City of Blaine
Department of Public Works

Electrical Utility Comprehensive Plan Report

Prepared for

City of Blaine
Electrical Division

Prepared by

CH2M HILL

March 1995

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Executive Summary

This Electrical Utility Comprehensive Plan Report comprises the electrical utilities element of the City of Blaine's Comprehensive Plan. It has been prepared for the City of Blaine's Electrical Division (the Division), which is a subdivision of the City's Department of Public Works. The report evaluates the City of Blaine's existing electrical utility service, projects future requirements for services, and discusses methods of financing projected capital expenditures.

This report incorporates the requirements of the Washington Administrative Code, Washington State's Growth Management Act, the City's power sales contract with the Bonneville Power Administration (BPA), and standard electrical utility practices. It draws on past studies of the Division, input from City of Blaine and BPA staff, site visits, studies performed specifically for this report, and local, state, and federal guidelines and regulations.

Projected Service Area and System Characteristics

The City of Blaine Electrical Division (the Division) currently provides electrical utility services to the area within the Blaine city limits as well as a few adjacent areas. The present service area is approximately 2,500 acres. The majority of commercial customers are located in the Central Blaine area and the Semiahmoo Spit.

This report evaluates three annexation alternatives in addition to a no-action (no annexation) alternative and projects customer totals along with their electric power needs at ultimate build-out, projected to occur sometime between 2030 and 2040. Peak customer demands for the annexation alternatives are projected to range from about 55 MW to 59 MW. (One megawatt, or MW, is one million watts of electric power or 1,000 kilowatts.) Peak customer demand for the no-annexation alternative is projected to be about 25 MW.

Ultimate demand influences a number of utility management decisions such as distribution voltage and standard substation size that, in turn, determine the utility's ability to serve future loads in a cost-effective manner. For example, many electric system investments, such as transmission lines, are expected to have a 20- to 30-year economic life, and facilities being planned and built now must be sized to handle ultimate demands. If they are undersized, much of the investment will be wasted and need to be redone later.

System Planning Criteria

The ways in which the Division provides electric service need to be consistent with both City policies and industry practices. Citywide goals regarding provision of all services are listed below:

- Develop and restructure the service organizations to provide the most effective and efficient service to the citizens of Blaine
- Increase and stabilize the revenue base while reviewing existing programs for fiscal efficiency
- Identify an acceptable level of public safety, provide a level of service consistent with community growth, and establish a comprehensive emergency plan
- Inventory assets and facilities for state regulatory compliance and to plan for adequate infrastructure to achieve maximum operating efficiency

From a public policy perspective, a number of customers and facilities are considered critical for continuity of service based on the nature of their function or business. As part of the Division's approach to providing electric service, these critical customers should be capable of receiving power from more than one distribution path. Existing critical loads or customers on the Division's system are:

Border crossings
Brokerage firms along the border
City wells
GSA border patrol office
High school, Blaine School District
Inn at Semiahmoo
Sewer lift stations and plant
Stafolt Good Samaritan Nursing Home
Water pump station in Semiahmoo

Currently, all critical loads, and the Division's customers in general, are susceptible to loss of power during a major component failure at the Blaine substation. Because the Blaine substation is fed from a radial transmission line, the City is also susceptible to a transmission line fault between the substation and the Kickerville-Birch Bay-Lynden Road tap point. The Blaine substation is located on a radial 115 kV transmission tap about 2.7 miles from Puget's 115 kV loop.

The City of Blaine is a BPA customer, and BPA has contracted with Puget Sound Power and Light Company (Puget Power) to provide transfer services to aid BPA in its service to the City of Blaine. The transfer agreement between BPA and Puget Power specifies a

number of the conditions of service that BPA has established in its service to the City through Puget Power's transmission system and substation. An alternative source of power could alleviate these vital reliability concerns. The City has explored such alternative sources of power. Population growth will require the addition of new electrical facilities; however, it is recommended that in selecting new facilities alternative sources be established to provide reliability, regardless of whether expansion occurs.

Generally, under industry practice, major or critical loads should be served in a way that allows for the failure of a single component without loss of load. Loads are assumed to be peak loads, which occur in winter in Blaine. If the outage is of moderate duration, slight overloading of equipment above normal limits is considered allowable.

To provide reliable service to critical loads, the following criteria are important:

- Consider the location of the load relative to the substation(s) and the main or "backbone" feeders that distribute the electricity
- Plan for backup source(s) specifically for that load, for emergency ties between feeders and/or substations, for stand-by generation, and for mobile generation
- Use protective devices appropriate for the load, the feeder it is on, and the desired operation; ensure proper coordination and review periodically
- Keep right-of-way for overhead feeders cleared of trees
- Locate facilities (poles, risers, or transitions between overhead and underground distribution, and transformers) so as to minimize exposure to vehicles, adverse weather conditions, and vandalism

Of the existing critical loads, the Semiahmoo area and the City wells at the end of Pipeline Road lack acceptable outage backup feeder paths. Any fault downstream of the east side of the submarine cable termination can leave all customers in the Semiahmoo area (except those with emergency generation) without service for an unpredictable period of time. The City wells are similarly susceptible to major faults downstream of the tap pole at Odell and Pipeline Roads. Both of these conditions could be remedied by having access to an alternative source of power. Semiahmoo could be adequately backed up (as well as permanently served) from a source to the south. The City wells could have contingency ties with Puget Power at Harvey and Pipeline Roads or interconnect from the east via an interconnection to the circuit that will feed the proposed H Street annexation. Alternatively, the Water Division could install backup generation or assist in funding construction of interconnection facilities (such as equipment pads and quick-disconnect capabilities) for the mobile generator currently owned by the Electrical Division.

Evaluation of Existing System

The City of Blaine Electrical Division's existing system consists of three distribution circuits, which are owned and maintained by the Division. These circuits are connected to the Blaine substation, which is owned and maintained by Puget Power. The Division is a BPA full-requirements customer and buys all of its power from BPA. The BPA power sales contract with the City of Blaine imposes many requirements upon both BPA and the Division. BPA has a transfer contract with Puget Power to wheel or transmit electricity over a Puget Power 115 kV transmission line to a Puget Power substation. The Division has three points of delivery from BPA. Current BPA policy is to impose more responsibility upon its customers for providing future delivery points.

Blaine Substation. The Division is served from Puget Power's Blaine substation via BPA's Custer substation under a transfer agreement between the two utilities. The Blaine substation has an operating capacity of approximately 24 MVA; the present BPA-Puget Power transfer agreement, however, limits service to the Division to 15.3 MVA. (An MVA is a megavolt amp which, depending upon the type of load, is roughly equivalent to a megawatt of power.) A request is being considered to increase the limit. The substation and its equipment provide an adequate power delivery mechanism to the Division during normal conditions. In the event of a transmission line failure or a substation transformer failure, the entire substation and its service areas could be out of service for an extended time. Also, BPA's historical peak load data indicate the Division has, on occasion, exceeded its allocated load capacity. Increased capacity, which is currently needed, could be provided by adding substation capacity at the Blaine substation or by providing additional capacity from another substation. If the capacity is provided from either a new substation or from adjacent Puget Power substations, reliability can be increased.

If the Blaine substation fails, it is Puget Power's responsibility to replace the transformer. Puget Power has mobile substations that could be moved to this location, but it would take several hours to several days to move a mobile substation and connect it. The City could discuss a mobile substation contingency plan with Puget Power; currently, such discussions should be part of the agreements between Puget Power and BPA. Because Puget Power customers are served from the substation, Puget Power could be expected to provide a backup source of power as quickly as possible.

Puget Power is also facing growth pressures in the Birch Bay area and at some point will need additional capacity. It may be possible to negotiate another "shared" substation under an arrangement similar to that at the Blaine substation, wherein Puget Power constructs and maintains the substation and provides the City with several circuits. This concept was pursued originally with Puget Power. Provided it is acceptable to BPA, and if negotiations can be fruitful with Puget Power on sharing the capacity of a substation at a reasonable cost, this alternative should be explored.

Distribution Circuit 15. This circuit or distribution feeder serves areas west of Interstate 5, including downtown. It has a summer recommended capacity of approximately 4.32 MVA and a winter capacity of 6.26 MVA, and has approached or exceeded its recommended capacity on various occasions. Increased capacity could be achieved by transferring some of the load onto another circuit or reconductoring the main circuit backbone to a location where the recommended capacity of the conductor is not exceeded or has room for growth.

Distribution Circuit 16. This circuit serves the area east of Odell Road and north of E Street, including the border crossing, the School District, the east side of the airport, the International Market, and the City's wells east of Pipeline Road. The circuit has a summer recommended capacity of 6.48 MVA and a winter capacity of 9.50 MVA, and is adequate for its present use under normal conditions. It is recommended that this circuit be upgraded as the opportunity arises.

Distribution Circuit 17. This circuit serves a small portion of Blaine including the west side of the airport and a sewer lift station on Marine Drive. It also serves the entire Semiahmoo area via a submarine cable that crosses the mouth of Drayton Harbor. Circuit 17 has a summer recommended capacity of 4.32 MVA and a winter capacity of 6.26 MVA. It is not heavily loaded; however, because of its length it is susceptible to voltage drop concerns, and the submarine cable is near the end of its service life. (Voltage drop is a situation where voltage at a customer's facility will be below industry standards. If voltage is too far below standard, motors can burn out and electronic equipment may not operate properly.)

At present there is no backup source to serve the Semiahmoo area in the event of an interruption. Backup service to the Semiahmoo area could be provided by a substation constructed either by the City of Blaine or by Puget Power. When this was explored in the past, Puget Power indicated that it would construct a substation only if the City agreed to certain service territory boundary limits and committed to a level of facility payments that was judged by the City as too high. Negotiations stopped pending a decision by the City on its preferred Growth Management Plan urban growth boundaries.

BPA was also involved in these discussions. BPA has indicated that under its customer service policy, it would not pay the additional cost of any new substation agreement that did not reduce its transfer contract charges with Puget Power. A new Puget Power substation in the Semiahmoo/Birch Bay area would increase the BPA transfer charges. The City of Blaine could either pay for such facilities directly to Puget Power, or pay through BPA. Tax-exempt capital costs associated with money borrowed by the City are lower than the cost of money to either Puget Power or BPA. Therefore, the City would be a lower-cost source of the funds to construct the substation. While construction by Puget Power would entail a lower first-year cost to the City, the City has the option of using bonds or borrowed funds to spread the capital cost over the useful life of the substation. Operation and maintenance (O&M) costs should not be a major factor in the overall cost.

BPA Power Sales Contract. The Division purchases its power from BPA under a power sales contract that places a number of constraints upon the City of Blaine, including requiring the Division to perform in a planned and prudent manner. BPA is proposing a tiered rate system that would charge higher fees for purchases of power above a set amount. In 1995 BPA will offer the City a new power sales contact. BPA's current policy is to adjust its electric power rates every 2 years. BPA has announced it will increase its rates to the Division on October 1, 1995.

Puget Power Service Area Agreements. The Division had a service area agreement with Puget Power that has expired. Once the Growth Management Plan boundaries are clarified, the Division should initiate negotiations with Puget Power to update the previous agreement.

Capital Improvements Plan

This section presents three expansion alternatives and a no-annexation alternative and discusses the capital improvements required to provide adequate service, assessing the capital improvement requirements for each of the expansion alternatives both with and without backup from Puget Power. The no-annexation alternative is discussed assuming that there will be no Puget Power backup contingency service available. This is the current situation.

Effective electrical system planning is based on delivering reliable power to customers. Our approach is to estimate the ultimate electric load within various areas. By comparing this future requirement to the current system, we can evaluate the locations and types of new facilities required and suggest ways to expand the existing system. This approach prevents the construction of temporary facilities that do not have long-term value.

Alternative 1

The Alternative 1 service area generally coincides with the historical City of Blaine/Puget Power service territory agreement (which has expired). The service area is bounded by Lincoln Road/Loomis Trail Road to the south and Valley View Road to the east. This service area would encompass approximately 11,060 acres; power demand at ultimate build-out of 10,283 dwelling units (estimated to occur in the year 2035) is estimated at 55 MW.

Alternative 1—Without Puget Power Backup (see Figure 1A). To meet the load requirements at ultimate build-out without relying on the aid of Puget Power for backup contingency, the total system capacity must be sufficient to carry the entire service area load in the event of a major transformer failure; a total system capacity of 84 MVA is recommended. To accomplish this, the transformer at the existing Blaine substation would be replaced at the end of its life cycle with a new 15/20/25 MVA transformer and double-banked with another 15/20/25 MVA station transformer when loading justifies it.

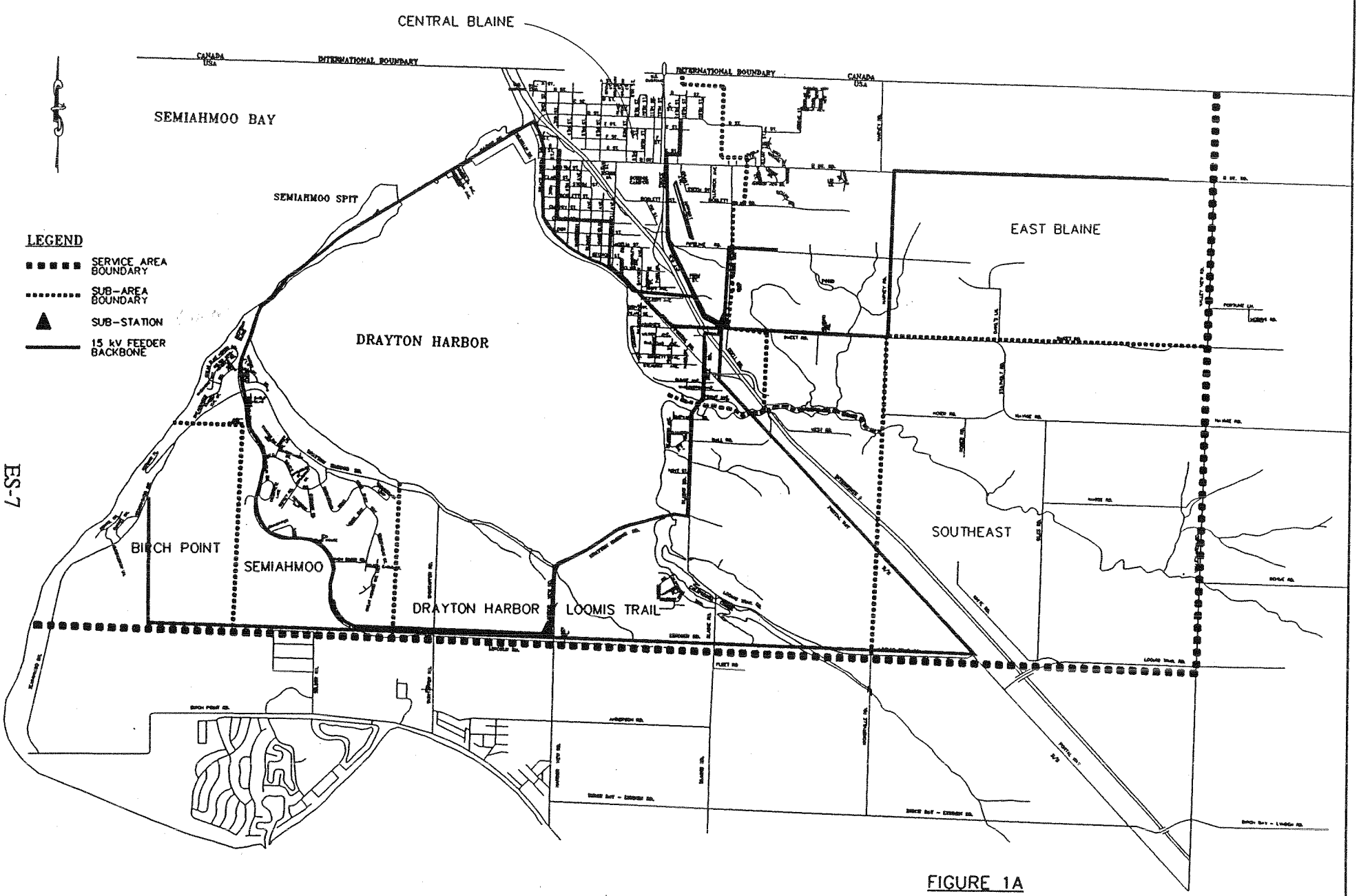

FIGURE 1A

ALTERNATIVE 1
SYSTEM CONFIGURATION WITHOUT
PUGET POWER BACKUP CONTINGENCY

Because of typical Northwest weather conditions, a 15/20/25 MVA transformer can serve 28 MVA of capacity. A new 15/20/25 MVA substation also would be built in the vicinity of Shintaffer, Harbor View, Drayton Harbor, and Lincoln Roads to serve the Birch Point, Semiahmoo, Drayton Harbor/Loomis Trail, and Southeast areas. With increased substation capacity, additional feeders would be needed to carry the loads. Seven feeders would be required to serve the upgraded substation and four would be required to distribute power to and from the new substation location.

Alternative 1—With Puget Power Backup (see Figure 1B). To meet the load needs at ultimate build-out with ample distribution interconnections with Puget Power, the total system capacity would be limited to that required to carry total loads and not to that required for backup contingency; the total system capacity would be approximately 56 MVA. To accomplish this at the time of ultimate build-out, it is recommended that appropriate interconnections be established with Puget Power, that the Blaine substation be upgraded at the end of the existing transformer's life cycle by replacement with a 15/20/25 MVA transformer, and that a new substation with a second 15/20/25 MVA transformer be built to serve the Birch Point, Semiahmoo, Drayton Harbor/Loomis Trail, and Southeast areas. Five feeders would be necessary to provide adequate distribution from the upgraded existing substation and to provide interconnections with the new substation. The new substation would be built in the vicinity of Shintaffer, Harbor View, Drayton Harbor, and Lincoln Roads and would carry as much of the Central Blaine area load as possible in the event of a major component failure at the Blaine substation, with the new substation's normal load being temporarily transferred to Puget Power during such an event. The new substation would require four feeders. This approach would transfer the construction of extra facilities required for reserves from the City to Puget Power. This would also require both BPA and Puget Power approval and would likely entail payments by the City for the backup power sources.

Alternative 2

The Alternative 2 service area roughly coincides with urban growth area proposed by the City under the Growth Management Act, and includes the proposed H Street annexation area. This alternative would encompass approximately 8,934 acres; power demand at ultimate build-out of 10,319 dwelling units (estimated to occur in the year 2035) is estimated at 55 MW.

Alternative 2—Without Puget Power Backup (see Figure 2A). Power demands for Alternative 2 without Puget Power backup are virtually the same as for Alternative 1 without Puget Power backup, and the recommended upgrades are also similar.

Alternative 2—With Puget Power Backup (see Figure 2B). Power demands for Alternative 2 with Puget Power backup are virtually the same as for Alternative 1 with Puget Power backup, as are the recommended upgrades.

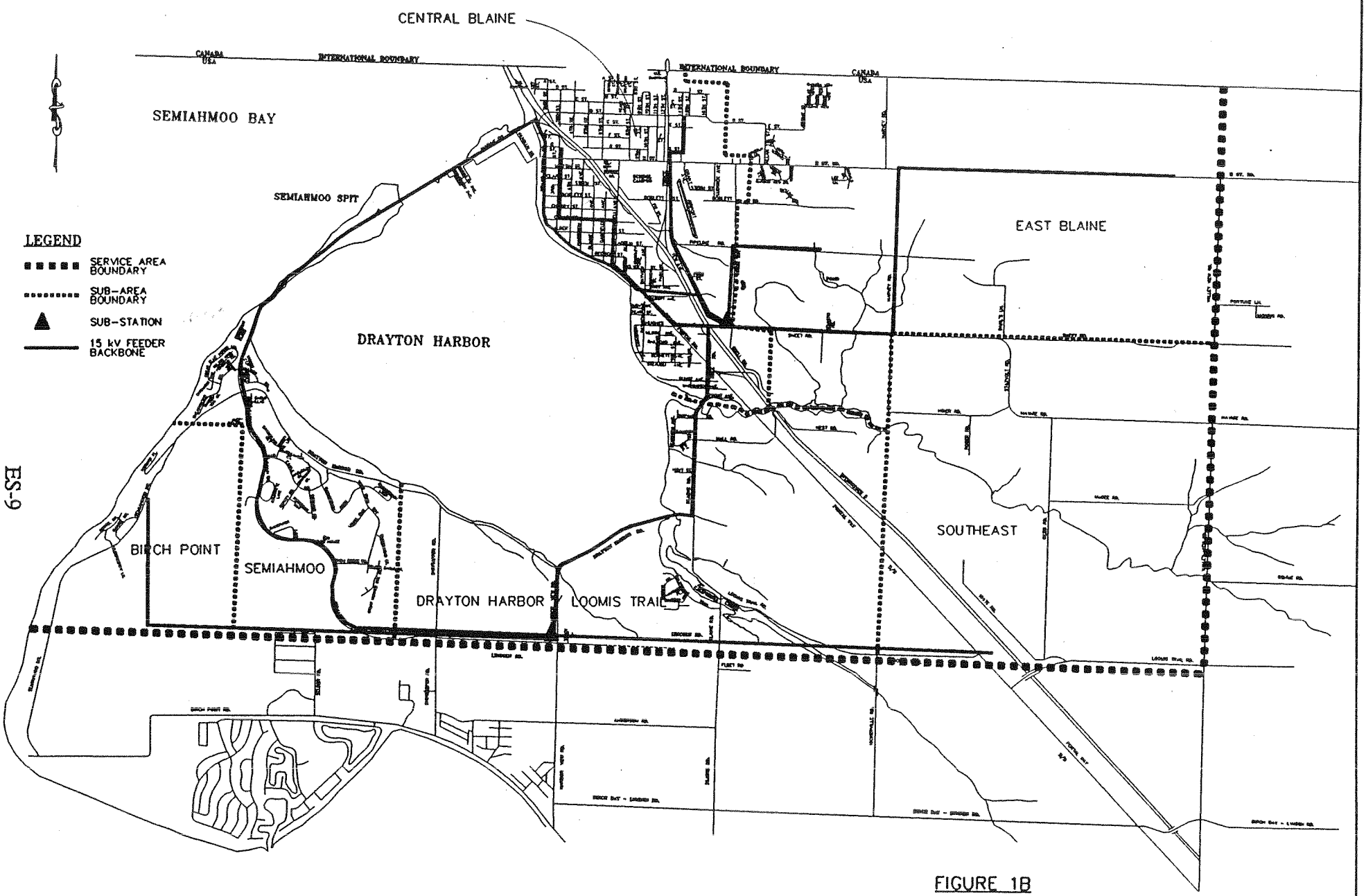

FIGURE 1B

ALTERNATIVE 1
SYSTEM CONFIGURATION WITH
PUGET POWER BACKUP CONTINGENCY

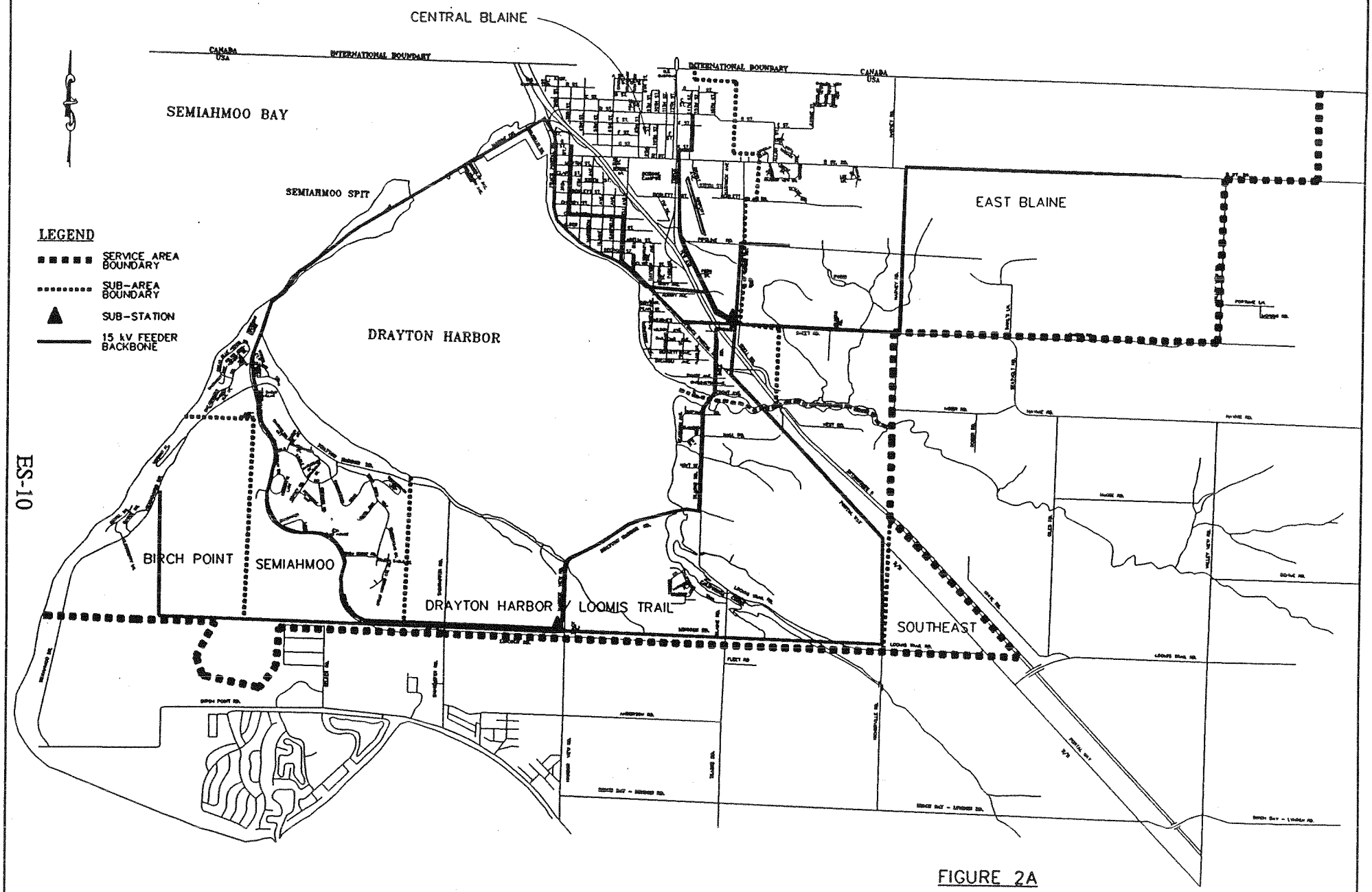

FIGURE 2A

ALTERNATIVE 2
SYSTEM CONFIGURATION WITHOUT
PUGET POWER BACKUP CONTINGENCY

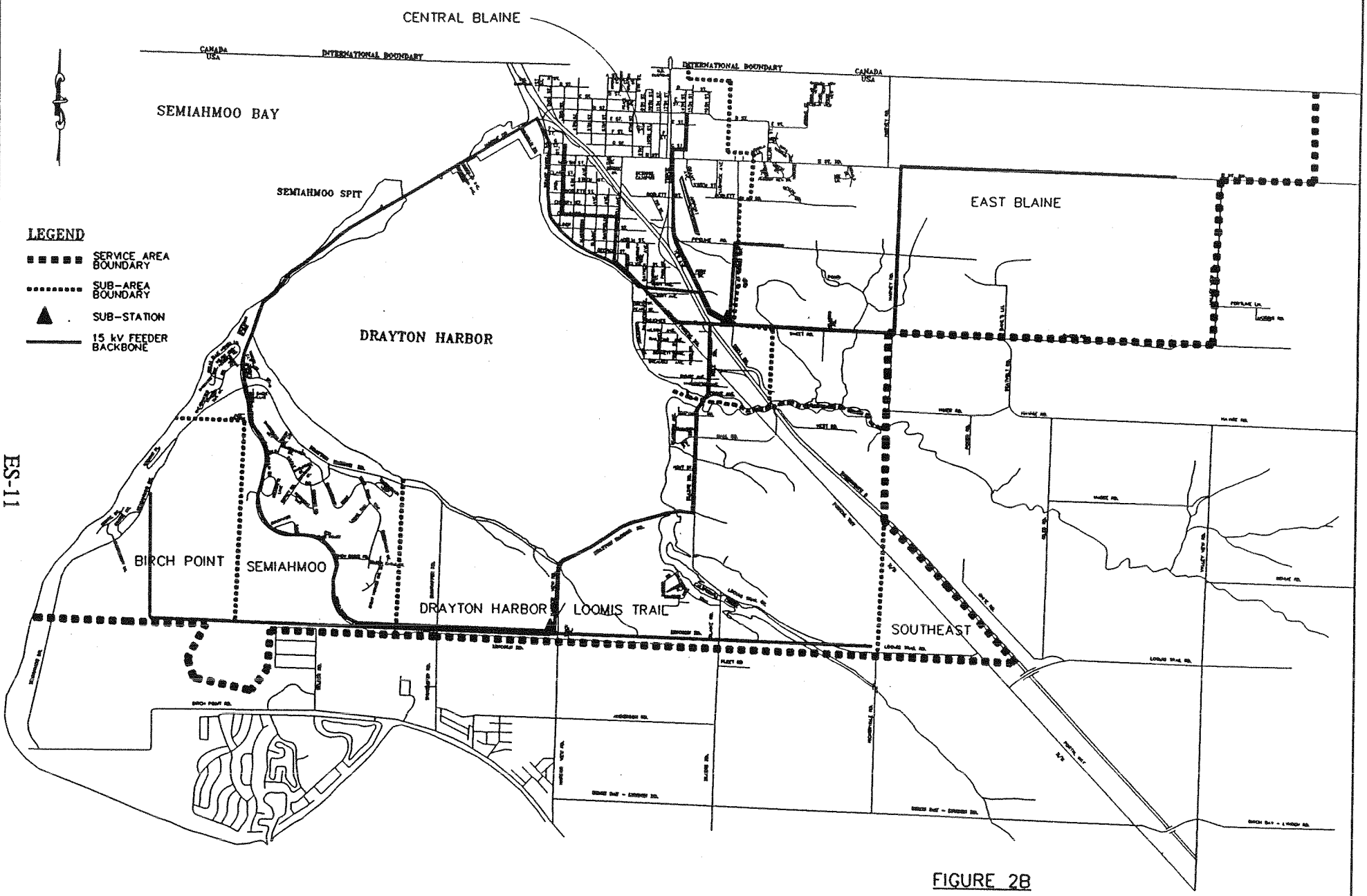

FIGURE 2B

ALTERNATIVE 2
SYSTEM CONFIGURATION WITH
PUGET POWER BACKUP CONTINGENCY

Alternative 3

The Alternative 3 service area includes all of the Alternative 2 service area plus an area south of Semiahmoo (including Birch Point) and another area east of I-5. This alternative would encompass approximately 11,272 acres; power demand at ultimate build-out of 11,467 dwelling units (estimated to occur in the year 2035) is estimated at 59 MW.

Alternative 3—Without Puget Power Backup (see Figure 3A). To meet the load requirements at ultimate build-out without relying on the aid of Puget Power for backup contingency, the total system capacity must be sufficient to carry the entire service area load in the event of a major transformer failure; a total system capacity of 93 MVA is recommended. To accomplish this, the transformer at the existing Blaine substation would be replaced at the end of its life cycle with a new 20/26/33 MVA transformer and double-banked with another 15/20/25 MVA station transformer when loading justifies it. A new 15/20/25 MVA substation would be built in the vicinity of Shintaffer, Harbor View, Drayton Harbor, and Lincoln Roads to serve the Birch Point, Semiahmoo, Drayton Harbor/Loomis Trail, and Southeast areas. With increased substation capacity, additional feeders would be needed to carry the loads. Seven feeders would be required to serve the upgraded substation and four would be required to distribute power to and from the new substation location.

Alternative 3—With Puget Power Backup (see Figure 3B). To meet the load needs at ultimate build-out with ample distribution interconnections with Puget Power, the total system capacity would be limited to that required to carry total loads and not to that required for backup contingency; the total system capacity would be approximately 56 MVA. To accomplish this at the time of ultimate build-out, it is recommended that appropriate interconnections be established with Puget Power, and that the existing Blaine substation transformer be upgraded at the end of its life cycle by replacement with a 20/26/33 MVA transformer. Six feeders would be necessary to provide adequate distribution from the upgraded existing substation and to provide interconnections with the new substation. Interconnection with Puget Power should be established and outage contingencies planned for the possibility of a major component failure; the interconnections should be capable of carrying approximately 30 MVA in the event that the Blaine substation transformer fails. Because of the load densities, adequate feeder connection between the existing Blaine substation and the new substation would be required so that portions of the existing substation's load could be shifted to the new substation and some of its load could, in turn, be shifted to Puget Power. The new substation would be built in the vicinity of Shintaffer, Harbor View, Drayton Harbor, and Lincoln Roads to serve the Birch Point, Semiahmoo, Drayton Harbor/Loomis Trail, and Southeast areas. The new substation would have a 15/20/25 MVA transformer and would require four feeders. This approach would transfer the construction of extra facilities required for reserves from the City to Puget Power. This would also require both BPA and Puget Power approval and would likely entail payments by the City for the backup power sources.

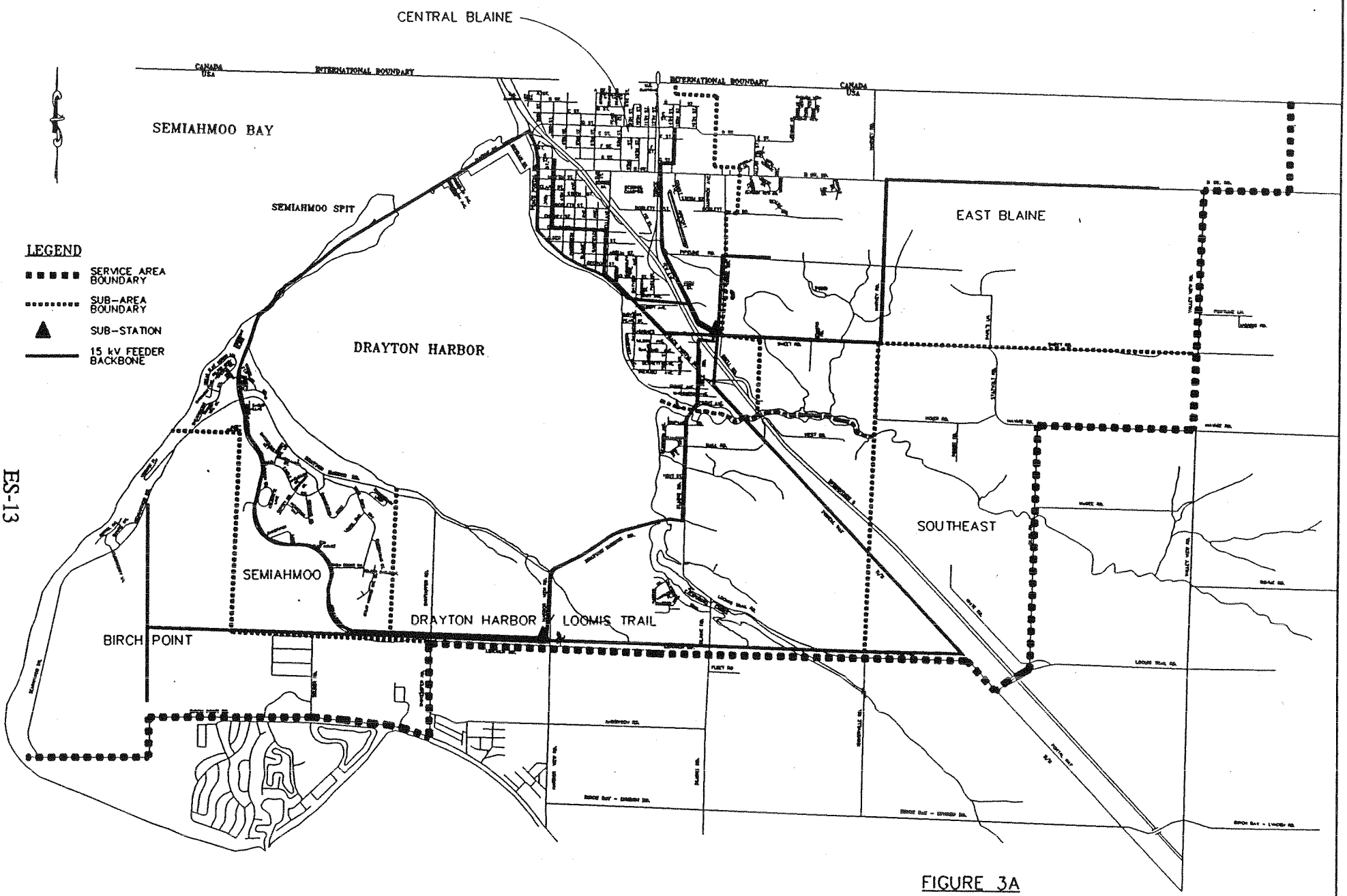

FIGURE 3A

ALTERNATIVE 3
SYSTEM CONFIGURATION WITHOUT
PUGET POWER BACKUP CONTINGENCY

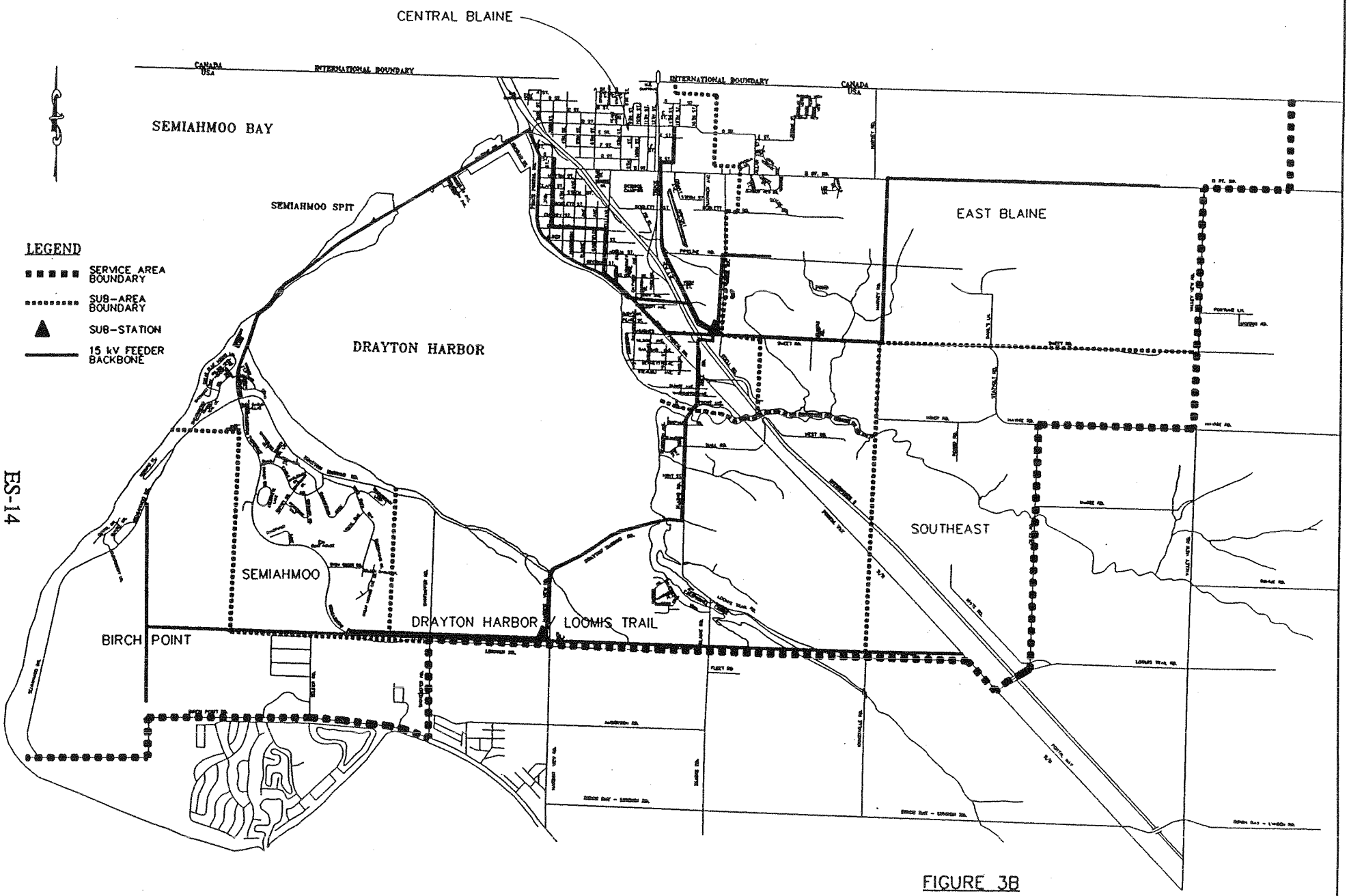

FIGURE 3B

ALTERNATIVE 3
SYSTEM CONFIGURATION WITH
PUGET POWER BACKUP CONTINGENCY

Alternative 4

Alternative 4 is the no-annexation alternative, or base case (see Figure 4). It assumes that the load at ultimate built-out (estimated to occur in the year 2035) would be that from within existing city limits and include loads currently served outside the city limits. This alternative would provide electrical service to some 2,500 acres and the approximate load would be 25 MW, with 17 MW from the Central Blaine area and the remainder from Semiahmoo and outside city limits. This alternative does not provide full service for a potential H Street annexation, and assumes that no Puget Power backup contingency is available. It is recommended that the capacity of the existing Blaine substation be increased and a new substation be built. The overall capacity required would be approximately 56 MVA. With two substations, there would be no need to increase the capacity of the existing substation. However, when the existing transformer reaches the end of its life cycle, we would recommend replacement of the 12/16/20 MVA transformer with a slightly larger 15/20/25 MVA transformer, which would increase the winter loading capacity to approximately 28 MVA. Four feeders would be required. For reliability and to serve the loads at Semiahmoo, a new 15/20/25 MVA substation should be built in the vicinity of Shintaffer, Harbor View, Drayton Harbor, and Lincoln Roads. Two feeder interconnections would be required.

Order-of-Magnitude Cost Estimates. The cost estimates for each alternative include the costs to acquire or construct required system components including substations, transmission lines, feeder backbones, three-phase and single-phase tap lines, distribution transformers, services, and protective devices. These costs also represent the full cost of constructing the additions to the system required at ultimate build-out. These cost estimates take into account existing facilities and customers served by the City, but do not account for Puget Power facilities that may be purchased and reused. The costs are gross costs in 1994 dollars and do not take into account any physical or financial contributions from Puget Power, from BPA, or from customers.

Alternative 1 - Without Puget Power	$47.4 million
Alternative 1 - With Puget Power	$43.5 million
Alternative 2 - Without Puget Power	$46.7 million
Alternative 2 - With Puget Power	$42.8 million
Alternative 3 - Without Puget Power	$51.8 million
Alternative 3 - With Puget Power	$47.9 million
Alternative 4 - Base Case Without Puget Power	$13.6 million

This report does not recommend a preferred alternative because the annexation policy decision will be made by the Blaine City Council after evaluating the other elements of the Comprehensive Plan and the implications of the various financial scenarios. An environmental checklist has been prepared based on the three expansion alternatives.

The three expansion alternatives and the no-annexation alternative are summarized in Table 1.

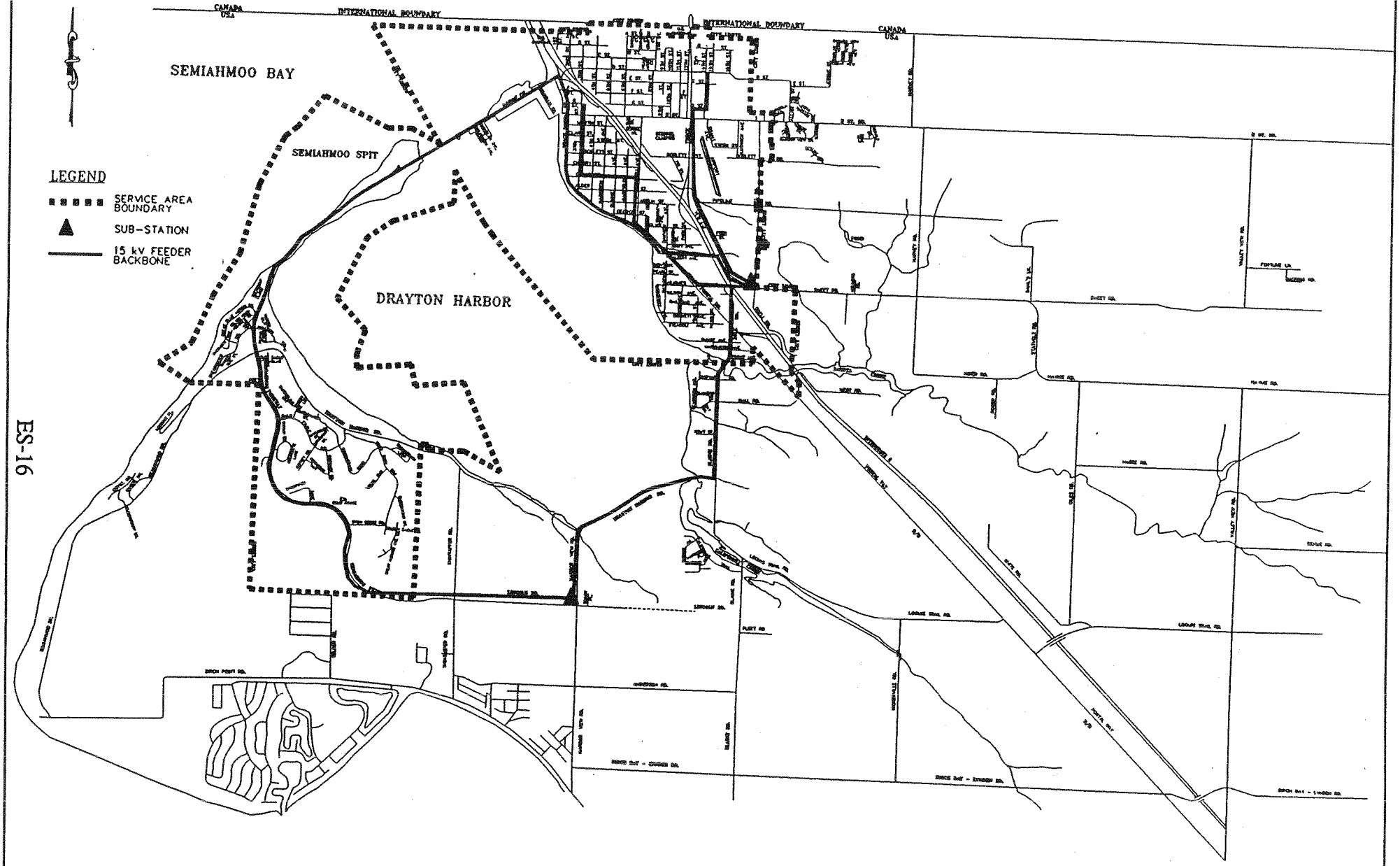

FIGURE 4

ALTERNATIVE 4 SYSTEM CONFIGURATION

Table 1 Summary of Alternatives					
Alternative	**Total System Requirements**	**Existing Substation (MVA)**	**New Substation (MVA)**	**Feeder Lines for each Substation**	**Order-of-Magnitude Cost Estimate ($ millions)**
1 - Without Puget Power backup 11,060 acres	84 MVA	Upgrade to 15/20/25; double-banked w/second 15/20/25	15/20/25	7 for existing; 4 for new	$47.4
1 - With Puget Power backup 11,060 acres	56 MVA	Upgrade to 15/20/25	15/20/25	5 for existing; 4 for new	$43.5
2 - Without Puget Power backup 8,934 acres	84 MVA	Upgrade to 15/20/25; double-banked w/ second 15/20/25	15/20/25	7 for existing; 4 for new	$46.7
2 - With Puget Power backup 8,934 acres	56 MVA	Upgrade to 15/20/25	15/20/25	5 for existing; 4 for new	$42.8
3 - Without Puget Power backup 11,272 acres	93 MVA	Upgrade to 20/26/33 double-banked w/ 15/20/25	15/20/25	7 for existing; 4 for new	$51.8
3 - With Puget Power backup 11,272 acres	56 MVA	Upgrade to 20/26/33	15/20/25	6 for existing; 4 for new	$47.9
4 - No Annexation (without Puget Power backup) 2,500 acres	56 MVA	Upgrade to 15/20/25	15/20/25	4 for existing; 2 for new	$13.6

Financial Plan

The City of Blaine Electrical Division currently has assets of approximately $4.6 million and annual revenues of approximately $3.1 million. The strengths of the Division's financial condition are its relatively low rates (20 percent less than Puget Power's) and the fact that it is free of long-term debt. However, the Division's financial reserves have dropped substantially in recent years and are now significantly below industry standards for operating reserves.

The Division is facing the prospect of rapid growth, additional increases in BPA rates in October 1995, and substantial capital costs associated with its needs for significant upgrades to the electric system. While rapid growth increases system revenues and offers some economies of scale, there is the prospect that BPA may establish a tiered rate system that charges higher prices for increased loads of wholesale customers such as the Division. The City of Blaine is also considering annexing some outlying areas and may choose to extend electrical service to these areas, replacing service currently provided by Puget Power. Acquisition of Puget Power's existing facilities or construction of new facilities in the potential annexation areas could increase the financial requirements of the City, and, depending on the investment cost, could require higher rates for the Division's customers overall. Conversely, the City could establish an annexation policy that would potentially require impact payments or new customer contributions so that annexation-induced growth would not raise rates higher than they would be because of other factors.

To establish a plan for the Division to follow in financing safe, reliable service for its customers, a financial planning computer model, FINPLAN, was developed. A number of assumptions were made in forecasting the Division's future financial condition. Blaine's population was assumed to grow by 2 to 5 percent per year; conservation programs were projected to reduce system loads by an additional 1.7 million kWh in 1994 and 5 million kWh in 1996. BPA power sales rates were forecast to increase an average of 5.1 percent per year between 1994 and 2000. General inflation was assumed to average 3 percent per year; the Division's future long-term debt interest rate was assumed to average 6.5 percent; interest earnings on Division investments were assumed to average 4.0 percent. Long-term bond financing costs were assumed to be 3 percent of the issue amount, with a 10 percent reserve requirement.

Five financial scenarios were evaluated. Scenario 1 assumes a medium load forecast associated with a 3.5 percent annual population increase and no expansion of the Division's service territory through annexation. Scenario 2 assumes a load growth of 2 percent and no annexation. Scenario 3 assumes 5 percent growth and no expansion. Scenario 4 assumes a 3.5 percent annual population increase and includes annexation; the existing utility plant in the annexed area would be acquired at a price equal to the estimated cost of replacing existing facilities with new facilities at current price levels. (Scenario 4 assumes the same service area described in Alternative 2; since all three of the annexation alternatives had similar financial outcomes, only Alternative 2 was analyzed.) Scenario 5 is the same as Scenario 4 except that the purchase price of the utility plant

was set equal to a payment that would result in essentially the same retail rate requirements as planned for Scenario 1. This last scenario defines either the level of annexed customer contributors required or the maximum price the Division can pay to Puget Power without impacting rates.

The results of applying the FINPLAN model to the above-described scenarios are presented in Table 2.

Table 2
Summary of Financial Scenarios

	Scenarios 1-3	Scenario 4	Scenario 5
Average Operating Cost Increase (nominal), 1994-2000	5.0 - 7.8%	10.9%	10.8%
Annual Debt Service on Capital Expenditures in 2000	$423,000 - $433,000	$1.17 million	$753,000
Average Revenue Requirements Increase (nominal), 1994-2000	8.1% - 10.3%	15.4%	14.2%
Average Rate Increase (nominal), 1994-2000	6.0 - 7.2%	7.6%	6.6% (same as for Scenario 1)
Debt-Equity Ratio in 2000 (percent of capitalization)	37.7 - 42.4%	62.0%	51.8%
Net Plant-in-Service in 2000 as a Multiple of 1994 (nominal)	2.4 to 2.7 times 1994	4.3 times 1994	3.4 times 1994

Financial System Planning Criteria. The Division will need to incur long-term debt to finance major capital improvements and the possible annexation of additional service area, requiring the adoption of bond covenants that will effectively require rates to be raised to meet debt service payments plus a margin that will likely be in the rage of 25 to 40 percent of the debt service payment. (This margin can be used to pay for ongoing capital improvements and to build reserves.) The Division should rebuild its reserves to approach the standard operating reserve levels described above. To keep rates low, the City should continue to use contributions in aid of construction from sources of system growth, and consider other funding sources such as impact fees and formation of local utility districts to fund investments that benefit specific groups of customers. The amount of long-term debt recommended in this Financial Plan was constrained by a goal of maintaining a "break-even" position on the Division's income statement; if the Division were willing to show losses on its income statement, it could reduce the size of rate increases in the short term (1995-1999) by issuing more long-term debt in such a way that the

utility's debt-equity ratio would approach 50 percent under Scenario 1. However, issuance of more long-term debt would result in much higher rates after 2000 and potentially higher interest rates in the short term.

Operations Plan

Two types of evaluations were performed in assessing the operations of the City of Blaine Electrical Division. An informal audit was conducted of the Division's management policies and procedures, and a statistical analysis was performed to establish performance benchmarks for the utility. Generally both types of evaluations indicated that the Division is well run. The principal concerns are in the areas of (1) communication between the Division and the public and (2) deteriorating financial reserves.

Planning is crucial for a public utility; planning helps to define objectives and develop policies and financial strategies. An important component of proper planning is an understanding of the long-term effects of short-term decisions. A utility should, therefore, establish a planning method that evaluates all elements of its operation. This evaluation requires recordkeeping that maintains comparability from year to year. Recordkeeping methods for utilities with at least 120,000 megawatt-hour sales have been standardized, and these statistics are published by the Energy Information Administration (EIA). The American Public Power Administration (APPA) collects and publishes similar data, sorted by class size, based on the number of customers the utility serves. The statistics used in establishing performance benchmarks for the Blaine Electrical Division draw from these sources.

The following types of information are illustrated graphically in the Operations Plan in this report. In some cases data were available from the Division to establish several years of trends. In other cases, the Division's performance is compared to that of other utilities. The following types of data were reviewed:

- Division Growth Statistics
  - Division customers per distribution line mile
  - Customers per Division employee over time
  - Customers per Division employee compared to other utilities
  - Division employees per customer over time
  - Division customers per meter reader
  - Customers per meter reader compared to other utilities
- Service Reliability Statistics
  - System reliability (comparison among utilities excluding Blaine)
- Revenue/Rate Statistics
  - Residential customer average electrical rates compared to other utilities
  - Division revenue per kWh sold by customer class

- Expense Statistics
  - Division total O&M expense compared with purchased power expense per kWh sold over time
  - Comparison of Division total O&M expense per kWh sold with other utilities
  - Division total O&M expense per retail customer over time
  - Division distribution and O&M expense per distribution line mile
  - Division administration and general expenses per retail customer

- Safety Statistics
  - OSHA incidence rates

- Customer Relations Statistics
  - Customer comments

- Employee Relations Statistics
  - Employee feedback forms

- Financial Performance Statistics
  - Division total cash reserve fund compared with industry standard operating reserves
  - Division total debt service coverage (net operating revenue/debt service)
  - Division projected debt/equity ratio
  - Division system losses (average kWh sold compared to kWh purchased from BPA)

Conservation Plan

The Division's energy conservation program began in 1991, with some elements not starting until 1993 and 1994. The Division's efforts have already resulted in a projected 1994 cumulative annual savings of more than 4 million kWh, or about 457 average kW, enough to provide power for approximately 320 average Washington households. Comparing Blaine's 1994 estimated cumulative kWh savings with its maximum achievable kWh savings potential in the year 2000 established by BPA, Blaine has already captured 78 percent of potential industrial savings, 61 percent of residential, 22 percent of existing commercial, and 8 percent of new commercial.

Blaine has exceeded the residential conservation annual targets set by BPA by as much as 244 percent. Commercial conservation savings for existing buildings were twice BPA's 1994 annual target. While the recorded number of participating commercial customers is slightly below the annual target set by BPA, this is a result of Blaine's strategic implementation of the program to focus initially on large commercial customers such as the border crossing. Commercial conservation for new buildings will no longer be a part of Blaine's conservation plan because Blaine will rely on the new-construction Model Conservation Standards code established in Washington State in 1994. Overall, the new

buildings were twice as energy efficient as expected; in 1994, with only 4 percent of the cumulative total of units expected to be participating by the year 2003, Blaine had already achieved 8 percent of the cumulative kWh savings goal. Conservation efforts for industrial customers have already resulted in achievement of 77 percent of the maximum achievable industrial kWh savings estimated by BPA.

At this time, participation in energy conservation programs is not mandatory for utilities. The main issue is the perception that each utility's *local* conservation efforts contribute primarily to the preservation and stabilization of the *regional* resource while providing local financial benefit. While conservation at the local level might enable a utility to buy smaller amounts of power from a wholesaler such as BPA, it may well be more cost-effective in an open power market for the utility to purchase power from another source rather than implementing conservation measures. Many other utilities look at conservation as an inexpensive source of power, much like generation.

In light of BPA's plan to end most conservation funding in October 1995 and to institute a tiered rate system that charges its utility customers a higher rate for larger amounts of power, there will be potential advantages to the City of minimizing its purchases of Tier 2 power. Because of this, and the need to evaluate conservation (or demand-side) resources on the same basis as supply-side resources such as power contracts and generation, continued implementation of many of the existing BPA conservation programs is recommended. While the City may wish to re-evaluate the conservation programs it offers, when the evaluation is completed, many if not most of the currently offered conservation programs may still be required. Because of BPA's plan to stop funding conservation, the Division's aggressive efforts at conservation have captured a larger than typical share of BPA money to fund local conservation measures.

Implementation Plan

The City of Blaine and the Electrical Division will be using the information and recommendations presented in this Comprehensive Plan Report to help make decisions regarding future directions for electrical service. Following is a summary of the recommendations presented in this report.

Projected Service Area and System Characteristics

For the three expansion alternatives, ultimate loads will run from about 55 to 59 MW of peak customer demand. The no-annexation alternative is projected to have an ultimate load of approximately 25 MW. It is apparent that the significant difference in capital facilities required to support these ultimate loads is between the no-annexation alternative (Alternative 4) and a Growth Management Plan-based service territory (Alternatives 1, 2, and 3). The differences in terms of invested capital or rates between Alternatives 1, 2, and 3 are small and should not influence the basic decision.

A number of facilities management and capital improvement decisions will be strongly influenced by the service area's ultimate load. Decisionmakers will need to keep in mind the ultimate load presented by the service area alternative when selecting the preferred alternative. All scenarios require construction of a new substation, associated transmission lines, replacement of the transformer within the existing Blaine substation, and construction of new feeders to connect the two substations at a distribution voltage.

System Planning Criteria

Specific objectives are suggested to support the following City goals:

- An acceptable level of public safety service delivery should be identified, consistent with community growth.
- A comprehensive emergency plan should be developed.
- The assets and facilities of the Division should be inventoried for state regulatory compliance and to plan for adequate infrastructure to achieve maximum operating efficiency.
- Divisional organization should be developed and restructured to provide the most effective and efficient electrical service to the citizens of Blaine.
- The Division should increase and stabilize its revenue base while reviewing existing programs for fiscal efficiency (i.e., the City should evaluate a capital borrowing program and/or assess impact payments from the developers of major new developments).

We recommend that the Division adopt these objectives and the suggested "single contingency-" based planning criteria.

Existing Facilities

To provide the required degree of reliability and to support the projected increase in ultimate demand, a number of upgrades are recommended:

- The Division should immediately investigate alternative substation sources of power delivery.
- A portion of the load from Circuit 15 could be transferred to Circuit 17 with proper protective device coordination.
- The main circuit backbone feeder conductor for Circuits 15 and 16 should be upgraded to 600 amps capacity as soon as practicable.

- Long-term and short-term contingency plans should be developed for the Semiahmoo area and for replacement of the submarine cable should it fail.

- Older wood-pole overhead lines should be monitored for decay, and periodic tree trimming should be performed along overhead line rights-of-way.

- Rates and financial requirements in the BPA power sales contract general services provisions (Sections 47 and 54) should be monitored. Changes in BPA services and rates should be monitored and the Division's rates adjusted in anticipation of such changes.

- Once the City Council has accepted the Growth Management Plan, negotiations should be initiated with Puget Power to update the previous service territory agreement.

Capital Improvements Plan

Four service area configuration alternatives have been discussed. Three expansion alternatives (based on three different annexation configurations) and one no-action alternative (based on no annexation) were evaluated, and an order-of-magnitude cost estimate was provided for each alternative. The three expansion alternatives (Alternatives 1, 2, and 3), whether configured with or without Puget Power backup contingency, are essentially the same in cost; the no-annexation alternative (Alternative 4) would cost about half as much as any of the expansion alternatives.

Projected load growth and reliability needs will require substantial capital investment regardless of which alternative is selected. The additional customers and power sales to an annexed area will help spread the costs of these basic improvements.

If an annexation policy is pursued similar to Alternatives 1, 2, and 3, the City Council should adopt policies to seek new customer capital contributions and impact fees.

Financial Plan

Five financial scenarios have been modeled, based on differing rates of population growth and annexation configuration. Regardless of which of the four service area alternatives described above becomes the preferred alternative, the Division will need to incur long-term debt to rebuild its reserves and to pay for ongoing capital improvements. It will also need to raise rates.

Scenarios 1, 2, and 3 assume low, medium, and high rates of growth, but no annexation. Under these circumstances, the Division's operating costs are projected to increase by an average of 5.0 to 7.8 percent in nominal terms between 1994 and 2000. Given that certain capital expenditures will be required for new projects regardless of load growth, the Division is forecast to be incurring debt service payments between $423,000 and

$433,000 in year 2000. It is recommended that the Division's unrestricted fund balance be rebuilt to a normal operating reserve level equal to 45 days of operating expenses excluding purchased power and depreciation. The Division's revenue requirements would increase by 8.1 to 10.3 percent per year. Lowest average rate increases occur with the highest customer or population growth.

Scenarios 4 and 5 assume annexation and are based on expansion Alternative 2. Scenario 4 assumes that annexation would include either purchase of Puget Power facilities within the annexation area at full replacement cost new (estimated at about $7.2 million in year 2000) or independent construction of such facilities by the Division. In annexations, utilities usually pay less than full replacement cost for the purchase of annexed property. However, in initial discussions with Puget Power about providing backup service to the City, Puget Power indicated that it should be compensated at the replacement cost new value. In the draft document circulated by Puget Power, dated April 28, 1993, it stated that "upon annexation by Blaine...Blaine shall...purchase...at a price equal to the amount, as reasonably determined by Puget Power, payable by Puget Power to replace such Distribution Facilities at the time of annexation." The costs of facilities in annexed areas in this report have been estimated at replacement cost new for two reasons: (1) it represents a "worst-case" cost of the facilities; and (2) it also provides for a cost that would allow the City to effectively construct duplicate facilities and therefore "strand" the Puget Power investment. If the City has evaluated full replacement cost new amounts, it is in a stronger negotiating position with Puget Power.

Scenario 5 assumes purchase of the facilities would be contracted so that the annexation would have no impact on rates between the assumed acquisition year of 1996 and the year 2000 (estimated at about $3.2 million). The Division's revenue requirements would increase in Scenario 4 at an average rate of 15.4 percent per year and in Scenario 5 at an average of 14.2 percent per year. Scenario 5 shows the level of discount that the City should try to achieve if it purchases Puget Power facilities, or the level of customer contributions if it is forced to build independent facilities.

Regardless of the financial scenario ultimately selected, the following are recommended as part of implementation of the Financial Plan:

- The financial reserves should be rebuilt as soon as possible by implementing a rate increase.

- The amount of rate increase could be reduced in the short term if the Division were willing to show losses on its income statement and issue more long-term debt in such a way that the Division's debt-equity ratio would approach 50 percent.

- The City of Blaine should continue to make use of contributions in aid of construction from sources of system growth.

- The Division needs to move quickly to borrow funds to implement needed capital improvements.

Operations Plan

The Operations Plan presents a number of statistics relating to the current performance of the Division, measured against its own past performance and against the performance of other electrical utilities. A number of different types of information can be gathered to assist the Division in assessing its performance. The Division should begin or continue gathering data of the types of information that best meet its needs.

The following recommendations for improving the operation of the Division are drawn from the informal management audit:

- The Division's informal verbal management style, which was suitable for a small utility, should be formalized into written policies and procedures.

- The Division's achievements should be communicated more clearly to City policymakers and the public.

- The Division needs better financial tracking and control information to properly manage its resources.

- The Division should provide the City Council with materials such as plans, charts, and recommendations, and provide clearer justification of expenditures and communication of requests.

- A Division policy should be developed for determining where City staff, Division staff, or contractors are used to accomplish certain tasks, and a procedure should be developed for supervising contractors.

Conservation Plan

In light of BPA's plans to end most funding for conservation programs and institute a tiered rate structure in one underlying recommendation is presented regarding the various energy conservation programs in which the Division is participating:

- The Division should review the cost-effectiveness of its conservation programs and maintain those that are effective in helping reduce the need to purchase additional power from BPA at more costly Tier 2 rates. Detailed information on Tier 2 policies is not yet available from BPA.

Under current BPA contracts, federal legislation, and regional policy, the City must maintain conservation programs. Under BPA's proposed rate increases, conservation measures will allow the Division to defer purchases of higher-cost Tier 2 power.

Conclusions

The Division has assets of about $4.6 million, annual revenues of about $3.1 million, and no significant outstanding debt. In addition, the Division's rates are favorable when compared to the rates of similar utilities and to those of Puget Power, which provides power outside the city. However, current Division rates are not recovering sufficient revenues and the Division's financial reserves are well below what they should be. This has occurred primarily because the City Council, in its evaluation of community needs, has not allowed the Division to pass along to its customers increases in the wholesale price of power that the Division purchases from BPA.

The Capital Improvements Plan and the Financial Plan show the changes to the physical system that need to take place under various City annexation alternatives. The Division should expend funds to reduce the potential for major outages on its system. The costs of implementing the required capital improvements will require higher rates. The size of the increase can be reduced by using borrowed funds that spread the cost of the major capital programs over their useful life. However, to borrow funds at favorable rates, the Division needs to show a solid financial program that includes increasing the Division's financial reserves. Because BPA is planning to raise rates again this fall, it is important that the Division's rates be increased before BPA's increase. That means a rate hearing at the City in the spring of 1995 and a rate increase in the summer of 1995.

