Line Loss Study

2007 Test Year Line Loss Study

For its 2007 test year general rate case, PGE is updating its estimated line losses from the estimates developed in 1988. Commencing in 2007, these updated line loss estimates will be used for load forecasting purposes and for regulated filings with the OPUC. Similar to the 1988 loss study, the proposed methodology discussed in this document segregates line losses into internal line losses, which are losses within the PGE system, and external line losses, which are contractual losses from the wheeling of power by others to PGE's system. Additionally, line losses by retail voltage class are separately estimated.

Summary of Study

The table below summarizes the estimated line losses by delivery voltage. The internal losses are estimated from an analysis of 2000-2004 historical data with an adjustment for the inclusion of Port Westward in 2007. The external losses are 2007 projections based on a snapshot of anticipated plant dispatch and contracts dated 3/8/05.

Delivery Voltage	Internal Loss Factor	External Loss Factor	Total Loss Factor
Secondary	6.28%	2.06%	8.34%
Primary	2.82%	2.06%	4.88%
Subtransmission	1.31%	2.06%	3.37%

Historical Internal and External Energy Losses

Because internal losses are not separately identified from total losses, the total energy losses and the external losses due to retail sales are derived first. Internal losses are then estimated as the difference between total energy losses and external energy losses. Attachment A discussed below provides a step-by-step process by which the historical losses are calculated.

Total energy used to meet retail loads for the years 2000-2004 is presented in column 1, of Attachment A. The source of the data is PGE's Energy Generated, Received, and Delivered Report (EGR&D), with the addition of the Montana Intertie loss returns. Columns 2 through 5 represent, by year, sources of energy by which PGE met retail load requirements. Column 2 is the sum of PGE's share of coal and gas generating stations, and its share of Mid-Columbia contracts, all of which utilize BPA Integration of Resource (IR) transmission. Column 3 is the sum of PGE owned hydro generation and column 4 represents purchased energy from within PGE's service territory, including purchases from the Tribes portion of Pelton Round Butte. Column 5 is the sum of contract purchases delivered to PGE's service territory, the most notable of which is BPA Subscription Power. Column 6 separately identifies the Montana Intertie losses, and column 7 calculates the remaining energy available for retail loads, some of which is delivered to PGE and some of which is wheeled by BPA transmission to PGE's service territory. Combining Column 7 with Column 8, Sales for Resales into Column 9 provides a basis by which external losses can be allocated to either retail sales or wholesale sales. Because historical data does not separately identify wheeling losses attributable to either retail or wholesale sales,

these losses must be allocated. Columns 10 and 11 are the percent calculations by which unassigned wheeling losses are allocated to either retail purchases or wholesale sales.

Column 12 presents the sum of IR, PTP, AC Intertie, DC Intertie, and Montana Intertie wheeling losses by year before any allocation or attribution occurs. Column 13 is a calculation of the wheeling losses directly attributable to retail customers; this calculation is the BPA IR contractual loss rate of 1.9% multiplied by the energy contained in column 2 plus the Montana Intertie losses in Column 6. Columns 14 through 16 then calculate the external losses not directly attributable to retail loads and the allocation of these losses to both retail and wholesale sales. Column 17 represents the total external losses attributable to retail sales, whether by direct assignment or by allocation.

Columns 18 through 22 are data and calculations that result in estimates of annual internal losses. Column 18 restates the system energy from column 1, while column 19 is PGE's retail loads at the meter. The differences between columns 18 and 19 are PGE's total losses attributable to retail loads. These figures are calculated in column 20. Subtracting column 21, external losses, from column 20, total losses provides the estimate of internal losses at column 22. Column 23 calculates the internal losses from column 22 as a percent of retail loads at the meter. The percent calculations in column 23 could be the basis of PGE's historical internal loss estimates except for the consideration of energy supplied by ESS's to PGE customers.

Columns 24 through 29 estimate the effect on internal losses resulting from ESS energy service to PGE customers during 2004. Column 24 is the energy delivered by ESS's to PGE's service territory and column 25 is the energy at the meter consumed by customers receiving service from an ESS. The difference between the two columns, therefore the losses is calculated in column 26 (the difference is also due to energy imbalances.) Adding the internal losses in column 26 to the previously calculated internal losses results in column 28, total internal losses by year. Column 29 is a summation of retail energy at the meter including energy consumed by customers receiving service from an ESS. Column 29 in conjunction with column 28 provides the basis upon which to calculate internal retail loss percents.

Columns 30 and 31 are the percent loss calculations for both external and internal losses. Column 30 is calculated by dividing the retail external losses calculated in column 17 by the retail sales in column 19. The energy consumption of customers receiving service from an ESS is not considered because PGE does not experience external losses from ESS deliveries. The historical internal loss percents by year are calculated in column 31; in this case the energy of customers receiving service from an ESS is considered because PGE does experience line losses within its system from all sources of energy. The five-year average of internal loss percent of 5.4% is the basis upon which losses by delivery voltage are calculated for the 2007 test-period.

Losses by Delivery Voltage

In order to estimate internal line losses by delivery voltage one has to rely upon a mixture of direct measurement and estimation. The methodology contained in Attachment B, "Calculation of Internal Losses by Delivery Voltage," employs 2004 internal line loss estimates from Attachment A as a starting point. Continuing from these internal loss estimates, percent estimates of line losses at subtransmission voltage (115 kV) and greater are utilized, as well as direct measurement at primary voltage (13kV) for the 2004 period. The 2004 line loss amounts not directly attributed to subtransmission and primary voltage customers are assigned to secondary delivery voltage customers. Finally, adjustments are made to the 2004 estimates to account for the difference between average five-year losses and 2004 losses, and the pro-forma effects of Port Westward.

Referencing Attachment B, columns 1 through 4 derive the 2004 energy necessary to serve retail loads. Column 1 is the System Energy from column 18 of Attachment A, column 2 is the ESS energy delivered to PGE, and column 3 is the calculated 2004 external losses, column 21 of Attachment A. Adding columns 1 and 2 and subtracting column 3 yields column 4, the net 2004 energy delivered to PGE's service territory.

