Q. **<u>GENERATION HYDRO</u>**

FACILITY REHABILITATION (POOLED), p. 2 of 81, $996,000

PUB 1.0
Please provide a breakdown of Table 1, p. 3 of 81, by project identified in 1.1 *2006 Hydro Plants Facility Rehabilitation*.

A. The following is a breakdown of Table 1, p. 3 of 81 which summarizes the cost by category for each item identified in 1.1 *2006 Hydro Plants Facility Rehabilitation*.

Table 1

Cost Breakdown by Item
2006
(000s)

Item Name	Materials	Labour-Internal	Engineering	Other	Total
Morris Canal Embankment Rehabilitation	$ 94	$ 5	$ 5	$ 1	$ 105
Tors Cove Forebay Dam Rehabilitation	89	4	6	2	101
Victoria Blue Hill Pond Dam Overtopping Protection	64	10	8	3	85
Victoria Rocky Pond Dam Overtopping Protection	64	10	8	3	85
West Brook Spillway Rehabilitation	67	5	5	4	81
Heart's Content Seal Cove Pond Dam Rehabilitation	85	12	8	3	108
Refurbish / Replace Hydro Generating Plant Infrastructure & Equipment	210	20	-	-	230
Cooling Coils Replacements	30	-	20	-	50
Projects <$50,000	94	27	23	7	151
Total	**$ 797**	**$ 93**	**$ 83**	**$ 23**	**$ 996**

Q. **GENERATION HYDRO**

FACILITY REHABILITATION (POOLED), p. 2 of 81, $996,000

PUB 2.0
Please provide a breakdown of Table 2, p. 3 of 81, by project identified in 1.1 *2006 Hydro Plants Facility Rehabilitation*.

A. Table 1 below provides a breakdown of Table 2, page 3 of 81, showing those expenditures in prior years related to the capital expenditure items identified in 1.1 *2006 Hydro Plants Facility Rehabilitation*.

Table 1
Cost Breakdown by Item
(000s)

Item Name	2001	2002	2003	2004	2005F
Morris Canal Embankment Rehabilitation	$ -	$ -	$ -	$ -	$ -
Tors Cove Forebay Dam Rehabilitation	-	-	-	-	-
Victoria Blue Hill Pond Dam Overtopping Protection	-	-	-	-	-
Victoria Rocky Pond Dam Overtopping Protection	-	-	-	-	-
West Brook Spillway Rehabilitation	-	-	-	-	-
Heart's Content Seal Cove Pond Dam Rehabilitation	-	-	-	-	-
Refurbish / Replace Hydro Generating Plant Infrastructure & Equipment	137	707	228	281	150
Cooling Coil Replacements	88	50	47	27	40
Projects <$50,000	840 [1]	208	124	166	140

[1] The 2001 Capital Budget approved by the Board in 2000 included projects less than $50,000 totaling $692,000. Some projects which were categorized as projects less than $50,000 in 2001 would be grouped and itemized separately under the Facility Rehabilitation project based on current capital budget criteria, and the total for projects less than $50,000 would be reduced accordingly.

Q. **<u>SUBSTATIONS</u>**

REBUILD SUBSTATIONS (POOLED), p. 10 of 81, $710,000

PUB 3.0
In 2004, according to Appendix A, p. A-1, of Section 2.1 2006 Rebuild Substations, 594,218 customer minutes of outages were caused by gap type lightning arrestors. Please provide a breakdown of the areas that were involved, the number of customers that were affected, and the duration of each outage.

A. In 2004 there were 3 major outages caused by gap type lightning arrestor failures in substations. A breakdown of these outages is outlined below:

Table 1

2004 Customer Outage Minutes due to Gap Type Lightning Arrestor Failures

Area Affected	Date	Customers Affected	Duration (minutes)	Total Customer Minutes
Port Au Port Peninsula	01-Apr	1,745	96	167,520
		862	56	48,272
Mount Pearl	29-May	1,172	33	38,676
		1,462	34	49,708
		1,669	35	58,415
		983	37	36,371
		1,429	62	88,598
Freshwater, Placentia, Argentia	12-Aug	1,095	93	101,835
		53	91	4,823
Total				**594,218**

These 3 outages represent 18% of the total 2004 customer minutes of unscheduled outages due to failures in substations.

Q. **<u>SUBSTATIONS</u>**

REBUILD SUBSTATIONS (POOLED), p. 10 of 81, $710,000

PUB 4.0
Please provide a breakdown of the 967,414 customer minutes of unscheduled outages experienced to the date of the Application in 2005 and caused by gap type lightning arrestors.

A. To date in 2005 there have been 2 major substation outages caused by gap type lightning arrestor failures. Table 1 below provides a breakdown of the associated 967,414 customer minutes of unscheduled outages referred to in the Application.

Table 1

2005 Customer Outage Minutes due to Gap Type Lightning Arrestor Failures

Area Affected	Date	Customers Affected	Duration (minutes)	Total Customer Minutes
Port au Port Peninsula	31-Mar	2,627	109	286,343
		1,759	106	186,454
		868	61	52,948
Port au Port Peninsula, Stephenville	30-May	1,146	88	100,848
		570	77	43,890
		1,058	74	78,292
		441	73	32,193
		2,626	71	186,446
Total				**967,414**

These 2 outages represent 42% of the total 2005 YTD customer outage minutes related to equipment failures in substations.

Q. **<u>SUBSTATIONS</u>**

REBUILD SUBSTATIONS (POOLED), p. 10 of 81, $710,000

PUB 5.0
Please provide a history of expenditures for each year from 1990 to 2005F for lightning arrestors, indicating whether these expenditures were related to transmission lines, distribution lines, substations or other.

A. Lightning arrestors are classed as either transmission or distribution voltage, and are installed to protect substation and distribution equipment from damage due to lightning strikes. Such lightning strikes may occur close to the protected equipment, or may strike at a distance and travel along distribution or transmission lines to where the equipment is located.

All of Newfoundland Power's transmission class voltage arrestors are located in substations, close to the equipment that they are designed to protect. Newfoundland Power installs lightning arrestors on all substation transformers.

Newfoundland Power has increased its use of lightning arrestors on its distribution equipment in recent years, primarily due to experience with lightning storms and associated failures of distribution transformers. A detailed review of this practice is contained in the report *Distribution Lightning Arrestors* filed in Newfoundland Power's 2004 Capital Budget Application as Distribution Appendix 2, Attachment B.

Newfoundland Power's system of accounts does not specifically track expenditures on lightning arrestors. However, the Company does have a record of the number of lightning arrestors issued from inventory each year since 1995.

Table 1 on page 2 of 2 shows the number of distribution and transmission class lightning arrestors issued from inventory each year since 1995, including both new installations and replacements for arrestors that have failed in service. Table 1 also provides the cost of materials for those lightning arrestors in 2005 dollars. Table 1 does not include the associated cost of installation.

Since 1995, the Company has acquired and installed an additional 24 lightning arrestors as part of the purchase of four substation power transformers. Information regarding these integrated lightning arrestors is also not included in Table 1.

Similar information with respect to the number of lightning arrestors issued from inventory during the period from 1990 to 1994, and their respective cost, is not readily available.

Table 1
Lightning Arrestors Issued From Inventory
1995 – 2005 [1]

	Distribution Class Lightning Arrestors		**Transmission Class Lightning Arrestors**	
	Number	**Cost of Materials (2005 $)**	**Number**	**Cost of Materials (2005 $)**
1995	545	$ 24,570	3	$ 1,795
1996	511	$ 26,036	6	$ 3,370
1997	704	$ 35,160	4	$ 6,762
1998	754	$ 37,995	3	$ 1,648
1999	1,316	$ 63,251	3	$ 1,722
2000	1,478	$ 80,890	18	$15,213
2001	1,427	$ 73,247	11	$ 6,289
2002	2,126	$ 94,941	4	$ 2,100
2003	5,177	$226,006	13	$ 7,339
2004	6,198	$271,325	14	$ 8,288
2005 YTD	2,819	$120,835	14	$13,185

[1] The information provided for 2005 represents year-to-date data only.

Q. **<u>SUBSTATIONS</u>**

REPLACEMENT AND STANDBY SUBSTATION EQUIPMENT (POOLED), p. 12 of 81, $1,918,000

PUB 6.0
How does the expenditure of $363,000 explained in section 3.0, Emergency Replacements, of 2.2 2006 Replacement and Standby Substation Equipment differ from the budgeted items explained in the sections previous to 3.0, which deal with the replenishment of pools of equipment for use in emergency and routine situations?

A. Newfoundland Power maintains a pool of standby substation equipment that can be installed in a timely manner in response to emergency and routine situations. The standby pool consists of equipment types referenced in Section 2.0 *Corporate Standby Equipment* (i.e., circuit breakers, reclosers, voltage regulators, etc).

The $660,000 expenditure referenced under Section 2.0 *Corporate Standby Equipment* is the cost to replenish the pool of standby equipment. It includes the cost to purchase new equipment, to refurbish equipment removed from service and to ensure that such equipment is ready for service. The budgeted amount is based on historic failure rates of specific equipment and engineering judgement. It does not include the cost of installing the equipment.

The $363,000 expenditure referenced under Section 3.0 *Emergency Replacements* is the cost of installing equipment from the standby pool in emergency situations. Emergency situations may be caused by events such vandalism, storm damage, lightning strikes, electrical or mechanical failure, or corrosion damage.

The $363,000 expenditure also includes the emergency cost to replace equipment and infrastructure not in the standby pool, such as stolen ground grid conductor and failed lightning arrestors. The $363,000 expenditure is based on engineering judgement and recent historical information.

