Appendix A

TOWN OF OAKVILLE – DETAILED DISTRICT ENERGY FEASIBILITY STUDY - FINAL REPORT

Town of Oakville

2024-09-20

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URBAN EQUATION

Report

To:	Town of Oakville
From:	Rathco ENG and Urban Equation
Date:	2024-09-20
Project Number:	TO-1019-C
Project Name:	Town of Oakville District Energy System – Detailed Feasibility

Revision	Date	Description	Made By	Approved By
1	2024-08-15	Draft Final	Mairead Kennedy Darynne Hagen Shirin Karoubi Aditya Bhujle	John Rathbone Aditya Bhujle
2	2024-09-16	Draft Final	Mairead Kennedy Darynne Hagen Shirin Karoubi Aditya Bhujle	John Rathbone Aditya Bhujle
3	2024-09-20	Final	Mairead Kennedy Darynne Hagen Shirin Karoubi Aditya Bhujle	John Rathbone Aditya Bhujle

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EXECUTIVE SUMMARY

Rathco ENG Ltd. were engaged by the Corporation of the Town of Oakville (the Town), supported by the Danish Energy Agency, to conduct a detailed feasibility study. Rathco ENG retained Urban Equation as a subcontractor to act as the business and financial advisor for the study. The detailed feasibility study is a continuation of the pre-feasibility study completed in 2022. With reference to Oakville's Community Energy Strategy (CES), this report falls under Strategic Direction 3 (SD3) - Local Energy Supply and Distribution. Under SD3, the CES established a series of Priority Projects which form a roadmap for the development of a district energy utility in Oakville to supply heating and cooling to buildings in Oakville. This detailed feasibility study is the final report that outlines the recommended DES for the Town of Oakville with consideration to the Council endorsed goals of the CES[1]:

- Increase energy efficiency by at least 40% by 2041 (compared to a 2016 baseline).
- Enable transition to carbon neutrality by reducing greenhouse gas (GHG) emissions by at least 50% by 2041 (compared to a 2016 baseline).
- Return at least $7 billion in cumulative energy cost savings to the community by 2041.

PROJECT BACKGROUND

The Hospital District is largely a new development area that has the potential to implement district energy in the short- to medium-term. The Hospital District covers 177 acres of land including the existing Oakville Trafalgar Memorial Hospital. The Area Specific Plan (ASP) for the Oakville Hospital District was used to develop land use, population and density. Landowners were engaged to better assess development timeline and potential customer connections to the DES. Of those landowners that were engaged, all stated an interest in connecting to the future DES depending on commercial outcome.

Figure 1: Hospital District

DEMANDS AND BASELINE EMISSIONS

Loads for heating, cooling, and domestic hot water (DHW) were approximated by applying a scaling factor for the projected floor areas to building profiles for typical new buildings of the corresponding use types in Ontario.

[1] Community Energy Strategy (last accessed 2020-12-29)

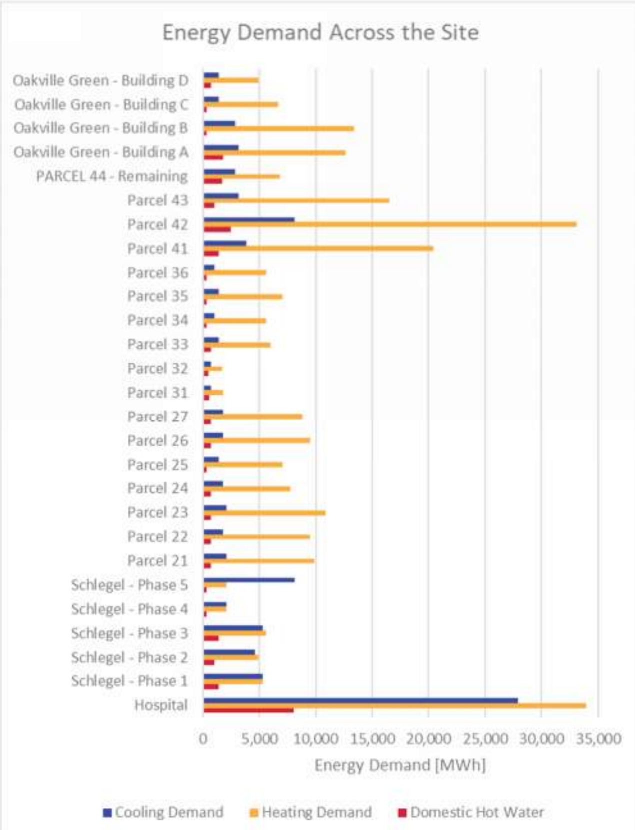

Figure 2: Energy Demand Across Hospital District

The approximate GHG emissions associated with the BAU were 16,932 tonnes per annum at full build-out. The GHG emissions and economics are based on a building HVAC system which comprised the following:

- Heating: Natural gas boilers connected to building condenser loop with in-suite heat pumps
- Cooling: Rooftop Fluid Coolers connected to building condenser loop and in-suite heat pumps
- Domestic Hot Water (DHW): Natural Gas Boilers

PROJECT DESCRIPTION

The recommended concept at the hospital site from the pre-feasibility study was the **hybrid geothermal** and **sewer energy exchange ambient district energy system**. This is the scenario that was agreed with the Town to take forward to this detailed feasibility study. The technologies are well suited for each other as the sewer can be used to balance the geothermal borefields instead of running external equipment like boilers or fluid coolers. The hybrid concept offers the added benefit of resiliency and borefield balancing with the addition of the sewer energy exchange component. In this feasibility study, DHW is provided by the ambient district energy system connected to heat pumps located at customer buildings.

PHASING

Table 1: Total Connected Floor Areas

Phase	GFA m2	Est. Operational Year
1	148,644	2028
2	97,633	2030
3	51,000	2031
4	98,399	2032
5	82,077	2033
6	136,682	2034
7	133,309	2040
8	57,048	2043
9	95,242	2045
10	47,481	2049

Table 2: System Phasing Summary

Phase	1	2	3	4	5	6	7	8	9	10
Investment Year	2027	2027	2028	2030	2031	2032	2038	2041	2043	2047
Operational Year	2028	2030	2031	2032	2033	2034	2040	2043	2045	2049

EMISSION REDUCTIONS

Annual emissions following Phase 10 are consistent with emissions represented in Phase 10.

Table 3: GHG Emission Assessment

Phase	1	2	3	4	5	6	7	8	9	10
Emissions (Electricity) [tonnes CO2e/yr]	310	478	520	731	831	1,036	1,267	1,364	1,594	1,625
Emissions (Natural Gas) [tonnes CO2e/yr]	0	373	525	346	454	821	1,529	1,933	2,613	3,006
Total Emissions [tonnes CO2e/yr]	310	852	1,045	1,077	1,284	1,857	2,796	3,297	4,207	4,632

The chart below shows the cumulative emissions comparison between the DES and the BAU scenarios. By full buildout, the DES is saving ~12,300 tonnes of CO2e per year, approximately 62% emissions reductions.

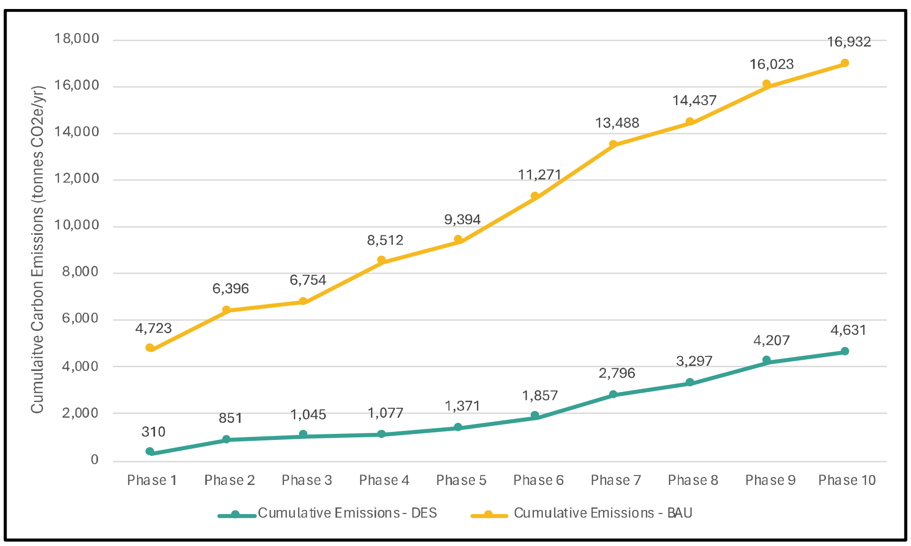

Figure 3: Emissions Comparison (Cumulative)

PROJECT COST SUMMARY

Table 4: Capital Cost Estimates

Capital Cost Estimates	CAPEX	Contingency	Total
Phase 1	$25,199,002	$3,779,850	**$28,978,853**
Phase 2	$15,171,056	$2,275,658	**$17,446,714**
Phase 3	$3,606,522	$540,978	**$4,147,500**
Phase 4	$16,060,857	$2,409,129	**$8,469,986**
Phase 5	$7,892,088	$1,197,313	**$9,179,401**
Phase 6	$10,836,343	$1,625,452	**$12,461,795**
Phase 7	$18,956,442	$2,843,466	**$21,799,908**
Phase 8	$7,207,726	$1,081,159	**$8,288,885**
Phase 9	$10,375,884	$1,556,383	**$11,932,267**
Phase 10	$5,727,524	$859,129	**$6,586,653**
Total	**$121,123,444**	**$18,168,517**	**$139,291,961**

Table 5: Cumulative Fixed Operating Cost Estimates

Phase	Water and Chemical Treatment	Insurance	Equipment Maintenance	Network Maintenance	Sewer Infrastructure Costs	Admin Costs	O&M Staffing
1	$19,808	$144,894	$122,115	$33,986	$39,980	$125,995	$150,000
2	$29,910	$232,128	$243,218	$74,945	$39,980	$201,850	$150,000
3	$32,533	$252,865	$261,700	$96,929	$39,980	$219,883	$150,000
4	$42,218	$345,215	$326,011	$104,277	$39,980	$300,187	$150,000
5	$47,390	$391,112	$363,168	$126,148	$39,980	$340,098	$150,000
6	$58,050	$453,421	$422,660	$138,646	$39,980	$394,279	$150,000
7	$70,324	$562,421	$528,750	$157,034	$39,980	$489,062	$200,000
8	$75,576	$603,865	$571,900	$178,905	$39,980	$525,100	$200,000
9	$84,345	$663,527	$640,337	$190,481	$39,980	$576,980	$200,000
10	$89,355	$696,460	$676,550	$194,656	$39,980	$605,617	$200,000

Annual operating costs following Phase 10 are consistent with operating costs represented in Phase 10, adjusted for inflation.

BUSINESS CASE

Table 6 and Table 7 present the business model results for a DES at the hospital district, both including and excluding terminal asset value, given the assumptions and estimates presented in the report. There is a promising business case for the project to proceed further, both with and without the consideration of terminal value.

No grants or funding have been assumed in this business case – this would only improve the business case. If financing facilities can be obtained at a low cost, then there would be substantial improvements as well.

Table 6: District Energy System Results with Terminal Value Considered

District Energy System – 30 Year Term		
Capital Costs	$201	M
Operating Costs	$404	M
TOTAL COSTS	**$605**	**M**
Thermal Energy Sales	$586	M
Connection Charges	$117	M
Terminal Value	$470	M
TOTAL REVENUE	**$1,173**	**M**
TOTAL PROFIT (FV)	**$706**	**M**
TOTAL PROFIT (PV)	**$13.8**	**M**
UIRR (pre-tax, excluding funding/financing)	**13.3**	**%**

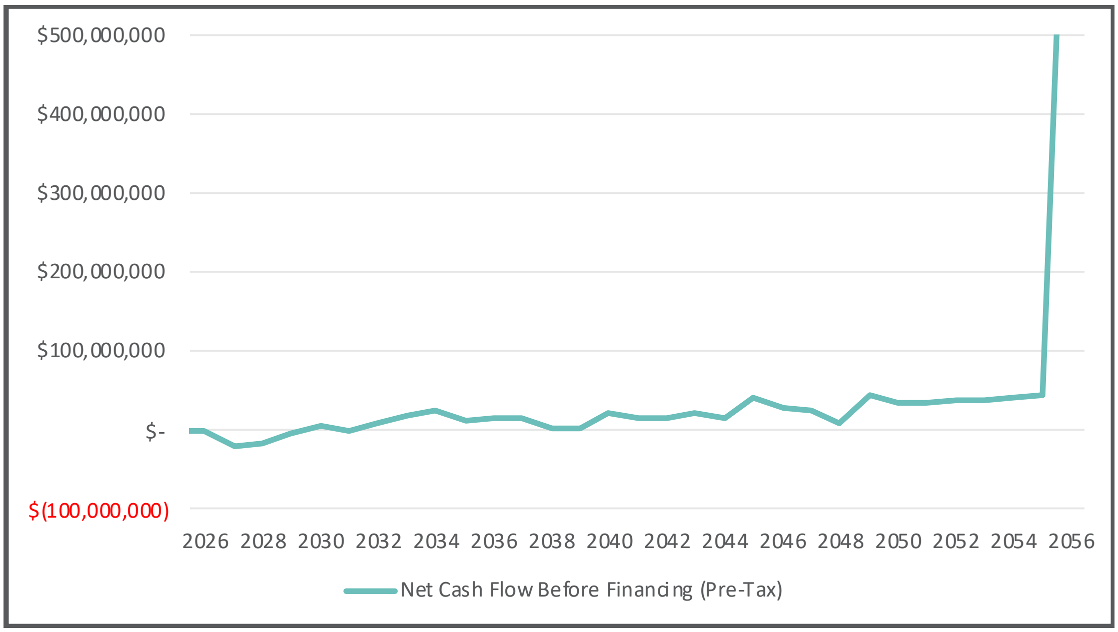

Figure 4: Net Cash Flow for the DES Business Case (With Terminal Value)

Table 7: District Energy System Results Without Terminal Value Considered

District Energy System – 30 Year Term		
Capital Costs	$201	M
Operating Costs	$404	M
TOTAL COSTS	**$605**	**M**
Thermal Energy Sales	$586	M
Connection Charges	$117	M
Terminal Value	$0	M
TOTAL REVENUE	**$703**	**M**
TOTAL PROFIT (FV)	**$236**	**M**
TOTAL PROFIT (PV)	**($1.2)**	**M**
UIRR (pre-tax, excluding funding/financing)	**10.7**	**%**

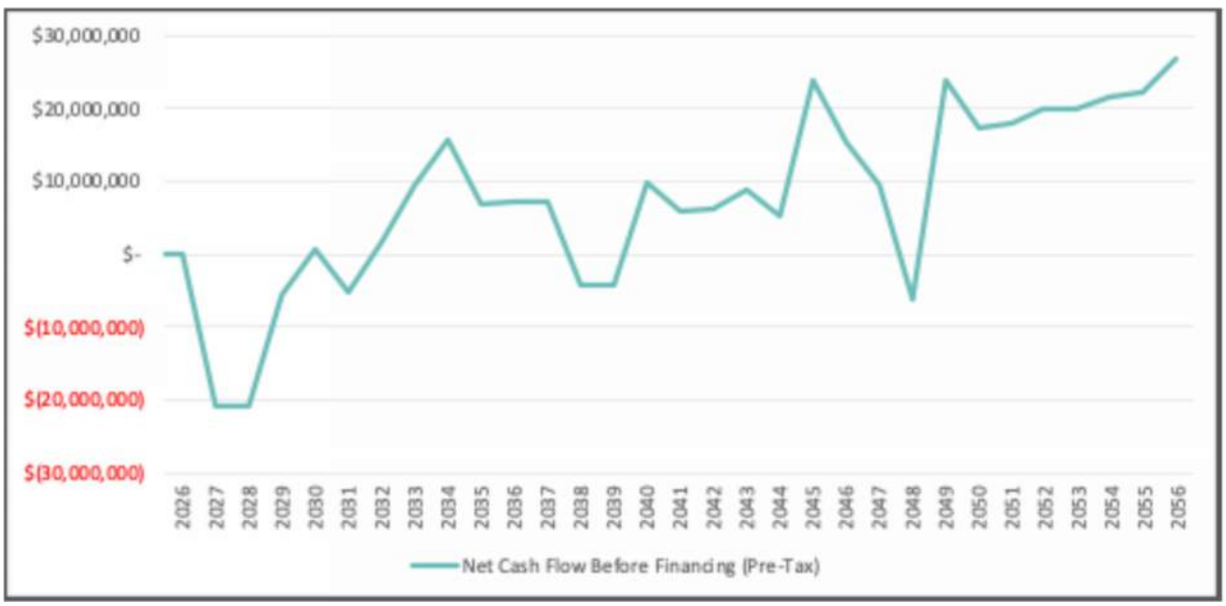

Figure 5: Net Cash Flow for the DES Business Case (Without Terminal Value)

Table 8 summarizes the business case for the wastewater heat supplier (WHS). Given that supplier capital costs are absorbed by the DES system, there is a substantial net present value for the WHS, gained through wastewater heat revenue. Figure 6 shows the WHS cash flow over the study period.

Table 8: Wastewater Heat Supplier Business Case Results

Wastewater Heat Supplier – 30 Year Term		
Capital Costs	$0	M
Operating Costs	$0	M
TOTAL COSTS	**$0**	**M**
Thermal Energy Sales	$7.2	M
TOTAL REVENUE	**$7.2**	**M**
TOTAL PROFIT (FV)	**$7.2**	**M**
TOTAL PROFIT (PV)	**$1.4**	**M**
UIRR (pre-tax, excluding funding/financing)	**-**	**%**

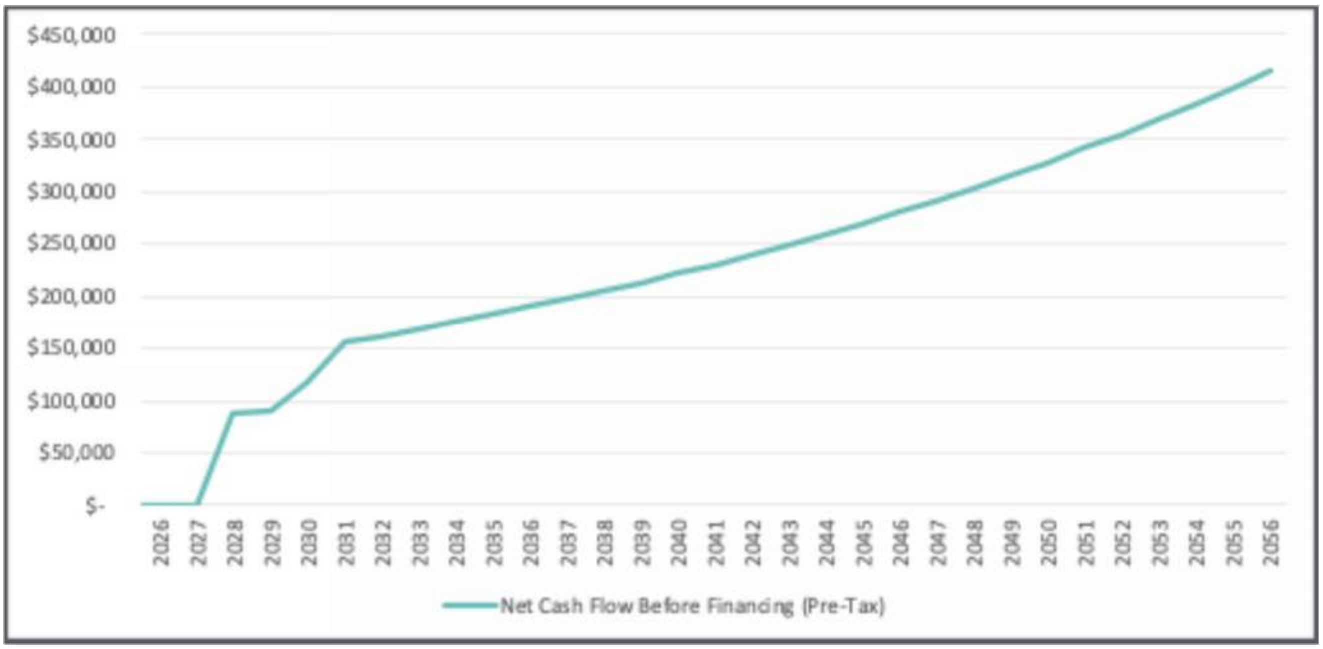

Figure 6: Net Cashflow for Wastewater Heat Supplier

Sensitivity Analysis: A detailed sensitivity analysis was performed to evaluate how changes to the assumptions or market conditions would impact the financial results. The analysis evaluated upside cases and downside cases relative to the target or assumed values for key variables as detailed in the report. This analysis was performed for the following reasons:

- To appropriately size the capacity of the project to withstand major financial and economic headwinds
- To establish a realistic and robust investment-grade baseline for the project

Ownership Archetype Modelling: There are three typical ownership models used to deliver district energy projects:

- Private project development companies,
- Public project development companies, and
- Hybrid public/private partnerships

A detailed list and descriptions of the ownership structures are presented in the report. For the purpose of this analysis, only two ownership archetypes were considered: a fully private and a fully public model.

Financing: The assumptions and associated returns for the two ownership structures evaluated are provided in Table 9. A publicly owned DES was modelled both with and without a terminal asset value in order to provide the Town with additional insights. Without terminal asset value considered, the publicly owned utility would be expected to receive a lower levered internal rate of return (LIRR) and a negative NPV over the 30-year term. While this may appear to indicate that a publicly owned utility would be a poor investment if not sold after 30 years, we do not believe this to be the case, as the DES would continue generating income if not sold after 30 years. This additional revenue would increase the LIRR for the public DES owner. Further, the benefits of such a system transcend economic considerations and bring enhanced social and environmental benefits.

For all financing options, a construction loan type of financing facility has been assumed over a 20-year term with an amortized repayment spanning 10 years following the loan maturity date.

Table 9: Ownership Model Results

Ownership Structure	Equity Ratio – Construction Costs	Terminal Asset Value	Discount Rate	Interest Rate	Net Present Value (NPV)	Levered Internal Rate of Return (LIRR)	Peak Equity Invested	Peak Equity Multiple
Private Ownership	40%	Terminal Value Included	9%	7.95%	$4.2M	9.53%	$56.4M	9.76x
	Total Construction costs (Escalated): $201,417,972 Total Construction Loan Proceeds: $120,850,783 Total Construction Equity Proceeds: $80,567,189							
Public Ownership	20%	Terminal Value Included	11%	6.3%	$971K	11.21%	$40.9M	13.11x
	Total Construction costs (Escalated): $201,417,972 Total Construction Loan Proceeds: $161,134,378 Total Construction Equity Proceeds: $40,283,594							
	20%	Terminal Value Excluded	11%	6.3%	($13M)	3.26%	$40.9M	1.61x
	Total Construction costs (Escalated): $201,417,972 Total Construction Loan Proceeds: $161,134,378 Total Construction Equity Proceeds: $40,283,594							

Governance Framework: Depending on the type of ownership model selected for the DES, a governance framework will be critical to ensure project success. Both public and private ownership models have their merits; however, a public governance framework would provide the following unique benefits:

- Allows for the alignment of municipal or town policy to enable low carbon community energy.
- Provides a means for the municipality/town to also generate revenues or dividends.
- Instills trust, given that municipalities are capable of carrying a long-term ownership model, which will ensure that the DES ownership and management will remain consistent for customers.
- Ensures that benefits of DES implementation (i.e. financial, environmental and social) remain within and are driven by the municipality.
- Provides access to more favourable financing terms, potentially improving project profitability.
- Similar to the governance and jurisdictional power like OEB, who regulates gas and electricity rates, the governance council of the municipality/town can ensure fair energy rates for the customers and residents while enjoying the benefits of low carbon energy.

Risk & Mitigants Study: It is important to understand key risks that can impact the project and understand their likelihoods, financial impact on the project budget and the impact to the project schedule. The report outlines the key risks and potential mitigation strategies that can be considered and developed further in the next stages of the project. For each risk a likelihood, impact and severity have been estimated, along with the project aspects each risk is expected to impact. The qualification is on a pre-mitigation basis or as seen today.

RECOMMENDATIONS AND NEXT STEPS

Based on the technical and economic findings of this assessment, it is expected that a publicly owned DES at the Hospital District is feasible. It is recommended that the Town move onto the next stage of project feasibility, which involves further assessment of the project ownership and governance model. The Town will need to investigate the possibility of bringing in a DES partner, who can lead the following next steps:

1. Engage with decision makers at the Town based on this document to ensure the municipality and public officials understand the significance and benefits of this project
2. Engage with primary lending and funding agencies to detail out application requirements and timelines and have a better view into commercial terms and structures
3. Engage a prime consultant or consortium to act as expert District Energy project managers and manage partner procurement and planning
4. Progress the outlining of major contracts and key material terms
5. Start discussions with key customers who can provide large anchor loads
6. Engage regularly with the Region to look into technical and commercial aspects of sewer energy exchange with an understanding of long-term commitments and impacts on design
7. Establish a position on the ownership and transfer of carbon credits and or energy attribute certificates that is in line with carbon accounting protocols
8. Public engagements

There is a significant opportunity for the Town of Oakville to develop a world-class and exemplary low-carbon district energy system that will enable the Town to achieve its GHG reduction targets and Climate action goals.

MILESTONE 1

PROJECT INTRODUCTION AND PURPOSE

1 PROJECT INTRODUCTION

Rathco ENG Ltd. was engaged by the Corporation of the Town of Oakville (the Town), supported by the Danish Energy Agency, to conduct a detailed feasibility study. Rathco ENG retained Urban Equation as a subcontractor to act as the business and financial advisor for the study. The detailed feasibility study is a continuation of the pre-feasibility study completed in 2022. Oakville's Community Energy Strategy (CES). Urban Equation are the Commercial Experts engaged by Rathco ENG to support this project.

This study is organized around 6 milestones:

- Milestone 1: Develop Scope of Work for Feasibility Study: Town of Oakville
- Milestone 2: Project Kick-off and Basis: Rathco
- Milestone 3: Modelling and Design: Rathco
- Milestone 4: Economic and Financial Analysis: Urban Equation
- Milestone 5: Implementation Planning: Urban Equation
- Milestone 6: Draft and Final Report: Rathco and Urban Equation

The Project Team for this project consists of the Consultant Team (Rathco ENG Ltd and Urban Equation), the District Energy Task Force at the Town (DE Task Force), Oakville Hydro, and Halton Region.

In this report, Oakville refers to the broader community while the Town refers to the municipal corporation.

1.1 District Energy Overview

District energy describes a distribution system that supplies heating and/or cooling to multiple buildings from a central location(s). There are three main elements to a district energy system:

1. Heat/cooling source,
2. Distribution piping,
3. Building connection to distribution piping.

A sample district heating system is shown below, where the energy supply is the heating/cooling source, the red and blue lines represent the distribution piping (where the red pipes are the heating supply piping and the blue pipes are the heating return piping), and the building connections are the points at which the red and blue lines connect to the buildings.

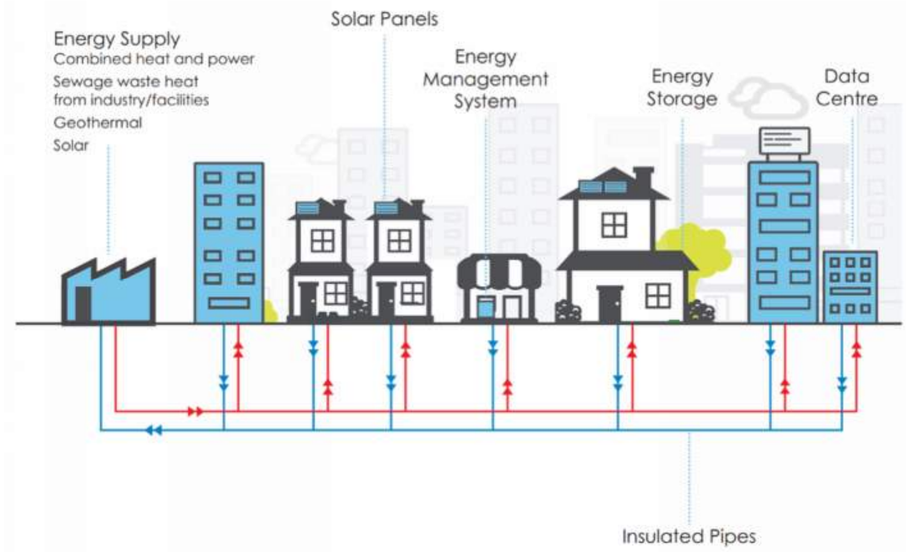

Figure 7: District Energy System (image courtesy of CES

1.2 Work to Date

1.2.1 Community Energy Strategy

In 2019 the Town's Council endorsed Oakville's Community Energy Strategy (CES) which identified emissions reduction strategies and energy savings initiatives. The goals and targets set out in the CES were pivotal in informing the development of the work of the completed pre-feasibility study.

The Council endorsed goals of the CES[2] are as follows:

- Increase energy efficiency by at least 40% by 2041 (compared to a 2016 baseline).
- Enable transition to carbon neutrality by reducing greenhouse gas (GHG) emissions by at least 50% by 2041 (compared to a 2016 baseline).
- Return at least $7 billion in cumulative energy cost savings to the community by 2041.

1.2.2 Governance Model Information Gathering

The Town of Oakville has already started the investigation into different governance models, which can be accessed in the August 2021 report titled "District Energy Governance Models: Opportunities for the Town of Oakville[3].

1.2.3 Heat Mapping and Pre-Feasibility Study

In 2022 a pre-feasibility study was completed that included:

[2] Community Energy Strategy (last accessed 2020-12-29)
[3] District Energy Governance Models: Opportunities for the Town of Oakville. August 2021.

- A mapping analysis to identify heating and cooling demand and supply opportunities in Oakville;
- Areas for district energy systems;
- Detailed analysis on two potential areas of focus;
- Lifecycle cost-benefit assessment, emissions reduction potential, economic modelling of the areas of focus;
- Recommended area of focus to pursue;
- Next steps.

For details on the analysis please refer to the pre-feasibility study.

Based on discussions with The Town, the Hospital District was chosen as a site to pursue for a district energy system.

2 PURPOSE

District Energy falls under Strategic Direction 3 (SD3) - Local Energy Supply and Distribution. Under SD3, the CES established a series of Priority Projects which form a roadmap for the development of a district energy utility in Oakville to supply heating and cooling to buildings in Oakville.

The pre-feasibility project and governance model assessment supported Priority Project 6.1 (Complete a business case for establishing a company to distribute thermal energy to homes and buildings). The purpose of this pre-feasibility study was to provide supporting information on district energy viability in Oakville to potential Delivery Partners, including Oakville Enterprises Corporation (OEC). In addition, the pre-feasibility study was a step toward achieving Priority Project 6.2 (Create a district energy company, based on the results of the business case). **The detailed feasibility study is a direct continuation of this work.**

The CES lists the following target for 2041:

- Serve 70% of existing target property and 80% of new target property with district heating in areas targeted for densification or new growth.

A goal of 70% of existing target properties connecting to district energy by 2041 is ambitious in the context of international best practice district energy systems. The goal of an 80% connection rate of new target property is also ambitious, although the Town has considerably more influence on early decision-making for new developments. The Consultant Team is seeing a large number of new developments in Southern Ontario pursuing community energy systems based on low-carbon thermal energy. The approach being assessed here could form the basis of a new approach across new developments in Oakville to achieve this 80% approach.

In terms of other goals, the proposed district energy system will exceed the first two bullet points:

- Increase energy efficiency by almost 100% at the Hospital District site by leveraging heat pumps.
- Reduce emissions by 62% based on the current approach.

It will further contribute to the CES by returning approximately 40 $/MWh in cost savings (capital, operational and fuel, etc.) back to the community.

MILESTONE 2

PROJECT KICK OFF AND BASIS

This Section outlines the work completed in Milestone 2 of the project to set the technical basis of the work prior to the detailed technical analysis in Milestone 3.

1. PROJECT BACKGROUND

1.1 Hospital District – Site Description

The Hospital District is largely a new development area that has the potential to implement district energy in the short-to-medium term. New developments have a variety of options for supply technologies as they can be designed to operate at temperatures more suitable to low carbon heating and cooling sources. The original pre-feasibility study outlined individual likely areas for DES success. It also articulated a potential future scenario whereby these areas could be interconnected. The Hospital district is physically separated from this future interconnected scenario. In saying that, although this study focuses on the feasibility assessment of the district energy system for the Hospital District, district energy infrastructure has the potential for expansion should development occur in the surrounding areas of the Hospital District. A cost-benefit analysis would be necessary depending on the distance of the development to the Hospital District's district energy system. Similarly, should Oakville be interested in DES in other parts of the Town, including urban areas a prefeasibility and a feasibility assessment need to be completed to assess viability. Typically, expansion would be limited to a few hundred metres due to distance piping costs however, a cost-benefit analysis would be required.

Figure 8: Oakville Hospital District demonstration plan from Area Specific Plan (ASP)[4].

[4] Revised Final Hospital District Area Specific Plan_Final.pdf (oakville.ca)

1.2 Area Specific Plan

The Area Specific Plan (ASP) for the Oakville Hospital District specified that the area should incorporate a variety of use types. These included residential, employment, and institutional (predominantly focussed on healthcare).

The ASP detailed population and employment densities for each area are on the following map in Figure 9. The use types and net floor areas (NFAs) for each of the residential, employment, and institutional parcels indicated on the map were derived from Appendix J of the ASP[5]. The NFAs and use types were used to develop load profiles for each development block (these load profiles can be seen in Sec. 3.2). Note that the floor areas for Parcel IDs 41-44 were adjusted upward by 14% from the ASP to reflect the plans provided by Oakville Green (OG). In addition, the load estimates for Parcel 44 were further revised to reflect more recent submissions by OG to the Town. Similarly, Parcels 11 – 15 were revised to reflect information provided by the Schlegel Group.

As part of the original pre-feasibility assessment, the Hospital was excluded from the district energy concept. Following good initial engagement with the Hospital the original exclusion was revisited, and **the DES concept was revised to include the Hospital as a potential energy customer**.

Figure 9 shows the parcels defined in the ASP. Figure 10 shows the breakdown of the use types and floor areas.

[5] Appendix J - Population and Employment Densities.pdf (oakville.ca)

Figure 9: Development blocks for specifying use type and densities from the ASP[4].

The floor area assessment carried out for the pre-feasibility assessment identified a breakdown that skewed heavily toward employment and institutional-type development as seen in Figure 10. At this time the data available for the site development was limited.

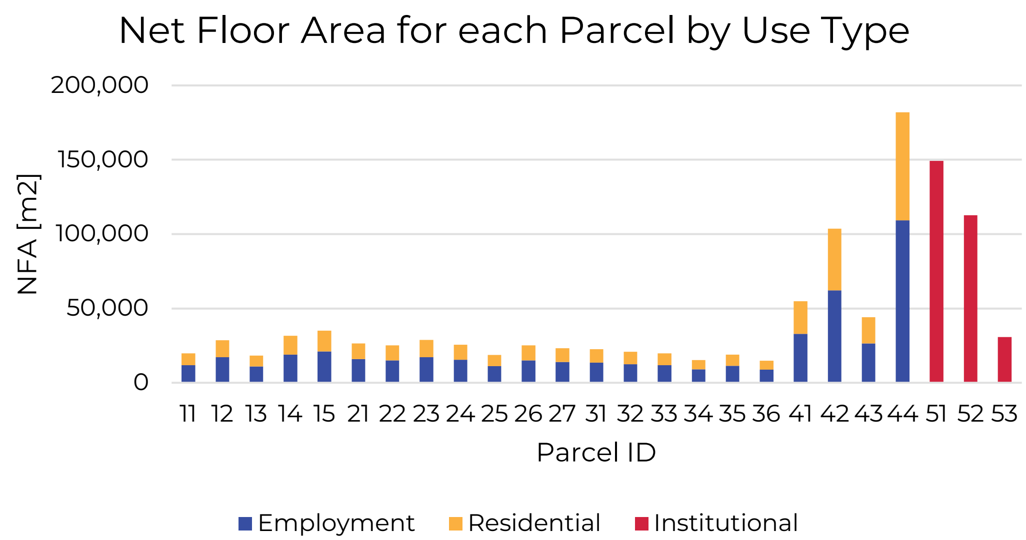

Figure 10: Hospital District net floor areas by use type for (a) parcels, including Hospital

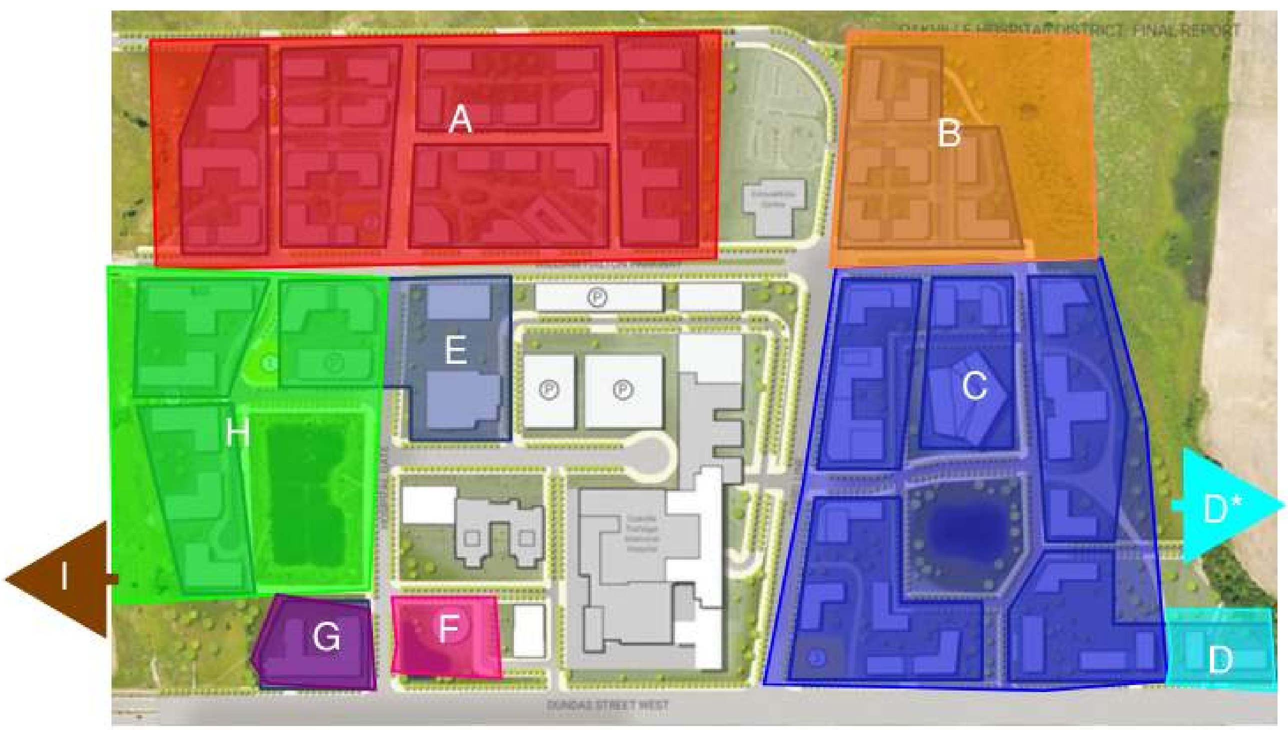

Figure 11: Hospital District ASP Development Update

Rathco engaged with the Town of Oakville Planning Department as part of this first assessment phase and received the following update on the development status as follows: **As this project develops beyond this feasibility study additional engagement should be pursued with site developers to understand phasing and site demands at a more detailed level.**

Table 10: Site Update

11 Reference	Notes	Update	Outcome
A	Site owned by Infrastructure Ontario – Planning Consultant currently engaged	The Project Team spoke with IO. No plans for development at this time.	Demand Assessment based on ASP information – included as Future Phases
B	Oakville Enterprises Corporation Site	Discussed with OEC	Demand Assessment based on ASP information – included as Future Phases
C	Oakville Green Site – Draft Plan Subdivision Approved	Good conversations with the Oakville Green team – data provided as requested.	Stage 1 of Oakville Green included with as much detail as is available – Future phases based on ASP information.
D & D*	Mattamy have a registered subdivision adjacent to the ASP at D* -there is also some proposed development south of Dundas Street Ownership of D is by Others	Good conversations with the Mattamy Team	Future phases based on ASP information for energy demands.
E	Hospital Site already constructed	Good conversations with the Hospital and IO Team – data provided as requested.	Included as a discrete Phase 1 for the project to build on.
F	Further expansion plans for the Hospital	Good conversations with the Hospital and IO Team.	Not enough information on future expansion plans currently available.
G	Constructed Seniors Care Home	No response to outreach.	Excluded at this time.

11 Reference	Notes	Update	Outcome
H	Schlegel Site Two Long Term Care Facilities, a retirement home and staff residences proposed – in the process of submitting an application.	Good conversations with the Schlegel Team – data provided as requested.	Included based on received information.
I	Infrastructure Ontario have recently sold land to the west	IO had no information on this site.	Excluded. (Not part of original ASP)

1.2.1 Site A

Site A is currently owned by Infrastructure Ontario (IO). The team met with IO and representatives indicated that there are no current plans for development at the site. As such the team has assumed that Site A would be developed after sites with current plans. The IO sites are included as Phases 7 – 10 in the phased analysis.

Should this Site be developed earlier they could still be included in the DES solution.

Site A is the assumed location for the Central Plant, given the potential land availability and the proximity to the trunk sewer in a currently undeveloped location.

1.2.2 Site B

Site B is currently understood to be owned by Oakville Enterprises Corporation (OEC). There are no known active planning applications or early engagements for this site. As such the team has assumed that Site B would be developed after sites with current plans. The sites are included as Phases 8 and 9 in the phased analysis.

Should this Site be developed earlier they could still be included in the DES solution.

1.2.3 Site C

Site C is the Oakville Green (OG) Site. The team had a productive meeting with the Site owners and identified the opportunities for energy services at the site.

Given the Timelines for OG and the proximity to the Hospital and Sewer connection, the OG Phase 1 site is assumed to be the DES Project Phase 2.

There are currently well-defined plans for OG Phase 1, and these are reflected in the site energy modelling. The remainder of the OG site (ASP areas 41, 42, 43 and 44 (less OG Phase 1)) is as of yet to be determined from a phasing and development standpoint. Assumptions have been made as to the remainder of the site.

1.2.4 Sites D & D*

This is a site adjacent to the ASP owned by Mattamy and Others. The team had a productive meeting with Mattamy representatives and determined that the low-rise portions for the development are already too far in development to be connected to this system and likely would not have been good candidates for connection due to the low density of the development (which can result in a high cost of connection compared to the business-as-usual/BAU). There are medium-density buildings proposed for the Mattamy sites, but these are also likely developing too quickly for inclusion in the initial DES opportunity (considering their distance from the initial site). Instead, these sites are potential candidates for connection at a later date. It is quite possible that these sites would feature some form of low-carbon energy source and may be available for future incorporation into the energy system, although details on the site are not currently available in sufficient detail to confirm this.

Sites D & D* are excluded from current energy modelling but connection in the future is safeguarded in the system sizing.

1.2.5 Site E & F

Sites E and F are the Hospital sites and the Hospital site's future development. The Hospital is currently determining a long term (30 year) development plan for the site and details are not yet available. The team conducted a fact-finding meeting with the Halton Healthcare and IO team including their Site operators EllisDon. As part of this meeting, the following was established:

- The Hospital central plant is sized for the full future site development,
- The Hospital operates a hot and chilled water HVAC distribution system with temperatures suitable for a district energy project.
- The Hospital is open to exploring potential decarbonization means for the site.
- The Hospital would need to have guaranteed supply at all times as a healthcare facility – meaning that there is limited opportunity for the DES system to leverage existing hospital equipment.

As an existing system, the Hospital was considered as a good candidate for a Phase 1 project.

1.2.6 Site G

Attempts were made to contact the Seniors Centre at Site G. This was unsuccessful, so this site is excluded at this time.

1.2.7 Site H

The team met with representatives for the Schlegel Site and has a very productive discussion regarding their development. The Schlegel team provided indicative phasing and floor areas for the site. The Schlegel team also indicated that they will be developing the site to a high energy standard (not a code SB-10 building) and indicated a willingness to share site load information once it is available, although this information could not be shared in time for this technical feasibility for the site.

The following was confirmed through discussion:

1. The Phase 1 building will progress before a DES system is developed. There may be a potential to connect this site later but that would be a negotiation with the DES developer.
2. Schlegel are considering geo-exchange and in-building heat pumps for parts of the site.
3. Phases 1 - 3 of the Schlegel site will have similar resiliency requirements as the healthcare facility.

Phase 1 of Schlegel is excluded from current energy modelling but connection in the future is safeguarded in the system sizing.

1.2.8 Site I

The team engaged with IO regarding this site, IO confirmed that this site was recently sold but has no further information. This site was excluded from further consideration.

2 DEMAND ASSESSMENT

2.1 Demands

The original Energy Demand Intensity (EDI) values from the pre-feasibility study for the aggregated loads of the Hospital District are shown in Table 11. These loads incorporated residential, employment, and institutional buildings.

