CITY OF KEIZER MISSION STATEMENT
KEEP CITY GOVERNMENT COSTS AND SERVICES TO A MINIMUM BY PROVIDING CITY SERVICES TO THE COMMUNITY IN A COORDINATED, EFFICIENT AND LEAST COST FASHION

A G E N D A

KEIZER CITY COUNCIL/KEIZER URBAN RENEWAL AGENCY
JOINT WORK SESSION

Monday, November 9, 2009
5:45 p.m.
Robert L. Simon Council Chambers
930 Chemawa Road NE
Keizer, Oregon 97303

1. **CALL TO ORDER**

2. **ROLL CALL**

3. **DISCUSSION**

    a. **Natural Gas Fired Combined Cycle Power Plant Financing (5:45 p.m. to 6:45 p.m.)**

    b. **Keizer Civic Center - Catering Center (6:45 p.m. to 7:45 p.m.)**

4. **ADJOURN**

[redacted]

MEMORANDUM

TO: **MAYOR AND CITY COUNCIL**

FROM: **CHRISTOPHER C. EPPLEY**
CITY MANAGER

SUBJECT: **NATURAL GAS FIRED COMBINED CYCLE POWER PLANT FINANCING**

BACKGROUND

Councilors:

Several weeks back, Chuck Sides invited a number of staff up to Portland to an attorney's office to hear a pitch for the City to ultimately own the 400MW power plant being talked about. The attorney, Larry Cable with Cable Huston Benedict Haagensen & Lloyd LLP (heretofore know as Cable Huston), specializes in structuring municipal power plant financings and service contracts and, according to Shannon, is well respected in the field. In the information below, I have tried to summarize the main deal points and the results of some research staff has done since then on the topic.

1. ***Why does the developer want the City to be involved?***

   The answer to this question is somewhat speculative since the developer has not offered these as definitive reasons, but I believe the rationales below are pretty solid.

   - The debt issuance would be pretty large ($400M or so) and having the City involved would add legitimacy to the project for the purpose of financing, negotiating power purchase agreements, and negotiation fuel purchase agreements.

   - If the City is involved, a large portion of the risk involved would be shared by the City instead of solely by the developer.

   - We can issue debt cheaper (tax free rate at 4%ish versus private rate at 7%ish).

   - I think most significantly, we can stretch debt service out for a longer period of time (25 to 30 years versus 10 to 15 years for private debt).

2. ***What would the City's participation look like?***

As you might have guessed, our participation would primarily be financial. In the case that was presented to us, the City would issue what are called ***non-recourse revenue bonds***. These bonds are so named because the City would not pledge the full faith and credit of the General Fund, or any other city resources of assets for the security of the bonds. The only revenue source which would be pledged by the City to pay the debt service would be the revenues from the sale of power from the plant after the payment of operations and maintenance and fuel costs. If the plant does not produce enough revenues to pay debt service under these types of bonds, the bond holders would be entitled to foreclose on the mortgages granted at financing to protect their investments. The City would lose its right to earn profits from the sale of power but would become entitled to the property tax payments because the plant would no longer be a public asset. The bond holders are expressly prohibited from seeking payment from any other source of revenues available to the City at any time, including following any default on the bonds.

This is a unique type of bond that I am unfamiliar with but our research with other cities who have used them for similar projects say they work exactly like described. Klamath Falls, OR actually defaulted on part of the bonds associated with constructing the power plant they owned for a period of time. They didn't default on the power plant portion of the bond issuance but instead on bonds they issued at the same time to purchase and rehab an old movie theatre. That venture that didn't pay off well for them and they went into default on that part of the debt issuance. They did suffer a hit to their credit rating for about 5-years, but there were no lasting negative effects from the failed project.

In exchange for financing the project, the City would end up as an equity owner of a majority of the power plant, meaning that we would share in the profits produced by the plant after debt service, fuel costs, and O&M. It is anticipated that the annual proceeds to the City after all expenses are accounted for would be far in excess of the property taxes we would earn if the plant were privately held…potentially 10X or more…and could even be 2X or more than what we collect annually in property taxes City wide, which could present the City Council with some interesting choices about whether or not to collect property taxes City Wide in any given year.

3. ***What are the potential positives for the City?***

The potential positives for the community are staggering. If the power market performs as most analysts expect, especially with large consumers moving toward more environmentally friendly alternatives to traditional coal power generation (i.e. the entire State of California choosing to legislatively prohibit the purchase of power made with coal within the next 18-months), natural gas fired power generation is likely to be in great demand and a very secure investment. If the City were to be able to lock in favorable power purchase agreements 20 or 30 years out (which is how I understand those things are negotiated) and reasonable fuel purchase agreement for the same time period, the revenues generated by the plant could significantly enhance the types of projects the City engages in to promote the safety, quality of life, and economic development of the community…more so than any other single revenue source that I can identify.

4. ***What are the risks for the City?***

The risks include, but are not limited to:

- ✓ If the power market takes a significant and unanticipated turn away from natural gas fired generation, the revenues generated by the plant could be insufficient to pay the costs, at which time the City would be forced to sell the plant or default on the debt.

- ✓ If California (the most likely destination of power generated from any plant built in Keizer) legislatively prohibits the purchase of power generated with natural gas, the revenues generated by the plant could be insufficient to pay the costs, at which time the City would be forced to sell the plant or default on the debt. I don't believe this to be a likely scenario, but the "no-coal" thing wasn't anticipated either…

- ✓ If federal regulations change to prohibit the production of power made from natural gas, the revenues generated by the plant could be insufficient to pay the costs, at which time the City would be forced to sell the plant or default on the debt.

- ✓ If future federal or state regulations make the production of power with natural gas too expensive to be financially feasible, the revenues generated by the plant could be insufficient to pay the costs, at which time the City would be forced to sell the plant or default on the debt.

- ✓ I'm sure there are other scenarios that would be bad.

None of these are very likely scenarios, but it is important to keep in mind that there are potential risks that need to be monitored.

5. ***Do other cities own power generation facilities?***

Our research has shown us that municipal ownership of electric generation facilities is not as uncommon as you might think. There are at least a dozen cities in Oregon, Utah and California that own or have recently owned some or all of the equity in a power generation facility. The most pertinent to our situation is Klamath Falls, who owned 50% of a natural gas fired combined cycle cogeneration plant. I have attached the feasibility report provided to them on the project for your review.

The general consensus of those cities that own a piece of power generation is pretty straight forward. In each case, we were told that if we can lock in favorable long-term power purchase agreements and negotiate reasonable fuel purchase agreements, it's a fantastic win and a huge asset for the community. If you don't get those things in place, it's better to step away and just settle on the property tax receipts. In the case of Klamath Falls, they only locked in 50% of their potential power purchase agreements and wanted to keep the other 50% open to sell at market. This worked really well for them for about 5-years and then the power market collapsed when California went put limits on their purchase pricing a few years back. Had they not tried to maximize their profits in a risky fashion, they would still own the plant, but instead, they sold their 50% equity interest to the company that was operating the plant for $1M/year for 25-years plus the property tax revenues and the new owner assumed the debt as part of the agreement.

6. ***What are the chances that the Power Plant will be built if the City is not involved in the financing?***

   It is clear that the project is more likely to occur if the city were to be involved as the financing tool. This would eliminate a great deal of the risk from the private sector of the equation and would remove a majority of the impediments to forward progress. Even with this, as has been relayed to City staff by Mr. Cable, Esq., only roughly 50% of projects of this nature end up being constructed after progressing through the full analysis and permitting process for various reasons, including political factors, high resulting transmission costs, lack of available reasonably priced fuel, etc.

   If the City is not involved as the financing tool I believe the project still has a relatively high likelihood of moving forward based on the natural site advantages of the Keizer location versus other locations, however the private sector does not have the same financing tools available to it as do public entities and, therefore private investors are much less tolerant to risk than public entities can be in this instance. Therefore, it stands to reason that the percentage chance that a project will go forward if the City is not involved is significantly lower than if we are.

RECOMMENDATION

After a great deal of consideration, I recommend that the Council directs staff to develop the appropriate resolution or other authorization to be brought back to the City Council at the next reasonable opportunity to propose to Keizer Energy, LLC that the energy facility project move forward with consideration of the City being the financing agent for the project and, ultimately the primary equity owner of the resulting power generation plant. As part of this proposal, staff would recommend that as a condition of any such agreement, Keizer Energy agree to fund, at their expense and at risk of not being reimbursed for the cost should a power plant project not ultimately be constructed, a professional analysis similar to the one conducted for the Klamath Falls, OR project, identifying the likely viability of the proposed project taking into consideration all identifiable factors, including but not limited to current and future power market factors, the state and federal regulatory environment, and the viability and cost of natural gas as the fuel type for the plant.

MEMORANDUM

TO: Keizer, LLC

FROM: Larry Cable

DATE: October 12, 2009

RE: Public Non-Recourse Bond Financing of Generating Facilities

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Introduction

The 400 MW natural gas generating facility to be located in Keizer, Oregon, can be financed in a variety of ways: private equity financing; capital provided by a long term power purchaser or power purchasers or by the issuance of municipal non-recourse revenue bonds. This Memorandum addresses the manner in which such facilities have been municipally financed.

Power of an Oregon City to Finance Generating Facilities

The Oregon Home Rule constitutional provisions as well as the Oregon Revised Statutes dealing with the ownership of thermal generating facilities authorize a City to issue debt of different types to finance a partial or complete ownership interest in a thermal generating facility. This action can be taken for the "benefit of its inhabitants or for profit." (Paraphrase of Oregon Supreme Court holding)

This power is that which allowed the City of Klamath Falls to issue approximately 350 million of revenue bonds to build the Klamath Co-Generation facility. It is not necessary that the City distribute or sell electricity to its inhabitants in order to own or finance such a facility. Klamath had not exercised its authority to provide electricity to its citizens when it financed the Klamath project.

Non-Recourse Revenue Bonds

The bonds issued to build the generating facility can be of different types - taxable recourse or non-recourse bonds, general obligation bonds, various types of state guaranteed bonds or tax exempt recourse or non-recourse bonds. Only non-recourse (taxable or tax exempt) bonds are here addressed.

Non-recourse bonds are so named because the Issuer City pledges only the revenues from a particular source or sources of revenue available to the City to pay the debt service on the bonds. In this case, the only revenue source which would be pledged by the City of Keizer to pay the debt service are the revenues received from the sale of power from the Project after the payment of operation and maintenance expenses and fuel costs. If the Project does not produce enough revenues to pay debt service under these arrangements, the bond holders are entitled to foreclose on the mortgages granted at financing to protect the bond holders. The City loses its right to earn profits from the sale of power but becomes entitled to earn property tax payments to the extent the City is so entitled under the tax laws to earn such sums. The bond holders are expressly prohibited from seeking payment from any other source of revenues available to the City at any time, including following any default on the bonds.

Procedures and Basic Contractual Structures

Since the bond holders can look only to the revenues from power sales to pay the debt service on the bonds, in most cases the power to be produced by the Project when constructed must be pre-sold to credit worthy power purchasers under agreements that effectively allow the bonds to be sold on the basis of the credit of the power purchasers and the terms of the agreements.

Further, a guaranteed project construction agreement must be in place that contractually ensures that the Project will be built to specifications, by a given date and perform to a contractually specified level (plant factor). If the contract is breached in any of these regards, liquidated damages are paid by the contractor building the Project. These damage payments are bonded (guaranteed) and they are used to pay down debt that would have been paid had the project been built in accordance with the construction contract requirements.

Fuel agreements may also be required that hedge the cost of the fuel and fuel transportation for some period of time. Qualified engineers and experts forecast gas and power prices and must opine that it is highly likely that the debt service will be paid given the forecasts and power purchase terms.

Plant operators are retained under suitable and bonded operational and maintenance agreements. These contractors operate the Project on behalf of the City.

The City is entitled to receive the net returns from the operation of the Project as follows:

First, all sums paid for power are paid to the Bond Fund Trustee.

Second, the Trustee pays all operation and maintenance costs.

Third, all fuel costs are paid by the Trustee.

Fourth, any required debt service or other reserves are supplemented as required by the terms of the Bond Indenture through payments by the Trustee.

Fifth, the City is paid the remaining sums on periodic pay out dates also specified in the Indenture.

The sums earned by the City are fully available to the City for any lawful use once they are distributed under the above-described procedures. These earnings will depend on how well the Project runs, the price of gas and, if any of the power is not pre-sold, on the market price of power.

Conclusion and Disclaimer

This summary is intended only as a very basic description of one of the alternatives for financing the Keizer facility. It is not a legal opinion and should not be relied upon by any entity absent specific confirming opinions.

There are many iterations to this basic structure which we can discuss this morning should City officials desire to do so. However, as we will also discuss, our view is that the City should only undertake financing such a Project if the vast majority of the power from the Project is sold under long term power purchase agreements with power purchasers that have outstanding credit; guaranteed construction agreements are in place; and, reasonably long-term fuel and transportation agreements are executed at the time of financing. Such arrangements are very likely required to use non-recourse financing in any event and to be able to sell the bonds on the above-described terms.

Thank you.

Larry Cable.

KLAMATH COGENERATION PROJECT
INDEPENDENT ENGINEER'S REPORT

Prepared By

RMI

RESOURCE MANAGEMENT
INTERNATIONAL, INC.

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INTRODUCTION

Presented herein is the Independent Engineer's Report (the Report) prepared by Resource Management International, Inc. (RMI) concerning our review and analyses of the proposal by the City of Klamath Falls, Oregon (the City) to issue $220,000,000 of Tax-Exempt Senior Lien Electric Revenue Refunding Bonds, Series 1999 (the Tax-Exempt Senior Lien Bonds), up to $30,000,000 of Taxable Senior Lien Electric Revenue Bonds, Series 1999 (the Taxable Senior Lien Bonds) and $60,000,000 of Taxable Second Lien Electric Revenue Bonds, Series 1999 (the Taxable Second Lien Bonds). The proceeds of the Tax-Exempt Senior Lien Bonds will be used to refund all $220,000,000 of the City's outstanding Electric Revenue Bonds Fixed/Adjustable Rate Series (the 1986 Bonds) originally issued by the City in the amount of $250,000,000. Proceeds of the 1986 Bonds, together with proceeds of the Taxable Senior Lien Bonds and the Taxable Second Lien Bonds will be used to fund the construction of the Klamath Cogeneration Project (the Project) and establish reserve accounts for the payment of debt service and for major maintenance and repair of the Project over the term of the Project Bonds. The Tax-Exempt Senior Lien Bonds, Taxable Senior Lien Bonds and the Taxable Second Lien Bonds are referred to herein as the Project Bonds.

The Project includes a cogeneration facility (the Facility) that will have the capacity to generate 483,790 kilowatts of electricity, or simultaneously generate 464,020 kilowatts of electricity and 200,000 pounds per hour of steam at average annual ambient conditions. The Facility will include two natural gas-fired combustion turbine generators, two heat recovery steam generators with exhaust stacks, a steam turbine generator, evaporative cooling tower, water treatment equipment, water storage tanks, main transformers, electrical switchyard, access and parking areas, a turbine building with space for operating and maintenance staff and services, pipelines to deliver steam to, and return condensate and makeup water from, an adjacent local wood products manufacturing facility (the Collins Facility) owned and operated by Collins Products LLC (Collins), and other items. The Facility will be located outside of the City limits on property leased by the City from Collins and adjacent to the Collins Facility.

The City will install, or cause to be installed, certain necessary supporting facilities to serve the Project. Pipelines will receive treated effluent from the City's Spring Street Waste Water Treatment Plant (SSWWTP) as Facility cooling water, and return treated Facility wastewater to the City sewer system. The SSWWTP is located approximately 5 miles north of the Facility site. The City will also install, or cause to be installed, a new potable water supply line to the Project. Payment to the City for these new interconnections will be funded from Project Bond proceeds.

PacifiCorp will re-align approximately 6500 feet of an existing 500 kilovolt transmission circuit line that runs between the Meridian substation to the west of the Project site, and the Captain Jack substation approximately 20 miles east of the Project site, to connect with the Facility switchyard and accept power from the Facility. Payment to PacifiCorp for this new interconnection will be funded from Project Bond proceeds.

The Facility will utilize enhanced combustion turbine generator technology that includes the best available emission control technology for oxides of nitrogen (NO_X). The Facility will be designed for efficient operation across a wide range of operating modes and conditions. The Facility will be designed according to accepted utility industry standards for high availability.

The Project site lies in close proximity to large high voltage transmission lines that are used to transfer power between the Pacific Northwest and California load centers. The Project site also lies in close proximity to the large capacity Pacific Gas & Electric Gas Transmission Northwest (PGTNW) interstate natural gas transportation pipeline that is used to deliver natural gas from Canadian producing regions into California load centers. Figure 1 illustrates the location of the Project relative to these major energy transportation corridors.

The Project will be owned by the City, and will be constructed, fueled, operated and managed under certain agreements between the City and other participants as described elsewhere in this Report. Approximately 47 percent of the power produced will be sold to a non regulated power marketing subsidiary of PacifiCorp for a term of 30 years. The balance of power will be sold on the open wholesale power market in the western U.S. to purchasers that meet certain federal tax-exempt status requirements. Likely purchasers include tax exempt municipal utilities and non-federal government agencies in the Pacific Northwest and California. Power not sold to qualified purchasers may be sold for terms of 30 days or less to any public or private wholesale purchaser.

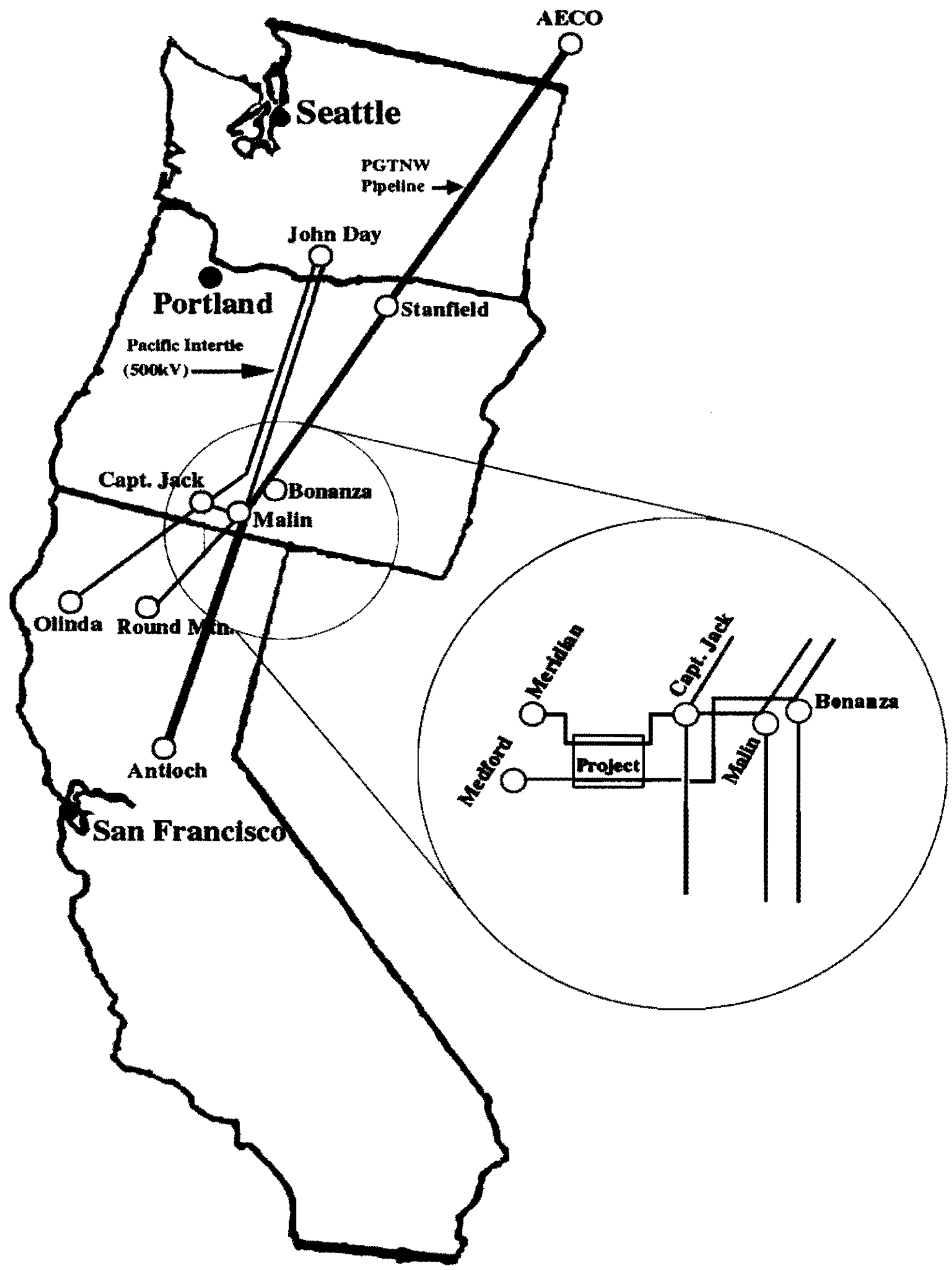
The Project has received all required material authorizations and permits for construction and initial operation. These include a Site Certificate from the Oregon Energy Facility Siting Council, an Air Contaminant Discharge Permit from the Oregon Department of Environmental Quality, and a Conditional Use Permit from Klamath County, Oregon.

The Project is strategically located near the California-Oregon Border, which is one of only two locations in the western U.S. that has been selected by the New York Mercantile Exchange (NYMEX) as a point of delivery for its standardized electricity futures contract. This location has become an active market for power trading in the California and Pacific Northwest markets. The Project will be interconnected with a 500 kV transmission line which ties directly with one of the two 500 kV substations which interconnect the Pacific Northwest electric system with the California electric system. The Project will be the closest generation source to the California Oregon Border trading point, enjoying low-cost transmission delivery to the trading point and the ability to sell into both the Pacific

Northwest and California/Nevada market as explained in more detail under report entitled "Electricity and Natural Gas Markets in the Western United States" under Appendix B to this Report.

RMI prepared a projection of the expected financial operating results of the Project for the years 2001 through 2029 for the purpose of determining the expected adequacy of revenues over costs and the resultant debt service coverage levels during this period. A simulation of the future wholesale power market in the western U.S. was performed by Henwood Energy Services, Inc. (HESI) to provide a forecast of expected power sale prices and capacity factors for the Project. HESI has provided a description of the forecast which is included in Appendix B to this Report. Additional forecasts of fuel costs, capacity, heat rate, and other variable and fixed operation and maintenance costs of the Project were obtained from the Project participants. Scheduled debt service and reserve funding requirements of the Project Bonds were obtained from the underwriters of the Project Bonds. The resulting projected operating results reveal that after payment of operating expenses, the ratio of revenues available for payment of debt service on the Tax-Exempt Senior Lien Bonds and the Taxable Senior Lien Bonds (debt service coverage ratio) is expected to be 1.74x at minimum, and 2.09x on average, over the entire period, and all Project Bonds will be fully defeased by the year 2019.

Figure 1
Location of the Project Relative to
Major Energy Corridors



PARTICIPANTS

The Owner

The City of Klamath Falls is located in south central Oregon near the California border along Oregon Highway 97 at an elevation of approximately 4,150 feet. The City was incorporated in 1905 and has a population of approximately 18,405. The local economy has historically been dominated by agriculture and ranching. However, the economy has recently been diversified through introduction of new manufacturing, communications and tourism related businesses in the area.

The City operates with a Council/Manager form of government under its own charter and State law. The City Council is composed of five members, each serving a four-year term. The Mayor also serves a four-year term, and presides over the City Council meetings. The Mayor appoints committee members and carries out City Council policy. The City Manager, Municipal Court Judge and City Attorney report directly to the City Council.

The City provides a full range of municipal services including water and sewer utility systems. The City does not currently own or operate an electric generating station or distribution system. Electric service within the City and surrounding area is provided by Pacific Power, a division of PacifiCorp. Water supplies for the City are generally supplied from groundwater. The City owns and operates the SSWWTP. The SSWWTP was constructed in 1957 and upgraded in 1972. It has a six million gallon per day design capacity.

The City and Pacific Klamath Energy, Inc. (PKE) have an existing agreement to develop the Project. PKE is a direct, wholly-owned special purpose subsidiary of PacifiCorp Group Holdings, Inc. (PGHC), which in turn is a wholly owned subsidiary of PacifiCorp. The City will own the Project. The City will contract with PKE, other PGHC subsidiaries, and third parties to engineer, construct, manage, operate, maintain, provide fuel to and broker power sales from the Project as described elsewhere in this Report. Necessary Project authorizations and permits have been obtained in the name of the City. The City will provide potable water service, and sanitary waste treatment service to the Facility. The City will also provide effluent from the SSWWTP to the Facility for use in evaporative cooling, and receive waste water from the Facility for disposal.

The Developer, Manager During Construction, and Operator

PKE was founded in 1996 for the primary purpose of development, management and operation of the Project under contract with the City. PKE is headquartered in Portland, Oregon. PKE, either directly or through cooperation with its affiliates will utilize experienced power generation engineering, financial and operations specialists to provide project management services during construction and to operate and maintain the Facility. PKE personnel recently successfully managed development, design, construction and operation of the 240 megawatt Crockett Cogeneration Project near San Francisco, California which utilizes technology similar to the Project. The Crockett Cogeneration Project entered commercial service in 1996.

PKE and the City have an existing agreement to develop the Project under the terms of a joint development agreement. PKE is also responsible for management of the Project during construction under terms of the Agreement for Project Management Services During Construction described elsewhere in this Report. Finally, PKE is responsible for operation and maintenance of the Project for a term of at least five years under terms of the Operation and Maintenance Agreement described elsewhere in this Report.

THE FUEL SUPPLIER, POWER PURCHASER, POWER BROKER AND MANAGER

PacifiCorp Power Marketing, Inc. (PPM) is a corporation existing under the state of Oregon. It is a direct, wholly-owned subsidiary of PGHC which in turn is a direct, wholly-owned subsidiary of PacifiCorp.

PPM is responsible for supply and delivery of all the natural gas fuel required for operation of the Facility for a term of 30 years or the duration of the Project Bonds, whichever is longer, under the Fuel Supply and Services Agreement with the City described elsewhere in this Report. PPM will either directly or indirectly subcontract with gas producers for fuel supply, and with gas pipeline companies for transportation service, including PGTNW. PPM holds firm capacity rights on the Medford Lateral, which is the section of the PGTNW system to which the Project will be connected. The capacity rights are sufficient to deliver the entire fuel requirement of the Project.

Upstream of the Medford Lateral, PPM will purchase a combination of short-term firm, long term firm and interruptible gas transportation service from PGTNW and other pipelines as necessary to deliver gas to the Medford Lateral. Charges for such service are typically based on pipeline tariff transportation rates, which include a large fixed component which must be paid regardless of actual volumes shipped. However, PPM will charge for gas transportation based on delivered volumes only. This reduces the fixed operating cost, and therefore the power marketing risk of the Project.

PPM is also responsible for purchase of approximately 47 percent of the electricity from the Facility for a term of 30 years or the duration of the Project Bonds, whichever is longer, under terms of the Power Purchase Agreement described elsewhere in this Report. Electricity purchased will be resold to others. For a term of at least 20 years, PPM is also responsible for arranging for the sale of the remaining amount of electricity from the Facility to certain qualified purchasers on behalf of the City under terms of the Power

Brokering Agreement described elsewhere in this Report. For a term of at least 20 years, PPM is also responsible for administrative management of the Facility under terms of the Management Agreement described elsewhere in this Report.

The performance of PPM under the above-mentioned agreements is guaranteed by PGHC.

PPM was formed in 1997 for the purpose of purchasing and selling electric power in domestic wholesale markets. Sales by PPM are made pursuant to a Federal Energy Regulatory Commission (FERC) approved wholesale rate schedule. Recently, PPM has been making sales within the Western Systems Coordinating Council (WSCC) as a member of the Western Systems Power Pool (WSPP). The WSPP is a group of utilities, power marketers and other wholesale market participants that operate a market for wholesale transactions within the WSCC. Sales among WSPP participants are made pursuant to a FERC approved wholesale rate schedule of the WSPP.

PPM is involved in power generation development, long-term structured power sale and purchase, forward and cash market power trading, power dispatch and scheduling, fuel procurement, and the various back office functions necessary to support such activities. PPM is focused on wholesale markets and large industrial customers in emerging retail markets. PPM is a certified Scheduling Coordinator with the California Independent System Operator (Cal-ISO) and actively trades in the bi-lateral and California Power Exchange (PX) markets. PPM's activities are conducted from a central office and trading floor located in Portland, Oregon. PPM's goal is to competitively serve wholesale and large retail markets in the WSCC by using strategic generation and contract resources, developing and marketing customized physical and financial power sales arrangements from such resources, and trading of power and fuel around such resources.

PACIFICORP

PacifiCorp is responsible for constructing, owning and operating the facilities necessary for interconnection of the Facility to the PacifiCorp transmission network. These responsibilities are defined in the Generation Interconnection Agreement described elsewhere in this Report.

PacifiCorp is a diversified energy company doing business in the United States and Australia. In the United States, PacifiCorp conducts a retail electric utility business as Pacific Power and Utah Power. Other wholly owned major subsidiaries include PGHC, which holds directly or through its wholly owned subsidiary, PacifiCorp International Group Holdings Company, Powercor Australia Limited, an Australian electricity distributor, and PacifiCorp Financial Services, Inc., a financial services business.

PacifiCorp's common stock (symbol PPW) is traded on the New York and Pacific Stock Exchanges.[1]

The majority of electricity sold by PacifiCorp during the first nine months of 1998 was at the wholesale level. Of the total 113,878 gigawatt-hours of energy sold, 79,019 gigawatt-hours (more than 69 percent) were sold to wholesale customers, generating more than $2.5 billion in revenue[2]. However, PacifiCorp has recently announced plans to significantly scale back its unregulated energy trading business, including the eastern U.S. electricity trading business of PPM. PacifiCorp has sold the TPC Corporation, a wholly-owned natural gas marketing and storage subsidiary. PacifiCorp is focusing its non-regulated power marketing activities in the West, where it can provide physical delivery of energy.

On December 7, 1998, PacifiCorp announced that it had reached a definitive agreement with ScottishPower of Glasgow, Scotland that would result in the merger of the two companies. ScottishPower is one of the largest power, water and telecommunication utility companies in the United Kingdom with a market capitalization of over $13 billion. The combined entity, which will be known as ScottishPower, will be headquartered in Glasgow. PacifiCorp will continue to operate under its current name and will serve as the headquarters for the U.S. operations of ScottishPower. Certain ScottishPower executives will assume positions at PacifiCorp, and certain PacifiCorp executives will assume executive and board level positions at ScottishPower. The merger is subject to approval by the shareholders of both companies, the U.S. Federal Energy Regulatory Commission, the regulatory commissions of certain states served by PacifiCorp and certain Australian regulatory authorities. The merging companies recently obtained clearance of the merger under the provisions of the Hart-Scott-Rodino Antitrust Improvements Act of the U.S. The transaction is expected to close in the fall of 1999.

Pacific Power and Utah Power serve 1.4 million retail customers in service territories aggregating about 153,000 square miles in portions of Utah, Oregon, Wyoming, Washington, Idaho, California and Montana. Power production, wholesale sales, fuel supply and administrative functions of the two distribution utilities are managed on a coordinated basis. The service area contains diversified industrial and agricultural economies. The geographical distribution of retail electric operating revenues for the year ended December 31, 1997 was Utah, 36 percent; Oregon, 33 percent; Wyoming, 13 percent; Washington, 9 percent; Idaho, 4 percent; California, 3 percent; and Montana, 2 percent. During 1997, no single retail customer accounted for more than 1.9 percent of PacifiCorp's retail utility revenues and the 20 largest retail customers accounted for 14.7 percent of total retail electric revenues. PacifiCorp's historical total firm peak load (including both retail and firm wholesale sales) of 10,871 MW occurred on August 22, 1997. For the period 1998

[1] PacifiCorp 1998 Third Quarter 10Q Statement to the Securities and Exchange Commission

[2] Ibid.

to 2001, the average annual growth in retail kilowatt-hour sales in PacifiCorp's franchised service territory is estimated to be about 2.5 percent. During this period, PacifiCorp may lose energy sales to other suppliers in connection with direct access pilot studies. Conversely, PacifiCorp expects to have opportunities to gain market share in areas outside its franchised service territory. Actual results will be determined by a variety of factors, including deregulation in the electric industry, economic and demographic growth, competition and the effectiveness of energy efficiency programs. [3]

On July 9, 1998, PacifiCorp announced its intent to seek buyers for its California and Montana electric distribution assets. This action was in response to the continued decline in earnings on the assets and changes in the legislative and regulatory environments in these states where PacifiCorp has few distribution properties. PacifiCorp issued requests for proposals to interested parties on July 20, 1998. On September 16, 1998, PacifiCorp entered into a Letter of Agreement with Flathead Electric Cooperative for sale of the Montana distribution assets. On November 5, 1998, the Company completed the sale and received after-tax proceeds of $92 million. The Company will return $4 million of the $8 million gain to Montana customers as negotiated with the Montana Public Service Commission and the Montana Consumer Counsel.[4]

PacifiCorp owns 52 hydroelectric generating plants with an aggregate plant net capability of 1,138 MW. It also owns or has interests in 17 thermal-electric generating plants with an aggregate plant capability of 7,143 MW. PacifiCorp's transmission system connects with other utilities in the Northwest having low-cost hydroelectric generation, and with utilities in California and the Southwest having higher-cost fossil-fuel generation. During the winter, PacifiCorp has been able to purchase power from Southwest utilities, either for its own peak requirements or for resale to other Northwest utilities. During the summer, PacifiCorp has been able to sell excess power to Southwest utilities to assist them in meeting their peak requirements. With its present generating facilities, under average water conditions, PacifiCorp expects that approximately 5 percent of its energy requirements for 1998 will be supplied by its hydroelectric plants and 55 percent by its thermal plants. The balance of 40 percent is expected to be obtained under long-term purchase contracts, interchange and other purchase arrangements. PacifiCorp currently purchases 1,100 MW of firm capacity annually from BPA pursuant to a long-term agreement. The purchase amount declines to 925 MW annually beginning in 2000, and then to 750 MW annually beginning in 2003 and continuing through 2011.[5]

PacifiCorp currently purchases power on a long-term basis from the Hermiston Generating Project, which entered commercial operation in late 1996 and is similar in size and

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[3] PacifiCorp 1997 10K Statement to the Securities and Exchange Commission

[4] PacifiCorp Second Quarter 1998 Statement to the Securities and Exchange Commission.

[5] PacifiCorp 1997 10k Statement to the Securities and Exchange Commission

technology to the Project. The Hermiston Generating Project is located in north central Oregon and receives natural gas from the PGTNW pipeline. PacifiCorp is a 50 percent owner of the Hermiston Generating Project.

PacifiCorp operates the 1,340 megawatt coal-fired Centralia Power Project in Washington. PacifiCorp owns a 47.5 percent share of the plant, with the balance owned by eight investor and publicly-owned utility partners. The owners have agreed to hire an investment advisor to pursue the possible sale of the plant and the adjacent Centralia Mine. The sale of the plant is being considered by the owners, in part, because of emerging deregulation and competition in the electricity industry[6]. PacifiCorp owns and operates the adjacent Centralia Mine.

THE CONTRACTOR

Black & Veatch Construction, Inc. (BVC) is a Missouri corporation that is a wholly owned subsidiary of Black & Veatch, Holding Company (Black & Veatch) a Delaware corporation. BVC will be responsible for detailed design, engineering, procurement, construction and startup of the Project. Design, engineering and major equipment procurement will likely be performed by other divisions of Black & Veatch. Black & Veatch has provided a guarantee to the City for the performance by BVC of its obligations under the EPC Agreement between BVC and the City described elsewhere in this Report.

BVC was founded in 1991 for the primary purpose of providing construction services to projects designed by the engineering divisions of the parent company. BVC reported approximately 784 employees, $527 million in revenues and a net worth of $19 million in the most recent fiscal year. Nearly all revenues have come from power plant projects.[7] Construction services typically provided by BVC include construction, construction management, labor relations and negotiations, safety-health program management, insurance administration, project security programs, quality assurance program management, onsite procurement, project scheduling, expediting and warehouse management, contract administration, startup and initial operation and site engineering liaison.

Black & Veatch has extensive experience in the engineering, procurement and construction of power plants including simple and combined-cycle combustion turbines and cogeneration facilities. They report experience with over 55 domestic and international combined-cycle projects representing over 16,000 MW of capacity. Power related engineering and construction revenues in 1997 exceeded $1 billion (including the revenues

[6] Ibid.

[7] Dun & Bradstreet, Inc. *Supplier Evaluation Report - Black & Veatch Construction*, September 24, 1998.

of BVC), making Black & Veatch one of the top five power related contractors in the country.[8]

THE STEAM PURCHASER

Collins Products LLC (Collins) is an Oregon limited liability company headquartered in Portland, Oregon. Collins employs approximately 571 people in the production of plywood, particleboard and hardboard siding at the Collins Facility near the City of Klamath Falls. Collins was formed in 1996 to purchase the Collins Facility from the Weyerhaeuser Corporation. Collins is 49 percent owned by Collins Pine Company Inc., a manufacturer of hardwood and softwood products, and 51 percent owned by Ostrander Resources, a natural resources development and investment company.

Annual production capacity at the Collins Facility is 160 Million square feet of plywood on a 3/8 inch basis, 112 million square feet of particleboard on a 3/4 inch basis and 130 million square feet of hardboard siding on a 7/16 inch basis. Steam is used in the drying and curing of finished product. Revenues of Collins exceeded $110 million in 1997 with a total capitalization of approximately $22 million.[9] Collins has estimated its 1998 revenue at $98 million.

Collins is responsible for leasing land adjacent to the Collins Facility to the City for the Facility, including necessary construction space and easements, for a period of 40 years. Collins has a right, but not an obligation to purchase steam from the Facility, with a concurrent obligation to return condensate and makeup water to the Facility, for the duration of the Project Bonds. Collins will also grant the City an option to purchase credits for emission of particulate matter larger than 10 microns in diameter (PM_{10} Credits) which Collins has banked under terms of its air contaminant discharge permit with the State of Oregon. These responsibilities are defined under terms of the various agreements between Collins and the City that are described elsewhere in this Report.

ELECTRICITY AND NATURAL GAS MARKETS IN THE WESTERN U.S.

PROJECT POWER SALES AND MARKETS

Although a large portion of the power produced by the Project will be sold on a long-term basis to PPM, the majority of power is expected to be sold on the open wholesale power market in the western U.S., Pacific Northwest, and California.

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[8] Engineering News Record *The Top 500 Design Firms Sourcebook* September 1998 and *The Top 400 Contractors* May 25, 1998, McGraw Hill Publications.

[9] Dun & Bradstreet, Inc. *Supplier Evaluation Report - Collins Products LLC*, September 24, 1998.

The Pacific Northwest and California power markets are the largest in the western U.S., and are highly diverse and complementary in their energy sources and consumption patterns. The Pacific Northwest region is characterized by winter peaking loads served primarily by hydroelectric and coal-fired resources. The California region is characterized by summer peaking loads served primarily by natural gas fired resources. Power generally flows on transmission interties from the Pacific Northwest to California during the summer months, and from California to the Pacific Northwest during winter months. The interties increase reliability in both regions; allow economic use of surplus non-firm hydropower from the Northwest; and allow exchanges where the Northwest supplies peak capacity to California and southwestern purchasers who return energy in their off-peak hours or season.

ELECTRIC INDUSTRY RESTRUCTURING

Historically, the wholesale power market in the western U.S. has been characterized by relatively large, long-term transactions between major utilities that own or control the high voltage transmission networks of the region. Surplus or non-firm power has been traded in bilateral transactions scheduled on a daily or weekly basis. However, prices were generally not open to competition . Passage of the 1992 National Energy Policy Act (EPAct92) created new competition in the wholesale power markets. EPAct92 authorized the Federal Energy Regulatory Commission (FERC) to mandate that utilities provide transmission access to all qualified electric wholesale generators (EWG), electric utilities, Federal power marketing agencies and power marketers under tariffs and rates approved by the FERC. This led to a proliferation of new participants, development of accepted market hubs with widely published prices, increased price risks and development of new risk management tools.

Utilities were slow to pass on cost benefits to their retail customers. EPAct92 left consideration of additional competitive measures, such as retail access, up to the individual States. Under retail access, retail customers of the local utility would have the ability to receive power from an alternative provider. The local utility would continue to provide distribution service through their existing distribution system. Today, the State of Oregon has implemented limited retail access programs in the service territories of Portland General Electric and PacifiCorp. The State of Washington has enacted legislation relating to dis-aggregation of rates into power generation, transmission and distribution components. California has enacted comprehensive legislation enabling retail access statewide, guaranteed rate recovery of high cost assets that were in existence as of September 1996 (stranded costs) for regulated utilities, and independent operation of the utilities' high voltage transmission systems through a new independent system operator (1996 Assembly Bill 1890). Although generally not subject to federal or state regulation, some municipal utilities in the Pacific Northwest and California are enacting retail access programs to remain competitive on both price and customer service. Some of them face large stranded cost potential, and are raising rates in the near term to temporarily accelerate debt repayment on their higher cost assets before retail competition becomes more wide spread.

PROJECT INTERCONNECTION AND MARKET ACCESS

The Project will be interconnected to an existing 500 kV transmission line that runs between the Meridian substation to the west of the Project site, and the Captain Jack substation approximately 20 miles east of the Project site. This 500 kV line is owned and operated by PacifiCorp, but southbound capacity is shared equally between PacifiCorp and the Bonneville Power Administration (BPA).

At Captain Jack, the 500 kV line is connected to the 500 kV transmission systems of BPA to the north and the Transmission Agency of Northern California (TANC) to the south. The actual division of ownership occurs at the border between California and Oregon, located a few miles south of Captain Jack. The BPA and TANC lines are collectively known as the Third AC Intertie. Captain Jack is also connected to the Malin substation, approximately five miles to the east. Malin is an interconnection between the 500 kV transmission systems of PacifiCorp, Portland General Electric (PGE) and BPA to the north, and Pacific Gas and Electric (PG&E) to the south. Again, the actual division of ownership occurs at the border between California and Oregon, located a few miles south of Malin. The PacifiCorp, PGE and PG&E lines are collectively known as the Pacific Intertie. There is also a direct current (DC) intertie that interconnects the BPA transmission system in northern Oregon with the transmission system of the Los Angeles Department of Water and Power (LADWP) in southern California (the DC Intertie). Direct interconnection with the DC Intertie at points other than the two terminals of the line is generally not economically feasible due to the cost of DC to AC conversion. The Pacific Intertie and the Third AC Intertie serve as the major north-south transmission paths for power flow between the Pacific Northwest and northern California, with a combined design transfer capacity of 4800 MW from north to south, and 3675 MW from south to north. Actual transfer capacity may be less than these amounts due to periodic maintenance, circuit failure, or reductions imposed by the intertie operators. North of Malin, both interties are operated by BPA, although capacity is shared among BPA, PacifiCorp, Portland General Electric, and other non-federal entities to whom BPA has sold life-of-facilities capacity rights. South of Malin, the interties are operated by the California Independent System Operator (Cal-ISO). Transmission capacity on the Pacific Intertie in California is generally owned by the major investor owned utilities, and transmission capacity on the Third AC Intertie is generally owned by the TANC participants which include municipal government tax-exempt utilities in the Pacific Northwest and California.

A few miles south of the Captain Jack and Malin substations is the California Oregon Border (COB), a popular and active point of delivery for firm or non-firm, long- or short-term power sales and exchanges between energy traders in the two regions. Prices for sales at COB are published on a daily basis in major national newspapers. The New York Mercantile Exchange (NYMEX) uses COB as the point of delivery for its standardized COB electricity futures contract. Other popular trading hubs in the Pacific Northwest and California include Mid-Columbia on the BPA transmission system in Washington, and the Power Exchange (PX) in California. Published daily prices at COB, Mid-Columbia and the PX are popular for use in setting prices for longer-term power sales contracts throughout the regions.

The proximity of the Project site to COB is a highly beneficial power marketing advantage for the Project in the region. No other power generation plant enjoys such low electric transmission costs to COB. The Project has the ability to deliver energy south to COB to meet the summer peak season needs of California, Nevada, and other southwestern locations. Other power sources in the Pacific Northwest, all of which are further north with higher transmission costs and greater transmission losses, must incur higher costs to reach the COB trading point to sell south. Similarly, with respect to the Pacific Northwest winter peak season, sources from south of COB seeking to sell into the Pacific Northwest will incur higher transmission service costs, and higher transmission energy losses, making the Project's cost of delivery more competitive.

Power sold to PPM will be delivered at the point of interconnection between the Project and the Meridian-Captain Jack line. PPM is responsible for obtaining all transmission service necessary to deliver this power to their purchasers. Power brokered by PPM on behalf of the City will be delivered by BPA to COB, where control will be transferred to the Cal-ISO for delivery into California. BPA will provide 280 megawatts of transmission service from the Project to COB using their rights to the Meridian-Captain Jack line under terms of a Transmission Service Agreement with the City described elsewhere in this Report. Fifty (50) megawatts of this service is in excess of what is needed for sales on a year-round basis to other purchasers, and has been assigned by the City to PPM. When and to the extent that any of the City's remaining transmission service under the Transmission Service Agreement is not used for sales to other purchasers, it will be brokered by PPM to third parties on behalf of the City under terms of the Power Brokering Agreement as described elsewhere in this Report. From COB, purchasers will be responsible for transmission service through the Cal-ISO to their loads, either through use of capacity rights they currently hold, or through contracting for capacity with the Cal-ISO. Purchasers north of COB must either use rights they currently hold to transmit power from COB to their loads, or obtain new transmission service from PacifiCorp, BPA or others to deliver power from the Project to their loads.

PACIFIC NORTHWEST MARKET OVERVIEW

The electric power market in the Pacific Northwest generally consists of the power systems of BPA, Pacific Power, Portland General Electric, Puget Energy, Washington Water Power, Idaho Power, Montana Power and a multitude of tax exempt municipal utilities including peoples utility districts and public utility districts. Over 460 electricity generating projects are located in the Pacific Northwest region. These projects provide about 40,570 megawatts of generating capacity and range in size from tens of kilowatts to the 6,500-megawatt Grand Coulee Dam. The primary energy source for most of this capacity is hydropower, followed by natural gas, coal, uranium (nuclear) and bio-mass. A small portion (about 320 megawatts) is pumped storage hydropower. [10]

The largest hydroelectric system in the region, the Columbia River, has a sustained peaking capacity of about 25,000 megawatts.[11] However, limitations on the storage capacity of the system results in significant variation in the system's energy output from year to year, depending on annual rainfall and snow pack accumulation. In the driest years, the average annual power production is only about 11,700 average megawatts. Utility planners can expect at least that much energy in any given year, so it is considered guaranteed or "firm" energy. In the wettest years, the system produces approximately 20,000 average megawatts. In average water years, the system produces approximately 16,500 average megawatts.[12]

The Pacific Northwest region power supply planning criteria and power market differs from the rest of the western United states due to the dominance of hydroelectric power plants as a source of power supply. Unlike gas, oil, coal, or nuclear-fueled thermal power plants which can be operated as needed up to their rated output capability, hydroelectric power plants can only operate to their rated output capability with adequate flow and reservoir levels, which vary from season to season and year to year. For this reason, power supply planning in the Pacific Northwest refers to the average megawatts of capacity available from these hydroelectric projects. The dependable Pacific Northwest generation in each month is therefore the sum of average megawatts of thermal (oil, gas, coal and nuclear fueled) power plants and the average megawatts of hydroelectric generation under low water conditions. This planning criteria is needed, because under low water conditions, the significant hydroelectric generation in the region will not be available to the full capability of the installed hydroelectric capacity to help meet the winter peak demand.

Generation in excess of what can be guaranteed is commonly referred to as "non-firm" or "secondary" energy. Non-firm energy is sold on the spot market or under short-term

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[10] Fourth Northwest Conservation and Electric Power Plan, Northwest Power Planning Council, 1996

[11] Ibid.

[12] Ibid.

contracts at prices which are typically lower than those obtained for firm energy. It is used to serve interruptible loads or to displace more expensive resources both in and out of the region.

BPA is a major and integral part of the region's power system. In an average year, it controls the marketing of almost 40 percent, or approximately 8000 average megawatts of the electricity sold in the region, most of which is relatively low-cost federal hydroelectric power. It also owns and operates the majority of the region's electricity transmission system. Depending on how regional transmission is defined, BPA owns between 50 and 80 percent of the region's transmission system. BPA sells approximately 3000 average megawatts of energy to the tax exempt municipal utilities, peoples utility districts, public utility districts, electric cooperatives and government agencies (collectively, "public agency customers") in the region under long term sales contracts.