Columns 5 through 10 derive the internal loss percent directly attributable to customers served at subtransmission voltage. Column 7 calculates the internal losses based upon the net energy delivered to PGE's service territory and the 115 kV loss energy factor in column 6. This energy loss factor utilizes calculated loss factors, demand losses, and load factors for the period 2001-2004. Attachment C contains

the specific data and calculations. Column 8 calculates the energy remaining after the losses in column 7 are subtracted, and column 9 calculates the retail energy internal loss factor which is column 7 divided by column 8. Column 10 is the retail energy served at 115 kV during 2004.

Columns 11 through 15 derive the primary voltage segment energy loss factor. Column 11 is the 2004 internal energy available for consumption after subtracting energy consumed or lost at higher voltages. Column 12 is the direct 2004 calculation of energy losses for PGE's 13 kV segment. Detail regarding this calculation is provided in Attachment D. Column 13 represents the energy available to be consumed at 13 kV after subtracting the losses in column 12 from the energy in column 11. Column 14 is the energy loss percent calculated as column 12 divided by column 13. Column 15 is the 2004 retail energy served at primary voltage.

Columns 16 through 19 are the calculations of 2004 energy losses attributable to the secondary voltage segment of PGE's system. Column 16 restates the internal losses calculated from Attachment A column 28, and column 17 calculates the internal energy losses remaining after the losses attributable to deliveries at higher voltages have been calculated. Column 18 is the 2004 retail energy consumed at secondary delivery voltage and column 19 is the calculated energy loss factor attributable to the secondary voltage segment of PGE's service territory. Column 20 restates PGE's 2004 total retail energy while column 21, normalized internal losses is the difference between the five-year internal loss percent calculated in column 31 of Attachment A and the 2004 internal loss percents.

Columns 22 through 27 calculate the internal energy losses by delivery voltage from above and also adjustments to these losses. Column 22 presents the energy losses by delivery voltage; the subtransmission segment is 1.18% of retail sales as calculated above; sales to customers at primary delivery voltage are the product of the subtransmission segment and the primary voltage segment while secondary losses are the product of losses at all three segments. Column 23 is the 2004 retail sales by delivery voltage and column 24 is the calculation of the 2004 internal losses directly attributable to each delivery voltage. Column 25 is the normalized losses of 0.31% allocated to each class. Column 26 sums columns 24 and 25 to reflect the total normalized 2004 losses. Column 27 is the internal percent energy loss factor by delivery voltage; ordinarily one could apply these factors to prospective energy sales, but one more adjustment must be made: the inclusion of Port Westward for the 2007 test period.

Columns 28 through 32 present the calculation of the additional loss factor associated with the 2007 dispatch of Port Westward. Column 28 reports the anticipated 2007 dispatch in MWH based on a March 8, 2005 projection of 2007 market conditions. Column 29 is the percent loss factor of Port Westward transmission and column 30 is the loss in MWH given the values in columns 28 and 29. Column 31 is the projected 2007 calendar retail loads and column 32 is the Port Westward transmission losses from column 30 divided by the projected MWH in column 31.

Columns 33 through 37 are calculations of the anticipated 2007 internal losses and loss percents by delivery voltage. Column 33 is the projected retail

calendar loads by delivery voltage, column 34 is the previously calculated internal loss factor, and column 35 is the Port Westward transmission losses as a percent of total retail loads. Summing columns 34 and 35 provides the projected internal loss factors by delivery voltage to be used for the 2007 test period (column 36.) Column 37 is a projection of the internal losses based on the data and calculations in columns 33 and 36.

It may be useful to compare the values in columns 36 and 37 to the internal loss values currently in use. PGE currently estimates internal losses as 1.60%, 3.30%, and 7.10% for subtransmission, primary, and secondary delivery voltages respectively. These previously estimated internal losses are higher than those estimated in this study. Possible explanations for the reduced internal loss estimates include the use of more efficient substation and utilization transformers, and reduced theft.

External Energy Losses

As previously stated PGE incurs contractual losses from utilizing BPA's transmission system. Utilizing a March 2005 projection of dispatch and loads, page 1 of Attachment E details by type of resource the external losses expected to be incurred by PGE for the 2007 test period. Commencing with hydro resources, the analysis on page 1 demonstrates that for PGE-owned assets, there are no external losses because these resources are located within PGE service territory and the energy is transmitted to customers on PGE's own transmission system; the losses are therefore accounted for within the internal losses previously discussed. The Mid-

Columbia hydro contracts utilize BPA IR transmission and are subject to the contractual 1.9% BPA loss returns.

For PGE's coal resources, the Boardman plant utilizes BPA IR wheeling and is subject to 1.9% loss returns. The Colstrip plants are subject not only to the 1.9% IR loss returns, but also loss returns from using the Montana Intertie. In order to estimate the 2007 test period losses on the Montana Intertie, PGE is using the most recent five-year average loss returns of 2.74%. Combining the IR and Montana Intertie loss returns yields a projection of 4.69% energy losses for the Colstrip plants.

PGE's Beaver and Coyote gas-fired resources both use BPA IR wheeling and are therefore subject to the 1.9% IR loss returns. Port Westward will use PGE-owned transmission and the losses from this transmission have been accounted for in the internal losses calculations.

For PGE's capacity contract with WWP, PGE incurs BPA IR losses of 1.9% for energy received from WWP, and usually does not incur losses for the return portion of contract because PGE is usually able to source out from Mid-Columbia and therefore avoid losses. For the delivery portion of the EWEB Capacity Contract, PGE does not incur losses because EWEB delivers to our system, however PGE does incur losses of 1.9% for the return portion to EWEB.

