Before the
Energy Facility Site Evaluation Council
State of Washington

Direct Testimony of Jim Lazar
on behalf of
Washington Department of Community, Trade, and Economic Development

Sumas Energy
Application 99-1

Q. Please state your name, address, and occupation.

A. Jim Lazar, 1063 Capitol Way S. #202, Olympia, Washington. I am a consulting economist, specializing in electric and natural gas utility rate and resource studies.

Q. Briefly summarize your experience and qualifications.

A. I have been in an independent consulting practice in this field since 1982. During that time, I have appeared as an expert witness on more than 100 occasions before more than thirty federal, state, and local regulatory bodies, including state regulatory commissions of Washington, Oregon, California, Idaho, Arizona, Hawaii, and Illinois. I have previously appeared before the Energy Facility Site Evaluation Council of Washington (EFSEC) as an expert witness in the matter of Northern Tier Pipeline, and served as a consultant to EFSEC in 1999 on the issue of nuclear power plant site restoration funding. Of particular relevance to this Application, I have served on the Least Cost Planning technical advisory committees for each of the natural gas utilities in Washington, and have testified before the Washington Utilities and Transportation Commission in regulatory proceedings involving each of the natural gas utilities in the state. I have authored numerous papers on various topics having to do with electricity supply and pricing, and served as a faculty member in numerous utility rate and resource training programs in the United States and abroad.

Exhibit ___(JL-1) summarizes my education and experience, and lists recent consulting clients.

Q. What is the purpose of your testimony in this proceeding?

A. I address several topics related to the proposed Sumas generating project. First, I address the impact that this plant will have independently and cumulatively with similar facilities upon the natural gas supply to Washington industries, businesses, and homes. Second, I address alternative backup fuel supply options, which could mitigate the adverse impacts on air quality that the use of diesel fuel would create. Third, I speak to the unnecessary risk of the proposal to add a self-maintained natural gas pipeline. Finally, I address the length of the "build window" in any permit.

POTENTIAL IMPACT ON NATURAL GAS SUPPLY

Q. What is the concern you have with the impact that this project would have on natural gas supply in Washington?

A. The proposed facility would be the largest natural gas fired power plant in the state, and its annual consumption would be more than a 50% increase in the natural gas currently used by all existing natural gas fired power plants in the state. As I will discuss further, the proposed plant could have a severe impact on the availability and cost of natural gas and diesel fuel for other purposes in the state. Neither the Application nor the Draft EIS addresses the potential impact that this much growth in natural gas demand would have on the reliability of service or the cost of service for other Washington natural gas consumers.

Q. What are the existing natural gas power plants in the state, and how much gas do they use?

A. Exhibit ___ (JL-2) shows a list of the existing natural gas fired power plants in Washington. Five of these (Sumas I, Encogen, March Point, Tenaska, River Road) are

baseload plants serving electric utilities, operating at a 70% - 95% capacity factor, partially depending on water conditions. Two plants are relatively small self-generation units, and the remainder is utility peaking plants with much lower levels of operation. As a group, these use an average of about 40,000 million cubic feet of gas per year (mmcf).

Q. How much of an increase in annual natural gas consumption for the state would the proposed facility cause?

A. As shown in Exhibit ___(JL-3), the proposed facility would increase total natural gas consumption for the state by about 14%. This is a very significant increase in natural gas demand for one facility to cause.

Q. Has any new natural gas load of this magnitude ever been absorbed in the state?

A. No. This would be the largest single increase in natural gas consumption ever experienced. It is more than twice as large as the next largest existing user of natural gas. It is approximately equal to 55% of the total residential consumption of natural gas in the state.

Q. Has the Applicant presented any information on how this addition load would affect the price or supply of natural gas to Washington businesses or residences?

A. No. Neither the Application nor the Draft Environmental Impact Statement address this issue adequately.

Q. Can you give an example of how growth of energy consumption, relative to the availability of energy supply, can affect prices?

