EXHIBIT NO. ___(SML-1CT)
DOCKET NO. UE-04____/UG-04____
2004 PSE GENERAL RATE CASE
WITNESS: SUSAN MCLAIN

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-04____** **Docket No. UG-04____**

PREFILED DIRECT TESTIMONY OF SUSAN MCLAIN (CONFIDENTIAL) ON BEHALF OF PUGET SOUND ENERGY, INC.

REDACTED VERSION

APRIL 5, 2004

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY OF SUSAN MCLAIN

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PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY OF SUSAN MCLAIN

I. INTRODUCTION

Q. Please state your name, business address and present position with Puget Sound Energy, Inc.

A. My name is Susan McLain. My business address is 10885 N.E. Fourth Street, P.O. Box 97034, Bellevue, Washington 98009-9734. I am the Senior Vice President, Operations for Puget Sound Energy, Inc. ("PSE" or "the Company").

Q. What is your educational and professional experience?

A. Exhibit No. ___(SML-2) describes my educational and professional experience.

Q. What are your duties as Senior Vice President for Operations?

A. I am responsible for all activities associated with the Company's gas and electricity delivery systems. This includes: system and maintenance planning; safety and standards; system design and engineering; gas and electric system construction and maintenance; substation construction, operations and maintenance; contractor and project management; system controls and protection; dispatch; emergency response; system mapping; quality assurance and control; operations performance measurement; purchasing and materials management; fleet management; and electric control center and electric transmission contracts.

Q. What is the purpose of your testimony?

A. I will discuss PSE's delivery operations, including our work to control costs associated with delivery operations and the Company's compliance with Service Quality Indices ("SQIs") related to delivery operations. I will also discuss challenges PSE faces in these areas, and some of the proposals we are making in this rate case to address such challenges.

Q. Please summarize your testimony.

A. PSE is facing increased customer demand, an aging infrastructure that requires increasing remediation and replacement, plus new federal, state and local regulations that require increased capital expenditures and maintenance costs. I discuss these pressures and PSE's efforts to control delivery operation costs. I also discuss PSE's request to continue the current accounting treatment associated with our TreeWatch program. Finally, I also discuss PSE's proposed revisions to the catastrophic storm definition so it more aptly covers costs incurred as a result of catastrophic damage to the Company's system, with provision for events that damage gas as well as electric facilities.

II. PSE HAS CONTROLLED COSTS WHILE KEEPING SERVICE QUALITY HIGH

A. Cost Control

Q. Has the Company taken steps to control costs over the past several years?

A. Yes. As outlined below, a wide variety of performance improvements and efficiencies have been implemented in order to provide higher quality service while lowering or controlling costs.

Q. Please describe some of PSE's efforts to reduce costs.

A. As one example, PSE has undertaken significant measures to coordinate work with municipalities. Whenever possible, PSE coordinates the timing of its utility infrastructure work to take advantage of improvements proposed by a municipality. For example, if a city plans to rebuild its sewer system, PSE will examine its remediation and capacity plans for facilities in that area to determine if PSE improvements can be made in collaboration with the city's project. PSE will take advantage of roadway openings and coordinate system planning and construction in conjunction with the municipal construction schedules.

Through a competitive bid process, we have also established long-term fixed unit pricing on the majority of our routine construction and maintenance work, which gives us both low cost and more predictability in cost. The longer-term, unit price contracting approach achieves scale economies, makes more efficient use of the workforce, and eliminates administrative expenses associated with issuing, processing and awarding bids.

Q. What programs has the Company implemented to control costs?

A. After the merger of Puget Sound Power & Light and Washington Energy Company in 1997, the Company developed a methodology to plan its gas and electric system infrastructure investments together. This process utilizes a variety of engineering modeling, financial analysis, and analytical hierarchy decision-making tools and is referred to as the Company's Total Energy System Planning ("TESP") process. TESP is a single planning and decision making process that does not favor gas projects over electric or vice versa.