Oakville does not have green development standards, so the assumptions used in the original study will be used here unless otherwise advised by **developers of specific sites or by the Town.**

Based on available information at this stage, the following assumptions have been made for the energy demand intensity at the new developments (not including Schlegel).

Table 11: Energy Demand Intensity (EDI) values for aggregated Hospital District New Developments (excluding Schlegel)

OBC SB-10	**EDI [kWh/m2]**		
Use Type	**Residential**	**Office**	**Retail**
Heating	77	82	75
Cooling	30	35	31
DHW	40	12	3.2

Table 12: Schlegel EDI Assumptions

Higher Performance		
Heating	30.9	kWh/m2
Cooling	45	kWh/m2
DHW	30	kWh/m2

The approach taken in the feasibility study is as follows:

> Loads for heating, cooling, and domestic hot water (DHW) were approximated by applying a scaling factor for the projected floor areas to building profiles for typical new buildings of the corresponding use types in Ontario.

The energy demands for the site were considered on aggregate. A summary of the peak and annual demands is shown in. These loads and demands are being updated.

Demands for the Hospital in the Tables below are based on actual metered data for the Hospital Site.

Table 13: Peak Block Loads for the Hospital District

Parcel / Building ID	DHW [MW]	Heating [MW]	DHW + Heating [MW]	Cooling [MW]
Hospital	10.6	12.2	14.1	13.4
Schlegel - Phase 1	0.4	1.5	1.8	1.5
Schlegel - Phase 2	0.3	1.4	1.6	1.3
Schlegel - Phase 3	0.4	1.6	1.9	1.5
Schlegel - Phase 4	0.1	0.6	0.7	0.6
Schlegel - Phase 5	0.1	0.6	0.7	2.3
Parcel 21	0.2	2.8	2.9	0.6
Parcel 22	0.2	2.7	2.8	0.5
Parcel 23	0.2	3.1	3.2	0.6
Parcel 24	0.2	2.2	2.3	0.5
Parcel 25	0.1	2.0	2.1	0.4
Parcel 26	0.2	2.7	2.8	0.5
Parcel 27	0.2	2.5	2.6	0.5
Parcel 31	0.2	2.0	2.1	0.5
Parcel 32	0.2	2	2.3	0.4
Parcel 33	0.2	1.7	1.8	0.4
Parcel 34	0.1	1.6	1.7	0.3
Parcel 35	0.1	2.0	2.1	0.4
Parcel 36	0.1	1.6	1.6	0.3
Parcel 41	0.4	5.8	6.1	1.1
Parcel 42	0.7	9.4	9.9	2.3
Parcel 43	0.3	4.7	4.9	0.9
Parcel 44 Remaining	0.567	9.055	9.34	1.799
Oakville Green - Building A	0.5	3.6	3.9	*0.9*
Oakville Green - Building B	0.1	3.8	3.8	0.8
Oakville Green - Building C	0.1	1.9	1.9	0.4
Oakville Green - Building D	0.2	1.4	1.6	0.4

Table 14: Annual Block Energy Demands Per Parcel

PARCEL / BUILDING ID	DHW [MWH]	HEATING [MWH]	COOLING [MWH]
HOSPITAL	8,068	33,912	27,877
SCHLEGEL - PHASE 1	1,110	1,143	1,665
SCHLEGEL - PHASE 2	990	1,020	1,485
SCHLEGEL - PHASE 3	1,140	1,174	1,710
SCHLEGEL - PHASE 4	420	433	630
SCHLEGEL - PHASE 5	420	432	630
PARCEL 21	613	2113	872
PARCEL 22	582	2006	828
PARCEL 23	669	2306	951
PARCEL 24	595	2053	847
PARCEL 25	433	1492	616
PARCEL 26	582	2008	828
PARCEL 27	540	1862	768
PARCEL 31	525	1812	747
PARCEL 32	486	1674	691
PARCEL 33	457	1575	650
PARCEL 34	353	1218	502
PARCEL 35	440	1518	626
PARCEL 36	343	1184	488
PARCEL 41	1,272	4,386	1,809
PARCEL 42	2,405	8,295	3,422
PARCEL 43	1,023	3,526	1,455
PARCEL 44 - REMAINING	1,706	6,797	2,830
OAKVILLE GREEN - BUILDING A	1,375	2,646	1,031
OAKVILLE GREEN - BUILDING B	395	2698	1152
OAKVILLE GREEN - BUILDING C	200	1367	583
OAKVILLE GREEN - BUILDING D	548	1054	411

Note in both tables above the action of in-building HVAC systems has not been considered (i.e. additional efficiencies have not been applied). This is applied in the energy supply section.

2.2 GHG Emissions

The approximate GHG emissions associated with the BAU were as follows: 9,636 tonnes for a total emissions intensity of 121.4 kg CO_2 / MWh.

This assessment will be revisited and the GHG emissions will be based on the following emissions factors:

- Natural gas emissions intensity: 189.9 kg CO2e/m3
- Grid electricity emissions intensity: 50 kg CO2e/MWh

The emissions factors are from the Ontario Building Code SB-10 (2017), Division 3 documentation. The results represent the energy consumption and emissions for the thermal system only.

2.3 Building HVAC Assumption

The GHG emissions and economics for the pre-feasibility were based on a building HVAC system which comprised the following:

- Heating: Natural gas boilers connected to building condenser loop with in-suite heat pumps
- Cooling: Rooftop Fluid Coolers connected to building condenser loop and in-suite heat pumps
- Domestic Hot Water: Natural Gas Boilers.

As part of the feasibility study and engagement with developers of the actual buildings – business-as-usual HVAC systems were assessed. Zonal or in-suite heat pumps are assumed as the preferred Building HVAC solution although it is noted that mechanical design for these buildings may vary as the site develops.

3 GEO-EXCHANGE POTENTIAL

3.1 Geo-Exchange Description

A geo-exchange or geothermal system uses the ground as a heat source to provide heating or a heat sink (heat storage) to provide cooling. The ground stays at moderate temperatures year-round, so it is able to meet heating and cooling needs in combination with a heat pump. Heat transfer with the ground occurs through a system of pipes with a circulating fluid. In a vertical geo-exchange system, numerous boreholes are drilled, and pipes installed within them to maximize the pipe surface area in the ground and therefore maximize the heat transfer potential.

Geo-Exchange Definitions

Heating: The space in the building is heated by extracting heat from the ground (borefield) through heat exchangers and transferring it into the building system. The heat is then rejected into the building space through coils or heat pumps. As a result, the ground (borefield) temperature trends down over the course of the heating season.

Cooling: The space in the building is cooled by extracting heat from the building through coils or heat pumps and transferring it to the building system. The heat is then transferred through a heat exchanger into the ground (borefield). As a result, the ground (borefield) temperature trends up over the course of the cooling season.

Heat of Compression: The heat of compression is the heat that is generated by the electrical component operation of the heat pumps (including the compressor and the fan). When the heat pump is in heating mode, the heat of compression (the additional heat) becomes part of the heat delivered to the space, reducing the amount of heat generation required from the system. When the heat pump is in cooling mode, the additional heat is added to the already existing heat rejection load due to cooling the space, increasing the amount of cooling required by the system.

Causes of Imbalance

Heating Dominance: The heating energy extracted from the ground is greater than the heat energy rejected into the ground during cooling.

Cooling Dominance: The heating energy rejected to the ground during cooling is greater than the heating energy extracted from the ground.

Figure A: Imbalanced borefield due to heating dominance

Figure B: Imbalanced borefield due to cooling dominance

The impact of imbalance can be a net increase (cooling dominant scenario) or decrease (heating dominant scenario) of the ground temperature over time. This can lead to negative impacts to system efficiency and in extreme cases can result in geo-exchange systems becoming non-operational.

This is why it is important to monitor system balance year on year and make adjustments to set points as necessary. Typically, these adjustments occur in the first 1 – 3 years of operation after which time the operators have the system fine-tuned.

Because balance is required, additional heat rejection and injection sources are often necessary.

3.2 Geo-Exchange Potential at the Hospital District Site

The values below are based on a nearby test hole drilled to 640 ft. A borehole depth of 850 ft is also common in Ontario and is likely an option at the Hospital District Site. The greater depth allows for fewer boreholes and greater efficiency in drilling equipment mobilization. The thermal properties presented for the site can be considered applicable for the 850 ft boreholes as well. It is recommended that prior to the first project commencing at the site, a site-specific test hole be drilled to 850 ft in order to confirm assumptions and uncover potential underground construction challenges. It is recommended that this borehole be used both as a test hole and a production hole (i.e., an operational part of the borefield).

The parameters below are favourable for a geo-exchange system at the site, the low overburden will reduce overall capital costs and improve efficiency for the site. There are many other sites in the GTHA moving forward with less favourable thermal properties.

Additionally, the North Oak project in Oakville (close to the hospital site) demonstrates the technical, environmental, and economic feasibility of site-level geo-exchange approaches.

An overview of the site and the proposed density indicates that there is ample room for geo-exchange boreholes to supply the majority of the heating and cooling for the site.

Table 15:Geo-exchange Borefield Assumptions

Property	Assumption
Undisturbed Ground Temperature	10.2 – 12.1 °C
System Fluid	Basis of design will be 25 % Propylene Glycol. Alternative approaches such as 20 % ethanol also acceptable.
Ground Thermal Conductivity	2.55 W/mK
Ground Thermal Diffusivity	0.104 m2/day
Grout Thermal Conductivity	2.08 W/mK *
Borehole Thermal Resistance	0.101 mK/W

For the purposes of this detailed feasibility assessment the following assumptions will be made when modelling the borefield:

- 4” borehole diameter
- 1.5” circuit piping diameter
- Pipe material will be HDPE 4710 DR11 for all circuit piping with DR 13 used for lateral runouts.
- A minimum borehole spacing of 6 m will be maintained.
- Approximately 20 m of overburden is assumed at the site (based on drilling records).
- An operational temperature range of -1 °C – 32 1 °C entering water temperature to heat pumps.

Using all of the inputs outlined here and the indicative building energy profile, the geo-exchange system will be modelled using the Ground Loop Design (GLD) software. The borefield will be sized to maintain system temperatures within the range outlined above.

3.3 Technical Description of the Proposed Borefield Design

A geo-exchange borefield comprises 3 main elements, the boreholes themselves, the runouts, and the manifold.

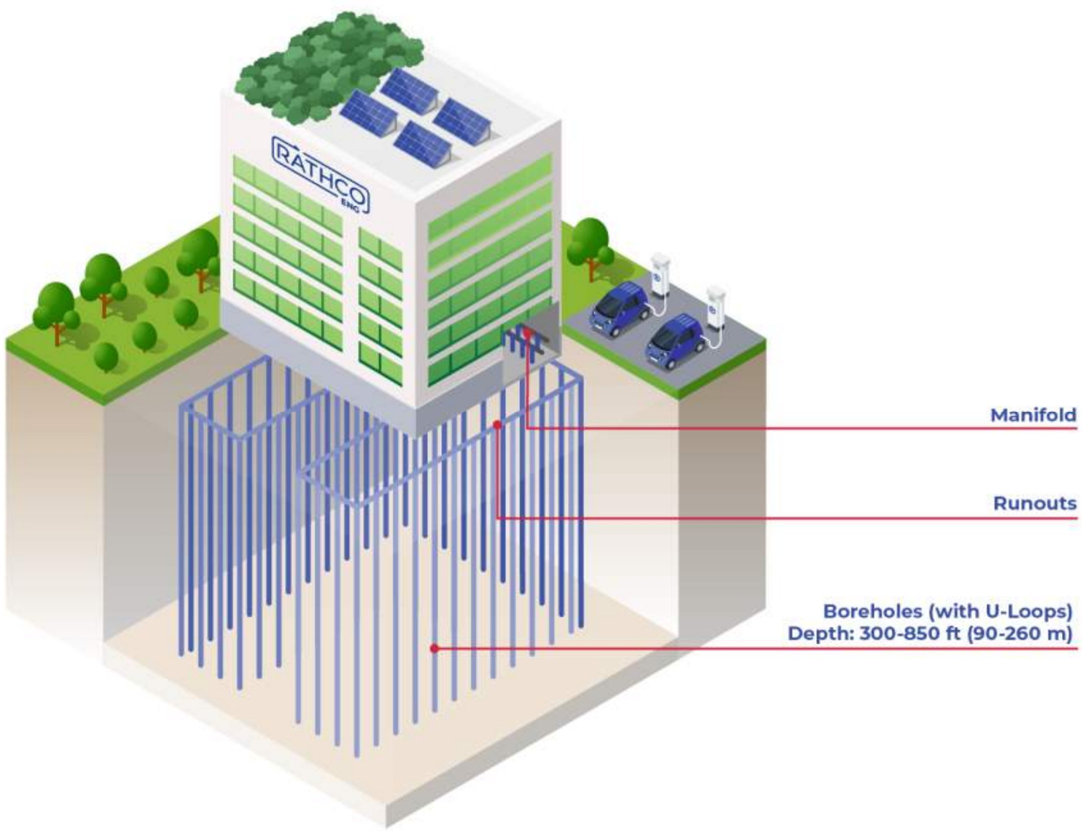

Figure 12: Borefield Infographic

The boreholes are drilled to depths of 600 – 850 ft, HDPE U loop piping in then installed the length of the borehole and then grouted in place.

Groups of 10 – 12 borehole U loops (or circuits) are then connected with headers referred to as runouts or laterals and meet at a common header (the manifold).

Boreholes can be drilled, and runouts laid beneath new development buildings with manifolds located in the basement mechanical rooms of these buildings.

The images below show the construction details of boreholes as described in 3.2 above.

Figure 13 shows the borehole construction in plan view with the corresponding section view shown in Figure 14. Figure 15 shows the typical header design for the runouts and Figure 16 shows a typical mechanical room detail for a geo-exchange system, including the Geo-exchange manifold.

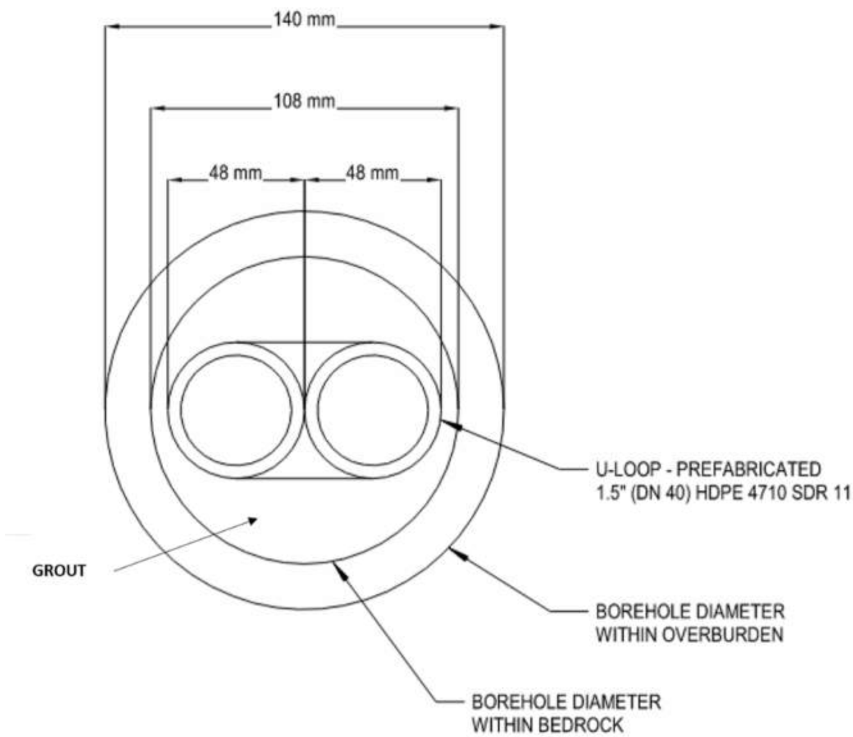

Figure 13: Borehole Construction Plan View

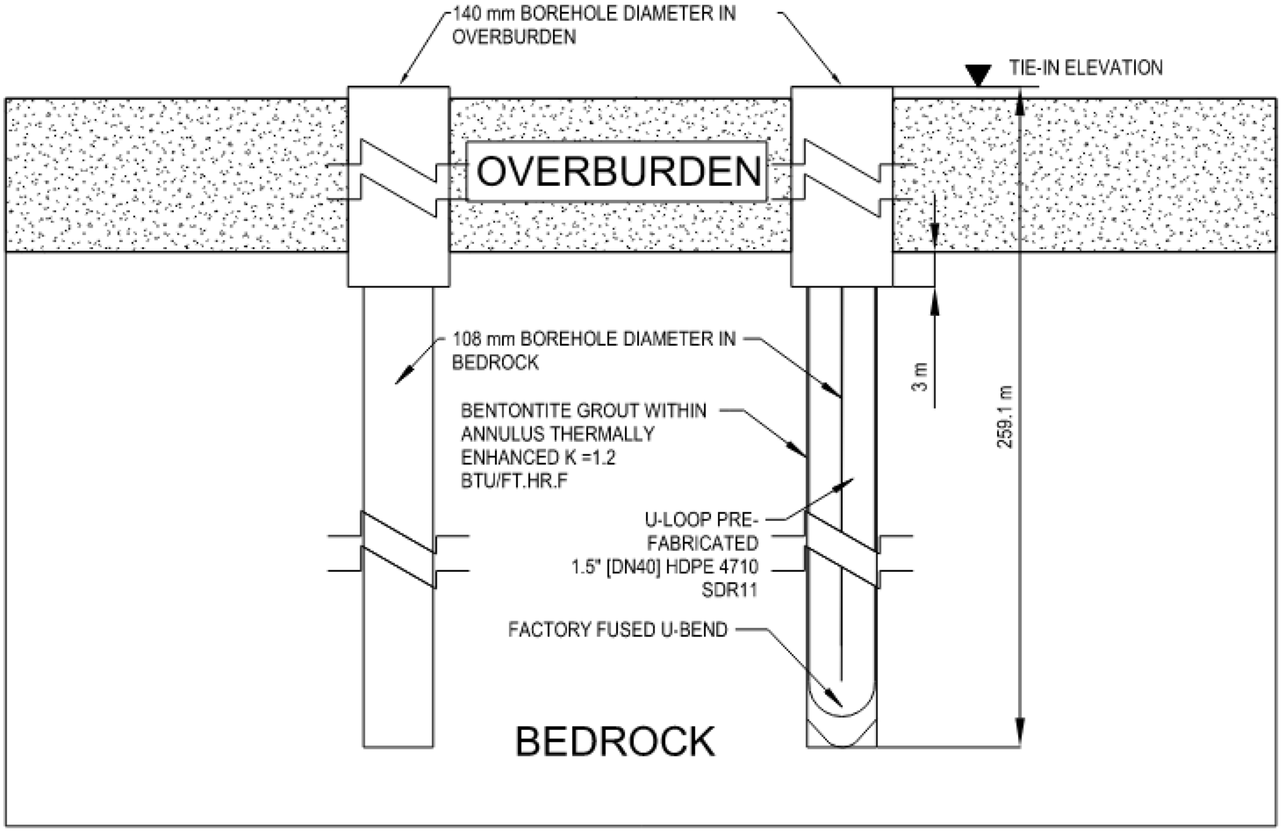

Figure 14: Borehole Construction Section View

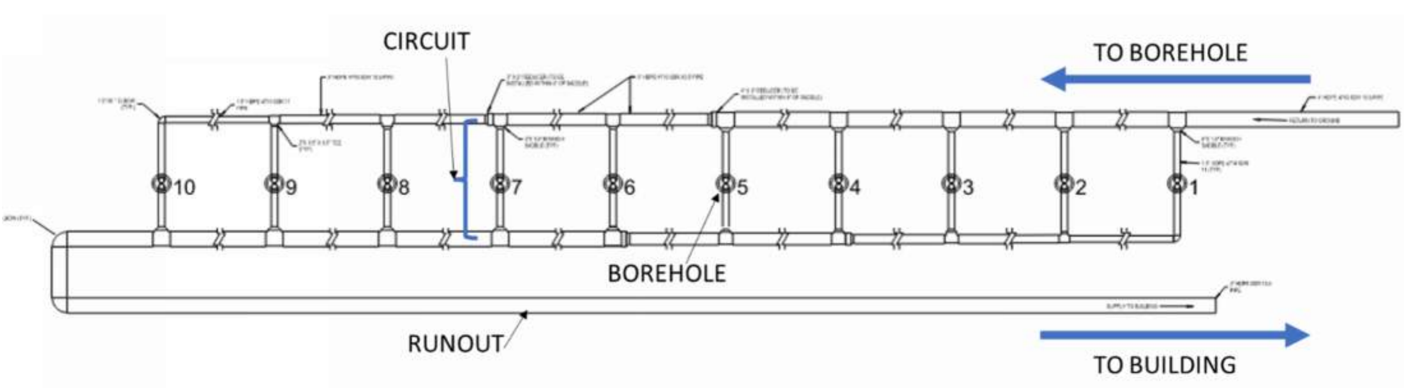

Figure 15: Header Piping (10 Circuits)

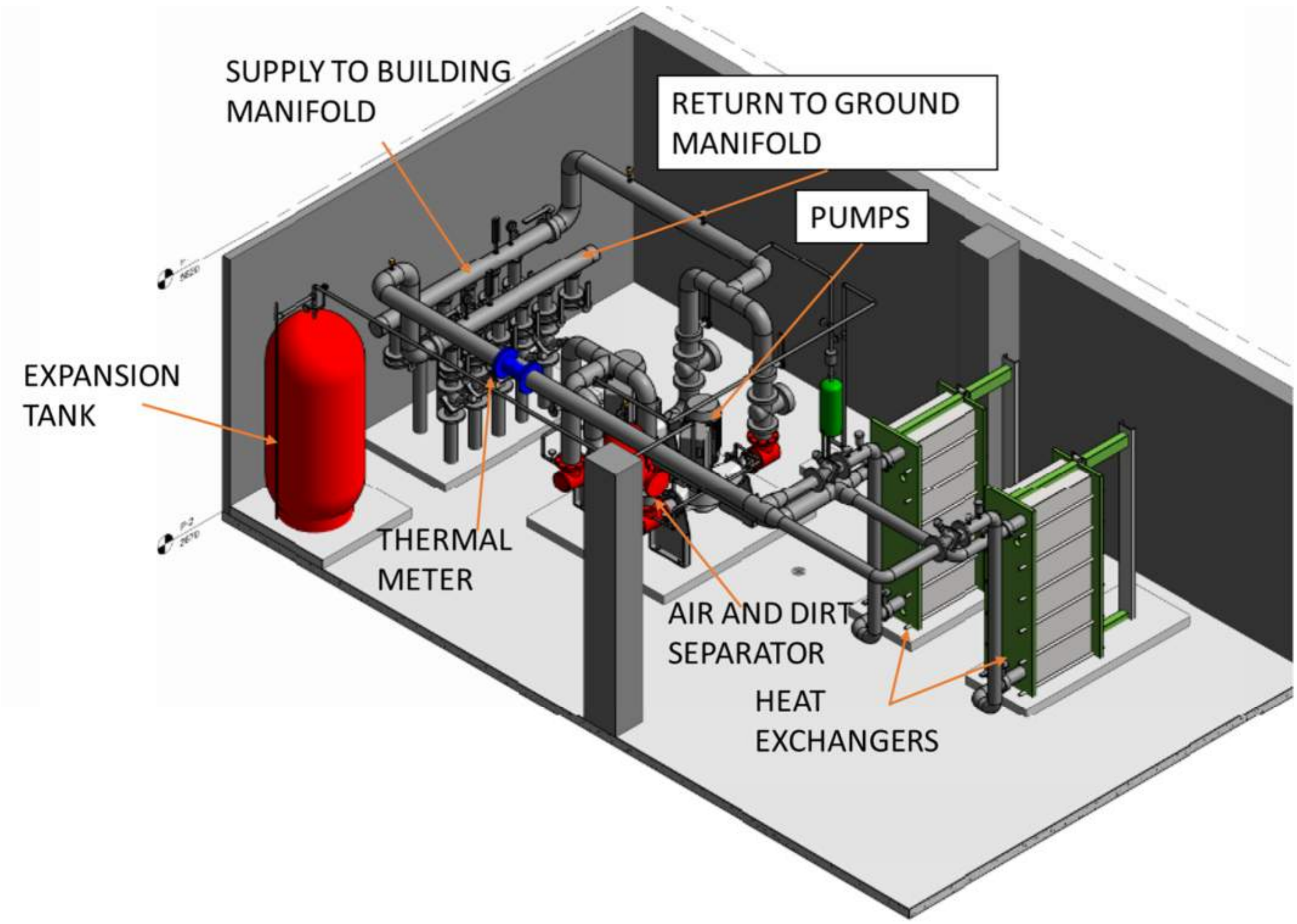

Figure 16: Typical Geo-Mechanical Room

4 SEWER ENERGY EXCHANGE POTENTIAL

4.1 Sewer Energy Exchange Description

Sewer energy exchange uses sewage flow as the heat source or heat sink (heat storage) in combination with a heat pump system to provide heating and cooling. Infrastructure is installed in sewer lines to direct sewage flow through a heat exchanger. In heating mode, the solids are temporarily separated allowing the 'clean water to flow through a wastewater holding tank where the heat is drawn into the heating system through the heat exchanger. In cooling mode, heat is rejected from the cooling system to the sewage through the heat exchanger. Heat pumps are then used to heat or cool the system to the appropriate temperatures. There is no net flow of sewage into the building or district energy distribution network.

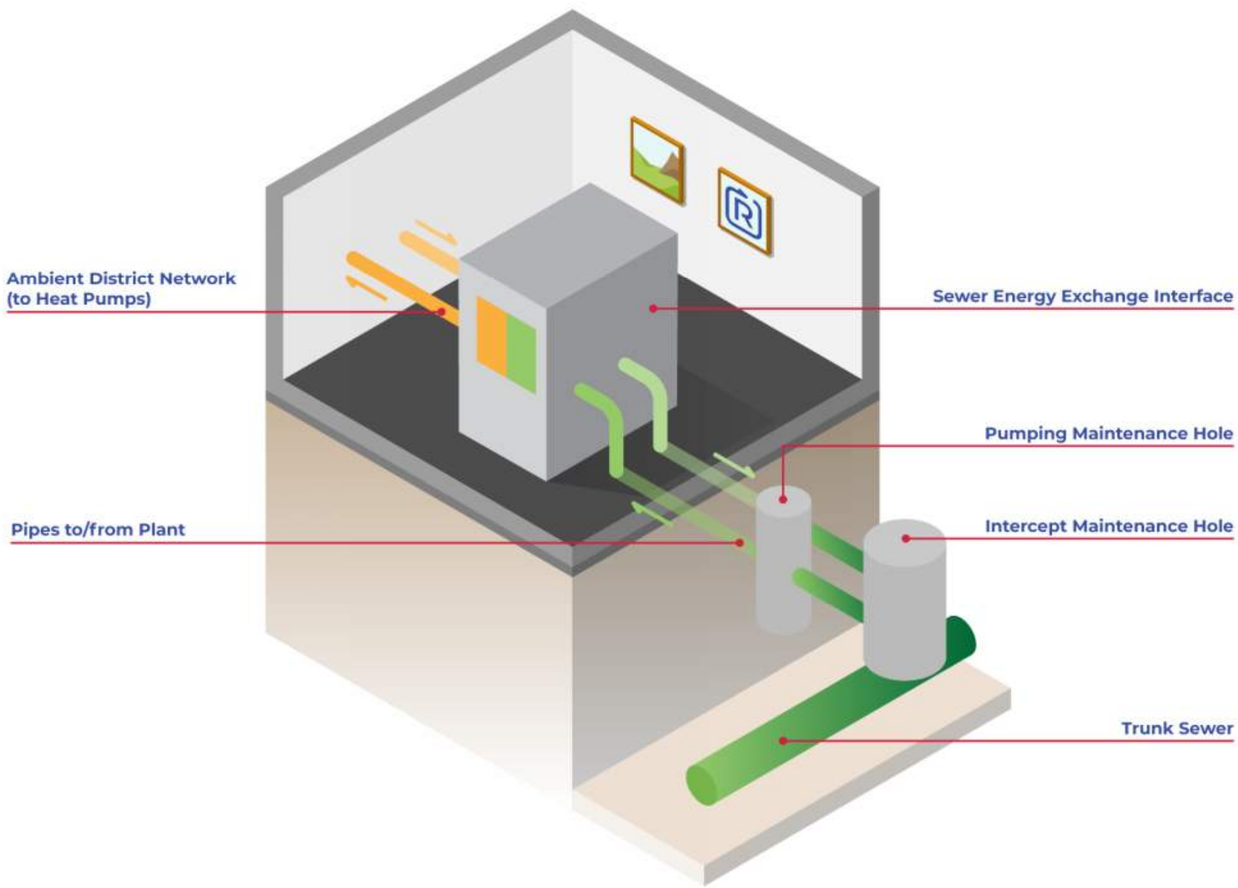

Figure 17: Sewer Energy Exchange Infographic

4.2 Sewer Energy Exchange Potential at the Hospital District

Rathco has engaged with the Region of Halton to gather site-specific information for the sewer energy capacity at the Hospital District site.

The Region has provided flow and temperature data for 3 monitoring sites upstream and 3 sites downstream of the proposed Hospital District connection point.

The information for these sites was provided on an hourly basis for the 2019 – 2023 period.

Figure 18 below shows the hourly flow-weighted average temperature at the proposed connection site.

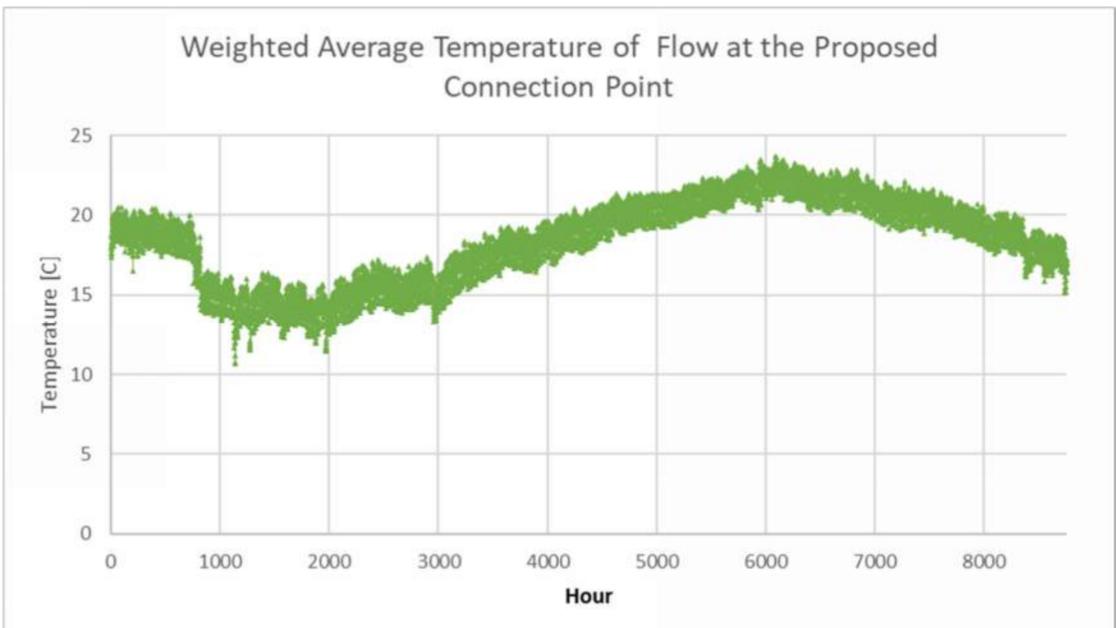

Figure 18: Weighted Average 2022 Temperature Upstream of Proposed Connection Point

The Combined 3 sites in Milton account for the total flow seen at the site of the proposed connection. Figure 19 below shows the weighted average flow at the proposed Hospital District connection point.

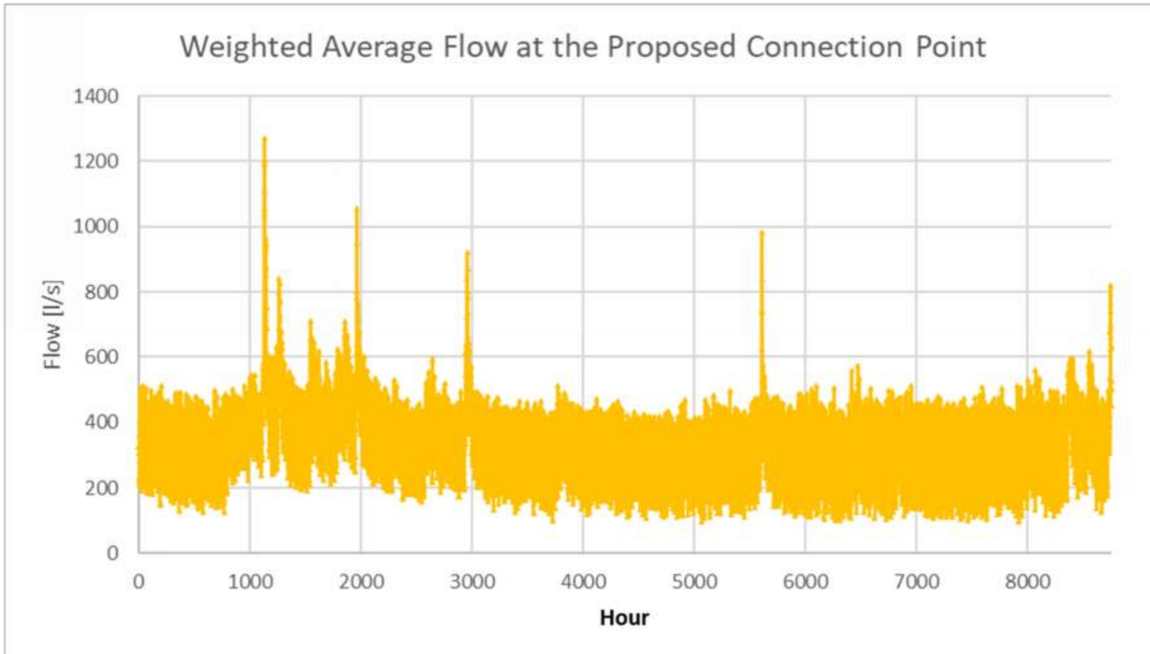

Figure 19: Weighted Average Flow at the Proposed Connection Point

A series of analyses were completed to determine the hourly heat rejection (cooling) and extraction (heating) possible from the sewer. The results for the analysis were conducted at an assumed heating temperature differential (the difference in temperature in the sewer before heat exchange vs after heat exchange) of 8 C and cooling differential of 10 C. This analysis was also conducted at a series of other temperature differentials (dT) to determine the potential operational range of the sewer.

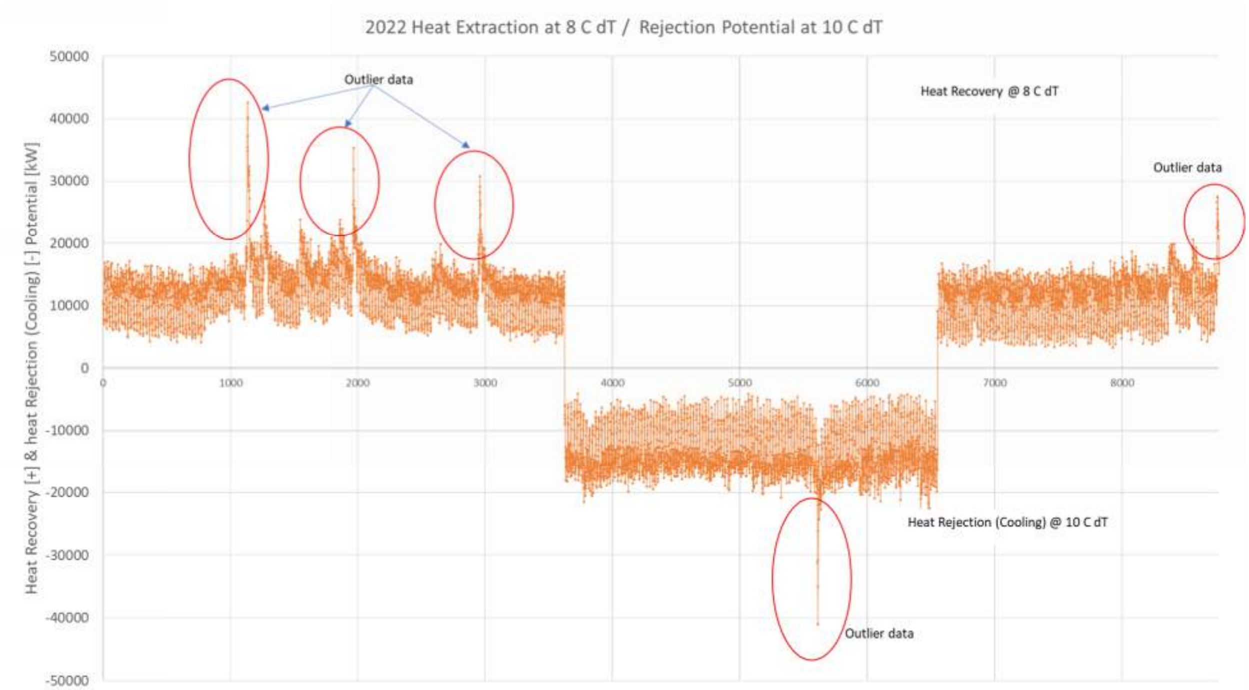

Figure 20: Assessed Heat Extraction / Rejection Capacity on an Hourly Basis

	Capacity [MW]					
	Cooling DT [C]			Heating DT [C]		
	5	7	10	5	8	10
All year – min	2.1	2.9	4.1	2.1	3.3	4.1
All year – average	7.5	10.4	14.9	7.6	12.1	15.1
All year – max	34.3	48.0	68.6	29.6	47.3	68.6
Summer/ Winter – min	2.1	2.9	4.1	2.1	3.3	4.1
Summer/Winter – average	7.5	10.4	14.9	7.6	12.1	15.2
Summer/ Winter – max	34.3	48.0	68.6	29.6	47.3	59.2

Figure 21: Heating and Cooling Analysis at Varying dTs

The average capacity available from the sewer in heating mode is 12.1 MW_{th}. The average capacity available from the sewer in cooling (heat rejection) mode is 14.9 $MW_{th.}$

The minimum capacity available from the sewer in heating mode is 3.3 MW_{th}. The minimum capacity available from the sewer in cooling (heat rejection) mode is 4.1 $MW_{th.}$

The numbers will vary somewhat once the annual energy demands of the site are applied to them.

When comparing this analysis to the original prefeasibility study the capacity assumed for the sewer energy exchange equipment was 4.4 $MW_{th.}$

This confirms that the assumptions in the original assessment were appropriate and in line with the lower end of the potential capacity for the site.

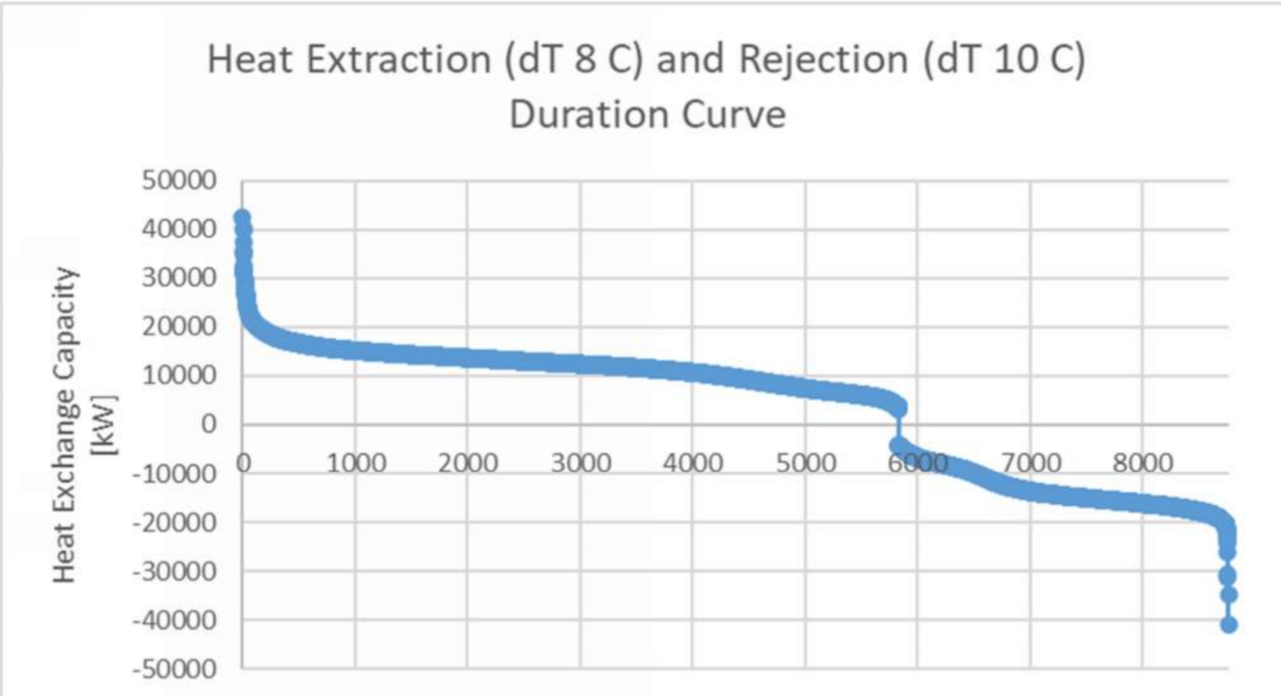

Figure 22: Hourly Duration Curve for Heat Exchange

The annual heating demand is approximately 69,000 MWh with peak cooling of 27,825 MWh. Based on Figure 22 above, the sewer energy exchange alone could contribute over 50% of the annual heating and cooling demands of the site.

As part of the next phase of the project, the 3 downstream sites will be assessed in a similar way once the ambient loop operation is modelled to evaluate the potential impact on temperatures to the mid-Halton wastewater treatment plant.

Based on other similar projects completed by the team, the impact to the treatment plant downstream is expected to be tempered by the additional flows to the wastewater treatment plant coming from the Oakville area which should help to ease any operational concerns for the plant.

4.3 Technical Description of Solution

The schematic below outlines a potential approach to the interconnection of the sewer system and the energy exchange with the Hospital District. An item of note here is that only energy is exchanged via heat exchangers with the site, there is no net change in sewer flow downstream of the connection point resulting from the interconnection. This piece of work is also separate from the site's sanitary sewer connection.

Wastewater from the Region's sewer will flow via a gravity main to the pumping chamber. From here the wastewater will be pumped via a forcemain through a fully hydronically separated heat exchanger. After this point, the wastewater will continue through the forcemain circuit back to a secondary manhole located within the property line of the Energy utility. From here the wastewater will return to the existing sewer. The sewer line will experience no net change in flow downstream of this manhole compared to upstream of the manhole.

Additional information has been requested from the region to inform the development of this concept.