A. Energy markets can be very sensitive to short-term supply imbalances. Perhaps the clearest example is the recent imbalance in world oil markets. In response to a shortfall of supply of less than 5% this past winter, world oil prices increased from less than $15/bbl to nearly $30/bbl. The proposed facility would increase Washington State natural gas usage by a much larger amount than the petroleum supply imbalance, which caused the recent change in gasoline prices.

Q. Does the fact that the natural gas supply would come from Canada change this analysis?

A. No. Virtually all of the natural gas sold in the state originates in British Columbia and Alberta; while Northwest Pipeline connects the state to gas producers in the Rocky Mountain region, gas from the south seldom moves north of Portland. The price of natural gas from Western Canada has increased sharply over the last two years, and incremental supplies are expected to be significantly more expensive than previously developed gas fields.

Q. The applicant has presented testimony by Mr. Jim Litchfield as to the need for new electrical generation in the Pacific Northwest. He testifies that the region is facing a shortfall of 3,626 average megawatts (Mwa) of electric supply.[1] Are you aware of electric generating facilities, which have been proposed to address this shortfall?

A. Yes. The Northwest Power Planning Council maintains a list of proposed power plants, and the current list exceeds 30,000 megawatts of capacity. Of that amount, more than 20,000 megawatts is proposed to be constructed in Washington state, of which more than 14,000 is fueled with natural gas, as shown on pages 2 - 4 of my Exhibit ___(JL-2). Washington is only about half of the regional load, so only about 2,000 megawatts of the regional deficit is forecast for Washington; the balance is due to anticipated load growth and resource depletion attributable to the other northwest states.

Q. How many natural gas power plants have been approved for construction in Washington State?

[1] An average megawatt is an amount of electricity equal to 1 megawatt of capacity operating for 8,760 hours per year, or 8.76 million kilowatt-hours. This is approximately enough electric to serve about 1,000 average American homes for a year.

A. EFSEC has approved the CRSS/Chehalis, Weyerhaeuser/Longview, EN/Satsop, and Creston facilities. These total about 2,250 megawatts (MW) of capacity. In addition to the EFSEC-approved plants, the Tenaska II 250 MW unit is in suspended construction at Fredrickson, and the Everett Delta 250 MW plant have been approved by local authorities. Together, these are more than adequate to meet Washington's share of the shortfall identified in Mr. Litchfield's testimony, especially if accompanied by an aggressive energy conservation program as identified in the testimony presented by my colleagues.

Q. What would be the cumulative impact on the state's consumption of natural gas if all of the already sited natural gas power plants were built?

A. If all of the currently permitted facilities were constructed, the state's consumption of natural gas would increase by more than 50%, as shown on my Exhibit ___(JL-4). If the currently approved plants plus those now before EFSEC for examination (Starbuck and Sumas II) were constructed, the state's consumption of natural gas would nearly double.

Q. Is this a probable scenario that all of these will be built?

A. All of these may not be built, but in the context of site certification, the plants at Everett, Fredrickson, Chehalis, Satsop, Creston, and Longview are currently permitted and could be built without further review by EFSEC.

Q. Has EFSEC or any other entity in the state conducted an assessment of whether that level of growth in natural gas demands is capable of being served with anything like the current gas infrastructure?

A. No, each facility has been examined individually. There has been no assessment of the cumulative impact of this level of increase in natural gas consumption.

Q. What are the possible impacts?

A. First and foremost, the load shape of the gas industry will change drastically, with much higher gas consumption during off-peak periods. Currently, residential and commercial use of gas is concentrated into on-peak winter periods, leaving off-peak demand to utilities filling storage fields and to industrial customers. This sharp growth can be expected to cause prices to rise sharply for industrial use of natural gas and for replenishment of storage gas.

Second, during the majority of winter days, Sumas Energy II plans to run on "flowing" gas coming into the state over Westcoast Pipeline. The other proposed facilities would also normally run on flowing gas from Northwest Pipeline or Pacific Gas Transmission. By increasing demand during the near-peak periods, we can expect sharp increases in the cost of natural gas for residential and commercial usage which is concentrated in these periods and already relies heavily on storage to supplement flowing gas during much of the winter.

