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# Energy District for South Lake Union/Denny Triangle

## *Phase 1 Feasibility Study Final Report*

***Prepared for Seattle City Light***

**February 19, 2004**

FVB ENERGY INC

COOPERATIVE EXTENSION
WASHINGTON STATE UNIVERSITY
ENERGY PROGRAM

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Phase 1 Feasibility Study Final Report

### Introduction

This study was undertaken for Seattle City Light (SCL) by Washington State University. The work was funded by the U.S. Department of Energy, Seattle City Light, American Public Power Association and Vulcan, a major real estate development company in the study area. FVB Energy Inc. is the primary consultant on this project. Subconsultants include Kathleen Callison, Attorney on water permitting issues, Sonnichsen Engineering on air permitting and Energy Expert Services on electrical distribution issues.

An Advisory Committee was established to provide a sounding board and guidance for the preparation of this feasibility study. Early meetings of the committee took place in November 2002 and March 2003. A more extensive workshop session was held in April 2003. A preliminary Draft Report was discussed by the Advisory Committee in August. Based on the feedback received, additional investigation and analysis was undertaken to identify and develop additional technology options with stronger environmental benefits. A Final Report Review Draft, discussed by the Advisory Committee in December 2003, presented the results of that investigation, and provided: a full economic and environmental comparison of key technology configurations; 20-year pro forma economic analysis; and comparison of costs for Energy District service to costs for “self-generation” of heating and cooling by individual buildings.

This Final Report reflects a number of key changes in the economic and environmental analysis, including revision of:

- Electricity price projections to be more consistent with SCL’s current forecasts;
- Assumed electricity generation resource mix (for emissions and economic comparisons) to reflect marginal capacity, based on discussion with SCL;
- Comparative analysis of technology options to reflect 20-year projected electricity and gas prices rather than static assumptions for these parameters; and
- Increased costs for environmental permitting for all technology options, especially options incorporating deep water cooling.

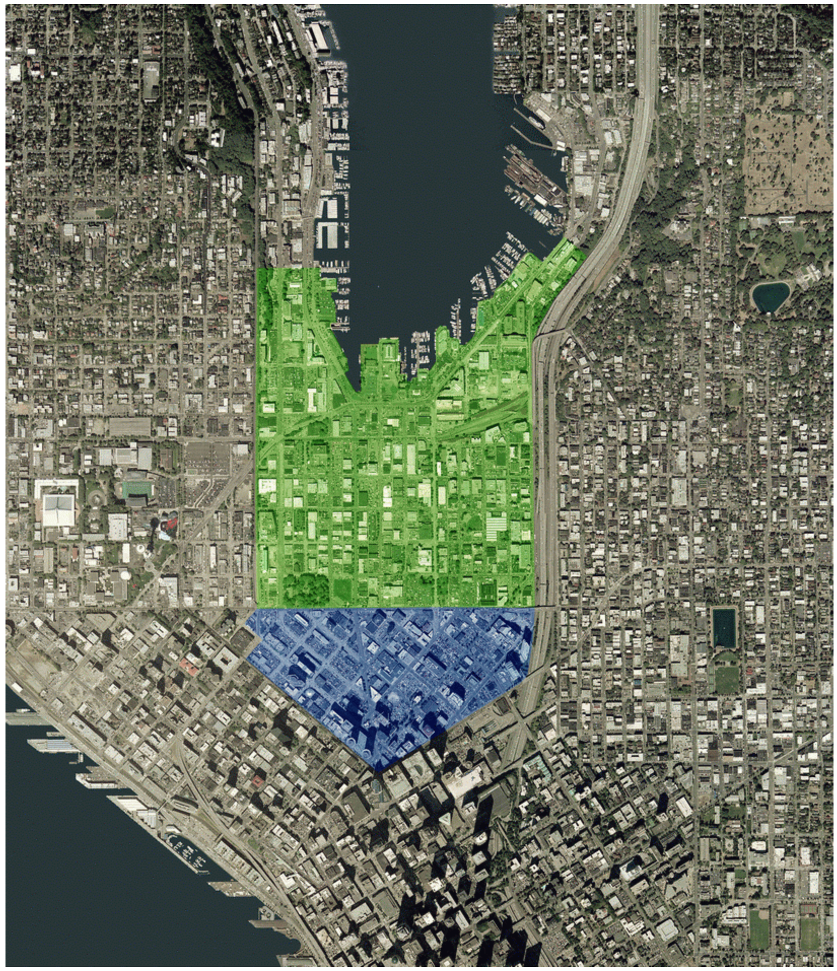
Rather than recommending a particular technology configuration, this Final Report concludes that:

- An Energy District in the study area offers significant opportunities for economic, energy and environmental benefits, and would open up many options for energy supply, some of which may not be currently anticipated;
- Significant questions regarding environmental impacts and permitting must be further addressed before a long-term technology configuration can be recommended; and
- An Energy District can be initiated with technologies that are relatively quickly implemented, enabling the Energy District to serve more of the near-term development.

## Study Area

The South Lake Union and Denny Triangle areas immediately north of downtown Seattle will see substantial redevelopment over the next 15 years. The study consists of two sub-areas -- South Lake Union (SLU) and Denny Triangle (DT) – and is illustrated on the next page in Figure ES-1.

***Figure ES-1. South Lake Union/Denny Triangle Study Area***



## Why an Energy District?

Redevelopment in the study area brings with it an opportunity to develop a sustainable energy infrastructure for the area that meets developer business objectives. This study was undertaken to evaluate the feasibility of establishing an "Energy District" that would meet the energy requirements of the buildings in the study area in a way that:

- Makes economic sense for developers and building owners;
- Supplies energy with better reliability than conventional approaches;
- Reduces reliance on fossil fuels through increased efficiency and/or use of renewable energy resources;
- Reduces environmental impact from meeting energy needs;
- *Potentially* improves water quality and salmon migration conditions as a byproduct of implementing deep water cooling; and
- "Future proofs" the buildings and the community by developing an infrastructure that provides flexibility to respond to challenges (e.g., increasing and/or volatile energy

prices) and opportunities (e.g., new technologies that are more sustainable and cost-effective) much more readily than individual building energy systems.

For the developer, sustainable energy approaches like an Energy District have the potential to provide a “triple bottom line” of economic, environmental and social payback.

## What is an Energy District?

The fundamental idea of an Energy District is to distribute heating (in the form of hot water or steam) and cooling (in the form of chilled water) from a highly efficient central plant or multiple plants to individual buildings through a network of pipes. Energy Districts provide space heating, air conditioning, domestic hot water and/or industrial process energy, and often also cogenerate electricity in Combined Heat and Power (CHP) systems. There are three major elements in an Energy District:

- Plants – equipment to produce hot water and chilled water, located at one or more locations. These plants can be designed to be attractive parts of the building landscape.
- Distribution -- buried pipes to distribute hot water and chilled water. There would be four pipes (hot water supply and return, and chilled water supply and return).
- Building connections – the interface between the distribution systems and the building heating and cooling systems. To use Energy District service, buildings must use hydronic heating, i.e. hot water and chilled water are distributed within the building to heat or cool the space.

It is important to understand that Energy Districts can use a diversity of energy resources, ranging from fossil fuels to renewable energy to waste heat. They are sometimes called “community energy systems” because, by linking a community’s energy users together, Energy Districts maximize efficiency and provide opportunities to connect generators of waste energy (e.g., electric power plants or industrial facilities) with consumers who can use that energy. The recovered heat can be used for heating or can be converted to cooling using absorption chillers or steam turbine drive chillers.

## Broader Context

This feasibility study was prepared in a broader, dynamic context of community debate concerning redevelopment in the study area, particularly SLU. A variety of issues face the City Council regarding how to guide, control and provide infrastructure for redevelopment, including: the character and density of development; impacts on current residents; transportation infrastructure; and electricity distribution infrastructure.

Several potentially positive factors for an Energy District in this broader context were not accounted for in this study. In late 2003 the City approved a new zoning ordinance that will allow higher density development than assumed in this study. This will improve the economics of an Energy District. In addition, changes to streets and construction of a streetcar system are being planned, which could provide potential opportunities to coordinate energy infrastructure with other construction. However, given the uncertainties surrounding the timing of construction of this infrastructure compared to Energy District development, no economic synergies were assumed in this study.

The substantial new development will bring significantly increased electricity demand, which will require Seattle City Light (SCL) to invest substantial capital into reinforcing the electrical distribution system in SLU. At a time of fiscal difficulty for SCL, it is useful to determine if an Energy District can delay or eliminate some of the capital investment required for electricity distribution infrastructure.

Finally, there is a broader community context of policy relating to sustainability and environmental impact. The City and SCL are committed to green energy and reduction in emissions of greenhouse gases (GHG). While SCL has historically been fortunate to have ample access to hydroelectric power, the future will not be like the past. With changes occurring in the structure of the electricity industry, and with regional electricity requirements growing, it will become more challenging to access resources for electricity supply that are both sustainable and economical. This study evaluates how an Energy District can help meet the City's green energy and GHG goals as part of an economical and diversified sustainability strategy.

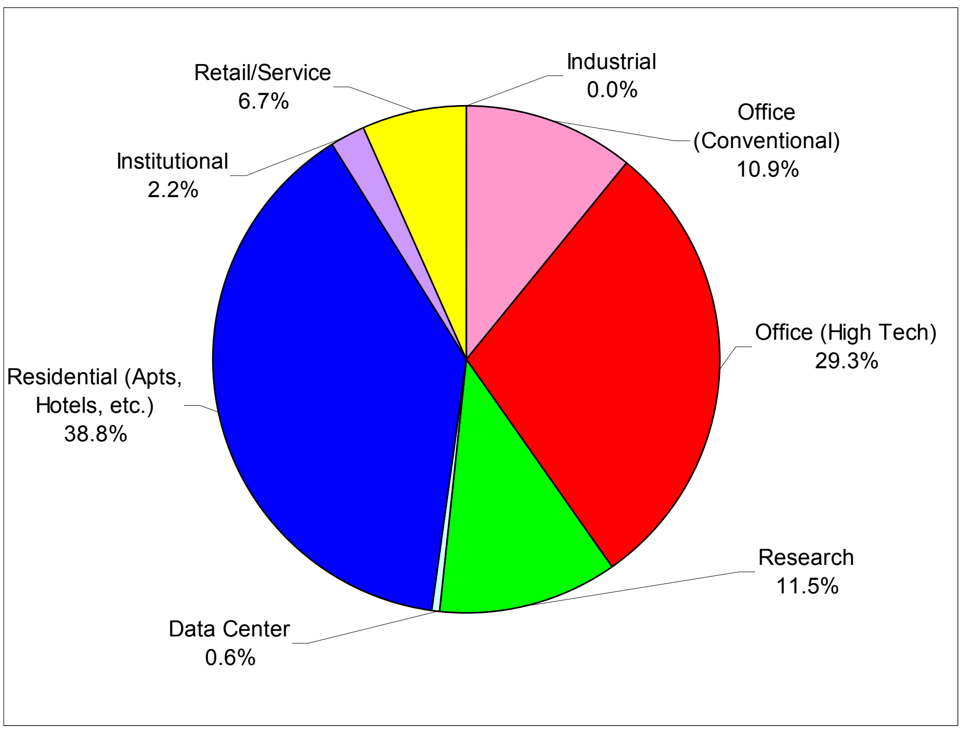
## Market Assessment

### Building Space

Over thirty million square feet of new development is anticipated in the study area through 2020, including biotechnology research facilities, commercial buildings and residential development. After years of community discussion of plans for redevelopment of these areas, the pace of development is rapidly picking up. There are two main regions of future load density, based on near and intermediate-term plans of developers. One of these regions of load concentration is in the middle of the SLU study area, toward Lake Union. The other region of load concentration is in the middle of the Denny Triangle area, to the east of Westlake Ave.

Projections of future building space in the study area were developed using a combination of specific planning information from developers and the growth forecasts of the SLU Capacity Model in the Heartland study (updated October 4, 2002) and the Downtown Environmental Impact Statement (for Denny Triangle). The breakdown of the total projected building space by type is summarized in Figure ES-2.

***Figure ES-2. Breakdown of Total Projected Building Space by Type***




### Energy Requirements

Based on analysis of timing, location and characteristics of projected development, the customer base for the Energy District is conservatively projected to total 18 million square feet (MSF) of building space, or about 55% of the projected building space. The coincident peak energy requirements of the Energy District at full build-out are estimated to be:

- peak cooling demand of 32,700 tons of refrigeration;
- peak heating demand of 210 million Btu per hour of heat; and
- peak power demand of 123 MegaWatts to meet power requirements other than production of heating or cooling.

## Why Customers Choose Energy District Service

Building owners choose Energy District service for a variety of reasons. First, it *makes building management easier and more effective*:

- Heating and cooling is available 24/7, so it's convenient and doesn't require management attention. This frees up time to focus on building manager's primary business.
- Energy Districts provide flexibility to increase the amount of capacity available to the building without an additional capital expenditure.
- Buildings are quieter because there is no heavy equipment generating vibration and noise, making tenants happier and more productive.

The Energy District concept fits very well with the general trend toward *outsourcing* of operations that are not central to a company's core business. By outsourcing heating and cooling, building managers can focus on their core business—whether it is biotech research, headquarters office operations, residential housing, attracting hotel, motel or condo renters, attracting and retaining tenants in a merchant office building, providing municipal services, etc.

Energy District service *reduces capital and operating risks*:

- No capital is tied up in the building for cooling and heating equipment.
- Risks associated with operation and maintenance of building heating and cooling equipment are eliminated.
- Energy Districts provide more flexibility to respond to changing energy prices, and to take advantage of new technologies.
- Costs are more predictable because more of the costs are fixed and less is spent on fuel and electricity, which can be volatile in price.

Energy District service also *reduces competitive risks*:

- Buildings that consistently provide reliable, high-quality energy services will attract and keep tenants.
- Energy District service increases the attractiveness of buildings in a competitive real estate market, thereby increasing the building's market value.

Energy Districts can deliver *better reliability* than typical individual building systems. The building owner and/or manager have a critical interest in reliability because they want to keep the occupants happy and want to avoid dealing with problems relating to maintaining comfort. Reliability takes on a critical importance for some buyers, such as biotech research facilities. Energy Districts can provide a level of equipment redundancy and round-the-clock expert management that individual buildings generally can't match. It is critical that customers be justifiably convinced that the Energy District utility can reliably deliver building comfort whenever it is needed. And it is essential the utility deliver on this promise through sound design, construction, operation and maintenance.

There are fundamental *cost advantages* that Energy Districts can provide:

- Better equipment loading, leading to better energy efficiency.
- Economies of scale to implement advanced technologies such as deep water cooling or CHP.
- Better staff economies.
- Reduced overall costs due to diversity in building loads.

Energy Districts also tend to have the disadvantage of capital-intensiveness. This approach typically requires more capital than individual building systems, and that capital tends to be "front-loaded" – it must be invested early, before growth of the system enables fully beneficial use of the technologies installed. A phased development approach can help mitigate, but not eliminate, this challenge.

In addition to capital-intensiveness, Energy Districts share other characteristics with real estate investments. It's a long-term investment, with real payoff as the system is built out, analogous to a building being fully leased. And like real estate, an Energy District needs contract commitments from initial anchor customers to support financing, analogous to pre-leasing a building.

Typically, Energy Districts charge for service through a fixed charge tied to peak demand ("demand charge" or "capacity charge"); and a variable charge for energy consumed ("energy charge"). The relationship between an Energy District and its customers is a lot like the relationship between building owners and tenants. The structure of an Energy District service agreement is analogous to a triple net lease: demand charges are like base rent; and operating costs are passed through.

## Technology Analysis and Conceptual Design

An Energy District provides flexibility to use a wide variety of energy sources, some of which are difficult to tap with individual building systems. These energy sources include:

- Waste heat from gas-fired power generation (combined heat and power), providing heating, cooling (using absorption chillers) and power production;
- Lake or sea water, which can be used for heating and cooling;
- Groundwater, which can be used for heating and cooling; or
- Industrial waste heat.

### Energy District Scenarios

Based on analysis of these innovative options as well as conventional heating and cooling technologies such as natural gas boilers and electric chillers, the following four technology scenarios were determined to be most viable for full concept design evaluation:

**Scenario 1.** Natural gas boilers for heating and electric centrifugal chillers for cooling. This conventional technology scenario is most conducive to a modular implementation approach, with equipment installed as load grows, and provides the lowest capital and total costs.

**Scenario 2.** Natural gas-fired combined heat and power (CHP) for production of power and by-product heat. The heat is used for a majority of the Energy District heating requirements (with gas boilers for peaking) and a significant portion of the cooling requirements (using absorption chillers that convert heat to cooling). Both gas turbines and gas engines were evaluated. A modular approach to implementing gas turbine CHP was selected, with 5 MW gas turbines installed consistent with load growth. Nitrogen oxide and carbon monoxide would be controlled with Selective Catalytic Reduction (SCR) with an oxidation catalyst. About 10% of the electricity generated would be used by Energy District plant facilities, with the remainder sold as wholesale electricity.

**Scenario 3.** Deep water cooling for the majority of cooling energy, with natural gas boilers for heating. Lake Washington can provide a renewable source of air conditioning energy from 60 meter (M) deep water that is 45-47 F year-round. The cold 60 M deep water can be used directly for over 75% of total annual cooling energy requirements. At peak demand conditions during the hottest weather, direct cooling from the water source must be supplemented with electrical chilling, using lake water for condenser cooling. Fortunately, there are very few annual hours when significant "tempering" with electrical chilling is required.

**Scenario 4.** Deep water cooling integrated with heat pumps for heating. Consistently cold 60 M temperatures can supply a natural source of cooling for building air conditioning, while shallower Lake Washington water can provide a renewable source of heat for space heating and domestic hot water using "heat pumps." This technology extracts the heat contained in relatively low temperature water (45-70 F) to produce Energy District hot water for building heating. There is ample experience with use of heat pumps with low-temperature sources in Sweden and other locations. Heat pumps fed by Lake Washington water could provide over 80% of the annual heating energy requirements. At peak demand conditions, during the coldest part of the year, the temperature of the district heating water must be increased using a boiler. However, because the Seattle climate is relatively mild, there are relatively few annual hours when substantial “tempering” with boilers will be required.

Implementation of water-based cooling and heating may also be possible using groundwater, which may be particularly appropriate for early-stage development because permitting of such an approach is expected to be quicker than with deep water cooling.

System implementation was assumed to take place in four phases, with start-up occurring in fall of 2006:

- Phase 1 – 2006-2007
- Phase 2 – 2008-2010
- Phase 3 – 2011-2015
- Phase 4 – 2016-2020

Note that the development of the Energy District is analyzed in terms of four *phases*. In addition, as discussed below, four technology *scenarios* were evaluated.

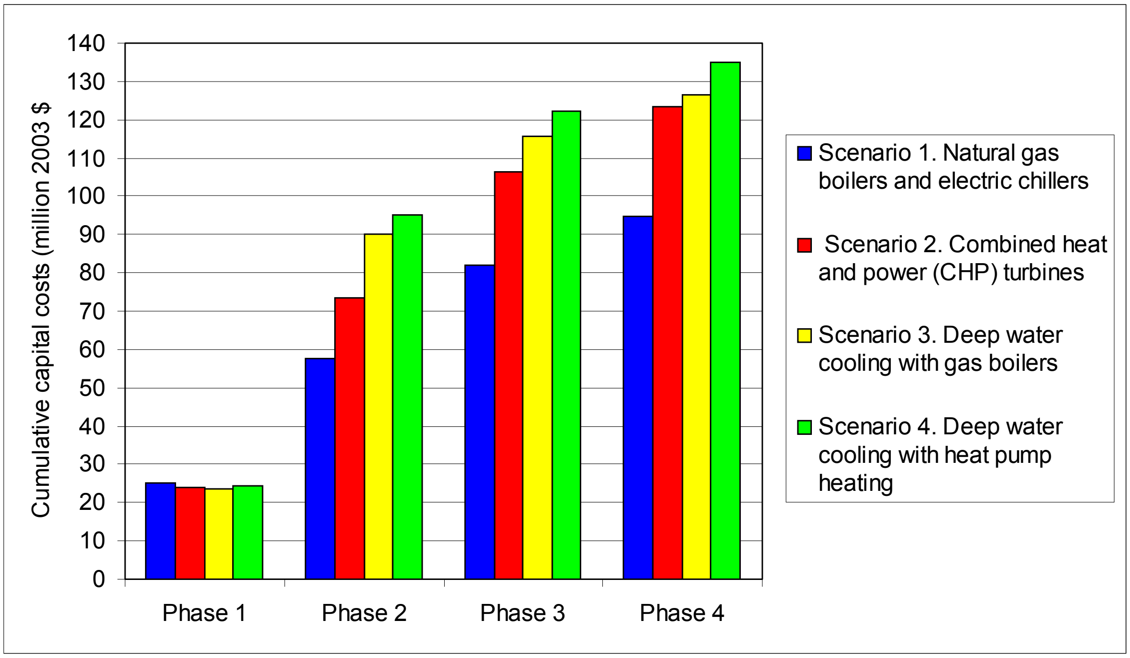
## Evaluation of Technology Scenarios

Conceptual designs for implementing each scenario were developed, including the capacities and characteristics of the equipment and facilities installed in each of four phases of system development at two plant locations. A two-plant approach was taken to minimize distribution piping cost. Each of the four scenarios starts with the same basic technologies: natural gas boilers and electric centrifugal chillers. This was done to facilitate an early start to the system – the other technologies involve more time for permitting.

### Economic Comparison

The capital and operating costs of each scenario (2003 $) were then estimated, and the total annual heating and cooling cost per Square Foot (SF) of building space at full build-out (year 2020) was calculated. Cumulative capital costs for each scenario are summarized in Figure ES-3. Scenario 1 (gas boilers and electric chillers) has the lowest total capital cost ($95 million), with Scenario 4 (deep water cooling and heat pumps) having the highest cumulative capital costs ($135 million) and the other two scenarios reaching cumulative costs of between $123 and $126 million.

***Figure ES-3. Cumulative Capital Costs (2003 $) for Energy District Scenarios***




The phasing of the Energy District infrastructure can to an extent track along with the actual pace of development and the success in marketing Energy District service. To the extent that development does not proceed at the pace envisioned, and/or market penetration is not the level projected, construction of later stages of the Energy District could be scaled back or eliminated. This would affect the higher-capital-cost approaches more than Scenario 1. This study did not include analysis of sensitivity to higher or lower levels of building space served. However, this study has conservatively assumed that only 55% of the projected building space in the study area would be served by the Energy District. It is important that follow-up studies undertake sensitivity analysis on this point.

For this screening economic analysis, total annual costs were calculated assuming amortization of capital costs at 5% interest over 20 years, plus all operating costs including fuel, purchased electricity, maintenance, labor and carbon dioxide emissions mitigation. Total annual costs per SF of customer building space at full build-out (Phase 4) are compared in Figure ES-4. Scenario 1 (gas boilers and electric chillers) has the lowest annual costs, and Scenario 4 (deep water cooling and heat pumps) has the highest annual costs under the base case projections for natural gas prices and wholesale electricity value. The Phase 4 total annual costs for Scenario 2 (CHP), Scenario 3 (deep water cooling) and Scenario 4 (deep water cooling and heat pumps) are 10%, 16% and 22%, respectively, higher than for Scenario 1 (natural gas boilers and electric chillers).

Projected total natural gas prices for the Energy District are illustrated in Figure ES-5. The price calculation is based on interruptible gas with 30% firming, and includes franchise fees. The technology scenarios include back-up fuel oil storage sufficient to meet peak requirements for 3 days. The base case projection is derived from third party forecasts incorporated into Puget Sound Energy's latest rate filing. The other scenarios are based on the same annual changes but start at a 2006 value that is $1.00 less or $1.00 to $2.00 more per million Btu.

The sensitivity of the annual cost per SF to natural gas cost is illustrated in Figure ES-6. As would be expected, CHP (Scenario 2) is highly sensitive to gas price, with gas boilers (Scenarios 2 and 3) less so, and the heat pump/boiler combination (Scenario 4) hardly at all.

***Figure ES-4. Annual Costs per Square Foot at Full Build-out (Year 2020)***

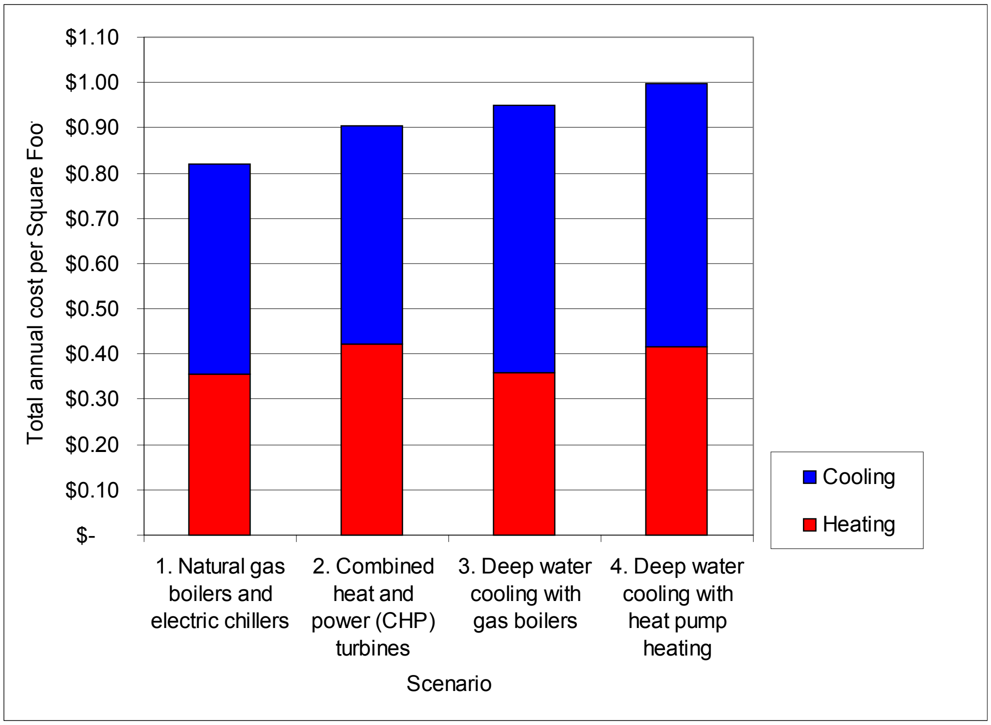



***Figure ES-5. Natural Gas Price Projections***

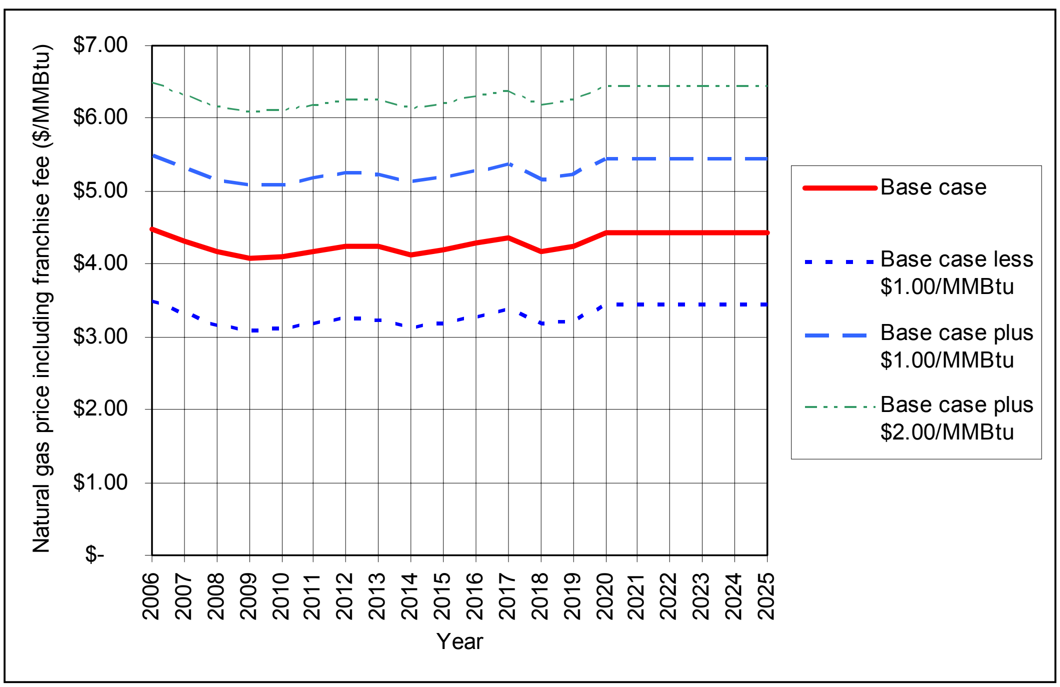
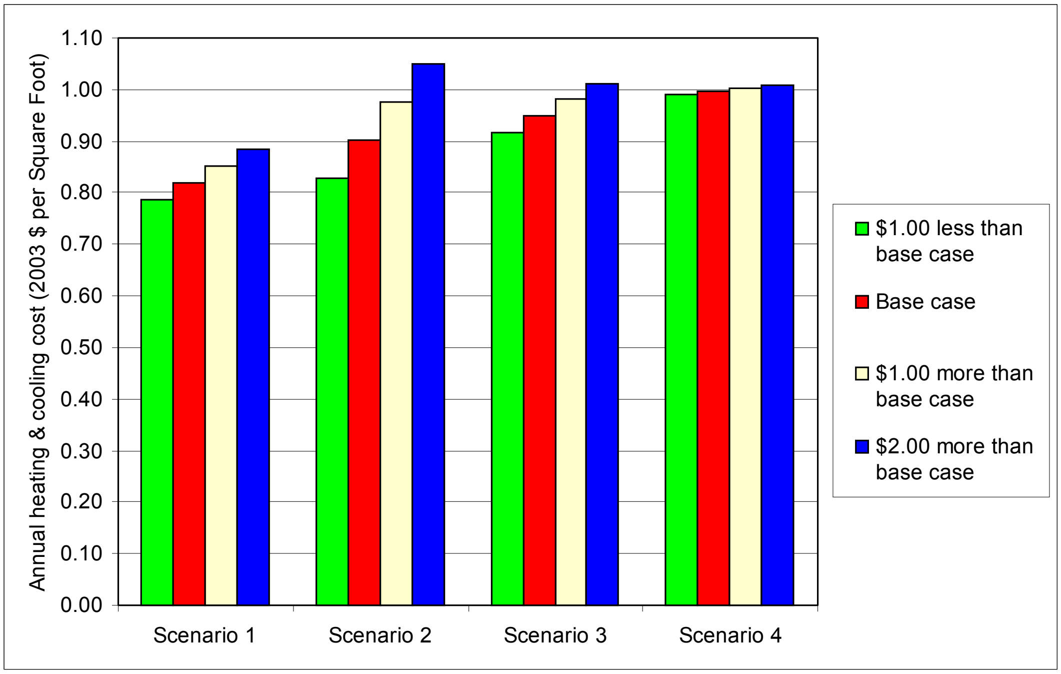


***Figure ES-6. Sensitivity of Annual Cost per Square Foot to Natural Gas Price***

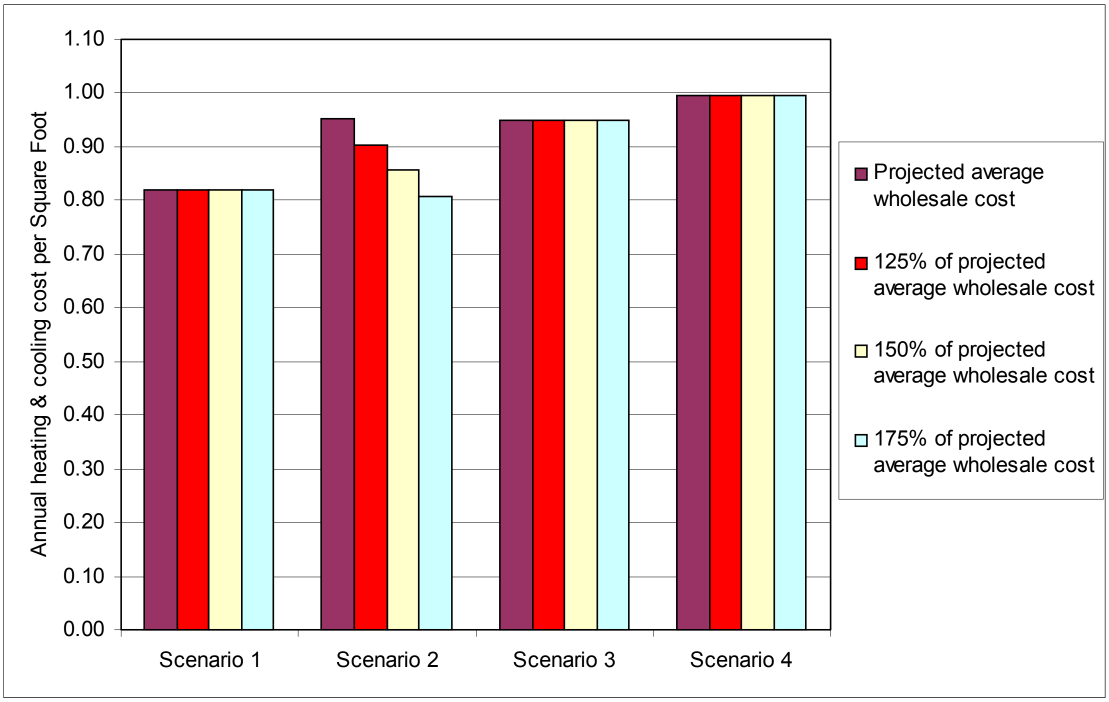



The sensitivity of the annual cost per SF to wholesale value of electricity is illustrated in Figure ES-7. CHP (Scenario 2) is the only technology sensitive to electricity value. In the base case projections, it is assumed that the value of net power production from CHP facilities was equal to 125% of the projected average summer and winter wholesale values of electricity as currently projected in a SCL working paper. Those projected wholesale values range from about $27/MWH (summer 2006) to about $38/MWH (winter 2020). The base case assumption that the value of CHP power is 125% of the average wholesale prices was made in an attempt to recognize that:

- marginal resource costs will be higher than average resource costs;
- a CHP facility can provide dispatchable power, which has a higher value than some types of renewable resources; and
- generation near load reduces transmission and distribution losses.

In a sensitivity analysis, the value of electricity was assumed to be 100%, 150% and 175% pf the projected average wholesale value. With the 175% assumption, the total costs of the CHP approach (Scenario 2) are equal to the costs of gas boilers and electric chillers (Scenario 1).

*Figure ES-7. Sensitivity of Annual Cost per Square Foot to Electricity Value*




The sensitivity of total Energy District costs to other variables was tested. For example, if the financing term for all capital is 30 years rather than 20 years, Phase 4 costs drop by $0.08-0.11 per SF. As described below, the Energy District will result in reductions in total carbon dioxide emissions, but no economic credit is given in the analyses described above. If the CO2 reductions are valued at $40 per metric ton (a value used by SCL in resource planning), the Phase 4 net costs of the Energy District decrease by $0.04-0.06 per SF.

## Emissions Comparison

The emissions associated with each Energy District scenario were estimated, including the regulated air pollutants nitrogen oxides (NOx) and carbon monoxide (CO) as well as the greenhouse gas carbon dioxide ($CO_2$). This analysis included direct emissions (e.g. emissions from an Energy District boiler stack) as well as indirect emissions, i.e. emissions resulting from generation of electricity obtained from Seattle City Light (SCL). Energy District emissions were then compared with the estimated emissions if no Energy District was implemented.

The emissions modeling required assumptions regarding the types of heating and cooling systems that would otherwise be installed, as well as estimation of the emissions associated with electricity obtained from SCL.

Without an Energy District, a mix of conventional heating, ventilation and air conditioning (HVAC) technologies will be implemented on an individual building scale, including: natural gas boilers; water loop heat pumps; electric resistance heat; and a variety of types of electric-driven cooling systems. Electric HVAC has been dominant in Seattle in the past, and is likely to continue to be a major element in building design. However, with recent increases in the price of electricity, its use for heating can reasonably be expected to decline somewhat. Based on consultation with Seattle City Light staff familiar with local practices, assumptions were developed for "default" (no Energy District) HVAC for each category of building space. The total shares of default HVAC are as summarized in Table ES-1.

***Table ES-1. Aggregated Shares of Default HVAC at full Build-out***

| **Heating** | | **Cooling** | |
|---|---|---|---|
| Electric resistance heating | 32% | DX cooling | 28% |
| Heat pump heating | 19% | Heat pump cooling | 19% |
| Gas heating | 49% | Centrifugal chiller cooling | 53% |

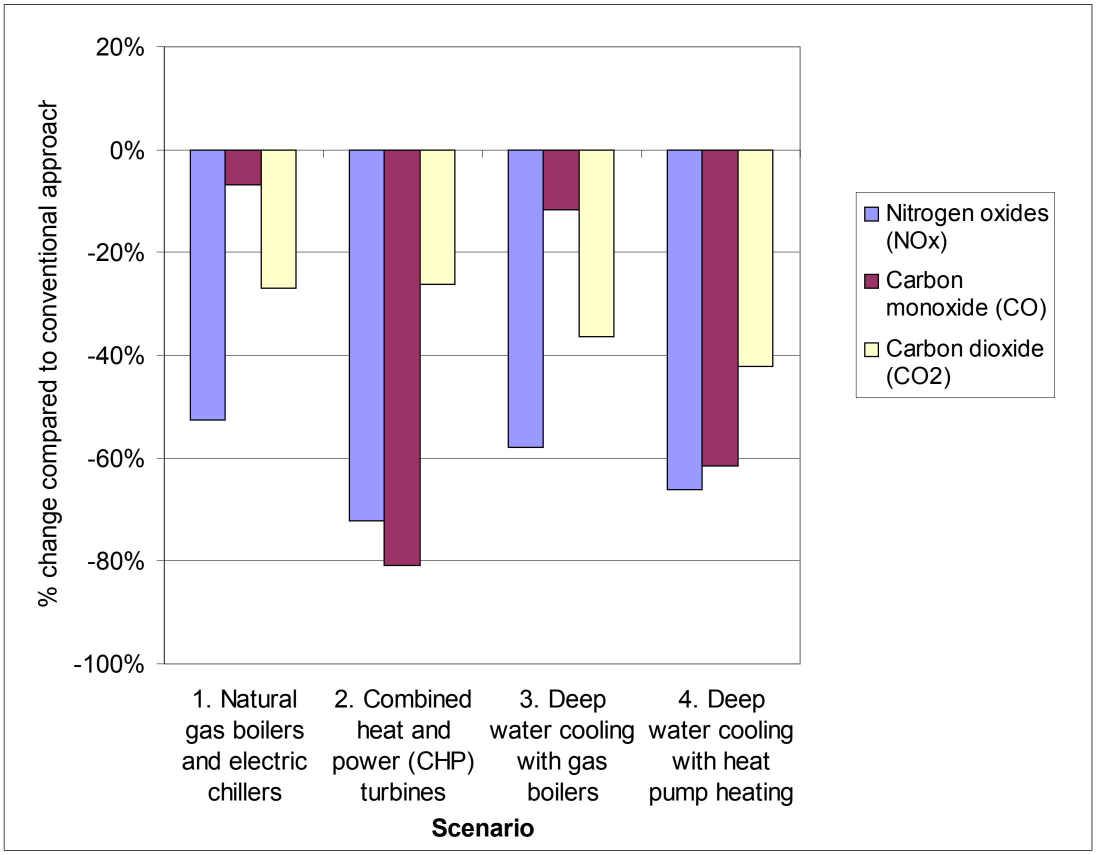
SCL's resource mix is currently 90.2 % hydro, 5.3% natural gas, 2.6% nuclear and the remainder wind, coal, waste and biomass (per the SCL website). However, since the peak capacity provided or avoided by the Energy District can be compared to SCL's alternatives for meeting new demand, the emissions characteristics of the Energy District should be compared with SCL's marginal resource (future increments of new capacity). Based on discussion with SCL, the marginal resource is assumed to be combined cycle gas turbines in the near term with a small amount of fluidized bed coal capacity in the longer term. Based on input from SCL, emissions factors for offset SCL resources were projected based on the estimated 2003 factors and the projected 2020 factors summarized in Table ES-2.

***Table ES-2 . Assumed Emission Factors for SCL Resources***

| | **Emission rates in lbs/MWH** | | | **Metric tons** | **Heat rate** |
|---|---|---|---|---|---|
| | NOx | CO | CO2 | CO2/MWH | (Btu/kWh) |
| New gas turbine combined cycle inc. 5% transmission losses | 0.105 | 0.044 | 848 | 0.385 | 7,185 |
| Estimated 2003 factor | 0.149 | 0.062 | 1,201 | 0.545 | 10,179 |
| Projected 2020 (90/10 combined cycle/coal mix) | 0.238 | 0.267 | 1,009 | 0.458 | 7,661 |

The resulting total net emissions comparison for the year 2020 is shown in Figure ES-9. This graph shows percentage savings with an Energy District compared to no Energy District. In 2020, the Energy District would reduce annual carbon dioxide ($CO_2$) emissions by 26 to 42 percent, and nitrogen oxides emissions by 52 to 72 percent (depending on technologies used) compared to conventional energy approaches.

*Figure ES-8. Percentage Emissions Reduction with Energy District Scenarios Compared to No Energy District*




Cumulative 20-year energy (fuel), electricity and $CO_2$ savings, and annual savings in 2020, are estimated in Table ES-3, with the range depending on Energy District technologies. Annual 2020 savings can be compared as follows:

- Fossil fuel savings could provide space and water heating for 6,800 to 11,200 multi-family residential units.
- Electricity savings could power 1,800 to 13,800 Seattle homes.
- $CO_2$ reductions are equal to 4.5 to 7.4 percent of annual emissions from Seattle City Light's generation portfolio in 2003.

*Table ES-3. Summary of Energy, Electricity and Carbon Dioxide Savings Compared to No Energy District*

| | **Cumulative** | **Year 2020** |
|---|---|---|
| Energy savings (trillion Btu) | 3.6 - 5.6 | 0.2 - 0.4 |
| Electricity savings (million MWH) | 0.3 - 2.8 | 0.02 - 0.17 |
| CO2 savings (million lbs.) | 495 - 820 | 33 - 54 |

## Environmental and Sustainability Policy and Permitting Issues

Based on the preliminary assessment performed for this study, there do not appear to be "showstopper" air quality permitting issues associated with any of the Energy District alternatives. In addition to regulated pollutants, carbon dioxide is a key policy issue. The City of Seattle has established a long-range goal of meeting the electric energy needs of Seattle with no net greenhouse gas (GHG) emissions. Per a resolution passed on Earth Day 2000, the City has committed SCL to meet growing demand with no net increases in GHG emissions by "using cost-effective energy efficiency and renewable resources to meet as much load growth as possible," and "mitigating or offsetting GHG emissions associated with any fossil fuels used to meet load growth." In addition to the City GHG policy, it is clear that key stakeholders in the study area have a strong interest in reducing the environmental impacts associated with meeting energy needs and the environmental benefits that may be realized.

As summarized above, all Energy District concepts would provide a net reduction in GHG emissions, and sensitivity analyses were performed to calculate the economic impact of including economic credit for these reductions using an SCL planning value of $40 per metric ton.

Scenario 3 (deep water cooling) and Scenario 4 (deep water cooling and heat pumps) raise a number of environmental issues associated with construction of deep water piping in water bodies and the withdrawal and return of water. Key concerns regarding the environmental impacts of deep water cooling relate to impacts from: laying of the pipeline; impact on aquatic life at the intake; and impact on aquatic life from discharge of water at elevated temperature and heating of water surrounding the pipeline. The impacts involved would have to be identified and addressed in a thorough environmental assessment of a heat pump and/or deep water cooling project.

There may be potential environmental benefits relative to improvement of water quality and enhancement of conditions for salmon migration. Water quality in Lake Union is poor, with a key indicator, dissolved oxygen, at zero in the lower depths of this shallow lake. This condition is related to lack of mixing between the stratified layers in the lake, biological oxygen demands within the sediments, relatively high water temperatures and a saline layer at the bottom of the lake during the July-September period. In addition, salmon migration is inhibited by a "thermal barrier," i.e. high water temperatures in the Ship Canal and the Montlake Cut.

Scenarios 3 and 4 may provide an opportunity to supply cooler, oxygenated water to Lake Union, the Ship Canal and the Montlake Cut, potentially facilitating salmon migration to Lake Washington, and improving water quality:

- Cold Lake Washington water, once used for air conditioning, would be pumped into Lake Union. Although heat would be added to the water (through its use for air conditioning), the system would discharge cleaner, cooler Lake Washington water to Lake Union, potentially providing an improvement to Lake Union water quality and a net cooling of Lake Union and the salmon migration route.
- Shallower Lake Washington water used for heating would be cooled in the process, also providing a net cooling of the water before discharge to Lake Union.
- The heat exchangers used in both the heating and cooling processes could be designed to introduce oxygen into the water, thereby further improving water quality.

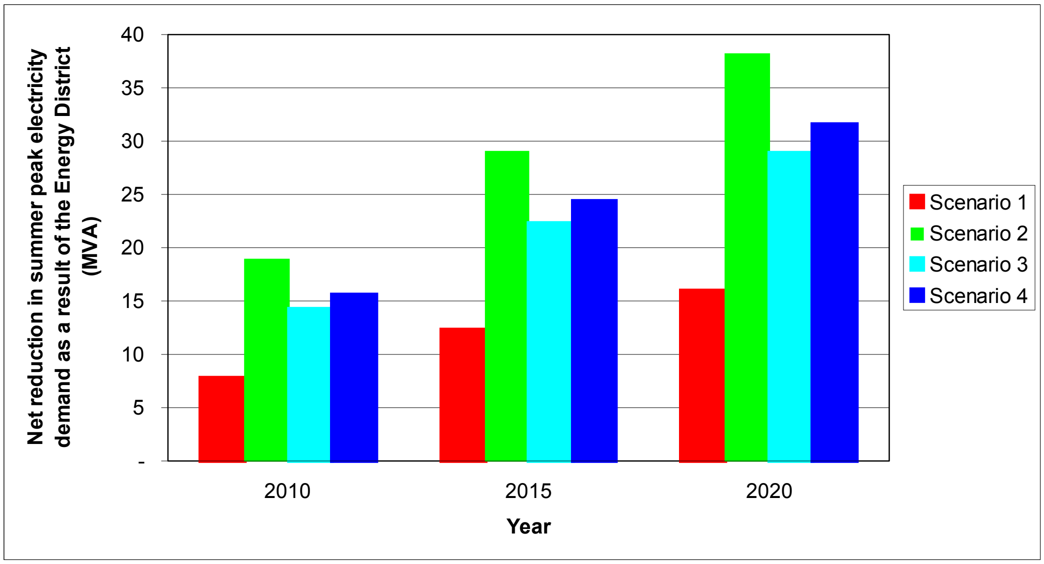
It is not clear to what extent these potential benefits are realizable. Assessment of the positive and negative impacts of a heat pump and/or deep water cooling Energy District on fisheries and water quality will require an extensive, complex and lengthy analysis.

Scenario 2 (CHP) also raises a number of policy and contractual issues relative to integration of CHP facilities into the SCL grid, relating to both technical requirements for grid interconnection as well as valuation of the power exported from the CHP facility to the wholesale markets.

### Seattle City Light Infrastructure

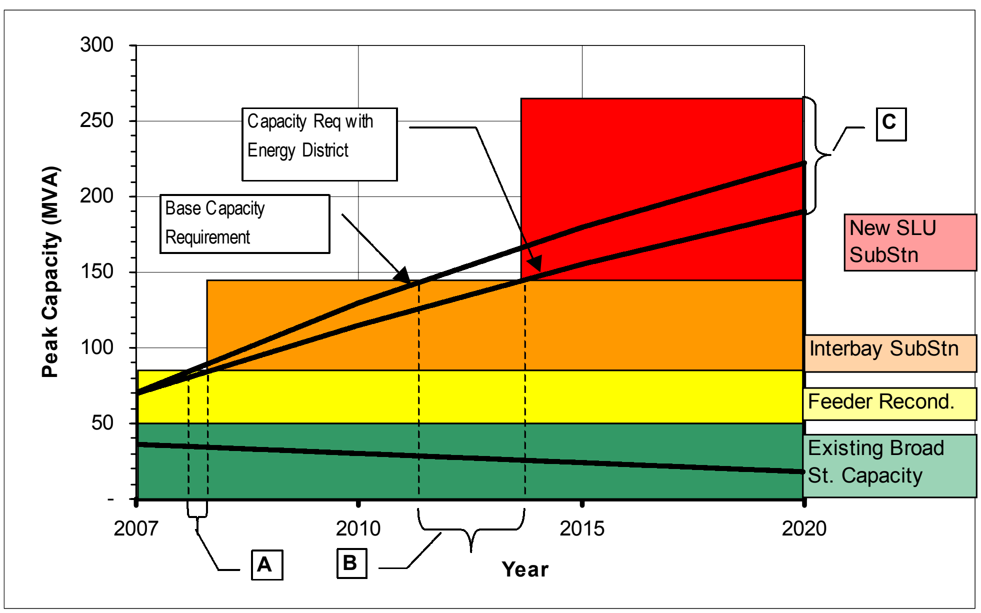
The Energy District is estimated to reduce total peak summer capacity requirements in the combined study by 16-38 MegaVolt-Amperes (MVA) depending on the Energy District technology. The Energy District is estimated to reduce total peak summer capacity requirements in the combined study area as summarized in Figure ES-9.

***Figure ES-9. Impact of Energy District on Total Study Area Peak Capacity Requirements***




The two sub-areas are served by two different electricity distribution systems. Of particular interest is the impact on potential capacity requirements in South Lake Union. Based on analysis by Kurt Conger of Energy Expert Services, the projected impact of the Energy District Scenario 2 is summarized in Figure ES-10. This indicates that the Energy District may enable a 2-3 year delay (interval "B") in adding a new substation to serve SLU.

***Figure ES- 10. Impact of Energy District Scenario 2 on South Lake Union Capacity Requirements***



## Economic Analysis

A full 20-year economic proforma analysis was prepared for Scenario 1 (natural gas boilers and electric chillers) and Scenario 4 (deep water cooling and heat pumps). These two scenarios were chosen because Scenario 1 offers the lowest overall costs and Scenario 4 offers the greatest carbon dioxide reductions. The proforma analyses included:

- full capital costs including financing costs and an operating reserve;
- debt service;
- depreciation;
- operating costs and other annual costs such as franchise fees;
- revenue and expense statement;
- cash flow; and
- calculation of internal rate of return.

A non-profit public-private entity was assumed for financing and ownership, with 100% debt assumed for the base case proforma. Variable costs were passed through to the customers in a variable energy rate, with a levelized demand rate charge based on customer peak demand. The demand rate level was set to yield a 5% internal rate of return on total capital.

Energy District costs were then compared to three prototype potential customers, summarized below:

***Case #1 – biotech research building***
Building use: research and related office
Heating: natural gas boilers with hot water serving air handling units
Cooling: water-cooled centrifugal chillers serving air handling units

***Case #2 -- residential plus mixed use***
Building use: mixed use (residential/hotel/retail)
Heating: water loop heat pumps with perimeter electric heat peaking
Cooling: water loop heat pumps

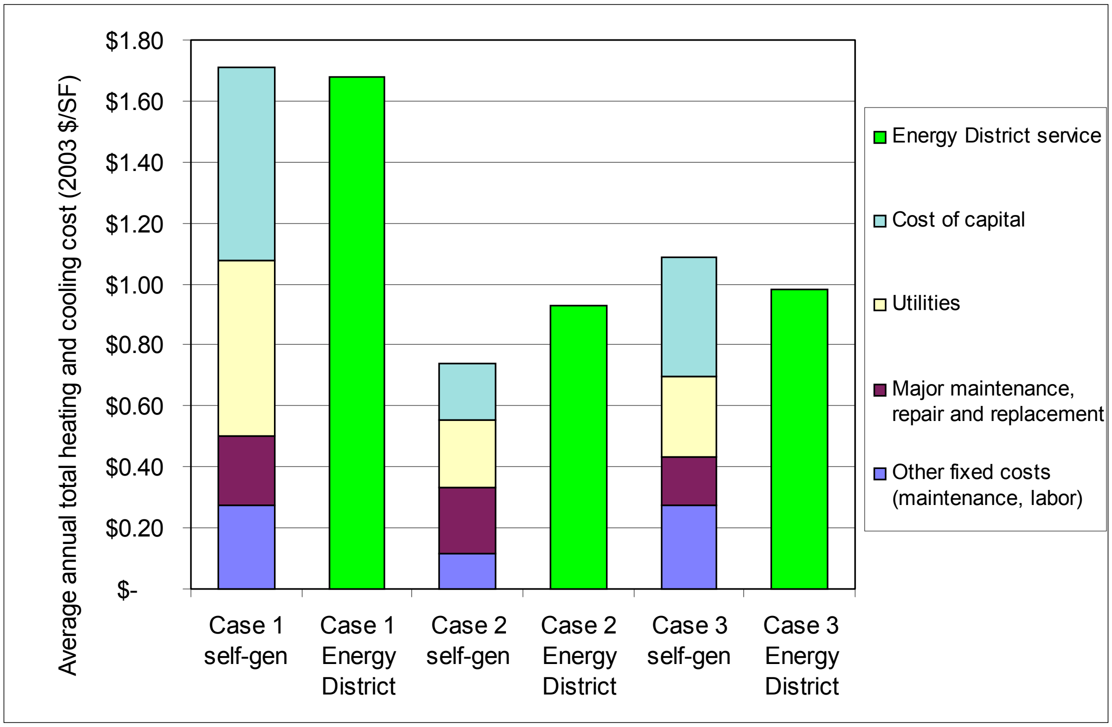
***Case #3 -- office building***
Building use: office
Heating: natural gas boilers with hot water serving air handling units
Cooling: water-cooled centrifugal chillers serving air handling units

Energy District costs, and costs for "self-generation" of heating and cooling, for a given customer may be higher or lower depending on energy requirements and usage patterns. Figure ES-11 illustrates the estimated total costs for self-generation for the three cases outlined above, and compares these costs with projected Energy District costs with the Scenario 1 technology concept.

It is important to note that the costs usually thought of as "utilities" are only one part of the total cost of providing heating and cooling for a building. Conventional heating and cooling requires not only capital investment but also ongoing expenses for fuel, electricity, labor, supplies, maintenance, and replacement.

The Energy District offers cost savings in Cases 1 and 3, and somewhat higher costs in Case 2. The cost of Energy District heating and cooling service for most customers is projected to be $0.90-1.00 per square foot per year (2003 dollars), depending on the technologies employed and the building energy usage pattern. Costs for buildings with most space devoted to intensive research activities would be higher – an estimated $1.70 per square foot – due to higher energy intensity. However, self-generation costs for energy intensive buildings are also expected to be significantly higher than self-generation for other building types, and higher than the Energy District cost for these energy-intensive buildings.

*Figure ES- 11. Total Heating and Cooling Costs for Three Self-Generation Cases with 9% Weighted Average Cost of Capital*




Energy District service is expected to be competitive with the total costs of conventional approaches for many customers with Scenario 1 and, depending on the value of CHP power production, with Scenario 2. With technology Scenarios 3 or 4, an Energy District would require significant financing assistance to be competitive with self-generation.

Although Energy District service would come at a cost premium in Case 2, it would also provide significant advantages relative to better indoor temperature controllability and comfort, improved reliability, ease of building operation and elimination of the headache of maintaining many heat pump units.

## Recommendations

Redevelopment in the study area brings with it an opportunity to develop a flexible and sustainable energy infrastructure for the area that meets developer business objectives. Based on this study, there appear to be significant public and private benefits realizable from an Energy District.

It is important to understand that an Energy District opens up many options for energy supply, some of which may not be anticipated currently. For an insight into how Energy Districts can evolve to provide energy, environmental and economic flexibility, it is useful to examine the experience of St. Paul, Minnesota. This Energy District started as a highly efficient hot water district heating system in the early 1980s, initiated by the building owners (through the Building Owners and Managers Association) and the City of St. Paul with technical and financial assistance from the State of Minnesota and the U.S. Department of Energy. Since then it has evolved to incorporate:

- Chilled water district cooling including electric and absorption chillers
- Thermal energy storage to reduce peak power demand
- Biomass combined heat and power (CHP) using waste wood to produce power, heating and cooling

The St. Paul system is owned and operated by a private non-profit corporation governed by a seven-member board of directors composed of City appointees and representatives elected by the customers.

Implementing an Energy District in Seattle will not be easy. It will require multiple private sector and public sector entities to work together. It will involve a variety of regulatory hurdles. And it will require significant capital investment – capital that is front-loaded ahead of the revenue-generating customer base.

A private non-profit company is the most promising approach for implementing an Energy District in the study area, for several reasons:

- It could be used to facilitate low-cost financing, thereby helping keep costs down for a capital-intensive energy infrastructure;
- It facilitates a governance approach that enables the stakeholders, including most importantly the customers, a voice in decision-making; and
- It has been proven to work successfully, for example in St. Paul, Minnesota.

An "Energy District Development Corporation" (EDDC) could be the non-profit vehicle for system development (just as the District Heating Development Company did in St. Paul, eventually morphing into District Energy St. Paul, an operating utility company). The stakeholders, both public and private, could participate in governance and decision-making of this ownership entity. EDDC could contract with a developer to design, construct and commission the system. EDDC could also contract with an operator to manage the system on a day-to-day basis. For example, Seattle Steam, which has many years of management and operations experience, could be excellent candidate for this role.

If the stakeholders agree that the potential benefits are significant enough to warrant further investigation, Phase 2 studies should be initiated to clarify the technical, economic, permitting, financial and organizational issues surrounding this opportunity. Key steps in Phase 2 studies are outlined below in two sub-phases. In this outline, reference will be made to "Initial System." This is intended to refer to the first phase of development of the Energy District system.

**Phase 2a**

1. Communication with potential customers regarding the benefits and costs of Energy District service, including potential service contract terms and costs, and comparison to customer alternatives.
2. Investigation of alternative technologies for the Initial System, including groundwater and small-scale CHP.
3. Development of a conceptual design for the Initial System, including plant siting, distribution routing, customer connections and related capital and operating costs.
4. Additional analysis of impacts of Energy District on electricity transmission and distribution systems.
5. Development of the organizational and financing approach for Energy District system design, permitting, construction and operation.
6. Development of a detailed plan and timeline for Initial System implementation including design, permitting, construction and operation.
7. Revision of Energy District economic and financial analysis based on the above.
8. Recommendations regarding proceeding.

**Phase 2b**

1. Negotiation with potential customers regarding the benefits and costs of Energy District service, including potential service contract terms and costs, and comparison to customer alternatives.
2. Design and preliminary implementation of a public outreach and involvement plan.
3. Updating of projections for building development and related customer heating and cooling loads.
4. Scoping and assessment of permitting issues and potential water quality and fish migration benefits associated with deep water cooling/heat pump technology.

5. Initiation of permitting and regulatory processes and environmental assessments in view of public input and permitting discussions with regulators.
6. Specification/negotiation of terms and conditions for electricity and gas service, and, as applicable, grid connection for power export.
7. Interactive with the above, revision of technology concept and economic analysis for full Energy District development.
8. Development of specific financing plan, including identification of funding sources and basic contractual relationships between capital sources, system developer, system owner and customers.
9. Presentation and communication of the Phase 2 Study results with public and private sector stakeholders.

# Section 1 Introduction

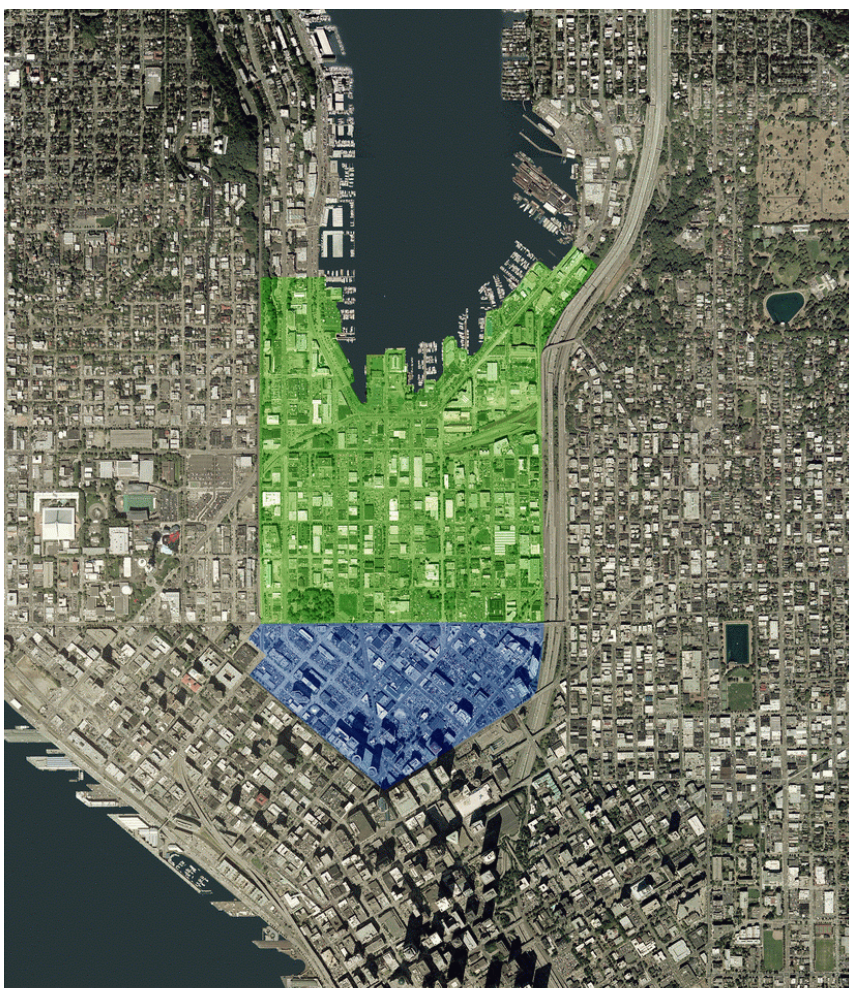
## 1.1 Purpose

### 1.1.1 South Lake Union and Denny Triangle

The South Lake Union (SLU) and Denny Triangle (DT) areas immediately north of downtown Seattle will see substantial redevelopment over the next 10-15 years. The study area is illustrated in Figure 12. The study area consists of two sub-areas: South Lake Union (SLU) and Denny Triangle (DT). The SLU portion of the study area is bounded by Denny Way on the south, Aurora Avenue on the west, Eastlake Avenue on the east, and Lake Union on the north. The Denny Triangle portion of the study area is bounded by Denny Way on the north, 5th Avenue on the southwest, and Olive Street on the southeast.

Over thirty million square feet of new development is anticipated in the study area through 2020, including biotechnology research facilities, commercial buildings and residential development. After years of community discussion of plans for redevelopment of these areas, the pace of development is rapidly picking up.

***Figure 12. South Lake Union/Denny Triangle Study Area***



Redevelopment in South Lake Union/Denny Triangle (SLU/DT) brings with it an opportunity to develop a sustainable energy infrastructure for the area that also meets developer business objectives. This study was undertaken to evaluate the feasibility of establishing an "Energy District" that would meet the energy requirements of the buildings in the study area in a way that:

- Makes economic sense for developers and building owners;
- Supplies energy with better reliability than conventional approaches;
- Reduces reliance on fossil fuels through increased efficiency and/or use of renewable energy resources;
- Reduces environmental impact from meeting energy needs; and
- "Future proofs" the buildings and the community by developing an infrastructure that provides flexibility to respond to changes in supply and price of energy resources.

For the developer, sustainable energy approaches like Energy District have the potential to provide a "triple bottom line" of economic, environmental and social payback. [1]

This feasibility study is being prepared in a broader, dynamic context of community debate concerning redevelopment in the study area, particularly SLU. A variety of issues face the City Council regarding how to guide, control and provide infrastructure for redevelopment. Key issues include:

- the character and density of development;
- impacts on current residents;
- transportation infrastructure; and
- electricity distribution infrastructure.

Several potentially positive factors for an Energy District in this broader context were not accounted for in this study. In late 2003 the City approved a new zoning ordinance that will allow higher density development than assumed in this study. This will improve the economics of an Energy District. In addition, changes to streets and construction of a streetcar system are being planned, which could provide potential opportunities to coordinate energy infrastructure with other construction. However, given the uncertainties surrounding the timing of construction of this infrastructure compared to Energy District development, no economic synergies were assumed in this study.

The substantial new development will bring significantly increased electricity demand, which will require Seattle City Light (SCL) to invest substantial capital into reinforcing the electrical distribution system in SLU. At a time of fiscal difficulty for SCL, it is useful to determine if an Energy District can delay or eliminate some of the capital investment required for electricity distribution infrastructure.

Finally, there is a broader community context of policy relating to sustainability and environmental impact. The City and SCL are committed to "green energy" and reduction in emissions of greenhouse gases (GHG). While SCL has historically been fortunate to have ample access to hydroelectric power, the future will not be like the past. With changes occurring in the structure of the electricity industry, and with regional electricity requirements growing, accessing sustainable resources for electricity supply will become more challenging. This study seeks to determine how an Energy District can help meet the City's green energy and GHG goals as part of a diversified sustainability strategy.

### 1.1.2 Energy Districts

The fundamental idea of an Energy District is to distribute heating (in the form of hot water or steam) and cooling (in the form of chilled water) from a highly efficient central plant or multiple plants to individual buildings through a network of pipes. Energy Districts provide space heating, air conditioning, domestic hot water and/or industrial process energy, and often also cogenerate electricity in Combined Heat and Power (CHP) systems.

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[1] "Future proofing" and the "triple bottom line" concepts are articulated in "Resource Guide for Sustainable Development in an Urban Environment, a Case Study in South Lake Union," prepared by the Urban Environmental Institute for Vulcan, October 22, 2002.

Energy Districts are variously called district energy systems or district heating and cooling systems. There is a wide variety of such systems throughout the world, serving downtown commercial buildings, colleges, universities, healthcare campuses and military bases. Many district heating systems in the U.S. date back to the early parts of the 20th century, and distribute steam. Seattle Steam, serving downtown, is a good example of these long-operating steam systems. [2] Other systems, such as District Energy St. Paul, distribute hot water for heating and chilled water for cooling. The St. Paul system also incorporates thermal energy storage and CHP fueled by community waste wood.

It is important to understand that Energy Districts can use a diversity of energy resources, ranging from fossil fuels to renewable energy to waste heat. They are sometimes called "community energy systems" because, by linking a community's energy users together, district energy systems maximize efficiency and provide opportunities to connect generators of waste energy (e.g., electric power plants or industrial facilities) with consumers who can use that energy. The heat recovered through district energy can be used for heating or can be converted to cooling using absorption chillers or steam turbine drive chillers. Storage of chilled water or ice is an integral part of many district cooling systems. Storage allows cooling energy to be generated at night for use during the hottest part of the day, thereby helping manage the demand for electricity and reducing the need to build power plants.

The general concept of an Energy District is illustrated in Figure 13. There are three major elements in an Energy District:

- Plants – equipment to produce hot water and chilled water, located at one or more locations. These plants can be designed to be attractive parts of the building landscape. Examples of Energy District plants are shown in Appendix 1.
- Distribution -- buried pipes to distribute hot water and chilled water. There would be four pipes (hot water supply and return and chilled water supply and return).
- Building connections – the interface between the distribution systems and the building heating and cooling systems. Depending on the system configuration and the location and characteristics of the building, these connections can be direct (Energy District distribution system water flows through the building systems) or indirect (the distribution system is separated from the building systems through heat exchangers).

These three major elements are discussed in more detail in Section 3.

An Energy District supplies "ready-to-use" thermal services for buildings, rather than electric energy or fuel that must be converted to thermal services on-site. In contrast, conventional on-site heating and cooling systems typically require combustion of fuel in a boiler to provide heating, and electrically-driven equipment to produce chilled water for air conditioning. District energy service can eliminate the need for on-site conversion by delivering chilled water, hot water and/or steam to the building.

Figure 14 gives examples of cites where district energy systems have been implemented throughout North America in the past 5 decades.

[2] In June 2003, Seattle Steam won the "System of the Year" award from the International District Energy Association. This award recognizes outstanding systems meeting reliability, efficiency and environmental criteria.

*Figure 13. General Concept of Energy Districts*

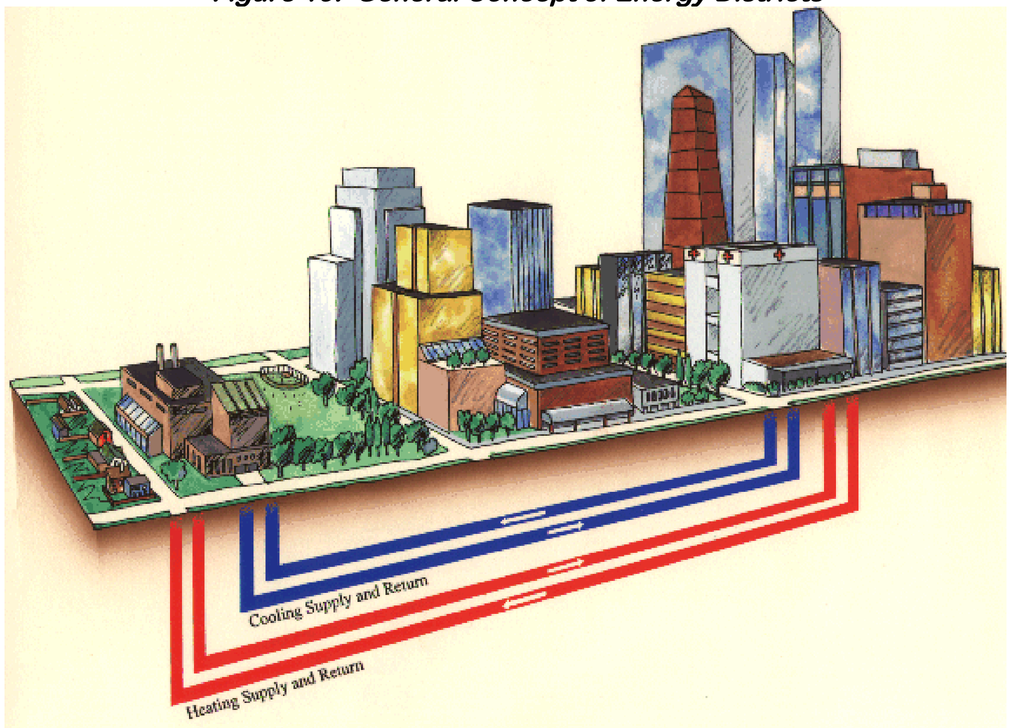
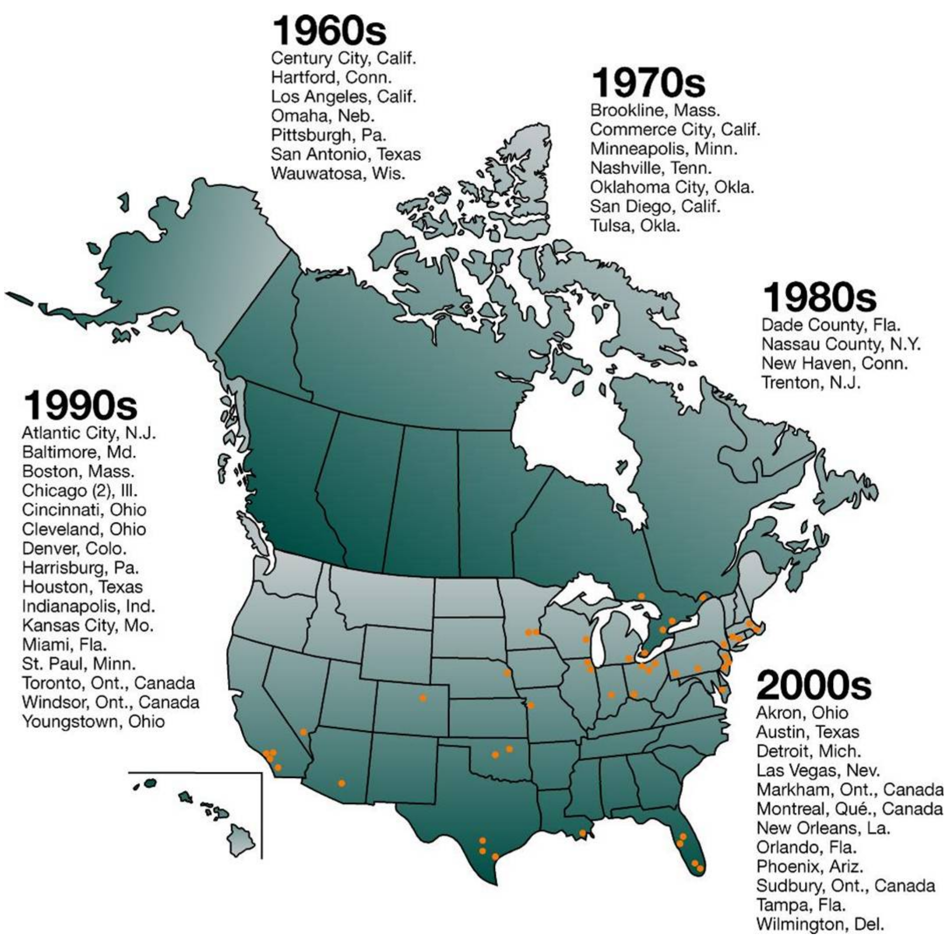



*Figure 14. Energy District Developments in North America*



## 1.2 Study Funding & Acknowledgements

This study was undertaken for Seattle City Light by Washington State University. The work was funded by the U.S. Department of Energy, Seattle City Light, American Public Power Association and Vulcan, a major real estate development company in the study area. FVB Energy Inc. is the primary consultant on this project. Sub-consultants include Kathleen Callison, Attorney, on water permitting issues, Sonnichsen Engineering on air permitting and Energy Expert Services on electrical distribution issues.

We would like to acknowledge that valuable assistance was provided to the project team by local offices of the following firms: Shannon & Wilson, Inc; Holaday Parks, Inc; Magnusson Klemencic Associates; and McKinstry Company.

## 1.3 Scope

This study evaluates the feasibility of establishing an Energy District to serve the SLU/DT areas. SCL contracted with WSU, with FVB Energy as the primary consultant, to complete the following scope of work. (The numbering of the tasks is presented consistent with the contractual scope of work rather than per the report outline.)

**1. Education and Market Assessment**

1.1 Hold project team kick-off meeting including consulting team and SCL staff to review project methodology, roles and responsibilities, and timeline. Convene Advisory Committee for first meeting to introduce all team members, discuss project goals, methods and timeline, and solicit Advisory Committee input.

1.2 Prepare and conduct a forum for the Advisory Committee and others (developers, architects/engineers) to present the draft results of the Phase I study. Alternatively, a community forum may be substituted.

1.3 Prepare appropriate interview and survey tools to assess energy demand and development considerations, and conduct interviews with identified South Lake Union and Denny Triangle developers.

1.4 Prepare peak demand and annual energy projections for heating, cooling and electricity.

**2. Technical Analysis and Conceptual Design**

2.1 Evaluate potential technologies for meeting heating and cooling energy requirements, and recommend preferred technologies. The evaluations will address technology performance, capital and operating costs, reliability, siting issues, natural gas supply, power grid access and environmental impacts. Technologies to be evaluated include deep water cooling, natural gas-fired combined heat and power (CHP), electric heat pumps, electric chillers, absorption chillers and thermal energy storage.

2.2 Develop two conceptual options for technology integration including one with primary emphasis on deep water cooling and the other emphasizing CHP for South Lake Union/Denny Triangle planning area.

2.3 Prepare a comparative analysis of the energy production options to include: energy efficiency; reliability; environmental impacts; and preliminary economics.

2.4 Based on the results of the comparative analysis, prepare one or more concept designs for an integrated district energy system in South Lake Union/ Denny Triangle that is most likely to be most cost-effective.

**3. Economic and Financial Analysis**

3.1 Prepare estimates of capital and operating costs for all plant, distribution and building interconnection equipment for the conceptual design alternatives.

3.2 Analyze the economics of the energy system alternatives to the owner/operator, including: capital costs; operating costs; debt service; depreciation; heating, cooling, power costs; system revenues; cash flow; and internal rate of return.

3.3 Prepare examples and prepare a case study of capital and operating costs for a typical potential customer to generate their own heating and cooling and compare with the results for the integrated district energy system alternatives.

3.4 Evaluate the impacts of the potential Energy District on existing and planned SCL infrastructure.

3.5 Develop and evaluate financing alternatives and develop recommendations relating to development of an integrated Energy District and financing strategies.

**4. Energy District Implementation Issues**

4.1 Estimate the potential environmental impacts of preferred Energy District concept, and identify regulatory and permitting requirements and issues.

4.2 Identify other legal and institutional issues and regulatory requirements associated with energy system implementation.

4.3 Assuming viable energy system alternatives, prepare work and budget for subsequent phases.

**5. Project Management**

5.1 Coordinate study parts, frame products and integrate final report including information required by APPA guidelines (see Appendix 2).

5.2 Support the establishment and on-going functioning of a project Advisory Committee.

5.3 Complete project wrap-up including preparation of APPA four-page summary abstract.

## 1.4 Advisory Committee

An Advisory Committee was established to provide a sounding board and guidance for the preparation of this feasibility study. Early meetings of the committee took place in November 2002 and March 2003. A more extensive workshop session was held in April 2003. A preliminary Draft Report was discussed by the Advisory Committee in August. Based on the feedback received, additional investigation and analysis was undertaken to identify and develop additional technology options with stronger environmental benefits. A Final Report Review Draft, discussed by the Advisory Committee in December 2003, presented the results of that investigation, and provided: a full economic and environmental comparison of key technology configurations; 20-year pro forma economic analysis; and comparison of costs for Energy District service to costs for “self-generation” of heating and cooling by individual buildings.

## 1.5 Final Report

This Final Report reflects a number of key changes in the economic and environmental analysis, including revision of:

- Electricity price projections consistent with SCL's current forecasts;
- Assumed electricity generation resource mix (for emissions and economic comparisons) to reflect marginal capacity, based on discussion with SCL;
- Comparative analysis of technology options to reflect 20-year projected electricity and gas prices rather than static assumptions for these parameters; and
- Increased costs for environmental permitting for all technology options, especially options incorporating deep water cooling.

Rather than recommending a particular technology configuration, this Final Report concludes that:

- An Energy District in the study area offers significant opportunities for economic, energy and environmental benefits, and would open up many options for energy supply, some of which may not be currently anticipated;
- Significant questions regarding environmental impacts and permitting must be further addressed before a long-term technology configuration can be recommended; and
- An Energy District can be initiated with technologies that are relatively quickly implemented, enabling the Energy District to serve more of the near-term development.

Section
# 2 Market Assessment

## 2.1 Introduction

This section evaluates the potential requirements for heating, cooling and electricity in the study area. The focus of this evaluation is new building space, because it is the new building space that will provide the vast majority of the customer base for the Energy District. Projections for new building space are presented, peak demands for heating, cooling and electricity are projected, and annual heating, cooling and electricity requirements are estimated.

## 2.2 Building Space Projections

Projections of future building space in the and Denny Triangle study area were developed using a combination of specific planning information from developers and long term space projections currently endorsed by the City of Seattle.

### 2.2.1 South Lake Union Projections

Projections of future building space in the South Lake Union (SLU) study area were developed using a combination of specific planning information from developers and the growth forecasts of the SLU Capacity Model in the Heartland study (updated October 4, 2002).[3]

#### Heartland Capacity Model

The City of Seattle currently relies on the projections of the South Lake Union Capacity Model, as detailed in the Heartland study of 2002, as the best estimate of building space development in the South Lake Union neighborhood though the year 2020. The Heartland study projects commercial square-footage and the number of residential units anticipated for the South Lake Union based on current zoning. Table 4 summarizes key data and projections from Heartland's SLU Capacity Model.

Key assumptions made by Heartland in developing their SLU Capacity model include:

- Average residential unit size of 750 square feet.
- Commercial space splits for new development at 50% office, 35% biotech, 10% retail, and 5% service.
- The "2002-2020 Growth Forecast" figure in Table 4 includes all adjustments from the capacity model. The maximum gross zoning capacity of each lot was adjusted as follows:
    - Commercial: 100% building efficiency, 90% building envelope efficiency, 90% 2020 forecast adjustment factor
    - Residential: 85% building efficiency, 90% building envelope efficiency, 64% or 75% lot usage (depending on zoning), 90% 2020 forecast adjustment

Heartland used the assumptions above to project square-footage for all lots except for a few lots where specific "pipeline" data was incorporated into the Capacity Model.

Except for lots where this Energy District study obtained specific information on building space development plans from developers, building space estimates for the study were taken directly from Heartland SLU Capacity Model projections for each lot.

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3 Memorandum dated July 2, 2002 from Matt Anderson, Heartland, to Ken Johnsen, Shiels, Obletz Johnsen, and updated October 4, 2002.

***Table 4. SLU Capacity Model Figures***
***(From Heartland Study)***

| | Commercial SF | Residential Units [1] | Residential SF [2] | Total SF |
|---|---|---|---|---|
| Total Existing Space | 7,680,137 | 944 | N/A | N/A |
| Total Existing "Developed" Space [3] | 3,222,400 | 897 | N/A | N/A |
| | | | | |
| Max Gross Zoning Capacity in Study Area | 18,208,430 | 15,951 | N/A | N/A |
| Max Gross Zoning Capacity of "Redevelopable" Sites | 14,132,619 | 14,332 | N/A | N/A |
| "Redevelopable" as % of Max Gross Zoning Capacity | 78% | 90% | N/A | N/A |
| | | | | |
| **2002-2020 Growth Forecast** | **11,693,335** | **10,113** | **7,961,709** | **19,655,000** |
| Growth Forecast as % of Max Gross Zoning Capacity | 64% | 63% | N/A | N/A |
| | | | | |
| Total Projected 2020 Inventory (growth forecast + "developed" space) | 14,915,735 | 11,010 | N/A | N/A |
| Projected 2020 Net Change (total projected - existing space) | 7,235,598 | 10,066 | N/A | N/A |

Notes:

[1] Residential unit figures taken from Heartland capacity model memo

[2] Residential SF figure taken from Heartland capacity model spreadsheet

[3] Existing building SF built on parcels unlikely to be redeveloped in the 2000-2020 period

## Planned Developments

For those lots where information on future development plans was available from the developers themselves or the public record, building space estimates were used based on these specific projections. The following is a partial list of the developers/owners whose building space development plans were incorporated into our market assessment for the SLU area:

- City Investors
- Harbor Properties
- Schnitzer Northwest
- Blume Company
- Fred Hutchinson Cancer Research Center
- Trammell Crow
- Lowes Enterprises
- Fortune Group
- Simpson Housing Limited Partnership
- Extended Stay America
- Consolidated Works
- Zymogenetics

**Building Space Phasing**

The timing of building space development was broken down into four phases as follows:

| | |
|---|---|
| Phase 1 | Years 2006 -- 2007 |
| Phase 2 | Years 2008 – 2010 |
| Phase 3 | Years 2011 – 2015 |
| Phase 4 | Years 2016 – 2020 |

For building space estimates based on specific developer plans, phasing was assumed per developer's estimates for project construction. The Heartland Capacity Model, however, did not provide projections for timing of building space construction. In the absence of timing information for Heartland space projections, phasing assumptions were made that yield the proportions for the SLU growth forecast shown in Table 5:

***Table 5. SLU Growth Forecast Phasing Assumptions***

| Phase | Growth Forecast (SF) | Percent of Total |
|---|---|---|
| Phase 1 | 4,234,900 | 21.5 % |
| Phase 2 | 5,503,400 | 28.0 % |
| Phase 3 | 5,110,300 | 26.0 % |
| Phase 4 | 4,806,400 | 24.5 % |
| | | |
| Total | 19,655,000 | 100.0 % |

### 2.2.2 Denny Triangle Projections

Projections of future building space in the Denny Triangle study area were developed using a combination of specific planning information from developers and the growth forecasts of the downtown EIS projections.[4]

**Downtown EIS Projections**

An environmental impact statement (EIS) was prepared for the City of Seattle to assess the impact of zoning changes in the downtown area. A real estate market study was prepared as part of the EIS, and forecasts of annual office space growth in the downtown area were made for each year from 2001 to 2020. Based on census tracts, these annual office building space projections for the entire downtown area were adjusted to reflect office space projections for the Denny Triangle only. Further, annual residential space projections for Denny Triangle were estimated based on expectations for office/residential mix in the area. Table 6 below summarizes building space projections from the EIS forecast data, in 5 year increments.

**Planned Developments**

For those lots where information on future development plans was available from the developers themselves or the public record, building space estimates were used based on these specific projections. The following is a list of some of the developers/owners whose building space development plans were incorporated into our market assessment for the Denny Triangle area:

- Milliken Development Corp.
- Vance Corporation
- Continental Bentall
- US General Services Administration

[4] Economic Research Associates for the City of Seattle Office of Housing, March 2000.

- Touchstone Development Inc.
- Clise Properties
- R.C. Hedreen Company
- Housing Resource Group
- Benaroya Properties

***Table 6. Downtown EIS Projections for Denny Triangle***

| Forecast Years | New Downtown Office Space Projection (SF) | New Denny Triangle Office Space Projection (SF) | New Denny Triangle Residential Space Projection (SF) | New Denny Triangle Total Space Projection (SF) |
|---|---|---|---|---|
| 2001-2005 | 3,261,760 | 1,515,683 | 966,249 | 2,481,932 |
| 2006-2010 | 3,902,759 | 1,813,545 | 1,156,116 | 2,969,661 |
| 2011-2015 | 6,010,980 | 2,793,199 | 1,780,635 | 4,573,834 |
| 2016-2020 | 4,010,980 | 1,863,833 | 1,188,194 | 3,052,027 |
| | | | | |
| 2001-2020 Total | 17,186,479 | 7,986,260 | 5,091,194 | 13,077,454 |

**Building Space Phasing**

The timing of building space development for Denny Triangle was broken down into four phases as discussed for SLU above. As for the SLU area, phasing was assumed per developer's estimates of project construction date for building space estimates based on specific developer plans. However, the building space totals for known developments for Phases 1 and 2 (including completed, under construction, and projected developments for Phase 1) exceed the EIS building space projections for these phases. In order to conserve the EIS projection total for the 2000-2020 time period, some building space from Phases 3 and 4 was shifted to Phases 1 and 2. These phasing assumptions yield the Denny Triangle growth forecast shown in Table 7.

***Table 7. Denny Triangle Growth Forecast Phasing Assumptions***

| Phase | Growth Forecast (SF) | Percent of Total |
|---|---|---|
| Phase 1 | 3,258,600 | 24.9 % |
| Phase 2 | 4,343,200 | 33.2 % |
| Phase 3 | 3,068,700 | 23.5 % |
| Phase 4 | 2,407,000 | 18.4 % |
| | | |
| Total | 13,077,500 | 100.0 % |

### 2.2.3 Combined Study Area Projections

The combined projection for new development building space in the SLU/Denny Triangle study area is summarized in Table 8 and Figure 15 below. The projected new development building space for the combined study area consists of 60% SLU square-footage and 40% Denny Triangle square-footage. Figure 16 below depicts projected new development square-footage for the SLU, Denny Triangle, and combined study area through 2020.

***Table 8. SLU/Denny Combined Growth Forecast***

| Phase | Growth Forecast (SF) | Percent of Total |
|---|---|---|
| Phase 1 | 7,493,500 | 19.9 % |
| Phase 2 | 9,846,600 | 30.2 % |
| Phase 3 | 8,179,000 | 25.9 % |
| Phase 4 | 7,213,400 | 24.0 % |
| | | |
| Total | 32,732,500 | 100.0 % |

***Figure 15. Breakdown of Combined Growth Forecast by Phase***

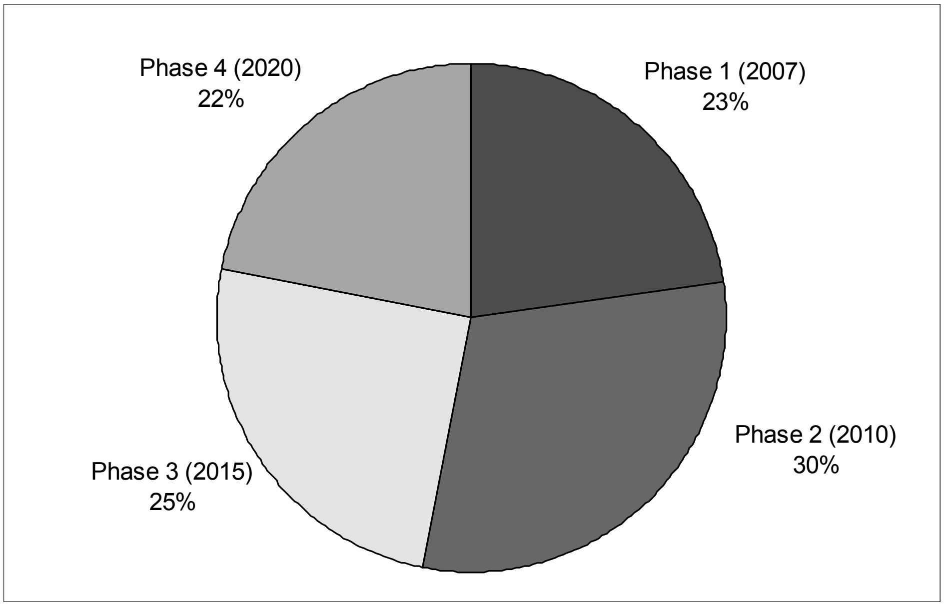
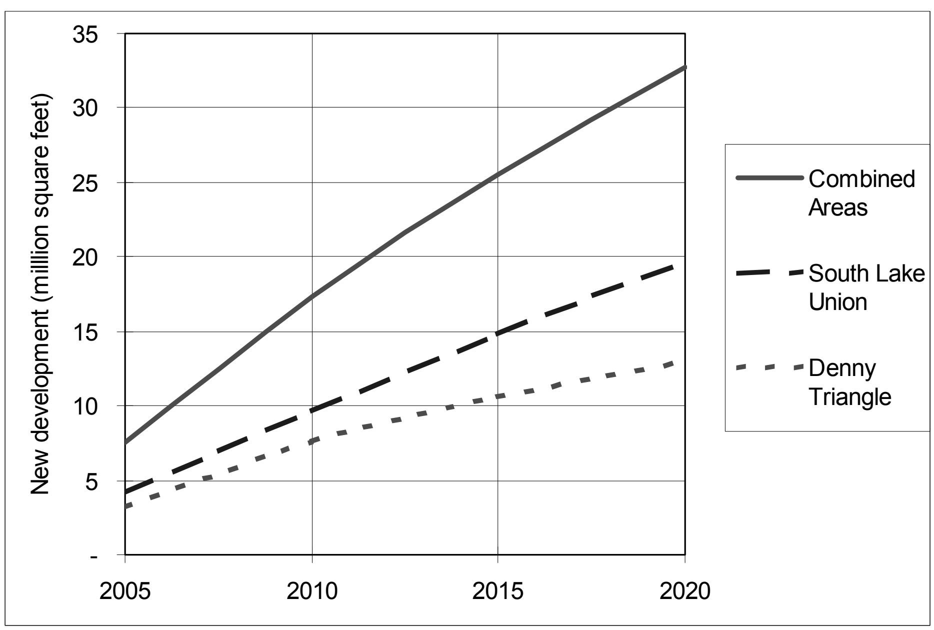



***Figure 16. South Lake Union, Denny Triangle and Combined Growth Forecast***



## 2.3 Projected Energy District Customer Base

The building space projections presented above were used to determine a realistic potential customer base for Energy District service. This projected customer base was then used in the economic feasibility analyses presented in this report. Early in the market assessment it became clear that there are two main regions of future load density, based on near and intermediate-term plans of developers. One of these regions of load concentration is in the middle of the SLU study area, toward Lake Union. The other region of load concentration is in the middle of the Denny Triangle area, to the east of Westlake Ave.

Working from these regions of load concentration, we established likely boundaries for the Energy District based on our determination of which projected new development sites could be reached efficiently by an Energy District distribution system. These boundaries are not meant to be absolute, but were developed as part of a methodology for identifying what portion of the total potential customer base will most likely become a feasible market for the Energy District.

The amount of projected new development square-footage in the combined study area is much greater than the existing building square-footage in the area. We have only included new development in the potential customer base that is used to evaluate the feasibility of the Energy District for several reasons:

1. New buildings are generally much more attractive (and economically viable) candidates for Energy District service than existing buildings. New buildings can be planned with hydronic heating and cooling system designs that easily interface with the Energy District. Many existing buildings would require expensive retrofitting to prepare them for service from the energy district. Depending on the HVAC system design of the existing building, it may not be feasible to retrofit some buildings. Also, existing buildings with heating and cooling equipment that is not yet near the end of its useful life will find it more difficult to justify service from the Energy District.

2. Many of the existing buildings in the study area are small, low-rise buildings. Smaller buildings are generally less attractive candidates for Energy District service due to the cost of interconnection to the Energy District relative to heating and cooling loads of the building.

3. Service to new development allows for more efficient use of environmentally friendly technologies by the Energy District. New buildings can be designed with heating systems that provide lower temperature heating return water to the Energy District, which makes technology options like CHP and heat pumps more attractive. New buildings can also be designed with cooling systems that provide higher temperature return water to the Energy District, which makes technology options like deep water cooling and heat pumps more attractive.

### 2.3.1 South Lake Union

We found that some of the fringes of the SLU study area are projected to have less new development load than other SLU areas. Since load density is critical to the economic viability of an Energy District, the projected customer base was limited to the higher load density regions, resulting in tighter distribution system for the Energy District. For those lots that fall within this area, the projected customer base includes:

- Identified future developments planned for construction in 2006 or beyond; and
- Growth forecast square-footage of those “redevelopable” lots from the SLU capacity model that are not accounted for by an identified future development.

The projected customer base excludes existing buildings and identified future developments planned for construction prior to 2006.

Based on the above criteria, Table 9 presents the projected Energy District customer building area for SLU.

***Table 9. South Lake Union Energy District Customer Building Space***

| Phase | Building Space (SF) | Percent of Total |
|---|---|---|
| Phase 1 | 1,778,600 | 18.8% |
| Phase 2 | 2,774,400 | 29.4% |
| Phase 3 | 2,750,600 | 29.1% |
| Phase 4 | 2,147,400 | 22.7% |
| Total | 9,451,000 | 100.0% |

### 2.3.2 Denny Triangle

For those lots that fall within the area initially identified for Denny Triangle, the projected customer base includes:

- All identified future developments planned for construction in 2006 or beyond.
- Nearly all of the EIS projection square-footage for Denny that remains after identified developments are accounted for.

The projected customer base excludes existing buildings and identified future developments planned for construction prior to 2006.

Based on the criteria above, Table 10 presents the projected Energy District customer building area for Denny Triangle.

***Table 10. Denny Triangle Energy District Customer Building Space***

| Phase | Building Space (SF) | Percent of Total |
|---|---|---|
| Phase 1 | 425,300 | 5.0% |
| Phase 2 | 3,908,900 | 45.9% |
| Phase 3 | 2,271,200 | 26.7% |
| Phase 4 | 1,915,600 | 22.5% |
| Total | 8,521,000 | 100.0% |

### 2.3.3 Combined Study Area

Aggregating Table 9 and Table 10, Table 11 presents the projected customer building space for the combined study area. The projected building space served by the Energy District totals 17,972,000 square feet, which represents approximately 55% of the total projected growth forecast for the study area.

***Table 11. Combined Energy District Potential Customer Building Space***

| Phase | Building Space (SF) | Percent of Total |
|---|---|---|
| Phase 1 | 2,204,000 | 12.3% |
| Phase 2 | 6,683,300 | 37.2% |
| Phase 3 | 5,021,800 | 27.9% |
| Phase 4 | 4,063,000 | 22.6% |
| | | |
| Total | 17,972,000 | 100.0% |

Slightly more than half, approximately 53%, of the year 2020 projected combined Base Case Energy District customer building space is in SLU, with 47% in Denny Triangle. Figure 17 below shows the breakdown of the customer building space by Phase. Figure 18 shows the growth in the SLU, DT and combined areas over 15 years.

