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July 20, 2009

Bull, Houser & Tupper LLP
3000 Royal Centre, P.O. Box 11130
1055 W. Georgia Street
Vancouver, BC
V6E 3R3

Attention: Mr. Brian Wallace

Dear Mr. Wallace:

Re: Terasen Gas Inc. ("TGI", the "Company"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGW")
Collectively the "Terasen Utilities"
Return on Equity and Capital Structure Application (the "Application")

Response to the Joint Industry Electricity Steering Committee ("JIESC"), the British Columbia Public Interest Advocacy Centre on behalf of the British Columbia Old Age Pensioners Organization *et al* ("BCOAPO"), and the Commercial Energy Consumers Association of British Columbia ("CEC") Joint Information Request ("IR") No. 1

On May 15, 2009, the Terasen Utilities filed the Application as referenced above. In accordance with the British Columbia Utilities Commission Order No. G-70-09 setting out the Regulatory Timetable for the Application, the Terasen Utilities respectfully submit the attached response to the joint JIESC/BCOAPO/CEC IR No. 1.

If there are any questions regarding the attached, please contact the undersigned.

Sincerely,

TERASEN GAS INC.
TERASEN GAS (VANCOUVER ISLAND) INC. and
TERASEN GAS (WHISTLER) INC.

Original signed by:

Scott A. Thomson
Vice President, Regulatory Affairs & CFO

Attachments

cc (email only): BCUC and Registered Parties

JIESC/BCOAPO/CEC-TGI-1.

TOPIC: **Comparable Return Standard**

REFERENCE: **Evidence of the Company**

REQUEST:

a) At page 6 the company repeats the NEB statement as to the comparable investment standard as the return has to

"be comparable to the return available from the application of the invested capital to other enterprises of like risk (comparable investment requirement)"

On page 10 the company provides Ms. McShane's interpretation as:

"to earn a return on investment commensurate with that of comparable risk Enterprises"

In the company's view are these two statements identical?

Response:

The wording is not identical but the concepts expressed are essentially one and the same.

b) Further to a), if another company that is otherwise identical is earning 10% but selling for twice book value, so that the return earned by the investor on the market value of their investment is 5.0%, what rate of return does the company view as meeting the comparable return standard; 5.0% or 10%. Please answer in detail.

Response:

The answer depends on what assumption is made as to the statement that the "otherwise identical" company "is earning 10%". Assuming the comparator company is earning 10% ROE on book equity, then the comparable return standard would imply the appropriate ROE for the utility is 10% since the regulator sets the return on historic book values. That said, a sample of one does not necessarily make for an appropriate comparator and the Terasen Utilities would expect that in applying the comparable return standard the Commission would look to an average of a sample of companies.

The BCUC regulates the utility company, and it is the utility company that is to be allowed the opportunity to earn a fair return.

c) If the answer to b) is 10% please explain how the capital from the company can be reallocated or invested to earn 10% if the company has to pay twice book value to get at that 10% return?

Response:

See response to JIESC/BCOAPO/CEC IR 1.1(b) above.

d) Please provide the amount of the total assets purchased by Fortis and the book value of the equity.

Response:

Fortis acquired the shares of Terasen Inc. which is primarily a utility holding company but which also holds a number of non-regulated businesses. The total book value of assets purchased was $3.25 billion and the book value of equity acquired was $1.18 billion.

e) Please indicate the purchase price Fortis paid for TGI both in terms of the total amount including the assumption of debt and on a straight equity basis.

Response:

Fortis acquired TGI indirectly as part of the purchase of Terasen Inc. which owned a number of regulated utilities and non-regulated companies as noted in the response to JIESC/BCOAPO/CEC IR 1.1(d) above. Also, please refer to the response to BCUC IR 1.85.2.

f) Please estimate the equity market to book ratio implicit in the acquisition of TGI by Fortis.

Response:

This question cannot be answered as Fortis did not allocate the purchase price to individual entities, however the market to book ratio paid for Terasen Inc was 1.28 times. Please refer to the response to BCUC IR 1.85.2.

JIESC/BCOAPO/CEC-TGI-2.

TOPIC: **Comparable Canadian Utility Returns**

REFERENCE: **Evidence of the Company, Page 13**

REQUEST:

a) Please explain how column 3 of the table was calculated.

Response:

Current Allowed ROE (Column 1) was multiplied by Equity Component (Column 2) to arrive at Effective Return in Column 3.

b) If the answer to b) is the ROE was multiplied by the equity component please explain the foundations for such a calculation and what it is supposed to mean.

Response:

Each of the Canadian utilities listed in the table have an allowed ROE in their deemed equity component which represents the earnings opportunity that is included for rate making purposes to reward them for the investing in the assets used to provide service. The table illustrates that for each dollar of rate base owned and operated, TGI has the lowest earnings opportunity of the group of Canadian utilities. This is not fair to TGI's investors.

JIESC/BCOAPO/CEC-TGI-3.

TOPIC: **ROE Studies**

REFERENCE: **Evidence of the Company, Page 17**

REQUEST:

a) Please confirm that the authors of both the Concentric and NERA studies have appeared as expert witnesses on behalf of utilities both in Canada and the United States.

Response:

The NERA study was co-authored by Kenneth Gordon, PhD and Jeff Makholm, PhD. Mr. Gordon is a Special Consultant and the Former Chairman of the Department of Public Utilities Massachusetts and the Public Utility Commission in Maine.

The Concentric Study was not attributed to individuals but was published in the name of the company. Individual executives of Concentric Energy Advisors have appeared as expert witnesses in both Canada and the United States. TGI does not know if the authors of the NERA study have appeared as witnesses.

b) Please explain why reports authored by experts on behalf of utilities that are not present to be cross examined in this hearing should be given any weight.

Response:

The studies noted in this question are offered in support of the statement that there has been a growing body of thought that the current ROE adjustment formulas in Canada have been producing inadequate returns for some time.

The Concentric report was commissioned by the Ontario Energy Board and the NERA study as mentioned was produced by authors such as Dr. Gordon who by virtue of their experience can be viewed as credible commentators on such matters.

It would be prohibitively costly to engage and produce for cross examination every source of information for this Application when such documents are on the public record elsewhere and are simply being reproduced here for completeness. For instance, Dr. Booth routinely asks for information such as rating agency reports be produced for the record but the authors of such reports are not required to be present for cross examination.

The Commission will ultimately decide whether or not to give weight to such evidence.

JIESC/BCOAPO/CEC-TGI-4.

TOPIC: **Risk Premium Over Corporate Bond Yields**

REFERENCE: **Evidence of the Company, Page 22**

REQUEST:

a) Please confirm that the yield on default risky corporate debt is a promised yield, that is, it is the promised payments discounted at a rate that sets their present value equal to the market value.

Response:

The yield on a corporate debt instrument is the expected yield to maturity that an investor would be expected to receive if the instrument was held from the point of acquisition to the maturity of the debt instrument. The price of a corporate debt instrument is the present value determined by taking the expected future cash flows to be earned from the instrument to maturity, and discounting those cash flows by a factor that is the market yield to maturity, where the yield reflects the relative risk of the security and the market conditions at the point in time that the price is being calculated.

b) Please indicate, with appropriate citations to the literature, any support for the claim that equity investors require a premium over debt investors if the debt return is the promised yield on corporate debt.

Response:

It is accepted financial theory that equity investors require a higher return for higher risk. Equity investors require a higher return on their investment relative to debt investors of the same issuer, as the debt has a senior ranking claim on the same cash flows and assets of the business in which the equity holders only have a residual claim to, after all senior ranking claims have been satisfied. This same conclusion applies within different classes of debt for the same issuer, for example, subordinated debt commands a higher risk premium relative to the senior ranking debt. In addition, debt holders typically have a contractual obligation to receive a predetermined amount of principal and interest. The order of claims indicates that the repayment of borrowed funds must be first satisfied by the business, regardless of whether or not it is profitable. Equity investors receive the residual earnings of the business, and experience greater variability in their return, accepting more business risk, for which they require greater return than a debt holder. While there may be circumstances where the promised yield is higher than the cost of equity due to the size of the default premium, as a relatively high grade issuer, this would not be the case for TGI.

c) Please confirm that there are lots of debt issues where the promised yield has been almost 100% because the probability of default and non-payment is also very high.

Response:

The Terasen Utilities are not in a position to confirm or deny the statement in the question regarding a situation where promised yields have been almost 100%. There may be situations where a promised yield is 100%, i.e. where a firm is close to or in default, although TGI is currently not aware of such situations. Further, they are not relevant to TGI's circumstances.

d) Please confirm that there have been many times in the past where utility commissions in Canada have awarded ROEs less than the government bond rate, let alone the utility's borrowing cost. If this cannot be confirmed please provide the allowed ROE and borrowing cost for TGI's predecessor companies for the period 1980-1985.

Response:

The Terasen Utilities is aware of situations where an awarded ROE was below a government debt rate. Terasen would submit that those occurrences have been rare, and reflected market conditions which are completely different from prevailing conditions. In those rare conditions when the awarded ROE was lower than the long-term Canada bond yield, inflation had risen to virtually unprecedented high levels in Canada, which produced a rise in government bond yields to over 18% (containing a so-called lock in premium to compensate investors in the bonds for inflation-related risk associated with being locked in to a long-term return). With the rising levels of inflation, the risk of holding even government bonds was extraordinarily high. Terasen Utilities does not believe the circumstances which gave rise to ROEs less than the government debt rate are at all relevant to current circumstances. If that situation were to arise in current circumstances, the Fair Return Standard would likely be violated.

The occurrence of circumstances when awarded returns on equity for utilities has been less than the long term government bond yield demonstrates that an AAM that tracks only a government bond yield does not produce a return on equity that meets the fair return standard.

JIESC/BCOAPO/CEC-TGI-5.

TOPIC: **Business Risk**

REFERENCE: **Evidence of the Company, Tab 1**

REQUEST:

a) Would TGI agree that for a regulated utility sooner or later its business risk has to materialise in terms of an inability to earn its allowed ROE if the risk is real? If not agreed, why not.

Response:

Not necessarily. As has been discussed in the Application, business risk can be characterized as being the risk of not earning a fair return on invested capital and the risk of not recovering that investment in rates. Such risks must continually be evaluated on a prospective basis and are informed by past experience, even though it is not necessarily an accurate predictor of the future.

A utility that continues to earn its allowed ROE when that allowed return is not adequate, not comparable to the returns being achieved by enterprises of similar risk (i.e. not a fair return) is experiencing the materialization of business risk.

Similarly, when a utility has investments in its utility assets excluded from rate base even though they are used and useful by their regulator has experienced a materialization of business risk as it speaks to the longer term inability to recover its investments in rates.

b) In TGI's judgment does the fact of being regulated by the BCUC increase or decrease its risk? Please be specific in terms of justifying the answer.

Response:

It does both. The BCUC has introduced measures through deferral accounts that smooth short term variability in earnings and which assist to ensure that costs are allocated to the appropriate party. For example, if TGI could predict its gas costs and throughput with precision, there would be no need for gas cost and volume related deferral accounts. Because this is not possible, these types of deferrals ensure that no windfall gains or losses accrue to either the company or the customers.

Like other utilities regulated by the BCUC, TGI must obtain approvals for its expenditures. In the case of large capital expenditures requiring a CPCN, a separate and often lengthy vetting process with an uncertain outcome may increase the risk that appropriate investments and business opportunities are delayed or lost altogether. This increases risks.

Non-regulated entities are more nimble in their ability to make investment decisions. They are also not restricted in their ability to charge what the market will bear and so while they are subject to greater variability in returns including negative returns, they have the ability to earn substantially higher returns than those allowed by regulation as well from time to time.

Regulatory lag is a real problem in many jurisdictions and the work load of the Commission and Staff has increased dramatically in recent years without a commensurate increase in resourcing.

With allowed returns being determined through the current adjustment mechanism, returns are not adequate.

So in the company's view, being regulated by the BCUC mitigates some business risks and introduces others.

c) Please provide TGI's (and predecessor companies) actual and allowed ROE since 1994 clearly itemising the impact of incentive agreements.

<u>Response:</u>

Please refer to BCUC IR 1.3.3.

d) Please explain any deviations of more than 0.20% in the data provided in a) and explain their cause.

<u>Response:</u>

See response to JIESC/BCOAPO/CEC IR 1.5(c) above for quantification of the deviations between allowed and achieved ROE during the period.

TGI has operated for most of this period under varying forms of incentive rate making. From 1994 to 1997, the company had an O&M expense related incentive earnings opportunity whereby variances from the O&M levels allowed in rates contributed to the achievement of incentive earnings.

From 1998 through 2001 TGI operated under an expanded incentive arrangement that introduced a capital expenditure incentive. Because of the nature of the mechanism the capital component in the incentive arrangement resulted in penalties that partially offset the favourable O&M incentives achieved. During the period from 1994-2001 the PBR arrangements including 50:50 sharing arrangements with customers

In 2002 and 2003 TGI operated under a rate freeze and traditional rates respectively with no sharing arrangements.

From 2004 through the end of 2009 a PBR settlement with a much more comprehensive incentive rate making arrangement has been in place along with 50:50 sharing of favourable and unfavourable O&M, capital expenditures and revenues.

Effective cost management and containment has contributed to favourable incentive earnings which have been partially offset by unfavourable revenues related to certain formula based revenue components like late payment charge revenues and connection fees due to customer attachment variances.

It is not practical to attempt to breakdown the source of the incentive for the past 15 years beyond that as costs and revenue forecasts have been reviewed and approved by the commission in revenue requirements proceedings or through the annual review process and the achievement or lack of achievement of incentive earnings through superior cost management under incentive earnings arrangements has no bearing on whether or not the allowed return and/or capital structure is set at a fair or appropriate level, which is what this Application seeks to achieve.

e) Can TGI or Ms. McShane please provide equivalent data to c) for Enbridge Gas Distribution Inc, Union Gas, ATCO Gas and Gaz Metro?

Response:

TGI has canvassed the other utilities to request this information but in the time available was unable to obtain it. On the basis of discussions with the other utilities TGI understands that Dr. Booth has asked similar questions of them in other proceedings in which he has appeared as a witness and for which he prepared information requests. Given that, TGI expects that Dr. Booth has most of this information already and it is relevant and of consequence to this proceeding he has adequate time and resources to present it in his evidence.

The company does not have the data to provide the actual returns achieved by the other Canadian utilities over the time period requested.

JIESC/BCOAPO/CEC-TGI-6.

TOPIC: **Business Risk**

REFERENCE: **Evidence of the company Tab 1**

REQUEST:

a) Please specify the major deferral accounts that have been available to TGI (and predecessor companies) since 1994, when they were introduced and which ones remain in effect. In the judgment of TGI have these deferral accounts increased or decreased TGI's risk?

Response:

The deferral accounts that TGI has employed have not had a significant impact on TGI's risk. The majority of the deferral accounts have been put in place to ensure forecast variances do not result in costs being inappropriately borne by customers or the company.

The major deferral accounts included in Attachment 6a are:

1. MCRA and CCRA (formerly GCRA) – GCRA was introduced in 1993 and the MCRA and CCRA remain in effect. The purpose of these deferral accounts is not so much to deal with risk as to reduce rate volatility of the cost of gas for the benefit of customers.
2. RSAM – introduced in 1994 and remains in effect. The purpose of this deferral account is not so much to deal with risk as to mitigate windfall gains/losses from forecast use rate variances and avoids disputes/gaming related to the underlying forecasts for the benefit of customers. It also decouples revenues from volumes to help support energy efficiency and conservation initiatives.
3. Deferral related to the SCP revenues and cost of service – introduced in 2000 and remains in effect. These accounts ensure that the appropriate level of SCP revenues is taken into account in the determination of customer rates.
4. Demand Side Management related deferrals – introduced prior to 1993 and remains in effect and match the cost of the programs to the benefits delivered by the programs. These accounts are not set up for risk mitigation, but to smooth the rate impact of energy efficiency programs to customers.
5. NGV Conversion Grants – introduced prior to 1993 and remains in effect to support energy efficiency and conservation measures.
6. Deferred Interest – introduced prior to 1993 and remains in effect. This account reduces the risk of over- or under-forecasting interest rates.
7. Property Tax – introduced in 1995 as part of a negotiated settlement (PBR) with customers, and remains in effect. This account ensures that over time the correct level of property tax expense is included in rates.

8. Pension & Insurance – introduced in 2004 as part of a negotiated settlement with customers, and remains in effect. This account recognizes that volatility of pension and insurance expense, and ensures that over time the correct pension & insurance expense is included in rates.
9. Earnings Sharing Mechanism deferrals have existed throughout the period whenever there has been a PBR in place. Since the amount of earnings sharing available is not known until after the end of a year, these accounts are used to capture the amount to be shared until that can occur.
10. OPEB funding deferral has been in place since 2000 and represents the amounts funding by customers and not yet paid out by the company related to OPEBs. The purpose of this account is to reflect the timing of payments related to OPEBs.
11. From the years 1994 to 2001, there were two accounts in place – Local Gas Development and Fraser Valley Gas Exploration. These were set up as a result of specific undertakings.

Certain tax-related deferrals have existed throughout the period, to account for changes in tax laws and rates. The current ones at the end of 2008 are the SCP tax reassessment, the corporate capital tax assessment, the 2006 large corporate tax elimination, and the 2008 carbon tax implementation.

A number of accounts were introduced starting in 1995 to deal with the Coastal Facilities project that are now all fully recovered.

Certain other accounts were introduced for a short period of time to deal with one-time events.

b) Can TGI or Ms. McShane please provide equivalent data to a) for Enbridge Gas Distribution Inc, Union Gas, ATCO Gas and Gaz Metro.

Response:

Please refer to the table below which outlines some of the major deferral accounts for Enbridge Gas, Union Gas, Atco Gas and Gaz Metro.

Deferral Account(s)	Description	Union Gas	Enbridge Gas	Gaz Metro	Atco Gas
Weather Stablization Adjustment Mechanism	Stabilizes the margins recovered from residential and commercial customers due to weather variances.	No	No	Yes	Yes
Customer Useage Stablization Adjustment Mechanism	Stabilizes the margins recovered from residential and commercial customers due to use rate variances, excluding weather.	Yes	Yes	No	No
Property Tax deferral account	Collects differences between actual property taxes and forecasted property tax	No	No	No	No
Pension Cost deferral account	Collects differences between actual pension costs and cost of service based	No	No	No	[1] No
Insurance Cost deferral account	Collects differences between actual insurance and cost of service based	No	No	No	Yes
Post Employment Benefits deferral account	Captures income tax payments along with unamortized OPEB costs associated with other post employment benefits	No	No	No	No
Deferred Interest on Short Term and Long Term Debt	Interest expense deferred due to difference between actual interest rates and interest rate approved by the Commission as well as difference due to timing of long term debt issues from that approved by the Commission.	No	No	[2] Yes	No
Long Term Debt Issue and Expense	To amortize the discount or premium and issue costs over the life of the medium and long term debt	[2] Yes	[2] Yes	[2] Yes	[2] Yes
Deferred Interest on Commodity Cost and/or Midstream Cost Reconciliation Accounts	Difference of actual versus forecast average balance of MCRA / CCRA times the composite interest rate	Yes	Yes	No	N/A
Deferred Interest on RSAM	Difference of actual versus forecast average balance of RSAM times the composite interest rate	No	No	No	Yes
Commercial Commodity Unbundling Program deferral accounts	Collects costs related to the implementation and annual operation of the Commercial Commodity Unbundling program.	No	Yes	No	N/A
Demand Side Management (DSM) deferral accounts	Various DSM programs	Yes	Yes	No	No
Gas Cost Variance Account (GCVA)	Difference between actual and approved cost of gas	Yes	Yes	Yes	[3] Yes

Notes:

[1] Application just filed with the Alberta Utilities Commission citing recernt financial market activitiy.

[2] All utilities shown defer and amortize long term debt issuance costs either through regulatory deferral accounts or by capitalizing costs in their balance sheets and amortizing as part of the liability.

[3] On upstream commodity costs.

c) In TGI's judgment has it more regulatory protection in terms of deferral accounts than the companies listed in b) above.

Response:

TGI has somewhat more short-term revenue protection than the other four gas utilities listed in (b) due to the RSAM, which mitigates variability in revenues related to weather-sensitive customer classes due to variations from forecast weather and customer consumption.

JIESC/BCOAPO/CEC-TGI-7.

TOPIC: **Business risk**

REFERENCE: **Evidence of the company Tab 1**

REQUEST:

a) Please indicate the regulated average depreciation rate in effect for each year since 1994 and the dates when depreciation studies have been filed with the BCUC.

Response:

Year	Average Depreciation Rate
1994	2.8%
1995	2.8%
1996	2.8%
1997	2.9%
1998	3.0%
1999	3.1%
2000	3.1%
2001	3.0%
2002	3.0%
2003	2.9%
2004	3.1%
2005	3.0%
2006	3.0%
2007	2.8%
2008	2.7%
2009 *	2.7%

* 2009 is projected

Note: excludes amortization associated with contribution in aid of construction

The table above outlines the actual average depreciation rates for TGI from 1994 to 2009 for TGI plant. Changes in the average composite depreciation rate are attributable to the mix of asset classes and their respective depreciation rates (i.e. hardware and software has a higher depreciation rate than mains plant).

Recently, as part of TGI's Revenue Requirement Application, an updated depreciation study dated December 31, 2007 prepared by Gannett Fleming was filed. Prior to this, that only other depreciation study reviewed with Commission staff was in the year 2000, a similar study prepared by Gannett Fleming dated December 31, 1998.

b) Please provide equivalent data to that in a) above for Enbridge Gas Distribution Inc, Union Gas, ATCO Gas and Gaz Metro.

<u>Response:</u>

The table below presents the actual average depreciation rates for Enbridge Gas, Union Gas, and Atco Gas, in addition to the years where depreciation studies were conducted as provided by the respective companies. TGI was not able to obtain historical depreciation rates for Gaz Metro.