Under a no-annexation policy, average retail rates will need to increase on the order of 6 to 7 percent per year until the year 2000. These average increases are based upon BPA increases of about 5 percent per year. The 6 to 7 percent per year forecast of average retail rate increases is derived from a modeling of all system costs including purchased power, debt service coverage on capital improvements, administration and general expenses, and operation and maintenance costs. BPA increases of 5 percent do not result in 6 to 7 percent per year retail increases. However, with the construction of capital improvements funded by bonds, rebuilding of the Division's reserve fund, forecasts of BPA purchase power increases, and other costs included within the financial model, a 6 to 7 percent average retail rate increase is the result.

The City's annexation policy does not need to increase the cost of power to its citizens; annexation can be accomplished in a revenue-neutral way, either by purchasing Puget Power facilities below their full replacement cost or by using impact fees and customer contributions associated with the expansion of major capital projects.

Once the City determines its urban growth boundaries and its annexation policy, the Division should negotiate with Puget Power to purchase facilities as the city limits

expand. The Division should conduct discussions with its BPA account executive to evaluate the new power sales contract that will be offered this year, and to determine the new costs that will be in BPA's rates. Concurrently, the Division should work with its financial advisor and bond counsel to acquire funds that will be used to pay for the necessary capital improvements recommended in this report. An important element of the funds acquisition process will be a commitment to improve the Division's financial condition.

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Chapter 1

Introduction

Chapter 1
Introduction

This Electrical Utility Comprehensive Plan Report comprises the electrical utilities element of the City of Blaine's Comprehensive Plan. It has been prepared for the City of Blaine's Electrical Division (the Division), which is a subdivision of the City's Department of Public Works. This report incorporates the requirements of the Washington Administrative Code, Washington State's Growth Management Act, the City's power sales contract with the Bonneville Power Administration (BPA), and standard electrical utility practices. It draws on past studies of the Division, input from City of Blaine and BPA staff, site visits, studies performed specifically for this report, and local, state, and federal guidelines and regulations.

The City's goals regarding provision of electrical service are listed below:

- Develop and restructure the utility's organization to provide the most effective and efficient service to the citizens of Blaine
- Increase and stabilize the revenue base while reviewing existing programs for fiscal efficiency
- Identify an acceptable level of public safety, provide a level of service consistent with community growth, and establish a comprehensive emergency plan
- Inventory assets and facilities for state regulatory compliance and to plan for adequate infrastructure to achieve maximum operating efficiency

This report evaluates the City of Blaine's existing electrical utility service, projects future requirements for services, and discusses methods of financing projected capital expenditures.

The report also presents three expansion alternatives in addition to a no-action (no-annexation) alternative, and discusses the capital improvements required to provide adequate service, assessing the capital improvement requirements for each of the expansion alternatives both with and without backup from Puget Power. The no-annexation alternative is discussed assuming that there will be no Puget Power backup contingency available.

This report does not recommend a preferred alternative because this decision will be made by the City Council after evaluating the other elements of the Comprehensive Plan and the implications of the various financial scenarios. An environmental checklist has been prepared based on the three expansion alternatives.

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Chapter 2

Projected Service Area and System Characteristics

Chapter 2

Projected Service Area and System Characteristics

Introduction

Effective electrical system planning is based on delivering reliable power to customers. Our approach is to estimate the ultimate electric loads within various areas based upon projected zoning and other factors. Once this ultimate load for an area is estimated, a generalized electric plan of service can be formulated. The electric plan of service will show the number of substations and number of major feeders that will eventually be required. By comparing this future requirement to the current system, we can evaluate the locations and types of new electric facilities that will be required, and suggest ways to expand the existing electrical system that will be consistent with the ultimate needs of the utility's customers. This approach minimizes wasted capital facilities.

To estimate the City of Blaine Electrical Division's ultimate loads, we first estimated the total number of residential customers to be served when the land served by the Division is fully developed. In general, the zoning of the area under consideration is used to approximate the number of residential customers in that area, which in turn is used to approximate the commercial and industrial loads. Adjustments to the zoning numbers are made for acreage that is not likely to be built upon, such as wetlands, setbacks from streams, open space requirements, and public facilities. These adjustments were discussed with City planning staff.

Estimates of peak demand usage per dwelling and percentage of homes electrically heated were then applied to the adjusted number of dwelling units to arrive at an ultimate load for the area. For our analysis we assumed a peak contribution of 4.6 kW per single-family electrically heated dwelling unit; 2.8 kW per electrically heated duplex/multifamily dwelling unit; 3 kW per non-electrically heated residential dwelling unit; and 2 kW per non-electrically heated duplex/multifamily dwelling unit. These are diversified peak loads at the substation and feeder backbone level; a single distribution transformer with multiple services would have a higher diversified peak load. These values were determined by CH2M HILL, based upon load research performed by Puget Sound Power and Light Company (Puget Power) and Snohomish County Public Utility District (PUD), and on judgments of peak usage at the time of full development.

While most utilities believe that energy usage per customer will decrease in the future, many utilities are reluctant to credit comparable peak reductions per customer during extremely cold weather. The CH2M HILL analysis assumes that peak usage per customer will only be slightly reduced. This implies that the system load factor will decrease over time. In an electrically heated dwelling, the majority of the energy consumption is due to heating (both space heating and hot water heating) because of the inherent energy requirements. The percentage of homes that will use electric heat in a

fully developed area was based upon judgments as to the present level of electric heat usage, the present availability of natural gas, and estimates as to the future penetration of natural gas usage into certain areas. Natural gas penetration was discussed with City planning and Electrical Division staff. The information was then combined in a spreadsheet program to produce peak loads by area. This final estimate of electric power needs for a given area is referred to as the ultimate load or ultimate load density.

The ultimate loads were determined for four different areas that were considered for future electrical service areas for the City of Blaine.

Alternative 1: This service area coincides with the historical City of Blaine/Puget Power service territory agreement. This area is bounded by Lincoln Road to the south and Valley View Road to the east (see Figure 1). Its load at ultimate build-out (estimated to occur in about the year 2035) is approximately 55 MW. (One megawatt, or MW, is one million watts of power or 1,000 kilowatts.)

Alternative 2. This service area roughly coincides with the City's proposed urban growth area (see Figure 2). This area is bounded on the south by Lincoln and Loomis Trail Roads; however, it also includes the portion of the Semiahmoo West development that lies outside of the city limits and to the south of an imaginary extension of Lincoln Road. At Interstate-5 the boundary runs northwest along the interstate to an imaginary extension of Harvey Road, then north to the Harvey Road and Sweet Road intersection. The boundary continues east along Sweet Road to Valley View Road, then north on Valley View Road to H Street, east on H Street to the eastern edge of the proposed H Street annexation area, then north to the border. Its ultimate load is approximately 55 MW.

Alternative 3. This service area was defined by the City to include the full proposed H Street annexation (see Figure 3); the area's boundary then runs south along the Valley View Road to Haynie Road, west to Giles Road, south to Loomis Trail Road, west along Loomis Trail and Lincoln Roads, south along Shintaffer Road, and west along the Birch Point Road to the water. Its ultimate load is approximately 59 MW.

Alternative 4: This service area lies roughly within the existing city limits and does not include the potential H Street annexation. It does include ultimate build-out within city limits and the load the City is currently serving outside the city limits. Its ultimate load is approximately 25 MW.

CH2M HILL evaluated zoning in the four alternative service areas. For those areas outside of the existing city limits, we evaluated both the existing county zoning and the zoning proposed within the City of Blaine's Growth Management Plan (GMP). On a "macro" basis, the amount of power required was not significantly different, with the exception of power requirements in the Birch Point area south of Semiahmoo. Because the existing county zoning resulted in slightly higher ultimate loads, we used that zoning

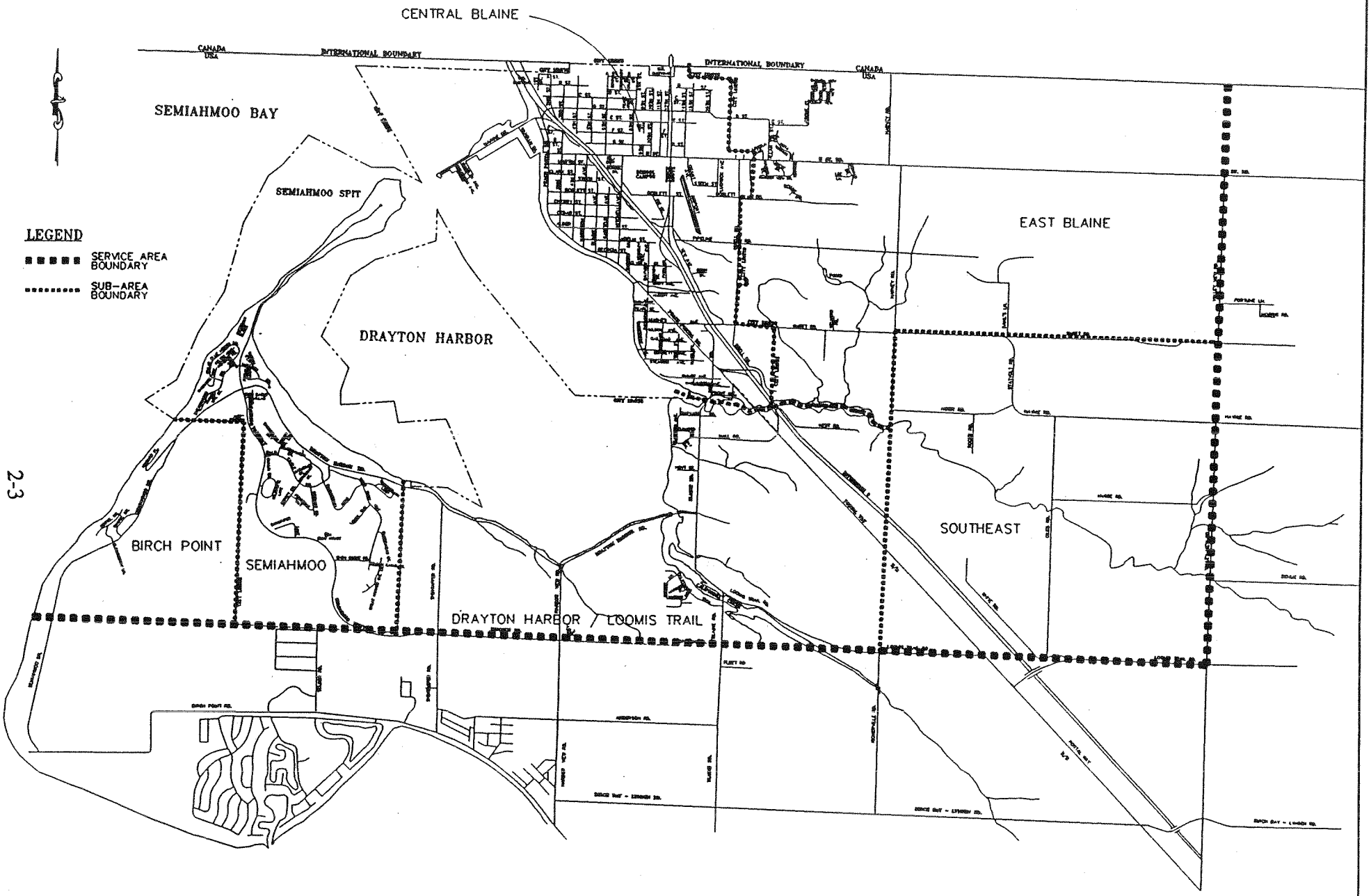

FIGURE 1

ALTERNATIVE 1 SERVICE AREA

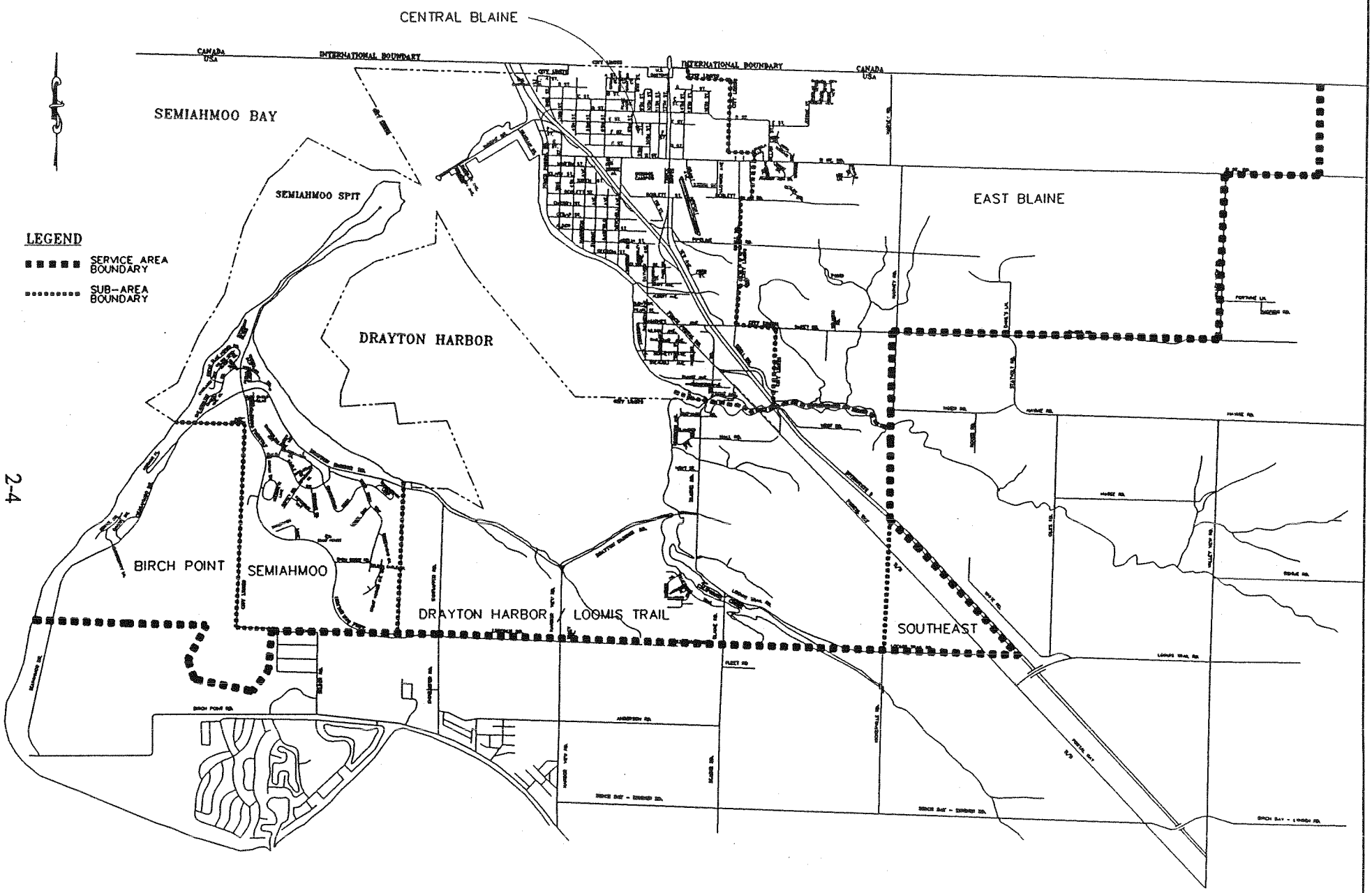

FIGURE 2

ALTERNATIVE 2 SERVICE AREA

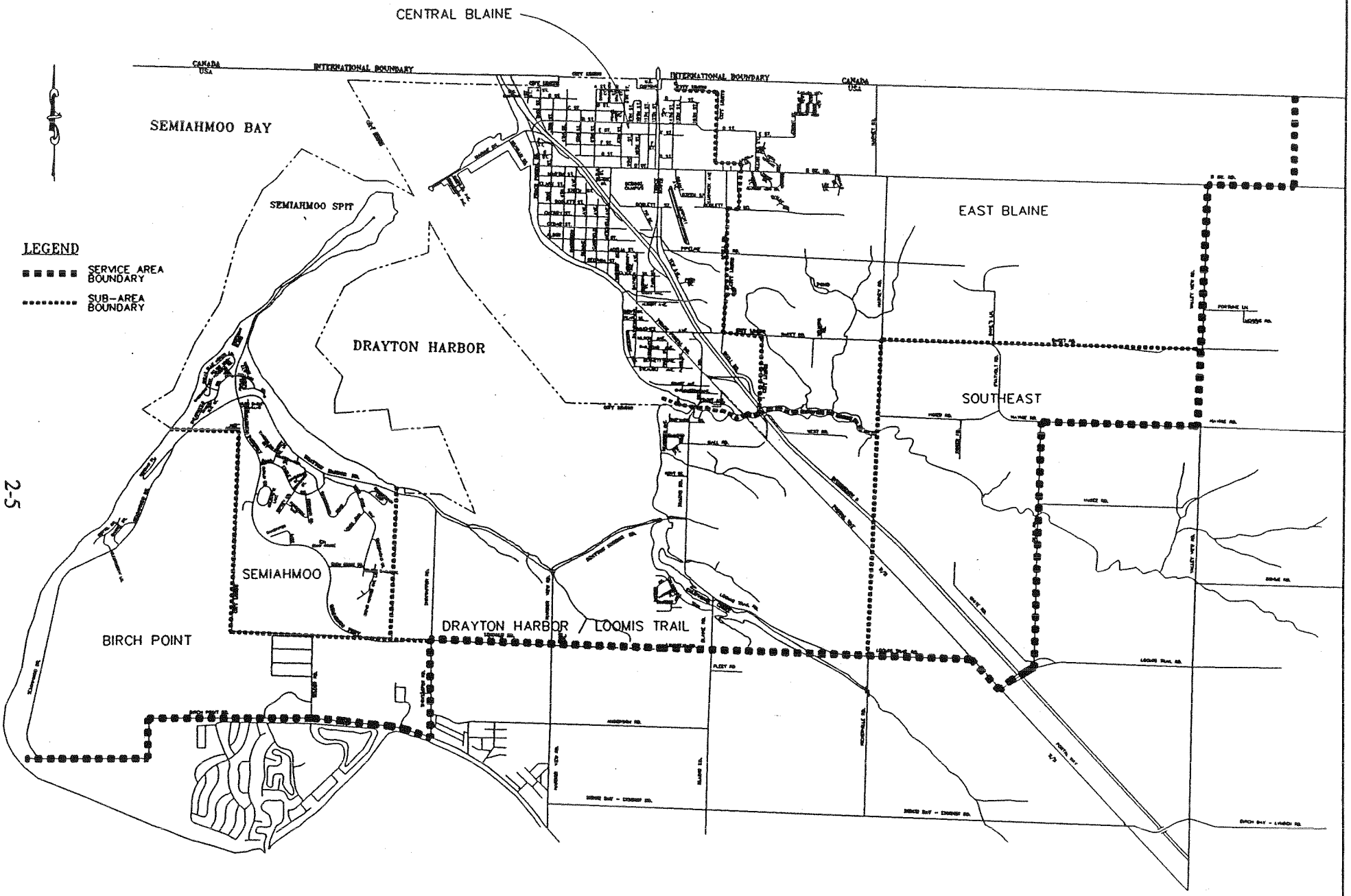

FIGURE 3

ALTERNATIVE 3 SERVICE AREA

to ensure that electric facilities would be compatible with the three areas as they are developed past the 2015 time horizon contained within the City's GMP. The use of this assumption should not significantly change the results, but it provides for a slightly more conservative approach to planning for the ultimate build-out of the areas.

Analysis by Geographic Area

Each alternative area discussed above was subdivided into six smaller areas for purposes of analysis. These smaller areas have been given the names used within the City of Blaine GMP. Their exact boundaries may not totally coincide with those terms used within the City's GMP as this study is being driven by utility boundaries. These smaller areas are shown in Figures 1, 2, and 3.

Central Blaine

This is the original site of Blaine, and is located to the northeast of Drayton Harbor and south of the Canadian border. The area boundaries are the same for all three alternatives. It represents the existing city boundaries and excludes the area across Drayton Harbor in the Semiahmoo development. At present, Central Blaine has the majority of the commercial zoning in the alternative areas. Therefore, the majority of commercial needs will be located within Central Blaine and the Semiahmoo Spit. Small commercial development outside of Central Blaine will be assumed to occur in response to residential development demands.

The loads for the Central Blaine area are principally due to commercial zoning. We have assumed in our estimate that only 40 percent of the acreage will be built upon, in light of wetlands, public facilities (roads, recreation areas), and open-space requirements. We have also assumed that 50 percent of all of the dwelling units are electrically heated at build-out. This part of the city presently has a high proportion (about 75 percent) of electric heat; however, future construction is expected to be primarily natural gas. Our ultimate estimate is that there will be approximately 1,796 dwelling units. This is about 50 percent more than the present number of dwelling units. Commercial and industrial load are assumed to grow to 10,000 and 2,000 kW, respectively. The ultimate loads for the Central Blaine area are assumed to be fully developed at 16,888 kW.

Semiahmoo

The Semiahmoo area is to the southeast of Drayton Harbor and includes the Semiahmoo and West Semiahmoo developments within the city limits. The area boundaries are the same for all three alternatives. Our estimate assumes that about 40 percent of the acreage will be built upon, with the remainder being devoted to open space, golf course and common areas. We have also assumed that almost all homes in the area will be heated with natural gas at build-out. Our ultimate estimate is that there will be approximately

1,431 dwelling units. Commercial load is estimated to grow to about 3,000 kW. The ultimate load for the Semiahmoo area is assumed to be fully developed at 6,894 kW.

Birch Point

The Birch Point area generally lies to the southwest of the Semiahmoo development, outside the city limits. The area boundaries are different for each alternative. For each alternative we have assumed that 60 percent of the acreage will be built upon; we have also assumed that only 20 percent of all dwelling units will be electrically heated at build-out. This whole area is presently served by Puget Power.

In Alternative 1, the Birch Point area is bounded on the north and east by the city limits, on the south by an imaginary extension of Lincoln Road, and on the west by Semiahmoo Bay (see Figure 1). Our ultimate estimate for Alternative 1 is approximately 900 dwelling units.

In Alternative 2, the Birch Point area is the same as in Alternative 1, except it includes the Semiahmoo West development which lies outside the city limits and to the south of the imaginary extension of Lincoln Road (see Figure 2). Our ultimate estimate for Alternative 2 is approximately 1,110 dwelling units.

In Alternative 3, there are additional developed lands just south of Lincoln Road and east of the central Birch Bay community area. This additional area is bounded by Lincoln Road to the north, Shintaffer Road to the east, and the Birch Point Road to the south. Our ultimate estimate for Alternative 3 is approximately 2,095 dwelling units.

In addition to residential loads, we estimate about 500 kW of commercial load. The ultimate loads for the Birch Point area are assumed to be fully developed at between approximately 3,488 to 7,456 kW, depending upon the area served. The portion south of Lincoln Road included in Alternative 3 represents a significant load increase.

Drayton Harbor/Loomis Trail

The Drayton Harbor/Loomis Trail area is to the east of the Semiahmoo development. It is bounded by Drayton Harbor and Dakota Creek to the north, Loomis Trail and Lincoln Roads to the south, an extension of Kickerville Road to the east, and the city limits at Semiahmoo to the west. The area boundaries are the same for all three alternatives. Our estimate assumes that about 40 to 70 percent of the land will be built upon. We have also assumed that 25 percent of dwelling units will be electrically heated at build-out. Our ultimate estimate is that there will be approximately 2,986 dwelling units. In addition, commercial load is estimated to grow to about 2,000 kW. One of the significant commercial loads in this area is the KARI radio station. The ultimate load for the Drayton Harbor/Loomis Trail area is assumed to be fully developed at 12,153 kW.

East Blaine

East Blaine is bounded on the north by the Canadian border, on the west by the Central Blaine area, on the south by the Drayton Harbor/Loomis Trail and Southeast areas (from the city limits and Dakota Creek, east to Harvey Road, north to Sweet Road, and east to Valley View Road), and on the east generally by Valley View Road. The area boundaries are the same for Alternatives 2 and 3, but differ for Alternative 1. For each alternative we have assumed that about 50 to 70 percent of the land acreage will be built upon; we have also assumed that between 50 to 100 percent of all dwelling units will be electrically heated at build-out, depending upon the distance from natural gas facilities.

In Alternative 1, East Blaine is bounded on the east by Valley View Road and an imaginary extension north to the border (see Figure 1). Our ultimate estimate for Alternative 1 is approximately 2,860 dwelling units.

In Alternatives 2 and 3, East Blaine is bounded on the east by Valley View Road to H Street (see Figures 2 and 3). The boundary then extends to the east to include the full potential H Street annexation. Our ultimate estimate for Alternatives 2 and 3 is approximately 2,971 dwelling units.

In addition to residential loads, we estimate about 2,000 kW of commercial load. The ultimate load for the East Blaine area is assumed to be fully developed at between approximately 13,222 to 13,662 kW, depending upon the area served.

Southeast

The Southeast area is generally bounded to the west by the Drayton Harbor/Loomis Trail area (extension of Kickerville and Harvey Roads) and to the north by the East Blaine area (Sweet Road). The area boundaries are different for each alternative. For each alternative we have assumed that 70 percent of the land will be built upon; we have also assumed that 85 percent of all dwelling units will be electrically heated at build-out.

In Alternative 1, the Southeast area has a southern boundary of Loomis Trail Road and an eastern boundary of Valley View Road (see Figure 1). This coincides to the historical Puget Power service territory agreement. Our ultimate estimate for Alternative 1 is approximately 310 dwelling units.

In Alternative 2, the Southeast area consists of a triangle of land bounded by an extension of the Kickerville Road to the west, Interstate-5 to the northeast, and Loomis Trail Road on the south (see Figure 2). Our ultimate estimate for Alternative 2 is approximately 25 dwellings.

In Alternative 3, the Southeast area is bounded on the east by Valley View Road between Sweet Road and Haynie Road, and by Giles Road between Haynie Road and the Loomis

Trail/Interstate-5 crossing (see Figure 3). Our ultimate estimate for Alternative 3 is approximately 188 dwelling units.

In addition to residential loads, we estimate about 1,000 kW of commercial load. The ultimate loads for the Southeast area are assumed to be fully developed at between approximately 1,108 to 2,351 kW, depending upon the area served. This area represents a relatively small portion of the overall loads.

No Annexation

Another alternative to be considered is "no annexation," Alternative 4. This would include ultimate build-out within the existing city limits and can be approximated by adding the Central Blaine and Semiahmoo area loads. The sum of these two areas represents about 23.8 MW of load.

The ultimate load for this service area, including the area that the City is currently serving outside the city limits, is approximately 25 MW.

Conclusions

The ultimate loads are summarized in Table 2-1. This table shows that for the three alternatives being evaluated (in addition to the no-annexation alternative), the ultimate loads will run from about 55 to 59 MW of peak customer demand. Therefore, on a macroscopic basis the differences among the GMP areas in these three alternatives in terms of peak load, and hence capital facilities required, should not be huge. The significant difference in capital facilities is between existing city boundaries (Alternative 4) and a GMP-based service territory (Alternatives 1, 2, and 3).

Table 2-1 also shows that there will be about 10,000 to 11,000 dwelling units at ultimate build-out. At roughly two people per household, this represents an ultimate population within the three alternative service areas of about 20,000 to 22,000 people.

In the analysis being conducted in support of the City's GMP, the population is estimated as shown in Table 2-2.

Therefore, the ultimate development projection of 20,000 to 22,000 people will occur well after the year 2015. At a growth rate of 5 percent per year, the ultimate development population would be reached between the years 2035 and 2038. While it is unlikely that the city would sustain 5 percent growth per year throughout the build-out period, we can use this assumption to test some of the electrical service planning assumptions.

Table 2-1
Ultimate Load Densities

AREA	ZONING	ACREAGE BY ZONING ALTERNATIVE 1	2	3	% USE	D.U./ AC	DWELLING UNITS ALTERNATIVE 1	2	3	% ELEC HEAT	POWER DEMAND (KW) ALTERNATIVE 1	2	3
Central Blaine	R	14	14	14	40%	0.3	2	2	2	50%	7	7	7
	RL	219	219	219	40%	4.7	412	412	412	50%	1,565	1,565	1,565
	SDR	128	128	128	40%	5.0	256	256	256	50%	614	614	614
	RM	322	322	322	40%	6.5	837	837	837	50%	2,009	2,009	2,009
	RH	20	20	20	40%	13.0	104	104	104	50%	250	250	250
	R/O	42	42	42	40%	11.0	185	185	185	50%	444	444	444
	Commercial	575	575	575	-	-	-	-	-	-	10,000	10,000	10,000
	Industrial	-	-	-	-	-	-	-	-	-	2,000	2,000	2,000
	Sub-total	1,320	1,320	1,320	-	-	1,796	1,796	1,796	-	16,888	16,888	16,888
East Blaine	"H" Street Annex	1,108	1,182	1,182	50%	3.0	1,662	1,773	1,773	60%	6,582	7,021	7,021
	UR4	454	454	454	60%	4.0	1,090	1,090	1,090	50%	4,140	4,140	4,140
	R10	1,554	1,554	1,554	70%	0.1	109	109	109	100%	500	500	500
	Commercial	113	113	113	-	-	-	-	-	-	2,000	2,000	2,000
	Sub-total	3,229	3,303	3,303	-	-	2,860	2,971	2,971	-	13,222	13,662	13,662
Southeast	R5	1,840	142	955	70%	0.2	258	20	134	85%	1,123	87	583
	R10	748	71	775	70%	0.1	52	5	54	85%	228	22	237
	Commercial	-	-	-	-	-	-	-	-	-	1,000	1,000	1,000
	Sub-total	2,588	213	1,730	-	-	310	25	188	-	2,351	1,108	1,819
Drayton Harbor/ Loomis Trail	UR4	1,487	1,487	1,487	40%	4.0	2,379	2,379	2,379	25%	8,089	8,089	8,089
	R5	600	600	600	50%	2.0	600	600	600	25%	2,040	2,040	2,040
	R10	99	99	99	70%	0.1	7	7	7	25%	24	24	24
	Commercial	-	-	-	-	-	-	-	-	-	2,000	2,000	2,000
	Sub-total	2,186	2,186	2,186	-	-	2,986	2,986	2,986	-	12,153	12,153	12,153
Semiahmoo	UR4	180	180	180	40%	6.0	432	432	432	0%	1,296	1,296	1,296
	RPR	750	750	750	40%	2.0	600	600	600	0%	1,800	1,800	1,800
	MPR	57	57	57	70%	10.0	399	399	399	0%	798	798	798
	Commercial	-	-	-	-	-	-	-	-	-	3,000	3,000	3,000
	Sub-total	987	987	987	-	-	1,431	1,431	1,431	-	6,894	6,894	6,894
Birch Point	UR4	750	925	1,746	60%	2.0	900	1,110	2,095	20%	2,988	3,685	6,956
	Commercial				-	-	-	-	-	-	500	500	500
	Sub-total	750	925	1,746	-	-	900	1,110	2,095	-	3,488	4,185	7,456
SYSTEM TOTAL		***11,060***	***8,934***	***11,272***	-	-	***10,283***	***10,319***	***11,467***	-	***54,997***	***54,891***	***58,873***

Load Assumptions:
4.6 kW power demand per electric heat residential customer.
2.8 kW power demand per electric heat duplex/multifamily customer.
3 kW power demand per non-electric heat residential customer.
2 kW power demand per non-electric heat duplex/multifamily customer.

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Table 2-2 City GMP Population Assumptions		
Growth Rate/Year	**2000**	**2015**
Low Growth (2 percent/year)	3,165	4,260
High Growth (5 percent/year)	4,108	8,539

Another way to examine the reasonableness of our ultimate build-out load estimate is to compare it to the most recent (1992) BPA peak forecast for the city. The BPA forecast is based upon no annexation and modest (less than 1.7 percent per year) growth. That forecast estimates the peak load to be 22.4 MW in the year 2011. If we look at the combined Central Blaine and Semiahmoo loads at build-out, they are about 23.8 MW. At a growth rate of about 1.7 percent per year, the 22.4 MW system load would grow to 23.8 MW in about 4 years or 2015. This cross-check again confirms that our ultimate load appears to be reasonable from an order-of-magnitude basis.

The reason that electric utilities consider looking at the ultimate load is that there are a number of decisions such as distribution voltage and standard substation size that determine the ability to serve ultimate loads in a cost-effective manner. Many electric system investments, such as transmission lines, are considered to have 20- to 30-year economic lives. If we did not consider ultimate loads, it may be necessary to abandon significant expenditures of capital assets in the future. By looking further, we are able to see if the voltages, feeder sizes, and substation sizes are reasonable long-term investments that will last their full economic life.

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Chapter 3

System Planning Criteria

Chapter 3
System Planning Criteria

In 1994, Blaine adopted a mission statement, beliefs, strategic policies and goals for the City. The Electrical Division, as part of the City, needs to have goals and objectives that are consistent with those of the City but are specific to its role in providing electric power. The following are reproduced from published City documents:

Blaine Mission Statement:

> "The City of Blaine will provide responsible and credible government for our community, by maximizing resources within the community and respecting diversity while committing to majority decisions."

The goals of the City of Blaine are listed below:

- "Develop and restructure departmental organization to provide the most effective and efficient service to the citizens of Blaine."
- "Increase and stabilize revenue base while reviewing existing programs for fiscal efficiency."
- "Identify an acceptable level of public safety service delivery consistent with community growth and establish a comprehensive emergency plan."
- "Inventory assets and facilities for state regulatory compliance and plan for adequate infrastructure to achieve maximum operating efficiency."

Suggestions for potential objectives for the Division are grouped under specific City goals that they support:

- Develop and restructure departmental organization to provide the most effective and efficient service to the citizens of Blaine.

  1. Conduct an informal audit of the Electrical Division in 1994. (The results of this audit are presented in Appendix A of this Comprehensive Plan Report.)

     An informal audit identifies where the utility is doing a good job and where additional effort may be required. It also includes an organizational review. (Information on the costs and statistics of other benchmark organizations, presented in Chapter 7, can be used to identify areas of potential change for the Division.)

2. Identify benchmark utilities to compare for labor comparisons and develop an annual reporting system.

   Participate in the APPA data collection program and publish a comparison of the Blaine Electrical Division to both APPA and selected Northwest utilities of comparable size and situation.

3. Develop monthly labor statistics for Division and start a monthly reporting system to the City Manager.

   Choose a method of recording labor (dollars or time) that identifies the amount of labor available on a monthly basis (potential labor reduced by sick leave, vacations, holidays, and mandatory regulatory training requirements). Track the amount of labor on a monthly basis and identify its principal uses (construction, operations, maintenance, administrative and supervision, inspection of work by others, etc.).

4. Perform an annual comparison of the Division's average electric rates to those of Puget Power and selected benchmark public utilities. (If the City of Blaine's rates were significantly above those of Puget Power, there could be pressure upon the City not to annex areas on the basis of electric rates. Similarly, if Blaine's rates are higher than the rates of Puget Power in surrounding areas, the ability of Blaine to attract industries and commercial tax base to the City will be constrained.)

   As part of the BPA Conservation Action Plan, rate comparisons were made. We suggest that these benchmark utilities be re-evaluated for future comparisons.

5. Identify major customers and develop a schedule to meet with them annually.

   Develop lists of the 10 largest electric customers, 10 reliability-sensitive loads, and large developers. Identify ways to meet with representatives of these groups at least annually to discuss areas of mutual concern.

6. Annually mail a brief (20-question or less) customer survey form with City bills to assess "customer owner satisfaction" and develop a database to measure future changes in satisfaction.

   Coordinate the mailing of an Electrical Division Questionnaire with the appropriate City departments.

7. Implement two public works rosters of pre-qualified contractors: excavation and hauling associated with electrical construction, and electrical contractors.

   Advertise, bid, evaluate, and award two public works rosters for contractors annually.

- Increase and stabilize revenue base while reviewing existing programs for fiscal efficiency.

1. Review the general financial condition using 1993 year-end data to make a pro forma estimate of 1994 financial condition based upon current rates.

   On the basis of the Financial Plan, determine the adequacy of existing rates for the rest of 1994.

2. Propose to the City Council a working capital reserve amount required for the Electrical Division.

   Based upon input from consultants and other City departments, determine the appropriate size of reserve funds for the Division.

3. Work with the finance department, consulting engineer, financial planner, and bond council to identify capital borrowing and impact payment programs.

   Recognizing the need for significant capital expenditures over the near term to provide looped service to Semiahmoo, to provide for additional substation capacity, and to perform deferred system improvements, the City should evaluate a capital borrowing program. Generally, growing utilities borrow a specific fraction of their capital needs to spread the costs of those facilities over the time that they are used. Public utilities like the Division can also work with developers to negotiate voluntary payments by the developers for

facility and infrastructure improvements needed to accommodate growth associated with specific developments. This approach shifts capital improvement costs from today's electric customer to the customers of the system over the life of the system improvement. Initial financing strategies are contained within the Financial Plan.

4. Develop a rate strategy based upon projected capital needs.

   Take estimates of future rate changes to the Electric Utility Advisory Committee, the City Council Utilities Subcommittee, and the City Council for discussion. Recognizing that the rates need to strike a balance between keeping rates low and providing for certain levels of service, seek policy guidance on a rate strategy. Preliminary survey information indicates that most Northwest utilities have chosen to develop a program where rates are raised in small increments, as opposed to large increases that create greater hardships. (Typically, utilities prefer to raise rates annually, in increments below 10 percent, rather than every 2 to 5 years in much higher amounts.) Similarly, there are a number of potential changes in BPA rates (tiered rates and unbundled services) that could put upward pressure on rates over and above the pressure needed to rebuild adequate financial reserves.

5. Work with the finance department to develop a group of monthly financial indicators for the Division.

   There are a number of short-term financial indicators that will help the Division recognize if costs and revenues need adjusting. Examples include the monthly tracking of working capital reserves, power revenues, purchased power costs, labor expenses, material expenses, and accounts payable. These indicators will need to be coordinated with the finance and accounting department of the City to minimize additional work for that department.

- Identify an acceptable level of public safety service delivery consistent with community growth and establish a comprehensive emergency plan.

1. Collect reliability data in a standard form and track with statistics to allow benchmark comparisons.

   Reliability data should be collected as reported in the APPA statistics.

2. Establish a long-term goal on reliability, such as "no more than x hundred customers will be without power for more than x hours due to the failure of a single electric system component owned by the City." (This could be implemented over time by building backup feeders or ties between feeders that would allow for load to be shifted between circuits.)

   In consultation with operations staff and CH2M HILL, the Division's Manager should determine a backup reliability goal as outlined above.

3. Develop a contingency plan for Semiahmoo service in the event of a submarine cable failure.

   The contingency plan for a submarine cable could include identification of materials, permits, risks, and development of work sketches for stringing a temporary overhead span across Drayton Harbor above the submarine cable on an emergency basis. A better solution would include an evaluation of and negotiations with Puget Power on temporary connections that could be used in the event of such a failure. A third alternative would be the identification of a submarine cable repair firm and determinations of the time it would take to repair the cable, likely cost, and contracting requirements.

4. Develop an employee standby service policy that specifies a general maximum response time to an outage event, and track statistics to measure the response time.

   The Division is in the process of developing a standby service policy. The initial target of a 30-minute response time from receiving a telephone call to having a person in the field investigating the problem appears reasonable. That policy should be completed. Response time to get initial personnel to an outage should be tracked, as should standard outage/reliability statistics.

- Inventory assets and facilities for state regulatory compliance and plan for adequate infrastructure to achieve maximum operating efficiency.

  1. Develop an inventory of major electric system assets (power circuits, substation capacity available, BPA contract, and service territory agreement) and evaluate the assets.

     This was accomplished as reported in Chapter 4, Evaluation of Existing System.

  2. Commit to an annual comparison of expenditures to budgeted funds, with discussions of deviations from budget.

     Each July, the Division should take actual year-end financial numbers and compare them to budgeted amounts for the previous year as part of its part of its budget planning process.

  3. Develop a long-range capital improvements plan as part of the Comprehensive Plan process, and update the 5-year portion of the long-range plan at least every 2 years.

     The initial component is Chapter 5 of this Comprehensive Plan Report.

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Chapter 4

Evaluation of Existing System

Chapter 4
Evaluation of Existing System

Introduction

The City of Blaine Electrical Division's existing system consists of three distribution circuits, which are owned and maintained by the Division. These circuits are connected to the Blaine substation, which is owned and maintained by Puget Sound Power & Light Company (Puget Power). The Division is a full-requirements customer of the Bonneville Power Administration (BPA) and buys all of its power from BPA. The BPA power sales contract with the City of Blaine is a comprehensive document that imposes many requirements upon both BPA and the Division. BPA has a transfer contract with Puget Power to wheel electricity over a Puget Power 115 kV transmission line to a Puget Power substation. The Division has three points of delivery (12.47 kV breaker positions within the Puget Power substation) from BPA.

Substation

The Division is served from Puget Power's Blaine substation, which is located at Hughes and Yew Avenues. Puget Power wheels power from BPA to the Division over a 115 kV transmission line from Puget Power's Portal Way substation, which is connected to BPA's Custer substation. This service is provided by Puget Power to BPA under a transfer agreement between the two utilities. The voltage is transformed from 115 kV to 12.47 kV (line to line) in the Blaine substation where five distribution breaker positions are available, three that are used by the Division and two that are used by Puget Power. The Blaine substation has an operating capacity of approximately 24 MVA (24 MVA is equal to 24 MW at unity power factor; 1,000 kW equals 1 MW). The present BPA-Puget Power transfer agreement limits service to the Division at 15.3 MW, and BPA has requested that Puget Power raise the limit to 17.5 MW. This request is under consideration by Puget Power and may require the completion of this analysis and a presentation of a long-range system plan by Blaine before the request is resolved. The substation and its equipment provide an adequate power delivery mechanism to the Division during normal conditions.

It is important to understand that the Blaine substation is being supplied with power via a radial transmission line and that there is a single-station transformer. This situation can be interpreted as providing limited reliability, but such limited reliability is not uncommon for an electric utility the size of the Division. In the event of a transmission line failure or a substation transformer failure, the entire substation and its service areas would be out of service for an extended period of time.

In addition, BPA's historical peak load data indicate that the City has, on occasion, exceeded its allocated load capacity. This is an indication that other substation or transformer sources of power delivery should be investigated in order to meet increasing customer demand. Possible alternatives to increase capacity would be to either add substation capacity at the Blaine substation or provide additional capacity from another substation location. BPA's customer service policy will not pay for a fourth feeder position. Therefore, additional capacity at another substation site would entail either removing one delivery point at the Blaine substation or paying for an additional customer convenience delivery point. However, the addition of transformer capacity at a different substation will potentially provide some added reliability during both transmission and substation outages.

If the Blaine substation fails, it is Puget Power's responsibility to replace the transformer. Puget Power has mobile substations that could be moved to this location, but it would take several hours to several days to move a mobile substation and connect it. The City could discuss a mobile substation contingency plan with Puget Power; currently, such discussions should be part of the agreements between Puget Power and BPA. Because Puget Power customers are served from the substation, Puget Power could be expected to provide a backup source of power as quickly as possible.

Puget Power is also facing growth pressures in the Birch Bay area and at some point will need additional capacity. It may be possible to negotiate another "shared" substation under an arrangement similar to that at the Blaine substation, wherein Puget Power constructs and maintains the substation and provides the City with several circuits. This concept was pursued originally with Puget Power. Provided it is acceptable to BPA, and if negotiations can be fruitful with Puget Power on sharing the capacity of a substation at a reasonable cost, this alternative should be explored.

Distribution Circuit 15

The service area of Circuit 15 is primarily on the west side of Interstate 5, excluding the Semiahmoo area. It serves the downtown area and Marine Drive in the north, and south to the Loomis Trail Golf Course clubhouse. This circuit consists primarily of overhead distribution lines; however the downtown area, Loomis Trail Golf Course, and certain residential areas are served by underground distribution. The downtown area has a number of critical reliability loads including police and fire services.

This circuit has a summer recommended capacity of approximately 4.32 MVA (200 amps) and a winter recommended capacity of 6.26 MVA (290 amps) based on the 1/0 ACSR (aluminum cable steel reinforced) main circuit backbone conductor. Circuit load data indicate that this circuit has approached or exceeded its recommended capacity on various occasions. There are two options available to remedy this situation. The first is to transfer some of the load onto another circuit; the second option is to reconductor

the main circuit backbone to a location where the recommended capacity of the conductor is not exceeded or preferably has room for growth. The first option is the most expeditious and least costly to implement. Circuit 17 is capable of carrying additional load; however, voltage levels should be examined at the end of the circuit to ensure proper voltage levels are being maintained with an increase in load.

Generally, to coincide with BPA delivery point customer service policy and typical Northwest utility practice, CH2M HILL would recommend that backbone circuits should be designed for approximately a 600-amp capacity. This corresponds to an overhead conductor size between 336.4 and 556.5 kCM or an underground conductor size between 750 and 1,000 kCM, based on conductor capacity required and cost of losses (economic conductor sizing). Before the circuit is to be reconductored, the ultimate load density and the optimal circuit configuration should be determined. From this information portions of the circuit can be upgraded periodically. These upgrades can occur when new construction is required because of specific customers, with the undergrounding of overhead facilities, or during road modifications. Other than a minor conductor capacity limitation, limited backup ties exist to Circuit 17. Circuit 17 should be capable of carrying partial load from Circuit 15. However, because of circuit length, voltage regulation may be required in the event of Circuit 17's carrying all the load of Circuit 15.

Distribution Circuit 16

Circuit 16 serves the area north of E Street and east of Odell Road, including south of "E" Street to Boblett between 8th Street and Odell Road. Notable customers are the border crossing, school, east side of the airport, the International Market, and the City's wells east of Pipeline Road. The border crossing represents a critical reliability load to the City. This circuit consists of both overhead and underground distribution lines.

Circuit 16 has a summer recommended capacity of approximately 6.48 MVA (300 amps) and a winter recommended capacity of 9.50 MVA (440 amps), based on the 4/0 ACSR main circuit backbone conductor. The historical peak load for this circuit is 4.54 MW, which occurred in October 1990. Circuit 16 provides adequate service for its present use under normal conditions. Again, as with Circuit 15, this circuit should be upgraded to a 600-amp circuit as the opportunity arises. Limited backup ties exist to Circuits 15 and 17. Depending upon loading at the time of required backup, Circuits 15 and 17 are capable of carrying ample load from Circuit 16. Because of circuit length, voltage regulation may be required in the event of Circuit 17's carrying excessive load from Circuit 16.

Distribution Circuit 17

Circuit 17 serves a small portion of Blaine along the Interstate 5 corridor to include the west side of the airport, commercial property south of the school on Fir Avenue, a sewer

lift station on Marine Drive, and a few residential customers. This portion of the circuit consists primarily of underground distribution lines. The circuit then continues to the submarine cable across Drayton Harbor. The majority of the load on this circuit is on the west side of the Semiahmoo area. This area serves the Semiahmoo resort, the City's sewage treatment plant, and the residential development adjacent to the golf course.

Circuit 17 has a summer recommended capacity of 4.32 MVA (200 amps) and a winter recommended capacity of 6.26 MVA (290 amps), based on the 1/0 ACSR main backbone circuit conductor. The historical peak load for this circuit is 3.24 MW, which occurred in October 1990. Circuit 17 is not heavily loaded; however, because of its length it is susceptible to voltage drop concerns. Long, heavily loaded circuits of limited conductor size may not be able to provide power of sufficient voltage unless regulators are installed. Under normal conditions, Circuit 17 does not have excessive voltage drop problems. If a load is to be transferred from another circuit to Circuit 17, voltages to the end of the line should be examined to ensure that proper voltage levels are maintained. If a load is to be permanently transferred to Circuit 17, care should be taken in selecting protective devices so that interruptions are properly sectionalized. For emergency backup, Circuit 15 is capable of carrying partial loads of Circuit 17. Because Circuit 15 is heavily loaded during peak conditions, the load at time of required backup would have to be closely examined.

Circuit 17 serves the entire Semiahmoo area via a submarine cable that crosses the mouth of Drayton Harbor. This submarine cable was installed in 1976. The submarine cable consists of a four-conductor (three single-phase conductors with a neutral conductor) 1/0 AWG copper cable with a rubber neoprene jacket installed in a 5-inch poly conduit. This conduit was jointly installed with sewer, water, and telephone services. The cables are near the end of the physical life of a typical submarine cable. At present there is no backup source to serve the Semiahmoo service area in the event of an interruption that could not be quickly repaired; e.g., a failure of the submarine cable. Repair or replacement of a damaged submarine cable probably would require a significant amount of time. A temporary overhead line backup would require significant permits and represent a potential legal liability to the Division because of clearance problems for ships during high tide. Because of age and likely condition of the submarine cable, short- and long-term contingency plans should be devised. Alternative electric feeds for the Semiahmoo service area have been investigated by CH2M HILL and others. The previous long-range recommendation was for the Division to attempt to share the capacity of a new substation with Puget Power and to develop a method for backing up Circuit 15, 16, and 17 loads from this new substation. These negotiations have been put on hold pending the adoption of the City's Growth Management Plan.

Backup service to the Semiahmoo area could be provided by a substation constructed either by the City of Blaine or by Puget Power. When this was explored in the past, Puget Power indicated that it would construct a substation only if the City agreed to certain service territory boundary limits and committed to a level of facility payments that

was judged by the City as too high. Negotiations stopped pending a decision by the City on its preferred Growth Management Plan urban growth boundary.

BPA was also involved in these discussions. BPA has indicated that under its customer service policy, it would not pay the additional cost of any new substation agreement that did not reduce its transfer contract charges with Puget Power. A new Puget Power substation in the Semiahmoo/Birch Bay area would increase the BPA transfer charges. The City of Blaine could either pay for such facilities directly to Puget Power, or pay through BPA. Tax-exempt capital costs associated with money borrowed by the City are lower than the cost of money to either Puget Power or BPA. Therefore, the City would be a lower-cost source of the funds to construct the substation. While construction by Puget Power would entail a lower first-year cost to the City, the City has the option of using bonds or borrowed funds to spread the capital cost over the useful life of the substation. Operation and maintenance (O&M) costs should not be a major factor in the overall cost.

BPA Power Sales Contract

The Division purchases its power from BPA under a BPA power sales contract. That contract is an important asset to the City and the Electrical Division. The contract provides that BPA will provide for the full electric power requirements of the Division. It also places certain limitations on what the Division can do. If Blaine desires to purchase resources from other sources (B.C. Hydro, cogeneration, etc.), it may do so only under certain specific notification requirements found within Section 12b. Section 12b allows for modification of the City's Exhibits I and J to the power sales contract.

Another constraint upon Blaine imposed by the BPA contract applies to the addition of large new loads. Within the Regional Power Act and Section 8 of the power sales contract are certain provisions dealing with new large single loads. These are usually very large industries. Such a load would have a peak demand in excess of 10,000 kW. While it is not likely that such large loads will occur within the City, any large industries should be evaluated as to their size and the Section 8 limits. Section 8 allows the City to serve such loads but at higher power costs and after significant notice.

The General Contract Provisions within Exhibit B to the power sales contract require the Division to perform in a planned and prudent way. Section 23 requires the Division to control power harmonics; Section 25 requires the Division to balance phases; and Section 31 pledges both BPA and the Division to operate within certain environmental constraints. Section 47 also relates specifically to cities. Section 47 states:

> "(a) Publicly owned city electric systems should be operated and maintained:

(1) primarily for the benefit of the users of electricity;
(2) in accordance with reasonable standards of safety, reliability, quality, and efficiency, and
(3) to maintain the cost of electric power at the lowest level consistent with good service and proper maintenance.

(b) Revenue requirements shall insure a financially sound and self-supporting electrical system. This requires that revenues be sufficient for:

(1) Reasonable and necessary current maintenance and operating expenses, including salaries, wages, cost of power at wholesale, materials, supplies, insurance, necessary renewals and replacements of plant, and the establishment of reasonable funds for such purposes, contingencies, and other lawful charges.
(2) Interest and principal of indebtedness incurred for the electric plant and payments required to be made into any special bond funds.
(3) Depreciation of electric system property to the extent not adequately provided for by amortization of debt and by renewals and replacement.
(4) Payments made into a governmental entity general fund via taxes or payments in lieu of taxes. The percentage of gross electric revenues used for this purpose shall be an amount not exceeding the greater of the following:
    (i) an amount which is equal to five percent of the gross electric revenues, unless a greater amount is provided pursuant to the city charter or agreements in effect as of December 5, 1980; or
    (ii) the amount of State or local taxes levied upon the Purchaser's electric system or its operations.

(c) A local governmental entity, when acting in its governmental capacity, and receiving electric service, shall be a Consumer and be billed for such services consistent with the rates charged other Consumers in the same class. The Purchaser shall receive prompt payment for such electric services. Payments by the Purchaser for necessary services or materials received by the Purchaser from other governmental departments, shall be limited to a fair, reasonable and nondiscriminatory charge.

(d) Taxpayers' investments in the electric system, made through use of general government funds of the city, should be treated in the same manner as funds borrowed by the electric system from outside

sources, and should receive a return approximating the market rate of interest on comparable securities. Such market rate of interest shall not exceed 6 percent per annum unless a larger amount is approved by Bonneville.

(e) All surplus revenues from retail sales remaining after meeting requirements of subsections (b), (c), and (d) above, where applicable, should be applied to reduction of rates. Surplus revenues earned in any year may properly be devoted to the purchase or retirement of system indebtedness before maturity, to the extent that such use thereof is consistent with the above principles and practices."

Section 54 contains certain commitments on establishing retail rates, maintaining data that support those rates, and providing BPA with notice of changes in rates.

The BPA power sales contract has been found to be a beneficial agreement for most Pacific Northwest electric utilities. It and BPA power have served the Division well in the past. BPA is undergoing a series of changes that will likely change the relationship between the Division and BPA. Some of the changes that are now being discussed are the "unbundling" of BPA services, which could encourage the Division to build transmission and substation facilities. Also, BPA is proposing a "tiered" rate system that would encourage the Division to increase its consideration of conservation and generation options to augment BPA power. The Division will need to monitor these changes and adjust to them.

City Undergrounding Policy

In the past the City's undergrounding policy has been interpreted by the Electrical Division to mean that all new and major projects within the city limits should be underground. Recently, in a road relocation project, an alternative was created that would allow consideration of rebuilding electric facilities associated with a road widening as either underground or overhead electric power lines. The undergrounding policy contains cost, visual aesthetic, and reliability implications. The existing Division electric system consists of both overhead and underground lines. Exceptions to the City's undergrounding policy have recently been approved by City Council.

CH2M HILL recommends that, in the review of the undergrounding policy, the Division policymakers allow 12.47-kV lines to be built as overhead lines in rural and low-density areas. Overhead lines generally have less capital cost than underground lines of similar capacity. Overhead lines also allow for greater flexibility in low-density areas for the connection of new customers. Underground lines are less susceptible to tree-related outages and are more aesthetically pleasing. Because the Electrical Division does not have a significant reserve fund and because of the financial pressure on the utility, lower-initial-cost construction is an important option, especially in rural areas.

Similarly, should the Division at some point own or operate transmission voltages in excess of 55 kV, those electric transmission lines are better as overhead lines from both cost and reliability considerations. Standard electric utility practice is to keep transmission facilities as overhead facilities except in specific situations (high-rise city centers, airports, and special sensitive environmental areas).

Service Area Agreement Between the City and Puget Power

The Division's service area agreement with Puget Power has expired. Under that agreement the Division would provide service generally to the north of Lincoln Road/Loomis Trail and to the west of Valley View Road. The agreement contemplated that, as the City annexed out into this area, the City would provide electric services to the customers. In turn, the City was to make payments to Puget Power for Puget's distribution lines sold to the City.

Service territory agreements are important between utilities. Many such agreements among Northwest utilities have not been used much; many have also expired. Recently, as electric utilities have become more competitive over new customers, the importance of service territory agreements has increased. It is CH2M HILL's recommendation that, once the Growth Management Plan boundaries are clarified, the Division initiate negotiations with Puget Power to update the previous service territory agreement.

Recommendations/Action Items

1. Investigate other substation sources of power delivery.

2. Transfer load from Circuit 15 to Circuit 17; examine voltage levels and provide protective device coordination.

3. Upgrade the main circuit backbone conductor of Circuits 15 and 16 to 600 amps as soon as practicable.

4. Devise short- and long-term contingency plans for the Semiahmoo service area.

5. Monitor condition of old wood-pole overhead lines for pole decay.

6. Perform periodic tree trimming along overhead line rights-of-way to minimize outages.

7. Monitor rates and financial requirements found within the BPA power sales contract general services provisions (Sections 47 and 54).

8. Monitor the changes in BPA services and rates and adjust the Division's practices accordingly.

9. Upon acceptance by the City of the Growth Management Plan, initiate negotiations with Puget Power to update the previous service territory agreement.

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Chapter 5

Capital Improvements Plan

Chapter 5

Capital Improvements Plan

Introduction

This chapter describes and summarizes the recommended substation and feeder (circuit) configurations considered likely for the electrical system expansion at ultimate build-out. Each of the four possible service area alternatives described in previous chapters is considered. The previously determined load densities, approved by the City, were the basis of arriving at the various configurations we will now discuss. Order-of-magnitude costs associated with each case are also summarized.

This chapter is organized into eight sections. The first four sections discuss each of the four possible service area alternatives. Two system configurations are discussed for each of Alternatives 1, 2, and 3; one configuration does not rely upon interconnection with Puget Power for contingency backup in the event of a major electrical component failure, while the other configuration does. Alternative 4, the no-annexation alternative, is discussed as one configuration only—without Puget Power backup.

The fifth section addresses special reliability needs. Critical loads are identified and considerations listed for the service and reliability of these and future critical loads.

The sixth section discusses material estimates. Recommendations for substations and feeders are discussed for each alternative, along with the estimation process for determining the number of three-phase and single-phase tap lines (lines extending from the feeder backbones), distribution transformers, secondary services, and protective devices.

Cost estimates are then discussed in the seventh section, with summaries of the order-of-magnitude costs associated with each alternative and with the recommended capital improvements through the year 2000.

The final section in this chapter lists specific substation and feeder backbone tasks, summarizes the total system facilities, and provides the construction unit costs used in the estimates. The described system improvements, when implemented, will address the current reliability concerns in many areas of the city.

An environmental checklist (Appendix B) has been prepared based on the three expansion alternatives.

Alternative 1

The Alternative 1 area coincides with the historical City of Blaine/Puget Power service territory agreement. It is bounded by Lincoln Road to the south and Valley View Road

to the east (Figure 1A). At ultimate build-out the approximate number of dwelling units will be 10,283. The approximate load for this alternative at ultimate build-out is 55 MW, with the load distributed as shown in Table 5-1.

Table 5-1
Alternative 1 Ultimate Load

Area	Power Demand[a] (kW)
Central Blaine	16,888
East Blaine	13,222
Southeast	2,351
Drayton Harbor/Loomis Trail	12,153
Semiahmoo	6,894
Birch Point	3,488
System Total	**54,997**

[a]Power demand values taken from Table 2-1, Ultimate Load Densities, in Chapter 2 of this report.

The order-of-magnitude cost estimates for required additional facilities based on the number of dwelling units and the system configuration chosen at ultimate build-out are summarized in Table 5-9 in the Cost Estimates section. Substation and feeder backbone tasks are listed in Table 5-11 in the last section of this chapter. Following is a discussion of the two system configurations to be considered.

Alternative 1 System Configuration Without Puget Power Backup Contingency

Figure 1A shows the approximate locations of the substations and possible routing of main feeder backbones for the system configuration under Alternative 1 without Puget Power backup contingency. To meet the load needs at ultimate build-out (estimated to occur in about the year 2035) without relying on the aid of Puget Power for backup contingency, the total system capacity must be sufficient to carry the entire service area load in the event of a major substation component (transformer) failure. To accomplish this, it is recommended that the capacity of the Blaine substation be significantly increased and a new substation be built to serve the Birch Point, Semiahmoo, and Drayton Harbor areas. Both improvements should be completed before ultimate load density occurs. The overall substation capacity would be increased to approximately 84 MVA.

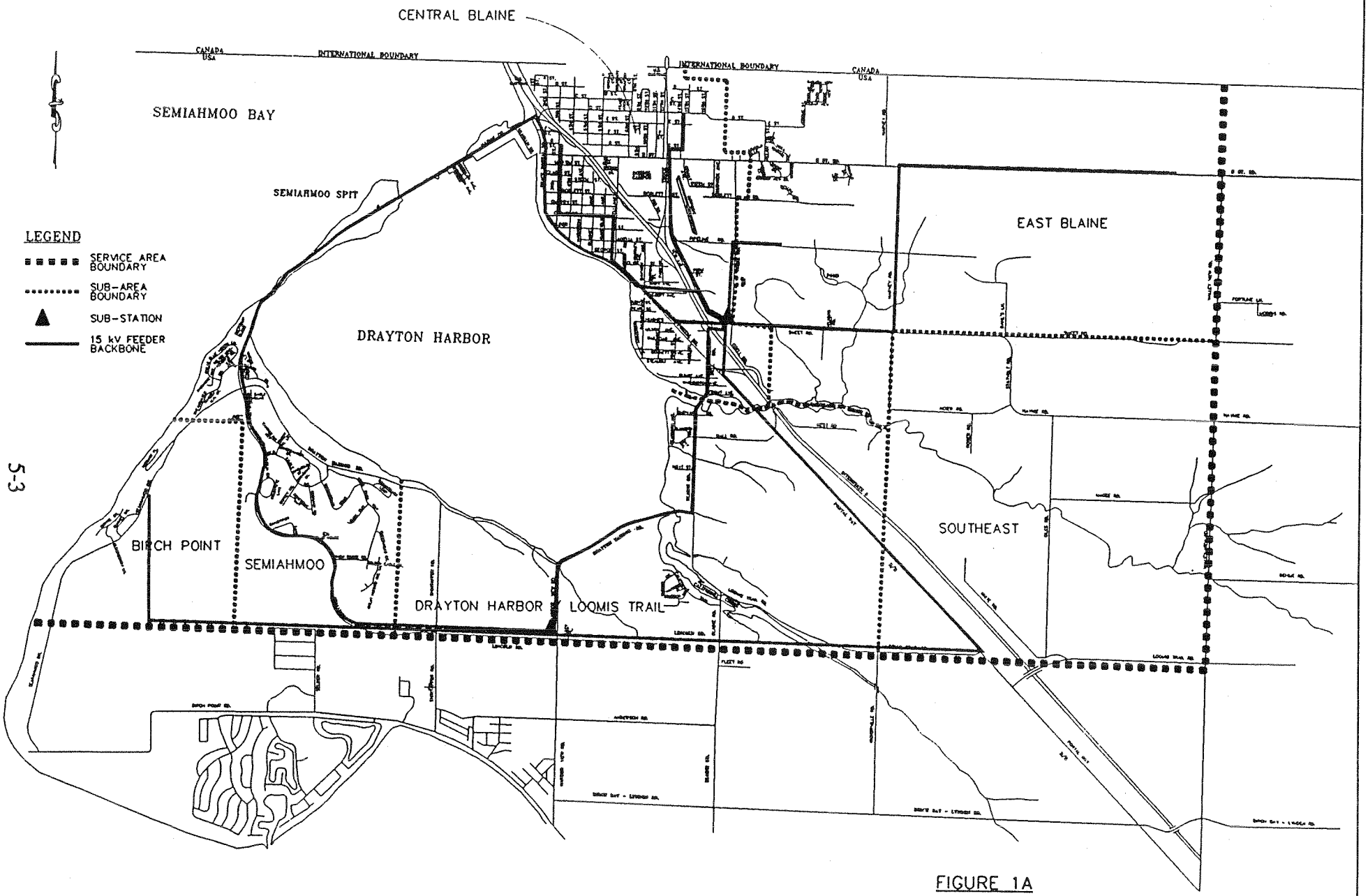

FIGURE 1A

ALTERNATIVE 1
SYSTEM CONFIGURATION WITHOUT
PUGET POWER BACKUP CONTINGENCY

Increasing the capacity of the Blaine substation would involve replacing the existing 12/16/20 MVA station transformer at the end of its lifecycle with one having a capacity of 15/20/25 MVA (Task A in Table 5-11). Also, the existing substation should be "double-banked" with another 15/20/25 MVA station transformer when loading justified (Tasks B and C in Table 5-11). This would increase the winter loading capacity (winter capacity is higher than summer because of lower ambient temperatures) of the station to approximately 56 MVA. At this capacity the Blaine substation could carry the loads of the entire Alternative 1 service area, given adequate system distribution interconnections.

With increased substation capacity there is a need for additional feeders to carry the loads. Typical 12.5-kV distribution feeder design can carry between 6 to 9 MW under normal load conditions; increased capacity is possible under emergency load conditions. Given this, seven distribution feeders would be adequate for normal and backup contingency loading conditions. The feeders would serve the following areas:

Feeder 1. The downtown area; roughly the area presently served by Circuit 15 (Task E in Table 5-11).

Feeder 2. The east side of I-5 within the current city limits; presently served by Circuit 16 (Task T).

Feeder 3. Would be used as an express feeder to the Semiahmoo area via the submarine cable that crosses the mouth of Drayton Harbor, having minimal loads under normal conditions (Task F).

Feeder 4. Primarily the potential H Street annexation loads (Task G).

Feeder 5. The area immediately east of the city center and south of H Street (Task H).

Feeder 6. Would be used as an express feeder with partial loading, routed through the Drayton Harbor/Loomis Trail area to the new substation. It would have a higher capacity than normal loads to provide backup contingency between substations in the event of a major component failure (Task I).

Feeder 7. The east side of the Drayton Harbor/Loomis Trail area and the southeast corner of the Alternative 1 service area (Task J). Similar to Feeder 6, this feeder would be partially loaded and be principally for reliability.

Because of the number of feeders leaving the Blaine substation, a combination of overhead and underground should be used to an appropriate distance outside of the substation to reduce the possibility of common mode failure. Common mode failure occurs when more than one feeder is interrupted by the same cause; e.g., a vehicle hitting a pole with a double circuit or a backhoe digging into two underground feeders that are buried in the same location.

To serve the loads in the Birch Point, Semiahmoo, Drayton Harbor/Loomis Trail, and Southeast areas, a new 15/20/25 MVA substation should be built in the vicinity of Shintaffer, Harbor View, Drayton Harbor, and Lincoln Roads (Task D). With a substation capacity of 15/20/25 MVA and typical loads, backup contingency requirements, and design criteria, four feeders should be adequate. These feeders would serve the following areas:

Feeder 1. Birch Point and portions of Semiahmoo (Task K).

Feeder 2. Semiahmoo (Tasks L and N). This feeder would be constructed as indicated with the intent that the Blaine substation carry the loads in the Semiahmoo and Birch Point areas.

