PUGET SOUND ENERGY

Electric Service

Reliability Report

2007 Annual Report

Submitted March 2008

In Compliance with WAC 480-100-398

CONTENTS

ELECTRIC SERVICE RELIABILITY REPORT
2007 ANNUAL REPORT

EXECUTIVE SUMMARY

This is Puget Sound Energy's (PSE or the Company) annual Reliability Report which covers the calendar year 2007, as required by WAC 480-100-398, Electric Service Reliability Reports.

Safe and reliable electric service at a reasonable cost is one of PSE's paramount goals. Information in this report is filed to provide the Washington State Utilities and Transportation Commission (Commission) and customers with reliability metrics on the service that PSE provides its customers. Information on electric reliability is provided from several perspectives. The first perspective is provided by the traditional reliability metrics including the number and duration of outages as measured against the Service Quality Indices (SQIs) established by the Commission in 1997. The second perspective is from sub-system information relating to outages by county, circuit, and cause. The third perspective includes customer concerns about service quality and reliability, received either firsthand or through the Commission.

In early 2005, PSE met with Commission Staff to enhance the format of this report and information provided. As a result, this report includes more detail regarding the three perspectives mentioned above. Specific enhancements include a broadening of the definition of Areas of Greatest Concern, the inclusion of circuit data and project identification, and the comparison of metrics using the SQI methodology against the new Institute of Electrical and Electronic Engineers (IEEE) methodology.

Based on the SQI and IEEE Methodologies, year 2007 SAIDI decreased by 22% and 12% (respectively), and year 2007 SAIFI decreased by 21% and 12% (respectively) when compared to the same metrics for 2006. Despite the improvements in the reliability metrics in 2007, the 2007 SAIDI did not meet the SAIDI SQI. The lower than benchmark performance was mainly the result of an unusually high number of outages due to wind events in January. None of the events met the criteria of a "major event" as defined in the SQI criteria and thus these outages and outages minutes were included in the Company's SAIDI performance for 2007. The January 2007 monthly performance of 54.8 minutes is more than three times the 2001-2006 January average of 15.8 minutes. If January 2007 had been an average January (based on the 5-year PSE SAIDI average), PSE would have met its 2007 SAIDI benchmark.

As this report's data shows, the total number of customer complaints in 2007 increased by 15% from 2006. Further detail on weather events is provided in Section III.

Table 1 "Summary For 2006-2007", summarizes the overall reliability results for 2007 and compares them to 2006.

TABLE 1 - SUMMARY FOR 2006- 2007

	2006	2007
Complaints		
PSE	23	32
Commission	56	59
Total	79	91
Statistics		
PSE SAIDI SQI	136	136
*SAIDI (Non-Storm)	214.45	167.11
PSE SAIFI SQI	1.3	1.3
*SAIFI (Non-Storm)	1.23	0.97
Number of Customers (Avg.)	1,033,546	1,053,821
Number outages (Non-Storm)	13,845	11,984
Major Events Impact		
Days	34	16
Total Number of Customers Impacted	1,342,624	466,108
Average Number of Customer's Impacted	39,489	29,132
Average Percentage of Total Customers	4%	3%

* Data for SAIDI and SAIFI calculated using the SQI method.

Section III "System Level Reliability", and IV "Subsystem Reliability", of this report details the system-wide and county reliability metrics as well as circuit results and outage causes in each county. Section VI, "Areas of Greatest Concern", identifies portions of the electric system in King, Jefferson/Kitsap, and Thurston counties as Areas of Greatest Concern based on the trend in system performance, number of customers affected, and complaints. While PSE believes that this annual report provides useful information to interested parties for the calendar year 2007, PSE cautions against putting too much emphasis on the usefulness of this information in determining year-to-year trends pertaining to system performance. A single year's result does not lend to adequate identification of the best solution for long term improvement. Actions taken based on an annual snapshot may result in "band-aid" solutions which may not meet long term objectives.

SECTION I – BACKGROUND AND PURPOSE

Electric utilities subject to commission jurisdiction are required to provide statements describing their reliability monitoring in an annual report pursuant to WAC 480-100-393 and WAC 480-100-398 as a result of monitoring. These rules were adopted in the Commission's rulemaking in Docket Number UE-991168.

WAC 480-100-393 (3) (b) requires the establishment of baseline reliability statistics. These baseline statistics are the established service quality indices established by the commission in 1997.

WAC 480-100-398 requires annual reporting of electric service reliability. This information is contained in this document, which reports Puget Sound Energy's (PSE) reliability metrics for the calendar year 2007.

PSE's electric system covers a nine county geographical area.

SECTION II – METHODOLOGY

This section describes the methodology used in defining and calculating reliability metrics which are then used to evaluate performance. WAC 480-100-398 (2) requires a utility to report changes made in this methodology including data collection and calculation of reliability information after the initial baselines are set. The utility must explain why the changes occurred and how the change is expected to affect comparisons of the newer and older information.

In the 2004 Annual Electric Service Reliability Report, PSE indicated that starting in 2005, reliability metrics using the Institute of Electrical and Electronic Engineers (IEEE) standard 1366 methodology as a guideline would be included. PSE has included a comparison of three key metrics in Table 2 "Comparison between Methods 2003-2007", using the IEEE methodology versus the methodology used when the SQIs were established. The methodology used when the SQIs were established defines Major Event Days as those days in which five percent or more customers are out of power during a twenty-four hour period. For purposes of this report, this is called the "SQI method". This methodology includes days which include customers that are still without power after the first day of a major event.

The purpose for moving to the IEEE standard 1366 methodology is to provide uniformity in reliability indices, identify factors which affect these, and aid in consistent reporting practices among utilities. T_{MED} (Major Event Day Threshold) is the reliability index that facilitates this consistency. A detailed equation for calculating T_{MED} is provided in Appendix A.

While the IEEE guidelines provide a standard for the industry, it is important to note that companies can create a variety of definitions of an outage or sustained outage. PSE defines sustained outages as those lasting longer than one minute as described in Appendix B – Data Collection. IEEE defines a sustained outage to be longer than five minutes. PSE will continue to use the one minute definition as PSE believes that tracking shorter duration outages allows us to better monitor the performance of the electric system and subsequently assess potential system improvements.

Table 2 "Comparison Between Methods 2003-2007", illustrates comparisons of three key metrics using the SQI and IEEE methods for the period 2003 through 2007. Both methods result in SAIDI and SAIFI metrics that are within six percent for years 2004 and 2005, but diverge for the years 2003, 2006 and 2007. The number of Major Event Days can vary year to year based on characteristics of the event and the previous five years of history as this is the basis for the IEEE method. Also, one method can account for more days one year and less the next year. There does not appear to be a correlation between number of days being included in one method versus the other and the difference in SAIDI or SAIFI results using those methods. For example, in 2003, fewer days were Major Event Days (and therefore excluded from the metric calculations) using the IEEE method versus the SQI method, at 9 versus 13, respectively. At the same time, SAIDI was also lower using the IEEE method versus the SQI method, at 106.73 versus 133.39, respectively. One might have expected a higher value for SAIDI based on the IEEE method (since less days were excluded from the calculation), but this was not the case.

TABLE 2 - COMPARISON BETWEEN METHODS 2003- 2007

Metrics	Year	PSE SQI Method	IEEE 1366 Method
SAIDI	2003	133.39	106.73
	2004	112.78	113.75
	2005	128.65	129.82
	2006	214.45	162.97
	2007	167.11	143.51
SAIFI	2003	0.8	0.71
	2004	0.77	0.77
	2005	0.94	0.95
	2006	1.23	1.03
	2007	0.97	0.91
Major Event Days	2003	13	9
	2004	9	5
	2005	7	4
	2006	34	24
	2007	16	7

Focusing in on 2007, there were sixteen Major Event Days meeting the five percent of total customers out criteria (SQI method) and there were seven Major Events Days using the IEEE methodology. Table 3 "Major Event Day Comparison", highlights the specific days for comparison.

TABLE 3 - MAJOR EVENT DAY COMPARISON

	2007 MAJOR EVENT DAYS	SAIDI	SAIFI
IEEE Method Threshold (Tmed) = 6.87	January 02	8.34	0.04
	January 05	11.53	0.05
	January 06	20.60	0.04
	January 09	23.47	0.07
	October 18	57.50	0.16
	November 12	40.35	0.08
	December 02	7.93	0.07
SQI Method	Jan 9 - Jan 12, 07	31.94	0.11
	Oct 18 - Oct 21, 07	62.13	0.17
	Nov. 12 - Nov. 15, 07	39.67	0.08
	Dec. 2 - Dec. 5, 07	11.59	0.08

As well as incorporating the new IEEE method for this reporting requirement, Puget Sound Energy also expanded the definition of Areas of Greatest Concern over the original submittal which was defined by the number of customers and commission complaints. PSE now defines Area of Greatest Concern by considering the trend in system performance based on circuits that exceed the SQI, number of customers affected by those circuits, and complaints. This aligns actual planning practice with this reporting requirement. During the planning process these concerns are evaluated along with other items such as load growth, other reliability concerns or improvement opportunities, maintenance needs, municipal concerns, and corporate commitments. Solutions are proposed that attempt to meet multiple issues and stakeholder concerns. The highest valued projects across all categories move forward in the process. Chapter 7 "Delivery System Planning" of PSE's "2007 Integrated Resource Plan" report provides a discussion regarding the planning and optimization process.