Q. **<u>SUBSTATIONS</u>**

DISTRIBUTION SYSTEM FEEDER REMOTE CONTROL (POOLED), p. 19 of 81, $779,000

PUB 7.0
Please provide a general plan, giving an indication of the number of feeders that will continue to use the older system at the end of each phase, for the replacement of the Company's electromechanical feeder relays and oil-filled reclosers to 2010.

A. The Company plans to complete the electromechanical feeder relay phase of this project by the end of 2010. At that time all electromechanical relays will be replaced.

The Company does not plan to replace all feeder reclosers due to the prohibitive cost of establishing telecommunications with some sites. It is currently expected that, at the end of 2010, there will be 121 reclosers that will not be automated. Of the 121 remaining, 36 will not be part of an automation project. The remaining 85 will be automated beyond 2010 as resources and priorities permit. Newfoundland Power will continue to monitor telecommunications developments that may ultimately allow the inclusion of all reclosers in the project.

The timing of both the relay and recloser phases of the plan may change as detailed engineering is undertaken for each substation and costs are better defined. The expected annual replacements are shown in Table 1 below.

Table 1

Relays and Reclosers
Expected Annual Replacements

	Relay Controlled Feeders		**Recloser Controlled Feeders**	
Year	**Annual Completion**	**Feeders Remaining**	**Annual Completion**	**Feeders Remaining**
2006	16	47	3	129
2007	15	32	0	129
2008	12	20	2	127
2009	11	9	3	124
2010	9	0	3	121

Q. **<u>SUBSTATIONS</u>**

DISTRIBUTION SYSTEM FEEDER REMOTE CONTROL (POOLED), p. 19 of 81, $779,000

PUB 8.0 Why does the Company not consider this a multi-year project?

A. The Provisional Capital Budget Application Guidelines dated June 2, 2005 (the "Guidelines") provide for the application for capital expenditure approval of Multi-Year Projects, whereby a project that is expected to extend beyond a single year would be approved on initial review, and subject to additional review only where there is a material change in the scope, nature or forecast cost of the project. The Guidelines contemplate Multi-Year Projects where the scope, nature and forecast cost of each annual component of the project can be reliably determined in advance of the request for approval.

In Newfoundland Power's view, a typical request for Board approval of a Multi-Year Project would involve a discrete project, such as the complete refurbishment of a hydroelectric generating plant, where planning of the total project has been completed in advance of the request for approval. In such circumstances, the scope, nature and forecast cost is less likely to change following the Board's review.

Further, such projects often require the completion of work in subsequent years before certain components of plant and equipment acquired or constructed in prior years can be put into useful service. Where the value of capital expenditures in a prior year is materially dependent on expenditures in a subsequent year, it is appropriate that the multi-year expenditures be considered together.

Distribution System Feeder Remote Control is not a discrete project. Rather, it is an ongoing program of capital expenditures for the replacement of older technology relays and reclosers which is expected to be included in Newfoundland Power's annual capital budgets for the foreseeable future. The annual expenditure requirements for such programs may vary with changing circumstances. Unanticipated developments affecting the electrical system, changes in technology and pricing, and competing demands on Newfoundland Power's resources may alter the Company's capital expenditure priorities and modify the requirements for expenditures on certain programs from year to year.

The value of the annual expenditures on programs such as Distribution System Feeder Remote Control is not typically dependent on expenditures in future years. In the case of Distribution System Feeder Remote Control, the benefits of the expenditures for the automation of the selected feeders in one year accrue commencing in that year, and do not depend on the automation of other components of the electrical system in subsequent years.

While it is conceivable that Newfoundland Power could seek a multi-year approval of ongoing expenditure programs such as Distribution System Feeder Remote Control, the Company believes it is most practical to present the annual components of the project separately for the Board's review.

Q. **<u>TRANSMISSION</u>**

REBUILD TRANSMISSION LINES (POOLED), p. 22 of 81, $4,054,000

PUB 9.0
Please provide a breakdown showing the total amount of each project included in the figure of $1,561,000, the budgeted amount for proposed transmission line rebuilding work due to deficiencies identified during routine inspections and engineering reviews.

A. Table 1 below provides a breakdown of the items included in the 2006 budgeted amount of $1,561,000 for transmission line rebuilding work due to deficiencies identified during routine inspections and engineering reviews, as referred to on p. 22 of 81.

Table 1

Cost Breakdown – Identified Deficiencies
2006

Transmission Line Item	**Cost (000s)**
100L Replace deteriorated poles	$ 15
110L Replace deteriorated poles	36
116L Replace deteriorated poles	145
123L Replace deteriorated insulators and hardware	372
124L Upgrade structures to increase clearances	75
140L Replace deteriorated poles	15
146L Replace deteriorated poles	104
20L Engineering for rebuilding section of line	36
358L Replace deteriorated insulators and hardware	93
363L Replace deteriorated crossarms	35
4L Relocate section due to encroachments onto right-of-way	45
111L Replace deteriorated poles	15
Upgrades & replacements based on 2005/2006 annual inspections in St. John’s Area	80
Upgrades & replacements based on 2005/2006 annual inspections in Avalon Area	111
Upgrades & replacements based on 2005/2006 annual inspections in Burin Area	38
Upgrades & replacements based on 2005/2006 annual inspections in Bonavista Area	90
Upgrades & replacements based on 2005/2006 annual inspections in Gander Area	118
Upgrades & replacements based on 2005/2006 annual inspections in Grand Falls Area	77
Upgrades & replacements based on 2005/2006 annual inspections in Corner Brook Area	20
Upgrades & replacements based on 2005/2006 annual inspections in Stephenville Area	41
Total Cost	**$1,561**

Q. **<u>DISTRIBUTION</u>**

EXTENSIONS (POOLED), p. 25 of 81, $6,766,000

PUB 10.0
Please provide a summary, by year, of the high and low data that has been excluded from the data provided in Table 2, p. 26 of 81, and of the effect that the inclusion of this data would have on the Unit Cost for each year from 2001 to 2006B.

A. The comment in the paragraph following Table 2 indicates that as part of the historical unit costing methodology, unusually high and low data is excluded in calculating historical unit costs. This describes the process in general, and is intended to indicate the exclusion of any unusually high or low data, only if it exists.

Nothing has been excluded from Extensions in the years from 2001 to 2005 in arriving at the data provided in Table 2. The stated expenditure for each year is the actual expenditure for Extensions in that year. The adjusted cost is based on the total actual expenditure, normalized for inflation only.

The 2006 budget expenditure shown in Table 2 on page 26 of 81 is therefore calculated as the actual average inflation adjusted unit cost over the period from 2001 to 2005 multiplied by the projected number of new customers, as follows.

Actual average inflation adjusted unit cost [1]		
($2,105 + $1,830 + $1,859 + $2,034 + $1,961) / 5	=	$1,958
Multiplied by the 2006 inflation factor	x	1.0158
Equals 2006 forecast unit cost	=	$1,989
Multiplied by the projected number of new customers	x	3,402
Equals the budgeted expenditure for 2006 [2]	=	$6,766,000

[1] 2005 Dollars.
[2] Rounded.

Q. <u>DISTRIBUTION</u>

EXTENSIONS (POOLED), p. 25 of 81, $6,766,000

PUB 11.0
Please provide a summary showing the budgeted expense for Extensions from each year from 2001 to 2005F and the actual expenditures, including the most recent forecast for 2005, for the same period. Please include the budgeted number of new customers and the actual number of new customers for each year.

A. A summary of budgeted and actual expenditures for Extensions for each year from 2001 to forecast 2005 is outlined in Table 1 below.

Table 1

Expenditures for Extensions
2001 – 2005F
(000s)

	2001	2002	2003	2004	2005F
Actual	$5,404	$5,717	$6,586	$8,406	$7,396
Budget	$4,005	$3,621	$4,322	$4,956	$6,374

A summary of the budgeted and actual number of new customer connections for each year from 2001 to forecast 2005 is outlined in Table 2 below.

Table 2

Number of New Customer Connections
2001 – 2005F

	2001	2002	2003	2004	2005F
Actual	2,906	3,485	3,833	4,294	3,771
Budget	2,652	2,600	2,446	2,975	3,071

Q. **<u>DISTRIBUTION</u>**

METERS (POOLED), p. 27 of 81, $1,192,00

PUB 12.0
Please explain the Government Retest Order process, including an explanation of why the number of meters required under these criteria has increased significantly in 2004, 2005F, and 2006F.

A. ***General***

Measurement Canada requires all meters to be certified for accuracy for use in billing. The Company maintains a database of all its meters. The database contains information such as meter type, year of purchase, year of certification and certification expiry date. Meters must be either recertified or removed from service prior to the certification expiry date.

Re-certification requirements differ depending on the meter type. For some meter types, energy-only meters for example, the regulations permit re-certification based on test results for a sample of the meter group ("compliance sampling"). For other meter types, demand meters for example, it is necessary to test and certify each individual meter.

Newfoundland Power purchases meters each year to replace those meters removed for inclusion in compliance testing samples. These meter replacements are referred to as "CSOs" (Compliance Sample Orders).

Meters that must be purchased to either (1) replace meter groups that do not pass compliance sample testing or (2) replace demand meters that must be individually tested and re-certified are referred to as "GROs" (Government Retest Orders).

Compliance Sampling of Energy-only Meters

Most energy-only meters used by Newfoundland Power for billing of Domestic Service and General Service Rate 2.1 customers are permitted by regulation to be re-certified based on the testing of a sample of meters in a meter group prior to the expiry of their certification.