***Figure 17. Combined Energy District Customer Building Space (Base Case) by Phase***

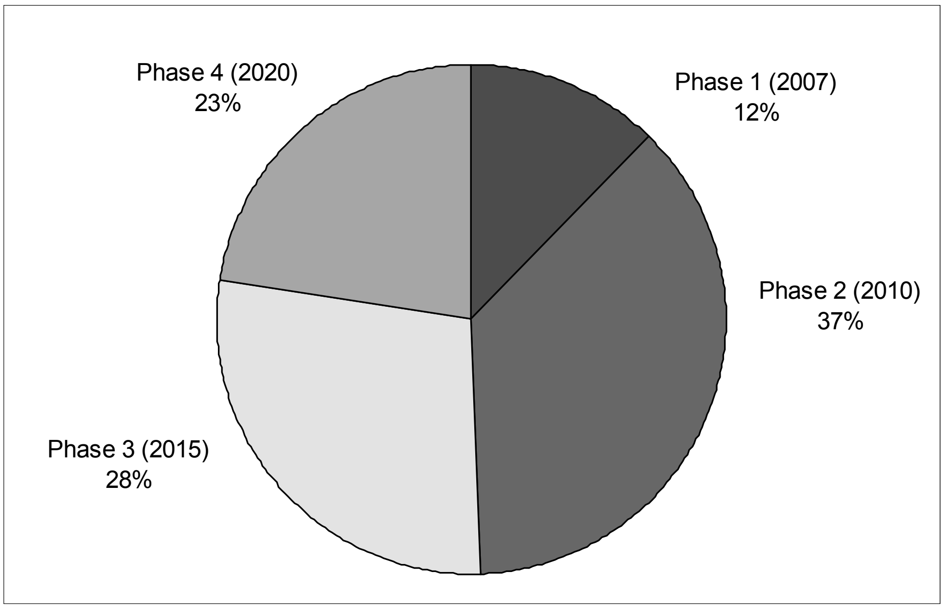
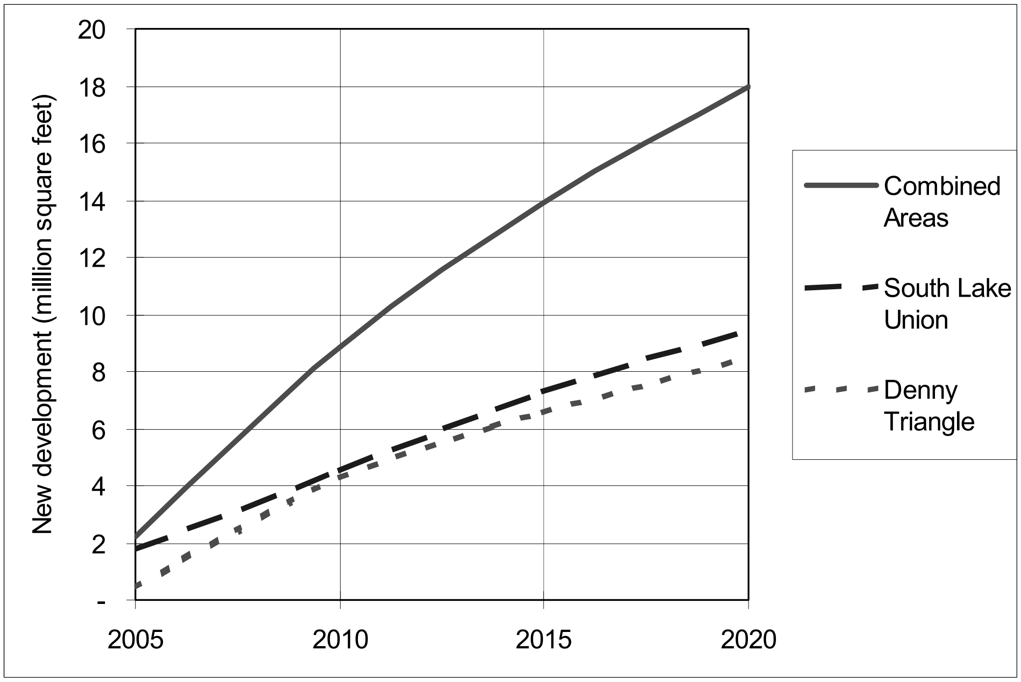


***Figure 18. South Lake Union, Denny Triangle and Combined Base Case Customer Building Space***




## 2.4 Thermal Energy Loads

### 2.4.1 Thermal Load Projection Methodology

Heating and cooling peak loads are estimated for all customers included in the Energy District using building space projections and load density factors based on space usage type. In order to capture the projected space usage of specific future developments, a comprehensive set of building space usage types were established and used for estimation of thermal loads in the market assessment database.

Commercial usage types include:

- high tech office
- conventional office
- research lab
- institutional
- retail
- data center
- service (grocery store, health/fitness, restaurant, theater, etc)

Residential usage types include:

- Apartments, condos and extended stay hotels
- Hotel and motels

For identified future developments, building space is split into usage type based on information gathered from developers or the public record.

Heartland's Capacity Model for South Lake Union assumed that new development of commercial space was split as follows: 50% office, 35% biotech, 10% retail, and 5% service. To translate these broad usage type splits into our more comprehensive usage type categories, we assumed the following breakdown for all projected SLU commercial building space that is not based on specific developer intelligence:

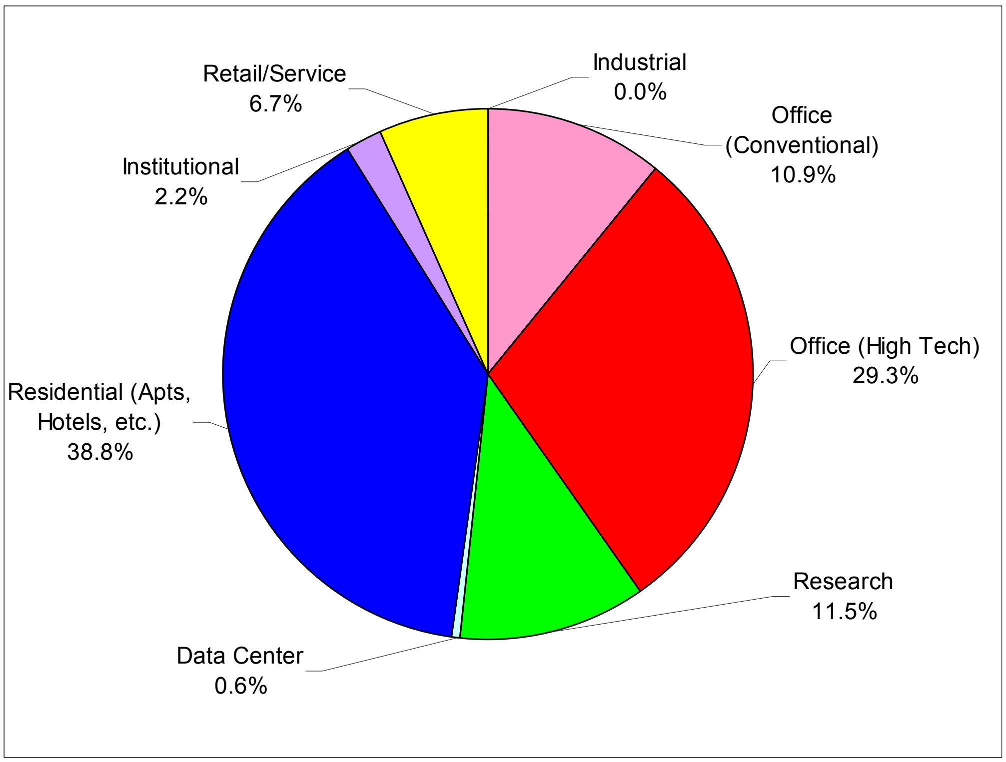
- 42% high tech office
- 3% data center
- 20% administrative office
- 10% research lab
- 10% major institution
- 10% retail
- 5% miscellaneous service

All projected SLU residential building space that is not based on specific developer intelligence is assumed to be apartment/condo/extended stay hotel.

For all projected Denny Triangle development that is not based on specific developer intelligence we have assumed that the average building space mix is 60% commercial and 40% residential. The commercial building usage type breakdown is assumed as follows: 50% high tech office, 40% administrative office, and 10% retail. Projected residential space is assumed to be apartment/condo/extended stay hotel.

Based on the assumptions detailed above, Figure 19 shows the breakdown of the projected Energy District customer building space by usage type.

***Figure 19. Projected Customer Building Space by Usage Type***



Heating and cooling load density factors for each building space usage type were developed after evaluating data from the following sources:

- HEATMAP© software [5]
- Weather data [6] [7] [8]
- Seattle Steam [9]
- Other district energy systems [10]
- Seattle City Light [11] [12] [13] [14]
- Local consulting engineers and contractors [15]
- Potential customers [16]
- Other sources [17] [18]

### 2.4.2 Heating Loads

The peak heating and cooling demand factors in listed in Table 12 below were used to estimate heating and cooling demand figures for Energy District customers. Based on the heating demand factors in Table 12 and the building space usage of the projected customer base, the total heating demand for the Energy District is given in Table 13 and Figure 20. This demand is "undiversified," i.e., it is the total of all individual customer demands. The Energy District peak demand will be lower due to load diversity (not all customers have a peak demand at the same time).

Confidentiality concerns preclude specific identification of loads on a block-by-block basis in this report. Heating load concentrations on a zone-by-zone basis are illustrated in Appendix 4.

[5] Heatmap Version 4.0, Washington State University Energy Program.
[6] United States Climate Normals, 1971-2000, Climatography of the United States No. 81, Supplement No. 2, National Oceanic and Atmospheric Administration.
[7] Binmaker Weather Summary Tool, Gas Research Institute, Jan. 1998.
[8] ASHRAE Fundamentals 1997, American Society of Heating, Refrigeration and Air-conditioning Engineers.
[9] Personal communication, James Young and Lanny Wuerch, Seattle Steam Company, Jan. 24, 2003, Jan. 27, 2003 and March 10, 2003.
[10] Multiple sources of confidential information provided by FVB Energy clients.
[11] Facility Assessment Reports and Operations and Resource Assessment reports, various dates.
[12] Sample of Commercial Building Facility Assessment Data in Support of South Lake Union Development Project, provided by Mary Winslow, Seattle City Light, April 2003.
[13] Multifamily Metering Study: Impact of the Model Conservation Standards, SBW Consulting, 1994.
[14] 2000 Residential Customer Characteristics Survey.
[15] Personal communication with: Tom Helm and Chris Whitmyre, Holaday Parks; Bob Witty, Veca Electric.
[16] Interviews with: Bob Cowan, Fred Hutchinson Cancer Research Center; Hamilton Hazlehurst, Vulcan; Shawn Parry, Touchstone Corp.; Paul Chen, PEMCO Financial Services; Lyn Krizanich and Michael Boyle, Clise Properties; Ron Brown, Seattle Times.
[17] Washington State Energy Code, State of Washington, effective July 1, 2002.
[18] Fred Hutchinson Cancer Research Center Campus Architecture, Robert W. Day Campus (undated).

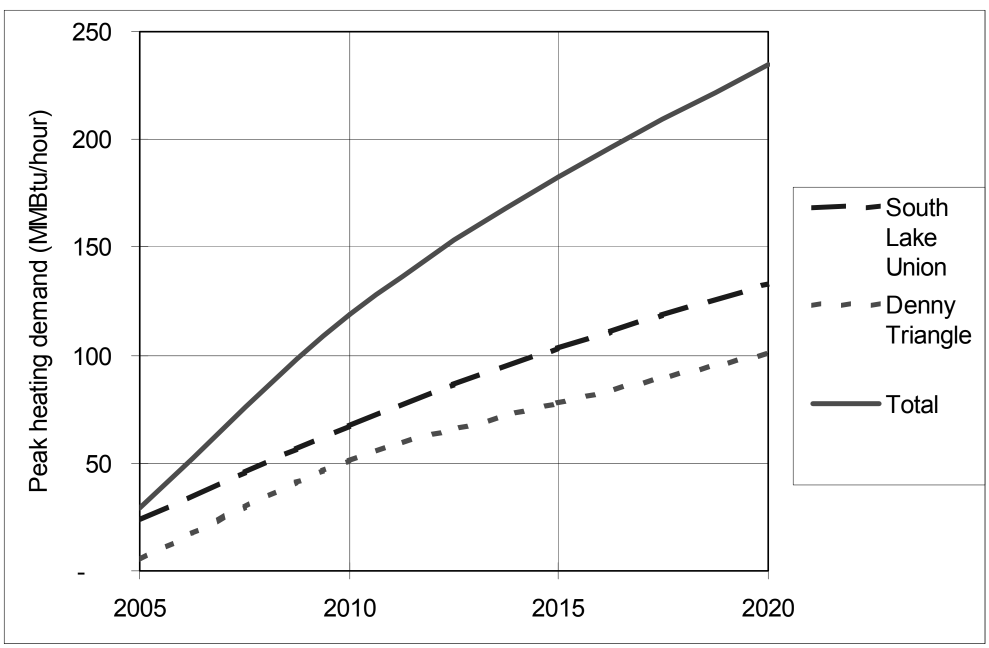
***Table 12. Heating and Cooling Peak Demand Factors***

| Space Usage Type | Peak Heating Demand Factor (Btu/hr/SF) | Peak Cooling Demand Factor (SF/Ton) |
|---|---|---|
| High Tech Office | 11.4 | 450 |
| Conventional Office | 12.0 | 615 |
| Research Lab | 20.4 | 350 |
| Institutional | 21.0 | 450 |
| Retail | 16.1 | 550 |
| Data Center | 7.2 | 58 |
| Grocery Store | 16.1 | 550 |
| Health/Fitness | 11.6 | 779 |
| Restaurant | 33.0 | 420 |
| Theater | 16.1 | 550 |
| Apartment/Condo/Extended Stay Hotel | 11.6 | 779 |
| Hotel/Motel | 11.6 | 779 |

***Table 13. District Heating Demand for Projected Customer Base (Undiversified)***

| Phase | Heating Demand (MMBtu/hr) | Percent of Total |
|---|---|---|
| Phase 1 | 29.4 | 12.5% |
| Phase 2 | 89.7 | 38.2% |
| Phase 3 | 63.3 | 27.0% |
| Phase 4 | 52.3 | 22.3% |
| | | |
| Total | 234.7 | 100.0% |

***Figure 20. District Heating Demand for Projected Customer Base (Undiversified)***



### 2.4.3 Cooling Loads

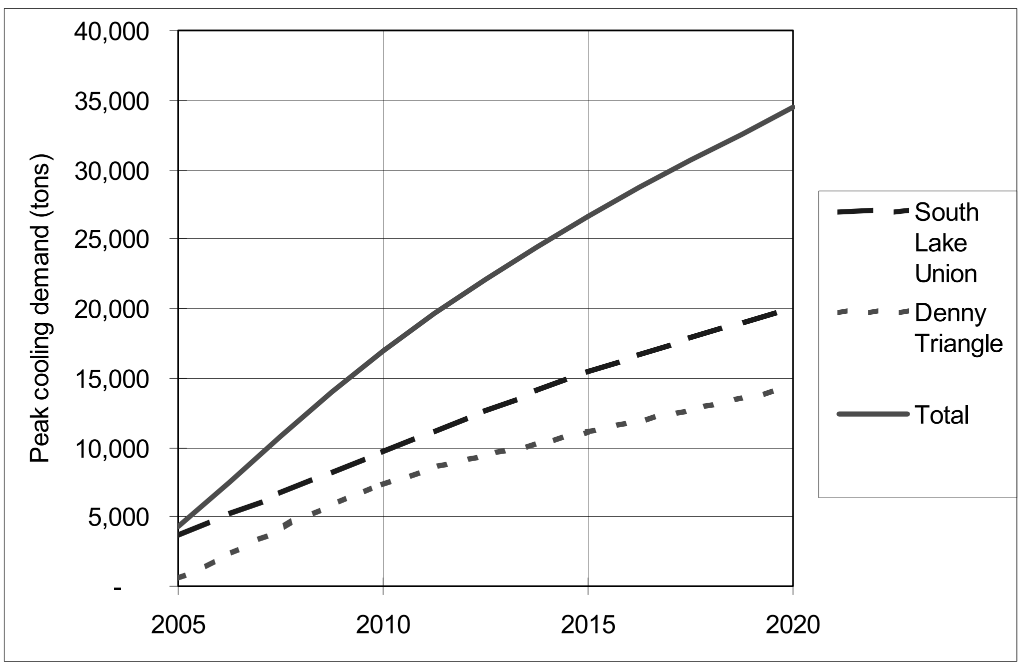
Based on the cooling demand factors in Table 12 and the building space usage of the projected customer base, the undiversified cooling demand for the Energy District is given in Table 14 and Figure 21.

Again, confidentiality concerns preclude specific identification of loads on a block-by-block basis in this report. Cooling load concentrations on a zone-by-zone basis are illustrated in Appendix 4.

***Table 14. District Cooling Demand for Projected Customer Base (Undiversified)***

| Phase | Cooling Demand (Tons) | Percent of Total |
|---|---|---|
| Phase 1 | 4,320 | 12.5% |
| Phase 2 | 12,660 | 36.7% |
| Phase 3 | 9,700 | 28.1% |
| Phase 4 | 7,810 | 22.6% |
| | | |
| Total | 34,490 | 100.0% |

***Figure 21. District Cooling Demand for Projected Customer Base (Undiversified)***



## 2.5 Electricity Loads

### 2.5.1 Electricity Load Projection Methodology

Electricity loads for the study area are estimated in this section in order to project the impact that an Energy District would have on electricity revenues and/or generation requirements. The electricity loads projected in this section are not intended to be used as a basis for power distribution infrastructure planning, since infrastructure must be built with a safety margin. Power load projections relevant to infrastructure planning are discussed in Section 5.1.

To estimate power load characteristics in the study area, the same area redevelopment assumptions used for estimating thermal loads based on space usage types were used for developing the electrical load forecast for new developments in each of the load areas. Load density factors include power density, which describes the peak power requirements of customer loads on a W/SF or VA/SF basis, and energy density, which describes the customer load characteristics on a kWh/SF basis.

Overall peak power density and demand factors for each building space usage type were estimated based on:

- Analysis of SCL Facility Assessment Report data (ORA reports) [19] [20]
- Analysis of SCL data on residential power use [21] [22]
- Power density and demand factors used by SCL T&D planning engineers for load estimation [23]
- Power intensity data from other projects [24]
- U.S. Energy Information Administration data [25]
- Studies and papers on data center power intensity [26] [27] [28]

The projections accounted for the fact that a particular building may have more than one usage type.

In order to assess the impact that the district heating and cooling components of the Energy District have on reducing the power requirements of the customer base, power requirements for thermal uses must be estimated. Peak power densities for thermal uses were developed for each building space usage type based on:

- Assumptions regarding mix of HVAC system types for each building type
- Estimated Coefficient of Performance (COP) for each HVAC system type
- Calculation of weighted average heating production power demand for each building type
- Calculation of weighted average cooling production power demand for each building type
- Calculated reduction in peak power demand based on most power-intensive thermal production requirement

For each building space usage type, the heating component of the HVAC system is assumed to consist of a mix of electric resistance heating, heat pump heating, and/or gas heating. Depending on the usage type and design philosophy, the HVAC system may consist of one, two or all three of these

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[19] Facility Assessment Reports and Operations and Resource Assessment reports, various dates.
[20] Sample of Commercial Building Facility Assessment Data in Support of South Lake Union Development Project, provided by Mary Winslow, Seattle City Light, April 2003.
[21] Multifamily Metering Study: Impact of the Model Conservation Standards, SBW Consulting, 1994.
[22] 2000 Residential Customer Characteristics Survey.
[23] See discussion in Section 5.1.
[24] Multiple sources from FVB Energy projects.
[25] Commercial Buildings Energy Consumption Survey 1995, U.S. Energy Information Administration.
[26] Energy Smart Data Centers: Apply Energy Efficient Design and Technology to the Digital Information Sector, Fred Beck, Renewable Energy Policy Project, Nov. 2002.
[27] Data Center Power Requirements: Measurements from Silicon Valley, Mitchell-Jackson et a, Review Draft submitted to Energy – the International Journal, Dec. 11, 2001.
[28] Space Cooling Demands from Office Plug Loads, Paul Komor, Ph.D., ASHRAE Journal, Dec. 1997.

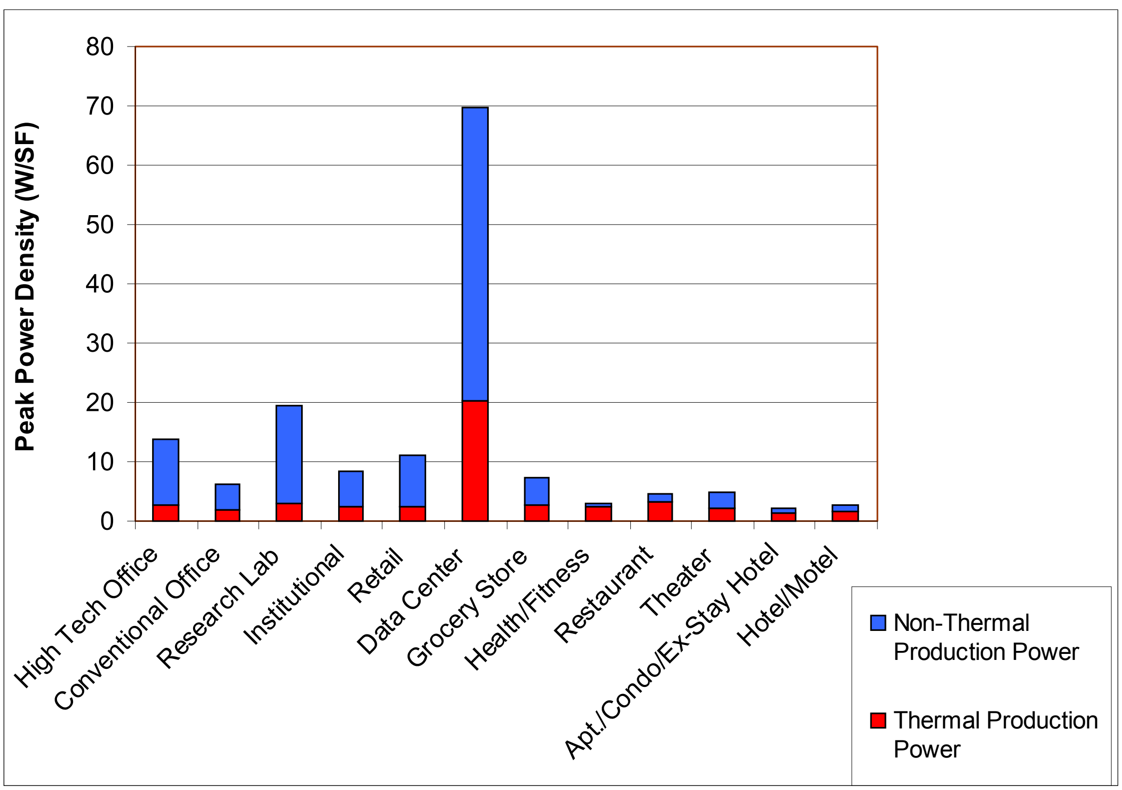
heating types. For each building space usage type, the cooling component of the HVAC system is assumed to consist of a mix of cooling with heat pump/chillers, DX units or central centrifugal chillers.

Estimates of power peak density for thermal uses, non-thermal uses, and both uses are presented in Table 15 and Figure 22.

***Table 15. Peak Power Densities***

| Space Usage Type | Peak Power Density For Thermal Uses (W/SF) | Peak Power Density For Non-Thermal Uses (W/SF) | Peak Power Density For All Uses (W/SF) |
|---|---|---|---|
| High Tech Office | 2.6 | 11.3 | |
| Conventional Office | 2.0 | 4.2 | 6.1 |
| Research Lab | 2.9 | 16.6 | 19.5 |
| Institutional | 2.3 | 6.1 | 8.4 |
| Retail | 2.3 | 8.8 | 11.1 |
| Data Center | 20.4 | 49.4 | 69.8 |
| Grocery Store | 2.7 | 4.7 | 7.4 |
| Health/Fitness | 2.4 | 0.7 | 3.0 |
| Restaurant | 3.3 | 1.3 | 4.6 |
| Theater | 2.1 | 2.8 | 4.9 |
| Apt./Condo/Ex-Stay Hotel | 1.5 | 0.6 | 2.1 |
| Hotel/Motel | 1.5 | 1.1 | 2.7 |

***Figure 22. Peak Power Densities***

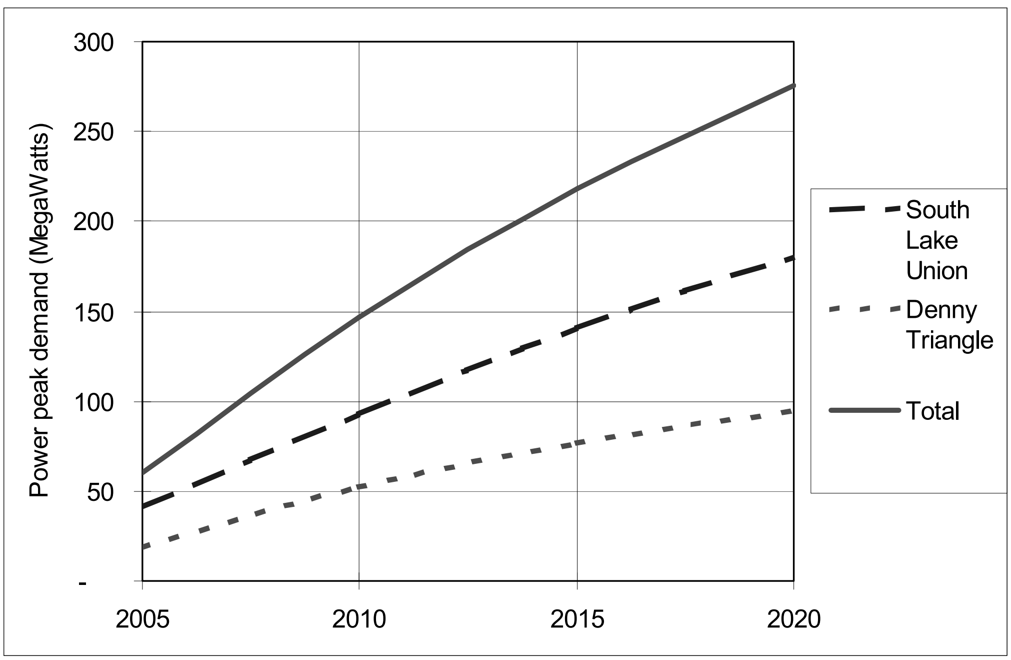


## 2.5.2 Total Power Demand

The total power demand for the total projected new development in the combined study area is presented in Figure 23 below. Total projected building space for the customer base is 32,732,500 square feet, as detailed in Table 8. This projection for the combined growth forecast is provided for informational purposed only. It is not intended that this power demand projection be used to plan electrical infrastructure requirements. There are several reasons why the growth forecast may be inappropriate to use for such purposes:

1. Much of the square-footage included in Phase 1 is already constructed and therefore contributing to current power demand.
2. The SLU portion of the growth forecast is based on new development square-footage and part of this new development replaces "redevelopable" existing building space that has a current power demand.
3. Several of the city blocks that we obtained specific developer information on have higher planned square-footage than was carried in the SLU Capacity model, so capacity model forecasts may be low.
4. A review of the zoning allowances in the Denny Triangle area suggests much greater growth potential than that included in the Denny EIS projections. Also, since the EIS projection was issued some zoning has been changed to allow taller buildings to be constructed.
5. Electrical infrastructure is designed with safety margins to ensure that actual demands never exceed the design capacity. (This is why the NEC is used to size building wiring and the NESC is used to design utility distribution facilities.)

***Figure 23. Total Peak Power Demand for All Projected Study Area New Development***



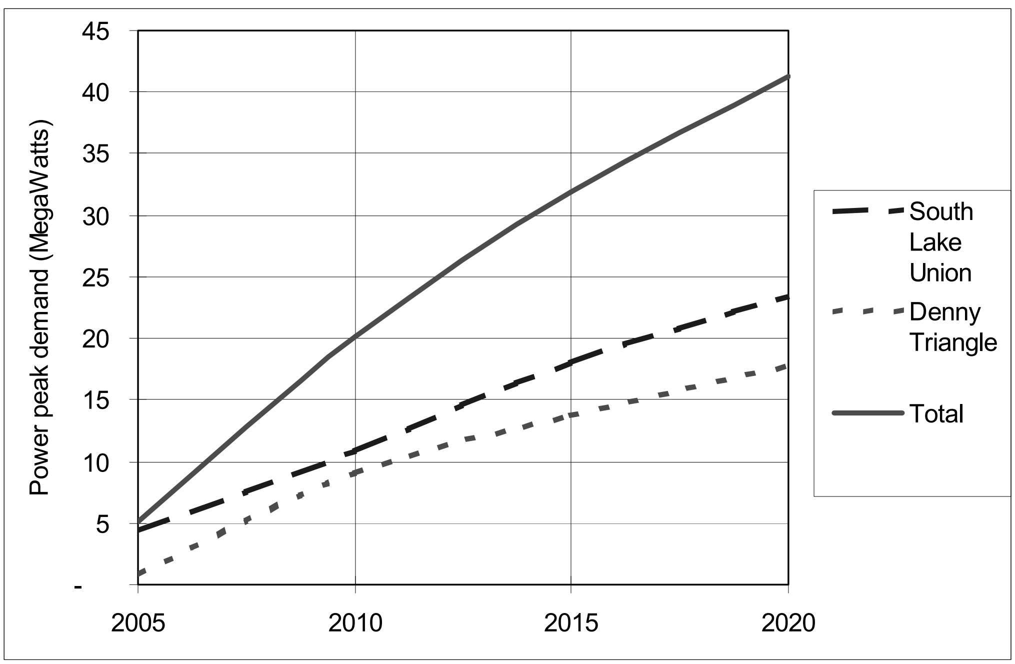
### 2.5.3 Avoided Power Demand from Thermal Production

The avoided peak power demand for the projected Energy District customer base is presented in Figure 24 below. Avoided power demand projections were developed using the peak power densities for thermal uses listed in Table 15. Figure 24 reflects our best estimate of avoided summer peak demand that would be realized if the Energy District were providing heating and cooling rather than customers self-generating their own heating and cooling through the assumed mix of HVAC technologies. This is a conservatively low projection, i.e., it should be used as a basis for projecting impact on electricity revenues and/or generation requirements rather than as a basis for planning for electricity infrastructure, because infrastructure should be sized with a safety margin.

Note that this calculation does not account for peak power requirements by the Energy District facilities. The analysis of the total *net* impact of the Energy District on peak power demand is presented in Section 5.

Confidentiality concerns preclude specific identification of loads on a block-by-block basis in this report. Avoided power load concentrations on a zone-by-zone basis are illustrated in Appendix 4.

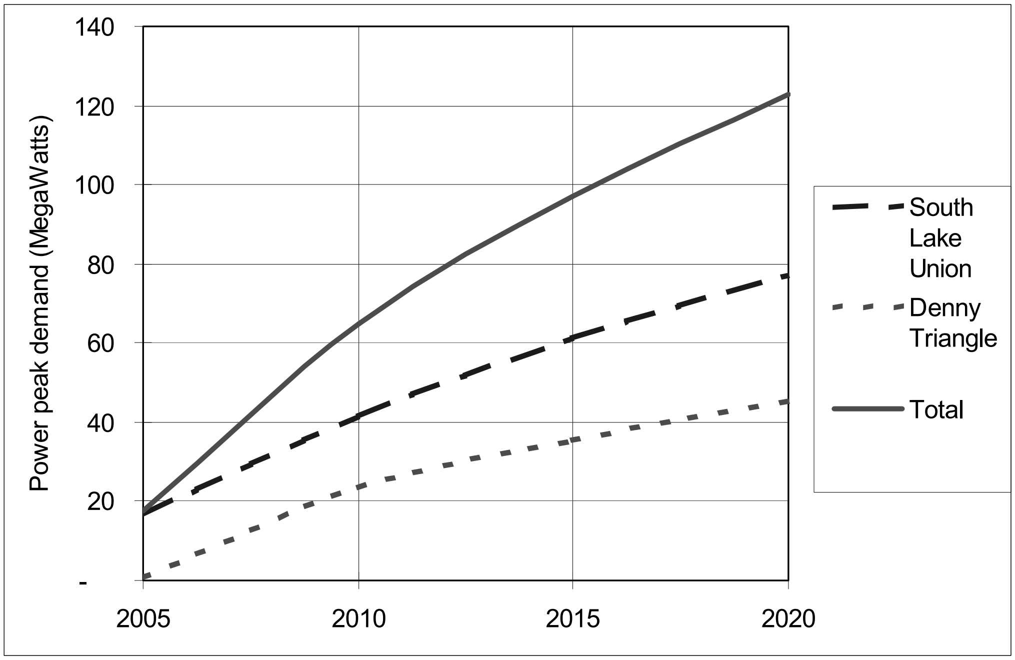
***Figure 24. Avoided Peak Power Demand from Thermal Production for Projected Energy District Customer Base***



### 2.5.4 Energy District Customers Power Demand

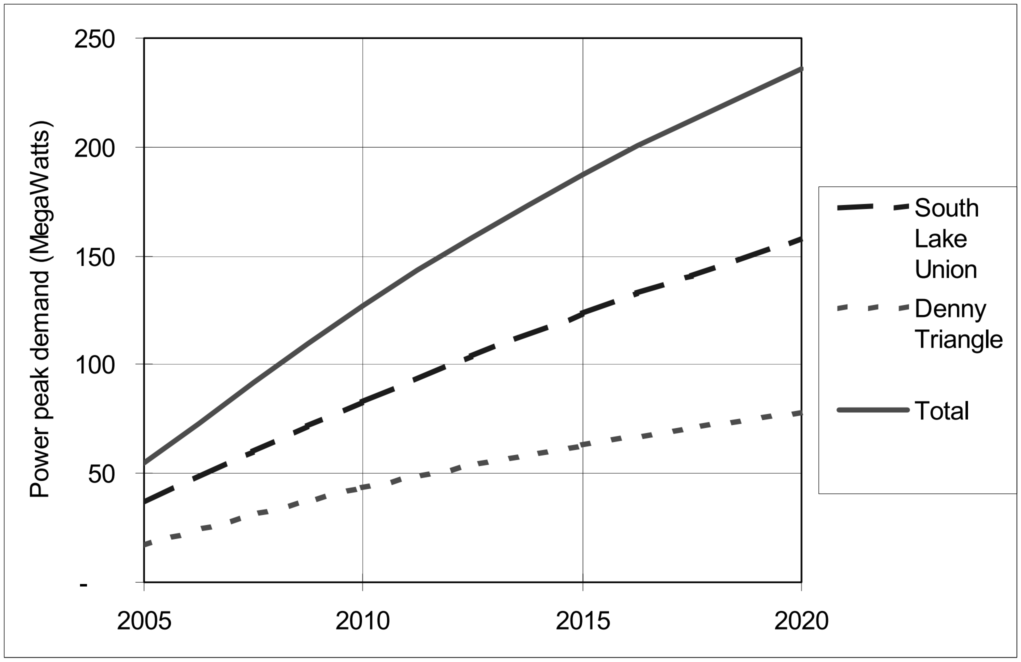
The peak power demand for the Energy District customer base is projected in Figure 25. This projection is based on the non-thermal peak power densities in Table 15.

***Figure 25. Peak Power Demand for Energy District Customer Base***




The remaining peak power demand for projected new development in the study area is presented in Figure 26 below. This is the peak power demand remaining after the avoided peak power demand shown in Figure 24 is subtracted from the total projected new development peak power demand shown in Figure 23. Again, this remaining power demand projection for the combined growth forecast is provided for informational purposed only and is not intended to be used for electrical infrastructure planning purposes.

***Figure 26. Remaining Peak Power Demand for New Development Based on Study Growth Forecasts***




### 2.5.5 Power Reliability and Power Quality

Power reliability and power quality is a growing priority for many building operators, particularly for biotechnology buildings. Not only is high reliability desired in order to avoid disruption in critical research activities, there are critical loads including ultra-low-temperature freezers and animal facilities for which the economic costs of power supply outages would be very high. In addition, power quality is of increasing importance for operation of a variety of technologies, with poor power quality leading to reduced equipment life and higher costs.

In response to these concerns, building owners and tenants are putting in back-up generators to address reliability issues, and equipment such as transient voltage surge suppressors to address power quality issues.

An Energy District can provide benefits to building owners and tenants relative to energy supply reliability and power quality. For example, eliminating chillers systems in a building can improve power quality by eliminating large variable frequency drives and the associated potential for harmonics problems. Poor power quality can reduce life of expensive research tools (e.g., laser bulbs). An Energy District can reduce peak power demand in the study area by meeting thermal energy requirements through the delivery of hot water and chilled water rather than through electric equipment in buildings. In addition, if an Energy District includes combined heat and power (CHP), power capacity can be provided where the power loads are, thereby helping mitigate distribution constraints and risks.

This study did not address the potential to develop a “mini-grid” supplied with power generated by a CHP facility located in the study area. Such an approach would entail additional capital costs, and would require the strong cooperation of Seattle City Light. The market value of high reliability and power quality may be worth the cost to certain types of customers, particularly biotech research facilities.

# Section 3 Technology Analysis

## 3.1 Scope of Technology Analysis

In this section we evaluate a range of technologies that could be implemented to produce heating, cooling and (in some cases) power to meet the energy requirements of an Energy District serving the study area.

Before examining technology options, key elements of the broader energy infrastructure are assessed. The natural gas supply infrastructure – the pipelines bringing natural gas from the wellhead through transmission and distribution system to the study area – is investigated to assess the ability of that infrastructure to deliver gas in the quantities and pressures required for potential Energy District production facilities. Then an overview is provided of the electricity infrastructure – the transmission and distribution facilities currently in place for potential supply of electricity to Energy District production facilities. The potential interface between the Energy District and the electricity grid, including assessment of requirements for upgrading the electricity infrastructure, is further considered in Section 5.

A variety of individual heating, cooling and combined heat and power (CHP) technologies options are then evaluated relative to efficiency, capital and operating costs, siting and infrastructure issues, reliability and environmental impacts. Technology options for thermal energy distribution and building interface are briefly discussed. A summary comparative analysis of technology options is then presented.

## 3.2 Natural Gas and Electricity Supply and Prices

### 3.2.1 Natural Gas

**Gas Supply**

Natural gas is by far the most important fossil fuel that could be used to generate electricity or produce thermal energy within the study area. The critical questions then become:

- Can sufficient quantities of natural gas be made available within the study area?
- What are the locations of accessible gas supply mains?
- What is the pressure of the available gas supply?

Natural gas is supplied to the study area through a pipeline system owned and operated by Puget Sound Energy (PSE). The study team held a number of discussions with Puget Sound Energy (PSE), and natural gas transmission and distribution maps were also obtained from PSE. High pressure mains are found within the study area, near both nodes of anticipated early Energy District development. Most attractive to the potential for siting Energy District plants would be the line that runs east-west along Mercer Street. Good possible plant locations occur at the intersection of Dexter and Mercer and at the intersection of Mercer and Fairview. Although other viable locations exist, these two locations would not require additional laying of mains.

Estimated gas requirements, including peak hourly demand and annual consumption, were provided to PSE for a range of technology configurations including an outside maximum of 80 MegaWatt (MW) combined heat and power (CHP). According to PSE, natural gas supply in the study area would be adequate for the largest CHP scenario estimated by the project team (80 MWe), with no additional gas pipeline construction required.

The two primary technologies for distributed generation of electricity are reciprocating engines and combustion turbines. Combustion turbines require pressures of 170 to 500 psi (depending on the particular turbine). Providing gas to the area at these pressures would, according to PSE, require significant construction of new mains and considering the recent opposition to pipelines and pipeline construction in general would face significant opposition. However, the gas at current pipeline pressures can be further pressurized at the CHP plant site through the use of on-site compressors.

In conclusion, although the discussions held and the analysis completed must be considered preliminary at this time, no major natural gas-related impediments to significant amounts of thermal energy generation or CHP have been identified at this time. Based on assumptions in this report, PSE projects no up-front capital costs to the customer subject to evaluation as additional project parameters are determined.

### Gas Prices

Natural gas prices vary depending on a complex variety of supply and demand factors. The cost of gas delivered to customers is based on the cost at the wellhead plus costs of transmission and distribution of the gas.

#### Wellhead Prices

Between 1985 and 2000, wellhead gas prices ranged between $1.25 and $3.00 per thousand cubic feet (MCF), with the exception of one very brief spike in 1997. One MCF contains about one million Btu (MMBtu) of energy. Since 2000, wellhead prices have been highly volatile, ranging from $2.00 to $8.00. [29]

Gas prices are expected to settle down somewhat from recent levels but are still expected to be higher than the averages during the last two decades. A significant factor in current and future gas demand is the substantial increases in use of natural gas for power generation. The U.S. Energy Information Administration (EIA) expects that natural gas wellhead prices increase in an uneven fashion as higher prices allow the introduction of major new, large-volume natural gas projects that temporarily depress prices when initially brought on line. From current (2003) West Coast wellhead prices of $2.89/MMBtu, EIA projects that wellhead prices will be $3.05 in 2005, $3.82 in 2010 and $4.19/MMBtu in 2020 (all 2001 dollars). [30]

Other projections suggest higher wellhead prices. For example, recent testimony in Congress suggests prices may vary significantly year-to-year but generally would range between $4.00 and $5.00 per MMBtu through 2020.[31]

PSE's Least Cost Plan (LCP), most recently filed with the Washington Utilities and Transportation Commission on July 31, 2003, projected that the long-term gas prices at the Sumas Hub are expected to range between $3.20 and $3.50 (in 2003 dollars) for the period of 2003-2025. This forecast is shown as "Base Case based on gas filing" in Figure 27. PSE's forecast is based on an average of four third-party forecasts: two from CERA, each representing different market scenarios, one from PIRA and one from the NW Power Planning Council. These three entities are respected forecasters and independent from PSE.

Two sensitivity cases are also presented in Figure 27: a "High Case based on gas filing" that is 20% above the "Base Case based on gas filing," and a "Low Case based on gas filing" that is 20% below the Base Case. The Energy District Study Base Case shown in Figure 27 is conservatively high, about mid-way between the Base and High cases per the gas filing.

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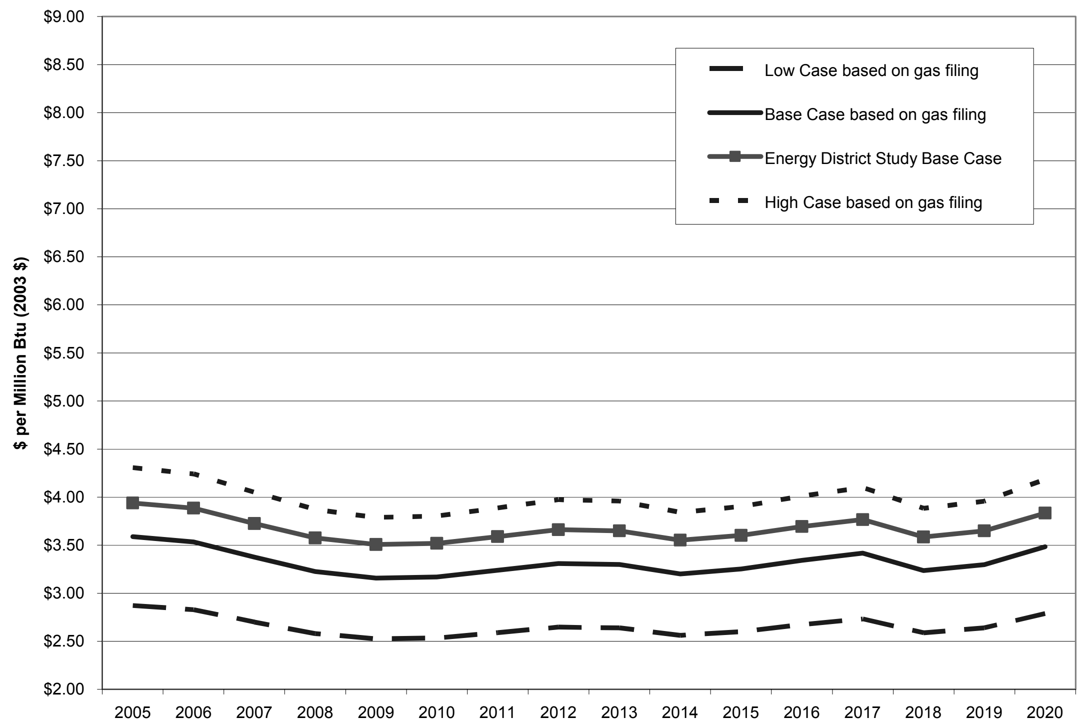
[29] American Council for an Energy Efficient Economy, based on data from the U.S. Energy Information Administration 2003.
[30] EIA AEO 2003, Supplemental Table 106. Natural Gas Delivered Prices by End-Use Sector in Census Division, Commercial Pacific. Region (2001 $ per MCF).
[31] Testimony of Joel Bluestein, Energy and Environmental Analysis, before the U.S. Senate Committee on Environment and Public Works, Subcommittee on Clean Air, Climate Change and Nuclear Safety, Hearings on Powerplant Multipollutant Legislation, May 8, 2003.

*Figure 27. Projections for Natural Gas Cost at Sumas Hub (2003 $)*




## PSE Gas Rates

PSE's gas rates were increased in October 2003 to reflect increases in the cost of gas. The current tariffs are summarized in Appendix 5. Total commercial natural gas costs under Commercial and Industrial General Service rate (Rate 31) including city tax is $0.817 per therm, or $8.17 per MMBtu, as shown in Table 16.

The Energy District would qualify for lower industrial gas rates such as Rate 87, which requires annual consumption in excess of 100,000 MMBtu/year. The average cost for any given user depends on the use pattern and the extent of "firming" of gas supply under this interruptible gas tariff. The current total cost of gas under Rate 87 (excluding city fee) ranges from $4.25/MMBtu with 0% firming to $5.17/MMBtu with 100% firming, as shown in Table 17. City fee is excluded because an Energy District would pay city fees at the retail level.

According to PSE, in a warm winter there would be no interruptions of supply to interruptible customers, and in a cold year about 20 days of interruption. The mean annual interruption level is 10 days per year for 3-4 hours per day, affecting 50% of interruptible customers. For the purpose of price projections for this Energy District study, we are assuming 30% firming. All gas-based production facilities in the scenarios presented later include light fuel oil storage sufficient to run at the peak hourly gas consumption for 3 days.

***Table 16. Current Puget Sound Energy Commercial Natural Gas Costs under Rate 31***

**Rate 31 -- Commercial and Industrial General Service**

| | | | | |
|---|---|---|---|---|
| Monthly customer charge | $ | 10.00 | | |
| **Commodity cost per Therm (100,000 Btu)** | | | Spread vs Sumas | |
| Cost at Sumas | $ | 0.457 | | |
| Delivery from Sumas to city gate | $ | 0.073 | | |
| Delivery from city gate to burner tip | $ | 0.239 | | |
| Conservation charge | $ | 0.002 | | |
| Tax | $ | 0.046 | | |
| Total | $ | 0.817 | $ | 0.360 |
| ***Breakdown of costs and total including tax ($/MMBtu)*** | | | *Spread vs Sumas* | |
| *Cost at Sumas* | *$* | *4.57* | | |
| *Delivery from Sumas to city gate* | *$* | *0.73* | | |
| *Delivery from city gate to burner tip* | *$* | *2.39* | | |
| *Conservation charge* | *$* | *0.02* | | |
| *Tax* | *$* | *0.46* | | |
| *Total* | *$* | *8.17* | *$* | *3.60* |

***Table 17. Current Puget Sound Energy Industrial Natural Gas Costs under Rate 87***

| | % firming | | | | | |
|---|---|---|---|---|---|---|
| | 0% | 10% | 20% | 30% | 50% | 100% |
| Sumas | $ 4.57 | $ 4.57 | $ 4.57 | $ 4.57 | $ 4.57 | $ 4.57 |
| Delivery | $ 0.35 | $ 0.35 | $ 0.35 | $ 0.35 | $ 0.35 | $ 0.35 |
| Firming | $ - | $ 0.09 | $ 0.18 | $ 0.28 | $ 0.46 | $ 0.92 |
| Total | $ 4.92 | $ 5.01 | $ 5.10 | $ 5.20 | $ 5.38 | $ 5.84 |

## Projected Gas Rates for Energy District Study

Based on the above, we projected natural gas rates in a Base Case projection, with sensitivity analyses at higher and lower price levels. Figure 28 shows projected commercial gas prices (applicable to gas used by individual buildings), and Figure 29 shows projected prices applicable to the Energy District plant assuming interruptible gas with 30% firming as discussed above. These projections were developed by adding a spread between the Sumas Hub cost (see Figure 27) and delivered cost of $3.60 and $0.35 per MMBtu for commercial and industrial prices, respectively. All projections are in 2003 dollars.

The Energy District Study base case projections are slightly higher but generally consistent with U.S. Energy Information Administration (EIA) projections. Figure 30 summarizes projections by EIA regarding regional natural gas prices for the Pacific region (Alaska, California, Hawaii, Oregon, and Washington). Commercial rates are projected to be about $7.00/MMBtu (in 2001 dollars) and industrial rates about $4.00/MMBtu (in 2001 dollars) for the period of 2010-2020.[32]

[32] EIA AEO 2003, Supplemental Table 106. Natural Gas Delivered Prices by End-Use Sector in Census Division, Commercial Pacific. region (2001 $ per MCF).

***Figure 28. Projected Commercial Natural Gas Prices (2003 $)***

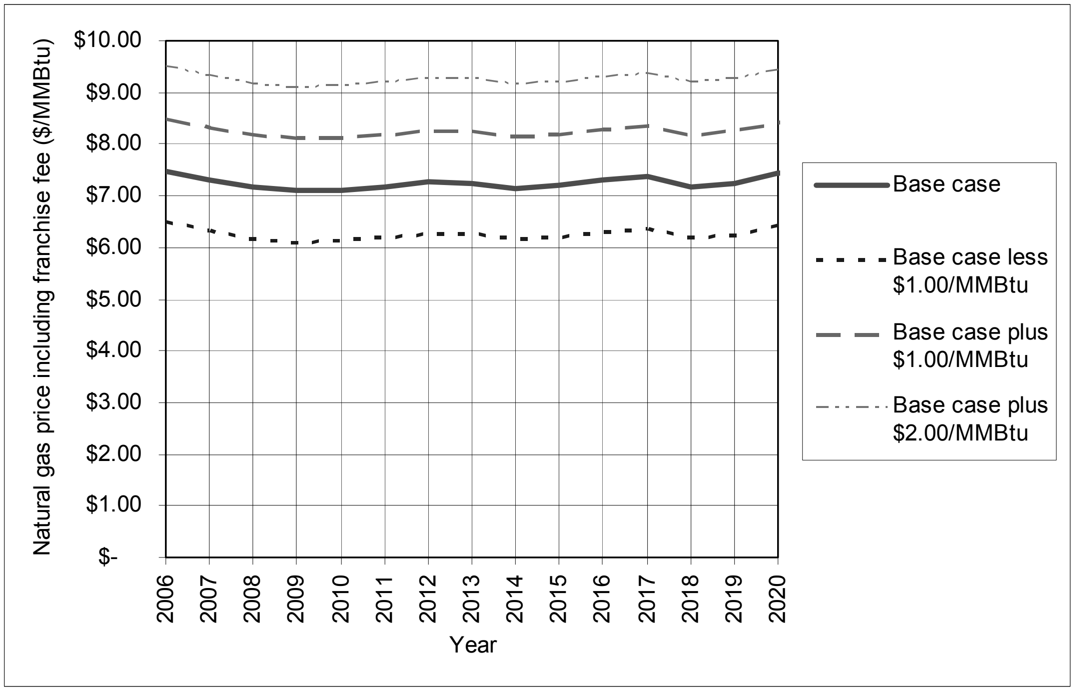
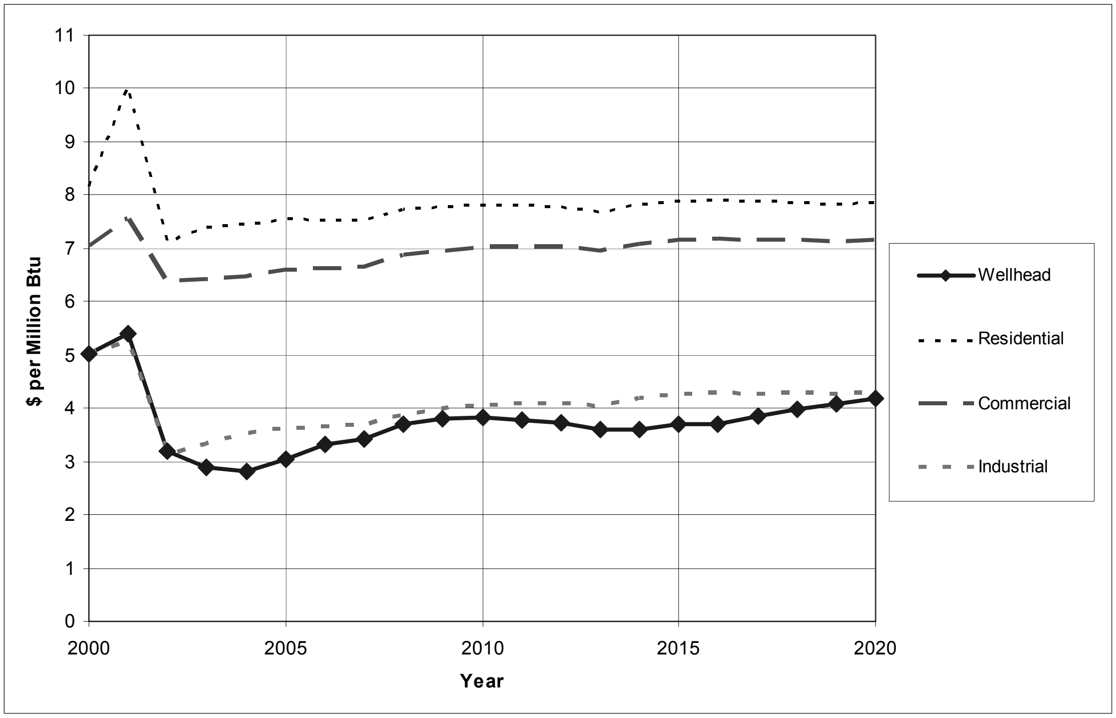



***Figure 29. Projected Energy District Natural Gas Prices (2003 $)***

*Figure 30. U.S. Energy Information Administration Projections for Natural Gas Prices (2001 $)*




## 3.2.2 Electricity

### Transmission and Distribution Infrastructure

The electrical transmission and distribution system is addressed in Section 5.

### Electricity Prices

#### Wholesale Electricity Sources and Prices

Seattle City Light's resource portfolio costs in 2002 ranged from a low of about $3 per MWH to a high of $75 per MWH, with an average of $17.37 per MWH.[33] SCL has surplus electrical energy supplies in the spring and summer (most strongly in May and June), but may see growing deficits during the winter, particularly after 2011. SCL's resource plan is currently being revised, and no official projections for SCL's long-term resource mix and prices are currently available. SCL shared an internal document that addresses projected annual wholesale prices.[34] This document does not address resource mix. Subsequent communication with SCL[35] [36] indicates that SCL considers gas turbine combined cycle to be the appropriate marginal plant for comparative analysis with alternative source of electricity generation or conservation.

SCL's existing resource plan also indicates that a key potential source of marginal capacity is natural gas turbines, either simple cycle or combined cycle. The 2002 resource cost for the Klamath Falls

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[33] "2002 Update to the 2000 Strategic Resource Assessment," Seattle City Light Strategic Planning Office, October 2002.
[34] "Working Paper – Planning Values for Energy," Garry Crane, Seattle City Light, Nov. 2003.
[35] Comments of Carol Everson, SCL Director of Finance, during the Dec. 10, 2003 advisory committee.
[36] Memorandum to Sue Walsh, SCL, from Lynn Best, SCL, Dec. 26, 2003, with follow-up communication with Corinne Grande of SCL.

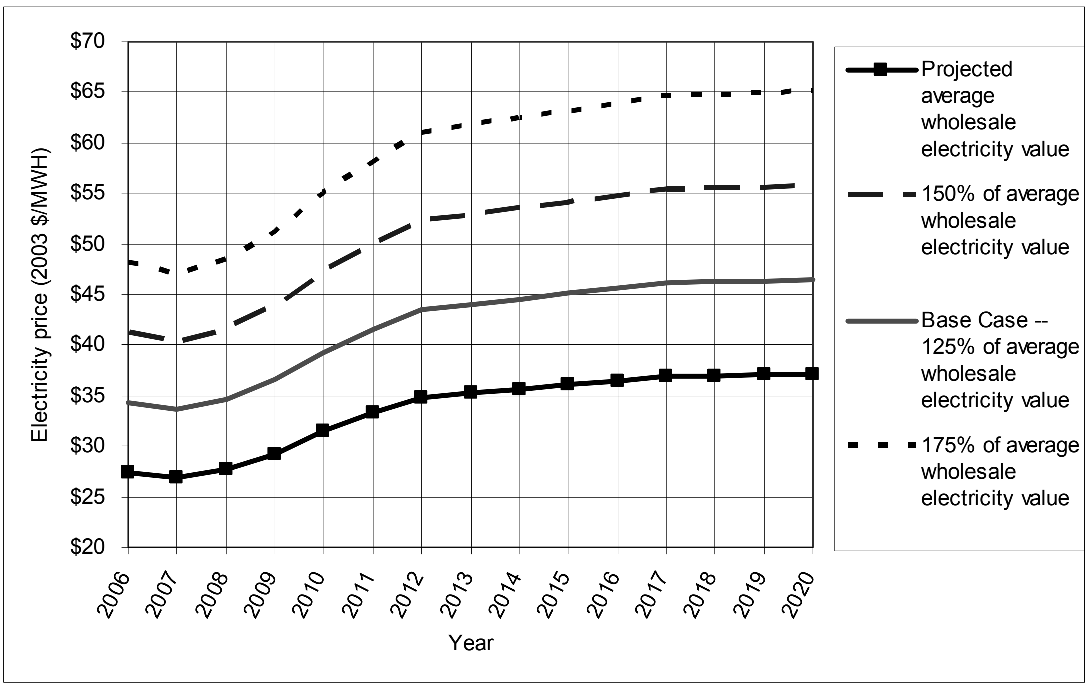
combined cycle plant was $60 per MWH. In SCL's resource plan, the cost of power from gas turbines ranges from $46 to $80 per MWH, depending on capacity factor, assuming $3.00 per MMBtu gas.

In this Energy District study, base case projections assumed that the value of net power production from CHP facilities was equal to 125% of the projected average summer and winter wholesale values of electricity as currently projected in a SCL working paper. Those projected wholesale values range from about $27/MWH (summer 2006) to about $38/MWH (winter 2020). Average annual projected wholesale resource costs are shown in Figure 31. The base case assumption that the value of CHP power is 125% of the average wholesale prices was made in an attempt to recognize that:

- marginal resource costs will be higher than average resource costs;
- a CHP facility can provide dispatchable power, which has a higher value than some types of renewable resources; and
- generation near load reduces transmission and distribution losses.

In later economic sensitivity analyses, the value of electricity was assumed to be 100%, 150% and 175% pf the projected average wholesale value.

***Figure 31. Electricity Resource Value Scenarios***




SCL's resource mix is currently 90.2 % hydro, 5.3% natural gas, 2.6% nuclear and the remainder wind, coal, waste and biomass. [37] However, since the peak capacity provided or avoided by the Energy District can be compared to SCL's alternatives for meeting new demand, the emissions characteristics of the Energy District should be compared with SCL's marginal resource (future increments of new capacity). Based on discussion with SCL, the marginal resource is assumed to be combined cycle gas turbines in the near term with a small amount of fluidized bed coal capacity in the longer term. Based on input from SCL, emissions factors for offset SCL resources were projected based on the estimated 2003 factors and the projected 2020 factors summarized in Table 18.

[37] SCL website, November 2003.

***Table 18. Assumed Emissions Factors for SCL Resources***

| | Emission rates in lbs/MWH | | | Metric tons | Heat rate |
|---|---|---|---|---|---|
| | NOx | CO | CO2 | CO2/MWH | (Btu/kWh) |
| New gas turbine combined cycle inc. 5% transmission losses | 0.105 | 0.044 | 848 | 0.385 | 7,185 |
| Estimated 2003 factor | 0.149 | 0.062 | 1,201 | 0.545 | 10,179 |
| Projected 2020 (90/10 combined cycle/coal mix) | 0.238 | 0.267 | 1,009 | 0.458 | 7,661 |

## Retail Prices

Current SCL rates are summarized in Table 19, based on the demand and energy rates in the tariffs shown in Appendix 6. Network rates are applicable in Denny Triangle. Rates were increased 58% in four increases during 2001. High Demand rates and possibly future New Large Load rates would be applicable to the Energy District facilities.

SCL's current long-range retail rate forecasts are illustrated in Figure 32.[38] These forecasts are in constant 2003 dollars. SCL indicated that the longer-range part of this forecast deserved some review. This becomes apparent when the retail rate forecast is contrasted with projected wholesale resource values (Figure 31). For this Energy District study, we prepared revised projections for retail rates, using the SCL forecast through 2010, thereafter basing retail rates on changes in wholesale resource costs plus a spread between wholesale and retail equal to 80-90% of the spread in 2010. These revised projections are shown in Figure 33.

***Table 19. Current Seattle City Light Electricity Rates***

| | Size range | | Estimated average rate (cents/kWh) | |
|---|---|---|---|---|
| | | | On-peak | Off-peak |
| Medium Network | > 50kW | < 1 MW | 6.8 | - |
| Large Network | > 1 mW | | 6.5 | 5.5 |
| Medium Standard | > 50kW | < 1 MW | 6.1 | - |
| Large Standard | > 1 mW | < 10 MW | 6.0 | 5.2 |
| High Demand | > 10 MW | | 5.8 | 5.0 |

[38] "Rate Forecast – GS," an Excel spreadsheet provided by Carol Everson, Director of Finance, SCL on Dec. 9, 2003.

*Figure 32. SCL Retail Electricity Price Projections (2003 $)*

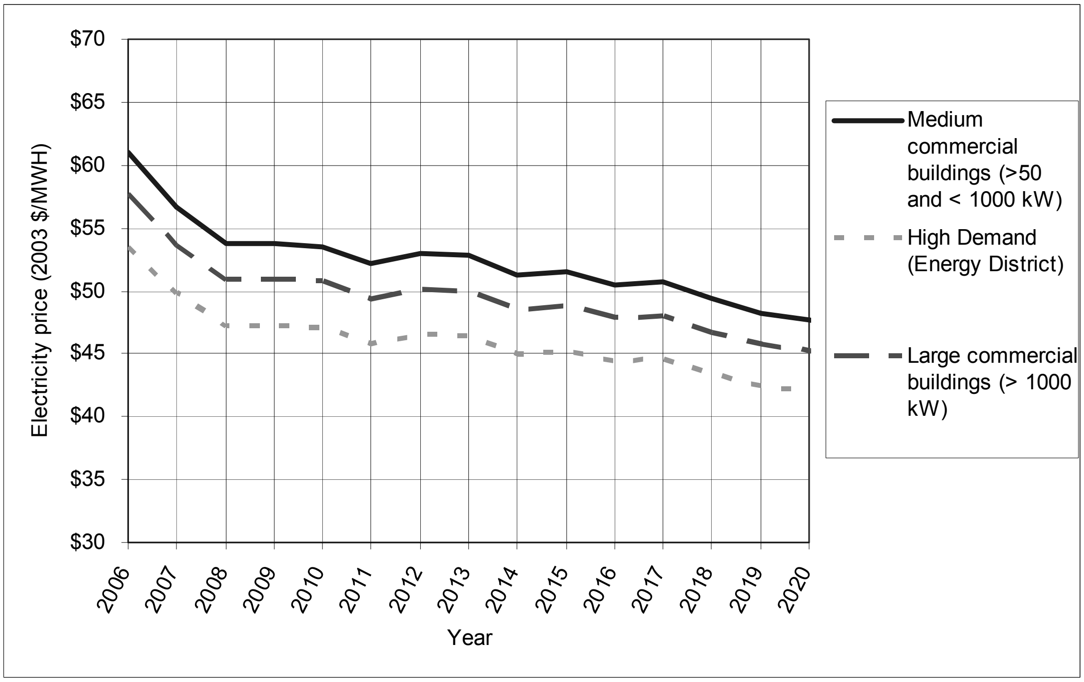
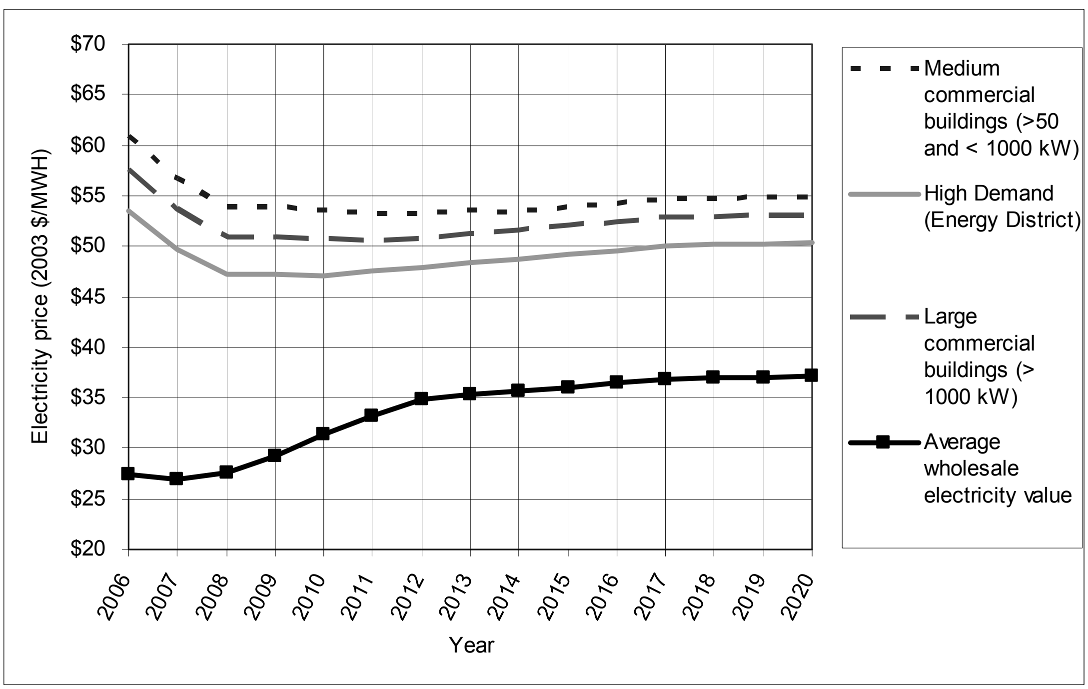



*Figure 33. Retail Price Projections Used in this Study (2003 $)*



## 3.3 Heating Technologies

### 3.3.1 Overview of this Section

This section briefly describes technology options for heat production and summarizes their efficiencies, costs, infrastructure issues, reliability and environmental impact characteristics. The focus of this section is on characteristics of individual technologies and their relative merits for inclusion in an Energy District. Once all heating and cooling technologies have been characterized, concepts for combining multiple technologies into an integrated Energy District will be described and evaluated.

### 3.3.2 Natural Gas Boilers

#### Technology Description

A boiler is a pressure vessel designed to transfer heat to water or steam. Generally, heat is generated in a boiler through combustion of fuel, although electricity is sometimes used for this purpose. Natural gas is the preferred fuel because it has generally been inexpensive, is easy to use and results in low air emissions. However, many boilers are also designed to use fuel oil as a back-up, to protect against potential disruptions in natural gas supply or significant increases in natural gas costs.

#### Efficiency

New gas-fired boilers can achieve efficiencies of about 80 percent on a Higher Heating Value (HHV) basis, although lower efficiencies on a seasonal average basis can result if the boiler is operated at widely varying loads. (HHV includes the latent heat of vaporization of water vapor in the combustion gases.)

#### Costs

The capital cost of hot water natural gas boilers, per unit of peak capacity, decreases with larger boiler sizes. In the size range of boilers likely to be used at an Energy District plant -- over 25 million Btu/hour (MMBtu) -- the total installed cost including all ancillary equipment but excluding building will be about $30,000 per MMBtu/hour of output capacity.[39] The total costs for constructing two natural gas boiler plants to serve the Energy District (one in South Lake Union and one in Denny Triangle) were estimated, assuming installation in four phases. The total average cost including building was $43,500 (2003 $) per MMBtu/hour of output capacity. These capital cost estimates are detailed in Appendix 7. (The costs per unit of output capacity in Appendix 7 were used in the total system economic analyses presented in Sections 4 and 6. In some cases, the output capacities, and thus costs, were increased from the values shown in Appendix 7.)

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Operating costs are highly dependent on fuel costs. For example, with natural gas costing $4.00 per MMBtu, the fuel cost of hot water output would be $5.00 per MMBtu with an 80% annual boiler efficiency. This variable is addressed more comprehensively in the comparative analysis of heating options below. Maintenance costs will depend somewhat on utilization; however, a representative levelized 20-year annual maintenance cost is $900 per MMBtu/hour of output capacity.[40]

With 2,150 average heating Equivalent Full Load Hours (EFLH)[41] and capital amortized with 5% interest over 20 years, the total cost of heat from natural gas boilers, including capital, operation and

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[39] Based on a variety of heating plant cost studies undertaken by FVB Energy Inc.

[40] Based on 1.5% of capital costs.

[41] EFLH is the ratio of annual energy to peak demand.

maintenance costs but excluding operating labor, varies from $6.08 to $11.08 per MMBtu at natural gas costs ranging from $3.00 to $7.00 per MMBtu.

#### Siting and Infrastructure Issues

Energy District boiler facilities will require access to the natural gas distribution system. As noted in Section 3.2 above, the study area has good natural gas access. The natural gas requirements to meet the projected Energy District heating load in 2020, if provided entirely with gas boilers, are summarized in Table 20.

***Table 20. Natural Gas Requirements with All Heating Provided with Natural Gas Boilers***

| | Year | | | |
|---|---|---|---|---|
| | **2006-2008** | **2009-2010** | **2011-2015** | **2016-2020** |
| Peak hourly gas consumption (therms per hour) | 195 | 1333 | 2040 | 2625 |
| Peak daily gas consumption (therms per day) | 2344 | 15991 | 24483 | 31496 |
| Annual gas consumption (therms) | 420,689 | 2,941,060 | 4,447,543 | 5,707,086 |
| Average therms/month | 35,057 | 245,088 | 370,629 | 475,590 |

Note: one therm = 100,000 Btu

#### Reliability

Natural gas boilers with fuel oil capability are well-proven, extremely reliable technologies. Fuel oil can be used in the event of disruption of gas deliveries. The economic analyses presented in Section 4 include costs for #2 fuel oil storage sufficient to operate the facility at peak hourly capacity for 3 days. An Energy District boiler plant can be designed to include multiple units, including a redundant boiler so that the peak requirement can be met even if the largest unit is out of service. The economic analysis in Section 4 includes sufficient capacity to meet this redundancy criterion.

#### Environmental Impacts

Natural gas boilers will emit 0.03 pounds of nitrogen oxides (NOx) per MMBtu of fuel combusted with low NOx burners plus flue gas recirculation. Carbon monoxide emissions can be expected to be 0.084 pounds per MMBtu of fuel combusted. Gas boilers emit essentially no sulfur dioxide and negligible particulates. Carbon dioxide emissions are 118 lbs of $CO_2$ per MMBtu of fuel.[42]

### 3.3.3 Seattle Steam

Seattle Steam Company, which provides district heating service in downtown Seattle, also provides service to some facilities in the Denny Triangle area, e.g. the Westin Hotel. Seattle Steam has expressed an interest in providing service to the Denny Triangle Area for new developments. A heat exchanger station could be installed to supply hot water to a Denny Triangle district heating system from the Seattle Steam loop.

Seattle Steam high pressure (140 psig) line ends at 6$^{th}$ and Pine, and can deliver 150,000 lbs/hour (about 150 million Btu/hour). This steam could be used to produce hot water, and potentially electricity, for the Energy District, with the steam condensate used for glass washing in the research facilities, or for laundry facilities.

This scenario was not fully developed in this Phase 1 study, but may merit evaluation in further studies.

[42] All boiler emission data from U.S. Environmental Protection Agency, Technology Transfer Network Clearinghouse for Inventories & Emission Factors AP-42, Fifth Edition, Volume I, Chapter 1: External Combustion Sources, Table 1.4-1.

## 3.3.4 Heat Pumps

### Technology Description

Heat pumps are devices that move heat from air or water at a lower temperature to air or water at a higher temperature. Heat pumps effectively reverse the natural process of heat flowing from a higher temperature substance to a lower temperature substance. Typically, this is accomplished with a mechanical device such as a compressor, usually powered with electricity. A heat pump is like a chiller or other refrigeration device, using the conventional vapor-compression refrigeration cycle (see "Electric Chillers" below), except that:

- The heat source is one of a number of water or air sources, instead of the district cooling or building cooling loop; and
- Instead of rejecting heat to the environment through the condenser water loop the heat is provided to the building space.

Heat pumps can be designed to provide:

- heating only;
- heating or cooling; or
- heating and cooling simultaneously.

The major types of heat pumps can be summarized as follows.

#### Open Loop Heat Pump

Open Loop Heat Pumps (OLHP) use groundwater or other sources as the heat sink (cooling) or heat source (heating). For example, water can be pumped from a well, circulated through the heat pump and injected into a second well or pumped to a surface water body, depending on environmental restrictions. Some states have banned "once through" use of groundwater (which is generally a high quality water resource) and disposal to surface water. There are also environmental issues associated with reinjection into aquifers due to concerns regarding groundwater contamination.

Alternatively, surface water (sea water or lake water), sewage effluent or other sources can be used as a heat source and/or sink.

Significant implementation of heat pumps using seawater, lake water or sewage effluent occurred in Sweden in the 1980s with the availability of surplus electricity capacity from nuclear plants. During this period a number of large heat pumps, up to 55 MegaWatts (MW) thermal (about 188 million Btu/hour), were installed. In the 1990's some of the heat pumps were adapted to simultaneously supply district heating from the heat pump condenser and district cooling from the heat pump evaporator for those times of the year (spring, fall and winter) when both heating and cooling are required.

Heat pumps can "pump up" the temperature of relatively low-temperature heat sources to the levels required for district heating or even industrial process heating. However, the output temperature depends on the particular heat pump design, including whether units are connected in series. European heat pumps can reach 180 F, whereas domestic heat pumps typically can't exceed 155 F. Although conventional building hydronic HVAC design in the US calls for supply and return temperatures of about 180-200 F supply and 160-180 F return, Europeans are increasingly pushing toward lower building HVAC temperatures, e.g. 160 F supply/105 F return or lower. [43] This facilitates uses of highly efficient CHP systems, industrial waste heat or heat pumps.

See the discussion on "Deep Water Cooling" below for further evaluation and examples of cooling applications of Open Loop concepts.

[43] "Skagestad and Mildenstein, "District Heating and Cooling Connection Handbook," International Energy Agency Programme of Research, Development and Demonstration on District Heating and Cooling, ISBN 90-5748-026-3.

Sewage Effluent as Heat Source. The Rya heat pump plant in Gothenburg, Sweden has a total heat pump capacity of 160 MegaWatts (MW) thermal, or 546 million Btu/hour, produced from treated sewage effluent. Closer to home, use of treated sewage effluent has been investigated in the Seattle area. Although there is currently no economically accessible source of treated effluent to serve the study area, this is a possibility should future wastewater treatment infrastructure planning make such a water source economically accessible to serve South Lake Union/Denny Triangle.

### Water Loop Heat Pump

A Water Loop Heat Pump (WLHP) system, sometimes called "Distributed Heat Pumps," consists of a closed water circulation system feeding multiple WLHPs located throughout a building. Each WLHP provides either heating or cooling to a particular zone within the building, using the water loop as a heat sink (for cooling) or a heat source (for heating). WLHP can be a workable solution for individual larger buildings with simultaneous heating and cooling requirements during a significant part of the year. If the water loop becomes too cool during the heating season, heat can be added to the loop with a boiler or electric resistance. If the water loop becomes too hot during the cooling season, the loop can be cooled with a cooling tower and, if required, a chiller.

WLHP are not recommended for an Energy District, as they lock the buildings into a single technology configuration without any possibility to respond to future price shifts or technology opportunities (in other words, work against "Future Proofing" as discussed in Section 1), and lack the ability to provide the synergies achievable through Energy Districts. WLHP also have high-maintenance costs, and do not provide the controllability, and thus comfort, of full hydronic heating and cooling. The WLHP is briefly profiled here because it is a potential approach to building scale heating and cooling design.

### Ground Source Heat Pump

Ground Source Heat Pumps (GSHP) use the ground as a heat source or sink, often coupled with WLHP systems. GSHP systems are closed loop systems using vertical boreholes or horizontal trenches to circulate water through the ground to heat or cool it. These systems are relatively expensive and are not practical for an Energy District scale system in study area due to the building development density. GSHP are briefly profiled here to provide background on the range of heat pump applications.

#### Efficiency

Heat pumps are the most efficient form of *electric* heating in mild and moderate climates, with a Coefficient of Performance (ratio of heat output to energy input) of 2.5 to 3.5 depending on the temperatures, with higher COPs for lower temperature lifts (difference between the heat source and heat sink) and higher COPs for lower heat sink temperatures. A representative COP value for heat pumps in heating applications is about 3.0; in the later economic analyses a heating COP of 2.8 was assumed. In contrast, electric resistance heating has a COP of 1.0. For total energy efficiency calculations, the fuel efficiency of electricity generation must also be taken into account.

#### Costs

Capital costs will vary depending on manufacturer, design and unit size. For the probable scale of units for the Energy District (about 30 MMBtu/hour), a range of installed capital costs of $76,000-152,000 per MMBtu/hour of peak heating capacity is estimated, with representative estimate of $114,000 per MMBtu/hour of peak capacity.[44] During the colder parts of the year, the hot water produced from the heat pump would have to be further heated with a boiler to reach the send-out

[44] RCG/Hagler Bailly, Chalmers Industritenik Energiteknisk Analys and IEA Heat Pump Centre, " Industrial Heat Pumps, Experiences, Potential and Global Environmental Benefits, International Energy Agency Heat Pump Programme, April 1995. Report No. HPP-AN21-1.

temperatures required for the coldest days. The total costs for constructing two heat pump/boiler plants to serve the Energy District (one in South Lake Union and one in Denny Triangle) were estimated, assuming installation in four phases. The total cost (2003 $) per MMBtu/hour of output capacity, was $109,975. These cost estimates were based on consultation with Axima, a major European manufacturer of heat pumps, based on temperature and design parameters provided by the project team.

Operating costs are based primarily on electricity costs. With a COP of 2.8 (per Axima) and electricity unit costs of $0.055 per kWh, the electricity cost would be $5.37 per MMBtu of heat. If electricity unit costs increased to $0.07 per kWh, the electricity cost would be $6.84 per MMBtu of heat.

Maintenance costs will depend on specific design and on unit utilization; however, a representative annual maintenance cost is $1,600 per MMBtu/hour of output capacity.[45]

With 2,150 average heating Equivalent Full Load Hours (EFLH) for the district heating system[46], the total cost of heat from heat pumps including capital, operating and maintenance costs, but excluding operating labor, varies from $10.93 to $12.50 per MMBtu at electricity costs ranging from 5.5 cents to 7.0 cents per kWh. Capital was amortized at 5% over 20 years.

#### Siting and Infrastructure Issues

Large central heat pumps would add to the size of the electric service required for Energy District plants in comparison to natural-gas-based heating plant options. However, that would not be a significant barrier. The advantage of heat pumps relative to siting would be the lack of an exhaust gas stack, which would most likely make it more acceptable from a neighborhood impact standpoint.

#### Reliability

The main issues with large heat pumps have been compressor breakdown and problems integrating the heat pump controls with the balance of the energy system. [47] With proper design and operation, heat pumps can and do operate very reliably. There is extensive experience in Sweden to draw upon to ensure appropriate design and operation.

#### Environmental Impacts

Heat pumps would not have any direct air emissions impacts, although they would have indirect emissions impacts to the extent that the electricity used to meet the heat pump requirements was generated with fossil-fuel-based power plants. Heat pumps likely to be used in an Energy District would use the refrigerants with little or no impact on stratospheric ozone, although there is some impact on global warming.

### 3.3.5 Electric Boilers

#### Technology Description

Electric boilers generate hot water or steam through electric resistance. They are not commonly used because electric resistance is an inefficient and generally expensive to generate heat.

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[45] Based on 1.5% of capital cost and corroborated with maintenance cost data on centrifugal chillers per Electric Power Research Institute.

[46] EFLH is the ratio of annual energy to peak demand.

[47] RCG/Hagler Bailly, Chalmers Industritenik Energiteknisk Analys and IEA Heat Pump Centre, " Industrial Heat Pumps, Experiences, Potential and Global Environmental Benefits, International Energy Agency Heat Pump Programme, April 1995. Report No. HPP-AN21-1.

### Efficiency

Electric boilers have a COP of 1.0, i.e. the efficiency of conversion of input electricity to output heat is 100%. For total efficiency calculations, the fuel efficiency of electricity generation must also be taken into account.

### Costs

Electric boilers are available in smaller sizes than gas boilers. For an Energy District total installed costs for an electric boiler with an output capacity of 12.2 MMBtu/hour, including all ancillary equipment but excluding building, was estimated to be about $20,000 per MMBtu/hour of output capacity.[48] Electric boilers take less space than gas boilers, so the building-related costs are lower. With an allowance for a high-quality building, the total cost of electric boiler plant capacity is estimated to be $24,000 per MMBtu/hour of output capacity.

Operating costs for electric boilers are directly related to the cost of electricity. SCL rates for High Demand General Service (for facilities with peak demand greater than 10 MW) are about $0.050 per kWh off-peak and $0.058 per kWh on-peak. "On-peak" is defined as 6:00 AM to 10:00 PM, Monday through Saturday, excluding major holidays. SCL is a winter-peaking utility, although summer peaks are becoming more important as electricity markets are increasingly integrated on a regional basis. There is no current difference in rates between winter and summer. If SCL moved to a rate structure that recovered more cost during high-demand periods, the average cost per kWh for electricity to run electric boilers may increase.

If electricity costs an average of $0.055 or $0.07 per kWh for an Energy District electric boiler, the electricity cost would be $16.11 or $20.51 per MMBtu, respectively.

Maintenance costs will depend on utilization. A representative annual maintenance cost is $4.00 per MMBtu/hour of output capacity.[49]

With 2,150 average heating Equivalent Full Load Hours (EFLH)[50], the total cost of heat from electric resistance heating including capital, operation and maintenance costs, but excluding operating labor, varies from $17.21 to $21.61 per MMBtu at electricity costs ranging from 5.5 cents to 7.0 cents per kWh. Capital was amortized at 5% over 20 years.

### Siting and Infrastructure Issues

Large electric boilers would add to the size of the electric service required for Energy District plants in comparison to natural-gas-based heating plant options. The advantage of electric boilers relative to siting would be the lack of an exhaust gas stack, which would most likely make it more acceptable from a neighborhood impact standpoint.

### Reliability

Electric boilers are well-proven, extremely reliable technologies. An Energy District electric boiler plant would be designed to include multiple units, including a redundant boiler so that the peak requirement can be met even if the largest unit is out of service. However, an electric boiler is dependent on a sole energy source, so it is vulnerable to disruption of the power supply, without the potential for back-up with fuel oil, as is the case with natural gas boilers.

[48] Means Mechanical Data 2003 plus additional costs for balance of plant based on FVB project cost estimates.
[49] Estimate based on 1.5% of capital cost.
[50] EFLH is the ratio of annual energy to peak demand.

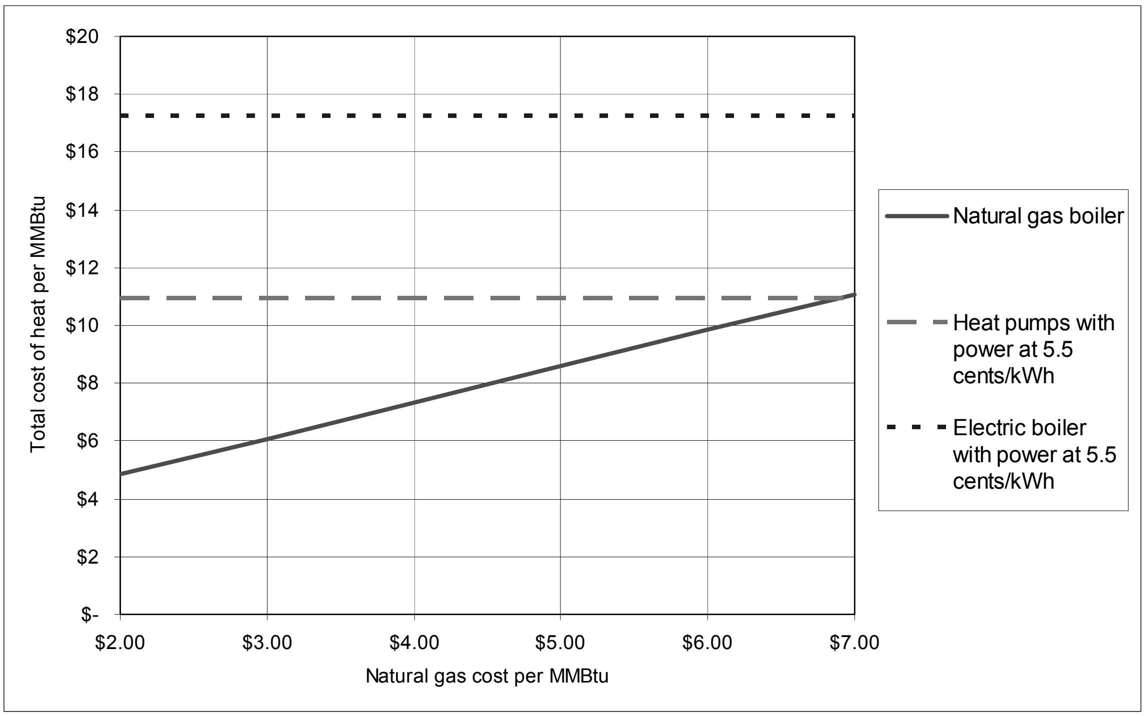
#### Environmental Impacts

Electric boilers would not have any direct air emissions impacts, although they would have indirect emissions impacts to the extent that the electricity used to meet the boiler requirements was generated with fossil-fuel-based power plants.

### 3.3.6 Heating Technology Economic Comparison

Figure 34 summarizes the economic comparison of Energy District heating options, excluding CHP, which will be discussed in Section 3.5 below. This comparison takes into account all capital and operating costs, with capital amortized at 5% over 20 years. Electric resistance heating compares poorly with natural gas boilers, due to the operating (energy) costs. Heat pumps are more competitive with gas, reaching annual cost parity at natural gas costs of $7.00/MMBtu.

***Figure 34. Economic Comparison of Energy District Heating Technology Options (excluding CHP) with 5% Cost of Capital***




## 3.4 Cooling Technologies

### 3.4.1 Overview of this Section

This section briefly describes technology options for cooling production and summarizes their efficiencies, costs, infrastructure issues, reliability and environmental impact characteristics. The focus of this section is on characteristics of individual technologies and their relative merits for inclusion in an Energy District. Later, once all heating and cooling technologies have been characterized, concepts for combining multiple technologies into an integrated Energy District will be described and evaluated.

## 3.4.2 Electric Chillers

### Technology Description

Electric centrifugal chillers use the compression cooling cycle, which can be summarized as follows:

- Refrigerant at a low pressure and at a dry saturated condition is compressed to a higher pressure.
- Due to the increased pressure, the refrigerant vapor is condensed and releases heat to the surroundings (condenser water) at a constant condensing temperature (85-105 F).
- The refrigerant condensate is expanded through a valve to a lower pressure.
- At the lower pressure the wet refrigerant vapor picks up heat from the surroundings (evaporator water) at a low temperature (34-50 F), thereby evaporating and returning to dry saturated conditions at constant temperature.

A variety of refrigerants are used in electric centrifugal chillers depending on manufacture, design type and size.

### Efficiency

New state-of-the-art electric centrifugal chillers operated at a good load factor typically require less than 0.58 kilowatt-hours (kWh) per ton-hour of cooling to drive the compressor, and an additional 0.13 kWh to run the auxiliaries (cooling tower, condenser pump and chiller pump) depending on the specific design, loading and operating profile. In a district cooling system, chillers can be loaded to achieve these high annual efficiencies. In addition, the district cooling system in the study area is projected to require an additional 0.05 kWh per ton-hour for distribution pumping. A reasonable total kWh/ton-hour assumption is 0.76, corresponding to an overall COP of about 4.6.

If cold water is available for condenser cooling instead of a cooling tower, the efficiency of the compressor increases and less power is used in the condenser, bringing total power requirements down to 0.52 kW/ton.

### Costs

The installed capital cost of electric centrifugal chiller plant capacity, including ancillary equipment, varies depending on the particular plant equipment and configuration. The total costs for constructing two electric centrifugal chiller plants to serve the Energy District (one in South Lake Union and one in Denny Triangle) were estimated, assuming installation in four phases. The total cost (2003 $) was $1,158/ton of output capacity.

Operating costs are primarily related to the cost of electricity used to drive the chillers. At $0.055 per kWh, the electricity cost of chilled water would be $0.042 per ton-hour. In addition, purchase of water and water treatment chemicals is required to make up for losses during cooling tower operation. Refrigerant must also be purchased to make up for losses during operation and maintenance, with the extent of loss depending on equipment age and operation and maintenance practices. For new chillers, the refrigerant loss rate can be expected to be less than 0.5% per year.

Maintenance costs for electric centrifugal units vary depending on plant configuration and the timeframe of the analysis. An economic analysis comparing alternatives which will be in service for perhaps 20 years or more must in some way account for costs over the lifetime of the facility. While it is reasonable to expect that many costs may increase at roughly the rate of inflation, chiller plant maintenance costs present a difficult problem because these costs tend to increase over time and involve periodic, high-cost preventive maintenance as well as unanticipated repairs in addition to the normal annual preventive maintenance. The annualized costs of maintaining a chiller plant over its lifetime must take into account the full costs of maintenance and repair, which include far more than annual chiller start-up and shut-down maintenance. For the comparative analysis of cooling options presented below, we have assumed an annualized maintenance cost for large capacity electric chillers of $15 per ton per year.[51]

With 1,070 average cooling Equivalent Full Load Hours (EFLH)[52], the total cost of chilled water production from an electric centrifugal chiller plant would be $0.142 per ton-hour assuming electricity costs of $0.055 per kWh. If power costs $0.07 per kWh, the cost of chilled water production increases to $0.153 per ton-hour.

#### Siting and Infrastructure Issues

Electric centrifugal chiller plants require a significant electric service, thus impacting SCL distribution infrastructure plans. There would be no exhaust gas stack, which would most likely make it more acceptable from a neighborhood impact standpoint. However, cooling towers would be required unless cool lake water or groundwater is available for condenser cooling.

#### Reliability

Centrifugal chillers are well-proven, extremely reliable technologies. An Energy District electric chiller plant would be designed to include multiple units, including a redundant chiller so that the peak requirement can be met even if the largest unit is out of service.

#### Environmental Impacts

Electric chillers would not have any direct air emissions impacts, although they would have indirect air emissions and global warming impacts to the extent that the electricity used to meet the chiller requirements was generated with fossil-fuel-based power plants. In addition, there would be some impact on ozone depletion and global warming, depending on the particular refrigerant used, due to small losses of refrigerant during normal operation and maintenance. We anticipate that the large capacity electric centrifugal units used in an Energy District would use R-134a, which has zero Ozone Depletion Potential (ODP) and a Global Warming Potential (GWP) of 1,200 compared to carbon dioxide.[53]

### 3.4.3 Absorption Chillers

#### Technology Description

The absorption cycle uses heat to generate cooling, using two media: a refrigerant and an absorbent. Water/lithium bromide and ammonia/water are the most common refrigerant/absorbent media pairs, but other pairs can be used.

The absorption cycle can be summarized as follows:

- Generator - Steam or hot water is used to boil a solution of refrigerant/absorbent (water/lithium bromide or ammonia/water). Refrigerant vapor is released and the absorbent solution is concentrated.
- Condenser - The refrigerant vapor released in the concentrator is drawn into the condenser. Cooling water cools and condenses the refrigerant.
- Evaporator - Liquid refrigerant flows through an orifice into the evaporator. Due to the lower pressure in the evaporator, flashing takes place. The flashing cools the remaining liquid refrigerant down to the saturation temperature of the refrigerant at the pressure present within the evaporator (approximately 39 F for a water/lithium bromide chiller). Heat is

[51] Based on data from "CFCs and Electric Chillers – Selection of Large-Capacity Water Chillers in the 1990s (Revision 1)," Electric Power Research Institute, TR-100537, Research Project 2891-78, May 1993.
[52] EFLH is the ratio of annual energy to peak demand.
[53] Assuming 100 year integration time frame, from Intergovernmental Panel on Climate Change (IPCC), per "Global Warming Implications of Replacing CFCs," by Fischer, et al, ASHRAE Journal, April 1992.

transferred from the chilled water to the refrigerant, thereby cooling the chilled water and vaporizing the refrigerant.
- Absorber - Refrigerant vapor from the evaporator is drawn to the absorber section by the low pressure resulting from absorption of the refrigerant into the absorbent. Cooling water removes the heat released when the refrigerant vapor returns to the liquid state in the absorption process. The diluted solution is circulated back to the generator.
- Heat exchanger - The heat exchanger transfers heat from the relatively warm concentrated solution being returned from the generator to the absorber and the dilute solution being transferred back to the generator. Transferring heat between the solutions reduces the amount of heat that has to be added in the generator and reduces the amount of heat that has to be rejected from the absorber.

In two-stage absorption cycles, heat derived from refrigerant vapor boiled from solution in the first stage generator is used to boil out additional refrigerant in a second generator, thereby increasing the efficiency of the process. Double-effect absorption requires a higher temperature thermal source than single effect absorption, but uses less thermal energy per ton-hour of cooling produced.

### Efficiency

One-stage and two-stage absorption chillers require:
- 18,000 Btu and 12,000 Btu of heat per ton-hour, respectively, to drive the compressor;
- 0.25 kWh of electricity per ton-hour to run the auxiliaries; and
- 0.052 kWh per ton-hour additional power required for district cooling distribution.

### Costs

The installed capital cost of absorption chiller plant capacity, including ancillary equipment, varies depending on the particular plant equipment and configuration. However, representative values for one-stage and two-stage absorption chiller systems are about $1,310 and $1,530 per ton of refrigeration capacity, respectively, including construction of plant space.[54]

Operating costs are directly related to the cost of generating heat used to drive the absorption cycle. It is not worthwhile considering absorption chillers unless heat from CHP or some other source of waste heat is available, as is made clear in the comparative analysis of chiller options below. In addition, purchase of water and water treatment chemicals is required to make up for losses during cooling tower operation.

Maintenance costs depend on how the unit is loaded and operated. Generally, maintenance costs for absorption chillers are slightly higher than for electric centrifugal units. We have assumed an annualized maintenance cost for large capacity absorption chillers of $17 and $19 per ton per year for one-stage and two-stage chillers, respectively. [55]

With 1,070 average cooling Equivalent Full Load Hours (EFLH)[56], the total cost of chilled water production from absorption chiller plants would range from about $0.11 per ton-hour to over $0.22 per ton-hour depending on the cost of heat used to drive the chiller, as discussed in the comparative analysis of chiller options below.

### Siting and Infrastructure Issues

Absorption chiller plants require a smaller electric service than electric centrifugal plants. Any exhaust gas stack would be associated with a CHP plant providing heat for the absorbers. However, cooling towers would be required unless cool lake water or groundwater is available for condenser cooling.

[54] Based on individual plant designs and cost estimates prepared by FVB Energy Inc.
[55] Based on data from “CFCs and Electric Chillers – Selection of Large-Capacity Water Chillers in the 1990s (Revision 1),” Electric Power Research Institute, TR-100537, Research Project 2891-78, May 1993.
[56] EFLH is the ratio of annual energy to peak demand.

#### Reliability

Absorption chillers are well-proven, extremely reliable technologies. An Energy District chiller plant would be designed to include multiple units, including a redundant chiller so that the peak requirement can be met even if the largest unit is out of service.

#### Environmental Impacts

Absorption chillers have no direct impact on ozone depletion or global warming. However, there are indirect impacts on global warming to the extent that fossil fuels are used to produce the heat that drive the absorption chillers, and/or to generate the electricity that is used to run the chiller auxiliaries.

### 3.4.4 Thermal Energy Storage

#### Technology Description

Thermal storage can be an important strategy for optimizing the integration of CHP with district heating or district cooling. Hot water storage is used in European district heating systems, but in the US thermal storage is generally limited to cooling systems based on energy price factors. Thermal storage systems are designed to be recharged on a cyclical basis (usually daily) and fulfill one or more of the following purposes:

- **Increase system capacity**. Demand for heating, cooling, or power is seldom constant over time, and the excess generation available during low demand periods can be used to charge the energy storage system in order to increase capacity during high demand periods. For example, cooling storage allows a district cooling system to install less chiller capacity and to use the installed capacity at a higher load factor.