PGE has numerous long-term purchase agreements, some of which are sourced within PGE's service territory such as the Covanta QF contract or the Tribes Mid-C index Purchase. These contractual arrangements do not utilize BPA transmission and therefore do not incur external losses. Some purchase agreements

such as the Transalta Purchased Power Agreement do utilize BPA transmission and therefore incur 1.9% losses. For the Chelan Exchange, PGE incurs BPA losses on the deliveries from Chelan, but is usually able to source-out from Mid-Columbia on the energy returns and hence avoid energy losses. Regarding the Glendale Exchange, PGE accepts delivery of energy at the Nevada-Oregon Border (NOB) and utilizes both the DC Intertie and BPA PTP transmission. The cumulative losses of 5.47% are the product of the 1.9% PTP losses and the 3.5% DC Intertie losses. For the return portion of the Exchange, PGE incurs the 3.5% DC Intertie losses.

For the sales agreements, PGE is able to source-out the Cove Replacement contracts and also the Colstrip Pumping Load, but must utilize the DC Intertie to fulfill the Glendale Sales Contracts.

Page 2 of Attachment E provides the calculation of the 2007 projected external loss percent of 2.06%. This figure is calculated by utilizing the load forecast SMAR05G7 and the previously calculated internal loss percents by delivery voltage. Other inputs include the individual external loss percents calculated on page 1 of this Attachment and the assumption that all remaining purchases to meet load requirements incur BPA contractual losses of 1.9%.

The projected external loss percent of 2.06% is twice the figure of 1.0% that is contained in the current loss study. The primary reasons for this significant change are the loss of the Trojan generating station (an internal resource in the previous loss study) and significant growth in retail loads since the historical period (1983-1987) which the previous loss study utilized. The bulk of this load growth uses BPA transmission and is subject to contractual losses of 1.9%.

Attachment A: Derivation of Historical Internal Losses

Attachment A: Derivation of Historical Internal Losses

Year	(1) System Energy	(2) External Generation & Mid-C Energy	(3) Internal Generation	(4) Internal Purchases	(5) Delivered Contract Purchases	(6) Montana Intertie Losses
2000	21,374,437	11,874,922	2,576,326	87,706	12,662	54,759
2001	20,409,312	12,282,424	2,103,169	86,643	525,507	63,322
2002	19,956,867	8,659,441	1,835,458	602,592	2,101,012	51,447
2003	19,782,814	8,675,503	1,812,169	599,934	2,271,171	60,091
2004	18,982,725	8,047,447	1,810,320	599,821	2,277,307	52,858
Totals	100,506,155	50,539,737	10,137,442	1,976,696	7,187,659	282,477

Source of system energy is EGR&D plus Montana Intertie losses. Int. of Resource Energy is energy generated or purchased that uses a BPA IR agreement for transportation. Internal generation is PGE-owned hydro; Internal purchases include Tribes Purchases and purchases from small power producers. Delivered Contract Purchases include BPA Subscription Power and miscellaneous contracts.

Year	(7)=(1)-(2 thru 6) Remaining Energy for Retail	(8) Sales for Resale	(9)=(7)+(8) Sum of Retail & Wholesale	(10)=(7)÷(9) Retail Percent	(11)=(8)÷(9) Wholesale Percent
2000	6,758,062	18,547,755	25,315,817	27%	73%
2001	5,348,247	9,764,183	15,112,430	35%	65%
2002	6,706,917	12,644,880	19,351,797	35%	65%
2003	6,363,946	12,081,910	18,445,856	35%	65%
2004	5,194,972	9,340,883	14,535,855	36%	64%
Totals	30,382,144	62,379,611	92,761,755	33%	67%

Year	(12) External Losses	(13)=(2)x1.9%+(5) External losses from Generation & Mid-C	(14)=(12)-(13) Remaining Ext. Losses	(15)=(14)x(10) Retail Allocated Losses	(16)=(14)x(11) Wholesale Allocated Losses	(17)=(13)+(15) Ext. Losses due to Retail
2000	446,577	280,383	166,194	44,431	121,763	324,814
2001	428,524	296,588	132,836	47,010	85,826	343,698
2002	410,775	215,976	194,799	67,513	127,286	283,489
2003	424,843	224,926	200,017	69,007	131,010	293,933
2004	424,472	224,759	199,713	71,375	128,337	296,135
Totals	2,135,291	1,242,732	893,559	299,337	594,222	1,542,069

Note: External losses include IR, PTP, AC Intertie, DC Intertie, and Montana Intertie losses

Year	(18)=(1) System Energy	(19) PGE Energy	(20)=(18)-(19) Total Losses	(21)=(17) External Retail Losses	(22)=(20)-(21) Internal Losses	(23)=(22)÷(19) Internal Losses due to Retail
2000	21,374,437	19,872,544	1,501,893	324,814	1,177,079	5.9%
2001	20,409,312	19,040,188	1,369,124	343,698	1,025,426	5.4%
2002	19,956,867	18,771,884	1,184,983	283,489	901,494	4.8%
2003	19,782,814	18,425,854	1,356,960	293,933	1,063,027	5.8%
2004	18,982,725	17,764,138	1,218,587	296,135	922,452	5.2%
Totals	100,506,155	93,874,608	6,631,547	1,542,069	5,089,477	5.42%

Note: 2004 System and Retail do not include ESS deliveries

Year	(24) ESS delivered Energy	(25) ESS Retail Energy	(26)=(24)-(25) ESS Internal Losses	(27)=(22) Internal Retail Losses	(28)=(26)+(27) Total Internal Losses	(29)=(19)+(25) Total Retail Energy
2000	0	0	0	1,177,079	1,177,079	19,872,544
2001	0	0	0	1,025,426	1,025,426	19,040,188
2002	0	0	0	901,494	901,494	18,771,884
2003	0	0	0	1,063,027	1,063,027	18,425,854
2004	814,952	792,715	22,237	922,452	944,689	18,556,853
Totals	814,952	792,715	22,237	5,089,477	5,111,714	94,667,323

Year	(30)=(17)÷(19) Retail External Loss Percent	(31)=(28)÷(29) Retail Internal Loss Percent	(32)=(30)+(31) Total Loss Percent
2000	1.6%	5.9%	7.6%
2001	1.8%	5.4%	7.2%
2002	1.5%	4.8%	6.3%
2003	1.6%	5.8%	7.4%
2004	1.7%	5.1%	6.8%
Totals	1.64%	5.40%	7.04%

