The Economic Value of Ground Source Heat Pumps for Building Sector Decarbonization

Review of a recent analysis estimating the costs of electrification in Canada

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About Dunsky

Dunsky provides strategic analysis and counsel focused exclusively on helping our clients accelerate the clean energy transition, effectively and responsibly.

With a focus on buildings, renewables and mobility, our team of experts support our clients – governments, utilities and others – through three key services: we **assess** opportunities (technical, economic, market); **design** strategies (programs, plans, policies); and **evaluate** performance (with a view to continuous improvement).

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Executive Summary

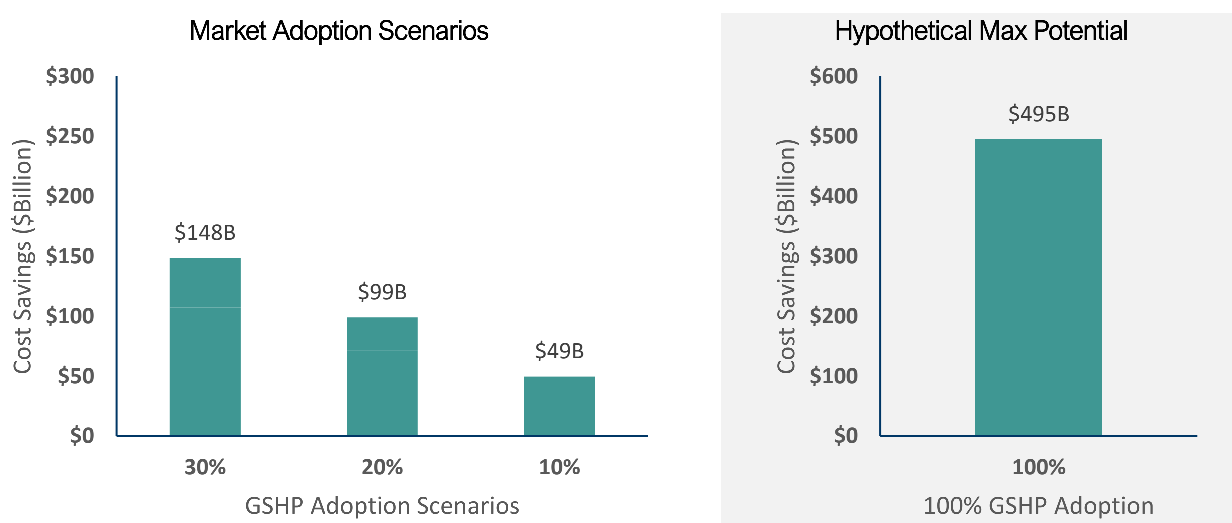
Dunsky was tasked with assessing the role ground source heat pumps (GSHP) could play in reducing the cost of heating electrification as defined in a recent study titled *Implications of Policy-Driven Electrification in Canada* (referred to as the "original study" hereafter).[1]

The original study, prepared by ICF for the Canadian Gas Association, estimates the cost of electrifying the vast majority of building, transportation and industrial fossil fuel consumption by 2050 (referred to as "aggressive electrification" in this report), under multiple scenarios of electric generation decarbonization. For space heating, in particular, the study assumes all buildings transition to electric air-source heat pumps (ASHP). Ultimately, the original study concludes this transition will be very costly compared to business as usual – up to $1.4 trillion under the most expensive scenario over the next 30 years. According to the original study, this substantial price tag is driven by the costs associated with the large-scale expansion of Canada's electricity grid needed to serve the additional electric load and peak demand caused by electrification.

Our analysis, rooted in detailed modelling of heat pump costs and performance for different building archetypes and climates, finds that inclusion of more efficient ground-source heat pumps (GSHPs) provides an opportunity to reduce the overall costs and impacts of electrifying space heating in most parts of Canada. That is because the peak load and electric consumption benefits of GSHPs can more than offset their higher upfront cost.

Specifically, we find that reasonably aggressive pursuit of GSHPs could save Canadians between $49 and $148 billion relative to the original study's findings (see Figure 1). That value climbs to nearly $500B in a hypothetical scenario where GSHPs secure total market share.

Figure 1. Estimate of Cost Savings Under GSHP Market Adoption Scenarios Relative to Original Study's ASHP-Only Cost Estimates (Renewables-Only Generation Scenario)



[1] Canadian Gas Association. *Implications of Policy-Driven Electrification in Canada (October 2019).* Available at: https://www.cga.ca/wp-content/uploads/2019/10/Implications-of-Policy-Driven-Electrification-in-Canada-Final-Report-October-2019.pdf

These results – which examine only one aspect of the original study – indicate that policy-driven decarbonization in Canada can be less costly than previously suggested, and that GSHPs can play an important role, alongside other low-carbon heating solutions, in minimizing costs and maximizing benefits to Canadians.

Why include Ground Source Heat Pumps?

The original study's analysis assumes all residential and commercial space heating is electrified with air source heat pumps (ASHP). While ASHPs are a critical component of efforts to decarbonize buildings, the study does not consider the potential for GSHPs to replace fossil fuel space heating equipment because – according to the study – these systems "require drilling and placement of underground heat exchangers, which results in much higher costs and limits their applicability."

While GSHPs will never achieve 100% market penetration, nor is 0% a realistic outcome. A more nuanced assessment is needed to account for the adoption of this technology. We note that many other countries with mature heat pump markets have seen GSHP's share of those markets in the range of 10% to 30%, with some achieving far higher.

Moreover, GSHPs offer unique benefits for a country like Canada, where ASHPs – while providing strong performance (especially new inverter-driven, cold-climate versions) – nonetheless experience a degradation of efficiency and heating capacity as outdoor temperatures decline, causing the systems to use more power to provide the same amount of heat. GSHPs are not directly impacted by outdoor air temperatures, as the temperature below ground remains relatively stable year-round. This allows GSHPs to minimize costly peak demand requirements on power grids, thereby reducing total costs in cold climate zones.

Our modelling found that increased investment in GSHPs in most parts of Canada can reduce the need to invest in expanded electricity infrastructure by a greater amount – resulting in overall cost reductions for Canadians.

In practice, numerous solutions will be required, in the near-term, to decarbonize Canada's building sector, including ASHPs, GSHPs, and renewable gas.

1 Background

The widespread electrification of fossil fuel-consuming technologies is commonly cited as a key tool for achieving Canada's greenhouse gas (GHG) emission targets. However, there remains significant uncertainty and debate regarding the overall costs and impacts of electrification. Accordingly, many interested stakeholders are undertaking analyses to understand the potential impacts of electrification and other low/no-carbon energy options.

Dunsky was tasked with assessing the role ground source heat pumps (GSHP) could have in reducing the cost of heating electrification as defined in a recent study prepared by ICF and published by the Canadian Gas Association (CGA) titled *Implications of Policy-Driven Electrification in Canada* (referred to as the "original study" hereafter).[2] The original study models the cost implications of replacing refined petroleum products and natural gas in homes, businesses, industry, and vehicles with electricity under various electrification and electricity generation decarbonization scenarios.

The original study concludes that widespread electrification will be very costly for Canada. Under the most aggressive electrification and electric generation decarbonization scenario, it finds that costs for Canadians will increase by a cumulative $1.4 trillion over the period between 2020 and 2050, which is equivalent to approximately $95,000 per Canadian household.[3] This substantial price tag is driven in large part by the costs associated with the significant expansion of Canada's electric grid, which the study asserts will be needed to serve a significantly increased peak electric load.

Significantly, the original study assumes 0% market share for ground-source heat pumps, which, due to their reliance on year-round underground heat, can significantly mitigate peak demand impacts.

[2] Canadian Gas Association. *Implications of Policy-Driven Electrification in Canada (October 2019).* Available at: https://www.cga.ca/wp-content/uploads/2019/10/Implications-of-Policy-Driven-Electrification-in-Canada-Final-Report-October-2019.pdf
[3] See Table 3 in *Implications of Policy-Driven Electrification in Canada (October 2019)*, page 17.

Analysis Limitations
The results of the analysis presented in this paper should be interpreted with the following caveats:

- **This study is limited to assessing the quantitative impact of the original study's exclusion of GSHPs.** It does not attempt to re-model unrelated benefit and cost estimates presented in that study, such as power and transmission generation costs. Nor does this analysis seek to address aspects of the original report's methodology, which themselves may warrant further review (see Appendix D). For this reason, the results of this analysis should be interpreted within the context of the original study, and not as an independent analysis of the cost and benefits of electrification.

- While we find that the original study overstates the costs associated with electrification options, **this should in no way be interpreted to suggest that electrification options alone should be pursued in the move to decarbonize Canada's heating sector.** In fact, an optimized approach can and should include multiple low/no-carbon heating options, including GSHPs, cold-climate ASHPs, renewable natural gas (RNG), and possibly hydrogen. Optimal solutions will likely differ by region, sector, building type, utility service territory, and market.

