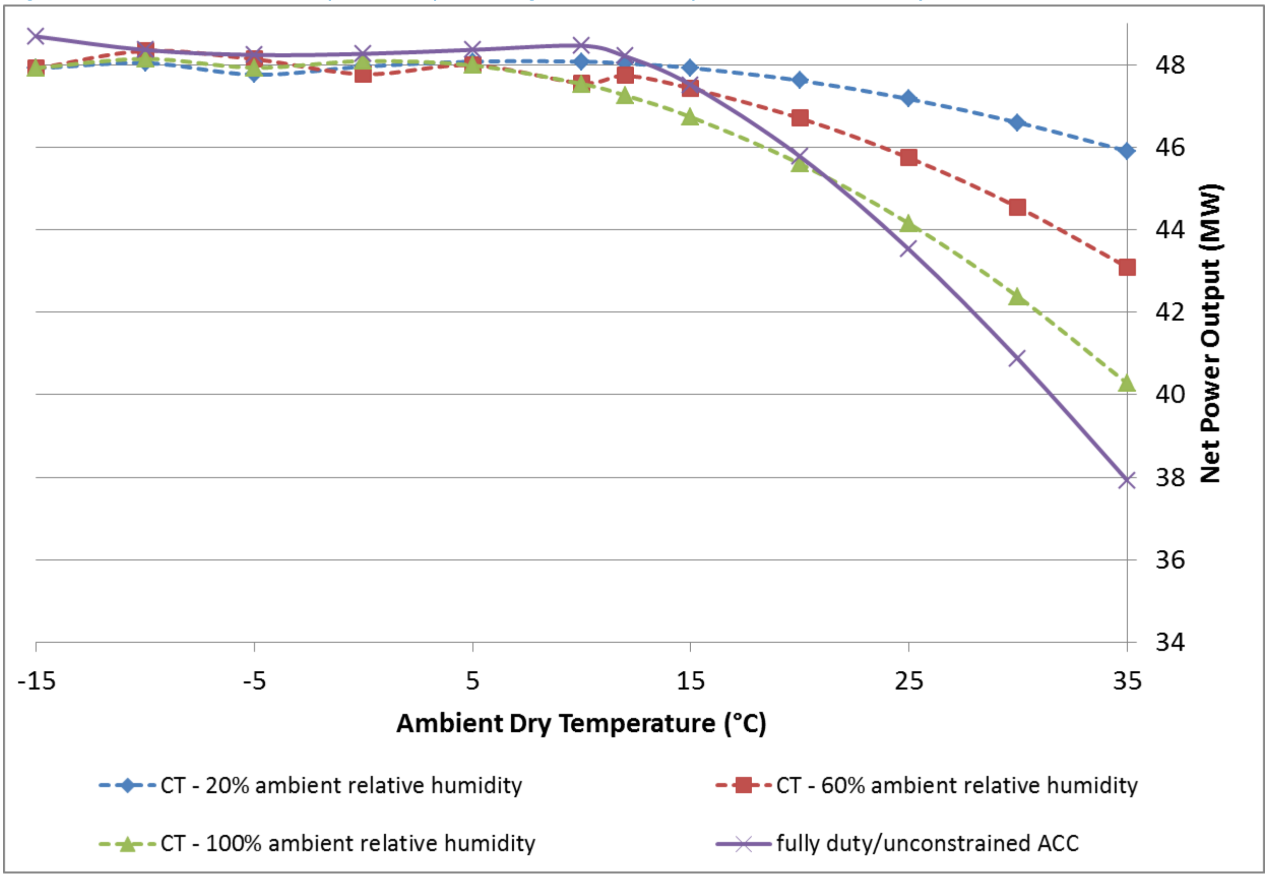
5.2.2.1 Electricity only mode

In this section, we have assessed SMR plant performance in electricity-only mode over the range of ambient conditions by creating two process models with either unconstrained ACCs or ECTs as the cooling method. Both process models were designed at ambient conditions of 12°C and 60% relative humidity.

Figure 5.6 compares the results of our modelling for a configuration with a full duty/unconstrained ACC against a configuration with ECTs in electricity-only mode.

As shown in Figure 5.6, there is no impact on plant performance with ambient conditions below the design temperature (12°C). However when the ambient temperature increases above the design temperature, the performance of a plant with an unconstrained ACC degrades at a greater rate than with ECTs. Above design temperature, the net power output of a plant with an unconstrained ACC is lower when compared with the use of ECTs. At maximum ambient temperature (+35°C) in electricity-only mode the configuration with an unconstrained ACC has a net power 12% lower than a configuration with ECTs.

Figure 5.6: Reduction in net power output for high ambient temperatures with full duty ACC



Note: Assumes 100% reactor thermal output and no steam extraction. Auxiliary load includes cooling tower/ACC fans and pumps, Steam turbine auxiliaries and feedwater and condensate pumps.
Source: Mott MacDonald

The installation of an unconstrained ACC with an equivalent duty to an ECT will require 1,280 m^2 (per Plant A module) of available space on site. At the design temperature (12°C), this configuration offers the same level of gross power (50MW_e per module) and a slightly higher net power (by less than 1%) than a configuration with ECTs. This minor increase in net power is due to a small reduction in auxiliary load with an unconstrained ACC.

For the ‘constrained’ ACC option, we created a third process model where the size of the ACC is reduced to the same footprint of the cooling towers (which is 46% smaller than a full duty/unconstrained ACC). In this case, at design point, the plant with a constrained ACC has a net power output which is 7% lower than a configuration with ECTs. At maximum ambient temperature, the net power output penalty reaches 25%.

Table 5.1 shows plant performance at the design temperature (12°C and 60% relative humidity) and maximum ambient temperature (35°C and 60% relative humidity) for the three process models:

1. Plant with ECTs;
2. Plant with a full duty/unconstrained ACC;
3. Plant with a restricted size/constrained ACC.

Table 5.1: Performance impact for unconstrained/constrained ACCs in electricity-only mode and 100% reactor load

	12°C dry ambient temperature			35°C dry ambient temperature		
Parameter	**Base Case (mechanical draught cooling towers)**	**Full duty/ unconstrained ACC**	**Constrained/ restricted size ACC**	**Base Case (mechanical draught cooling towers)**	**Full duty/ unconstrained ACC**	**Constrained/ restricted size ACC**
Reactor thermal output (MW_{th})	159.4	159.4	159.4	159.4	159.4	159.4
DH heat load (MW_{th})	0	0	0	0	0	0
Plot plan (m^2)	850	1,200	850			
Gross Power Output (MW)	**50**	**50.1 0.4%**	**46.2 -7.5%**	**45.2**	**39.7 -12.1%**	**34.1 -24.4%**
Condensing pressure (bara)	0.070	0.070	0.134	0.147	0.253	0.472
Auxiliary Load (MW)						
CT fans	0.72	0.00	0.000	0.686	0.00	0.00
CT pump	0.43	0.00	0.000	0.422	0.00	0.00
ACC fans	0.00	0.88	0.655	0.000	0.88	0.66
Condensate Pump	0.03	0.03	0.026	0.029	0.03	0.03
Feedwater pump	0.39	0.46	0.455	0.399	0.45	0.45
ST auxiliaries	0.11	0.11	0.11	0.11	0.11	0.11
Miscellaneous	0.49	0.49	0.46	0.45	0.40	0.41
Make up water pump	0.00	0.00	0.00	0.00	0.0	0.00
TOTAL (MW)	**2.187**	**1.97**	**1.70**	**2.094**	**1.87**	**1.66**
Net Power Output (MW)	**47.7**	**48.16 0.9%**	**44.49 -6.8%**	**43.1**	**37.87 -12.1%**	**32.56 -24.5%**
Gross electric efficiency	31.32%	31.45%	28.96%	28.35%	24.93%	21.41%
Net electrical efficiency	29.95%	30.21%	27.89%	27.04%	23.76%	20.41%

Source: Mott MacDonald

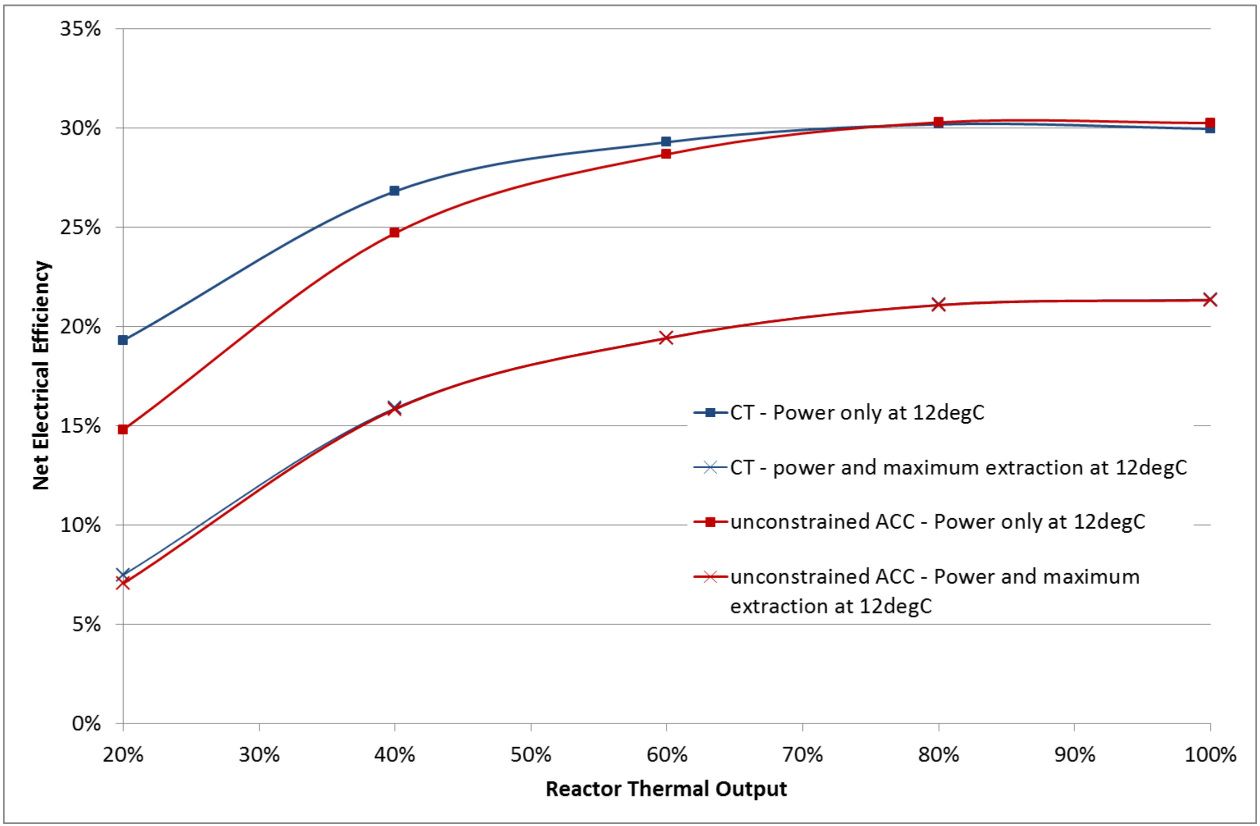
5.2.2.2 Performance across different CHP operational modes

To understand the impact of ACCs on the performance of CHP SMR plants, we created three additional process design models for a CHP plant with ECTs and ACCs as per above and analysed their performance in different CHP operational modes (with varying levels of core reactor output).

Figures 5.7 to 5.10 compare the net electrical efficiency in electricity only mode at maximum steam extraction for unconstrained and constrained ACCs. In each case results are shown for two ambient temperatures – 12°C (design temperature) and 35°C (assumed maximum ambient temperature).

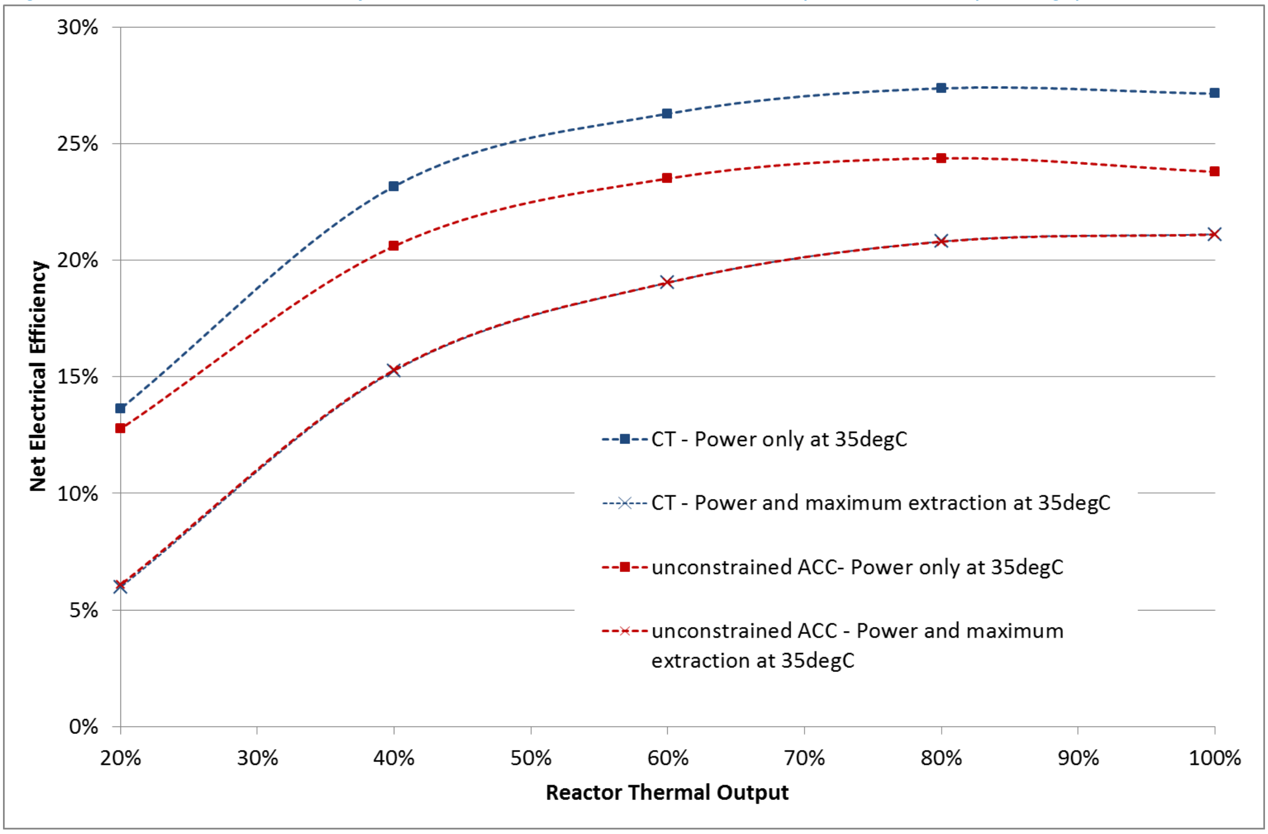
It should be noted that net electrical efficiency in Figures 5.7 to 5.10 includes the auxiliary loads for power supply to the DH pumps needed for the CHP DH network.

Figure 5.7: Net electrical efficiency of unconstrained ACC vs ECT at 12°C (over reactor output range)



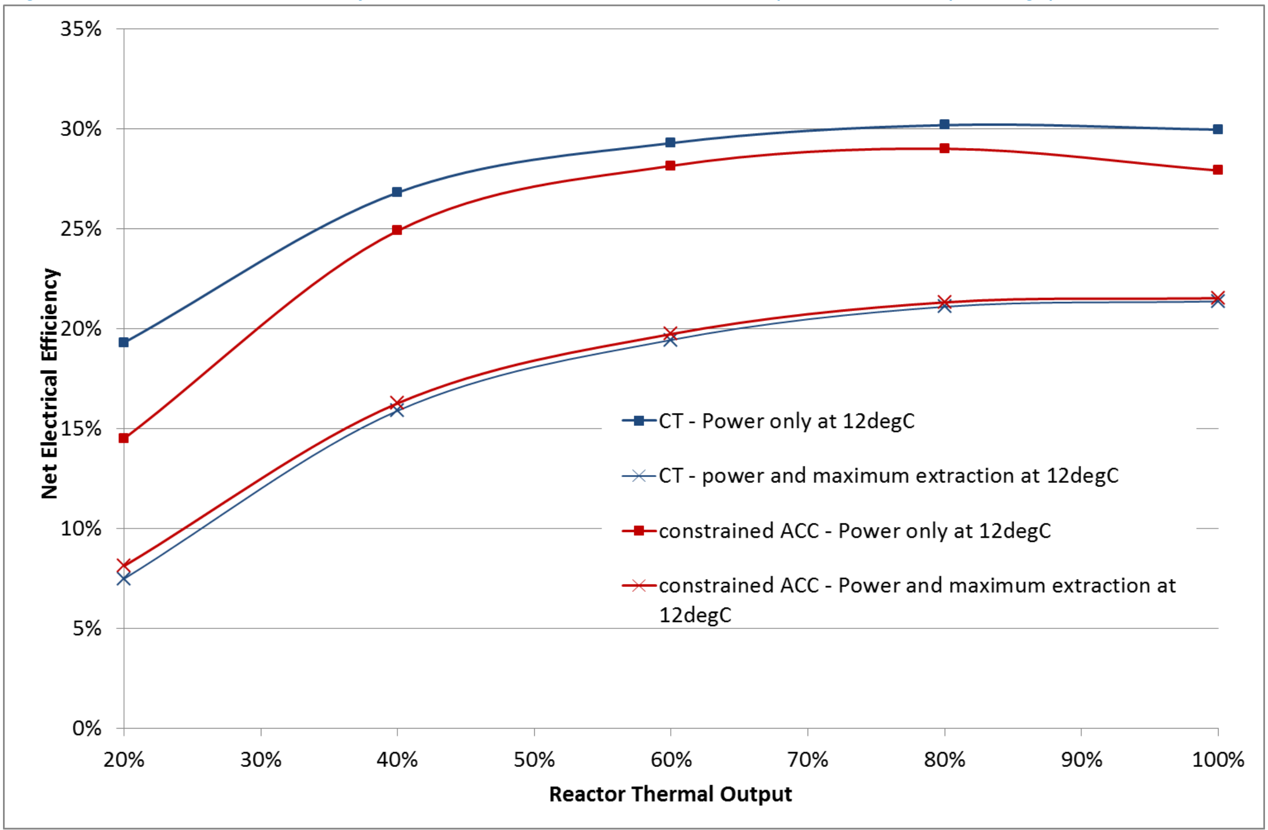
Source: Mott MacDonald

Figure 5.8: Net electrical efficiency for unconstrained ACC vs ECT at 35°C (over reactor output range)



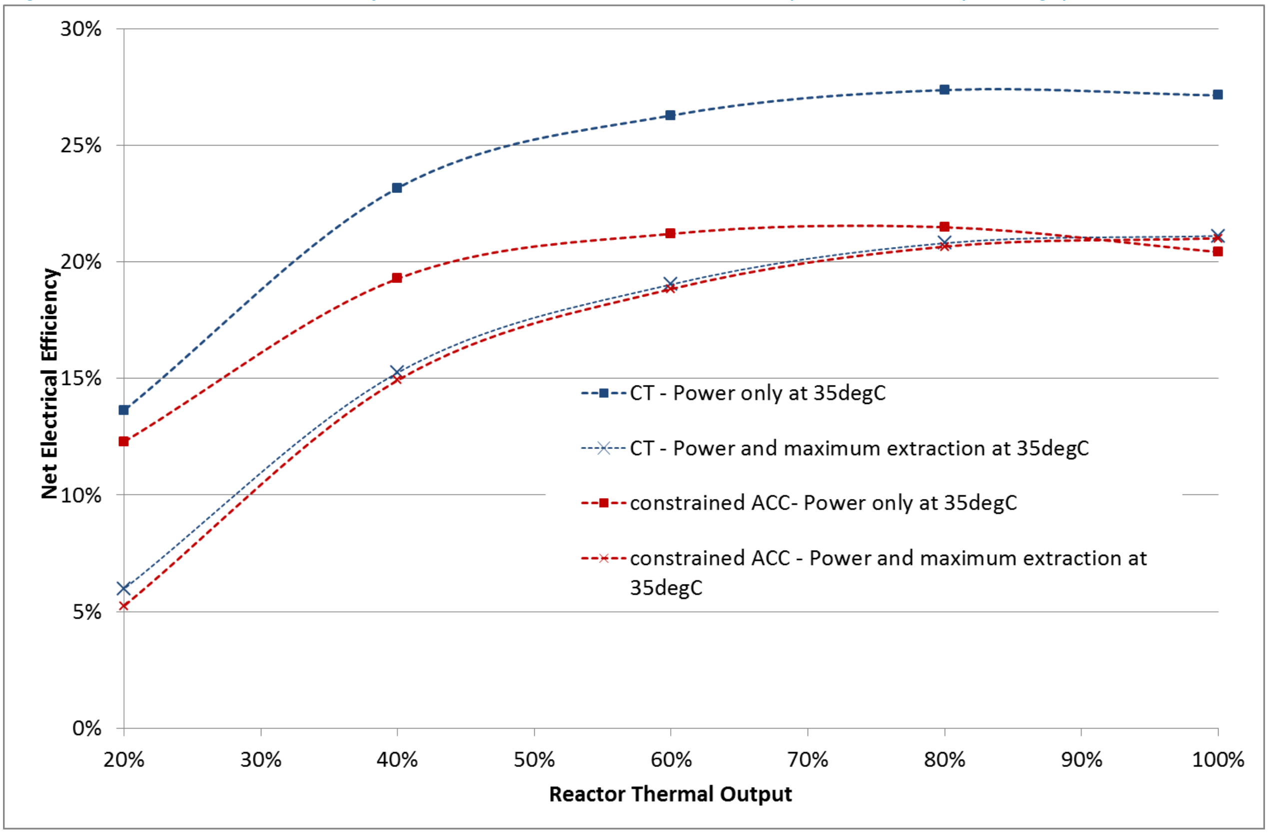
Source: Mott MacDonald

Figure 5.9: Net electrical efficiency for constrained ACC vs ECT at 12°C (over reactor output range)



Source: Mott MacDonald

Figure 5.10: Net electrical efficiency for constrained ACC vs ECT at 35°C (over reactor output range)



Source: Mott MacDonald

Table 5.2 summarises the performance of one Plant A, 50MW$_e$ SMR module at core reactor outputs ranging from 20% to 100%, in both electricity-only and CHP modes at design and maximum ambient temperature (12°C and 35°C). The key results are marked **in bold.**

Table 5.2: Performance of unconstrained/constrained ACC against ECTs

	Ambient temperature 12°C					Ambient temperature 35°C				
Reactor thermal output	100%	80%	60%	40%	20%	100%	80%	60%	40%	20%
Mechanical draught cooling towers - one module										
Electricity only mode										
Gross Power (MW)	50	40	29.	18	7	45.2	36.4	26.4	16.0	5.7
Net Power (MW)	**48**	**38**	**27**	**16**	**6.0**	**43.3**	**34.5**	**24.6**	**14.4**	**4.3**
DH Condenser (MW_{th})	0	0	0	0	0	0	0	0	0	0
Gross efficiency	31.32%	31.51%	30.59%	28.15%	21.14 %	28.35%	28.90%	28.18%	25.78%	18.39%
Net efficiency	29.95%	29.87%	28.72%	25.84%	17.51%	27.03%	27.37%	26.28%	23.17%	13.63%
Maximum steam extraction										
Gross Power (MW)	37.0	28.7	19.8	11.2	3.5	36.4	28.1	19.2	10.5	2.8
Net power - included booster pump (MW)	**34.1**	**26.6**	**18.2**	**9.9**	**2.3**	**33.7**	**26.2**	**17.8**	**9.5**	**1.9**
DH Condenser (MW_{th})	109.3	84.3	60.8	37.6	13.8	109.6	84.9	61.3	38.1	13.9
Gross efficiency	23.17%	22.73%	21.12%	17.97%	11.08%	22.83%	22.27%	20.49%	16.96%	8.85%
Net efficiency	21.33%	21.09%	19.43%	15.89%	7.48%	21.12%	20.81%	19.03%	15.25%	5.97%
Ratio of maxi heat output to max NET electrical output	**2.23**									
Gross derating	**-26.2%**									
Net derating	**-28.7%**									
Unconstrained ACC - one module										
Electricity only mode										
Gross Power (MW)	50.1	39.8	28.1	16.2	5.1	39.7	32.3	23.5	14.0	5.0
Net Power (MW)	**48.2**	**38.2**	**26.9**	**15.3**	**4.6**	**37.9**	**30.7**	**22.0**	**12.8**	**4.0**
Net power penalty compared with cooling tower case	**0.9%**	**1.1%**	**-0.6%**	**-5.1%**	**-17.1%**	**-12.4%**	**-11.0%**	**-10.6%**	**-11.1%**	**-6.3%**
DH Condenser (MW_{th})	0	0	0	0	0	0	0	0	0	0
Gross efficiency	31.44%	31.55%	29.98%	26.03%	16.21%	24.92%	25.66%	25.03%	22.58%	16.07%
Net efficiency	30.21%	30.27%	28.67%	24.70%	14.80%	23.76%	24.37%	23.50%	20.60%	12.77%
Net efficiency penalty compared with cooling tower case	**0.28%**	**0.34%**	**-0.16%**	**-1.33%**	**-3.04%**	**-3.35%**	**-3.00%**	**-2.78%**	**-2.57%**	**-0.86%**
Maximum steam extraction										
Gross Power (MW)	36.3	27.9	19.0	10.4	2.5	36.2	27.9	19.0	10.4	2.6
Net power included booster pump (MW)	**34.0**	**26.6**	**18.2**	**9.8**	**2.2**	**33.6**	**26.2**	**17.8**	**9.5**	**1.9**

	Ambient temperature 12°C					Ambient temperature 35°C				
Reactor thermal output	100%	80%	60%	40%	20%	100%	80%	60%	40%	20%
Net power penalty compared with cooling tower case	**-0.2%**	**-0.1%**	**-0.1%**	**-0.4%**	**-5.7%**	**-0.1%**	**-0.1%**	**0.0%**	**0.3%**	**1.7%**
DH Condenser (MW_{th})	109.9	84.9	61.3	38.0	14.1	109.9	85.0	61.4	38.2	14.1
Gross efficiency	22.74%	22.15%	20.32%	16.68%	8.08%	22.74%	22.15%	20.32%	16.69%	8.20%
Net efficiency	21.32%	21.07%	19.41%	15.83%	7.05%	21.10%	20.79%	19.04%	15.29%	6.08%
Net efficiency penalty compared with cooling tower case	**-0.04%**	**-0.02%**	**-0.02%**	**-0.06%**	**-0.43%**	**-0.01%**	**-0.01%**	**0.00%**	**0.04%**	**0.10%**
Ratio of maxi heat output to max NET electrical output	**2.22**									
Gross derating	**-27.6%**									
Net derating	**-29.5%**									
Constrained ACC - one module										
Electricity only mode										
Gross Power (MW)	46.2	38.1	27.7	16.5	5.2	34.1	28.5	21.2	13.1	4.8
Net Power (MW)	**44.5**	**36.6**	**26.4**	**15.5**	**4.5**	**32.6**	**27.1**	**19.9**	**12.0**	**3.8**
Net power penalty compared with cooling tower case	**-6.8%**	**-3.1%**	**-2.4%**	**-4.4%**	**-18.8%**	**-24.5%**	**-21.5%**	**-19.3%**	**-16.8%**	**-9.9%**
DH Condenser (MW_{th})	0	0	0	0	0	0	0	0	0	0
Gross efficiency	28.97%	30.22%	29.53%	26.49%	16.54%	21.42%	22.64%	22.59%	21.12%	15.46%
Net efficiency	27.90%	29.00%	28.14%	24.89%	14.49%	20.42%	21.49%	21.21%	19.28%	12.29%
Net efficiency penalty compared with cooling tower case	**-2.05%**	**-0.94%**	**-0.69%**	**-1.14%**	**-3.35%**	**-6.72%**	**-5.88%**	**-5.07%**	**-3.89%**	**-1.34%**
Maximum steam extraction										
Gross Power (MW)	36.8	28.5	19.6	10.9	3.2	36.3	28.0	19.1	10.4	2.6
Net power included booster pump (MW)	**34.3**	**26.9**	**18.5**	**10.1**	**2.5**	**33.5**	**26.0**	**17.6**	**9.3**	**1.6**
Net power penalty compared with cooling tower case	**0.7%**	**1.0%**	**1.5%**	**2.3%**	**8.6%**	**-0.5%**	**-0.7%**	**-1.0%**	**-2.1%**	**-12.3%**
DH Condenser (MW_{th})	109.2	83.9	60.3	37.7	14.0	109.5	84.2	60.7	38.0	14.2
Gross efficiency	23.08%	22.60%	20.93%	17.61%	10.26%	22.75%	22.17%	20.35%	16.74%	8.31%
Net efficiency	21.52%	21.31%	19.72%	16.26%	8.12%	21.01%	20.66%	18.84%	14.92%	5.24%
Net efficiency penalty compared with cooling tower case	**0.16%**	**0.22%**	**0.29%**	**0.37%**	**0.64%**	**-0.10%**	**-0.15%**	**-0.20%**	**-0.33%**	**-0.73%**
Ratio of maxi heat output to max NET electrical output	**2.39**									
Gross derating	**-20.3%**									
Net derating	**-22.9%**									

Source: Mott MacDonald

Our modelling indicates that when the plant operates at maximum steam extraction there is no penalty in plant efficiency for either unconstrained or constrained ACCs at design and maximum temperatures.

In electricity-only mode, the configuration with a constrained ACC imposes an efficiency penalty over the whole range of ambient conditions and over the whole reactor load range.

In electricity-only mode, a configuration with an unconstrained ACC has no efficiency penalty at design temperature and at reactor loads above 80%. If the plant with an unconstrained ACC operates above 12°C and/or at reactor load below 60% in electricity-only mode, there is a net efficiency penalty which reaches a maximum of 3% at a 35°C ambient temperature.

The performance of plants using an unconstrained ACC differs from plants using an ECT mainly when ambient conditions are above design temperature and there is a low DH load. The efficiency penalty reaches a maximum on hot days and in electricity-only mode. The penalty is at a minimum on cold days or at maximum steam extraction. The net effect over the year will depend on the level of DH required throughout the year and the frequency of hot and cold days.

5.2.3 Weather analysis

The previous sections estimated the difference in net power between a mechanical draught ECT and an ACC to be ~12 % at 35°C ambient temperature in electricity-only mode. However in the UK the temperature is usually only this high for short periods in the summer. Therefore to better understand the overall impact of an ACC on power plant efficiency and output over an entire year we analysed 2010 weather data from Heathrow Airport and modelled the impact of this for both an electricity-only and CHP SMR plant.

5.2.3.1 Electricity-only SMR plant

Using recorded temperature and humidity data for a single year (2010) from Heathrow Airport (weather station 37720), a frequency analysis was conducted to determine how many hours per year the plant would operate with temperature and humidity within certain ranges. This can be seen below in Table 5.3.

Table 5.3: Frequency (in hours) of temperature verses relative humidity for Heathrow Airport in 2010

		Relative Humidity (%)									
		100-90	90-80	80-70	70-60	60-50	50-40	40-30	30-20	20-10	10-0
Temperature (°C)	-10 to -5	5	0	0	0	0	0	0	0	0	0
	-5 to 0	64	81	3	0	0	0	0	0	0	0
	0 to 5	365	479	245	56	18	1	0	0	0	0
	5 to10	620	701	384	159	58	23	2	0	0	0
	10 to15	478	462	385	238	162	108	17	0	0	0
	15 to 20	344	616	443	290	192	143	59	6	0	0
	20 to 25	34	128	190	233	291	238	70	9	0	0
	25 to 30	0	0	2	18	49	131	117	7	0	0
	30 to 35	0	0	0	0	0	2	22	9	0	0

Source: Mott MacDonald analysis of Met Office Data

Several models were then run to compare the net power of mechanical draught ECTs to unconstrained ACCs for a range of temperatures using the mode (most frequent) relative humidity for power only configuration i.e. 20-25°C at 60-50% relative humidity. This was then multiplied by the amount of time per year this occurs to determine the total impact on plant net power over a year. The results are presented in Table 5.4

Table 5.4: Net power reduction for ACC vs ECT over a year in power only mode (one 50MW$_e$ plant A module)

Temperature (°C)	Net power impact (MW)
15 to 20	0.079
20 to 25	-0.186
25 to 30	-0.117
30 to 35	-0.021
Total	-0.245MW per Plant A module (equivalent to 0.5% of net power in electricity-only mode at 12°C)

Source: Mott MacDonald

In power only mode, the impact on net power with an ACC may be ~12% at high ambient temperatures (35°C), but as these do not occur often in the UK or for extended periods, the impact is only ~0.5% reduction in net annual electricity generation based on figures for 2010. This factor clearly depends on specific weather conditions at specific locations but suggests the revenue impact in the UK would be modest.

5.2.3.2 CHP SMR plant

We would expect the efficiency loss associated with an ACC at high ambient temperature to be lower on average for a CHP plant than an electricity-only plant. This is because part of the cooling duty is likely to be taken by the heat supply to a DH network. Even in summer, when space heating is not required, hot water heating is still necessary.

The efficiency penalty for a CHP plant will therefore be dependent on the DH network load. To determine the frequency of certain heat loads, the same temperature and relative humidity analysis as above was compared to the UK heat demand data for 2010 used in the ANT Phase 1 and 2 modelling. This provided a frequency analysis of temperature events against heat demand on a half hourly basis. It was assumed that the maximum heat output from the SMR would meet 40% of the peak heat demand, as per the assumption made in the ANT Phase 1 and 2 reports. The results obtained are presented in Table 5.5.

Table 5.5: Frequency analysis of temperature verses heat demand in 2010

		Low grade heat (GW)									
		305-129	129-115	115-101	101-87	87-73	73-59	59-45	45-31	31-17	17-3
Temperature (°C)	-10 to -5	0	0	1	0	0	0	1	0	1	7
	-5 to 0	86	17	12	12	13	22	15	8	30	81
	0 to 5	698	97	93	105	156	209	229	88	155	496
	5 to 10	694	195	192	222	222	285	495	343	203	1043
	10 to 15	284	172	192	222	277	283	489	539	244	948
	15 to 20	18	43	73	140	181	301	505	821	871	1235
	20 to 25	2	1	1	9	33	112	216	385	980	647
	25 to 30	0	0	0	0	1	4	19	69	206	349
	30 to 35	0	0	0	0	0	0	0	4	21	41

Source: Mott MacDonald

The net power of mechanical draught ECTs to ACCs was then compared for a range of temperatures and heat demands. The results obtained were multiplied by the amount of time per year each temperature range occurs to determine the total impact on plant efficiency over a year. The results obtained are presented in Table 5.6.

Table 5.6: Net power reduction (MW) of ACC vs ECT over a year in CHP mode with heat export following demand

		Heat load (MW)								
		110-97	97-84	84-72	72-59	59-47	47-34	34-22	22-9	9-0
Temperature (°C)	15 to 20	-0.00	-0.00	-0.00	0.00	0.0	0.01	0.01	0.02	0.02
	20 to 25	0.00	-0.00	-0.00	-0.00	-0.0	-0.01	-0.02	-0.05	-0.04
	25 to 30	0.00	0.00	0.00	-0.00	-0.0	-0.0	-0.01	-0.03	-0.05
	30 to 35	0.00	0.00	0.00	0.00	0.0	0.0	0.00	0.00	-0.01
Total		-0.15MW (equivalent to 0.33% of net power in electricity-only mode at 12°C)								

Source: Mott MacDonald

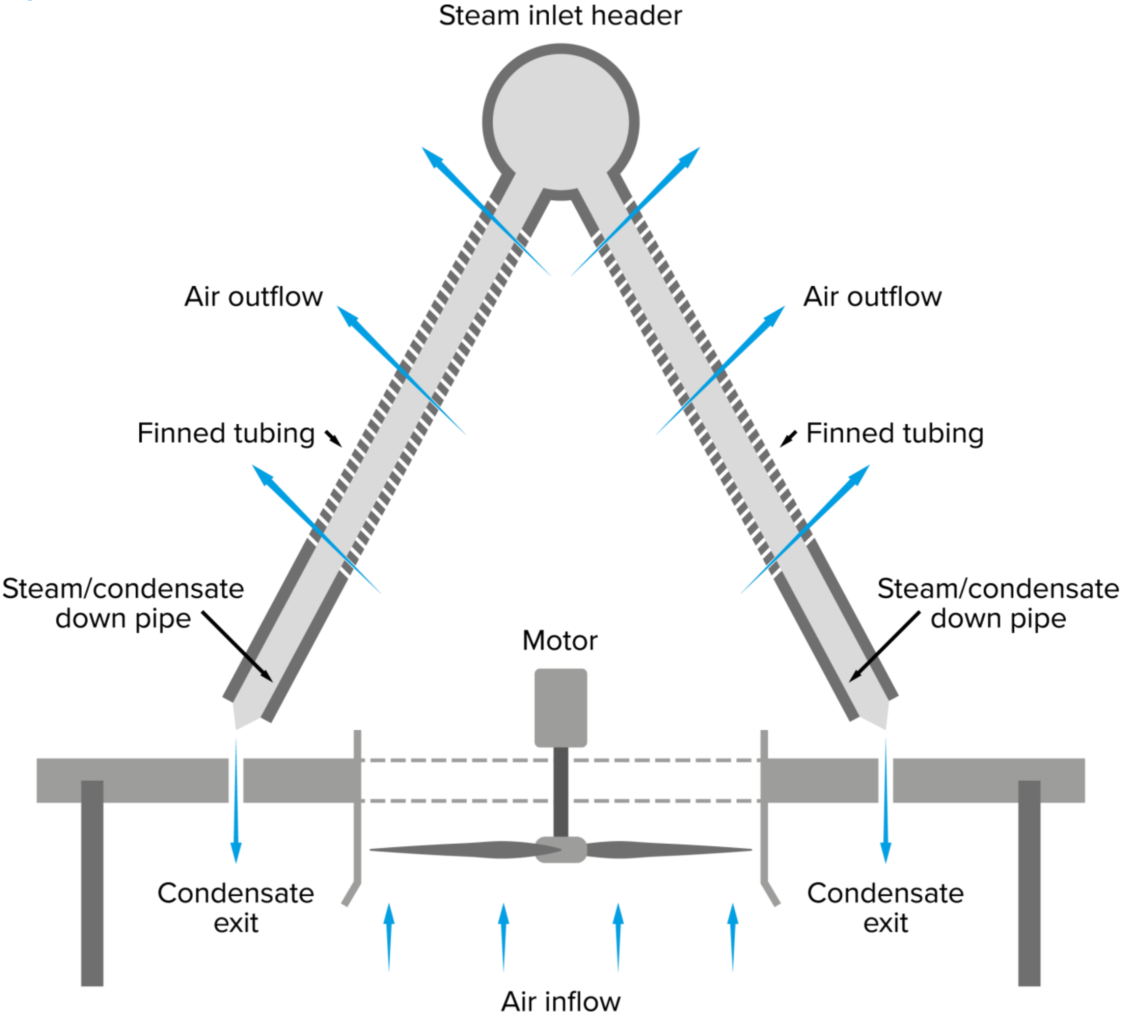
In CHP mode, the impact of an ACC on plant net power may be ~12% at high ambient temperatures, but as these do not occur often in the UK or for extended periods, the impact is only ~0.33% reduction in electrical output over the year.