Attachment B: Internal Losses by Delivery Voltage

Attachment B: Calculation of Internal Losses by Delivery Voltage

Derivation of Internal Energy Deliveries

Year	(1) System Energy	(2) ESS Deliveries	(3) External Losses	(4)=(1)+(2)-(3) Internal Energy Deliveries
2004	18,982,725	814,952	296,135	19,501,542

Derivation of Subtransmission Internal Losses

Year	(5)=(4) Incoming Energy	(6) 115 kV Energy Loss Factor	(7)=(5)x(6) 115 kV Losses	(8)=(5)-(7) Remaining Energy	(9)=(7)÷(8) 115 kV Retail Loss Factor	(10) 115 kV Retail Energy
2004	19,501,542	1.16%	226,932	19,274,610	1.18%	1,191,301

Derivation of Primary Internal Losses

Year	(11)=(8)-(10) 13 kV Energy	(12) 13 kV Losses	(13)=(11)-(12) Remaining 13 kV Energy	(14)=(12)÷(13) 13 kV Retail Loss Factor	(15) 13 kV Retail Energy
2004	18,083,309	251,830	17,831,479	1.41%	2,680,713

Derivation of Secondary and Other Internal Loss Percents

Year	(16) Total Internal Losses	(17)=(16)-(7)-(12) Remaining Losses	(18) Secondary Energy	(19)=(17)÷(18) Secondary Loss Factor	(20) Total Retail Energy	(21) Normalized Internal Losses
2004	944,689	465,927	14,684,839	3.17%	18,556,853	0.31%

Note: Normalized internal loss percent is the difference between five-year average and 2004 internal loss percent.

Derivation of Internal Delivery Voltage Loss Percents

Delivery Voltage	(22) 2004 Direct Loss Percents	(23) Retail Energy	(24)=(22)x(23) Direct Losses	(25) Normalized Losses	(26)=(24)+(25) Total Internal Losses	(27)=(26)÷(23) Normalized Internal Loss Factors
Subtrans.	1.18%	1,191,301	14,026	851	14,877	1.25%
Primary	2.61%	2,680,713	69,867	4,239	74,106	2.76%
Secondary	5.86%	14,684,839	860,797	52,228	913,025	6.22%
Totals		18,556,853	944,689	57,318	1,002,007	5.40%

Direct loss percents are multiplicative by delivery voltage.

Port Westward Internal Loss Adjustment

Year	(28) Port Westward 2007 Dispatch	(29) Port Westward Loss Factor	(30)=(28)x(29) Port Westward Energy Losses	(31) Projected 2007 Retail Energy	(32)=(30)÷(31) PW additional Loss Factor
2007	1,605,844	0.751%	12,060	20,050,987	0.06%

2007 Test Period Internal Losses by Delivery Voltage

Delivery Voltage	(33) 2007 Calendar Energy	(34) Internal Loss Factor	(35) PW additional Loss Factor	(36) 2007 Internal Loss Factor	(37) 2007 Internal Losses
Subtrans.	1,164,085	1.25%	0.06%	1.31%	15,250
Primary	2,912,225	2.76%	0.06%	2.82%	82,125
Secondary	15,974,676	6.22%	0.06%	6.28%	1,003,210
Totals	20,050,987			5.49%	1,100,584

Attachment C: Internal Transmission Losses

Attachment C

Transmission Loss Calculations

	Historical Information								
Month/Year	2004		2003		2002		2001		4-year average
	ave	peak	ave	peak	ave	peak	ave	peak	
Jan	61981	3942	58230	3183	61325	3331	63716	3512	
Feb	56482	3105	58079	3221	58331	3218	62849	3422	
Mar	51319	2917	55577	2973	56775	3188	58041	3167	
Apr	49234	2653	53989	3036	51874	2835	55358	3088	
May	48426	2521	50956	2680	49976	2757	51906	2950	
Jun	50976	3094	50807	3191	50467	3106	50790	2863	
Jul	54658	3401	53378	3351	53318	3283	51561	2964	
Aug	54908	3448	51552	3061	53417	3408	53443	3045	
Sep	49539	2634	50023	3215	51094	2954	51447	2821	
Oct	51028	2811	49564	2846	52380	3091	52713	2944	
Nov	56632	3329	56259	3065	55924	3131	55827	3168	
Dec	60302	3234	59221	3299	59773	3279	60735	3304	
12 month$_{daily\text{-}ave}$	53790		53970		54555		55699		
Year - peak		3942		3351		3408		3512	
Mw-hr$_{ave}$	2241		2249		2273		2321		2271
Load Factor	0.569		0.671		0.667		0.661		0.642
Transmission Demand Loss from PF Model									0.0155

Loss Factor = 0.3*(Load Factor) + 0.7*(Load Factor)^2

Load Factor	Loss Factor
0.642	0.481

Energy Loss (%) = {(Loss Factor*Demand Loss) / Load Factor}*100

Load Factor	Demand Loss	Loss Factor	Energy Loss
0.642	0.0155	0.481	1.16%

Attachment D: 2004 Primary Distribution Loss Analysis

PRIMARY DISTRIBUTION LOSS ANALYSIS

SUMMARY

The primary distribution system consists of substation transformers and primary feeders. Losses for transformers and feeders were computed separately. The analysis was based on loading and system configuration data for 2004. The system peak load for 2004 of 3,942 MW occurred on January 5th and exceeded the expected peak of 3,633.5 MW by 8.5%. Energy sales were approximately 1.5% below expected levels.

Coincident peak and average losses were both computed. The losses at the time of the system peak were adjusted to reflect losses for expected (i.e., 1 in 2) loading. Average losses were not adjusted because energy sales for the entire year were only slightly below expected levels. Both the winter and summer peak, while only lasting briefly, were higher than expected and this tended to offset the effect of lower average loads on the loss calculations.