- **Enable dispatch of CHP plants**. CHP plants are generally operated to meet the demands of the connected thermal load, which often results in excess electric generation during periods of low electric use. By incorporating thermal energy storage, the plant need not be operated continuously and can be dispatched within some limits.

- **Shift energy purchases to low demand/low cost periods**. Cooling storage allows a district cooling system to shift electricity demand from costly daytime on-peak periods to lower-cost nighttime periods.

- **Increase system reliability**. Thermal storage increases the flexibility and reliability of district cooling by ensuring that there is a readily available source of cooling which can be supplied to users with only a minimal requirement for pumping energy.

The daily variation between maximum and minimum loads for cooling is much greater than for heating. Building cooling systems are usually operated more on/off than heating systems. During nighttime when the ventilation air to an office can be shut off, the outdoor temperature is lower and there is less internal heat gain, so the cooling system can be shut off. In contrast, a heating system still must be operated at night. With the on/off operation of building cooling systems, a morning peak can occur when the buildings are cooled down before office hours. However, the cooling load profile for a specific system depends on weather conditions, types of buildings served, operation of the building cooling systems and the district cooling system rate structure.

Cool storage can be provided through storage of chilled water, ice or ice slurry. Chilled water is the most common form of cool storage, using concrete or steel tanks to store chilled water generated with any type of conventional chiller. Chilled water is typically stored between 40°F to 44°F in one large or several tanks located above ground or below ground. However, the system thermal efficiency is optimized with one large tank. Approximately 12 to 15 cubic feet of storage volume is required per ton-hour of chilled water storage.

Where space is available for chilled water storage, the economies of scale for this technology can provide significant economic advantages over ice storage. Under normal conditions a chilled water storage tank is always filled with water. During discharge, cold water is pumped from the bottom of the tank and warm return water is supplied in the top. Due to the different densities for water at different temperatures a stable stratification can be obtained.

Ice generation and storage is a well-developed technology, and allows storage in a more compact space -- often a key issue in urban environments. The volume required for ice storage is 15 to 25 percent of the space required by chilled water storage for the same energy storage capacity. Ice storage also provides an opportunity to reduce the temperature of cooling distribution and therefore reduce distribution system and building system capital costs. These advantages must be weighed against higher capital and operating costs for ice-making equipment compared to water chillers. The average capital costs of ice storage are about twice those of chilled water storage, and the energy requirements are higher by about one third.[57]

Given the relatively modest cooling requirements in Seattle, and the relatively weak price signals from SCL rate structures, we recommend only chilled water storage for consideration in an Energy District serving the study area.

### Efficiency

Efficiencies for chilled water storage are similar to those of straight chiller plants.

### Costs

The capital cost of chilled water storage per ton of peak cooling capacity depends on many case-specific factors, including the shape of the peak day load profile. Costs may range from $450 to $850 per ton of peak capacity.

Operating costs are slightly higher than for a straight chiller plant, corresponding to the efficiency difference noted above.

Additional maintenance will also be required for the chilled water storage tank, with an annualized cost estimated to be less than 1% of the capital cost.

### Siting and Infrastructure Issues

A chilled water storage tank requires additional site area. For example, 5,000 tons of peak cooling capacity (about 30% of the projected year 2010 district cooling demand) could be provided with a storage tank with a diameter of 100 feet and a height of 48 feet. It is important that the storage facility be designed to address neighborhood concerns regarding esthetics. Many storage facilities are well accepted, even in high-visibility areas. For example, the storage facility at District Energy St. Paul is on the Mississippi River and is right next door to a the Science Museum of Minnesota. In other cases, storage facilities are integrated with other functions. In another example, a very fancy restaurant is sited on top of the hot water storage facility serving the Reykjavik, Iceland geothermal district heating system.

### Reliability

Chilled water storage adds to system reliability because it represents a flexible, relative low tech source of chilled water. Using the storage requires only a pump (generally installed with redundancy) in contrast to chiller equipment with many more components.

[57] ASHRAE Transactions 1995, V. 101, Pt. 2, "ASHRAE RP-766: Study of Operational Experience with Thermal Energy Storage Systems," as noted in "Energy and Economic Implications of Combining District Cooling and Thermal Storage," Andrepont, Kooy and Winters, 10th Annual Cooling Conference, International District Energy Association, October 1995.

### Environmental Impacts

There are no special environmental impacts associated with chilled water storage in contrast to a straight chiller plant.

## 3.4.5 Deep Water Cooling

### Technology Description

Deep water cooling is a technology that uses cold water drawn from deep sources such as lakes, seas, or underground aquifers to provide cooling needs to buildings connected to an Energy District. There are a number of district cooling systems utilizing deep water cooling throughout the world, particularly in Sweden. There are at least 7 deep water cooling systems in Sweden. Examples include:

- Stockholm, where the Baltic Sea is used in combination with heat pumps to supply over 70,000 tons of cooling for downtown Stockholm.
- Södertälje, with a 17,000 ton district cooling system at Lake Mälaren supplying a pharmaceutical plant and other commercial customers.
- Sollentuna, a 1,100 ton district cooling system that includes aquifer storage. During the winter, cold sea water from a bay of the Baltic Sea is stored in the aquifer to reduce the warmer temperature of the sea water during summer.

Figure 35 shows polyethylene pipe being installed in Lake Mälaren.

***Figure 35. Pipe Installation in Lake Mälaren, Sweden***


Domestically, a deep lake water cooling system has been implemented recently to provide cooling for the Cornell University campus. In Toronto, the largest lake water cooling system in the world is being developed using Lake Ontario as its water source. Also, Earthsource Cooling Operations (ECO) uses seawater from the Burrard Inlet to provide condenser cooling for Canada Place in Vancouver, British Columbia. ECO hopes to expand use of the seawater to provide direct cooling to an expanded customer base.

The Toronto deep water cooling system will use a fresh water source, and is designed to use part or all of the water drawn from the water source as potable water after the cooling energy has been extracted from it. Generally, however, deep water cooling systems return all of the water back to the source after cooling energy is extracted. Water is returned to the water source at shallow depths where the water is warmer to lessen or eliminate the impact of warm water rejection on the local ecosystem.

Typically, a separate, closed chilled water distribution loop, which is isolated from the open deep water source loop, carries chilled water to buildings for cooling use. Often, the temperature of the chilled water supply in this closed loop is reduced further with electric chillers at times of peak cooling use.

Deep water cooling systems are very capital intensive projects. A typical deep water cooling system includes the following components:

- An intake pipeline running from the depths of the water source to the shore.
- A heat exchange facility at the shore that isolates the open lake or sea water loop from the closed distribution loop that carried chilled water to customer buildings. This facility consists of heat exchangers, pumps, valves and controls, piping, and a structure to house it all.
- An outfall pipeline that returns water to the water source at a shallow depth after it has passed though the heat exchangers on shore.
- A closed loop transmission pipeline (supply & return piping) that carries district cooling water from the heat exchange facility to the location of cooling loads and then back to the heat exchange facility.

In addition to deep water cooling systems that use the water from the deep source to provide cooling "directly" to buildings, there are also some deep water cooling systems that use deep water as condenser water for chillers at a central cooling plant. The temperature of the condenser water from the deep water source is lower than that of condenser water cooled with a traditional cooling tower solution, which results in increased chiller efficiency and lower energy consumption. This type of system may be employed when deep water temperatures are not low enough for direct cooling use. Also, in systems with a combination of direct deep water cooling and electric chillers, deep source water can be used for both direct cooling and as condenser water for the chillers. In addition to energy savings, using a deep water source for condenser water heat rejection eliminates the need for cooling towers and the space and make-up water requirements that accompany them.

### Potential Water Sources

One of the most important criteria that drive feasibility of a deep water cooling system is the deep water temperatures available. There are three different water sources that could potentially be used by an Energy District in the study area. These sources are: Puget Sound (Elliott Bay), Lake Union, and Lake Washington. The temperatures at depth for these water sources are outlined in Table 21 below.

***Table 21. Water Source Temperatures***

| Water Source | Depth (feet) | Summer (F) | Winter (F) |
|---|---|---|---|
| Puget Sound | ~500 | ~52.5 | ~46.5 |
| Elliott Bay | ~180 | ~53.5 | ~47.5 |
| Lake Union | ~35 | ~69.0 | ~45.5 |
| Lake Washington | ~200 | ~46.0 | ~44.5 |

For comparison, the deep water temperature provided by Lake Cayuga for the Cornell system in the summer is 39°F and the temperature anticipated from Lake Ontario for the Toronto system is 40.5°F.

Lake Union cannot be considered as a water source since summer water temperatures are much too high in the summer. With its shallow depth, water temperatures in Lake Union track closely with ambient air temperature and there is little difference between surface temperature and temperature at depth.

*Puget Sound / Elliott Bay*

The summertime water temperatures from Elliott Bay are much cooler than Lake Union's but this water source is still too warm to provide direct cooling effectively. After considering heat exchanger "approach temperatures" (i.e., the difference in temperature between the water flowing across each side of the heat exchanger), there is little difference between the summer temperature of water from Elliott Bay and return temperatures that can be expected from district cooling customers. However, it may be possible to use Elliott Bay as a heat sink for condenser water for chillers at a central plant or plants.

Water temperatures in both Elliott Bay and Puget Sound were investigated to determine their viability as deep water cooling sources[58]. Elliott Bay temperature data was obtained for monitoring station ELB008, located off the coast of Duwamish Head. For the deepest measurement points available from a nine year data set, the average depth and temperature for summertime measurements were approximately 200 feet and 53.5 degrees, respectively. Although drawing water from Elliott Bay would be more desirable than Puget Sound itself, since the deep water pipeline would be shorter and to a shallower depth, measurement data for Puget Sound was obtained in the hope that colder water would be available.

Sets of temperature data at depth were obtained for several monitoring stations in Puget Sound. The closest monitoring station to the study area is LSEP01, located about 3.5 miles off of the shore of downtown Seattle at Broad St. The data from this monitoring station, at depth of approximately 500 feet, is listed for Puget Sound in Table 21. Two other monitoring stations, KSBP01 and LSNT01, take readings at even deeper parts of the Sound (approximately 650 foot depth), but are located several miles to the north and south of LSEP01 and are too far from the study area. However, as Figure 36 (a chart of the three monitoring stations at depth from 1998 to 2002) illustrates, there is little difference between temperatures at these stations and the shallower LSEP01 station.

Although the summertime water temperatures in Elliott Bay and Puget Sound are much cooler than in Lake Union, these water sources are still too warm to provide direct cooling effectively. After considering heat exchanger "approach temperatures" (i.e., the difference in temperature between the water flowing across each side of the heat exchanger), there is little difference between the summer temperature of water from Elliott Bay or Puget Sound and return temperatures that can be expected from district cooling customers at times of peak cooling. However, it may be possible to use Elliott Bay as a heat sink for condenser water for chillers at a central plant or plants.

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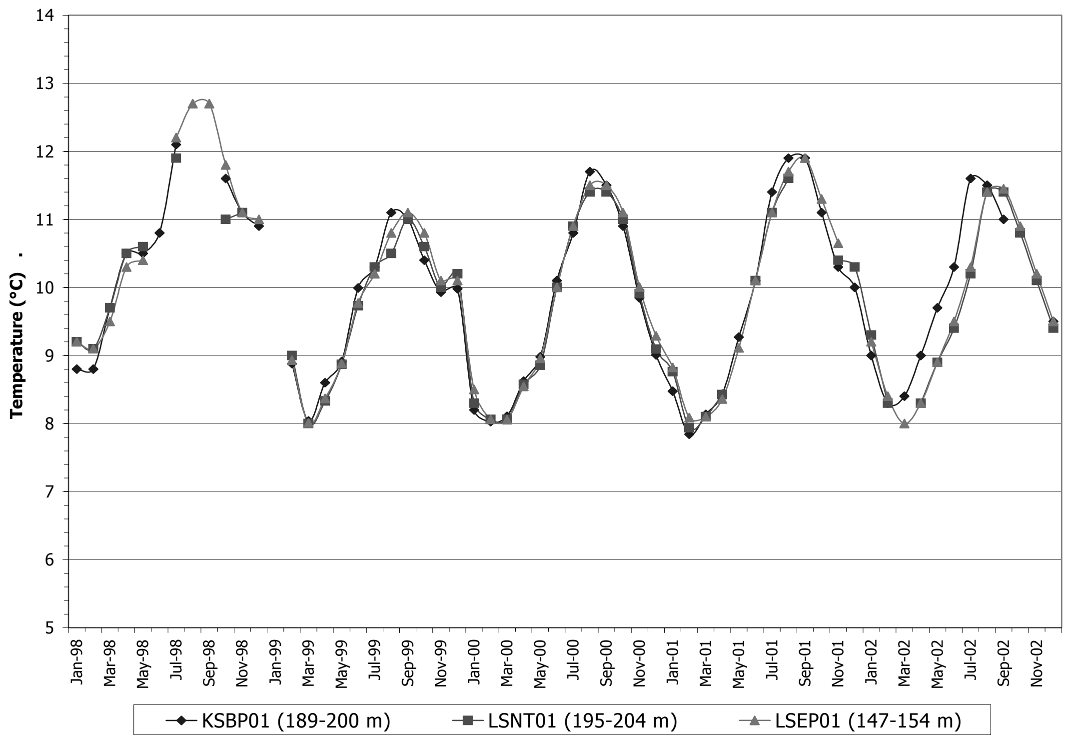
[58] Temperature data for Elliott Bay was obtained from the Washington State Department of Ecology and temperature data for Puget Sound was obtained from the King County Department of Natural Resources & Parks.

*Figure 36. Puget Sound Water Temperature at Depth*




*Lake Washington*

Lake Washington offers the best temperatures for a deep water cooling application but, unfortunately, this body of water is also furthest from the study area. Although summertime Lake Washington temperatures are the most suitable of the three water sources for deep water cooling, they are still high enough that direct cooling from this water source must be supplemented with a significant amount of electrical chilling at times of peak cooling demand. Fortunately, however, there are very few annual hours when the system is operating near its peak cooling demand, so for the majority of system operation significant “tempering” with electrical chilling is not required.

Water temperature in Lake Washington is monitored by the King County DNR. Figure 37 shows the locations of monitoring sites in Lake Washington. The Madison Park monitoring site, Site 0852, is located near the mouth of Union Bay and very close to where a deep water cooling intake would likely be located. Figure 38 shows annual temperatures (in °C) for Site 0852 at depth. Conversion from C to F is provided in Table 22. The average water temperature for the summer months at this site is 46.0°F. Figure 39 shows Lake Washington temperatures (in °C) at varying depths for each month of the year.

*Table 22. Conversion of °C to °F*

| C | F |
|---|---|
| 6.0 | 42.8 |
| 8.0 | 46.4 |
| 10.0 | 50.0 |
| 12.0 | 53.6 |
| 14.0 | 57.2 |
| 16.0 | 60.8 |
| 18.0 | 64.4 |
| 20.0 | 68.0 |
| 22.0 | 71.6 |
| 24.0 | 75.2 |

*Figure 37.  Lake Washington Monitoring Sites*

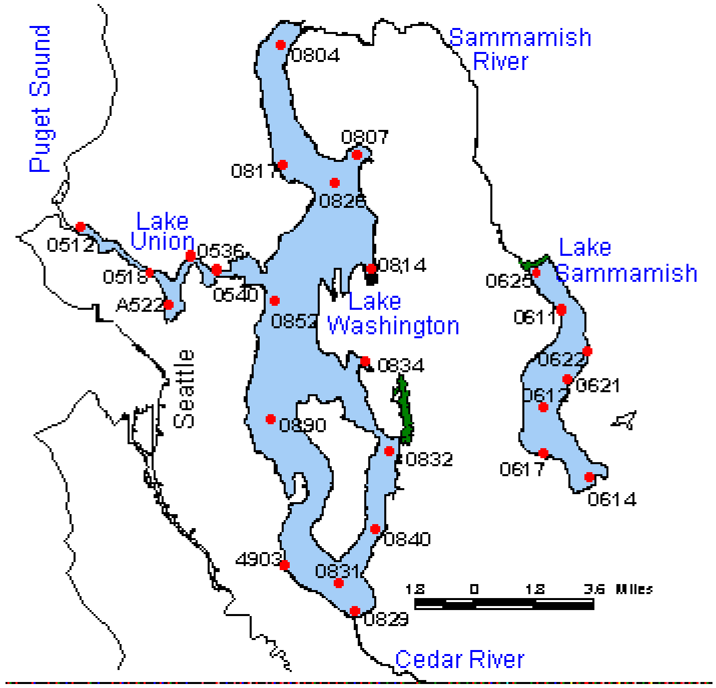



*Figure 38.  Lake Washington Temperatures at 60 Meters, 1998-2002*

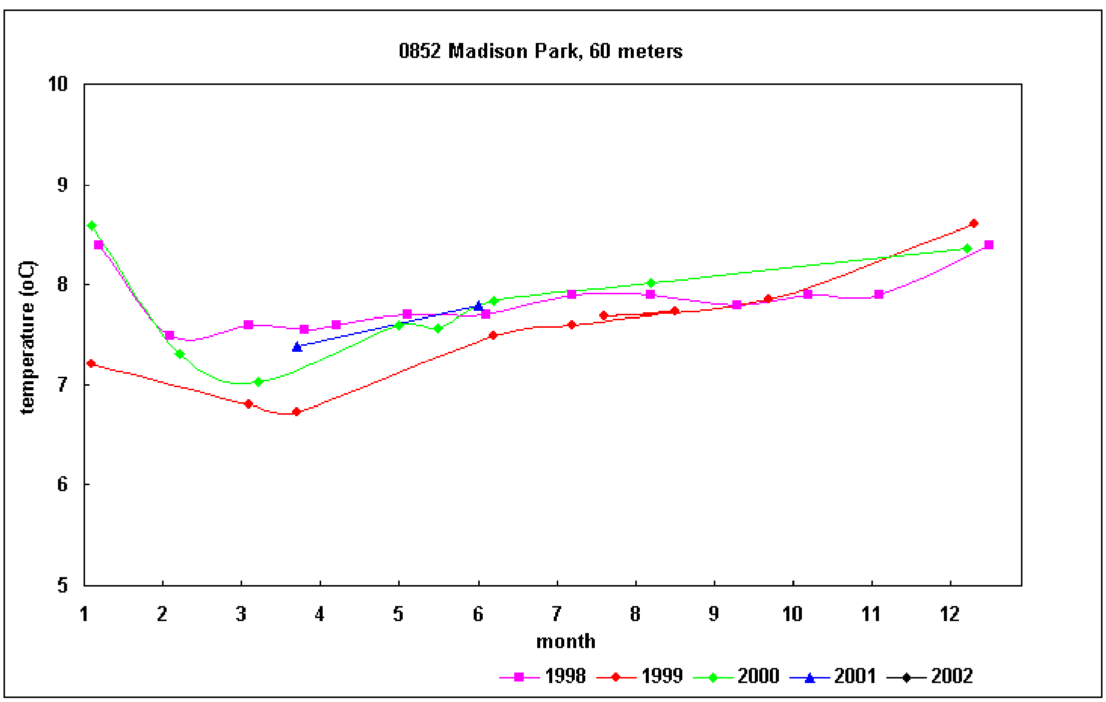
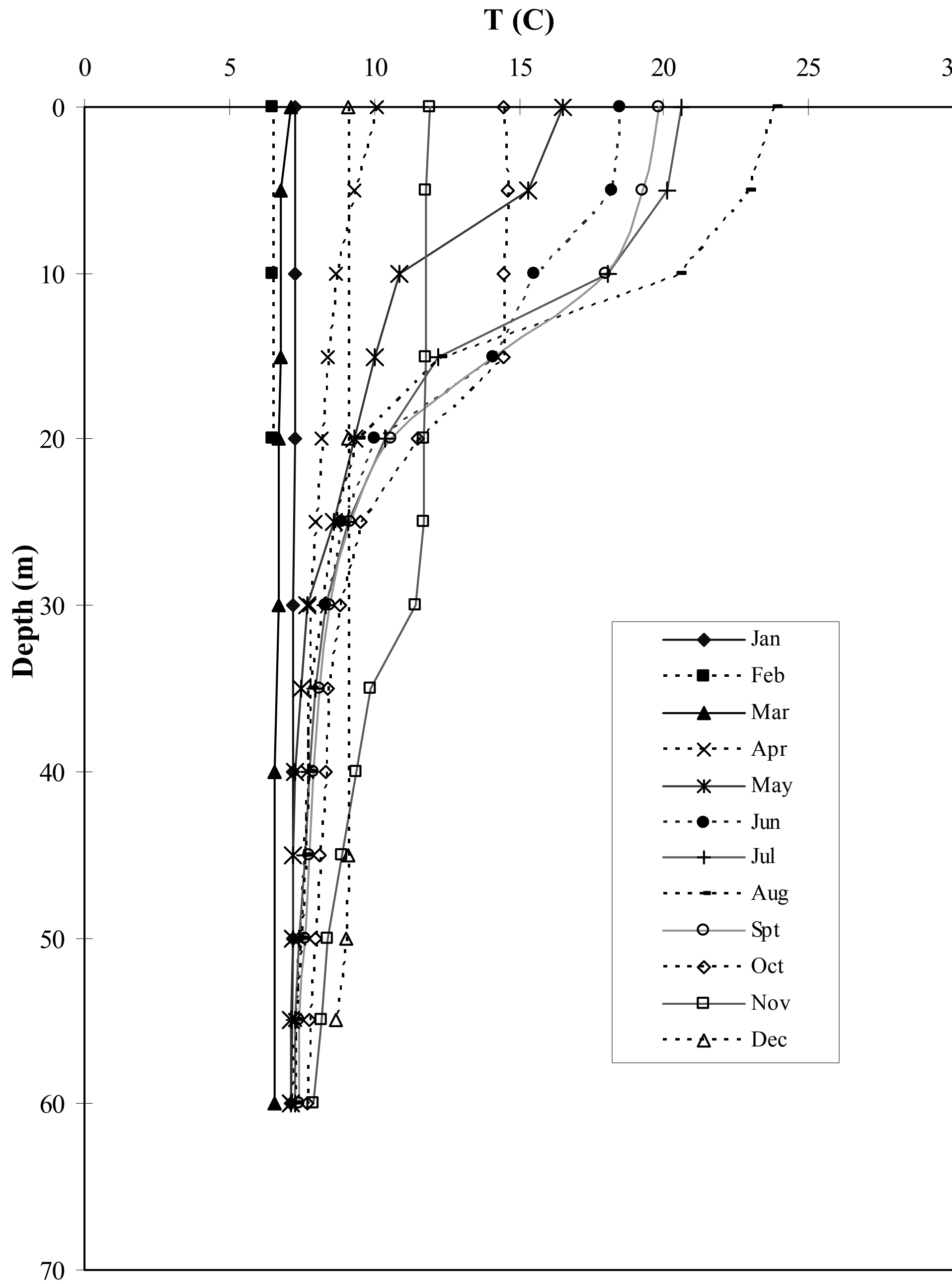


*Figure 39.  Monthly Lake Washington Temperatures at Varying Depths*



### Efficiency

Deep water cooling is extremely efficient. For systems without peaking chillers, the only energy costs are those required for pumping the water-source and transmission pipelines. Pumping energy requirements are projected to range from 0.055 kWh/ton-hour in Phase 2 to 0.07 kWh/ton-hour in Phase 4. Systems that use some mechanical compression for peaking can realize nearly as much annual energy savings, since peaking chillers typically run for only a handful of hours out of the year. Also, the water source can be used for condenser cooling, thereby increasing the energy efficiency of the peaking chillers. As an example, since startup, the Cornell deep lake cooling system has been operating with an annual average energy consumption of 0.10 kW/ton[59].

### Costs

Deep water cooling projects are always capital intensive, but the capital cost required for these projects can vary significantly from one project to another. Some of the most important factors that can affect the capital cost required are:

- Distance from the coast of the water source to the location of the cooling load
- Length and depth of the intake pipeline required
- Amount, if any, of chiller capacity that must be installed to supplement deep water temperatures

One benefit of deep water cooling with respect to capital cost is that system life for a deep water cooling system may be expected to be 2-3 times as long as for mechanical chillers.

Operating costs will be incurred for maintenance of the intake and outfall pipelines, the transmission pipeline, pumps and heat exchangers that separate the two loops. The intake and outfall pipelines may require regular pigging to clean out growth of algae or crustaceans within the pipelines.

For the SLU/Denny Energy District, the capital costs of a deep water cooling system will be high due to the relatively distant location of the water sources. A pipeline from the Elliott Bay coast to the two nodes of load concentration in the SLU and Denny Triangle areas will be approximately 7000' long. A pipeline from the Lake Washington coast along the I-5 and SR-520 highway routes to the two nodes of load concentration in the SLU and Denny Triangle areas will be approximately 4 miles long and consist of a pair of large (54" to 63") pipes if water must be returned to Lake Washington.

### Siting and Infrastructure Issues

There are both positive and negative aspects to siting and infrastructure issues surrounding deep water cooling.

On the positive side, a deep water cooling system significantly reduces the footprint required for a cooling plant site compared to a straight centrifugal or absorption chiller plant. In addition to plant cost reduction, this may allow for more creative siting of a cooling plant. Another benefit of deep water cooling is that it eliminates the need for cooling towers at the plant. The elimination of the need for rooftop space for cooling towers and the absence of a cooling tower plume can make plant siting much more flexible and affordable.

On the negative side, the development of deep water cooling system will face significant regulatory and permitting hurdles, entailing an enormous amount of study relating to the environmental impact of the system. Regulatory issues associated with deep water cooling are addressed in Section 7. However, as discussed in Section 7, there are also some potentially significant positive impacts relative to the water quality of Lake Union

[59] ASHRAE Journal, "Lake Source Cooling", T. Peer and W. S. Joyce, April 2002

### Reliability

Deep water cooling systems have the potential to be very reliable sources of cooling. Although no statistics were obtainable for this study, anecdotal evidence suggests that the existing systems have operated very reliably. Because a single pipeline would carry cooling from the deep water source for the Seattle system, this lack of redundancy may prove a serious concern to some potential customers, particularly customers like research facilities for whom reliability is critical. Reliability concerns are alleviated by the fact that a deep water cooling system serving the study area would have to be supplemented with electric chillers at the central plants in order to bring the chilled water temperature down sufficiently at times of peak cooling demand. This allows a portion of the peak system load to be served even if a problem arises with the deep water cooling transmission pipeline, intake pipeline, or outflow pipeline.

### Environmental Impacts

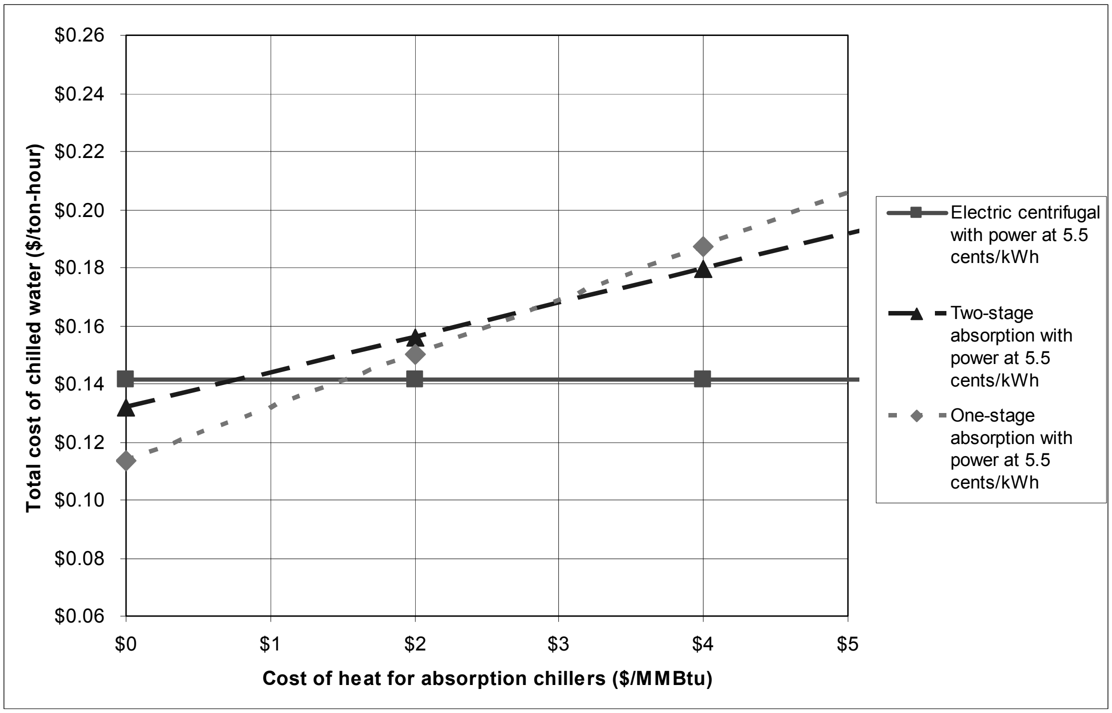
Deep water cooling is a naturally renewable, sustainable energy system. The enormous reduction in electric power requirements for cooling yields commensurate reductions in greenhouse and ozone-depleting gases. Also, direct deep water cooling does not require any refrigerant-like chillers, so there is not chance of leakage of ozone-depleting refrigerant to the environment. In addition, the specific situation in Seattle offers the potential opportunity to benefit water quality and salmon habitat in the process of providing renewable energy, as discussed further in Section 4. On the other hand, there are significant environmental impact questions which must be answered relative to impacts on marine ecosystems, as discussed in Section 7.

## 3.4.6 Cooling Technology Economic Comparison

Figure 40 summarizes the economic comparison of Energy District chiller options. (Deep water cooling must be addressed in Section 4 because it requires a complex analysis of a mix of deep water sources and chillers.) This comparison takes into account all capital and operating costs, with capital amortized at 5% over 20 years.

One-stage absorption chillers have lower total costs than electric chillers when the cost of heat to drive the absorbers is less than about $1.40/MMBtu, with electricity costing 5.5 cents/kWh. Two-stage absorption chillers have lower total costs than electric chillers when the cost of heat to drive the absorbers is less than about $0.75/MMBtu, with electricity costing 5.5 cents/kWh. One-stage absorption chillers have lower total costs compared to two-stage at heat costs of less than about $3.00/MMBtu, with a 5% cost of capital.

*Figure 40. Economic Comparison of Energy District Cooling Technology Options With 5% Cost of Capital*




## 3.5 Combined Heat and Power (CHP) Technologies

### 3.5.1 Overview of CHP Technologies

**Power Generation Technologies**

A variety of technologies can be used to generate electricity, including hydroelectric systems as well as steam turbines, gas turbines, reciprocating engines and fuel cells. Steam turbine power plants are the most common type of plant in the world today. Any type of fuel can be burned in a boiler to make steam, which drives a steam turbine which in turn spins a generator. The capital cost of steam turbine plants are higher than for other alternatives, but the ability to burn lower-cost fuels (coal, wood, municipal solid waste, etc.) can make steam turbine plants cost-effective, particularly for large facilities. Steam turbines are not analyzed in this study because it is not likely that solid fuel combustion in the study area would be considered acceptable. Fuel cells are too expensive to be considered for SLU/DT in the near term.

Gas turbines and reciprocating engines are evaluated below as CHP options for the South Lake Union/Denny Triangle area.

In electric-only power plants, most of the energy input to the plant ends up as waste heat. In simple cycle gas turbines all of the energy in the exhaust gases is wasted. Power plants using a steam turbine (either steam turbine or gas turbine combined cycle plants) condense the steam exiting from the turbine. This creates a vacuum on the exit end of the steam cycle, thus increasing the torque and power output of the steam turbine. However, most of the energy then ends up in the condenser cooling system (using cooling towers which put the heat into the air, or dissipating the heat in a body of water such as a river). Reciprocating engines lose heat through the exhaust gas, engine cooling jacket, lubricating oil and other systems.

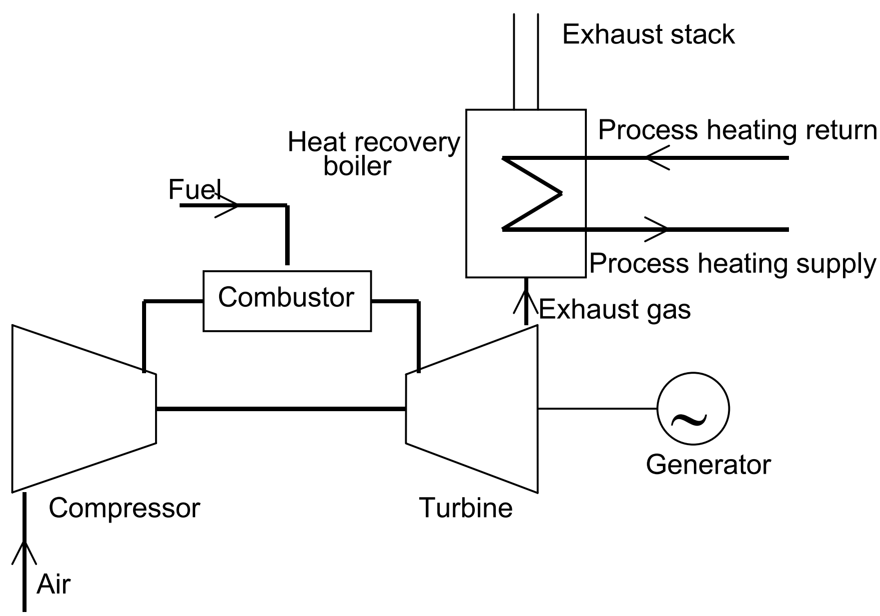
With each of these power generation technologies adapted for CHP, much or all of the waste heat can be recovered for heating or for conversion to cooling using absorption chillers as discussed under “Cooling Technologies.”

## 3.5.2 Gas Turbine CHP

### Technology Description

Gas turbines, often called combustion turbines, are basically like jet engines (in fact, many commercial systems are so-called “aero-derivatives,” i.e., they are directly evolved from aircraft engines). Fuel, usually natural gas (fuel oil could be used) is combusted, and the hot gases drive a turbine which in turn spins a generator. (See Figure 41.) The exhaust gas coming out of the turbine is very hot (850-1000 F) and represents a significant portion of the input energy. In a gas turbine plant, all of the heat in the exhaust gases is available. The hot exhaust gases from a gas turbine (about 1000 F) can be directed to a heat recovery boiler to generate steam or hot water for thermal energy end-uses.

***Figure 41. Gas Turbine CHP Process***




A combined cycle system uses the steam generated by the heat recovery boiler to turn a steam turbine-generator. A gas turbine plant which does not use the exhaust gas to make steam is called a “simple cycle” gas turbine. Gas turbine combined cycle plants use the hot gases exiting from the gas turbine to make steam, which drives a separate steam turbine which in turn spins a generator. In a gas turbine combined cycle plant, the heat recoverable for Energy District thermal uses is in the steam exhausted from the steam turbine that would otherwise be dissipated in the cooling towers. However, given the size of the likely CHP used to serve a SLU/DT Energy District, we believe a simple cycle gas turbine with a heat recovery steam generator would be more cost-effective.

### Efficiency

The power generation efficiency of a gas turbine plant depends on the specific technology, plant design and climate conditions. Gas turbine power output drops as the ambient air temperature increases. Quoted efficiencies are typically measured under specific conditions: 60 F outdoor air, 60 percent relative humidity and 1 atmosphere barometric pressure. Efficiency is generally higher in larger turbines. However, electric efficiencies in the 20-40 MWe interval are relatively high (most are in the 35-40 percent range) because many aero-derivative gas turbines, which generally have higher efficiencies, are available in that size range. Electric efficiencies of smaller turbines are lower, generally under 30% for turbines in the 3-7 MW range. Combined cycle power-only plants are more efficient than simple cycle power-only plants, with power generation efficiencies for plants under 100 MegaWatts (MW) in the range of 45-55 percent, with efficiencies of 50-60 percent achievable in larger plants.

### Costs

Gas turbine capital costs are sensitive to unit size. Installed capital costs range from $1800/kWe for a 1 MWe gas turbine CHP system to less than $600/kWe for large systems (hundreds of MWe). For the size range likely to be economically appropriate for the study area (5-25 MWe units), the total installed cost of gas turbine CHP plant capacity would range from $860/kWe (25 MWe unit) to $1040/kWe (5 MWe unit).[60] [61] These estimates include dry low NOx emissions control, unfired heat recovery steam generator, fuel gas compression and water treatment for boiler feedwater. With allowances for supplemental firing, utility interconnection for parallel generation, construction of plant space and additional pollution control systems (Selective Catalytic Reduction and oxidation catalysts), the total installed costs range from $1,190/kWe (25 MWe unit) to $1,465/kWe (5 MWe unit)

Gas turbine operation and maintenance (O&M) costs include:

- monthly maintenance which can be accomplished without equipment shutdown;
- periodic maintenance (approximately every 4,000 hours of operation) including borescope inspection for blade erosion and checkout of fuel systems, sensors and controls, burner cleaning; and
- major overhaul at intervals of 30,000 to 40,000 hours.

For the size range likely to be economically appropriate for the study area (5-25 MWe units), the O&M cost, excluding labor, for gas turbine CHP plants would range from $0.005/kWhe (25 MWe unit) to $0.006/kWhe (5 MWe unit).[62]

The net cost of heat from CHP is highly dependent on the value of the power generated. Power can be used to offset in-house purchases of power to operate the facility or excess power can be sold in the wholesale market. The net heat cost presented in Figure 42 that takes into account the total capital, operating and maintenance costs of 5 MW simple cycle gas turbine CHP minus an assumed average electricity value. A conservatively low capacity factor of 0.68 was assumed, based on analysis of the potential loads in SLU/DT, and assuming installation of absorption chiller capacity capable of using the unfired heat generation capacity of the CHP units. As discussed in Section 3.2.2, the long-run marginal cost of new electricity resources can be estimated to be $50-60/MWH. However, sensitivity analyses were run at lower electricity value, down to $20/MWH, about the average SCL portfolio cost in 2002.[63]

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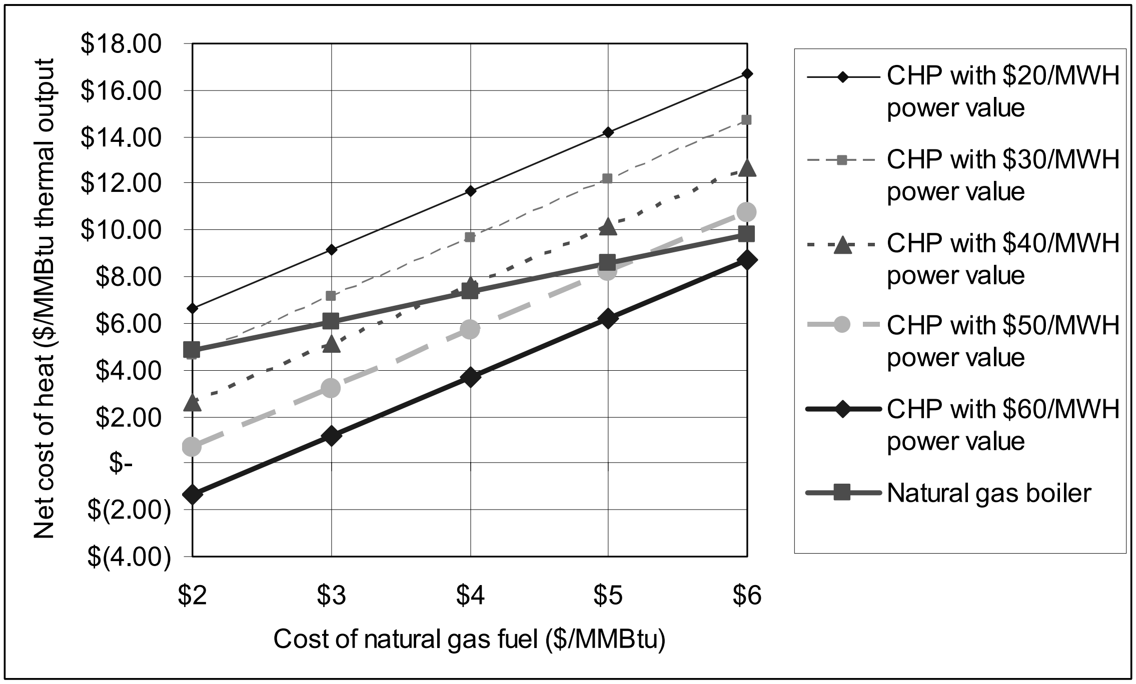
[60] "CHP Technology Characterizations," Energy Nexus Group, prepared for the U.S. Environmental Protection Agency, Feb. 2002.

[61] Gas Turbine World 2001-2002 Handbook, Gas Turbine World magazine, Volume 22.

[62] "CHP Technology Characterizations," Energy Nexus Group, prepared for the U.S. Environmental Protection Agency, Feb. 2002.

[63] "2002 Update to the 2000 Strategic Resource Assessment," Seattle City Light Strategic Planning Office, October 2002.

*Figure 42. Net Cost of 5 MW Gas Turbine CHP Heat at a Range of Power Values*




At the projected base case cost of natural gas for the Energy District ($4.50/MMBtu), CHP provides lower cost heat than natural gas boilers at electricity values above $45/MWH.

**Siting and Infrastructure Issues**

As discussed in Section 3.2, a key infrastructure requirement is adequate natural gas supply. As noted, there is adequate delivery capacity, but system pressures are such that a CHP would require its own gas compression equipment.

**Reliability**

Gas turbines are well-proven, highly reliability technologies, with availabilities in excess of 95%. [64] As discussed in Section 4, it is recommended to install multiple smaller turbine units to boost overall plant reliability.

**Environmental Impacts**

Gas turbines are the among the cleanest commercially implemented fossil-fuel fired power generation technologies. The primary pollutants from gas turbines are nitrogen oxides (NOx), carbon monoxide (CO), and volatile organic compounds (VOCs). Emissions of sulfur dioxide (SO2) and particulates are insignificant with turbines fired with natural gas.

NOx emissions have been the focus of research and development in gas turbine emissions control. Turbine manufacturers are moving to lean premixed combustion, sometimes called "dry-low" combustion, as a primary means of NOx control. With this approach, natural gas and compressed air are mixed so that there are no local zones of high temperatures where high levels of NOx would form. Manufacturers will guarantee performance at 25 parts per million (ppm) with dry-low combustion, or about 0.09 lbs of NOx per MMBtu of natural gas fuel. NOx levels as low as 9 ppm

[64] "CHP Technology Characterizations," Energy Nexus Group, prepared for the U.S. Environmental Protection Agency, Feb. 2002.

have been achieved with dry-low combustion, but manufacturers are still working to be able to guarantee consistent operation at these levels.

The primary post-combustion NOx control is selective catalytic reduction (SCR), in which ammonia is injected into the flue gas and reacts with NOx in the presence of a catalyst. When used in conjunction with dry-low combustion, NOx emission reductions of 80-90% can be achieved, the resulting emissions of 2-5 ppm. SCR systems are expensive and can particularly affect the economic viability of small CHP projects. For a 5 MW CHP system, adding SCR can increase the capital cost by $100-150/kWe.[65] Catalytic combustion for NOx control in gas turbines is also being introduced, providing emission levels of about 3 ppm. However, the long-term performance of these systems has not been demonstrated, with durability of the catalyst a key concern.

With SCR and oxidation catalysts, carbon monoxide (CO) emissions in gas turbines can be reduced to about 3 ppm from about 20 ppm.[66] Gas turbines emit essentially no sulfur dioxide and negligible particulates when fired with natural gas. Carbon dioxide emissions are 118 lbs of CO2 per MMBtu of fuel.

Gas-fired CHP raises issues relative to air emissions regulatory and policies relating to reduction in greenhouse gases, as discussed in Section 7.

### 3.5.3 Reciprocating Engines

#### Technology Description

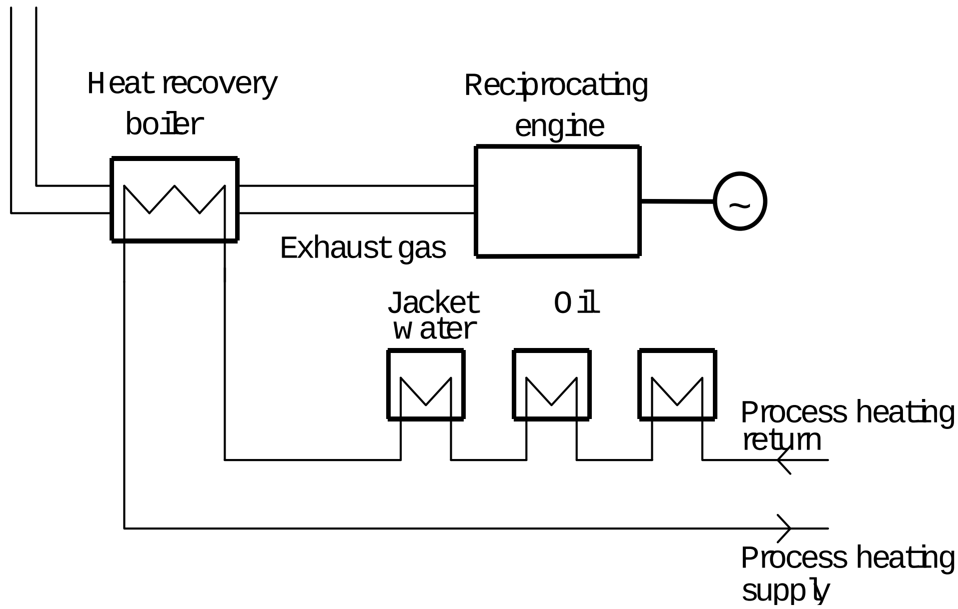
Reciprocating engine CHP is illustrated in Figure 43 and can be briefly described as follows:

- A generator attached to the engine shaft generates electricity.
- Heat is recovered when the hot exhaust gas is cooled in a heat recovery boiler.
- Heat can also be recovered from the engine cooling water and oil lubrication system.
- In addition, heat can be recovered from the turbocharger and intercooler.

The diesel engine is dominant over spark-ignited engines in sizes above 1-2 MWe. “Diesel” refers to the ignition process, not necessarily the fuel. Both the diesel engine and the spark-ignited engine can be found in a number of different applications and designs, including 4 and 2 stroke, with 1 to 20 cylinders. Turbochargers are common on both types to increase the efficiency and power output. Diesel engines are available in sizes up to 50 MWe. Spark-ignited engines are usually limited to below 2 MWe, although some manufacturers are developing larger (5-10 MWe) spark-ignited engines because it is increasingly difficult to meet nitrogen oxide emission limits with diesel engines without expensive catalytic converters. These engines are sometimes called "spark-ignited diesel engines" or "gas engines."

[65] “Performance and Cost Trajectories of Clean Distributed Generation Technologies,” Energy Nexus Group, May 2002.
[66] Long-term performance of these systems has not been demonstrated, with durability of the catalyst a key concern.

***Figure 43. Gas Engine CHP Process***




Multiple-stage intercoolers as well as exhaust gas turbines producing additional electricity can be used for larger engines if economical. A multi-stage intercooler provides the possibility of making some of the heat rejected from the cooling of compressed air available at a higher and more usable temperature. An exhaust gas turbine converts some of the high temperature "waste" heat to electricity. Many variations are possible for the design of specific equipment for CHP, depending on site-specific conditions.

Both gaseous and liquid fuels can be used in reciprocating engines. However, fuel ignition in diesel engines presents a challenge when using natural gas (with an ignition temperature of about 1200 F as opposed to about 480 F for fuel oil). Conversion of reciprocating engines to use gaseous fuels is achieved in two ways:

- Injection of oil as a "pilot fuel," using about 5% oil at full load and up to about 10% at part loads. This can be achieved by mixing air with gas fuel outside the engine. However, in modern larger diesel engines converted to gas combustion the gas fuel is compressed in an external compressor up to a pressure of about 3650 psig. The compressed gas is then injected into the engine, where air already has been compressed, just before the ignition point. With this method, the power output is usually not affected by conversion to gaseous fuels, and the engine can be switched between gaseous and liquid fuels.

- Conversion to spark ignition in combination with "lean burn" (high air/fuel ratio) designs. This is generally the approach taken with smaller (under 6 MWe) engines, although R&D is continuing to increase the size of engines employing this approach due to its environmental benefits. One disadvantage is the lack of ability to switch fuels. This modified engine has a higher compression ratio than a normal spark-ignited engine but low enough not to self-ignite. The electric efficiency of this modified engine is higher than a conventional spark-ignited engine.

Since the beginning of 1970s, intensive diesel engine R&D has been performed, especially regarding diesel engines for ships due to rapidly increasing oil prices during that time. During the 1970s and 1980s the efficiency was increased from 40% to over 50% for the most efficient two-stroke engines. Substantial increases in efficiency are not expected in the near future. Instead, R&D is concentrated on reducing emissions and maintenance requirements and, to a lesser extent, use of alternative fuels.

When engines are used in CHP applications, heat can be recovered from a variety of sources in engines, including the exhaust gas, engine cooling jacket, lubricating oil and other systems.

### Efficiency

Electric efficiencies for smaller reciprocating engines range from 35% for a 1 MWe engine to about 40% for a 5 MWe engine. Efficiencies over 50% can be achieved with slow-speed two-stroke engines. However, these engines are larger in size, are expensive and have higher emissions relative to gas turbines, with which they will be competing in this size range. The higher efficiency slow-speed two-stroke engines are not addressed in this report because gas turbines are usually a better choice from the standpoints of both economy and emissions.

For a CHP plant the power to heat ratio (the ratio of electric output to thermal output) depends on the temperature of the thermal output required, with higher ratios when higher temperature thermal output is required. The power to heat ratio will be range from 1.1 to 1.3, with total efficiency 68% to 74%, at hot water recovery temperatures of 212 to 250 F, respectively.[67] The electric efficiency is unchanged regardless of heat supply temperature as long as the intercooler or jacket water temperatures are not raised to accommodate higher heat supply temperatures.

### Costs

Engine capital costs are sensitive to unit size. Installed capital costs range from $1,200/kWe for a 1 MWe gas engine CHP system to $1,100/kWe for 5 MW systems. Larger engines are available, however, generally, engines do not compete well with gas turbines in sizes above 5 MW. The capital cost estimates include heat recovery steam generator, ancillary equipment and basic utility interconnection for parallel generation. With allowances for supplemental firing and construction of plant space, the total installed cost for a 5 MW engine CHP system would be about $1,280/kWe.

Engine CHP operation and maintenance (O&M) costs include:

- monthly maintenance which can be accomplished without equipment shutdown;
- periodic maintenance (every 500-2,000 hours of operation) including inspections and adjustments and replacement of engine oil and filter, coolant and spark plugs; and
- major overhaul at intervals of 30,000 to 60,000 hours.

For 5 MW engine CHP plants, the O&M cost, excluding labor, would be about $0.0011/kWhe at a 0.68 capacity factor.

### Siting and Infrastructure Issues

As discussed in Section 3.2, a key infrastructure requirement is adequate natural gas supply. There is adequate gas delivery capacity, as well as adequate system pressures.

### Reliability

Reciprocating engines are well-proven, highly reliability technologies, with availabilities in excess of 91%, with a 6.1% forced outage rate and a 3.5% scheduled outage rate. [68]

### Environmental Impacts

Engine emissions vary based on the particular engine, fuels used and flue gas cleaning equipment. Actual emissions for a facility can only be determined based on facility-specific factors and are

[67] "Integrating District Cooling with Combined Heat and Power," Resource Efficiency Inc. for the International Energy Agency, N1 ISBN 90-72130-87-1, 1996.

[68] "CHP Technology Characterizations," Energy Nexus Group, prepared for the U.S. Environmental Protection Agency, Feb. 2002.

strongly affected by regulatory requirements which vary by location. The primary pollutants from gas engines are nitrogen oxides (NOx), carbon monoxide (CO), and volatile organic compounds (VOCs). Emissions of sulfur dioxide (SO2) and particulates are insignificant with engines fired with natural gas.

NOx emissions of about 100 ppm can be achieved without post-combustion control with lean-burn engines. Three-way catalytic conversion, selective catalytic reduction (SCR) and oxidation catalysts are the key post-combustion technologies for reducing NOx and/or CO. SCR can bring NOx down to about 15 ppm. These processes are expensive, and are particularly expensive (on a unit of output basis) for smaller projects.

## 3.6 Thermal Distribution Technologies

The thermal distribution piping system consists of a network of supply and return piping that carry chilled water and hot water from the central plants to customers to serve their heating and cooling needs.

### 3.6.1 Cooling Distribution Piping

Historically welded steel or ductile iron pipes (DIP) have been used in larger chilled water distribution systems. Steel piping systems are welded to form a leak free system that is coated for corrosion protection. The coating options are fusion-bonded epoxy, fiberglass reinforced polyester (FRP), PVC and urethane. Cathodic protection (imposed current or sacrificial anodes) is required for additional corrosion protection at all exposed metal components. Although steel piping is more expensive to install than other chilled water piping options, its major advantage is strength, ruggedness, water tightness, and higher velocity allowance (18 fps versus 10 fps for ductile iron piping) which can result in smaller pipe diameters.

Ductile iron pipe (DIP) is virtually immune to internal and external corrosion. DIP traditionally has a push joint (bell and spigot) design that is more susceptible to leakage due to construction practices, misalignment, thermal expansion and contraction, and pressure surges. However lugged ductile pipe is also available, which provides a more rugged, water-tight design. DIP and fittings are more expensive than steel, but installation costs are usually lower. Ductile iron will last close to 100 years and does not require cathodic protection in most soil conditions. There are also more contractors available that are familiar with ductile iron than other materials since it has been around for many years in the city water industry. Familiarity leads to reduced installation costs.

High Density Polyethylene (HDPE) piping is gaining in popularity for use in district cooling applications. HDPE piping is virtually immune to internal and external corrosion and is electrically non-conductive. HDPE uses a butt fusion welding process that is inherently leak proof, strong and, therefore, superior to all other plastic systems. For contractors familiar with its installation, HDPE is relatively easy to install and is very cost effective in pipe sizes less than 24” outside diameter (OD). For larger sizes it is usually cost prohibitive based on the expense of the fittings or on availability. For pipe size over 24” OD, pre-insulated steel piping may be used with a flanged steel-to-HDPE coupling creating a hybrid system. HDPE piping can prove more economical than all welded steel piping for distribution systems that would require a significant number of offsets due to crowded conditions in the street. In these cases, the flexible nature of HDPE piping can result in reduced labor costs. However, it is recommended that HDPE piping should be used only if there are contractors available in the area that are familiar with its installation. HDPE piping with a dimension ratio (DR) of 11 would be recommended for this project since it is rated for 160 psig operating pressure and can withstand surges over twice this pressure without compromising its integrity.

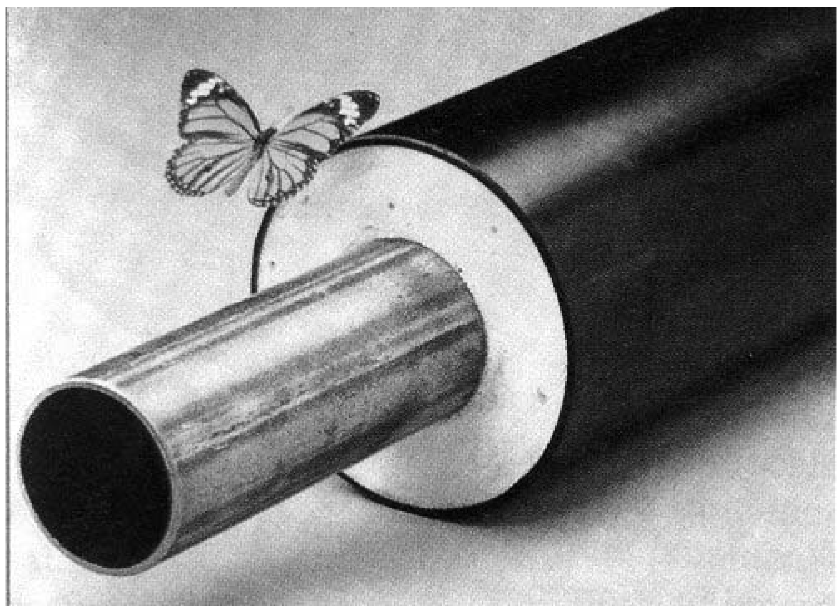
More investigation into the specific pipe installation challenges in the SLU/Denny area is required before a chilled water distribution pipe type can recommended. For this report, distribution system capital cost estimates were developed based on pre-insulated steel distribution piping for both the heating and cooling systems.

### 3.6.2 Heating Distribution

Low temperature hot water distribution systems throughout the world are typically constructed of pre-insulated steel pipe. In the United States, this consists of 1-2 inches of polyurethane insulation applied over a standard weight steel pipe with an additional polyurethane, HDPE or FRP water vapor jacket applied over the insulation, as illustrated in Figure 44. In European systems the carrier pipe is usually thin-walled EN-253 steel pipe. Because the pre-insulated piping system isolates the steel carrier pipe from contact with the earth, cathodic protection of the piping itself is unnecessary. However, cathodic protection (imposed current or sacrificial anodes) is required for corrosion protection at all exposed metal components.

These polyurethane pre-insulated piping systems are designed for hot water service up to 250°F, with some manufacturers allowing hot water temperatures of up to 280°F. Pre-insulated hot water piping can be procured with an integrated leak detection system that is built into the pre-fabricated pipe sections.

***Figure 44. Pre-insulated Piping***



### 3.6.3 Pipe Insulation

Like the steel piping used for hot water systems, most other chilled water pipe materials can be pre-insulated for thermal protection as well. Again, the pre-insulated piping typically consists of 1-2 inches of polyurethane insulation applied over the carrier pipe with additional polyurethane, HDPE, or FRP water vapor jacket applied over the insulation. Pre-insulating also provides additional benefits in terms of corrosion protection and in steel systems. The capital cost for the pre-insulated system is 10 to 50 percent more expensive than bare or coated piping. For district cooling piping, at smaller pipe diameters the added cost of insulating is often warranted because of the higher energy losses for these pipe sizes.

The most important factors affecting heat transfer are the difference between the soil and fluid temperatures, and the material thermal conductivity characteristics. Other factors influencing the heat transfer are:

1. *Soil conductivity*. This is related to the soil moisture content and density. The greater the soil conductivity, the greater the energy loss to the soil.

2. *Burial depth and distance*. The soil around the piping acts as an insulator, so the more distance between the hot ambient air at the surface and the chilled water lines, results in less heat transfer (gain).
3. *Pipe size*. The allowable distribution system pressure drop typically governs this factor.
4. *Pipe velocity*. The maximum velocity in the smaller pipes is significantly slower than in the larger pipes. This slower velocity causes the water to linger in any one section of pipe longer, thus allowing more temperature gain to the fluid.

Of all of the factors listed above, the single most critical factor in the heat gain to the pipe is the fluid velocity. Insulating the piping will mitigate this heat transfer to the pumped medium and save operating costs.

District heating piping for the Energy District should be pre-insulated for thermal protection and be installed with the integrated leak detection system. However, a thermal analysis must be undertaken to determine if district cooling piping should be insulated. A thermal analysis has not yet been undertaken for this draft report. Given Seattle's mild climate it is likely that insulation will not be required for district cooling piping, except perhaps for smaller sized piping where temperature rise and heat gain are greater. However, some of the technologies that are being considered for the Energy District, such as deep water cooling and heat pumps are sensitive to degradation in supply temperatures.

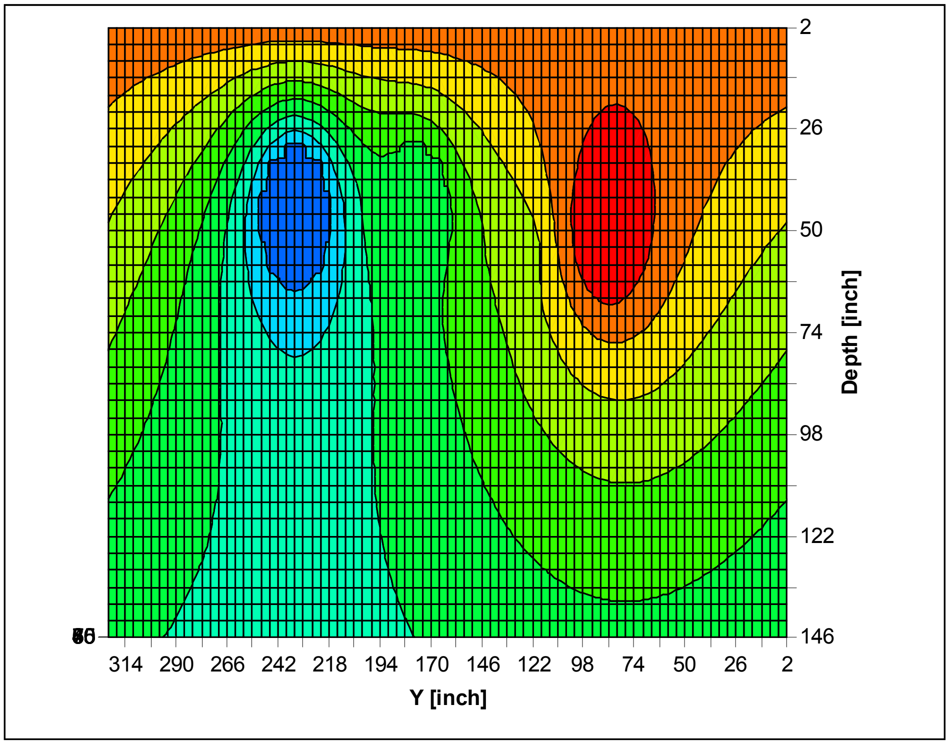
### 3.6.4 Impact of Hot Water Piping on Buried Power Lines

Ideally, cost savings to utilities will be achieved in the South Lake Union area by combining infrastructure improvement projects. The distribution system capital cost estimates prepared for the economic analyses in this report do not include savings from cost-sharing, however, since it is not known if it will be logistically feasible to install district energy piping and other infrastructure simultaneously.

In one potential infrastructure combination, underground power lines would be installed at the same time as district heating or cooling piping. Seattle City Light has raised concerns about the effect that district heating piping could have on their underground power lines. Certainly, elevated temperatures in the ground surrounding buried power lines could reduce heat dissipation and de-rate power lines. Our experience is that power lines must be around 4 to 6 feet away from district heating pipes to be unaffected, unless special measures are taken. However, there are a number of methods by which elevation of ground temperature around the lines can be mitigated or eliminated.

The most straightforward method, since both heating and cooling pipes will be installed for the energy district, is to install power lines on the district cooling side of the trench if heating and cooling pipes are installed in a side-by-side arrangement. The district cooling pipes will then act as a buffer to prevent elevated temperatures in the ground around the power lines. Figure 45 shows an example of the temperature gradient surrounding a set of heating and cooling pipes. In this example, four pipes installed, from left to right are: chilled water supply, chilled water return, condensate return, and steam supply (note that the two return pipes in the middle do not exhibit a well-defined heat signature). This example shows how soil temperature to the left of the pipes is not impacted by the heating pipes, only by the cooling pipes and normal ground temperature variation.

***Figure 45. Example of District Energy Piping Temperature Gradient***




If power lines must be installed in close proximity (beside, beneath, or above) to district heating pipes, then foam boards can be installed between the power lines and the heating pipes. These rigid, load-resistant foam panels can mitigate or eliminate temperature gain to the soil surrounding the power lines. This foam board installation may be required if heating and cooling pipes are installed in a stacked arrangement and power lines are installed in the same trench. Foam boards can also be installed at intersections where heating pipes cross, and are in close proximity to, existing underground power lines.

## 3.7 Building Interconnection

Energy is transferred from the Energy District distribution systems to the building heating or cooling system in one of two ways. In direct systems the Energy District supply water is circulated directly through the customer's radiators or air-handling equipment. In indirect systems the distribution system and the building systems are isolated from each other. Heat exchangers are used to transfer heat between the two systems.

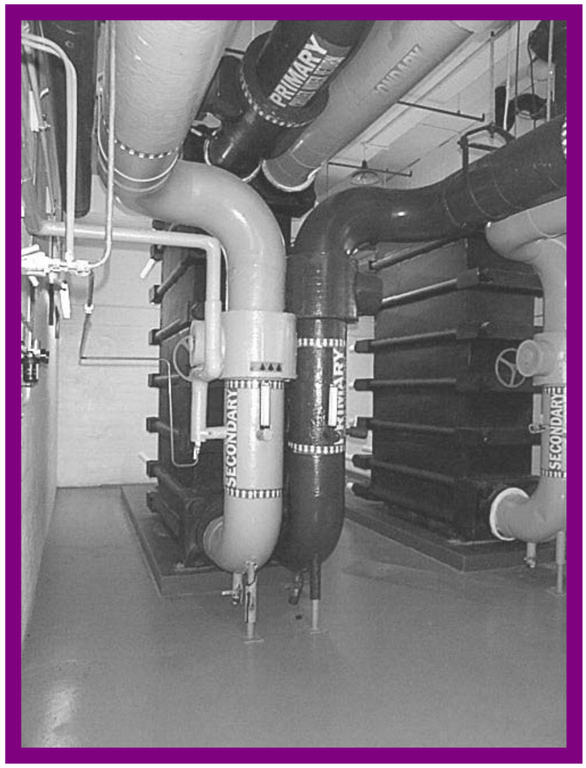
Most district heating systems use indirect connections. In district cooling systems the choice of connection type varies depending on the design philosophy of the Energy District managers, the system supply pressures at the building location, the condition of the building equipment and the height of the building.

A direct connection between the distribution system and the building internal system is the most common type of energy transfer station (ETS) for district cooling systems. Furthermore, this type of connection is preferred when the customer's chilled water distribution piping, valves, coils and fittings sufficiently rated. It normally provides the most economical solution as well as providing the largest "delta T" (temperature difference between supply and return water). High delta T is important to maximizing the cost-effectiveness and efficiency of district cooling systems.

An indirect connection (either plate or shell in tube heat exchangers) between the distribution system and the building circulation system is normally used when the secondary system pressure is either too high or too low for direct connection. This connection provides a much more flexible operation since the distribution and building systems are totally isolated from each other by a heat exchanger.

Figure 46 shows an example of an indirect connection, including two heat exchangers, piping, valves, controls. This installation serves a 1 million square foot building with a 3,350 ton cooling load.

***Figure 46. Example of Indirect District Cooling Building Connection***




For a successful interconnection it is desirable that each building have:

- A state of the art energy management system to control and monitor the heating, ventilation and air conditioning (HVAC) systems.
- A central domestic hot water system in lieu of point of use heaters at toilet rooms, break rooms, etc.
- Variable speed drives and two-way control valves on at least 90% of all hydronic terminal units and air handling units. Variable frequency drives should have modbus communication module for communicating with district energy control panel.
- Energy Transfer Station room to have adequate lighting, ventilation, floor drains (4" minimum) and domestic water connection (1" minimum).
- Any critical cooling or heating requirements (water temperatures and thermal loads) that are served by emergency power should be identified.
- Available 120 Volt power for Energy District control valves and control panel.

The above are basic design considerations for interconnecting building heating and cooling systems with an Energy District. For more detailed information, see the guidebook recently published by the International Energy Agency.[69]

[69] "District Heating and Cooling Connection Handbook," Skagestad and Mildenstein, International Energy Agency Programme of Research, Development and Demonstration on District Heating and Cooling, ISBN-90-5748-026-3, 2003.

# Section 4 Conceptual Design

## 4.1 Load Phasing

System implementation was assumed to take place in four phases, with start-up occurring in fall of 2006, and the years proceeding from that date (e.g., year 2008 is the year starting in fall of 2008):

- Phase 1 – 2006-2007
- Phase 2 – 2008-2010
- Phase 3 – 2011-2015
- Phase 4 – 2016-2020

Table 23 summarizes the peak demands and annual energy for the base case load described in Section 2. The peak demands for heating and cooling are the demands on the Energy District systems, and therefore reflect some diversity of loads.

***Table 23. Base Case Peak and Annual Energy District Loads***

| | Phase 1 2006-07 | Phase 2 2008-2010 | Phase 3 2011-2015 | Phase 4 2016-2020 |
|---|---|---|---|---|
| **Building Space** | | | | |
| Square feet (SF) of building space served | 2,203,982 | 8,887,241 | 13,909,045 | 17,972,025 |
| **Heating** | | | | |
| Peak heating sendout (MMBtu/hour) | 26.3 | 106.6 | 163.2 | 210.0 |
| Annual heating consumption (MMBtu) | 52,762 | 225,873 | 341,571 | 438,304 |
| **Cooling** | | | | |
| Peak cooling sendout (tons) | 4,090 | 16,085 | 25,278 | 32,676 |
| Annual cooling consumption (1000 ton-hours) | 4,429 | 16,834 | 26,645 | 34,410 |

The conceptual systems described below are designed to meet the above heating and cooling requirements. Electricity service is assumed to be most cost-effectively provided by SCL.

## 4.2 Technology Scenarios

As noted in Section 2, there will be two initial regions of development: one in the middle of the SLU study area, toward Lake Union, and the other in the middle of the Denny Triangle area, to the east of Westlake Ave. We anticipate that the most cost-effective approach will be construction of two initial plant facilities to serve these two regions, rather than one plant. However, depending on the actual phasing of development, even more than two plants may be optimal. Advances in information technology make it possible to integrate a multiplicity of energy resources into a “virtual central plant.” With a fiber optic communication system the multiple plant configuration can be operated as a virtual central plant leading to operating efficiencies and economics of scale. The multiple plant configuration has a two-fold purpose:

1. Rather than construct a single plant in anticipation of electric and thermal demand over the next 5, 10, or 20 years, plants and/or components can be added as the build-out occurs and demand increases in the same area. This translates into less risk, greater flexibility and the ability to incorporate new technologies.
2. A multiple plant configuration will lead to a more reliable, failsafe operation than a single plant (the developers of biotech and other high tech facilities require reliability). Requirements for such high reliability could provide justification for incorporation of a diversity of technologies.

The most cost-effective, and quickest-to-implement, technologies to serve the Phase 1 loads will be conventional natural gas boilers to provide heating and electric centrifugal chillers to provide cooling. From this initial technology configuration, four technology scenarios were determined to be most viable for full concept design evaluation, as summarized in Table 24. This table is intended to simply communicate the key technologies in each phase; in fact, generally a mix of technologies would be implemented. For example, some additional gas boiler capacity would be added with each increment of CHP (Scenario 2) or heat pumps (Scenario 4).

No thermal energy storage was incorporated into any of the scenarios because of the lack of incentives to implement storage in SCL electricity rates. However, thermal energy storage may become a beneficial element in an Energy District if SCL implement time-of-day rates or other rate structures that provide incentives for peak-shifting, or non-rate mechanisms to recognize the value of shifting demand to non-peak periods.

***Table 24. Summary of Technology Scenarios***

| | Energy District Scenario | | | |
|---|---|---|---|---|
| | *1* | *2* | *3* | *4* |
| | *1. Natural gas boilers and electric chillers* | *2. Combined heat and power (CHP) turbines* | *3. Deep water cooling with gas boilers* | *4. Deep water cooling with heat pump heating* |
| **Heating** | | | | |
| Phase 1 | Gas boilers | Gas boilers | Gas boilers | Gas boilers |
| Phase 2 | Gas boilers | CHP | Gas boilers | Heat pumps |
| Phase 3 | Gas boilers | CHP | Gas boilers | Heat pumps |
| Phase 4 | Gas boilers | CHP | Gas boilers | Heat pumps |
| **Cooling** | | | | |
| Phase 1 | Electric chillers | Electric chillers | Electric chillers | Electric chillers |
| Phase 2 | Electric chillers | Electric + absorption chillers | Deep water cooling | Deep water cooling |
| Phase 3 | Electric chillers | Electric + absorption chillers | Deep water cooling | Deep water cooling |
| Phase 4 | Electric chillers | Electric + absorption chillers | Deep water cooling | Deep water cooling |

### 4.2.1 Scenario 1 – Gas Boilers and Centrifugal Chillers

The performance, capital cost and operating cost characteristics of the technologies are as presented in Section 3. Plant capacity is added in increments to meet each phase of load. This conventional technology scenario is most conducive to a modular implementation approach, with equipment installed as load grows, and provides the lowest capital and total costs.

### 4.2.2 Scenario 2 – Combined Heat and Power

This scenario focuses on natural gas turbine combined heat and power (CHP) for production of power and by-product heat. It was assumed that only the SLU plant would incorporate CHP. The heat is used for a majority of the Energy District heating requirements (with gas boilers for peaking) and a significant portion of the cooling requirements (using absorption chillers that convert heat to cooling). Both gas turbines and gas engines were evaluated. In order to minimize emissions, gas turbine CHP was selected. A modular approach to implementation, with 5 MW gas turbines installed consistent with load growth, was chosen to minimize capital risk and maximize reliability. Nitrogen oxide and carbon monoxide would be controlled with Selective Catalytic Reduction (SCR) with an oxidation catalyst. About 10% of the electricity generated would be used by Energy District plant facilities, with the remainder exported to the grid.

The performance, capital cost and operating cost characteristics of gas turbine CHP are as presented in Section 3. Two-stage absorption chillers were assumed to be implemented with each stage of new CHP, sized for the unfired heat output of the CHP minus projected summertime district heating load.

### 4.2.3 Scenario 3 – Deep Water Cooling with Natural Gas Heating

As discussed later in Section 7, there may be a unique opportunity to improve the water quality in Lake Union and enhance conditions for salmon migration by supplying Lake Union with cool, oxygenated water from Lake Washington. However, it is important to note that significant study must be undertaken to fully understand the potential environment impacts, as discussed in Section 7. In addition, adding Lake Washington water to Lake Union instead of returning it to Lake Washington allows for installation of a single pipe between Lake Washington and the plants in the SLU/Denny area, instead of a pair of supply and return pipes. The concept for a deep water cooling system design on this basis is outlined in this section.

#### 4.2.3.1 Design Temperatures and Capacity Mix

As discussed in Section 3.4, Lake Washington is the only water source in the area with temperatures low enough to provide direct cooling for part of the system cooling load. The approximate mix of direct deep water cooling and cooling with electric centrifugal chillers was determined based on published summer water temperatures averaging 46°F for Lake Washington and assuming a 56°F return temperature from Energy District customers at time of peak cooling load. With a 2°F approach across the lake water / district water heat exchanger and 1°F temperature rise in the lake water transmission line at peak conditions, approximately 49°F supply water is delivered to the central cooling plants. At times of peak cooling load, this water is further chilled from 49°F to 40°F by electric chillers before it is distributed to district customers. Assuming indirect customer interconnections (with a heat exchanger), and a 2°F approach across customer heat exchangers, the supply temperature to customer's HVAC systems at peak times is 42°F. With a 58°F customer return, the temperature differential at customers is 16°F (58°F-42°F).

Based on the design temperature scenario outlined above, approximately 44% of the cooling effect at peak load conditions is provided by the deep water source, with the balance of the cooling effect provided by electric chillers. Accordingly, enough electrical chillers must be installed at the plant to satisfy approximately 56% of the customer cooling demand at times of peak load. Cooling towers are not required since district return water is used for condenser cooling before it is discharged. For scenarios with deep water cooling, capital costs were developed for cooling plants on this basis.

At off-peak times, a lower supply temperature can be provided to customers and, therefore, a larger percentage of system load can be met with direct cooling, reducing energy consumption. For a portion of the year (albeit when customer cooling loads are small) all of the system cooling load can be met with direct cooling from Lake Washington. For the conceptual design, we have assumed a district supply temperature reset from 40°F, at times of peak cooling, up to 49°F when outside air temperature is at 40°F or below. Figure 47 shows the temperature reset schedule for the deep water cooling conceptual design. Based on this reset schedule, Figure 48 shows the percentage of cooling effect that is provided by deep water cooling (versus electrical chilling). There are very few annual hours when the system is operating near its peak cooling demand, so for the majority of system operation significant “tempering” with electrical chilling is not required. For the conceptual design outlined in this section, over 75% of total annual cooling energy requirements can be provided “directly” by the lake water cooling source.

***Figure 47. Chilled Water Temperature Reset***

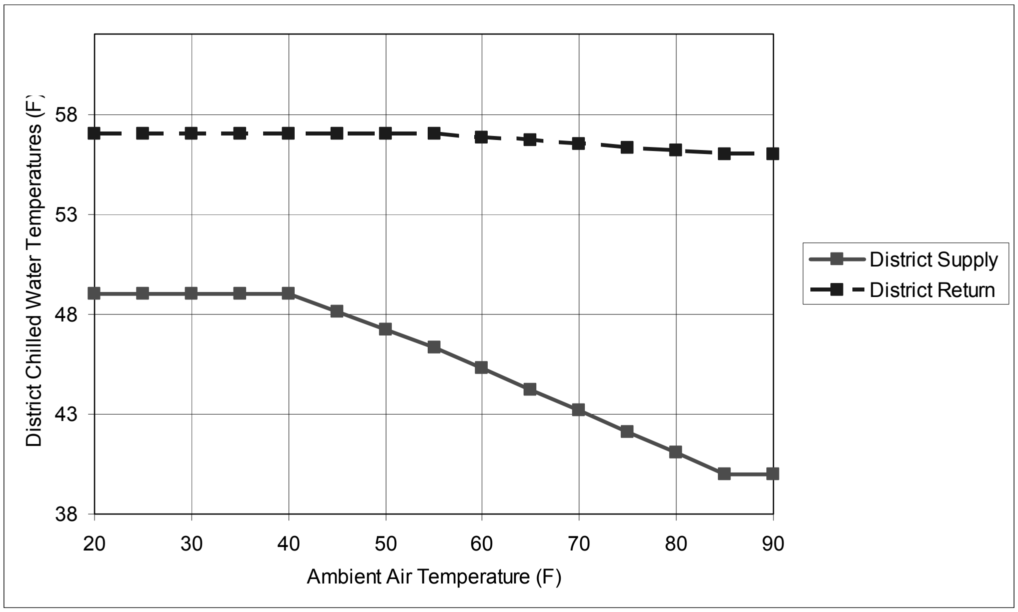
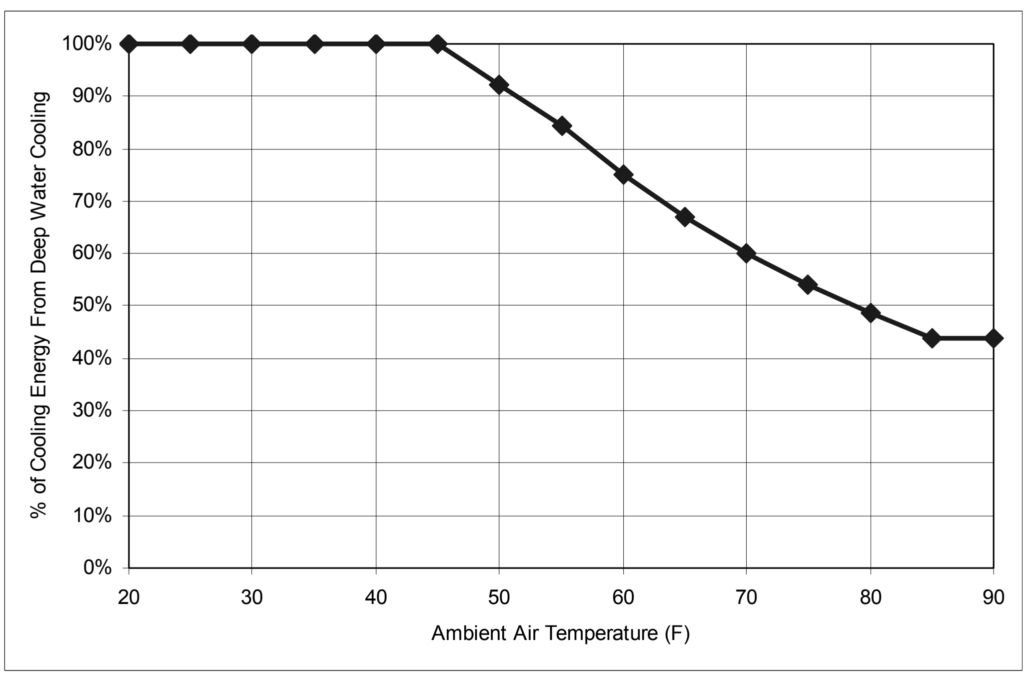



***Figure 48. Cooling Energy from Deep Water Cooling***



The design temperature scheme for the deep water cooling conceptual design allows Lake Washington water below 60°F to be delivered to Lake Union for much of the cooling season, but with temperatures of up to 64°F at times of peak cooling. However, if environmental analysis concludes that lower water temperatures must be supplied at all times during the summer, then the lake water transmission system could be designed to provide this by increasing the capacity of the lake water pipeline.

#### 4.2.3.2 Lake Water Pipeline

A variety of different design alternatives for the lake water pipeline were reviewed and the conceptual design based on the most viable alternative, given the limited information available at this phase of design development. Figure 49 is a map that shows the lake water pipeline routing assumed for the conceptual design. Each of the pipeline segments shown on this map are discussed below.

*Segment 1:* This is the lake water intake piping that runs from the bottom of Lake Washington, at ~200' depth, to a pumping station located on shore[70]. The intake piping run is approximately 7,750' long. The piping material employed is high-density polyethylene (HDPE), which is virtually corrosion-proof, cost-effective to install, and available in a wide variety of different pressure ratings. Based on the projected cooling load for the Energy District, approximately 50,000 gallons per minute (gpm) of flow are required for deep water cooling. To accommodate this flow, an intake piping with a 63" nominal diameter is used[71]. An important consideration in the design of the intake piping is that any pressure drop in the piping, from the intake end to the pumps on shore, creates a vacuum within the piping. The piping must be stout enough to resist collapse from this induced vacuum. Since 63" HDPE is not available with a thick enough wall thickness to accommodate this vacuum, external stiffeners (collars) must be installed along a portion of the pipeline closest to the pumping station. The intake manifold, located at depth in Lake Washington, is designed to protect lake wildlife and is recoverable to the surface for cleaning and maintenance.

*Segment 2:* At the pumping station on shore, the Lake Washington water receives the boost needed to transport it all the way to Lake Union. Since the water in the piping is under pressure after the pumping station, eliminating the potential for collapse, the piping can be sized somewhat smaller, with a nominal diameter of 54" and can also have a slightly thinner wall thickness. This piping is run buried (either direct-buried or bored[72]) from the pumping station to the shore of Portage Bay.

*Segment 3:* This segment of piping is installed submerged on the floor of Portage Bay.

*Segment 4:* As shown in Figure 49, this segment of piping crosses Capital Hill, where the topography of the hill reaches an elevation approximately 250' above shore level. If this segment of piping were installed using traditional buried trench methods, this large elevation change would increase pumping costs and design pressure of the piping. Instead, this piping is proposed to be bored using directional drilling technology. According to a local tunneling expert[73], it should be possible to directional drill the piping run of Segment 4 in a single pull, eliminating the need for multiple access points that would be required by other tunneling technologies, such as mircotunneling. Portage Bay would be used as the staging point for the directional drilling effort.

*Segment 5:* After the directional drilling of Segment 4 piping is run using traditional open-trench methods down to an Energy District plant in the South Lake Union area. The portion of lake water needed for direct cooling at the SLU plant is passed through heat exchangers that transfer cooling energy from the lake water to the chilled water loop serving the SLU area.

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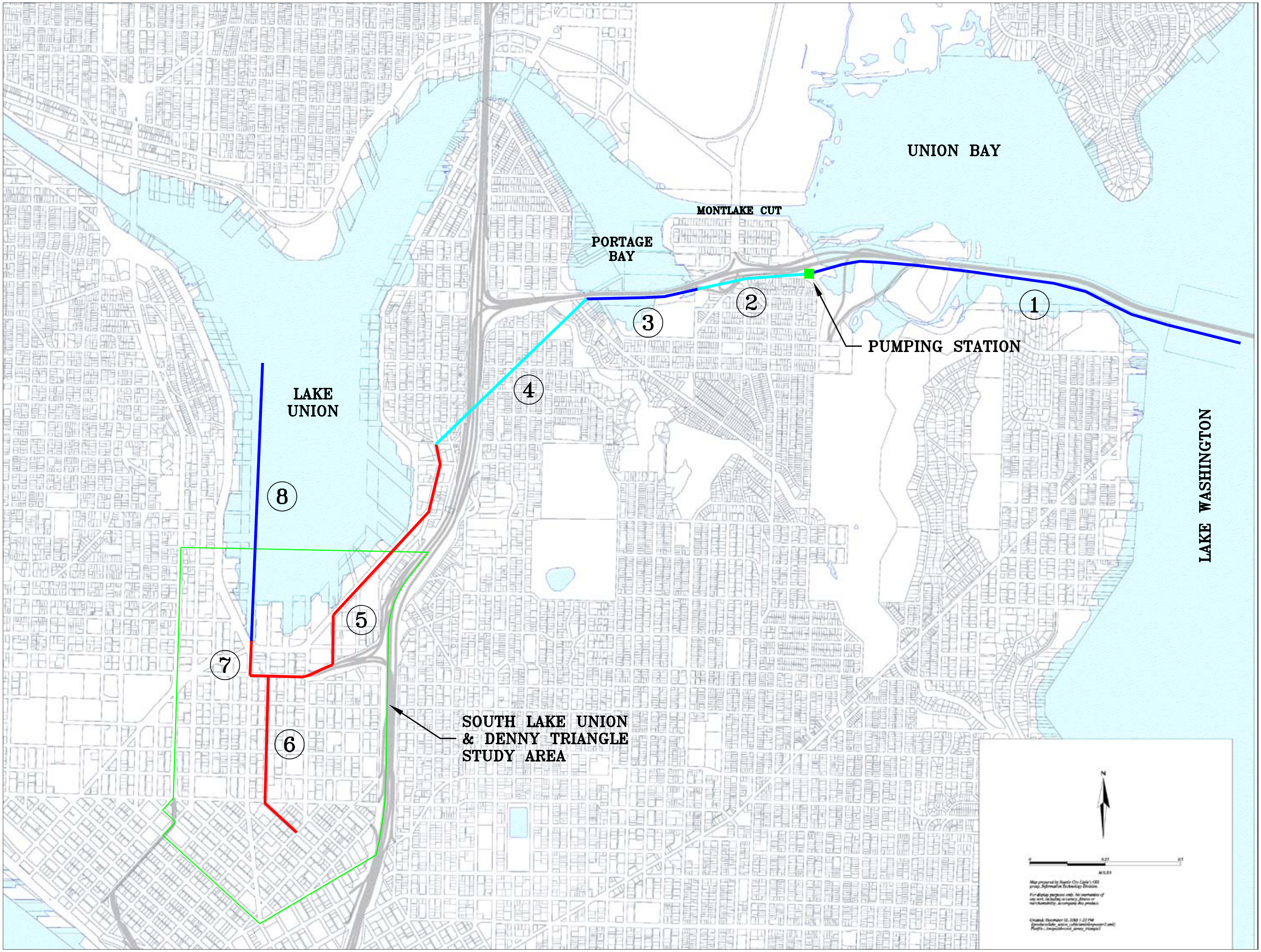
[70] Location of pumping station is approximate only; station siting must be determined in next phase of project development.
[71] 63" is the largest commercially available HDPE pressure piping at time of this report's publication. However, HDPE manufacturers are purportedly planning to introduce larger sizes in the future.
[72] Capital cost estimates are based on the assumption that this piping will have to be bored.
[73] Information provided by Red Robinson of Shannon & Wilson.

## Figure 49.  Deep Water Piping Arrangement



*Segment 6:* A pair of direct-buried 36” HDPE supply and return pipes take the portion of lake water needed for direct cooling of the Denny Triangle to an Energy District plant located in the DT area and then return it to the SLU plant.

*Segment 7:* After the lake water is used for direct cooling purposes at the Energy District plants, a buried pipeline takes the water from the plants to the shore of Lake Union.

*Segment 8:* This piping segment is a submerged outfall pipeline that delivers cool, clean Lake Washington water to Lake Union. The outfall would be designed with a diffuser to distribute this water into Lake Union at very low velocities so that sediment on the floor of Lake Union is not disturbed.

Table 25 summarizes the piping components, sizing and estimated capital costs for the lake water pipeline outlined above. Capital costs for the pumping station are estimated at $9.7 million.

***Table 25. Capital Cost Estimates for Deep Water Cooling Piping***

| Pipe Seg-ment | Description | HDPE Pipe Nominal Size | HDPE Dimen- sion Ratio | Approx-imate Length (ft) | Capital Cost Estimate (mil $) |
|---|---|---|---|---|---|
| 1 | Intake piping (with ~3,500' of stiffeners) | 63" | DR21 | 5,450 | $6.79 |
| 2 | Directional drilled transmission piping across Montlake | 54" | DR17 | 1,970 | $2.66 |
| 3 | Submerged piping in Portage Bay | 54" | DR17 | 1,950 | $1.07 |
| 4 | Directional drilled piping through Capital Hill | 54" | DR17 | 3,620 | $4.89 |
| 5 | Direct buried piping to SLU District Energy Plant | 54" | DR17 | 5,980 | $5.98 |
| 6 | Pair of direct-buried pipes to/from DT Plant [1] | 36" | DR21 | 3,100 | $2.48 |
| 7 | Direct-buried piping from SLU Plant to shore of Lake Union | 54" | DR17 | 600 | $0.60 |
| 8 | Submerged outfall piping in Lake Union | 54" | DR17 | 4,870 | $2.72 |
| | | | | | |
| | Total | | | 27,540 | $27.2 |

Note: [1] Based on marginal cost of increased trench size only, assuming pipes are installed in same trench as distribution mains

Based on the pipeline conceptual design detailed above, pumping costs for each phase of the Energy District were calculated and entered in the economic analyses for scenarios with deep water cooling.

### 4.2.4 Heat Pumps with Deep Water Cooling

For the deep water cooling Scenario 3 described above, the heating loads of the district are served with gas-fired boilers. Scenario 4 exploits the opportunity to use the lake water cooling infrastructure to meet a large part of the district heating requirements with water-source heat pumps.

In the summertime water is drawn from the depths of Lake Washington, where the water is cool year-round. In the winter months, however, water will be drawn from a shallow depth near the pumping station, where the water is warmer in the shoulder months of the winter season. This temperate water is routed into the evaporator side of the heat pump, is used as heat source by the heat pump and rejected at a lower temperature. Return water from the heating district enters the condenser side of the heat pump and is “pumped” up to a higher temperature.

Also, the fact that the energy district combines both heating and cooling duties into a single plant allows for the opportunity to “recover” heat rejected by chillers in the summer time to supply the domestic hot water heating requirements of district customers.

Industrial water-source heat pumps are available from Europe that can provide hot water supply temperatures from the evaporator of up to 180°F, temperatures high enough to meet the space heating and domestic hot water heating requirements of buildings connected to the district. However, in order to minimize the size of the district hot water distribution piping, at time of peak heating load, the hot water that leaves the heat pump is "peaked" with gas-fired hot water boilers. This increases the temperature differential ($\Delta$T) of the hot water, reducing the flow requirements of the heating district piping. However, the number of hours in the year where significant peaking with the boiler is required are relatively few and, consequently, approximately 80% of the annual heating requirements of the district can be provided by the heat pumps. Figure 50 gives the temperature reset schedule assumed for hot water supply and return for both the district heating distribution system and for customers, assuming indirect customer interconnections. Based on this reset schedule, Figure 51 shows the percentage of heating energy to the district that can be provided by heat pumps.

***Figure 50. Hot Water Temperature Reset Schedule***

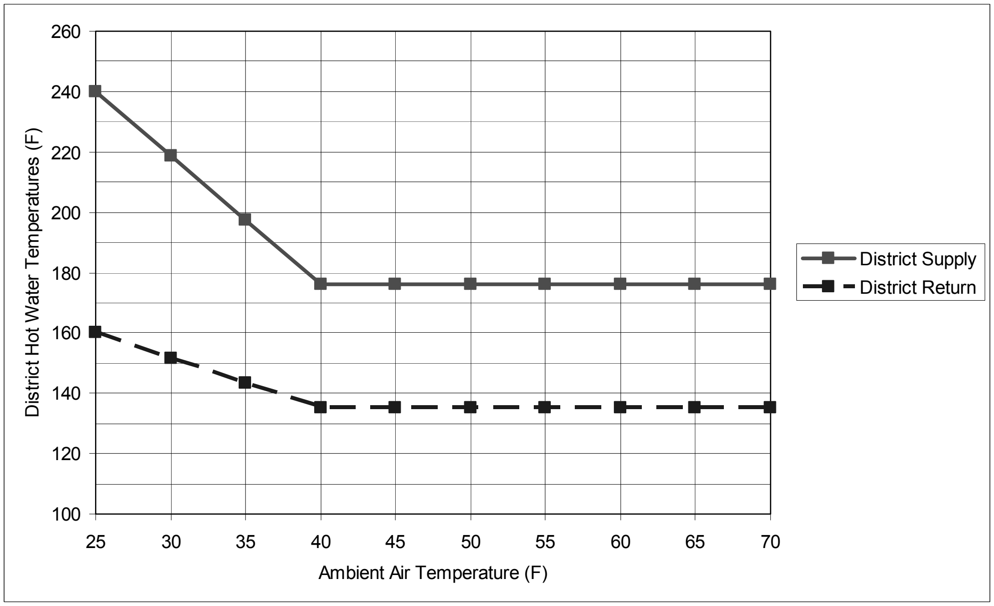
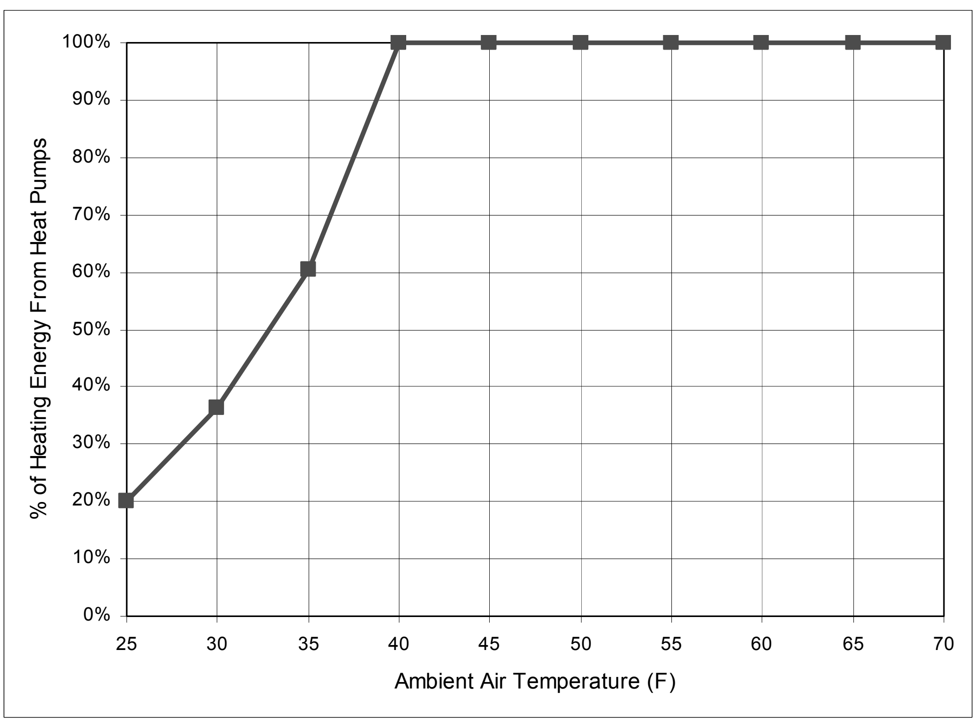



***Figure 51. Heating Energy from Heat Pumps***



Since the boilers provide energy for 80% of heating send-out at peak, but the heat pumps supply the majority of heating energy at off-peak conditions, the combined installed boiler and heat pump capacity for the plants exceeds peak design plant capacity. Capital cost estimates for the SLU and Denny Triangle boiler/heat pump plants are found in Appendix 7. (As noted previously, the costs per unit of output capacity in Appendix 7 were used in the total system economic analyses presented in Section 4.4 and in Section 6. In some cases, the output capacities, and thus costs, were increased from the values shown in Appendix 7.)

## 4.3 Thermal Energy Distribution and Building Interconnection

To size heating and cooling distribution piping for estimation of distribution system costs, hydraulic analysis was performed using the HEATMAP© district energy analysis software. The Washington State University Energy Program in conjunction with Seven Technologies and other sponsors developed this software, which is exclusively designed for district energy applications. The hydraulic modeling component of the HEATMAP© software uses the Danish program HEATCALC© as its core calculation engine.

An absolute roughness coefficient of 0.0003 feet to simulate aged pipe (versus ~0.00015 feet for new steel pipe) was applied to all pipes in the model. Piping was sized such that pressure loss in piping approaches but does not exceed 1.0 psi per 100 feet. The differential pressure at the critical customer was set at 25 psig for both heating and cooling systems, assuming indirect customer interconnections.