This analysis shows that the impact of an ACC on SMR plant efficiency and output is likely to be very small when considered on an annual basis when compared with the same plant using ECT. This conclusion relates to both electricity only and CHP SMR plants.

5.2.4 Indicative list of main plant and equipment with indicative equipment sizes

Figure 5.11 shows a general view of an ACC comprising a typical A-frame design.

Figure 5.11: Air-cooled condenser



Source: Mott MacDonald

The installation of an ACC will normally necessitate the installation of the following additional equipment:

- The heat exchange surface and supporting steel structure;
- Steam ducting from the steam turbine exhaust to the heat exchanger bundles;
- Fans with electrical motors, with speed reduction via a gearbox;

- Condensate tank;
- Condensate and drain pumps;
- Steam jet evacuation unit consisting of start-up ejector and operating ejectors;
- Internal piping to condensate tank and ejectors; and
- Special control unit to adjust the air-cooled condenser to different air temperatures and amounts of steam flow.

The following table summarises the size of the main equipment necessary for the different configurations.

Table 5.7: Size of main equipment

	Mechanical draught ECTs	Unconstrained ACC	Constrained ACC
Surface condenser	Length 8.8m Width 2.9m 70 t (operating wet weight – excluding vacuum forces)	N/A	N/A
Cooling water pump and motor	3 x 50% Length 3.3m Width 0.9m	N/A	N/A
Cooling Towers/ACC			
Total number of cells	5	9	9
Cell dimensions	Width 13.5m Height 9.4	Width 11.9m Height 23.6m Fan deck height 14.7m Weight 96 t	Width 9.75m Height 22.38m Fan deck height 14.73m Weight 66 t
Fan diameter	8.5m	8.9 m	7.6 m
Overall Dimensions	Length per row 63.5m Length per cell 12.7m Width at top of cell 13.5m Cell height 9.4m Fan stack height 3.1m	Length 35.66m Width 35.66m	Length 29.26m Width 29.26m
Plot Area	850 m^2	1,280 m^2	850 m^2

Source: Mott MacDonald

5.2.5 Indicative plant layout

Using the equipment dimensions from Table 5.7 and typical equipment configurations from the thermal modelling software, a indicative equipment layout has been created to show the potential extent of footprint modifications required to install ACCs to Plant A with 6x50MW_e modules. This is shown in Appendix G.3.

5.2.6 Discussion on benefits and disadvantages

Compared to ECTs the typical disadvantages of ACCs are:
1. Efficiency/output penalty on hottest days and in electrical power generation only mode (or alternatively requires overdesign / increased equipment to minimise these impacts);
2. Increased capital and operating costs;
3. Larger footprint (1.4 times than a ECTs plot area);
4. Potential increased noise;
5. Performance and maintenance could be affected by high wind conditions.

5.2.6.1 Wind

ACC performance and maintenance could be affected by high wind conditions. Prevailing wind could be significant, especially given the typical height of air inlets and fans on an ACC. For example the fans in the ACC configurations considered in this report are assumed to be located at 15m high.

Wind walls are sometimes necessary to protect the finned tubes from wind gusts that can upset equilibrium operating conditions and at times cause freezing in some remote parts of the tower. Partition walls between fan cells isolate operating cells from non-operating ones. Without partition walls, a non-operating fan would induce bypass of air intended for the bundles.

5.2.6.2 Noise

ACCs have been known to generate excessive noise during operation and there are reports of the effects of channelling affecting condensing performance during high wind conditions.

Sound pressure levels can be reduced via sound walls and similar external sound absorption systems; these are not typically required for ACCs and result in additional capital cost. The primary noise abatement solution is to address the issue in the fan selection and fan design. The degree to which either noise absorption devices or low noise fans are employed depends upon the sound-pressure levels required by the site.

5.2.6.3 Fan and Gearbox Maintenance

The installation of an ACC incurs additional major maintenance related to its fans and gearboxes.

ACCs include large diameter fans which can be subject to mechanical failure. The frequency of fan outages as well as the probability of changing complete fans, gearboxes and motors are dependent upon local site conditions and can be increased significantly if the site is subject to high winds and/or wind gusts.

5.2.6.4 Fouling of ACC Coils

The external surfaces of the finned tubes on ACCs are known to be very prone to fouling. Ambient dust can contribute to the inlet air dust loadings to the ACC and resultant fouling. Furthermore, leaky gear boxes can lead to a carryover of gear box grease to the heat exchange surfaces. The ACC could be equipped with fin tube cleaning systems and it is recommended that capital costs allowance be made for these cleaning systems.

5.2.6.5 Coil Freezing

ACCs supporting installed SMRs in the UK will be required to be capable of operating over ambient air temperatures ranging from -15°C to 35°C. Furthermore, they may be required to undergo “cold starts” (i.e. initial operation without a heat load) and operate successfully over a full range of heat loads. Particular attention to ACC design and operation is necessary to prevent the freezing of condensate as well as proper removal of non-condensable gases.

Freezing can take place at low load or during start-up, but is less of a problem when operating at higher loads.

5.2.7 ‘ACC readiness’

The analysis presented here suggests that it is technically feasible to retrofit an ACC to an existing plant with ECTs (whether an electricity-only or CHP plant). This will be greatly simplified and considerably cheaper if the original plant has been designed and built ‘ACC ready’.

The potential requirements below represent criteria that could be required to define a facility as being ‘ACC ready’. The project developer should:

- Demonstrate that retrofitted ACC equipment can be connected to the existing equipment effectively and without an excessive outage period and that there will be sufficient space available to construct and safely operate additional ACC facilities.
- Plant features that should be ***installed when the plant is built***:
  - A steam turbine plinth of sufficient size to install a low pressure steam connection to the ACC;
  - Civils and structures are designed for additional CHP equipment in existing buildings.
- The following ***additional space requirements*** should also be built into the plant:
  - Space for on-site ACC pipework;
  - Space available for all the ACC equipment with suitable space for maintenance of equipment;
  - Space for additional transformers, Motor Control Centre (MCC) and cabling or a suitably sized auxiliary power supply for the future CHP loads;
  - Space for additional I/O for CHP control;
  - Ability to extend site utilities to accommodate CHP equipment e.g. instrument air, lighting etc.;
  - Space necessary to facilitate construction activities.

Overall, ensuring an SMR plant is ‘ACC ready’ involves little additional cost but requires the above features to be built into the plant, and requires consideration of a larger site.

5.3 Option 2: Sea Water ECTs

This option assumes that the make-up water required by the ECTs will be extracted from the sea rather than from a nearby river which may be unable to provide a reliable coolant source in the future due to climate change effects. For inland SMR sites like those identified in the Power Plant Siting Study, this solution therefore implies long-distance transportation of sea water to site via pipes.

This option requires the construction of:

- Seawater intake structure on the near shore;
- Supply pipelines;
- Discharge pipelines and outfall structure, if discharge is to be released to sea.

Table 5.8 summarises the impact on performance, space requirements and capital costs if make-up water is supplied from a coastal distant location.

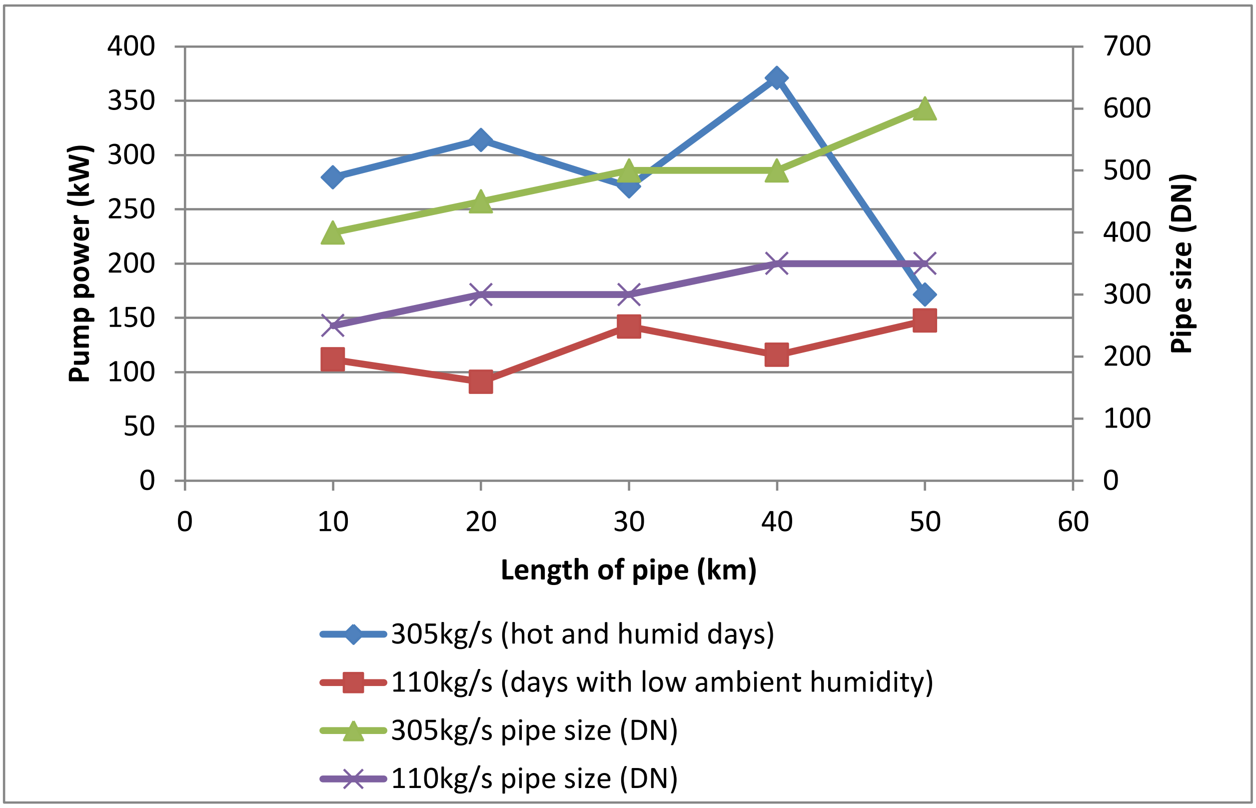
Table 5.8: Sea Water ECTs with Long Distance Make-up Supply from the Coast

Aspect	Comment
Performance Impact	The net power is lower than the base case (mechanical draught cooling towers) due to higher pumping work to transport seawater. Figure 5.12 gives an indication of the power required to transport make-up water to distant sites from the sea for distances between 10-50km.
Water requirements (excludes services and sanitation)	Owing to salt content from seawater, the water requirements for a sea water cooling tower is expected to around 110 kg/s per module during days at low ambient humidity and 305kg/s per module during hot and humid days.
Space requirement	Additional space at the coast will be required for: - Seawater intake and discharge structure - Pumping station Additional space between the coast and the SMR site will be required for: - Seawater supply and discharge pipe
Additional CAPEX/OPEX	Additional capital and operating costs will be required for: - Seawater supply and discharge pipe (capital costs of these structures are highly dependent on the distance from sea) - Seawater intake and discharge structure (capital costs of these structures are highly dependent on the sea conditions) - Pumping station
Other Considerations	Saline make-up water requires the cooling tower and condenser to be built with higher specification materials (such as titanium) to prevent corrosion. Care also should be taken when operating ECTs with seawater. Salt entrained in the drift can land on plant buildings and equipment, speeding up corrosion. Drift eliminators can be installed to restrict drift from the tower. Potential long distance way leaves for installation and maintenance of pipes will be required. Power supply to pumping (and booster) station(s) will need to be considered.

Source: Mott MacDonald

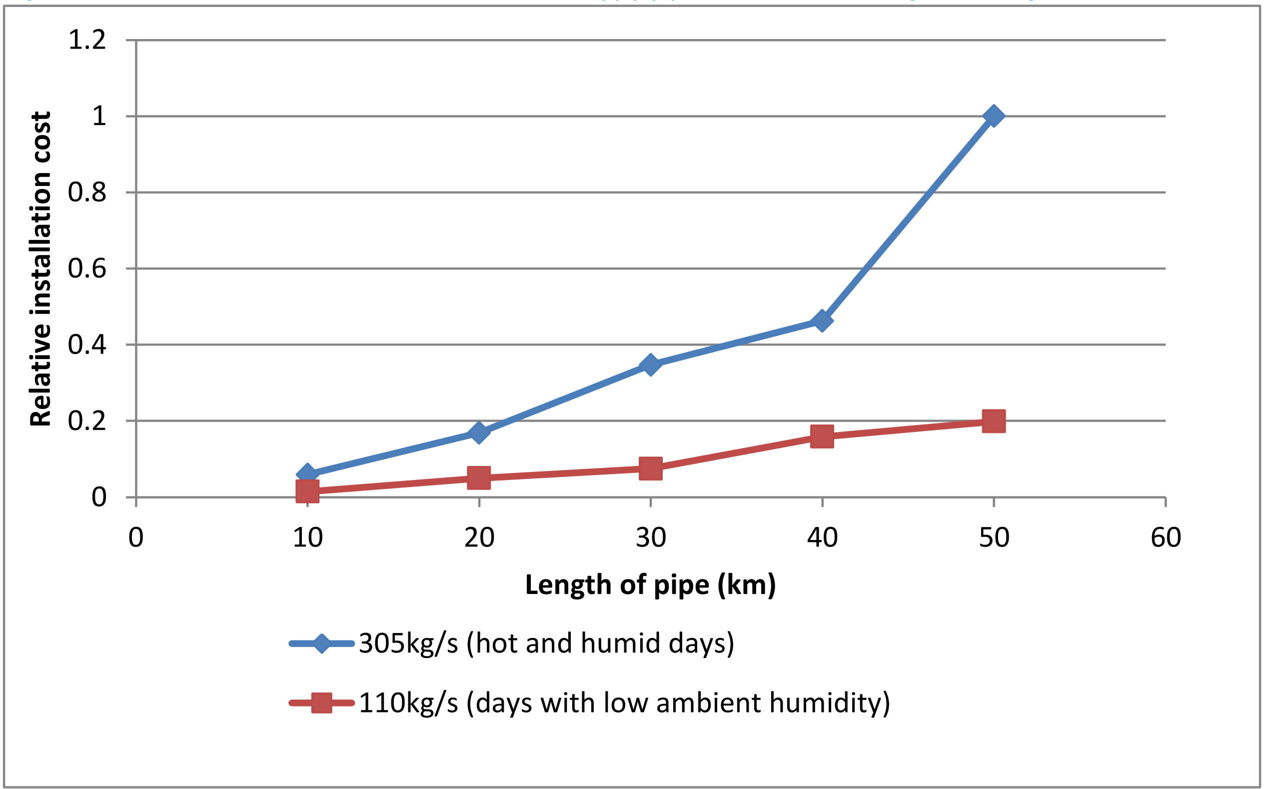
Figure 5.12 gives an indication of the power required to transport make-up water to distant sites from the sea for distances between 10 to 50km (per $50MW_e$ module). It was assumed that the maximum pipe design pressure would be 16bara; the step increase in pipe diameter results in a corresponding step reduction in pump power as can be seen in Figure 5.12. An alternative approach would be to have parallel pipes or pumping booster stations every 10km and keep the line size fixed. Figure 5.13 shows the relative, indicative, installation costs associated with pipes capable of supplying 110kg/s or 305kg/s of seawater.

Figure 5.12: Indicative pumping requirement for water transportation from the sea (for one $50MW_e$ module)



Source: Mott MacDonald

Figure 5.13: Indicative installation costs for seawater supply pipelines for either 120kg/s or 334kg/s



Source: Mott MacDonald

Overall, the use of ECTs with long distance access to sea water from the coast is considered technically feasible provided the water-cooled condenser and cooling towers are designed for saline water. Saline make-up water requires the cooling tower and water-cooled condenser to be built with higher specification materials (such as titanium) to prevent corrosion. When compared with the fresh water, the use of saline make-up water requires the cooling tower and condenser to be built with improved (and more expensive) materials, increasing the costs of cooling towers and condenser by approximately 20% and the costs of the overall plant by approximately 1.5%.

If SMR plants with ECTs are built without due consideration given to future operation with the use of sea water supply, there is a risk that the costs and complexities of a mid-life plant upgrade to use this solution would be prohibitive. To future-proof the plant for this eventuality, the water-cooled condenser and ECTs would need to be designed for use of sea water and in the future the construction of a seawater intake and outfall structures on the near shore and the installation of supply and discharge pipelines would be required. The costs of these structures are project specific.

When compared with the ACC option, it is believed that the cooling towers with seawater make-up may be competitive for inland site close to the coast or estuaries – assuming that it is possible to obtain the necessary planning and consent permits and way leaves.

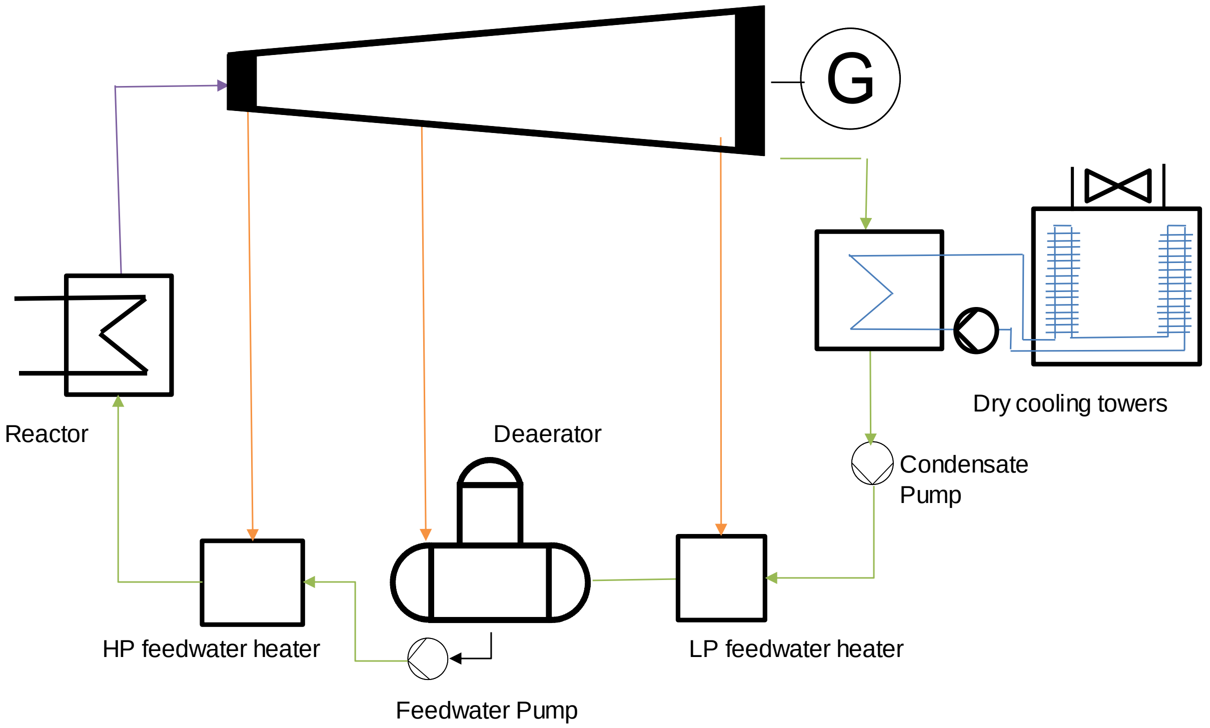
5.4 Option 3: Dry Cooling Towers

Dry cooling towers (also named as water based fin-fan cooling radiators) are another dry cooling system option. As with ACCs, dry cooling towers are a potential option for SMR sites where water is scarce or not available and/or where water based cooling operations are uneconomic.

ACCs and dry cooling towers are both dry cooling technologies in which the ultimate heat rejection is achieved by the heating of atmospheric air passed across finned-tube heat exchangers.

ACCs are direct dry cooling while dry cooling towers are indirect cooling systems which condense steam in a water-cooled condenser (similar to ECTs) with the heated cooling water then cooled in an air-cooled heat exchanger. A typical dry cooling system is shown schematically in Figure 5.14.

Figure 5.14: Plant A with Dry Cooling Towers

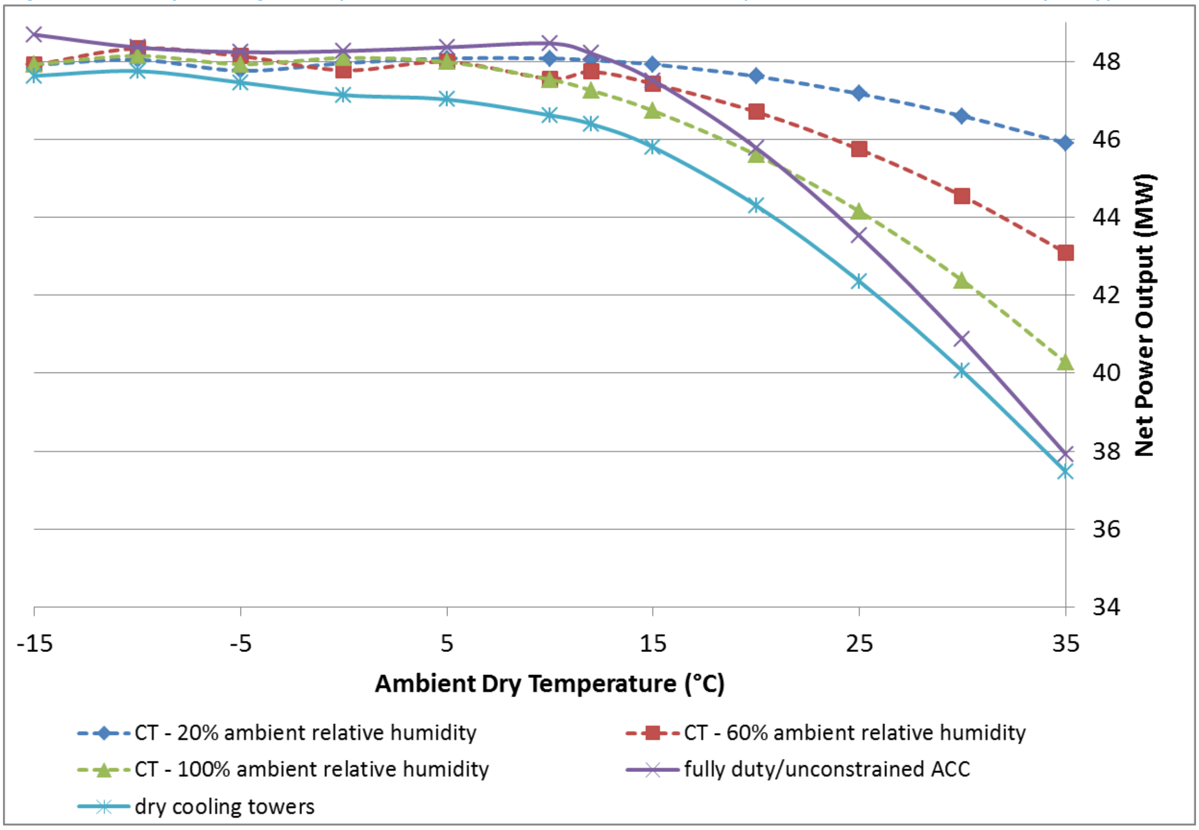


Source: Mott MacDonald

Because the air-side heat transfer coefficients are relatively low, the required heat exchanger surface area is very high, making towers of this type expensive. The footprint and auxiliary power consumption of a dry cooling tower are also larger than those for an ECT.

Assuming a condenser temperature rise of 12°C and approach temperature of 10°C, Figure 5.15 shows the impact of dry cooling towers on SMR performance in electricity-only mode over the ambient conditions range. The modelling results indicate that dry cooling towers have the lowest performance when compared to ECTs and ACCs over the range of ambient conditions considered.

Figure 5.15: Dry cooling tower performance for one 50MW$_e$ module (100% reactor load; electricity-only)



Source: Mott MacDonald

Table 5.9 below summarises the impact of dry cooling towers on performance, space requirements and capital costs.

Table 5.9: Impact of dry cooling towers

Aspect	Comment
Performance Impact	Assuming a condenser temperature rise of 12°C and approach temperature of 10°C, our modelling shows that dry cooling towers have the lowest performance when compared to evaporative cooling and unconstrained ACC (although at 35°C ambient temperature the difference is minimal).
Water requirements (excluded water demand for services and sanitation)	As low as the ACC configuration (Option 1).
Space requirement (for one 50MW$_e$ module)	38 cells of 11.78mx 11.78m Total space requirements of 5,280m^2 (which is more than six times bigger than evaporative cooling and four times larger than an unconstrained ACC of equivalent duty).
Additional CAPEX/OPEX	The dry cooling tower needs to have an additional water-cooled condenser and additional cooling water pumps and piping compared to an ACC.
Other Considerations	The use of dry cooling towers eliminates one of main issues of using an ACC, which is the need to pipe the low pressure steam for a considerable distance between the exhaust and the condenser cells. Even a small pressure drop in the ACC pipes is significant leading to considerable loss in performance (because of low absolute pressure). In addition, the low density of the exhaust steam requires the ACC to have very large pipes. The steam piping and the large ACC surface area result in a large volume under vacuum, requiring large vacuum pumps and increasing the possibility of air leaking into the system. Furthermore, since the cooling water and ambient air are not in direct contact, the dry cooling towers have the advantage that their operation is less subject to the issues of ice and freezing than the wet cooling tower option.

Source: Mott MacDonald

Overall, dry cooling towers are considered to be technically feasible. An SMR plant which initially operates with an ECT could be later converted to operate with both an ECT and dry cooling towers, the latter being used for periods of water scarcity. In the context of future uncertainty of availability of river water, this option – using dry cooling towers in conjunction with ECT – has the advantage of exploiting the higher steam cycle efficiency of the ECT during times of sufficient water whilst maintaining the ability to operate when water is scarce, albeit with a slightly reduced efficiency.

Dry cooling towers could be a direct substitute coolant system to ECT. The water-cooled condenser (originally installed for the ECTs) does not need to be future proofed and could be re-used, reducing capital investment. This is one of the advantages of dry cooling towers compared with the two other alternative coolant methods investigated in this section.

However compared with ACCs, the use of dry cooling towers will incur a higher efficiency penalty and will require sufficient space on site to accommodate the larger dry cooling tower footprint (more than six times bigger than evaporative cooling and four times larger than as unconstrained ACC of equivalent duty). There would be a trade-off between the reduced revenue from the higher efficiency penalty and the cost savings resulting from the re-use of the water-cooled condenser. The competitiveness of the retrofit of dry cooling towers against other alternative methods is likely to be site specific. A more detailed analysis is outside the scope of this report and should be undertaken on a case by case basis.

5.5 Comparison of alternative cooling methods

The advantages, disadvantages and relative costs of the cooling options which have been considered are summarised in Table 5.10 below.

Table 5.10: Advantages and disadvantages of different cooling options

	Advantages	Disadvantages
Base Case Mechanical draught ECTs	Small footprint Lower capital costs	Potential issues with freezing Visible plume Depend on water source available
Option 1A ACC on unconstrained site area (whether as part of hybrid system with ECT or as standalone ACC)	Low water requirements	Larger foot print (unconstrained ACC requires ~1.4 times more space than an ECT) Visual impact Efficiency/output penalty on hottest day and in power only mode. Our analysis shows that this is likely to have minimal impact on overall plant performance over the course of a year Increased capital and operating costs Potential increased noise Performance and maintenance could be affected by high wind conditions
Option 1B ACC on constrained site area (whether as part of hybrid system with ECT or as standalone ACC)	Same as Option 1A Smaller footprint (than unconstrained ACC)	Same as Option 1A Slightly reduced capital costs when compared to Option 1A (unconstrained ACC) Greater reduction in efficiency
Option 2 Long distant coolant supply from the coast	Retains Base Case efficiency	Higher auxiliary load (MW_e) Higher water requirements due to salt in make-up water Saline make-up water requires the cooling tower and condenser to be originally designed with improved materials (such as titanium) Requires seawater intake and outfall structures near the coast Requires potential long distance way leaves
Option 3 Dry cooling towers	Low water requirements No visible plume Limited equipment under vacuum Avoid replacing the main	Higher space requirement (more than 6 times than base case plot area) Lower performance and reduced efficiency Increased capital and operating costs

	Advantages	Disadvantages
	condenser Cooling tower construction does not require improved materials reducing capital investment	Potential increased noise Visual impact Greater auxiliary load More cleaning required increasing maintenance costs

Source: Mott MacDonald

5.6 Summary

There are a number of technically viable cooling methods for SMR plants that could be used in the event of the primary water coolant source being constrained. Options include ACCs, long-distance coolant supply from the coast and dry cooling towers. This is important because a number of potential SMR sites identified in the Power Plant Siting Study are inland, and it is conceivable that more frequent and severe droughts in the future will result in restrictions on water abstraction rates from inland water sources such as rivers and lakes.

A core assumption behind our analysis is that an alternative cooling approach such as an ACC or dry cooling tower would operate *alongside* an ECT. These hybrid solutions assume cooling water will still be available for safe reactor shutdown. This should be reconfirmed should the project proceed.

Whilst the most suitable alternative cooling technology would need to be determined on a case-by-case basis, we explored the ACC option in more detail here.

A hybrid solution with an ACC operating alongside an ECT has the advantage of exploiting the higher steam cycle efficiency of the ECTs, during times of sufficient water, and also of operating when water is scarce, with the ACC. Although there is an efficiency penalty when using an ACC at high ambient temperatures, this is likely to have minimal impact on overall plant performance over the course of a year (~0.5% reduction in net electrical output over the course of a year).

It is technically feasible to retrofit an ACC to an existing plant with ECTs (whether an electricity-only or CHP plant). This will be greatly simplified and considerably cheaper if the original plant has been designed and built ‘ACC ready’. This would involve a steam cycle configuration with space for this modification. Ensuring an SMR plant is ‘ACC ready’ involves little additional cost but requires selection of a larger site at the outset.

6 Cost assessment

For the cost modelling of the equipment within the power plant boundary we used PEACE, a preliminary plant engineering and cost estimation module within the Thermoflow suite of software tools which includes the Thermoflex thermal modelling tool. Costs for Plant A were calculated using 6x48MW$_e$ net (287MW$_e$ net) and costs for Plant B were scaled using 1.7x172MW$_e$ net (also 287MW$_e$ net) to provide the same net electrical output for comparison. A fraction of a power plant is not a realistic scenario, but was chosen to provide a basis for direct comparison of absolute figures and to compare differences in the DH network downstream.

The purpose of this work was to develop and compare incremental cost estimates (CAPEX and OPEX) for CHP LWR SMR plants (versus an electricity only plant) for the plant options and configurations investigated in Section 4. Power only equipment requirements were compared to the additional and/or modified equipment required for the CHP options. This gave an absolute CAPEX/OPEX uplift. We then translated this into specific electrical CAPEX (£/kW$_e$) and specific thermal CAPEX (£/kW$_{th}$).

This section also determines the potential costs of cooling technology choice and how that could potentially impact the incremental costs of CHP SMR.

6.1 Cost modelling

PEACE can be used for feasibility studies and to determine likely cost impacts for techno-economic optimisation. This software derives the logical cost functions for all equipment and balance-of-plant from the detailed hardware specifications, so that any design change is reflected in corresponding changes in both performance and cost.

The PEACE cost estimate database estimates a reference cost on a project in the USA and applies cost multipliers for a project located in the UK in order to reflect the differences in the basic prices of the item as well as the additional costs for shipping, insurance, import duties, VAT and labour cost. However it should be noted that PEACE cost estimate uses high-level approximations with limitations as outlined below.

Mott MacDonald recommends that PEACE outputs should only be used for high level pricing guidance and relative comparison of prices between techno-economic options for reasons set out below:

- PEACE cost data is only updated annually and therefore does not fully take account of international price movements. Also, the costs of equipment are highly market dependent and PEACE costs do not reflect a contractor's willingness for a project. The last update for PEACE before the analysis in this report was June 2015.
- The contractor has standard designs and direct contacts with suppliers; therefore the contractor is best placed to assess the balance between increasing costs (highly market specific) and increasing value of improved performance.

Costs for long distance heat mains, i.e. outside the power plant boundary, have been estimated (on an indicative basis only) using typical ratios from analogous industries: oil and gas and water for the buried section and metro tunnelling for the tunnelled section.

Given the uncertainties described above, all the cost estimates in this report should be taken as preliminary. The general Association for the Advancement of Cost Engineering (AACE) cost estimate classification system[9], provides a useful matrix to help specify an estimate classification. This provides a wide range of expected accuracy that can be narrowed further by using the AACE cost estimate classification system for process industries[10]. In this report, AACE classifies this level of study as a 'Class 5' as defined in below in Table 6.1.

Table 6.1: Matrix of AACE estimate classifications

Estimate Class	Level of project definition Expressed as % of complete definition	End usage Typical purpose of estimate	Methodology Typical estimating method	Expected accuracy range Typical variation in low and high ranges	Preparation effort Typical degree of effort relative to least cost index of 1
Class 5	0%-2%	Concept screening	Capacity factored, parametric models, judgement or analogy	L: -20% to -50% H: +30% to +100%	1
Class 4	1%-15%	Study of feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%	2-4
Class 3	10%-40%	Budget authorisation, or control	Semi detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%	3-10
Class 2	30%-70%	Control or bid/tender	Detailed unit cost with forced detailed take off	L: -5% to -15% H: +5% to +20%	4-20
Class 1	50%-100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%	5-100

Source: AACE International Recommended Practice No. 18R97

The cost estimates in this report can therefore be considered to typically have an accuracy range of between -20% to -50% and +30% to +100%. AACE references ANSI Z94.2-1989, which provides an order of magnitude estimate range of -30% to +50%. This accuracy range has been assumed and used in this report.

[9] AACE International Recommended Practice No. 17R-97 – Cost estimate classification system - TCM Framework: 7.3 – Cost Estimating and Budgeting

[10] AACE International Recommended Practice No. 18R97 – Cost estimate classification system – As applied in engineering, procurement and construction for the process industries

6.2 CAPEX

In this section estimates are developed for the incremental specific CAPEX of a CHP SMR plant compared to a power only SMR plant. These estimates compare Plant A described in Section 4 utilising ECT technology with two ACC CHP options described in Section 4 and Plant B utilising ECTs. This has been split accordingly in the following sections:

- Estimated CAPEX inside the plant boundary;
  - ACC increment;
  - CHP increment;
- Estimated CAPEX outside the plant boundary (CHP increment).

The CAPEX values in this section are in GBP. These have been converted from the PEACE outputs which are in USD. The exchange rate for this conversion has been assumed to be £1:$1.4, the exchange rate at the time of writing.

6.2.1 Estimated CAPEX inside the plant boundary

The cost breakdown below in Table 6.2 represents an installed cost for the equipment required for an operational power plant, excluding the reactor. The contractors internal cost includes utilities, electrical equipment, piping, civils, installation costs, buildings etc. The Contractor’s price includes the contractor’s soft costs such as contingency and profit. The Total Owner’s cost also includes legal and financial costs and escalation and interest during construction.