Feeder 3. The majority of the Drayton Harbor/Loomis Trail and Southeast areas (Task M).

Feeder 4. Partial loads in the Drayton Harbor/Loomis Trail area. Would be used as an express feeder to the Blaine substation (Task I).

Alternative 1 System Configuration With Puget Power Backup Contingency

Figure 1B shows the approximate locations of the substations and possible routing of main feeder backbones for the system configuration under Alternative 1 with Puget Power backup contingency.

With ample distribution interconnections with Puget Power, total system capacity would be limited to that required to carry total loads and not that required for backup contingency. To accomplish this at the time of ultimate build-out, it is recommended that the capacity of the Blaine substation be increased (at the end of the existing station transformer's economic life); a new substation built to serve the Birch Point, Semiahmoo, Drayton Harbor/Loomis Trail, and Southeast areas; and appropriate interconnections be established with Puget Power. The overall system capacity would be approximately 56 MVA. Such an approach would transfer the construction of extra facilities required for reserves from the City to Puget Power. This would also require both BPA and Puget Power approval and would likely entail payments by the City for the backup power sources.

To adequately serve the anticipated loads from the Blaine substation, the existing 12/16/20 MVA station transformer should be replaced at the end of its lifecycle with a 15/20/25 MVA station transformer (Task A in Table 5-11). The capacity will be adequate to serve loads in the Central Blaine and East Blaine areas. Interconnection to the east and south with Puget Power should be established and outage contingencies planned. Because of the load densities in these areas, it is also necessary to have adequate distribution feeder interconnections between the Blaine substation and the new substation.

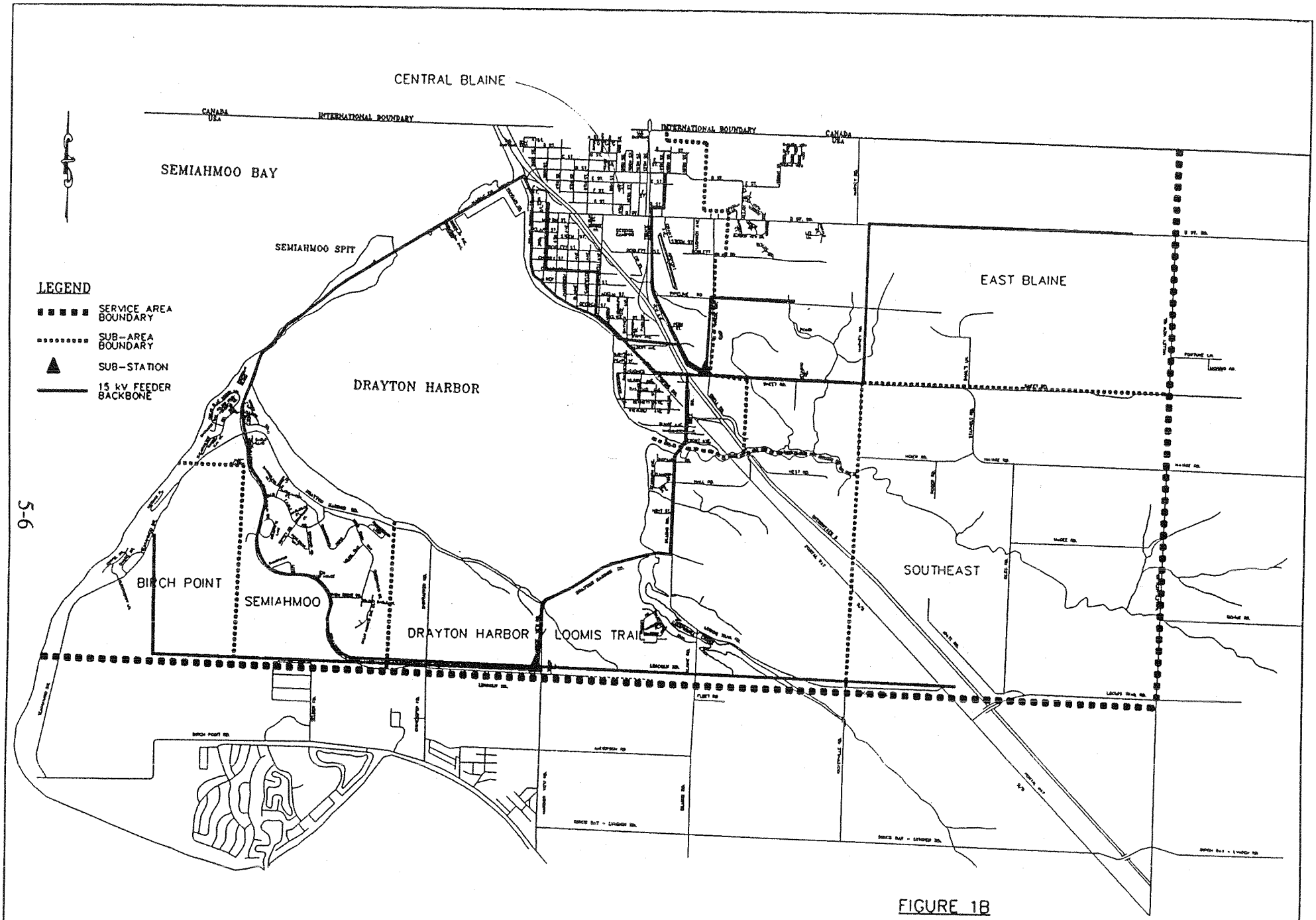

FIGURE 1B

ALTERNATIVE 1
SYSTEM CONFIGURATION WITH
PUGET POWER BACKUP CONTINGENCY

Adequate interconnection can be established through the Semiahmoo express feed via the mouth of Drayton Harbor and through normal feeder ties around the south side of Drayton Harbor.

Five distribution feeders should be adequate for normal and emergency tie conditions. The feeders would serve the following areas:

Feeder 1. The downtown area, roughly the area presently served by Circuit 15 (Task E in Table 5-11).

Feeder 2. The east side of I-5 within the current city limits, presently served by Circuit 16 (Task T).

Feeder 3. Would be used as an express feeder to the Semiahmoo area via the submarine cable that crosses the mouth of Drayton Harbor, having minimal loads under normal conditions (Task F).

Feeder 4. Would primarily serve the potential H Street annexation loads (Task G).

Feeder 5. The area immediately east of the city center and south of H Street (Task H).

To serve the loads in the Birch Point, Semiahmoo, Drayton Harbor/Loomis Trail, and Southeast areas, a new 15/20/25 MVA substation (Task D) should be built in the vicinity of Shintaffer, Harbor View, Drayton Harbor, and Lincoln Roads. It would be necessary for the new substation to carry as much of the Central Blaine area loads as possible in the event of a major component failure at the Blaine substation. This is because the Central Blaine area has a large load density and is relatively remote from Puget Power facilities for backup. The normal load on the new substation could be transferred to Puget Power so that it would have the capacity to carry the Central Blaine area. With a substation capacity of 15/20/25 MVA and typical loads, emergency tie requirements, and design criteria, four feeders should be adequate for this service area. These feeders would serve the following areas:

Feeder 1. Birch Point and portions of Semiahmoo (Task K).

Feeder 2. Semiahmoo and as an emergency tie to Central Blaine (Tasks L, N, and S). This feeder would be constructed as indicated with the intent that the new substation carry as much of the Central Blaine area loads as possible.

Feeder 3. The majority of the Drayton Harbor/Loomis Trail and Southeast areas (Task M).

Feeder 4. The north Drayton Harbor/Loomis Trail area and portions of the Semiahmoo area; this feeder would be built to carry a significant load to the Blaine substation service area for emergency backup (Task I). This feeder would tie to Feeder 1 of the Blaine substation.

Alternative 2

The Alternative 2 area roughly coincides with the City's proposed urban growth area (Figure 2A). At Loomis Trail and I-5, the boundary follows I-5 northwesterly to an imaginary extension of Harvey Road, then northerly to Sweet Road. From this point the boundary travels east along Sweet Road to Valley View Road and north to H Street. At H Street, the boundary extends to the east to include the proposed H Street annexation area. At ultimate build-out, the approximate number of dwelling units will be 10,319. The approximate load for this alternative at ultimate build-out is 55 MW, with the load distributed as shown in Table 5-2.

Table 5-2
Alternative 2 Ultimate Load

Area	Power Demand[a] (kW)
Central Blaine	16,888
East Blaine	13,662
Southeast	1,108
Drayton Harbor/Loomis Trail	12,153
Semiahmoo	6,894
Birch Point	4,185
System Total	**54,891**

[a]Power demand values taken from Table 2-1, Ultimate Load Densities, in Chapter 2 of this report.

Table 5-9 in the Lost Estimates section summarizes the order-of-magnitude cost estimates for required additional facilities based on the number of dwelling units and the system configuration chosen at ultimate build-out. Substation and feeder backbone tasks are listed in Table 5-11 in the last section of this chapter. Following is a discussion of the two system configurations to be considered.

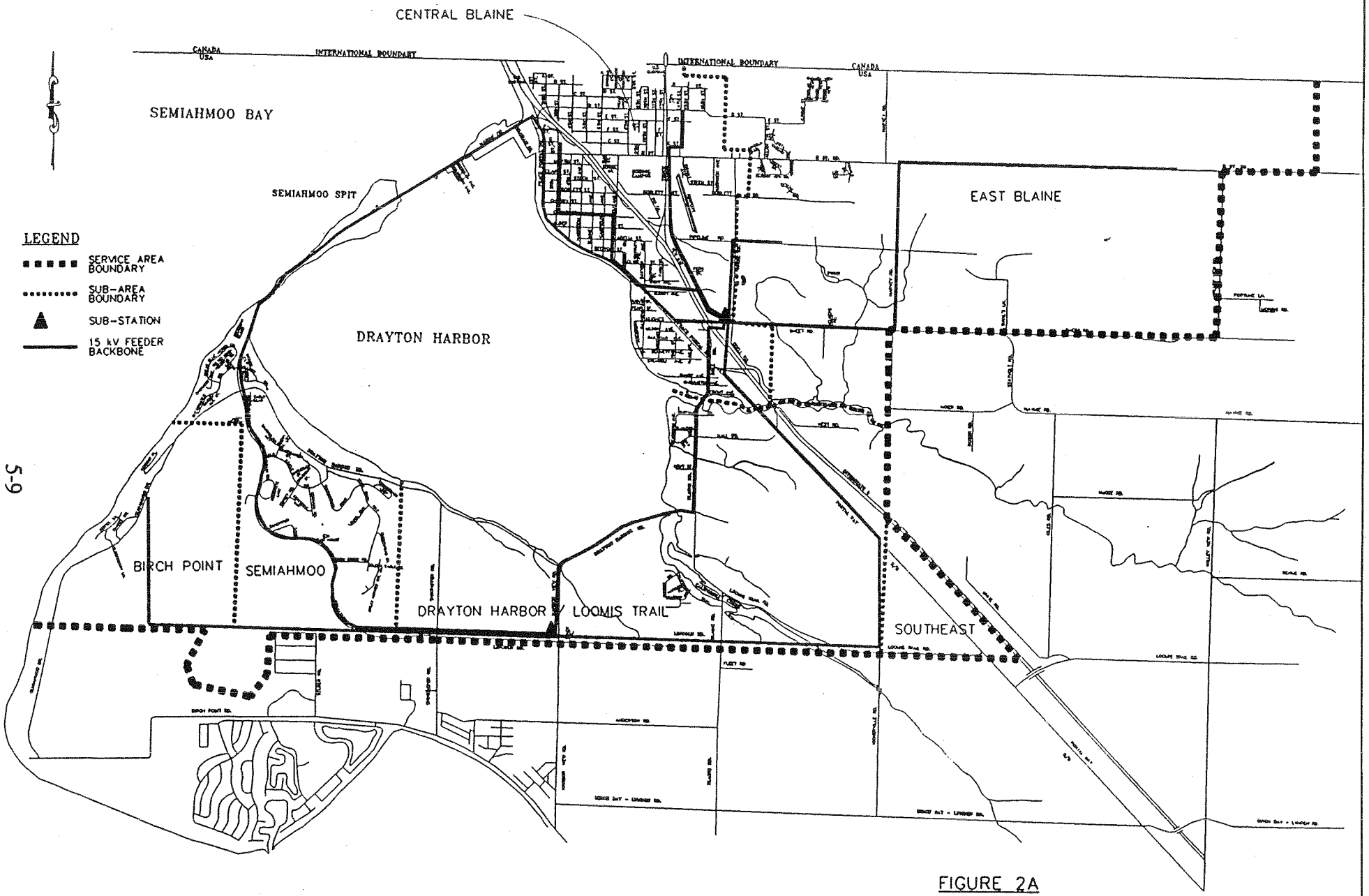

FIGURE 2A

ALTERNATIVE 2
SYSTEM CONFIGURATION WITHOUT
PUGET POWER BACKUP CONTINGENCY

Alternative 2 System Configuration Without Puget Power Backup Contingency

Figure 2A shows the approximate locations of the substations and possible routing of main feeder backbones for the system configuration under Alternative 2 without Puget Power backup contingency. To meet the load needs at ultimate build-out (estimated to occur at about the year 2035) without relying on the aid of Puget Power for backup contingency, the total system capacity must be sufficient to carry the entire service area load in the event of a major substation component (transformer) failure. To accomplish this, it is recommended that the capacity of the Blaine substation be significantly increased and a new substation be built to serve the Birch Point, Semiahmoo, and Drayton Harbor areas. Both improvements should be completed before ultimate load density occurs. The overall substation capacity would be increased to approximately 84 MVA.

Increasing the capacity of the Blaine substation would involve replacing the existing 12/16/20 MVA station transformer at the end of its lifecycle with one having a capacity of 15/20/25 MVA (Task A in Table 5-11). Also, the existing substation should be "double-banked" with another 15/20/25 MVA station transformer when loading justifies (Tasks B and C in Table 5-11). This would increase the winter loading capacity (winter capacity is higher than summer because of lower ambient temperatures) of the station to approximately 56 MVA. At this capacity, the Blaine substation could carry the loads of the entire Alternative 2 service area, given adequate distribution system interconnections.

With increased substation capacity, there is a need for additional feeders to carry the loads. Typical 12.5-kV distribution feeder design can carry from 6 to 9 MW under normal load conditions; increased capacity is possible under emergency load conditions. Given this, seven distribution feeders would be adequate for normal and backup contingency loading conditions. The feeders would serve the following areas:

Feeder 1. The downtown area; roughly the area presently served by Circuit 15 (Task E in Table 5-11).

Feeder 2. The east side of I-5 within the current city limits; presently served by Circuit 16 (Task T).

Feeder 3. Would be used as an express feeder to the Semiahmoo area via the submarine cable that crosses the mouth of Drayton Harbor, having minimal loads under normal conditions. This feeder should be capable of carrying the majority of the Semiahmoo/ Birch Point loads (Task F).

Feeder 4. Primarily the potential H Street annexation loads, but also the area south of H Street and north of Sweet Road (Task G).

Feeder 5. The area immediately east of the city center and south of H Street (Task H).

Feeder 6. Would be an express feeder through the Drayton Harbor/Loomis Trail area to the new substation. It would have a higher capacity than normal to provide backup contingency between substations in the event of a major component failure (Task I).

Feeder 7. The east side of the Drayton Harbor/Loomis Trail area (Task O). Similar to Feeder 6, this feeder would be partially loaded and principally for reliability.

These feeders should be a combination of overhead and underground to an appropriate distance outside of the substation to eliminate the possibility of common mode failure.

To serve the loads in the Birch Point, Semiahmoo, Drayton Harbor/Loomis Trail, and Southeast areas, a new 15/20/25 MVA substation should be built in the vicinity of Shintaffer, Harbor View, Drayton Harbor, and Lincoln Roads (Task D). With a substation capacity of 15/20/25 MVA and typical loads, backup contingency requirements, and design criteria, four feeders should be adequate for this service area. These feeders would serve the following areas:

Feeder 1. Birch Point and portions of Semiahmoo (Task K).

Feeder 2. Semiahmoo (Tasks L and N). This feeder would be constructed as indicated with the intent that the Blaine substation carry the loads in the Semiahmoo and Birch Point areas.

Feeder 3. The majority of the Drayton Harbor/Loomis Trail and Southeast areas (Task Q; this feeder is shorter than in Alternative 1).

Feeder 4. Partial loads in the Drayton Harbor/Loomis Trail area. Would be used as an express feeder to the Blaine substation (Task I).

Alternative 2 System Configuration With Puget Power Backup Contingency

Figure 2B shows the approximate locations of the substations and possible routing of main feeder backbones for the system configuration under Alternative 2 with Puget Power backup contingency.

With ample distribution interconnections with Puget Power, total system capacity would be limited to that required to carry total loads and not that required for backup contingency. To accomplish this at the time of ultimate build-out, it is recommended that the capacity of the Blaine substation be increased (at the end of the existing station transformer's economic life); a new substation be built to serve the Birch Point, Semiahmoo, Drayton Harbor/Loomis Trail, and Southeast areas; and appropriate interconnections be established with Puget Power. The overall system capacity would be approximately 56 MVA. Such an approach would transfer the construction of extra facilities required

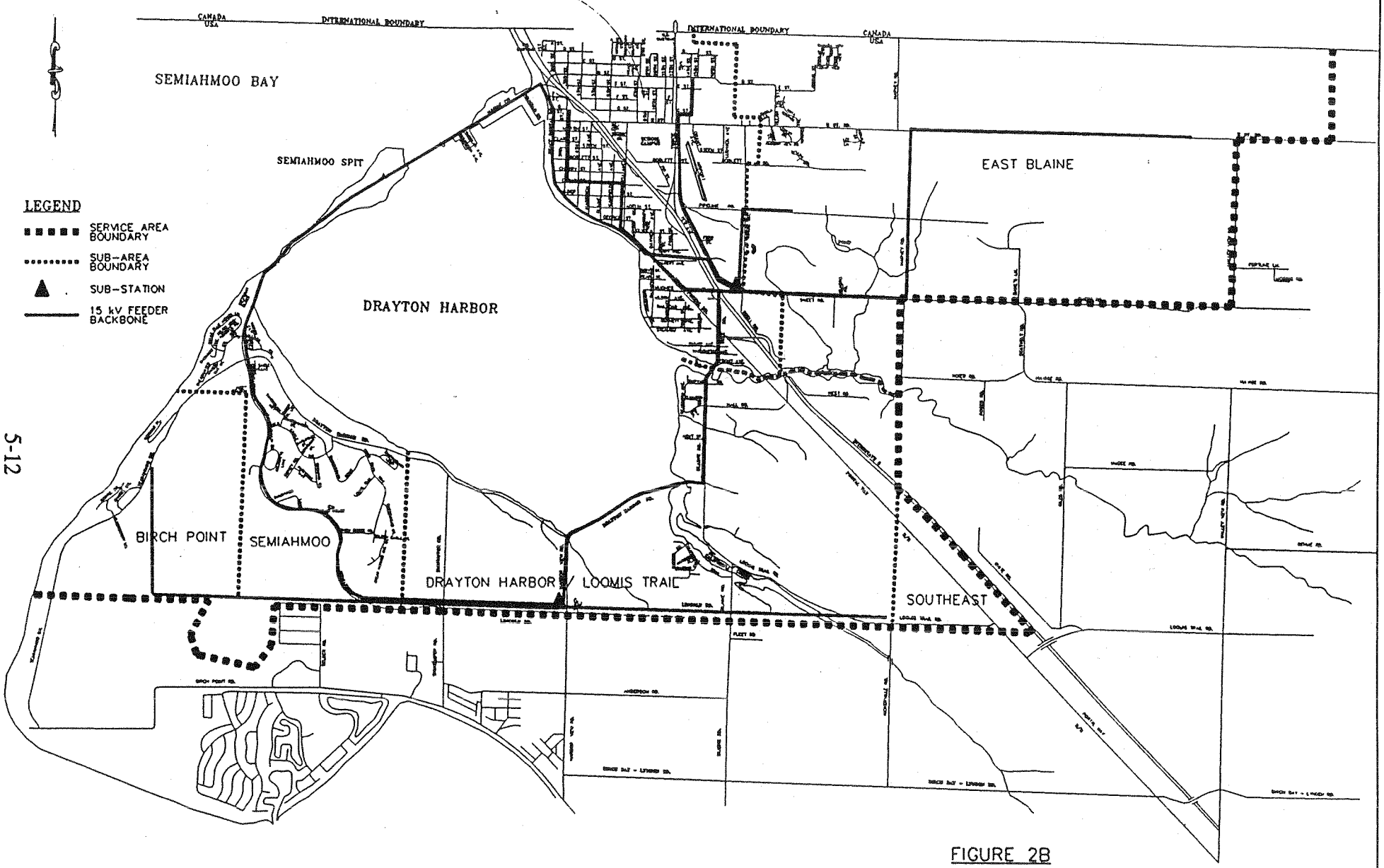

FIGURE 2B

ALTERNATIVE 2
SYSTEM CONFIGURATION WITH
PUGET POWER BACKUP CONTINGENCY

for reserves from the City to Puget Power. This would also require both BPA and Puget Power approval and would likely entail payments by the City for the backup power sources.

To adequately serve the anticipated loads from the Blaine substation, the existing 12/16/20 MVA station transformer should be replaced at the end of its lifecycle with a 15/20/25 MVA station transformer (Task A in Table 5-11). The capacity will be adequate to serve loads in Central Blaine and East Blaine areas. Interconnection with Puget Power should be established and outage contingencies planned for the possibility of a major component failure. Interconnections should be capable of carrying a total of approximately 30 MVA in the event that the Blaine substation transformer fails. Given normal 12.47-kV distribution line design, approximately four interconnections with Puget Power are required. Because of the load densities in these areas, it is necessary also to have adequate feeder interconnection between the Blaine substation and the new substation so that portions of the Blaine substation load could be shifted to the new substation and some of its load can, in turn, be shifted to Puget Power. Sufficient interconnection can be established through the Semiahmoo express feed via the mouth of Drayton Harbor and through an express feeder around the south side of Drayton Harbor.

Five distribution feeders should be adequate for normal and emergency tie conditions. The feeders would serve the following areas:

Feeder 1. The downtown area, roughly the area presently served by Circuit 15 (Task E in Table 5-11).

Feeder 2. The east side of I-5 within the current city limits, presently served by Circuit 16 (Task T).

Feeder 3. Would be used as an express feeder to the Semiahmoo area via the submarine cable that crosses the mouth of Drayton Harbor, having minimal loads under normal conditions (Task F).

Feeder 4. Primarily the potential H Street annexation loads (Task G).

Feeder 5. The area immediately east of the city center and south of H Street (Task H).

To serve the loads in the Birch Point, Semiahmoo, Drayton Harbor/Loomis Trail, and Southeast areas, a new 15/20/25 MVA substation should be built in the vicinity of Shintaffer, Harbor View, Drayton Harbor, and Lincoln Roads (Task D in Table 5-11). It would be necessary for the new substation to carry as much of the Central Blaine area loads as possible in the event of a major component failure at the Blaine substation. This is because the Central Blaine area has a large load density and is relatively remote from Puget Power facilities for backup. The normal load on the new substation could be transferred to Puget Power so that it would have the capacity to carry the Central Blaine area. With a substation capacity of 15/20/25 MVA and typical loads, emergency tie

requirements, and design criteria, four feeders should be adequate for this service area. These feeders would serve the following areas:

Feeder 1. Birch Point (Task K).

Feeder 2. Semiahmoo and as an emergency tie to Central Blaine (Tasks L, N, and S). This feeder would be constructed as indicated with the intent that the new substation carry as much of the Central Blaine area loads as possible.

Feeder 3. The majority of the Drayton Harbor/Loomis Trail and Southeast areas (Task Q; this feeder is shorter than Feeder 3 in Alternative 1).

Feeder 4. Would be an express feeder to the Blaine substation. It would have a higher capacity than normal to be used for backup contingency between substations in the event of a major component failure (Task I). This feeder differs from Feeder 4 in Alternative 1 because it has a dedicated breaker.

Alternative 3

The Alternative 3 area (see Figure 3A) was defined by the City to include the full proposed H Street annexation; the area's boundary then runs south along Valley View Road to Blaine-Lynden Road, west to Giles Road, south to Loomis Trail and Lincoln Roads, west along Loomis Trail and Lincoln Roads, south along Shintaffer Road, and west along the Birch Point Road to Semiahmoo Bay. At ultimate build-out, the approximate number of dwelling units will be 11,467. The approximate load for this alternative at ultimate build-out is 59 MW, with the load distributed as shown in Table 5-3.

Table 5-3
Alternative 3 Ultimate Load

Area	Power Demand[a] (kW)
Central Blaine	16,888
East Blaine	13,662
Southeast	1,819
Drayton Harbor/Loomis Trail	12,153
Semiahmoo	6,894
Birch Point	7,456
System Total	**58,873**

[a]Power demand values taken from Table 2-1, Ultimate Load Densities, in Chapter 2 of this report.

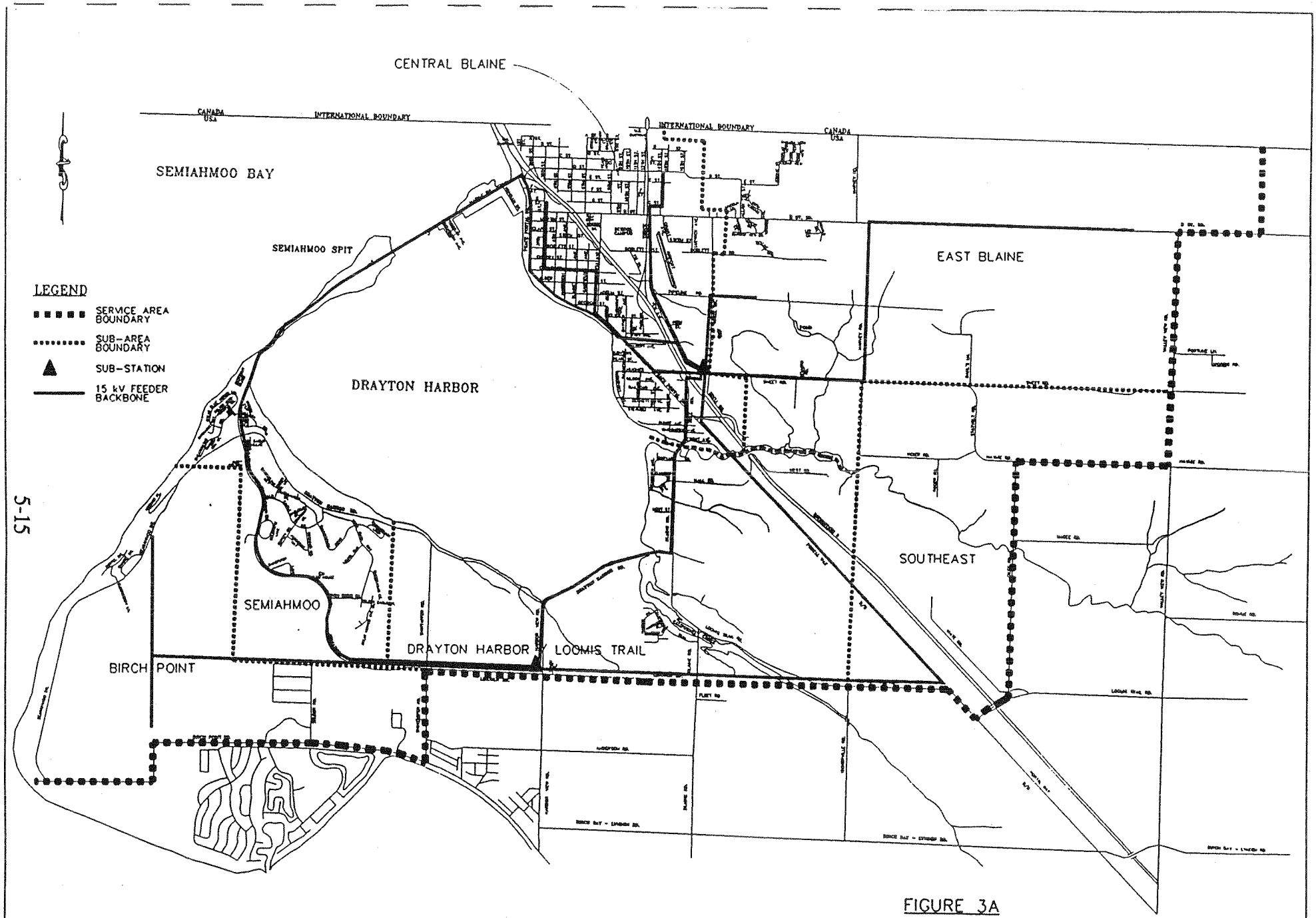

FIGURE 3A

ALTERNATIVE 3
SYSTEM CONFIGURATION WITHOUT
PUGET POWER BACKUP CONTINGENCY

Table 5-9 in the Cost Estimates section summarizes the order-of-magnitude cost estimates of required additional facilities based on the number of dwelling units and the system configuration chosen at build-out. Substation and feeder backbone tasks are listed in Table 5-11 in the last section of this chapter. Following is a discussion of the two system configurations to be considered.

Alternative 3 System Configuration Without Puget Power Backup Contingency

Figure 3A shows the approximate locations of the substations and possible routing of main feeder lines for system configuration for Alternative 3 without Puget Power backup contingency. To meet the load needs at ultimate build-out (estimated to occur at about the year 2035) without relying on the aid of Puget Power for backup contingency, the total system capacity must be great enough to carry the entire service area load in the event of a major substation component (transformer) failure. To accomplish this, it is recommended that the capacity of the Blaine substation be significantly increased and a new substation be built to serve the Birch Point, Semiahmoo, and Drayton Harbor areas. Both improvements should be completed before ultimate load density occurs. The overall substation capacity would be increased to approximately 93 MVA.

Increasing the capacity of the Blaine substation would involve replacing the existing 12/16/20 MVA station transformer at the end of its lifecycle with one having a capacity of 20/26/33 MVA (Task P in Table 5-11). Also, the existing substation should be "double-banked" with another 15/20/25 MVA station transformer when loading justified (Tasks B and C). This would increase the winter loading capacity (winter capacity is higher than summer because of lower ambient temperatures) of the station to approximately 65 MVA. At this capacity, the Blaine substation could carry the loads of the entire Alternative 3 service area, given adequate distribution interconnections.

With increased substation capacity, there is a need for additional feeders to carry the loads. Typical 12.5-kV distribution feeder design can carry between 6 to 9 MW under normal load conditions; increased capacity is possible under emergency load conditions. Given this, seven distribution feeders would be adequate for normal and backup contingency loading conditions. The feeders would serve the following areas:

Feeder 1. The downtown area, roughly the area presently served by Circuit 15 (Task E in Table 5-11).

Feeder 2. The east side of I-5 within the current city limits, presently served by Circuit 16 (Task T).

Feeder 3. Would be used as an express feeder to the Semiahmoo area via the submarine cable that crosses the mouth of Drayton Harbor, having minimal loads under normal conditions (Task F). This feeder should be capable of carrying the majority of the Semiahmoo/Birch Point loads.

Feeder 4. Primarily the potential H Street annexation loads, but also the area south of H Street and north of Haynie Road (Task G).

Feeder 5. The area immediately east of the city center and south of H Street (Task H).

Feeder 6. Would be an express feeder through the Drayton Harbor/Loomis Trail area to the new substation. It would have a higher capacity than normal to provide for backup contingency between substations in the event of a major component failure (Task I).

Feeder 7. The east side of the Drayton Harbor/Loomis Trail area (Task J). Similar to Feeder 6, this feeder would be partially loaded and be principally for reliability.

These feeders should be a combination of overhead and underground to an appropriate distance outside of the substation to eliminate the possibility of common mode failure.

To serve the loads in the Birch Point, Semiahmoo, Drayton Harbor/Loomis Trail, and Southeast areas, a new 15/20/25 MVA substation should be built in the vicinity of Shintaffer, Harbor View, Drayton Harbor, and Lincoln Roads (Task D in Table 5-11). With a substation capacity of 15/20/25 MVA and typical loads, backup contingency requirements, and design criteria, four feeders should be adequate for this service area. These feeders would serve the following areas:

Feeder 1. Birch Point (Task K).

Feeder 2. Semiahmoo (Tasks L, N, and S). This feeder would be constructed as indicated with the intent that the Blaine substation carry as much of the Semiahmoo and Birch Point loads as possible. (Because of loads, a 750 kCM feeder is required between the Semiahmoo Parkway/Drayton Harbor Road intersection and the end of the parkway.)

Feeder 3. The majority of Drayton Harbor/Loomis Trail and the southeast corner (Task M).

Feeder 4. Partial loads in the Drayton Harbor/Loomis Trail area; would be used as an express feeder to the Blaine substation (Task I).

Alternative 3 System Configuration With Puget Power Backup Contingency

Figure 3B shows the approximate locations of the substations and possible routing of main feeder backbones for the system configuration under Alternative 3 with Puget Power backup contingency.

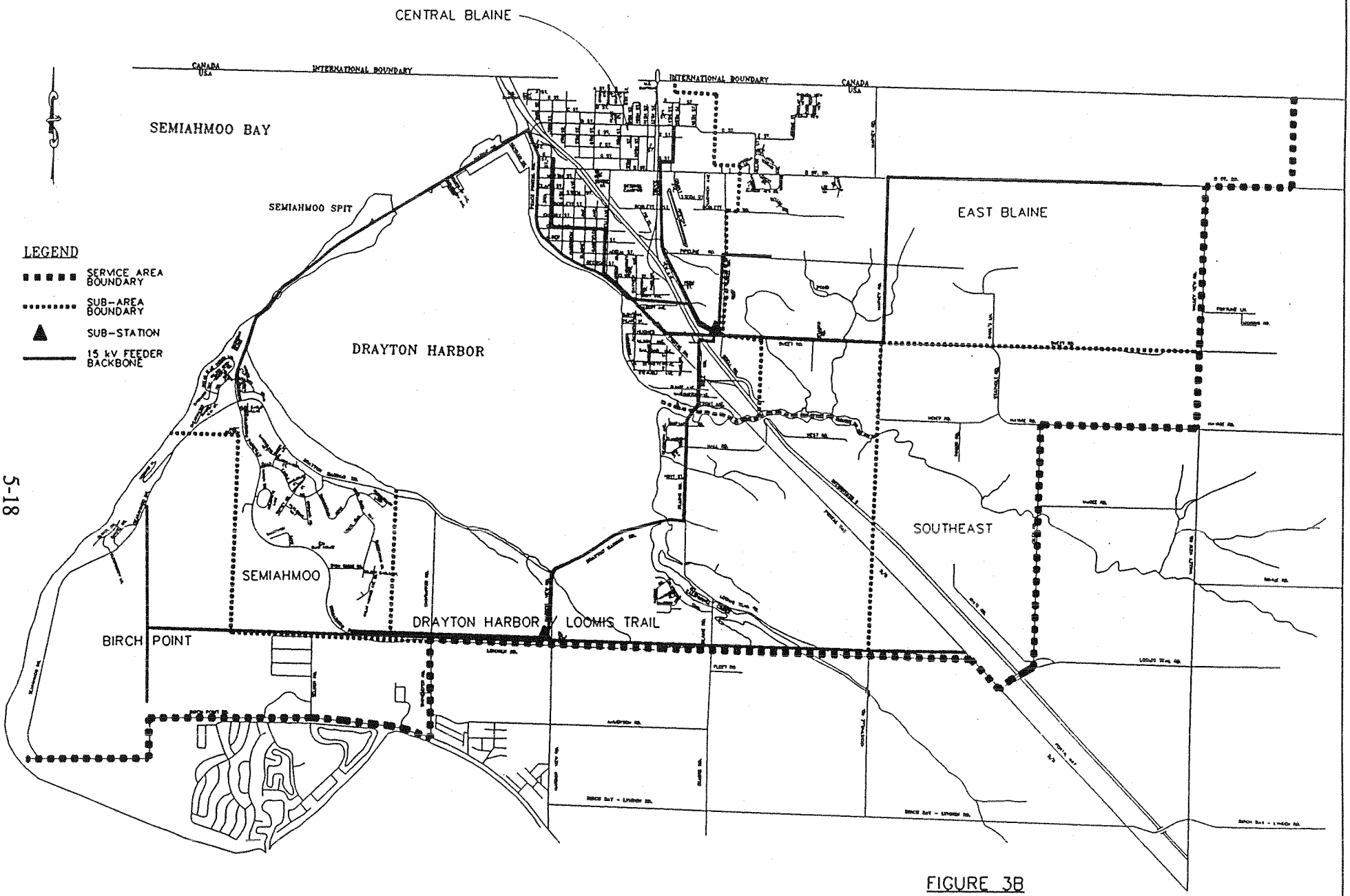

FIGURE 3B

ALTERNATIVE 3
SYSTEM CONFIGURATION WITH
PUGET POWER BACKUP CONTINGENCY

With ample distribution interconnections with Puget Power, total system capacity would be limited to that required to carry total loads and not that required for backup contingency. To accomplish this, it is recommended that the capacity of the Blaine substation be increased (at the end of the existing station transformer's economic life); a new substation be built to serve the Birch Point, Semiahmoo, Drayton Harbor/Loomis Trail, and Southeast areas; and appropriate interconnections are established with Puget Power. The overall system capacity would be approximately 56 MVA. Such an approach would transfer the construction of extra facilities required for reserves from the City to Puget Power. This would also require both BPA and Puget Power approval and would likely entail payments by the City for the backup power sources.

To adequately serve the anticipated loads from the Blaine substation, the existing 12/16/20 MVA station transformer should be replaced at the end of its lifecycle with a 20/26/33 MVA station transformer (Task P in Table 5-11). The capacity will be adequate to serve loads in Central Blaine, East Blaine, and north of Haynie Road. Interconnection with Puget Power should be established and outage contingencies planned for the possibility of a major component failure. Interconnections should be capable of carrying approximately 30 MVA in the event that the Blaine substation transformer failed. Given normal 12.47-kV distribution line design, approximately four interconnections with Puget Power are required. Because of the load densities in these areas, it is necessary also to have adequate feeder interconnection between the Blaine substation and the new substation so that portions of the Blaine substation load could be shifted to the new substation and some of its load can, in turn, be shifted to Puget Power. Sufficient interconnection can be established through the Semiahmoo express feed via the mouth of Drayton Harbor and through an express feeder around the south side of Drayton Harbor.

For normal loads, five distribution feeders would be adequate; however, to be able to transfer the required power in the event of a major component failure, six distribution feeders are required for emergency tie conditions. The feeders would serve the following areas:

Feeder 1. The downtown area, roughly the area presently served by Circuit 15 (Task E in Table 5-11).

Feeder 2. The east side of I-5 within the current city limits, presently served by Circuit 16 (Task T).

Feeder 3. Would be used as an express feeder to the Semiahmoo area via the submarine cable that crosses the mouth of Drayton Harbor, having minimal loads under normal conditions (Task F).

Feeder 4. Primarily the potential H Street annexation loads (Task G).

Feeder 5. The area immediately east of the city center and south of H Street (Task H).

Feeder 6. Would be an express feeder to the new substation. It would have a higher capacity than normal to provide backup contingency between substations in the event of a major component failure (Tasks I and R). This feeder is included because the amount of required load transfer capacity is greater than for Alternative 1.

To serve the loads in the Birch Point, Semiahmoo, Drayton Harbor/Loomis Trail, and Southeast areas, a new 15/20/25 MVA substation should be built in the vicinity of Shintaffer, Harbor View, Drayton Harbor, and Lincoln Roads (Task D). With a substation capacity of 15/20/25 MVA and typical loads, emergency tie requirements, and design criteria, four feeders should be adequate for this service area. These feeders would serve the following areas:

Feeder 1. Birch Point (Task K).

Feeder 2. Semiahmoo (Tasks L, N, and S).

Feeder 3. The majority of the Drayton Harbor/Loomis Trail and Southeast areas (Task M).

Feeder 4. Would be an express feeder to the Blaine substation. It would have a higher capacity than normal to provide backup contingency between substations in the event of a major component failure (Tasks I and R). This feeder differs from Feeder 7 in Alternative 1 because it has a dedicated breaker.

Alternative 4

This alternative examines the ultimate build-out principally within the existing city limits and with no annexation; loads currently served outside the city limits are assumed to continue being served. This alternative does not provide service for the proposed H Street annexation. The approximate load is 25 MW; 17 MW in Central Blaine and the remainder in Semiahmoo and outside the city limits. With an increase in capacity at the Blaine substation, that facility could carry the entire system load. However, for reliability, another substation is recommended in the Semiahmoo area. These reliability concerns are due to historical outages to Semiahmoo and the vulnerability of the Central Blaine area as demonstrated recently during the Puget Power transmission maintenance outage. Alternative 4 will be examined assuming that there would be no Puget Power backup contingency available. However, in all likelihood the new substation, as well as the existing Blaine substation, would include shared facilities with Puget Power. Figure 4 shows the approximate locations of the substations and possible routing of main feeder backbones for this configuration.

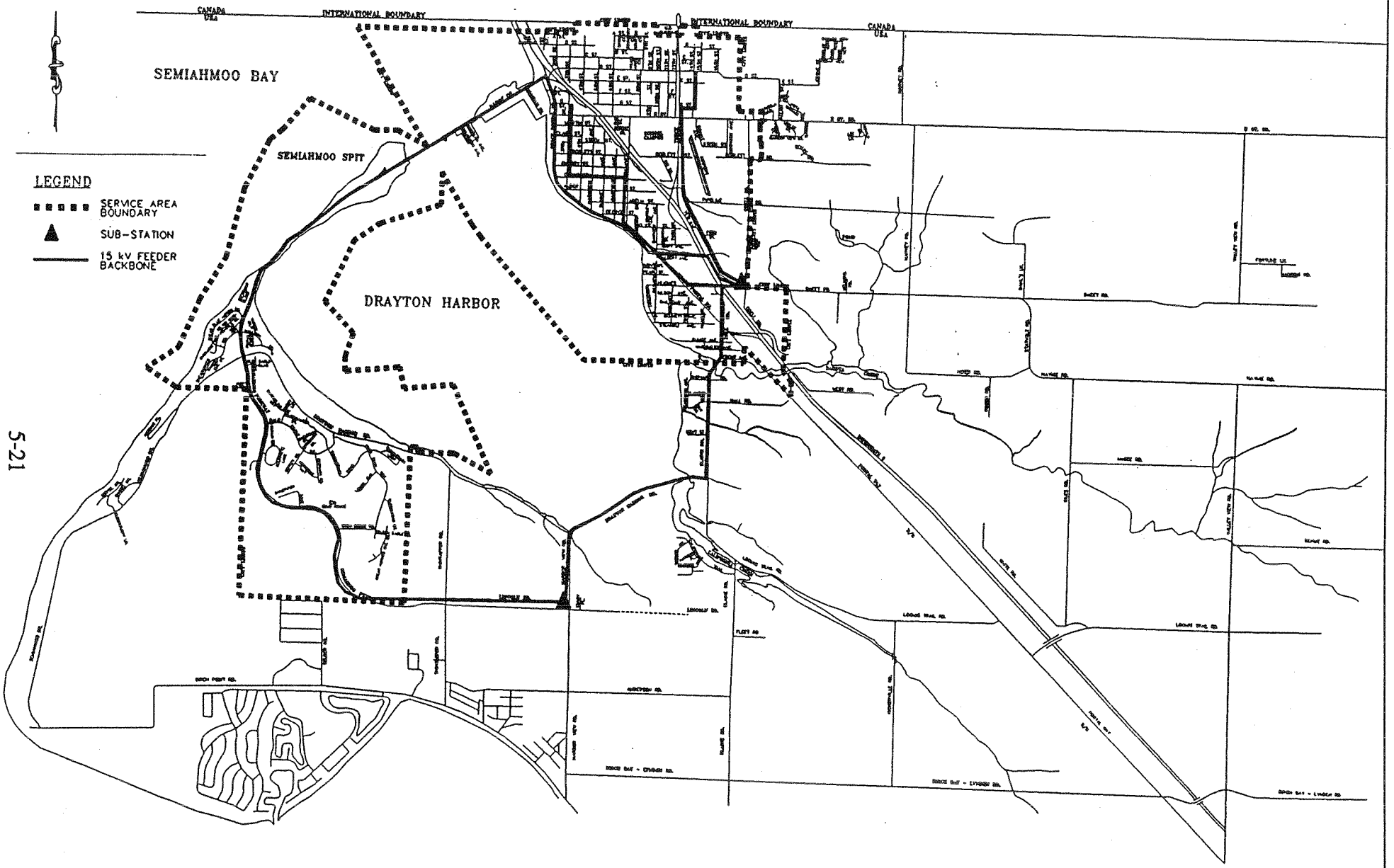

FIGURE 4

ALTERNATIVE 4 SYSTEM CONFIGURATION

It is recommended that the capacity of the Blaine substation be increased and a new substation be built to serve the Birch Point, Semiahmoo, and Drayton Harbor areas. The overall capacity would be approximately 56 MVA. Two feeder interconnections will be required between the normal service areas of the Blaine substation and the new substation.

Under a two-substation scheme there would be no need to increase the capacity of the existing Blaine substation. However, there would be a need to replace the existing 12/16/20 MVA station transformer at the end of its lifecycle. If replacement is needed, we would recommend a slightly larger transformer with a capacity of 15/20/25 MVA (Task A in Table 5-11). This would increase the winter loading capacity (winter capacity is higher than summer because of lower ambient temperatures) of the station to approximately 28 MVA.

At this capacity the Blaine substation could carry the loads of the entire Alternative 4 service area.

Four distribution feeders are required to carry the load of Central Blaine and the load of Semiahmoo for emergency backup. These feeders would serve the following areas:

Feeder 1. The downtown area, roughly the area presently served by Circuit 15 (Task E in Table 5-11).

Feeder 2. The east side of I-5 within the current city limits, presently served by Circuit 16 (Task T).

Feeder 3. Would be used as an express feeder to the Semiahmoo area via the submarine cable that crosses the mouth of Drayton Harbor, having minimal loads under normal conditions, presently Circuit 17 (Task F).

Feeder 4. Would be an express feeder to the Drayton Harbor/Loomis Trail area. It would have a higher capacity than justified by normal loads, in order to provide backup contingency between substations in the event of a major component failure (Task I).

For reliability and to serve the loads at Semiahmoo, a new 15/20/25 MVA substation should be built in the vicinity of Shintaffer, Harbor View, Drayton Harbor, and Lincoln Roads (Task D). Two feeder interconnections will be required between the new substation and the Blaine substation; one an interconnect to the Central Blaine service area via the submarine cable and the other an express feeder to a breaker at the Blaine substation. These feeders would serve the following areas:

Feeder 1. Semiahmoo (Tasks L, N, and S).

Feeder 2. As an express feeder to the Blaine substation (Task I).

Special Reliability Needs

There are a number of loads (customers and/or facilities) that are considered critical for continuity of service based on the nature of their business or function. Existing critical loads on the city's system are:

- Border crossings at Pacific and Douglas
- Brokerage firms along the border
- City wells (end of Pipeline Road and in Lincoln Park)
- GSA border patrol office
- High school, Blaine School District
- Inn at Semiahmoo
- Sewer lift stations and plant
- Stafolt Good Samaritan Nursing Home at 4th and C Streets
- Water pump station in Semiahmoo

To provide reliable service to these and other loads deemed critical, it is important to take the following actions:

1. Consider the location of the load relative to the substation(s) and the main backbone feeders.

2. Plan for backup source(s) specifically for that load, for emergency ties between feeders and/or substations, for stand-by generation, and for mobile generation.

3. Use protective devices appropriate for the load, the feeder it is on, and the desired operation. Ensure proper coordination and review periodically.

4. Keep right-of-way for overhead feeders cleared of trees.

5. Locate facilities (poles, risers, transformers, etc.) so as to minimize exposure to vehicles, weather, and vandalism.

If outages occur because of problems on a particular feeder, the Division should first attempt to temporarily (or permanently) transfer the load to another feeder. It is important to quickly identify and correct problems that are affecting continuity of service to critical loads.

Of the existing critical loads, the Semiahmoo area and the City wells at the end of Pipeline Road do not have acceptable outage backup feeder paths. For Semiahmoo, any fault downstream of the east side submarine cable termination can leave all customers (except those with emergency generation) in the Semiahmoo area without service for an unpredictable period of time. The City wells are similarly susceptible to major faults downstream of the tap pole at Odell and Pipeline Roads. Both of these conditions could be

remedied by having access to an alternate source of power. Semiahmoo could be adequately backed up (as well as permanently served) from a source to the south. The City wells could have contingency ties with Puget Power at Harvey and Pipeline Roads or interconnect from the east. Alternatively, the Water Division could install backup generation or assist in funding construction of interconnection facilities (equipment pads, quick-disconnecting means, etc.) for the mobile generator currently owned by the Electrical Division.

Currently, all critical loads, as well as all customers in general, are susceptible to a major component failure at the Blaine substation. Because the Blaine substation is fed from a radial transmission line, the City is also susceptible to a transmission line fault between the substation and the Kickerville/Birch Bay-Lynden Road tap point. The Blaine substation is located on a radial 115 kV transmission tap about 2.7 miles from Puget's 115 kV loop.

The City of Blaine is a BPA customer, and BPA has contracted with Puget Power to provide transfer services to aid BPA in its service to the City of Blaine. The transfer agreement between BPA and Puget Power specifies a number of the conditions of service that BPA has established in its service to the City through Puget Power's transmission system and substation. An alternate source of power could alleviate these vital reliability concerns. The City has explored such alternative sources of power. Population growth will require the addition of other sources; however, it is recommended that alternate sources be established to provide reliability, regardless of whether expansion occurs.

Each of the three service area alternatives has a different set of electrical system reliability concerns and geographical limitations. Some portions of the service areas will have a greater degree of reliability than others because of the locations of the anticipated new substation or feeder backbones in relation to the locations of projected load densities.

The anticipated substation and feeder backbones were located and configured to serve the City under both normal and outage conditions.

The proposed H Street annexation area is in the northeast corner of each of the three service area alternatives. The anticipated load density indicates that this area should have an alternate source (circuit) to enhance power reliability. Because of the geographic location of the H Street area, enhancing reliability with an alternate circuit is impractical. However, this does not preclude this area from being connected to other adjacent feeders through three-phase ties (even though these ties were not indicated as backbones of the Figures 1A to 3B). Additional reliability can be provided by appropriate design of the feeder backbone serving this area.

The Southeast area also appears to be lacking in reliability. In contrast with the proposed H Street annexation area, the Southeast area does not have the load density to warrant the same degree of reliability concern as other areas. Again, this area could be connected to adjacent feeders through three-phase ties (even though these ties were not indicated as backbones of the Figures 1A to 3B).

Material Estimates

The ultimate load densities were based largely upon the number of dwelling units in each area and to a lesser extent the expected amount of commercial growth. Similarly, for estimated amount of materials required, the number of dwelling units is again used to approximate the number of tap lines, distribution transformers, services, and protective devices required on the system. The amount of these materials will remain essentially the same for a particular alternative regardless of the configuration chosen.

Tap Lines

To determine the number of circuit miles of tap line required for each alternative, a typical size conductor was selected for three-phase and for single-phase tap lines, so that the amount of circuit feet of conductor per dwelling unit could be determined. The following conductor sizes were chosen for the following types of line:

- 1/0 AWG ACSR for three-phase overhead taps
- 4/0 AWG AL for three-phase underground taps
- #2 AWG ACSR for single-phase overhead taps
- #2 AWG AL for single-phase underground taps

Data from the City of Blaine and Puget Power were used to determine the number of circuit feet of tap line per dwelling unit. Table 5-4 lists per-unit quantities of tap line based on population concentration and type of distribution facilities.

Using the data presented in Table 5-4 and the total number of dwelling units for each alternative, the required tap lines for each alternative were calculated. These amounts are summarized in Table 5-5.

Transformers and Services

To approximate the number of customer distribution transformers required, several factors were taken into account. First, anticipated customer load was determined based on whether the customer uses electric or gas heat. Second, a typical transformer size was selected based on anticipated customer load, typical number of customers to be served from a single transformer, industry standards, and historical data from the City of Blaine. The typical transformer selected was 37.5 kVA with four residential customers (dwelling units) connected to each transformer. Finally, inspection of each service area and determination of the expected type of distribution equipment was necessary to approximate the percentage of overhead versus pad-mounted equipment. Each dwelling unit will have a secondary service and meter. See Table 5-6 for the estimated quantities of transformers and services for each alternative.

Table 5-4 Tap Line Per-Unit Quantities				
	Overhead Circuit Feet/ Dwelling Unit		Underground Circuit Feet/ Dwelling Unit	
Type of Facilities/Population Density	3-Phase	1-Phase	3-Phase	1-Phase
Predominantly underground construction with moderate population concentration	13.5	16.5	31.6	25
Predominantly underground construction with higher population concentration	8.5	10.2	22	14.5
Predominantly overhead construction with sparse population concentration	50	90	20	60
For mixed overhead and underground construction with moderate to higher population concentration	18	20	18	20
Exclusively underground construction with moderate population concentration	--	--	45	41.5

Table 5-5 Tap Line Requirements				
	Overhead Circuit Miles of Tap Line		Underground Circuit Miles of Tap Line	
Alternative	3-Phase	1-Phase	3-Phase	1-Phase
1	18.1	31.2	49.8	50.4
2	16.0	27.0	51.0	49.1
3	20.0	32.9	57.5	55.6
4	1.5	2.3	7.4	8.8

Note: The above required facilities are in addition to the existing Blaine electrical system, and exclude backbone feeders (refer to Table 5-12 for breakdown by area).

Table 5-6 Transformer and Service Requirements					
	Distribution Transformers		Other Transformers (300 kVA)	Services	
Alternative	Overhead	Pad-Mounted		Overhead	Underground
1	543	1,628	42	2,172	6,512
2	545	1,635	42	2,180	6,540
3	617	1,850	42	2,468	7,400
4	43	435	27	172	1,740

Note: The above required facilities are in addition to the existing Blaine electrical system; distribution transformer size is 37.5 kVA; and all alternative areas are assumed to consist of 75 percent underground construction at build-out.

Commercial and industrial transformer needs were based on estimated power demand at build-out. Transformers were assumed to be 100 percent utilized (transformer rating equivalent to the expected power demand) and to employ 300 kVA pad-mount installation. Commercial and industrial requirements are shown in Table 5-6 under "Other Transformers."

Protective Devices

Protective devices, which are used to isolate the cause of a system fault and maintain service to as many customers as possible, include fuses, reclosers, and interrupters.

Fuses are by far the most common and inexpensive device for distribution-level protection. Typical fuse types that are and will continue to be in use for Blaine are the cut-out fuse for overhead applications on distribution transformers and tap points, and pad-mounted three-phase and single-phase fuses for underground applications.

Reclosers and interrupters are adjustable protective devices. Reclosers are used on overhead applications to clear temporary faults and maintain service. Interrupters are used on underground applications to clear faults at critical points on the feeder. The number of overhead cut-outs and pad-mounted fuses required is based on estimates of the areas served. The number of major feeder protective devices required is determined by the size and makeup of the service area. Table 5-7 summarizes per-unit quantities used for estimating and Table 5-8 lists the amounts of devices required by alternative.

Table 5-7 Protective Device Per-Unit Quantities	
Device	**Per-Unit Quantity**
Overhead Cut-Outs	1 per overhead distribution transformer 6 per mile of 3-phase overhead line 5 per mile of 1-phase overhead line
Pad-Mounted Fused Switches	
3-Phase	1 per 2 miles of 3-phase underground line
1-Phase	1 per mile of 3-phase underground line 2 per mile of 1-phase underground line
Reclosers, 3-Phase	1 per predominantly overhead feeder
Interrupters, 3-Phase	1 per predominantly underground feeder

Table 5-8
Protective Device Requirements

Alternative	Overhead Cut-Outs	Pad-Mounted Fuses		Reclosers	Interrupters
		3-Phase	1-Phase		
1	808	25	151	2	5
2	776	26	149	1	5
3	902	29	169	2	5
4	64	4	25	0	1

Note: The above required facilities are in addition to the existing Blaine electrical system.

Cost Estimates

The cost estimates for each alternative include costs to acquire or construct required system components, including substations, transmission lines, feeder backbones, three-phase and single-phase tap lines, distribution transformers, services, and protective devices. These costs also represent the full cost of constructing the additions to the system required at ultimate build-out. These cost estimates take into account existing facilities and customers served by the City, but do not account for Puget Power facilities that may be purchased and reused. It is also important to note that these costs are gross costs in 1994 dollars, and do not take into account any physical or financial contributions

from Puget Power, from BPA, or from customers. Similarly, under some alternatives, facilities may be purchased from Puget Power at amounts less than the full replacement cost.

The order-of-magnitude costs for each alternative are summarized in Table 5-9, and are broken down into substation and feeder backbone costs, and other facilities costs, including tap lines, distribution transformers, other transformers, services, and protective devices. Substation and feeder backbone costs are based on service area alternative, the particular system configuration, and the tasks required for each (discussed above). The need to implement capital improvements depends largely upon when and where loads develop.

The cost estimates included in Table 5-9 were made without consideration of existing Puget Power facilities. That is, the estimates were made as if Puget Power facilities did not exist or were not available to the City of Blaine. The costs to replace existing Puget Power facilities are as follows for each expansion alternative:

- Alternative 1: $7.6 million
- Alternative 2: $7.2 million
- Alternative 3: $7.2 million

The existing system is lacking in reliability, which is an immediate concern. Several improvements are necessary to bring system reliability up to an acceptable level. Table 5-10 outlines a schedule of recommended capital improvements and investments through the year 2000. Although these improvements appear to be required due to reliability concerns, they are also required to meet future load growth. The improvements are in order of priority and are common to all alternatives.

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Table 5-9
Order-of-Magnitude Cost Estimates for Total Facility Requirements by Alternative

	Alternative 1		Alternative 2		Alternative 3		Alternative 4
Description	**Without Puget**	**With Puget[a]**	**Without Puget**	**With Puget[a]**	**Without Puget**	**With Puget[a]**	
Substation and Feeder Tasks[b]	**A-N, T, U[b]**	**A, D-I, K-N, S, T, U[b]**	**A-I, K, L, N, O, Q, T, U[b]**	**A, D-I, K, L, N, Q, S-U[b]**	**B-N, P, S-U[b]**	**D-I, K-N, P, R-U[b]**	**A, D-F, I, L, N, S, T, U[b]**
Subtotal Costs (x 1,000)	**$14,178**	**$10,323**	**$13,672**	**$9,837**	**$14,313**	**$10,438**	**$7,567**
Other Facilities							
Tap Lines	22,516.3		22,285.5		25,380.7		3,418.4
Distribution Transformers	3,256.5		3,270		3,700.5		717
Other Transformers	504		504		504		324
Services	6,512.8		6,540		7,400.8		1,495.2
Protective Devices	424.45		399.15		456.05		57.35
Subtotal Costs (x 1,000)	**$33,214**		**$32,999**		**$37,442**		**$6,012**
Total Order-of-Magnitude Costs (x 1,000)	**$47,392**	**$43,537**	**$46,671**	**$42,836**	**$51,755**	**$47,880**	**$13,579**

[a]The costs, if any, to establish distribution emergency ties with Puget Power for the system configuration with Puget Power backup contingency are not included.
[b]See Table 5-11.

Note: Costs are for facilities in addition to those currently owned by the City of Blaine and are estimated as if Puget Power facilities (other than the Blaine substation and transmission line) do not exist or are not available to the City. These costs are gross costs in 1994 dollars, and do not take into account any contributions from Puget Power, from BPA, or from customers.

Table 5-10 Capital Improvements Schedule Through 2000								
PRI	Description	Total Costs[a] (x 1000)	1995	1996	1997	1998	1999	2000
1	Upgrade feeder back-bone for existing Circuit 15 (Task E[b])	$150	$150					
2	Construct new sub-station and trans-mission line (Task D[b])	$2,475	$250	$575	$825	$825		
3	New Semiahmoo feeder (Task L[b])	$370			$185	$185		
4	Upgrade submarine cable (Task F[b])	$275					$275	
5	Substation intertie feeder (Task I[b])	$275					$138	$137
6	Express feeder for Semiahmoo (Task F[b])	$942					$314	$628
Totals		**$4,487**	**$400**	**$575**	**$1,010**	**$1,010**	**$727**	**$765**

[a]Gross costs in 1994 dollars.
[b]See Table 5-11.

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Component Tasks, System Facilities, and Construction Unit Cost Estimates

Table 5-11 summarizes, by task, recommended substation and backbone feeder additions and associated costs. (The specific tasks required for each alternative are presented on Table 5-9.) Table 5-12 shows the total system facilities needed for Alternatives 1, 2, and 3 and additions needed for Alternative 4, broken down by overhead and underground circuit miles. Table 5-13 presents construction unit cost estimates.

Table 5-11
Substation and Feeder Task List

Task	Description	1994 Cost
A	Replace the existing 115-12.47/7.2-kV, 12/16/20 MVA station transformer at the Blaine substation with a 115-12.47/7.2-kV, 15/20/25 MVA, 3-833-kVA VR regulator (does not include cost of disposal of old transformer).	$390,000
B	Rebuild existing radial transmission line with a double circuit steel pole transmission loop from the Birch Bay/Lynden/Kickerville Roads tap to the Blaine substation (3.45 miles at $742,000/mile).	$2,500,000
	Install high-side structures, breakers, and bus work for loop 115-kV with two station transformer positions.	$600,000
C	Install an additional 115-12.47/7.2-kV, 15/20/25 MVA station transformer at the Blaine substation; connect to existing 12.47-kV bus, add two 15 kV breaker positions with 3-833-kVA VR regulators, and two underground get-aways at 250 feet each. Moderate site work (does not include cost of land acquisition or permits).	$600,000
D	Construct a new substation at Lynden/Harbor View Roads with a 115-12.47/7.2-kV, 15/20/25 MVA transformer, dead-end, disconnect switch, fuses and structures, 4-bay rack, with 3-833-kVA VR regulators, aux bus, and four underground get-aways at 250 feet each. Site work and land acquisition not included.	$1,650,000
	Construct radial transmission line from Puget Power's Birch Bay substation; 4.5 miles at $160,000/mile and a 115-kV circuit breaker at $97,000.	$825,000
E	Construct reconductor feeder from the Blaine substation to the downtown area; 3-phase, 4-wire 336 kCM ACSR, 1.8 miles at $85,000/mile (assume rebuild). *NOTE - If an express feeder is to be tied to this feeder (existing Circuit 15) for backup contingencies, ensure that feeder capacities are equivalent; i.e., if the express feeder is 556 kCM ACSR ensure that 556 kCM ACSR or a conductor with equivalent capacity is installed between the connection point of Circuit 15 and the Blaine substation.*	$150,000

Table 5-11 Substation and Feeder Task List		
Task	**Description**	**1994 Cost**
F	Construct an underground express feeder to Semiahmoo via the submarine cable; 3-phase, 3-conductor, 750 kCM AL, 2.9 miles at $280,000/mile, with 13 vaults at $10,000 each. Replace submarine cable; 3-phase, 3-conductor, 500 kCM copper, 1,700 ft.	$942,000 $275,000
G	Construct feeder from the Blaine substation to the proposed H Street annexation area; 3-phase, 4-wire 336 kCM ACSR, 4 miles at $85,000/mile.	$340,000
H	Construct feeder from the Blaine substation to the area immediately east of the present city limits; 3-phase, 3-conductor 750 kCM AL, 1 mile at $280,000/mile, with 8 vaults at $10,000 each.	$360,000
I	Construct a heavy feeder from the Blaine substation to the new substation for backup contingency ties; 3-phase, 4-wire 556 kCM ACSR, 2.8 miles at $97,000/mile.	$275,000
J	Construct feeder from the Blaine substation down Peace Portal Way to Drayton Harbor and the southeast corner; 3-phase, 4-wire 336 kCM ACSR, 2.7 miles at $92,000/mile.	$250,000
K	Construct feeder from the new substation to the Birch Point area; 3-phase, 3-conductor 750 kCM AL, 3.6 miles at $280,000/mile with 20 vaults at $10,000 each.	$1,400,000
L	Construct feeder from the new substation to connect to the Semiahmoo Parkway feeder; 3-phase, 3-conductor 750 kCM AL, 1.1 miles at $280,000/mile with 6 vaults at $10,000 each.	$370,000
M	Construct feeder from the new substation east to serve the majority of Drayton Harbor and the southeast corner; 3-phase, 3-conductor 750 kCM AL, 1.7 miles at $280,000/mile with 7 vaults at $10,000 each; then 3-phase, 4-wire 336 kCM ACSR, 1.0 mile at $85,000/mile. Install disconnect switch for tie interconnection; 2 poles with 1-2 spans and disconnect switch.	$631,000 $25,000
N	Upgrade feeder from west side of submarine cable termination to the intersection of Drayton Harbor Road and the Semiahmoo Parkway; 3-phase, 3-conductor 750 kCM AL, 1.78 miles at $47,000/mile.	$85,000
O	Construct feeder from the Blaine substation down Peace Portal Way to Drayton Harbor and the southeast corner; 3-phase, 4-wire 336 kCM ACSR, 2.5 miles at $92,000/mile.	$230,000
P	Replace the existing 115-12.47/7.2-kV, 12/16/20 MVA station transformer at the Blaine substation with a 115-12.47/7.2-kV, 20/26/33 MVA, 3-833-kVA VR regulator (does not include cost of disposal of old transformer).	$430,000

Table 5-11 Substation and Feeder Task List		
Task	**Description**	**1994 Cost**
Q	Construct feeder from the new substation east to serve the majority of Drayton Harbor and the southeast corner; 3-phase, 4-wire 336 kCM ACSR, 2.0 miles at $85,000/mile.	$170,000
R	Add a sixth feeder position at Blaine substation; extend 15 kV bus, add circuit breaker, underground get-away at 250 feet.	$75,000
S	Upgrade feeder from the end of Semiahmoo Parkway to the intersection of Drayton Harbor Road; 3-phase, 3-conductor 750 kCM AL, 2 miles at $47,000/mile.	$95,000
T	Reconductor existing Circuit 17 from the corner of Pipeline Road and the truck route to where the underground begins; 3-phase, 4-wire 336 kCM ACSR, 1,000 feet at $85,000/mile.	$20,000
	Establish and upgrade the underground feeder from where the overhead ends to the vault at 14th and E St.; 3-phase, 3-conductor 750 kCM AL, 3,500 feet at $280,000/mile.	$190,000
U	Purchase the Blaine substation.	$1,700,000
	Purchase transmission line from the Blaine substation to the tap point; 3.45 miles.	$600,000
Note: Upgraded underground feeders assume that there is existing reusable duct (Tasks N and S).		