Distribution mains for the chilled water system were sized to accommodate the peak system send-out of approximately 32,700 tons with a system $\Delta T$ of 16°F. Distribution mains for the hot water system were sized to accommodate the peak system send-out of approximately 210 MMBH with a system $\Delta T$ of 75°F. All potential customers that were included in our assumed Energy District customer base were included in the hydraulic model. The hydraulic model was used to size the distribution system and determine the length of pipe per diameter. Pipe offsets (45° elbows), drains, vents, valves and branch connections were assumed based on the routing and entered as quantity take-offs into an Excel spreadsheet. The spreadsheet was used to estimate the distribution system cost based on material and labor unit pricing found in the RSMeans® Mechanical Cost Data, and on vendor pricing for specific critical components (pre-insulated pipes and fittings, valves, etc.). Trenching and restoration costs figures were estimated based on feedback from Seattle Steam on piping projects in the area, and on feedback from local consultants regarding existing utilities in the study area.

Once the estimated construction costs were sub-totaled:

- 6.5% Washington sales tax was applied to all construction materials.
- 13% contractor's overhead and profit margin was added to the subtotal of the construction costs and sales tax.
- 8% percent design and construction contingency was added to the sum of the construction costs and sales tax.
- 5.5% design fee was added to the above subtotal for each phase.

Distribution piping installation was phased as required to serve the customers that were included in our assumed Energy District customer base. Table 26 lists the estimated distribution system capital costs for each phase of the Energy District.

*Table 26. Distribution System Capital Costs*

| Phase | TF Per Phase | Cost Per TF | Capital Cost |
|---|---|---|---|
| Phase 1 | 7,780 | 1,140 | $ 8,854,000 |
| Phase 2 | 12,440 | 1,105 | $ 13,715,000 |
| Phase 3 | 5,570 | 985 | $ 5,481,000 |
| Phase 4 | 2,060 | 960 | $ 1,982,000 |
| | | | |
| All Phases | 27,850 | 1,080 | $ 30,032,000 |

Note that distribution system capital costs outlined in the table above include the small service lines to connect energy district customers to the distribution system, which brings the average cost per trench foot down considerably relative to the cost for distribution mains alone. Full cost estimates for the distribution system are found in Appendix 8.

The conceptual design scenarios assume that heating service is provided through indirect connections, and that cooling service is provided with a mix of direct and indirect connections depending on building-specific circumstance, particularly building height and hydraulic pressure considerations.

## 4.4 Screening Analysis of Scenarios

### 4.4.1 Economic Comparison

#### 4.4.1.1 Capital costs

Capital costs for the scenarios are summarized in Table 27, and are illustrated graphically in Figure 52. More detail on the capital costs can be found in Appendix 8. The breakdown of cumulative capital costs by Energy District system component is illustrated in Figure 53.

*Figure 52. Cumulative Capital Costs for each Scenario (2003 $)*

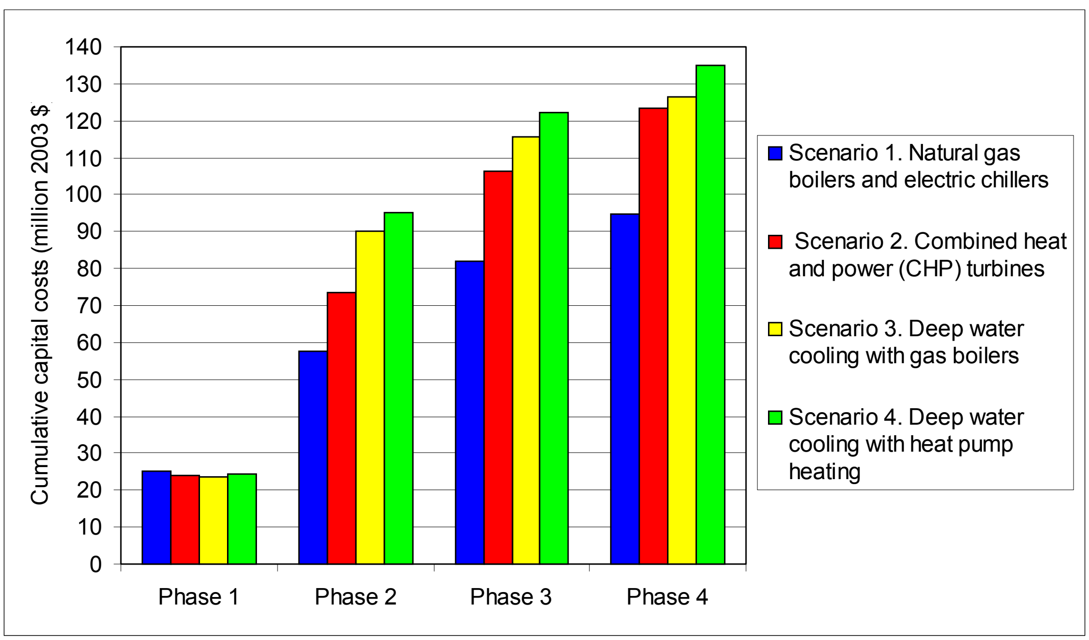


*Table 27. Capital Costs for each Scenario by Phase (million 2003 $)*

## Scenario 1

**Capital Costs ($ million)**

| | Phase 1 | Phase 2 | Phase 3 | Phase 4 | Total |
|---|---|---|---|---|---|
| Plant | $ 15.1 | $ 15.3 | $ 15.9 | $ 8.5 | $ 54.8 |
| Deep water cooling | $ - | $ - | $ - | $ - | $ - |
| Distribution | $ 8.8 | $ 13.7 | $ 5.5 | $ 2.0 | $ 30.0 |
| Building Interface | $ 1.2 | $ 3.7 | $ 2.7 | $ 2.2 | $ 9.8 |
| Total | $ 25.1 | $ 32.7 | $ 24.1 | $ 12.8 | $ 94.6 |

## Scenario 2

**Capital Costs ($ million)**

| | Phase 1 | Phase 2 | Phase 3 | Phase 4 | Total |
|---|---|---|---|---|---|
| Plant | $ 14.1 | $ 32.1 | $ 24.6 | $ 12.9 | $ 83.6 |
| Deep water cooling | $ - | $ - | $ - | $ - | $ - |
| Distribution | $ 8.8 | $ 13.7 | $ 5.5 | $ 2.0 | $ 30.0 |
| Building Interface | $ 1.2 | $ 3.7 | $ 2.7 | $ 2.2 | $ 9.8 |
| Total | $ 24.1 | $ 49.4 | $ 32.8 | $ 17.1 | $ 123.4 |

## Scenario 3

**Capital Costs ($ million)**

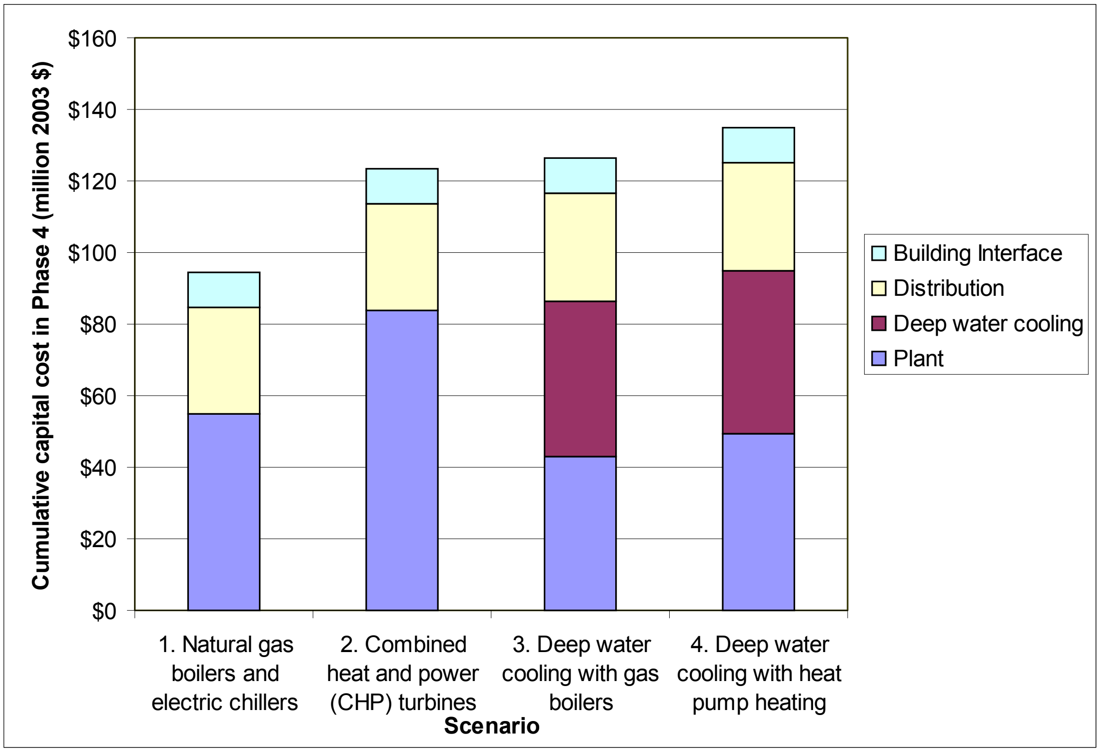
| | Phase 1 | Phase 2 | Phase 3 | Phase 4 | Total |
|---|---|---|---|---|---|
| Plant | $ 13.5 | $ 9.9 | $ 13.1 | $ 6.4 | $ 43.0 |
| Deep water cooling | $ - | $ 39.4 | $ 4.2 | $ - | $ 43.6 |
| Distribution | $ 8.8 | $ 13.7 | $ 5.5 | $ 2.0 | $ 30.0 |
| Building Interface | $ 1.2 | $ 3.7 | $ 2.7 | $ 2.2 | $ 9.8 |
| Total | $ 23.5 | $ 66.7 | $ 25.5 | $ 10.7 | $ 126.4 |

## Scenario 4

**Capital Costs ($ million)**

| | Phase 1 | Phase 2 | Phase 3 | Phase 4 | Total |
|---|---|---|---|---|---|
| Plant | $ 14.5 | $ 11.8 | $ 14.8 | $ 8.4 | $ 49.5 |
| Deep water cooling | $ - | $ 41.4 | $ 4.2 | $ - | $ 45.6 |
| Distribution | $ 8.8 | $ 13.7 | $ 5.5 | $ 2.0 | $ 30.0 |
| Building Interface | $ 1.2 | $ 3.7 | $ 2.7 | $ 2.2 | $ 9.8 |
| Total | $ 24.5 | $ 70.5 | $ 27.1 | $ 12.6 | $ 134.8 |

*Figure 53. Breakdown of Cumulative Capital Costs by Energy District System Component*




#### 4.4.2.1 Annual costs

Key operating cost assumptions are summarized in Appendix 8. All calculations are in 2003 dollars. Capital amortization is based on 5% interest over 20 years. Aside from the natural gas and electricity price projections presented earlier, other operating costs were assumed to increase at the rate of inflation, i.e., no increase in 2003 dollars. This screening analysis does not take into account additional costs for funding an operating reserve to smooth out rates, as discussed in Section 6.2.

Total annual costs at full build-out (year 2020) for the four scenarios are summarized in Table 28. These costs include debt amortization at 5% interest over 20 years, operation and maintenance, personnel for management, marketing and operations, and carbon emissions mitigation. In the base case estimates in Table 28, the value of net power production from CHP is conservatively assumed to be equal to SCL's projected average wholesale cost, as discussed in Section 3.2.

The sensitivity analyses presented in Section 4.4.2.3 test the sensitivity of total costs per square foot of building space served to:

- natural gas prices;
- values of export power;
- cost of capital;
- term of financing; and
- credit for carbon dioxide reductions.

#### 4.4.2.2 Costs per Unit of Energy and per Square Foot

##### Costs per Unit of Energy

Base case estimates for costs per unit of energy, at full build-out (Phase 4) are summarized in Table 29.

##### Costs per Square Foot

Base case estimates of total annual heating and cooling costs, expressed as $ per Square Foot per year at full build-out, are summarized in Figure 54.

#### 4.4.2.3 Sensitivity Analyses

Figure 55 illustrates the sensitivity of Phase 4 costs per SF to the price of natural gas. As expected, the Scenario 2 (CHP) is most sensitivity to gas price, increasing by $0.074 per SF for a $1.00 increase in gas price. Scenarios 1 and 3 shift by only $0.032 per SF, and Scenario 4 only $0.005 per SF.

Figure 56 illustrates the sensitivity of Phase 4 costs to the value of export power. Scenario 2 (CHP) is the only scenario affected. The base case assumption that the value of CHP power is 125% of the average wholesale prices was made in an attempt to recognize that:

- marginal resource costs will be higher than average resource costs;
- a CHP facility can provide dispatchable power, which has a higher value than some types of renewable resources; and
- generation near load reduces transmission and distribution losses.

In the sensitivity analysis, the value of electricity was assumed to be 100%, 150% and 175% pf the projected average wholesale value. These wholesale electricity cost scenarios were illustrated in Figure 31. With the 175% assumption, the total costs of the CHP approach (Scenario 2) drop by about $0.10 per SF compared to the base case assumption of 125% of wholesale value, becoming equal to the costs of gas boilers and electric chillers (Scenario 1). In SCL's resource plan, the cost of power from gas turbines ranges from $46 to $80 per MWH, depending on capacity factor, assuming $3.00 per MMBtu gas (a gas price assumption that now appears low).

Figure 57 illustrates the sensitivity of Phase 4 costs to the cost of capital, with costs increasing by $0.19 to $0.25 per SF per year when the cost of capital increases from 5% to 10%.

Figure 58 illustrates the sensitivity of Phase 4 costs to the term of financing (at 5% cost of capital), with costs decreasing by $0.08 to $0.11 per SF per year when the term increases from 20 years to 30 years.

Figure 59 illustrates the sensitivity of Phase 4 costs to the inclusion of credit for reduction of carbon dioxide emissions, with costs decreasing by $0.04 to $0.06 per SF per year when these reductions are credited at $40 per metric ton of carbon dioxide.

*Table 28. Base Case Annual Costs for the Four Energy District Scenarios (Phase 4)*

| | Energy District Scenario | | | |
|---|---|---|---|---|
| | 1 | 2 | 3 | 4 |
| | *1. Natural gas boilers and electric chillers* | *2. Combined heat and power (CHP) turbines* | *3. Deep water cooling with gas boilers* | *4. Deep water cooling with heat pump heating* |
| **Heating** | | | | |
| Capital recovery | $ 2.3 | $ 2.0 | $ 2.4 | $ 3.5 |
| Natural gas | $ 2.4 | $ 0.0 | $ 2.4 | $ 0.4 |
| CHP heat | $ - | $ 3.9 | $ - | $ - |
| Purchased electricity | $ 0.0 | $ 0.0 | $ 0.0 | $ 1.8 |
| Plant maintenance | $ 0.2 | $ 0.1 | $ 0.2 | $ 0.4 |
| Distribution maintenance | $ 0.2 | $ 0.2 | $ 0.2 | $ 0.2 |
| Personnel | $ 1.3 | $ 1.3 | $ 1.3 | $ 1.3 |
| Carbon mitigation | $ - | $ - | $ - | $ - |
| Total | $ 6.4 | $ 7.6 | $ 6.5 | $ 7.5 |
| **Cooling** | | | | |
| Capital recovery | $ 5.3 | $ 5.5 | $ 7.8 | $ 7.3 |
| Purchased electricity | $ 0.8 | $ 0.0 | $ 0.4 | $ 0.7 |
| CHP heat | $ - | $ 0.9 | $ - | $ - |
| Water, chemicals and supplies | $ 0.2 | $ 0.2 | $ 0.0 | $ 0.0 |
| Plant maintenance | $ 0.5 | $ 0.5 | $ 0.4 | $ 0.3 |
| Distribution maintenance | $ 0.2 | $ 0.2 | $ 0.8 | $ 0.8 |
| Personnel | $ 1.3 | $ 1.3 | $ 1.3 | $ 1.3 |
| Carbon mitigation | $ - | $ - | $ - | $ - |
| Total | $ 8.3 | $ 8.6 | $ 10.6 | $ 10.4 |
| **Combined annual costs** | | | | |
| Capital recovery | $ 7.6 | $ 7.5 | $ 10.1 | $ 10.8 |
| Natural gas | $ 2.4 | $ 0.0 | $ 2.4 | $ 0.4 |
| CHP heat | $ - | $ 4.8 | $ - | $ - |
| Purchased electricity | $ 0.9 | $ 0.1 | $ 0.4 | $ 2.5 |
| Water, chemicals and supplies | $ 0.2 | $ 0.2 | $ 0.0 | $ 0.0 |
| Plant maintenance | $ 0.7 | $ 0.7 | $ 0.6 | $ 0.7 |
| Distribution maintenance | $ 0.4 | $ 0.4 | $ 0.9 | $ 1.0 |
| Personnel | $ 2.5 | $ 2.5 | $ 2.5 | $ 2.5 |
| Carbon mitigation | $ - | $ - | $ - | $ - |
| Total | $ 14.7 | $ 16.2 | $ 17.1 | $ 17.9 |

*Table 29. Costs per Unit of Energy at Full Build-out (Phase 4)*

| | 1 | 2 | 3 | 4 |
|---|---|---|---|---|
| | *1. Natural gas boilers and electric chillers* | *2. Combined heat and power (CHP) turbines* | *3. Deep water cooling with gas boilers* | *4. Deep water cooling with heat pump heating* |
| Heating ($/MMBtu) | $ 14.61 | $ 17.30 | $ 14.72 | $ 17.03 |
| Cooling ($/ton-hour) | $ 0.25 | $ 0.26 | $ 0.32 | $ 0.32 |

*Figure 54. Base Case Total Annual Heating and Cooling Costs ($/Square Foot) at Full Build-out*

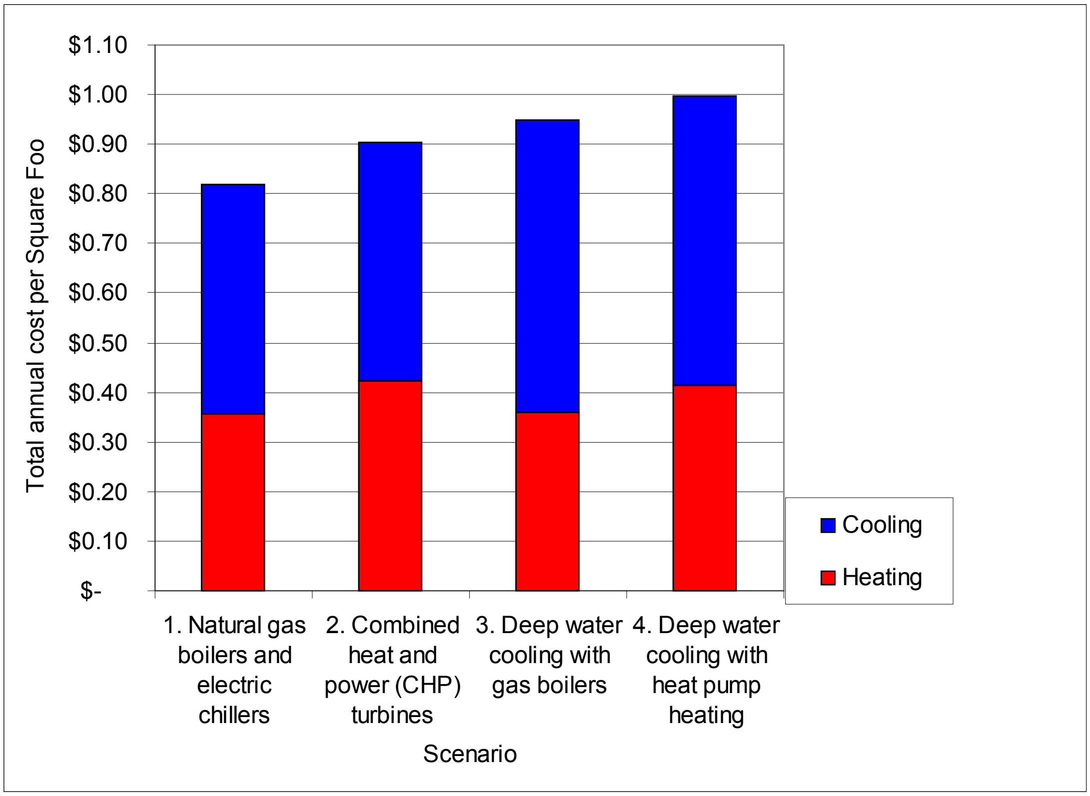



*Figure 55. Sensitivity of Phase 4 Annual Costs per Square Foot to Natural Gas Prices*

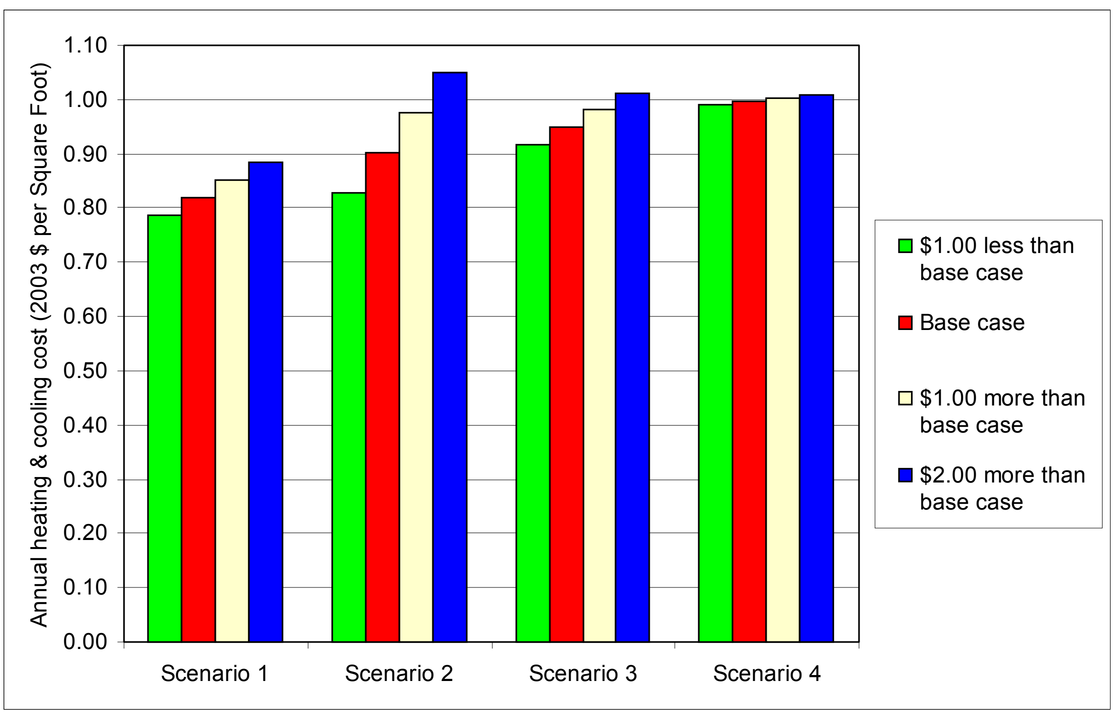


*Figure 56. Sensitivity of Phase 4 Annual Costs per Square Foot to Export Electricity Value*

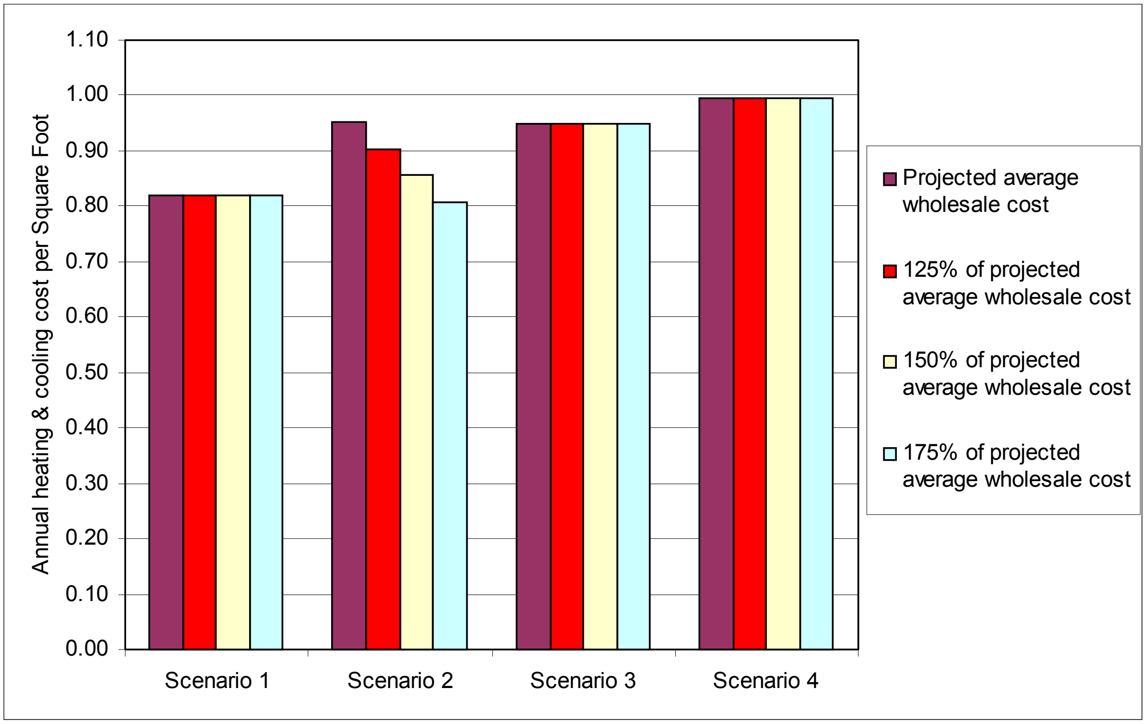



*Figure 57. Sensitivity of Phase 4 Annual Costs per Square Foot to Cost of Capital*

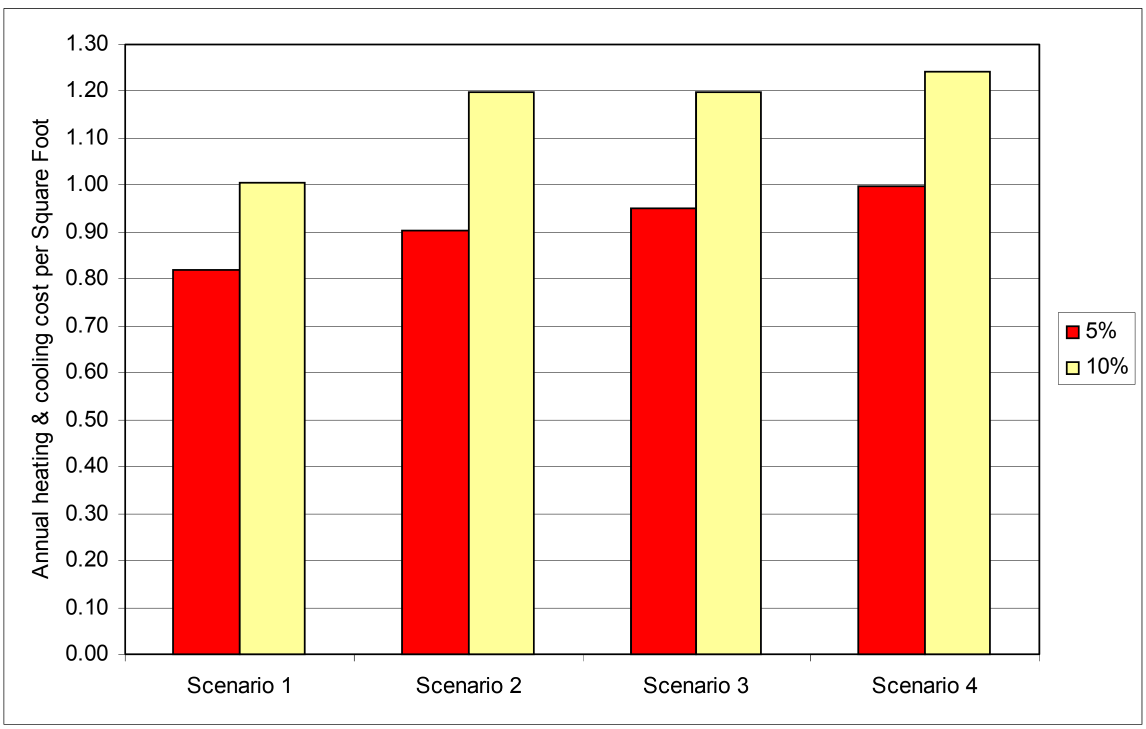


*Figure 58. Sensitivity of Phase 4 Annual Costs to Term of Financing*

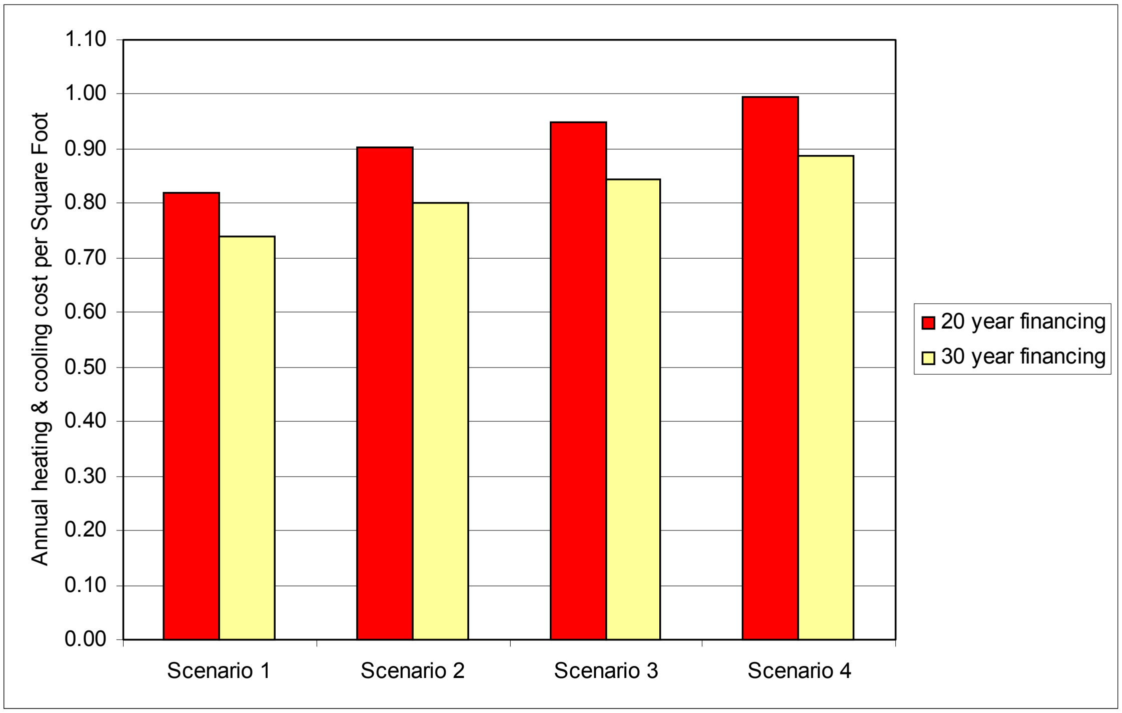
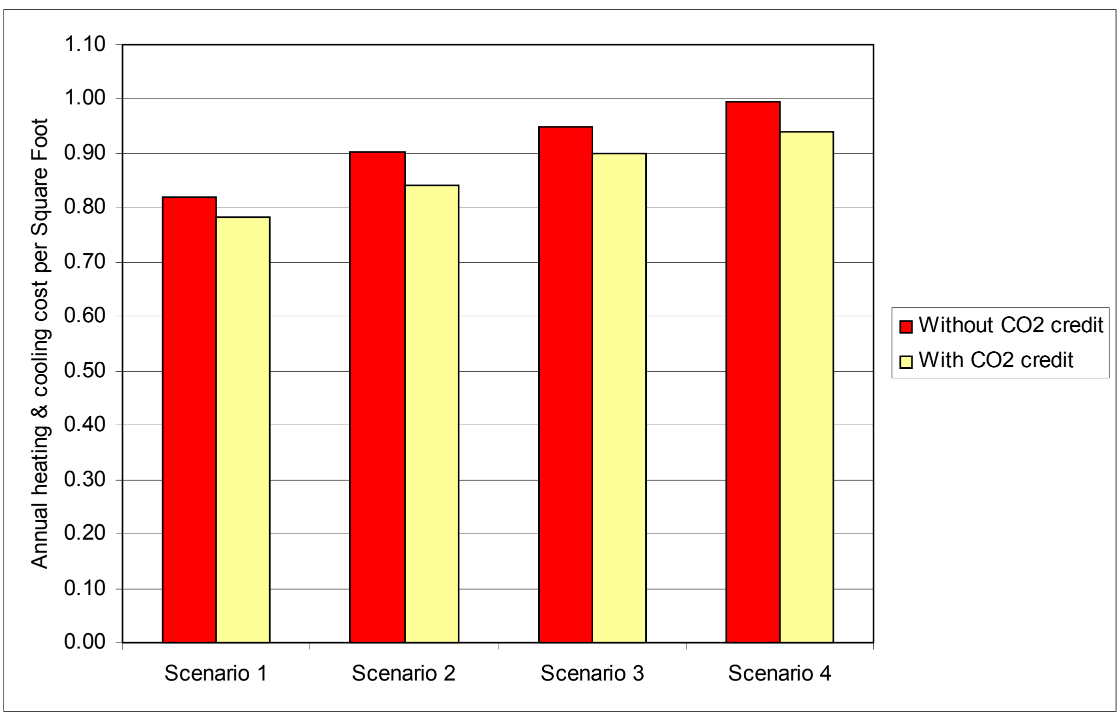



*Figure 59. Sensitivity of Phase 4 Annual Costs to Carbon Dioxide Credit Revenue*



### 4.4.2 Emissions Comparison

The emissions associated with each Energy District scenario were estimated, including the regulated air pollutants nitrogen oxides (NOx) and carbon monoxide (CO) as well as the greenhouse gas carbon dioxide ($CO_2$). This analysis included direct emissions (e.g. emissions from an Energy District boiler stack) as well as indirect emissions, i.e. emissions resulting from generation of electricity obtained from Seattle City Light (SCL). Energy District emissions were then compared with the estimated emissions if no Energy District was implemented.

The emissions modeling required assumptions regarding the types of heating and cooling systems that would otherwise be installed, as well as estimation of the emissions associated with electricity obtained from SCL.

Without an Energy District, a mix of conventional heating, ventilation and air conditioning (HVAC) technologies will be implemented on an individual building scale, including: natural gas boilers; water loop heat pumps; electric resistance heat; and a variety of types of electric-driven cooling systems. Electric HVAC has been dominant in Seattle in the past, and is likely to continue to be a major element in building design. However, with recent increases in the price of electricity, its use for heating can reasonably be expected to decline somewhat. Based on consultation with Seattle City Light staff familiar with local practices, assumptions were developed for "default" (no Energy District) HVAC for each category of building space. The total shares of default HVAC are as summarized in Table 30.

***Table 30. Aggregated Shares of Default HVAC at Full Build-out***

| **Heating** | | **Cooling** | |
|---|---|---|---|
| Electric resistance heating | 32% | DX cooling | 28% |
| Heat pump heating | 19% | Heat pump cooling | 19% |
| Gas heating | 49% | Centrifugal chiller cooling | 53% |

SCL's resource mix is currently 90.2 % hydro, 5.3% natural gas, 2.6% nuclear and the remainder wind, coal, waste and biomass.[74] However, since the peak capacity provided or avoided by the Energy District can be compared to SCL's alternatives for meeting new demand, the emissions characteristics of the Energy District should be compared with SCL's marginal resource (future increments of new capacity). Based on discussion with SCL, the marginal resource is assumed to be combined cycle gas turbines in the near term with a small amount of fluidized bed coal capacity in the longer term. Based on input from SCL, emissions factors for offset SCL resources were projected based on the estimated 2003 factors and the projected 2020 factors summarized in Table 31.

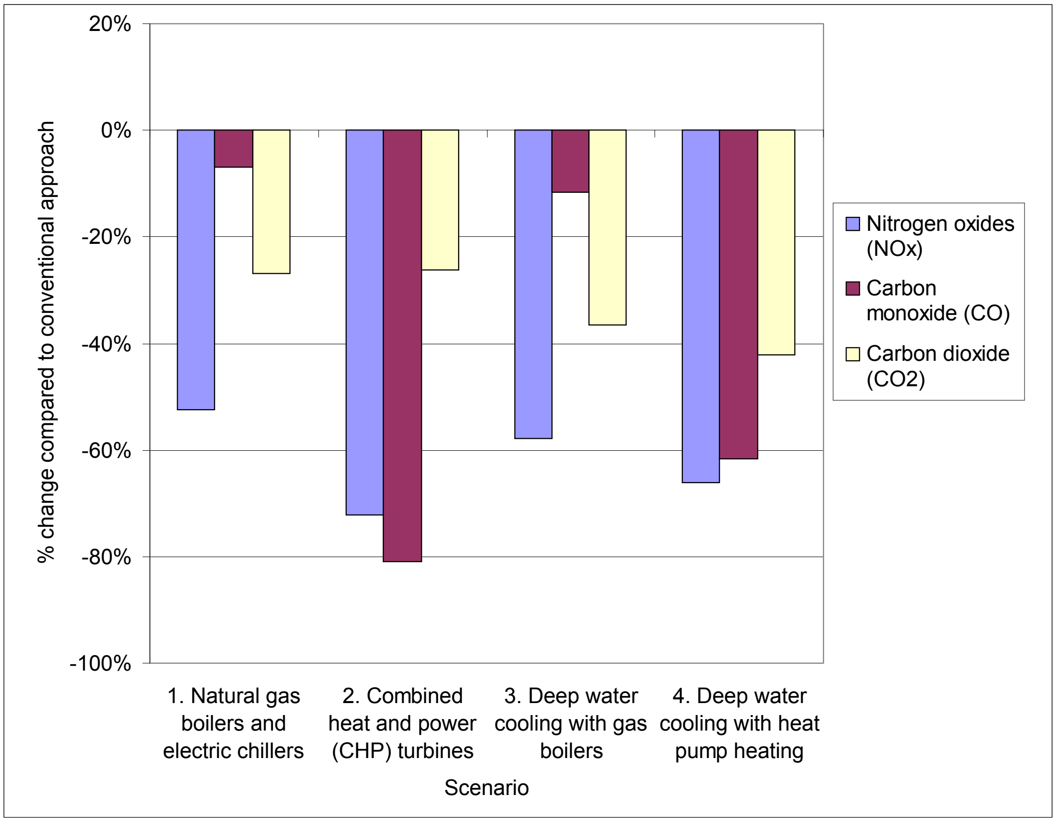
***Table 31. Assumed Emissions Factors for SCL Resources***

| | **Emission rates in lbs/MWH** | | | **Metric tons** | **Heat rate** |
|---|---|---|---|---|---|
| | NOx | CO | CO2 | CO2/MWH | (Btu/kWh) |
| New gas turbine combined cycle inc. 5% transmission losses | 0.105 | 0.044 | 848 | 0.385 | 7,185 |
| Estimated 2003 factor | 0.149 | 0.062 | 1,201 | 0.545 | 10,179 |
| Projected 2020 (90/10 combined cycle/coal mix) | 0.238 | 0.267 | 1,009 | 0.458 | 7,661 |

The resulting base case total net emissions comparison is shown in Figure 60. This graph shows percentage savings with an Energy District compared to no Energy District. In 2020, the Energy District would reduce annual carbon dioxide ($CO_2$) emissions by 26 to 42 percent, and nitrogen oxides emissions by 52 to 72 percent (depending on technologies used) compared to conventional energy approaches.

[74] Seattle City Light website, December 2003.

***Figure 60. Percentage Emissions Reduction with Energy District Scenarios Compared to No Energy District***




### 4.4.3 Policy and Permitting Issues

Based on the preliminary assessment performed for this study, there do not appear to be significant air quality permitting issues associated with any of the Energy District alternatives. In addition to regulated pollutants, carbon dioxide is a key policy issue. The City of Seattle has established a long-range goal of meeting the electric energy needs of Seattle with no net greenhouse gas (GHG) emissions. Per a resolution passed on Earth Day 2000, the City has committed SCL to meet growing demand with no net increases in GHG emissions by "using cost-effective energy efficiency and renewable resources to meet as much load growth as possible," and "mitigating or offsetting GHG emissions associated with any fossil fuels used to meet load growth."

As summarized above, all Energy District concepts would provide a net reduction in GHG emissions, and sensitivity analyses were performed to calculate the economic impact of including economic credit for these reductions using an SCL planning value of $40 per metric ton.

In addition to the City GHG policy, it is clear that key stakeholders in the study area have a strong interest in reducing the environmental impacts associated with meeting energy needs.

Scenario 3 (deep water cooling) and Scenario 4 (deep water cooling and heat pumps) raise a number of environmental issues associated with construction of deep water piping in water bodies and the withdrawal and return of water. Key concerns regarding the environmental impacts of deep water cooling relate to impacts from: laying of the pipeline; impact on aquatic life at the intake; and impact on aquatic life from discharge of water at elevated temperature and heating of water surrounding the pipeline. The impacts involved would have to be identified and addressed in a thorough environmental assessment of a heat pump and/or deep water cooling project.

There may be potential environmental benefits relative to improvement of water quality and enhancement of conditions for salmon migration. Water quality in Lake Union is poor, with a key indicator, dissolved oxygen, at zero in the lower depths of this shallow lake. This condition is related to lack of mixing between the stratified layers in the lake, biological oxygen demands within sediments, relatively high water temperatures and a saline layer at the bottom of the lake during the July-September period. In addition, salmon migration is inhibited by a “thermal barrier,” i.e. high water temperatures in the Ship Canal and the Montlake Cut.

Scenarios 3 and 4 may provide an opportunity to supply cooler, oxygenated water to Lake Union, the Ship Canal and the Montlake Cut, potentially facilitating salmon migration to Lake Washington, and improving water quality:

- Cold Lake Washington water, once used for air conditioning, would be pumped into Lake Union. Although heat would be added to the water (through its use for air conditioning), the system would discharge cleaner, cooler Lake Washington water to Lake Union, potentially providing an improvement to Lake Union water quality and a net cooling of Lake Union and the salmon migration route.
- Shallower Lake Washington water used for heating would be cooled in the process, also providing a net cooling of the water before discharge to Lake Union.
- The heat exchangers used in both the heating and cooling processes could be designed to introduce oxygen into the water, thereby further improving water quality.

It is not clear to what extent these potential benefits are realizable. Assessment of the positive and negative impacts of a heat pump and/or deep water cooling Energy District on fisheries and water quality will require an extensive, complex and lengthy analysis.

Scenario 2 (CHP) also raises a number of policy and contractual issues relative to integration of CHP facilities into the SCL grid, relating to both technical requirements for grid interconnection as well as valuation of the power exported from the CHP facility to the wholesale markets.

### 4.4.4 Seattle City Light Infrastructure

The Energy District is estimated to reduce total peak summer capacity requirements in the combined study by 16-38 MegaVolt-Amperes (MVA) depending on the Energy District technology. The Energy District is estimated to reduce total peak summer capacity requirements in the combined study area as summarized in Figure 61.

The two sub-areas are served by two different electricity distribution systems. Of particular interest is the impact on potential capacity requirements in South Lake Union. Based on analysis by Kurt Conger of Energy Expert Services, the projected impact of the Energy District Scenario 2 is summarized in Figure 62. This indicates that the Energy District may enable a 2-3 year delay (interval “B”) in adding a new substation to serve SLU.

Additional discussion of impacts on SCL infrastructure can be found in Section 5.

*Figure 61. Impact of Energy District on Total Study Area Peak Capacity Requirements*

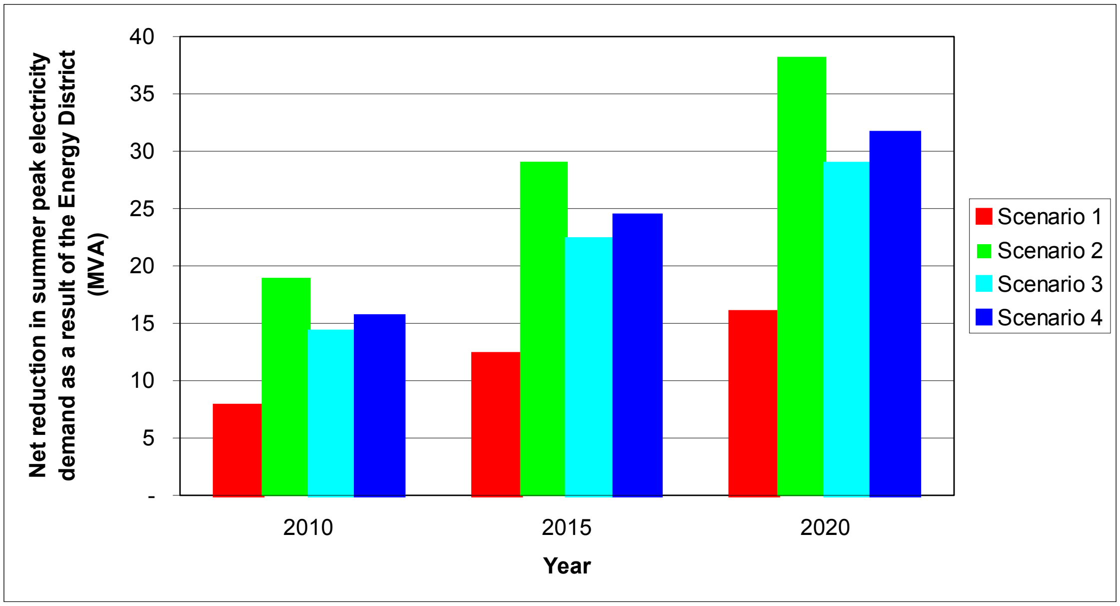
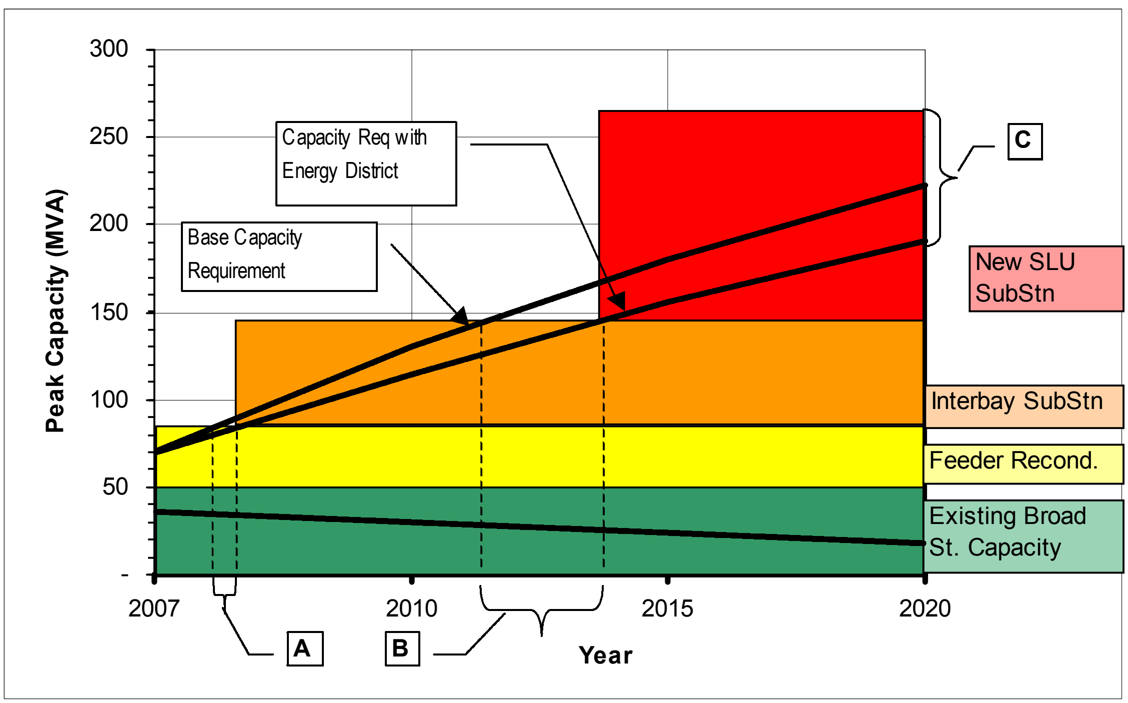



*Figure 62. Impact of Energy District Scenario 2 on South Lake Union Capacity Requirements*



## 4.5 Technology Recommendations

Based on the above evaluation, Scenario 1 provides lowest costs under base case assumptions. However, if CHP has a higher economic value than assumed in the base case (and there are a variety of reasons why this may be so, as discussed above), then CHP would provide a particularly attractive combination of economic and environmental benefits.

Deep water cooling combined with boilers (Scenario 3) and deep water cooling with heat pumps (Scenario 4) hold the potential for enormous sustainability benefits, including:

- Sustainable energy for the major redevelopment area in Seattle;
- Stable energy costs for buildings in the Energy District;
- Reduced emissions of air pollution and carbon dioxide;
- Improved conditions for salmon migration; and

However, the capital and total costs of these scenarios are higher, and the net water quality and fishery impacts require significant study. Scenarios 3 and 4 are unlikely to provide competitive energy services to customers unless additional financial support is provided, e.g., in the form of grants in recognition of the water quality and fisheries benefits (if indeed it is determined that those hypothetical benefits are realizable). If that can be accomplished, it would be a tremendous achievement for sustainability. But many complex questions must be answered before it can be determined if this environmental synergy will work, including permitting issues relating to withdrawal and discharge of water from these natural water bodies.

As noted above, although thermal energy storage was not incorporated into the technology scenarios because of a lack of incentives in SCL electricity rates. However, thermal energy storage may become a beneficial element in an Energy District if SCL implement time-of-day rates or other rate structures that provide incentives for peak-shifting, or non-rate mechanisms to recognize the value of shifting demand to non-peak periods.

It is extremely important to understand that an Energy District opens up many options for energy supply, some of which may not be anticipated currently. Four integrated technology scenarios were evaluated here, but other approaches may become attractive in the near or long term.

Section
# 5 Seattle City Light Distribution System Impact Assessment

## 5.1 Base Capacity Plan

### 5.1.1 Load Density Assumptions

Load density factors include power density, which describes the peak power requirements of customer loads on a W/SF or VA/SF basis, and energy density, which describes the customer load characteristics on a kWh/SF basis.

#### 5.1.1.1 Power Density Method from SCL Capacity Plan Review Phase 1

Consistent with existing SCL T&D capacity planning practice, this analysis is based on “bottom-up” techniques for estimating small area forecast loads. Peak power capacity requirements are estimated from engineering analysis of customer connected load densities and adjusted to reflect diversity of customer uses.

To forecast the peak demand for designing distribution system capacity requirements of the new developments, power density and demand factor values used by SCL T&D planning engineers were multiplied to provide a per square foot estimate of customer capacity requirements (in Volt-Amperes or VA) at the utility service point. The method uses power density and demand factor values that are based on National Electrical Codes requirements for purposes of fire prevention in building premises wiring.[75] Next, these values are multiplied by coincidence factors derived from handbook values to produce a peak load per square foot by Space Usage Type forecast to estimate distribution system capacity requirements at the distribution substation in the SLU/DT study area.[76] Single developments may have multiple Space Usage Types designated for specific square footage portions of the development. The results generated for this design forecast method are intended to estimate a peak power demand that has zero probability of being exceeded.

Table 32 summarizes the peak power densities (coincident peak at substation) used for various Space Usage Types in the study area. The last column in this table shows the estimated weighted average peak power density avoided with the Energy District, based on the assumptions regarding mix of default HVAC are shown in Appendix 9.

#### 5.1.1.2 Energy Density Values

Annual energy density values, based on the detailed assumptions in Appendix 10, are summarized in Table 33.

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75 Refer to Article 220 of the National Fire Protection Association (NFPA) National Electrical Code (NEC) for load estimation standards.

76 Coincidence factor is the inverse of the diversity factor. Values for “user to substation” diversity factors were taken from Fink and Beaty, Standard Handbook for Electrical Engineers, 1993, Table 18-28.

### Table 32. Peak Power Densities by Space Usage Type

| Space Usage Type | Connected power density VA/SF | Peak power demand factor | NEC peak power density VA/SF | Coincidence factor | Peak power density at substation VA/SF | minus base cooling peak capacity requirement | Base non-thermal power density at substation |
|---|---|---|---|---|---|---|---|
| Administrative Office | 26.7 | 0.60 | 16.0 | 0.45 | 7.21 | (3.06) | 4.15 |
| Apartment, Condo, Ex Stay Hotel | 20.0 | 0.30 | 6.0 | 0.50 | 3.00 | (2.39) | 0.61 |
| Grocery Store | 25.0 | 0.70 | 17.5 | 0.50 | 8.75 | (4.09) | 4.66 |
| Health/ Fitness Center | 20.0 | 0.50 | 10.0 | 0.35 | 3.50 | (2.83) | 0.67 |
| High-Tech Office | 48.8 | 0.70 | 34.1 | 0.45 | 15.36 | (4.04) | 11.32 |
| Research Laboratory | 40.0 | 0.70 | 28.0 | 0.75 | 21.00 | (4.42) | 16.58 |
| Hospital, University, Major Institution | 28.6 | 0.45 | 12.9 | 0.75 | 9.65 | (3.54) | 6.11 |
| Hotel, Motel | 20.0 | 0.30 | 6.0 | 0.60 | 3.60 | (2.46) | 1.14 |
| Manufacturing, Warehousing | 20.0 | 0.50 | 10.0 | 0.45 | 4.50 | (0.86) | 3.64 |
| Restaurant | 28.6 | 0.45 | 12.9 | 0.50 | 6.44 | (5.18) | 1.26 |
| Retail Store | 31.3 | 0.80 | 25.0 | 0.50 | 12.50 | (3.68) | 8.82 |
| Server Farm, Data Center, Telecom Hotel | 106.7 | 1.00 | 106.7 | 0.75 | 80.03 | (30.64) | 49.39 |
| Theater | 20.0 | 0.50 | 10.0 | 0.60 | 6.00 | (3.23) | 2.77 |
| School, Library | 20.0 | 0.50 | 10.0 | 0.35 | 3.50 | (2.71) | 0.79 |

### Table 33. Annual Energy Densities by Space Usage Type

| Space Usage Type | Annual heating MMBtu/SF | Weighted average annual heating MMBtu electricity/SF | Weighted average annual heating kWh electricity/SF | Weighted average heating COP | Weighted average cooling COP | Tons cooling per kW power | Weighted average kW/ton | Cooling ton-hours/SF | Cooling kWh/SF |
|---|---|---|---|---|---|---|---|---|---|
| Administrative Office | 0.0183 | 0.0103 | 3.03 | 1.57 | 3.04 | 0.86 | 1.16 | 1.19 | 1.38 |
| Apartment, Condo, Ex Stay Hotel | 0.0272 | 0.0118 | 3.46 | 2.14 | 3.06 | 0.87 | 1.15 | 0.70 | 0.80 |
| Grocery Store | 0.0213 | 0.0011 | 0.31 | 1.00 | 2.36 | 0.67 | 1.49 | 1.04 | 1.55 |
| Health/ Fitness Center | 0.0152 | 0.0107 | 3.13 | 1.00 | 2.66 | 0.76 | 1.32 | 0.74 | 0.97 |
| High-Tech Office | 0.0165 | 0.0066 | 1.93 | 1.00 | 3.02 | 0.86 | 1.16 | 2.77 | 3.22 |
| Research Laboratory | 0.0419 | 0.0021 | 0.61 | 1.00 | 3.44 | 0.98 | 1.02 | 3.14 | 3.21 |
| Hospital, University, Major Institution | 0.0479 | 0.0048 | 1.40 | 1.00 | 3.38 | 0.96 | 1.04 | 2.85 | 2.97 |
| Hotel, Motel | 0.0224 | 0.0093 | 2.74 | 2.33 | 2.95 | 0.84 | 1.19 | 0.70 | 0.83 |
| Manufacturing, Warehousing | 0.0082 | 0.0016 | 0.48 | 1.00 | 3.26 | 0.93 | 1.08 | 0.29 | 0.32 |
| Restaurant | 0.0431 | 0.0086 | 2.52 | 1.00 | 2.54 | 0.72 | 1.38 | 1.01 | 1.40 |
| Retail Store | 0.0185 | 0.0074 | 2.17 | 1.00 | 2.78 | 0.79 | 1.26 | 1.04 | 1.32 |
| Server Farm, Data Center, Telecom Hotel | 0.0066 | 0.0022 | 0.64 | 3.00 | 3.00 | 0.85 | 1.17 | 25.47 | 29.86 |
| Theater | 0.0185 | 0.0019 | 0.54 | 1.00 | 3.02 | 0.86 | 1.16 | 1.04 | 1.21 |
| School, Library | 0.0201 | 0.0054 | 1.57 | 2.67 | 3.01 | 0.86 | 1.17 | 1.08 | 1.26 |

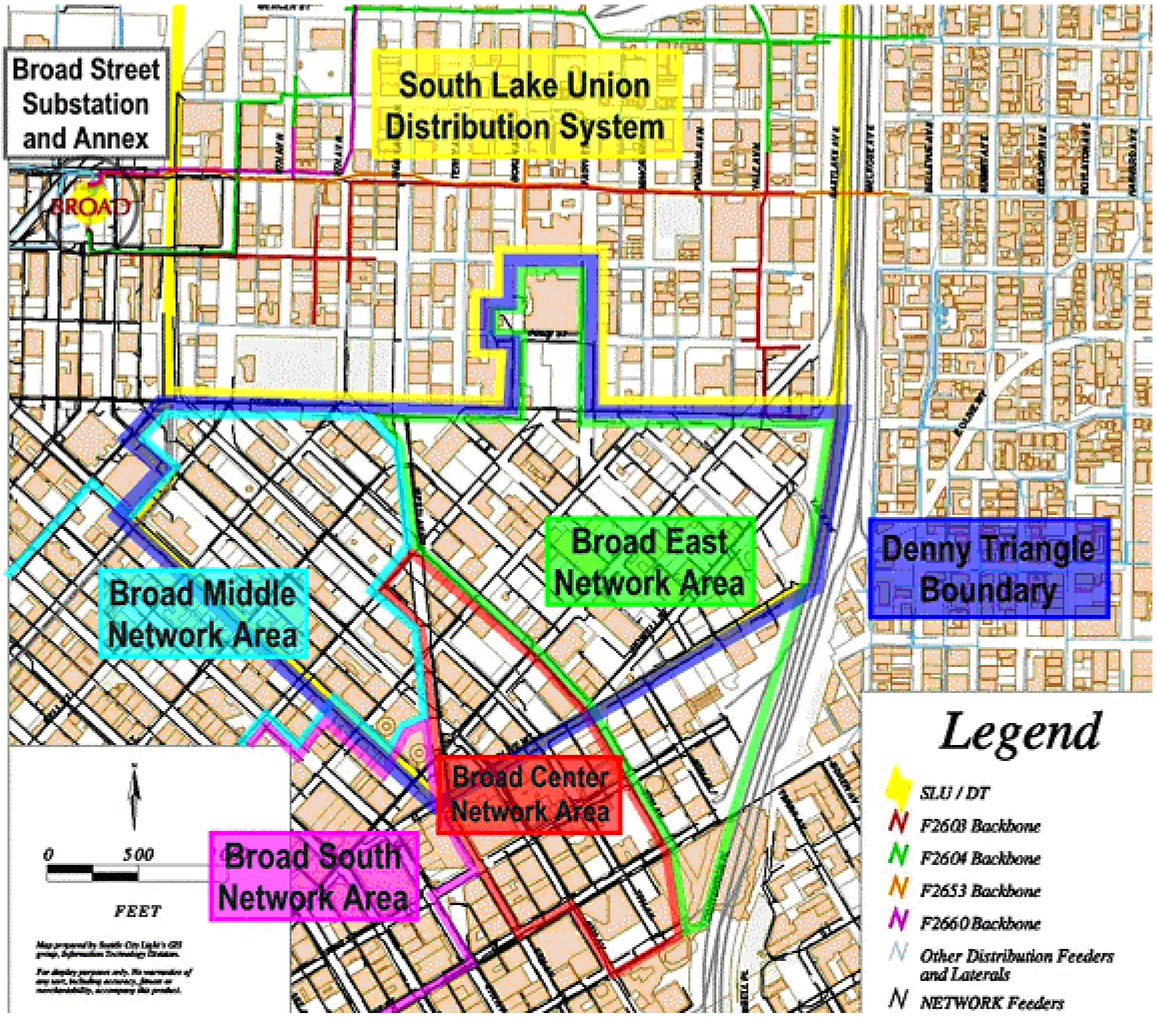
## 5.1.2 Electric Load Analysis for SLU/DT Energy District Study

To estimate load characteristics in the study area, the same area redevelopment assumptions used for estimating thermal loads based on Space Usage Types were used for developing the electrical load forecast for new developments in each of the load areas.

The SLU/DT study area encompasses two topologically different electric distribution systems that must be analyzed using different methods. In South Lake Union the distribution system topology is characterized by mostly overhead radial feeders that can be reconfigured to balance loads and provide emergency ties for reliability. The Denny Triangle area is characterized by predominantly underground secondary network distribution service with spot networks feeding larger buildings.

Figure 63 provides an overview of the distribution systems in the study area.

*Figure 63. Overview of Study Area Electricity Distribution Systems*




#### 5.1.2.1 Peak Demand Forecast for Distribution Capacity Design

Existing Demand and Capacity in South Lake Union

From SCADA/EMS data (15 minute average demand interval), the existing feeder loads in the South Lake Union area are estimated to produce a coincident peak power demand of approximately 36 MVA on four feeders connected to Broad Street substation. See Appendix 10 for the assumptions underlying this estimate.

The non-coincident peak load of approximately 60 MVA results in each of these four feeders nearing or exceeding their target operating ratings during some period each year. The combined operating ratings of the four feeders serving SLU is 49.1 MVA (summer) and 52.6 MVA (winter). The feeder ratings and 2002 loadings for the relevant Broad Street feeders serving South Lake Union are shown in Figure 64.

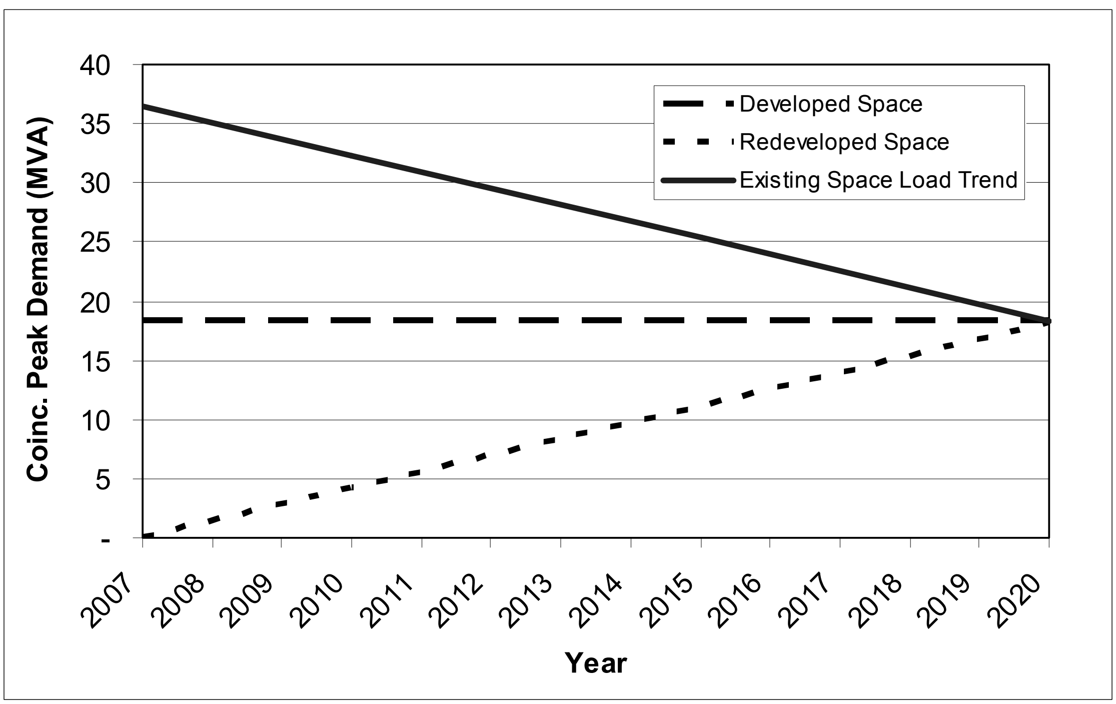
*Figure 64. Feeder Ratings and 2002 Loadings for Broad Street Feeders serving SLU*

| Broad Street Substation | | Design Rating | | Seasonal Operating Rating | | Peak | % of | |
|---|---|---|---|---|---|---|---|---|
| **Bus** | **Feeder** | **Amps** | **MVA** | **Sum MVA** | **Win MVA** | **MVA** | **Capacity** | **Peak Mon** |
| A | 2653 | 600 | 26 | 9.69 | 11.43 | 12.06 | **105.5%** | Dec |
| A | 2660 | 1200 | 52 | 18.29 | 18.29 | 19.21 | **105.0%** | Jan |
| C | 2603 | 600 | 26 | 11.43 | 11.43 | 10.81 | 94.5% | Nov |
| C | 2604 | 600 | 26 | 9.69 | 11.43 | 18.36 | **189.5%** | Jun |
| Total South Lake Union | | | | 49.10 | 52.58 | 60.44 | | |
| Coincident Peak | | | | | | 36.44 | | |

A majority of the other feeders at the Broad Street substation are also loaded past their seasonal operating ratings indicating that at present loadings, the substation is fully loaded and provides little operating margin without design modifications (e.g. feeder or getaway reconductoring).

The 36 MVA existing coincident peak demand may be affected by the new development activity. Heartland estimated that approximately 36% of the total land area in SLU is unlikely to redevelop within the planning period. Approximately half of the existing conditioned space in SLU is expected to be “redeveloped”. The existing “developed” space accounts for approximately 3,222,400 SF commercial and 1,417,000 SF residential out of the total existing space of 9,206,963 SF. This indicates an existing average peak power density on a gross square footage basis of approximately 3.96 VA/SF coincident peak at the Broad Street Substation for the SLU area. For purposes of this analysis 50% of the existing load, or 18 MVA coincident peak (CP) demand, is assumed to remain constant throughout the phases of redevelopment. This amount is separate from the new loads. The 18 MVA CP demand from existing loads that are subject to redevelopment will decline linearly over the redevelopment period. The existing load curve will therefore be shaped as shown in Figure 65.

*Figure 65. South Lake Union Load Curve for Existing Space*



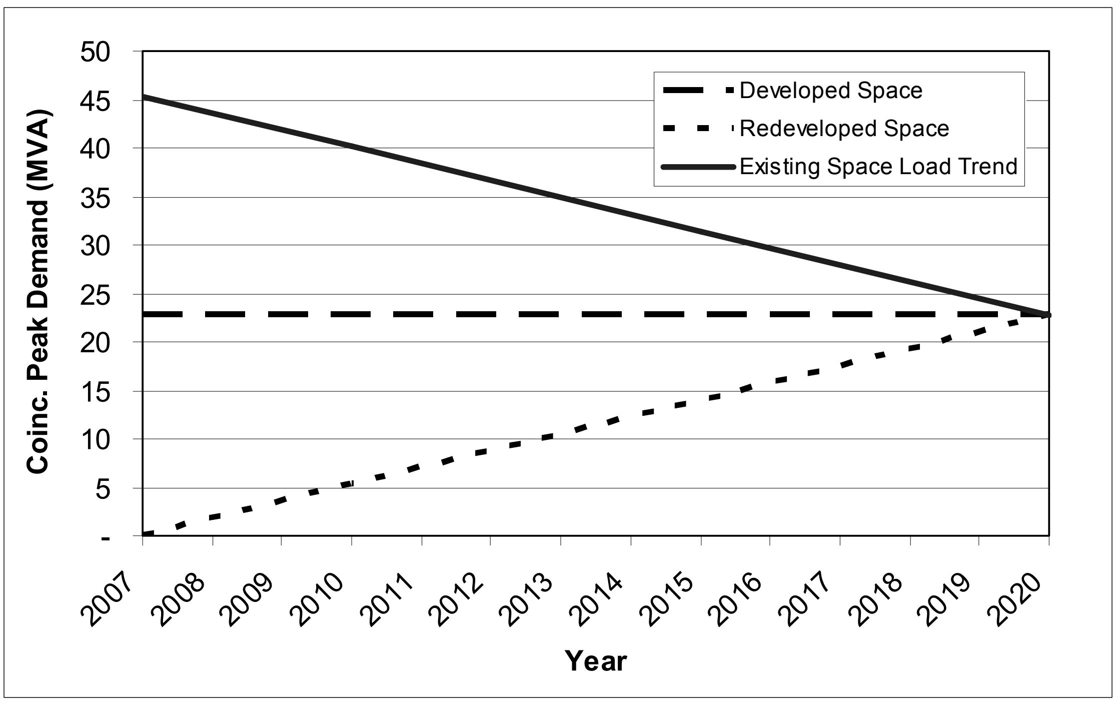
## Existing Demand in Denny Triangle

As mentioned above, the Denny Triangle study area is predominantly served by a secondary network distribution system that consists of five secondary subnetworks that are fed by thirty 13 kV feeders connected to the Broad Street Annex. The historical Broad Annex feeder coincident peak demand is approximately 120 MVA. The existing connected loads have been estimated to be capable of creating a peak demand of 185.92 MVA non-coincident and 153 MVA coincident under more favorable economic conditions (e.g. higher occupancy rates) and potential extreme weather conditions (e.g. winter cold-snap or summer high temperature range).

At present there is approximately 55.31 MVA of existing non-coincident peak load located within the Denny Triangle portion of the study area boundary (approximately 45.4 MVA coincident). This load is primarily located in Broad East, Broad Middle and Broad Center subnetworks, but some Denny Triangle loads are also located in Broad North and Broad South subnetworks. By comparison, the Denny Triangle study area load currently represents approximately 29.7% of the total Broad Annex load on either a coincident or non-coincident basis.

There is no analysis of the probable “redeveloped” versus “developed” space for Denny Triangle. For simplicity, it is assumed that the existing land in Denny Triangle consists of 50% developed space that will not be redeveloped during the 2005 – 2020 study period. The remaining 50% represents the land upon which the redevelopment occurs. This assumption facilitates estimation of Denny Triangle load curve for existing space similar to the SLU load curve shown above. In the case of Denny Triangle, the existing loads are assumed to be 45.4 MVA in 2005 and decline to 22.7 MVA in 2020, as shown in Figure 66.

***Figure 66. Denny Triangle Load Curve for Existing Space***




Because Denny Triangle is only a portion of the load served by the Broad Street Annex, the capacity available to serve existing and forecast load growth in the study area must be analyzed in conjunction with existing and forecast growth in the Broad Annex subnetworks outside of the study area. At this time SCL has new load requests totaling 29 MVA in the outside subnetworks that will place an additional 24 MVA coincident peak demand on Broad Annex.

## New Peak Power Demand and Capacity Requirements in South Lake Union and Denny Triangle

From the peak power densities described above, the peak power capacity requirements for the combined study area were calculated by multiplying by the square footage projections by these power densities for each of the study areas to produce peak power demands by development.[77] These values are summed by phase and by area to estimate the appropriate peak power design capacity requirements for each area in each phase of development. Table 34 below shows the results of this calculation. The percentage shares of each Space Usage Type is as summarized in Section 2.

***Table 34. Capacity Requirements by Space Usage Type (MVA)***

| Space Usage Type | Capacity Req. SLU | Capacity Req. DT | Capacity Requirement Combined Area | H or C |
|---|---|---|---|---|
| High-Tech Office | 80.12 | 57.29 | 137.42 | C |
| Research Laboratory | 55.83 | 3.74 | 59.57 | C |
| Apartment, Condo, Ex Stay Hotel | 23.89 | 14.04 | 37.93 | C |
| Administrative Office | 11.20 | 22.07 | 33.27 | H |
| Retail Store | 11.72 | 10.45 | 22.16 | C |
| Server Farm, Data Center, Telecom Hotel | 14.08 | 0.00 | 14.08 | C |
| Hospital, University, Major Institution | 5.57 | 0.00 | 5.57 | C |
| Hotel, Motel | 0.00 | 1.48 | 1.48 | C |
| Grocery Store | 0.50 | 0.41 | 0.91 | C |
| Theater | 0.47 | 0.00 | 0.47 | C |
| Restaurant | 0.38 | 0.05 | 0.43 | C |
| School, Library | 0.33 | 0.04 | 0.37 | C |
| Health/ Fitness Center | 0.21 | 0.07 | 0.28 | H |
| Manufacturing, Warehousing | 0.07 | 0.00 | 0.07 | C |

Note: the value in the H or C column indicates whether the thermal peak is a heating (H) or cooling (C) peak capacity requirement. Because the peak cooling capacity is the predominant value for the Space Usage Types in the study area, the thermal peak capacity requirement calculation used for district energy system analysis is based on the peak cooling capacity plus eight percent of the peak heating capacity requirement which accounts for hot water supply.

Combining the coincident peak capacity requirements of the existing loads and new development loads results in the total peak capacity requirements curve shown in Figure 67. These data are presented in tabular form in Table 35.

Note that for the study period, capacity requirements are expected to increase at a rate of approximately 12 MVA per year in South Lake Union and 5 MVA per year in Denny Triangle. While additional development potentials exist in the study area after the year 2020, load growth may be expected to taper off as the area reaches its full development potential.

[77] As stated in early sections of this report, building space projections from the Heartland South Lake Union Capacity model and downtown Environmental Impact Statement (EIS for Denny Triangle).

*Figure 67. Existing plus New Power Load Capacity Requirements*

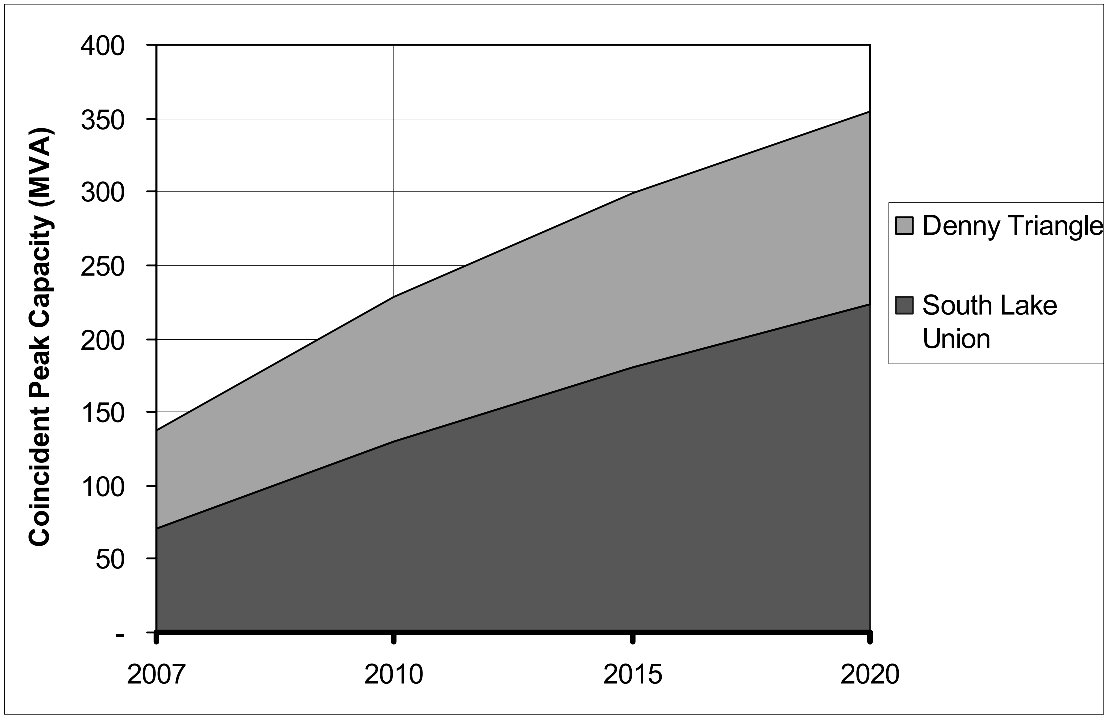



*Table 35. Existing and New Power Load Capacity Requirements by Phase*

| | Total | South Lake Union | Denny Triangle |
|---|---|---|---|
| **New Power Load Capacity Requirements by Phase** | | | |
| | Total | South Lake Union | Denny Triangle |
| Phase 1 (2007) | 56.19 | 34.61 | 21.59 |
| Phase 2 (2010) | 104.19 | 65.02 | 39.17 |
| Phase 3 (2015) | 83.59 | 55.95 | 27.63 |
| Phase 4 (2020) | 70.04 | 48.79 | 21.25 |
| **Cumulative Capacity Requirements by Phase** | | | |
| | Total | South Lake Union | Denny Triangle |
| 2007 | 56.19 | 34.61 | 21.59 |
| 2010 | 160.38 | 99.63 | 60.76 |
| 2015 | 243.97 | 155.58 | 88.39 |
| 2020 | 314.01 | 204.37 | 109.64 |
| **Existing Loads** | | | |
| 2007 | | 36.44 | 45.35 |
| 2010 | | 30.41 | 37.79 |
| 2015 | | 24.39 | 30.24 |
| 2020 | | 18.36 | 22.68 |
| **Total Load** | | | |
| 2007 | 137.99 | 71.05 | 66.94 |
| 2010 | 228.59 | 130.04 | 98.55 |
| 2015 | 298.59 | 179.97 | 118.62 |
| 2020 | 355.05 | 222.73 | 132.32 |

#### 5.1.2.2 Electrical Energy Forecast for Cost Analysis

Because the peak demand forecast used for distribution system design described in the previous section is intended to always produce peak power capacity values that have 100% probability of exceeding actual peak loads (for safety and reliability reasons), it does not provide a suitable basis for estimating electrical energy consumption. For heating and cooling energy consumption, energy density factors (in kWh/SF) were developed using thermodynamic models that consider thermal load characteristics.

Non-thermal energy consumption is not considered in this impact analysis.

#### 5.1.2.3 Sensitivities

Additional sensitivity analysis can be performed, however there are many variables that may range widely, thus producing a large data set of results. The following are considered possible values that could be varied over a range to test the sensitivity of the model to different inputs.

- Building space projections: The load model results will vary significantly with changes to the development assumptions. The base model assumes building space projections from Heartland and the downtown EIS. The simplest sensitivity assumes proportional scaling of building space projections while preserving the space usage type ratios.
- Variations from assumed space usage types. Because the peak power densities of different space usage types vary significantly, changes in the composition of space usage will significantly change the capacity forecast.
- Load Density Assumptions. Load density data should be collected to determine whether the values used are appropriate for each Space Usage Type in Seattle.
- Coincidence Factors. Additional load research to establish probable diversity characteristics by Space Usage Type could provide greater certainty regarding the load-to-substation values.
- HVAC Modes of Study Area. Because the existing developments and a percentage of the new developments are not expected to take service from the energy district, assumptions regarding the modes of heating and cooling are made for these structures. At the extremes, all gas heat tends to reduce heating demands, whereas, all electric heating can cause the heating peak demand to exceed the cooling peak demand.
- Seasonal Load Variations. In particular, the thermal loads are driven by either cooling peaks or heating peaks. The model could be refined to discriminate whether the annual peak occurs during heating or cooling seasons and find the single highest peak value.
- Seasonal Ratings. T&D infrastructure ratings will vary depending on ambient weather conditions. Typically winter ratings are higher than summer ratings.

### 5.1.3 Existing SCL Transmission and Distribution Infrastructure

#### 5.1.3.1 Transmission Facilities Serving SLU/DT

SCL owns, maintains and operates all of the 115 kV transmission facilities connected to the substations that serve South Lake Union and Denny Triangle. Broad Street substation is the primary station serving SLU and Denny Triangle, with East Pine and University providing limited feeder transfer capacity to the SLU area. Under current loads, transmission capacity for power delivery to the substations serving the SLU/DT study area is considered adequate. However, if an additional load growth occurs, a new substation in South Lake Union is planned, and reconfiguration of the existing transmission facilities will be necessary. SCL T&D Planning staff have prepared a horizon transmission system plan which envisions the addition of substations at Interbay, South Lake Union and Downtown. These stations will be designed to operate at either 115 kV or 230 kV so that voltage conversion can take place when additional capacity is required.

The existing 115 kV cable from East Pine to Broad Street is over 40 years old and will need to be replaced regardless of whether load growth necessitates transmission capacity increases. SCL currently proposes to design the replacement cable for 230 kV operation, but utilize it at 115 kV until additional capacity is required. This cable will also be a primary connection to the proposed South Lake Union substation.

#### 5.1.3.2 South Lake Union Distribution System

The South Lake Union area is currently served by four feeders that are connected to the Broad Street substation. During contingencies, loads can be transferred to feeders connected to the East Pine and University substations for some of the feeders fed from Broad Street Substation. In aggregate there is 45 MW (50 MVA at 90% power factor) of existing substation and feeder capacity available to serve the South Lake Union area. Under historical loadings, the feeders in South Lake Union have had sufficient capacity in aggregate to reliably serve loads in this area. New load requests indicate future stress on the system beyond the operating capacities of the Broad Street substation. SCL has already begun reconductoring feeders to increase distribution capacity in the SLU area 28 MW by 2005. An additional 52 MW (61.2 MVA) of feeder capacity can be made available to the SLU area by transferring load to the yet to be built Interbay substation (unfunded). Including only existing substation/feeder capacity and the funded reconductoring projects, SLU capacity is limited to 86 MVA (53 + 33 MVA).

There is no additional capacity at East Pine substation that can be used to serve loads in the South Lake Union area. At East Pine substation, 11 out of 16 feeders already significantly exceeded their recommended operating ratings for multiple months during 2002. For this reason, East Pine can only provide limited backup to SLU for temporary outage restoration.

Broad Street cannot be upgraded substantially because there is insufficient capacity to transfer loads to feeders from other substations and getaway duct banks are thermally limited due to common heating of adjacent conductors. Near term capacity additions may be limited to use of mobile substations located adjacent to the 115 kV overhead transmission circuits in the vicinity of the Broad Street substation.

#### 5.1.3.3 Denny Triangle Distribution System

Denny Triangle is served by secondary network grids fed from the Broad Street Annex substation as shown in Figure 63.

The peak operating capacity of Broad Annex is approximately 168 MVA.[78] With the existing coincident peak demand of 153 MVA, the Broad Annex is loaded within 15 MVA of its current firm rating. Therefore, under the current network configuration there is little additional capacity for Denny Triangle available from Broad Annex.[79] Furthermore, it would be desirable to reduce existing loadings on the Broad Annex feeders to avoid exceeding operating limits.

Under the development and power density assumptions described above, an additional 111 MVA of distribution system capacity will be needed for load service from the Broad Annex between now and 2020.[80] Combining existing loads with this additional capacity requirement results in a peak capacity requirement for the five Broad Annex subnetworks equal to 264 MVA (153 + 111). Because of the network topology and location of Denny Triangle, the study area must be fed from the north, i.e. Broad Annex or a new 13 kV substation in the study area.

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78 The Broad Street Annex is powered by four 56 MVA transformers (at 65º C rise) which under single contingency can provide 3 x 56 MVA = 168 MVA firm capacity. Note that 65º C rise may not be practical as a summer rating given higher ambient temperatures. Using the 55º C rise rating the capacity of each transformer is limited to 50 MVA.

79 SCL staff indicate that an additional 24 MVA of capacity has been requested by new loads outside the Denny Triangle study area but within the Broad Annex network areas.

80 This consists of: 110 MVA new redevelopment load in DT – 23 MVA existing load replaced by redevelopment in DT + 24 MVA of new load outside DT.

One option would be to serve the study area exclusively from Broad Annex. This would be done over time as the subnetworks could be reconfigured and fed from another substation that would need to be built. The amount of load that would be transferred from Broad Annex would be 130 MVA plus load growth during the period through 2020 for the area that is outside of the Denny Triangle study area.

A further consideration in the Denny Triangle area is the limitation on rights of way. Existing infrastructure occupies cross-sections of road and utility corridors to a depth of 9 to 12 feet. Energy district pipe would therefore need to be bored through soil at a minimum depth of 13 feet.

### 5.1.4 T&D Infrastructure to Serve New Loads

#### 5.1.4.1 South Lake Union Capacity

For purposes of this study, the potential SLU capacity build-up options (in MVA) are shown in Figure 68. A peak load power factor of 90% was assumed and applied to MW values provided by T&D Planning to estimate MVA capacities. Table 36 summarizes this information in tabular form, and shows estimated costs for each expansion option.

***Figure 68. South Lake Union T&D Capacity Build-up Plan***

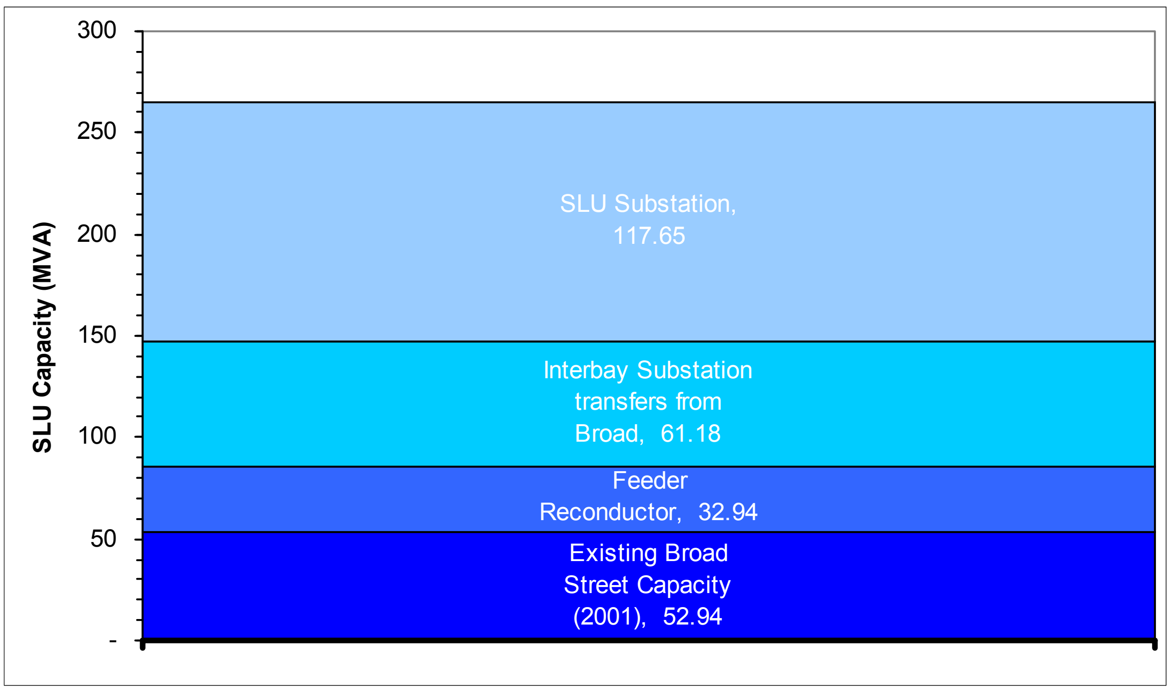



***Table 36. SLU Capacity Expansion Options and Costs***

| Capacity Expansion Options | MW | MVA | Cum. | Cost |
|---|---|---|---|---|
| Existing Broad Street Capacity (2001) | 45 | 52.94 | 52.94 | $0.0 M |
| Feeder Reconductor | 28 | 32.94 | 85.88 | Funded |
| Interbay Substation transfers from Broad | 52 | 61.18 | 147.06 | $21.0 M |
| SLU Substation | 100 | 117.65 | 264.71 | $120.0 M |
| SLU Substation Expansion | 100 | 117.65 | 382.35 | $5.0 M |

#### 5.1.4.2 Denny Triangle/Broad Annex Capacity

The existing capacity of Broad Annex is approximately 168 MVA and options for increasing the electrical distribution capacity of the subnetworks feeding Denny Triangle are quite limited. SCL has developed a plan to that would increase the capacity of Broad Annex to 213 MVA,[81] but this is neither approved nor funded at this time. Furthermore, 213 MVA falls short of the 264 MVA estimated capacity requirement for 2020 described in the previous section titled Denny Triangle Distribution System. The build up options for the Broad Annex are shown in Figure 69.

***Figure 69. Broad Annex T&D Capacity Build-up Plan***


Options being discussed for increasing capacity in the Broad Annex subnetworks for service to Denny Triangle include:

- Reconductoring and cable replacements (likely to result in only a slight increase in capacity since 115 to 13 kV transformer capacity is limited).
- Increasing the capacity of existing transformers powering the Broad Annex subnetworks. This approach, however, is limited by the getaway capacity of feeders exiting the Broad Street substation.
- Construction of a new substation to provide capacity that would permit transfer ("cut-and-tap") of Broad Annex loads outside of Denny Triangle to the new substation.
- Construction of a new substation that would permit division of the existing Broad Annex subnetworks.

Options that increase existing facility ratings are further limited because existing operating flexibility is extremely limited. For example, reconductoring to increase getaway capacity requires load transfers to adjacent feeders that have sufficient operating margin to temporarily carry the loads of both feeders. In some instances this will not be possible without operating under a zero contingency

[81] This 45 MVA increase may be possible by increasing the ratings of the substation transformers serving the Broad Annex. High temperature bushings and improved cooling methods are being considered.

reliability criteria, i.e. there will be no spare feeder capacity to back up feeder getaways that are being reconductored.

## 5.2 Energy District Impact Assessment

Thermal loads that would otherwise be served by building electrical systems may be served by the Energy District. For planning purposes, SCL engineers need to be informed as early as possible regarding thermal loads being served by the Energy District so that long term SCL capacity plans do not unnecessarily assume electric heating and cooling loads. The new load application and building permitting process should be made more rigorous to ensure that planners get adequate early word on customer heating and cooling plans. Absent such a process, planners may have little choice but to estimate capacity requirements based on conventional assumptions regarding heating and cooling loads.

For purposes of this study, both loads and Energy District implementation are assumed to increase gradually between phases. In practice, both electrical loads and Energy District implementation are likely to create a "lumpy" profile.

In the figures in each section below, the coincident summer peak demand avoided due to the Energy District was subtracted from the Base Capacity Requirement (No Energy District) to produce an adjusted load curve for both South Lake Union and Denny Triangle. The avoided peak demand is the difference between the cooling capacity displaced by the Energy District and the net summer Energy District electrical capacity requirements.

### 5.2.1 District Energy System Impacts on SCL Transmission and Distribution System Capacity Requirements

#### 5.2.1.1 South Lake Union

For South Lake Union the most significant net Energy District impacts on capacity requirements occur with Scenarios 2 and 4.

Scenario 2 includes a combined heat and power (CHP) plant located in SLU with 20 MWe output rated at 90% power factor.[82] This requirement establishes that the capability of the 20 MWe CHP plant must be 22.2 MVA. Provided that the plant is capable of meeting the firm output requirements (N-1) for 20 MWe and that it can be dispatched by the SCL system control center when needed for feeder loading relief, the potential firm capacity reduction of 22.2 MVA is possible.[83] This is illustrated in the chart below.

Considering all potential impacts of the Energy District, including reduction in peak load capacity requirements in buildings, and the peak load capacity requirements of the Energy District facilities, in South Lake Union the net Energy District impact of Scenario 2 is approximately 32 MVA in 2020, as illustrated in Figure 70.

With Scenario 4, the total net reduction is approximately 14 MVA in 2020, as illustrated in Figure 71.

The impacts of these reductions on infrastructure additions is illustrated in Figure 72 and Figure 73 for Scenarios 2 and 4, respectively. These charts are intended to illustrate the potential timing and capacity reduction impacts of the energy district reduction in distribution system capacity requirements for South Lake Union. It does not represent a planning forecast for the study area. To

[82] The draft SCL generator interconnection standard requires that generators have a continuous reactive capability between 0.95 leading and 0.90 lagging power factor. Appendix B-1, D.6.c.1. Performance Requirements, Reactive Power and Voltage Regulators, Synchronous Generators.

[83] One possible configuration is 5 x 5 MW generating units. This would provide a firm rating of 20 MW for the plant under singe contingencies.

the extent that load growth does not occur in a smooth, linear trend, capacity requirements may need to be advanced or delayed accordingly.

For each illustration callouts A and B show the approximate time deferral that may be gained from each of the energy district options. Callout C shows the ultimate substation capacity reduction in year 2020 that may be possible if the energy district is able to displace load. The decrease in capacity required to serve loads in the SLU area that are taking service from the DES may allow the installation of a smaller substation [callout C]. Instead of a substation based on 2 x 100 or 2 x 75 MVA transformers, a 2 x 50 MVA size appears to be adequate. In either case, SCL typically plans substations to include space provisions for a third transformer allowing for future increase in the substation capacity.

Because the utility planning horizons typically reevaluate substation requirements annually, these estimates will be reevaluated to periodically to determine whether load is growing at the rate forecast in prior periods and whether the DES and CHP are effectively displacing load that would otherwise be served by the utility. The analysis presented provides a baseline for estimating the economic feasibility of the energy district options being considered.