SECTION III – SYSTEM LEVEL RELIABILITY

Puget Sound Energy's overall system outage duration metric (SAIDI) in 2007 did not meet the established SQI due to the weather related events in 2007, however significant improvement was made over 2006. The overall system outage frequency (SAIFI) metric in 2007 did meet the established SQI. Our focus on reducing the average frequency and duration of electric system outages had resulted in PSE continually meeting the established SQI prior to 2006. PSE will continue to manage the number of outages and their duration overall for the system to meet the established SQI, and we will evaluate opportunities to modify sections of our electric system to perform more effectively in the environments that they are located within.

In January 2007, the Puget Sound Region experienced unusually high wind events following extreme wet weather in December 2006, which resulted in several major events to start the year. After relatively uneventful second and third quarters, October 18, November 12 and December 2 experienced wind storms with recorded gusts between 47-53 mph.[1]

Figure 1 "SAIDI Historical Trends" and Figure 2 "SAIFI Historical Trends" illustrate the comparison between the SQI, PSE methodolgy and IEEE methodology for the last ten years. For the time period 1998-2005, we met the SQI requirements for each of these metrics. Clearly, this was not the case for 2006 and 2007, as our SAIDI metric increased significantly due to the unique combination of weather events which took place during these two years. The anomalous 2006-07 conditions render trending analysis more difficult at this time. As has been the case during past years, we continue to focus on identifying projects that will reduce SAIDI, while managing other aspects of system performance. We will also continue to monitor our system performance metrics with the goal of identifying trends and causes and, ultimately, identifying other possible improvements.

[1] "Winter Weather Review," *Skywarn spotter News,* Spring 2007 Edition; and "Fall Weather Review," *Skywarn spotter News*, Winter 2007 Edition, http://www.wrhnoaa.gov/sew/news.php, accessed on February 8th, 2008.

FIGURE 1 – SAIDI HISTORICAL TRENDS

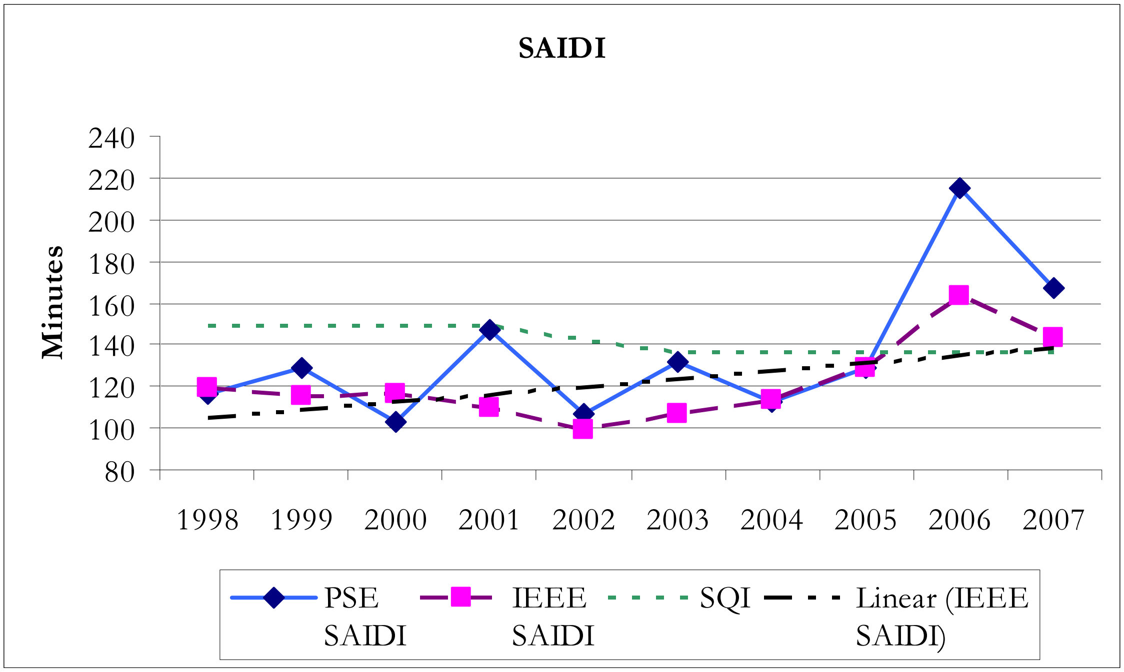
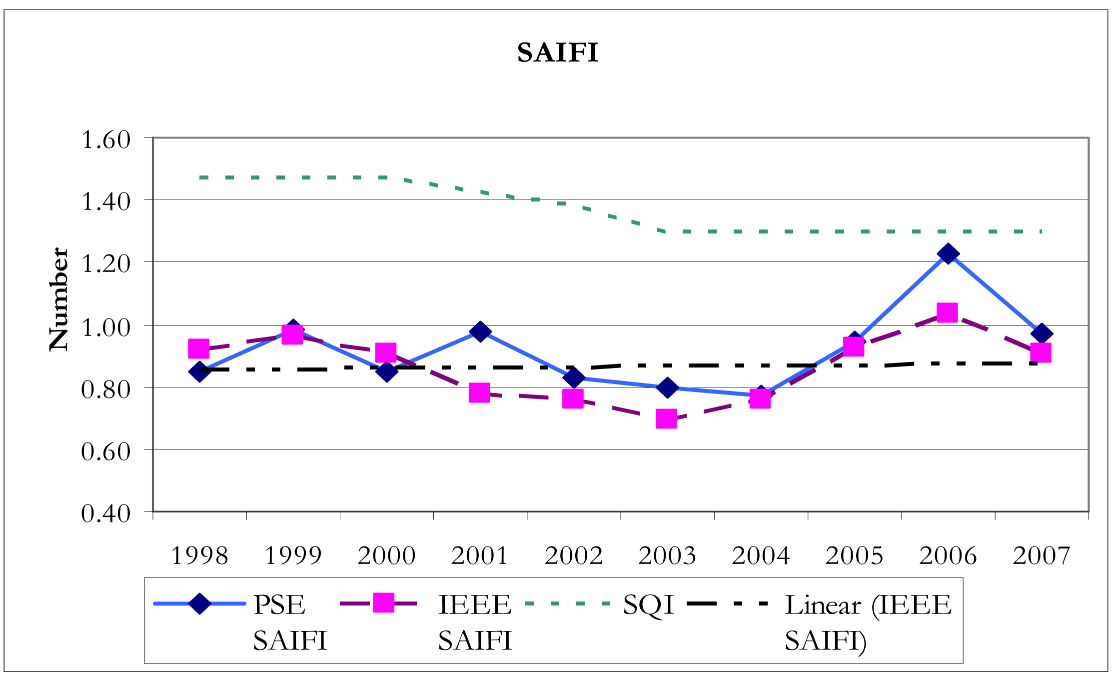


FIGURE 2 – SAIFI HISTORICAL TRENDS



As discussed previously, in 2007 there were seven days that were classified as Major Event Days by the IEEE methodology. Those days were January 2, January 5, January 6, January 9, October 18, November 12 and December 2 as shown previously in Table 3 "Major Event Day Comparison," and here again in Table 4 "Major Events Based on IEEE-1366 Methodology". Table 4 provides further information regarding customer impact and cause. Events that were greater than a T_{MED} of 6.87 were removed from the SAIDI and SAIFI calculation shown for the IEEE 1366 Method on Table 2. As shown, wind was the contributor to these events in 2007. October 18 was the largest event of 2007, impacting approximately 16.1% of PSE's electric customers.

TABLE 4- MAJOR EVENTS BASED ON IEEE-1366 METHODOLOGY

Major Event Days	SAIDI	Customers Out	*% Customers Out	Cause
1/2/2007	8.34	39,243	3.72%	wind
1/5/2007	11.53	52,418	4.97%	wind
1/6/2007	20.60	39,938	3.79%	wind
1/9/2007	23.47	75,866	7.20%	wind
10/18/2007	57.50	169,712	16.10%	wind
11/12/2007	40.35	89,095	8.45%	wind
12/2/2007	7.93	68,563	6.51%	wind

THRESHOLD (Tmed) 6.87

*Percentage based on year-end customer count

This section reviews the reliability of PSE's system at a more detailed subsystem level. This is done by evaluating performance at the county and circuit level.