- In most instances, the original study provides results and inputs at the Canada-wide geographical level and in 2020 through 2050 cumulative terms. For this reason, much of this analysis's results cannot be directly extrapolated to more granular locations (e.g. provinces or utility service territories) or time periods.

- In quantifying the impact of including GSHPs in the original study, this analysis makes high-level assumptions regarding the adoption and applicability of ASHPs and GSHPs including a purely hypothetical scenario in which 100% of buildings could adopt GSHPs. This assumption is made for illustrative purposes and should not be interpreted as suggestive that all buildings are suitable for GSHPs.

1.1 The Original Study's Scenarios

The original study models four different scenarios with varying assumptions regarding electrification and the decarbonization of the electricity system. This analysis focuses on the first three scenarios, which are based on the same electrification assumptions and differ on assumptions regarding the electric system that supports this electrification.[4] Under these scenarios, the original study assumes the following electrification occurs:

- All residential and commercial space heating, water heating, and cooking transitions from fossil fuels to electricity,
- All passenger vehicle sales are electric by 2040, and
- 50% of fossil fuel use in industry transitions to electricity.

For simplicity, these scenarios are referred to as the **aggressive electrification** scenarios throughout this report. The aggressive electrification scenarios are differentiated by assumptions regarding the degree to which the electricity generation decarbonizes over the study period with Scenario 1 representing the

[4] The fourth scenario models a less aggressive electrification approach where fossil-fuel based heating systems remain in place as back-up heating sources (as opposed to electric resistance back-up heating systems), less industrial electrification occurs, and renewable natural gas is substituted for some applications.

highest degree of decarbonization and Scenario 3 representing the least. Table 1 further describes these assumptions.

Table 1. Description of Electricity Generation Assumptions in the Original Study's Aggressive Electrification Scenarios

Scenario	Electric Generation Assumptions Description
Renewables-Only (Scenario 1)	Wind, solar, and battery storage replace all fossil fuel generation by 2050 so that 100% of generation is carbon-free by the end of the study period
Renewables & Existing Gas (Scenario 2)	All new power generation capacity is wind, solar, and battery storage, but existing natural gas & oil power generation is maintained so that most generation is carbon-free by the end of the study period
Market-Based Generation (Scenario 3)	All power generation expansion uses the most economic options representing a business-as-usual scenario where policymakers do not pursue additional decarbonization in the electricity sector

Note: Electricity system assumptions description adapted from Table 2 of the original study (page 7).

1.2 The Original Study's Cost Estimates

The original study estimates the total cost of electrification by calculating the incremental difference in costs associated with fossil-fuel consumption, electricity consumption, and electrification equipment between each scenario and a reference case where aggressive electrification and generation decarbonization do not happen as described in the Canadian Energy Regulator (CER) Energy Futures 2018 Reference Case.[5]

The original study breaks these costs down into five categories as listed in Table 2. For the first three scenarios, the incremental difference in costs for fuel, electrical energy, and equipment are identical as these costs only vary based on the degree of electrification (e.g. equipment costs will be the same because each scenario assumes the same amount of fossil-fuel based equipment is replaced with electric counterparts), which is constant across each scenario. Power generation and transmission costs vary between scenarios as these costs are sensitive to the type of generation built to supply the increase in electricity consumption resulting from electrification.

[5] CER's Energy Futures Reports explore and model possible long-term energy pathways in Canada. Reports are accessible at: https://www.cer-rec.gc.ca/nrg/ntgrtd/ftr/index-eng.html

Table 2. Description of the Original Study's Cost Components

Cost Component	Description
Fuel Costs	The reduction in customer bills from the reduction in fossil fuel consumption.
Electrical Energy Costs	The increase in customer bills from the increase in electricity purchases.
Incremental Equipment Costs	The additional costs of the electric technology relative to the conventional fossil fuel option.
Power Generation Costs	The increase in costs associated with the power generation required to serve the additional electric load.
Transmission Costs	The increase in costs associated with building out transmission infrastructure required to connect additional power generation to the grid.

Note: The study also estimates costs associated with renewable natural gas, which is explored in the original study's Scenario 4 and not addressed in this report because of its inapplicability to GSHPs.

It is important to note the difference between "electrical energy" costs and "power generation and transmission" costs as included in the original study. The original study estimates electrical energy costs by calculating the increase in consumers' electricity bills by multiplying customers' additional electricity consumption by forecasted retail electricity rates. The study uses electric rates based on the forecasted prices provided in the 2018 Canadian Energy Regulator (CER) Energy Futures report. The rates in the CER report reflect retail rates paid by consumers, and the study does not adjust these rates for any scenario. Thus, the electrical energy costs in the original study reflect the additional cost consumers will pay on their electricity bills due to increased electricity consumption assuming business-as-usual rates, and the estimated costs do not change between scenarios.

For power generation costs, the study's authors leverage ICF's Integrated Planning Model (IPM), which is a production cost simulation model used to estimate the cost of electric generation capacity expansion. As described in the study, IPM estimates the lowest-cost solution to supply a given amount of electricity under various defined constraints (e.g. all new generation must be solar, wind, or battery storage). The power generation costs include "capital, fuel, and operations and maintenance (fixed and variable) components."[6] The study estimates power generation costs by taking "the difference between the costs modeled for each scenario and the reference case". In other words, it estimates how much more it will cost to build, maintain, and operate Canada's electric generation under each electrification scenario compared to a business-as-usual reference case.

For transmission costs, the study estimates costs from the capital cost component of the power generation costs using "a ratio of planned investments in transmission infrastructure and planned new construction investment in generation capacity".[7] Notably, the power generation and transmission costs do not include an assessment of electric distribution costs, which would undoubtedly increase with growth in electric loads.

Figure 2 reproduces the cumulative incremental costs from 2020 to 2050 broken down by each cost component as reported in the original study. As can be seen, the study concludes that aggressive electrification will result in monetary savings from reduced fossil fuel consumption but additional monetary

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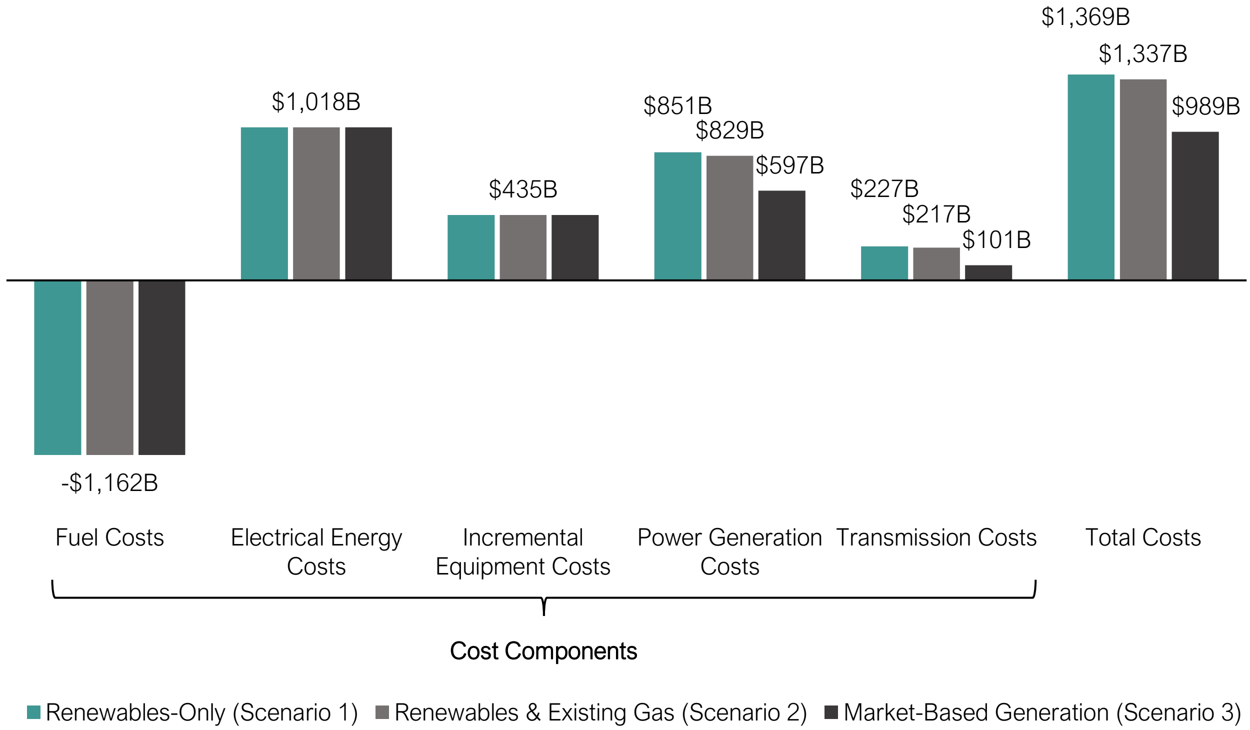
[6] *Implications of Policy-Driven Electrification in Canada (October 2019)*, page 34.
[7] *Implications of Policy-Driven Electrification in Canada (October 2019)*, page 35.

costs from increased electricity consumption and the purchase of more expensive electrified equipment. These additional costs outweigh the monetary benefits of reduced fossil fuel consumption resulting in net cumulative costs between $989 billion and $1,369 billion over the study period.[8]

Figure 2. Cumulative Incremental Costs from 2020 to 2050 as Reported in Original Study ($Billions)



Note: Figure reproduced from *Figure 13: Cumulative Incremental Costs from 2020 to 2050* of the original study (page 16).

