EXHIBIT NO. ____(KCH-6T)
DOCKET NO. UE-040641/UG-040640
2004 PSE GENERAL RATE CASE
WITNESS: KEVIN C. HIGGINS

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-040641** **Docket No. UG-040640**

PREFILED CROSS-ANSWER TESTIMONY OF
KEVIN C. HIGGINS
ON BEHALF OF THE KROGER CO.

November 3, 2004

Table of Contents

Introduction.. 1
Cross-Answer to Mr. Lazar…………………………………………………………... 2

CROSS-ANSWER TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 39 Market Street, Suite 200, Salt Lake City, Utah, 84101.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this phase of the proceeding?

A. My testimony is being sponsored by The Kroger Co. ("Kroger") on behalf of its Fred Meyer Stores and Quality Food Centers divisions.

Q. Are you the same Kevin C. Higgins who has pre-filed response testimony in this proceeding on behalf of Kroger?

A. Yes, I am.

Q. What is the purpose of your cross-answer testimony?

A. My cross-answer testimony addresses certain issues pertaining to distribution cost-of-service that were discussed in the pre-filed direct testimony of Jim Lazar, witness for Public Counsel, The Energy Project, and A.W.I.S.H..

Q. Please summarize your cross-answer testimony.

A. Mr. Lazar is critical of PSE's treatment of distribution costs in PSE's cost-of-service study. He asserts that the Company's treatment of transformer costs contains a theoretical error that results in a double-counting of some costs. Because of this alleged error, Mr. Lazar concludes that the Company's methodology of directly assigning much of its distribution costs should be rejected. Instead of direct assignment, Mr. Lazar favors using an allocation formula based on class non-coincident peak (NCP) demand.

In my cross-answer testimony I demonstrate that there is no double-counting in the Company's treatment of transformer costs. Therefore, any recommendation to reject the Company's approach based on this alleged theoretical error is without justification. PSE's use of information technology to directly assign discrete distribution costs is vastly superior to reliance on an aggregate allocation methodology that, at best, is merely a proxy for direct assignment. Choosing "allocation" over "direct assignment" would be a step backward, as such a choice would purposely ignore available and accessible information, with the result that valuable insight into cost causation would be masked.

PSE's methodology for distribution cost-of-service is a significant advancement over the 1992 method and should be accepted.

Cross-Answer to Mr. Lazar

Q. What objections does Mr. Lazar raise with respect to PSE's methodology for distribution cost-of-service?

A. Mr. Lazar's critique focuses on PSE's method for allocating the cost of transformers. Mr. Lazar states:

> First and foremost, the Company has double-counted the cost of providing transformation to the residential class, by first assigning the costs of approximately 85% of the transformers providing service to a single class directly to that class, and then assigning approximately 70% of the remaining transformer cost to the residential class as well. The theoretical problem with this is that the load served by the directly-assigned transformers needs to be netted out when determining the allocation factors for the residual amount, and the Company does not appear to have done this. The result is to double-count the cost of transformers for the residential class. [1]

Q. Does PSE's methodology double-count the cost of transformers for the residential class?

A. No. In analyzing transformer costs, PSE utilizes its database to identify each of the customers classes served on its 233,000 transformers. In the case of transformers that serve only one class, the costs are directly assigned to the relevant class. The reasonableness of such direct assignment is unassailable. As Mr. Lazar points out, this direct assignment covers 85 percent of PSE's transformers.

Mr. Lazar's quarrel is with the remaining 15 percent of transformers, which is where he asserts the double-counting occurs. The inference in Mr. Lazar's testimony is that an allocation takes place with respect to these residual transformers that does not take account of the transformers that have already been directly assigned. The problem with this reasoning, however, is that it misconstrues the manner in which the residual transformers are handled methodologically.

[1] Pre-filed direct testimony of Jim Lazar, p. 23, lines 9-18.

As explained in PSE's Response to WUTC Staff Data Request 259, attached as Exhibit No.___(KCH-7), the cost of the residual transformers is not allocated using an aggregate allocation factor, but is allocated on a transformer-by-transformer basis, as a function of NCP load factor and the *class energy consumption for each individual transformer*. This is clearly shown in the example on pages 5-6 of Attachment A to the Response. With respect to the residual 15 percent of transformers, costs are allocated to the residential class only to the extent that specific residential customers consume a specific amount of energy on specific transformers. Thus, there is no double-counting of previously-assigned costs. Mr. Lazar's recommendation to reject the Company's approach based on an alleged theoretical error is without justification.

