EXHIBIT NO. _______ (EMM-25)
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2003 POWER COST ONLY RATE CASE
WITNESS: ERIC M. MARKELL

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, INC., Respondent.	Docket No. ____________

DIRECT TESTIMONY OF
ERIC M. MARKELL
ON BEHALF OF PUGET SOUND ENERGY, INC.

Ex. _____ (EMM-25)

FINAL REPORT

Assessment and Report on Self-Build Generation Alternative for Puget Sound Energy's 2002-2003 Least Cost Plan

Prepared by Tenaska, Inc.
Omaha, Nebraska

March 2003

Tenaska, Inc.
Assessment and Report on Self-Build Generation Alternative for Puget Sound Energy's 2002-2003 Least Cost Plan

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Disclaimer

This report is based on information obtained from various sources and Tenaska's best judgment and experience as of December 2002. This report also contains some forward-looking opinions. Certain unanticipated factors could cause actual results to differ. While we believe the information to be correct, Tenaska makes no assurances or warranties as to accuracy or completeness, and assumes no responsibility for the results of any actions taken by Puget on the basis of this report.

Section 1 – Introduction

Tenaska, Inc. (Tenaska) is pleased to provide this document for use in Puget Sound Energy's (PSE's) 2002-2003 Least Cost Plan. As part of its resource planning process, PSE retained Tenaska to prepare an assessment and report on alternatives for generation project self-development by PSE. Tenaska has extensive knowledge and experience as a developer of new electric generating facilities, including siting, permitting, design, major equipment procurement, and construction management for over 9,000 megawatts (MW) of project capacity. Tenaska also provides operations and maintenance services for all six of its domestic, operating projects and will provide similar services for three more domestic projects which are currently under construction. This experience includes development, ownership and operation of a combined-cycle facility near Ferndale, WA.

Natural gas-fired, combined-cycle combustion turbine technology is the most common type of new electric generation resource now being developed in North America. PSE could potentially acquire long-term power supplies from this type of resource under several alternative mechanisms, including: (a) self-building a project at a greenfield site; (b) purchasing and completing a project that is partially-developed; or (c) purchasing power output from a project that is owned by a third party. Comparison of the advantages and disadvantages of these three alternative resource acquisition methods is beyond the scope of this report. However, information provided in this report may be useful for comparing the self-build alternative with other methods of acquiring power from natural gas-fired, combined-cycle resources.

Following this Introduction, the discussion provides more detailed information on various aspects of self-development including project design, siting, permitting, equipment procurement, project construction, startup, operation and maintenance. Estimates of project development costs and time schedules are also provided. A brief overview of current market conditions affecting the price and availability of combustion turbines and other prime mover equipment, as well as similar information for EPC (engineering, procurement and construction) contractor services is also provided.

Section 2 – Report Approach

Tenaska's assignment for this report can be summarized as follows:

- identify and screen a range of potential sites;
- narrow the potential sites to a short list of leading candidates;
- describe possible project configurations;
- estimate project permitting and construction costs and schedules;
- estimate non-fuel project operating costs; and

- finally integrate all project performance and cost characteristics to estimate total resource costs of a hypothetical self build option.

For costing purposes, the primary focus of this report is to identify representative "reference" costs under market conditions that are relatively stable. Tenaska also discusses recent industry events that have caused actual EPC and equipment prices to vary from "equilibrium" levels. The report uses a bottom-up approach to develop cost estimates, including breakout of costs into major categories. A standardized format, or "template" is used to present the cost estimates for "generic" plants. Actual costs are very project-specific; we have used our experience and judgment to customize these generic estimates to several project configurations for two PSE sites possibilities. This template can then be used to evaluate specific self-build project development opportunities in a systematic, consistent fashion as such opportunities arise in PSE's ongoing resource identification and evaluation process.

The focus for this report is to develop estimates of capital costs and non-fuel operating and maintenance costs for the self-build alternative. Topics such as capital structures that might be used to finance a self-build project and forecasts of costs for natural gas supply to fuel a project do not receive extensive attention in this report. While total power, or PSE "resource," costs are estimated at several points, many financial, macro economic and energy market parameters need to be consistent with those used in the analysis of other PSE resource alternatives before final least cost comparisons can be reached.

Finally, this report does not draw conclusions about which site or sites PSE might actually select to construct a generating project. Instead, the purpose of this report is to assess and develop reasonable estimates of costs, permitting, schedules and other project development considerations. Any decision to proceed with self-build development of a generation project by PSE would require more specific and detailed analysis. As indicated above, such a project would also have to be shown to be consistent with PSE's least cost electric resource plan and preferable to other available alternatives.