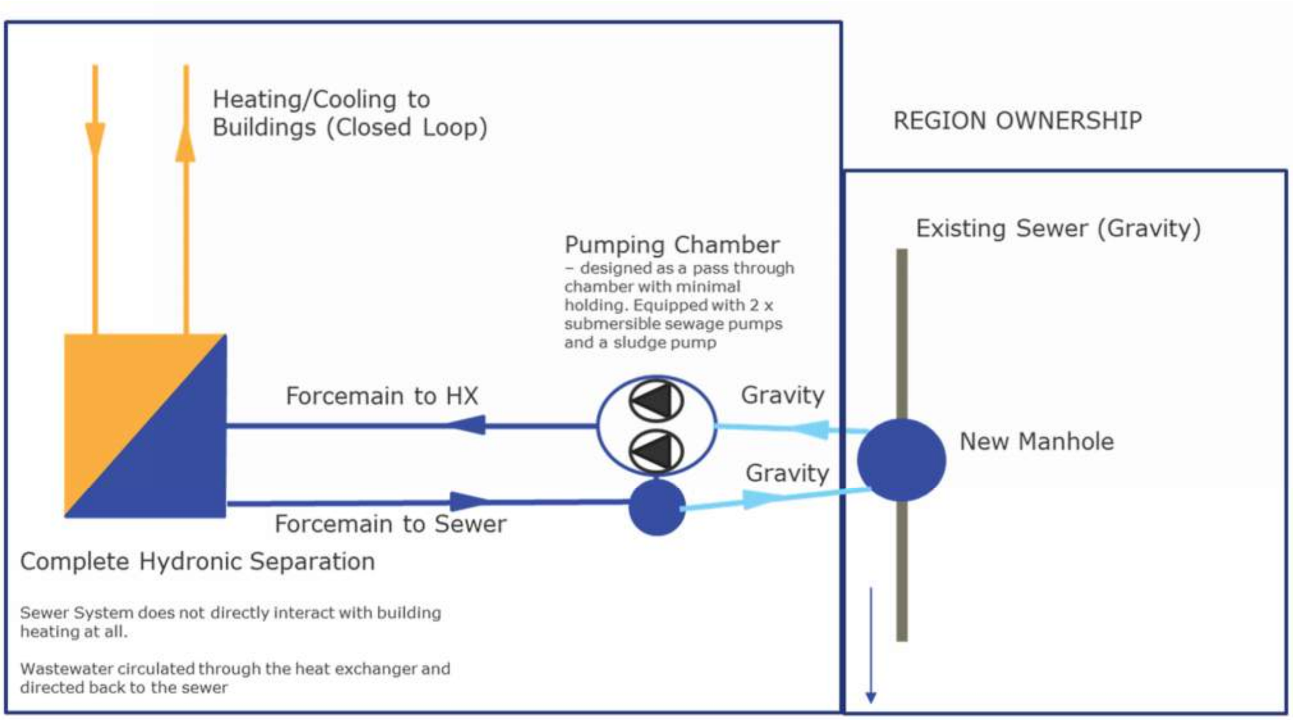

Figure 23: Sewer Connection Interface

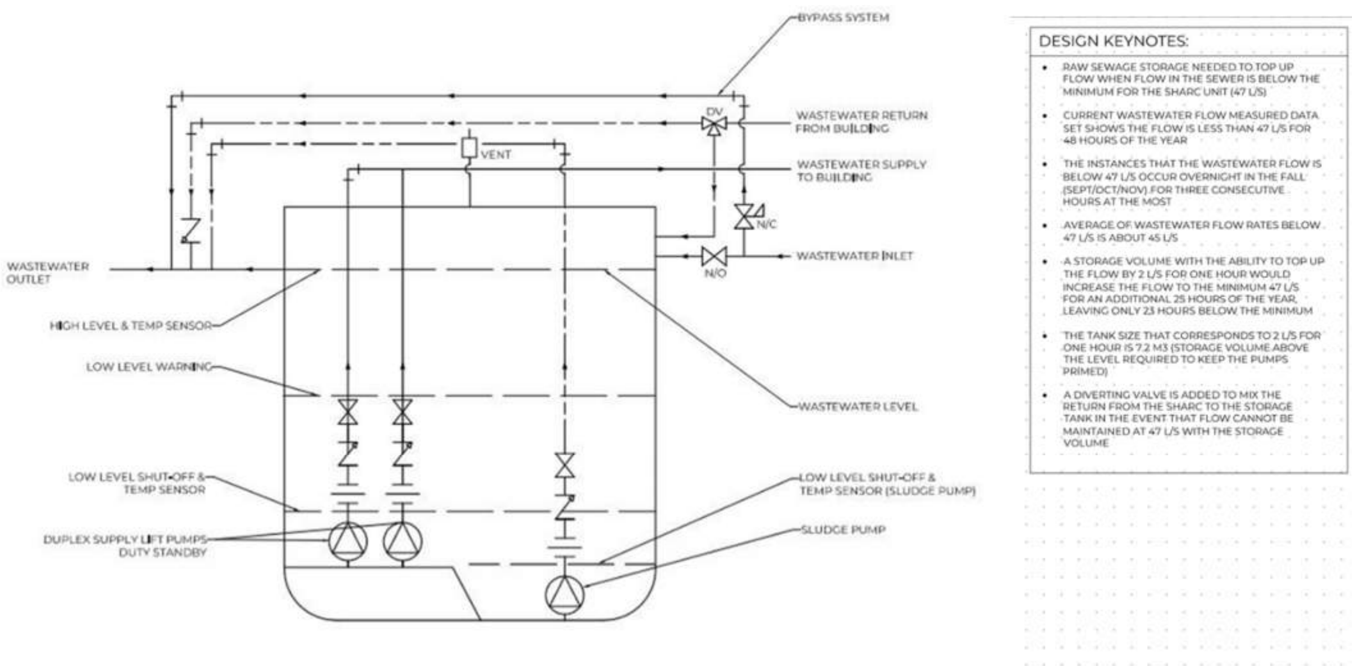

Figure 24: Pumping Tank Schematic

The pumping tank schematic above outlines the proposed pumping manhole arrangement which will be part of the Energy Utility System. There will be an integrated sludge pump in the system for maintenance reasons.

5 PROJECT DESCRIPTION

The recommended concept at the hospital site from the Pre-Feasibility Study was the **hybrid geothermal** and **sewer energy exchange ambient district energy system**. In the pre-feasibility findings, the geo-exchange only system had comparable outcomes to the recommended concept (sewer energy + geo-exchange). In addition, a domestic hot water (DHW) district energy system should be implemented to reduce the space and operating requirements for customers. The DHW system used natural gas boilers for heating and had the potential to use the waste heat in the summer months to pre-heat the incoming cold water at each building.

This hybrid concept offered an IRR of about 14% under 2021 carbon tax assumptions). It was not highly sensitive to carbon policy as it predominantly relied upon renewable resources. This concept would also allow the future Hospital District to reduce Greenhouse Gas (GHG) emissions by about 62% over the baseline business-as-usual scenario. These economic results changed between the Pre-Feasibility Study and this Detailed Feasibility Study. Consideration was given to the impact of the Investment Tax Credit on the project economics.

The hybrid combination of geothermal and sewer energy exchange was the most promising concept as the two technologies provide a resilient low carbon energy source (heating) and sink (cooling). The technologies are well suited for each other as the sewer can be used to balance the geothermal borefields instead of running external equipment like boilers or fluid coolers. The hybrid concept offers the added benefit of resiliency and borefield balancing with the addition of the sewer energy exchange component.

The hybrid geothermal and sewer energy exchange concept is shown in Figure 25. Fluid coolers are shown for reference in the event that cooling peaking equipment is required but have not been included in the analysis.

Like buildings and homes utilizing natural gas, the DES will be developed with N+1 redundancy. This system will follow the same energy and fuel standards as seen in individual building natural gas connections. No additional NG connection to buildings is required.

The building on the left represents a customer building that houses a distributed central plant, geothermal borefield, and energy transfer station. The energy transfer stations are indicated by heat exchangers (HX) in the diagram and are the point at which the energy from the district energy system is exchanged with the individual buildings. The central plant equipment, geothermal equipment, and energy transfer station are likely located below grade, with the potential for rooftop space also being required in the event that cooling peaking equipment is needed. The remainder of the building is customer space.

The building on the right represents a customer building that only houses a geothermal borefield and energy transfer station. This equipment would be located on the lower levels, with the remainder of the building remaining as customer space.

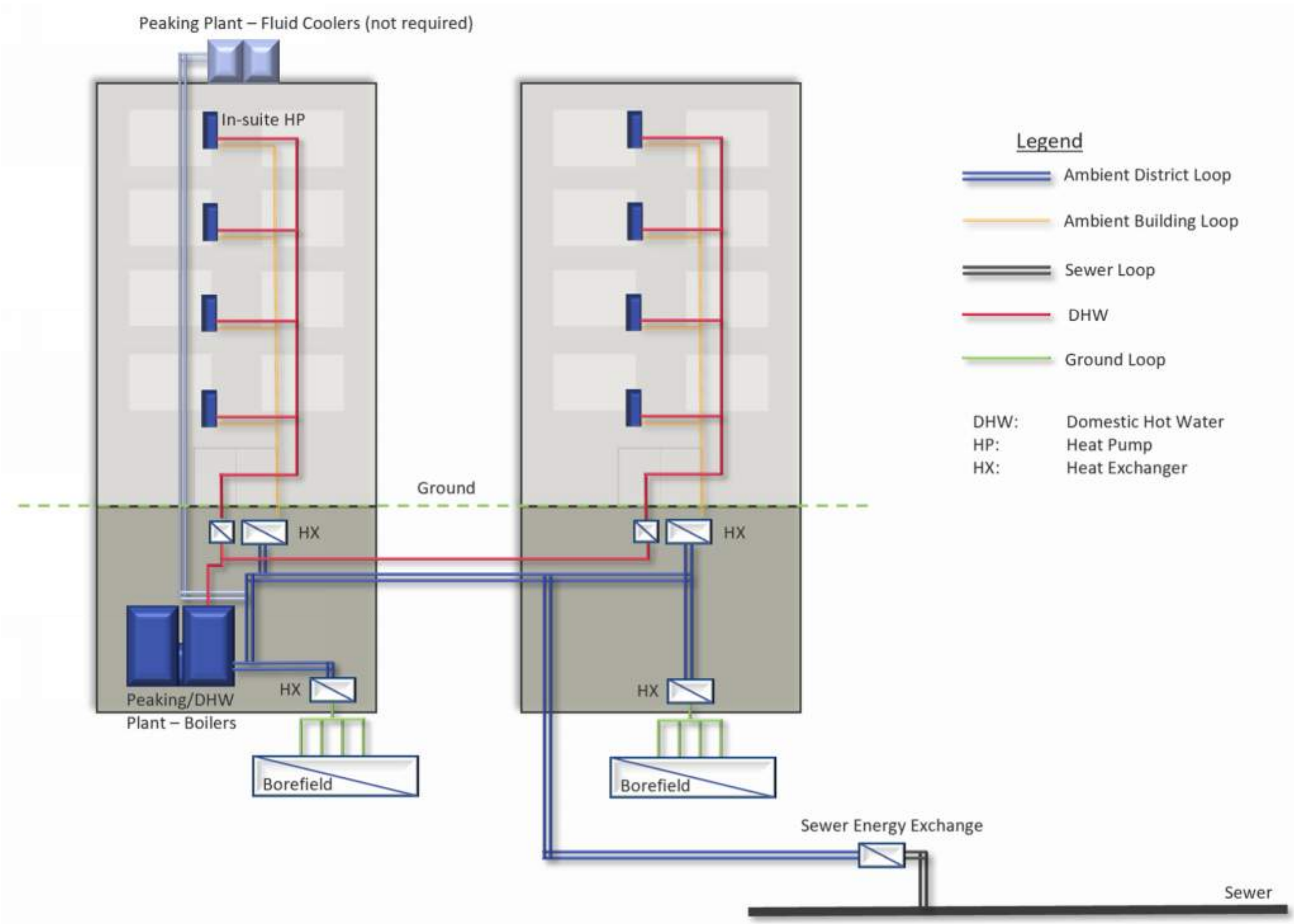

Figure 25: Hospital site hybrid geothermal and sewer energy exchange concept diagram.

The original concept considered the addition of a domestic hot water district energy system for the site. The basis of this was that a central heating plant would increase the overall capital, technical and environmental performance of domestic hot water provision by achieving high efficiencies. **In this feasibility study, the potential to decouple the DHW from natural gas boilers was assessed.**

This concept involved a number of different distributed plants across the site and was based on a high-level understanding of development plans based on the ASP. **In this study engagement with developers to determine phasing and demand information is being pursued to provide greater detail as to the technical feasibility of this approach.**

While this concept is still the basis of design for this detailed feasibility assessment, the optimizations highlighted above such as removing the DHW loop to further reduce emissions are being pursued.

5.1 Ambient Loop Technical Details

5.1.1 Fluid Type and Chemical Composition

The fluid distributed through the closed-loop piping system is water at varying temperatures. As this is a closed-loop system the water circulating through the pipe loop never leaves the closed system, i.e., is not distributed to end-use customers. The water is strictly used as a heat transfer medium.

5.1.2 Pipe Information

The ambient loop pipes will be a standard fused HDPE product commonly used in potable water applications. These pipes will be HDPE 4710 DR17 DN400 (16") diameter. These pipes will not be insulated and will be buried below the frost line.

For the DHW system either a pre-insulated steel (EN253) or pre-insulated Raised Temperature Polyethylene (PE-RT) HDPE pipe will be used.

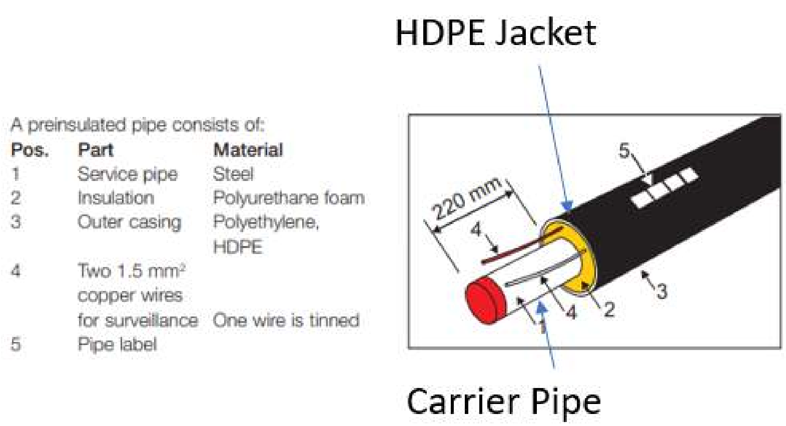

Figure 26: EN253 Piping Infographic (Courtesy of Logstor)

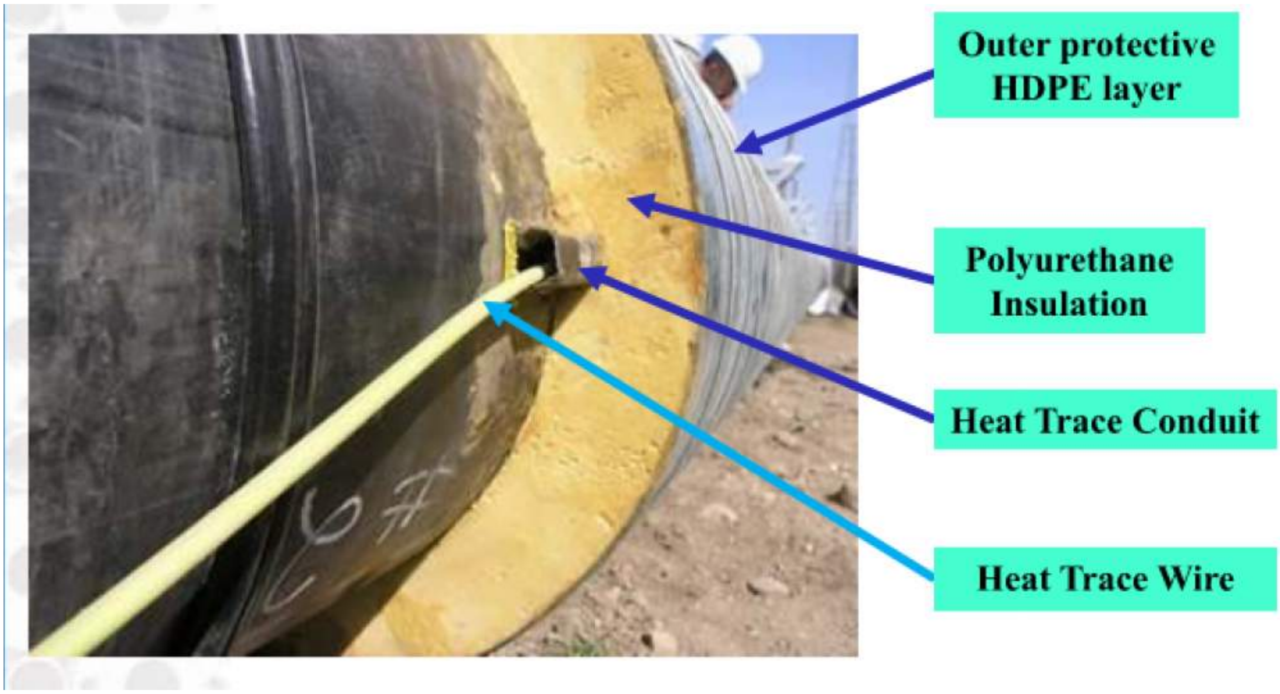

Figure 27: Pre-insulated PE-RT Infographic (courtesy of EMCO)

6 SUMMARY

6.1 Low Carbon Supply Assessment

The initial assumptions regarding low carbon supply opportunities in the pre-feasibility study were confirmed as accurate as part of this initial baseline assessment.

The timeline for development of the site was much clearer and though some developments have already progressed, the majority of the site is moving at a timeline suitable for the development of a district energy system.

MILESTONE 3

MODELLING AND DESIGN

1 INTRODUCTION

This Section outlines the work completed in Milestone 3 of the project to set the detailed technical analysis prior to the economic analysis in Milestone 4.Concept Overview

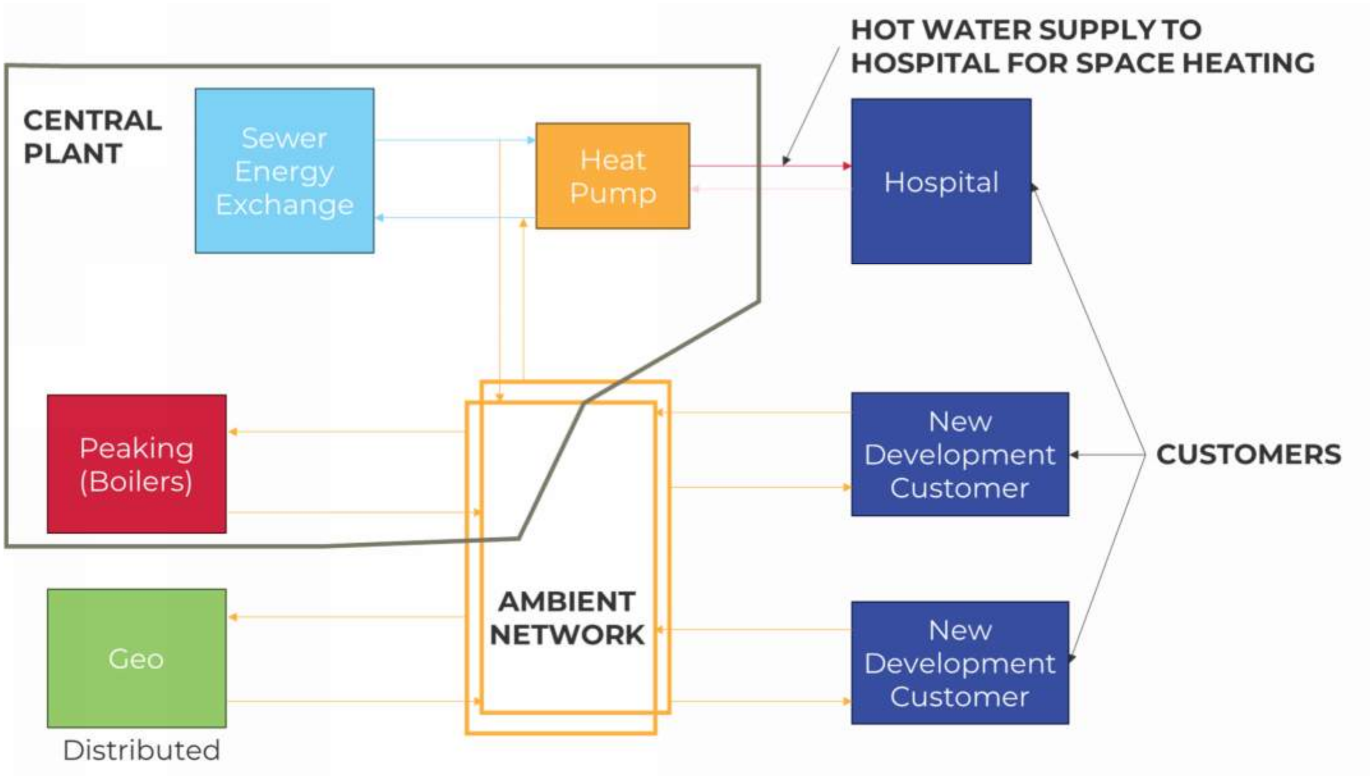

Figure 28: Conceptual Overview of the Proposed System at Full Build-Out

Based on the findings of the Baseline Memo the Rathco team has developed the system concept outlined above.

1.1 Phase 1

Phase 1 consists of a heat pump connected to the sewer energy exchange system supplying heating to the hospital building. The intent of this system is not to provide peak load to the hospital, but rather to offset the current utilization of baseload natural gas for heating and domestic hot water.

This Phase 1 project could also be considered a discrete opportunity in itself with the potential to act as the wedge project (a successful first project from which the broader opportunity could be realized) for district energy in this area.

Alternative supply points and sewer tapping locations could be considered.

Supply of cooling load to the hospital is not included as based on the available data, it is estimated that the efficiency of cooling supply from the sewer energy system could not improve upon existing infrastructure.

1.2 Phase 2 Onwards

Following the first project at the hospital, the next phase would be an ambient loop connection from the central plant to new development customers. At first, these connections will leverage excess capacity in the sewer energy exchange system for heating and cooling. As this capacity is spoken for, vertical borehole geo-exchange systems will be developed.

As the overall system is intended to be heating-dominant (more heating is needed annually than cooling) additional peak heating capacity will be added at the central plant.

For sites where development takes place in advance of the district energy system, there are opportunities for those developments to safeguard for future connection to the system. This could be either as offtake customers to replace fossil fuel-based peaking plants with low carbon energy from the ambient system or as energy sharing approaches where connections could also supply into the network. Options for the DES provider to purchase existing systems could also be considered. (for example, by the time of DES system development, Schlegel Phase 1 and the Mattamy site will likely already be built and operating).

As new geo-exchange systems are built out, the DES developer will need to engage with developments on a case-by-case basis to determine the design and location of distributed borefields.

The assumption in this feasibility study is that the borefields would be located beneath new buildings and integrated into the overall system design. Manifold rooms would be located at these buildings which would account for 30 – 50 m^2 of required space. No other space for generation equipment on site would be required other than the energy transfer station equipment estimated to require another 40m^2 (see Milestone 3, Section 5 for details).

1.3 Changes from the Pre-Feasibility Concept

This concept builds on the work from the pre-feasibility study by augmenting the previous concept. The following are the primary changes to the concept:

- A connection to the existing hospital building.
- The dedicated hot water loop is removed and instead the ambient network will provide domestic hot water to buildings via a water-to-water heat pump. This was flagged as a potential augmentation in the technical baseline memo and has been deemed the more cost-effective course of action here.

2 PHASING

The phasing proposed for the project is based on the findings of the stakeholder engagement undertaken described in Milestone 2 Section 1.2.

The phasing below shows Schlegel Phase 1 and 41C and 41D included in the system – this is shown this way to demonstrate that these connections are safeguarded for in the future despite the timing mismatch for the potential DES project.

Figure 29: Phasing Map

Table 16 below shows the Block Peak and Annual demands for the site phased over time. Only base loads for hospital space heating are carried. In addition, as described previously Schlegel Phase 1 and the 41 C and 41D buildings are not assumed connected to the network, but costs have been included in the system infrastructure planning to enable their future connection. Costs are not estimated for retrofit works for connection or for purchasing future site-based systems as it is not possible to estimate this at this time. The table below shows block loads and energy demands for the different phases, this does not include in-building equipment efficiencies or other considerations.

Table 16: Block Peak and Annual Demands

	Cumulative Peaks [MW]			Cumulative Totals [MWh]		
Phase	**DHW**	**Heating**	**Cooling**	**DHW**	**Heating**	**Cooling**
1		3.2			24,836	
2	0.7	7.6	2.0	2,517	7,766	3,177
3	1.0	8.4	2.7	3,507	8,785	4,662
4	1.7	17.2	5.2	6,353	16,756	9,202
5	2.2	22.5	6.6	7,796	20,715	11,287
6	3.0	28.5	8.8	10,621	29,442	15,338
7	4.0	41.5	10.8	13,714	40,107	19,737
8	4.4	47.4	11.6	15,037	44,671	21,620
9	5.1	57.4	13.2	17,247	52,290	24,763
10	5.6	62.5	14.2	18,511	56,649	26,561

2.1 Total Connected Floor Areas

The total connected floor areas are shown in Table 17 below. Note the Hospital (Phase 1) floor area is not shown as DES-connected as this building is not considered connected to the broader ambient loop DES network, though the energy transfer infrastructure is part of the DES system. Floor areas account for the sites deemed excluded above.

Table 17: Total Connected Floor Areas

Phase	GFA m2	Total GFA – DES m2
1	148,644	0
2	97,633	97,633
3	51,000	148,633
4	98,399	247,032
5	82,077	329,109
6	136,682	465,791
7	133,309	599,100
8	57,048	656,148
9	95,242	751,390
10	47,481	798,871

3 ENERGY SUPPLY

3.1 Energy Demand

An additional 10% has been carried out in this model to account for energy loss through the heating water distribution system to the Hospital, this is expressed in the documentation as a reduction in the energy sales to the Hospital. Note heat losses are close to negligible in the ambient system due to lower operating temperatures, particularly in winter.

3.2 Technical Description of Sewer Energy Exchange

To make this system work a gravity feed from the main sewer line to the energy transfer equipment is required. In general, this design case (of flow from a trunk sewer to energy exchange equipment) is not accounted for in Regional Design Guidelines, confirmed in our review of the Region of Halton design Guide Documents.

A pipe connection below the pipe spring line (at 5 o'clock in Figure 30) is recommended in order to maximize thermal offtake. A connection at the spring line could not access the thermal energy required for this project.

Further engagement with the Region is required in order to agree the design of the connection. In the development of this Technical Memo, the more cost-conservative method of including a manhole has been assumed.

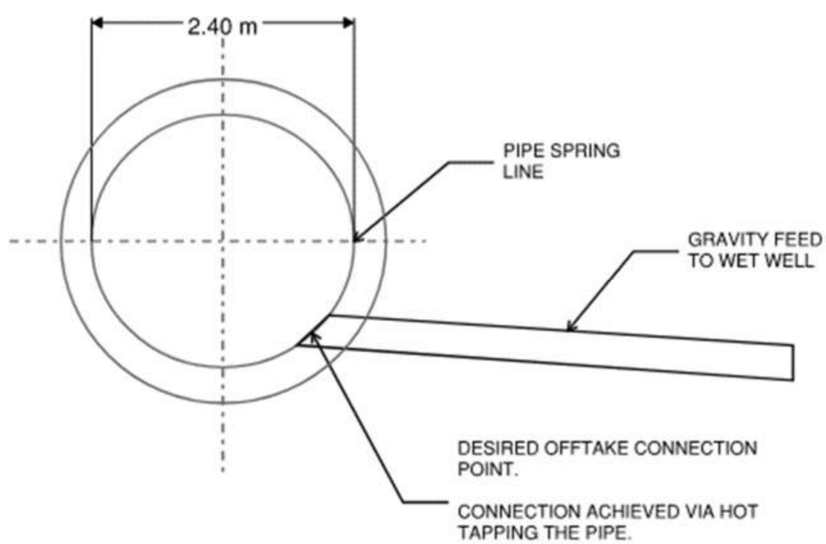

Figure 30: Sewer Offtake

This can either be achieved via a hot tap directly in the mainline of the pipe or could required the inclusion of a manhole depending on the Region's preference.

The gravity sewer average depths in this area are in the range of 8 – 10 m from grade to top of pipe. While this is deep, this system is accessible for energy exchange. The new Toronto Western Hospital system for example connects to a larger (3 m diameter in Toronto vs 2.4 m in Oakville), deeper (50 m deep in Toronto vs 10 m in

Oakville) sewer main than that proposed here and is already under construction. The proposed system at Oakville has approximately half the thermal capacity of the Toronto site and is in an area with less construction restrictions such as those experienced in Toronto with less traffic, public transit utilities etc.

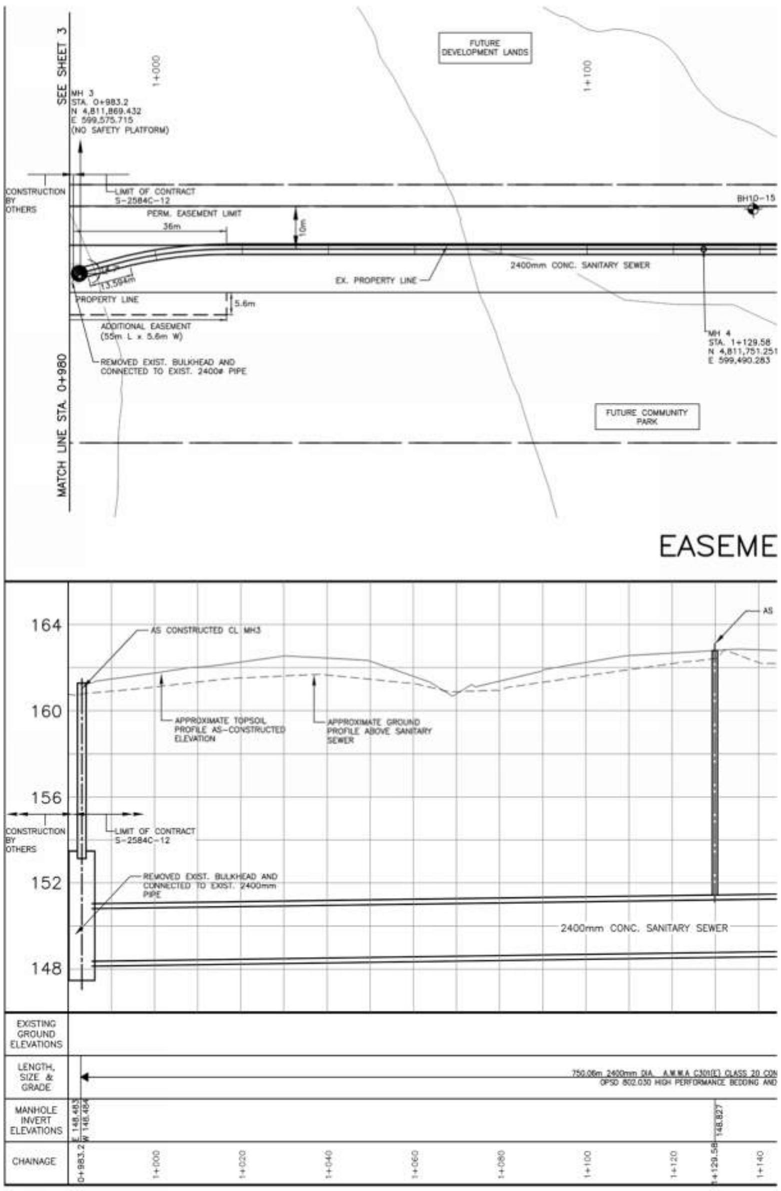

Figure 31: Sewer Depth

The schematic below outlines a potential approach to the interconnection of the sewer system and the energy exchange with the Hospital District. An item of note here is that only energy is exchanged via heat exchangers with the site, there is no net change in sewer flow downstream of the connection point resulting from the interconnection. This piece of work is also separate from the site's sanitary sewer connection.

Wastewater from the Region's sewer will flow via a gravity main to the pumping chamber / wet well. From here the wastewater will be pumped via a forcemain through a fully hydronically separated heat exchanger. After this point, the wastewater will continue through the forcemain circuit back to a secondary manhole located within the property line of the District Energy utility. From here the wastewater will return to the existing sewer. The sewer line will experience no net change in flow downstream of this manhole compared to upstream of the manhole.

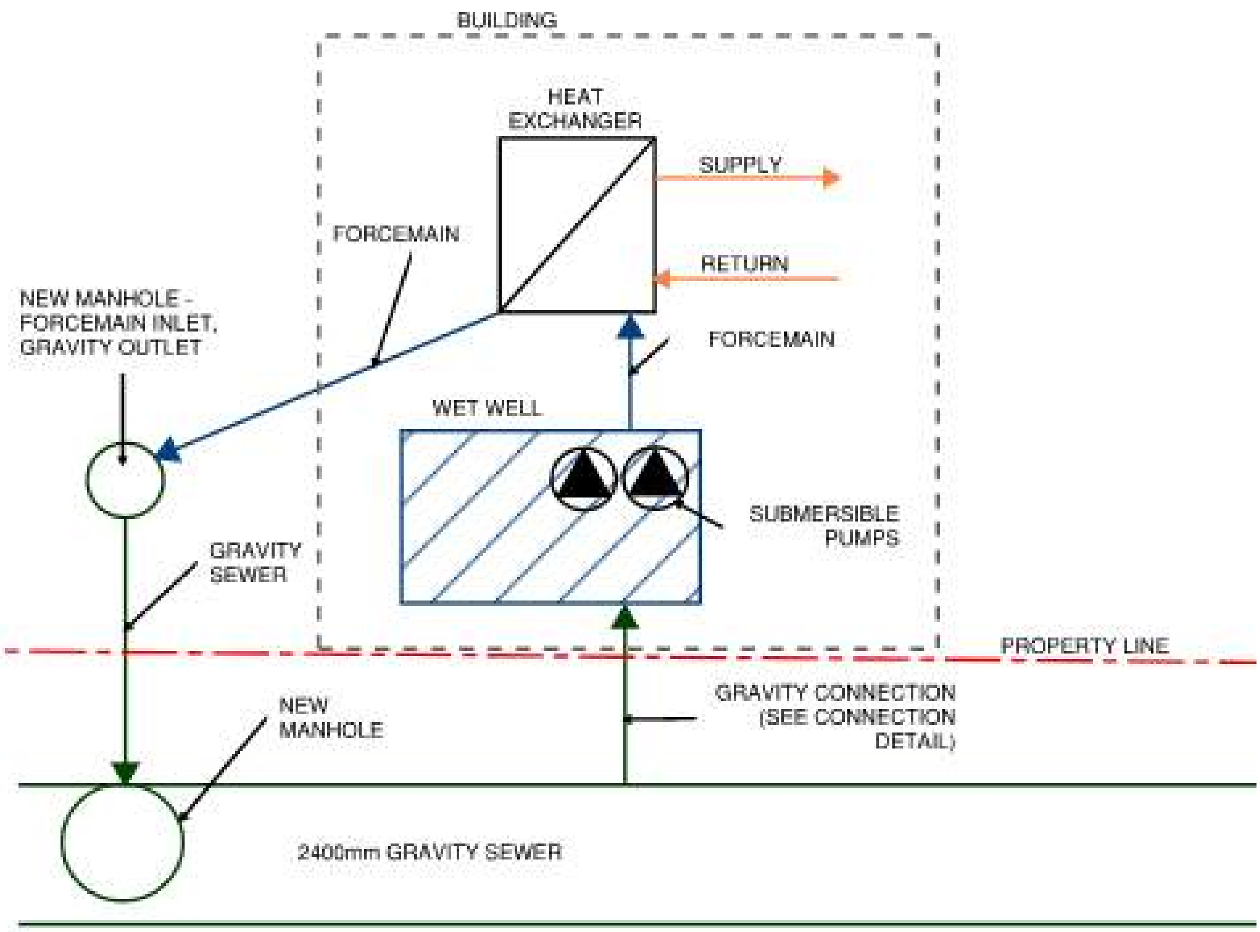

Figure 32: Sewer Connection Interface

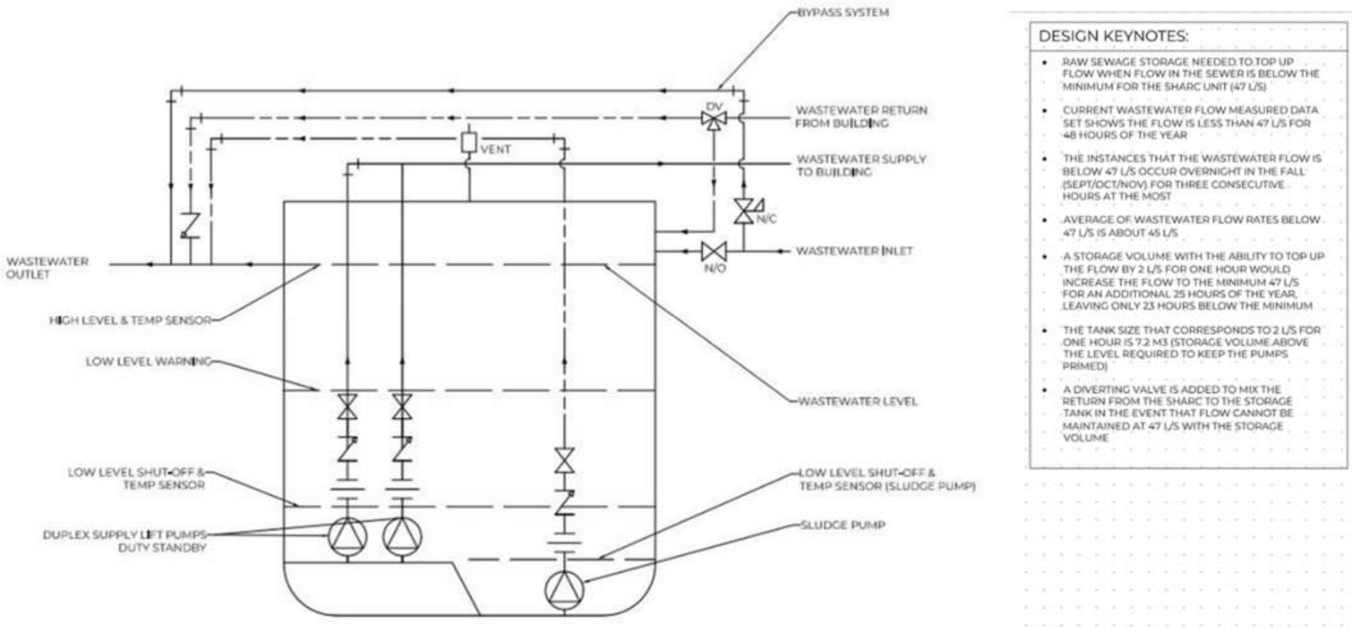

Figure 33: Pumping Tank Schematic

The pumping tank schematic above outlines the proposed pumping manhole arrangement which will be part of the Energy Utility System. There will be an integrated sludge pump in the system for maintenance reasons.

Two sewer energy exchange units are expected in Phase 1 of the project for a total capacity of 3.2 MW. An additional unit is anticipated in Phase 2 of the project adding another 1.6 MW for a total sewer energy exchange capacity of 4.8 MW.

3.3 Geo-Exchange Potential at the Hospital District Site

The values below are based on a nearby test hole drilled to 640 ft. A borehole depth of 850 ft is also common in Ontario and is likely an option at the Hospital District Site. The greater depth allows for fewer boreholes and greater efficiency in drilling equipment mobilization. The thermal properties presented above for the site can be considered applicable for the 850 ft boreholes as well. It is recommended that prior to the first project commencing at the site, a site-specific test hole be drilled to 850 ft in order to confirm assumptions and uncover potential underground construction challenges. It is recommended that this borehole be used both as a test hole and a production hole (i.e., an operational part of the borefield).

The parameters below are favourable for a geo-exchange system at the site, the low overburden will reduce overall capital costs and improve efficiency for the site. There are many other sites in the GTHA moving forward with less favourable thermal properties.

Additionally, the North Oak project in Oakville (close to the hospital site) demonstrates the technical, environmental, and economic feasibility of site-level geo-exchange approaches.

An overview of the site and the proposed density indicates that there is ample room for geo-exchange boreholes to supply the majority of the heating and cooling for the site.

Table 18: Geo-exchange Borefield Assumptions.

Property	Assumption
Undisturbed Ground Temperature	10.2 – 12.1 °C
System Fluid	Basis of design will be 25 % Propylene Glycol. Alternative approaches such as 20 % ethanol also acceptable.
Ground Thermal Conductivity	2.55 W/mK
Ground Thermal Diffusivity	0.084 m2/day
Grout Thermal Conductivity	2.08 W/mK *
Borehole Thermal Resistance	0.106 mK/W

For the purposes of this detailed feasibility assessment, the following assumptions will be made when modelling the borefield:

- 4” borehole diameter
- 1.5” circuit piping diameter
- Pipe material will be HDPE 4710 DR11 for all circuit piping with DR 13 used for lateral runouts.
- A minimum borehole spacing of 6 m will be maintained.
- Approximately 20 m of overburden is assumed at the site (based on drilling records).
- An operational temperature range of 0 °C – 30 °C entering water temperature to heat pumps.

Using all of the inputs outlined here and the indicative building energy profile, the geo-exchange system was modelled using the Ground Loop Design (GLD) software. The borefields were sized to maintain system temperatures within the range outlined above.

Table 19: Phase Borefield Implementation

	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5	Phase 6	Phase 7	Phase 8	Phase 9	Phase 10
Year	2028	2030	2031	2032	2033	2034	2040	2043	2045	2049
# Boreholes	0	45	62	411	521	695	854	918	1043	1122

3.4 Central Plant Design

The Process Flow Diagram (PFD) below is intended to show in greater detail than Figure 28 the intended operation of the system.

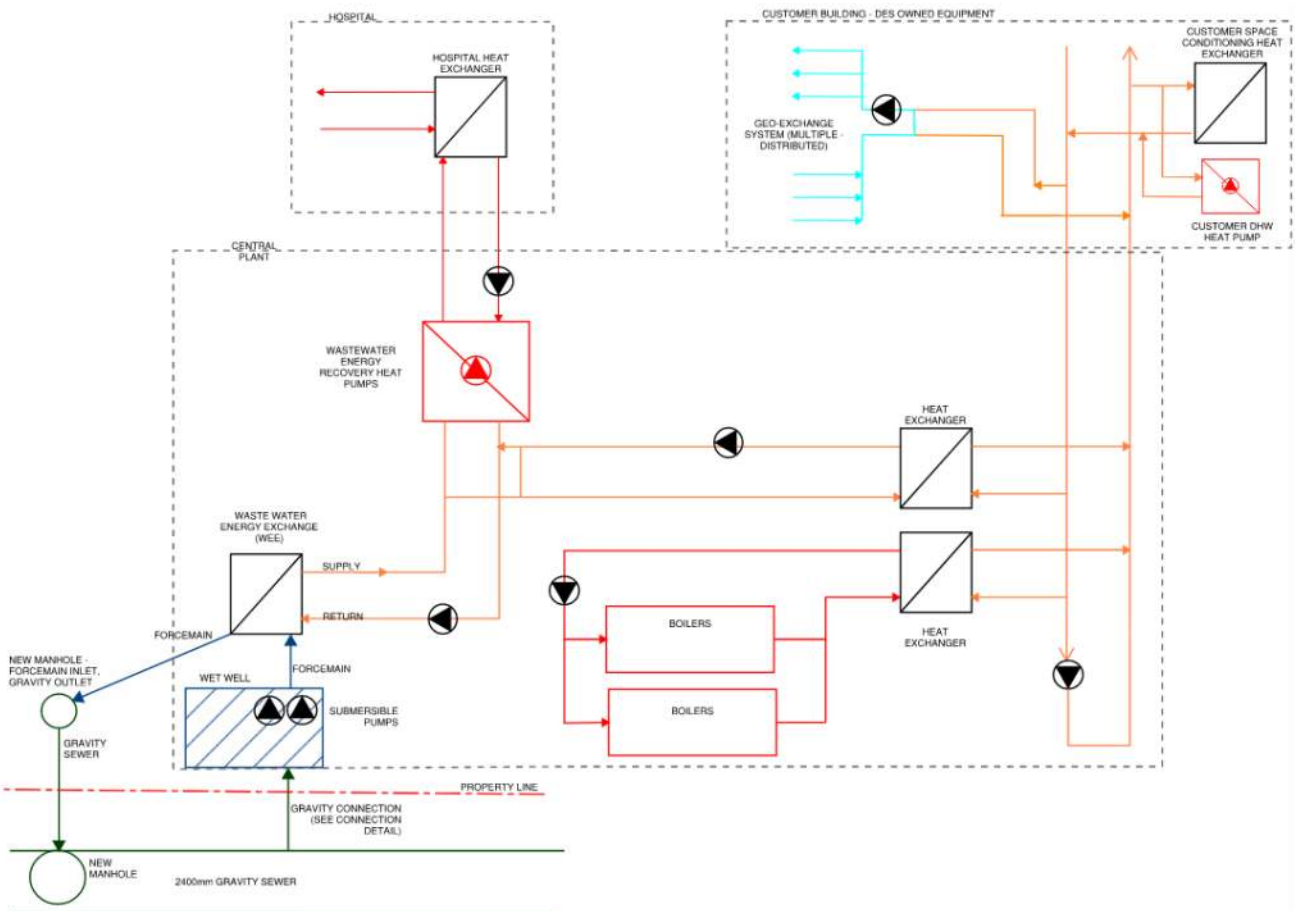

Figure 34: Process Flow Diagram for DES Concept

Figure 35 shows an indicative size and layout of the Central Plant designed for Phases 1 – 6 inclusive. Given the uncertainty of achieving the fully built out condition for the site, the central plant as currently shown is only intended to supply up to and including Phase 6.

It is likely that a second plant or an extension to the original would be required should the full site build out. Costs have been carried to include for a second future peaking plant. The required size for the secondary plant would be half that of the initial plant. The second plant would not require the heat pump and sewer energy recovery equipment and would instead predominantly house peaking boilers.