Q. What is your recommendation to the Commission with respect to PSE's methodology for allocating distribution costs?

A. PSE's use of information technology to directly assign discretely-identifiable distribution costs is vastly superior to reliance on an aggregate allocation methodology that, at best, is merely a proxy for direct assignment. With respect to the residual distribution cost components that must be allocated, the allocation method employed by the Company is both rigorous and reasonable.

In the case of transformers, PSE's analysis demonstrates that 85 percent of transformer costs can be allocated to specific classes. It makes no sense to ignore this information in favor of an allocation formula. In this instance, choosing "allocation" over "direct assignment" would be a step backward, as such a choice would purposely ignore available and accessible information, with the result that valuable insight into cost causation would be masked.

Far from being theoretically flawed, PSE's study of distribution cost-of-service is a commendable analytical effort. It represents a significant advancement over the 1992 method and should be accepted by the Commission.

Q. Does this conclude your cross-answer testimony?

A. Yes, it does.

EXHIBIT NO. ____(KCH-7)
DOCKET NO. UE-040641/UG-040640
2004 PSE GENERAL RATE CASE
WITNESS: KEVIN C. HIGGINS

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, INC., Respondent.	Docket No. UE-040641 Docket No. UG-040640

EXHIBIT TO
CROSS-ANSWER TESTIMONY OF
KEVIN C. HIGGINS
ON BEHALF OF THE KROGER CO.

PSE Response to WUTC Staff Data Request No. 259

November 3, 2004

BEFORE THE WASHINGTON UTILITIES 'AND TRANSPORTATION COMMISSION

Docket Nos. UG-040640 and UE-040641
Puget Sound Energy, Inc.'s General Rate Case
for Gas and Electric Operations

WUTC STAFF DATA REQUEST NO. 259

WUTC STAFF DATA REQUEST NO. 259:

Please provide a narrative description of the step-by-step procedure the company undertook for calculating substations, distribution lines, and transformer costs. Provide an example for one substation, one feeder, and one transformer serving one or more classes.

Response:

Please see Puget Sound Energy, Inc.'s ("PSE") Response to WUTC Staff Data Request No. 236 for a narrative description of the step-by-step procedure PSE undertook for calculating substations, distribution lines, and transformer costs. Additional narrative for these steps is provided below. Attached as Attachment A to PSE's Response to WUTC Staff Data Request No. 259, please find example calculations, which are simplified examples and not necessarily the actual data.

Allocation of Substations:

PSE allocated the costs on a substation-by-substation basis using the calculated non-coincident peaks of each class also calculated on a substation-by-substation basis. These factors are calculated using the following steps:

1) Calculate class level NCP factors by month and schedule. Load research data are used to calculate class level NCP factors for each month and schedule. These data are entered into arrays and used in a SAS program.

2) Calculate the NCP of each class on each substation by month. The calculation starts with the energy use by month, class, and substation. The energy use is converted to a NCP by dividing the average loss-adjusted hourly load by the class monthly NCP factors.

- The SAS program sums the monthly consumption for each class on, each substation based using the database of customer monthly ' ' consumption which also includes a variable for the primary substation that serves the customer.

- The load by class, month and substation is divided by the appropriate class load factor to determine the class non-coincident peak.

3) On a substation-by-substation basis calculate the percentage of the total NCP that is attributable to each rate class. Each class' non-coincident peak on the substation is summed and the class' allocation to the total for each substation is calculated.

4) Average the 12 monthly percentage contributions for each class on each substation.

5) Multiply the average of the monthly percentage contributions for each class on each substation by the respective costs in accounts 360 — 362 for each substation. The substation costs used are the net book costs.

6) Sum up the costs allocated to each class separately for accounts 360 — 362. The percentage of each class' cost to the total cost is the resulting allocation factor.