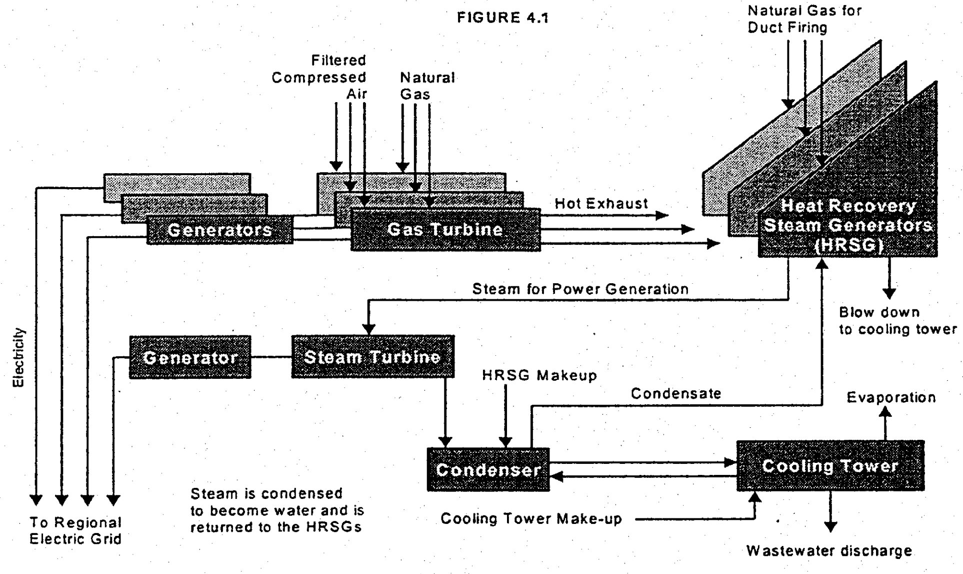
Section 3 – Basic Project Configurations

Gas-fired power plants can be separated into two basic types depending on their intended market service. "Peaking units" operate and produce electricity only during periods of high electricity demand. These peak demand periods generally occur during the extreme hot spells of summer and extreme cold spells in the winter. "Baseload units," on the other hand, generally operate full time. For gas turbine (GT) power plants, peaking units are usually comprised of simple cycle GT's and baseload units are usually comprised of GT's operating in combined cycle with one or more steam turbines (ST's).

A simple cycle gas turbine is a combustion engine with three major parts: an air compressor, burner(s), and power turbine. In the air compressor, a series of bladed rotors compresses the incoming air from the atmosphere. A portion of this compressed air is then diverted through the burners (also called combustors), where fuel (usually natural gas at pressures of 325 to 500 psig) is burned raising the temperature of the compressed air. This very hot gas is mixed with the rest of the compressed air and directed to the power turbine at temperatures up to 2350°F. In the power turbines, the force of the hot compressed air as it expands pushes another series of blades, rotating a shaft. Greater than 60 percent of the mechanical energy produced by the power turbine is consumed to drive the air compressor. The balance of the mechanical energy turns a generator and makes electricity. The cycle efficiency, defined as a percentage of useful shaft energy output to fuel energy input, is typically in the 30 to 35 percent range.

The difference between simple cycle and combined cycle is that in combined cycle, the hot exhaust gases from the GT do not directly go to the atmosphere. Instead, the hot exhaust gases, which are typically above 1000°F, are ducted through a waste heat boiler (a heat recovery steam generator, or "HRSG") to generate steam. This steam is then used to drive a steam turbine generator (or "ST") to make additional electricity. The recovery of the heat energy in the exhaust of a gas turbine in this manner can increase the cycle efficiency of a combined cycle plant to 50 percent or more. The additional electricity that can be produced by a combined cycle installation is accompanied by additional capital costs for the HRSG, ST and a cooling system. However, the operating cost per unit of electricity produced is usually lower compared to that of simple cycle turbines due to the higher energy recovery. Figure 4.1 illustrates the basic components of a combined cycle facility.

FIGURE 4.1



Because it appears that a portion of PSE's need for new resources could be met with base load generation, Tenaska focused on combined cycle plant designs, or "configurations." The cost and performance of combined cycle plants is very dependent on the size and number of the basic GT unit(s) around which the overall plant is designed. These plants are commonly referred to by the number of gas turbines and steam turbines they feature. A "one by one" (1 X 1), for example, represents one gas turbine, paired with one steam turbine/HRSG. Larger plants can be designed as "3 X 1" (three GT's and three HRSG's paired with one larger ST), "4 X 2," and so on.

Initial Results

In June of 2002, Tenaska provided basic performance and cost information for five generic or "reference" combined cycle plants based on two standard General Electric (GE) frame gas turbines (FA's and EA's). Refer to Table 4.1. As indicated, these five plants cover a range of combined cycle capacity from 146 MW (1 X 1 EA) to 893 MW (3 X 1 FA).

The capital and operating costs associated with these plants were our first estimates and feature only very high-level detail. The initial estimates were based on Tenaska's experience with similar projects. The capital and operating costs were "inputs" to an economic model which also added the various financial parameters and assumptions necessary to determine an all-in cost of electricity expressed in $/MWh.. PSE provided many of the financial assumptions such that the results reflect a utility's analytic approach and determination of total project cost and revenue requirement rather than that of an IPP developer. The all-in costs shown on Table 3.1 represent the price of electricity needed per MWh, assuming 7884 annual operating hours , to cover fuel, all fixed and variable operating costs, debt service and to earn a return on invested equity. A summary of the results follows:

Table 3.1

Gas Turbine Type	Configuration	MW	Total Capital MM$	Total Capital $/kW	All-In Cost $/MWh
GE 7FA	1 X 1	294	216.4	735	43.07
	2 X 1	593	367.8	620	40.25
	3 X 1	893	490.4	549	38.81
GE 7 EA	1 X 1	146	158.0	1081	53.73
	2 X 1	295	234.4	794	46.91