	Year	Average Depreciation Rate	Depreciation Study Filed
Enbridge Gas	1994	Not available	√
Union Gas		3.79%	√
Atco Gas		Not available	
Enbridge Gas	1995	Not available	
Union Gas		Not available	
Atco Gas		Not available	
Enbridge Gas	1996	Not available	
Union Gas		Not available	
Atco Gas		Not available	
Enbridge Gas	1997	4.36%	
Union Gas		Not available	
Atco Gas		Not available	
Enbridge Gas	1998	4.36%	
Union Gas		3.63%	√
Atco Gas		Not available	
Enbridge Gas	1999	4.36%	
Union Gas		3.66%	
Atco Gas		Not available	
Enbridge Gas	2000	4.36%	
Union Gas		3.66%	
Atco Gas		Not available	
Enbridge Gas	2001	4.36%	√
Union Gas		3.66%	
Atco Gas		Not available	
Enbridge Gas	2002	4.40%	
Union Gas		3.66%	
Atco Gas		Not available	
Enbridge Gas	2003	4.40%	
Union Gas		3.66%	√
Atco Gas		3.81%	
Gaz Metro		Not available	√
Enbridge Gas	2004	4.40%	
Union Gas		3.30%	
Atco Gas		3.84%	
Enbridge Gas	2005	4.50%	√
Union Gas		3.30%	
Atco Gas		3.93%	√
Enbridge Gas	2006	4.50%	
Union Gas		3.30%	
Atco Gas		3.98%	√
Enbridge Gas	2007	4.50%	
Union Gas		3.30%	
Atco Gas		3.97%	
Enbridge Gas	2008	4.50%	
Union Gas		3.30%	
Atco Gas		3.95%	√
Enbridge Gas	2009	4.50%	
Union Gas		3.30%	
Atco Gas		3.96%	

JIESC/BCOAPO/CEC-TGI-8.

TOPIC: **Business risk**

REFERENCE: **Evidence of the company Tab 1**

REQUEST:

a) Please provide the regulated capital structures in effect for TGI (and predecessor companies) for each year since 1994 broken out into long term debt, short term debt, preferred shares and common shares.

Response:

The following table represents the actual capital structure for TGI for each year ending December 31:

	Unfunded Debt	Long Term Debt	Preferred Shares	Common Shares*
1994	14.01%	44.78%	8.21%	33.00%
1995	13.71%	46.82%	6.47%	33.00%
1996	12.84%	44.16%	10.00%	33.00%
1997	13.53%	43.97%	9.50%	33.00%
1998	13.19%	44.39%	9.42%	33.00%
1999	13.04%	45.99%	7.97%	33.00%
2000	4.26%	59.03%	3.71%	33.00%
2001	12.97%	54.03%	0.00%	33.00%
2002	6.53%	60.47%	0.00%	33.00%
2003	7.28%	59.72%	0.00%	33.00%
2004	9.97%	57.03%	0.00%	33.00%
2005	7.01%	59.99%	0.00%	33.00%
2006	6.33%	58.67%	0.00%	35.00%
2007	4.37%	60.62%	0.00%	35.01%
2008	9.41%	55.58%	0.00%	35.01%

*Deemed equity

b) Please provide equivalent data to that in a) above for Enbridge Gas Distribution Inc, Union Gas, ATCO Gas and Gaz Metro.

Response:

Please see the capital structure comparisons provided on page 13 of the Application which reflect the current debt and equity mix of the other companies. To the extent that the other peer Canadian gas LDCs have publicly disclosed the additional breakdown requested in this question, they can be found in the regulatory filings of the individual companies which Dr. Booth has the same opportunity to access as does Terasen.

JIESC/BCOAPO/CEC-TGI-9.

TOPIC: **Business Risk**

REFERENCE: **Evidence of the Company, Tab 1**

REQUEST:

a) Please indicate when TGI (or predecessor companies) moved from being regulated on an historic test year basis to a forward test year basis.

Response:

The first Revenue Requirements Application of Inland Natural Gas Co. Ltd. (predecessor to TGI) was filed in January 1977. The information in that application related primarily to a test year ending June 30, 1977. In its August 1977 Decision the British Columbia Energy Commission stated:

> "*The test year obviously did not follow the conventional "normalized and annualized" approach. However, in applying the appropriate tests, the Commission has concluded that the information presented by the Applicant, although not in the form originally requested, was sufficient to permit the Commission to reach a fair and reasonable return."*

In its March 12, 1979 Decision relating to the July 1978 Application of Inland, the Commission indicated that in the past it had generally utilized a test period described as a normalized and annualized historic test year, but it would in the circumstances accept as the test period the forecast test year proposed by the Applicant.

b) Please provide extracts from any testimony introduced at the time of the change to indicate that the allowed ROE was reduced since it was being applied to a forward instead of an historic test year rate base.

Response:

Since both the 1977 and 1979 applications made use of forecast data, and since the 1977 proceeding was the first Revenue Requirements Application of Inland, there would have been no discussion of a reduction from a previously allowed ROE.

c) In TGI's judgment should the allowed ROE be the same for two otherwise identical utilities that differ only in being regulated on an historic versus a forward test year basis?

Response:

Like many things it depends on the circumstances of the "otherwise identical utilities", but generally the answer would be yes. There are multiple factors which determine the ability to earn the allowed return on the actual rate base in place particularly with relatively low rates of inflation; therefore there is no reason to conclude that there should necessarily be any difference in the allowed ROE.

The extent of differences between the measurement of rate base on a historic versus forecast test period depends on how the historic rate base is measured. Historic test year rate bases are frequently year-end, rather than mid-year, and may be adjusted for known and measurable changes. As a result, a rate case filed on April 1 would reflect a rate base measured as of December 31, adjusted for known and measurable changes. To the extent that the two "otherwise identical utilities" would have the same expected knowledge of the adjustments that would have to be made to the historic test period then the resulting revenue requirement proposals could be quite similar. Further, other factors determine a utility's ability to earn the allowed return, including, for example, customer and load growth in relation to the trends in the costs incurred to serve those customers.

When a forecast test year is used, economies of scale achieved through customer growth are flowed through to ratepayers. If historic normalized costs and load are the basis for rates, economies of scale achieved through growth in customers and sales would be retained by the utility.

Evidence of Mr. Carmichael

JIESC/BCOAPO/CEC-TGI-10

TOPIC: **BCUC Formula ROE**

REFERENCE: **Evidence of Mr. Carmichael, Pages 3-4**

REQUEST

a) Please indicate the BCUC ROE formula in effect for each of the periods between the reviews in 1997, 1999 and 2006 and the specific changes made after each review.

<u>Response:</u>

For 1997:

ROE = 12.25% + .8 x (LTCY – 9.25%); result rounded to the nearest 25 bps

For 1999:

ROE = 9.50% + ((IF LTCY> 6%, Then .8 x (LTCY – 6.00%), Else 1.0 x (LTCY – 6.00%)), results rounded to the nearest 25 bps.

For 2006:

ROE = 9.145% + .75 x (LTCY – 5.25%)

b) Please indicate the allowed ROE produced for 2010 for the different ROE formula in a) above based on a forecast long term Canada (LTC) forecast yield of 4.25% and 4.75% respectively.

Response:

At a GOC expected yield of 4.25%:

ROE = 9.145% +.75 X (4.25% – 5.25%)

ROE = 8.395%

At a GOC expected yield of 4.75%:

ROE = 9.145% + .75 X (4.75% - 5.25%)

ROE = 8.77%

The results of the 1997 and 1999 formula can easily be calculated by the author of the question.

c) In Mr. Carmichael's view are any of the ROEs produced by the various BCUC ROE formula fair and reasonable?

Response:

The ROEs produced by the BCUC's formula have been consistently at the lower end of a band of reasonable returns and when the formula produced returns on common equity have been combined with the relatively thin common equity base deemed for Terasen Gas, the resulting financial performance of the utility has been weak. This conclusion is broadly accepted in the capital markets.

Under recent economic and capital market conditions, the return produced by the formula may not be fair and reasonable again after taking into account the relatively thin common equity base. Downward movements of long term Canada bond yields have produced via the formula lower returns for the company while the company's actual cost of capital have been increasing.

d) Does Mr. Carmichael believe that the BCUC conducted a fair and careful examination of the evidence placed before it in these reviews?

Response:

Yes. It would appear that the BCUC has attempted to improve the formula through each generic hearing.

e) Mr Carmichael refers to the change in LTC yields in 2008 and 2008 as "major". Please indicate the decline in LTC yields between these ROE reviews mentioned in a) above, were these also major and if so what change in yields would Mr. Carmichael not consider major (for example, 0.50%, 0.75%)?

Response:

The 1997 decision was dated April 1997, the 1999 decision was August 1999, while the 2006 decision was March 2006.

The yield in April 1997 was approximately 7.3%, dropping to 5.9% by August 1999, a change of approximately 19%. Between August 1999 and March 2006, the decrease was approximately 28%.

The long Canada yields in January 2008 were 4.2%. By the end of 2008 the yield was in the range of 3.40%, a drop of approximately19% over the year.

With the very low yields in the Government of Canada bond market a decline of 80 basis points represents a change approaching 20% and is considered large by market participants. While the magnitude of the drop is similar to prior periods, the drop in 2008 occurred over 1 year, instead of a longer period, emphasizing the significance of the change.

JIESC/BCOAPO/CEC-TGI-11.

TOPIC: **US Comparables**

REFERENCE: **Evidence of Mr. Carmichael, Page 5**

REQUEST

a) Does Mr. Carmichael judge "Comparable" to mean "the same" or like the BCUC does he judge the rating agencies to mean comparable in the sense of a benchmark to which they then make adjustments when coming to a definite [?] conclusion?

Response:

Comparable means that two comparable companies could score quite differently on a series of benchmarks but when all benchmarks are considered in aggregate the two companies would achieve similar rating scores. The companies are comparable but not the same in all of the benchmarks.

b) As Mr. Carmichael mentions (page 40), Moody's adjusts the rating for TGI from that produced mechanically from simple financial metrics to a higher rating based on the protective regulatory environment in BC. Does Mr. Carmichael believe that this exercise of judgement is unique to Moody's or does he judge other investors to make similar adjustments?

Response:

Other lenders and credit rating agencies do form positive or negative opinions regarding the business and financial risks and make adjustments to their credit rating and/ or the required pricing of the company's debt securities based on their informed judgment.

c) Provide a copy of the last presentation (pitch) Mr. Carmichael made as an investment dealer to sell Fortis and/or Terasen debt issues to prospective investors.

Response:

While Mr. Carmichael has acted as the lead underwriter in a number of financings for Fortis and its regulated subsidiaries, he has not acted as a lead underwriter for Terasen Gas Inc. Presentation material, if any, produced during the course of a securities offering is the property of the issuer and Mr. Carmichael is not in possession of any such material.

When a company such as Fortis or Terasen is in the process of selling a debt issue to prospective lenders, such lenders do not want a presentation from investment bankers and therefore investment bankers usually do not make presentations to sell the issue. Presentations which are made, are made by the issuer and they summarize information in the short form or MTN prospectus and other information filed with security commissions.

d) Provide a copy of the last presentation (pitch) Mr. Carmichael made as an investment dealer to sell a Canadian utility debt issue to prospective investors.

Response:

Mr. Carmichael is unable to provide any presentation as such presentations are the property of the issuer and are required by securities law to simply re-state in a condensed form what is also stated in the short form prospectus, annual information form, annual reports and other documents filed with provincial security regulators.

JIESC/BCOAPO/CEC-TGI-12.

TOPIC: **NEB TQM Decision**

REFERENCE: **Evidence of Mr. Carmichael, Page 8**

REQUEST

a) Can Mr. Carmichael confirm that the NEB's 2008 TQM decision applies specifically to the years 2007 and 2008 and only to TQM and that the NEB ROE formula is still in force for other pipelines and for TQM for subsequent years? If not confirmed, why not.

Response:

The TQM decision applies to years 2007 and 2008 and the decision applied the ATWACC approach only to TQM. RH-2-94 was used to determine ROEs for pipelines in 2009. Whether RH-2-94 continues to apply to TQM and other pipelines in the future depends on the outcome of a review of Decision RH-2-94 initiated by the NEB on July 3 2009.

b) Can Mr. Carmichael speculate as to why such a major change in regulatory policy is restricted to only one Class 1 NEB regulated pipeline and only for two specific years?

Response:

The reason that the decision applied to one party and for a specified two year period, is based simply on the facts that the Application was brought forth by only TQM, the proceeding was not a generic hearing, and TQM applied for approval of the Cost of Capital to be utilized in determining tolls for a specific period, January 1, 2007 to December 31, 2008.

The NEB has recognized the significance of its decision, and the fact that a major policy change should be more broadly considered, and on July 3, 2009 announced that it will initiate a review of the continuing applicability of the RH-2-94 Decision.

c) Please confirm that almost all TQM's debt is up for renewal so that the market and embedded cost of debt is essentially the same. If not confirmed, why not.

Response:

In Decision RH-1-2008, the NEB commented as follows:

> *"The difference between market cost of debt and embedded cost of debt in this case is small and therefore does not require consideration of a grandfathering or transition phase for TQM for 2007 and 2008."*

d) Can Mr. Carmichael provide TGI's embedded cost of debt for each year since 2000, including a forecast for 2009?

Response:

The forecast embedded cost of debt for 2009 is approximately 6.64%. The embedded cost of debt since 2000 has been as follows:

Year	**Embedded Cost of Debt**
2000	8.15%
2001	7.74
2002	7.32
2003	7.17
2004	6.76
2005	6.91
2006	6.77
2007	6.87
2008	6.89

e) If TGI is awarded a 6.4% ATWACC on its book value rate base similar to TQM, please estimate TGI's ROE using the 2009 embedded cost of debt. Please provide all the necessary calculations.

Response:

Mr. Carmichael is not providing evidence in support of an ATWACC methodology. Mr. Carmichael does not consider himself an expert on the ATWACC methodology, and therefore, is not in a position to provide the calculation.

f) What tax rate would Mr. Carmichael recommend should be used with the ATWACC methodology adopted by the NEB; the statutory rate or a flow through rate?

Response:

Mr. Carmichael can confirm that 30 year yields were approximately 3.85% during the week of July 7, 2009. Mr. Carmichael does not have a recommendation. Mr. Carmichael is not presenting evidence with regard to an ATWACC methodology, and does not consider himself expert in that methodology.

JIESC/BCOAPO/CEC-TGI-13.

TOPIC: **BC Economy**

REFERENCE: **Evidence of Mr. Carmichael, Page 15**

REQUEST:

a) Mr. Carmichael indicates that the current Canadian recession will be milder than the last two and discusses the current state of the BC economy and then on page 41 raises this as a risk factor. Please provide TGI (and predecessor companies) actual and allowed ROE for each year since 1997 and identify the impact of incentive regulation on the actual ROEs.

<u>Response:</u>

See response to JIESC/BCOAPO/CEC IR 1.5(c) and (d).

b) How sensitive does Mr. Carmichael regard TGI's actual ROE to economic conditions and in his judgment does TGI's RSAM mitigate this sensitivity? If not, why not and to what degree does it not.

<u>Response:</u>

Mr. Carmichael understands that the RSAM deferral mechanism provides short-term use per customer protection for revenues from residential and commercial sales customers and thereby provides short term stabilization in revenues from these customer rate classes. Forecast variances for use per customer are captured in the deferral for recovery from or refund to customers in the following 3 years. To the extent that recessionary conditions impact actual use per customer for existing customers, then the RSAM mechanism stabilizes the recorded revenues from these customers but puts additional rate pressure on those customer groups in subsequent years thereby impacting competitiveness.

To the extent that recessionary conditions result in the loss of such customers or the failure to attach customers that were forecast and whose forecast revenues were included in rates, the RSAM mechanism provides no protection and the risk is to the company. So the RSAM mechanism affords some short term earnings protection but does not impact long term business risk.

The RSAM mechanism has already been factored into the credit rating and business risk assessment of Terasen Gas. However a serious economic downturn in the BC economy would attack the underlying strength of the Terasen Gas service territory and the business environment in which the company operates. Moody's has justified its A3 debt rating due in part to the Company's supportive business environment, a slowdown in the BC economy could remove this justification of the increased rating grade.

JIESC/BCOAPO/CEC-TGI-14.

TOPIC: **LTC Yields**

REFERENCE: **Evidence of Mr. Carmichael, Page 17**

REQUEST:

a) In the table on page 17 would Mr. Carmichael agree that the yield curve between 2005 and 2007 generally reflected a tightening monetary policy? taTt is, the Bank of Canada was deliberately forcing up interest rates to slow down the Canadian economy and that this policy was only changed in December 2007 after which the Bank started cutting rates to offset a slowdown? If not, why not?

Response:

The table on page 17 indicates that 10 and 30 year Canada yields were quite stable over the period 2005 to 2007 and yields increased only in the 5 year term. The increased yield in the 5 year term may indicate that the Bank of Canada was slowly tightening monetary policy to slow the economy. In 2008 and the first quarter of 2009, short term rates declined as the economic outlook worsened and the Bank of Canada loosened monetary policy to stave off a slowdown. While longer term yields did decline, the declines were not as pronounced as those in the 5 year term.

b) Would Mr Carmichael agree that during the flight to quality following the collapse of Lehman Brothers, Treasury bill yields went negative in the US as investors were willing to put money into a "safe" short term investments for a guaranteed negative rate of return?

Response:

Rates on new issues of Treasury bills did not reach negative territory; however, it was reported in the financial press some trade of 3 months bills did take place at a negative yield.

c) Can Mr. Carmichael provide the Canadian Treasury bill yield for the same periods as in the table on page 17 and confirm that these yields have collapsed from the 2.0% level of September 2008 to the 0.35% level of Spring 2009? If not confirmed, please provide weekly Canadian T Bill yields since August 2008.

Response:

Please refer to Tab 3 Schedule 1 of the Application.

d) Would Mr. Carmichael agree that during this tighter monetary policy period the LTC yields barely moved and that they only dropped below 4.0% in December 2008 as fears of a "Great Depression-2" and deflation started being raised?

Response:

Mr. Carmichael understands that 30 year benchmark yields were approximately 4.30% in October and November 2008. At the end of November 2008, yields fell to 3.85% to 3.90% and trended lower from this level to approximately 3.6% at the end of March 2009.

e) Can Mr. Carmichael confirm that from December 2008 until the current period there has been no significant decline in the stock of long Canada bonds outstanding, so the decline in LTC yields can not be caused by a "supply" effect due to budget surpluses? If not confirmed, why not?

Response:

Mr. Carmichael confirms the fact that repayment has declined in recent fiscal quarters. However, he does accept the notion that the decline in LTC yield was not caused by a "supply" effect due to budget surpluses. On page 18 of Mr. Carmichael's pre-filed evidence a chart of the federal government's debt position is presented. The debt to GDP ratio has declined from approximately 63% in the 1994-95 fiscal year to approximately 29% at the end of the 2007 and 2008 fiscal year. Even with the government budget stimulus and anticipated deficit, it is expected that the debt to GDP ratio will increase to 32% or about one half the ratio's level in 1994 when the automatic adjustment mechanism was put in place. The federal debt stood at $457.6 billion at the end of 2007–08, down $105.2 billion from its peak of $562.9 billion in 1996–97 (see Annual Financial Report of the Government of Canada 2007-2008).

f) Can Mr. Carmichael confirm that LTC yields are now above 4.0% as deflationary fears have subsided and the recognition has set in that we are simply in a recession?

Response:

Mr. Carmichael can confirm that 30 year yields are now approximately 3.90%during the week of July 13 2009. There are many different economic outlooks that impact trading markets from day to day. The risk of further economic set backs and deflation have not been completely ruled out.

g) Given his answers to a)-f) above can Mr. Carmichael weight the three factors he gives in order of their importance in affecting current LTC yields?

Response:

Mr. Carmichael would give slightly more weight (say, 40% compared to 30% for the other factors) to the improving financial performance of the Government of Canada. As noted even after incurring a substantial deficit this fiscal year the debt to GDP ratio is only anticipated to rise to approximately 32% and subsequently return to a declining path. It is anticipated that the Minister of Finance may adopt a longer term target of 25% for the debt to GDP ratio. As institutional portfolios of debt grow, demand pressure should keep Government of Canada yields low.

JIESC/BCOAPO/CEC-TGI-15.

TOPIC: **Credit Spreads**

REFERENCE: **Evidence of Mr. Carmichael, Page 21**

REQUEST:

a) Please provide all the data underlying chart 4 on page 21 in Excel machine readable form so that the graph can be replicated.

Response:

The detailed data is not available to Mr. Carmichael.

b) Can Mr. Carmichael confirm that bonds are predominantly traded in a dealer market where the original underwriter normally commits to making a market in those bonds?

Response:

Bonds or debentures are traded in an over the counter market run by the major bond underwriters in Canada. Each of the major dealers has direct telephone lines to its major institutional lenders. A major underwriter of bonds is expected to provide bond research on the issuer and call a market for the bonds for at least some period of time following the offering of the bonds. Bond dealers take their responsibilities quite seriously; however, describing it as a commitment may be overstating the dealer's responsibility.

c) Can Mr. Carmichael confirm that following the near bankruptcy of the major US investment banks these dealer inventories were massively liquidated from September-December 2008 and the major US investment banks no longer bought bonds for the own account via proprietary trading, which is why liquidity in many areas of the bond market "virtually" disappeared?

Response:

In the U.S. corporate bond inventories were reduced over much of the year due to growing credit problems in the sub-prime mortgage market and the anticipated slowing of the U. S. economy. As the full extent of the problems in the sub-prime market became known and as the U.S. housing market continued to decline in value, lenders began to doubt the stability of the financial system which led to continued selling of credit into a tightening market for corporate credit. The near bankruptcy of the major U.S. investment banks exacerbated an already resistant market for corporate risk.

d) Given his answer to c) above how much of the increase in corporate spreads would Mr. Carmichael ascribe to liquidity concerns and the unwillingness or inability of investment banks to hold corporate bonds in inventory to make a market?

Response:

The impact of reduced liquidity in the corporate credit market was in Mr. Carmichael's opinion quite marginal, as the market for additional corporate credit had virtually closed entirely due to a combination of factors including the expected decline in the U.S. economy, the collapse of the sub-prime mortgage market and concerns regarding the stability of the U.S. banking system.

e) Would Mr. Carmichael agree that the collapse in credit spreads from their peaks in March 2009 has coincided with a recovery in bank shares as fears of the failure of more US banks has subsided and US government intervention in support of its banks has allowed them to return to "normal" activities.

Response:

Mr. Carmichael would agree that the U.S. government's stabilization of the U.S. banking system and its attempts to stimulate the granting of corporate credit has allowed banks to return to more normal lending activities, although liquidity is still constrained. The government's stimulus package for the real economy has also reduced concerns regarding the expected future course of the U.S. economy and the credit quality of U. S. corporations, although spreads are still at elevated levels.

f) Can Mr. Carmichael update chart 4 and also provide the latest spreads for TGI?

Response:

Mr. Carmichael is unable to update Chart 4. Interest rate spreads for Terasen Gas Inc. on July 6, 2009 were as follows:

	5 year Maturity	**10 year Maturity**	**30 year Maturity**
Canada benchmark yield	2.41%	3.34%	3.86%
TGI credit Spread	1.25	1.50	1.70
Required New Issue Yield	3.66%	4.84%	5.56%

JIESC/BCOAPO/CEC-TGI-16.

TOPIC: **TGI Spreads**

REFERENCE: **Evidence of Mr. Carmichael, Page 22-33**

REQUEST:

a) On page 24 Mr. Carmichael recognizes that spreads are volatile and cyclical (regular). Does he agree that from his table on page 22, the 5, 10 and 30 year credit spreads increased from 2006 to 2009 by 225, 208 and 171 bps respectively?