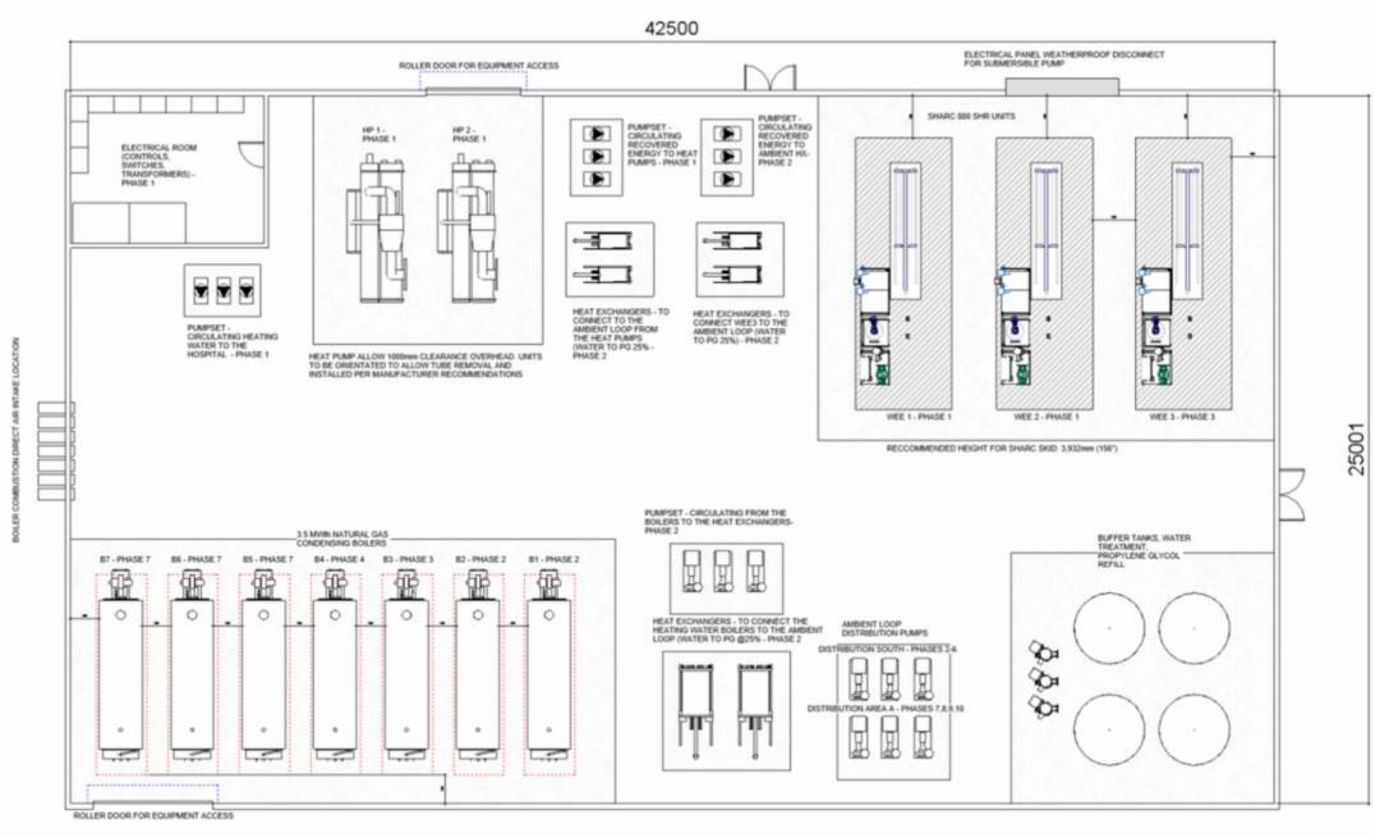

Figure 35: Central Plant 1

Geo-manifolds will be required in most development blocks from Phase 2 onwards an example of a geo-manifold room is shown in Figure 36.

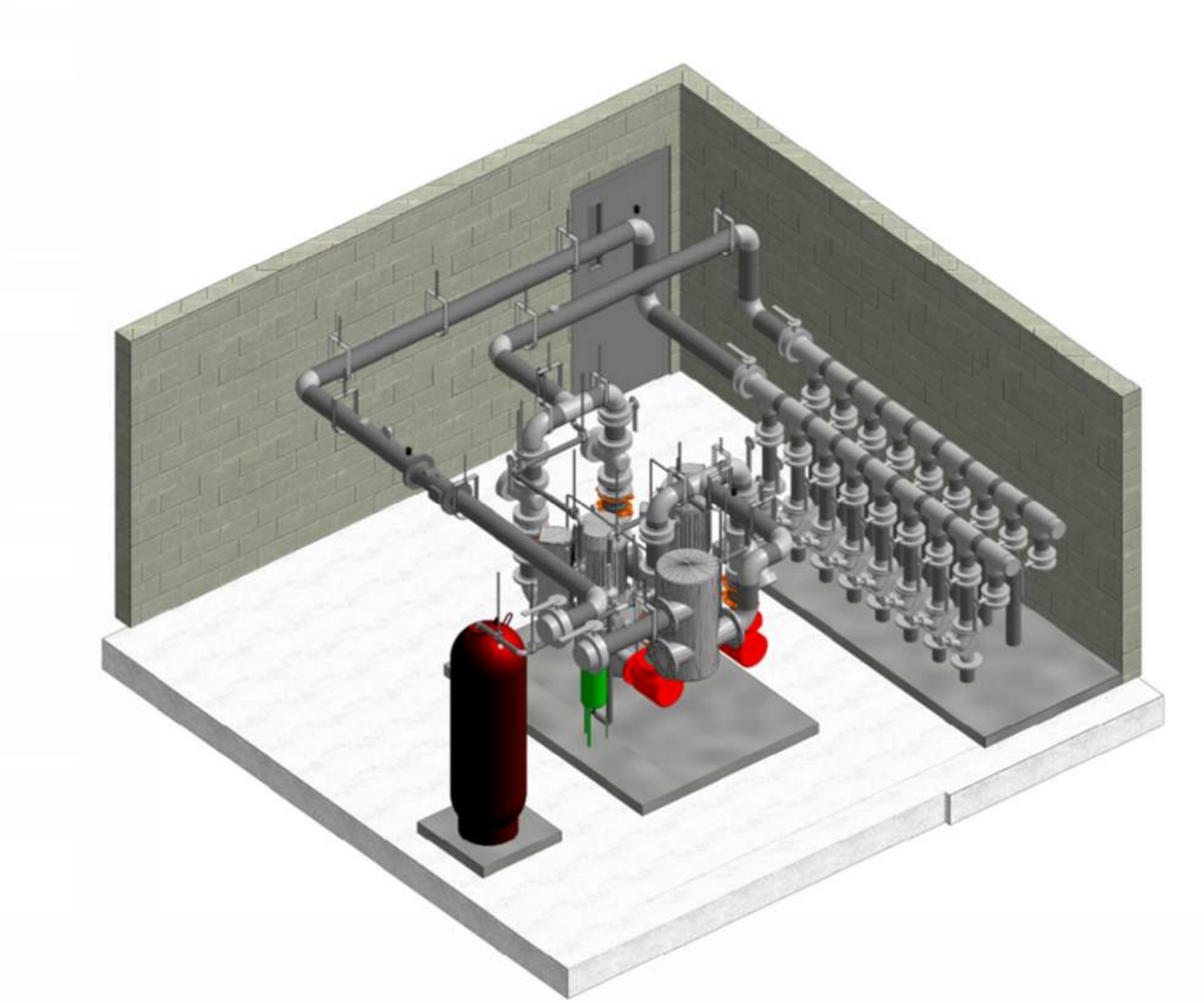

Figure 36: Example of Geo-Manifold Room

3.5 Cost Assessment

The capital cost assessment for the central plant is outlined in Table 20 (Phases 1 – 5) and Table 21 (Phases 6 – 10).

Table 20: Central Plant Capital Assessment (Phases 1 – 5)

Phase	1 $	2 $	3 $	4 $	5 $
Central Energy Recovery					
Sewer Heat Pump	4,480,000	-	-	-	-
Boilers	-	748,316	160,343	814,482	571,054
Buffer Tanks	150,000				
Pressurization	150,000				
Pumps	390,000	585,000	-	-	-
Water and Chemical Treatment	50,000				
Flue		50,000		25,000	25,000
Plumbing and Drainage	25,000				
Heat Exchangers	-	2,637,000	-	-	-
Piping and instrumentation	75,000	60,000	12,500	12,500	12,500
Hookups	40,000	60,000	15,000	12,500	12,500
Combustion Air		60,000			
Controls	150,000	-	45,000	15,000	25,000
Commissioning	75,000	25,000	25,000	15,000	20,000
Electrical and Wiring	120,000	70,000	10,000	10,000	10,000
Eye wash station etc. c/w integrated shower heat unit	10,000				
Installation Costs	1,715,000	1,289,000	80,000	271,000	203,000
Subtotal	7,430,000	5,584,316	347,843	1,175,482	879,054
Design Planning and Permitting	445,800	335,059	20,871	70,529	52,743
Contractor OH&P	891,600	670,118	41,741	141,058	105,486
Building Cost	5,350,000				
Land Purchase	856,000				
Total	14,973,400	6,589,492	410,454	1,387,069	1,037,284

Table 21: Central Plant Capital Assessment (Phases 6 – 10)

Phase	6 $	7 $	8 $	9 $	10 $
Central Energy Recovery					
Sewer Heat Pump					
Boilers	686,371	1,435,061	664,263	1,101,958	718,153
Buffer Tanks					
Pressurization					
Pumps	-	390,000	-	-	-
Water and Chemical Treatment					
Flue		50,000			
Plumbing and Drainage		20,000			
Heat Exchangers	-	1,319,000	-	-	-
Piping and instrumentation	12,500	55,000	12,500	12,500	13,000
Hookups	12,500	60,000	12,500	12,500	12,500
Combustion Air	50,000				
Controls	15,000	55,000	15,000	15,000	15,000
Commissioning	15,000	45,000	15,000	15,000	15,000
Electrical and Wiring	10,000	10,000	10,000	10,000	10,000
Eye wash station etc. c/w integrated shower heat unit		10,000			
Installation Costs	240,000	1,035,000	219,000	350,000	235,000
Subtotal	1,041,371	4,484,061	948,263	1,516,958	1,018,653
Design Planning and Permitting	62,482	269,044	56,896	91,017	61,119
Contractor OH&P	124,964	538,087	113,792	182,035	122,238
Building Cost		2,675,000			
Land Purchase		428,000			
Total	1,228,817	8,394,192	1,118,950	1,790,010	1,202,011

The capital cost assessment for the sewer energy interchange is outlined in Table 22 below.

Table 22: Sewer Interface Assessment

Phase	1	2
	$	$
Sewer Interface		
Sewer Diversion	200,000.00	
Wet Well	3,450,000	
Forcemain to Heat Exchangers (open cut construction)	24,000	
Heat Exchanger	1,546,000	773,000
Forcemain Return to manhole A	24,000	
Manhole A	150,000	
New Manhole	150,000	
Installation Costs		
Civil Costs		
Subtotal	5,544,000	773,000
Design Planning and Permitting	332,640	46,380
Contractor OH&P	665,280	92,760
Total	6,541,920	912,140

The capital cost assessment for the geo-manifold rooms are outlined in Table 23 (Phases 1 – 5) and Table 24 (Phases 6 – 10).

Table 23: Geo-Manifold Room Capital Assessment (Phases 1 - 5)

Phase	1	2	3	4	5
	$	$	$	$	$
Geo-Exchange Manifold Rooms					
Boreholes	-	1,338,750	505,750	10,382,750	3,272,500
Expansion Tanks		32,000	16,000	24,000	32,000
Pumps		160,000	80,000	120,000	160,000
Air and Dirt Separators		20,000	10,000	15,000	20,000
Valves + Instrumentation + Piping		80,000	40,000	60,000	80,000
Controls		60,000	30,000	45,000	60,000
Installation		106,000	53,000	79,000	106,000
Subtotal		1,796,750	734,750	10,725,750	3,730,500
Design Planning and Permitting		26,951	11,021	160,886	55,958
Contractor OH&P		54,960	27,480	41,160	54,960
Total		1,878,661	773,251	10,927,796	3,841,418

Table 24: Geo-Manifold Room Capital Assessment (Phases 6 – 10)

Phase	6	7	8	9	10
	$	$	$	$	$
Geo-Exchange Manifold Rooms					
Boreholes	5,176,500	4,730,250	1,904,000	3,718,750	2,350,250
Expansion Tanks	32,000	88,000	64,000	80,000	24,000
Pumps	160,000	440,000	320,000	400,000	120,000
Air and Dirt Separators	20,000	55,000	40,000	50,000	15,000
Valves + Instrumentation + Piping	80,000	220,000	160,000	200,000	60,000
Controls	60,000	165,000	120,000	150,000	45,000
Installation	106,000	290,000	211,000	264,000	79,000
Subtotal	5,634,500	5,988,250	2,819,000	4,862,750	2,693,250
Design Planning and Permitting	84,518	89,824	42,285	72,941	40,399
Contractor OH&P	54,960	150,960	109,800	137,280	41,160
Total	5,773,978	6,229,034	2,971,085	5,072,971	2,774,809

4 NETWORK OVERVIEW

The proposed District Energy Network for the Hospital District is shown in Figure 37. As can be seen there are two types of networks proposed, a dedicated heating water network to the Hospital and an ambient temperature network to the rest of the site. Alternate pipe routing from the second option for the central plant location is also shown.

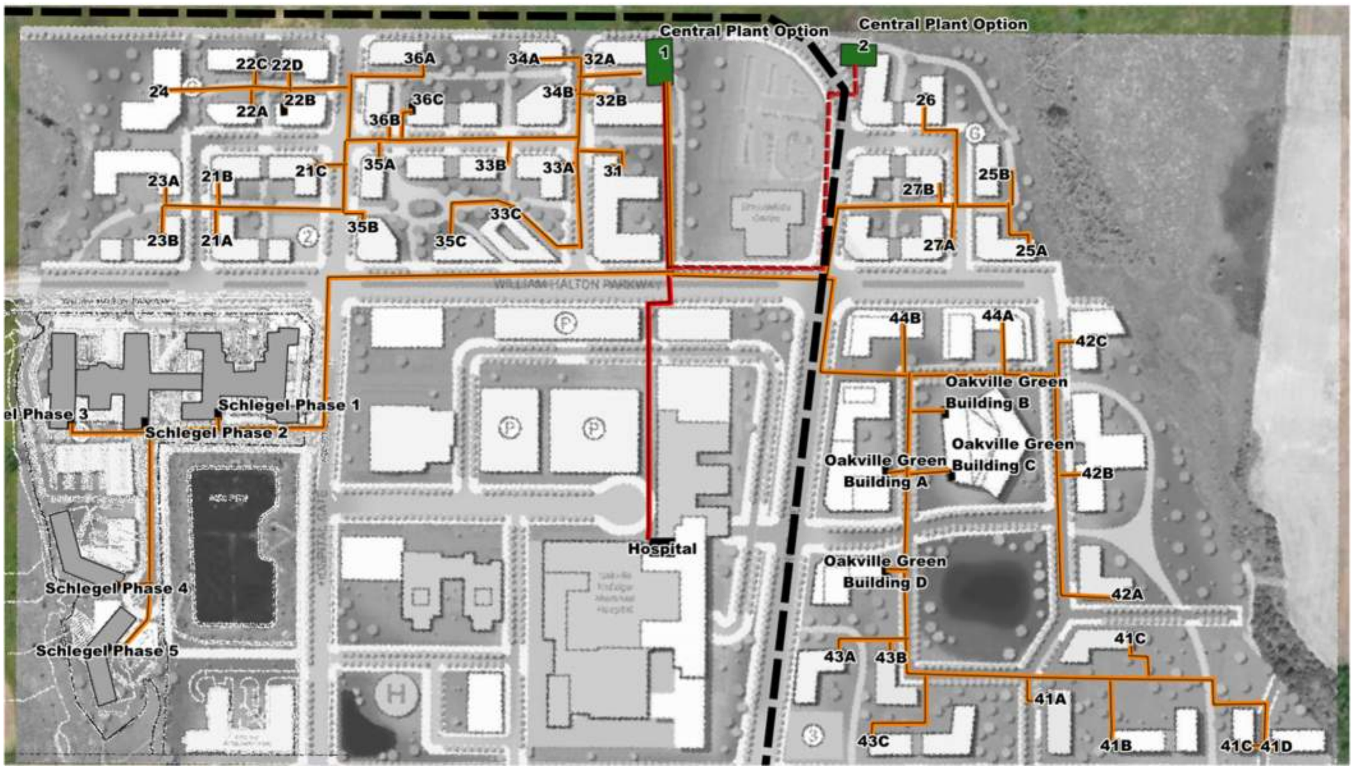

Figure 37: Proposed Energy Network

4.1 Fluid Type and Chemical Composition

The fluid distributed through the closed-loop piping system is water with freeze protection at varying temperatures. As this is a closed-loop system the water circulating through the pipe loop never leaves the closed system, i.e., is not distributed to end-use customers. The water is strictly used as a heat transfer medium.

4.2 Pipe Information

The ambient loop pipes will be a standard fused HDPE product commonly used in potable water applications. These pipes will vary in diameter, the diameters required are outlined in Table 25. These pipes will be HDPE 4710 DR17. These pipes will not be insulated and will be buried below the frost line.

For the hospital connection system, a pre-insulated steel pipe is recommended due to required temperatures. The standard pre-insulated product for district energy is EN253 piping such as the example shown below. These pipes are supplied in 12m (40ft) sections. This is a pre-insulated product comprised of thin-walled steel pipes encased in insulation with a HDPE outer jacket. These pipes have integrated leak detection systems for added resilience. It is required that the installed pipes be tested, and quality controlled according to ASME B31.1, it is recommended that the additional quality control requirements of EN13941 be incorporated.

Two pipes are required in the trench to supply hot water out to buildings with cooler water then returning via the return pipe to the central plant, completing the closed loop.

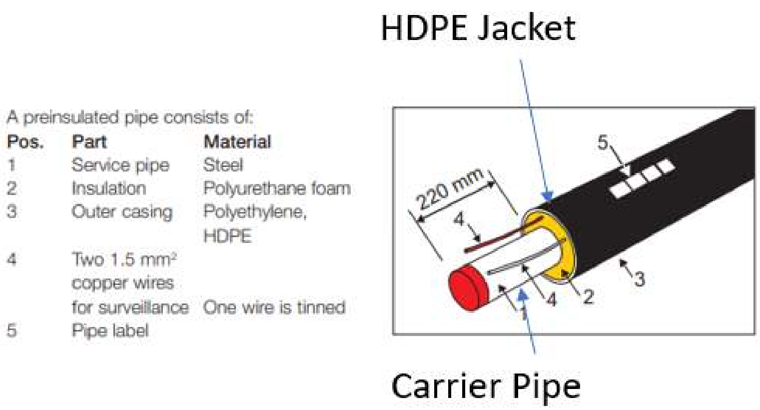

Figure 38: EN253 Piping Infographic (image courtesy of Logstor)

4.3 Network Phasing

The proposed network phasing (in line with the site phasing as outlined in Milestone 3 Section 2) is shown in Figure 39 below. Routing through existing roadways has been avoided where possible, and it is assumed that most networks can be laid in greenfield space during site construction enabling cost efficiencies to be found with site servicing requirements. Cost efficiencies have been assumed in these areas. Alternate pipe routing from the second option for the central plant location is also shown.

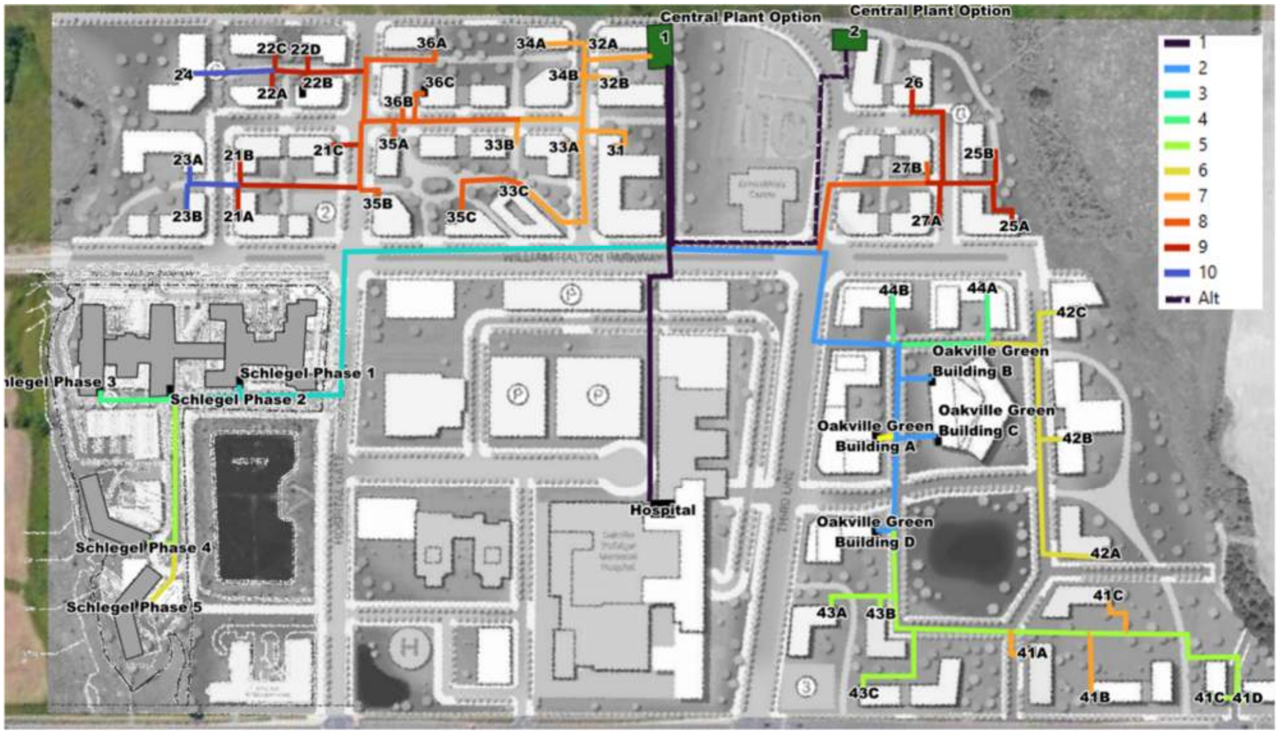

Figure 39: Network by Phase

4.4 Network Sizing

Network sizing is based on the following parameters:

- Maximum pressure drop in network: 300 Pa/m
- Minimum supply / return temperature differential in ambient network: 5 °C
- Minimum supply / return temperature differential in heating water network: 15 °C
- Sizing is based on the demands as outlined in Table 27.

Alternate pipe routing from the second option for the central plant location is also shown.

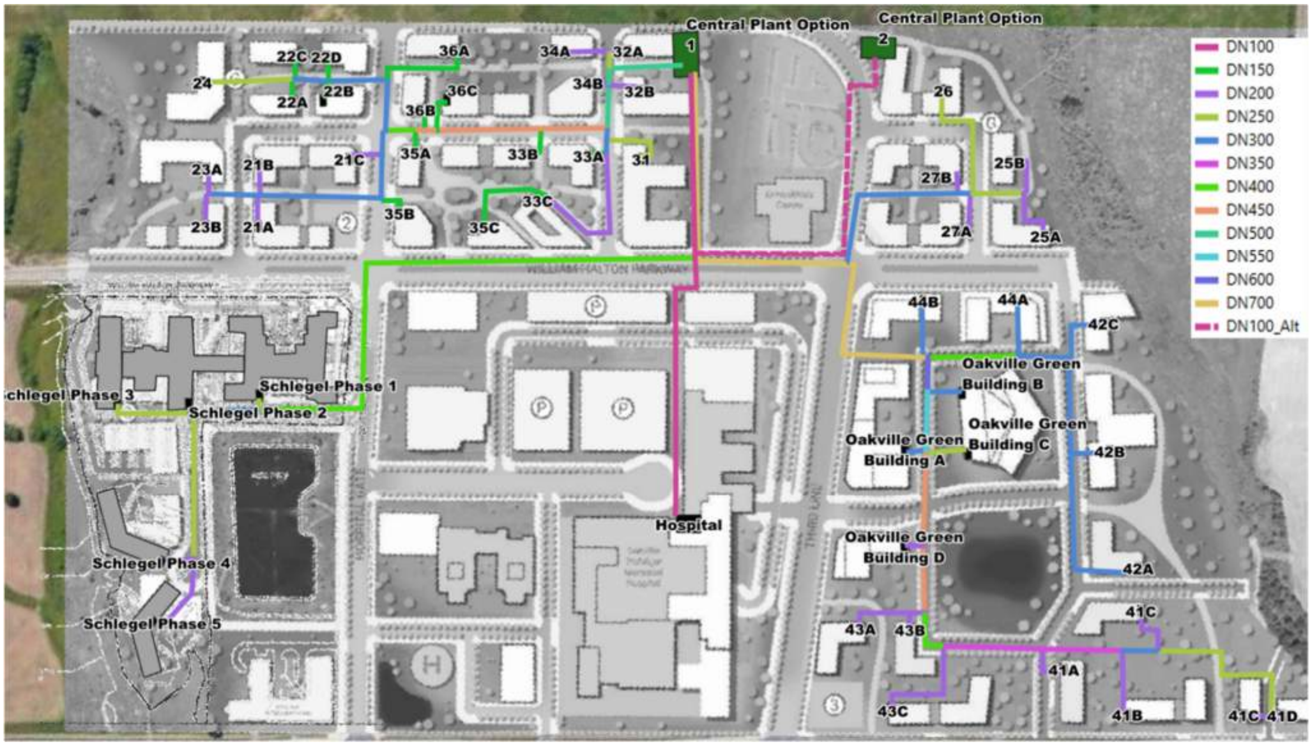

Figure 40: Network by Diameter

The following table outlines the total metres of trench required per pipe size. To calculate the total metres of pipe these values are to be multiplied by two.

Table 25: Network Schedule

Phase	1	2	3	4	5	6	7	8	9	10	Total (by Diameter)
Nominal Diameter	**Trench Length expressed in metres [m]**										
DN100	450										450
DN150							59	289	78		426
DN200		18			259	84	427	67	188	51	1,094
DN250		37	17	80	321		86	130	52	88	810
DN300		50	68	98	33	416	24	295	225	50	1,259
DN350					174						174
DN400			567	86	47			32			731
DN450		94			65		62	122			343
DN500							119				119
DN550		59									59
DN600		34									34
DN700	281	463									744
Total (by Phase)	731	754	651	263	898	501	777	936	542	188	6,242

4.5 Network Construction

Typical Network construction for ambient and heating water systems are shown in Figure 41, Figure 42 and Figure 43 below.

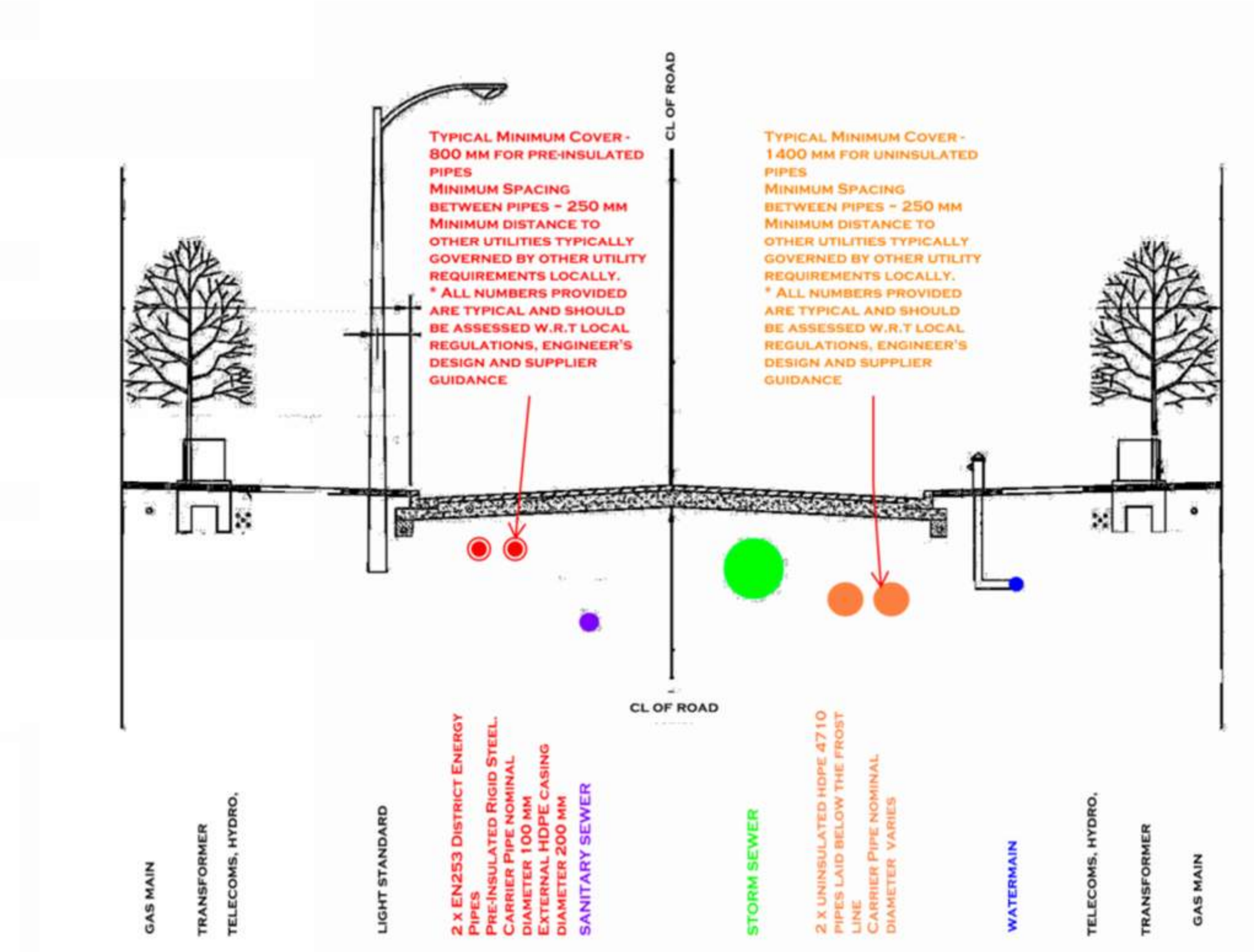

Figure 41: Typical Road Cross Section with Buried Utilities (District Heat Pipe in Red, Ambient Loop in Orange)

Figure 42 below shows a trench cross-section for a pre-insulated pipe pair. These pre-insulated pipes can be laid at shallower depths than uninsulated piping (see Figure 43) as their insulation layer protects the pipe from excessive heat loss. The higher cost of this pipe however makes it unsuitable for ambient temperature applications where larger diameter pipes are required and thermal losses are not as high as for higher temperature systems.

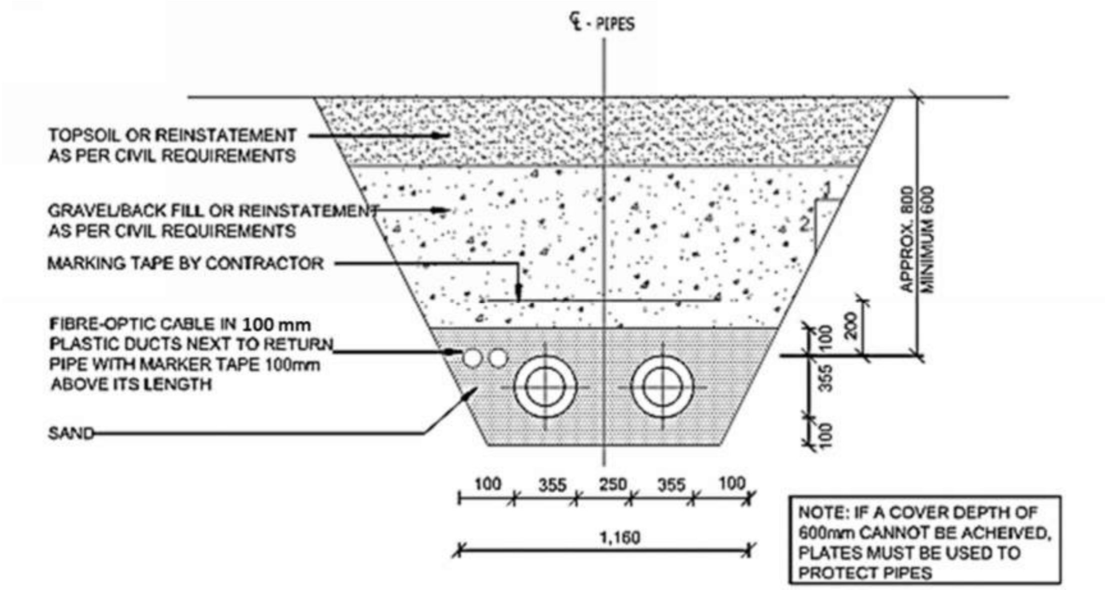

Figure 42: Typical Trench Profile (Pre-Insulated Piping)

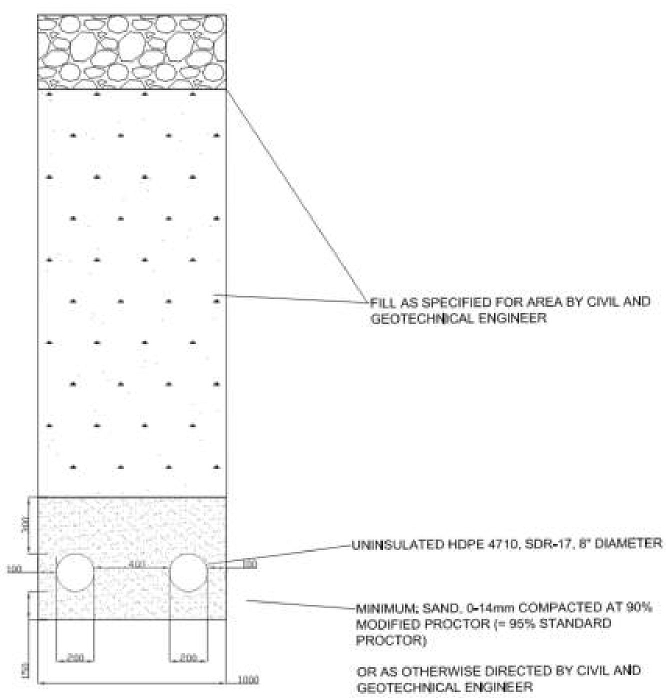

Figure 43: Typical Trench Profile - Uninsulated HDPE Piping

4.6 Network Costs

Phased network costs are shown in Table 26 below.

Table 26: Phased Network Costs

Phase	1	2	3	4	5	6	7	8	9	10	Total
DN100	1,029,686	-	-	-	-	-	-	-	-	-	1,029,686
DN150	-	-	-	-	-	-	57,385	280,342	75,166	-	412,893
DN200	-	21,268	-	-	307,787	100,379	508,290	80,244	223,557	60,236	1,301,762
DN250	-	54,982	24,715	118,106	475,484	-	127,258	192,076	77,078	130,083	1,199,782
DN300	-	88,111	120,069	172,143	57,503	732,872	42,464	519,915	395,949	88,032	2,217,060
DN350	-	-	-	-	343,329	-	-	-	-	-	343,329
DN400	-	-	1,320,766	199,646	108,881	-	-	74,137	-	-	1,703,430
DN450	-	238,656	-	-	165,061	-	157,493	311,335	-	-	872,545
DN500	-	-	-	-	-	-	332,951	-	-	-	332,951
DN550	-	180,469	-	-	-	-	-	-	-	-	180,469
DN600	-	112,507	-	-	-	-	-	-	-	-	112,507
DN700	1,236,025	2,034,650	-	-	-	-	-	-	-	-	3,270,675
											12,977,088

5 CUSTOMER CONNECTION

5.1 Hospital Building

Each building proposed for connection will require a new hot water energy transfer station (ETS, pictured below) to supply heating water and domestic hot water (DHW) to the buildings. ETS units are pre-manufactured skids containing heat exchangers, controls, instrumentation, valving, and piping needed to ensure that the ETS can be installed quickly and efficiently in customer buildings as a "plug and play" solution to minimize on-site construction and disruption. ETS units directly replace heating and hot water boilers.

ETS' are compact units and require substantially less space than the boiler equipment they replace. Building audits have not been conducted to confirm available space – this step is required at the next stage.

Figure 44: ETS on a Skid (image courtesy of Danfoss)

ETS installation works typically include:

- Customer Service Isolation Valves
- Riser
- Piping, Supports, and Insulation
- High Point Vents, Low Point Drains, Cleaning Ports
- ETS Skid
- Domestic Hot Water (DHW) incorporated in skid
- Energy Meter, Controls, Instrumentation, etc.
- Delivery, rigging, Install, and Commissioning
- Mechanical costs for bringing district piping into the building (buried piping etc. are carried under the thermal network costing)
- An allowance has been carried out for the integration of the new ETS with the existing building boilers and heating system.

5.2 Other Connections

Connections other than the hospital will require the following:

5.2.1 Space Heating and Cooling

If the proposed connection has a 4-pipe fan coil system, a dedicated 6-pipe centralized heat pump will be required for space heating and cooling. These units are capable of providing simultaneous heating and cooling supply. If the building's business-as-usual HVAC system is 4-pipe fan coil, the central heat pump would replace the building's boiler, chiller and cooling tower systems with significant savings. The heat pump would also serve as the point of commercial and hydronic demarcation between the building and the DES provider.

If the building opts for central or zonal heat pumps, a heating and a cooling ETS similar to that shown for the Hospital using heat exchangers would be required in order to ensure hydronic separation of the building and network systems.

5.2.2 Domestic Hot Water

For domestic hot water supply, a specialized water to water heat pump will be required. An example of such a heat pump is shown below. This heat pump can meet the temperature requirements of the buildings. This unit would replace the building's central DHW boiler unit. It is assumed that the buffer tanks would be provided by the building side system.

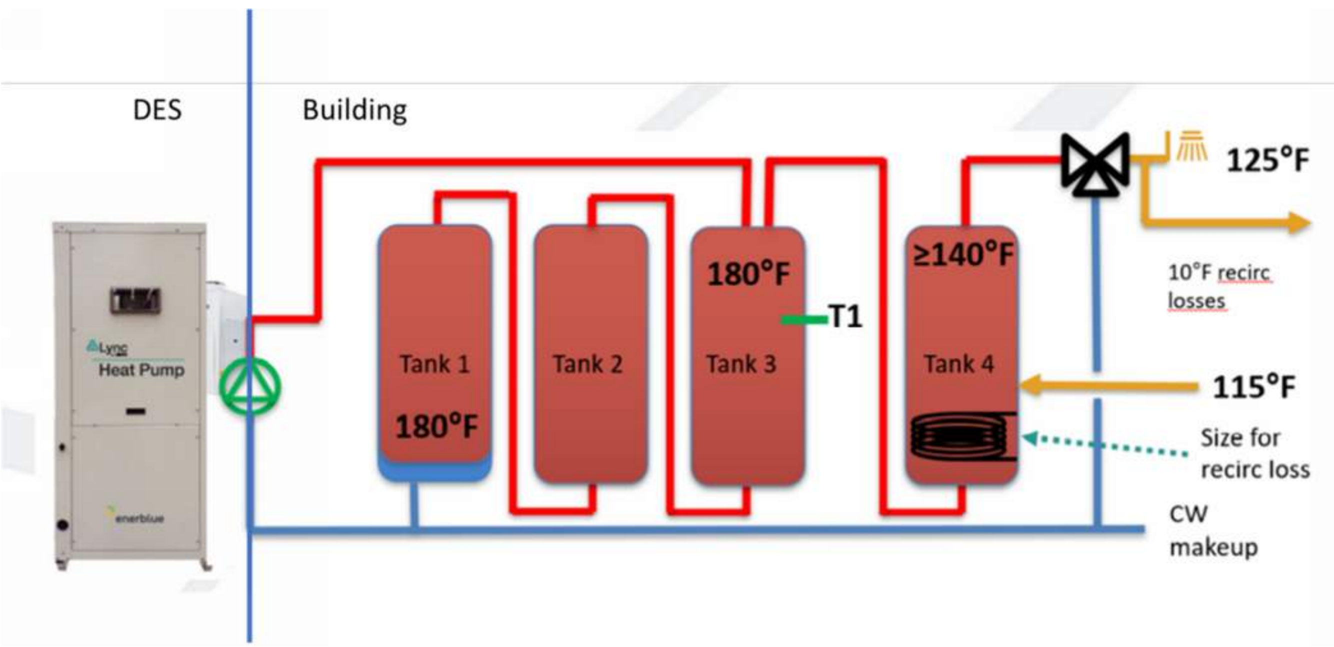

Figure 45: DHW Heat Pump Schematic

The heat pump would also serve as the point of commercial and hydronic demarcation between the building and the DES provider.

5.3 Connection Summary

A summary table of the required energy supply to each building is shown in Table 27 below. Note this table is used to report the peak load that the Heat Pumps and Energy Transfer Stations at each building will be sized for; the peak loads therefore also include the Heat of Compression of downstream heat pumps.

The heat of compression is the heat that is generated by the electrical component operation of the heat pumps (including the compressor and the fan). When the heat pump is in heating mode, the heat of compression (the additional heat) becomes part of the heat delivered to the space, reducing the amount of heat generation required from the system. When the heat pump is in cooling mode, the additional heat is added to the already existing heat rejection load due to cooling the space, increasing the amount of cooling required by the system. Note this sizing was also used to inform the network diameters for this site.

If there is an “N” in the “Sized for DHW and Space Heating” column below, it indicates that the sizing is for a cooling load instead. In ambient systems, the sizing is for the greater of the two loads.

Table 27: Customer Connection Sizing (Heat of Compression Included)

Connection Ref	Equipment Sizing DHW [kW]	Equipment Sizing (Space Conditioning) [kW]	Sized for DHW + Space Heating	Phase
Hospital		3600	Y	1
Oakville Green Building A	320	2480	Y	2
Oakville Green Building B	102	2641	Y	2
Oakville Green Building C	52	1338	Y	2
Oakville Green Building D	127	988	Y	2
Schlegel Phase 2	230	1689	N	3
44A	198	3156	Y	4
44B	198	3156	Y	4
Schlegel Phase 3	265	1944	N	4
43A	79	1089	Y	5
43B	79	1089	Y	5
43C	79	1089	Y	5
Schlegel Phase 4	98	716	N	5
42B	172	2186	Y	6
42C	172	2186	Y	6
Schlegel Phase 5	98	716	N	6
31	122	1363	Y	7

Connection Ref	Equipment Sizing DHW [kW]	Equipment Sizing (Space Conditioning) [kW]	Sized for DHW + Space Heating	Phase
32A	56	776	Y	7
32B	56	776	Y	7
33A	35	395	Y	7
33B	35	395	Y	7
33C	35	395	Y	7
34A	41	564	Y	7
34B	41	564	Y	7
41A	59	813	Y	7
41B	59	813	Y	7
41C	59	813	Y	7
42A	172	2186	Y	6
27A	63	863	Y	8
27B	63	863	Y	8
35A	30	469	Y	8
35B	30	469	Y	8
35C	30	469	Y	8
36A	27	366	Y	8
36B	27	366	Y	8
36C	27	366	Y	8
26	135	1861	Y	9
21A	48	653	Y	9
21B	48	653	Y	9
21C	48	653	Y	9
22A	34	465	Y	9
22B	34	465	Y	9
22C	34	465	Y	9
22D	34	465	Y	9
25A	50	692	Y	9
25B	50	692	Y	9
24	138	1544	Y	10
23A	78	1069	Y	10
23B	78	1069	Y	10

5.4 Cost Estimates

Phased ETS costs are shown Table 28 below.

Table 28: Phased ETS Costs

Phase	DHW Heat Pump Interface Costs	Energy Transfer Station Costs
1		1,350,000
2	1,025,100	1,953,100
3	440,000	473,300
4	1,127,400	2,114,000
5	571,200	1,030,400
6	1,047,300	1,928,000
7	1,019,800	2,050,800
8	506,900	1,109,000
9	878,600	1,839,400
10	501,400	962,600
Grand Total	7,117,700	14,810,600

Costs for a Schlegel Phase 1 Connection and 41 C and 41D Connections are not carried based on the outline discussion in Milestone 2 Section 1.2 but have been estimated as follows:

Table 29: Estimated Costs for Schlegel Phase 1 and 41 C & 41 D Connections

Phase	DHW Heat Pump Interface Costs	Energy Transfer Station Costs
Schlegel Phase 2	392,300	422,300
41 C	100,600	211,800
41 D	100,600	211,800

6 ENERGY AND COST RESULTS

The total delivered demand for all phases is outlined below:

6.1 Energy Modelling

Energy sales to buildings from the DES utility are outlined in Table 30 below.

Table 30: Energy Modelling Results

Phase	1	2	3	4	5	6	7	8	9	10
Total Delivered Heating (MWh)	26,388	34,153	35,172	39,154	42,170	48,819	56,945	60,422	66,227	69,540
Total Delivered DHW (MWh)	0	2,517	3,507	6,353	7,796	10,621	13,714	15,037	17,247	18,510
Total Delivered Cooling (MWh)	0	3,706	5,439	10,736	13,168	17,894	23,027	25,223	28,890	30,988

6.2 Capital Costing

A summary of the capital costing presented in Milestone 3 Sections 3.5, 4.6 and 5.4 is shown in the tables below.