A Note on Costs

It is important to note that while the original study estimates the net costs of electrification in Canada, it does not attempt to estimate how these costs may be distributed among consumers, utilities, governments, or other entities. Instead, the study takes a *total resource perspective* in its cost-benefit analysis approach, which accounts for the costs incurred by the utility system and the customers that participate in electrification.[9] These costs include expenses associated with increased electricity consumption and the purchase of more expensive equipment (e.g. a heat pump versus a furnace) as well as the benefit of reduced fossil-fuel consumption.

Depending on policy and regulatory structures, these costs may be directly incurred by utilities, customers, governments (e.g. via subsidies or incentive payments), or other entities. However, since the study expresses costs in terms of dollars per household, it implicitly suggests that all costs of electrification will ultimately be passed on to Canadians whether through direct cost increases, higher utility rates, or higher taxes. This report takes the same approach and expresses costs in terms in a total resource perspective that does not attribute the costs to a specific entity.

[8] All costs presented in both the original study and this report are in nominal terms.

[9] For more information on total resource benefit-cost analysis and other types of benefit-cost analyses, please see *The National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (August 2020).

2 Value of Ground Source Heat Pumps

One of the primary costs estimated in the original study is the need to build additional electric generation and transmission infrastructure to serve the increased peak load resulting from electrification. While the study considers the electrification of multiple end-uses including industrial processes and personal transportation, the majority of electrification's peak demand impacts result from electrifying residential and commercial space heating.[10]

For space heating electrification, the study assumes all existing fossil fuel-based space heating equipment is replaced with ASHPs at the end of the existing equipment's' useful life and all new construction uses electric equipment for the duration of the study. The study does not consider the potential for GSHPs to replace fossil fuel space heating equipment because – according to the study – these systems "require drilling and placement of underground heat exchangers, which results in much higher costs and limits their applicability."

While the average installation cost of a GSHP will certainly be higher than an ASHP, the study fails to consider the additional benefits of GSHPs – in particular, the provision of highly-efficient electric heat with much lower peak demand impacts relative to ASHPs. While the cold-climate performance of certain ASHPs has improved dramatically in recent years, the efficiency and heating capacity of ASHPs nonetheless degrades as outdoor temperatures decline, causing the systems to use more power to provide the same amount of heat. If it becomes too cold outside, ASHPs must revert to a backup heating system. In a full electrified scenario, this backup heating will be an electric resistance heating system, which is much less efficient than a heat pump and draws a significant amount of power, thus increasing peak demand needs. Unlike ASHPs, however, the efficiency of GSHPs is not directly impacted by outdoor air temperatures.

This benefit is particularly relevant when considered in the context of the original study's implicit costs associated with building additional generation and transmission infrastructure to serve an increased electric peak load. Based on the results and methodological assumptions reported in the original study, we estimate an additional kilowatt (kW) increase in peak load results in an additional $2,500 to $5,500 in power generation and transmission capital expenses depending on the degree of electric generation decarbonization as represented in the study's first three scenarios (see Appendix C for a description of how these costs are derived).[11] These peak load costs indicate that it is worthwhile to consider any technology that would contribute less to peak load such as GSHPs.

To assess the possible impact of including GSHPs in the analysis, we model and compare GSHP and ASHP performance and costs for three representative climate locations in Canada and four building archetypes and apply these results to the avoided electric energy supply costs derived from the results of the original study. We assume GSHPs experience similar cost and performance improvements as ASHPs

[10] Figure 8 of the original study (page 12) breaks down the components of incremental peak electricity load for the aggressive electrification scenarios. According to the study, the aggressive electrification scenarios will result in a peak load 174GW higher than the reference case. Of this increase, approximately 135GW (78%) is attributable to the residential and commercial sectors after accounting for heat pump improvement and buildings with electric resistance heat adopting more efficient ASHPs.

[11] These estimates of the cost of peak load increases represent a one-time cost incurred to build additional generation and transmission infrastructure. The analysis includes recurring kW and kWh avoided costs, but the bulk of avoided costs derive from the avoided up-front capital costs of additional generation and transmission.

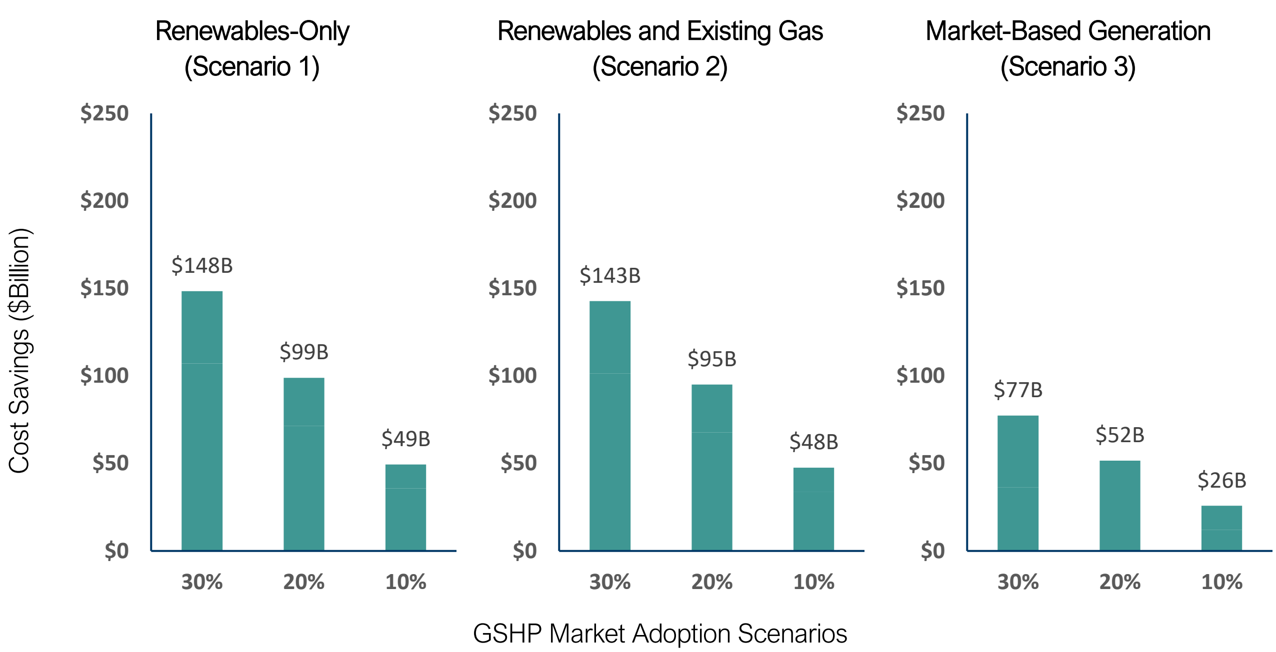
in the original study. We then scale these results to estimate the possible Canada-wide cost savings when GSHPs are included as a heating electrification solution under a range of market adoption scenarios – from 10% to 30% of the total assumed heat pump market, as observed in certain mature markets[12] – as well as a hypothetical maximum potential scenario where 100% of space heating electrification is accomplished with GSHPs.

A description of the modeling approach used to derive these results can be found in Appendix A. Additional results and discussion on climate location-specific and building archetype-specific results are included in Appendix B.

2.1 Savings from GSHPs

Our results suggest the inclusion of GSHPs can produce significant cost savings relative to a scenario where aggressive electrification is pursued with only ASHPs for space heating. As shown in Figure 3, if 30% of buildings are electrified with GSHPs, the original study's cost of electrification could be reduced by $77B to $148B dollars under the most aggressive power generation decarbonization scenario. Under lower market adoption scenarios and less aggressive generation decarbonization scenarios, savings are lower but still significant. If even one of every ten buildings electrifies with GSHPs, Canada's energy system would save between $26-49 billion relative to the original study's estimates.

