EXHIBIT NO. ___(SML-1CT)
DOCKET NO. UE-06___/UG-06___
2006 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-06____ Docket No. UG-06____

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

CONFIDENTIAL per
WAC 480-07-160

FEBRUARY 15, 2006

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF SUSAN MCLAIN

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PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF SUSAN MCLAIN

I. INTRODUCTION

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

A. My name is Susan McLain. My business address is 10885 N.E. Fourth Street Bellevue, WA 98004. I am the Senior Vice President, Operations for Puget Sound Energy, Inc. ("PSE" or the "Company").

Q. Have you prepared an exhibit describing your education, relevant employment experience, and other professional qualifications?

A. Yes, I have. It is Exhibit No. ___(SML-2).

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

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; regulatory compliance; 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; electric control center and electric transmission contracts on the Company's system

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

A. My testimony describes the job the Company has been doing in controlling the costs associated with delivering electricity and natural gas to PSE's customers while at the same time maintaining high levels of service quality.

Despite these successes, PSE's aging infrastructure, expanding customer base, and the Company's need to comply with increasingly stringent safety and environmental standards place substantial and increasing cost pressures on the Company. These cost pressures have escalated to the point that costs related to the Company's gas and electric infrastructure investments and maintenance reflected in the test period for this case--the twelve months ended September 30, 2005--are far below the costs that the Company anticipates incurring during the rate year for this case--calendar year 2007--and beyond.

PSE will need to be in a position to invest the increased amounts it is projecting in its gas and electric infrastructure in order to maintain and promote system integrity and reliability, provide for public and worker safety, and maintain existing levels of service quality.

II. PSE CONTINUES TO CAREFULLY CONTROL ITS COSTS WHILE PROVIDING HIGH QUALITY SERVICE TO ITS CUSTOMERS

Q. Has the Company attempted to control its costs before coming in for a rate increase?

A. Yes. The Company has carefully controlled its costs, both with respect to capital costs and operations and maintenance costs. Looking at all non-production/generation operations and maintenance expenses on a cost per customer basis, PSE is, and expects to remain, one of the lowest cost providers among investor-owned utilities in the United States. *See* Exhibit No. ___(SML-3).

Q. What steps has the Company taken to control its costs?

A. PSE has implemented a wide variety of process and performance improvements that have resulted in cost efficiencies as well as the provision of high quality service. The Company also has tools and methodologies in place to allocate its resources efficiently in support of gas and electric system reliability. In addition, I describe later in my testimony the outsourcing of construction and maintenance work and the programmatic system maintenance and replacement projects that help the Company control its transmission and distribution system costs.

As part of this effort, PSE participates in industry groups, industry surveys, and other benchmarking initiatives to compare the Company's performance to industry averages and best practices and to stay current on new ideas and trends in cost control.

Q. Please describe some of PSE's process and performance improvements and resulting efficiencies?

A. As one example, PSE has undertaken measures to coordinate work with municipalities in order to save costs. Whenever possible, PSE coordinates the timing of its utility infrastructure work to take advantage of synchronized construction with 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.

PSE also works with municipalities to value engineer or jointly develop innovative solutions to minimize utility relocation costs. An example of this recently occurred in the City of SeaTac. PSE was faced with the possibility of relocating an 800-foot section of 16-inch high-pressure gas main due to City road improvements with an estimated cost of $300,000. PSE's work with the City led to an engineering solution that allowed the Company's gas main to remain in place and resulted in an estimated $240,000 of cost savings.

With respect to internal processes, PSE Operations has internal control processes in place where each and every new or vacant staff position is reviewed by senior management to ensure alternative process efficiencies have been considered and a solid business case justifies every full time or temporary staffing placement.

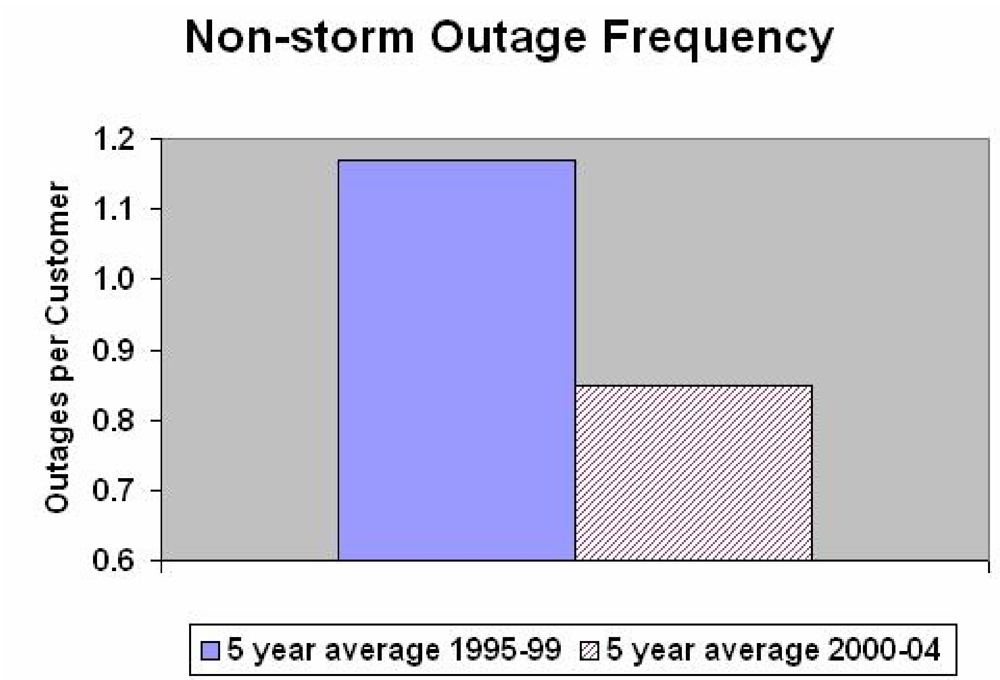
Q. How does the Company allocate its resources to support gas and electric system reliability and minimize costs?