On December 21, 1998, BPA released its Power Subscription Strategy Record of Decision (BPA ROD) which addresses the time period in which customers may subscribe for power purchases, amounts of power offered for sale to various customer groups, products offered, product pricing and the contract elements by which BPA will offer power. The BPA ROD estimates that BPA will be able to meet the entire net firm load requirements of its public agency customers in the Pacific Northwest region. BPA proposes to open the subscription window in February 1999 and keep it open for contract negotiations until 120 days after the Record of Decision in the 1999 BPA power rate case is issued. Rates for post-2001 service will be set in this rate case, which is scheduled to begin in April 1999. Subscription contracts signed prior to the end of the rate case will be subject to the final rate(s) established in the rate case.

Regional forecasts for electric customer needs address primarily annual peak demand, which provides an estimate of electric capacity and energy required in a region to reliably meet the peak load. This information is useful as a general indication of the need for new generation. In situations where there is a potential deficit in the available capacity or energy to meet peak load, sellers in such markets can generally expect upward pressure on prices for output. For this reason, regional forecasts of electric peak load versus capacity for California and for the Pacific Northwest are included herein as an indication of the market for the sale of output from the Project.

The ability of a generating plant to produce energy (kilowatt-hours) at a lower price than other sellers into the market will be the factor which most affects its economic performance. Periods of excess generation (where installed generation exceeds regional needs) can result in short-term reductions in price where sellers may not be able to recover fixed costs of their generating plants. Similarly, periods of impending shortage of generation to meet regional needs can bid up the price in the market until new generation is installed. To reasonably estimate the ability of any given generating plant to compete, a detailed model of the demand for power and the operation and cost of production from available power supply sources in the region to meet that demand is required. Such a model was used by Henwood Energy Services, Inc. (HESI) to estimate future market prices as described under Projected Operating Results elsewhere in this report. The following description of regional demand and available generation provides a general background of the market into which the Project will be selling its output.

Electricity forecasts indicate that Pacific Northwest loads could grow by about 5,920 average megawatts by the year 2015 if medium economic growth occurs.[13] Since 1991, the region has added 2,470 average megawatts of generating resources and conservation. Natural gas generation accounted for 57 percent of these additions.[14] The region has also lost some electricity resources. The closure of the Trojan nuclear plant decreased energy supplies by about 725 average megawatts. In addition, changes in how the hydropower system is operated, designed to protect endangered salmon and other fish and wildlife, have reduced the firm energy capability of the region's hydroelectric system by about 850 average megawatts.[15] The region continues to face uncertainty with respect to the degree to which the operation of the hydropower system might be further constrained to protect fish or wildlife. Several alternative hydropower operation plans have been promoted recently by interest groups within the region. Virtually all of the alternative hydroelectric operation plans considered credible evaluate the range of potential loss of future hydroelectric generation capability in the region, principally due to concerns about the impacts of existing hydroelectric operations on various salmon and other fish species in the region. Some of these plans forecast a decrease in hydroelectric generation by several thousand average megawatts. These changes are uncertain. There is no way to be certain if, when and to what extent new fishery recovery measures might be implemented resulting in hydroelectric generation capacity reductions. These reductions are not reflected in the base case energy price projections used later in this Report. To the extent there were major reductions in hydroelectric generation capability for fish recovery reasons or otherwise, it would result in upward pressure on Pacific Northwest prices for output from the Project, further enhancing its financial performance.

A recent forecast of loads and resources for the Pacific Northwest region prepared by Bonneville in 1997 is summarized in Table 1. This is the most recent public domain forecast typically relied upon by the region's utility and power supply industry. It shows a need for new generation of over 2,000 MW beginning in the year 2000, escalating to over 3,600 MW by 2008. However, this forecast does not consider the impact of any non-utility generation (such as the Project) that may enter commercial operation during this period. In

[13] Ibid.

[14] Ibid.

[15] Ibid.

addition, it assumes worst case stream flow conditions resulting in minimum hydroelectric production. In an average water year, an additional 3,000 to 4,000 average megawatts of energy can be expected to cover the deficits shown here.

The region's utilities cannot rely upon average water years in every year, however, and therefore the low water year conditions are used to establish the amount of generation which is required to reliably meet peak demand. In preparing the market price forecasts for use in the Projected Operating Results elsewhere in this Report, HESI has assumed low water year conditions to determine the need for new generation in the Pacific Northwest. HESI has assumed average water year conditions to determine the need for energy. Due to the fishery impact challenges facing the major hydroelectric resources in the region, utility power purchasers will likely increase their demand for generation from non-hydroelectric resources to meet prudent planning and generating reserve margin requirements.

Table 1
Forecast Loads and Resources for the Pacific Northwest Region Under Medium Load Growth (Average Megawatts)[16]

	2000-2001	2003-2004	2007-2008
Loads and Exports	23,557	23,885	24,208
Hydro Resources	12,153	11,993	11,994
Other Resources Net of Maintenance	9,209	8,883	8,571
Net Resources	21,359	20,876	20,564
Total Surplus (Deficit)	(2,198)	(3,008)	(3,644)

Approximately 2,400 megawatts of large scale generating resources are at various stages of development in the Pacific Northwest region. They are all combined-cycle combustion turbine based plants similar to the Project. Table 2 provides a summary. These potential projects have not been considered by BPA in their forecast of load and resources shown in Table 1.

Table 2
Major Power Plant Projects Under Development in the Northwest [17]

Project Name	Capacity	Location
Sumas II	720 MW	Sumas, Washington

[16] Bonneville Power Administration, 1997 Pacific Northwest Loads and Resources Study

[17] The Washington Energy Facility Siting Council, the Oregon Energy Facility Siting Council, press release from Avista Energy, Inc.

Table 2 Major Power Plant Projects Under Development in the Northwest [17]		
Project Name	**Capacity**	**Location**
Chehalis Generation Facility	460 MW	Chehalis, Washington
Cowlitz Cogeneration Project	460 MW	Longview, Washington
Rathdrum Generating Project	270 MW	Rathdrum, Idaho
Hermiston Power Project	536 MW	Hermiston, Oregon

Other projects not listed above have been proposed and are either very early in the development process or development is on hold. The Hermiston Power Project listed in Table 2 is not the Hermiston Generating Project that is in commercial operation as referenced under the PacifiCorp section of this Report. The in-service date, fuel efficiency, fuel costs, price level and term of power sales contracts (if any) for these projects are unknown at this time. It is highly unlikely that all of these proposed projects will reach commercial operation Those that do will likely not enter service in advance of the Project since none have received both final regulatory permits and financing at this time. None of these projects are located near the California-Oregon Border and none will have the comparative ease of serving both California and Pacific Northwest markets as will the Project.

As described under Projected Operating Results elsewhere in this Report, the HESI regional energy price forecasting model assumes the addition of only 1,400 MW of generic new CCCT plants in the Pacific Northwest between 2001 and 2008 to meet reserve margin requirements. This is less than the capacity of the new projects under development shown in Table 2 above. Therefore, market clearing prices would be depressed below those forecast by HESI if all of the above plants were to enter commercial operation. However, the effect on senior debt service coverage for the Project under such an event would be moderate as can be seen in the overbuild scenario described under the Sensitivity Analysis section of this Report.

CALIFORNIA MARKET OVERVIEW

The wholesale electric power market in California generally consists of the state sponsored Power Exchange (PX) which controls access to the loads of the three major investor owned utilities (IOU's) including PG&E, Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E). These IOU's have a combined peak load of nearly 46,000 MW. The market also includes loads on the electric systems of various municipal utilities, agencies and large industrial consumers.

California consumes more electricity on an annual basis than any other state, except Texas. Consumption is expected to increase by 1.8 percent per year from 1998 through 2007, with a capacity need reaching nearly 73,000 MW.[18] Table 3 summarizes a forecast of loads and resources for the state during this period as forecast by the California Energy Commission (CEC). This is the most recent forecast available, and is generally used by the utilities and power suppliers in California for planning purposes.

Table 3
Forecast Loads and Resources for California (Megawatts)[19]

	2000	2003	2007
Capacity Requirements	66,030	69,057	72,836
Existing and Committed Resources	59,538	58,752	57,356
Surplus (Deficit)	(6,492)	(10,305)	(15,480)
Uncommitted Demand Side Management	4,469	5,171	6,366
Potential Out of State Capacity Purchases	2,377	2,377	2,377
Total Potential Resources	6,846	7,548	8,743
Total Surplus (Deficit)	354	(2,757)	(6,737)
Portion Due to Tax Exempt Municipal Utilities	(852)	(1,620)	(2,852)

The table reveals a supply deficit of nearly 7,000 megawatts by the year 2007. A large portion of this deficit for the years 2000 and 2003 is from tax-exempt municipal utilities in the state, including the Sacramento Municipal Utility District (SMUD) and others (the Los Angeles Department of Water and Power is not forecast to have a deficit). However, this forecast does not include the impact of the large number of new generating resources planned by non-utility generators in the state (see Table 4 below). These have yet to receive regulatory approval, and therefore are not considered as "committed" by the CEC. Those that do proceed to completion would serve to reduce these deficits.

Generation resources in California are predominantly gas fired. Major interstate natural gas transportation pipelines deliver fuel at the Oregon and Arizona borders, which is then transported to generators located in or near the major load centers of Los Angeles and San Francisco. Significant hydroelectric resources are located on storage reservoirs throughout the State. Diablo Canyon and San Onofre are the state's two operating nuclear facilities. High voltage transmission interconnections with the Pacific Northwest and the Desert

[18] The California Energy Commission, 1996 Electricity Report, November 1997, p 71.

[19] Ibid., p71.

Southwest allow import of several thousand megawatts. Finally, several thousand megawatts of small power and cogeneration facilities are in service throughout the State. Although the generation portfolio is diverse, many of the natural gas fired resources in the region are nearing the end of their service lives and must either be re-powered or retired in the near future.

The natural gas fired plants owned by PG&E, SCE and SDG&E are generally the highest cost resources in California, and are used to serve the last increment of load not served by the hydroelectric plants, out of state imports or nuclear plants. Under terms of AB1890, the utilities are required to divest themselves of these resources by selling them to third parties. Divestiture is intended to limit the power of these utilities to manipulate PX market clearing prices (as discussed below). It is also intended to identify the market value of these resources relative to book value, and provide for recovery of stranded costs through rates. To date, nearly all of the roughly 10,000 megawatts of utility owned natural gas fired plants have been sold to third parties through competitive auction. The buyers have generally been large out of state utilities. PG&E also recently announced plans to divest some or all of its 3,980 MW of hydroelectric plants to its non-regulated subsidiary U.S. Generating Company, Inc. This proposal is presently under review by the California Public Utilities Commission.

The high voltage transmission systems of PG&E, SCE and SDG&E are operated by the state sponsored Cal-ISO. Both the PX and Cal-ISO were established by AB1890 for the purposes of creating an independent and non-discriminatory marketplace for wholesale electricity among the three IOU's and other participants. On a day-ahead or hour-ahead basis, each IOU must bid its generation supply and load requirements into the PX. The PX accepts the bids, determines a market clearing price for all bids, and submits balanced schedules of generation and load to the Cal-ISO. The Cal-ISO in turn, determines the resulting transmission loadings, levels of necessary ancillary services, and any re-dispatch necessary to alleviate transmission congestion between multiple transmission zones in the State. Participation by publicly owned utilities and agencies in the PX and the Cal-ISO is voluntary. Most have chosen not to participate at this time. In managing power flow over the IOU systems, the Cal-ISO must consider the transmission capacity rights that various publicly owned utilities hold on the IOU systems pursuant to past contracts and agreements. As these contracts expire, the tax exempt municipal utilities will have to obtain replacement service from the Cal-ISO.

Over 12,000 megawatts of new, large-scale generating resources have been proposed for development in the state at this time.[20] The vast majority of these are combined-cycle combustion turbine based plants similar to the Project. Table 4 summarizes those that have, or soon will be, presented to the California Energy Commission (CEC) for site

[20] The California Energy Commission, Current and Expected Future Power Plant Licensing Cases, October 1998.

certification. None of these have received regulatory approval from the CEC and therefore have not been considered by the CEC in their forecast of supply deficits shown in Table 3.

Table 4
Major Power Plant Projects Under Development in California [21]

Project Name	Capacity	Location
Antelope	1,000 MW	California City, Kern County
Blythe	400 MW	Blythe, Riverside County
Delta Energy Center	535 - 800 MW	Pittsburg, Contra Costa County
Elk Hills	500 MW	Elk Hills, Kern County
High Desert	680-720 MW	Victorville, San Bernardino County
La Paloma	1,048 MW	McKittrick area of Kern County
Long Beach District Energy Facility	500 MW	Long Beach, Los Angeles County
Midway Sunset	500 MW	Fellows, Kern County
Moss Landing	1000 MW	Moss Landing, Monterey County
Morro Bay	530 MW	Morro Bay, San Luis Obispo County
Otay Mesa	1,050 MW	Otay Mesa area, San Diego County
Pastoria	960 MW	Tejon Ranch, Kern County
Pittsburg District Energy Facility	500 MW	Pittsburg, Contra Costa County
South City	550 MW	South San Francisco
Sunlaw	800 MW	Vernon, Los Angeles County
Sunrise Cogeneration	300 MW	Fellows, Kern County
Sutter Power	500 MW	Yuba City area, Sutter County
Three Mountain Power	500 MW	Burney, Shasta County

The fuel efficiency, fuel costs, price level and term of power sales contracts (if any) for these projects are unknown at this time. The majority will likely enter service after the date of Substantial Completion of the Project due to the current 12 to 18 month lead time required for CEC permitting. In addition, they will be competing for CEC staff resources for application review. It is highly unlikely that all of these proposed projects will reach commercial operation. Environmental constraints have slowed regulatory approval of two

[21] Ibid.

of the above projects which are the most advanced in the California permitting process. This is in contrast to the Project, for which all major permits have been received. Of the approximately 12,000 MW of projects which have been announced, only approximately 1,200 MW are in advanced stages of regulatory review. More importantly, more than 8,000 MW of these projects are in the southern half of California. Present seasonal transmission constraints from south to north to serve into the service territories of Pacific Gas & Electric (PG&E) and tax-exempt municipal utilities in the PG&E territory will likely result in either physical or economic barriers to entry to that market area for over 8,000 MW of the projects listed in Table 3. This greatly reduces the impact of this capacity on the market to be served by the Project. None of the projects are expected to be price competitive with the Project for sales into the Pacific Northwest on a sustained basis due to the extra electric transmission service costs to reach the COB or markets north and the added gas transportation cost to deliver fuel to these plants as compared to the Project. None of these projects are located near the California-Oregon Border and none will have the comparative ease of serving both California and Pacific Northwest markets as will the Project.

NATURAL GAS SUPPLY AND TRANSPORTATION

The Facility will be interconnected with the high pressure gas transportation system of PGTNW along the Medford Lateral. The Medford lateral provides service to local gas distribution companies in southern Oregon from the PGTNW mainline which runs approximately 20 miles east of the Facility site near Malin, Oregon. The Medford Lateral has a capacity of approximately 200 million cubic feet per day, while the mainline has a capacity of over 1 billion cubic feet per day. The Facility is expected to consume 75 million cubic feet per day on average(90 million cubic feet per day maximum) of natural gas. Transportation service on the mainline and the Medford Lateral will be provided by PPM under terms of the Fuel Supply Agreement described elsewhere in this Report.

The PGTNW mainline serves as the main north-south path for natural gas to travel from the producing regions of Alberta, Canada to the markets of the Pacific Northwest and California. Gas purchased in Canada is first delivered on the NOVA and Alberta Natural Gas transmission systems to the PGTNW mainline near Kingsgate, British Columbia. The mainline then intersects further south with Williams Pipeline Northwest at Stanfield, Oregon near the borders of Oregon and Washington. This interconnection allows PGTNW customers to also purchase gas from the major producing regions of British Columbia and the Rocky Mountains. From Stanfield, gas flows south on PGTNW to the California Border where it is delivered into the intra-state system of PG&E. A relatively small amount also flows into the Tuscarora Pipeline for delivery to Reno, Nevada. Malin has become a popular point of delivery for sales between gas traders in Canada and the California utilities, marketers and industrials that hold capacity on the various California intra-state gas transmission pipelines.

Gas reserves in Alberta and British Columbia are substantial. Table 4 and Table 5 illustrate that production of just the current proven reserves (taking no credit for potential reserves) in these supply areas, along with the relatively minor amounts from California, and the Rocky Mountains, could satisfy all of the current demand of the Pacific Northwest, California, the Rocky Mountain area, and western Canada for approximately 17 years based on present proven reserves. Producers are expected to drill and continue to expand the proven reserves and bring new gas supply to the market in order to earn a return on their acquisition costs.

Table 5
Proven Natural Gas Reserves Various Supply Regions[22]

Supply Region and Proven Reserves in Trillions of Cubic Feet (TCF):	
Alberta	52.8
British Columbia	10.5
California	5.1
Rocky Mountains	4.9
Total Reserves	73.3

Table 6
Forecast 1999 Natural Gas Demand for Various Demand Regions[23]

Demand Regions and 1999 Forecast Demand (TCF/yr.):	
Western Canada	1.3
Pacific Northwest	0.4
California	2.0
Rocky Mountains	0.6
Total Demand	4.3

There is an active market for gas transportation capacity release on the PGTNW system today. In December of 1998, there was more that 750,000 MMBtu per day of released capacity in service from Kingsgate to Malin, more than half of the capacity of the pipeline. Over 61,000 MMBtu per day of this was released in December alone by 10 different shippers. Prices varied widely, from 1 percent to 100 percent of full tariff cost, averaging

[22] The California Energy Commission, Natural Gas Market Outlook, Supplemental Staff Report to the Biennial Fuels Report, June 1998, Appendix A

[23] Ibid., Appendix C

about 67 percent. Full tariff cost is the cost that PGTNW would charge to deliver gas under their FERC approved gas transportation tariffs. Since July 1997, there has been at least 412,000 MMBtu/day of released capacity in service on this segment.[24] This would be more than enough to serve the approximately 75,000 MMBtu/day average daily need of the Project.

Although firm gas transportation service on the NOVA, Alberta Natural Gas and PGTNW systems is offered through the respective pipeline companies at established tariffs and rates, capacity is generally fully subscribed today and must be obtained from existing shippers through capacity release. Capacity may be released through competitive bid sponsored by the pipeline, or by negotiated sale by the shipper. In some cases, fuel can be purchased on a delivered basis where transportation capacity is bundled with the supply. Today, capacity utilization rates on the Alberta to Malin delivery path are approaching 100 percent. Capacity utilization is forecast to increase over the next twenty years to more that 125 percent of the existing capacity of the path, indicating a need for future capacity increases[25].

Significant pipeline capacity additions are under development at this time to improve delivery from Alberta to areas of the eastern U.S. This is expected to increase demand and prices for natural gas from Alberta. California demand is expected to remain strong and capacity expansions along the PGTNW delivery path are expected to occur. The CEC expects prices for gas delivered at Malin to increase at a real rate of approximately 2 percent per year over the next 20 years.[26] A real escalation rate excludes the effect of inflation. This is similar to the 1.8 percent per year (real) rate of increase in the cost of fuel delivered to the Facility that is assumed by HESI in their COB Electricity Market Price Forecast that was used to develop projected operating results as described elsewhere in this Report. HESI has assumed a 2.8 percent per year inflation rate in their model. This rate must be added to the 1.8 percent per year real rate of increase to determine the price of gas in future (nominal) dollars.

THE PROJECT

THE FACILITY

The Project includes a cogeneration facility (the Facility) that will be designed to 1) generate and deliver 483,790 kilowatts of electricity with no steam delivery; and 2) simultaneously generate and deliver 464,020 kilowatts of electricity and 200,000 pounds

[24] Pacific Northwest Natural Gas Market Review, January 1999, Brent Friedenberg Associates, Ltd.

[25] The California Energy Commission, Natural Gas Market Outlook, Supplemental Staff Report to the Biennial Fuels Report, June 1998, Appendix A

[26] Ibid., p 41.

per hour of steam without using the auxiliary boiler, at average ambient operating conditions.

The Facility will include two natural gas-fired combustion turbine generators with a nominal capacity of 161 megawatts each, two heat recovery steam generators with low, intermediate and high pressure steam systems, auxiliary duct burners and 150 foot tall exhaust stacks, a steam turbine generator with a nominal capacity of 175 megawatts, an evaporative cooling tower, water treatment equipment, three nominal 400,000 gallon water storage tanks, a dual fuel auxiliary boiler, an above ground 200,000 gallon fuel oil storage tank, three 18/500 kV main transformers, a 500 kV electrical switchyard, an interconnection to the nearby natural gas metering station, a storm water collection and evaporation pond, access and parking areas, an approximately 80 foot tall turbine building with space for operating and maintenance staff and services, a steam delivery pipeline, condensate return pumps and pipeline, and makeup water pipeline connected to the Collins Facility, and other items.

The Project will also include certain necessary supporting facilities including cooling water and potable water supply pipelines, a wastewater discharge pipeline, and certain rights of way. These supporting facilities are described in more detail in the following sections of this Report.

THE FACILITY SITE

The Facility will be located outside the City limits on approximately 19 acres of property leased by the City from Collins and adjacent to the Collins Facility. The site is zoned M3-Heavy Industrial and is currently vacant. It is located approximately 3 miles south of the central area of the City, 1200 feet north of the Klamath River, and adjacent to a smaller residential area known as West Klamath Falls. The site is approximately 4150 feet above sea level and receives an average of 10 to 15 inches of precipitation annually.

A study was performed in the Facility site area by Golder Associates Inc. (Golder) in 1995 to evaluate the potential for environmental impacts at the Facility site due to past and/or present operations or conditions at the Collins Facility (the Golder Study). Weyerhaeuser, Inc. was the owner and operator of the Collins Facility at the time the Golder Study was performed. The Collins Facility, including the Facility site area, was purchased by Collins from Weyerhaeuser, Inc. in 1996. The scope of the Golder Study included a Collins Facility inspection, interviews with on site personnel, review of environmental permits and regulatory files, and review of certain federal and local lists of known or suspected hazardous waste sites or spills within a one mile radius. The Golder Study revealed that the Facility site had historically been used for periodic log storage and minor rock excavation. The Facility site had not been used for industrial land filling. However, adjacent areas of the Collins Facility were used for land filling by Weyerhaeuser, Inc.

Oregon Department of Environmental Quality (ODEQ) records showed that industrial wastes were placed into at least five landfill sites, including paint wastes, urea formaldehyde, phenolic resins, wastewater sludge and process wastes. Two of these sites, which are small pits, are located to the north of the Facility site (within approximately 500 feet) and to the south of the existing road that links the Facility site area with the main Collins Facility. A third landfill site is located across the existing road to the north, between 500 and 1000 feet from the Facility site. Two more landfill areas are within 1,000 feet of the Facility site. Based on discussions with Collins (formerly Weyerhaeuser) personnel, the two pits nearest to the Facility site are older and relatively insignificant in size and extent of potential contamination, while the third site is more recent and likely to contain the waste materials referenced in the ODEQ records. The fourth and fifth sites were judged to be insignificant in size and extent of potential contamination.

Based on the results of the Golder study, Weyerhaeuser was consulted to assist in locating the Facility site in an area of low probability for subsurface contamination. Subsequently, the present Facility site was chosen. Golder recommended that a more detailed study be performed to investigate the specific Facility site, and to estimate the extent and cost of remediation activities needed. A more detailed study would involve sub-surface exploration including geophysical, soil gas, test pit and monitoring well tests. However, Golder concluded that the Facility site was not listed as a hazardous waste site or a Superfund site with the ODEQ or the federal Environmental Protection Agency (EPA), and records showed no such site within a one mile radius.[27]

Given the results of the Golder Study and the fact that subsequent excavations by both Golder and PKE (described below) did not indicate the presence of subsurface contamination, the City and PKE determined that a more detailed environmental study was not necessary. BVC is responsible for removing or remediating any hazardous substance discovered during construction of the Facility under terms of the EPC Agreement described elsewhere in this Report. BVC may submit a request for cost reimbursement and/or schedule extension due to the removal or remediation. Collins is responsible for the cost of such removal or remediation under terms of the Lease described elsewhere in this Report. The City is not liable for the performance or cost of any remediation of pre-existing hazardous substances on the Facility site, and will be indemnified and held harmless by Collins with respect to remediation costs.

Golder performed a geologic and seismic hazards evaluation of the Facility site in November, 1996. Golder found the site had been classified as seismic zone 3 based on expected ground acceleration during seismic events. It slopes gently down towards the Klamath River, and consists of soil and organic debris fills from one to nine feet deep and

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[27]Phase One - Environmental Study, Proposed Site of the Klamath Cogeneration Project, Weyerhaeuser Mill Site, Klamath Falls Oregon, Golder Associates, Inc., Portland Oregon, September 14, 1995.

sandstone or lava bedrock at relatively shallow depths. Golder concluded that there are no known geologic or seismic hazards that would preclude use of the site for the Facility.[28] In early 1998, PKE performed exploratory drilling at the new site to determine the depth of fill (e.g., soil, sawdust, wood debris) to bedrock. Depth to bedrock varied from one to twelve feet. BVC commissioned a geophysical study of the Facility site in April 1998. The study used seismic refraction techniques to measure the density of sub-surface structures and estimate the difficulty of excavation during Facility construction. No unexpected subsurface conditions were found.

Based on the reports from the Golder seismic evaluation, the PKE exploratory drilling and the BVC geophysical study, the Facility site appears suitable for the construction work required to complete the Facility. The provisions under the EPC Agreement and the Lease for removal or remediation of hazardous materials found at the Facility site are also reasonable and typical. Due to the maximum depth of 12 feet to bedrock at the Facility site as reported by BVC, in the unexpected event that subsurface contamination is encountered, there is no reason to believe that the avoidance or remediation of such contamination would materially delay the timely completion of Project construction.

POWER GENERATION TECHNOLOGY

The Facility will utilize combined cycle combustion turbine (CCCT) based power generation technology. This technology has become popular for power generation over the last few decades as combustion turbine reliability and performance have improved and the cost of natural gas has fallen. Today, CCCT technology is the most fuel efficient generating technology that is commercially available. The vast majority of power generation projects proposed for development in the U.S. today propose to use CCCT technology.

Under this technology, ambient air is ingested by a combustion turbine which consists of axial flow compressor, combustion, and turbine sections. Ambient air is compressed, mixed with natural gas and combusted. The resulting hot gasses expand through the power turbine section of the combustion turbine which drives an electric generator. Exhaust gasses from the power turbine then exit the machine and pass through a heat recovery steam generator (HRSG). Heat from the exhaust gasses cause the water in the HRSG to boil, generating high pressure steam that is fed to a separate steam turbine electric generator. At the Facility, some steam will be extracted from the steam turbine and delivered to Collins. The remaining steam will be further expanded and then condensed prior to returning it to the HRSG to be heated again.

Exhaust gasses passing through the HRSG are injected with ammonia and passed through a chemical catalyst to remove nitrogen oxides (NO_X) before being vented to the atmosphere

[28] EPC Agreement, Exhibit A - Geotechnical Investigation Report, Golder Associates, Inc., November 6, 1996.

through an exhaust stack. This is known as selective catalytic reduction (SCR) emissions control technology. The combustion turbines will also employ special Dry Low NO_X combustors that do not require water injection for NO_X emission reduction. This combination of SCR and Dry Low NO_X technologies has been accepted as the Best Available Control Technology (BACT) for NO_X emissions from the Facility by the ODEQ under terms of the Air Discharge Contamination Permit (ADCP) issued for the Project and described elsewhere in this Report.

The Facility will also employ various condensing, cooling water, water treatment, transformer, equipment protection, fire protection, and control system technologies and equipment that are typical for modern combined cycle generation plants.

Combined cycle combustion turbine power generation is a proven technology that is widely accepted in the industry, and is acceptable for use at the Project. Use of this technology will enable the Project to be a low cost and reliable producer relative to other power generators in the wholesale power market. The majority of existing power generation plants in the market rely on obsolete non-combustion turbine based gas, coal and nuclear technologies that are less efficient and more costly to operate and maintain. New non-combustion turbine based power generation technologies currently under development, such as fuel cells and photo-voltaics, are not expected to reach commercialization and wide spread industry acceptance in the near future.

FACILITY DESIGN AND RELIABILITY

Design specifications of the Facility specify that it be designed based on accepted utility industry practices and standards, for primarily base load operation, with a service life of at least 30 years. As has been the case with other power generation facilities designed to such standards, the Facility can be expected to operate for approximately forty years assuming proper maintenance and reasonable periodic capital improvements are performed. The Facility will have two independent combustion turbine generator and HRSG sets rated at approximately 161 MW each at site specific average ambient conditions, and a single steam turbine generator set rated at approximately 175 MW. Each generator will have its own independent transformer to step up generator voltage for interconnection to the 500 kV Meridian to Captain Jack transmission line.

The Facility will be designed to be capable of operating at reduced capacity with only one combustion turbine generator/HRSG/transformer set in service. The Facility will also be designed such that inadvertent shutdown of one combustion turbine/HRSG/transformer set will not cause shutdown of the other. Prolonged failure of the steam turbine generator and transformer, or any of the electric, gas or cooling water interconnection lines, would lead to Facility shutdown. The Facility will be designed to achieve an annual availability, which is the percentage of hours in a year that the Facility is capable of operating, of at least 93 percent. With proper maintenance and periodic capital expenditures, this level of availability can be reasonably expected over its commercial life. A sinking fund for repair and major maintenance has been established under the Bond Indenture and is included in the projected operating results pro forma with the objective of maintaining Facility output capability and availability.

The Facility will utilize various microprocessor based computer systems for control, data acquisition, communication and other purposes. Certain microprocessor based computer systems in general use today at some existing power generation facilities are expected to fail due to the upcoming date transition from the year 1999 to 2000. However, many of the microprocessor based systems that will be used at the Facility will likely be manufactured after the year 2000. In addition, the performance of many of the computer systems will be tested prior to starting or operating the Facility. Therefore, failure of these computer systems due to date transition is unlikely and is not expected to impact Facility construction or operation. BVC is responsible for procurement and testing of all equipment at the Facility, and for repair or replacement of computer systems that do fail under terms of the one year warranty they are providing under the EPC Agreement described elsewhere in this Report.

COMBUSTION TURBINE TECHNOLOGY

Each combustion turbine at the Facility will be a model 501FD combustion turbine manufactured by Siemens Westinghouse Power, Inc. This model is the latest version of the model 501F combustion turbine that is in service throughout the utility industry. The model 501F combustion turbine was introduced in 1992. Fifty eight 501F combustion turbines are in service worldwide. The combined 501F and 701F (the latter for 50 hertz international markets) fleet has accumulated approximately 500,000 hours of service. The oldest machine in the fleet is a 501F in service at the Martin generating station of Florida Power and Light, where it has accumulated approximately 42,000 hours of service since 1993. Annual availability of this machine has averaged 95.3 percent.

The 501FD generally includes longer blades in the first two compressor stages, more aerodynamically efficient blades in compressor stages 3 through 16, and larger and more aerodynamically efficient turbine blades in the turbine stage 4 as compared with earlier versions of the 501F. The result is increased capacity and decreased heat rate. Table 7 below summarizes key performance parameters of the 501FD as compared to the 501F, as well as the 501G that is currently under development by Siemens Westinghouse.

Table 7
Estimated Performance of Siemens Westinghouse Model 501 Combustion Turbines in Simple Cycle at Sea Level and 59 degrees F

	Model 501F	Model 501FD	Model 501G
Capacity	160 MW	167 MW	230 MW
Heat Rate (HHV Basis)	10,663 Btu/kWh	10,107 Btu/kWh	9,831 Btu/kWh

No 501FD combustion turbines are in operation at this time. A full speed, no load test of a 501FD compressor section was recently performed to bench mark the computational tools used to design the 501FD. The first 501FD model is scheduled to ship in October of 1999. It will go into simple cycle (no steam turbine) service. Instrumentation will be used to monitor flows, temperatures, vibrations and other parameters during an initial testing period. Results from the testing will be used to correct any design deficiencies prior to shipment of the 501FD combustion turbines that will be used in the Facility. These are scheduled to ship in mid 2000. Eighteen to twenty other 501FD combustion turbines will have been shipped by the middle of 2000.

There are likely to be continued marginal improvements in the fuel efficiency of combined cycle generation technology. However, the rate of improvement is reaching the point of diminishing return. This can be seen by observing the 5.2 percent heat rate improvement of the 501FD model over the 501F model versus the smaller 2.7 percent heat rate improvement of the 501G model over the 501FD model. The fuel efficiency of a combustion turbine based CCCT plant (as with any power plant or engine) is driven primarily by its operating (firing) temperature, pressure, mass flow and heat transfer capability. CCCT technology has reached the point at which continued small improvements in these key areas will require ever larger advancements in metallurgy, ceramics, and heat recovery. The research and development costs of these technology advancements will increase the capital costs of CCCT technology, placing a practical limit on the level of fuel efficiency ultimately available from these plants. Today, market participants generally consider this practical limit to be 6500 Btu/kWh. The 6,795 Btu/kWh combined cycle heat rate of the Project (as described more fully under the EPC Agreement section of this Report) compares well with this expected practical limit.

Any disadvantage the Project may face with respect to future, more efficient plants may be overshadowed by its site location advantage which results in reduced transmission service costs and losses to reach COB. Furthermore, the owners of future, more efficient plants will have to recover an expected higher cost per kilowatt of installed capacity due to the technology improvements. Finally, existing generators with significantly higher heat rates than the Project are expected to continue operation well after the time the Project begins commercial operation. These facilities will set the market clearing price (as described under the Projected Operating Results section of this Report) for many years after the Project is in operation.

The addition of higher efficiency future combustion turbine and combined cycle units in the future is expected to have little impact on senior debt service coverage of the Project given that the heat rate of the Project compares favorably with the expected practical heat rate limit as discussed above.

OPERATING MODES

Simultaneous cogeneration of electricity and steam will be the normal operating mode of the Facility. The electrical generating capacity of the Facility will vary inversely with ambient temperature. This is typical of combustion turbine based plants, and is caused by variations in air density in conjunction with the fixed volume capacity of the combustion turbine. The Facility will be able to compensate for this loss of capacity through evaporative cooling of combustion turbine inlet air, and the use of auxiliary burners in the HRSG to boost steam production. The electrical output capacity of the Facility will degrade as operating hours increase. This is also typical of combustion turbine based plants due to normal wear of rotating components. The majority of this capacity loss will be recovered through periodic compressor washing, and overhaul and refurbishment of the combustion turbines.

The Facility will be designed to operate at any point from 30 percent to 100 percent of full load capability while delivering up to the maximum expected steam demand to Collins (275,000 pounds per hour). Steam may also be supplied from the auxiliary boiler, in particular when the power generation equipment at the Facility is shutdown. The auxiliary boiler will be designed to augment steam delivery to Collins only, and not to augment power production from the steam turbine generator. The auxiliary boiler will be capable of operating on distillate fuel oil as well as natural gas. This ensures that steam can be delivered to Collins when natural gas is unavailable. The Facility will also be designed to operate while delivering no steam to Collins (Combined Cycle Mode).

The Facility will be designed to meet all the permitted air, water and noise emission levels during all operating modes. The Facility will be designed to startup from a warm standby condition (less than 48 hours following a previous shutdown) to full load in Combined Cycle Mode within two hours, and to shutdown from full load within two hours.

ELECTRIC INTERCONNECTION

PacifiCorp will relocate a portion of the existing 500 kV transmission system near the Facility (approximately 6500 feet total), and install necessary protective relaying, remote data acquisition and metering, to interconnect the Project with the existing 500 kV Meridian-Captain Jack transmission line at the 500 kV substation at the Facility. The proposed route for the relocated line lies entirely on Collins property except for a one quarter acre parcel owned by Columbia Plywood, Inc. The City will pay PacifiCorp for this relocation and interconnection under terms of the Interconnection Agreement described elsewhere in this Report. Payment will be funded from Project Bond proceeds.

Transmission service on this line for delivery of Project output can be provided by both PacifiCorp and BPA. The line is owned by PacifiCorp, but BPA has rights to a portion of the transmission capacity. Delivery of the portion of Project output sold to qualified purchasers and other third parties at COB will be provided under the Transmission Services Agreement with BPA described later in this Report, supplemented periodically with short term transmission purchases from BPA. Delivery of the portion of Project output purchased by PPM will be provided by BPA or PacifiCorp at PPM's expense. The transmission services under contract with BPA are sufficient to deliver all Project output sold to qualified purchasers and other third parties to COB or other points where purchasers are anticipated to desire delivery. Transmission system modeling studies performed by RMI in cooperation with PacifiCorp and BPA have demonstrated that all Project output can be transmitted from the Project to COB without encountering transmission constraints.

FUEL INTERCONNECTION AND SUPPLY

PGTNW will install tap, regulation and metering facilities at their existing 450 pounds per square inch (psig) natural gas regulation and metering station adjacent to the Facility site as necessary to allow connection of the Facility to the Medford Lateral and to supply all the gas fuel needs of the Facility. The cost for this interconnection will be recovered by PGTNW through the gas transportation rate charged under terms of the FTSA agreement described elsewhere in this Report. The Facility will include all necessary separation, filtering and other equipment to ensure that fuel delivered to the combustion turbines complies with the quality requirements of the manufacturer.

WATER SUPPLY AND WASTEWATER DISCHARGE

The City will install, or cause to be installed, a new potable water supply pipeline to connect the Facility to the existing water distribution system of the City. The pipeline will run northwest from the Facility site for approximately one mile. It will follow existing Klamath County street rights-of-way along Weyerhaeuser Road until it reaches the City system. Under terms of the Site Certificate described elsewhere in this Report, up to 160 gallons per minute of potable water may be consumed on an average annual basis if cooling water from the SSWWTP (as described below) is available. Up to 137 gallons per minute is expected to be consumed under maximum demand conditions. This potable water will be used for evaporative cooling of combustion turbine inlet air, a portion of condensate makeup needs, and various minor building uses. Construction of the pipeline will be funded from Project Bond proceeds. The line will be built, owned and operated by the City. Water will be provided by the City under terms of the Water Services Agreement described elsewhere in this Report.

The City will also install, or cause to be installed, a new cooling water supply pipeline to connect the Facility to the existing SSWWTP of the City. The pipeline will run northeast from the Facility site for approximately 5 miles. It will follow existing City easements and Oregon Department of Transportation (ODOT) rights-of-way. Two new cooling water supply pumps will be installed at the SSWWTP. Up to 2,279 gallons per minute of treated effluent from the SSWWTP will be used to replace water evaporated from the plant cooling tower under maximum expected demand conditions. This is the largest consumptive water use of the Facility. Up to 3.1 million gallons per day (equivalent to 2,152 gallons per minute over any 24-hour period) may be used under terms of the Reclaimed Water Use Plan described elsewhere in this Report. Actual consumption is not expected to exceed the allowed daily limit, since maximum consumption will occur during high ambient temperature conditions (95 degrees) which will not occur during all hours of the day. Use of treated effluent from the SSWWTP allows the City to reduce the volume of effluent discharged from the SSWWTP to the Klamath River. Construction of the pipeline will be funded from Project Bond proceeds. The pipeline will be built, owned and operated by the City. Water will be provided by the City under terms of the Water Services Agreement described elsewhere in this Report.

The City will also install, or cause to be installed, a new wastewater discharge pipeline to connect the Facility to the existing sewer system of the City. It will run along the same route as the cooling water supply pipeline. Up to 647 gallons per minute of sanitary drains, and water rejected from the HRSG's, water treatment system, cooling tower and combustion turbine will be collected and sent to the existing sewer system under maximum expected discharge conditions. Up to 1,000,800 gallons per day (equivalent to 695 gallons per minute) on an monthly average basis may be discharged under terms of the Industrial Waste Discharge permit described elsewhere in this Report. Construction of the pipeline will be funded from Project Bond proceeds. The line will be built, owned and operated by the City. Sewer service will be provided by the City under terms of the Water Services Agreement described elsewhere in this Report.

Storm water will be collected through a system of drains and directed to an evaporation pond located on the site. This storm water collection system will be built by BVC under the EPC Agreement described elsewhere in this Report.

STEAM EXPORT, CONDENSATE RETURN AND MAKEUP WATER

The Facility will include a new nominal 325 psig steam pipeline to connect the steam system of the Facility with the steam system of the Collins Facility. Up to 275,000 pounds per hour of steam from either the steam turbine, the auxiliary boiler, the HRSG's or some combination of these will be made available to the Collins Facility. The Project will also include new condensate return pumps at the Collins Facility and a condensate return pipeline from the Collins Facility to the Facility. Approximately 60 percent of the steam delivered to Collins will be returned as condensate. The balance will be returned as makeup water from an existing water well at the Collins Facility. The Project will include a makeup water supply pipeline from the well water system at the Collins Facility. Makeup water will be used to replace condensate not recovered from the Collins Facility as well as a portion of the steam or condensate lost from the Facility itself. Under maximum expected demand conditions, up to 240 gallons per minute of condensate will be returned from the Collins Facility and up to 160 gallons per minute will be withdrawn from the well. Up to 601 gallons per minute of makeup water may be withdrawn from the well under terms of the Authorization to Appropriate Public Waters described elsewhere in this Report. The steam delivery, condensate and makeup water return pipelines will run southwest from the Facility site on property owned by Collins for approximately half a mile. The pipelines and pumps will be owned by the City and built by BVC as part of their scope under the EPC Agreement. The pipelines and pumps will be maintained by Collins.

AUTHORIZATIONS, PERMITS, AND COMPLIANCE

The primary governmental permits and approvals required for the Project are a state site certificate, air emissions permit, local conditional use permit, water supply and discharge permits, storm water permit, and various transportation and other local permits and approvals. The requirements and status of these permits and approvals are described below.

SITE CERTIFICATE

Pursuant to the State of Oregon Revised Statutes (ORS), no energy facility with an electric generation capacity of 25 megawatts or more may be constructed or operated in Oregon without first obtaining a Site Certificate from the Oregon Energy Facility Siting Council (EFSC), or an exemption therefrom. In reviewing an Application for Site Certificate (ASC), EFSC must determine that the siting, construction and operation of the energy facility will be accomplished in a manner consistent with protection of the public health and safety, and in compliance with the energy, air, water, solid waste, land use and other environmental protection policies of Oregon. A Site Certificate issued by EFSC binds the state, and all counties, cities and political subdivisions of Oregon. Once EFSC issues the Site Certificate, any necessary permits that are addressed in the Site Certificate must be issued by the responsible state agency or local government without further proceedings.

EFSC issued a Site Certificate for the Project to the City in August 1997. This Site Certificate was amended in April 1998 to incorporate a two combustion turbine Facility design, and again in December 1998 to incorporate a 500 kV interconnection. The Site

Certificate contains a detailed description of the Project including capacity, major equipment, site conditions, electric, gas and water interconnections, sources and volumes of water, wastewater discharges and other information. The Site Certificate also contains certain conditions that the City must meet in design, construction and operation of the Project. These represent the requirements of all the individual state and local agencies that have permitting jurisdiction over the Project (e.g., fish and wildlife, endangered species, etc.) as well as additional conditions imposed by EFSC itself. Many of the conditions are based on commitments made previously on behalf of the City during the application process.

The key conditions of the Site Certificate include; 1) the Project must be designed, constructed, operated and retired substantially as described in the Site Certificate, 2) the City must obtain an Air Contaminant Discharge Permit (ACDP), water discharge permits, an interconnection agreement with PacifiCorp and a steam sale agreement prior to construction, 3) construction of the Facility must commence on or before March 5, 2000 and must be completed (Substantial Completion) by September 5, 2002, 4) the City must develop a Facility decommissioning plan and establish $6.85 million (1997 dollars) in interest bearing reserves to fund decommissioning, and 5) all water supplied to the Facility must be from the SSWWTP other than makeup water from the Collins Facility and up to 160 gallons per minute of potable water on an annual average basis from the City water system.

If water from the SSWWTP is unavailable or of unsuitable quality, the Facility must use storm water collected on the Facility site. If storm water is unavailable, then an alternative source approved by EFSC may be used temporarily. The Facility should be able to operate for approximately 24 hours after loss of cooling water from the SSWWTP if potable water is used as an alternative source. This is based on the expected potable water delivery capacity of the City water system, the design water storage capacities of the Facility, and the expected maximum demand level for potable water at the Facility.

The Site Certificate also requires that the Facility meet certain initial performance levels. The City must test the Facility upon initial operation to prove that the full load output capacity is equal to or less than 500 MW and the heat rate is equal to or less than 6,795 Btu per kWh at average annual ambient conditions while not exporting steam. This is expected to be tested and proven through achievement of the Combined Cycle Heat Rate Guarantee under terms of the EPC Agreement between the City and BVC described elsewhere in this Report.

The Site Certificate also requires that the City make available at least 200,000 pounds per hour of steam for off-site industrial use on a five-year average basis to displace another source of carbon dioxide from fossil fuels that would have otherwise occurred. If Collins fails to consume the required amount of steam, the City must sell to another party an amount of steam equivalent to the shortfall. Alternatively, the City may present a plan to offset an amount of CO_2, NO_x, or PM_{10} from other sources, the cost of the plan being equal to the monetized value of emissions that would have occurred if fossil fuels had been used to generate an amount of steam equivalent to the steam shortfall.

The Site Certificate also requires that the City deposit $3.1 million (expressed in 1998 dollars) into an interest bearing escrow account to fund a series of alternative energy programs and projects (the Offset Portfolio). The City must monitor and verify actual performance of the Offset Portfolio (such monitoring cost limited to no more than $50,000 per year), provide an annual performance report to the U.S. Department of Energy for 30 years, and a detailed report to EFSC every five years reconciling actual performance versus forecast performance. The City must also establish a $300,000 contingency account (expressed in 1996 dollars) to be drawn upon in years 10, 20 and 30 to fund additional measures if performance is significantly less than forecast.

The Site Certificate also requires that the City provide initial and annual funding to the Oregon Climate Trust for the purposes of implementing CO_2 emission offset measures. Initial funding will be based on a portion of the tons of CO_2 forecast to be emitted from the Facility over 30 years multiplied by a rate of $0.57 per ton of CO_2. The Site Certificate includes a detailed stepwise calculation method, which yields an initial funding amount of approximately $1.3 million assuming a 6,795 Btu/kWh heat rate. Funds must be deposited into an interest bearing escrow account prior to construction. Over the life of the Facility, the City must deposit additional amounts into the account annually if Facility heat rate degrades more than 3 percent from the heat rate at the end of the first year of operation. The Facility heat rate (adjusted for any steam deliveries, non-standard ambient conditions and physical degradation) will be determined through performance of a full load 100 hour test at the end of each operating year.

The Site Certificate conditions were reviewed by PKE and the City and those conditions which impact design and performance have been incorporated in the design criteria and scheduling provisions of the EPC contract which has been executed with BVC. The conditions are expected to be met in the design, construction, and operation of the Facility. The City must provide periodic Project construction and operation reports to EFSC. Construction reports will be generated by BVC under terms of the EPC Agreement described elsewhere in this Report. Operation reports will be generated by PPM under terms of the Management Agreement described elsewhere in this Report. EFSC has certain audit and inspection rights, and may revoke or suspend the Site Certificate for failure to comply with the terms or conditions of the Site Certificate.

AIR EMISSIONS

The Facility will emit certain air pollutants during operation and is therefore subject to federal and state air pollution control regulations. Application and enforcement of state air quality regulations for the Project is the responsibility of the ODEQ. ODEQ has been delegated authority by the federal EPA to apply and enforce federal air quality regulations. PKE, on behalf of the City, submitted an application for an Air Discharge Contamination Permit (ADCP) to ODEQ on February 27, 1996 and a supplemental application on April 11, 1997. ODEQ issued an ADCP to the City on January 27, 1998. In September 1998, the City filed a request to amend the ACDP to allow a higher SO_2 emission rate due to a potentially higher than expected sulfur content in the gas supply to the Facility. This request was approved in November 1998.

Approval to construct under the ADCP becomes invalid if construction of the Facility has not commenced by July 27, 1999 (18 months from the original ADCP issue date), or if construction is discontinued for a period of 18 months, or if construction is not completed within 18 months of the scheduled construction completion date. ODEQ may extend these deadlines upon satisfactory showing by the City that an extension is justified.

The ADCP contains certain conditions that the City must satisfy in both design and operation of the Facility. The combustion turbines must utilize Dry Low NO_X and selective catalytic reduction (SCR) technology to reduce NO_X emission levels. These were determined to be the BACT for NO_X for the Facility. Specific emission rate limits for each combustion turbine are shown in Table 8 below:

Table 8
Allowable Emission Levels from Each Combustion Turbine Measured at HRSG Stack

Pollutant	Instantaneous Concentration Limit (ppm) @ 15% O_2	Daily Rate Limit (lbs/hr)
NO_X	4.5	33.1 (24 hour average)
CO	15 (at base load)	71.3 (8 hour average)
PM_{10}	None	6.8

These combustion turbine emission limits do not apply during Facility startup and shutdown operations. The combustion turbines may only use pipeline quality natural gas fuel. Each of the duct burners in the HRSG's can emit no more than 0.2 pounds of NO_X for every MMBtu of natural gas input.

With respect to the auxiliary boiler, NO_X emission concentrations cannot exceed 30 ppm (at 0.3 percent O_2) while on natural gas fuel and 60 ppm while on distillate fuel except during startup and shutdown operations. The auxiliary boiler also has certain instantaneous SO_2

and PM_{10} emission concentration limits. Distillate fuel must have a sulfur content of 0.05 percent or less by weight.