Table 31: Capital Cost Summary 1 of 2, Total for Site and Phases 1-5

Phase		1	2	3	4	5
	Total – 2024 Dollars	$	$	$	$	$
Central Energy Recovery	**38,131,680**	14,973,400	6,589,492	410,454	1,387,069	1,037,284
Sewer Interface	**7,454,060**	6,541,920	912,140	-	-	-
Geo-Exchange Manifold Rooms	**40,243,003**		1,878,661	773,251	10,927,796	3,841,418
Network	**13,366,402**	2,333,682	2,812,562	1,509,517	504,592	1,501,786
Customer Connections	**21,928,300**	1,350,000	2,978,200	913,300	3,241,400	1,601,600
Total System Capital Costs	**121,123,444**	25,199,002	15,171,056	3,606,522	16,060,857	7,982,088
Contingency	**18,168,517**	3,779,850	2,275,658	540,978	2,409,129	1,197,313
Total Incl. Contingency	**139,291,961**	28,978,853	17,446,714	4,147,500	18,469,986	9,179,401

Table 32: Capital Cost Summary 2 of 2, Phases 6-10

	6	7	8	9	10
	$	$	$	$	$
Central Energy Recovery	1,228,817	8,394,192	1,118,950	1,790,010	1,202,011
Sewer Interface	-	-	-	-	-
Geo-Exchange Manifold Rooms	5,773,978	6,229,034	2,971,085	5,072,971	2,774,809
Network	858,249	1,262,616	1,501,790	794,903	286,705
Customer Connections	2,975,300	3,070,600	1,615,900	2,718,000	1,464,000
Total System Capital Costs	10,836,343	18,956,442	7,207,726	10,375,884	5,727,524
Contingency	1,625,452	2,843,466	1,081,159	1,556,383	859,129
Total Incl. Contingency	12,461,795	21,799,908	8,288,885	11,932,267	6,586,653

6.3 Operational Costs

A summary of the system's operational costs are shown in Table 33 (Phases 1 – 5) and Table 34 (Phases 6 – 10) below.

Table 33: Operational Cost Assessment 1 of 2, Phases 1-5

	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
Water and Chemical Treatment	$16,779	$25,351	$27,765	$37,826	$42,689
Insurance (Cumulative)	$144,894	$232,128	$252,865	$345,215	$391,112
Equipment Maintenance	$122,115	$243,218	$261,700	$326,011	$363,168
Network Maintenance (Cumulative)	$33,986	$74,945	$96,929	$104,277	$126,148
Sewer Infrastructure Costs	$39,980	$39,980	$39,980	$39,980	$39,980
Admin Costs	$127,008	$205,096	$223,814	$306,549	$347,661
O&M Staffing	$150,000	$150,000	$150,000	$150,000	$150,000

Table 34: Operational Cost Assessment 2 of 2, Phases 6-10

	Phase 6	Phase 7	Phase 8	Phase 9	Phase 10
Water and Chemical Treatment	$52,743	$64,353	$69,321	$77,616	$82,355
Insurance (Cumulative)	$453,421	$562,421	$603,865	$663,527	$696,460
Equipment Maintenance	$422,660	$528,750	$571,900	$640,337	$676,550
Network Maintenance (Cumulative)	$138,646	$157,034	$178,905	$190,481	$194,656
Sewer Infrastructure Costs	$39,980	$39,980	$39,980	$39,980	$39,980
Admin Costs	$404,074	$501,159	$538,410	$592,328	$622,063
O&M Staffing	$150,000	$200,000	$200,000	$200,000	$200,000

6.4 Fuel Consumption

Fuel consumption for all phases is outlined in Table 35 below. This included electricity used for pumping and for DHW production in the DHW heat pumps at customer buildings but excludes in-suite or zonal heat pump electricity consumption as it is assumed it is paid for by building occupants. This is also in line with the DES sales values where the sales for space heating and cooling are for the supply **before** heat pumps and for DHW the supply **after** the heat pumps.

Table 35: Fuel Consumption

Phase	1	2	3	4	5	6	7	8	9	10
Electricity (DES Utility) [MWh]	6,209	9,566	10,400	14,625	16,612	20,713	25,330	27,279	31,875	32,508
Natural Gas [MWh]	0	2,085	2,934	1,932	2,535	4,588	8,544	10,798	14,598	16,795

6.5 Reinvestment Costs

Reinvestment costs for major equipment for all phases are outlined in Table 36 (Phases 1 – 5) and Table 37 (Phases 6 – 10) below.

Table 36: Reinvestment Cost Assessment 1 of 2, Phases 1-5

Repair and Replacement Costs	Year (added to Phase Investment Year)	% of Initial Capital	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
Heat Pump	20	50%	3,136,000	717,570	308,000	789,180	399,840
Pumps	20	50%	273,000	521,500	56,000	84,000	112,000
Ancillary Equipment	20	20%	4,249,280	163,800	1,041,688	100,896	298,055
Piping	30	15%	21,000.0	29,400.0	11,025.0	15,225.0	19,425.0
ETS in buildings	15	50%	675,000	976,550	236,650	1,057,000	515,200
District Energy Network Costs	40	10%	226,571	273,064	146,555	48,990	145,805
Sewer Infrastructure	25	10%	554,400	77,300	-	-	-

Table 37: Reinvestment Cost Assessment 2 of 2, Phases 6-10

Repair and Replacement Costs	Year (added to Phase Investment Year)	% of Initial Capital	Phase 6	Phase 7	Phase 8	Phase 9	Phase 10
Heat Pump	20	50%	733,110	713,860	354,830	615,020	350,980
Pumps	20	50%	112,000	581,000	224,000	280,000	84,000
Ancillary Equipment	20	20%	252,295	273,384	1,016,137	339,994	498,948
Piping	30	15%	19,425.0	61,950.0	36,225.0	44,625.0	15,330.0
ETS in buildings	15	50%	964,000	1,025,400	554,500	919,700	481,300
District Energy Network Costs	40	10%	83,325	122,584	145,805	77,175	27,835
Sewer Infrastructure	25	10%	-	-	-	-	-

6.6 GHG Emissions

GHG emissions from the DES system are outlined in Table 38 below.

Table 38: GHG Emission Assessment

Phase	1	2	3	4	5	6	7	8	9	10
Emissions (Electricity) [tonnes CO2e/yr]	310	478	520	731	831	1,036	1,267	1,364	1,594	1,625
Emissions (Natural Gas) [tonnes CO2e/yr]	0	373	525	346	454	821	1,529	1,933	2,613	3,006
Total Emissions [tonnes CO2e/yr]	310	852	1,045	1,077	1,284	1,857	2,796	3,297	4,207	4,632

7 SUMMARY

7.1 Next Steps

The next step for this project is the Economic and Financial Analysis Milestone 4.

This stage incorporates:

- Steering Group Meetings
- Coordination Meetings
- Fuel Cost Study
- Funding Sources Scan
- Meeting: Town Input for Financial Model
- Rate Assessment
- Develop Techno-Economic Model
- Sensitivity Analysis
- Business Case Report

MILESTONE 4

ECONOMIC AND FINANCIAL ANALYSIS

This Section outlines the work completed in Milestone 4 of the project to set the economic analysis prior to the implementation strategy in Milestone 5.

1. PURPOSE AND MILESTONE GOALS

The purpose of Milestone 4 is to analyze the conceptual design identified in Milestone 3 from a business perspective. Techno-economic modelling for the selected scenario was advanced in order to establish expected internal rates of return (IRR), net present values (NPV) and emissions savings.

We expanded the modelling by conducting sensitivity and profitability analyses on the Business Case. Specifically, we evaluated the impact of key inputs such as load variation, cost fluctuations, development delays, market volatility, carbon tax, and policy measures on the Project. We have also identified and summarized key potential risks for the project. and their associated mitigation strategies based on our analysis and assigned high-level qualifiers to their likelihood of occurrence, financial impact and schedule impact as observed at this point in time.

1.1 Outcome

The key outcomes for this Milestone are:

- A high-level discussion to present the economic viability assessment of the preferred scenario.
- A financial analysis to identify key risks/opportunities and inform the ownership options.
- A business case to demonstrate the economic argument for progressing the development of the preferred scenario further
- A decision on moving forward with the implementation planning and the next steps in the project development process

2. BUSINESS CASE APPROACH

Our approach for this business case is as follows:

- **Global Benefit Approach:** We have defined the preferred financial solution from a global benefit, life-cycle cost perspective. The DES is informed by balancing the impact on the vertical developers, end users (residents/tenants), DES operators, and sewer energy suppliers. The allocation of cost/benefit by party has been determined based on comparable market estimates and acceptable levels of returns.
    - Note that DES systems can present the opportunity to reduce electricity and gas peak requirements through energy sharing, ultimately reducing the size and cost of utility infrastructure. This benefit has not been qualified as part of this early-stage model, and it's recommended that potential grid-scale benefits be further explored in future, more detailed stages of this project.
- **Revenue Assumptions:** The business model factors in an estimate for DES revenue equivalent to market rates for thermal energy based on our database of past DES and Energy as a Service (EaaS) projects (see Appendix B: Fuel Cost Study for more details). A connection charge was also applied on the basis of an avoided capital cost concept which is estimated to be the capital cost savings on account of not having to install a heat injection or rejection plant at the building level.
    - For the hospital, the connection charges are based on the costs associated with connecting to the system's central plant as the hospital is expected to retain its existing heat injection plant for redundancy and backup purposes
    - The sewer waste heat supplier revenues were also benchmarked to rates seen in sewer and effluent based waste heat recovery projects
- **Finance Assumptions:** The business model also evaluates the project with and without financing to check the impacts of financing on a pre-tax basis. The current business case has been without the benefit of funding. Financing has been included in the latter stages.
- **Value of Information:** At this stage, the conceptual design for the preferred scenario has been developed and the cost estimates are at the Class C level. We have completed the analysis using these estimates and also using assumptions from previous related project experience. The business modeling is of the required level of detail to review core assumptions, study the impact of project financing, evaluate ownership options and confirm the results.

Note that DES systems can present the opportunity to reduce electricity and gas peak energy requirements through energy sharing, ultimately reducing the size and cost of utility infrastructure. This benefit has not been considered at this stage, and it's recommended that potential grid-scale benefits be further explored in future, more detailed stages of this project.

2.1 Business Case Components

The key components of the commercial model and core assumptions are presented in the figure below.

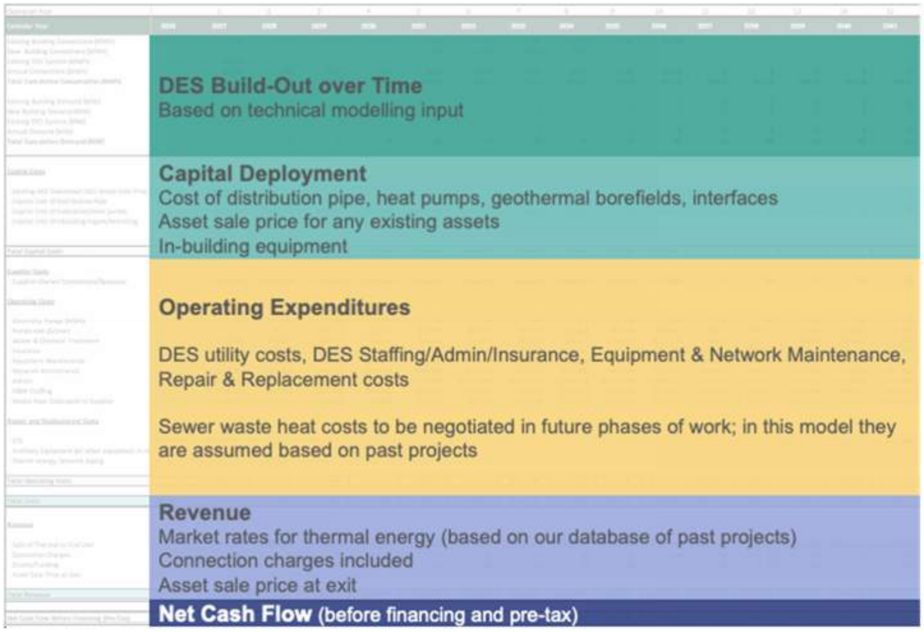

Figure 46: Economic Viability Model Components

2.2 Business Case Assumptions

Detailed business model inputs and assumptions are presented in Milestone 4 Section 3. Many core assumptions were reviewed and confirmed with Rathco ENG including our previous project experience. Initial inputs to the economic viability model were reviewed with the project team in March 2024 and then reviewed with the wider steering group in April 2024. Some of the updated inputs and assumptions were reviewed with the project teams again in May 2024. The assumptions addressed in this phase of modelling are:

Operating expenditures assumptions:

- Costs for sewer energy are typically negotiated depending on project specifics, including risk, equipment ownership, project boundaries, bilateral energy uptake and supply commitments and environmental benefits. In the business model, the costs for sewer energy have been estimated based on rates seen in the market. Sewer interface costs have been assumed to be carried by the District energy system. Environmental benefits and any related reduction in waste heat costs would need to be negotiated at later stages.

- Cost of electricity. An average value for Class B utility costs is used for electricity. A direct switch from Class B to Class A does not guarantee a reduction in utility costs. Customers need to optimize their systems to reduce energy demand during the five peak times for the electricity grid in Ontario (peak shaving). We are suggesting a targeted rate of $0.135 per kwh for heat pumps as this is a conservative estimate. Lower electricity costs may be achievable with proper peak management, which can be investigated further in future phases of diligence. Refer to Appendix B for further explanation.

Revenue Assumptions:

- Market rate for thermal energy was established by benchmarking the total cost of delivering thermal energy from our database of past DES and Energy as a Service (EaaS) projects. Refer to Milestone 4 Section 3.7 for further explanation.
- Revenue from connection charges. Similarly, in the business model, the revenue from fixed charges to cover connection costs is assumed to be equal to the avoided capital costs or savings in initial capital costs for in-building mechanical equipment, thus cost-neutral for the vertical developer. This cost is to justify the cost of in-building equipment and connection costs incurred by the DES operator.
- Asset sale price for the DES. The cash flow includes an asset sale price for the DES, also known as an "exit value" or "resale value". This value is used in calculating the Unlevered Internal Rate of Return (UIRR) for the system. The economic model assumes a terminal capitalization rate of 5%.
    - We have also tested scenarios without the asset sale price to check the impact on UIRR.

Financing Assumptions:

- Start date: 2028
- Term length – 30 years from start date
- Discount rates: 11% for DES; 9% for Sewer-heat supplier (WHS)
- No grants or funding have been assumed here in this case as the project shows a healthy return as it stands. This would only improve the business case substantially if applied for and sanctioned for use towards the project.
- Refer to Appendix C for a review of available funding for the project. Funding has the potential to improve the UIRR substantially.
- The addition of financing and funding has been added in the more detailed financial modelling for implementation planning in Milestone 5.
- We have assumed project financing with a loan term length of 20 years and an amortized repayment over the next 10 years

The intent of the business model is to determine economic merits along with identifying any funding gaps and estimating the financing requirements for the project including potential debt capacities.

3. BUSINESS CASE INPUTS AND RESULTS

The inputs to the business model follow the phasing plans, demand and energy estimates, capital operating and rehabilitation costs developed during Milestone 3 – Modelling and Design by Rathco and are summarized in this section.

3.1 Phasing

It was assumed that the system was phased according to the schedule established by Rathco in Milestone 3. Phasing is summarized in Table 39.

Table 39: System Phasing Summary

	Phase									
	1	2	3	4	5	6	7	8	9	10
Investment Year	2027	2027	2028	2030	2031	2032	2038	2041	2043	2047
Operational Year	2028	2030	2031	2032	2033	2034	2040	2043	2045	2049

3.2 Demand and Energy

The annual and peak energy values delivered were established by Rathco during the Modeling and Design phase. Both the incremental and cumulative system delivered annual energy values used as part of this assessment are summarized in Table 40.

Table 40: System Delivered Annual Energy Summary

	System Delivered Heating (MWh_{th})		System Delivered DHW (MWh_{th})		System Delivered Cooling (MWh_{th})	
	Incremental	Cumulative	Incremental	Cumulative	Incremental	Cumulative
Phase 1	26,388	26,388	-	0.0	-	0.0
Phase 2	7,764	34,153	2,517	2517	3,177	3177
Phase 3	1,019	35,172	990	3507	1,485	4662
Phase 4	3,982	39,154	2,846	6,353	6,074	10,736
Phase 5	3,016	42,170	1,443	7,796	2,432	13,168
Phase 6	6,649	48,819	2,825	10,621	4,727	17,894
Phase 7	8,125	56,945	3,093	13,714	5,132	23,027
Phase 8	3,477	60,422	1,323	15,037	2,196	25,223
Phase 9	5,805	66,227	2,210	17,247	3,667	28,890
Phase 10	3,313	69,540	1,263	18,510	2,098	30,988

Both the diversified and undiversified cumulative system delivered peak energy values used as part of this assessment are summarized in Table 41.

Table 41: Cumulative System Peak Demand Summary

	System Delivered Peak Heating (MW_{th})		System Delivered Peak DHW (MW_{th})		System Delivered Peak Cooling (MW_{th})	
	Diversified	Undiversified	Diversified	Diversified	Undiversified	Diversified
Phase 1	3.6	3.6	-	-	-	
Phase 2	9	11.1	0.7	0.9	2.3	2.9
Phase 3	10	13.1	1.0	1.6	3.2	4.4
Phase 4	17	20.5	1.7	2.6	6.1	8.3
Phase 5	21	28.3	2.2	3.4	7.7	11.3
Phase 6	25	35.2	3.0	4.2	10.3	14.7
Phase 7	35	40.5	4.0	4.9	12.6	16.6
Phase 8	40	44.7	4.4	5.3	13.6	18.0
Phase 9	47	51.8	5.1	6	15.4	20.3
Phase 10	51	55.5	5.6	6.4	16.6	21.6

3.3 Capital Costs

The capital cost estimates were established by Rathco in the Technical Assessment phase of the project and refined along with the modelling. These are summarized by phase in Table 42.

Table 42: Capital Cost Estimates

Capital Cost Estimates	CAPEX	Contingency	Total
Phase 1	$25,199,002	$3,779,850	**$28,978,853**
Phase 2	$15,171,056	$2,275,658	**$17,446,714**
Phase 3	$3,606,522	$540,978	**$4,147,500**
Phase 4	$16,060,857	$2,409,129	**$8,469,986**
Phase 5	$7,892,088	$1,197,313	**$9,179,401**
Phase 6	$10,836,343	$1,625,452	**$12,461,795**
Phase 7	$18,956,442	$2,843,466	**$21,799,908**
Phase 8	$7,207,726	$1,081,159	**$8,288,885**
Phase 9	$10,375,884	$1,556,383	**$11,932,267**
Phase 10	$5,727,524	$859,129	**$6,586,653**
TOTAL	**$121,123,444**	**$18,168,517**	**$139,291,961**

3.4 Operating Costs

The operating cost assumptions were established after further evaluations and iterations with Rathco using the estimates from Milestone 3. The fixed costs are summarized in Table 43. These costs were escalated in the model year, according to the corresponding escalators in Table 51.

Table 43: Cumulative Fixed Operating Cost Estimates

Phase	Water and Chemical Treatment	Insurance	Equipment Maintenance	Network Maintenance	Sewer Infrastructure Costs	Admin Costs	O&M Staffing
1	$19,808	$144,894	$122,115	$33,986	$39,980	$125,995	$150,000
2	$29,910	$232,128	$243,218	$74,945	$39,980	$201,850	$150,000
3	$32,533	$252,865	$261,700	$96,929	$39,980	$219,883	$150,000
4	$42,218	$345,215	$326,011	$104,277	$39,980	$300,187	$150,000
5	$47,390	$391,112	$363,168	$126,148	$39,980	$340,098	$150,000
6	$58,050	$453,421	$422,660	$138,646	$39,980	$394,279	$150,000
7	$70,324	$562,421	$528,750	$157,034	$39,980	$489,062	$200,000
8	$75,576	$603,865	$571,900	$178,905	$39,980	$525,100	$200,000
9	$84,345	$663,527	$640,337	$190,481	$39,980	$576,980	$200,000
10	$89,355	$696,460	$676,550	$194,656	$39,980	$605,617	$200,000

In addition to the fixed costs, the DES will be responsible for electricity, natural gas and sewer heat energy costs to operate the system. The estimated cumulative electricity, natural gas and sewer heat consumption values were provided by Rathco in Milestone 3, and are summarized in Table 44 and Table 45. The electricity values include pumping energy and heat pump energy for domestic hot water and Phase 1 but exclude energy for in-suite heat pumps.

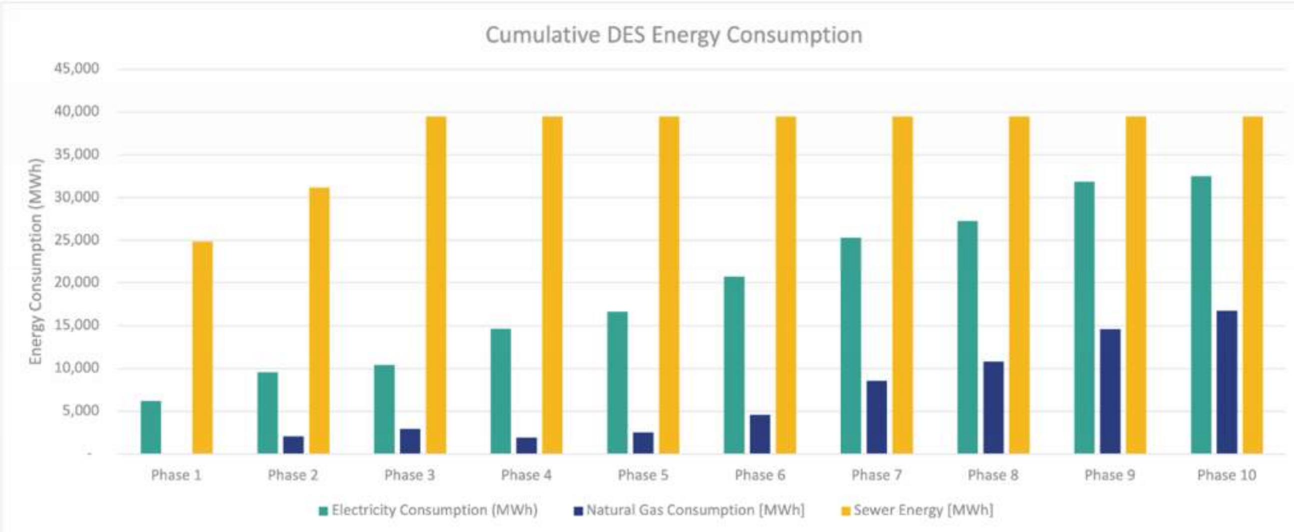

Figure 47: Cumulative DES Commodity Energy Consumption

Table 44: Cumulative DES Electricity and Natural Gas Consumption

Phase	Cumulative Electricity Consumption (MWh)	Cumulative Natural Gas Consumption (MWh)	Cumulative Sewer Energy (MWh)
1	6,209	-	24,836
2	9,566	2,085	31,193
3	10,400	2,934	39,465
4	14,625	1,932	39,465
5	16,612	2,535	39,465
6	20,713	4,588	39,465
7	25,330	8,544	39,465
8	27,279	10,798	39,465
9	31,875	14,598	39,465
10	32,508	16,759	39,465

The electricity, gas and sewer heat consumption values were then multiplied by the assumed fuel costs, provided in Table 45 and then escalated according to the corresponding annual escalators in Table 51. The fuel costs were informed by the Fuel Cost Study carried out by UE (Appendix B).

While the DES may be able to operate as a Class A customer and leverage cheaper costs of electricity, further analysis will be needed to confirm this including detailing out the understanding of the plant location and associated utility connections and infrastructure that may be present or planned. Therefore, to remain conservative for the purpose of this analysis, it was assumed that the DES was a Class B electricity customer.

Table 45: DES Fuel Costs

Commodity	Value
Electricity Price, Class B ($/kWh delivered)	$0.135/kWh
Natural Gas Price, incl. Carbon Tax ($/kWh delivered)	$0.33/kWh
Waste Heat ($/MWh) – paid by DES to sewer energy provider	$3.00/MWh

3.5 Repairs and Replacement Costs

The repair and replacement cost estimates were established by Rathco in the Technical Assessment memo. These are summarized in Table 46.

Table 46: Repair and Replacement Costs

Repair and Replacement Costs	Heat Pump	Pumps	Ancillary Equipment	Piping	ETS in buildings	DES Network Costs	Sewer Infrastructure
Year (After Investment Year)	20	20	20	30	15	40	25
% of Initial Capital	50%	50%	20%	15%	50%	10%	10%
Phase 1	$3,136,000	$273,000	$4,249,280	$21,000	$675,000	$226,571	$554,400
Phase 2	$717,570	$521,500	$163,800	$29,400	$976,550	$273,064	$77,300
Phase 3	$308,000	$56,000	$1,041,688	$11,025	$236,650	$146,555	-
Phase 4	$789,180	$84,000	$100,896	$15,225	$1,057,000	$48,990	-
Phase 5	$399,840	$112,000	$298,055	$19,425	$515,200	$145,805	-
Phase 6	$733,110	$112,000	$252,295	$19,425	$964,000	$83,325	-
Phase 7	$713,860	$581,000	$273,384	$61,950	$1,025,400	$122,584	-
Phase 8	$354,830	$224,000	$1,016,137	$36,225	$554,500	$145,805	-
Phase 9	$615,020	$280,000	$339,994	$44,625	$919,700	$77,175	-
Phase 10	$350,980	$84,000	$498,948	$15,330	$481,300	$27,835	-

3.6 Business-as-usual (BAU) – Market rate assessment

The analysis used an established business-as-usual case, which was identified in Milestone 3 - Technical Assessment phase and reviewed with the project team. The economics for the pre-feasibility were also based on a BAU building HVAC system which comprised of the following:

- **Heating:** Natural gas boilers connected to building condenser loop with in-suite heat pumps
- **Cooling:** Rooftop Fluid Coolers connected to building condenser loop and in-suite heat pumps
  Domestic Hot Water: Natural Gas Boilers.

Three options for the business-as-usual (BAU) case were evaluated as shown in Table 47.

Table 47: Business as Usual Scenarios

	Option 1	Option 2	Option 3
System Type	Natural Gas Boiler for heating and DHW. Chiller and cooling tower for cooling	Hybrid heat pump & Natural Gas Boiler for heating and DHW. Chiller and cooling tower for cooling	Full electric heat pump without gas backup. Chiller and cooling tower for cooling
Rationale	Conventional and most widely used fossil-fuel-based heating system	Aligns with electrification requirements of ZCB-Design v3. May be more reflective of market conditions when system is operational	Current best practice
Relative cost premiums		10-20% premium	15-30% premium

Option 1 was priced as the business-as-usual comparator and used for carrying out the economic assessment. The BAU costs are essentially the costs that are avoided by connecting to the DES. Typically, heat injection plants cost about $600-$1,200 per kW in the GTA. The midpoint was $900 per kW. For cooling plants, the range is $1,600 - $2,100 per kW in the GTA. The midpoint was $1,850 per kW.

For ongoing thermal energy rates charged to customers, the business-as-usual cost of thermal energy was used for Phases 2-10, as they will leverage heating, cooling and DHW from the DES. For Phase 1 (the hospital) UE leveraged established rates from our past project database for a heating-only DES. The rates are shown in the table below:

Table 48: Business as Usual Rate Estimates

Item	Assumption
Heat injection plant per MW	$900,000
Cooling plant per MW	$1,850,000
Market rate for Thermal Energy (DE) per MWh	$164
Rate Estimate for Heating Energy Only (DE) per MWh	$106

To be conservative, the business-as-usual costs were decreased by a discount factor of 20% to arrive at the rates for the new base case. The 20% discount allows for some negotiation room and flexibility based on how the discussions progress with the developers. Additionally, this provides some flexibility to account for the changes that cannot be anticipated in the market by the time the system is fully designed and operational. It is important to note that green development standards in the Greater Toronto Area are all trending towards low-carbon hybrid systems and could thus influence the business-as-usual cost comparison. The discounted business-as-usual rates are summarized in Table 49 below.

Table 49: Business as Usual Rate Estimates (Discounted)

Item	Assumption
Discounted Heat injection plant per MW	$720,000
Discounted Cooling plant per MW	$1,480,000
Discounted Hospital Connection Costs per MW	$305,500
Discounted Market rate for Thermal (heating and cooling) Energy (DE) per MWh	$132
Discounted Rate for Heating-only Energy (DE) per MWh	$85

The connection charges for the hospital are based on the costs associated with connecting to the system's central plant as the hospital is expected to retain its existing heat injection plant for redundancy and backup purposes. Therefore, the connection fees for Phase 1 of the DES were assumed to be equal to the costs of the energy transfer station (ETS), and then discounted at 20%, similar to the rest of the revenues. Therefore, the assumed connection fees for the hospital were about $305,500 per MW of heating capacity.

3.7 District Energy Rates

The district energy rates are the charges that customers who connect to the district energy system would pay and are determined by comparing them with the BAU estimates mentioned above. The key components of district energy rates typically follow the classic utility model, and they are:

- Connection / Upfront Charge
- Capacity Charge (annual)
- Energy Consumption Charge (based on actuals)
- Operating and Maintenance / Distribution Fee

3.8 Market Rates for Thermal Energy

Using our database of past DES and Energy as a Service (EaaS) projects, we have benchmarked the total cost of delivering thermal energy.

The cost to deliver thermal energy offsets several fixed and variable operating expenditures for end-user buildings, including:

- Electricity
- Natural Gas with carbon charges
- Water
- Chemicals
- Reserve Fund – for repairs and replacements
- Operations & Maintenance
- Administrative expenses
- Insurance for the heat injection and cooling plant

The rate charged for thermal energy is assumed to be equal to these costs, plus a 20% discount so that end users are charged a cost-competitive market rate. As shown in Figure 48 below, the equivalent market rate for thermal energy falls within the current market rates for electricity and natural gas.

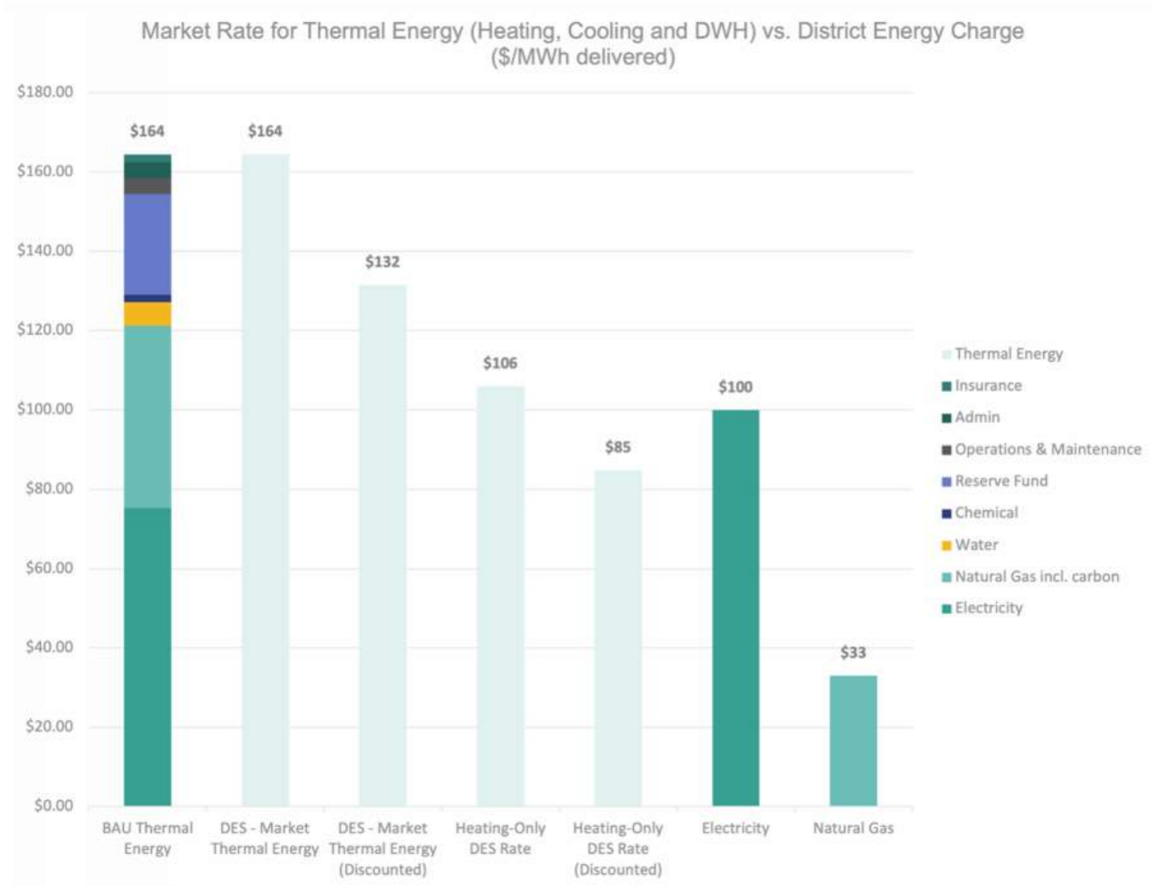

Figure 48: Expected Business as Usual Market Rates ($/MWh Delivered

The first bar in the chart above was generated by totalling all costs to operate the heating, cooling and DHW plants for the BAU scenario, and dividing by the total amount of thermal energy provided. This resulted in an indicative baseline cost per MWh in a business-as-usual scenario – this is what future DES customers would be paying to operate their buildings without a DES connection. Therefore, a DES system with the same rates would be cost-competitive over the course of any given year, meaning that $164/MWh (or $0.164/kWh) would be a competitive market rate for thermal energy. To layer in additional conservatism, a 20% discount was applied to this rate, and $132/MWh (or $0.132/kWh) was selected for the base rate for thermal energy.

As the hospital (Phase 1) will only be leveraging the DES for heating (compared to the rest of the customers, who will be using the DES for heating, cooling and DHW), a unique rate was assigned for the hospital's connection. This rate ($106/MWh) was established using our database of past heating-only DES and Energy as a Service (EaaS) projects. To remain consistently conservative across the assessment, this rate was further discounted by 20%, resulting in a base case thermal energy rate of $85/MWh (or $0.085/kWh) for Phase 1 of the DES.

Note that the costs shown for electricity and natural gas in the figure above (i.e. the sixth and seventh bars in the chart) are **fuel costs only** and are present only to show that the assumed BAU commodity rates are within a reasonable range.

Note that for the business model, fixed charges to cover connection costs are assumed to be equivalent to savings in initial capital costs for in-building mechanical equipment (heat injection or cooling plant).

3.8.1 Sewer Waste Heat Rates

The third rate that is important to establish is the price paid to suppliers for sewer waste heat or energy. Typically, this rate is negotiated between the DES and the sewer heat suppliers. It can depend on several factors:

1. Who owns the equipment (i.e., heat pumps) that extract the sewer heat and supply it to the DES?
2. What level of capital investment is required by the sewer energy suppliers, if any?
3. Who gets credit for any related carbon reductions, for example, no cost for the waste heat if the waste heat suppliers are getting some of the carbon reductions?
4. DES owns and pays for all heat recovery plants, and suppliers are to provide only piping connections and bypasses (i.e. equipment on their property).
5. Sensitivity analyses have also been run for the waste heat rates.

3.8.2 Base Case Rates

As stated before, Option 1 of the 3 options shown in Table 47 was priced as the BAU case. The rates arrived at for the base case are shown in Table 50 and were set equivalent to the discounted BAU rate estimates. This was done to provide some flexibility in the analysis, as market conditions may change significantly between now and the time the system becomes operational. The connection charge which is levied during the year of connection or start of service was set to the equivalent avoided central plant capacity that customers would avoid.

Table 50: Base Case Rates for DES and Sewer Energy

Item	Assumption
Connection Charge Heating and DHW (Upfront) per MW (Phases 2-10)	$720,000
Connection Charge Cooling (Upfront) per MW (Phases 2-10)	$1,480,000
Connection Charge – Hospital Only (Total $)	$1,081,593
Market rate for Thermal (Heating and cooling) Energy (DE) per MWh (charged to Phases 2-10)	$132
Rate for Heating Energy (DE) per MWh (charged to Phase 1)	$85
Waste Heat ($/MWh) – paid by DES to sewer energy provider	$3.00

3.9 Escalation Rates

Table 51: Escalation Rates shows the escalation rates assumed for the business model. Refer to the footnotes as well.

Table 51: Escalation Rates

Value	Escalation Rate	Value	Escalation Rate
CPI[6]	3.5%	Thermal Energy[7]	4%
Capital Expense	3.5%	Gas	3.5%
Electricity	3.5%	Maintenance	3.5%
Water	3.5%	Carbon Tax	5% (after 2030)[8]

[6] Conservative value assumed

[7] Half percent higher than CPI to account for revenue growth

[8] Escalates to government shadow price of $300 per tonne by early 2040s.

4. RESULTS & PROJECT VIABILITY

4.1 DES Results - With Terminal Value

The following table and figures present the business model results for all 10 phases of the DES, considering a terminal value of the asset, given the assumptions and estimates presented in the previous sections up to the date of issue.

Table 52: District Energy System Results with Terminal Value Considered

District Energy System Results with Terminal Value Considered – 30 Year Term		
Capital Costs	$201	M
Operating Costs	$404	M
TOTAL COSTS	**$605**	**M**
Thermal Energy Sales	$586	M
Connection Charges	$117	M
Terminal Value	$470	M
TOTAL REVENUE	**$1,173**	**M**
TOTAL PROFIT (FV)	**$706**	**M**
TOTAL PROFIT (PV)	**$13.8**	**M**
UIRR (pre-tax, excluding funding/financing)	**13.3**	**%**

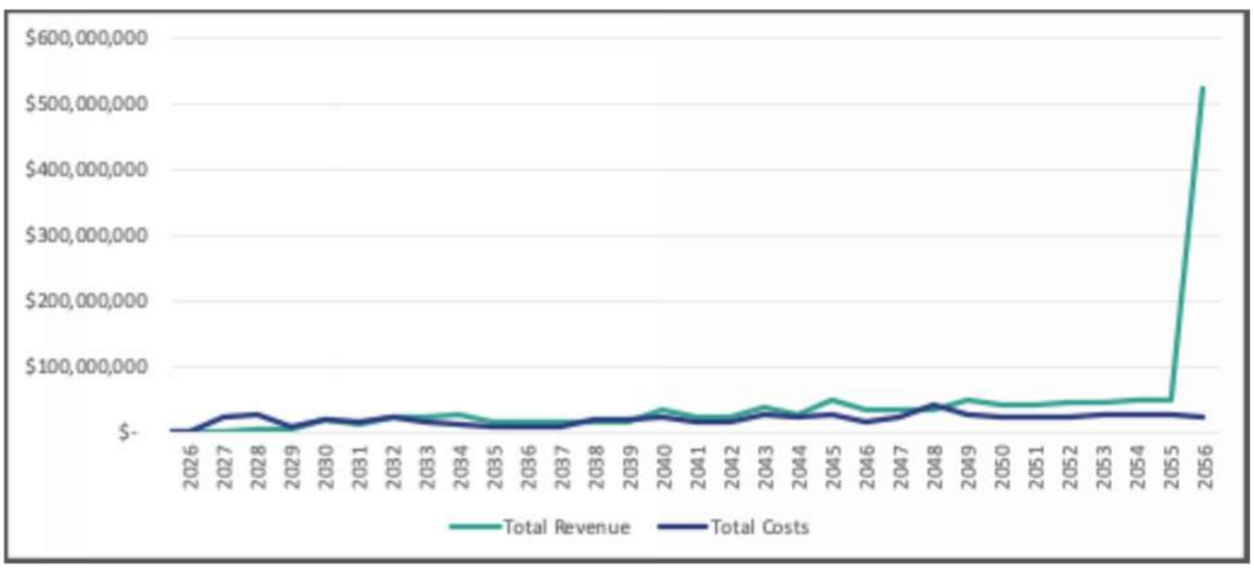

Figure 49: Revenue vs Cost for the DES Business Case (With Terminal Value)

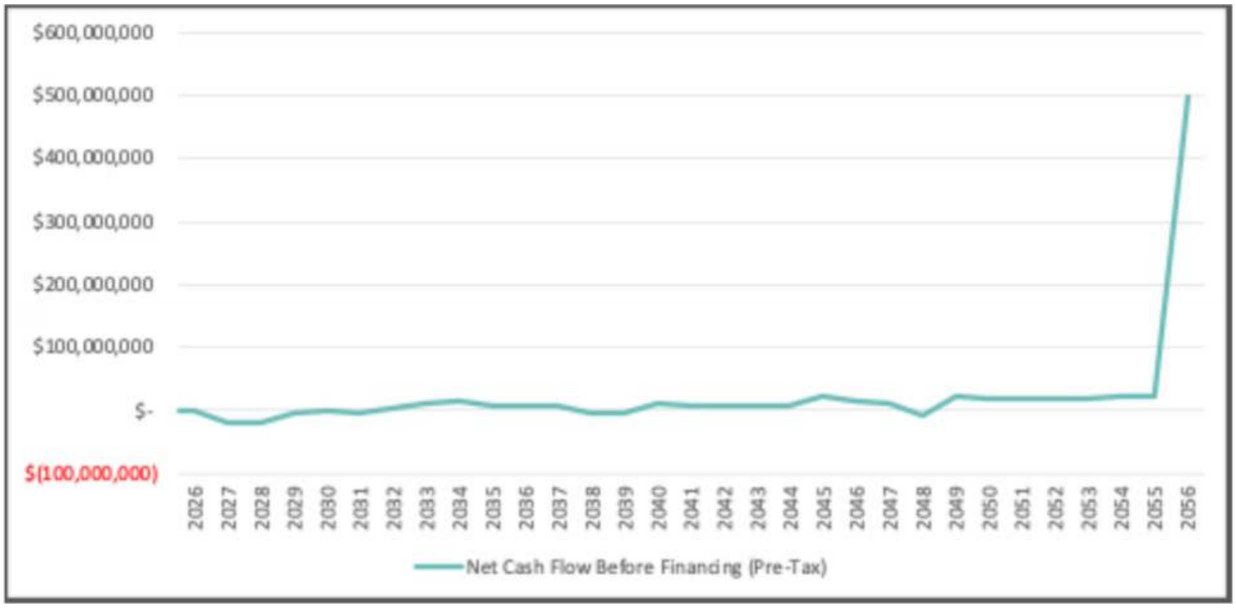

Figure 50: Net Cash Flow for the DES Business Case (With Terminal Value)

4.2 DES Results - Without Terminal Value

The following table and figures present the business model results for all 10 phases of the DES, without a terminal value, given the assumptions and estimates presented in the previous sections up to the date of issue.

Table 53: District Energy System Results Without Terminal Value Considered

District Energy System	30 Year Term	
Capital Costs	$201	M
Operating Costs	$404	M
TOTAL COSTS	**$605**	**M**
Thermal Energy Sales	$586	M
Connection Charges	$117	M
Terminal Value	$0	M
TOTAL REVENUE	**$703**	**M**
TOTAL PROFIT (FV)	**$236**	**M**
TOTAL PROFIT (PV)	**($1.2)**	**M**
UIRR (pre-tax, excluding funding/financing)	**10.7**	**%**

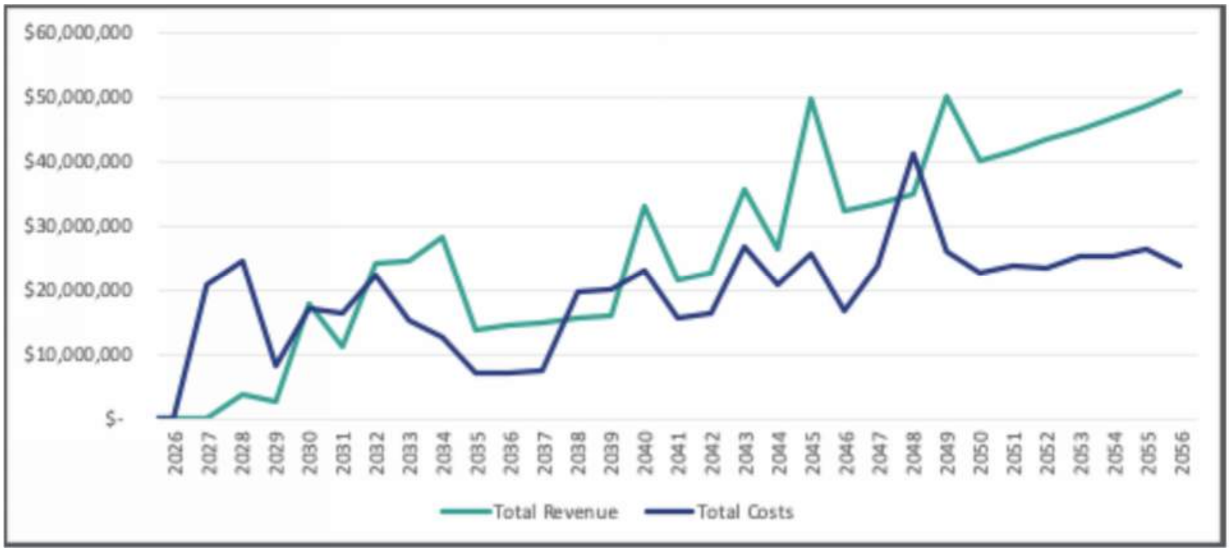

Figure 51: Revenue vs Cost for the DES Business Case (Without Terminal Value)

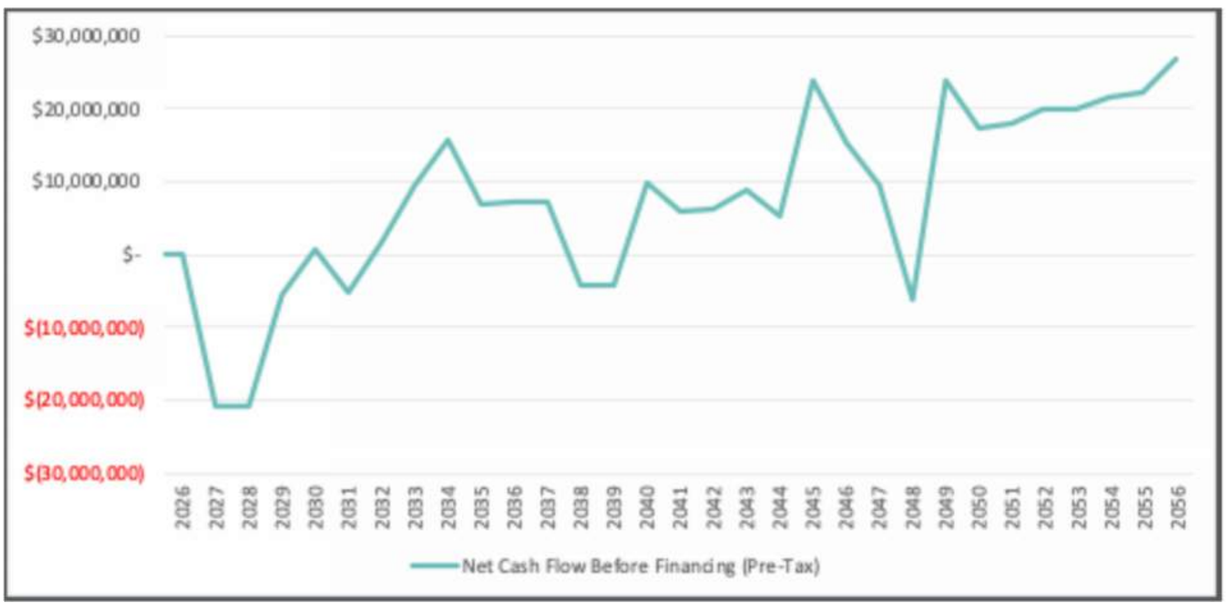

Figure 52: Net Cash Flow for the DES Business Case (Without Terminal Value)

4.3 Wastewater Heat Supplier Results

Table 54 provides a summary of the business case results for the wastewater heat supplier (WHS). Given that it was assumed that the DES scope includes the costs of all supplier connections, it is expected that the WHS will experience no capital or operating costs as a result of the DES connection. Rather, the WHS will experience only financial upside through thermal energy sales (as per the rates summarized in Table 50), resulting in a positive NPV of $1.4M.