Table 5 "County Metrics", details the system-wide and county reliability metrics at the end of 2007. To calculate the county metrics using the IEEE method, local events in the county that exceeded the system T_{MED} of 6.87 were excluded. To calculate the county metrics using the SQI Method, any outage occurring within a major event date (as shown in Table 3) and time was excluded from the calculation of the metrics in Table 5. What can be inferred from the comparison of the IEEE statistics against the SQI statistics is that in the rural counties local storms were significant as indicated by the difference in the results.

For example, Island County IEEE SAIDI was 86.47 versus the SQI SAIDI of 686.42. Three incidents related to trees caused outages resulting in 13,336,102 customer minutes which is over 34% of the customer minutes seen by the Island County customers in 2007. If these three incidents were removed, the SQI SAIDI of 686.42 and SAIFI of 1.63 for Island County would have been reduced to 297.70 and 1.26, respectively. Similar types of events, while they don't exceed the 5% criteria, become significant to the local reliability performance. These types of events filter out in the IEEE methodology as indicated by a SAIDI that is much lower than that which results from use of the SQI Method. It is the use of the system T_{med} across these metrics that provides uniformity in reporting across utilities.

TABLE 5 - COUNTY METRICS

County	IEEE SAIDI	SQI SAIDI	IEEE SAIFI	SQI SAIFI	SQI Total Outages	SQI Total Customers Impacted	SQI Total Customers*
Whatcom	103.66	135.09	0.81	0.97	1,094	90,815	93,636
Skagit	89.59	189.04	0.48	0.79	801	44,461	56,453
Island	86.47	686.42	0.54	1.63	551	55,755	34,308
Jefferson and Kitsap	122.94	267.73	1.26	1.68	1,892	220,449	130,945
King	134.92	118.38	0.91	0.85	5,109	432,769	511,947
Kittitas	37.76	135.11	0.18	0.42	248	4,738	11,304
Pierce	67.25	57.39	0.51	0.48	905	47,556	98,443
Thurston	118.71	214.07	0.77	0.90	1,376	104,745	116,787

*Average Number of Customers per County in 2007

Focusing on performance at the next lower level, Table 6 "Percentages of Circuits Better than SQI", shows the percentage of circuits in each county with SAIDI and SAIFI metrics that are better than the five year average for these metrics as calculated by the SQI Method. The circuit analysis is based on the SQI methodology where we excluded outages within the major event dates listed in Table 3, and is based on the last five years of performance data. Six of the eight county areas had at least 60% of their circuits performing better than the SAIDI SQI, and seven of the eight county areas had at least 60% of the circuits performing better than the SAIFI SQI.

Only Kittitas and Island counties had less than 60% of its circuits better than the SQI. Kittitas County has relatively few circuits when compared to the other counties where we provide electric service. Specifically, there are 16 circuits in Kittitas County, and 20 to 538 circuits in the other counties that we serve. This means that the performance of a relatively small number of circuits can have a significant impact on the percentages shown in the following table. Circuit performance is also challenged by the fact that the circuits in Kittitas County, like other circuits in rural areas, are relatively long, and exposed to more trees than the shorter circuits that are found in urban areas.

TABLE 6 –PERCENTAGES OF CIRCUITS BETTER THAN SQI

	SAIDI %	SAIFI %
System	78%	79%
Whatcom	80%	84%
Skagit	75%	80%
Island	57%	57%
Jefferson and Kitsap	65%	66%
King	83%	81%
Kittitas	56%	63%
Pierce	87%	85%
Thurston	68%	81%

Reviewing the cause of outages helps to better understand performance at the subsystem level. Table 7 "Outage by Cause", details the outage causes in each county in 2007. It shows that trees, birds and animals, and equipment failures continue to be the primary reasons for outages in 2007 as in previous years. While the number of scheduled outages is significant, it is not considered a reliability concern because the scheduled outages are usually taken to perform system upgrades and maintenance, which results in higher system reliability.

TABLE 7 -OUTAGE BY CAUSE

	Whatcom	Skagit	Island	Kittitas	King	Pierce	Thurston	Jefferson and Kitsap	Total
AO	32	28	16	6	171	39	45	61	398
BA	115	114	57	26	829	178	239	281	1839
CP	25	22	10	5	117	38	46	39	302
CR	1	1	0	1	52	3	5	4	67
DU	26	22	16	14	219	46	57	49	449
EC	0	0	0	0	1	0	0	0	1
EF	536	356	235	154	2065	356	595	643	4940
EO	17	4	3	4	36	11	32	18	125
FI	1	0	0	1	11	2	5	7	27
LI	10	6	0	5	22	12	12	1	68
MM	0	0	1	0	1	0	0	1	3
NW	0	0	0	0	0	0	1	0	1
NYD	0	0	0	0	1	0	1	1	3
OD	1	0	0	0	0	0	0	2	3
OE	1	0	0	0	7	1	2	5	16
OTH	0	0	0	0	0	0	1	0	1
PO	63	30	24	7	227	2	2	6	361
SO	75	18	27	3	611	118	84	198	1134
TF	95	106	78	12	302	73	155	109	930
TO	78	80	79	11	315	23	84	448	1118
TV	0	0	0	0	0	0	0	0	0
UI	0	0		0	0	0	0	0	0
UN	18	14	5	1	112	4	10	16	180
VA	1	0	0	0	10	0	2	5	18
Total	1095	801	551	250	5109	906	1377	1895	11984

CAUSE CODE LEGEND							
AO	Accident Other with Fires	**EO**	Electrical Overload	**NYD**	Not Yet Determined	**TF**	Tree-Off Right of Way
BA	Bird or Animal	**FI**	Faulty Installation	**OD**	Outside Disturbance; BPA Lines Down	**TO**	Tree-On Right of Way
CP	Car Pole Accident	**IO**	Inadvertent Overvoltage	**OE**	Operating Error	**TV**	Trees/Vegetation
CR	Customer Request	**LI**	Lightning	**OTH**	Other Cause	**UN**	Unknown Cause(Unknown Equip Involved Only)
DU	Dig Up Underground	**MM**	Manufacturer-Material Defect	**PO**	Partial Outage	**UI**	Unkown - Investigation Inconclusive
EC	External Corr/Contamination	**MW**	Manufacturer Workmanship	**SO**	Scheduled Outage	**VA**	Vandalism
EF	Equipment Failure	**NW**	Normal Wear, Aging, End of Useful Life				

Evaluating causes at a lower level to understand specific components or factors that are impacting reliability is important. Table 8 "Outages by Equipment", presents the equipment categories for the majority of Equipment Failure causes as an example of the lower level information. The largest number of failures are attributed to overhead transformer fuses, overhead conductor (usually due to trees), and underground primary cable. A large majority of overhead transformer fuse "failures" are actually the result of proper operation of these components usually due to tree contacts with the power lines. PSE continues to invest significantly in remediating underground cable as can be seen by the number of cable projects in Table 9 "2008 Projects by County."

TABLE 8 – OUTAGES BY EQUIPMENT

	Whatcom	Skagit	Island	Kittitas	King	Pierce	Thurston	Jefferson and Kitsap	Total
OCN	19	14	24	3	110	16	22	14	222
OCO	134	129	92	15	533	75	206	323	1507
OFC	46	31	26	8	99	24	37	65	336
OFU	133	162	59	16	490	99	152	267	1378
OJU	13	8	6	5	34	6	21	11	104
OPO	31	29	15	3	184	39	46	75	422
OSV	56	45	29	19	278	62	79	128	696
OTF	245	176	82	79	854	228	297	333	2294
OTR	68	34	36	8	216	39	69	124	594
SPT	0	0	0	0	0	0	1	0	1
UEL	3	1	1	2	35	10	5	3	60
UFJ	3	2	3	4	70	4	13	7	106
UPC	119	53	51	17	757	111	196	156	1460
UPT	27	10	10	8	140	22	15	76	308
USV	83	35	46	30	643	92	99	132	1160
UTC	15	21	4	9	203	21	40	59	372
UTR	14	6	6	1	72	5	6	7	117
VCB	1	0	0	0	0	1	0	0	2
Other	85	45	61	21	392	52	75	113	844
Total	1095	801	551	250	5108	906	1379	1893	11983

EQUIPMENT CODE LEGEND							
OCN	OH Secondary Connector	**OJU**	Jumper Wire	**OTR**	OH Transformer	**UPT**	Padmount Transformer
OCO	OH Conductor	**OPO**	Pole	**UEL**	UG Elbow	**USV**	UG Service
OFC	OH Cut-Out	**OSV**	OH Service	**UFJ**	UGJ-Box	**UTC**	UG Terminal Fuse
OFU	Fuse Link/O.H. Line Fuse	**OTF**	OH TRF Fuse	**UPC**	UG Primary Cable	**UTR**	Submersible TRF
VCB	Vacuum (power) Circuit Breaker						

PSE performs vegetation maintenance on its overhead electric system on a cyclical based approach. The maintenance program focuses on achieving a safe and reliable system. Maintaining proper clearance from energized electric lines is paramount to public safety. Clearances also prevent tree related contact outages from occurring.