<u>Response:</u>

Mr. Carmichael has only recognized that credit spreads tend to widen during times of economic or financial uncertainties. Average spreads have increased by the indicated amounts between 2006 and 2009.

b) Can Mr. Carmichael further confirm from his table on page 33 that TGI's new issue yields changed over this same period by -4, 85 and 113 bps respectively?

<u>Response:</u>

TGI's average new issue yield increased by -4 basis points for 5 year financing, 82 basis points for 10 year financing and by 113 basis points for 30 year financing between 2006 and 2009.

c) Can Mr. Carmichael confirm that in February 2009 TGI issued long term debt and indicate its maturity.

<u>Response:</u>

As noted in my testimony, TGI issued $100 million of debentures on February 24, 2009 due February 24, 2039 at a coupon of 6.55% and a spread over 30 year Long Canada Bond yields of 285 basis points.

d) Given that long term (10 year and above) debt involved an absolute increase in yield since 2006 and Mr. Carmichael acknowledges that these sorts of spread changes occur regularly, does he judge TGI to have acted prudently in issuing long term debt, rather than shorter term debt which they could then role over once markets returned to more normal conditions as they now have done?

Response:

At the time of the financing TGI had approximately $1,414,500,000 of debt obligations outstanding with $59.9 million of maturing Series E 10.75% debentures due in June 2009. Fixed income markets had been unstable since October 2008 with credit spreads increasing significantly from week to week. TGI's 30 year credit spread peaked early in January 2009 and began a decline shortly thereafter. At a spread of 285 and new issue yield of 6.55%, TGI refinanced the maturing Series E debentures with a saving of 420 basis points and lowered its average cost of debt and achieved an appropriate piece of long term financing.

Shorter term financing (say 5, 6 or 7 year maturities) would not have been as prudent as the longer term issue in my opinion, given the approximate $275 million of Purchase Money Mortgages coming due in 2015 and 2016.

e) As an investment banker would Mr. Carmichael have recommended a long term bond issue in February 2009 given the temporary liquidity conditions in the bond market and cyclically higher spreads? ,If the answer is yes, please indicate all Canadian non rate of return regulated companies that issued non-callable 30 year debt in the period January-May 2009 and the amount they raised.

Response:

At the time of the financing, TGI had a reasonable use of proceeds and the cost of the debt financing was 420 basis points below the debt being re-financed. The direction of movement of corporate spreads was not positive but a major narrowing of spreads was not anticipated. As a result, I would have recommended Terasen Gas to proceed with the financing.

Issuers of 30 year debt between January and May 2009 include: Plenary Health Niagara ($134 million, spread 395 bps, maturity 31-Mar-42), UMH Energy Partnership ($200 million, spread 365 bps, maturity 8-May-41), Power Corporation of Canada ($150 million, spread 490 bps, maturity 22-April-39). TD Capital Trust and CIBC Capital Trust also issued debt with terms in excess of 30 years in January and March of 2009. These bonds can be called at the Canada Yield Price as can the TGI debentures.

JIESC/BCOAPO/CEC-TGI-17.

TOPIC: **Earnings Yield**

REFERENCE: **Evidence of Mr. Carmichael, Page 30**

REQUEST:

a) All else constant, what happens to the earnings yield of a company with very high growth prospects versus one with declining or negative growth prospects?

Response:

As investors anticipate higher growth of earnings and dividends, their expected return (k=(D/P) + (g+ A)) will increase. Assuming that the investor required return on the asset class has not changed, and since k-A = (D/P) + g, if A is a positive number, the required return will decline and the price of the stock will go up. If the market price of the company's stock goes up, the earnings yield should go down as it is assumed earnings are constant. If A is a negative number, then the investors new required return is higher and the price of the share will be reduced in the market place. As the price of the share declines, the earning yield should increase given that earnings remain constant.

b) Can Mr. Carmichael explain the dividend discount, DCF, Gordon or constant growth model and explain what happens to the dividend yield if an investor wants a 10% rate of return and the expected growth rate changes from 4% to 6%?

Response:

The dividend yield would decline based on the following: the price of the stock is equal to the present value of its dividend stream discounted at the investors required rate of return which in this case is equal to 10%. The constant growth model assumes that the current price of the stock is equal to the discounted value of the expected stream of dividends which is equal to the current dividend D_0 which is expected to increase annually at a constant growth rate of g so

$$P = D_0 + D_0\frac{(1+g)}{(1+k)} + D_0\frac{(1+g)^2}{(1+k)^2} + D_0\frac{(1+g)^3}{(1+k)^3} + D_0\frac{(1+g)^4}{(1+k)^4} + \ 0\ 0\ 0$$

where g is the assumed constant growth rate and k is the investor's discount rate or required rate of return. If the expected growth rate increases from 4% to 6%, the term (1+g) also increases and if k remains at 10%, the market value of the company P will increase to a higher value. Since D_0 has remained constant, the dividend yield should decline as the market price P is now higher.

c) Can Mr. Carmichael confirm that increases in both the earnings yield and dividend yield are also a natural consequence of a reduction in investor growth expectations? If not confirmed, why not?

Response:

From the response to JIESC/BCOAPO/CEC IR 1.17(b) above, if growth is expected to be lower in the future than has been assumed to set the current price, the price of the company's stock would decline. With a reduced price, the earnings yield and dividend yield would both increase.

d) Can Mr. Carmichael confirm that earnings and dividend growth expectations fall during a recession as corporate profitability declines? If not confirmed, why not?

Response:

Since securities markets are forward looking, earnings and dividend growth expectations are usually reduced before the actual decline of economic activity in the real economy. Securities markets are generally viewed as leading indicators of economic activity. So over the past four months a rally has been going on in the financial markets while real economic conditions continue to deteriorate. Mr. Carmichael believes that the decline in investors' growth expectations occur prior to the decline in the real economy. Capital markets are currently looking through the slow down to future growth and profit opportunities.

e) Can Mr. Carmichael provide extracts of any testimony he filed indicating a decline in the cost of equity when the earnings yield and dividend yield were below their long run average values, for example in 2004?

Response:

Mr. Carmichael did not testify in 2004 and, to the best of his memory, has not discussed earnings yield and dividend in his previous testimony.

JIESC/BCOAPO/CEC-TGI-18.

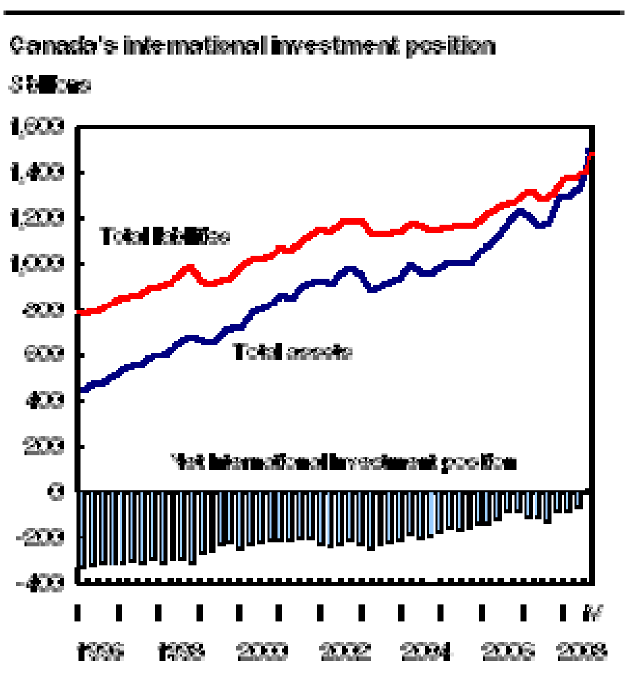
TOPIC: **Investment Outflows**

REFERENCE: **Evidence of Mr. Carmichael, Page 33**

REQUEST:

a) Mr. Carmichael refers to the investment outflows following the repeal of the foreign property rules. Please indicate the amounts of Canadian portfolio investment outflows since 1995 deflated by some aggregate measure that Mr. Carmichael deems appropriate such as GDP or total market capitalisation.

Response:



Date Modified: 2009-03-12
Source: Statistics Canada

The above graph indicates that Canada's total investment in foreign assets increased from approximately $420 billion in 1995 to approximately $1,493 billion at the end of 2008, an increase of 255%. There is a noticeable spike in total foreign assets commencing in 2004-2005 following the full repeal of the foreign property investment rules, notwithstanding the increase in the Canadian dollar from approximately $.72 to $.94 from 2004 to 2008.

b) Given a) above when does Mr. Carmichael regard investment outflows as peaking and is the trend to increasing or decreasing outflows?

Response:

The trend toward international investment by Canadian institutional and retail investors has definitely not peaked. Investment in international assets increased by 11.8% in the fourth quarter of 2008. Canadian institutional investors continue to search abroad for investment in infrastructure projects. The global economic slowdown and credit crisis in the U.S. may cause investors to liquidate some investments in the short term; however, foreign investment balances will continue to grow.

c) By diversifying into foreign markets is the risk of an average Canadian equity portfolio increased or decreased? That is, are foreign markets on average perfectly correlated with the Canadian market?

Response:

The focus of institutional investors is not to diversify into foreign markets but to purchase longer term private infrastructure assets whose values are less sensitive to public market value fluctuations. By purchasing such assets, investors are attempting to reduce the correlation of their public and private market valuations.

Generally, developed foreign markets are not perfectly correlated to the Canadian market.

d) If foreign and Canadian equity markets are not perfectly correlated and risk is reduced what does basic financial theory say happens to the investor's required rate of return or cost of equity capital? If Mr. Carmichael says anything other than risk is reduced, please provide relevant citations to the literature.

Response:

The question misses the point of the discussion. As noted above, investors do not want to invest in foreign publicly traded markets as much as they prefer to invest in foreign utility-like infrastructure facilities to reduce the volatility of their portfolio valuation by diversifying away from public market securities and investing more heavily in long term infrastructure assets whose value is more stable than that of the public market..

JIESC/BCOAPO/CEC-TGI-19.

TOPIC: **Investment Restrictions**

REFERENCE: **Evidence of Mr. Carmichael, Page 42**

REQUEST:

a) Please provide all citations to regulations that prohibit Canadian institutions from holding sub A(low) rated corporate debt.

Response:

Prudency dictates that Canadian institutions limit or restrict their purchase of BBB category bonds as this segment represents from approximately 7% to 12% of the total market. From time-to-time (for example January and February 2009), the liquidity of the BBB sector of the market virtually disappears.

Institutional buyers also consider the quality and derivation of the bond rating in making a purchase decision. Usually lenders will consider a bond that is split rated, for example, A3/BBB and will attempt to price the security based on its BBB rating. Lenders also recognize that certain ratings are limited by the rating of the utility's parent company and lenders again use the lower BBB to increase the yield on a new issue.

b) Please confirm that within the last twenty years both TransCanada Pipelines and Westcoast have been rated below A(low).

Response:

Neither the Company nor Mr. Carmichael has a complete history on the ratings of either TransCanada Pipelines Limited or Westcoast Energy Inc. for the last twenty years. To the best of their knowledge, and on information provided by RBC Capital Markets, going back to 1995, TransCanada has never been rated less than A(low). Westcoast, during that time frame, was rated at times lower than A(low) by S&P, but maintained an A(low) rating from DBRS.

c) Please confirm that at the current point in time several Canadian utility holding companies are rated below A(low) by S&P.

Response:

While certain Canadian utility holding companies have ratings by S&P below A(low), there are a number of holding companies in fact in the A rating category.

d) Please confirm that the modal (median) bond rating for US utilities is below A(Low). If Mr. Carmichael cannot so confirm please provide the S&P bond ratings for all utilities and utility holding companies in the US as of the end of 2008.

Response:

As noted above, S&P does not determine ratings of utility subsidiaries on a stand alone basis. Based on its methodology, the rating of the utility subsidiary cannot be higher than the rating of the parent company. For this reason, generalized assumptions about utility credit quality may not be made and relying on ratings from S&P does not provide an accurate measure of credit quality.

JIESC/BCOAPO/CEC-TGI-20.

TOPIC: **Concentric Report**

REFERENCE: **Evidence of Mr. Carmichael, Page 42**

REQUEST:

a) Please confirm that the Concentric Energy report discussed on page 42 was produced by the same consulting firm that provided testimony on behalf of utilities in the recent AUC generic cost of capital hearing.

Response:

Mr. Carmichael has no personal knowledge of whether or not Concentric Energy provided testimony in the recent AUC hearing. Mr. Carmichael can only confirm that, according to the Ontario Energy Board website, the OEB retained Concentric Energy to perform a study which is now posted on their website. Mr. Carmichael has referred to the study in his pre-filed testimony.

b) Please confirm that the Concentric report also shows that the US utilities had higher common equity ratios and lower bond ratings. If Mr. Carmichael cannot so confirm, please provide the common equity ratios for all the US utilities for which he is providing bond ratings in answer to c) above.

Response:

Mr. Carmichael confirms this.

c) Please indicate how, if the business risk is the same between US and Canadian utilities, the Canadian utilities can have higher bond ratings while at the same time having lower ROEs and lower common equity ratios?

Response:

The Canadian utilities are rated by DBRS and S&P. If only the S&P ratings are considered for both the U.S. and Canadian utilities (that is, if only one consistent rating methodology is employed), the Canadian utilities would be rated at a similar level to the U.S. utilities at approximately BBB+. The rating agencies have greater confidence in the Canadian regulatory environment and have, in the past, been willing to accept weaker financial performance than the financial performance of utilities in the U.S.

JIESC/BCOAPO/CEC-TGI-21.

TOPIC: **ROE and A Spreads**

REFERENCE: **Evidence of Mr. Carmichael, Page 45**

REQUEST:

a) Please confirm that the ROE in the table on page 45 is based on forecast LTC yields and explain the basis for the new issue TGI yield, that is, is this the average for the year, a forecast based on the same LTC yield forecast or what is it? Please provide the data to support this TGI yield.

Response:

The ROEs for 2006 to 2009 are the result of the Application of the automatic adjustment formula and are based on the forecast long term Canada yield in the proceeding November. The bond yields are the actual yields at which TGI issued 30 year debt during the year indicated. The differential is the awarded return on equity minus the required bond yield. For 2010, the expected awarded return on equity based on the approximate average yield for long Canada bonds in April 2009 and the Application of the formula was 7.95% while the expected cost of Terasen Gas 30 year debt funding, based on a 30 year benchmark Canada yield of 3.67% and the average credit spread for April 2009 of 273 bps, was expected to be 6.40%, giving rise to a differential of only 155 bps.

b) Please estimate the ROE based on forecast LTC yields of 4.25% and 4.75%.

Response:

Please refer to the response to JIESC/BCOAPO/CEC IR 1.10(c).

c) Please estimate the current new issue cost consistent with that estimated in the table on Page 45, based on a spread of 125 bps.

Response:

Based on a long Canada yield of approximately 4.00%, and the current new issue spread of approximately 1.80%, a new issue yield comparable to the table on page 45 would be approximately 5.80%, before issuance costs. While utilizing 1.25% is not relevant given market conditions, the yield would be 5.25%, before considering new issue costs.

d) What spread between the ROE and TGI's borrowing cost would Mr. Carmichael judge to result in a fair and reasonable ROE.

Response:

Mr. Carmichael is not recommending that the BCUC should determine a fair and reasonable return for Terasen Gas based only on a specified spread between the cost of common equity and the cost of new long term debt. The purpose of the table on page 45 is to indicate that, in the case of Terasen Gas, this spread has collapsed from 360 basis points in 2006 to approximately 155 in April of this year.

The spread between new debt and common equity costs is only one consideration in the determination of a fair and reasonable return on common equity. But it is important to lenders and investors. Sun Life Financial, a major lender and investor in Canada, replied to the Ontario Energy Board in its review of formula generated variables under current economic and financial market conditions noting that the proposed ROE is not much higher compared to the cost of long term debt and that spread between the two had declined by more than 200 bps between 2008 and 2009.

The Company's proposed rate application incorporates an acceptable spread.

e) Further to d) above, is Mr. Carmichael aware that utilities have in the past suggested that ROE formulae should remain intact as long as the ROE spread over the LTC yield were twice the spread of their borrowing costs over the LTC yield? Can Mr. Carmichael estimate and provide this value for each year in the table on page 45, for his current forecast LTC yield and that which is produced from his answers to b) and c) above?

Response:

Mr. Carmichael is not aware of any such proposal, either by Terasen Gas or any other utilities in Canada. Mr. Carmichael views the question as being hypothetical and he declines to answer.

JIESC/BCOAPO/CEC-TGI-22.

TOPIC: **Broken ROE Formula**

REFERENCE: **Evidence of Mr. Carmichael, Page 47**

REQUEST:

a) Can Mr. Carmichael provide a copy of the RBC report that categorically says that the formula is broken?

Response:

Mr. Carmichael has included an RBC Capital Markets Energy Infrastructure Industry Report dated January 16, 2009 which indicates in RBC's view the Formula is broken and is producing directionally incorrect adjustments. This report follows an earlier report on the same subject dated October 28, 2008. The initial report raises the question of whether the formula is broken.

b) Can Mr. Carmichael confirm that the RBC report was written when LTC yields were at their cyclical lows?

Response:

On January 10, 2009 the 30 year Canada benchmark yield was 3.68% and on January 17, 2009, it was 3.72%. At February 17, 2009, the 30 year benchmark Canada yield was 3.57%. Long (30 year) Canada yields were close to their recent lows when the second report was written. On October 14, 2008, while the first RBC report was being written, 30 year Canada yields were 4.35% about 75 basis points from the apparent low point of yields.

c) In terms of the BMO capital markets report, can Mr. Carmichael indicate whether in his judgment increasing the allowed ROE can ever be viewed as bad news for bond holders?

Response:

If the return on common equity is increased while at the same time the common equity base of the utility is reduced, the result could weaken the expected financial performance of the utility and lower cash flow and interest and cash flow coverages. This could be viewed as bad news for bondholders.

d) Please provide the most recent copy of the BMO credit weekly.

Response:

Please refer to Attachment 22d.

Evidence of Ms. McShane

JIESC/BCOAPO/CEC-TGI-23.

TOPIC: **Comparable Earnings Testimony**

REFERENCE: **Evidence of Ms. McShane Pages 3-4**

REQUEST:

a) Please indicate (with full references and citations) any ROE decisions by a Canadian regulator in the last ten years that has placed any weight on comparable earnings testimony in the manner developed by Ms. McShane for TGI.

Response:

Ms. McShane is not aware of any decisions in the past 10 years which have given weight to the comparable earnings test as applied by Ms. McShane. In arriving at its cost of capital decision for TGI and TGVI in March 2006, the British Columbia Utilities Commission stated that it did not believe comparable earnings had outlived its usefulness, and that it may yet play a role in future ROE hearings. The BCUC did conclude in that decision that there was insufficient evidence before it regarding whether or not a market/book ratio adjustment was merited and, if so, how it might be accomplished. As indicated at pages F-6 to F-9 of her testimony in this proceeding, Ms. McShane explains why an adjustment is not warranted.

b) Please indicate (with full references and citations) any ROE decisions by a Canadian regulator in the last twenty years that has placed any weight on comparable earnings testimony in the manner developed by Ms. McShane for TGI without a market to book adjustment.

Response:

In RH-2-92 (2/93) for TransCanada PipeLines, the National Energy Board stated,

> *"Both the comparable earnings and equity risk premium techniques provided the Board with useful information in its determination of the appropriate rate of return to be allowed on TransCanada's deemed common equity component. However, the Board remains of the view that the results of the risk premium method should be given more weight than those of the comparable earnings method." The NEB decision did not discuss the need for a market to book adjustment.*

In E95070 (6/95) for the City of Edmonton, the Alberta Energy and Utilities Board stated,

> *"In arriving at a rate of return on common equity, the Board considers that, for the purposes of this Decision, all three tests of measuring common equity return are relevant. The Board does not agree with the opinion of the witness for the ERWCG, Mr. Kahal, that the comparable earnings test is of little help or relevance to these hearings because it does not attempt to measure the market cost of equity for the companies in the comparison sample. Rather, the Board considers that there is still some merit in the comparable earnings test to the extent that regulation is considered a surrogate for competition and the comparable earnings test attempts to measure the achieved accounting rates of return on common equity of enterprises of similar risk. The Board does, however, recognize that there may well be distortion in the market to book ratios caused by the effects of inflation on retained earnings of companies, notwithstanding their similarity in risk. Similarly, the comparable earnings test may be sensitive to the selection of the business cycle under study." The AEUB did not mention the need for a market to book adjustment.*

c) Please indicate (with full references and citations) any ROE decisions by a Canadian regulator in the last ten years that has placed any weight on discounted cash flow estimates in any manner, particularly as implemented by Ms. McShane for TGI.

<u>Response:</u>

The BCUC gave weight to the DCF method as applied by Ms. McShane in its March 2006 decision. At page 55 of the decision, the BCUC stated "The Commission Panel is more persuaded by Ms. McShane's evidence which compares Value Line and I/B/E/S forecasts and finds no upward bias in the latter. Accordingly, the Commission Panel will give weight to Ms. McShane's first DCF Test, which yielded an indicated return of 8.8 percent."

d) Please indicate (with full references and citations) any ROE decisions by a Canadian regulator in the last ten years that has placed any weight on direct evidence of the fair ROE derived from US utilities or US stock market performance.

Response:

The NEB gave weight to evidence derived from U.S. markets and to U.S. utilities specifically in its March 2009 RH-1- 2008 decision for TransQuébec and Maritimes Pipeline. Relevant citations from that decision include:

> *"In the Board's view, global financial markets have evolved significantly since 1994. Canada has witnessed increased flows of capital and implemented tax policy changes that facilitate these flows. As a result, the Board is of the view that Canadian firms are increasingly competing for capital on a global basis. The Board notes that Canada has been diversifying its business partners such that there is currently proportionally less Canadian foreign direct investment in the United States than there was in the 1990s. Nonetheless, the evidence is also clear that the United States is the single most important recipient of Canadian investments." (pages 66-67)*
>
> *"The Board is satisfied that the evidence establishes that TQM and U.S. LDCs are sufficiently similar in risk so as to make comparisons meaningful." (page 68)*
>
> *"Nonetheless, the Board found that litigated U.S. returns were useful as a check against the results from the analyses which relied upon market returns." (page 69)*
>
> *"In light of the Board's views expressed above on the integration of U.S. and Canadian financial markets, the problems with comparisons to either Canadian negotiated or litigated returns, and the Board's view that risk differences between Canada and the U.S. can be understood and accounted for, the Board is of the view that U.S. comparisons are very informative for determining a fair return for TQM for 2007 and 2008." (p. 71)*

The BCUC gave weight to evidence derived from U.S. utilities inasmuch as it gave weight to the DCF test applied to a sample of U.S. utilities as indicated in JIESC/BCOAPO/CEC IR 1.23(c) above. The BCUC also gave weight to U.S. market returns in determining the market equity risk premium.