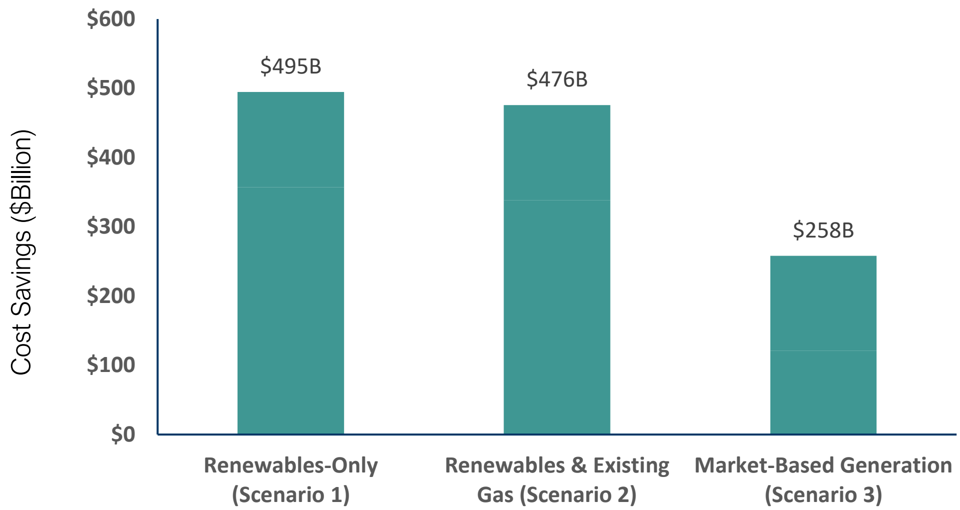
Figure 3. Estimate of Cost Savings Under GSHP Market Adoption Scenarios Relative to Original Study's ASHP-Only Cost Estimates



[12] For example, in Europe GSHPs occupy between 10-30% market share among heat pumps in most counties, and up to 70% in select countries.

In a hypothetical scenario where *all* space heating is electrified with GSHPs in areas where it makes sense, **our analysis suggests aggressive electrification could cost Canadians nearly $500 billion less than the original study's estimates** as shown in Figure 4.[13] While electrifying all space heating with GSHPs is unrealistic due to physical and other constraints, this hypothetical example illustrates the benefits of incorporating GSHPs into a comprehensive decarbonization strategy.

Figure 4. Estimated Cost Savings Under GSHP Theoretical Max Potential Adoption Scenario Relative to Original Study's ASHP-Only Cost Estimates



Note: The range of savings represent uncertainty regarding the assumed generation power mix.

This hypothetical example also highlights how the potential savings from GSHPs decline under less aggressive generation decarbonization scenarios, especially under the market-based generation scenario (Scenario 3). This is due to two reasons.

First, incremental electricity-related costs are lowest for the market-based generation scenario of the three aggressive electrification scenarios in the original study as the study's power system modeling concludes a scenario where policymakers do not pursue additional decarbonization in the electricity sector will be less expensive relative to one where they do (which also leads to fewer emission reductions). This means there are less incremental costs caused by electrification from which GSHPs can create savings.

And second, under the market-based generation scenario, avoided electric supply costs are weighted more towards variable costs (i.e. per kWh costs) than fixed costs (i.e. per kW costs) relative to scenarios featuring renewables as the former scenario consists of more generation such as natural gas generation that have higher variable costs but lower fixed costs compared to renewables such as wind and solar. **While GSHPs provide both energy (i.e. per kWh) and peak load (i.e. per kW) benefits, our modeling suggests the peak load benefits are greater.** For example, a single-family home in Toronto that installs a GSHP over an ASHP will have 58% lower peak load impacts but only 29% lower energy consumption (see Appendix B for additional climate and building archetype results). For this reason, GSHPs will produce

[13] This hypothetical example assumes GSHPs are only installed in locations where the monetary value of the energy and peak load benefits of GSHPs relative to ASHPS outweigh the additional equipment costs. As further detailed in Appendix B, these locations are areas with colder climates where seasonal ASHP performance is diminished due to colder outdoor temperatures. Further, the example's assumption that all space heating is electrified with GSHPs is for illustrative purposes only and does not reflect a realistic outcome as GSHPs will not be feasible in all buildings due to technical constraints and other factors.

greater savings under generation scenarios where the relative cost of peak load is higher, such as ones where policymakers pursue aggressive electric system decarbonization through solar and wind deployment.

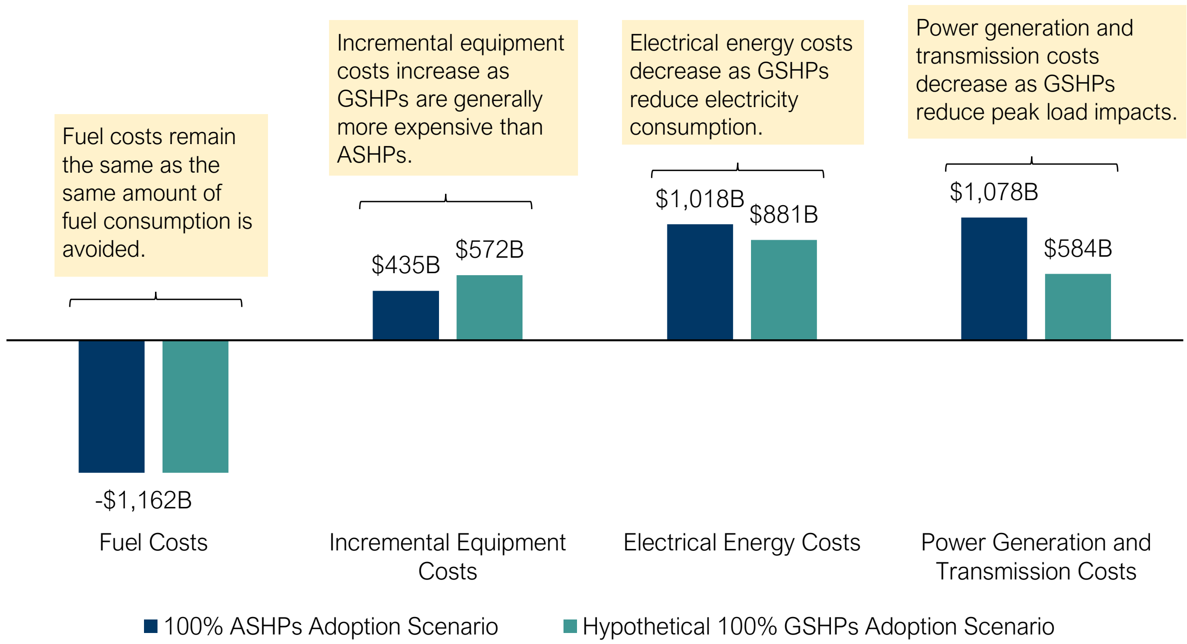
2.2 Cost Component Impacts from GSHPs

The inclusion of GSHPs creates cost savings relative to a scenario with 100% ASHPs by reducing incremental electricity costs to a greater degree than incremental equipment costs increase. Figure 5 demonstrates this by showing the estimated change in each cost component under the renewables-only generation scenario (Scenario 1) under the hypothetical example where 100% of buildings electrify with GSHPs. The figure illustrates the following three observations:

- **Fuel costs reductions remain the same** since the reduction in fuel consumption does not change whether an ASHP or GSHP is used to fully electrify space heating.
- **Incremental equipment costs increase by approximately $137 billion** as the installation of a GSHP is more expensive than the installation of an equivalent ASHP.
- **Electric energy costs decrease by (incidentally) $137 billion and power generation and transmission costs decrease by $494 billion** when all space heating is electrified with GSHPs, which is driven by an approximate 50% reduction in the peak load impacts of electrifying space heating compared to the only-ASHP scenario.

Since the reduction in electricity-related costs eclipse the increase in incremental equipment costs, the 100% GSHP scenario produces savings relative to the 100% ASHP scenario. In other words, **the analysis indicates an increased investment in GSHPs can reduce the need to invest in expanded electricity infrastructure by a greater amount, leading to overall cost reductions for Canada's energy system.**

Figure 5. Cumulative Costs from 2020 to 2050 by Cost Component Under Renewables-Only Generation Scenario (Scenario 1) Assuming 100% of Buildings Electrify with ASHPs vs. 100% GSHPs ($Billions)



3 Conclusion

Electrification, combined with other low-carbon energy sources, will play a key role in decarbonizing Canada's economy. For this reason, many interested stakeholders have and will investigate the implications of this energy transition. Our analysis of the original *Implications of Policy-Driven Electrification in Canada* study finds that **including GSHPs as a space heating electrification solution can help to reduce the overall costs of electrification for Canadians by $49B to $148B assuming 10-30% market share**, and by nearly $500B assuming a hypothetical 100% market share over the next 30 years.

Our findings suggest that policymakers should not inadvertently lockout viable options such as GSHPs. To the contrary, price signals and incentives should be aligned with the value created by various decarbonization solutions, including GSHPs, to minimize costs and maximize benefits to Canadians.

In the case of GSHPs, our analysis shows that including this technology in the suite of options to electrify space heating can have profound impacts on the overall costs of reducing building-related fossil fuel consumption. **This benefit is driven by the significantly lower peak load impacts of GSHPs relative to ASHPs.** In an energy future where the electric system continues to decarbonize through the addition of zero-marginal cost resources such as wind and solar (i.e. an electric system where costs are driven primarily by how much generation capacity is built and not by how much electricity is consumed), the ability to reduce peak load impacts becomes critical to minimizing system-wide costs.