<u>Overhead and Underground Lines</u>

PSE allocated the costs of each feeder using the calculated non-coincident peaks of each class multiplied by the overhead and under ground miles of each feeder. (These factors could have been converted into dollars by multiplying those factors by an average cost per mile of UG and OH lines, but the linear transformation would not change the allocation factor.) These factors are calculated using the following steps:

1) Calculate class level NCP factors by month and schedule. Load research data are used to calculate class level NCP factors for each month and schedule. These data are entered into arrays and used in a SAS program.

2) Calculate the NCP of each class on each feeder by month..The calculation starts with the energy use by month, class, and feeder. The energy use is converted to a NCP by dividing the average loss-adjusted hourly load by the class monthly NCP factors.

- The SAS program sums"the monthly consumption for each class on each substation based using the database of customer monthly consumption which also includes a variable for the primary substation that serves the customer.

- The load by class, month and feeder is divided by the appropriate class load factor to, determine the class non-coincident peak.

3) On a feeder-by-feeder basis calculate the percentage of the total NCP that is attributable to each rate class. Each class' non-coincident peak on the substation is summed and the class' allocation to the total for each substation is calculated.

4) Average the 12 monthly NCP loads for each class on each feeder.

5) Multiply the average monthly NCP load for each class on each feeder by the respective number of overhead and underground line miles of the feeder.

6) Sum up the costs allocated to each class separately for overhead and underground line costs. The percentage of each class' circuit mile weighted load to the total is the resulting allocation factor.

<u>Overhead and Pad Mount Transformers</u>

PSE allocated the costs of each transformer based upon the classes contribution to the non-coincident peak on the transformer. (Please see PSE's Response to WUTC Data Request No. 122.) The overhead and pad mount allocation factors are calculated using the following steps:

1) Calculate class level NCP factors by month and schedule (please see Attachment A to PSE's Response to WUTC Data Request No. 259).

2) For each transformer determine the amount of energy use by each rate class using the transformer. This calculation is done by summing the monthly energy used linked to each transformer by month and rate class.

3) Calculate the NCP of each class on each transformer by month. The calculation starts with the energy use by month, class, and transformer. The energy use is converted to a NCP by dividing the average loss-adjusted hourly load by the class monthly NCP factors.

4) On a transformer-by-transformer basis calculate the percentage of the total NCP that is attributable to each rate class.

5) Average the 12 monthly NCP load for each class on each transformer.

6) Multiply the average monthly NCP for each class on each transformer by the installed cost of a comparable new transformer.

7) Sum up the costs allocated to each class separately for overhead and underground transformers. The percentage of each class allocated transformer cost divided by the total transformer cost is the resulting allocation factor for pad mount and overhead transformers.

Attachment A to PSE's Response to WUTC Staff Data Request No. 259

Substation Cost Allocation Example

Step 1: **NCP load factors from Load Research**

Loss Factors

Schedule	Distribution Losses
7	0.0739
24	0.0725
25	0.0725
26	0.0725
29	0.0725
31	0.0388
35	0.0388
43	0.0388

Weekday NCP load factors

Schedule	Jan	Feb	March	April	May	**June**	**July**	Aug	**Sept**	Oct	**Nov**	Dec
7	0.510	0.559	0.541	0.528	0.526	0.571	0.597	0.572	0.522	0.487	0.531	0.540
24	0.575	0.576	0.561	0.517	0.490	0.476	0.483	0.484	0.476	0.526	0.579	0.598
25	0.584	0.553	0.563	0.528	0.484	0.505	0.545	0.532	0.537	0.510	0.535	0.569
26	0.599	0.590	0.587	0.553	0.554	0.564	0.577	0.588	0.577	0.597	0.518	0.571
31	0.595	0.575	0.592	0.585	0.589	0.598	0.625	0.624	0.609	0.616	0.585	0.558

Step 2: NCP of Each Class on Substation by Month

Total Energy Consumption on Northrup Substation

Schedule	Jan	**Feb**	March	**April**	**May**	**June**	**July**	**Aug**	**Sept**	Oct	**Nov**	Dec
7	1,360,360	1,335,893	1,204,290	1,076,670	1,013,232	999,764	928,987	1,008,078	959,888	962,221	1,175,373	1,351,699
24	2,125,828	2,016,166	2,105,645	1,829,465	1,699,038	1,799,161	1,861,664	1,964,975	1,977,824	1,772,752	1,936,056	2,047,828
25	1,874,430	1,862,570	1,882,980	1,689,320	1,637,430	1,760,540	1,813,080	1,852,280	1,904,270	1,775,264	1,812,460	1,877, 880
26	225,840	218,040	199,920	218,880	209,760	235,440	256,920	277,200	269,040	218,520	249,240-	206,880
31	4,499,100	4,472,400	4,294,200	4,546,800	4,524,000	4,935,900	5,259,600	5,027,700	4,711,200	4,611,600	4,490,700	4,384,200