The planning process and tools have evolved over time in an effort to optimize and improve the benefits obtained from capital spending. PSE's System Planning engineers utilize system data and engineering modeling tools to identify potential areas of system weakness. TESP is used to determine least-cost infrastructure investments and to prioritize those investments.

Additionally, the Company has recently created a maintenance planning group tasked with prioritizing maintenance spending. PSE also participates in industry groups, industry surveys, and other benchmarking initiatives to compare itself to industry averages and stay current on new ideas and trends in cost control.

Q. Please provide an example of how TESP has been used to prioritize projects.

A. Using the TESP process, the Company reviewed several alternatives that would support continued gas customer growth in the Gig Harbor area. These alternatives included a new high pressure main across the Tacoma Narrows waterway; a high pressure main and service from Cascade Natural Gas' Shelton supply system; a permanent Liquefied Natural Gas ("LNG") facility sited in the Gig Harbor area; or the continued use of mobile compressed natural gas ("CNG") and LNG vehicles to inject into the system during cold weather peaks. The evaluation of cost and reliability through TESP resulted in the decision to install a permanent LNG facility. It is now operational and will meet the planned demand for the next 20 years.

Q. Has the Company been successful in controlling costs?

A. Yes. Since 1999, the operations and maintenance costs associated with delivering energy on a cost per customer basis have been kept relatively constant despite inflationary and other cost pressures.

Q. How do you measure your cost control efforts?

A. We use a "cost per customer" measure, which takes into account additional system components that have been built to serve new customers and must now be maintained and operated. Examining costs on a cost per customer basis allows the Company to compare its performance in a consistent fashion against others and provides a framework to drive business performance improvements.

Q. How do PSE's costs compare with its historical costs?

A. On a cost per customer basis, there has been less than a 1% increase over the five-year period, from 1999 through 2003, or approximately a 0.2% annualized increase.

Q. Does PSE anticipate it can continue to manage costs at the present level?

A. We continually look for ways to reduce costs, but because of overall continued system growth, we have larger systems to maintain and the system is aging. As a consequence, resources must be sized to take into account the size of the system and age of system components. While PSE may be able to take short-term temporary cost cutting actions, primarily through the temporary deferral of system re-enforcement, PSE must invest in its system in order to continue to deliver safe, reliable, quality service. In many cases, short-term cost cutting actions may end up costing more in the long run because the asset replacement or maintenance costs increase disproportionately over time.

For example, a 1997 Deferred Utility Tree Maintenance study conducted by Environmental Consultants, Inc., as published in *Arborist News Magazine*, April 1997, shows that for every dollar ($1.00) deferred, between $1.16 and $1.27 will be needed to perform the same work in the following year and each subsequent year until the utility is back on its normal trimming cycle. Deferring needed system improvements often negatively impacts the quality of service to customers in either longer or more frequent electric outages, or increased frequency of gas odors and leaks.

Q. What are some of the challenges facing the Company in terms of maintaining the reliability of the existing system?

A. Without a continued programmatic approach to aging cables, cast iron, bare steel, substation equipment, district regulators and other components, PSE will have difficulty maintaining reliable service.

Using a programmatic approach saves money and accomplishes more by being able to focus designers and crews on holistic programs and repetitive processes, with definable anticipated results. Incorporating programs that result from emerging laws and codes such as pipeline integrity rules, potential underwater pipe inspection regulation, and transmission reliability will be challenging but manageable using the current planning and optimization process.

Moving forward, the Company will continue to review aging assets likely to impact system performance and corresponding costs. Measuring asset performance against metrics such as the System Average Interruption Duration Index ("SAIDI"), the System Average Interruption Frequency Index ("SAIFI"), gas leakage rates, and system utilization, as well as the evaluation of maintenance and replacement costs, helps determine priorities and develop the overall plan and programmatic approach.

B. Service Quality

Q. Has PSE been able to provide high quality service while keeping costs low?

A. Yes. Since the inception of SQIs in 1997, the Company has met or exceeded all benchmarks in the delivery operations area. In many of these areas, the Company has improved its performance.