In addition to these concentration and daily average rate limits, the sources must be operated such that emissions do not exceed certain maximum annual and hourly average Plant Site Emission Limits (PSEL) except during startup and shutdown operations. The PSEL are summarized in Table 9 below.

Table 9
Plant Site Emission Limits (PSEL)

Pollutant	Turbines and Duct Burners	Auxiliary Boiler, Natural Gas	Auxiliary Boiler, Distillate Oil	Totals (Natural Gas)
PM_{10}	14 lb/hr, 56.8 tons/year	2.0 lb/hr, 2.6 tons/yr	5.4 lb/hr, 8.1 tons/yr	16 lb/hr 59.4 tons/yr
CO	143 lb/hr, 536 tons/year	16.3 lb/hr, 21.4 tons/yr	18.2 lb/hr, 60.9 tons/yr	159.3 lb/hr 558 tons/yr
NO_X	66 lb/hr, 251 tons/year	14.4 lb/hr, 18.9 tons/yr	29.9 lb/hr, 56.5 tons/yr	80.4 lb/hr 270 tons/yr
SO2	6.6 lb/hr, 25 tons/year	0.8 lb/hr, 1.0 tons/yr	20.6 lb/hr, 6.7 tons/yr	20.6 lb/hr 29 tons/yr
VOC	35 lb/hr, 120 tons/year	1.9 lb/hr, 2.5 tons/yr	1.9 lb/hr, 7.1 tons/yr	36.9 lb/hr 123 tons/yr
NH_3	52 lb/hr, 200 tons/year	n/a	n/a	52 lb/hr 200 tons/yr

The combustion turbines may be operated at partial loads where emissions exceed these limits, but not below 50 percent of combustion turbine base full load capacity and not for more than 200 hours per year. During such periods, the PSEL for each combustion turbine will be increased to 227 lbs/hr of CO and 76 lbs/hr of VOC. The duct burners may be operated without limitation, provided that the combined PSEL for the combustion turbines and duct burners shown above is not exceeded. Emissions per year from the auxiliary boiler may exceed the auxiliary boiler PSEL if there is a corresponding decrease in operation of the combustion turbines that offset the excess emissions. The auxiliary boiler can operate on distillate fuel only when the Facility combustion turbines and the boilers at the Collins Facility are shut down. The combustion turbines and duct burners may operate simultaneously, but the combustion turbines, duct burners and auxiliary boiler cannot operate simultaneously for more than 875 hours per year.

The City must perform an emissions test of the Facility within 60 days of achieving maximum firing rate, but no later than 180 days after initial startup, to demonstrate that the Facility can meet the combustion turbine emission limits and the auxiliary boiler emission limits. The test must be performed in accordance with ODEQ test procedures.

BVC is responsible for performance of this test under terms of the EPC Agreement described elsewhere in this Report.

The City must also install a continuous emissions monitoring system (CEMS) to monitor and record NO_X, CO and O_2 emissions from the combustion turbines, a CEMS system to monitor and record O_2 levels from the auxiliary boiler, and a continuous opacity monitoring system (COMS) to monitor and record opacity levels from the auxiliary boiler. Alternatively, the City may substitute an opacity monitoring plan for the COMS subject to ODEQ and (EPA) approval. The auxiliary boiler will also require NO_X monitoring if NO_X emission levels from the auxiliary boiler exceed 70 percent of the NO_X emission limit for the auxiliary boiler during the emissions test.

The City must submit a detailed annual Facility operating report to ODEQ including hours of operation of each source, operating levels, emission levels, fuel constituents, maintenance records, and other information. PKE is responsible for generating this report under terms of the O&M Agreement described elsewhere in this Report. The City must submit a new permit application to ODEQ prior to installing any new source, modifying an existing source, or changing the process or hours of operation of the Facility that may increase emissions. The City must also submit an Acid Rain permit application to ODEQ at least 24 months prior to operation of the Facility, and an Oregon Title V Operating Permit application no later than one year after initial startup. The Acid Rain permit application was filed with the ODEQ in February 1999.

PKE is responsible for operating the Project and preparing reports in compliance with the requirements of the ACDP under terms of the O&M Agreement described elsewhere in this Report.

The modeling of air emissions from the Facility to assess the ability to comply with the above emission limitations was performed based on operating characteristics consistent with the 501FD turbine and related Facility equipment. The model results were reviewed by ODEQ, which determined that the Facility is expected to comply with the air permit operating conditions and emission limitations.

Under terms of the Steam Sale Agreement described elsewhere in this Report, Collins will cease operation of their gas-fired steam boilers number 8 and 9 at the Collins Facility whenever steam is available from the Facility. This shutdown is consistent with the assumptions made for modeling the PM_{10} emission impacts of the Facility during application for the ACDP. It is also consistent with the economic incentive of Collins to take steam from the Facility rather than from the older and less fuel efficient boilers 8 and 9. There is no reason to believe at this time that Collins would continue to operate boilers 8 and 9, causing the City to be required to obtain PM_{10} emission offsets from other sources to limit the PM_{10} emission impact of the Facility. However, PM_{10} emission offsets are available through the PM_{10} .Offset Purchase Agreement described elsewhere in this Report. Additional PM_{10} offsets are expected to be available from Collins and other industrial facilities in the general vicinity of the Facility.

CONDITIONAL USE PERMIT

As a major new industrial facility located in Klamath County, with portions of its supporting facilities located in the City of Klamath Falls, the Project must receive Conditional Use Permits (CUP) from the County and the City.

The County planning commission must determine if the proposed use of the site is consistent with the Klamath County Land Development Code and the Comprehensive Land Use Plan for the County. The County review considers a broad range of impacts including impacts on agricultural and forest lands, open space and scenic areas, cultural and historic areas, wildlife habitat, groundwater resources, surface water runoff, recreation and others.

The City requested and received a CUP from the County for a single combustion turbine configuration plant on June 7, 1995 (CUP-29-95). On August 1, 1997, the City requested and received a CUP for the transmission line, cooling water supply line, potable water pipeline and wastewater discharge pipeline to serve the plant (CUP 54-97). On December 30, 1997, the City received an amendment to CUP-29-95 to allow development of a single or dual turbine configuration plant. Finally, in December 1998, the City requested and received a new CUP (CUP-102-98) amending CUP-29-95 to authorize construction of a either a 230kV or 500kV switchyard, and expansion of the Facility site to 20 acres. These CUPs, in aggregate, constitute County approval of the Project. The Project was found to be consistent with the existing zoning and use of surrounding properties. The CUPs do require that the visual impact of the Project viewed from Oregon Highway 97 be mitigated by the use of neutral color schemes and landscaping, and that access to the Project site will be subject to approval of the Oregon Department of Transportation (ODOT), and that construction work on ODOT right of way shall require application and permits from ODOT. A description of the necessary ODOT permits and approvals is provided under Other Authorizations and Permits elsewhere in this Report.

Although the Project site is outside the City limits, the cooling water supply pipeline and wastewater return pipeline of the Project pass through the City limits. The Community Development Ordinance of the City requires a CUP for all structures. The City has indicated in a letter dated February 13, 1996 that underground pipelines do not qualify as structures. Therefore, no CUP is necessary for the pipelines.

On March 6, 1996, the City issued CUP 6-96 for installation of 230 kV electric interconnection lines to interconnect the Facility with the PacifiCorp 230 kV system. The City and PKE have since chosen to interconnect the Facility with the 500 kV system of PacifiCorp. On December 10, 1998, PacifiCorp obtained CUP101-98 from the County for the re-alignment of the PacifiCorp 500 kV transmission system that is necessary for this interconnection.

WATER SUPPLY, DISCHARGE AND STORM WATER

The City has received various authorizations and permits for water supply and discharge for the Facility.

The City received a Permit to Appropriate Public Waters on October 1, 1997 from the Oregon Water Resources Department (OWRD) for the purpose of providing boiler condensate makeup water to the Facility. OWRD determined that groundwater use by the Facility is compliant with the Groundwater Act of 1955. The permit expands the rights under an existing Collins certificate, and allows the City and Collins to withdraw up to 1.34 cubic feet per second (601 gallons per minute) of water from an existing well at the Collins Facility. The maximum expected demand for boiler condensate makeup water at the Facility, net of condensate returned from the Collins Facility, is 160 gallons per minute. The City must install a flow meter and report flows to OWRD every year. Construction of necessary pipelines and use of the water must begin no later than October 1, 2002.

Potable water will be supplied by a separate connection to the existing City potable water system. The Facility is expected to consume up to 137 gallons per minute of potable water at design maximum demand conditions. EFSC has determined that use of potable water will not adversely impact the City's water rights.

To allow the use of effluent from the SSWWTP as cooling water for the Facility, the City requested and received a modification to their existing National Pollutant Discharge Elimination System (NPDES) permit for the SSWWTP on October 21, 1997. Application and enforcement of the NPDES within Oregon has been delegated to ODEQ by the federal EPA. The ODEQ, in consultation with the OWRD and the Oregon Department of Fish and Wildlife (ODFW), has determined that no additional water rights are necessary for use of the effluent and that use of the effluent should improve Klamath River water quality. The revised permit requires the City to pre-treat SSWWTP effluent prior to use by the Facility. The City must also monitor and record flow, temperature, chlorine and Coliform level of the effluent. The City must also adhere to its approved Reclaimed Water Use Plan. Under the Plan, up to 3.1 million gallons per day of effluent can be used by the Facility, a backup supply of cooling water will be used if quality limits of the permit are exceeded, and signs, markings and other safeguards must be employed to prevent human consumption of effluent at the Facility.

The City issued an Industrial Wastewater Discharge Permit for the Facility on March 1, 1998. Discharge from the Facility's wastewater pre-treatment system to the SSWWTP (exclusive of sanitary waste) cannot exceed 1,000,800 gallons per day with a pH between 5.0 and 10.0. Up to 647 gallons per minute (931,680 gallons per day) of discharge is expected under design maximum conditions. Concentrations of certain metals and other parameters cannot exceed limits listed in the permit. Concentrations of these parameters must be sampled and reported in June and December of each year. Discharge flow and pH must also be measured and recorded. The Site Certificate requires that effluent consumption less wastewater discharge (net consumption of effluent) at the Facility must not exceed 1,640 gallons per minute (2,361,600 gallons per day). This effectively limits withdrawal from the Klamath River for the purpose of protecting threatened and endangered species.

On October 8, 1997, the City requested and received coverage of Facility storm water discharge under the State of Oregon general NPDES storm water permit issued by ODEQ. An application to transfer the permit to PKE was filed January 29, 1999 and the transfer was approved by ODEQ on February 28, 1999. The permit requires that an Erosion and Sediment Control Plan (ESCP) be submitted to the ODEQ. The ESCP must be approved by the ODEQ prior to construction of the Project. BVC is responsible for preparation of the ESCP under terms of the EPC Agreement described elsewhere in this Report. The ESCP must be developed and implemented to prevent the discharge of significant amounts of sediment to surface waters. The ESCP must include detailed descriptions of the site, site grading and drainage plans, erosion and sediment control measures to be used and other information. BVC must properly operate and maintain the control measures, halt or reduce activity if the measures fail, and remove and dispose of any sediment that improperly accumulates. There is no reason to believe that the ESCP will not be approved on a timely basis consistent with the planned schedule for commercial operation of the Facility.

OTHER AUTHORIZATIONS, PERMITS AND REQUIREMENTS

The City must obtain an Approach Road Permit from the Oregon Department of Transportation (ODOT) prior to construction of site access from State highway 97. The City must also obtain ODOT permits for construction of water and wastewater pipelines located in ODOT rights of way, and for passage of any oversize or overweight loads on state or federal highways. The issuance of these permits is contingent upon submission of detailed Project design documents to ODOT. These will be provided by BVC during the detailed design phase of the Project and after financial closing. However, these are relatively minor permits and there is no reason at this time to believe that they will not be obtained.

Under terms of the Site Certificate, the City must coordinate with ODFW in creation or restoration of wildlife habitat, and provide up to $20,000 for repair of the Haymaker Dyke located in the ODFW Klamath Wildlife Area.

The Site Certificate requires the City to flag and avoid disturbing an archaeological site near the proposed cooling water supply pipeline route. If disturbance is unavoidable, the City must first obtain necessary permits from the Oregon State Historic Preservation Office (OSHPO). During construction, a member of the Klamath Tribe will be employed to monitor site excavation activities. The City must halt earth disturbing work and notify EFSC, OSHPO and the Klamath Tribe if archeological sites or objects are found during construction of the Project. The City must then obtain OSHPO permits and not restart work until it has complied with conditions of the permits. The City is also required to have a representative of the Klamath Tribe present on the Facility site during excavation work.

The City must consult with Klamath County concerning noise impacts from construction and operation of the Project. Construction activities must be limited to the hours of 7:00 a.m. to 10:00 p.m. The City must retain a qualified noise specialist to measure actual facility noise levels at the nearest residential area and at the Klamath Wildlife Refuge within six months after initial commercial operation of the Facility. If noise levels do not comply with applicable DEQ regulations, the City must take actions necessary to bring Facility noise levels into compliance. BVC is required to design the Project so that noise levels at these locations do not exceed an L-10 level of 50 dBA during all reasonable Facility operating conditions. L-10 means that the noise level cannot be exceeded for more than 10% of the time during a one hour period.

The City must obtain all state and local building permits necessary for construction and operation of the Facility. These will be obtained by BVC on behalf of the City under terms of the EPC Agreement described elsewhere in this Report. Design and construction of the Facility must be consistent with Seismic Zone 3 requirements, and in compliance with applicable laws and regulations of the Building Codes Division of the Oregon Department of Consumer and Business Services (DCBS). If pre-construction seismic analysis reveals the need for enhanced seismic design, safety structures critical to public health and safety (such as hazardous waste storage and operating control rooms) must be designed in consultation with DCBS.

The City must comply with the Oil Spill Contingency and Prevention Plan program administered by the Water Quality Division of ODEQ regulating the transport, storage, handling, spill prevention and control of petroleum products. The City must also comply with various programs addressing fire protection and safety, and the storage, use, handling, and emergency response for hazardous materials and community right to know laws for hazardous materials administered by the Oregon State Fire Marshall's Office. The natural gas and electric transmission lines connected to the Project must conform to design and safety standards administered by the Safety Section of the Oregon Public Utilities Commission. The City must comply with various regulations of the Oregon State Health Division relating to possession, use and transfer of radioactive materials, and potability of water from domestic water supply systems.

The Facility must be certified for compliance with the federal Power Plant and Industrial Fuel Use Act (FUA). The FUA requires that the Facility be capable of being modified to use coal or another alternative fuel as its primary fuel source. Certification may be accomplished by submission of a brief form letter to the United States Department of Energy Office of Coal and Power. The City submitted such a letter on January 28, 1999.

The conditions imposed on the Project by the above described relevant authorizations and permits appear reasonable and typical for a power generation project of this type and size. Except for the ODOT and building permits described above, all permits necessary to begin construction of the Facility have been obtained at this time. There is no reason at this time to conclude that the remaining permits cannot be obtained on a timely basis.

PROJECT AGREEMENTS

OVERVIEW

The following section describes the key provisions of each of the agreements that have been, or will be, executed relating to the design, engineering, procurement, construction, fueling, operation, management, and sales of output from the Project (Project Agreements). The Project Agreements include the following:

1) Site Lease Agreement;
2) Engineering, Procurement and Construction Agreement;
3) Agreement for Project Management Services During Construction;
4) Power Purchase Agreement;
5) Power Brokering Agreement;
6) Steam Sale Agreement;
7) Fuel Supply and Services Agreement;
8) Operations and Maintenance Agreement;
9) Management Agreement;

10) PM_{10} Emissions Purchase Option Agreement;

11) Generation Interconnection Agreement;

12) Transmission Services Agreement; and

13) Municipal Effluent and Water Services Agreement.

The Project Agreements are described in more detail in the appendices of the Limited Offering Memorandum.

SITE LEASE AGREEMENT

The City will enter an agreement to lease the Facility site (Lease) with Collins prior to the date of financial closing of the Project Bonds. The Lease will commence on the date upon which all of the following are satisfied (the Lease Effective Date);

1) The City has entered into the Bond Indenture;
2) The first draw of construction funds is authorized under the Bond Indenture; and
3) The City has delivered a notice to proceed to BVC.

If the Lease Effective Date has not occurred by December 31, 1999, then the City may either terminate the Lease, or propose a new Lease Effective Date that is no later than December 31, 2002 and pay $4,000 per month to Collins as compensation for the delay in rent payments. If the Lease Effective Date does not occur by December 31, 2002, then Collins may terminate the Lease. Collins may also terminate the Lease if the City defaults by failing to make rent payments or materially comply with applicable permits and laws and other provisions of the Lease after a specified cure period. Upon expiration or termination of the Lease for any reason, the City is obligated to remove the Facility.

The term of the Lease is 40 years after the date of Substantial Completion of the Facility as defined in the EPC Agreement described elsewhere in this Report. The City has the right to extend the term for up to three additional five-year periods. Rent payments during the Facility construction period will include $750,000 due at the commencement of construction, $750,000 due one year later, and $1 million due thirty days after the date of Substantial Completion. Rent payments during the Facility operating period will be $250,000 per year payable in advance. Rent will be escalated based on gross domestic product inflation indices. Rent payments are secured solely by the assets of the Facility and revenues from sale of electricity and steam. Collins will have no recourse to any other funds of the City.

The Lease requires Collins to provide the City with a site free of environmental contamination. If construction of the Facility reveals that hazardous materials are present at the Facility site, the City may elect to either terminate the Lease or commence with the necessary remediation work to make the site suitable for the Facility. Collins will reimburse the City for the cost of the remediation. Collins will remain responsible for all hazardous materials identified and/or removed from the Facility site, except those released by parties other than Collins during the construction or operation of the Facility.

Collins will grant the City all easements on the adjacent Collins property as necessary for construction, operation and maintenance of the Facility. Under terms of a Construction Access and Use Agreement between Collins and the City, Collins will also provide all necessary Facility site access on and across the adjacent Collins property, (including rail spur access), and construction lay down space and parking space for BVC workers during construction. Collins will also provide construction water, and may provide other utility services to the City and BVC.

The City will be responsible for paying all real estate, personal property, special assessments or other taxes levied against its interest in the Facility. If the City fails to maintain or repair the Facility, and such failure adversely impacts Collins under the Steam Sale Agreement (described elsewhere in this Report), then Collins has a right to perform the necessary work and be immediately reimbursed by the City. Under terms of the Bond Indenture, an amount of at least $6.85 million (1998 dollars) will be reserved from Project Bond proceeds (Site Restoration Fund) to provide for Facility removal and site restoration.

ENGINEERING, PROCUREMENT AND CONSTRUCTION AGREEMENT

The City entered into an agreement to design, engineer, procure and construct the Facility (the EPC Agreement) with BVC on August 31, 1998. BVC will obtain site control and begin construction activities upon issuance of a Notice to Proceed by the City. The EPC Agreement will continue through the date on which the Facility is mechanically complete, has achieved performance levels guaranteed by BVC (as described below), is in compliance with all applicable laws and permits, and is operating in compliance with the requirements of the Power Purchase Agreement and the Steam Sales Agreement as described elsewhere in this Report (Substantial Completion). The term will continue until all outstanding, relatively minor scope and performance issues are resolved (Final Completion). If the Notice to Proceed does not occur on or before October 1, 1999, then BVC may terminate the EPC Agreement. The Notice to Proceed is expected to be issued by the City at the financial closing of the Project Bonds.

BVC will prepare detailed design of the Facility including construction specifications and drawings. The Facility must comply with the Technical Scope Document of the City included as Appendix A to the EPC Agreement, the Contractor's Description of Equipment and Facility Systems included as Exhibit B to the EPC Agreement, the 500 kV Switchyard Option Scope of Work and Specifications included in Attachment 11 of Exhibit A and the Fire Protection Requirements described in Exhibit K. BVC will procure equipment and employ subcontractors as necessary to construct the Facility, selecting from a list of acceptable suppliers shown in Attachment 10 of Exhibit A to the EPC Agreement. BVC will coordinate the Facility design and construction with the design and construction of interconnection facilities by the City, PacifiCorp, PGTNW, ODOT and Collins. BVC will also coordinate with regulators and obtain all necessary approvals and permits other than the major federal, state and local permits (Final Permits) that the City will obtain and which are listed in Appendix D to the EPC Agreement. BVC will provide a full time project manager and staff on site to manage construction of the Facility, including inspection, quality control, schedule and cost control, material expediting, storage, owner presentation and report preparation tasks. BVC will complete the Facility in general accordance with the Construction Schedule included in Exhibit E. BVC has agreed to pay wage rates no less than the prevailing wage rates for local labor as described in Appendix E to the EPC Agreement.

The City, through PKE, will provide personnel on site to monitor construction of the Facility. PKE will also provide on-site Facility operating personnel at least six months prior to the scheduled date of Substantial Completion to receive training and assist in Facility startup and testing. These PKE services will be performed under terms of the Project Management During Construction Agreement and the O&M Agreement as described elsewhere in this Report. The City must provide potable water, cooling water, wastewater connection, natural gas supply, and 500 kV electric transmission interconnection to the Facility within the quality, quantity and location requirements (terminal points) as shown in Attachments 1 through 5 of Exhibit A of the EPC Agreement. The geotechnical and environmental features of the Facility site must substantially conform to those identified in the geotechnical studies and the Golder Study provided by the City, included in Attachments 6 and 7 of Exhibit A. The quality and temperature of the condensate collected from the Collins Facility must substantially conform to that specified in the Collins plant return condensate analysis provided by the City and included in Attachment 9 of Exhibit A.

For provision of the Facility and services, the City will pay BVC a lump sum price of $183.3 million, plus an additional $7.363 million for the 500kV switchyard, plus an amount of escalation based on a producer price index formula as shown in Exhibit N of the EPC agreement from October 1, 1998 to the Notice to Proceed Date (the Lump Sum Price). These figures include a non-refundable, one million dollar down payment that was paid by PKE to BVC on behalf of the City in order to obtain the Substantial Completion Date Guarantee as described elsewhere in this section (CT Slot). Monthly progress payments will be made on a schedule shown in Exhibit F of the EPC Agreement. Payments will be subject to approval by PKE, the City, and an independent engineer. Five percent of each invoice will be retained by the City (the Retainage). Alternatively, BVC may post an irrevocable retainage letter of credit (RLOC) equal to five percent of all invoices to date in the form shown in Exhibit L to the EPC Agreement. Either the City or BVC may request to add, delete or change the work to be performed by BVC (a Change Order). Upon approval by the City, BVC will perform the Change Order work for an additional lump sum amount. If the City and BVC cannot agree on a lump sum amount, the amount will be calculated based on the time and material compensation rates included in Exhibit G to the EPC Agreement. A Change Order may also change the guarantees or warranty provided by BVC described elsewhere in this Report. BVC may not submit a Change Order due to unanticipated subsurface conditions at the site, unless the condition is a hazardous substance (as defined in the EPC Agreement), or is an underground pipeline or other utility that is estimated to cost more than $100,000 to remove.

Title to all work, equipment and materials will pass from BVC to the City, free and clear of all liens, when payments are received by BVC. BVC has provided a one year warranty on all materials, equipment and workmanship commencing from the date of Substantial Completion, plus an additional one-year warranty on repairs made during the original one-year warranty period. Until the date of Substantial Completion, risk of loss remains with BVC and BVC must maintain insurance on the Facility including all risk builders risk (ARBR) insurance. ARBR will cover direct damage, testing and business interruption in an amount equal to the Lump Sum Price, plus limited earthquake damage.

The City may terminate the EPC Agreement prior to any Notice to Proceed due to the City's inability to finance, permit, obtain property rights or complete other development related tasks. The City may terminate after giving the Notice to Proceed, but must pay BVC all costs to date including the cost of any equipment already delivered to the Facility site plus reasonable amounts for overhead and profit. If the City terminates the EPC Agreement for its convenience and then completes the Facility by other means, then the City must pay BVC an amount equal to BVC's unrealized profits from the EPC Agreement, subject to a maximum of $5 million.

BVC will be in default if they do not begin to cure any bankruptcy, any failure to perform, failure to pay subcontractors, or violation of law within ten days. The City may then take possession and complete the Facility. BVC will be liable to the City for any cost of completion in excess of the Lump Sum Price. Conversely, the City will be liable to BVC for any cost savings under the Lump Sum Price. BVC will post a performance bond equal to the Lump Sum Price upon receipt of the Notice to Proceed. BVC has also provided a Contractor Parent Guarantee from Black & Veatch as shown in Exhibit O of the EPC Agreement to ensure their performance.

The obligations of the City under the EPC Agreement, including payments and the cost of other performance, are limited solely to the available proceeds of the Project Bonds, any revenues from Facility operation and proceeds of insurance policies. BVC has no recourse to the general funds of the City. BVC will execute a Consent Agreement as shown in Exhibit M of the EPC Agreement to acknowledge the rights of the bondholders with respect to the EPC Agreement.

Performance Guarantees

BVC has provided several Facility performance guarantees to the City as described below. Performance tests, as described in Exhibits H and I of the EPC Agreement, will be conducted on the Facility following mechanical completion to demonstrate that performance meets the guaranteed values. These performance tests will be conducted in general accordance with the Overall Plant Performance Test Code 46 of the American Society of Mechanical Engineers (ASME PTC 46). An allowance for measurement error will be calculated for each performance test by BVC per ASME PTC6R and PTC19.1 (Test Uncertainty Tolerance Value). The Test Uncertainty Tolerance Value will be applied to the tested values as described below.

If the tested performance of the Facility fails to meet the guaranteed values by more than 5 percent, BVC is obligated to correct the Facility at BVC's cost and re-perform the tests until the guaranteed values are met within 5 percent. If Facility tested performance is within five percent of the guaranteed values, BVC may elect to either correct and re-test the Facility or allow the City to draw liquidated damages as described in Exhibit J of the EPC Agreement from the Retainage or the RLOC. The City may draw liquidated damages in any case if the guarantee values have not been met by the date of Final Completion. Liquidated damages are the City's sole remedy for failure of the Facility to meet the performance guarantees if the tested Facility performance is within 5 percent of the guaranteed values.

BVC has guaranteed that the Facility will achieve an output rate of at least 464,020 kilowatts while exporting 200,000 pounds per hour of steam to Collins (the Cogeneration Output Guarantee) while consuming no more than 7,005 British thermal units (Btu's) of natural gas per kilowatt-hour (kWh) of production (the Cogeneration Heat Rate Guarantee). If the tested electrical output rate is less than the guaranteed value, then BVC will owe the City liquidated damages at the rate of $500 for every kilowatt of output rate shortfall (Cogeneration Output Liquidated Damages). In this case, the Test Uncertainty Tolerance Value for cogeneration output would added to the tested electrical output rate to benefit BVC. BVC can earn a bonus at the rate of $300 for every kilowatt of tested output rate excess over the guaranteed value, subject to a cap of $2 million (Cogeneration Output Bonus). In this case, the Test Uncertainty Tolerance Value for cogeneration output would not be added to the tested electrical output rate to benefit the City. If the tested heat rate is greater than the guaranteed value, then BVC will owe the City liquidated damages at the rate of $55,000 for every Btu per kWh of heat rate excess (Cogeneration Heat Rate Liquidated Damages). In this case, the Test Uncertainty Tolerance Value for cogeneration heat rate would be subtracted from the tested heat rate to benefit BVC. BVC can earn a bonus at the rate of $35,000 for every Btu per kWh that the demonstrated heat rate is under the guaranteed value, subject to a cap of $5 million (Cogeneration Heat Rate Bonus). In this case, the Test Uncertainty Tolerance Value for cogeneration heat rate would not be subtracted from the tested heat rate to benefit the City.

BVC has also guaranteed that the Facility will achieve a heat rate of no more than 6,795 Btu's per kilowatt-hour while exporting no steam to Collins (the Combined Cycle Heat Rate Guarantee). If the tested heat rate is greater than the guaranteed value, then BVC will owe the City liquidated damages at the rate of $45,000 for every Btu per kWh of excess heat rate (Combined Cycle Heat Rate Liquidated Damages). In this case, the Test Uncertainty Tolerance Value for combined cycle heat rate would be subtracted from the tested heat rate to benefit BVC. There is no opportunity for BVC to earn a bonus if the tested heat rate is less than the guaranteed value.

If the Facility fails to meet both the Cogeneration Heat Rate Guarantee and the Combined Cycle Heat Rate Guarantee, BVC will owe only the Cogeneration Heat Rate Liquidated Damages or the Combined Cycle Heat Rate Liquidated Damages, whichever is greater.

The sum of the Cogeneration Output Bonus and Cogeneration Heat Rate Bonus payable to BVC (if any) is limited to $5 million. The City will reserve $3 million of Project Bond proceeds for payment of these bonuses. If the bonuses payable exceed this amount, the excess must be first paid out of other available Project Bond proceeds, and to the extent these are insufficient, then out of distributions payable to the City over the first 5 years of Project operation.

BVC has also guaranteed that the auxiliary boiler will achieve a steam output of 275,000 pounds per hour (the Auxiliary Boiler Capacity Guarantee) while consuming natural gas at a rate no greater than 376.6 million Btu's (MMBtu) per hour (the Auxiliary Boiler Fuel Use Guarantee). If the tested steam output rate is less than the guaranteed value, then BVC will owe the City liquidated damages at the rate of $15 for every pound per hour of output rate shortfall. In this case, the Test Uncertainty Tolerance Value for auxiliary boiler output would be added to the tested value to benefit BVC. If the tested fuel consumption rate is greater than the guaranteed value, then BVC will owe the City liquidated damages at the rate of $25,000 for every million Btu per hour of fuel consumption rate excess. In this case, the Test Uncertainty Tolerance Value for auxiliary boiler fuel use would be subtracted from the tested value to benefit BVC. There is no opportunity for BVC to earn a bonus.

Review of EPC Contract Liquidated Damage Provisions

The liquidated damage amounts described above are intended to compensate the City for the decrease in expected power sale revenues and/or the increase in expected fuel costs that would likely occur over the life of the Project if the Project is not capable of performing at the expected guarantee levels.

The Cogeneration Output liquidated damage rate appears to be sufficient compensation considering that the cost of replacing this lost capacity through duct firing, evaporative cooling, and/or purchases from other generators, should always be less than the cost of installing a new stand alone combustion turbine, which is less than $500/kilowatt based on prices generally known in the power generation industry today.

The Cogeneration Heat Rate liquidated damage rate of $55,000 per Btu/kWh appears sufficient, assuming the Facility would 1) achieve a 93 percent capacity factor, 2) incur typical combustion turbine output and heat rate degradation, 3) face a levelized annual delivered fuel cost of $1.75 per MMBtu, and 4) pass approximately 47 percent of the increase through to PPM via the Monthly Fuel Charge under the Power Purchase Agreement over a period of 20 years. The Combined Cycle Heat Rate liquidated damage rate also appears sufficient for similar reasons.

The liquidated damage rate for auxiliary boiler output appears sufficient considering that the cost of replacing this lost capacity should always be less than the cost of installing an additional boiler, which is less than $15/pound per hour of capacity based on prices generally known in the power generation industry today. Finally, the liquidated damage rate for auxiliary boiler fuel consumption appears sufficient assuming a levelized annual delivered fuel cost of $1.75 per MMBtu and a 10 percent annual capacity factor over 20 years.

Other Guarantees and Tests

BVC has also provided other guarantees and has agreed to perform certain other tests of the Facility as described below. There are no liquidated damages associated with these guarantees and tests. However, achievement of these guarantees and performance of these tests is a prerequisite for achieving Substantial Completion.

BVC has guaranteed that, for each Facility operating case described in Figure I-1 of Exhibit I of the EPC Agreement, the Facility will achieve an electrical output and a heat rate within five percent (5 percent) of the Net Plant Output and Net Plant Heat Rate values shown for each operating case. BVC has also guaranteed that the Facility will operate in compliance with all Facility air emission permits at loads above 60 percent of full load (the Emission Guarantee).

BVC has also agreed to perform a ten day Firm Capacity Availability Test, a 100 hour Reliability Test, and certain Functional Tests as described in Exhibit H of the EPC Agreement, all of which may be completed concurrently.

Substantial Completion Guarantee

Substantial Completion will occur after:

1) The as tested Facility performance is generally within 1.5 percent of the performance guarantee values or the appropriate liquidated damages have been paid;
2) The Emission Guarantee has been met;
3) The guarantee to achieve the Figure I-1 performance has been met; and
4) The Facility has successfully passed the Firm Capacity Availability Test, the Reliability Test and the Functional Tests.

BVC has guaranteed that Substantial Completion will occur on the later of 1) July 1, 2001 or 2) 790 days after the Notice to Proceed date. BVC may extend this guaranteed date on a day for day basis if the Notice to Proceed is not received by May 3, 1999. BVC may propose to extend this date upon receipt of a substantial Change Order from the City, or a substantial change in Final Permits or applicable Law, or occurrence of an uncontrollable event.

If Substantial Completion occurs after the scheduled date, then BVC will owe the City liquidated damages in the amount of $20,875 for each day of delay. After 15 days of delay, the liquidated damages rate increases to $41,750 per day. After 30 days of delay, the liquidated damages rate increases to $83,500 per day. During the period in which liquidated damages are accruing, BVC will receive a credit against the amount of liquidated damages equal to the excess of any power sale revenues over all cash expenses of the Facility. After Substantial Completion is achieved, the Retainage or the RLOC will be reduced to a level equal to twice the estimated cost to repair remaining minor deficiencies in the Facility (the Punch List).

The City has the right to accept the Facility for commercial operation prior to Substantial Completion. Such acceptance would relieve BVC of the Substantial Completion delay related liquidated damages liability only. BVC would remain liable for performance related liquidated damages. Upon Substantial Completion, risk of loss is transferred to insurance policies held by the City.

The total aggregate amount of damages payable by BVC, including any loss, damages, non-performance of BVC or subcontractors or suppliers, cannot exceed 50 percent of the Lump Sum Price. However, this limitation on liability does not extend to BVC's obligation to complete the physical construction of the Facility to the point at which it is capable of making energy deliveries consistent with prudent utility practices (Commercial Completion), nor to any cost of warranty work by any subcontractor or vendor. BVC's liability for delay and performance liquidated damages is limited to 30 percent of the Lump Sum Price.

AGREEMENT FOR PROJECT MANAGEMENT SERVICES DURING CONSTRUCTION

The City will enter into an agreement with PKE for provision of project management services during construction of the Project (the Management During Construction Agreement) on the date of financial closure of the Project Bonds. The Management During Construction Agreement will commence on this date and will expire on the date of Final Completion.

PKE is responsible for planning, scheduling and conducting all business incidental to the design, construction and startup of the Facility. General tasks include administration of the EPC Agreement and other contractor agreements, administration of the Power Purchase Agreement as described elsewhere in this Report, review and approval of schedules, plans, drawings, specifications, invoices and change orders from BVC and other contractors, establishment and maintenance of administrative office facilities and on-site representatives, provision of monthly cost, schedule and progress reports to the City, inspection and consultation on the work in progress, coordination of interconnection facility installation, coordination of operating staff training, and other tasks. PKE will review and approve all applications for payment, assemble documents required to make the monthly draw request under the Bond Indenture, certify the construction draw requests as Owner's agent, and forward construction draw requests to the Independent Engineer and the City. The City will review and approve the draw request for certification by the Independent Engineer and payment by the Bond Trustee. PKE will not cause the City to incur contractual obligations that exceed available funds under the Bond Indenture.

PKE's costs in performing these services, including wages, overhead, office supplies, utilities, and others, will be paid by the City from proceeds of the Project Bonds. Project Bond proceeds will also be used to pay PKE a fee of $1.5 million, payable in 30 equal monthly installments beginning on the first day of the month following the date that a Notice to Proceed is issued by the City to BVC under the EPC Agreement (the Project Manager Fee). The principal amount of the Project Bonds include funds for payment of these services.

PKE may approve any change order that 1) does not exceed $100,000 in cost, and 2) would not cause the total amount of change orders on a single contract to exceed the lesser of $1,000,000 or 25 percent of the value of the applicable contract, and 3) would not cause the budget for construction costs established by the Bond Indenture (Approved Construction Budget) to be exceeded. PKE is responsible for administering any warranty, breach or other claims arising under the EPC Agreement and other contractor agreements. PKE must obtain City approval to settle claims that exceed $100,000 individually, or where the total aggregate of claims exceeds the lesser of $1,000,000 or 25 percent of the contract value. PKE may not acquire assets or services for the Project from any affiliate of PKE except at arm's length, in the ordinary course of the Project Manager's business, and with the City's consent after first presenting a description of the scope of assets or services to be provided. The City is responsible for funding the costs of construction, and reviewing and approving proposed change orders within 20 days of receipt. A change order will be deemed approved if the City does not respond within 20 days.

PKE may enter into agreements with qualified, experienced, reputable contractors on behalf of the City (a contract between the City and the contractor) as may be necessary or desirable for the performance of PKE's duties under the Management During Construction Agreement without prior approval of the City if 1) the agreement calls for expenditure of no more than $100,000 in an operating year, and 2) the agreement will not cause the aggregate amount of expenditures under all such contractor agreements for an operating year to exceed 5 percent of the Approved Construction Budget, and 3) the agreement will not cause the Approved Construction Budget to be exceeded. Contracts that are expected to exceed $250,000 in cost in any one operating year and have not received an exemption from the local contract review board, will be awarded pursuant to a competitive bid procedure. PKE, for itself, may enter into agreements with qualified, experienced, reputable subcontractors (contract between PKE and the contractor) without restriction.

Disputes related to a change order or the qualifications of any subcontractor will be referred to binding arbitration. The liability of PKE for any claim in any operating year under the Management During Construction Agreement is limited to the amount of the Project Manager Fee for the operating year in which the claim occurred. In case of default by either party, the party not in default may terminate the Management During Construction Agreement by giving the defaulting party 45 days' prior notice (15 days in the case of failure by the City to make payment when due). Any such notice will become null and void if the defaulting party has cured or undertaken to cure the default within 30 days of the notice (10 days in the case of failure by the City to make payment when due). The City must pay PKE the portion of the Project Manager Fee payable as of the date of termination. Prior to termination and for a period up to 180 days afterward, PKE will provide services to the City reasonably sufficient to enable a new project manager to begin managing the Facility. The City will pay the reasonable costs of such services after the termination date.

In the event of breach or default by the City, PKE will have no recourse against the general funds of City. PKE may only make claims against moneys available under the Bond Indenture to satisfy claims against the Owner, or if the Bond Indenture has been terminated, from proceeds of the disposition of Facility assets, and from insurance policies providing coverage for any such claims. Upon default by the City, the Bond Trustee is entitled to cure the default and exercise all of the City's rights under the Management During Construction Agreement. PPM will accept assignment of the Management During Construction Agreement to the Bond Trustee, or will offer a substantially similar agreement to the Bond Trustee.

POWER PURCHASE AGREEMENT

The City will enter into a Power Purchase Agreement with PPM on the date of financial closure of the Project Bonds. The Power Purchase Agreement will continue in its initial term until the later of 1) the 30th anniversary of date of Substantial Completion or 2) the final maturity of the bonds issued pursuant to the Bond Indenture. The Power Purchase Agreement will terminate if Substantial Completion has not occurred on or before December 31, 2003. Prior to expiration of the Power Purchase Agreement, PPM may extend the term of the Power Purchase Agreement to the date on which the duration of the term will equal 80 percent of the useful life of the Facility. The useful life of the Facility must be determined by a qualified independent engineer appointed jointly by PPM and the City. PPM must also present an opinion of bond counsel that the term extension will not have an adverse effect on the exclusion of interest on the Project Bonds from the taxable income of the bond holders.

PPM will purchase 100 percent of the power produced by the Facility prior to the date of Substantial Completion (Test Power). After the date of Substantial Completion, PPM will purchase approximately 47 percent of Facility Base Capacity, which is defined as 484 megawatts measured at the high voltage terminals of the Facility main transformers, and approximately 10 megawatts of Facility Peaking Capacity, which is defined as 22 megawatts measured at the high voltage terminals of the Facility main transformers made available from duct firing of the HRSG's. The Facility Base Capacity and the Facility Peaking Capacity is collectively the Facility Nominal Capacity, and the amount purchased by PPM is the Purchased Capacity. PPM may schedule power to be delivered from zero to 100 percent of the Purchased Capacity in any given hour, subject to 1) a maximum load rate of change of five megawatts per minute per combustion turbine then operating, or such other rate as determined by the City or its agent, and 2) a minimum load limit such that no permit conditions are violated but not less than 25 percent of the Facility Nominal

Capacity (Facility Output). Schedules must be received from PPM in accordance with the scheduling provisions of Exhibit E to the Power Purchase Agreement.

If the Facility Nominal Capacity increases during the term of the Power Purchase Agreement due to technology improvements or other Facility enhancements, then the amount of Purchased Capacity will increase by approximately 47 percent of the increase provided that 1) PPM has agreed to pay approximately 47 percent of any Additional Bonds and Excess Facility Operating Expenses (as described below) incurred to obtain such increase and 2) bond counsel has provided an opinion that such an increase will not have an adverse effect on the exclusion of interest on tax-exempt bonds issued under the Bond Indenture. The point of delivery is in the Facility switchyard on the high voltage side of the main transformers located in the Facility switchyard. The City must construct, operate and maintain the Facility in accordance with prudent utility practices and applicable laws. The City must maintain Facility insurance as described in Exhibit D of the Power Purchase Agreement.

For Test Power, PPM will pay a price equal to 75 percent of the then current "hour ahead zonal market clearing price at NW1" as posted each hour by the California Independent System Operator.

For Facility Output, PPM will be charged a Monthly Demand Charge, plus a Monthly Operations Charge, plus a Monthly Major Maintenance Fund Charge, plus a Monthly Fuel Charge, plus a Monthly Fuel Transportation Charge as specified in Exhibit A of the Power Purchase Agreement and as described below.

The Monthly Demand Charge will equal the sum of 1) one sixth of approximately 47 percent of the scheduled interest due on all Project related bonds on the next semi-annual interest payment date, plus 2) one twelfth of approximately 47 percent of the scheduled principal payment due on all Project related bonds on the next annual principal payment date, plus 3) approximately 47 percent of all fees paid to PGHC for credit support of the Taxable Second Lien Electric Revenue Bonds in the given month as described in a Second Lien Bond Credit Facility Agreement between PGHC and the City, less 4) approximately 47 percent of the earnings on certain funds and accounts established under the Bond Indenture, and less 5) approximately 47 percent of the amount remaining in the senior debt service reserve account after retirement of the senior debt, less 6) approximately 47 percent of transfers into the Revenue Fund from the Reserve and Contingency Fund. Project related bonds include the outstanding Project Bonds, plus any bonds issued to refund the Project Bonds, plus any additional debt issued by the City to maintain or improve the safe and reliable operation of the Facility (Additional Bonds).

The Monthly Operations Charge will equal approximately 47 percent of all costs that are incurred by the City during the then current month that are classified as Facility Operating Expenses under the Power Purchase Agreement. Such Facility Operating Expenses are all Facility costs (other than any costs for Gas under the Fuel Supply Agreement or Special Arrangements) classified as operating expenses in the Bond Indenture, to the extent such operating expenses are prudently incurred to operate, repair and maintain the Facility and to generate and deliver Facility Output to the Facility busbar. Facility Operating Expenses also includes costs incurred by the City to review proposals, reports and other documents contemplated by the Bond Indenture and other Project related agreements, including internal costs and the costs of legal, accounting, consulting and other third party services (Owner's Review Costs) and arbitration and litigation costs that are both 1) included as operating expenses in the Bond Indenture and 2) prudent to carry out the City's obligations under the Bond Indenture or applicable law. Owner's Review Costs related to deliveries beyond the Facility busbar may not be treated as Facility Operating Expenses. Facility Operating Expenses for this purpose will generally include the cost of:

1) Scheduled, routine, preventative and unscheduled maintenance;
2) Consumables and spare parts;
3) Handling of hazardous substances;
4) Utilities, administrative and consulting services;
5) Complying with authorizations and permits;
6) Lease payments to Collins under the Lease described elsewhere in this Report;
7) Costs of insurance;
8) Costs for administering completion of the Punch List after Substantial Completion under the EPC Agreement described elsewhere in this Report;
9) The O&M Fee, O&M Performance Incentive and Overtime Costs under the O&M Agreement as described elsewhere in this Report; and
10) Amounts payable to third party contractors for O&M services, the Management Fee and Management Performance Incentive under the Management Agreement as described elsewhere in this Report.

PPM is not obligated to pay for any Facility Operating Expenses that are in excess of the projected annual Facility Operating Expenses specified in Exhibit B to the Power Purchase Agreement, unless agreed in advance by PPM (Excess Facility Operating Expenses). PPM can only disapprove if the excess expenses are not in accord with the Facility Agreements or are not necessary to comply with prudent utility practices relating to operation of the Facility.

The Monthly Major Maintenance Fund Charge will equal approximately 47 percent of one twelfth of the Change in Major Maintenance Fund Requirements amount as calculated under the Management Agreement described elsewhere in this Report.

The Monthly Fuel Charge will be calculated by first calculating the cost of gas used for delivery of Facility Output from Facility Peaking Capacity using a heat rate of 9,329/BTUs per kilowatt-hour. The same heat rate is used to calculate the cost of gas used for output sold to other purchasers from Facility Peaking Capacity. The cost of gas used for delivery of Facility Output from Facility Base Capacity will be allocated to PPM pro-rata to the percentage of Facility Output (other than Facility Output delivered to PPM or other purchasers from Facility Peaking Capacity mentioned above) scheduled by and delivered to PPM. For this pro-ration, total steam sold during the month will be deemed converted to electric energy at the rate of one kilowatt-hour per ten pounds of steam and will not be treated as part of PPM's share of Facility Output scheduled and delivered during the month. Any charges or revenues related to Special Arrangements under the Fuel Supply Agreement described elsewhere in the Report, and any gas imbalance costs or other gas costs related to changes in scheduled Facility Output after the pre-schedule period will also be charged to PPM to the extent they were incurred on behalf of PPM.

The Monthly Fuel Transportation Charge will equal one twelfth of approximately 47 percent of all charges for use of the Medford Lateral as defined under Fuel Agreement as described elsewhere in this Report.

In addition to these monthly charges, PPM will pay approximately 47percent of any additions to the Site Restoration Account if and when additions to this account are required under terms of the Bond Indenture.

The City will pay to PPM approximately 47 percent of any insurance proceeds received by the City due to any Facility outage or reduction in generating capability except that, for any period with respect to which PPM is not required due to Force Majeure to make payments, the City shall be allocated an additional portion of business interruption insurance proceeds (to the extent such business interruption insurance proceeds are made available) equal to all such payments from which PPM so obtains relief.

If the reliability of the Facility, excluding outages caused by Force Majeure events (as defined in the Power Purchase Agreement) other than equipment failure (Facility Reliability) as determined in accordance with Exhibit C of the Power Purchase Agreement is less than 92 percent in any year, PPM will receive a refund of the Monthly Demand Charge, Monthly Operating Charge and Monthly Fuel Transportation Charge based on the percentage shortfall below 92 percent. Facility Reliability will increase if the City delivers replacement power to PPM during Facility outages or derating periods. This refund provision does not apply during the period of time that PKE is serving as the Operator under the O&M Agreement as described elsewhere in this Report. PPM may also suspend payments for the duration of any Facility shutdown caused by an uncontrollable event if, and to the extent that such shutdown has lasted for more than 12 months. PPM is also not obligated to pay any costs arising from modification to the rights and duties of any party to any of the Facility Agreements, unless PPM has agreed to the applicable cost adjustments. Such approval shall not be unreasonably withheld if the modification is necessary to maintain the Facility in a safe and reliable manner and is in accord with Prudent Utility Practices as defined in the Power Purchase Agreement.

Disputes under the Power Purchase Agreement will be referred first to a meeting of senior officers or officials of PPM and the City and thereafter, if necessary, to binding arbitration. In case of default by either party, the other party may terminate the Power Purchase Agreement on 45-days notice (15 days in the case of a failure to make payments when due). The right to terminate will be deferred if the Party in default has cured or undertaken to cure such default within 30 days of delivery of notice (10 days in the case of failure to make a payment when due) and thereafter diligently pursues such cure until accomplished. The notice of default also will be deferred during the dispute resolution process invoked to resolve a good faith challenge to an alleged default. In addition, the Bond Trustee may cure on behalf of Owner and is entitled to notice of City's default and its own periods to cure any defaults of City.

In the event of breach or default by the City, PPM will have no recourse against the general funds of City or against the City's officials or employees. PPM may only make claims against the assets of the Facility, its accounts receivable, proceeds from the sale of electricity and steam, any separate Facility accounts, proceeds from the sale of the Facility or insurance policies. Upon default by the City, the trustees on behalf of Project Bond holders (the Bond Trustees) are entitled to cure the default and exercise all of the City's rights under the Power Purchase Agreement. PPM will accept assignment of the Power Purchase Agreement to the Bond Trustees, or will offer a substantially similar agreement to the Bond Trustees.