Convert to NCP's by Class

Schedule	**Jan**	**Feb**	March	**April**	**May**	**June**	**July**	**Aug**	**Sept**	**Oct**	Nov	**Dec**
7	3,924	3,516	3,275_	3,000	2,834	2,576	**2,289**	2,593	2,705	2,907	3,256	3,682
24	5,432	5,143	**5,514**	**5,199**	5,094	**5,553**	5,663	**5,965**	6,105	**4,951**	4,913	5,031
25	4,716	4,948	**4,914**	4,701	4,970	5,122	**4,888**	5,115	5,210	5,114	4,977	**4,849**
26	554	543	500	582	556	**613**	**654**	693	685	**538**	707	532
31	10,760	11,068	10,322	11,060	10,930	11,746	11,975	11,466	11,008	10,653	10,924	11,181

Substation Cost Allocation Example

Step 3: **Calculate percent** of **substation load attributed to each class**

Schedule	**Jan**	**Feb**	March	April	**May**	June	July	Aug	**Sept**	Oct	**Nov**	Dec
7	15%	14%	13%	12%	12%	10%	9%	10%	11%	12%	13%	15%
24	21%	20%	22%	21%	21%	22%	22%	23%	24%	20%	20%	20%
25	19%	20%	20%	19%	20%	20%	19%	20%	20%	21%	20%	19%
26	2%	2%	2%	2%	2%	2%	3%	3%	3%	2%	3%	2%
31	42%	44%	42%	45%	45%	46%	47%	44%	43%	44%	44%	44%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Step 4: Average the 12 NCPs

Schedule	**Average** 12 NCP
7	12%
24	21%
25	20%
26	2%
31	44%

Step 5: **Multiple by Substation Net Book Cost**

Account	Northrup
360	$ 42,046
361	$ 8,477
362	$ 585,407

Schedule	**Account 361**	**Account 361**	**Account 362**
7	$ 5,113	$ 1,031	$ 71,195
24	$ 9,016	$ 1,818	$ 125,533
25	$ 8,320	$ 1,678	$ 115,844
26	$ 999	$ 201	$ 13,913
31	$ 18,596	$ 3,750	$ 258,922

Line Allocation Example

Step 1: NCP load factors from Load Research

Loss Factors

Schedule	Distribution Losses
7	0.0739
24	0.0725
25	0.0725
26	0.0725
29	0.0725
31	0.0388
35	0.0388
43	0.0388

Weekday NCP **load factors**

Schedule	Jan	Feb	March	April	May	June	July	Aug	Sept	Oct	Nov	Dec
7	0.510	0.559	0.541	0.528	0.526	0.571	0.597	0.572	0.522	0.487	0.531	0.540
24	0.575	0.576	0.561	0.517	0.490	0.476	0.483	0.484	0.476	0.526	0.579	0.598
25	0.584	0.553	0.563	0.528	0.484	0.505	0.545	0.532	0.537	0.510	0.535	0.569
26	0.599	0.590	0.587	0.553	0.554	0.564	0.577	0.588	0.577	0.597	0.518	0.571
31	0.595	0.575	0.592	0.585	0.589	0.598	0.625	0.624	0.609	0.616	0.585	0.558

Step 2: NCP of Each Class on Feeder by Month

Total Energy Consumption on Northrup Circuit #25

Schedule	Jan	Feb	March	April	May	June	July	Aug	Sept	Oct	Nov	Dec
7	978,489	960,350	867,927	775,268	731,356	**714,515**	658,074	714,392	681,095	681,152	835,784	959,801
24	259,093	247,627	255,325	233,448	215,874	243,500	258,902	275,873	228,180	225,999	257,021	263,668
25	368,970	390,810	388,110	369,110	352,050	402,450	419,260	**443,480**	413,760	348,218	375,410	380,770
26	225,840	218,040	199,920	218,880	209,760	235,440	256,920	277,200	269,040	218,520	249,240	206,880
31	578,400	571,800	553,800	556,800	583,800	684,600	720,000	704,400	634,800	625,800	609,600	587,400