Many of the SQI benchmarks for the delivery operations area were made more stringent, effective January 1, 2003, as part of the Company's general rate case settlement in 2002. Benchmarks that were made more stringent or added in 2003 were:

- Customer Satisfaction with Gas Field Services--from 85% satisfied to 90% satisfied;
- Non-Storm Electric Outage Frequency, also known as System Average Interruption Frequency Index (SAIFI)--from 1.384 average outages to 1.30 average outages;
- Non-Storm Electric Outage Duration, also known as System Average Interruption Duration Index (SAIDI)--from 142.7 minutes to 136 minutes;
- Electric Safety Response Time--reporting requirement began with January 1, 2003 data.

Delivery operations SQIs in which PSE has improved its service quality over time include three out of six areas: Customer Satisfaction with Gas Field Services: Average Gas Emergency Response Time; and Non-Storm Electric Outage Frequency (SAIFI). Exhibit Nos. ___(SML-3) through ___(SML-5) illustrate these trends.

Starting in 1997, the Company targeted investments that would reduce non-storm electric system outages, purposefully targeting improvement of our SAIFI performance. After several years of these investments, we found we were making significant improvement in reducing the number of outages but not the duration of outages. In 2002, we began placing emphasis on reducing the duration of outages. We expect investments made in 2003 and later years will improve our Non-Storm Electric Outage Duration (SAIDI) performance.

Q. Is PSE proposing any changes to the SQIs?

A. No, we are not seeking any changes as part of this case.

III. A HIGH LEVEL OF CUSTOMER GROWTH PLACES INCREASING COST PRESSURES ON THE COMPANY

Q. Has the Company seen a change in the demand for natural gas?

A. Yes. Since the merger, we have had significant growth in the number of natural gas customers, as well as an increase in overall natural gas load. Our gas customer additions have grown 13.7% from 1998 through 2002, or approximately 20,000 per year for an average of 3.4% per year. About 95% of this growth is in the residential sector. There was a slight slowing in customer growth during

2001, due primarily to the economic recession. Since then, our gas customer additions have steadily increased each year: 2.8% growth in 2002 and 3.6% growth in 2003. We expect customer growth to continue.

Besides an increase in the number of customers, we have also experienced an increase in total overall load of 5.7% in this same period, 1998 through 2002, as well as an increasing peak load. On January 4, 2004, we recorded a record sendout of 716,000 decatherms, breaking the previous record of 698,000 decatherms set on December 21, 1998.

Q. What is driving the increased demand for natural gas?

A. There are a number of factors driving the increased demand. First, economic conditions are driving investments in the home, leading to conversions, and new single family building permits are increasing (most such new construction involves installation of natural gas services). Second, since the energy crisis of 2000-2001, there is a broader awareness of the price of energy and a heightened commitment to look for ways to save. Natural gas continues to have a price advantage over other energies. As of January 2004, residential customers who choose natural gas can save, on average, 50% of what they would have spent using electricity, oil, or propane.

Q. How does the increased demand affect the gas delivery system?

A. This increased demand affects the Company's need for additional system capacity and maintenance projects, as well as additional resources to handle customer requests. New customer construction requests and growth impact the overall gas system in that new capacity projects and upgrades are required to ensure customers can be served during peak conditions. Large capital projects are required now to ensure future growth can occur and to maintain reliable service during peak conditions.

Q. Has the Company seen an increase in natural gas usage on a per customer basis?

A. No. The amount of natural gas used per residential customer has been steadily declining by approximately 2% per year for the last five years, and there is no reason to believe this trend will change. This appears to be primarily due to energy efficiency improvements in appliances and changing housing characteristics (such as better insulation, windows, building code changes, etc.) The increasing price of natural gas and its effect on consumer behavior (price elasticity) can also affect usage. This declining usage adversely affects the Company's revenues, as discussed in the testimony of Mr. James Heidell, Exhibit No. ___(JAH-1T). Under PSE's current rate design, this reduced usage results in underrecovery of the fixed costs required to make gas service available to individual households.