Table 6.2: Estimated CAPEX (inside the plant boundary) for Plant A with different cooling options and Plant B with the cooling tower option

Project Cost Summary	Unit	Plant A Cooling tower Without DH	Plant A Cooling tower With DH	Plant A ACC Without DH	Plant A ACC With DH	Plant A Constrained ACC Without DH	Plant A Constrained ACC With DH	Plant B Cooling tower Without DH	Plant B Cooling tower With DH
I Specialized Equipment	£m	76.2	76.2	110.6	110.6	97.4	97.4	52.3	52.3
II Other Equipment	£m	19.7	47.7	10.9	38.8	10.9	38.8	15.8	40.0
III Civil	£m	41.8	41.8	34.1	34.1	33.5	33.5	24.9	24.9
IV Mechanical	£m	43.2	44.2	64.0	64.0	51.4	51.4	29.1	29.9
V Electrical Assembly & Wiring	£m	6.7	6.7	8.1	8.1	8.1	8.1	3.9	3.9
VI Buildings & Structures	£m	24.6	24.6	23.8	23.8	23.8	23.8	11.3	11.3
VII Engineering & Plant Startup	£m	48.4	48.4	50.7	50.7	50.7	50.7	22.9	22.9
Subtotal - Contractor's Internal Cost	£m	260.5	289.5	302.1	330.1	275.7	303.7	160.2	185.2
VIII Contractor's Soft & Miscellaneous Costs	£m	10.4	10.7	12.1	12.3	11.0	11.3	6.4	6.6
Contractor's Price	£m	270.9	300.2	314.2	342.5	286.8	315.0	166.6	191.8
IX Owner's Soft & Miscellaneous Costs	£m	54.2	55.5	62.8	64.2	57.4	58.7	33.3	34.5
Total - Owner's Cost	£m	325.1	355.7	377.1	406.6	344.1	373.7	199.9	226.2
Nameplate Net Plant Output (Note 1)	MW_e	286.6	286.6	275.4	275.4	251.8	251.8	286.6	286.6
Cost per kW - Contractor's	£ per kW_e	946	1048	1086	1187	1074	1184	581	669
Cost per kW - Owner's	£ per kW_e	1135	1241	1304	1409	1289	1404	698	790

Note 1: For electrical only configuration
Source: Mott MacDonald

The specific CAPEX results in Table 6.2 are higher for Plant A configurations compared to Plant B because the Plant A costs from PEACE are for a single unit which is then multiplied by 6 units to achieve 300MW$_e$. This does not take into account the potential saving for multiple units and phased construction.

The base plant costs (electricity only) in Table 6.2 are lower than the values estimated in Phases 1 and 2 as these values are from PEACE which uses steam systems from thermal power plant only and does not include any potential uplift required for a nuclear steam circuit which may include additional valves, enhanced control and instrumentation, segregation or redundancy.

The two differences outlined above do not affect the main objective here, which is to determine the increment of CHP above base plant costs.

6.1.1.1 ACC increment

Table 6.3 below breaks out the cost of installing the two ACC configurations on a green field site and an existing site, i.e. a site being retrofitted with ACCs. Building on an existing site should include an increased cost factor, estimated here to be 15-20%. This is owing to issues with the scale of the project and the potential difficulties of fitting the ACCs onto the site, considering potential site constraints.

Table 6.3: Total installed CAPEX of new build and retrofit ACC installation

	Unit	Green field ACC installation	Existing site ACC installation	Green field area constrained ACC installation	Existing site area constrained ACC installation
I Specialized Equipment	£	43,610,000	52,332,000	30,411,000	36,493,200
II Other Equipment	£	1,765,000	2,118,000	1,765,000	2,118,000
III Civil	£	267,000	320,000	267,000	320,400
IV Mechanical	£	40,557,000	48,668,000	27,966,000	33,559,200
V Electrical Assembly & Wiring	£	1,696,000	2,035,000	1,696,000	2,035,200
VI Buildings & Structures	£	-	-	-	-
VII Engineering & Plant Startup	£	2,300,000	2,760,000	2,300,000	2,760,000
Subtotal - Contractor's Internal Cost	£	90,195,000	108,234,000	64,405,000	77,286,000
VIII Contractor's Soft & Miscellaneous Costs	£	1,664,000	1,997,000	608,000	729,600
Contractor's Price	£	91,859,000	110,231,000	65,013,000	78,015,600
IX Owner's Soft & Miscellaneous Costs	£	8,655,000	10,386,000	3,162,000	3,794,400
Total - Owner's Cost	£	100,514,000	120,617,000	68,175,000	81,810,000
Incremental specific electrical CAPEX	(£/kW$_e$)	347	417	255	306

Source: Mott MacDonald

The specific CAPEX results in Table 6.3 are considered at the high end of the potential cost range because the costs from PEACE are for a single unit which is then multiplied by 6 units to achieve 300MW$_e$. This does not take into account the potential saving which can be achieved with the installation of multiple units and phased construction.

The area constrained ACC is cheaper because it is physically smaller than the unconstrained ACC, reducing materials and installation costs. The main disadvantage of an area constrained ACC is the reduction in plant efficiency as discussed in Section 4.

Further analysis on the impact of these costs can be seen in Section 7.

6.1.1.2 CHP increments

Based on the results in Table 6.2 the CAPEX of the DH equipment does not change with the change in cooling option. Adding the cross-over to the steam turbine did not increase its cost in PEACE.

As can be seen from Table 6.4 below, the DH circulating pumps are the biggest cost element, the accuracy of the DH pump CAPEX from PEACE has been checked against internal Mott MacDonald metrics for pumps of a similar size, but from a different industry (desalination). Both CAPEX estimates have been found to be of a similar order of magnitude and within the variance outlined in Section 6.1.

Table 6.4: CAPEX of CHP equipment for Plant A and Plant B

	Plant A				Plant B			
Equipment	Number	Capacity	Installed CAPEX per item (£)	Total installed CAPEX (£M)	Number	Capacity	Installed CAPEX per item (£)	Total installed CAPEX (£M)
DH condenser	2 x 50% per reactor	$55MW_{th}$ each	471,000	5.7	4 x 25% per reactor	$87MW_{th}$ each	727,000	4.8
DH pump	3 x 50%	84m pump pressure rise	6,727,000	20.2	3 x 50%	68m pump pressure rise	5,750,000	17.3
DH condensate pump	3 x 50% per reactor	27m pump pressure rise	25,000	0.5	3 x 50% per reactor	51m pump pressure rise	92,000	0.5
DH power plant pipework	~40m @ DN2200, ~100m @ DN1700, ~240m @ DN810, ~45m @ DN1400	29,000m3/h	1,001,000	1.0	~40m @ DN2200, ~100m @ DN1700, ~100m @ DN810, ~45m @ DN1400	25,000m3/h	781,000	0.8
DH expansion tank	1 off	10,000m3	1,429,286	1.4	1 off	10,000m3	1,429,286	1.4
Miscellaneous (Note 1)	per reactor	N/A	47,000	0.3	per reactor	N/A	73,000	0.1
Subtotal - Contractor's Internal Cost			9,700,286	29.1			8,852,286	24.9
Contractor's Price				29.3				25.2
Total - Owner's Cost				30.6				26.3

Source: Mott MacDonald

CAPEX values below in Table 6.5 are based on the incremental increase of a CHP SMR plant compared to a power only SMR plant.

Table 6.5: Incremental CAPEX (£/kW$_e$) for Plant A cooling options & Plant B DH equipment (inside plant boundary)

Equipment	Incremental specific CAPEX for Plant A with cooling towers (£/kW$_e$)	Incremental specific CAPEX for Plant A with ACC (£/kW$_e$)	Incremental specific CAPEX for Plant A with area constrained ACC (£/kW$_e$)	Incremental specific CAPEX for Plant B with cooling towers (£/kW$_e$)
DH condenser	19.9	19.7	21.4	16.8
DH pump	70.5	69.8	75.7	60.4
DH condensate pump	1.7	1.7	1.9	1.7
DH power plant pipework	3.5	3.5	3.7	2.8
DH expansion tank	5.0	4.9	5.4	5.0
Miscellaneous	1.0	1.0	1.1	0.3
Subtotal - Contractor's Internal Cost	101.7	100.7	109.1	87.0
Contractor's Price	102.1	101.1	109.6	87.9
Total - Owner's Cost	106.7	105.7	114.6	91.9

Note 1: PEACE has a line item called miscellaneous. This is 5% of the cost of the DH condenser.
Source: Mott MacDonald

Table 6.5 shows total incremental specific electrical CAPEX compared to a power only SMR for the CHP equipment within the power plant boundary to be between £91.9-114.6/kW$_e$. The costs in Table 6.5 are constant across the three Plant A cooling options and only vary due to minor differences in net electrical output due to slight changes in efficiency when using an ACC. The costs for Plant A and Plant B in Table 6.5 are based on the same electrical output and only vary due to the slight differences in configuration and Plant B has a smaller DH pump due to less heat being delivered to the DH network.

Incremental specific electrical CAPEX compared to a power only SMR for the CHP equipment within the power plant boundary is therefore in the range £91.9 to £114.6/kW$_e$.

6.2.2 Estimated CAPEX outside the plant boundary

Buried pipes are likely to cost in the region of £12.5m/km for three pairs of DN1200 pipe. This value (on an indicative basis only) is based on pipe quotes and benchmarks for land ownership and stakeholder interface for the London area (considered to be the worst case). This has been broken down below in Table 6.6. Further details can be seen in Appendix H.

Table 6.6: Cut and buried CAPEX breakdown

Cost element	6 x DN1200 pipe cut and buried through fields (£m/km)
Labour	0.5
Plant	0.5
Materials	5.9 (including 5.4 for piping)
Sub con	1.5
Subtotal	8.3
Contractor preliminaries and client costs	4.2
Total	12.5

Source: Mott MacDonald

Tunnelling CAPEX has been estimated (on an indicative basis only) using typical ratios from analogous industries (metro tunnelling) and has been broken down in Table 6.7. Further details can be seen in Appendix I.

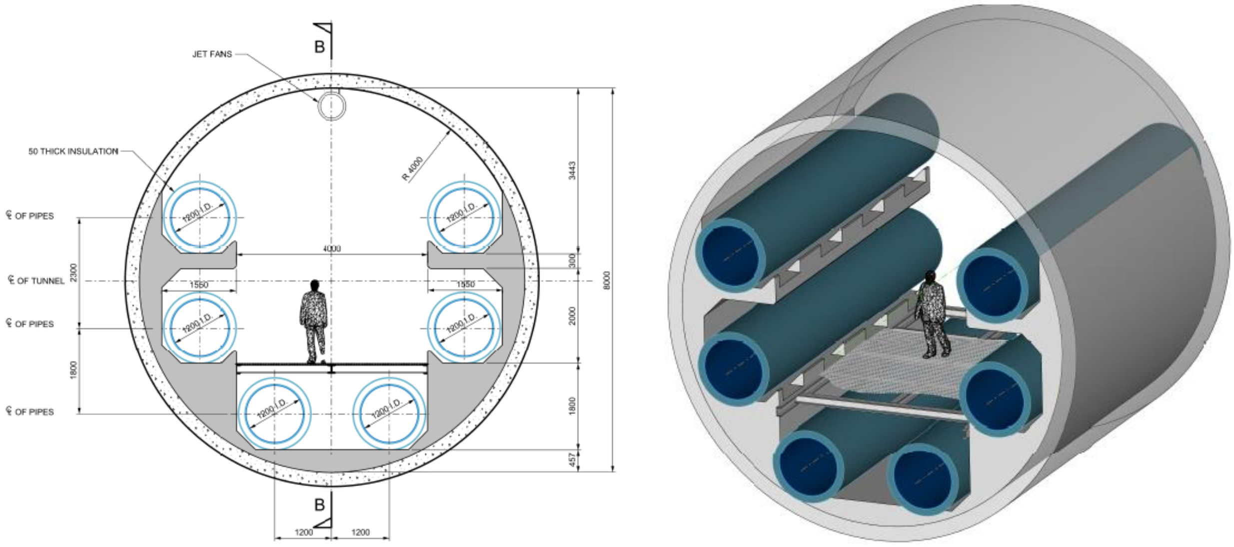
Table 6.7: Tunnelling CAPEX breakdown

Cost element	8m Internal Diameter (ID) tunnel (£m/km)
Bored Tunnel	21.0
Intervention /Ventilation Shafts	0.8
Utility Diversions at shafts/construction sites	1.2
Design Development (Feasibility and Detailed)	1.7
Insurances	1.2
Site investigation	0.2
Pipework	5.4
Total	31.5

Source: Mott MacDonald

Tunnelled pipes are likely to cost in the region of £31.5m/km for an 8m diameter pipe carrying three pairs of DN1200 pipe.

Figure 6.1: Potential cross section for 8m diameter pipe carrying 6 x DN1200 DH pipes



Source: Mott MacDonald

In order to achieve the balance between pipe design pressure and system pressure drop for three pairs of DN1200 pipes, an additional booster pump was required at the far end of the long distance main. Additional cost optimisation is necessary to confirm if increasing the number of pairs of pipes from three to four or adding additional booster pumps is desirable to optimise CAPEX and OPEX of the DH main. Based on initial modelling, the CAPEX of the long distance main booster pump will be similar to the DH pumps at the power plant.

Every SMR location will have different requirements for the DH system outside of the power plant boundary, so specific CAPEX estimates have been provided per 5km for buried and tunnelled DH pipework in Table 6.8 below. CAPEX values below show the incremental cost (outside the fence) for a CHP SMR compared to a power only equivalent.

The costs in Table 6.8 are constant across the three Plant A cooling options and for Plant B and only vary due to differences in net electrical output.

Table 6.8: Incremental specific electrical CAPEX (£/kW$_e$) for equipment outside of power plant boundary

Equipment	Incremental specific CAPEX for Plant A with cooling towers (£/kW$_e$)	Incremental specific CAPEX for Plant A with ACC (£/kW$_e$)	Incremental specific CAPEX for Plant A with area constrained ACC (£/kW$_e$)	Incremental specific CAPEX for Plant B (£/kW$_e$)
Buried pipe (per 5km)	219	216	235	219
Tunnelled pipe (per 5km)	550	545	590	550
Long distance main booster pump	70	70	76	60

Source: Mott MacDonald

Phase 1 and 2 of the ANT project used a long distance main of 20km to compare specific CAPEX figures. Here it has been assumed that only half the length (10km) of the long distance DH main is due to siting requirements of an SMR verses a traditional thermal plant. Based on the above figures, 10km of installed pipework will cost at least £438/kW$_e$.

6.2.3 Total CAPEX increment for CHP over power only SMR with cooling towers

The addition of the incremental costs inside and outside the power plant boundary compared to a power only SMR with cooling towers are shown below in Table 6.9.

Table 6.9: Incremental specific electrical CAPEX (£/kW$_e$) for a CHP SMR compared to a power only SMR

Equipment	Incremental specific CAPEX for CHP Plant A with cooling towers (£/kW$_e$)	Incremental specific CAPEX for CHP Plant A with ACC (£/kW$_e$)	Incremental specific CAPEX for CHP Plant A with area constrained ACC (£/kW$_e$)	Incremental specific CAPEX for CHP Plant B (£/kW$_e$)
Additional cost of ACC	0	347 (243 to 521)	255 (179 to 383)	0
On site costs for CHP	107 (75 to 160)	106 (74 to 159)	115 (80 to 172)	92 (64 to 138)
Buried pipe (10km)	437 (306 to 656)	433 (303 to 649)	469 (328 to 704)	437 (306 to 656)
Total	544 (381 to 816)	886 (620 to 1329)	839 (587 to 1259)	529 (370 to 793)

Source: Mott MacDonald

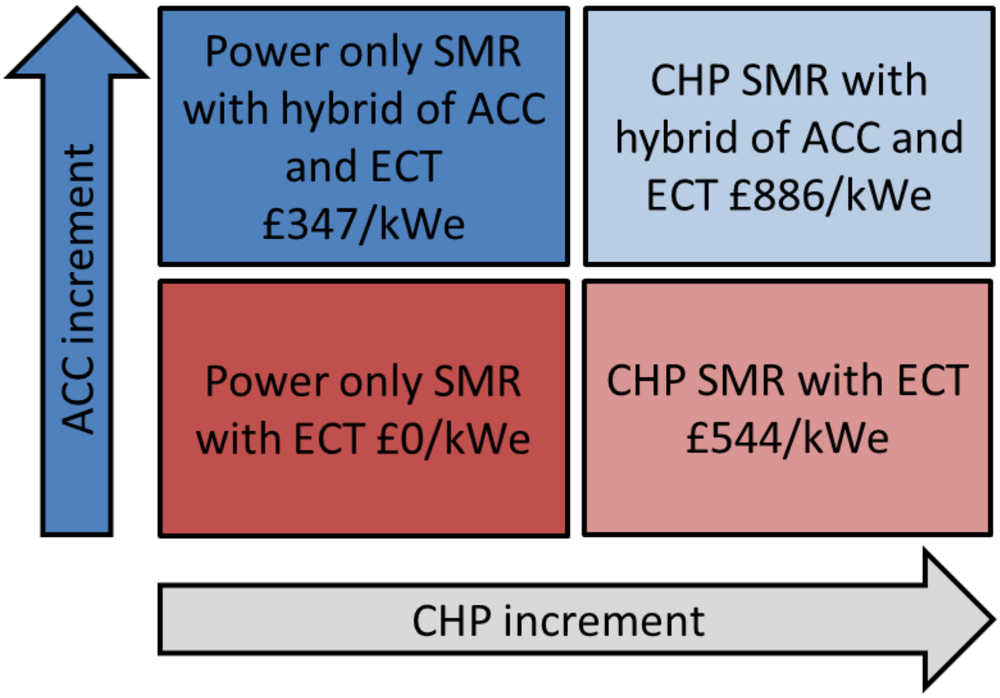
The costs in Table 6.9 show that the predominant cost for all the options are for the buried pipe outside of the plant boundary. The incremental specific electrical CAPEX costs for the two cooling tower only options are broadly similar and only differ due to the configurations of the equipment and the size of the DH pumps, although Plant B only delivers ~580MW$_{th}$ verses Plant A which delivers ~660MW$_{th}$. The incremental specific electrical CAPEX costs for the two ACC options are notably higher as these hybrid options include the costs of both ACCs and cooling towers within the power plant boundary.

Table 6.9 shows that the incremental specific CAPEX compared to a power only SMR has been calculated to be £529 to £886/kW$_e$ (£370 to £1329/kW$_e$ with AACE cost estimate uncertainty range applied). This is greater than the estimate in Phases 1 and 2 of this work, which was £300/kW$_e$ for First-of-a-Kind (FOAK) and £200/kW$_e$ for Nth-of-a-Kind (NOAK). The incremental specific electrical CAPEX here is higher than was previously estimated in Phases 1 and 2 of the ANT project due to two reasons: (1) the costs of buried pipework is higher than was previously anticipated and (2) the incremental costs associated with ACC use were not considered in Phases 1 and 2.

Part of what is driving the high cost of the buried pipework is that the maximum heat load available from this plant is 660MW$_{th}$ verses the Phase 1 and 2 value of 540MW$_{th}$. This therefore requires larger pumps (the dominant DH CAPEX costs within the power plant boundary), and larger DH pipes to be buried. The benefit of this additional CAPEX is that there would be up to 20% more heat to sell to the end users.

Based on Table 6.9, incremental specific CAPEX could be reduced by siting the power plant as close to the thermal power plant alternative/being replaced as practical as pipe routing is a significant proportion of the potential costs.

Figure 6.2: Summary of incremental CAPEX (£/kW$_e$) for CHP and ACC



Source: Mott MacDonald

Figure 6.2 provides a summary of the incremental specific electrical CAPEX of adding DH equipment for CHP and adding an ACC for climate resilience. This separates the costs of adding DH from the costs of adding an ACC as these activities have different purposes and may occur at different times in the project lifecycle.

6.3 Total OPEX increment over power only SMR with cooling towers

The cost of DH equipment inside the fence is £30.6m for Plant A and £26.3m for Plant B as shown in Table 6.4. OPEX figures below in Table 6.10 have been calculated based on an assumed OPEX cost equating to 4% per year of the DH equipment overall CAPEX. This will primarily cover the additional maintenance costs of the DH equipment within the plant boundary as it is expected that no additional labour would be required for operation.

Table 6.10: Incremental specific OPEX uplift over electricity only SMR plant

	Plant A with cooling towers	Plant A with ACC	Plant A with area constrained ACC	Plant B with cooling towers
Additional OPEX for ACC (£/year)	-	4,021,000	2,727,000	-
OPEX for DH (£/year)	1,223,000	1,223,000	1,223,000	1,053,000
Incremental specific OPEX (£/kW$_e$ per annum)	4.3	18.1	14.8	3.7

Source: Mott MacDonald

As Table 6.10 shows, the OPEX for the DH equipment inside the power plant boundary is split into two categories, one for the additional ACC and one for DH equipment. For the two cooling tower options, the incremental specific electrical OPEX (£/kW$_e$) is higher for Plant A compared to Plant B due to the number of individual items of equipment to be maintained for Plant A i.e. 6 x steam turbines. The incremental specific electrical OPEX (£/kW$_e$) is significantly higher for the two ACC options, as this equipment also requires maintenance as well as the cooling towers for a hybrid cooling solution.

Potential maintenance costs can be dependent on inspection and maintenance requirements under the Pressure Equipment Directive (PED). The design pressures and temperatures of the DH equipment in this analysis equate to a category I, group 2 fluid. If the design conditions of the pipework increase to a point in which flashing may occur in the event of a leak, this would equate to a category III, group 2 fluid. This could have implications on OPEX by increasing the inspection requirements during outages under PED.

OPEX for the long distance main has not been considered in this report as maintenance is likely to be in the scope of supply of the operator of the DH network. Maintenance costs of the DH main are not expected to be high as the operating temperature of the pipework is well within its maximum design temperature.

6.3.1 Increment OPEX over power only SMR summary

Table 6.10 shows that the OPEX varies between £3.7/kW$_e$ and £18.1/kW$_e$ (£2.6 to 27.2/kW$_e$ with the AACE cost estimate uncertainty range applied), which is comparable to the Phase 1 and 2 report which estimated incremental specific OPEX to be ~£5/kW$_e$, but did not consider the additional OPEX of maintaining an additional ACC.

6.4 Summary

Incremental specific electrical CAPEX for a CHP SMR compared to a power only SMR was calculated to be £529 to £886/kW$_e$ (£370 to £1329/kW$_e$ with the AACE cost estimate uncertainty range applied). This is higher than those estimated in Phase 1 and 2 (£300/kW$_e$ for FOAK and £200/kW$_e$ for NOAK) mainly due to the higher estimated cost of installing the DH pipes for the long distance main as there is little difference in DH uplift between cooling options (£92 to £115/kW$_e$).

The incremental specific CAPEX can be minimised by seeking a plant location nearer to the DH system, or alternatively near to an existing fossil fuelled CHP plant if this is being replaced and a DH system connection is already in place.

The cost of the buried pipework is also high because the maximum heat output available from this plant is 580 to 660MW$_{th}$ compared with the Phase 1 and 2 estimated value of 540MW$_{th}$. This therefore requires larger pumps (the dominant DH CAPEX costs within the power plant boundary), and larger DH pipes to be buried. The benefit of this additional CAPEX is that there would be 5-20% more heat to sell to the end users.

Calculated OPEX was £3.7 to £18.1/kW$_e$ (£2.6 to £27.2/kW$_e$ with the AACE cost estimate uncertainty range applied), which is comparable to the Phase 1 and 2 report which estimated incremental specific OPEX to be ~£5/kW$_e$ as it did not consider the additional OPEX of maintaining an additional ACC.

7 Economics of CHP SMRs and alternative plant cooling systems

To test the impact of the new findings from the previous sections on SMR plant economics we used the same SMR economic model developed for ANT Phases 1 and 2. This assessment is presented in two parts:

- The first part focusses on the modification of an electricity-only SMR plant to a CHP SMR plant. It considers the additional CAPEX and OPEX costs of heat extraction and the extra revenues from heat sales. It compares the economics of two steam cycle models based on different sizes and efficiencies of SMR module (Plants A and B). It uses updated input assumptions based on the engineering and cost analysis described in this report and confirms the conclusion of ANT Phases 1 and 2 that heat extraction has the potential to improve the economic position of SMR plants.
- The second part focusses on the impact of using plant cooling systems that have very low water requirements, specifically the impact of installing an ACC in addition to an ECT. It uses cost and performance figures from the above sections to compare the economics of Plant A with and without an ACC.

7.1 Summary of ANT Phases 1 and 2 economic appraisal

The economic appraisal undertaken for ANT Phases 1 and 2 served two functions. Firstly, and most importantly, it estimated broad ‘target costs’ for SMRs – i.e. the *maximum* amount an SMR power plant could cost whilst still delivering commercial rates of return to investors under projected future market conditions. These target costs should be understood as the upper cost limit for viable SMR projects in the UK. Secondly, the appraisal developed an indicative scenario for actual SMR costs by making high-level estimates of future CAPEX and OPEX for LWR type SMRs. This scenario was then compared with target costs to provide an initial view of the relative viability of different SMR energy service offerings.

The target cost for an electricity-only SMR was estimated to be £3,600/kW$_e$, which broadly equates to a Levelised Cost of Electricity (LCOE) of £80/MWh$_e$. Our indicative cost scenario for a ‘first factory’ NOAK SMR plant came in at £4,500-£5000/kW$_e$, significantly above the target cost.

The target cost for a CHP SMR was estimated to be £6,500/kW$_e$ under our base-case assumptions of a 40% heat Annual Capacity Factor (ACF) and £65/MWh$_{th}$ heat price. Our indicative cost scenario assumed a CHP plant would cost around £200/kW$_e$ more than the electricity-only plant. This small cost increase was more than offset by the large extra revenues from heat sales, resulting in a much more favourable economic position for CHP plants and suggesting that CHP SMR plants could be economically viable even in moderate downside scenarios. This analysis is based on the assumption that decarbonising heat in the UK will require the roll-out of city-scale DH infrastructure in densely populated urban areas, providing a potential market for heat from large thermal or nuclear plants.

To undertake the economic appraisal, we developed a discounted cash-flow (DCF) model that calculates the LCOE, IRR and Net Present Value (NPV) for SMR plants offerings different energy services under a range of input assumptions. The model focusses on the economics of future SMR power plants from a developer / investor perspective, in line with project objectives. It does not provide an energy system wide economic appraisal of SMR technology, nor does it consider pre-FOAK technology development and design licensing activities.

More detail on the methodology and assumptions used for the economic appraisal can be found in the ANT Phases 1 and 2 Full Project Report (August 2015).

7.2 Updated appraisal of CHP SMRs

For Phase 3 of the ANT project we revisited the economic case for CHP SMRs using the updated cost and performance information outlined in this report. We did this by re-running our economic model for both the Plant A and B options, changing the following model input variables as required:

- CAPEX (£/kW$_e$) – to reflect the CHP CAPEX increment (including 10km heat mains built using cut-and-bury techniques);
- OPEX (£/kW$_e$ p/a) – to reflect the CHP OPEX increment;
- Heat to Power ratio – defined as the maximum net heat output in CHP mode (after DH mains losses) to the maximum net power output in electricity-only mode;
- Electrical derating – defined as the reduction in net maximum electrical output in full CHP mode (this is translated into a reduction in electricity Annual Capacity Factor for the purpose of the model).[11]

Table 7.1 summarises the economic model inputs and results for the analysis undertaken in ANT Phases 1 and 2 and for Plants A and B as defined in this report.

The results are provided for two different base plant cost scenarios and two different heat price scenarios.

Two base plant cost scenarios are provided because a detailed cost estimation exercise of base plant costs (which include the reactor module) has not been undertaken for any phase of the ANT project. Therefore our intention is to emphasise the *relative* improvement of plant economics that results from heat extraction rather than put any undue emphasis on one particular set of possible costs. Our first scenario assumes the base 'electricity-only' plant has a CAPEX of ~£4,700/kW$_e$, in line with our indicative cost estimates from Phases 1 and 2 and in excess of the target cost (therefore unlikely to be economically attractive without heat production). Our second scenario assumes the base electricity-only plant achieves the target CAPEX of ~£3,600/kW$_e$, therefore meeting the assumed investor hurdle rate of a 10% IRR even without heat production.

The two heat price scenarios reflect the base case price of £65/MWh$_{th}$ and low case price of £45/MWh$_{th}$, as estimated in Phases 1 and 2.

[11] See Appendix J

Table 7.1: Economic appraisal of CHP SMRs – inputs and results

			ANT1&2 (power only)	ANT1&2 (CHP)	Plant A (CHP)	Plant B (CHP)
Model inputs		Gross electrical efficiency in power-only mode	37%	37%	31.4%	34.4%
Model inputs		CHP CAPEX increment - £/kW$_e$ (net)	-	£200	£544	£529
Model inputs		CHP OPEX increment - £/kW$_e$ p/a (net)	-	£5	£4	£4
Model inputs		H:P ratio	-	1.8	2.23	1.95
Model inputs		Electrical output derating in CHP mode	-	20%	28.7%	28.3%
Model inputs		Electricity ACF in CHP mode	-	75%	73.5%	73.7%
	Scenario 1: Base electricity-only plant CAPEX = ~£4,700 (indicative cost scenario from Phases 1& 2)					
Model outputs	Base-case: £65MWh$_{th}$ / 40% heat ACF	LCOE (with heat credit) - £/MWh$_e$	95.8	50.3	42.3	51.8
Model outputs	Base-case: £65MWh$_{th}$ / 40% heat ACF	IRR - %	7.7%	12.9%	13.3%	12.5%
Model outputs	Base-case: £65MWh$_{th}$ / 40% heat ACF	NPV - £m (10% discount rate)	-376	563	707	525
Model outputs	Downside 1: £45MWh$_{th}$ / 40% heat ACF	LCOE (with heat credit) - £/MWh$_e$	95.8	69.5	66.5	72.9
Model outputs	Downside 1: £45MWh$_{th}$ / 40% heat ACF	IRR - %	7.7%	11%	11.2%	10.6%
Model outputs	Downside 1: £45MWh$_{th}$ / 40% heat ACF	NPV - £m (10% discount rate)	-376	185	238	115
	Scenario 2: Base electricity-only plant CAPEX = ~£3,600 (target cost from Phases 1 and 2)					
Model outputs	Base-case: £65MWh$_{th}$ / 40% heat ACF	LCOE (with heat credit) - £/MWh$_e$	78.6	30.9	22.4	32.0
Model outputs	Base-case: £65MWh$_{th}$ / 40% heat ACF	IRR - %	10.1%	15.9	16.2	15.3
Model outputs	Base-case: £65MWh$_{th}$ / 40% heat ACF	NPV - £m (10% discount rate)	7	946	1,090	908
Model outputs	Downside 1: £45MWh$_{th}$ / 40% heat ACF	LCOE (with heat credit) - £/MWh$_e$	78.6	50.1	46.7	53.2
Model outputs	Downside 1: £45MWh$_{th}$ / 40% heat ACF	IRR - %	10.1%	13.7%	13.7%	13.0%
Model outputs	Downside 1: £45MWh$_{th}$ / 40% heat ACF	NPV - £m (10% discount rate)	7	567	621	498

Source: Mott MacDonald

These results support the headline conclusion from ANT Phases 1 and 2 that heat extraction from an SMR plant to supply a DH network has the potential to significantly improve SMR economics. Using the updated cost and performance inputs derived from the engineering and cost analysis presented in this report, key economic metrics for CHP plant performance remain more favourable than for electricity-only SMR plants. In Scenario 1, where the higher base plant CAPEX means the electricity-only plant achieves only a 7.7% IRR (and with a £65/MWh_{th} heat price), Plants A and B achieve IRRs above 13% and 12% respectively, well above the investor hurdle rate of 10%. In Scenario 2 where the base plant is viable, heat extraction pushes IRRs even higher.

The results also show that there is little difference between the economic performance of Plants A and B. Both plants have a significantly higher CHP CAPEX increment than was assumed for ANT Phases 1 and 2, mainly due to the high cost of the heat mains connecting the CHP plant to the DH network. However this is compensated for by the higher revenues/additional heat production that result from less efficient steam cycle models than were previously assumed. In our analysis, the less efficient of the two steam cycle models (Plant A) is actually in a slightly more favourable economic position than the higher efficiency steam cycle (Plant B) because, for a given specific CAPEX, a lower efficiency steam cycle model equates to more energy available for heat production. However the difference between the two plants is relatively minor and can be considered to be within the error bounds of our results given the indicative nature of the assumptions that underpinned our steam cycle modelling.

7.3 Appraisal of alternative plant cooling mechanism

To understand the impact of an ACC on plant economics, we used the Plant A cost and performance figures which are based on an ECT as our base case. We then re-ran our economic model for two alternative plant cooling approaches to compare the results:

- A hybrid cooling system with both an ECT and ACC installed and operating in parallel. For the purposes of our analysis here we have assumed both are built together upfront with the core plant. In practice it might be expected that the ACC would be retrofitted at a later date, meaning its costs would be discounted in any project financial appraisals. The scenario we have modelled here can therefore be considered conservative.
- A plant cooling system based only on an ACC (built upfront as part of the core plant, with no ECT).

We used amended cost and performance figures for each plant cooling approach, derived from sections 5 and 6 of this report.

Table 7.2 summarises the economic model inputs and results for this analysis. It considers the impact of the different cooling approaches on the same base plant cost scenarios and heat price scenarios that were used for the CHP economic analysis above.

Table 7.2: Economic appraisal with and without ACC – inputs and results (based on Plant A performance)

	Assumes 12C dry ambient temperature		Electricity-only (Plant A)			CHP (Plant A)		
			Cooling Tower	Cooling Tower + ACC (unconstrained)	ACC only (unconstrained)	Cooling Tower	Cooling Tower + ACC (unconstrained)	ACC only (unconstrained)
Model inputs	Max. net power output – MW_e		47.7	48.2	48.2	34.1	33.9	33.9
	CAPEX increment - £/kW_e (net)		£0	£347	£169	£544	£886	£708
	OPEX increment - £/kW_e p/a (net)		£0	£10	£7	£4	£15	£12
	H:P ratio		n/a	n/a	n/a	2.23	2.22	2.22
	Electrical output derating		0%	-1.0%	-1.0%	28.7%	28.9%	28.9%
	Electricity ACF (adjusted)		85%	85.8%	85.8%	73.5%	73.4%	73.4%
	Scenario 1: Base electricity-only plant CAPEX = ~£4,700 (indicative cost scenario from Phases 1& 2)							
Model outputs	Base-case: £65MWh_{th} / 40% heat ACF	LCOE (with heat credit) - £/MWh_e	95.8	101.6	98.4	42.4	50.6	46.9
		IRR - %	7.7%	7.1%	7.4%	13.3%	12.4%	12.8%
		NPV - £m (10% discount rate)	-376	-511	-440	707	546	617
	Downside 1: £45MWh_{th} / 40% heat ACF	LCOE (with heat credit) - £/MWh_e	95.8	101.6	98.4	66.5	74.8	71.1
		IRR - %	7.7%	7.1%	7.4%	11.2%	10.4%	10.7%
		NPV - £m (10% discount rate)	-376	-511	-440	238	79	150
	Scenario 2: Base electricity-only plant CAPEX = ~£3,600 (target cost from Phases 1 and 2)							
Model outputs	Base-case: £65MWh_{th} / 40% heat ACF	LCOE (with heat credit) - £/MWh_e	78.6	84.6	81.4	22.4	30.7	27.0
		IRR - %	10.1%	9.1%	9.6%	16.2%	15.0%	15.5%
		NPV - £m (10% discount rate)	7	-128	-57	1090	929	1000
	Downside 1: £45MWh_{th} / 40% heat ACF	LCOE (with heat credit) - £/MWh_e	78.6	84.6	81.4	46.7	54.9	51.2
		IRR - %	10.1%	9.1%	9.6%	13.7%	12.6%	13.1%
		NPV - £m (10% discount rate)	7	-128	-57	621	462	533

Source: Mott MacDonald

The results show that a hybrid cooling system built upfront, comprising both an ECT and AACC, has a relatively small impact on overall plant economics compared to a plant built with only an ECT. Looking across all scenarios explored in Table 7.2, project IRRs decrease by between 0.6% and 1.2% as the base case ECT is replaced by the hybrid system. Although such a reduction could make a difference to the financial attractiveness of the upgraded hybrid plant the costs can be considered relatively minor when viewed as an insurance policy against the risk of stranded assets in a changing climate.

The plant performance inputs used for this economic comparison assume an ambient temperature of 12°C and pressure of one atmosphere (1.01325 bara). In reality, as conditions deviate from these assumptions the performance of an ACC would reduce more than an ECT. For example, at 35°C the net electrical efficiency of an electricity-only SMR plant using an ACC is estimated to be 12% lower than the same plant using an ECT. Over the course of a year however, this effect is likely to be very small. Analysis undertaken in Section 5 suggests that it would result in an effective derating of maximum electrical output of only 0.5% for an electricity-only plant and 0.33% for a CHP plant. This makes a negligible impact to plant IRR and LCOE.

Finally, when considering a SMR plant with an ACC *instead* of an ECT the results suggest a minor negative impact on plant economics, reducing project IRRs by 0.5% or less.

7.4 Summary

By re-running our economic model with the updated cost and performance figures presented in this report we have validated a core finding from ANT Phases 1 and 2: that heat supply to DH networks has the potential to significantly improve SMR plant economics. Whilst some of the cost input figures to the economic model have changed, the overall results and conclusions drawn have not. We also conclude that the size and efficiency of SMR module does not make a material difference to the economic performance of CHP SMR plants. Whilst in our analysis the less efficient module delivers slightly improved metrics (IRR, LCOE), this difference is small and not considered significant in the context of the assumptions used for our steam cycle modelling.

In addition, our analysis suggests that alternative plant cooling systems appear to have only a relatively small effect on SMR plant economics. Whether the additional investment required to deliver hybrid ECT-ACC cooling systems is justified will depend in part on the extent of future water abstraction restrictions at inland sites, and the extent to which cooling systems that require very little water are considered desirable to avoid the possibility of stranded assets.