Details of the loss computations are given in the Methodology section below. Primary distribution system losses are summarized in the following table:

	TRANSFORMERS	FEEDERS	TOTAL
Average Loss in MW	10.46	18.21	28.67
1:2 Adjusted Coincident Peak Demand Loss in MW	19.45	49.26	68.71

METHODOLOGY

OVERVIEW

Because of a significant increase in the telemetry in the PGE system, the implementation of a data historian and feeder analysis software, this study has produced results for the primary distribution system that are calculated, and not estimated, as has been the accepted industry practice.

The PGE PI data historian provides detailed transformer and feeder loading history. The majority of PGE's substation transformers and feeders are monitored by SCADA telemetry that sends data to PI with a frequency of between 15 to 30 seconds. The majority of the remainder are equipped with MV90, that sends 30 minute data to PI on a weekly basis. A small portion of the substations do not have remote monitoring and loading data is read manually on a monthly basis.

Table 1. Transformer Telemetry Types.

Telemetry Type	Number of XFMRs monitored
SCADA	144
MV90	94
Unattended	15
TOTAL	**253**

The losses on the primary distribution system were computed in two parts: substation transformers losses and primary feeders losses. Calculations are based on 2004 loading data. Transformer losses are calculated using load data from the PI server. Feeder losses are calculated using CYMDIST feeder analysis software for all radial feeders and PTI's PSS/E program for network feeder losses.

TRANSFORMER LOSSES

Transformer losses consist on No-Load Losses and Load Losses. No-Load Losses represent the energy required to magnetize the transformer and are available from the manufacturers test report. Load losses are largely the I^2R losses in the transformer windings.

AVERAGE TRANSFORMER LOSSES:

The following formula was used to calculate the total average losses of the transformers:

$$AverageLoss = LL_{avg} + NLL$$
$$= 3 \times \left(\frac{KVA_{rms}}{3 \times KV_{L-N}} \right)^2 \times R + NLL$$

Where:

LL_{avg}	=	average yearly load loss of the transformer
KVA_{rms}	=	annual RMS value of the hourly averages of KVA of the transformer
R	=	resistance of the transformer [Ohms]
KV_{L-N}	=	line to neutral voltage of the secondary side of the transformer
3	=	multiplier that accounts for the 3 phases of the transformer.
NLL	=	no load loss from manufacturer test reports

TRANSFORMER LOSS FACTORS:

Load loss factors for each transformer were calculated to be used in the determination of average losses for the associated feeders. This provides a loss factor for feeders that is more accurate than using a system loss factor. This is because the transformer loading patterns are closer to the feeder loading pattern, providing a more accurate loss factor than using one derived for the system as a whole. A comparison of several transformers and feeders proved that there was a close correlation between transformer loss factors and the loss factors for associated feeders. This is a significant improvement over earlier studies. The transformer load loss factor was computed as follows:

$$LssF = \left(\frac{KVA_{rms}}{KVA_{peak}} \right)^2$$

For the unattended substations, where hourly loading was not available, the losses were estimated using the following standard formula:

$$LssF = H \times LF^2 + (1 - H) \times LF$$

where:

$LssF$	=	Loss Factor
LD	=	Load Factor
H	=	Hoebel coefficient

Load factors used were calculated values for transformers with load data in PI that had a similar load profile. The Hoebel coefficient can depend on the load profile and can vary from 0.7 to 1. Based on comparisons of actual calculated Loss Factors, and those derived from the above formula using Load Factors, we determined that a value of H=1 yields the best result.

COINCIDENT PEAK TRANSFORMER LOSSES:

To obtain the peak transformer loss value coincident with the system peak, the following formula was used:

$$Coincidental_Peak_Losses = LL_{peak} + NLL$$

$$= 3 \times \left(\frac{KVA_{peak}}{3 \times KV_{L-N}} \right)^2 \times R + NLL$$

Where:

LL_{peak} =	Load loss of the transformer during 1 hour System Peak
KVA_{peak} =	Average transformer load on January 5, 2004 between 17:30 and 18:30.
R =	resistance of the transformer [Ohms]
KV_{L-N} =	line to neutral voltage on the secondary side of the transformer
3 =	multiplier that accounts for the 3 phases of the transformer.
NLL =	no load loss from manufacturer test reports

COINCIDENT PEAK TRANSFORMER LOSSES ADJUSTED TO FORECAST 1:2 PEAK LOAD

Coincident peak Transformer losses were adjusted to the forecast 1:2 system peak load according to the following formula:

$$\sum Transformer\ Loss_{1:2\ peak} = \sum Transformer\ Loss_{sys_peak}\ x\ 0.832$$

See attached "Loss Adjustment Factors for Primary Distribution System" for the computation of the adjustment factor.

PRIMARY FEEDER LOSSES

This section covers loss calculations on the primary distribution feeders. The voltage of the primary feeders are 4 KV, 11 KV and 13 KV nominal line to line. The majority of the system is 13 KV, with some areas of central Portland served by 4 KV and 11 KV feeders. Computations were made for feeder peak load losses, feeder average losses and feeder load losses coincident with system peak load and adjusted for forecast peak1:2 loading.

FEEDER LOSS CALCULATIONS:

Radial feeder loss calculations were performed using the CYMDIST program. Each radial feeder has an electrical model defined in CYMDIST. The model shows circuit connectivity downstream of feeder breaker with wire/cable section impedances and feeder load points at the primary level. Most feeder loads are non-demand type where only energy consumption (kWh) is known. The power consumption (KW,KVAR) at every load point was estimated by allocating the metered load at the feeder breaker. The allocation of feeder breaker demand to a load point was proportional to its energy consumption (kWh).

SCADA & MV90 monitors loading at the feeder breaker and these data are displayed/stored in the PI system. The loading data over the year (2004) was analyzed and processed to find the feeder peak loading. For unattended substations, the peak monthly reading was used. Unusual spikes in loading such as load transfers are removed to get normal peak loading of a feeder. This information is reported in the PGE Weak-Link Report.

For the study, the feeder peak loading (MVA) in CYMDIST was assigned from the Weak-Link Report. The power factor at peak was unknown and was assumed to be unity (PF=1) since line-losses are irrespective of power factor.