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Table 5-12
Total System Facilities

AREA	DWELLING UNITS ALTERNATIVE 1	2	3	Facility Allocation (ft/DU) OH 3-PH	OH 1-PH	UG 3-PH	UG 1-PH	Total Facilities - ALT 1 OH 3-PH	OH 1-PH	UG 3-PH	UG 1-PH	Total Facilities - ALT 2 OH 3-PH	OH 1-PH	UG 3-PH	UG 1-PH	Total Facilities - ALT 3 OH 3-PH	OH 1-PH	UG 3-PH	UG 1-PH
Central Blaine	2	2	2	18	20	18	20	36	40	36	40	36	40	36	40	36	40	36	40
	412	412	412	18	20	18	20	7416	8240	7416	8240	7416	8240	7416	8240	7416	8240	7416	8240
	256	256	256	18	20	18	20	4608	5120	4608	5120	4608	5120	4608	5120	4608	5120	4608	5120
	837	837	837	18	20	18	20	15066	16740	15066	16740	15066	16740	15066	16740	15066	16740	15066	16740
	104	104	104	18	20	18	20	1872	2080	1872	2080	1872	2080	1872	2080	1872	2080	1872	2080
	185	185	185	18	20	18	20	3330	3700	3330	3700	3330	3700	3330	3700	3330	3700	3330	3700
Subtotal	1,796	1,796	1,796	-	-	-	-	32328	35920	32328	35920	32328	35920	32328	35920	32328	35920	32328	35920
East Blaine	1,662	1,773	1,773	0	0	45	41.5	0	0	74790	68973	0	0	79785	73580	0	0	79785	73580
	1,090	1,090	1,090	13.5	16.5	31.6	25	14715	17985	34444	27250	14715	17985	34444	27250	14715	17985	34444	27250
	109	109	109	50	90	20	60	5450	9810	2180	6540	5439	9790	2176	6527	5439	9790	2176	6527
Subtotal	2,861	2,972	2,972	-	-	-	-	20165	27795	111414	102763	20154	27775	116405	107356	20154	27775	116405	107356
Southeast	258	20	134	50	90	20	60	12880	23184	5152	15456	994	1789	398	1193	6685	12033	2674	8022
	52	5	54	50	90	20	60	2618	4712	1047	3142	250	450	100	300	2713	4883	1085	3255
Subtotal	310	25	188	-	-	-	-	15498	27896	6199	18598	1244	2239	498	1493	9398	16916	3759	11277
Drayton Harbor/	2,379	2,379	2,379	13.5	16.5	31.6	25	32117	39254	75176	59475	32117	39254	75176	59475	32117	39254	75176	59475
Loomis Trail	600	600	600	50	90	20	60	30000	54000	12000	36000	30000	54000	12000	36000	30000	54000	12000	36000
	7	7	7	50	90	20	60	347	624	139	416	347	624	139	416	347	624	139	416
Subtotal	2,986	2,986	2,986	-	-	-	-	62463	93877	87315	95891	62463	93877	87315	95891	62463	93877	87315	95891
Semiahmoo	432	432	432	0	0	45	41.5	0	0	19440	17928	0	0	19440	17928	0	0	19440	17928
	600	600	600	0	0	45	41.5	0	0	27000	24900	0	0	27000	24900	0	0	27000	24900
	399	399	399	0	0	45	41.5	0	0	17955	16559	0	0	17955	16559	0	0	17955	16559
Subtotal	1,431	1,431	1,431	-	-	-	-	0	0	64395	59387	0	0	64395	59387	0	0	64395	59387
Birch Point	900	1,110	2,095	13.5	16.5	31.6	25	12150	14850	28440	22500	14985	18315	35076	27750	28283	34568	66202	52375
Subtotal	900	1,110	2,095	-	-	-	-	12150	14850	28440	22500	14985	18315	35076	27750	28283	34568	66202	52375
SYSTEM TOTAL	***10,284***	***10,320***	***11,468***	-	-	-	-	142604	200339	330091	335058	131174	178127	336016	327796	152625	209055	370404	362206
SYSTEM TOTAL (Circuit-Miles)								27.0	37.9	62.5	63.5	24.8	33.7	63.6	62.1	28.9	39.6	70.2	68.6
Existing (Circuit-Miles)								8.9	6.7	12.7	13.0	8.9	6.7	12.7	13.0	8.9	6.7	12.7	13.0
Total Additional Required (Circuit-Miles)								18.1	31.2	49.8	50.4	16.0	27.0	51.0	49.1	20.0	32.9	57.5	55.6
Total Alternative 4 (Circuit-Miles)								6.1	6.8	18.3	18.1								
Existing Alternative 4 (Circuit-Miles)								4.6	4.5	11.0	9.2								
Additions to Alternative 4 (Circuit-Miles)								1.5	2.3	7.4	8.8								

Table 5-13 1994 Construction Unit Cost Estimates	
Description	**$/Unit**
Main Circuit Backbone	
556 kCM ACSR	$97,000/mile
336 kCM ACSR	$85,000/mile
4/0 ACSR	$81,000/mile
750 kCM AL UG	$280,000/mile
3-Phase Taps	
1/0 AWG ACSR	$67,000/mile
4/0 AWG AL URD	$230,000/mile
1-Phase Taps	
#2 AWG ACSR	$33,000/mile
#2 AWG AL URD	$175,000/mile
Transformers	
Overhead or Pad-mount, single phase, 37.5 kVA	$1,500 each
Pad-mount, 300 kVA, 3-phase, 100-foot secondary	$12,000 each
Services	
Overhead, 150-foot with meter	$600 each
Underground, 150-foot with meter	$800 each
Protective Devices	
Cut-outs	$150 each
Fused Switches, 3-phase	$1,000 each
Fused Switches, 1-phase	$750 each
Recloser, electronic, 3-phase	$20,000 each
Interrupter, electronic, 3-phase	$25,000 each
Sectionalizing	
Switches	$4,000 each

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Chapter 6

Financial Plan

Chapter 6
Financial Plan

Existing Financial Condition

The City of Blaine Electrical Division currently has assets of about $4.6 million and annual revenues of approximately $3.1 million. The Division balance sheets, income statements, and statements of cash flows for 1992 and 1993 are shown in Appendix D.

Strong points of the Division's financial condition include its relatively low rates and the fact that the utility is free of long-term debt. Blaine's average residential rate in 1993 was about 113 percent of the state average residential rate (about 3.9 cents) and 78 percent of that for Puget Power. The fact that the Division has no long-term debt (97 percent of the Division's capital and liabilities are composed of equity in the form of retained earnings and contributions in aid of construction) puts the Division in position to finance major new capital additions with long-term bonds as long as the City is willing to raise rates to pay debt service and "coverage" (or operating margin) requirements of associated bond covenants.

On the downside, the Division's financial reserves have dropped substantially in recent years and are now significantly below industry standards for operating reserves. This has resulted from attempts to keep rates as low as possible in the face of rising operating costs. In October of 1993, the Division endured a 15.8 percent increase in rates from BPA, its wholesale power supplier, and as a result, increased energy charges to its rate schedules (excluding the senior/disabled rate) by 10.0 percent. Following the 1994 rate increase, the Division's average revenue per kWh sold to all customers is about 5.0 cents, with average revenue per kWh sold to residential customers averaging 4.8 cents. The Division is facing the prospect of additional increases in BPA rates beginning in October 1995 and substantial uncertainty about future BPA rate forms and their impacts on the Division's purchased power costs.

Additionally, the Division faces the prospect of incurring substantial capital costs associated with its needs for significant upgrades to the electric system. The capital improvements program described in Chapter 5 will more than double the City's investment in net plant in real terms and nearly triple it in nominal terms by the turn of the century.[1]

The Division is also facing the prospect of rapid growth. While this growth increases system revenues, it also increases system costs. With growth, the City benefits from economies of scale to the extent that this growth increases the density of its service area and any excess capacity is used. This is especially true if the City continues to seek and

[1]As noted in Chapter 5, several of these investments such as the submarine cable replacement and the looped service to Semiahmoo have been deferred for a number of years.

obtain "contributions in aid of construction" to mitigate or avoid costs associated with adding new customers. A key risk factor associated with growth is the prospect of BPA establishing a "tiered" rate that charges higher prices for increased loads of wholesale customers like the Division. Given such a rate form and the Division's continued reliance on BPA to meet its overall energy supply requirements, growth would have a negative impact on the Division's average cost of doing business.

The City may also choose to annex outlying areas as described in Chapter 5. As part of such annexation, the City may choose to extend its electric service to these areas, replacing service currently provided by Puget Power. Acquisition of Puget Power's existing facilities or construction of new facilities in the potential annexation areas would increase the financial requirements of the City, and, depending on the investment cost, could require higher rates for the City overall.

Financial Planning Model (FINPLAN)

In order to establish a plan for the Division to follow in financing safe, reliable service for its customers, a financial planning computer model was developed. This model, called FINPLAN, was used to forecast financial conditions and to evaluate planning options available to the City. The model, described below, is being provided to the City as a tool to continue to evaluate financial and policy options as conditions change in the future. On the basis of projections made with FINPLAN, a 6-year plan was developed for financing the Division's proposed capital improvements program, evaluating uncertainty surrounding future growth in the Division's service area, and planning future rate levels and financial reserve levels.

The FINPLAN model developed for the City incorporates estimates of future purchased power expenses, other operation expenses, maintenance expenses, other operating costs, and capital investments. Future capital needs are based on assumptions of customer growth, the Capital Improvements Plan (CIP), and annexation possibilities.

For capital costs, the model incorporates financing alternatives. The financing component of the model includes analysis of contributions from customers, long-term debt financing, and the accumulation of reserves for financing capital expenditures.

The model has eight analytical modules. Each contains analytical tables and some have report tables. The modules that comprise the model and the analytical and report tables associated with each module are as shown in Table 6-1.

Table 6-1 Analytical Modules			
Module	Number of Analytical Tables	Report Tables	
		Number	Names
Summary	2	2	Summary-1 and Summary-1A
Flow of Funds	1	1	FF-1
Capital Improvement Program	4	4	CIP-1 through CIP-4
Contributions in Aid of Construction	4	0	
Load Forecast	10	7	LF-4 through LF-10
Operation and Maintenance	3	3	O&M-1 through O&M-3
BPA Rate Forecast	2	0	
Revenues	3	3	

Report tables for each of five scenarios analyzed for this Comprehensive Plan Report are provided in Appendix D. Each module included in FINPLAN is described below.

Summary Module. The summary module reports historic and projected income statements for the Division as well as projections of key financial statistics for the utility. The summary report (Table Summary-1) is used as a the primary basis for developing the Division's financial plan.

The model forecasts financial results in the summary report on the basis of current rates. The financial analyst using the model is then allowed to plan rate increases and bond financing of capital improvements for the 7-year forecast period of 1994-2000, or change any general or specific assumption included in other modules. (The general assumptions used in the model are reported in Table Summary 1-A.) The analyst then can rerun the model and check the financial results. Additional adjustments can then be made and results checked again. In this way, the financial plan is created in an interactive fashion.

As mentioned above, key financial parameters directly input by the analyst include annual bond financing and rate increases by the Division. Key financial parameters affected by

these inputs and monitored in the summary report as part of the iterative planning process include projections of reserve fund balances, bond coverage, debt-equity ratio, net income and average rates per kWh.

Flow of Funds Module. The utility's overall cash flow is projected in Table FF-1, Sources and Uses of Funds.

CIP Module. The Division's overall Capital Improvements Program (CIP) is covered in the CIP module. Table CIP-1 presents projected capital improvements in terms of renewals and replacements, customer line extension costs, costs associated with major system improvements, and annexation costs (for scenarios with assumed annexation of property outside of the existing city limits). This table reports CIP cost details in constant 1994 dollars and translates the total CIP expenditures into nominal future-year dollars.

Customer contributions shown on the bottom of Table CIP-1 are related to contributions for new service connections only. Table CIP-2 shows the funding sources for all capital improvements including customer contributions for new connections and other capital contributions including those from developers, local utility district contributions, and other potential sources. Funding from revenue bonds, grants, and expenditures from the Division's reserve funds are also shown in this table. Table CIP-3 shows details of projected bond sales, including issuance costs, reserve requirements, and debt service payments. Table CIP-4 shows the calculation of projected bond coverage.

Contributions Module. The contributions module projects contributions in aid of construction for new service connections. The number of new service connections, by customer class, is read from the load forecast module and then multiplied times the average contribution projected for new customers in each class. Residential and senior/disabled customers are projected to pay one-half the cost of new connections through connection fees while customers in each of the other classes are assumed to pay all new connection costs through connection fees.

Load Forecast Module. The load forecast module develops a projection of kWh sales by customer class on the basis of an input population growth rate, projections of future use per customer by class, and estimates of future increases in programmatic conservation. The population growth rate used in this analysis was taken from the City of Blaine's Growth Management Plan. As discussed below, projected use per customer was taken from supporting documents to the Division's conservation action plan (October 1993) prepared by BPA. Projections of programmatic conservation were prepared by the Division.

Projections of the number of customers are shown in Tables LF-4 and LF-5. These are translated into the number of projections of kWh sales in Table LF-6. Tables LF-7

and LF-8 show projections of the number of customers associated with annexation to the Division's service area and Tables LF-9 and LF-10 show projections of the combined existing in annexed service areas.

O&M Module. The O&M module (Tables O&M-1, O&M-2, and O&M-3) forecasts increases in operation and maintenance (O&M) expenses and administrative and general (A&G) expenses on the basis of historic costs per kWh and assumed costs associated with increased energy sales in the future. Assumptions regarding O&M and A&G expenses associated with increased future sales are described below under Forecast Assumptions.

BPA Rate Forecast Module. Forecasts of increases in BPA's priority firm (PF) rate to the Division are shown in the BPA Rate Forecast Module. Projections used in this study were taken from an independent forecast of BPA's PF rate prepared by CH2M HILL (March 1994).

Revenue Module. The revenue module includes analysis of annual revenues that can be produced from the Division's 1994 rate increase.

Forecast Assumptions

In forecasting future financial conditions for the Division, it was necessary to make a number of assumptions. FINPLAN allows testing of financial impacts from changes in these assumptions and is intended to test changed assumptions as part of its decision-making process. The assumptions in the financial forecast included:

- Load growth: Blaine's population was assumed to grow by 2 to 5 percent per year; use per customer was assumed to decline, as forecast by the Bonneville Power Administration in its Conservation Action Plan (October 1993); and the number of commercial customers was expected to continue to grow slightly more rapidly than the number of residential customers.

- The Division's programmatic conservation program was projected to reduce system loads by an additional 1.7 million kWh in 1994, and by 5 million kWh in 1996.

- The annual system load factor was assumed to remain at about 47 percent.

- General inflation was assumed to average 3 percent per year.

- BPA power sales rates were assumed to increase an average of 5.1 percent per year between 1994 and 2000.

- Average system power losses were assumed to average 4.5 percent.

- The interest rate on the Division's long-term debt was assumed to average 6.5 percent; interest earnings on the Division's investments were assumed to average 4.0 percent.

- It was assumed long-term bond financing costs will be 3 percent of the issue amount, and bonds will have a 10 percent reserve requirement.

- New customers were projected to increase system O&M costs by 25 percent of the average O&M costs per kWh for the system as a whole; similarly, new customers were projected to increase system A&G costs per kWh by 25 percent of the system average A&G costs per kWh.

- For energy requirements of each new customer added through annexation, O&M costs were assumed to increase at 100 percent of the average system O&M costs per kWh; A&G costs were assumed to increase at 30 percent of the average system A&G cost per kWh.

- Except for residential customers, the costs of adding new customer connections were assumed to be entirely covered through customer contributions; approximately one-half the cost of new residential connections were assumed to be covered through customer contributions in aid of construction.

- For annexed areas, only the proposed H Street annexation area was assumed to be paid for through contributions in aid of construction.

- Renewals and replacements were assumed to average about $175,000 per year; it was expected that about 40 percent of these renewals and replacements will be paid for through contributions in aid of construction.

- Major new investments to upgrade the Division's system were projected as shown in Table 7-7 in Chapter 7; about 10 percent of these costs were expected to be paid through contributions in aid of construction.

Financial Forecast and Plan

In preparing the Division's Financial Plan, five scenarios were evaluated. Variables in the assumptions evaluated through these scenarios were future load growth and future prospects for expansion of the Division's service area through annexation. The five scenarios are as follows:

- Scenario 1—This is considered to be the base case to the Financial Plan. It assumes a medium load forecast associated with a 3.5 percent annual population increase and no expansion of the Division's service territory through annexation.

- Scenario 2—This scenario assumes load growth associated with a 2 percent average annual increase in population and no expansion of the Division's service territory through annexation.

- Scenario 3—This scenario assumes high load growth associated with a 5 percent average annual population increase and no expansion of the Division's service territory through annexation.

- Scenario 4—This scenario assumes the medium load forecast with expansion of the Division's service territory through annexation of areas not currently served by the Division. In this scenario, it is assumed that the existing utility plant in the annexed areas would be acquired at a price equal to the "replacement cost new" (RCN) value of the facilities.[2] (RCN is the estimated cost of replacing the existing facilities with all new facilities at current price levels.) Each of the annexation alternatives described in Chapter 5 would likely have a similar cost; therefore, only one alternative, Alternative 2, was evaluated for the Division's Financial Plan. As specific annexation proposals are developed, they can be evaluated through the FINPLAN model.

- Scenario 5—This scenario assumes the medium load forecast and expansion of the Division's service area through annexation. In this scenario, the purchase price associated with acquisition was set equal to a payment that would result in the same retail rate requirements through 2000 as planned for Scenario 1.

On the basis of assumptions described above, a financial forecast and plan were prepared for each of these five scenarios. Summary results are shown in Table 6-2 in terms of nominal future price levels and in Table 6-3 in terms of constant 1994 price levels. As described above, detailed FINPLAN report tables for Scenarios 1 through 5 are shown in Appendix D. These detailed reports are in nominal price levels unless otherwise noted in the reports.

Financial Plans Assuming No Annexation

As described above, Scenarios 1 through 3 assume that the Division's service area is not expanded through annexation. Under these circumstances, the Division's operating costs are projected to increase by an average of 5.0 to 7.8 percent in nominal terms (2.0 to 4.7 percent in real terms) between 1994 and 2000, depending on load-growth assumptions. Given that the CIP requires $5.5 million in capital expenditures for major new

[2]Use of RCN is not meant to imply that this would be an appropriate price to pay for acquisition of existing utility facilities in annexation areas. Rather, it establishes a benchmark measurement of the cost the Division could incur if it were to build the facilities itself.

Table 6-2
City of Blaine Electrical Division
Financial Plan – Summary of Results
(Nominal Dollars)

Description	Scenario 1 (Med. Load/ No Annex)	Scenario 2 (Low Load/ No Annex)	Scenario 3 (High Load/ No Annex)	Scenario 4 (Med. Load/ Annex @ RCN)	Scenario 5 (Med. Load/ Rev. Neutral Annexation
Operating Costs (Excluding Depreciation)					
1994	$3,087,904	$3,081,877	$3,093,931	$3,087,904	$3,087,904
2000	4,481,936	4,133,900	4,858,621	5,741,662	5,725,408
Average Annual Change (%)	6.4%	5.0%	7.8%	10.9%	10.8%
Annual Debt Service					
1994	$0	$0	$0	$0	$0
2000	428,224	432,918	423,008	1,174,617	752,753
Average Annual Change (%)	NA	NA	NA	NA	NA
Revenues/Requirements					
1994 Revenues	$3,037,143	$2,992,119	$3,082,166	$3,037,143	$3,037,143
1995 Requirements	3,384,583	3,316,078	3,455,724	3,387,764	3,384,583
2000 Requirements	5,152,365	4,784,821	5,549,568	7,155,200	6,735,533
Average Annual Change (%)*	9.2%	8.1%	10.3%	15.4%	14.2%
Average Revenues per kWh**					
1994	$0.049	$0.049	$0.049	$0.049	$0.049
2000	$0.072	$0.075	$0.070	$0.077	$0.072
Average Annual Change (%)	6.6%	7.2%	6.0%	7.6%	6.6%
Unrestricted Ending Fund Balance					
1994	46,952	16,819	77,085	46,952	46,952
2000	161,345	176,674	142,198	170,916	184,629
Average Annual Change (%)	22.8%	48.0%	10.7%	24.0%	25.6%
Net Plant in Service					
1994	3,626,212	3,560,402	3,692,021	3,626,212	3,626,212
2000	9,201,810	8,668,314	9,787,636	15,595,476	12,365,256
Average Annual Change (%)	16.8%	16.0%	17.6%	27.5%	22.7%
Debt/Equity Ratio					
1994	0.00%	0.00%	0.00%	0.00%	0.00%
2000	40.04%	42.40%	37.68%	61.96%	51.76%
Average Annual Change (%)	NA	NA	NA	NA	NA

*1994 - 2000
**Assumes rates are increased to meet projected revenue requirements.

Table 6-3
City of Blaine Electrical Division
Financial Plan – Summary of Results
(Constant 1994 Dollars)

Description	Scenario 1 (Med. Load/ No Annex)	Scenario 2 (Low Load/ No Annex)	Scenario 3 (High Load/ No Annex)	Scenario 4 (Med. Load/ Annex @ RCN)	Scenario 5 (Med. Load/ Rev. Neutral Annexation
Operating Costs (Excluding Depreciation)					
1994	$3,087,904	$3,081,877	$3,093,931	$3,087,904	$3,087,904
2000	3,753,551	3,462,077	4,069,019	4,808,552	4,794,939
Average Annual Change (%)	3.3%	2.0%	4.7%	7.7%	7.6%
Debt Service					
1994	$0	$0	$0	$0	$0
2000	358,631	362,562	354,263	983,723	630,418
Average Annual Change (%)	NA	NA	NA	NA	NA
Revenues/Requirements					
1994 Revenues	$3,037,143	$2,992,119	$3,082,166	$3,037,143	$3,037,143
1995 Requirements	3,286,003	3,219,493	3,355,072	3,289,091	3,286,003
2000 Requirements	4,315,025	4,007,212	4,647,676	5,992,368	5,640,903
Average Annual Change (%)*	6.0%	5.0%	7.1%	12.0%	10.9%
Average Revenues per kWh**					
1994	$0.049	$0.049	$0.049	$0.049	$0.049
2000	0.060	0.063	0.058	0.064	0.060
Average Annual Change (%)	3.5%	4.1%	2.9%	4.5%	3.5%
Unrestricted Ending Fund Balance					
1994	$46,952	$16,819	$77,085	$46,952	$46,952
2000	135,124	147,962	119,088	143,140	154,624
Average Annual Change (%)	19.3%	43.7%	7.5%	20.4%	22.0%
Net Plant in Service					
1994	$3,626,212	$3,560,402	$3,692,021	$3,626,212	$3,626,212
2000	7,706,371	7,259,577	8,196,991	13,060,965	10,355,707
Average Annual Change (%)	13.4%	12.6%	14.2%	23.8%	19.1%
Debt/Equity Ratio					
1994	0.00%	0.00%	0.00%	0.00%	0.00%
2000	40.04%	42.40%	37.68%	61.96%	51.76%
Average Annual Change (%)	NA	NA	NA	NA	NA

*1994 - 2000
**Assumes rates are increased to meet projected revenue requirements.

projects between 1995 and 2000 regardless of load growth, the Division is forecast to be incurring debt service payments of between $423,000 and $433,000 in year 2000. In addition, we recommend rebuilding the Division's unrestricted fund balance to approach normal operating reserve levels equal to 45 days of operating expenses excluding purchased power and depreciation. The combination of increases in operating costs, particularly in power supply costs from BPA, the addition of annual debt service requirements, and the need to rebuild the Division's reserves results in increases in the Division's revenue requirements over 1994 revenues by an average of 8 to 10 percent per year.

Under this plan, the Division's average revenue (or rate) per kWh sold would increase from 4.9 cents in 1994 to 7.0 to 7.5 cents per kWh in nominal price levels in the year 2000, or to 5.8 to 6.3 cents per kWh in constant 1994 price levels. Under the assumptions of the financial plan, growth in system loads are forecast to lessen needed increases in the Division's average rate per kWh. This is because in addition to general inflation, the primary factor causing the need for rate increases between 1995 and 2000 is planned capital expenditure unrelated to growth. During this period, capital expenditure unrelated to growth will increase the Division's annual revenue requirement by $400,000 (nominal dollars). This is equal to about 13 percent of estimated 1994 Division revenues. The impact of this added revenue requirement on the Division's average rate per kWh is reduced with greater levels of system sales. Therefore, in 2000, the Division's average rate per kWh is projected to be 7.5 cents under low-load-growth conditions (Scenario 2) and 7.0 cents under high-load-growth conditions (Scenario 3).

However, while higher growth rates result in lower Division rates per kWh under the assumptions in the plan, changes in BPA pricing policies may make higher growth rates more expensive. BPA may establish a tiered rate system that charges higher prices for increased loads of its customers, including the Division. Such changes in BPA pricing policies are not included in this Financial Plan.

Currently, the Division's residential rates are set at about 95 percent of the average rate for all customers. If this relationship were to hold in the future, residential rates in the year 2000 would average between 5.5 and 6.0 cents per kWh at 1994 general price levels. This compares to 1993 average residential rates of 5.5 cents per kWh for Puget Power, 5.4 cents per kWh for the City of Sumas, and 3.9 per kWh for the State of Washington as a whole.

Given the overall Capital Improvements Plan shown in Table CIP-1, the Division's net plant-in-service would increase to about 2.5 times its current level in 2000. (In constant 1994 price levels, net plant-in-service would more than double.) Consistent with this increase in plant-in-service, and related debt requirements described above, the Division's debt-equity ratio would increase from no debt in 1994 to approximately 40 percent of total capitalization in 2000.

Financial Plans Assuming Annexation

With expansion of the Division's service territory through annexation, its financial requirements would naturally increase. Given the assumptions associated with annexation Alternative 2, overall operating costs would increase an average of nearly 11 percent per year between 1994 and 2000. Scenario 4 estimates that the annexation costs associated with Alternative 2 would be about $7.2 million if purchased at full RCN value. This would result in overall annual debt service of about $1.2 million in year 2000 and bring the Division's overall revenue requirements to over $7 million in year 2000, for an average annual revenue increase of 15.4 percent in nominal terms (12 percent in constant dollar terms). This would require average annual rate increases of 7.6 percent in nominal terms (4.5 percent in constant dollar terms).

However, given the age and condition of utility properties in the prospective annexation areas, the actual purchase price of these properties is likely to be substantially lower than RCN. In Scenario 5, it was estimated that a purchase price of approximately $3.2 million (44 percent of "replacement cost new") could be contracted so that the annexation would have no impact on rates between the assumed acquisition year of 1996 and the year 2000.[3]

Given this purchase price, the Division's overall revenue requirements would increase an average of 14.2 percent per year (nominal terms) between 1994 and 2000. BCL's average rate per kWh sold would increase an average of 6.6 percent per year in nominal terms and 3.5 percent per year in constant dollar terms.

Under Scenario 5, net plant-in-service in nominal terms would increase to 3.4 times its current level. Financing requirements associated with this scenario would result in a slightly greater than 50 percent debt-equity ratio.

Key Aspects of the Division's Financial Plan

Key aspects of the Division's Financial Plan proposed above are as follows:

1. In order to finance the major capital improvements and possible annexation of additional service area, the Division will need to incur long-term debt. Depending on the financing source and associated costs and actual timing of capital investments, the Division may obtain all of its financing requirements at one time or obtain funds as needed over a number of years. (The tables included in Appendix D assume that financing is obtained on an

[3]As shown in Table CIP-1 of Scenario 5 (Appendix D), the annexation payment would need to equal the following stream of payments in order for the Division's revenue per kWh to equal those shown in Scenario 1 for the years 1996 through 2000: 1996—$2.2 million, 1997—$330,000, 1998—$327,000, 1999—$222,000, 2000—$209,000.

as-needed basis.) Incurring this debt will require adoption of bond covenants that will effectively require rates will be raised to meet debt service payments plus a margin that will likely be in the range of 25 to 40 percent of the debt service payment. This margin can be used to pay for ongoing capital improvements and to build reserves.

2. The Division should rebuild its reserves to at least approach standard operating reserve levels, described above, as soon as possible. In Appendix D, operating reserves are assumed to be rebuilt to close to these levels in 1995 and to remain at near this level over the course of the 1996-2000 forecast period.

3. In order to keep rates as low as possible, the City of Blaine should continue to make use of contributions in aid of construction from sources of system growth. This includes continuation of the Division's current policies with regard to contributions in aid of construction as well as consideration of other methods such as impact fees and formation of local utility districts to fund investments that benefit specific groups of customers.

4. The amount of long-term debt recommended to be incurred through this Financial Plan was constrained by other financial parameters referred to above. Specifically, long-term debt was planned at lower levels than possible to minimize interest expense and coverage requirements and to maintain essentially a "break-even" position or better on the Division's income statement. If the Division were willing to show losses on its income statement, it would be able to reduce the size of rate increases in the short-term (1995-1999) by issuing more long-term debt in such a way that the utility's debt-equity ratio would approach 50 percent under Scenario 1.[4]

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[4]Net income is calculated after all cash and non-cash expenses for the year have been subtracted from a utility's revenues, as shown in Table Summary-1 in Appendix D. Cash available for debt service payments and the calculation of debt service coverage, shown in Table CIP-4, excludes the deduction of depreciation expense and interest expense and therefore is greater than net income by the amount of these expenses. Under certain circumstances when a utility has a relatively low amount of debt (as the Division currently does), it is possible to show negative net income in the utility's income statement while at the same time also showing strong debt service coverage. This circumstance would allow the utility for a limited number of years to take on additional debt and show greater losses of net income while at the same time maintaining coverage requirements. Taking on more debt would keep revenue requirements, and therefore rates, lower in the short run but higher in the long run. In developing the Division's Financial Plan, rates were assumed to be set such that net income was essentially at a "break-even" level or better.

Chapter 7

Operations Plan

Chapter 7

Operations Plan

Introduction

This chapter presents statistics about the City of Blaine Electrical Division. The statistics are illustrated in the form of charts, visual tools that can be compared and interpreted. Some charts compare the Division's performance from year to year; others compare the Division to other utilities. The charted information was chosen to assist the Division in understanding its past operations, in planning for future projected growth, and to effectively communicate information about the Division to others such as customers and the City Council.

The background section of this chapter discusses issues concerning performance statistics. The statistical charts section contains the actual statistics in the form of charts and provides detail as necessary. The charts are divided into eight statistical categories: division growth, service reliability, revenue/rate, expense, safety, customer relations, employee relations, and financial performance.

Appendix C lists the references used to compile the statistics presented in this chapter.

Background

The many facets of a public utility make measuring its performance complex. Among other things, a public utility must deal with the effectiveness with which capital is employed, the efficiency of its operations, its responses to public and governmental interests, regulatory issues, technical advancements, and environmental concerns. The first step in planning should be setting objectives and priorities. For example, efficient operation and stable revenue are essential for a public utility to cover investment charges and operating and maintenance costs. Similarly, public relations are a high priority since a consumer-owned public utility supports local interests and its operation is essential to the public welfare.

Accordingly, planning is crucial to a public utility. Planning helps to define objectives and to develop policies and financial strategies. An important component of proper planning is an understanding of the long-term effects of short-term decisions. A utility should, therefore, establish a planning method that evaluates all elements of its operation.

Following through with planning requires keeping track of results. This, in turn, requires recordkeeping. The most essential characteristic of recordkeeping is maintaining comparability from year to year so that the results can be compared and combined. In this manner the utility builds a collection of valid information classified for such uses as budgetary control, operations planning, and public relations. In an effort to foster recordkeeping efficiency and comparability among utilities, the practice of building the classifications around certain standard accounts that are required of all utilities, large and small, has been introduced. Recordkeeping for utilities with at least 120,000 megawatt-hour sales has been standardized, and statistics are published.

Two major organizations that collect standardized data and publish statistics for utilities with at least 120,000 megawatt-hour sales are the Energy Information Administration (EIA) and American Public Power Administration (APPA). The EIA uses Form EIA-412 (accounting, financial, and operating data required by all utilities with at least 120,000 megawatt-hour sales) and Form EIA-861 (power production and sales data, mandatory by all utilities) to publish a yearly document titled *Financial Statistics of Major U.S. Publicly Owned Electric Utilities.* The data from this publication can be consistently compared from year to year.

The APPA also uses the Standard Forms EIA-412 and EIA-861 along with its APPA performance indicator survey to publish an annual report titled *Selected Financial and Operating Ratios of Public Power Systems*. The advantage of this report is that it sorts statistics by customer size, ranging from "2,000 to 5,000 Customers" to "More Than 100,000 Customers." A disadvantage is that utility response is not mandatory, and for any year the composition of utilities responding may have changed. The publication's statistics, therefore, should not necessarily be compared across years.

It is very important when comparing statistics among utilities that comparative information is used. A deeper look into the records of smaller public utilities reveals that accounting systems can vary substantially. A set of data including Northwest public utilities of Blaine's size has been incorporated into specific charts. Acquiring large amounts of relevant data for all charts would, however, require substantial cooperation among utilities and their accounting staffs. In addition, this data collection would have to recur yearly. CH2M HILL therefore recommends that the Division establish statistics that pertain to its own organization and also obtain relevant statistics that are already published (e.g., the APPA publication). In this way the Division can more easily maintain consistent data with which to create annual comparative charts.

Statistical Charts

As noted earlier, the following charts are organized into eight statistical categories: division growth, service reliability, revenue/rate, expense, safety, customer relations, employee relations, and financial performance. Some of the charts require information that the Division has not historically recorded. In these cases, sample data are used for illustration purposes, and the charts are titled "Example Charts."

The Division may also wish to target other areas of its operation by augmenting or reorganizing the information presented in this chapter. When reviewing the charts that compare the Division to other utilities, it is very important to remember that the charts should *not* be used to draw conclusions about the Division's performance until all aspects of the chart are understood. The comparative charts may use information from many different types of utilities and only illustrate *relative* levels of performance. While relative performance can be a useful tool, these comparative charts do not provide definitive information, nor should the levels of others' performance be taken as the "correct" levels of performance. The financial and operating comparisons can provide a useful starting point for analysis or may be used to indicate areas for further investigation. The comparisons should be analyzed in the light of broader information and should not form the basis for general conclusions.

Division Growth Statistics

Number of Division Customers per Distribution Line Mile. The Division has seen a steady increase in the number of customers since 1988. Chart 7-1 can be used to illustrate future changes in the population density of the electrical system.

Chart 7-1
Blaine Electrical Division: Customers per Distribution Line Mile

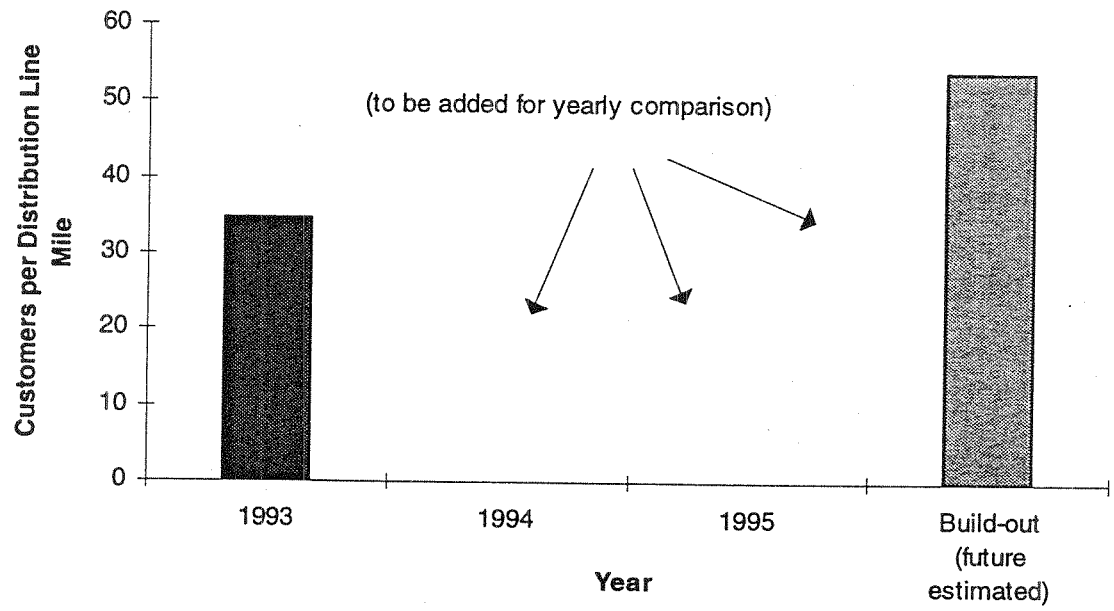


Table 7-1 shows the estimated build-out information from the Capital Improvements Plan, Alternative 1, that was used to develop Chart 7-1.

Table 7-1
Estimated Build-Out Information

Estimated Total Distribution Miles at Build-Out, Overhead + Underground:	188.5
Estimated Total Number of Dwelling Units at Build-Out:	10,186

Number of Division Customers per Employee. Charts 7-2a and 7-2b can help evaluate Division staffing issues as the number of electrical customers changes. Chart 7-2a and 7-2b illustrate the effect of the Division's changing the way it counted "Boats" within its customer class system after 1992: there was a noticeable reduction in the effective number of customers per employee. This example of how changes in accounting systems can affect statistics reinforces the recommendation that these charts must be interpreted carefully. Chart 7-2b compares the Division's 1992 statistics with APPA statistics for the number of customers per utility employee and indicates that Blaine's employee count is in line with those of the other utilities.

Chart 7-2a
Blaine Electrical Division: Customers per Employee

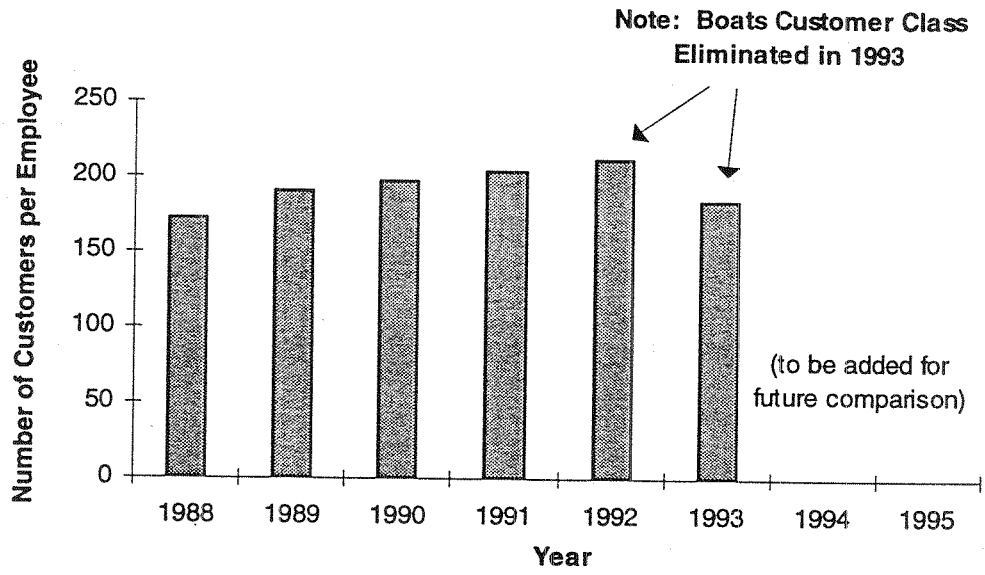


Table 7-2a shows the information that was used in Chart 7-2a:

Table 7-2a
Blaine Electrical Division: Customers per Employee

Year:	Number of Division Customers:	Number of Division Employees
1988	1,726	10
1989	1,906	10
1990	1,968	10
1991	2,036	10
1992	2,118	10
1993	1,954	10

1993 Comparison: Number of Customers per Employee, Northwest Utilities. This chart compares the Blaine Electrical Division, a utility with about 2,000 customers, with utilities of other sizes, and shows the relative numbers of customers per employee in non-power generation jobs.

Chart 7-2b
Comparison: Northwest Utility Customers per Employee

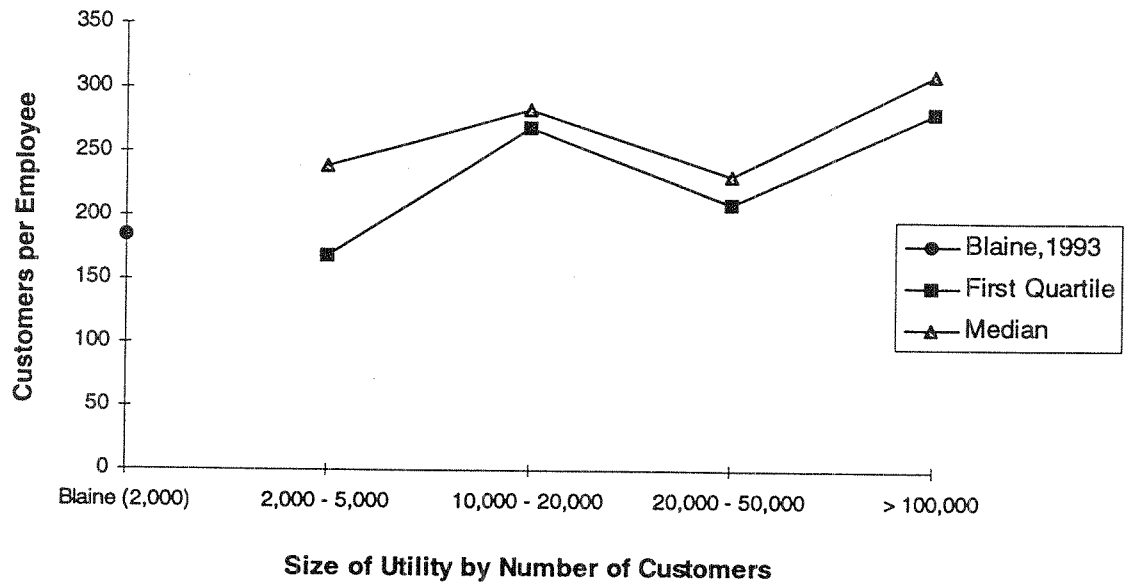


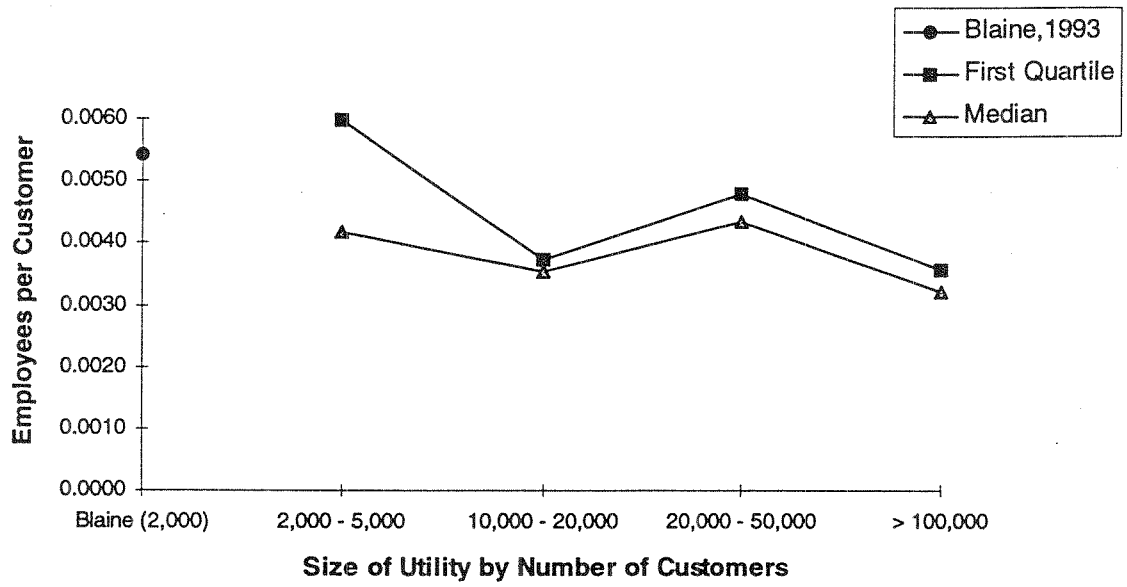
Chart 7-2b was based on information from the utilities shown in Table 7-2b.

Table 7-2b
Utility Customer Numbers

Number of Customers	Utility	Number of Customers	Utility
2,000-5,000	Wahkiakum County PUD No. 1	**20,000-50,000**	Clallam County PUD No. 1
	Kittitas County PUD No. 1		Lewis County PUD No. 1
	Ferry County PUD No. 1		Mason County PUD No. 3
	Mason County PUD No. 1		Chelan County PUD No. 1
	Skamania County PUD No. 1		Grant County PUD No. 2
5,000-10,000	Pend Oreille County PUD No. 1		Grays Harbor County PUD No. 1
	Klickitat County PUD No. 1		Cowlitz County PUD No. 1
10,000-20,000	Douglas County PUD No. 1	**> 100,000**	Clark County PUD No. 1
	Pacific County PUD No. 2		Snohomish County PUD No. 1
	Franklin County PUD No. 1		Snohomish County PUD No. 1
	Okanogan County PUD No. 1		

Chart 7-2c reverses the comparisons made in Charts 7-2a and 7-2b, and shows employees per customer. Both sets of comparisons can be used to evaluate the staffing of the Blaine Electrical Division.

Chart 7-2c
Comparison: Northwest Utility Employees per Customer



Number of Division Customers per Meter Reader. Chart 7-3a can help evaluate staffing needs as the number of Division customers changes. As in Chart 7-2a, the change in the way "Boats" are counted is reflected in the number of customers per meter reader.

Chart 7-3a
Blaine Electric Division: Customers per Meter Reader

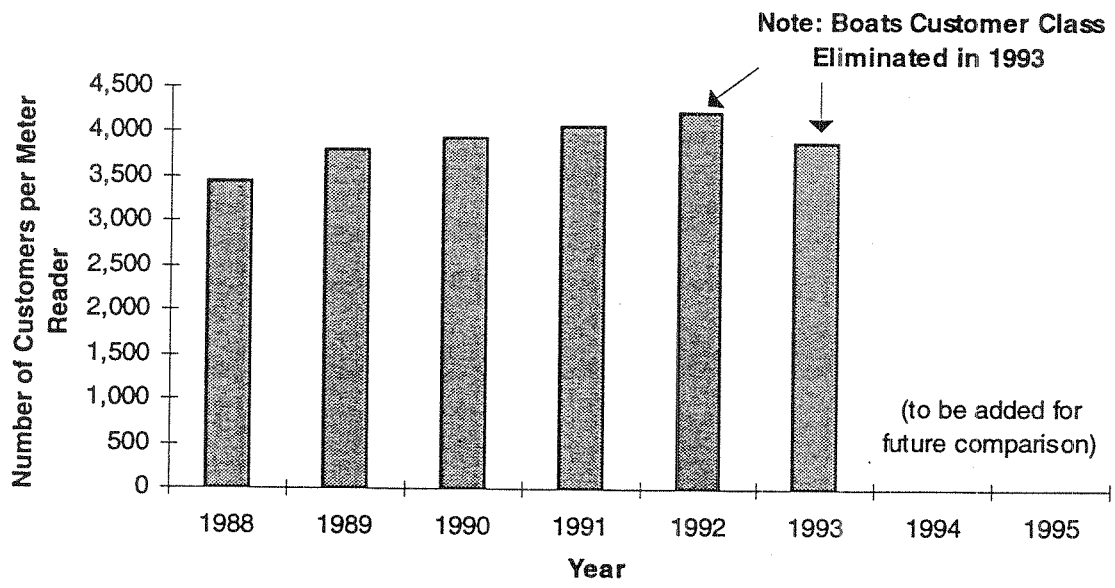


Table 7-3a shows the information that was used to develop Chart 7-3a.

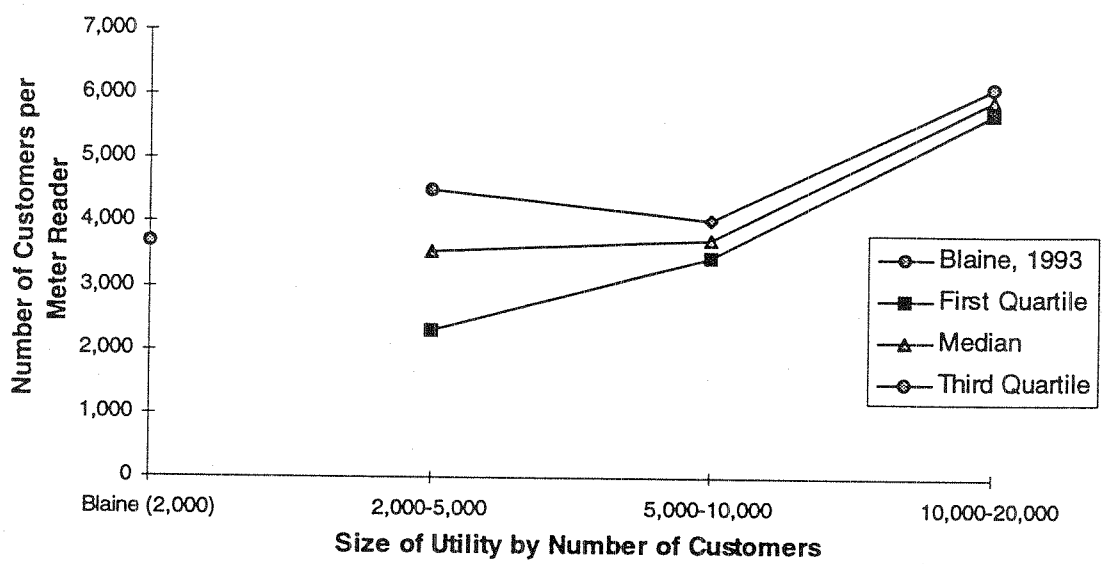
Table 7-3a
Blaine Electrical Division: Number of Customers per Meter Reader

Year:	Number of Division Customers	Number of Division Meter Readers[a]
1988	1,726	0.5
1989	1,906	0.5
1990	1,968	0.5
1991	2,036	0.5
1992	2,118	0.5
1993	1,954	0.5

[a]One meter reader shared among departments.

1993 Comparison: Median Number of Customers per Meter Reader, Selected Northwest Utilities. Note that it is common for smaller utilities (i.e., under 2,000 customers) to share meter-readers with other departments, to use part-time meter readers, or to contract out the meter-reading service.

Chart 7-3b
1993 Comparison: Northwest Utility Customers per Meter Reader



Information from the utilities shown in Table 7-3b was used to develop Chart 7-3b.

Table 7-3b
Customer Numbers of Utilities Used for Comparison

Number of Customers	Utility
2,000-5,000	Wahkiakum County PUD No. 1
	Ferry County PUD No. 1
	Mason County PUD No. 1
	Skamania County PUD No. 1
5,000-10,000	Pend Oreille County PUD No. 1
	Klickitat County PUD No. 1
10,000-20,000	Douglas County PUD No. 1
	Pacific County PUD No. 2
20,000-50,000	Clallam County PUD No. 1

Service Reliability Statistics

Service reliability statistics are an effective way to illustrate the reliability of Blaine's electrical system. Note that a looped feed to the Semiahmoo area and proper coordination of protective devices could increase reliability significantly. The System Average Interruption Durations Index (SAIDI) is commonly used by utilities. Since there is no industry standard, it would be advisable to track this information for annual comparison and for comparison with other utilities.

Example Table: System Reliability. The following example table uses data collected and published by the APPA for 1992. The SAIDI measures the average length of time (in minutes) each customer can expect to be without power during the course of a year. (An asterisk (*) in the table indicates too few responses to calculate the quartile.)

Example Table
1992 APPA Comparison: System Average Interruption Durations Index

Minimum Outage Duration (in customer minutes)	Number of Utilities	Mean	1st Quartile	Median	3rd Quartile
Less than 1 minute	18	47	10	30	55
1-2 minutes	58	51	27	44	80
5 minutes	11	29	2	22	35
15 minutes	12	22	10	22	39
30 minutes	7	36	*	16	*
60 minutes	8	41	*	12	*

Customer minutes refer to the total amount of time, in minutes, a given number of customers experience power outages. For example, if 30 customers experience loss of power for 20 minutes, the outage would have lasted a total of 600 customer minutes (30 customers times 20 minutes).

A utility's SAIDI ratio will be influenced by the minimum outage duration used. For example, utilities that do not record outages of less than 30 customer minutes may have more favorable (lower) SAIDI ratios than utilities that record all but instantaneous outages, all else being equal. The minimum outage duration recorded by a utility may reflect the type of technology used to monitor and record such outages, or it may be a matter of policy. Some utilities exclude outages caused by storm damage, which also affects the index.

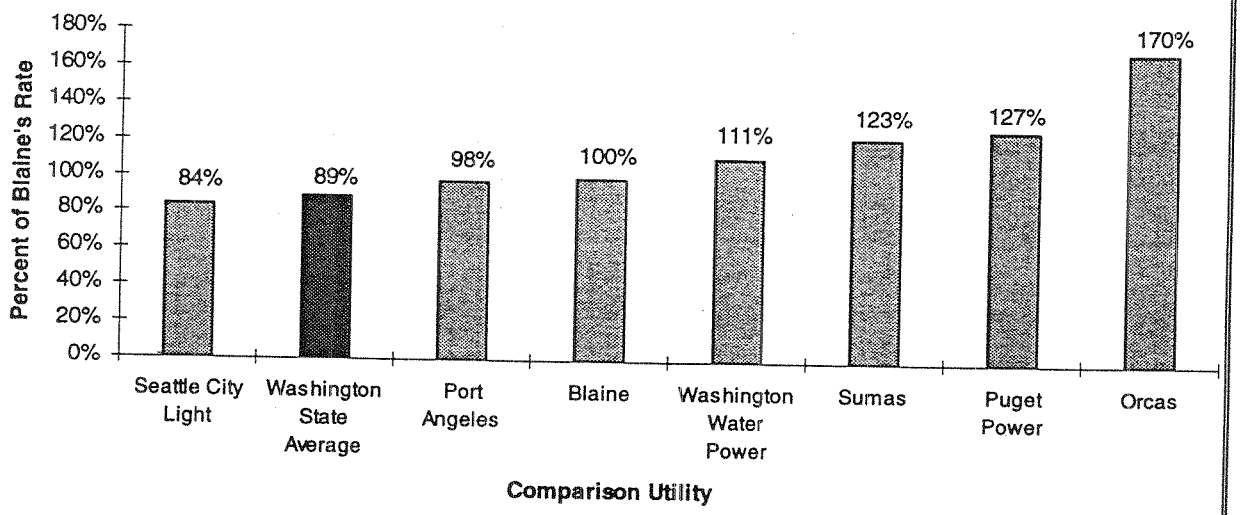
Revenue/Rate Statistics

Chart 7-4 shows that the average rate for the Division's 1994 residential customer is on the lower end compared with other selected Washington State utility rates, but is near the state average as supplied by the Bonneville Power Administration. It should be noted that the Washington State average includes other utilities that have very low rates because of the availability of inexpensive hydroelectric power. Chart 7-5 shows the amount of revenue per kWh sold and indicates that

Blaine appears to receive equal amounts of revenue from all customer classes. The significance of this depends upon the differences in the cost of serving the different customer classes.

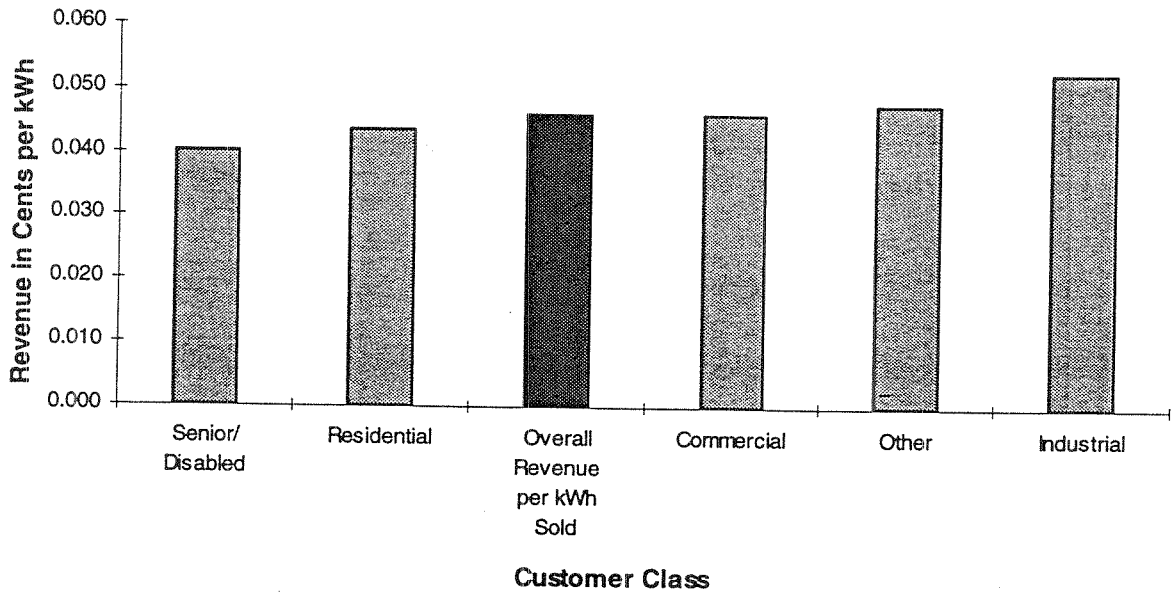
1994 Comparison: Average Electrical Rates, Residential Customers. Chart 7-4 illustrates data collected from individual utilities and from BPA, and shows how other utilities' rates compare to Blaine's, which is shown as the 100 percent basis for comparison. It should be noted that these utilities represent a variety of geographical and organizational situations (i.e., small city, major metropolitan area, quasi-public utility, private company), and only Sumas is directly comparable to Blaine.

Chart 7-4
1994 Comparison: Residential Customer Average Electrical Rates



1993 Division Revenue per kWh Sold by Customer Class. Chart 7-5 illustrates overall revenue and revenue from various classes of customers. The chart does not reflect the 1994 rate increases.

Chart 7-5
Blaine Electrical Division: Revenue per kWh Sold by Customer Class

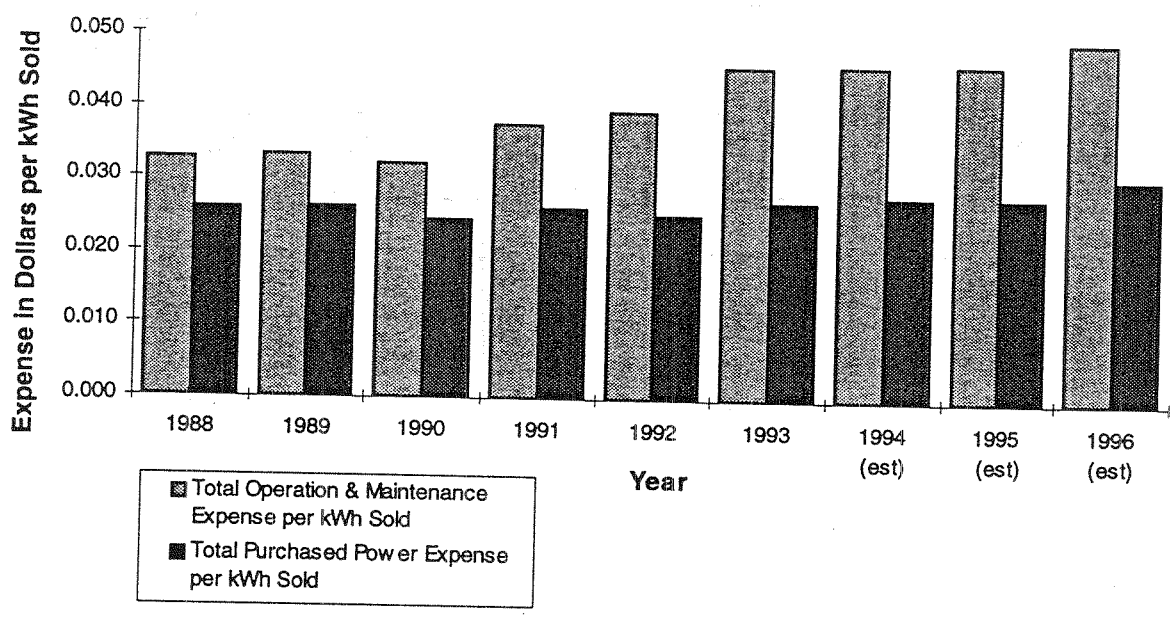


Expense Statistics

Comparison of Blaine's 1992 total operation and maintenance (O&M) expenses and administration and general (A&G) expenses with those of other APPA utilities indicates that Blaine's expenses were in line with those of the other utilities. Comparison of Blaine's A&G expenses from 1988 to 1993 is another example of how the charts can be affected by a change in the way costs are allocated. A&G costs were allocated differently after 1992, and this results in a noticeable increase in A&G expense costs between 1992 and 1993.

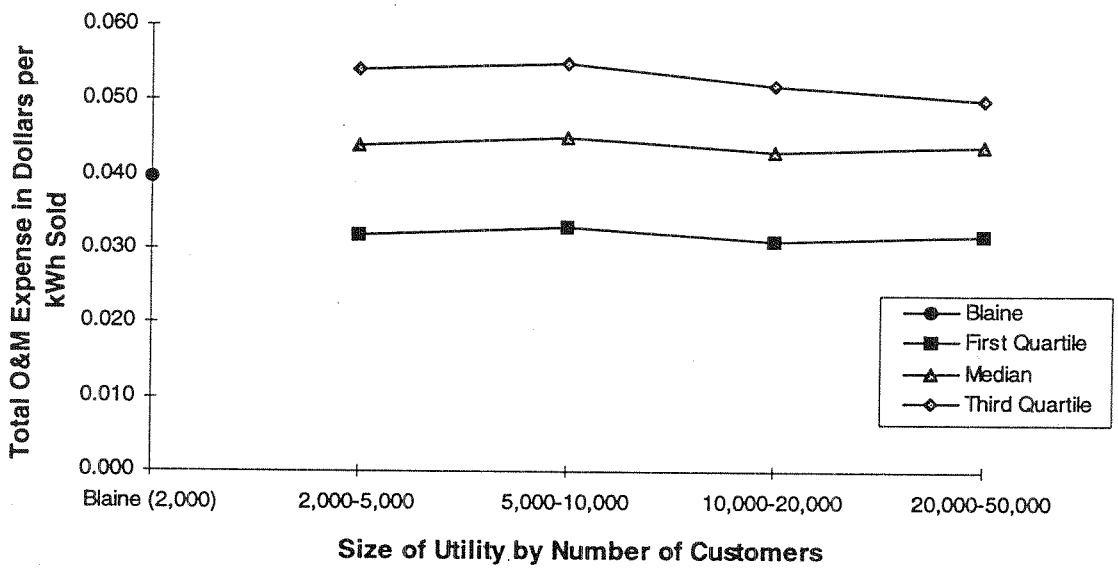
Total Division O&M Expense. The total O&M expense shown in Chart 7-6a is as defined by the Code of Federal Regulations. This includes distribution O&M expense, A&G expense, purchased power expense, and miscellaneous expense. This total expense is compared to the expense for purchased power and shows the portion of the total represented by the purchased power. The data source was the Scenario 1 financial model.

Chart 7-6a
Blaine Electrical Division: Total Operation and Maintenance Expense Compared with Purchased Power Expense per kWh Sold



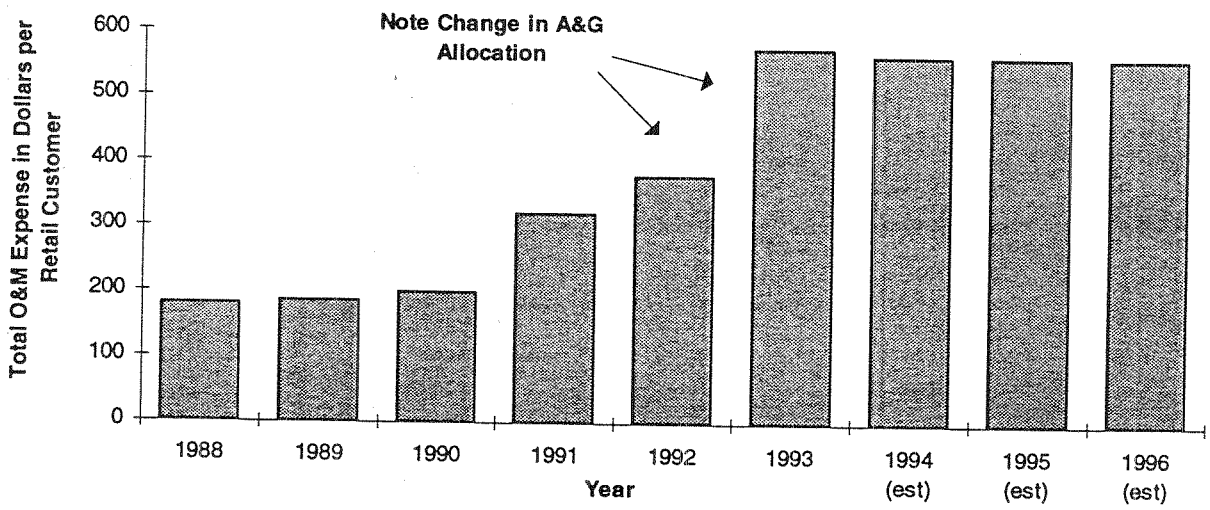
Comparison: Total O&M Expense per kWh. Chart 7-6b uses data collected and published by APPA for 1992. The total O&M expense used in Chart 7-6b is as defined by the Code of Federal Regulations. This includes distribution O&M expense, A&G expense, purchased power expense, and miscellaneous expense. The Blaine data source was the Scenario 1 financial model.