A. The Company has developed a proven methodology to effectively 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 Total Energy System Planning ("TESP") process. TESP is a single planning and decision making process that allows the Company to evaluate and prioritize capital and maintenance spending initiatives and programs and does not favor gas projects over electric or vice versa. The planning process and tools have continued to evolve over time in an effort to optimize and improve the benefits obtained from the Company's capital and operations and maintenance spending.

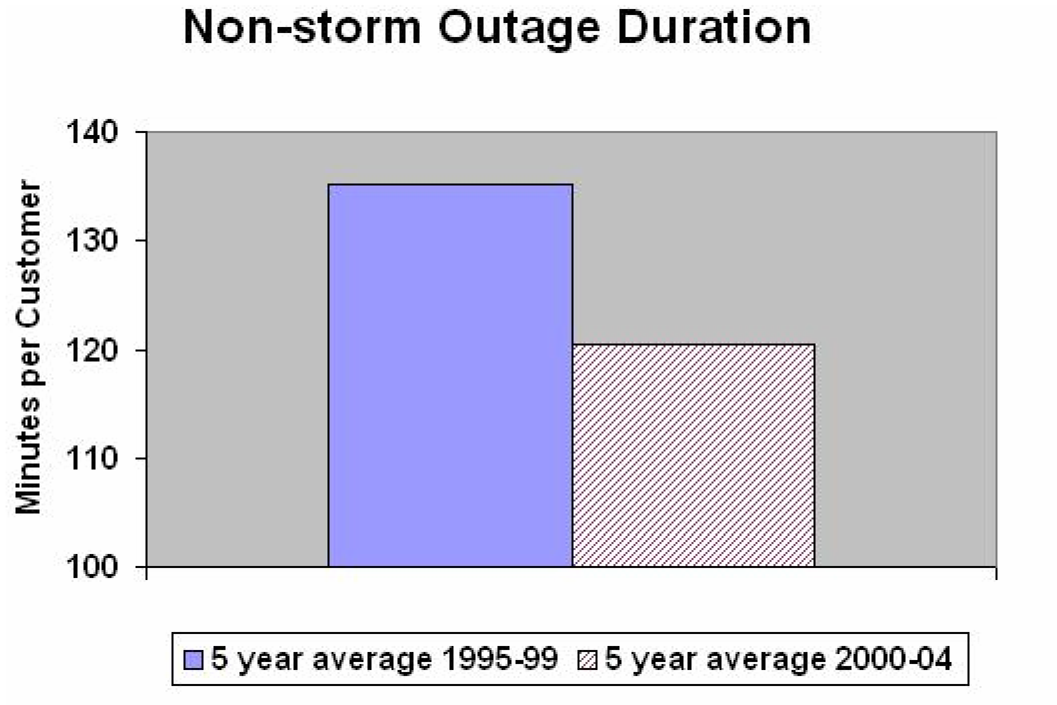
Q. Have PSE's reliability investments and maintenance programs reduced customer service disruptions and improved gas system integrity?

A. Yes. PSE's ongoing reliability, asset replacement and remediation, maintenance, and vegetation management programs have reduced customer service interruptions and strengthened PSE's delivery systems. As a gauge of program effectiveness, PSE regularly measures performance against industry standards for system reliability and integrity.

PSE's electric customers are experiencing, on average, fewer and shorter electric system interruptions. Looking at historical five-year averages for non-storm System Average Interruption Frequency Index ("SAIFI") performance, PSE's customers have experienced, on average, a 28% reduction in the number of interruptions per customer, as shown below.



Looking at historical five-year averages for the non-storm System Average Interruption Duration Index ("SAIDI") performance, PSE's customers have experienced, on average, a 11% reduction in the duration of interruptions per customer, as shown below.



SAIDI and SAIFI are key performance indicators utilized by PSE in monitoring and measuring electric system customers' system availability.