Appendix A: Methodology

Modeling Approach

To assess the possible impact of including GSHPs in the original study, we model and compare GSHP and ASHP performance and cost for three representative climate locations in Canada for four building archetypes and apply these results to the original study's aggregate Canada-wide cost estimates.

The three climate locations selected are Vancouver, Toronto, and Winnipeg. These climates are selected to represent the breadth of climatic conditions experienced by most of Canada's population. The four building archetypes selected are a single-family home, a multi-unit residential building (MURB) with 45 units, a small commercial building (7,500 ft^2), and a large commercial building (150,000 ft^2). These building archetypes are the same ones considered in the original study and are chosen to maintain comparability.[14]

For each jurisdiction, we model the cost and performance of ASHPs and GSHPs – both with electric resistance back-up heating systems - to provide each building archetype's space heating requirements as summarized in Table 3. The ground loop for the GSHPs is assumed to be a vertical closed loop in all cases. We attempt to maintain consistency with the original study to the greatest extent possible by assuming ASHPs are cold climate rated systems – except in Vancouver where we assume standard air-to-air ASHPs.

However, for building archetypes with hydronic heating systems (i.e. MURBs and Large Commercial) that require air-to-water heat pump retrofits, we assume cold climate rated systems regardless of climate location. While outdoor air temperatures in Vancouver are much higher than in the other climate zones, buildings with hydronic heating still typically need high-temperature hot water. A high-performance air-to-water heat pump is needed to provide adequately hot water, so a high-performance unit is used for all climate zones in the building archetypes with hydronic distribution.

We then compare the performance of GSHPs to ASHPs and estimate how this would impact the cost components for each aggressive electrification scenario in the original study. To estimate electricity-related cost impacts, we derive avoided electricity supply costs from the inputs and results described in the original study (see Appendix C for a description of these calculations).

[14] See Table 8 in Appendix D of CGA study (page 33).

Table 3. Summary of Building Archetypes Modeled

Building Archetype	Baseline Heating and Cooling System	ASHP System	GSHP System
Single Family Home	Gas furnace and Central Air Conditioner	Central ASHP (split central air to air)	Central GSHP (split central water to air)
MURB (45 units)	Gas Boiler and Chiller	Air to Water Heat Pump* (split central air to water)	Water to Water Heat Pump* (split central water to water)
Small Commercial (7,500 ft^2)	Gas Rooftop	Rooftop ASHP (packaged air to air)	Rooftop GSHP (packaged water to air)
Large Commercial (150,000 ft^2)	Gas Boiler and Chiller	Air to Water Heat Pump* (split central air to water)	Water to Water Heat Pump* (split central water to water)

*Chiller stays in place to provide cooling – heat pump provides heating only

Modeling Heat Pump Performance

The cost and performance of ASHPs and GSHPs are estimated using Dunsky's Heating Electrification Adoption (HEAT™) model.

The HEAT™ model uses location-specific climate data to calculate hourly heat pump efficiency and output capacity. The model can simulate multiple heat pump control strategies, including systems that run in tandem with other non-heat pump heating systems (e.g. a furnace, boiler, or electric resistance backup system) and systems that switch between heat pump and non-heat pump systems at specific temperature set points. In this study, the electric resistance back-up is assumed to run in tandem with the heat pump, covering the portion of the heating load that exceeds the heat pumps output capacity.

The model determines heating system capacity based on the building archetype's heating load profile in the jurisdiction's prevailing climate. It can model multiple heat pump sizing strategies representative of typical customer use-cases such as sizing to serve the full heating load of the building or sizing to serve the building's cooling load. Sizing strategies will significantly impact the energy and demand impacts of heating electrification but can also significantly impact customer economics.

Upfront and maintenance costs are estimated through a bottom-up approach as a function of heating pump size and efficiency as well as the heat pump's back-up system. This approach allows for the estimation of building and jurisdiction-specific incremental costs where average heating system sizes will vary based on average building heating requirements.

Dunsky's HEAT™ model is also capable of estimating customer adoption of heating electrification technologies – but this type of analysis was beyond the scope of this report.

Optimal Heat Pump Sizing

For this analysis, we model multiple heat pump sizing strategies and select the option that minimizes the total resource cost of the ASHP or GSHP (i.e. minimizes incremental equipment costs and energy supply costs). When comparing sizing strategies, we vary the percentage of the building's heating demand that the heat pump covers. For heat pump technologies that also provide cooling (residential ASHP's and rooftop heat pumps), the building's cooling requirement may also set the minimum heat pump size if the cooling requirement is higher than the heating requirement. The lowest cost sizing strategy for a certain building archetype will often be different for a GSHP and an ASHP. In a single-family home in Toronto, for example, the lowest total resource cost sizing strategy for a GSHP is to install a 3.4 ton heat pump. For an ASHP, however, the lowest total resource cost sizing strategy is to install a 2.3 ton heat pump. The difference stems from the extent to which adding extra heating capacity contributes to reducing peak load impacts.

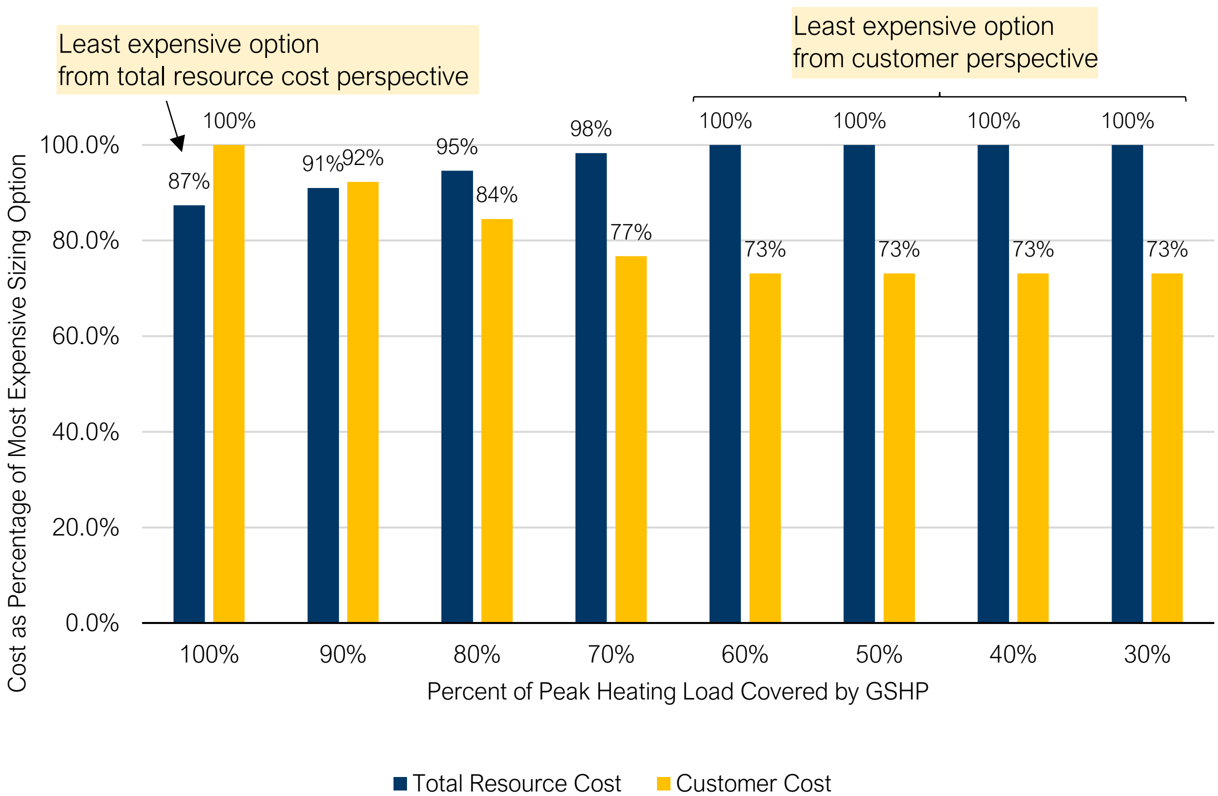
As previously noted, the costs in this analysis represent total resource costs and not necessarily the costs incurred by the customer. For this reason, the selected sizing strategy does not necessarily represent the strategy that would be most beneficial to the customer given prevalent rate structures, incentives, and other mechanisms that impact customer economics – and therefore the optimal sizing strategy does not represent the most likely sizing strategy to be selected by the customer.

As an example, Figure 6 compares the total resource cost and customer cost of various sizing options for a GSHP in the Toronto climate location for a single family home. In this example, the customer is assumed to bear the entire equipment cost of the GSHP and play a flat per kWh rate for electricity. The figure presents costs as a percentage of the most expensive sizing option (i.e. a sizing option at 100% represents the most expensive option).