Vegetation maintenance is conducted on the overhead distribution system and on the cross-country transmission system utilizing industry accepted pruning standards. Tree trimming occurs on various cycles, depending on the facilities. Tree trimming occurs on the overhead electric distribution system (which includes any portion of the transmission system on the same poles) every 4 years for lines in urban areas and every 6 years for lines in rural areas. Danger trees are removed in these right-of-way corridors at the same time. In 2007, vegetation maintenance was performed on 1,562 miles of overhead distribution which, due to storm work, did not meet the 2007 internal goal of 1,898 miles.

Tree trimming occurs on the high-voltage distribution system and cross-country transmission corridor system every 3 years. Spray and mowing activities are done and danger trees are removed along the edge of these corridors at the same time. In 2007, 364 miles of high-voltage distribution and 327 miles of transmission corridors were maintained which met the 2007 internal goal of 364 miles and 327 miles, respectively.

Hot spotting and mid-cycle work and patrols occur yearly on the overhead distribution system, high voltage distribution system, and the cross-country transmission system. This work focuses on fast growing species which could come into contact with the conductors faster than the rest of the circuits. Spraying on the overhead distribution system occurs during mid-cycle as well, focusing again on fast growing undesirable species. This reduces costs for the next several cycles because the trimming needed, which is the most expensive maintenance activity, is reduced. In 2007, a total of 300 miles were treated.

PSE also continues to manage vegetation impacts with its TreeWatch Program, whose implementation was authorized by a WUTC Order in July 8, 1998. In the proposed program, PSE had demonstrated that it could realize significant reliability improvements for its customers as a result of a focused and targeted off right-of-way tree removal plan. This plan entailed identification of trees whose structural integrity had been compromised, often from disease or recent exposure to greater wind forces via the creation of tree buffer strips or improper logging operations. The program would essentially "harden" the electric delivery system for both routine and significant weather events. The benefits from the program would be realized over 16 years while the program expenditures occurred within the first five (later amended to six) years, and thus a "regulatory asset" was considered a reasonable accounting mechanism for the program. Upon receiving the approved order, the TreeWatch program commenced by significantly increasing the vegetation resources available, communicating the program within PSE's jurisdictions and initiating communication with owners whose property bordered selected circuits.

The original TreeWatch accounting order expired June 30, 2004. In May 2004, PSE filed for a Petition for an order regarding the continuation of the deferred accounting treatment of its TreeWatch expenditures at a reduced spending level of $2 million per year to focus on transmission and high voltage distribution systems. Because of the benefits derived during the original program, the WUTC granted an order authorizing PSE to continue deferring TreeWatch expenditures, at a level of up to $2 million annually beginning July 1, 2004, to end June 30, 2005. This treatment was to be re-examined in the general rate case.

The deferred program continued until February 28, 2005. At that time, with the general rate case order, the deferred accounting TreeWatch program stopped, and commenced as an operating expense program, at a $2 million annual funding level.

In 2007, approximately 691 miles of transmission and high voltage distribution line voltages were worked under the TreeWatch program. Trees removed numbered 2,960.

In 2008 , the TreeWatch program will continue as an O&M program specifically focused on the transmission corridors in order to remove danger trees that threaten transmission and high voltage distribution facilities, as well as distribution circuits with "pockets" of trees which threaten these lines. Since this program is focused on addressing relatively small areas of concern that are distributed over many miles of lines, we plan to measure the impact of this program by focusing on the results achieved, which in this case, is the number of trees removed or trimmed. This will provide an enhanced assessment of the benefits of the TreeWatch Program since it will identify the number of cases in which we removed a threat to our electrical system. In 2008, we plan to remove or trim 15, 000 off right of way danger trees.

SECTION V- COMPLAINTS

This section discusses reliability and power quality complaints received by Puget Sound Energy and the Commission as defined in Appendix A – Definitions. For 2007, PSE received thirty-two complaints relating to reliability and power quality concerns. These complaints came through PSE's complaint process and are shown in tabular form in Appendix D − 2007 PSE Complaints and Resolutions of this report.

The Commission received fifty-nine complaints relating to the reliability of PSE's energy delivery system. These complaints are shown in Appendix C − 2007 PSE Complaints Filed with the Commission of this report

Appendix E − 2007 Areas of Greatest Concern Map graphically presents these complaints as defined by the PSE process and those complaints filed with the Commission. In addition, Appendix G − 2006 Areas of Greatest Concern Map has been included for reference and comparison. The maps indicate by county the number of customer complaints received by PSE, the number of commission complaints, and the number of reliability projects for the year following the complaints as discussed further in Section VI.

Appendix F is the 2006 PSE Complaints and Resolutions updated to include follow-up actions taken by PSE in 2007.

SECTION VI – AREAS OF GREATEST CONCERN

As discussed in Section II "Methodology", for purposes of this report starting in 2006 Puget Sound Energy defines an Area of Greatest Concern by considering the trends in system performance, customers impacted and number of complaints. For 2008, projects are planned for all counties including Areas of Greatest Concern. Appendix E – 2007 Areas of Greatest Concern Map include the number of projects for each county indicating focus. Overall PSE plans to initiate over 290 projects in 2008 across the entire system to improve reliability. These projects are prioritized using a detailed decision modeling tool to place funding focus on resolving concerns with the highest value to multiple stakeholders. Included also is Appendix G – 2006 Areas of Greatest Concern Map summarizing the 79 complaints and over 220 projects that were initiated in 2007.

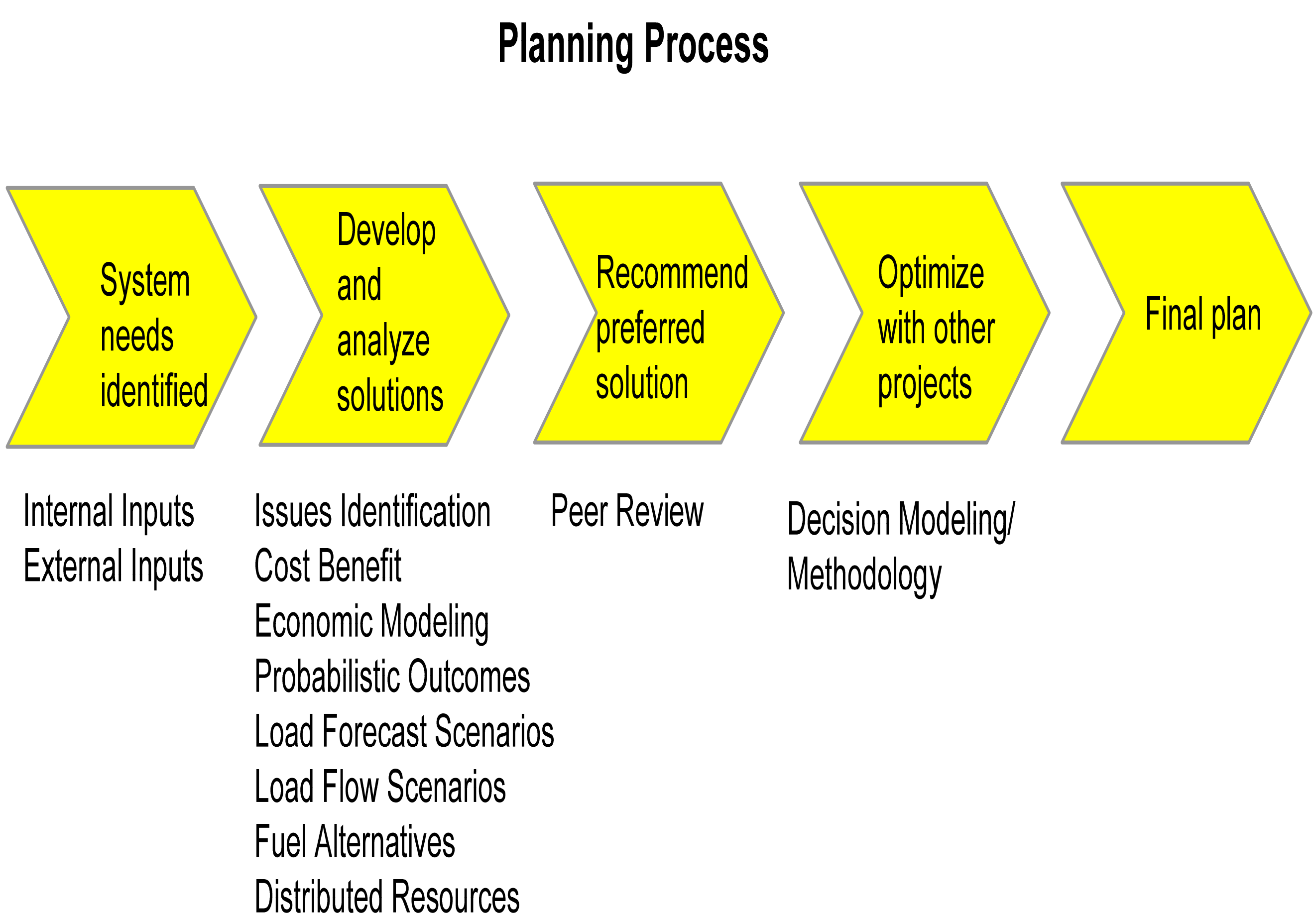
The 2008 projects as shown in Table 9 "2008 Projects by County", identifies the planned projects for 2008 by county and by type of work which solve the top causes of diminished reliability. It is also important to notice that all counties receive focus towards resolving these issues. Appendix E – 2007 Areas of Greatest Concern Map shows this data on the map for comparison with complaints