Convert to NCP's by Class

Schedule	Jan	Feb	March	April	May	June	July	Aug	Sept	Oct	Nov	Dec
7	2,822	2,527	2,360	2,160	2,045	1,841	1,622	1,837	1,919	2,058	2,315	2,615
24	662	632	669	663	647	752	788	837	704	631	652	648
25	928	1,038	1,013	1,027	1,069	1,171	1,130	_1,225	1,132	1,003	1,031	983
26	554	543	500	582	556	613	**654**	693	685	538	707	532
31	1,383	1,415	1,331	1,354	1,410	1,629	1,639	1,606	1,483	1,446	1,483	1,498

Line Allocation Example

Step 3: Calculate percent of the feeder load attributed to each class

Schedule	Jan	Feb	March	April	May	June	July	Aug	Sept	Oct	Nov	Dec
7	44%	41%	40%	37%	36%	31%	28%	30%	32%	36%	37%	42%
24	10%	10%	11%	11%	11%	13%	14%	14%	12%	11%	11%	10%
25	15%	17%	17%	18%	19%	19%	19%	20%	19%	18%	17%	16%
26	9%	9%	9%	10%	10%	10%	11%	11%	12%	9%	11%	8%
31	22%	23%	23%	23%	25%	27%	28%	26%	25%	25%	24%	24%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Step 4: Average the 12 NCPs

Schedule	**Average 12 NCP**
7	36%
24	12%
25	18%
26	10%
31	25%

Step 5: Multiple by Overhead and Underground Line Miles

Miles	**NRU-25**
OH	2.85
UG	4.37

Schedule	OH	**UG**
7	1.03	1.58
24	0.33	0.50
25	0.51	0.78
26	0.28	0.43
31	0.70	1.07

Example Transformer Cost Allocation

Step 1: NCP load factors from Load Research

Loss Factors

Schedule	Distribution Losses
7	0.0739
24	0.0725
25	0.0725
26	0.0725
29	0.0725
31	0.0388
35	0.0388
43	0.0388

Weekday NCP load factors

Schedule	Jan	Feb	March	April	May	June	July	Aug	Sept	Oct	Nov	Dec
7	0.510	0.559	0.541	0.528	0.526	0.571	0.597	0.572	0.522	0.487	0.531	0.540
24	0.575	0.576	0.561	0.517	0.490	.0.476	0.483	0.484	0.476	0.526	0.579	0.598
25	0.584	0.553	0.563	0.528	0.484 -	0.505	0.545	- 0.532	0.537	0.510	0.535	0.569
26	0.599	0.590	0.587	0.553	0.554	0.564	0.577	0.588	0.577	11597	0.518	0.571
31	0.595	0.575	0.592	0.585	0.589	0.598	0.625	0.624	0.609	0.616	0.585	0.558

Step 2: NCP of Each Class on Transformer X by Month

Total Energy Consumption on transformer at TGRID 00000-00000 - 25 kVA pad mount transformer (sample data)

Customer	Schedule	Jan	Feb	March	April	May	June	July	Aug	Sept	Oct	Nov	Dec
3	7	3.433	3.370	3.045	2.720	2.566	2.507	2.309	2.507	2.390	2.390	2.933	3.368
1	24	1.993	1.905	1.964	1.796	1.661	1.873	1.992	2.122	1.755	1.738	1.977	2.028

Step 3: Convert to NCP's by Class

Transformers

Example Transformer Cost Allocation

Schedule	Jan	Feb	March	April	May	June	July	Aug	Sept	Oct	Nov	Dec
7	9.90	8.87	8.28	7.58	7.18	6.46	5.69	6.45	6.73	7.22	8.12	9.17
24	5.09	4.86	5.14	5.10	4.98	5.78	6.06	6.44	5.42	4.86	5.02	4.98