***Figure 70. SLU Capacity Requirements with Scenario 2 Energy District Impacts***

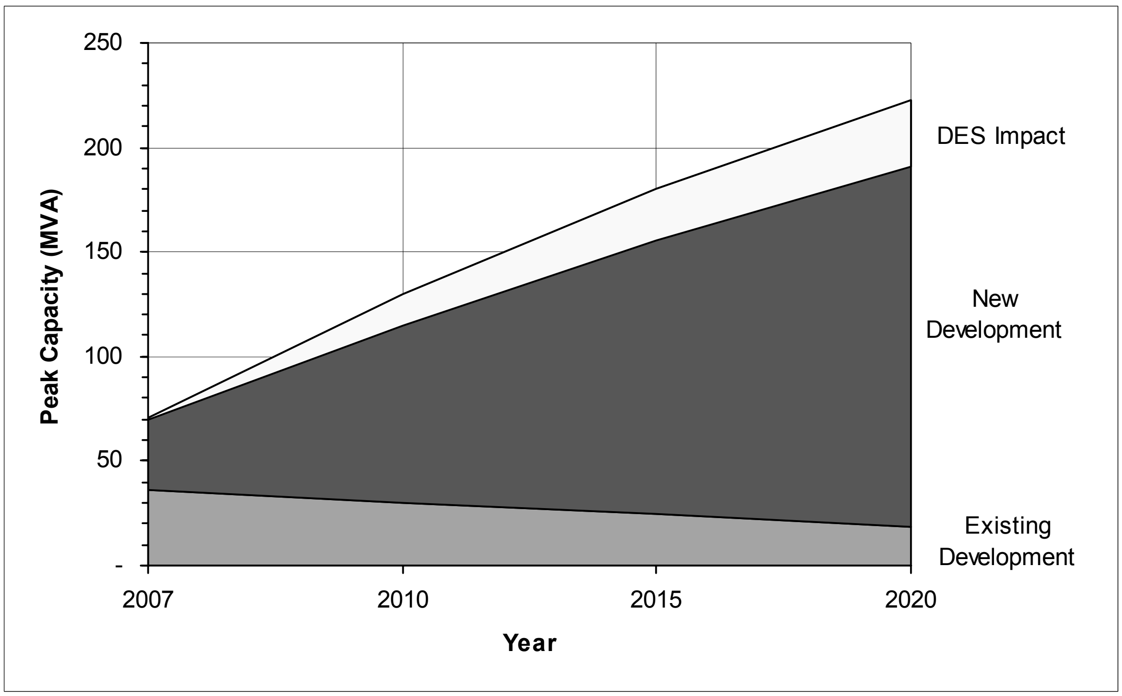


***Figure 71. SLU Capacity Requirements with Scenario 4 Energy District Impacts***

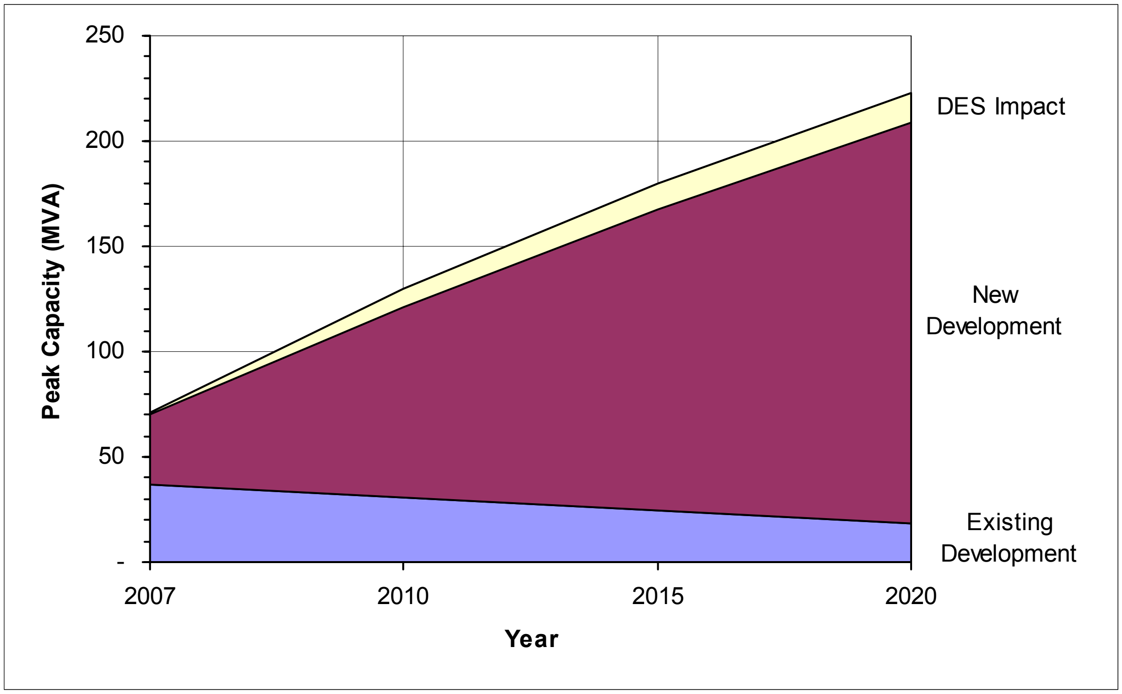



***Figure 72. Impact of Energy District Scenario 2 on SCL Infrastructure***

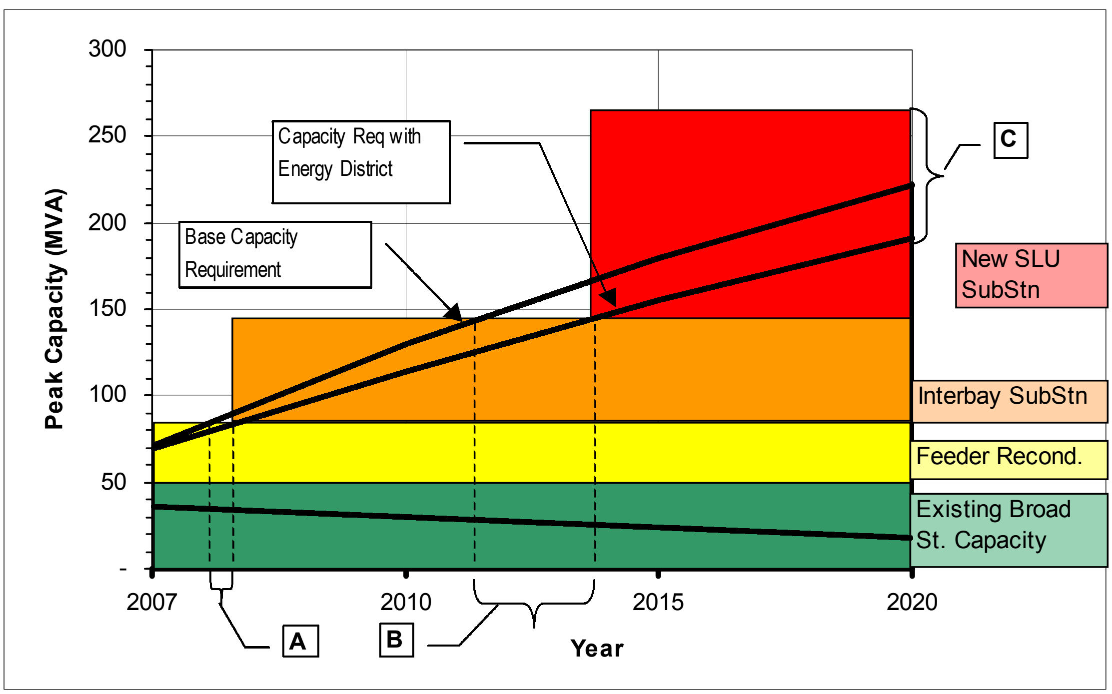
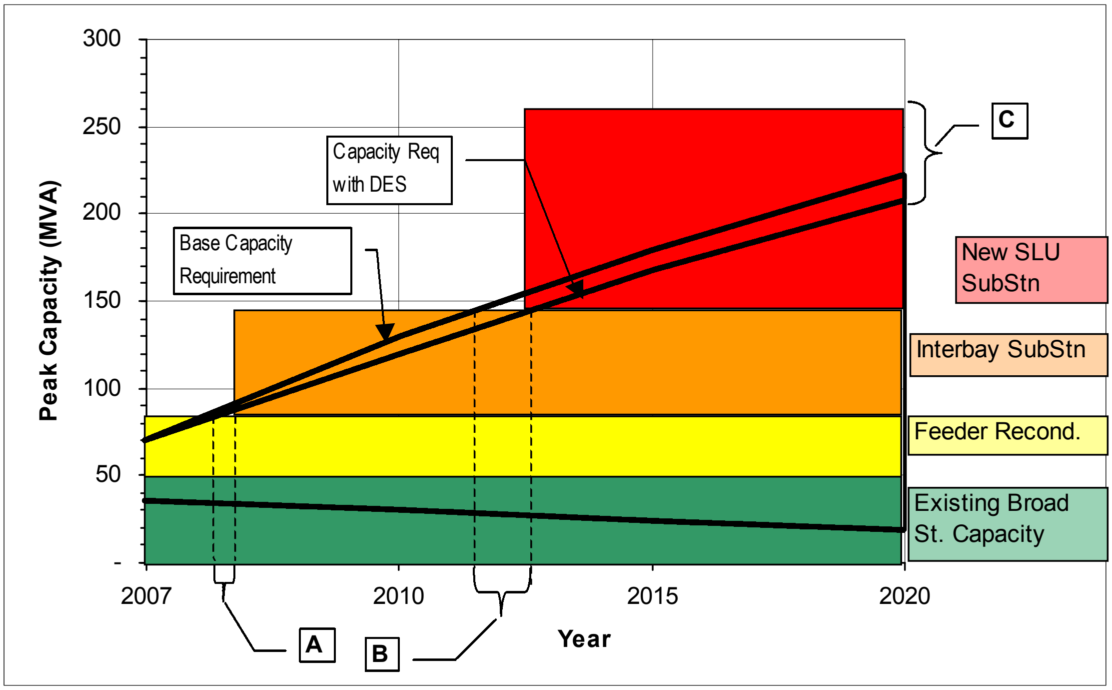


*Figure 73. Impact of Energy District Scenario 4 on SCL Infrastructure*




### 5.2.1.1 Denny Triangle

As stated earlier, Denny Triangle analysis is based on the impact on Broad Annex capacity since the capacity of this facility is affected by the aggregate load for the area served by the five subnetworks, which includes the Denny Triangle study area. In the charts below, the bottom two areas show the peak demand profile for the existing and new development loads in Denny Triangle. To this the Broad Annex load outside the Denny Triangle area is added. From the upper edge of the curve the reduction potential of the District Energy System is shown.

The net reduction in peak summer electrical capacity requirements due to the Energy District in Denny Triangle is projected to be 7.5 MVA in 2020 for Scenario 2 (Figure 74) and 14.2 MVA in 2020 for Scenario 4 (Figure 75).

In the Denny Triangle area, the existing capacity of 168 MVA is only sufficient for current capacity requirements. New development in 2007 and beyond will necessitate additional capacity to serve that area.

***Figure 74. Denny Triangle Capacity Requirements with Energy District Scenario 2 Impacts***

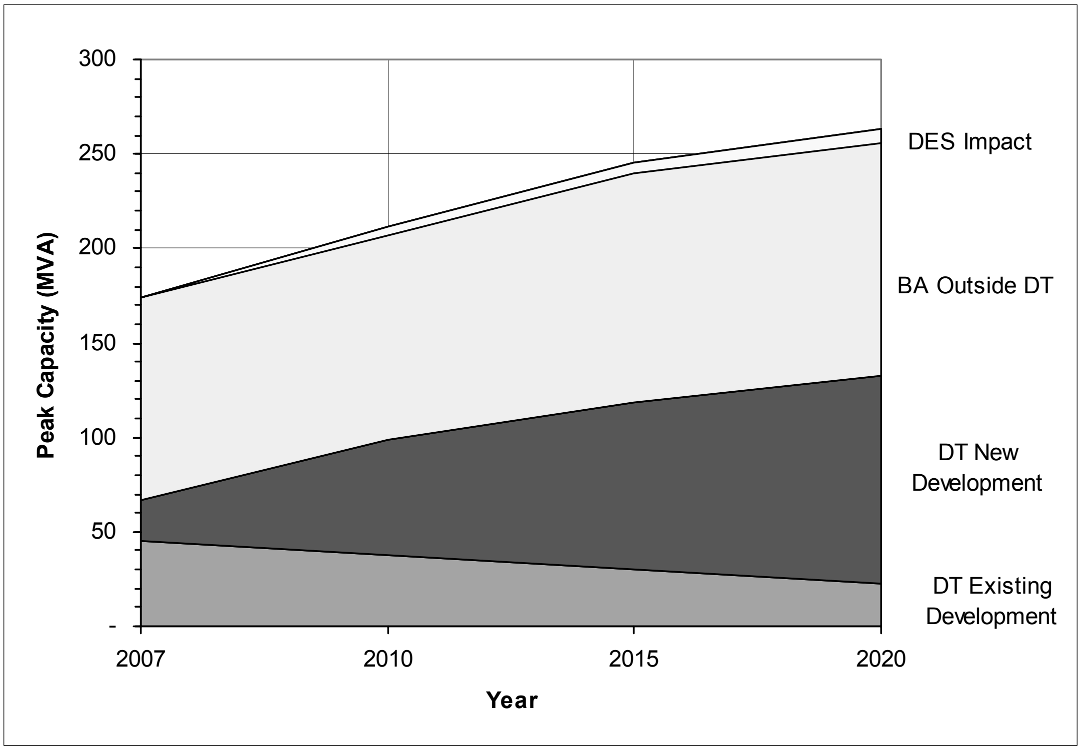
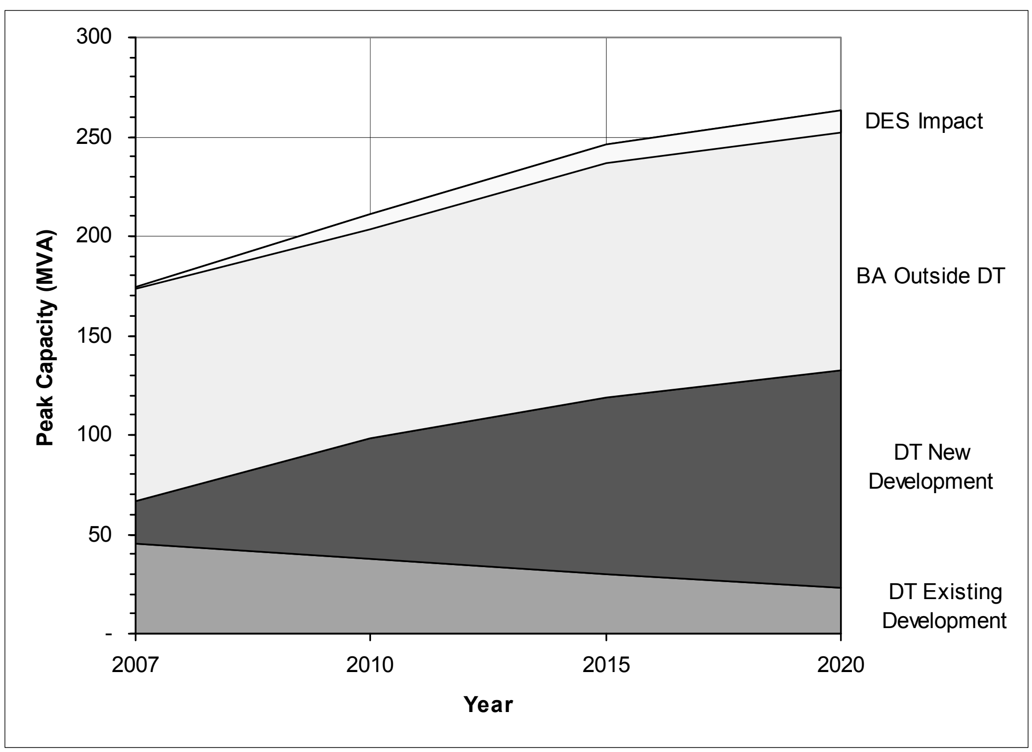



***Figure 75. Denny Triangle Capacity Requirements with Energy District Scenario 2 Impacts***



## 5.2.2 Reliability Impacts of Energy District Alternatives

### 5.2.2.1 District Energy Only

Under scenarios 1, 3 and 4, the electrical requirements of the new developments are reduced due to the provision of thermal energy by the district energy plant. The greatest percentage of thermal load in the study area is cooling loads associated with High-Tech Office and Research Lab space. Furthermore, these peak cooling loads can be expected in the summer when T&D equipment operating ratings are reduced by higher ambient operating conditions. With the energy district, feeders serving new developments that are limited by "weak-links" would carry lower electrical loads because they are not loaded by cooling plants in the new developments. Providing sufficient electrical capacity to the DES plant would, however, be imperative. As a single, critical load, electrical service to the DES plant should be designed with a high degree of reliability.

### 5.2.2.2 District Energy and Combined Heat and Power

It is expected that the CHP plant would normally be operated in parallel with the Seattle City Light electrical system—that is, it would be synchronized with the interconnection and deliver power over distribution feeders to a substation in the South Lake Union area. The size of the CHP plant should be kept in perspective. At 22 MVA, its output is comparable to the peak load on two typical feeders. Under most operating conditions, the entire output of the generator will be immediately consumed by loads on adjacent feeders. Nevertheless, load that would otherwise impact the upstream substation and transmission facilities will be displaced by the CHP plant.

#### CHP Operation in Parallel with SCL

To contribute to power system reliability, the CHP plant should be dispatchable by Seattle City Light so that its output can be used to reduce peak loadings on the substation and transmission facilities that it is connected to. For example, if the System Control Center (SCC) observes that a bank of substation transformers is approaching an operating limit, the CHP plant could be dispatched to reduce loading on the transformer bank if it is connected to the secondary bus of that substation.

#### CHP as Backup Generator

Instances of system blackout are extremely rare. Nevertheless, the CHP plant could be configured to provide backup generation service under blackout conditions if the feeder and switching configuration is designed to support isolated operation of the plant. In addition, to automatic switching capabilities, the CHP plant must be designed to have black start capabilities and to operate as a standalone synchronous generating plant. Additional equipment will be required to support this mode of operation.

#### CHP Effect on Transmission Losses

Injecting power close to load tends to reduce transmission and distribution system losses, particularly when the load serving utility relies on generation that is distant from load. A WECC powerflow simulation case (06HWS1A) was used to evaluate the effect of displacing 20 MW of load at the Broad Street substation. The reduction of Broad Street load from 266 MW to 246 MW results in a corresponding reduction in SCL 115 and 230 kV transmission as well as regional transmission grid power flows since that load will no longer be carried by another SCL generator or power purchase contract.

Three base and change cases were examined. In all of the cases, 20 MW of load was assumed to be displaced at Broad Street substation (bus 46409) by the CHP plant. In the first case, the corresponding generator output reduction was 20 MW at Ross 44 (bus 46441). In the second case, the corresponding generator output reduction was 20 MW at Boundary (bus 46405). The third case used Priest Rapids (bus 46063) as a proxy for reducing power purchased at Mid-C by 20 MW. The loss reductions on the BPA and the SCL transmission systems are shown in Table 37. Losses in the

Broad Street substation transformers are not modeled in the WECC cases, but additional loss savings will result from load reduction in the substation transformers.

***Table 37 . Loss Reduction from CHP Plant (MW)***

| Generation Bus | SCL Loss Reduction | BPA Transmission Loss Reduction |
|---|---|---|
| Ross 44 (46441) | 1.12 | 1.44 |
| Boundary (46405) | 0.52 | 2.53 |
| Priest Rapids (46063) | 0.53 | 2.48 |

#### 5.2.2.3 Other Considerations

Some concern has been expressed that SCL may be required to back up the heating systems of the Energy District in the event that either the gas pipeline fails or the Energy District experiences a forced outage. This concern should be tempered by the fact that under existing design guidelines, customers using gas heat would not include a load estimate for an electrical backup heating system on their service request.

Energy District cooling systems may experience forced outages of certain components, however, like the electric power system, component redundancy is typically built-in to ensure reliable service under single contingencies.

### 5.2.3 Interconnection and Generator Control Standards for CHP

Background and Assumptions:

- CHP plant would be phased in beginning in the 2008 to 2010 timeframe.
- CHP power plant consists of 2 x 5 MW simple cycle combustion turbines in 2010. 3 x 5 MW in 2015 and 5 x 5 MW in 2020.
- CHP output would be at constant monthly amounts, i.e. the plant will run at a high capacity factor to meet its thermal output requirements.
- The CHP plant would be dispatchable by the SCL control center, however, it would typically produce at least as much power as needed to optimize the energy district thermal load requirements.
- Availability of CHP generating units is at least 90%.

From the SCL SRA 2002:

- Monthly surplus/deficit forecasts are provided for the years 2003, 2007 and 2011.
- SCL is forecast to have surplus energy in the months of March through August.
- It may have deficits in the months September through February depending on water conditions (i.e. critical water will likely result in deficits) and whether BPA and Klamath Falls contracts are changed or extended.
- Significant energy deficits are likely if the BPA entitlement contract changes and Klamath Falls is not extended.
- SCL has not analyzed whether capacity deficits are likely during these months.
- "In summary, under critical water conditions and assuming the base forecast of customer load and the utility's current resource portfolio, City Light would not need additional resources for the remainder of the forecast horizon, except to meet monthly deficits of 100 to 150 MW a few months of the year."
- High and low load forecast ranges shift the energy surplus/deficit charts down and up respectively.
- Base market prices are expected to be around $30/MWh through 2007.
- SCL's average embedded resource portfolio cost ranges between $17 and $25 per MWh depending on whether average water or critical water is assumed. No monthly price forecasts are described.

The following options describe possible commercial arrangements that would form the basis for recovering the cost of power production by the CHP plant.

1. CHP Output Integrated into SCL Resource Portfolio
    - Ownership by SCL or cost-based payment for all electrical output.
    - Electrical energy is consumed by SCL loads at the distribution system busbar effectively reducing consumption from other SCL resources.
    - If owned by SCL the thermal output would be sold by SCL to energy district. Otherwise, the energy district would develop its cost-based rate to SCL with consideration for the heat being used for thermal processes.

2. CHP Owner Compensated for Output by SCL at market rate

The CHP plant will displace load in the SCL control area thus reducing tie-line power flows into SCL by an amount equivalent to the generator output plus avoided losses. SCL pays the CHP owner for the energy that it does not purchase for load or is able to sell as additional surplus.

A. Indexed Price

SCL pays CHP owner for displaced energy at an Indexed Price, e.g. Mid-C. SCL has existing resources in excess of 20 MW that can be delivered to Mid-C to effectively create an exchange in real-time.

B. Negotiated Price

The CHP owner and SCL establish a price for the CHP plant output that reflects its value as a firm resource delivered within the SCL control area.

3. Value is established by "Offset Metering"
If the CHP plant is connected to specific customer loads, the output will offset the customer's revenue meter values. This method is not recommended because it may result in the customers avoiding fixed cost payments to SCL that are currently included in retail energy charges to recover the cost of generation, transmission and distribution capacity.

4. Output "wheeled" to tie-lines for resale
As a practical matter, 20 MW delivered at most SCL substations will simply displace existing load and result in reductions in SCL transmission system and tie-line power flows. Like with option 2, the output could be considered power that is "wheeled" to the SCL tie-lines with other utilities. The drawback to this approach is that in spite of the benefits that local generation provides, the CHP plant may be charged a T&D transmission charge by SCL and which ever utility wheels the power from SCL's tie-lines to the ultimate point of delivery. This could result in two or more pancaked wheeling charges.

5. Output purchased by BPA as component of supply to SCL
BPA is obligated to deliver power to SCL under existing power supply contracts. At times BPA must purchase power to meet its combined obligations to power customers. BPA could purchase the output from the CHP plant and deliver it to SCL at the point where the CHP plant is connected to the SCL distribution system.

# Section 6 Economic and Financial Analysis

## 6.1 Financing and Ownership Options

### 6.1.1 Evaluation of Options

Potential financing options include tax exempt revenue bonds, taxable bonds, bank financing and potential grant or low-interest-loan funding from the federal government. The private sector could play a role in ownership and financing depending on the goals established for the Energy District and how the various stakeholders wish to allocate costs, risks and rewards. It is essential that SCL determine its objectives for the Energy District, what it wants to get out of it, what risks it is willing to bear, what control it wants and what financial and human resources it is willing and able to devote to it.

Given the need to keep costs down, public sector financing is appealing because of the potential for tax exempt financing and grant or low-interest loans. However, general obligation (GO) bonds are an unlikely source of funding. GO bonds are subject to a number of restrictions, including state debt limitations that limit municipal debt to a given percentage of the taxable property in the jurisdiction.

Tax exempt revenue bonds are a potential financing source, but significant barriers must be overcome. Most significantly, revenue bonds must be secured by the project. Specifically, the underwriters must be assured that the system can repay the loan. There are a number of types of risks associated with a project such as this, including risks relating to fuel sources (natural gas), the construction process, operations, the technology and the market. All of these risks are manageable, but it is the market risk which is most difficult. Long-term contracts are critical to address market risk. However, securing substantial early contractual commitments will be difficult given the likely significant dependence on future buildings as the mainstay of the customer base. The City of Seattle may have to play a role in securing financing until the customer base grows.

**Seattle City Light**

SCL has had significant financial difficulties which will likely make it difficult for it to play a pivotal role in financing an Energy District. SCL raised electricity rates 58% in four increases during 2001. In April 2003, Mayor Nickels announced that Seattle City Light will cut spending by nearly $32 million to avoid further rate increases and new borrowing. Over the next two years, SCL will cut $5 million from its conservation programs, among others, and will cut general expenses across the board. [84]

**Special-purpose municipal entity**

The City of Seattle could establish a special purpose entity, such as a Public Development Authority (PDA) or Local Improvement District (LID) to finance an Energy District.

**Private non-profit corporation**

This approach has been used to great success in St. Paul, Minnesota. Based on studies undertaken with federal support, a private non-profit corporation was formed to develop a hot water district heating system. Its initial board of directors included representatives of building owners, the City of St. Paul and the local electric utility. Final feasibility studies and marketing were completed in 1982 and the system was operating in 1983. The initial project cost, including construction, financing and other expenses (not including building conversions) was $45.6 million in 1982 dollars. Funding

[84] The Seattle Times - April 16, 2003, “Seattle Utility to Tighten Belt, Control Rates.”

sources included tax exempt revenue bonds and loans from the City of St. Paul and Housing and Urban Development (HUD) funds. The heating system now serves over 27 million square feet of building space, with a market share of over 80 percent. District cooling was implemented in 1992 Since that time the system has grown steadily and now serves over 12 million square feet of building space. In 2003, District Energy St. Paul commissioned a 25 MW combined heat and power plant fired with community waste wood.

**Private for-profit corporation**

A for-profit entity could finance and operate an Energy District. Many new district cooling systems have been created this way. However, a for-profit entity will have a higher cost of capital. Also, the recent changes in the power industry will make this approach more challenging.

**Public-private partnership**

This approach has been used to good effect, particularly in Canada. A variety of partnership arrangements have been implemented, e.g., municipal ownership of the distribution system and private financing and ownership of the plant facilities.

### 6.1.2 Recommended Financing and Ownership Options

We believe that the private non-profit model would be most appropriate for the SLU/Denny Triangle Energy District, for several reasons:

1. It could be used to facilitate low-cost financing, thereby helping keep costs down for a capital-intensive energy infrastructure;
2. It facilitates a governance approach that enables the stakeholders, including most importantly the customers, a voice in decision-making; and
3. It has been proven to work successfully.

## 6.2 Economic Proforma

Fundamental capital and operating costs of Scenario 1 were discussed above under “Evaluation of Technology Scenarios.” A full 20-year economic proforma analysis was prepared for this technology concept, including:

- full capital costs including financing costs and an operating reserve;
- debt service;
- depreciation;
- operating costs and other annual costs such as franchise fees;
- revenue and expense statement;
- cash flow; and
- calculation of internal rate of return.

A non-profit public-private entity was assumed for financing and ownership, with 100% debt assumed for the base case proforma. Variable costs were passed through to the customers in a variable energy rate, with a levelized demand rate charge based on customer peak demand. The demand rate level was set to yield a 5% internal rate of return on total capital. An operating reserve was capitalized to keep early-year rates down and smooth out swings in rates as new capacity is brought on line.

A $9 million operating reserve was assumed to be financed as a mechanism for keeping rates fairly level. This has the effect of changing rates compared to what they would be if rate were strictly based on that year’s annual costs: reductions in rates in the early years and increases in rates in later years.

It was assumed that City franchise fees would be paid on the fuel and electricity used by the Energy District, rather than on the total service fees charged by the Energy District. Such an arrangement would require negotiation with the City.

The results for the base case proforma yield rates for Energy District service that would be competitive with self-generation (discussed below). Average costs charged to customers per Square Foot are illustrated in Figure 76. Average heating rates are shown in Figure 77. Average cooling rates are shown in Figure 78. The full proforma is provided in Appendix 11.

***Figure 76. Average Costs Charged to Customers by Cost Type***

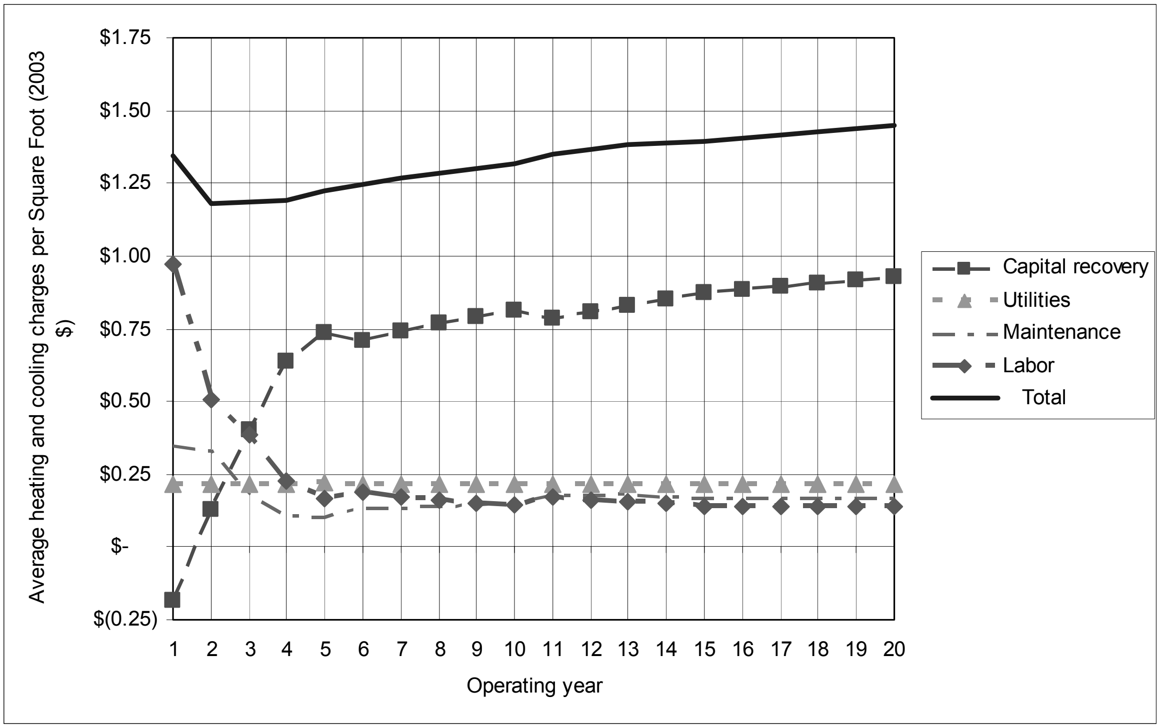


***Figure 77. Average Heating Rates Through Year 20***

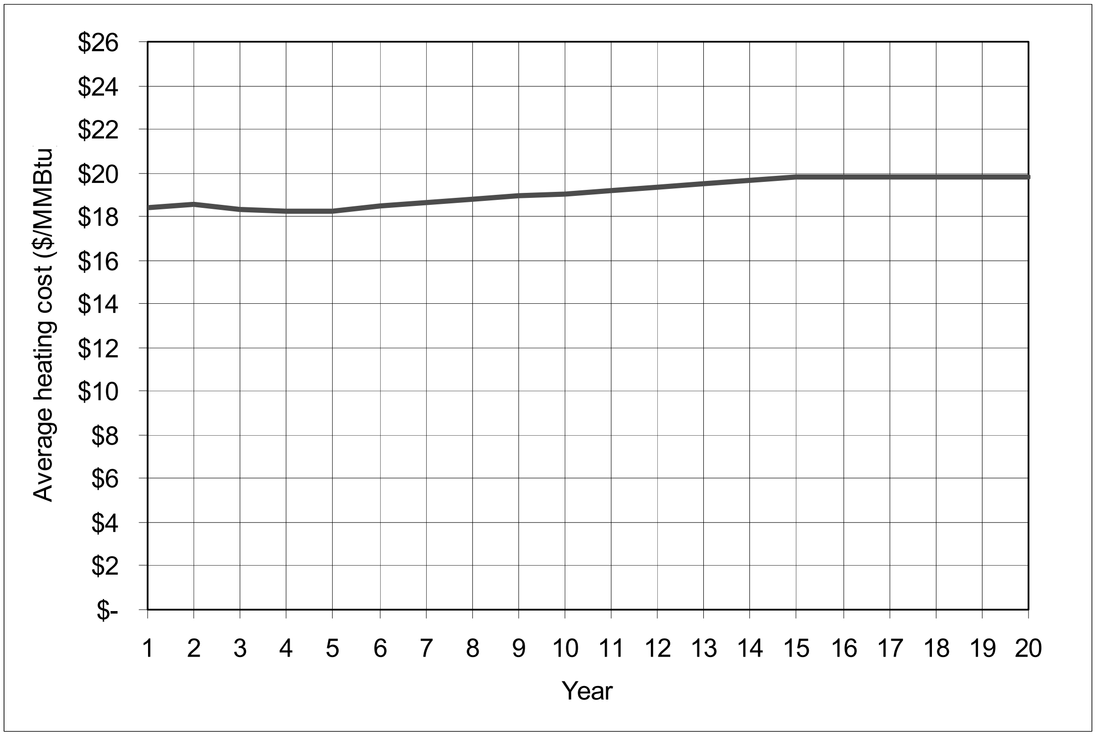
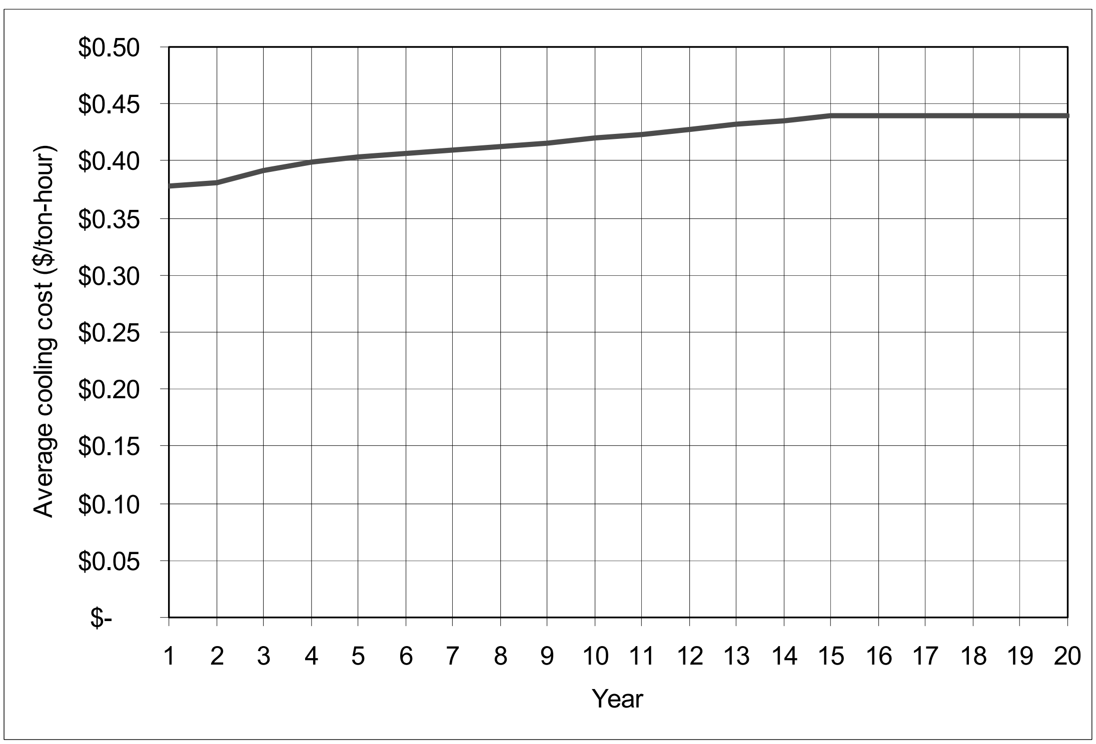



***Figure 78. Average Cooling Rates Through Year 20***



## 6.3 District Energy Service as a Business Proposition

### 6.3.1 Why Building Owners Choose Energy District Service

Building owners choose Energy District service for a variety of reasons. First, it *makes building management easier and more effective*:

- Heating and cooling is available 24/7, so it's convenient and doesn't require management attention. This frees up time to focus on building manager's primary business.
- Energy Districts provide flexibility to increase the amount of capacity available to the building without an additional capital expenditure.
- Buildings are quieter because there is no heavy equipment generating vibration and noise, making tenants happier and more productive.

The Energy District concept fits very well with the general trend toward *outsourcing* of operations that are not central to a company's core business. By outsourcing heating and cooling, building managers can focus on their core business—whether it is biotech research, headquarters office operations, residential housing, attracting hotel, motel or condo renters, attracting and retaining tenants in a merchant office building, providing municipal services, etc.

Energy District service *reduces capital and operating risks*:

- No capital is tied up in the building for cooling and heating equipment.
- Risks associated with operation and maintenance of building heating and cooling equipment are eliminated.
- Energy Districts provide more flexibility to respond to changing energy prices, and to take advantage of new technologies.
- Costs are more predictable because more of the costs are fixed and less is spent on fuel and electricity, which can be highly volatile in price.

Energy District service also *reduces competitive risks*:

- Buildings that consistently provide reliable, high-quality energy services will attract and keep tenants.
- Energy District service increases the attractiveness of buildings in a competitive real estate market, thereby increasing the building's market value.

Energy Districts can deliver *better reliability* than typical individual building systems. The building owner and/or manager has a critical interest in reliability because they want to keep the occupants happy and want to avoid dealing with problems relating to maintaining comfort. Reliability takes on a critical importance for some buyers, such as biotech research facilities. Energy Districts can provide a level of equipment redundancy and round-the-clock expert management that individual buildings generally can't match. It is critical that customers be justifiably convinced that the Energy District utility can reliably deliver building comfort whenever it is needed. And it is essential the utility deliver on this promise through sound design, construction, operation and maintenance.

There are fundamental *cost advantages* that Energy Districts can provide:

- Better equipment loading, leading to better energy efficiency.
- Economies of scale to implement advanced technologies such as deep water cooling or CHP.
- Better staff economies.
- Reduces overall costs due to diversity in building loads.

As investments, Energy District share some characteristics with real estate:

- It's capital-intensive, with capital front-loaded.
- It's a long-term investment, with real payoff as the system is built out, analogous to a building being fully leased.

- The Energy District needs contract commitments from initial anchor customers to support financing, analogous to pre-leasing a building.

Typically, Energy Districts charge for service through a fixed charge tied to peak demand (“demand charge” or “capacity charge”); and a variable charge for energy consumed (“energy charge”). The relationship between an Energy District and its customers is a lot like the relationship between building owners and tenants. The structure of an Energy District service agreement is analogous to triple net lease: demand charges are like base rent; and operating costs are passed through.

### 6.3.2 Comparison of District Energy Service to Other Options

Comparing Energy District service to self-generation requires consideration of all capital costs and operating costs, including electricity, fuels, maintenance and repair, labor and administration, water, chemicals and supplies.

#### 6.3.2.1 Capital costs

With Energy District service there is no need to purchase and install boilers, chillers or other equipment for producing heating and cooling in a new building, or retrofit or replace equipment in an existing building. The building owner will need to make some modifications to interface with the Energy District, including installation of heat exchangers if it is required due to hydraulic considerations, as well as metering and controls. Overall, Energy Districts can generally provide significant capital savings for the building owner compared to many types of HVAC designs. On the other hand, the hydronic systems required for interface with Energy District have higher capital costs than some types of building HVAC approaches, such as electric resistance heating or unitary heat pumps. On the other hand, hydronic systems provide better energy efficiency and operating economies.

The value of the capital savings depends on the type and circumstances of the buyer, and the perspective of the individual investor including his or her investment timeframe. The building owner is likely to place a higher value on capital savings than the manager or operating engineer.

#### 6.3.2.2 Electricity

Electricity costs for building cooling equipment are often underestimated because they do not account for the true seasonal efficiency of heat pumps or on-site electric chillers, cooling towers and other auxiliaries. Cooling towers and other auxiliaries are frequently specified with single-speed or two-speed drives, and for most of the annual operating hours the auxiliaries are requiring more electricity per unit of cooling output than is the case at 100 percent of chiller plant capacity.

#### 6.3.2.3 Fuel

Natural gas is the fuel that would be used for building heating designs incorporating boilers. As discussed in Section 3, gas prices have been highly volatile.

#### 6.3.2.4 Maintenance and repair

An economic analysis comparing alternatives which will be in service for perhaps 20 years or more must in some way account for costs over the lifetime of the facility. While it is reasonable to expect that many costs may increase at roughly the rate of inflation, heating and cooling maintenance costs present a difficult problem because these costs tend to increase over time and involve periodic, high-cost preventive maintenance as well as unanticipated repairs in addition to the normal annual preventive maintenance. A reasonable estimate of the annualized costs of maintaining heating and cooling equipment over its lifetime must take into account the full costs of maintenance and repair, which include more than normal annual maintenance.

#### 6.3.2.5 Labor and administration

Many buildings, particularly larger ones, are able to reduce staffing after initiating Energy District service because of the elimination of requirements for equipment operation and maintenance. These costs add up, particularly given the labor-intensive nature of heat pumps, cooling tower maintenance, etc. Labor reductions will likely be viewed differently depending on the individual's personal role, e.g., the operating engineer compared to the building manager. While some operating engineers may feel threatened by Energy District service due to reductions in operating responsibilities, others may welcome it as an opportunity to free up time for other pressing operation and maintenance responsibilities.

The reduction in labor requirements for operation and maintenance should be taken into account in a cost comparison with Energy District service. Whether or not the number of staff are reduced when a building begins service, building staff time can be redirected to other endeavors, such as maintenance and upgrades which are more visible to building tenants. In addition, some administrative oversight of heating and cooling operation and maintenance is required, particularly given increasing regulatory oversight of refrigerant handling and worker safety.

#### 6.3.2.6 Water, chemicals and supplies

Purchase of water and water treatment chemicals is required to make up for losses during cooling tower operation. Refrigerant must also be purchased to make up for losses during operation and maintenance, with the extent of loss depending on equipment age and operation and maintenance practices.

## 6.4 Comparison of Energy District Service to Self-Generation

Energy District costs were compared to three prototypical potential customers, summarized below:

***Case #1 – biotech research building (200,000 SF)***
Building use: research and related office
Heating: natural gas boilers with hot water serving air handling units
Cooling: water-cooled centrifugal chillers serving air handling units

***Case #2 -- residential plus mixed use (470,000 SF)***
Building use: mixed use (residential/hotel/retail)
Hydronic heat pumps with electric heat peaking

***Case #3 -- office building (200,000 SF)***
Building use: office
Heating: natural gas boilers with hot water serving air handling units
Cooling: water-cooled centrifugal chillers serving air handling units

Energy District costs, and costs for "self-generation" of heating and cooling, for a given customer may be higher or lower depending on energy requirements and usage patterns. In addition, the cost of capital is a key variable, particularly for cooling. The analysis of self-generation costs accounted for the additional capital costs required for self-generation compared with Energy District service. These additional capital costs ranged from $5.77/SF in Case 1, with relatively high energy requirements, to $1.69/SF in Case 2, because Energy District service would require additional hydronic piping in the building, to $3.54/SF for Case 3.

Figure 79, Figure 80 and Figure 81 illustrate the estimated total costs for self-generation for the three cases outlined above, at a range of assumed costs of capital. It is important to note that the costs usually thought of as "utilities" are only one part of the total cost of providing heating and cooling for a building. Conventional heating and cooling requires not only capital investment but also ongoing expenses for fuel, electricity, labor, supplies, maintenance, and replacement.

Figure 82 compares the calculated annual self-generation costs (assuming a weighted average cost of capital of 9%) to costs with the Energy District. The Energy District offers the same or lower costs in Cases 1 and 3, and somewhat higher costs in Case 2. The cost of Energy District heating and cooling service for most customers is projected to be $0.90-1.00 per square foot per year (2003 dollars), depending on the technologies employed and the building energy usage pattern. Costs for buildings with most space devoted to intensive research activities would be higher due to higher energy intensity. However, self-generation costs for energy intensive buildings are also expected to be significantly higher than self-generation for other building types, and higher than the Energy District cost for these energy-intensive buildings.

Figure 83, Figure 84 and Figure 85 compare cumulative cash flow for the building owners with Energy District compared to self-generation, using a 9% discount factor to account for the weighted average cost of capital. Payback time for the additional capital investment for self-generation are estimated to be 10, 4 and 14 years for Cases 1, 2 and 3, respectively. Although Energy District service would come at a cost premium in Case 2, it would also provide significant advantages relative to ease of building operation, elimination of the headache of maintaining many heat pump units, and improved reliability.

Detailed calculations on the self-generation comparison can be found in Appendix 12.

***Figure 79. Costs for Self Generation of Heating and Cooling (Case 1)***

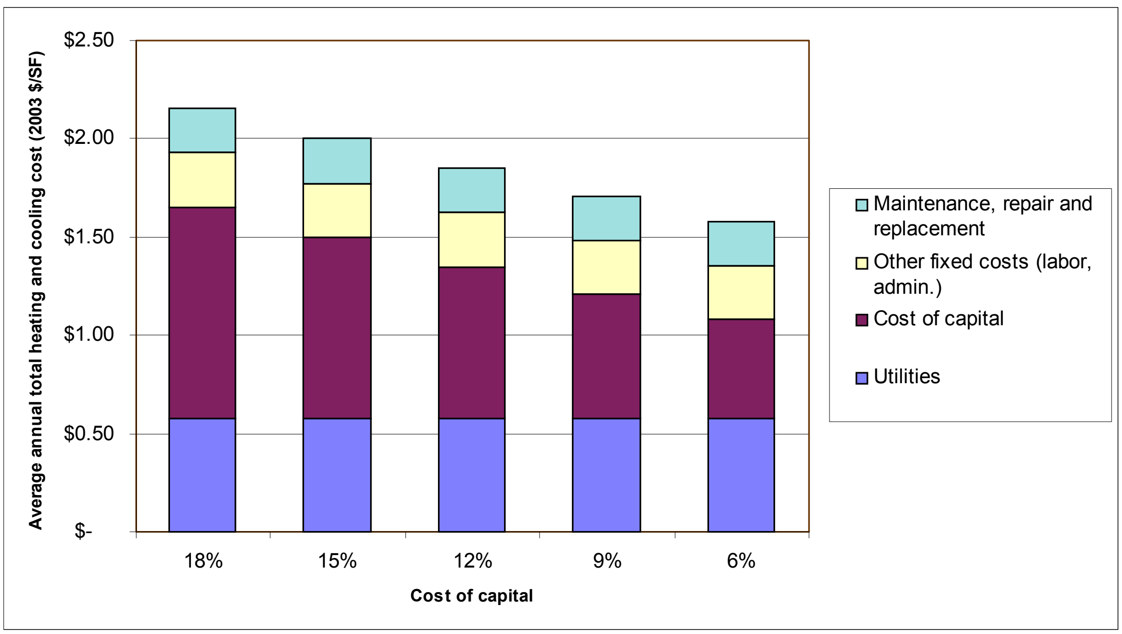


***Figure 80. Costs for Self-Generation of Heating and Cooling (Case 2)***

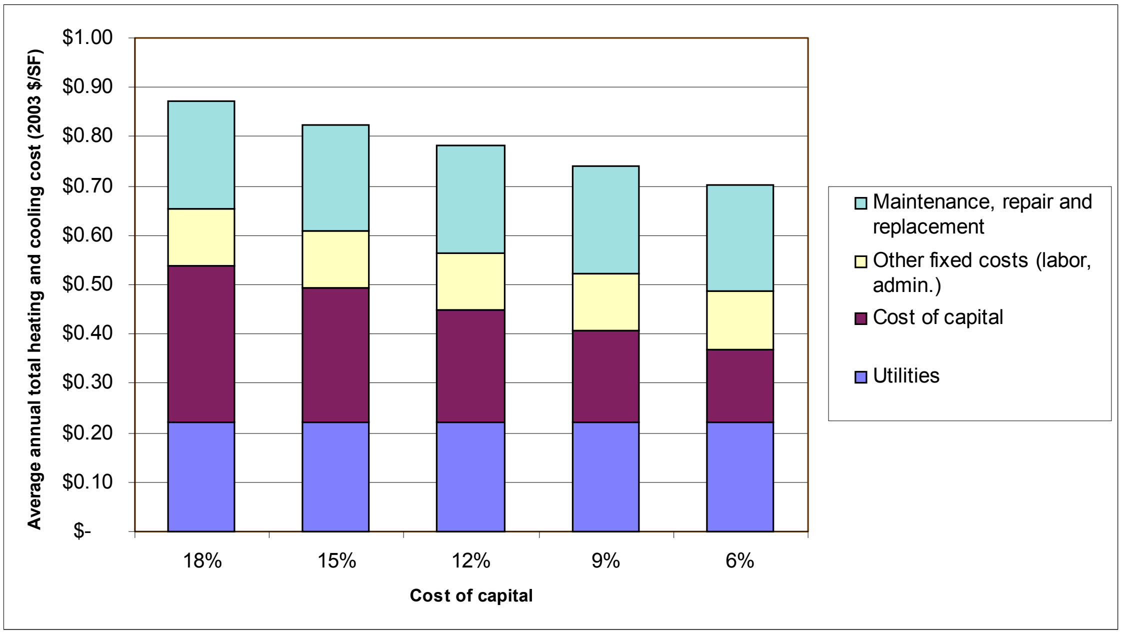



***Figure 81. Costs for Self-Generation of Heating and Cooling (Case 3)***

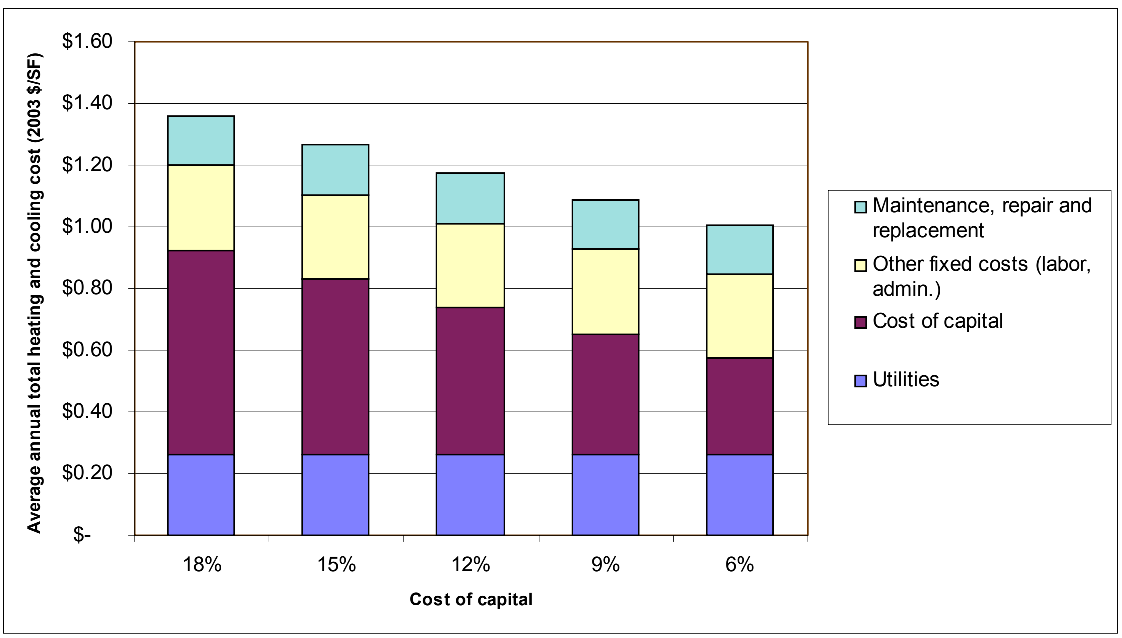


*Figure 82. Comparison of Self-Generation Costs to Energy District Costs Assuming 9% Weighted Average Cost of Capital*

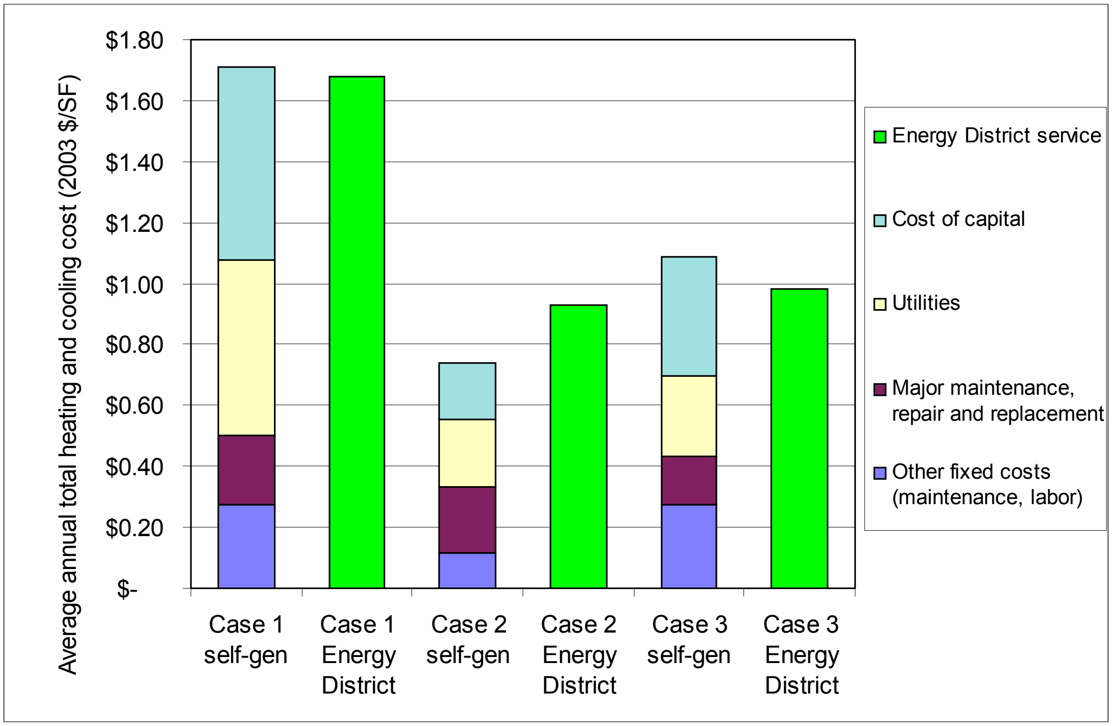



*Figure 83. Comparison of Self-Generation to Energy District based on Cumulative Discounted Cash Flow at 9% Weighted Average Cost of Capital (Case 1)*

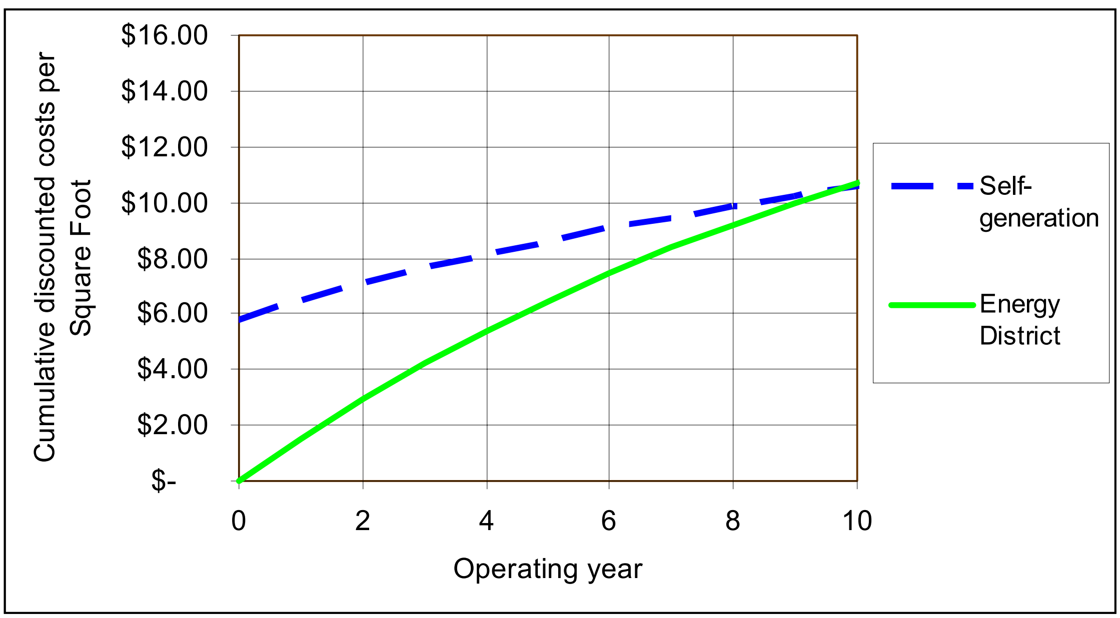


***Figure 84. Comparison of Self-Generation to Energy District based on Cumulative Discounted Cash Flow at 9% Weighted Average Cost of Capital (Case 2)***

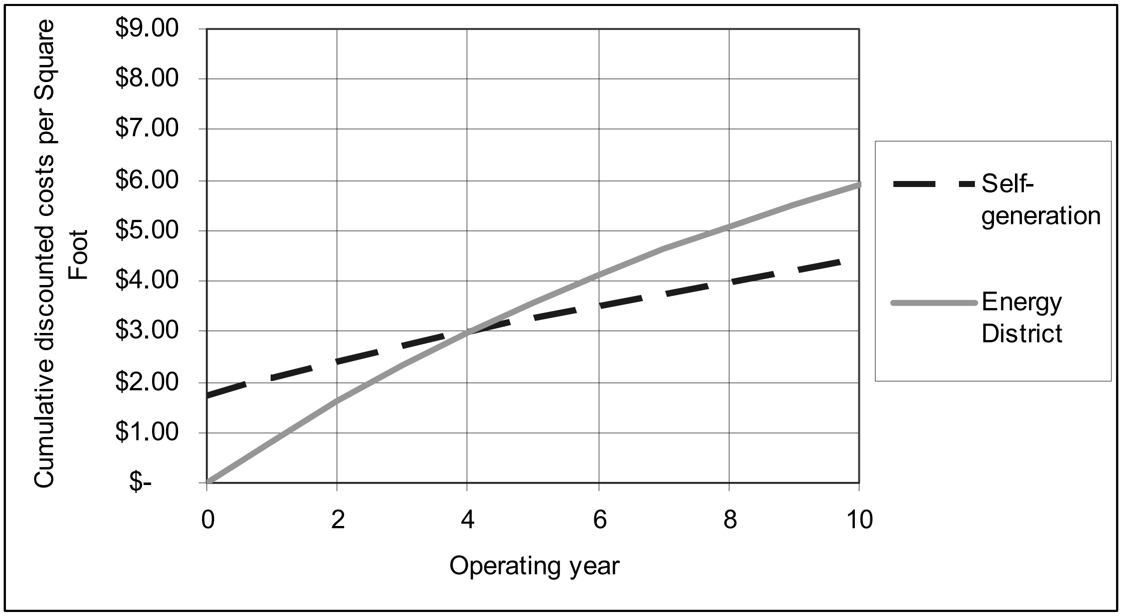
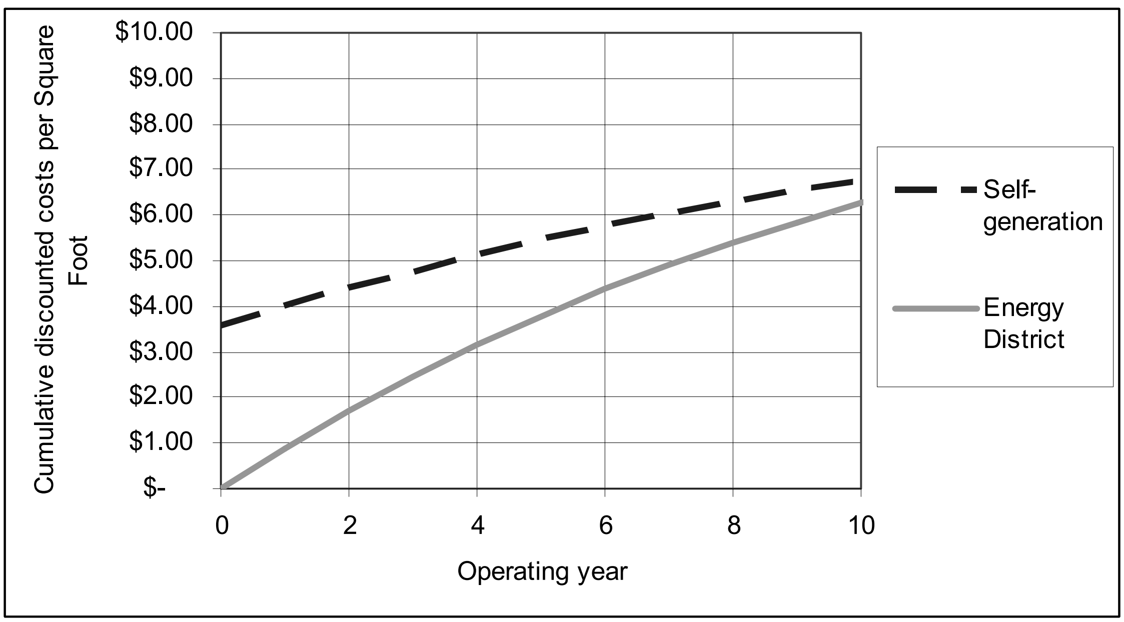



***Figure 85. Comparison of Self-Generation to Energy District based on Cumulative Discounted Cash Flow at 9% Weighted Average Cost of Capital (Case 3)***



Section
# 7 Implementation Issues

## 7.1 Introduction

The primary implementation issues include air quality emissions associated with CHP, greenhouse gas (GHG) emission and water temperature and fisheries impacts associated with deep water cooling. Overall, no "showstoppers" were identified. However, significant issues were raised that will require substantial effort during subsequent phases of the project.

## 7.2 Air Emissions

The study team conducted a preliminary determination of the impacts on air pollution emissions of CHP development in the study area. The objectives of the study were to:

- Determine the current attainment status for key pollutants;
- Evaluate the potential impacts of CHP development in the study area on regulated pollutants and $CO^2$ emission levels; and
- Begin discussions with regulatory agencies to evaluate the complexities of obtaining air permits for a CHP facility.

Key regulatory requirements are summarized below.

- A notice of Construction will be required under (WAC 173-400-110). The CHP facility will be considered as an entirely new source and have no relationship to the existing permitted air pollution sources in the study area.

- Total emissions of each regulated criteria pollutant should be maintained below 100 tons/year to avoid classification as a "major source" (WAC 173-400-030). *Not being classified as a major source will greatly simplify the permitting process by making it a local and not a federal issue and by avoiding a Prevention of Significant Deterioration (PSD) review (WAC 173-400-141).*

- The Seattle metropolitan area is in attainment for all criteria air pollutants. *Therefore, there will be <u>no</u> special requirements for emission "offsets" for the CHP facility or the application of "lowest achievable emission rates" (LAER's) (WAC 173-400-112).*

- Washington State law requires the application of "best available control technology" (BACT) for all criteria air pollutants (70.94 RCW). What constitutes BACT is subject to the type of emission source and pollutant under consideration, and is limited by economic and practical technology issues. *Due to the high "visibility" of the project, it is strongly advised that any CHP project include the application of state-of-the-art BACT emission controls*.

- Washington State law also requires demonstration by computational modeling that no exceedance of the "acceptable source impact level" (ASIL) for any specified toxic air pollutants (TAP) will result from the project (WAC 173-400-150 and 160). *Not that this is a key regulatory requirement that could severely limit the size and location of the CHP facility.*

- Washington State law also requires the application of 'good engineering practices" (GEP) in determining minimum stack heights in order to avoid building downwash and adverse local ambient air quality (AAQ) impacts (WAC 173-400-200 (2) (a)(ii)). The required stack height is determined using:

Hg = H + 1.5 L    Where:    Hg = GEP stack height
H = height of 'nearby" structures
L = less dimension of height or width of nearby structures

Nearby structures are defined as within a distance of 5 L.  Note that EPA limits the maximum stack height to 65 m.

- Puget Sound Clean Air's program to control green house gas emissions is voluntary. *Mitigation activities, if required, will be handled directly by Seattle City Light.*

Preliminary dispersion modeling indicates the following:

- The South Lake Union/Denny Triangle area lies in a 'valley' surrounded by Capital Hill on the east, Seattle's large commercial buildings to the south, and the Space Needle to the west.
- The exhaust of the combined cycle unit through a single stack will produce a plume that will rise to final stable height of approximately 200 m.
- Locating the stack in close proximity to the base of Capital Hill, the downtown high-rise buildings, or the Space Needle could result in plume impact levels in excess of some ASIL's.

## 7.3 Greenhouse Gases

The installation of CHP or other natural gas-fired options in the study area would result in increases of $CO_2$, as discussed and quantified in Section 4. The City of Seattle has established a long-range goal of meeting the electric energy needs of Seattle with no net greenhouse gas (GHG) emissions. Per a resolution passed on Earth Day 2000, the City has committed SCL to meet growing demand with no net increases in GHG emissions by "using cost-effective energy efficiency and renewable resources to meet as much load growth as possible," and "mitigating or offsetting GHG emissions associated with any fossil fuels used to meet load growth."  In addition to the City GHG policy, it is clear that key stakeholders in the study area have a strong interest in reducing the environmental impacts associated with meeting energy needs.

As summarized in Section 4, all Energy District concepts would provide a net reduction in GHG emissions, and sensitivity analyses were performed to calculate the economic impact of including economic credit for these reductions using an SCL planning value of $40 per metric ton.

## 7.4 Water Permitting

### 7.4.1 Review of Technical Concepts

**Lake water heat pump heating and deep water cooling**

- Cooling during summer would be provided using direct heat transfer to deep (60 meters) Lake Washington water (at a constant 44-46° F temperature), with mechanical chiller tempering (using lake water for condenser cooling) as required for peaking.  Once used for cooling, the Lake Washington water would be pumped into South Lake Union and/or the Shipping Canal and Montlake Cut at a temperature of 59-62°F – warmer than the entering water from Lake Washington but still cooler than South Lake Union temperatures during July through October – a critical period for salmon migration.
- Heating would be provided year-round with relatively shallow (5-6 meter) South Lake Union water entering the heat pump evaporators at a temperature ranging from 44°F in February to 68°F in September. Additional heat would be provided with boilers to meet peak heating demand.
- Cooling during non-summer months would be provided from the "cold side" of the heat pumps operated to extract heat from South Lake Union water as noted above.

- Heat pump operations would oxygenate and reduce the temperature of South Lake Union water by about 5-8°F before being pumped into South Lake Union and/or the Shipping Canal and Montlake Cut.

**Groundwater heat pump heating and condenser cooling**
- Pumping of groundwater from multiple wells of approximately 300 foot depth and reinjection in separate well set at approximately 200 foot depth.
- Heat pump operations will decrease groundwater temperature from an assumed entering temperature of 50F to about 38F.
- Condenser cooling operations will increase groundwater temperature from an assumed entering temperature of 50F to about 65F.
- However, as the well sets are operated, and depending on groundwater flow rates, the temperatures in the aquifer around the two well sets will diverge, with the "cold" set moving down in temperature and the "warm" set moving up in temperature. The cold set would be pumped for condenser cooling and reinjected into the warm set, while the warm set would be pumped for heating and reinjected into the cold set.

### 7.4.2 Summary of Permitting Requirements

The study team has evaluated a number of alternative sources of water for direct cooling (deep water cooling) or for sources of water for condenser cooling of large conventional centrifugal electric or absorption chillers. In addition, water sources for use in heat pumps for provision of heating were also evaluated.

The water sources evaluated for use in various alternative cooling scenarios include: Puget Sound (Elliott Bay), Lake Washington, and groundwater. Sources of water for use in heat pumps include Lake Union, Lake Washington and groundwater.

Although the initial focus was on use of water from Elliott Bay, it was determined that water temperatures were too high to be used for direct cooling. Focus was then shifted to Lake Washington, where temperatures were found to be much better suited to direct cooling and/or use as condenser cooling.

The use of any of the above potential sources will present a number of challenges including a number of fish-related concerns.

Permitting will require close coordination with a number of federal, state, and local agencies, as well as with environmental groups and Indian tribes. Withdrawal or disposal of water into or near the local shipping canal may require preparation of a federal environmental impact statement (EIS) under requirements of the National Environmental Policy Act.

The role of the US Army Corps of Engineers will likely be significant and would entail permits administered by the Corps under Section 404 of the Clean Water Act and Section 10 of the Rivers and Harbors Act.

See Appendix 13 for a more complete discussion of permitting issues and recommendations related to permitting, including a detailed list of permits and responsible agencies prepared by the Law Office of Kathleen Callison.

See Appendix 14 for an overview on Regulatory Process for Geothermal Heat Pump Applications.

Of major concern will be protection or enhancement of fisheries, especially Chinook salmon, which are listed as "threatened" under the Federal Endangered Species Act (ESA). The project will not be permitted to take any action that may result in harm to the species under Section 9 of the Act.

Compliance with the State Environmental Policy Act and/or the National Environmental Policy Act could take up to three years, and potentially longer if decisions are appealed. Compliance with SEPA and/or NEPA and preparation of an EIS could exceed $1,000,000, and higher if the decision is appealed.

Withdrawal of water from Lake Union or Lake Washington will require a water right from the Washington Department of Ecology. Approval of a water right can be expected to take several years, depending on mitigation requirement, technical studies and negotiations that may be required, as well as any appeals that may be filed following a decisions on the water right by the Dept. of Ecology.

Disposal of the water will require a compliance with Section 90.48 RCW Water Pollution Control, and would require a National Pollution Discharge Elimination System (NPDES) permit. It would be prudent to assume that it will take 2-3 years to gain approval for a discharge to any water body in Western Washington.

The use of groundwater together with geothermal heat pumps as a source of heating and cooling would require the drilling of a significant number of water wells in the study area.

Ground waters of the state of Washington are subject to appropriation under a permitting scheme administered by the Washington State Dept. of Ecology.

It may be possible through careful management of production and injection to achieve some level of seasonal thermal storage, thereby significantly increasing the overall efficiency of both heating and cooling systems.

A geothermal heat pump project will need to acquire a water right or certificate issued by the Washington Department of Ecology. Well construction activities are also managed by the Department of Ecology (RCW 18.104).

Disposal of groundwater may be through injection wells. Underground Injection Control wells are regulated under Chapter 90.48 RCW (Water Pollution Control). Chapter 173-218 WAC (Underground Injection Control Program) and Chapter 173-200 WAC (Water Quality Standards for Ground Waters of the State of Washington). Geothermal wells are considered class V injection wells, under the federal government's Underground Injection Control (UIC) program. All new Class V wells must apply to the UIC Program for approval. The application includes information needed to satisfy the requirements of 40 Code of Federal Regulations (CFR) Part 146.

Permits from the U.S. Army Corps of Engineers would also be required.

### 7.4.3 Conclusions

Scenario 3 (deep water cooling) and Scenario 4 (deep water cooling and heat pumps) raise a number of environmental issues associated with construction of deep water piping in water bodies and the withdrawal and return of water. Key concerns regarding the environmental impacts of deep water cooling relate to impacts from: laying of the pipeline; impact on aquatic life at the intake; and impact on aquatic life from discharge of water at elevated temperature and heating of water surrounding the pipeline. These issues would have to be addressed in a thorough environmental assessment of a heat pump and/or deep water cooling project.

There may be potential environmental benefits relative to improvement of water quality and enhancement of conditions for salmon migration. Water quality in Lake Union is poor, with a key indicator, dissolved oxygen, at zero in the lower depths of this shallow lake. This condition is related to lack of mixing between the stratified layers in the lake, oxygen demands by sediments, relatively high water temperatures and a saline layer at the bottom of the lake during the July-September period. In addition, salmon migration is inhibited by a "thermal barrier," i.e. high water temperatures in the Ship Canal and the Montlake Cut.

The renewable Energy District may provide an opportunity to supply cooler, oxygenated water to Lake Union, the Ship Canal and the Montlake Cut, potentially facilitating salmon migration to Lake Washington, and improving water quality:

- Cold Lake Washington water, once used for air conditioning, would be pumped into Lake Union. Although heat would be added to the water (through its use for air conditioning) the water would provide a net cooling of the lake and the salmon migration route. Lake Washington water is cleaner than Lake Union, providing an improvement to Lake Union water quality.
- Shallower Lake Washington water used for heating would be cooled in the process, also providing a net cooling of the water before it is returned to the lake.
- The heat exchangers used in both the heating and cooling processes could be designed to introduce oxygen into the water, thereby further improving water quality.

It is not clear to what extent these potential benefits are realizable. Assessment of the positive and negative impacts of a heat pump and/or deep water cooling Energy District on fisheries and water quality will require an extensive, complex and lengthy analysis.

## 7.5 Other Permitting

Scenario 2 (CHP) raises a number of policy and contractual issues relative to integration of CHP facilities into the SCL grid, relating to both technical requirements for grid interconnection as well as valuation of the power exported from the CHP facility to the wholesale markets.

The State of Washington has given considerable attention to establishing an institutional framework that facilitates the development of district energy systems.

In the early 1980's the state legislature passed legislation that established the rights of local governments to develop, own, and operate district energy systems and to sell bonds for that purpose.

The legislature has also passed legislation to deregulate district energy systems, i.e. district energy systems are no longer subject to regulation by the Washington State Utilities and Transportation Commission.

Section
8
# Conclusions

## 8.1 Customer Base

Over thirty million square feet of new development is anticipated in the study area through 2020, including biotechnology research facilities, commercial buildings and residential development.

There are two main regions of future load density, based on near and intermediate-term plans of developers. One of these regions of load concentration is in the middle of the SLU study area, toward Lake Union. The other region of load concentration is in the middle of the Denny Triangle area, to the east of Westlake Ave.

Based on analysis of timing, location and characteristics of projected development, the Energy District customer base is conservatively projected to total 18 million square feet (MSF) of building space, or about 55% of the projected building space. The coincident peak energy requirements of the Energy District at full build-out are estimated to be:

- peak cooling demand of 32,700 tons of refrigeration;
- peak heating demand of 210 million Btu per hour of heat; and
- peak power demand of 123 MegaWatts to meet power requirements other than production of heating or cooling.

## 8.2 Infrastructure Impacts

The anticipated new development in SLU will bring significantly increased electricity demand, which will require Seattle City Light (SCL) to invest substantial capital into reinforcing the electrical distribution system in SLU. Estimated 2020 net reduction in peak summer power demand as a result of the Energy District are 38 MVA with CHP and 32 MVA with deep water cooling. At a time of fiscal difficulty for SCL, an Energy District can delay or eliminate some investments in additional distribution infrastructure.

The natural gas supply infrastructure – the pipelines bringing natural gas from the wellhead through transmission and distribution system to the study area – is adequate to serve the projected natural gas requirements of a gas-based Energy District.

## 8.3 Technology Evaluation

Based on the above evaluation, Scenario 1 provides lowest costs under base case assumptions. However, if CHP has a higher economic value than assumed in the base case (and there are a variety of reasons why this may be so, as discussed above), then CHP would provide a particularly attractive combination of economic and environmental benefits.

Deep water cooling combined with boilers (Scenario 3) and deep water cooling with heat pumps (Scenario 4) hold the potential for enormous sustainability benefits, including:

- Sustainable energy for the major redevelopment area in Seattle;
- Stable energy costs for buildings in the Energy District;
- Reduced emissions of air pollution and carbon dioxide;
- Improved conditions for salmon migration; and

However, the capital and total costs of these scenarios are higher, and the net water quality and fishery impacts require significant study. Scenarios 3 and 4 are unlikely to provide competitive energy services to customers unless additional financial support is provided, e.g., in the form of grants in recognition of the water quality and fisheries benefits (if indeed it is determined that those hypothetical benefits are realizable). If that can be accomplished, it would be a tremendous achievement for sustainability. But many complex questions must be answered before it can be determined if this environmental synergy will work, including permitting issues relating to withdrawal and discharge of water from these natural water bodies.

Extending the financing period of some of the Energy District assets would also help reduce the costs of the higher-capital-cost scenarios (Scenario 2, 3 and 4).

It is extremely important to understand that an Energy District opens up many options for energy supply, some of which may not be anticipated currently. Four integrated technology scenarios were evaluated here, but other approaches may become attractive in the near or long term.

## 8.4 Economic Feasibility

Cumulative capital costs (2003 $) are estimated to be:

- $95 million for Scenario 1 (gas boilers and electric chillers)
- $123 million for Scenario 2 (combined heat and power)
- $126 million for Scenario 3 (deep water cooling and gas boilers)
- $135 million for Scenario 4 (deep water cooling and heat pumps)

Heating and cooling are projected to be provided at an average total annual cost in the first five years of $1.20 per Square Foot (2003 $), gradually rising to $1.40 per SF by 2020 (2003 $). The financial proforma included financing of a $9 million operating reserve to keep rates lower in the early years.

Scenario 1 (gas boilers and electric chillers) has the lowest annual costs, and Scenario 4 (deep water cooling and heat pumps) has the highest annual costs under the base case projections for natural gas prices and wholesale electricity value. The Phase 4 total annual costs for Scenario 2 (CHP), Scenario 3 (deep water cooling) and Scenario 4 (deep water cooling and heat pumps) are 10%, 16% and 22%, respectively, higher than for Scenario 1 (natural gas boilers and electric chillers). However, if net power production from CHP has a higher market value than assumed in the base case estimates (175% of the average wholesale resource cost instead of 125%), the total costs of the CHP approach (Scenario 2) are equal to the costs of gas boilers and electric chillers (Scenario 1).

The Energy District offers cost savings in Cases 1 and 3 and costs slightly more in Case 2. Although Energy District service would come at a cost premium in Case 2, it would also provide significant advantages relative to ease of building operation, elimination of the headache of maintaining many heat pump units, and improved reliability.

## 8.5 Environmental Impacts

The emissions associated with each Energy District scenario were estimated, including the regulated air pollutants nitrogen oxides (NOx) and carbon monoxide (CO) as well as the greenhouse gas carbon dioxide (CO2). This analysis included direct emissions (e.g. emissions from an Energy District boiler stack) as well as indirect emissions, i.e. emissions resulting from generation of electricity obtained from Seattle City Light (SCL). Energy District emissions were then compared with the estimated emissions if no Energy District was implemented.

In 2020, the Energy District is estimated to reduce annual carbon dioxide (CO2) emissions by 26 to 42 percent, and nitrogen oxides emissions by 52 to 72 percent (depending on technologies used) compared to conventional energy approaches. Cumulative 20-year energy (fuel), electricity and CO2 savings, and annual savings in 2020, are as follows, with the range depending on Energy District technologies:

| | **Cumulative** | **Year 2020** |
|---|---|---|
| Energy savings (trillion Btu) | 3.6 - 5.6 | 0.2 - 0.4 |
| Electricity savings (million MWH) | 0.3 - 2.8 | 0.02 - 0.17 |
| CO2 savings (million lbs.) | 495 - 820 | 33 - 54 |

Annual 2020 savings can be compared as follows:
- Fossil fuel savings could provide space and water heating for 6,800 to 11,200 multi-family residential units.
- Electricity savings could power 1,800 to 13,800 Seattle homes.
- CO2 reductions are equal to 4.5 to 7.4 percent of annual emissions from Seattle City Light's generation portfolio in 2003.

## 8.6 Implementation Issues

The primary implementation issues include air quality emissions associated with CHP, greenhouse gas (GHG) emission and water temperature and fisheries impacts associated with deep water cooling. Overall, no "showstoppers" were identified. However, significant issues were raised that will require substantial effort during subsequent phases of the project. Key issues regarding the environmental impacts of deep water cooling relate to impacts from: laying of the pipeline; impact on aquatic life at the intake; and impact on aquatic life from discharge of water at elevated temperature and heating of water surrounding the pipeline.

## 8.7 Customer and Community Benefits

An Energy District could meet the energy requirements of the buildings in SLU/Denny Triangle in a way that:
- Makes economic sense for developers and building owners;
- Makes it easier to manage buildings and budget for building operation;
- Reduces investment risks for real estate investors;
- Supplies energy with better reliability than conventional approaches;
- Reduces reliance on fossil fuels through increased efficiency and/or use of renewable energy resources;
- Reduces environmental impact from meeting energy needs;
- *Potentially* improves water quality and salmon migration conditions as a byproduct of implementing deep water cooling; and
- "Future proofs" the buildings and the community by developing an infrastructure that provides flexibility to respond to challenges (e.g., increasing and/or volatile energy prices) and opportunities (e.g., new technologies that are more sustainable and cost-effective) much more readily than individual building energy systems.

A further note on "future proofing." An Energy District can provide flexibility to respond to variety of future energy problems and opportunities. Energy Districts can address problems such as:
- High and volatile fuel prices;
- Need to phase out ozone-destroying refrigerants;
- Need to reduce emissions of greenhouse gases; and
- Uncertainty regarding future power prices.

Once in place, Energy Districts can evolve in beneficial ways that may not have been initially envisioned.

# Section 9 Recommendations

Redevelopment in the study area brings with it an opportunity to develop a flexible and sustainable energy infrastructure for the area that meets developer business objectives. Based on this study, there appear to be significant public and private benefits realizable from an Energy District.

It is important to understand that an Energy District opens up many options for energy supply, some of which may not be anticipated currently. For an insight into how Energy Districts can evolve to provide energy, environmental and economic flexibility, it is useful to examine the experience of St. Paul, Minnesota. This Energy District started as a highly efficient hot water district heating system in the early 1980s, initiated by the building owners (through the Building Owners and Managers Association) and the City of St. Paul with technical and financial assistance from the State of Minnesota and the U.S. Department of Energy. Since then it has evolved to incorporate:

- Chilled water district cooling including electric and absorption chillers
- Thermal energy storage to reduce peak power demand
- Biomass combined heat and power (CHP) using waste wood to produce power, heating and cooling

The St. Paul system is owned and operated by a private non-profit corporation governed by a seven-member board of directors composed of City appointees and representatives elected by the customers.

Implementing an Energy District in Seattle will not be easy. It will require multiple private sector and public sector entities to work together. It will involve a variety of regulatory hurdles. And it will require significant capital investment – capital that is front-loaded ahead of the revenue-generating customer base.

A private non-profit company is the most promising approach for implementing an Energy District in the study area, for several reasons:

- It could be used to facilitate low-cost financing, thereby helping keep costs down for a capital-intensive energy infrastructure;
- It facilitates a governance approach that enables the stakeholders, including most importantly the customers, a voice in decision-making; and
- It has been proven to work successfully, for example in St. Paul, Minnesota.

An “Energy District Development Corporation” (EDDC) could be the non-profit vehicle for system development (just as the District Heating Development Company did in St. Paul, eventually morphing into District Energy St. Paul, an operating utility company). The stakeholders, both public and private, could participate in governance and decision-making of this ownership entity. EDDC could contract with a developer to design, construct and commission the system. EDDC could also contract with an operator to manage the system on a day-to-day basis. For example, Seattle Steam, which has many years of management and operations experience, could be excellent candidate for this role.

If the stakeholders agree that the potential benefits are significant enough to warrant further investigation, Phase 2 studies should be initiated to clarify the technical, economic, permitting, financial and organizational issues surrounding this opportunity. Key steps in Phase 2 studies are outlined below in two sub-phases. In this outline, reference will be made to “Initial System.” This is intended to refer to the first phase of development of the Energy District system.

**Phase 2a**

1. Communication with potential customers regarding the benefits and costs of Energy District service, including potential service contract terms and costs, and comparison to customer alternatives.

2. Investigation of alternative technologies for the Initial System, including groundwater and small-scale CHP.
3. Development of a conceptual design for the Initial System, including plant siting, distribution routing, customer connections and related capital and operating costs.
4. Additional analysis of impacts of Energy District on electricity transmission and distribution systems.
5. Development of the organizational and financing approach for Energy District system design, permitting, construction and operation.
6. Development of a detailed plan and timeline for Initial System implementation including design, permitting, construction and operation.
7. Revision of Energy District economic and financial analysis based on the above.
8. Recommendations regarding proceeding.

**Phase 2b**

1. Negotiation with potential customers regarding the benefits and costs of Energy District service, including potential service contract terms and costs, and comparison to customer alternatives.
2. Design and preliminary implementation of a public outreach and involvement plan.
3. Updating of projections for building development and related customer heating and cooling loads.
4. Scoping and assessment of permitting issues and potential water quality and fish migration benefits associated with deep water cooling/heat pump technology.
5. Initiation of permitting and regulatory processes and environmental assessments in view of public input and permitting discussions with regulators.
6. Specification/negotiation of terms and conditions for electricity and gas service, and, as applicable, grid connection for power export.
7. Interactive with the above, revision of technology concept and economic analysis for full Energy District development.
8. Development of specific financing plan, including identification of funding sources and basic contractual relationships between capital sources, system developer, system owner and customers.
9. Presentation and communication of the Phase 2 Study results with public and private sector stakeholders.

# Appendices

## Appendix 1 – Examples of Energy District Plants

**Houston ice storage district cooling 33,000 tons**

**Atlantic City 17,100 ton cooling,140 million Btu per hour heating**

## Appendix 2 – Format of DEED Report to APPA

**Project Title**
The official project title as submitted in the original proposal to the DEED board of directors.

**General Overview**
Include the applicability of the project to other utilities and alternatives available to them (if known), problems that arose during the course of the project and how they were resolved, a discussion of whether the project goals were achieved (and if not, why not), and recommendations regarding the technology/technique.

**Purpose**
Thoroughly describe why the project was undertaken. Explain the problem the project was intended to solve.

Utility Name and Address
Name and address of sponsoring utility (include other participants under "Additional Notes").

**Utility Description**
Include sponsoring utility's size (i.e., number of customers per class), annual load per class, services offered (i.e., electric, water, etc.), generation resources, and other relevant information.

**Key Personnel & Phone Numbers**
List personnel from sponsoring utility as well as contractors who worked on the project. Describe the responsibilities each person had during the project.

**Description**
Thoroughly describe the scope of the project.

**Diagram**
Not all projects lend themselves to use of a diagram, but most do. The diagram can be a flow- chart, schematic, drawing, graph, or other pictorial that will add to the readers' understanding of the project. Please include as many of these diagrams, charts, etc. as possible.

**Dates**
Please describe the project's term as submitted in the original DEED proposal, and if applicable, as subsequently adjusted and agreed upon by the DEED administrator. Also provide information on the events that caused each change in the project's term.

**Alternatives**
Thoroughly describe all known alternatives to the project. To the extent known, for each alternative, include information on the scope of research needed for the project alternative, costs, etc. Include an explanation on why the chosen path was taken.

Results to Date
Thoroughly describe what has occurred on the project up to the time of completion of the DEED grant. This section should include all relevant data resulting from the project.

**Status**
The status of the project when the DEED grant was concluded.

**Applicability**
Thoroughly explain how others might use the results of the project. In particular, explain if there are public power systems (those of a particular generation resource, with high distribution losses, etc.) that might find the results of this project especially useful.

**Future Plans**
If applicable, provide information about continued or tangential work planned for the project, whether to be conducted by you or another party. If none is planned, discuss, why not.

**Equipment**
List equipment purchased and/or used for this project, if any. For each piece of equipment, where applicable, include information on its efficiency, and why it was chosen over another brand/size/model, and how it performed for the project.

**Budget**
Develop funding and cost sections. Under funding, on an annual basis, list all organizations that contributed funds to the project (both monetary and in-kind), including the host utility. Under the costs section, provide annual information about what was spent on the project for hardware, labor, etc.

It is important to break down budget as much as possible so that others can see the itemized costs. You may include a budgeted and actual figure for each item under costs. The totals for funding and costs should be the same. If the figures are different, you must include an explanation why. A complete budget should show all sources of funding and compare funding totals with each costs (actual versus budgeted), e.g., for each piece of equipment, consultant fees, utility staff time, etc.

**Additional Notes**
Include additional information about the project that is important to know, but does not fit into any of the previous categories.

**References**
Include a list of publications referred to during the course of the project and any publications or papers resulting from the project. A bibliography, if available, should be attached.

# Appendix 3 – Advisory Committee

Eric Hausman, Advisory Committee Chair
University of Washington
Director, Financial and Administrative Services, Facilities Services

John Chapman
University of Washington
Director of Campus Operations

Hamilton Hazlehurst
Real Estate Development Manager
Vulcan, Inc

Bob Cowan
Manager, Facilities Engineering
Fred Hutchinson Cancer Research Center

Paul Chen
Sr. Facilities Engineer/Supervisor
PEMCO Financial Services

Ron Brown
Manager, Facilities Operations
Seattle Times

Shawn Parry
Touchstone Corporation

Lyn Krizanich, RPA
Clise Properties, Inc.

Michael Boyle
Clise Properties

Derek Bottles
R. C. Hedreen Company

Cliff Braddock
Austin Energy

James Young
President & CEO
Seattle Steam Corporation

Arun Jhaveri
Regional Technology Manager
Federal Energy Management Program
United States Department of Energy
Seattle Regional Office

Chuck Collins
Distributed Energy and Electric Reliability
US Department of Energy
Seattle Regional Office

Ken Johnsen (City of Seattle's South Lake Union Project Manager)
Shiels Obletz Johnsen

Hardev Juj
Director of Transmission and Distribution Planning
Seattle City Light

Betty Tobin
Director of Central Electrical Services
Seattle City Light

Nancy Glaser
Director of Strategic Planning
Seattle City Light

Carol Everson
Director of Finance
Seattle City Light

Bob Klug
Account Executive Office
Seattle City Light

Chuck Peterson
Account Executive Office
Seattle City Light

Sue Walsh
Account Executive Office

Laurie Geissinger
Environment & Safety Division
Seattle City Light

David Docter
Strategic Planning Office
Seattle City Light

Mark Velicer
Puget Sound Energy

Jake Fey
Director
Washington State University Energy Program

David Sjoding
Division Manager, Renewable Resources and Technical/Engineering Services
Washington State University Energy Program

Gordon Bloomquist, Ph.D.
Senior Scientist
Geothermal, Hydrothermal & Integrated Energy Systems
Washington State University Energy Program

Cliff Braddock
Austin Energy

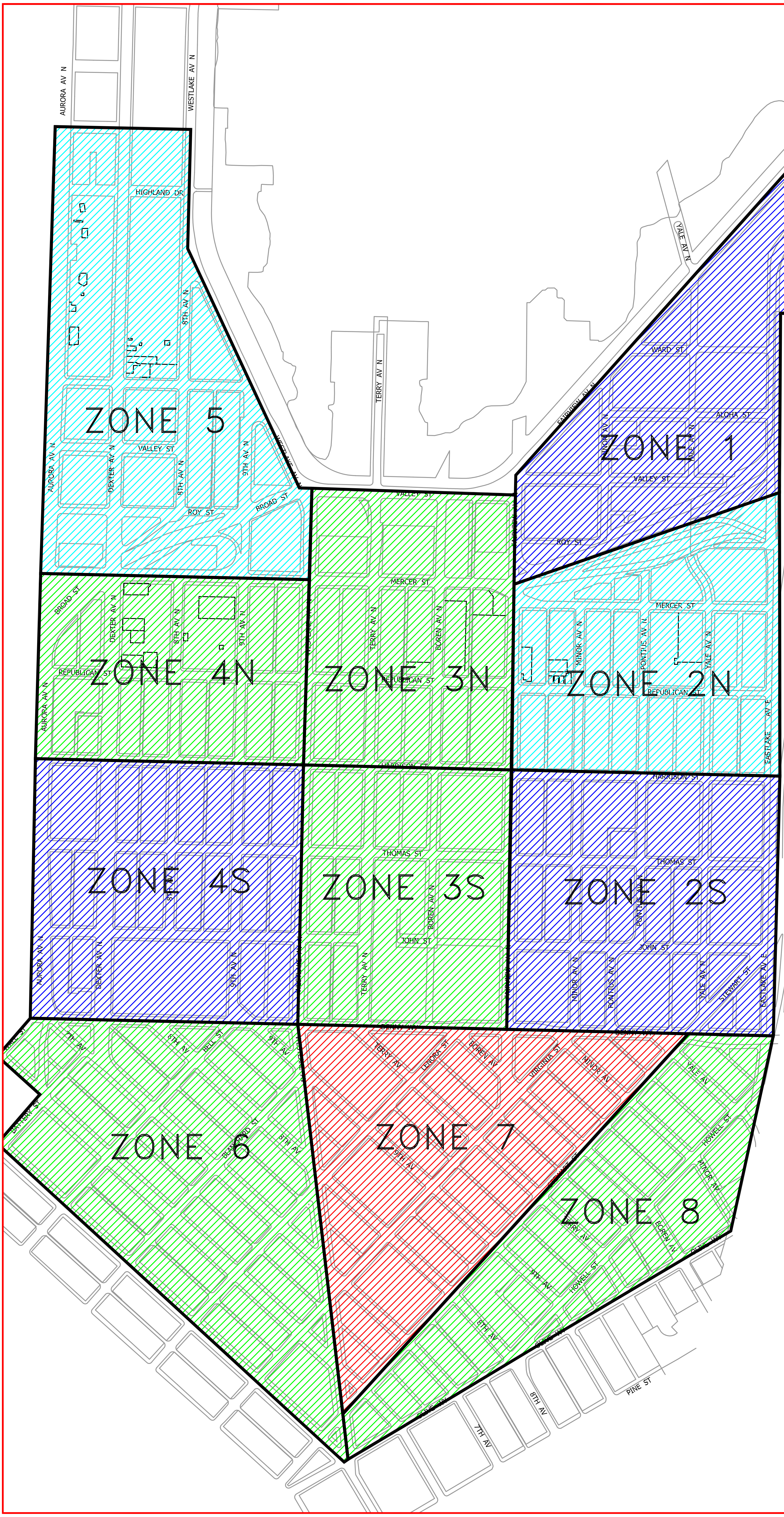
Anders Rydaker
District Energy St. Paul, Inc.

Stanley Gent
Comfort Link, Inc.

Bryan Kleist
Mechanical Engineer
FVB Energy, Inc.

Mark Spurr
Vice President
FVB Energy, Inc.