AVERAGE FEEDER LOSSES:

Average feeder loss is calculated from the peak feeder loss by the equation below:

$$Feeder\ Loss_{avg} = Feeder\ Loss_{peak} \times LssF_{transformer}$$

where
$LssF_{sub}$ = Loss Factor computed for the substation transformer serving that feeder

COINCIDENT PEAK FEEDER LOSSES:

To calculate feeder losses at system peak, the feeder peak loss was scaled by an adjustment factor. This gives us the feeder loss at system peak (Jan 5, 5.30 – 6.30 PM).

$$Feeder\ Loss_{sys_peak} = Feeder\ Loss_{peak} \times \left(\frac{Feeder\ Loading_{sys_peak}\ (mva)}{Feeder\ Loading_{peak}\ (mva)} \right)^2$$

Where:
$Feeder\ Loss_{sys_peak}$ = Feeder loss at system peak
$Feeder\ Loss_{peak}$ = Feeder loss at feeder peak
$Feeder\ Loading_{sys_peak}$ = Coincident feeder loading at system peak
$Feeder\ Loading_{peak}$ = Annual feeder peak loading

The aggregate of all feeder losses at system peak gives us the total primary distribution feeder loss at the time of the 2004 system peak.

COINCIDENT PEAK FEEDER LOSSES ADJUSTED TO FORECAST 1:2 PEAK LOAD:

Coincident peak feeder losses were adjusted to the forecast 1:2 peak load according to the following formula

$$\sum Feeder\ Loss_{1:2\ peak} = \sum Feeder\ Loss_{sys_peak} \times 0.832$$

See attached "Loss Adjustment Factors for Primary Distribution System" for the computation of the adjustment factor.

RESULTS:

The attached "Primary Distribution Loss Calculations" spread sheet lists loss calculation data for each PGE substation transformer and feeder.

Coincident peak demand primary losses from spread sheet = 81.8MW.

Coincident peak demand loss adjusted to 1:2 forecast system peak

Transformer	*= 0.832x23.375MW*	*= 19.45MW*
Feeders	*= 0.832x58.449 =*	*49.26MW*
Total	*=*	*68.71MW*