POWER BROKERING AGREEMENT

The City will enter a power brokering agreement with PPM (the Power Brokering Agreement) on the date of financial closure of the Project Bonds. The Power Brokering Agreement commences when a Notice to Proceed is issued to BVC under the EPC Agreement (Term Commencement Date) and continues for a term of 20 years. On the fifteenth anniversary of the Term Commencement Date and on each fifth anniversary thereafter, the Power Brokering Agreement will be automatically renewed for five additional years from the end of the then current term (thus creating a five year term extension) unless a Party that does not wish to renew the Power Brokering Agreement gives written notice to that effect to the other Party on or before such anniversary of the Term Commencement Date. In the event the agreement is terminated, this service can be readily provided by others. There are several power marketers and power brokers operating in the western United States at present, and the trend towards competitive power markets can be expected to result in a continuation of several capable companies providing such services from which to select.

Under the Power Brokering Agreement, PPM is responsible for selling to third parties all Brokered Facility Output, which is all Facility Output except that which 1) is purchased by PPM under the Power Purchase Agreement or 2) is used by the City to sell to retail customers located in Klamath county, Oregon (Retail Power). Brokered Facility Output is expected to be approximately 53 percent (or 248,000 kilowatts) of Facility Nominal Capacity, assuming 200,000 pounds per hour of steam sales as described under the Steam Sale Agreement as described elsewhere in this Report, and no Retail Power sales. The City may terminate the Power Brokering Agreement with 3 months notice if PPM has failed to sell at least 95 percent of all Brokered Facility Output for the prior year and two of the prior five years (the Brokering Sales Standard). General duties of PPM will include preparation of an Annual Brokering Plan, negotiation and execution of sales contracts on behalf of the City that are consistent with the Plan, designation of a qualified employee to sell Brokered Facility Output for terms of 30 days or less (Short Term Sales), and billing, collecting, remitting and reporting of sales revenues. PPM must also offer to procure certain transmission services and Transmission Ancillary Services for delivery of Brokered Facility Output as necessary. Transmission services include contracts for wheeling of Brokered Facility Output to locations other than COB. Transmission Ancillary Services include spinning reserve, non-spinning reserve, imbalance service, scheduling service, reactive power and other services that are offered by utilities under their FERC approved open access transmission tariffs.

An offer to purchase Brokered Facility Output received by PPM will be classified as either a Debt Covering Offer or a Debt Deficient Offer. A Debt Covering Offer will be one in which the incremental revenues from the sale, when calculated based on a hypothetical purchase of 484 megawatts of Facility Base Capacity for the then current operating year, would exceed the incremental costs of such a hypothetical sale for the operating year (including gas, gas transportation, electric transmission, transmission services and Transmission Ancillary Services and other costs), and such excess would be sufficient to make timely deposits to all accounts through and including the Third Lien Bond Fund as defined under the Bond Indenture for the then current operating year. If the offer to purchase will require the use of Facility Peaking Capacity, then it will be considered a Debt Covering Offer if the incremental revenues exceed the cost of the maximum amount of gas that would be necessary to generate the power assuming a heat rate of 9,329 Btu/kWh. Any offer that is not a Debt Covering Offer is a Debt Deficient Offer. A detailed sample calculation of a Debt Covering Offer determination is included in Schedule 1 of the Power Brokering Agreement.

At least 120 days prior to the beginning of a year, the City must provide an initial projection of the amounts of Brokered Facility Output that will be available for sale during future years. At least 60 days prior to the beginning of the year, PPM will submit a proposed Annual Brokering Plan for the year. The Annual Brokering Plan will include the following:

1) Details on Requests for Proposals that will be issued to qualified tax exempt power purchasers during the upcoming year;
2) Any changes to Schedule 1 of the Power Brokering Agreement that are necessary to allow determination of Debt Covering Offers for new types of offers not contemplated;
3) Credit standards against which potential purchasers will be measured; and
4) Plans for any Short Term Sales, and other information.

The Annual Brokering Plan will be treated as confidential information by PPM, the City and the Independent Engineer.

The City will review the Annual Brokering Plan and will inform PPM of any changes to be made to the plan. If the City does not propose any changes on or before a date thirty days prior to commencement of the then upcoming operating year, the Annual Brokering Plan will be deemed approved and PPM will be authorized to implement the plan. If PPM raises a dispute that the City's changes will (i) not be in accord with Prudent Marketing Practices (as defined in the Power Brokering Agreement), or (ii) will require PPM to take actions in conflict with the Power Brokering Agreement or which otherwise are unreasonable given the scope of and consideration for PPM's services, such dispute will be resolved pursuant to the dispute resolution provisions of the Power Brokering Agreement.

The Independent Engineer will also review the Annual Brokering Plan on behalf of the Trustee to determine if the plan reasonably meets the requirements of the Annual Brokering Plan under the Power Brokering Agreement. Disputes between PPM and the City, or between PPM and the Independent Engineer with respect to the Annual Brokering Plan will be resolved through an expedited arbitration process with a single arbitrator.

PPM will also provide a projection for the upcoming operating year of revenues from the sale of Brokered Facility Output and Retail Power, along with a projection of all gas, electric transmission services, transmission services and Transmission Ancillary Services costs (as described below) to produce such power (Projection of Revenues and Gas Costs).

In making this projection, PPM will 1) assume the amount of Brokered Facility Output and Retail power sales and the Facility heat rates are equal to the amounts supplied by the Manager in the previously approved Annual Budget (as described under the Management Agreement section of this Report), 2) assume revenues from all Brokered Facility Output and Retail Power sales currently in place and the cost of gas needed to execute these sales, 3) assume that all remaining Brokered Facility Output and Retail Power will be sold at forward market prices for firm energy sold at COB, and gas will be purchased at forward prices of gas at points relevant to the Gas Market Price Index under the Fuel Supply Agreement described elsewhere in this Report, but that Brokered Facility Output is sold only during periods when the incremental revenues from the sales would exceed the incremental cost of the gas, transmission, transmission services and Transmission Ancillary Services to make the sales, and 4) include the cost of any additional electric transmission or distribution that may be required to make the sales.

Any offer to purchase Brokered Facility Output that is received by PPM must be submitted to the City, along with a recommendation to accept or reject the offer, if the offer is 1) for a term longer than 30 days, and 2) is made by a Qualified Purchaser as defined under the Power Brokering Agreement that meets the credit quality standards of the Annual Brokering Plan, and 3) is received pursuant to either a request for proposals issued in accordance with an Annual Brokering Plan, or received by PPM outside of its role as Broker, but which PPM has agreed to share with the Project. PPM must simultaneously submit proposed Special Arrangements (financial risk management measures described elsewhere in this Report) if the offer to purchase is for a term longer than 12 months. PPM will cooperate with the Fuel Supplier under the Fuel Supply Agreement to enable the Fuel Supplier to obtain any necessary Gas Price Hedges as described under the Fuel Supply Agreement. If the City does not respond to an offer within the time period specified by PPM so that the offer can be timely accepted by PPM on the City's behalf, then PPM may accept or reject the offer on behalf of the City in accordance with PPM's recommendation. Acceptance of the offer will include acceptance of the Special Arrangements by the City and the gas suppliers. PPM will accept or reject offers for Short Term Sales, and may enter into Special Arrangements for such sales, at its discretion. The City may at its election, in the Annual Brokering Plan or otherwise, provide PPM with standing instructions, which may be amended by the City from time to time, as to any offers or shares of an offer that PPM may accept or reject without further action by the City.

As described above, PPM will acquire on the City's behalf, and consistent with the provisions of the Annual Brokering Plan, all transmission services (using, where available, firm transmission held by the City) and related Transmission Ancillary Services that transmission providers are required to provide, as needed for the delivery of the Brokered Facility Output, as unit-contingent power, from the Facility's busbar to the point of delivery specified in the applicable sales contract. To the extent additional generation services are desired by a potential purchaser in order to convert a delivery of Brokered

Facility Output into firm energy that is not unit-contingent, PPM will make reasonable efforts to procure and offer such additional generation services with any sale of Brokered Facility Output. PPM may charge to the purchaser of Brokered Facility Output any charge lawful under applicable law for any such additional generation services The price for such additional generation services offered by PPM, however, must be stated to the purchaser separately from the price for the Brokered Facility Output, and the purchaser must be informed in each instance that PPM will cooperate fully in permitting the purchaser to self-supply such additional generation services or to acquire comparable services from other Persons qualified to provide such services. PPM will not state or imply that any sale of Brokered Facility Output is contingent on the purchase of any such additional generation services or on the purchase of any other products or services from PPM.

For services rendered, the City will pay PPM a fee of $5000 per month prior to Substantial Completion. After Substantial Completion, the City will pay a fee of $700,000 per year, payable in equal monthly installments (the Brokering Base Fee). The Brokering Base Fee will escalate annually at the consumer price index. The City will also pay an incentive bonus to PPM equal to 25 percent of the Brokering Base Fee if PPM achieves the Brokering Sales Standard in the previous year.

Disputes under the Power Brokering Agreement will be referred first to a meeting of senior officers or officials of PPM and the City and thereafter, if necessary, to binding arbitration. In case of default by either party, the other party may terminate the Power Brokering Agreement on 45-days notice (15 days in the case of a failure to make payments when due). The right to terminate will be deferred if the Party in default has cured or undertaken to cure such default within 30 days of delivery of notice (10 days in the case of failure to make a payment when due) and thereafter diligently pursues such cure until accomplished. The notice of default also will be deferred during the dispute resolution process invoked to resolve a good faith challenge to an alleged default. In addition, the Bond Trustee may cure on behalf of the City and is entitled to notice of City's default and its own periods to cure any defaults of City. The liability of PPM for any claim under the Power Brokering Agreement is limited to the amount of the Brokering Base Fee and the Brokering Incentive Bonus Payment for the operating year in which the claim occurred.

In the event of breach or default by the City, PPM will have no recourse against the general funds of City or against the City's officials or employees. PPM may only make claims against the assets of the Facility, its accounts receivable, proceeds from the sale of electricity and steam, any separate Facility accounts, proceeds from the sale of the Facility or insurance policies. Upon default by the City, the trustees on behalf of Project Bond holders (the Bond Trustees) are entitled to cure the default and exercise all of the City's rights under the Power Purchase Agreement. PPM will accept assignment of the Power Brokering Agreement to the Bond Trustee, or will offer a substantially similar agreement to the Bond Trustee.

STEAM SALE AGREEMENT

The City will enter into a Steam Sale Agreement with Collins prior to the date of financial closure of the Project Bonds. Deliveries of steam will commence during startup and testing of the Facility, and will continue for the duration of the Project Bonds. Collins may terminate the Steam Sale Agreement upon one year advance notice if the date of Substantial Completion has not occurred by December 31, 2002, or with no notice if it has not occurred by December 31, 2003. However, this date may be extended due to delay in Facility completion. Prior to expiration of the Agreement, Collins may exercise an option to extend the agreement on a year to year basis so long as the Facility remains in commercial operation and the Lease remains in effect.

The City will continuously deliver steam at 320 psig and 430 degrees Fahrenheit (Steam) to the Collins Facility at a rate of up to 275,000 pounds per hour, with a total annual limit of 1.752 billion pounds of Steam, which is equivalent to 200,000 pounds per hour on an annual average basis. Collins has an option to increase the total annual limit to 2.190 billion pounds of Steam, which is equivalent to 250,000 pounds per hour on an annual average basis. There is no minimum amount of Steam that Collins is required to take from the Facility. In the event Collins takes less Steam than the amount to which it is entitled, the Facility will have a greater amount of electrical power which can be sold into the power market. Revenue foregone from reduced Steam sales is reasonably expected to be obtained from short-term sales of Facility output into the market. Collins will not operate its boilers numbered 8 and 9 when Steam is available from the Facility.

Collins will collect the condensed Steam (Condensate) and return it to the Facility. Collins will also deliver an amount of well water from the Collins Facility to compensate for Steam that is not recovered from the Collins Facility and for Steam and Condensate that are rejected or lost from the Facility itself (Makeup Water). The City, through the EPC Agreement with BVC, will construct the necessary Steam delivery, Condensate return and Makeup Water systems including meters, tanks and pumps, on property owned and easements granted by Collins. Electric power necessary for operation of facilities at the Collins Facility will be supplied by Collins at no charge. Collins will also maintain the facilities.

Collins will also accept Steam, return Condensate and supply Makeup Water prior to the date of Substantial Completion, subject to schedules from BVC and periodic interruption.

For Steam delivered, Collins will pay a monthly charge equal to the product of the Steam energy actually delivered during the month (net of Condensate and Makeup Water energy returned) and a calculated Steam price (the Monthly Steam Charge). The steam price will equal the sum of 1) the price for supply of one month spot natural gas delivered at AECO "C" & NIT as published in the Canadian Gas Price Reporter expressed in U.S. $ per

MMBtu, plus 2) a gas market premium determined pursuant to the Fuel Supply Agreement, plus 3) the cost of firm transportation at tariff rates on the NOVA, ANG and PGTNW pipelines expressed in U.S. $ per MMBtu, plus 4) the cost of interruptible transportation on the Medford Lateral expressed in U.S. $ per MMBtu, plus 5) the cost of all taxes expressed in U.S. $ per MMBtu, the sum of these divided by a factor of 0.8. The determination and weighting of these components may be changed pursuant to the Fuel Supply Agreement. If a natural gas price or gas market premium is expressed in Canadian dollars, it will be converted to U.S. dollars using the exchange rate determined under the Fuel Supply Agreement. Collins will also pay a charge equal to 1) the amount of Steam delivered less (2) the amount of Condensate collected, this sum multiplied by 3) $0.25 per thousand pounds, escalating annually at the Producer Price Index (Water Preconditioning Charge). For up to four months following the date of Substantial Completion, rejected Condensate will not be considered in calculation of the Water Preconditioning Charge. This is due to the expected de-scaling of the Collins piping systems which may temporarily result in poor water quality.

Collins will receive a Steam Rebate Amount at the end of each fiscal year of the Project. The rate of rebate in the first year of the Steam Sale Agreement is $0.76 per million Btu on the first 75,000 pounds per hour of annual average Steam volume. This rate increases to $1.55 per million Btu in the remaining years. However, payment of the Steam Rebate Amount is subordinate to payment of all other fees, operating costs, debt service and funding of reserves for the Facility. There may be insufficient funds available to pay the Steam Rebate in any given year. Steam Rebate Amounts that are not paid annually will accrue and earn interest to the benefit of Collins until paid. The City must provide to Collins a calculation of current and projected future amounts of cash available from the Project to pay the Steam Rebate Amount in any year when the City is unable to pay the full Steam Rebate Amount.

Condensate and Makeup Water collected from the Collins Facility must meet certain quality specifications as described in Exhibit A and Exhibit B to the Steam Supply Agreement. Condensate and Makeup Water that does not meet the respective specification may be rejected by the City. Collins will be liable for paying the City's cost to dispose of rejected Condensate and Makeup Water, and to obtain water from an alternate source.

Steam supply is not guaranteed by the City. However, the City is required to use best efforts to maintain Steam supply during periods of Facility shutdown or low load operation, including the use of the auxiliary boiler at the Facility. The liability of the City is limited to the cost to repair damage to Collins equipment due to excessive Steam pressure, and for the loss of any Steam Rebate Amount. Collins will maintain the existing boilers at the Collins Facility in a standby mode to provide Steam in case of a prolonged unplanned outage of the Facility. The City must provide at least 14 days advance notice to Collins of any planned Facility shutdown.

Disputes under the Steam Sale Agreement will be referred to binding arbitration. Collins will have no recourse against the general funds of City. Collins may only make claims against the assets of the Facility, its accounts receivable, proceeds from the sale of electricity and Steam, any separate Facility accounts, proceeds from the sale of the Facility or insurance policies.

The Steam Sale Agreement terms create an incentive for Collins to purchase Steam from the Facility because the resultant price of delivered Steam is expected to be lower than if Collins purchased fuel to produce steam in its own boilers.

FUEL SUPPLY AND SERVICES AGREEMENT

The City will enter into a Fuel Supply and Services Agreement (the Fuel Supply Agreement) with PPM on the date of financial closure of the Project Bonds. The term of the Fuel Supply Agreement commences on the date that the City issues a Notice to Proceed to BVC under the EPC Agreement, and continues until the 30th anniversary of this date, or until the final maturity date of the Project Bonds, whichever occurs later. Prior to expiration of the Fuel Supply Agreement, PPM may extend the term to the date on which the duration of the term will equal 80 percent of the useful life of the Facility. For the purposes of such extension of the term of the agreement, the useful life of the Facility must be determined by a qualified independent engineer appointed jointly by PPM and the City. PPM must also present an opinion of bond counsel that the term extension will not have an adverse effect on the exclusion of interest on the Project Bonds from the taxable income of the bond holders. Upon expiration or termination of the Fuel Supply Agreement, PPM will assign to the City all of the transportation agreements in use to deliver gas to the Facility, including the FTSA for transportation of fuel over the Medford Lateral as described below.

PPM is responsible for supplying and delivering all of the gas fuel needs of the Facility on a continuous basis up to a rate of 90,000 MMBtu's per day (the Contract Demand). PPM is also responsible for arranging all necessary gas transportation service to deliver gas to the Facility. PPM is also responsible for supplying gas in excess of the Contract Demand on an incidental but not sustained basis to the extent that gas and transportation are reasonably available.

To deliver gas, the City has assigned its firm transportation service agreement with PGTNW for service on the Medford Lateral (the FTSA) to PPM. The FTSA became effective on February 24, 1995. The initial term of the FTSA, as amended and restated, will begin on the date on which PPM first nominates transportation and will extend through October 31, 2025 (the Initial Term). After the initial term, the FTSA will continue from year to year until May 31, 2030, unless canceled by PPM, and thereafter from year to year unless canceled by either PPM or PGTNW. PGTNW must provide capacity to deliver natural gas to the Facility of up to 45,000 MMBtu per day (the Initial Quantity) plus up to an additional 45,000 MMBtu per day (the Option Quantity) as elected by PPM during the initial term of the FTSA. Service on the Medford Lateral will be firm, meaning that shipments to other users under lower priority service types (e.g., interruptible, balancing) will be curtailed before service to the Facility is curtailed due to uncontrollable events or pipeline maintenance. PPM will pay a fixed monthly charge to PGTNW, which will be passed through to the City as the Medford Lateral Charge as described below. The charges specified in the FTSA will remain fixed throughout the Initial Term. PPM may, but is not obligated to, obtain firm transportation service on the PGTNW mainline or any other pipeline to serve the Facility. If PPM obtains firm transportation service, it will use reasonable efforts to limit the period of time that any such transportation agreement extends beyond the term of the Fuel Supply Agreement.

On the business day before the day on which gas is to be delivered to the Facility, the City must provide to PPM a schedule of the nominated gas quantity required by the Facility at least thirty minutes prior to the earlier of 1) the earliest nomination deadline of the pipelines used to transport gas to the Facility, or 2) the earliest pre-schedule deadline in effect for the wholesale electric power markets located within two (2) third party transmission systems from the Facility. The specific daily notice procedures, electric transmission systems, and related scheduling deadlines are specified in Schedule 4.2(b) of the Fuel Supply Agreement. The City is obligated to purchase gas that it has scheduled and burn it at the Facility. The City may not resell the gas to third parties. PPM will use reasonable efforts to accommodate intra-day schedule changes from the City, and will adjust nominations as necessary to minimize any potential pipeline imbalance charges and penalties. The City must notify PPM at the earliest possible time of any potential reduction in gas demand at the Facility due to a scheduled reduction in power purchases by PPM or other power purchasers, or due to scheduled maintenance.

At any time, PPM may exercise an option to deliver electric power directly to any or all of the power purchasers instead of delivering gas to the Facility. PPM must deliver power to each purchaser as required by the relevant power sale agreements or to other points of delivery as agreed by the power purchaser. The City will provide relevant delivery point and schedule information to PPM to effect deliveries of electricity. The City will also make available to PPM any electric transmission capacity held by the City to the extent that such capacity will not be used for sale of electricity from the Facility. During the period when PPM is delivering electricity in lieu of gas, the City may nevertheless require PPM to deliver gas to the Facility (Supplemental Gas) to the extent that adequate gas and transportation are available. The amount of Supplemental Gas cannot exceed the amount of gas that PPM would have delivered if the electricity delivery option had not been exercised.

For delivered gas and electricity, the City will pay a Monthly Commodity Charge, a Monthly Transportation Charge, a Monthly Medford Lateral Charge, a Monthly Electricity Charge and a Fuel Management Fee as described below.

The Monthly Commodity Charge will equal 1) the average price paid for a one month firm supply of gas delivered in that same month at the Alberta Energy Company -Canada (AECO-C) trading hub as published in the Canadian Gas Price Reporter (the Gas Market Price Index) plus 2) a Gas Market Premium as defined below, the sum of these multiplied by 3) the amount of gas actually delivered by PPM to the Facility for the month including any Supplemental Gas. During the term of the Fuel Supply Agreement, either PPM or the City may propose a change to the Gas Market Price Index, either adding or deleting supply point price references or changing the weighting of supply point price references to more accurately reflect the market price of gas actually consumed by the Facility. The Gas Market Price Index may be changed only once a year. The Gas Market Price Index will be reflected in Schedule 9.3(b) of the Fuel Supply Agreement. The Gas Market Premium is intended to capture that premium (positive, zero or negative) relative to the Gas Market Price Index that PPM would have to pay to obtain a two year supply of gas for delivery to the Facility. It will equal the difference between 1) the average price quoted to PPM for a two year firm supply of gas of at least 10,000 MMBtu's per day and similar in nature to the needs of the Facility delivered at the supply points of the Gas Market Price Index, less 2) the Gas Market Price Index. The Gas Market Premium will be determined at least 60 days prior to the date of Substantial Completion, and will be re-determined every two years thereafter.

The Monthly Gas Transportation Charge will equal 1) the amount of gas actually delivered to the Facility, multiplied by 2) the tariff rates, fees, taxes and surcharges that would be incurred for firm transportation of such an amount on the transportation systems connecting the Facility with the points of supply listed in the then current Gas Market Price Index. The Monthly Medford Lateral Charge will equal the actual charges incurred by PPM under the FTSA for use of the Medford Lateral.

The Monthly Electricity Charge will be assessed for the months in which, and to the extent that, PPM delivers electricity instead of gas. It will be calculated by applying the Monthly Commodity Charge, the Monthly Transportation Charge and the Monthly Medford Lateral Charge to an amount of gas equal to the difference between 1) the amount of gas actually delivered by PPM during the period of electricity delivery and 2) the amount that would have been delivered to the Facility if it would have been operated to deliver the electricity provided by PPM (Replaced Gas). The calculation methodology for Replaced Gas is described in Schedule 5.4 of the Fuel Supply Agreement. A curve of Facility heat rate versus Facility output is used, in conjunction with the actual amount of electricity delivered by PPM, to determine the amount of gas that would have been delivered. The actual heat rate of the Facility during the period of electricity delivery is used to determine the amount of gas actually delivered. Use of the actual heat rate captures the impact of reduced Facility fuel efficiency at part load operation. If the Facility is shutdown due to the reduced delivery of gas, then the volume of Replaced Gas will be reduced by the amount of any gas consumed during Facility shutdown or startup operations. The City would also receive a credit for the cost of electric power consumed by the Facility during the shutdown period. In addition to a charge for Replaced Gas, the Monthly Electricity Charge will also include amounts equal to what the City would have paid to transmit the electricity from the Facility to the purchasers, less the incremental costs that the City must pay during the period that PPM is utilizing electric transmission held by the City to deliver its electricity.

The Fuel Management Fee will equal 1) the quantity of gas actually delivered to the Facility by PPM plus the quantity of Replaced Gas, the sum of these multiplied by 2) $.03 per million Btu. The fee rate of $0.03 per million Btu will escalate annually based on the gross national product price deflator rate from the US Department of Commerce. The City must also pay any sales, excise, value added or other taxes and royalties on the delivered gas.

If PPM fails to deliver gas, or electricity in lieu of gas, and these failures are not due to an uncontrollable event (a Supply Failure), the City has the right to purchase and take delivery of gas from third parties in an amount sufficient to generate steam required by the Steam Sale Agreement described elsewhere in this Report (Alternate Gas). The City may use any unused gas transportation capacity held by PPM to deliver Alternate Gas. The City also has the right to purchase and take delivery of electricity from third parties in an amount sufficient to satisfy sales to all power purchasers (Alternate Electricity). PPM must compensate the City for the cost of Alternate Gas that exceeds the cost that the City would have paid for the same amount of gas from PPM. PPM must also compensate the City for the cost of Alternate Electricity that exceeds the cost that the City would have incurred to produce and deliver the same amount of electricity from the Facility. The City must use reasonable efforts to obtain Alternate Gas and Alternate Electricity at the lowest price reasonably available. Generally, PPM may not claim failure of a gas supplier or transporter to perform as an uncontrollable event.

In the case of default by either party, the party not in default may terminate the Fuel Supply Agreement by giving 45 days' prior notice to the defaulting party (15 days in the case of a failure by the City to make payment when due). Any such notice will become null and void if the defaulting party has cured or undertaken to cure the default within 30 days of the notice (10 days in the case of a failure by the City to make payment when due).

PPM must cooperate with the City in evaluating Gas Pricing Hedges with third parties that would effectively provide future gas price protection to the City. These could include fixed price gas purchases and/or hedging via financial instruments for all or a portion of the Facility's requirements. If the City chooses to enter such arrangements, the City and PPM will enter into a separate confirmation of their agreement concerning the price, quantity and duration of such arrangements.

In case of breach or default by the City, PPM will have no recourse against the general funds of City. PPM may only make claims against moneys available under the Bond Indenture to satisfy claims against the Owner, or if the Bond Indenture has been terminated, from proceeds of the disposition of Facility assets, and from insurance policies providing coverage for any such claims. Upon default by the City, the Bond Trustee are entitled to cure the default and exercise all of the City's rights under the Fuel Supply Agreement. PPM will accept assignment of the Fuel Supply Agreement to the Bond Trustee, or will offer a substantially similar agreement to the Bond Trustee.

OPERATIONS AND MAINTENANCE AGREEMENT

The City will enter into an Operations and Maintenance Agreement (O&M Agreement) with PKE on the date of financial closure of the Project Bonds. The O&M Agreement commences 18 months prior to the date of Substantial Completion and terminates five years from the date of Substantial Completion. On each anniversary of the date of Substantial Completion, the O&M Agreement will be automatically extended for one additional year at the end of the current five-year term (thus creating a new five year term) unless a party that does not wish to extend gives written notice of its intent before the anniversary date, in which case the O&M Agreement will terminate at the end of its then current term. The City may terminate the O&M Agreement upon 90 days notice if the effective date of termination will occur after the third year of any such five-year term. For a period of one year after termination for any reason, the City cannot hire away PKE employees that have managerial responsibility.

PKE is responsible for operation and maintenance of, or supervising the operation and maintenance of, the Facility in a prudent, clean, safe, legal and efficient manner in accordance with operating procedures, an Annual Budget approved under the Management Agreement described elsewhere in this Report and power production schedules. For power sold to PPM, schedules will be submitted by PPM under terms of the Power Purchase Agreement as described elsewhere in this Report. For power sold to other purchasers, schedules will be submitted by PPM acting as Manager under the Management Agreement, or by PPM acting as Broker under the Power Brokering Agreement described elsewhere in this Report. At least 4 hours notice is required for any schedule change that requires a startup or shutdown of a combustion turbine or a steam turbine. PKE is also responsible for performing the annual heat rate tests described in Exhibit D to the O&M Agreement.

The Annual Budget will be approved under terms of the Management Agreement described elsewhere in this Report. PKE is responsible for procuring spare parts, maintaining material and tool inventories, maintaining offices, hiring personnel, developing and maintaining safety procedures, maintaining accurate operating logs, maintaining drawings, instruction books and manuals, providing reports to local permitting agencies, and other duties. Personnel hired must be made available for training by BVC in advance of Substantial Completion as required under the EPC Agreement described elsewhere in this Report.

PKE may enter into agreements with qualified, experienced, reputable contractors on behalf of the City (a contract between the City and the contractor) to perform PKE's responsibilities under the O&M Agreement without prior approval of the City provided that 1) the agreement calls for expenditure of no more that $100,000 in an operating year, and 2) the agreement will not cause the aggregate amount of expenditures under all such contractor agreements for an operating year to exceed the lesser of $1,000,000 or 15 percent of the approved Annual Budget, and 3) the agreement will not cause the capital expense or the non-discretionary expense component of the approved Annual Budget, as applicable, to be exceeded. If a contractor agreement is expected to exceed $250,000 in any operating year and has not received an exemption from the local contract review board, PKE must select the contractor pursuant to a competitive bid procedure. PKE, for itself, may enter into agreements with qualified, experienced, reputable contractors (contract between PKE and the contractor) without restriction.

The City is responsible for paying all operating expenses of the Facility as defined in the Bond Indenture. These will generally include the costs of scheduled and unscheduled maintenance, consumables, fuel, handling of hazardous substances, spare parts, capital expenditures, water, heat and telephone service for the Facility offices, professional services; taxes, lease payments, insurance, contractors, and other costs of the Facility. The City is also responsible for paying the Construction Period Fee, the O&M Fee, the O&M Performance Incentive Payment, and Overtime Costs as described below.

The Construction Period Fee is intended to cover the cost of PKE to assemble and pay an operation and maintenance workforce for the Facility prior to operation. It will be paid monthly through the date of Substantial Completion according to a five step schedule included in Exhibit A to the O&M Agreement. This schedule will escalate beginning on July 1, 1999 and each July 1 thereafter by the percentage change in the Consumer Price Index since January 1, 1998. Table 10 summarizes the schedule (expressed in 1998 dollars).

The Construction Period Fee steps will be adjusted as described in Exhibit A to the O&M Agreement to account for delays in the date of Substantial Completion.

Table 10
Schedule for Payment of the Construction Period Fee (1998 $)

Months Prior to the date of Substantial Completion	Construction Fee Payable per Month
18 to 13	$18,250
12 to 11	$22,970
10 to 9	$41,273
8 to 7	$91,750
6 to date of Substantial Completion	$236,120

The O&M Fee is intended to cover PKE's costs of wages and benefits for PKE employees at the Facility (excluding overtime costs), costs of training employees, and costs for maintaining an office at the Facility. The O&M Fee will be paid monthly beginning with the date of Substantial Completion at a rate of $244,500 per month, escalating on July 1, 1999 and each July 1 thereafter by the percentage change in the Consumer Price Index since January 1, 1998.

Overtime Costs must be submitted separately by PKE. PKE is entitled to payment for Overtime Costs incurred as a result of abnormal operation, equipment failure, startup or other abnormal events, but not Overtime Costs due to vacations, illness or absenteeism.

The O&M Performance Incentive is an annual payment that will be made to PKE if the Facility achieves certain annual availability and heat rate goals for the prior year as described in Exhibit C and D to the O&M Agreement. Availability is defined as the percent of time that the Facility was available for service during the hours of 7:00 a.m. through 11:00 p.m. Monday through Saturday for all such periods in the year (Heavy Load Hours). Hours in which the Facility was shutdown for scheduled maintenance, or for transmission system induced outages, are not counted as Heavy Load Hours. Availability is decreased for hours in which the Facility actual generation falls short of scheduled generation during Heavy Load Hours. PKE will earn $100,000 for every one percent that Facility availability is greater than 95 percent. There is no penalty for availability less than 95 percent. With respect to heat rate, the annual average heat rate of the Facility will be calculated based on total fuel consumption and total power production of the combustion turbines for the year. A target heat rate is calculated based on the most recent heat rate test of the Facility and curves of heat rate versus load and heat rate versus operating hours (degradation) as included in Exhibit D. PKE will earn $3,000 for every one Btu/kWh that Facility heat rate is less than the target heat rate. There is no penalty for heat rate greater than the target heat rate. The O&M Performance Incentive payment may not exceed $1.5 million annually. This limit, and the individual incentive amounts for availability and heat rate, will escalate beginning on July 1, 1999 and each July 1 thereafter by the percentage change in the Consumer Price Index since January 1, 1998. In any given operating year, the sum of any approved overtime costs paid and any O&M Performance Incentive payable cannot exceed the sum of the Construction Period Fee paid and O&M Fee paid.

Disputes related to the calculation of the O&M Performance Incentive, or the qualifications of any contractor will be referred to binding arbitration. The liability of PKE for any claim is limited to the sum of any Construction Period Fee and O&M Fee payable for the operating year in which the claim occurred. In case of default by either party, the party not in default may terminate the O&M Agreement by giving the defaulting party 45 days' prior notice (15 days in the case of a failure by the City to make payment when due). Any such notice will become null and void if the defaulting party has cured or undertaken to cure the default within 30 days of the notice (10 days in the case of a failure by the City to make payment when due). The City must pay any O&M Fee or O&M Performance Incentive due PKE upon termination. Prior to termination and for a period up to 180 days afterward, PKE will provide services to the City reasonably sufficient to enable a new operator to begin operating the Facility. The City will pay the reasonable costs of such services after the termination date.

In case of breach or default by the City, PKE will have no recourse against the general funds of City. PKE may only make claims against moneys available under the Bond Indenture to satisfy claims against the Owner, or if the Bond Indenture has been terminated, from proceeds of the disposition of Facility assets, and from insurance policies providing coverage for any such claims. Upon default by the City, the Bond Trustee is entitled to cure the default and exercise all of the City's rights under the O&M Agreement. PKE will accept assignment of the O&M Agreement to the Bond Trustee, or will offer a substantially similar agreement to the Bond Trustee.

MANAGEMENT AGREEMENT

The City will enter into a Management Agreement with PPM on the date of financial closure of the Project Bonds. The term of the Management Agreement commences on the date of Substantial Completion, and continues for a term of 20 years. On the fifteenth anniversary of the date of Substantial Completion and on each fifth anniversary thereafter, the Management Agreement will be automatically renewed for five additional years from the end of the then current term (thus creating a five-year extension) unless a party that does not wish to extend gives written notice to the other party on or before the applicable anniversary date, in which cast the Management Agreement will terminate at the end of the then current term.

PPM is responsible for the administrative management of the Facility on behalf of the City. General tasks include preparation of drawing documents to facilitate payment of operation and maintenance expenses out of accounts established under the Bond Indenture, administration of all the Project agreements including nominations and notices under the Fuel Supply Agreement, development of spare parts and inventory programs, generation of financial reports and books of account, development of annual operating and capital improvement budgets, and other tasks.

PPM will develop and propose an Annual Budget for the Facility consisting of a detailed operating budget and a detailed capital budget. PPM will submit the Annual Budget to the City for approval on or before March 1 of the year proceeding the operating year.

As part of the Annual Budget, PPM will provide, for each operating year for the remaining life of the Bond Indenture, a schedule of the projected amounts needed to make timely deposits to all funds and accounts up to and including the Third Lien Bond Fund as described under the Bond Indenture (Schedule 2.2). This information will be used by PPM in determination of Debt Covering Offers in its role as Broker under the Power Brokering Agreement described elsewhere in this Report.

Also as part of the Annual Budget, PPM will calculate the level of funding required during the upcoming year for the Major Maintenance Reserve Account under the Bond Indenture, in addition to amounts existing in the account, that are necessary to fund planned major maintenance of the Facility for the upcoming year (Change in Major Maintenance Reserve Account Requirement). The Change in Major Maintenance Reserve Account Requirement will be used to determine the level of the Major Maintenance Fund Charge under the Power Purchase Agreement.

Although PPM will administer the Project agreements, PPM will not pursue any dispute resolution and similar enforcement action against any affiliate of PPM. The City is responsible for funding the relevant accounts for payment of operating expenses, and reviewing and approving the Annual Budget.

PPM may enter into agreements with qualified, experienced, reputable contractors on behalf of the City (contract between the City and the contractor) to perform PPM's responsibilities under the Management Agreement without prior approval of the City provided that 1) the agreement does not call for expenditure of more that $100,000 in an operating year, and 2) the agreement will not cause the aggregate amount of expenditures under all such subcontractor agreements for an operating year to exceed the lesser of $1,000,000 or 15 percent of the approved Annual Budget, and 3) the agreement will not cause the capital expense or the non-discretionary operating expense components of the approved Annual Budget, as applicable, to be exceeded. If the agreement is expected to exceed $250,000 in any operating year and has not received an exemption from the local contract review board, PPM must select the subcontractor pursuant to a competitive bid procedure. PPM, for itself, may enter into agreements with qualified, experienced, reputable subcontractors (contract between PPM and the subcontractor) without restriction. PPM may not acquire assets or services from any PPM affiliate without first presenting a description of the scope of assets or services to be provided and obtaining the written consent of the City.

For services rendered, the City will pay PPM a fee of $64,583 per month (the Management Fee). The Management Fee will escalate on July 1, 1999 and each July 1 thereafter by the percentage change in the Consumer Price Index since January 1, 1998. The City will also make an annual incentive payment to PPM equal to 50 percent of the amount that actual operating expenses for the operating year are less than those in the approved Annual Budget (the Management Performance Incentive). In determining operating expenses for the operating year, fuel and capital costs are excluded and variable costs such as water and chemicals are adjusted to account for actual Facility operation above or below budgeted levels. The Management Performance Incentive cannot exceed 25 percent of the Management Fee paid for the operating year.

Disputes between the City, PKE and the Independent Engineer (Budget Participants) related to the Annual Budget, or an amendment to an approved Annual Budget will be first referred to senior management of the Budget Participants, and then to binding arbitration. Disputes between the City and PKE concerning 1) the calculation of the Management Performance Incentive, 2) the qualifications of any subcontractor, or 3) proposals to use portions of the Facility for operation of additional electric generating facilities that are not subject to the Bond Indenture (Additional Facilities) will be first referred to senior management of the parties, and then to binding arbitration. The liability of PPM for any claim under the Management Agreement is limited to the amount of the Management Fee for the operating year in which the claim occurred.

In case of default by either party, the party not in default may terminate the Management Agreement by giving 45 days' prior notice to the defaulting party (15 days in the case of a failure by the City to make payment when due). Any such notice will become null and void if the defaulting party has cured or undertaken to cure the default within 30 days of the notice (10 days in the case of a failure by the City to make payment when due). The City must pay all fees and incentives due PPM upon termination. Prior to termination and for a period up to 180 days afterward, PPM will provide services to the City reasonably sufficient to enable a new manager to begin managing the Facility. The City will pay the reasonable costs of such services after the termination date.

In case of breach or default by the City, PPM will have no recourse against the general funds of City. PPM may only make claims against moneys available under the Bond Indenture to satisfy claims against the Owner, or if the Bond Indenture has been terminated, from proceeds of the disposition of Facility assets, and from insurance policies providing coverage for any such claims. Upon default by the City, the Bond Trustee is entitled to cure the default and exercise all of the City's rights under the Management Agreement. PPM will accept assignment of the Management Agreement to the Bond Trustee, or will offer a substantially similar agreement to the Bond Trustee.

PM_{10} EMISSIONS PURCHASE OPTION AGREEMENT

The City will enter into a PM_{10} Emissions Purchase Option Agreement (the PM_{10} Option Agreement) with Collins prior to the date of financial closure of the Project Bonds. PM10 means particulate matter larger than 10 microns in diameter. The PM10 Option Agreement will commence on this date and continue for an initial term of six months, unless exercised or extended by the City as described below. The PM_{10} Purchase Option Agreement will allow the City to purchase PM_{10} Credits and apply them against the PM_{10} emissions of the Facility if required in the future by ODEQ to achieve the expected air quality benefits proposed under terms of the ADCP described elsewhere in this report. Air quality impact modeling that was performed by the City as part of the ADCP application process assumed application of the PM_{10} Credits.

For a price of $5,000, Collins has granted the City an exclusive and irrevocable option to purchase 44.6 tons per year of PM_{10} emission reduction credits (the PM_{10} Credits) from Collins at a price of $2,500 each (a single lump sum amount of $111,500) at any time during the initial term (the Option). The City may extend the Option and the Option Agreement for an additional six month term by paying another $5,000 to Collins prior to expiration of the initial term. The City may repeatedly extend the Option and Option Agreement in this fashion up to five times beyond the initial term (36 month overall term of the Option Agreement).

All payments made by the City to acquire or extend the Option will be credited towards the purchase price of the PM_{10} Credits. The City intends to exercise the Option if and when the PM_{10} Credits are needed to satisfy the requirements of the Air Contaminant Discharge Permit (ACDP) for the Facility described elsewhere in this Report. The purchase price of the PM_{10} Credits will be funded from proceeds of the Project Bonds. Funds will be placed in escrow until such time that the Option is exercised by the City. Upon exercise, the City and Collins will apply to ODEQ for transfer of the PM_{10} Credits to the City. The purchase price payment will be paid to Collins when the escrow agent has received written acknowledgment from the ODEQ that the PM_{10} Credits are useable by the City and that title to the PM_{10} Credits has been transferred to the City. If the City, at any time after consultation with ODEQ, determines that the PM_{10} Credits are not suitable for this use, the City may terminate the Option Agreement.

In the event of breach or default by the City, Collins will have no recourse against the general funds of City. Collins may only make claims against the assets of the Facility, its accounts receivable, proceeds from the sale of electricity and steam, any separate Facility accounts, proceeds from the sale of the Facility or insurance policies.

INTERCONNECTION AGREEMENT

The City entered into a Generation Interconnection Agreement (the Interconnection Agreement) with PacifiCorp on February 19, 1999. The Interconnection Agreement commenced on this date and continues for the useful life of the Facility.

PacifiCorp will construct and own all of the transmission lines, towers, and other equipment and facilities necessary to electrically connect the 500 kV switchyard of the Facility with the electric system of PacifiCorp (the Interconnection Facilities), up to the 500 kV breakers and related disconnect switches which will be owned by the City. PacifiCorp will use reasonable efforts to complete work on the Interconnection Facilities within 480 days after receipt by PacifiCorp of a Notice to Proceed. PacifiCorp will operate and maintain the Interconnection Facilities, and at least two of the breakers and related disconnect switches. The other three breakers and related disconnect switches also may be operated and maintained by PacifiCorp if the City so elects.

The City must pay PacifiCorp's cost of the Interconnection Facilities. An estimate of such costs is included in Annex C to the Interconnection Agreement, along with a schedule for payment by City in installments of such estimated costs. Following completion of construction of the Interconnection Facilities, PacifiCorp shall calculate its actual costs to complete the Interconnection Facilities, including applicable overheads, and shall send a copy of the final calculations to the City along with an invoice or a refund for the difference between the estimated and actual cost.

PacifiCorp will charge an annual fee for operation and maintenance of the Interconnection Facilities, breakers and disconnect switches, using a formula as set out in Annex C to the Interconnection Agreement. The City also must pay for replacement, repair or removal of the Interconnection Facilities in the event of a major failure of such facilities. If the Facility is not completed or is later abandoned, the City must pay PacifiCorp its reasonable actual costs to remove facilities no longer required for the interconnection with the Facility (possibly including relocation of the transmission line to its previous configuration) and to restore the full functionality of PacifiCorp's transmission.

The City will construct, own, operate and maintain the 500 kV switchyard of the Facility, except for those certain components noted above that will be operated and maintained by PacifiCorp. The City must comply at all times with the PacifiCorp Interconnection and Operating Requirements, as set forth in Annex B to the Interconnection Agreement. The City also must comply with standards, guidelines, criteria, or other requirements (i) that (A) govern the design, construction, operation, appurtenant facilities, inspection, testing, maintenance, metering, data gathering requirements, or communications capabilities of Facilities; (B) are promulgated, adopted, or imposed by a state, regional or national regulatory or standard-setting body; and (C) are applicable to any of PacifiCorp, the PacifiCorp Transmission System, the City, or the Facility; or (ii) that require the collection or submission of data or information relating to any of the foregoing (the Standards). City's obligations include sole responsibility for carrying out and paying for any upgrades to the Facility required by the Standards.

The City must indemnify PacifiCorp from and against any claims resulting from (1) a failure of the Facility to comply with a Standard, or (2) a failure by PacifiCorp or the PacifiCorp Transmission System to comply with any Standard that is caused by the Facility. If the PacifiCorp Transmission System is modified to change the line voltage of the PacifiCorp Transmission System at the point of interconnection with the Facility, the City shall be solely responsible to the same extent as other similar interconnected customers for all upgrades to the Facility and the Interconnection Facilities needed as a result of the change in line voltage.

PacifiCorp shall have the right to disconnect the Facility from the PacifiCorp transmission system and maintain the disconnection for so long as PacifiCorp believes in good faith that the risk of injury, damage, or an electric disturbance is continuing. If the City fails to perform its obligation under the Interconnection Agreement and such failure creates a serious and continuing threat to the safety, reliability, or facilities and equipment of the PacifiCorp transmission system, PacifiCorp may terminate the Interconnection Agreement upon 90 days written notice to the City and, as of the effective date of termination, disconnect the Facility from the PacifiCorp Transmission system.

TRANSMISSION AGREEMENT

The City entered into a Service Agreement for Point-to-Point (PTP) Transmission with the Bonneville Power Administration (BPA) on January 19, 1999 (Transmission Agreement). Service under the Transmission Agreement will commence on July 1, 2001 and terminate on the earlier of June 30, 2031 or the date of termination established pursuant to the Open Access Transmission Tariff (Tariff) of BPA. BPA's current Tariff does not permit BPA to terminate the Transmission Agreement before the June 30, 2031 termination date, but does permit the City to reduce transmission demand or terminate transmission service upon two years notice to BPA.

Under the Transmission Agreement, BPA is responsible for delivering up to 280,000 kilowatts of power from the Facility to COB along the Meridian to Captain Jack 500 kV line. BPA will make the power available to the Cal-ISO at COB. Metering will be performed by PacifiCorp, and data will be telemetered to BPA. PPM is the designated scheduling agent on behalf of the City. BPA will not provide any energy to eliminate imbalances, reserve capacity to meet control area requirements, or energy to meet load following requirements. These must be purchased by the City from PacifiCorp as the control area operator, or from other entities as selected by the City from time to time. BPA will provide scheduling and dispatch service and reactive power as necessary to make deliveries.

The City will pay BPA a Reservation Fee of $356,720 per year to keep this transmission capacity available until July 1, 2001. Payment of the Reservation Fee for 1999 was shared equally between PPM and the City under terms of their joint development agreement. Proceeds of the Project Bonds will be used to reimburse PPM for this payment and to pay the Reservation Fee for 2000 and 2001 when due. The Reservation Fee payment due in January 2001 will be for a full year, and will not be prorated to the expected date of transmission service. Upon commencement of deliveries, the City will take and pay for PTP transmission services under terms of the Tariff in effect at such time and as the Tariff is amended from time to time. The City must also compensate BPA for transmission losses by either purchasing equivalent energy from BPA, or supplying equivalent energy to BPA within 168 hours. Losses under the current Tariff for the service provided equals the amount of energy delivered multiplied by 3 percent.

In the event of any irreconcilable difference between the Tariff and the Transmission Agreement, the language of the Transmission Agreement will govern. However, with approval of the Federal Energy Regulatory Commission, BPA may revise the Transmission Agreement to make it consistent with revisions to the terms of the Tariff. The City may terminate the Transmission Agreement upon 30 days notice after the Transmission Agreement is revised in this manner. The City must then replace the transmission service with new transmission service under the Tariff. Disputes will be resolved using the dispute resolution mechanisms specified under the Tariff. In the event of breach or default by the City, BPA will have no recourse against the general funds of the City. BPA may only make claims against the assets of the Facility, its revenues, and proceeds from the sale of the Facility or insurance policies. However, in order for such non-recourse provisions to be effective, the City must maintain in force at all times during the term of the Transmission Agreement an assurance of payment as approved from time to time in writing by BPA, securing the payment of all of the City's obligations under the Transmission Agreement.

Agreement for the Assignment of Transmission Service

The City entered into an Agreement for the Assignment of Transmission Service (Transmission Assignment Agreement) with PPM on January 19, 1999.

Under the Transmission Assignment Agreement, the City has assigned to PPM all of its rights and liabilities with respect to 50 megawatts of the total 280 megawatts of transmission service available to the City under the Transmission Agreement with BPA as described above. This assignment will take effect on the date that the City commences taking transmission service under the Transmission Agreement. The City has a right to recall some or all of this transmission service at any time prior to issuance of the Project Bonds, but not thereafter. To the extent that the City declares as available for short-term assignment, any transmission service (other than transmission service assigned to PPM and not recalled by the City), PPM will broker such transmission service for the City, with the City to receive all revenues from such short-term assignments.

The projected operating results in this Report assume that to the extent the City does not exercise its option to increase its transmission capacity from BPA to levels above 230 MW, any transmission service obtained by PPM to deliver Brokered Facility Output will be obtained at prices and transmission loss rates not greater than the BPA transmission services tariff established in the Transmission Agreement with BPA.

The City is responsible for payment of the Reservation Fee under the Transmission Agreement as necessary to maintain any transmission service not recalled. Upon commencement of transmission service, PPM is responsible for all charges under the Transmission Agreement related to the transmission service that has not been recalled. PPM also reserves any rights granted by BPA under the Transmission Agreement to reduce or terminate transmission service assigned to PPM that has not been recalled by the City.