Chart 7-6b
1992 APPA Comparison: Total Operation and Maintenance Expense per kWh Sold (includes purchased power)



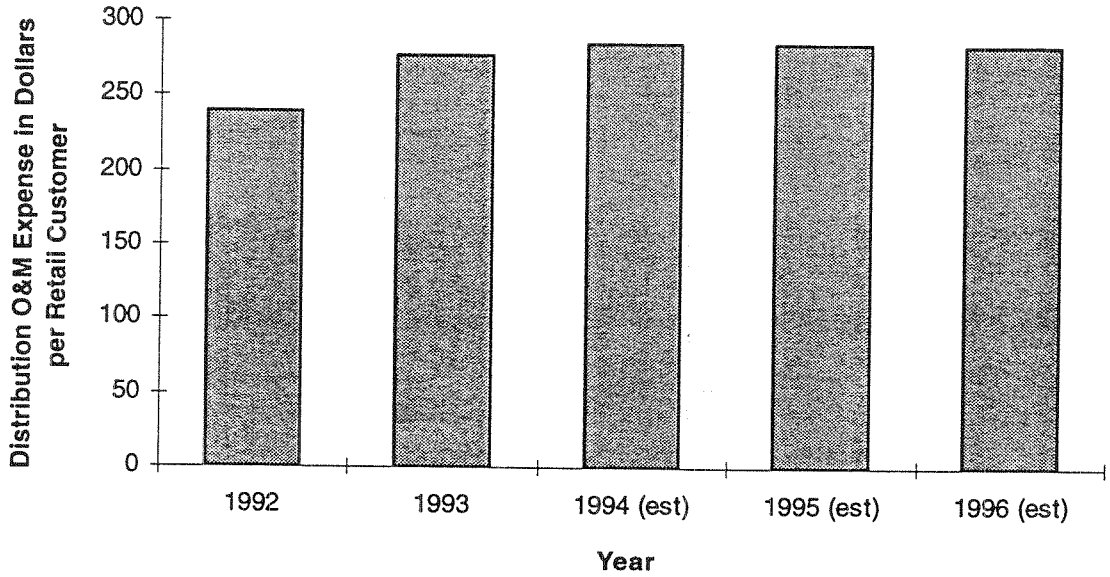
Total Division O&M Expense per Retail Customer. The total O&M expense used in Chart 7-7 is as defined by the Code of Federal Regulations. This includes distribution O&M expense, A&G expense, and miscellaneous expense. The data source was the Scenario 1 financial model. Note that A&G expense was allocated differently after 1992. This resulted in a noticeable increase in the Division's A&G expense and a corresponding increase in the total O&M expense.

Chart 7-7
Blaine Electrical Division: Total Operation and Maintenance Expense per Retail Customer (excludes purchased power)



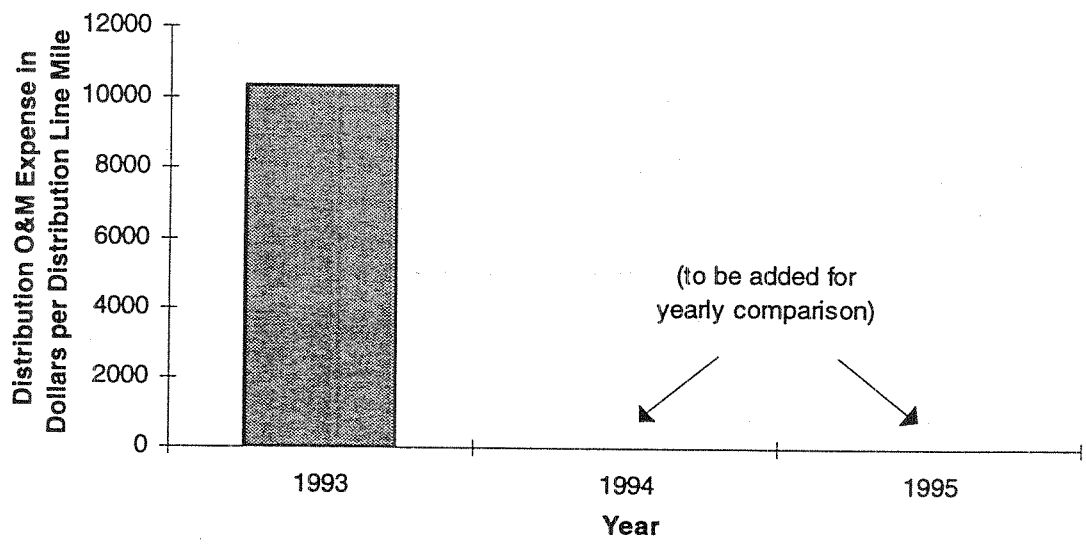
Division Distribution O&M Expense per Retail Customer. The distribution O&M expense used in Chart 7-8 is as defined by the Code of Federal Regulations. The data source was the Scenario 1 financial model.

Chart 7-8
Blaine Electrical Division: Distribution Operation and Maintenance Expense per Retail Customer (excludes purchased power)



Division Distribution O&M Expense per Distribution Line Mile. The distribution O&M expense used in Chart 7-9 is as defined by the Code of Federal Regulations. The data source estimated the 1993 distribution line miles to be approximately 53.3.

Chart 7-9
Blaine Electrical Division: Distribution Operation and Maintenance Expense per Distribution Line Mile (excludes purchased power)



Division Administration and General Expense per Retail Customer. The A&G expenses used in Charts 7-10a and 7-10b are as defined by the Code of Federal Regulations and exclude the cost of purchased power. The data source for Chart 7-10a was the Scenario 1 financial model. Note that Blaine changed the way it allocated costs after 1992, which resulted in a noticeable increase in the total A&G costs.

Chart 7-10b uses data collected and published by APPA for 1992. Chart 7-10b shows that A&G expenses tend to increase as the number of customers decreases. For this reason it was decided that the First Quartile, Median, and Weighted Mean data for utilities of 2,000-5,000 and 5,000-10,000 customers gave the best overall comparative representation of A&G expenses. The APPA A&G expense numbers are based on data from small public utility districts and cities.

Chart 7-10a
Blaine Electrical Division: Administration and General Expenses per Retail Customer

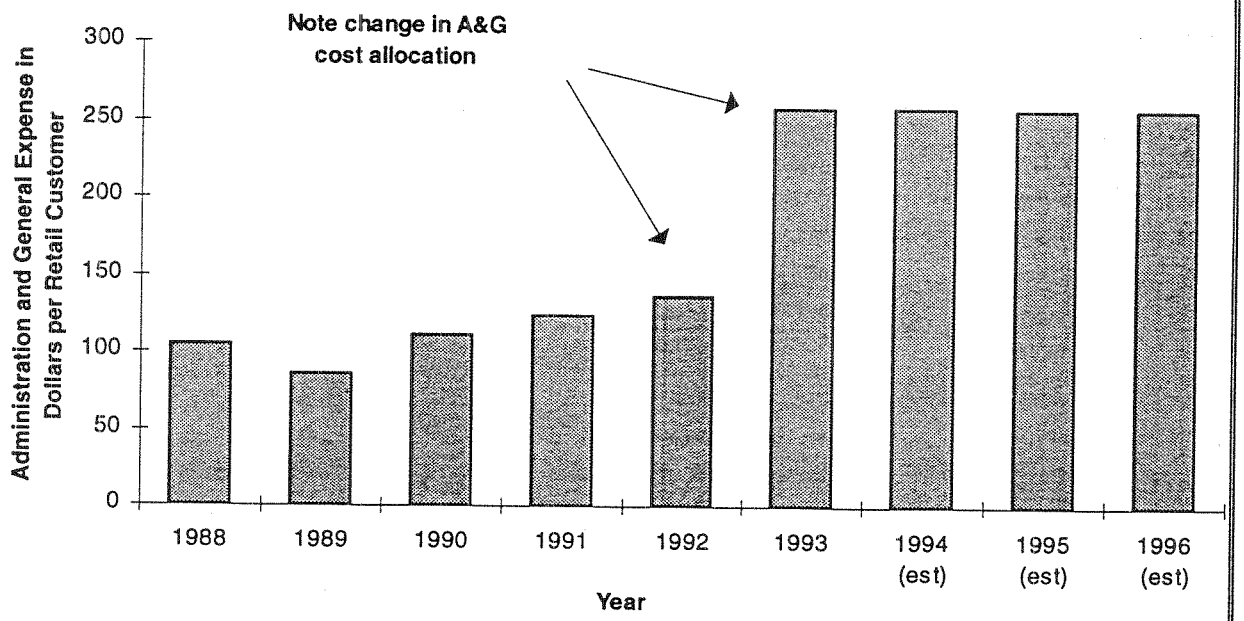
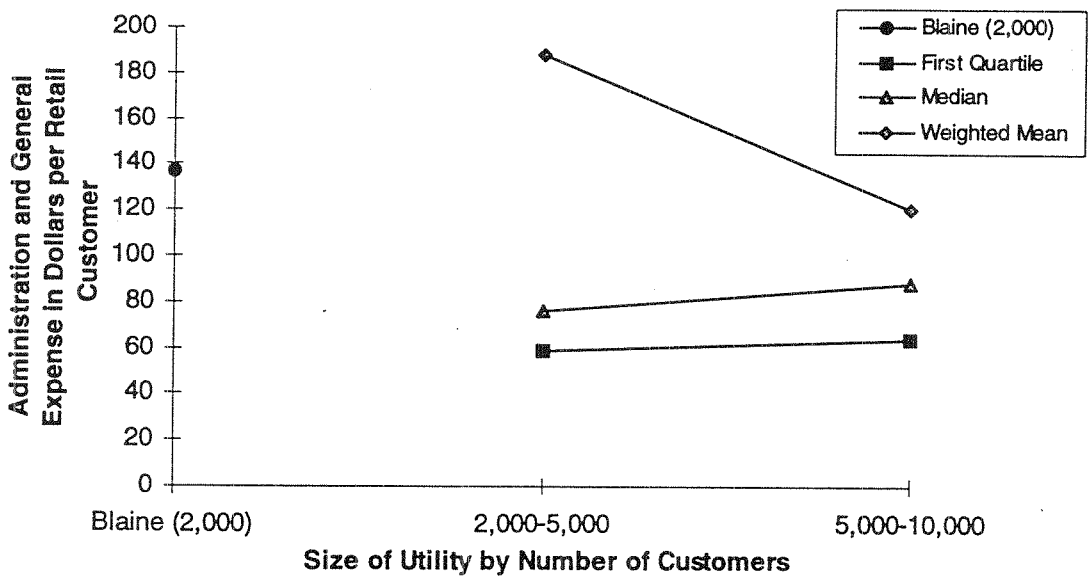


Chart 7-10b
1992 Comparison: Administration and General Expense per Retail Customer

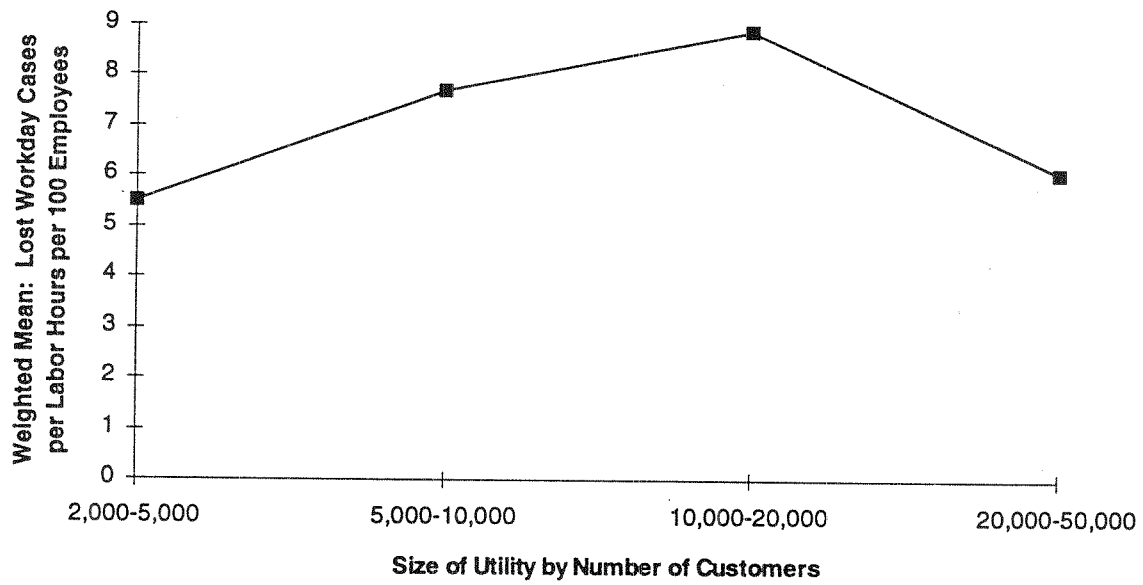


Safety Statistics

The example chart illustrates 1992 APPA data for OSHA incident rates. Tracking this information for Blaine and comparing it to previous years as well as to other utilities will illustrate utility safety in terms of lost workday cases per labor hours.

Example Chart: OSHA Incidence Rates. The example chart shown below illustrates 1992 APPA data describing the ratio of lost workday cases per hours of labor exposure per 100 employees.

Example Chart
OSHA Incidence Rates
Weighted Mean Ratio of Lost Workday Cases
Per Labor-Hours of Exposure
(per 100 Employees)

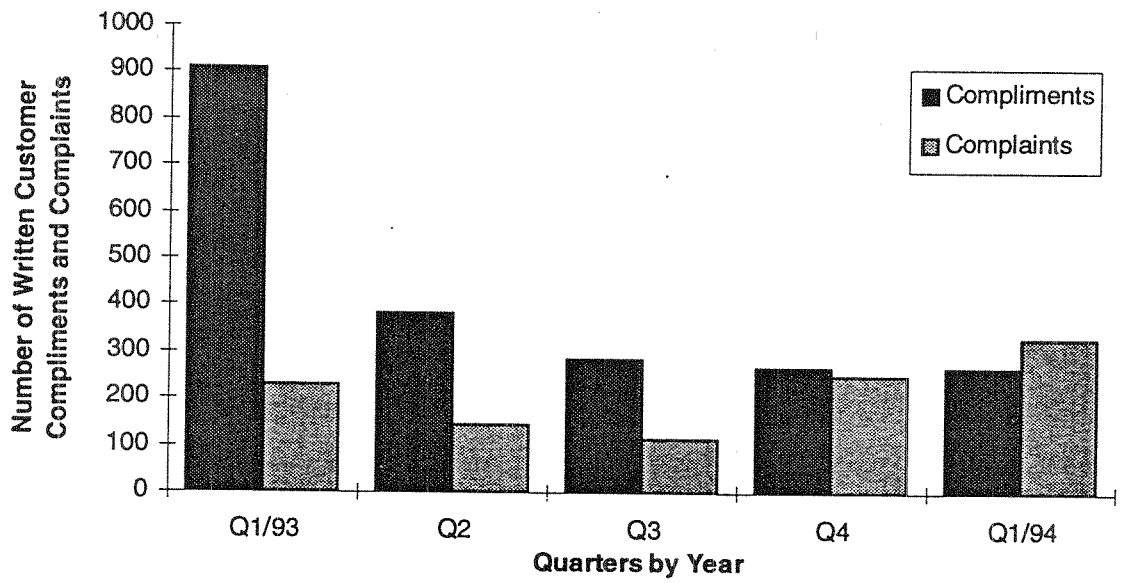


Customer Relations Statistics

It is recommended that the Division implement a customer relations program that is easy to administer and gives customers the opportunity to provide input. One way might be to send customer comment cards with billings and to tally the results. In Blaine's case, since electric bills are combined with water and sewer bills, comments regarding electrical service might be influenced by, for example, the water portion of the bill. The Division may want to send customer comment cards separately. In that case, the cards could also state a few positive facts and figures about the Division.

Example Chart: Snohomish County PUD Customer Comments. The example chart shown below illustrates quarterly tracking of written customer comments, using the data and format used by Snohomish County PUD for 1993 and first quarter 1994.

Example Chart
Snohomish County PUD Customer Comments

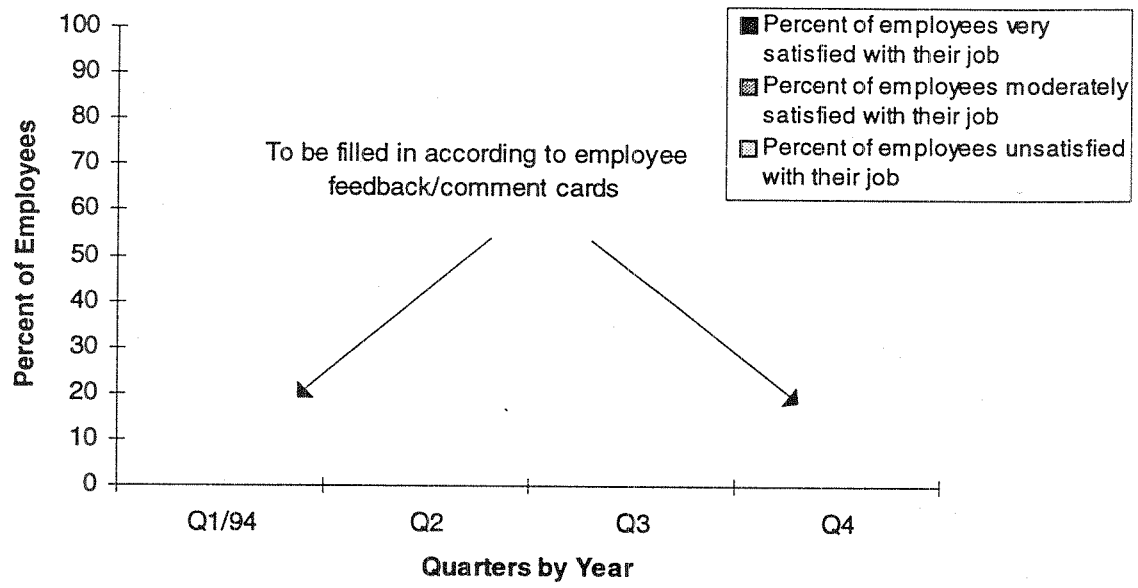


Employee Relations Statistics

It is recommended that the Division implement an employee relations program that is easy to administer and that gives employees the opportunity to provide feedback and suggestions to the utility. One way might be to include anonymous feedback/comment cards monthly with pay-checks and to tally the results. In such a situation the cards should be postage-paid and returned to an entity viewed as a neutral third party, such as an advisory committee chairperson or another City department.

Example Chart: Tabulation of Feedback/Suggestion Forms. The example chart below illustrates one way of tracking responses from employees regarding job satisfaction. No values are shown since employee feedback mechanisms have not yet been implemented.

Example Chart
Blaine Electrical Division: Tabulation of Employee Feedback Forms

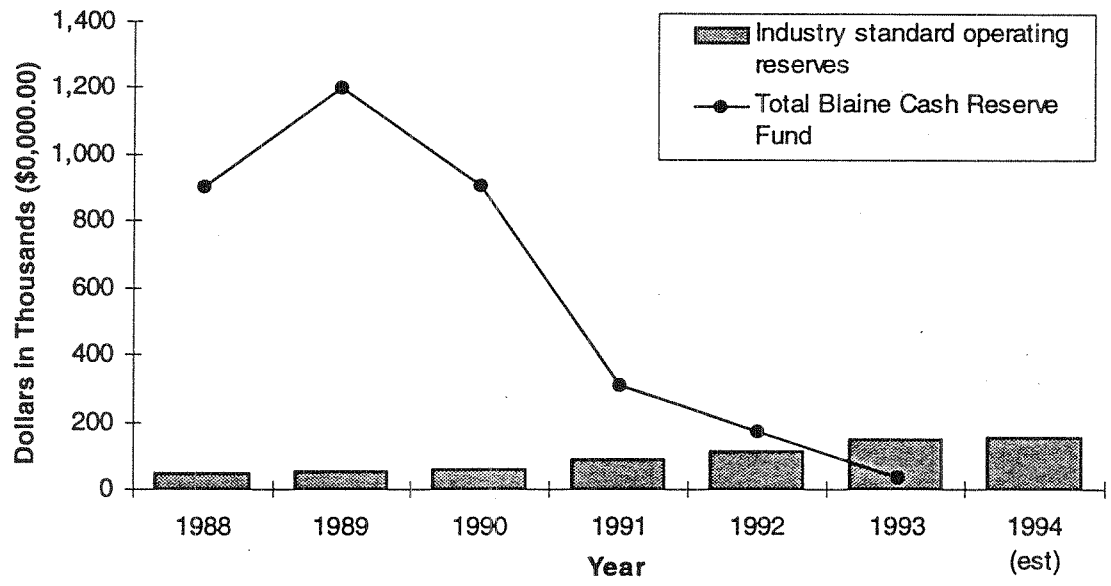


Financial Performance Statistics

The information in the following charts, based on the Capital Improvements Plan and the Financial Plan, illustrates statistics that would occur if the Division followed through with projected capital improvements. The charts indicate that the Financial Plan has established an acceptable level of debt/equity ratio by industry standards. Also indicated is the noticeable rate at which the Total Blaine Cash Reserve Fund is being depleted compared with industry standard operating reserves. The relatively low electric rates may have been a factor in the results shown in Chart 7-11a over time.

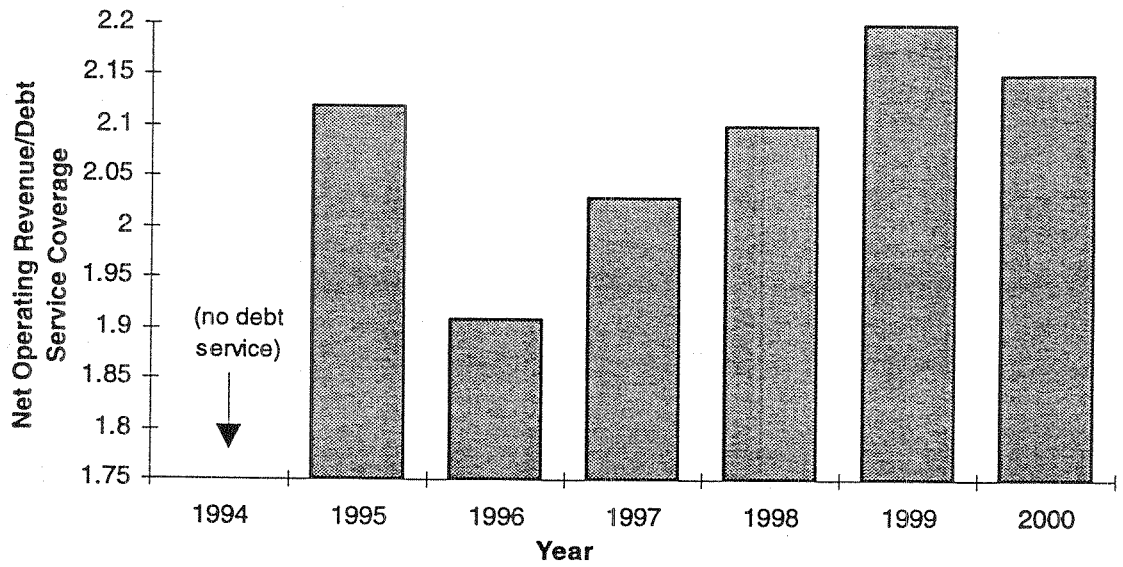
Blaine Electrical Division: Total Cash Reserve Fund Compared with Suggested Industry Standard Operating Reserves. The data source for Chart 7-11a was the Scenario 1 financial model. The industry standard working capital reserve is 45 days of operation costs. The definition of operation costs includes distribution O&M costs, administration costs, miscellaneous costs, and taxes.

Chart 7-11a
Blaine Electrical Division: Total Cash Reserve Fund Compared with Industry Standard Operating Reserves



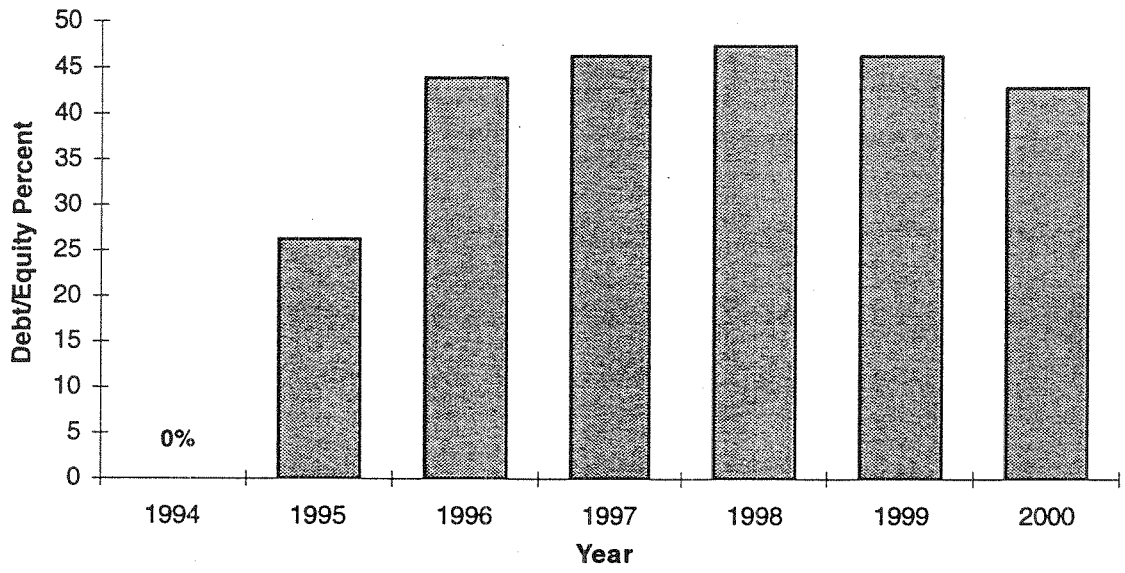
Blaine Electrical Division: Projected Debt Service Coverage. As can be seen in Chart 7-11b, the City of Blaine does not currently have outstanding debt. The chart illustrates the projected debt service coverage for system improvements outlined in the capital improvement plan and calculated from the Scenario 1 financial model.

Chart 7-11b
Blaine Electrical Division: Projected Debt Service Coverage
(Net operating revenue/debt service)



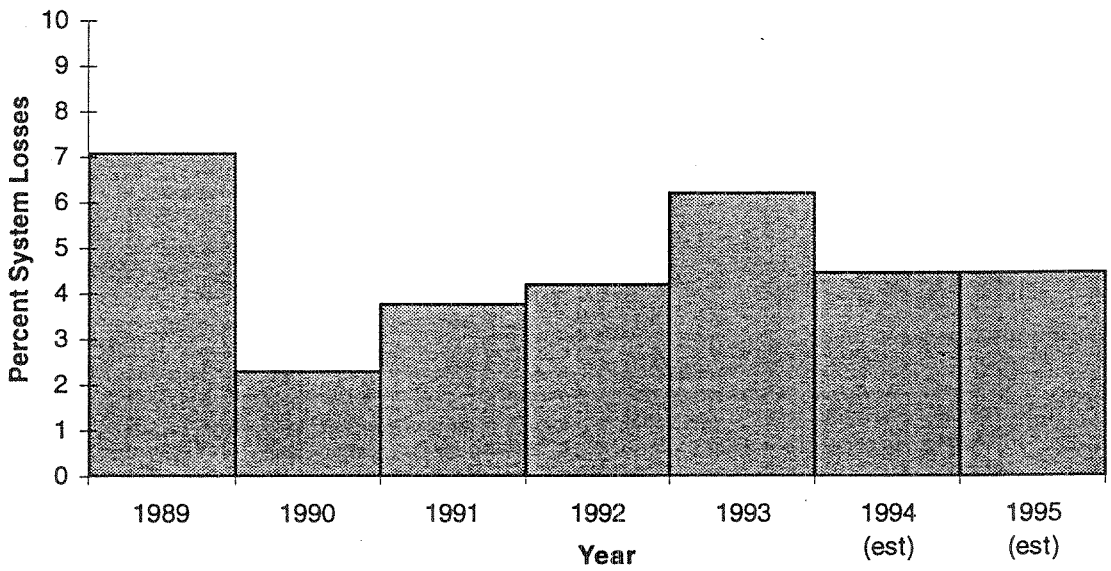
Blaine Electrical Division: Projected Debt/Equity Ratio. Chart 7-11c illustrates the projected debt/equity ratio for the system improvements outlined in the Capital Improvements Plan and calculated from the Scenario 1 financial model. A debt/equity ratio of up to 50 percent is an accepted industry standard.

Chart 7-11c
Blaine Electrical Division: Projected Debt/Equity Ratio (percent)



Blaine Electrical Division: System Losses. Chart 7-11d illustrates data from the Scenario 1 financial model. Note that the actual time period that utilities typically use to calculate their periodic average kWh sold may be slightly different from the time period used to determine the kWh purchased by Blaine from BPA. This slight difference would tend to even itself out over the course of the year but could cause unusual values if it occurred at year-end. For example, if a very large number of kWh were sold in December of 1992 but not recorded until January of 1993, the ratio of losses in 1993 might appear comparatively high. For this reason it is recommended that charts such as Chart 7-11d should be used for trends over a period covering at least 5 to 10 years.

Chart 7-11d
Blaine Electrical Division: System Losses
Average kWh Sold Compared to kWh Purchased from BPA



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Chapter 8

Energy Conservation Plan

Chapter 8

Energy Conservation Plan

Introduction

This chapter discusses energy conservation at the City of Blaine Electrical Division. This chapter uses data provided by McElhinney & Associates and the Bonneville Power Administration (BPA), and general conservation information from various other sources (listed in Appendix C). The scope of this chapter will be to address energy conservation in general, to recognize the Division's conservation accomplishments from 1992 to 1994, and to compare the Division's energy conservation with that at other utilities. This chapter also summarizes the latest changes in BPA conservation policies and recommends future energy conservation efforts for the Division.

Summary

Comparison of the Division's 1992 to 1994 conservation accomplishments as reported by McElhinney & Associates with the conservation targets set for Blaine by the BPA's 1993 Conservation Action Plan shows an exceptional overall energy conservation effort by the Division. This assessment stems from information (included in this chapter as a series of charts) that documents that Blaine's relatively new conservation program efforts have surpassed the targets set by BPA in most cases. While most comparably sized utility customers of BPA use a conservative approach and a few others adopt a very aggressive approach, the Division has chosen a moderately aggressive approach for implementing energy conservation policies.

While Blaine's conservation program has been officially in place only since 1991, with some elements not starting until 1993 and 1994, the results of the Division's efforts already boast a projected 1994 cumulative annual savings of 4,006,704 kWh (approximately 457 average kW). Considering that "one average megawatt could provide enough power for 700 average Washington households" (McElhinney & Assoc.), the 1994 savings from Blaine's conservation program could provide power for approximately 320 homes. Comparing Blaine's 1994 estimated cumulative kWh savings with Blaine's maximum achievable kWh potential established by BPA, Blaine has already captured 78 percent of industrial potential savings, 61 percent of residential, 22 percent of existing commercial, and 8 percent of new commercial.

The Division tracks its energy savings in three areas: residential, commercial, and industrial. Residential conservation efforts have been the most aggressive, and the Division's records show that annual targets set by BPA were exceeded by as much as 244 percent. Commercial conservation savings for existing buildings were twice the BPA 1994 target. While the recorded number of participating customers is slightly below the annual target set by BPA, this is a result of Blaine's strategic implementation of the program to focus initially on large commercial customers such as the border crossing. Commercial conservation for new buildings will no longer be a part of Blaine's conservation plan because Blaine will rely on the new-construction Model Con-

Blaine in 1994 have already reached 77 percent of the maximum achievable industrial kWh savings estimated by BPA.

The regional energy conservation system is approaching a transformation period. The changes proposed for 1995 for the present system under BPA could radically affect the way conservation is financed. Because no definite policies have been confirmed, little can be speculated at this time about what the new policies will entail. What can be speculated, however, is that the need for, and political support of, energy conservation is not going to disappear. It is recommended that the Division and all public utilities continue their energy conservation measures. The Division is also encouraged to continue to strive for maximum internal management efficiency in the implementation of the conservation programs. Energy conservation and the unbundling of energy rates will be the most effective tools for positioning the Division to make the most productive decisions for the short term and the long term.

Energy Conservation

Energy conservation is generally recognized to be efficient utilization of resources. One definition of the objective of energy conservation is "to obtain optimal use of electrical energy. Optimal in this case refers to measures taken to use minimal overall energy where the potential or real energy savings are justified on an economic or cost-benefit basis" (IEEE Std. 739-1984). According to the Pacific Northwest Electric Power Planning and Conservation Act, Section 3 (3), conservation means "any reduction in electric power consumption as a result of increases in the efficiency of energy use, production, or distribution."

In 1980 the Pacific Northwest Electric Power Planning and Conservation Act established, among other things, BPA guidelines for administering energy conservation. Since that time, BPA has provided avenues for utilities to implement cost-effective energy conservation and tracked the costs and savings due to energy conservation. Public interest groups (most notably the Northwest Conservation Act Coalition, a regionwide alliance of environmental, consumer, and other public interest groups and utilities) strongly support energy conservation and enforce BPA's role in providing conservation opportunities.

The questions "How important is energy conservation compared with other alternatives?" and "What is the best way to implement energy conservation?" provoke philosophical debate. For example, should energy conservation be regarded as lost revenue and its value be judged according to its effect on utility rates and other cost implications, or should energy conservation be regarded as a relatively inexpensive form of generation that should be mandatory for reasons of regional energy stability, environmental concerns, and community enhancement?

One drawback with the implementation of energy conservation programs (especially residential programs) is that they are very labor-intensive and can represent a significant management challenge to a utility. Another drawback is that the cost benefits and energy savings are long-term or not seen immediately, and some benefits are seen regionally rather than locally. Similarly, certain benefits of conservation are intangibles that cannot be easily documented. Examples of these are personal comfort, public responsibility to regional resources, improvement in public relations,

relations, value added to a residential home (such as a potential increase in dollar value or an increase in desirability), and value added to the local community (such as desirability or services/jobs created). Since conservation is not mandatory and is subject to philosophical debate, effective communication programs must be firmly in place to gain acceptance by customers and management alike. The Pacific Northwest Power Planning and Conservation Act recognizes that "Management needs to provide effective personnel motivation, planning, and administration to achieve meaningful energy savings. The establishment of a formalized energy management responsibility is highly desirable to give the effort both the focus and direction required."

Conservation at Blaine Electrical Division

Energy conservation programs at the Division have been officially administered since 1991 by Sheila McElhinney of McElhinney & Associates. The conservation efforts are geared toward programs sponsored by BPA. Ms. McElhinney's approach has placed Blaine well above most conservation targets set by BPA. McElhinney & Associates adopts the viewpoint that conservation is "the most cost-effective, environmentally sound method of producing power." In addition, conversations with Ms. McElhinney indicate that she uses her conservation interactions as an avenue for furthering customer relations as well as overall public relations for the City. Ms. McElhinney also noted how implementation of her programs has encouraged community involvement.

The charts on the following pages are based on information from the Division's conservation records for 1993 and 1994. In general, these charts compare the Division's progress against conservation goals set for Blaine by BPA and show performance compared to both intermediate yearly goals and cumulative 2003 goals.

Residential

Weatherization Program. Chart 8-1a compares the BPA conservation target for weatherization of residential properties with the Division's performance for each year between 1992 and 1994. As can be seen, the target number of residences to be weatherized is greater each year, and Blaine has achieved 100 percent or better of each annual goal. Chart 8-1b illustrates the Division's progress toward BPA's cumulative goal for 2003. BPA set an interim goal of 73 percent of the cumulative goal to be achieved by 1994; Blaine has already achieved 79 percent.

Super Good Cents Program. First implemented in 1993, this has been one of the Division's most successful conservation programs. As can be seen from Chart 8-2a, Blaine achieved more than 200 percent of BPA's annual goals each year and, as can be seen from Chart 8-2b, has already achieved 41 percent of the 2003 cumulative goal. In comparison, the BPA interim goal for 1994 was only 17 percent of the 2003 cumulative goal.

Showerhead Appliance Efficiency Program. This program was also implemented first in 1993, as indicated by Chart 8-3a, which shows that Blaine achieved zero percent of the BPA goal for 1992.

Chart 8-1a
Residential Weatherization Program: Blaine Electrical Division's Annual Performance Compared to BPA's Annual Targets

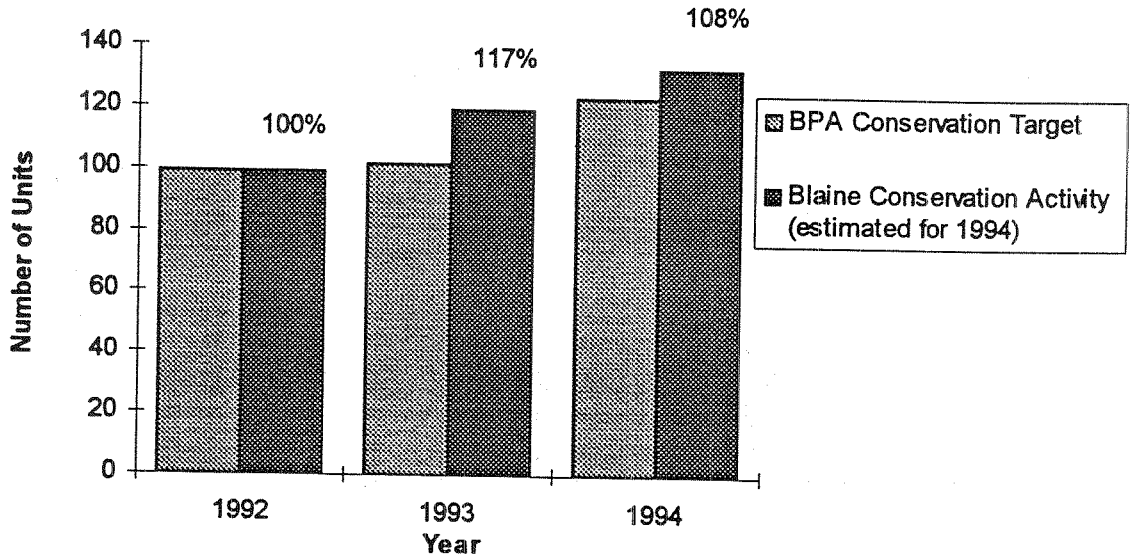


Chart 8-1b
Residential Weatherization Program: Blaine Electrical Division's Cumulative Performance Compared to BPA's Cumulative Target

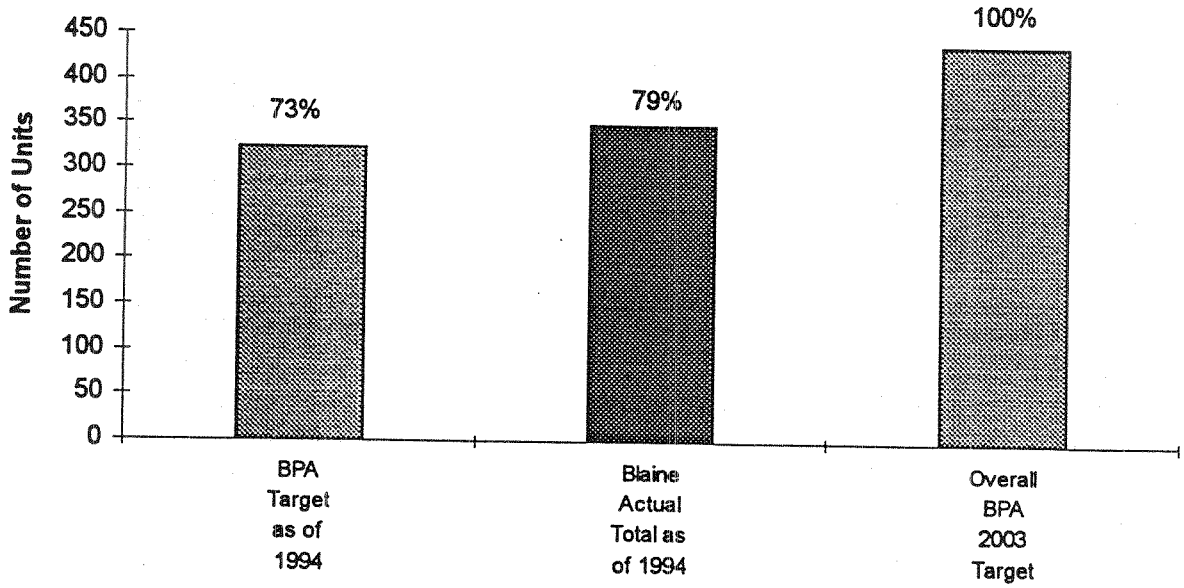


Chart 8-2a
Residential Super Good Cents Program: Blaine Electrical Division's Annual Performance Compared to BPA's Annual Targets

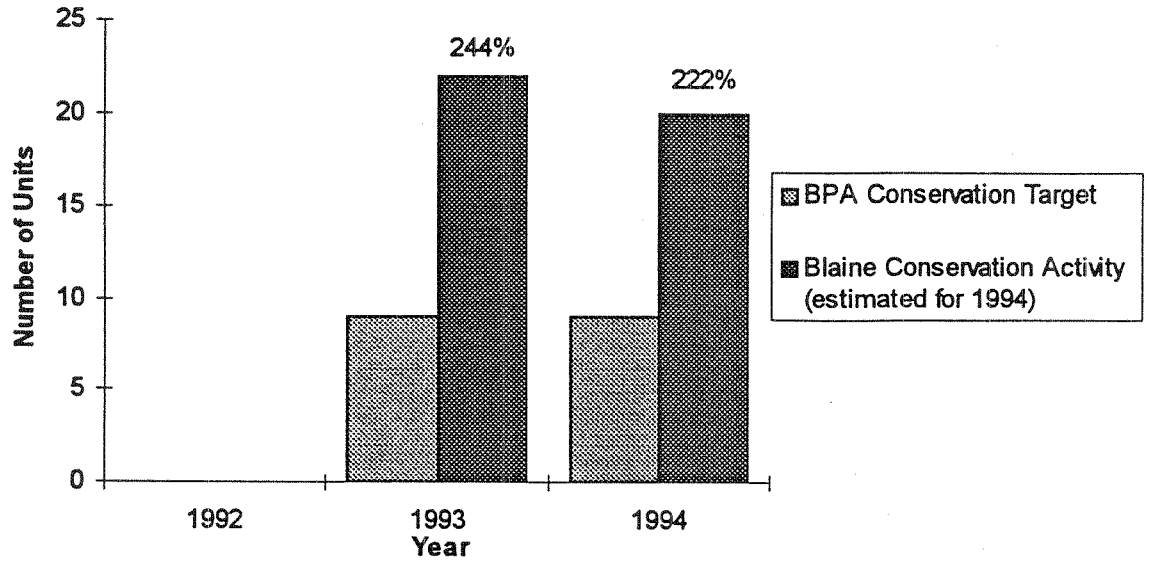


Chart 8-2b
Residential Super Good Cents Program: Blaine Electrical Division's Cumulative Performance Compared to BPA's Cumulative Target

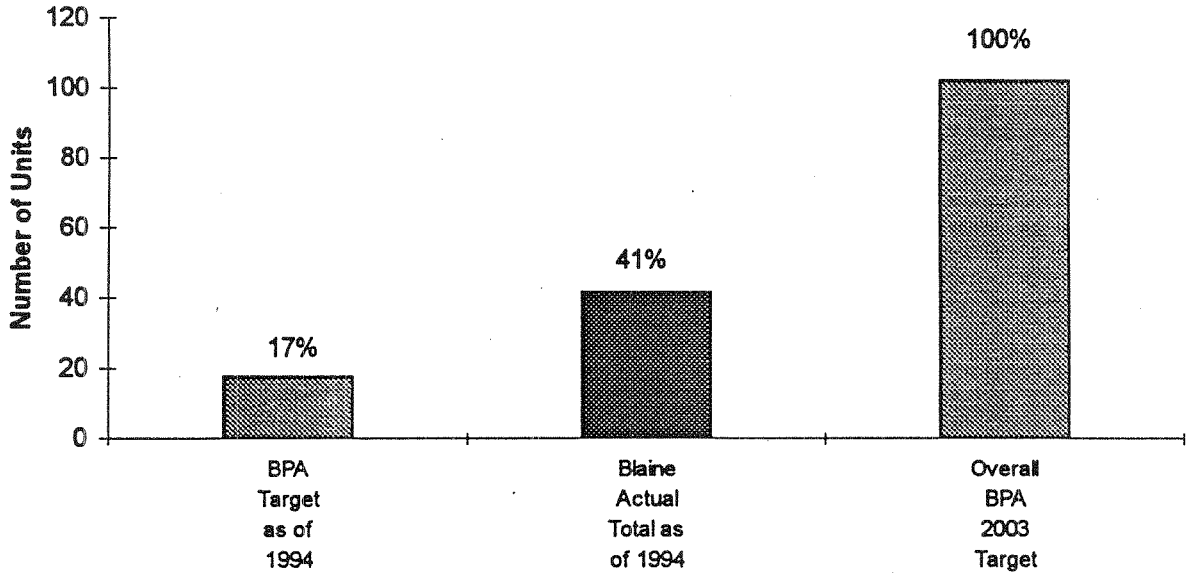


Chart 8-3a
Residential Showerhead Appliance Efficiency Program: Blaine Electrical Division's Annual Performance Compared to BPA's Annual Targets

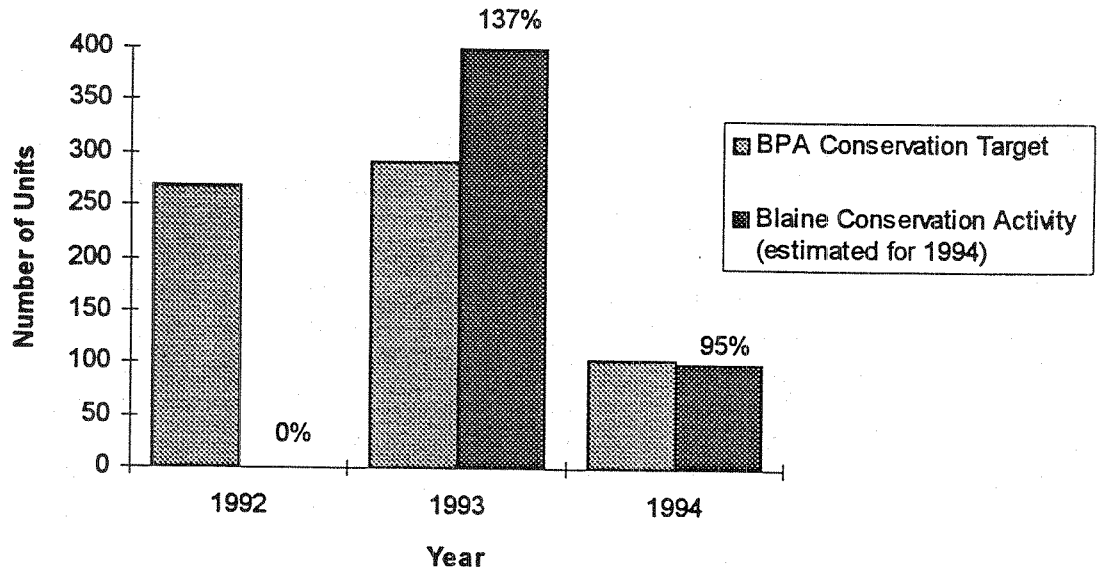
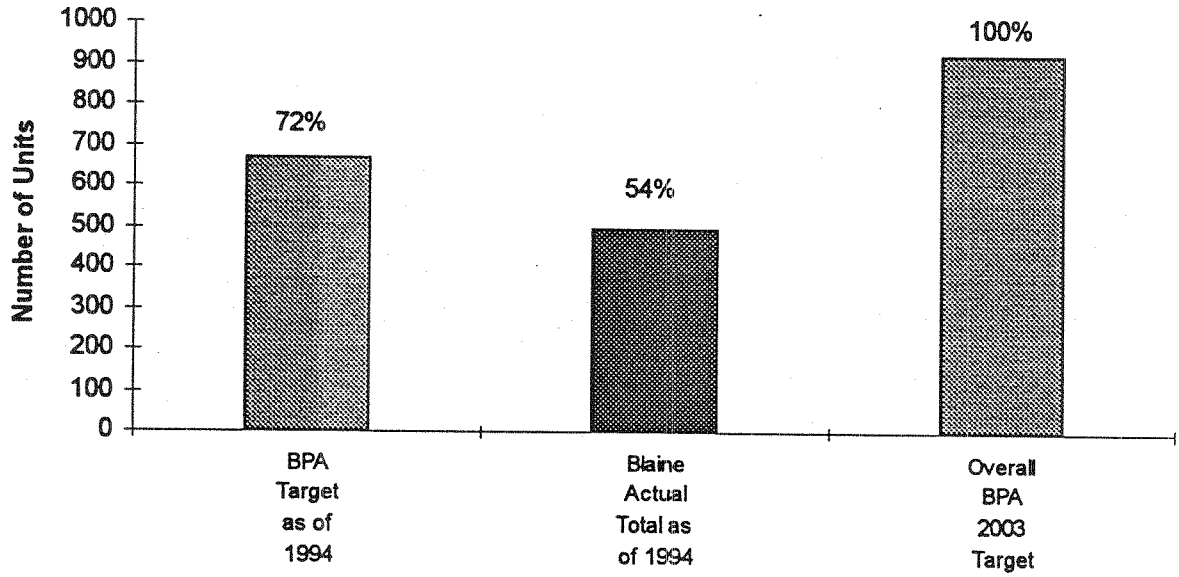


Chart 8-3b
Residential Showerhead Appliance Efficiency Program: Blaine Electrical Division's Cumulative Performance Compared to BPA's Cumulative Target



However, in 1993, the Division's aggressive approach achieved 137 percent of the BPA goal for that year and in 1994 achieved 95 percent of that year's goal. As shown in Chart 8-3b, even with the late start, by 1994 Blaine had achieved 54 percent of BPA's 2003 cumulative goal and was only 18 percentage points short of BPA's 1994 target of 72 percent of the 2003 cumulative total.

Commercial and Industrial

Existing Buildings, Number of Units. The Division's strategy for promoting energy conservation in existing commercial buildings focused initially on large commercial customers. As shown in Chart 8-4a, Blaine achieved 72 percent of BPA's target for *numbers* of buildings participating in 1993 and 97 percent of BPA's target for 1994. As shown in Chart 8-4b, Blaine was only 4 percentage points short of the BPA goal for 1994 of 26 percent of the cumulative 2003 total.

Existing Buildings, Energy Saved. The success of the Division's strategy of concentrating first on the larger commercial customers is not as readily apparent when measured by *numbers* of buildings participating in the program as when measured by *kWh saved*. Achieving 72 percent of BPA's unit goal (see Chart 8-4a) resulted in achieving 171 percent of BPA's kWh goal for 1993 (see Chart 8-5a). Similarly, achieving 97 percent of BPA's unit goal in 1994 resulted in achieving 230 percent of the kWh goal. As shown in Chart 8-5b, this strategy enabled Blaine to achieve 53 percent of BPA's cumulative goal for 2003 by 1994, more than twice the interim 1994 goal of 26 percent of the cumulative goal.

New Buildings, Number of Units. Because the predicted growth in numbers of new commercial buildings has not materialized in Blaine, the Division's strategy for new buildings will be to rely on the conservation implementation set forth in construction codes. With fewer new buildings being built than expected, fewer new buildings were participating in conservation programs, and Blaine achieved only 9 percent of the BPA goal for numbers of new units participating in 1993 and 27 percent of the BPA goal for 1994, as shown in Chart 8-6a. By 1994 this shortfall in new commercial building activity resulted in Blaine meeting only 4 percent of the BPA's cumulative 2003 goal for new buildings, falling short of the 1994 target by 16 percentage points, as shown in Chart 8-6b.

New Buildings, Energy Saved. The smaller-than-expected number of new commercial buildings in Blaine also resulted in smaller-than-targeted energy savings. However, these new buildings were relatively effective in conserving kWh, as can be seen by comparing Charts 8-6a and 8-7a. With only 9 percent of the targeted number of new buildings in 1993, the Division's policies achieved energy savings that were 37 percent of the targeted kWh goal, as shown in Chart 8-7a. Similarly, with 27 percent of the expected number of new buildings in 1994, energy savings reached 43 percent of the targeted kWh goal for that year. Overall, the new buildings were twice as energy-efficient as expected, as can be seen by comparing Chart 8-6b and Chart 8-7b. With only 4 percent of the 2003 cumulative total of units by 1994, Blaine had achieved 8 percent of the 2003 cumulative kWh savings goal, falling short of the 1994 target of 20 percent by 12 percentage points.

Chart 8-4a
Commercial Conservation (Existing Buildings) by Number of Units: Blaine Electrical Division's Annual Performance Compared to BPA's Annual Targets

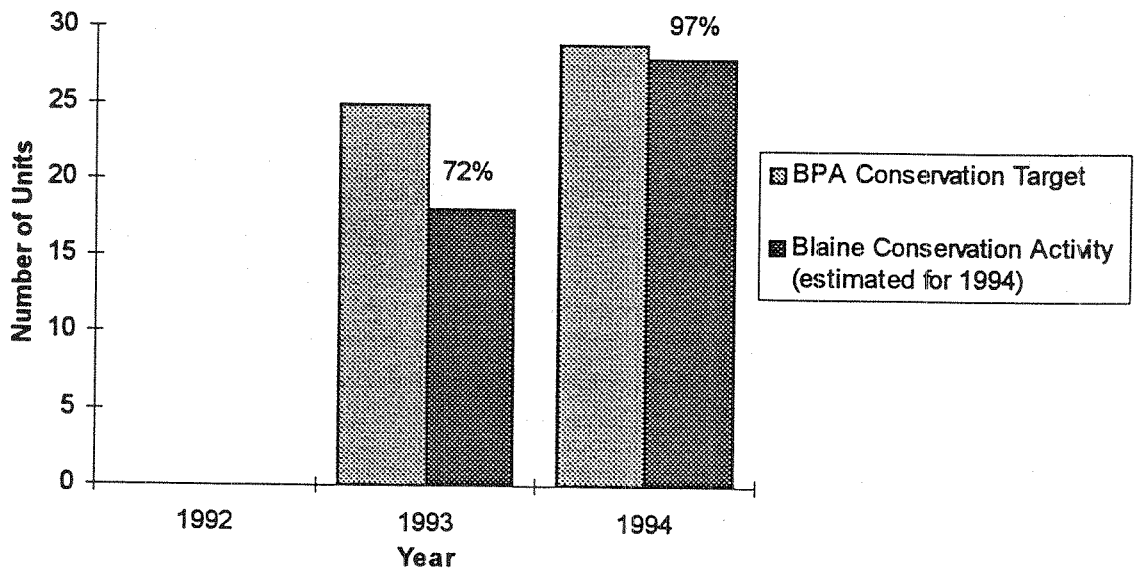


Chart 8-4b
Commercial Conservation (Existing Buildings) by Number of Units: Blaine Electrical Division's Cumulative Performance Compared to BPA's Cumulative Target

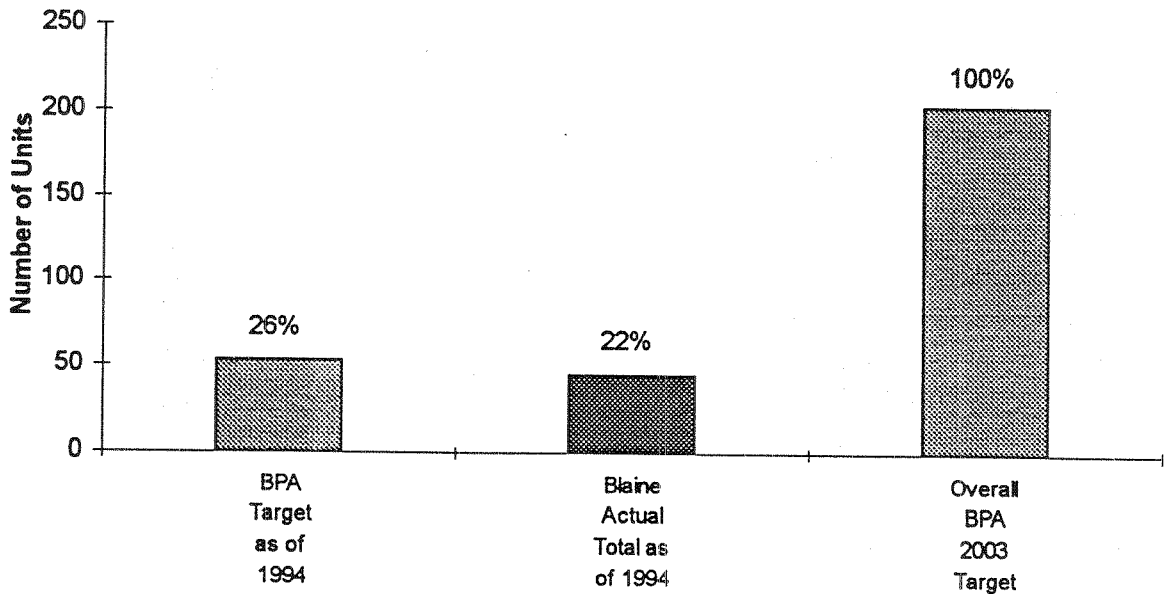


Chart 8-5a
Commercial Conservation (Existing Buildings) by kWh Saved: Blaine Electrical Division's Annual Performance Compared to BPA's Annual Targets

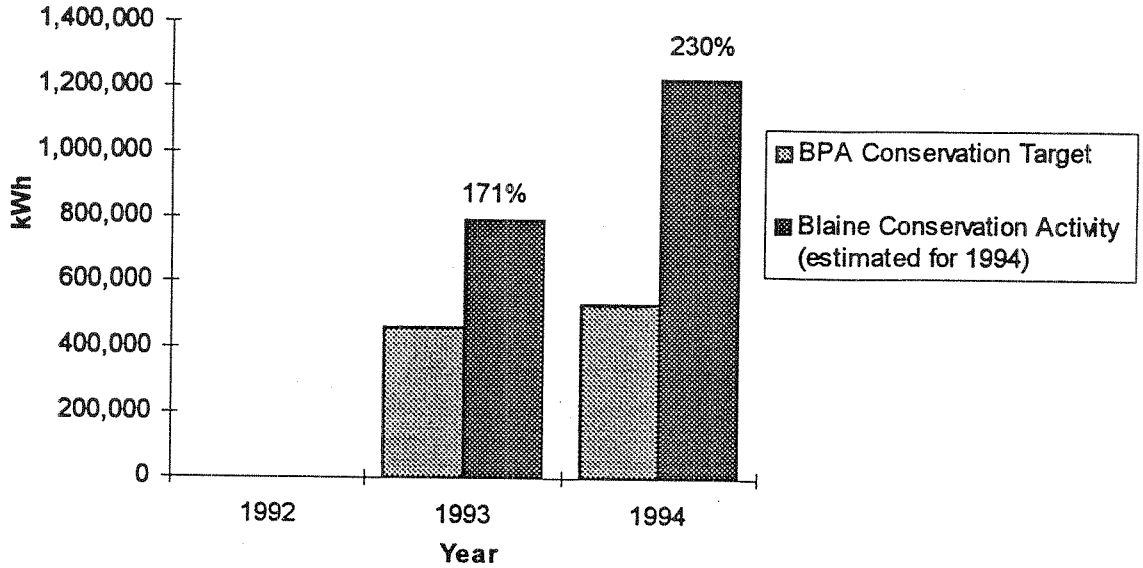


Chart 8-5b
Commercial Conservation (Existing Buildings) by kWh Saved: Blaine Electrical Division's Cumulative Performance Compared to BPA's Cumulative Target

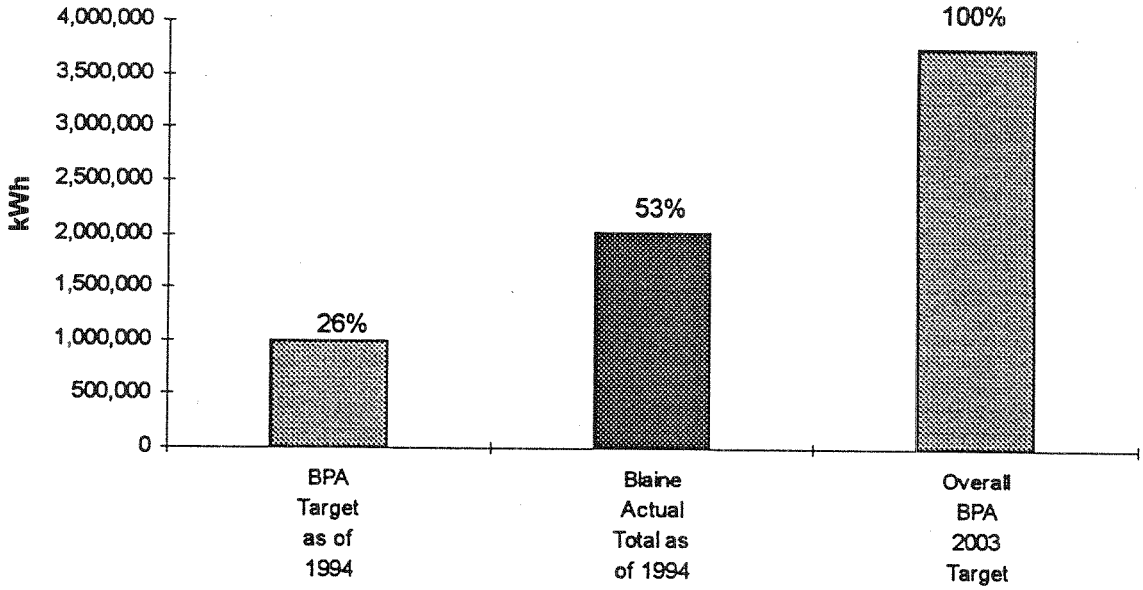


Chart 8-6a
Commercial Conservation (New Buildings) by Number of Units: Blaine Electrical Division's Annual Performance Compared to BPA's Annual Targets

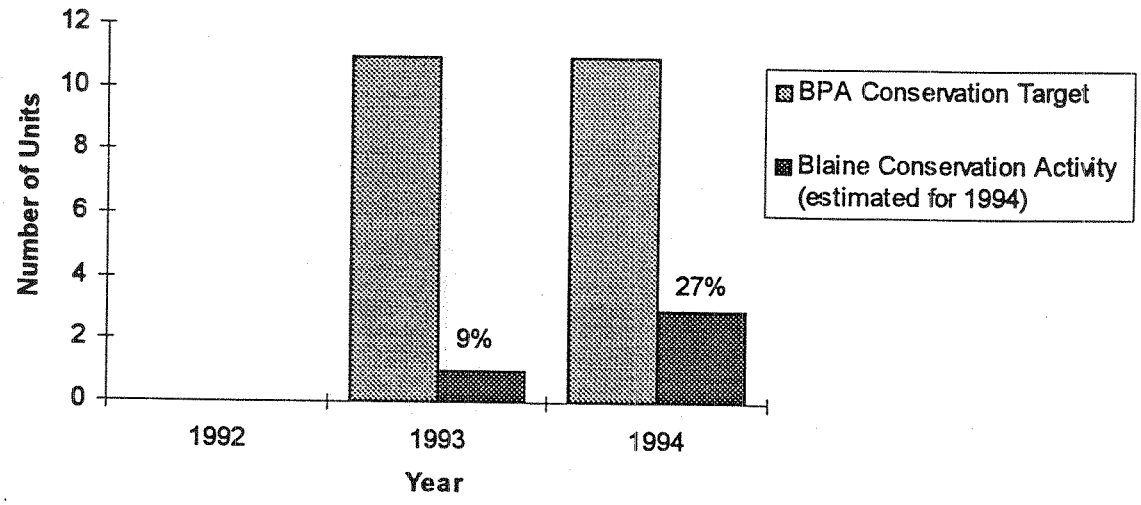


Chart 8-6b
Commercial Conservation (New Buildings) by Number of Units: Blaine Electrical Division's Cumulative Performance Compared to BPA's Cumulative Target

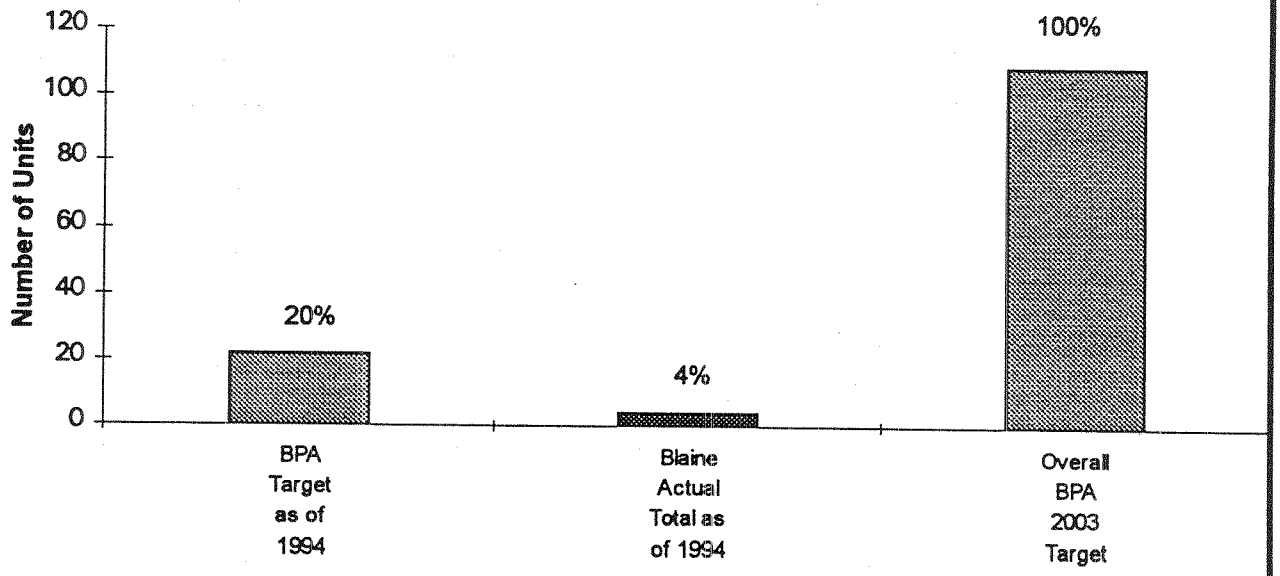


Chart 8-7a
Commercial Conservation (New Buildings) by kWh Saved: Blaine Electrical Division's Annual Performance Compared to BPA's Annual Targets

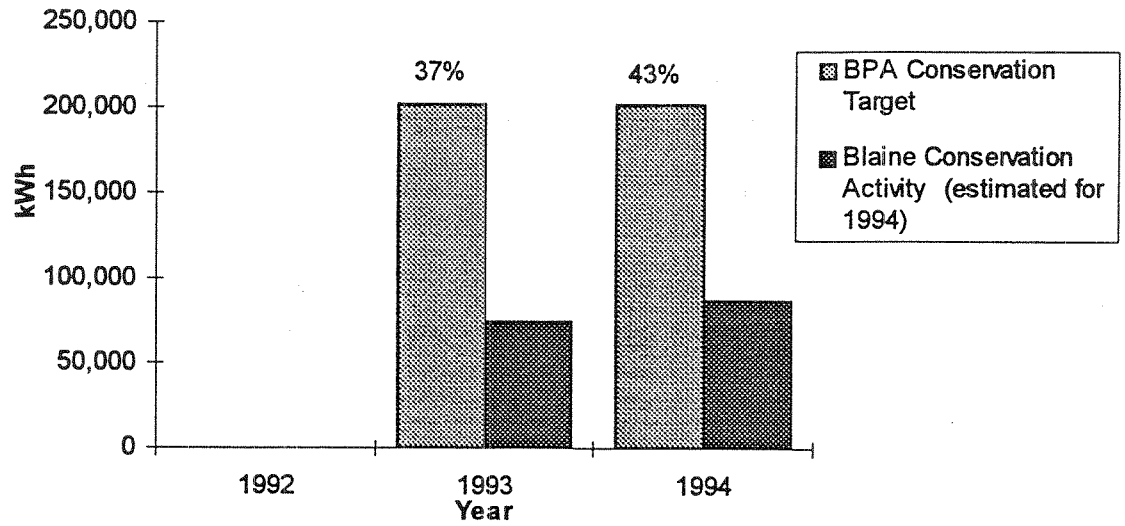
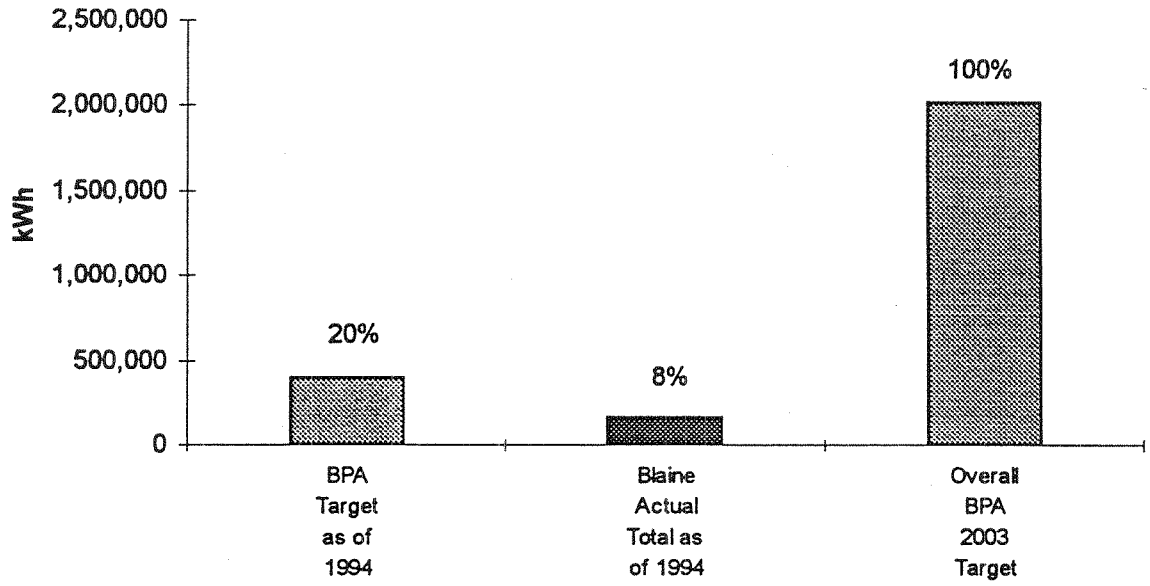


Chart 8-7b
Commercial Conservation (New Buildings) by kWh Saved: Blaine Electrical Division's Annual Cumulative Performance Compared to BPA's Cumulative Target



Industrial Facilities. Blaine recently completed its first industrial energy conservation project, and estimates that two more facilities will be completed during 1994 and 1995. Because BPA did not set industrial targets for Blaine, the Division's accomplishments are compared with BPA's maximum achievable kWh conservation potential. Chart 8-8 shows that, in 1 year, Blaine achieved 77 percent of its maximum achievable kWh industrial conservation potential.