8 Global review of nuclear CHP and large scale DH

To understand the international precedents that exist for the use of nuclear heat in DH networks, we undertook a review of relevant publicly available literature and carried out interviews with CHP plant operators in two stages:

Firstly, we looked into examples of DH networks energised by large (mostly non-nuclear) thermal CHP plants. We reviewed these examples for DH system operational issues including fuel types and heat distribution. Secondly, we focused specifically on examples of nuclear CHP plants, identifying locations, plant designs and key operational and technical issues.

Industry and Government reports, academic articles, energy suppliers' websites, news articles, case studies and marketing information were all used as sources of information. A comprehensive list of the sources reviewed is given in Appendix L.

A key constraint in undertaking this review was that the amount of published information on nuclear CHP is limited, and detailed information on plant design and specific operational parameters is scarce.

For the interviews, a number of plant operators/owners were contacted. Three responded to the questions posed and their answers are reflected in this section, although the plants and interviewees in question remain anonymous here. One was a nuclear power plant (NPP) linked to a DH network; another was a NPP which has previously investigated supplying a DH network (but does not currently do this); and the third was a coal-fired CHP plant linked to a DH network.

8.1 International examples of large-scale DH networks

The principle of DH – centralised heating distributed to multiple customers via a network of pipes – has been around since the 1800s, and has many benefits over individual heating methods such as improved energy efficiency, lower emissions, easier operation and maintenance, and added convenience for the customer. The earliest example of a commercial DH network, as it is thought of today (providing heat to households and businesses), is the steam based DH system installed in 1877, in Lockport, New York.

8.1.1 DH network locations

Nowadays thousands of DH networks exist across the globe, particularly in the northern hemisphere where sustained low temperatures exist, along with areas of high population density. An interview with a large power plant operator revealed that all except one of their Scandinavian thermal power plants are connected to a DH network. This is similar for their Russian thermal plants. The scale at which DH is used in Europe is significant – according to the International Atomic Energy Agency (IAEA) "DH accounts for almost half of the heat market in Denmark, Estonia, Finland, Poland, Romania and Sweden."[12]

[12] International Atomic Energy Agency, Advanced Applications of Water Cooled Nuclear Power Plants

Further details on European cities with DH networks are provided in the 2012 *Heat Roadmap Europe* report, produced by Aalborg and Halmstad Universities.[13] Further details on DH networks in the USA are available from the International District Energy Association.[14]

According to the International Energy Agency (IEA), Russia is the largest single user of DH. In 2007, about 1,700,000GWh[15] of heat was supplied to 74% of the country's inhabitants by more than 500 CHP stations, 200,000+km of DH pipeline and 65k+ boiler houses[16].

One of the longest transmission distances, from source to customer, is from the Melnik coal-fired power station in the Czech Republic. A direct 32km long pipeline supplies heat to the centre of Prague; the plant has a maximum heat output of 80MW_{th} and 500TJ/year[17].

8.1.2 Large-scale DH networks

The following are examples of large, well-established, DH networks that use large (100MW_{th}+) CHP plants to supply heat to the system, as well as generate electricity by way of a steam turbine. They are by no means the only successfully operating DH systems but are presented here to highlight the size and scale that DH schemes can achieve. Although the source of heat for the generation of steam differs between a NPP and a conventionally fired carbon-based power plant, they both use steam turbine cycles for power generation.

To aid the reliability of a DH network as well as negate high initial capital costs and slow implementation, many DH networks utilise numerous low power sources such as Internal Combustion (IC) engines and peaking boilers, instead of relying solely on a few large power plants. These smaller heat-only sources are not examined in detail here because the focus of this report is the use of nuclear generation using steam turbines.

8.1.2.1 Warsaw, Poland (POL)

The Polish capital, Warsaw, has around 1.7M inhabitants and a DH system that supplies 76% of the city's heat – over 11,000GWh of heat per annum. Approximately 1,800km of piping is used; three CHP plants and two heat plants provide around 5,100MW_{th} of heat supply capacity with coal being the dominant fuel source. The network has been in place since the 1950s[18] [19].

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[13] Available at: https://www.euroheat.org/wp-content/uploads/2016/04/Heat-Roadmap-Europe-I-2012.pdf

[14] Available at: http://www.districtenergy.org/u-s-district-energy-systems-map/

[15] Lack of metering means accurate end-use information is not available.

[16] International Energy Agency, CHP/DH Country Profile: Russia

[17] European Commission, Background Report on EU-27 District Heating and Cooling Potentials, Barriers, Best Practice and Measures of Promotion

[18] CAS, "SMART HEAT DISTRIBUTION NETWORK" for specs. A. (heat power engineering company) in Warsaw

[19] PGNiG TERMIKA, About PGNiG Termika

The following table shows the size of the CHP plants that are used for Warsaw's DH network.

Table 8.1: Large CHP Plants used for Warsaw's DH Network

Plant Name	Operator	Fuel	Electrical Output (MW_e)	Heating Output (MW_{th})
Zeran	PGNiG TERMIKA	Coal/ Biomass	350	1561
Siekierki	PGNiG TERMIKA	Coal	620	2078
Pruszkow	PGNiG TERMIKA	Coal	8	186
Total			978	3825

Source: Mott MacDonald based on information provided by PGNiG TERMIKA

8.1.2.2 Copenhagen, Denmark (DNK)

The capital of Denmark, Copenhagen, has an urban population of around 1.2M and a DH network that supplies heat to 98% of its inhabitants – over 4,000GWh of heat per annum. The DH network is powered by over 50 peaking boilers (required to provide just 3% of heat produced), three waste incineration plants and four large CHP plants; it was initially set-up in 1984. The network consists of 160km of primary and 1,500km of distribution pipes (1,370km hot water, 130km steam), to connect the city centre with 15 other suburban districts[20 21].

The size of the four large CHP plants is shown in the following table; they all operate a boiler and steam turbine arrangement, apart from unit 8 of H. C. Ørstedsværket which is an Open Cycle Gas Turbine.

Table 8.2: Large CHP Plants used for Copenhagen's DH Network

Plant Name	Operator	Fuel	Electrical Output (MW_e)	Heating Output – Water (MW_{th})	Heating Output – Steam (MW_{th})
Svanemølleværket	Dong Energy	Coal/ Oil	?	256	-
Amagerværket	HOFOR Energiproduktion	Coal/ Oil	433	710	-
H. C. Ørstedsværket	Dong Energy	Gas/ Oil	278.5	822	318
Avedøreværket	Dong Energy	Coal/ Biomass	700	900	-
Total			1411.5	2688	318

Source: Mott MacDonald based on information provided by Dong Energy and IGSS

8.1.2.3 Helsinki, Finland (FIN)

Helsinki, the capital of Finland, has an urban population of around 1.2M and a DH network that has a 93% coverage – over 7,100GWh of heat per annum. Three CHP plants, a sewage heat recovery plant and 11

[20] Engineering Timelines, District Heating and Cooling in Copenhagen

[21] New York City Global Partners, Best Practice: District Heating System

peaking boilers supply heat to the DH network. A network of over 1,200km of pipes are arranged in a ring allowing alternate supply routes when maintenance works need to be carried out on individual pipe sections; in 2007 there was an average outage of only 3 hours per customer. A 30km tunnel is used to connect the Vuosaari power plant to the DH network, one of the largest DH tunnels in Europe[22][23].

The table below shows the size of the CHP plants which comprise of conventionally fired coal power plants and Combine Cycle Gas Turbines (CCGTs).

Table 8.3: Large CHP Plants used for Helsinki's DH Network

Plant Name	Operator	Fuel	Electrical Output (MW_e)	Heating Output (MW_{th})
Salmisaari	Helen	Coal	160	480
Hanasaari	Helen	Coal	228	420
Vuosaari	Helen	Gas (CCGT)	630	580
Total			1018	1480

Source: Mott MacDonald based on information provided by Helen

8.1.3 DH system operation

8.1.3.1 European DH fuel mix

According to Euroheat & Power[24], during 2003 natural gas and coal were the dominant fuel sources for DH for European Union (EU) and three European Free Trade Association (EFTA) (Iceland, Norway and Switzerland) countries, with NPPs providing only 0.3% of the total energy supply to these networks[25][26]. Of the total heat that was generated – 2,302PJ – 68.3% came from CHP plants (assumed to be a mixture of plants both in regards to power capacity and fuel).

[22] C40 Cities, Case Study

[23] Cogeneration & On-Site Power Production, District energy for Helsinki - a highly efficient heating and cooling model

[24] Euroheat & Power, Possibilities with more district heating in Europe

[25] Many of the 10 Russian NPPs (34 reactors) are thought to supply heat for DH networks, but as the Euroheat report was only for EU and EFTA countries, these NPPs and DH networks were not encompassed by the report scope.

[26] Ignalina Nuclear Power Plant, in Lithuania, supplied heat for a nearby district heating network but was closed in 2009, after the publication of the Euroheat report.

Table 8.4: Energy Supply for DH for EU25, ACC4 and EFTA3 countries in 2003

Energy Supply	Heat Generated (PJ)	Share (%)
Natural Gas	928	40.3
Coal & Coal Products	827	35.9
Combustible Renewables	165	7.1
Petroleum Products	160	7.0
Waste	135	5.9
Heat	42	1.8
Geothermal	26	1.1
Electricity	13	0.6
Nuclear	6	0.3
Solar Thermal	0.05	0.002
Total	2,302	-
CHP share	1,573	68.3
Renewable share	325	14.1

Source: Mott MacDonald based on information provided by Euroheat & Power

8.1.3.2 DH network working fluids

DH networks can operate with either steam or water as the medium for transferring heat from the source to the customer. The earlier DH networks usually operated with steam; due to its necessity in power plants, it was relatively easy to divert a portion to neighbouring customers. However, steam based systems have higher rates of heat loss (due to raised temperatures), result in less efficient co-generation, and are more dangerous and expensive to construct and operate compared with water based networks.

Numerous factors affect the transmission temperature range for DH water; they include the transmission distance, ambient air temperature (heat losses), energy quantity and customer requirements.

A study performed in 2012 by the CEA (French Alternative Energies and Atomic Energy Commission)[27] looked at the possibility of supplying heat from the Nogent-sur-Seine NPP in France up to 150km to the cities of Melun, Vitry-Choisy and Créteil. The study identified a transmission temperature of 100-140°C as being an optimal balance between supplied heat and generated electricity, for the transportation of 3000MW$_{th}$ of hot water at 12m^3/s over 150km.

The following table is derived from different sources and shows recommended fluid temperatures for heat transportation within a DH network (post extraction, pre household), as well as the response from an interviewed plant with an 8 bar hot water DH network. Above 100°C the necessity for pressurised transmission lines, to stop boiling, incurs additional costs.

[27] French Alternative Energies and Atomic Energy Commission, Heat recovery from nuclear power plants

Table 8.5: Typical/ Recommended DH Transmission Temperatures

Temperature Ranges (°C)	Date	Source
100-140	2012	CEA, Heat recovery from nuclear power plants
100-150	1997	IAEA, Nuclear power applications: Supplying heat for homes and industries
80-150	2007	IAEA, Advanced Applications of Water Cooled Nuclear Power Plants
100-170	2002	IAEA, Desalination and Other Non-electric Applications of Nuclear Energy
Winter 129/64, Summer 68/50 – (Out/Return)	2016	Interview response

Source: Mott MacDonald

Separate from these identified values, a 2012 report by the European Commission suggested that a general trend towards lower temperature water transmission is underway, with cases of heat transportation as low as 50°C being used in some instances[28], with 75°C said to be more realistic for large new systems. A key driver behind this trend is that the lower the temperature of the recovered heat, the higher the overall plant efficiency, as more energy can be extracted from the steam for electrical generation. Phase 3 of the ANT project concentrates on the use of DH for both space heating and domestic hot water, therefore these very low transmission temperatures are not applicable.

To kill Legionella bacteria, domestic heating systems would need to be heated to at least 60°C once a day[29] [17], meaning the supply temperature from a CHP plant would need to be significantly higher than this to account for transmission losses. This would either need to be achieved through heat supplied by the DH network or potentially by smaller household electric heaters that provide a daily ‘boost’.

The connection method – direct or indirect – between the DH network and a customer’s house also affects the minimum allowable transmission temperature. An indirect connection uses a heat exchanger to transfer heat from the DH network to the household network. This increases the cost and results in the requirement for higher temperature differences (due to the heat exchanger) when compared to DH water being directly piped into a house. However the indirect method provides a layer of separation and an easier connection to the network. An indirect method also increases the simplicity of retro-fitting households with individual gas-fired boiler central heating systems, a boiler could be swapped for a heat exchanger and the household piping remain unchanged.

[28] Underfloor heating can utilise these low temperatures but requires chlorine dosing to kill Legionella bacteria.

[29] Heat around 40°C can be used for under floor heating if properly dosed with chemicals e.g. chlorine.

8.2 Nuclear powered CHP

The first industrial scale NPP was Calder Hall, located in Sellafield, England, which came into operation in 1954 and supplied 50MW_e to the national grid as well as heat to a neighbouring fuel reprocessing plant (process co-generation). Another example of an early NPP used for co-generation is a small 12MW_e Pressurised Heavy Water Reactor (PHWR) that provided DH to a suburb near Stockholm, Sweden, from 1964-1974[30]. Since their realisation, a number of NPPs have been used for co-generation and plans exist for more to be created.

8.2.1 Locations

The use of a NPP for CHP is quite common with many NPPs providing process steam for their own desalination plants, which in turn provide cooling water. However, the review of publically available information undertaken for this report has provided very little indication of the nuclear co-generation of heat for DH or industrial processes outside of Europe, Scandinavia and Russia; the only exceptions being the decommissioned Bruce Bulk Steam System (BBSS) at the Bruce NPP in Canada and two small desalination plants in India (one experimental, the other planned).

Currently, NPPs are used to supply DH in Bulgaria, Hungary, Romania, Russia, Slovakia, Sweden, Switzerland and Ukraine, with a combined reactor life of over 500 years[12] . All four of Switzerland's NPPs operate as CHP plants[31] and in 2009 7.5% of Swiss DH heat was generated by NPPs[17].

In total 18 NPPs were identified that operate as CHP plants and supply heat to DH networks. Of these, some were identified and described by multiple different publicly available sources whilst others (in Russia and Hungary) were only briefly referenced by one or a small number of sources. The operational status of this latter group is more uncertain.

The size of the plants varied from 48MW_e (net) at Bilibino NPP, in Russia, up to 6,232MW_e (gross) at the Bruce NPP in Canada, although the BBSS at the Bruce NPP was de-commissioned during the period 2000-2010 due to the closure of the Bruce Heavy Water Plant (BHWP) which it mainly supplied along with office and industrial buildings.

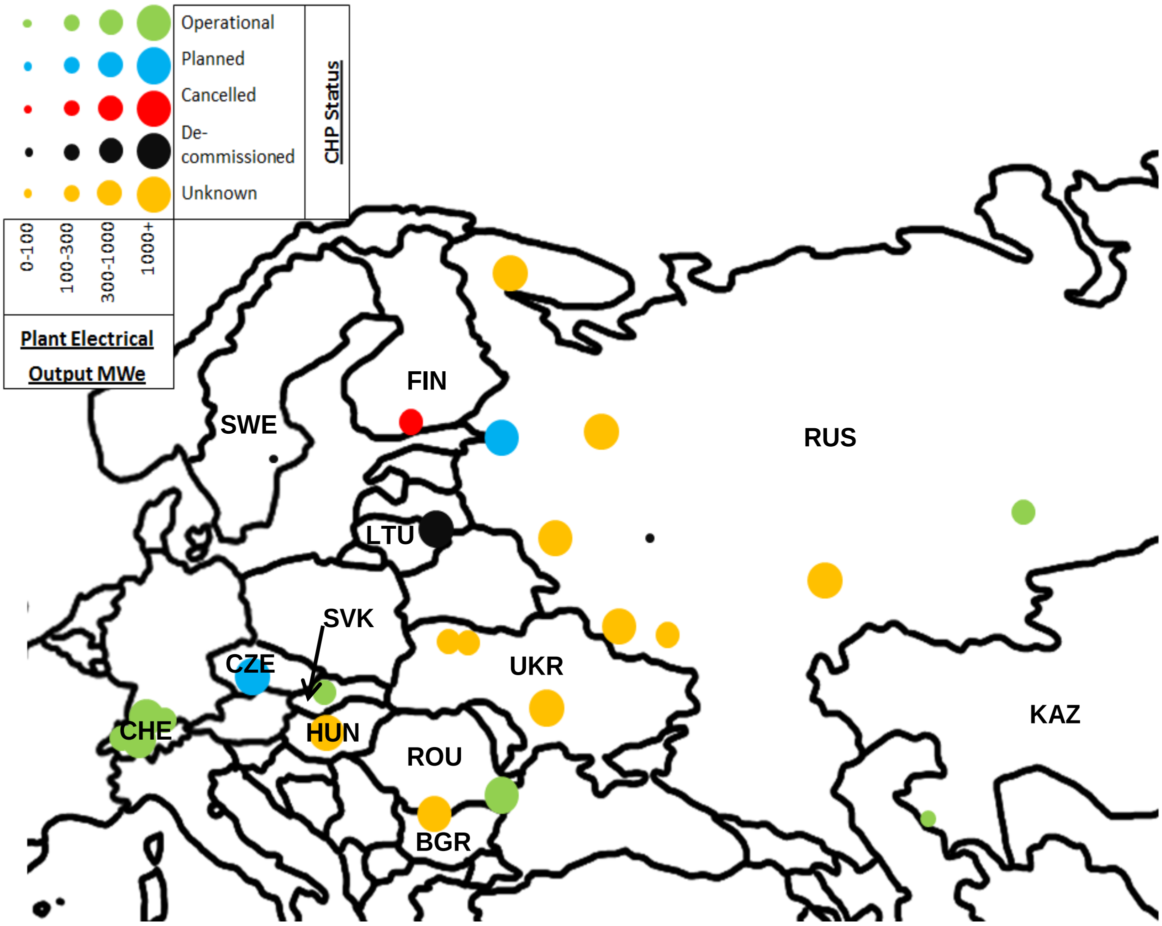
More comprehensive information compiled from publically available information, showing all NPPs that were identified as operating or planned as CHP plants is included in Appendix K. Information regarding their size, status and operation is included.

Figure 8.1 shows a map of Europe and western Russia with spots used to identify NPPs that have, do or will operate as a CHP plant. The size of each spot relates to the electrical power output of the plant.

[30] Nuclear Energy, Nuclear power plant of AGESTA, Sweden

[31] Only Beznau NPP supplies heat to a large DH network, the other NPPs supply process heat or heat for nearby offices.

Figure 8.1: Map of Co-Generating Nuclear Power Plants



Source: Mott MacDonald

8.2.2 Nuclear DH networks

The following two examples show how nuclear power has been successfully used to supply heat to DH networks for decades.

8.2.2.1 Beznau, Switzerland (CHE)

Located in Dottingen, about 35km north-west from Zurich, Beznau Nuclear Power Plant consists of two identical Pressurised Water Reactor (PWR) units, each producing 365MW$_e$ (net) of electricity. The units became commercially operational in 1969 & 1972. The power plant supplies approximately 70MW$_{th}$ of heat to the REFUNA DH system which has operated since 1983; this reduces electrical output by up to 7.5MW$_e$[32].

The REFUNA DH network consists of 31km of main and 103km of district pipelines which supplies heat to 11 municipalities equating to about 15,000 people. The pipes are monitored for leaks along its entire length. Electricity is generated by four 190MW$_e$ ABB steam turbines; the steam for DH is extracted from the cold re-heat cross-over pipe between the HP and LP turbines at 127^{o}C which is then used to supply heat via a heat exchanger to the 80-125^{o}C (seasonal variation) 16bar main DH network. In addition to the main pumping station, nine pressure booster stations can be called upon during periods of high heat demand (i.e. winter) to ensure the required pressure differential between the plant and the furthest customer is maintained. A parallel pipeline system is used for out and return flows; four reserve heating plants also exist in case the NPP stopped supplying heat.

A double-stage heat extraction method where 85^{o}C steam is also taken post-LP turbine was found to increase total heat recovery efficiency by 20% and heat extraction capacity by 30%. It is not known whether the single or double-stage heat recovery method is used for normal operation[33] [34]. The Beznau co-generation system uses two heat exchangers to separate the DH network and pressurised coolant water.

8.2.2.2 Bilibno, Russia (RUS)

Located in the remote Chukchi Autonomous District in north-eastern Russia, Bilibino NPP operates four Model EGP-6 Graphite-moderated Boiling-Water Reactors (GBWR) for CHP, each with a gross capacity of 11/12MW$_e$ with up to 29MW$_{th}$ of heat supplied to the local DH network. The four units became operational over a two year period between 1974 and 1976[35]. It is understood that heat is supplied to 14,000 people via above ground conduits for several miles[36].

The small capacity of each unit was determined to allow for shutdown of individual units without adversely affecting the grid system too greatly. Whilst operating all four units at 62MW$_{th}$ each, steam is extracted at 95.5t/hr with 107^{o}C feed water resulting in up to 77MW$_{th}$ of heat being supplied to the DH network. If ambient temperatures reduce to -50^{o}C, then thermal output can be increased to 116MW$_{th}$ with a reduction in electrical output to 38MW$_e$, down from 48MW$_e$[35].

[32] An image of the Beznau co-generation system can be found in the Axpo brochure at: https://www.axpo.com/content/dam/axpo/switzerland/documents/about_us/151208_about_us_nuclear_kkb_brochure_e.pdf.res/151208_about_us_nuclear_kkb_brochure_e.pdf

[33] Axpo, Experience of operating nuclear district heating in Switzerland

[34] K. H. Handl, 75 MW heat extraction from Beznau nuclear power plant (Switzerland)

[35] Rosenergoatom, Bilibino NPP

[36] The New York Times, Bilibino journal; what price nuclear power? in Siberia, it's high

8.2.3 Nuclear and DH operation

A common feature shared between most NPPs and fossil fuel plants is the use of a steam turbine for power generation, although the achievable temperatures in NPP reactor cores and fossil fuel furnaces differ. The lower temperature of a nuclear reactor mean lower quality (pressure and temperature) steam is generated which affects where in the steam cycle the steam should be extracted.

As can be seen from the table in Appendix K more than half (19 of 31) of the reactors used in the identified CHP NPPs are PWRs. In a PWR, water is used to both cool the core and act as the transport medium to transfer heat to the Steam Generator (SG) with pressure ensuring the water does not boil due to peak temperatures around 340^{o}C. The experience and usage of large PWRs for CHP applications supports the proposition that SMRs could also be used for CHP, as many SMRs are based upon PWRs.

The interviewed NPP which supplied a DH network also operated with PWRs. In their experience the integration with a DH network (hot water based) had “no impact or negative effects on the availability, maintenance and performance of the nuclear plant”. The other interviewed NPP (also PWR based) suggested, based on their previous work, that the main obstacle to NPP DH was political/social, and that no new technologies or innovations would be necessary for its implementation. An interviewed coal-fired CHP plant mentioned that in the past, problems with heat exchangers had been encountered (namely gasket damage) but that this issue had been successfully resolved.

Appendix M contains all the system diagrams that were found during the review of publically available literature. The details of the diagrams are very high level and do not offer much in the way of specific plant operation. However it can be seen that in all cases identified in this report steam is extracted mid or post turbine with a heat exchanger or intermediate circuit used to transfer heat to the DH/process network.

8.2.3.1 Steam generation

In addition to generating the steam to power the steam turbine and feed a DH network, a SG also provides a layer of separation between the irradiated coolant water and the DH network. The moisture of the steam is important as excessive wetness can lead to Water Drop Erosion (WDE) of the steam turbine blades. A maximum wetness at full load (worst case) is considered to be between 12-15% upon exit from the LP turbine to limit blade erosion to acceptable levels.

There are three types of SGs used with PWRs, produced by Westinghouse, Combustion Engineering and Babcock & Wilcox. The latter design employs a once through set-up whereby the primary coolant travels from the top of the SG to the bottom; the other two designs allow the heat to transfer via U-shaped tubes. No moisture is present in the steam exiting the Babcock & Wilcox design but despite the inclusion of moisture separators the U-shaped designs produce steam with up to 0.25% wetness [37] [38].

[37] Westinghouse Electric Corporation, The Westinghouse pressurized water reactor nuclear power plant

[38] Institutt for energiteknikk (IFE), Description of Sizewell B Nuclear Power Plant

The use of wet steam is not uncommon and in fact specific wet steam turbines are used in many NPPs. As WDE is proportional to turbine speed, wet steam turbines tend to run slower than their fossil fuel counter parts. Blade hardening and moisture separators between turbine stages can also be employed to extend the life of wet steam turbines. Although issues could be encountered with turbine blade erosion, experience from other NPPs of using low quality steam can be called upon to allow incorporation of wet steam management techniques into a CHP SMR.

The following table contains operating values typical of a PWR using both SG designs.

Table 8.6: Characteristic Pressurised Water Reactor Operating Values

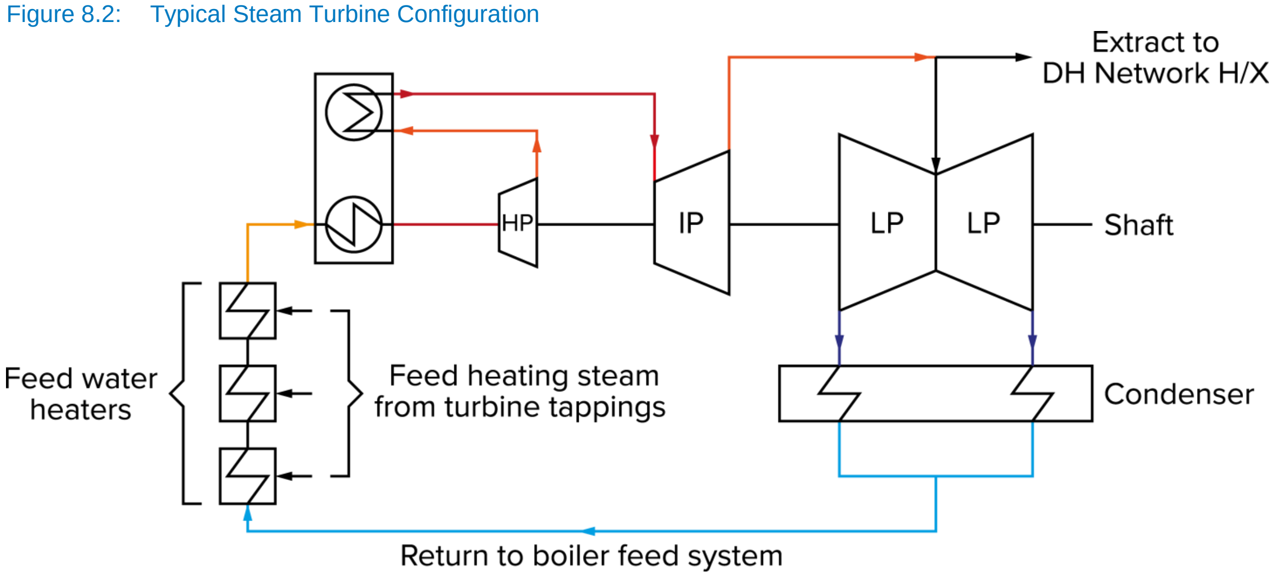
Reactor Type	Typical Primary Coolant Temperatures (°C)	Steam Pressure (MPa)	Steam Temperature (°C)	Steam Wetness (%)
PWR (U-Shaped SG)	280-320	6.5	280	Up to 0.25
PWR (Once-Through SG)	280-320	6.9	312	0

Source: Mott Macdonald based on information provided by IAEA and USNRC

8.2.3.2 Steam extraction

Once steam has been generated, depending on the quality, the electrical generation and steam extraction processes in a CHP NPP are similar to that of a conventional coal/gas/oil-fired CHP plant. Figure 8.2 shows a typical turbine layout; links to turbine further layout diagrams of conventional steam turbines with a HP, IP and dual flow LP turbine and similar arrangements are provided in Appendix M.

Figure 8.2: Typical Steam Turbine Configuration



Source: Mott MacDonald

Based upon the review of publically available data a common point of steam extraction for the purpose of DH is from the IP-LP cross-over pipe although a form of throttling is necessary to maintain consistent extraction conditions for varying loads. However, extraction directly from a turbine is also shown to be possible in Siemens' 2013 presentation[39]; steam is extracted from points along the LP turbine to 'pre-heat' the DH fluid before it is heated by the cross-over steam. The desired steam pressure and temperature is a key factor for selecting the extraction point in any given case.

A thermodynamic analysis of the coal-fired Yatagan plant was performed in 2010 by the Yildiz Technical University, Turkey. The analysis found that steam extraction from the cross-over pipe provided the best balance for co-generation of heat and electricity; this is in keeping with Mott MacDonald's experience of steam extraction for co-generation purposes.

A 2014 report by SMR developer NuScale looked at the advantages and disadvantages of steam extraction for process steam from pre, mid and post turbine tapping points. Only one single flow turbine is shown in the schematic drawings. Key conclusions from the NuScale report were:

- Pre-Turbine take-off (High Pressure) – Gives maximum flexibility of balancing steam and electrical production, but the main steam is 300^{o}C and 3.5MPa.
- Mid-Turbine take-off (Medium Pressure) – Can achieve virtually any desired pressure, depending on extraction location, but there are limitations on the amount of throttling of the steam extraction due to minimum and maximum allowable exhaust flows out of the turbine.
- Post-Turbine take-off (Low Pressure) – Utilises all of the steam, although at a lower grade. The ratio of electricity and steam generation is largely fixed at full load; a steam bypass or multi-stage turbine could be used to mitigate this.

A 2013 presentation by Siemens[39] showed the difference between three different steam extraction set-ups for CCGTs. The three steam extraction configurations were:

- Extraction from the end of the IP turbine or from the IP/LP cross-over pipe;
- Extraction from the end of the IP turbine or from the IP/LP cross-over pipe, plus one additional tapping from the LP turbine;
- Extraction from the end of the IP turbine or from the IP/LP cross-over pipe, plus two additional tappings from the LP turbine.

A butterfly valve on the cross-over pipe was necessary for all scenarios to ensure a constant steam extraction pressure was achieved for varying loads. The purpose of the additional tappings was to 'pre-heat' the DH fluid in a way analogous to feed heating in a steam cycle. The performance achieved during heat extraction was found to increase with additional extraction points but, as expected, so did the cost and complexity of the system; the layout can be seen under reference 12 in Appendix M.

8.2.3.3 Radiation Protection

The assumption is that the nuclear plant is of modern design to recognised standards and that the operation of the plant is appropriately regulated. This already introduces multiple boundaries between sources of radiation and potential contamination of the DH system circulating water within the power plant. Additional preventative measures could include:

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[39] Siemens AG, Flexible steam turbine solutions for combined heat and power in combined cycle power plants

- A DH network comprises of multiple separate networks that are linked via heat exchangers;
- Each network having its own supply of water - this places numerous layers of protection between any irradiated coolant water and the customers' household heating[40];
- Supplying heated water to heat exchangers located in boiler houses both separates the source and customer further, and also enables peak demand and downtime support by the boilers.

By maintaining a higher pressure in the main DH network than the adjacent network, which is closer to the NPP, any heat exchanger leaks would result in fluid flowing in one direction – high to low pressure – effectively 'up-stream' towards the NPP and away from the end-user, and so avoid any chance of harmful substances entering the main DH network. This is used at the Beznau NPP where steam extraction occurs at 2.2 to 2.8bar and the DH network operates at 16 bar[34]. In Mott MacDonald's experience this is a normal process design strategy that is employed in petrochemical facilities.

The type of DH network (open or closed-loop) also affects the level of safety. Historically, DH networks in Siberia (e.g. Bratsk, Russia) have operated open-loop networks, where DH water can actually be extracted via household taps, but such a network design is not assumed for the DH solutions proposed in this report.

8.2.3.4 Nuclear DH safety issues

Our research into NPP cogeneration for this report has not identified any publically documented safety issues relating to the integration of the nuclear plant steam cycle to a DH network.

The public's perception of nuclear power and its use in supplying heating and water (nuclear powered desalination plants) is likely to have a strong bearing on the implementation of any nuclear CHP project. Although outside the scope of this project, the research we have conducted has not produced any information/reports documenting irradiated water due to a nuclear powered DH network or desalination plant.

8.2.4 Future nuclear powered co-generation plants

Public domain literature also identifies multiple cases of future plans to use nuclear power as both a source of electricity and municipal heating.

The largest identified project is the expansion of the Leningrad II NPP in Russia. Construction is underway to replace the four 1000MW_e RBMK-1000 reactors (1974-81) with four 1,170MW_e VVER-1200 reactors, the first becoming operational in 2016/17. In addition to supplying 1,170MW_e of electricity each reactor will also supply around 290MW_{th} of heat for DH; the customer for the DH is unknown[41].

We also found two smaller projects, one Russian and the other Chinese. These projects plan to create floating/barge nuclear power stations which could be towed to locations where electricity and/or heat is

[40] The concept of multiple layers of separation gives merit to the indirect connection method between district heating networks and household heating.

[41] World Nuclear News, First steam generators delivered to Leningrad II-2

required. The Russian Akademik Lomonosov design uses two ice breaker derived KLT-40s PWRs to produce up to 35MW$_e$ of electricity or 150MW$_{th}$ of heat. Sources indicate completion of the first ships could be as soon as 2016[42]. A single ACP100s PWR is planned for the Chinese design, supplying up to 100MW$_e$ of electricity and an unknown amount of heat; completion is planned for 2019.

The Finnish energy company, Fortum, owns and operates numerous power generation facilities in Finland, Sweden, Russia and Poland, with a total electrical capacity of 14.6GW$_e$ and 17.4GW$_{th}$ of DH. In 2009 Fortum applied to the Finnish government to expand the Loviisa NPP with the addition of a third reactor of between 1,000-1,800MW$_e$ electrical generation capacity. The plans included an 80-100km pipeline to supply the Helsinki DH network with about 1000MW$_{th}$ of heat, however a negative 'decision-in-principle' was given for the project by the government in 2010[43].

8.3 Summary

Based upon the review of publically available information regarding the historical, current and future use of large scale DH networks including the use of nuclear based power heat generation, the following points can been concluded:

- DH has been commercially used since 1877 and is mainly used in the northern hemisphere by countries which require domestic heating for much of the year. It accounts for almost half the domestic and commercial heat market in Denmark, Estonia, Finland, Poland, Romania and Sweden.
- Large city-scale DH networks such as Warsaw, Copenhagen and Helsinki have provided reliable heating to 100,000s of people for many decades. Thousands of kilometres of pipes are used to distribute the heated fluid. The longest identified point-to-point pipe is 32km in the Czech Republic.
- Heat can be, and is, supplied to DH networks by a variety of thermal energy sources including large conventionally fired power stations, and large nuclear plants, operating as CHP plants. In 2003, 2,302PJ of heat was generated in European and EFTA countries with 68.3% from CHP sources.
- For DH networks supplying low-grade heat to residential and commercial end-users, water rather than steam is often the preferred heat transfer medium. Customer end heat exchangers could replace household gas-fired boilers, retaining the original central heating system. Studies suggest the optimal post extraction temperature for large-scale networks to be in the 75^{o}C to 150^{o}C range. A minimum of 60^{o}C at the user end is necessary to protect against Legionnaires disease. This would either need to be achieved through heat supplied by the DH network or potentially by smaller household electric heaters that provide a daily 'boost'.
- Over 500 reactor life years have been achieved by nuclear power plants supplying heat to DH in Bulgaria, Hungary, Romania, Russia, Slovakia, Sweden, Switzerland and Ukraine. Nuclear power for DH appears restricted to Europe, Scandinavia and Russia. In 2009, 7.5% of Swiss DH was generated by nuclear power plants.

[42] OKBM, FNPP "Academician Lomonosov"

[43] Cogeneration & On-Site Power Production, Carbon-free nuclear district heating for the Helsinki area?

- Beznau nuclear power plant in Switzerland has supplied approximately 70MW_{th} of heat to the 15,000 customers of REFUNA DH network for over 30 years. Bilibino nuclear power plant in Russia has supplied heat to 14,000 people since the mid-1970s.
- Pressurised Water Reactors – similar to many SMR designs – operate with typically low peak steam temperatures (around 340^{o}C). This means that for certain configurations and types of Steam Generators moisture is present in the produced steam. Excessive levels of steam wetness can lead to turbine blade erosion, but this issue has been encountered and addressed in the past by 'wet steam turbines' at many NPPs.
- An interviewed PWR based NPP with a hot water DH network, stated that in their experience the integration with a DH network had "no impact or negative effects on the availability, maintenance and performance of the nuclear plant".
- The optimal point of steam extraction from the steam turbine cycle is the cross-over pipe between the IP and LP steam turbines. Mid-turbine extraction is possible for multi-extraction configurations where low grade steam is extracted from the LP turbine to 'pre-heat' the DH fluid, before it is heated to its final transmission temperature by higher grade steam.
- There are a number of proven techniques to ensure a DH network cannot become contaminated with nuclear power plant radiation. Our research into NPP cogeneration for this report has not identified any publically documented safety issues relating to the integration of the nuclear plant steam cycle with DH networks. Despite this, public perception of nuclear powered DH networks and desalination plants will have a strong influence on the success of any NPP CHP plants.

Overall, the reviewed information indicates that the use of a nuclear reactor as a CHP plant is a proven and viable technological partnership which has been successfully used by numerous countries for many decades.

9 Conclusions

Analysis undertaken for this report validates the main finding from Phases 1 and 2 of the ANT project that SMRs could play an important role in the UK's future energy system by operating as Combined Heat and Power plants providing low-carbon heat to city-scale DH networks.