TABLE 9 – 2008 PROJECTS BY COUNTY

	Whatcom	Skagit	Island	Jefferson & Kitsap	King	Kittitas	Pierce	Thurston	Total
Cable Projects (EF)	2		3	32	77	3	17	12	146
Pole Replacement	6		2	2	16		1	3	30
Tree Wire (TF, TO)	1		2	1	2			1	7
Protection Devices (EF, BA)	3	2	2	2	6		3	2	20
Other Reliability Projects	5	5	2	7	57		10	4	90
Total	17	7	11	44	158	3	31	22	293

To truly understand how these projects are determined to receive funding, PSE's planning process is reviewed. The goal of the planning process is to find cost-effective ways to meet customer needs and stakeholder values. Figure 3 "Planning Process", represents the delivery system planning process beginning with an analysis of the current situation and an understanding of the existing operational and reliability challenges. Planning considerations include both internal and external factors, load forecasting and customer expectations. Having incorporated all of these inputs, planners then determine the magnitude of the issues based on the performance definitions and probability analysis. Alternatives for improving the infrastructure are developed and the benefits for each are determined considering qualitative and quantitative values such as integration of local and regional plans. Each proposed project alternative is compared using a decision tool that involves building a hierarchy of the value these benefits bring to the stakeholders. This provides a useful mechanism for checking the consistency of the evaluation measures and alternatives suggested by the team, thus reducing bias in decision making. Total value is optimized across resource constraints and the result is a set of capital and maintenance projects. A more detailed discussion of this process can be found in Chapter 7 "Delivery System Planning" of PSE's "2007 Integrated Resource Plan".

FIGURE 3 – PLANNING PROCESS



APPENDIX A

DEFINITIONS

APPENDIX A – DEFINITIONS

AMR – Automated Meter Reading system, which is a sophisticated communication network capable of providing the Company with certain information pertaining to sustained outages automatically.

Area of Greatest Concern – An area targeted for specific actions to improve the level of service reliability or quality by considering the number of complaints, the circuit performance and the number of customers impacted.

Area of Greatest Concern Map – A plot of localized areas of concern on a geographic map. Areas include PSE complaints and concerns filed with the commission and projects planned.

Cause Codes – A list of codes used to identify the Company's best estimation of what caused a Sustained Interruption to occur. The following is the PSE Interruption Causes code information:

AO	Accident Other, with Fires
BA	Bird or Animal
CP	Carpole Accident
CR	Customer Request
DU	Dig Up Underground
EF	Equipment Failure
EO	Electrical Overload
FI	Faulty Installation
IO	Inadvertent Overvoltage
LI	Lightning
MD	Manufacturer – Design
MW	Manufacturer – Workmanship
NW	Normal Wear / End of Useful Life
NYD	Not Yet Determined
OD	Outside Disturbance; BPA Lines Down
OE	Operating Error
OTH	Other Cause
PO	Partial Outage
SO	Scheduled Outage, was WR – Work Required
TF	Tree – Off Right of Way
TO	Tree – On Right of Way
TV	Trees/Vegetation
UN	Unknown Cause (unknown equipment involved only)
VA	Vandalism

CLX – Consumer LinX, PSE's customer information system.

Commission Complaint – any single concern filed by a customer with the Washington Utility and Transportation Commission (WUTC).

Customer Complaint – a customer comment relating to dissatisfaction with the resolution or explanation of a concern related to a Sustained Interruption or Power Quality. This is indicated by two or more contacts to the Company over a 24-month period, where by, after investigation by the Company, the cause of the concern is found to be on the Company's energy delivery system.

<u>Customer Count</u> – the number of customers relative to focus of topic or data. The source of the data will be the outage reporting system that is a part of SAP, the Company's Work Management and Financial Information System.

<u>Customer Inquiry</u> – an event whereby a customer contacts the Company to report a Sustained Interruption or Power Quality concern.

<u>Duration of Sustained Interruption</u> – the period, measured in minutes, or hours or days, beginning when the Company is first informed the service to a customer has been interrupted and ending when the problem causing the interruption has been resolved and the line has been re-energized. An interruption may require Step Restoration tracking to provide reliable index calculation. As an example, two trees could be down, one taking out a major feeder on a main street affecting numerous customers, another down the line in a side street, affecting only a few customers off the major feeder. When the major line is restored and service to most customers is resumed, it is possible that the second tree will prevent resumption of service to the smaller group of customers. The Sustained Interruption associated with the second tree is treated as a separate incident for reporting and tracking purposes.

<u>Equipment Codes</u>

OCN	Overhead Secondary Connector
OCO	Overhead Conductor
OFC	Overhead Cut - Out
OFU	Overhead Line Fuse / Fuse Link
OJU	Overhead Jumper Wire
OPO	Distribution Pole
OSV	Overhead Service
OTF	Overhead Transformer Fuse
OTR	Overhead Transformer
UEL	Underground Elbow
UFJ	Underground J – Box
UPC	Underground Primary Cable
UPT	Padmount Transformer
USV	Underground Service
UTC	Underground Terminal Fuse
UTR	Submersible Transformer
VCB	Vacuum (Power) Circuit Breaker

<u>Major Event Days</u>– per the SQI method, a catastrophic event that exceeds design limits of the electric power system and is characterized by more than five percent of the customers out of service during a 24-hour period. Under the IEEE 1366 definition, a major event is a day in which the daily system SAIDI exceeds a threshold value, T_{MED} that is determined by using the 2.5 beta method.

Outage − the state of a system component when it is not available to perform its intended function due to some event directly associated with that component. For the most part, a component's unavailability is considered an outage when it causes a sustained interruption of service to customers.

Power Quality − there are no industry standards that are broad enough to be able to define power quality or how and when to measure it. For purposes of this rule, power quality includes all other physical characteristics of electrical service except for Sustained Interruptions, including but not limited to momentary outages, voltage sags, voltage flicker, harmonics and voltage spikes.

SAIDI – System Average Interruption Duration Index. This index is commonly referred to as customer minutes of interruption or customer hours, and is designed to provide information about the average time the customers are interrupted. SAIDI will be calculated according to the following:

$$\text{SAIDI} = \frac{\sum \text{Duration of Sustained Interruptions (in minutes) experienced by customers}}{\text{Total number of customers served}}$$

SAIFI – System Average Interruption Frequency Index (sustained interruptions). This index is designed to give information about the average frequency of sustained interruptions per customers over a predefined area. SAIFI will be calculated according to the following:

$$\text{SAIFI} = \frac{\text{Total number of customers that experienced Sustained Interruptions}}{\text{Total number of customers served}}$$

SQI – Service Quality Index are the established indices per conditions of the Puget Power and Washington Natural Gas merger in 1997.

Step Restoration – the restoration of service to blocks of customers in an area until the entire area or feeder is restored.

Sustained Interruption – any interruption not classified as a momentary event. PSE records interruptions longer than one minute.

T_{MED} – Tmed is the major event day identification threshold value that is calculated at the end of each reporting period (typically one year) for use during the next report period. It's determined by reviewing the past 5 years of daily system SAIDI, and using the IEEE 2.5 beta methodology in calculating the threshold value. Statistically, any days having a daily system SAIDI greater than Tmed are days on which the energy delivery system experienced stresses beyond the normally expected, which are classified as Major Event Days.

$$T_{MED} = e^{(\alpha + 2.5\beta)}$$

APPENDIX B

DATA COLLECTION

APPENDIX B – DATA COLLECTION

This section explains how PSE collects the underlying data for each annual report. The process described below identifies how an interruption is captured and documented within PSE. These interruptions are then expressed in terms of the reliability metrics SAIDI and SAIFI as discussed in the previous sections.

Puget Sound Energy's objective is to meet customer reliability needs in the most appropriate and cost-effective way. In response to the Commission rulemaking procedure PSE developed a process to respond to customer complaints about reliability and power quality. The process summarizes customer complaints about reliability and power quality by plotting the result graphically. Figure 4, "Process for Responding and Tracking Reliability and Power Quality Inquiries," on page 32 represents this process graphically.