Average Losses

Transformers	*=*	*10.46MW*
Feeders	*=*	*18.21MW*
Total	*=*	*28.67MW*

Attachment E: Calculation of 2007 Projected External Losses

Attachment E: 2007 External Loss Projections

Resources	MWH	tDNo.	POR	IR & PTP Loss Factor	Mont. Int Loss Factor	AC Interlie Loss Factor	DC Interlie Loss Factor	PGE Ext. Loss Factor	External Losses MWH	Energy to PGE	Loss Returns MWH
Round Butte	561,493		PGE	0.00%	0.00%	0.00%	0.00%	0.00%	0	561,493	0
Pelton	288,584		PGE	0.00%	0.00%	0.00%	0.00%	0.00%	0	288,584	0
Oak Grove	225,122		PGE	0.00%	0.00%	0.00%	0.00%	0.00%	0	225,122	0
North Fork	233,851		PGE	0.00%	0.00%	0.00%	0.00%	0.00%	0	233,851	0
Faraday	220,902		PGE	0.00%	0.00%	0.00%	0.00%	0.00%	0	220,902	0
River Mill	122,949		PGE	0.00%	0.00%	0.00%	0.00%	0.00%	0	122,949	0
Bull Run	69,254		PGE	0.00%	0.00%	0.00%	0.00%	0.00%	0	69,254	0
Sullivan	121,480		PGE	0.00%	0.00%	0.00%	0.00%	0.00%	0	121,480	0
Portland Hydro Project	88,505		PGE	0.00%	0.00%	0.00%	0.00%	0.00%	0	88,505	0
Wells	765,369		Mid-C	-1.90%	0.00%	0.00%	0.00%	-1.90%	(14,542)	750,827	14,542
Rocky Reach	726,758		Mid-C	-1.90%	0.00%	0.00%	0.00%	-1.90%	(13,808)	712,949	13,808
Wanapum	695,363		Mid-C	-1.90%	0.00%	0.00%	0.00%	-1.90%	(13,212)	682,151	13,212
Priest Rapids (Existing through Oct 31-2005)	0		Mid-C	-1.90%	0.00%	0.00%	0.00%	-1.90%	0	0	0
Priest Rapids (Renewal from Nov. 1-2005)	256,023		Mid-C	-1.90%	0.00%	0.00%	0.00%	-1.90%	(4,864)	251,158	4,864
Priest Rapids Displacement (Renewal from Nov. 1-200	404,205		Mid-C	-1.90%	0.00%	0.00%	0.00%	-1.90%	(7,680)	396,525	7,680
Total Hydro	4,779,858								(54,107)	4,725,749	54,107
Boardman	2,858,478		IR	-1.90%	0.00%	0.00%	0.00%	-1.90%	(54,311)	2,804,167	54,311
Colstrip Unit 3	1,015,454		IR+Mon. Int.	-1.90%	-2.74%	0.00%	0.00%	-4.69%	(47,640)	967,814	47,640
Colstrip Unit 4	1,166,039		IR+Mon. Int.	-1.90%	-2.74%	0.00%	0.00%	-4.69%	(54,704)	1,111,335	54,704
Total Coal	5,039,971								(156,655)	4,883,316	156,655
Beaver Units 1-7	518,666		IR	-1.90%	0.00%	0.00%	0.00%	-1.90%	(9,855)	508,811	9,855
Beaver Unit 8	0		IR	-1.90%	0.00%	0.00%	0.00%	-1.90%	0	0	0
Coyote Off - Fire Auxiliary Boiler	(856)		IR	0.00%	0.00%	0.00%	0.00%	0.00%	0	(856)	0
Coyote In Extraction Steam Mode - Incremental	1,516,249		IR	-1.90%	0.00%	0.00%	0.00%	-1.90%	(28,809)	1,487,440	28,809
Coyote - Fire Auxiliary Boiler to Increase Power	0		IR	-1.90%	0.00%	0.00%	0.00%	-1.90%	0	0	0
Coyote Misting	0		IR	-1.90%	0.00%	0.00%	0.00%	-1.90%	0	0	0
Coyote Duct Firing	0		IR	-1.90%	0.00%	0.00%	0.00%	-1.90%	0	0	0
Port Westward 1	1,560,317		PGE	0.00%	0.00%	0.00%	0.00%	0.00%	0	1,560,317	0
Port Westward 1 Duct Firing	45,527		PGE	0.00%	0.00%	0.00%	0.00%	0.00%	0	45,527	0
Total Gas	3,639,902								(38,663)	3,601,239	38,663
WWP Capacity Nov-Mar	162,000	436 / 1048	Mid-C	-1.90%	0.00%	0.00%	0.00%	-1.90%	(3,078)	158,922	3,078
WWP Capacity Nov-Mar	(161,700)		Mid-C	0.00%	0.00%	0.00%	0.00%	0.00%	0	(161,700)	0
WWP Capacity Apr-Sep	229,500	436 / 1048	Mid-C	-1.90%	0.00%	0.00%	0.00%	-1.90%	(4,360)	225,140	4,360
WWP Capacity Apr-Sep	(229,275)		Mid-C	0.00%	0.00%	0.00%	0.00%	0.00%	0	(229,275)	0
EWEB Capacity - Summer	13,200	472	PGE	0.00%	0.00%	0.00%	0.00%	0.00%	0	13,200	0
EWEB Capacity - Summer	(13,140)	1071	PGE	1.90%	0.00%	0.00%	0.00%	1.90%	(250)	(13,390)	250
EWEB Capacity - Winter	12,900	472	PGE	0.00%	0.00%	0.00%	0.00%	0.00%	0	12,900	0
EWEB Capacity - Winter	(12,860)	1071	PGE	1.90%	0.00%	0.00%	0.00%	1.90%	(244)	(13,104)	244
EWEB Stone Creek Capacity Benefit	37		PGE	0.00%	0.00%	0.00%	0.00%	0.00%	0	37	0
EWEB Stone Creek Capacity Benefit	(26)		PGE	1.90%	0.00%	0.00%	0.00%	1.90%	(0)	(26)	0
Total Capacity	636								(7,933)	(7,297)	7,933
Dispatchable Standby Generation Monthly Test	571		PGE	0.00%	0.00%	0.00%	0.00%	0.00%	0	571	0
Wells Settlement Agreement On-Peak	133,995	928	Mid-C	-1.90%	0.00%	0.00%	0.00%	-1.90%	(2,546)	131,450	2,546
Wells Settlement Agreement Off-Peak	104,369	928	Mid-C	-1.90%	0.00%	0.00%	0.00%	-1.90%	(1,983)	102,386	1,983
Canadian Entitlement Allocation Extension	(146,700)	4617	Mid-C	0.00%	0.00%	0.00%	0.00%	0.00%	0	(146,700)	0
Mt. Tabor Hydro	642	614	PGE	0.00%	0.00%	0.00%	0.00%	0.00%	0	642	0
Lake Oswego Hydro	295	27 / 460	PGE	0.00%	0.00%	0.00%	0.00%	0.00%	0	295	0
PPL Streetlighting	11,080	461	PGE	0.00%	0.00%	0.00%	0.00%	0.00%	0	11,080	0
Covanta Municipal Solid Waste to Energy	84,797	614	PGE	0.00%	0.00%	0.00%	0.00%	0.00%	0	84,797	0
Chelan Exchange In - Summer	58,231	483	Mid-C	-1.90%	0.00%	0.00%	0.00%	-1.90%	(1,105)	57,124	1,105
Chelan Exchange Out - Summer	(41,031)	997 / 1001	Mid-C	0.00%	0.00%	0.00%	0.00%	0.00%	0	(41,031)	0
Chelan Exchange Out - Winter	(29,910)	997 / 1001	Mid-C	0.00%	0.00%	0.00%	0.00%	0.00%	0	(29,910)	0
Glendale Exchange In	30,960	945 / 948	NOB	-1.90%	0.00%	0.00%	-3.50%	-5.47%	(1,692)	29,268	1,692
Glendale Exchange Out	(30,309)	509	NOB	0.00%	0.00%	0.00%	3.50%	3.50%	(1,061)	(31,369)	1,061
ESI Vansycle Partners LP Wind	73,672	4580	PGE	-1.90%	0.00%	0.00%	0.00%	-1.90%	(1,400)	72,272	1,400
Tribes Mid-C Index Purchase	373,021	5083/1608	PGE	0.00%	0.00%	0.00%	0.00%	0.00%	0	373,021	0
Confederated Tribes of Warm Springs Reservation	122,800	73413	PGE	0.00%	0.00%	0.00%	0.00%	0.00%	0	122,800	0
Morgan Stanley Daily On-Peak Tolling	122,800	78178	Mid-C	-1.90%	0.00%	0.00%	0.00%	-1.90%	(2,333)	120,467	2,333
PPM (Wind) Klondike II	132,562	9667D	Mid-C	-1.90%	0.00%	0.00%	0.00%	-1.90%	(2,519)	130,043	2,519
PPM (Wind) Klondike II	103,534	9667D	Mid-C	-1.90%	0.00%	0.00%	0.00%	-1.90%	(1,967)	101,566	1,967
TransAlta PPA from Centralia Plant	815,556	77508	CW Paul	-1.90%	0.00%	0.00%	0.00%	-1.90%	(15,496)	800,060	15,496
Morgan Stanley Capital Group Inc.	96,202	78171	Mid-C	-1.90%	0.00%	0.00%	0.00%	-1.90%	(1,828)	94,374	1,828
Morgan Stanley Capital Group Inc.	122,800	78171	Mid-C	-1.90%	0.00%	0.00%	0.00%	-1.90%	(2,333)	120,467	2,333
Total Purchases	2,139,936								(36,264)	2,103,672	36,264
Cove Replacement Obligation to PPL	(8,000)	32	PGE	0.00%	0.00%	0.00%	0.00%	0.00%	0	(8,000)	0
Cove Obligation to US Bureau of Reclamation	(3,334)		PGE	0.00%	0.00%	0.00%	0.00%	0.00%	0	(3,334)	0
Colstrip Pumping Load – Avista (Nichols Sub)	(8,760)	67269	IR+Mon. Int.	0.00%	0.00%	0.00%	0.00%	0.00%	0	(8,760)	0
Glendale Sales based on Beaver Price	(7,345)	465	NOB	0.00%	0.00%	0.00%	3.50%	3.50%	(257)	(7,602)	257
Glendale Sales based on Coyote Price	(94,500)	465	NOB	0.00%	0.00%	0.00%	3.50%	3.50%	(3,308)	(97,808)	3,308
Sales Totals	(121,939)								(3,565)	(125,503)	3,565
Totals	15,478,352								(297,187)	15,181,175	297,187
Remaining Load Requirements			Mid-C	-1.90%	0.00%	0.00%	0.00%	-1.90%			