Additionally, PSE's reliability investments and maintenance programs have improved the gas system performance and increased capacity, which has resulted in fewer mandatory curtailments and a system that is less susceptible to corrosion and environmental degradation.

Q. Has PSE continued to provide high quality service notwithstanding the challenges facing its transmission and distribution systems?

A. Yes. Since the inception of the Service Quality Index ("SQI") system in 1997, the Company has met or exceeded all benchmarks in the delivery operations area.

Q. Are you concerned about the Company's ability to continue to meet the operations area SQIs?

A. Yes, I am. Although PSE has been able to deliver high quality service for many years, additional transmission and delivery infrastructure investments must be made in order to continue to deliver good service, as described below.

In addition, I am generally concerned about meeting the expectations of PSE's customers with respect to the quality of service that we provide. PSE's expanding customer base seems to be increasingly aware of, and sensitive to, any disruption in utility service. As customers use more electronic equipment, they are becoming more sensitive to even minor disruptions in service that may have been tolerated in the past. In addition, when customers relocate from urban areas to rural settings they can be frustrated with the higher frequency of power disruptions in rural areas of PSE's service territory. While urban areas tend to have greater redundancies and relatively infrequent power disruptions, rural areas have fewer alternate power feeds and more frequent tree-related disruptions. It may become increasingly difficult to continue to meet our customers' expectations even if we are successful in maintaining historical service quality levels.

III. PSE NEEDS TO ADD TO, REPLACE AND MAINTAIN ITS GAS AND ELECTRIC INFRASTRUCTURE TO ENSURE SYSTEM INTEGRITY AND RELIABILITY

A. <u>PSE is Facing Transmission and Distribution Investments and Related Operations and Maintenance Costs Substantially Higher Than Recent Historical Levels</u>

Q. What is the magnitude of the financial challenges facing PSE related to its electric and natural gas transmission and distribution systems?

A. In order to meet the operations challenges described in my testimony, PSE is facing:

- <u>The need to make substantial investments in PSE's transmission and distribution system</u>. Anticipated investments of $[redacted] million in 2006 and $[redacted] million in 2007 are considerably higher than historical investment levels of $266 million in 2004 and $286 million in 2005. *See* Exhibit No. ___(SML-4) at 1. PSE's expected transmission and distribution system capital investments for 2006 and 2007 total $[redacted] million. This exceeds PSE's 2004 and 2005 transmission and distribution investments of $552 million by $[redacted] million, or [redacted]%. The $[redacted] million anticipated investment for 2007, the rate year in this case, is $[redacted] million greater than the test year investments of $228 million. This represents a [redacted]% increase in PSE's transmission and distribution system capital investment. These increases are driven primarily by adding more gas and electric distribution system capacity, constructing new electric transmission facilities, adding electric substation capacity, programmatic replacement and remediation of aging gas and electric facilities, and relocating existing facilities at the direction of local jurisdictions.

- <u>Increasing operations and maintenance expenditures needed to operate PSE's transmission and distribution system</u>. Anticipated expenditures (excluding storm costs) of $[redacted] million in 2006 and $[redacted] million in 2007 are considerably higher than historical levels of $88 million in 2004 and $104 million in 2005. During the rate year (2007) alone, PSE expects operations and maintenance

> expenditures of nearly $[redacted] million for its transmission and distribution systems. This is $[redacted] million greater than the test period expenditures (excluding storm costs) of $92 million and represents a [redacted]% increase. These increases are driven primarily by increased gas and electric maintenance requirements, regulatory compliance, vegetation management and locating costs, and Operations & Maintenance Related to Construction cost.

Q Are such increases expected to be temporary?

A. No, the Company expects that ongoing investments, similar to those planned for 2006 and 2007, will be needed for many years beyond 2007.

In addition, there are other issues that have just begun to impact PSE's transmission and distribution system costs but are expected to drive costs higher in the future. For example, PSE and the entire utility industry are facing the serious issue that many long term and experienced skilled craft, technical and professional employees have left or will be leaving the workforce to pursue retirement. Industry research shows that over 60% of the workforce is over the age of 45. An analysis of PSE's workforce mirrors industry data with approximately 60% of the Company's staff older than age 45. PSE expects that 40% of its employees will retire within 10 years. Locating and hiring replacements is challenging and costly. High housing costs, particularly in King County, can be a detractor in PSE's ability to hire and retain employees. The Company has also experienced lengthy candidate searches and must plan for extended training periods with overlap to transfer specific PSE system knowledge to the new staff.

B. A High Level of Customer Growth Places Increasing Cost Pressures on the Company

Q. Please describe the increases the Company has experienced in new electric and natural gas customers and overall natural gas load.

A. The Company's gas customer base grew by 17% or nearly 103,000 customers, from 2001 through 2005. This is approximately 20,600 per year for an average of 3.3% per year. About 96% of this growth is in the residential sector.

Besides an increase in the number of customers, PSE has also experienced an increasing peak load. On January 4, 2004, PSE recorded a record sendout of 716,000 decatherms, breaking the previous record of 698,000 decatherms set on December 21, 1998.