The engineering and cost modelling presented shows that extracting heat from the steam cycles of Light Water Reactor type SMR plants is both technically feasible and relatively easy to implement. The indicative steam cycle model solutions we have developed are capable of providing heat and power simultaneously and independently. Furthermore, whilst our analysis has resulted in some amendments to our earlier assumptions regarding CHP plant performance and cost, these changes do not alter the central finding of our economic analysis that heat sales have the potential to significantly improve the economic attractiveness of SMR plants. This is because the costs of modifying an SMR steam cycle model to allow for heat extraction are relatively small, whilst the revenues from heat sales are potentially large.

This conclusion is based on the starting assumptions (defined by the ETI) that unabated gas will need to be phased out by mid-century in order for the UK to meet its decarbonisation targets, and that large-scale DH networks will be required to cost effectively decarbonise heat supply in densely populated urban areas.

We also investigated whether or not the design philosophy adopted by SMR vendors – namely the size and efficiency of SMR module – makes a significant difference to the cost and performance of heat extraction. Our conclusion is that it does not. We developed two indicative SMR plant steam cycle models, one based on a small relatively low efficiency module and the other on a larger more efficient module, and found that variations in cost and performance were found to be minor.

As a result of these findings, and based on the ETI's energy system modelling that shows a potentially significant role for SMRs in the UK's future energy system, it will be important that any SMR design selected for regulatory assessment in the UK via the GDA process is capable of heat supply. ***The evidence strongly suggests that should SMRs be deployed in the UK they should be configured 'CHP ready', even if they are initially required to supply electricity only***. 'CHP readiness' can be delivered for a small incremental cost (~£10/kW$_e$) and would ensure that SMR plants are ready for a subsequent upgrade to allow heat extraction to supply DH networks. If a FOAK SMR is deployed in the UK, CHP readiness should be considered even if it cannot be demonstrated due to a lack of infrastructure/heat demand.

We also suggest that further consideration is given to ensuring that an SMR design entered into the UK licensing process is capable of other cogeneration applications more suited to international markets, such as desalination. Whilst such applications were outside the scope of this project, ensuring that a UK licensed SMR design is flexible enough to meet international requirements may be a material factor in achieving the economic case for SMRs, which rests on cost reductions driven by the factory production of large numbers of identical components.

If the UK does embark on a strategy for decarbonising heat that involves the use of nuclear powered DH networks, it will not be without precedent. Our review of relevant international examples indicates that the use of a nuclear reactor as a Combined Heat and Power plant is a proven and viable technological partnership which has been successfully used by numerous countries for many decades, including

Switzerland and Russia. In addition, large city-scale non-nuclear DH networks such as Warsaw, Copenhagen and Helsinki have provided reliable heating to 100,000s of people for many decades.

Finally we conclude that plant cooling technologies that use very little water (such as an Air Cooled Condenser) are technically feasible and could be retrofitted to existing SMR plants that were initially built with only Mechanical Draught ECTs. Such hybrid solutions have the advantage of exploiting the higher steam cycle efficiency of the ECT during times of sufficient water, and of being able to continue operating when water is scarce with the ACC[44].

This finding is important because a number of potential SMR sites identified in the Power Plant Siting Study are inland, and it is conceivable that more frequent and severe droughts in the future could result in restrictions on water abstraction rates from inland water sources such as rivers and lakes. The ability to switch SMR plants to cooling methods that require less water could therefore be an important factor supporting long-term deployment and building in resilience to a changing climate.

Depending on SMR location and potential future water constraints (i.e. not coastal or rivers locations where extraction is a small percentage of the total flow), we suggest that consideration is given to the potential risk of constrained plant operation/ loss of revenue, and how this could be mitigated by building the SMR plant ‘ACC ready’. This would involve little additional cost but require selection of a larger site and design of a steam cycle configuration with space for subsequent modification.

By validating the findings of Phases 1 and 2 of the ANT project, we conclude that SMR heat supply could be a significant benefit to both plant economics and the decarbonisation of the UK’s energy supply. The cost of designing and building SMR plants ready to supply future DH networks is relatively small, but the benefits are potentially large. This report may have relevance for organisations considering the potential deployment of SMRs into a future UK low carbon energy systems.

[44] These hybrid solutions assumed cooling water would still be available for safe reactor shutdown.

Appendices

Appendix A. Key findings from ANT Project Summary Report (Phases 1 & 2)

The following key findings are described in more detail in the ANT Project Summary Report (Phases 1 and 2) which at the time of writing is available at the ETI website:

http://www.eti.co.uk/wp-content/uploads/2015/10/ANT-Summary-Report-with-Peer-Review.pdf.

Functional Requirements workstream

The functional requirements workstream focussed on determining what SMRs will need to do from a technical perspective to be of value to the UK's future energy system. It involved a wide range of project tasks. Some were aimed at understanding what SMRs might realistically offer in terms of energy services, commercial readiness and long-term deployment rates. Others explored the needs of the energy system in more detail, such as low-carbon heat for DH network energisation, technology capable of being located on a diverse range of sites close to demand, and the compatibility of nuclear power plant fuel cycles with existing UK infrastructure. These pieces of analysis, supported by additional expert input, fed into the development of a list of SMR technical requirements.

The key findings are:

- It is likely to be technically feasible for SMRs to offer a range of different energy services, including baseload electricity, load-following electricity, heat for DH networks, and – if integrated with new storage technologies – energy balancing and other ancillary services.
- Development of a low risk evolutionary LWR type SMR from initial basis of design to the point of FOAK commissioning could take ~17 years and cost a minimum of ~£1.3bn (excluding FOAK capital costs). This assumes no full-scale design demonstrator plant is required. Many SMR concepts are already some way along this timeline.
- More radical SMR concepts would probably require a full-scale design demonstrator to prove the technological case for the design in question, adding ~£1bn to these development costs, with timescales as high as 26 years.
- From a technology development perspective, it is reasonable to assume that the first commercially deployed SMR power plants could be operating in the UK in the early 2030s. However if SMR concepts are selected that take longer to develop, there is a risk that the market opportunity will be lost.
- From the early 2030s, it is possible to envisage a regular deployment drumbeat that could lead to multiple gigawatts of deployed SMR capacity by 2050. This would require substantial challenges relating to supply chain development, investment and public acceptability to be overcome. The ANT project did not include an assessment of these issues.
- Our analysis of heat demand data suggests there are around 50 conurbations in GB potentially suitable for hosting SMR energised DH networks. The theoretical SMR capacity needed to energise all these networks is $22.3GW_e/40.1GW_{th}$.
- It is unlikely SMRs will meet a DH's heat load in its entirety. Heat storage and low CAPEX technologies are likely to be used for meeting periods of peak load, whilst SMRs will be competing with other high

CAPEX low carbon technologies to provide 'baseload' and 'mid-merit' heat. Reliable long-term offtake arrangements will be needed to secure upfront investment in these high CAPEX plant.

- The PPSS study, which was not exhaustive, has identified a significant number of site locations in England and Wales that are potentially suitable for small thermal plants like SMRs. The total 'stand-alone' electrical capacity that could be hosted by these sites is $66.9GW_e$. Less than 10% of this capacity is 'lost' when water cooling availability due to shared watercourses is taken into account. It should be noted that the PPSS represents the first stage of a multi stage assessment process for new nuclear power plants. Actual plant capacity deployed on the identified sites will be lower once the full assessment process has run its course.
- The proximity of the PPSS site capacity to the identified DH networks suggests there could be a potential market for SMR heat in the England and Wales. This strengthens the conclusion that SMRs in the UK should be able to produce heat for DH networks.
- All of the existing siting criteria set out in the UK's National Policy Statement for Nuclear Power Generation (2011) are relevant to SMRs. However some may need to be applied flexibly, as they were in the PPSS, to account for the unique characteristics of SMR technologies and unlock the full range of potential sites.
- It is feasible for a small number of standardised SMR modules and plug-in systems configured at the site level to be deployed in a diverse range of contexts. This is important because it is a prerequisite for realising the economic benefits of factory production and standardised processes that SMRs could offer.
- In practice, for SMRs to produce heat as well as electricity, the reactor will need to run at a near constant rate (maintaining a relatively stable core power) whilst throttling heat production up and down to meet demand. There are a variety of technical solutions to achieve this but to date it appears that vendors have given little consideration to this requirement.
- From a technical perspective, SMRs could be deployed in areas with a limited cooling water supply provided that an engineered ultimate heat sink can be made available, for example by utilising forced draught cooling towers. Turning SMRs off for scheduled maintenance in summer when cooling water is unavailable may facilitate such deployment. However there are regulatory and safety challenges that will need to be overcome to allow this.
- The deployment of a fleet UK SMRs will add to the UK's national nuclear infrastructure requirements. In particular, additional capacity for all levels of nuclear waste handling and disposal is likely to be required. The cost of these 'back-end' infrastructure upgrades could be lower if deployment is based on LWR designs rather than more novel technologies. In addition, SMRs that require changes to Government policy on waste management to accommodate alternative fuel cycles and waste-forms may face additional delays to deployment whilst such policy matters are concluded. The capability and skills to service novel fuel cycles also need to be considered.

We identified a list 98 technical requirements relevant to SMRs if they are to meet the needs of the UK's future energy system. These cover technical readiness, infrastructure compatibility and the capability to provide heat and flexibility as well as baseload electricity. A number of stringent standards relating to safety, performance, and design will also need to be met – factors that will likely have a significant impact on the public and political acceptability of large-scale SMR deployment in the UK.

Business Case workstream

The business case workstream focussed primarily on what SMRs will need to achieve from an economic perspective to be of value to the UK's future energy system. The main component was the economic appraisal, which served two functions. First, and most important for the ANT project, it estimated broad 'target costs' for SMRs – i.e. the *maximum* amount an SMR power plant could cost whilst still delivering commercial rates of return to investors under future market conditions. Thus, 'target costs' should be understood as the upper cost limit for viable SMR projects in the UK. Second, the appraisal developed an indicative scenario for actual SMR costs by making high-level estimates of future CAPEX and OPEX for LWR type SMRs and how these might reduce over time. This scenario was compared with target costs to provide an initial view on the relative viability of different SMR service offerings.

We stress here that there is a great deal of uncertainty about the future costs of SMRs and this element of our economic appraisal should be treated as indicative only. Given the pre-commercial status of the technology, the lack of current real-world cost data, and the fact it was not part of the ANT project to undertake any kind of detailed engineering cost assessment of SMR designs, we caution against any over-interpretation of our results. We recognise that other cost scenarios are possible.

The business case workstream also included tasks to identify some of the main risks and opportunities for SMR deployment in the UK, and explore the high-level issues and options Government and Industry would need to consider in deploying and financing a fleet of UK SMRs.

The key findings are:

- We estimate the future unit prices available to SMR plants for low-carbon electricity to be ~£80/MWhe for baseload power and ~£163/MWhe for peaking power.
- There is significant uncertainty about the future price of low-carbon heat. Our base case estimate of the price available to CHP SMR plants is ~£65/MWh_{th}. Note that these prices reflect what we think could be available to generators. They are not retail prices and they do not include network costs (transmission and distribution in the case of electricity or DH network infrastructure in the case of heat).
- The target CAPEX for electricity-only SMR plants providing baseload power is <£3,600/kW_e. This broadly equates to a target LCOE of <£80/MWhe.
- Our own indicative cost scenario (which is speculative at this stage) suggests electricity-only SMRs could have a higher first factory CAPEX than the target cost. This is reflected in an indicative project IRR of just under 8%, which is lower than our assumed 10% hurdle rate. By second factory stage, if costs fall further, our scenario would broadly reach parity with target costs.
- The target CAPEX for CHP SMR plants providing baseload power and operating at a 40% heat ACF is <£6,500/kW_e. This reduces to <£5,000/kW_e in downside scenarios with more pessimistic assumptions.

This target includes the cost of the heat mains from the plant to the DH network, but excludes all other DH network infrastructure costs.

- Our indicative costs scenario suggests CHP SMR plant CAPEX could be significantly lower than the target cost. This is reflected in an indicative project IRR of ~13% under our base case assumptions, suggesting CHP SMRs would be attractive to investors. Whilst this conclusion should be treated with caution, our analysis suggests CHP plants could be viable even in moderate downside scenarios.
- The target incremental CAPEX for Extra-flex SMR plants is estimated at £350-£750/kW$_e$, depending on the size of the capacity boost. This target reflects the maximum *additional* CAPEX that could be justified for providing the storage system and extra generation equipment, based on the additional revenues available. Target costs would vary further with different peaking price and storage capacity assumptions.
- Our indicative cost scenario (based broadly on molten salt storage costs) suggests that the incremental CAPEX for Extra-flex facilities would exceed the target costs. This suggests that in order to be viable new storage technologies capable of fulfilling the Extra-flex function will need to have lower costs than are achieved by currently available commercial storage solutions. However both the target costs and cost scenario for Extra-flex have high levels of uncertainty and further work is recommended here.
- Deploying a fleet of UK SMRs in time to help meet 2050 decarbonisation targets is likely to require Government leadership and active intervention over a period of decades. Whilst there will be options over the extent of this intervention, Government will need to provide funding, take risks, create markets and ensure supportive regulatory and planning frameworks are in place.

To ensure enough certainty is in place for investors in SMR plants, Government will need to ensure reliable long-term offtake arrangements are in place. For electricity this could be in the form of CfD contracts awarded for multi-gigawatt tranches of SMR capacity. For heat this could come via a contractually guaranteed minimum heat price and/or capacity payment for plants energising DH networks.

Conclusion

The analysis undertaken for the ANT project supports the proposition that SMRs have the potential to make a valuable contribution to the UK's future energy system. Our work suggests that in addition to baseload electricity they could provide low-carbon heat to energise city-scale DH networks; open up a diverse range of sites to deliver more capacity than would be available from large plants alone; and, potentially, integrate with new storage technologies to provide flexible 'load-following' electricity for the grid.

To turn this potential into reality, SMR technologies will need to meet a number of functional and economic energy system requirements. On the functional requirements side, these cover a wide range of issues including construction based on high levels of off-site manufacture and modularity, heat provision, transportability, safety, and compatibility with the UK's national nuclear infrastructure. On the economic requirements side, ambitious cost reductions will need to be realised in order for SMR plants to be attractive to investors and developers. A comparison between our estimated target costs and our indicative cost scenario suggests CHP SMRs will be in the most economically favourable position, whilst electricity-only and Extra-flex SMRs (those with new storage and surge technologies) may need to achieve lower NOAK costs than we have assumed in order to exceed investor hurdle rates.

The ANT project sets out an initial view of these energy system requirements. The project outputs are intended to provide guidance to SMR developers interested in the UK market and to be a useful framework for assessing the potential suitability of different SMR designs for the UK context. They also set out a number of high-level strategic issues and options for overcoming the challenges associated with SMR fleet deployment. As such they have relevance for Government and Industry bodies interested in taking up this task.

Appendix B. NuScale and mPower information sources

IAEA (2014) *Advances in SMR technology developments. A supplement to IAEA Advance reactors information system (ARIS).* Available at: https://www.iaea.org/NuclearPower/Downloadable/SMR/files/IAEA_SMR_Booklet_2014.pdf

mPower (2013) *B&W mPower Program IAEA SMR Technical Meeting* (Presentation). Robert Temple, Chengdu China, September 3 2013.

mPower (2013) *B&W mPower SMR: Creating the power of the future* (Presentation). NEI Nuclear Fuel Supply Forum, January 30 2013.

NuScale (2014) *Overview of new nuclear technologies* (Presentation). Joint Select Task Force on Nuclear Energy, September 25 2014.

NuScale (2014) *NuScale Small Modular Reactor* (Factsheet).

NuScale (2015) *The NuScale value proposition: Simple, Safe, Economic* (Presentation). Jay Surina, CFO, Mike McGough, CCO, February 18 2015.

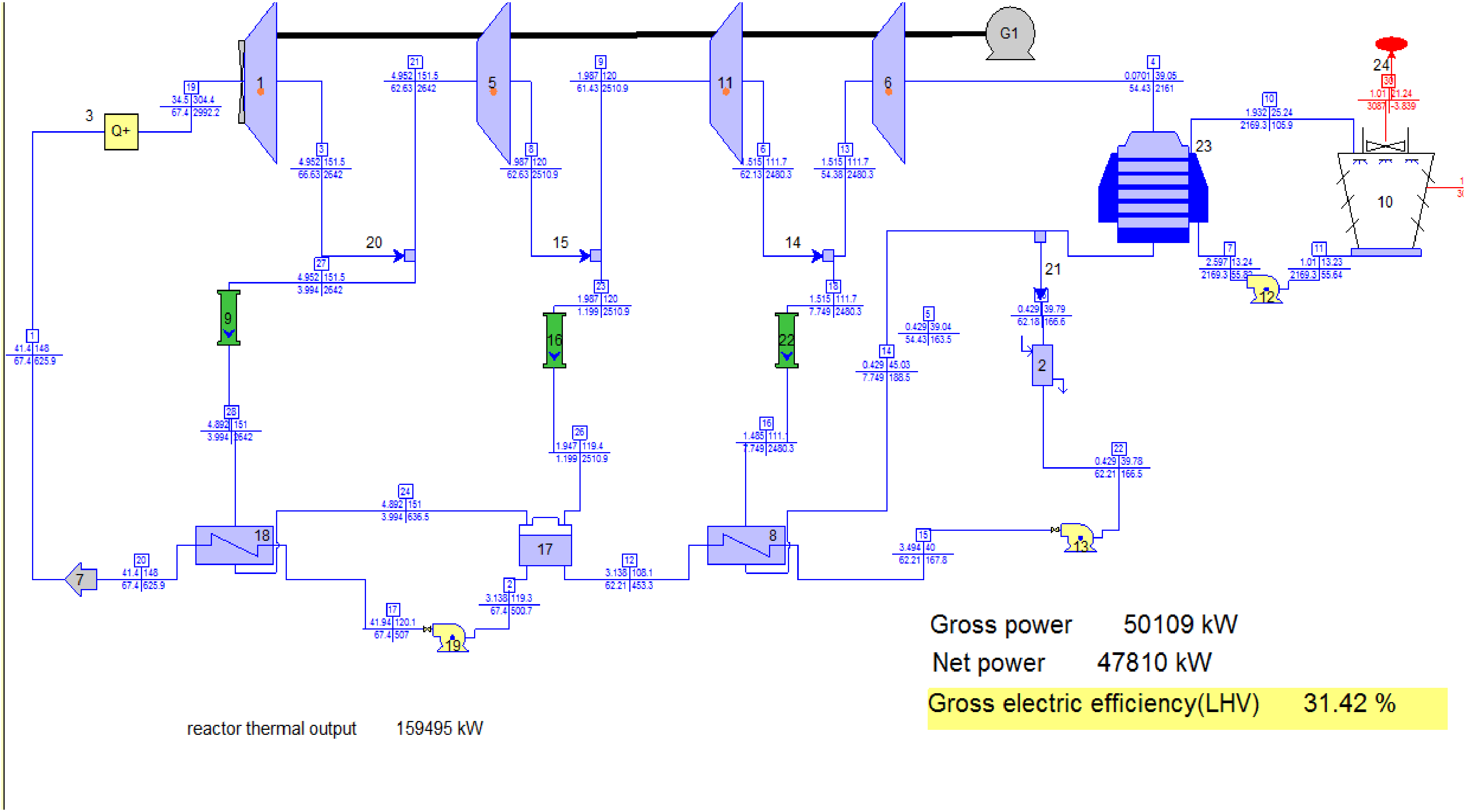
NuScale (2016) *Prospectus: A nuclear energy opportunity for the UK.*

World Nuclear Association website (2016) *Small Nuclear Power Reactors*. Available at: http://www.world-nuclear.org/information-library/nuclear-fuel-cycle/nuclear-power-reactors/small-nuclear-power-reactors.aspx [Accessed 24th February 2016]

mPower (2010) *ANS/DC Chapter Presentation* (Presentation). T.J.Kim

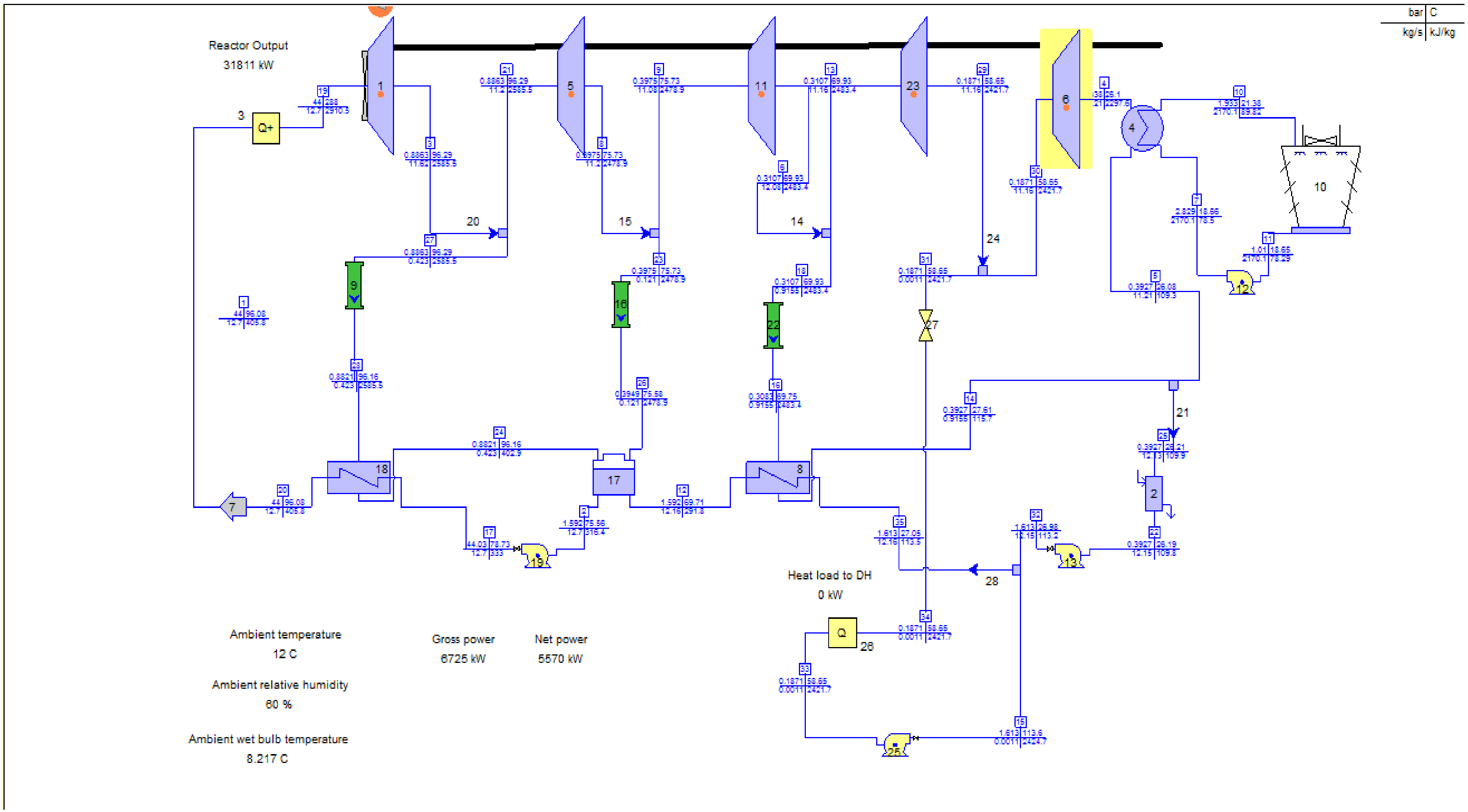
Appendix C. Plant heat & mass balances (electricity only mode)

Figure C.1: Plant A (electricity only) – heat and mass balance at 100% reactor load



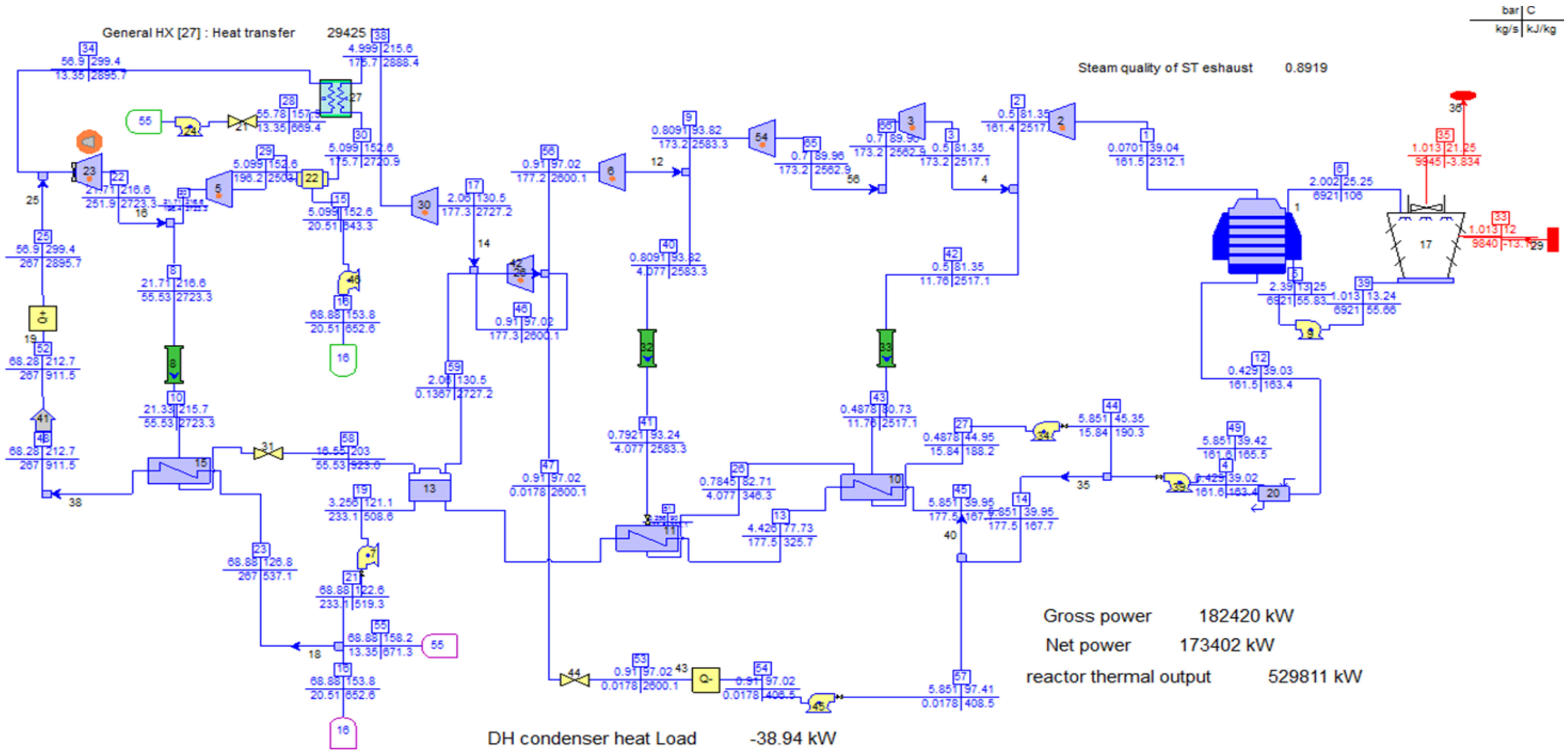
Source: Mott MacDonald

Figure C.2: Plant A (electricity only) – heat and mass balance at 20% reactor load



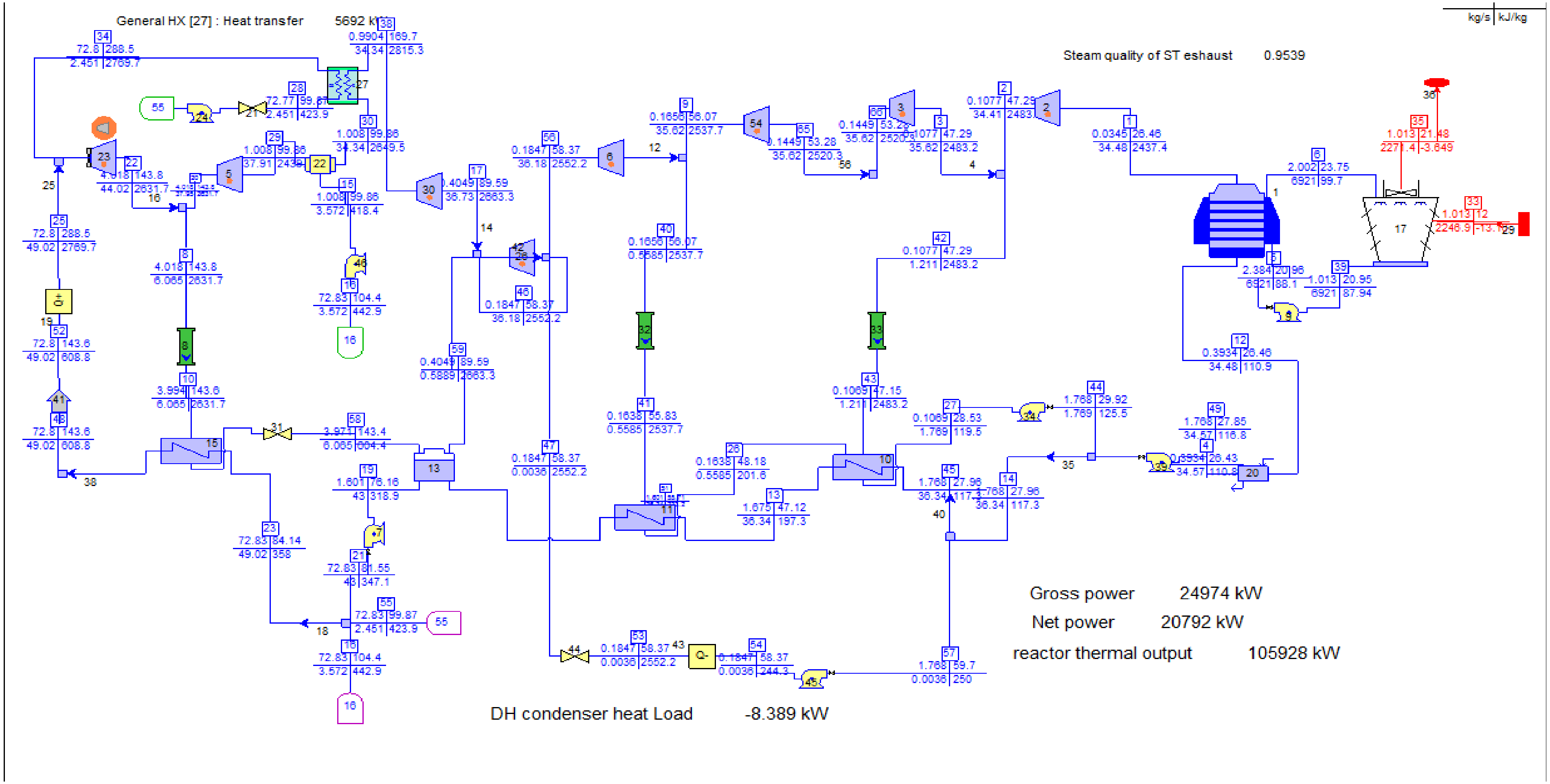
Source: Mott MacDonald

Figure C.3: Plant B (electricity only) – heat and mass balance at 100% reactor load



Source: Mott MacDonald

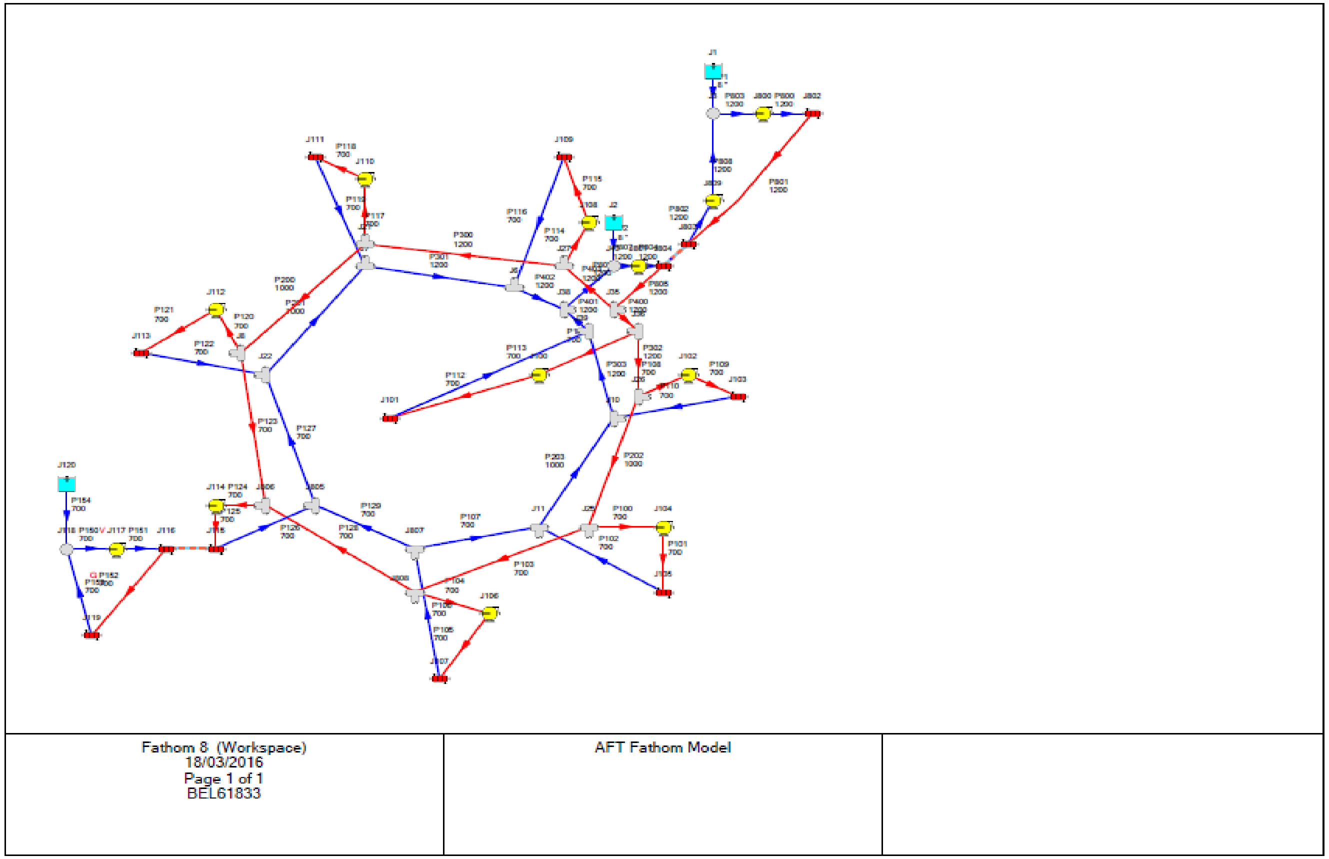
Figure C.4: Plant B (electricity only) – heat and mass balance at 20% reactor load



Source: Mott MacDonald

Appendix D. DH pressure drop and heat loss modelling

Figure D.1: DH pressure drop and heat loss modelling



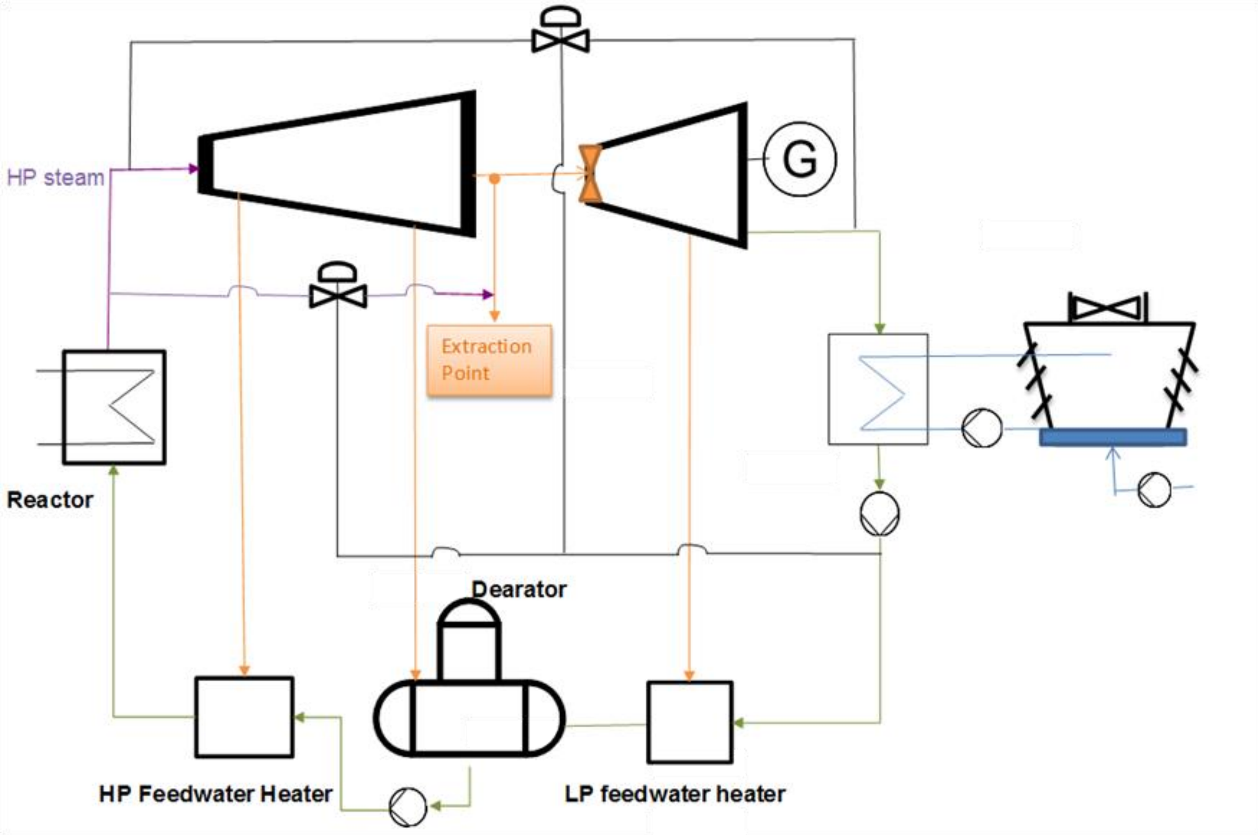
Source: Mott MacDonald

Appendix E. Steam cycle modification

Additional operating modes to those investigated in Section 4, where more heat is extracted by bypassing the steam turbine and reducing its electrical output are shown below in Figure E.1.