Calculation of 2007 External Loss Percent

Delivery Voltage	2007 Calendar Energy	2007 Distribution Loss Factor	2007 Distribution Losses	2007 Energy to PGE
Secondary	15,974,676	6.28%	1,003,210	16,977,886
Primary	2,912,225	2.82%	82,125	2,994,350
Subtransmission	1,164,085	1.31%	15,250	1,179,335
Totals	20,050,987		1,100,584	21,151,570

PGE Internal Load Requirements	21,151,570	
Dispatch and Contracts to PGE	15,181,175	
Remaining Requirements	5,970,395	
Busbar Energy for Rem. Req.	6,086,030	(add 1.9% external losses)
Losses	115,635	
Losses on Contracts and Dispatch	297,187	
Total External Losses	412,821	
External Losses Factor (as percent of meter load)	2.06%	

Attachment F: Historical External Losses

PGE Historical External Losses 2000-2004

Year	IR	PTP	AC Intertie	DC Intertie	Colstrip	Totals	Totals w/o Colstrip
2000	305,518	10,047	64,539	11,714	54,759	446,577	380,104
2001	308,735	6,330	45,737	5,400	63,322	429,524	360,802
2002	226,090	55,840	67,596	9,802	51,447	410,775	349,526
2003	237,596	54,291	62,377	10,588	60,091	424,943	354,264
2004	251,659	45,891	68,713	5,351	52,858	424,472	366,263
Totals '00-04	1,329,598	172,399	308,962	42,855	282,477	2,136,291	1,810,959

Colstrip Loss Percent

Year	Colstrip Production	Montana Int. Losses	Loss Percent
2000	1,970,560	54,759	2.78%
2001	2,154,822	63,322	2.94%
2002	1,911,652	51,447	2.69%
2003	2,124,744	60,091	2.83%
2004	2,149,753	52,858	2.46%
	10,311,531	282,477	2.74%

Attachment G: Historical Production Data

Note: 2000 plant data from FERC Form 1 Worksheet

Year	IR Beaver	IR Beaver 8	IR Coyote	IR Colstrip	IR Boardman	IR Mid-Columbia	Centralia Coal	Centralia Hydro	WS Internal Bull Run	WS Internal Faraday	WS Internal North Fork	WS Internal Oak Grove	WS Internal River Mill
2000	2,839,768	0	1,818,157	1,970,560	2,291,180	2,955,196	0	61	101,514	168,548	193,191	260,823	104,684
2001	3,313,038	15,471	1,944,110	2,154,822	2,883,563	1,971,420	0	0	85,424	124,902	143,975	194,245	80,236
2002	362,327	3,463	1,279,958	1,911,652	2,336,412	2,765,629	0	0	92,250	151,158	175,146	240,400	101,198
2003	316,959	47	984,355	2,124,744	2,794,337	2,455,061	0	0	96,150	153,541	169,115	223,568	97,582
2004	361,895	7	1,586,907	2,149,753	2,312,562	2,636,323	0	0	117,729	154,392	169,968	197,857	99,492
Totals	7,193,987	18,988	7,613,487	10,311,531	12,618,054	12,783,629	0	61	493,067	752,541	851,395	1,116,893	483,192

Year	WS Internal Sullivan	WS Internal Portland Hydro	Internal Pelton	Internal Round Butte	Internal Purchases Pelton	Internal Purchases Round Butte	Internal Rereg from Warm Springs	Internal Covanta	Internal Small Power	Internal Mt. Tabor	Internal Lake Osw.	Del BPA Subscription	Del PPW STL
2000	129,026	77,847	466,352	1,074,341	0	0	0	85,134	1,402	645	525	0	12,662
2001	125,784	73,409	385,002	890,192	0	0	0	84,682	1,094	673	194	512,488	13,019
2002	128,948	75,266	262,387	608,705	131,194	304,349	78,773	86,872	576	632	196	2,089,754	11,258
2003	123,124	86,491	258,019	604,579	129,012	302,289	80,539	86,196	962	672	264	2,260,080	11,091
2004	76,082	81,868	272,887	640,045	136,444	320,022	56,514	84,695	1,079	501	566	2,266,272	11,035
Totals	582,964	394,881	1,644,647	3,817,862	396,650	926,660	215,826	427,579	5,113	3,123	1,745	7,128,594	59,065

Year	IR Energy	Centralia Generation	Internal Generation	Internal Purchases	Delivered Purchases	Totals	EGR&D Energy	Allocable Retail Energy
2000	11,874,861	61	2,576,326	87,706	12,662	14,551,616	21,319,678	6,768,062
2001	12,282,424	0	2,103,169	86,643	525,507	14,997,743	20,345,990	5,348,247
2002	8,659,441	0	1,835,458	602,592	2,101,012	13,198,503	19,905,420	6,706,917
2003	8,675,503	0	1,812,169	599,934	2,271,171	13,358,777	19,722,723	6,363,946
2004	9,047,447	0	1,810,320	599,821	2,277,307	13,734,895	18,929,867	5,194,972