Overall Cumulative Energy Savings

While the foregoing charts have shown the Division's annual progress, Chart 8-9 illustrates the progress Blaine is making toward reaching its maximum achievable conservation potential as established by BPA. Over three-fourths of the industrial conservation potential, over one-half of the residential conservation potential, and almost one-fourth of the existing commercial potential have already been achieved. (As discussed above, new commercial potential has not been a primary focus in the Division's strategy, and less than one-tenth of this potential has been captured.)

Comparison of Conservation Programs

At this time, utilities may choose not to invest in energy conservation programs, may implement their own conservation programs, or may use BPA-sponsored programs. Most smaller utilities choose to implement residential, commercial, and industrial programs sponsored by BPA, such as Weatherwise, Super Good Cents, Appliance Efficiency, and Energy Smart Design. Large utilities, such as Puget Power, implement their own conservation programs. The components of Puget Power's energy conservation programs echo those provided by BPA. Similarly, the Power Smart conservation programs offered by BC Hydro for residential, commercial, and industrial are comparable to those offered by BPA. BC Hydro stands out, however, as being very active in conservation education in the school systems, in the community, and within its own employee structure. BC Hydro reinforces efficiency within its own organization, has established a clear direction for its own conservation efforts, and promotes itself as a model to encourage its customers.

Commonly, conservation efforts within smaller utilities are financially motivated and depend upon the financial ability of a utility to absorb the front-end costs of implementing conservation programs. Financially motivated utilities that expect growth and high operating costs tend to prefer a slower implementation of conservation programs to keep rates down. Utilities that expect slower growth and lower operating costs can be more aggressive without affecting their rate structures. Compared to other utilities of similar size, Blaine has maintained a moderately aggressive approach toward the implementation of conservation programs. For example, according to BPA, the Division's implementation of conservation programs is aggressive when compared to Orcas Power and Light but is moderate when compared to McLeary Municipal, which has already achieved almost all of its conservation potential.

The Future of Energy Conservation

Regional energy conservation is approaching a transformation period. Changes proposed by BPA for 1995 could radically affect the way conservation is financed.

Chart 8-8
Blaine Electrical Division: 1994 (est.) Industrial kWh Conservation Activity Compared to BPA's Maximum Achievable kWh Target

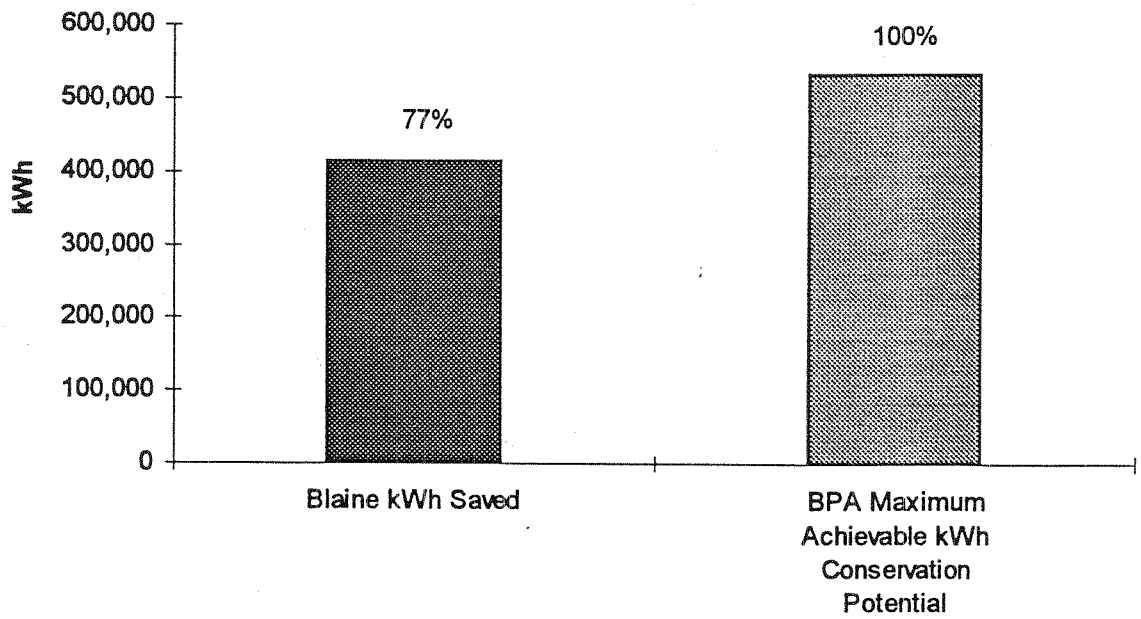
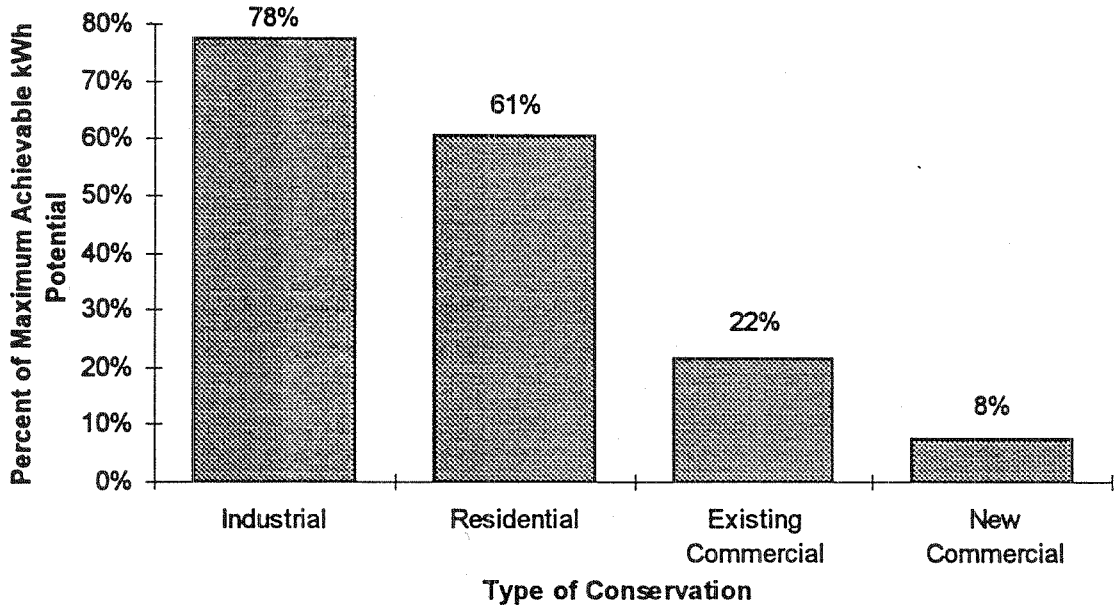


Chart 8-9
Blaine Electrical Division: 1994 Total Conservation kWh Savings as a Percent of BPA's Maximum Achievable kWh Potential (including 6.0% T&D credit)



Historically, BPA has provided financial incentives for utilities to implement energy conservation. The Pacific Northwest Electric Power Planning and Conservation Act (the Act) was enacted by Congress in 1980 and commissions BPA "to assist the electrical consumers of the Pacific Northwest...to achieve cost-effective energy conservation, to encourage the development of renewable energy resources, to establish a representative regional power planning process, [and] to assure the region of an efficient and adequate power supply."

The main issue is the perception that each utility's *local* conservation efforts contribute primarily to the preservation and stabilization of the *regional* resources. BPA, which, under the direction of the Act, has historically provided financial motivation to utilities for implementing conservation programs, is now trying to redirect its historical responsibilities onto individual utilities; with an open power market, BPA risks losing customers (and therefore revenue) and is trying to get rid of high-liability items such as the cost of supporting regional conservation. BPA is doing this through a tiered rate structure that assumes that after utilities have purchased all of their allocated BPA low-rate Tier 1 power, they will then turn to energy conservation as a way to avoid buying more power at higher Tier 2 rates. The problem with this redirection of responsibility is that after purchasing low-rate Tier 1 power from BPA, utilities may well find it more cost-effective in an open power market to satisfy the rest of their energy needs through other power purchases rather than by implementing energy conservation. BPA has also proposed offering conservation loans with resulting energy service charges; however, at this time there are no penalties for non-participation. In summary, individual utilities, in the same fashion as BPA, may also choose to evade the relatively high costs of implementing energy conservation programs.

If utilities do not choose energy conservation, BPA does not at this time have a backup plan. However, BPA Administrator Randy Hardy has stated that BPA is "absolutely committed to achieving all cost-effective conservation, period. We'll do whatever it takes to achieve that goal" (Northwest Conservation Act Report, March 11, 1994). This points to yet another unresolved issue: Does BPA have the right, considering its responsibilities as set forth in the Act, to redirect its historical energy conservation responsibilities onto individual utilities? The Northwest Conservation Act Coalition, and others such as Congressman DeFazio, Governor Lowry, and Governor Roberts, do not think so. Other unresolved issues center on regional resources, such as regional risk minimization and regional system stability.

Some utilities may also consider foregoing energy conservation for low-cost gas-fired technology. However, the financial benefits of this option could be superficial, considering the "upstream" environmental effects. For example, "greenhouse-gas" carbon dioxide is emitted in both production and combustion phases of natural gas use. "Other 'upstream' impacts include the release of sulfur compounds into the environment, water pollution, lost wilderness values, disruption of aboriginal cultures and ancestral lands, and fragmentation of wildlife habitat by production and processing infrastructure" (Northwest Conservation Act Report, March 25, 1994). Already the Canadian National Energy Board has put six projects on hold pending review of the full range of environmental effects caused by energy export (Northwest Conservation Act Report, June 24, 1994).

Until energy conservation is mandatory, a utility's environmental and financial philosophies will continue to be the driving force behind local energy conservation efforts. While stewardship of

regional resources and community enhancement are two primary reasons to advocate conservation, the financial benefits of keeping down local utility operating costs (and therefore local utility rates) are a strong force against energy conservation. Retroactive surveys of customer attitudes indicate that "saving money and lowering the electric bill are by far the most important customer motivations to action, with 'conserving energy,' 'improving the comfort of the home,' and 'increasing the home's value' all rating a good deal lower on the motivation scale" (Sawhill and Cotton, 1986).

In contrast, a prime example of a philosophy that endorses energy conservation is that of the Emerald PUD in Oregon. This PUD's support of conservation stems from the belief that a public utility should not be seen as a source of revenue but as a prudent investor in the community. The PUD views conservation as an inexpensive source of generation and believes that the benefits to the community from investing in residential homes, for example, are much greater than the benefits of the same investment in power supply. This is because 85 to 100 percent of residential conservation investment can be recouped within 5 years and the value of the houses and the community increases; the homeowner's bill goes down and stays down; and jobs are created within the community. The PUD is a firm believer in investing in community and quality of life and believes concerns about electromagnetic fields, carbon dioxide emissions, and regional energy will not disappear.

In summary, the only constant in the field of energy conservation is change. Led by environmental support groups, interest in energy conservation is not likely to diminish, and conservation measures may even become mandatory. Technology advances offer alternatives such as load bank cells and energy-efficient distribution design to cut kW losses. Advances in utility management offer new alternatives such as demand-side management. Creative methods of funding conservation, such as no-interest bonds, sharing conservation costs with the customer, and pooling conservation resources among utilities, are being explored.

In light of BPA's plan to end most conservation funding in October 1995 and to implement a tiered rate system that will charge its utility customers a low-cost Tier 1 rate and a higher-cost Tier 2 rate, there will be potential advantages for the City in minimizing its purchases of Tier 2 power. Because of this, and the need to evaluate conservation (or demand-side) resources on a basis similar to supply-side resources (such as power contracts and generation), CH2M HILL recommends continued implementation of many of the existing BPA conservation programs. While the City may wish to re-evaluate the programs it offers, when the evaluation is completed, many if not most of the currently offered conservation programs may still be required.

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Chapter 9

Implementation Plan

Chapter 9
Implementation Plan

The City of Blaine and the Electrical Division will be using the information and recommendations presented in this Comprehensive Plan Report to help make decisions regarding future directions for electrical service. This chapter summarizes the recommendations presented in the preceding chapters.

Projected Service Area and System Characteristics

For the three expansion alternatives, ultimate loads will run from about 55 to 59 MW of peak customer demand. The no-annexation alternative is projected to have an ultimate load of approximately 25 MW. It is apparent that the significant difference in capital facilities required to support these ultimate loads is between the no-annexation alternative (Alternative 4) and a Growth Management Plan-based service territory (Alternatives 1, 2 and 3). The differences in terms of invested capital or rates between Alternatives 1, 2, and 3 are small and should not influence the basic decision.

A number of facilities management and capital improvement decisions will be strongly influenced by the service area's ultimate load. Decisionmakers will need to keep in mind the ultimate load presented by the service area alternative when selecting the preferred alternative. All scenarios require construction of a new substation, associated transmission lines, replacement of the transformer within the existing Blaine substation, and construction of new feeders to connect the two substations at a distribution voltage.

System Planning Criteria

The following City goals will guide the Division in planning system improvements:

- An acceptable level of public safety service delivery should be identified, consistent with community growth.
- A comprehensive emergency plan should be developed.
- The assets and facilities of the Division should be inventoried for state regulatory compliance and to plan for adequate infrastructure to achieve maximum operating efficiency.
- Divisional organization should be developed and restructured to provide the most effective and efficient electrical service to the citizens of Blaine.

- The Division should increase and stabilize its revenue base while reviewing existing programs for fiscal efficiency (e.g., the City should evaluate a capital borrowing program and/or assess impact payments from the developer of major new developments).

Existing Facilities

To provide the required degree of reliability and to support the projected increase in ultimate demand, a number of upgrades of existing facilities are recommended:

- The Division should investigate alternative substation sources of power delivery.

- The load from Circuit 15 could be transferred to Circuit 17 with proper protective device coordination.

- The main circuit backbone conductor for Circuits 15 and 16 should be upgraded to 600 amps as soon as practicable.

- Long-term and short-term contingency plans should be developed for the Semiahmoo service area.

- Older wood-pole overhead lines should be monitored for decay, and periodic tree trimming should be performed along overhead line rights-of-way.

- Rates and financial requirements in the BPA power sales contract general services provisions (Section 47 and 54) should be monitored. Changes in BPA services and rates should be monitored and the Division's practices adjusted.

- Once the City Council has accepted the Growth Management Plan, negotiations should be initiated with Puget Power to update the previous service territory agreement.

Capital Improvements Plan

Four service area configuration alternatives were discussed. Three expansion alternatives (based on three different annexation configurations) and one no-action alternative (based on no annexation) were evaluated, and an order-of-magnitude cost estimate was provided. The three expansion alternatives (Alternatives 1, 2, and 3), whether configured with or without Puget Power backup contingency, are essentially the same in cost; the no-annexation alternative (Alternative 4) would cost about half as much as any of the expansion alternatives.

- Alternative 1, without Puget Power backup, would require overall substation capacity of approximately 84 MVA. Increasing the capacity of the Blaine substation would involve replacing the existing transformer with a 15/20/25 MVA transformer and double-banking it with a second 15/20/25 MVA transformer; a second substation should be built with a 15/20/25 MVA transformer. A total of 11 feeders would be required.

- Alternative 1, with Puget Power backup, would require overall substation capacity of approximately 56 MVA. Increasing the capacity of the Blaine substation would involve replacing the existing transformer with a 15/20/25 MVA transformer and interconnecting it with Puget Power; a second substation should be built with a 15/20/25 MVA transformer. A total of nine feeders would be required.

- Alternative 2, without Puget Power backup, would require overall substation capacity of approximately 84 MVA. Increasing the capacity of the Blaine substation would involve replacing the existing transformer with a 15/20/25 MVA transformer and double-banking it with a second 15/20/25 MVA transformer; a second substation should be built with a 15/20/25 MVA transformer. A total of 11 feeders would be required.

- Alternative 2, with Puget Power backup, would require overall substation capacity of approximately 56 MVA. Increasing the capacity of the Blaine substation would involve replacing the existing transformer with a 15/20/25 MVA transformer and interconnecting it with Puget Power; a second substation should be built with a 15/20/25 MVA transformer. A total of nine feeders would be required.

- Alternative 3, without Puget Power backup, would require overall substation capacity of approximately 93 MVA. Increasing the capacity of the Blaine substation would involve replacing the existing transformer with a 20/26/33 MVA transformer and double-banking it with a 15/20/25 MVA transformer; a second substation should be built with a 15/20/25 MVA transformer. A total of 11 feeders would be required.

- Alternative 3, with Puget Power backup, would require overall substation capacity of approximately 56 MVA. Increasing the capacity of the Blaine substation would involve replacing the existing transformer with a 15/20/25 MVA transformer and interconnecting it with Puget Power; a second substation should be built with a 15/20/25 MVA transformer. A total of 10 feeders would be required.

- Alternative 4, without Puget Power backup, would require overall substation capacity of approximately 56 MVA. Increasing the capacity of the Blaine substation would involve replacing the existing transformer with a 15/20/25 MVA transformer and interconnecting it with Puget Power; a

second substation with a 15/20/25 MBA transformer is recommended to provide reliability and to serve the loads at Semiahmoo. A total of six feeders would be required.

Projected load growth and reliability needs will require substantial capital investment regardless of which alternative is selected. Before selecting a preferred alternative, the City Council will need to weigh these alternatives in light of considerations associated with other City services.

Financial Plan

Five financial scenarios were modeled, based on differing rates of population growth and annexation configuration. Regardless of which of the four service area alternatives described above becomes the preferred alternative, the Division will need to incur long-term debt to rebuild its reserves and to pay for ongoing capital improvements.

Scenarios 1, 2, and 3 assume low, medium, and high rates of growth, but no annexation. Under these circumstances, the Division's operating costs are projected to increase by an average of 5.0 to 7.8 percent in nominal terms between 1994 and 2000. Given that certain capital expenditures will be required for new projects regardless of load growth, the Division is forecast to be incurring debt service payments between $423,000 and $433,000 in year 2000. It is recommended that the Division's unrestricted fund balance be rebuilt to a normal operating reserve level equal to 45 days of operating expenses excluding purchased power and depreciation. The Division's revenue requirements would increase by 8.1 to 10.3 percent per year.

Scenarios 4 and 5 assume annexation and are based on expansion Alternative 2. Scenario 4 assumes that annexation would include purchase of Puget Power facilities within the annexation area at full replacement cost new (estimated at about $7.2 million in year 2000) or independent construction of such facilities by the Division. In annexations, utilities usually pay less than full replacement cost for the purchase of annexed property. However, in initial discussions with Puget Power about providing backup service to the City, Puget Power indicated that it should be compensated at the replacement cost new value. In the draft document circulated by Puget Power, dated April 28, 1993, it stated that "upon annexation by Blaine... Blaine shall... purchase... at a price equal to the amount, as reasonably determined by Puget Power, payable by Puget Power to replace such Distribution Facilities at the time of annexation." The costs of facilities in annexed areas in this report have been estimated at replacement cost new for two reasons: (1) it represents a "worst-case" cost of the facilities; and (2) it also provides for a cost that would allow the City to effectively construct duplicate facilities and therefore "strand" the Puget Power investment. If the City has evaluated full replacement cost new amounts, it is in a stronger negotiating position with Puget Power.

Scenario 5 assumes purchase of the facilities would be contracted so that the annexation would have no impact on rates between the assumed acquisition year of 1996 and the year 2000 (estimated at about $3.2 million). The Division's revenue requirements would increase in Scenario 4 at an average of 15.4 percent per year and in Scenario 5 at an average of 14.2 percent per year.

Regardless of the financial scenario ultimately selected, the following recommendations should be part of implementation of the Financial Plan:

- The financial reserves should be rebuilt as soon as possible by implementing a rate increase.
- The amount of rate increase could be reduced in the short term if the Division were willing to show losses on its income statement and issue more long-term debt in such a way that the Division's debt-equity ratio would approach 50 percent.
- The City of Blaine should continue to make use of contributions in aid of construction from sources of system growth.
- The Division needs to move quickly to borrow funds to implement needed capital improvements.

Operations Plan

The Operations Plan presents a number of statistics relating to the current performance of the Division, measured against its own past performance and against the performance of other electrical utilities. A number of different types of information can be gathered to assist the Division in assessing its performance. The Division should evaluate the usefulness of the various types of information presented and begin or continue gathering data of the types which best meet its needs.

The following recommendations for improving the operation of the Division were drawn from the informal management audit:

- The Division's informal verbal management style, which was suitable for a small utility, should be formalized into written policies and procedures more useful to a larger organization.
- The Division's goals and objectives should be more clearly stated.
- The Division's achievements should be tracked more clearly.

- The Division should address the need for better financial tracking and control through the City Manager and the City Council.

- The Division should provide City Council with materials such as plans, charts, and recommendations, and provide clearer justification of expenditures and communication of requests.

- A policy should be developed for determining whether City staff, Division staff, or contractors are used to accomplish certain tasks, and a procedure should be developed for supervising contractors.

Conservation Plan

In light of BPA's plans to end most funding for conservation programs and institute a tiered rate structure in October 1995, one underlying recommendation is presented regarding the various energy conservation programs in which the Division is participating:

- The Division should review the cost-effectiveness of its conservation programs and maintain those which are effective in helping reduce the need to purchase additional power from BPA at more costly Tier 2 rates.

Under current BPA contracts, federal legislation, and regional policy, the City must maintain conservation programs. Under BPA's proposed rate increases, conservation measures will allow the Division to defer purchases of higher-cost Tier 2 power.

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Chapter 10

Conclusions

Chapter 10
Conclusions

CH2M HILL has worked in partnership with the City of Blaine, its Public Works Department, and the Electrical Division of the Public Works Department, to provide the Division with a comprehensive evaluation of its operations and needs. We evaluated the physical system as it now exists and looked at how it should change to accommodate growth in customers. We provided a short-term and long-term Capital Improvements Plan and quantified its environmental impacts. Our evaluation also included the financial impacts of customer growth as presented through various annexation packages. We evaluated the costs to the Division and how those costs compare to those of other utilities.

We provided recommendations on objectives consistent with those of the City and based upon input from City officials and staff. We also reviewed the major aspects of the Division's facilities and evaluated their suitability. As part of this review, CH2M HILL recommended improvements to the physical system, which have or are being implemented by the Division.

In addition to reviewing the Division's physical system, we reviewed its operations. We found that the Division's costs are reasonable when compared to similarly sized utilities. As part of the process we recommend that a set of statistics should be compiled to document the comparative performance of the Division.

CH2M HILL has also reviewed the conservation program implemented by the Division and found it to be an important contribution to its success. Under current Bonneville Power Administration (BPA) contracts, federal legislation, and regional policy, the City needs to maintain a conservation program. Such a program will help keep electric power costs to the customers of the utility below what they would otherwise be. The conservation program will become more important as BPA moves toward a two-tiered pricing structure. Under such a pricing system, conservation will allow the utility to defer purchases of higher-cost Tier 2 power.

The Capital Improvements Plan and the Financial Plan show the changes to the physical system that need to take place under various City annexation alternatives. These alternatives were used to create alternative capital improvements plans. For the intermediate term, selected capital improvements plan alternatives and customer growth scenarios were evaluated.

The Division has assets of about $4.6 million, annual revenues of about $3.1 million, and no significant outstanding debt. In addition, the Division's rates are favorable when compared to the rates of similar utilities and those of Puget Power, which provides power outside the city.

Our evaluation has shown that current Division rates are not recovering sufficient revenues and that the Division's financial reserves are well below what they should be. This situation has occurred principally because the City Council, in its evaluation of community needs, has not allowed the Division to pass along to its customers increases in the wholesale price of power that the Division purchases from BPA.

Our reviews also suggest that the Division should expend funds to reduce the potential for major outages on its system; this reliability problem is well-known to its customers. The costs of implementing these capital improvements will require higher rates. The size of the increase can be reduced by using borrowed funds and spreading the cost of the major capital programs over their useful life. However, to borrow funds at favorable rates, the Division needs to show a solid financial program, which includes increasing the Division's financial reserves. Because BPA is planning to raise rates again this fall, it is important that the Division's rates be increased before the BPA increase occurs. That means a rate hearing at the City in the spring of 1995 and a rate increase in the summer of 1995.

The financial modeling performed by CH2M HILL shows that, under a no-annexation policy, average retail rates will need to increase on the order of 6 to 7 percent per year until the year 2000. These average increases are based upon BPA increases of about 5 percent per year. The 6 to 7 percent per year forecast of average retail rate increases is derived from a modeling of all system costs including purchased power, debt service coverage on capital improvements, administration and general expenses, and operation and maintenance costs. BPA increases of 5 percent do not result in 6 to 7 percent per year retail increases. However, with the construction of capital improvements funded by bonds, rebuilding of the Division's reserve fund, forecasts of BPA purchase power increases, and other costs included within the financial model, a 6 to 7 percent average retail rate increase is the result.

CH2M HILL has shown in its analyses that the City's annexation policy does not need to increase the cost of power to its citizens. Annexation can be accomplished in a revenue-neutral way, either by purchasing Puget Power facilities below their full replacement cost or by using impact fees and customer contributions associated with the expansion of major capital projects.

Once the City determines its urban growth boundaries and its annexation policy, the Division should negotiate with Puget Power to purchase facilities as the city limits expand. The Division should conduct discussions with its BPA account executive to evaluate the new power sales contract that will be offered this year, and to determine the new costs that will be in BPA's rates. Concurrent with this, the Division should work with its financial advisor and bond counsel to acquire funds that will be used to pay for the necessary capital improvements recommended in this report. An important element of that implementation program will be a commitment to improve the Division's financial condition.

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Appendix A

Informal Audit of the Blaine Electrical Division

Appendix A

Informal Audit of the Blaine Electrical Division

Introduction

CH2M HILL conducted an informal audit of the Electrical Division (the Division) of the City of Blaine Public Works Department. The audit was based upon observations of this utility and interviews with key personnel including Bill Duffy (Water/Sewer Operations Manager), John Hergesheimer (City Engineer), Butch Hinchey (Acting City Manager), Steve Tehee (General Foreman), Sylvia Goodwin (Planner), Larry Croft (crew foreman), Dave Chapman (Operations Manager, Semiahmoo), John Hobberlin (Mayor), Meredith Riely (Finance Department), and Frank Bresnan (City Councilman).

The following pages represent a compilation of the opinions of the people interviewed and of insights gained during the interview process. An alternative approach to determining the relative effectiveness of the Division was compiled for the Operation Plan, which reviews Division costs and staffing and presents descriptive statistics that compare the Division's historic performance and that of other Northwest utilities.

The use of an interview-based audit, as discussed in this section, when combined with a statistics-based review, provides a more complete review of the Division.

In general, this utility appears to be well run and highly valued by clients and stakeholders. The major needs are the implementation of better financial systems, and providing clearer justification of expenditures. Most of the other areas require only minor modifications or formalization. The utility compares very favorably to most municipal utilities of similar size.

For the interview-based portion of the review, CH2M HILL used the Canadian effectiveness audit method for evaluating organizations, which was developed by the Canadian Auditor General to evaluate politically funded programs. We have found that this approach is appropriate for evaluating publicly owned electric utilities and provides a comprehensive evaluation of municipal enterprises. This method establishes the following evaluation criteria: management direction, relevance, appropriateness, achievement of intended results, acceptance, secondary impacts, costs and productivity, responsiveness, financial results, working environment, protection of assets, and monitoring and reporting.

1. *Management Direction: The extent to which the Division's objectives are clearly laid out, are communicated to and understood by employees, and the achievement of the objectives are measurable.*

The Division has principally used informal management direction. Considering the history of the utility and the number of employees, this is not an unusual approach. This informal verbal approach has worked well in the past, but there is a need to more clearly state objectives and measure achievements. Policy direction from the City Council and City Manager also has undergone significant change over the past few years. Similarly, the utility has grown in staff and complexity. The utility is also under increasing pressure to maintain competitive rates.

As a result, Electrical Division employees and City policymakers need clearly laid-out documents stating the objectives of the utility. The Comprehensive Plan Report, combined with employee and City Council discussions of the report, should help the Division's managers to communicate their objectives to employees and policymakers.

In general, staff in the Electrical Division understand what they are meant to be doing, although some interviewees expressed a concern the Division needs to have a better understanding with the other Public Works divisions, and some crews need to better understand general service from a technical perspective. Others feel that workers on the road have a good understanding of what they are doing, but that on the management level there is a need for more management and supervisory knowledge or skills.

The objectives of the Division are not always clearly understood by the employees and those outside of the Division who interact with the electric utility.

The Division does not always understand the desires of the City policymakers. It was noted that City leaders need to be educated about what the various Divisions do; the policymakers need to be presented with recommendations, educational background material, and options. In addition, others felt that Division staff could use management training in dealing with the political aspects of their job. Historically, the frequent staffing changes in City Council, City Manager, and key personnel have resulted in a lack of continuity.

Another concern voiced was that the City Council and citizens feel that the Division is over-staffed by about four people. This concern does not appear to be supported by comparison with other utilities of similar size.

There is a feeling by some that the Division does not truly want to follow City Council direction. These individuals feel that the Division has its own policy direction, which is based upon history and the interests of employees.

The Division's management plans would be enhanced by long-term planning such as would be provided by a Comprehensive Plan.

2. *Relevance: The extent to which the activities of the Division make sense in regard to the current conditions.*

The major activities of the Division are meter reading, billing, engineering, customer inquiries, regulatory compliance, accommodating new construction using Division crews, inspecting construction by others, performing preventive maintenance, responding to outages, and management of staff.

Generally the activities of the Division have a high degree of relevance; there do not appear to be any areas where the effort needs to be totally abandoned. However, one area that should be addressed is services from other City departments, such as an economic evaluation of financial, billing, and meter-reading functions. The Division should also evaluate contracting more construction work when this is cost-effective. Similarly, the Division has been performing deferred maintenance of existing facilities, which was not done previously, in an effort to reduce future outages. There is a need to implement the Division's standby policy and to create contingency plans for certain types of long-term outages.

Many utilities are focusing on their "core functions." For example, Washington Water Power is having its computer services and billing (two "non-core" functions from its perspective) performed by another company. There are proposals before the Washington Utilities and Transportation Commission, which regulates investor owned gas and electric utilities, to have shared meter-reading services. Presently, the meter-reading and billing functions of the Electrical Division have been turned over to other City departments; for example, water and electric meter-reading have been combined. Similarly, billing for all of the public works enterprise funds is combined. Tradeoffs between better using meter-reading labor and accountability, hourly labor rates, cost savings from the performance of other tasks at the same time, other uses of readers' time, and the skills needed should all be considered. Private firms are now employed by some utilities to perform meter-reading and billing functions. This alternative may allow the Division to benchmark the rates charged by other City departments.

Engineering capability has been provided by Public Works staff, consultants, and limited internal staff effort. The degree to which "core" engineering capability needs to remain within the Public Works Department and the Electrical Division should be addressed.

Customer inquiries appear to be handled on an ad hoc basis, a method that appears to have worked very well. As the electric system grows, a more formal way of tracking customer inquiries may be adopted. It will always be important to provide customers answers as quickly and as close to the point of inquiry as possible. For example, a customer asking a crew member or the meter reader about electric rates is best answered by a courteous, informed response there and then. However, such questions should be documented so that management knows if there is a new public information need that can be handled through mailings or newspaper articles.

The Division appears to have a good safety record and regulatory compliance record. This is an area where skills can be shared with Public Works Department divisions and other electric utilities. Continued participation in the NWPPA and its training seminars on regulatory issues is a cost-effective way to stay current with specific electric utility regulatory issues.

The Division's construction activities can be broken down into two categories: accommodating new construction using Division crews, and inspecting construction by others. The Division has had problems with the work of some outside construction crews, which has led to a desire to minimize outside construction work. That, in turn, has resulted in questions concerning Division interpretation of state public works bid laws.

Contractor workmanship may be improved through the use of quality specifications. (The Division may wish to hire an engineering company to review its standard construction specifications.) The Division may also use qualified utility employee inspectors (an approach that has been used quite successfully). A third approach is to establish long-term alliances with contractors; however, this approach must follow the Public Bid law process. One way to meet the bid law requirements, secure fair prices, and establish an alliance is through the use of a roster of pre-qualified public works contractors.

While the use of Division employees for construction seems to be effective in avoiding contractor workmanship problems that have historically resulted in outages, policymakers appear to desire that more contracting be performed. Additional contracting will require the training of staff in inspection and supervision of the work of others. It will also divert some staff from present duties. The optimal mix between contract labor and Division labor is a balance that changes over time. The principal areas of evaluation are quality of work, utilization of staff on a 12-month basis, and the willingness of contractors to provide services on a non-recurring basis.

Performing preventive maintenance is another major Division function. Survey responses imply that perhaps too little maintenance was done in the past but that present maintenance levels are appropriate. The Division has been working with CH2M HILL on a number of upgrade and maintenance assignments. The recent fuse coordination work is a major maintenance enhancement. The Financial Plan will also provide a benchmark for typical maintenance expenses.

Other factors that most electric utilities consider when they evaluate the number of electrical employees is the minimum crew size and number of crews that are required for emergency outage repairs. The Division has done a good job in responding to small outages. Implementation of a standby policy, discussed later in this audit, is an important aspect in outage response. Similarly, the increased preventive maintenance should reduce the need for outage response. Certain classes of major outage responses still need contingency plans. These include Semiahmoo submarine cable outage, failure of a Puget Power transmission line or substation transformer, or a major disaster such as a fire or earthquake that destroys a major circuit in multiple locations. Many utilities have mutual-aid agreements to share inventory and crews in the event of such disasters.

The management of the Division appears to be effective and relevant in that morale does not seem to be a problem, employee turnover is low, and those interviewed generally believe that the utility is doing well. Compared to a number of utilities of different sizes, the Division appears to be reasonably well run and has implemented a number of progressive programs (conservation, CAD, fuse coordination, underground service in conduit) that other utilities of similar size have not yet considered.

Survey respondents indicated that some activities within the Division could be reorganized. Some duties such as cutting grass around poles or painting could be done by non-linemen who have lower salaries, while well-trained people would do value-added work.

Other respondents indicated that the Division does not have time to do a variety of things that were important in the past: for example, checking street lights.

Another comment was that the City needs to evaluate the full-time mapping engineering effort; it might need to go to part-time status.

When asked whether the Division is putting its effort into all the right places, respondents indicated that the Division is evolving and that while budgeting, finance, and planning are areas that need additional effort, maintenance and operations need to come first. Others felt the need for planning for upgrades and expansion. Others put priority on maintenance rather than new construction.

Strategies suggested by survey respondents for the use of contract construction crews included using two small works rosters: one for excavation and hauling and a second for licensed electrical contractors.

Because the City Council wants the Division to use more outside contractors the Division needs to show which is more cost-effective. Perhaps City staff should do all construction below the $20,000 limit.

Others indicated they prefer City staff perform maintenance, be sized to handle storm outages, and do a minimum of construction because the small size of the City does not allow for specialized equipment to be purchased by the City.

3. *Appropriateness: The extent to which the internal organization structure of the Division and the level and type of effort are logical in light of the objectives.*

Generally, there is a feeling that the internal organizational structure is appropriate. The Division appears to have good delegation, responsibility, and accountability. However, there is a need to document and better communicate the reasons for the structure and whether that structure should change. Historically, the organization has concentrated on its own internal definition of customer service; today, publicly funded organizations need to focus outwardly.

In the private sector many companies are downsizing and experimenting with contracting out more of their non-core business functions. Some public agencies are also experimenting with "privatizing" certain functions not associated with health or safety. The Division should explore ways of contracting for additional construction in a cautious manner, while developing optimal scheduling of skilled linemen's time. To the extent that some work is done by contractors, the Division will be better able to "base load" its crews' time and accommodate staffing variations by using contract employees.

Survey respondents commented that there have been significant staffing changes at the City. There is a need for clearer accountability definition and better distribution of job classifications; the staff is toward the high end of all salary ranges.

It was suggested that assignment of a specific foreman to a specific circuit could provide some specialization and knowledge benefits, and that crews need to get more cross-training. One comment was that some Division employees spend too much time reinventing design standards; a manual to provide such information is in development.

Added engineering is needed on a day-to-day basis to allow quicker turnaround on developer and City Council questions.

4. *Achievement of Intended Results: The extent to which the Division's objectives are being achieved.*

The Division is generally achieving its major objectives, although there is room for improvement in identifying all of its objectives and communicating them to its customers, employees, and policymakers so that all can focus on achieving the intended results.

Survey respondents differed on the definition of the proper level of power reliability. Some put priority on essential services: water wells, sewer pump stations, the Semiahmoo Inn, nursing homes, the border crossing, and some industries, stating that the Division should try to provide options and let people choose the level of reliability they want.

Others felt public safety, health care facilities, and the Good Samaritan Nursing Home need special consideration, but that Semiahmoo deserves no more reliability care than the rest of the town.

Others put priority on the same level of reliability for all customers.

Residential uses were generally given lowest priority, with the exception that during very cold weather, residential service may be one of the most important priorities because of public health concerns.

Potential efficiency improvements in the Division included improvements in bookkeeping, sharing the cost and coordinating with other City construction for utility corridors, more efficient use of unskilled labor, and instituting standard operating procedures.

5. *Acceptance: The extent to which the customers and stakeholders are satisfied with the Division's performance.*

Customer satisfaction appears to be a major success at Blaine, resulting from the initiative and policies of the management team and employees. The Division does very well, in the eyes of respondents, in responding quickly to customers' problems and in maintaining facilities.

To maintain this level of satisfaction, the Division will need to be able to explain to the public the issues driving rates, the need for large projects, and the utility's performance. The Division needs to open up communications with customers so that their opinions can be solicited in a quantifiable way. Providing this extra level of communication should allow the Division to maintain its favorable level of customer satisfaction.

Communication with policymakers appears to be an area that needs work. While this does not mean that there is a problem, there is a need to justify and explain the management functions within the Division to policymakers.

Interviewees suggested that levels of customer-owner satisfaction could be ascertained through questions in billing flyers and talking to walk-in bill payers. It was noted that the Public Works Advisory Committee had looked into measuring levels of satisfaction, and found that conducting door-to-door survey was unrealistically expensive.

Survey respondents felt the rates charged by the Division were reasonable or possibly too low, but that customers think the electric rates are just right or too high.

Respondents attributed the increase in electric rates to a wide variety of factors: expenditures in 1993 and 1994 from the reserve fund for unrelated electric utility costs, the increase in the cost of power purchased from BPA, the water shortage and fishery problems, the cost of materials and labor, undergrounding power lines, bureaucracy, state regulations, auditors, environmental regulations, consultants, and improvements of Circuit 17.

Most respondents believed that rate increases should occur as small annual increases of about the magnitude of the Consumer Price Index, for example, or every 2 years, and timed so that they do not occur during the winter.

Staff working in the other Public Works divisions appear to have some conflict and concern over Electrical Division salaries—light crews, for example, have a reputation for being too expensive (Teamster vs. IBEW wage scales). Using linemen to do unskilled labor is a concern. Respondents believe that customers underestimate the work performed by the Division and do not understand planning, engineering, and training requirements. The public may feel there are too many employees, too much overtime, and problems with timely billing. Most people do not understand state requirements and safety requirements.

6. *Secondary Impacts: The extent to which the way the Division operates has unintended positive or negative impacts on other groups or products.*

This is an area that is traditionally very difficult to measure. One of the clearest secondary impacts of the Electrical Division has been its economic contributions to the City General Fund and to other divisions of the Public Works Department.

The electric utility industry is becoming much more competitive. People are viewing electric service more as a commodity than a utility. While superior customer service, a local understanding of the utility, and a feeling of local control are important ways to expand a customer's definition of electricity, rate competition between neighboring electric utilities will still increase. This implies that other City departments may not be able to rely on the same levels of assistance and support from the Electrical Division as they have in the past. This secondary impact will occur as the Division's costs and rates are pressed by market forces and it no longer has discretionary funds that can be used in anything but core areas.

7. *Costs and Productivity: The extent to which the Division's costs compare favorably with those of other groups.*

The Financial Plan looks at establishing specific benchmarks for cost components within the City of Blaine budget. The Division will be under increasing pressure to use labor and money more productively. Interview replies indicate a generally positive view of cost and productivity.

The Division's rates are probably too low based upon the way it is now operated and financed, and considering the significant reduction in reserves and working capital. The Finance Plan, determination of revenue adequacy, and the need for certain large capital projects will encourage the utility to modify its financial practices.

8. *Responsiveness: The extent to which the Division is able to respond quickly to changes in circumstances.*

There are two types of responsiveness. The first is the need for an organization to be flexible in its organization and objectives. The recent history of Blaine includes major changes within City Council and City Manager positions. Similarly, the Division is growing at a phenomenal rate, and has dealt with these changes and still performed its principal functions of providing reliable, cost-effective electric power. The changes have not occurred without occasional tension on the part of policymakers or City employees. Historically, however, the Division has met the test of responsiveness. As change becomes a more important element of life in the 1990s, the Division will need to take steps to become even more responsive in the future.

A second type of responsiveness is the ability to respond to outages. The Division has recognized this in its implementation of a standby response policy. Contingency plans for major outages need to be provided.

Respondents generally agreed that the target response time for an outage should be 30 minutes.

9. *Financial Results*

This evaluation component in the Canadian effectiveness audit methodology is covered by other sections of this report.

10. *Working Environment*

Generally, the working environment at the Division appears to get high marks. This is attributable to the skills of the Division's management team. Better communications of objectives, team building, and training are all areas that should improve staff morale and performance. (These functions may need to be implemented in phases.) As utilities become more competitive, higher productivity is required of each employee. As with an automobile, frequent tuning and careful (human resource) maintenance are important in getting the most out of an investment.

Respondents listed several regulatory compliance issues affecting the work environment, including the new OSHA regulations dealing with operating practices for distribution, confined space, and first aid, which take effect at the end of May.

Training that might benefit Division staff includes team building with supervisory staff, management and supervisory training, system protection training, safety training, and role playing for situations dealing with customer service.

11. *Protection of Assets*

While the protection of assets is principally a question for the state auditor and the financial department of the City, there appears to be a need to implement better financial tracking and control systems. These systems are not the sole responsibility of the Electrical Division. It also appears that the Division has an opportunity to set the standard for other divisions and departments within the City. Integrating financial tracking systems with electric utility activities is difficult for many small municipal utilities. One of the respondents described an incident where a payment deadline to BPA was missed, resulting in an interest penalty. While a number of positive steps are being taken, the significant reduction of reserves and the missed payment indicate the need to do better. For the Division to implement such systems unilaterally is neither appropriate nor wise. The Division should address the need for better financial systems with new City Manager and the City Council.

Survey responses regarding controls to ensure that the Division's financial affairs are carried out in a proper manner indicated that some areas need improvement, such as customer accounting and customer billing for new service. The Division has implemented a work order system, and the City is upgrading financial systems and reporting. An older

version of total utility maintenance system is being implemented by the Public Works Department.

Respondents indicated a variety of opinions on whether budget targets, or the amount of effort for each job, are established or understood for all projects.

12. *Monitoring and Reporting: The extent to which key matters pertaining to performance are identified, reported, and carefully monitored.*

The Division has done a reasonable job of qualitative reporting of its performance. This can be judged by its ability to get budgets approved, raise rates as needed, and maintain positive customer satisfaction. The utility now needs to implement a quantitative reporting method that justifies the economic and labor resources spent by the Division.

Respondents identified several reports that the Division could prepare for City policymakers that would help them better understand the Division's performance. One was an executive summary of this audit.

Others included simple, to-the-point statistics such as sales vs. revenues, number of services per month, recurring maintenance, number of inspections, examinations of plans, timeliness of billing, and estimates. To justify its staff, the Division needs to present revenue and/or expense statistics.

Educational reports were reported as effective; Computer Aided Design (CAD) mapping was cited as an example of a persuasive educational tool. Other areas where educational reports would be helpful are debt service, capital replacement funds, and systems replacement.

Other reports suggested include changes in workloads, revenues, number of commercial and residential services, miles of overhead conductor, underground replacement of equipment, FTE (full-time equivalent) employee count, customers per revenue, number of outages and length of the outage, comparison of rates (Blaine vs. BPA), kilowatt hours (kWh) sold (currently there is no annual report), and how often the load exceeds the Division's ability to provide power.

Another suggestion was for quarterly reports in the newspaper, which could show people what they are getting for their money.

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Appendix B

Environmental Checklist

Appendix B
Environmental Checklist

A. BACKGROUND

1. **Name of proposed project, if applicable:**

   City of Blaine Electrical Division Comprehensive Plan

2. **Name of Applicant:**

   City of Blaine Electrical Division

3. **Address and phone number of applicant and contact person:**

   Wayne Mathers, Manager
   1200 Yew Street
   Blaine, Washington 98230
   (206) 332-8820

4. **Date checklist prepared:**

   December 1994

5. **Agency requesting checklist:**

   City of Blaine Department of Public Works

6. **Proposed timing or schedule (including phasing, if applicable):**

   The projects will be funded and constructed in a phased approach as load growth occurs. The major components required over the next 30 to 40 years will be the construction of approximately seven major 600 amp distribution feeders, the construction of a 15/20/25 MVA substation in the Semiahmoo/Birch Point/Drayton Harbor area, a double-banked substation in the vicinity of the existing Puget Sound Power & Light Company Substation and 115 kV transmission to these sites. Alternatives to the "circuit, substation and transmission" construction include joint use or acquisition of Puget Sound Power & Light Company facilities as the City annexes into the Urban Growth Boundary.

   Specific short-term actions are included within an action plan. They include:

- Upgrade backbone feeder for existing Circuit 15 between the Blaine substation and the downtown area

- Construct a new 115 kV to 12.47 kV substation in the Semiahmoo/ Birch Point/Drayton Harbor area and 115 kV transmission line to the substation

- Construct a new feeder between the existing distribution system on the Semiahmoo Parkway and the new substation

- Upgrade the tie feeder between the existing Blaine substation and the Semiahmoo area via the Semiahmoo spit to allow for mutual backup between the Blaine substation and the new substation

- Replace and submarine cable, which is near the end of its projected life

- Construct an intertie feeder around the south of Drayton Harbor that allows for mutual backup between the Blaine substation and the new substation

7. **Do you have any plans for future additions, expansion, or further activity related to or connected with this proposal? If yes, explain.**

As indicated in 6 above, the project being evaluated is a long-range plan of service. All major alternatives contemplated at this time are discussed within the plan.

8. **List any environmental information you know about that has been prepared, or will be prepared, directly related to this proposal.**

The City is preparing an environmental impact statement associated with its implementation of the Growth Management Act process.

Under existing Washington State Environmental Policy Act (SEPA) rules, many of the Electrical Division's activities are categorically exempt from SEPA. Most maintenance activities are exempt under WAC 197-11-800 (3), which states:

> "The following activities shall be categorically exempt: The repair, remodeling, maintenance, or minor alteration of existing private or public structures, facilities or equipment, including utilities, involving no material expansions or changes in use beyond that previously existing, except that, where undertaken wholly or in part on lands covered by water, only minor repair or replacement of structures may be exempted (examples include repair or replacement of

pilings, ramps, floats, or mooring buoys, or minor repair, alternation or maintenance of docks).

The following maintenance activities shall not be considered exempt under this subsection:

(a) Dredging;
(b) Reconstruction/maintenance of groins and similar shoreline protection structures; or
(c) Replacement of utility cables that must be buried under the surface of the bedlands. Repair/rebuilding of major dams, dikes, and reservoirs shall also not be considered exempt under this subsection."

Other major activities are exempt under WAC 197-11-800 (24), which states:

"Utilities. The utility-related actions listed below shall be exempt, except for installation, construction, or alteration on lands covered by water. The exemption includes installation and construction, relocation when required by other governmental bodies, repair, replacement maintenance, operation or alteration that does not change the action from an exempt class.

(a) ...
(b) ...
(c) All electric facilities, lines, equipment or appurtenances, not including substation, with an associated voltage of 55,000 volts or less; and the overbuilding of existing distribution lines (55,000 volts or less) with transmission lines (more than 55,000 volts); and the undergrounding of all electric facilities, lines, equipment or appurtenances.
(d) ...
(e) All developments within the confines of any existing electric substation, reservoir, pump station or well: Provided, That additional appropriations of water are not exempted by this subsection.
(f) ...
(g) All grants of rights of way by agencies to utilities for use for distribution (as opposed to transmission) purposes.
(h) All grants of franchises by agencies to utilities
(i) All disposal of rights of way by utilities."

To the extent that new 115 kV transmission lines, new substations, or a non-emergency or buried replacement of the 12.47 kV submarine cable across Drayton Harbor are required, they will be the subject of site-specific environmental analysis at the time of their commitment by the City. Some activities are exempt from SEPA if they are of an emergency nature.

Similarly, the language in WAC 197-11-800 (3)(c) refers to "...utility cables that must be buried under the surface of the bedlands." The City needs to develop contingency plans for failure of the submarine cable that serves Semiahmoo. This checklist does not address the City's submarine cable contingency plan.

9. **Do you know whether applications are pending for governmental approvals of other proposals directly affecting the property covered by your proposal? If yes, explain.**

Aside from the City of Blaine environmental impact statement to implement the City's Urban Growth Boundary under the Growth Management Act, there are no known proposals or actions.

10. **List any government approvals or permits that will be needed for your proposal, if known.**

If county road rights-of-way are used for new distribution lines, a permit will be required from the county. If wetlands are crossed within the City of Blaine, compliance with the City's wetland ordinance will be required. Major capital projects that result in the creation of bond resolutions will need to go before the City Council. If the City Council prefers to finance the projects out of current rates, the rate increases will need to go before the City Council.

11. **Give a brief, complete description of your proposal, including the proposed uses and the size of the project and site. There are several questions later in this checklist that ask you to describe certain aspects of your proposal. You do not need to repeat those answers on this page. (Lead agencies may modify this form to include additional specific information on project description.)**

This project is to allow the Electrical Division to serve the chosen alternative area described in item 12 below. It will include the maintenance, operations, and construction required by the electric customers of that area. Generally, electric power is purchased from BPA (but potentially from other sources in the future), transmitted, and delivered by Puget Power to the Blaine Electrical Division at 12.47 kV. The Division then distributes the power through overhead and underground 12.47 kV feeders to overhead and underground transformers where the power is converted to a lower voltage for use by the customer. The proposal includes continued conservation programs to mitigate the need for additional facilities. It also includes an evaluation of the new major distribution feeders, substations, and 115 kV transmission lines that will be required to serve the customers within the chosen service territory.

12. **Location of the proposal. Give sufficient information for a person to understand the precise location of your proposed project, including a street address, if any, and section, township, and range, if known. If a proposal would occur over a range of area, provide the range or boundaries of the site(s). Provide a legal description, site plan, vicinity map, and plans required by the agency, you are not required to duplicate maps or detailed plans submitted with any permit applications related to this checklist.**

Four alternatives were considered in the planning for the Division. These are identified as Alternatives 1, 2, 3, and a No Action alternative, Alternative 4.

The Alternative 1 service area coincides with the historic City of Blaine/ Puget Power service territory agreement. This area is bounded by Lincoln Road to the south and Valley View Road to the east. It will provide electrical service to approximately 11,060 acres of land.

The Alternative 2 service area roughly coincides with the City's proposed growth management boundary and includes a portion south of Lincoln Road. At Loomis Trail Road and I-5, the boundary follows I-5 in a northwesterly direction to an imaginary extension of Harvey Road, then northerly along Sweet Road. From this point the boundary moves east along Sweet Road to Valley View Road. The service area also includes a portion of the proposed annexation east of an extension of Valley View Road and north of H Street. It will provide electrical service to approximately 8,934 acres of land.

The Alternative 3 service area was defined by the City to include the full proposed H Street annexation, then south along Valley View Road to Blaine-Lynden Road, west to Giles Road, south to Loomis Trail/Lincoln Roads, west along Loomis Trail/Lincoln Roads, south along Shintaffer Road, and west along Birch Point Road to the water. It will provide electrical service to approximately 11,272 acres of land.

The No Action Alternative is continued service to the areas of Central Blaine and Semiahmoo with a few services provided outside these areas. Central Blaine is the original site of Blaine located to the northeast of Drayton Harbor and south of the U.S. Border. It represents the existing City boundaries excluding those across Drayton Harbor in the Semiahmoo development. This area includes approximately 1,320 acres. The Semiahmoo area is to the southeast of Drayton Harbor. It includes the Semiahmoo development and West Semiahmoo, which are within the city limits. It represents about 960 acres of land. There is additional land outside the

city limits that is currently served by the utility that would continue to be served. The No Action alternative will provide electrical service to approximately 2,500 acres of land within northern Whatcom County.

B. ENVIRONMENTAL ELEMENTS

1. Earth

a. General description of the site (circle one): Flat, rolling, hilly, steep slopes, mountainous, other.

The area that the Electrical Division serves and where the modifications would occur is characterized by flat and rolling terrain.

b. What is the steepest slope on the site (approximate percent slope)?

Although there may be local instances of steep slope, the vast majority of the area is relatively flat, averaging about 1 to 3 percent slope.

c. What general types of soils are found on the site (for example, clay, sand, gravel, peat, muck)? If you know the classification of agricultural soils, specify them and note any prime farmland.

The project area includes a wide variety of soil types. The most common are silt loam, silty clay loam, gravelly sandy loam, and sandy loam.

d. Are there surface indications or history of unstable soils in the immediate vicinity? If so, describe.

There is no known history of unstable soils. If unstable soils are encountered, special construction techniques will be initiated on a case-by-case basis to prevent both erosion and slides.

e. Describe the purpose, type, and approximate quantities of any filling or grading proposed. Indicate source of fill.

A small amount of filling and grading associated with construction is anticipated to be located at the new substation site and for access to transmission line locations.

f. **Could erosion occur as a result of clearing, construction or use? If so, generally describe.**

No significant erosion is expected.

g. **About what percent of the site will be covered with impervious surfaces after project construction (for example, asphalt or buildings)?**

Significant increases in impervious surfaces are not anticipated as part of the attached system plan. The impervious surfaces that will be added are quite minor. They include: the power poles (where only ground was previously), underground padmount transformers, and transformer vaults. With the exception of substation switchgear (which would be covered under a separate site-specific environmental analysis), there are no buildings (including roofs), roads, or paved parking areas included as part of the projects being considered.

h. **Proposed measures to reduce or control erosion, or other impacts to the earth, if any:**

None warranted although each phase will be considered on a case-by-case basis.

2. **Air**

a. **What types of emissions to the air would result from the proposal (i.e., dust, automobile, odors, industrial wood smoke) during construction and when the project is completed? If any, generally describe and give approximate quantities if known.**

Emissions during construction include vehicle and construction equipment exhaust (primarily CO and PM_{10}). Fugitive dust emissions (TSP) can be generated from vehicle movement over unpaved surfaces, wind erosion of aggregate storage piles associated with underground trenching, or heavy construction activities. Although not quantified, air emissions during construction are expected to be minimal.

b. **Are there any off-site sources of emissions or odor that may affect your proposal? If so, generally describe.**

None.

c. **Proposed measures to reduce or control emissions or other impacts to air, if any:**

Construction-related fugitive dust emissions will be mitigated using a watering program, if needed, during the dry season. Cleaning of vehicles and/or wheel washing prior to leaving the site will mitigate dust generated by carry-out.

3. **Water**

a. **Surface:**

1. **Is there any surface water body on or in the immediate vicinity of the site (including year-round and seasonal streams, saltwater, lakes, ponds, wetlands)? If yes, describe type and provide names. If appropriate, state what stream or river it flows into.**

Yes, the project area is adjacent Drayton Harbor, Semiahmoo Bay and the waters of the Strait of Georgia. California Creek and Dakota Creek collect surface water from a system of smaller tributaries within the project area. Both creeks flow into Drayton Harbor. Approximately 10 percent of the land within the City of Blaine and approximately 25 percent of the land within the Urban Growth Boundary are impacted by wetlands.

2. **Will the project require any work over, in, or adjacent to (within 200 feet) the described waters? If yes, please describe and attach available plans.**

Certain distribution and transmission poles will be placed in pasture wetlands and near road drainage ditch wetlands. Similarly, certain transmission and distribution lines may be placed across streams or near shoreline areas depending upon right-of-way alignments chosen during the final design process. Work will conform to the City's wetland ordinance requirements if it is within the city limits.

3. **Estimate the amount of fill and dredge material that would be placed in or removed from surface water or wetlands and indicate the area of the site that would be affected. Indicate the source of fill material.**

None.

4. **Will the proposal require surface water withdrawals or diversions? Give general descriptions, purpose, and approximate quantities if known.**

   No.

5. **Does the proposal lie within a 100-year floodplain? If so, note location on the site plan.**

   Distribution and/or transmission poles or underground distribution lines may be placed within flood hazard areas located along Dakota and California Creeks.

6. **Does the proposal involve any discharges of waste materials to surface waters? If so, describe the type of waste and anticipated volume of discharge.**

   No.

b. **Ground:**

1. **Will groundwater be withdrawn, or will water be discharged to groundwater? Give general description, purpose, and approximate quantities if known.**

   No.

2. **Describe waste material that will be discharged into the ground from septic tanks or others sources, if any (for example: domestic sewage; industrial, containing the following chemicals . . .; agricultural; etc.). Describe the general size of the system, the number of such systems, the number of houses to be served (if applicable), or the number of animals or humans the system(s) is expected to serve.**

   None.

c. **Water Runoff (including storm water):**

1. **Describe the source of runoff (including storm water) and method of collection and disposal, if any (include quantities, if known). Where will this water flow? Will this water flow into other waters? If so, describe.**

   Runoff is not anticipated.

2. **Could waste materials enter ground or surface waters? If so, generally describe.**

Not anticipated.

d. **Proposed measures to reduce or control surface, ground, and runoff water impacts, if any:**

None anticipated beyond construction period.

4. **Plants**

a. **Check or circle types of vegetation found on the site:**

X deciduous tree: alder, maple, aspen, other:
X evergreen tree: fir, cedar, pine, other:
X shrubs
X grass
X pasture
___ crop or grain
X wet soil plants: cattail, buttercup, bulrush, skunk cabbage, other: soft rush
___ water plants: water lily, eelgrass, millfoil, other:
___ other types of vegetation

b. **What kind and amount of vegetation will be removed or altered?**

Less than 10 acres will be altered to construct the distribution lines associated with the project. Depending upon the specific site and whether the distribution line is overhead or underground, the alteration could range from temporary disruption of grasses and ground cover for underground lines to the trimming and cutting of trees along overhead distribution lines. Less than half of the alteration would be through the removal of mixed coniferous/deciduous trees. The two substations would occupy approximately one-quarter to one-half acre each and result in the removal of most vegetation from the site.

c. **List threatened or endangered species known to be on or near the site.**

None.

d. **Proposed landscaping, use of native plants, or other measures to preserve or enhance vegetation on the site, if any:**

Clearing of vegetation will be the minimum required to construct the facility. Any undisturbed native vegetation will be allowed to remain on the site. Periodic tree trimming near overhead distribution lines will occur to prevent power outages. Similarly, tree removal over new underground lines will occur to prevent tree roots from destroying underground distribution feeders.

5. **Animals**

a. **Circle any birds and animals which have been observed on or near the site or are known to be on or near the site:**

Birds: hawk, heron, eagle, songbirds, other:

See below regarding eagles. Herons, hawks, and waterfowl frequent portions of the proposed alternative areas.

Mammals: deer, bear, elk, beaver, other:
Fish: bass, salmon, trout, herring, shellfish, other:

b. **List any threatened or endangered species known to be on or near the site.**

Bald eagles nest on portions of the Semiahmoo/Birch Point area.

c. **Is the site part of a migration route? If so, explain.**

It is not believed that the site is part of land animal migration routes. However, the shoreline of the Strait of Georgia and Drayton Harbor is a likely migration route for shorebirds and raptors. Dakota Creek and California Creek are used by coho and chum salmon. It is not expected that the project will disturb migration patterns.

d. **Proposed measures to preserve or enhance wildlife, if any:**

Site clearing will be the minimum amount needed to accomplish the project.

6. **Energy and Natural Resources**

a. **What kinds of energy (electrical, natural gas, oil, wood stove, solar) will be used to meet the completed project's energy needs? Describe whether it will be used for heating, manufacturing, etc.**

The project will provide increased electric energy. Electric power losses will be minimized through the incorporation of modern design. Similarly, part of the project includes recommendations on continued implementation of electric power conservation programs.

b. **Would your project affect the potential use of solar energy by adjacent properties? If so, generally describe.**

No.

c. **What kinds of energy conservation features are included in the plans of this proposal? List other proposed measures to reduce or control energy impacts, if any:**

The principal conservation will be a continuation of various BPA projects. In the residential sector the focus is on continuation of the Weatherwise, Appliance Efficiency—Shower Head and Water Heater, Long Term Super Good Cents, and Manufactured Acquisition programs. In the commercial and industrial sectors, the measures include continued participation in Energy Smart Design and Energy $avings Plan programs. For more information please see the section on electric energy conservation programs. This is found in Chapter 8 of the Electrical Division Comprehensive Plan Report.

7. **Environmental Health**

a. **Are there any environmental health hazards, including exposure to toxic chemicals, risk of fire and explosion, spill, or hazardous waste, that could occur as a result of this proposal? If so, describe.**

There are no potential environmental health hazards anticipated with this project.

1. **Describe special emergency services that might be required.**

None should be necessary.

2. **Proposed measures to reduce or control environmental health hazards, if any:**

None should be necessary.

b. **Noise**

1. **What types of noise exist in the area which may affect your project (for example: traffic, equipment, operation, other)?**

There are no offsite noises that would affect this project adversely. The principal noise impact will be from transformer hum at padmount transformers and corona noise on overhead distribution insulators.

2. **What types and levels of noise would be created by or associated with the project on a short-term or a long-term basis (for example: traffic, construction, operation, other)? Indicate what hours noise would come from the site.**

Typical noise levels of transformers and insulators will be within industry standards and less than 55 dBA at 400 feet. The principal source of noise will be from transformers, which will be in operation 24 hours a day.

3. **Proposed measures to reduce or control noise impacts, if any:**

The transformers will be specified to comply with modern noise control requirements and comply with applicable noise regulations.

8. **Land and Shoreline Use**

a. **What is the current use of the site and adjacent properties?**

The project area is being used currently for a variety of residential, commercial and industrial purposes. Most electric utility distribution lines are within, follow, or are parallel to road, railroad, or electric transmission rights-of-way. Transmission lines of 115 kV are generally sited in a similar manner.

b. **Has the site been used for agriculture? If so, describe.**

There are agricultural areas within the project area. Distribution lines by their nature, especially when sited in or along road rights-of-way, do not consume large quantities of land. No significant conversion of agricultural lands is contemplated by the construction of Division electrical facilities.

c. **Describe any structures on the site.**

Because of right-of-way acquisition costs, structures on the routes will be generally avoided.

d. **Will any structures be demolished? If so, what?**

None is anticipated to be demolished.

e. **What is the current zoning classification of the site?**

The project areas include a full spectrum of zoning classifications. The zoning classifications within the City of Blaine include:

CB	Downtown Pedestrian
HC	Highway Commercial
M	Manufacturing with Restaurant as accessories
M	Manufacturing with restaurant permitted
MC	Marine Commercial
PC	Planned Commercial
R	Rural
RH	Residential High Density
RM	Residential Medium Density
SDR	Single Duplex Residential
RL	Residential Low Density
R/O	Residential/Office
MPR	Marine Planned Recreation
RPR	Residential Planned Recreation

Whatcom County zoning classifications within the project area include:

UR4	Urban Residential 4DU/Ac
R5A	Rural 1DU/5Ac
R10A	Rural 1DU/10Ac

f. **What is the current Comprehensive Plan designation of the site?**

The site is generally within the City of Blaine's Urban Growth Boundary; please refer to that document for the final Comprehensive Plan designation.

g. If applicable, what is the current Shoreline Master Program designation of the site?