The Company's electric customer base grew by 10% or more than 94,000 customers from 2001 through 2005. This is approximately 18,900 per year for an average of 2% per year. Approximately 88% of this growth is in the residential sector.

Besides an increase in the number of customers, the Company also experienced an increase in total overall electric load of approximately 7% in this same period, 2001 through 2005.

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

A. There are a number of factors driving the increased demand for natural gas. First, with economic growth in the region, population in PSE's service territory has increased. Most new housing units, especially single family homes, are equipped with natural gas. Second, even with recent increases in the price of gas, the cost of heating with natural gas continues to have an advantage over the cost of heating with electric or oil; hence, conversions from electric and oil to gas furnaces in older housing stock are expected to continue.

Q. How does this increased demand affect the energy delivery system?

A. For both the gas and electric systems, this increased demand results in the need for additional system capacity and maintenance projects, as well as additional resources to meet customer requests. Large capital investments, such as the $32 million, 14 mile, high pressure "Everett Delta" gas main project, are required to provide for growth and to maintain reliable service to existing customers during peak conditions. Benefits from investments of this type were made apparent during the mid-December 2005 "cold snap" when below freezing temperatures were experienced for multiple consecutive days. PSE's need to take cold weather actions (such as curtailing gas deliveries to some customers) were greatly reduced from what had been necessary in previous years with similar system demands.

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

A. No. The amount of actual natural gas used per residential customer has been steadily declining by approximately 3% per year for the last five years. This appears to be primarily due to energy efficiency improvements in appliances and changing housing characteristics (such as better insulation, windows, building code requirement changes, etc.). The increasing price of natural gas and its effect on consumer behavior (price elasticity) also affects usage. Declining usage adversely affects the Company's revenues, as discussed in the testimony of Mr. Ron Amen, Exhibit No. ___(RJA-1T). As Mr. Amen explains, this reduced usage results in under recovery of the fixed costs the Company incurs to make gas service available to individual households.

Q. Doesn't the Company recover its costs related to new customers through its line extension tariffs?

A. Both of PSE's line extension tariffs, Electric Schedule 85 and Gas Rule 7 (and the related Schedule 7), only recover costs related to the extension of PSE's delivery system to the new customer. The customer pays for the cost of the extension, 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 regularly updates these tariffs in an effort to ensure the tariff rates are sufficient to cover the line extension costs. However, neither line extension tariff provides for recovery of costs for backbone system improvements needed to support growth. As an example, the cost of a typical substation ranges from $3 million to $5 million and can take two to four years to design, permit and construct. It would be very difficult to isolate such costs and associate them with specific new customers. In addition, there are often reliability or system performance benefits associated with such improvements that are shared by existing, as well as newer, PSE customers.

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

A. A major cost control measure undertaken by the Company was the outsourcing of repetitive construction and maintenance work, including new customer construction. The change was put in place in gas and electric operations in 2001 and 2002, respectively. In early 2005, these contracts were renewed at fixed prices through 2006 with options to extend the contracts through 2008. The Company has periodically evaluated savings associated with outsourcing electric and gas crew work. This model has lowered construction costs and the Company continues to realize value for PSE's customers as a result of these contractual arrangements. Other cost control measures related to operations are described later in my testimony.

C. <u>Much of the Company's Aging Gas and Electric System Assets Require Replacement</u>

Q. How is the age of the Company's system related to increased costs?

A. The Company has an aging transmission and distribution system in which many assets have reached or are approaching the end of their service lives, and they require replacement. Details regarding the programmatic manner in which the Company is approaching these issues are described later in my testimony for the gas and electric systems, respectively.

In addition, the costs required to replace transmission and distribution system assets far exceed the costs incurred by the Company and added to its ratebase when the components were originally installed. For example, the cost to install a 45 foot distribution pole has increased from $470 in 1974 to over $2,300 in 2004. For certain gas facilities, the costs have increased even more dramatically, as the cost to install one foot of 2-inch diameter plastic gas main has increased from $3 per foot in 1974 to nearly $22 per foot in 2004. It is not simply that there have been increases in the costs for the physical asset involved, but that additional costs related to the physical asset are now required. For example, current requirements for construction permitting and inspection and preventative actions to minimize soil erosion were not necessarily required in original installations, as they are today.

Q. Do such increased capital investment requirements for the transmission and distribution systems have any impact on the Company's operations and maintenance costs?

A. Yes, capital infrastructure investments generate an associated Operations & Maintenance Related to Construction cost ("OMRC"). As prescribed by Federal Energy Regulatory Commission ("FERC") accounting practices, when certain construction activities take place, there is an associated operations and maintenance component. For example, if an older gas main is replaced but the service lines going to individual residences and businesses are not replaced, then the work associated with tying the existing services into the new gas main is considered an operations and maintenance expense. As capital infrastructure investment is increased, the Company anticipates OMRC will increase to $[redacted] million in 2006 and $[redacted] million in 2007. These amounts exceed the 2004 OMRC level of $6 million and the 2005 OMRC level of $11 million.