As can be seen, the least expensive option from the customer perspective is one of the most expensive options from a total resource perspective, while the least expensive total resource cost option is the most expensive customer option. This result is primarily due to the fact the customer is indifferent to the peak load impacts of the GSHP. For the customer, a smaller-sized GSHP will cost substantially less but still provide significant electric consumption savings. In the absence of policies such as time-of-use rates, demand charges, or other policies that would incentivize a customer to prefer a larger GSHP that contributes less to peak load, an economically rational customer would choose the system that creates more resource costs in total.

Another interesting observation is that equipment costs do not change for systems sized at 60% of heating load and below. This is because GSHP system becomes limited by the building's cooling requirement once the system's size reaches 60% of heating load and thus will not be sized any smaller to ensure it can provide adequate cooling energy to the building.

Figure 6. Comparing Total Resource Cost and Customer Cost of GSHP Sizing Strategies (Toronto, Single Family)



Heat Pump Costs and Efficiencies

The costs and efficiencies used in Dunsky's HEAT™ model for each technology and building archetype combination is shown in the tables below. The equipment sizes shown in this table are the equipment sizes found to have the lowest total resource cost under the estimated avoided costs for the renewables-only generation scenario (Scenario 1).

Single Family Home

Table 4. Heat Pump Costs and Performance for Single Family Homes with Split-Central Forced Air Heating and Cooling Systems

Climate zone	Heat pump type	Nominal capacity (tons)	Upfront cost	Annual maintenance cost	Average seasonal COP	Minimum COP	Percentage of heating covered by the heat pump[15]
Toronto	ccASHP	2.3	11,500	91	2.8	1.3	92%
Toronto	GSHP	3.4	27,500	91	3.7	3.7	100%
Vancouver	ASHP	2.4	5,500	91	3.2	2.5	100%
Vancouver	GSHP	2.3	19,500	91	3.7	3.7	100%
Winnipeg	ccASHP	2.3	11,500	91	2.4	1.0	65%
Winnipeg	GSHP	4.8	36,500	91	3.7	3.7	100%

The lowest total resource cost sizing option for GSHPs in all climate zones and for ASHPs in Vancouver is sizing to cover the buildings full heating load. For ASHPs in Toronto and Winnipeg, it is more cost effective to size the heat pump smaller such that it only covers a portion of the heating load with backup heating covering the rest.

Multi-Unit Residential Buildings (MURBs)

Table 5. Heat Pump Costs and Performance for MURBs with Hydronic Heating Systems

Climate zone	Heat pump	Nominal capacity (tons)	Upfront cost	Annual maintenance cost	Average seasonal COP	Minimum COP	Percentage of heating covered by the heat pump
Toronto	ccASHP	18	96,500	2,795	2.1	1.2	67%
Toronto	GSHP	31	216,000	2,455	2.7	1.8	80%
Vancouver	ccASHP	29	160,000	3,271	2.4	1.8	100%
Vancouver	GSHP	39	272,500	2,732	3.0	2.5	100%
Winnipeg	ccASHP	18	96,500	2,795	1.8	1.0	44%
Winnipeg	GSHP	33	234,000	2,543	2.3	1.7	61%

[15] Indicates the proportion of the building's heating energy requirement that is provided by the heat pump. The remainder is provided by the backup system.

The lowest total resource cost sizing option for hydronic GSHPs and ASHPs in Vancouver is sizing to cover the full heating load (this results in a different nominal capacity because the ratio of output capacity at the design outdoor air temperature to nominal capacity is different for the two technologies). In Toronto and Winnipeg, the lowest total resource cost sizing option for ASHPs is to size smaller than the lowest total resource cost sizing option for GSHPs. The difference stems from the extent to which adding extra heating capacity contributes to reducing peak load impacts.

Small Commercial

Table 6. Heat Pump Costs and Performance for Small Commercial Buildings with Rooftops for Heating and Cooling

Climate zone	Heat pump	Nominal capacity (tons)	Upfront cost	Annual maintenance cost	Average seasonal COP	Minimum COP	Percentage of heating covered by the heat pump
Toronto	ccASHP	19	74,500	838	2.5	1.3	100%
Toronto	GSHP	19	131,500	838	3.7	3.7	100%
Vancouver	ASHP	19	42,000	838	2.9	2.4	100%
Vancouver	GSHP	19	131,500	838	3.7	3.7	100%
Winnipeg	ccASHP	19	74,500	838	2.0	1.0	89%
Winnipeg	GSHP	19	131,500	838	3.7	3.7	100%

The small commercial building's cooling demand exceeds its heating demand in all cases so the ASHP and the GSHP are both sized to meet the cooling demand.

Large Commercial

Table 7. Heat Pump Costs and Performance for Large Commercial Buildings with Hydronic Heating Systems

Climate zone	Heat pump	Nominal capacity (tons)	Upfront cost	Annual maintenance cost	Average seasonal COP	Minimum COP	Percentage of heating covered by the heat pump
Toronto	ccASHP	78	428,500	5,271	2.1	1.2	67%
Toronto	GSHP	137	961,000	6,098	2.7	1.8	80%
Vancouver	ccASHP	130	711,500	7,385	2.4	1.8	100%
Vancouver	GSHP	173	1,212,000	7,326	3.0	2.5	100%
Winnipeg	ccASHP	78	428,500	5,271	1.8	1.0	44%
Winnipeg	GSHP	149	1,041,000	6,488	2.3	1.7	61%

The lowest total resource cost sizing option for hydronic GSHPs and ASHPs in Vancouver is sizing to cover the full heating load (this results in a different nominal capacity because the ratio of output capacity at the design outdoor air temperature to nominal capacity is different for the two technologies). In Toronto and Winnipeg, the lowest total resource cost sizing option for ASHPs is to size smaller than the lowest total

resource cost sizing option for GSHPs. The difference stems from the extent to which adding extra heating capacity contributes to reducing peak load impacts.

Appendix B: Climate and Building Archetype Results

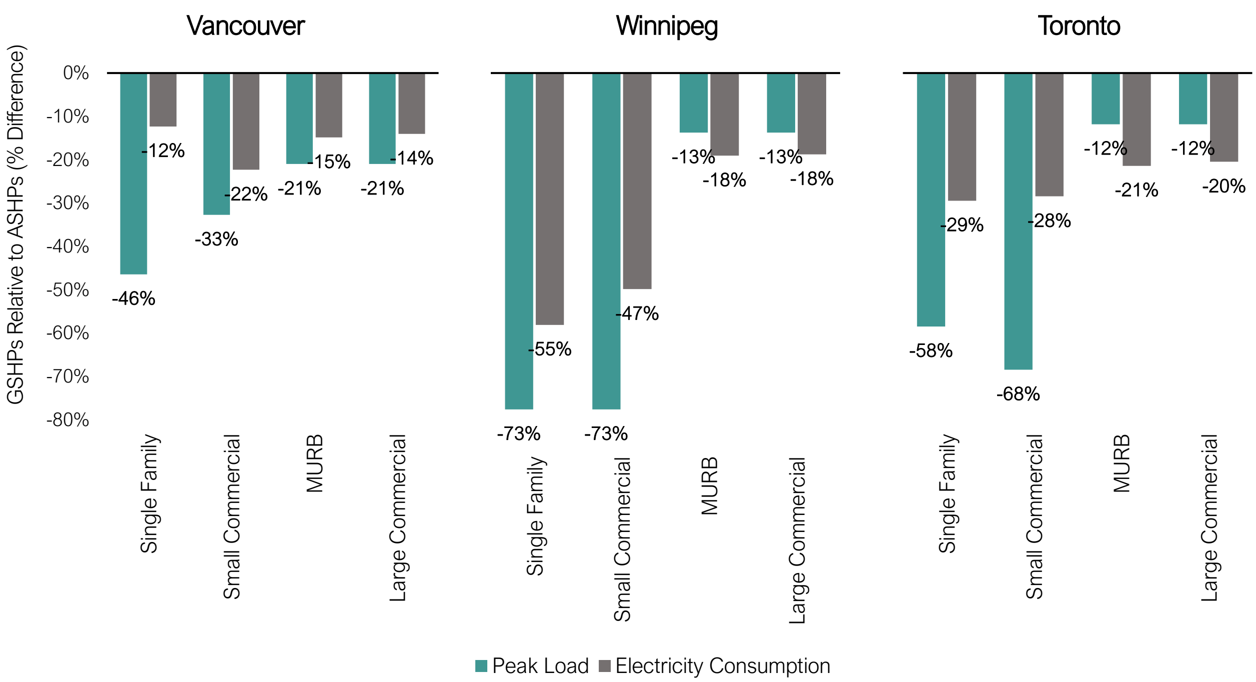
The following appendix presents the results of the model exercise to compare GSHP and ASHP cost and performance for different climate locations and building archetypes.

Heat Pump Performance and Costs

The relative difference between GSHPs and ASHPs in equipment costs, peak load, and energy consumption varies by climatic location and building type.