Figures 4.2 and 4.3 graphically show the results from this high level analysis for all five generic plant configurations. These graphs clearly show how project size impacts cost. Capital costs range from about $1100/kW for the smallest EA-based plant (about 146 MW) to under $600/kW for the largest FA-based plant (about 893

MW). All-in costs in \$/MWh range from about \$54 to about \$38, respectively, over the same range (using common financial assumptions and fuel cost). FA-

FIGURE 4.2
Generic Combined Cycle Plants - All In Cost
June 2002 Results

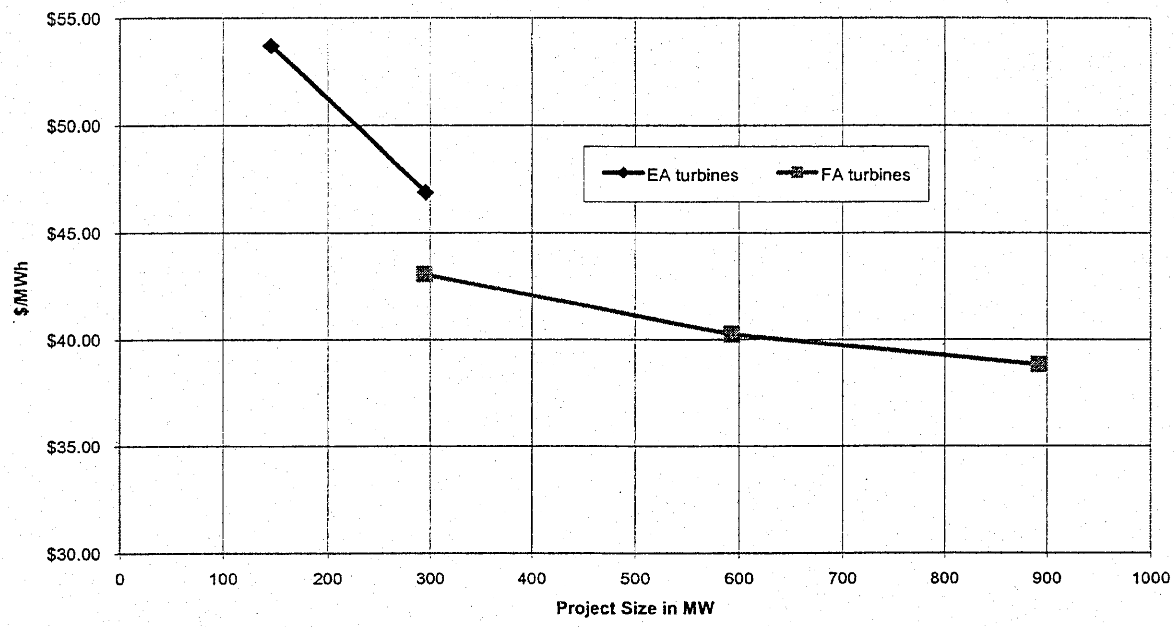
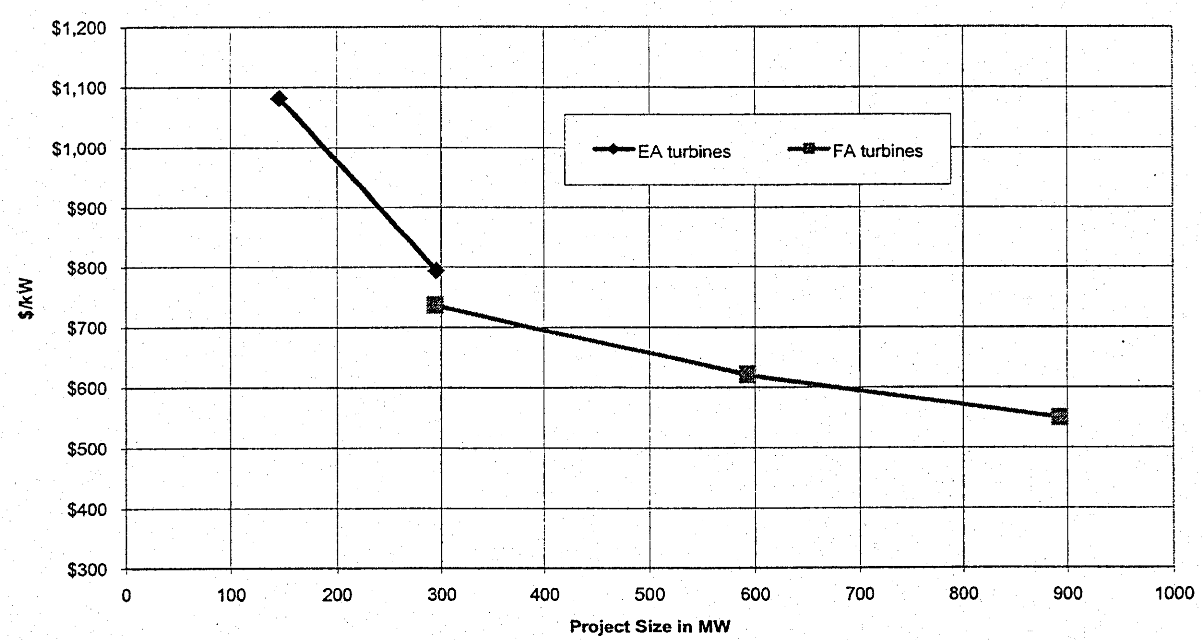


FIGURE 4.3
Generic Combined Cycle Plants - Capital Cost
June 2002 Results



based plants are also clearly more economic than EA technology if resource requirements match this plant size.