Q. In your opinion, could increases in gas demand due to electric generating facilities being added cause a shortfall in supply and/or an increase in price for gas?

A. Yes. During the past two years, wholesale natural gas prices have more than doubled, as shown on Exhibit ___(JL-5). It is reasonable to expect that a sharp increase in demand would cause further increases.

Q. As an example, if a 20% increase in the demand for natural gas due to electric facility additions led to a 20% increase in the cost of all natural gas in the state, what would the effective cost of the incremental gas supplies be?

A. If the average cost of gas before the increase in demand were $.30/therm, and the average went up to $.36/therm, the incremental cost would be $.66/therm. Marginal cost is measured as the change in total cost with respect to a change in demand. The arithmetic would be as follows (the units of current and future demand are unimportant, so long as the relationship between them is a 20% increase):

Impact of a 20% Increase In Natural Gas Demand Causing a 20% Increase In Natural Gas Price
(Illustrative Example)

Current Demand	100 million therms @ $.30/therm
Total Cost of Meeting Current Demand	$30 million
New Demand	120 million therms @ $.36 (20% increase)
Total Cost of Meeting Increased Demand	$43.2 million
Increase in Cost:	$13.2 million
Increase in Demand	20 million therms
Marginal Cost of Additional Gas:	**$.66/therm**

Q. At a cost of $.66/therm, is natural gas electric generation cost-effective?

A. At the fuel efficiency of the proposed Sumas project, this incremental fuel cost alone would come to about $.04/kwh; in addition there would be capital costs to recovery the investment, operation and maintenance costs, and transmission costs. This fuel cost alone is at or above the current forecasted wholesale market prices for electric supply, and implies a total price roughly equal to the cost of developing renewable resources such as wind generation. But the developer would not pay the incremental cost of gas, only the average cost.

Q. What has the trend in Pacific Northwest natural gas prices been in recent years?

A. Prices are up sharply in the last two years. Exhibit ___(JL-5) shows the two-year price history for imports of natural gas at the Sumas location; average prices have more than doubled during this period.

Q. What has happened to retail natural gas prices during this period?

A. Each of the natural gas utilities in the state has raised rates sharply during the past two years due to increases in the wholesale cost of gas. None have increased the delivery charges, which range from $.02/therm for large industrial customers to $.30/therm for residential and commercial customers, although both Northwest Natural Gas and Avista are before the Washington Utilities and Transportation Commission for increases in their gas delivery rates. The table below shows the change in the Weighted Average Cost of Gas for each utility in the past year; these increases have all been flowed through in the form of retail price increases.

Weighted Average Cost of Gas
$/therm

	Avista	**Cascade**	**PSE**
6/99 Cost of Gas	$.223	$.327	$.262
Current Cost of Gas	$.270	$.384	$.318
% Increase 1999 - 2000	21%	17%	21%

Q. Do owners of electric generating facilities pay the full cost of augmenting the capacity of the natural gas transmission system to serve their demands?

A. No, typically not. Proposals to charge incremental loads the full incremental cost of pipeline capacity have not always been implemented. In general, new demands have been serviced with averaged, or "rolled in" pricing. The result is that a large part of the cost of serving the gas transmission needs of new customers is paid by existing customers through rate increases. For example, in the 1993 Northwest Pipeline rate case before the Federal Energy Regulatory Commission, the pipeline's total allowed revenue requirement approximately doubled in response to approximately a 20% increase in

capacity. While the incremental cost of gas pipeline capacity was $.85/mcf[2], it was averaged with existing capacity with an average cost of $.23/mcf to produce a new rate of $.33/mcf. That capacity was added to serve the needs of (now existing) electric generating facilities, but all pipeline users faced rate increases to pay for it. My concern is that the same may be true for the gas supply and transportation to serve the Sumas facility, leading to adverse impacts on existing gas users.