The re-certification of a large number of meters based on the testing of a statistical sample can provide substantial cost savings compared to the individual testing of all meters in the group. Newfoundland Power avails of compliance sampling whenever there are sufficient numbers of meters to form a group. Groups are formed based on the information stored in the Company's database.

The grouping of meters for the purpose of sample compliance testing is governed by detailed regulations. Generally, meters in a group must be of the same manufacturer type or model, the same "seal year", and have the same certification expiry date. New meters and reworked meters[1] cannot be included in the same group.

The regulations do allow meters of the same model and year to be included in different groups, which provides some flexibility in the sizing of groups. Sample testing offers potential savings; however, the inclusion of large numbers of meters in a single group exposes all those meters to the consequences of testing failure. To balance the competing considerations of testing costs and the risks associated with test failures, Newfoundland Power will often limit the size of its meter groups where appropriate. For example, meters of the same model that were supplied at different times during the year may have been manufactured under different conditions. It may therefore be appropriate to include them in different groups for compliance testing.

The certification period, or "seal period", for new meters varies from 6 to 12 years depending on meter type. The older electromechanical energy-only meters were initially certified for a 12-year period; electronic energy-only meters, which are the Company's current standard, are certified for 10 years. Energy-only meters comprise approximately 95% of Newfoundland Power's meters currently in service.

Before a meter group's certification is due to expire, a random sample of meters is selected from the group for compliance testing. Sample sizes vary depending on the number of meters in the meter group, and range from 28 meters for groups of 500 meters or less, to as many as 330 meters for very large meter groups.

Sampling Results

The meters identified for the sample are removed from service and forwarded to an accredited testing facility. If the test results show that the sample meters are within the required accuracy, the certification of the entire meter group from which the sample was taken is extended. The regulations provide for an extension of between 2 and 8 years, depending on the meter type and the results of the accuracy test.

If a significant number of the meters tested fall outside Measurement Canada's accuracy criteria, all remaining meters in the group must be removed from service. These meters must either be recalibrated and resealed, or permanently retired.

Due to the low cost of new energy-only meters and the high cost of replacement parts and labour, it is more economic to purchase new meters than to rework meters that have not passed sample testing. Because energy-only meters comprise the vast majority of Newfoundland Power's meters in service, failure to pass the accuracy test can result in the need to purchase a significant number of new meters.

In addition to the accuracy requirements of the regulations, the physical condition of meters is also important. For example, some meter groups may continue to meet

[1] Reworked meters are those that have been previously removed from service, re-calibrated or refurbished and subsequently returned to service.

Measurement Canada's accuracy requirements, but have faceplates that have faded to the point where they are difficult to identify or read. In 2004, the Company began replacing an increased number of meters that have deteriorated in this manner.

Testing of Demand Meters

Demand meters are not currently eligible for re-certification by compliance sampling, and must be tested individually. Prior to the expiry of their certification, all demand meters must be removed from service, recalibrated and resealed, or permanently retired.

Because demand meters cost significantly more than energy-only meters, it is generally more economical to have them recalibrated and resealed, subject to the meters being in acceptable physical condition.

Changing Recalibration Requirements

Demand meters are given an initial seal period of 6 years. Historically, demand meters have also been eligible to be re-certified for 6 years. However, effective January 1, 2005, demand meters can only be re-certified for 5 years. Effective January 1, 2009, the seal period for demand meters will be further reduced to 4 years.

Measurement Canada is in the process of reviewing all seal periods and sampling programs for revenue meters. It is also working on a compliance sampling program for electronic demand meters. The savings from a program that permits utilities to re-certify electronic demand meters by sample testing may offset, to some extent, the costs associated with the reduced seal periods applicable to demand meters.

Capital Budgeting for Meter Replacements

Table 1 is a summary of required meter replacements for the period 2001 to 2006.

Table 1
GRO/CSO Meter Replacements

Reason	2001 [1]	2002 [1]	2003 [1]	2004	2005F	2006F
GRO						
Meter Type D5S				2,363	7,600	941
Meter Type M1S						1,803
Physical Condition				2,682	1,557	262
Other Meter Types	989	914	464	2,162	1,537	1,872
Total GRO	989	914	464	7,207	10,694	4,878
CSO	915	1,356	991	1,337	1,266	1,547
Total	**1,904**	**2,270**	**1,455**	**8,544**	**11,960**	**6,425**

[1] A breakdown of GROs by the categories shown for 2004 through 2006 is not readily available for 2001 through 2003.

The number of meters due for replacement due to GROs in each year depends mainly on the results of compliance sampling conducted in the previous year. In 2003, two groups of Type D5S domestic meters failed to meet compliance testing criteria, and were therefore replaced in 2004. These two groups contained a total of 2,363 meters.

Another 7,600 Type D5S meters are to be replaced in 2005 because two large groups of meters that were sample tested in 2004 failed to meet compliance criteria.
A further group of 941 Type D5S meters is expected to fail compliance sampling testing and require replacement in 2006. This group was tested in 2004 and qualified for only the minimal 2-year extension. Considering the recent history of failure of Type D5S meters, it was deemed prudent to include the cost of replacing this group in the 2006 budget.

Another group of meters due for re-certification in 2006 is also expected to require replacement. A preliminary test of a group of 1,803 Type M1S meters was performed in 2004 because of a high incidence of stopped meters. Based on the preliminary test results, this group is not expected to pass compliance sample testing, and the cost of replacement has been included in the 2006 capital budget.

There are a significant number of older meters in service that were purchased in the late 1950s and early 1960s. As noted above, Newfoundland Power evaluates the physical condition of meters in its compliance samples, and in 2004 began replacing an increased number of meters that have deteriorated to the point where they are difficult to identify or read. Beginning in 2004, replacements of this nature are classified by Newfoundland Power as GROs, and are included in the line item “Physical Condition” in Table 1.

The “Other Meter Types” in Table 1 consist mainly of older meters that were refurbished and resealed 12 years prior to the replacement date shown in the table. These meters are made up of several different model types and vintages, are not currently eligible for compliance testing, and therefore must be replaced.

Q. **<u>DISTRIBUTION</u>**

REBUILD DISTRIBUTION LINES (POOLED), p. 40 of 81, $3,190,000

PUB 13.0
Please provide a listing, including the work to be performed, the 2006 budgeted amount, any planned future expenditures for each, and the expenditure history over the most recent five years, of the 47 feeders, the padmount transformers and the underground services indicated on page 40.

A. In 2006, capital expenditures are proposed on 47 feeders under the Rebuild Distribution Lines project. The cost of these items is estimated to be $3,190,000.

The project explanation for Rebuild Distribution Lines (Schedule B, page 40 of 81) contained an incorrect reference to the replacement of deteriorated padmount transformers and underground services. These expenditures are not included under the Rebuild Distribution Lines project. Expenditures associated with the replacement of deteriorated padmount transformers are budgeted as part of the Transformer project (Schedule B, page 36 of 81). Expenditures associated with the replacement of underground services are budgeted as part of the Services project (Schedule B, page 30 of 81). The project description for the Rebuild Distribution Lines project has been revised to correct the error.

Table 1 provides a cost breakdown by feeder and a listing of the type of work to be carried out in 2006 on each feeder rebuild proposed for this project.

Table 1

Cost Breakdown and Planned Work by Feeder
2006

		Work Required				
Feeder	**Estimated Cost**	**Insulator Replacement**	**Lightning Arrestor Installation**	**Cutout Replacement**	**Pole Replacement**	**Current Limiting Fuse**
CHA-03	$ 82,170	Y	Y	Y	Y	Y
GDL-04	69,912	Y	Y	Y	Y	Y
GOU-01	97,370	Y	Y	Y		Y
GOU-02	36,583	Y	Y	Y		Y
KBR-09	50,022	Y	Y	Y		Y
KBR-10	64,429	Y	Y	Y		Y
KEN-04	77,726	Y	Y	Y		Y
PUL-02	88,487	Y	Y	Y	Y	Y

Table 1

Cost Breakdown and Planned Work by Feeder
2006

		Work Required				
Feeder	**Estimated Cost**	**Insulator Replacement**	**Lightning Arrestor Installation**	**Cutout Replacement**	**Pole Replacement**	**Current Limiting Fuse**
RRD-09	71,373	Y	Y	Y	Y	Y
VIR-01	95,015	Y	Y	Y	Y	Y
VIR-02	40,294	Y	Y	Y		Y
VIR-03	18,842	Y	Y	Y		Y
VIR-04	37,974	Y	Y	Y		Y
VIR-05	28,691	Y	Y	Y		Y
VIR-06	45,548	Y	Y	Y		Y
BLA-01	91,842	Y	Y	Y	Y	Y
MSY-03	98,633	Y	Y	Y	Y	Y
MSY-04	28,922	Y	Y	Y	Y	Y
CAT-01	33,928	Y	Y	Y		Y
LOK-01	196,865	Y	Y	Y	Y	Y
NWB-02	163,592	Y	Y	Y	Y	Y
BVS-04	74,606	Y	Y	Y		Y
PAS-01	65,220	Y	Y	Y		Y
BVS-02	31,581	Y	Y	Y		Y
WES-03	66,320	Y	Y	Y		Y
GBS-02	70,000	Y	Y	Y		Y
COB-01	62,810	Y	Y	Y		Y
GFS-06	134,433	Y	Y	Y	Y	Y
TWG-01	76,860	Y	Y	Y		Y
BFS-01	61,843	Y	Y	Y		Y
STG-01	45,180	Y	Y	Y		Y
DOY-01	89,250	Y	Y	Y		Y
GAL-03	49,250	Y	Y	Y		Y
STG-02	68,958	Y	Y	Y		Y
DUN-01	167,026	Y	Y	Y	Y	Y
RVH-01	72,953	Y	Y	Y		Y
WAV-01	87,922	Y	Y	Y		Y
WAV-02	21,736	Y	Y	Y		Y
BRB-01	76,033	Y	Y	Y	Y	Y
HGR-03	30,098	Y	Y	Y	Y	Y
HCT-01	33,485	Y	Y	Y	Y	Y
CAR-01	46,161	Y	Y	Y	Y	Y

Table 1

Cost Breakdown and Planned Work by Feeder
2006

		Work Required				
Feeder	**Estimated Cost**	**Insulator Replacement**	**Lightning Arrestor Installation**	**Cutout Replacement**	**Pole Replacement**	**Current Limiting Fuse**
COL-01	74,476	Y	Y	Y	Y	Y
OPL-03	46,992	Y	Y	Y	Y	Y
VIC-01	48,555	Y	Y	Y	Y	Y
HUM-08	23,691	Y	Y	Y	Y	Y
HUM-09	46,343	Y	Y	Y	Y	Y
Total	**$3,190,000**					

* Y indicates work is planned

Newfoundland Power's system of accounts does not track capital expenditures by specific distribution feeder. Therefore, the requested expenditure history for the 47 feeders included in this project is not available.