> *"In the Commission Panel's view a MRP of 5.8 percent is appropriate, given the Canadian experienced premiums since the Second World War, adjusted upwards in part to recognize both the fact that bond returns will most likely decrease in future years, and in part to recognize U.S. returns." (page 53)*

In its April 2002 Decision D-2002-95, for Hydro Québec Transmission, the Régie de L'Énergie gave 40% weight to U.S. returns in its estimation of the equity market risk premium.

> *"Enfin, concernant la question spécifique du pourcentage à accorder entre les etudes canadiennes et américaines retenue par la Régie dans sa décision D-99-150 rendue le 20 août 1999, en accordant une pondération de 40 % aux données d'études américaines, la Régie constate que dans le présent dossier, aucun élément nouveau n'a été présenté en preuve à ce sujet. La Régie considère opportun d'inclure les données américaines dans son estimation de la prime de risque du marché. Pour ces motifs susmentionnés, la Régie décide de maintenir la pondération qui a été édictée par cette dernière décision.*

JIESC/BCOAPO/CEC-TGI-24.

TOPIC: **Fair Return Standard**

REFERENCE: **Evidence of Ms. McShane Pages 5-6**

REQUEST:

a) Does Ms. McShane accept Mr. Justice Lamont's definition of a fair rate of return quoted in A1 as a return on other securities of equal attractiveness, stability and certainty to that of the company's enterprise? If not why not?

Response:

Ms. McShane accepts that the fair return is, as defined by the Court, as follows:

> *"By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise."*

b) Would Ms. McShane accept that Mr Justice Lamont's definition came out of changed conditions in the money market and it is to the money market (now capital) market that we should look to estimate fair rates of return? If not why not?

Response:

The question before the Court, as stated at page 193, was:

> *"Had the Board jurisdiction to find as a fact how conditions of the money market had altered between November, 1922 and July, 1927, without any witness testifying at the hearing that an alteration had taken place"*

The central issue before the Court related to the Board's jurisdiction to investigate money market conditions without a witness being called, Mr. Justice Lamont did not say that, "we should look to the money market to estimate fair rates of return".

It should be noted that the Board and the Court were not discussing returns on equity. The return that had been set by the Board was a return on rate base.

Ms. McShane agrees that the Board had considered changed conditions in what was referred to as the money market; the Court decision states that "To properly fix a fair return the Board must necessarily be informed of the rate of return which money would yield in other fields of investment."

c) Given her answers to a) and b) would Ms McShane accept that the yield on government securities, as a default free instrument, is an accurate reflection of investor expected returns from holding those securities? If not why not?

Response:

Ms. McShane agrees that the yield on government bond securities reflects the return that investors expect from holding those securities. This response is independent of, and does not rely on, the answers to a) and b).

d) Would Ms. McShane accept that the cornerstone of any discount rate or required rate of return or fair rate of return is the risk free rate from investing in Government of Canada securities? If not why not?

Response:

Ms. McShane agrees that a risk-free rate is the cornerstone of the Application of the Capital Asset Pricing Model, and that the long-term Government of Canada bond yield is typically used as a proxy for the risk-free rate. She does not agree, however, that it is necessary to start with the yield on long-term Government of Canada bonds to estimate a fair return. Other models can be used to estimate a fair return which do not require starting with the yield on long-term government securities, including risk premium tests which use corporate bond yields as the base to which a premium is applied or the discounted cash flow model.

There is nothing in the Supreme Court of Canada decision in the Northwestern case that suggests that the fair return that a company is allowed should be determined by reference to the risk free rate from investing in Government of Canada securities. To the contrary, the

Northwestern decision refers to comparable ("attractiveness, stability and certainty equal") investments rather than risk free investments.

e) What other "objective" factors that all expert witnesses can agree on, can Ms. McShane point to that drive equity return requirements or fair rates of return, other than the yields on Government of Canada bonds? Please list them and indicate why she feels that they are both objective and commonly accepted by other expert witnesses? If necessary please provide citations to other expert witness testimony both on the part of companies and interveners.

Response:

The historic reviews referenced in the table above were comprehensive. In addition to the historic reviews, there are now a number of reviews that are currently under way. The extent to which these reviews are comprehensive will not be known until they are complete. Ms. McShane has no basis to conclude that the regulators did not consider the full range of information with which they were provided. Given the wide divergence of views of experts, and fact that the preponderance of Canadian utilities have been operating under similar automatic adjustment mechanisms, it is Ms. McShane's view that it becomes increasingly difficult for regulators to abandon the prevailing formula approach. It is, in Ms. McShane's view, imperative for regulators to now do so and provide for returns that meet the fair return standard.

f) Please provide a full list of all ROE adjustment formulae currently in use in Canada, when they were first adopted and when they have been reviewed and/or changed.

Response:

Automatic adjustment mechanisms which are still in use in Canada include:

Province/ Jurisdiction	**Status**	**First Adopted**	**Dates of Reviews between First Adoption and Last Review**	**Last Reviewed**	**Comments**
NEB	Under Generic Review as of July 3, 2009	1995	2001 (for TransCanada)	For TQM for 2007 and 2008	Formula not relied upon for TQM
Newfoundland and Labrador	Under Review	1998	none	Reviewed in 2003 and amended	Settlement for 2007 rates included ROE based on formula as amended in 2003
Québec	Currently Under Review for Gaz Metro	1998	Confirmed in 2004 for Gaz Metro at request of Company	Reviewed in 2007 and amended; suspension of formula requested in 2008 denied	
Ontario	Currently under Review for Electricity Distributors	1997	Reviewed in 2003 for Gas Distributors, and confirmed, Reviewed in 2006 for Electricity Distributors and confirmed	Reviewed in OPG rates proceeding in 2007 and confirmed	
Alberta	Currently under Review in Generic Cost of Capital Proceeding	2004		Adopted in 2004	
British Columbia	Currently under Review for Terasen Gas	1994	Reviewed in 1999 and amended	Reviewed in 2006 and amended	

g) Please indicate whether Ms. McShane judges the reviews indicated in f) above to have been comprehensive and the decisions based on all the evidence put before them by both the company and intervener witnesses; or whether a particular decision was based either on incomplete evidence or faulty analysis.

Response:

The historic reviews referenced in the table above were comprehensive. In addition to the historic reviews, there are now a number of reviews that are currently under way. The extent to which these reviews are comprehensive will not be known until they are complete. Ms. McShane has no basis to conclude that the regulators did not consider the full range of information with which they were provided. Given the wide divergence of views of experts, and fact that the preponderance of Canadian utilities have been operating under similar automatic adjustment mechanisms, it is Ms. McShane's view that it becomes increasingly difficult for regulators to abandon the prevailing formula approach. It is, in Ms. McShane's view, imperative for regulators to now do so and provide for returns that meet the fair return standard.

h) Please indicate whether Ms. McShane would judge similar conclusions made by regulatory tribunals faced with the same sorts of analyses to involve circular reasoning or the lack of independent analysis by the regulatory tribunal involved. In particular, which tribunals would Ms. McShane judge to have been negligent in arriving at their decision on their ROE formula?

Response:

Ms. McShane is not suggesting that regulators have been negligent in arriving at their decisions. To the extent that regulators look to other jurisdictions for the confirmation of their decisions, there is an inevitable amount of circularity. The circularity becomes more problematic when virtually all of the ROEs are determined on the basis of automatic adjustment formulas which yield the same result.

i) Please indicate which tribunals Ms. McShane provided expert testimony to when their ROE formula were either implemented or changed and which she regards as having used circular reasoning rather than basing their decisions on the evidence before them.

Response:

Please see response to JIESC/BCOAPO/CEC IR 1.24(g) above.

JIESC/BCOAPO/CEC-TGI-25.

TOPIC: **Long Canada Bond Yields**

REFERENCE: **Evidence of Ms. McShane Page 6**

REQUEST:

a) For the decline in long Canada bond yields please provide evidentiary support for the notion that equities are not "locked in" similar to long bonds. In particular is it Ms. McShane's view that equities performed well during the 1970s when inflation reached into double figures in Canada? If so please provide evidentiary support.

Response:

The conceptual basis for the conclusion that equities are not locked in similar to bonds recognizes that equities have a greater ability than bonds to maintain purchasing power during a period of inflation. With higher expected inflation, investors would expect both higher input and output prices of the underlying companies' products and services, so that the present value of the expected cash flows are unaffected by the rate of inflation. That is not to say that equities have been a good hedge against inflation over the short-term in inflationary periods, particularly when there are inflationary shocks to the system as there were in the 1970s with the rise in oil prices and the compounding effect of monetary policy, when companies were not able to raise prices to offset rising input costs. In his book, *Stocks for the Long Run*, 4th Edition, 2007, page 205, Dr. Jeremy Siegel concluded that "The message of this chapter is that stocks are not good hedges against increased inflation in the short run. However, no financial asset is. In the long run, stocks are extremely good hedges against inflation, while bonds are not. Stocks are also the best financial asset if you fear rapid inflation since many countries with high inflation can still have quite viable, if not booming, stock markets. Fixed-income assets, on the other hand, cannot protect investors from excessive government issuance of money."

Looking specifically at Canadian market returns, for the post-World War II years in which inflation was in excess of 7%, stocks on average had a positive real return of approximately 1.5%, but the real return on long-term Canada bonds for those same years averaged close to -4.5%.

b) In terms of the supply impact on Long Canada yields, please define what she understands by the break-even inflation rate (BEIR) and confirm that the yield on the nominal bond is depressed for whatever reason the BEIR is a biased low estimate of future inflation? If she can not so confirm please explain why not?

Response:

Ms. McShane understands the break even rate of inflation to be the differential between the yield on conventional or nominal government securities and the yield on similar term inflation-indexed government securities.

c) If in b) above Ms. McShane feels that the yield on the real return bond is similarly depressed, please provide all evidentiary basis for the conclusion that the supply impact is equally felt in these two areas of the bond market.

Response:

Not necessarily. The yield may reasonably reflect long-term inflation expectations, while the real return component is lower than its long-term equilibrium value. Currently, the difference between the yield on nominal long-term Government of Canada bonds and real return bonds (3.85% versus 1.85%) is approximately equal to the most recent (April 2009) consensus forecast of inflation from 2009 to 2019 of approximately 2.0%.

d) Please provide all evidentiary support that the current BEIR is a biased low estimate of future inflation.

Response:

While the supply impacts on the yields of conventional and inflation-indexed bonds may not be identical, the supply of long-term inflation indexed bonds is relatively small compared to the total supply of long-term Government of Canada bonds. Inflation-indexed bonds are an important component of pension funds' asset mix; the long-term target for the Ontario Municipal Employees Retirement System is 5%. The Ontario Teachers' Pension Plan has reduced its exposure to equities and increased its exposure to inflation-sensitive assets including real return bonds. Over the long-term it is reasonable to expect the yield on inflation-indexed bonds to approximately equate to the long-term real growth in the economy. The current yield on the long-term inflation-indexed bond of 1.85% is relatively low compared to the long-term forecast real GDP growth rate of 2.5%, suggesting that the inflation-indexed bond yield is abnormally low.

JIESC/BCOAPO/CEC-TGI-26.

TOPIC: **Comparability of US Utilities**

REFERENCE: **Evidence of Ms. McShane Page 8**

REQUEST:

a) Would Ms. McShane agree that the US and Canadian banking systems, like the utilities, have a similarity in their business and operating environment? If not please discuss the technological differences in US vs Canadian banking.

Response:

Yes, the business and operating environments have similarities. Ms. McShane's testimony does not address the banking industries in the U.S. and Canada; it addresses utilities. It is the similarities between Canadian and U.S. utilities, not the banking systems, which are relevant to the determination of a fair return.

b) Please list all the Canadian and US banks that have either failed or been taken over due to fears surrounding their future profitability, solvency or viability over the last two years.

Response:

While Ms. McShane's evidence and analysis relate to the utility industries, not to the banking industries, she has provided a list of US banks that have either failed or been taken over due to fears surrounding their future profitability in the last two years. These are listed in Attachment 26b. Ms. McShane is not aware of any Canadian bank failures in the last two years. The last bank failures in Canada of which Ms. McShane is aware were in 1985.

c) Please list all the Canadian and US utility holding companies that have either failed or been taken over due to fears surrounding their future profitability, solvency or viability over the last ten years.

Response:

The following investor-owned US utility holding companies have either failed or been taken over due to fears surrounding their future profitability: Enron (due to non-regulated operations), Entergy New Orleans (as a result of Hurricane Katrina), Northwestern Corp. (as a result of non-utility operations), and Pacific Gas & Electric Co. There have been no Canadian utility failures. Note that a significant percentage of the utility assets in Canada are owned by provincial and municipal governments, which provide support to those utilities.

JIESC/BCOAPO/CEC-TGI-27.

TOPIC: **US Fair Return Awards**

REFERENCE: **Evidence of Ms. McShane Page 9**

REQUEST:

a) Ms. McShane refers to US regulators using a variety of cost of equity tests. Please indicate for each of the US utilities in her US tests how their allowed ROE was last set and the weights that the regulator applied to each cost of equity test.

Response:

Ms. McShane does not maintain the requested information. The results of a review of recent decisions[1] in the jurisdictions within which the proxy companies operate to determine the cost of equity tests presented is shown in the table below. While the use of multiple cost of equity tests is the norm, in almost all instances the commission does not specify explicit weights to be applied to the results of particular cost of equity tests.

State & Year	Party Presenting Evidence and Number of Versions of Test Presented if Known	Comments
Georgia (2008)	**Staff:** DCF, Risk Premium and Comparable Earnings **Company:** DCF, CAPM and Comparable Earnings	Decision "strikes a balance" between the Company and Staff witness recommendations
Indiana (2004)	**Staff:** No independent study, analyzed Company testimony **Company:** DCF (6), CAPM, ECAPM, Risk Premium (6)	"Consistent with our analysis of the specific inputs and issues in dispute, we recognize that it is not necessary for us to agree or disagree with the specific inputs or overall cost of equity proposed by any single expert. Rather, our determination regarding the appropriate cost of equity in this matter should be a product of our evaluation of the entirety of the evidence presented on this issue by the various parties."

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[1] In many cases, the most recent decision specifically for the proxy company was a settlement and information on the cost of equity tests utilized is not presented.

State & Year	Party Presenting Evidence and Number of Versions of Test Presented if Known	Comments
Kentucky (2005)	**Staff:** DCF, CAPM **Company:** DCF (2), Risk Premium (4) and CAPM	"The Commission encourages the appropriate use of the DCF, the Risk Premium, and the CAPM methods."
Maryland (2007)	**Staff:** DCF, Risk Premium and CAPM **Company:** DCF, CAPM, ECAPM, Risk Premium (2) and Comparable Earnings(2)	"..considered a broad range of credible return on equity analyses and methodologies…found Staff's cost of equity estimates to be 'most persuasive'"
Massachusetts (2009)	**Staff:** DCF, Risk Premium **Company:** DCF, Risk Premium, CAPM, ECAPM & Comparable Earnings	"…we have considered both qualitative and quantitative aspects of the Company's various methods for determining its proposed rate of return on equity, as well as the arguments of the parties in this proceeding."
New York (2009)	**Staff:** DCF, CAPM, zero-beta CAPM **Company:** DCF, CAPM, zero-beta CAPM and Risk Premium	"We conclude that the Company is correct to contend that all three methods presented in this case involve the use of some subjective judgment. On that basis, and given our recommendation that the Risk Premium Method not be employed, we recommend the DCF result and simple average of the two CAPM results be given equal weight."
Ohio (2009)	**Staff:** DCF, CAPM **Company:** no detail on ROE methodology	Adopted Staff's proposed range
Oregon (2007)	**Staff:** DCF (3) and CAPM as 'check' **Company:** DCF (1) and Risk Premium(3) **ICNU/CUB:** DCF, CAPM and Risk Premium (2)	Results of ICNU/CUB framework provided "suitable starting point" for ROE discussion as the DCF results were 'cross-checked' against the results of several other methods
Pennsylvania (2007)	**Staff:** DCF only **Company:** DCF, CAPM, ECAPM	"We will also use the results of the CAPM and ECAPM methods as a check of the reasonableness of our DCF derived equity return calculation."

State & Year	Party Presenting Evidence and Number of Versions of Test Presented if Known	Comments
Washington, D.C. (2008)	**Staff:** DCF (2), CAPM **Company:** DCF(2), Risk Premium(3) and CAPM	"… the Commission finds that, while substantial weight should be given to the DCF method, exclusive reliance on that method would not be appropriate. Accordingly, the Commission will give weight to the alternate approaches presented in this proceeding."

b) Further to a) above please indicate (complete with citations) which US jurisdictions apply any material weight to either the comparable earnings test as implemented by Ms. McShane or CAPM.

Response:

Ms. McShane has not done a detailed survey of all the regulatory jurisdictions.

c) Please indicate the "average" period between rate reviews for the US utilities included in Ms. McShane's sample and whether regulatory lag would tend to increase or decrease the sensitivity of a US utility's allowed ROE to interest rate changes.

Response:

U.S. utilities do not have a prescribed schedule for rate reviews; except where they are subject to a rate freeze, utilities have the flexibility to apply for new rates as they deem warranted. The allowed ROEs utilized in the regression are only those determined by regulators in the specific year. The issue of regulatory lag is thus not relevant to the regression.

d) Further to c) above please confirm that Ms. McShane's 0.55 estimate comes from regressing the allowed ROE against actual (lagged) and not forecast long term interest rates.

Response:

Confirmed. However, the actual interest rates are entered into the regression with a six-month lag. As noted in footnote 3, page 9, the lag was introduced "to take account of the fact that the date of the decision lags the period covered by the market data on which the ROE decision was based."

JIESC/BCOAPO/CEC-TGI-28.

TOPIC: **Karen Taylor's Remarks**

REFERENCE: **Evidence of Ms. McShane Page 11**

REQUEST:

In terms of Karen Taylor's remarks please confirm that these were made after TransCanada took a request for review and variance of the NEB's confirmation of its ROE formula in 2001 to the Appeals Court and were rejected.

Response:

Confirmed. Ms. Taylor's comments were made in late 2006. The Appeals Court decision was in 2004.

JIESC/BCOAPO/CEC-TGI-29.

TOPIC: **Default Risky Bond Yields**

REFERENCE: **Evidence of Ms. McShane Page 11**

REQUEST:

a) Please provide a detailed explanation of how yields to maturity on default risky bonds are calculated and explain why they are commonly called "promised" yields.

Response:

The yield to maturity is the rate of return an investor would achieve if he or she held a bond to maturity and all payments were made as promised. It is calculated for a default risky bond as the rate of return which equates the current price to the present value of the promised payments. The yields to maturity on default risky bonds are sometimes called promised yields because they are the returns an investor will achieve if he or she receives payment of all the coupons and the principal at maturity as promised, that is, the issuer does not default.

b) Please provide a detailed explanation on whether in Ms. McShane's judgement a promised yield on a default risky bond is an expected rate of return on a stock as calculated by her DCF and risk premium studies.

Response:

The promised yield on a default risky bond is not an expected return on a stock. The promised yield on a bond is explained in part a) above. The promised yield is equal to the expected return on a bond when there is no default risk. The application of the DCF tests and risk premium tests results in an expected return on equity.

c) If in Ms. McShane's judgement yields on default risky bonds are not expected rates of return please explain in detail the factors that go into determining promised yields and whether these are the sole factors that affect equity rates of return. If they are not please discuss the additional factors that affect equity returns.

Response:

The promised yield is a function of market rates of interest (which reflect a real rate plus the expected rate of inflation), the duration of the bond, the probability of default, the expected recovery in the case of default, the liquidity of the bond and investors' risk aversion. Additional factors which would impact the expected return on equity include business risk from an equity investor's perspective, financial leverage, expected growth in earnings (which would be a function of the industry and of the economy), dividend yield, and returns available from alternative investments of comparable risk.

d) Please explain in detail how promised yields can be compared to expected returns without making any adjustment? Please provide a theoretical model that Ms. McShane relies on to make such a judgment and provide the relevant citations.

Response:

The expected return on a bond is equal to the risk-free rate plus a risk premium for market risk. The promised yield on a bond includes both of those elements plus a default premium. The discussion on page 11 is to trends in yields on a basket of A rated utility bonds, where the probability of default is small, and consequently the difference between the expected return on the bonds and the promised yield on the bonds is small. Thus trends in yields and spreads on A rated utility bonds can be used without adjustment to the yields or the spreads as one indicator of trends in the utility cost of equity and equity risk premium.. Since both debt and equity holders have financial claims on the same cash flows of a corporation, all other things equal, it makes logical sense that an increase in the firm's cost of debt will be accompanied by an increase in its cost of equity. Ms. McShane would further note that corporate spreads are a widely used variable for estimating equity returns and various empirical studies have shown that there is a positive relationship between corporate spreads and the equity risk premium, i.e. Chen, N. F., R. Roll and S. A. Ross, 1986, "Economic Forces and the Stock Market", *Journal of Business*, 59, pages 383-403; Harris, R.S. and F.C. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts", Summer 1992, *Financial Management*, pages 63-70.

To the extent that Ms. McShane relies directly on utility bond spreads for the estimation of the cost of equity (i.e. in the DCF based equity risk premium test or the relationship between allowed returns, government bond yields and spreads), she has considered the empirical relationship indicated by the relevant data.

e) On Page 12 Ms. McShane refers to the difference between the allowed ROE and the TGI bond yield as being 2.4-2.7% in 1999 and 2006. If this difference increases from the referenced 1.4% at the time of her testimony back to 2.0-2.7% level at the time of the hearing would Ms. McShane accept the Board's ROE formula as being reasonable? If not why not?

Response:

No. First, the empirical evidence indicates that the ROE is not as sensitive to long-term government bond yields as the formula indicates. Second, the analysis that Ms. McShane conducted, which takes into account factors other than the interest rate environment, i.e., returns available to investments of comparable risk, indicates a fair ROE is materially higher than the formula ROE would indicate.

f) In 2003 Ms. McShane provided testimony on behalf of the ATCO group of companies before the Alberta EUB. At that time ATCO recommended that the AEUB automatically call a hearing to review its ROE formula if it produced a utility risk premium less than half the spread between "A" rated utility debt and the equivalent term long Canada bond. Can Ms. McShane confirm this condition and would she accept the BCUC's ROE formula satisfied this condition? If not why not?

Response:

The proposal was that the formula should be reviewed if the spread on an agreed-upon index of long-term A-rated utility bond yields exceeds 50% of the benchmark utility risk premium implicit in the allowed return. She would not accept the BCUC's formula if it simply met this condition. It is important to recall that the proposal in the referenced proceeding was premised on both the applied for return on equity and the proposed formula (which was to vary the ROE by 50% of the change in long-term Canada bond yields).