Q. Please explain how this would come about?

A. Westcoast Pipeline recognizes that some new capacity additions will cost more than the average cost of existing capacity. If capacity additions on Westcoast Pipeline are charged the same prices as existing capacity, then existing users will subsidize new users. Similarly, new natural gas exploration and drilling costs are 10% - 30% more expensive than historical costs of developing gas supplies, but if all users pay the same market rates needed to support incremental development, then all existing users will be adversely affected by growth in natural gas demand.

Q. Has Westcoast Pipeline made provision to serve additional loads such as Sumas Energy II?

A. No. Westcoast currently has sufficient capacity from the gas fields in northern British Columbia to the border to meet existing needs. The current capacity is 1.6 billion cubic feet (bcf) per day. In addition, Westcoast has identified capacity additions sufficient to serve an additional 300 million cubic feet per day (mmcf/d). Projected core market usage is expected to utilize approximately half of this additional capacity. That leaves a maximum of 150 mmcf/d to serve additional power generating facilities. The currently

[2] Quantities of natural gas are measured in thousand cubic feet (mcf), million cubic feet (mmcf), billion cubic feet (bcf), therms (100,000 British Thermal Units or BTU; a BTU is the amount of energy needed to raise the temperature of one pound of water by one degree fahrenheit), million British Thermal Units (mmbtu), and gigajoules (1,000,000,000 joules; a joule is equal to 10,000,000 ergs.) One thousand cubic feet is roughly equal to one million BTU; retail sales of natural gas by gas utilities are measured in therms.

EFSEC approved plants in Western Washington (Satsop, Longview, and Chehalis) would require approximately 200 mcf/d; adding the currently locally-approved plants (Tenaska II and Everett Delta) would increase this to approximately 273 mmcf/d. The Creston plant is not included in this, as it would be expected to be served from the PGT pipeline, not by Westcoast.

Q. Have you directly inquired of Westcoast if it has plans to be able to serve demands beyond those which could be served with the 300 mmcf/d in capacity additions it has identified?

A. Yes. Mr. Douglas Haughey, President, Pipeline and Field Services Divisions of Westcoast Energy stated to me on June 5, 2000 that Westcoast does not expect more than 1,250 megawatts of new generation to be added in the next five years, and has no current plans to expand its capacity beyond the identified levels.

Q. What do you conclude with respect to the impact that approval of Sumas Energy II would have on other natural gas users?

A. If the plant is approved and constructed, I believe it will adversely affect the supply and price of natural gas for all users in western Washington. If it is approved and construction is not begun immediately, it will create uncertainty as to supply, which may inhibit other projects from moving forward.

Q. Do other types of electric generating facilities cause this type of adverse impact on existing users of fuel?

A. Generally not. Coal-fired power plants such as Centralia are often built at the location of the fuel supply. The coal mining capacity is added at the same time that the power plant is constructed, and there is no impact on the cost of coal supplies developed elsewhere. For nuclear facilities, fuel is a very small part of the total cost. Wind energy facilities constructed in one location do not use a fuel, which could be used in a different location. Landfill gas must be either flared or used productively, and there is no impact on other

landfills of using the waste gas from any particular landfill. Natural gas fired facilities are perhaps unique in this regard. Because substantially all of the natural gas in the state comes from Alberta and British Columbia over two pipelines, the reliability of supply and price of gas for all gas users in the state are potentially affected in a way that would not be the case for other types of generating facilities.

Q. Are there potential environmental impacts from gas price increases or supply constraints that should be considered prior to permitting a large additional natural gas use in the state?

A. Yes. If increased demand for gas causes supplies to tighten, large industrial customers who have the ability to burn heavy residual fuel oil may find it cost-competitive to do so. Heavy oil can have sulphur content as high as 3%, and the impact on sulphur dioxide emissions may be significant. There has been no analysis of the impact that the proposed facility may have on gas prices, and no analysis of the impact of gas prices on alternative fuel use by existing industrial customers. During the 20 years I have been involved in natural gas regulation in this state, there have been numerous occasions when industrial customers have reverted to high sulphur residual fuel oil.[3]