The process is triggered by customer's comments about reliability that is then followed by creation of a Service Order and tracking of an Inbound Client Comment in the Company's Customer Information System (CLX). A summary report captures the inbound comments received within the calendar year, with a comment topic of "outage" (frequency or duration) and/or "power quality". If only one comment has been received from any one customer within a 24-month period, it will be counted as a customer "inquiry." When two or more comments on service reliability and/or power quality have been received from a customer within the 24-month period, it will be counted as a "complaint."

PSE has identified key phrases for our Customer Service Representatives (CSR) to listen for in order to help categorize problems. PSE developed a Desktop Learning tool to help train employees. This has been key to obtaining accurate information from the customer and route the information to the various groups responsible to assess the customer "inquiry."

<u>Methods for Identifying a Sustained Interruption</u>

1. Customer calls the Company's customer access center, either through the automated voice response unit or talking with a customer representative.
2. A customer calls directly to a PSE employee rather than through the customer access center.
3. Automated system information from the Company's AMR system (may precede customer call).
4. Possible Causes of Data Inconsistencies:

   a)If service to a customer that previously was affected by a service interruption remains out after the problem suspected to have caused the interruption has been corrected, a follow-up call from the customer may be reported as a new incident. This can especially be the case during Step Restoration which occurs when customers experiencing an outage have their service restored in smaller groups, rather than restoring service to all of the customers at the same time.

b) Customers may call to report a Sustained Interruption that was caused by their own equipment and not shared by other customers. If the customer's power has been restored before crews arrive to investigate, the incident may still be reported as a sustained interruption.

c) It is likely, as with any computer information system, that the AMR reports may provide reports on some outages that were not verified. The number of such false reads, if any, has not been established.

d) Data entry mistakes can create inconsistencies.

e) Major storm events have an impact on data accuracy. In general, data accuracy is inversely proportional to the magnitude of the storm event.

<u>Methods to Specify When the Duration of a Sustained Interruption Ends</u>

1. PSE services personnel will log the time when the problem causing the outage has been resolved.
2. Possible Causes of Data Inconsistencies:
   a) There may be multiple layers of issues contributing to a Sustained Interruption for a specific customer as described in the above section.
   b) Data entry errors can affect the accuracy of the information.

<u>Recording Cause Codes</u>

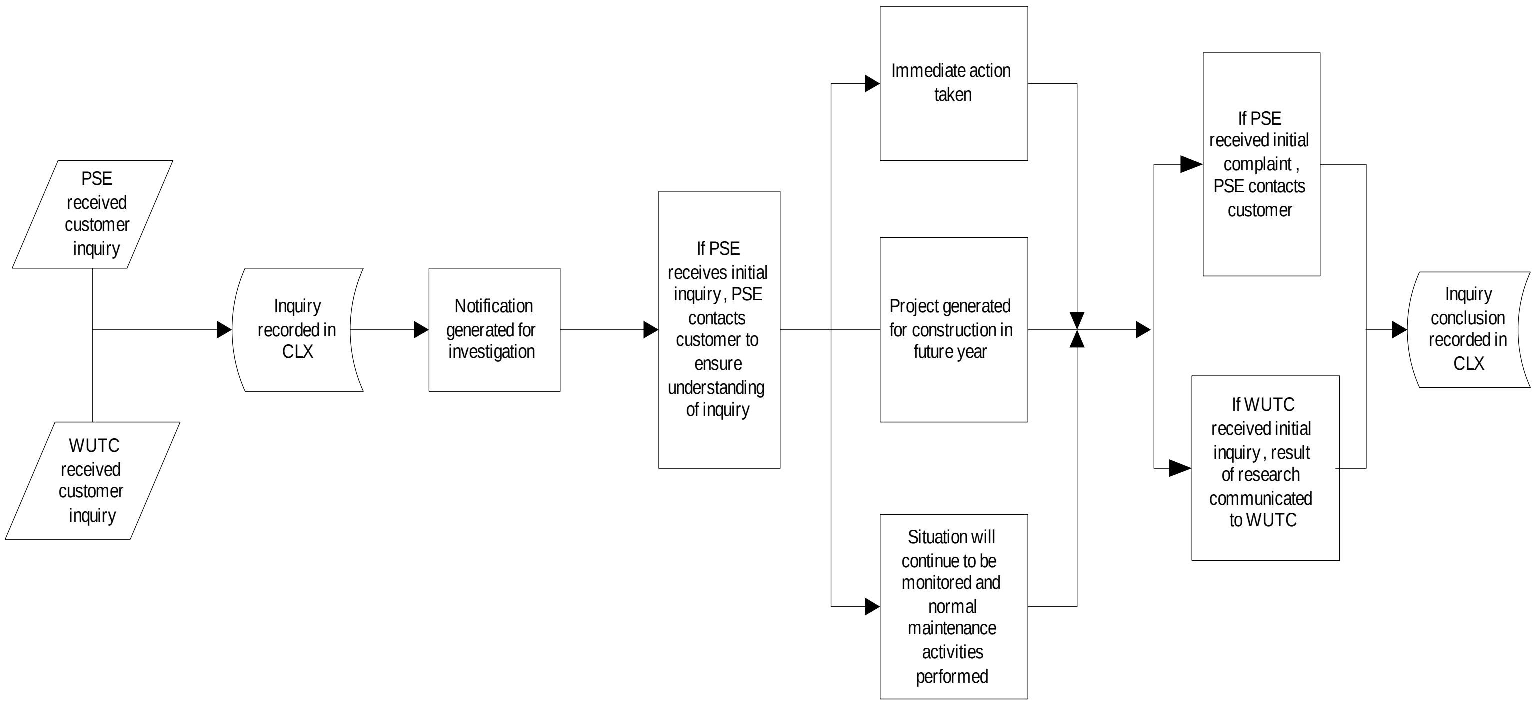
1. Outage cause codes are reported by the PSE service personnel responding to the outage location.
2. Possible Causes of Data Inconsistencies:
   a) Major storm event will have an impact of data accuracy. In general, the greater the storm the less time spent in recording accurate data up front due to the focus on the restoration effort.
   b) The cause of the outage and the location of the protective device may be separated by a significant distance. Pinpointing the exact location of the outage and the cause may be secondary to the outage restoration effort.
   c) Inspecting the distribution feeder to find temporary or momentary contacts with the distribution system is difficult.
   d) A series of outages effecting a group or groups of customers at the same time or approximate times with several causes are difficult to capture.
   e) Determining the difference between different cause codes is difficult in cross-country terrain and in the darkness.

<u>Recording and Tracking Customer Inquiries</u>

1. Customer inquiries will be tracked in CLX by personnel that follow-up customer inquiries related to Power Quality and Sustained Interruptions.

2. In 2002 PSE implemented some enhancements to the process of logging inbound comments from customers in CLX, simplifying the number of topic and sub-topics to ensure greater data quality. PSE also enhanced the process to ensure customer feedback received outside of the customer service center (e.g. inquiries to field engineering) was posted to CLX inbound comments, thus improving our ability to track customer inquiries related to outages frequency, duration and/or power quality.
3. Possible Causes of Data Inconsistencies:
   a) Using the manual process, it is possible that the feedback loop may occasionally not be closed due to data entry and tracking errors. PSE will minimize this inaccuracy by having the team involved with responding to inquiries, who are most knowledgeable about the specific situation, track customer inquiries.
   b) Sources of inaccuracy include improper data entry. PSE will minimize this inaccuracy by having the team involved with responding to inquiries, who are most knowledgeable about the specific situation, track customer inquiries, which will help catch errors in data entry.
   c) High volumes of customer inquiries, during storms for example, may increase likelihood of data entry errors, leading to less accurate information.

FIGURE 4 – PROCESS FOR RESPONDING AND TRACKING RELIABILITY AND POWER QUALITY INQUIRIES



APPENDIX C

2006 PSE COMPLAINTS FILED WITH COMMISSION

APPENDIX C - 2007 CONCERNS FILED WITH COMMISSION

PSE has provided the Commission with background information on all of the following concerns.