The landward shoreline designations for the portions of the project area within the City of Blaine along Semiahmoo Spit and Drayton Harbor are natural conservancy and urban. Shoreline designations in the Central Blaine area include urban, rural, conservancy, and a small natural area at the mouth of Dakota Creek.

Whatcom County designates the southern shoreline of Drayton Harbor within the project area as rural. The shorelines of California Creek are designated rural and the shorelines of Dakota Creek include areas designated both rural and conservancy.

h. Has any part of the site been classified as an "environmentally sensitive" area? If so, specify.

Approximately 10 percent of the land within the city limits and approximately 25 percent of the land within the Blaine planning area are impacted by wetlands. These land areas are classified according to the city wetland management ordinance, with Category 1 being the most important and Category 3 being the least valuable. Detailed maps and additional information about the wetlands and regulations are available from the Community and Economic Development Department.

Other critical areas and natural resource lands within the Blaine planning area include the aquifer recharge area east of the city limits that recharges the groundwater supply serving the entire Blaine/Birch Bay area. Potentially unstable slopes are along the eastern and southern shorelines of Drayton Harbor; flood hazard areas are along Dakota and California Creeks and portions of Semiahmoo Spit; and sand and gravel resource areas are located in the vicinity of H Street and Valley View Road.

i. Approximately how many people would reside or work in the completed project?

The types of facilities (substations, distribution and transmission lines) do not have people residing at them as part of the project. During operation of the proposed project enhancements some additional maintenance will be required, which will result in additional Division staff.

j. **Approximately how many people would the completed project displace?**

No one would be displaced by this project.

k. **Proposed measures to avoid or reduce displacement impacts, if any:**

None necessary.

l. **Proposed measures to ensure the proposal is compatible with existing and projected land uses and plans, if any:**

The Division's long-range plan will be integrated with other elements of the City of Blaine Comprehensive Plan to ensure that electric utilities will be adequate to serve future development and to ensure consistency with other elements of the Comprehensive Plan.

9. Housing

a. **Approximately how many units would be provided, if any? Indicate whether high, middle, or low-income housing.**

There are no plans for housing in this project.

b. **Approximately how many units, if any, would be eliminated? Indicate whether high, middle, or low income housing.**

None.

c. **Proposed measures to reduce or control housing impacts, if any:**

None necessary.

10. Aesthetics

a. **What is the tallest height of any proposed structure(s), not including antennas. What is the principal exterior building material(s) proposed?**

Typical structure heights above ground level will be as follows:

Overhead 115 kV transmission poles . . . . . 70 feet
Overhead 12.47 kV distribution poles . . . . . 34 feet
New substation . . . . . 40 feet

b. **What views in the immediate vicinity would be altered or obstructed?**

There would be little or no impact on views in the immediate vicinity.

c. **Proposed measures to reduce or control aesthetic impacts, if any:**

The height of the proposed overhead transmission and distribution would be consistent with electrical safety requirements but would be designed to minimize visual impacts.

11. **Light and Glare**

a. **What type of light or glare will the proposal produce? What time of day would it mainly occur?**

Exterior lighting is not a direct part of this project. Some additional street lighting and yard lighting may occur as an indirect result of this project. However, it is not anticipated that it would create an adverse impact to adjacent uses.

b. **Could light or glare from the finished project be a safety hazard or interfere with views?**

No.

c. **What existing off-site sources of light or glare may affect your proposal?**

None.

d. **Proposed measures to reduce or control light and glare impacts, if any:**

Not necessary.

12. **Recreation**

a. **What designated and informal recreational opportunities are in the immediate vicinity?**

The project area has a number of golf courses and recreational areas. There are golf courses at Semiahmoo, Loomis Trail, and Dakota Creek. Furthermore the Birch Bay/Birch Point/Semiahmoo area is a destination recreational area that depends heavily upon tourism. Other

parks include the Peace Arch Park, a county park at Semiahmoo, seven neighborhood parks, school district recreation fields, Lincoln Park, and a marine park.

b. **Would the proposed project displace any existing recreational uses? If so, describe.**

No.

c. **Proposed measures to reduce or control impacts to recreation, including recreation opportunities to be provided by the project or applicant, if any:**

None necessary.

13. **Historic and Cultural Preservation**

a. **Are there any places or objects listed on, or proposed for, national, state, or local preservation registers known to be on or next to the site? If so, generally describe.**

Our review to date has determined no known places or objects that would be affected by providing electric service to the various alternative areas. Much of the City of Blaine dates from the turn of the century and could qualify for registration. However, providing electric service to the general area should not interfere with registration.

b. **Generally describe any landmarks or evidence of historic, archaeological, scientific, or cultural importance known to be on or next to the site.**

The Semiahmoo Spit is an area of archaeological and cultural significance. This is an area that has been used by Native Americans over an extensive period of time. The proposed construction and maintenance of electric facilities should not conflict with this area. We know of no other landmarks or evidence or sites that would conflict with providing electric service to the area. If and when 115 kV transmission and substations are constructed, their specific routes and sites will be examined for any such impact.

c. **Proposed measures to reduce or control impacts, if any:**

None necessary.

14. Transportation

a. Identify public streets and highways serving the site, and describe proposed access to the existing street system. Show on site plans, if any.

The project area is bounded by, and can be accessed from, Mountain View Road, Kickerville Road, Lincoln Road, and Loomis Trail. Main access within the area is by Interstate 5.

b. Is site currently served by public transit? If not, what is the approximate distance to the nearest transit stop?

Whatcom Transit Authority plans for service to start in the fall of 1994. Greyhound bus and an airport service also provide some transportation to and from the area. There is also some taxi service within the area.

c. How many parking spaces would the completed project have? How many would the project eliminate?

No change is anticipated.

d. Will the proposal require any new roads or streets, or improvements to existing roads or streets, not including driveways? If so, generally describe (indicate whether public or private).

No.

e. Will the project use (or occur in the immediate vicinity of) water, rail, or air transportation? If so, generally describe.

There are no plans for regularly using rail, water, or air transportation.

f. How many vehicular trips per day would be generated by the completed project? If known, indicate when peak volumes would occur.

Traffic during operation would come from two sources: electric utility maintenance and meter reading.

Maintenance and associated construction trip volume should not significantly impact the area. Maintenance construction activity is scheduled so that crews are dispatched to perform work in one area and then moved to an adjacent area to minimize the amount of time spent on the road.

Providing electric service would require a visit by a meter reader once a month to all locations within the service territory. A meter reader reads all meters within a neighborhood before moving to another area. Those areas now served by Puget Power already have meter readers in the area every other month. Present Blaine policy is to provide a combined water and electric meter reading on a monthly basis.

g. **Proposed measures to reduce or control transportation impacts, if any:**

Because of the small volume of traffic associated with the project, it is not anticipated that project-generated traffic will require mitigation.

15. Public Services

a. **Would the project result in an increased need for public services (for example: fire protection, police protection, health care, schools, other)? If so, generally describe.**

It is anticipated that impacts on public services will be insignificant.

b. **Proposed measures to reduce or control direct impacts on public services, if any.**

No extraordinary fire protection, non-electric utilities, or police protection would be required. Impacts upon electric services are included with the rates for those services.

16. Utilities

a. **Circle utilities currently available at the site: <u>electricity</u>, <u>natural gas</u>, <u>water</u>, <u>refuse service</u>, <u>telephone</u>, <u>sanitary sewer</u>, <u>septic system</u>, other.**

Utilities underlined above are available at the project area or in the immediate vicinity.

b. **Describe the utilities that are proposed for the project, the utility providing the service, and the general construction activities on the site or in the immediate vicinity which might be needed.**

Electricity to the Growth Management Area of the City of Blaine will be provided by this proposed project. Electricity is purchased by the City of Blaine Electrical Division from the Bonneville Power Administration (BPA). Additional electricity, if needed, can be provided either by BPA or through participation in conservation and generation projects.

Appendix C

Operations Plan and Conservation Plan References

Appendix C

Operation Plan and Conservation Plan References

Operations Plan References

American Public Power Association (APPA). *Selected Financial and Operating Ratios of Public Power Systems: 1992.* March 1994.

Energy Information Administrator (EIA). *Financial Statistics of Major U.S. Publicly Owned Electric Utilities, 1992.* January 1994.

Conservation Plan References

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McElhinney & Associates. *Conservation Programs in the City of Blaine.*

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Northwest Conservation Act Report. Volume 13, Number 5. March 11, 1994.

Northwest Conservation Act Report. Volume 13, Number 6. March 25, 1994.

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Appendix D
Financial Forecasts

Scenario 1

Base Case
Medium Forecast and
No Annexation

Scenario 1 Base Case: Medium Forecast & No Annexation

Table Summary-1
Utility Financial Plan
City of Blaine Light Fund
Financial Plan Summary

24-Aug-94

	HISTORICAL OPERATING RESULTS						FORECAST						
	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
INCOME STATEMENT													
OPERATING REVENUES													
Sales Revenues	$1,844,844	$2,019,057	$2,080,541	$2,267,438	$2,541,362	$2,772,870	$3,037,143	$3,180,999	$3,207,473	$3,296,707	$3,392,340	$3,490,822	$3,606,841
Revenues from Post '94 Rate Increases	0	0	0	0	0	0	(0)	203,584	488,537	790,839	1,015,675	1,271,959	1,545,524
Total Sales Revenues	$1,844,844	$2,019,057	$2,080,541	$2,267,438	$2,541,362	$2,772,870	$3,037,143	$3,384,583	$3,696,010	$4,087,546	$4,408,015	$4,762,782	$5,152,365
Other Revenues	$74,680	$21,201	$29,154	$34,058	$37,314	$76,834	$40,000	$41,200	$42,436	$43,709	$45,020	$46,371	$47,762
Total Operating Revenues	$1,919,524	$2,040,258	$2,109,695	$2,301,496	$2,578,676	$2,849,704	$3,077,143	$3,425,783	$3,738,446	$4,131,255	$4,453,035	$4,809,152	$5,200,127
OPERATING EXPENSES													
Purchased Power	$1,182,846	$1,271,926	$1,261,773	$1,476,600	$1,489,690	$1,640,772	$1,807,908	$1,861,968	$2,057,590	$2,271,488	$2,410,653	$2,616,355	$2,843,540
Operations & Maintenance	131,034	186,892	171,683	313,919	482,628	566,920	587,841	608,667	628,193	651,408	675,674	700,848	727,697
Administration & General	180,744	163,469	220,249	253,310	317,727	512,315	531,220	550,041	567,686	588,665	610,594	633,344	657,606
Depreciation	73,362	79,537	83,300	153,114	125,925	160,500	139,806	200,756	235,293	287,774	342,121	386,927	435,000
Utility Taxes	69,808	70,031	77,085	85,663	95,932	103,916	119,178	132,681	144,790	160,004	172,466	186,258	201,401
Misc. Expenses		4,617	10	84,268	33,177	40,271	41,757	43,236	44,624	46,273	47,996	49,785	51,692
Total Operating Expenses	$1,637,794	$1,776,472	$1,814,100	$2,366,874	$2,545,079	$3,024,694	$3,227,710	$3,397,348	$3,678,176	$4,005,611	$4,259,505	$4,573,517	$4,916,936
Net Operating Revenues	$281,730	$263,786	$295,595	($65,378)	$33,597	($174,990)	($150,567)	$28,435	$60,270	$125,644	$193,530	$235,635	$283,191
NONOPERATING REVENUES (EXPENSES)													
Interest Expense	($9,144)	($7,080)	($7,080)	($7,080)	($8,935)	($7,080)	$0	($31,379)	($66,060)	($132,647)	($198,479)	($241,738)	($287,476)
Interest Income	56,950	91,751	65,803	45,077	72,888	27,078	4,544	4,016	5,854	5,732	5,710	5,841	6,350
Other Income	0	0	0	(2,364)	(35,383)	28,469	0	0	0	0	0	0	0
NET INCOME	$329,536	$348,457	$354,318	($29,745)	$62,167	($126,523)	($146,023)	$1,071	$64	($1,272)	$762	($261)	$2,065
KEY FINANCIAL STATISTICS													
NET PLANT													
Gross Plant	2,367,434	2,509,607	3,047,396	3,504,415	4,160,228	4,620,815	4,965,107	5,735,877	6,722,655	8,222,122	9,774,882	11,055,061	12,428,576
Accumulated Depreciation	(659,273)	(722,383)	(799,777)	(946,914)	(1,057,177)	(1,199,089)	(1,338,895)	(1,539,651)	(1,774,944)	(2,062,718)	(2,404,839)	(2,791,766)	(3,226,766)
Net Plant	1,708,161	1,787,224	2,247,619	2,557,501	3,103,051	3,421,726	3,626,212	4,196,227	4,947,712	6,159,404	7,370,043	8,263,295	9,201,810
FUND BALANCE													
Average Unrestricted Fund Balance						$192,764	$113,605	$100,400	$146,342	$143,288	$142,758	$146,028	$158,747
Ending Unrestricted Fund Balance						180,257	46,952	147,572	138,014	134,890	136,730	145,539	161,345
45 Days of Operating Expenses (Less Purchased Power and Deprec.)						150,833	157,808	164,543	170,790	178,317	185,761	193,591	201,994
RATE INCREASES													
Annual Percent Rate Increases							0.0%	6.4%	8.3%	7.6%	4.8%	5.0%	4.7%
Average Revenues per kWh (Nominal)							$0.049	$0.054	$0.058	$0.063	$0.066	$0.069	$0.072
Average Revenues per kWh (1994 $)							$0.049	$0.052	$0.055	$0.057	$0.058	$0.059	$0.060
LONG-TERM DEBT													
Non-Contributed CIP Expenditures							$127,088	$502,497	$685,513	$1,134,786	$1,169,794	$910,649	$979,901
Net Bond Proceeds							0	420,000	475,000	915,000	930,000	655,000	710,000
Projected Bond Coverage							NA	5.32	3.23	2.22	1.89	1.77	1.69
Debt-Equity Ratio (Long-term Debt/(Long-term Debt + Retained Earnings and Contributed Capital)						0.00%	0.00%	9.12%	16.58%	27.15%	34.26%	37.39%	40.04%

Scenario 1 Base Case: Medium Forecast & No Annexation

Table Summary 1-A
Utility Financial Plan
Financial Plan Assumptions

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
ASSUMPTIONS & INPUTS													
Annual Capital Improvement Additions	$0	$0	$0	$0	$0	$58,990	$344,292	$770,771	$986,778	$1,499,467	$1,552,760	$1,280,179	$1,373,515
Purchased Power (MWh)	--	52,337	52,415	58,676	61,010	64,034	64,624	66,027	66,577	68,429	70,414	72,458	74,866
Average Losses	--	7.1%	2.3%	3.8%	4.2%	6.2%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
MWh Sales	45,594	48,639	51,216	56,446	58,440	60,058	61,716	63,056	63,581	65,350	67,245	69,198	71,497
Percent Change in Sales from Previous Year		6.68%	5.30%	10.21%	3.53%	2.77%	2.76%	2.17%	0.83%	2.78%	2.90%	2.90%	3.32%
Average System Power Cost ($)	$1,182,846	$1,271,926	$1,261,773	$1,476,600	$1,489,690	$1,640,772	$1,807,908	$1,861,968	$2,057,590	$2,271,488	$2,410,653	$2,616,355	$2,843,540
Average System Power Cost ($/MWh)	--	24.3	24.1	25.2	24.4	25.6	28.2	28.2	30.9	33.2	34.2	36.1	38.0
Average System Sales Rate ($/MWh)	40.5	41.5	40.6	40.2	43.5	46.2	49.2	53.7	58.1	62.5	65.6	68.8	72.1
Average Sales Rate Excluding Rate Increases	40.5	41.5	40.6	40.2	43.5	46.2	49.2	50.4	50.4	50.4	50.4	50.4	50.4
Annual % Change in BPA PF Rate	--	--	--	--	--	--	--	0.0%	9.6%	7.4%	3.1%	5.5%	5.2%
Average Losses	4.5%												
Inflationary Growth in O&M, A&G, and Other Ex	3.0%												
Utility Taxes as % of Gross Revenues	3.873%												
Annual Depreciation on Utility Plant	3.5%												
Rate on Interest Earnings	4.0%												

Scenario 1 Base Case: Medium Forecast & No Annexation

Table FF-1
Utility Financial Plan
City of Blaine Light Fund
Sources and Uses of Funds

Description	1994	1995	1996	1997	1998	1999	2000
Sources of Funds							
Beginning Fund Balance							
Unrestricted	$180,257	$46,952	$147,572	$138,014	$134,890	$136,730	$145,539
Restricted for Debt Service	0	0	48,276	102,874	208,046	314,943	390,230
Operating Revenues	3,037,143	3,384,583	3,696,010	4,087,546	4,408,015	4,762,782	5,152,365
Other Revenues	40,000	41,200	42,436	43,709	45,020	46,371	47,762
Interest Earnings	4,544	4,016	5,854	5,732	5,710	5,841	6,350
Issuance of Revenue Bonds (Net)	0	420,000	475,000	915,000	930,000	655,000	710,000
Bond Proceeds for Debt Reserve	0	42,000	47,500	91,500	93,000	65,500	71,000
Grants	0	0	0	0	0	0	0
Customer Contributions	147,203	154,974	166,001	177,825	190,504	204,101	218,685
Other Capital Contributions	70,000	113,300	135,265	186,856	192,462	165,428	174,929
Total	$3,479,147	$4,207,024	$4,763,913	$5,749,055	$6,207,647	$6,356,696	$6,916,860
Uses of Funds							
Purchased Power	$1,807,908	$1,861,968	$2,057,590	$2,271,488	$2,410,653	$2,616,355	$2,843,540
Operations & Maintenance	587,841	608,667	628,193	651,408	675,674	700,848	727,697
Administration & General	531,220	550,041	567,686	588,665	610,594	633,344	657,606
Utility Taxes	119,178	132,681	144,790	160,004	172,466	186,258	201,401
Misc. Expenses	41,757	43,236	44,624	46,273	47,996	49,785	51,692
Capital Improvements	344,292	770,771	986,778	1,499,467	1,552,760	1,280,179	1,373,515
Debt Service	0	43,813	93,364	188,815	285,830	354,159	428,224
Ending Fund Balance							
Unrestricted	46,952	147,572	138,014	134,890	136,730	145,539	161,345
Restricted for Debt Service	0	48,276	102,874	208,046	314,943	390,230	471,839
Total	$3,479,147	$4,207,024	$4,763,913	$5,749,055	$6,207,647	$6,356,696	$6,916,860

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Scenario 1 Base Case: Medium Forecast & No Annexation

Table CIP-1
Utility Financial Plan
City of Blaine Light Fund
Capital Improvements Program

Description	1994	1995	1996	1997	1998	1999	2000
CIP in 1994$							
Renewal and Replacement	$175,000	$175,000	$175,000	$175,000	$175,000	$175,000	$175,000
Customer Line Extension							
Residential	49,373	51,102	52,890	54,741	56,657	58,640	60,693
Others	119,918	122,219	127,243	132,483	137,950	143,653	149,605
Major Projects							
Feeders	0	150,000	0	185,000	185,000	452,000	765,000
Substation	0	250,000	575,000	825,000	825,000	0	0
Submarine Cable	0	0	0	0	0	275,000	0
Annexation							
H Street	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0
Unused	0	0	0	0	0	0	0
Total (1994$)	$344,292	$748,321	$930,133	$1,372,224	$1,379,607	$1,104,293	$1,150,297
Expected Inflation Rate	0.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Inflation Factor	1.000	1.030	1.061	1.093	1.126	1.159	1.194
Total CIP (Nominal $)	$344,292	$770,771	$986,778	$1,499,467	$1,552,760	$1,280,179	$1,373,515
Customer Contributions (Nominal $)							
Residential	$27,285	$29,088	$31,009	$33,057	$35,240	$37,568	$40,049
Other	119,918	125,886	134,992	144,768	155,264	166,533	178,636
Total	$147,203	$154,974	$166,001	$177,825	$190,504	$204,101	$218,685

Table CIP-2
Utility Financial Plan
City of Blaine Light Fund
Funding Sources for Improvements

Description	1994	1995	1996	1997	1998	1999	2000
Expenditures from Fund Balance	$127,088	$82,497	$210,513	$219,786	$239,794	$255,649	$269,901
Issuance of Revenue Bonds (Net)	0	420,000	475,000	915,000	930,000	655,000	710,000
Grants	0	0	0	0	0	0	0
Customer Contributions	147,203	154,974	166,001	177,825	190,504	204,101	218,685
Other Capital Contributions	70,000	113,300	135,265	186,856	192,462	165,428	174,929
Total	$344,292	$770,771	$986,778	$1,499,467	$1,552,760	$1,280,179	$1,373,515

Scenario 1 Base Case: Medium Forecast & No Annexation

Table CIP-3
Utility Financial Plan
City of Blaine Light Fund
Estimated Revenue Bond Debt Issue Size and Costs

Description	1994	1995	1996	1997	1998	1999	2000
Issue Sizing							
Bond Proceeds Required	$0	$420,000	$475,000	$915,000	$930,000	$655,000	$710,000
Issuance Costs	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Reserve Requirement	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Issue Size	$0	$482,759	$545,977	$1,051,724	$1,068,966	$752,874	$816,092
Debt Service Requirements							
Term (Years)	20	20	20	20	20	20	20
Interest Rate	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
New Annual Debt Service Costs	$0	$43,813	$49,551	$95,451	$97,015	$68,328	$74,066
Accumulated Debt Service	$0	$43,813	$93,364	$188,815	$285,830	$354,159	$428,224
Debt Service Components							
Amortization of Principal - Series 1994	$0	$0	$0	$0	$0	$0	$0
Amortization of Principal - Series 1995		12,434	13,242	14,103	15,020	15,996	17,036
Amortization of Principal - Series 1996			14,062	14,976	15,950	16,987	18,091
Amortization of Principal - Series 1997				27,089	28,849	30,725	32,722
Amortization of Principal - Series 1998					27,533	29,322	31,228
Amortization of Principal - Series 1999						19,391	20,652
Amortization of Principal - Series 2000							21,020
Amortization of Principal - Series 2001							
Amortization of Principal - Series 2002							
Amortization of Principal - Series 2003							
Amortization of Principal - Series 2004							
Amortization of Principal - Series 2005							
Total	$0	$12,434	$27,305	$56,168	$87,352	$112,421	$140,748
Interest	$0	$31,379	$66,060	$132,647	$198,479	$241,738	$287,476
Outstanding Debt	$0	$482,759	$1,016,302	$2,040,721	$3,053,518	$3,719,040	$4,422,711
Weighted Interest Rate on Debt	0.00%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%

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Scenario 1 Base Case: Medium Forecast & No Annexation

Table CIP-4
Utility Financial Plan
City of Blaine Light Fund
Projection of Bond Coverage

Description	1994	1995	1996	1997	1998	1999	2000
Annual Debt Service	$0	$43,813	$93,364	$188,815	$285,830	$354,159	$428,224
Net Revenues							
Gross Revenues							
Operating Revenues	$3,077,143	$3,425,783	$3,738,446	$4,131,255	$4,453,035	$4,809,152	$5,200,127
Interest Income	4,544	4,016	5,854	5,732	5,710	5,841	6,350
Total Gross Revenues	$3,081,687	$3,429,799	$3,744,299	$4,136,987	$4,458,745	$4,814,994	$5,206,477
Less: Operating Expenses (Excluding Depr.)	(3,087,904)	(3,196,592)	(3,442,883)	(3,717,837)	(3,917,384)	(4,186,590)	(4,481,936)
Net Revenues	($6,217)	$233,206	$301,416	$419,149	$541,361	$628,404	$724,541
Bond Coverage							
Minimum Target	1.40	1.40	1.40	1.40	1.40	1.40	1.40
Actual	NA	5.32	3.23	2.22	1.89	1.77	1.69
Additional Revenues Required	$0	$0	$0	$0	$0	$0	$0

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Table LF-4
Utility Financial Plan
City of Blaine Light Fund
Blaine Forecast of Customers per Residential Customer

Customer Class	1993	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Unused	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial (50 KVA or Less)	4.20	4.17	4.13	4.10	4.07	4.03	4.00	3.97
Commercial (Over 50 KVA)	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
Industrial	142.37	142.37	142.37	142.37	142.37	142.37	142.37	142.37
Senior/Disabled	14.34	14.34	14.34	14.34	14.34	14.34	14.34	14.34
Public Street Lighting	1,388.13	1,388.13	1,388.13	1,388.13	1,388.13	1,388.13	1,388.13	1,388.13
Public Authorities	27.72	27.72	27.72	27.72	27.72	27.72	27.72	27.72
Other (City)	51.41	51.41	51.41	51.41	51.41	51.41	51.41	51.41

Table LF-5
Utility Financial Plan
City of Blaine Light Fund
Blaine Forecast Number of Customers in Existing Service Area

Customer Class	1993	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	1,388	1,437	1,487	1,539	1,593	1,649	1,706	1,766
Unused	0	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	334	345	360	375	392	409	427	445
Commercial (Over 50 KVA)	79	85	87	91	94	97	100	104
Industrial	10	10	10	11	11	12	12	12
Senior/Disabled	97	100	104	107	111	115	119	123
Public Street Lighting	1	1	1	1	1	1	1	1
Public Authorities	50	52	54	56	57	59	62	64
Other (City)	27	28	29	30	31	32	33	34
Total	1,986	2,057	2,132	2,210	2,290	2,374	2,460	2,550
Growth Rate		3.59%	3.64%	3.64%	3.64%	3.65%	3.65%	3.65%

Scenario 1 Base Case: Medium Forecast & No Annexation

Table LF-6
Utility Financial Plan
City of Blaine Light Fund
Forecast Sales in Existing Service Area

Customer Class	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	19,973,134	20,584,461	21,124,849	21,688,999	22,275,005	22,827,685	23,278,735
Unused	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	8,407,508	8,979,167	9,481,606	10,011,410	10,570,072	11,159,168	11,780,365
Commercial (Over 50 KVA)	17,430,665	18,134,076	18,422,149	18,740,063	19,086,455	19,460,289	19,860,791
Industrial	4,412,399	4,814,018	5,151,865	5,083,814	5,041,410	5,020,217	5,351,397
Senior/Disabled	1,392,694	1,435,320	1,473,001	1,512,338	1,553,199	1,591,737	1,623,188
Public Street Lighting	407,790	422,063	436,835	452,124	467,948	484,327	501,278
Public Authorities	6,952,403	7,285,681	7,518,625	7,712,547	7,920,378	8,134,399	8,386,530
Other (City)	4,439,444	4,801,230	4,971,877	5,148,362	5,330,906	5,519,735	5,715,078
Total	63,416,038	66,456,016	68,580,808	70,349,658	72,245,375	74,197,555	76,497,363
Less: Conservation	(1,700,000)	(3,400,000)	(5,000,000)	(5,000,000)	(5,000,000)	(5,000,000)	(5,000,000)
Total W/Conservation	61,716,038	63,056,016	63,580,808	65,349,658	67,245,375	69,197,555	71,497,363
Percent Change		2.17%	0.83%	2.78%	2.90%	2.90%	3.32%

Scenario 1 Base Case: Medium Forecast & No Annexation

Table LF-7
Utility Financial Plan
City of Blaine Light Fund
Blaine Forecast Number of Customers in Annexed Service Area

Customer Class	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	0	0	0	0	0	0	0
Unused	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	0	0	0	0	0	0	0
Commercial (Over 50 KVA)	0	0	0	0	0	0	0
Industrial	0	0	0	0	0	0	0
Senior/Disabled	0	0	0	0	0	0	0
Public Street Lighting	0	0	0	0	0	0	0
Public Authorities	0	0	0	0	0	0	0
Other (City)	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0
Percent Change		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

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Scenario 1 Base Case: Medium Forecast & No Annexation

Table LF-8
Utility Financial Plan
City of Blaine Light Fund
Forecast of Sales in Annexation Area

Customer Class	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	0	0	0	0	0	0	0
Unused	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	0	0	0	0	0	0	0
Commercial (Over 50 KVA)	0	0	0	0	0	0	0
Industrial	0	0	0	0	0	0	0
Senior/Disabled	0	0	0	0	0	0	0
Public Street Lighting	0	0	0	0	0	0	0
Public Authorities	0	0	0	0	0	0	0
Other (City)	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0
Less: Conservation	0	0	0	0	0	0	0
Total W/Conservation	0	0	0	0	0	0	0
Percent Change		NA	NA	NA	NA	NA	NA

Scenario 1 Base Case: Medium Forecast & No Annexation

Table LF-9
Utility Financial Plan
City of Blaine Light Fund
Blaine Forecast Number of Total Customers
(Existing and Annexed Service Area)

Customer Class	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	1,437	1,487	1,539	1,593	1,649	1,706	1,766
Unused	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	345	360	375	392	409	427	445
Commercial (Over 50 KVA)	85	87	91	94	97	100	104
Industrial	10	10	11	11	12	12	12
Senior/Disabled	100	104	107	111	115	119	123
Public Street Lighting	1	1	1	1	1	1	1
Public Authorities	52	54	56	57	59	62	64
Other (City)	28	29	30	31	32	33	34
Total	2,057	2,132	2,210	2,290	2,374	2,460	2,550
Percent Change		3.64%	3.64%	3.64%	3.65%	3.65%	3.65%

Scenario 1 Base Case: Medium Forecast & No Annexation

Table LF-10
Utility Financial Plan
City of Blaine Light Fund
Forecast of Use by Customer Class (KWh)
(Blaine Total Customer Forecast Times BPA Consumption per Customer)

Customer Class	1993	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	17,395,870	19,973,134	20,584,461	21,124,849	21,688,999	22,275,005	22,827,685	23,278,735
Unused	0	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	8,088,142	8,407,508	8,979,167	9,481,606	10,011,410	10,570,072	11,159,168	11,780,365
Commercial (Over 50 KVA)	20,632,442	17,430,665	18,134,076	18,422,149	18,740,063	19,086,455	19,460,289	19,860,791
Industrial	3,331,920	4,412,399	4,814,018	5,151,865	5,083,814	5,041,410	5,020,217	5,351,397
Senior/Disabled	1,114,340	1,392,694	1,435,320	1,473,001	1,512,338	1,553,199	1,591,737	1,623,188
Public Street Lighting	394,080	407,790	422,063	436,835	452,124	467,948	484,327	501,278
Public Authorities	6,584,250	6,952,403	7,285,681	7,518,625	7,712,547	7,920,378	8,134,399	8,386,530
Other (City)	2,516,900	4,439,444	4,801,230	4,971,877	5,148,362	5,330,906	5,519,735	5,715,078
Total	60,057,944	63,416,038	66,456,016	68,580,808	70,349,658	72,245,375	74,197,555	76,497,363
Less: Conservation	0	(1,700,000)	(3,400,000)	(5,000,000)	(5,000,000)	(5,000,000)	(5,000,000)	(5,000,000)
Total W/Conservation	60,057,944	61,716,038	63,056,016	63,580,808	65,349,658	67,245,375	69,197,555	71,497,363
Growth		2.76%	2.17%	0.83%	2.78%	2.90%	2.90%	3.32%

Scenario 1 Base Case: Medium Forecast & No Annexation

Table O&M-1
Utility Financial Plan
City of Blaine Light Fund
Forecast of O&M Cost Growth Rate

Description	1994	1995	1996	1997	1998	1999	2000
Additional Sales (kWh)							
Existing Service Area	1,658,094	1,339,978	524,793	1,768,850	1,895,716	1,952,181	2,299,808
Proposed Annexation Area	0	0	0	0	0	0	0
Total	1,658,094	1,339,978	524,793	1,768,850	1,895,716	1,952,181	2,299,808
Percent Increase in Sales							
Existing Service Area	2.76%	2.17%	0.83%	2.78%	2.90%	2.90%	3.32%
Proposed Annexation Area	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	2.76%	2.17%	0.83%	2.78%	2.90%	2.90%	3.32%

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Scenario 1 Base Case: Medium Forecast & No Annexation

Table O&M-2
Utility Financial Plan
City of Blaine Light Fund
Percentage Increase in O&M Costs

Description	1994	1995	1996	1997	1998	1999	2000
Percent of Growth Toward Cost Increase							
Existing Service Area	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Proposed Annexation Area	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Weighted Average Growth Rates in kWh							
Existing Service Area	0.69%	0.54%	0.21%	0.70%	0.73%	0.73%	0.83%
Proposed Annexation Area	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	0.69%	0.54%	0.21%	0.70%	0.73%	0.73%	0.83%
Non-Growth Related Increases	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Total Growth Rate	3.69%	3.54%	3.21%	3.70%	3.73%	3.73%	3.83%

Scenario 1 Base Case: Medium Forecast & No Annexation

Table O&M-3
Utility Financial Plan
City of Blaine Light Fund
Percentage Increase in A&G Costs

Description	1994	1995	1996	1997	1998	1999	2000
Percent of Growth Toward Cost Increase							
Existing Service Area	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Proposed Annexation Area	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
Weighted Average Growth Rates							
Existing Service Area	0.69%	0.54%	0.21%	0.70%	0.73%	0.73%	0.83%
Proposed Annexation Area	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	0.69%	0.54%	0.21%	0.70%	0.73%	0.73%	0.83%
Non-Growth Related Increases	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Total Growth Rate	3.69%	3.54%	3.21%	3.70%	3.73%	3.73%	3.83%

Scenario 2

Low Forecast and No Annexation

Scenario 2: Low Forecast & No Annexation

Table Summary-1
Utility Financial Plan
City of Blaine Light Fund
Financial Plan Summary

23-Aug-94

	HISTORICAL OPERATING RESULTS						FORECAST						
	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
INCOME STATEMENT													
OPERATING REVENUES													
Sales Revenues	$1,844,844	$2,019,057	$2,080,541	$2,267,438	$2,541,362	$2,772,870	$2,992,119	$3,084,724	$3,059,414	$3,095,596	$3,135,984	$3,177,107	$3,232,162
Revenues from Post '94 Rate Increases	0	0	0	0	0	0	0	231,354	518,877	821,903	1,042,963	1,293,729	1,552,660
Total Sales Revenues	$1,844,844	$2,019,057	$2,080,541	$2,267,438	$2,541,362	$2,772,870	$2,992,119	$3,316,078	$3,578,291	$3,917,499	$4,178,947	$4,470,837	$4,784,821
Other Revenues	$74,680	$21,201	$29,154	$34,058	$37,314	$76,834	$40,000	$41,200	$42,436	$43,709	$45,020	$46,371	$47,762
Total Operating Revenues	$1,919,524	$2,040,258	$2,109,695	$2,301,496	$2,578,676	$2,849,704	$3,032,119	$3,357,278	$3,620,727	$3,961,208	$4,223,967	$4,517,208	$4,832,583
OPERATING EXPENSES													
Purchased Power	$1,182,846	$1,271,926	$1,261,773	$1,476,600	$1,489,690	$1,640,772	$1,807,908	$1,805,500	$1,962,487	$2,132,784	$2,228,341	$2,381,077	$2,547,991
Operations & Maintenance	131,034	186,892	171,683	313,919	482,628	566,920	585,672	604,077	620,960	641,425	662,760	684,815	708,326
Administration & General	180,744	163,469	220,249	253,310	317,727	512,315	529,260	545,893	561,150	579,644	598,924	618,855	640,101
Depreciation	73,362	79,537	83,300	153,114	125,925	160,500	139,806	195,935	227,721	277,200	328,270	369,504	413,683
Utility Taxes	69,808	70,031	77,085	85,663	95,932	103,916	117,434	130,027	140,231	153,418	163,594	174,951	187,166
Misc. Expenses		4,617	10	84,268	33,177	40,271	41,603	42,910	44,110	45,563	47,079	48,646	50,316
Total Operating Expenses	$1,637,794	$1,776,472	$1,814,100	$2,366,874	$2,545,079	$3,024,694	$3,221,683	$3,324,342	$3,556,658	$3,830,034	$4,028,968	$4,277,847	$4,547,584
Net Operating Revenues	$281,730	$263,786	$295,595	($65,378)	$33,597	($174,990)	($189,564)	$32,936	$64,068	$131,175	$194,999	$239,360	$285,000
NONOPERATING REVENUES (EXPENSES)													
Interest Expense	($9,144)	($7,080)	($7,080)	($7,080)	($8,935)	($7,080)	$0	($33,621)	($68,617)	($135,133)	($201,263)	($244,431)	($290,447)
Interest Income	56,950	91,751	65,803	45,077	72,888	27,078	3,942	3,538	6,268	6,408	6,517	6,637	7,028
Other Income	0	0	0	(2,364)	(35,383)	28,469	0	0	0	0	0	0	0
NET INCOME	$329,536	$348,457	$354,318	($29,745)	$62,167	($126,523)	($185,623)	$2,853	$1,720	$2,450	$254	$1,566	$1,580
KEY FINANCIAL STATISTICS													
NET PLANT													
Gross Plant	2,367,434	2,509,607	3,047,396	3,504,415	4,160,228	4,620,815	4,899,297	5,598,129	6,506,321	7,919,995	9,379,149	10,557,255	11,819,522
Accumulated Depreciation	(659,273)	(722,383)	(799,777)	(946,914)	(1,057,177)	(1,199,089)	(1,338,895)	(1,534,830)	(1,762,551)	(2,039,751)	(2,368,021)	(2,737,525)	(3,151,208)
Net Plant	1,708,161	1,787,224	2,247,619	2,557,501	3,103,051	3,421,726	3,560,402	4,063,299	4,743,770	5,880,244	7,011,128	7,819,730	8,668,314
FUND BALANCE													
Average Unrestricted Fund Balance						$192,764	$98,538	$88,446	$156,699	$160,205	$162,930	$165,918	$175,689
Ending Unrestricted Fund Balance						180,257	16,819	153,349	152,877	153,860	158,029	164,019	176,674
45 Days of Operating Expenses (Less Purchased Power and Deprec.)						150,833	157,065	163,098	168,466	175,075	181,523	188,293	195,523
RATE INCREASES													
Annual Percent Rate Increases							0.0%	7.5%	8.8%	8.2%	5.3%	5.6%	5.2%
Average Revenues per kWh (Nominal)							$0.049	$0.054	$0.059	$0.064	$0.067	$0.071	$0.075
Average Revenues per kWh (1994 $)							$0.049	$0.053	$0.056	$0.058	$0.060	$0.061	$0.063
LONG-TERM DEBT													
Non-Contributed CIP Expenditures							$117,622	$492,210	$674,342	$1,122,662	$1,156,643	$896,392	$964,453
Net Bond Proceeds							0	450,000	480,000	915,000	935,000	655,000	715,000
Projected Bond Coverage							NA	4.95	3.07	2.16	1.83	1.72	1.63
Debt-Equity Ratio (Long-term Debt/(Long-term Debt + Retained Earnings and Contributed Capital)						0.00%	0.00%	10.00%	17.75%	28.63%	36.08%	39.46%	42.40%

Scenario 2: Low Forecast & No Annexation

Table Summary 1-A
Utility Financial Plan
Financial Plan Assumptions

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
ASSUMPTIONS & INPUTS													
Annual Capital Improvement Additions	$0	$0	$0	$0	$0	$58,990	$278,482	$698,832	$908,192	$1,413,674	$1,459,154	$1,178,106	$1,262,268
Purchased Power (MWh)	--	52,337	52,415	58,676	61,010	64,034	63,662	64,025	63,500	64,250	65,089	65,942	67,085
Average Losses	--	7.1%	2.3%	3.8%	4.2%	6.2%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
MWh Sales	45,594	48,639	51,216	56,446	58,440	60,058	60,797	61,144	60,642	61,359	62,160	62,975	64,066
Percent Change in Sales from Previous Year		6.68%	5.30%	10.21%	3.53%	2.77%	1.23%	0.57%	-0.82%	1.18%	1.30%	1.31%	1.73%
Average System Power Cost ($)	$1,182,846	$1,271,926	$1,261,773	$1,476,600	$1,489,690	$1,640,772	$1,807,908	$1,805,500	$1,962,487	$2,132,784	$2,228,341	$2,381,077	$2,547,991
Average System Power Cost ($/MWh)	--	24.3	24.1	25.2	24.4	25.6	28.2	28.2	30.9	33.2	34.2	36.1	38.0
Average System Sales Rate ($/MWh)	40.5	41.5	40.6	40.2	43.5	46.2	49.2	54.2	59.0	63.8	67.2	71.0	74.7
Average Sales Rate Excluding Rate Increases	40.5	41.5	40.6	40.2	43.5	46.2	49.2	50.5	50.5	50.5	50.5	50.5	50.5
Annual % Change in BPA PF Rate	--	--	--	--	--	--	--	0.0%	9.6%	7.4%	3.1%	5.5%	5.2%
Average Losses	4.5%												
Inflationary Growth in O&M, A&G, and Other Ex	3.0%												
Utility Taxes as % of Gross Revenues	3.873%												
Annual Depreciation on Utility Plant	3.5%												
Rate on Interest Earnings	4.0%												

Scenario 2: Low Forecast & No Annexation

Table FF-1
Utility Financial Plan
City of Blaine Light Fund
Sources and Uses of Funds

Description	1994	1995	1996	1997	1998	1999	2000
Sources of Funds							
Beginning Fund Balance							
Unrestricted	$180,257	$16,819	$153,349	$152,877	$153,860	$158,029	$164,019
Restricted for Debt Service	0	0	51,724	106,897	212,069	319,540	394,828
Operating Revenues	2,992,119	3,316,078	3,578,291	3,917,499	4,178,947	4,470,837	4,784,821
Other Revenues	40,000	41,200	42,436	43,709	45,020	46,371	47,762
Interest Earnings	3,942	3,538	6,268	6,408	6,517	6,637	7,028
Issuance of Revenue Bonds (Net)	0	450,000	480,000	915,000	935,000	655,000	715,000
Bond Proceeds for Debt Reserve	0	45,000	48,000	91,500	93,500	65,500	71,500
Grants	0	0	0	0	0	0	0
Customer Contributions	90,860	93,321	98,586	104,156	110,049	116,286	122,886
Other Capital Contributions	70,000	113,300	135,265	186,856	192,462	165,428	174,929
Total	$3,377,177	$4,079,256	$4,593,919	$5,524,902	$5,927,424	$6,003,628	$6,482,772
Uses of Funds							
Purchased Power	$1,807,908	$1,805,500	$1,962,487	$2,132,784	$2,228,341	$2,381,077	$2,547,991
Operations & Maintenance	585,672	604,077	620,960	641,425	662,760	684,815	708,326
Administration & General	529,260	545,893	561,150	579,644	598,924	618,855	640,101
Utility Taxes	117,434	130,027	140,231	153,418	163,594	174,951	187,166
Misc. Expenses	41,603	42,910	44,110	45,563	47,079	48,646	50,316
Capital Improvements	278,482	698,832	908,192	1,413,674	1,459,154	1,178,106	1,262,268
Debt Service	0	46,943	97,015	192,466	290,003	358,331	432,918
Ending Fund Balance							
Unrestricted	16,819	153,349	152,877	153,860	158,029	164,019	176,674
Restricted for Debt Service	0	51,724	106,897	212,069	319,540	394,828	477,011
Total	$3,377,177	$4,079,256	$4,593,919	$5,524,902	$5,927,424	$6,003,628	$6,482,772

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Scenario 2: Low Forecast & No Annexation

Table CIP-2
Utility Financial Plan
City of Blaine Light Fund
Funding Sources for Improvements

Description	1994	1995	1996	1997	1998	1999	2000
Expenditures from Fund Balance	$117,622	$42,210	$194,342	$207,662	$221,643	$241,392	$249,453
Issuance of Revenue Bonds (Net)	0	450,000	480,000	915,000	935,000	655,000	715,000
Grants	0	0	0	0	0	0	0
Customer Contributions	90,860	93,321	98,586	104,156	110,049	116,286	122,886
Other Capital Contributions	70,000	113,300	135,265	186,856	192,462	165,428	174,929
Total	$278,482	$698,832	$908,192	$1,413,674	$1,459,154	$1,178,106	$1,262,268

Scenario 2: Low Forecast & No Annexation

Table CIP-3
Utility Financial Plan
City of Blaine Light Fund
Estimated Revenue Bond Debt Issue Size and Costs

Description	1994	1995	1996	1997	1998	1999	2000
Issue Sizing							
Bond Proceeds Required	$0	$450,000	$480,000	$915,000	$935,000	$655,000	$715,000
Issuance Costs	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Reserve Requirement	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Issue Size	$0	$517,241	$551,724	$1,051,724	$1,074,713	$752,874	$821,839
Debt Service Requirements							
Term (Years)	20	20	20	20	20	20	20
Interest Rate	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
New Annual Debt Service Costs	$0	$46,943	$50,072	$95,451	$97,537	$68,328	$74,587
Accumulated Debt Service	$0	$46,943	$97,015	$192,466	$290,003	$358,331	$432,918
Debt Service Components							
Amortization of Principal - Series 1994	$0	$0	$0	$0	$0	$0	$0
Amortization of Principal - Series 1995		13,322	14,188	15,110	16,093	17,139	18,253
Amortization of Principal - Series 1996			14,210	15,134	16,118	17,165	18,281
Amortization of Principal - Series 1997				27,089	28,849	30,725	32,722
Amortization of Principal - Series 1998					27,681	29,480	31,396
Amortization of Principal - Series 1999						19,391	20,652
Amortization of Principal - Series 2000							21,168
Amortization of Principal - Series 2001							
Amortization of Principal - Series 2002							
Amortization of Principal - Series 2003							
Amortization of Principal - Series 2004							
Amortization of Principal - Series 2005							
Total	$0	$13,322	$28,399	$57,333	$88,741	$113,900	$142,471
Interest	$0	$33,621	$68,617	$135,133	$201,263	$244,431	$290,447
Outstanding Debt	$0	$517,241	$1,055,643	$2,078,969	$3,096,348	$3,760,481	$4,468,420
Weighted Interest Rate on Debt	0.00%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%

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Scenario 2: Low Forecast & No Annexation

Table CIP-4
Utility Financial Plan
City of Blaine Light Fund
Projection of Bond Coverage

Description	1994	1995	1996	1997	1998	1999	2000
Annual Debt Service	$0	$46,943	$97,015	$192,466	$290,003	$358,331	$432,918
Net Revenues							
Gross Revenues							
Operating Revenues	$3,032,119	$3,357,278	$3,620,727	$3,961,208	$4,223,967	$4,517,208	$4,832,583
Interest Income	3,942	3,538	6,268	6,408	6,517	6,637	7,028
Total Gross Revenues	$3,036,061	$3,360,816	$3,626,995	$3,967,617	$4,230,484	$4,523,844	$4,839,611
Less: Operating Expenses (Excluding Depr.)	(3,081,877)	(3,128,408)	(3,328,937)	(3,552,834)	(3,700,698)	(3,908,344)	(4,133,900)
Net Revenues	($45,817)	$232,408	$298,058	$414,783	$529,786	$615,501	$705,710
Bond Coverage							
Minimum Target	1.40	1.40	1.40	1.40	1.40	1.40	1.40
Actual	NA	4.95	3.07	2.16	1.83	1.72	1.63
Additional Revenues Required	$0	$0	$0	$0	$0	$0	$0

Table LF-4
Utility Financial Plan
City of Blaine Light Fund
Blaine Forecast of Customers per Residential Customer

Customer Class	1993	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Unused	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial (50 KVA or Less)	4.20	4.17	4.13	4.10	4.07	4.03	4.00	3.97
Commercial (Over 50 KVA)	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
Industrial	142.37	142.37	142.37	142.37	142.37	142.37	142.37	142.37
Senior/Disabled	14.34	14.34	14.34	14.34	14.34	14.34	14.34	14.34
Public Street Lighting	1,388.13	1,388.13	1,388.13	1,388.13	1,388.13	1,388.13	1,388.13	1,388.13
Public Authorities	27.72	27.72	27.72	27.72	27.72	27.72	27.72	27.72
Other (City)	51.41	51.41	51.41	51.41	51.41	51.41	51.41	51.41

Table LF-5
Utility Financial Plan
City of Blaine Light Fund
Blaine Forecast Number of Customers in Existing Service Area

Customer Class	1993	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	1,388	1,416	1,444	1,473	1,503	1,533	1,563	1,595
Unused	0	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	334	340	349	359	369	380	391	402
Commercial (Over 50 KVA)	79	83	85	87	88	90	92	94
Industrial	10	10	10	10	11	11	11	11
Senior/Disabled	97	99	101	103	105	107	109	111
Public Street Lighting	1	1	1	1	1	1	1	1
Public Authorities	50	51	52	53	54	55	56	58
Other (City)	27	28	28	29	29	30	30	31
Total	1,986	2,027	2,071	2,115	2,160	2,207	2,254	2,302
Growth Rate		2.09%	2.14%	2.14%	2.14%	2.14%	2.15%	2.15%

Scenario 2: Low Forecast & No Annexation

Table LF-6
Utility Financial Plan
City of Blaine Light Fund
Forecast Sales in Existing Service Area

Customer Class	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	19,683,668	19,992,133	20,219,624	20,458,736	20,706,988	20,913,215	21,017,359
Unused	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	8,285,660	8,720,787	9,075,308	9,443,534	9,826,006	10,223,292	10,635,980
Commercial (Over 50 KVA)	17,178,047	17,612,259	17,632,739	17,677,072	17,742,891	17,828,229	17,931,445
Industrial	4,348,451	4,675,493	4,931,102	4,795,445	4,686,527	4,599,191	4,831,544
Senior/Disabled	1,372,510	1,394,018	1,409,881	1,426,554	1,443,864	1,458,244	1,465,506
Public Street Lighting	401,880	409,918	418,116	426,478	435,008	443,708	452,582
Public Authorities	6,851,644	7,076,032	7,196,443	7,275,069	7,362,834	7,452,198	7,571,834
Other (City)	4,375,105	4,663,073	4,758,826	4,856,332	4,955,645	5,056,816	5,159,896
Total	62,496,965	64,543,713	65,642,040	66,359,221	67,159,763	67,974,892	69,066,146
Less: Conservation	(1,700,000)	(3,400,000)	(5,000,000)	(5,000,000)	(5,000,000)	(5,000,000)	(5,000,000)
Total W/Conservation	60,796,965	61,143,713	60,642,040	61,359,221	62,159,763	62,974,892	64,066,146
Percent Change		0.57%	-0.82%	1.18%	1.30%	1.31%	1.73%

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Scenario 2: Low Forecast & No Annexation

Table LF-7
Utility Financial Plan
City of Blaine Light Fund
Blaine Forecast Number of Customers in Annexed Service Area

Customer Class	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	0	0	0	0	0	0	0
Unused	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	0	0	0	0	0	0	0
Commercial (Over 50 KVA)	0	0	0	0	0	0	0
Industrial	0	0	0	0	0	0	0
Senior/Disabled	0	0	0	0	0	0	0
Public Street Lighting	0	0	0	0	0	0	0
Public Authorities	0	0	0	0	0	0	0
Other (City)	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0
Percent Change		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Table LF-8
Utility Financial Plan
City of Blaine Light Fund
Forecast of Sales in Annexation Area

Customer Class	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	0	0	0	0	0	0	0
Unused	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	0	0	0	0	0	0	0
Commercial (Over 50 KVA)	0	0	0	0	0	0	0
Industrial	0	0	0	0	0	0	0
Senior/Disabled	0	0	0	0	0	0	0
Public Street Lighting	0	0	0	0	0	0	0
Public Authorities	0	0	0	0	0	0	0
Other (City)	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0
Less: Conservation	0	0	0	0	0	0	0
Total W/Conservation	0	0	0	0	0	0	0
Percent Change		NA	NA	NA	NA	NA	NA

Table LF-9
Utility Financial Plan
City of Blaine Light Fund
Blaine Forecast Number of Total Customers
(Existing and Annexed Service Area)

Customer Class	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	1,416	1,444	1,473	1,503	1,533	1,563	1,595
Unused	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	340	349	359	369	380	391	402
Commercial (Over 50 KVA)	83	85	87	88	90	92	94
Industrial	10	10	10	11	11	11	11
Senior/Disabled	99	101	103	105	107	109	111
Public Street Lighting	1	1	1	1	1	1	1
Public Authorities	51	52	53	54	55	56	58
Other (City)	28	28	29	29	30	30	31
Total	2,027	2,071	2,115	2,160	2,207	2,254	2,302
Percent Change		2.14%	2.14%	2.14%	2.14%	2.15%	2.15%

Table LF-10
Utility Financial Plan
City of Blaine Light Fund
Forecast of Use by Customer Class (KWh)
(Blaine Total Customer Forecast Times BPA Consumption per Customer)

Customer Class	1993	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	17,395,870	19,683,668	19,992,133	20,219,624	20,458,736	20,706,988	20,913,215	21,017,359
Unused	0	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	8,088,142	8,285,660	8,720,787	9,075,308	9,443,534	9,826,006	10,223,292	10,635,980
Commercial (Over 50 KVA)	20,632,442	17,178,047	17,612,259	17,632,739	17,677,072	17,742,891	17,828,229	17,931,445
Industrial	3,331,920	4,348,451	4,675,493	4,931,102	4,795,445	4,686,527	4,599,191	4,831,544
Senior/Disabled	1,114,340	1,372,510	1,394,018	1,409,881	1,426,554	1,443,864	1,458,244	1,465,506
Public Street Lighting	394,080	401,880	409,918	418,116	426,478	435,008	443,708	452,582
Public Authorities	6,584,250	6,851,644	7,076,032	7,196,443	7,275,069	7,362,834	7,452,198	7,571,834
Other (City)	2,516,900	4,375,105	4,663,073	4,758,826	4,856,332	4,955,645	5,056,816	5,159,896
Total	60,057,944	62,496,965	64,543,713	65,642,040	66,359,221	67,159,763	67,974,892	69,066,146
Less: Conservation	0	(1,700,000)	(3,400,000)	(5,000,000)	(5,000,000)	(5,000,000)	(5,000,000)	(5,000,000)
Total W/Conservation	60,057,944	60,796,965	61,143,713	60,642,040	61,359,221	62,159,763	62,974,892	64,066,146
Growth		1.23%	0.57%	-0.82%	1.18%	1.30%	1.31%	1.73%

Scenario 2: Low Forecast & No Annexation

Table O&M-1
Utility Financial Plan
City of Blaine Light Fund
Forecast of O&M Cost Growth Rate

Description	1994	1995	1996	1997	1998	1999	2000
Additional Sales (kWh)							
Existing Service Area	739,021	346,748	(501,673)	717,181	800,542	815,129	1,091,253
Proposed Annexation Area	0	0	0	0	0	0	0
Total	739,021	346,748	(501,673)	717,181	800,542	815,129	1,091,253
Percent Increase in Sales							
Existing Service Area	1.23%	0.57%	-0.82%	1.18%	1.30%	1.31%	1.73%
Proposed Annexation Area	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	1.23%	0.57%	-0.82%	1.18%	1.30%	1.31%	1.73%

Scenario 2: Low Forecast & No Annexation

Table O&M-2
Utility Financial Plan
City of Blaine Light Fund
Percentage Increase in O&M Costs

Description	1994	1995	1996	1997	1998	1999	2000
Percent of Growth Toward Cost Increase							
Existing Service Area	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Proposed Annexation Area	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Weighted Average Growth Rates in kWh							
Existing Service Area	0.31%	0.14%	-0.21%	0.30%	0.33%	0.33%	0.43%
Proposed Annexation Area	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	0.31%	0.14%	-0.21%	0.30%	0.33%	0.33%	0.43%
Non-Growth Related Increases	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Total Growth Rate	3.31%	3.14%	2.79%	3.30%	3.33%	3.33%	3.43%

Scenario 2: Low Forecast & No Annexation

Table O&M-3
Utility Financial Plan
City of Blaine Light Fund
Percentage Increase in A&G Costs

Description	1994	1995	1996	1997	1998	1999	2000
Percent of Growth Toward Cost Increase							
Existing Service Area	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Proposed Annexation Area	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
Weighted Average Growth Rates							
Existing Service Area	0.31%	0.14%	-0.21%	0.30%	0.33%	0.33%	0.43%
Proposed Annexation Area	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	0.31%	0.14%	-0.21%	0.30%	0.33%	0.33%	0.43%
Non-Growth Related Increases	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Total Growth Rate	3.31%	3.14%	2.79%	3.30%	3.33%	3.33%	3.43%

Scenario 3

High Forecast and No Annexation

Scenario 3: High Forecast & No Annexation

Table Summary-1
Utility Financial Plan
City of Blaine Light Fund
Financial Plan Summary

24-Aug-94

	HISTORICAL OPERATING RESULTS						FORECAST						
	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
INCOME STATEMENT													
OPERATING REVENUES													
Sales Revenues	$1,844,844	$2,019,057	$2,080,541	$2,267,438	$2,541,362	$2,772,870	$3,082,166	$3,278,676	$3,359,879	$3,506,742	$3,663,981	$3,828,093	$4,015,533
Revenues from Post '94 Rate Increases	0	0	0	0	0	0	0	177,048	457,656	760,553	981,918	1,249,183	1,534,035
Total Sales Revenues	$1,844,844	$2,019,057	$2,080,541	$2,267,438	$2,541,362	$2,772,870	$3,082,166	$3,455,724	$3,817,535	$4,267,295	$4,645,899	$5,077,276	$5,549,568
Other Revenues	$74,680	$21,201	$29,154	$34,058	$37,314	$76,834	$40,000	$41,200	$42,436	$43,709	$45,020	$46,371	$47,762
Total Operating Revenues	$1,919,524	$2,040,258	$2,109,695	$2,301,496	$2,578,676	$2,849,704	$3,122,166	$3,496,924	$3,859,971	$4,311,005	$4,690,920	$5,123,647	$5,597,331
OPERATING EXPENSES													
Purchased Power	$1,182,846	$1,271,926	$1,261,773	$1,476,600	$1,489,690	$1,640,772	$1,807,908	$1,919,261	$2,155,491	$2,416,355	$2,603,846	$2,869,315	$3,165,937
Operations & Maintenance	131,034	186,892	171,683	313,919	482,628	566,920	590,009	613,270	635,465	661,474	688,733	717,107	747,398
Administration & General	180,744	163,469	220,249	253,310	317,727	512,315	533,180	554,201	574,258	597,761	622,395	648,036	675,410
Depreciation	73,362	79,537	83,300	153,114	125,925	160,500	139,806	205,648	243,092	298,830	356,821	405,701	458,323
Utility Taxes	69,808	70,031	77,085	85,663	95,932	103,916	120,922	135,436	149,497	166,965	181,679	198,439	216,785
Misc. Expenses		4,617	10	84,268	33,177	40,271	41,911	43,563	45,140	46,988	48,924	50,939	53,091
Total Operating Expenses	$1,637,794	$1,776,472	$1,814,100	$2,366,874	$2,545,079	$3,024,694	$3,233,737	$3,471,379	$3,802,943	$4,188,372	$4,502,398	$4,889,537	$5,316,944
Net Operating Revenues	$281,730	$263,786	$295,595	($65,378)	$33,597	($174,990)	($111,570)	$25,545	$57,028	$122,632	$188,522	$234,109	$280,386
NONOPERATING REVENUES (EXPENSES)													
Interest Expense	($9,144)	($7,080)	($7,080)	($7,080)	($8,935)	($7,080)	$0	($28,764)	($63,512)	($129,797)	($195,715)	($238,692)	($284,164)
Interest Income	56,950	91,751	65,803	45,077	72,888	27,078	5,147	4,431	5,419	5,084	4,903	4,998	5,544
Other Income	0	0	0	(2,364)	(35,383)	28,469	0	0	0	0	0	0	0
NET INCOME	$329,536	$348,457	$354,318	($29,745)	$62,167	($126,523)	($106,423)	$1,212	($1,065)	($2,081)	($2,291)	$416	$1,766
KEY FINANCIAL STATISTICS													
NET PLANT													
Gross Plant	2,367,434	2,509,607	3,047,396	3,504,415	4,160,228	4,620,815	5,030,916	5,875,666	6,945,472	8,537,988	10,194,886	11,591,468	13,094,946
Accumulated Depreciation	(659,273)	(722,383)	(799,777)	(946,914)	(1,057,177)	(1,199,089)	(1,338,895)	(1,544,543)	(1,787,635)	(2,086,464)	(2,443,285)	(2,848,987)	(3,307,310)
Net Plant	1,708,161	1,787,224	2,247,619	2,557,501	3,103,051	3,421,726	3,692,021	4,331,122	5,157,838	6,451,524	7,751,601	8,742,481	9,787,636
FUND BALANCE													
Average Unrestricted Fund Balance						$192,764	$128,671	$110,778	$135,472	$127,110	$122,570	$124,961	$138,596
Ending Unrestricted Fund Balance						180,257	77,085	138,719	125,128	115,494	115,751	124,459	142,198
45 Days of Operating Expenses (Less Purchased Power and Deprec.)						150,833	158,551	166,003	173,140	181,626	190,076	199,051	208,687
RATE INCREASES													
Annual Percent Rate Increases							0.0%	5.4%	7.8%	7.1%	4.2%	4.6%	4.2%
Average Revenues per kWh (Nominal)							$0.049	$0.053	$0.057	$0.061	$0.064	$0.067	$0.070
Average Revenues per kWh (1994 $)							$0.049	$0.052	$0.054	$0.056	$0.057	$0.058	$0.058
LONG-TERM DEBT													
Non-Contributed CIP Expenditures							$136,554	$513,076	$697,318	$1,147,941	$1,184,434	$926,924	$997,972
Net Bond Proceeds							0	385,000	475,000	910,000	930,000	650,000	705,000
Projected Bond Coverage							NA	5.87	3.41	2.31	1.95	1.85	1.76
Debt-Equity Ratio (Long-term Debt/(Long-term Debt + Retained Earnings and Contributed Capital)						0.00%	0.00%	8.18%	15.46%	25.66%	32.50%	35.32%	37.68%

Scenario 3: High Forecast & No Annexation

Table Summary 1-A
Utility Financial Plan
Financial Plan Assumptions

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
ASSUMPTIONS & INPUTS													
Annual Capital Improvement Additions	$0	$0	$0	$0	$0	$58,990	$410,101	$844,749	$1,069,807	$1,592,516	$1,656,898	$1,396,582	$1,503,478
Purchased Power (MWh)	--	52,337	52,415	58,676	61,010	64,034	65,587	68,059	69,745	72,793	76,057	79,464	83,355
Average Losses	--	7.1%	2.3%	3.8%	4.2%	6.2%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
MWh Sales	45,594	48,639	51,216	56,446	58,440	60,058	62,635	64,996	66,606	69,517	72,635	75,888	79,604
Percent Change in Sales from Previous Year		6.68%	5.30%	10.21%	3.53%	2.77%	4.29%	3.77%	2.48%	4.37%	4.48%	4.48%	4.90%
Average System Power Cost ($)	$1,182,846	$1,271,926	$1,261,773	$1,476,600	$1,489,690	$1,640,772	$1,807,908	$1,919,261	$2,155,491	$2,416,355	$2,603,846	$2,869,315	$3,165,937
Average System Power Cost ($/MWh)	--	24.3	24.1	25.2	24.4	25.6	28.2	28.2	30.9	33.2	34.2	36.1	38.0
Average System Sales Rate ($/MWh)	40.5	41.5	40.6	40.2	43.5	46.2	49.2	53.2	57.3	61.4	64.0	66.9	69.7
Average Sales Rate Excluding Rate Increases	40.5	41.5	40.6	40.2	43.5	46.2	49.2	50.4	50.4	50.4	50.4	50.4	50.4
Annual % Change in BPA PF Rate	--	--	--	--	--	--	--	0.0%	9.6%	7.4%	3.1%	5.5%	5.2%
Average Losses	4.5%												
Inflationary Growth in O&M, A&G, and Other Ex	3.0%												
Utility Taxes as % of Gross Revenues	3.873%												
Annual Depreciation on Utility Plant	3.5%												
Rate on Interest Earnings	4.0%												

Scenario 3: High Forecast & No Annexation

Table FF-1
Utility Financial Plan
City of Blaine Light Fund
Sources and Uses of Funds

Description	1994	1995	1996	1997	1998	1999	2000
Sources of Funds							
Beginning Fund Balance							
Unrestricted	$180,257	$77,085	$138,719	$125,128	$115,494	$115,751	$124,459
Restricted for Debt Service	0	0	44,253	98,851	203,448	310,345	385,057
Operating Revenues	3,082,166	3,455,724	3,817,535	4,267,295	4,645,899	5,077,276	5,549,568
Other Revenues	40,000	41,200	42,436	43,709	45,020	46,371	47,762
Interest Earnings	5,147	4,431	5,419	5,084	4,903	4,998	5,544
Issuance of Revenue Bonds (Net)	0	385,000	475,000	910,000	930,000	650,000	705,000
Bond Proceeds for Debt Reserve	0	38,500	47,500	91,000	93,000	65,000	70,500
Grants	0	0	0	0	0	0	0
Customer Contributions	203,547	218,373	237,224	257,719	280,001	304,230	330,577
Other Capital Contributions	70,000	113,300	135,265	186,856	192,462	165,428	174,929
Total	$3,581,117	$4,333,614	$4,943,350	$5,985,643	$6,510,228	$6,739,399	$7,393,397
Uses of Funds							
Purchased Power	$1,807,908	$1,919,261	$2,155,491	$2,416,355	$2,603,846	$2,869,315	$3,165,937
Operations & Maintenance	590,009	613,270	635,465	661,474	688,733	717,107	747,398
Administration & General	533,180	554,201	574,258	597,761	622,395	648,036	675,410
Utility Taxes	120,922	135,436	149,497	166,965	181,679	198,439	216,785
Misc. Expenses	41,911	43,563	45,140	46,988	48,924	50,939	53,091
Capital Improvements	410,101	844,749	1,069,807	1,592,516	1,656,898	1,396,582	1,503,478
Debt Service	0	40,162	89,713	184,642	281,658	349,464	423,008
Ending Fund Balance							
Unrestricted	77,085	138,719	125,128	115,494	115,751	124,459	142,198
Restricted for Debt Service	0	44,253	98,851	203,448	310,345	385,057	466,092
Total	$3,581,117	$4,333,614	$4,943,350	$5,985,643	$6,510,228	$6,739,399	$7,393,397