Q. In meeting this demand for new gas services, how does the Company recover its costs?

A. Both of PSE's line extension tariffs--Electric Schedule 85 and Gas Rule 7 (and the related Schedule 7)--recover costs only for the extension of PSE's delivery system to the new customer. The customer pays for the cost of the extension, as designated under the two tariffs, with an offset for the revenues (based on gas usage) or a margin allowance (for electric) that are expected to be received from the new customer over time. PSE has recently updated these tariffs to seek to ensure the tariff rates are sufficient to cover the line extension costs. However, neither line extension tariff provides for recovery of costs for the core system improvements needed to support growth.

Q. What steps has PSE taken to address the cost pressures associated with increased growth?

A. Overall, the major cost control measure undertaken by the Company was the outsourcing of repetitive construction and maintenance work, including new customer construction. Based upon an analysis using the Company's 1999 actual costs, the Company determined restructuring its existing contractor arrangements and moving all electric and gas crew work to two major suppliers would likely lower these construction costs. The model was put in place in gas and electric operations in 2001 and 2002, respectively. The Company continues to evaluate this outsourcing and, thus far, it is lowering the Company's construction costs.

In addition to the value of the contractor arrangements and the associated annual review of costs, collaboration with the builder community has also resulted in cost saving measures that have benefited all parties. For example, the majority of new residential single family job sites involve installation of new gas services. A jointly developed process for installation of new services has reduced the number of red tags, which are job sites unready for utility construction when the PSE contractor crew arrives. This prevents the crew from having to return at a later date. This collaborative work has resulted in more jobs being installed on the first trip, which provides direct savings for the builders and will ultimately mitigate costs for the Company when pricing reviews take place with the contractors.

Q. How much does the Company anticipate spending in the future to support this growth?

A. In the next five years (2004-2008), the Company anticipates capital spending to support growth in the following categories:

- Electric new customer construction (the construction of both line extensions in plats and services as requested by customers)--average annual expenditures of approximately $[redacted] million;
- Electric increased capacity (the construction and/or upgrade of facilities to support current and future anticipated system demands)--average annual expenditures of approximately $[redacted] million;
- Gas new customer construction (the construction of both main extensions and

services requested by customers)--average annual expenditures of approximately $[redacted] million; and

- Gas increased capacity (the construction and/or upgrade of facilities to support current and future anticipated system demands)--average annual expenditures of approximately $[redacted] million.

IV. PSE NEEDS TO REPLACE AND MAINTAIN ITS INFRASTRUCTURE AND SYSTEMS TO ENSURE SAFETY AND RELIABILITY

Q. Does the Company expect infrastructure costs will increase?

A. Over the next five years, PSE expects increased capital funding will be required for both the electric and gas systems to meet utilization targets, eliminate capacity constraints, address needs associated with the Company's aging system, and maintain SQI performance. Without the increase, maintaining rather than replacing increasingly older components can be expected to drive O&M costs up, as additional funding will be required to respond to system failures in a reactive, rather than proactive manner.

A. Gas Infrastructure

Q. Please describe the Company's gas infrastructure that requires maintenance or replacement spending?

A. Gas infrastructure includes PSE-owned gas mains, services, valves, cathodic protection sites, and pressure regulating stations needed to provide gas service to PSE customers. Existing infrastructure ranges in age from 1899 to new. PSE has added, on average, approximately $101 million in gas infrastructure each year since 1999. *See* Exhibit No. ___(SML-6) at page 1.

Of the $101 million of gas infrastructure added each year, over 15% is in the reliability, replacement and remediation area. In the next five years, the Company anticipates spending capital of approximately $[redacted] million per year in the gas reliability, replacement and remediation area. Projects included in this category improve the reliability of a system being impacted by construction and material defects, age, leakage, compliance initiatives, and replacement projects that arise due to unplanned events such as dig-ups.

PSE's inspection, maintenance, and replacement strategies for gas infrastructure are based on the age and condition of the equipment and regulatory requirements. Maintenance requirements for aging equipment often increase. For example, corrosion becomes more of an issue for aging steel gas mains than for newly installed gas mains. In order to maintain safe and reliable operation of this particular type of pipe, PSE has specific programs targeted at cathodically protecting a steel main or replacing it if it is more cost effective to do so. In addition to cathodic protection and main replacement, PSE has several other well-established programs including valve and gas regulating station inspection and maintenance.