## Appendix 4 – Heating, Cooling and Electricity Peak Demand Concentrations by Zone




| | Phase | Building Space (SF) | Cooling Load (Tons) |
|---|---|---|---|
| ZONE 1 | 1 | - | - |
| | 2 | 266,400 | 619 |
| | 3 | 242,100 | 497 |
| | 4 | 349,200 | 793 |
| | Total | 857,700 | 1,909 |
| ZONE 2N | 1 | - | - |
| | 2 | 325,800 | 485 |
| | 3 | - | - |
| | 4 | - | - |
| | Total | 325,800 | 485 |
| ZONE 2S | 1 | 337,500 | 493 |
| | 2 | - | - |
| | 3 | 235,200 | 465 |
| | 4 | 545,700 | 1,078 |
| | Total | 1,118,400 | 2,035 |
| ZONE 3N | 1 | 415,100 | 867 |
| | 2 | 1,227,200 | 2,423 |
| | 3 | 306,500 | 742 |
| | 4 | 69,100 | 159 |
| | Total | 2,017,900 | 4,191 |
| ZONE 3S | 1 | 119,700 | 266 |
| | 2 | 466,200 | 1,094 |
| | 3 | 678,800 | 1,733 |
| | 4 | 527,900 | 1,227 |
| | Total | 1,792,600 | 4,319 |
| ZONE 4N | 1 | 351,000 | 1,003 |
| | 2 | 360,000 | 1,029 |
| | 3 | 829,900 | 1,633 |
| | 4 | 139,500 | 247 |
| | Total | 1,680,400 | 3,912 |
| ZONE 4S | 1 | 555,300 | 1,092 |
| | 2 | 39,900 | 71 |
| | 3 | 458,200 | 812 |
| | 4 | 323,800 | 671 |
| | Total | 1,377,100 | 2,646 |
| ZONE 5 | 1 | - | - |
| | 2 | 89,000 | 191 |
| | 3 | - | - |
| | 4 | 192,200 | 412 |
| | Total | 281,100 | 602 |
| ZONE 6 | 1 | - | - |
| | 2 | 924,600 | 1,948 |
| | 3 | 1,128,600 | 1,899 |
| | 4 | 298,300 | 502 |
| | Total | 2,351,500 | 4,349 |
| ZONE 7 | 1 | 425,300 | 596 |
| | 2 | 1,284,100 | 2,302 |
| | 3 | 155,400 | 261 |
| | 4 | 1,287,500 | 2,166 |
| | Total | 3,152,400 | 5,326 |
| ZONE 8 | 1 | - | - |
| | 2 | 1,700,100 | 2,500 |
| | 3 | 987,200 | 1,661 |
| | 4 | 329,700 | 555 |
| | Total | 3,017,100 | 4,716 |

PEAK COOLING LOAD OF PROJECTED ENERGY DISTRICT CUSTOMERS AT FULL BUILDOUT

- GREATER THAN 5000 TONS
- 3000 TONS - 5000 TONS
- 1000 TONS - 3000 TONS
- LESS THAN 1000 TONS

Seattle City Light

REVISIONS

| DATE | REMARKS | NO. |
|---|---|---|
| 12/4/03 | REVISED MARKET DATA | 01 |

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FAX: (612) 338-3427

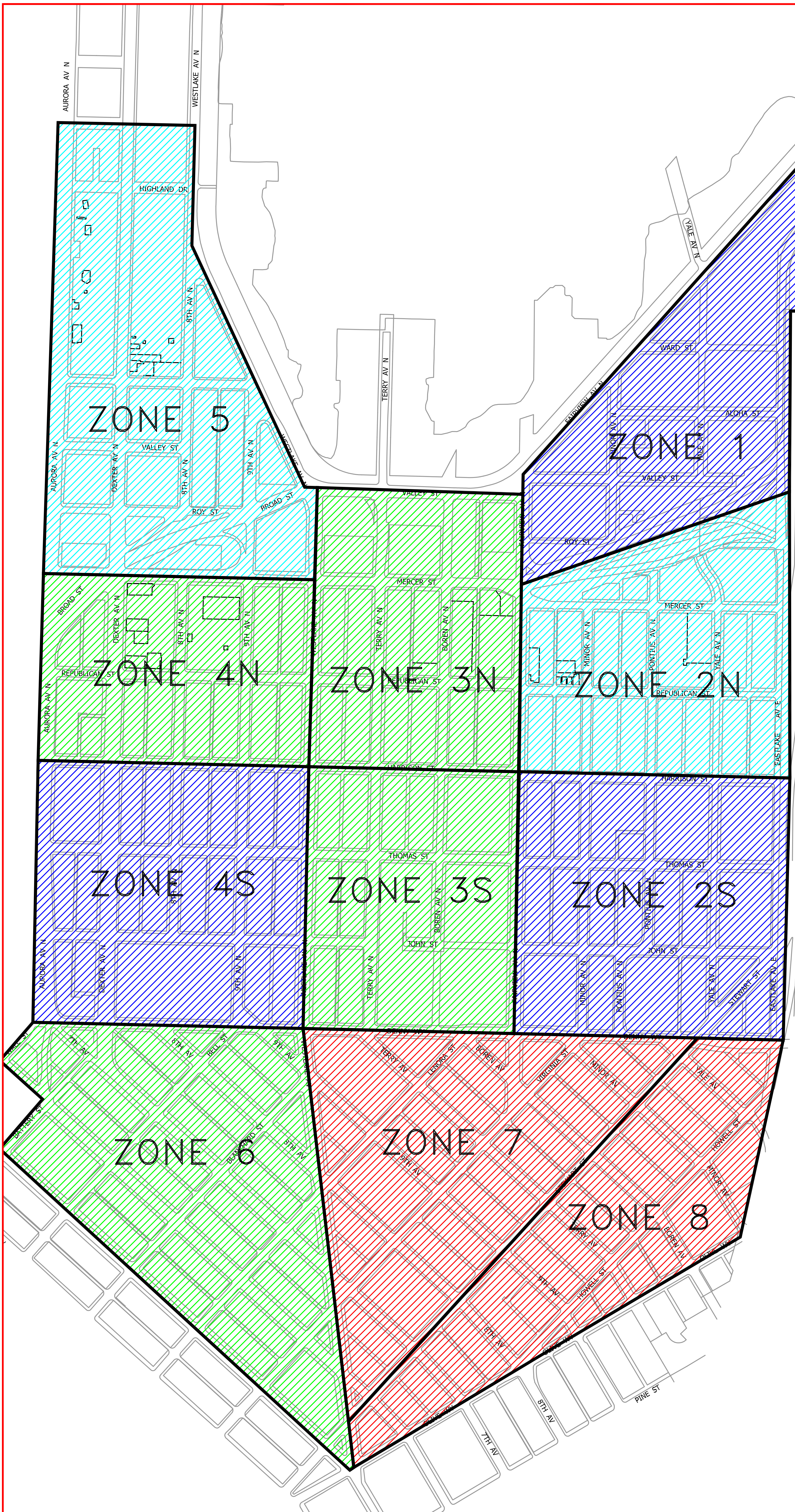
COOPERATIVE EXTENSION
Washington State University
ENERGY PROGRAM

PROJECT TITLE: SEATTLE ENERGY DISTRICT STUDY

SHEET TITLE: PROJECTED CUSTOMER BASE PEAK COOLING LOAD ESTIMATES BY ZONE

| | | | |
|---|---|---|---|
| DGN: | BMK | SCALE: | 1"=450' |
| DWN: | BMK | JOB NO.: | 302230 |
| APPR: | CMS | DATE: | 07/31/03 |

DWG NO.: ZONES-01




| | Phase | Building Space (SF) | Heating Load (MMBtu/hr) |
|---|---|---|---|
| ZONE 1 | 1 | - | - |
| | 2 | 266,400 | 4.6 |
| | 3 | 242,100 | 3.0 |
| | 4 | 349,200 | 5.8 |
| | Total | 857,700 | 13.4 |
| ZONE 2N | 1 | - | - |
| | 2 | 325,800 | 4.0 |
| | 3 | - | - |
| | 4 | - | - |
| | Total | 325,800 | 4.0 |
| ZONE 2S | 1 | 337,500 | 4.1 |
| | 2 | - | - |
| | 3 | 235,200 | 3.0 |
| | 4 | 545,700 | 7.1 |
| | Total | 1,118,400 | 14.2 |
| ZONE 3N | 1 | 415,100 | 4.9 |
| | 2 | 1,227,200 | 17.7 |
| | 3 | 306,500 | 4.2 |
| | 4 | 69,100 | 0.9 |
| | Total | 2,017,900 | 27.8 |
| ZONE 3S | 1 | 119,700 | 1.4 |
| | 2 | 466,200 | 8.2 |
| | 3 | 678,800 | 9.5 |
| | 4 | 527,900 | 7.2 |
| | Total | 1,792,600 | 26.3 |
| ZONE 4N | 1 | 351,000 | 7.2 |
| | 2 | 360,000 | 7.3 |
| | 3 | 829,900 | 10.7 |
| | 4 | 139,500 | 1.7 |
| | Total | 1,680,400 | 26.9 |
| ZONE 4S | 1 | 555,300 | 6.5 |
| | 2 | 39,900 | 0.5 |
| | 3 | 458,200 | 5.7 |
| | 4 | 323,800 | 4.2 |
| | Total | 1,377,100 | 17.0 |
| ZONE 5 | 1 | - | - |
| | 2 | 89,000 | 1.2 |
| | 3 | - | - |
| | 4 | 192,200 | 2.5 |
| | Total | 281,100 | 3.7 |
| ZONE 6 | 1 | - | - |
| | 2 | 924,600 | 10.7 |
| | 3 | 1,128,600 | 13.4 |
| | 4 | 298,300 | 3.5 |
| | Total | 2,351,500 | 27.7 |
| ZONE 7 | 1 | 425,300 | 5.4 |
| | 2 | 1,284,100 | 15.3 |
| | 3 | 155,400 | 1.8 |
| | 4 | 1,287,500 | 15.3 |
| | Total | 3,152,400 | 37.8 |
| ZONE 8 | 1 | - | - |
| | 2 | 1,700,100 | 20.2 |
| | 3 | 987,200 | 11.7 |
| | 4 | 329,700 | 3.9 |
| | Total | 3,017,100 | 35.9 |

PEAK HEATING LOAD OF PROJECTED ENERGY DISTRICT CUSTOMERS AT FULL BUILDOUT

- GREATER THAN 30 MMBH
- 20 MMBH - 30 MMBH
- 10 MMBH - 20 MMBH
- LESS THAN 10 MMBH

Seattle City Light

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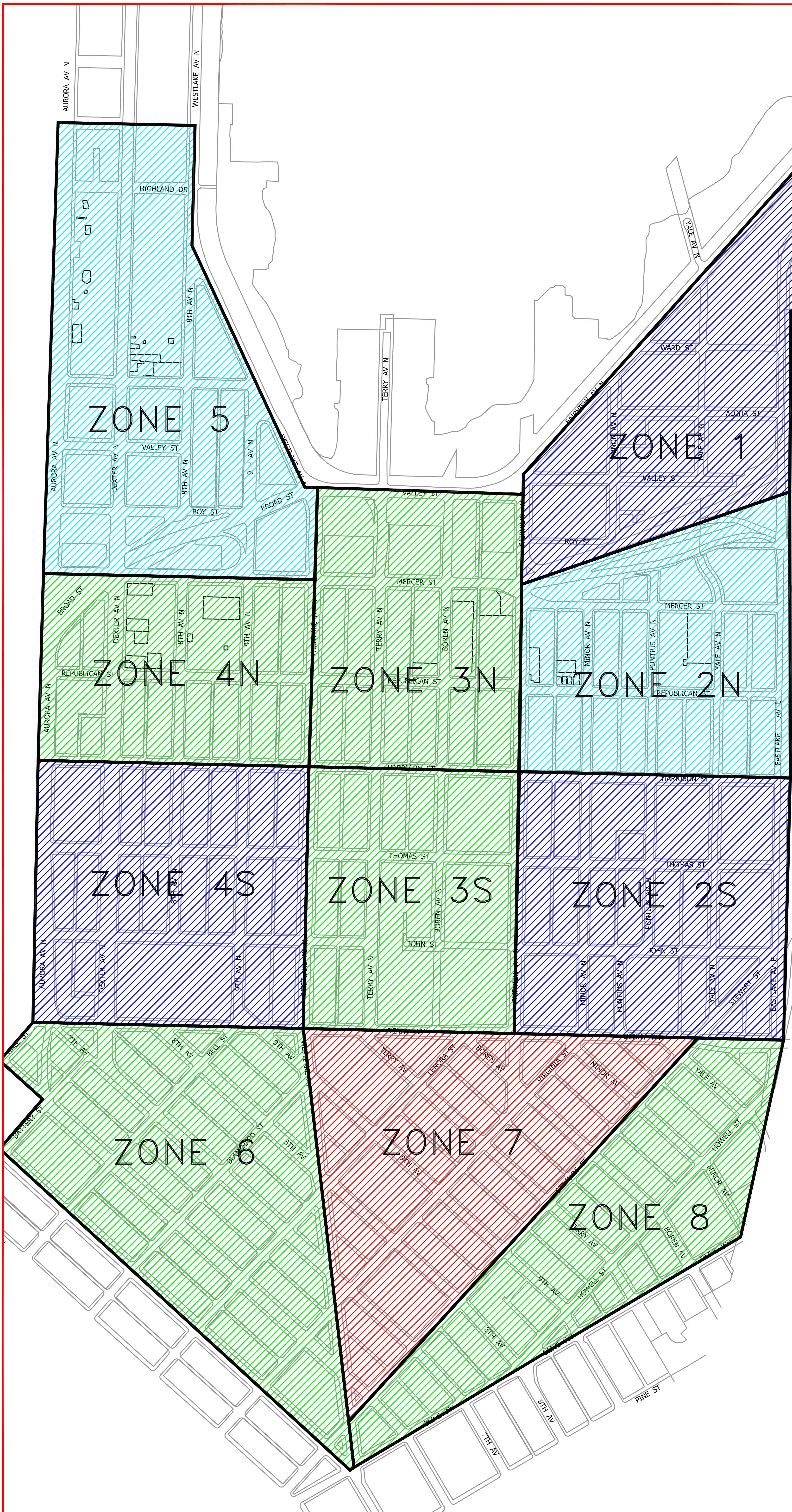
COOPERATIVE EXTENSION
Washington State University
ENERGY PROGRAM

PROJECT TITLE: SEATTLE ENERGY DISTRICT STUDY

SHEET TITLE: PROJECTED CUSTOMER BASE PEAK HEATING LOAD ESTIMATES BY ZONE

| | |
|---|---|
| DGN: BMK | SCALE: 1"=450' |
| DWN: BMK | JOB NO.: 302230 |
| APPR: CMS | DATE: 07/31/03 |
| DWG NO.: ZONES-02 | |




| | Phase | Building Space (SF) | Avoided Power Load (MW) |
|---|---|---|---|
| ZONE 1 | 1 | - | - |
| | 2 | 266,400 | 0.7 |
| | 3 | 242,100 | 0.6 |
| | 4 | 349,200 | 0.9 |
| | Total | 857,700 | 2.1 |
| ZONE 2N | 1 | - | - |
| | 2 | 325,800 | 0.6 |
| | 3 | - | - |
| | 4 | - | - |
| | Total | 325,800 | 0.6 |
| ZONE 2S | 1 | 337,500 | 0.6 |
| | 2 | - | - |
| | 3 | 235,210 | 0.6 |
| | 4 | 545,690 | 1.3 |
| | Total | 1,118,400 | 2.5 |
| ZONE 3N | 1 | 415,140 | 1.1 |
| | 2 | 1,227,150 | 2.8 |
| | 3 | 306,500 | 0.9 |
| | 4 | 69,090 | 0.2 |
| | Total | 2,017,880 | 4.9 |
| ZONE 3S | 1 | 119,700 | 0.3 |
| | 2 | 466,200 | 1.2 |
| | 3 | 678,780 | 2.1 |
| | 4 | 527,910 | 1.5 |
| | Total | 1,792,580 | 5.0 |
| ZONE 4N | 1 | 351,000 | 1.0 |
| | 2 | 360,000 | 1.1 |
| | 3 | 829,850 | 2.0 |
| | 4 | 139,540 | 0.3 |
| | Total | 1,680,400 | 4.4 |
| ZONE 4S | 1 | 555,300 | 1.3 |
| | 2 | 39,870 | 0.1 |
| | 3 | 458,170 | 1.0 |
| | 4 | 323,780 | 0.8 |
| | Total | 1,377,120 | 3.2 |
| ZONE 5 | 1 | - | - |
| | 2 | 88,950 | 0.2 |
| | 3 | - | - |
| | 4 | 192,160 | 0.5 |
| | Total | 281,110 | 0.7 |
| ZONE 6 | 1 | - | - |
| | 2 | 924,640 | 2.4 |
| | 3 | 1,128,560 | 2.4 |
| | 4 | 298,330 | 0.6 |
| | Total | 2,351,530 | 5.3 |
| ZONE 7 | 1 | 425,340 | 0.8 |
| | 2 | 1,284,150 | 2.8 |
| | 3 | 155,380 | 0.3 |
| | 4 | 1,287,540 | 2.7 |
| | Total | 3,152,410 | 6.6 |
| ZONE 8 | 1 | - | - |
| | 2 | 1,700,100 | 3.1 |
| | 3 | 987,250 | 2.1 |
| | 4 | 329,740 | 0.7 |
| | Total | 3,017,090 | 5.9 |

PEAK AVOIDED POWER LOAD FOR PROJECTED ENERGY DISTRICT CUSTOMERS AT FULL BUILDOUT

- GREATER THAN 6.0 MW
- 3.5 MW - 6.0 MW
- 1.0 MW - 3.5 MW
- LESS THAN 1.0 MW

Seattle City Light

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| DATE | REMARKS | NO. |
|---|---|---|
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COOPERATIVE EXTENSION
Washington State University
ENERGY PROGRAM

PROJECT TITLE: SEATTLE ENERGY DISTRICT STUDY

SHEET TITLE: PROJECTED CUSTOMER BASE PEAK AVOIDED POWER LOAD ESTIMATES BY ZONE

| | |
|---|---|
| DGN: BMK | SCALE: 1"=450' |
| DWN: BMK | JOB NO.: 302230 |
| APPR: CMS | DATE: 07/31/03 |
| DWG NO.: ZONES-03 | |

## Appendix 5 – Puget Sound Energy Natural Gas Tariffs

### Puget Sound Energy

**Commercial and Industrial Firm Sales Rate**
**Sheet No. S-10. Effective 10/01/03**

**Rate 87 -- Non-Exclusive Interruptible Service with Firm Option**

Available to non-residential customers whose interruptible requirement exceeds 1 million therms/yr.

| | | | |
|---|---|---|---|
| This is equal to: | | 100,000 | MMBtu/year |
| | | 11.42 | average MMBtu/hour |
| Monthly customer charge | $ | 300.00 | |
| Commodity costs per Therm | | | |
| Monthly contract volume charge | $ | 0.01981 | |
| Total interruptible delivery charge | | | |
| First 25000 therms | $ | 0.11889 | |
| Next 25000 therms | $ | 0.07665 | |
| Next 50000 therms | $ | 0.04978 | |
| Next 100000 therms | $ | 0.03268 | |
| Next 300000 therms | $ | 0.02490 | |
| Subtotal | | | |
| All over 500000 therms | $ | 0.01992 | |
| Cost of gas | $ | 0.47216 | |
| Conservation charge | $ | 0.01640 | |
| Firming charges | | | |
| Firm gas charges (monthly charge per therm of contracted daily firm gas) | | | |
| Firm delivery demand charge | $ | 0.99000 | |
| Firm gas supply charge | $ | 1.04000 | |
| Total firming charges | $ | 2.03000 | |
| City taxes | | 6.00% | of gas cost |
| | | 6.36% | of total bill |

**Rate 31 -- Commercial and Industrial General Service**

| | | |
|---|---|---|
| Monthly customer charge | $ | 10.00 |
| Commodity cost per therm | | |
| Delivery charge | $ | 0.2386 |
| Cost of gas | $ | 0.5301 |
| Conservation charge | $ | 0.0002 |
| Total tariff rate | $ | 0.7688 |

*Reference: Data from PSE website www.pse.com, with additional analysis provided by FVB Energy, Inc.*

# Appendix 6 – Seattle City Light Electricity Rates

## Seattle City Light Electric Rates

Effective April 1, 2002

| | | | | Energy ($/kWh) | | Demand ($/kW) | | 375 kWh/kW/mo Average $/kWh | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | On-peak | Off-peak | On-peak | Off-peak | On-peak | Off-peak | Average |
| Medium Network General Service (City) | MDD | > 50kW | < 1 MW | $ 0.0635 | | $ 1.5900 | | $ 0.0677 | $ - | |
| Large Network General Service (City) | LGD | > 1 mW | | $ 0.0624 | $ 0.0548 | $ 0.8400 | $ 0.1700 | $ 0.0646 | $ 0.0553 | $ 0.060 |
| Small General Service (City) | SMC | < 50kW | | $ 0.0605 | | | | $ 0.0605 | $ - | |
| Medium Standard General Service (City) | MDC | > 50kW | < 1 MW | $ 0.0586 | | $ 1.0300 | | $ 0.0613 | $ - | |
| Large Standard General Service (City) | LGC | > 1 mW | < 10 MW | $ 0.0591 | $ 0.0517 | $ 0.4000 | $ 0.1700 | $ 0.0602 | $ 0.0522 | $ 0.056 |
| High Demand General Service | HDC | > 10 MW | | $ 0.0572 | $ 0.0496 | $ 0.4000 | $ 0.1700 | $ 0.0583 | $ 0.0501 | $ 0.054 |
| Variable Rate General Service | VRC | > 10 MW | | Based on wholesale prices | | | | | | |

# Appendix 7 – Capital Costs

- Distribution System Cost Estimates
- Plant Capital Cost Estimates

### *Cost Estimate for Full Heating and Cooling Distribution System (SLU & Denny Triangle Areas)*

| DESCRIPTION | SIZE | QTY | UNIT | MAT | LABOR | EQUIP | TOTAL (US$) | Phase1 (US$) | Phase2 (US$) | Phase3 (US$) | Phase4 (US$) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **General Conditions** | | | | | | | | | | | |
| Mobilization | | 8 | LS | $ - | $ - | $ 20,000 | $ 160,000 | $ 44,671 | $ 71,474 | $ 32,014 | $ 11,841 |
| Temporary Facilities (Field Off, Toilets, Tool Rm) | | 25 | MOs | $ - | $ - | $ 10,000 | $ 250,000 | $ 69,799 | $ 111,678 | $ 50,022 | $ 18,502 |
| Utility Hook-ups/Utility Charges (water/elec) | | 25 | MOs | $ - | $ - | $ 1,300 | $ 32,500 | $ 9,074 | $ 14,518 | $ 6,503 | $ 2,405 |
| Construction Supervision (PM, Supt, Foreman) | | 31 | MOs | $ - | $ 25,200 | $ - | $ 781,200 | $ 218,107 | $ 348,970 | $ 156,307 | $ 57,816 |
| Trench Safety | | 27,848 | TF | $ 6 | $ - | $ - | $ 167,088 | $ 46,650 | $ 74,640 | $ 33,432 | $ 12,366 |
| Permits and Fees | | 2 | LS | $ 40,000 | $ - | $ - | $ 80,000 | $ 22,336 | $ 35,737 | $ 16,007 | $ 5,921 |
| Testing of piping system | | 27,848 | TF | $ 8 | $ - | $ - | $ 222,784 | $ 62,200 | $ 99,520 | $ 44,576 | $ 16,488 |
| Commissioning | | 27,848 | TF | $ 4 | $ - | $ - | $ 111,392 | $ 31,100 | $ 49,760 | $ 22,288 | $ 8,244 |
| | | | | | | **Sub-Total** | **$ 1,804,964** | **$ 503,935** | **$ 806,297** | **$ 361,148** | **$ 133,583** |
| **Quantity Take-offs for Open Trenching** | | | | | | | | | | | |
| Insulated Welded Stl Piping | 30 | 150 | LF | $ 112 | $ 142 | $ - | $ 38,063 | $ 38,063 | $ - | $ - | $ - |
| Insulated Welded Stl Elbow | 30 | 2 | EA | $ 1,850 | $ 1,215 | $ - | $ 6,130 | $ 6,130 | $ - | $ - | $ - |
| Insulated Welded Stl Tee | 30 | 2 | EA | $ 2,300 | $ 1,580 | $ - | $ 7,759 | $ 7,759 | $ - | $ - | $ - |
| Flanged Pipe Connector | 30 | - | EA | $ 225 | $ 181 | $ - | $ - | $ - | $ - | $ - | $ - |
| Butterfly Valves with valve boxes | 30 | - | EA | $ 7,060 | $ 1,035 | $ - | $ - | $ - | $ - | $ - | $ - |
| Insulated Welded Stl Piping | 24 | 3,298 | LF | $ 72 | $ 106 | $ - | $ 586,065 | $ 109,110 | $ 476,955 | $ - | $ - |
| Insulated Welded Stl Elbow | 24 | 61 | EA | $ 1,500 | $ 908 | $ - | $ 146,889 | $ 16,856 | $ 130,033 | $ - | $ - |
| Insulated Welded Stl Tee | 24 | 18 | EA | $ 1,700 | $ 1,180 | $ - | $ 51,847 | $ 11,522 | $ 40,326 | $ - | $ - |
| Flanged Pipe Connector | 24 | - | EA | $ 225 | $ 181 | $ - | $ - | $ - | $ - | $ - | $ - |
| Butterfly Valves with valve boxes | 24 | - | EA | $ 5,620 | $ 906 | $ - | $ - | $ - | $ - | $ - | $ - |
| Insulated Welded Stl Piping | 20 | 2,496 | LF | $ 48 | $ 92 | $ - | $ 348,575 | $ 348,575 | $ - | $ - | $ - |
| Insulated Welded Stl Elbow | 20 | 28 | EA | $ 1,000 | $ 636 | $ - | $ 45,804 | $ 45,804 | $ - | $ - | $ - |
| Insulated Welded Stl Tee | 20 | 14 | EA | $ 1,400 | $ 827 | $ - | $ 31,172 | $ 31,172 | $ - | $ - | $ - |
| Flanged Pipe Connector | 20 | 4 | EA | $ 225 | $ 181 | $ - | $ 1,625 | $ 1,625 | $ - | $ - | $ - |
| Butterfly Valves with valve boxes | 20 | 2 | EA | $ 2,595 | $ 776 | $ - | $ 6,743 | $ 6,743 | $ - | $ - | $ - |
| Insulated Welded Stl Piping | 18 | 2,148 | LF | $ 40 | $ 79 | $ - | $ 255,654 | $ 47,608 | $ 208,046 | $ - | $ - |
| Insulated Welded Stl Elbow | 18 | 39 | EA | $ 720 | $ 488 | $ - | $ 47,129 | $ 4,834 | $ 42,295 | $ - | $ - |
| Insulated Welded Stl Tee | 18 | 14 | EA | $ 1,060 | $ 635 | $ - | $ 23,729 | $ 6,780 | $ 16,950 | $ - | $ - |
| Flanged Pipe Connector | 18 | 4 | EA | $ 225 | $ 181 | $ - | $ 1,625 | $ - | $ 1,625 | $ - | $ - |
| Butterfly Valves with valve boxes | 18 | 2 | EA | $ 2,125 | $ 712 | $ - | $ 5,673 | $ - | $ 5,673 | $ - | $ - |
| Insulated Welded Stl Piping | 16 | 3,324 | LF | $ 36 | $ 64 | $ - | $ 329,772 | $ 139,290 | $ 190,482 | $ - | $ - |
| Insulated Welded Stl Elbow | 16 | 52 | EA | $ 565 | $ 398 | $ - | $ 50,061 | $ 19,254 | $ 30,807 | $ - | $ - |
| Insulated Welded Stl Tee | 16 | 18 | EA | $ 700 | $ 517 | | $ 21,906 | $ 12,170 | $ 9,736 | $ - | $ - |
| Flanged Pipe Connector | 16 | 8 | EA | $ 228 | $ 375 | $ 32.00 | $ 5,080 | $ - | $ 5,080 | $ - | $ - |
| Butterfly Valves with valve boxes | 16 | 4 | EA | $ 1,740 | $ 556 | $ - | $ 9,186 | $ - | $ 9,186 | $ - | $ - |
| Insulated Welded Stl Piping | 14 | 8,322 | LF | $ 32 | $ 58 | $ - | $ 752,290 | $ 313,680 | $ 380,575 | $ 58,035 | $ - |
| Insulated Welded Stl Elbow | 14 | 95 | EA | $ 410 | $ 355 | $ - | $ 72,654 | $ 29,826 | $ 37,474 | $ 5,353 | $ - |
| Insulated Welded Stl Tee | 14 | 30 | EA | $ 550 | $ 461 | $ - | $ 30,336 | $ 16,179 | $ 10,112 | $ 4,045 | $ - |
| Flanged Pipe Connector | 14 | 12 | EA | $ 170 | $ 270 | $ 23.00 | $ 5,556 | $ 3,704 | $ 1,852 | $ - | $ - |
| Butterfly Valves with valve boxes | 14 | 6 | EA | $ 1,250 | $ 518 | $ - | $ 10,606 | $ 7,070 | $ 3,535 | $ - | $ - |
| Insulated Welded Stl Piping | 12 | 13,236 | LF | $ 28 | $ 49 | $ - | $ 1,007,726 | $ 352,506 | $ 474,018 | $ 163,691 | $ 17,511 |
| Insulated Welded Stl Elbow | 12 | 225 | EA | $ 310 | $ 316 | $ - | $ 140,828 | $ 48,820 | $ 70,101 | $ 18,777 | $ 3,130 |
| Insulated Welded Stl Tee | 12 | 50 | EA | $ 365 | $ 411 | $ - | $ 38,784 | $ 12,411 | $ 18,616 | $ 7,757 | $ - |
| Flanged Pipe Connector | 12 | 36 | EA | $ 126 | $ 222 | $ 18.00 | $ 13,176 | $ 4,392 | $ 5,856 | $ 1,464 | $ 1,464 |
| Butterfly Valves with valve boxes | 12 | 18 | EA | $ 905 | $ 466 | $ - | $ 24,675 | $ 8,225 | $ 10,967 | $ 2,742 | $ 2,742 |
| Insulated Welded Stl Piping | 10 | 8,062 | LF | $ 23 | $ 40 | $ - | $ 503,906 | $ 141,009 | $ 203,762 | $ 101,256 | $ 57,879 |
| Insulated Welded Stl Elbow | 10 | 112 | EA | $ 220 | $ 263 | $ - | $ 54,124 | $ 12,565 | $ 25,129 | $ 11,598 | $ 4,833 |
| Insulated Welded Stl Tee | 10 | 24 | EA | $ 245 | $ 342 | $ - | $ 14,093 | $ 5,872 | $ 5,872 | $ 2,349 | $ - |
| Flanged Pipe Connector | 10 | 44 | EA | $ 86 | $ 170 | $ 14.00 | $ 11,880 | $ 2,160 | $ 3,240 | $ 4,320 | $ 2,160 |
| Butterfly Valves with valve boxes | 10 | 22 | EA | $ 825 | $ 419 | $ - | $ 27,374 | $ 4,977 | $ 7,466 | $ 9,954 | $ 4,977 |
| Insulated Welded Stl Piping | 8 | 20,728 | LF | $ 14 | $ 34 | $ - | $ 995,902 | $ 220,820 | $ 434,338 | $ 240,423 | $ 100,320 |
| Insulated Welded Stl Elbow | 8 | 288 | EA | $ 147 | $ 212 | $ - | $ 103,455 | $ 19,757 | $ 47,417 | $ 24,786 | $ 11,495 |
| Insulated Welded Stl Tee | 8 | 44 | EA | $ 168 | $ 276 | $ - | $ 19,531 | $ 10,653 | $ 8,878 | $ - | $ - |
| Flanged Pipe Connector | 8 | 148 | EA | $ 50 | $ 140 | $ 12.00 | $ 29,896 | $ 3,232 | $ 11,312 | $ 10,504 | $ 4,848 |
| Butterfly Valves with valve boxes | 8 | 74 | EA | $ 675 | $ 285 | $ - | $ 71,016 | $ 7,677 | $ 26,871 | $ 24,952 | $ 11,516 |
| Insulated Welded Stl Piping | 6 | 13,738 | LF | $ 10 | $ 28 | $ - | $ 523,220 | $ 197,512 | $ 199,797 | $ 107,173 | $ 18,738 |
| Insulated Welded Stl Elbow | 6 | 179 | EA | $ 104 | $ 158 | $ - | $ 46,889 | $ 19,384 | $ 16,765 | $ 9,430 | $ 1,310 |
| Insulated Welded Stl Tee | 6 | 36 | EA | $ 116 | $ 205 | $ - | $ 11,568 | $ 5,141 | $ 4,499 | $ 1,285 | $ 643 |
| Flanged Pipe Connector | 6 | 40 | EA | $ 32 | $ 112 | $ 9.00 | $ 6,120 | $ 1,224 | $ 612 | $ 3,672 | $ 612 |
| Butterfly Valves with valve boxes | 6 | 20 | EA | $ 330 | $ 131 | $ - | $ 9,220 | $ 1,844 | $ 922 | $ 5,532 | $ 922 |
| Insulated Welded Stl Piping | 5 | 9,610 | LF | $ 8 | $ 23 | $ - | $ 300,086 | $ 106,107 | $ 99,862 | $ 59,455 | $ 34,661 |
| Insulated Welded Stl Elbow | 5 | 137 | EA | $ 79 | $ 151 | $ - | $ 31,463 | $ 11,253 | $ 10,105 | $ 6,660 | $ 3,445 |
| Insulated Welded Stl Tee | 5 | 30 | EA | $ 95 | $ 196 | $ - | $ 8,726 | $ 2,909 | $ 2,909 | $ 2,909 | $ - |
| Flanged Pipe Connector | 5 | 64 | EA | $ 36 | $ 85 | $ 11.00 | $ 8,448 | $ 2,640 | $ 2,640 | $ 1,584 | $ 1,584 |
| Butterfly Valves with valve boxes | 5 | 32 | EA | $ 315 | $ 112 | $ - | $ 13,666 | $ 4,271 | $ 4,271 | $ 2,562 | $ 2,562 |
| Insulated Welded Stl Piping | 4 | 14,762 | LF | $ 6 | $ 19 | $ - | $ 382,330 | $ 36,622 | $ 226,311 | $ 84,070 | $ 35,327 |
| Insulated Welded Stl Elbow | 4 | 216 | EA | $ 69 | $ 141 | $ - | $ 45,347 | $ 3,359 | $ 27,712 | $ 9,237 | $ 5,039 |
| Insulated Welded Stl Tee | 4 | 22 | EA | $ 79 | $ 183 | $ - | $ 5,769 | $ 524 | $ 4,196 | $ 1,049 | $ - |
| Flanged Pipe Connector | 4 | 104 | EA | $ 19 | $ 72 | $ 9.00 | $ 10,400 | $ 800 | $ 4,400 | $ 3,600 | $ 1,600 |
| Butterfly Valves with valve boxes | 4 | 52 | EA | $ 215 | $ 85 | $ - | $ 15,574 | $ 1,198 | $ 6,589 | $ 5,391 | $ 2,396 |
| Insulated Welded Stl Piping | 3 | 9,596 | LF | $ 5 | $ 15 | $ - | $ 194,676 | $ 11,117 | $ 52,463 | $ 97,663 | $ 33,433 |
| Insulated Welded Stl Elbow | 3 | 121 | EA | $ 43 | $ 122 | $ - | $ 19,905 | $ 987 | $ 4,935 | $ 11,022 | $ 2,961 |
| Insulated Welded Stl Tee | 3 | 4 | EA | $ 52 | $ 158 | $ - | $ 840 | $ - | $ 420 | $ - | $ 420 |
| Flanged Pipe Connector | 3 | 100 | EA | $ 16 | $ 48 | $ 6.00 | $ 7,000 | $ 560 | $ 1,680 | $ 3,640 | $ 1,120 |
| Butterfly Valves with valve boxes | 3 | 50 | EA | $ 215 | $ 60 | $ - | $ 13,750 | $ 1,100 | $ 3,300 | $ 7,150 | $ 2,200 |
| Insulated Welded Stl Piping | 2 | 1,706 | LF | $ 4 | $ 10 | $ - | $ 23,540 | $ 7,423 | $ 9,493 | $ 1,297 | $ 5,326 |
| Insulated Welded Stl Elbow | 2 | 19 | EA | $ 40 | $ 108 | $ - | $ 2,807 | $ 886 | $ 1,182 | $ 148 | $ 591 |
| Insulated Welded Stl Tee | 2 | - | EA | $ 46 | $ 140 | $ - | $ - | $ - | $ - | $ - | $ - |
| Flanged Pipe Connector | 2 | 16 | EA | $ 12 | $ 40 | $ 4.00 | $ 896 | $ 224 | $ 224 | $ 224 | $ 224 |
| Butterfly Valves with valve boxes | 2 | 8 | EA | $ 207 | $ 56 | $ - | $ 2,104 | $ 526 | $ 526 | $ 526 | $ 526 |
| Insulated Welded Stl Piping | 1 | 216 | LF | $ 3 | $ 9 | $ - | $ 2,476 | $ - | $ 2,476 | $ - | $ - |
| Insulated Welded Stl Elbow | 1 | 2 | EA | $ 22 | $ 33 | $ - | $ 111 | $ - | $ 111 | $ - | $ - |
| Insulated Welded Stl Tee | 1 | 2 | EA | $ 25 | $ 43 | $ - | $ 137 | $ - | $ 137 | $ - | $ - |
| Flanged Pipe Connector | 1 | 4 | EA | $ 12 | $ 28 | $ 6.00 | $ 184 | $ - | $ 184 | $ - | $ - |
| Butterfly Valves with valve boxes | 1 | 2 | EA | $ 89 | $ 32 | $ - | $ 242 | $ - | $ 242 | $ - | $ - |
| Vents | | 111 | EA | $ 750 | $ 1,750 | $ - | $ 278,480 | $ 77,750 | $ 124,400 | $ 55,720 | $ 20,610 |
| Drains | | 111 | EA | $ 1,250 | $ 3,250 | $ - | $ 501,264 | $ 139,950 | $ 223,920 | $ 100,296 | $ 37,098 |
| Aluminum Warning Tape | | 111,392 | LF | $ 0.5 | $ - | $ - | $ 55,696 | $ 15,550 | $ 24,880 | $ 11,144 | $ 4,122 |
| Alarm system for pipeline | | 55,696 | LF | $ 1 | $ 2 | $ - | $ 167,088 | $ 46,650 | $ 74,640 | $ 33,432 | $ 12,366 |
| Foam pads | | 827 | EA | $ 30 | $ 100 | $ - | $ 107,494 | $ 30,012 | $ 48,019 | $ 21,508 | $ 7,955 |
| 4" Communications Conduit and (3) Innerducts | | 27,848 | LF | $ 6 | $ 3 | $ - | $ 250,632 | $ 69,975 | $ 111,960 | $ 50,148 | $ 18,549 |
| Fiber Optic Cable | | 27,848 | LF | $ 3 | $ 2 | $ - | $ 139,240 | $ 38,875 | $ 62,200 | $ 27,860 | $ 10,305 |
| Communications Manhole | | 80 | EA | $ 800 | $ 600 | $ 150 | $ 124,000 | $ 34,620 | $ 55,392 | $ 24,811 | $ 9,177 |
| Contribution to Trenching & Restoration Costs for Heating pipe 3" and smaller (including: escavation, backfill, top soil, trenching, all work done between the hours of 6am & 6pm, 6' cover, fuel, & all equipment rental) | | 5,759 | Trench Ft | $ 90 | $ - | $ - | $ 519,232 | $ 144,966 | $ 231,946 | $ 103,891 | $ 38,428 |
| Contribution to Trenching & Restoration Costs for Heating pipe 4" to 8" (including: escavation, backfill, top soil, trenching, all work done between the hours of 6am & 6pm, 6' cover, fuel, & all equipment rental) | | 19,765 | Trench Ft | $ 161 | $ - | $ - | $ 3,174,840 | $ 886,397 | $ 1,418,235 | $ 635,242 | $ 234,966 |
| Contribution to Trenching & Restoration Costs for Heating pipe 10" to 18" (including: escavation, backfill, top soil, trenching, all work done between the hours of 6am & 6pm, 6' cover, fuel, & all equipment rental) | | 2,324 | Trench Ft | $ 283 | $ - | $ - | $ 658,410 | $ 183,824 | $ 294,119 | $ 131,739 | $ 48,728 |
| Contribution to Trenching & Restoration Costs for Cooling pipe 4" to 8" (including: escavation, backfill, top soil, trenching, all work done between the hours of 6am & 6pm, 6' cover, fuel, & all equipment rental) | | 9,654 | Trench Ft | $ 153 | $ - | $ - | $ 1,476,981 | $ 412,365 | $ 659,783 | $ 295,523 | $ 109,310 |
| Contribution to Trenching & Restoration Costs for Cooling pipe 10" to 18" (including: escavation, backfill, top soil, trenching, all work done between the hours of 6am & 6pm, 6' cover, fuel, & all equipment rental) | | 15,222 | Trench Ft | $ 270 | $ - | $ - | $ 4,116,555 | $ 1,149,318 | $ 1,838,909 | $ 823,666 | $ 304,662 |
| Contribution to Trenching & Restoration Costs for Cooling pipe 20" and larger (including: escavation, backfill, top soil, trenching, all work done between the hours of 6am & 6pm, 6' cover, fuel, & all equipment rental) | | 2,972 | Trench Ft | $ 456 | $ - | $ - | $ 1,356,550 | $ 378,741 | $ 605,985 | $ 271,427 | $ 100,397 |
| | | | | | | **Sub-Total** | **$ 20,562,248** | **$ 6,105,437** | **$ 9,417,933** | **$ 3,703,691** | **$ 1,335,187** |
| **Total Trench Feet** | | **27,848** | | | **SUBTOTAL CONSTRUCTION COSTS** | | **$ 22,367,212** | **$ 6,609,373** | **$ 10,224,230** | **$ 4,064,839** | **$ 1,468,771** |
| | | | | **6.5%** | | **TAX** | **$ 958,696** | **$ 267,662** | **$ 428,260** | **$ 191,822** | **$ 70,952** |
| | | | | | | **SUBTOTAL** | **$ 23,325,909** | **$ 6,877,035** | **$ 10,652,490** | **$ 4,256,661** | **$ 1,539,723** |
| | | | | **13.0%** | | **OVERHEAD & PROFIT** | **$ 3,032,368** | **$ 894,015** | **$ 1,384,824** | **$ 553,366** | **$ 200,164** |
| | | | | | | **SUBTOTAL** | **$ 26,358,277** | **$ 7,771,050** | **$ 12,037,314** | **$ 4,810,027** | **$ 1,739,887** |
| | | | | **8.0%** | | **CONTINGENCY** | **$ 2,108,662** | **$ 621,684** | **$ 962,985** | **$ 384,802** | **$ 139,191** |
| | | | | | | **SUBTOTAL** | **$ 28,466,939** | **$ 8,392,734** | **$ 13,000,299** | **$ 5,194,829** | **$ 1,879,078** |
| | | | | **5.5%** | | **DESIGN FEES** | **$ 1,565,682** | **$ 461,600** | **$ 715,016** | **$ 285,716** | **$ 103,349** |
| | | | | | | **TOTAL** | **$ 30,032,621** | **$ 8,854,334** | **$ 13,715,315** | **$ 5,480,545** | **$ 1,982,427** |
| | | | | | | **Cost/TF - Total** | **$ 1,078** | **$ 1,139** | **$ 1,103** | **$ 984** | **$ 962** |
| | | | | | | **Cost/TF - Const. Costs Only** | **$ 803** | **$ 850** | **$ 822** | **$ 730** | **$ 713** |
| | | | | | | **Trench Feet Per Phase** | **27,848** | **7,775** | **12,440** | **5,572** | **2,061** |

### *Cost Estimate for Heating and Cooling Distribution System in South Lake Union Area*

| DESCRIPTION | SIZE | QTY | UNIT | MAT | LABOR | EQUIP | TOTAL (US$) | Phase1 (US$) | Phase2 (US$) | Phase3 (US$) | Phase4 (US$) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **General Conditions** | | | | | | | | | | | |
| Mobilization | | 4 | LS | $ - | $ - | $ 20,000 | $ 80,000 | $ 26,087 | $ 30,348 | $ 17,130 | $ 6,435 |
| Temporary Facilities (Field Off, Toilets, Tool Rm) | | 14 | MOs | $ - | $ - | $ 10,000 | $ 140,000 | $ 45,652 | $ 53,109 | $ 29,978 | $ 11,261 |
| Utility Hook-ups/Utility Charges (water/elec) | | 14 | MOs | $ - | $ - | $ 1,300 | $ 18,200 | $ 5,935 | $ 6,904 | $ 3,897 | $ 1,464 |
| Construction Supervision (PM, Supt, Foreman) | | 17 | MOs | $ - | $ 25,200 | $ - | $ 428,400 | $ 139,696 | $ 162,513 | $ 91,733 | $ 34,458 |
| Trench Safety | | 18,400 | TF | $ 6 | $ - | $ - | $ 110,400 | $ 36,000 | $ 41,880 | $ 23,640 | $ 8,880 |
| Permits and Fees | | 1 | LS | $ 40,000 | $ - | $ - | $ 40,000 | $ 13,043 | $ 15,174 | $ 8,565 | $ 3,217 |
| Testing of piping system | | 18,400 | TF | $ 8 | $ - | $ - | $ 147,200 | $ 48,000 | $ 55,840 | $ 31,520 | $ 11,840 |
| Commissioning | | 18,400 | TF | $ 4 | $ - | $ - | $ 73,600 | $ 24,000 | $ 27,920 | $ 15,760 | $ 5,920 |
| | | | | | | **Sub-Total** | **$ 1,037,800** | **$ 338,413** | **$ 393,687** | **$ 222,225** | **$ 83,475** |
| **Quantity Take-offs for Open Trenching** | | | | | | | | | | | |
| Insulated Welded Stl Piping | 30 | 150 | LF | $ 112 | $ 142 | $ - | $ 38,063 | $ 38,063 | $ - | $ - | $ - |
| Insulated Welded Stl Elbow | 30 | 2 | EA | $ 1,850 | $ 1,215 | $ - | $ 6,130 | $ 6,130 | $ - | $ - | $ - |
| Insulated Welded Stl Tee | 30 | 2 | EA | $ 2,300 | $ 1,580 | $ - | $ 7,759 | $ 7,759 | $ - | $ - | $ - |
| Flanged Pipe Connector | 30 | - | EA | $ 225 | $ 181 | $ - | $ - | $ - | $ - | $ - | $ - |
| Butterfly Valves with valve boxes | 30 | - | EA | $ 7,060 | $ 1,035 | $ - | $ - | $ - | $ - | $ - | $ - |
| Insulated Welded Stl Piping | 24 | 614 | LF | $ 72 | $ 106 | $ - | $ 109,110 | $ 109,110 | $ - | $ - | $ - |
| Insulated Welded Stl Elbow | 24 | 7 | EA | $ 1,500 | $ 908 | $ - | $ 16,856 | $ 16,856 | $ - | $ - | $ - |
| Insulated Welded Stl Tee | 24 | 4 | EA | $ 1,700 | $ 1,180 | $ - | $ 11,522 | $ 11,522 | $ - | $ - | $ - |
| Flanged Pipe Connector | 24 | - | EA | $ 225 | $ 181 | $ - | $ - | $ - | $ - | $ - | $ - |
| Butterfly Valves with valve boxes | 24 | - | EA | $ 5,620 | $ 906 | $ - | $ - | $ - | $ - | $ - | $ - |
| Insulated Welded Stl Piping | 20 | 2,496 | LF | $ 48 | $ 92 | $ - | $ 348,575 | $ 348,575 | $ - | $ - | $ - |
| Insulated Welded Stl Elbow | 20 | 28 | EA | $ 1,000 | $ 636 | $ - | $ 45,804 | $ 45,804 | $ - | $ - | $ - |
| Insulated Welded Stl Tee | 20 | 14 | EA | $ 1,400 | $ 827 | $ - | $ 31,172 | $ 31,172 | $ - | $ - | $ - |
| Flanged Pipe Connector | 20 | 4 | EA | $ 225 | $ 181 | $ - | $ 1,625 | $ 1,625 | $ - | $ - | $ - |
| Butterfly Valves with valve boxes | 20 | 2 | EA | $ 2,595 | $ 776 | $ - | $ 6,743 | $ 6,743 | $ - | $ - | $ - |
| Insulated Welded Stl Piping | 18 | 400 | LF | $ 40 | $ 79 | $ - | $ 47,608 | $ 47,608 | $ - | $ - | $ - |
| Insulated Welded Stl Elbow | 18 | 4 | EA | $ 720 | $ 488 | $ - | $ 4,834 | $ 4,834 | $ - | $ - | $ - |
| Insulated Welded Stl Tee | 18 | 4 | EA | $ 1,060 | $ 635 | $ - | $ 6,780 | $ 6,780 | $ - | $ - | $ - |
| Flanged Pipe Connector | 18 | - | EA | $ 225 | $ 181 | $ - | $ - | $ - | $ - | $ - | $ - |
| Butterfly Valves with valve boxes | 18 | - | EA | $ 2,125 | $ 712 | $ - | $ - | $ - | $ - | $ - | $ - |
| Insulated Welded Stl Piping | 16 | 1,632 | LF | $ 36 | $ 64 | $ - | $ 161,910 | $ 96,432 | $ 65,478 | $ - | $ - |
| Insulated Welded Stl Elbow | 16 | 18 | EA | $ 565 | $ 398 | $ - | $ 17,329 | $ 10,590 | $ 6,739 | $ - | $ - |
| Insulated Welded Stl Tee | 16 | 12 | EA | $ 700 | $ 517 | $ - | $ 14,604 | $ 9,736 | $ 4,868 | $ - | $ - |
| Flanged Pipe Connector | 16 | 8 | EA | $ 228 | $ 375 | $ 32.00 | $ 5,080 | $ - | $ 5,080 | $ - | $ - |
| Butterfly Valves with valve boxes | 16 | 4 | EA | $ 1,740 | $ 556 | $ - | $ 9,186 | $ - | $ 9,186 | $ - | $ - |
| Insulated Welded Stl Piping | 14 | 7,998 | LF | $ 32 | $ 58 | $ - | $ 723,002 | $ 313,680 | $ 351,286 | $ 58,035 | $ - |
| Insulated Welded Stl Elbow | 14 | 89 | EA | $ 410 | $ 355 | $ - | $ 68,065 | $ 29,826 | $ 32,886 | $ 5,353 | $ - |
| Insulated Welded Stl Tee | 14 | 28 | EA | $ 550 | $ 461 | $ - | $ 28,314 | $ 16,179 | $ 8,090 | $ 4,045 | $ - |
| Flanged Pipe Connector | 14 | 12 | EA | $ 170 | $ 270 | $ 23.00 | $ 5,556 | $ 3,704 | $ 1,852 | $ - | $ - |
| Butterfly Valves with valve boxes | 14 | 6 | EA | $ 1,250 | $ 518 | $ - | $ 10,606 | $ 7,070 | $ 3,535 | $ - | $ - |
| Insulated Welded Stl Piping | 12 | 4,552 | LF | $ 28 | $ 49 | $ - | $ 346,567 | $ 123,644 | $ 107,503 | $ 115,421 | $ - |
| Insulated Welded Stl Elbow | 12 | 51 | EA | $ 310 | $ 316 | $ - | $ 31,921 | $ 11,266 | $ 10,014 | $ 10,640 | $ - |
| Insulated Welded Stl Tee | 12 | 20 | EA | $ 365 | $ 411 | $ - | $ 15,513 | $ 6,205 | $ 6,205 | $ 3,103 | $ - |
| Flanged Pipe Connector | 12 | 12 | EA | $ 126 | $ 222 | $ 18.00 | $ 4,392 | $ 1,464 | $ 2,928 | $ - | $ - |
| Butterfly Valves with valve boxes | 12 | 6 | EA | $ 905 | $ 466 | $ - | $ 8,225 | $ 2,742 | $ 5,483 | $ - | $ - |
| Insulated Welded Stl Piping | 10 | 5,472 | LF | $ 23 | $ 40 | $ - | $ 342,021 | $ 134,008 | $ 89,755 | $ 60,379 | $ 57,879 |
| Insulated Welded Stl Elbow | 10 | 61 | EA | $ 220 | $ 263 | $ - | $ 29,478 | $ 11,598 | $ 7,732 | $ 5,316 | $ 4,833 |
| Insulated Welded Stl Tee | 10 | 18 | EA | $ 245 | $ 342 | $ - | $ 10,570 | $ 5,872 | $ 2,349 | $ 2,349 | $ - |
| Flanged Pipe Connector | 10 | 24 | EA | $ 86 | $ 170 | $ 14.00 | $ 6,480 | $ 1,080 | $ 2,160 | $ 1,080 | $ 2,160 |
| Butterfly Valves with valve boxes | 10 | 12 | EA | $ 825 | $ 419 | $ - | $ 14,931 | $ 2,489 | $ 4,977 | $ 2,489 | $ 4,977 |
| Insulated Welded Stl Piping | 8 | 14,266 | LF | $ 14 | $ 34 | $ - | $ 685,427 | $ 200,064 | $ 260,891 | $ 168,930 | $ 55,541 |
| Insulated Welded Stl Elbow | 8 | 158 | EA | $ 147 | $ 212 | $ - | $ 56,757 | $ 16,524 | $ 21,553 | $ 14,010 | $ 4,670 |
| Insulated Welded Stl Tee | 8 | 28 | EA | $ 168 | $ 276 | $ - | $ 12,429 | $ 9,765 | $ 2,663 | $ - | $ - |
| Flanged Pipe Connector | 8 | 104 | EA | $ 50 | $ 140 | $ 12.00 | $ 21,008 | $ 3,232 | $ 7,272 | $ 8,080 | $ 2,424 |
| Butterfly Valves with valve boxes | 8 | 52 | EA | $ 675 | $ 285 | $ - | $ 49,903 | $ 7,677 | $ 17,274 | $ 19,194 | $ 5,758 |
| Insulated Welded Stl Piping | 6 | 10,772 | LF | $ 10 | $ 28 | $ - | $ 410,258 | $ 128,729 | $ 174,204 | $ 88,587 | $ 18,738 |
| Insulated Welded Stl Elbow | 6 | 120 | EA | $ 104 | $ 158 | $ - | $ 31,434 | $ 9,954 | $ 13,359 | $ 6,811 | $ 1,310 |
| Insulated Welded Stl Tee | 6 | 28 | EA | $ 116 | $ 205 | $ - | $ 8,997 | $ 3,856 | $ 3,213 | $ 1,285 | $ 643 |
| Flanged Pipe Connector | 6 | 32 | EA | $ 32 | $ 112 | $ 9.00 | $ 4,896 | $ 1,224 | $ 612 | $ 2,448 | $ 612 |
| Butterfly Valves with valve boxes | 6 | 16 | EA | $ 330 | $ 131 | $ - | $ 7,376 | $ 1,844 | $ 922 | $ 3,688 | $ 922 |
| Insulated Welded Stl Piping | 5 | 6,342 | LF | $ 8 | $ 23 | $ - | $ 198,038 | $ 65,138 | $ 71,946 | $ 33,475 | $ 27,479 |
| Insulated Welded Stl Elbow | 5 | 71 | EA | $ 79 | $ 151 | $ - | $ 16,306 | $ 5,282 | $ 5,971 | $ 2,756 | $ 2,297 |
| Insulated Welded Stl Tee | 5 | 18 | EA | $ 95 | $ 196 | $ - | $ 5,235 | $ 1,745 | $ 2,327 | $ 1,163 | $ - |
| Flanged Pipe Connector | 5 | 36 | EA | $ 36 | $ 85 | $ 11.00 | $ 4,752 | $ 1,056 | $ 2,112 | $ 528 | $ 1,056 |
| Butterfly Valves with valve boxes | 5 | 18 | EA | $ 315 | $ 112 | $ - | $ 7,687 | $ 1,708 | $ 3,416 | $ 854 | $ 1,708 |
| Insulated Welded Stl Piping | 4 | 8,992 | LF | $ 6 | $ 19 | $ - | $ 232,889 | $ 36,622 | $ 124,629 | $ 60,450 | $ 11,189 |
| Insulated Welded Stl Elbow | 4 | 100 | EA | $ 69 | $ 141 | $ - | $ 20,994 | $ 3,359 | $ 11,127 | $ 5,458 | $ 1,050 |
| Insulated Welded Stl Tee | 4 | 14 | EA | $ 79 | $ 183 | $ - | $ 3,671 | $ 524 | $ 2,098 | $ 1,049 | $ - |
| Flanged Pipe Connector | 4 | 56 | EA | $ 19 | $ 72 | $ 9.00 | $ 5,600 | $ 800 | $ 2,400 | $ 2,000 | $ 400 |
| Butterfly Valves with valve boxes | 4 | 28 | EA | $ 215 | $ 85 | $ - | $ 8,386 | $ 1,198 | $ 3,594 | $ 2,995 | $ 599 |
| Insulated Welded Stl Piping | 3 | 7,992 | LF | $ 5 | $ 15 | $ - | $ 162,135 | $ 11,117 | $ 50,759 | $ 66,826 | $ 33,433 |
| Insulated Welded Stl Elbow | 3 | 89 | EA | $ 43 | $ 122 | $ - | $ 14,641 | $ 987 | $ 4,606 | $ 6,087 | $ 2,961 |
| Insulated Welded Stl Tee | 3 | 4 | EA | $ 52 | $ 158 | $ - | $ 840 | $ - | $ 420 | $ - | $ 420 |
| Flanged Pipe Connector | 3 | 84 | EA | $ 16 | $ 48 | $ 6.00 | $ 5,880 | $ 560 | $ 1,400 | $ 2,800 | $ 1,120 |
| Butterfly Valves with valve boxes | 3 | 42 | EA | $ 215 | $ 60 | $ - | $ 11,550 | $ 1,100 | $ 2,750 | $ 5,500 | $ 2,200 |
| Insulated Welded Stl Piping | 2 | 1,706 | LF | $ 4 | $ 10 | $ - | $ 23,540 | $ 7,423 | $ 9,493 | $ 1,297 | $ 5,326 |
| Insulated Welded Stl Elbow | 2 | 19 | EA | $ 40 | $ 108 | $ - | $ 2,807 | $ 886 | $ 1,182 | $ 148 | $ 591 |
| Insulated Welded Stl Tee | 2 | - | EA | $ 46 | $ 140 | $ - | $ - | $ - | $ - | $ - | $ - |
| Flanged Pipe Connector | 2 | 16 | EA | $ 12 | $ 40 | $ 4.00 | $ 896 | $ 224 | $ 224 | $ 224 | $ 224 |
| Butterfly Valves with valve boxes | 2 | 8 | EA | $ 207 | $ 56 | $ - | $ 2,104 | $ 526 | $ 526 | $ 526 | $ 526 |
| Insulated Welded Stl Piping | 1 | 216 | LF | $ 3 | $ 9 | $ - | $ 2,476 | $ - | $ 2,476 | $ - | $ - |
| Insulated Welded Stl Elbow | 1 | 2 | EA | $ 22 | $ 33 | $ - | $ 111 | $ - | $ 111 | $ - | $ - |
| Insulated Welded Stl Tee | 1 | 2 | EA | $ 25 | $ 43 | $ - | $ 137 | $ - | $ 137 | $ - | $ - |
| Flanged Pipe Connector | 1 | 4 | EA | $ 12 | $ 28 | $ 6.00 | $ 184 | $ - | $ 184 | $ - | $ - |
| Butterfly Valves with valve boxes | 1 | 2 | EA | $ 89 | $ 32 | $ - | $ 242 | $ - | $ 242 | $ - | $ - |
| Vents | | 74 | EA | $ 750 | $ 1,750 | $ - | $ 184,000 | $ 60,000 | $ 69,800 | $ 39,400 | $ 14,800 |
| Drains | | 74 | EA | $ 1,250 | $ 3,250 | $ - | $ 331,200 | $ 108,000 | $ 125,640 | $ 70,920 | $ 26,640 |
| Aluminum Warning Tape | | 73,600 | LF | $ 0.5 | $ - | $ - | $ 36,800 | $ 12,000 | $ 13,960 | $ 7,880 | $ 2,960 |
| Alarm system for pipeline | | 36,800 | LF | $ 1 | $ 2 | $ - | $ 110,400 | $ 36,000 | $ 41,880 | $ 23,640 | $ 8,880 |
| Foam pads | | 394 | EA | $ 30 | $ 100 | $ - | $ 51,188 | $ 16,692 | $ 19,418 | $ 10,961 | $ 4,117 |
| 4" Communications Conduit and (3) Innerducts | | 18,400 | LF | $ 6 | $ 3 | $ - | $ 165,600 | $ 54,000 | $ 62,820 | $ 35,460 | $ 13,320 |
| Fiber Optic Cable | | 18,400 | LF | $ 3 | $ 2 | $ - | $ 92,000 | $ 30,000 | $ 34,900 | $ 19,700 | $ 7,400 |
| Communications Manhole | | 53 | EA | $ 800 | $ 600 | $ 150 | $ 82,150 | $ 26,788 | $ 31,163 | $ 17,591 | $ 6,608 |
| Contribution to Trenching & Restoration Costs for Heating pipe 3" and smaller (including: escavation, backfill, top soil, trenching, all work done between the hours of 6am & 6pm, 6' cover, fuel, & all equipment rental) | | 4,957 | Trench Ft | $ 86 | $ - | $ - | $ 428,285 | $ 139,658 | $ 162,469 | $ 91,709 | $ 34,449 |
| Contribution to Trenching & Restoration Costs for Heating pipe 4" to 8" (including: escavation, backfill, top soil, trenching, all work done between the hours of 6am & 6pm, 6' cover, fuel, & all equipment rental) | | 12,461 | Trench Ft | $ 144 | $ - | $ - | $ 1,794,384 | $ 585,125 | $ 680,696 | $ 384,232 | $ 144,331 |
| Contribution to Trenching & Restoration Costs for Heating pipe 10" to 18" (including: escavation, backfill, top soil, trenching, all work done between the hours of 6am & 6pm, 6' cover, fuel, & all equipment rental) | | 982 | Trench Ft | $ 240 | $ - | $ - | $ 235,680 | $ 76,852 | $ 89,405 | $ 50,466 | $ 18,957 |
| Contribution to Trenching & Restoration Costs for Cooling pipe 4" to 8" (including: escavation, backfill, top soil, trenching, all work done between the hours of 6am & 6pm, 6' cover, fuel, & all equipment rental) | | 7,725 | Trench Ft | $ 144 | $ - | $ - | $ 1,112,400 | $ 362,739 | $ 421,987 | $ 238,199 | $ 89,476 |
| Contribution to Trenching & Restoration Costs for Cooling pipe 10" to 18" (including: escavation, backfill, top soil, trenching, all work done between the hours of 6am & 6pm, 6' cover, fuel, & all equipment rental) | | 9,045 | Trench Ft | $ 240 | $ - | $ - | $ 2,170,800 | $ 707,870 | $ 823,488 | $ 464,834 | $ 174,608 |
| Contribution to Trenching & Restoration Costs for Cooling pipe 20" and larger (including: escavation, backfill, top soil, trenching, all work done between the hours of 6am & 6pm, 6' cover, fuel, & all equipment rental) | | 1,630 | Trench Ft | $ 400 | $ - | $ - | $ 652,000 | $ 212,609 | $ 247,335 | $ 139,613 | $ 52,443 |
| | | | | | | **Sub-Total** | **$ 12,002,802** | **$ 4,421,626** | **$ 4,359,160** | **$ 2,369,983** | **$ 852,033** |
| **Total Trench Feet** | | **18,400** | | **SUBTOTAL CONSTRUCTION COSTS** | | | **$ 13,040,602** | **$ 4,760,039** | **$ 4,752,847** | **$ 2,592,207** | **$ 935,508** |
| | | | | **6.5%** | | **TAX** | **$ 548,166** | **$ 178,750** | **$ 207,946** | **$ 117,379** | **$ 44,092** |
| | | | | | | **SUBTOTAL** | **$ 13,588,768** | **$ 4,938,789** | **$ 4,960,793** | **$ 2,709,586** | **$ 979,600** |
| | | | | **13.0%** | | **OVERHEAD & PROFIT** | **$ 1,766,540** | **$ 642,043** | **$ 644,903** | **$ 352,246** | **$ 127,348** |
| | | | | | | **SUBTOTAL** | **$ 15,355,308** | **$ 5,580,832** | **$ 5,605,696** | **$ 3,061,832** | **$ 1,106,948** |
| | | | | **8.0%** | | **CONTINGENCY** | **$ 1,228,425** | **$ 446,467** | **$ 448,456** | **$ 244,947** | **$ 88,556** |
| | | | | | | **SUBTOTAL** | **$ 16,583,732** | **$ 6,027,298** | **$ 6,054,151** | **$ 3,306,779** | **$ 1,195,504** |
| | | | | **5.5%** | | **DESIGN FEES** | **$ 912,105** | **$ 331,501** | **$ 332,978** | **$ 181,873** | **$ 65,753** |
| | | | | | | **TOTAL** | **$ 17,495,838** | **$ 6,358,800** | **$ 6,387,130** | **$ 3,488,652** | **$ 1,261,257** |
| | | | | | | **Cost/TF - Total** | **$ 951** | **$ 1,060** | **$ 915** | **$ 885** | **$ 852** |
| | | | | | | **Cost/TF - Const. Costs Only** | **$ 709** | **$ 793** | **$ 681** | **$ 658** | **$ 632** |
| | | | | | | **Trench Feet Per Phase** | **18,400** | **6,000** | **6,980** | **3,940** | **1,480** |

### *Cost Estimate for Heating and Cooling Distribution System in Denny Triangle Area*

| DESCRIPTION | SIZE | QTY | UNIT | MAT | LABOR | EQUIP | TOTAL (US$) | Phase1 (US$) | Phase2 (US$) | Phase3 (US$) | Phase4 (US$) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **General Conditions** | | | | | | | | | | | |
| Mobilization | | 4 | LS | $ - | $ - | $ 20,000 | $ 80,000 | $ 15,030 | $ 46,232 | $ 13,819 | $ 4,920 |
| Temporary Facilities (Field Off, Toilets, Tool Rm) | | 11 | MOs | $ - | $ - | $ 10,000 | $ 110,000 | $ 20,666 | $ 63,569 | $ 19,001 | $ 6,764 |
| Utility Hook-ups/Utility Charges (water/elec) | | 11 | MOs | $ - | $ - | $ 1,300 | $ 14,300 | $ 2,687 | $ 8,264 | $ 2,470 | $ 879 |
| Construction Supervision (PM, Supt, Foreman) | | 14 | MOs | $ - | $ 25,200 | $ - | $ 352,800 | $ 66,281 | $ 203,883 | $ 60,941 | $ 21,695 |
| Trench Safety | | 9,448 | TF | $ 6 | $ - | $ - | $ 56,688 | $ 10,650 | $ 32,760 | $ 9,792 | $ 3,486 |
| Permits and Fees | | 1 | LS | $ 40,000 | $ - | $ - | $ 40,000 | $ 7,515 | $ 23,116 | $ 6,909 | $ 2,460 |
| Testing of piping system | | 9,448 | TF | $ 8 | $ - | $ - | $ 75,584 | $ 14,200 | $ 43,680 | $ 13,056 | $ 4,648 |
| Commissioning | | 9,448 | TF | $ 4 | $ - | $ - | $ 37,792 | $ 7,100 | $ 21,840 | $ 6,528 | $ 2,324 |
| | | | | | | **Sub-Total** | **$ 767,164** | **$ 144,127** | **$ 443,344** | **$ 132,516** | **$ 47,176** |
| **Quantity Take-offs for Open Trenching** | | | | | | | | | | | |
| Insulated Welded Stl Piping | 24 | 2,684 | LF | $ 72 | $ 106 | $ - | $ 476,955 | $ - | $ 476,955 | $ - | $ - |
| Insulated Welded Stl Elbow | 24 | 54 | EA | $ 1,500 | $ 908 | $ - | $ 130,033 | $ - | $ 130,033 | $ - | $ - |
| Insulated Welded Stl Tee | 24 | 14 | EA | $ 1,700 | $ 1,180 | $ - | $ 40,326 | $ - | $ 40,326 | $ - | $ - |
| Flanged Pipe Connector | 24 | - | EA | $ 225 | $ 181 | $ - | $ - | $ - | $ - | $ - | $ - |
| Butterfly Valves with valve boxes | 24 | - | EA | $ 5,620 | $ 906 | $ - | $ - | $ - | $ - | $ - | $ - |
| Insulated Welded Stl Piping | 18 | 1,748 | LF | $ 40 | $ 79 | $ - | $ 208,046 | $ - | $ 208,046 | $ - | $ - |
| Insulated Welded Stl Elbow | 18 | 35 | EA | $ 720 | $ 488 | $ - | $ 42,295 | $ - | $ 42,295 | $ - | $ - |
| Insulated Welded Stl Tee | 18 | 10 | EA | $ 1,060 | $ 635 | $ - | $ 16,950 | $ - | $ 16,950 | $ - | $ - |
| Flanged Pipe Connector | 18 | 4 | EA | $ 225 | $ 181 | $ - | $ 1,625 | $ - | $ 1,625 | $ - | $ - |
| Butterfly Valves with valve boxes | 18 | 2 | EA | $ 2,125 | $ 712 | $ - | $ 5,673 | $ - | $ 5,673 | $ - | $ - |
| Insulated Welded Stl Piping | 16 | 1,692 | LF | $ 36 | $ 64 | $ - | $ 167,862 | $ 42,858 | $ 125,004 | $ - | $ - |
| Insulated Welded Stl Elbow | 16 | 34 | EA | $ 565 | $ 398 | $ - | $ 32,732 | $ 8,664 | $ 24,068 | $ - | $ - |
| Insulated Welded Stl Tee | 16 | 6 | EA | $ 700 | $ 517 | $ - | $ 7,302 | $ 2,434 | $ 4,868 | $ - | $ - |
| Flanged Pipe Connector | 16 | - | EA | $ 228 | $ 375 | $ 32.00 | $ - | $ - | $ - | $ - | $ - |
| Butterfly Valves with valve boxes | 16 | - | EA | $ 1,740 | $ 556 | $ - | $ - | $ - | $ - | $ - | $ - |
| Insulated Welded Stl Piping | 14 | 324 | LF | $ 32 | $ 58 | $ - | $ 29,289 | $ - | $ 29,289 | $ - | $ - |
| Insulated Welded Stl Elbow | 14 | 6 | EA | $ 410 | $ 355 | $ - | $ 4,589 | $ - | $ 4,589 | $ - | $ - |
| Insulated Welded Stl Tee | 14 | 2 | EA | $ 550 | $ 461 | $ - | $ 2,022 | $ - | $ 2,022 | $ - | $ - |
| Flanged Pipe Connector | 14 | - | EA | $ 170 | $ 270 | $ 23.00 | $ - | $ - | $ - | $ - | $ - |
| Butterfly Valves with valve boxes | 14 | - | EA | $ 1,250 | $ 518 | $ - | $ - | $ - | $ - | $ - | $ - |
| Insulated Welded Stl Piping | 12 | 8,684 | LF | $ 28 | $ 49 | $ - | $ 661,158 | $ 228,862 | $ 366,515 | $ 48,270 | $ 17,511 |
| Insulated Welded Stl Elbow | 12 | 174 | EA | $ 310 | $ 316 | $ - | $ 108,907 | $ 37,554 | $ 60,086 | $ 8,137 | $ 3,130 |
| Insulated Welded Stl Tee | 12 | 30 | EA | $ 365 | $ 411 | $ - | $ 23,270 | $ 6,205 | $ 12,411 | $ 4,654 | $ - |
| Flanged Pipe Connector | 12 | 24 | EA | $ 126 | $ 222 | $ 18.00 | $ 8,784 | $ 2,928 | $ 2,928 | $ 1,464 | $ 1,464 |
| Butterfly Valves with valve boxes | 12 | 12 | EA | $ 905 | $ 466 | $ - | $ 16,450 | $ 5,483 | $ 5,483 | $ 2,742 | $ 2,742 |
| Insulated Welded Stl Piping | 10 | 2,590 | LF | $ 23 | $ 40 | $ - | $ 161,885 | $ 7,000 | $ 114,007 | $ 40,877 | $ - |
| Insulated Welded Stl Elbow | 10 | 51 | EA | $ 220 | $ 263 | $ - | $ 24,646 | $ 967 | $ 17,397 | $ 6,282 | $ - |
| Insulated Welded Stl Tee | 10 | 6 | EA | $ 245 | $ 342 | $ - | $ 3,523 | $ - | $ 3,523 | $ - | $ - |
| Flanged Pipe Connector | 10 | 20 | EA | $ 86 | $ 170 | $ 14.00 | $ 5,400 | $ 1,080 | $ 1,080 | $ 3,240 | $ - |
| Butterfly Valves with valve boxes | 10 | 10 | EA | $ 825 | $ 419 | $ - | $ 12,443 | $ 2,489 | $ 2,489 | $ 7,466 | $ - |
| Insulated Welded Stl Piping | 8 | 6,462 | LF | $ 14 | $ 34 | $ - | $ 310,475 | $ 20,756 | $ 173,447 | $ 71,493 | $ 44,779 |
| Insulated Welded Stl Elbow | 8 | 130 | EA | $ 147 | $ 212 | $ - | $ 46,699 | $ 3,233 | $ 25,864 | $ 10,777 | $ 6,825 |
| Insulated Welded Stl Tee | 8 | 16 | EA | $ 168 | $ 276 | $ - | $ 7,102 | $ 888 | $ 6,214 | $ - | $ - |
| Flanged Pipe Connector | 8 | 44 | EA | $ 50 | $ 140 | $ 12.00 | $ 8,888 | $ - | $ 4,040 | $ 2,424 | $ 2,424 |
| Butterfly Valves with valve boxes | 8 | 22 | EA | $ 675 | $ 285 | $ - | $ 21,113 | $ - | $ 9,597 | $ 5,758 | $ 5,758 |
| Insulated Welded Stl Piping | 6 | 2,966 | LF | $ 10 | $ 28 | $ - | $ 112,962 | $ 68,783 | $ 25,594 | $ 18,586 | $ - |
| Insulated Welded Stl Elbow | 6 | 59 | EA | $ 104 | $ 158 | $ - | $ 15,455 | $ 9,430 | $ 3,405 | $ 2,620 | $ - |
| Insulated Welded Stl Tee | 6 | 8 | EA | $ 116 | $ 205 | $ - | $ 2,571 | $ 1,285 | $ 1,285 | $ - | $ - |
| Flanged Pipe Connector | 6 | 8 | EA | $ 32 | $ 112 | $ 9.00 | $ 1,224 | $ - | $ - | $ 1,224 | $ - |
| Butterfly Valves with valve boxes | 6 | 4 | EA | $ 330 | $ 131 | $ - | $ 1,844 | $ - | $ - | $ 1,844 | $ - |
| Insulated Welded Stl Piping | 5 | 3,268 | LF | $ 8 | $ 23 | $ - | $ 102,048 | $ 40,969 | $ 27,916 | $ 25,980 | $ 7,182 |
| Insulated Welded Stl Elbow | 5 | 66 | EA | $ 79 | $ 151 | $ - | $ 15,158 | $ 5,971 | $ 4,134 | $ 3,904 | $ 1,148 |
| Insulated Welded Stl Tee | 5 | 12 | EA | $ 95 | $ 196 | $ - | $ 3,490 | $ 1,163 | $ 582 | $ 1,745 | $ - |
| Flanged Pipe Connector | 5 | 28 | EA | $ 36 | $ 85 | $ 11.00 | $ 3,696 | $ 1,584 | $ 528 | $ 1,056 | $ 528 |
| Butterfly Valves with valve boxes | 5 | 14 | EA | $ 315 | $ 112 | $ - | $ 5,979 | $ 2,562 | $ 854 | $ 1,708 | $ 854 |
| Insulated Welded Stl Piping | 4 | 5,770 | LF | $ 6 | $ 19 | $ - | $ 149,441 | $ - | $ 101,682 | $ 23,620 | $ 24,138 |
| Insulated Welded Stl Elbow | 4 | 116 | EA | $ 69 | $ 141 | $ - | $ 24,353 | $ - | $ 16,585 | $ 3,779 | $ 3,989 |
| Insulated Welded Stl Tee | 4 | 8 | EA | $ 79 | $ 183 | $ - | $ 2,098 | $ - | $ 2,098 | $ - | $ - |
| Flanged Pipe Connector | 4 | 48 | EA | $ 19 | $ 72 | $ 9.00 | $ 4,800 | $ - | $ 2,000 | $ 1,600 | $ 1,200 |
| Butterfly Valves with valve boxes | 4 | 24 | EA | $ 215 | $ 85 | $ - | $ 7,188 | $ - | $ 2,995 | $ 2,396 | $ 1,797 |
| Insulated Welded Stl Piping | 3 | 1,604 | LF | $ 5 | $ 15 | $ - | $ 32,541 | $ - | $ 1,704 | $ 30,837 | $ - |
| Insulated Welded Stl Elbow | 3 | 32 | EA | $ 43 | $ 122 | $ - | $ 5,264 | $ - | $ 329 | $ 4,935 | $ - |
| Insulated Welded Stl Tee | 3 | - | EA | $ 52 | $ 158 | $ - | $ - | $ - | $ - | $ - | $ - |
| Flanged Pipe Connector | 3 | 16 | EA | $ 16 | $ 48 | $ 6.00 | $ 1,120 | $ - | $ 280 | $ 840 | $ - |
| Butterfly Valves with valve boxes | 3 | 8 | EA | $ 215 | $ 60 | $ - | $ 2,200 | $ - | $ 550 | $ 1,650 | $ - |
| Vents | | 38 | EA | $ 750 | $ 1,750 | $ - | $ 94,480 | $ 17,750 | $ 54,600 | $ 16,320 | $ 5,810 |
| Drains | | 38 | EA | $ 1,250 | $ 3,250 | $ - | $ 170,064 | $ 31,950 | $ 98,280 | $ 29,376 | $ 10,458 |
| Aluminum Warning Tape | | 37,792 | LF | $ 0.5 | $ - | $ - | $ 18,896 | $ 3,550 | $ 10,920 | $ 3,264 | $ 1,162 |
| Alarm system for pipeline | | 18,896 | LF | $ 1 | $ 2 | $ - | $ 56,688 | $ 10,650 | $ 32,760 | $ 9,792 | $ 3,486 |
| Foam pads | | 433 | EA | $ 30 | $ 100 | $ - | $ 56,306 | $ 10,578 | $ 32,539 | $ 9,726 | $ 3,463 |
| 4" Communications Conduit and (3) Innerducts | | 9,448 | LF | $ 6 | $ 3 | $ - | $ 85,032 | $ 15,975 | $ 49,140 | $ 14,688 | $ 5,229 |
| Fiber Optic Cable | | 9,448 | LF | $ 3 | $ 2 | $ - | $ 47,240 | $ 8,875 | $ 27,300 | $ 8,160 | $ 2,905 |
| Communications Manhole | | 27 | EA | $ 800 | $ 600 | $ 150 | $ 41,850 | $ 7,862 | $ 24,185 | $ 7,229 | $ 2,574 |
| Contribution to Trenching & Restoration Costs for Heating pipe 3" and smaller (including: escavation, backfill, top soil, trenching, all work done between the hours of 6am & 6pm, 6' cover, fuel, & all equipment rental) | | 802 | Trench Ft | $ 113 | $ - | $ - | $ 90,947 | $ 17,086 | $ 52,558 | $ 15,710 | $ 5,593 |
| Contribution to Trenching & Restoration Costs for Heating pipe 4" to 8" (including: escavation, backfill, top soil, trenching, all work done between the hours of 6am & 6pm, 6' cover, fuel, & all equipment rental) | | 7,304 | Trench Ft | $ 189 | $ - | $ - | $ 1,380,456 | $ 259,347 | $ 797,766 | $ 238,453 | $ 84,890 |
| Contribution to Trenching & Restoration Costs for Heating pipe 10" to 18" (including: escavation, backfill, top soil, trenching, all work done between the hours of 6am & 6pm, 6' cover, fuel, & all equipment rental) | | 1,342 | Trench Ft | $ 315 | $ - | $ - | $ 422,730 | $ 79,418 | $ 244,296 | $ 73,020 | $ 25,996 |
| Contribution to Trenching & Restoration Costs for Cooling pipe 4" to 8" (including: escavation, backfill, top soil, trenching, all work done between the hours of 6am & 6pm, 6' cover, fuel, & all equipment rental) | | 1,929 | Trench Ft | $ 189 | $ - | $ - | $ 364,581 | $ 68,494 | $ 210,691 | $ 62,976 | $ 22,420 |
| Contribution to Trenching & Restoration Costs for Cooling pipe 10" to 18" (including: escavation, backfill, top soil, trenching, all work done between the hours of 6am & 6pm, 6' cover, fuel, & all equipment rental) | | 6,177 | Trench Ft | $ 315 | $ - | $ - | $ 1,945,755 | $ 365,550 | $ 1,124,452 | $ 336,100 | $ 119,653 |
| Contribution to Trenching & Restoration Costs for Cooling pipe 20" and larger (including: escavation, backfill, top soil, trenching, all work done between the hours of 6am & 6pm, 6' cover, fuel, & all equipment rental) | | 1,342 | Trench Ft | $ 525 | $ - | $ - | $ 704,550 | $ 132,364 | $ 407,160 | $ 121,700 | $ 43,326 |
| | | | | | | **Sub-Total** | **$ 8,559,446** | **$ 1,532,601** | **$ 5,275,991** | **$ 1,288,421** | **$ 462,433** |
| **Total Trench Feet** | | **9,448** | | | | **SUBTOTAL CONSTRUCTION COSTS** | **$ 9,326,610** | **$ 1,676,728** | **$ 5,719,336** | **$ 1,420,937** | **$ 509,609** |
| | | | | **6.5%** | | **TAX** | **$ 410,531** | **$ 77,127** | **$ 237,246** | **$ 70,913** | **$ 25,245** |
| | | | | | | **SUBTOTAL** | **$ 9,737,141** | **$ 1,753,855** | **$ 5,956,581** | **$ 1,491,850** | **$ 534,855** |
| | | | | **13.0%** | | **OVERHEAD & PROFIT** | **$ 1,265,828** | **$ 228,001** | **$ 774,356** | **$ 193,941** | **$ 69,531** |
| | | | | | | **SUBTOTAL** | **$ 11,002,969** | **$ 1,981,856** | **$ 6,730,937** | **$ 1,685,791** | **$ 604,386** |
| | | | | **8.0%** | | **CONTINGENCY** | **$ 880,238** | **$ 158,548** | **$ 538,475** | **$ 134,863** | **$ 48,351** |
| | | | | | | **SUBTOTAL** | **$ 11,883,207** | **$ 2,140,404** | **$ 7,269,412** | **$ 1,820,654** | **$ 652,737** |
| | | | | **5.5%** | | **DESIGN FEES** | **$ 653,576** | **$ 117,722** | **$ 399,818** | **$ 100,136** | **$ 35,901** |
| | | | | | | **TOTAL** | **$ 12,536,783** | **$ 2,258,126** | **$ 7,669,229** | **$ 1,920,790** | **$ 688,637** |
| | | | | | | **Cost/TF - Total** | **$ 1,327** | **$ 1,272** | **$ 1,405** | **$ 1,177** | **$ 1,185** |
| | | | | | | **Cost/TF - Const. Costs Only** | **$ 987** | **$ 945** | **$ 1,047** | **$ 871** | **$ 877** |
| | | | | | | **Trench Feet Per Phase** | **9,448** | **1,775** | **5,460** | **1,632** | **581** |

## South Lake Union Centrifugal Chiller Plant Cost Estimate

| | | Full Plant | | | Phase 1 | | | Phase 2 | | | Phase 3 | | | Phase 4 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Installed units | | $ Cost | Installed units | | $ Cost | Installed units | | $ Cost | Installed units | | $ Cost | Installed units | | $ Cost |
| 1. Building | | | | | | | | | | | | | | | | |
| 1.01 | Engineering fees | 10.0% | | $257,000 | 10.0% | | $206,000 | 0.0% | | $0 | 7.0% | | $82,000 | 0.0% | | $0 |
| 1.02 | project management | 8.0% | | $205,000 | 8.0% | | $136,000 | 8.0% | | $0 | 8.0% | | $94,000 | 8.0% | | $0 |
| 1.03 | mobilization | 1.0% | | $26,000 | 1.0% | | $17,000 | 1.0% | | $0 | 1.0% | | $12,000 | 1.0% | | $0 |
| 1.04 | demolition and remodel | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.05 | foundation, building | 26,130 | fdn sf | $818,000 | 15,626 | fdn sf | $518,000 | 0 | fdn sf | $0 | 10,504 | fdn sf | $349,000 | 0 | fdn sf | $0 |
| 1.06 | foundation, cooling tower | 0 | fdn sf | $0 | 0 | fdn sf | $0 | 0 | fdn sf | $0 | 0 | fdn sf | $0 | 0 | fdn sf | $0 |
| 1.07 | structure, foundation to roof | 26,130 | gross sf | $575,000 | 15,626 | gross sf | $364,000 | 0 | gross sf | $0 | 10,504 | gross sf | $245,000 | 0 | gross sf | $0 |
| 1.08 | roofing | 26,130 | roof sf | $312,000 | 15,626 | roof sf | $198,000 | 0 | roof sf | $0 | 10,504 | roof sf | $133,000 | 0 | roof sf | $0 |
| 1.09 | exterior wall/finish, building | 14,225 | wall sf | $122,000 | 11,000 | wall sf | $100,000 | 0 | wall sf | $0 | 9,019 | wall sf | $82,000 | 0 | wall sf | $0 |
| 1.10 | exterior wall/finish, cooling tower | 14,225 | wall sf | $243,000 | 11,000 | wall sf | $199,000 | 0 | wall sf | $0 | 9,019 | wall sf | $163,000 | 0 | wall sf | $0 |
| 1.11 | elevator | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.12 | retail space | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.13 | office, break room, locker room | 1 | LS | $25,000 | 1 | LS | $25,000 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.14 | building interior/finishes | 26,130 | gross sf | $298,000 | 15,626 | gross sf | $189,000 | 0 | gross sf | $0 | 10,504 | gross sf | $127,000 | 0 | gross sf | $0 |
| 1.15 | plumbing /drainage | 26,130 | gross sf | $120,000 | 15,626 | gross sf | $76,000 | 0 | gross sf | $0 | 10,504 | gross sf | $51,000 | 0 | gross sf | $0 |
| 1.16 | miscellaneous | 26,130 | gross sf | $54,000 | 15,626 | gross sf | $34,000 | 0 | gross sf | $0 | 10,504 | gross sf | $23,000 | 0 | gross sf | $0 |
| | **Building subtotal** | | | **$3,054,000** | | | **$2,063,000** | | | **$0** | | | **$1,360,000** | | | **$0** |
| 2. Mechanical | | | | | | | | | | | | | | | | |
| 2.01 | Eng, permits, fees | 4% | | $728,000 | | | $339,000 | 3% | | $148,000 | 3% | | $159,000 | 3% | | $101,000 |
| 2.02 | project management | 2% | | $364,000 | | | $82,000 | 2% | | $106,000 | 2% | | $114,000 | 2% | | $72,000 |
| 2.03 | Other Mech installation | 20,100 | plant tons | $2,005,000 | 4,000 | plant tons | $415,000 | 6,000 | plant tons | $622,000 | 6,000 | plant tons | $622,000 | 4,100 | plant tons | $425,000 |
| 2.04 | centrifugal chiller | 20,100 | cent tons | $4,020,000 | 4,000 | cent tons | $800,000 | 6,000 | cent tons | $1,200,000 | 6,000 | cent tons | $1,200,000 | 4,100 | cent tons | $820,000 |
| 2.05 | Cooling Towers | 20,100 | CT tons | $1,917,000 | 4,000 | CT tons | $381,000 | 6,000 | CT tons | $572,000 | 6,000 | CT tons | $572,000 | 4,100 | CT tons | $391,000 |
| 2.06 | Lake water heat exchangers | 0 | LWC ton | $0 | 0 | LWC ton | $0 | 0 | LWC ton | $0 | 0 | LWC ton | $0 | 0 | LWC ton | $0 |
| 2.07 | Pumps | 20,100 | plant tons | $574,000 | 4,000 | plant tons | $114,000 | 6,000 | plant tons | $171,000 | 6,000 | plant tons | $171,000 | 4,100 | plant tons | $117,000 |
| 2.08 | piping and insulation | 20,100 | plant tons | $4,481,000 | 4,000 | plant tons | $927,000 | 6,000 | plant tons | $1,391,000 | 6,000 | plant tons | $1,391,000 | 4,100 | plant tons | $951,000 |
| 2.09 | Elect equip and shipping | 20,100 | chiller tons | $2,020,000 | 4,000 | chiller tons | $418,000 | 6,000 | chiller tons | $627,000 | 6,000 | chiller tons | $627,000 | 4,100 | chiller tons | $429,000 |
| 2.10 | elect equip installation | 20,100 | chiller tons | $321,000 | 4,000 | chiller tons | $66,000 | 6,000 | chiller tons | $100,000 | 6,000 | chiller tons | $100,000 | 4,100 | chiller tons | $68,000 |
| 2.11 | elect power wiring | 20,100 | chiller tons | $1,010,000 | 4,000 | chiller tons | $209,000 | 6,000 | chiller tons | $314,000 | 6,000 | chiller tons | $314,000 | 4,100 | chiller tons | $214,000 |
| 2.12 | controls and Instrumentation | 20,100 | plant tons | $564,000 | 4,000 | plant tons | $117,000 | 6,000 | plant tons | $175,000 | 6,000 | plant tons | $175,000 | 4,100 | plant tons | $120,000 |
| 2.13 | C&I wiring | 20,100 | plant tons | $368,000 | 4,000 | plant tons | $76,000 | 6,000 | plant tons | $114,000 | 6,000 | plant tons | $114,000 | 4,100 | plant tons | $78,000 |
| 2.14 | ventilation | 26,130 | gross sf | $309,000 | 15,626 | gross sf | $192,000 | 0 | gross sf | $0 | 10,504 | gross sf | $129,000 | 0 | gross sf | $0 |
| 2.15 | fire protection | 26,130 | gross sf | $50,000 | 15,626 | gross sf | $31,000 | 0 | gross sf | $0 | 10,504 | gross sf | $21,000 | 0 | gross sf | $0 |
| 2.16 | startup, test, balance & Comm | 26,130 | gross sf | $144,000 | 15,626 | gross sf | $90,000 | 0 | gross sf | $0 | 10,504 | gross sf | $60,000 | 0 | gross sf | $0 |
| 2.17 | Miscellaneous | 26,130 | gross sf | $427,000 | 15,626 | gross sf | $265,000 | 0 | gross sf | $0 | 10,504 | gross sf | $178,000 | 0 | gross sf | $0 |
| | **Mechanical/electrical subtotal** | | | **$19,302,000** | | | **$4,524,000** | | | **$5,540,000** | | | **$5,948,000** | | | **$3,786,000** |
| | | | | | | | | | | | | | | | | |
| | **Plant Cost** | | | **$22,356,000** | | | **$6,586,000** | | | **$5,540,000** | | | **$7,308,000** | | | **$3,786,000** |
| | **Plant Capactity** | | | **20,100** | | | **4,000** | | | **6,000** | | | **6,000** | | | **4,100** |
| | **$/Ton** | | | **$1,112** | | | **$1,647** | | | **$923** | | | **$1,218** | | | **$923** |

## Denny Triangle Centrifugal Chiller Plant Cost Estimate

| | | Full Plant | | | Phase 1 | | | Phase 2 | | | Phase 3 | | | Phase 4 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Installed units | | $ Cost | Installed units | | $ Cost | Installed units | | $ Cost | Installed units | | $ Cost | Installed units | | $ Cost |
| 1. Building | | | | | | | | | | | | | | | | |
| 1.01 | Engineering fees | 10.0% | | $189,000 | 10.0% | | $155,000 | 0.0% | | $0 | 7.0% | | $59,000 | 0.0% | | $0 |
| 1.02 | project management | 8.0% | | $151,000 | 8.0% | | $104,000 | 8.0% | | $0 | 8.0% | | $67,000 | 8.0% | | $0 |
| 1.03 | mobilization | 1.0% | | $19,000 | 1.0% | | $13,000 | 1.0% | | $0 | 1.0% | | $8,000 | 1.0% | | $0 |
| 1.04 | demolition and remodel | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.05 | foundation, building | 18,720 | fdn sf | $586,000 | 11,544 | fdn sf | $383,000 | 0 | fdn sf | $0 | 7,176 | fdn sf | $238,000 | 0 | fdn sf | $0 |
| 1.06 | foundation, cooling tower | 0 | fdn sf | $0 | 0 | fdn sf | $0 | 0 | fdn sf | $0 | 0 | fdn sf | $0 | 0 | fdn sf | $0 |
| 1.07 | structure, foundation to roof | 18,720 | gross sf | $412,000 | 11,544 | gross sf | $269,000 | 0 | gross sf | $0 | 7,176 | gross sf | $167,000 | 0 | gross sf | $0 |
| 1.08 | roofing | 18,720 | roof sf | $223,000 | 11,544 | roof sf | $146,000 | 0 | roof sf | $0 | 7,176 | roof sf | $91,000 | 0 | roof sf | $0 |
| 1.09 | exterior wall/finish, building | 12,040 | wall sf | $103,000 | 9,455 | wall sf | $86,000 | 0 | wall sf | $0 | 7,455 | wall sf | $68,000 | 0 | wall sf | $0 |
| 1.10 | exterior wall/finish, cooling tower | 12,040 | wall sf | $206,000 | 9,455 | wall sf | $171,000 | 0 | wall sf | $0 | 7,455 | wall sf | $135,000 | 0 | wall sf | $0 |
| 1.11 | elevator | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.12 | retail space | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.13 | office, break room, locker room | 1 | LS | $25,000 | 1 | LS | $25,000 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.14 | building interior/finishes | 18,720 | gross sf | $214,000 | 11,544 | gross sf | $140,000 | 0 | gross sf | $0 | 7,176 | gross sf | $87,000 | 0 | gross sf | $0 |
| 1.15 | plumbing /drainage | 18,720 | gross sf | $86,000 | 11,544 | gross sf | $56,000 | 0 | gross sf | $0 | 7,176 | gross sf | $35,000 | 0 | gross sf | $0 |
| 1.16 | miscellaneous | 18,720 | gross sf | $38,000 | 11,544 | gross sf | $25,000 | 0 | gross sf | $0 | 7,176 | gross sf | $16,000 | 0 | gross sf | $0 |
| | **Building subtotal** | | | **$2,253,000** | | | **$1,574,000** | | | **$0** | | | **$970,000** | | | **$0** |
| 2. Mechanical | | | | | | | | | | | | | | | | |
| 2.01 | Eng, permits, fees | 4% | | $522,000 | | | $197,000 | 3% | | $160,000 | 3% | | $100,000 | 3% | | $78,000 |
| 2.02 | project management | 2% | | $261,000 | | | $26,000 | 2% | | $115,000 | 2% | | $71,000 | 2% | | $56,000 |
| 2.03 | Other Mech installation | 14,400 | plant tons | $1,436,000 | 1,000 | plant tons | $104,000 | 6,500 | plant tons | $674,000 | 3,750 | plant tons | $389,000 | 3,150 | plant tons | $327,000 |
| 2.04 | centrifugal chiller | 14,400 | cent tons | $2,880,000 | 1,000 | cent tons | $200,000 | 6,500 | cent tons | $1,300,000 | 3,750 | cent tons | $750,000 | 3,150 | cent tons | $630,000 |
| 2.05 | Cooling Towers | 14,400 | CT tons | $1,373,000 | 1,000 | CT tons | $95,000 | 6,500 | CT tons | $620,000 | 3,750 | CT tons | $358,000 | 3,150 | CT tons | $300,000 |
| 2.06 | Lake water heat exchangers | 0 | LWC ton | $0 | 0 | LWC ton | $0 | 0 | LWC ton | $0 | 0 | LWC ton | $0 | 0 | LWC ton | $0 |
| 2.07 | Pumps | 14,400 | plant tons | $411,000 | 1,000 | plant tons | $29,000 | 6,500 | plant tons | $186,000 | 3,750 | plant tons | $107,000 | 3,150 | plant tons | $90,000 |
| 2.08 | piping and insulation | 14,400 | plant tons | $3,210,000 | 1,000 | plant tons | $232,000 | 6,500 | plant tons | $1,507,000 | 3,750 | plant tons | $869,000 | 3,150 | plant tons | $730,000 |
| 2.09 | Elect equip and shipping | 14,400 | chiller tons | $1,447,000 | 1,000 | chiller tons | $105,000 | 6,500 | chiller tons | $679,000 | 3,750 | chiller tons | $392,000 | 3,150 | chiller tons | $329,000 |
| 2.10 | elect equip installation | 14,400 | chiller tons | $230,000 | 1,000 | chiller tons | $17,000 | 6,500 | chiller tons | $108,000 | 3,750 | chiller tons | $62,000 | 3,150 | chiller tons | $52,000 |
| 2.11 | elect power wiring | 14,400 | chiller tons | $724,000 | 1,000 | chiller tons | $52,000 | 6,500 | chiller tons | $340,000 | 3,750 | chiller tons | $196,000 | 3,150 | chiller tons | $165,000 |
| 2.12 | controls and Instrumentation | 14,400 | plant tons | $404,000 | 1,000 | plant tons | $29,000 | 6,500 | plant tons | $190,000 | 3,750 | plant tons | $109,000 | 3,150 | plant tons | $92,000 |
| 2.13 | C&I wiring | 14,400 | plant tons | $264,000 | 1,000 | plant tons | $19,000 | 6,500 | plant tons | $124,000 | 3,750 | plant tons | $71,000 | 3,150 | plant tons | $60,000 |
| 2.14 | ventilation | 18,720 | gross sf | $221,000 | 11,544 | gross sf | $142,000 | 0 | gross sf | $0 | 7,176 | gross sf | $88,000 | 0 | gross sf | $0 |
| 2.15 | fire protection | 18,720 | gross sf | $36,000 | 11,544 | gross sf | $23,000 | 0 | gross sf | $0 | 7,176 | gross sf | $14,000 | 0 | gross sf | $0 |
| 2.16 | startup, test, balance & Comm | 18,720 | gross sf | $103,000 | 11,544 | gross sf | $66,000 | 0 | gross sf | $0 | 7,176 | gross sf | $41,000 | 0 | gross sf | $0 |
| 2.17 | Miscellaneous | 18,720 | gross sf | $306,000 | 11,544 | gross sf | $196,000 | 0 | gross sf | $0 | 7,176 | gross sf | $122,000 | 0 | gross sf | $0 |
| | **Mechanical/electrical subtotal** | | | **$13,828,000** | | | **$1,532,000** | | | **$6,002,000** | | | **$3,741,000** | | | **$2,909,000** |
| | **Plant Cost** | | | **$16,081,000** | | | **$3,105,000** | | | **$6,002,000** | | | **$4,711,000** | | | **$2,909,000** |
| | **Plant Capactity** | | | **14,400** | | | **1,000** | | | **6,500** | | | **3,750** | | | **3,150** |
| | **$/Ton** | | | **$1,117** | | | **$3,105** | | | **$923** | | | **$1,256** | | | **$923** |