JIESC/BCOAPO/CEC-TGI-30.

TOPIC: **Risk Assessments**

REFERENCE: **Evidence of Ms. McShane Pages 12-13**

REQUEST:

a) Please indicate whether share prices fall when investors perceive the economy is going into recession and earnings are expected to fall?

Response:

Typically, yes.

b) Given Ms. McShane's answer to a) above how much of the increase in dividend yields does she allocate to declining growth in earnings versus increases in risk aversion? Please explain in full.

Response:

It is not possible to be precise about the extent of the decline in the market which is due to lower expected earnings and what part is due to increased investor uncertainty or increased risk aversion. The components are not additive, as an increase in the cost of equity with no change in expected earnings themselves would result in a higher yield than would be the case if the same increase in the cost of equity were simultaneously accompanied by a decrease in expected earnings growth. Between March 2006 and March 2009, the yields on 10-year BBB rated corporate bond yields had increased by 225 basis points. Thirty-year A rated bond yields had increased by close to 200 basis points. These increases provide a perspective on the likely corresponding increase in the market cost of equity.

c) Please indicate whether or not the value of the VIX is the implied volatility from a call option on the TSX60 index.

Response:

It is not confirmed. The VIX is a measure of the implied volatility from a wide range of options based on the S&P 500. It is the symbol for the Chicago Board Option Exchange's volatility index. The MVX is the symbol for the Montreal Exchange's implied volatility index. It is calculated from the current prices of at-the-money options on the shares of the Canadian S&P/TSX 60 Fund. Implied volatilities are forward-looking measures of uncertainty.

d) Please indicate all financial and economic theory that indicates that observing an increase in volatility means that investor risk aversion or attitude towards risk has increased.

Response:

An increase in volatility does not *per force* mean that investor risk aversion has increased. The VIX is widely considered to be a measure of investor sentiment and risk aversion. Robert Whaley, Professor of Business Administration at Duke University, in "The Investor Gauge: An Explication of the CBOE VIX", *Journal of Portfolio Management*, Spring 2000, states, "VIX is said to be the 'investor fear gauge'. We say 'fear' because investors are averse to risk."

e) Please indicate whether Ms. McShane accepts basic financial theory that an investor's risk premium is determined by the product of the perceived risk and risk aversion. If not why not?

Response:

Confirmed. Increased risk aversion results in an increase in the required return for a given level of risk, i.e., in the context of the CAPM, the slope of the security market line increases.

JIESC/BCOAPO/CEC-TGI-31.

TOPIC: **NEB's TQM Decision**

REFERENCE: **Evidence of Ms. McShane, Page 16**

REQUEST:

a) With reference to the NEB's TQM decision please provide the full passage in the decision that indicates that the NEB believes that US companies were relevant proxies for the cost of capital for all Canadian utilities rather than pipelines that have pipe on both sides of the border and are fully integrated into one continental pipeline system.

Response:

The NEB did not state that it believes U.S. companies were relevant proxies for the cost of capital for all Canadian utilities, nor did it state that U.S. companies were only relevant to pipelines that have pipe on both sides of the border and are fully integrated into one continental pipeline system. At page 80, of the decision, the NEB stated that it "found market returns of U.S. companies to be relevant to the cost of capital of Canadian firms, as U.S. market returns can be a useful proxy for investment opportunities in the increasingly integrated global capital markets."

b) Please confirm that the NEB's TQM decision was specifically restricted to TQM for 2007 and 2008 just as its 2001 decision was restricted to the TransCanada Mainline.

Response:

The decision was specifically for TQM for 2007 and 2008. The NEB did however reach conclusions (as per pages 15 and 16 of Ms. McShane's testimony) that are generic in nature even though the conclusions were applied specifically to TQM. Further, the NEB has initiated a review of the RH-2-94 decision as indicated in response to BCUC IR 1.1.2.

c) Please indicate whether the NEB regarded TQM's business risk as having increased or decreased since 1994 and why.

Response:

Increased, due to increased supply, competitive and market risk (which are interrelated).

d) Please indicate whether in its 2001 and 2004 decision the NEB regarded the TransCanada Mainline's business risks as having increased or decreased and how the NEB responded to that assessment.

Response:

Increased. In those decisions, the NEB increased the deemed equity ratio.

JIESC/BCOAPO/CEC-TGI-32.

TOPIC: **Fair Return Standard**

REFERENCE: **Evidence of Ms. McShane, Pages 18-28**

REQUEST:

a) With reference to the fair return standard and Ms. McShane's prior references to the NEB's TQM decision, please indicate whether the NEB stated that there were three standards or three implications of one standard and provide the full statement and citation.

Response:

In the TQM decision on pages 6-7, the NEB stated,

> *"Therefore, the Board reaffirms the Fair Return Standard as articulated on page 17 of the RH-2-2004, Phase II Decision. The Fair Return Standard requires that a fair or reasonable overall return on capital should:*
>
> - be comparable to the return available from the application of the invested capital to other enterprises of like risk (comparable investment requirement);
> - enable the financial integrity of the regulated enterprise to be maintained (financial integrity requirement); and
> - permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (capital attraction requirement)."

As per footnote 14 to the citation, the NEB noted that that in previous decisions it had used the word "standard" for each of the elements of the Fair Return Standard. It then stated that "the Board has changed the description to "requirement" to clarify that there are three requirements which should be met under the Fair Return Standard."

b) Does Ms. McShane regard the rates that Canadian utilities have been paying for debt capital as fair and reasonable?

Response:

Yes.

c) Please provide all the weekly copies of the RBC publication listed on page 28 since January 2, 2007.

Response:

The requested publications are subject to copyright protection. The TGI spreads reported in the publications from January 2007 to the end of May 2009 are contained in Attachment 32c. RBC stopped distribution of the publication at the end of May 2009. The spreads for TGI as of July 13, 2009 are found in response to BCUC IR 1.53.1.

JIESC/BCOAPO/CEC-TGI-33.

TOPIC: **Comparable Returns**

REFERENCE: **Evidence of Ms. McShane, Page 30**

REQUEST:

a) Would Ms. McShane agree that when market interest rates go down, older equivalent maturity bonds with higher interest rates sell on higher prices so their yields to maturity, based on current market prices are approximately the same? If not why not?

Response:

Yes.

b) In accessing the debt markets does Ms. McShane believe that an entity has to issue debt at the old higher interest rate in order to compete with those higher interest rate bonds or that bonds can be issued at the new lower market interest rate? Please explain in detail.

Response:

No. The old bonds issued at a higher coupon would trade at a premium to par value and yield the lower market rate. The entity would issue new bonds at the market rate.

c) If bonds can be issued at the new lower market interest rate would Ms. McShane accept that a firm can raise capital even when there are bonds with higher coupon rates in the market? Would Ms. McShane agree that such a situation does not compromise the fair return standard? If she disagrees please explain in detail.

Response:

Yes, because all the bonds would trade at the current market price irrespective of the initial coupon. Such a situation does not compromise the fair return standard.

d) If a utility in another jurisdiction has a higher allowed ROE due to regulatory lag would Ms. McShane argue that this compromises the fair return standard based on the arguments on page 30?

Response:

Ms. McShane does not understand the premise of the question. At page 30, Ms. McShane indicates that the fair return standard requires that the returns be comparable to the returns of comparable risk companies. Although not explicitly stated at page 30, it would not be reasonable to consider returns that might have been adopted under materially different economic and capital market conditions as a reasonable benchmark or indicator of comparable returns.

e) Please explain in detail whether allowing a lower ROE based on current capital market conditions violates the fair return standard if other utilities are on higher allowed ROEs due to regulatory lag.

Response:

Please see the response to JIESC/BCOAPO/CEC IR 33(d) above.

JIESC/BCOAPO/CEC-TGI-34.

TOPIC: **Business Risk**

REFERENCE: **Evidence of Ms. McShane, Page 31**

REQUEST:

a) Please provide a cost comparison of natural gas against its major competitor fuels (fuel oil and electricity) for TGI's major rate classes for each year since 2000.

Response:

Please refer to Attachment 34a for a cost comparison of Terasen rates against electricity and fuel oil for the Lower Mainland Rate Classes 1, 2, and 3.

b) Please indicate TGI's current depreciation rate based on its major asset classes for each year since 2000.

Response:

Please refer to the response to JIESC/BCOAPO/CEC IR 1.7a.

c) Please file a copy of the last depreciation study TGI filed with the BCUC.

Response:

Included as Attachment 34c, is the updated depreciation study dated December 31, 2007. This study was prepared by Gannett Fleming and was recently filed as part of TGI's 2010-2011 Revenue Requirement Application.

d) Please indicate whether TGI has filed any material change statements in regards to its business risk over the last five years and provide copies.

Response:

TGI's material change reports are publicly available on www.sedar.com. TGI has not filed a material change report with respect to it business risk in the last five years. TGI is a reporting issuer with publicly issued debt. It maintains its disclosure on risk factors current through its quarterly management discussion and analysis as well as its annual information form. The lack of a material change report with respect to evolving business risks does not mean that TGI's business risk has not increased. The requirement to file a material change report is based on securities disclosure laws, intended to inform a class of securities holders of a significant event or occurrence that in itself could have a material impact on the value of its securities, in this case, debt investors. The *Securities Act* (British Columbia) defines a "material change" as follows:

> "(i) a change in the business, operations or capital of the issuer that would reasonably be expected to have a significant effect on the market price or value of a security of the issuer, or
>
> (ii) a decision to implement a change referred to in subparagraph (i) made by
>
> (A) the directors of the issuer, or
> (B) senior management of the issuer who believe that confirmation of the decision by the directors is probable."

TGI, as outlined in this Application, has experienced an increase in its business risk. However, based on the Company's interpretation of its disclosure requirement, the increased business risk has not warranted separate disclosure by way of a material change report.

e) Please indicate whether the MD&A discussion in regulatory filings with the OSC accurately reflect the company's view of its business risk.

Response:

Yes. As indicated in the response to JIESC/BCOAPO/CEC-TGI-34(d) above, the Company maintains its disclosure on risk factors current through its quarterly and annual management discussion and analysis as well as its annual information form.

A copy of the first quarter March 31, 2009 MD&A is attached and the last annual December 31, 2008 MD&A which is incorporated by reference was filed in response to BCUC IR 1.84.7.

f) Please indicate whether in Ms. McShane's view TGI has greater lesser or equivalent business risk to EGDI, Union Gas and ATCO Gas and provide the supporting rationale.

Response:

In Ms. McShane's view, TGI is of reasonably similar business risk to ATCO, Enbridge and Union Gas. TGI has somewhat greater short-term revenue protection than the other three LDCs, by virtue of its RSAM, which has both weather and customer consumption protection as relates to weather-sensitive customers. By comparison, ATCO has a weather deferral account but no customer consumption protection; Enbridge and Union have mechanisms for reduction in customer consumption, but no weather protection. In this regard, the BCUC has in the past attributed 10 basis points in ROE to the RSAM. All of the gas distributors either have purchased gas adjustment clauses (which include pipeline charges) or in the case of ATCO, which no longer sells gas but has a deferral account for pipeline charges. In total TGI recovers approximately one-third of its fixed costs in a fixed customer or demand charge, compared to 55% for ATCO, 50% for Union (including its contract storage and transportation), and 25% for Enbridge. With respect to customer profile, as indicated in part (j) below, TGI has higher exposure in terms of margin to industrial customers than either ATCO or Enbridge. Its industrial load is more concentrated than either Enbridge's or Union's, with relatively high exposure to a single industry, pulp and paper. While Union has a higher proportion of margin attributable to industrial customers than TGI (14% vs approximately 9%), approximately 25% of Union's total margin is attributable to transmission and storage volumes. Union's regulated transmission operations are underpinned by long-term contracts largely with pipelines and LDCs. With respect to competition, none of the other three LDCs faces significant competition from alternative energy sources in its residential and commercial sectors, in contrast to TGI, which faces significant competition from electricity. On balance, TGI faces somewhat lower short-term revenue risks, but higher competitive risk than the other three LDCs.

g) Please indicate the extent to which Ms. McShane's business risk assessment has taken into account the RSAM available to TGI relative to EGDI, Union Gas and ATCO Gas.

Response:

Please refer to the response to JIESC/BCOAPO/CEC IR 1.34(f) above.

h) Please indicate the extent to which Ms. McShane's business risk assessment has taken into account the composition of revenues earned by TGI relative to EGDI, Union Gas and ATCO Gas, that is, revenue broken out according to industrial, commercial and residential revenue.

Response:

Please refer to the response to JIESC/BCOAPO/CEC IR 1.34(f) above.

i) Please provide the revenue breakdown for TGI, EGDI, Union Gas and ATCO Gas according to industrial, commercial and residential revenue for each year since 2000.

Response:

Ms. McShane has not compiled data for each year since 2000. The data below reflect the most recent margin (revenue net of gas supply related costs) percentages available by customer class.

ATCO Gas (2008)		**Enbridge Gas – Distribution only (2009)**		**TGI (2008)**	
Residential	72.5%	Residential	66.3%	Residential	61.3%
Commercial	25.4%	General Service	29.6%	Commercial	28.0%
Industrial	1.9%	Industrial Large Volume	3.7%	Firm	1.4%
Irrigation	0.2%	Wholesale	0.3%	Industrial	9.2%

Union Gas (2007)	
Residential:	45%
Small Volume	16%
Industrial/Utility	14%
Transmission/Storage:	25%

j) Please provide the annual growth in rate base for TGI, EGDI, Union Gas and ATCO Gas for each year since 2000 and the forecasts for 2009 and 2010.

Response:

The data which were available to Ms. McShane are provided below.

Company	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
ATCO	0.6%	2.5%	2.5%	6.8%	11.7%	13.5%	NA
Enbridge	0.0%	5.9%	6.2%	3.1%	NA	NA	NA
TGI	2.5%	4.4%	1.4%	-0.7%	2.0%%	-2.5%	5.1%
Union	-2.0%	1.2%	3.8%	0.2%	4.5%	3.9%	1.8%

JIESC/BCOAPO/CEC-TGI-35.

TOPIC: **Relative Credit Metrics**

REFERENCE: **Evidence of Ms. McShane, Pages 32-40**

REQUEST:

a) With reference to the comparison with the TransCanada pipelines please confirm the following:

a. The 36% for Foothills and the TCPL BC System and 40% for the Mainline arose from negotiated settlements where other items were traded off by the shippers. If not confirmed, why not.

Response:

They were negotiated settlements. Typically in settlements, there are trade-offs.

b. For the Mainline please confirm that the shippers negotiated for the Mainline to repurchase its junior subordinated debentures (JSDs) and apply the capital gain to reduce tolls. If not confirmed, why not.

Response:

Confirmed.

c. The NEB regards the business risk of all the export pipelines as having increased due to the maturing of the WCSB and has also increased their depreciation rate accordingly.

Response:

Ms. McShane is unable to confirm that the NEB has concluded that it regards the business risk of all the export pipelines as having increased due to the maturing of the WCSB and has also increased their depreciation rate accordingly.

d. Shale gas development may have a material effect on natural gas reserves and production.

Response:

As stated by the NEB in its 2009 decision for Trans Quebec & Maritimes Pipelines Inc., (RH-1-2008, March 2009) "Unconventional supply, including CBM and shale gas, is more uncertain given their early stages of development. Although unconventional supply is expected to at least partially offset future declines in conventional production from the WCSB, the extent to which it will and when this may occur remains uncertain."

e. Please file the latest TransCanada throughput study.

Response:

The most recent throughput study is publicly available on the Alberta Utilities Commission website, filed by NGTL as part of their evidence in the generic cost of capital proceeding (Proceeding 85).

b) For the electric transmission and distribution companies on page 33:

a. Please confirm that the Union Gas 36% common equity was the result of a negotiated settlement and indicate what the interveners traded off to agree to the increase.

Response:

It is confirmed that Union Gas' 36% common equity ratio, an increase of 1%, was the result of a negotiated settlement. The Settlement Agreement was a comprehensive agreement covering many issues. As with virtually all negotiated settlements, the negotiations are confidential and the decision does not indicate the 'trade-offs' that both sides made in reaching agreement.

b. For the Electric distribution companies (Discos) please confirm that the OEB simply removed the lower common equity ratio of 35% and moved all Discos to the same 40% so that the vast bulk of the Ontario Discos had an unchanged common equity ratio. If not confirmed, why not.

Response:

In its report entitled *The Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (December 2006) the Board eliminated three categories of size-related deemed common equity ratios and opted to deem a single capital structure containing 40% equity for all distributors. In its remarks the Board stated that the industry had undergone significant change over the period since 1998 as it transitioned from an industry characterized by many, very small distributors toward one of fewer and larger distributors.

c) With respect to the unsolicited rating by S&P please provide the ratings history of TGI by S&P, the reasons why TGI stopped paying for the rating and the press release when the decision was announced.

Response:

Terasen Gas decided early in 2004 to discontinue the engagement of S&P to provide credit ratings on the debt of Terasen Gas. The decision of TGI to discontinue the engagement of S&P was the subject of information requests in the 2005 cost of capital proceeding. As stated in response to BCUC IR 1.57.2 in that proceeding, "To initiate or maintain a credit rating relationship, an issuer must believe that the costs of soliciting credit ratings (primarily fees charged by the agency and management's time spent maintaining the relationship) will be less than the benefits of having credit ratings, whether in a lower cost of capital, enhanced access to capital, or a combination thereof. Terasen's assessment at the time was that the benefits of the S&P ratings did not exceed the costs of maintaining the rating relationship." In its annual reports since that time, Terasen Gas has stated that it believes the credit ratings issued by Moody's and DBRS will be sufficient to service the requirements of creditors and maintain the Company's access to capital. S&P continues to provide an unsolicited rating on Terasen Gas' outstanding debt based on publicly available information. TGI did not issue a press release. TGI did file a prospectus supplement on March 11, 2004, which is included in Attachment 35c.

The table below presents the ratings history for TGI's senior unsecured debentures by S&P from May 2001 to present.

19-Jun-2007	A
26-Feb-2007	BBB/Watch Pos
30-May-2006	BBB/Watch Neg
06-Dec-2005	BBB
02-Aug-2005	BBB/Watch Neg
26-Jun-2003	BBB
19-Nov-2002	BBB+/Watch Neg
08-May-2001	BBB+

d) With respect to the Moody's quote on page 35 please provide the full quote and confirm that Mr. Carmichael's quotation on page 39-40 is accurate and that Moody's regards the BCUC's protective regulatory environment as offsetting the straight statistical comparison.

Response:

With respect to the quote on page 35, Ms. McShane utilized the entire quote from the Moody's *Credit Opinion Terasen Gas Inc.*, May 27, 2008. Similarly, Mr. Carmichael has accurately and completely set forth the statement contained in the Moody's report. As set forth in the quote presented by Mr. Carmichael, the supportive regulatory regime partially offsets the results of the rating methodology model by increasing the rating one notch above that implied by the rating methodology model, with the "one to two notch band that Moody's rating methodologies aim to achieve."

e) Please explain why Ms. McShane feels that it is not necessary to note Moody's judgment of the supporting nature of the BCUC regulatory environment.

Response:

As Moody's affords TGI an implied Aa rating as set forth on Table 4, page 35, it is clear that Moody's considers TGI to operate in a supportive regulatory environment, similar to the median rating in this category for the LDCs in Ms. McShane's proxy utility sample (Aaa/Aa). Ms. McShane notes Moody's assessment of TGI's business risk as relatively low. As stated on page 33, lines 861-863, the regulatory support factor is afforded 10% weighting by Moody's as compared to 60% weighting for financial strength and flexibility.

f) With respect to the Canadian utilities please calculate the ratios in Schedules 5 separately for the private investor owned and government owned utilities and explain why Ms. McShane chose to compare TGI with Crown and government owned entities rather than private investor owned utilities.

Response:

The calculations are shown in Attachment 35f. The comparison is to all Canadian utilities with rated debt including Crown and government owned entities but not solely. The table below shows that TGI ranks below the private companies in all four credit metric categories.

	Common Equity Ratio	EBIT Coverage	FFO/Debt	FFO Coverage
All Private Companies ex. TGI	39.4%	2.4	13.8	3.1
Terasen Gas Inc.	34.8%	2.0	9.1	2.4

Ms. McShane's considered that it was reasonable of all Canadian utilities which are rated, not guaranteed and which are regulated on a stand-alone basis by their respective regulators to gauge the overall level of credit metrics which have been maintained by various utility sectors and the regulated sector as a whole.

g) For the US utilities in Table 6 Ms. McShane has restricted her sample to utilities with "A" bond ratings. Please provide equivalent data for all US utilities regardless of their bond rating so the total population of US utilities can be analysed similar to the total population of Canadian utilities that she uses.

Response:

The calculations are shown in Attachment 35g. The comparison is to all Canadian utilities with rated debt including Crown and government owned entities but not solely. The table below shows that TGI ranks below the private companies in all four credit metric categories.

	Common Equity Ratio	EBIT Coverage	FFO/Debt	FFO Coverage
All Private Companies ex. TGI	39.4%	2.4	13.8	3.1
Terasen Gas Inc.	34.8%	2.0	9.1	2.4

Ms. McShane's considered that it was reasonable of all Canadian utilities which are rated, not guaranteed and which are regulated on a stand-alone basis by their respective regulators to gauge the overall level of credit metrics which have been maintained by various utility sectors and the regulated sector as a whole.

h) Please provide the schedules Ms. McShane used for US electric utilities in her Ontario Power Generation testimony in 2007 and explain in detail why she has chosen to compare the total population of Canadian utilities to a restricted sample of US utilities.

Response:

Ms. McShane relied on a benchmark sample of utilities in her OPG testimony as the basis for estimating the "benchmark" utility cost of equity. The relevant schedules are provided in Attachment 35h. As OPG is an electricity generator, Ms. McShane used alternative samples made up solely of vertically integrated electric utilities and electric utilities with a high proportion of generating assets to estimate the difference in the cost of capital between OPG and the benchmark. In this proceeding, Ms. McShane similarly relied on a benchmark sample of U.S. utilities to estimate the cost of capital for TGI. Since TGI was determined to be of similar risk to the benchmark, there was no requirement to rely on alternative samples to establish a differential cost of capital with the benchmark.

JIESC/BCOAPO/CEC-TGI-36.

TOPIC: **Long Canada Forecast**

REFERENCE: **Evidence of Ms. McShane, Page 44**

REQUEST:

a) Please update your long Canada forecast for 2010 and provide the referenced pages from the Consensus forecast.