A pressure reducing de-superheating valve (PRDS), similar to a turbine bypass valve, could be used to depressurise HP steam to 0.91bara and de-superheat to 97°C, saturated temperature. This could only be done up to a maximum of the heat duty at full power full heat as all DH equipment is designed for this duty. If additional steam was available, this would go through the existing turbine bypass valve. If the plant was generating heat and not power, the SMR would need to import power from the grid.

Figure E.1: Steam cycle modification for heat extraction higher than the corresponding power requirements

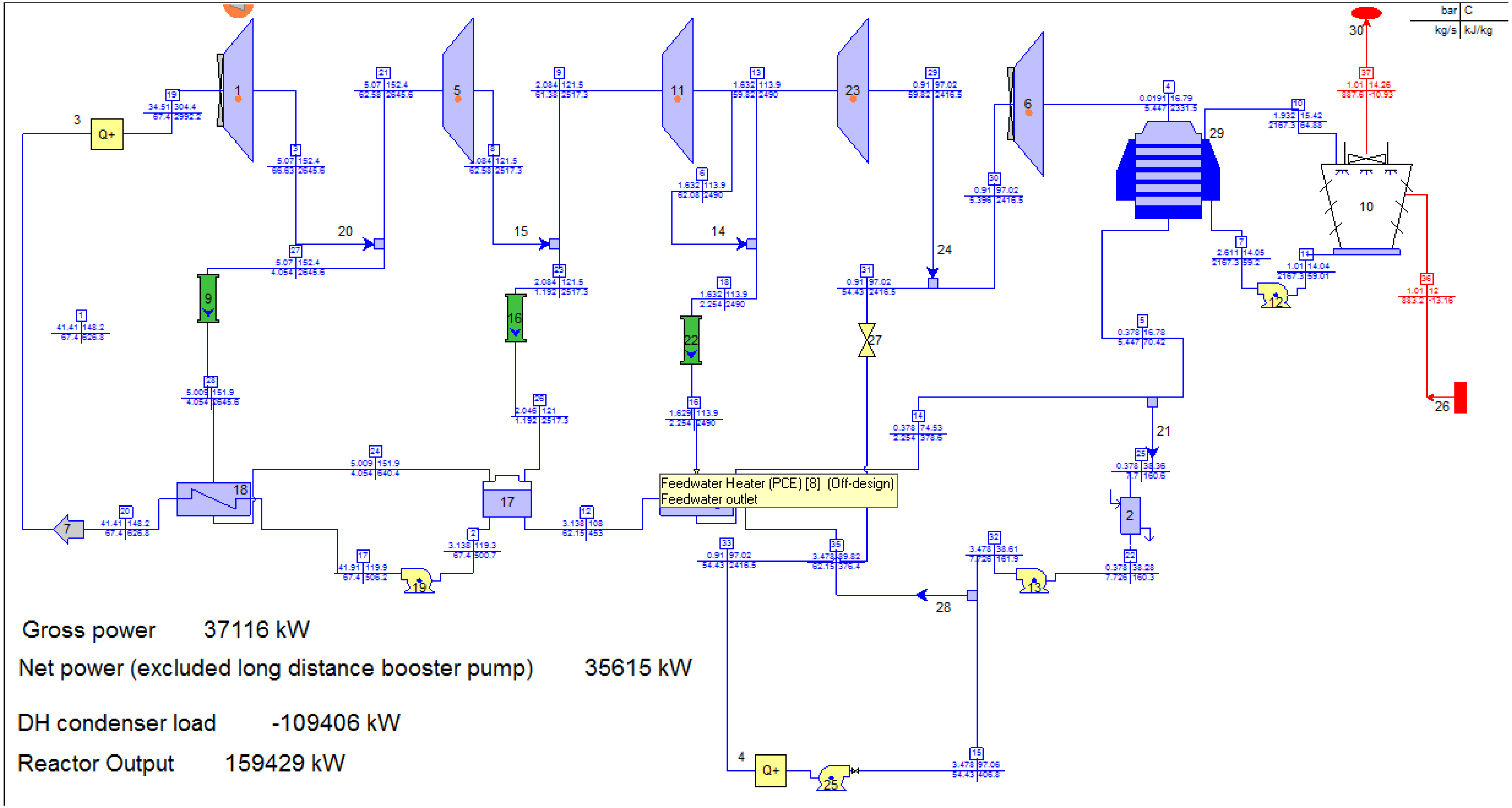


Source: Mott MacDonald

Appendix F. Plant heat & mass balances (maximum steam extraction)

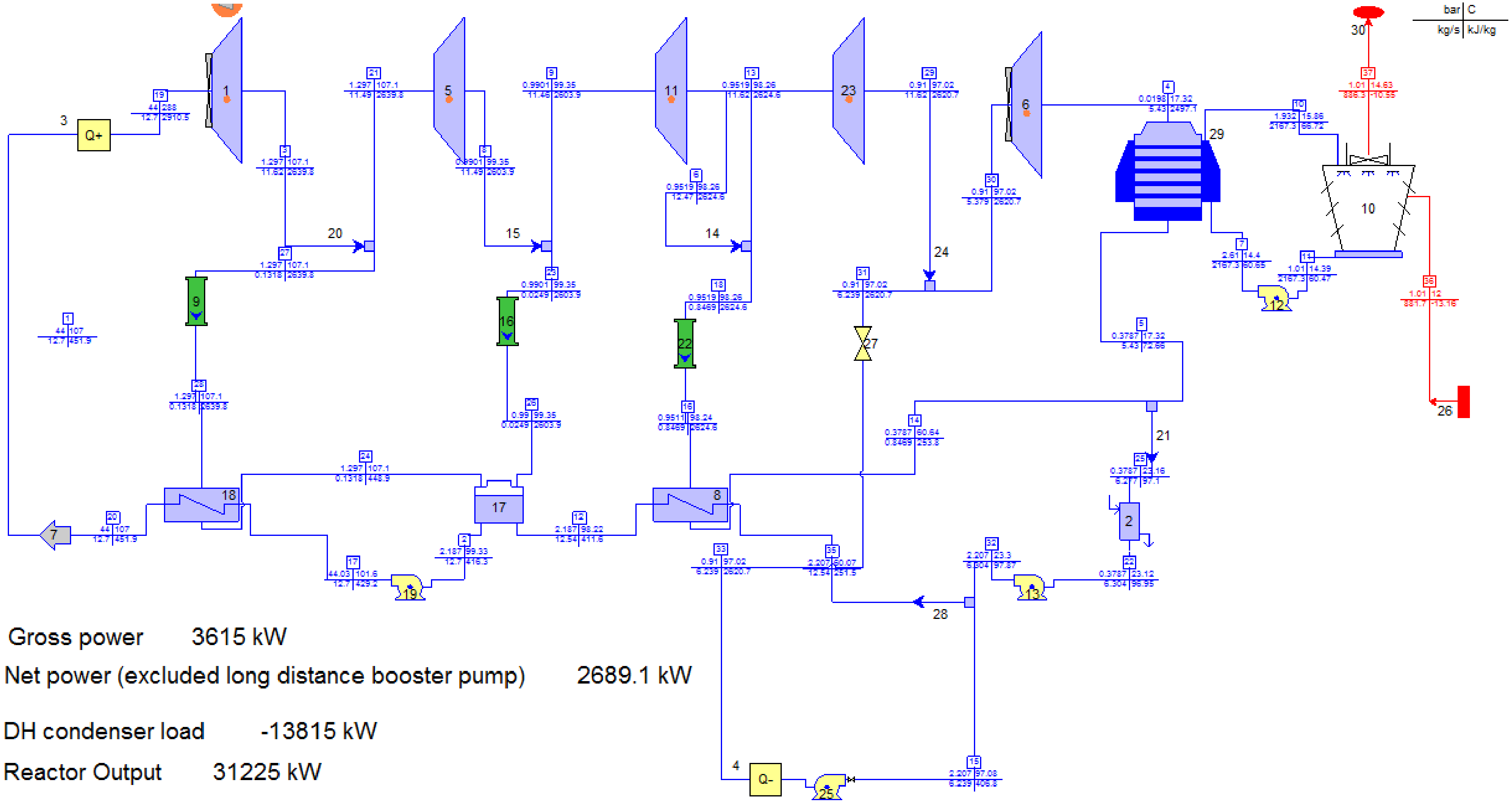
Below we provide the heat and mass balance diagrams for Plant A and B heat extraction at both 100% and 20% reactor loads. These are provided as a representative sample of the extensive thermal modelling conducted for this report.

Figure F.1: Plant A (maximum extraction) – heat and mass balance at 100% reactor load



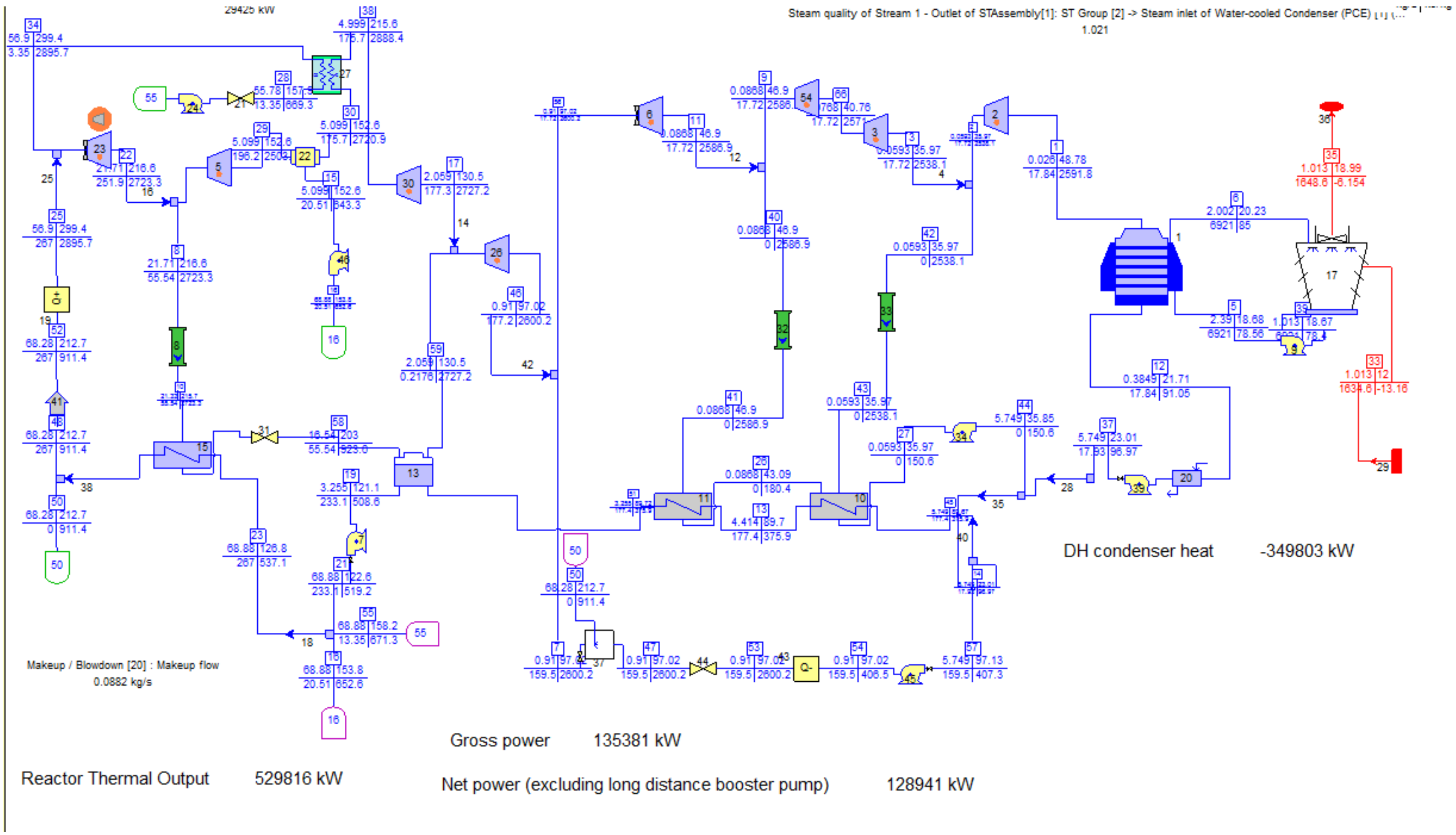
Source: Mott MacDonald

Figure F.2: Plant A (maximum extraction) – heat and mass balance at 20% reactor load



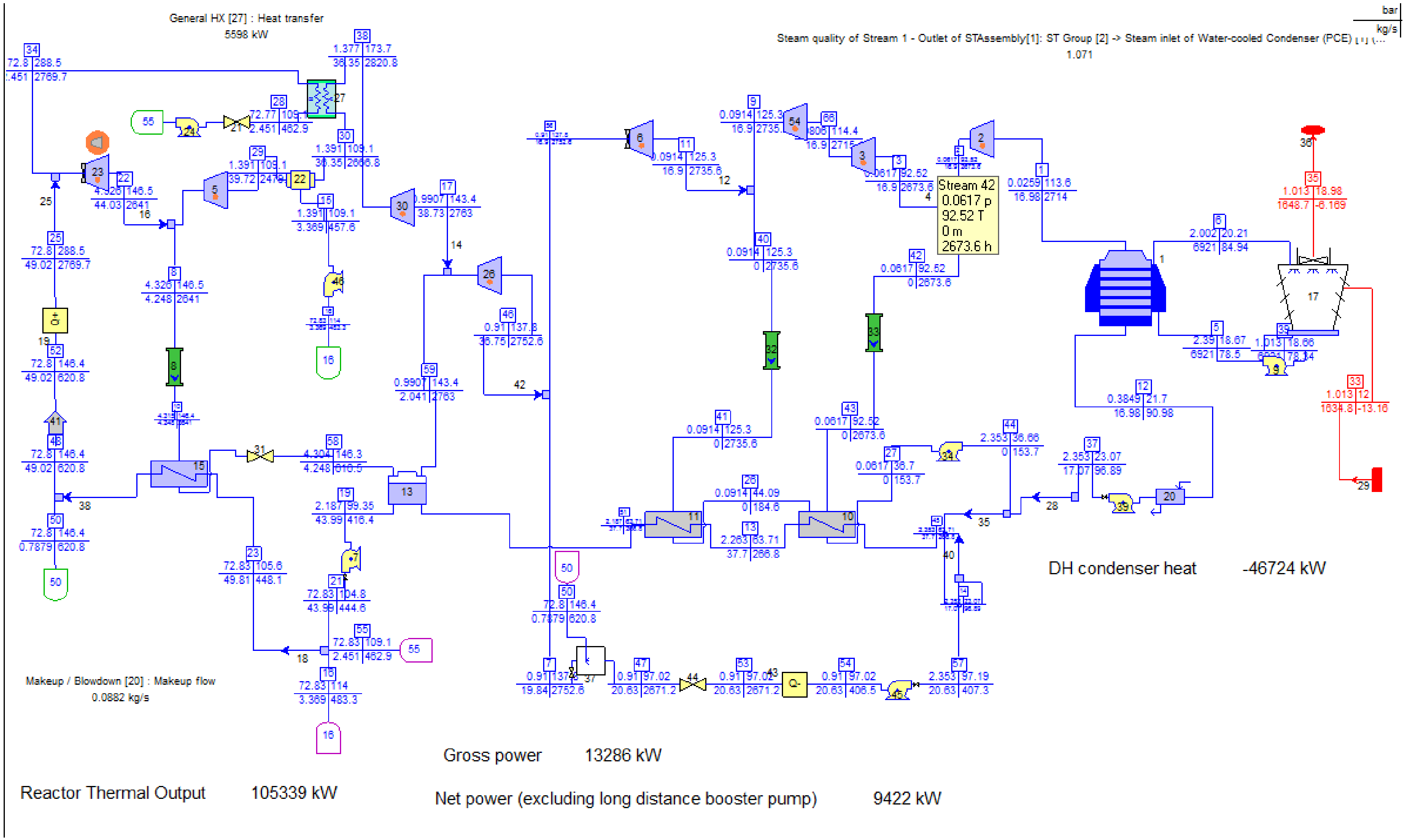
Source: Mott MacDonald

Figure F.3: Plant B (maximum extraction) – heat and mass balance at 100% reactor load



Source: Mott MacDonald

Figure F.4: Plant B (maximum extraction) – heat and mass balance at 20% reactor load

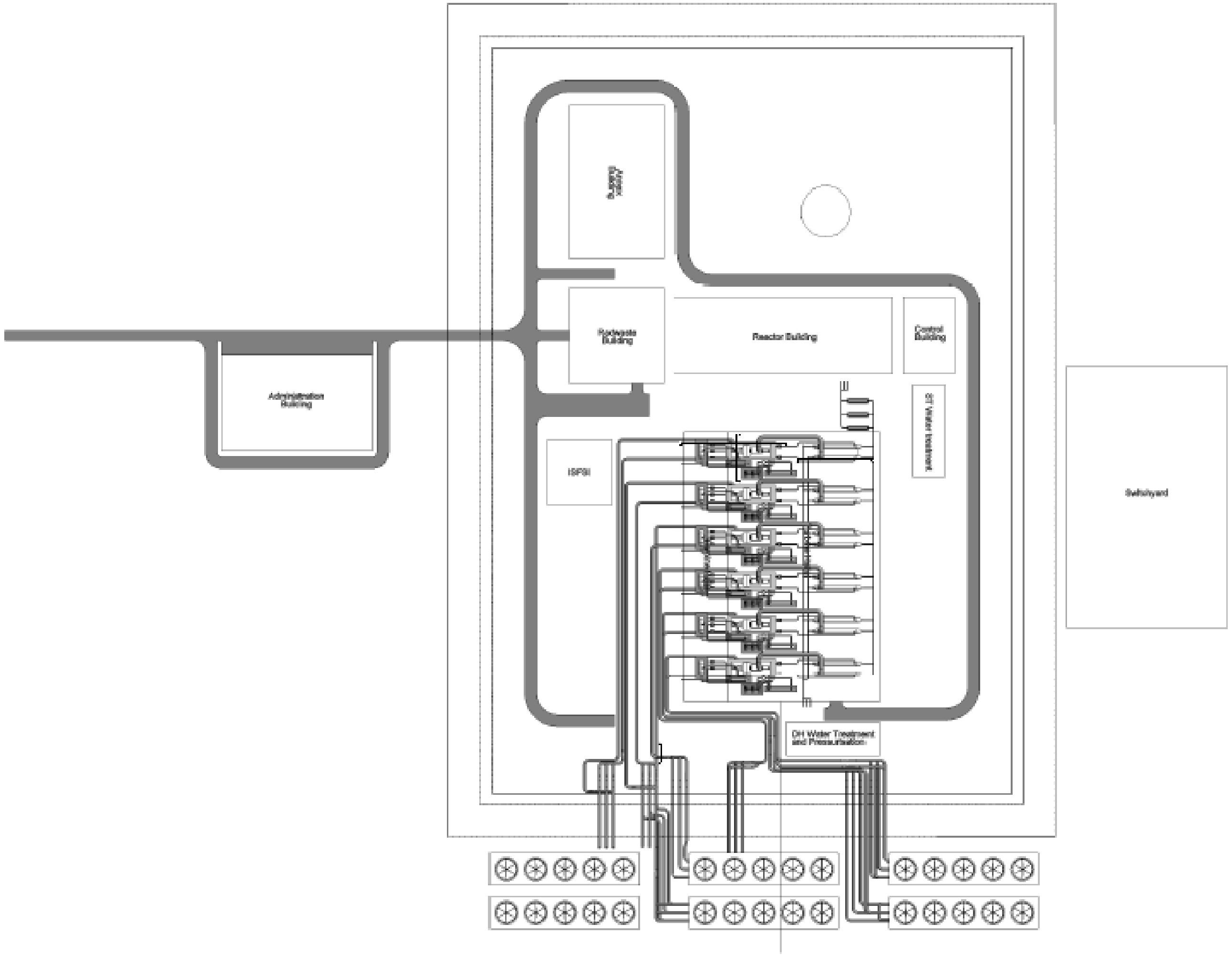


Source: Mott MacDonald

Appendix G. Plant layout & 3D view

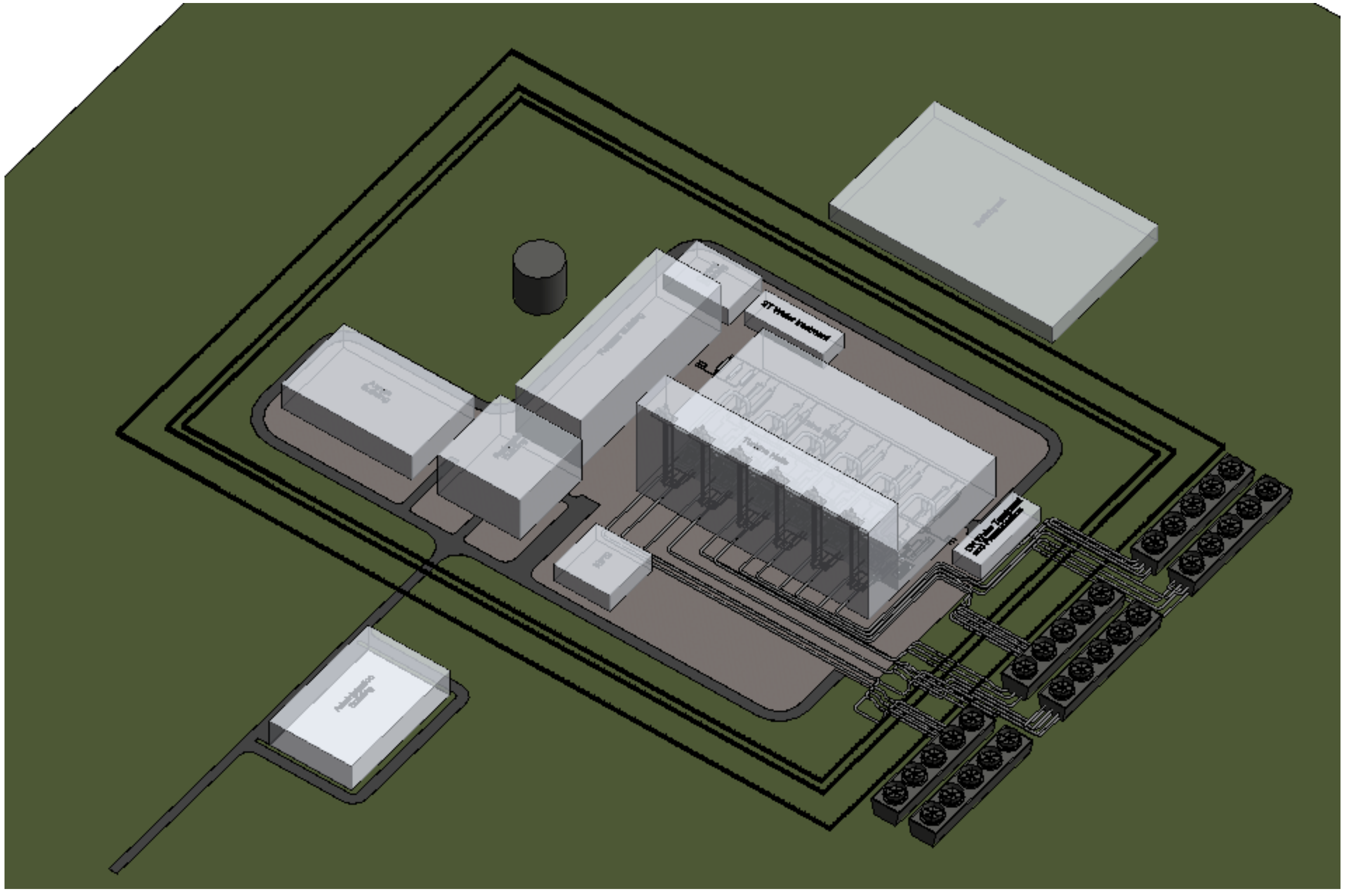
G.1 6 x 50MW$_e$ Plant A (based on ECTs)

Figure G.1: 6 x 50MW$_e$ Plant A (based on ECTs) – Plant Layout



Source: Mott MacDonald

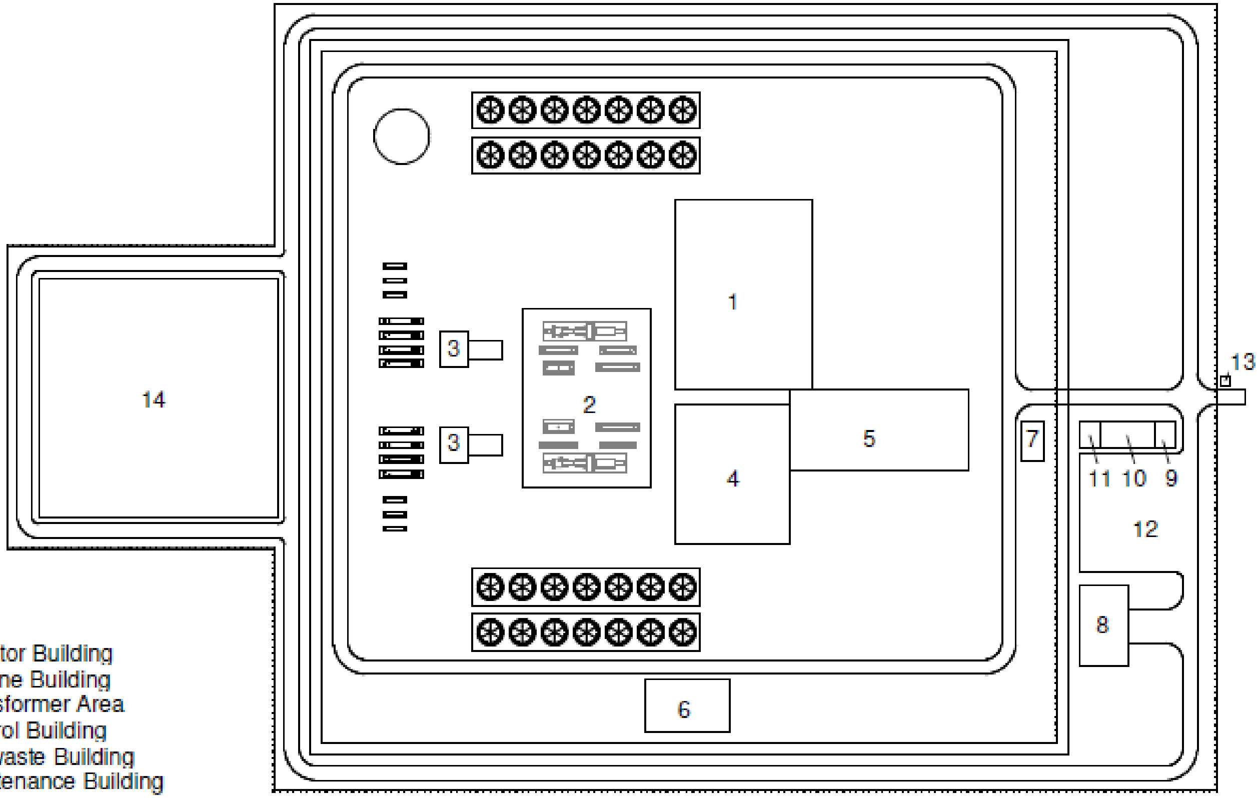
Figure G.2: 6 x 50MW$_e$ Plant A (based on ECTs) – 3D View



Source: Mott MacDonald

G.2 2 x 180MW$_e$ Plant B (based on ECTs)

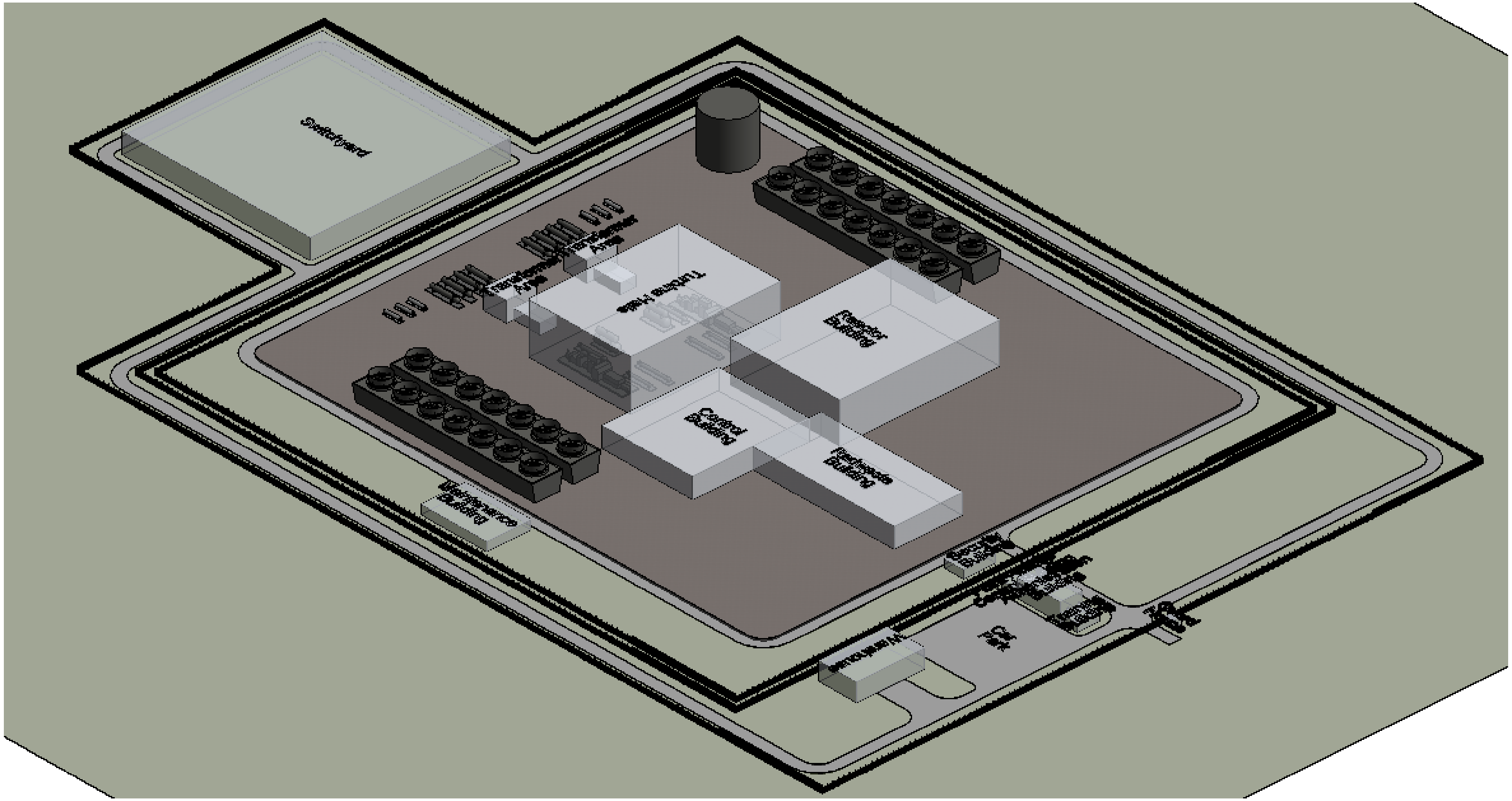
Figure G.3: 2 x 180MW$_e$ Plant B (based on ECTs) – Plant Layout



1. Reactor Building
2. Turbine Building
3. Transformer Area
4. Control Building
5. Radwaste Building
6. Maintenance Building
7. Security Building
8. Warehouse
9. Training Building
10. Administration Building
11. Plant Access Control Building
12. Car Park
13. Guard house
14. Switchyard

Source: Mott MacDonald

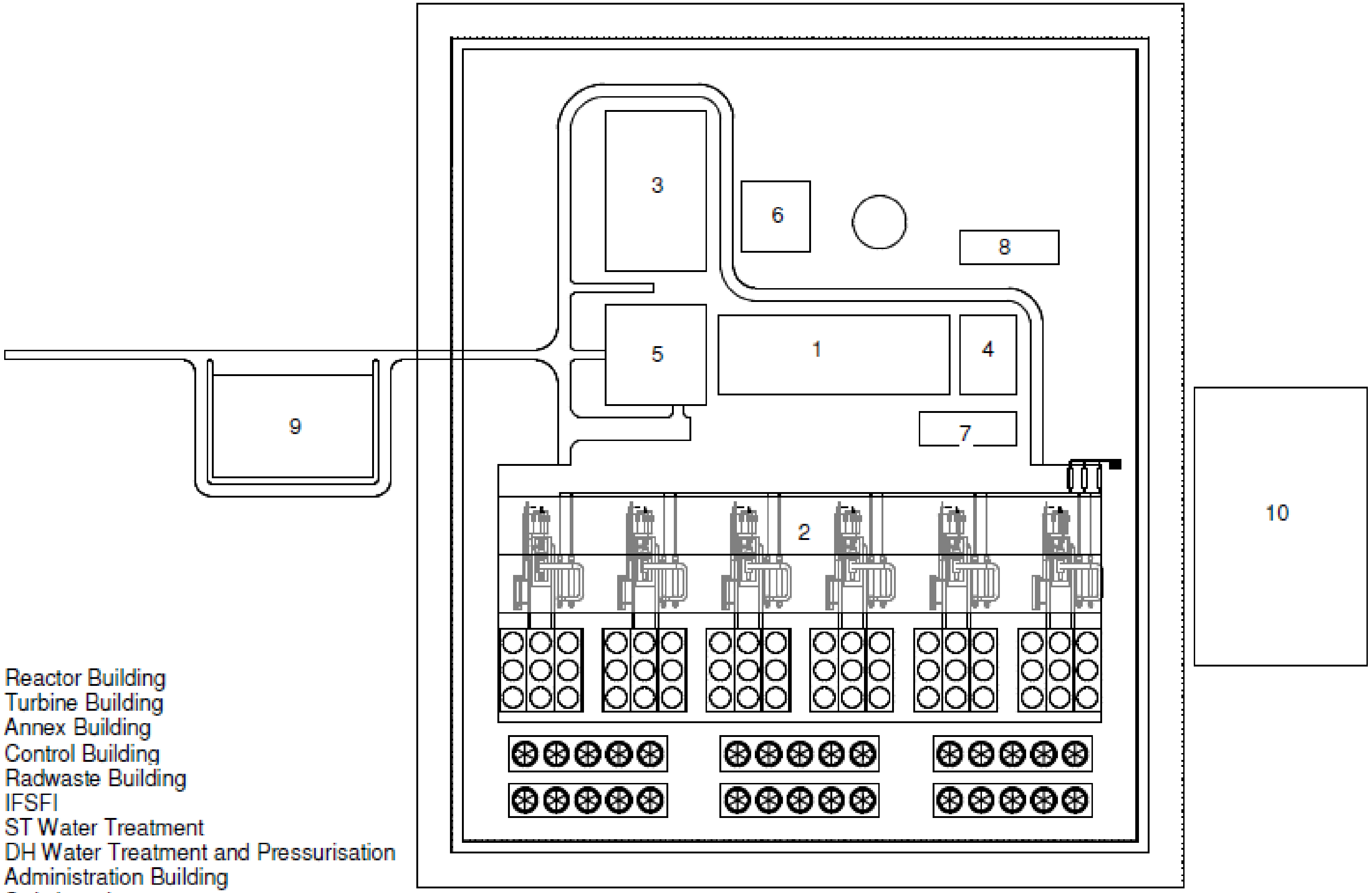
Figure G.4: 2 x 180MW$_e$ Plant B (based on ECTs) – 3D View



Source: Mott MacDonald

G.3 6 x 50MW$_e$ Plant A (based on hybrid cooling solution: ECT with unconstrained ACC)