In the event of breach or default by the City, PPM will have no recourse against the general funds of City. PPM may only make claims against the assets of the Facility, its revenues, any proceeds from the sale of the Facility or insurance policies.

Municipal Effluent and Water Services Agreement

The City will enter into an Municipal Effluent and Water Services Agreement (Water Services Agreement) with PKE on the date of financial closure of the Project Bonds. The Water Services Agreement will commence on this date and will terminate on the final maturity date of the Project Bonds unless mutually extended by the City and PKE during any period the Facility remains in commercial operation. There is no provision for early termination of the Water Services Agreement. The Water Services Agreement is unlike the other Project related agreements in that the City is a supplier to the Project.

Under terms of the Water Services Agreement, the City will supply cooling water to the Facility from the publicly owned treatment works (POTW), supply potable water to the Facility from the municipal water supply system (Water System), and accept wastewater from the Facility.

The City will supply up to 3.1 million gallons per day of POTW effluent for condenser cooling purposes. Rates charged for delivery of POTW effluent will be in accordance with a rate schedule acceptable to the City and PKE.

POTW effluent must meet or exceed certain quality standards as specified in exhibits to the Water Services Agreement. The delivery, use and return of POTW effluent must comply with the requirements of the NPDES Permit 100701, the Industrial Waste Discharge Permit and the Reclaimed Water Use Plan (the "Water Permits") which are included in exhibits to the Water Services Agreement. PKE may modify the POTW effluent quality specifications from time to time as approved by the City (and the ODEQ if ODEQ approval is required). PKE may reject POTW effluent that does not meet the ODEQ requirements or the quality specifications. The rejected effluent may be returned to the City in the wastewater stream of the Facility at no cost to PKE. If at any time the City is unable to supply the demanded quantities of POTW effluent, PKE will use storm water from the storm water storage pond for cooling purposes. If storm water is unavailable, PKE may use water from the Water System on a temporary basis as approved by EFSC. The City may charge for such supplemental water from the Water System at rates in effect for similar users located outside the City limits.

POTW effluent will be delivered to the Project site boundary at the point specified in the EPC Agreement. The City is responsible for installing and operating all necessary pumps, pipelines, meters and ancillary facilities to deliver to this point. These facilities must be complete at least 30 days in advance of when POTW effluent is required for initial startup of the Facility.

The City will supply potable water for boiler makeup, domestic supply and other uses. The City may impose a charge to extend and/or expand the Water System to serve the Facility (system development charge). The City may also charge for potable water supplied at rates in effect for similar users located outside the City limits.

The City will accept and dispose of all wastewater from the Facility, so long as the wastewater is in compliance with the Industrial Waste Discharge Permit for the Facility that is included in Exhibit A of the Water Supply Agreement. The City may charge for acceptance of wastewater generated by the Project at rates in effect for similar dischargers located outside the City limits. Any cost for the discharge of POTW effluent will be at rates acceptable to the City and PKE.

The City will install, or cause to be install, all necessary pumps, pipelines, meters and ancillary services to deliver POTW effluent and Water System water, and receive POTW effluent at the points of interconnection with the Facility as specified under the EPC Agreement. The City must complete these facilities at least eight months prior to the date of Substantial Completion of the Facility. The cost of these facilities will be funded from Project Bond proceeds. If the City chooses to oversize these facilities to accommodate deliveries of POTW effluent or Water System water to other customers, those costs specific to the oversizing will not be funded from Project Bond proceeds. The operation and maintenance costs of these facilities, and certain future costs to modify or relocate the facilities will be recovered by the City through the aforementioned water and wastewater rates. Upon request of the City and with the consent of PKE, PKE will arrange for the construction of the new facilities and will manage the City's contractors.

If the City fails to exercise reasonable diligence and care in furnishing a continuous and sufficient supply of POTW effluent or water from the Water System, the City will be liable only for the costs of any necessary replacement water obtained from other sources. The City will provide reasonable advance notice as circumstances permit of any interruption in delivery of POTW effluent or potable water necessary to make repairs or improvements to the POTW or the Water System. The City will not be liable for any consequential damages or claims attributable to interruption, outage or change in the characteristics of the water delivery or wastewater receipt services provided. Neither the City nor PKE will be liable to the other for failure to perform due to an uncontrollable event.

Disputes under the Water Services Agreement will be referred first to the senior officers or officials of PKE and the City, and then to binding arbitration. In case of breach or default the City may only make claims against moneys available for such purposes under the Bond Indenture, or if the Bond Indenture has been terminated, from proceeds of the disposition of Facility assets, and from insurance policies providing coverage for any such claims. Upon default by PKE, the Bond Trustee is entitled to cure the default and exercise all of PKE's rights under the Water Services Agreement. The City will accept assignment of the Water Services Agreement to the Bond Trustee, or will offer a substantially similar agreement to the Bond Trustee.

PROJECTED OPERATING RESULTS

BACKGROUND

We have prepared a projection of the financial operating results of the Project for the years 2001 through 2029 for the purpose of estimating the expected adequacy of revenues over costs and the resultant debt service coverage level during this period.

Approximately 47 percent of the 484,000 kilowatts of Facility Base Capacity and the 22,000 kilowatts of Facility Peaking Capacity (approximately 238,000 kilowatts) will be sold on a long-term, actual-cost basis under the Power Purchase Agreement to PPM. This provides long-term financial security for a significant portion of the Project. The remaining output of the Project (Brokered Facility Output) will be sold on the open wholesale power market in the western U.S. Due to federal law relating to private use of tax-exempt debt, sales of longer than 30 days duration must be made to purchasers that meet certain federal tax-exempt status requirements. Sales of 30 days duration or less may be made to any power purchaser. The price levels of these open market power sales will be a function of the supply and demand for power in the western region of the U.S.

PPM is an active power marketer in the western U.S. Brokered Facility Output is expected to be sold whenever the price in the wholesale market is greater than the cost of output. Under terms of the Brokering Agreement, PPM has flexibility to market Brokered Facility Output at prices which cover variable operating costs plus a portion of the allocated fixed cost of the Project on a per kilowatt-hour basis. Some sales are expected to be made at prices well above the fully allocated cost of output, while some sales are expected to cover only a portion of the fully allocated costs.

To assess the likelihood that sales of Brokered Facility Output will produce revenue sufficient to meet target debt service coverage levels over the long-term, the regional wholesale market for power must be simulated under a range of reasonably expected market conditions. Such a market simulation was performed for this Report and is described below.

MARKET SIMULATION

Wholesale power prices in the western U.S. are driven by a multitude of factors including weather and related electricity demand, precipitation and related hydropower production, the supply and price of natural gas and coal, the power transfer capability of the Pacific Intertie, the operating cost and retirement of existing generating plants, forced and scheduled outages of generating plants, and the cost, fuel efficiency and timing of new generating resource additions. A dynamic, chronological, computer based simulation of these factors for the entire western U.S. power market must be performed to generate a wholesale price forecast of suitable quality for use in this Report. Such a simulation was performed by Henwood Energy Services, Inc. (HESI) under subcontract to RMI. The methodology, assumptions and results of the HESI simulation are described in more detail in the report entitled "COB Electricity Market Price Forecast 2001-2025" which is attached as Exhibit 1 to this Report (the HESI Report).

Under the simulation methodology, the wholesale market in the western U.S. was segmented into certain regions. Each generating plant in each region was modeled as a resource with certain capacity, heat rate, outage rate and O&M costs. Each generating plant, including each new plant added over time, was dispatched in least operating cost order to serve the forecast load in its specific region and other regions. Fuel cost, variable O&M costs and variable transmission wheeling costs were considered as operating costs. Fixed costs were generally not considered when determining the least cost order, except for peak demand periods when owners of existing plants were assumed to "bid" a portion of the fixed O&M cost of their plant in addition to its variable cost. New, generic combined cycle combustion turbine (CCCT) and simple cycle (CT) generating plants were added to the simulation when total generating capacity fell to less than 110 percent of expected load in a market region any simulation year. Power flow between regions was limited by the combined rated transmission capacities between the regions. The cost paid to (or price received by) the plant operated to serve the last increment of load demand for a given region was considered the market clearing price for that region.

To capture seasonal and time of use price differentials, the COB market clearing price was forecast by HESI for one week per month, for both peak (6 am - 10 p.m. Monday through Saturday) and off peak (all other hours) periods. These were then aggregated into average annual on-peak and off-peak prices. The simulation was performed for certain years of the forecast period, with results interpolated for the intervening years. The prices are representative of non-firm deliveries. Firm deliveries, where the seller offers liquidated damages or other security to the buyer for failure to deliver, typically command a price premium in the market. HESI has not included such a premium in their forecast, and the cost of providing firming services were not included in the projected operating results.

The Project was included in the simulation as a generating plant beginning in the year 2001. Capacity available from the Facility under normal operating mode (Facility Base Capacity) was assumed to equal the Cogeneration Output Guarantee (464,020 kilowatts). The heat rate for Facility Base Capacity was assumed to equal 6,700 Btu/kWh. This heat rate is representative of the fuel used to generate power only. Costs for fuel used to generate steam sold to Collins are recovered in steam sale revenues, and therefore could be ignored by HESI in determining electric production costs. The incremental amount of capacity available from duct firing of the HRSG's (Facility Peaking Capacity) was assumed to equal 30,000 kilowatts with a heat rate of 9,100 Btu/kWh based on the increase in

Facility output and heat rate likely during summer peak temperature operation shown in Exhibit I to the EPC Agreement. In the simulation, Project Peaking Capacity was constrained to be available only when Project Base Capacity was operating. Variations in capacity and heat rate with ambient temperature, operating hours and overhauls (degradation) were included. By including the Project in the simulation, HESI was able to simulate how the Project would perform compared to other generators in the market, and generate a forecast of monthly generation versus generating capacity (capacity factor) for the Project.

HESI provided a "COB MCP (California-Oregon border marginal cost price) Base Case Forecast" of market clearing prices and a Project capacity factor forecast as described in the HESI Report. Under this Base Case, COB prices are forecast to increase at an annual average rate of 10 percent per year from 2001 through 2005, and to increase at an annual average rate of 2.5 percent per year from 2006 through 2025. The sharp increase from 2001 through 2005 is due to a significant increase in the number of sellers in California and the Pacific Northwest that are expected to include some of their fixed O&M costs of their existing generating plants in their offers to sell as described in more detail in the HESI Report in Appendix B to this Report. These sellers are expected to be existing, higher operating cost plants that are no longer recovering their fixed costs out of utility rates or must-run contracts.

Unlike the variable cost production model used by HESI to develop estimated market clearing prices, the fixed cost bidding component of the estimate is based on judgment as to the market behavior of participants in the market. It is unclear how much of the fixed costs of existing generators may be successfully bid into the market during this period of market transition. To estimate a base market price floor without the effects of fixed cost bidding, HESI provided an alternative market clearing price forecast. This forecast assumed that no fixed costs would be bid by the existing higher cost plants that would be coming out of rate base. This forecast is shown as the "COB MCP Alternative Forecast" in the HESI Report. RMI has adopted this alternative forecast as a conservative base case for determination of projected operating results of the Project. Table 11 below summarizes this market clearing price forecast and the Project capacity ("dispatch") factor forecast. The market price forecast is presented in nominal dollars, assuming a 2.8 percent annual inflation rate. The capacity factor forecast is shown for both Facility Base Capacity and Facility Peaking Capacity.

Table 11 Forecasts of Market Price and Project Capacity Factor					
Year	Market Clearing Price for COB (Annual Average Peak and Off-Peak Periods, $/MWH)			Annual Dispatch Factor for Facility Base Capacity	Annual Dispatch Factor for Facility Peaking Capacity
	Peak	Off Peak	Average	Average	Average
2001	$32.44	$21.73	$26.83	93%	79%
2002	$34.14	$24.54	$29.11	87%	69%
2003	$36.03	$26.11	$30.83	87%	72%
2004	$38.27	$27.32	$32.53	89%	73%
2005	$42.54	$28.18	$35.02	90%	73%
2006	$40.98	$29.03	$34.71	91%	72%
2007	$44.92	$29.75	$36.97	89%	69%
2008	$44.79	$30.52	$37.31	90%	67%
2009	$50.23	$31.03	$40.17	91%	67%
2010	$48.06	$31.82	$39.55	91%	69%
2011	$50.73	$32.81	$41.34	90%	68%
2012	$52.45	$33.98	$42.77	91%	68%
2013	$51.02	$34.90	$42.58	91%	68%
2014	$54.71	$36.03	$44.93	92%	67%
2015	$55.67	$36.97	$45.87	91%	66%
2016	$54.57	$36.82	$45.27	91%	62%
2017	$61.17	$38.02	$49.04	91%	61%
2018	$58.05	$39.08	$48.11	91%	58%
2019	$58.82	$40.62	$49.28	92%	59%
2020	$61.39	$41.47	$50.95	90%	53%
2021	$61.04	$43.30	$51.74	91%	53%
2022	$63.64	$44.56	$53.64	91%	51%
2023	$68.28	$46.63	$56.94	89%	51%
2024	$69.37	$48.21	$58.29	89%	47%
2025	$70.24	$50.30	$59.79	90%	47%

The COB MCP Alternative Forecast shows that the COB market clearing price is forecast to increase at an annual average rate of 7 percent per year from 2001 through 2005, and to increase at an annual average rate of 2.7 percent per year from 2006 through 2025. Results also show that the forecast capacity factor for Facility Base Capacity is generally near 90 percent throughout the forecast period. In addition, the forecast capacity factor for Facility Peaking Capacity ranges from 50 percent to 70 percent throughout the forecast period. This indicates that the Project is expected to be highly competitive on a variable cost basis. However, the variable cost revenues must be measured against all remaining variable and fixed costs of the Project to determine if sufficient debt service coverage will be achieved. The revenue and cost forecast methodology is described in the following sections.

PROJECTED PROJECT REVENUES AND COSTS

During development of the Project, PKE and the City utilized a pro-forma economic analysis model to forecast certain key performance and cost parameters and assess the economic viability of the Project, including debt coverage on the Project Bonds. We have reviewed this model and the forecasts, and have found them to be reasonable for use in assessing the economic viability of the Project for the purposes of this Report. This pro forma model is used for purposes of the projected operating results presented in this report. These forecasts and assumptions are described below.

To forecast power sale revenues from PPM, it was assumed that PPM would schedule its share of Facility Base Capacity for a percent of hours per year equal to the lesser of a) the forecast Facility Base Capacity factor or b) 93 percent. Ninety-three percent is the expected annual average availability of the Facility. Similarly, it was assumed that PPM would schedule its share of Facility Peaking Capacity at a rate equal to the lesser of a) the forecast Facility Peaking Capacity factor or b) 60 percent. Sixty percent is a conservative estimate of maximum allowable duct burner operation under the turbine and duct burner PSEL as described under the Air Emissions section of this Report. The limitations on duct burner firing for air emission purposes is based on the combined emissions from the combustion turbine firing and duct burner firing. Actual duct burner operation may be greater to the extent the combustion turbines are operating at less than 100 percent capacity factor and the duct burners are fired at less than their maximum fuel rate. The remaining amounts of Facility Base Capacity and Facility Peaking Capacity were assumed to be sold as Facility Brokered Output (as defined under the Power Brokering Agreement), scheduled at the same respective capacity factors as the PPM sales and earning the COB market clearing price. The COB market clearing price is indicative of the market into which PPM will be brokering Project output. To the extent PPM enters into longer term contracts for sale of output to qualified purchasers, prices may be higher or lower at any particular time.

Steam revenues were based on a forecast of the gas commodity price index used in the Steam Sale Agreement (AECO-C commodity price plus all gas transportation and premiums to the Facility site), and on a 200,000 pounds per hour average annual volume delivered at a 100 percent annual capacity factor. The commodity price forecast was taken from the AECO-C forecast provided by HESI. The auxiliary boiler was assumed to operate on natural gas to deliver steam during periods when no power was scheduled due to forced, scheduled or economic outages.

Delivered gas costs were based on a forecast of gas commodity prices at AECO, plus the cost of firm transportation at tariff rates on the NOVA, ANG and PGTNW pipeline systems necessary to deliver gas to the Facility. This forecast was the same as used by HESI in their simulation. We have assumed there is no net Gas Market Premium (as described under the Fuel Supply Agreement section earlier in this Report. The Gas Market Premium is the premium above (or it can be negative, depending upon market conditions) short-term gas market prices that sellers are demanding for two year term gas sales of at least 10,000 MMBtu per day and similar in nature to that needed by the Project. Costs for pipeline fuel consumption were assumed to equal 6 percent of consumed volume per year. Medford Lateral costs were based on the rates in the FTSA. Gas volumes were based on power sales quantities multiplied by the respective heat rates for Facility Base Capacity and Facility Peaking Capacity. Facility Base Capacity and Facility Peaking Capacity were assumed to degrade approximately 1 percent per year on average, with recovery of most of this periodic degradation after each combustion turbine major maintenance outage (every four years). This "saw tooth" degradation pattern is typical of CCCT projects. Similarly, the heat rate for Facility Base Capacity was assumed to increase at a rate of 0.4 percent per year on average with a similar recovery every four years. As discussed under the Operating Modes section of this Report, the capacity and heat rate of the Facility are expected to degrade over time due to normal wear of combustion turbine components. This is typical of combustion turbine based power plants. The Fuel Management Fee, which is paid to PPM by the City under the Fuel Supply Agreement, was based on delivered volumes and the base fee escalated over time.

Projected annual fixed and variable operating costs for the year 2002 (first full year of operation) is shown in Table 12 below. Fuel Cost includes the cost of gas commodity, gas transportation, the Gas Market Premium and the Fuel Management Fee. Fixed O&M includes the O&M Fee under the O&M Agreement, plus the cost of maintenance subcontracts. Variable O&M includes the cost of utilities, waste disposal, potable and cooling water from the City, water treatment chemicals and other consumables. A contingency amount was also estimated. Owners Fixed O&M includes the cost of lease payments to Collins, the cost of insurance and fire service, City administration expenses, the cost of monitoring the CO2 Offset Portfolio, the Management Fee, the Brokering Base Fee and the Brokering Incentive Bonus Payment. The O&M Performance Incentive Payment under the O&M Agreement was assumed to be zero (targets met but not exceeded). The Management Performance Incentive under the Management Agreement was assumed to be zero (actual costs equal to budget). The Brokering Incentive Bonus Payment under the Power Brokering Agreement was assumed to equal 25 percent of the total annual Brokering Base Fee. Major Maintenance Expense includes the cost of funding combustion turbine overhauls and spare parts replenishment. These were treated as variable costs, with overhaul frequency and cost dependent upon cumulative combustion turbine operating hours. Electric Transmission includes the cost of transmission service from BPA under the Transmission Service Agreement. BPA transmission was assumed to be used for delivery of all Brokered Facility Output. All costs, except for Major Maintenance and Electric Transmission costs, were assumed to escalate at 2.8 percent annually throughout the life of the Project.

Table 12 Estimated Annual Fixed and Variable Operating Costs for 2002	
Category	**Amount ($000's)**
Fuel Costs	$62,934
Variable O&M	$1,466
Fixed O&M	$4,017
Owners Fixed O&M	$3,428
Contingency	$75
Major Maintenance Expense	$1,281
Lateral Demand Costs	$1,270
Electric Transmission	$3,065
Total	$77,537

Projected capital costs are summarized in Table 13 below. EPC Cost was based on the total Lump Sum Price plus escalation per the EPC Agreement from October 1, 1998 to May 3, 1999 (the expected Notice to Proceed Date). Interconnection Costs include costs for realignment and upgrade of the PacifiCorp 500 kV system to accept Project output, as well as costs for water, cooling water and wastewater pipelines. Owners Construction Costs include the costs for site utilities and services, telephone and electric power, and temporary water and sewer facilities. Startup Costs include the Construction Period Fee under the O&M Agreement, plus the cost of natural gas, high voltage power, water, sewer and other services used during startup testing, plus the initial stock of supplies and consumables following startup testing, less the expected revenues from sale of Test Power to PPM under terms of the Power Purchase Agreement. Spare Parts includes the cost of combustion turbine and other major equipment related spares necessary for startup activities and others necessary to establish an initial inventory. O&M Furnishings & Equipment are costs for maintenance shop tools, office furniture and supplies and vehicles. Environmental Costs include the costs to acquire emission offsets and to fund the Offset Portfolio. Management During Construction Costs include the labor cost of the Project Manager, Project Engineer, Project control, accounting and administration staff and site representatives, and the cost of offices, equipment, travel, and the Project Manager Fee under the Project Management Agreement. Development Expenses and Fees include the labor costs of PKE and the City and support staff incurred prior to issuance of the Project Bonds, plus the cost of a development fee paid to PKE and retirement of a note payable to a previous developer. Land Costs include the initial site lease payments to Collins and the cost of certain easements obtained. Insurance and Taxes includes the cost of Owner's liability coverage and a business license. Reserves are the cost of funding all required reserves under the Bond Indenture. Interest During Construction includes the cost of interest payments on Project bonds payable during the construction period. Professional fees include the cost of legal, financial, permitting and engineering services related to development and financing of the Project. A contingency amount equal to 3 percent of the Lump Sum Price of the EPC Agreement, plus $3,000,000 for potential BVC performance bonus payments, was also included in the capital cost estimate. All capital costs, except for startup gas costs and electric revenues, development expenses, lease payments, reserves and professional fees were assumed to escalate at 2.8 percent per year through the construction period.

Table 13
Forecast of Project Capital Costs

Category	Amount ($000's)
EPC Cost	$192,730
Interconnection Costs	$8,422
Owner's Construction Costs	$1,116
Startup Costs	$3,146
Spare Parts	$5,703
O&M Furnishings & Equipment	$451
Environmental Costs	$5,079
Management During Construction Costs	$3,994
Development Expenses and Fees	$12,997
Land Costs	$2,450
Insurance	$335
Taxes	$0
Reserves	$26,169
Interest During Construction	$38,936
Professional Fees	$6,478
Subtotal Capital Costs	$308,005
Contingency	$7,787
Total	$315,792

PROJECT FINANCING

Financing for the Project, as described in the Bond Indenture is issued in three Series. Tax Exempt Senior Lien Bonds have a par value of $220,000,000 and an interest rate of 6.0 percent. The Taxable Senior Lien Bonds have a par value of $26,200,000 and an interest rate of 8.56 percent. The Taxable Second Lien Bonds have a par value of $60,000,000 and an interest rate of 7.81 percent. The Taxable Second Lien Bonds are also secured through a Second Lien Bond Credit Facility Agreement with PGHC.

Proceeds of the Tax-Exempt Senior Lien Bonds will be used to refund the principal of the 1986 Bonds. Transferred proceeds of the 1986 Bonds and proceeds of the Taxable Senior Lien Bonds and the Taxable Second Lien Bonds will be used to fund Project construction costs, Project insurance, Project development costs, repayment of an outstanding note on the Project, capitalized interest on the Project Bonds, creation of Debt Service Reserve Funds, creation of a Major Maintenance Reserve Fund, creation of a Working Capital Reserve Fund, and underwriter's fees. Table 14 presents the sources and uses of funds.

Table 14 Sources and Uses of Funds Series 1999 Bonds	
Sources:	
Proceeds from Tax Exempt Senior Lien Bonds	$220,000,000
Proceeds from Taxable Senior Lien Bonds	$26,200,000
Proceeds from Taxable Second Lien Bonds	$60,000,000
Transferred Proceeds of 1986 Bonds	$220,000,000
Accrued Interest	$1,118,262
Investment Earnings	$9,820,822
Total Sources	$537,139,084
Uses	
Refunding of the 1986 Bonds	$220,000,000
EPC Construction Costs	$192,729,626
Additional Construction Costs	$43,968,120
Project Insurance	$335,000
PKE Development Costs	$5,470,000
DEI Note	$2,057,000
Total Capitalized Interest	$38,935,547
Total Debt Service Reserve Fund	$10,479,092
Site Restoration Fund	$7,033,018
Major Maintenance Reserve Fund	$0
Working Capital Reserve Fund	$10,000,000
Costs of Issuance	$2,300,000
Underwriter's Discount	$3,827,500
Additional Funds	$4,180
Total Uses	$537,139,084

PROJECT FLOW OF FUNDS

After Project operating costs are paid, Project revenues are used to pay senior debt service, fund working capital and major maintenance, and then subordinate debt service on the Project. After debt service payments have been made, remaining Project funds are used to pay an annual credit support fee to PGHC that is equal to 5.0 percent of the outstanding principal amount of the Second Lien Taxable Bonds. In addition, any funds advanced to the Project from PGHC under the Second Lien Bond Credit Facility Agreement are repaid at this time (pending available funds for distribution). To the extent that Project funds are available after meeting Second Lien Bond Credit Facility Agreement obligations, a rebate is paid to Collins under the Steam Sales Agreement. In addition, any past due payments to Collins for unpaid rebate amounts are to be paid at this time with interest at the Bank of America prime rate plus 2 percent.

To the extent that Project funds are available after meeting all rebate obligations to Collins, a deposit is made to the City Distribution Fund of the lesser of all remaining funds or $1,000,000. If the $1,000,000 account to the City Distribution Fund is made, remaining funds are deposited to the Equity Allocation Fund. Any funds in the Equity Allocation Fund are used in the following manner: (1) funds constituting shared revenues are deposited in a Defeasance Account, and (2) of the balance of funds, 25 percent is distributed to the City; and 75 percent is deposited to the Defeasance Account.

PROJECTED OPERATING RESULTS

The resulting forecast of Project revenues and costs were combined in a pro-forma financial statement format to calculate projected operating results, and to project the estimated debt service coverage in each year of the forecast period. The base case projected operating results for selected years are shown in Table 15 below. The minimum senior debt service coverage in the period of analysis is estimated to be 1.74 achieved in 2006. The minimum total debt service coverage is estimated to be 1.37, also achieved in 2006. All Project Bonds are expected to be defeased in 2019 under this Base Case. Detailed Operating Results are provided in Appendix A.

Table 15
Projected Operating Results - Base Case
Selected Years

	2002	2003	2004	2009	2014	2019	2024	2029
PROJECT ENERGY PRICES ($/MWh)								
On-Peak	34.78	36.58	38.43	50.26	54.75	58.92	69.65	74.90
Off-Peak	26.69	28.57	29.43	32.38	37.16	41.65	49.97	55.26
OPERATING REVENUES ($000)								
Municipal Power Sales	54,243	56,975	62,728	76,917	86,337	97,338	106,902	122,931
PacifiCorp Power Sales	42,317	46,734	50,836	61,635	67,285	77,093	79,344	87,128
Steam Sales	6,180	6,380	6,657	8,230	9,568	11,444	14,062	15,577
Interest Income	1,739	1,958	1,906	1,680	1,793	2,118	2,764	1,106
OPERATING EXPENSES ($000)								
Fixed Expenses	8,715	8,844	8,976	9,676	10,450	11,308	12,259	13,315
Variable Expenses	60,761	70,454	73,575	96,498	111,541	139,117	158,797	173,076
Wheeling Expenses	3,065	3,042	3,211	3,172	3,227	3,342	3,076	3,268
FUNDS AVAILABLE FOR DEBT SERVICE ($000)								
Operating Income	31,938	29,708	36,364	39,116	39,764	34,226	28,940	37,083
Less: Senior Debt Service	15,338	15,084	20,416	19,213	17,222	14,197	0	0
Less: Subordinate Debt Service	4,654	4,577	5,633	5,267	4,662	3,869	0	0
Cash Available for Subordinate Expenses	11,946	10,047	10,316	14,635	17,881	16,160	28,940	37,083
Less: Credit Support Fees	2,980	2,930	2,840	2,257	1,363	116	0	0
Less: Collins Rebate	848	1,137	1,137	1,137	1,137	1,137	1,137	1,137
Cash Available for Distribution	8,119	5,979	6,338	11,240	15,381	14,906	27,803	35,946
Less: Distribution to City	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Cash to Equity Allocation	7,119	4,979	5,338	10,240	14,381	13,906	26,803	34,946
Less: Equity Allocation to City	1,780	1,245	1,335	2,560	3,595	3,477	26,803	34,946
Allocation to Bond Defeasance	5,339	3,734	4,004	7,680	10,785	10,430	0	0
DEBT SERVICE COVERAGES								
Senior Debt Service Coverage Base	2.08x	1.97x	1.78x	2.04x	2.31x	2.41x	NA	NA
Total Debt Service Coverage Base	1.60x	1.51x	1.40x	1.60x	1.82x	1.89x	NA	NA

SENSITIVITY ANALYSES

To help assess the potential impact of detrimental operating result variations on potential debt coverage, additional operating result projections were performed using alternative values for certain key assumptions (Sensitivity Cases). Potential events and trends were examined in development of the Sensitivity Cases. The selected Sensitivity Cases include a low gas commodity price scenario, a high gas commodity price scenario, a high hydroelectric production scenario, and a generation overbuild scenario. These Sensitivity Cases are described below.

For each of these Sensitivity Cases, the HESI simulation was performed to generate a market price forecast and capacity factor forecast. These revised forecasts were used to generate revised pro-forma operating result forecasts. Table 15 below summarizes certain key parameters of the forecast operating results for each of the identified Sensitivity Cases.

The low gas commodity price scenario simulates a market condition of low production costs and low market clearing prices. Market clearing prices should drop with gas prices, particularly in California due to the large (and growing) number of gas-fired generators. To simulate this condition, the 1999 AECO-C gas commodity price was reduced by $0.15/MMBtu compared to the base case gas price forecast, and then escalated at only 0.5 percent real over the entire study period (versus 1.8 percent real in the base case).

The high gas commodity price scenario simulates a high production cost condition for the Project relative to production costs for gas-fired generators that purchase gas from San Juan and other basins, as well as hydroelectric and coal-fired generators in the WSCC. This scenario could potentially occur as additional pipeline capacity is built out of Alberta to the midwest, allowing Alberta prices to compete more directly with San Juan. To simulate this condition, the 1999 AECO-C commodity price was maintained at a constant $0.40/MMBtu below the San Juan basin commodity price forecast over the entire study period resulting in Alberta prices rising at a faster rate than in the base case (under the base case, Alberta prices rise more slowly than San Juan).

The high hydroelectric production scenario simulates low market clearing prices for the Project and all other generators in the WSCC during a period of high hydroelectric generation at a level and of a duration typical of historic high water years. High hydroelectric generation conditions are cyclical, but the timing of high hydroelectric production due to high water years cannot be predicted. Historic precipitation and associated high hydroelectric production typically spans no more than two years. For the years 2004 and 2005, Pacific Northwest stream flow conditions were increased to the level experienced in the years 1995 and 1996, which were two of the highest stream flow years in all regions of the WSCC over the past 20 years. This should depress market clearing prices at COB, resulting in reduced Facility Brokered Output revenue for the Project in these years. The years 2004 and 2005 were selected as a conservative case because these are the first two years in which the Project experiences full principal repayment.

The generation overbuild scenario was intended to simulate low market clearing prices caused by an oversupply of new CCCT generating plants entering the market. With the restructuring of the electric power market, developers must estimate where and when to build new power plants based on imperfect market information. Temporary capacity surpluses are likely, as is common in other commodity markets. To simulate this scenario, HESI modified their market simulation such that an excess (beyond what was needed to meet regional generating reserve margin requirement under the base case) of 2500 megawatts of new CCCT plants was added to the resource mix in the year 2005. As a result, no new CCCT plants were added for several years afterward until demand growth reached the reserve margin requirement.

Table 16
Key Parameters of Sensitivity Case Results for Selected Years
All Figures are Average Annual Values

	2002	2003	2004	2005	2006
Base - Full Defeasance In: 2019					
Market Clearing Price ($/MWH)	29.11	30.83	32.53	35.02	34.71
Gas Commodity Price ($/MMBtu)	1.87	1.95	2.06	2.15	2.29
Project Base Capacity Factor	86.7%	86.7%	88.9%	90.2%	90.6%
Senior Debt Service Coverage	2.08x	1.97x	1.78x	1.93x	1.74x
Total Debt Service Coverage	1.60x	1.51x	1.40x	1.51x	1.37x
Low Gas - Full Defeasance In: 2021					
Market Clearing Price ($/MWH)	26.59	28.11	29.61	31.36	31.83
Gas Commodity Price ($/MMBtu)	1.53	1.58	1.63	1.69	1.74
Project Base Capacity Factor	86.7%	87.7%	90.9%	91.1%	91.6%
Senior Debt Service Coverage	2.00x	2.01x	1.76x	1.85x	1.82x
Total Debt Service Coverage	1.53x	1.54x	1.38x	1.45x	1.42x
High Gas - Full Defeasance In: 2021					
Market Clearing Price ($/MWH)	29.76	31.58	33.32	34.88	36.07
Gas Commodity Price ($/MMBtu)	2.06	2.15	2.24	2.34	2.44
Project Base Capacity Factor	84.9%	85.1%	88.9%	89.7%	89.9%
Senior Debt Service Coverage	1.96x	1.98x	1.74x	1.77x	1.78x
Total Debt Service Coverage	1.51x	1.52x	1.37x	1.39x	1.39x
High Hydro - Full Defeasance In: 2020					
Market Clearing Price ($/MWH)	29.11	30.83	31.52	29.51	34.71
Gas Commodity Price ($/MMBtu)	1.87	1.95	2.06	2.15	2.29
Project Base Capacity Factor	86.7%	86.7%	87.7%	76.7%	90.6%
Senior Debt Service Coverage	2.08x	1.97x	1.68x	1.40x	1.72x
Total Debt Service Coverage	1.60x	1.51x	1.32x	1.10x	1.35x
Overbuild - Full Defeasance In: 2020					
Market Clearing Price ($/MWH)	29.11	30.83	32.53	32.16	34.49
Gas Commodity Price ($/MMBtu)	1.87	1.95	2.06	2.15	2.29
Project Base Capacity Factor	86.7%	86.7%	88.9%	88.5%	89.4%
Senior Debt Service Coverage	2.08x	1.97x	1.78x	1.69x	1,68x
Total Debt Service Coverage	1.60x	1.51x	1.40x	1.32x	1.32x

Results show that debt coverage levels are the most significantly influenced under the high hydroelectric production scenario. This significant increase in low-cost hydroelectric production results in a decrease in market clearing price in 2005, leading to a lower capacity factor and slightly lower senior debt service coverage. Debt service coverage is also slightly reduced under the overbuild scenario in 2005. The addition of 2500 megawatts of new high efficiency CCCT plants results in a decrease in market clearing price and resultant coverage in 2005. Debt service coverage is affected less under both the low and high gas price scenarios.

Across all of the sensitivity cases, the debt service coverage ratio for senior debt is estimated to be no lower than 1.40x and the debt service coverage ratio for total debt which includes the second lien debt is estimated to be no lower than 1.10x, both occurring under the high hydro scenario. Even in the worst case scenario, defeasance is not expected to be significantly delayed (2021 versus 2019). In summary, the projected operating results of the Project are relatively insensitive to a broad range of plausible operating scenarios.

PRINCIPAL CONSIDERATIONS AND ASSUMPTIONS

This Report summarizes our review and analyses of the Project to the date of this Report. The results of the analyses performed in preparation of this Report are predicated upon the general condition that the assumptions presented herein are reasonable and will continue, as stated, for the period covered without major modification or change. Although we believe our considerations and the use of the assumptions and information to be reasonable for the purposes of this Report, RMI makes no representation that the assumed conditions will, in fact, occur. Additional issues for consideration may arise in the future, actual future conditions and events may differ from those assumed, and information provided to us by others may prove to be inaccurate due to unanticipated events and circumstances. Our forecasts, findings and conclusions stated herein will differ from actual events to the extent that the considerations, assumptions and information stated herein vary from actual conditions and data. Further, RMI has assumed that all contracts, agreements, and ordinances which have been relied upon in the conduct of its investigations and analyses will be fully enforceable in accordance with their terms and conditions. RMI makes no representations or warranties, and provides no opinion concerning the enforceability or legal interpretations of such contractual and legal requirements.

The provisions of certain written Project agreements are described in general in this Report. Such descriptions are illustrative summaries only, and are not intended to be legal conclusions of the meanings or interpretations of the actual agreements. The description of any Project agreement contained in this Report should not be considered an alteration or modification of any such agreement, nor a waiver of any provision therein.

The principal considerations and assumptions made by us in preparation of this Report, and the information provided to us by others, include the following:

1. All of the agreements, authorizations and permits related to the Project are valid and enforceable in accordance with their terms, and all parties to them will comply with the provisions of their respective agreements;
2. The date of Substantial Completion will be July 1, 2001;
3. The Facility will satisfy conditions of the Cogeneration Output Guarantee, the Cogeneration Heat Rate Guarantee, the Combined Cycle Heat Rate Guarantee and the Emission Guaranty upon the date of Substantial Completion, as such terms are defined in the EPC Agreement;
4. All Brokered Facility Output will be sold to qualified purchasers at prices, on average, no less than the market prices as forecast by HESI;
5. The cost of natural gas at AECO-C will be consistent with the fuel price forecast used by HESI for the power market price projection presented in this Report and the net average (positive and negative) Gas Market Premium established in the Fuel Supply Agreement will be zero;
6. Use of the duct burners during summer peak temperature operation will increase Facility Output by 30,000 kilowatts and will have an incremental heat rate of 9,100 Btu/kWh;
7. Facility capacity will degrade approximately 1 percent per year on average, and the heat rate for the Facility will increase approximately 0.4 percent per year on average, with recovery of most of this periodic degradation after each combustion turbine major maintenance outage (approximately every four years);
8. The capacity factor of the Facility will be as forecast by HESI;
9. The capital costs of the Project will be as forecast by PKE and the City;
10. The variable and fixed operating costs of the Project will be as forecast by PKE and the City;
11. Inflation will be 2.8 percent per year over the life of the Facility;
12. The frequency and cost to repair or overhaul the combustion turbines will be as estimated by Siemens Westinghouse;
13. The annual average availability of the Facility, which considers the impact of outages necessary to repair, overhaul and/or replace the 501FD combustion turbines, will be equal to 93 percent;

14. Suitable replacement parts and service will be available from accepted industry sources for the combustion turbines and all other major capital equipment at the Facility for the duration of the Facility life;

15. The Project will be operated, maintained, overhauled and improved consistent with accepted industry standards and equipment manufacturer recommendations;

16. The principal amount, interest rates, reserve funding requirements and other information relative to the Project Bonds will be as stated by the underwriters;

17. Debt service reserve and other reserves relative to the Project will earn interest at the rate forecast by the City's financial advisor and the Project underwriters;

18. Any necessary renewals of Project related authorizations and permits over the life of the Facility will not require significant capital improvements or introduce significant new operating constraints;

19. Significant amounts of hazardous substances and significant archeological resources will not be discovered on or beneath the Facility site or the routes of any interconnecting pipelines or transmission lines during construction;

20. The SSWWTP will continue to operate and provide cooling water to the Facility for the life of the Facility;

21. Collins will purchase 200,000 pounds per hour of steam from the Project on an annual average basis;

22. Any transmission service needed for delivery of more than 230 megawatts of Brokered Facility Output will be obtained by the City at rates and loss factors no greater than those under the Transmission Service Agreement with BPA.

FINDINGS AND CONCLUSIONS

On the basis of the foregoing considerations and assumptions and our studies and analyses, RMI concludes that:

1. Based on a) the historic performance of the 501F, b) the proposed testing plan and manufacturing schedule for the 501FD, c) the recent satisfactory performance history of incremental improvements made to combined cycle generation technology, and d) the reputations of Siemens Westinghouse and BVC, the 501FD combustion turbine is expected to cause the Facility to perform consistent with the performance requirements of the EPC Agreement.

2. The technology improvements that are incorporated in the Siemens Westinghouse 501FD combustion turbine are reasonable, incremental technology improvements

over the 501F. Such advancements are common among combustion turbine manufacturers as they apply new designs, materials and computational tools to increase the capability of an existing machine over the course of the product life cycle.

3. All material authorizations and permits have been obtained to complete construction of the Project and there appear to be no technical related issues that would prevent the issuance of the remaining permits or proposed modifications to existing permits.

4. The Phase I environmental assessment performed by Golder appears to have been conducted in a manner consistent with industry standards.

5. Based on the Golder seismic evaluation, the PKE exploratory drilling and the BVC geophysical study, the Facility site is suitable for the construction work required to complete the Facility. In the event environmental contamination is encountered at the Facility site during construction, BVC will be responsible for remediation efforts and Collins will be responsible for the costs thereof. Due to the lack of subsurface contamination noted in the Golder Study and the PKE excavation report, and the relatively shallow depth to the bedrock discovered by BVC, if contamination is encountered at the Facility site, remediation efforts are not expected to materially delay substantial completion of the Facility construction beyond the planned completion date.

6. The EPC Agreement between the City and BVC is generally consistent with EPC agreements for other similar projects. The scope of work and the obligations of BVC are consistent with those that have been required for completion of power plants similar to the Project. BVC has extensive experience in the engineering, procurement and construction of power generation plants of the scale and complexity of the Project. BVC is qualified to perform under the EPC Agreement.

7. The Lump Sum Price of the EPC Agreement appears competitive and reasonable for similarly sized high-efficiency combined cycle projects, and the total Project capital costs appear reasonable. The provisions for mitigation of the costs, if any, associated with unanticipated subsurface conditions discovered during construction of the Facility as described in the EPC Agreement are reasonable and typical. The provisions for mitigation of force majeure events are reasonable.

8. The Substantial Completion Date is reasonable and BVC is capable of achieving Substantial Completion. The completion date guarantee and performance guarantees provided by BVC are reasonable and typical. The performance test procedures are reasonable, typical, and appropriate to test the capability of the Project.

9. Based on reasonable assumptions of replacement electric capacity cost, replacement steam generating capacity cost, and Facility operation and fuel costs, the

Cogeneration Output liquidated damage rate, the Cogeneration Heat Rate liquidated damage rate, the Combined Cycle Heat Rate liquidated damage rate, and the liquidated damage rate for auxiliary boiler output are sufficient to compensate the City for the decrease in expected power sale revenues and/or the increase in expected fuel costs that would likely occur over the life of the Project if the Project is not capable of performing at the expected guarantee levels.

10. The Operation and Maintenance Agreement between the City and PKE is generally consistent with operation and maintenance agreements for other similar projects. The Construction Period Fee and the O&M Fee are reasonable for the expected requirements for staffing the Facility. The provision for payment of Overtime Costs is reasonable. The form and rate of payment of the O&M Performance Incentive is reasonable. The provisions of the O&M Agreement, including the performance requirements, level of fees and responsibilities to the Manager under the Management Agreement, are consistent with those accepted by operators of other facilities similar to the Project, and, if PKE should cease to be the operator in the future, the City should be able to attract another operator under similar terms and conditions with PPM remaining as Manager under the Management Agreement.

11. PKE and its affiliates have extensive experience in the operation and maintenance of power generation plants of the scale and complexity of the Project. PKE and its affiliates are qualified to operate and maintain the Project to meet the operation and maintenance requirements of the Operation and Maintenance Agreement.

12. The Agreement for Project Management Services During Construction provides for the services and responsibilities required to be performed on behalf of an owner of facility such as the Project. PKE and its affiliates, together with subcontractors which can be retained in the market, are expected to have the capabilities and skills needed to manage the EPC Agreement and other services needed to complete Project construction and commence commercial operation.

13. PPM is an active power marketer in the WSCC region and is qualified to market power from the Project as contemplated under the Power Brokering Agreement. The level of the brokering fee prior to substantial completion under the Power Brokering Agreement is reasonable. The Brokering Base Fee appears reasonable for provision of the planning, brokering, hedging and other services provided under the Agreement. The form of the Incentive Bonus under the Power Brokering Agreement is reasonable.

14. If PPM should cease to be the Broker under the Power Brokering Agreement, the City should be able to attract another Broker under similar terms and conditions.

15. PPM and its affiliates, through appropriate subcontracting for fuel supply and transportation services, are qualified to perform as contemplated under the Fuel Supply and Services Agreement. The provisions obligating PPM to deliver fuel are

reasonable and typical. We find that a) the provisions for scheduling, balancing, increasing and reducing deliveries are reasonable and typical, b) the provisions for pricing of delivered fuel are reasonable, c) the Fuel Management Fee is reasonable for the scope of services provided and d) the provisions for supply of electricity in lieu of gas are reasonable.

16. PPM and its affiliates, are qualified to perform as contemplated under the Management Agreement. We find that a) the provisions for development of an Approved Annual Budget are reasonable, b) the Management Fee under the Management Agreement is reasonable, and c) the form of Management Performance Incentive is reasonable. In the event that PPM should cease to be the Manager under the Management Agreement, the City should be able to attract another Manager under similar terms and conditions.

17. The Project should have a useful life extending beyond the final maturity of the Project Bonds if the Project is constructed, operated and maintained in accordance with all of the Project Agreements and the recommendations of the equipment manufacturers.

18. The assumptions and forecasts underlying the projected operating results are reasonable for the purpose for which they have been relied upon and the projected operating results reasonably represent the expected future financial performance of the Project consistent with those assumptions and forecasts.

19. Arrangements for provision of fuel, electric interconnection, water, and wastewater for the Facility appear adequate and reasonable.

20. The Project should achieve an average annual availability factor of 93 percent or greater through the final maturity date of the Project Bonds if the Facility is constructed in accordance with the EPC Agreement and operated and maintained in accordance with the O&M Agreement and the recommendations of the major equipment manufacturers.

21. The training plans expressed in the EPC Agreement and the O&M Agreement are reasonable and in accordance with typical industry practice.

22. The operation and maintenance related costs of the Facility as forecast by PKE and the City are reasonable.

23. The water supply for the Project, including provisions for temporary supply of cooling water from alternative sources in case of inadequate SSWWTP effluent quantity or quality, are suitable to support Project operation

24. Forecast electric and steam sale revenues are expected to be sufficient to pay the forecast annual operating costs of the Project and provide a forecast annual debt service coverage of 1.74x minimum, and 2.09x average, on the Senior Tax-Exempt Bonds and the Senior Taxable Bonds under base case assumptions The Senior Tax-

Exempt Bonds and Senior Taxable Bonds are estimated to be fully defeased by the year 2019.

APPENDIX A

DETAILED PROJECTED OPERATING RESULTS

APPENDIX B

THE CALIFORNIA-OREGON BORDER ELECTRICITY MARKET PRICE FORECAST 2001-2025

APPENDIX C

OVERVIEW OF COMPETITIVE MARKET PERFORMANCE OF THE KLAMATH COGENERATION PROJECT

The following is additional information, or further clarification of information provided in the main body of the Independent Engineers' Report, regarding the competitive market performance of the Klamath Cogeneration Project (Project). The information in the Independent Engineers' Report should be read in its entirety and the assumptions, conclusions, and supporting data in that report are not modified by the provision of this Overview. Project costs and market clearing prices in this Overview are derived from the information used to prepare the Independent Engineers' Report and are consistent with that report.

Key Factors Impacting Market Clearing Price

The market clearing price projection set forth in the Independent Engineers' Report, as prepared by Henwood Energy Services Inc. (HESI) and used by Resource Management International, Inc. (RMI), was generated by a detailed power generation production cost model which simulates operation of the individual existing and estimated future generation additions within the entire Western Systems Coordinating Council (WSCC) region. The projection is based on the assumption that the region will continue its trend to an open competitive market similar to that which commenced in California in 1998. Under such a market, the market clearing prices are primarily a function of the following variables:

- The mix of generating resources, including the number of generators, their individual heat rates (fuel efficiency), their minimum operating levels, and their ability to deliver power through interconnection with the high voltage electric transmission system;
- The changes in the cost of natural gas (and to a far lesser extent the price of delivered coal); and
- The extent of hydroelectric generation, particularly that in the Pacific Northwest and California, which occurs in any given year based upon regional water supply conditions and operating constraints on hydroelectric generation plants.

These factors, and changes therein, will have the greatest impact on the market clearing price which the Project, or any competing facility in the region, will face. These factors figure prominently in assessing the performance of the Project and in evaluating potential alternative sensitivity cases to determine the potential financial performance vulnerability of the Project, as described further herein.

Seasonal Market Clearing Price and Project Cost Performance Trends

Figure 1, enclosed with this Overview, presents the estimated monthly average market clearing price for the California-Oregon Border (COB) point of delivery and sale of energy for the year 2004 (selected as a representative year after the expected end of the California electric energy market transition period described in the Independent Engineers' Report). As shown in Figure 1, the prices are highest in the August through October period, corresponding with the summer peak demand season in California, and in the December through February period corresponding with the winter peak demand period in the Pacific Northwest. The lowest prices are expected to occur during the typical late spring and early summer high stream flow period in the Pacific Northwest and, to a lesser extent California. During this period, there is typically significantly higher hydroelectric production, which places downward pressure on regional electric energy prices, as depicted in Figure 1.

June is expected to be the lowest price month in a typical year. The Project is expected to undergo scheduled maintenance during this period. Performing maintenance in this seasonally low price period ensures that the Project will not incur reduced hours of operation for scheduled maintenance in the months when market clearing prices are typically higher.

Figure 1 also shows the base case projection of the monthly average production cost of Project energy (including all fuel and variable costs) for 2004 as compared to the monthly estimated market clearing price of energy to demonstrate the monthly trend of Project performance for the months of that year.