Q. What is your recommendation to EFSEC in this proceeding?

A. I recommend that the Council defer consideration of additional natural gas generation until a cumulative impact assessment on both price and supply of completing the existing permitted facilities is prepared, and an evaluation of the marginal cost of providing gas to serve the existing permitted facilities is available. There are already sufficient natural gas power plants approved for construction to meet Washington's share of the projected

[3] For example, in Cause No. U-86-100, the Washington Utilities and Transportation Commission permitted rates below the fully allocated cost of service to industrial customers, stating: "The Commission acknowledges the necessity of making prices to industrial customers more competitive with the prices of alternative fuels." [Cause U-86-100 Fourth Supplemental Order, P. 17]

regional supply deficiency. If it can be demonstrated that there will not be serious adverse impacts on either price or supply of gas from completing the existing permitted facilities should additional facilities be considered. Conversely, if there is a risk of a shortfall to existing gas users as a result of a proposed new facility, that adverse impact should be avoided.

Q. If this facility is to be approved without completion of a programmatic environmental impact statement or other statewide analysis, what restrictions should be placed on this Applicant as a condition of a site certification agreement to prevent adverse impacts on other natural gas consumers?

A. If the Council is to approve this facility without first preparing an assessment of the cumulative impact of gas fired generation, of if a cumulative impact assessment indicates an adverse impact on the price or supply of natural gas to Washington consumers, EFSEC should place restrictions which ensure that this specific facility does not adversely affect the reliability of fuel supply for the homes and businesses in the state. First, the Applicant should be required to contract for newly developed capacity on Westcoast Pipeline for delivery of gas from northern British Columbia to the border. This will avoid any adverse impacts in terms of gas transmission availability. Second, the Applicant should be required to contract for a minimum of five years of natural gas supply from newly developed natural gas supplies. This will avoid any short-term adverse impacts in terms of gas supply.

Over time, gas markets will recognize this additional demand, and it is likely that the price of gas to other consumers will be indirectly affected, but this is probably not something that EFSEC can address through conditions in the site certification agreement.

ALTERNATIVE BACKUP FUEL OPTIONS

Q. What is the proposed backup fuel for this project?

A. The Applicant is proposing to use distillate fuel oil (diesel) as the backup fuel when natural gas supplies are constrained or gas prices are high.

Q. What are the concerns with use of diesel fuel as a backup?

A. There are two concerns. First, there are air quality concerns. These include greatly elevated levels of emissions of oxides of nitrogen, sulphur dioxide, volatile organic compounds, particulate matter, and carbon dioxide compared with the use of natural gas. It is my understanding that other witnesses are addressing the air quality impacts of diesel use.

The second concern, and one which I address in this testimony, is the sheer volume of diesel fuel that could be consumed, and the potential impact this consumption would have on the availability of this important transportation and agricultural fuel for other diesel users.

Q. How much diesel fuel does the Applicant indicate it might use in a year?

A. In her testimony, Ms. Chaney indicates that the plant might operate on diesel fuel for 15 days per year. The DEIS indicates that this would total 616,656 gallons per day, or about 9.2 million gallons/year, or 220,000 barrels. That would be about 1% of total distillate fuel oil consumption in the entire state for automobile fuel, trucking, rail transportation, marine transportation (ferries, tugs, and ships) home heating oil, and agricultural needs combined. In a supplemental letter dated June 22, 2000, the Applicant has indicated that the use of fuel oil will not exceed an <u>average</u> of 10 days per year.

Q. What would the effect of this level of oil consumption be on availability and price for distillate fuel oil in the state?

A. If this was spread throughout the year, the impact would probably be modest on both supply and price. However, the facility is designed to store only about four days of backup fuel on-site, and if an extended period of high natural gas prices and/or natural gas supply curtailment occurred, the owners would likely be looking to acquire additional fuel to support continued operation of the facility. That is a very different matter. As shown in Exhibit ___(JL-3), the daily consumption of diesel by this facility would be equal to approximately 25% of the total daily distillate fuel oil consumption in the state. The short-term disruption of the transportation and home heating oil market if diesel demand suddenly increased by 25% could be significant. There is no practical way that the refineries could be expected to respond to a sudden 25% increase for demand of a single product. Because this is a daily impact during those specific days and years when the plant operates on backup fuel, the "10 day average" commitment of June 22, 2000 would not necessarily mitigate this risk.