Table 54: Wastewater Heat Supplier Business Case Results

Wastewater Heat Supplier	30 Year Term	
Capital Costs	$0	M
Operating Costs	$0	M
TOTAL COSTS	**$0**	**M**
Thermal Energy Sales	$7.2	M
TOTAL REVENUE	**$7.2**	**M**
TOTAL PROFIT (FV)	**$7.2**	**M**
TOTAL PROFIT (PV)	**$1.4**	**M**
UIRR (pre-tax, excluding funding/financing)	**-**	**%**

A graph depicting net cashflow for the wastewater heat supplier has been provided Figure 53. It can be seen that the WHS sees only positive cashflow, indicating a strong business case.

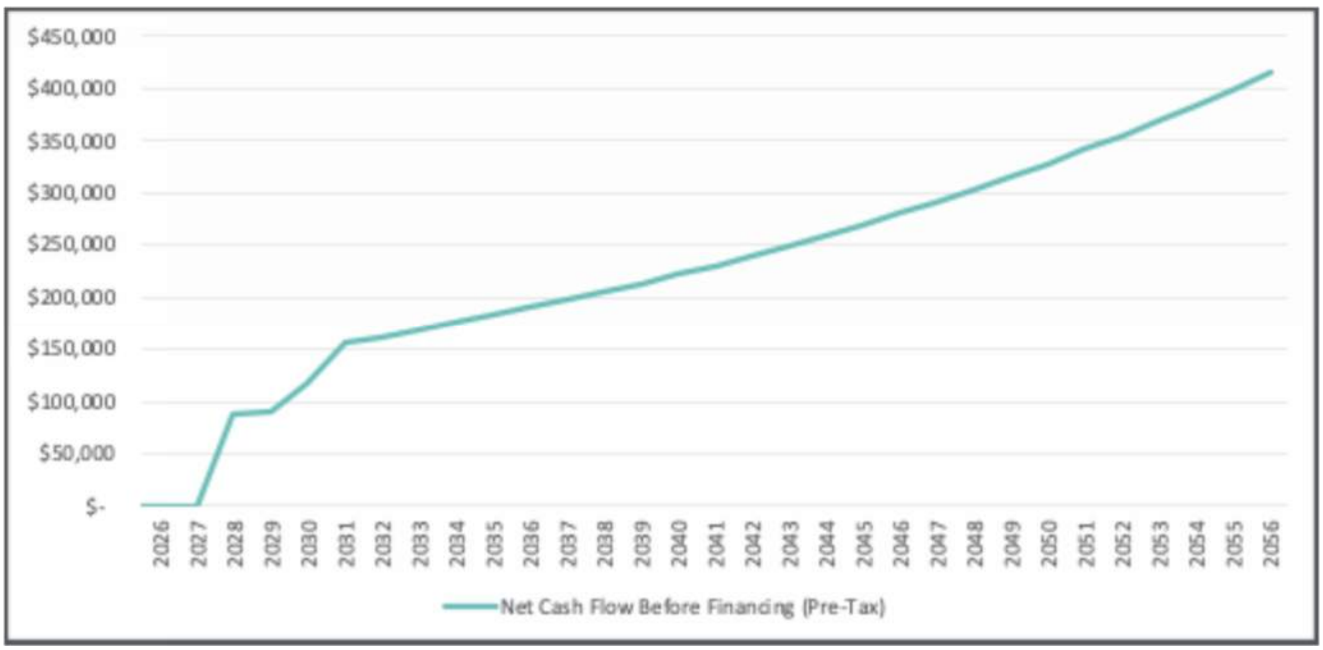

Figure 53: Net Cashflow for Wastewater Heat Supplier

4.4 Emissions Comparison

Figure 54 shows how the incremental carbon emissions for the DES compare to that of the baseline scenario. Overall, each phase shows a reduction in emissions for the DES, when compared to the BAU scenario.

Furthermore, it can be seen that Phase 1 shows drastic savings in emissions, given that the hospital connection is solely providing heating, which is using only natural gas in the baseline scenario. A notable savings in emissions can also be seen in Phase 4, as it's expected that this phase brings more heat pump capacity online, allowing for some natural gas boiler use to be reduced. Ultimately, this reduces the emissions intensity for this phase when compared to the previous phase.

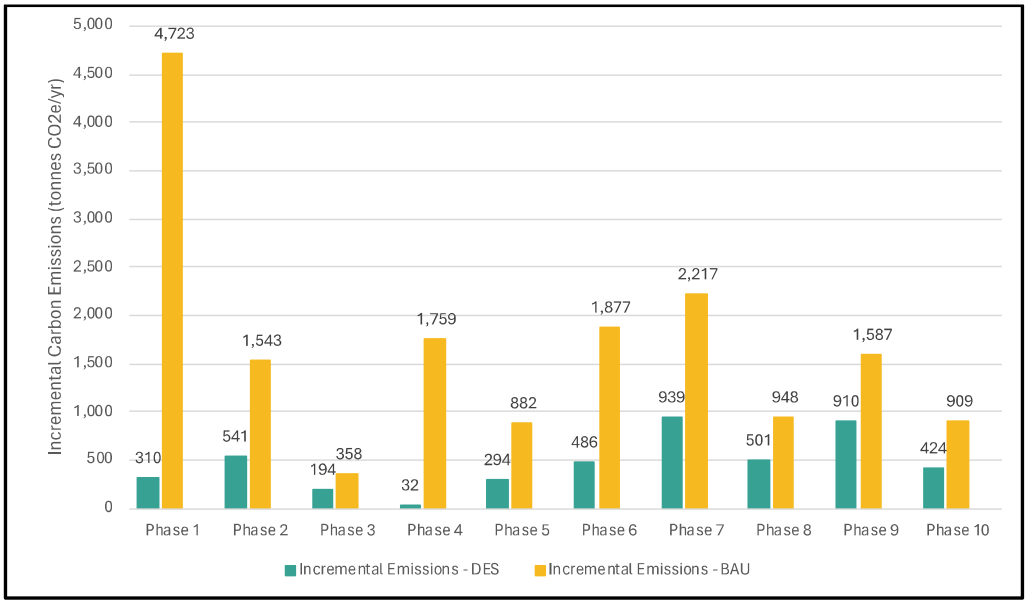

Figure 54: Emissions Comparison (Incremental)

Figure 55 shows the cumulative emissions comparison between the DES and the BAU scenarios. By full buildout, the DES is saving ~12,300 tonnes of CO2e per year.

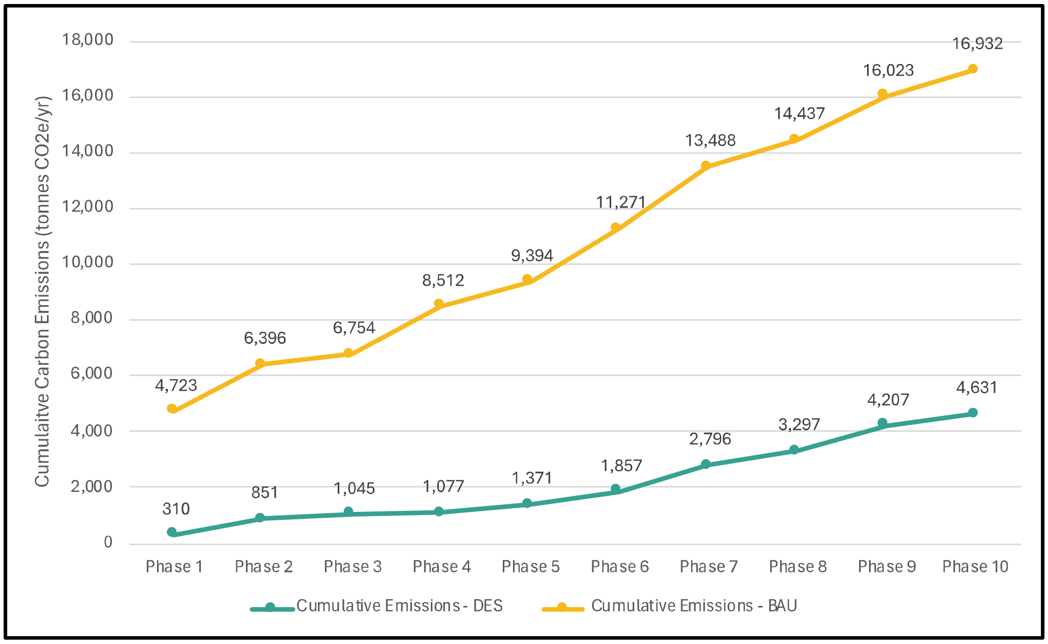

Figure 55: Emissions Comparison (Cumulative)

5. SENSITIVITY ANALYSIS

A sensitivity analysis was performed to evaluate how changes to the assumptions or market conditions would impact the financial results. The analysis evaluated upside cases and downside cases for the district energy supplier's (DES) unlevered rate of return (UIRR), net present value (NPV), and the waste heat supplier's (WHS) net present value of savings relative to the target or assumed values for the following key variables as shown in following tables below:

- Thermal Energy Rates Discount (applied to all sensitivity analyses)
- Thermal Demand
- Revenue / Market Utility Rates
- Discount Rates (Supplier and Developer)
- Project phasing risks
- Capital expenditures
- Operational expenditures
- Repairs and rehabilitation expenditures
- Financial Escalators
- Contingency levels
- Carbon tax

This analysis was performed for the following reasons:

- To appropriately size the capacity of the project to withstand major financial and economic headwinds
- To establish a realistic and robust investment-grade baseline for the project

This analysis was carried out without considering a terminal asset value in addition to the other conservative assumptions made in the base case.

An indicative range for the sensitivities has also been shown based on what is possible and probable in projects like this. A more detailed sensitivity analysis using more data points is recommended over the development of the project to develop a finer understanding of the associated risks, impacts and required commercial structures. Table 55 provides a summary of the base-case scenario as a reference for the subsequent sensitivity analyses. It is important to note that while the base-case NPV is negative, this is due to the conservative 11% discount rate assumption made for the DES owner. Typical minimum unlevered rates of return in the DES market range between 8 and 12%, and therefore it's expected that any unlevered rate of return greater than 8% remains promising for this project.

Table 55: Sensitivity - Base Case Summary

Supplier	Unlevered Internal Rate of Return (%UIRR)	Net Present Value (NPV) ($2024)
District Energy Supplier (DES)	10.7%	($1.2M)
Waste Heat Supplier (WHS)	-	$1.4M

5.1 Sensitivity to Thermal Demand, Revenues and Rates

This sensitivity analysis shows the effect on the business case as thermal demand and revenues increase or decrease. These factors have a material impact on the business case as revenues are substantially impacted as seen in Table 56.

When annual heating energy loads increase by about 29% or 20,000 MWh from the currently estimated 69,545 MWh, returns for the DES increase to 14.0%. Conversely, if heating energy demand decreases by about 29% or 20,000 MWh, the returns drop to 6.5%. This indicates that the DES profitability is highly sensitive to heating demand. Similarly, both the DHW and cooling energy values were sensitized by +/- 28% and 29%, respectively. While they did impact the financial outcomes, they were far less severe than the heating demand change, given the large heating energy demand across the system. For the purpose of this analysis, the energy delivered, and the rates charged by the WHS were assumed to remain consistent, even as the thermal energy demands on the DES changed, thus leaving the NPV for the WHS system unchanged.

Thermal energy rates also have a material impact as they directly affect revenues for the DES; when rates for the DES are increased 20%, returns go up to 12.4%. However, if rates are lowered by 10%, then return drops to 8.4%.

To sensitize the importance of the hospital to the project's profitability, a scenario without Phase 1 loads and thermal energy demand was assessed. To remain conservative, this analysis did not change the capital costs of the project (i.e. the DES was constructed as currently configured, but they did not connect and add to the DES revenue generation). Without the revenue from the hospital, the DES IRR drops to 7.4%. This indicates that the hospital, as the anchor tenant, is reasonably important to the profitability of the DES. As such, continued stakeholder engagement with the hospital remains critical to project success.

5.1.1 Development Delays

Table 56 also shows the impact of development delays and risks that phases and buildings take longer to connect and come online. For this analysis, Phases 2-10 were delayed by 2 years and 5 years to check the impact on the business case. For both a 2- and 5-year delay, there was a slight reduction the financial performance for both the DES or the WHS, indicating that the project is relatively resilient to both minor and major time delays.

Under a 2-year delay scenario, the DES UIRR decreased to 10.4%, but when the delay was increased to 5 years, the DES UIRR dropped to 9.8%. This occurs because the capital-intensive central plant is being constructed for the first phase but won't be fully utilized until the later phases come online.

At the request of the Town, an additional time-delay sensitivity analysis was conducted: the buildout for Phases 1-3 was doubled to simulate supply-chain delays in construction. This was carried out to assess potential impacts of COVID-19 related supply chain delays impacting the project phasing during the first three phases. The connections for Phases 4-10 were shifted back as a result of the delay, but their build-out schedules were unchanged. This delay resulted in an immaterial decrease in the project UIRR, indicating that is not expected to be a notable project risk.

5.1.2 Discount Rates

Table 57 summarizes the impact on the business case when the discount rates for both the DES and WHS are altered. In the case of the DES, the sensitivity range for the discount rate is 9-13%. At a discount rate of 9%, the

DES sees a positive NPV, as the discount rate is lower than the project IRR. When the discount rate was increased to 13%, the DES NPV became more negative than in the base case. However, given that the 11% discount rate leveraged in the base-case analysis is a conservative assumption, it's expected that a discount rate of 13% is highly unlikely.

In the case of the WHS, who is only seeing positive cashflows for the sale of waste heat, increasing the discount rate does slightly decrease the NPV, but overall, there is still a strong financial outcome for the WHS.

5.2 Sensitivity to Project Costs

This sensitivity analysis shows the effect on the business case as various aspects of the project cost increase or decrease. This includes capital costs, operating costs, repairs and rehabilitation costs, contingency amounts and carbon tax. The results are summarized in Table 58.

If all capital costs for the DES were to decrease by 10%, then returns could increase to 12.6%. Conversely, if all capital costs were to increase by 30%, returns drop substantially to 6.5%. This indicates that changes in capital costs have a material impact on the business case. The contingency levels, however, are not expected to have a material impact on the business case as they form a much smaller part of the project's costs.

Increases or decreases in fixed operating costs do not have a significant impact on the business case. However, changes to the variable commodity costs did show a reduction in DES UIRR to 8.4% under the downside scenario. While the project still meets the typical market minimum rate of return of 8%, commodity costs should be monitored carefully throughout this project due to their impact on the business case.

5.2.1 Carbon tax

A key policy factor and risk to low-carbon projects like these is the role of carbon taxes. While it is difficult to say with certainty whether carbon taxes will stay as they are, increase or be removed completely, these cases need to be tested to ensure the model is resilient to such changes. Table 58 provides a summary of the impact of sensitizing the carbon tax impact.

The current assumption is that carbon tax holds up to 2030, as per the rates defined and is escalated (at 5% after 2030) up to the government shadow price of $300 per tonne by the early 2040s. If carbon taxes are removed, the thermal energy rates for the DES would come down to align with the lower costs of gas, and thus lower returns for the DES to 9.8%. Conversely, if the carbon tax escalates faster at 6.5% after 2030, the impact on the DES business case is relatively minimal.

5.3 Sensitivity to escalation rates

Table 59 shows the sensitivity analysis for the project cost escalation rates. The results of this analysis show that the escalations in thermal energy, capital expenses, and electricity have the most significant impacts on the business case.

While capital expenses and electricity have a notable impact on the returns, under both downside scenarios the IRR for the DES remains above typical market minimums of 8%. If the thermal energy rates escalate at 2.5% per year instead of the assumed 4%, however, the IRR for the DES will drop to 3.3%, indicating that the financial performance of this project is heavily dependent on the thermal energy rate escalator. Given that thermal energy rates are the only recurring revenue generation that this project has, if they don't escalate enough to overcome the escalation of operational costs and future recapitalization, the project's profitability will be at risk.

Similar to commodity costs, it's recommended that market thermal energy rates are monitored closely as this project progresses, in order to minimize risk.

5.3.1 Escalation Rates – Conservative Scenario

Given that most escalation rates are often closely tied to standard market inflation, it would be expected that changes to annual escalation in one category would also be seen in the others. To model another escalation scenario, the business case model was re-run with a new set of escalation rates for all OPEX and revenue costs.

Table 60 summarizes the assumptions and returns for a scenario where the market escalates at lower rates than initially modelled, including the annual thermal market escalator. While reduced OPEX escalators may be desirable for the project, it would also likely drive market tolerance for higher thermal energy rate escalators down, which would in turn drive down total revenue. Indeed, under a scenario with lower annual escalators, the overall project rate of return dropped to 8.48%. While this IRR is likely to still be attractive to prospective DES owners, market escalation rates should be closely monitored as the project progresses to ensure overall profitability.

Table 56: Sensitivity – Thermal Demand, Revenue, and Project Phasing

Risk / Lever	Scenarios	Target or current	Realistic Upside	DES (% UIRR)	DES NPV ($2024)	WHS NPV ($2024)	Realistic Downside	DES (% UIRR)	DES NPV ($2024)	WHS NPV ($2024)	Proposed Sensitivity Range
Heating Demand	Increase or decrease	69,540 MWh	20,000 (29%)	14.0%	$12.6M	$1.4M	-20,000 (-29%)	6.5%	($15M)	$1.4M	+/- 50%
DHW Demand	Increase or decrease	18,510 MWh	5,000 (28%)	11.5%	$2.1M	$1.4M	-5,000 (-28%)	9.8%	($4.5M)	$1.4M	+/- 50%
Cooling Demand	Increase or decrease	30,988 MWh	9,000 (29%)	12.1%	$4.7M	$1.4M	-9,000 (-29%)	9.0%	(7M)	$1.4M	+/- 50%
Revenues / Thermal Energy Rates	Increase or decrease	Market-based	20%	14.4%	$14.6M	$1.7M	-10%	8.4%	($9.2M)	$1.2M	-10% to 20%
Supply Chain Risks	Delayed completion of early phases	No Delay	-	-	-	-	Phases 1-3 take twice as long to complete	10.0%	($3.2M)	$1.3M	-
Project Phasing Risks	Delay in phases 2-10 coming online	No delay	-	-	-	-	2-year delay	10.3%	($2.6M)	$1.3M	0-5 years
Project Phasing Risks	Delay in phases 2-10 coming online	No delay	-	-	-	-	5-year delay	9.8%	($4M)	$1.2M	0-5 years
Hospital Revenue	Hospital Does Not Connect	Hospital Connected	-	-	-	-	No Hospital Revenues or fuel costs	7.42%	($13.9)	$1.3M	-

Table 57: Sensitivity - Discount Rates

Risk / Lever	Scenarios	Target or current	Realistic Upside	DES (% UIRR)	DES NPV ($2024)	WHS NPV ($2024)	Realistic Downside	DES (% UIRR)	DES NPV ($2024)	WHS NPV ($2024)	Proposed Sensitivity Range
Discount Rate (WHS)	Increase or decrease	9%	7%	10.7%	($1.2M)	$1.9M	11%	10.7%	($1.2M)	$1M	7% to 11%
Discount Rate (DES)	Increase or decrease	11%	9%	10.7%	$8.4M	$1.4M	13%	10.7%	($6.9M)	$1.4M	9% to 13%

Table 58: Sensitivity – Project Costs

Risk / Lever	Scenarios	Target or current	Realistic Upside	DES (% UIRR)	DES NPV ($2024)	WHS NPV ($2024)	Realistic Downside	DES (% UIRR)	DES NPV ($2024)	WHS NPV ($2024)	Proposed Sensitivity Range
Capital Cost	Increase or decrease	0%	-10%	12.6%	$5.6M	$1.4M	30%	6.5%	($21.7M)	$1.4M	-10% to 30%
Contingency	Increase or decrease	15%	10%	10.7%	($1M)	$1.4M	20%	10.6%	($1.4M)	$1.4M	25% to 45%
OPEX - Fixed	Increase or decrease	0%	-20%	11.4%	$1.6M	$1.4M	20%	9.9%	($4M)	$1.4M	-20% to 20%
Commodity Costs	Increase or decrease	0%	-30%	12.7%	$6.9M	$1.4M	30%	8.4%	($9.3M)	$1.4M	-30% to 30%
REPEX – R&R	Increase or decrease	0%	-10%	10.8%	($884K)	$1.4M	30%	10.4%	($2.1M)	$1.4M	-10% to 30%
Carbon tax	Removed	5% (after 2030)	No carbon tax	9.7%	($4.9M)	$1.4M	6.5% after 2030	10.6%	($1.6M)	$1.4M	Rates defined up to 2030. 5% after.

Table 59: Sensitivity - Annual Escalation Rates

Risk / Lever	Scenarios	Target or current	Realistic Upside	DES (% UIRR)	DES NPV ($2024)	WHS NPV ($2024)	Realistic Downside	DES (% UIRR)	DES NPV ($2024)	WHS NPV ($2024)	Proposed Sensitivity Range
Capital Expense	3.5%	Increase or decrease	2%	11.7%	$2.5M	$1.4M	5%	9.5%	($5.7M)	$1.4M	2% to 5%
Electricity	3.5%	Increase or decrease	2%	11.9%	$3.7M	$1.4M	5%	8.7%	($7.7M)	$1.4M	2% to 5%
Water & Chemicals	3.5%	Increase or decrease	2%	10.7%	($1.1M)	$1.4M	5%	10.7%	($1.3M)	$1.4M	2% to 5%
Thermal Energy	4%	Increase or decrease	5.5%	15%	$21.4M	$1.7M	2.5%	3.3%	($18.3M)	$1.1M	2.5% to 5.5%
Gas	3.5%	Increase or decrease	2%	10.8%	($918K)	$1.4M	5%	10.6%	($1.6M)	$1.4M	2% to 5%
Maintenance	3.5%	Increase or decrease	2%	10.9%	($433K)	$1.4M	5%	10.4%	(2.2M)	$1.4M	2% to 5%

Table 60: Conservative Market Escalation Sensitivity Scenario

Escalator	Base Case Value	New Value	DES (% UIRR)	DES NPV ($ 2024)	WHS NPV ($2024)
Capital Cost Escalator	3.5%	2.5%	8.48%	($8M)	$1.2M
Electricity Escalator	4%	3%			
Water and Chemicals	3.5%	2.5%			
Thermal Energy Escalator	4%	3%			
Natural Gas Escalator	3.5%	2.5%			
Maintenance Escalator	3.5%	2.5%			
Carbon Tax Escalator	5% (after 2030)	5% (after 2030)			

5.4 Project Ramp

Figure 56 shows how the project's returns ramp up with each phase coming online. It can be seen that Phase 1 of the project (the hospital) exhibits significantly lower returns compared to the rest of the project. This is because Phase 1 carries a significant amount of the project's capital cost (about 20%), but the hospital's connection fees and ongoing thermal energy rates are lower than the other phases, as they are only using heating energy. Therefore, the cost-to-revenue ratio for the Phase 1 alone is higher than the other phases, explaining the lower rates of return. The project crosses typical market return thresholds of 8% in Phase 4, and the IRR steadies around 10.5% after Phase 7. This trend is very common in DES projects, as they are very capital-intensive in the early phases, but start to generate more revenue as later phases come online and begin generating additional revenue. This ramp illustrates the importance of engaging future customers early in the process to ensure the investments made in Phase 1 are utilized fully as the project progresses.

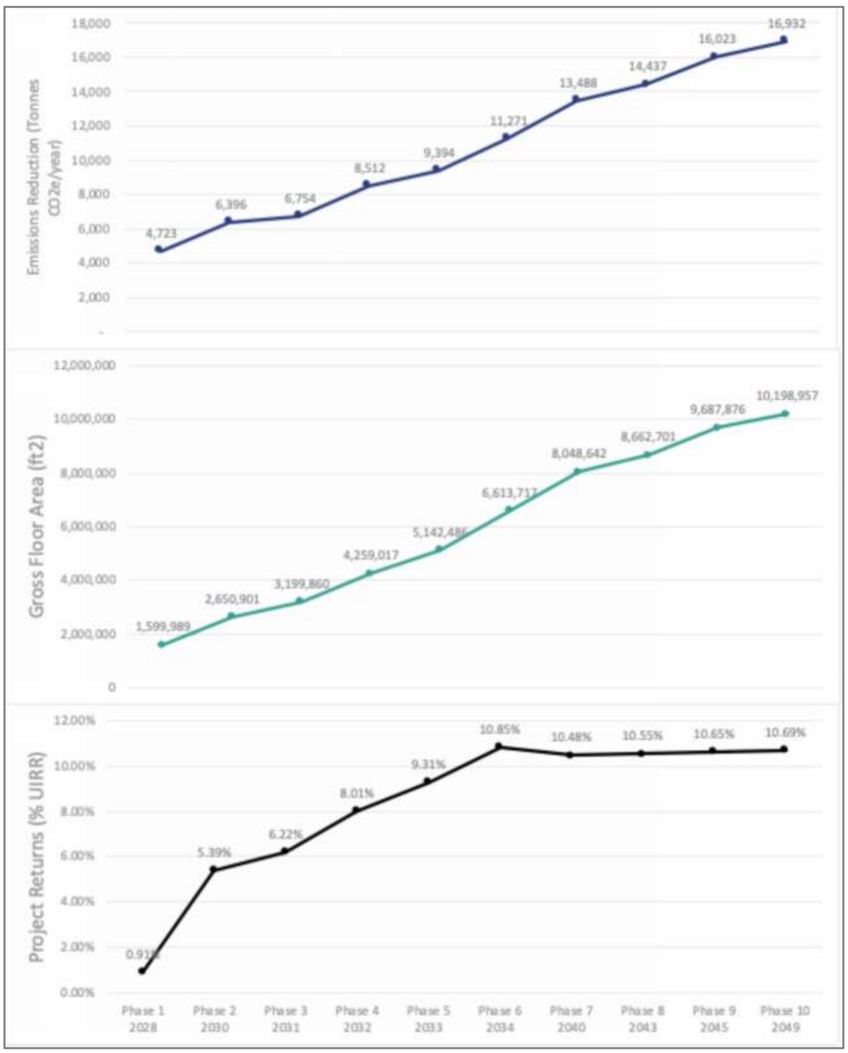

Figure 56: Project Ramp

6. ENVIRONMENTAL, SOCIAL AND GOVERNANCE ATTRIBUTES

The business case defines the investability and opportunities involved for key stakeholders in implementing the DES project for the hospital district. It serves as a Gate 1 checkpoint that determines the level of investment and effort needed for the following phases of Implementation planning, project development and execution. With refined costing and financial inputs, the impacts to key financial parameters have been well understood and presented. A stable and reliable energy infrastructure also supports increased economic activities by attracting new investments in land development and a complementary mix of energy consumers that would improve the performance of the DES. The hospital can expeditiously meet its net-zero and decarbonization ambitions and expect to have a net lowering of energy and operational costs that would improve their cash flows as well.

- **Governance:**
  This stage of the project presented suitable ownership models. The next stage will go into this further to determine the appropriate level of equity and debt participation from the private and public sectors. The business case informs the governance frameworks and required agreements for the planning, design and implementation phases of the project. We will work with the Town to identify a preferred governance framework and operating model for the Town and external stakeholders.

- **Social:**
  The project would serve as a fantastic educational avenue. It can engage students from colleges and universities to delve into certain aspects and expand the learning avenues for decarbonization, climate change mitigation and clean energy strategies. Once fully built up, the project infrastructure facilities can incorporate educational aspects and centers to host students and community members to showcase the project and share the learnings from its development and implementation with a global audience. The project would create additional jobs through the development and execution and would also need to hire 2 full-time operators.

- **Environmental:**
  The project supports massive carbon reduction at scale. Emissions savings at full buildout are estimated to be approximately 12,300 tCOe on an annual basis and over 70% compared to assumed business-as-usual heating and cooling systems. The project uses geo-exchange and sewer energy recovery which will lower overall heating, cooling, and DHW energy-related emissions as well as harness other renewable sources for phasing out additional emissions. The project would also need to establish a position on the ownership and transfer of carbon credits and or energy attribute certificates that is in line with carbon accounting protocols for the sewer energy and the geo-exchange related energy as borefields would be distributed throughout the hospital district and below several of the developments that would potentially connect to the system.

MILESTONE 5

IMPLEMENTATION PLANNING

This Section outlines the work completed in Milestone 5 of the project to the implementation strategy and next steps required for the project.

1. PURPOSE AND MILESTONE GOALS

The purpose of the Implementation Planning Assessment is to assess how the technically and financially optimized DES might be best implemented.

The goal of this milestone is to develop a high-level implementation plan that will offer the team an overview of key project risks and mitigation strategies, key partnership opportunities, implementation considerations and the preferred governance framework.

1.1 Outcome

The key outcome for this milestone is:

- An implementation plan that identifies key risks and mitigation strategies, key partnerships, implementation considerations and the preferred governance framework.

2. MARKET SOUNDING EXERCISE

In order to ensure that a DES is feasible within any given study area, it's critical to obtain a strong understanding of what the business and ESG objectives of each party are, and how they impact the DES financial analysis. This exercise intended to

- establish which developers in the study area were interested in connecting to the system;
- determine whether there was interest amongst known and established key industry stakeholders and district energy providers; and
- glean relevant feedback from local authorities in order to determine if there were any real or perceived regulatory challenges or opportunities posed by the project.

As part of this scope of work, UE met with six (6) developers, five (5) key industry stakeholders and district energy suppliers, and four (4) regulatory bodies. To do this, UE contacted seventeen (17) relevant stakeholders, with the understanding that it may not be possible to meet with all the stakeholders within the allocated timeframe.

Table 61: Market Sounding Stakeholder ListTable 61 below summarizes which stakeholders UE contacted and ultimately met with.

Table 61: Market Sounding Stakeholder List

Stakeholder Group	Stakeholder Name	Status
Local Developers	Halton Healthcare	Contacted, no response
	Oakville Green	Interviewed
	Schlegel Village	Interviewed
	Infrastructure Ontario	Interviewed
	Mattamy Developments	Interviewed
	Zibi	Interviewed
	Local Developer – Anonymized	Interviewed
Key Industry Stakeholders	Enwave	Interviewed
	Creative Energy	Interviewed
	Corix	Interviewed
	OEC	Interviewed
	Noventa Energy	Interviewed
Regulatory Bodies	Enbridge Gas	Interviewed
	Halton Region	Interviewed
	Durham Region	Interviewed
	Ontario Energy Board	Contacted, no response
	Oakville Hydro	Interviewed

Each stakeholder meeting began with UE presenting an introductory slide deck to the stakeholders, which provided them with a holistic overview of the project's technical details. Stakeholders were encouraged to ask questions throughout and following the presentation. Once the overview was completed, UE began asking the stakeholders focused questions, which had been pre-approved by the Town.

2.1 Results - Local Developers

The purpose of these meetings was to gain insights from property owners within the study area in order to get a better understanding of project feasibility, including, but not limited to:

- interest in connecting to the project; should it be constructed as currently phased;
- preferred contracting methods;
- perceived risks and/or challenges related to project scope, location, regulatory implications, market readiness, etc.;
- financial assumptions used to determine business case;
- example thermal energy rates and connection fees based on past experience; and
- 'lessons learned' or recommendations for the Town, based on past experience.

Overall, UE found that all local developers within the study area would consider connecting to the district energy system, so long as the commercial terms were satisfactory. The primary concerns regarding their decisions to connect included, but were not limited to the following:

- **Cost of Connecting to the System**: all developers expressed that connecting to the DES would have to be cost-neutral or cheaper than their business-as-usual system. When asked, most developers were planning to leverage a conventional gas-fed heating system.
- **Timing of System Phasing**: given that the DES will be constructed in 10 phases over about 20 years, most developers expressed concerns about when the connection will be available for their development. Some developers are planning to construct their building well in advance of a connection being available but are planning to design to a 'DES-ready' standard. This will ensure they can operate their building as normal until the connection is ready.
- **Reliability of the System**: developers who have owned land in the study area for a long time expressed concerns about whether or not the system will be built, and how reliable it will be once commissioned. This was driven by their experience with the Town in the past, and their concerns with the scale and complexity of the project. Many developers were concerned about what would happen to their central plants, if they had to commission their buildings prior to the DES connection becoming available.

2.2 Results – Key Industry Stakeholders

The purpose of these meetings was to gain insights from service providers in the DES market in order to get a better understanding of project feasibility, including, but not limited to:

- interest in bidding on the project in the future, should it progress to RFQ stage;
- preferred contracting and bidding methods;
- perceived risks and/or challenges related to project scope, location, regulatory implications, market readiness, etc.;
- financial assumptions used to determine business case;
- example thermal energy rates and connection fees based on past experience; and
- 'lessons learned' or recommendations for the Town, based on past experience.

Overall, UE found that all DES providers were interested in supporting the project in some way and were eager to learn more about the project. The primary concerns gleaned from the key industry stakeholders included, but was not limited to:

- **Partner Selection:** all of the DES providers that UE interviewed wanted to caution the Town against choosing a DES partner using a quantitative RFP process. It was mentioned that project costs and DES fees cannot be accurately determined at such an early of the project. It was recommended that the Town select a DES partner based on past project experience, financing capabilities, and project development approach.
- **Revenue Certainty:** concerns surrounding revenue certainty were expressed by all DES providers, who confirmed that commercial agreements with each customer would need to be signed prior to any capital expenditure. Given that the Town of Oakville doesn't have a Green Standard that would require developers to connect to a low-carbon DES, the providers were concerned about having to compete with conventional, carbon-intensive HVAC costs. It was suggested that the Town look at the role of a quasi-regulator for setting long-term rates and key terms for all developers and land owners.
- **Stakeholder Coordination:** due to the size of the system, most DES providers also expressed concerns about how the system would be developed, governed and operated from a partnership perspective. Large, multi-phase DES systems can be challenging to move forward, and many of the interviewed providers suggested that having a 'champion' to progress the project would be critical to the project's success.

2.3 Results - Local Authorities

The purpose of the meeting was to gain insights from local authorities about opportunities and challenges perceived for the project from a regulatory perspective.

Given that district energy systems are unregulated in the province of Ontario, it was critical to socialize the project with all relevant local authorities to ensure that there were no regulatory roadblocks or opportunities that could impede the project's success. The primary takeaways gleaned from the local authorities included, but was not limited to:

- **DES Connection Uptake:** given that natural gas is currently the most prominent and cost-effective method for building heating in Ontario, some regulatory agencies expressed concerns that developers would choose to connect to the system.
- **Lack of Information Available:** all the interviewed regulatory bodies highlighted that it was difficult to offer any real feedback at this time, given that relevant detailed information (such as peak electrical loading for the central plant, or sewer connection details for the SHR system) are not available at this time. All the local authorities UE interviewed expressed the need for continued collaboration with the Town, as each regulatory body has its own feasibility exercises and processes to carry out before approvals or connections can be provided.

3. OWNERSHIP OPTIONS MODELLING

3.1 Summary of Ownership Options

There are three typical business models used to deliver district energy projects:

- Private project development companies,
- Public project development companies, and
- Hybrid public/private partnerships

A detailed list and descriptions of the ownership structures are provided in Table 62.

Table 62: Ownership Structure Examples

Ownership Structure	Description
100% Private	• Private sector group owns, maintains and operates DES • DES is financed through private debt or equity • Fewer opportunities for accessing public funding • Commonly pursued where there is a high rate of return for the private body and limited public support is required • Expected ROI is higher than for publicly owned systems
100% Public	• Public sector owns, maintains and operates DES • Public-sector financing and grants are used to fund DES • Generates revenue for municipality • In Canada, the majority of DES business models are publicly owned or involve the public sector in some capacity
Concession	• Public sector is involved in the design and development • Private sector group is engaged to develop, finance and operate DES • Public sector generally has option to buy back DES in future
Joint Venture	• Shared ownership where shares are dictated by equity invested • Public partner: land and access to lower cost debt capital • Private partner: skills/experience, shorter procurement period, and access to external capital
Special Purpose Vehicle	• Special purpose subsidiary created for owning, operating and maintaining DES • Ownership split between private and public entities

Stakeholder Owned Special Purpose Vehicle	• A cooperative model where ownership is shared amongst a variety of stakeholders, such as:
	    • Customers receiving the thermal energy (e.g. major building owners connected to the DES)
	    • The municipality
	    • Members of the community/a cooperative

The ownership structure chosen would have an impact on the project returns as there can be varying interest rates, commercial terms and equity participation. Out of the options presented in Table 62, the Town chose to evaluate the following:

1) **100% Private Ownership:** A project company owned and led by a private developer/investor
2) **100% Public Ownership:** A project company owned and led by publicly held company and the Town

3.2 Ownership Model Overview

To accurately model the outcomes of the different ownership options, UE layered project financing into the business case model developed in Milestone 4. Based on market experience and feedback gleaned from UE's market-sounding exercise, the base case for the ownership options model leveraged the assumptions summarized in Table 63. Note that the discount rate of 11% selected for the public ownership model was an intentionally conservative approach. In UE's experience, public entities are typically more risk averse and are more conservative in their approach. It is likely that a lower discount rate can be leveraged in future analyses, as more information becomes available.

Table 63: Ownership Option Model Inputs

Ownership Model	Description	Inputs
Private Ownership	A project company owned and led by private developer/ investor	• Private: 40% equity contribution; 60% debt • Cost of Debt Capital: 7.95% (prime[9] + 100 bps) • Discount Rate: 9%
Public Ownership	A project company owned and led by public company and the Town of Oakville	• Public: 20% equity; 80% debt* • Cost of Debt Capital: 6.3% (10 yr Canada bond rate[10] + 3%) • Discount Rate: 11%

** The delivery and partnership process selected will inform the financing. For example, if the delivery partners are also required to finance along with design, build, and operate, then to that extent the financing requirements would be impacted. Similarly, based on available lower-cost financing facilities, the DES business case is expected to benefit substantially and can be brought in once the path forward has been selected.*

[9] Prime interest rate published as 6.75% on July 17th, 2024 on the Bank of Canada website.

[10] 10-year bond rate published as 3.3% on July 17th, 2024 on the Bank of Canada website.

3.3 Ownership Model Results

Using the assumptions laid out in Table 63, the levered internal rate of return (LIRR) and net present value (NPV) were calculated for both a private and public DES ownership. The privately owned DES was modelled with terminal asset value included, given that it is commonplace for private entities to factor int the value of assets at any time. Based on previous conversations with the Town, the publicly owned DES was modelled both with and without the terminal asset value considered, given that it is unlikely that the Town would factor in selling the DES following the 30-year term.

The results of the ownership model are summarized in Table 64. For all financing options, a construction loan type of financing facility has been assumed over a 20-year term with an amortized repayment spanning 10 years following the loan maturity date.

Table 64: Ownership Model Results

<table>
<tr><th>Ownership Structure</th><th>Equity Ratio – Construction Costs</th><th>Terminal Asset Value</th><th>Discount Rate</th><th>Interest Rate</th><th>Net Present Value (NPV)</th><th>Levered Internal Rate of Return (LIRR)</th><th>Peak Equity Invested</th><th>Peak Equity Multiple</th></tr>
<tr><td rowspan="2">Private Ownership</td><td>40%</td><td>Terminal Value Included</td><td>9%</td><td>7.95%</td><td>$4.2M</td><td>9.53%</td><td>$56.4M</td><td>9.76x</td></tr>
<tr><td colspan="8">Total Construction costs (Escalated): $201,417,972
Total Construction Loan Proceeds: $120,850,783
Total Construction Equity Proceeds: $80,567,189</td></tr>
<tr><td rowspan="4">Public Ownership</td><td>20%</td><td>Terminal Value Included</td><td>11%</td><td>6.3%</td><td>$971K</td><td>11.21%</td><td>$40.9M</td><td>13.11x</td></tr>
<tr><td colspan="8">Total Construction costs (Escalated): $201,417,972
Total Construction Loan Proceeds: $161,134,378
Total Construction Equity Proceeds: $40,283,594</td></tr>
<tr><td>20%</td><td>Terminal Value Excluded</td><td>11%</td><td>6.3%</td><td>($13M)</td><td>3.26%</td><td>$40.9M</td><td>1.61x</td></tr>
<tr><td colspan="8">Total Construction costs (Escalated): $201,417,972
Total Construction Loan Proceeds: $161,134,378
Total Construction Equity Proceeds: $40,283,594</td></tr>
</table>

This analysis is showing lower levered rates of return, when compared to the unlevered rates of return shown in Table 52 and Table 53. It was assumed that for the project financing facilities, the DES owner is paying interest costs on the full debt facility every year (i.e. 60% of the project costs for the private owner, and 80% of the project costs for the public owner). The treatment of interest is unique to each financing facility, and given the preliminary nature of this assessment, a conservative analysis was carried out. The business case should be re-assessed throughout project development, based on discussions with the financing agencies and update the assumptions as they become available.

Even with a conservative treatment of interest costs, both the private and publicly owned DES' show strong LIRR and a positive NPV with the terminal value included in the assessment, indicating that it would be an attractive investment. Without terminal asset value considered, however, the publicly owned utility would be expected to receive a lower LIRR and a negative NPV over the 30-year term. While this may appear to indicate that a publicly owned utility would be a poor investment if not sold after 30 years, we do not believe this to be the case, for the following reasons:

- **Continued Revenue Generation:** if a terminal asset value is not realized by the publicly owned utility (i.e. if the asset is not sold), the asset will continue generating revenue for the owner, which will improve the IRR and NPV. While the DES may not achieve a positive NPV in the first 30 years under the current financial assumptions, it will show a positive financial result over a longer term (such as 40 or 50 years). This is because the majority of the capital costs have already been expended, and the cash flow following the modelled 30-year term would be predominantly profit after accounting for repairs and rehabilitations.
- **Discount Rate Considerations:** This analysis leverages an 11% discount rate for the 100% public ownership scenario, which is considered to be conservative by market standards and given the higher interest rate regime. This indicates that the publicly owned utility (i.e. the Town) would need to achieve an 11% IRR in order for the asset to have a positive NPV. Given that interest rates are expected to return to the previously seen lower levels, and considering the Town will receive other, qualitative social, environmental and community-driven benefits to the development of the DES, it would be expected that the discount rate could be reduced below typical market values.

3.4 Ownership Model Sensitivity Analysis – Private Sector Interest Rates

Given that there has been a significant amount of volatility in the market in recent years, a small sensitivity analysis has been carried out on the interest rates for a private sector DES owner. To illustrate a reasonable range for a levered rate of return, the maximum and minimum prime interest rates over the last 20 years were extracted from the Bank of Canada data archive and were used to re-run the model. The maximum prime interest rate was determined to be 7.2% and the minimum prime interest rate was determined to be 2.25%. The results of this sensitivity analysis are summarized in Table 65. Note that this assessment considered the asset's terminal value.