In any year, the Company incurs capital expenditures for most of its distribution feeders. These expenditures are budgeted under several Distribution projects, including Reconstruction and Extensions.

The proposed 2006 capital expenditures for the Rebuild Distribution Lines project addresses items that have been identified through ongoing line inspections, engineering reviews, or during day-to-day operations. To the extent that capital expenditures have been made on these 47 feeders during the last 5 years, those expenditures would have the effect of reducing the expenditures required under this project in 2006.

There is no future capital work beyond 2006 specifically identified and planned for these 47 feeders.

Q. **<u>DISTRIBUTION</u>**

DISTRIBUTION RELIABILITY INITIATIVE (POOLED), p. 45 of 81, $3,114,000

PUB 14.0
Given that the data gathered prior to 2002 for feeder BOT-01 had unusually high customer minutes which have already been partially addressed, what are the SAIFI and SAIDI statistics for the period from 2002 to 2004?

A. Table 1 below provides the unscheduled distribution outage SAIDI and SAIFI statistics for the BOT-01 feeder for the period 2002 to 2004.

Table 1

SAIDI and SAIFI Statistics
Unscheduled Distribution Outages
BOT-01

Year	SAIDI	SAIFI
2002	4.00	1.79
2003	2.48	0.74
2004	20.17	6.56
Average	8.88	3.03
Corporate 3 Year Average	**2.23**	**1.56**

In 2000, customers served by the BOT-01 feeder experienced unusually high customer outage minutes due to a problem with the protective coordination settings on a recloser.

Protective coordination settings are based on system models and engineering calculations. The settings are applied to a recloser to limit outages due to faults on the power system to the smallest practical area.

In 2001, the protective coordination problem on BOT-01 was solved. Given that the reason for the extraordinary outages in 2000 and 2001 had been identified and remedied, it was decided that it would be appropriate to exclude the 2000 and 2001 outage data from the engineering assessment of the reliability performance of the feeder.

Q. **<u>DISTRIBUTION</u>**

DISTRIBUTION RELIABILITY INITIATIVE (POOLED), p. 45 of 81, $3,114,000

PUB 15.0
What is the total budgeted amount for brush clearing, and why has it been included in the capital expenditure estimates (p. 5, Botwood-01 Feeder Study, June 2005)?

A. Brush clearing is included in capital expenditure estimates when clearing of vegetation is required to:

- Construct a new line on a new Right of Way ("ROW");
- Relocate an existing line to a new ROW;
- Facilitate construction associated with a capital project on an existing line (e.g. when it is necessary to clear a path through brush to allow materials to be brought to the site and installed); or
- Accommodate a standards change (e.g. upgrading a line from single phase to three phase would require the ROW to be widened from 5.4 meters to 7.5 meters. Clearing the additional 2.1 meters is a capital expenditure).

In cases of routine maintenance and operations, the Company charges brush clearing expenditures to an operating account.

In 2006, a total of $68,000 is included in the Botwood-01 reliability project capital budget estimate for brush clearing as follows:

- $8,000 is required to clear ROW for the relocation of a section of line to the road at the beginning of Route 352 from Northern Arm to Charles Brook.
- $36,250 is required to clear ROW for the relocation of a section of line to the road from the intersection of Route 352 to Point Leamington.
- $23,750 is required to relocate a section of line near Leading Tickles from the Glovers Harbour tap to the road.

Q. **<u>DISTRIBUTION</u>**

DISTRIBUTION RELIABILITY INITIATIVE (POOLED), p. 45 of 81, $3,114,000

PUB 16.0
Please give reasons why or why not the upgrade of Feeder BOT-01 should be considered a multi-year project.

A. The response to Request for Information PUB 8.0 NP provides Newfoundland Power's general views on the presentation of proposed capital projects as Multi-Year Projects. In general terms, discrete projects for which the scope, nature and forecast cost is unlikely to change are appropriate for presentation as Multi-Year Projects, particularly where the value of expenditures in one year is dependent on the completion of work in a subsequent year.

The Distribution Reliability Initiative project included in the 2006 capital budget is comprised of the 7 distribution feeder upgrades outlined in Table 1 on p. 45 of 81. Three of the feeders require additional upgrading that is currently anticipated to be completed in 2007 (BOT-01, GLV-02 and LEW-02), including 2 feeders that also require further work that is currently planned for 2008 (BOT-01 and GLV-02).

The work proposed for the BOT-01 and GLV-02 feeders in 2006, 2007 and 2008, and the work proposed for the LEW-02 feeder in 2006 and 2007 has been sufficiently defined and planned such that material changes in the scope, nature and forecast cost are not likely. On that basis, these 3 feeder upgrades could potentially be considered as discrete Multi-Year projects.

In Newfoundland Power's view, however, there is no compelling reason to consider these feeder upgrades as Multi-Year projects. The work planned for each of these feeders in specific years will provide reliability benefits to customers on the feeders regardless of the completion of the work planned for subsequent years. It is therefore not inappropriate to consider the individual annual components for each feeder on its own merits.

Furthermore, while Newfoundland Power's current capital expenditure plans include the completion of the subsequent components of work on the BOT-01, GLV-02 and LEW-02 feeders as indicated in the engineering reports 4.2.1, 4.2.2 and 4.2.3, the Company has chosen not to present the BOT-01, GLV-02 and LEW-02 feeder initiatives as Multi-Year Projects. This approach provides flexibility for subsequent years with respect to competing capital expenditure priorities that may arise as a result of changed or unanticipated circumstances.

Q. **<u>DISTRIBUTION</u>**

DISTRIBUTION RELIABILITY INITIATIVE (POOLED), p. 45 of 81, $3,114,000

PUB 17.0
What is the total budgeted amount for brush clearing, and why has it been included in the capital expenditure estimates (p. 5, Lewisporte-02 Feeder Study, June 2005)?

A. The Company's guideline for capitalizing expenditures associated with brush clearing is detailed in the response to Request for Information PUB 15.0 NP.

In 2006, a total of $3,000 is included in the capital budget estimate for the Lewisporte-02 reliability project for brush clearing. This expenditure is required to clear a new right-of-way on a section of line being relocated to the road near Michael's Harbour.

Q. **<u>DISTRIBUTION</u>**

DISTRIBUTION RELIABILITY INITIATIVE (POOLED), p. 45 of 81, $3,114,000

PUB 18.0
Please give reasons why or why not the upgrade of Feeder LEW-02 should be considered a multi-year project.

A. Please refer to the Company's response to Request for Information PUB 16.0 NP.

Q. **<u>DISTRIBUTION</u>**

DISTRIBUTION RELIABILITY INITIATIVE (POOLED), p. 45 of 81, $3,114,000

PUB 19.0
Given that a 12/6 km. section of feeder GLV-02 was upgraded in 2003 and 2004, excluding this section what are the SAIFI and SAIDI statistics for the period from 2000 to 2004?

A. Table 1 below shows the unscheduled distribution SAIDI and SAIFI statistics for the period 2000 to 2004 for the GLV-02 feeder, excluding the sections upgraded in 2003 and 2004.

Table 1

Select SAIDI and SAIFI Statistics for GLV-02 Unscheduled Distribution Outages 2000-2004 [1]

Year	SAIDI	SAIFI
2000	0.17	0.19
2001	1.80	1.95
2002	0.23	0.13
2003	12.00	4.23
2004	5.98	4.31

[1] Excluding the sections of GLV-02 that were upgraded in 2003 and 2004.

Q. **<u>DISTRIBUTION</u>**

DISTRIBUTION RELIABILITY INITIATIVE (POOLED), p. 45 of 81, $3,114,000

PUB 20.0
What is the total budgeted amount for brush clearing, and why has it been included in the capital expenditure estimates (p. 5, Glovertown-02 Feeder Study, June 2005)?

A. The Company's guideline for capitalizing expenditures associated with brush clearing is provided in the response to Request for Information PUB 15.0 NP.

In 2006, a total of $9,000 is included in the capital budget estimate for the Glovertown-02 reliability project for brush clearing. This expenditure is required to clear rights-of-way for line relocations on Pit Lane, the tap to Culls Harbour, and the tap to Traytown.

Q. **<u>DISTRIBUTION</u>**

DISTRIBUTION RELIABILITY INITIATIVE (POOLED), p. 45 of 81, $3,114,000

PUB 21.0
Please give reasons why or why not the upgrade of Feeder GLV-02 should be considered a multi-year project.