Q Could the Company delay some of these replacements and thereby avoid these cost increases?

A. Although some replacements of aging equipment could be delayed, maintaining rather than replacing increasingly older components can be expected to drive up operations and maintenance costs due to an increasing need for maintenance and to respond to system failures in a reactive manner. Short-term cost cutting actions can end up costing more in the long run because the asset replacement or maintenance costs increase disproportionately over time. In addition, deferring needed system improvements often negatively impacts the quality of service to customers through longer or more frequent electric outages or decreased gas system reliability and integrity.

Q. What steps has PSE taken to address the cost pressures associated with its aging system?

A. PSE employs several targeted asset maintenance and replacement programs designed to reduce service disruptions, extend asset life, reduce costs and improve efficiency. Using a programmatic approach saves money and accomplishes more by focusing designers and crews on holistic programs and repetitive processes with definable, anticipated results. Examples of these programs include cable remediation, line and substation maintenance, pole treatment and replacements, and cast iron and bare steel replacements. These programs are discussed in greater detail below.

D. Details Regarding PSE's Gas Infrastructure Investment Needs

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

A. Gas infrastructure includes PSE-owned gas mains, services, valves, meters, cathodic protection sites, and pressure regulating stations needed to provide gas service to PSE customers. Replacement and remediation projects target system components being impacted by age, leakage, compliance initiatives, and replacement as a result of unplanned events such as dig-ups.

Q. What is the magnitude of the Company's gas infrastructure maintenance or replacement spending?

A. PSE has, on average, made investments (other than new customer connections) of approximately $60 million in gas infrastructure each year since 2001. PSE anticipates investments of $[redacted] million will be required in 2006 and $[redacted] million in 2007 for similar types of gas infrastructure. *See* Exhibit No. ___(SML-4) at 2. This represents a [redacted]% increase over PSE's 2004 and 2005 investments of $140 million. PSE's system analysis indicates that ongoing gas system investments similar to 2006 and 2007 will be needed for several years beyond 2007.

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

A. Yes. For decades PSE has been adding gas plant that has been operated and maintained and which eventually must be replaced. Many of PSE's gas assets are nearing the end of their useful life and are in need of replacement. PSE has implemented a programmatic approach to the replacement of aging facilities in order to manage costs and impacts to customers. Examples of these efforts include the cast iron and bare steel pipe replacement programs.

Q. How do the cast iron and bare steel replacement programs affect gas system reliability and safety?

A. Although state-of-the art when installed, cast iron is more susceptible to leakage due to its physical characteristics and joining technology. Bare steel is more susceptible to the influences of external corrosion, which may result in increased leakage over time. 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 working toward replacing all of its cast iron since 1992. In addition, the bare steel system has undergone planned replacement for areas exhibiting increased leakage. In 2005, PSE began a more aggressive bare steel program that will result in replacing all unprotected bare steel main by the end of 2014.

Q. What is the status of the cast iron and bare steel replacement programs?

A. Since the inception of the program, PSE has replaced 265 miles of cast iron main. The 15-year program will be completed in 2007 and annual replacements of approximately 12 miles per year remain. During 2004 and 2005, PSE replaced a total of 18 miles of bare steel main. Approximately 171 miles of unprotected bare steel main remain. Commission Docket Nos. PG-030080 and PG-030128 prescribe future replacements of 18.8 miles to be completed annually.

Q. What are the costs associated with this work?

A. PSE has made total investments of $36 million on the cast iron replacement program since 1999 and anticipates capital investments of approximately $[redacted] million per year during 2006 and 2007.

PSE has made investments of $17 million on the bare steel replacement program since 2002 and anticipates capital investments of approximately $[redacted] million per year in 2006 and 2007.

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. PSE anticipates total investments of $[redacted] million during 2006 and 2007 in this area, which represents a [redacted]% increase over PSE's 2004 and 2005 investment level of $22 million. The anticipated increase is due to expected road and transportation projects, as well as increased requirements during project construction, such as erosion remediation, restrictive work hours for traffic or noise mitigation and increased restoration requirements.

Q. Has the Company initiated other gas system maintenance and inspection programs?

A. Yes, through Company initiatives and collaborative negotiations with the Commission Staff, the following program enhancements have been instituted: (i) an increased leak survey schedule; (ii) continuing surveillance deployment; (iii) isolated facilities identification and remediation; (iv) SAP software enhancements for inspection scheduling; and (v) a wrapped steel service assessment study. These enhancements are preliminarily estimated to cost approximately $[redacted] million in operations and maintenance and $[redacted] million in capital during 2006 and 2007.