Revised and Updated Results

These high level results formed the basis for more detailed analysis of PSE's self-build options and some of the plant design trade-offs which need to be considered. Subsequent to Tenaska's initial work for PSE, which was highlighted above, we increased the level of technical and cost detail for the five original generic plants during a second phase of our assignment which was conducted in November and December of 2002. This analysis includes more detail on the components of capital and operating costs and indicates many of the physical requirements of each generic configuration (fuel use, water requirements, site size, etc.). Once again this data was combined with the requisite economic parameters in a financial model to estimate all-in project costs and revenue requirements, the results of which are discussed in later sections.

Two design issues should be mentioned at least briefly. First is cooling. Refer back to Figure 4.1. When steam exits the steam turbine it is condensed back into water and further cooled to be recirculated through the steam cycle or discharged. "Wet" cooling uses large open towers and evaporation to cool process water while "dry" or "air" cooling condenses steam and passes hot water through large radiator-like facilities in a closed system. Wet cooling has a large raw water requirement, approximately 2 million gallons per day for a generic 1 X 1 on Table 3.1 depending on climatic conditions and technical configuration. Typically more than 80% or so of this raw water is "consumed" due to evaporation. For the same 1X1, dry cooling uses only a small fraction of the daily raw water volume of wet cooling, typically less than 10%, but suffers two disadvantages: efficiency is lower (hence project capacity is reduced by 2-3% or about 6-8 MW at summer conditions) and capital costs are higher (15% more EPC cost or about $10MM). Dry cooling can be an important option, however, if water is not physically available in the quantities required or if environmental or community circumstances restrict its use. Municipal wastewater, if available, is another source of make-up water for a wet cooling system. Additional pretreatment may be required and typically more wastewater is produced also due to the lower quality raw feedwater. The fact that this water is often very low cost (often free), usually offsets the incremental treating and wastewater discharge costs.

The second design issue is duct firing. When ambient temperatures increase, gas turbine output and overall plant output decrease. This loss of output can be more than offset by adding supplemental firing, via "duct burners," to the hot gases passing through the HRSG's into the steam turbine. Typically, combined cycle steam turbines are "over-sized" to accommodate duct firing during such ambient conditions. Over-sized steam turbines do suggest a small cost and efficiency penalty when duct firing is available but not in use. The overriding benefit, however, is that although duct firing adds capital cost, the cost per incremental MW added is quite attractive. For a generic 7FA 1 X 1 on Table 3.1, duct firing adds 38 MW of capacity from 256

MW to 294 MW) and about $6MM, or about $150/kW. Simple cycle peaking plants typically cost about twice this per kW. The incremental heat rate for duct firing is also much lower than the simple cycle peaking alternative (say 9,200 btu/kWh versus 11,000 to 12,000).

Additional output over and above duct firing can also be derived on hot days by inlet air cooling either by evaporative cooling or mechanical refrigeration. Evaporative cooling (or fogging) is the most cost effective technique but gas turbine compressor inlet temperatures are of course limited to the ambient wet bulb temperature. Typically inlet cooling is not placed in service unless ambient dry bulb temperatures exceed 59 degrees F.

Section 4 – Current Status of Equipment and EPC Markets

The largest portion of a combined cycle plant's capital cost is the EPC contract (Engineering, Procurement and Construction) and the cost of the major equipment components. Contracting practices obviously vary by project and from developer to developer, but a common approach is to negotiate a single EPC contract with one construction firm to serve as the "general contractor" and to provide all construction materials, labor and supervision and all "balance of plant" components. Developers/owners often independently provide the major equipment components and "turnkey" contracts for the interconnects (power, fuel and water). Some or all of these latter items can also be assigned to the EPC contractor contractually. Contractor fees vary depending the scope of services and materials provided and the amount of project risk, both in terms of schedule and dollar budget, the EPC contractor takes on.

EPC costs and fees and equipment prices vary with market conditions. In general, both have fallen with the 2002 down-turn in the energy sector. Making generalizations can be difficult because both can be very project-specific; however, we observed a change in EPC and equipment costs during 2002 between our initial (June) and final (December) work based on Tenaska's judgment and conversations with industry sources, contractors and equipment vendors. EPC differences are the most difficult to determine because so few new contracts have been announced or awarded recently. The reduction has generally been 5 to 10%. Appropriately scaling these changes up or down with project size is also project specific. EPC costs have fallen; this reflects a revision in our scaling factor for smaller projects not an increase in price.