Q. Has this issue been addressed previously with respect to combustion turbine construction in this state?

A. Yes. In the late 1970's and early 1980's, when Puget Power was proposing to construct what are now known as the Whitehorn 2/3, Fredrickson, and Fredonia power plants, the Oil Heat Institute of Washington raised concerns about the impact on diesel fuel supplies in the state. My recollection was that the Economic Regulatory Administration (which had jurisdiction at that time under the Powerplant and Industrial Fuel Use Act) required Puget to maintain a 9-day supply of backup fuel at the time they were approved for construction.

Q. Are you aware of a pending stipulation between between the Applicant and other parties that would limit the number of days of distillate oil firing to an average of 10 days per year over a 10 year period?

A. Yes, I am aware of this.

Q. Does this change your testimony?

A. No. First, the stipulation is not final as of the time this is being written, and I do not have the pertinent details to determine its effect or enforcability. The concern I raise is of a sudden increase in the daily consumption of diesel. The stipulation only deals with average usage over a period of years, not the number of days of usage of diesel in any particular year. My concerns about the impact on the diesel market of a sudden increase in state diesel demand on the order of magnitude that Sumas II could cause remains.

Q. Are there other impacts which you believe should be considered beyond the supply of home heating oil?

A. Yes, there are other critical uses of distillate fuel oil (diesel). The trucking industry is essentially 100% dependent on diesel. The state ferry system is 100% dependent on diesel. The railroads are 100% dependent on diesel. A sudden increase of diesel demand on the order of magnitude which Sumas could cause (25%) might create supply problems which could cripple the transportation infrastructure of the state.

Q. What is your recommendation in this proceeding?

A. If the Application is approved, the Site Certification Agreement should require the Applicant to keep 15 days of backup fuel in inventory as of November 1 of each year. That inventory need not be immediately at the site, but should be within a reasonable transportation distance of the site.

Q. What options for storage of backup supply do you recommend be considered?

A. The key requirement in any site certification agreement is that the Applicant be required to maintain 15 days of backup fuel supply by the beginning of the winter when gas supplies may be constrained. The storage location can be either on-site or within a short-haul transportation distance.

If the Council determines that the environmental effects of diesel operation are acceptable, then it would be appropriate to permit any combination of on-site storage

coupled with contractual storage at one or more of the refineries in Whatcom or Skagit Counties. I see no reason to expand the size of the on-site storage tank.

Q. Should oil storage in the Lower Mainland be an acceptable option?

A. While the Abbotsford refinery operated by Shell Canada is close to the site, and may be preferable from a truck haul perspective, I am skeptical about storage outside of the boundaries of the United States based on experience in the late 1970's, when exports of crude oil from Canada to the U.S. refineries were curtailed on relatively short notice. The purpose of permitting a facility is to secure reliable electric service for consumers. Because a need to rely on oil will occur on short notice during extreme weather, and the withdrawal of oil from storage may adversely affect other diesel users directly or indirectly, there may be reasons to exclude Canadian storage. The Company should bear the burden of demonstrating that there are no reliability risks associated with storage in Canada.

Q. What if the Council is persuaded that the environmental impacts of diesel backup are unacceptable? Are there other backup fuels available?

A. Yes. If the Council determines that the environmental effects of diesel operation are not acceptable, then it would be appropriate to require that the Applicant contract with a provider of liquified natural gas (LNG) storage for 15 days of standby operation.

Q. Is it practical to secure sufficient LNG capacity to operate a power plant of this size?

A. Yes. The daily consumption of the facility at full power is approximately one-third of the daily output of a typical 3 billion cubic feet (bcf) LNG facility. As of three years ago, there were three LNG facilities proposed for the immediate vicinity of the Sumas facility. Cherry Point LNG Company (an alliance of PGT and HNG Storage Company) proposed a 2 - 4.5 bcf facility for Cherry Point. Williams International Pipeline Company (like Northwest Pipeline, one of the Williams companies) proposed a 3 bcf facility for Sumas.