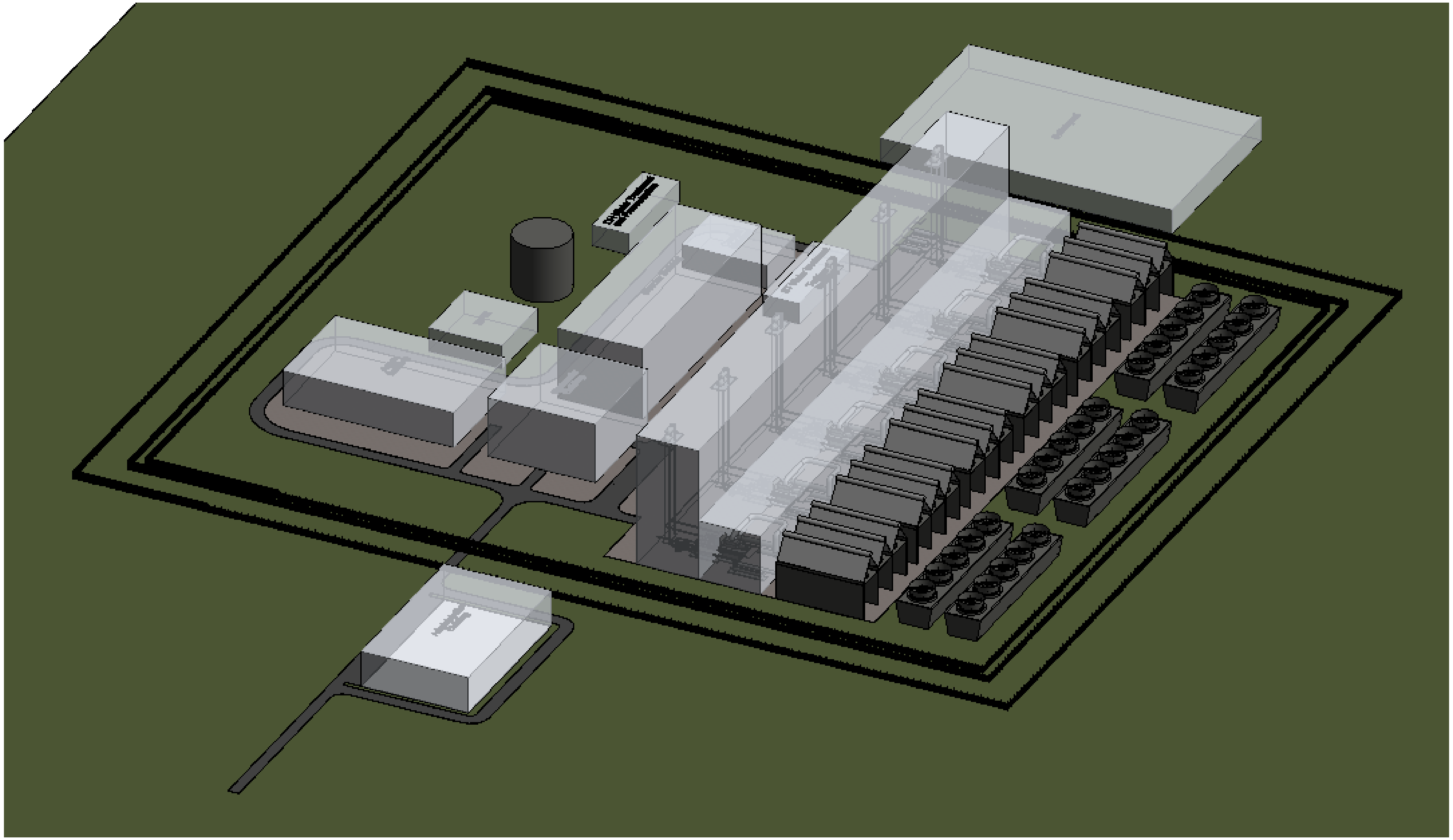
Figure G.5: 6 x 50MEe Plant A (ECT with unconstrained ACC) – Plant Layout



1. Reactor Building
2. Turbine Building
3. Annex Building
4. Control Building
5. Radwaste Building
6. IFSFI
7. ST Water Treatment
8. DH Water Treatment and Pressurisation
9. Administration Building
10. Switchyard

Source: Mott MacDonald

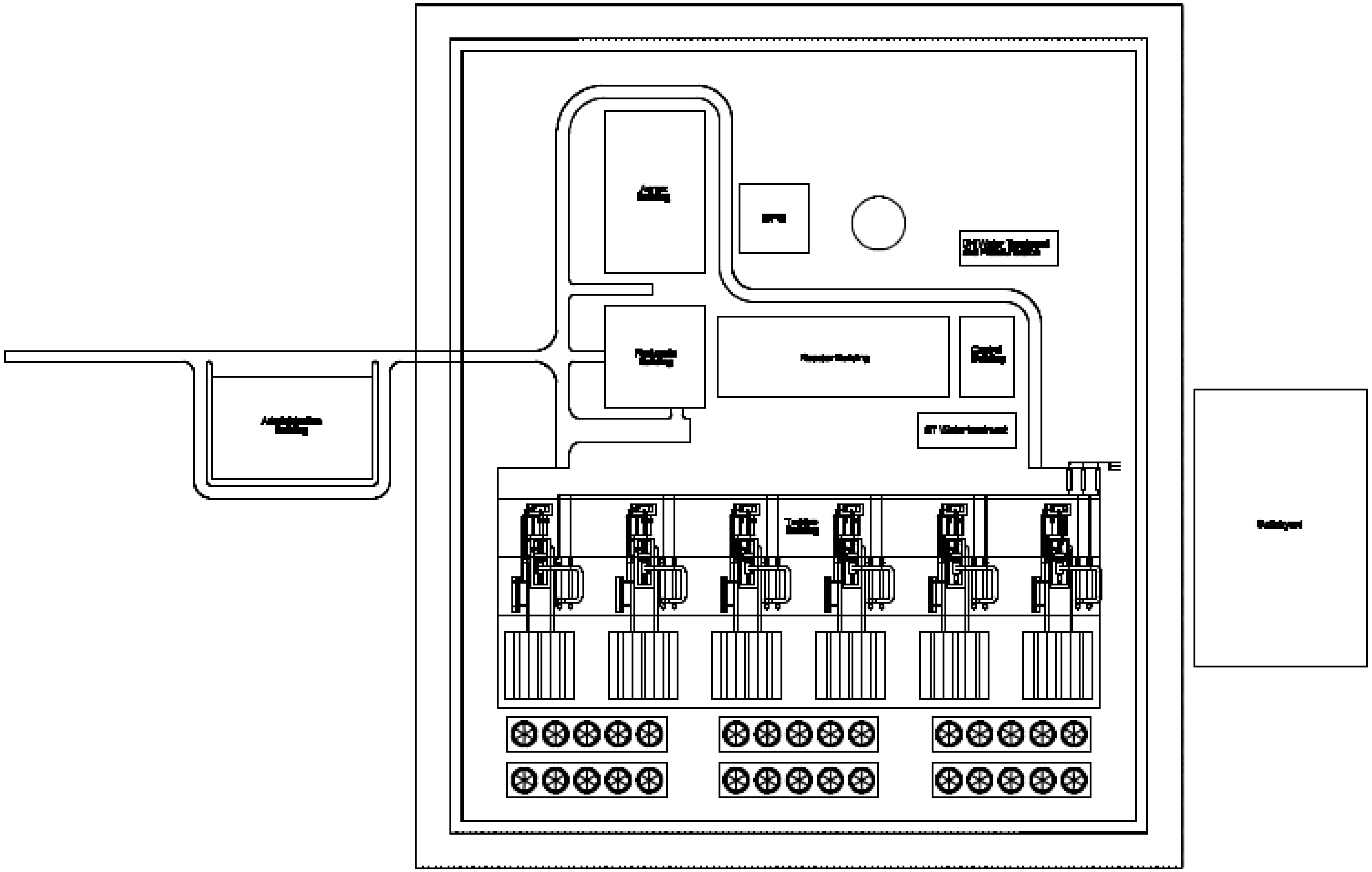
Figure G.6: 6 x 50MW$_e$ Plant A (ECT with unconstrained ACC) – 3D View



Source: Mott MacDonald

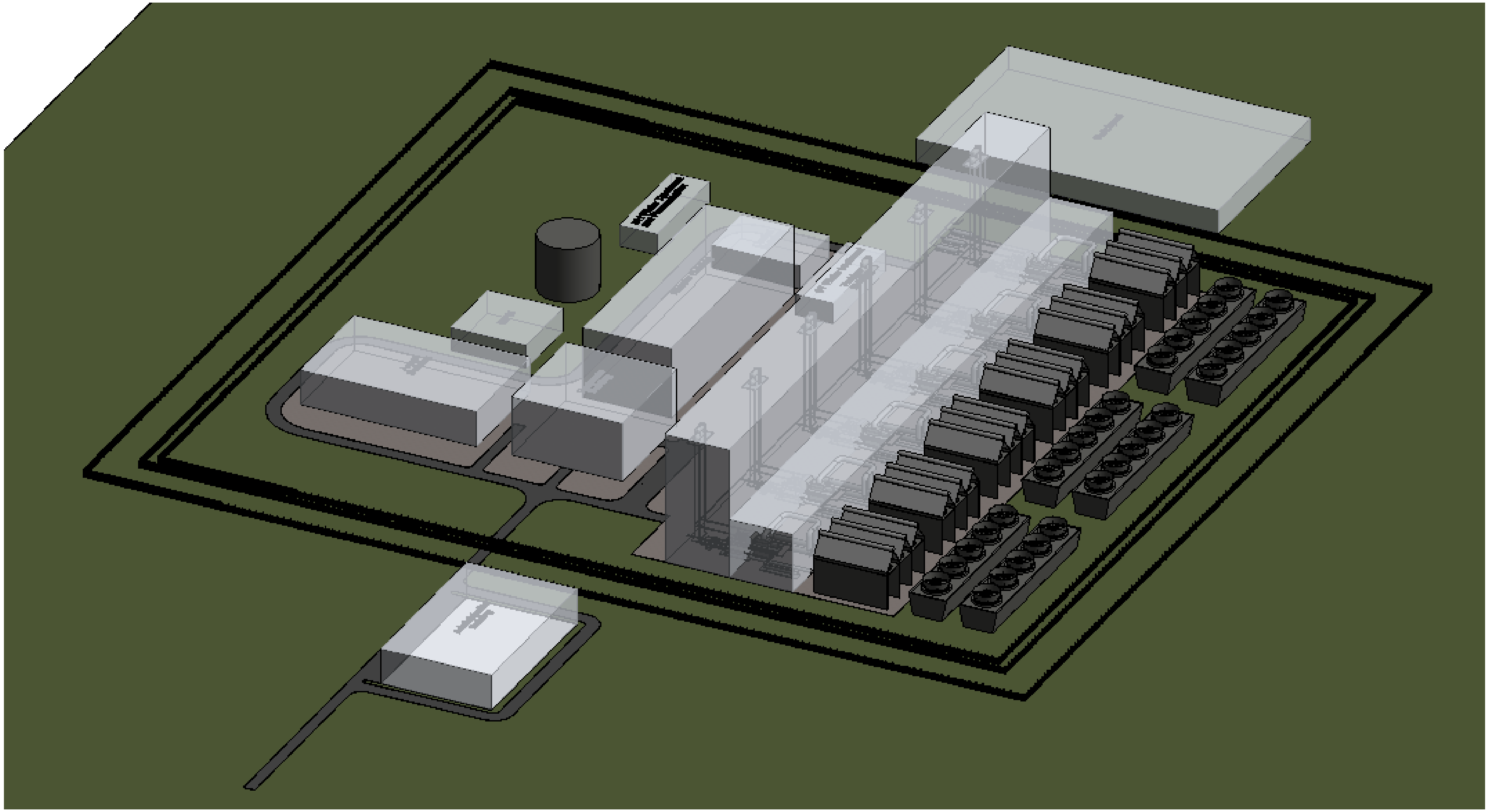
G.4 6 x 50MW$_e$ Plant A (hybrid solution: ECT with based on constrained ACC)

Figure G.7: 6 x 50MW$_e$ Plant A (ECT with constrained ACC) – Plant Layout



Source: Mott MacDonald

Figure G.8: 6 x 50MW$_e$ Plant A (constrained ACC) – 3D View



Source: Mott MacDonald

Appendix H. Buried Pipes

H.1 High level estimates

Table H.1: Buried pipe cost estimate

Pipe diameter ID	Bank	Rate per m	Total for 7500m	Time
1200mm ID in field	6 bank	£8,349	£62,620,357	7500m / Production @ 8m per day = 938 days
1200mm ID in road	6 bank	£10,489	£78,667,776	7500m / Production @ 4m per day = 1,874 days
1200mm ID in field	3 bank	£4,736	£35,519,732	7500m / Production @ 10m per day = 750 days
1200mm ID in road	3 bank	£6,784	£50,878,519	7500m / Production @ 6m per day = 1250 days

Source: Mott MacDonald

All the above costs are base construction costs only. Contractor's preliminaries and client costs will likely add on a further approx. 50%- 75%.

H.2 Construction cost breakdown table

The table above shows the breakdown of costs for Labour, Plant, Materials and Sub Contracts. This shows that a large percentage of the cost is associated with material and sub contract packages.

Table H.2: Buried pipe cost breakdown

Pipe diameter ID	Bank	Labour	Plant	Materials	Sub Contracts	Total for 7500m
1200mm ID in field	6 bank	£4,012,500	£3,611,231	£42,919,594	£11,077,031	£62,620,357
1200mm ID in road	6 bank	£6,000,000	£4,759,312	£48,650,182	£19,258,281	£78,667,776
1200mm ID in field	3 bank	£3,210,000	£3,106,425	£22,723,306	£6,480,000	£35,519,732
1200mm ID in road	3 bank	£4,000,000	£3,172,875	£25,538,894	£18,166,750	£50,878,519

Source: Mott MacDonald

Table H.3: A list of typical sub contract packages

Field	Road
Material Cart Away	Material Cart Away
Welding	Welding
Flushing, Testing and Reporting of Pipe on Completion	Flushing, Testing and Reporting of Pipe on Completion
Reinstatement (Top-soiling/Seeding etc)	Reinstatement (Tarmac)
	Traffic Management
	Saw Cutting
	Service Diversion (Minor amount only included)

Source: Mott MacDonald

Table H.4: A list of typical materials used

Field	Road
Pipe	Pipe
Bends	Bends
Fuel	Fuel
Shingle (Pipe Surround)	Shingle (Pipe Surround)
	Type 1 aggregate

Source: Mott MacDonald

Risks:

- Insert 6 off 1200mm diameter pipes in a road will prove problematic due to the trench width required unless they are stacked on top of each other. This however will result major issues with future maintenance and any repair (if this is required).
- Even if stacked on top of each other, installation of the size and number of pipes would require full road closures. The excavations would require extensive ground support (Temporary sheet piles or bracing) appropriate temporary works. Cost includes for trench boxes and strutting only. Some areas may require sheet piled type systems which would incur additional costs.
- Existing service crossings are unknown. Extensive service diversions likely required which would increase the installation cost.
- Dealing with existing foundations of structures would require breaking out if discovered.
- Installing pipes under existing bridge structures (Could occur multiple times)
- Any other potential bridge crossings (over rivers) May require tunnelling.
- Construction in field: Crossings of ditches, hedges, wooded areas, tree roots and dealing with existing fences, gates, agricultural fencing, livestock in the field section could prove a risk. Specific environmental issues (e.g. nesting birds) may result in construction being carried out at certain times of the year.
- Excavation in fields could encounter water – especially where there is a high water table. Over-pumping or well point dewatering could be required increasing installation costs.
- Dealing with contaminated excavated material. (Road & Field) This will add significant costs as material will need to be taken to a licenced tip. Average price for inert material is approx. £30 per m3. Price for contaminated is £80+ per m3.
- If pipe trenches in road area need a reinforced concrete foundation then additional costs will be incurred. In addition no allowance for any potential piling has been allowed due to bad ground conditions.
- We have made no allowance for any intermediate drop chambers.
- We have made no allowance for the rental/purchase of any land. This could be significant and will increase the client costs significantly. There are also likely multiple land owners which may require compensation.
- Shipping/freight costs of any materials. Pipe could be imported – e.g. from Europe / Turkey.
- Linked to the above the programme durations are significant so material and fuel prices could be impacted by inflation.
- Opportunity - Pipe volumes of this nature will warrant discounts from suppliers. This could also be said for any bulk bought shingle/type 1 etc. Procurement negotiations to be utilised at an early stage.

Appendix I. Tunnelling

I.1 Purpose

The purpose of this Appendix is to provide a background to the issues surrounding the use of tunnels to deliver the pipelines required for DH mains supplied by heated water from SMRs.

The issues discussed include potential tunnel layouts, logistics, construction methods, and costs.

I.2 Potential tunnel layouts

The configuration of the pipes within the tunnel will depend on maintenance and access requirements. A typical 8m tunnel cross section allows for access by walkways but also a kinematic envelope for potential transport and lifting equipment to maintain and replace sections of pipe. Clear definition on such requirements is important since it impacts on the required size of the tunnel.

I.3 Logistics

Using London as an example, available land would be required for construction sites, ventilations shafts and access points.

Additionally routes would need to be identified that avoid existing infrastructure: for example;

- London Underground tunnels,
- Crossrail 1 and 2,
- High Speed 1 and 2,
- Power tunnels, and
- Water and Wastewater tunnels including the Thames Tideway tunnel.

The use of brown field areas such as old gas domes or existing businesses may be required to locate sites needed for construction and permanent use. Other stakeholders will also be interested in obtaining potential sites for infrastructure or property development.

Special statutory powers would be required to enable efficient routing and planning the tunnel network with environmental impact assessments required to identify sensitive receptors and mitigations. Methods and costs for dealing with excavated spoil removal would also need to be identified.

I.4 Construction methods

As the project appears to involve the use of long tunnels with a similar cross section, this lends itself to the use of repetitive tunnelling techniques for longer drives. As such, a Tunnel Boring Machine (TBM) with concrete segmental lining has been assumed as the likely form of construction for the main tunnels.

In favourable ground conditions, it is possible to install pre cast concrete rings like wedgeblock expanded rings and achieve very high rates of production, typically 150m to 200m per week at peak output. For those areas where water bearing ground has to be negotiated it will be necessary to use bolted gasketted rings and closed face tunnelling machines. Production rates will be slower in these conditions, typically 100m per week at peak output.

I.5 Tunnel costs

To estimate the tunnelling costs the following has been assumed as a concept.

- Twin bore tunnels with cross passages at 100m spacing
- Length unknown but likely to be several hundred kilometres based on concept of scheme.
- Multiple TBMs will be required for the many separate contracts required to construct the tunnel
- Ventilation/Intervention shafts though number not yet determined
- The diameter of the tunnel can vary depending on the chosen configuration though for the purposes of this memo it is assumed that safe access will be required to access the pipes hence these vary from 6m to 9m.

Infrastructure projects known for high final costs are numerous and highly publicised. These include the Channel Tunnel, the Great Belt Tunnel in Denmark, Denver International Airport, major sporting events such as the Olympics and World Cups, and Wembley Stadium, which holds the record for being one of the most costly sports stadium ever built.

In reviews of “mega-projects” over the last century, the costs of the works are consistently underestimated. This can often be due to the requirement to undertake a public review and approval process for these projects.

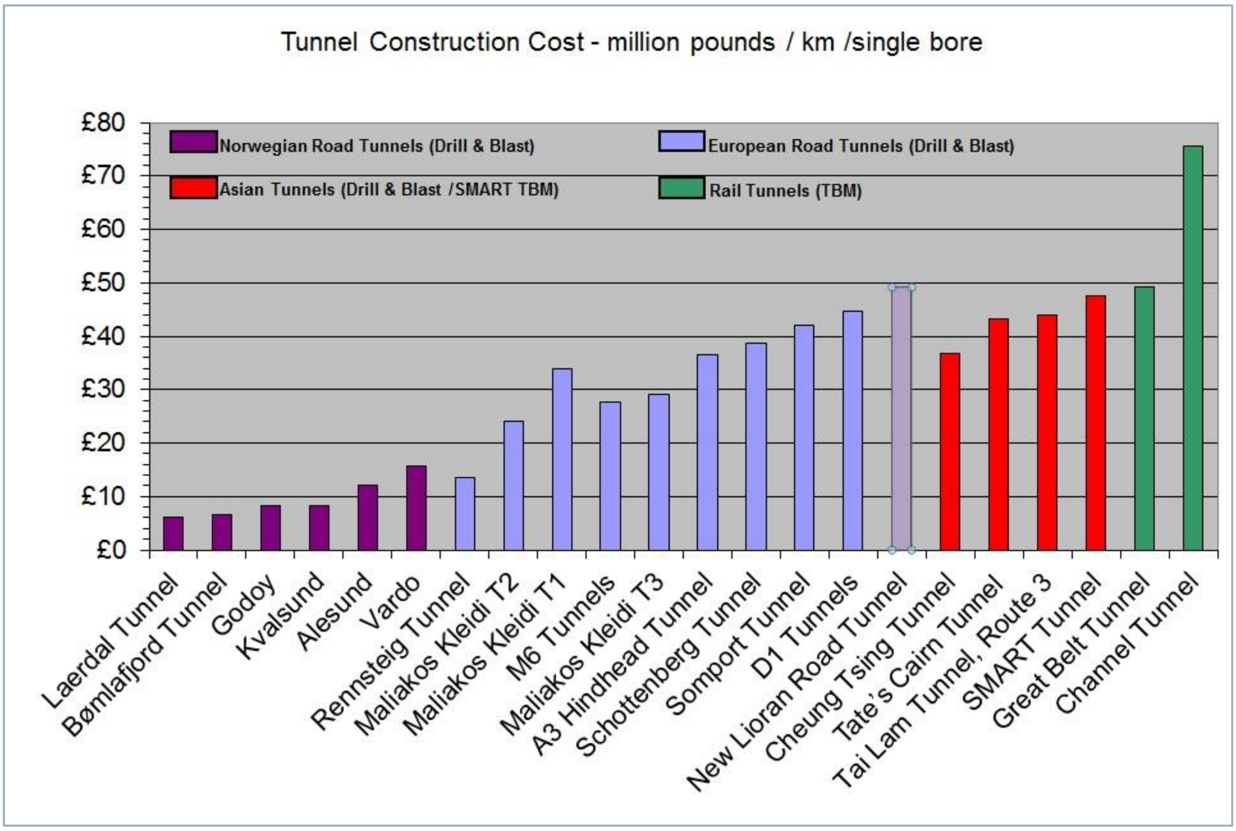
Reasons for cost increases include the following:

- Optimistic programming,
- Poorly defined scope, and
- Political pressures to stay within budget.

It may be worth considering adding an ‘optimism bias’ to the estimated costs for the scheme. Transport for London’s Green Book guidance allows for 66%.

Figure I.1 below illustrates the range of construction costs for other major tunnels that have been built around the world over the past 20 years. It shows a large variation in tunnelling costs, which may be explained by a number of factors including; geological conditions, tunnel length, contractual, economic and market conditions, regulatory requirements, working practices and local environmental conditions. These costs are based on the case histories and are indicative only. They are deemed to include the total capital cost of the tunnel project including civil works, material disposal costs, portal/entrance structures but not geotechnical investigations, design or land acquisition costs.

Figure I.1: Example Driving Costs (£million per km) for large diameter tunnels (excludes fit out and surface features)

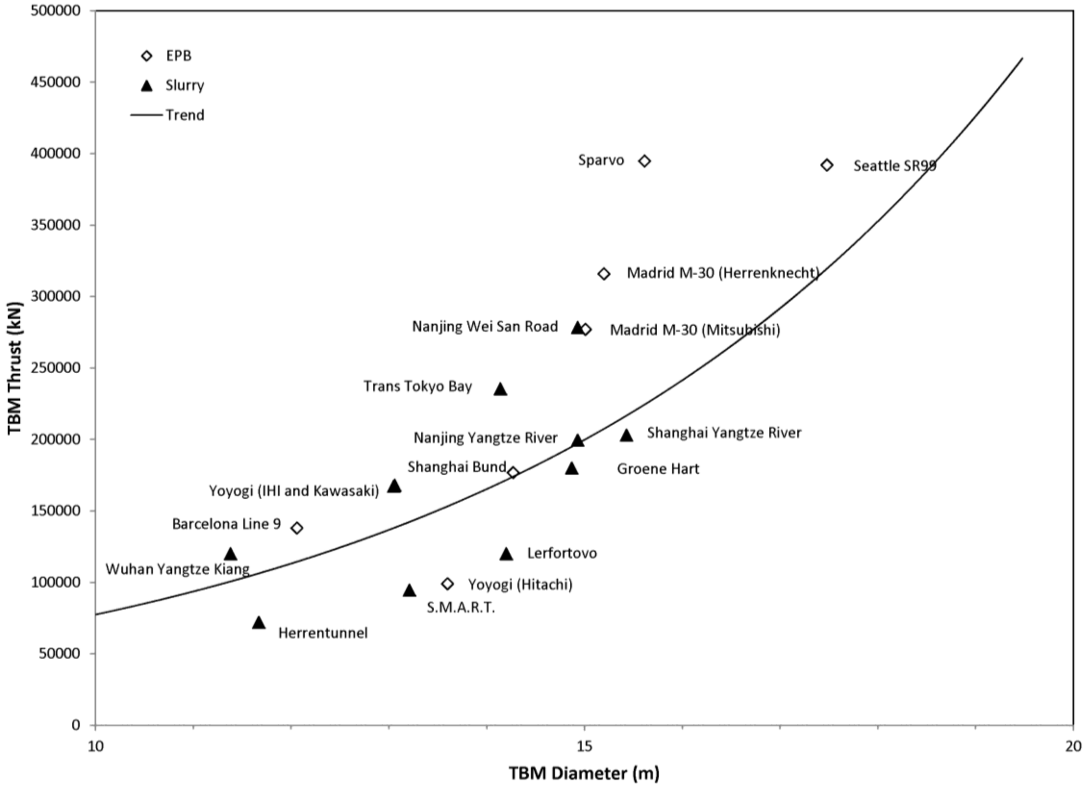


Source: Mott MacDonald

When considering tunnel costs, there will be some economies of scale that can be achieved, such as repetitive lining design and spreading the cost of the tunnel boring machines over the whole scheme. The power requirements for tunnels can increase substantially for the larger TBMs. Power to operate the TBMs will require 11kV supplies, possibly requiring new substations.

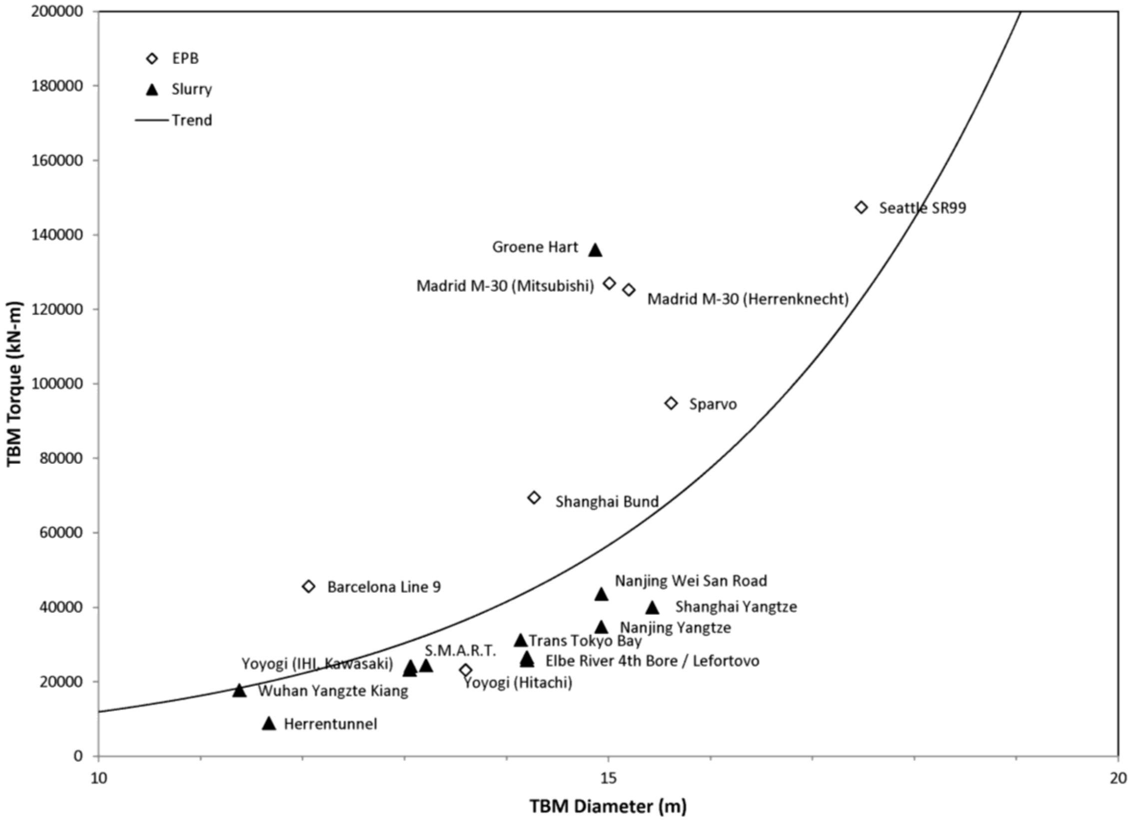
With increasing tunnel diameter the power requirements of the TBM will also increase. The requirements will include increased thrust and torque as demonstrated in the graphs below which were developed for a study into the requirements of larger diameter TBMs.

Figure I.2: Graphs showing thrust requirements against diameter



Source: Mott MacDonald

Figure I.3: Graphs showing torque requirements against diameter



Source: Mott MacDonald

For a DH Mains scheme the diameter of the tunnels and length are currently unknown, however it can be reasonably assumed that a single twin tunnel contract may extend for about 10km hence costs per 10km section have been developed below. These are just ballpark estimates and further information would be required for various sizes of tunnels based on excavation in London Clay and other materials. Additionally spoil removal strategy would need to be planned and costs determined.

I.6 For a 8m ID tunnel for 10k section

The costs for this tunnel arrangement are shown below in Figure I.4.

This includes the cost of driving the tunnel with tunnel boring machines with segmental lining, vent shafts and construction sites plus enabling and design costs.

Figure I.4: Tunnel cost estimates for 8m segmental lining tunnel

Project: District heating Mains				Mott MacDonald	
Calculations for: Cost Estimate for 10k section of single tunnel - 8m diameter	**Div'n/Dep't:**	TUN	**Job No/File No:**	342089	
	Calculated by:	AH	**Date:**	23/02/2016	**Sheet No:** 1
	Checked by:		**Date:**	23/02/2016	OUTPUT

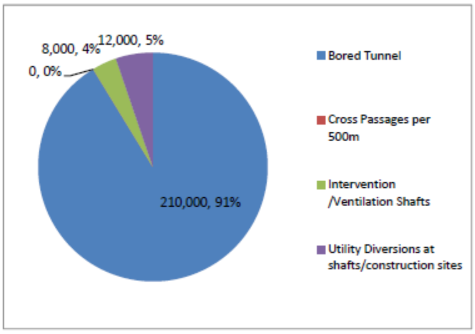
District Heating Mains 10km section **AH** **29/01/2016**

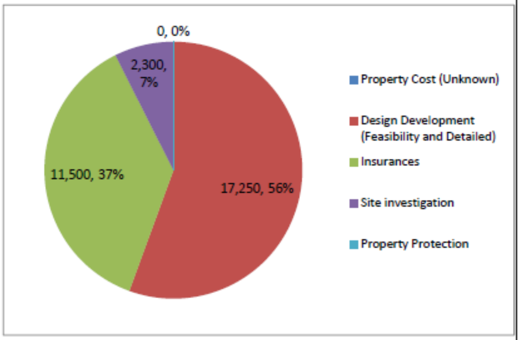
Proposed Tunnel	District Heating Mains	Method of construction	Approximate proposed length (m)	Diameter (m)
		Bored tunnel	10,000 x 2	9 approx

Item	Unit (m, per unit)	Unit Rate (£000)	Cost (£ 000)	Based on
Bored Tunnel	10000	21	210,000	
Cross Passages per 500m	0	£1 million	0	Hindhead Tunnel
Intervention /Ventilation Shafts	4	£2 million ea.	8,000	High Speed 1
Utility Diversions at shafts/construction sites	2 launch and reception sites plus 4 vent shafts	Allow £2 million per site	12,000	Crossrail
		TOTAL	**230,000**	

Item	Unit (m, per unit)	Unit Rate (£000)	Cost (£ 000)	Based on
Construction Cost	As estimated above		**230,000**	
Property Cost (Unknown)	Unknown			
Design Development (Feasibility and Detailed)	~7.5%		17,250	
Insurances	Allow 5% of construction Cost		11,500	
Site investigation	~1%		2,300	
Property Protection			Unknown	
	Sub total		**261,050**	
Total			**261,050**	

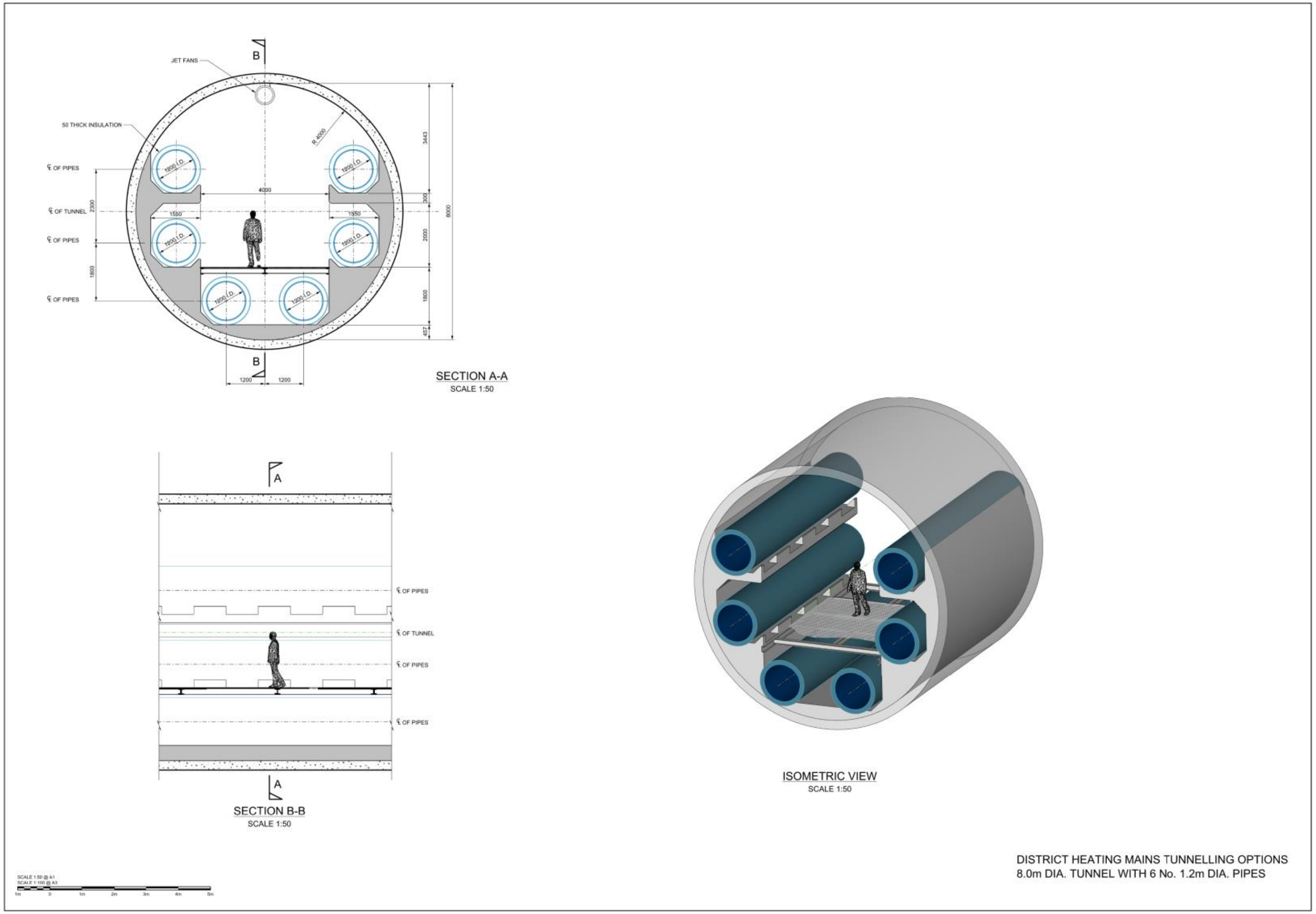
TOTAL (£ 000)	**261,050**





Source: Mott MacDonald

Figure I.5: DH mains tunnelling options



Source: Mott MacDonald

Appendix J. CHP electricity Annual Capacity Factors

Table J.1 shows how the CHP mode electrical derating of 20% assumed in Phases 1 and 2 was translated into a reduced electricity ACF of 77% (approximated to ~75% to avoid spurious accuracy).

Table J.1: Build-up of electricity ACF for CHP SMR plants in Phase 1 and 2 work

	Winter	Shoulder	Summer	Annual average
Assuming 100% availability				
% of year	25%	50%	25%	
Assumed heat seasonal capacity factor (SCF)*	75%	40%	12.5%	
Product of heat SCF and weighting	0.188	0.2	0.031	0.419
Resulting heat ACF				~42% ACF
Average de-rating of electric capacity across season**	15%	8%	2.5%	
Net electricity SCF (100%-de-rate)	85%	92%	97.5%	
Product of electricity SCF and weighting	0.213	0.46	0.244	0.917
Resulting electricity ACF				~92% ACF
Assuming 85% availability (55 days taken all in summer; 60% of the summer season)				
Heat SCF net of outage	75%	40%	5%	~40% ACF
Electricity SCF net of outage	85%	92%	39%	**~77% ACF**

Source: Mott MacDonald

* These are estimated heat SCFs only. In practice these would depend on the DH network load profile in question

** These would be ~20% if seasonal heat capacity factor were 100%

Tables J.2 and J.3 show the equivalent calculation for Plants A and B as defined in this report.