Changes in equipment prices are much easier to observe. Gas turbines have a high degree of interchangeability and hence a "secondary" market exists were GT's are bought and resold. The price of gas turbines rose quickly in the late 1990's and early 2000's with the surge in gas-fired plant development. Waiting periods for delivery reached "years." The opposite has occurred this year. FA turbines peaked at about

$40MM each in early to mid 2001. Today's manufacturer price is perhaps $30MM; prices on the secondary market are perhaps $20MM. Steam turbines and HRSG's are less "commodity-like" and a larger number of manufacturers exist than for GT's. Hence prices have not been as volatile as prices for GT's, but in our view some softening has occurred.

Occasionally, very distressed pricing can be observed in the secondary market, usually through equipment brokers which protect the identity of the actual owner/seller. The lowest price Tenaska has observed has been a package of three 1 X 1 FA power islands for about $70MM (a GT, ST and HRSG). We do not recommend basing an investment decision in a resource planning context on such numbers. Availability of this pricing on an ongoing basis is very uncertain and such sales are "as is, where is." Significant costs can be associated with relocating and reusing such equipment components.

Section 5 – Potential Sites

Selection of a suitable site is a major step in the development of a new power generation facility. A number of site-specific factors can significantly influence a particular location's feasibility and attractiveness. Some factors are 'knockout' factors, such as when zoning for a prospective site would prohibit its use for power generation. Other factors influence the cost of development, including availability or accessibility of electric transmission.

It should be noted that discussion of potential sites in this report is primarily for the purpose of illustrating various factors that need to be considered and estimating representative costs associated with particular sites. Nothing in this report should be interpreted to mean that a particular site has been selected for development, or that other sites would be excluded from future consideration.

In the site review, transmission constraints and regulatory uncertainties, as discussed elsewhere in this document, were of primary concern. Early in the process it was determined that the company should avoid building new generation in locations where the ability to deliver the power to the company's retail loads was uncertain. This first meant that new generation sites should focus on west of the Cascades as there are already trans-Cascades constraints on the regional transmission system. West of the Cascades, there are some south-north constraints as well, which removed Whatcom and Skagit counties from consideration. After eliminating some geographic areas, the search focused on PSE's service territory in King, Pierce and Thurston counties.

Map A-6-1 shows the location of twenty-four sites that were considered. None of the sites were perfect in every aspect. For example, some substation sites were large enough, but they were not close to a gas supply line, while other sites had become encumbered with suburban growth. For a first cut, it was determined to remove the sites with non-economic constraints: zoning and public acceptance. A group of PSE municipal land planners reviewed the sites and identified a “short list” of sites which could provide the appropriate zoning environment (Map A-6-2). The process led to a fundamental paradox: the further a site was located from its customers, the greater the cost for gas, transmission and water.

PSE personnel and Tenaska conducted on-site inspections of the short list properties before initiating financial analyses. The on-site inspections allowed for discovery of developments and other locational issues that did not show up on inspection of maps. These issues were further investigated by direct contact with local authorities, and PSE personnel who were knowledgeable of specific sites and processes.

The financial analysis will focus on two sites: Dieringer, which is a substation near the White River hydro plant; and Frederickson, which currently holds two gas turbine peakers. The Dieringer site could contain a “one-on-one” 250+ megawatt combined cycle turbine with a steam generator as it is limited by size. The Frederickson site has more room for expansion and could be used for either a ”one-on-one” or a ”two-on-one” (250+ mw and 500+ mw, respectively).

The evaluations of these sites by Tenaska included many important issues such as power system upgrades and fuel and water availability and costs. Nevertheless, this report is still a rough cut to be used as a benchmark for comparison with other alternatives. A detailed analysis would still require engineering reports for construction, OASIS-based transmission upgrade studies, and negotiations with municipalities for services and taxes

Section 6 – Site Specific Project Description and Cost Estimates

Table 6.1, based on the technical characteristics of the generic combined cycle plants detailed on Table 3.1 and the specific attributes of PSE’s two main site alternatives listed on Table 6.1, summarizes Tenaska’s view of the capital cost of a 1 X 1 and a 2 X 1 project at Frederickson and a 1 X 1 project at Dieringer. Two scenarios are provided for each configuration to highlight the impact of possible equipment price differences. As discussed previously for the initial June results, these capital costs were added to an economic model that calculated “soft costs” and then total installed project cost. A summary follows using “Base” equipment pricing:

Table 6.1

	Units	Frederickson 1 X 1	Frederickson 2 X 1	Dieringer 1 X 1
Capacity	MW	294	593	294
EPC Cost	MM$	76.0	137.4	75.6
Equipment (GT,	MM$	54.8	102.5	53.6

ST & HRSG's)				
Interconnects	MM$	31.2	75.3	14.4
Soft Cost	MM$	68.3	105.7	65.4
Total Cost	MM$	230.4	420.8	209.0
	$/kW	784	710	711

The economies of scale associated with larger plants usually suggest declining capital cost per kW as plant size increases as is evident with the two Frederickson cases ($784/kW falling to $710/kW using higher equipment pricing). Notice that the Dieringer 1 X 1 shows about the same capital cost per kW as the Frederickson 2 X 1. Interconnect costs at Frederickson are a significant issue. This location may have offsetting system benefits to PSE, but all other things equal, Frederickson appears to be a higher cost site.

Section 7 – Project Permitting

The construction and operation of a new project will require approvals from certain federal, state, and local authorities. The following information characterizes the process of obtaining these approvals and the costs and schedule associated with completion of the permitting process.