As illustrated in Figure 7, our analysis shows that GSHPs will reduce peak load in every climatic location and building archetype combination and electricity consumption in every combination when compared to ASHPs. For example, a GSHP in a single-family home in Winnipeg will consume 55% less electricity and contribute 73% less to peak load compared to an ASHP. In Vancouver, however, a GSHP reduces these impacts by only 12% and 46%, respectively.

Figure 7. Relative Difference in Peak Load and Electricity Consumption of GSHPs Compared to ASHPs by Jurisdiction and Building Archetype



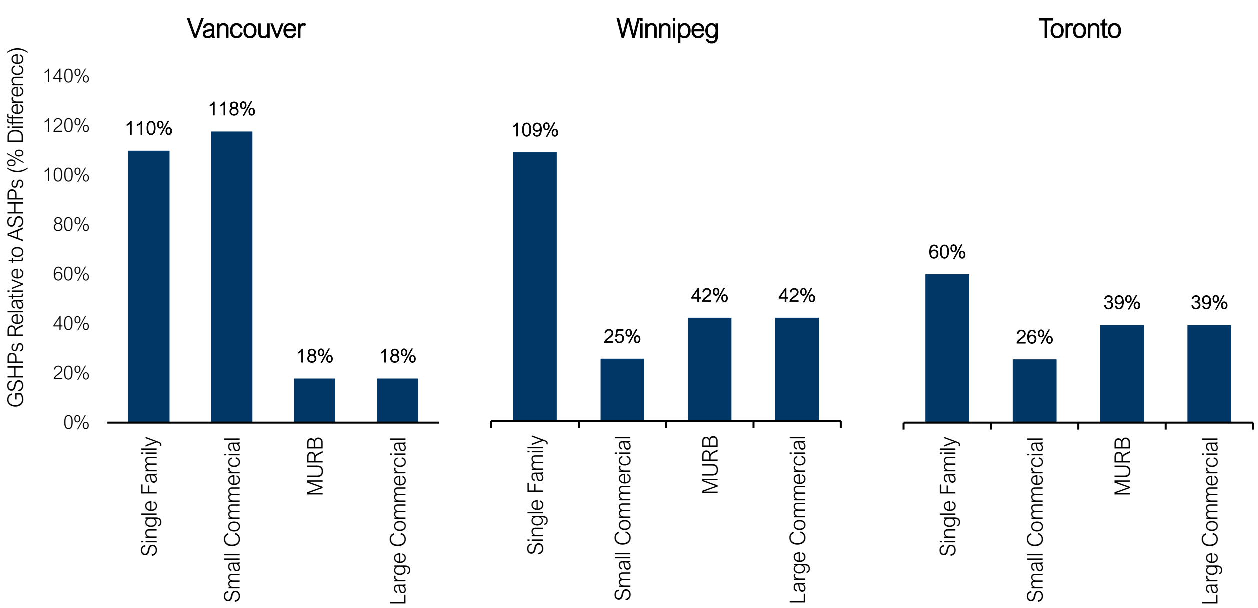
Based on these results, the following trends are observed:

- **The peak load and energy consumption benefits of GSHPs are greatest in colder climates.** This trend is due to the diminished performance of ASHPs as outdoor temperature decreases, which results in the heat pump drawing additional power to provide adequate heat or switching over to electric resistance backup. The performance of GSHPs, on the other hand, are not impacted by outdoor temperature and provide heat at similar performance levels in each modeled climate. Thus, as the climate becomes colder, the relative difference between an ASHP and GSHP in terms of peak load and electricity consumption grows.

- **Buildings with forced air heat distribution systems (i.e. single-family homes and small commercial buildings) tend to have greater peak load and electricity consumption reductions from GSHPs relative to ASHPs.** For buildings with hydronic distribution systems (i.e. MURBs and large commercial buildings), the relative impact on peak load and electricity consumption is smaller because the ratio of GSHP performance to ASHP performance is lower for hydronic systems than it is for forced air systems.[16]

The relative difference in equipment costs across building archetypes and climate locations is shown in Figure 8. For all climatic locations and building archetypes, GSHPs cost more to install than ASHPs.[17]

Figure 8. Relative Difference in Equipment Cost of GSHPs Compared to ASHPs by Jurisdiction and Building Archetype



These cost differences are driven not only by the difference in equipment cost between GSHPs and ASHPs but also by the differences in lowest cost sizing strategy between the two technologies. Comparing the magnitude of these cost differences between climatic locations and building archetypes reveals the following trends:

[16] The performance of hydronic ASHP's and GSHP's is highly dependant on the building side water temperature. In this analysis we assume a maximum building side water temperature of 65°C when the outdoor air temperature is -20°C. Maximum water temperatures as high as 85°C are not uncommon, meaning some buildings would have to retrofit the hydronic distribution system to achieve the results presented here.
[17] The comparison of equipment costs accounts for the longer useful life of GSHPs. The study assumes GSHPs have an effective useful life (EUL) of 25 years and ASHPs have an EUL of 18 years. To compare equipment costs, we increase the upfront costs of ASHPs by the ratio of the EULs to account for the fact an ASHP system will need to be replaced earlier than a GSHP.

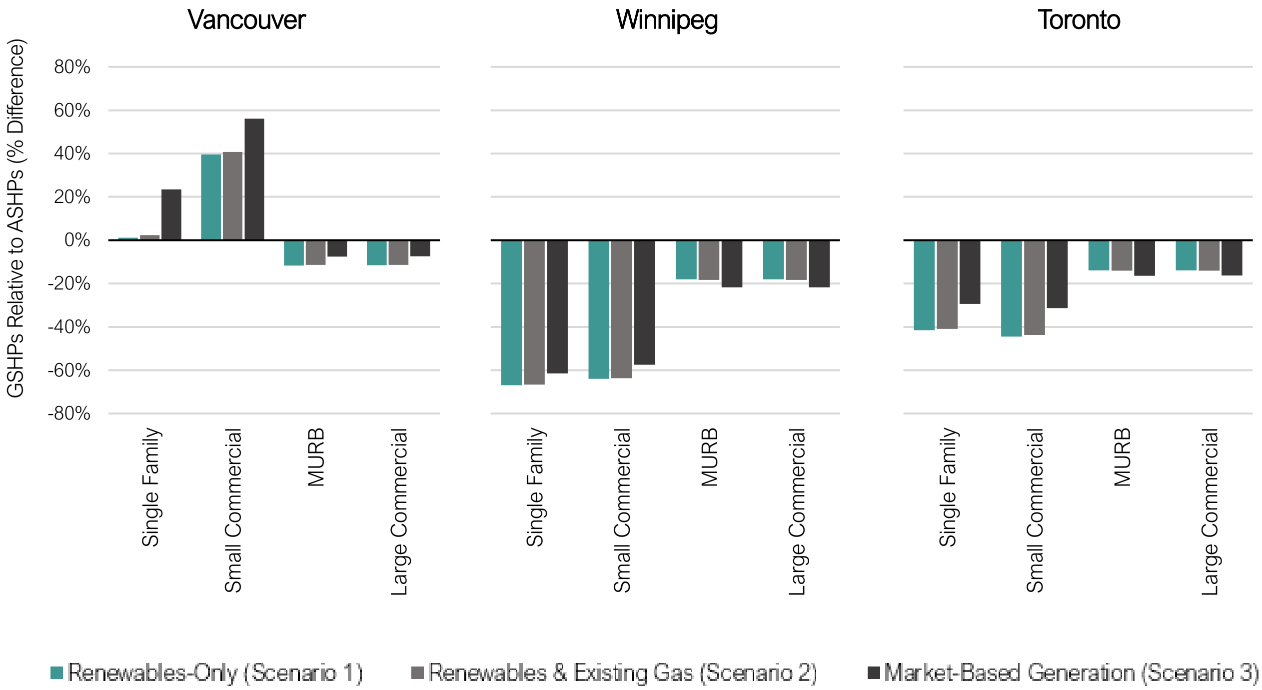
- **For small buildings (i.e. single family homes and small commercial buildings), GSHPs are generally proportionally more expensive than ASHPs in Vancouver than in colder climates such as Toronto and Winnipeg.** This is driven by the assumption that a standard ASHP will be installed in the Vancouver climate and a more expensive cold climate ASHP will be installed in Toronto and Winnipeg. Sizing assumptions also play a role:
    - In small commercial buildings, the cooling demand of the building sets the size of both the ASHP and the GSHP such that they are both the same size.
    - In single family homes in Toronto and Winnipeg the lowest cost sizing strategy for GSHPs is to meet the peak heating load, whereas the lowest cost sizing strategy for ASHPs is to only cover a small portion of the buildings peak heating load. The GSHP option is therefore larger than the ASHP option, further increasing the difference in price.