Response:

The average yield on long-term Canada bonds for the first six months of 2009 has been 3.8%. The three-month forward Consensus Forecast 10-year Government of Canada forecast as of June 2009 is 3.3% and the recent spread between 10-year and 30-year Canada bond yields has been approximately 0.50% indicating a long-term Canada forecast of approximately 3.8%. Based on the actual yields and the 3.8% forecast three months forward, the average yield for 2009 would be 3.8%.

For 2010, the 12 month forward forecast of 10-year Canada bonds is 3.8%. With an unchanged spread of 0.50%, the forecast 30-year Canada for 2010 is approximately 4.3%. The relevant pages from the June 2009 consensus forecast are provided in Attachment 36a.

b) Is it Ms. McShane's judgment that the Consensus Economics forecast has been and is an accurate forecast of the future long Canada yield? If so, please provide the evidentiary basis for this.

Response:

As utilized to estimate the following year's actual average yield, the consensus forecasts have produced estimates of the 30-year Government of Canada bond yield which have been approximately 0.40% higher than the actual 30-year yields from 1995-2008. Since movements in interest rates are a function of multiple underlying variables, including the state of the domestic and global economies, monetary and fiscal policy, and not inconsequentially, human behaviour, forecasts of interest rates (as with any other variable) are subject to forecast error. Given the decline in long-term Canada bond yields from close to 9.5% in 1995 to less than 3.5% in 2008, an average difference between the actuals and forecasts of less than 0.50% suggests that the forecasts have been reasonably accurate on average.

c) Please indicate why the best forecast for next year's 30 year yield cannot be obtained from the current yield curve?

Response:

While estimating forward yields from the spot yield curve is an alternative to relying on a consensus forecast, there is no a priori reason that that approach will turn out to have been a better forecast than the consensus. Further, the construction of a forward yield from a 'spot' yield curve is not practicable because (1) the yield curve between 10 and 30 years is an interpolation; and (2) there are no Government of Canada bonds longer term than 30 years from which to estimate the 30-year forward yield. Any risk premium analysis, which is forward looking, should reflect investors' outlook for interest rates. The consensus forecast is a transparent means of representing investors' expectations for the long-term Canada bond yield.

JIESC/BCOAPO/CEC-TGI-37.

TOPIC: **Investment Flows**

REFERENCE: **Evidence of Ms. McShane, Pages 45-7**

REQUEST:

a) If only 47% of Canadian outward portfolio investment is to the US why should sole reliance be placed on historic US equity risk premiums?

Response:

Ms. McShane does not place sole reliance on the U.S. historic equity risk premiums. (See page 48, lines 1194-1197, page 51, lines 1255-1259 and lines 1273-1275) The U.S. is by far the most important recipient of Canadian portfolio and direct investment abroad. In terms of portfolio investment, portfolio investment in the U.S. exceeds the next largest recipient (the U.K.) by over 5 to 1. The two economies are highly integrated. The U.S. accounts for approximately three-quarters of the exports of Canada and the U.S. provides approximately 50% of Canadian imports. There has been a high degree of correlation between the equity markets in the two countries. In terms of relative risk, the equity markets have exhibited similar levels of volatility in returns.

b) If US interest rates are expected to be 0.20% higher than in Canada why would we expected equity rates of return to be the same?

Response:

While, in principle, all other things equal, a higher interest rate environment suggests a higher inflation and higher cost of capital environment generally , a differential in long-term interest rate forecasts (which are subject to forecast error) of 0.2% is not a material difference.

c) In Ms. McShane’s judgement is the US treasury yield a correct indicator of a US risk free rate in view of the US$ position as the world’s reserve currency? If Ms. McShane believes it to be unaffected by liquidity considerations please provide the evidentiary basis for such an assumption.

Response:

The U.S. Treasury yield may understate the "true" U.S. risk-free rate inasmuch as the U.S. dollar is the reserve currency and Treasuries are valued for their liquidity. Factors such as a flight to quality or a Treasury buy back of securities may increase the price investors are willing to pay (lowering the yield) for the liquidity value of U.S. Treasuries.

d) On page 49 Ms. McShane estimates the realized arithmetic market risk premium in Canada at 4.6%, but in her estimates she uses 6.75% (page 57). Please provide the evidentiary basis for assuming that Canadian investors will earn an average 2.15% going forward more than they have earned for the last 60 years. In other words how are they going to earn this extra risk premium?

Response:

As explained in Ms. McShane's testimony, the historic risk premium (the difference between returns on stocks and bonds) in Canada reflects a significantly higher return on bonds than is impounded in current and expected bond yields. The higher risk premium relative to history primarily reflects an expected value of equity returns similar to history but lower bond returns.

e) In light of d) above and the reduction in investment barriers, if capital leaves Canada for other areas due to higher rates of return, is it Ms. McShane's judgment that a reduction in demand for Canadian equities will increase or decrease their value? If the answer is decrease, how can Canadian investors expect to earn higher returns in the future?

Response:

Ms. McShane assumes that the question is asking how Canadian investors can expect to earn higher returns on Canadian equities in the future. Ms. McShane's estimated equity return for the market is not premised on a material difference between expected future and historic equity market returns. A flight of capital would cause values to decline. A revaluation would reduce prices so that that going forward, investors would be able to earn their required returns.

JIESC/BCOAPO/CEC-TGI-38.

TOPIC: **Investment Flows**

REFERENCE: **Evidence of Ms. McShane, Page 51**

REQUEST:

a) Ms. McShane calculates the average common equity return in Canada on page 51 over different time horizons. Please provide the average CPI rate of inflation over those same time horizons and the real rate of return.

Response:

The requested real returns are presented below:

	1924-2008	**1947-2008**
Returns	11.3%	11.6%
Inflation	3.1%	4.2%
Real Returns	8.2%	7.4%

b) Please indicate what Ms. McShane's forecast long run inflation rate is and the expected return on the Canadian equity market given the real rate of return estimated in a) above. If the long run inflation forecast exceeds the mid point of the Bank of Canada's range please indicate why she expects the Bank not to be able to enforce its policy objectives.

Response:

The most recent (April 2009) long-term (2009-2019) consensus forecast of inflation is approximately 2.0%, consistent with the mid-point of the Bank of Canada's range. Adding the historic average real return to the forecast long term rates of inflation would produce returns in an approximate range of 9.5% to 10.0%. That calculation, however, presumes a one-for-one relationship between the real return and the rate of inflation. A review of the historical return and inflation values over the period 1924-2008 shows the following:

Inflation Range	Nominal Equity Return	Average Rate of Inflation	Real Equity Return
Less than 1%	14.5%	-1.5%	16.0%
1-3%	12.8%	1.9%	10.9%
3-5%	4.8%	4.1%	0.7%
Over 5%	12.5%	9.2%	3.3%

The historic data indicate that the real rate of return on equities has generally been lower at higher rates of inflation. The observed negative relationship between the real return and the inflation rate support reliance on nominal historic returns for the purpose of estimating the equity risk premium from historical data.

c) In the calculation of the market risk premium of 6.75% would she agree that the realized inflation rate over the period that generated the 11.0-12.0% equity return differs from the inflation forecast implicit in the current 4.25%-5.25% forecast long Canada bond yields? Why or why not?

Response:

Yes. The long-term Canada bond yield forecasts as provided by the Consensus Economics *Consensus Forecasts* presumably are consistent with the corresponding consensus forecast rates of inflation, referenced in response to 38(b) above. The historic rates of inflation are provided in response to 38(a) above.

JIESC/BCOAPO/CEC-TGI-39.

TOPIC: **Relative Standard Deviations**

REFERENCE: **Evidence of Ms. McShane, Page 52**

REQUEST:

Please provide all evidentiary support for the proposition that relative risk can be measured by the ratio of the standard deviations of two undiversified portfolios.

Response:

The relative standard deviation model is one of the models described in Ibbotson, *2008 Valuation Yearbook*, for estimating the international cost of capital. Relative standard deviations are also used in the Goldman modified beta approach for the same purpose.

JIESC/BCOAPO/CEC-TGI-40.

TOPIC: **Risk Measures**

REFERENCE: **Evidence of Ms. McShane, Page 54**

a) On page 54 Ms. McShane notes the low R Squared of her regressions, please indicate why 32% is low and what the benchmark is for assessing explained variance in stock market returns.

Response:

The 32% is low because it means that almost 70% of the utility returns are unexplained by equity market returns. The conclusion that the R^2 is low was not based on a specific benchmark but on the observation that over two-thirds of the variance was not explained.

b) Please explain in full why she chose the time period 1970-2008 rather than the full period for which data is available?

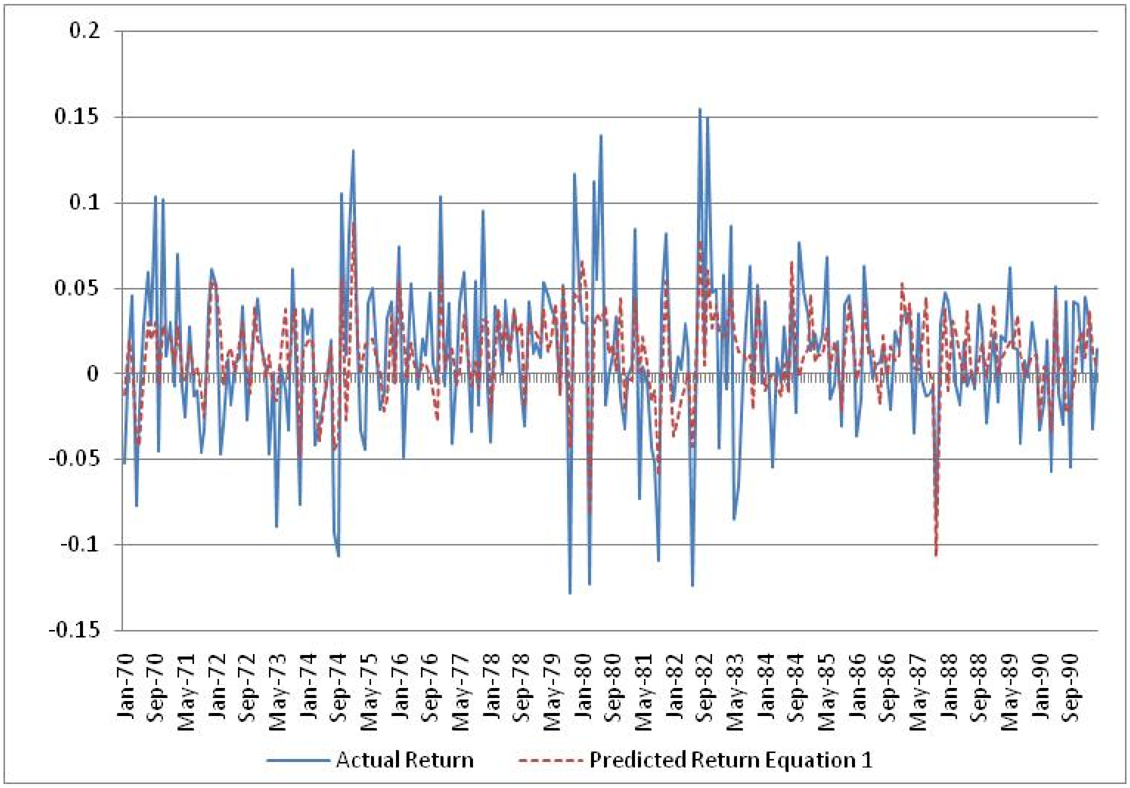
Response:

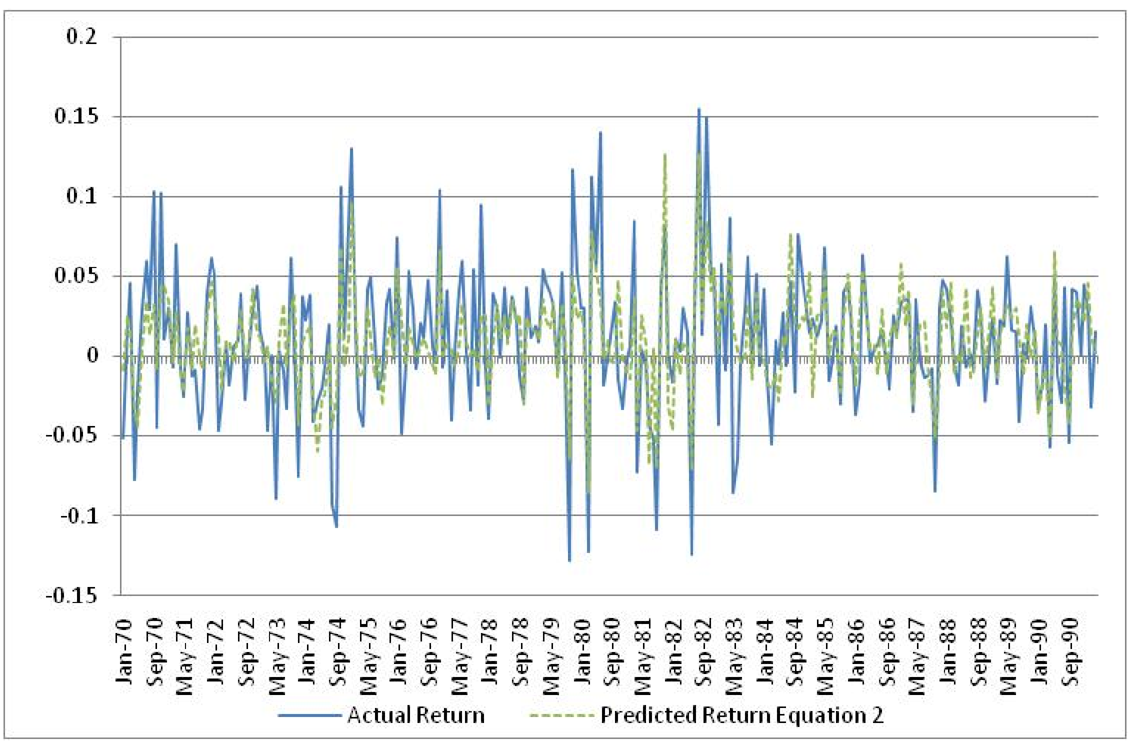
The period 1970-2008 represents the full period for which Ms. McShane had monthly total return data.

c) Please provide a graph of the actual and fitted values for the two regression equations on page 52.

Response:

Please refer to the following two graphs.


0.2
0.15
0.1
0.05
0
-0.05
-0.1
-0.15
Jan-70 Sep-70 May-71 Jan-72 Sep-72 May-73 Jan-74 Sep-74 May-75 Jan-76 Sep-76 May-77 Jan-78 Sep-78 May-79 Jan-80 Sep-80 May-81 Jan-82 Sep-82 May-83 Jan-84 Sep-84 May-85 Jan-86 Sep-86 May-87 Jan-88 Sep-88 May-89 Jan-90 Sep-90
Actual Return
Predicted Return Equation 1


0.2
0.15
0.1
0.05
0
-0.05
-0.1
-0.15
Jan-70 Sep-70 May-71 Jan-72 Sep-72 May-73 Jan-74 Sep-74 May-75 Jan-76 Sep-76 May-77 Jan-78 Sep-78 May-79 Jan-80 Sep-80 May-81 Jan-82 Sep-82 May-83 Jan-84 Sep-84 May-85 Jan-86 Sep-86 May-87 Jan-88 Sep-88 May-89 Jan-90 Sep-90
Actual Return
Predicted Return Equation 2

d) Please indicate whether or not the 2.25% on page 55 reflects the intercept of the two equations on page 54. If so provide the calculations in full as to how she obtained them from the intercept values on page 54. If not please explain.

Response:

It represents the intercept of the second equation, which is a monthly return, annualized. Specifically, it represents $(1+.00185)^{12}-1 = .0225=2.25\%$.

e) Please explain why the BCUC should place any reliance on an unexplained factor on the assumption that whatever it is it will repeat itself?

Response:

The objective of using a relative risk adjustment is to estimate the expected or required return. Calculated Canadian utility betas have persistently underestimated utility returns; that persistent underestimation needs to be recognized. The explicit recognition of the value of the intercept demonstrates the utility risk premium is approximately 0.70 of the market risk premium, much closer to the adjusted than to the raw betas.

f) With reference to e) above, would Ms. McShane agree that one reason for the higher returns could be the improved regulatory environment as represented by the adoption of forward test years, the removal of the commodity function, fuel pass-throughs, the increased use of deferral accounts, the adoption of ROE formulae, since these have made utilities progressively lower risk and more valuable? If not please explain how these risk reduction changes would show up in her regression model when she uses fixed coefficients, that is, the risk factors (betas) are constant throughout the time period.

Response:

While Ms. McShane acknowledges that the referenced regression analysis covers an extended time frame (i.e., it is not time varying), the conclusion that utility stocks earn higher returns than the single variable CAPM predict is an empirical observation that is not solely related to utility stocks, but to low beta stocks generally (with the converse observed for high beta stocks). As applied specifically to utilities, it is not an empirical observation limited to Canadian utilities, but has been identified as an issue for U.S. utilities as well. Nor is it simply a recent phenomenon. Studies which have identified and attempted to account for the underestimation date back to the late 1970s and early 1980s. If the issue were simply that the failure of the model to explain returns was due to the factors suggested in the question, it is unlikely that academics would have devoted considerable time and effort to attempting to specify models which more closely captured the risk/return relationship. Indeed, various factors have been identified which may account for the empirically observed relationships, including the preferential tax treatment of dividends versus capital gains, the misspecification of the market portfolio (which should in theory include all investable assets), and skewness or asymmetry in returns potential (upside more constrained than downside).

g) Please provide citations to any and all Canadian regulatory decisions that have approved the use of adjusted betas by "squashing" them with 1.0 as indicated on page 55.

Response:

Ms. McShane is not aware of any Canadian decisions which have specifically relied on the adjustment methodology. It is widely accepted by U. S. regulators As she indicated in her testimony, the methodology is a standard method for adjusting betas; it is consistent with the empirical evidence which shows that low (high) beta stocks have achieved higher (lower) returns than the simple CAPM model posits.

JIESC/BCOAPO/CEC-TGI-41.

TOPIC: **Risk Premium Fair Return Estimates**

REFERENCE: **Evidence of Ms. McShane, Page 57**

a) In this testimony Ms. McShane uses a utility risk adjustment (beta) of 0.65-0.70 and a market risk premium of 6.75%. For each Canadian case where she has filed testimony since 1995 can she please provide her benchmark beta and her market risk premium estimates and explain why they have changed over time.

<u>Response:</u>

Ms. McShane does not maintain a data base with that information. The following table contains a representative sample of estimates from 1994 to 2009. The file shows the market risk premium, the benchmark beta and the forecast long-term Canada bond yield. The differences in individual testimony estimates were based on Ms. McShane's expert judgment applied to the data available at the time of preparation. With specific respect to the general increase in the estimated market risk premium, it reflects in large part the decline in the relative risk of Government of Canada bonds.

Proceeding/Company	Date of Testimony	Benchmark ROE Recommendation	Market Risk Premium	Beta	Long Canada Forecast
Group 1 Pipelines RH-2-94	Oct-94	13.00%	5.25%	0.700	8.75%
Enbridge Gas	Jan-96	12.38%	5.50%	0.700	7.75%
Enbridge Gas	Jan-97	12.13%	6.00%	0.700	7.25%
Newfoundland Power	May-98	11.00%	6.50%	0.700	6.00%
ATCO Electric	Oct-98	11.00%	6.63%	0.675	5.88%
BC Benchmark	May-99	10.75%	6.50%	0.700	5.50%
ATCO Electric	May-00	11.13%	6.50%	0.650	6.00%
ATCO Gas	Oct-00	11.63%	6.50%	0.650	6.25%
Union Gas	Jun-01	11.50%	7.00%	0.625	5.85%
Enbridge Gas	Sep-01	11.50%	7.00%	0.625	6.00%
Nova Scotia Power	Aug-02	11.50%	6.50%	0.625	6.13%
Enbridge and Union Gas	Feb-03	11.75%	6.25%	0.625	6.00%
Alberta Generic	Jul-03	11.25%	6.00%	0.625	5.75%
BC Benchmark	Jul-05	10.50%	6.25%	0.650	5.25%
Hydro One	Aug-06	10.50%	6.50%	0.675	5.00%
Newfoundland Power	Mar-07	10.38%	6.50%	0.675	4.88%
Ontario Power Generation	Nov-07	10.50%	6.50%	0.675	5.00%
Terasen Gas	May-09	11.00%	6.75%	0.675	4.25%
Newfoundland Power	May-09	11.00%	6.75%	0.675	4.25%

b) Please provide the allowed ROE for TGI with the current formula ROE at Ms. McShane's forecast 4.25-5.25% long Canada bond yields.

Response:

At the mid-point of the range, 4.75%, the ROE with the current formula is 8.77%.

c) Please confirm that in her 2007 OPG testimony Ms. McShane recommended that the OEB formula ROE should not be reviewed unless the forecast long Canada bond yield fell outside of a range from 3.0% to 8.0%.

Response:

Confirmed, but based on a recommended ROE of 10.5%.

JIESC/BCOAPO/CEC-TGI-42.

TOPIC: **Risk Comparisons**

REFERENCE: **Evidence of Ms. McShane, Page 58**

a) Please provide all statistical work that Ms. McShane has performed to justify the assumption that US utilities are comparable in risk to TGI.

Response:

Reliance on a sample of U.S. utilities as comparables was not based on statistical analysis. It was based on knowledge of both the regulatory and operating environments of both Canadian and U.S. utilities, an understanding of the capital markets in both countries, supplemented by the following specific considerations : (1) the U.S. utilities selected not only fall into the same S&P business risk class as the typical Canadian utility, but specific Canadian and U.S. utility company comparisons (i.e., AltaLink versus stand-alone U.S. transmission utilities) indicate that S&P considers Canadian and U.S. utilities operating in the same utility sector to be comparable; (2) Moody's assessments of specific Canadian utilities (i.e., Terasen Gas and FortisAlberta) indicate that they find Canadian and U.S. utilities operating in the same utility sector to be comparable; (3) all of the selected companies have S&P debt ratings in the A category, similar to the ratings assigned by S&P to Canadian utilities; (4) the Safety Rankings assigned by *Value Line* to the selected U.S. utilities are equal to or higher than the Safety Rankings that they have assigned to the two regulated Canadian companies (Enbridge Inc. and TransCanada Corporation) that they follow; (5) a review of the regulatory climate in each state, including the various regulatory mechanisms is included under Attachment 42a.

b) Please confirm that the Concentric report referenced in footnote 62 was authored by the same people who appeared as expert witnesses on behalf of various utilities in the Alberta Utilities Commission's 2008 generic cost of capital hearing.

Response:

Confirmed.

c) Please explain why the BCUC should give more weight to the Concentric report than any other utility sponsored expert testimony that has been presented over the last two years.