Q. For what new gas system compliance regulations is the Company responsible?

A. "Integrity management" is a new and ongoing regulatory requirement mandated by the Pipeline Safety Improvement Act of 2002 ("PSIA"). In order to comply with PSIA, PSE developed and implemented a pipeline integrity management program that incorporates inspection, remediation, formal documentation and record keeping processes. PSIA addresses transmission pipeline integrity and a total of 30 miles of PSE's pipeline system falls under PSIA. As required by PSIA, PSE's program targets 9.5 miles of transmission pipeline in High Consequence Areas with mandated actions. PSE conducts annual assessments of the other 20.5 miles of pipeline for compliance with other state and federal requirements and to determine if changes in the surrounding area warrant reclassification to a High Consequence Area.

Q. Are there any other regulatory requirements that are increasing costs?

A. Yes, another example of gas system compliance regulations relates to the licensing requirements for PSE's Gas First Response employees. Under Washington State Department of Labor & Industries ("L&I") regulations promulgated in 2000, PSE employees performing maintenance on customer natural gas fueled appliances (e.g., furnaces and water heaters), gas system remote telemetry units ("RTU") and cathodic protection ("CP") rectifiers were required to secure an 06 and 07 electrician's license. The 06 electrician's license is necessary to install or maintain electrical equipment such as RTUs, CP rectifiers, and furnaces and the 07 electrician's license is required to perform residential maintenance, repair, or replacement of existing water heaters.

Initially, the impact to PSE was limited because existing technicians were grandfathered with an 06 electrician's license. However, recent L&I interpretations of the Washington Administrative Code ("WAC") licensing requirements have a significant impact on PSE. First, all existing grandfathered employees must prepare for and secure the 07 electrician's license. Second, all new employees performing appliance repair must secure both 06 and 07 licenses by passing a state test. Additionally, for a new employee to secure an 06 and 07 electrician's license, he or she must first serve as an apprentice working under direct supervision for 4,000 hours.

Q. Has the Company attempted to mitigate the impact of this requirement?

A. Yes, initially PSE attempted to reduce the impact of this regulation by requiring an electrician's license for new hires. However, it became apparent that there were not enough applicants with both the electrician's license and the necessary apprentice training in the maintenance and repair of natural gas appliances to meet the demand. This has forced PSE to look at providing more existing PSE employees with the necessary 4,000 hours of apprentice work to secure the required electrician's license. The corresponding impact to PSE is that it forces the Company to double the employees responding to customer requests for repair of natural gas fueled appliances (historically, a single employee would respond) in order to allow employees to secure their 4,000 hours of supervised apprentice work.

As PSE looks beyond the test year and into the future, the impact of this regulation will only continue to increase the cost to PSE of complying with the necessity of an electrician's license for gas field employees.

E. Details Regarding PSE's Electric Infrastructure Investment Needs

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

A. Electric infrastructure includes PSE-owned transmission and distribution poles, cables, conductors, transformers, circuit breakers, structures, switches, controls and associated apparatus needed to provide electric service to PSE's customers.

Reliability, replacement and remediation projects include work designed to improve system components which can be impacted by trees, animals, environmental degradation, age, compliance initiatives and projects that arise due to unplanned events such as car-pole accidents, dig-ups 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. But, maintenance requirements often increase for aging equipment. PSE uses planned inspection and maintenance programs to identify or mitigate problems in a proactive manner.

Q. What is the magnitude of the Company's electric infrastructure maintenance or replacement spending?

A. PSE has, on average, made investments (other than new customer connections) of approximately $81 million in electric infrastructure each year since 2001. PSE anticipates that investments of $[redacted] million will be required in 2006 and $[redacted] million in 2007 for similar types of electric infrastructure. *See* Exhibit No. ___(SML-4) at 3. This represents a [redacted]% increase over PSE's 2004 and 2005 investments of $223 million. Based upon PSE's analysis of the system, ongoing electric system investments similar to 2006 and 2007 will be needed for several years beyond 2007.

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

A. Yes. For decades PSE has been adding electric plant that has been operated and maintained and which eventually must be replaced. Many of PSE's electric assets are nearing the end of their useful lives and are in need of replacement. PSE has implemented a programmatic approach to the replacement of aging facilities in order to manage costs and impacts to customers. Examples of these efforts include the pole replacement and cable remediation programs.

Q. Please describe the Company's pole replacement programs.

A PSE began a ground inspection program in 1999 to inspect the approximately 31,500 transmission poles on its system. By the end of 2005, all of the Company's transmission poles have been inspected. During 2005, approximately 140 transmission poles were proactively replaced as part of the transmission pole replacement program. The inspection identified an additional 7,000 structures where further review is needed to determine the timing and scope of pole and crossarm replacement schedules. Poles and crossarms identified as needing future replacement will be included in capacity upgrade or other projects when possible in order to minimize overall costs.

Distribution poles are replaced on a planned basis through the distribution pole replacement program. During 2005, approximately 350 distribution poles were proactively replaced as part of this program. This program focuses on poles that were purchased and installed prior to changes in Company specifications requiring full-length pressure treatment of poles in the early 1960s. PSE also replaces transmission and distribution poles when poles are damaged by storms or falling trees, in relocation or other planned projects or when poles are identified by field personnel during day to day operations as needing accelerated replacement.