For larger buildings (i.e. MURBs and large commercial buildings), GSHPs are proportionally more expensive in colder climates than Vancouver. GSHPs are roughly 40% more expensive than ASHPs in larger buildings (i.e. MURBs and large commercial buildings) in colder climates (i.e. Toronto and Winnipeg) while only 18% more expensive in Vancouver. The same cold climate technology is installed in Vancouver as in Winnipeg and Toronto due to the need to produce adequately hot water to serve the existing hydronic heating systems. As such, the difference here is driven by differences in optimal sizing strategy. In Winnipeg and Toronto, the lowest cost ASHP size is much smaller than the lowest cost GSHP size, leading to a bigger difference than in Vancouver, where the lowest cost ASHP size is only slightly smaller than the lowest cost GSHP size.

Total Resource Cost Impacts

When GSHPs' higher equipment cost is compared to the value of avoided costs of power generation and transmission resulting from decreased peak load impacts and decreased electricity consumption, we can determine the overall impact on total resource costs of GSHPs compared to ASHPs. Figure 9 shows the relative difference in overall resource costs of GSHPs compared to ASHPs for each electricity generation decarbonization scenario in the original study.

Figure 9. Relative Difference in Total Resource Cost of GSHPs Compared to ASHPs by Jurisdiction and Building Archetype



Based on these results, the following observations can be made:

- **In colder climates, GSHPs cost less than ASHPs from a total resource cost perspective for all building archetypes under all generation decarbonization scenarios.** This is because the monetary benefit of avoiding power generation and transmission costs by installing GSHPs with lower peak load impacts outweigh the additional cost of installing GSHPs. The cost difference between GSHPs and ASHPs is diminished under the market-based generation scenario (Scenario 3), which is due to the lower avoided cost of capacity under this generation scenario.
- **In warmer climates (e.g. Vancouver), ASHPs incur less total resource costs than GSHPs for buildings with forced air heat distribution.** GSHPs have higher total resource costs in this climate location primarily due to the ability to install cheaper, non-cold climate ASHPs, and due to the smaller benefit from reducing peak load. Since outdoor air temperatures are higher in this location, ASHPs can provide heat without the elevated peak load impacts experienced in colder climates. This result suggests it would be more cost-effective to use ASHPs for forced air buildings in warmer climates such as Vancouver.
- **However, for buildings with hydronic heat distribution in warmer climates**, a high-performance air-to-water heat pump is needed to provide adequately hot water. With this more expensive ASHP, the benefits of avoiding power generation and transmission costs by installing GSHPs outweigh the additional cost of installing GSHPs, unlike for buildings with forced air heat distribution.[18]

[18] This result is highly dependant on the building's required supply water temperature and the optimal option will depend on the particular building.

- **In general, the total resource value of GSHPs compared to ASHPs is highest under aggressive generation decarbonization scenarios.** This is because the avoided cost of electric capacity is much higher under these scenarios. In an energy future where electricity is increasingly generated from resources with low or no marginal costs (e.g. solar and wind), the primary factor driving electric system costs will be peak load, while overall electric consumption will be less important.

Appendix C: Avoided Electric Supply Costs

This appendix describes how avoided electricity supply costs are derived from the inputs and results described in the original study.

The avoided cost of capacity is derived for each scenario in the original study using the study's reported incremental peak load impact, electrical energy costs, power generation costs, and transmission costs as well as various methodological assumptions described in the report.

First, power generation costs are segmented into generation capital costs and generation operating costs (i.e. fuel and O&M costs) by dividing transmission costs by 0.308 since transmission costs are estimated by multiplying the capital cost component of power generation costs by the same factor in the original study.[19]

Next, **power generation operating costs** are segmented into fixed (i.e. costs that vary based on generation capacity) and variable (i.e. costs that vary based on electricity production) costs by multiplying other generation costs by the ratio of renewable electric generation to total electric generation in 2050 as reported in Figure 11 of the original study. Under this approach, scenarios that feature greater penetration of renewable generation are assumed to have a smaller portion of generation operating costs as variable costs since these resources have minimal to non-existent non-capital generation costs (e.g. zero marginal cost generation).

Generation capital costs, **non-capital fixed generation costs**, and **transmission capital costs** are converted into per kW avoided energy supply costs by dividing each cost by the incremental peak load impact of electrification as reported in Table 8 of the original study. Generation and transmission capital costs are assumed to be incurred once in response to an increase in peak load, while non-capital fixed generation costs are assumed to be incurred on an annual basis.

Non-capital variable generation costs, including fuel and variable O&M costs, are converted into per kWh avoided costs by dividing the cost by the estimated total incremental electric consumption over the study period. These costs represent the avoided cost of electric consumption embedded within incremental power generation costs. Total incremental electric consumption was not reported in the original study, but are derived by assuming incremental electricity consumption increases linearly over the study period until it reaches the reported incremental increase in electricity consumption in 2050 (see Figure 4 and accompanying text in original study).

The avoided costs of electric consumption embedded within incremental electric energy costs are converted into per kWh avoided costs by dividing the original study's total electric energy cost estimate by the estimated total incremental electric consumption over the study period described previously.

It is important to note these avoided costs are derived from the Canada-wide results of the original study. Thus, they represent an average avoided cost for the entire country. In reality, avoided costs will differ significantly between provinces and local jurisdictions due to local conditions and other factors.

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[19] See description of transmission costs in Appendix D – Cost Assumptions (page 35).

Table 8 presents the inputs taken from the original study and intermediate calculations used to derived avoided costs and outputs of this analysis.

Table 8. Original Study Inputs and Intermediate Calculations Used to Derive Avoided Energy Supply Costs

Avoided Cost Calculation Components	Scenario 1	Scenario 2	Scenario 3	Source
Incremental Electric Energy Costs ($B)	1,018	1,018	1,018	Original study, Figure 13
Incremental Power Generation Costs ($B)	851	829	597	Original study, Figure 13
Incremental Transmission Costs ($B)	227	217	101	Original study, Figure 13
Incremental Power Generation Capital Costs ($B)	737	705	328	Calculated. Based on incremental transmission costs and generation capital cost ratio assumption from original study.
Incremental Power Generation Non-Capital Costs ($B)	114	124	269	Calculated. Based on incremental transmission costs and generation capital cost ratio assumption from original study.
% of Incremental Power Generation Non-Capital Costs That Are Fixed	12%	16%	46%	Calculated. Based on the ratio of zero-marginal cost generation to total generation in 2050 from original study (Figure 11).
Incremental Peak Load Impact (GW)	174	174	174	Original study, Figure 8.
Incremental Generation, 2020-2050 (TWh)	7,328	7,328	7,328	Calculated. Based on incremental electric generation in 2050 from original study (Figure 4 and accompanying text).

Table 9 presents the avoided energy supply costs used to estimate the cost impacts of including GSHPs in the original study's analysis. As can be seen, the one-time avoided cost of peak load is the most significant avoided cost, while the avoided cost of electric consumption is relatively minimal. This reflects the high degree of zero- and low-marginal cost resources such as hydro and nuclear that currently makes up Canada's generation profile (approximately 82%) and the original study's assumptions that much of the remaining generation is replaced by other zero-marginal cost resources such as wind and solar.

Table 9. Avoided Energy Supply Costs

Avoided Costs	Scenario 1	Scenario 2	Scenario 3	Source
One-Time Avoided Cost of Peak Load ($/kW)	$5,540	$5,296	$2,465	Calculated. Incremental power generation capital costs and transmission capital costs divided by incremental peak load impact.
Recurring Avoided Cost of Peak Load ($/kW-year)	$38	$40	$56	Calculated. Incremental power generation non-capital fixed costs divided by incremental peak load impact.
Avoided Cost of Electric Consumption Embedded within Incremental Power Generation Costs ($/kWh)	$0.0018	$0.0027	$0.0169	Calculated. Incremental power generation non-capital variable costs divided by incremental 2020-2050 electric generation.
Avoided Cost of Electric Consumption Embedded within Electrical Energy Costs ($/kWh)	$0.14	$0.14	$0.14	Calculated. Incremental electric energy costs divided by incremental 2020-2050 electric generation.

Appendix D: Uncertainty in Cost Components

Given that this study is limited to a reassessment of the original study's *heat pump component*, we assume for purposes of this report that all power system costs assumed by ICF are as stated in their report, and appropriate.

That said, we are aware that a detailed review by a government agency of the nearly identical study conducted by ICF in the U.S., raises questions about the validity of the study's methodology and inputs.[20] As a result, the reader should be aware that any changes in the original analysis of system-wide costs, would likely impact our quantification of the benefits of GSHPs. While ICF has provided some clarification on its methodological approach to accounting for electricity supply and infrastructure costs, further examination of the issue may be appropriate.

[20] See Government of the District of Columbia (Department of Energy and Environment)'s filing of June 26, 2020 before the D.C. Public Service Commission (case no. 1142), pages 53-63. Available at https://edocket.dcpsc.org/apis/api/filing/download?attachId=105393&guidFileName=9bdbe1aa-b3f8-4282-8dbe-e5f994464caa.pdf.

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