Q. Is there a larger volume of assets requiring replacement and maintenance than in previous years?

A. Yes. PSE adds more gas plant each year that must be maintained at some point in the future. PSE has implemented a programmatic approach to replacement of aging facilities in order to manage costs and impacts to customers.

Q. How does the cast iron replacement program affect gas system reliability and safety?

A. Cast iron is an older vintage system and due to its material composition, may be more susceptible to leakage with age. Leakage can directly affect gas system reliability and safety depending on the proximity to the public as well as the impact to customers when mains have to be taken out of service for leakage repair. PSE actively evaluates systems that are more susceptible to leakage and has been aggressively replacing all of its cast iron since 1992. Such replacement has reduced the number of gas leaks in PSE's system. Exhibit No. ___(SML-7) is a graph of Repaired Leaks on PSE's Cast Iron Main System since the inception of the program.

Q. What is the status of the cast iron replacement program?

A. Since the inception of the program, PSE has replaced 233 miles of cast iron main. The 15-year program will be completed in 2007 with remaining annual replacements of approximately 13.6 miles pe

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Q. What are the costs associated with this work?

A. Since 1999, the Company has spent $25 million on this program. PSE anticipates an average annual budget of approximately $[redacted] million for the remaining years of the program.

Q. How does the bare steel replacement program affect gas system reliability and safety?

A. For the same reasons PSE replaces cast iron mains, the Company also has been actively replacing or cathodically protecting bare steel mains. PSE initiated the bare steel program in 2002. In addition to main replacements, certain bare steel mains that are in excellent condition can be cathodically protected in order to reduce the likelihood of future leakage at a cost lower than full replacement. Thus, unlike the cast iron program, not all the bare steel in PSE's system is intended for replacement in the short term.

Q. What is the status of the bare steel replacement?

A. Since 2002, PSE replaced 17.7 miles and added cathodic protection to 6.2 miles of bare steel. Approximately 190 miles of unprotected main remain. The Company intends to accelerate this replacement program following the completion of the cast iron replacement program in 2007.

Q. What are the costs associated with this program?

A. Since its inception in 2002, the Company has spent $8 million on this program. PSE anticipates an annual budget of approximately $[redacted] million through 2008. Upon completion of the cast iron replacement program, PSE expects to redirect dollars currently allocated to that program to the bare steel replacement program.

Q. How does the critical bond program affect gas system reliability and safety?

A. In addition to replacing older mains more susceptible to leakage due to material composition and/or aging, PSE protects newer, wrapped steel mains from corrosion to maximize their useful life and reduce the potential for leakage through the application of cathodic protection. The critical bond program helps ensure the cathodic protection system can be adequately monitored for its performance.

Q. What is the status of the critical bond program?

A. Since 1999, PSE has added 2,537 test sites to the cathodic protection system. A review of the entire system and installation of cathodic protection systems is scheduled to be completed in 2007. At this time, there are 91 impressed current cathodic protection systems and 821 galvanic cathodic protection systems remaining where test sites will be added.

Q. What are the costs associated with the critical bond program?

A. Since 1999, the Company has spent $10.2 million on this program. PSE anticipates an average annual capital budget of approximately $[redacted] million through 2008.

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Q. Are there other maintenance and repair needs that must be addressed in order to ensure continued gas reliability and safety?

A. The integrity management program is a new and ongoing regulatory requirement mandated by the Pipeline Safety Improvement Act of 2002 ("PSIA"). The Company is in the process of performing the required assessment, which will determine the scope of any necessary remediation.

Q. In addition to the programs previously discussed, are there any other areas where gas infrastructure expenditures are made?