Table 65: Sensitized Ownership Model Results - Private Ownership

Scenario	Interest Rate (Prime + 100bps)	Net Present Value (NPV)	Levered Internal Rate of Return (IRR)
Lower Prime Interest Rate	3.25%	$43.2M	18.48%
Higher Prime Interest Rate	8.2%	$1.9M	9.23%

It can be seen that the base case interest rate assumptions for the privately owned utility are quite close to the maximum rate seen in the last 20 years; indicating that this assessment is already quite conservative. Therefore, it's possible that prime interest rates will trend back down towards the 20-year average (around 3.8%, according to Bank of Canada archives), making this project even more profitable. Ultimately, market conditions should be closely monitored in order to ensure the business case is as current as possible.

4. PLANNING TEAM SUPPORT

UE conducted market research in other jurisdictions to identify planning by-laws, development policies and incentives that the Town's Planning Team can implement to help overcome barriers to the implementation of DES.

4.1 Barriers to DES Implementation

To provide context for this analysis, UE began by first establishing the most prevalent barriers to DES implementation. The barriers summarized in Table 66 were established through both desktop research and feedback received as part of the market-sounding study summarized in Milestone 5 Section 2.

Table 66: List of Barriers to DES Implementation

Barrier	Description
Cost Competition with Market Rates	• DES suppliers must compete with market rates for conventional systems, which is significantly more challenging in jurisdictions without Green Development Standards or other policies that limit GHG emissions or energy use. • Without any incentive to connect to a more efficient, less carbon-intensive system, customers will often opt to leverage a conventional gas-based heating systems, due to their short-term affordability and comfort with the technology.
High Upfront Costs	• DES centralizes energy production to produce economies of scale, which results in a high upfront capital cost to design and build the central plant, in order to connect to a large number of customers
Extensive Build-Out Schedules	• Due to the scale of the infrastructure, the build-out schedule is often long, creating significant lag times between initial capital expenditure and revenue generation. • This leads to significant financial risk for the DES provider, as they are required to finance the cost of the central plant until revenue can be generated.
Land Use Planning Uncertainty	• Given the extensive build-out schedules and evolving needs of municipalities and the communities they serve, land use planning can change many times over the course of the DES planning cycle. This leads to increased uncertainty and risk for both DES providers and customers.
Revenue Uncertainty	• In the absence of mandated connections, DES providers must negotiate contracts with each customer, creating significant load and revenue uncertainty. Contract negotiations take time, and connections are not guaranteed until an agreement is signed, meaning DES providers face a significant amount of uncertainty and risk, as planning and investments must be made very early in the process to ensure the DES can be developed smoothly.

Barrier	Description
Significant Stakeholder Coordination	• With large-scale DES that require support from the municipality and other relevant local stakeholders, project complexity is increased significantly. This further extends the buildout schedule and can limit DES supplier's ability to offer customers certainty on scheduling, contract terms and fees.

The following analysis will provide the Town's Planning Team with recommendations to overcome the barriers laid out in Table 66.

4.2 Tools Available to Ontario Municipalities

Before any recommendations could be made, UE carried out research to establish the tools the Town can leverage to incentivize the implementation of DES.

Given that each province has a unique regulatory landscape, UE grounded this analysis in various policy vehicles that Ontario municipalities have at their disposal to incentivize the implementation of DES. Table 67 provides an overview of proven policy vehicles available to the Town that are relevant to DES implementation:

Table 67: Municipal Policy Vehicles to Support DES

Tool	Description
Green Development Standards (GDS)	• GDS are typically managed through the Site Plan Approval process and require developments within a certain use-case (often medium to high-density residential, commercial and institutional) to meet minimum energy efficiency and GHG reduction targets. • GDS that require high thermal energy performance and GHG reductions either require or incentivize developers to use higher efficiency heating, cooling and domestic hot water systems in their development. • When developers are required to meet higher building performance, DES systems becomes a more financially attractive option. as they are cost-competitive with other standalone low-carbon energy systems, but with additional benefits (energy reliability, redundancy, space savings in their buildings, etc.). • GDS are the most impactful policy vehicle available to Planning Staff in Ontario currently.
Property Taxation Rebates	• Offering property tax rebates to residents connected to a DES could be used to incentivize connection by driving public interest and market demand.

Tool	Description
Development Charge (DC) Rebates	• Offering developers development charge rebates for connecting to a DES can be a useful tool in incentivizing connections. • DC rebates have been successfully used in jurisdictions like Toronto and Vancouver to incentivize developers to meet more stringent energy efficiency and carbon emissions targets. • DC rebate can be tied to voluntary GDS criteria to administer more efficiently.
Accelerated Approval Timelines	• Approval timelines were identified by local developers as a notable challenge through UE's market sounding exercise. Therefore, if developers connecting to a DES could be offered accelerated development timelines, it could be a highly valuable tool in overcoming barriers to DES implementation. • Specifically, Ontario municipalities may leverage a Community Planning Permit System (CPPS), which combines site plan control, zoning and minor variances to streamline development timelines. • CPPS can be tied to 'District Energy Nodes' within the OP to provide streamlined and preferential approvals to developments that connect to DES systems and provide other community benefits.
Official Plans (OPs)	• OPs can help to align community intensification objectives with energy strategies to supply residential, commercial and institutional buildings. • Energy-related policies can be included in an OP to incorporate integrated community energy solutions into the community's future growth strategy (such as GHG reductions, energy efficiency, requirements for community energy planning)
Zoning By-Laws	• Zoning by-laws and amendments are an indirect way for municipalities to support DES implementation. • Zoning by-laws can be used to incentivize DES through intensification, compact development, mixed-use development, renewable energy infrastructure, and better support for public transportation; all of which can improve the technical and financial feasibility of DES.

4.3 Green Development Standard – DES Best Practices

Based on both desktop research and the market-sounding study carried out by UE, the implementation of a Green Development Standard is anticipated to be the most impactful policy tool that the Town could implement. The following is a summary of DES-specific criteria to consider including in GDS requirements to ensure DES are incentivized appropriately.

4.3.1 Energy and Carbon Requirements

1) When setting requirements for both thermal and non-thermal energy intensity limits at a building level, provide allowances for projects connecting to a district energy system (existing or future), given that connecting to a DES system supplying building heating and cooling reduces strain on the electrical grid and improves resilience during power outages at the individual building location.

2) Allow projects connecting to a DES system to automatically meet any minimum/mandatory GHG emissions targets.
3) Create a separate compliance path for voluntary requirements, which allows projects connecting to a DES using or with defined plans to use renewable energy or waste heat to automatically comply.

4.3.2 Renewable Energy Requirements

1) Allow projects to meet mandatory renewable energy generation targets by utilizing off-site renewables through a DES.
2) When defining renewables, ensure that geothermal and geo-exchange systems, sewage heat recovery or sewage energy exchange, and industrial residual (waste) heat within the definition of 'renewable'
3) Enable geo-exchange bore fields to be placed under the building as well as adjacent parks, greenspaces and rights-of-ways.
4) Require the inclusion of onsite thermal and electrical energy storage to better manage peaks and balance the electrical grid. This requirement would be waived for a DES connection.
5) Treat all low-carbon energy or energy harvested from waste streams as renewable energy for the GDS.
6) Allow renewable energy to be allocated by the DES to a specific user, even if it mixes with other higher-carbon energy streams as part of the delivery network.

4.3.3 District Energy Requirements

1) Define district energy systems (DES) to include both thermal (heating and cooling) and electrical energy/microgrids.
2) Adopt formal DE-ready guidelines. For example, the City of Toronto has adopted formal guidelines and acknowledged the pivotal role of district energy systems in reducing GHG emissions from buildings and driving towards net zero while also reducing demands on the additional energy infrastructure needed.
3) Require GDS applicants to investigate the feasibility of DES for their development at a minimum and encourage voluntary connections to existing DES through incentives (such as DC rebates). If DES systems are not available in time in their area, consider developing guidelines and requirements for developers to design their buildings to be DE-ready. Incentivize GDS applicants to adopt the Town's DE-ready guideline in preparation for future DES connections.
4) Specify that the Investigation of the feasibility of a shared energy solution contains, at a minimum:
    a. Definition of the project's baseline energy consumption and demands, conversion efficiencies, operating temperatures, utility costs, and carbon emissions. This baseline energy assessment is to be established and agreed on with inputs from the developer and the DES operator. This baseline analysis informs the platform against which the energy supply opportunities will be measured and compared.
    b. A lifecycle financial comparison analysis between an on-site energy solution and a DES solution, given that there is a vital need to make sustainability accessible, relevant and affordable for all members of the community.
    c. Shared energy solution/campus energy alternatives in the event that a DES is not commercially available.
    d. Transition alternatives to allow for the period between construction completion and connection to a shared energy solution/campus energy alternative.
    e. An implementation roadmap for taking the building from being district energy ready to actual connection to a DES.
5) Require that the SPA Submission include a letter signed by a local DES operator, signalling that DES feasibility was considered.
6) Allow for transition periods where the new building may not be sufficient to expand or commission a new or existing DE system. Temporary energy centers or systems or plants should be allowed to operate in the interim to achieve the required densities to enable the DE system to be commissioned and replace the temporary systems.

4.4 Town Planning Feedback

The information gleaned as part of this assessment was presented to the Town's Planning Team (Planning) on July 24th, 2024, with the intent of soliciting their feedback and input. Based on the discussion, the following was understood by UE:

- At present, the Town is planning to investigate a Green Development Standard as part of the 2025 budget year. This assessment can be taken and leveraged as part of that assessment.
- Planning has little control over development approval times, as much of that has to do with the province. The Town is investigating the Community Planning Permit System (CPPS) as a means to streamline development applications, but they are unable to provide guaranteed approval timelines as an incentive for DES connections.
- There exists some hesitancy surrounding financial incentives for developers, as development should pay for itself.
- Official Plans and Zoning By-Laws remain the Planning Team's most powerful tools as they relate to incentivizing low-carbon developments and DES connections. Planning will continue to investigate these tools and their applicability to DES.

5. RISK REGISTER AND MITIGATION PLAN

Urban Equation and Rathco have prepared a detailed risk register outlining commercial, technical, economic, and other risks. In addition, we have prepared a mitigation plan that addresses each key risk, assesses their associated mitigation strategies and assigns high-level qualifiers to their likelihood of occurrence, financial impact and schedule impacts.

Table 68 below outlines the key risks and the associated mitigating actions, based on the current understanding of the project. Each risk has been assigned a score out of 10 for both probability and impact of occurrence. The framework for assigning these scores is summarized in Figure 57 and Figure 58, respectively. Those two scores were then multiplied together to calculate a risk severity score out of 100, which indicates how it should be addressed according to Figure 59.

Rating		Interpretation
High	10	Fact
	9	
	8	High Probability
	7	
Medium	6	Medium-High Probability
	5	
	4	Medium Probability
Low	3	
	2	Low Probability
	1	

Figure 57: Risk Probability Scoring Matrix

Rating		Interpretation
High	10	Project Failure
	9	Over Budget or Delay by 40%
	8	Over Budget or Delay by 30-40%
	7	Over Budget or Delay by 20-30%
Medium	6	Over Budget or Delay by 10-20%
	5	Slightly over budget
	4	Large reduction of reserves (time or cost)
Low	3	Medium reduction of reserves (time or cost)
	2	Small reduction of reserves (time or cost)
	1	No Impact

Figure 58: Risk Impact Scoring Matrix

Probability	10	10	20	30	40	50	60	70	80	90	100
	9	9	18	27	36	45	54	63	72	81	90
	8	8	16	24	32	40	48	56	64	72	80
	7	7	14	21	28	35	42	49	56	63	70
	6	6	12	18	24	30	36	42	48	54	60
	5	5	10	15	20	25	30	35	40	45	50
	4	4	8	12	16	20	24	28	32	36	40
	3	3	6	9	12	15	18	21	24	27	30
	2	2	4	6	8	10	12	14	16	18	20
	1	1	2	3	4	5	6	7	8	9	10
		1	2	3	4	5	6	7	8	9	10
		Impact									

Green	Can be Ignored
Yellow	Further Analysis and Investigation
Red	Response or other immediate action

Figure 59: Risk Severity Scoring Matrix

The project development phases should include a detailed risk management program to continuously monitor and evaluate the risks and mitigation strategies that include the development of a risk register and cross-functional risk reviews with project groups and critical stakeholders identified by the project governance team. The risks and their impacts should be quantified and qualified on both a pre-mitigation and post-mitigation process.

For large infrastructure projects like this to be successful, it is not always viable to carry the financial impacts of all risks within contingencies. However, the project's budgets typically do account for risk-related contingencies on a reasonable basis. Further, the understanding of these risks is also important to guide the contractual frameworks and governance processes with the stakeholders.

Table 68: Key Potential Risks

No.	Category	Key Potential Risks	Probability (/10)	Impact (/10)	Severity (/100)	Impacted Project Area	Key Potential Mitigating Actions
1	Commercial	Project development timelines don't align (delayed in comparison) with upcoming new developments	8	8	64	Schedule, Design, Budget, Revenues	• A detailed project schedule needs to be developed at the earliest with key milestone dates, approvals schedules and detailed design and construction schedules. Understanding the dependencies and the required decisions on project structuring, financing mechanisms and project delivery partners is critical to building the implementation plan and decision timelines. • For developments progressing faster than the development of the DE system, temporary energy centers (TECs) can be explored as a stopgap/temporary measure until the DES is commissioned. • For developments that have proceeded with standalone thermal energy solutions, future integration with the DES would have to be mapped out and ongoing coordination with those developers would be required. • Policy drivers would also play a role in accounting for and suggesting how timeline alignment should be dealt with.
2	Commercial	Client-specific business-as-usual cost comparators being accepted by clients, especially in the case of larger institutional clients like the Hospital	9	10	90	Budget, Revenues	• The Town should consider policies and incentives that support the connection to District Energy systems. The Town can look into quasi-regulatory frameworks that enable uniform rate-setting and connection requirements. Covenants on land parcels may also be considered in land use planning policies. • Early engagement is required with key clients that could provide the anchor loads for the system to build on with indicative rates and entering into MOUs that would outline the path to contract signing.
3	Financial	Construction cost escalations - from initial	6	9	54	Budget, Revenues	• Adopt an iterative design and costing approach for both business-as-usual scenarios for key clients and the DES system to accurately account for cost fluctuations.

No.	Category	Key Potential Risks	Probability (/10)	Impact (/10)	Severity (/100)	Impacted Project Area	Key Potential Mitigating Actions
		rate estimates to commissioning of the system					• Policy measures would also have to be considered to inform the rate-setting process through quasi-regulation.
4	Technical	Construction schedule delays that impact commissioning and connection dates	8	8	64	Schedule, Budget, Revenues	• Confirm final location of assets with a clear understanding of the permitting, regulatory, commercial and contractual aspects will help ensure necessary steps are in place to ensure a smooth construction process. It would also be important to continuously monitor and lock down access requirements through rights-of-way, temporary and permanent easements.
5	Commercial	Policy changes related to carbon tax or grid capacity demand charges	9	6	54	Revenues	• Through the sensitivity analysis we have tested the impact of policy changes related to carbon taxes. The impact as a result of carbon tax being removed is a drop in returns by approximately 1.5%, whereas if the carbon tax accelerates faster after 2030 at (6.5% a year vs 5% a year) the impact is an increase in returns by 1 %. Proactively addressing any impacts resulting from policy changes, with robust change management procedures in place is an important practice to adopt as the project proceeds through the next stages. • Grid capacity impacts and demand charges expected for future electrification of buildings, if the buildings were to shift from conventional gas-based systems to fully electric ones, need to be thought through.
6	Commercial	Procurement method misalignment with project implementatio n plan	5	7	35	Schedule, Design, Budget, Revenues	• Based on the project ownership path selected and the partners onboarded, a strategic evaluation of the procurement model will have to be looked at. This is critical to aligning the goals and timelines of the project while managing risks on several factors discussed here. The commonly used project delivery models for such projects could be design-build, design-build-performance, design-build-transfer with or without financing, a concession structure with transfer of assets and ownership at a future date such as full buildout.
7	Technical	Procurement timelines associated with	8	8	64	Schedule, Budget, Revenues	• Until recently, supply chains were vastly disrupted due to the pandemic with very long and unpredictable lead times. Establishing procurement timelines for critical items would need to be detailed in the next phase of work and

No.	Category	Key Potential Risks	Probability (/10)	Impact (/10)	Severity (/100)	Impacted Project Area	Key Potential Mitigating Actions
		long-lead items and supply chain issues					built into the detailed schedule. Lead times for drilling contractors in particular can be a number of months in the current Ontario market.
8	Technical	Performance benchmarking and guarantees	3	3	9	Revenues	• Tied to the procurement strategy, the performance (efficiencies and operating parameters) and key metrics need to be established and validated with appropriate guarantees in place. System operations and component performance directly impact the economics of the project and those of clients based on how the utility costs are negotiated.
9	Technical	GHG and CO2e emission reduction targets not being achieved	5	5	25	Budget, Revenues	• Allowances may be made to catch up with any shortfalls in GHG and CO2 emission reduction targets with some redundancies built into the electric equipment capacities.
10	Commercial	Development risk - Buildings do not go online as planned and connections are delayed as a result	9	8	72	Revenues	• If buildings and connections are delayed, there is an impact on revenues and returns of the project. It is important to have ongoing engagement with commitments on off-takes and minimum payment terms if delays occur beyond a reasonably determined timeframe. As commonly seen with most regulated utilities, fixed charges commence based on the connection dates and commissioning schedules. Quasi-regulatory policies can also help address this issue.
11	Technical	Energy source fluctuations in quality and quantity	4	6	24	Budget, Revenues	• There is a risk that the sewer waste-heat quantity and quality (temperatures) can fluctuate and thereby impact operating efficiencies, costs, and system performance. A tolerance level should be established to assure a minimum quantity is delivered for a high percentage of time within an acceptable temperature range for the negotiated rates. Rate structures and adjustments would have to be looked at to factor in deviations beyond the established range. This risk has already been largely mitigated through assessing 3 years of historic sewer flows and temperatures, the proposed project is based on average minimum flows over these 3 years only.

No.	Category	Key Potential Risks	Probability (/10)	Impact (/10)	Severity (/100)	Impacted Project Area	Key Potential Mitigating Actions
							• For the geothermal borefields, balancing and monitoring would be important to ensure the geothermal borefields are operating within the designed criteria.
12	Financial	Interest rate fluctuations and changes in cost of capital	9	6	54	Budget, Revenues	• The project is very sensitive to interest rates / cost of capital and thus as part of project development, it would be important to enter into discussions with large funding agencies like the Canada Infrastructure Bank for a financing facility with a locked-in rate structure and flexible repayment structure. Given where we are at with interest rates, the capital stack would need to be planned such that it limits risks around rate fluctuations.
13	Commercial	Permits and approvals management	2	3	6	Schedule, Budget	• Understand and develop detailed permits and approvals management plan that identifies permit requirements and ensure application and approval timelines are synchronized with project schedule. • Similarly, identifying any required easements, and access to the right of ways as per construction schedule is also an important part of the process.
14	Technical	Geotechnical and environmental risks	4	5	20	Schedule, Design, Budget, Revenues	• Assess and effectively manage risks related to geotechnical and environmental factors by conducting relevant preliminary assessments through the next stage of design development and understand contamination related issues and costs associated with site remediation. As geo-exchange is a major part of the energy mix, understanding ground conditions well is important.
15	Technical	Scope gaps and demarcation points in design and construction	4	6	24	Schedule, Design, Budget, Revenues	• Given that multiple consultants, contractors, public and/or private entities are expected to get involved in this project soon in order to progress forward, potential scope gaps would need to be carefully managed. Engaging a prime consultant will address this issue and ensure project continuity efficiently. Similarly, a general contractor may also be brought on board at the right time to ensure pre-construction issues are addressed. Separation of time and space will also have to be maintained to accommodate site constructors' activities effectively.

URBAN EQUATION

RATHCO ENG

No.	Category	Key Potential Risks	Probability (/10)	Impact (/10)	Severity (/100)	Impacted Project Area	Key Potential Mitigating Actions
16	Technical	Region of Halton implements new technical specification requirements, that are required for the connection	5	5	25	Design, budget, revenues	• The Region would have to be brought into the project through the governance frameworks and timelines and boundaries for including technical specifications would have to be established.
17	Technical	Gas peaking connections may be expensive for the gas consumption levels identified	6	6	36	Design, budget, revenues	• Peak electrical and gas demand response strategies may need to be looked at closely to support peak shaving strategies by employing electrical and gas storage systems in combination with cogeneration units if the cost differentials can be justified.
18	Commercial	Central plant location's commercial aspects	7	8	56	Schedule, Design, Budget, Revenues	• The central plant location will have to be finalized and requires working through the details with Infrastructure Ontario who currently own the land. Ownership or lease of the land, building and access requirements with the associated terms and conditions would have to be looked into at the earliest.
19	Technical	Site Servicing - grid and natural gas servicing constraints	7	8	56	Schedule, Design, Budget, Revenues	• Lack of grid / natural gas supply capacity impacting the ability to service the site. This needs to be mitigated through ongoing coordination with Enbridge and Oakville Hydro early on in the development of the project.
20	Technical	Climate change impacting energy demands and	8	6	48	Operation, revenues	• Climate change may alter the heating and cooling patterns and preferences of the customers, as well as the availability and quality of the renewable energy sources. For example, warmer winters and hotter summers may increase the cooling demand and decrease the heating demand, while droughts and floods may affect the sewer flow and temperature. These changes may cause an imbalance between the supply and demand of

No.	Category	Key Potential Risks	Probability (/10)	Impact (/10)	Severity (/100)	Impacted Project Area	Key Potential Mitigating Actions
		causing system imbalance					thermal energy in the DES, and lead to system instability, inefficiency, and degradation. To mitigate the impact of climate change on the DES, the system should incorporate adaptive and resilient design and operation features that can adjust to the changing energy demands and conditions. For example, the DES should use dynamic and smart control systems that can monitor and optimize the system performance and energy balance and implement demand response and load-shifting strategies that can reduce or shift the peak demand. Furthermore, the DES should conduct regular and rigorous climate risk assessment and scenario analysis that can inform the system planning and decision making.
21	Commercial	Low Customer Uptake	8	7	56	Design, budget, revenues	• One of the main challenges for a DES is to attract and retain enough customers to ensure its economic viability and optimal performance. Customers may be reluctant to join a DES due to various reasons, such as lack of awareness, trust, or incentives, high connection fees, long-term contracts, or perceived loss of control or flexibility. Low customer uptake may result in insufficient thermal load and revenue for the DES, as well as increased system losses and inefficiencies. To increase customer uptake, the DES should adopt a proactive and comprehensive marketing and engagement strategy that targets potential customers and stakeholders and provides them with clear and accurate information, benefits, and incentives for joining the DES. The DES should also offer flexible and competitive pricing and contract options and provide technical and financial assistance for customers to connect to the system. Moreover, the DES should establish a strong and transparent governance and management structure that ensures customer satisfaction and trust. Support from local government such as a consideration of mandatory connection policies should be explored to determine if this is possible. Ongoing developer engagement will also be critical.
22	Technical	Operator Training	7	9	63	Operation, revenues	• Operators may lack the necessary knowledge, skills, or experience to operate and maintain a DES, which is a complex and novel technology that requires specialized training and expertise. Human operators may also make mistakes, oversights, or misjudgments that can cause system failures,

No.	Category	Key Potential Risks	Probability (/10)	Impact (/10)	Severity (/100)	Impacted Project Area	Key Potential Mitigating Actions
							accidents, or damages. For example, operators may fail to detect or respond to system faults, alarms, or anomalies, or may override or misuse the system controls or settings. To reduce the risk of human operation of the system, the DES should provide adequate and ongoing training and education for the system operators and maintenance staff and ensure that they are familiar and competent with the system functions, features, and protocols. The DES should also implement robust and reliable system monitoring and automation systems that can assist and support the human operators, and provide them with clear and timely feedback, alerts, and guidance. Moreover, the DES should establish and enforce strict and consistent system operation and maintenance standards and procedures that can prevent or minimize human errors or negligence.
23	Technical	Undersizing of key equipment	6	8	48	Design, budget, operation	• Undersizing of key equipment, such as the geo-exchange boreholes, the sewer energy exchange heat exchangers, the pumps, the pipes, or the heat pumps, that can affect the system capacity, efficiency, and longevity. Undersizing of key equipment may occur due to inaccurate or incomplete data, assumptions, or calculations during the system design and sizing process, or due to budget constraints, regulatory limitations, or site conditions that restrict the size or number of the equipment. Undersizing of key equipment may result in insufficient or uneven heat transfer, increased system losses or pressure drops, reduced system performance or lifespan, or increased system wear and tear or maintenance costs. • To avoid or overcome the risk of undersizing of key equipment, the DES should conduct thorough and rigorous data collection and analysis and use reliable and validated models and methods for the system design and sizing process. The ATDES should also consider the future growth and variability of the system load and conditions and incorporate safety factors and contingency plans for the system sizing. The DES should also seek to optimize the system design and configuration and use high-quality and efficient equipment that can maximize the system's capacity and performance. Additionally, the DES should regularly monitor and evaluate

No.	Category	Key Potential Risks	Probability (/10)	Impact (/10)	Severity (/100)	Impacted Project Area	Key Potential Mitigating Actions
							the system operation and performance and identify and address any issues or gaps related to the system sizing.
24	Technical	Equipment malfunction / failure	6	9	54	Operation, revenues	• Equipment malfunction or failure may affect the building's comfort and indoor air quality, as well as the system's energy efficiency and cost-effectiveness. For example, heat pump malfunction or failure may cause insufficient or excessive heating or cooling, increased noise or vibration, or increased energy consumption or emissions. A rigorous preventative maintenance and repair programme should be established as part of the project governance and must be a foundational consideration for the system as it develops. This will ensure a resilient reliable system moving forward.
25	Technical	Inadequate system controls	8	9	72	Operation, revenues	• ATDES systems are far more complex to control than traditional 4th generation or earlier DES systems. The establishment of a suitable controls and monitoring system alongside adequate operator training is essential for the long-term viability of the project to head off potential issues with customer satisfaction in the system.

6. GOVERNANCE FRAMEWORK

6.1 Governance Framework Overview

While strong technical and engineering practices are essential to the success of a district energy system, the economic and financial structures combined with appropriate business models supported by solid governance frameworks are even more critical.

The type of governance model chosen is also determined by the ownership structure selected for the project. The ownership structures commonly seen in district energy projects have been outlined in Milestone 5 Section 3.1 already. For this project, the 2 ownership options selected were the fully private model and the fully public model.

The ownership and governance models are essential to managing and allocating risks and ensuring projects progress and are delivered successfully. Typically, the entity carrying the risks needs to be compensated for it and if there is a transfer of risk it is also accompanied by a transfer of the associated compensations or value. The governance aspect of district energy systems is an ongoing process and requires continuously monitoring the progress of the project to meet the set objectives; and incorporating and enabling best practices in design, construction, customer acquisitions and operations.

The key factors for success of these projects include:

1) Establishing a single project champion, who will provide leadership, commitment to vision, continuity in policy as well as long-term leadership.
2) Optimizing resource allocation as projects progress
3) Mitigate risk with robust risk identification, mitigation planning and continuous monitoring
4) Establishing investability for project partners, funding and financing agencies
5) Aligning stakeholders by actively engaging with them through a planned process, sharing information appropriately, and identifying key decision-making and approval milestones
6) Finally, these projects must have a full life-cycle perspective and consider long-term sustainability keeping in mind policy changes and climate-related risks

6.2 Governance Framework and Operating Model for a Private District Energy Company

A private district energy system model is one in which a private company (can also be a public company listed on stock exchanges) or a company held by a group of publicly listed entities or institutional investors own, operate and maintains the DES from the initial stages of design through completion of the operating term.

6.2.1 Board of Directors

Once a private model is selected for the DES, a board of directors would have to be constituted. The responsibilities of the board include providing strategic oversight and direction, risk management and ownership, developing detailed execution plans and policies, authorizing and adhering to budgets, monitoring performance of the entity and ensuring regulatory compliance.

The Board is typically composed of executive, non-executive and independent directors, the CEO and other key executives as required. Directors have a fiduciary duty to act in the best interests of the company and its shareholders.

The board then identifies committees that are critical to the successful governance of the company. Each committee has specific roles to play, and the most commonly seen committees include the audit committee, executive or steering committee, risk management committee, sustainability or ESG committee, compensation committee, ad hoc committees or other specialized committees as may be needed.

6.2.2 Executive Management

The executive management includes the C-suite, namely:

- CEO – The Chief executive officer is responsible for overall management and leadership of the entity.
- CFO – The Chief Financial officer is responsible for financial planning, fundraising, financial reporting and investor relations.
- CTO – The Chief Technology officer oversees the technical strategy, innovation and integration of technologies
- COO – The chief operating officer is responsible for day-to-day operations of the entity and improving operational efficiencies and maintenance of the systems.
- General or Legal Counsel – the legal counsel manages legal affairs, compliance and regulatory issues of the firm.
- CSO – it is increasingly seen that the C-suite has a chief sustainability officer who links into all aspects of sustainability, and ensures compliance with reporting requirements, local standards and regulations.

The executive management has further oversight over the project development and project management activities, ongoing operations and maintenance, finance and accounting, marketing, sales, customer acquisitions and servicing, human resources and IT and data management systems.

6.2.3 Policies

The executive management is also responsible for laying out the policies of the firm. Key policies include the privacy policy, code of conduct policy, supplier standards of conduct policy, accessibility policy, conflict of interest policy, whistleblower policy, environmental and sustainability policies.

6.2.4 Procedures

At the corporate governance level, the executive management is also responsible for establishing clearly defined procedures for decision-making, approvals, financial authorization, performance evaluation and improvements, stakeholder management, health and safety, compliance and risk management.

Compliance frameworks would have to be implemented for regulatory compliance to ensure adherence to local, provincial, and federal regulations. Internal audit teams are required to ensure regulatory compliance and external audit teams need to be brought in periodically. It is also important to consider engagements with governmental agencies and public authorities to be informed about policy changes and advocate for favourable policies and regulations through a government liaison. Finally, compliance reporting systems need to be planned and implemented alongside the above measures.

6.2.5 Stakeholder Management

A significant challenge for most large energy infrastructure projects is getting the right people engaged at the right time and ensuring that meaningful and ongoing dialogue is maintained throughout. A detailed stakeholder engagement plan was developed for the project in Milestone 2. This plan can be expanded by reconfirming the identified stakeholders, their expectations from the entity, their impact on the entity and the project's needs from the stakeholders.

6.2.6 Project Management Structure

The project management group is responsible for all activities of the project from the initiation stage through to the execution and commissioning of the system Figure 60 shows a structure that would enable the successful delivery of the DE system.

The project management group is typically comprised of the following:

- **Project Steering Group** – responsible for project oversight, ensuring risks are appropriately managed, providing direction, holding key relations and ensuring the necessary resources are made available.
- **Project Advisory Board** – the project team may choose to have an advisory board of subject matter experts and industry veterans to provide guidance, feedback and share best practices and learnings from other projects
- **The Project Management (PM) Team** – is responsible for all daily project management tasks and activities and are typically comprised of project directors, project managers and senior executives
- **Financial Group** – the financial group ties into the project team through the PM team. They assist the PM team by developing detailed cash flows and conducting detailed financial analyses on an ongoing basis to account for changes in assumptions, financial impacts of risks, sensitivity analysis and the development of rates along with the commercial group.
- **Commercial Group** – the commercial group would be responsible for legal and regulatory aspects, customer acquisition, negotiating contracts and enabling the project team to progress with the project with required contractual commitments that are financially vetted and feasibly
- **Technical Group** – the technical group would comprise of the internal and external engineering teams. The internal teams are typically subdivided into the design, construction and operations.
    a. The design team leads the engineering and technical development of the system in collaboration with external engineering consultants.
    b. The construction team would weigh in on practical construction aspects and manage a team of construction managers and contractors required for executing the project.
    c. The operations team would ensure the systems operates as designed following the required levels of system performance and efficiency with a team of operators – both on-site and off-site. The operations team may also include customer relations or support teams to uphold the service standards being delivered and provide ongoing support.

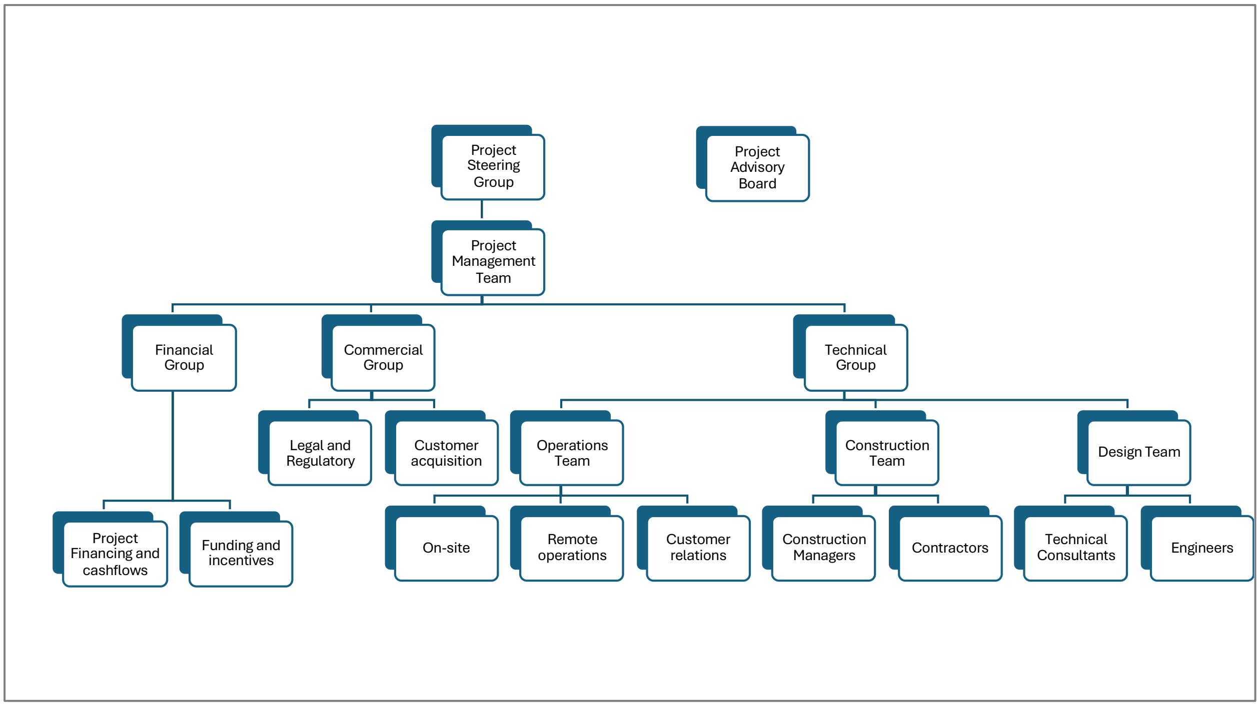

Figure 60: Project Management Team Structure

6.2.7 Stages of Project Development, Management and Execution

There are several stages for large infrastructure projects such as DE projects. The project management team described above would take a DES project like this through the major phases that are as follows:

- Concept design (CD)
- Schematic Design (SD)
- Design Development (DD)
- Detailed Design and Tendering
- Construction Documents (CD)
- Procurement
- Construction
- Installation and Commissioning
- Customer Connections
- Operations and Maintenance

While the stages can be progressed sequentially as shown in the figure below, it is recommended and necessary at times to iterate on a subset of stages of the project development process. This is necessary to reconfirm that the technical feasibility and economic arguments for the project are consistent and substantiate the business case. An evolving business model allows for better alignment and planning of technologies, business aspects, financial considerations and governance structures.

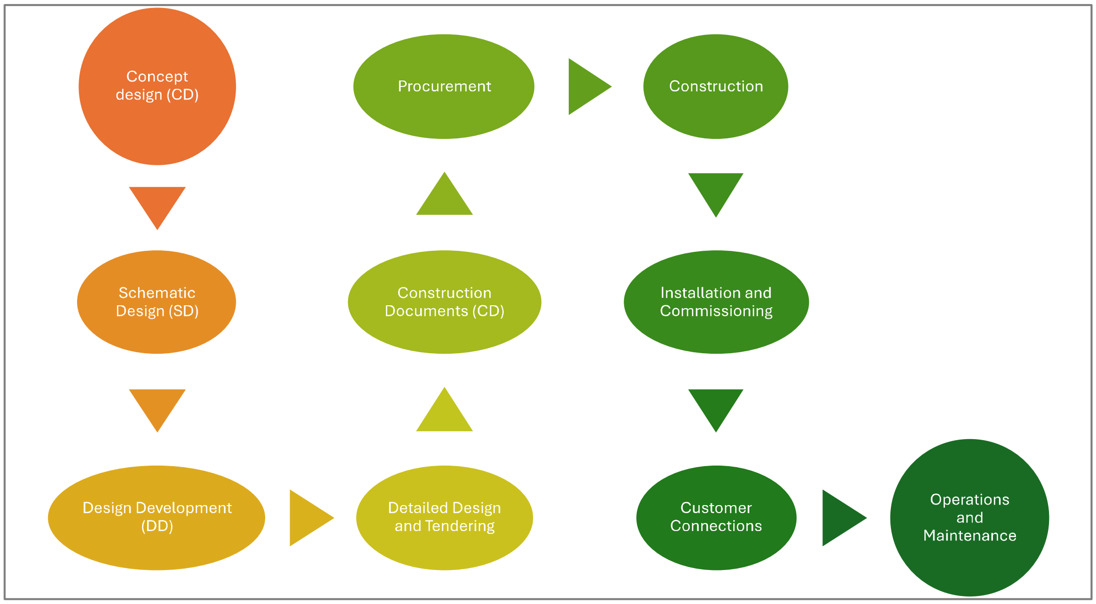

Figure 61: DE Project Development Phases

6.3 Governance Framework and Operating Model for a Public District Energy Company

A public district energy system model is one in which a city, town or municipality would own, maintain and operate the DES. In the public model, the DES can be delivered either directly through the Town or through a subsidiary corporation of the Town. There is also an option to start the DES directly by the Town and then transition it to a subsidiary corporation at a later date.

The main advantages of the public ownership model are the access to lower-cost capital and lower profitability requirements or aim to maintain a not-for-profit business model. Decision-making would not be entirely driven by financial parameters, but heavily consider social and economic aspects of the district, Town and the Region. Funding and lines of credit from previously identified institutions such as the FCM and CIB would be available to enhance project viability. As a public initiative, the finances of the system would be fully transparent, thereby making rate-setting and investment decisions simpler with faster buy-in from the stakeholders. Other benefits of a publicly-owned DES are as follows:

- Allows for the alignment of municipal or town policy to enable low carbon community energy.
- Provides a means for the municipality/town to also generate revenues or dividends.
- Any potential returns or positive business cases can be controlled and benefited by the public entity
- Public ownership allows for more utilization of regulation tools to encourage customer connections to the DES
- Public ownership allows for more stability through rate control as it is not driven by profits, but rather municipal mandate.
- Public entities have access to funding opportunities including: Grants, Subsidies, and low interest loans.

- Instills trust, given that municipalities are capable of carrying a long term ownership model, which will ensure that the DES ownership and management will remain consistent for customers.
- Ensures that benefits of DES implementation (i.e. financial, environmental and social) remain within and are driven by the municipality.
- Similar to the governance and jurisdictional power like OEB, who regulates gas and electricity rates, the governance council of municipality/town can ensure fair energy rates for the customers, residents while enjoying the benefits of low carbon energy.
- Opportunity for a local job creation through the development of a publicly owned DES

6.3.1 Direct Ownership by the Town

This is the case where the DES is delivered directly through the Town, which would be faster and possibly easier to commence. There would be a need to look in to establishing separate budgets, personnel and resources to carry the project forward. The permitting and approvals process can also be made simpler given the common governance of the departments throughout the Town. An example of this system is the Southeast False Creek Neighborhood Energy Utility in Vancouver, Canada which had the first sewage heat recovery plant in Canada. It is still owned and operated by the City as the Neighborhood Energy Utility (NEU).

The challenges with direct ownership include the longer procurement and decision-making times as the council would have control over decision-making and the daily activities of the DES. The capital would have to be deployed by the Town and this can become challenging to manage and convince the taxpayers that the funds are being allocated in the best way possible. Also, the Town would become directly liable legally and financially and would have to enter into contracts and agreements directly.

The Town would need to form a project management group as explained above to take the project forward and likely need to structure special committees to oversee the activities of the project management group. The stages of project of project development, management and execution would also broadly follow the stages explained above.

6.3.2 Indirect Ownership by the Town

In the indirect ownership case, the Town would look to incorporate a separate subsidiary company for the DES. The subsidiary company would own, operate and maintain the DE system from the initial stages of design through completion of the operating term.

A board of directors and executive team as outlined above would have to be formulated for the subsidiary company. The Town can choose to retain voting rights and veto powers to have control over key resolutions and decision making. The entity would have the ability to raise financing and lines of credit in addition to those brought forward by the Town thereby allowing the Town to allocate resources elsewhere. This would also enable the separation of the financials and the balance sheet of the DES from those of the Town.

The challenges in this model are the reduced availability of Town funding and financing mechanisms compared to departmentally owned entities. The formation of the subsidiary and staffing would require initial investments. As the operations would be separate from other departments of the Town, the coordination times can be longer, especially around the permitting and approvals.

7. CONCLUSIONS & RECOMMENDATION

The project led by the steering committee and the Oakville community is in a favourable position to successfully progress the hospital district DES project based on the results and findings presented in the business case. This business case is an important step in establishing the financial parameters and investability in a DES project of the size and scale detailed through the report. The business model based on the conceptual design and noted assumptions suggests that there is a reasonable business case to be made for a district energy system connecting sewer and geothermal energy sources and the new developments as noted. Thus, the team recommends moving forward with the next stages as outlined in the implementation planning for the project.

The factors that make this location beneficial for district energy include:

- There is a good mix of different building uses, (commercial, residential, institutional) which creates a stable baseload for the district energy system
- The presence of the sewer trunk main for energy exchange in a greenfield site.
- Favorable drilling conditions for geo-exchange per engagement with local drillers.

While greenfield sites often provide favourable conditions for developing district energy systems, many successful examples exist in urban centres. Each district energy system, however, should be evaluated individually based on its specific site characteristics. All of the above favourable conditions are still subject to connection uptake. Should there be poor sign up then the business case for DES gets worse. The sensitivity explored in this report demonstrates this.

The Town is exploring other options for incentivizing connection. One example leveraged in other jurisdictions is mandatory connection. However, even under a mandated connection policy, there would still need to be engagement and discussion with developers, mandated connections still have minimum requirements that both parties must meet.

The DES provider (whether public or private) is responsible for working with developers to establish the success framework for the business case. It may also be possible for a neutral third-party or expert district energy consultant to review and opine on the business case. Even if the DES is delivered as a public entity – third parties can be brought in to operate and manage connection negotiations. Further to the details presented, Urban Equation recommends the following next steps:

1. Engage with decision-makers at the Town based on this document to ensure the municipality and public officials understand the significance and benefits of this project
    a. Identify project champions who will take on the responsibility for successful implementation of the project
    b. Explore the possibilities to bring in requirements for new buildings to be DE-ready to easily connect to the current or future district energy systems.
    c. Similarly explore the possibility to bring in requirements for all retrofit projects to also DE ready to easily connect to the current or future district energy systems.
    d. Explore and participate in the development of the planned Green Development Standards (GDS) that encourage the use of sewer energy, geo-exchange or low-carbon thermal energy networks

    e. Discuss the possibility of financial incentives and expedited approvals processes with other departments for developments who connect to low-carbon thermal energy networks to achieve ambitious GHG intensity levels in new and existing developments
2. Engage with primary lending and funding agencies to detail out application requirements and timelines and have a better view into commercial terms and structures
3. Engage a prime consultant or consortium to act as expert District Energy project managers and manage partner procurement and planning
    a. Detail out project schedules and delivery plans
    b. Establish project development budgets and align on governance processes
    c. Progress discussions on locking down the locations of assets
4. Value in the avoided cost of infrastructure - it is recognized that the DES can lower peak requirements for other utilities (gas and electric) and as such, create avoid costs benefits which have not been factored at this stage. There may be a challenge in quantifying the benefits and how they are applied through the regulatory process, it is recommended to explore this further as the project design progresses.
5. Progress the outlining of major contracts and key material terms
6. Start discussions with key customers who can provide large anchor loads
    a. After general agreement, provide a Letter of Intent is generally signed
    b. Initial technical and commercial work is then undertaken which then forms the basis of a Memorandum of Understanding (MOU)
    c. Enter into MOUs with indicative rates and paths to contract signing
    d. There are multiple workstreams that would have to progress in parallel with decision gates and checkpoints. As technical and financial evaluations are progressed, agreements are also mapped out to ensure alignment in timing, binding commitments and risk sharing.
7. Engage regularly with the Region to look into technical and commercial aspects of sewer energy exchange with an understanding of long-term commitments and impacts on design
8. Establish a position on the ownership and transfer of carbon credits and or energy attribute certificates that is in line with carbon accounting protocols
9. Public engagements
    a. For the stakeholder groups identified, develop customized plans to reach and engage them
    b. Develop communication collaterals and hold stakeholder workshops to raise awareness and enable opportunities for public participation

There is a significant opportunity for the Oakville community to develop a world-class and exemplary ambient temperature thermal energy network based on sewer heat recovery and geo-exchange systems that will enable the Town of Oakville to achieve its GHG reduction targets and Climate action goals.