## South Lake Union Lake Water Cooling Plant Cost Estimate

| | | Full Plant | | | Phase 1 | | | Phase 2 | | | Phase 3 | | | Phase 4 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Installed units | | $ Cost | Installed units | | $ Cost | Installed units | | $ Cost | Installed units | | $ Cost | Installed units | | $ Cost |
| 1. Building | | | | | | | | | | | | | | | | |
| 1.01 | Engineering fees | 10.0% | | $201,000 | 10.0% | | $158,000 | 0.0% | | $0 | 7.0% | | $65,000 | 0.0% | | $0 |
| 1.02 | project management | 8.0% | | $161,000 | 8.0% | | $104,000 | 8.0% | | $0 | 8.0% | | $75,000 | 8.0% | | $0 |
| 1.03 | mobilization | 1.0% | | $20,000 | 1.0% | | $13,000 | 1.0% | | $0 | 1.0% | | $9,000 | 1.0% | | $0 |
| 1.04 | demolition and remodel | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.05 | foundation, building | 19,970 | fdn sf | $625,000 | 11,826 | fdn sf | $392,000 | 0 | fdn sf | $0 | 8,144 | fdn sf | $270,000 | 0 | fdn sf | $0 |
| 1.06 | foundation, cooling tower | 0 | fdn sf | $0 | 0 | fdn sf | $0 | 0 | fdn sf | $0 | 0 | fdn sf | $0 | 0 | fdn sf | $0 |
| 1.07 | structure, foundation to roof | 19,970 | gross sf | $439,000 | 11,826 | gross sf | $276,000 | 0 | gross sf | $0 | 8,144 | gross sf | $190,000 | 0 | gross sf | $0 |
| 1.08 | roofing | 19,970 | roof sf | $238,000 | 11,826 | roof sf | $149,000 | 0 | roof sf | $0 | 8,144 | roof sf | $103,000 | 0 | roof sf | $0 |
| 1.09 | exterior wall/finish, building | 12,436 | wall sf | $106,000 | 9,570 | wall sf | $87,000 | 0 | wall sf | $0 | 7,941 | wall sf | $72,000 | 0 | wall sf | $0 |
| 1.10 | exterior wall/finish, cooling tower | 12,436 | wall sf | $213,000 | 9,570 | wall sf | $173,000 | 0 | wall sf | $0 | 7,941 | wall sf | $144,000 | 0 | wall sf | $0 |
| 1.11 | elevator | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.12 | retail space | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.13 | office, break room, locker room | 1 | LS | $25,000 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.14 | building interior/finishes | 19,970 | gross sf | $228,000 | 11,826 | gross sf | $143,000 | 0 | gross sf | $0 | 8,144 | gross sf | $99,000 | 0 | gross sf | $0 |
| 1.15 | plumbing /drainage | 19,970 | gross sf | $92,000 | 11,826 | gross sf | $58,000 | 0 | gross sf | $0 | 8,144 | gross sf | $40,000 | 0 | gross sf | $0 |
| 1.16 | miscellaneous | 19,970 | gross sf | $41,000 | 11,826 | gross sf | $26,000 | 0 | gross sf | $0 | 8,144 | gross sf | $18,000 | 0 | gross sf | $0 |
| | **Building subtotal** | | | **$2,389,000** | | | **$1,580,000** | | | **$0** | | | **$1,085,000** | | | **$0** |
| 2. Mechanical | | | | | | | | | | | | | | | | |
| 2.01 | Eng, permits, fees | 4% | | $496,000 | | | $258,000 | 3% | | $83,000 | 3% | | $121,000 | 3% | | $48,000 |
| 2.02 | project management | 2% | | $248,000 | | | $75,000 | 2% | | $59,000 | 2% | | $87,000 | 2% | | $34,000 |
| 2.03 | Other Mech installation | 20,100 | plant tons | $1,516,000 | 3,750 | plant tons | $389,000 | 6,150 | plant tons | $447,000 | 7,700 | plant tons | $559,000 | 2,500 | plant tons | $182,000 |
| 2.04 | centrifugal chiller | 11,300 | cent tons | $2,260,000 | 3,750 | cent tons | $750,000 | 1,750 | cent tons | $350,000 | 3,300 | cent tons | $660,000 | 2,500 | cent tons | $500,000 |
| 2.05 | Cooling Towers | 3,750 | CT tons | $358,000 | 3,750 | CT tons | $358,000 | 0 | CT tons | $0 | 0 | CT tons | $0 | 0 | CT tons | $0 |
| 2.06 | Lake water heat exchangers | 8,800 | LWC ton | $396,000 | 0 | LWC ton | $0 | 4,400 | LWC ton | $198,000 | 4,400 | LWC ton | $198,000 | 0 | LWC ton | $0 |
| 2.07 | Pumps | 20,100 | plant tons | $574,000 | 3,750 | plant tons | $107,000 | 6,150 | plant tons | $176,000 | 7,700 | plant tons | $220,000 | 2,500 | plant tons | $71,000 |
| 2.08 | piping and insulation | 20,100 | plant tons | $3,780,000 | 3,750 | plant tons | $869,000 | 6,150 | plant tons | $1,202,000 | 7,700 | plant tons | $1,454,000 | 2,500 | plant tons | $406,000 |
| 2.09 | Elect equip and shipping | 11,300 | chiller tons | $1,136,000 | 3,750 | chiller tons | $392,000 | 1,750 | chiller tons | $183,000 | 3,300 | chiller tons | $345,000 | 2,500 | chiller tons | $261,000 |
| 2.10 | elect equip installation | 11,300 | chiller tons | $180,000 | 3,750 | chiller tons | $62,000 | 1,750 | chiller tons | $29,000 | 3,300 | chiller tons | $55,000 | 2,500 | chiller tons | $42,000 |
| 2.11 | elect power wiring | 11,300 | chiller tons | $568,000 | 3,750 | chiller tons | $196,000 | 1,750 | chiller tons | $91,000 | 3,300 | chiller tons | $173,000 | 2,500 | chiller tons | $131,000 |
| 2.12 | controls and Instrumentation | 20,100 | plant tons | $564,000 | 3,750 | plant tons | $109,000 | 6,150 | plant tons | $179,000 | 7,700 | plant tons | $225,000 | 2,500 | plant tons | $73,000 |
| 2.13 | C&I wiring | 20,100 | plant tons | $368,000 | 3,750 | plant tons | $71,000 | 6,150 | plant tons | $117,000 | 7,700 | plant tons | $147,000 | 2,500 | plant tons | $48,000 |
| 2.14 | ventilation | 19,970 | gross sf | $236,000 | 11,826 | gross sf | $145,000 | 0 | gross sf | $0 | 8,144 | gross sf | $100,000 | 0 | gross sf | $0 |
| 2.15 | fire protection | 19,970 | gross sf | $38,000 | 11,826 | gross sf | $23,000 | 0 | gross sf | $0 | 8,144 | gross sf | $16,000 | 0 | gross sf | $0 |
| 2.16 | startup, test, balance & Comm | 19,970 | gross sf | $110,000 | 11,826 | gross sf | $68,000 | 0 | gross sf | $0 | 8,144 | gross sf | $47,000 | 0 | gross sf | $0 |
| 2.17 | Miscellaneous | 19,970 | gross sf | $326,000 | 11,826 | gross sf | $201,000 | 0 | gross sf | $0 | 8,144 | gross sf | $138,000 | 0 | gross sf | $0 |
| | **Mechanical/electrical subtotal** | | | **$13,154,000** | | | **$4,075,000** | | | **$3,115,000** | | | **$4,544,000** | | | **$1,795,000** |
| | **Plant Cost** | | | **$15,543,000** | | | **$5,655,000** | | | **$3,115,000** | | | **$5,628,000** | | | **$1,795,000** |
| | **Plant Capactity** | | | **20,100** | | | **3,750** | | | **6,150** | | | **7,700** | | | **2,500** |
| | **$/Ton** | | | **$773** | | | **$1,508** | | | **$923** | | | **$731** | | | **$718** |

## Denny Triangle Lake Water Cooling Plant Cost Estimate

| | | Full Plant | | | Phase 1 | | | Phase 2 | | | Phase 3 | | | Phase 4 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Installed units | | $ Cost | Installed units | | $ Cost | Installed units | | $ Cost | Installed units | | $ Cost | Installed units | | $ Cost |
| 1. Building | | | | | | | | | | | | | | | | |
| 1.01 | Engineering fees | 10.0% | | $149,000 | 10.0% | | $119,000 | 0.0% | | $0 | 7.0% | | $50,000 | 0.0% | | $0 |
| 1.02 | project management | 8.0% | | $119,000 | 8.0% | | $78,000 | 8.0% | | $0 | 8.0% | | $58,000 | 8.0% | | $0 |
| 1.03 | mobilization | 1.0% | | $15,000 | 1.0% | | $10,000 | 1.0% | | $0 | 1.0% | | $7,000 | 1.0% | | $0 |
| 1.04 | demolition and remodel | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.05 | foundation, building | 14,310 | fdn sf | $448,000 | 8,258 | fdn sf | $274,000 | 0 | fdn sf | $0 | 6,052 | fdn sf | $201,000 | 0 | fdn sf | $0 |
| 1.06 | foundation, cooling tower | 0 | fdn sf | $0 | 0 | fdn sf | $0 | 0 | fdn sf | $0 | 0 | fdn sf | $0 | 0 | fdn sf | $0 |
| 1.07 | structure, foundation to roof | 14,310 | gross sf | $315,000 | 8,258 | gross sf | $193,000 | 0 | gross sf | $0 | 6,052 | gross sf | $141,000 | 0 | gross sf | $0 |
| 1.08 | roofing | 14,310 | roof sf | $171,000 | 8,258 | roof sf | $104,000 | 0 | roof sf | $0 | 6,052 | roof sf | $76,000 | 0 | roof sf | $0 |
| 1.09 | exterior wall/finish, building | 10,527 | wall sf | $90,000 | 7,997 | wall sf | $72,000 | 0 | wall sf | $0 | 6,846 | wall sf | $62,000 | 0 | wall sf | $0 |
| 1.10 | exterior wall/finish, cooling tower | 10,527 | wall sf | $180,000 | 7,997 | wall sf | $145,000 | 0 | wall sf | $0 | 6,846 | wall sf | $124,000 | 0 | wall sf | $0 |
| 1.11 | elevator | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.12 | retail space | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.13 | office, break room, locker room | 1 | LS | $25,000 | 1 | LS | $25,000 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.14 | building interior/finishes | 14,310 | gross sf | $163,000 | 8,258 | gross sf | $100,000 | 0 | gross sf | $0 | 6,052 | gross sf | $73,000 | 0 | gross sf | $0 |
| 1.15 | plumbing /drainage | 14,310 | gross sf | $66,000 | 8,258 | gross sf | $40,000 | 0 | gross sf | $0 | 6,052 | gross sf | $30,000 | 0 | gross sf | $0 |
| 1.16 | miscellaneous | 14,310 | gross sf | $29,000 | 8,258 | gross sf | $18,000 | 0 | gross sf | $0 | 6,052 | gross sf | $13,000 | 0 | gross sf | $0 |
| | **Building subtotal** | | | **$1,769,000** | | | **$1,178,000** | | | **$0** | | | **$836,000** | | | **$0** |
| 2. Mechanical | | | | | | | | | | | | | | | | |
| 2.01 | Eng, permits, fees | 4% | | $397,000 | | | $156,000 | 3% | | $103,000 | 3% | | $73,000 | 3% | | $76,000 |
| 2.02 | project management | 2% | | $199,000 | | | $24,000 | 2% | | $74,000 | 2% | | $52,000 | 2% | | $55,000 |
| 2.03 | Other Mech installation | 14,400 | plant tons | $1,248,000 | 1,000 | plant tons | $104,000 | 6,450 | plant tons | $538,000 | 3,850 | plant tons | $334,000 | 3,100 | plant tons | $322,000 |
| 2.04 | centrifugal chiller | 8,100 | cent tons | $1,620,000 | 1,000 | cent tons | $200,000 | 2,250 | cent tons | $450,000 | 1,750 | cent tons | $350,000 | 3,100 | cent tons | $620,000 |
| 2.05 | Cooling Towers | 8,100 | CT tons | $772,000 | 1,000 | CT tons | $95,000 | 2,250 | CT tons | $215,000 | 1,750 | CT tons | $167,000 | 3,100 | CT tons | $296,000 |
| 2.06 | Lake water heat exchangers | 6,300 | LWC ton | $284,000 | 0 | LWC ton | $0 | 4,200 | LWC ton | $189,000 | 2,100 | LWC ton | $95,000 | 0 | LWC ton | $0 |
| 2.07 | Pumps | 14,400 | plant tons | $411,000 | 1,000 | plant tons | $29,000 | 6,450 | plant tons | $184,000 | 3,850 | plant tons | $110,000 | 3,100 | plant tons | $88,000 |
| 2.08 | piping and insulation | 14,400 | plant tons | $3,070,000 | 1,000 | plant tons | $232,000 | 6,450 | plant tons | $1,398,000 | 3,850 | plant tons | $844,000 | 3,100 | plant tons | $719,000 |
| 2.09 | Elect equip and shipping | 8,100 | chiller tons | $814,000 | 1,000 | chiller tons | $105,000 | 2,250 | chiller tons | $235,000 | 1,750 | chiller tons | $183,000 | 3,100 | chiller tons | $324,000 |
| 2.10 | elect equip installation | 8,100 | chiller tons | $129,000 | 1,000 | chiller tons | $17,000 | 2,250 | chiller tons | $37,000 | 1,750 | chiller tons | $29,000 | 3,100 | chiller tons | $51,000 |
| 2.11 | elect power wiring | 8,100 | chiller tons | $407,000 | 1,000 | chiller tons | $52,000 | 2,250 | chiller tons | $118,000 | 1,750 | chiller tons | $91,000 | 3,100 | chiller tons | $162,000 |
| 2.12 | controls and Instrumentation | 14,400 | plant tons | $404,000 | 1,000 | plant tons | $29,000 | 6,450 | plant tons | $188,000 | 3,850 | plant tons | $112,000 | 3,100 | plant tons | $90,000 |
| 2.13 | C&I wiring | 14,400 | plant tons | $264,000 | 1,000 | plant tons | $19,000 | 6,450 | plant tons | $123,000 | 3,850 | plant tons | $73,000 | 3,100 | plant tons | $59,000 |
| 2.14 | ventilation | 14,310 | gross sf | $169,000 | 8,258 | gross sf | $102,000 | 0 | gross sf | $0 | 6,052 | gross sf | $74,000 | 0 | gross sf | $0 |
| 2.15 | fire protection | 14,310 | gross sf | $27,000 | 8,258 | gross sf | $16,000 | 0 | gross sf | $0 | 6,052 | gross sf | $12,000 | 0 | gross sf | $0 |
| 2.16 | startup, test, balance & Comm | 14,310 | gross sf | $79,000 | 8,258 | gross sf | $47,000 | 0 | gross sf | $0 | 6,052 | gross sf | $35,000 | 0 | gross sf | $0 |
| 2.17 | Miscellaneous | 14,310 | gross sf | $234,000 | 8,258 | gross sf | $140,000 | 0 | gross sf | $0 | 6,052 | gross sf | $103,000 | 0 | gross sf | $0 |
| | **Mechanical/electrical subtotal** | | | **$10,528,000** | | | **$1,366,000** | | | **$3,852,000** | | | **$2,738,000** | | | **$2,863,000** |
| | **Plant Cost** | | | **$12,297,000** | | | **$2,544,000** | | | **$3,852,000** | | | **$3,573,000** | | | **$2,863,000** |
| | **Plant Capactity** | | | **14,400** | | | **1,000** | | | **6,450** | | | **3,850** | | | **3,100** |
| | **$/Ton** | | | **$854** | | | **$2,544** | | | **$923** | | | **$928** | | | **$923** |

## South Lake Union Boiler Plant Cost Estimate

| | | Full Plant | | | Phase 1 | | | Phase 2 | | | Phase 3 | | | Phase 4 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Installed units | | $ Cost | Installed units | | $ Cost | Installed units | | $ Cost | Installed units | | $ Cost | Installed units | | $ Cost |
| 1. Building | | | | | | | | | | | | | | | | |
| 1.01 | Engineering fees | 12.0% | | $149,000 | 10.0% | | $125,000 | 0.0% | | $0 | 8.4% | | $45,000 | 0.0% | | $0 |
| 1.02 | project management | 8.0% | | $99,000 | 8.0% | | $71,000 | 8.0% | | $0 | 8.0% | | $43,000 | 8.0% | | $0 |
| 1.03 | mobilization | 1.0% | | $12,000 | 1.0% | | $9,000 | 1.0% | | $0 | 1.0% | | $5,000 | 1.0% | | $0 |
| 1.04 | foundation, building | 11,700 | fdn sf | $366,000 | 7,380 | fdn sf | $245,000 | 0 | fdn sf | $0 | 4,320 | fdn sf | $143,000 | 0 | fdn sf | $0 |
| 1.05 | structure, foundation to roof | 11,700 | gross sf | $257,000 | 7,380 | gross sf | $172,000 | 0 | gross sf | $0 | 4,320 | gross sf | $101,000 | 0 | gross sf | $0 |
| 1.06 | roofing | 11,700 | roof sf | $140,000 | 7,380 | roof sf | $93,000 | 0 | roof sf | $0 | 4,320 | roof sf | $55,000 | 0 | roof sf | $0 |
| 1.07 | exterior wall/finish, building | 9,519 | wall sf | $81,000 | 7,560 | wall sf | $69,000 | 0 | wall sf | $0 | 5,784 | wall sf | $52,000 | 0 | wall sf | $0 |
| 1.08 | exterior wall/finish, cooling tower | 9,519 | wall sf | $163,000 | 7,560 | wall sf | $137,000 | 0 | wall sf | $0 | 5,784 | wall sf | $105,000 | 0 | wall sf | $0 |
| 1.09 | elevator | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.10 | retail space | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.11 | office, break room, locker room | 1 | LS | $25,000 | 1 | LS | $25,000 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.12 | building interior/finishes | 11,700 | gross sf | $134,000 | 7,380 | gross sf | $89,000 | 0 | gross sf | $0 | 4,320 | gross sf | $52,000 | 0 | gross sf | $0 |
| 1.13 | plumbing /drainage | 11,700 | gross sf | $54,000 | 7,380 | gross sf | $36,000 | 0 | gross sf | $0 | 4,320 | gross sf | $21,000 | 0 | gross sf | $0 |
| 1.14 | miscellaneous | 11,700 | gross sf | $24,000 | 7,380 | gross sf | $16,000 | 0 | gross sf | $0 | 4,320 | gross sf | $9,000 | 0 | gross sf | $0 |
| | **Building subtotal** | | | **$1,505,000** | | | **$1,087,000** | | | **$0** | | | **$632,000** | | | **$0** |
| 2. Mechanical | | | | | | | | | | | | | | | | |
| 2.01 | Eng, permits, fees | 8% | | $302,000 | 17% | | $138,000 | 6% | | $74,000 | 6% | | $54,000 | 6% | | $45,000 |
| 2.02 | project management | 2% | | $75,000 | 2% | | $16,000 | 2% | | $27,000 | 2% | | $19,000 | 2% | | $16,000 |
| 2.03 | Other mechanical | 130,000 | plant MBH | $650,000 | 20,000 | plant MBH | $104,000 | 50,000 | plant MBH | $260,000 | 30,000 | plant MBH | $156,000 | 30,000 | plant MBH | $156,000 |
| 2.04 | Boilers | 130,000 | boiler MBH | $780,000 | 20,000 | boiler MBH | $120,000 | 50,000 | boiler MBH | $300,000 | 30,000 | boiler MBH | $180,000 | 30,000 | boiler MBH | $180,000 |
| 2.05 | Heat Pumps | 0 | heatpump MBH | $0 | 0 | heatpump MBH | $0 | 0 | heatpump MBH | $0 | 0 | heatpump MBH | $0 | 0 | heatpump MBH | $0 |
| 2.06 | piping and insulation | 130,000 | plant MBH | $780,000 | 20,000 | plant MBH | $125,000 | 50,000 | plant MBH | $312,000 | 30,000 | plant MBH | $187,000 | 30,000 | plant MBH | $187,000 |
| 2.07 | Elect equip and power wiring | 130,000 | plant MBH | $741,000 | 20,000 | plant MBH | $119,000 | 50,000 | plant MBH | $296,000 | 30,000 | plant MBH | $178,000 | 30,000 | plant MBH | $178,000 |
| 2.08 | controls and Instrumentation | 130,000 | plant MBH | $403,000 | 20,000 | plant MBH | $64,000 | 50,000 | plant MBH | $161,000 | 30,000 | plant MBH | $97,000 | 30,000 | plant MBH | $97,000 |
| 2.09 | ventilation | 11,700 | gross sf | $138,000 | 7,380 | gross sf | $91,000 | 0 | gross sf | $0 | 4,320 | gross sf | $53,000 | 0 | gross sf | $0 |
| 2.10 | fire protection | 11,700 | gross sf | $22,000 | 7,380 | gross sf | $15,000 | 0 | gross sf | $0 | 4,320 | gross sf | $9,000 | 0 | gross sf | $0 |
| 2.11 | startup, test, balance & Comm | 11,700 | gross sf | $65,000 | 7,380 | gross sf | $42,000 | 0 | gross sf | $0 | 4,320 | gross sf | $25,000 | 0 | gross sf | $0 |
| 2.12 | Miscellaneous | 11,700 | gross sf | $191,000 | 7,380 | gross sf | $125,000 | 0 | gross sf | $0 | 4,320 | gross sf | $73,000 | 0 | gross sf | $0 |
| | **Mechanical/electrical subtotal** | | | **$4,147,000** | | | **$959,000** | | | **$1,431,000** | | | **$1,030,000** | | | **$858,000** |
| | | | | | | | | | | | | | | | | |
| | **Plant Cost** | | | **$5,652,000** | | | **$2,046,000** | | | **$1,431,000** | | | **$1,663,000** | | | **$858,000** |
| | **Plant Capacity, MBH** | | | **130,000** | | | **20,000** | | | **50,000** | | | **30,000** | | | **30,000** |
| | **$/MBH** | | | **$43.5** | | | **$102.3** | | | **$28.6** | | | **$55.4** | | | **$28.6** |

## Denny Triangle Boiler Plant Cost Estimate

| | | Full Plant | | | Phase 1 | | | Phase 2 | | | Phase 3 | | | Phase 4 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Installed units | | $ Cost | Installed units | | $ Cost | Installed units | | $ Cost | Installed units | | $ Cost | Installed units | | $ Cost |
| 1. Building | | | | | | | | | | | | | | | | |
| 1.01 | Engineering fees | 12.0% | | $119,000 | 10.0% | | $98,000 | 0.0% | | $0 | 8.4% | | $39,000 | 0.0% | | $0 |
| 1.02 | project management | 8.0% | | $79,000 | 8.0% | | $54,000 | 8.0% | | $0 | 8.0% | | $37,000 | 8.0% | | $0 |
| 1.03 | mobilization | 1.0% | | $10,000 | 1.0% | | $7,000 | 1.0% | | $0 | 1.0% | | $5,000 | 1.0% | | $0 |
| 1.04 | foundation, building | 9,000 | fdn sf | $282,000 | 5,400 | fdn sf | $179,000 | 0 | fdn sf | $0 | 3,600 | fdn sf | $119,000 | 0 | fdn sf | $0 |
| 1.05 | structure, foundation to roof | 9,000 | gross sf | $198,000 | 5,400 | gross sf | $126,000 | 0 | gross sf | $0 | 3,600 | gross sf | $84,000 | 0 | gross sf | $0 |
| 1.06 | roofing | 9,000 | roof sf | $107,000 | 5,400 | roof sf | $68,000 | 0 | roof sf | $0 | 3,600 | roof sf | $46,000 | 0 | roof sf | $0 |
| 1.07 | exterior wall/finish, building | 8,348 | wall sf | $71,000 | 6,467 | wall sf | $59,000 | 0 | wall sf | $0 | 5,280 | wall sf | $48,000 | 0 | wall sf | $0 |
| 1.08 | exterior wall/finish, cooling tower | 8,348 | wall sf | $143,000 | 6,467 | wall sf | $117,000 | 0 | wall sf | $0 | 5,280 | wall sf | $96,000 | 0 | wall sf | $0 |
| 1.09 | elevator | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.10 | retail space | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.11 | office, break room, locker room | 1 | LS | $25,000 | 1 | LS | $25,000 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.12 | building interior/finishes | 9,000 | gross sf | $103,000 | 5,400 | gross sf | $65,000 | 0 | gross sf | $0 | 3,600 | gross sf | $44,000 | 0 | gross sf | $0 |
| 1.13 | plumbing /drainage | 9,000 | gross sf | $41,000 | 5,400 | gross sf | $26,000 | 0 | gross sf | $0 | 3,600 | gross sf | $18,000 | 0 | gross sf | $0 |
| 1.14 | miscellaneous | 9,000 | gross sf | $18,000 | 5,400 | gross sf | $12,000 | 0 | gross sf | $0 | 3,600 | gross sf | $8,000 | 0 | gross sf | $0 |
| | **Building subtotal** | | | **$1,196,000** | | | **$836,000** | | | **$0** | | | **$542,000** | | | **$0** |
| 2. Mechanical | | | | | | | | | | | | | | | | |
| 2.01 | Eng, permits, fees | 8% | | $232,000 | 21% | | $98,000 | 6% | | $60,000 | 6% | | $52,000 | 6% | | $30,000 |
| 2.02 | project management | 2% | | $58,000 | 2% | | $9,000 | 2% | | $21,000 | 2% | | $19,000 | 2% | | $11,000 |
| 2.03 | Other mechanical | 100,000 | plant MBH | $500,000 | 10,000 | plant MBH | $52,000 | 40,000 | plant MBH | $208,000 | 30,000 | plant MBH | $156,000 | 20,000 | plant MBH | $104,000 |
| 2.04 | Boilers | 100,000 | boiler MBH | $600,000 | 10,000 | boiler MBH | $60,000 | 40,000 | boiler MBH | $240,000 | 30,000 | boiler MBH | $180,000 | 20,000 | boiler MBH | $120,000 |
| 2.05 | Heat Pumps | 0 | heatpump MBH | $0 | 0 | heatpump MBH | $0 | 0 | heatpump MBH | $0 | 0 | heatpump MBH | $0 | 0 | heatpump MBH | $0 |
| 2.06 | piping and insulation | 100,000 | plant MBH | $600,000 | 10,000 | plant MBH | $62,000 | 40,000 | plant MBH | $250,000 | 30,000 | plant MBH | $187,000 | 20,000 | plant MBH | $125,000 |
| 2.07 | Elect equip and power wiring | 100,000 | plant MBH | $570,000 | 10,000 | plant MBH | $59,000 | 40,000 | plant MBH | $237,000 | 30,000 | plant MBH | $178,000 | 20,000 | plant MBH | $119,000 |
| 2.08 | controls and Instrumentation | 100,000 | plant MBH | $310,000 | 10,000 | plant MBH | $32,000 | 40,000 | plant MBH | $129,000 | 30,000 | plant MBH | $97,000 | 20,000 | plant MBH | $64,000 |
| 2.09 | ventilation | 9,000 | gross sf | $106,000 | 5,400 | gross sf | $66,000 | 0 | gross sf | $0 | 3,600 | gross sf | $44,000 | 0 | gross sf | $0 |
| 2.10 | fire protection | 9,000 | gross sf | $17,000 | 5,400 | gross sf | $11,000 | 0 | gross sf | $0 | 3,600 | gross sf | $7,000 | 0 | gross sf | $0 |
| 2.11 | startup, test, balance & Comm | 9,000 | gross sf | $50,000 | 5,400 | gross sf | $31,000 | 0 | gross sf | $0 | 3,600 | gross sf | $21,000 | 0 | gross sf | $0 |
| 2.12 | Miscellaneous | 9,000 | gross sf | $147,000 | 5,400 | gross sf | $92,000 | 0 | gross sf | $0 | 3,600 | gross sf | $61,000 | 0 | gross sf | $0 |
| | **Mechanical/electrical subtotal** | | | **$3,190,000** | | | **$573,000** | | | **$1,145,000** | | | **$1,002,000** | | | **$572,000** |
| | **Plant Cost** | | | **$4,387,000** | | | **$1,409,000** | | | **$1,145,000** | | | **$1,543,000** | | | **$572,000** |
| | **Plant Capacity, MBH** | | | **100,000** | | | **10,000** | | | **40,000** | | | **30,000** | | | **20,000** |
| | **$/MBH** | | | **$43.9** | | | **$140.9** | | | **$28.6** | | | **$51.4** | | | **$28.6** |

## South Lake Union Heat Pump / Boiler Plant Cost Estimate

| | | Full Plant | | | Phase 1 | | | Phase 2 | | | Phase 3 | | | Phase 4 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Installed units | | $ Cost | Installed units | | $ Cost | Installed units | | $ Cost | Installed units | | $ Cost | Installed units | | $ Cost |
| 1. Building | | | | | | | | | | | | | | | | |
| 1.01 | Engineering fees | 12.0% | | $183,000 | 10.0% | | $152,000 | 0.0% | | $0 | 8.4% | | $56,000 | 0.0% | | $0 |
| 1.02 | project management | 8.0% | | $122,000 | 8.0% | | $85,000 | 8.0% | | $0 | 8.0% | | $53,000 | 8.0% | | $0 |
| 1.03 | mobilization | 1.0% | | $15,000 | 1.0% | | $11,000 | 1.0% | | $0 | 1.0% | | $7,000 | 1.0% | | $0 |
| 1.04 | foundation, building | 14,700 | fdn sf | $460,000 | 9,180 | fdn sf | $305,000 | 0 | fdn sf | $0 | 5,520 | fdn sf | $183,000 | 0 | fdn sf | $0 |
| 1.05 | structure, foundation to roof | 14,700 | gross sf | $323,000 | 9,180 | gross sf | $214,000 | 0 | gross sf | $0 | 5,520 | gross sf | $129,000 | 0 | gross sf | $0 |
| 1.06 | roofing | 14,700 | roof sf | $175,000 | 9,180 | roof sf | $116,000 | 0 | roof sf | $0 | 5,520 | roof sf | $70,000 | 0 | roof sf | $0 |
| 1.07 | exterior wall/finish, building | 10,669 | wall sf | $91,000 | 8,431 | wall sf | $76,000 | 0 | wall sf | $0 | 6,538 | wall sf | $59,000 | 0 | wall sf | $0 |
| 1.08 | exterior wall/finish, cooling tower | 10,669 | wall sf | $182,000 | 8,431 | wall sf | $153,000 | 0 | wall sf | $0 | 6,538 | wall sf | $119,000 | 0 | wall sf | $0 |
| 1.09 | elevator | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.10 | retail space | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.11 | office, break room, locker room | 1 | LS | $25,000 | 1 | LS | $25,000 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.12 | building interior/finishes | 14,700 | gross sf | $168,000 | 9,180 | gross sf | $111,000 | 0 | gross sf | $0 | 5,520 | gross sf | $67,000 | 0 | gross sf | $0 |
| 1.13 | plumbing /drainage | 14,700 | gross sf | $68,000 | 9,180 | gross sf | $45,000 | 0 | gross sf | $0 | 5,520 | gross sf | $27,000 | 0 | gross sf | $0 |
| 1.14 | miscellaneous | 14,700 | gross sf | $30,000 | 9,180 | gross sf | $20,000 | 0 | gross sf | $0 | 5,520 | gross sf | $12,000 | 0 | gross sf | $0 |
| | **Building subtotal** | | | **$1,843,000** | | | **$1,312,000** | | | **$0** | | | **$781,000** | | | **$0** |
| 2. Mechanical | | | | | | | | | | | | | | | | |
| 2.01 | Eng, permits, fees | 8% | | $629,000 | 27% | | $244,000 | 6% | | $186,000 | 6% | | $112,000 | 6% | | $101,000 |
| 2.02 | project management | 2% | | $157,000 | 2% | | $18,000 | 2% | | $66,000 | 2% | | $40,000 | 2% | | $36,000 |
| 2.03 | Other mechanical | 130,000 | plant MBH | $650,000 | 20,000 | plant MBH | $104,000 | 50,000 | plant MBH | $260,000 | 30,000 | plant MBH | $156,000 | 30,000 | plant MBH | $156,000 |
| 2.04 | Boilers | 95,000 | boiler MBH | $570,000 | 27,143 | boiler MBH | $163,000 | 27,143 | boiler MBH | $163,000 | 20,357 | boiler MBH | $122,000 | 20,357 | boiler MBH | $122,000 |
| 2.05 | Heat Pumps | 60,000 | heatpump MBH | $2,700,000 | 0 | heatpump MBH | $0 | 30,000 | heatpump MBH | $1,350,000 | 15,000 | heatpump MBH | $675,000 | 15,000 | heatpump MBH | $675,000 |
| 2.06 | piping and insulation | 130,000 | plant MBH | $1,104,000 | 20,000 | plant MBH | $125,000 | 50,000 | plant MBH | $480,000 | 30,000 | plant MBH | $271,000 | 30,000 | plant MBH | $271,000 |
| 2.07 | Elect equip and power wiring | 130,000 | plant MBH | $1,767,000 | 20,000 | plant MBH | $119,000 | 50,000 | plant MBH | $830,000 | 30,000 | plant MBH | $445,000 | 30,000 | plant MBH | $445,000 |
| 2.08 | controls and Instrumentation | 130,000 | plant MBH | $552,000 | 20,000 | plant MBH | $64,000 | 50,000 | plant MBH | $239,000 | 30,000 | plant MBH | $135,000 | 30,000 | plant MBH | $135,000 |
| 2.09 | ventilation | 14,700 | gross sf | $174,000 | 9,180 | gross sf | $113,000 | 0 | gross sf | $0 | 5,520 | gross sf | $68,000 | 0 | gross sf | $0 |
| 2.10 | fire protection | 14,700 | gross sf | $28,000 | 9,180 | gross sf | $18,000 | 0 | gross sf | $0 | 5,520 | gross sf | $11,000 | 0 | gross sf | $0 |
| 2.11 | startup, test, balance & Comm | 14,700 | gross sf | $81,000 | 9,180 | gross sf | $53,000 | 0 | gross sf | $0 | 5,520 | gross sf | $32,000 | 0 | gross sf | $0 |
| 2.12 | Miscellaneous | 14,700 | gross sf | $240,000 | 9,180 | gross sf | $156,000 | 0 | gross sf | $0 | 5,520 | gross sf | $94,000 | 0 | gross sf | $0 |
| | **Mechanical/electrical subtotal** | | | **$8,652,000** | | | **$1,177,000** | | | **$3,574,000** | | | **$2,162,000** | | | **$1,942,000** |
| | **Plant Cost** | | | **$10,495,000** | | | **$2,489,000** | | | **$3,574,000** | | | **$2,942,000** | | | **$1,942,000** |
| | **Plant Capacity, MBH** | | | **130,000** | | | **20,000** | | | **50,000** | | | **30,000** | | | **30,000** |
| | **$/MBH** | | | **$80.7** | | | **$124.5** | | | **$71.5** | | | **$98.1** | | | **$64.7** |

## Denny Triangle Heat Pump / Boiler Plant Cost Estimate

| | | Full Plant | | | Phase 1 | | | Phase 2 | | | Phase 3 | | | Phase 4 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Installed units | | $ Cost | Installed units | | $ Cost | Installed units | | $ Cost | Installed units | | $ Cost | Installed units | | $ Cost |
| 1. Building | | | | | | | | | | | | | | | | |
| 1.01 | Engineering fees | 12.0% | | $146,000 | 10.0% | | $120,000 | 0.0% | | $0 | 8.4% | | $47,000 | 0.0% | | $0 |
| 1.02 | project management | 8.0% | | $97,000 | 8.0% | | $66,000 | 8.0% | | $0 | 8.0% | | $45,000 | 8.0% | | $0 |
| 1.03 | mobilization | 1.0% | | $12,000 | 1.0% | | $8,000 | 1.0% | | $0 | 1.0% | | $6,000 | 1.0% | | $0 |
| 1.04 | foundation, building | 11,400 | fdn sf | $357,000 | 6,840 | fdn sf | $227,000 | 0 | fdn sf | $0 | 4,560 | fdn sf | $151,000 | 0 | fdn sf | $0 |
| 1.05 | structure, foundation to roof | 11,400 | gross sf | $251,000 | 6,840 | gross sf | $159,000 | 0 | gross sf | $0 | 4,560 | gross sf | $106,000 | 0 | gross sf | $0 |
| 1.06 | roofing | 11,400 | roof sf | $136,000 | 6,840 | roof sf | $86,000 | 0 | roof sf | $0 | 4,560 | roof sf | $58,000 | 0 | roof sf | $0 |
| 1.07 | exterior wall/finish, building | 9,396 | wall sf | $80,000 | 7,278 | wall sf | $66,000 | 0 | wall sf | $0 | 5,942 | wall sf | $54,000 | 0 | wall sf | $0 |
| 1.08 | exterior wall/finish, cooling tower | 9,396 | wall sf | $161,000 | 7,278 | wall sf | $132,000 | 0 | wall sf | $0 | 5,942 | wall sf | $108,000 | 0 | wall sf | $0 |
| 1.09 | elevator | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.10 | retail space | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.11 | office, break room, locker room | 1 | LS | $25,000 | 1 | LS | $25,000 | 0 | LS | $0 | 0 | LS | $0 | 0 | LS | $0 |
| 1.12 | building interior/finishes | 11,400 | gross sf | $130,000 | 6,840 | gross sf | $83,000 | 0 | gross sf | $0 | 4,560 | gross sf | $55,000 | 0 | gross sf | $0 |
| 1.13 | plumbing /drainage | 11,400 | gross sf | $52,000 | 6,840 | gross sf | $33,000 | 0 | gross sf | $0 | 4,560 | gross sf | $22,000 | 0 | gross sf | $0 |
| 1.14 | miscellaneous | 11,400 | gross sf | $23,000 | 6,840 | gross sf | $15,000 | 0 | gross sf | $0 | 4,560 | gross sf | $10,000 | 0 | gross sf | $0 |
| | **Building subtotal** | | | **$1,471,000** | | | **$1,021,000** | | | **$0** | | | **$662,000** | | | **$0** |
| 2. Mechanical | | | | | | | | | | | | | | | | |
| 2.01 | Eng, permits, fees | 8% | | $492,000 | 33% | | $182,000 | 6% | | $148,000 | 6% | | $100,000 | 6% | | $74,000 |
| 2.02 | project management | 2% | | $123,000 | 2% | | $11,000 | 2% | | $53,000 | 2% | | $36,000 | 2% | | $26,000 |
| 2.03 | Other mechanical | 100,000 | plant MBH | $500,000 | 10,000 | plant MBH | $52,000 | 40,000 | plant MBH | $208,000 | 30,000 | plant MBH | $156,000 | 20,000 | plant MBH | $104,000 |
| 2.04 | Boilers | 73,000 | boiler MBH | $438,000 | 14,038 | boiler MBH | $84,000 | 22,462 | boiler MBH | $135,000 | 25,269 | boiler MBH | $152,000 | 11,231 | boiler MBH | $67,000 |
| 2.05 | Heat Pumps | 48,000 | heatpump MBH | $2,160,000 | 0 | heatpump MBH | $0 | 24,000 | heatpump MBH | $1,080,000 | 12,000 | heatpump MBH | $540,000 | 12,000 | heatpump MBH | $540,000 |
| 2.06 | piping and insulation | 100,000 | plant MBH | $830,000 | 10,000 | plant MBH | $62,000 | 40,000 | plant MBH | $369,000 | 30,000 | plant MBH | $247,000 | 20,000 | plant MBH | $185,000 |
| 2.07 | Elect equip and power wiring | 100,000 | plant MBH | $1,391,000 | 10,000 | plant MBH | $59,000 | 40,000 | plant MBH | $664,000 | 30,000 | plant MBH | $391,000 | 20,000 | plant MBH | $332,000 |
| 2.08 | controls and Instrumentation | 100,000 | plant MBH | $429,000 | 10,000 | plant MBH | $32,000 | 40,000 | plant MBH | $191,000 | 30,000 | plant MBH | $128,000 | 20,000 | plant MBH | $95,000 |
| 2.09 | ventilation | 11,400 | gross sf | $135,000 | 6,840 | gross sf | $84,000 | 0 | gross sf | $0 | 4,560 | gross sf | $56,000 | 0 | gross sf | $0 |
| 2.10 | fire protection | 11,400 | gross sf | $22,000 | 6,840 | gross sf | $13,000 | 0 | gross sf | $0 | 4,560 | gross sf | $9,000 | 0 | gross sf | $0 |
| 2.11 | startup, test, balance & Comm | 11,400 | gross sf | $63,000 | 6,840 | gross sf | $39,000 | 0 | gross sf | $0 | 4,560 | gross sf | $26,000 | 0 | gross sf | $0 |
| 2.12 | Miscellaneous | 11,400 | gross sf | $186,000 | 6,840 | gross sf | $116,000 | 0 | gross sf | $0 | 4,560 | gross sf | $77,000 | 0 | gross sf | $0 |
| | **Mechanical/electrical subtotal** | | | **$6,769,000** | | | **$736,000** | | | **$2,848,000** | | | **$1,918,000** | | | **$1,424,000** |
| | **Plant Cost** | | | **$8,240,000** | | | **$1,756,000** | | | **$2,848,000** | | | **$2,580,000** | | | **$1,424,000** |
| | **Plant Capacity, MBH** | | | **100,000** | | | **10,000** | | | **40,000** | | | **30,000** | | | **20,000** |
| | **$/MBH** | | | **$82.4** | | | **$175.6** | | | **$71.2** | | | **$86.0** | | | **$71.2** |

## Appendix 8 – Key Operating Cost Factors

### Operating Cost Factors

| | | | | | |
|---|---|---|---|---|---|
| **Energy inputs** | | | | | |
| *Electricity* | | | | | |
| Cost inflation factor (%) | | **SCL projections** | | | |
| Base case cost ($/kWh) | | $ 0.050 | $ 0.047 | $ 0.046 | $ 0.043 |
| Cost used in analysis ($/kWh) | | $ 0.050 | $ 0.047 | $ 0.046 | $ 0.043 |
| *Natural gas* | | | | | |
| Cost inflation factor (%) | | **Projections based on PSE filings** | | | |
| Base case cost ($/MMBtu) | | $ 4.30 | $ 4.09 | $ 4.24 | $ 4.17 |
| Cost used in this analysis ($/MMBtu) | | $ 4.30 | $ 4.09 | $ 4.24 | $ 4.17 |
| | | | | | |
| *Value of electric energy output available for grid ($/MWH)* | | | | | |
| *SCL projections for wholesale power value* | | | | | |
| Winter | | $ 28.82 | $ 31.42 | $ 36.99 | $ 38.78 |
| Summer | | $ 25.41 | $ 27.38 | $ 32.84 | $ 34.79 |
| *Used in this analysis* | **125%** | | | | |
| Winter | | $ 36.03 | $ 39.28 | $ 46.24 | $ 48.48 |
| Summer | | $ 31.76 | $ 34.23 | $ 41.05 | $ 43.49 |
| | | | | | |
| **Cooling cost factors for peak demand** | | | | | |
| *Electric chiller/cooling tower system efficiency (kW/ton)* | | | | | |
| Chillers | | 0.58 | 0.58 | 0.58 | 0.58 |
| Auxilliaries | | 0.125 | 0.125 | 0.125 | 0.125 |
| Distribution pumping | | 0.052 | 0.052 | 0.052 | 0.052 |
| Total | | 0.76 | 0.76 | 0.76 | 0.76 |
| *Electric chiller/lake water condenser system efficiency (kW/ton)* | | | | | |
| Chillers | | 0.41 | 0.41 | 0.41 | 0.41 |
| Auxilliaries | | 0.060 | 0.060 | 0.060 | 0.060 |
| Distribution pumping | | 0.052 | 0.052 | 0.052 | 0.052 |
| Total | | 0.52 | 0.52 | 0.52 | 0.52 |
| *Absorption chiller system efficiency (kW/ton)* | | | | | |
| Chillers | | - | - | - | - |
| Auxilliaries | | 0.25 | 0.25 | 0.25 | 0.25 |
| Distribution pumping | | 0.052 | 0.052 | 0.052 | 0.052 |
| Total | | 0.30 | 0.30 | 0.30 | 0.30 |
| *Free cooling system efficiency (kW/ton)* | | | | | |
| Chillers | | - | - | - | - |
| Auxilliaries | | 0.125 | 0.125 | 0.125 | 0.125 |
| Distribution pumping | | 0.052 | 0.052 | 0.052 | 0.052 |
| Total | | 0.18 | 0.18 | 0.18 | 0.18 |
| *Deep water cooling system efficiency (kW/ton)* | | | | | |
| Transmission pumping | | 0.116 | 0.116 | 0.116 | 0.116 |
| Auxilliaries | | - | - | - | - |
| Distribution pumping | | 0.052 | 0.052 | 0.052 | 0.052 |
| Total | | 0.17 | 0.17 | 0.17 | 0.17 |
| | | | | | |
| **Cooling cost factor for annual energy** | | | | | |
| *Electric chiller/cooling tower system efficiency (kWh/ton-hr)* | | | | | |
| Chillers | | 0.52 | 0.52 | 0.52 | 0.52 |
| Auxilliaries | | 0.125 | 0.125 | 0.125 | 0.125 |
| Distribution pumping | | 0.037 | 0.037 | 0.037 | 0.037 |
| Total | | 0.68 | 0.68 | 0.68 | 0.6820 |
| *Electric chiller/lake water condenser system efficiency (kWh/ton-hr)* | | | | | |
| Chillers | | 0.41 | 0.41 | 0.41 | 0.41 |
| Auxilliaries | | 0.06 | 0.06 | 0.06 | 0.060 |
| Distribution pumping | | 0.04 | 0.04 | 0.04 | 0.037 |
| Total | | 0.51 | 0.51 | 0.51 | 0.5070 |
| *Absorption chiller system efficiency (kWh/ton-hr)* | | | | | |
| Chillers | | - | - | - | - |
| Auxilliaries | | 0.250 | 0.250 | 0.250 | 0.25 |
| Distribution pumping | | 0.037 | 0.037 | 0.037 | 0.037 |
| Total | | 0.29 | 0.29 | 0.29 | 0.2870 |

| | | | | | |
|---|---|---|---|---|---|
| *Free cooling system efficiency (kWh/ton-hr)* | | | | | |
| Chillers | | - | - | - | - |
| Auxilliaries | | 0.125 | 0.125 | 0.125 | 0.125 |
| Distribution pumping | | 0.037 | 0.037 | 0.037 | 0.037 |
| Total | | 0.16 | 0.16 | 0.16 | 0.1620 |
| *Deep water cooling system efficiency (kWh/ton-hr)* | | | | | |
| Transmission pumping | | 0.055 | 0.055 | 0.062 | 0.070 |
| Auxilliaries | | - | - | - | - |
| Distribution pumping | | 0.037 | 0.037 | 0.037 | 0.037 |
| Total | | 0.09 | 0.09 | 0.10 | 0.11 |
| % of heat pump electricity allocated to cooling | | 20% | 20% | 20% | 20% |
| **Cooling distribution thermal losses (%)** | | 4% | 4% | 4% | 4% |
| **Operating cost inflation factor (%)** | 0% | | | | |
| **Other cooling operating costs** | | | | | |
| *Supplies* | | | | | |
| Make-up water requirements (gallons per ton-hour) | 3.00 | $ 3.00 | $ 3.00 | $ 3.00 | $ 3.00 |
| Make-up water costs ($/1000 gallons) | $ 1.50 | $ 1.50 | $ 1.50 | $ 1.50 | $ 1.50 |
| Chemical costs ($/1000 gallons) | $ 0.50 | $ 0.50 | $ 0.50 | $ 0.50 | $ 0.50 |
| Total cost of treated water ($/1000 gallons) | $ 2.00 | $ 2.00 | $ 2.00 | $ 2.00 | $ 2.00 |
| *Maintenance* | | | | | |
| Electric plant maintenance ($/ton capacity) | $ 15.00 | $ 15.00 | $ 15.00 | $ 15.00 | $ 15.00 |
| Absorption plant maintenance ($/ton capacity) | $ 15.00 | $ 15.00 | $ 15.00 | $ 15.00 | $ 15.00 |
| Deep water cooling plant maintenance ($/ton capacity) | $ 7.00 | $ 7.00 | $ 7.00 | $ 7.00 | $ 7.00 |
| Thermal storage plant maintenance ($/ton capacity) | $ 4.00 | $ 4.00 | $ 4.00 | $ 4.00 | $ 4.00 |
| Piping maintenance (% of capital) | 1.25% | $ 0.01 | $ 0.01 | $ 0.01 | $ 0.01 |
| **Heating cost factors** | | | | | |
| *Heating plant efficiency* | | | | | |
| Boiler efficiency (%) | | 80% | 80% | 80% | 80% |
| Heat pump plant efficiency (COP) | | 2.80 | 2.80 | 2.80 | 2.80 |
| **Heating distribution thermal losses (%)** | | 4% | 4% | 4% | 4% |
| **Other heating cost factors for peak demand** | | | | | |
| *Power requirements (kW/MMBH sendout)* | | | | | |
| Distribution pumping | | 0.91 | 0.98 | 1.30 | 1.67 |
| Other power requirements | | 0.60 | 0.60 | 0.60 | 0.60 |
| Heat pump power requirements | | 104.6 | 104.6 | 104.6 | 104.6 |
| *Maintenance* | | | | | |
| Boiler plant maintenance ($/MMBtu-hr capacity) | $ 900 | $ 900 | $ 900 | $ 900 | $ 900 |
| Heat pump plant maintenance ($/MMBtu-hr capacity) | $ 1,600 | $ 1,600 | $ 1,600 | $ 1,600 | $ 1,600 |
| Distribution maintenance (% of capital) | 1.50% | 1.50% | 1.50% | 1.50% | 1.50% |
| **Other heating cost factors for annual energy** | | | | | |
| *Power requirements (kWh/MMBtu sendout)* | | | | | |
| Distribution pumping | | 0.65 | 0.70 | 0.93 | 1.19 |
| Other power requirements | | 0.6 | 0.6 | 0.6 | 0.6 |
| Heat pump power requirements | | 104.6 | 104.6 | 104.6 | 104.6 |
| **Gas turbine CHP cost factors excluding fuel** | | | | | |
| *Other power requirements* | | | | | |
| CHP gas compressor (kWh per MWH electric output) | 8 | 8 | 8 | 8 | 8 |
| Misc. (kWh per MMBtu send-out) | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 |
| *Maintenance* | | | | | |
| Fixed cost ($/MW capacity) | $ 10,000 | $ 10,000 | $ 10,000 | $ 10,000 | $ 10,000 |
| Variable cost ($/MWH) | $ 6.60 | $ 6.60 | $ 6.60 | $ 6.60 | $ 6.60 |
| | | | | | $ 2 |
| **Personnel costs** | | | | | |
| Management $/FTE | $ 110,000 | $ 110,000 | $ 110,000 | $ 110,000 | $ 110,000 |
| Administration $/FTE | $ 75,000 | $ 75,000 | $ 75,000 | $ 75,000 | $ 75,000 |
| Operations $/FTE | $ 75,000 | $ 75,000 | $ 75,000 | $ 75,000 | $ 75,000 |

# Appendix 9  Assumptions on Default HVAC

| | Administrative Office | Apartment, Condo, Ex Stay Hotel | Grocery Store | Health/ Fitness Center | High-Tech Office | Research Laboratory | Hospital, University, Major Institution | Hotel, Motel | Manufacturing, Warehousing | Restaurant | Retail Store | Server Farm, Data Center, Telecom Hotel | Theater | School, Library |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Assumed HVAC %s for Thermal Calcs** | | | | | | | | | | | | | | |
| ***Heating*** | | | | | | | | | | | | | | |
| Electric resistance heating | 50% | 30% | 5% | 70% | 40% | 5% | 10% | 25% | 20% | 20% | 40% | 0% | 10% | 10% |
| Heat pump heating | 20% | 40% | 0% | 0% | 0% | 0% | 0% | 50% | 0% | 0% | 0% | 100% | 0% | 50% |
| Gas heating | 30% | 30% | 95% | 30% | 60% | 95% | 90% | 25% | 80% | 80% | 60% | 0% | 90% | 40% |
| *Total* | *100%* | *100%* | *100%* | *100%* | *100%* | *100%* | *100%* | *100%* | *100%* | *100%* | *100%* | *100%* | *100%* | *100%* |
| ***Cooling*** | | | | | | | | | | | | | | |
| DX cooling | 30% | 20% | 95% | 70% | 40% | 5% | 10% | 25% | 20% | 80% | 60% | 0% | 40% | 20% |
| Heat pump cooling | 20% | 40% | 0% | 0% | 0% | 0% | 0% | 50% | 0% | 0% | 0% | 100% | 0% | 50% |
| Centrifugal chiller cooling | 50% | 40% | 5% | 30% | 60% | 95% | 90% | 25% | 80% | 20% | 40% | 0% | 60% | 30% |
| *Total* | *100%* | *100%* | *100%* | *100%* | *100%* | *100%* | *100%* | *100%* | *100%* | *100%* | *100%* | *100%* | *100%* | *100%* |
| **Seasonal electric COPs for default HVAC** | | | | | | | | | | | | | | |
| Electric resistance heating | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Heat pump heating | 3.00 | 3.00 | 3.00 | 3.00 | 3.00 | 3.00 | 3.00 | 3.00 | 3.00 | 3.00 | 3.00 | 3.00 | 3.00 | 3.00 |
| Gas boiler heating | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| DX cooling | 2.30 | 2.30 | 2.30 | 2.30 | 2.30 | 2.30 | 2.30 | 2.30 | 2.30 | 2.30 | 2.30 | 2.30 | 2.30 | 2.30 |
| Heat pump cooling | 3.00 | 3.00 | 3.00 | 3.00 | 3.00 | 3.00 | 3.00 | 3.00 | 3.00 | 3.00 | 3.00 | 3.00 | 3.00 | 3.00 |
| Centrifugal chiller cooling | 3.50 | 3.50 | 3.50 | 3.50 | 3.50 | 3.50 | 3.50 | 3.50 | 3.50 | 3.50 | 3.50 | 3.50 | 3.50 | 3.50 |
| Seasonal average natural gas boiler efficiency | 75% | 75% | 75% | 75% | 75% | 75% | 75% | 75% | 75% | 75% | 75% | 75% | 75% | 75% |
| **Conversion of annual heating energy assumptions into annual electricity use** | | | | | | | | | | | | | | |
| Annual heating MMBtu/SF | 0.0183 | 0.0272 | 0.0213 | 0.0152 | 0.0165 | 0.0419 | 0.0479 | 0.0224 | 0.0082 | 0.0431 | 0.0185 | 0.0066 | 0.0185 | 0.0201 |
| Weighted average annual heating MMBtu electricity/SF | 0.0103 | 0.0118 | 0.0011 | 0.0107 | 0.0066 | 0.0021 | 0.0048 | 0.0093 | 0.0016 | 0.0086 | 0.0074 | 0.0022 | 0.0019 | 0.0054 |
| Weighted average annual heating kWh electricity/SF | 3.03 | 3.46 | 0.31 | 3.13 | 1.93 | 0.61 | 1.40 | 2.74 | 0.48 | 2.52 | 2.17 | 0.64 | 0.54 | 1.57 |
| Weighted average COP | 1.57 | 2.14 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 2.33 | 1.00 | 1.00 | 1.00 | 3.00 | 1.00 | 2.67 |
| **Conversion of annual cooling energy assumptions into annual electricity use** | | | | | | | | | | | | | | |
| Weighted average COP | 3.04 | 3.06 | 2.36 | 2.66 | 3.02 | 3.44 | 3.38 | 2.95 | 3.26 | 2.54 | 2.78 | 3.00 | 3.02 | 3.01 |
| Tons cooling per kW power | 0.86 | 0.87 | 0.67 | 0.76 | 0.86 | 0.98 | 0.96 | 0.84 | 0.93 | 0.72 | 0.79 | 0.85 | 0.86 | 0.86 |
| Weighted average kW/ton | 1.16 | 1.15 | 1.49 | 1.32 | 1.16 | 1.02 | 1.04 | 1.19 | 1.08 | 1.38 | 1.26 | 1.17 | 1.16 | 1.17 |
| Cooling ton-hours/SF | 1.19 | 0.70 | 1.04 | 0.74 | 2.77 | 3.14 | 2.85 | 0.70 | 0.29 | 1.01 | 1.04 | 25.47 | 1.04 | 1.08 |
| Cooling kWh/SF | 1.38 | 0.80 | 1.55 | 0.97 | 3.22 | 3.21 | 2.97 | 0.83 | 0.32 | 1.40 | 1.32 | 29.86 | 1.21 | 1.26 |
| **Conversion of heating energy into gas use** | | | | | | | | | | | | | | |
| MMBtu/year/SF | 0.007 | 0.011 | 0.027 | 0.006 | 0.013 | 0.053 | 0.057 | 0.007 | 0.009 | 0.046 | 0.015 | - | 0.022 | 0.011 |
| MMBtu/year for Base Case customers | | | | | | | | | | | | | | |
| Phase 1 | 1,456 | 6,143 | 1,140 | - | 10,807 | 18,622 | - | 679 | - | 190 | 1,951 | - | - | - |
| Phase 2 | 4,616 | 34,519 | 1,235 | 21 | 33,857 | 82,842 | 2,015 | 2,764 | - | 351 | 6,864 | - | 78 | 145 |
| Phase 3 | 9,754 | 55,234 | 1,706 | 128 | 54,711 | 93,360 | 12,057 | 2,764 | - | 1,153 | 11,596 | - | 466 | 332 |
| Phase 4 | 14,283 | 71,941 | 2,029 | 201 | 69,400 | 109,603 | 18,947 | 2,764 | - | 1,704 | 15,181 | - | 732 | 774 |

# Appendix 10 Assumptions Underlying the Existing Load Estimate for South Lake Union

While load transfer switching effects are an important consideration, SCL has not analyzed in detail the load transfer effects on specific feeder loads, so there were no adjusted data to work from. Nevertheless, detailed feeder maps were examined and this topic was discussed with staff in some detail. The following observations were made:

- Load transfer options from Broad to East Pine are limited due to capacity constraints on East Pine substation and to the extent that they affect Broad Street feeder loading they should considered temporary.
- University feeder 2663 can pick up load from SLU around Fred Hutchison clinic, but Broad feeder 2660 is also used as backup for 2663. Concluding that 2663 (UN) carries load in SLU may only be correct under abnormal operating conditions.
- Two Broad feeders (2620 and 2657) that serve loads along Westlake and Dexter were not included in the analysis because a high percentage of their loads are predominantly outside of the SLU/DT study area. Nevertheless some load in the SLU area is served by these feeders.
- For purposes of this analysis, it was recognized that using the non-coincident peak would clearly be an incorrect method for evaluating the Broad Street substation.

The following assumptions are provided to qualify the precision regarding the load estimate from SCADA information:

- The purpose of this table is to estimate the existing load in the SLU study area. Specifically the load is expressed as a coincident peak load at the Broad Street substation.
- Four out of seven feeders that serve load in the SLU study area were considered. The four feeders included in the estimate predominantly serve loads in the SLU study area. The other three predominantly serve areas outside of the study area.
- The coincident peak value is a rough approximation based on the highest monthly value for sum of the peak loads on the four feeders that predominantly serve SLU.
- The non-coincident peak value is based on the sum of the highest monthly peak loads on each of the four SLU feeders.
- The data was developed from SCADA “EMS 15 minute snapshot” average values.

| Broad Street Substation | | Design Rating | | Seasonal Operating Rating | | Peak | % of | Peak Mon |
|---|---|---|---|---|---|---|---|---|
| Bus | Feeder | Amps | MVA | Sum MVA | Win MVA | MVA | Capacity | |
| A | 2653 | 600 | 26 | 9.69 | 11.43 | 12.06 | **105.5%** | Dec |
| A | 2660 | 1200 | 52 | 18.29 | 18.29 | 19.21 | **105.0%** | Jan |
| C | 2603 | 600 | 26 | 11.43 | 11.43 | 10.81 | 94.5% | Nov |
| C | 2604 | 600 | 26 | 9.69 | 11.43 | 18.36 | **189.5%** | Jun |
| Total South Lake Union | | | | 49.10 | 52.58 | 60.44 | | |
| Coincident Peak | | | | | | 36.44 | | |

A reasonable range for existing coincident peak load in South Lake Union is 30 to 40 MVA.

# Appendix 11 Economic Proforma

# South Lake Union and Denny Triangle

**Scenario: 1**

## Loads

| *Year beginning Sept. of year shown* | Phase 1 2006 | Phase 1 2007 | Phase 2 2008 | Phase 2 2009 | Phase 2 2010 | Phase 3 2011 | Phase 3 2012 | Phase 3 2013 | Phase 3 2014 | Phase 3 2015 | Phase 4 2016 | Phase 4 2017 | Phase 4 2018 | Phase 4 2019 | Phase 4 2020 | Phase 4 2021 | Phase 4 2022 | Phase 4 2023 | Phase 4 2024 | Phase 4 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Loads** | | | | | | | | | | | | | | | | | | | | |
| **Sensitivity analysis adjustment factor** | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| **Building Space total per phase** | | | | | | | | | | | | | | | | | | | | |
| Net square feet of building space | | | | | | | | | | | | | | | | | | | | |
| New development | 2,203,982 | 2,203,982 | 6,683,259 | 6,683,259 | 6,683,259 | 5,021,804 | 5,021,804 | 5,021,804 | 5,021,804 | 5,021,804 | 4,062,979 | 4,062,979 | 4,062,979 | 4,062,979 | 4,062,979 | 4,062,979 | 4,062,979 | 4,062,979 | 4,062,979 | 4,062,979 |
| Existing buildings | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Total new district energy load | 2,203,982 | 2,203,982 | 6,683,259 | 6,683,259 | 6,683,259 | 5,021,804 | 5,021,804 | 5,021,804 | 5,021,804 | 5,021,804 | 4,062,979 | 4,062,979 | 4,062,979 | 4,062,979 | 4,062,979 | 4,062,979 | 4,062,979 | 4,062,979 | 4,062,979 | 4,062,979 |
| Cumulative building space | 2,203,982 | 2,203,982 | 8,887,241 | 8,887,241 | 8,887,241 | 13,909,045 | 13,909,045 | 13,909,045 | 13,909,045 | 13,909,045 | 17,972,025 | 17,972,025 | 17,972,025 | 17,972,025 | 17,972,025 | 17,972,025 | 17,972,025 | 17,972,025 | 17,972,025 | 17,972,025 |
| **Building Space in each year** | | | | | | | | | | 100% | | | | | | | | | | |
| % of phase total | 30.0% | 70.0% | 25.0% | 40.0% | 35.0% | 35.0% | 20.0% | 17.5% | 15.0% | 12.5% | 20.0% | 20.0% | 20.0% | 20.0% | 20.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Net square feet of building space | | | | | | | | | | | | | | | | | | | | |
| New development | 661,195 | 1,542,787 | 1,670,815 | 2,673,304 | 2,339,141 | 1,757,631 | 1,004,361 | 878,816 | 753,271 | 627,726 | 812,596 | 812,596 | 812,596 | 812,596 | 812,596 | - | - | - | - | - |
| Existing buildings | - | | - | | | - | | | | | - | | | | | | | | | |
| Total new district energy load | 661,195 | 1,542,787 | 1,670,815 | 2,673,304 | 2,339,141 | 1,757,631 | 1,004,361 | 878,816 | 753,271 | 627,726 | 812,596 | 812,596 | 812,596 | 812,596 | 812,596 | - | - | - | - | - |
| Cumulative building space -- total | 661,195 | 2,203,982 | 3,874,797 | 6,548,101 | 8,887,241 | 10,644,873 | 11,649,234 | 12,528,049 | 13,281,320 | 13,909,045 | 14,721,641 | 15,534,237 | 16,346,833 | 17,159,429 | 17,972,025 | 17,972,025 | 17,972,025 | 17,972,025 | 17,972,025 | 17,972,025 |
| Cumulative building space -- per phase | 661,195 | 2,203,982 | 1,670,815 | 4,344,118 | 6,683,259 | 1,757,631 | 2,761,992 | 3,640,808 | 4,394,079 | 5,021,804 | 812,596 | 1,625,192 | 2,437,788 | 3,250,383 | 4,062,979 | 4,062,979 | 4,062,979 | 4,062,979 | 4,062,979 | 4,062,979 |
| **Power load (non-thermal-generation)** | | | | | | | | | | | | | | | | | | | | |
| *Demand* | | | | | | | | | | | | | | | | | | | | |
| New Energy District customer peak power demand (MW) | 5.32 | 12.42 | 11.82 | 18.91 | 16.55 | 11.18 | 6.39 | 5.59 | 4.79 | 3.99 | 5.20 | 5.20 | 5.20 | 5.20 | 5.20 | - | - | - | - | - |
| Cumulative Energy District customer peak power demand (MW) | 5.32 | 17.74 | 29.56 | 48.47 | 65.02 | 76.20 | 82.59 | 88.18 | 92.97 | 96.96 | 102.16 | 107.36 | 112.55 | 117.75 | 122.95 | 122.95 | 122.95 | 122.95 | 122.95 | 122.95 |
| *Energy* | | | | | | | | | | | | | | | | | | | | |
| New Energy District customer power consumption (MWH) | 29,695 | 69,289 | 65,734 | 105,174 | 92,027 | 61,709 | 35,263 | 30,855 | 26,447 | 22,039 | 28,580 | 28,580 | 28,580 | 28,580 | 28,580 | - | - | - | - | - |
| Cumulative Energy District customer power consumption (MWH) | 29,695 | 98,984 | 164,718 | 269,892 | 361,919 | 423,629 | 458,891 | 489,746 | 516,193 | 538,232 | 566,812 | 595,393 | 623,973 | 652,554 | 681,134 | 681,134 | 681,134 | 681,134 | 681,134 | 681,134 |
| **Cooling load** | | | | | | | | | | | | | | | | | | | | |
| *Demand* | | | | | | | | | | | | | | | | | | | | |
| New peak cooling demand (tons) | 1,295 | 3,022 | 3,166 | 5,065 | 4,432 | 3,396 | 1,941 | 1,698 | 1,455 | 1,213 | 1,562 | 1,562 | 1,562 | 1,562 | 1,562 | - | - | - | - | - |
| Cumulative peak cooling demand (tons) | 1,295 | 4,317 | 7,482 | 12,547 | 16,979 | 20,375 | 22,316 | 24,014 | 25,469 | 26,682 | 28,244 | 29,806 | 31,368 | 32,929 | 34,491 | 34,491 | 34,491 | 34,491 | 34,491 | 34,491 |
| Diversification factor | 0.90 | 0.90 | 0.90 | 0.90 | 0.90 | 0.90 | 0.90 | 0.90 | 0.90 | 0.90 | 0.90 | 0.90 | 0.90 | 0.90 | 0.90 | 0.90 | 0.90 | 0.90 | 0.90 | 0.90 |
| Diversified peak demand (tons) | 1,166 | 3,885 | 6,734 | 11,292 | 15,281 | 18,337 | 20,084 | 21,612 | 22,922 | 24,014 | 25,419 | 26,825 | 28,231 | 29,636 | 31,042 | 31,042 | 31,042 | 31,042 | 31,042 | 31,042 |
| Winter demand (% of summer peak) | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% |
| Winter demand (tons) | 58 | 194 | 337 | 565 | 764 | 917 | 1,004 | 1,081 | 1,146 | 1,201 | 1,271 | 1,341 | 1,412 | 1,482 | 1,552 | 1,552 | 1,552 | 1,552 | 1,552 | 1,552 |
| Distribution losses at peak (%) | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% |
| Peak send-out (tons) | 1,227 | 4,090 | 7,089 | 11,887 | 16,085 | 19,303 | 21,141 | 22,750 | 24,129 | 25,278 | 26,757 | 28,237 | 29,717 | 31,196 | 32,676 | 32,676 | 32,676 | 32,676 | 32,676 | 32,676 |
| *Energy* | | | | | | | | | | | | | | | | | | | | |
| New cooling energy consumption (1000 ton-hours) | 1,276 | 2,976 | 2,977 | 4,764 | 4,168 | 3,296 | 1,884 | 1,648 | 1,413 | 1,177 | 1,491 | 1,491 | 1,491 | 1,491 | 1,491 | - | - | - | - | - |
| Cumulative cooling energy consumption (1000 ton-hrs) | 1,276 | 4,252 | 7,229 | 11,993 | 16,161 | 19,457 | 21,341 | 22,989 | 24,402 | 25,579 | 27,070 | 28,561 | 30,052 | 31,542 | 33,033 | 33,033 | 33,033 | 33,033 | 33,033 | 33,033 |
| Average system EFLH | 1,094 | 1,094 | 1,074 | 1,062 | 1,058 | 1,061 | 1,063 | 1,064 | 1,065 | 1,065 | 1,065 | 1,065 | 1,064 | 1,064 | 1,064 | 1,064 | 1,064 | 1,064 | 1,064 | 1,064 |
| Average customer EFLH | 985 | 985 | 966 | 956 | 952 | 955 | 956 | 957 | 958 | 959 | 958 | 958 | 958 | 958 | 958 | 958 | 958 | 958 | 958 | 958 |
| Average annual distribution losses (%) | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% |
| Annual send-out (1000 ton-hours) | 1,329 | 4,429 | 7,531 | 12,493 | 16,834 | 20,268 | 22,230 | 23,947 | 25,419 | 26,645 | 28,198 | 29,751 | 31,304 | 32,857 | 34,410 | 34,410 | 34,410 | 34,410 | 34,410 | 34,410 |
| **Heating load** | | | | | | | | | | | | | | | | | | | | |
| *Demand* | | | | | | | | | | | | | | | | | | | | |
| New peak heating demand (MMBtu/hr) | 8.8 | 20.6 | 22.4 | 35.9 | 31.4 | 22.1 | 12.7 | 11.1 | 9.5 | 7.9 | 10.5 | 10.5 | 10.5 | 10.5 | 10.5 | - | - | - | - | - |
| Cumulative peak heating demand (MMBtu/hr) | 8.8 | 29.4 | 51.8 | 87.7 | 119.1 | 141.3 | 153.9 | 165.0 | 174.5 | 182.4 | 192.9 | 203.3 | 213.8 | 224.2 | 234.7 | 234.7 | 234.7 | 234.7 | 234.7 | 234.7 |
| Diversification factor | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 |
| Diversified peak demand (MMBtu/hr) | 7 | 25 | 44 | 75 | 101 | 120 | 131 | 140 | 148 | 155 | 164 | 173 | 182 | 191 | 199 | 199 | 199 | 199 | 199 | 199 |
| Estimated summer demand (% of winter peak) | 8% | 8% | 8% | 8% | 8% | 8% | 8% | 8% | 8% | 8% | 8% | 8% | 8% | 8% | 8% | 8% | 8% | 8% | 8% | 8% |
| Estimated summer demand (MMBtu/hour) | 0.60 | 2.00 | 3.52 | 5.97 | 8.10 | 9.61 | 10.47 | 11.22 | 11.87 | 12.40 | 13.12 | 13.83 | 14.54 | 15.25 | 15.96 | 15.96 | 15.96 | 15.96 | 15.96 | 15.96 |
| Distribution losses at peak (%) | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% |
| Peak send-out (MMBtu/hour) | 8 | 26 | 46 | 79 | 107 | 126 | 138 | 148 | 156 | 163 | 173 | 182 | 191 | 201 | 210 | 210 | 210 | 210 | 210 | 210 |
| *Energy* | | | | | | | | | | | | | | | | | | | | |
| New customer heating energy consumption (MMBtu) | 15,829 | 36,933 | 43,278 | 69,245 | 60,589 | 40,494 | 23,140 | 20,247 | 17,355 | 14,462 | 19,347 | 19,347 | 19,347 | 19,347 | 19,347 | - | - | - | - | - |
| Cumulative customer heating energy consumption (MMBtu) | 15,829 | 52,762 | 96,040 | 165,284 | 225,873 | 266,368 | 289,507 | 309,754 | 327,109 | 341,571 | 360,918 | 380,264 | 399,611 | 418,958 | 438,304 | 438,304 | 438,304 | 438,304 | 438,304 | 438,304 |
| Average system EFLH | 2,111 | 2,111 | 2,180 | 2,216 | 2,230 | 2,218 | 2,212 | 2,208 | 2,205 | 2,203 | 2,202 | 2,200 | 2,199 | 2,198 | 2,197 | 2,197 | 2,197 | 2,197 | 2,197 | 2,197 |
| Average customer EFLH | 1,795 | 1,795 | 1,853 | 1,884 | 1,896 | 1,885 | 1,881 | 1,877 | 1,874 | 1,872 | 1,871 | 1,870 | 1,869 | 1,868 | 1,868 | 1,868 | 1,868 | 1,868 | 1,868 | 1,868 |
| Average annual distribution losses (%) | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% |
| Annual send-out (MMBtu) | 16,488 | 54,960 | 100,041 | 172,171 | 235,285 | 277,466 | 301,570 | 322,661 | 340,739 | 355,803 | 375,956 | 396,109 | 416,261 | 436,414 | 456,567 | 456,567 | 456,567 | 456,567 | 456,567 | 456,567 |

# South Lake Union and Denny Triangle

## Scenario: 1

## Capital Costs (thousand 2003 $)

| | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year capital expended** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
| **Year facilities in operation** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| Land purchase | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cooling plant | $ 9,691 | $ - | $ 11,542 | $ - | $ - | $ 12,019 | $ - | $ - | $ - | $ - | $ 6,695 | $ - | $ - | $ - | $ - |
| Heating plant | $ 4,690 | $ - | $ 2,942 | $ - | $ - | $ 3,245 | $ - | $ - | $ - | $ - | $ 1,522 | $ - | $ - | $ - | $ - |
| CHP plant | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Deep water cooling intake and outfall pipeline | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Deep water cooling transmission and inter-plant pipes | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Deep water cooling heat exchange facility | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cooling distribution and service pipe | $ 5,650 | $ - | $ 8,649 | $ - | $ - | $ 3,443 | $ - | $ - | $ - | $ - | $ 1,301 | $ - | $ - | $ - | $ - |
| Heating distribution and service pipe | $ 3,135 | $ - | $ 5,029 | $ - | $ - | $ 2,044 | $ - | $ - | $ - | $ - | $ 726 | $ - | $ - | $ - | $ - |
| Subtotal | $ 23,166 | $ - | $ 28,163 | $ - | $ - | $ 20,752 | $ - | $ - | $ - | $ - | $ 10,243 | $ - | $ - | $ - | $ - |
| Environmental review and permitting | $ 695 | $ - | $ 845 | $ - | $ - | $ 623 | $ - | $ - | $ - | $ - | $ 307 | $ - | $ - | $ - | $ - |
| Building connection cooling | $ 755 | $ - | $ 2,216 | $ - | $ - | $ 1,698 | $ - | $ - | $ - | $ - | $ 1,367 | $ - | $ - | $ - | $ - |
| Building connection heating | $ 470 | $ - | $ 1,436 | $ - | $ - | $ 1,012 | $ - | $ - | $ - | $ - | $ 836 | $ - | $ - | $ - | $ - |
| Subtotal | $ 1,226 | $ - | $ 3,652 | $ - | $ - | $ 2,710 | $ - | $ - | $ - | $ - | $ 2,203 | $ - | $ - | $ - | $ - |
| Total | $ 25,087 | $ - | $ 32,660 | $ - | $ - | $ 24,085 | $ - | $ - | $ - | $ - | $ 12,753 | $ - | $ - | $ - | $ - |
| **Costs by category** | | | | | | | | | | | | | | | |
| Plant | $ 15,077 | $ - | $ 15,330 | $ - | $ - | $ 15,887 | $ - | $ - | $ - | $ - | $ 8,524 | $ - | $ - | $ - | $ - |
| Deep water cooling facilities | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Distribution | $ 8,784 | $ - | $ 13,678 | $ - | $ - | $ 5,488 | $ - | $ - | $ - | $ - | $ 2,027 | $ - | $ - | $ - | $ - |
| Building interconnection | $ 1,226 | $ - | $ 3,652 | $ - | $ - | $ 2,710 | $ - | $ - | $ - | $ - | $ 2,203 | $ - | $ - | $ - | $ - |
| Total | $ 25,087 | $ - | $ 32,660 | $ - | $ - | $ 24,085 | $ - | $ - | $ - | $ - | $ 12,753 | $ - | $ - | $ - | $ - |
| **Cumulative capital cost** | | | | | | | | | | | | | | | |
| Cooling plant | $ 9,691 | $ 9,691 | $ 21,234 | $ 21,234 | $ 21,234 | $ 33,253 | $ 33,253 | $ 33,253 | $ 33,253 | $ 33,253 | $ 39,948 | $ 39,948 | $ 39,948 | $ 39,948 | $ 39,948 |
| Cooling deep water facilities | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cooling distribution | $ 5,650 | $ 5,650 | $ 14,299 | $ 14,299 | $ 14,299 | $ 17,742 | $ 17,742 | $ 17,742 | $ 17,742 | $ 17,742 | $ 19,043 | $ 19,043 | $ 19,043 | $ 19,043 | $ 19,043 |
| Cooling ETS | $ 755 | $ 755 | $ 2,971 | $ 2,971 | $ 2,971 | $ 4,669 | $ 4,669 | $ 4,669 | $ 4,669 | $ 4,669 | $ 6,036 | $ 6,036 | $ 6,036 | $ 6,036 | $ 6,036 |
| Total Cooling | $ 16,097 | $ 16,097 | $ 38,504 | $ 38,504 | $ 38,504 | $ 55,665 | $ 55,665 | $ 55,665 | $ 55,665 | $ 55,665 | $ 65,027 | $ 65,027 | $ 65,027 | $ 65,027 | $ 65,027 |
| Heating plant | $ 4,690 | $ 4,690 | $ 7,633 | $ 7,633 | $ 7,633 | $ 10,878 | $ 10,878 | $ 10,878 | $ 10,878 | $ 10,878 | $ 12,400 | $ 12,400 | $ 12,400 | $ 12,400 | $ 12,400 |
| Heating distribution | $ 3,135 | $ 3,135 | $ 8,163 | $ 8,163 | $ 8,163 | $ 10,208 | $ 10,208 | $ 10,208 | $ 10,208 | $ 10,208 | $ 10,934 | $ 10,934 | $ 10,934 | $ 10,934 | $ 10,934 |
| Heating ETS | $ 470 | $ 470 | $ 1,906 | $ 1,906 | $ 1,906 | $ 2,919 | $ 2,919 | $ 2,919 | $ 2,919 | $ 2,919 | $ 3,755 | $ 3,755 | $ 3,755 | $ 3,755 | $ 3,755 |
| Total Heating | $ 8,295 | $ 8,295 | $ 17,703 | $ 17,703 | $ 17,703 | $ 24,004 | $ 24,004 | $ 24,004 | $ 24,004 | $ 24,004 | $ 27,088 | $ 27,088 | $ 27,088 | $ 27,088 | $ 27,088 |
| Combined total heating and cooling | $ 24,392 | $ 24,392 | $ 56,207 | $ 56,207 | $ 56,207 | $ 79,669 | $ 79,669 | $ 79,669 | $ 79,669 | $ 79,669 | $ 92,115 | $ 92,115 | $ 92,115 | $ 92,115 | $ 92,115 |

# South Lake Union and Denny Triangle

**Scenario: 1**

## Debt Service

| | Equity | Conventional loan | Subsidized loan | Grant | Total |
|---|---|---|---|---|---|
| Debt Ratio | 0% | 100% | 0% | 0% | 100% |
| Cost for financing | | 7% | 7% | | |
| Debt Interest Rate | | 5% | 4% | | |
| Term | | 20 | 20 | | |
| Capital Recovery Factor | | 0.08024 | 0.07358 | | |

| Operating year | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Operating year | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
| **Capital cost (1000 $US)** | 25,087 | 0 | 32,660 | 0 | 0 | 24,085 | 0 | 0 | 0 | 0 | 12,753 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Distribution of financing (1000 $US)** | | | | | | | | | | | | | | | | | | | | | |
| Equity | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Conventional loan | 25,087 | 0 | 32,660 | 0 | 0 | 24,085 | 0 | 0 | 0 | 0 | 12,753 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subsidized loan | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Grant | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 25,087 | 0 | 32,660 | 0 | 0 | 24,085 | 0 | 0 | 0 | 0 | 12,753 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Financing cost (1000 $US)** | | | | | | | | | | | | | | | | | | | | | |
| Conventional loan | 1,756 | 0 | 2,286 | 0 | 0 | 1,686 | 0 | 0 | 0 | 0 | 893 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subsidized loan | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total financing cost | 1,756 | 0 | 2,286 | 0 | 0 | 1,686 | 0 | 0 | 0 | 0 | 893 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Operating Reserve Funding (1000 $US)** | | | | | | | | | | | | | | | | | | | | | |
| Grant | 0 | | 0 | 0 | 0 | | | | | | | | | | | | | | | | |
| Conventional loan | 4,000 | 0 | 5,000 | 0 | 0 | | | | | | | | | | | | | | | | |
| Subsidized loan | 0 | | 0 | 0 | 0 | | | | | | | | | | | | | | | | |
| Total | 4,000 | 0 | 5,000 | 0 | 0 | 0 | 0 | | | | | | | | | | | | | | |
| **Debt to be financed (1000 $US)** | | | | | | | | | | | | | | | | | | | | | |
| Conventional loan | 30,843 | 0 | 39,946 | 0 | 0 | 25,771 | 0 | 0 | 0 | 0 | 13,646 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subsidized loan | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total debt | 30,843 | 0 | 39,946 | 0 | 0 | 25,771 | 0 | 0 | 0 | 0 | 13,646 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Debt Service (1000 $US)** | | | | | | | | | | | | | | | | | | | | | |
| **Conventional loan (P&I)** | | | | | | | | | | | | | | | | | | | | | |
| Loan -- Year 2005 | | 2,475 | 2,475 | 2,475 | 2,475 | 2,475 | 2,475 | 2,475 | 2,475 | 2,475 | 2,475 | 2,475 | 2,475 | 2,475 | 2,475 | 2,475 | 2,475 | 2,475 | 2,475 | 2,475 | 2,475 |
| Loan -- Year 2007 | | | | 3,205 | 3,205 | 3,205 | 3,205 | 3,205 | 3,205 | 3,205 | 3,205 | 3,205 | 3,205 | 3,205 | 3,205 | 3,205 | 3,205 | 3,205 | 3,205 | 3,205 | 3,205 |
| Loan -- Year 2010 | | | | | | | 2,068 | 2,068 | 2,068 | 2,068 | 2,068 | 2,068 | 2,068 | 2,068 | 2,068 | 2,068 | 2,068 | 2,068 | 2,068 | 2,068 | 2,068 |
| Loan -- Year 2015 | | | | | | | | | | | | 1,095 | 1,095 | 1,095 | 1,095 | 1,095 | 1,095 | 1,095 | 1,095 | 1,095 | 1,095 |
| Total | | 2,475 | 2,475 | 5,680 | 5,680 | 5,680 | 7,748 | 7,748 | 7,748 | 7,748 | 7,748 | 8,843 | 8,843 | 8,843 | 8,843 | 8,843 | 8,843 | 8,843 | 8,843 | 8,843 | 8,843 |
| **Conventional loan interest** | | | | | | | | | | | | | | | | | | | | | |
| Loan -- Year 2005 | | 1,542 | 1,496 | 1,447 | 1,395 | 1,341 | 1,284 | 1,225 | 1,162 | 1,097 | 1,028 | 956 | 880 | 800 | 716 | 628 | 536 | 439 | 337 | 230 | 118 |
| Loan -- Year 2007 | | | | 1,997 | 1,937 | 1,873 | 1,807 | 1,737 | 1,664 | 1,586 | 1,505 | 1,420 | 1,331 | 1,238 | 1,139 | 1,036 | 927 | 813 | 694 | 568 | 436 |
| Loan -- Year 2010 | | | | | | | 1,289 | 1,250 | 1,209 | 1,166 | 1,121 | 1,073 | 1,023 | 971 | 916 | 859 | 798 | 735 | 668 | 598 | 525 |
| Loan -- Year 2015 | | | | | | | | | | | | 682 | 662 | 640 | 617 | 593 | 568 | 542 | 514 | 485 | 455 |
| Total | | 1,542 | 1,496 | 3,444 | 3,332 | 3,215 | 4,380 | 4,211 | 4,035 | 3,849 | 3,654 | 4,132 | 3,896 | 3,649 | 3,389 | 3,116 | 2,830 | 2,529 | 2,213 | 1,882 | 1,534 |
| **Conventional loan principal** | | | | | | | | | | | | | | | | | | | | | |
| Loan -- Year 2005 | | 933 | 979 | 1,028 | 1,080 | 1,134 | 1,190 | 1,250 | 1,313 | 1,378 | 1,447 | 1,519 | 1,595 | 1,675 | 1,759 | 1,847 | 1,939 | 2,036 | 2,138 | 2,245 | 2,357 |
| Loan -- Year 2007 | | | | 1,208 | 1,268 | 1,332 | 1,398 | 1,468 | 1,542 | 1,619 | 1,700 | 1,785 | 1,874 | 1,968 | 2,066 | 2,170 | 2,278 | 2,392 | 2,511 | 2,637 | 2,769 |
| Loan -- Year 2010 | | | | | | | 779 | 818 | 859 | 902 | 947 | 995 | 1,044 | 1,097 | 1,151 | 1,209 | 1,270 | 1,333 | 1,400 | 1,470 | 1,543 |
| Loan -- Year 2015 | | | | | | | | | | | | 413 | 433 | 455 | 478 | 502 | 527 | 553 | 581 | 610 | 640 |
| Total | | 933 | 979 | 2,236 | 2,348 | 2,466 | 3,368 | 3,537 | 3,714 | 3,899 | 4,094 | 4,712 | 4,947 | 5,195 | 5,454 | 5,727 | 6,013 | 6,314 | 6,630 | 6,961 | 7,309 |
| **Principal at year end** | | | | | | | | | | | | | | | | | | | | | |
| Loan -- Year 2005 | | 29,910 | 28,931 | 27,903 | 26,823 | 25,689 | 24,499 | 23,249 | 21,936 | 20,558 | 19,111 | 17,591 | 15,996 | 14,321 | 12,562 | 10,715 | 8,776 | 6,740 | 4,602 | 2,357 | 0 |
| Loan -- Year 2007 | | | | 38,738 | 37,469 | 36,137 | 34,739 | 33,271 | 31,729 | 30,110 | 28,410 | 26,625 | 24,751 | 22,783 | 20,717 | 18,547 | 16,269 | 13,878 | 11,366 | 8,729 | 5,960 |
| Loan -- Year 2010 | | | | | | | 24,991 | 24,173 | 23,314 | 22,411 | 21,464 | 20,469 | 19,425 | 18,328 | 17,177 | 15,968 | 14,698 | 13,365 | 11,966 | 10,496 | 8,953 |
| Loan -- Year 2015 | | | | | | | | | | | | 13,233 | 12,800 | 12,345 | 11,867 | 11,366 | 10,839 | 10,286 | 9,705 | 9,095 | 8,455 |
| Total | | 29,910 | 28,931 | 66,641 | 64,292 | 61,827 | 84,229 | 80,692 | 76,978 | 73,079 | 68,985 | 77,919 | 72,972 | 67,777 | 62,323 | 56,596 | 50,583 | 44,268 | 37,639 | 30,677 | 23,368 |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Subsidized loan (P&I)** | | | | | | | | | | | | | | | | | | | | |
| Loan -- Year 2005 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Loan -- Year 2007 | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Loan -- Year 2010 | | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Loan -- Year 2015 | | | | | | | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | | | | | | | | | | | | | | | | 0 | 0 | 0 | 0 | 0 |
| Total | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Subsidized loan interest** | | | | | | | | | | | | | | | | | | | | |
| Loan -- Year 2005 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Loan -- Year 2007 | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Loan -- Year 2010 | | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Loan -- Year 2015 | | | | | | | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Subsidized loan principal** | | | | | | | | | | | | | | | | | | | | |
| Loan -- Year 2005 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Loan -- Year 2007 | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Loan -- Year 2010 | | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Loan -- Year 2015 | | | | | | | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Principal at year end** | | | | | | | | | | | | | | | | | | | | |
| Loan -- Year 2005 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Loan -- Year 2007 | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Loan -- Year 2010 | | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Loan -- Year 2015 | | | | | | | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Combined debt** | | | | | | | | | | | | | | | | | | | | |
| Combined interest | | | | | | | | | | | | | | | | | | | | |
| Conventional loan | 1,542 | 1,496 | 3,444 | 3,332 | 3,215 | 4,380 | 4,211 | 4,035 | 3,849 | 3,654 | 4,132 | 3,896 | 3,649 | 3,389 | 3,116 | 2,830 | 2,529 | 2,213 | 1,882 | 1,534 |
| Subsidized loan | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total interest | 1,542 | 1,496 | 3,444 | 3,332 | 3,215 | 4,380 | 4,211 | 4,035 | 3,849 | 3,654 | 4,132 | 3,896 | 3,649 | 3,389 | 3,116 | 2,830 | 2,529 | 2,213 | 1,882 | 1,534 |
| Combined principal | | | | | | | | | | | | | | | | | | | | |
| Conventional loan | 933 | 979 | 2,236 | 2,348 | 2,466 | 3,368 | 3,537 | 3,714 | 3,899 | 4,094 | 4,712 | 4,947 | 5,195 | 5,454 | 5,727 | 6,013 | 6,314 | 6,630 | 6,961 | 7,309 |
| Subsidized loan | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Principal | 933 | 979 | 2,236 | 2,348 | 2,466 | 3,368 | 3,537 | 3,714 | 3,899 | 4,094 | 4,712 | 4,947 | 5,195 | 5,454 | 5,727 | 6,013 | 6,314 | 6,630 | 6,961 | 7,309 |
| Total interest and principal | 2,475 | 2,475 | 5,680 | 5,680 | 5,680 | 7,748 | 7,748 | 7,748 | 7,748 | 7,748 | 8,843 | 8,843 | 8,843 | 8,843 | 8,843 | 8,843 | 8,843 | 8,843 | 8,843 | 8,843 |
| Combined remaining principal | | | | | | | | | | | | | | | | | | | | |
| Conventional loan | 29,910 | 28,931 | 66,641 | 64,292 | 61,827 | 84,229 | 80,692 | 76,978 | 73,079 | 68,985 | 77,919 | 72,972 | 67,777 | 62,323 | 56,596 | 50,583 | 44,268 | 37,639 | 30,677 | 23,368 |
| Subsidized loan | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total remaining principal | 29,910 | 28,931 | 66,641 | 64,292 | 61,827 | 84,229 | 80,692 | 76,978 | 73,079 | 68,985 | 77,919 | 72,972 | 67,777 | 62,323 | 56,596 | 50,583 | 44,268 | 37,639 | 30,677 | 23,368 |

# South Lake Union and Denny Triangle    Scenario: 1

## Annual Costs (thousand 2003$)

| *Operating year beginning Sept. of year s* | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
| **Cooling** | | | | | | | | | | | | | | | | | | | | |
| Capital recovery | $ 1,633 | $ 1,633 | $ 3,891 | $ 3,891 | $ 3,891 | $ 5,414 | $ 5,414 | $ 5,414 | $ 5,414 | $ 5,414 | $ 6,243 | $ 6,243 | $ 6,243 | $ 6,243 | $ 6,243 | $ 6,243 | $ 6,243 | $ 6,243 | $ 6,243 | $ 6,243 |
| Purchased electricity | $ 40 | $ 132 | $ 225 | $ 373 | $ 502 | $ 604 | $ 663 | $ 714 | $ 758 | $ 795 | $ 841 | $ 887 | $ 934 | $ 980 | $ 1,026 | $ 1,026 | $ 1,026 | $ 1,026 | $ 1,026 | $ 1,026 |
| CHP heat | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Water, chemicals and supplies | $ 8 | $ 27 | $ 45 | $ 75 | $ 101 | $ 122 | $ 133 | $ 144 | $ 153 | $ 160 | $ 169 | $ 179 | $ 188 | $ 197 | $ 206 | $ 206 | $ 206 | $ 206 | $ 206 | $ 206 |
| Plant maintenance | $ 75 | $ 75 | $ 263 | $ 263 | $ 263 | $ 409 | $ 409 | $ 409 | $ 409 | $ 409 | $ 518 | $ 518 | $ 518 | $ 518 | $ 518 | $ 518 | $ 518 | $ 518 | $ 518 | $ 518 |
| Transmission and distribution maintenance | $ 71 | $ 71 | $ 179 | $ 179 | $ 179 | $ 222 | $ 222 | $ 222 | $ 222 | $ 222 | $ 238 | $ 238 | $ 238 | $ 238 | $ 238 | $ 238 | $ 238 | $ 238 | $ 238 | $ 238 |
| Personnel | $ 410 | $ 410 | $ 745 | $ 745 | $ 745 | $ 1,005 | $ 1,005 | $ 1,005 | $ 1,005 | $ 1,005 | $ 1,265 | $ 1,265 | $ 1,265 | $ 1,265 | $ 1,265 | $ 1,265 | $ 1,265 | $ 1,265 | $ 1,265 | $ 1,265 |
| Carbon mitigation | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Depreciation | $ 635 | $ 635 | $ 1,458 | $ 1,458 | $ 1,458 | $ 2,169 | $ 2,169 | $ 2,169 | $ 2,169 | $ 2,169 | $ 2,564 | $ 2,564 | $ 2,564 | $ 2,564 | $ 2,564 | $ 2,564 | $ 2,564 | $ 2,564 | $ 2,564 | $ 2,564 |
| Total | $ 2,871 | $ 2,982 | $ 6,806 | $ 6,984 | $ 7,139 | $ 9,944 | $ 10,014 | $ 10,076 | $ 10,129 | $ 10,173 | $ 11,837 | $ 11,893 | $ 11,948 | $ 12,004 | $ 12,059 | $ 12,059 | $ 12,059 | $ 12,059 | $ 12,059 | $ 12,059 |
| Subtotal cash costs | $ 2,236 | $ 2,348 | $ 5,347 | $ 5,525 | $ 5,681 | $ 7,775 | $ 7,846 | $ 7,907 | $ 7,960 | $ 8,004 | $ 9,273 | $ 9,329 | $ 9,385 | $ 9,440 | $ 9,496 | $ 9,496 | $ 9,496 | $ 9,496 | $ 9,496 | $ 9,496 |
| Fixed | $ 2,824 | $ 2,824 | $ 6,536 | $ 6,536 | $ 6,536 | $ 9,218 | $ 9,218 | $ 9,218 | $ 9,218 | $ 9,218 | $ 10,827 | $ 10,827 | $ 10,827 | $ 10,827 | $ 10,827 | $ 10,827 | $ 10,827 | $ 10,827 | $ 10,827 | $ 10,827 |
| Variable | $ 48 | $ 159 | $ 270 | $ 448 | $ 603 | $ 726 | $ 796 | $ 858 | $ 911 | $ 954 | $ 1,010 | $ 1,066 | $ 1,121 | $ 1,177 | $ 1,233 | $ 1,233 | $ 1,233 | $ 1,233 | $ 1,233 | $ 1,233 |
| Total | $ 2,871 | $ 2,982 | $ 6,806 | $ 6,984 | $ 7,139 | $ 9,944 | $ 10,014 | $ 10,076 | $ 10,129 | $ 10,173 | $ 11,837 | $ 11,893 | $ 11,948 | $ 12,004 | $ 12,059 | $ 12,059 | $ 12,059 | $ 12,059 | $ 12,059 | $ 12,059 |
| **Heating** | | | | | | | | | | | | | | | | | | | | |
| Capital recovery | $ 842 | $ 842 | $ 1,789 | $ 1,789 | $ 1,789 | $ 2,335 | $ 2,335 | $ 2,335 | $ 2,335 | $ 2,335 | $ 2,600 | $ 2,600 | $ 2,600 | $ 2,600 | $ 2,600 | $ 2,600 | $ 2,600 | $ 2,600 | $ 2,600 | $ 2,600 |
| Natural gas | $ 93 | $ 308 | $ 561 | $ 966 | $ 1,320 | $ 1,557 | $ 1,692 | $ 1,810 | $ 1,912 | $ 1,996 | $ 2,109 | $ 2,222 | $ 2,335 | $ 2,449 | $ 2,562 | $ 2,562 | $ 2,562 | $ 2,562 | $ 2,562 | $ 2,562 |
| CHP heat | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Purchased electricity | $ 1 | $ 4 | $ 8 | $ 15 | $ 20 | $ 28 | $ 31 | $ 33 | $ 35 | $ 36 | $ 46 | $ 48 | $ 50 | $ 53 | $ 55 | $ 55 | $ 55 | $ 55 | $ 55 | $ 55 |
| Plant maintenance | $ 36 | $ 36 | $ 126 | $ 126 | $ 126 | $ 180 | $ 180 | $ 180 | $ 180 | $ 180 | $ 225 | $ 225 | $ 225 | $ 225 | $ 225 | $ 225 | $ 225 | $ 225 | $ 225 | $ 225 |
| Distribution maintenance | $ 47 | $ 47 | $ 122 | $ 122 | $ 122 | $ 153 | $ 153 | $ 153 | $ 153 | $ 153 | $ 164 | $ 164 | $ 164 | $ 164 | $ 164 | $ 164 | $ 164 | $ 164 | $ 164 | $ 164 |
| Personnel | $ 410 | $ 410 | $ 745 | $ 745 | $ 745 | $ 1,005 | $ 1,005 | $ 1,005 | $ 1,005 | $ 1,005 | $ 1,265 | $ 1,265 | $ 1,265 | $ 1,265 | $ 1,265 | $ 1,265 | $ 1,265 | $ 1,265 | $ 1,265 | $ 1,265 |
| Carbon mitigation | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Depreciation | $ 327 | $ 327 | $ 671 | $ 671 | $ 671 | $ 935 | $ 935 | $ 935 | $ 935 | $ 935 | $ 1,068 | $ 1,068 | $ 1,068 | $ 1,068 | $ 1,068 | $ 1,068 | $ 1,068 | $ 1,068 | $ 1,068 | $ 1,068 |
| Total | $ 1,756 | $ 1,975 | $ 4,023 | $ 4,434 | $ 4,793 | $ 6,193 | $ 6,331 | $ 6,451 | $ 6,554 | $ 6,640 | $ 7,477 | $ 7,593 | $ 7,708 | $ 7,824 | $ 7,939 | $ 7,939 | $ 7,939 | $ 7,939 | $ 7,939 | $ 7,939 |
| Subtotal cash costs | $ 1,429 | $ 1,648 | $ 3,352 | $ 3,763 | $ 4,122 | $ 5,258 | $ 5,395 | $ 5,516 | $ 5,619 | $ 5,705 | $ 6,409 | $ 6,525 | $ 6,640 | $ 6,756 | $ 6,871 | $ 6,871 | $ 6,871 | $ 6,871 | $ 6,871 | $ 6,871 |
| Fixed | $ 1,662 | $ 1,662 | $ 3,453 | $ 3,453 | $ 3,453 | $ 4,608 | $ 4,608 | $ 4,608 | $ 4,608 | $ 4,608 | $ 5,322 | $ 5,322 | $ 5,322 | $ 5,322 | $ 5,322 | $ 5,322 | $ 5,322 | $ 5,322 | $ 5,322 | $ 5,322 |
| Variable | $ 94 | $ 313 | $ 570 | $ 981 | $ 1,340 | $ 1,585 | $ 1,723 | $ 1,843 | $ 1,946 | $ 2,033 | $ 2,155 | $ 2,270 | $ 2,386 | $ 2,501 | $ 2,617 | $ 2,617 | $ 2,617 | $ 2,617 | $ 2,617 | $ 2,617 |
| Total | $ 1,756 | $ 1,975 | $ 4,023 | $ 4,434 | $ 4,793 | $ 6,193 | $ 6,331 | $ 6,451 | $ 6,554 | $ 6,640 | $ 7,477 | $ 7,593 | $ 7,708 | $ 7,824 | $ 7,939 | $ 7,939 | $ 7,939 | $ 7,939 | $ 7,939 | $ 7,939 |
| **Total annual costs** | | | | | | | | | | | | | | | | | | | | |
| Capital recovery | $ 2,475 | $ 2,475 | $ 5,680 | $ 5,680 | $ 5,680 | $ 7,748 | $ 7,748 | $ 7,748 | $ 7,748 | $ 7,748 | $ 8,843 | $ 8,843 | $ 8,843 | $ 8,843 | $ 8,843 | $ 8,843 | $ 8,843 | $ 8,843 | $ 8,843 | $ 8,843 |
| Natural gas | $ 93 | $ 308 | $ 561 | $ 966 | $ 1,320 | $ 1,557 | $ 1,692 | $ 1,810 | $ 1,912 | $ 1,996 | $ 2,109 | $ 2,222 | $ 2,335 | $ 2,449 | $ 2,562 | $ 2,562 | $ 2,562 | $ 2,562 | $ 2,562 | $ 2,562 |
| Purchased electricity | $ 41 | $ 137 | $ 233 | $ 387 | $ 522 | $ 633 | $ 694 | $ 747 | $ 793 | $ 831 | $ 887 | $ 935 | $ 984 | $ 1,033 | $ 1,082 | $ 1,082 | $ 1,082 | $ 1,082 | $ 1,082 | $ 1,082 |
| Water, chemicals and supplies | $ 8 | $ 27 | $ 45 | $ 75 | $ 101 | $ 122 | $ 133 | $ 144 | $ 153 | $ 160 | $ 169 | $ 179 | $ 188 | $ 197 | $ 206 | $ 206 | $ 206 | $ 206 | $ 206 | $ 206 |
| Plant maintenance | $ 111 | $ 111 | $ 389 | $ 389 | $ 389 | $ 589 | $ 589 | $ 589 | $ 589 | $ 589 | $ 743 | $ 743 | $ 743 | $ 743 | $ 743 | $ 743 | $ 743 | $ 743 | $ 743 | $ 743 |
| Distribution maintenance | $ 118 | $ 118 | $ 301 | $ 301 | $ 301 | $ 375 | $ 375 | $ 375 | $ 375 | $ 375 | $ 402 | $ 402 | $ 402 | $ 402 | $ 402 | $ 402 | $ 402 | $ 402 | $ 402 | $ 402 |
| Personnel | $ 820 | $ 820 | $ 1,490 | $ 1,490 | $ 1,490 | $ 2,010 | $ 2,010 | $ 2,010 | $ 2,010 | $ 2,010 | $ 2,530 | $ 2,530 | $ 2,530 | $ 2,530 | $ 2,530 | $ 2,530 | $ 2,530 | $ 2,530 | $ 2,530 | $ 2,530 |
| Carbon mitigation | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Electricity sales | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Depreciation | $ 962 | $ 962 | $ 2,129 | $ 2,129 | $ 2,129 | $ 3,104 | $ 3,104 | $ 3,104 | $ 3,104 | $ 3,104 | $ 3,631 | $ 3,631 | $ 3,631 | $ 3,631 | $ 3,631 | $ 3,631 | $ 3,631 | $ 3,631 | $ 3,631 | $ 3,631 |
| Total | $ 4,627 | $ 4,957 | $ 10,829 | $ 11,417 | $ 11,932 | $ 16,137 | $ 16,345 | $ 16,527 | $ 16,683 | $ 16,813 | $ 19,314 | $ 19,485 | $ 19,656 | $ 19,828 | $ 19,999 | $ 19,999 | $ 19,999 | $ 19,999 | $ 19,999 | $ 19,999 |