Requirements

PSE would need to self-certify under the requirements of the Power Plant and Industrial Fuel Use Act of 1978. A Certificate of Compliance would be filed with the Office of Fuels Programs, Department of Energy. Publication of a Public Notice by the Department of Energy would also be required.

Stationary thermal power plants to be sited in Washington with a net electrical generating capacity greater than 350 MW are included within the definition of Major Energy Facilities and subject to licensing review by the Washington State Energy Facility Site Evaluation Council (EFSEC or Council) and case-by-case approval by the governor. The state's energy facility license is obtained in the form of a Site Certification Agreement. The licensing process includes application to the Council, evaluation of the application, and recommendation by the Council to the governor to approve and sign a Site Certification Agreement. The Council will apply its regulatory standards to subject facilities, and is currently in the process or reviewing those standards.

Smaller projects (i.e., less than 350 MW) that do not meet the definition of a Major Energy Facility do not require a Site Certification Agreement or governor approval, but are subject to applicable state and local permitting requirements, including federal air quality and water quality reviews that are delegated by the United States Environmental Protection Agency (USEPA) to the State of Washington or local jurisdictions. Such requirements include air quality permits, wastewater discharge or pretreatment permits, and local land use or zoning and building construction permits.

The State Environmental Policy Act (SEPA) process provides broad interdisciplinary environmental review and will be lead by EFSEC for Major Energy Facilities or by other state or local agencies for smaller projects. In the event that there is a material federal environmental review required by the National Environmental Policy Act (NEPA), the lead agency under SEPA may conduct a coordinated review with federal agencies whose action with respect to the Project is subject to NEPA.

Notable federal jurisdiction is that of the U.S. Army Corps of Engineers (USACE) over certain construction activities in waterways and wetlands. If such construction is necessary, including interconnecting water, gas, and electrical infrastructure, some form of permit may be required from the USACE. Review of permit applicability and compliance by the USACE also includes review of cultural resource issues under the requirements of the National Historic Preservation Act as well as review of potential impacts to threatened and endangered species required by the Endangered Species Act. The USACE will coordinate the reviews of state and federal agencies with expertise in these areas, or coordination will be provided by the lead agency under NEPA. A detailed delineation of wetlands and other waters of the United States must be developed to help avoid jurisdictional waters and to determine potential USACE requirements.

The potential site alternatives include discharge of cooling water and minor volumes of other process effluents to the collection systems of publicly owned wastewater treatment works. Storm water drainage, retention, and discharge facilities will also comply with the treatment requirements and approvals established by local ordinances, State of Washington regulations, and the National Pollutant Discharge Elimination System.

Given available emissions control technology, combined cycle combustion turbine projects subject to EFSEC are also likely to be subject to federal new source review or Prevention of Significant Deterioration (PSD) permit requirements. Smaller project alternatives may not necessarily be subject to PSD depending on final equipment and emissions control selection decisions. Federal land management agencies, such as the National Park Service and U.S. Forest Service, must be consulted in the PSD permitting process with respect to air quality impacts on certain public lands that they administer, such as national parks and wilderness areas. Detailed air quality modeling, potentially including emissions from other sources as well as the Project, may be required to address federal land manager concerns.

The air quality permitting process includes a review of applicable construction standards, assessment of potential project impacts to ambient air quality, and a determination of best available control technology. An air quality construction permit will establish operating and emission limits for project equipment, requirements for initial emissions testing, as well as monitoring and reporting requirements.

New projects must also apply for a permit under the Clean Air Act acid rain prevention program at least 24 months prior to the date when electricity is first provided to the grid system. The acid rain prevention program includes additional monitoring requirements for emissions of sulfur dioxide, oxides of nitrogen, and carbon dioxide. Projects must certify and operate a continuous emissions monitoring system in accordance with the requirements of the acid rain prevention program.

After completion of construction, projects will also apply for an operating permit. When issued, the operating permit will identify applicable regulatory requirements including a requirement to regularly certify compliance with all applicable air quality regulations and conditions of the operating permit. The acid rain permit is issued as one part of the operating permit.

Unless site conditions dictate otherwise, new projects generally will not require hazardous waste transfer, storage, or disposal permits or underground storage tank registration (no underground storage tanks are included). Projects will be required to submit to the USEPA and Ecology a Facility Response Plan detailing contingency plans for oil spills and a Risk Management Plan governing hazardous materials contingencies.

Estimated Costs

Budgetary cost estimates for permitting range from $0.8 to $1.7 million exclusive of preliminary design engineering that may be required to support permitting efforts. In addition to costs directly associated with project permitting, new EFSEC global warming mitigation costs could be imposed as a result of currently ongoing regulatory rulemaking. One of the regulatory options for such mitigation is based upon Oregon Energy Facility Siting Council (EFSC) requirements. Under the Oregon program, these mitigation costs are paid lump-sum prior to commercial operation (i.e. the fee would be treated as another up-front capital cost). For the size range of projects Tenaska evaluated for PSE, the fee would range from about $4MM for a small 146 MW project to over $14MM for a 3 X 1. Given the status of the debate on this subject, however, no mitigation costs have been included in Tenaska's project cost estimates.