A. Please refer to the Company's response to Request for Information PUB 16.0 NP.

Q. **GENERAL PROPERTY**

ADDITIONS TO REAL PROPERTY (POOLED), p. 55 of 81, $132,000

PUB 22.0
Please identify the specific total budget amount allocated to each project outlined in this project description.

A. Table 1 below identifies the 2006 budgeted project expenditures for each item outlined in this project description.

Table 1

Additions to Real Property
Individual Project Expenditures
2006

Description	**Amount (000s)**
UPS Room Cooling System, Duffy Place	$ 45
Storage Sheds for Treated Cross-arms	25
Washroom Upgrades	15
General Building Upgrades	47
Total	**$ 132**

Q. **<u>GENERAL PROPERTY</u>**

STANDBY DIESEL GENERATORS – DUFFY PLACE & CLARENVILLE (POOLED), p. 57 of 81, $665,000

PUB 23.0
Please identify the specific total budgeted amount allocated to each project outlined in this project description.

A. Table 1 below identifies the 2006 budgeted project expenditures for each item outlined in this project description.

Table 1

Standby Diesel Generators – Duffy Place & Clarenville
Individual Project Expenditures
2006

Description	Amount (000s)
Diesel Generating Unit for Duffy Place Building	$ 500
Diesel Generating Unit for Clarenville Building	165
Total	**$ 665**

Q. **<u>GENERAL PROPERTY</u>**

STANDBY DIESEL GENERATORS – DUFFY PLACE & CLARENVILLE (POOLED), p. 57 of 81, $665,000

PUB 24.0
In previous widespread power outages involving NP buildings, what was the Company's experience with regard to a continuation of service? Please provide relevant excerpts of any relevant reports that were produced as a result of these outages.

A. ***Historical Experience – 1984 and 1994***

The most recent storm that resulted in widespread power outages involving Company buildings over a period of days occurred in December 1994. At that time, a severe winter storm caused widespread damage to the transmission and distribution systems on the Avalon, Burin and Bonavista Peninsulas, and resulted in widespread power outages lasting several days. Prior to that event, the most recent power outage of similar magnitude occurred as a result of a 1984 sleet storm.

The major outages of 1984 and 1994 were largely confined to the eastern portion of the island. At the time of the 1994 outage, the backup generator at the Company's Kenmount Road building provided sufficient power for the building to be fully operational. The backup power supply at the Duffy Place building did not have sufficient capacity to provide full power. However, there was sufficient capacity to provide power to a call centre, some offices, and operations areas.

During the outages of 1984 and 1994, the Company's power restoration efforts would undoubtedly have been affected to some extent as a result of power interruptions affecting its buildings. However, the report entitled *Blackout '94: Storm Report January, 1995*, which was filed with the Board following the 1994 outage does not include any specific reference to the impact of power supply problems at Company buildings. The Company was unable to locate a copy of any report on the 1984 outage.

Then and Now – A Comparison

Then
In those Company buildings affected by the power interruptions of 1984 and 1994, lighting and heating systems, and electrical equipment such as building cranes, would not have been functional, creating challenges for employees working there. In that regard, the first order of business would have been to acquire an emergency generator to provide sufficient power to enable people to work productively and effectively.

At the time of the 1994 outage, the organization and management of Newfoundland Power's power restoration efforts was still paper-based, and executed with minimal support from information technology. Once a heated and lighted workspace had been secured, these activities could be pursued in a normal manner.

In addition to the system information provided by the SCADA System, the Company relies on information obtained via trouble calls from individual customers to gauge the scope and nature of storm damage sustained by the electrical distribution system. In 1984 and 1994, information from trouble calls was recorded on paper and sorted manually. The paper reports were then reviewed by an outage management team who would assess the scope and nature of individual problems based on their experience and knowledge of the system, and dispatch line crews as required to address identified problems.

Due to the paper-based process, the Company's ability to update customers on the ongoing progress of power restoration efforts was limited. To begin with, it would have been impractical to track and assess progress on an ongoing basis given the large volume of paper. Secondly, system repair and power restoration was the priority, given the large numbers of customers without power in winter conditions. As a result, information that could be made immediately available to customers was limited.

Now

In the more than 10 years that have passed since the last major extended power interruption, there have been many changes in the way Newfoundland Power's operations are managed. Advances in information technology have facilitated changes in the manner in which power restoration efforts are conducted, and in the Company's ability to communicate with its customers during major outages.

These changes have enabled the Company, since 1994, to reduce the size of its regular workforce from more than 800 to fewer than 600 employees. While these changes have made the Company more efficient and helped to control costs, they have also greatly increased the Company's reliance on information technology.

In 2005, power restoration efforts for distribution system outages are coordinated by the regional offices and supported by the System Control Centre and the centralized Customer Contact Centre. Customer trouble calls are received at the Customer Contact Centre, where employees use personal computers to enter relevant information into an outage management database. The latest information on power restoration efforts is made available to customers through the TVD automated outage information system.

The outage management database serves as the central control hub for interactions between the regional offices, the System Control Centre and the Customer Contact Centre. Coordination of power restoration efforts is led by employees in the regional offices, whose ability to respond quickly and effectively to customer requirements and power system problems is dependent on the availability and accuracy of the information contained in the database.

When a major storm causes widespread damage to the electrical system, customers begin calling immediately to report the loss of their electrical service. Customer trouble calls are still an important source of information for pinpointing specific damage and assessing the scope and nature of the outage.

The computer-based outage management system now provides power restoration teams with ready access to information and the ability to sort through and analyze large quantities of information. This allows those directing power restoration efforts to efficiently identify and prioritize problems on the electrical system, and to plan and track the dispatch of crews and equipment in the most effective manner. These benefits are of particular importance when the outage is a lengthy one affecting large numbers of customers and large portions of the electrical system.

All of the buildings housing Newfoundland Power's operations are equipped with battery-powered emergency lighting. However, with the exception of the St. John's buildings (Kenmount Road, Duffy Place and the System Control Centre) and the Carbonear building, none of the buildings have standby generators that would allow operations housed in the buildings to function normally. In particular, they would not have enough power to run the Company's computer systems or provide for basic needs such as heat and light. If a major extended outage, such as one caused by a major winter snow or ice storm, were to affect the Newfoundland Power's Corner Brook or Gander buildings, for example, the Company's ability to fully utilize its technological resources to restore power in those areas would be hampered.

As a result, power restoration would take more time, and information on the Company's progress in restoring service would not be available to customers on a timely basis.

Concluding
Newfoundland Power's reliance on computer systems, personal computers, shared servers, and network infrastructure is much greater today than it was in 1994. Critical systems include computer systems to support the Customer Contact Centre technology used to handle customer inquiries; a customer outage reporting system; a switching application for the safe restoration of power; and electrical distribution system control via the SCADA application.

These technological tools facilitate more efficient operations, and are the tools that Newfoundland Power personnel are accustomed to using in the performance of their duties. Organizing and directing a major power restoration effort without the ability to sort, analyze and display the large volume of electrical system and customer trouble information would require the staff of a regional office to rely on inefficient paper-based methods, lengthening the time required to restore electrical service.

Without back-up generation at its regional operations centres, the Company would be unable to employ its information technology resources to provide those managing and carrying out power restoration efforts with the necessary information and electrical system control to ensure efficient and timely restoration of electrical service.

Other Canadian Utilities

During the last two years, Nova Scotia Power Inc.'s (NSPI) electrical system has been affected by several lengthy and widespread power outages caused by weather. Following the latest storm, in November 2004, the Nova Scotia Utility and Review Board (UARB), at the request of the Province of Nova Scotia, commenced a review of NSPI's storm response. A report submitted by an independent consultant selected by the UARB included the following recommendation in relation to NSPI's preparedness for extended service interruptions:

> "NSPI should make sure it has the appropriate contingencies in place to deal with the implications of power failures in its storm response and call centers, network downtime, and failures of any of the systems or technologies supporting storm response and communication. **This includes establishing back-up power**, redundant systems and databases, spare parts and equipment, on-call or on-site support, as well as manual business continuity plans." (emphasis added) [1]

Newfoundland Power is of the view that the consultant's recommendations for NSPI are equally applicable to its own emergency preparedness. Adequate back-up generation in the Company's regional offices will ensure that Newfoundland Power is able to provide an effective and efficient power restoration response in the event of a major outage affecting Company buildings.

[1] Liberty Consulting Group, *Report on Nova Scotia Power Company's Transmission System and Outage Communications*, March 4, 2005, p. 61.

Q. **<u>GENERAL PROPERTY</u>**

DEMAND/LOAD CONTROL – COMPANY BUILDINGS (OTHER), p. 59 of 81, $143,000

PUB 25.0
Although the Cost Benefit Analysis provided uses the cost of automated load control and the possible reduction in demand charges from Hydro as a result of a 2.5 MW reduction in peak, it does not include the cost of the utilization of auxiliary back-up generation as a substitute source of electricity (2006 Load Control Initiative, June 2005, p. 1, para. 2). How does this factor into the analysis?

A. The cost of utilizing the auxiliary back-up generation as a substitute source of electricity is the incremental cost of fuel required to run the generation, less the reduced charges from Hydro for the energy purchases avoided when the back-up generation is in operation.

Based on a diesel fuel cost of 44 cents per litre and 30% diesel plant efficiency, the cost of operating a diesel generator is 13.5 cents per kilowatt hour. The avoided end block energy cost from Hydro is 4.7 cents per kilowatt hour, providing a net cost of 8.8 cents per kilowatt hour. On that basis, operating both the 400 kW Kenmount Road and 145 kW Duffy Place diesels would cost $48 per hour ((400 kW + 145 kW) x 8.8 cents per kilowatt hour).