Table J.2: Build-up of electricity ACF for Plant A (CHP)

	Winter	Shoulder	Summer	Annual average
Assuming 100% availability				
% of year	25%	50%	25%	
Assumed heat seasonal capacity factor (SCF)	75%	40%	12.5%	
Average de-rating of electric capacity across season	21.53%	11.48%	3.59%	
Net electricity SCF (100%-de-rate)	78.48%	88.52%	96.41%	
Resulting electricity ACF				~88% ACF
Assuming 85% availability (55 days taken all in summer; 60% of the summer season)				
Heat SCF net of outage	75%	40%	5%	~40% ACF
Electricity SCF net of outage	78.48%	88.52%	38.57%	**~73.5% ACF**

Source: Mott MacDonald

Table J.3: Build-up of electricity ACF for Plant B (CHP)

	Winter	Shoulder	Summer	Annual average
Assuming 100% availability				
% of year	25%	50%	25%	
Assumed heat seasonal capacity factor (SCF)	75%	40%	12.5%	
Average de-rating of electric capacity across season	21.23%	11.32%	3.54%	
Net electricity SCF (100%-de-rate)	78.78%	88.68%	96.46%	
Resulting electricity ACF				~88% ACF
Assuming 85% availability (55 days taken all in summer; 60% of the summer season)				
Heat SCF net of outage	75%	40%	5%	~40% ACF
Electricity SCF net of outage	78.78%	88.68%	38.59%	**~73.7% ACF**

Source: Mott MacDonald

Appendix K. Nuclear powered CHP plants

The following table shows all past, current and planned CHP nuclear power plants identified in our literature. Due to the sensitivity and high security surrounding nuclear power plants, many key plant characteristics could not be identified.

		Status		Site Data			Operational Milestones		Power (Plant)			District Heating			
Plant Name	Location	Power Plant	CHP	No. of Reactors	Reactor Type	Reactor Model	Commercially Operational	Shut Down	MWt	MWe (gross)	MWe (net)	MWth	Gcal/yr	TJ/yr	Electrical Drain (MWe)
Bilibino	Russia	Operational	Operational	4	GBWR	EGP-6	1974-1976		248	48		78-115			10
Baloyarsk	Russia	Operational	Operational	1	FNR	BN-600	1980			600					
Bohunice V2	Slovakia	Operational	Operational	2	PWR	VVER-440	1984-1987	2025		505					
Beznau	Switzerland	Operational	Operational	2	PWR		1969-1972			730		80			7.5
Gosgen	Switzerland	Operational	Operational	1	PWR		1979			1035		12			
Cernavoda	Romania	Operational	Operational	2	PHWR	CANDU-6	1996/2007				1310		67500	282.42	
Beijing	China	Operational	Operational	1		NHR-5	1989								
MAPS	India	Operational	Operational	2	PHWR	MAPS	1984/86			340					
Leibstadt	Switzerland	Operational	Operational	1	BWR		1984			1220					
Muhleburg	Switzerland	Operational	Operational	1	BWR		1972			372					
Kozloduy	Bulgaria	Operational	Unknown	2	PWR	VVER-1000	1987,91				1906	40			
Paks	Hungary	Operational	Unknown	4	PWR	VVER-440	1974,79			2000					
Novovoronezh 3,4	Russia	Operational	Unknown	2	PWR	VVER-440	1972-73			417	385	65			
Balakovo	Russia	Operational	Unknown	4	PWR	VVER-1000	1986-93				3800	800			
Kalinin 1,2	Russia	Operational	Unknown	2	PWR	VVER-1000	1984-86				1900	160			
Kola 1-4	Russia	Operational	Unknown	4	PWR	VVER-440	1973-75,82-84				1644	55			
Kursk	Russia	Operational	Unknown	4	GBWR	RBMK-1000	1977-79,84-86				3700	652.5			
Smolensk	Russia	Operational	Unknown	3	GBWR	RBMK-1000	183-85,90				2775	519			
Rivne 1,2	Ukraine	Operational	Unknown	2	PWR	VVER-440	1981-82				757	116			
Rivne 3	Ukraine	Operational	Unknown	1	PWR	VVER-1000	1987				950	233			
South Ukraine	Ukraine	Operational	Unknown	3	PWR	VVER-1000	1983-89				2850	534			
Temelin	Czech Republic	Operational	Planned	4	PWR	VVER-440	1985-1987		5500	2040				3700	
Seversk/ Tomsk-7	Russia	Planned	Planned	2	PWR	VVER-1200	2030			2340			1,800,000.00	7500	
Leningrad 2	Russia	Planned	Planned	4	PWR	VVER-1200	2017-			4680				36680	
Akademik Lomono	Russia (Floating NPP)	Planned	Planned	2	PWR	KLT-40S	2016?-			70		150			
CNNC	China (Floating NPP)	Planned	Planned	1	PWR	ACP100S	2019		310	100					
Kudankulam	India	Planned	Planned	2	PWR	VVER-1000	2015?				1900				
Bruce PGS	Canada	Operational	De-com	8	PHWR	CANDU	1977-79,84-87				6232				
Agesta	Sweden	De-com	De-com	1	PHWR		1964	1975	68	12					
Obninsk	Russia	De-com	De-com	1			1954	2002	30	5		10-20			
Ignalina	Lithuania	De-com	De-com	2	GBWR	RBMK-1500	1983,87	2009	9600	2760					
Aktau	Kazakhstan	De-com	De-com	1	SFR	BN-350	1973	1999		135					
Loviisa 3	Finland	Cancelled	Cancelled	1	PWR/BWR	Undecided			2800-4600			1000			

			De-Sal Water		Plant Steam Extraction			Distict Heating Network						
Plant Name	Location	Process Steam (MW)	m3/day	Electrical Drain (MWe)	Location	Temp (degC)	Pressure (bar)	Temp Out (degC)	Temp Return (degC)	Pressure (bar)	Qty. (t/hr)	Flow Rate	Max Distance to Heat Cosumer (km)	Notes
Bilibino	Russia				HP Turbine Exit			150					3.5	
Baloyarsk	Russia													
Bohunice V2	Slovakia												100	
Beznau	Switzerland				Cold re-heat crossover pipe between HP & LP. LP Exit.	125/85	2.2-2.8	80-125	50	16			12	
Gosgen	Switzerland	57					12-15 (Process)	120	70	15	10		3	
Cernavoda	Romania													
Beijing	China													Prototype. Basis for NHR-200 that is planned for DH.
MAPS	India		6300	4										
Leibstadt	Switzerland													Warm water from the cooling tower used by local garden centre.
Muhleburg	Switzerland				Heat extraction between HP and LP turbines.			125	75			4.4l/s	2	DH for office and nearby residential area.
Kozloduy	Bulgaria													Only units 5&6 still operate.
Paks	Hungary												5	Only mention that the NPP supplied DH to Paks.
Novovoronezh 3,4	Russia													
Balakovo	Russia													
Kalinin 1,2	Russia													
Kola 1-4	Russia													
Kursk	Russia													
Smolensk	Russia													
Rivne 1,2	Ukraine													
Rivne 3	Ukraine													
South Ukraine	Ukraine													
Temelin	Czech Republic												35	
Seversk/ Tomsk-7	Russia												32	
Leningrad 2	Russia													
Akademik Lomono	Russia (Floating NPP)													Balance between electricity and DH is unknown
CNNC	China (Floating NPP)													
Kudankulam	India		7200											
Bruce PGS	Canada													Steam for heavy water plant, greenhouses, distilleries, and DH for the site.
Agesta	Sweden													Prototype. Heating of local suburb
Obninsk	Russia													Prototype. Multi-purpose inc. heating of local suburb
Ignalina	Lithuania													
Aktau	Kazakhstan		80000											
Loviisa 3	Finland											4-5m3/s	100	

Source: Mott MacDonald

Appendix L. Global review literature list

The following table contains a list of the publically available sources reviewed for Section 8 of this report.

Table L.1: Referenced sources and literature

Subject Area	Title	Source	Source Type	Name/link
Agesta Nuclear Power Plant	Nuclear power plant of AGESTA, Sweden	Nuclear Energy	Website	http://nuclear-energy.net/nuclear-power-plants/sweden/agesta.html
Akademik Lomonosov Floating Nuclear Power Plant	New documents show cost of Russian floating nuclear power plant skyrockets	Bellona	Website	http://bellona.org/news/nuclear-issues/2015-05-new-documents-show-cost-russian-nuclear-power-plant-skyrockets
	FNPP “Academician Lomonosov”	OKBM	Website	http://www.okbm.nnov.ru/english/lomonosov
	World’s first floating nuclear power plant to begin operating in Russia in 2016	RT	Website	https://www.rt.com/news/floating-nuclear-plant-russia-759/
Baloyarsk Nuclear Power Plant	Russia's BN-800 unit brought to minimum controlled power	World Nuclear News	Website	http://www.world-nuclear-news.org/NN-Russias-BN-800-unit-brought-to-minimum-controlled-power-04081501.html
	SITE BELOYARSK NPP	Rosenergoatom	Website	http://www.belnpp.rosenergoatom.ru/
	Nuclear Power in Russia	World Nuclear Association	Website	http://www.world-nuclear.org/info/country-profiles/countries-o-s/russia--nuclear-power/
Beznau Nuclear Power Plant	Experience of operating nuclear district heating in Switzerland	Axpo	Presentation	https://www.oecd-nea.org/ndd/workshops/nucogen/presentations/5_Schmidiger_Experience-Operating-Nuclear-Swi.pdf
	Beznau-1 Operational Data	IAEA	Website	https://www.iaea.org/PRIS/CountryStatistics/ReactorDetails.aspx?current=55
	Beznau-2 Operational Data	IAEA	Website	https://www.iaea.org/PRIS/CountryStatistics/ReactorDetails.aspx?current=57
	75 MW HEAT EXTRACTION FROM BEZNAU NUCLEAR POWER PLANT (SWITZERLAND)	K. H. Handl	Article	http://www.iaea.org/inis/collection/NCLCollectionStore/_Public/29/067/29067739.pdf
	Nuclear Power Plant Beznau	Axpo	Presentation	https://www.axpo.com/content/dam/axpo/switzerland/erleben/dokumente/axpo_KKB_prospekt_en.pdf.res/axpo_KKB_prospekt_en.pdf
	Axpo reassures on Beznau plant ‘irregularities’	swissinfo.ch	Website	http://www.swissinfo.ch/eng/nuclear-power_axpo-reassures-on-beznau-plant--irregularities-/41708580
	Nuclear critics threaten legal action over Beznau plant	swissinfo.ch	Website	http://www.swissinfo.ch/eng/nuclear-power_nuclear-critics-threaten-legal-action-over-beznau-plant/41614406
	Kernkraftwerk Beznau-1 und -2 (KKB)	Kernkraftwerk Leibstadt	Website	https://www.kkl.ch/kraftwerk/alles-ueber-kernenergie/who-is-who/die-anderen-kernkraftwerke-der-schweiz/kkw-beznau-1-2-kkb.html
	Further inspections for Beznau reactor vessels	World Nuclear News	Website	http://www.world-nuclear-news.org/RS-Further-inspections-for-Beznau-reactor-vessels-1707154.html

Subject Area	Title	Source	Source Type	Name/link
	Axpo cleared for Beznau vessel head replacements	World Nuclear News	Website	http://www.world-nuclear-news.org/RS-Axpo-cleared-for-Beznau-vessel-head-replacements-1103154.html
Bilibino Nuclear Power Plant	BILIBINO JOURNAL; WHAT PRICE NUCLEAR POWER? IN SIBERIA, IT'S HIGH	The New York Times	Website	http://www.nytimes.com/1987/04/20/world/bilibino-journal-what-price-nuclear-power-in-siberia-it-s-high.html
	Glitching safety system at Russia's aged Bilibino NPP causes emergency reactor shutdown	Bellona	Website	http://bellona.org/news/nuclear-issues/nuclear-russia/2010-11-glitching-safety-system-at-russias-aged-bilibino-npp-causes-emergency-reactor-shutdown
	Bilibino NPP	Rosenergoatom	Website	http://www.rosenergoatom.ru/wps/wcm/connect/rosenergoatom_copy/site_en/NPP/bilnpp/
Bohunice V2 Nuclear Power Plant	Nuclear Power in Slovakia	World Nuclear Association	Website	http://www.world-nuclear.org/info/Country-Profiles/Countries-O-S/Slovakia/
	AE BOHUNICE	Enel	Website	http://www.seas.sk/bohunice-nuclear-power-plant
	History of the nuclear power industry in Slovakia and Czech Republic	JESS	Website	http://www.jess.sk/en/home/about-nuclear-power-industry/history-of-the-nuclear-power-industry-in-slovakia-and-czech-republic
Bruce Nuclear Power Plant	Bruce Power Generating Station, Toronto, Canada	power-technology	Website	http://www.power-technology.com/projects/brucepowergenerating/
	Introduction to CANDU Processes	Can Teach	Report	https://canteach.candu.org/Content%20Library/20042624.pdf
	Ontario Power Generation demolishes Bruce Bulk Steam system smoke stack	Kincardine News	Website	http://www.kincardinenews.com/2015/07/31/ontario-power-generation-demolishes-bruce-bulk-steam-system-smoke-stack
Cernavoda Nuclear Power Plant	Cernavoda NPP's performance and its availability to supply steam for district heating	Nuclearelectrica National Company Ltd.	Article	https://inis.iaea.org/search/search.aspx?orig_q=RN:31042424
	Plant website	CNE Cernavoda	Website	http://www.cne.ro/
	Nuclear Power in Romania	World Nuclear Association	Website	http://www.world-nuclear.org/info/Country-Profiles/Countries-O-S/Romania/
Combined Heat and Power	Catalog of CHP Technologies	US Environmental Protection Agency	Report	http://www3.epa.gov/chp/documents/catalog_chptech_full.pdf
	"Potential for Combined Heat and Power and District Heating and Cooling from Waste to-Energy Facilities in the U.S. – Learning from the Danish Experience"	Columbia University	Thesis	http://www.researchgate.net/publication/265821903_Potential_for_Combined_Heat_and_Power_and_District_Heating_and_Cooling_from_Waste-_to-Energy_Facilities_in_the_U.S.__Learning_from_the_Danish_Experience
	Suomenoja power plant	Fortum	Presentation	https://www.fortum.com/Lists/ArchiveLibraryList/Capital%20Markets%20Day%202010/CMD2010_Suomenoja_sitevisit_Savikoski.pdf
	3. ENERGY PERFORMANCE ASSESSMENT OF COGENERATION SYSTEMS WITH STEAM AND GAS TURBINES	Bureau of Energy Efficiency	Report	http://www.enercon.gov.pk/images/pdf/4ch3.pdf

Subject Area	Title	Source	Source Type	Name/link
	7. COGENERATION	Bureau of Energy Efficiency	Report	http://www.em-ea.org/guide%20books/book-2/2.7%20cogeneration%20.pdf
	Cogeneration Case Studies Handbook	CODE Project	Report	http://www.code-project.eu/wp-content/uploads/2011/04/CODE_CS_Handbook_Final.pdf
	Steam Turbines in CHP	Siemens Energy Inc.	Presentation	http://extension.psu.edu/natural-resources/energy/wood-energy/resources/2010-biomass-presentations/0105Turbines
	District Heating/ Cogeneration Application Studies for the Minneapolis - St. Paul Area	Oak Ridge National Laboratory	Report	http://web.ornl.gov/info/reports/1979/3445605557144.pdf
	Instructions for designing district heating systems	Danfoss	Book	http://heating.danfoss.com/pcmfiles/1/master/other_files/library/heating_book/chapter5.pdf
	District heating systems used in Western Europe	Danfoss	Book	http://heating.danfoss.com/pcmfiles/1/master/other_files/library/heating_book/chapter2.pdf
	Flexible steam turbine solutions for combined heat and power in combined cycle power plants	Siemens AG	Presentation	http://m.energy.siemens.com/us/pool/hq/energy-topics/publications/Technical%20Papers/Steam%20Turbines/Power_Russia_Helesch_Internet.pdf
Copenhagen District Heating	Amagerværket	IGSS	Marketing	http://d2i1dro1ulg1xm.cloudfront.net/customercases/IGSS_CustomerCase_Amagervaerket_eng.pdf
	REAL CASE PERSPECTIVE ON FLEXIBILITY OF POWER AND CHP	Ramboll	Presentation	https://www.b2match.eu/district-heating-matchmaking/system/files/PNVM-Ramboll-ScottishEnterprise-Power_and_heat-Nov2012.pdf
	The H. C. Ørsted værket CHP plant	Dong Energy	Marketing	https://stateofgreen.com/files/download/82
	The Avedøreværket CHP plant	Dong Energy	Marketing	https://stateofgreen.com/files/download/36
	Case story: Copenhagen	District Energy Partnership	Marketing	www.cowi.com%2Fmenu%2FNewsandMedia%2FNews%2FNewsarchive%2FDocuments%2FCase%2520stories%2520from%2520central%2520Copenhagen.pdf&usg=AFQjCNFCCygxLUp8GFqOvXjcTzTdFVxCsw&sig2=_Ip8bLVgHWh5FOHcCa0Dxg
	District Heating and Cooling in Copenhagen	Engineering Timelines	Website	http://www.engineering-timelines.com/why/lowCarbonCopenhagen/copenhagenDistrictHeating_03.asp
	Best Practice: District Heating System	New York City Global Partners	Report	http://www.nyc.gov/html/ia/gprb/downloads/pdf/Copenhagen_districtheating.pdf
	98% of Copenhagen City Heating Supplied by Waste Heat	C40 Cities	Website	http://www.c40.org/case_studies/98-of-copenhagen-city-heating-supplied-by-waste-heat
District Heating	District Heating Solutions	Alstom Energy	Website	http://alstomenergy.gepower.com/products-services/product-catalogue/power-generation/industry-process/district-heating/index.html
	District heating: a hot idea whose time has come	The Guardian	Website	http://www.theguardian.com/cities/2014/nov/18/district-heating-a-hot-

Subject Area	Title	Source	Source Type	Name/link
				idea-whose-time-has-come
	District heating: cities that generate their own heat	energy lab	Website	http://www.energylab.es/eng/sala_prensa_detalle.asp?nar1=&nar2=1138&var2=District+heating%3A+cities+that+generate+their+own+heat#.Vk77A2cnzcs
	Lesson from Denmark: how district heating could improve energy security	The Guardian	Website	http://www.theguardian.com/big-energy-debate/2014/aug/20/denmark-district-heating-uk-energy-security
	District Heating	Doosan	Website	http://www.doosanskodapower.com/en/steam/districtheating.do
	District Heating	Triveni Turbines	Website	http://www.triveniturbines.com/district-heating.html
	Converting steam-based district heating systems to hot water	Bine	Report	http://www.bine.info/fileadmin/content/Publikationen/Englische_Infos/projekt_0107_engl_internetx.pdf
	Possibilities with more district heating in Europe	Euroheat & Power	Report	http://www.euroheat.org/files/filer/ecoheatcool/documents/Ecoheatcool_WP4_Web.pdf
	Heat Roadmap Europe	Heat Roadmap Europe	Website	http://www.heatroadmap.eu/maps.php?_sm_au_=isV57SKbRMWFqlV7
	National District Energy System Maps	International District Energy Association	Website	http://www.districtenergy.org/national-district-energy-system-maps
	CHP/DH Country Profile: Russia	International Energy Agency	Website	https://www.iea.org/media/files/chp/profiles/russia.pdf
	Home Page: REFUNA Distirct Heating	REFUNA	Website	http://www.refuna.ch/
	Background Report on EU-27 District Heating and Cooling Potentials, Barriers, Best Practice and Measures of Promotion	European Commission	Report	https://setis.ec.europa.eu/system/files/1.DHCpotentials.pdf
	Energy production	Fortum	Website	http://www.fortum.com/en/energy-production/energy-production/pages/default.aspx
	The Melnik Power Station	CEZ GROUP	Website	http://www.cez.cz/en/power-plants-and-environment/coal-fired-power-plants/cr/melnik.html
Dukovany Nuclear Power Plant	The Dukovany Nuclear Power Station	CEZ GROUP	Website	http://www.cez.cz/en/power-plants-and-environment/nuclear-power-plants/dukovany.html
	Nuclear Power in Czech Republic	World Nuclear Association	Website	http://www.world-nuclear.org/info/country-profiles/countries-a-f/czech-republic/
Gosgen Nuclear Power Plant	Technology and Operation Gösgen nuclear power plant	Kernkraftwerk Gosgen	Marketing	https://www.kkg.ch/upload/cms/user/KKG_Broschre_E.pdf
	Nuclear Power in Switzerland	World Nuclear Association	Website	http://www.world-nuclear.org/info/Country-Profiles/Countries-O-S/Switzerland/
Helsinki District	District Heating & Cooling in Helsinki	Helsingin Energia	Presentation	https://www.iea.org/media/workshops/2013/chp/MarkoRiipinen.pdf

Subject Area	Title	Source	Source Type	Name/link
Heating	About Us: Power Plants	Helsingin Energia	Website	https://www.helen.fi/en/households/information/about-us/energy-production/power-plants/
	Case Study	C40 Cities	Website	http://www.c40.org/case_studies/eco-efficient-heating-and-cooling-in-helsinki-saves-27-mt-co2-every-year
	District energy for Helsinki - a highly efficient heating and cooling model	Cogeneration & On-Site Power Production	Website	http://www.cospp.com/articles/print/volume-10/issue-3/project-profile/district-energy-for-helsinki-a-highly-efficient-heating-and-cooling-model.html
	Carbon-free nuclear district heating for the Helsinki area?	Cogeneration & On-Site Power Production	Website	http://www.cospp.com/articles/print/volume-11/issue-3/features/carbon-free-nuclear.html
Kozloduy Nuclear Power Plant	Generation	Kozloduy NPP	Website	http://www.kznpp.org/index.php?lang=en
	Nuclear Power in Bulgaria	World Nuclear Association	Website	http://www.world-nuclear.org/info/Country-Profiles/Countries-A-F/Bulgaria/
Kudankulam Nuclear Power Plant	Kudankulam Atomic Power Project	Nuclear Power Corporation of India Limited	Website	http://www.npcil.nic.in/main/ConstructionDetail.aspx?ReactorID=77
Leningrad II Nuclear Power Plant	Leningrad II may be delayed by a year, says project chief	World Nuclear News	Website	http://www.world-nuclear-news.org/NN-Leningrad-11-may-be-delayed-by-a-year-says-project-chief-16021501.html
	Construction starts on second Leningrad II unit	World Nuclear News	Website	http://www.world-nuclear-news.org/NN-Construction_starts_on_second_Leningrad_II_unit-1904104.html
	First steam generators delivered to Leningrad II-2	World Nuclear News	Website	http://www.world-nuclear-news.org/NN-First-steam-generators-delivered-to-Leningrad-II-2-19061502.html
Loviisa 3 Nuclear Power Plant	Fortum submits application for Loviisa 3	World Nuclear News	Website	http://www.world-nuclear-news.org/newsarticle.aspx?id=24601
	Nuclear District Heating Plans from Loviisa to Helsinki Metropolitan Area	Fortum	Presentation	https://www.oecd-nea.org/ndd/workshops/nucogen/presentations/3_Tuomisto_Nuclear-District-Heating-Plans.pdf
	Carbon-free nuclear district heating for the Helsinki area?	Cogeneration & On-Site Power Production	Website	http://www.cospp.com/articles/print/volume-11/issue-3/features/carbon-free-nuclear.html
	Fortum ei saa lupaa Loviisa 3:lle	Loviisan Sanomat	Website	http://www.loviisansanomat.net/lue.php?id=4199
Madras Atomic Power Station	Madras Atomic Power Station (MAPS)	Nuclear Power Corporation of India Limited	Website	http://www.npcil.nic.in/main/ProjectOperationDisplay.aspx?ReactorID=75
Nuclear Combined Heat and Power	COGENERATION IN THE FORMER SOVIET UNION	Brookhaven National Laboratory	Article	http://www.iaea.org/inis/collection/NCLCollectionStore/_Public/29/011/29011234.pdf

Subject Area	Title	Source	Source Type	Name/link
	Economic Comparison of Different Size Nuclear Reactors	Westinghouse Electric Company	Report	http://las-ans.org.br/Papers%202007/pdfs/paper062.pdf
	Nuclear Co-Generation Desalination Complex with Simplified Boiling Water Reactor VK-300	N.A.Dollezhal Research and Development Institute of Power Engineering	Article	http://www-pub.iaea.org/MTCD/publications/PDF/P1500_CD_Web/htm/pdf/topic5/5S07_Y.%20Kuznetsov.pdf
	SMALL MODULAR REACTORS	Los Alamos National Laboratory	Presentation	http://hpicorg.com/downloads/Small%20Modular%20Reactors.pdf
	Status report 66 - VBER-300 (VBER-300)	Advanced Reactor Information System	Report	https://aris.iaea.org/sites/..%5CPDF%5CVBER-300.pdf
	NUCLEAR POWER REACTOR CHARACTERSITICS	World Nuclear Association	Marketing	http://www.world-nuclear.org/uploadedFiles/org/WNA/Publications/Nuclear_Information/Pocket%20Guide%20Reactors.pdf
	What is District Energy?	EESI	Marketing	http://www.districtenergy.org/assets/pdfs/White-Papers/What-IsDistrictEnergyEESI092311.pdf
	Experience of Operating Nuclear District Heating in Russia	OECD Nuclear Energy Agency	Presentation	https://www.oecd-nea.org/ndd/workshops/nucogen/presentations/6_Sozoniuk_Experience-operating-nuclear-Rus.pdf
	Small Nuclear Power Reactors	World Nuclear Association	Website	http://www.world-nuclear.org/info/Nuclear-Fuel-Cycle/Power-Reactors/Small-Nuclear-Power-Reactors/
	INTERIM REPORT OF THE AMERICAN NUCLEAR PRESIDENT'S SPECIAL COMMITTEE ON SMALL AND MEDIUM SIZED REACTOR GENERIC LICENSING ISSUES	American Nuclear Society	Report	http://www2.ans.org/pi/smr/ans-smr-report.pdf
	Small Scale Nuclear Power: an Option for Alaska?	Alaska Center for Energy and Power	Presentation	http://www.uaf.edu/files/acep/Small%20Scale%20Nuclear%20Presentation.pdf
	NuScale Power Small Modular Reactors The Future of Nuclear Energy	NuScale Power	Presentation	http://www.floridaenergysummit.com/pdfs/presentations2015/MikeMcGough.pdf
	Selecting main technical solutions for heat supply systems equipped with nuclear cogeneration stations	INEI RAN	Article	ISSN 0040-6015, Thermal Engineering, 2008, Vol. 55, No.11, pp. 939-946
	The technical and economic principles and lines of development of nuclear district heating cogerneration	INEI RAN	Article	ISSN 0040-6015, Thermal Engineering, 2008, Vol. 55, No.11, pp. 926-938
	A NUCLEAR REACTOR FOR DISTRICT HEATING	Atomic Energy of Canada Limited	Article	Chalk River Nuclear Laboratories, 1989

Subject Area	Title	Source	Source Type	Name/link
	SMALL PWRS USING COATED PARTICLE FUEL FOR DISTRICT HEATING, PFPWR50	Hokkaido University	Article	Progress in Nuclear Energy, Vol. 47, No. 1-4, pp. 155-162, 2005
	Thermodynamic analysis of an existing coal-fired power plant for district heating/cooling application	Yildiz Technical University	Article	Applied Thermal Engineering 30 (2010) 181–187
	Process heat cogeneration using a high temperature reactor	National Institute for Nuclear Research, Mexico	Article	Nuclear Engineering and Design 280 (2014) 137–143
	Heat recovery from nuclear power plants	French Alternative Energies and Atomic Energy Commission	Article	Electrical Power and Energy Systems 42 (2012) 553–559
	NuScale Small Modular Reactor for Co-Generation of Electricity and Water	NuScale Power	Article	Desalination, Volume 340, 1 May 2014, Pages 84–93
	Integration of NuScale SMR with Desalination Technologies	NuScale Power	Article	http://www.nuscalepower.com/images/our_technology/NuScale-Desalination-ASME-SMR14.pdf
	Advanced Applications of Water Cooled Nuclear Power Plants	International Atomic Energy Agency	Report	http://www-pub.iaea.org/MTCD/publications/PDF/te_1584_web.pdf
	Nuclear power applications: Supplying heat for homes and industries	International Atomic Energy Agency	Report	https://www.iaea.org/sites/default/files/publications/magazines/bulletin/bull39-2/39205082125.pdf
	Desalination and Other Non-electric Applications of Nuclear Energy	International Atomic Energy Agency	Report	http://users.ictp.it/~pub_off/lectures/lns020/Majumdar/Majumdar_2.pdf
Obninsk Nuclear Power Plant	June 27, 1954: World's First Nuclear Power Plant Opens	WIRED	Website	http://www.wired.com/2012/06/june-27-1954-worlds-first-nuclear-power-plant-opens/
	Obninsk Nuclear Power Plant	Engineering and Technology History Wiki	Website	http://ethw.org/Obninsk_Nuclear_Power_Plant
	Nuclear power plants, world-wide	European Nuclear Society	Website	https://www.euronuclear.org/info/encyclopedia/n/nuclear-power-plant-world-wide.htm
Pressurised Water Reactors (PWRs)	Pressurised Water Reactor (PWR) Systems	USNRC	Manual	http://www.nrc.gov/reading-rm/basic-ref/students/for-educators/04.pdf
	PWR Description	MIT	Presentation	http://ocw.mit.edu/courses/nuclear-engineering/22-06-engineering-of-nuclear-systems-fall-2010/lectures-and-readings/MIT22_06F10_lec06a.pdf
	PRESSURIZED WATER REACTORS	Dr. M Ragheb	Book	http://mragheb.com/NPRE%20402%20ME%20405%20Nuclear%20Pow

Subject Area	Title	Source	Source Type	Name/link
				er%20Engineering/Pressurized%20Water%20Reactors.pdf
	the westinghouse pressurized water reactor nuclear power plant	Westinghouse Electric Corporation	Book	http://www4.ncsu.edu/~doster/NE405/Manuals/PWR_Manual.pdf
	Description of Sizewell B Nuclear Power Plant	Institutt for energiteknikk (IFE)	Report	http://www.iaea.org/inis/collection/NCLCollectionStore/_Public/29/010/29010110.pdf
Seversk/ Tomsk-7 Nuclear Power Plant	Tomsk-7 / Seversk	GlobalSecurity.org	Website	http://www.globalsecurity.org/wmd/world/russia/tomsk-7_nuc.htm
	Russia's Nuclear Fuel Cycle	World Nuclear Association	Website	http://www.world-nuclear.org/info/Country-Profiles/Countries-O-S/Russia--Nuclear-Fuel-Cycle/
Temeliin Nuclear Power Plant	The Temelín Nuclear Power Station	CEZ GROUP	Website	http://www.cez.cz/en/power-plants-and-environment/nuclear-power-plants/temelin.html
Warsaw District Heating	Construction of 156MW coal-fired CHP plant in Bielsko-Biała, Poland completed	International District Energy Association	Website	http://www.districtenergy.org/blog/2013/07/18/construction-of-50mw-coal-fired-chp-plant-in-bielsko-biala-poland-completed/
	CHP plant Siekierki, Warsaw	CODE Project	Marketing	http://www.code-project.eu/wp-content/uploads/2010/09/CODE-CS-Siekierki-Poland.pdf
	How Warsaw's district heating system keeps the capital cleaner than Kraków	The Guardian	Website	http://www.theguardian.com/cities/2015/apr/13/warsaw-district-heating-system-poland-capital-cleaner-krakow
	"SMART HEAT DISTRIBUTION NETWORK" FOR SPEC S.A. (HEAT POWER ENGINEERING COMPANY) IN WARSAW	CAS	Website	http://www.cas.eu/Projects/ISC.aspx
	About PGNiG Termika	PGNiG TERMIKA	Website	http://termika.pgnig.pl/about-pgnig-termika/our-plants/
	Warsaw: major acquisition in Poland for Veolia Energy - Dalkia	Veolia	Website	http://www.veolia.com/en/veolia-group/media/news/warsaw-major-acquisition-poland-veolia-energy-dalkia

Appendix M. International DH system examples

The following table provides references to DH system diagrams found during our review.

Table M.1: References to diagram examples of international DH systems

Reference	Title / Description	Weblink / reference
1	Steam extraction for a coal-fired power plant from the cross-over pipe between the IP and LP steam turbines, for further use in district heating/cooling	Hasan Huseyin Erdem, Ahmet Dagdas, Suleyman Hakan Sevilgen, Burhanettin Cetin, Ali Volkan Akkaya, Bahri Sahin, Ismail Teke, Cengiz Gungor, Selcuk Atas, Thermodynamic analysis of an existing coal-fired power plant for district heating/cooling application, Applied Thermal Engineering, Volume 30, Issues 2–3, February 2010, Pages 181-187, ISSN 1359-4311, http://dx.doi.org/10.1016/j.applthermaleng.2009.08.003. (http://www.sciencedirect.com/science/article/pii/S1359431109002476)
2	Steam extraction from an unknown point of the steam turbine for a NPP, with heat then transferred to a desalination circuit via an intermediate circuit	http://www-pub.iaea.org/MTCD/publications/PDF/P1500_CD_Web/htm/pdf/topic5/5S07_Y.%20Kuznetsov.pdf
3	Steam extraction an unknown point of the steam turbine for a NPP, with heat then transferred to a DH circuit via an intermediate circuit	Smirnov, I.A., Svetlov, K.S. & Khrilev, Selecting main technical solutions for heat supply systems equipped with nuclear cogeneration stations L.S. Therm. Eng. (2008) 55: 939. Doi:10.1134/S0040601508110050 & Kuznetsov, Y.N., Khrilev, L.S. & Brailov, The technical and economic principles and lines of development of nuclear district heating cogeneration V.P. Therm. Eng. (2008) 55: 926. Doi:10.1134/S0040601508110049
4	Steam extraction an unknown point of the steam turbine for the Bohunice NPP, with heat then transferred to a DH network via a heat exchanger	http://www.iaea.org/inis/collection/NCLCollectionStore/_Public/29/011/29011234.pdf
5	Steam extraction from the intermediate separator (assumed to operate in a similar manner to the IP/LP cross-over pipe some unknown point of the steam turbine) for the Bilibino NPP, with heat then transferred to a DH network via a heat exchanger	http://www.iaea.org/inis/collection/NCLCollectionStore/_Public/29/011/29011234.pdf
6	Steam extraction from a cross-over pipe between the multiple turbine stages for the Beznau NPP, with heat then transferred to the REFUNA DH network via a heat exchanger	https://www.axpo.com/content/dam/axpo/switzerland/erleben/dokumente/axpo_KKB_prospekt_en.pdf.res/axpo_KKB_prospekt_en.pdf

Reference	Title / Description	Weblink / reference
7	Steam extraction from a cross-over pipe between the HP and LP turbines and from the LP turbine for the Beznau NPP, with heat then transferred to the REFUNA DH network via a heat exchanger	http://www.iaea.org/inis/collection/NCLCollectionStore/_Public/29/067/29067739.pdf
8	Safety valves used in the REFUNA DH network	http://www.iaea.org/inis/collection/NCLCollectionStore/_Public/29/067/29067739.pdf
9	Steam extraction from an unknown point of the steam turbine for a NPP, with heat then transferred to a DH network via a heat exchanger	https://aris.iaea.org/sites/..%5CPDF%5CVBER-300.pdf
10	Post-turbine steam extraction for gas-fired power plant, it is not shown how DH water is generated	https://stateofgreen.com/files/download/82
11	Multiple steam extraction options for a CCGT	http://m.energy.siemens.com/us/pool/hq/energy-topics/publications/Technical%20Papers/Steam%20Turbines/Power_Russia_Helesch_Internet.pdf
12	Steam extraction from an unknown point of a steam turbine, with heat then transferred to a DH network via a heat exchanger	https://www.oecd-nea.org/ndd/workshops/nucogen/presentations/5_Schmidiger_Experience-Operating-Nuclear-Swi.pdf

Source: Mott MacDonald

Glossary

AACE	Association for the Advancement of Cost Engineering
ABB	ASEA Brown Boveri
ACC	Air Cooled Condenser
ACF	Annual Capacity Factor
AFT	Advanced Flow Technology
ANSI	American National Standards Institute
ANT	Advanced Nuclear Technology
BBSS	Bruce Bulk Steam System
BHWP	Bruce Heavy Water Plant
CAPEX	Capital Expenditure
CCGT	Closed Cycle Gas Turbine
CEA	French Alternative Energies and Atomic Energy Commission
CHP	Combined Heat and Power
DCF	Discounted Cash Flow
DETR	Department of the Environment, Transport and the Regions
DH	District Heating
DN	Diametre Nominel
ECT	Evaporative Cooling Tower
EFTA	European Free Trade Association
ETI	Energy Technologies Institute
EU	European Union
FEED	Front End Engineering Design
FOAK	First of a Kind
GBP	Great British Pounds
GBWR	Graphite-moderated Boiling-Water Reactors
GDA	Generic Design Assessment
HP	High Pressure
IAEA	International Atomic Energy Agency
ID	Internal Diameter
IP	Intermediate Pressure
IRR	Internal Rate of Return
LCOE	Levelised Cost of Electricity
LP	Low Pressure
LWR	Light Water Reactor
MSR	Moisture Separator Reheater

NOAK	Nth of a Kind
NPP	Nuclear Power Plant
NPSH	Net Positive Suction Head
NPV	Net Present Value
OCGT	Open Cycle Gas Turbine
OPEX	Operational Expenditure
PEACE	Plant Engineering and Construction Estimator
PED	Pressure Equipment Directive
PHWR	Pressurised Heavy Water Reactor
PPSS	Power Plant Siting Study
PRDS	Pressure Reducing De-superheating Valve
PWR	Pressurised Water Reactor
SG	Steam Generator
SMR	Small Modular Nuclear Reactor
ST	Steam Turbine
TBM	Tunnel Boring Machine
UK	United Kingdom
USA	United States of America
USD	United States Dollars
WDE	Water Drop Erosion