Schedule

EFSEC's web site provides a generalized siting process timeline. EFSEC suggests a potential schedule involving four to eight months of preliminary site study plus an additional 14 months for the various other steps for development of air and water permits and the Site Certification Agreement as well as public hearings and other procedural steps. A smaller project not subject to Council requirements could anticipate a permitting timeline of 10 to 14 months, depending upon procedural options selected by the lead SEPA agency and assuming no significant federal involvement.

Section 8 – Project Construction

As an example, Table 8.1 lists the major components of the cost to construct a 1 X 1 at the Frederickson site. At this level of detail, construction costs (often called total installed cost) are highly site-specific. The EPC contract reflects all balance of plant requirements (i.e. non-equipment requirements) such as buildings, cooling towers, site preparation and excavation, footings and foundations, installing utilities and all piping, fans and control systems. The EPC contract also includes the contractor's fees and profit and is reflective of the amount of risk the contractor assumes. One important risk is related to labor (both hours and wage rates). With fully loaded wage rates of $50/hour and 600,000 total man-hours the Frederickson 1 X 1 would have about $30MM of labor cost, or almost 40% of the total EPC contract. Typically EPC contracts also contain premium/penalty provisions that set out the cost or benefit of achieving or missing key schedule milestones and/or equipment performance.

Table 8.1

Example of Total Installed Project Costs ($2002)		
	000 $	Percent of Total
EPC contract	$ 76,000	33.0%
Equipment	$ 54,840	23.8%
Interconnects	$ 31,190	13.5%
Subtotal	$ 162,030	70.3%
Interest During Construction	$ 11,479	5.0%
Contingency	$ 10,238	4.4%
Sales Tax	$ 9,512	4.1%
Development Costs	$ 7,000	3.0%
LTSA-related and Spares	$ 5,782	2.5%
Startup Including Fuel	$ 5,639	2.4%
Project Management	$ 5,500	2.4%
Lender-related	$ 5,472	2.4%
Insurance-related	$ 2,900	1.3%
Land- related	$ 2,500	1.1%
Working Capital	$ 1,750	0.8%
All Other	$ 591	0.3%
Subtotal	$ 68,363	29.7%
Total Installed Cost	$ 230,393	100.0%

This example suggests that costs other than EPC, equipment and interconnects (commonly called "soft costs") comprise about 30% of total installed costs. These costs are very dependent on what type of company sponsors and builds a project (regulated utility or independent power producer) and how it is financed. The costs related to bank financing (interest during construction and lender-related fees and reimbursables) total about $17MM. The philosophy on contingency and spare parts also varies from sponsor to sponsor and may be dependent upon lender requirements.

A schedule should reflect site and project specific characteristics, but in Tenaska's experience a general rule of thumb for a 3 X 1 configuration is 24 months. 2 X 1's and 1 X 1's might be one month less each (i.e. 23 months and 22 months). This particular schedule also assumes a two or three month "Limited Notice To Proceed (LNTP)" during which the contractor and sometimes subcontractors get a "head start" on certain site-preparation and engineering items. The permitting and construction timelines, of course, are additive. The following table summarizes the total timeline for a new gas-fired project. 1 X 1's might range from 33 to 39 months; 2 X 1's might range from 40 to 48 months. Some of the individual activities can be accomplished concurrently. In our experience the regulatory process is highly uncertain; it is critically important to gain local community support and communicate regularly with all of a project's stakeholders.

Table 8.2

Configuration	Site Study Permit Preparation	EFSEC?	Regulatory Approvals	Construction
1 X 1	2 – 4 mos	No	10 – 14 mos	21 mos
2 X 1	4 – 8 mos	Yes	14 – 18 mos	22 mos

Section 9 – Operating and Maintenance Requirements and Cost Estimates

Non-fuel operating and maintenance ("O&M") costs are typically broken into two categories. The first category, "fixed" costs, generally does not vary with a plant's level of output. Fixed costs include plant labor, ongoing utilities and building/grounds upkeep, usually some allocated corporate overhead and fees paid to the operator. Operator fees of course are eliminated if Puget self operates.

Variable costs generally change with a plant's annual hours of operations. Water treatment, chemicals, environmental controls and catalyst replacement, etc. all are directly related to hours of operation. The largest single item in the variable category is major maintenance of the gas and steam turbines. Scheduled, routine maintenance occurs on a very carefully managed timeline related to annual hours and the number of starts per year, typically as follows:

Table 9.1

Activity	Operating Hours Between Each Activity	Starts Between Each Activity
Combustion Inspection	8,000	400
Hot Gas Path Inspection	24,000	800

Major Overhaul	48,000	2,400

Although some plant owners/operators manage and conduct these major maintenance activities themselves, others opt to contract with third parties for these services, frequently with the manufacturer of the equipment. In such cases Long Term Service Agreements (LTSA's) describe these maintenance practices and include all the parts and labor needed. LTSA's usually levelize annual maintenance costs using a charge per fired hour with an annual fixed minimum fee ($450 to $500/fired hour for a 1 X 1, for example). In this fashion, the manufacturer assumes most of the risks associated with parts availability, premature wear, etc. and some equipment performance issues.