Finally, Westcoast Gas Services Inc, an affiliate of Westcoast Pipeline, proposed a 3 bcf facility on the Canadian side of the border at McNab Creek. Any of these facilities would contain enough natural gas to fuel the proposed facility for 20 - 40 days at full power. It would be possible for the Applicant to contract for a portion of the storage at any of these locations to meet backup fuel requirements. If this were done, there would be none of the air quality or market impact concerns, which would exist if diesel fuel were used, and the Council could then preclude the use of diesel as a backup fuel.

Q. What would be the approximate cost of this option?

A. The construction costs for the LNG facility proposed by Williams at Sumas (about twice the size needed to provide 15 days or 3 times the size needed to provide 10 days of backup to Sumas II) was estimated at $90 million (1997$). If it were owned by the developer of Sumas II, it would therefore add about 10% to the construction cost. The total facility cost of service was estimated by Williams at $6.54/mmcf. This is approximately equal to $38/bbl diesel equivalent, compared with a current diesel price of about $35/bbl. If the LNG service were taken under contract, rather than owned, the incremental fuel cost would therefore appear be modest relative to the cost of the diesel fuel for the proposed Sumas II project.

Q. What would be the advantages of using LNG as a backup fuel?

A. There are several advantages. First, the generating plant would be cheaper to build; there would be no need to have dual fuel capability, and that capability carries a price. This would tend to offset some part of the cost of construction of an LNG storage facility. There would be no need for a diesel storage tank. That would offset an additional part of the cost of construction of an LNG storage facility. There would be none of the additional air quality impacts from using diesel. Finally, there would be no risk of adverse impact on the state's diesel fuel supply.

Q. In preliminary discussions, the Applicant has indicated that they would be willing to limit their use of diesel to no more than 10 days per year. How would this proposal, if adopted, affect your recommendation above?

A. It would reduce the requirement for fuel oil inventory to 10 days, rather than 15 days. With approximately 4 days of inventory in the on-site, only 6 days of inventory would need to be maintained at an off-site location. I have not examined whether the proposed change would adversely affect the cost or reliability of natural gas supply to core market customers.

Q. In these same preliminary discussions, the Applicant has indicated that it would be willing to limit the oxides of nitrogen emissions to a level lower than examined in the DEIS during periods when the plant is operating on diesel fuel. How would this proposal, if adopted, affect your recommendation above?

A. My recommendation is not affected. If the Council approves the use of diesel fuel as a backup, then sufficient backup diesel fuel should be in inventory by November of each year. If the Council does not approve the use of diesel fuel, than sufficient backup in the form of LNG should be in inventory by November of each year. The issue of whether to permit the use of diesel fuel is an environmental issue, which is beyond the scope of my testimony.

SELF-MAINTAINED NATURAL GAS PIPELINE

Q. How does the Applicant plan to deliver natural gas to the facility?

A. The Applicant plans to build a second pipeline parallel to the existing pipeline serving Sumas I. This pipeline would be operated and maintained by the Applicant.

Q. What is the alternative means of providing natural gas to the site?

A. This area is served by Cascade Natural Gas, which holds a Certificate of Public Convenience and Necessity to offer natural gas service in the Sumas area. The Applicant could apply to Cascade for service.

Q. What would be the advantage of obtaining service from Cascade?

A. The primary public advantage is that the pipeline would be owned and operated by a regulated utility with a long history of providing safe and reliable service. In the event of a malfunction, Cascade would be in a position to respond on an emergency basis. Cascade serves other electric generation customers already. I question whether it is prudent from a safety perspective to have entities, which are not in the natural gas distribution business owning and maintaining natural gas pipelines. As a condition of approval of this facility, the Council might require the Applicant to turn over management of the existing pipeline to Cascade as well. There would be public benefits to having this customer served by Cascade. For example, Cascade's administrative, operation, and maintenance costs could be spread over a larger sales base, holding down costs to all customers, from residential through electric generation.