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Scenario 3: High Forecast & No Annexation

Table CIP-1
Utility Financial Plan
City of Blaine Light Fund
Capital Improvements Program

Description	1994	1995	1996	1997	1998	1999	2000
CIP in 1994$							
Renewal and Replacement	$175,000	$175,000	$175,000	$175,000	$175,000	$175,000	$175,000
Customer Line Extension							
Residential	70,534	74,060	77,763	81,651	85,734	90,021	94,522
Others	164,568	171,085	180,632	190,726	201,398	212,683	224,618
Major Projects							
Feeders	0	150,000	0	185,000	185,000	452,000	765,000
Substation	0	250,000	575,000	825,000	825,000	0	0
Submarine Cable	0	0	0	0	0	275,000	0
Annexation							
H Street	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0
Unused	0	0	0	0	0	0	0
Total (1994$)	$410,101	$820,145	$1,008,395	$1,457,377	$1,472,132	$1,204,704	$1,259,139
Expected Inflation Rate	0.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Inflation Factor	1.000	1.030	1.061	1.093	1.126	1.159	1.194
Total CIP (Nominal $)	$410,101	$844,749	$1,069,807	$1,592,516	$1,656,898	$1,396,582	$1,503,478
Customer Contributions (Nominal $)							
Residential	$38,979	$42,156	$45,592	$49,307	$53,326	$57,672	$62,372
Other	164,568	176,217	191,633	208,412	226,676	246,558	268,205
Total	$203,547	$218,373	$237,224	$257,719	$280,001	$304,230	$330,577

Table CIP-2
Utility Financial Plan
City of Blaine Light Fund
Funding Sources for Improvements

Description	1994	1995	1996	1997	1998	1999	2000
Expenditures from Fund Balance	$136,554	$128,076	$222,318	$237,941	$254,434	$276,924	$292,972
Issuance of Revenue Bonds (Net)	0	385,000	475,000	910,000	930,000	650,000	705,000
Grants	0	0	0	0	0	0	0
Customer Contributions	203,547	218,373	237,224	257,719	280,001	304,230	330,577
Other Capital Contributions	70,000	113,300	135,265	186,856	192,462	165,428	174,929
Total	$410,101	$844,749	$1,069,807	$1,592,516	$1,656,898	$1,396,582	$1,503,478

Scenario 3: High Forecast & No Annexation

Table CIP-3
Utility Financial Plan
City of Blaine Light Fund
Estimated Revenue Bond Debt Issue Size and Costs

Description	1994	1995	1996	1997	1998	1999	2000
Issue Sizing							
Bond Proceeds Required	$0	$385,000	$475,000	$910,000	$930,000	$650,000	$705,000
Issuance Costs	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Reserve Requirement	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Issue Size	$0	$442,529	$545,977	$1,045,977	$1,068,966	$747,126	$810,345
Debt Service Requirements							
Term (Years)	20	20	20	20	20	20	20
Interest Rate	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
New Annual Debt Service Costs	$0	$40,162	$49,551	$94,929	$97,015	$67,807	$73,544
Accumulated Debt Service	$0	$40,162	$89,713	$184,642	$281,658	$349,464	$423,008
Debt Service Components							
Amortization of Principal - Series 1994	$0	$0	$0	$0	$0	$0	$0
Amortization of Principal - Series 1995		11,398	12,139	12,928	13,768	14,663	15,616
Amortization of Principal - Series 1996			14,062	14,976	15,950	16,987	18,091
Amortization of Principal - Series 1997				26,941	28,692	30,557	32,543
Amortization of Principal - Series 1998					27,533	29,322	31,228
Amortization of Principal - Series 1999						19,243	20,494
Amortization of Principal - Series 2000							20,872
Amortization of Principal - Series 2001							
Amortization of Principal - Series 2002							
Amortization of Principal - Series 2003							
Amortization of Principal - Series 2004							
Amortization of Principal - Series 2005							
Total	$0	$11,398	$26,201	$54,845	$85,943	$110,772	$138,844
Interest	$0	$28,764	$63,512	$129,797	$195,715	$238,692	$284,164
Outstanding Debt	$0	$442,529	$977,108	$1,996,884	$3,011,004	$3,672,188	$4,371,761
Weighted Interest Rate on Debt	0.00%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%

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Scenario 3: High Forecast & No Annexation

Table CIP-4
Utility Financial Plan
City of Blaine Light Fund
Projection of Bond Coverage

Description	1994	1995	1996	1997	1998	1999	2000
Annual Debt Service	$0	$40,162	$89,713	$184,642	$281,658	$349,464	$423,008
Net Revenues							
Gross Revenues							
Operating Revenues	$3,122,166	$3,496,924	$3,859,971	$4,311,005	$4,690,920	$5,123,647	$5,597,331
Interest Income	5,147	4,431	5,419	5,084	4,903	4,998	5,544
Total Gross Revenues	$3,127,313	$3,501,355	$3,865,390	$4,316,089	$4,695,823	$5,128,645	$5,602,874
Less: Operating Expenses (Excluding Depr.)	(3,093,931)	(3,265,731)	(3,559,852)	(3,889,543)	(4,145,577)	(4,483,836)	(4,858,621)
Net Revenues	$33,383	$235,625	$305,538	$426,546	$550,246	$644,809	$744,253
Bond Coverage							
Minimum Target	1.40	1.40	1.40	1.40	1.40	1.40	1.40
Actual	NA	5.87	3.41	2.31	1.95	1.85	1.76
Additional Revenues Required	$0	$0	$0	$0	$0	$0	$0

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Table LF-4
Utility Financial Plan
City of Blaine Light Fund
Blaine Forecast of Customers per Residential Customer

Customer Class	1993	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Unused	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial (50 KVA or Less)	4.20	4.17	4.13	4.10	4.07	4.03	4.00	3.97
Commercial (Over 50 KVA)	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
Industrial	142.37	142.37	142.37	142.37	142.37	142.37	142.37	142.37
Senior/Disabled	14.34	14.34	14.34	14.34	14.34	14.34	14.34	14.34
Public Street Lighting	1,388.13	1,388.13	1,388.13	1,388.13	1,388.13	1,388.13	1,388.13	1,388.13
Public Authorities	27.72	27.72	27.72	27.72	27.72	27.72	27.72	27.72
Other (City)	51.41	51.41	51.41	51.41	51.41	51.41	51.41	51.41

Scenario 3: High Forecast & No Annexation

Table LF-5
Utility Financial Plan
City of Blaine Light Fund
Blaine Forecast Number of Customers in Existing Service Area

Customer Class	1993	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	1,388	1,458	1,530	1,607	1,687	1,772	1,860	1,953
Unused	0	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	334	350	370	392	415	439	465	492
Commercial (Over 50 KVA)	79	86	90	95	99	104	109	115
Industrial	10	10	11	11	12	12	13	14
Senior/Disabled	97	102	107	112	118	124	130	136
Public Street Lighting	1	1	1	1	1	1	1	1
Public Authorities	50	53	55	58	61	64	67	70
Other (City)	27	28	30	31	33	34	36	38
Total	1,986	2,087	2,194	2,307	2,426	2,551	2,682	2,820
Growth Rate		5.10%	5.14%	5.14%	5.15%	5.15%	5.15%	5.15%

Scenario 3: High Forecast & No Annexation

Table LF-6
Utility Financial Plan
City of Blaine Light Fund
Forecast Sales in Existing Service Area

Customer Class	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	20,262,599	21,185,435	22,056,697	22,973,931	23,936,606	24,886,027	25,745,541
Unused	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	8,529,356	9,241,318	9,899,854	10,604,521	11,358,544	12,165,375	13,028,709
Commercial (Over 50 KVA)	17,683,284	18,663,510	19,234,777	19,850,290	20,510,206	21,214,997	21,965,404
Industrial	4,476,347	4,954,566	5,379,122	5,384,997	5,417,473	5,472,884	5,918,475
Senior/Disabled	1,412,878	1,477,225	1,537,977	1,601,934	1,669,060	1,735,262	1,795,194
Public Street Lighting	413,700	434,385	456,104	478,909	502,855	527,998	554,398
Public Authorities	7,053,163	7,498,390	7,850,283	8,169,465	8,511,197	8,867,866	9,275,236
Other (City)	4,503,784	4,941,405	5,191,193	5,453,369	5,728,564	6,017,442	6,320,695
Total	64,335,111	68,396,235	71,606,006	74,517,416	77,634,506	80,887,850	84,603,652
Less: Conservation	(1,700,000)	(3,400,000)	(5,000,000)	(5,000,000)	(5,000,000)	(5,000,000)	(5,000,000)
Total W/Conservation	62,635,111	64,996,235	66,606,006	69,517,416	72,634,506	75,887,850	79,603,652
Percent Change		3.77%	2.48%	4.37%	4.48%	4.48%	4.90%

Scenario 3: High Forecast & No Annexation

Table LF-7
Utility Financial Plan
City of Blaine Light Fund
Blaine Forecast Number of Customers in Annexed Service Area

Customer Class	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	0	0	0	0	0	0	0
Unused	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	0	0	0	0	0	0	0
Commercial (Over 50 KVA)	0	0	0	0	0	0	0
Industrial	0	0	0	0	0	0	0
Senior/Disabled	0	0	0	0	0	0	0
Public Street Lighting	0	0	0	0	0	0	0
Public Authorities	0	0	0	0	0	0	0
Other (City)	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0
Percent Change		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Scenario 3: High Forecast & No Annexation

Table LF-8
Utility Financial Plan
City of Blaine Light Fund
Forecast of Sales in Annexation Area

Customer Class	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	0	0	0	0	0	0	0
Unused	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	0	0	0	0	0	0	0
Commercial (Over 50 KVA)	0	0	0	0	0	0	0
Industrial	0	0	0	0	0	0	0
Senior/Disabled	0	0	0	0	0	0	0
Public Street Lighting	0	0	0	0	0	0	0
Public Authorities	0	0	0	0	0	0	0
Other (City)	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0
Less: Conservation	0	0	0	0	0	0	0
Total W/Conservation	0	0	0	0	0	0	0
Percent Change		NA	NA	NA	NA	NA	NA

Scenario 3: High Forecast & No Annexation

Table LF-9
Utility Financial Plan
City of Blaine Light Fund
Blaine Forecast Number of Total Customers
(Existing and Annexed Service Area)

Customer Class	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	1,458	1,530	1,607	1,687	1,772	1,860	1,953
Unused	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	350	370	392	415	439	465	492
Commercial (Over 50 KVA)	86	90	95	99	104	109	115
Industrial	10	11	11	12	12	13	14
Senior/Disabled	102	107	112	118	124	130	136
Public Street Lighting	1	1	1	1	1	1	1
Public Authorities	53	55	58	61	64	67	70
Other (City)	28	30	31	33	34	36	38
Total	2,087	2,194	2,307	2,426	2,551	2,682	2,820
Percent Change		5.14%	5.14%	5.15%	5.15%	5.15%	5.15%

Scenario 3: High Forecast & No Annexation

Table LF-10
Utility Financial Plan
City of Blaine Light Fund
Forecast of Use by Customer Class (KWh)
(Blaine Total Customer Forecast Times BPA Consumption per Customer)

Customer Class	1993	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	17,395,870	20,262,599	21,185,435	22,056,697	22,973,931	23,936,606	24,886,027	25,745,541
Unused	0	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	8,088,142	8,529,356	9,241,318	9,899,854	10,604,521	11,358,544	12,165,375	13,028,709
Commercial (Over 50 KVA)	20,632,442	17,683,284	18,663,510	19,234,777	19,850,290	20,510,206	21,214,997	21,965,404
Industrial	3,331,920	4,476,347	4,954,566	5,379,122	5,384,997	5,417,473	5,472,884	5,918,475
Senior/Disabled	1,114,340	1,412,878	1,477,225	1,537,977	1,601,934	1,669,060	1,735,262	1,795,194
Public Street Lighting	394,080	413,700	434,385	456,104	478,909	502,855	527,998	554,398
Public Authorities	6,584,250	7,053,163	7,498,390	7,850,283	8,169,465	8,511,197	8,867,866	9,275,236
Other (City)	2,516,900	4,503,784	4,941,405	5,191,193	5,453,369	5,728,564	6,017,442	6,320,695
Total	60,057,944	64,335,111	68,396,235	71,606,006	74,517,416	77,634,506	80,887,850	84,603,652
Less: Conservation	0	(1,700,000)	(3,400,000)	(5,000,000)	(5,000,000)	(5,000,000)	(5,000,000)	(5,000,000)
Total W/Conservation	60,057,944	62,635,111	64,996,235	66,606,006	69,517,416	72,634,506	75,887,850	79,603,652
Growth		4.29%	3.77%	2.48%	4.37%	4.48%	4.48%	4.90%

Scenario 3: High Forecast & No Annexation

Table O&M-1
Utility Financial Plan
City of Blaine Light Fund
Forecast of O&M Cost Growth Rate

Description	1994	1995	1996	1997	1998	1999	2000
Additional Sales (kWh)							
Existing Service Area	2,577,167	2,361,125	1,609,770	2,911,411	3,117,090	3,253,344	3,715,802
Proposed Annexation Area	0	0	0	0	0	0	0
Total	2,577,167	2,361,125	1,609,770	2,911,411	3,117,090	3,253,344	3,715,802
Percent Increase in Sales							
Existing Service Area	4.29%	3.77%	2.48%	4.37%	4.48%	4.48%	4.90%
Proposed Annexation Area	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	4.29%	3.77%	2.48%	4.37%	4.48%	4.48%	4.90%

Scenario 3: High Forecast & No Annexation

Table O&M-2
Utility Financial Plan
City of Blaine Light Fund
Percentage Increase in O&M Costs

Description	1994	1995	1996	1997	1998	1999	2000
Percent of Growth Toward Cost Increase							
Existing Service Area	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Proposed Annexation Area	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Weighted Average Growth Rates in kWh							
Existing Service Area	1.07%	0.94%	0.62%	1.09%	1.12%	1.12%	1.22%
Proposed Annexation Area	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	1.07%	0.94%	0.62%	1.09%	1.12%	1.12%	1.22%
Non-Growth Related Increases	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Total Growth Rate	4.07%	3.94%	3.62%	4.09%	4.12%	4.12%	4.22%

Scenario 3: High Forecast & No Annexation

Table O&M-3
Utility Financial Plan
City of Blaine Light Fund
Percentage Increase in A&G Costs

Description	1994	1995	1996	1997	1998	1999	2000
Percent of Growth Toward Cost Increase							
Existing Service Area	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Proposed Annexation Area	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
Weighted Average Growth Rates							
Existing Service Area	1.07%	0.94%	0.62%	1.09%	1.12%	1.12%	1.22%
Proposed Annexation Area	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	1.07%	0.94%	0.62%	1.09%	1.12%	1.12%	1.22%
Non-Growth Related Increases	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Total Growth Rate	4.07%	3.94%	3.62%	4.09%	4.12%	4.12%	4.22%

Scenario 4

Medium Forecast and Annexation

Scenario 4: Medium Forecast & Annexation

Table Summary-1
Utility Financial Plan
City of Blaine Light Fund
Financial Plan Summary

24-Aug-94

	HISTORICAL OPERATING RESULTS						FORECAST						
	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
INCOME STATEMENT													
OPERATING REVENUES													
Sales Revenues	$1,844,844	$2,019,057	$2,080,541	$2,267,438	$2,541,362	$2,772,870	$3,037,143	$3,180,999	$4,269,225	$4,371,604	$4,479,531	$4,589,604	$4,715,116
Revenues from Post '94 Rate Increases	0	0	0	0	0	0	(0)	206,765	1,264,139	1,606,087	1,841,747	2,133,114	2,440,085
Total Sales Revenues	$1,844,844	$2,019,057	$2,080,541	$2,267,438	$2,541,362	$2,772,870	$3,037,143	$3,387,764	$5,533,364	$5,977,691	$6,321,278	$6,722,718	$7,155,200
Other Revenues	$74,680	$21,201	$29,154	$34,058	$37,314	$76,834	$40,000	$41,200	$42,436	$43,709	$45,020	$46,371	$47,762
Total Operating Revenues	$1,919,524	$2,040,258	$2,109,695	$2,301,496	$2,578,676	$2,849,704	$3,077,143	$3,428,964	$5,575,800	$6,021,400	$6,366,298	$6,769,089	$7,202,963
OPERATING EXPENSES													
Purchased Power	$1,182,846	$1,271,926	$1,261,773	$1,476,600	$1,489,690	$1,640,772	$1,807,908	$1,861,968	$2,738,703	$3,012,111	$3,183,229	$3,439,887	$3,717,275
Operations & Maintenance	131,034	186,892	171,683	313,919	482,628	566,920	587,841	608,667	831,353	861,278	892,432	924,688	958,750
Administration & General	180,744	163,469	220,249	253,310	317,727	512,315	531,220	550,041	622,764	645,276	668,708	692,964	718,562
Depreciation	73,362	79,537	83,300	153,114	125,925	160,500	139,806	200,756	502,653	555,928	611,121	656,829	705,863
Utility Taxes	69,808	70,031	77,085	85,663	95,932	103,916	119,178	132,804	215,951	233,209	246,567	262,167	278,971
Misc. Expenses		4,617	10	84,268	33,177	40,271	41,757	43,236	59,055	61,181	63,394	65,685	68,105
Total Operating Expenses	$1,637,794	$1,776,472	$1,814,100	$2,366,874	$2,545,079	$3,024,694	$3,227,710	$3,397,471	$4,970,480	$5,368,983	$5,665,451	$6,042,218	$6,447,525
Net Operating Revenues	$281,730	$263,786	$295,595	($65,378)	$33,597	($174,990)	($150,567)	$31,492	$605,320	$652,417	$700,848	$726,870	$755,437
NONOPERATING REVENUES (EXPENSES)													
Interest Expense	($9,144)	($7,080)	($7,080)	($7,080)	($8,935)	($7,080)	$0	($31,006)	($606,615)	($655,918)	($705,142)	($731,630)	($761,104)
Interest Income	56,950	91,751	65,803	45,077	72,888	27,078	4,544	3,987	8,850	7,277	6,996	6,823	6,935
Other Income	0	0	0	(2,364)	(35,383)	28,469	0	0	0	0	0	0	0
NET INCOME	$329,536	$348,457	$354,318	($29,745)	$62,167	($126,523)	($146,023)	$4,474	$7,555	$3,776	$2,701	$2,063	$1,269
KEY FINANCIAL STATISTICS													
NET PLANT													
Gross Plant	2,367,434	2,509,607	3,047,396	3,504,415	4,160,228	4,620,815	4,965,107	5,735,877	14,361,526	15,883,664	17,460,593	18,766,538	20,167,521
Accumulated Depreciation	(659,273)	(722,383)	(799,777)	(946,914)	(1,057,177)	(1,199,089)	(1,338,895)	(1,539,651)	(2,042,304)	(2,598,232)	(3,209,353)	(3,866,182)	(4,572,045)
Net Plant	1,708,161	1,787,224	2,247,619	2,557,501	3,103,051	3,421,726	3,626,212	4,196,227	12,319,222	13,285,432	14,251,240	14,900,356	15,595,476
FUND BALANCE													
Average Unrestricted Fund Balance						$192,764	$113,605	$99,675	$221,247	$181,933	$174,896	$170,576	$173,386
Ending Unrestricted Fund Balance						180,257	46,952	146,197	181,015	169,850	166,418	165,171	170,916
45 Days of Operating Expenses (Less Purchased Power and Deprec.)						150,833	157,808	164,558	213,180	222,034	230,684	239,857	249,582
RATE INCREASES													
Annual Percent Rate Increases							0.0%	6.5%	21.7%	5.5%	3.2%	3.8%	3.6%
Average Revenues per kWh (Nominal)							$0.049	$0.054	$0.065	$0.069	$0.071	$0.074	$0.077
Average Revenues per kWh (1994 $)							$0.049	$0.052	$0.062	$0.063	$0.063	$0.064	$0.064
LONG-TERM DEBT													
Non-Contributed CIP Expenditures							$127,088	$502,497	$7,833,621	$1,144,928	$1,180,606	$922,176	$992,189
Net Bond Proceeds							0	415,000	7,715,000	870,000	905,000	640,000	715,000
Projected Bond Coverage							NA	5.46	1.32	1.29	1.28	1.26	1.25
Debt-Equity Ratio (Long-term Debt/(Long-term Debt + Retained Earnings and Contributed Capital)						0.00%	0.00%	9.02%	62.44%	62.73%	62.92%	62.41%	61.96%

Scenario 4: Medium Forecast & Annexation

Table Summary 1-A
Utility Financial Plan
Financial Plan Assumptions

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
ASSUMPTIONS & INPUTS													
Annual Capital Improvement Additions	$0	$0	$0	$0	$0	$58,990	$344,292	$770,771	$8,625,649	$1,522,138	$1,576,929	$1,305,945	$1,400,983
Purchased Power (MWh)	--	52,337	52,415	58,676	61,010	64,034	64,624	66,027	88,615	90,740	92,981	95,265	97,871
Average Losses	--	7.1%	2.3%	3.8%	4.2%	6.2%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
MWh Sales	45,594	48,639	51,216	56,446	58,440	60,058	61,716	63,056	84,628	86,657	88,796	90,978	93,466
Percent Change in Sales from Previous Year		6.68%	5.30%	10.21%	3.53%	2.77%	2.76%	2.17%	34.21%	2.40%	2.47%	2.46%	2.73%
Average System Power Cost ($)	$1,182,846	$1,271,926	$1,261,773	$1,476,600	$1,489,690	$1,640,772	$1,807,908	$1,861,968	$2,738,703	$3,012,111	$3,183,229	$3,439,887	$3,717,275
Average System Power Cost ($/MWh)	--	24.3	24.1	25.2	24.4	25.6	28.2	28.2	30.9	33.2	34.2	36.1	38.0
Average System Sales Rate ($/MWh)	40.5	41.5	40.6	40.2	43.5	46.2	49.2	53.7	65.4	69.0	71.2	73.9	76.6
Average Sales Rate Excluding Rate Increases	40.5	41.5	40.6	40.2	43.5	46.2	49.2	50.4	50.4	50.4	50.4	50.4	50.4
Annual % Change in BPA PF Rate	--	--	--	--	--	--	--	0.0%	9.6%	7.4%	3.1%	5.5%	5.2%
Average Losses	4.5%												
Inflationary Growth in O&M, A&G, and Other Ex	3.0%												
Utility Taxes as % of Gross Revenues	3.873%												
Annual Depreciation on Utility Plant	3.5%												
Rate on Interest Earnings	4.0%												

Scenario 4: Medium Forecast & Annexation

Table FF-1
Utility Financial Plan
City of Blaine Light Fund
Sources and Uses of Funds

Description	1994	1995	1996	1997	1998	1999	2000
Sources of Funds							
Beginning Fund Balance							
Unrestricted	$180,257	$46,952	$146,197	$181,015	$169,850	$166,418	$165,171
Restricted for Debt Service	0	0	47,701	934,483	1,034,483	1,138,506	1,212,069
Operating Revenues	3,037,143	3,387,764	5,533,364	5,977,691	6,321,278	6,722,718	7,155,200
Other Revenues	40,000	41,200	42,436	43,709	45,020	46,371	47,762
Interest Earnings	4,544	3,987	8,850	7,277	6,996	6,823	6,935
Issuance of Revenue Bonds (Net)	0	415,000	7,715,000	870,000	905,000	640,000	715,000
Bond Proceeds for Debt Reserve	0	41,500	771,500	87,000	90,500	64,000	71,500
Grants	0	0	0	0	0	0	0
Customer Contributions	147,203	154,974	166,001	190,354	203,861	218,340	233,865
Other Capital Contributions	70,000	113,300	626,026	186,856	192,462	165,428	174,929
Total	$3,479,147	$4,204,676	$15,057,076	$8,478,385	$8,969,450	$9,168,605	$9,782,431
Uses of Funds							
Purchased Power	$1,807,908	$1,861,968	$2,738,703	$3,012,111	$3,183,229	$3,439,887	$3,717,275
Operations & Maintenance	587,841	608,667	831,353	861,278	892,432	924,688	958,750
Administration & General	531,220	550,041	622,764	645,276	668,708	692,964	718,562
Utility Taxes	119,178	132,804	215,951	233,209	246,567	262,167	278,971
Misc. Expenses	41,757	43,236	59,055	61,181	63,394	65,685	68,105
Capital Improvements	344,292	770,771	8,625,649	1,522,138	1,576,929	1,305,945	1,400,983
Debt Service	0	43,292	848,103	938,859	1,033,267	1,100,030	1,174,617
Ending Fund Balance							
Unrestricted	46,952	146,197	181,015	169,850	166,418	165,171	170,916
Restricted for Debt Service	0	47,701	934,483	1,034,483	1,138,506	1,212,069	1,294,253
Total	$3,479,147	$4,204,676	$15,057,076	$8,478,385	$8,969,450	$9,168,605	$9,782,431

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Scenario 4: Medium Forecast & Annexation

Table CIP-1
Utility Financial Plan
City of Blaine Light Fund
Capital Improvements Program

Description	1994	1995	1996	1997	1998	1999	2000
CIP in 1994$							
Renewal and Replacement	$175,000	$175,000	$175,000	$175,000	$175,000	$175,000	$175,000
Customer Line Extension							
Residential	49,373	51,102	52,890	75,489	78,131	80,866	83,696
Others	119,918	122,219	127,243	132,483	137,950	143,653	149,605
Major Projects							
Feeders	0	150,000	0	185,000	185,000	452,000	765,000
Substation	0	250,000	575,000	825,000	825,000	0	0
Submarine Cable	0	0	0	0	0	275,000	0
Annexation							
H Street	0	0	462,590	0	0	0	0
Other	0	0	6,737,778	0	0	0	0
Unused	0	0	0	0	0	0	0
Total (1994$)	$344,292	$748,321	$8,130,501	$1,392,972	$1,401,081	$1,126,519	$1,173,301
Expected Inflation Rate	0.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Inflation Factor	1.000	1.030	1.061	1.093	1.126	1.159	1.194
Total CIP (Nominal $)	$344,292	$770,771	$8,625,649	$1,522,138	$1,576,929	$1,305,945	$1,400,983
Customer Contributions (Nominal $)							
Residential	$27,285	$29,088	$31,009	$45,586	$48,597	$51,807	$55,229
Other	119,918	125,886	134,992	144,768	155,264	166,533	178,636
Total	$147,203	$154,974	$166,001	$190,354	$203,861	$218,340	$233,865

Table CIP-2
Utility Financial Plan
City of Blaine Light Fund
Funding Sources for Improvements

Description	1994	1995	1996	1997	1998	1999	2000
Expenditures from Fund Balance	$127,088	$87,497	$118,621	$274,928	$275,606	$282,176	$277,189
Issuance of Revenue Bonds (Net)	0	415,000	7,715,000	870,000	905,000	640,000	715,000
Grants	0	0	0	0	0	0	0
Customer Contributions	147,203	154,974	166,001	190,354	203,861	218,340	233,865
Other Capital Contributions	70,000	113,300	626,026	186,856	192,462	165,428	174,929
Total	$344,292	$770,771	$8,625,649	$1,522,138	$1,576,929	$1,305,945	$1,400,983

Scenario 4: Medium Forecast & Annexation

Table CIP-3
Utility Financial Plan
City of Blaine Light Fund
Estimated Revenue Bond Debt Issue Size and Costs

Description	1994	1995	1996	1997	1998	1999	2000
Issue Sizing							
Bond Proceeds Required	$0	$415,000	$7,715,000	$870,000	$905,000	$640,000	$715,000
Issuance Costs	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Reserve Requirement	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Issue Size	$0	$477,011	$8,867,816	$1,000,000	$1,040,230	$735,632	$821,839
Debt Service Requirements							
Term (Years)	20	20	20	20	20	20	20
Interest Rate	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
New Annual Debt Service Costs	$0	$43,292	$804,811	$90,756	$94,408	$66,763	$74,587
Accumulated Debt Service	$0	$43,292	$848,103	$938,859	$1,033,267	$1,100,030	$1,174,617
Debt Service Components							
Amortization of Principal - Series 1994	$0	$0	$0	$0	$0	$0	$0
Amortization of Principal - Series 1995		12,286	13,085	13,935	14,841	15,806	16,833
Amortization of Principal - Series 1996			228,403	243,249	259,060	275,899	293,833
Amortization of Principal - Series 1997				25,756	27,431	29,214	31,112
Amortization of Principal - Series 1998					26,793	28,534	30,389
Amortization of Principal - Series 1999						18,947	20,179
Amortization of Principal - Series 2000							21,168
Amortization of Principal - Series 2001							
Amortization of Principal - Series 2002							
Amortization of Principal - Series 2003							
Amortization of Principal - Series 2004							
Amortization of Principal - Series 2005							
Total	$0	$12,286	$241,488	$282,941	$328,124	$368,400	$413,513
Interest	$0	$31,006	$606,615	$655,918	$705,142	$731,630	$761,104
Outstanding Debt	$0	$477,011	$9,332,541	$10,091,054	$10,848,343	$11,255,851	$11,709,290
Weighted Interest Rate on Debt	0.00%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%

Scenario 4: Medium Forecast & Annexation

Table CIP-4
Utility Financial Plan
City of Blaine Light Fund
Projection of Bond Coverage

Description	1994	1995	1996	1997	1998	1999	2000
Annual Debt Service	$0	$43,292	$848,103	$938,859	$1,033,267	$1,100,030	$1,174,617
Net Revenues							
Gross Revenues							
Operating Revenues	$3,077,143	$3,428,964	$5,575,800	$6,021,400	$6,366,298	$6,769,089	$7,202,963
Interest Income	4,544	3,987	8,850	7,277	6,996	6,823	6,935
Total Gross Revenues	$3,081,687	$3,432,951	$5,584,650	$6,028,677	$6,373,294	$6,775,912	$7,209,898
Less: Operating Expenses (Excluding Depr.)	(3,087,904)	(3,196,716)	(4,467,826)	(4,813,055)	(5,054,330)	(5,385,390)	(5,741,662)
Net Revenues	($6,217)	$236,235	$1,116,824	$1,215,622	$1,318,964	$1,390,522	$1,468,236
Bond Coverage							
Minimum Target	1.40	1.40	1.40	1.40	1.40	1.40	1.40
Actual	NA	5.46	1.32	1.29	1.28	1.26	1.25
Additional Revenues Required	$0	$0	$70,520	$98,781	$127,609	$149,520	$176,228

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Table LF-4
Utility Financial Plan
City of Blaine Light Fund
Blaine Forecast of Customers per Residential Customer

Customer Class	1993	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Unused	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial (50 KVA or Less)	4.20	4.17	4.13	4.10	4.07	4.03	4.00	3.97
Commercial (Over 50 KVA)	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
Industrial	142.37	142.37	142.37	142.37	142.37	142.37	142.37	142.37
Senior/Disabled	14.34	14.34	14.34	14.34	14.34	14.34	14.34	14.34
Public Street Lighting	1,388.13	1,388.13	1,388.13	1,388.13	1,388.13	1,388.13	1,388.13	1,388.13
Public Authorities	27.72	27.72	27.72	27.72	27.72	27.72	27.72	27.72
Other (City)	51.41	51.41	51.41	51.41	51.41	51.41	51.41	51.41

Table LF-5
Utility Financial Plan
City of Blaine Light Fund
Blaine Forecast Number of Customers in Existing Service Area

Customer Class	1993	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	1,388	1,437	1,487	1,539	1,593	1,649	1,706	1,766
Unused	0	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	334	345	360	375	392	409	427	445
Commercial (Over 50 KVA)	79	85	87	91	94	97	100	104
Industrial	10	10	10	11	11	12	12	12
Senior/Disabled	97	100	104	107	111	115	119	123
Public Street Lighting	1	1	1	1	1	1	1	1
Public Authorities	50	52	54	56	57	59	62	64
Other (City)	27	28	29	30	31	32	33	34
Total	1,986	2,057	2,132	2,210	2,290	2,374	2,460	2,550
Growth Rate		3.59%	3.64%	3.64%	3.64%	3.65%	3.65%	3.65%

Scenario 4: Medium Forecast & Annexation

Table LF-6
Utility Financial Plan
City of Blaine Light Fund
Forecast Sales in Existing Service Area

Customer Class	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	19,973,134	20,584,461	21,124,849	21,688,999	22,275,005	22,827,685	23,278,735
Unused	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	8,407,508	8,979,167	9,481,606	10,011,410	10,570,072	11,159,168	11,780,365
Commercial (Over 50 KVA)	17,430,665	18,134,076	18,422,149	18,740,063	19,086,455	19,460,289	19,860,791
Industrial	4,412,399	4,814,018	5,151,865	5,083,814	5,041,410	5,020,217	5,351,397
Senior/Disabled	1,392,694	1,435,320	1,473,001	1,512,338	1,553,199	1,591,737	1,623,188
Public Street Lighting	407,790	422,063	436,835	452,124	467,948	484,327	501,278
Public Authorities	6,952,403	7,285,681	7,518,625	7,712,547	7,920,378	8,134,399	8,386,530
Other (City)	4,439,444	4,801,230	4,971,877	5,148,362	5,330,906	5,519,735	5,715,078
Total	63,416,038	66,456,016	68,580,808	70,349,658	72,245,375	74,197,555	76,497,363
Less: Conservation	(1,700,000)	(3,400,000)	(5,000,000)	(5,000,000)	(5,000,000)	(5,000,000)	(5,000,000)
Total W/Conservation	61,716,038	63,056,016	63,580,808	65,349,658	67,245,375	69,197,555	71,497,363
Percent Change		2.17%	0.83%	2.78%	2.90%	2.90%	3.32%

Table LF-7
Utility Financial Plan
City of Blaine Light Fund
Blaine Forecast Number of Customers in Annexed Service Area

Customer Class	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	0	0	624	646	668	692	716
Unused	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	0	0	1	2	2	2	2
Commercial (Over 50 KVA)	0	0	0	0	0	0	0
Industrial	0	0	0	0	0	0	0
Senior/Disabled	0	0	0	0	0	0	0
Public Street Lighting	0	0	0	0	0	0	0
Public Authorities	0	0	0	0	0	0	0
Other (City)	0	0	75	75	75	75	75
Total	0	0	700	723	745	769	793
Percent Change		0.00%	0.00%	3.26%	3.13%	3.14%	3.15%

Table LF-8
Utility Financial Plan
City of Blaine Light Fund
Forecast of Sales in Annexation Area

Customer Class	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	0	0	8,565,024	8,793,757	9,031,352	9,255,435	9,438,312
Unused	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	0	0	25,259	51,118	51,718	52,318	52,918
Commercial (Over 50 KVA)	0	0	0	0	0	0	0
Industrial	0	0	0	0	0	0	0
Senior/Disabled	0	0	0	0	0	0	0
Public Street Lighting	0	0	0	0	0	0	0
Public Authorities	0	0	0	0	0	0	0
Other (City)	0	0	12,456,522	12,462,500	12,468,000	12,473,077	12,477,778
Total	0	0	21,046,805	21,307,375	21,551,070	21,780,830	21,969,008
Less: Conservation	0	0	0	0	0	0	0
Total W/Conservation	0	0	21,046,805	21,307,375	21,551,070	21,780,830	21,969,008
Percent Change		NA	NA	1.24%	1.14%	1.07%	0.86%

Scenario 4: Medium Forecast & Annexation

Table LF-9
Utility Financial Plan
City of Blaine Light Fund
Blaine Forecast Number of Total Customers
(Existing and Annexed Service Area)

Customer Class	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	1,437	1,487	2,163	2,239	2,317	2,398	2,482
Unused	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	345	360	376	394	411	429	447
Commercial (Over 50 KVA)	85	87	91	94	97	100	104
Industrial	10	10	11	11	12	12	12
Senior/Disabled	100	104	107	111	115	119	123
Public Street Lighting	1	1	1	1	1	1	1
Public Authorities	52	54	56	57	59	62	64
Other (City)	28	29	105	106	107	108	109
Total	2,057	2,132	2,910	3,013	3,119	3,229	3,343
Percent Change		3.64%	36.48%	3.55%	3.52%	3.53%	3.53%

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Table LF-10
Utility Financial Plan
City of Blaine Light Fund
Forecast of Use by Customer Class (KWh)
(Blaine Total Customer Forecast Times BPA Consumption per Customer)

Customer Class	1993	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	17,395,870	19,973,134	20,584,461	29,689,873	30,482,757	31,306,358	32,083,120	32,717,048
Unused	0	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	8,088,142	8,407,508	8,979,167	9,506,865	10,062,528	10,621,790	11,211,486	11,833,283
Commercial (Over 50 KVA)	20,632,442	17,430,665	18,134,076	18,422,149	18,740,063	19,086,455	19,460,289	19,860,791
Industrial	3,331,920	4,412,399	4,814,018	5,151,865	5,083,814	5,041,410	5,020,217	5,351,397
Senior/Disabled	1,114,340	1,392,694	1,435,320	1,473,001	1,512,338	1,553,199	1,591,737	1,623,188
Public Street Lighting	394,080	407,790	422,063	436,835	452,124	467,948	484,327	501,278
Public Authorities	6,584,250	6,952,403	7,285,681	7,518,625	7,712,547	7,920,378	8,134,399	8,386,530
Other (City)	2,516,900	4,439,444	4,801,230	17,428,398	17,610,862	17,798,906	17,992,812	18,192,856
Total	60,057,944	63,416,038	66,456,016	89,627,613	91,657,034	93,796,445	95,978,385	98,466,372
Less: Conservation	0	(1,700,000)	(3,400,000)	(5,000,000)	(5,000,000)	(5,000,000)	(5,000,000)	(5,000,000)
Total W/Conservation	60,057,944	61,716,038	63,056,016	84,627,613	86,657,034	88,796,445	90,978,385	93,466,372
Growth		2.76%	2.17%	34.21%	2.40%	2.47%	2.46%	2.73%

Scenario 4: Medium Forecast & Annexation

Table O&M-1
Utility Financial Plan
City of Blaine Light Fund
Forecast of O&M Cost Growth Rate

Description	1994	1995	1996	1997	1998	1999	2000
Additional Sales (kWh)							
Existing Service Area	1,658,094	1,339,978	524,793	1,768,850	1,895,716	1,952,181	2,299,808
Proposed Annexation Area	0	0	21,046,805	260,571	243,695	229,760	188,178
Total	1,658,094	1,339,978	21,571,597	2,029,420	2,139,411	2,181,941	2,487,986
Percent Increase in Sales							
Existing Service Area	2.76%	2.17%	0.83%	2.09%	2.19%	2.20%	2.53%
Proposed Annexation Area	0.00%	0.00%	33.38%	0.31%	0.28%	0.26%	0.21%
Total	2.76%	2.17%	34.21%	2.40%	2.47%	2.46%	2.73%

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Scenario 4: Medium Forecast & Annexation

Table O&M-2
Utility Financial Plan
City of Blaine Light Fund
Percentage Increase in O&M Costs

Description	1994	1995	1996	1997	1998	1999	2000
Percent of Growth Toward Cost Increase							
Existing Service Area	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Proposed Annexation Area	100.00%	100.00%	100.00%	25.00%	25.00%	25.00%	25.00%
Weighted Average Growth Rates in kWh							
Existing Service Area	0.69%	0.54%	0.21%	0.52%	0.55%	0.55%	0.63%
Proposed Annexation Area	0.00%	0.00%	33.38%	0.08%	0.07%	0.06%	0.05%
Total	0.69%	0.54%	33.59%	0.60%	0.62%	0.61%	0.68%
Non-Growth Related Increases	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Total Growth Rate	3.69%	3.54%	36.59%	3.60%	3.62%	3.61%	3.68%

Scenario 4: Medium Forecast & Annexation

Table O&M-3
Utility Financial Plan
City of Blaine Light Fund
Percentage Increase in A&G Costs

Description	1994	1995	1996	1997	1998	1999	2000
Percent of Growth Toward Cost Increase							
Existing Service Area	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Proposed Annexation Area	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
Weighted Average Growth Rates							
Existing Service Area	0.69%	0.54%	0.21%	0.52%	0.55%	0.55%	0.63%
Proposed Annexation Area	0.00%	0.00%	10.01%	0.09%	0.08%	0.08%	0.06%
Total	0.69%	0.54%	10.22%	0.61%	0.63%	0.63%	0.69%
Non-Growth Related Increases	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Total Growth Rate	3.69%	3.54%	13.22%	3.61%	3.63%	3.63%	3.69%

Scenario 5

Medium Forecast and Rate-Neutral Annexation

Scenario 5: Medium Forecast & Rate Neutral Annexation

Table Summary-1
Utility Financial Plan
City of Blaine Light Fund
Financial Plan Summary

24-Aug-94

	HISTORICAL OPERATING RESULTS						FORECAST						
	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
INCOME STATEMENT													
OPERATING REVENUES													
Sales Revenues	$1,844,844	$2,019,057	$2,080,541	$2,267,438	$2,541,362	$2,772,870	$3,037,143	$3,180,999	$4,269,225	$4,371,604	$4,479,531	$4,589,604	$4,715,116
Revenues from Post '94 Rate Increases	0	0	0	0	0	0	(0)	203,584	650,254	1,048,694	1,341,182	1,672,325	2,020,417
Total Sales Revenues	$1,844,844	$2,019,057	$2,080,541	$2,267,438	$2,541,362	$2,772,870	$3,037,143	$3,384,583	$4,919,479	$5,420,298	$5,820,713	$6,261,929	$6,735,533
Other Revenues	$74,680	$21,201	$29,154	$34,058	$37,314	$76,834	$40,000	$41,200	$42,436	$43,709	$45,020	$46,371	$47,762
Total Operating Revenues	$1,919,524	$2,040,258	$2,109,695	$2,301,496	$2,578,676	$2,849,704	$3,077,143	$3,425,783	$4,961,915	$5,464,007	$5,865,733	$6,308,300	$6,783,295
OPERATING EXPENSES													
Purchased Power	$1,182,846	$1,271,926	$1,261,773	$1,476,600	$1,489,690	$1,640,772	$1,807,908	$1,861,968	$2,738,703	$3,012,111	$3,183,229	$3,439,887	$3,717,275
Operations & Maintenance	131,034	186,892	171,683	313,919	482,628	566,920	587,841	608,667	831,353	861,278	892,432	924,688	958,750
Administration & General	180,744	163,469	220,249	253,310	317,727	512,315	531,220	550,041	622,764	645,276	668,708	692,964	718,562
Depreciation	73,362	79,537	83,300	153,114	125,925	160,500	139,806	200,756	318,082	383,974	452,061	506,788	564,563
Utility Taxes	69,808	70,031	77,085	85,663	95,932	103,916	119,178	132,681	192,175	211,621	227,180	244,320	262,717
Misc. Expenses		4,617	10	84,268	33,177	40,271	41,757	43,236	59,055	61,181	63,394	65,685	68,105
Total Operating Expenses	$1,637,794	$1,776,472	$1,814,100	$2,366,874	$2,545,079	$3,024,694	$3,227,710	$3,397,348	$4,762,132	$5,175,440	$5,487,004	$5,874,331	$6,289,972
Net Operating Revenues	$281,730	$263,786	$295,595	($65,378)	$33,597	($174,990)	($150,567)	$28,435	$199,783	$288,567	$378,729	$433,968	$493,324
NONOPERATING REVENUES (EXPENSES)													
Interest Expense	($9,144)	($7,080)	($7,080)	($7,080)	($8,935)	($7,080)	$0	($31,379)	($206,119)	($296,031)	($384,854)	($441,825)	($499,827)
Interest Income	56,950	91,751	65,803	45,077	72,888	27,078	4,544	4,016	6,399	6,025	6,378	6,739	7,353
Other Income	0	0	0	(2,364)	(35,383)	28,469	0	0	0	0	0	0	0
NET INCOME	$329,536	$348,457	$354,318	($29,745)	$62,167	($126,523)	($146,023)	$1,071	$64	($1,439)	$254	($1,118)	$850
KEY FINANCIAL STATISTICS													
NET PLANT													
Gross Plant	2,367,434	2,509,607	3,047,396	3,504,415	4,160,228	4,620,815	4,965,107	5,735,877	9,088,055	10,970,672	12,916,036	14,479,662	16,130,375
Accumulated Depreciation	(659,273)	(722,383)	(799,777)	(946,914)	(1,057,177)	(1,199,089)	(1,338,895)	(1,539,651)	(1,857,733)	(2,241,706)	(2,693,767)	(3,200,556)	(3,765,119)
Net Plant	1,708,161	1,787,224	2,247,619	2,557,501	3,103,051	3,421,726	3,626,212	4,196,227	7,230,323	8,728,966	10,222,269	11,279,107	12,365,256
FUND BALANCE													
Average Unrestricted Fund Balance						$192,764	$113,605	$100,400	$159,987	$150,622	$159,460	$168,468	$183,821
Ending Unrestricted Fund Balance						180,257	46,952	147,572	137,292	144,893	154,626	168,672	184,629
45 Days of Operating Expenses (Less Purchased Power and Deprec.)						150,833	157,808	164,543	210,248	219,373	228,293	237,656	247,578
RATE INCREASES													
Annual Percent Rate Increases							0.0%	6.4%	8.3%	7.6%	4.8%	5.0%	4.7%
Average Revenues per kWh (Nominal)							$0.049	$0.054	$0.058	$0.063	$0.066	$0.069	$0.072
Average Revenues per kWh (1994 $)							$0.049	$0.052	$0.055	$0.057	$0.058	$0.059	$0.060
LONG-TERM DEBT													
Non-Contributed CIP Expenditures							$127,088	$502,497	$2,560,151	$1,505,406	$1,549,042	$1,179,857	$1,241,920
Net Bond Proceeds							0	420,000	2,349,638	1,275,478	1,298,435	912,681	959,730
Projected Bond Coverage							NA	5.32	1.81	1.61	1.50	1.45	1.42
Debt-Equity Ratio (Long-term Debt/(Long-term Debt + Retained Earnings and Contributed Capital)						0.00%	0.00%	9.12%	36.14%	43.24%	48.15%	50.15%	51.76%

Scenario 5: Medium Forecast & Rate Neutral Annexation

Table Summary 1-A
Utility Financial Plan
Financial Plan Assumptions

ASSUMPTIONS & INPUTS	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Annual Capital Improvement Additions	$0	$0	$0	$0	$0	$58,990	$344,292	$770,771	$3,352,178	$1,882,617	$1,945,364	$1,563,626	$1,650,713
Purchased Power (MWh)	--	52,337	52,415	58,676	61,010	64,034	64,624	66,027	88,615	90,740	92,981	95,265	97,871
Average Losses	--	7.1%	2.3%	3.8%	4.2%	6.2%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
MWh Sales	45,594	48,639	51,216	56,446	58,440	60,058	61,716	63,056	84,628	86,657	88,796	90,978	93,466
Percent Change in Sales from Previous Year		6.68%	5.30%	10.21%	3.53%	2.77%	2.76%	2.17%	34.21%	2.40%	2.47%	2.46%	2.73%
Average System Power Cost ($)	$1,182,846	$1,271,926	$1,261,773	$1,476,600	$1,489,690	$1,640,772	$1,807,908	$1,861,968	$2,738,703	$3,012,111	$3,183,229	$3,439,887	$3,717,275
Average System Power Cost ($/MWh)	--	24.3	24.1	25.2	24.4	25.6	28.2	28.2	30.9	33.2	34.2	36.1	38.0
Average System Sales Rate ($/MWh)	40.5	41.5	40.6	40.2	43.5	46.2	49.2	53.7	58.1	62.5	65.6	68.8	72.1
Average Sales Rate Excluding Rate Increases	40.5	41.5	40.6	40.2	43.5	46.2	49.2	50.4	50.4	50.4	50.4	50.4	50.4
Annual % Change in BPA PF Rate	--	--	--	--	--	--	--	0.0%	9.6%	7.4%	3.1%	5.5%	5.2%
Average Losses	4.5%												
Inflationary Growth in O&M, A&G, and Other Ex	3.0%												
Utility Taxes as % of Gross Revenues	3.873%												
Annual Depreciation on Utility Plant	3.5%												
Rate on Interest Earnings	4.0%												

Scenario 5: Medium Forecast & Rate Neutral Annexation

Table FF-1
Utility Financial Plan
City of Blaine Light Fund
Sources and Uses of Funds

Description	1994	1995	1996	1997	1998	1999	2000
Sources of Funds							
Beginning Fund Balance							
Unrestricted	$180,257	$46,952	$147,572	$137,292	$144,893	$154,626	$168,672
Restricted for Debt Service	0	0	48,276	318,349	464,956	614,201	719,107
Operating Revenues	3,037,143	3,384,583	4,919,479	5,420,298	5,820,713	6,261,929	6,735,533
Other Revenues	40,000	41,200	42,436	43,709	45,020	46,371	47,762
Interest Earnings	4,544	4,016	6,399	6,025	6,378	6,739	7,353
Issuance of Revenue Bonds (Net)	0	420,000	2,349,638	1,275,478	1,298,435	912,681	959,730
Bond Proceeds for Debt Reserve	0	42,000	234,964	127,548	129,844	91,268	95,973
Grants	0	0	0	0	0	0	0
Customer Contributions	147,203	154,974	166,001	190,354	203,861	218,340	233,865
Other Capital Contributions	70,000	113,300	626,026	186,856	192,462	165,428	174,929
Total	$3,479,147	$4,207,024	$8,540,792	$7,705,909	$8,306,562	$8,471,584	$9,142,923
Uses of Funds							
Purchased Power	$1,807,908	$1,861,968	$2,738,703	$3,012,111	$3,183,229	$3,439,887	$3,717,275
Operations & Maintenance	587,841	608,667	831,353	861,278	892,432	924,688	958,750
Administration & General	531,220	550,041	622,764	645,276	668,708	692,964	718,562
Utility Taxes	119,178	132,681	192,175	211,621	227,180	244,320	262,717
Misc. Expenses	41,757	43,236	59,055	61,181	63,394	65,685	68,105
Capital Improvements	344,292	770,771	3,352,178	1,882,617	1,945,364	1,563,626	1,650,713
Debt Service	0	43,813	288,922	421,977	557,427	652,636	752,753
Ending Fund Balance							
Unrestricted	46,952	147,572	137,292	144,893	154,626	168,672	184,629
Restricted for Debt Service	0	48,276	318,349	464,956	614,201	719,107	829,421
Total	$3,479,147	$4,207,024	$8,540,792	$7,705,909	$8,306,562	$8,471,584	$9,142,923

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Scenario 5: Medium Forecast & Rate Neutral Annexation

Table CIP-1
Utility Financial Plan
City of Blaine Light Fund
Capital Improvements Program

Description	1994	1995	1996	1997	1998	1999	2000
CIP in 1994$							
Renewal and Replacement	$175,000	$175,000	$175,000	$175,000	$175,000	$175,000	$175,000
Customer Line Extension							
Residential	49,373	51,102	52,890	75,489	78,131	80,866	83,696
Others	119,918	122,219	127,243	132,483	137,950	143,653	149,605
Major Projects							
Feeders	0	150,000	0	185,000	185,000	452,000	765,000
Substation	0	250,000	575,000	825,000	825,000	0	0
Submarine Cable	0	0	0	0	0	275,000	0
Annexation							
H Street	0	0	462,590	0	0	0	0
Other	0	0	1,767,026	329,888	327,350	222,278	209,145
Unused	0	0	0	0	0	0	0
Total (1994$)	$344,292	$748,321	$3,159,749	$1,722,861	$1,728,431	$1,348,798	$1,382,446
Expected Inflation Rate	0.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Inflation Factor	1.000	1.030	1.061	1.093	1.126	1.159	1.194
Total CIP (Nominal $)	$344,292	$770,771	$3,352,178	$1,882,617	$1,945,364	$1,563,626	$1,650,713
Customer Contributions (Nominal $)							
Residential	$27,285	$29,088	$31,009	$45,586	$48,597	$51,807	$55,229
Other	119,918	125,886	134,992	144,768	155,264	166,533	178,636
Total	$147,203	$154,974	$166,001	$190,354	$203,861	$218,340	$233,865

Scenario 5: Medium Forecast & Rate Neutral Annexation

Table CIP-2
Utility Financial Plan
City of Blaine Light Fund
Funding Sources for Improvements

Description	1994	1995	1996	1997	1998	1999	2000
Expenditures from Fund Balance	$127,088	$82,497	$210,513	$229,928	$250,606	$267,176	$282,189
Issuance of Revenue Bonds (Net)	0	420,000	2,349,638	1,275,478	1,298,435	912,681	959,730
Grants	0	0	0	0	0	0	0
Customer Contributions	147,203	154,974	166,001	190,354	203,861	218,340	233,865
Other Capital Contributions	70,000	113,300	626,026	186,856	192,462	165,428	174,929
Total	$344,292	$770,771	$3,352,178	$1,882,617	$1,945,364	$1,563,626	$1,650,713

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Scenario 5: Medium Forecast & Rate Neutral Annexation

Table CIP-3
Utility Financial Plan
City of Blaine Light Fund
Estimated Revenue Bond Debt Issue Size and Costs

Description	1994	1995	1996	1997	1998	1999	2000
Issue Sizing							
Bond Proceeds Required	$0	$420,000	$2,349,638	$1,275,478	$1,298,435	$912,681	$959,730
Issuance Costs	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Reserve Requirement	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Issue Size	$0	$482,759	$2,700,734	$1,466,067	$1,492,454	$1,049,059	$1,103,138
Debt Service Requirements							
Term (Years)	20	20	20	20	20	20	20
Interest Rate	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
New Annual Debt Service Costs	$0	$43,813	$245,109	$133,055	$135,450	$95,209	$100,117
Accumulated Debt Service	$0	$43,813	$288,922	$421,977	$557,427	$652,636	$752,753
Debt Service Components							
Amortization of Principal - Series 1994	$0	$0	$0	$0	$0	$0	$0
Amortization of Principal - Series 1995		12,434	13,242	14,103	15,020	15,996	17,036
Amortization of Principal - Series 1996			69,561	74,083	78,898	84,026	89,488
Amortization of Principal - Series 1997				37,761	40,215	42,829	45,613
Amortization of Principal - Series 1998					38,440	40,939	43,600
Amortization of Principal - Series 1999						27,020	28,776
Amortization of Principal - Series 2000							28,413
Amortization of Principal - Series 2001							
Amortization of Principal - Series 2002							
Amortization of Principal - Series 2003							
Amortization of Principal - Series 2004							
Amortization of Principal - Series 2005							
Total	$0	$12,434	$82,804	$125,946	$172,573	$210,810	$252,926
Interest	$0	$31,379	$206,119	$296,031	$384,854	$441,825	$499,827
Outstanding Debt	$0	$482,759	$3,171,058	$4,554,321	$5,920,829	$6,797,315	$7,689,643
Weighted Interest Rate on Debt	0.00%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%

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Scenario 5: Medium Forecast & Rate Neutral Annexation

Table CIP-4
Utility Financial Plan
City of Blaine Light Fund
Projection of Bond Coverage

Description	1994	1995	1996	1997	1998	1999	2000
Annual Debt Service	$0	$43,813	$288,922	$421,977	$557,427	$652,636	$752,753
Net Revenues							
Gross Revenues							
Operating Revenues	$3,077,143	$3,425,783	$4,961,915	$5,464,007	$5,865,733	$6,308,300	$6,783,295
Interest Income	4,544	4,016	6,399	6,025	6,378	6,739	7,353
Total Gross Revenues	$3,081,687	$3,429,799	$4,968,315	$5,470,032	$5,872,112	$6,315,039	$6,790,648
Less: Operating Expenses (Excluding Depr.)	(3,087,904)	(3,196,592)	(4,444,050)	(4,791,467)	(5,034,943)	(5,367,543)	(5,725,408)
Net Revenues	($6,217)	$233,206	$524,264	$678,565	$837,169	$947,495	$1,065,240
Bond Coverage							
Minimum Target	1.40	1.40	1.40	1.40	1.40	1.40	1.40
Actual	NA	5.32	1.81	1.61	1.50	1.45	1.42
Additional Revenues Required	$0	$0	$0	$0	$0	$0	$0

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Table LF-4
Utility Financial Plan
City of Blaine Light Fund
Blaine Forecast of Customers per Residential Customer

Customer Class	1993	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Unused	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial (50 KVA or Less)	4.20	4.17	4.13	4.10	4.07	4.03	4.00	3.97
Commercial (Over 50 KVA)	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
Industrial	142.37	142.37	142.37	142.37	142.37	142.37	142.37	142.37
Senior/Disabled	14.34	14.34	14.34	14.34	14.34	14.34	14.34	14.34
Public Street Lighting	1,388.13	1,388.13	1,388.13	1,388.13	1,388.13	1,388.13	1,388.13	1,388.13
Public Authorities	27.72	27.72	27.72	27.72	27.72	27.72	27.72	27.72
Other (City)	51.41	51.41	51.41	51.41	51.41	51.41	51.41	51.41

Scenario 5: Medium Forecast & Rate Neutral Annexation

Table LF-5
Utility Financial Plan
City of Blaine Light Fund
Blaine Forecast Number of Customers in Existing Service Area

Customer Class	1993	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	1,388	1,437	1,487	1,539	1,593	1,649	1,706	1,766
Unused	0	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	334	345	360	375	392	409	427	445
Commercial (Over 50 KVA)	79	85	87	91	94	97	100	104
Industrial	10	10	10	11	11	12	12	12
Senior/Disabled	97	100	104	107	111	115	119	123
Public Street Lighting	1	1	1	1	1	1	1	1
Public Authorities	50	52	54	56	57	59	62	64
Other (City)	27	28	29	30	31	32	33	34
Total	1,986	2,057	2,132	2,210	2,290	2,374	2,460	2,550
Growth Rate		3.59%	3.64%	3.64%	3.64%	3.65%	3.65%	3.65%

Scenario 5: Medium Forecast & Rate Neutral Annexation

Table LF-6
Utility Financial Plan
City of Blaine Light Fund
Forecast Sales in Existing Service Area

Customer Class	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	19,973,134	20,584,461	21,124,849	21,688,999	22,275,005	22,827,685	23,278,735
Unused	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	8,407,508	8,979,167	9,481,606	10,011,410	10,570,072	11,159,168	11,780,365
Commercial (Over 50 KVA)	17,430,665	18,134,076	18,422,149	18,740,063	19,086,455	19,460,289	19,860,791
Industrial	4,412,399	4,814,018	5,151,865	5,083,814	5,041,410	5,020,217	5,351,397
Senior/Disabled	1,392,694	1,435,320	1,473,001	1,512,338	1,553,199	1,591,737	1,623,188
Public Street Lighting	407,790	422,063	436,835	452,124	467,948	484,327	501,278
Public Authorities	6,952,403	7,285,681	7,518,625	7,712,547	7,920,378	8,134,399	8,386,530
Other (City)	4,439,444	4,801,230	4,971,877	5,148,362	5,330,906	5,519,735	5,715,078
Total	63,416,038	66,456,016	68,580,808	70,349,658	72,245,375	74,197,555	76,497,363
Less: Conservation	(1,700,000)	(3,400,000)	(5,000,000)	(5,000,000)	(5,000,000)	(5,000,000)	(5,000,000)
Total W/Conservation	61,716,038	63,056,016	63,580,808	65,349,658	67,245,375	69,197,555	71,497,363
Percent Change		2.17%	0.83%	2.78%	2.90%	2.90%	3.32%

Table LF-7
Utility Financial Plan
City of Blaine Light Fund
Blaine Forecast Number of Customers in Annexed Service Area

Customer Class	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	0	0	624	646	668	692	716
Unused	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	0	0	1	2	2	2	2
Commercial (Over 50 KVA)	0	0	0	0	0	0	0
Industrial	0	0	0	0	0	0	0
Senior/Disabled	0	0	0	0	0	0	0
Public Street Lighting	0	0	0	0	0	0	0
Public Authorities	0	0	0	0	0	0	0
Other (City)	0	0	75	75	75	75	75
Total	0	0	700	723	745	769	793
Percent Change		0.00%	0.00%	3.26%	3.13%	3.14%	3.15%

Scenario 5: Medium Forecast & Rate Neutral Annexation

Table LF-8
Utility Financial Plan
City of Blaine Light Fund
Forecast of Sales in Annexation Area

Customer Class	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	0	0	8,565,024	8,793,757	9,031,352	9,255,435	9,438,312
Unused	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	0	0	25,259	51,118	51,718	52,318	52,918
Commercial (Over 50 KVA)	0	0	0	0	0	0	0
Industrial	0	0	0	0	0	0	0
Senior/Disabled	0	0	0	0	0	0	0
Public Street Lighting	0	0	0	0	0	0	0
Public Authorities	0	0	0	0	0	0	0
Other (City)	0	0	12,456,522	12,462,500	12,468,000	12,473,077	12,477,778
Total	0	0	21,046,805	21,307,375	21,551,070	21,780,830	21,969,008
Less: Conservation	0	0	0	0	0	0	0
Total W/Conservation	0	0	21,046,805	21,307,375	21,551,070	21,780,830	21,969,008
Percent Change		NA	NA	1.24%	1.14%	1.07%	0.86%

Table LF-9
Utility Financial Plan
City of Blaine Light Fund
Blaine Forecast Number of Total Customers
(Existing and Annexed Service Area)

Customer Class	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	1,437	1,487	2,163	2,239	2,317	2,398	2,482
Unused	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	345	360	376	394	411	429	447
Commercial (Over 50 KVA)	85	87	91	94	97	100	104
Industrial	10	10	11	11	12	12	12
Senior/Disabled	100	104	107	111	115	119	123
Public Street Lighting	1	1	1	1	1	1	1
Public Authorities	52	54	56	57	59	62	64
Other (City)	28	29	105	106	107	108	109
Total	2,057	2,132	2,910	3,013	3,119	3,229	3,343
Percent Change		3.64%	36.48%	3.55%	3.52%	3.53%	3.53%

Scenario 5: Medium Forecast & Rate Neutral Annexation

Table LF-10
Utility Financial Plan
City of Blaine Light Fund
Forecast of Use by Customer Class (KWh)
(Blaine Total Customer Forecast Times BPA Consumption per Customer)

Customer Class	1993	1994	1995	1996	1997	1998	1999	2000
Residential and Farm	17,395,870	19,973,134	20,584,461	29,689,873	30,482,757	31,306,358	32,083,120	32,717,048
Unused	0	0	0	0	0	0	0	0
Commercial (50 KVA or Less)	8,088,142	8,407,508	8,979,167	9,506,865	10,062,528	10,621,790	11,211,486	11,833,283
Commercial (Over 50 KVA)	20,632,442	17,430,665	18,134,076	18,422,149	18,740,063	19,086,455	19,460,289	19,860,791
Industrial	3,331,920	4,412,399	4,814,018	5,151,865	5,083,814	5,041,410	5,020,217	5,351,397
Senior/Disabled	1,114,340	1,392,694	1,435,320	1,473,001	1,512,338	1,553,199	1,591,737	1,623,188
Public Street Lighting	394,080	407,790	422,063	436,835	452,124	467,948	484,327	501,278
Public Authorities	6,584,250	6,952,403	7,285,681	7,518,625	7,712,547	7,920,378	8,134,399	8,386,530
Other (City)	2,516,900	4,439,444	4,801,230	17,428,398	17,610,862	17,798,906	17,992,812	18,192,856
Total	60,057,944	63,416,038	66,456,016	89,627,613	91,657,034	93,796,445	95,978,385	98,466,372
Less: Conservation	0	(1,700,000)	(3,400,000)	(5,000,000)	(5,000,000)	(5,000,000)	(5,000,000)	(5,000,000)
Total W/Conservation	60,057,944	61,716,038	63,056,016	84,627,613	86,657,034	88,796,445	90,978,385	93,466,372
Growth		2.76%	2.17%	34.21%	2.40%	2.47%	2.46%	2.73%

Scenario 5: Medium Forecast & Rate Neutral Annexation

Table O&M-1
Utility Financial Plan
City of Blaine Light Fund
Forecast of O&M Cost Growth Rate

Description	1994	1995	1996	1997	1998	1999	2000
Additional Sales (kWh)							
Existing Service Area	1,658,094	1,339,978	524,793	1,768,850	1,895,716	1,952,181	2,299,808
Proposed Annexation Area	0	0	21,046,805	260,571	243,695	229,760	188,178
Total	1,658,094	1,339,978	21,571,597	2,029,420	2,139,411	2,181,941	2,487,986
Percent Increase in Sales							
Existing Service Area	2.76%	2.17%	0.83%	2.09%	2.19%	2.20%	2.53%
Proposed Annexation Area	0.00%	0.00%	33.38%	0.31%	0.28%	0.26%	0.21%
Total	2.76%	2.17%	34.21%	2.40%	2.47%	2.46%	2.73%

Scenario 5: Medium Forecast & Rate Neutral Annexation

Table O&M-2
Utility Financial Plan
City of Blaine Light Fund
Percentage Increase in O&M Costs

Description	1994	1995	1996	1997	1998	1999	2000
Percent of Growth Toward Cost Increase							
Existing Service Area	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Proposed Annexation Area	100.00%	100.00%	100.00%	25.00%	25.00%	25.00%	25.00%
Weighted Average Growth Rates in kWh							
Existing Service Area	0.69%	0.54%	0.21%	0.52%	0.55%	0.55%	0.63%
Proposed Annexation Area	0.00%	0.00%	33.38%	0.08%	0.07%	0.06%	0.05%
Total	0.69%	0.54%	33.59%	0.60%	0.62%	0.61%	0.68%
Non-Growth Related Increases	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Total Growth Rate	3.69%	3.54%	36.59%	3.60%	3.62%	3.61%	3.68%

Scenario 5: Medium Forecast & Rate Neutral Annexation

Table O&M-3
Utility Financial Plan
City of Blaine Light Fund
Percentage Increase in A&G Costs

Description	1994	1995	1996	1997	1998	1999	2000
Percent of Growth Toward Cost Increase							
Existing Service Area	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Proposed Annexation Area	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
Weighted Average Growth Rates							
Existing Service Area	0.69%	0.54%	0.21%	0.52%	0.55%	0.55%	0.63%
Proposed Annexation Area	0.00%	0.00%	10.01%	0.09%	0.08%	0.08%	0.06%
Total	0.69%	0.54%	10.22%	0.61%	0.63%	0.63%	0.69%
Non-Growth Related Increases	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Total Growth Rate	3.69%	3.54%	13.22%	3.61%	3.63%	3.63%	3.69%