Assuming that the back-up generation is used between 5 and 10 hours per year to help control peak, the total operating cost of the back-up generation ranges from $240 to $480 per year. This cost does not materially affect the analysis of this project which will provide estimated annual benefits of $200,000 in reduced demand charges from Hydro. The cost of utilizing the auxiliary back-up generation as a substitute source of electricity was therefore not specifically included in the analysis.

Q. **<u>TRANSPORTATION</u>**

PURCHASE VEHICLES AND AERIAL DEVICES (POOLED), p. 62 of 81, $2,755,000

PUB 26.0
Using the actual expenditure history from Table 3, please provide a comparison of the actual average cost per heavy fleet vehicle, per passenger vehicle, and per off-road vehicle for 2001 to 2004 with the forecast average cost of each type for 2005 and 2006.

A. Table 1 below provides the average unit cost per vehicle category for 2001 through 2004 and the forecast average unit cost for 2005 and 2006.

Table 1
2001 – 2006F Average Unit Cost per Category
(000s)

Category	2001	2002	2003	2004	2005F	2006F
Heavy Fleet Vehicles	$ 211	$ 243	$ 271	$ 199	$ 134	$ 185
Passenger Vehicles	$ 24	$ 27	$ 27	$ 31	$ 29	$ 30
Off-Road Vehicles	$ 6	$ 6	$ 5	$ 13	$ 37	$ 25

Heavy Fleet Vehicles
Heavy Fleet vehicles includes three classifications of equipment; light-duty, medium-duty and heavy-duty. The per unit cost of light-duty equipment is less than that of medium-duty equipment, which in turn is less than the per unit cost of heavy-duty equipment.

The average cost of Heavy Fleet vehicles increased in 2002 and 2003 due to requirements to purchase additional tandem axle trucks in those years (i.e. heavy-duty equipment).

Only medium-duty and light-duty equipment is required to be purchased in 2005. Therefore, the average cost of Heavy Fleet vehicles in 2005 is lower than in previous years.

Passenger Vehicles
No significant change is forecast in the average cost of Passenger vehicles for 2005 and 2006.

Off-Road Vehicles
The average cost of Off-Road vehicles increased in 2004 due to the purchase of higher cost equipment trailers and off-road equipment. This included two reel trailers at $37,000 each and two 8-wheel all terrain vehicles at $24,000 each.

The forecast average cost of Off-Road vehicles is high in 2005 and 2006 due to the purchase of line tensioning equipment. Line tensioning equipment is required to improve the safety of conductor stringing operations. The four line tensioning units being purchased in 2005 will cost a total of approximately $200,000. Three additional line tensioning units are budgeted in 2006 at a total cost of approximately $156,000.

Q. **<u>INFORMATION SYSTEMS</u>**

APPLICATION ENHANCEMENTS (POOLED), p. 69 of 81, $1,589,000

PUB 27.0
Of the 10% of the Company's customers who have two or more bill accounts, what percentage generally receives two consolidated bills each month instead of one as a result of the number of billing days between meter readings?

A. Approximately 20,000 customers have two or more accounts in their name totaling approximately 56,000 individual bill accounts.

Currently, 132 customers subscribe to the group bill program based on their desire to receive one consolidated bill. Of these, 34 customers or 26 percent still receive two or more consolidated bills each month.

This project will address deficiencies which currently exist within the group billing process. These deficiencies compromise the level of functionality and service to customers that the group bill program was initially intended to provide, and generally serve as a disincentive to customers wishing to participate in the program. The improvements to be made include providing customers with two or more accounts the opportunity to receive only one consolidated bill each month regardless of how many billing days there are between meter readings.

Overall, this project will implement improvements to make the group bill program more efficient and beneficial to all customers with two or more accounts. Improving the group bill program should result in increased customer participation in future.

Q. **<u>INFORMATION SYSTEMS</u>**

APPLICATION ENHANCEMENTS (POOLED), p. 69 of 81, $1,589,000

PUB 28.0
Over the past 24-month period, how many complaints or enquiries has the Company received from customers who receive two consolidated bills each month concerning the possibility of receiving one?

A. The Company has not separately tracked the number of complaints or enquiries from customers who wish to further consolidate their bills.

A Customer Account Representative currently spends approximately 3 hours per day devoted to group bill administration, answering an average of 12 enquiries from customers daily. The majority of this time is spent manually addressing problems caused by deficiencies within the current process.

For example, when a meter reading route is reorganized for reading efficiency purposes, this can have negative effects on group bill customers. The Company may have to remove one or more bills from a customer's group bill if the meter reading route change results in one or more of the customer's accounts being billed at a later time in the month. Customers who enjoy the convenience of group billing express their displeasure with this change, which is a deficiency of the current group bill program.

Also, when a payment is received late but should have been credited to the customer's account earlier because of mail or bank processing delays, late payment charges and forfeited discount charges need to be reversed. For customers not on group bill, this reversal happens automatically within the Customer Service System and the customer's account is billed properly. For customers on group bill, these charges will reverse, however, the bill itself will not automatically generate and billing for those customers is consequently delayed. Manual intervention is required by a Customer Account Representative to get these affected accounts to bill properly.

Deficiencies such as these serve as a disincentive to customers wishing to participate in the current group bill program. This project will implement improvements to make the group bill program more efficient and beneficial to all customers with two or more accounts.

Q. **<u>INFORMATION SYSTEMS</u>**

APPLICATION ENHANCEMENTS (POOLED), p. 69 of 81, $1,589,000

PUB 29.0
Of the eleven items listed in this category, five, totaling $690,000, and a part of another, for an additional $58,310, are not accompanied by a Cost Benefit Analysis. How does the Company plan to objectively measure the effectiveness of these improvements and their overall benefit to ratepayers?

A. Investment in technology is critical to improving customer service, increasing system reliability and controlling costs. Application Enhancement projects are justified taking into account both quantitative and qualitative benefits. Where the primary justification is cost savings, a cost benefit analysis such as a Net Present Value analysis will be completed.

Where the primary justification is not cost savings, the Company monitors the impact of these projects through other measures such as the Customer Satisfaction Rating, Operating Costs per Customer, Outage Hours per Customer (SAIDI) and Outages per Customer (SAIFI).

The benefits of information technology investment for ratepayers can be seen in several areas:

i) *Meeting customer expectations* by supporting interactions with customers, enabling flexible services, and accommodating changing customer needs. One of the means the Company uses to gauge its level of effectiveness in meeting customer expectations is its Customer Satisfaction Index (CSI). Newfoundland Power's CSI has increased from 84% in 1998 to 89% in 2004, with an all time high of 91% achieved in 2002.

ii) *Enhancing communications* amongst employees and between the Company, its customers, and outside suppliers. The demand for enhanced communications is rising, especially through customers' use of the Internet and electronic mail. Since 1999, average monthly visits to the Company's Internet website have increased over 700%, from 2,076 in 1999 to 17,865 in 2004.

iii) *Achieving productivity improvements and cost savings* by automating manual processes, reducing transaction costs, and minimizing staff requirements. Productivity improvements have helped with reducing the number of Full-Time Equivalents (FTEs) in the Company. At year-end 2004, the Company was operating with a workforce of 660.8 FTEs, a reduction of 15% since 1998.

The Company also continues to realize reductions in its operating cost per customer served. The Company's operating cost per customer has decreased from $243 in 1998 to $220 in 2004.

As stated in the Company's Information Technology Strategy 2004 – 2008, filed with the Company's 2004 Capital Budget Application, the Company plans to continue investing in technology to maintain and improve customer service and help to provide customers with a low cost supply of electrical energy.

Q. **<u>INFORMATION SYSTEMS</u>**

APPLICATION ENHANCEMENTS (POOLED), p. 69 of 81, $1,589,000

PUB 30.0
In the Cost Benefit Analyses presented in support of this expenditure, the projects show labour savings and a positive net present value over the next five years. How many Full Time Equivalent positions are expected to be associated with the labour savings as a result of these improvements over the five-year period?

A. The labour savings associated with the projects with positive net present value calculations equate to 2.7 Full Time Equivalent positions. The labour savings are comprised of a series of incremental improvements in productivity across a variety of work functions.

Labour savings facilitated through technology investment such as the application enhancements budgeted for 2006 help the Company manage its overall labour requirement through initiatives such as early retirement programs and organizational restructuring.

Q. **<u>INFORMATION SYSTEMS</u>**

APPLICATION ENHANCEMENTS (POOLED), p. 69 of 81, $1,589,000

PUB 31.0
The budgeted level of spending on this category, at $1,589,000 is the highest that it has been over the period from 2001 to 2006F. Please provide a breakdown of the expenditures for each year and a comparison of the expenditures.

A. Table 1 below provides a breakdown and relative comparison of the Company's expenditures on Application Enhancements for each year from 2001 to forecast 2006.

Table 1
Application Enhancements
(000s)

Budget Category	**2001**[1]	**2002**[1]	**2003**	**2004**	**2005F**	**2006F**
Customer Service System	$ 352	$ 381	$ 341	$ 273	$ 377	$ 479
Business Support Systems			170	108	115	-
Operations and Engineering Systems	77		93	614	388	667
Internet / Intranet			111	163	101	293
Various Minor Enhancements	190	345	205	155	151	150
Total	**$ 619**	**$ 726**	**$ 920**	**$1,313**	**$1,132**	**$1,589**

[1] Application Enhancement expenditures for 2001 and 2002 were not recorded on a basis consistent with the categories used in the 2006 Capital Budget Application.

During the period from 2001 to 2003, the Company invested in several new software applications, including Business Support Systems, the Hand Held Meter Reading System, Facilities Management and Operations Support Systems. The implementation of these major systems was budgeted as separate projects and not as Application Enhancements. Application Enhancements for this same period were lower, reflecting the Company's focus on investments in new applications.