Monthly on-peak, off-peak, and total average prices are estimated by the HESI model, and these monthly patterns are reflected in the projected prices in every year of the price forecast.

Figure 2 shows the base case projection, by month, of the estimated capacity factor operation of the Project for the year 2004, selected as a representative year, based on the HESI model simulation.

Relative Dispatch Order

The relative order of dispatch of the generating plants in the WSCC region can change daily and seasonally based upon regional customer loads, weather, the status of maintenance outages of major generating units, transmission constraints, fuel prices, operating limitations of generating facilities, and other factors. These dynamic factors are modeled and simulated by the aforementioned HESI production cost model used for this evaluation. Through the use of such a model, the hours per month or per year of operation (dispatch) of the Project can be estimated and compared to other resource types under varying conditions.

Figure 3 shows the percentage of total power supply needs in the WSCC region which are expected to be met by various power generation resource types and how this mix of resource dispatch changes over time. The Project is expected to fall within the new combined cycle block shown in Figure 3 (noted as "CC new"). As is shown in Figure 3, new combined cycle projects are expected to provide an increasing amount of the energy to meet regional needs, growing from about 10 percent of total energy supply in 2005, to about 35 percent of the total energy supply in 2020. This is due to the belief that new combined cycle projects are expected to be increasingly successful in competing with existing power supplies and other new power plant additions.

To assess how the Project is expected to compete within this block of new combined cycle projects, Table 1 presents the estimated operating cost (fuel commodity and transportation, variable O&M) per megawatt hour (MWh) for the Project relative to other new combined cycle plants, previously installed combined cycle plants, and the range of other generation resources in the WSCC region as listed on the table. This comparison shows that the Project is expected to have a cost well below that of other combined cycle generating units and is expected to dispatch at a level near or above 90 percent throughout the term of the bonds.

Another illustration of the Project's expected ability to compete can be seen in the WSCC load duration curves for the years 2005, 2010, 2015 and 2020 shown as Figures 4, 5, 6 and 7. In all years, the Project is expected to be dispatched year round at the bottom of the new combined cycle block.

Ability of Project to Compete With Future High-Efficiency Generating Facilities

Figures 8, 9, 10 and 11 show the percentage of time for each of years 2005, 2010, 2015, and 2020 that different power generation resource types are expected to be serving the last increment of load (on the margin) effectively setting the market clearing price. As this figure shows, in the early years in the life of the Project, new combined cycle projects are expected to be at the margin only approximately 16 percent of the time. Over the life of the Project, as more combined cycle projects are added, displacing less efficient generation, the newer combined cycle projects (of which the Project is one) are on the margin a greater amount, growing to over 43 percent of the time by 2020 in the model results. The relative cost advantage of the Project, as discussed above, shows that the Project is expected to dispatch well in competition with these combined cycle projects and other resources.

The HESI model assumes that new combined cycle power plants are added with an average heat rate of approximately 7,100 Btu/kWh (on a higher heating value or "HHV" basis). This is in comparison to the 6,700 Btu/kWh heat rate assumed for the Project. This unusually low heat rate is due to the approximately 200,000 lb/hr base load cogeneration steam load served by the Project. This reduces the net cost of fuel chargeable to power. Gains in efficiency in combined cycle plants are reaching the point of diminishing returns as discussed in more detail in the Independent Engineers' Report. However, some further technology gains may occur. The theoretical practical limit of combined cycle efficiency is expected to be about 6,500 Btu/kWh (HHV), and it is not clear that the performance at such levels can be maintained in base load operations (such as the 90 percent capacity factor operation of the Project), or at what capital cost per kW of capacity such units will be available. Nevertheless, to address the relative dispatch of combined cycle plants of different efficiencies in the future, the Project variable operating cost was compared to a range of fuel conversion efficiencies for the block of assumed new combined cycle units in year 2015 in the HESI model.

As of 2015, the HESI model assumes there will be 160 new (added from 1999 through 2015) combined-cycle generating units operating in the WSCC. Table 2 shows the absolute and percentile ranking of the Project against those units based on estimated energy production cost for scenarios in which all of the competing projects were added at heat rates varying from 7,100 (which is assumed in the model) down to 6,500 Btu/kWh. As shown in Table 2, there is essentially no change in competitiveness with a 200 Btu/kWh reduction from the base case assumed 7,100 Btu/kWh heat rate for all of the competing plants, and even with <u>all</u> of the other plant additions achieving what is considered the practical, long-term efficiency limit of 6,500 Btu/kWh, the Project still is in the top 36 of 160 (approximately the top 23 percent). More importantly, the lowest 60 of the combined cycle units are still expected to dispatch at a level of at least 90 percent capacity factor.

It is unlikely that a competing project can be developed today at a location with (1) a 200,000 lb/hr base load steam load to serve, and (2) a 500kV electric transmission interconnection near a major regional market sales and delivery point, with (c) a local gas lateral or distribution cost of less than $0.05/MMBtu. As the regional production cost model results demonstrate, the Project is expected to be highly competitive with other generation resources, even if significant incremental gains in fuel conversion efficiency are achieved by future competing plants.

Break-Even "Spark Spread"

A key indication of the margin of comfort with the Project's operating results in a competitive market is the difference between the estimated market clearing price and that price which is required to cover all fixed costs (debt service coverage ratio of 1.0). This comparison is most clearly demonstrated by computing the "spark spread" (the difference between the market clearing price and the variable cost of fuel, variable O&M, electric transmission, and related costs to produce electrical energy by the Project) and determining the total average price per kWh in each year needed to meet the 1.0 debt service coverage ratio. Figure 12 compares the spark spread under the base case conditions with the price levels needed for 1.0 coverage for the Senior Bonds and also for all debt. This same relationship is shown in terms of a percent margin of spark spread over the level needed for 1.0 coverage in Figure 13. Figure 13 shows margins from over 150 percent to approximately 250 percent for senior debt coverage and from approximately 50 percent to over 115 percent for total debt coverage.

Similar comparisons are provided in Figures 14 through 21 for the low and high gas price sensitivity cases, the high hydroelectric production sensitivity case, and the generating capacity overbuild case described in the Independent Engineers' Report and described in more detail later in this Overview. In each case these sensitivity cases show the Project is expected to have a comfortable margin between the estimated market clearing price for energy and the minimum required to pay for all fixed and variable Project costs.

Project-Specific Variable Cost Competitive Advantages
The variable cost competitive advantages of the Project which contribute to its ability to compete favorably in the market are principally its heat rate, and the gas supply and electric transmission service costs associated with its favorable location as follows:

- **Gas Transportation Costs** -The Project is located near the California-Oregon border (COB) and therefore enjoys a lower cost per million Btu for gas transportation relative to projects that are located in California. Gas transportation costs are distance related, with costs rising as gas is transported farther from the supply source. As an example, a project located in the Central California valley area will face gas transportation tariffs of approximately $0.25 to $0.35 more than the Project's cost for mainline gas pipeline transportation, due primarily to the additional cost of California intra-state transportation. This results in an approximately $2.00/MWh to $2.50/MWh savings in delivered fuel costs for the Project compared to these competing plants assuming the same plant efficiency. This comparison does not take into consideration the added cost of additional gas shrinkage that would be incurred by California plants due to the added distance for gas transportation as compared to the Project. Relative to those projects in the Pacific Northwest which require the use of a local gas distribution company or the construction of a lateral off of a main pipeline, the Project has another cost advantage. The Project was able to secure a local gas transportation rate that is approximately half of the local tariff by opportunistically negotiating to increase the diameter of the Medford Lateral that was nearing construction to serve other gas customers. This resulted in a modest approximately $0.05/MMBtu gas transportation cost on the lateral, saving over $0.05/MMBtu from the tariff rate. Local gas transportation costs or transportation costs across similar, new laterals to serve major combined cycle projects typically range from $0.12/MMBtu to $0.20/MMBtu or more. This advantage can result in a 3 percent to 6 percent or higher delivered gas cost savings over competitors, on top of the main pipeline transportation cost savings.

- **Electric Transmission Service** - Depending upon the season, the Project can be competing with other generators located north of COB seeking to sell into the California market (typically in summer) or those in California seeking to sell into the

Pacific Northwest (typically in the winter). The Project enjoys an electric transmission cost savings over these competitors. The Project is opportunistically located next to an existing 500 kilovolt (kV) Meridian to Captain Jack electric transmission line. This proximity enables interconnection at this high voltage without the need to build any significant length of new 500 kV transmission, which would otherwise be very costly (on the order of $750,000 per mile). This interconnection enables the Project to deliver power to the COB trading and delivery point by paying only a Southern Intertie transmission service charge to the Bonneville Power Administration (BPA) at a rate equivalent to $1.75/MWh. Most other competitors in the Pacific Northwest would pay the Southern Intertie rate plus an additional BPA Network tariff rate to reach COB, likely resulting in an added cost of the equivalent of $1.50 to $2.00/MWh plus transmission losses as compared to the Project. Similarly, a project located in Central or Northern California seeking delivery and sales at COB to sell into the Pacific Northwest would face the California Independent System Operator's (ISO) tariff rate of $1.81/KW-month for transmission service, plus $0.78/MWh for grid maintenance charges. For a 90 percent capacity factor operation this converts to approximately $3.50/MWh total transmission service cost to reach COB. The Project's relative electric transmission charges are therefore expected to result in savings of approximately 6 percent to 8 percent in total costs, and 9 percent to 12 percent savings in variable costs compared to regional competitors seeking to sell in to the same market. There are presently no other known, planned projects that will have this advantage.

- **Cost of Capital Savings-** Although it does not impact variable costs and relative dispatch, the Project's largely tax-exempt debt financing and lack of equity return or income tax obligation also reduces Project costs. If the Project were to be financed using the traditional 35 percent equity, 65 percent taxable debt structure, the total cost of Project energy would increase by over $3.00/MWh, or about ten percent based on year 2005 costs. Even if the Project were to be financed with 100 percent taxable debt, the total cost of Project energy would increase approximately $2.50/MWh, or about ten percent higher than the Project's "all-in" costs of energy excluding any other cost factors. While lower fixed costs do not improve Project dispatch, such lower all-in costs enable the Project to have higher margins on all-in costs and better debt coverage ratios than competing projects, all other factors being equal.

Fuel Price Sensitivity

Both the energy production cost of the Project and the market clearing price for energy at COB will be influenced by the price of gas. In the Independent Engineers' Report, the HESI regional production cost simulation model was used to estimate both the costs of energy production by the Project and the COB market clearing price using high and low gas commodity price assumptions. In the high gas case, market clearing prices and the Project's price of production increase relative to the base case. In the low gas case, the Project would enjoy the lower cost of fuel commodity, but the reduced regional cost of gas supply would also lower the market clearing price. Figure 22 shows the difference in the assumed prices of gas for the base, low gas price and high gas price cases expressed in constant, 1998 dollars. These different fuel price assumptions result in the spark spread margins shown in Figures 14, 15, 16 and 17 described earlier in this Overview.

The low gas price case assumptions are considered quite conservative. The 1999 gas price is reduced $0.15/MMBtu from the 1998 price, and then escalated at only 0.5 percent (real) annually throughout the forecast period (2025). The assumed average annual gas price escalation rate under the base case is 1.8 percent (real). Therefore, under the low gas case, gas prices are assumed to rise in real value by an average of 1.3 percent less annually for nearly 30 years as compared to the base case. As shown in Table 16 from the Independent Engineers' Report, the Project is expected to have strong debt service coverage even under these conservative fuel cost assumptions.

High Hydroelectric Production Impacts
The market clearing price at COB will be impacted by the level of hydroelectric production in the Pacific Northwest and California in any given year. Table 3 presents the historic variability in hydroelectric production in the Pacific Northwest and California for the past twenty years. As is seen in Table 3, sustained very high periods of hydroelectric production have historically been no more than two years duration. The high hydroelectric production sensitivity case presented in the Independent Engineers' Report evaluates the potential impact on the projected operating results from the occurrence of the same stream flow conditions which were present in 1995 and 1996. As shown in Table 3, these two years combined represent approximately the 80th percentile of high water years in the prior twenty year record. Given that these have occurred recently, they likely more accurately depict the constraints which have increasingly been placed on Columbia River basin hydroelectric production for fishery protection and recovery reasons, and therefore are expected to be good examples of future high hydroelectric production periods in the region. Based on recent developments (1999) in fishery protection measures announced for the Columbia River basin, it is likely that changes in operations will be made which could reduce the impacts of high water year conditions on regional hydroelectric production, although it is difficult to precisely quantify these effects at this time.

Recognizing that high hydroelectric production conditions are sporadic, this evaluation focuses only on the two year period during which the high hydroelectric conditions occur. All other years in this case were modeled at average conditions. The years 2004 and 2005 were selected for the high hydroelectric production conditions because 2004 is the first year in which the Project incurs full principal and interest payment obligations on all debt, therefore resulting in the highest potential for stress to the operating results. As shown in Table 16 in the Independent Engineers' Report, these two years result in the following estimated change from the base case results:

	2004	2005
Base Case		
Market Clearing Price ($/MWh)	32.5	35.0
Senior Debt Service Coverage	1.81x	1.96x
Total Debt Service Coverage	1.40x	1.52x
Project Capacity Factor Operation	88.9%	90.2%
High Hydro Case		
Market Clearing Price ($/MWh)	31.5	29.5
Senior Debt Service Coverage	1.71x	1.47x
Total Debt Service Coverage	1.32x	1.14x
Project Capacity Factor Operation	87.7%	76.7%

Overbuild Case

The base case assumes the addition of sufficient capacity in the WSCC to meet a cumulative WSCC reserve capacity margin of approximately 20 percent. This results in the addition, by 2008, of approximately 12,400 MW of new capacity in California (approx. 11,000 MW) and the Pacific Northwest (approx. 1,400 MW). The Independent Engineers' Report presents the results of an overbuild case in which 2,500 MW of capacity in addition to that in the base case is constructed during this same period, or approximately a 21 percent increase over that which is needed to meet WSCC reliability criteria. As shown in Table 16 of the Independent Engineers' Report, this change would begin to impact operating results in 2005 when (a) the capacity factor operation of the Project is estimated to drop slightly, (b) market clearing prices are estimated fall by about 8 percent compared to the base case, and (c) senior debt coverage ratios are reduced from approximately 1.96x to 1.47x. Coverage is estimated to rebound to 1.70x on senior debt in the next year, with a continued trend upwards.

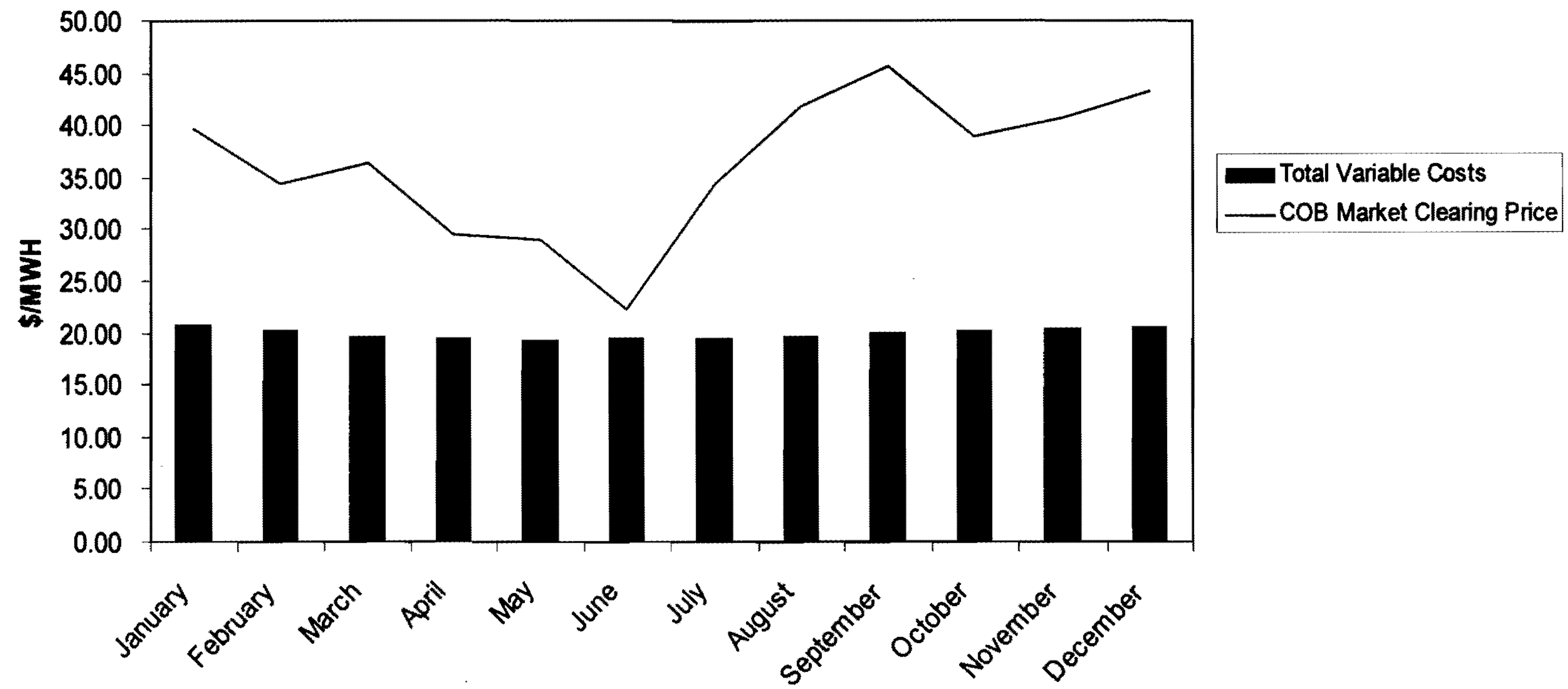
The amount and timing of additional capacity that can be constructed in California, is limited by the presence of one of the most comprehensive scope power plant site certification processes in the nation. A Site Certificate from the California Energy Commission (CEC) is required for any project in excess of 100 MW. The CEC Site Certification process has served to significantly delay the planned date of commencement of construction of several power projects from the dates initially announced by developers. The first merchant power project application was filed in early 1997, and has yet to receive approval. Subsequent projects are also incurring longer periods of permitting processes than planned. The CEC process involves a rigorous review of all aspects of project development, and requires an independent review by the California ISO of the impact of proposed project on the region's transmission grid. The ISO provides the CEC with an assessment of any transmission constraints that a project may create to the detriment of the system. The CEC is on record indicating that its review will consider the ability of a plant to physically deliver power to the market and that certification could be withheld if the

California ISO and the CEC determine that a project is unduly constrained or causes undue impacts on the transmission system.

To add an additional 2,500 MW into the California and Oregon system on top of the 12,400 MW assumed in the HESI model will be a challenge without either (a) major transmission system upgrades, or (b) installation of that capacity near existing older generation sites (primarily those previously owned by Pacific Gas & Electric Company (PG&E)), and utilizing the existing transmission exit capability made available from retirement of the plants. Additional excess generation beyond the incremental 2,500 MW overbuild case presented in the Independent Engineer's Report is therefore unlikely to receive CEC approval. If it does receive approval, it is likely to be at a location which either requires transmission upgrades to be paid for by the project creating the need for the upgrade, or at a location which replaces an existing PG&E divested generating plants. All such existing PG&E locations of major thermal generating plants are at points in the San Francisco Bay area, or further south, where the distance-related gas transportation costs will add approximately \$0.26 to \$0.35 per MMBtu to the cost of delivered gas as compared to the Project. This would result in an increase of approximately \$2.00 to \$2.50/MWh in delivered cost as compared to the Project.

In addition, any project constructed at these locations seeking to sell north to COB for Pacific Northwest peak season deliveries will incur the above described additional costs for transmission delivery to COB. The present California ISO tariff for transmission service to COB from plants located in Northern or Central California includes a \$1.81/kW-month Access Charge (which converts to approximately \$2.75/MWh at a ninety percent capacity factor) and a Grid Management Charge of \$0.78/MWh, for a total approximate transmission cost of \$3.50/MWh compared to the Project's cost of \$1.75/MWh under its Bonneville transmission tariff. As a result, even if there were an even greater overbuild than the 2,500 MW sensitivity case shown in the Independent Engineers' Report, the Project is expected to favorably compete.

Figure 1
Comparison of Estimated Monthly Average COB Market Clearing Price versus Total Estimated Variable Production Costs per kWH for the Klamath Cogeneration Project for the Year 2004



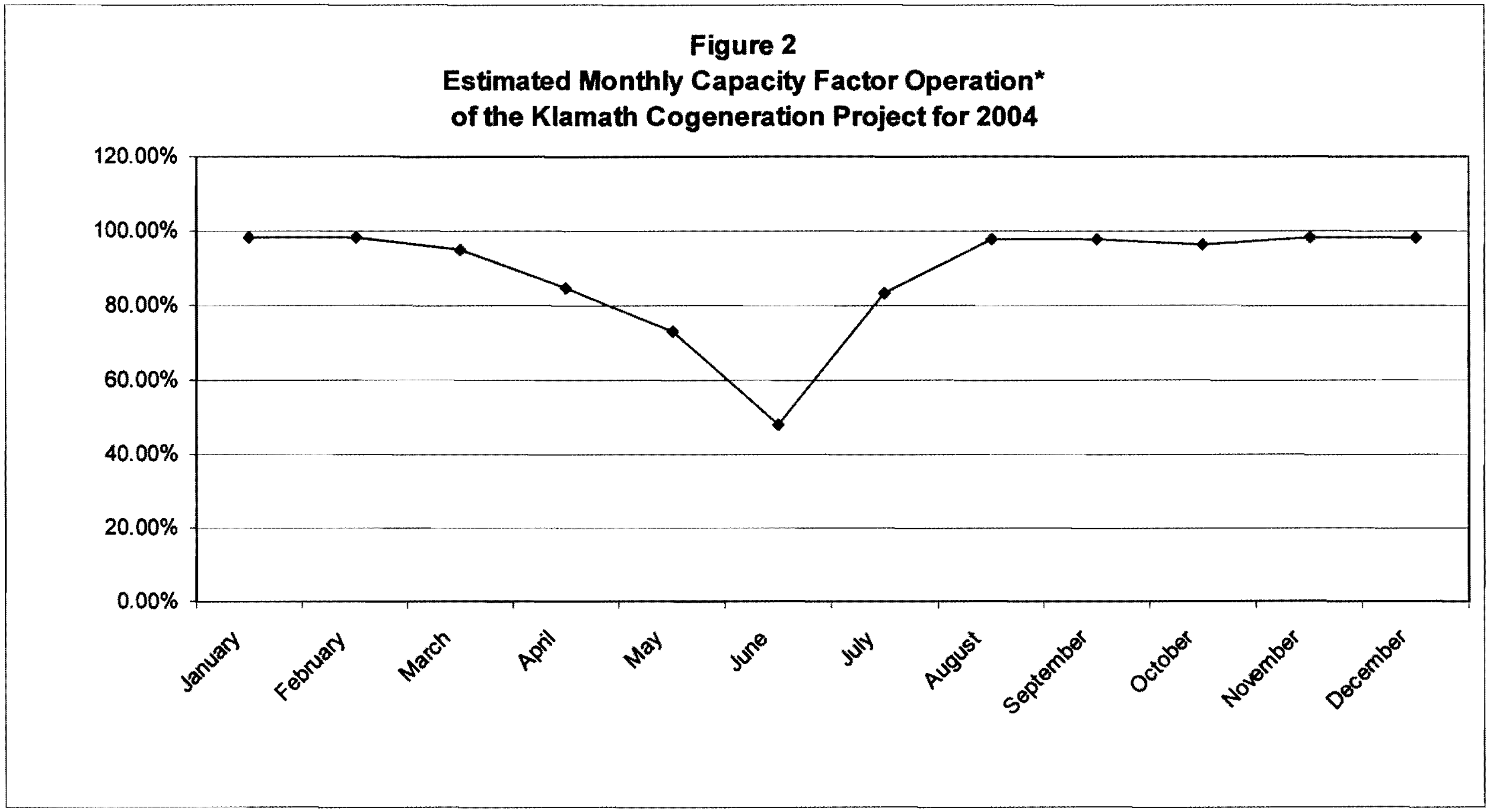
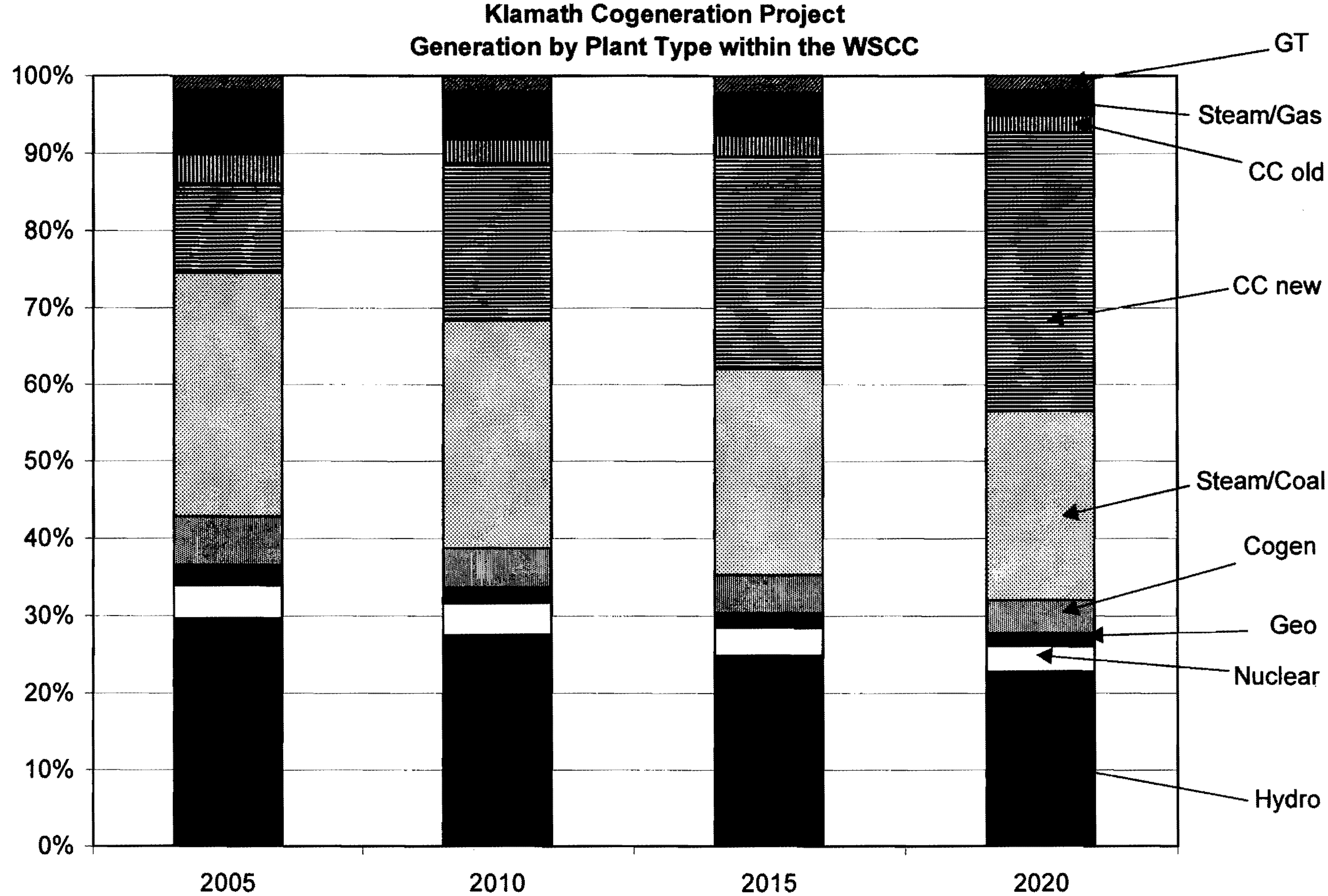


Figure 2
Estimated Monthly Capacity Factor Operation*
of the Klamath Cogeneration Project for 2004
120.00%
100.00%
80.00%
60.00%
40.00%
20.00%
0.00%
January
February
March
April
May
June
July
August
September
October
November
December

Figure 3
Klamath Cogeneration Project
Generation by Plant Type within the WSCC



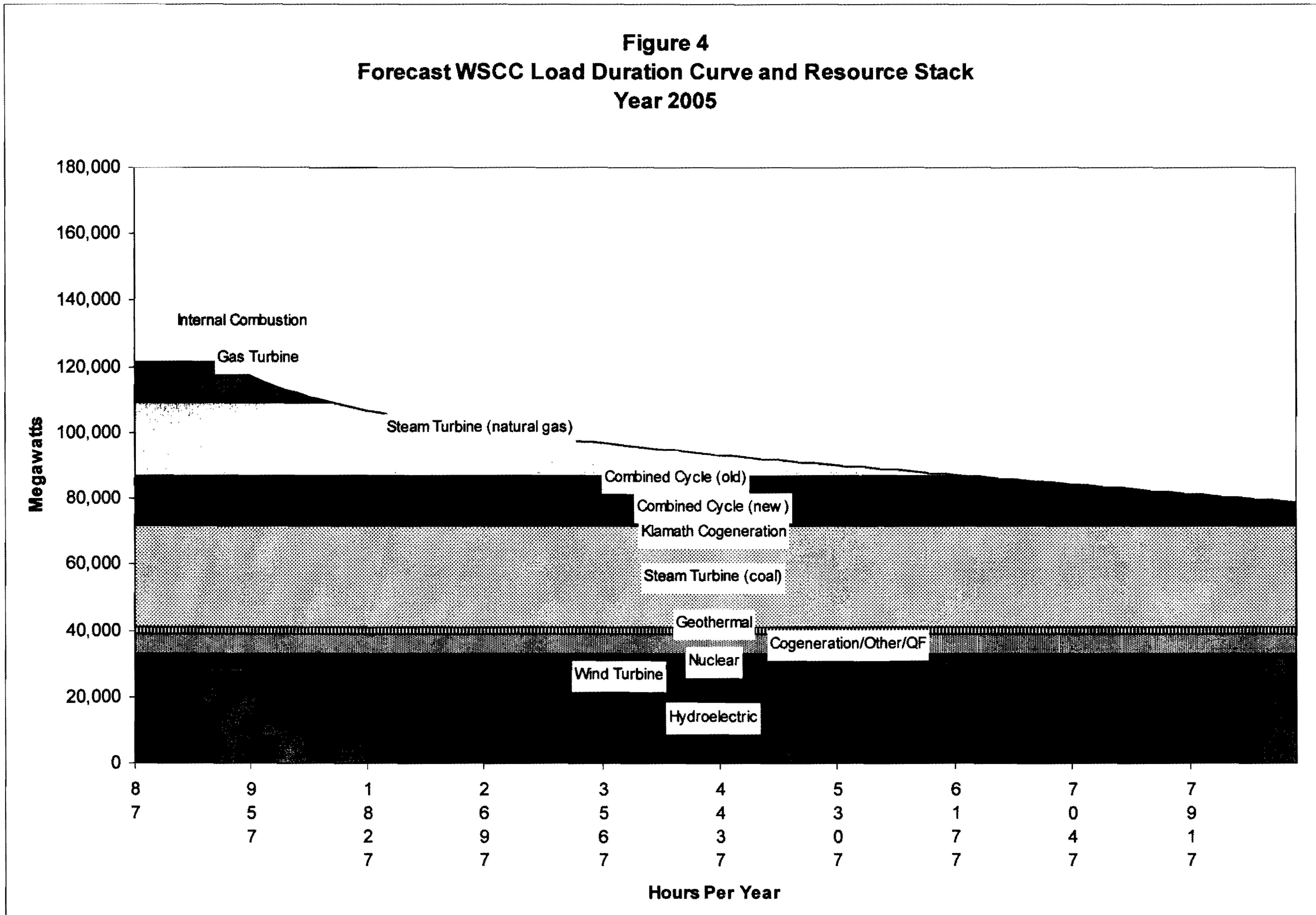
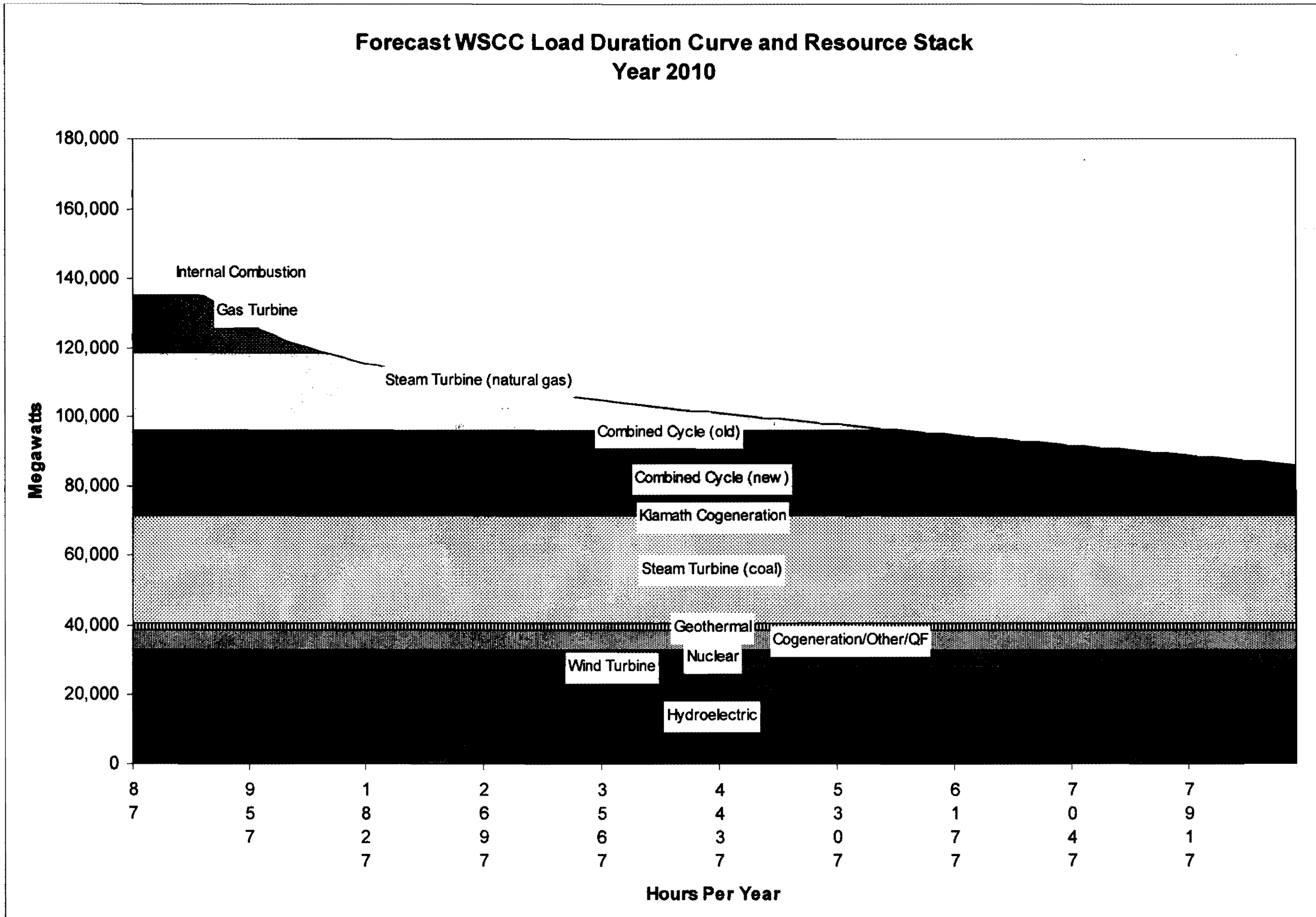
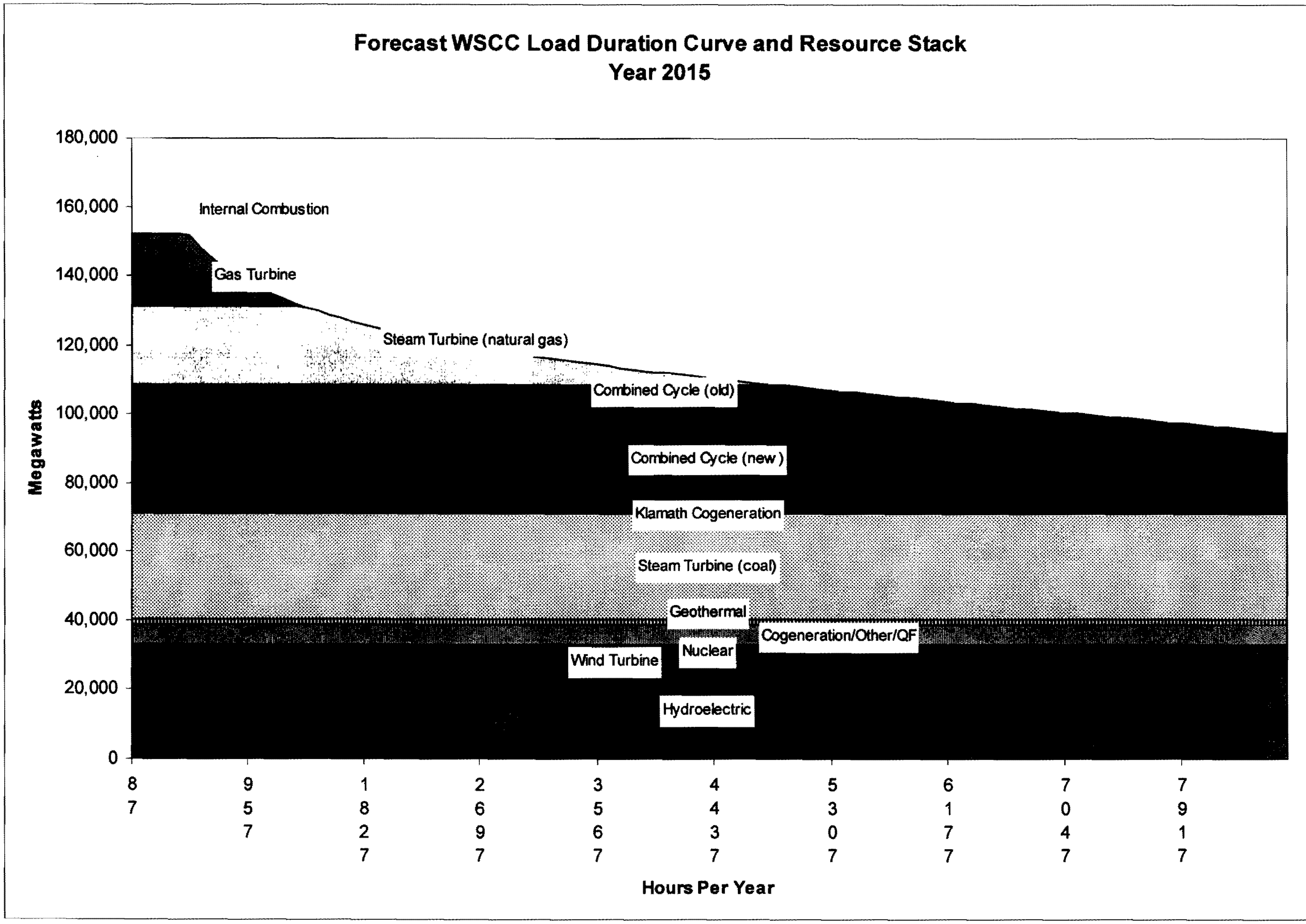
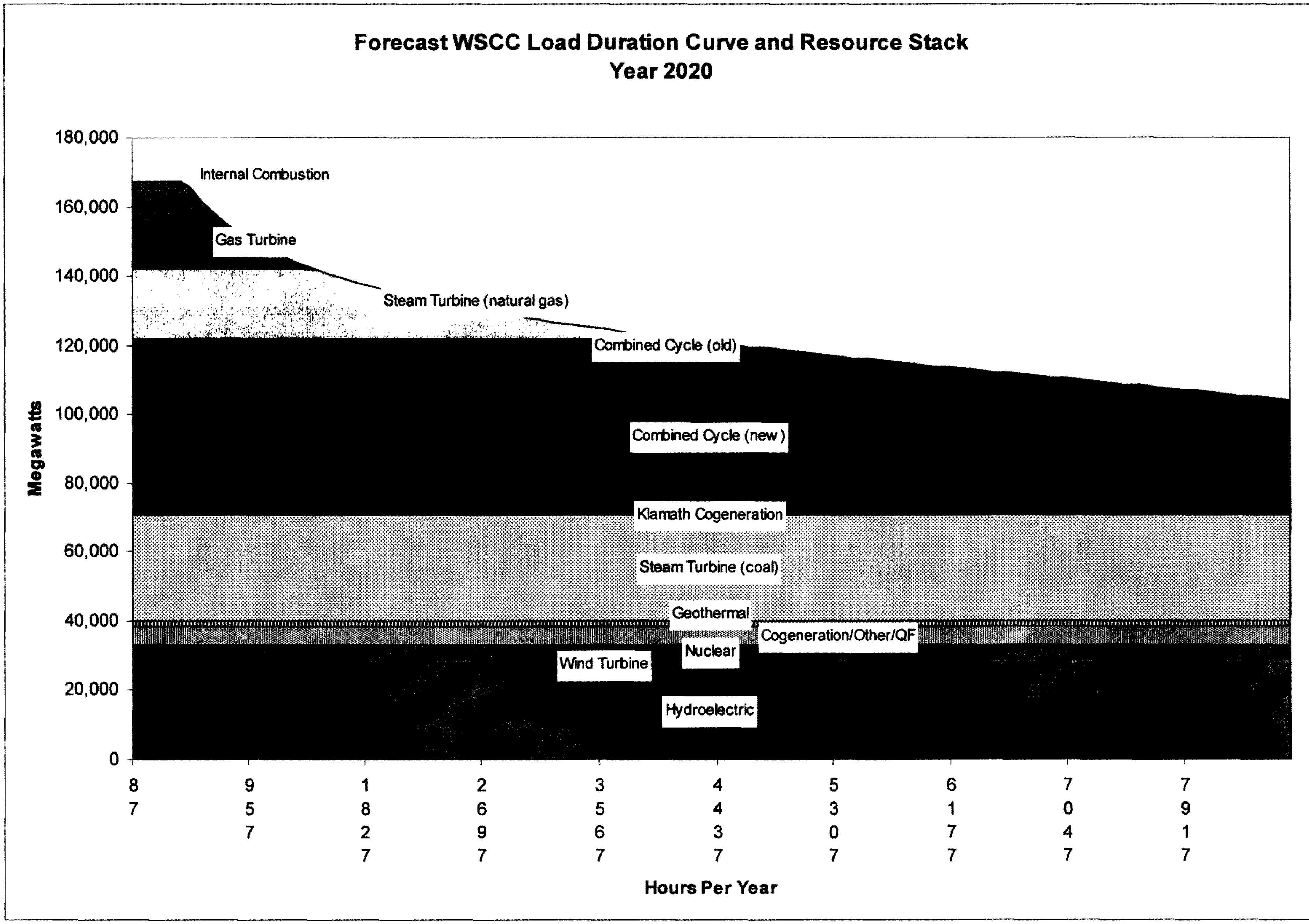


Figure 4
Forecast WSCC Load Duration Curve and Resource Stack
Year 2005
Megawatts
180,000
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
Internal Combustion
Gas Turbine
Steam Turbine (natural gas)
Combined Cycle (old)
Combined Cycle (new)
Klamath Cogeneration
Steam Turbine (coal)
Geothermal
Cogeneration/Other/QF
Nuclear
Wind Turbine
Hydroelectric
87
957
1827
2697
3567
4437
5307
6177
7047
7917
Hours Per Year



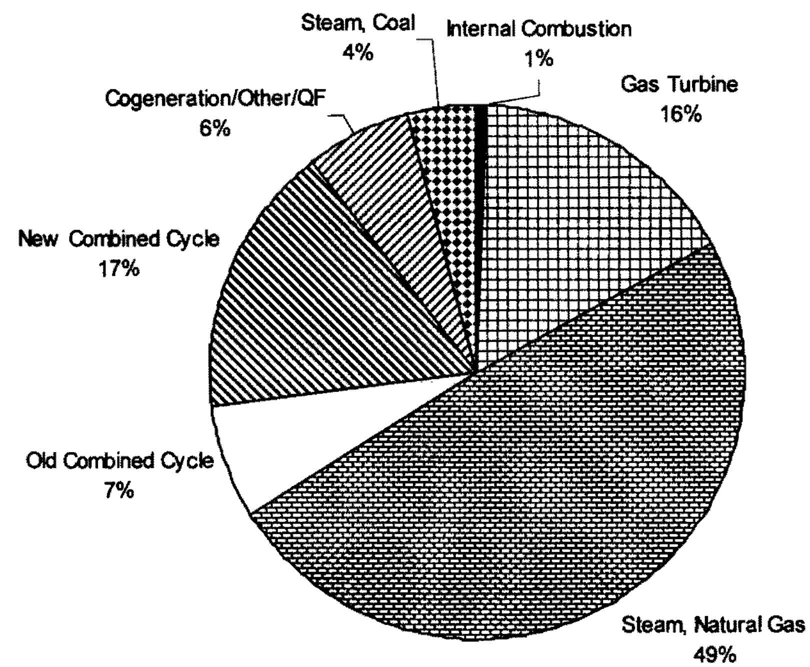
Forecast WSCC Load Duration Curve and Resource Stack
Year 2010
180,000
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
Megawatts
Internal Combustion
Gas Turbine
Steam Turbine (natural gas)
Combined Cycle (old)
Combined Cycle (new)
Klamath Cogeneration
Steam Turbine (coal)
Geothermal
Cogeneration/Other/QF
Nuclear
Wind Turbine
Hydroelectric
87
957
1827
2697
3567
4437
5307
6177
7047
7917
Hours Per Year


Forecast WSCC Load Duration Curve and Resource Stack
Year 2015
180,000
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
Megawatts
Internal Combustion
Gas Turbine
Steam Turbine (natural gas)
Combined Cycle (old)
Combined Cycle (new)
Klamath Cogeneration
Steam Turbine (coal)
Geothermal
Cogeneration/Other/QF
Nuclear
Wind Turbine
Hydroelectric
87
957
1827
2697
3567
4437
5307
6177
7047
7917
Hours Per Year



Forecast WSCC Load Duration Curve and Resource Stack
Year 2020
180,000
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
Megawatts
Internal Combustion
Gas Turbine
Steam Turbine (natural gas)
Combined Cycle (old)
Combined Cycle (new)
Klamath Cogeneration
Steam Turbine (coal)
Geothermal
Cogeneration/Other/QF
Nuclear
Wind Turbine
Hydroelectric
87
957
1827
2697
3567
4437
5307
6177
7047
7917
Hours Per Year

Figure 8
Relative Time on Margin
By Plant Type and Time Period
2005



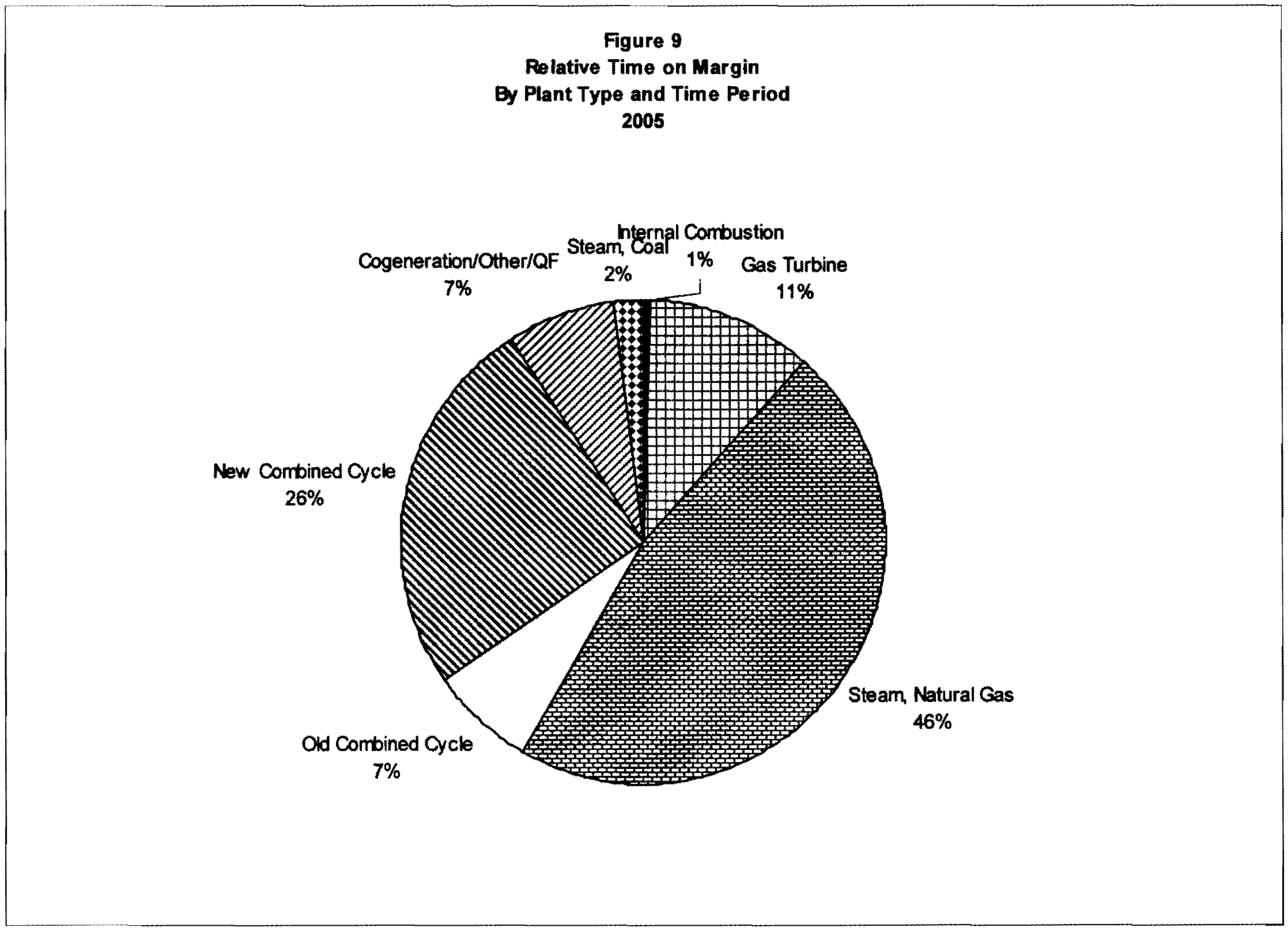


Figure 9
Relative Time on Margin
By Plant Type and Time Period
2005
Internal Combustion
1%
Steam, Coal
2%
Cogeneration/Other/QF
7%
Gas Turbine
11%
New Combined Cycle
26%
Steam, Natural Gas
46%
Old Combined Cycle
7%