During 2005, approximately 830 distribution and transmission poles were replaced on an unplanned basis. In total during 2005, PSE replaced over 1,300 poles.

PSE conducted a pilot transmission and distribution pole inspection and treatment program in 2005. Information gathered will be used to develop and implement a comprehensive 10-year transmission and distribution pole inspection and treatment program for PSE's approximately 357,000 poles. The objectives of the program are to utilize pole reinforcement (external bracing), replacement and wood preservative treatment in order to minimize the number of unplanned pole replacements and maintain pole assets at the lowest possible cost. The Company will inspect approximately 35,700 poles each year through this program.

Q. What are the costs associated with pole replacements?

A. In 2005, the Company spent approximately $4 million in capital and $1.2 million in OMRC on the proactive replacement of transmission and distribution poles. PSE anticipates proactive investments of $[redacted] million in capital and $[redacted] million in OMRC for replacement of transmission and distribution poles for the two-year period 2006 and 2007. The Company will likely increase proactive replacements should the results from the new planned distribution pole inspection and treatment program indicate the need to do so based on pole condition.

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

A. The goal of the Company's 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 program entailed either abandonment or direct replacement of HMW cable. Since 1996, PSE has injected some of these cables with silicone fluid rather than abandoning or replacing them. Silicone injection results in restoration of the insulation quality of the cable, extending the life of the cables for up to 20 years or more without the disruption and costs of trenching through established commercial areas or 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, physical condition of the cable, and length of the outages.

Q. What is the status of this program?

A. The underground cable remediation program is an ongoing reliability and cost control initiative. 2005 marked the sixteenth year of the cable remediation program, resulting in a total of over 1,821 miles of cable remediated out of the estimated 4,800 miles of HMW cable installed Company-wide.

In order to maintain the objective of less than 1,500 cable outages per year, the program was expanded in 2004. For example, the annual cable outage rate in year 2001 was 1,076 outages. By 2003 the annual outage rate had risen to 1,333 outages. Accelerating the program in 2004 and 2005 lowered the outage rate to 1,139 outages in 2005. While the total miles of HMW cables have been reduced, the failure rate of the remaining cable is increasing. As a result, PSE continues to monitor the performance of these cables to determine if the remediation program should be expanded further.

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

A. The Company faces ongoing costs to remediate HMW cables for another 13 to 18 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 13 to 18 years on cable replacement. PSE anticipates total investments of approximately $[redacted] million in 2006 and 2007.

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

A. Substation maintenance costs will increase in response to development and implementation of maintenance programs for some substation equipment that historically had been operated without a maintenance program. The need for these additional programs is driven primarily by focused efforts to increase the asset life of aging equipment at the least cost. They include, for example, repair or replacement of pincap insulators, transformer load metering, oil level monitoring equipment, and foundation and substation equipment structure repair.

Electric line maintenance costs for overhead wire, switches and right of way access roads are expected to increase due to the equipment, development of maintenance practices for assets that have historically been operated without a maintenance program, and other changes (such as increased development around PSE's transmission lines).

In addition, inspections are showing that some aging equipment needs to be retrofitted or maintained on a more frequent cycle in order to keep equipment in good working order. For example, PSE's operating experience with an older technology substation transformer showed that the transformer had to be retrofitted with new parts, in order to prevent a buildup of carbon sludge from interfering with the equipment's reliable operation. Another example is transmission line switches that degrade due to exposure to the elements and, as a result, must be inspected and maintained to prevent the switches from overheating and melting.

Q. Are regulatory requirements increasing costs associated with substation maintenance?

A. Yes. For example, on July 17, 2002, the Environmental Protection Agency ("EPA") published the newly revised Spill Prevention Control & Countermeasure ("SPCC") rule. Numerous changes directly impact electric utilities within the United States. A key change is the inclusion of "users of oil" in the regulation. This directly impacts the utility industry as it specifically addresses oil filled electrical equipment with a capacity of 55 or more gallons of oil, and facilities with 1,320 or more gallons of oil on site. Under the rule, facilities of this type are required to have an SPCC plan. This has a major impact on PSE, as most of its 350 substations contain more than 1,320 gallons of oil. To meet the regulatory requirement, sufficient spill containment must be present at facilities to prevent a release of oil from reaching navigable waters. These changes must be implemented by August 18, 2006.

Q. Please describe the Company's vegetation management program.

A. PSE's vegetation management program includes tree trimming, vegetation removal and replacement, and targeted herbicide application for vegetation located in the right of way and growing proximate to PSE's overhead distribution and transmission lines. Vegetation pruning on the distribution system occurs on a four-year cycle in urban areas and a six-year cycle in rural areas. Vegetation pruning on the transmission system occurs on a three-year cycle. For the last three years, PSE has spent in excess of $8 million of operations and maintenance dollars per year for proactive vegetation management on its overhead system.