No.	Date of Complaint	Location	Complaint Type
1	1/2/2007	Issaquah	Reliability
2	1/2/2007	Redmond	Reliability
3	1/2/2007	Renton	Reliability
4	1/2/2007	Vashon	Reliability
5	1/9/2007	Tenino	Reliability
6	1/11/2007	Mercer Island	Reliability
7	1/11/2007	Mercer Island	Reliability
8	1/19/2007	Coupeville	Reliability
9	1/30/2007	Yelm	Reliability
10	1/30/2007	Yelm	Reliability
11	1/30/2007	Roy	Reliability
12	1/30/2007	Yelm	Reliability
13	1/30/2007	Yelm	Reliability
14	1/30/2007	Yelm	Reliability
15	1/30/2007	Yelm	Reliability
16	1/30/2007	Yelm	Reliability
17	1/30/2007	Roy	Reliability
18	1/30/2007	Yelm	Reliability
19	1/30/2007	Yelm	Reliability
20	1/30/2007	Yelm	Reliability
21	1/30/2007	Roy	Reliability
22	1/30/2007	Yelm	Reliability
23	1/30/2007	Yelm	Reliability
24	1/30/2007	Rainier	Reliability
25	1/30/2007	Rainier	Reliability
26	1/31/2007	Yelm	Reliability
27	1/31/2007	Roy	Reliability
28	2/1/2007	Yelm	Reliability
29	2/5/2007	Yelm	Reliability
30	2/6/2007	Bothel	Reliability
31	2/6/2007	Yelm	Reliability
32	2/6/2007	Yelm	Reliability
33	2/12/2007	Snoqualmie	Reliability
34	2/16/2007	Normandy Park	Reliability
35	2/20/2007	Yelm	Reliability
36	3/6/2007	Yelm	Reliability
37	3/28/2007	Olympia	Reliability

No.	Date of Complaint	Location	Complaint Type
38	4/19/2007	Bremerton	Reliability
39	5/1/2007	Bremerton	Reliability
40	5/3/2007	Bremerton	Reliability
41	5/17/2007	Bremerton	Reliability
42	6/28/2007	Duvall	Reliability
43	8/21/2007	Bellingham	Reliability
44	8/28/2007	Bellingham	Reliability
45	9/13/2007	Puyallup	Reliability
46	10/4/2007	Bellingham	Reliability
47	10/19/2007	Renton	Reliability
48	10/19/2007	Puyallup	Reliability
49	11/27/2007	Yelm	Reliability
50	11/27/2007	Bellingham	Reliability
51	12/13/2007	Enumclaw	Reliability
52	1/16/2007	Bellingham	Power Quality
53	1/20/2007	Yelm	Power Quality
54	2/12/2007	Poulsbo	Power Quality
55	2/14/2007	Poulsbo	Power Quality
56	3/26/2007	Auburn	Power Quality
57	5/15/2007	Olympia	Power Quality
58	11/17/2007	Olympia	Power Quality
59	12/3/2007	Bellingham	Power Quality

APPENDIX D

2007 PSE COMPLAINTS AND RESOLUTIONS

APPENDIX D – 2007 PSE COMPLAINTS AND RESOLUTIONS

No.	Date of Complaint	Location	Complaint Type	Circuit	Response	Action by PSE
1	Dec 2006 July 2007	OLYMPIA	Reliability	GRI-16	Contacted customer to discuss concerns.	Switching and load balance was performed. Ongoing circuit monitoring and maintenance will continue.
2	Dec 2006 Jan 2007	CLINTON	Reliability	LGY-16	Contacted customer to discuss concerns.	Multi-year projects including a new substation and transmission line right of way improvements will improve reliability.
3	Dec 2006 Oct 2007	BELLEVUE	Reliability	SOM-16	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue.
4	Jan 2006 Mar 2007	OLYMPIA	Reliability	MOT-15	Contacted customer to discuss concerns.	Poles were replaced in early 2007 as part of the transmission line upgrade project.
5	Dec 2006 Sept 2007	RENTON	Reliability	FWD-15	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue.
6	Aug 2006 Oct 2007	BELLEVUE	Reliability and Power Quality	SOM-15	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue.
7	Nov 2006 Jan 2007	CONCRETE	Reliability	HAM-15	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue.
8	Feb 2006 Jan 2007 Mar 2007 Nov 2007	YELM	Reliability	LON-22	Contacted customer to discuss concerns.	A substation transformer was replaced. A new circuit is to be installed from the substation to split the LON-22 load.
9	Mar 2006 Jan 2007	KINGSTON	Reliability	KIN-22	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue. New substation completed in late 2007 to strengthen area service.
10	Nov 2006 Nov 2007	SEDRO WOOLLEY	Reliability	NLM-15	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue. One system improvement project completed in 2007.

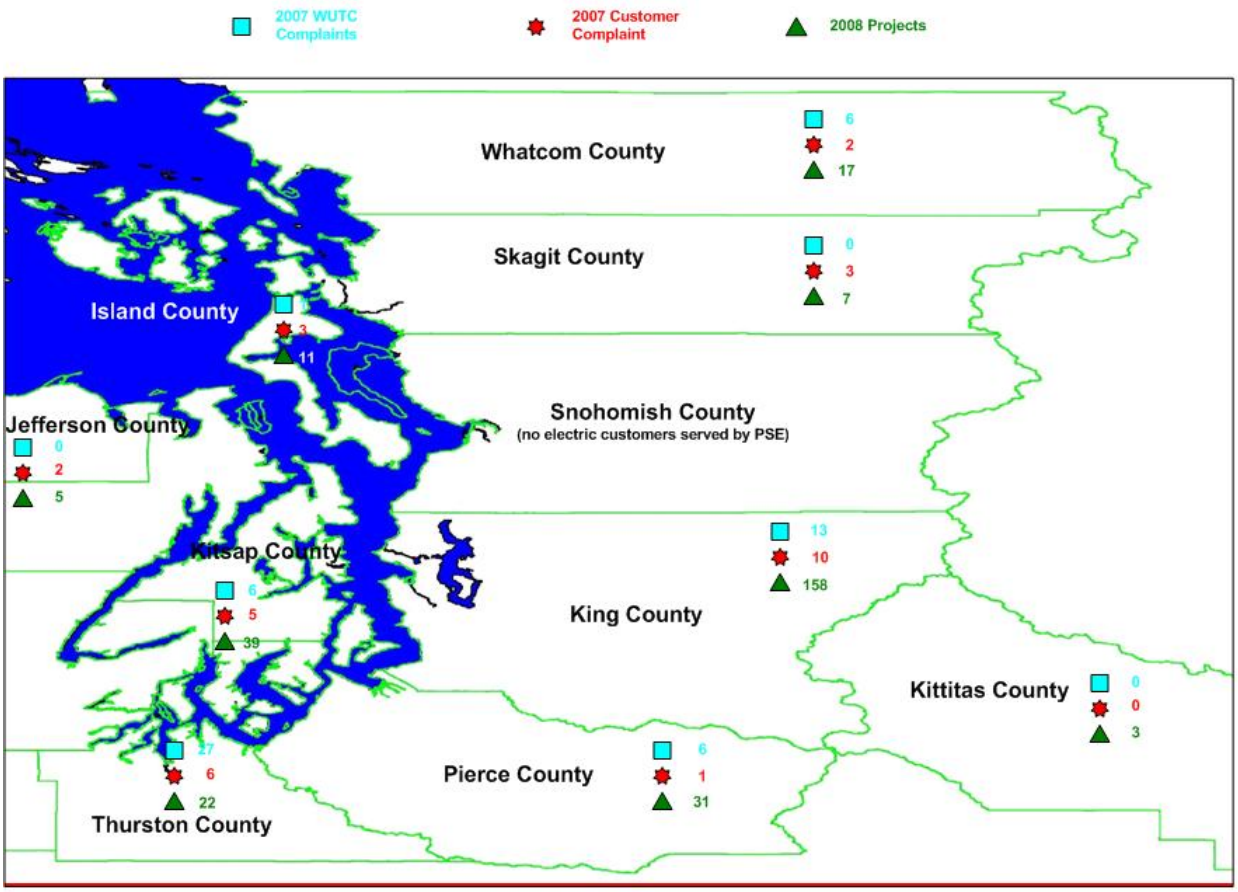
No.	Date of Complaint	Location	Complaint Type	Circuit	Response	Action by PSE
11	Dec 2006 Jan 2007	FREELAND	Reliability	FLD-12	Contacted customer to discuss concerns.	Multi-year projects including a new substation and transmission line right of way improvements will improve reliability.
12	Dec 2006 June 2007	LYNDEN	Reliability	LYN-17	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue.
13	July 2006 Feb 2007	KINGSTON	Reliability	KIN-24	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue. New substation completed in late 2007 to strengthen area service.
14	Nov 2006 Dec2006 Jan 2007 Dec 2007	BARING	Reliability and Power Quality	SKY-25	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue.
15	Jan 2006 Feb 2006 Dec 2007	POULSBO	Reliability	SWD-14	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue.
16	Nov 2006 Apr 2007	YELM	Reliability	LON-22	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue.
17	July 2006 Dec 2006 Oct 2007	FEDERAL WAY	Reliability and Power Quality	LAT-17	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue.
18	Feb 2006 Sept 2007	WOODINVILLE	Reliability	COT-13	Contacted customer to discuss concerns.	More aggressive tree trimming being pursued in 2008.
19	Feb 2006 Apr 2007	PORT LUDLOW	Reliability	PTL-16	Contacted customer to discuss concerns.	One system project completed in 2007 to solve voltage concerns.
20	Dec 2006 Jan 2007 Oct 2007	YELM	Reliability	LON-22	Contacted customer to discuss concerns.	A substation transformer was replaced. A new circuit is to be installed from the substation to split the LON-22 load.