Figure 10
Relative Time on Margin
By Plant Type and Time Period
2005

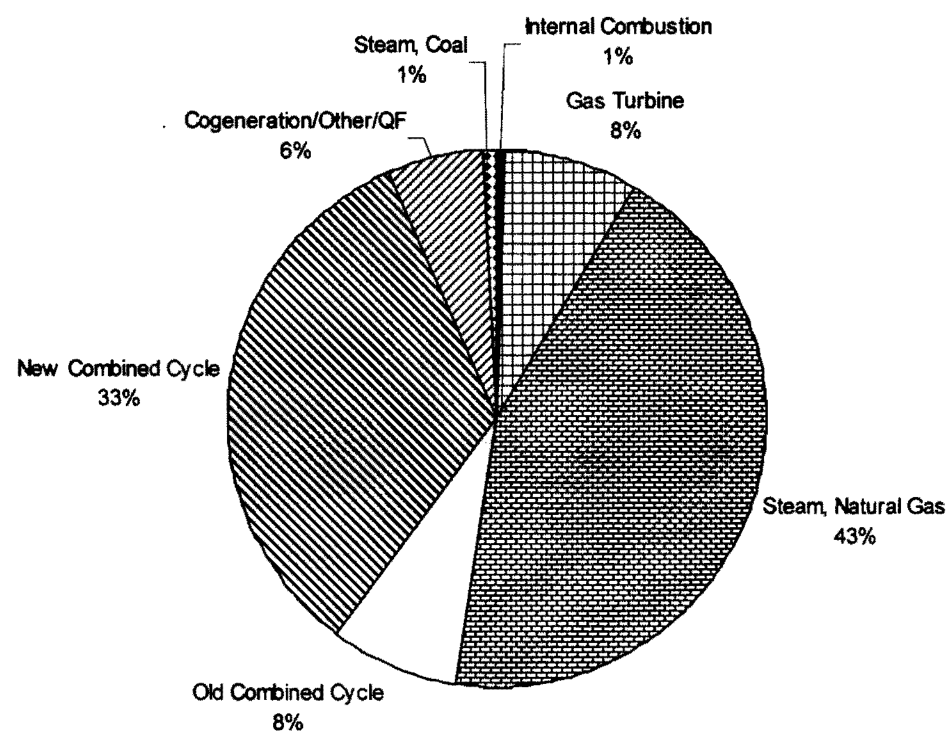
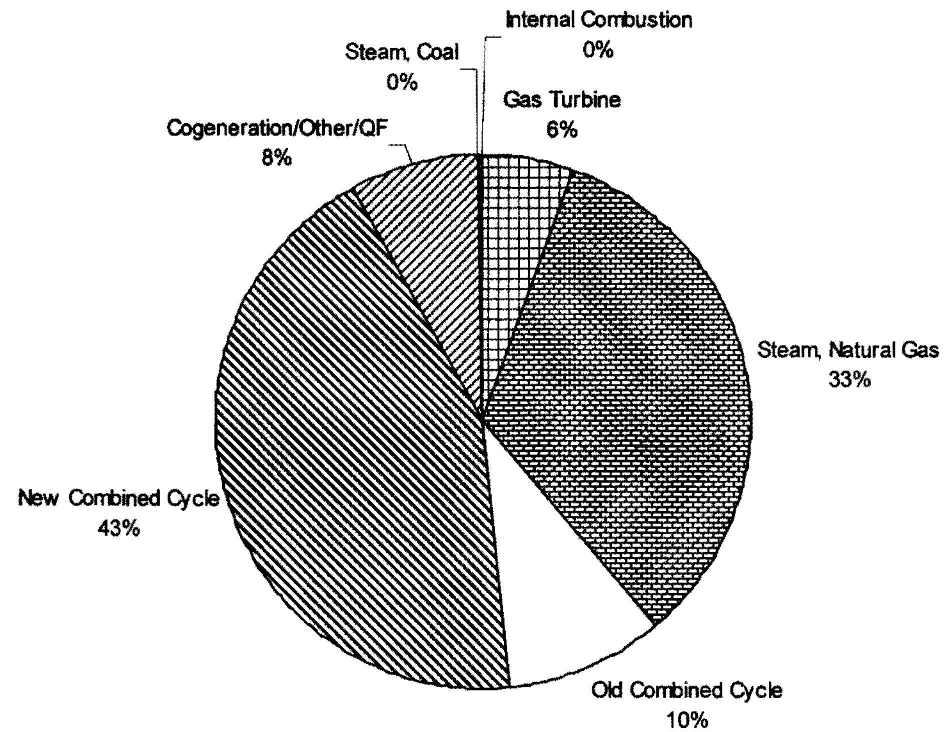


Figure 11
Relative Time on Margin
By Plant Type and Time Period
2005



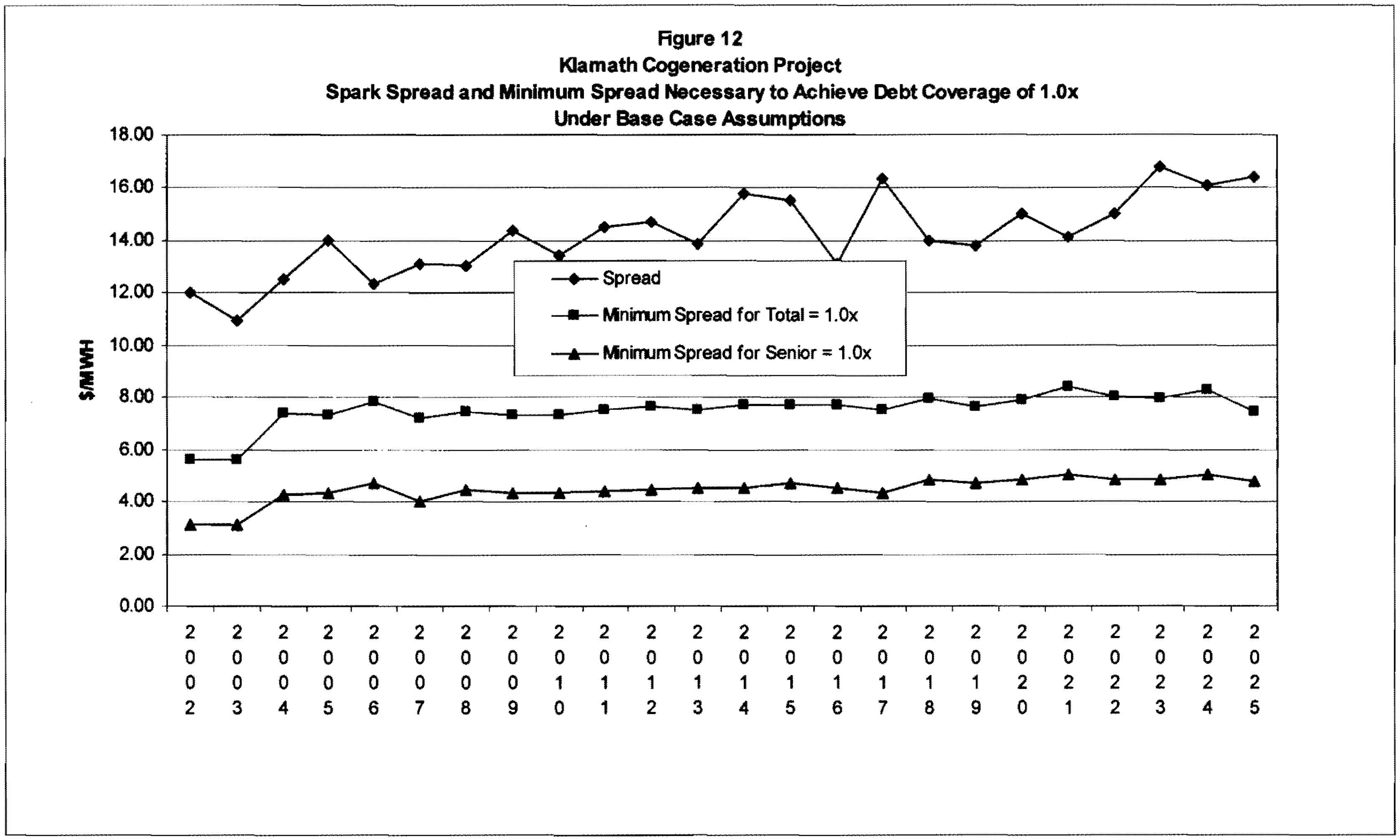
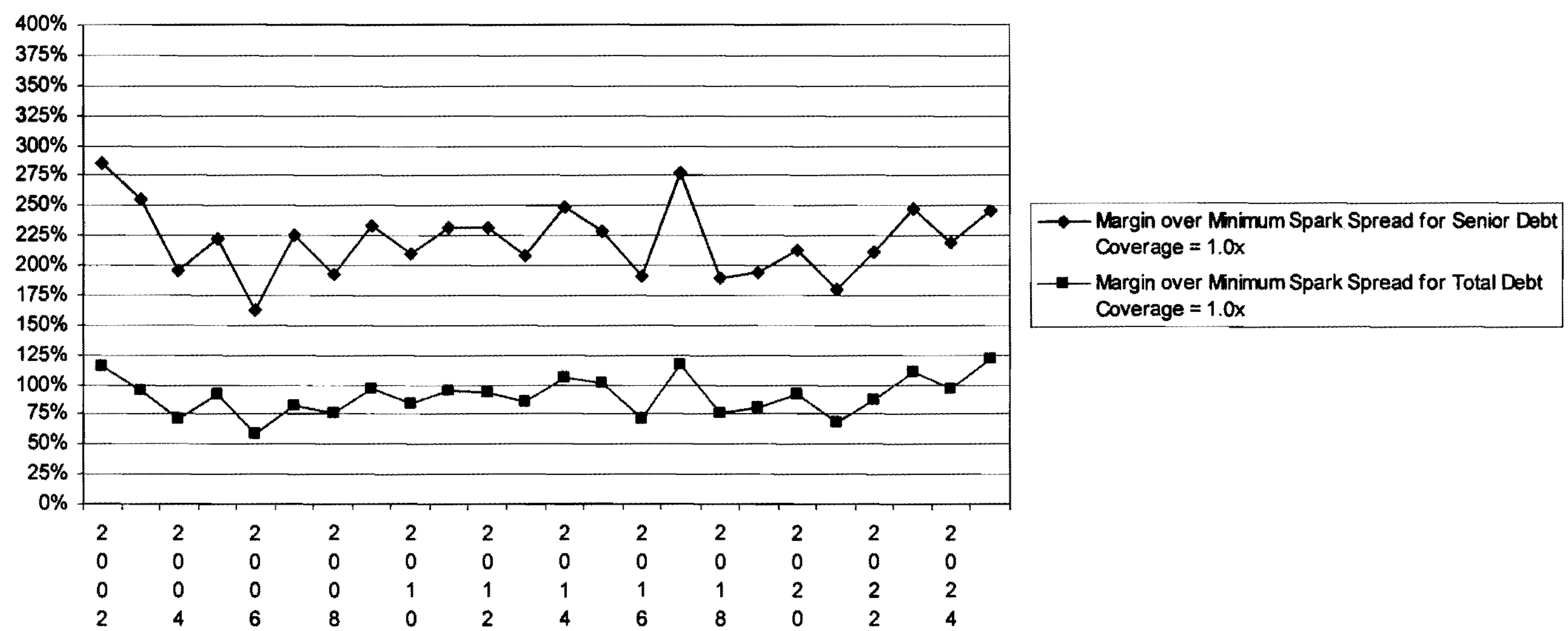


Figure 12
Klamath Cogeneration Project
Spark Spread and Minimum Spread Necessary to Achieve Debt Coverage of 1.0x
Under Base Case Assumptions
$/MWH
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Spread
Minimum Spread for Total = 1.0x
Minimum Spread for Senior = 1.0x
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025

Figure 13
Klamath Cogeneration Project
Margin of Forecast Spark Spread
Over Minimum Spread Necessary to Achieve Debt Coverage of 1.0x
Under Base Case Assumptions



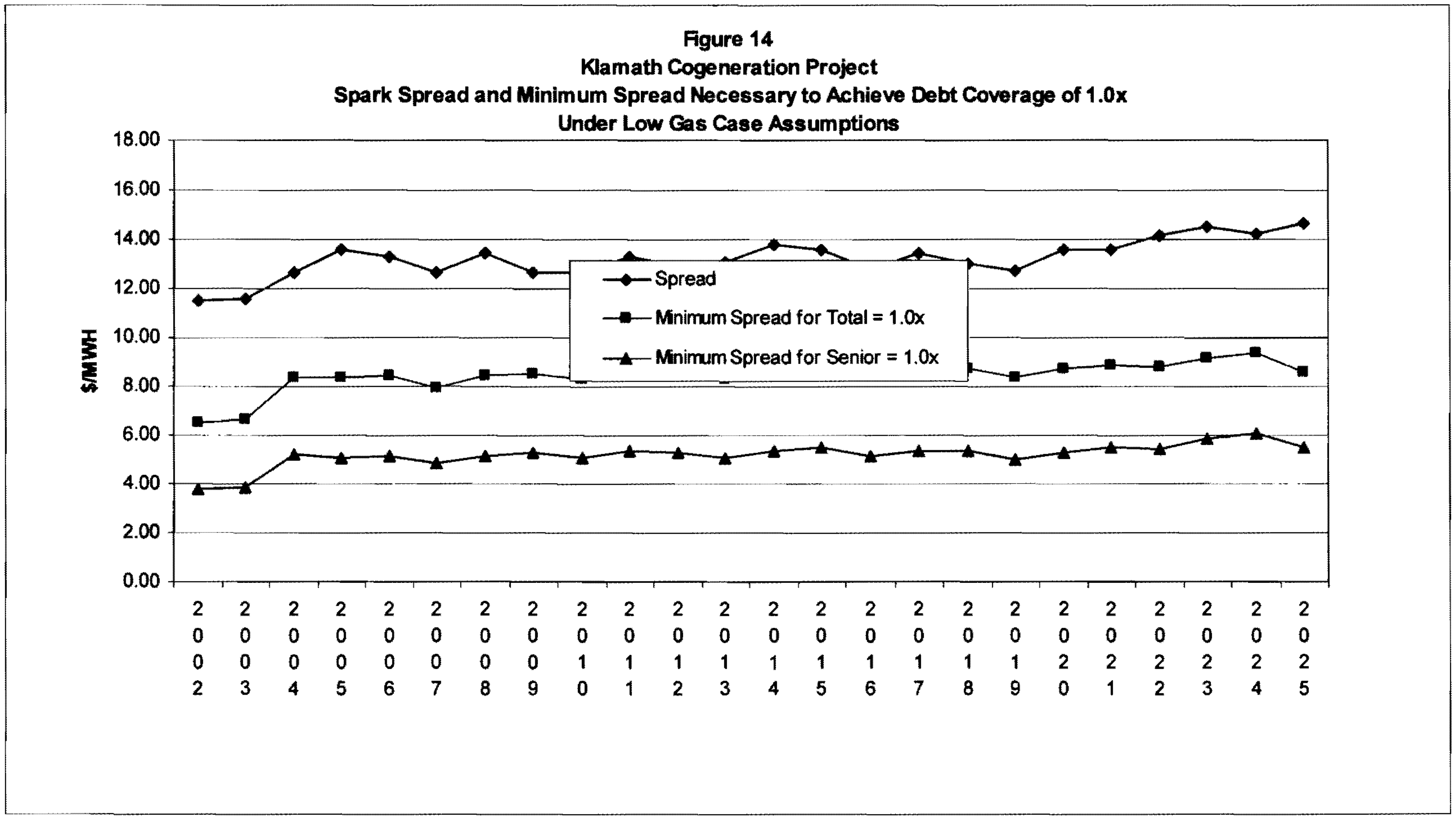


Figure 14
Klamath Cogeneration Project
Spark Spread and Minimum Spread Necessary to Achieve Debt Coverage of 1.0x
Under Low Gas Case Assumptions
$/MWH
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Spread
Minimum Spread for Total = 1.0x
Minimum Spread for Senior = 1.0x
2002
2003
2004
2005
2006
2007
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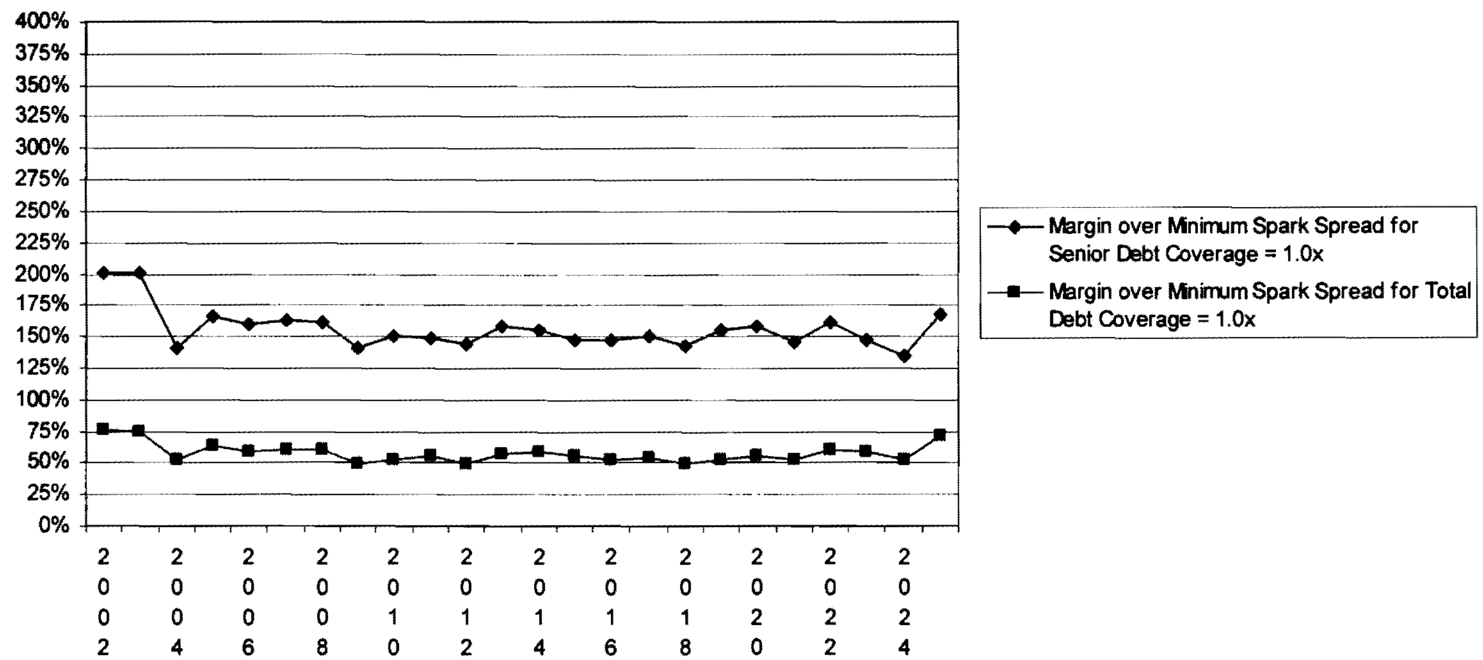
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025

Figure 15
Klamath Cogeneration Project
Margin of Forecast Spark Spread
Over Minimum Spread Necessary to Achieve Debt Coverage of 1.0x
Under Low Gas Price Assumptions



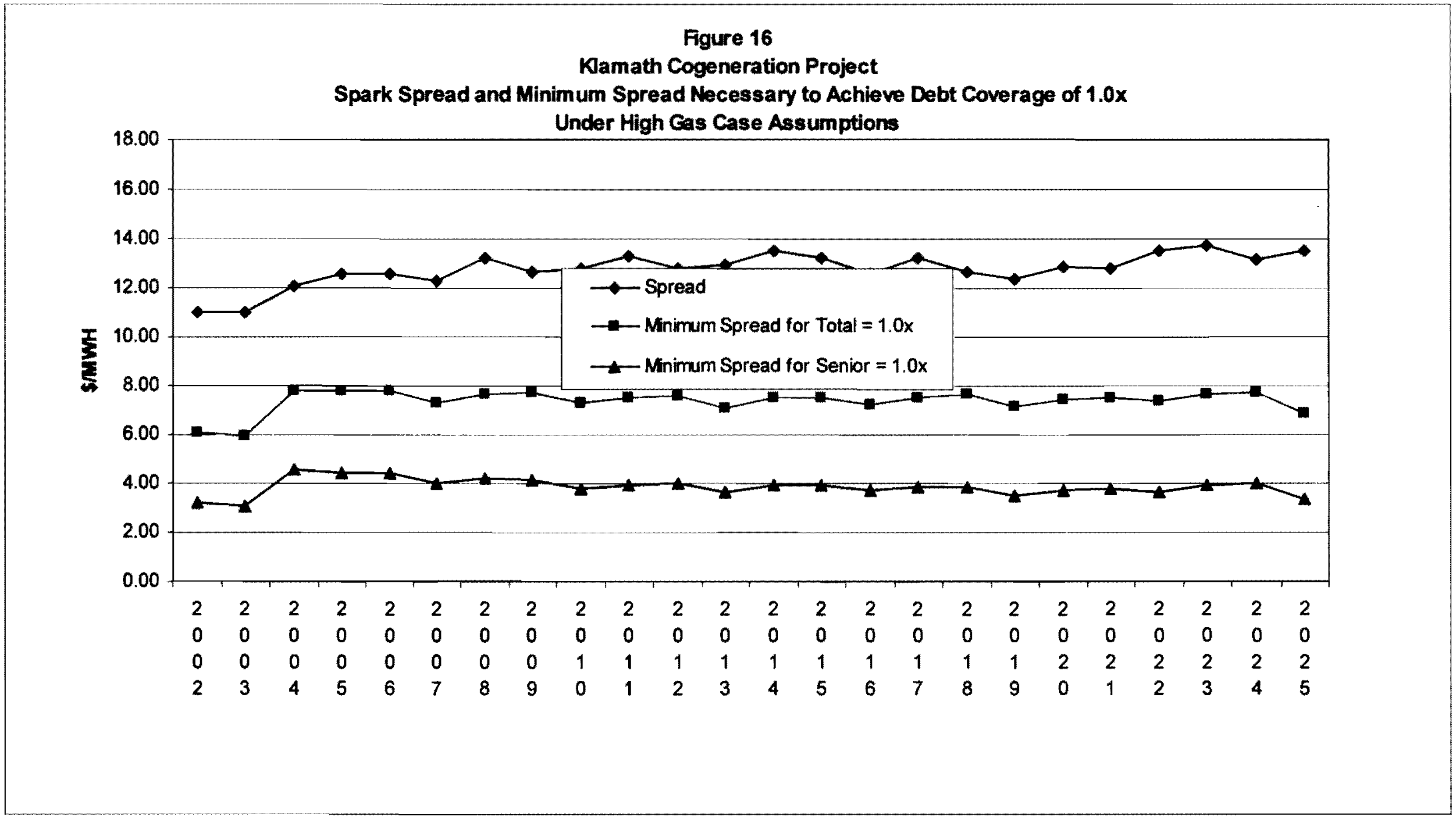
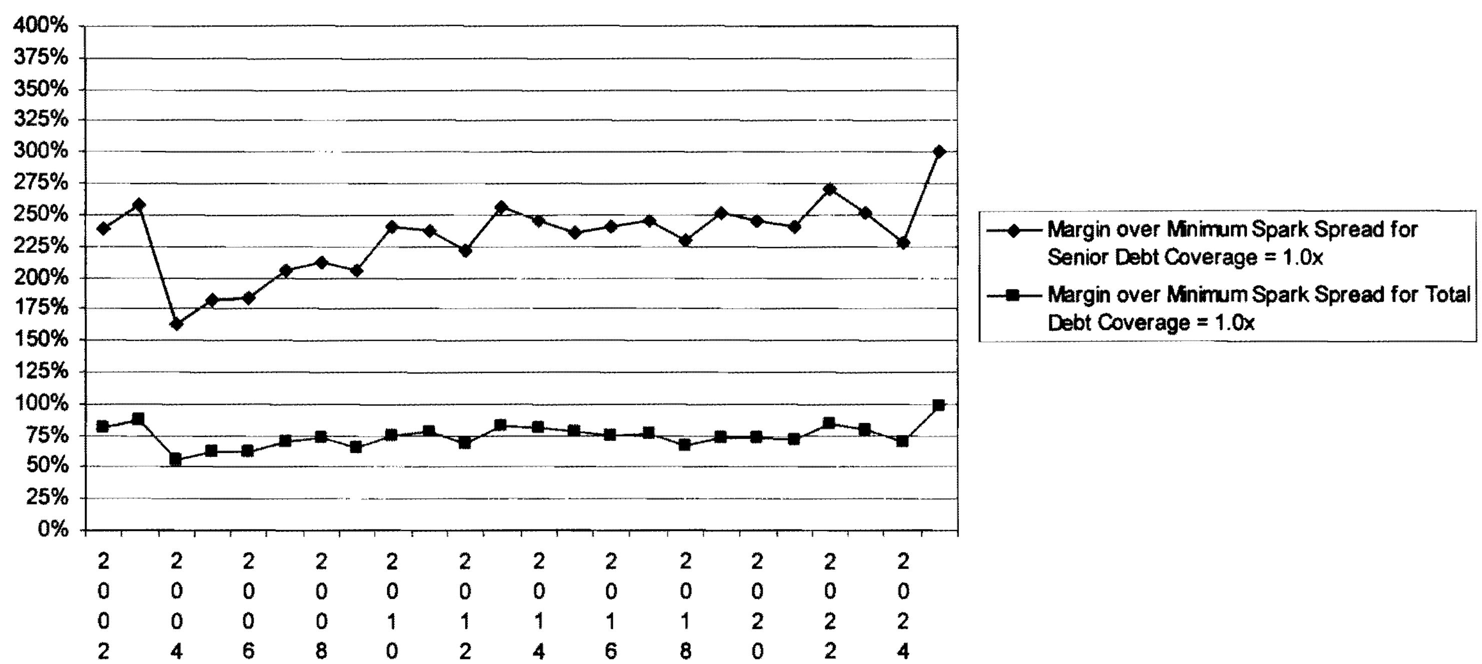


Figure 16
Klamath Cogeneration Project
Spark Spread and Minimum Spread Necessary to Achieve Debt Coverage of 1.0x
Under High Gas Case Assumptions
$/MWH
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Spread
Minimum Spread for Total = 1.0x
Minimum Spread for Senior = 1.0x
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025

Figure 17
Klamath Cogeneration Project
Margin of Forecast Spark Spread
Over Minimum Spread Necessary to Achieve Debt Coverage of 1.0x
Under High Gas Price Assumptions



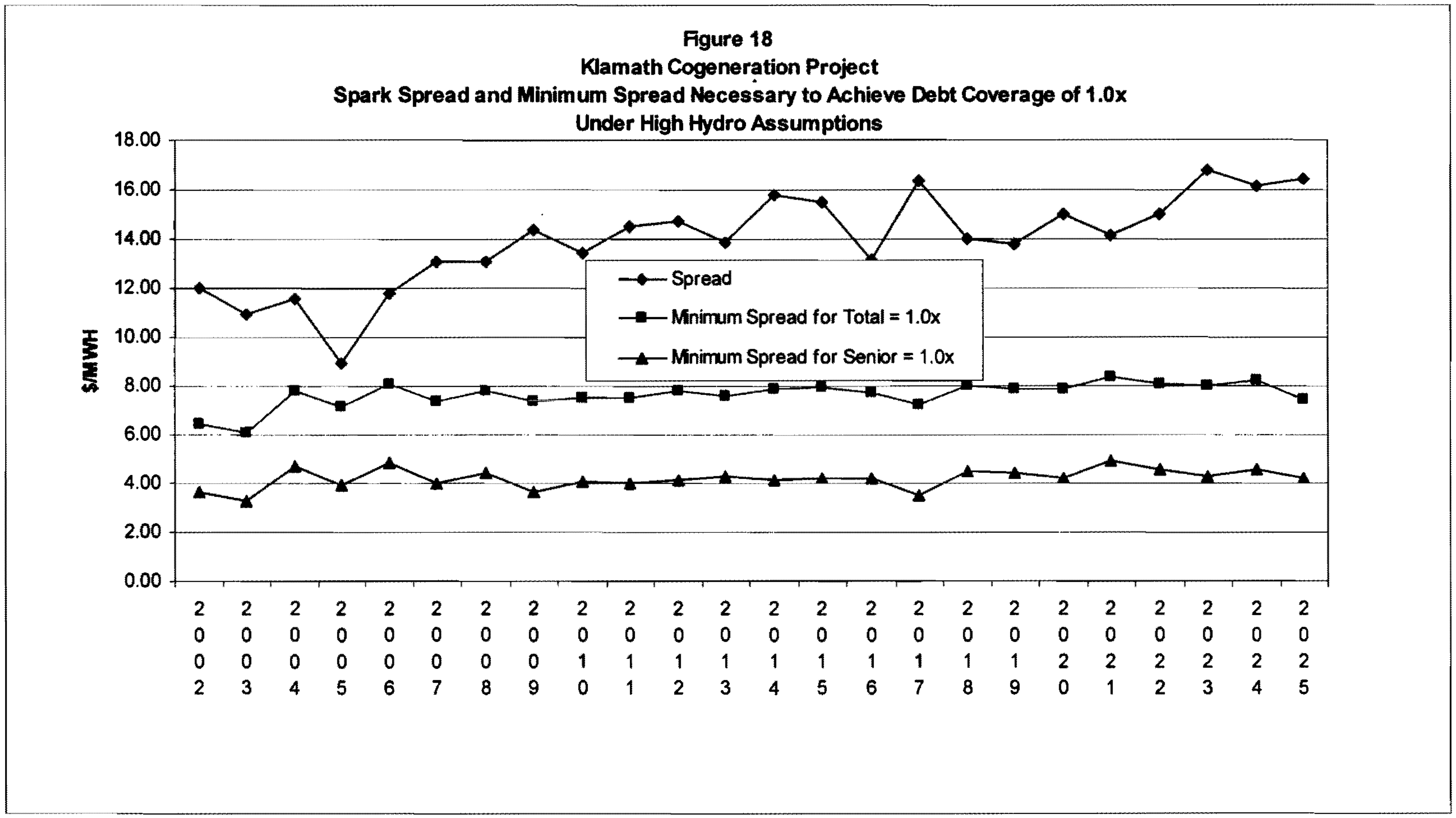


Figure 18
Klamath Cogeneration Project
Spark Spread and Minimum Spread Necessary to Achieve Debt Coverage of 1.0x
Under High Hydro Assumptions
$/MWH
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Spread
Minimum Spread for Total = 1.0x
Minimum Spread for Senior = 1.0x
2002
2003
2004
2005
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2022
2023
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2025

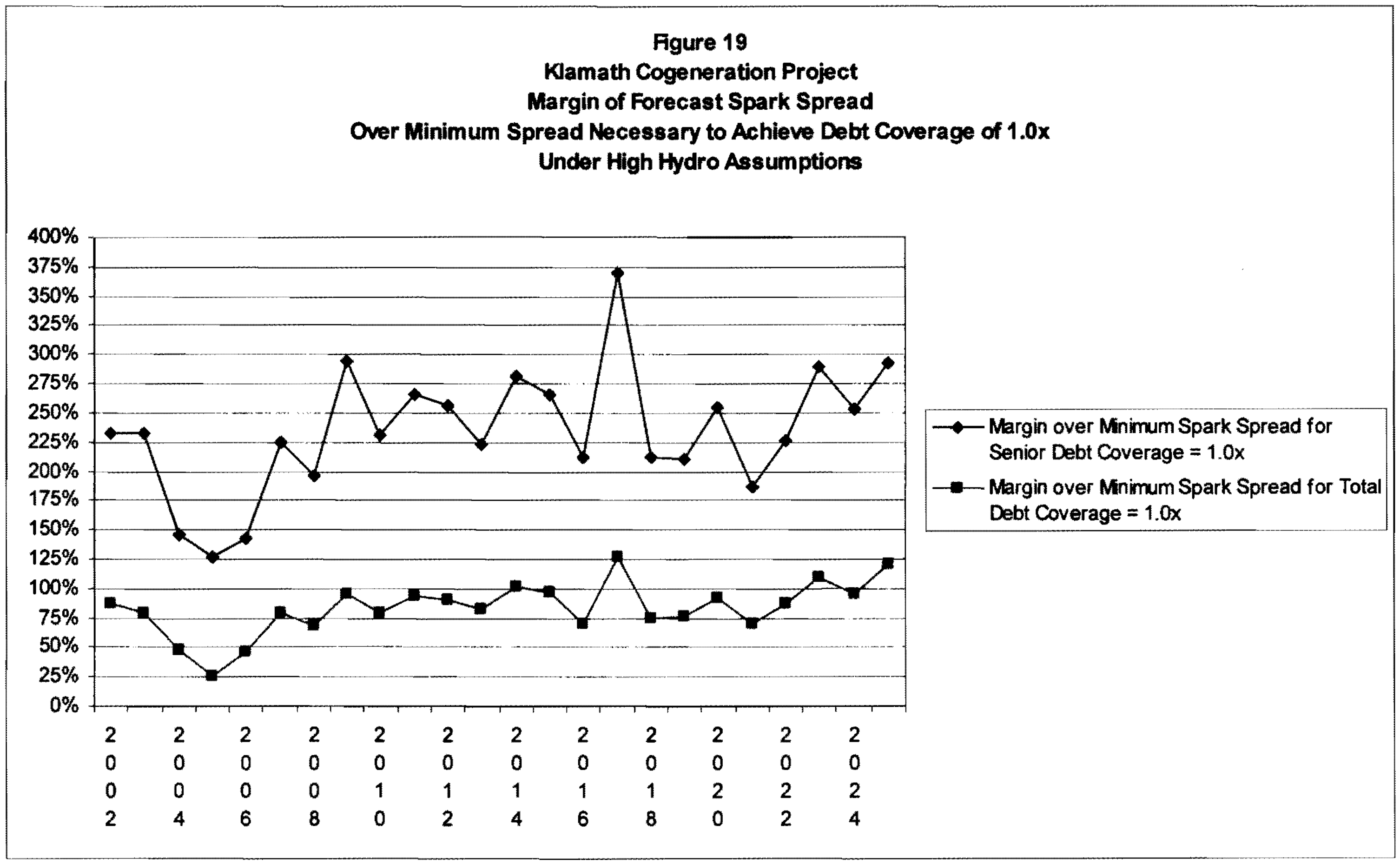


Figure 19
Klamath Cogeneration Project
Margin of Forecast Spark Spread
Over Minimum Spread Necessary to Achieve Debt Coverage of 1.0x
Under High Hydro Assumptions
400%
375%
350%
325%
300%
275%
250%
225%
200%
175%
150%
125%
100%
75%
50%
25%
0%
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
Margin over Minimum Spark Spread for Senior Debt Coverage = 1.0x
Margin over Minimum Spark Spread for Total Debt Coverage = 1.0x

Figure 20
Klamath Cogeneration Project
Spark Spread and Minimum Spread Necessary to Achieve Debt Coverage of 1.0x
Under Overbuild Assumptions

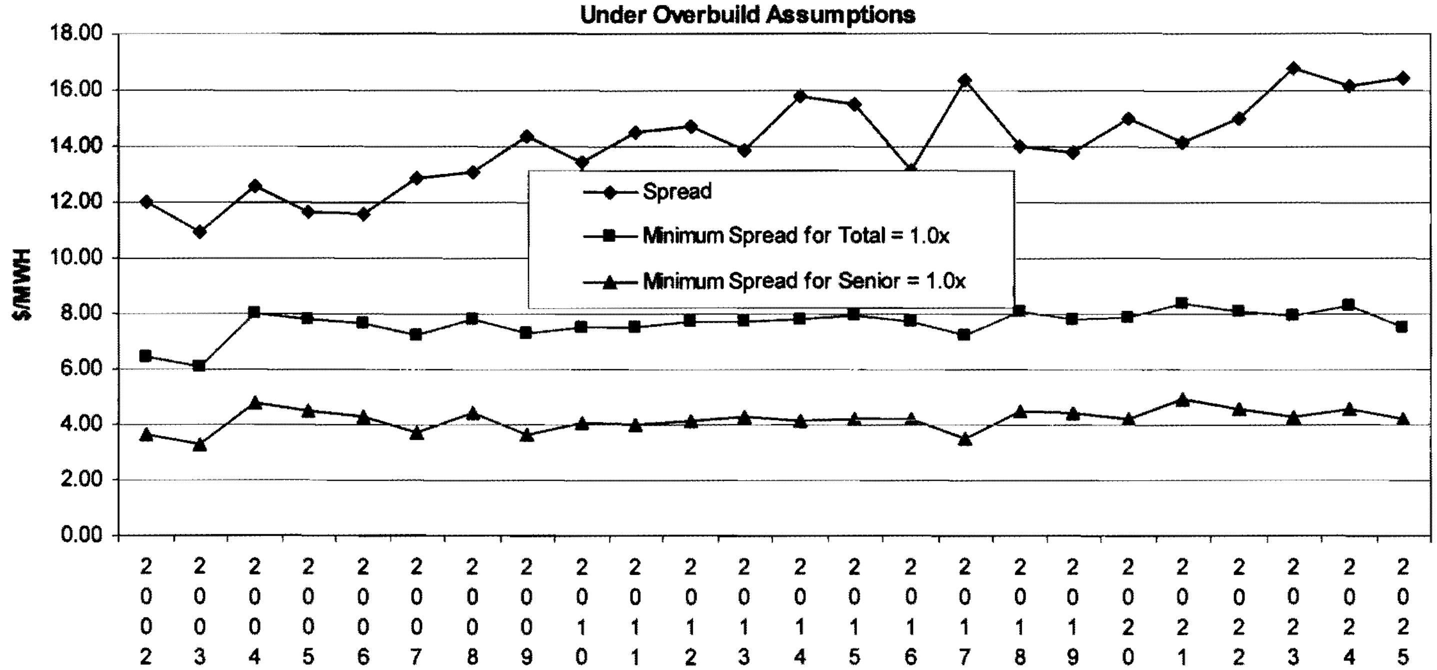
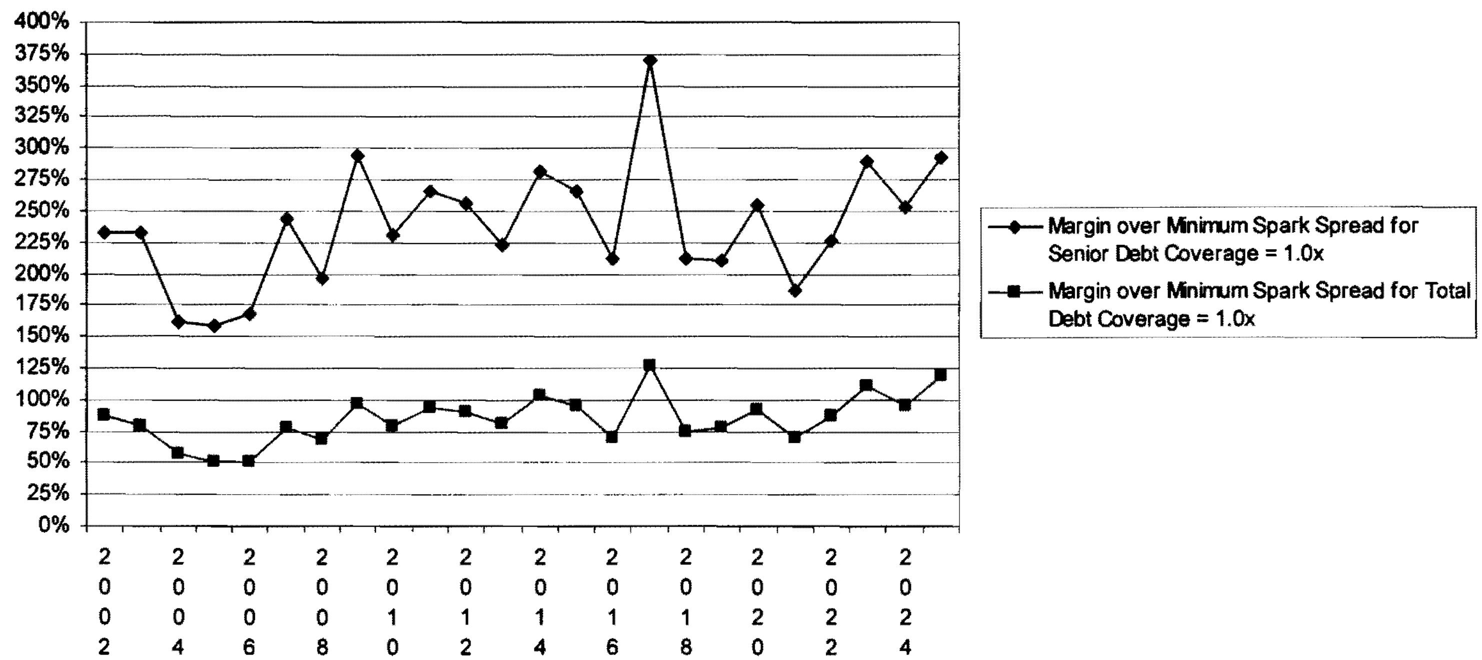
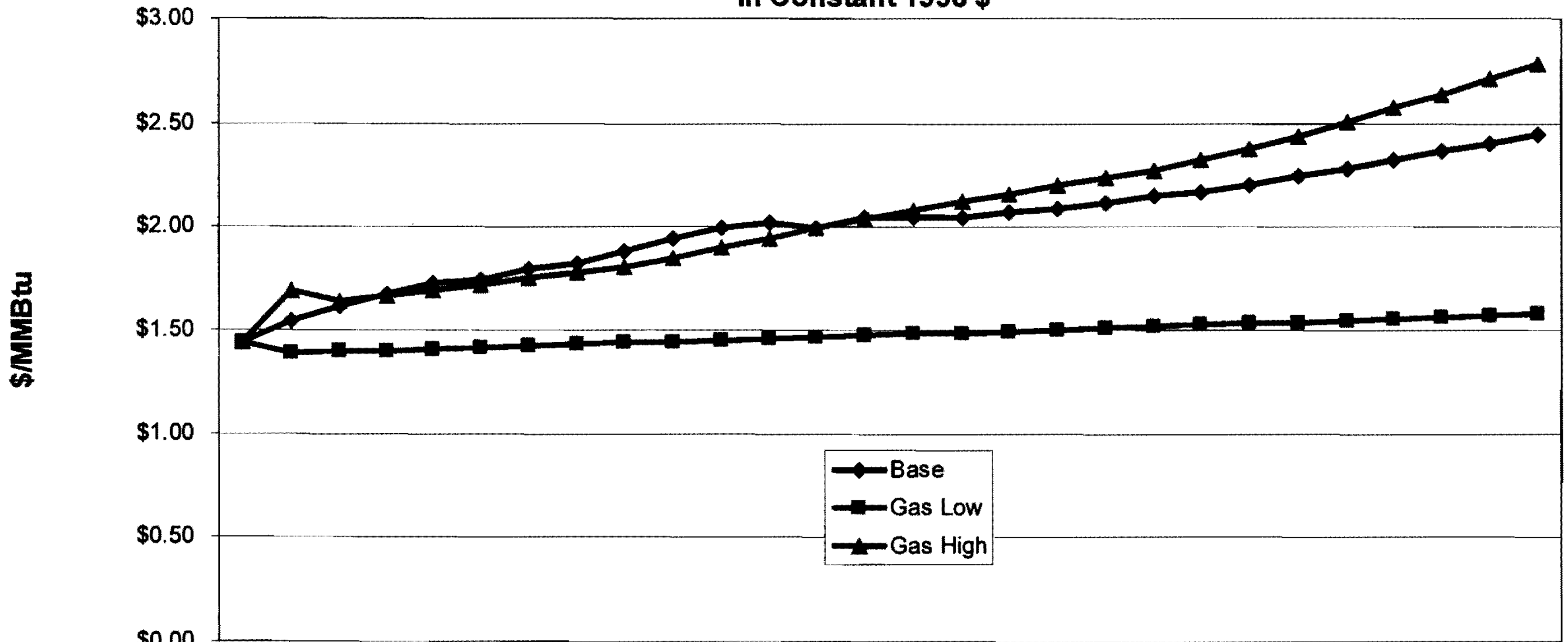


Figure 21
Klamath Cogeneration Project
Margin of Forecast Spark Spread
Over Minimum Spread Necessary to Achieve Debt Coverage of 1.0x
Under Overbuild Assumptions



[redacted]

Figure 22
Klamath Cogeneration Project
Gas Commodity Price Forecasts
In Constant 1998 $*



	1998	1999	2001	2002	2004	2005	2007	2008	2010	2011	2013	2014	2016	2017	2019	2020	2022	2023	2025
Base	1.439	1.54	1.671	1.725	1.793	1.824	1.94	1.992	1.995	2.042	2.047	2.075	2.112	2.15	2.203	2.242	2.322	2.363	2.448
Gas Low	1.439	1.386	1.4	1.407	1.421	1.428	1.442	1.45	1.464	1.471	1.486	1.494	1.509	1.516	1.531	1.539	1.554	1.562	1.578
Gas High	1.439	1.694	1.664	1.69	1.748	1.775	1.85	1.897	1.995	2.035	2.125	2.162	2.234	2.274	2.373	2.438	2.571	2.64	2.782

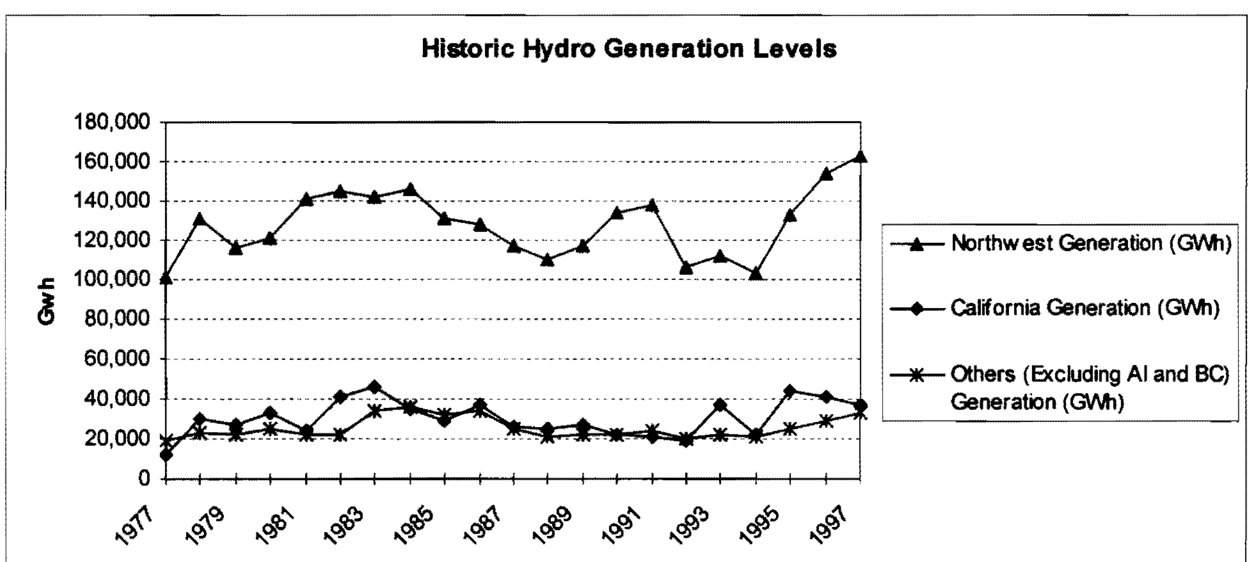
Table 1
Average Operating Costs by Plant Type in the WSCC

Plant Type	2005 GWh	2005 $/MWh	2005 Cap Fac	2010 GWh	2010 $/MWh	2010 Cap Fac	2015 GWh	2015 $/MWh	2015 Cap Fac
Internal Combustion	145	65.08	6.5	87	80.32	3.9	55	92.98	2.5
Gas Turbine	15,817	42.66	15.3	20,165	51.18	14.2	22,537	60.57	12.4
Steam Turbine (natural gas)	69,387	37.99	35.0	59,811	46.90	30.3	54,095	56.92	27.5
Combined Cycle (old)	31,677	28.30	65.0	29,792	34.38	60.3	27,910	41.11	56.6
Combined Cycle (new)	96,979	26.33	84.1	182,827	31.60	83.0	276,348	37.69	82.2
Klamath Cogeneration	**3,752**	**20.19**	**90.3**	**3,812**	**24.52**	**91.20**	**3,760**	**29.19**	**91.2**
Steam Turbine (coal)	267,889	14.02	82.3	268,383	15.48	82.4	268,588	17.09	82.5
Geothermal	18,383	38.67	92.4	17,764	47.22	92.5	15,415	60.40	93.3
Cogeneration/Other/QF	52,646	25.29	63.0	50,551	38.05	60.5	49,276	45.18	59.0
Nuclear	35,885	13.60	83.1	35,885	14.65	83.1	35,891	15.78	83.1
Wind Turbine	3,399	10.48	21.9	3,436	12.24	21.7	3,436	14.05	21.9
Hydroelectric [2]	250,026	6.81	47.5	250,070	7.82	47.5	250,110	8.98	47.5
Total	845,985		57.2	922,582			1,007,421		

[1] Cost based on fuel and variable O&M in nominal dollars
[2] Cost based on average aggregated operating expenses of hydroelectric facilities in the WSCC as reported to FERC on FERC Form 1
(2.8% annual inflation rate)

Table 2				
Ranking of Klamath Cogeneration Project				
Versus Other CCCT Plants in the WSCC Resource Stack in Year 2015				
Under Various Heat Rate Assumptions				
	Heat Rate of	Rank of		
	Generic New	Klamath		
	CCCT Plants	Project	Percentile*	
	7100	17	11%	
	7000	17	11%	
	6900	18	11%	
	6800	28	18%	
	6700	28	18%	
	6600	28	18%	
	6500	36	23%	
	* Percent of CCCT plants that have a heat rate			
	lower than the Klamath Project out of			
	a total of 160 CCCT plants assumed			
	to be operaing in year 2015 in the			
	HESI model			

Table 3									
Historic WSCC Hydroelectric Generation Data									
Year	California		Northwest		Others (Excluding Al and BC)				
	Generation (GWh)		Generation (GWh)		Generation (GWh)		Total		
1977	11,507		100,966		18,792		131,265	0%	percentile
1978	30,042		130,745		22,904		183,691	55%	percentile
1979	27,389		116,261		22,262		165,912	25%	percentile
1980	32,999		121,397		25,179		179,575	45%	percentile
1981	24,040		141,000		22,266		187,306	60%	percentile
1982	40,560		145,119		22,404		208,083	80%	percentile
1983	45,954		142,258		33,653		221,865	90%	percentile
1984	34,900		146,027		36,282		217,209	85%	percentile
1985	28,884		131,224		32,228		192,337	65%	percentile
1986	36,529		127,541		33,894		197,964	70%	percentile
1987	26,087		116,804		24,567		167,459	30%	percentile
1988	24,837		109,569		20,783		155,189	15%	percentile
1989	27,253		116,542		21,987		165,783	20%	percentile
1990	21,908		134,486		22,287		178,681	40%	percentile
1991	20,530		138,056		24,279		182,865	50%	percentile
1992	18,659		105,706		19,616		143,982	5%	percentile
1993	36,617		111,540		21,567		169,724	35%	percentile
1994	21,592		103,424		20,705		145,721	10%	percentile
1995	44,269		132,506		24,830		201,605	75%	percentile
1996	40,716		154,455		29,039		224,211	95%	percentile
1997	37,437		162,869		32,755		233,061	100%	Percentile
Min	11,507	1977	100,966	1977	18,792	1977	131,265	1977	
Max	45,954	1983	162,869	1997	36,282	1984	233,061	1997	
Median	28,884	1985	130,745	1978	22,904	1978	182,865	1991	



MEMORANDUM

TO: MAYOR AND CITY COUNCIL

FROM: CHRISTOPHER C. EPPLEY
CITY MANAGER

SUBJECT: CATERING CENTER

BACKGROUND

As the Civic Center was planned, the Civic Center Task Force made a conscious decision not to build a full kitchen for the community center for a number of reasons including but not limited to:

- Cost containment.
- Desire not to compete in the convention business so as to avoid harming local businesses that offer similar services.
- Attempt to function purely as a community center and not an event center.