BUILD WINDOW

Q. What do you mean by the term "Build Window?"

A. I use that term to describe the period between issuance of a site certification agreement and the last date that commercial operation of the facility can occur before the permit lapses and a new permit must be applied for.

Q. Why should EFSEC have a limited Build Window?

A. EFSEC has previously approved plants at Creston, Longview, Chehalis, and Elma. None of these have commenced construction. I have discussed above how those plants, together with smaller units such as Tenaska I, are adequate to meet projected power needs. However, unless the developers contract for gas supply, secure transmission system access, and begin construction, there can be no assurance that the power will be available if and when it is needed. By requiring a limited Build Window, EFSEC can be more certain that a facility will be built, or that the Applicant will recognize that

circumstances preclude construction. The current situation, with many facilities approved but none under construction, seems to me to be unacceptable from a state energy policy perspective.

Q. Why is it unacceptable to have many facilities approved, but none under construction?

A. The uncertainty with respect to state energy planning is one concern. In addition, I previously addressed the fact that the approved plants exceed the planned gas pipeline additions, making it unclear whether the plant could operate if it were built. By requiring developers to build promptly, this type of uncertainty can be resolved.

Q. What has EFSEC required in the past for a Build Window?

A. In the past, EFSEC has required that construction begin within 5 - 10 years of a Site Certification Agreement.

Q. What Build Window do you recommend?

A. I recommend that this be reduced to 4 years for natural gas fired power plants. That is enough time to enter into a contract for the sale of power (as recommended by Mr. Warren as a condition of approval), secure financing, construct a facility, and begin commercial operation. A maximum of 2 years should be allowed between issuance of a Site Certification Agreement (or, perhaps the expiration of the appeal period following such issuance) and the commencement of construction. If the facility is not under active construction, with a contract let for the earthmoving and site preparation activities, the site certification agreement would lapse. An additional 2 years should be allowed to achieve commercial operation. This is entirely consistent with Mr. Eaden's testimony that the Sumas plant would be under construction commissioned in later 2002 and begin commercial operation in the first quarter of 2003.

Q. Why shouldn't "site banking" be permitted, with a ten-year Build Window as previously approved by EFSEC?

A. The 10-year Build Window has led to too much uncertainty. Developers of alternative facilities may be unwilling to proceed with construction knowing that other facilities could be constructed in the same time frame and glut the market with power, diminishing project economics. The concept of site banking may have made sense when only regulated utilities or independent power producers selling to regulated utilities were building power plants (and, therefore, the certainty of cost recovery was much higher). The current situation, with merchant plants being constructed on a speculative basis, could create a situation where because of a large number of approved facilities, no individual developer is willing to move forward until the economics become extremely compelling, meaning that the reliability of electric service has declined sharply.

SUMMARY

Q. Please summarize your recommendations.

A. First, I recommend that EFSEC commission a comprehensive review of the cumulative impact of natural gas fired electric generation on the cost and availability of natural gas for residential, commercial, and industrial service in the state. This review should be undertaken in conjunction with the Washington Utilities and Transportation Commission and the Energy Policy Division of the Department of Community, Trade, and Economic Development.

Second, I recommend that the Applicant be required to secure sufficient backup fuel capacity to avoid placing a sudden burden on the state's fuel supply infrastructure. This could be done by contracting for additional diesel fuel storage if the diesel option is approved by EFSEC, or by contracting for LNG storage. Annual operation of the plant on the backup fuel beyond the level of storage provided for in the Site Certification Agreement and held in inventory by the Applicant should require a declaration of an emergency by the Governor.

Third, I recommend that the Applicant's request to construct a self-maintained pipeline be rejected, and the Applicant be required to take service from a natural gas distribution company.

Finally, I recommend that the Applicant be granted only a short Build Window, with a requirement to begin physical construction at the site within 24 months, and begin Commercial Operation within 48 months of final approval of the Site Certification Agreement. If the Applicant misses either deadline, the SCA should be automatically terminated.

Q. Does this complete your testimony?

A. Yes.

END OF TESTIMONY