Step 4: **Percent of Transformer Attributable to Each Class**

Schedule	Jan	Feb	March	April	May	June	July	Aug	Sept	Oct	Nov	Dec
7	0.66	0.65	0.62	0.60	0.59	0.53	0.48	0.50	0.55	0.60	0.62	0.65
24	0.34	0.35	0.38	0.40	0.41	0.47	0.52	0.50	0.45	0.40	0.38	0.35

Step 5: **Average the 12 Monthly NCP allocations**

Schedule	Average
7	0.59
24	0.41

Step 6: **Allocate out the transformer cost**

25 kVA Padmount: $1,588.86

Schedule	Cost Allocation
7	932.38
24	656.48

Example Data

PRIM UN	STATION_NAME	CIRKV	NUMCUS1	OH_MI	UG_MI	TOT MI	ALTSCH	CDRSCUS	COND KWH	CONO KWH	COND KWH	COND KWH	COND KWH	CONO KWH	COND KWH	COND KWH	CONO KWH	COND KWH	COND KWH	COND KWH_ONTV_200309
NRU-23	NORTHRUP	12 5	284	13.3	28.78	42.08	07	322	**273.649**	329.091	378,947	367,021	**361.603**	**322,961**	**290.535**	273,023	277059	**263.696**	285.459	271.307
NRU-23	NORTHRUP	12.5	0	0	0.17	0.17	24	107	164.485	177,467	195.304	196.699	191,553	184,186	167.942	165.222	190.949	192.194	213,243	213,918
NRU-23	NORTHRUP	12.5	0	0	0.17	0.17	25	19	294.677	323.120	354.800	329,960	342,400	345,040	302.680	293,440	326,600	318,120	333.440	342.240
NRU-25	NORTHRUP	12.5	874	2.85	4 37	7.22	07	1391	**681,152**	835,784	959.801	978,489	960,350	867,927	775,268	731.356	714,515	658,074	714,392	681,095
NRU-25	NORTHRUP	12.5	874	2.85	4.37	7.22	24	144	**225.999**	257,021	263,668	259.093	247.627	**255,325**	233.448	215,874	243.500	258.902	275.873	228,180
NRU-25	NORTHRUP	12.5	874	2.85	4.37	7.22	25	22	348,218	375,410	380,770	368,970	390,810	388.110	369.110	352,050	402,450	419.260	443,480	413.760
NRU-25	NORTHRUP	12.5	874	2.85	4.37	7 22	26	1	218,520	249.240	206,880	225,840	218,040	**199.920**	**218.880**	209.760	235,440	256,920	277,200	269.040
NRU-25	NORTHRUP	12.5	874	2.85	4.37	7.22	31	2	625.800	609,600	587.400	578,400	571,800	**553.800**	**556.800**	583,800	684,600	720.000	704,400	634,800
NRU-26	NORTHRUP	12 5	165	0.75	3.62	4.37	07	40	5.106	7.897	9,116	10.344	9,836	10.115	8.048	6.550	5,471	4,401	4,575	4.808
NRU-26	NORTHRUP	12 5	**165**	0.75	3.62	4.37	24	279	220,785	261.495	**269,149**	**283,676**	272,234	273,029	250,688	232,611	239,476	243,757	253.213	247,364
NRU-26	NORTHRUP	12.5	165	0.75	3 62	4 37	25	14	149,480	170,560	175,640	202,640	197.240	**184.960**	185,800	**189,520**	181,160	183.800	177,520	167,520
NRU-26	NORTHRUP	12 5	165	0 75	3 62	4 37	31	3	3.985,800	3.881 100	3,796,800	3.920.700	3,900,600	3,740,400	3,990,000	3.940,200	4,251,300	4,539.600	4.323.300	4.076,400
NRU-27	NORTHRUP	12 5	641	1	2.52	3 52	07	3	2,314	2,601	**3.835**	4,506	4.104	3,287	2.819	2,303	2,719	2,816	3,652	2.678
NRU-27	NORTHRUP	125	641	1	2.52	3.52	24	1228	1.161.483	1,240,073	1,319, 707	1,386,360	1.304.752	**1.393.105**	1,177.387	1.085.331	1,125,236	1.166.811	1.222.646	1,288,362
NRU-27	NORTHRUP	12.5	641	1	2.52	3.52	25	60	**982,889**	943,370	966.670	972.860	932,120	964.870	831.730	802,420	**850,330**	891.900	897,840	980,750