Since these major systems were installed, expenditures for new software implementations have decreased and expenditures for Application Enhancements have increased. This is consistent with the Company's Information Technology Strategy 2004 – 2008 filed with the Company's 2004 Capital Budget Application where it stated that:

> *Over the next five years, the Company's IT investments will be focused more on getting further value out of its existing technology investments, and less on the implementation of new applications as in the past five years.*

The benefits to be derived from the Application Enhancements included in the 2004 Capital Budget are individually outlined in Volume II, Tab 6.1, *2006 Application Enhancements.* As indicated there, Newfoundland Power operates and supports over fifty computer applications. Identifying opportunities to improve these applications, either through vendor supplied functionality enhancements or internal software development, ensures the Company remains responsive to changing business requirements.

Q. **<u>INFORMATION SYSTEMS</u>**

SYSTEM UPGRADES (POOLED), p. 71 of 81, $1,076,000

PUB 32.0
Of the eight items outlined in this category, the purchase of the Microsoft Enterprise Agreement appears to be the only one that will incur a known cost over the upcoming three years. Why has the Company not chosen to set this item out separately and identify it as a multi-year project, given that the understanding of a multi-year project is one that, once commenced, will continue into future fiscal years with associated financial responsibility in those years?

A. The formal contract document reflecting the Microsoft Enterprise Agreement ("MEA") between Newfoundland Power and Microsoft Corporation ("Microsoft") historically included a term that gave the Company the option of canceling the agreement on short notice without penalty. Consequently, the agreement was not considered by Newfoundland Power as obliging the Company to incur capital expenditures beyond a single year.

With the current agreement due to expire, Microsoft recently presented Newfoundland Power with a new formal contract document for the MEA. Under the terms of the proposed MEA contract, Newfoundland Power would not have the option of canceling the 3-year agreement on short notice without penalty. The agreement proposed by Microsoft for 2006 and beyond effectively obliges Newfoundland Power to pay the costs and charges associated with the MEA for a term of 3 years.

In Newfoundland Power's view, the proposed MEA constitutes a Multi-Year Project as contemplated by the Provisional Capital Budget Application Guidelines dated June 2, 2005 (the "Provisional Guidelines"). Approval is therefore sought for the entire 3-year expenditure, as noted at page 72 of 81, Schedule B.

As noted in the transmittal letter to the Board dated June 29, 2005 and accompanying the Application, Newfoundland Power exercised a considerable degree of judgment in applying the Provisional Guidelines to the filing of the Application. While implementation of the Provisional Guidelines required some change in presentation, the Company also attempted to ensure a level of continuity and comparability with previous budget filings.

In that regard, while approval is sought for the MEA as a Multi-Year Project, the Company elected to pool this capital expenditure item for consideration with other System Upgrades expenditure items, consistent with its presentation in previous capital budget applications. It would not be difficult to present Multi-Year Projects separately in future, if it would be helpful to the Board in its consideration of Newfoundland Power's capital budget applications.

Q. **INFORMATION SYSTEMS**

SYSTEM UPGRADES (POOLED), p. 71 of 81, $1,076,000

PUB 33.0
In the description of the purchase of the Microsoft Enterprise Agreement three options are outlined. Please provide the Cost Benefit Analysis that was used to determine that the chosen option is the least expensive.

A. The Company considered the following options when determining the least expensive Microsoft software purchasing strategy:

1. Do nothing now and upgrade once within three years;
2. Renew the existing Microsoft Enterprise Agreement ("MEA"); and
3. Purchase licenses under a Select Agreement from a third party reseller.

Table 1 below provides cost estimates associated with the purchase and ownership of the Company's personal computer ("PC") software under these three options.

Table 1

Cost Estimates for Microsoft Software

Software	**(Option 1) Upgrade Once in Three Years** [1]	**(Option 2) MEA Renewal** [2]	**(Option 3) Purchase under Select Agreement** [3]
Total for Microsoft Licenses with MEA		$ 271	
Windows Professional Upgrade	$ 225		$ 421
Office Professional	551		1,030
SharePoint Portal Server and SQL Server CAL[4]	85		148
Systems Management Server CAL	49		86
Exchange Server CAL	80		141
Windows Server CAL	35		61
		x 3 years	
Total (per PC)	**$ 1,025**	**$ 813**	**$ 1,887**

[1] This is current pricing from Microsoft and is subject to possible price fluctuations.
[2] This pricing is fixed for the 3-year term of the contract.
[3] This is current pricing from xwave for the initial license and upgrades and is subject to possible price fluctuations.
[4] CAL is a Client Access License.

Renewal of the existing MEA (Option 2) provides an overall cost savings of approximately 21% as compared to Option 1 and 57% as compared to Option 3. The MEA pricing model (Option 2) is structured such that for the Company's requirements it is always less costly than other available options.

Renewing the MEA distributes fixed purchasing costs for software over three years, and provides the Company with the flexibility to install any version of the software products as required including the most recent versions of the software upon expiry of the agreement.

Purchasing software licenses under either Option 1 or Option 3 is not operationally efficient, since they introduce increased administrative effort and additional costs each time a new software license is required.

As shown by this analysis, renewing the MEA remains the least expensive option for the purchase of required Microsoft software licensing.

Q. **<u>LEASES</u>**

1.5 MW PORTABLE DIESEL GENERATOR, p. 3 of 3, $12,000/Year

PUB 34.0
Please provide a history of the month-to-month lease of the portable unit that is located in Trepassey, including the reason for the lease and the analysis that was used to determine that this was the least cost alternative.

A. Portable generation is used by Newfoundland Power to maintain service to customers during construction and upgrading activities during the summer months, and during emergency conditions at all times of the year.

Newfoundland Power currently owns 2 portable generation units; a 7.2 MW portable gas turbine and a 2.5 MW portable diesel generator. Both units are located at Grand Bay Substation in Port aux Basques, except when they are required elsewhere for emergencies or to support construction activities.

In 1999, Newfoundland Power became aware that a 1990-vintage 1.5 MW portable diesel generator was available for lease on a temporary basis from a private Newfoundland-based contractor. The Company entered into an arrangement with the owner to lease the unit on a month-to-month basis at a rental of $833.33 per month plus HST, paid semi-annually, and has continued to lease the unit on this basis since that time.

The 1.5 MW portable diesel provides Newfoundland Power with a back up generation unit upon very favourable terms. The proposed lease rate of $12,000 per year for 2006 and 2007 equates to $8.00/kW per year for the 1.5 MW unit. The longer term arrangement that is now proposed provides a measure of certainty to Newfoundland Power with respect to availability of the unit.

The proposed lease is the least cost alternative to fulfill a requirement for portable generation of this size. The price to purchase a comparable new unit is approximately $750,000 and the price of a comparable used generator would be approximately $300,000. At a financing rate of 5%, the annual interest charge alone associated with the purchase of a similar generator would exceed the annual cost of the current arrangement.

Newfoundland Power will ensure that the unit continues to be located where it will maximize overall system reliability. During the winter, it will be located in an area that is subject to severe winter weather conditions and is served by a radial transmission system. The unit will be relocated as required to respond to outages caused by major winter storms. Further, the unit will normally be connected to the electrical system, and can be called upon as needed to support system capacity requirements.

In the summer months, the unit will be relocated as necessary to support construction or repair activities. Distribution feeder and radial transmission construction work is performed most cost-effectively when electrical circuits are de-energized. Using a portable generator to provide uninterrupted service to customers, while at the same time allowing electrical equipment to be de-energized for construction or repair, contributes to reduced distribution and transmission construction costs.

The response to Request for Information PUB 35.0 NP provides a review of the usage history of the 1.5 MW portable unit.

Q. **<u>LEASES</u>**

1.5 MW PORTABLE DIESEL GENERATOR, p. 3 of 3, $12,000/Year

PUB 35.0
Please provide a history since its procurement of the usage of the 1.5 MW portable unit located in Trepassey, including the locations and the reasons for the usage.

A. Table 1 provides the usage history of the 1.5 MW portable diesel now located in Trepassey. It also indicates the locations and the reasons for the usage.

Table 1

Usage History of 1.5 MW Portable Generation Unit

Date	Location	Purpose	Run Time (HRS)	Generation (kWh)	Fuel Used (L)
20-Feb 99 to 6 – Mar-99	Corner Brook	Canada Winter Game - Standby	N/A	N/A	N/A
05-Aug-99	Trepassey	Testing	0.3	N/A	175
09-Aug-99	Lark Harbour	For Lark Harbour & Frenchman's Cove Project	15.0		1,803
10-Aug-99	Lark Harbour	For Lark Harbour & Frenchman's Cove Project	12.0		1,621
11-Aug-99	Lark Harbour	For Lark Harbour & Frenchman's Cove Project	12.0		2,502
12-Aug-99	Lark Harbour	For Lark Harbour & Frenchman's Cove Project	12.0		1,875
13-Aug-99	Lark Harbour	For Lark Harbour & Frenchman's Cove Project	12.0		2,110
15-Aug-99	Lark Harbour	For Lark Harbour & Frenchman's Cove Project	4.5		1,183
16-Aug-99	Lark Harbour	For Lark Harbour & Frenchman's Cove Project	11.0	108,375	2,158
17-Aug-99	Lark Harbour	For Lark Harbour & Frenchman's Cove Project	11.5		2,079
18-Aug-99	Lark Harbour	For Lark Harbour & Frenchman's Cove Project	11.0		1,740
19-Aug-99	Lark Harbour	For Lark Harbour & Frenchman's Cove Project	11.5		2,818
20-Aug-99	Lark Harbour	For Lark Harbour & Frenchman's Cove Project	10.0		1,756
23-Aug-99	Lark Harbour	For Lark Harbour & Frenchman's Cove Project	12.0		2,068
24-Aug-99	Lark Harbour	For Lark Harbour & Frenchman's Cove Project	11.5		1,601