Section 10 – Summary of Results

As discussed in previous sections, Tenaska looked at two Puget self-build site alternatives for Frederickson (1 X1 and 2 X 1) and one for Dieringer (1 X 1). Table 10.1 integrates all of these estimates for plant performance, capital and operating cost, permitting and construction schedules as well as all of the necessary financial modeling assumptions to calculate total installed capital cost (in MM$ and $/kW) and all-in power costs (in $/MWh). Capacity cost in $/kW-month estimates the fixed payment that a plant owner needs to receive to support the full cost of new capacity. This payment covers all fixed costs including repayment of debt and earns the project owner a minimum "profit." The capacity payment is independent of hours of operation (i.e. it's "take or pay"). The all-in cost in $/MWh covers the capacity payment as well as fuel and all variable costs (i.e. all of the costs which are incurred based on hours operated). The all-in cost is clearly very dependent on the assumption about annual hours of operation. A summary of the results using "Base" equipment pricing follows:

Table 10.1

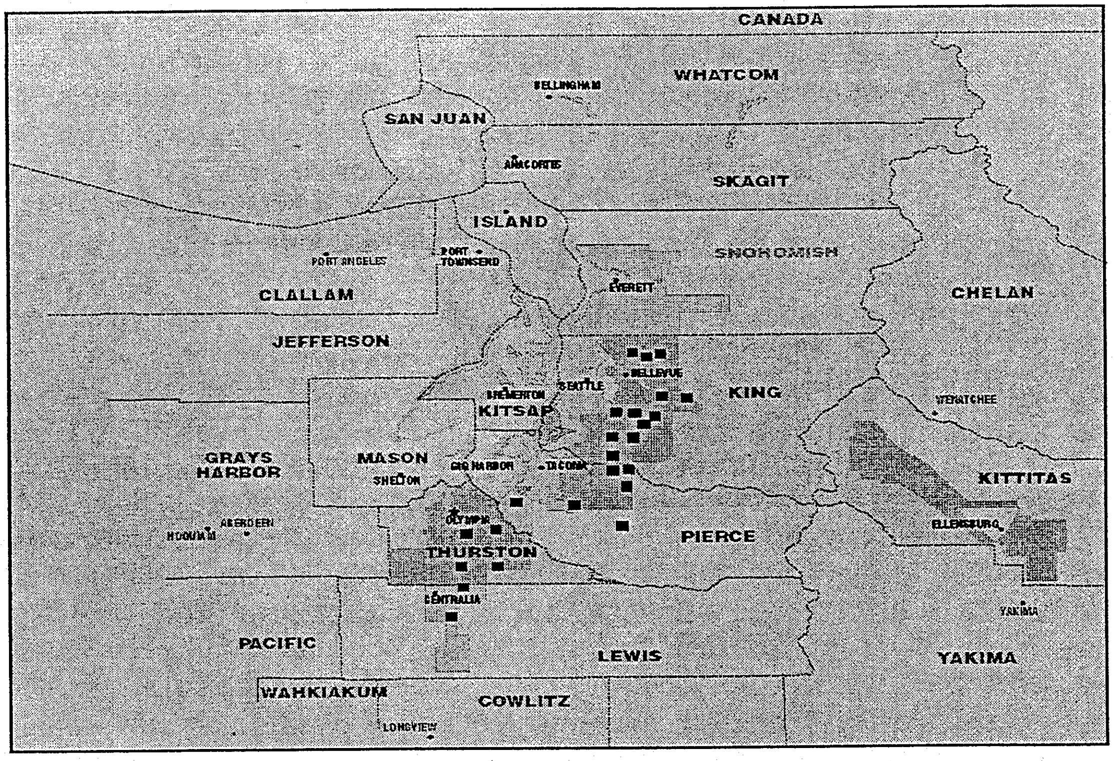
	Units	Frederickson 1 X 1	Frederickson 2 X 1	Dieringer 1 X 1
Capacity	MW	294	593	294
Capital Cost	MM$	230.4	420.9	209.0
	$/kW	784	710	711
Capacity Cost	$/kW-mon	8.36	7.17	7.68
All-In Cost	$/MWh			
Capacity Factor	60%	52.33	49.34	51.01
	70%	49.17	46.29	47.77
	80%	46.54	43.98	45.32
	90%	44.48	42.18	43.41

Capital costs for the 1 X 1's range from $711/kW at Dieringer to $784/kW at Frederickson. Interconnect costs account for the vast majority of the difference.

Notice that interconnect costs for a Frederickson 2 X 1 are substantially higher than for a 1 X 1, but the scale of a larger plant offsets the increase. If lower priced equipment is available, capital costs for the lower cost sites fall to about $660/kW. The only difference in non-fuel operating costs is water and wastewater cost at Dieringer (less cycles of cooling concentration due to water quality). All-in costs, based on $3.63/mmbtu fuel, and other financial assumptions, range from about $42/MWh for a Frederickson 2 X 1 with a capacity factor of 90% to about $52.33/MWh for a Frederickson 1 X 1 with a capacity factor of 60%. Lower equipment prices and hence capital cost push the all-in costs down about $.80/mWh.

Maps A-6-1, A-6-2

PUGET SOUND ENERGY SERVICE TERRITORY



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