Response:

The report referenced was not utility sponsored testimony. It was a report that was commissioned by the Ontario Energy Board regulatory policy staff on behalf of the Board. As such, it would not be expected that either the organization selected to prepare the report or the report itself would have a bias toward any particular conclusions.

d) Please confirm that Ms. McShane appeared alongside the authors of the Concentric report in the recent AUC generic hearing on behalf of several Alberta utilities. Explain why this is not mentioned in her report.

Response:

Confirmed. As noted in response to JIESC/BCOAPO/CEC IR 1.42(c), the referenced report was a report prepared at the request of the OEB staff. The report was completed and made public well in advance of Concentric's appearance on behalf of the ATCO Utilities in the generic cost of capital proceeding. In that context, Ms. McShane did not think it was of consequence to report in her testimony that she later appeared on behalf of the same client in a proceeding.

JIESC/BCOAPO/CEC-TGI-43.

TOPIC: **Risk Comparisons**

REFERENCE: **Evidence of Ms. McShane, Page 59**

a) Please provide in an Excel readable format the full data set used in the analysis on page 59, that is, the monthly dividend yield, growth forecast and treasury yield from March 1991 to March 2009 for the US utilities.

Response:

Please refer to Attachment 43a.

b) Please provide separately a regression equation similar to that in Schedule 12 of the dividend yield against the explanatory variables and the growth forecast against the explanatory variables.

Response:

Regression equations follow:

DCF-BASED EQUITY RISK PREMIUM STUDY FOR BENCHMARK US ELECTRIC AND GAS UTILITIES
Regression Analysis Results

Equation 1:

Dividend Yield = 1.20 + 0.64 (30-Year Treasury Yield)

t-statistics:
Long-term Bond Yield = 30.50
R^2 = 81%

Dividend Yield at Long-Term Bond Yield of 4.25% = 3.91

Equation 2:

Dividend Yield = 0.39 + 0.71 (30-Year Treasury Yield) + 0.29 (Spread)

Where Spread = Spread between A-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:
Long-term Bond Yield = 32.03
Utility/government bond yield spread = 6.27

R^2 = 84%

Dividend Yield at Long-term Bond Yield of 4.25% and Spread of 2.25-2.50 = 4.1

DCF-BASED EQUITY RISK PREMIUM STUDY FOR BENCHMARK US ELECTRIC AND GAS UTILITIES
Regression Analysis Results

Equation 1:

Growth Forecast = 7.05 - 0.35 (30-Year Treasury Yield)

t-statistics:
Long-term Bond Yield = -9.25
R^2 = 28%

Growth Forecast at Long-Term Bond Yield of 4.25% = 5.54

Equation 2:

Growth Forecast = 4.57 - 0.15 (30-Year Treasury Yield) + 0.89 (Spread)

Where Spread = Spread between A-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:
Long-term Bond Yield = -4.56
Utility/government bond yield spread = 13.03

R^2 = 59%

Growth Forecast at Long-term Bond Yield of 4.25% and Spread of 2.25-2.50 = 6.0

c) At the bottom of page 60 Ms. McShane jumps from the regression results based on US data to discussing the impact of the long term Canada yield. Please indicate whether she judges the Government of Canada's bond issues to be those of a reserve currency with a similar international demand to those issued by the US government.

Response:

No, Government of Canada bonds do not have the same demand as U.S. Treasuries.

d) Would Ms. McShane agree that US government bond yields are lower than would be the case if the US was not the world's reserve currency and her market risk premium estimates correspondingly lower? If not why not?

Response:

Yes, they could be somewhat lower. Please see response to JIESC/BCOAPO/CEC IR 1.37.

No, because the expected market risk premium is based on expected equity market returns relative to long-term Government of Canada bond yields.

e) Can Ms. McShane agree that TGI's bond spreads over long Canadas have now dropped by a further 75 basis points since the time of her testimony which with her coefficient on the spread of 1.23 indicates a drop in the fair rate of return of almost 1.0%? If not why not.

Response:

No, Ms. McShane cannot agree. The estimate which Ms. McShane did using the DCF-based risk premium test was premised on a further reduction in spreads from the level prevailing at the time the evidence was prepared. The indicated spread for a new 30-year TGI issue at July 13, 2009 was approximately 180 basis points, compared to the spread of 225-250 basis points used in the application of the DCF-based equity risk premium test (a decline of 45 to 70 basis points). The lower than anticipated spread reduces the results of this form of the DCF-based risk premium test by approximately 0.7%. In addition, this form of the DCF-based equity risk premium test is only one of multiple tests that Ms. McShane performed.

f) Further to e) above please update the rate of return estimate to reflect Ms. McShane's current interest rate forecast and TGI's current spread.

Response:

Ms. McShane has not changed her forecast of long-term Canada bond yields. If considered appropriate, she will update her test results prior to the hearing. At the current spread of 180 basis points and the forecast long-term Canada bond yield of 4.25%, the two-variable DCF-based risk premium test produces a return, including the financing flexibility adjustment, of 10.15%.

g) Please indicate whether in Ms. McShane's judgment a utility regulator should pass through all the volatility observed over the last year in A spreads into the allowed ROE or whether the regulator should take a longer term view of spreads that clearly fluctuate with the business cycle?

Response:

Ms. McShane believes that the allowed ROE should reflect the cost of equity at the time the allowed ROE is set. Trends in utility bond yields (which reflect both the risk-free rate and the spread) are a relevant indicator of the cost of equity and should be recognized, just as other indicators (i.e. DCF costs) should be.

JIESC/BCOAPO/CEC-TGI-44.

TOPIC: **Experienced Returns**

REFERENCE: **Evidence of Ms. McShane, Page 62**

a) With reference to experienced returns on utilities, please indicate whether or not these returns would be higher or lower if allowed ROEs were systematically set too high and too low?

Response:

Either is a theoretical possibility. If either were true, the implication would be that regulators in both Canada and the U.S. have consistently over-estimated or under-estimated a fair and reasonable return on average over the entire period for which the returns were estimated (1947/1956-2008).

b) Please estimate these experienced returns for the two sub periods 1956 (1947)-1981 and 1982-2008 and whether in her judgement the "risk premia" are the same in both periods.

Response:

The experienced returns are provided in Attachment 44b. The achieved risk premiums are not the same in the two sub-periods.

c) Please discuss any differences and why such estimates are not circular in reflecting pervious regulatory decisions.

Response:

The most significant differences between the two periods are: (1) the differences in bond total returns and (2) the levels of equity returns achieved by the U.S. electric utility sector. All of the market-based tests as applied to utilities entail some circularity because the inputs (i.e. prices and changes in prices, growth expectations, actual returns) reflect some reaction on the part of investors to what returns regulators have set or what returns they expect regulators to set. The advantage of this test is that it provides a direct estimate of the utility expected return. Achieved market returns generally may differ from what investors had expected. More stable sectors of the market are more likely to have actual returns that are closer to what investors had expected. As utilities are relatively low risk equity investments, the expected and actual returns are more likely to converge over the long-run than those of more volatile sectors, and thus provide a better estimate of the expected utility risk premium than a CAPM or CAPM-like risk premium test, which requires that utility specific expected returns be inferred from those of the overall market.

d) Please indicate any Canadian regulator which has explicitly placed any reliance on such experienced returns.

Response:

The BCUC gave weight to this test as applied to Canadian utilities in its March 2006 cost of capital decision for Terasen Gas and TGVI.

JIESC/BCOAPO/CEC-TGI-45.

TOPIC: **DCF Tests**

REFERENCE: **Evidence of Ms. McShane, Page 65**

a) With reference to the accepted optimism of analyst growth forecasts, please indicate the regulatory bodies who have questioned their reliability and any bodies that have accepted them and based their ROE awards on them without adjustment.

Response:

The forecasts have been accepted without adjustment by the BCUC in its March 2006 cost of capital decision for TGI and TGVI (page 55). In its most recent decision on cost of capital (for Ontario Power Generation dated October 2008), the Ontario Energy Board stated, "The Board finds that each of the analytical tests has value as each provides a different perspective on the question of the appropriate ROE. However, each test also has its weaknesses. For example, there is evidence of analyst bias, which although not conclusive with respect to utilities, suggests that the DCF cannot be relied upon wholly." The Alberta Energy and Utilities Board gave no weight to DCF in its Generic Cost of Capital Decision dated July 2004 because it found both the applicants' and intervenors' applications problematic.

b) Please provide all evidence that "sell side" analyst forecasts are accepted by investors and fully incorporated into equity prices. Further please indicate why "buy side" analysts exist if sell side analyst's views are fully incorporated into equity prices?

Response:

Sell side analysts work for brokerage firms; their research is focused on determining whether an investment is suitable for the firm's clients generally. Buy side analysts work for pension funds and other institutional investors; their research is more focused on determining if investments are appropriate for specific portfolios or investment strategies. Buy side analysts' research is not available outside of the firm by which they are employed.

c) Please indicate how the well accepted analyst optimism bias is removed even if they are accepted and fully incorporated into equity prices given that analysts disagree? That is, which analyst forecasts are fully incorporated into equity prices and why would it be the median or average when a new analyst has an incentive to give a radical forecast to distinguish them from the crowd?

Response:

The preamble is premised on a questionable assumption, particularly in the case of utilities, where the business model is relatively well understood. The release of "radical" growth forecasts for a utility (which Ms. McShane interprets to mean outside of a range that is reasonably supportable by the company's earnings prospects) would be counterproductive for analysts, who are likely to be concerned with building reputation and an upward career path. As such, the median or average forecast represents the best estimate of the forecast that is built into share prices.

d) Please indicate why Ms. McShane believes that a private forecaster like Value Line whose estimates are not widely available is more likely to have their forecasts impounded into equity prices than other forecasters? Please indicate the annual cost of a Value Line subscription.

Response:

The reasons for using *Value Line* as an alternative to the consensus of analysts' forecasts were primarily because (a) *Value Line* is widely available; it is available without charge in many public libraries and (b) as noted at page 63-64, Value Line is an independent research firm which has no incentive to inflate its growth estimates and represents a means of testing the reasonableness of the consensus of analysts' forecasts. The annual subscription fee for Value Line is $750 for an individual.

e) Please provide the annual dividend per share for each of the firms in her US DCF sample both individually and as a sample average and provide a time series regression of their annual dividend per share growth rate against the growth rate in nominal US GDP to verify the assumption that growth rates will taper off to the long run GDP growth rate.

Response:

Dividend data are provided for the companies in the sample for the longest period for which Ms. McShane has data for individual companies, in Attachment 45e. The requested regression is also provided. There is no statistical relationship historically between dividend growth and GDP growth, nor would Ms. McShane expect that there would be a significant correlation. In the late 1970s to early 1980s, when inflation was at relatively high levels, utility earnings did not keep pace with inflation, thus constraining both earnings growth and dividend growth. When inflation started to decline, the decline in inflation was accompanied by reductions in allowed returns, which had reached levels of 15-16% in the mid-1980s. By the mid 1990s, they were in the range of 11.0-11.5%. Such reductions are not compatible with earnings keeping pace with long-term economic growth. Other idiosyncratic factors (i.e. industry restructuring for electric utilities) would also impact observed relationships.

f) If these utilities are comparable to a mature utility like NP please justify in full why a mature company is likely to grow at the average GDP growth rate. That is, where is the "room" for above average growth companies in GDP growth if mature companies are growing at the GDP growth rate?

Response:

Ms. McShane presumes that the reference is to Terasen Gas and not Newfoundland Power. The life cycle of industries includes periods of above average growth, average growth when industries are mature and below average growth when the industries are in decline.

JIESC/BCOAPO/CEC-TGI-46.

TOPIC: **Overall Recommendation**

REFERENCE: **Evidence of Ms. McShane, Page 73**

a) Ms. McShane recommends a fair ROE of 11.0% on a 40% common equity ratio. Please indicate any Canadian local distribution company (gas or electric) that is allowed to earn 11.0% or more on 40% or more common equity and provide the specific circumstances of those utilities.

Response:

Distribution utilities in Canada allowed to earn an ROE of 11% on equity are the greenfield utilities Enbridge Gas New Brunswick (13% on 50% equity) and Heritage Gas (13% on 45% equity).

b) Please confirm that in explicitly considering the usefulness of ATWACC the EUB stated (Decision U-99099, page 300)

"The Board observes that the intrinsic long-run value of a pure play regulated entity is best represented by book value. In other words, the present worth of future regulated earnings, discounted at the allowed return, is by definition equal to book value assuming achieved regulated earnings on average equal allowed regulated earnings. Accordingly, the Board considers that book capitalization represents the best indicator of the long-run market capitalization for a pure play regulated firm."

Response:

Confirmed. It should also be noted, as indicated in response to JIESC/BCOAPO/CEC IR 1.23 above, in an earlier decision the EUB concluded "Rather, the Board considers that there is still some merit in the comparable earnings test to the extent that regulation is considered a surrogate for competition and the comparable earnings test attempts to measure the achieved accounting rates of return on common equity of enterprises of similar risk."

c) Please also confirm that in the same decision (U99099, page 303) the AEUB stated:

"The Board would be derelict in its statutory responsibilities to recognize market capitalization ratios that are derived from a market value capitalization that deviates from the intrinsic long-run value of the regulated firm."

Response:

Confirmed.

d) Please explain why the BCUC should accept a methodology that is based on using market values that are significantly above the regulated book values when this indicates that investors have, by definition, earned an above average rate of return and bid up the value of the regulated assets.

Response:

TGI is not asking the BCUC to adopt the ATWACC methodology. However, the ATWACC methodology does recognize that the cost of capital reflects the market value of the firm's capital, both debt and equity. When the market value common equity ratio is higher (lower) than the book value common equity ratio, the market is attributing less (more) financial risk to the firm than is "on the books" as measured by the book value capital structure. Higher financial risk leads to a higher cost of common equity, all other things equal. The higher market than book values do not by definition mean that investors have earned an above average rate of return and bid up the value of the regulated assets. Please see response to JIESC/BCOAPO/CEC IR 1.46(e) below.

e) Please confirm that if the value of regulated assets significantly exceeds their book value and the ROE has consistently been fair then by definition the investor then earns an above average rate of return. If not why not and explain in detail.

Response:

It is not confirmed. The observation that market to book ratios of regulated utilities are above book, particularly when the overall market has maintained market values well in excess of book, does not lead to the conclusion that the utility earns an above average return. Market values in excess of book value for regulated companies can reflect multiple factors, including (1) differences between GAAP accounting which reflects among other things, historic depreciated cost, and economic values; (2) expectations of future earnings; (3) going concern value; and (4) the tenor of the overall equity market.

JIESC/BCOAPO/CEC-TGI-47.

TOPIC: **Risk Free Rate**

REFERENCE: **Evidence of Ms. McShane, Appendix B**

a) Ms McShane discusses problems with the use of the long Canada bond rate as the risk free rate. Please indicate whether the same criticism is at work for the long Treasury yield in the US with the added proviso that it is issued by the only reserve currency in the world. If not, why not.

Response:

Yes, although the Euro is also held as a reserve currency; please see responses to JIESC/BCOAPO/CEC IR 1.37 and JIESC/BCOAPO/CEC IR 1.43.

b) Please discuss how she has adjusted for a) above in her US estimates?

Response:

She has not made any explicit adjustments. However, her market risk premium estimates are partially based on the expected return on the equity market less the expected bond return, where the latter is the forecast yield on long-term Canada bonds. Thus to the extent that the yield on long-term government bonds understates the "true" risk-free rate, it is reflected in both the risk-free rate and market risk premium estimates. In other words, a lower than "true" risk-free rate is offset by a higher market risk premium.

c) Please estimate the betas for the Canadian utility sample against the US market index (S&P500) both with and without adjustments for the C$:US$ exchange rate and compare them with those on page 56.

Response:

The betas are shown in the following table:

Company	**"Raw" Beta As Shown on Table 8 of Testimony**	**"Raw" Beta Vs. S&P 500**	**"Raw" Beta Vs. S&P 500 Adjusted For Exchange Rate**
Canadian Utilities	0.41	0.27	0.25
Emera	0.38	0.31	0.22
Enbridge	0.56	0.49	0.40
Fortis	0.49	0.40	0.32
TransCanada	0.47	0.44	0.30
Median	**0.47**	**0.40**	**0.30**

d) Please confirm that the sector weights in market index depend on the state of the stock market and how frequently the indexes are rebalanced.

Response:

Confirmed.

e) Please indicate whether Ms. McShane has published any asset pricing tests in any academic journal and whether in her judgement the results in Table B-3 reflect the methodology used in such tests.

Response:

Ms. McShane has not published any asset pricing tests in academic journals. The methodology she used is a simple correlation between betas and returns which demonstrates that over a long period of time, the betas of lower and higher risk sectors of the economy and the returns they have achieved have not conformed to the relationship predicted by the single beta (equity market composite) CAPM, leading to the conclusion that depending on a raw beta to predict the expected return is problematic at best. The methodologies used by academics to test the CAPM and to perform other asset pricing studies are significantly more complex. While the academic models are more complex econometrically, the results of Ms. McShane's simple correlation are not inconsistent with the findings of more complex studies.

JIESC/BCOAPO/CEC-TGI-48.

TOPIC: **Financial Flexibility**

REFERENCE: **Evidence of Ms. McShane, Appendix E**

a) Ms. McShane's financing flexibility adjustment on page E-4 is explicitly based on targeting a market to book ratio of 1.05-1.1 so that the utility can issue stock at above book value. In her judgment is such an adjustment still needed if the market to book is for example 2.0 such that there is no chance of selling stock below book value even before a financing flexibility adjustment. Please explain in full.

Response:

Yes. As explained in Appendix E, "An adjustment to the equity risk premium and discounted cash flow test results for financing flexibility is required because the measurement of the return requirement based on market data results in a "bare-bones" cost. It is "bare-bones" in the sense that, theoretically, if this return is applied to (and earned on) the book equity of the rate base (assuming the expected return corresponds to the approved return), the market value of the utility would be kept close to book value." The actual market to book ratio reflects, among other things, expected earnings. For the sample of U.S. utilities, whose average market to book ratio in 2008 was approximately 1.6 times, the average *Value Line* forecast ROE was approximately 12.25% for the period 2012-2014. (See Schedule 15) By comparison, Ms. McShane's three market-based tests for estimating the cost of equity (before the financing flexibility allowance) averaged 10.25%.

JIESC/BCOAPO/CEC-TGI-49.

TOPIC: **Overall Recommendation**

REFERENCE: **Evidence of Ms. McShane, Appendix F**

a) Please provide the underlying data [in Excel format] used to construct Figure F-1 and provide the source documents.

Response:

The underlying data is provided in Attachment 49a. The data was downloaded directly from the Federal Reserve website; series numbers for the data used are provided in Attachment 49a.

b) Please provide the underlying data used to construct Figure F-2 and provide the source documents in addition please provide the ROE consistent with the data.

Response:

The underlying data are provided in Attachment 49b. The market/book values were provided by RBC Capital Markets Quantitative Research. The ROEs for the S&P 500 are also provided in Attachment 49b. Ms. McShane does not have ROE data for the TSX Composite.

Evidence of Dr. Vander Weide

JIESC/BCOAPO/CEC-TGI-50.

TOPIC: **Background of Dr. Vander Weide**

REFERENCE: **Evidence of Dr. Vander Weide**

REQUEST:

a) Please provide a copy of the research summary for Dr. Vander Weide and copies of all working papers listed on Duke University's web site for Dr. Vander Weide.

Response:

Although Dr. Vander Weide has not performed a detailed risk ranking of TGI relative to TransAlta and the other Canadian unregulated power firms included in the S&P/TSX utilities index, TransAlta's description of their business provided in response to part c) indicates that the business risk of investing in TGI would be relatively similar to the business risk of investing in TransAlta.

b) Please provide copies of all research publications by Dr. Vander Weide during the last twenty years, that is, since 1988.

Response:

Copies of Dr. Vander Weide's research publications since 1988 are included in Attachment 50b.

Measuring Investors' Growth Expectations: the Analysts vs. History, *The Journal of Portfolio Management*, Spring 1988 (with W. Carleton).

Entry Auctions and Strategic Behaviour under Cross-Market Price Constraints, *International Journal of Industrial Organization*, 20 (2002) 611-629 (with J. Anton and N. Vettas).

Principles for Lifetime Portfolio Selection: Lessons from Portfolio Theory, *Handbook of Portfolio Construction: Contemporary Applications of Markowitz Techniques*, John B. Guerard, (Ed.), Springer, forthcoming Fall 2009.

c) Please indicate all testimony filed by Dr. Vander Weide in a utility rate hearing since 1988 that was sponsored by an entity, other than the utility being examined and the name of the sponsoring party.

<u>Response:</u>

Dr. Vander Weide filed testimony on behalf of MidAmerican Energy in two Interstate Power And Light Company cases in Iowa, Dockets No. SPU-06-5 and RPU-02-3.

JIESC/BCOAPO/CEC-TGI-51.

TOPIC: **ROE Formula**

REFERENCE: **Evidence of Dr. Vander Weide, Page 8**

REQUEST:

a) Dr. Vander Weide's estimate of the BCUC formula return relies on the Consensus Economics long bond forecast yield of 3.69%. Please provide the relevant pages of this forecast, and indicate whether it is for the 30 year or 10 year bond.

<u>Response:</u>

Consistent with the policy of the BC Utilities Commission, Dr. Vander Weide's estimate relies on a forecast of the Canada long bond. As described by the Commission,

"A forecast of long-term Canada bonds is developed based on the Consensus Economics forecast of 10-year bonds (step 1) and the observed spread between 10 and 30 year bonds over a defined period (step 2). This establishes a forecast yield for long Canada bonds (step 3)."

The relevant pages of the Consensus Economics document are provided in Attachment 51a.

b) Please update this forecast and ROE estimate using the latest data.

<u>Response:</u>

The requested information is presented in the following table:

ROE Calculation Date	**2009** **July**
1. Ten Year Canada bond yield forecast - 3 month	3.500
Ten Year Canada bond yield forecast - 12 month	3.800
10 year bonds - Average of 3 & 12 month forecast	3.650
2. Add 10 year / 30 year Bond Yield Spread (these are actual spreads from prior month)	0.490
3. Equals Forecast Yield on 30 year Canada bonds	4.140
4a. Sliding scale 75% Adjustment when rates > 5.25%	
4b. Sliding scale 75% Adjustment when rates < 5.25%	-0.833
5. Benchmark ROE	9.145
6. Un-rounded Allowed ROE	8.312
7. Rounded to 2 decimal places	8.31%

JIESC/BCOAPO/CEC-TGI-52.

TOPIC: **Achieved Utility Returns**

REFERENCE: **Evidence of Dr. Vander Weide, Page 10 on**

REQUEST:

a) Is Professor Vander Weide aware of any Canadian regulatory board that has specifically accepted achieved returns on utility holding companies as an estimate of the ex ante risk premium for regulated utilities?