A. Yes. As a condition of the Company being able to use public rights-of-way, the Company is required from time-to-time to relocate its facilities as outlined in a specific jurisdiction's franchise. This has averaged over $7 million per year for the five-year period ending in 2003. In the next five years, the Company anticipates an average annual capital budget to support these relocations of approximately $[redacted] million. The higher future expenditure level is due to our anticipation of significant road and transportation projects.

B. Electric Infrastructure

Q. Please describe the Company's electric infrastructure that requires maintenance or replacement spending.

A. Electric infrastructure includes PSE-owned transmission and distribution conductors, transformers, circuit breakers, structures, switches, and associated apparatus needed to provide electric service to PSE's customers. Existing infrastructure ranges in age from 1917 vintage to new. PSE has added, on average, approximately $105 million in electric infrastructure each year since

1999. *See* Exhibit No. ___(SML-6) at page 2.

Of the $105 million of electric infrastructure added each year, approximately 37% is in the reliability, replacement and remediation area. In the next five years, the Company anticipates spending capital of approximately $[redacted] million per year in the electric reliability, replacement and remediation area. Projects included in this category improve the reliability of a system which can being impacted by trees, animals, construction and material defects, age, compliance initiatives and projects that arise due to unplanned events such as car-pole accidents or equipment failure.

PSE has several well-established maintenance and refurbishment programs including cable replacement and substation maintenance. Maintenance and replacement strategies are based on the age and condition of the equipment. Maintenance requirements often increase for aging equipment. PSE uses planned inspection and maintenance programs to identify or mitigate problems in a proactive manner.

Q. Please describe PSE's underground cable remediation program.

A. The goal of the underground cable remediation program is to remediate all high molecular weight polyethylene insulated (HMW) 15kV cables while preventing cable outages from exceeding 1,500 per year. Initially the Company's program entailed either abandonment or direct replacement of HMW cable. Since 1996, PSE has injected some of these cables with silicon rather than abandoning or replacing them. Silicon injection results in restoration of the insulation quality of the cable, extending the life of the cables for 20 years or more without the disruption and costs of trenching through established neighborhoods.

Cables are selected for remediation using a prioritization process in which Company-wide outage history is reviewed. Those neighborhoods or commercial areas with repeated outages are reviewed for remediation. Factors evaluated are: number and frequency of outages due to cable failures, number of customers affected, neutral condition, and length of the outages.

Q. What is the status of this program?

A. The underground cable remediation program is an on-going reliability initiative by PSE. 2003 marked the fourteenth year of the cable remediation program, resulting in a total of over 1,490 miles of cable remediated to date, out of the approximately 4,800 miles of HMW cable installed.

Q. What costs does the Company face related to cable remediation?

A. Since 1999, the Company has spent $40.1 million on this program to remediate 437 miles of cable. The Company faces ongoing costs to remediate HMW cables for another 15-20 years. Based on current costs and the goal of no more than 1,500 cable outages per year, the Company expects to spend approximately $[redacted] million over the next 15-20 years on cable replacement. Acceleration of this remediation program is being considered, should the Company experience higher cable failure rates due to cable age and condition.

Q. Please describe PSE's substation maintenance program.

A. PSE applies Reliability Centered Maintenance (RCM) principles to identify maintenance activities for substation equipment. This has allowed the Company to utilize inexpensive inspection and maintenance methods to identify developing problems that could result in equipment damage or customer impacts.

For example, during 2003, almost 9,200 preventive tasks were performed in our substation maintenance program. These tasks ranged from visual inspections of substations and equipment to overhauls of circuit breakers. Most of the maintenance tasks were low cost, non-intrusive actions designed to identify and mitigate problems before they result in significant equipment damage, or customer impacts. For example, in 2003, 97.5% of the substation maintenance tasks had a weighted average cost of $102 per task. The remaining 2.5% of maintenance tasks were higher cost, intrusive tasks designed to address failures or to improve the condition of worn components. Costs for these had a weighted average cost of $3,156 per task.

Q. Please describe the increasing costs the Company faces relating to substation maintenance.

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A. We are facing increasing costs due to equipm resulting in a gradual degradation of equipment. Eventually, this results in equipment that can no longer function reliably or at all.