Q. What changes are anticipated in PSE's vegetation management program?

A. A change affecting all vegetation management programs is the critical area ordinances, mandated by the Growth Management Act in Washington State. These regulations have been implemented in King County and similar changes are being implemented throughout PSE's service territory. These regulations require extensive mitigation activities in association with PSE's vegetation management line clearance activities. The ordinance in effect in unincorporated King County has increased PSE's costs for performing vegetation trimming by $112 per overhead line mile, a 3% increase. These are new costs to the Company that did not exist prior to the enactment of the ordinance. It is estimated that as other counties enact their ordinances, PSE's costs will increase accordingly. Another change to transmission system vegetation management is the addition of new miles of transmission line, which will increase vegetation maintenance costs.

Q. Are any other changes in the program anticipated?

A. Yes, major changes are also developing in transmission system vegetation management practices as a result of the August 11, 2003 blackout in the Northeastern United States. A report commissioned by the FERC found that a major cause of the blackout was conductors sagging into trees on the rights of way. As a result, the North American Electric Reliability Council ("NERC") is implementing a transmission vegetation management reliability standard for transmission lines rated 200kV and above. This reliability standard includes 17 best practices and requires utilities to annually report on their overall vegetation management plan and standards, identify which lines will be maintained in that year, and report vegetation related outages.

PSE has historically adhered to 16 of the 17 best practices identified. The practice that was not being followed was the wire zone/border zone right of way practice. This practice requires creating a predictable and low-growing environment of vegetation under and adjacent to rights of ways. PSE has historically allowed topped trees in some rights of way, which will no longer be permitted under the wire zone/border zone right of way practice because of a concern that such trees may cause an outage if loading and temperatures cause conductors to sag into the trees.

Q. How will changes to the vegetation management program impacts costs?

A. These program changes are expected to cost nearly $1 million per year.

Q. Please describe the Company's TreeWatch program.

A. PSE's TreeWatch program, which removes dead, dying and diseased trees from private property along PSE's overhead system, became a $2 million operations and maintenance program on March 1, 2005, per the Commission's final orders in PSE's 2004 general rate case, Docket Nos. UG-040640 et al. PSE is currently focusing on applying this treatment to the transmission and high voltage distribution systems, and to previously treated distribution system circuits where reliability results did not meet expectations. The benefits of this program are a safer and more reliable overhead system.

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 for 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 at some expense to the Company under its tariff Schedule 74. PSE anticipates investments of $[redacted] million during 2006 and 2007. This represents a [redacted]% increase over PSE's 2004 and 2005 investments of $23 million. The anticipated increase is due to expected road and transportation projects, as well as increased requirements during project construction, such as erosion remediation, restrictive work hours for traffic or noise mitigation and increased restoration requirements.

Q. For what new electric transmission reliability measures is the Company responsible?

A. PSE's transmission system is planned and operated according to reliability criteria that are established by the North American Electric Reliability Council ("NERC") and the Western Electricity Coordinating Council ("WECC"). These criteria consist of both the NERC/WECC planning/operating standards as well as the WECC Reliability Management Systems ("RMS"). After the August 2003 blackout in the Northeastern United States, NERC clarified and consolidated all 90 of its standards into a new Version 0, which became effective on April 1, 2005. More NERC standards are being developed.

In anticipation of these evolving reliability standards, PSE is proactively planning new transmission infrastructure to continue to maintain a reliable system. PSE anticipates average annual expenditures of $23 million in 2006 and 2007 to meet emerging needs.

Q. Please provide an example of a transmission investment that you have made to comply with these requirements?

A. PSE has recently completed the $6 million Bothell – Sammamish 230kV transmission line project. PSE's project is a part of a larger joint effort which included related transmission improvements by Seattle City Light and Bonneville Power Administration and directly supports Northwest electric companies' efforts to control congestion on the Puget Sound Area Network. The coordinated effort not only benefits PSE by adding load service capacity, but it also benefits the region's electric customers by providing additional regional transfer capacity. This project included the reconductor of approximately 14 miles of PSE transmission line and the rebuild of two dead-end terminal structures.

Q. Has the Energy Policy Act of 2005 impacted PSE with respect to infrastructure investments?

A. The Energy Policy Act of 2005 amends the Federal Power Act to make additional reliability standards for the bulk-power system mandatory and enforceable, and gives FERC jurisdiction over the reliability of the bulk-power system in the United States. Although not yet finalized, administrative and compliance costs for PSE are likely to increase, perhaps significantly. The impacts to PSE planning, operations, and compliance activities will become more apparent as FERC's rulemaking unfolds and will consume resources to implement and monitor the evolving rules.

IV. CONCLUSION

Q. Please summarize your testimony.

A. PSE continues to be an efficient, low-cost provider of high-quality electric and natural gas service to its customers. However, the Company's aging electric and gas transmission and distribution systems and high levels of customer growth are resulting in major operational challenges that are accelerating over time. Substantial and continued capital investments and operations and maintenance expenditures will be required if PSE is to continue to provide reliable, safe and high quality service to its customers.

Q. Does that conclude your testimony?

A. Yes.

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