# South Lake Union and Denny Triangle

## Scenario: 1

## Rates and Revenues

| | Phase 1 | Phase 1 | Phase 2 | Phase 2 | Phase 2 | Phase 3 | Phase 3 | Phase 3 | Phase 3 | Phase 3 | Phase 4 | Phase 4 | Phase 4 | Phase 4 | Phase 4 | Phase 4 | Phase 4 | Phase 4 | Phase 4 | Phase 4 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ***Operating year beginning Sept. of year shown*** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** |
| | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** |
| **Heating** | Fixed rate escalator | | 1% | | | | | | | | | | | | | | | | | |
| *Capacity Rate* | | | | | | | | | | | | | | | | | | | | |
| Heating fixed cash operating costs (thousand 2003 $) | $ 493 | $ 493 | $ 993 | $ 993 | $ 993 | $ 1,338 | $ 1,338 | $ 1,338 | $ 1,338 | $ 1,338 | $ 1,654 | $ 1,654 | $ 1,654 | $ 1,654 | $ 1,654 | $ 1,654 | $ 1,654 | $ 1,654 | $ 1,654 | $ 1,654 |
| Heating debt service (thousand 2003 $) | $ 842 | $ 842 | $ 1,789 | $ 1,789 | $ 1,789 | $ 2,335 | $ 2,335 | $ 2,335 | $ 2,335 | $ 2,335 | $ 2,600 | $ 2,600 | $ 2,600 | $ 2,600 | $ 2,600 | $ 2,600 | $ 2,600 | $ 2,600 | $ 2,600 | $ 2,600 |
| Depreciation (thousand 2003 $) | $ - | $ - | $ - | $ - | $ 67 | $ 140 | $ 187 | $ 234 | $ 281 | $ 327 | $ 427 | $ 481 | $ 534 | $ 534 | $ 534 | $ 534 | $ 534 | $ 534 | $ 534 | $ 534 |
| Net flow into (out of) operating reserve (thousand 2003 $) | $ (1,137) | $ (668) | $ (1,595) | $ (753) | $ 1 | $ (339) | $ (4) | $ 299 | $ 570 | $ 806 | $ 528 | $ 838 | $ 1,153 | $ 1,474 | $ 1,801 | $ 1,862 | $ 1,923 | $ 1,985 | $ 2,047 | $ 2,110 |
| Basis for fixed rate (thousand 2003 $) | $ 198 | $ 667 | $ 1,187 | $ 2,029 | $ 2,851 | $ 3,474 | $ 3,856 | $ 4,206 | $ 4,523 | $ 4,806 | $ 5,210 | $ 5,573 | $ 5,942 | $ 6,263 | $ 6,590 | $ 6,650 | $ 6,712 | $ 6,773 | $ 6,836 | $ 6,899 |
| Total customer peak annual heating demand (MMBtu/hour) | 8.8 | 29.4 | 51.8 | 87.7 | 119.1 | 141.3 | 153.9 | 165.0 | 174.5 | 182.4 | 192.9 | 203.3 | 213.8 | 224.2 | 234.7 | 234.7 | 234.7 | 234.7 | 234.7 | 234.7 |
| Heating capacity rate ($ per MMBtu/hour per month) | $ 1,871 | $ 1,890 | $ 1,908 | $ 1,928 | $ 1,994 | | | | | | | | | | | | | | | |
| Heating capacity rate ($ per MMBtu/hour per month) | $ 1,871 | $ 1,890 | $ 1,908 | $ 1,928 | $ 1,947 | $ 1,966 | $ 1,986 | $ 2,006 | $ 2,026 | $ 2,046 | $ 2,067 | $ 2,087 | $ 2,108 | $ 2,129 | $ 2,150 | $ 2,172 | $ 2,194 | $ 2,216 | $ 2,238 | $ 2,260 |
| *Energy Rate* | | | | | | | | | | | | | | | | | | | | |
| Heating variable costs (thousand 2003 $) | $ 94 | $ 313 | $ 570 | $ 981 | $ 1,340 | $ 1,585 | $ 1,723 | $ 1,843 | $ 1,946 | $ 2,033 | $ 2,155 | $ 2,270 | $ 2,386 | $ 2,501 | $ 2,617 | $ 2,617 | $ 2,617 | $ 2,617 | $ 2,617 | $ 2,617 |
| Total annual heating energy sales (MMBtu) | 15,829 | 52,762 | 96,040 | 165,284 | 225,873 | 266,368 | 289,507 | 309,754 | 327,109 | 341,571 | 360,918 | 380,264 | 399,611 | 418,958 | 438,304 | 438,304 | 438,304 | 438,304 | 438,304 | 438,304 |
| Heating energy rate ($ per MMBtu) | $ 5.93 | $ 5.93 | $ 5.93 | $ 5.93 | $ 5.93 | $ 5.95 | $ 5.95 | $ 5.95 | $ 5.95 | $ 5.95 | $ 5.97 | $ 5.97 | $ 5.97 | $ 5.97 | $ 5.97 | $ 5.97 | $ 5.97 | $ 5.97 | $ 5.97 | $ 5.97 |
| Total heating revenue (thousand 2003 $) | $ 292 | $ 979 | $ 1,757 | $ 3,010 | $ 4,191 | $ 5,059 | $ 5,579 | $ 6,049 | $ 6,469 | $ 6,839 | $ 7,365 | $ 7,844 | $ 8,328 | $ 8,764 | $ 9,207 | $ 9,267 | $ 9,329 | $ 9,390 | $ 9,453 | $ 9,516 |
| Comparison with annual heating costs | $ 1,756 | $ 1,975 | $ 4,023 | $ 4,434 | $ 4,793 | $ 6,193 | $ 6,331 | $ 6,451 | $ 6,554 | $ 6,640 | $ 7,477 | $ 7,593 | $ 7,708 | $ 7,824 | $ 7,939 | $ 7,939 | $ 7,939 | $ 7,939 | $ 7,939 | $ 7,939 |
| Average unit cost ($/MMBtu) | $ 18.44 | $ 18.56 | $ 18.29 | $ 18.21 | $ 18.26 | $ 18.47 | $ 18.62 | $ 18.77 | $ 18.92 | $ 19.06 | $ 19.22 | $ 19.36 | $ 19.50 | $ 19.65 | $ 19.79 | $ 19.79 | $ 19.79 | $ 19.79 | $ 19.79 | $ 19.79 |
| | $ 18.19 | $ 18.19 | $ 18.19 | $ 18.19 | $ 18.19 | $ 18.19 | $ 18.19 | $ 18.19 | $ 18.19 | $ 18.19 | $ 18.19 | $ 18.19 | $ 18.19 | $ 18.19 | $ 18.19 | $ 18.19 | $ 18.19 | $ 18.19 | $ 18.19 | $ 18.19 |
| **Cooling** | Fixed rate escalator | | 1% | | | | | | | | | | | | | | | | | |
| *Capacity Rate* | | | | | | | | | | | | | | | | | | | | |
| Cooling fixed cash operating costs (thousand 2003 $) | $ 556 | $ 556 | $ 1,186 | $ 1,186 | $ 1,186 | $ 1,636 | $ 1,636 | $ 1,636 | $ 1,636 | $ 1,636 | $ 2,021 | $ 2,021 | $ 2,021 | $ 2,021 | $ 2,021 | $ 2,021 | $ 2,021 | $ 2,021 | $ 2,021 | $ 2,021 |
| Cooling debt service (thousand 2003 $) | $ 1,633 | $ 1,633 | $ 3,891 | $ 3,891 | $ 3,891 | $ 5,414 | $ 5,414 | $ 5,414 | $ 5,414 | $ 5,414 | $ 6,243 | $ 6,243 | $ 6,243 | $ 6,243 | $ 6,243 | $ 6,243 | $ 6,243 | $ 6,243 | $ 6,243 | $ 6,243 |
| Depreciation (thousand 2003 $) | $ - | $ - | $ - | $ - | $ 146 | $ 325 | $ 434 | $ 542 | $ 651 | $ 759 | $ 1,025 | $ 1,154 | $ 1,282 | $ 1,282 | $ 1,282 | $ 1,282 | $ 1,282 | $ 1,282 | $ 1,282 | $ 1,282 |
| Net flow into (out of) operating reserve (thousand 2003 $) | $ (1,755) | $ (728) | $ (2,519) | $ (745) | $ 844 | $ 128 | $ 891 | $ 1,580 | $ 2,195 | $ 2,732 | $ 2,194 | $ 2,882 | $ 3,584 | $ 4,298 | $ 5,025 | $ 5,158 | $ 5,292 | $ 5,428 | $ 5,565 | $ 5,703 |
| Basis for fixed rate (thousand 2003 $) | $ 434 | $ 1,461 | $ 2,558 | $ 4,333 | $ 6,068 | $ 7,503 | $ 8,373 | $ 9,171 | $ 9,894 | $ 10,540 | $ 11,482 | $ 12,299 | $ 13,129 | $ 13,843 | $ 14,570 | $ 14,703 | $ 14,837 | $ 14,973 | $ 15,110 | $ 15,248 |
| Total customer peak cooling demand (tons) | 1,295 | 4,317 | 7,482 | 12,547 | 16,979 | 20,375 | 22,316 | 24,014 | 25,469 | 26,682 | 28,244 | 29,806 | 31,368 | 32,929 | 34,491 | 34,491 | 34,491 | 34,491 | 34,491 | 34,491 |
| Cooling capacity rate ($ per ton per month) | $ 27.93 | $ 28.21 | $ 28.49 | $ 28.78 | $ 29.07 | $ 29.36 | $ 29.65 | $ 29.95 | $ 30.25 | $ 30.55 | $ 30.85 | $ 31.16 | $ 31.47 | $ 31.79 | $ 32.11 | $ 32.43 | $ 32.75 | $ 33.08 | $ 33.41 | $ 33.74 |
| *Energy Rate* | | | | | | | | | | | | | | | | | | | | |
| Cooling variable costs (thousand 2003 $) | $ 48 | $ 159 | $ 270 | $ 448 | $ 603 | $ 726 | $ 796 | $ 858 | $ 911 | $ 954 | $ 1,010 | $ 1,066 | $ 1,121 | $ 1,177 | $ 1,233 | $ 1,233 | $ 1,233 | $ 1,233 | $ 1,233 | $ 1,233 |
| Total annual cooling energy sales (1000 ton-hours) | 1,276 | 4,252 | 7,229 | 11,993 | 16,161 | 19,457 | 21,341 | 22,989 | 24,402 | 25,579 | 27,070 | 28,561 | 30,052 | 31,542 | 33,033 | 33,033 | 33,033 | 33,033 | 33,033 | 33,033 |
| Cooling energy rate ($ per ton-hour) | $ 0.037 | $ 0.037 | $ 0.037 | $ 0.037 | $ 0.037 | $ 0.037 | $ 0.037 | $ 0.037 | $ 0.037 | $ 0.037 | $ 0.037 | $ 0.037 | $ 0.037 | $ 0.037 | $ 0.037 | $ 0.037 | $ 0.037 | $ 0.037 | $ 0.037 | $ 0.037 |
| Total cooling revenue (thousand 2003 $) | $ 482 | $ 1,620 | $ 2,828 | $ 4,780 | $ 6,671 | $ 8,229 | $ 9,170 | $ 10,029 | $ 10,805 | $ 11,494 | $ 12,492 | $ 13,365 | $ 14,250 | $ 15,020 | $ 15,803 | $ 15,936 | $ 16,070 | $ 16,206 | $ 16,342 | $ 16,481 |
| Comparison with annual cooling costs | $ 2,871 | $ 2,982 | $ 6,806 | $ 6,984 | $ 7,139 | $ 9,944 | $ 10,014 | $ 10,076 | $ 10,129 | $ 10,173 | $ 11,837 | $ 11,893 | $ 11,948 | $ 12,004 | $ 12,059 | $ 12,059 | $ 12,059 | $ 12,059 | $ 12,059 | $ 12,059 |
| Average unit cost ($/ton-hour) | $ 0.38 | $ 0.38 | $ 0.39 | $ 0.40 | $ 0.40 | $ 0.41 | $ 0.41 | $ 0.41 | $ 0.42 | $ 0.42 | $ 0.42 | $ 0.43 | $ 0.43 | $ 0.44 | $ 0.44 | $ 0.44 | $ 0.44 | $ 0.44 | $ 0.44 | $ 0.44 |
| Franchise fee | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 0.00% | | | | | | | | | | | | | | | | | | | | |
| Total revenue (thousand 2003 $) | $ 774 | $ 2,599 | $ 4,585 | $ 7,790 | $ 10,861 | $ 13,288 | $ 14,748 | $ 16,078 | $ 17,275 | $ 18,333 | $ 19,858 | $ 21,208 | $ 22,578 | $ 23,784 | $ 25,010 | $ 25,203 | $ 25,399 | $ 25,596 | $ 25,795 | $ 25,997 |

# South Lake Union and Denny Triangle

**Scenario: 1**

## Depreciation

| | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ***Operating year beginning Sept. of year shown*** | | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** |
| ***Year investment made*** | | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** |
| | | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** |
| **Depreciation periods (years)** | | | | | | | | | | | | | | | | | | | | | |
| Plant | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Piping | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 |
| Building connection | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 |
| **Capital Cost to be Depreciated (1000 $US)** | | | | | | | | | | | | | | | | | | | | | |
| Plant | | $14,382 | $ - | $ 14,485 | $ - | $ - | $15,264 | $ - | $ - | $ - | $ - | $ 8,216 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Piping | | $ 8,089 | $ - | $ 12,833 | $ - | $ - | $ 4,865 | $ - | $ - | $ - | $ - | $ 1,719 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Building connection | | $ 1,226 | $ - | $ 3,652 | $ - | $ - | $ 2,710 | $ - | $ - | $ - | $ - | $ 2,203 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Total | | $23,697 | $ - | $ 30,970 | $ - | $ - | $22,840 | $ - | $ - | $ - | $ - | $ 12,139 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Annual Depreciation (1000 $US)** | | | | | | | | | | | | | | | | | | | | | |
| **PLANT** | | | | | | | | | | | | | | | | | | | | | |
| **Depreciation of 2005 Investment** | | | | | | | | | | | | | | | | | | | | | |
| Beginning Book Value | | 14,382 | 13,663 | 12,944 | 12,225 | 11,505 | 10,786 | 10,067 | 9,348 | 8,629 | 7,910 | 7,191 | 6,472 | 5,753 | 5,034 | 4,315 | 3,595 | 2,876 | 2,157 | 1,438 | 719 |
| Depreciation year | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
| Depreciation | | 719 | 719 | 719 | 719 | 719 | 719 | 719 | 719 | 719 | 719 | 719 | 719 | 719 | 719 | 719 | 719 | 719 | 719 | 719 | 719 |
| Ending Book Value | | 13,663 | 12,944 | 12,225 | 11,505 | 10,786 | 10,067 | 9,348 | 8,629 | 7,910 | 7,191 | 6,472 | 5,753 | 5,034 | 4,315 | 3,595 | 2,876 | 2,157 | 1,438 | 719 | 0 |
| **Depreciation of 2007 Investment** | | | | | | | | | | | | | | | | | | | | | |
| Beginning Book Value | | | | 14,485 | 13,761 | 13,036 | 12,312 | 11,588 | 10,864 | 10,139 | 9,415 | 8,691 | 7,967 | 7,242 | 6,518 | 5,794 | 5,070 | 4,345 | 3,621 | 2,897 | 2,173 |
| Depreciation year | | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 |
| Depreciation | | | | 724 | 724 | 724 | 724 | 724 | 724 | 724 | 724 | 724 | 724 | 724 | 724 | 724 | 724 | 724 | 724 | 724 | 724 |
| Ending Book Value | | | | 13,761 | 13,036 | 12,312 | 11,588 | 10,864 | 10,139 | 9,415 | 8,691 | 7,967 | 7,242 | 6,518 | 5,794 | 5,070 | 4,345 | 3,621 | 2,897 | 2,173 | 1,448 |
| **Depreciation of 2010 Investment** | | | | | | | | | | | | | | | | | | | | | |
| Beginning Book Value | | | | | | | 15,264 | 14,501 | 13,738 | 12,975 | 12,211 | 11,448 | 10,685 | 9,922 | 9,159 | 8,395 | 7,632 | 6,869 | 6,106 | 5,342 | 4,579 |
| Depreciation year | | | | | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 |
| Depreciation | | | | | | | 763 | 763 | 763 | 763 | 763 | 763 | 763 | 763 | 763 | 763 | 763 | 763 | 763 | 763 | 763 |
| Ending Book Value | | | | | | | 14,501 | 13,738 | 12,975 | 12,211 | 11,448 | 10,685 | 9,922 | 9,159 | 8,395 | 7,632 | 6,869 | 6,106 | 5,342 | 4,579 | 3,816 |
| **Depreciation of 2015 Investment** | | | | | | | | | | | | | | | | | | | | | |
| Beginning Book Value | | | | | | | | | | | | 8,216 | 7,806 | 7,395 | 6,984 | 6,573 | 6,162 | 5,752 | 5,341 | 4,930 | 4,519 |
| Depreciation year | | | | | | | | | | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| Depreciation | | | | | | | | | | | | 411 | 411 | 411 | 411 | 411 | 411 | 411 | 411 | 411 | 411 |
| Ending Book Value | | | | | | | | | | | | 7,806 | 7,395 | 6,984 | 6,573 | 6,162 | 5,752 | 5,341 | 4,930 | 4,519 | 4,108 |
| **PIPING** | | | | | | | | | | | | | | | | | | | | | |
| **Depreciation of 2005 Investment** | | | | | | | | | | | | | | | | | | | | | |
| Beginning Book Value | | 8,089 | 7,887 | 7,685 | 7,483 | 7,281 | 7,078 | 6,876 | 6,674 | 6,472 | 6,269 | 6,067 | 5,865 | 5,663 | 5,460 | 5,258 | 5,056 | 4,854 | 4,651 | 4,449 | 4,247 |
| Depreciation year | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
| Depreciation | | 202 | 202 | 202 | 202 | 202 | 202 | 202 | 202 | 202 | 202 | 202 | 202 | 202 | 202 | 202 | 202 | 202 | 202 | 202 | 202 |
| Ending Book Value | | 7,887 | 7,685 | 7,483 | 7,281 | 7,078 | 6,876 | 6,674 | 6,472 | 6,269 | 6,067 | 5,865 | 5,663 | 5,460 | 5,258 | 5,056 | 4,854 | 4,651 | 4,449 | 4,247 | 4,045 |
| **Depreciation of 2007 Investment** | | | | | | | | | | | | | | | | | | | | | |
| Beginning Book Value | | | | 12,833 | 12,512 | 12,192 | 11,871 | 11,550 | 11,229 | 10,908 | 10,587 | 10,267 | 9,946 | 9,625 | 9,304 | 8,983 | 8,662 | 8,342 | 8,021 | 7,700 | 7,379 |
| Depreciation year | | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 |
| Depreciation | | | | 321 | 321 | 321 | 321 | 321 | 321 | 321 | 321 | 321 | 321 | 321 | 321 | 321 | 321 | 321 | 321 | 321 | 321 |
| Ending Book Value | | | | 12,512 | 12,192 | 11,871 | 11,550 | 11,229 | 10,908 | 10,587 | 10,267 | 9,946 | 9,625 | 9,304 | 8,983 | 8,662 | 8,342 | 8,021 | 7,700 | 7,379 | 7,058 |
| **Depreciation of 2010 Investment** | | | | | | | | | | | | | | | | | | | | | |
| Beginning Book Value | | | | | | | 4,865 | 4,743 | 4,622 | 4,500 | 4,379 | 4,257 | 4,135 | 4,014 | 3,892 | 3,770 | 3,649 | 3,527 | 3,406 | 3,284 | 3,162 |
| Depreciation year | | | | | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 |
| Depreciation | | | | | | | 122 | 122 | 122 | 122 | 122 | 122 | 122 | 122 | 122 | 122 | 122 | 122 | 122 | 122 | 122 |
| Ending Book Value | | | | | | | 4,743 | 4,622 | 4,500 | 4,379 | 4,257 | 4,135 | 4,014 | 3,892 | 3,770 | 3,649 | 3,527 | 3,406 | 3,284 | 3,162 | 3,041 |
| **Depreciation of 2015 Investment** | | | | | | | | | | | | | | | | | | | | | |
| Beginning Book Value | | | | | | | | | | | | 1,719 | 1,676 | 1,633 | 1,590 | 1,547 | 1,504 | 1,461 | 1,418 | 1,375 | 1,333 |
| Depreciation year | | | | | | | | | | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| Depreciation | | | | | | | | | | | | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 |
| Ending Book Value | | | | | | | | | | | | 1,676 | 1,633 | 1,590 | 1,547 | 1,504 | 1,461 | 1,418 | 1,375 | 1,333 | 1,290 |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **BUILDING CONNECTIONS** | | | | | | | | | | | | | | | | | | | | |
| **Depreciation of 2005 Investment** | | | | | | | | | | | | | | | | | | | | |
| Beginning Book Value | 1,226 | 1,185 | 1,144 | 1,103 | 1,062 | 1,022 | 981 | 940 | 899 | 858 | 817 | 776 | 736 | 695 | 654 | 613 | 572 | 531 | 490 | 449 |
| Depreciation year | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
| Depreciation | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 |
| Ending Book Value | 1,185 | 1,144 | 1,103 | 1,062 | 1,022 | 981 | 940 | 899 | 858 | 817 | 776 | 736 | 695 | 654 | 613 | 572 | 531 | 490 | 449 | 409 |
| **Depreciation of 2007 Investment** | | | | | | | | | | | | | | | | | | | | |
| Beginning Book Value | | | 3,652 | 3,530 | 3,408 | 3,287 | 3,165 | 3,043 | 2,921 | 2,800 | 2,678 | 2,556 | 2,435 | 2,313 | 2,191 | 2,069 | 1,948 | 1,826 | 1,704 | 1,582 |
| Depreciation year | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 |
| Depreciation | | | 122 | 122 | 122 | 122 | 122 | 122 | 122 | 122 | 122 | 122 | 122 | 122 | 122 | 122 | 122 | 122 | 122 | 122 |
| Ending Book Value | | | 3,530 | 3,408 | 3,287 | 3,165 | 3,043 | 2,921 | 2,800 | 2,678 | 2,556 | 2,435 | 2,313 | 2,191 | 2,069 | 1,948 | 1,826 | 1,704 | 1,582 | 1,461 |
| **Depreciation of 2010 Investment** | | | | | | | | | | | | | | | | | | | | |
| Beginning Book Value | | | | | | 2,710 | 2,620 | 2,530 | 2,439 | 2,349 | 2,259 | 2,168 | 2,078 | 1,988 | 1,897 | 1,807 | 1,717 | 1,626 | 1,536 | 1,446 |
| Depreciation year | | | | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 |
| Depreciation | | | | | | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 |
| Ending Book Value | | | | | | 2,620 | 2,530 | 2,439 | 2,349 | 2,259 | 2,168 | 2,078 | 1,988 | 1,897 | 1,807 | 1,717 | 1,626 | 1,536 | 1,446 | 1,355 |
| **Depreciation of 2015 Investment** | | | | | | | | | | | | | | | | | | | | |
| Beginning Book Value | | | | | | | | | | | 2,203 | 2,129 | 2,056 | 1,982 | 1,909 | 1,836 | 1,762 | 1,689 | 1,615 | 1,542 |
| Depreciation year | | | | | | | | | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| Depreciation | | | | | | | | | | | 73 | 73 | 73 | 73 | 73 | 73 | 73 | 73 | 73 | 73 |
| Ending Book Value | | | | | | | | | | | 2,129 | 2,056 | 1,982 | 1,909 | 1,836 | 1,762 | 1,689 | 1,615 | 1,542 | 1,468 |

## Total Depreciation (thousand 2003 $)

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Beginning Book Value | 23,697 | 22,735 | 52,743 | 50,614 | 48,485 | 69,195 | 66,091 | 62,987 | 59,883 | 56,779 | 65,813 | 62,182 | 58,550 | 54,919 | 51,287 | 47,656 | 44,025 | 40,393 | 36,762 | 33,130 |
| Depreciation | 962 | 962 | 2,129 | 2,129 | 2,129 | 3,104 | 3,104 | 3,104 | 3,104 | 3,104 | 3,631 | 3,631 | 3,631 | 3,631 | 3,631 | 3,631 | 3,631 | 3,631 | 3,631 | 3,631 |
| Ending Book Value | 22,735 | 21,773 | 50,614 | 48,485 | 46,356 | 66,091 | 62,987 | 59,883 | 56,779 | 53,674 | 62,182 | 58,550 | 54,919 | 51,287 | 47,656 | 44,025 | 40,393 | 36,762 | 33,130 | 29,499 |
| | | | | | | | | | | | | | | | | | | | | |
| Heating depreciation | 327 | 327 | 671 | 671 | 671 | 935 | 935 | 935 | 935 | 935 | 1,068 | 1,068 | 1,068 | 1,068 | 1,068 | 1,068 | 1,068 | 1,068 | 1,068 | 1,068 |
| Cooling depreciation | 635 | 635 | 1,458 | 1,458 | 1,458 | 2,169 | 2,169 | 2,169 | 2,169 | 2,169 | 2,564 | 2,564 | 2,564 | 2,564 | 2,564 | 2,564 | 2,564 | 2,564 | 2,564 | 2,564 |

# South Lake Union and Denny Triangle    Scenario: 1

## Net Income and Cash Flow (thousand 2003 $)

| *Operating year beginning fall of year shown* | | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
| **Net Income (1000 $US)** | | | | | | | | | | | | | | | | | | | | | |
| Revenue from sales | | 774 | 2,599 | 4,585 | 7,790 | 10,861 | 13,288 | 14,748 | 16,078 | 17,275 | 18,333 | 19,858 | 21,208 | 22,578 | 23,784 | 25,010 | 25,203 | 25,399 | 25,596 | 25,795 | 25,997 |
| Total cash O&M expenses | | (1,190) | (1,520) | (3,019) | (3,608) | (4,123) | (5,285) | (5,493) | (5,675) | (5,831) | (5,961) | (6,840) | (7,011) | (7,182) | (7,353) | (7,524) | (7,524) | (7,524) | (7,524) | (7,524) | (7,524) |
| Net operating income | | (417) | 1,079 | 1,566 | 4,183 | 6,739 | 8,003 | 9,256 | 10,404 | 11,444 | 12,373 | 13,018 | 14,198 | 15,396 | 16,431 | 17,486 | 17,679 | 17,874 | 18,072 | 18,271 | 18,472 |
| Depreciation | | (962) | (962) | (2,129) | (2,129) | (2,129) | (3,104) | (3,104) | (3,104) | (3,104) | (3,104) | (3,631) | (3,631) | (3,631) | (3,631) | (3,631) | (3,631) | (3,631) | (3,631) | (3,631) | (3,631) |
| Interest expense | - | (1,542) | (1,496) | (3,444) | (3,332) | (3,215) | (4,380) | (4,211) | (4,035) | (3,849) | (3,654) | (4,132) | (3,896) | (3,649) | (3,389) | (3,116) | (2,830) | (2,529) | (2,213) | (1,882) | (1,534) |
| Interest income | | 188 | 291 | 242 | 67 | 3 | 41 | 34 | 75 | 163 | 295 | 467 | 611 | 806 | 1,055 | 1,362 | 1,731 | 2,125 | 2,545 | 2,993 | 3,470 |
| Net income before tax | | (2,733) | (1,087) | (3,765) | (1,211) | 1,398 | 561 | 1,974 | 3,340 | 4,654 | 5,909 | 5,722 | 7,281 | 8,922 | 10,466 | 12,100 | 12,949 | 13,839 | 14,772 | 15,751 | 16,777 |
| Net income as % of sales | | -353% | -42% | -82% | -16% | 13% | 4% | 13% | 21% | 27% | 32% | 29% | 34% | 40% | 44% | 48% | 51% | 54% | 58% | 61% | 65% |
| Net income as % of operating income | | 656% | -101% | -240% | -29% | 21% | 7% | 21% | 32% | 41% | 48% | 44% | 51% | 58% | 64% | 69% | 73% | 77% | 82% | 86% | 91% |
| Tax rate (%) | | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Taxes | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Net income after tax | | (2,733) | (1,087) | (3,765) | (1,211) | 1,398 | 561 | 1,974 | 3,340 | 4,654 | 5,909 | 5,722 | 7,281 | 8,922 | 10,466 | 12,100 | 12,949 | 13,839 | 14,772 | 15,751 | 16,777 |
| **Cash Flow (1000 $US)** | | | | | | | | | | | | | | | | | | | | | |
| Total revenue including city fee | | 774 | 2,599 | 4,585 | 7,790 | 10,861 | 13,288 | 14,748 | 16,078 | 17,275 | 18,333 | 19,858 | 21,208 | 22,578 | 23,784 | 25,010 | 25,203 | 25,399 | 25,596 | 25,795 | 25,997 |
| Cash O&M expenses | | (1,190) | (1,520) | (3,019) | (3,608) | (4,123) | (5,285) | (5,493) | (5,675) | (5,831) | (5,961) | (6,840) | (7,011) | (7,182) | (7,353) | (7,524) | (7,524) | (7,524) | (7,524) | (7,524) | (7,524) |
| Franchise fee | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Net interest | | (1,354) | (1,204) | (3,202) | (3,265) | (3,211) | (4,339) | (4,178) | (3,959) | (3,686) | (3,359) | (3,664) | (3,285) | (2,843) | (2,334) | (1,754) | (1,099) | (404) | 332 | 1,111 | 1,936 |
| Taxes | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Capital expenses (principal + equity) | - | (933) | (979) | (2,236) | (2,348) | (2,466) | (3,368) | (3,537) | (3,714) | (3,899) | (4,094) | (4,712) | (4,947) | (5,195) | (5,454) | (5,727) | (6,013) | (6,314) | (6,630) | (6,961) | (7,309) |
| Net cash flow | - | (2,703) | (1,104) | (3,873) | (1,430) | 1,061 | 296 | 1,541 | 2,731 | 3,859 | 4,919 | 4,642 | 5,965 | 7,358 | 8,643 | 10,005 | 10,567 | 11,156 | 11,774 | 12,421 | 13,099 |
| Net cash flow as % of sales | | -349% | -42% | -84% | -18% | 10% | 2% | 10% | 17% | 22% | 27% | 23% | 28% | 33% | 36% | 40% | 42% | 44% | 46% | 48% | 50% |
| Accumulated cash position | | (2,703) | (3,808) | (7,680) | (9,111) | (8,049) | (7,753) | (6,212) | (3,481) | 378 | 5,297 | 9,939 | 15,904 | 23,263 | 31,906 | 41,911 | 52,477 | 63,633 | 75,407 | 87,828 | 100,927 |
| **Cash Flow with Residual Value and Residual Debt Based on Total Capital (1000 $US)** | | | | | | | | | | | | | | | | | | | | | |
| Residual value | | | | | | | | | | | | | | | | | | | | | |
| Residual debt | | | | | | | | | | | | | | | | | | | | | |
| Capital invested | (30,843) | - | (39,946) | - | - | (25,771) | - | - | - | - | (13,646) | - | - | - | - | - | - | - | - | - | - |
| Cash flow from operations | | (1,771) | (125) | (1,636) | 918 | 3,527 | 3,665 | 5,078 | 6,444 | 7,758 | 9,014 | 9,354 | 10,913 | 12,553 | 14,098 | 15,732 | 16,580 | 17,470 | 18,403 | 19,382 | 20,409 |
| Total cash flow | (30,843) | (1,771) | (40,071) | (1,636) | 918 | (22,243) | 3,665 | 5,078 | 6,444 | 7,758 | (4,632) | 9,354 | 10,913 | 12,553 | 14,098 | 15,732 | 16,580 | 17,470 | 18,403 | 19,382 | 20,409 |

**Financial Performance with Residual Value and Residual Debt Based on Total Capital**

Internal rate of return 5.00%

Net Present Value (NPV) $ 37 at discount rate of 5.00%

| | | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Net cash flow with operating reserve** | | | | | | | | | | | | | | | | | | | | | |
| Net cash flow | | (2,703) | (1,104) | (3,873) | (1,430) | 1,061 | 296 | 1,541 | 2,731 | 3,859 | 4,919 | 4,642 | 5,965 | 7,358 | 8,643 | 10,005 | 10,567 | 11,156 | 11,774 | 12,421 | 13,099 |
| Operating fund disbursement (replenishment) | | 2,892 | 1,396 | 4,115 | 1,498 | (845) | 211 | (887) | (1,879) | (2,764) | (3,538) | (2,722) | (3,720) | (4,737) | (5,772) | (6,827) | (7,020) | (7,216) | (7,413) | (7,612) | (7,813) |
| Net operating cash flow | | 188 | 291 | 242 | 67 | 216 | 507 | 655 | 851 | 1,094 | 1,381 | 1,920 | 2,245 | 2,621 | 2,871 | 3,178 | 3,547 | 3,940 | 4,361 | 4,809 | 5,286 |
| **Operating Reserve (1000$US)** | | | Interest income on reserve | | | 4.5% | | | | | | | | | | | | | | | |
| External funding of reserve | 4,000 | - | 5,000 | - | - | - | | | | | | | | | | | | | | | |
| Beginning | 4,000 | 4,180 | 6,477 | 5,372 | 1,500 | 69 | 918 | 749 | 1,669 | 3,624 | 6,551 | 10,384 | 13,573 | 17,904 | 23,447 | 30,275 | 38,464 | 47,215 | 56,555 | 66,513 | 77,118 |
| (Disbursement) or inflow | - | (2,892) | (1,396) | (4,115) | (1,498) | 845 | (211) | 887 | 1,879 | 2,764 | 3,538 | 2,722 | 3,720 | 4,737 | 5,772 | 6,827 | 7,020 | 7,216 | 7,413 | 7,612 | 7,813 |
| Interest income | 180 | 188 | 291 | 242 | 67 | 3 | 41 | 34 | 75 | 163 | 295 | 467 | 611 | 806 | 1,055 | 1,362 | 1,731 | 2,125 | 2,545 | 2,993 | 3,470 |
| Ending total cash balance | 4,180 | 1,477 | 5,372 | 1,500 | 69 | 918 | 749 | 1,669 | 3,624 | 6,551 | 10,384 | 13,573 | 17,904 | 23,447 | 30,275 | 38,464 | 47,215 | 56,555 | 66,513 | 77,118 | 88,402 |
| Reserve balance as % of revenue | | 191% | 207% | 33% | 1% | 8% | 6% | 11% | 23% | 38% | 57% | 68% | 84% | 104% | 127% | 154% | 187% | 223% | 260% | 299% | 340% |
| Debt service coverage ratio without operating reserve | | (0.17) | 0.44 | 0.28 | 0.74 | 1.19 | 1.03 | 1.19 | 1.34 | 1.48 | 1.60 | 1.47 | 1.61 | 1.74 | 1.86 | 1.98 | 2.00 | 2.02 | 2.04 | 2.07 | 2.09 |
| Debt service coverage ratio with operating reserve | | 1.00 | 1.00 | 1.00 | 1.00 | 1.04 | 1.06 | 1.08 | 1.10 | 1.12 | 1.14 | 1.16 | 1.18 | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 |

# Appendix 12 Self-Generation Comparison for Three Cases

## Self-Generation Costs

### Case 1

| Operating year ----> | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cooling | | | | | | | | | | | | | | | | | | | | | |
| Capital | $ 909,883 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Electricity | $ - | $ 34,825 | $ 32,380 | $ 30,718 | $ 30,715 | $ 30,579 | $ 29,768 | $ 30,248 | $ 30,164 | $ 29,263 | $ 29,400 | $ 28,849 | $ 28,958 | $ 28,180 | $ 27,554 | $ 27,265 | $ 26,843 | $ 26,843 | $ 26,843 | $ 26,843 | $ 26,843 |
| Water and chemicals | $ - | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 |
| Maintenance | $ - | $ 6,655 | $ 7,320 | $ 7,986 | $ 8,651 | $ 9,317 | $ 9,982 | $ 10,648 | $ 11,313 | $ 11,979 | $ 12,644 | $ 13,310 | $ 13,975 | $ 14,641 | $ 15,306 | $ 15,972 | $ 16,637 | $ 17,303 | $ 17,968 | $ 18,634 | $ 19,299 |
| Capital replacement | $ - | $ - | $ - | $ - | $ - | $ 7,986 | $ 9,982 | $ 11,979 | $ 13,975 | $ 15,972 | $ 17,968 | $ 19,965 | $ 21,961 | $ 23,957 | $ 26,952 | $ 29,947 | $ 32,942 | $ 35,936 | $ 38,931 | $ 41,926 | $ 43,922 |
| Labor | $ - | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 |
| Administration/management | $ - | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 |
| Total | $ 909,883 | $ 72,390 | $ 70,611 | $ 69,615 | $ 70,278 | $ 78,792 | $ 80,643 | $ 83,785 | $ 86,363 | $ 88,125 | $ 90,923 | $ 93,034 | $ 95,805 | $ 97,689 | $ 100,723 | $ 104,094 | $ 107,332 | $ 110,992 | $ 114,653 | $ 118,313 | $ 120,975 |
| Heating | | | | | | | | | | | | | | | | | | | | | |
| Capital | $ 244,777 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Electricity | $ - | $ 46,041 | $ 44,305 | $ 42,685 | $ 41,933 | $ 42,071 | $ 42,827 | $ 43,607 | $ 43,481 | $ 42,419 | $ 42,962 | $ 43,960 | $ 44,750 | $ 42,787 | $ 43,471 | $ 45,497 | $ 45,497 | $ 45,497 | $ 45,497 | $ 45,497 | $ 45,497 |
| Water and chemicals | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Maintenance | $ - | $ 2,448 | $ 2,693 | $ 2,937 | $ 3,182 | $ 3,427 | $ 3,672 | $ 3,916 | $ 4,161 | $ 4,406 | $ 4,651 | $ 4,896 | $ 5,140 | $ 5,385 | $ 5,630 | $ 5,875 | $ 6,119 | $ 6,364 | $ 6,609 | $ 6,854 | $ 7,099 |
| Capital replacement | $ - | $ - | $ - | $ - | $ - | $ 2,937 | $ 3,672 | $ 4,406 | $ 5,140 | $ 5,875 | $ 6,609 | $ 7,343 | $ 8,078 | $ 8,812 | $ 9,913 | $ 11,015 | $ 12,116 | $ 13,218 | $ 14,319 | $ 15,421 | $ 16,155 |
| Labor | $ - | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 |
| Administration/management | $ - | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 |
| Total | $ 244,777 | $ 75,989 | $ 74,498 | $ 73,122 | $ 72,615 | $ 75,935 | $ 77,670 | $ 79,429 | $ 80,283 | $ 80,200 | $ 81,722 | $ 83,698 | $ 85,468 | $ 84,484 | $ 86,515 | $ 89,886 | $ 91,233 | $ 92,579 | $ 93,925 | $ 95,271 | $ 96,251 |
| Total | | | | | | | | | | | | | | | | | | | | | |
| Capital | $ 1,154,660 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Electricity | $ - | $ 80,865 | $ 76,685 | $ 73,403 | $ 72,648 | $ 72,650 | $ 72,594 | $ 73,854 | $ 73,645 | $ 71,683 | $ 72,362 | $ 72,809 | $ 73,708 | $ 70,968 | $ 71,025 | $ 72,761 | $ 72,340 | $ 72,340 | $ 72,340 | $ 72,340 | $ 72,340 |
| Water and chemicals | $ - | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 | $ 3,411 |
| Maintenance | $ - | $ 9,103 | $ 10,013 | $ 10,923 | $ 11,833 | $ 12,744 | $ 13,654 | $ 14,564 | $ 15,474 | $ 16,385 | $ 17,295 | $ 18,205 | $ 19,116 | $ 20,026 | $ 20,936 | $ 21,846 | $ 22,757 | $ 23,667 | $ 24,577 | $ 25,487 | $ 26,398 |
| Capital replacement | $ - | $ - | $ - | $ - | $ - | $ 10,923 | $ 13,654 | $ 16,385 | $ 19,116 | $ 21,846 | $ 24,577 | $ 27,308 | $ 30,039 | $ 32,769 | $ 36,866 | $ 40,962 | $ 45,058 | $ 49,154 | $ 53,250 | $ 57,347 | $ 60,077 |
| Labor | $ - | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 |
| Administration/management | $ - | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 |
| Total | $ 1,154,660 | $ 148,379 | $ 145,109 | $ 142,737 | $ 142,892 | $ 154,727 | $ 158,313 | $ 163,214 | $ 166,646 | $ 168,324 | $ 172,645 | $ 176,733 | $ 181,273 | $ 182,174 | $ 187,238 | $ 193,980 | $ 198,565 | $ 203,571 | $ 208,578 | $ 213,584 | $ 217,225 |

### Case 2

| Operating year ----> | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cooling | | | | | | | | | | | | | | | | | | | | | |
| Capital | $ 593,426 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Electricity | $ - | $ 25,737 | $ 23,930 | $ 22,703 | $ 22,700 | $ 22,599 | $ 22,000 | $ 22,355 | $ 22,293 | $ 21,627 | $ 21,728 | $ 21,321 | $ 21,402 | $ 20,827 | $ 20,364 | $ 20,150 | $ 19,838 | $ 19,838 | $ 19,838 | $ 19,838 | $ 19,838 |
| Water and chemicals | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Maintenance | $ - | $ 13,792 | $ 15,171 | $ 16,550 | $ 17,929 | $ 19,309 | $ 20,688 | $ 22,067 | $ 23,446 | $ 24,825 | $ 26,205 | $ 27,584 | $ 28,963 | $ 30,342 | $ 31,721 | $ 33,101 | $ 34,480 | $ 35,859 | $ 37,238 | $ 38,617 | $ 39,997 |
| Capital replacement | $ - | $ 4,138 | $ 8,275 | $ 12,413 | $ 16,550 | $ 20,688 | $ 24,825 | $ 28,963 | $ 33,101 | $ 37,238 | $ 41,376 | $ 45,513 | $ 49,651 | $ 53,788 | $ 59,995 | $ 66,201 | $ 72,408 | $ 78,614 | $ 84,820 | $ 91,027 | $ 95,164 |
| Labor | $ - | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 |
| Administration/management | $ - | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 |
| Total | $ 593,426 | $ 71,167 | $ 74,877 | $ 79,166 | $ 84,680 | $ 90,096 | $ 95,013 | $ 100,885 | $ 106,340 | $ 111,191 | $ 116,809 | $ 121,918 | $ 127,516 | $ 132,458 | $ 139,580 | $ 146,952 | $ 154,226 | $ 161,811 | $ 169,397 | $ 176,982 | $ 182,499 |
| Heating | | | | | | | | | | | | | | | | | | | | | |
| Capital | $ 202,649 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Electricity | $ - | $ 78,319 | $ 72,821 | $ 69,084 | $ 69,078 | $ 68,770 | $ 66,946 | $ 68,026 | $ 67,837 | $ 65,812 | $ 66,119 | $ 64,881 | $ 65,125 | $ 63,377 | $ 61,968 | $ 61,317 | $ 60,368 | $ 60,368 | $ 60,368 | $ 60,368 | $ 60,368 |
| Water and chemicals | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Maintenance | $ - | $ 6,491 | $ 7,141 | $ 7,790 | $ 8,439 | $ 9,088 | $ 9,737 | $ 10,386 | $ 11,036 | $ 11,685 | $ 12,334 | $ 12,983 | $ 13,632 | $ 14,281 | $ 14,930 | $ 15,580 | $ 16,229 | $ 16,878 | $ 17,527 | $ 18,176 | $ 18,825 |
| Capital replacement | $ - | $ 1,947 | $ 3,895 | $ 5,842 | $ 7,790 | $ 9,737 | $ 11,685 | $ 13,632 | $ 15,580 | $ 17,527 | $ 19,474 | $ 21,422 | $ 23,369 | $ 25,317 | $ 28,238 | $ 31,159 | $ 34,080 | $ 37,002 | $ 39,923 | $ 42,844 | $ 44,791 |
| Labor | $ - | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 |
| Administration/management | $ - | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 |
| Total | $ 202,649 | $ 114,258 | $ 111,356 | $ 110,216 | $ 112,807 | $ 115,096 | $ 115,868 | $ 119,545 | $ 121,952 | $ 122,524 | $ 125,427 | $ 126,786 | $ 129,627 | $ 130,475 | $ 132,636 | $ 135,556 | $ 138,177 | $ 141,748 | $ 145,318 | $ 148,888 | $ 151,485 |
| Total | | | | | | | | | | | | | | | | | | | | | |
| Capital | $ 796,075 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Electricity | $ - | $ 104,057 | $ 96,751 | $ 91,787 | $ 91,778 | $ 91,370 | $ 88,946 | $ 90,381 | $ 90,130 | $ 87,439 | $ 87,847 | $ 86,202 | $ 86,527 | $ 84,204 | $ 82,332 | $ 81,467 | $ 80,207 | $ 80,207 | $ 80,207 | $ 80,207 | $ 80,207 |
| Water and chemicals | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Maintenance | $ - | $ 20,283 | $ 22,312 | $ 24,340 | $ 26,368 | $ 28,397 | $ 30,425 | $ 32,453 | $ 34,482 | $ 36,510 | $ 38,538 | $ 40,567 | $ 42,595 | $ 44,624 | $ 46,652 | $ 48,680 | $ 50,709 | $ 52,737 | $ 54,765 | $ 56,794 | $ 58,822 |
| Capital replacement | $ - | $ 6,085 | $ 12,170 | $ 18,255 | $ 24,340 | $ 30,425 | $ 36,510 | $ 42,595 | $ 48,680 | $ 54,765 | $ 60,850 | $ 66,935 | $ 73,020 | $ 79,105 | $ 88,233 | $ 97,360 | $ 106,488 | $ 115,615 | $ 124,743 | $ 133,871 | $ 139,956 |
| Labor | $ - | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 |
| Administration/management | $ - | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 |
| Total | $ 796,075 | $ 185,425 | $ 186,233 | $ 189,382 | $ 197,487 | $ 205,192 | $ 210,882 | $ 220,430 | $ 228,292 | $ 233,715 | $ 242,236 | $ 248,704 | $ 257,142 | $ 262,932 | $ 272,216 | $ 282,508 | $ 292,403 | $ 303,559 | $ 314,715 | $ 325,871 | $ 333,984 |

**Case 3**

| Operating year ----> | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cooling | | | | | | | | | | | | | | | | | | | | | |
| Capital | $ 552,522 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Electricity | $ - | $ 14,445 | $ 13,431 | $ 12,742 | $ 12,740 | $ 12,684 | $ 12,347 | $ 12,547 | $ 12,512 | $ 12,138 | $ 12,195 | $ 11,966 | $ 12,012 | $ 11,689 | $ 11,429 | $ 11,309 | $ 11,134 | $ 11,134 | $ 11,134 | $ 11,134 | $ 11,134 |
| Water and chemicals | $ - | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 |
| Maintenance | $ - | $ 4,041 | $ 4,445 | $ 4,849 | $ 5,253 | $ 5,658 | $ 6,062 | $ 6,466 | $ 6,870 | $ 7,274 | $ 7,678 | $ 8,082 | $ 8,486 | $ 8,890 | $ 9,295 | $ 9,699 | $ 10,103 | $ 10,507 | $ 10,911 | $ 11,315 | $ 11,719 |
| Capital replacement | $ - | $ - | $ - | $ - | $ - | $ 6,466 | $ 8,082 | $ 9,699 | $ 11,315 | $ 12,932 | $ 14,548 | $ 16,165 | $ 17,781 | $ 19,397 | $ 21,822 | $ 24,247 | $ 26,671 | $ 29,096 | $ 31,521 | $ 33,945 | $ 35,562 |
| Labor | $ - | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 |
| Administration/management | $ - | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 |
| Total | $ 552,522 | $ 47,401 | $ 46,791 | $ 46,506 | $ 46,909 | $ 53,722 | $ 55,406 | $ 57,626 | $ 59,612 | $ 61,259 | $ 63,336 | $ 65,128 | $ 67,194 | $ 68,892 | $ 71,461 | $ 74,169 | $ 76,823 | $ 79,652 | $ 82,481 | $ 85,310 | $ 87,330 |
| Heating | | | | | | | | | | | | | | | | | | | | | |
| Capital | $ 156,234 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Electricity | $ - | $ 22,044 | $ 21,213 | $ 20,437 | $ 20,077 | $ 20,144 | $ 20,505 | $ 20,879 | $ 20,819 | $ 20,310 | $ 20,570 | $ 21,048 | $ 21,426 | $ 20,487 | $ 20,814 | $ 21,784 | $ 21,784 | $ 21,784 | $ 21,784 | $ 21,784 | $ 21,784 |
| Water and chemicals | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Maintenance | $ - | $ 1,562 | $ 1,719 | $ 1,875 | $ 2,031 | $ 2,187 | $ 2,344 | $ 2,500 | $ 2,656 | $ 2,812 | $ 2,968 | $ 3,125 | $ 3,281 | $ 3,437 | $ 3,593 | $ 3,750 | $ 3,906 | $ 4,062 | $ 4,218 | $ 4,375 | $ 4,531 |
| Capital replacement | $ - | $ - | $ - | $ - | $ - | $ 1,875 | $ 2,344 | $ 2,812 | $ 3,281 | $ 3,750 | $ 4,218 | $ 4,687 | $ 5,156 | $ 5,624 | $ 6,327 | $ 7,031 | $ 7,734 | $ 8,437 | $ 9,140 | $ 9,843 | $ 10,311 |
| Labor | $ - | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 | $ 25,000 |
| Administration/management | $ - | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 | $ 2,500 |
| Total | $ 156,234 | $ 51,107 | $ 50,432 | $ 49,812 | $ 49,609 | $ 51,706 | $ 52,692 | $ 53,691 | $ 54,256 | $ 54,372 | $ 55,257 | $ 56,360 | $ 57,363 | $ 57,048 | $ 58,235 | $ 60,064 | $ 60,923 | $ 61,783 | $ 62,642 | $ 63,501 | $ 64,126 |
| Total | | | | | | | | | | | | | | | | | | | | | |
| Capital | $ 708,755 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Electricity | $ - | $ 36,489 | $ 34,644 | $ 33,179 | $ 32,818 | $ 32,827 | $ 32,853 | $ 33,425 | $ 33,330 | $ 32,449 | $ 32,765 | $ 33,014 | $ 33,438 | $ 32,176 | $ 32,243 | $ 33,093 | $ 32,918 | $ 32,918 | $ 32,918 | $ 32,918 | $ 32,918 |
| Water and chemicals | $ - | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 | $ 1,415 |
| Maintenance | $ - | $ 5,603 | $ 6,164 | $ 6,724 | $ 7,285 | $ 7,845 | $ 8,405 | $ 8,966 | $ 9,526 | $ 10,086 | $ 10,647 | $ 11,207 | $ 11,767 | $ 12,328 | $ 12,888 | $ 13,448 | $ 14,009 | $ 14,569 | $ 15,129 | $ 15,690 | $ 16,250 |
| Capital replacement | $ - | $ - | $ - | $ - | $ - | $ 8,341 | $ 10,426 | $ 12,511 | $ 14,596 | $ 16,681 | $ 18,766 | $ 20,852 | $ 22,937 | $ 25,022 | $ 28,150 | $ 31,277 | $ 34,405 | $ 37,533 | $ 40,660 | $ 43,788 | $ 45,873 |
| Labor | $ - | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 | $ 50,000 |
| Administration/management | $ - | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 | $ 5,000 |
| Total | $ 708,755 | $ 98,508 | $ 97,223 | $ 96,318 | $ 96,517 | $105,428 | $108,099 | $111,317 | $113,867 | $115,631 | $118,593 | $121,488 | $124,556 | $125,940 | $129,696 | $134,233 | $137,747 | $141,435 | $145,123 | $148,811 | $151,456 |

## Energy District Costs

| Operating year ----> | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Case 1** | | | | | | | | | | | | | | | | | | | | | |
| Fixed costs | | $268,755 | $271,442 | $274,157 | $276,898 | $279,667 | $282,464 | $285,289 | $288,142 | $291,023 | $293,933 | $296,873 | $299,841 | $302,840 | $305,868 | $308,927 | $312,016 | $315,136 | $318,288 | $321,470 | $324,685 |
| Variable costs | | $ 66,822 | $ 66,822 | $ 66,854 | $ 66,854 | $ 66,854 | $ 66,992 | $ 66,992 | $ 66,992 | $ 66,992 | $ 66,992 | $ 67,147 | $ 67,147 | $ 67,147 | $ 67,147 | $ 67,147 | $ 67,147 | $ 67,147 | $ 67,147 | $ 67,147 | $ 67,147 |
| Total costs | | $335,577 | $338,265 | $341,010 | $343,752 | $346,521 | $349,456 | $352,280 | $355,133 | $358,015 | $360,925 | $364,019 | $366,988 | $369,986 | $373,015 | $376,073 | $379,163 | $382,283 | $385,434 | $388,617 | $391,832 |
| **Case 2** | | | | | | | | | | | | | | | | | | | | | |
| Fixed costs | | $352,440 | $355,964 | $359,524 | $363,119 | $366,750 | $370,417 | $374,122 | $377,863 | $381,641 | $385,458 | $389,312 | $393,206 | $397,138 | $401,109 | $405,120 | $409,171 | $413,263 | $417,396 | $421,570 | $425,785 |
| Variable costs | | $ 83,602 | $ 83,602 | $ 83,650 | $ 83,650 | $ 83,650 | $ 83,863 | $ 83,863 | $ 83,863 | $ 83,863 | $ 83,863 | $ 84,101 | $ 84,101 | $ 84,101 | $ 84,101 | $ 84,101 | $ 84,101 | $ 84,101 | $ 84,101 | $ 84,101 | $ 84,101 |
| Total costs | | $436,042 | $439,566 | $443,174 | $446,769 | $450,400 | $454,280 | $457,985 | $461,726 | $465,504 | $469,321 | $473,414 | $477,307 | $481,239 | $485,210 | $489,221 | $493,273 | $497,364 | $501,497 | $505,671 | $509,887 |
| **Case 3** | | | | | | | | | | | | | | | | | | | | | |
| Fixed costs | | $165,906 | $167,565 | $169,241 | $170,933 | $172,643 | $174,369 | $176,113 | $177,874 | $179,653 | $181,449 | $183,264 | $185,096 | $186,947 | $188,817 | $190,705 | $192,612 | $194,538 | $196,484 | $198,448 | $200,433 |
| Variable costs | | $ 30,637 | $ 30,637 | $ 30,652 | $ 30,652 | $ 30,652 | $ 30,718 | $ 30,718 | $ 30,718 | $ 30,718 | $ 30,718 | $ 30,792 | $ 30,792 | $ 30,792 | $ 30,792 | $ 30,792 | $ 30,792 | $ 30,792 | $ 30,792 | $ 30,792 | $ 30,792 |
| Total costs | | $196,543 | $198,202 | $199,893 | $201,585 | $203,295 | $205,087 | $206,831 | $208,592 | $210,371 | $212,167 | $214,056 | $215,888 | $217,739 | $219,609 | $221,497 | $223,404 | $225,330 | $227,276 | $229,240 | $231,225 |

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February 28, 2003

Dr. Gordon Bloomquist
Senior Scientist
Washington State University
PO Box 43165
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*D R A F T*

Re: Initial Assessment of Project Water-Related Issues, Seattle Energy Project

Dear Gordon:

I am writing to present a draft preliminary assessment of water-related issues and to recommend "next steps," based on a preliminary review of the applicable laws and regulations, and my experience with the relevant regulatory programs. This letter is not intended to provide you with a complete assessment or opinion, and is not intended as legal advice. Based on comments from you and Mark Spurr, received at my office by close of business March 10th, I will finalize the letter and get it to you on March 12, if that meets your needs. I am also continuing to research several issues. I will include additional information in the final letter, as available.

You have asked me whether there are any "show-stoppers" relative to the use of water for the purposes of heating and cooling and possible power generation in Seattle. My initial assessment indicates that there are no "show stoppers." However, a strategy for management of water, and most particularly, discharge of water, must be carefully crafted and implemented in order to avoid potentially cost-prohibitive studies, lengthy regulatory negotiations or unnecessarily onerous permit conditions.

My initial assessment is based on a survey of the statutes, regulations, policies, and programs now in place relative to federal, state and local permitting requirements. In addition, I have been in communication with water resources and wastewater permitting staff at the Dept. of Ecology (Ecology), scientific staff at Washington Dept. of Fish and Wildlife (WDFW), City of Seattle staff and councilmembers, and King County Metro wastewater staff.

**Marine Water Withdrawal and Use**

At the present time, water right permits are not required for withdrawal of salt water from marine waters for the purpose of putting water to beneficial use. See Ecology policy POL 1015, attached. However, Ecology reserves the authority to regulate saltwater withdrawals and may seek to assert its authority with respect to this project, where significant public process will be involved and questions raised about the project's impacts. Even if a review and approval process is required, I do not anticipate significant impediments with respect to permitting of water use.

*Recommendation: None at this time.*

**Discharge of Water to the Marine Environment Following Use**

Discharge of water following use is potentially the most complex regulatory issue that presents itself. While there are no "show stoppers" immediately apparent, the array of state and federal permits that may be required will be substantial and interconnected, demanding significant investment of time and financial resources. For example, a federal permit will be required for dredging and construction of an outfall in the navigable waters of the United States; this process triggers associated state water quality certifications that may be time consuming and will provide an opportunity for placement of significant conditions on the project by the various "commenting" agencies.

One significant issue that potentially impacts the placement of the discharge pipes and appurtenances in marine water is current development of a "total maximum daily load" (TMDL) for various physical and chemical water quality parameters in Elliott Bay. Ecology has taken the position that no discharge permits will be issued pending development of a TMDL for any parameter that may be implicated by the permitting process. The Department bases this policy on the Clean Water Act prohibition of issuance of a permit, unless the permitted use is not a "source or cause" of the problem. 33 USC. Section 122.

TMDL development for Elliott Bay is about to be undertaken by the Dept. of Ecology, in partnership with the King County Dept. of Natural Resources (DNR). The process will identify the "carrying capacity" of the receiving water body for each parameter and allocate portions of the appropriate loading within that carrying capacity to various users. Depending on the characteristics of various discharges to receiving water body, project approval may not be forthcoming if the load is over-allocated, exceeding the receiving water's carrying capacity. One of the parameters for which a TMDL is proposed in Elliott Bay is temperature.

The origin of the parameters to be considered for development of a TMDL is the submittal of monitoring results showing exceedances of water quality criteria in specific segments of the water policy. If accepted, the water quality parameter is incorporated into the so-called "303(d) list," named after the applicable section of the federal Clean Water Act. Each parameter is related to a specific "water quality impaired water body" under Section 301 of the Clean Water Act. Usually the water body in question is a segment of a fresh water river or stream. Occasionally, marine waters may be implicated, especially where chemical contamination from fresh waters or from heavy industrial and commercial use has contaminated marine waters or associated sediments. The official list which we have identified for Elliott Bay does not identify temperature as a water quality parameter of concern. Duwamish River and Elliott Bay have been identified for establishment of TMDLs for pH, mercury, fecal coliform and dissolved oxygen (DO). The TMDL process is just getting underway and we are in touch with the lead Ecology staff.

*Recommendations with respect to TMDLs:*

1) Project participants should seek to join a Citizen's Advisory Committee that will be set up to help guide the process.

2) The documents supporting a temperature TMDL should be evaluated to see if the load allocation should be limited geographically, or by depth.
3) Ecology should be encouraged not to list temperature for an Elliott Bay TMDL if the problem can be isolated to and controlled by management of discharge in the Duwamish River. This comment may take place if the evaluation undertaken in Recommendation #1 (above) indicates comment is justified, through the citizen advisory group, the TMDL process generally, or the permitting process.
4) Ecology should be encouraged to take into account improvements in stormwater management, and habitat enhancements undertaken by Seattle and King County Metro, such as the Denny Way Combined Sewer Overflow (CSO) facilities, which may have or which may in future result in enhanced temperature control and management. This approach may further eliminate the need for a TMDL.

As you can see, the development of a TMDL for temperature may make permit approval by Ecology challenging and may substantially delay approval.

As I mentioned to Mark Spurr in my meeting with him on February 20, there is a possibility that the state wastewater discharge permitting process may be avoided, by what appears to be special treatment of thermal discharges under the federal Clean Water Act. Specifically, the statutory provisions delegating permitting regulatory authority to the state under certain circumstances appear to reserve certain authorities relating to these discharges to the federal government.

*Recommendations with respect to permitting authority:*

1) The Project should further evaluate special treatment afforded to thermal discharges under the Clean Water Act.
2) Project representatives should evaluate the opportunities to acquire discharge permits separate from or simultaneously with the state TMDL process.

Any discharge to Puget Sound will be conditioned upon protection or enhancement of fisheries, specifically Chinook salmon, which are listed as “threatened” under the Federal Endangered Species Act (ESA). The applicant will not be permitted to take action that results in harm to the species under Section 9 of the Act. Not only must the applicant avoid harm or disruption of the fish and its habitat, the City and other federal and state permitting agencies may not authorize actions causing harm to listed species through issuance of development or environmental permits. For those actions requiring federal permits, such as a dredge & fill permit required under Section 404 of the Clean Water Act, the proponent will be required to undertake a “consultation” with the National Marine Fisheries Service under Section 7 of the ESA. This consultation will be very time consuming and may result in substantial mitigation requirements, monitoring and adaptive management. On the positive side, the federal agencies are granted considerable discretion in making their own determination that an action authorized under their permit will not harm listed species.

Based on initial discussions with WDFW staff, it appears the temperature issue probably will be significant if the change in temperature is more than several degrees. There is a potential conflict between Ecology’s position on discharges, which is that discharges should be deep, and WDFW’s position on impacts to Chinook, which is that Chinook will more likely be affected by deep discharges than they would be by shallow discharges. We are currently researching the depth of Chinook habitat in the Bay, temperatures at various depths in the Bay, and critical habitat areas within the Bay.

**Seattle and King County regulations, development guidelines, and utility limitations.**

A preliminary review of the Seattle Municipal Code and utility planning documents does not indicate any "show stoppers." Seattle Public Utilities (water/stormwater), Transportation (Right of Way), and King County/Metro (wastewater) will be affected by the project and will have concerns about use of property (e.g. construction of facilities in right of way), or granting of a franchise (e.g. competing water supplier). This appears to be a political rather than regulatory issue. As you know, I have initiated discussions with City Council members, including our meeting with Councilmember Richard Conlin. Both Seattle City Council and King County Council are very supportive of and looking for opportunities to promote environmental protection and sustainable natural resource use (including water use) and energy development.

Approval, design and construction of facilities will present significant potential disruption of city transportation systems and businesses. There is significant potential that soil or groundwater contamination may be discovered during construction on private property, in city right of way, and/or in marine sediments. Studies have been conducted that indicated that shallow groundwater and surface soils particularly may be contaminated with petroleum hydrocarbons and other contaminants in this area. Significant study and remedial work may be required to deal with this issue.

*Recommendations with respect to City and County issues:*

1) Continue to outreach to City and County staff with respect to the general project concept.
2) Discuss with local staff the possibility and benefits of Corps of Engineers lead entity status. If the Corps is designated as lead for environmental review purposes, project team members can seek designation as the Corps' designee. This will provide the project with the benefit of federal discretion in decision-making relating to fishery resources, and more opportunity for the project to provide input to the process.
3) Continue discussions and research with Seattle WDFW and the services relative to fishery issues in Elliott Bay.
4) Careful evaluation should be undertaken of the joint use of existing facilities belonging to King County Metro, Seattle Steam or other dischargers into Elliott Bay. This step may save significant amounts of both time and money at the planning, design, and construction phases, relative to utility placement in city streets and private property, as well as discharge to Puget Sound.
5) A better understanding of the existing contamination in the area should be gained through review of Denny Way CSO Phase I and Phase II environmental assessments.

**Alternative Option: Beneficial Use of Wastewater**

As I discussed with Mark Spurr, if the energy project can dovetail with the existing King County Metro wastewater system in any way, that will be beneficial for the project. The connection between the two systems might take the form of joint use of conveyance pipes, tunnels or other facilities; joint use of discharge (outfall facilities); or "in-line" use and discharge of water within the existing wastewater system. In addition to the efficiencies of joint use of physical facilities and existing (waste) water streams, a significant added benefit will be realized if the requirement to gain a new discharge permit can be avoided. In this scenario, an existing discharge permit could be amended to include elements of the energy project or the project might be authorized within King County Metro's existing pretreatment program.

In one version of this option, the project could use untreated wastewater “in-line,” perhaps picked up at a lift station that apparently exists in the area of the west end of Denny Way, screened and used, with the waste stream potentially returned to the system without requiring a federal or state discharge permit. A pretreatment permit for discharge to the wastewater system might be required.

Another related approach would take secondary treated wastewater from the West Point wastewater treatment plant and run it through a conveyance facility, probably running along the arterials near the Lake Washington Ship Canal and Lake Union, to the point of use; and return it back to the treatment plant, following use. As you and I have discussed, Metro and Seattle have a strong interest in this type of project from a plant capacity standpoint (avoided cost of new facilities and avoidance of potentially prohibited increased flow discharged to Puget Sound). The flow (volume) limitation on discharges to Puget Sound does not make a lot of sense, in my opinion, but Ecology has taken the position, when renewing certain wastewater discharge permits, that no additional flow volume will be allowed. I am currently working with the LOTT Wastewater Alliance in South Puget Sound on reclaimed water issues, and there is the possibility that the partners may seek to challenge Ecology on that assumption. I will advise you of any developments there.

Seattle and King County Metro may support a reclaimed water project because it is environmentally responsible. The fact that Metro will be constructing the Brightwater plant northeast of Seattle, at an estimated cost in the range of $1.8 billion, indicates that permitting limitations combined with environmental concerns may motivate the utility to commit to the expenditure of substantial funds. I believe that a well-drafted proposal that meets King County Metro’s needs, and Seattle’s needs (including Seattle Public Utilities) might gain funding support as well as program and policy support from local governments.

*Recommendation:* Continue discussions with project engineers, Seattle Public Utilities and Metro on the use of reclaimed water as an alternative source of water. If the volume or temperature is not sufficient to meet project needs at full buildout, perhaps a combination approach may work.

**Summary and General Recommendations**

The use and discharge of sea water is likely approvable following negotiations and study over a period of two or more years, and potential expenditure of significant funds for studies, soil or marine sediment remediation, and fish habitat improvements. Careful consideration should be given to options that may avoid or minimize these permitting, consultation and regulatory processes. These options might include the following scenarios:

- Work with the federal agencies, rather than the state, to gain a new NPDES discharge permit, taking advantage of any exemptions in the governing statute, if applicable.
- Avoid costs and time involved in placement of a new transmission facility and discharge structure in Puget Sound, by discharging through existing structures. The permitting process might take the form of an amendment to an existing permit rather than new discharge permit. The temperature and volume of flow may still trigger significant study and remediation.
- Avoid the requirement to gain a new NPDES discharge permit by using reclaimed water or wastewater, and seeking approval within the existing wastewater system.

The latter scenario presents the opportunity to fulfill goals and requirements of the utilities, Seattle City Council, and King County Council, with respect to conservation, reuse, and protection of fish, either by avoiding an additional impact on the environment directly, or by reducing the impact to the environment of increased power demand or water use at other existing facilities.

As I indicated when I arranged a meeting with Seattle City Councilmember Conlin, there may be additional water quality and efficiency benefits to be realized through discharge of highly treated Class A reclaimed wastewater to Lake Union. These benefits would help gain city and county approvals.

In terms of the "big picture" of environmental permitting and coordination of environmental permitting, the entire process will probably be triggered through submittal of a proposal to the Seattle development review authorities. The State Environmental Policy Act (SEPA) process which requires assessment and review of environmental impacts and compliance with state and federal regulations will identify the various required permits. An alternative approach is to run the project through the State Energy Facility Site Evaluation Council ("EFSEC") process under RCW 80.50, if the project qualifies. This process is a "one-stop shopping" approach by which the State coordinates environmental permitting, including NPDES discharge permits. The process is subject to the less extensive public review and comment constraints and may be desirable if there is strong political support for the project.

Very truly yours,

Kathleen Callison

KC:hbs

cc: Mr. Mark Spurr, FVB Energy Inc.
Client file

Enclosures: Ecology POL 1015
Federal Issues as they relate to Seattle
Seattle Regulatory Issues Initial Summary
Partial List of Applicable Laws and Permits

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November 21, 2003

Dr. Gordon Bloomquist
Senior Scientist
Washington State University
PO Box 43165
Olympia, WA 98504-3165

Re: South Lake Union District Energy Project, Phase 1 Supplemental Report

Dear Dr. Bloomquist:

This letter is supplement to my previous letter report dated May 9, 2003, outlining water-related issues for the South Lake Union District Energy Project. It is intended to add to previous information relating to the current project focus, which is the potential beneficial use of water from Lake Washington and/or Lake Union, and discharge of water to those water bodies following use. This letter is not intended to provide legal advice or a legal opinion. It is intended to bring to your attention certain issues that I recommend the project team consider during Phase 2.

- I recommend that the project team identify federal permitting requirements as a high priority in Phase 2. If the Lake Washington/Lake Union option moves forward, the role of the US Army Corps of Engineers will likely be significant. Permits administered by the Corps under Section 404 of the Clean Water Act and Section 10 of the Rivers and Harbors Act may require special attention. Also, identifying the applicability and requirements of the National Environmental Policy Act (NEPA), and the early scoping of issues under that Act, as applicable, will be critical tasks in Phase 2.
- Scoping of the assessment of impacts on fisheries, and identification of regulatory requirements associated with the various species, should be undertaken in Phase 2. Successful scoping of these issues will be critical to the success of the project.
- In Phase 2, the project team should develop a conceptual plan for outreach to interested parties and the general public. Elements of this plan may include government-to-government contact with affected tribes, communications with government agencies and nongovernmental organizations, and outreach to other interested parties and the general public.
- Research goals should be established and sources identified to address potential project impacts and to prepare mitigation strategies required for permit approvals, using best available science. Information is available from federal, state and local government natural resource departments, tribal natural resource staffs and academic institutions. It will be important to gain a focused understanding, from credible sources, of site-specific as well as system-wide hydraulics and fisheries issues.
- I recommend that the team look at recent large utility or transportation projects in the area, and review Capital Facilities Plans for utilities and transportation projects identified by Seattle and King County. Looking at projects with similar permitting challenges or planned for construction at the same location will help the project team frame scientific and policy issues; identify permitting requirements; identify best available science to support the project; and identify capital projects for partnering. Partnering might take the form of cooperation on design and construction, coordinated funding efforts, and joint permit applications.
- In the context of water right applications and environmental impact assessment, the potential dewatering of a by-pass reach between the point of diversion of water and the point of discharge may be an issue. The real or perceived loss of a portion of the existing flow through that stretch of waterway may raise concerns with the federal services, tribes and the Dept. of Ecology. The

theoretical loss of water may in reality be offset by the storage provided by the control structure at the Hiram M. Chittenden Locks. Any required adjustment of the operation of the Locks may be justified by contribution of cooler flows to Lake Union, benefiting the environment and fisheries.
- Potential temperature and water quality effects in the bypass reach should be scoped in Phase 2, and looked at in more detail in the predesign stage.
- The team may wish to scope a task to investigate the potential for any cultural and archaeological issues for local tribes at the project site.
- Sediment quality and contamination of the bottoms of the waterways at the project locations should be the subject of a preliminary ("Phase 1") investigation in predesign. This work might be scoped in Phase 2 of the feasibility study.
- The project team should identify any requirements that may be placed on landowners and/or facility owner/operators by the Corps of Engineers (e.g., for the recording of easements or other binding agreements) relating to operation within the Lake Washington system.
- I recommend that the project team consider the benefits of returning the water after use to the point of withdrawal. Priority processing of water rights may be available in those circumstances, under WAC 173-152 and Ecology's new policy POL-1021. Also, returning water to the point of diversion may also avoid "by-pass reach" issues discussed above. In Phase 2, preparation of preliminary cost estimates for this approach may be appropriate.
- Finally, ownership of the lake bottoms and associated channel bottoms to be traversed by the facilities should be identified, and the need for lease or easement arrangements with landowners should be assessed. Rights of way and utility easements should be identified and mapped. If right of way or utility issues may be involved (e.g. in the 520 Bridge corridor), initial discussions with the affected transportation and utility agencies should be held.

Please feel free to contact me with any questions you may have. It would be my great pleasure to continue to assist the project team to accomplish its goals in Phase 2 of this innovative project.

Very truly yours,

Kathleen Callison

KC:hbs

# Partial List of Federal, State, and Local Laws & Permits

**Compiled by the Law Offices of Kathleen Callison**

Table 1: Federal Laws/Permits
Federal Clean Water Act Section 404
*Implementation:* Permit required for placement of dredge or fill materials including any related draining, flooding and excavation.
*Jurisdiction*: Waters of the United States.
*Application to Wetlands:* Includes wetlands (with some exemptions).
*Implementing Agency*: United States Army Corps of Engineers/Environmental Protection Agency.

Federal Clean Water Act Section 401
*Implementation:* Certification that the proposed project will meet state water quality standards is a condition of federal permit approvals.
*Jurisdiction:* Federal permits affecting waters of the US including wetlands.
*Application to Wetlands:* Includes all wetlands that may be affected by a federally permitted activity.
*Implementing Agency:* Washington Department of Ecology.

Federal River and Harbor Act Section 10
*Implementation:* Permit required for all construction activity.
*Jurisdiction:* Navigable waters to the mean high water mark of tidal waters and the ordinary high water mark (OHWM) of fresh water.
*Application to Wetlands:* Wetlands within the limits of "navigable waters."
*Implementing Agency:* United States Army Corps of Engineers.

Federal Coastal Zone Management Act
*Implementation:* A notice of consistency with the state coastal zone management plan is a condition of federal activities, federal license and permit approval, and federal support of local activities.
*Jurisdiction:* Applies to Washington's 15 Coastal Counties.
*Application to Wetlands:* Wetlands within the 15 coastal counties of Washington.
*Implementing Agency:* Washington Department of Ecology.

National Environmental Policy Act (NEPA)
*Implementation:* Federal process which requires full disclosure of potential impacts associated with proposed actions.
*Jurisdiction:* All federal actions.
*Application to Wetlands:* All wetlands.
*Implementing Agency:* Varies (usually the federal agency issuing the permit).

Table 2: Primary State Laws/Permits

State Growth Management Act

*Implementation:* Consistency with local comprehensive plans and development regulations. Various permits may be required.
*Jurisdiction:* All cities and counties in Washington State.
*Application to Wetlands:* Requires protection of all wetlands designated as "critical areas."
*Implementing Agency:* Local jurisdiction Washington Department of Community Trade & Economic Development.

State Shoreline Management Act

*Implementation:* Permits required to ensure that proposed activity complies with local shoreline master plan and the Shoreline Management Act.
*Jurisdiction:* Shorelines of the state including streams with flows greater than 20 cfs or lakes 20 acres or larger and landward area 200 feet from OHWM or floodway; associated wetlands, river deltas and certain floodplains.
*Application to Wetlands:* Includes all land within 200 feet of the OHWM of a state shoreline. Jurisdiction may be extended to include the entirety of an associated wetlands and/or floodplains.
*Implementing Agency:* Local jurisdiction/Washington Department of Ecology.

State Water Pollution Control Act

*Implementation:* Permits, orders, certifications or compliance with water quality standards.
*Jurisdiction:* Any pollution of waters of the state.
*Application to Wetlands:* All waters of the state including wetlands.
*Implementing Agency:* Washington Department of Ecology.

State Hydraulic Code

*Implementation:* Permit (Hydraulic Project Approval) required for all work.
*Jurisdiction:* Activities affecting waters of the state.
*Application to Wetlands:* Includes wetlands that are important to fish life.
*Implementing Agency:* Washington Department of Fish & Wildlife.

Local Laws

*Implementation:* Consistency with local comprehensive plans, zoning, ordinances, shoreline master program. Various permits may be required.
*Jurisdiction:* As defined by local plants, ordinances, and regulations.
*Application to Wetlands:* May identify specific wetlands and performance standards.
*Implementing Agency:* Local jurisdiction.

# Appendix 14 Regulations Relating to Geothermal Heat Pump Applications

The direct use of geothermal water resources, including but not limited to greenhouse heating, warm water aquaculture, space heating, irrigation, swimming pools and hot spring baths, is covered by a separate regulatory process from the process that applies to electric power production. Washington State characterizes direct use geothermal resources as groundwater, which is subject to the appropriation procedure as described in Title 90 RCW, Water Rights-Environment.

For most applications, direct use geothermal projects follow the same regulatory process as that governing the development of conventional water wells. This process involves obtaining the necessary water rights and well construction permits. The major difference is that direct use projects also need to dispose of the water once it has been used for its design application. Disposal is accomplished either through returning the water back into the ground by way of an injection well, or through surface disposal if injection is not an option.

The Department of Ecology (DOE) is the lead agency in charge of administering the various rules and regulations governing water use and water quality in Washington State. DOE is responsible for issuing water rights, well construction permits and fluid disposal plans, including underground injection. Finally, developers need to contact local and county agencies to ensure compliance with local land use laws including building permits and zoning restrictions.

The regulatory process for developing a direct use geothermal project consists of the following steps:

Contact local and/or county agencies to ensure compliance with local land use laws including building permits and zoning restrictions.
Obtain water right. **(DOE)**
Permit/construct production well. **(DOE)**
Determine fluid disposal option and obtain permits for either injection or surface disposal. **(DOE)**

**Water Rights**

<u>Background</u>

The waters of Washington State collectively belong to the public and cannot be owned by any one individual or group. Instead, individuals or groups may be granted rights to use them. A water right is a legal authorization to use a predefined quantity of public water for a designated purpose. This purpose must qualify as a *beneficial use*. Beneficial use involves the application of a reasonable quantity of water to a non-wasteful use, such as irrigation, domestic water supply, or power generation, to name a few.

Washington State law requires certain users of public waters to receive approval from the state prior to use of the water - in the form of a water right permit or certificate. Any use of surface water (lakes, ponds, rivers, streams, or springs) which began after the state water code was enacted in 1917 requires a water-right permit or certificate. Likewise, ground-water withdrawals from 1945 onward, when the state ground-water code was enacted, require a water-right permit or certificate, with the following exceptions:
Use of 5000 gallons per day or less for:
Stock watering
Single or group domestic purposes
Industrial purposes, including direct use applications
Watering a lawn or non-commercial garden that is not larger than one-half acre

These uses of ground water are *exempt* from the need to obtain a water right permit or certificate, but are still considered water rights. They are referred to as *exempt ground-water withdrawals*.
Water use of any sort is subject to the "first in time, first in right" clause, originally established in historical Western U.S. water law and now part of Washington State law. This means that a senior

right cannot be impaired by a junior right. Seniority is established by *priority date* - the date an application was filed for a permitted or certificated water right - or the date that water was first put to beneficial use in the case of water claims and exempt groundwater withdrawals.

Water right permitting may also be impacted by the Critical Aquifer Recharge Area (CARA) ordinance. The ordinance was passed to provide local governments with a mechanism to classify, designate, and regulate those areas deemed necessary to provide adequate recharge and protection to aquifers used as sources of potable (drinking) water.

Water Right Permit Process

A geothermal direct use project will need to acquire a water right permit or certificate unless it meets the definition of an *exempt groundwater withdrawal* as described above. Water right permits are issued by the Department of Ecology only if the proposed use meets the following requirements: water will be put to beneficial use; no impairment to existing or senior rights; water is available for appropriation; and, issuance of the water right will not harm the public's welfare. Water rights are issued by Ecology's regional offices located in Lacey, Bellevue, Yakima and Spokane.

The process involves a series of steps from submitting a water right application, to obtaining a Certificate of Water Right. Depending on the complexity of water use and availability within a watershed, obtaining a water right may take anywhere from months to years. Early consultation with Ecology should provide the applicant with a better understanding of the time required and any outstanding issues that may complicate the process. The following steps outline the permit process:

Prepare and submit an application and a $10 filing fee to the appropriate regional office. The applicant is required to provide information on the proposed use, amount, location and ownership. A copy of the form with instructions is available on-line at http://www.ecy.wa.gov/programs/wr/forms/forms.html#wrapp.

Upon receipt of the application, Ecology will send the applicant a legal notice to be published in a local newspaper for a period of two weeks describing the project and offering public input for up to 30 days. At the end of the publication period the applicant must submit a notarized *Affidavit of Publication* to Ecology.

Ecology conducts an investigation of the application and issues a *Report of Examination* which contains a denial or approval of the water right request. A copy of the report is sent to the applicant and other interested parties. The applicant (and others) have 30 days to accept or appeal the Examiner's recommendation to the Pollution Control Hearing Board.

Provided there are no appeals, the applicant is issued a *Permit to Appropriate Public Waters.* The permit allows for the construction and operation of the water project and contains a schedule and a date by which the applicant should put the water to use.

After construction, the applicant submits a *Proof of Appropriation* affidavit form which includes information on the amount of water used; where it is being used; for what purpose; the type of facility and equipment used; and a statement that all conditions of the permit have been met.

Ecology will issue a Certificate of Water Right to the applicant based on the information submitted. The certificate is recorded at the County Auditor's Office where the project is located and at Ecology. Any fees associated with recording the certificate are paid by the applicant.

**Well Construction**

The Department of Ecology manages well construction activities in the state. RCW 18.104 establishes the regulatory framework for water well construction and identifies the Department of Ecology as the lead agency. The minimum standards for well construction and maintenance; and, the regulation and licensing of well contractors and operators are described in Chapters 173-160 and

173-162 of the Washington Administrative Code, respectively. Each year about 10,000 water wells are constructed in Washington

Before starting well construction, the developer of a geothermal project may want to review data from other wells in the area. Well log data can be obtained from a number of sources including county health offices and the Department of Ecology's regional offices (see Appendix A). The data available through these resources includes size, depth, capacity and location. The Geo-Heat Center, located in Klamath Falls, Oregon also maintains an extensive database covering wells and springs greater than 50 degrees C (122 $^{0}$F) for 16 western states. Information on the database can be found at http://geoheat.oit.edu/databse.htm. County planning and or health departments should also be contacted at this time to check for any additional county regulations or ordinances covering well placement and construction.

The process for constructing an open loop, geothermal well mirrors that of a conventional water well. As previously described, a water right is required for applications consuming more than 5000 gallons per day. For these applications, the developer must have received a *Permit to Appropriate Public Waters* before well construction can begin. Closed loop systems, such as ground source heat pumps, which do not withdraw groundwater, are exempt from RCW 173-160. Developers of closed loop systems are still required to protect groundwater resources during construction and decommissioning of the system.

To begin well construction, a developer must submit a *Notice of Intent* form to the Department of Ecology *at least 72 hours* prior to well construction. The notice allows Ecology to track well activities and to inspect a well to make sure it is constructed according to state regulations. The notice does not give authority for construction nor does it guarantee water rights to the applicant. The forms are available through Ecology's Regional Offices, county building departments or on-line at http://apps.ecy.wa.gov/startcards/. A fee for construction of a new water well is also collected at this time. For a well with a minimum top casing of less than 12 inches, the fee is $100. For well casings 12 inches or greater the fee is $200.

Only a duly licensed and bonded well contractor is permitted to construct wells in the state of Washington. The license must be issued by the Department of Ecology. The Department of Ecology Well Drilling Coordinator maintains a list of licensed well drillers and should be contacted for verification.

**Disposal of Geothermal Fluids**

The regulations governing the disposal of low temperature geothermal fluids will depend on the type of application. Non contact geothermal projects, where the geothermal fluids are kept in a closed system and do not come in contact with outside contaminants, will typically have an easier compliance path then projects where contact with potential contaminants is made. When contact is made and water quality is potentially degraded, regulatory requirements may become more stringent to ensure that water quality is maintained.

There are basically three disposal options available to a developer of a direct use geothermal project: underground injection; disposal to surface waters; and/or, disposal to the ground or land application. In some cases, the regulatory agency(s) will specify the preferred disposal method. For example, in critical groundwater areas, reinjection may be required to ensure that the aquifer is maintained. However, in most cases, it will be up to the project developer to determine the best disposal method based on regulatory requirements and the cost of compliance.

Underground Injection Control

The Underground Injection Control (UIC) Program was established in 1982 when Congress passed the Safe Drinking Water Act. This program regulates, to one degree or the other, every "injection" of "fluid" into the subsurface. An "injection" is the emplacement of "fluids" regardless of whether the injection requires the application of pressure or not, and a fluid is defined as any liquid, gas or semisolid which can be made to flow. The intent of the program is to preserve and protect underground water from becoming polluted.

From a resource perspective, the preferred method of disposing of geothermal fluids is to return them to the ground by way of injection wells. Injection wells are wells that are used as an entry point for some type of fluid (such as geothermal fluid), which is put underground for temporary or permanent disposal or storage. Underground Injection Control wells are regulated under Chapter 90.48 RCW (Water Pollution Control), Chapter 173-218 WAC (Underground Injection Control Program), and Chapter 173-200 WAC (Water Quality Standards for Ground Waters of the State of Washington). The purpose of this law and these regulations is to protect existing and future beneficial uses of underground sources of drinking water (USDW). In Washington State all sources of ground water are considered USDW.

The purpose of the Underground Injection Control Program is to enforce the rules and regulations protecting groundwater. A key component of the program with respect to geothermal water is: Disposal of waste fluids from industrial, commercial, or municipal sources into wells will not be authorized unless the requirements of this chapter are met. "Waste fluid" is defined as any discarded, abandoned, unwanted or unrecovered fluids, **except** for the following: 1) discharges into the ground or ground water of return flow, unaltered except for temperature, *from a ground water heat pump used for space heating or cooling, provided* that the discharge does not have significant potential to affect ground water quality. (cite)

All injection wells come under the jurisdiction of the Department of Ecology. Geothermal wells are considered Class V injection wells under the federal government's Underground Injection Control (UIC) program. Washington State only allows Class V wells that are used to inject uncontaminated stormwater, *heat pump return water*, aquifer storage and recovery water, water undergoing remediation via pump-and-treat processes at leaking underground storage tank (LUST) sites, or other fluid deemed appropriate by the Washington State Department of Ecology.

All new Class V wells must apply to the UIC Program for approval. {WAC 173-218(2)(3)} The application includes information needed to satisfy the requirements of *40 Code of Federal Regulations* (CFR) *Part 146.* There are two main requirements of the program:

A *non-endangerment* performance standard must be met, prohibiting injection that allows the movement of fluids containing any contaminant into underground sources of drinking water. In Washington, all ground water is considered a potential source of drinking water.
All well owners must provide *inventory information*.

A determination as to whether a proposed injected fluid will be allowed under a Class V designated well is based on Chapter 173-200 WAC. Key components of Chapter 173-200 WAC:
Ground Water Quality Standards were established, together with the state's technology-based treatment requirements, to provide protection of existing and future beneficial uses of ground water. {173-200-010(5)}

The technology-based treatment requirements are part of the definition of best management practices (BMPs) {173-200-020(5)}, also referred to as *AKART* (all known, available and reasonable methods of prevention, control and treatment).

Closed loop heat pump and or heat exchanger return water meets the non-endangerment performance standard and can be reinjected directly. Applications where the groundwater is treated or comes in contact with potential contaminants, such as in a spa, cannot be reinjected unless it meets water quality standards as described in Chapter 173-200 WAC. If the injection well is deeper than the vadose zone (the zone immediately below the land surface and above the water table), or drills into a confined aquifer, the well should also follow the requirements of the Chapter 173-160 Minimum Standard for the Construction and Maintenance of wells. While the WAC currently exempts UIC wells from these standards, both the UIC and Chapter 173-160 are going through rule revision to make this a requirement for deep wells.

The Washington Department of Ecology has regulatory authority over the UIC program for Washington State. The program is rule authorized, which means the wells have to be registered but do not require a permit. Registration fulfills the inventory requirement. This program requires all injection wells in the state to be registered, *whether or not they are used*. Registration is free, but requires completing a **registration form**, which designates the location and use of the well, among other items. This information is entered into the UIC inventory. Registration is especially important if the well is located in a **Wellhead Protection Area, Critical Aquifer Recharge Area**, or other sensitive water quality protection area. It is the responsibility of the developer to keep Ecology informed of the status of the well, e.g. active, closed, change in ownership or change in use, among others.

Surface Disposal of Geothermal Fluids

If there is a discharge of wastewater containing pollutants in this State it is covered by two laws. Discharges to waters of the State (surface water and ground water) and industrial discharges to municipal wastewater treatment plants are regulated under Chapter 90.48 RCW Water Pollution Control. A discharge to waters of the US is also regulated by the federal Clean Water Act. A booklet containing background and permitting procedures under these laws can be found at http://www.ecy.wa.gov/biblio/wqr019.html. Other material on wastewater permitting can be found at http://www.ecy.wa.gov/programs/wq/wastewater/index.html.

In general, surface disposal to ground is preferable to discharging into surface waters. Discharging to ground minimizes the chance of degrading existing water quality. Discharging to ground also keeps the water within the same geographic resource area. A direct use project discharging fluids to the ground surface is required to obtain a state waste water discharge permit. A project that disposes fluids to surface waters would need a National Pollution Discharge Elimination System permit.

*National Pollution Discharge Elimination System (NPDES)*

Discharge of low temperature fluids to surface waters would require an NPDES permit. The most likely permit forms covering a direct use application are EPA NPDES forms 1 and 2D. Form 1 collects general information from the applicant and must be filled out in addition to a supplemental form. Form 2D covers process wastewater discharge. Because many direct use geothermal applications involve non-contact heat exchange, a developer may consider using Form 2E. This form was designed by the US Environmental Protection Agency to cover projects which do not discharge process wastewater. However, the Department of Ecology which administers Washington States' NPDES program currently requires all applicants to submit Form 2D.

An NPDES applicant will need to provide mapping information, flow data, an estimate of the type and quantities of pollutants discharged and a brief description of any planned treatment. This information will be used to determine the conditions of the permit including appropriate control or treatment strategies, monitoring and reporting requirements. Since most direct use applications involve non-contact geothermal heat exchange, the water quality of the source water is unaffected. For these type of projects, permit conditions should be strait-forward. Even so, a developer may still be required to cool the geothermal water before discharging into a surface water source.

NPDES permit fees are defined under 173-224 WAC and vary with the type of project. Currently, there is no specific category for direct use geothermal projects. In addition to the annual permit fee, a one-time application fee of 25% of the annual permit fee, or $250 (whichever is greater) is assessed. The process for obtaining NPDES permits can range from 2 months to one year. NPDES forms are posted at http://www.ecy.wa.gov/programs/wq/wastewater/index.html#npdes. The Department of Ecology advises applicants to contact the regional office permit coordinator before submitting an application form.

Although not currently available in Washington, some states may offer the option to proceed with a general permit versus an individual permit. A general permit covers a set of like facilities, such as a coal facility or a fish farm. Here, a set of conditions are already developed which meet the general operating conditions of these similar facilities. In these cases, a developer would complete Form 1 to see if they qualify under the general permit. If eligible the developer would also need to submit a Notice of Intent form or equivalent, which provides additional information needed by the resources agency administering the NPDES program. The advantage of the general form is that the resource agency can issue the permit as soon as all information needs are satisfied. For individual permits, there is an additional 30 day public notice process, as well as the potential for intervention on the terms and conditions of the permit.

*State Waste Water Discharge Permit*

A direct use project discharging fluids to the ground surface or to a publicly owned waste water treatment plant would need to apply for a wastewater discharge permit. If the project is planning to discharge wastewater to the ground surface, the appropriate form is Form 040-179. If the project is considering discharging to a municipal waste water treatment plant an applicant would need to use Form 040-177. The application forms are available for downloading at http://www.ecy.wa.gov/biblio/ecy040179.html.

The waste water discharge forms require that the regional permit writer determine the parameters to be measured in the effluent. Permit applications provide the Department with information on pollutants in the waste stream, materials which may enter the waste stream, the flow characteristics of the discharge, and the site characteristics at the point of discharge. The Department of Ecology advises applicants to contact the regional office permit coordinator before submitting an application form (see Appendix A).

Depending on the circumstances and nature of the wastewater, Ecology might not require a wastewater discharge permit for discharge to ground. For example, if temperature was the only pollutant, the volume of wastewater was low and the wastewater was infiltrated into the ground then Ecology may elect not to issue a permit. In addition, if temperature were the only wastewater pollutant, Ecology would generally not issue a permit for discharge to a municipal treatment plant because clean water reduces treatment efficiency for organic material.