Q. What is the status of the Company's pole replacement initiatives?

A. PSE began a ground inspection program in 1999 to inspect the approximately 31,500 transmission poles on its system. Since the program's inception, 84% of our transmission poles have been inspected. As a result of our inspection efforts, 708 poles have been replaced.

PSE currently replaces distribution poles based both on field reports and the use of the TESP pole replacement program, which reviews areas of pre-1961 installed poles and prioritizes them for replacement.

During 2003, 598 distribution poles were replaced as part of the proactive TESP pole replacement program. Approximately 525 additional distribution poles were replaced when they were damaged during storms or when field reports indicated immediate replacement was necessary.

Q. What are the costs associated with pole replacements?

A. Since 1999, the Company has spent $14.5 million in capital and $3 million in O&M on the proactive replacement of 708 transmission and 2,009 distribution poles. Through 2008, PSE's anticipates an average annual budget of $[redacted] million for replacement of poles. The Company may increase proactive replacement should inspections indicate the need to do s

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Q. In addition to the programs previously discussed, are there any other areas where electric infrastructure expenditures are made?

A. Yes. As with gas infrastructure, the Company is required from time-to-time to relocate its facilities as outlined in a specific jurisdiction's franchise, or to accommodate other utility work, or upgrades to PSE facilities that are part of a regional transmission grid project. The Company also undertakes conversions of existing overhead line to underground facilities under its tariff Schedule 74. Expenditures in this area have averaged over $14 million per year for the five-year period ending in 2003. In the next five years, the Company anticipates capital spending to support these types of expenditures of approximately $[redacted] million per year. The reason for the anticipated increase is due to expected road and transportation projects, as well as anticipated regional transmission grid projects.

V. THE EXPIRING TREE WATCH PROGRAM SHOULD BE CONTINUED

Q. What is TreeWatch?

A. In the mid-1990s, a study was conducted by Environmental Consultant Inc., which showed trees on private property more than 15 feet from PSE's overhead conductors caused over 60% of PSE's non-storm tree related outages. The TreeWatch program was implemented in 1998 for the purpose of removing dead, dying and diseased trees from private property along PSE's distribution system that present a danger to PSE's overhead facilities. TreeWatch differs from PSE's vegetation management program in that it focuses on trees located off PSE's rights-of-way.

Q. What is the status of the TreeWatch program?

A. The TreeWatch program is progressing according to plan and is scheduled to end on June 30, 2004. Customer acceptance of the program has been positive. The cost effectiveness of the program, as last reported in the May 1, 2003 filing with the Commission, has also exceeded expectations. *See* Exhibit No. ___(SML-8).

Q. Do you plan to continue the TreeWatch program?

A. Yes. Although TreeWatch was originally considered a one-time program, we believe a continuation of the program will benefit ratepayers. By continuing the program, PSE can preserve the enhanced vegetation impact areas along the distribution corridors that the original TreeWatch program established. Over time, currently healthy trees will die, thus reducing the enhanced reliability we have achieved. By preserving the new clear area, PSE's customers will continue to receive the benefit of a safer and more reliable overhead system well beyond the original ten years of estimated benefit.

Additionally, PSE plans to utilize TreeWatch to create new, enhanced vegetation management areas outside of PSE's rights-of-way along targeted transmission corridors. The August 14, 2003 blackout in the eastern portion of the U.S., which was triggered by vegetation, highlights the importance of utilizing all available vegetation management practices in transmission corridors.

Q. What is the Company's proposal with respect to the TreeWatch program?

A. The original TreeWatch program was a one time, deferred asset program which has proven it can deliver cost-effective improvements to system reliability and safety. The Company seeks approval to continue the existing program, but at a reduced level of expenditure: $2 million annually. Because the existing program expires in June 2004, the Company intends to file an accounting petition prior to the expiration date to continue deferring these costs pending the Commission's decision on PSE's proposal in this rate case.

VI. CATASTROPHIC EVENTS

Q. Please describe the catastrophic events affecting the Company and the corresponding losses sustained by the Company as a result of these events.