APPENDIX A - STAKEHOLDER ENGAGEMENT PLAN

1. STAKEHOLDER ENGAGEMENT PLAN

November 10, 2023

The greatest challenge for most large energy infrastructure projects is getting the right people engaged at the right time and ensuring that meaningful and ongoing dialogue is maintained through the project development cycle. This work will build upon the stakeholder engagement done in the pre-feasibility assessment, where Rathco engaged the District Energy (DE) Task Force consisting of critical stakeholders in key positions with the Town of Oakville (ToO), as well as representatives from Oakville Hydro and Halton Region, called the Project Team. This round will involve more direct engagement with potential customers/developers and continued discussions with the Project Team. For this project, Rathco has partnered with Urban Equation (UE).

1.1 Summary Of Key Stakeholder Engagement Activities

This document summarizes the key scope of work related to stakeholder engagement:

- Initial engagement workshop with local developers to introduce the feasibility project and parties ("Developer Introduction Session") in Milestone 2.
- Rathco working with stakeholders to define project phasing in Milestone 3.
- UE meeting with the ToO and Project Team to get input for financial modelling for the project in Milestone 4. Ongoing conversations with the ToO on the Town's ability to access capital and preferences for DE ownership (in coordination and steering group meetings).
- UE leading market-sounding sessions with developers and the feasibility team to develop the technical concepts and confirm inputs for the economic modelling in Milestone 5.
- UE providing Planning Team support to encourage district energy adoption in Milestone 5.

1.2 Identifying Key Stakeholders

Stakeholder Group	What does the stakeholder expect from the project?	How does the stakeholder impact the project?	What does the project need from each stakeholder?
Town of Oakville/ Halton Region	A detailed DES feasibility study with a clear business case and implementation plan	Project owner sets timelines and provides input	Ongoing project approvals and support
Developers	Ongoing stakeholder engagement to provide key inputs and updates on DES project timing and requirements	Interest is key to technical design and project financial viability	Information about development timing, interest in connecting, proposed loads and mechanical systems
Utilities	To understand the impact on future energy needs of the community. Potentially an ownership stake in DES.	Advises on current comparable utility rates, connection requirements, partnership needs.	Information about utility rates, connection requirements, and potential partnership/ownership.
Other Interested Parties	To be determined.	To be determined.	To be determined.

1.3 Key Stakeholder Representatives

Stakeholder Group	Organization	Contact
Town of Oakville/ Halton Region	Town of Oakville District Energy Task Force	Economic Development and Corporate Strategy
		Facilities and Construction Management
		Planning Services (with representatives from Urban Design and Development Services)
		Transportation and Engineering
		Climate Action
	Halton Region	Water and Wastewater Treatment Climate Change Response and Sustainability, Strategic Policy & Government Relations
Developers	Oakville Green	Senior Development Lead
	Halton Healthcare	P3 Operations, P3 Operations
	Infrastructure Ontario	P3 Asset Management
	Schlegel Village	Senior Development Lead and Architect
	All Seniors Care	NA
Utilities	Oakville Hydro	NA
	Oakville Enterprises Corporation	Senior Leadership
Other Interested Parties	To be determined.	

1.4 Managing Stakeholder Input

As part of the stakeholder engagement process, stakeholders may provide views, opinions, and requests that are outside of existing scope and need to be managed. These types of requests will be managed by the consultants as shown in the following flow chart.

Process to manage additional stakeholder input

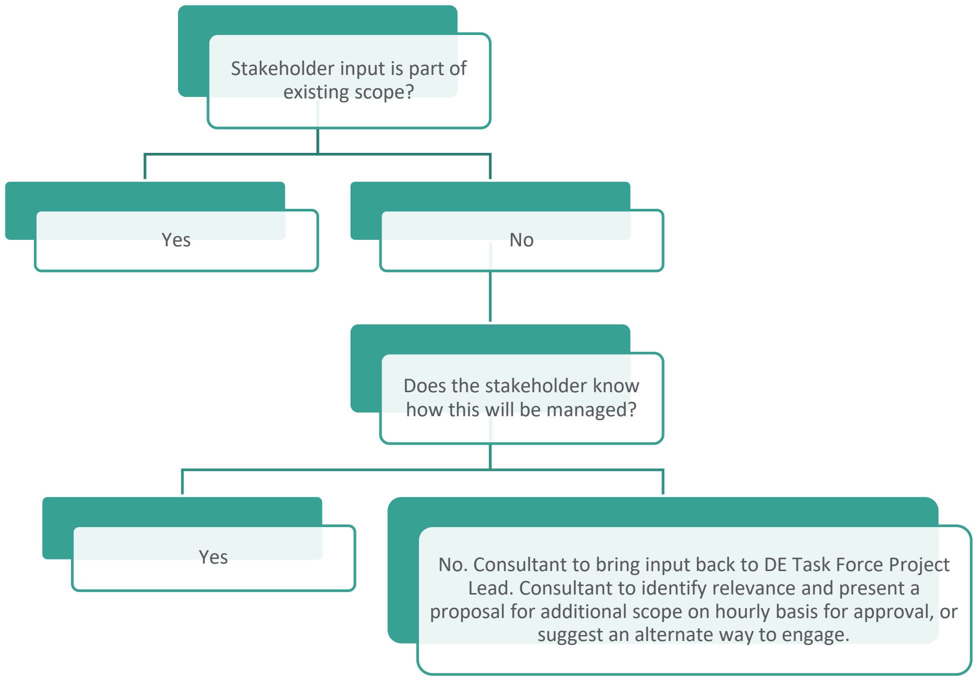

Figure 62: Process to manage additional stakeholder input

2. DEVELOPER INTRODUCTION SESSION (MILESTONE 2)

At the Hospital District, specific and ongoing discussions with landowners and developers will be needed to move the proposed project from concept to reality.

The goal of this initial introduction session with the local developers was to provide general education and build alignment. We wanted the developers to have basic information and a general idea of timing (i.e., in the next 5 years) so they could gather their input prior to the phasing calls that will occur in Milestone 3 and the market sounding calls that will occur in Milestone 5. Key outcomes were to obtain general interest of the developers, which will start to define the project boundary.

UE prepared a presentation and facilitated the engagement session on Wednesday, October 18, 2023, at 10 am. There was strong attendance from all organizations above (26 attendees).

The following list of agenda items were discussed in the meeting:

- Attendee introductions
- Rathco/UE Introductions
- What is District Energy
- Benefits for Developers
- Background work completed to date

- Why Hospital District
- Results of Pre-feasibility Study
- Current Workplan
- Stakeholder Engagement/Activities: initial goal is to figure out developer timelines
- Key Input Required: follow up phasing calls
- Next Steps:
    - Finish data collection
    - Start Milestone 3
    - Stakeholder calls Nov/Dec
- Other key items of discussion
    - Oakville Green would like to clarify recovery costs before making a serious commitment to DES, to understand how much DES will add to their building operating costs
    - Oakville Green is interested in:
        - using stormwater management ponds for geo-exchange. Rathco commented that the Stormwater ponds are not large enough for this.
        - implementing a horizontal piping system, below their parking lot that will be close to 7 or 8 acres.
        - rainwater storage with distributed thermal batteries at every building to avoid the need of a massive system.

3. PROJECT PHASING MEETINGS (MILESTONE 3)

Rathco will work with stakeholders to agree on the phasing for the overall district energy project including highlighting timelines for critical building connections, sewer energy exchange, etc.

The latest schedule aims for this to occur in the weeks of November 13 and 20, 2023.

4. FINANCIAL INPUTS MEETING (MILESTONE 4)

Urban Equation will facilitate a financial kick-off meeting with the Project Team. The goal of this meeting will be to discuss the workplan and agree upon the approach and key inputs for the business model: including market size, projected revenues and expenses, energy escalations, profitability, and ownership models, among others.

The latest schedule aims for this to occur the week of January 8, 2024.

5. ECONOMIC VIABILITY MEETING (MILESTONE 4)

Urban Equation will present the results of the economic viability model to the ToO and the Project Team. The outcome of this 1.5-hour meeting is to agree upon the business-as-usual model, preferred ownership structures, products and services, market size, projected revenues and expenses, energy escalations, profitability, and what sensitivity will be run in the more refined techno-economic model. UE will collect the Town's feedback to be addressed in the techno-economic model. Rathco will take the results into consideration for the Technical Report (Milestone 3).

The latest schedule aims for this to occur the week of Feb 26, 2024.

6. MARKET SOUNDING SESSIONS (MILESTONE 5)

Engagement with local developers to support the business analysis is included under Market Sounding in Milestone 5. UE will lead market-sounding meetings to inform both the financial modelling in Milestone 4 and the implementation strategy in Milestone 5.

The first round of market sounding will help solve the question: what are the business and ESG objectives of each party and how do they impact the DES financial analysis? The key outcome will be which developments are on board and when. The next round of market sounding will help solve the key question: what is the preferred ownership structure and how to deliver?

- Up to six 1-hour meetings with local developers in the Hospital District to gauge their interest and seek feedback as to real and perceived challenges and opportunities of connecting to the DES.
- Up to four 1-hour meetings with other key industry stakeholders to assist in investigating the practical potential of the scenarios and review other constraints/opportunities of district energy at the Hospital District. The identified stakeholders should include any identified and suitably qualified DES suppliers.
- Up to four 1-hour meetings with stakeholders from Local Authorities (e.g., Oakville Hydro, Enbridge Gas, Halton Region, OEB, etc.) to present the proposed solution(s) for the site and seek feedback as to real and perceived challenges and opportunities to the realization of the energy vision for the site.

Identification of the interviewees will be done collaboratively with ToO. UE will prepare key questions to address during the meeting as well as meeting notes. We have assumed ToO will coordinate virtual meeting logistics, however happy to adjust as helpful.

The latest schedule is aiming for this to occur from March to June 2024.

7. PLANNING TEAM SUPPORT (MILESTONE 5)

UE will conduct market research in other jurisdictions with a focus on identifying planning by-laws, development policies and incentives that have proven to help encourage developers to adopt and invest in similar DE systems. We will examine the common barriers associated with planning, development, and approvals, and make recommendations to overcome these barriers.
We will present our findings in a 1-hour meeting with the ToO Planning Team. We have assumed up to 2 days of work.

The latest schedule aims for this to occur during the weeks of May 13 to May 27, 2024.

APPENDIX B - FUEL COST STUDY

OAKVILLE DISTRICT ENERGY

Fuel Cost Study

TOWN OF OAKVILLE

MARK BEBAWY
SENIOR CLIMATE OFFICER

URBAN
EQUATION

URBAN EQUATION

To:	Town of Oakville
From:	Urban Equation
Date:	June 4, 2024
Project Name:	Town of Oakville District Energy Detailed Feasibility Assessment

Revision	Date	Description
0	April 18, 2024	Draft Issue
1	June 4, 2024	Draft Issue

URBAN EQUATION

1 Summary

This fuel cost study provides background information on fuel costs in Ontario and documents why certain fuel costs were used in the economic model to assess economic viability of the Oakville District Energy System. Overall, fuel cost rates In Ontario are difficult to estimate because the rates depend on volume of consumption and the required capacity/demand. Without an hourly energy model for each consumer, a level of data that is not available at this stage in the project, it is impossible to accurately assess each rate.

For simplicity, in the economic model we have assumed:

1. one default rate for electricity: $0.135/kWh and one high volume rate for large-scale energy consumers at $0.10/kWh
2. one average rate for natural gas that will be uniform across all end user types: $0.033/ekWh
3. thermal energy is supplied at equivalent market rates, offsetting the building's total equivalent costs of providing thermal energy (heating, cooling, DHW): $165/MWh

URBAN EQUATION

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2 Electricity Rates

2.1 Background

Electricity rates in Ontario are made up of a number of charges including the Hourly Ontario Energy Price (HOEP), the Global Adjustment (GA), and Local Distribution Company (LDC) charges. These charges are regulated by several governmental agencies including the Ontario Energy Board (OEB), Ministry of Energy (MoE), and the Independent Electricity System Operator (IESO). The Ontario Energy Board sets rates once a year on November 1.

- The Hourly Ontario Energy Price (HOEP) is the wholesale price of electricity, which is determined in the real-time market administered by the IESO and then charged to large consumers and LDCs.[i]

- The Global Adjustment (GA) covers the cost of building new electricity infrastructure, maintaining and refurbishing existing generation resources and delivering conservation programs in order to ensure adequate long term electricity supply in Ontario.[ii]
    - Class A customers that participate in the Industrial Conservation Initiative (ICI) pay their share of GA based on their Peak Demand Factor (PDF), which is their percent contribution to Ontario's total electricity demand during the grid's top five peak hours of the year. This encourages demand reduction/"peak shaving" initiatives that can be used at specific times of high demand.
    - Other Class B customers (typically residential and small business customers) pay their share of GA based on their monthly consumption multiplied by the applicable Class B rate. For these customers on the Regulated Price Plan (RPP), the GA charge is factored into the rate set by the Ontario Energy Board.
    - Other customers sign a contract with a licensed electricity retailer.[iii]
- Local Distribution Company (LDC) charges include delivery (transmission and distribution) and regulatory charges.

2.2 Electricity Rates in Oakville

In Oakville, the Local Distribution Company (LDC) is Oakville Hydro.

For Class B residential and small business customers, there are three different types of rates: Time of Use (TOU), Ultra-Low Overnight (ULO) and Tiered. With TOU and ULO, the price depends on when electricity is used. With Tiered, you can use a certain amount of electricity each month at a lower price. Once that limit is exceeded, a higher price applies.

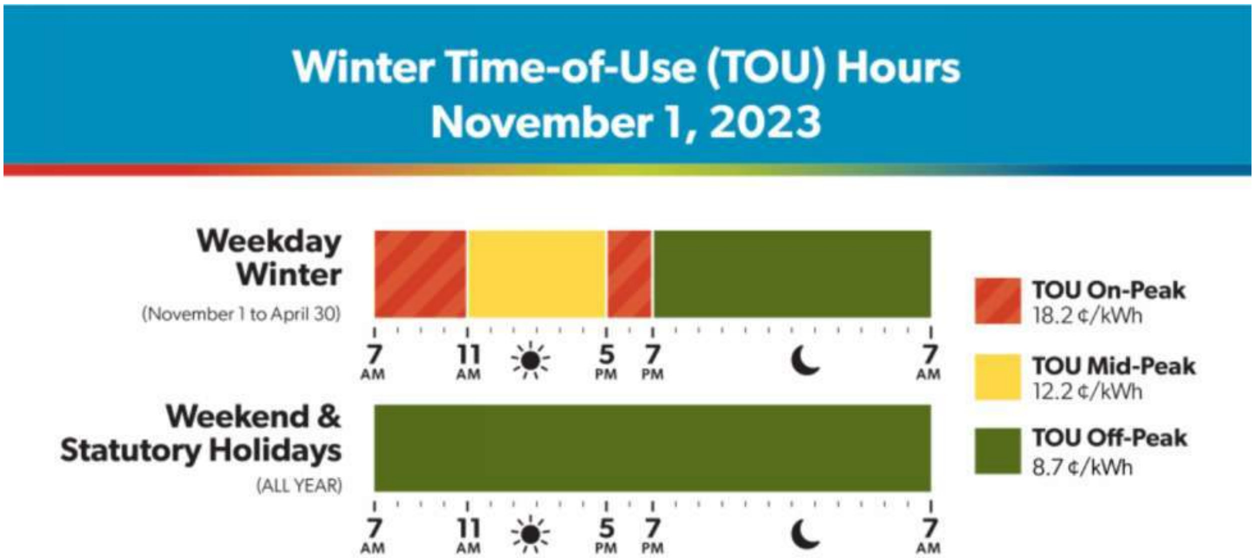


Figure 1. Residential Electricity Rates Time of Use Pricing, 2023

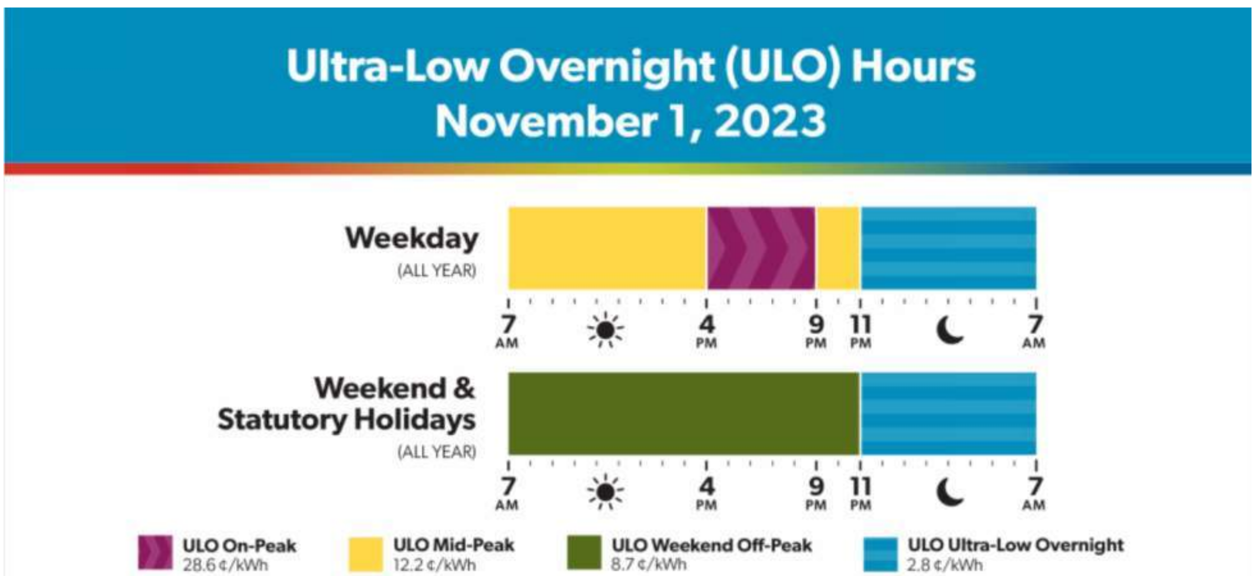


Figure 2. Residential Electricity Ultra-Low Overnight Pricing, 2023

Figure 3. Residential Electricity Rates Tiered Pricing, 2023

Using rates and LDC charges from Oakville Hydro, our analysis (including assumptions to spread time of use out across the day/year), suggests the following average electricity rates:

Table 1. Average Electricity Rates in Oakville, 2023.

Class B Residential			
Average Bill Size (kWh)	Average Cost /kWh		
	Tiered	Time of Use	Ultra Low Overnight
1200	0.148	0.162	0.179
5000	0.137	0.141	0.149
8000	0.136	0.139	0.146
10000	0.135	0.138	0.145
Class B Small Business			
Average Bill Size (kWh)	Average Cost /kWh		
	Tiered	Time of Use	Ultra Low Overnight
5000	0.172	0.185	0.179
10000	0.148	0.155	0.149
15000	0.144	0.149	0.143
20000	0.143	0.148	0.142

Class A ICI Customers with Demand > 50kW		
Average Demand (kW)	Average Bill Size (kWh)	Average Cost /kWh GS 50kW-4999kW
50	27000	0.281
100	54000	0.202
1000	540000	0.138
4000	2160000	0.134

Note that the Class A ICI rates use the average HOEP and average GA from the latest data from 2019-2021. It is anticipated that participants in the Class A ICI rates would practice methods of peak shaving to achieve lower electricity rates; this is not included in the table above.

2.3 Electricity Rates for the Oakville District Energy Study

We cannot comment on ICI rates until there is sufficient design and an hourly energy model to estimate demand and consumption rates as well as peak shaving strategies, for both end users and the DES. **In the economic model, we have assumed that the default electricity rate will be Class B at $0.135/kWh. We have assumed that the heat pumps can access Class A rates and we will target peak shaving strategies to achieve a rate of $0.10/kWh.**

Once the implementation of the DES has been approved, and we are looking at establishing connection charges and variable rates at the building level, we could take a closer look at market rates for each building connecting to the DES (not within the scope of the current study).

3 Natural Gas Rates

3.1 Background

Natural Gas rates in Ontario are made up of:

- Natural Gas supply charge which is a commodity price based on the amount used.
- Natural Gas price adjustment to correct to actual market supply costs because rates are forecast in advance.
- Delivery charges to cover the cost of transporting, storing and distributing natural gas, typically based on consumption and/or demand.
- Federal carbon charges associated with the federal Greenhouse Gas Pollution Pricing Act, based on the amount used.
- Monthly customer charges to administer the account, such as meter reading and customer service.

Natural gas rates are volatile and follow the commodity market. The following chart presents Natural Gas Rates for Union South Rate zone, which includes transportation charges since January 2017.[iv]

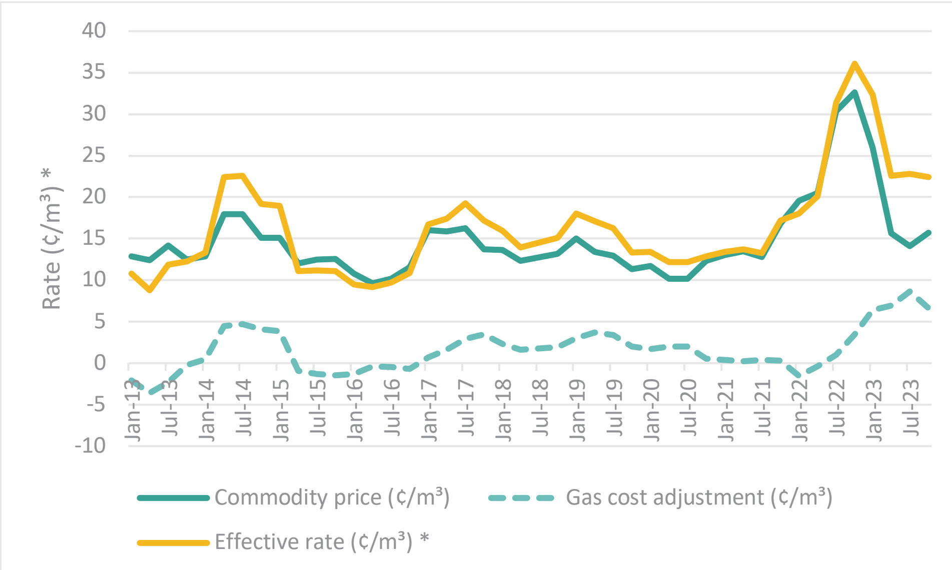


Figure 4. Natural Gas Rates for Union South over time[v]

Note that this chart does not include delivery charges or federal carbon charges.

3.2 Natural Gas Rates in Oakville

Oakville is served by Enbridge Gas Inc. in rate zone for Union South.

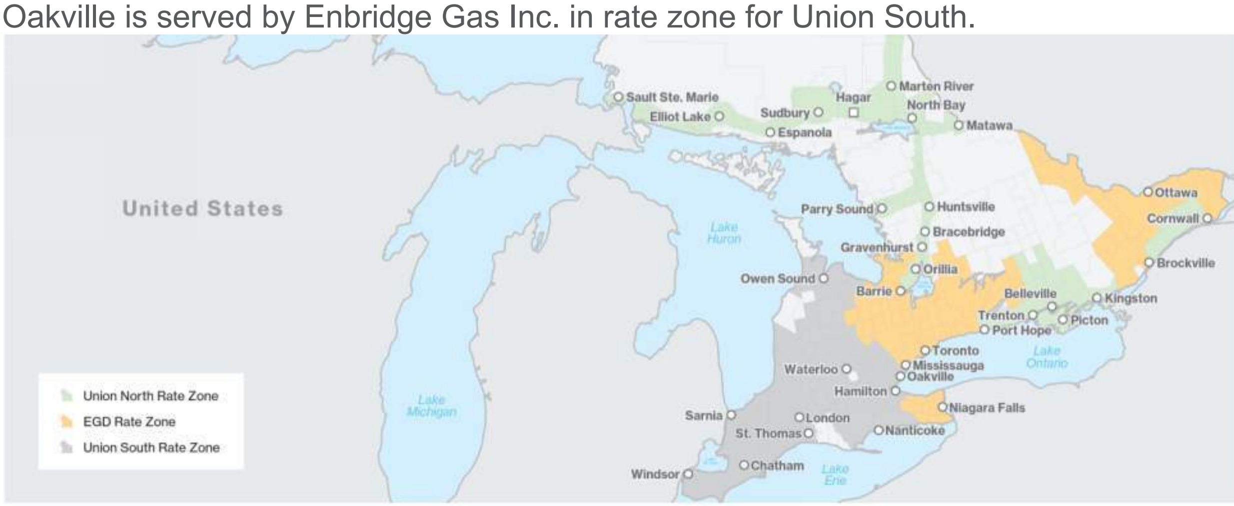


Figure 5. Ontario Natural Gas Rates Zones from Enbridge[vi]

Small businesses located in the Union rate zones that consume less than 50,000 m3 of natural gas each year are listed in the residential rates section Rate M1.[vii]

Table 2. Residential Natural Gas Rate M1 in Oakville, 2024. [viii]

Charges	Rates at Jan. 1, 2024	Annual increase or (decrease)
Customer Charge	$23.98 Monthly fee	No change
Delivery to You		($0.12)
First 100 m³	7.3842 ¢/m³	
Next 150 m³	7.0718 ¢/m³	
All over 250 m³	6.2653 ¢/m³	
Facility Carbon Charge (included in Delivery to You on the bill)	0.0157 ¢/m³	($0.02)
Federal Carbon Charge	12.3900 ¢/m³	No change
Total Annual Impact		**($0.14)**

Business rate M2 applies to medium - large commercial and small industrial customers, such as small businesses, small greenhouses, restaurants, hotels and retail stores that consume more than 50,000 m3 of natural gas each year.[ix]

Table 3. Business Natural Gas Rate M2 in Oakville, 2024. [x]

Charges	Rates at Jan. 1, 2024	Annual increase or (decrease)
Customer Charge	$77.58 Monthly fee	No change
Delivery to You		
First 1,000 m³	7.0440 ¢/m³	
Next 6,000 m³	6.9351 ¢/m³	($3.95)
Next 13,000 m³	6.5632 ¢/m³	
All over 20,000 m³	6.1753 ¢/m³	
Facility Carbon Charge (included in Delivery to You on the bill)	0.0157 ¢/m³	($0.37)
Federal Carbon Charge	12.3900 ¢/m³	No change
Total Annual Impact		**($4.32)**

Large commercial and industrial businesses that consume more than 500,000 m3 of natural gas each year and have signed a contract with Enbridge Gas can be found in the commercial and industrial rates section. For institutional and commercial customers with large volume distribution contracts, there is a complicated rate table[xi]:

Table 4. Large ICI Natural Gas Rates in Oakville, 2024. [xii]

Large Volume Rate Class	Rate M4	Rate M5A	Rate M7	Rate M9	Rate M10	Rate T1	Rate T2	Rate T3
Service Type	Firm/interruptible distribution service	Interruptible/firm distribution service	Firm/interruptible distribution service	Firm distribution service	Firm distribution service	Firm / interruptible distribution service	Firm / interruptible distribution service	Firm distribution service
Minimum load factor	✗	✗	✗	✗	✗	✗	✗	✗
Monthly customer charge	✗	✓	✗	✗	✗	✓	✓	✓
Contract demand charge	✓	✗	✓	✓	✗	✓	✓	✓
Delivery charge	✓	✓	✓	✓	✓	✓	✓	✓
Minimum annual volume requirement	Take or pay for a minimum consumption of 146 days of firm CD per year	Minimum consumption of 350,000 m^3 per year	✗	✗	✗	Minimum consumption of 2,500,000 m^3 per year at each consumption point	✗	Minimum consumption of 700,000 m^3 per year
Contract demand (CD)	Daily CD requirement between 2,400 and 60,000 m^3/day	Daily CD requirement between 2,400 and 60,000 m^3/day	Daily CD requirement greater than 60,000 m^3/day	✗	✗	Daily CD requirement up to 140,870 m^3/day.	Daily CD requirement over 140,870 m^3/day.	✗
Annual minimum bill charge	✓	✓	✓	✓	✗	✓	✓	✗
Notice of interruption	4 hours	4 hours	4 hours	✗	✗	4 hours	4 hours	4 hours
	Details	Details	Details	Details	Details	Details	Details	Details

Using the above rates from Enbridge, our high-level analysis suggests the following average natural gas rates:

Table 5. Average Natural Gas Rates in Oakville, 2024.

Small Business Rate M1		Medium-Large Business Rate M2		ICI Rate M4 (daily contracted demand between 2 400 m³ and 60 000 m³)		
Average Bill Size (m3)	Average Cost $/ekWh	Average Bill Size (m3)	Average Cost $/ekWh	Average Bill Size (m3)	Daily Contracted Demand (kW)	Average Cost $/ekWh
250	0.048	50000	0.036	480000	16000	0.035
1000	0.035	100000	0.036	900000	30000	0.033
10000	0.031	200000	0.036	1650000	55000	**0.033**
25000	**0.031**	500000	**0.036**			

For all of these rates, $0.0117/ekWh comes from the federal carbon charge.

3.3 Natural Gas Rates for the Oakville District Energy Study

We cannot comment on ICI rates until there is sufficient design and an hourly energy model to estimate demand and consumption rates. **For simplicity, in the economic model, we have assumed one average rate for natural gas that will be uniform across all end user types: $0.033/ekWh.**

Once the implementation of the DES has been approved, and we are looking at establishing connection charges and variable rates at the individual building level, it would be possible to take a closer look at market rates for each building connecting to the DES (Note: not within the scope of the current study).

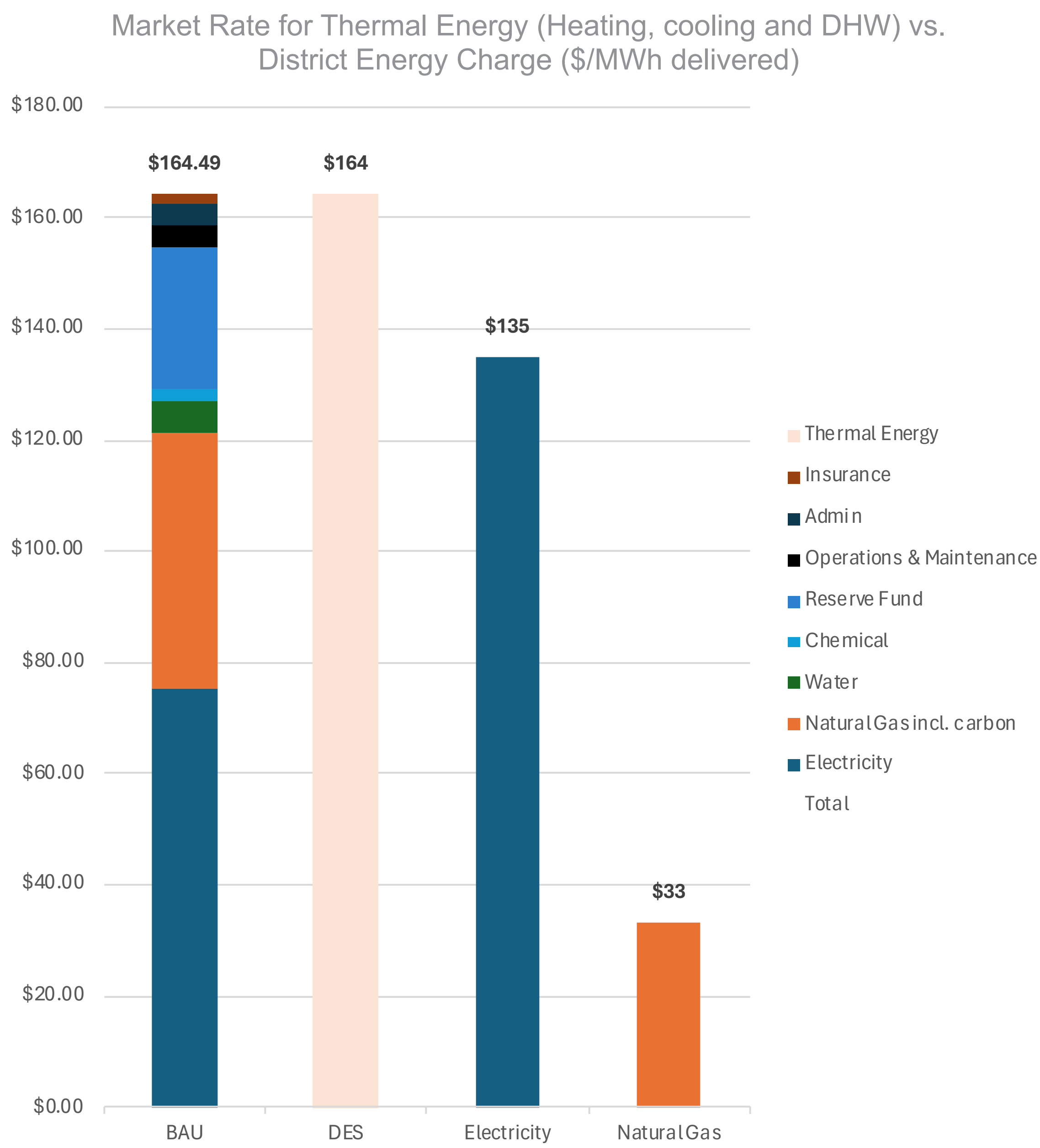
4 Thermal Energy Rates

For the initial economic modeling and assessment we will use our database of past DES and EaaS projects to estimate BAU capital costs to inform connection charges and operating expenses to estimate thermal energy rates. In the next stage of rate assessment, we will refine the BAU costs further along with inputs on proposed system sizing and commodity consumption numbers in conjunction with Rathco.

Using our database of past DES and Energy as a Service (EaaS) projects, we have benchmarked the total cost of delivering thermal energy for heating, cooling and domestic hot water. The rate arrived at is $165/MWh of energy delivered.

The cost to deliver thermal energy offsets several operating expenditures for end user buildings, including: Electricity, Natural Gas including carbon charges, Water, Chemicals, Reserve Fund, Operations & Maintenance, Admin, and Insurance for HVAC systems. The rate charged for thermal energy is assumed to be equal to these costs, so that end users are charged an equivalent market rate.

Figure 6. Business-As-Usual Market Rate for Thermal Energy (Heating, cooling, DHW) vs. District Energy System Charge ($/MWh delivered)



[i] Source: IESO, accessed March 22, 2024https://www.ieso.ca/en/Power-Data/Price-Overview/Hourly-Ontario-Energy-Price

[ii] Source: IESO "Global Adjustment", accessed March 22, 2024. https://www.ieso.ca/en/Power-Data/Price-Overview/Global-Adjustment

[iii] Source: IESO "Global Adjustment", accessed March 22, 2024. https://www.ieso.ca/en/Power-Data/Price-Overview/Global-Adjustment

[iv] Source OEB, accessed March 22, 2024. https://www.oeb.ca/consumer-information-and-protection/natural-gas-rates/historical-natural-gas-rates

[v] Source OEB, accessed March 22, 2024. https://www.oeb.ca/consumer-information-and-protection/natural-gas-rates/historical-natural-gas-rates

[vi] Source: Enbridge, accessed March 22, 2024. https://www.enbridgegas.com/-/media/Extranet-Pages/Business-and-industrial/Commercial-and-Industrial/Large-Volume-Rates-and-Services/enbridge-gas-rate-zones-map.ashx

[vii]Source: Enbridge, accessed March 22, 2024. https://www.enbridgegas.com/residential/my-account/rates
https://www.enbridgegas.com/-/media/Extranet-Pages/residential/myaccount/rates/UG---Rate-M1---South-Marketer---Residential.ashx?la=en&rev=b7bfd973575f455395a64f710b7804b0&hash=2264579E0E6B11F99A4C4957AB10F99C

[viii]Source: Enbridge, accessed March 22, 2024. https://www.enbridgegas.com/residential/my-account/rates
https://www.enbridgegas.com/-/media/Extranet-Pages/residential/myaccount/rates/UG---Rate-M1---South-Marketer---Residential.ashx?la=en&rev=b7bfd973575f455395a64f710b7804b0&hash=2264579E0E6B11F99A4C4957AB10F99C

[ix]Source: Enbridge, accessed March 22, 2024. https://www.enbridgegas.com/business-industrial/business/rates

[x]Source: Enbridge, accessed March 22, 2024. https://www.enbridgegas.com/business-industrial/business/rates

[xi]Source: Enbridge, accessed March 22, 2024. https://www.enbridgegas.com/business-industrial/commercial-industrial/large-volume-services-rates/union-south/rate-m4

[xii]Source: Enbridge, accessed March 22, 2024. https://www.enbridgegas.com/business-industrial/commercial-industrial/large-volume-services-rates/union-south/rate-m4

APPENDIX C - FUNDING SOURCE SCAN

URBAN EQUATION

RATHCO ENG

OAKVILLE DISTRICT ENERGY

TOWN OF OAKVILLE

MARK BEBAWY
SENIOR CLIMATE OFFICER

URBAN EQUATION

URBAN EQUATION

To:	Town of Oakville
From:	Urban Equation
Date:	June 4, 2024
Project Name:	Town of Oakville District Energy Detailed Feasibility Assessment

Revision	Date	Description
0	April 18, 2024	Draft Issue
1	June 4, 2024	Draft Issue

1 Summary

The Funding Sources Scan was prepared using desktop research and was completed in March 2024.

There are a wide range of incentives available and/or anticipated to fund innovative district energy projects with low carbon goals for the surrounding community. This report outlines funding opportunities available through various levels of government (Federal, Provincial and Municipal). Further study is required to confirm eligibility and specific funding amounts.

Based on published data, the Federation of Canadian Municipalities (FCM) Green Municipal Fund offers the largest potential funding opportunity for early planning and study and municipalities such as Oakville can apply directly. A submission would require a formal proposal and application. Much of the work required to secure funding through FCM could be repurposed and used to attract additional funding partners (see summary table below for most relevant sources). Key program considerations and recommended next steps are outlined below.

1.1 Key Considerations

- **Funding cycle**: Many incentives have annual allocations where the full allocation is given out throughout the same year. Some are replenished in a similar or a slightly evolved format the following year. Some are replenished less frequently. Others are one-time programs or competitions.

- **Funding proposal**: Many incentives require a proposal or formal application that shows how the project meets the funding program's specific goals, often requiring innovation or a pilot within a specific focus area.

- **Hidden details**: Many funding bodies do not disclose or confirm the details of total potential funding available until they receive an application.

- **Partnerships**: In order to secure funding, some incentives require partnerships with others, such as organizations, academic institutions and non-governmental organizations (NGOs). For the Town of Oakville, partnering with an organization my make the project eligible for additional funding or interest free loans.

1.2 Next Steps

The most promising funding source is the FCM Green Municipal Fund. It combines a low interest loan at 80% with a grant of up to 15%. Our recommendation is to pursue FCM funding, while making outreach to the other incentive providers. The content prepared for the FCM proposal may be discussed and detailed through formal engagements.

FCM Focus:

1. Review and confirm FCM eligibility with FCM Outreach team.
2. Prepare an incentive proposal that outlines the Oakville DES project potential

Other Incentive Providers:

As outlined in the table below, there are many other related incentive providers. While the published data on total funding potential and eligibility requirements is limited, Oakville may wish to investigate further to better understand funding potential. The following additional loan programs are promising, but may not be a perfect match:

- Innovation, Science, and Economic Development Canada – Strategic Innovation Fund
- Canada Infrastructure Bank

Next steps beyond FCM include:

1. Initiate contact with Innovation, Science, and Economic Development Canada to discuss the project.
2. Initiate contact with the Canada Infrastructure Bank to discuss the project.
3. Tailor FCM proposal to apply for other incentives.
4. <u>Monitor funding providers that are not taking applications for re-activation of programming or additional intakes.</u>
5. Pending the outcomes from the above investigation, consider preparing full applications to relevant incentive programs.

2 Funding/Incentives List

Incentive	Provider	Potential Funding ($)	Description (High Level)	Funding Requirements	Timing for Funding (if applicable)
Green Municipal Fund – Capital Project Energy recovery or district energy	Federation of Canadian Municipalities	Combined grant and low-interest loan up to $10 million and covering up to 80% of total project costs. The grant can be worth up to 15% of the loan amount. An additional 5% grant is available if the project involves remediation of a brownfield site.	The GMF helps municipalities switch to sustainable practices faster. Each application to the GMF is reviewed on an individual basis depending on the communities' needs and feasibility of improvements.	Project must be able to reduce GHG emissions by 40%, compared to current performance	Until fund is fully allocated
Strategic Innovation Fund - Net Zero Accelerator Initiative	Innovation, Science, and Economic Development Canada	Minimum contribution of $10 million with total project cost of at least $20 million.	NZA supports the government's strengthened climate plan to deliver a stronger economy that thrives in a low-carbon world.	Fund prioritizes near-term emissions reductions, developed technologies that can be used by 2030, and additional or quicker benefits as a result of NZA investment.	Applications are currently ongoing. The steps are: 1) consultations, 2) statement of interest 3) full application
Canada Infrastructure Bank	Canada Infrastructure Bank (CIB)	CIB typically takes on 55% to 75% of the total debt for infrastructure projects (depending on	CIB has a mandate to invest and seek to attract private sector investment in projects	Should CIB come on board, the debt will be dependent on principles of	No specific timing. The application process is open

Incentive	Provider	Potential Funding ($)	Description (High Level)	Funding Requirements	Timing for Funding (if applicable)
		assets class) at a below market rate.	in Canada that are in the public interest.	optimal risk allocation. Investments have been increased in clean power infrastructure to advance decarbonization and district energy.	but it is not a direct application process, Instead, CIB's investment team customizes solutions after going through an intake and consultation process.
Commercial Buildings Retrofit Incentive	Canada Infrastructure Bank	Loans available at below market rates.	Initiative provides investments in the decarbonization of buildings and provides attractive financing to reduce investment barriers. While not specifically applicable to district energy systems, it could provide support to help connect buildings.	Minimum $25 million CIB investment opportunity up to a maximum of 80% except for public or MUSH where the max will be limited to 60%-70%. Minimum 25% reduction in carbon or energy savings.	Capital must be invested in 2-5 years.
Clean Technology Investment Tax Credit	Federal Government	Refundable 30% tax credit on capital cost of investment made by taxable entities in wind, solar PV and energy-storage technologies.	Budget 2023 proposes to expand eligibility for the Clean Technology Investment Tax Credit to include geothermal energy systems.	Unknown	Starting May 28, 2023, through to 2034 (reductions applicable for projects starting after 2032)
Canada Community Building Fund	Government of Canada - Association of	A total of $890 million was administrated in Ontario for the year of 2023-2024. The	CCBF is a source of funding to support local infrastructure	Not stated	After 2021 there is no more funding to be

Incentive	Provider	Potential Funding ($)	Description (High Level)	Funding Requirements	Timing for Funding (if applicable)
	Municipalities administered by the City of Toronto and Toronto and the CCBF on behalf of the province	Town of Oakville was allocated approximately $6.4 million.	projects. The fund supports 18 project categories including 'community energy systems'.		allocated for new projects. It appears that there is continued funding for existing projects. Money allocated to the Town of Oakville may still be accessible.
Low Carbon Economy Challenge	Environment and Climate Change Canada	Applicants are able to request between $1 million and $25 million for eligible expenditures with cost sharing range from 25% (for-profit private sector) to 50% (provincial government bodies)	Part of the Low Carbon Economy Fund, this incentive supports reducing emissions and clean growth by providing $500 million in funding. The challenge section is divided into two streams, the championship stream and the partnership stream.	Project must result in reduction of GHG in 2030 and over the lifetime of the project.	Application period closed on February 8, 2024, 8 PM EST. Assessment process started on February 9, 2024. Another round of funding may open in the future.
Towards Net-Zero Communities	NRCan	No funding limit within the budget. Budget (in millions) $4.2 in 2022-2023, $4.2 in 2023-2024, $3 in 2024-2025, $3 in 2025-2026.	Funding for innovative projects to support creative energy efficiency initiatives for the Canadian residential sector.	Legal entities in Canada including for-profit. Projects must contribute to the improved energy efficiency of homes and increased	Applications are no longer being accepted after September 21, 2022. Path 2 for Indigenous organizations

Incentive	Provider	Potential Funding ($)	Description (High Level)	Funding Requirements	Timing for Funding (if applicable)
				understanding of the housing sector or energy-using products that affect energy consumption.	opened on October 5, 2022. Oakville should monitor this program for additional budget and offerings.
Energy Innovation Program	Ontario Ministry of Energy managed by the Office of Energy Research and Development	Annual grants	The EIP advances clean energy technologies that will help Canada meet its climate targets while supporting transition to low carbon economy.	Responsibility of the applicant to demonstrate why a particular amount of funding is necessary to support the project.	As of March 2024, the only eligible categories are methane mitigation and battery innovation. This changes often. Monitor for future intakes.