As the community center has functioned for nearly 6-months now, a number of realities have made themselves known to us:

- Passively existing in the market and attempting to avoid attracting business away from existing local businesses does not prevent events from booking at the community center.
- As long as the space is available, a wide variety of events will be attracted to it.
- The lack of a catering center is a hindrance for large events from utilizing the space efficiently.

Based on comments provided by those booking the space staff provided a recommendation to the City Council to design a commercial kitchen as an addition to the Civic Center to serve the community center space with an estimated price of $700K plus $75K for design and engineering. A wide cross section of the business community did not support the concept of building a large and expensive commercial kitchen. Since then, staff has worked with a number of area caterers, our architect team and a commercial kitchen designer to develop the current proposal for a scaled back space that we are now referring to as a catering center. This space provides room for caterers to prep and dish up food service for large events but does not include the types cost intensive equipment that a full commercial kitchen would. It has been designed to provide those services identified as important for caterers but not for the start to finish preparation of meals on site. This new plan is estimated to cost approximately $370K and $65K for design and engineering. This new plan has received the positive endorsement of the Keizer Chamber of Commerce Economic Development and Governmental Affairs Committee, and the Keizer Renaissance Inn.

Staff would like direction from the City Council to bring this proposal as presented, with any modifications suggested this evening, to the City Council at the next earliest opportunity for deliberation and positive vote to proceed.

Eppley, Christopher

From: Brett Hanson [BHanson@grpmack.com]
Sent: Monday, October 12, 2009 2:54 PM
To: Eppley, Christopher; Watson, Kevin
Cc: Jeff Humphreys
Subject: Keizer Catering: Cost Estimates
Attachments: Keizer City Hall Kitchen Addition Conceptual.pdf; #48 Keizer City Hall Kitchen Addition WBS Cost.pdf

Afternoon Chris,
We've itemized the totals currently identified for the project for your use in presentation to City Council.
See attached for itemized construction budget.

Cost Estimate Summary:

Phase I/II:

Construction Cost (Building):	$262,750.30
Equipment Cost:	$70,550.55*
A/E Services:	$65,000.00**
Design Contingency (5%):	$19,915.04
Total:	$418,215.89

Phase III:

Construction Cost (Canopy):	$8,558.27***
A/E CA Services:	$13,308.00
Permit Fees:	$3,269.65****
Health Inspection Fee:	$474.00
Total:	$25,609.92

Total Project Cost: **$443,825.81 (plus canopy design fees)**
Total Project Cost (no canopy): **$435,267.54**

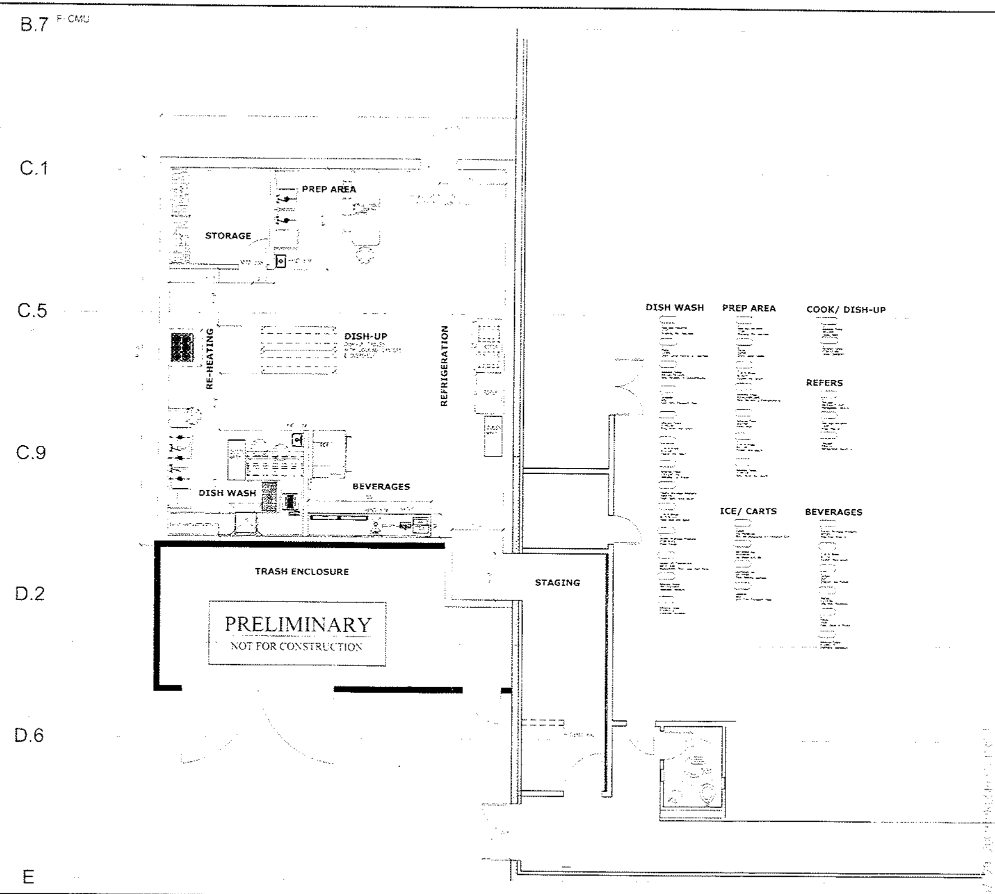
* *Note that items listed as 'Optional' in the equipment estimate are not included in total equipment cost.*
** *Decreased A/E fee reflects exclusion of Construction Administration & optional canopy design in Phase I/II.*
*** *Optional canopy. Design fee not included, which may range from 50-60% of construction cost due to complexity.*
**** *Fees for Marion County only, Keizer permit fees not included. Special Inspection not included.*

To aid in reducing costs, we would recommend not pursuing the canopy at this time.
Note that this estimate reflects an average construction cost and may be lower in a competitive bid.
As you review the estimate please contact Jeff or myself with any questions.

Thanks,
Brett

MACKENZIE

RiverEast Center | 1515 SE Water Avenue, Suite 100 | Portland, OR 97214
P.O. Box 14310 | Portland, OR 97293
T: 503.224.9560 | F: 503.228.1285 | www.groupmackenzie.com | vCard
PORTLAND, OREGON | SEATTLE, WASHINGTON | VANCOUVER, WASHINGTON



BARGREEN ELLINGSON

KEIZER CITY HALL
BANQUET KITCHEN
KEIZER, OR

DON VEATCH

FOOD SERVICE EQUIPMENT PLAN

K-1

TSCM
1515 SE Water Ave
Portland, OR 97214

WBS Price
#48 Keizer City Hall Kitchen Addition
10/06/09

Description	Quantity	Unit	Unit Price	Total Price
Addition				
Remove Wall, Masonry, Dispose	320.00	SF	3.38	1,081.30
Erosion Control	2,250.00	SF	0.05	116.85
Strip Top Soil	2,250.00	SF	0.32	730.35
Fine Grading	2,250.00	SF	0.19	438.21
Grading, Site	2,250.00	SF	0.65	1,460.68
Excavation and Backfill, Footing	18.00	CY	18.18	327.19
Load and Haul, 5 to 10 Miles	83.00	CY	15.58	1,293.19
Perimeter Drainage, 4" Perf Pipe, 2' wide drain rock band to subbase	120.00	LF	13.74	1,648.42
Baserock - 6" , Site: walks, aprons, pads, footings Building: SOG	39.00	CY	35.06	1,367.19
Slab on Grade, 3000 PSI 4"	1,520.00	SF	7.14	10,854.49
CMU, Decorative, Scored ground face, Grouted, Reinforcing	1,930.00	SF	24.67	47,611.74
CMU, Regular, 8x8x16, Grouted, Reinforcing	153.00	SF	19.48	2,979.79
L4x4x1/4	0.38	T	6,232.26	2,368.26
Bar Joist, 24LH05	1.66	T	6,362.08	10,561.05
Metal deck, 3" thick, 20 ga	1,520.00	SF	4.52	6,877.79
2"x8" at Parapet	120.00	LF	3.90	467.42
Sheathing, Wall, Plywood, 1/2" - Backing for Shelving	400.00	SF	1.75	700.08
Fiberglass Reinforced Panels (FRP) White - All walls 8' AFF	1,568.00	SF	2.65	4,153.16
Vapor barrier, Polyethylene - SOG	1,520.00	SF	1.88	2,851.77
Insulation, Batt, 3 1/2"	1,680.00	SF	1.17	1,968.61
Insulation, Roof, Deck, 5"	1,520.00	SF	4.22	6,414.03
Built-up roofing, 5 ply	1,520.00	SF	2.98	4,524.34
Built-up roofing, Cap sheet / White	1,520.00	SF	0.93	1,416.01
Sheet Metal Flashing and Trim - Parapet with sheet metal on backside to roofing	300.00	SF	13.63	4,089.91
Roof expansion joint	76.00	LF	164.39	12,493.52
Caulking and Sealant, SF of Building Area	1,520.00	SF	0.19	296.03
Hollow Metal Doors, 3070, Complete w/Frame and Hardware	1.00	EA	1,493.15	1,493.15
Hollow Metal Doors, 4070, Complete w/Frame and Hardware	2.00	EA	2,077.41	4,154.82
Studs, Metal, 16" oc, 3 5/8", 5/8 Gypboard, Tape and Finish - Exterior Walls	1,760.00	SF	4.47	7,860.94
Studs, Metal, 16" oc, 3 5/8", 5/8 Gypboard, Tape and Finsih - Interior Walls	220.00	SF	6.49	1,428.23
Gypboard Ceiling	1,520.00	SF	8.05	12,235.97
Base molding, Resilient tile, Coved, 6"	207.00	LF	2.82	584.59
Floor Coatings, Epoxy	1,520.00	SF	8.09	12,295.18
Paint exterior, Door and frame, 2 sides, 2 coats	2.00	EA	207.58	415.15
Paint interior, 2 coat	1,600.00	SF	1.10	1,765.80
Gas, Pipe, Black, Grooved, w/ Grooved fittings, hangers, & valves, 3/4"	100.00	LF	30.30	3,029.79
Floor Drain	3.00	EA	201.25	603.76
Wet Pipe Sprinkler System	1,520.00	SF	3.90	5,920.63
Floor Sinks Rough-in and Installation	3.00	EA	1,428.22	4,284.67
Fixture Rough-in and Fixture Installation	7.00	EA	2,466.93	17,268.51
Packaged Rooftop Units Cost per Ton w/Curb	5.00	T	1,558.06	7,790.30
Ductwork, SF Allowance ; SA/RA, Diff, Grills, Insulation, Louver,	1,520.00	SF	11.40	17,327.72
Automatic Temperature Control, Electric control, by Square feet	1,520.00	SF	1.17	1,771.24
Adjust and Balance, by SF	1,520.00	SF	0.65	986.76
Panels 225A 208 120V	1.00	EA	3,440.72	3,440.72
Conduit and Wire	150.00	LF	33.76	5,063.70

Description	Quantity Unit	Unit Price	Total Price
Motor connection, Fractional horsepower	3.00 EA	401.00	1,203.01
Motor, Mounting, 5 HP - Roof Top Unit (RTU)	1.00 EA	194.35	194.35
Disconnect, 30A 3P Fused Switch WP (Ice machine, Re-Heating)	2.00 EA	460.92	921.84
Feeders & Conduit , Mechanical Motors , Equipment	240.00 LF	20.12	4,829.99
Recessed Direct Fluorescent Central Basket, 2x4	16.00 EA	293.44	4,694.96
Exit Lighting, LED w Battery, Single Face	2.00 EA	175.28	350.56
Lighting, Power, Boxes, Conduit, Whips, Misc	1,520.00 SF	3.31	5,032.54
Exterior, Type Luminaire, Cast Aluminum, 42W	2.00 EA	246.70	493.39
Fire Alarm System - (1) Duct Detector, (1) Smoke, (2) Horn Strobe tie to existing system	1,520.00 SF	1.17	1,776.19
Tele / Data - 2 Locations	1,520.00 SF	0.65	986.76
General Purpose Power - Outlets, Refrigerators,	1,520.00 SF	2.27	3,453.70
			262,750.30
Canopy			
Fine Grading	272.00 SF	0.58	158.93
Grading, Site	272.00 SF	2.08	565.05
Excavation and Backfill, Footing, Column, w/ Granular - Canopy	1.00 CY	350.56	350.56
Baserock - 6" , Site: walks, aprons, pads, footings Canopy: SOG	7.00 CY	45.44	318.11
Slab on Grade, 3000 PSI 4" - Canopy	272.00 SF	9.09	2,472.12
HSS6x4x1/4	0.33 T	6,232.24	2,056.64
HSS4x4x1/4	0.15 T	6,232.27	934.84
Metal deck, 1 1/2" thick, 22 ga	272.00 SF	3.46	941.17
Paint exterior, Canopy	1.00 LS	760.85	760.85
			8,558.27
		Total Price	$271,308.57

TSCM
1515 SE Water Ave
Portland, OR 97214

WBS Unit Price Analysis

#48 Keizer City Hall Kitchen Addition
10/06/09

Description	Quantity	Unit	Unit Price	Total Price	Job %
Not Assigned	0.00		0.00		
Addition	0.00		0.00	262,750.30	96.8
Canopy	0.00		0.00	8,558.27	3.1

TSCM
1515 SE Water Ave
Portland, OR 97214

Division Unit Price Analysis

#48 Keizer City Hall Kitchen Addition
10/06/09

Description	Quantity	Unit	Unit Price	Total Price	Job %
2 Sitework	1,520.00	SF	6.48	9,856.03	3.6
3 Concrete	1,520.00	SF	8.76	13,326.61	4.9
4 Masonry	1,520.00	SF	33.28	50,591.53	18.6
5 Metals	1,520.00	SF	15.61	23,739.75	8.7
6 Wood and Plastics	1,520.00	SF	3.50	5,320.66	1.9
7 Thermal and Moisture	1,520.00	SF	22.40	34,054.22	12.5
8 Doors and Windows	1,520.00	SF	3.71	5,647.97	2.0
9 Finishes	1,520.00	SF	24.57	37,346.71	13.7
15 Mechanical	1,520.00	SF	38.80	58,983.38	21.7
16 Electrical	1,520.00	SF	21.34	32,441.71	11.9

TSCM
1515 SE Water Ave
Portland, OR 97214

Estimate Summary

10/06/09

Project:	#48 Keizer City Hall Kitchen Addition	Client:	Brent Hanson Group Mackenzie 1515 SW Moody Suite 100 Portland, OR	Bid Date:	10/01/09
Estimator:	Michael Shadley			Status:	Active
Type:	Commercial			Size:	1520

Description	Tax %	Burden %	Tax $	Burden $	Total
Material	0.00	0.00	0.00	0.00	$18,272.85
Labor	0.00	35.00	0.00	4,413.87	$17,024.94
Sub-Contracts	0.00	0.00	0.00	0.00	$0.00
Equipment	0.00	0.00	0.00	0.00	$0.00
Other	0.00	0.00	0.00	0.00	$173,660.88
Total Estimate Cost					$208,958.67

Markups	Percentage	Apply To	Compound	Markup $	Total
General Conditions	7.00	All		14,627.11	
Bond and Insurance	2.00	All	X	4,471.69	
Contractors FEE	5.00	All	X	11,402.89	
Contingency	10.00	All	X	23,946.02	
Escalation 2Q2010	3.00	All	X	7,902.19	
Total Markups					$62,349.90
Total Estimate Price					$271,308.57

Description	Quantity	Unit	Unit Cost	Total Cost
2 Sitework				
2003000 Demolition Walls				
Remove Wall, Masonry, Dispose	320.00	SF	2.60	832.80
				832.80
2006000 Site Preparation				
Erosion Control	2,250.00	SF	0.04	90.00
Strip Top Soil	2,250.00	SF	0.25	562.50
				652.50
2007000 Grading				
Fine Grading	2,522.00	SF	0.45	459.90
Grading, Site	2,522.00	SF	1.60	1,560.20
				2,020.10
2009000 Excavation/Backfill				
Excavation and Backfill, Footing	18.00	CY	14.00	252.00
Excavation and Backfill, Footing, Column, w/ Granular - Canopy	1.00	CY	270.00	270.00
Load and Haul, 5 to 10 Miles	83.00	CY	12.00	996.00
Perimeter Drainage, 4" Perf Pipe, 2' wide drain rock band to subbase	120.00	LF	10.58	1,269.60
				2,787.60
2013000 Concrete Paving				
Baserock - 6" , Site: walks, aprons, pads, footings Canopy: SOG	7.00	CY	35.00	245.00
Baserock - 6" , Site: walks, aprons, pads, footings Building: SOG	39.00	CY	27.00	1,053.00
				1,298.00
			2 Sitework	**7,591.00**
3 Concrete				
3010000 Concrete Slab on Grade				
Slab on Grade, 3000 PSI 4"	1,520.00	SF	5.50	8,360.00
Slab on Grade, 3000 PSI 4" - Canopy	272.00	SF	7.00	1,904.00
				10,264.00
			3 Concrete	**10,264.00**
4 Masonry				
4008000 Masonry Block				
CMU, Decorative, Scored ground face, Grouted, Reinforcing	1,930.00	SF	19.00	36,670.00
CMU, Regular, 8x8x16, Grouted, Reinforcing	153.00	SF	15.00	2,295.00
				38,965.00
			4 Masonry	**38,965.00**
5 Metals				
5009000 Structural Steel				
HSS4x4x1/4	0.15	T	4,800.00	720.00
HSS6x4x1/4	0.33	T	4,800.00	1,584.00
L4x4x1/4	0.38	T	4,800.00	1,824.00
Bar Joist, 24LH05	1.66	T	4,900.00	8,134.00
				12,262.00
5011000 Metal Decking				

Description	Quantity Unit	Unit Cost	Total Cost
Metal deck, 1 1/2" thick, 22 ga	272.00 SF	2.67	724.88
Metal deck, 3" thick, 20 ga	1,520.00 SF	3.49	5,297.20
			6,022.08
		5 Metals	**18,284.08**
6 Wood and Plastics			
6010000 Wood Other			
2"x8" at Parapet	120.00 LF	3.00	360.00
			360.00
6011000 Sheathing			
Sheathing, Wall, Plywood, 1/2" - Backing for Shelving	400.00 SF	1.35	539.20
			539.20
6022000 Panelwork			
Fiberglass Reinforced Panels (FRP) White - All walls 8' AFF	1,568.00 SF	2.04	3,198.72
			3,198.72
		6 Wood and Plastics	**4,097.92**
7 Thermal and Moisture			
7004000 Vapor Retarders			
Vapor barrier, Polyethylene - SOG	1,520.00 SF	1.45	2,196.40
			2,196.40
7005000 Insulation			
Insulation, Batt, 3 1/2"	1,680.00 SF	0.90	1,516.20
Insulation, Roof, Deck, 5"	1,520.00 SF	3.25	4,940.00
			6,456.20
7011000 Bituminous Roofing			
Built-up roofing, 5 ply	1,520.00 SF	2.29	3,484.60
Built-up roofing, Cap sheet / White	1,520.00 SF	0.72	1,090.60
			4,575.20
7014000 Flashing and Sheet Metal			
Sheet Metal Flashing and Trim - Parapet with sheet metal on backside to roofing	300.00 SF	10.50	3,150.00
			3,150.00
7016000 Roof Accessories			
Roof expansion joint	76.00 LF	126.61	9,622.36
			9,622.36
7018000 Sealants and Caulking			
Caulking and Sealant, SF of Building Area	1,520.00 SF	0.15	228.00
			228.00
		7 Thermal and Moisture	**26,228.16**
8 Doors and Windows			
8001000 Metal Doors			
Hollow Metal Doors, 3070, Complete w/Frame and Hardware	1.00 EA	1,150.00	1,150.00
Hollow Metal Doors, 4070, Complete w/Frame and Hardware	2.00 EA	1,600.00	3,200.00
			4,350.00
		8 Doors and Windows	**4,350.00**
9 Finishes			
9001000 Wall Framing Systems			

Description	Quantity Unit	Unit Cost	Total Cost
Studs, Metal, 16" oc, 3 5/8", 5/8 Gypboard, Tape and Finish - Exterior Walls	1,760.00 SF	3.44	6,054.40
Studs, Metal, 16" oc, 3 5/8", 5/8 Gypboard, Tape and Finsih - Interior Walls	220.00 SF	5.00	1,100.00
			7,154.40
9019000 Special Ceiling Surfaces			
Gypboard Ceiling	1,520.00 SF	6.20	9,424.00
			9,424.00
9025000 Resilient Tile Flooring			
Base molding, Resilient tile, Coved, 6"	207.00 LF	2.18	450.23
			450.23
9029000 Special Coatings			
Floor Coatings, Epoxy	1,520.00 SF	6.23	9,469.60
			9,469.60
9030000 Exterior Painting			
Paint exterior, Door and frame, 2 sides, 2 coats	2.00 EA	159.88	319.75
Paint exterior, Canopy	1.00 LS	586.00	586.00
			905.75
9031000 Interior Painting			
Paint interior, 2 coat	1,600.00 SF	0.85	1,360.00
			1,360 00
		9 Finishes	**28,763.98**
15 Mechanical			
15001000 Pipe, Black			
Gas, Pipe, Black, Grooved, w/ Grooved fittings, hangers, & valves, 3/4"	100.00 LF	23.34	2,333.50
			2,333.50
15007000 Pipe, Soil			
Floor Drain	3.00 EA	155.00	465.00
			465.00
15019000 Wet Pipe Sprinkler Systems			
Wet Pipe Sprinkler System	1,520.00 SF	3.00	4,560.00
			4,560.00
15024000 Plumbing Fixtures			
Floor Sinks Rough-in and Installation	3.00 EA	1,100.00	3,300.00
Fixture Rough-in and Fixture Installation	7.00 EA	1,900.00	13,300.00
			16,600.00
15045000 Packaged Air-Conditioning Units			
Packaged Rooftop Units Cost per Ton w/Curb	5.00 T	1,200.00	6,000.00
			6,000.00
15054000 Ductwork			
Ductwork, SF Allowance ; SA/RA, Diff, Grills, Insulation, Louver,	1,520.00 SF	8.78	13,345.60
			13,345.60
15060000 Control Systems			
Automatic Temperature Control, Electric control, by Square feet	1,520.00 SF	0.90	1,364.20
			1,364.20
15061000 Mechanical Equipment Testing			
Adjust and Balance, by SF	1,520.00 SF	0.50	760.00
			760.00
		15 Mechanical	**45,428.30**

Description	Quantity Unit	Unit Cost	Total Cost
16 Electrical			
16000100 Service and Distribution			
Panels 225A 208 120V	1.00 EA	2,650.00	2,650.00
Conduit and Wire	150.00 LF	26.00	3,900.00
			6,550.00
16006000 Motors and Generators			
Motor connection, Fractional horsepower	3.00 EA	308.85	926.54
Motor, Mounting, 5 HP - Roof Top Unit (RTU)	1.00 EA	149.69	149.69
Disconnect, 30A 3P Fused Switch WP (Ice machine, Re-Heating)	2.00 EA	355.00	710.00
Feeders & Conduit , Mechanical Motors , Equipment	240.00 LF	15.50	3,720.00
			5,506.23
16010000 Interior Lights			
Recessed Direct Fluorescent Central Basket, 2x4	16.00 EA	226.00	3,616.00
Exit Lighting, LED w Battery, Single Face	2.00 EA	135.00	270.00
Lighting, Power, Boxes, Conduit, Whips, Misc	1,520.00 SF	2.55	3,876.00
			7,762.00
16011000 Exterior Lights			
Exterior, Type Luminaire, Cast Aluminum, 42W	2.00 EA	190.00	380.00
			380.00
16025000 Systems			
Fire Alarm System - (1) Duct Detector, (1) Smoke, (2) Horn Strobe tie to existing system	1,520.00 SF	0.90	1,368.00
Tele / Data - 2 Locations	1,520.00 SF	0.50	760.00
General Purpose Power - Outlets, Refrigerators,	1,520.00 SF	1.75	2,660.00
			4,788.00
		16 Electrical	**24,986.23**
		Total Cost	$208,958.67
		Markup	$62,349.90
		Total Price	$271,308.57

BARGREEN ELLINGSON
FOODSERVICE SUPPLY & DESIGN

8/11/2009

Quote

KEIZER

To: Keizer City Hall
Keizer, Oregon

From: Bargreen-Ellingson- Portland
Don Veatch
3232 NW Industrial
Portland, OR 97210-1617
Phone: (503) 345-0723
Fax: (503) 345-0738

Thank you for the opportunity to provide this BUDGET proposal.

Item	Qty		Description	Sell Each	Sell Total
1			Spare No.		Spare
2			Spare No.		Spare
3			Spare No.		Spare
4			Spare No.		Spare
5	1	ea	**REFRIGERATOR, ROLL-IN**	9,712.98	9,712.98
			Traulsen Model No. RRI232HUT-FHS		
			Spec-Line Refrigerator, Roll-in, Two-Section, self-contained refrigeration, s/s exterior and interior, standard depth cabinet, full-height doors, accepts 72" high racks, with INTELA-TRAUL™		
	1	ea	115v/60/1ph, w/cord & plug attached, standard		
	1	ea	1 yr service/labor & 5 yr compressor warranty (std.)		
	1	ea	Left door hinged left/right hinged right, standard		
			Extended Total for Item No. 5: $9,712.98		
6	1	ea	**REFRIGERATOR, REACH-IN**	2,725.00	2,725.00
			Traulsen Model No. G20010		
			Dealer's Choice Refrigerator, Reach-in, Two-Section, self-contained refrigeration w/Microprocessor control, s/s front & full height doors (hinged left/right), anodized aluminum sides & interior, (3) epoxy coated shelves per section (factory installed), 6" high casters, UL & NSF listed, EnergyStar® rated		
	1	ea	115v/60/1ph, 8.5 amps, NEMA 5-15P, standard		
	1	ea	1 yr service/labor & 5 yr compressor warranty (std.)		
			Extended Total for Item No. 6: $2,725.00		
7	2	ea	**ROLL-IN REFRIGERATOR RACK**	527.36	1,054.72
			New Age Model No. 1335 Packed: each		
			Roll-In Refrigerator/Proofer Rack, universal, open frame design, 64"H, w/slides for (18) 18"x26" pans, slides on approximately 3" centers, all welded aluminum construction, end loading, (4) 5" platform casters, (2) swivel, (2) swivel with brakes, NSF		
	2	ea	Lifetime warranty against rust & corrosion, 5 year construction warranty, std.		
			Extended Total for Item No. 7: $1,054.72		
8	4	ea	**SHELVING, WIRE**	30.90	123.60
			Focus Foodservice Model No. FF2460C Packed: 2 pieces		
			Shelf, 24"W x 60"L, chromate wire		

Item	Qty		Description	Sell Each	Sell Total
	8	ea	FG086C Post, 86"H, stationary, chromate	9.15	73.20
	2	ea	FFSF2460CH Frame, 3 sided, 24" x 60", tubular, chromate	26.10	52.20
			Extended Total for Item No. 8: $249.00		
9			Spare No.		Spare
10			Spare No.		Spare
11			Spare No.		Spare
12			Spare No.		Spare
13	4	ea	TRASH CONTAINER Rubbermaid Model No. 263200 GRAY Packed: 6 pieces Round BRUTE® Container, without lid, 32 gallon, 22"D x 27-1/4"H, reinforced rims, built in handles, double rimmed base, high-impact plastic construction, gray	27.24	108.96
	4	ea	264000 BLA BRUTE® Dolly, 18-1/4"D x 6-5/8"H, heavy duty 3" casters, 250 lb. capacity, black	43.08	172.32
			Extended Total for Item No. 13: $281.28		
14	1	ea	SINK, TWO (2) COMPARTMENT Advance Tabco Model No. 93-42-48-24RL Regaline Sink, two compartment, w/left & right-hand drainboards, 24" front-to-back x 24" wide sink compartment, 12" deep, with 8" high splash, s/s open frame base, side crossrails, 16/304 stainless steel, 24" drainboards, overall 31" F/B x 101" L/R	2,292.23	2,292.23
			Extended Total for Item No. 14: $2,292.23		
15	2	ea	FAUCET T & S Brass Model No. B-0231 Sink Mixing Faucet, with 12" swing nozzle, wall mounted, 8" centers on sink faucet with 1/2" IPS eccentric flanged female inlets, lever handles	96.03	192.06
			Extended Total for Item No. 15: $192.06		
16	2	ea	LEVER WASTE Fisher Model No. 22209 Packed: each DrainKing Waste Valve, with flat strainer, 12 GPM drain rate, cast red brass body	74.38	148.76
			Extended Total for Item No. 16: $148.76		
17	2	ea	SHELF, WALL-MOUNTED New Age Model No. 1126 Packed: each Shelf, wall-mounted, solid w/marine edge design with turned down edges, aluminum construction, 12"W x 48"L, mounted on heavy duty shelf brackets, 18 ga., NSF	47.20	94.40
	2	ea	Lifetime warranty against rust & corrosion, 5 year construction warranty, std.		
			Extended Total for Item No. 17: $94.40		
18	1	ea	WORK TABLE, 96" LONG Advance Tabco Model No. MS-368 Work Table, 36" wide top, without splash, 96" long, with adjustable undershelf, s/s frame & shelf, 16 gauge, type 304 stainless steel top, s/s bullet feet	1,060.75	1,060.75
	1	st	TA-25A Casters, 5", swivel, with rubber wheels (set of 6; 2 with brakes)	234.68	234.68
	1	ea	TA-25B Brakes, on all casters	69.37	69.37
	2	ea	SS-2020 Deluxe Drawer, 20" x 20" x 5", stainless steel, with drawer slides	211.07	422.14
			Extended Total for Item No. 18: $1,786.94		
19			Spare No.		Spare

Keizer City Hall

Item	Qty		Description	Sell Each	Sell Total
20	1	ea	**SINK, HAND**	286.34	286.34
			Advance Tabco Model No. 7-PS-50		
			Hand Sink, wall model, 14" wide x 10" front-to-back x 5" deep bowl, 20 gauge stainless steel construction, with splash mounted faucet, lever drain w/overflow, P-trap, wall bracket		
			Extended Total for Item No. 20: $286.34		
21	1	ea	**FAUCET**	82.35	82.35
			T & S Brass Model No. B-1146		
			Faucet, gooseneck nozzle, splash mounted		
			Extended Total for Item No. 21: $82.35		
22			Spare No.		Spare
23			Spare No.		Spare
24			Spare No.		Spare
25	1	ea	**SINK, THREE (3) COMPARTMENT**	2,885.09	2,885.09
			Advance Tabco Model No. 93-43-72-24RL		
			Regaline Sink, three compartment, w/left & right-hand drainboards, 24" front-to-back x 24" wide sink compartment, 12" deep, with 8" high splash, s/s open frame base, side crossrails, 16/304 stainless steel, 24" drainboards, overall 31" F/B x 127" L/R		
			Extended Total for Item No. 25: $2,885.09		
26	2	ea	**FAUCET**	96.03	192.06
			T & S Brass Model No. B-0231		
			Sink Mixing Faucet, with 12" swing nozzle, wall mounted, 8" centers on sink faucet with 1/2" IPS eccentric flanged female inlets, lever handles		
			Extended Total for Item No. 26: $192.06		
27	3	ea	**LEVER WASTE**	119.53	358.59
			Fisher Model No. 22306 Packed: each		
			DrainKing Waste Valve, flat strainer, overflow body, 19 x 21 tube & elbow, 12 GPM drain rate, cast red brass body		
			Extended Total for Item No. 27: $358.59		
28	2	ea	**SHELF, WALL-MOUNTED**	55.40	110.80
			New Age Model No. 1127 Packed: each		
			Shelf, wall-mounted, solid w/marine edge design with turned down edges, aluminum construction, 12"W x 60"L, mounted on heavy duty shelf brackets, 18 ga., NSF		
	2	ea	Lifetime warranty against rust & corrosion, 5 year construction warranty, std.		
			Extended Total for Item No. 28: $110.80		
29			Spare No.		Spare
30	1	ea	**DISHTABLE SORTING SHELF**	506.76	<optional>
			Advance Tabco Model No. DT-6R-13		
			Sorting Shelf, traditional design, 62" long, holds three racks		
			Extended Total for Item No. 30: $506.76		
31	1	ea	**DISHTABLE, CLEAN**	1,034.18	<optional>
			Advance Tabco Model No. DTC-S30-84R		
			Straight-Clean Dishtable, left-to-right, 10-1/2" backsplash, 3" rolled front & side rims, stainless steel legs, with stainless steel crossrails, 83" long, 14/304 stainless steel		
	1	ea	SPECIFY DISH MACHINE BRAND AND MODEL to ensure proper fit, refer to attached document (AQNet only) or consult		<optional>

Item	Qty		Description	Sell Each	Sell Total
			www.advancetabco.com for compatibility listing. Certain dish machines require modifications at additional cost not shown here		
			Extended Total for Item No. 31: **$1,034.18**		
32	1	ea	**DISHWASHER, DOOR TYPE**	11,717.33	<optional>
			Hobart Model No. AM15T-2		
			Dishwasher, Door Type, Tall Chamber, hot water/chemical sanitizing, 58-65 racks/hour, straight-thru or corner, solid-state controls w/digital status, with booster heater, electric tank heat, auto-fill, s/s tank, frame, doors & feet, 208-240/60/3, sheet pan rack		
	1	ea	1-Year parts, labor & travel time during normal working hours		<optional>
33	1	ea	**HOOD**	951.60	<optional>
			Custom Model No. KEIZER33		
			Vapor Hood over dishwasher, 42" x 42" x 18" tall, fluted, 10" dia s/s duct collar shipped loose, 613 cfm		
	1	ea	KEIZER33A Custom Stainless: Hood to ceiling closure panel	315.60	<optional>
34			Exhaust Fan: By Others		<optional>
35			Exhaust Duct: By HVAC		<optional>
36	1	ea	**FLASHING**	1,076.40	<optional>
			Custom Model No. KEIZER36		
			Custom Stainless: Wall Flashing in dishroom		
37	1	ea	**HOSE REEL ASSEMBLY**	743.37	<optional>
			T & S Brass Model No. B-7132-01		
			Hose Reel, open, stainless steel, 35' hose, 3/8" ID with spray valve		
38	1	ea	**DISHTABLE, SOILED**	4,366.01	<optional>
			Advance Tabco Model No. DTS-U30-72L		
			Dishtable, soiled, u-shaped, left-to-right, 59" x 108" x 71" w/landing, 10-1/2" backsplash, with pre-rinse sink, 16 ga. 304 stainless steel legs w/crossrails front-to-back, 14/304 stainless steel, s/s bullet feet		
	1	ea	SPECIFY DISH MACHINE BRAND AND MODEL to ensure proper fit, refer to attached document (AQNet only) or consult www.advancetabco.com for compatibility listing. Certain dish machines require modifications at additional cost not shown here		<optional>
			Extended Total for Item No. 38: **$4,366.01**		
39	1	ea	**SORTING SHELF**	948.00	<optional>
			Custom Model No. KEIZER39		
			Custom Stainless: Double sided slant rack, 72"long, mounted to soiled dishtable		
40	2	ea	**UTILITY CART**	1,354.86	2,709.72
			Lakeside Manufacturing Model No. 462 Packed: each		
			Open Tray Truck, 6 shelf, shelf size 21" x 50", all edges down, 7-3/8" clearance, stainless steel w/push handle, 500 lb. capacity		
	2	ea	Casters, 5" all cushion tread,std,		
			Extended Total for Item No. 40: **$2,709.72**		
41	1	ea	**FLOOR TROUGH**	1,232.28	<optional>
			Pacific Stainless Products Model No. FT3618-FG		
			Floor Trough, 14/304 s/s 36"L x 18"W x 4"D, fiberglass grating and 3" no-hub drain		
42	1	ea	**SINK, HAND**	286.34	286.34
			Advance Tabco Model No. 7-PS-50		
			Hand Sink, wall model, 14" wide x 10" front-to-back x 5" deep bowl, 20 gauge stainless steel construction, with splash mounted faucet, lever drain		

Keizer City Hall

Item	Qty		Description		Sell Each	Sell Total
			w/overflow, P-trap, wall bracket			
			Extended Total for Item No. 42:	$286.34		
43	1	ea	**FAUCET**		82.35	82.35
			T & S Brass Model No. B-1146			
			Faucet, gooseneck nozzle, splash mounted			
			Extended Total for Item No. 43:	$82.35		
44			Spare No.			Spare
45			Spare No.			Spare
46			Spare No.			Spare
47	1	ea	**ICE BIN**		7,706.80	7,706.80
			Follett Corporation Model No. ITS1350SG-60 Packed: each			
			ITS Ice Storage & Transport System, elevated bin, 1350 lb. bin storage, for cube or flake ice, incl: (2) polyethylene carts w/lid & casters, cart cap. 240 lb., ice paddle, poly liner, SmartGATE™, poly lift door w/PowerHinge, s/s exterior, custom cut top			
	1	ea	206950 Set of (6) Totes, for ITS models		433.49	433.49
			Extended Total for Item No. 47:	$8,140.29		
48	1	ea	**ICE MAKER, CUBE-STYLE**		2,870.75	2,870.75
			Manitowoc Model No. SY-0604A Packed: each			
			S-Series Ice Maker, cube-style, air-cooled, self-contained condenser, up to 650-lb approximately/24 hours, stainless steel finish, half-dice size cubes, ENERGY STAR® Qualified			
	1	ea	3 year parts & labor warranty			
	1	ea	5 year parts & labor warranty on evaporator			
	1	ea	5- year parts & 3- year labor warranty on compressor			
	1	ea	208-230v/60/1ph, std.			
			Extended Total for Item No. 48:	$2,870.75		
49	1	ea	**WATER FILTER ASSEMBLY**		507.87	507.87
			Manitowoc Model No. AR-40000 Packed: each			
			Arctic Pure® Primary Water Filter Assembly, includes head, shroud, hardware, mounting assembly, and two filter cartridges, 40,000 gallon capacity, 1,001-2,500 lbs./ice per day			
			Extended Total for Item No. 49:	$507.87		
50			Spare No.			Spare
51			Spare No.			Spare
52			Spare No.			Spare
53			Spare No.			Spare
54			Hood and Fire System: By Owner			Spare
55			Exhaust Fan: By Others			Spare
56			Exhaust Duct: By HVAC			Spare
57			Makeup Air Unit: By Others			Spare
58			Makeup Air Heater: By Others			Spare
59			Makeup Air Duct: By Others			Spare
60	1	ea	**FLASHING**		690.00	690.00
			Custom Model No. KEIZER60			
			Custom Stainless: Wall Flashing - 22 ga fluted, 90"L x 80"H			
			Extended Total for Item No. 60:	$690.00		
61			Range: By Owner			Spare
62			Spare No.			Spare

Item	Qty		Description	Sell Each	Sell Total
63			Spare No.		Spare
64	1	ea	**SINK, HAND**	286.34	286.34
			Advance Tabco Model No. 7-PS-50		
			Hand Sink, wall model, 14" wide x 10" front-to-back x 5" deep bowl, 20 gauge stainless steel construction, with splash mounted faucet, lever drain w/overflow, P-trap, wall bracket		
			Extended Total for Item No. 64: $286.34		
65	1	ea	**FAUCET**	82.35	82.35
			T & S Brass Model No. B-1146		
			Faucet, gooseneck nozzle, splash mounted		
			Extended Total for Item No. 65: $82.35		
66			Spare No.		Spare
67			Spare No.		Spare
68	2	ea	**WORK TABLE, 96" LONG**	895.44	1,790.88
			Advance Tabco Model No. MS-308		
			Work Table, 30" wide top, without splash, 96" long, with adjustable undershelf, s/s frame & shelf, 16 gauge, type 304 stainless steel top, s/s bullet feet		
	2	st	TA-25A Casters, 5", swivel, with rubber wheels (set of 6; 2 with brakes)	234.68	469.36
	2	ea	TA-25B Brakes, on all casters	69.37	138.74
	2	ea	OTS-12-96 Shelf, table mounted, single deck, 12" wide, 8 feet long, 18 gauge 430 stainless steel, not adjustable, old style	416.23	832.46
	2	ea	Center of table shelf location		
			Extended Total for Item No. 68: $3,231.44		
69			Spare No.		Spare
70			Spare No.		Spare
71			Spare No.		Spare
72			Spare No.		Spare
73			Spare No.		Spare
74			Spare No.		Spare
75			Spare No.		Spare
76			Spare No.		Spare
77	1	ea	**BEVERAGE COUNTER**	7,404.00	7,404.00
			Custom Model No. KEIZER77		
			Custom Stainless: Beverage Counter with marine edge 30" x 168" x 36"H with 6" x 1" backsplash, built in dril rail w/drain, coutnertop cutouts, 18g s/s cabinet body with 6" legs, doors and shelves where possible, weld in hand sink 14" x 10" x 7", rack slides		
			Extended Total for Item No. 77: $7,404.00		
78	1	ea	**ICE BIN, DROP-IN**	753.68	753.68
			Delfield Model No. 203		
			Ice Chest, drop-in design, 90 lb. ice capacity		
	1	ea	1 Yr. Service & labor warranty (net)	295.20	295.20
			Extended Total for Item No. 78: $1,048.88		
79	1	ea	**DRIP TRAY TROUGH, BEVERAGE**	94.28	94.28
			Perlick Corporation Model No. C21379A		
			Recessed Drainer, for beer dispensing units, 14-1/16" x 7-5/8", stainless steel		
			Extended Total for Item No. 79: $94.28		
80	1	ea	**GLASS FILLER FAUCET**	132.35	132.35

Item	Qty		Description	Sell Each	Sell Total
			Fisher Model No. 1009 Packed: each		
			Glass/Pitcher Filler, 8" pedestal type, double service, push-back, 6" swing spout, with add-on body, stainless steel stream strainer, 3/8"M, ANSI/NSF 61, section 9 certified		
			Extended Total for Item No. 80: $132.35		
81	1	ea	**DISHTABLE SORTING SHELF**	506.76	506.76
			Advance Tabco Model No. DT-6R-13		
			Sorting Shelf, traditional design, 62" long, holds three racks		
			Extended Total for Item No. 81: $506.76		
82	1	ea	**FAUCET**	72.50	72.50
			T & S Brass Model No. B-1141		
			Faucet, gooseneck nozzle, deck mounted		
			Extended Total for Item No. 82: $72.50		
83	1	ea	**DRIP TRAY TROUGH, BEVERAGE**	507.60	507.60
			Pacific Stainless Products Model No. DP42DI		
			Drop-In Drip Tray, 42"L x 4"W, 1" 16/304 s/s construction, flanged top and 1" x 3" bottom drain nipple, 18/304 perforated removable trivet with fingerholes included		
			Extended Total for Item No. 83: $507.60		
84			Fetco Coffee Maker: By Others		Spare
85			Wilbur Curtis Iced Tea/Iced Coffee Dispenser: By Others		Spare
86			Bunn O Matic Ice Tea Brewer: By Others		Spare
87	1	ea	**UTILITY CART**	383.40	383.40
			Cambro Model No. BC2354S-110 Packed: each		
			Service Cart, open design, three shelves, shelf size approximately 21" x 32", polyethylene exterior, 5" casters (4 swivel, 1 with brake), 500 lb. load capacity, black		
			Extended Total for Item No. 87: $383.40		
88			Spare No.		Spare
89			Spare No.		Spare
90	4	ea	**CORNER GUARDS**	45.60	182.40
			Custom Model No. KEIZER90		
			Custom Stainless: Corner Guards, 2 x 2 x 48		
			Extended Total for Item No. 90: $182.40		
91	1	ea	**INSTALLATION**	14,412.00	14,412.00
			Custom Model No. INSTALLATION		
			Installation of custom stainless, field measure, plans and permits for hood, deliver and set in place buy out equipment		
			Extended Total for Item No. 91: $14,412.00		

Merchandise	66,084.22
Freight	4,466.33
Total	70,550.55

TERMS: Standard terms are 50% deposit with signed order, 40% due 1 week before installation and balance due net 30 days from delivery pending credit approval. For purchases over $15,000 accepted methods of payment are: Cash, Check, Cashier's check, Wire transfer.

FREIGHT: Freight is an estimation only and is subject to change based on current rates at