A. Windstorms are not uncommon in the Pacific Northwest, and PSE is allowed a provision for an average level of storm damage in rates. However, some storm events are so severe they cause widespread outages and damage to our infrastructure. These extraordinary events are unpredictable and uncontrollable. In order to deal with large, one-time expenses from extraordinary storm events, the Commission has approved deferral and recovery of such expenses over time. This helps to mitigate the financial impact of catastrophic storm events in the year they occur.

Q. How does the Commission currently define extraordinary losses from catastrophic events?

A. Currently, a catastrophic storm is defined as an event where more than 25% of PSE's electric customers are without power due to weather-related causes.

Q. What is the Company's current practice for amortizing these losses?

A. These costs are deferred and, when approved for recovery by the Commission, they are amortized to expense over 3 years.

Q. What is the storm damage reserve under the existing policy that the Company proposes to be amortized?

A. The catastrophic storm damage reserve the Company proposes to be amortized in this case equals $18,497,304, which will be amortized over three years, starting March 1, 2005 to February 28, 2008, at $6,165,768 per year. *See* Exhibit No. ___(JHS-E3).

Q. Is the current threshold for extraordinary losses appropriate?

A. No, the percent-of-customers threshold has no relation to the potential system impacts and related costs of an event.

Q. Is the Company proposing a change to the definition of extraordinary losses from catastrophic/extraordinary events?

A. Yes. The current definition of extraordinary storm damage is restricted by the threshold of percentage of customers without power. However, the Company's electric plant investment covers a diverse area including significant rural and low-density population areas. Because the current definition is customer/outage based, it does not recognize the plant investment the Company has in less populated areas can be severely damaged during catastrophic events, and can require extensive restoration. Even though the number of customers that may be impacted in these areas would not reach the 25% criteria for extraordinary storm damage, the cost of repair and restoration of service can be equivalent to a similar repair effort in a high-density population area.

For example, the snow and ice storm of January 7-9, 2004 caused widespread damage in rural King, Pierce, Thurston, and Kitsap Counties. At its peak, 146,500 customers were without power. Outages existed on 60 distribution circuits, 6 transmission lines were down, and 10 substations were off-line. Approximately 78 line and tree crews and 63 servicemen were involved in restoration efforts. The total cost was $5.7 million, which was expensed, as the 25% criteria to defer cost was not met. This is in contrast to the November 23, 1998 storm with costs of $4.8 million and the January 16, 2000 storm with costs of $2.7 million, both of which met the 25% customer criteria and were deferred.

Notably, 63% of the overhead distribution system and 58% of the in-state transmission system is outside of King County. An event causing outages for 100% of our Whatcom, Skagit, and Island County customers would not qualify for deferred treatment under the current definition. For the most part, an event must include King County to currently qualify, and even then it may not.

Another problem with the current definition relates to the context in which the policy was implemented. The definition of catastrophic storm, which was developed in Puget Sound Power & Light Company's 1992 general rate case, predated the merger with Washington Energy Company. Thus, it was focused on damage to Puget Power's *electric* system.

In addition, the current definition does not clearly protect the Company from catastrophic damage caused by *non-storm* events, such as earthquakes or terrorism.

Q. What is the Company's proposal to replace the definition of catastrophic storm?

A. The Company requests the Commission change the definition of "catastrophic storm" to "catastrophic event" and include damage to our electric and/or gas infrastructure due to catastrophic natural events, such as windstorms, ice storms, and earthquakes, and also to cover manmade disasters such as terrorist attacks on our infrastructure. The new definition should include extraordinary events causing severe damage to PSE's electric and/or gas infrastructure resulting in repair and restoration costs beyond what would be considered a reasonable level. Events causing $2 million or more damage exceed what is reasonable for a single event, and the Company seeks approval to defer those costs under the current catastrophic damage accounting treatment.

Q. What is the impact of this definition on the measurement of the SQIs?

A. None. There is no change in the way in which the Company would calculate either non-storm SAIDI or non-storm SAIFI.

Q. Does this conclude your testimony?

A. Yes, it does.

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