Table 1

Usage History of 1.5 MW Portable Generation Unit

Date	Location	Purpose	Run Time (HRS)	Generation (kWh)	Fuel Used (L)
25-Aug-99	Lark Harbour	For Lark Harbour & Frenchman's Cove Project	12.5		3,035
26-Aug-99	Lark Harbour	For Lark Harbour & Frenchman's Cove Project	12.0		2,458
27-Aug-99	Lark Harbour	For Lark Harbour & Frenchman's Cove Project	9.0		1,354
30-Aug-99	Lark Harbour	For Lark Harbour & Frenchman's Cove Project	8.0		1,249
06-Oct-99	St. Vincent's	Testing	0.3	N/A	N/A
14-Oct-99	St. Vincent's	To support planned upgrade of RVH-01	5.0	N/A	1,225
15-Oct-99	St. Vincent's	To support planned upgrade of RVH-01	5.0	N/A	1,193
18-Oct-99	St. Vincent's	To support planned upgrade of RVH-01	5.5	N/A	1,349
20-Oct-99	St. Vincent's	To support planned upgrade of RVH-01	6.3	N/A	1,614
21-Oct-99	St. Vincent's	To support planned upgrade of RVH-01	4.5	N/A	626
25-Oct-99	St. Vincent's	To support planned upgrade of RVH-01	4.8	N/A	806
27-Oct-99	St. Vincent's	To support planned upgrade of RVH-01	7.8	N/A	795
28-Oct-99	St. Vincent's	To support planned upgrade of RVH-01	7.3	N/A	741
01-Nov-99	St. Vincent's	To support planned upgrade of RVH-01	5.5	N/A	1,274
02-Nov-99	St. Vincent's	To support planned upgrade of RVH-01	6.0	N/A	453
04-Nov-99	St. Vincent's	To support planned upgrade of RVH-01	5.0	N/A	337
21-Dec-99	Trepassey	Testing	0.3	N/A	73
06-Jan-00	Trepassey	Testing	0.8	N/A	N/A
15-Feb-00	Trepassey	Testing	0.2	N/A	N/A
06-Oct-00	Trepassey	Testing	0.5	N/A	N/A
25-Jan-01	Trepassey	Testing	1.0	N/A	N/A
14-Mar-01	Trepassey	Testing	0.8	N/A	N/A
15-Mar-01	Trepassey	Testing	0.8	N/A	N/A
10-May-01	Lamaline	To accommodate reconductoring of LAU-02	N/A	N/A	N/A
15-May-01	Lamaline	To accommodate reconductoring of LAU-02	8.9	N/A	2,154
17-May-01	Lamaline	To accommodate reconductoring of LAU-02	6.5	N/A	1,475
23-May-01	Lamaline	To accommodate reconductoring of LAU-02	10.0	N/A	1,853
24-May-01	Lamaline	To accommodate reconductoring of LAU-02	6.0	N/A	1,362
29-May-01	Lamaline	To accommodate reconductoring of LAU-02	7.5	N/A	1,028

Table 1

Usage History of 1.5 MW Portable Generation Unit

Date	Location	Purpose	Run Time (HRS)	Generation (kWh)	Fuel Used (L)
31-May-01	Lamaline	To accommodate reconductoring of LAU-02	3.8	N/A	862
04-Jun-01	Lamaline	To accommodate reconductoring of LAU-02	4.1		906
05-Jun-01	Lamaline	To accommodate reconductoring of LAU-02	8.2		2,249
06-Jun-01	Lamaline	To accommodate reconductoring of LAU-02	2.5		796
07-Jun-01	Lamaline	To accommodate reconductoring of LAU-02	5.2		894
11-Jun-01	Lamaline	To accommodate reconductoring of LAU-02	4.8		853
19-Jun-01	Lamaline	To accommodate reconductoring of LAU-02	4.8		705
20-Jun-01	Lamaline	To accommodate reconductoring of LAU-02	5.1	22,648	1,103
July 01	Abraham's Cove	Located at ABC, for use during upgrading if load exceeded other capacity	0.0	0.0	0.0
Aug 01	Abraham's Cove	Located at ABC, for use during upgrading if load exceeded other capacity	0.0	0.0	0.0
Sep 01	Port-Aux-Basques	Located at GBS, but not used	0.0	0.0	0.0
04-Oct-01	Burnt Point	Testing	N/A	N/A	N/A
09-Oct-01	Burnt Point	Testing	0.8	N/A	148
16-Oct-01	Burnt Point	To supply various sections of OPL-02 during upgrade project	7.0		753
17-Oct-01	Burnt Point	To supply various sections of OPL-02 during upgrade project	5.8		697
19-Oct-01	Burnt Point	To supply various sections of OPL-02 during upgrade project	6.8		888
23-Oct-01	Burnt Point	To supply various sections of OPL-02 during upgrade project	6.5		685
24-Oct-01	Burnt Point	To supply various sections of OPL-02 during upgrade project	6.2		523
25-Oct-01	Burnt Point	To supply various sections of OPL-02 during upgrade project	5.1		360
26-Oct-01	Burnt Point	To supply various sections of OPL-02 during upgrade project	5.2	10,320	307
02-Nov-01	Burnt Point	To supply various sections of OPL-02 during upgrade project	5.6	3,740	1,281
04-Nov-01	Burnt Point	To provide supply during outage on 43L	8.2		1,310

Table 1

Usage History of 1.5 MW Portable Generation Unit

Date	Location	Purpose	Run Time (HRS)	Generation (kWh)	Fuel Used (L)
18-Nov-01	Burnt Point	To provide supply during outage on 65L	5.2		1,150
20-Dec-01	Trepassey	Testing	1.7	467	20
20-Feb-02	Trepassey	Testing to troubleshoot	0.8	890	174
11-Apr-02	Trepassey	Testing & Annual Inspection	1.5	1,192	278
17-Jul-02	Trepassey	Testing & Inspection	1.5	870	180
02-Oct-02	Trepassey	Testing	1.5	N/A	227
14-Nov-02	Trepassey	Testing	0.8	950	187
12-Mar-03	Trepassey	Testing	1.5	950	187
09-May-03	Trepassey	Testing	0.8	1,000	100
20-Jun-03	Trepassey	Testing	N/A	N/A	10
08-Jul-03	Trepassey	Testing	1.2	N/A	228
10-Jul-03	Trepassey	Replacing valves	N/A	N/A	10
06-Oct-03	Trepassey	Testing	1.2	1,000	295
11-Nov-03	Eastport	Testing	0.4	N/A	N/A
13-Nov-03	Eastport	Testing	8.2	N/A	2,487
14-Nov-03	Eastport	To support planned upgrade of GLV-02	N/A		
17-Nov-03	Eastport	To support planned upgrade of GLV-02	N/A		
18-Nov-03	Eastport	To support planned upgrade of GLV-02	N/A		
19-Nov-03	Eastport	To support planned upgrade of GLV-02	N/A		
25-Nov-03	Eastport	To support planned upgrade of GLV-02	N/A		
26-Nov-03	Eastport	To support planned upgrade of GLV-02	N/A		
27-Nov-03	Eastport	To support planned upgrade of GLV-02	N/A	31,835	9,210
01-Dec-03	Eastport	To support planned upgrade of GLV-02	N/A		
02-Dec-03	Eastport	To support planned upgrade of GLV-02	N/A		
03-Dec-03	Eastport	To support planned upgrade of GLV-02	N/A	12,165	3,790
01-Apr-04	Trepassey	Testing	0.5		15
02-Apr-04	Trepassey	Testing to troubleshoot generator	1.0	1,053	289
12-May-04	Trepassey	Testing	1.5		278
20-May-04	Trepassey	Testing	0.4	1,767	92
23-Jun-04	Trepassey	Testing	0.6	500	1,382
05-Aug-04	Trepassey	Testing	0.2		N/A
10-Aug-04	Trepassey	Testing	0.5		N/A
17-Aug-04	Trepassey	Testing	0.1		N/A
19-Aug-04	Trepassey	Testing & Maintenance	1.3	751	N/A
06-Oct-04	Trepassey	Testing	1.2	1,770	388
19-Oct-04	Trepassey	Testing for Replaced Governor	0.2	N/A	3
16-Nov-04	Trepassey	Testing	0.5	1,283	53

Table 1

Usage History of 1.5 MW Portable Generation Unit

Date	Location	Purpose	Run Time (HRS)	Generation (kWh)	Fuel Used (L)
23-Nov-04	Trepassey	Testing for Nexus Meter	0.5		37
21-Dec-04	Trepassey	Testing & Monthly Inspection	1.0		181
21-Jan-05	Trepassey	Testing	N/A		N/A
27-Jan-05	Trepassey	Testing	1.7	1,112	315
14-Feb-05	Trepassey	Testing to Repair Synchronizing	0.4		N/A
16-Feb-05	Trepassey	Testing	0.8		91
18-Feb-05	Trepassey	Testing	2.0	2,750	656
18-Mar-05	Trepassey	Testing	1.3	958	247
28-Apr-05	Trepassey	Testing	1.0	780	210
04-May-05	Trepassey	Testing for Heater Replacement	N/A	N/A	9
27-May-05	Trepassey	Testing	1.0	628	170
29-Jun-05	Trepassey	Testing & Monthly Inspection	1.5	1,182	320