No.	Date of Complaint	Location	Complaint Type	Circuit	Response	Action by PSE
21	Nov 2006 Oct 2007	CLINTON	Reliability	LGY-12	Contacted customer to discuss concerns.	Multi-year projects including a new substation and transmission line right of way improvements will improve reliability.
22	Apr 2006 Feb 2007	NORMANDY PARK	Reliability	NNO-15	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue.
23	Dec 2006 Apr 2007	SNOQUALMIE	Reliability	SNQ-13	Contacted customer to discuss concerns.	Future transmission projects will strengthen area reliability. Ongoing circuit monitoring and maintenance will continue.
24	Dec 2006 Feb 2007	NEWCASTLE	Reliability	HAZ-12	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue.
25	Mar 2006 June 2007	BOW	Power Quality	WLS-16	Contacted customer to discuss concerns.	One system project completed in 2007 to solve voltage concerns.
26	May 2006 Apr 2007	BELLINGHAM	Reliability	LLS-15	Contacted customer to discuss concerns.	One transmission line project scheduled for 2009.
27	Nov 2006 Mar 2007	KIRKLAND	Reliability	ROS-21	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue.
28	Feb 2006 Jan 2007	GIG HARBOR	Reliability and Power Quality	FRA-16	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue.
29	Feb 2006 Nov 2006 Jan 2007	YELM	Reliability	LON-22	Contacted customer to discuss concerns.	A substation transformer was replaced. A new circuit is to be installed from the substation to split the LON-22 load.
30	Oct 2006 Oct 2006 Nov 2006 Jan 2007	SEDRO WOOLLEY	Reliability	HAM-15	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue.
31	Nov 2006 Dec 2007	GIG HARBOR	Reliability and Power Quality	FRA-16	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue.
32	Aug 06 Mar 07	QUILCENE	Reliability and Power Quality	SIL-13	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue.

APPENDIX E

2007 AREAS OF GREATEST CONCERN MAP

APPENDIX E - 2007 Customer Complaints with 2008 System Projects



APPENDIX F

2006 PSE COMPLAINTS AND RESOLUTIONS

APPENDIX F - 2006 PSE COMPLAINTS AND RESOLUTIONS

No.	Date of Complaint	Location	Circuit	Complaint Type	Response	Action by PSE	Follow Up on Action Taken by PSE
1	Feb 2005 Sep 2006	Auburn	KCR-17	Reliability	Contacted customer to discuss concerns.	One system improvement project completed in 2006. Tree wire project to be completed in 2007.	Tree wire project completed in 2007.
2	May 2005 May 2005 Mar 2006	Bellevue	SOM-15	Reliability	Contacted customer to discuss concerns.	Underground system rebuild project completed in 2006. Continue to monitor area cable performance.	Underground system rebuild project completed in 2006. Will continue to monitor area cable performance.
3	May 2005 Jan 2006	Bellevue	EGT-28	Reliability	Contacted customer to discuss concerns.	Cable Remediation project completed in 2006. Will continue to monitor area cable performance	Cable Remediation project completed in 2006. Will continue to monitor area cable performance
4	Nov 2005 Jan 2006 Mar 2006	Bellevue	KWH-25	Reliability	Contacted customer to discuss concerns.	Tree Trimming completed in 2006. Will continue to monitor tree related outages for additional mid-cycle attention.	Tree Trimming completed in 2006. Will continue to monitor tree related outages for additional mid-cycle attention.
5	Jan 2005 Dec 2006	Bellingham	HAP-16	Reliability	Contacted customer to discuss concerns.	One system improvement project completed in 2006.	One system improvement project completed in 2007. Ongoing circuit monitoring and maintenance will continue.
6	Nov 2005 Jan 2006	Bothell	ING-15	Reliability	Contacted customer to discuss concerns.	Tree wire project completed in 2006. Tree trimming scheduled for completion by February 2007.	Tree wire project completed in 2006. Tree trimming completed in March 2007.
7	Dec 2005 Feb 2006	Bremerton	SHE-26	Reliability	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue.	Ongoing circuit monitoring and maintenance will continue.

No.	Date of Complaint	Location	Circuit	Complaint Type	Response	Action by PSE	Follow Up on Action Taken by PSE
8	Oct 2005 Mar 2006	Kirkland	BTR-22	Reliability	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue.	Ongoing circuit monitoring and maintenance will continue. One system improvement project to be completed in 2008.
9	Dec 2005 Feb 2006	Lynden	LYN-13	Reliability	Contacted customer to discuss concerns.	Installed a recording volt meter and determined customers transformer is not overloaded. Will continue to monitor.	Voltage complaint resolved. Ongoing circuit monitoring and maintenance will continue.
10	Jul 2005 Jun 2006	Normandy Park	MHT-13	Reliability	Contacted customer to discuss concerns.	Cable remediation project completed in 2006.	Cable remediation project completed in 2006. Ongoing circuit monitoring and maintenance will continue.
11	Aug 2005 Jan 2006	Olympia	CAP-13	Reliability	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue.	Ongoing circuit monitoring and maintenance will continue.
12	Sep 2005Nov 2006Nov 2006	Port Hadlock	IRO-13	Reliability	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue.	Ongoing circuit monitoring and maintenance will continue.
13	Dec 2005 Feb 2006	Poulsbo	SKE-26	Reliability	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue.	Ongoing circuit monitoring and maintenance will continue.
14	Nov 2005 Jan 2006 Jan 2006 Feb 2006	Rainier	LON-26	Reliability	Contacted customer to discuss concerns.	Continue monitoring and regular maintenance.	Ongoing circuit monitoring and maintenance will continue.
15	Nov 2005 Jan 2006	Rainier	LON-26	Reliability	Contacted customer to discuss concerns.	Tree wire project completed in 2006	Tree wire project completed in 2006 and tree trimming completed in 2007.

No.	Date of Complaint	Location	Circuit	Complaint Type	Response	Action by PSE	Follow Up on Action Taken by PSE
16	Oct 2005 Dec 2006	Renton	FWD-16	Reliability	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue. Will submit cable remediation project for potential funding in 2008.	Ongoing circuit monitoring and maintenance will continue. Cable remediation project to be completed in 2008.
17	Aug 2005 Nov 2006	Rockport	BRS-24	Reliability	Contacted customer to discuss concerns.	Reliability project funded for 2007. Significant right of way issues in project area. PSE is in negotiations with property owner.	Right of Way issues remain unresolved. Project has been re-scoped to 34 kV tree wire job, allowing project to proceed in 2008.
18	Dec 2005 Feb 2006	Seabeck	SIL-15	Reliability	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue.	Ongoing circuit monitoring and maintenance will continue.
19	Dec 2005 Feb 2006	Yelm	LON-22	Reliability	Contacted customer to discuss concerns.	Five system improvement projects completed in 2006	Cable remediation completed and Phase 1 of feeder cable replacement completed in 2007 with Phase 2 scheduled for 2008. New substation circuit installed in early 2008 to split LON-22 load into two circuits.
20	Nov 2005 Dec 2006	Hansville	PGA-13	Reliability and Power Quality	Contacted customer to discuss concerns.	A new substation is scheduled to be energized in Winter of 2007-2008	A new substation was energized in the December 2007. Ongoing circuit monitoring and maintenance will continue.

No.	Date of Complaint	Location	Circuit	Complaint Type	Response	Action by PSE	Follow Up on Action Taken by PSE
21	Jan 2005 Dec 2005 Feb 2006 Feb 2006 Oct 2006	Yelm	LON-22	Reliability and Power Quality	Contacted customer to discuss concerns.	Five system improvement projects completed in 2006	Cable remediation completed and Phase 1 of feeder cable replacement completed in 2007 with Phase 2 scheduled for 2008. New substation circuit installed in early 2008 to split LON-22 load into two circuits.
22	Dec 2005 Mar 2006	Yelm	LON-22	Reliability and Power Quality	Contacted customer to discuss concerns.	Five system improvement projects completed in 2006	Cable remediation completed and Phase 1 of feeder cable replacement completed in 2007 with Phase 2 scheduled for 2008. New substation circuit installed in early 2008 to split LON-22 load into two circuits.
23	May 2005 May 2006	Vashon Island	VAS-23	Power Quality	Contacted customer to discuss concerns.	Ongoing circuit monitoring and maintenance will continue.	Voltage problem corrected in 2006. Ongoing circuit monitoring and maintenance will continue.

APPENDIX G

2006 AREAS OF GREATEST CONCERN MAP

APPENDIX G - 2006 Customer Complaints with 2007 System Projects