Response:

Dr. Vander Weide has not studied Canadian regulatory board decisions to determine whether "any Canadian regulatory board … has specifically accepted achieved returns on utilities as an estimate of the ex ante risk premium for regulated utilities."

b) Can Professor Vander Weide confirm that if due to regulatory lag the allowed ROE is not decreased with market interest rates and fair returns, then utility stock prices will increase in response to the higher than fair allowed return? If not confirmed, why not?

Response:

Cannot confirm. The question assumes that the required ROE declines when market interest rates decline. If the yield on the long Canada bond is used as an estimate of market interest rates, this assumption is invalid. In particular, since October 2008, interest rates on long Canada bonds have declined, but the required ROE has increased. Furthermore, other things equal, a utility's stock price will only increase in theory if the allowed ROE is held constant when market interest rates and fair returns *unexpectedly* decline. Of course, other things, such as the state of the economy, the rate of unemployment, the passage of new environmental legislation, and consumer spending, do not remain constant.

c) Can Professor Vander Weide confirm that achieved returns by utility holding companies in part reflect the actions of the regulator in changing the fair return in response to market conditions? If not confirmed, can Dr. Vander Weide discuss in detail why investors in utilities do not react to the decisions of regulators in terms of the fair return?

Response:

Not confirmed. Regulators can only change the allowed return, not the fair return. The fair return is determined in the marketplace. In addition, achieved market returns in a given period only react to *unexpected* actions of regulators. Further, once the unexpected actions of regulators become known, the market price of a utility's stock will adjust to this new information; and hence, future market returns will not be affected by the unexpected action that initiated the price change. Since: (1) the impact of unexpected actions is recognized quickly; and (2) the impact of unexpected actions may be either positive or negative, the actions of regulators are unlikely to induce bias in the average achieved market return on a utility's stock as an estimate of the expected return.

d) If Dr. Vander Weide accepts that achieved returns in part reflect the actions of regulators, can he explain why such evidence should not be regarded as circular? Further if it is regarded as circular in reflecting in part the actions of the regulator, please explain how this can be regarded as objective evidence as to expected returns.

Response:

Please see response to JIESC/BCOAPO/CEC IR 1.52(c).

JIESC/BCOAPO/CEC-TGI-53.

TOPIC: **Achieved Utility Returns**

REFERENCE: **Evidence of Dr. Vander Weide, Page 10 on**

REQUEST:

a) Please discuss the composition of the "legacy" utility sub index of the TSE prior to 1999 and whether it includes regulated and non-regulated activities.

Response:

Dr. Vander Weide does not have a list of the companies included in the legacy utility sub-index of the TSX prior to 1999, and he has been informed by the TSX that such a list is not readily available.

b) Please discuss whether BCE and Nortel were a part of the legacy utility sub-index and whether this introduces a bias into the achieved return.

Response:

BCE was part of the S&P/TSX legacy utilities sub index; Nortel was not. Dr. Vander Weide does not believe that the inclusion of BCE creates a bias in the achieved return on the legacy utilities sub index because Dr. Vander Weide did not use the utilities sub index after 1998; thus, the significant increase in BCE's stock price in 1999 is not reflected in the achieved returns on the S&P/TSX utilities. Prior to 1999, the relative weight of BCE in the composite was less than 6 percent.

c) Please discuss why Dr. Vander Weide did not use either the electricity or gas sub indexes of the legacy TSE index, or the pipeline index instead of the overall utility sub index.

Response:

Dr. Vander Weide did not use the electricity or gas sub-indices of the legacy S&P/TSX or the pipeline index because data for these indices are only available for limited periods of time. Data on a combined gas/electric utilities sub index are available only from January 1992 to January 2004. Data on a separate gas index and a separate electric index are available only from January 1981 to December 1991. No data for gas and/or electric utilities, other than the data for the larger legacy index that Dr. Vander Weide chose to use, are available for the years before 1981. In short, the legacy index that Dr. Vander Weide uses in his evidence is the only S&P/TSX Canadian index that contains electric and gas utilities stock price total return data going back to 1956. With respect to data for pipeline companies, Dr. Vander Weide did not use pipeline stock price index data because this index only contained three companies, and data for this index are available only for the period January 1979 to January 2004.

d) Can Dr. Vander Weide explain whether or not pipelines have ever been a part of the legacy TSX utility sub index?

Response:

Dr. Vander Weide does not know if pipelines were ever part of the legacy utilities index.

e) With reference to footnote 2, please confirm that it was the TSE300 and its constituent sub indexes that were discontinued in 2002 when the TSX sub contracted out the maintenance of its indexes to S&P and that S&P played no role in the management of the TSE's indexes until that date.

Response:

Dr. Vander Weide's understanding is that on May 1, 2002, the TSE 300 Composite was re-branded as the S&P/TSX Composite Index and that the 14 industry groups previously found in the TSE 300 were also replaced by ten new indices that adopt the Global Industry Classifications Standard (GICS), which was developed jointly by Standard & Poor's and Morgan Stanley Capital International, in order to make the index and its components comparable to other world markets. His understanding is that maintenance of the index is a collaboration between Standard & Poor's and the TSX. Dr. Vander Weide has not studied whether Standard & Poor's played any role in managing TSE indices before 2002.

JIESC/BCOAPO/CEC-TGI-54.

TOPIC: **Achieved Utility Returns**

REFERENCE: **Evidence of Dr. Vander Weide, Page 13, Table 1**

REQUEST:

a) Would Dr. Vander Weide confirm that utility shares are regarded as interest sensitive since they generally have relatively large dividend yields? If not confirmed, can Dr. Vander Weide please provide the dividend yields of the comparables in Table 1 and the dividend yield on the TSX Composite for the same time periods.

Response:

Dr. Vander Weide agrees that utility shares are regarded as being more interest sensitive than shares in the S&P 500. One factor in explaining the relative interest sensitivity of utility shares is the relatively higher dividend yields of utility shares compared to the dividend yields of the S&P 500. Intervenors may obtain dividend yields for these companies from several publicly-available sources. Dividend yields on utility shares are typically in the range 3.5 percent to 4.0 percent, while dividend yields on the S&P 500 are typically approximately 2.0 percent.

b) Would Dr. Vander Weide agree that interest rates have declined since 1983 and as a result interest sensitive investments like utility shares have earned returns above what was expected? If not agreed, can Dr. Vander Weide please provide a table of long Canada interest rates for each year since 1956?

Response:

Dr. Vander Weide agrees that interest rates have declined since 1983. Although it is possible that utility shares have earned returns above what was expected, Dr. Vander Weide does not know of any way to determine whether and to what extent utility shares have earned returns above what was expected because he knows of no way to determine what interest rates were expected by investors in each period.

c) In Dr. Vander Weide's judgement, can some of the higher experienced risk premium earned by the BMO utility sample since 1983 relative to that of the TSX utility group since 1956 be due to the decline in interest rates since 1983? If not please explain in detail.

Response:

While it is possible that some of the higher experienced risk premium earned by the BMO CM utility sample since 1983 relative to risk premium experienced by the S&P/TSX utilities since 1956 is due to the decline in interest rates since 1983, in Dr. Vander Weide's opinion, there is no way to know whether the higher experienced risk premium earned by the BMO CM data set of stocks is due to the decline in interest rates since 1983. Because Dr. Vander Weide believes there is no way to know whether the higher experienced risk premium on the BMO CM is the result of declining interest rates, he believes it is reasonable to give equal weight to the risk premiums on the BMO CM utility stocks and the S&P/TSX utilities index. Please refer also to the response to JIESC/BCOAPO/CEC IR 1.54(b) above and 1.54(d) below.

d) In view of Dr. Vander Weide's judgment on page 8 that "it is best to use long run periods of history," why should any weight be placed on the period since 1983, rather than the longer period since 1956?

Response:

Dr. Vander Weide believes that equal weight should be placed on returns for the BMO CM utilities stocks since 1983 because: (i) the BMO CM utilities stocks database contains Canadian companies that receive a higher percentage of revenues from traditional utility operations than the companies in the S&P/TSX index; and (ii) the longest period for which the BMO CM data are available is 1983 to the present.

e) Please provide the return on the long Canada bond for the two sub periods in Table 1 from the same CIA source used to obtain the yields.

Response:

In responding to the request, Dr. Vander Weide notes that the total annual return index for long-term Government of Canada bonds is not relevant to this proceeding because the AAM ROE Formula is based on the CAPM, which requires information on the risk-free rate of interest, not the return on long-term Canada bonds. For long-term investments such as utility stocks, the risk-free rate is best measured by the yield to maturity on long-term government bonds. However, the requested information on the average return on long-term Canada bonds for each year from 1956 through 2008 is shown below. The average return on the long Canada bond over the period 1956 – 2008, as measured by the Canadian Institute of Actuaries, is 7.85 percent. The average return on the long Canada bond over the period 1983 – 2008 is 11.24 percent. The returns in each year beginning in 1956 are shown in the table below.

Line	**Year**	**Return Canada Long Bonds**
1	1956	-3.63
2	1957	5.89
3	1958	-5.69
4	1959	-4.43
5	1960	7.10
6	1961	9.78
7	1962	3.05
8	1963	4.26
9	1964	6.97
10	1965	0.96
11	1966	1.55
12	1967	-2.20
13	1968	-0.80
14	1969	-2.01
15	1970	21.98
16	1971	11.55
17	1972	1.11
18	1973	1.71
19	1974	-1.69
20	1975	2.82
21	1976	19.02
22	1977	5.97
23	1978	1.29
24	1979	-2.62
25	1980	2.06
26	1981	-3.02
27	1982	42.98
28	1983	9.60
29	1984	15.09

Line	**Year**	**Return Canada Long Bonds**
30	1985	25.26
31	1986	17.54
32	1987	0.45
33	1988	10.45
34	1989	16.29
35	1990	3.34
36	1991	24.43
37	1992	13.07
38	1993	22.88
39	1994	-10.46
40	1995	26.28
41	1996	14.29
42	1997	17.45
43	1998	14.13
44	1999	-7.15
45	2000	13.64
46	2001	3.92
47	2002	10.09
48	2003	8.06
49	2004	8.46
50	2005	15.05
51	2006	3.22
52	2007	3.30
53	2008	13.65
54	Average 1956-2008	7.85
55	Average 1983- 2008	11.24

JIESC/BCOAPO/CEC-TGI-55.

TOPIC: **TSX Utilities**

REFERENCE: **Evidence of Dr. Vander Weide, Page 13, Table 1**

REQUEST:

a) Please confirm that most of the firms listed as TSX utilities are power firms (electricity generation).

Response:

Dr. Vander Weide confirms that most of the firms included in the S&P/TSX utilities index are involved in electricity generation, but some are also involved in the transmission and distribution of natural gas, electricity, and/or water.

b) Please discuss why Professor Vander Weide uses a BMO index as well as a TSX index and his involvement with personnel from BMO in developing his testimony and knowledge of Canada,

Response:

Dr. Vander Weide uses a BMO CM utilities stocks database as well as the S&P/TSX utilities index because the BMO CM utilities stocks database contains Canadian companies that receive a higher percentage of revenues from traditional utility operations than the companies in the S&P/TSX index. In Dr. Vander Weide's professional judgment, the Canadian companies in the BMO CM utilities stocks database provide useful information for determining the experienced returns on Canadian utilities stocks. Dr. Vander Weide received data on the returns in the BMO CM utilities stocks database from BMO. However, Dr. Vander Weide developed the opinions he provides in his written evidence independently and without any involvement of BMO personnel.

c) Please discuss the rate of return regulated activities of TransAlta.

Response:

Dr. Vander Weide has not studied the rate-of-return-regulated activities of TransAlta.

d) Please discuss in full Dr. Vander Weide's risk ranking of TGI relative to TransAlta and the other Canadian unregulated power firms included in the TSX utilities group.

Response:

Dr. Vander Weide has not performed a detailed risk ranking of TGI relative to TransAlta and the other Canadian unregulated power firms included in the S&P/TSX utilities index.

JIESC/BCOAPO/CEC-TGI-56.

TOPIC: **0.50 bp Adjustment to Long Canada Bond Yields**

REFERENCE: **Evidence of Dr. Vander Weide, Page 17**

REQUEST:

a) Is Professor Vander Weide aware and agree that if the "beta " of a utility is 0.50, then using an adjustment mechanism of 0.50 means that the market expected return is invariant to interest rate changes? If not in agreement, why not?

Response:

Dr. Vander Weide recognizes that if both: (i) the expected return on the market is invariant to changes in interest rates; and (ii) the traditional CAPM completely explains the expected rates of return on utility stocks, then the change in the cost of equity will equal (1 – beta) times the change in the risk-free rate. If either condition fails, then the conclusion does not follow.

b) Does Professor Vander Weide believe that the expected return on the market is invariant to changes in interest rates?

Response:

No.

c) Does Professor Vander Weide believe in the CAPM and does he believe that CAPM expected rates of return are invariant to changes in interest rates?

Response:

Dr. Vander Weide recognizes that the CAPM is one approach to estimating the cost of equity and that there continues to be research into the ability of the CAPM to explain security market returns. However, Dr. Vander Weide provides evidence in his Written Evidence that the CAPM does not predict the relationship between risk and return for Canadian utility stocks. Specifically, while the CAPM predicts that a utility company's beta will equal the ratio of the risk premium on the utility's stock to the risk premium on the market index, and investors generally believe that utilities are less risky than the market index, Dr. Vander Weide's ex post risk premium studies indicate that the actual risk premiums on utility stocks from 1956 to the present and 1983 to the present have substantially exceeded the risk premium on the Canadian market index. This evidence suggests either that the BCUC should: (1) give less weight to the results of the CAPM than in previous decisions; or (2) apply the CAPM with a significantly higher beta than that used in previous decisions. Dr. Vander Weide does not believe that CAPM expected rates of return are invariant to changes in interest rates.

d) Does Professor Vander Weide teach the CAPM and portfolio theory? If so, please provide a copy of his most recent course outlines.

Response:

Dr. Vander Weide briefly discusses the CAPM and other cost of equity models in executive education programs, for which there are no course outlines.

e) Please discuss if the volatility attached to utility stocks is idiosyncratic and can be removed through diversification or not.

Response:

The volatility of utility stocks consists of two parts: (i) a part that is explained by specific factors such as the return on a market index, interest rates, market capitalization, and book-to-market; and (ii) a random error term that cannot be explained by specific economic factors. Only that part of the volatility of utility stock returns that is due to the random error term can be diversified away.

f) Please confirm that the only risk comparison in Dr. Vander Weide's testimony is the statement on page 16 that Canadian utilities have more regulatory risk due to the fact that they have formula determined ROEs. If not please explain in full where and on what basis he has assessed the risk of TGI relative to his sample of US utilities.

Response:

Dr. Vander Weide's assessment of the risk of TGI relative to his sample of U. S. utilities is as follows:

Risk	Risk Factor	TGI Compared to U. S. Utilities
BUSINESS RISK		
	Exposure to competition	More risky because electricity is more competitively priced in British Columbia
	Exposure to changing technology	Similar risk
	Exposure to environmental restrictions	Similar risk
	Overall assessment	Similar business risk
Regulatory Risk		
	Cost of service regulation	Similar risk
	Deferral accounts	Similar risk
	Annual rate setting	TGI Less risky
	Rate decoupling	Similar risk
	Income taxes	TGI more risky due to flow-through treatment compared to normalized treatment in U. S.
	Allowed ROEs	TGI more risky because formula ROE more likely to differ from the market cost of equity than ROEs based on market evidence in each rate proceeding
	Overall assessment	Slightly more risky
Financial Risk		
	Capital Structure	TGI more risky due to lower allowed equity ratios
	Overall assessment	TGI greater financial risk

JIESC/BCOAPO/CEC-TGI-57.

TOPIC: **US and Canadian Utility Comparability**

REFERENCE: **Evidence of Dr. Vander Weide, Page 16**

REQUEST:

a) Dr Vander Weide claims that US and Canadian utilities are similar in terms of business risk because they use the same technology, have the same underlying economics and the same regulatory principles, would he agree that the same principle applies to banking since both countries enforce the same regulatory principles set by the Bank for International Settlements (BIS)? If not agreed, why not? Outline in what ways the US and Canadian utilities are dissimilar.

Response:

Dr. Vander Weide's written evidence addresses the fair rate of return for TGI, not the fair rate of return for Canadian banks. A study of the comparability of U.S. and Canadian banks would not provide any relevant information on TGI's fair rate of return. Further, Dr. Vander Weide notes that U.S. and Canadian banks are dissimilar to U.S. and Canadian utilities in that U. S. and Canadian banks face greater competition and are not rate-of-return regulated. In addition, banks in general have numerous lines of business with different business and financial risk profiles than utilities.

b) Please indicate all Canadian and US banks that have either failed or been forcibly acquired over the last two years.

Response:

Dr. Vander Weide has not studied which Canadian and U. S. banks have failed or been forcibly acquired over the last two years; he believes that such a study is irrelevant to his evidence provided in this proceeding which relates to the fair rate of return for Canadian utilities, not the fair rate of return for Canadian banks.

c) Is Dr. Vander Weide aware of the new proposals in the US outlined by President Obama to remedy the regulatory failures evident in the US financial system? Briefly outline the proposals.

Response:

President Obama's proposals to regulate the U. S. financial system are irrelevant to this proceeding because banks are not regulated as to their rate of return, as are utilities. In addition, banks do not have similar risks to those of regulated utilities.

d) Can Dr. Vander Weide explain what he understands by "light handed" regulation in the US and whether this has had any influence on the failures of the US regulatory system?

Response:

Dr. Vander Weide does not understand what the question means by the phrase, "light-handed regulation in the U. S." Dr. Vander Weide does not believe that the regulation of U. S. utilities is "light handed" in any sense, nor does he believe that the U. S. regulatory system for utilities has failed. Further, there is no connection between the U. S. regulatory system for banks and the U. S. regulatory system for utilities. Therefore, any opinions Dr. Vander Weide might have regarding the regulatory system for banks are completely irrelevant to his opinions about the regulatory system for U. S. utilities.

e) Can Dr. Vander Weide please indicate which of the companies in his US utility samples in Exhibits 5 & 6 are regulated on an historic cost rather than a forward test year basis, and whether the allowed ROE should be the same regardless of the test year basis of the rate base to which it is applied.

Response:

Dr. Vander Weide has not studied which of the companies in his U. S. utility samples in Exhibit 5 and Exhibit 6 are regulated on an historic cost basis rather than on a forward test year basis. Such a study would be both time consuming and costly and is irrelevant to this proceeding because Dr. Vander Weide's evidence relates to the average overall risk of U. S. utilities compared to TGI, not simply to the risk of using historical cost versus forward cost test years. In addition, Dr. Vander Weide does not claim that each utility in his groups of U. S. utilities is comparable in risk to TGI; rather, for the reasons cited in his written evidence, Dr. Vander Weide believes that the groups of U. S. utilities are comparable on average to the risk of TGI.

JIESC/BCOAPO/CEC-TGI-58.

TOPIC: **Forward Looking Utility Risk Premiums**

REFERENCE: **Evidence of Dr. Vander Weide, Page 17 on**

REQUEST:

a) Can Dr. Vander Weide please confirm that his forward looking estimates are based on analyst forecasts compiled from the IBES data base?

Response:

Dr. Vander Weide confirms that his forward-looking estimates of the required risk premium on utility stocks use data on analysts' forecasts from the I/B/E/S Thomson Reuters financial data base.

b) Please provide all analyses that Professor Vander Weide has performed to correct for the well known optimism bias attached to analyst forecasts.

Response:

Dr. Vander Weide denies the hypothesis of the question.

c) Please provide copies of any research performed by Dr. Vander Weide on the unbiased nature of analyst forecasts during the period up to 2002 when US investment banks in the Global Settlement admitted that such forecasts and reports were biased.

Response:

Dr. Vander Weide has reviewed the research literature on analysts' forecasts. The research literature on analysts' growth forecasts addresses three basic questions: (1) Are analysts' forecasts superior to historical growth extrapolations in their ability to forecast future earnings per share? (2) Is the correlation between changes in analysts' EPS growth forecasts and stock prices greater than the correlation between historical earnings growth rates and stock prices? and (3) Are analysts' growth forecasts overly optimistic? With regard to the research literature on whether analysts' forecasts are superior to historical growth extrapolations in their ability to forecast future earnings per share, Dr. Vander Weide concludes that the research literature provides strong support for the conclusion that security analysts' EPS growth forecasts are reasonable proxies for investor growth expectations, while historical growth extrapolations and retention growth rates are not. With regard to the literature regarding whether the correlation between changes in analysts' EPS growth forecasts and stock prices is greater than the correlation between historical earnings growth rates and stock prices, Dr. Vander Weide concludes that the research literature supports the conclusion that analysts' growth forecasts are the best proxy for investors' growth expectations. With regard to the literature regarding whether analysts' growth forecasts are overly optimistic, Dr. Vander Weide concludes that available research evidence strongly supports the hypothesis that analysts' growth forecasts are not optimistic.

In addition, Dr. Vander Weide does not agree that U.S. banks admitted that analysts' "forecasts and reports were biased." Rather, U.S. banks agreed to settle the complaint without admitting or denying Mr. Spitzer's allegations.

d) Can Dr. Vander Weide please confirm that his "forward looking estimates are based in part on data from the period when US investment banks have admitted that US security analyst reports were biased.

Response:

Dr. Vander Weide does not confirm the statement. See response to JIESC/BCOAPO-CEC IR 1.58(c).

e) Can Dr. Vander Weide confirm that unlike other witnesses, like Ms. McShane, he has not moderated his use of analyst growth estimates by tapering them to a longer run forecast based on GDP growth estimates?

Response:

Dr. Vander Weide confirms that he relies entirely on analysts' growth forecasts to estimate the growth component in his DCF analyses.

JIESC/BCOAPO/CEC-TGI-59.

TOPIC: **DCF Implied Risk Premiums**

REFERENCE: **Evidence of Dr. Vander Weide, Page 18-20**

REQUEST:

a) Please provide the full regression model [in Excel format if possible], complete with standard statistics, estimated for the equation on page 20 and the actual estimate that produces the forward looking risk premia of 7.5-8.0%.

Response:

The full regression model in excel format is provided under Attachment 59a. The data used in the regression studies are shown in Exhibit 5 and Exhibit 6 and the full regression model with standard statistics is described in the attached Exhibit 13, Appendix 3, pp. 53 – 54, of Dr. Vander Weide's evidence. Dr. Vander Weide notes that the response to BCUC IR 1.78.2, Attachment 78.2 contains a corrected version of Appendix 3 replacing the filed document, which contained typographical errors in the statistics.

b) Please break out the data in Exhibits 5 & 6 into the dividend yield and growth components and provide the monthly data back to September 1999.

Response:

The quarterly DCF equation used to estimate the cost of equity in Exhibit 5 and Exhibit 6 does not contain a simple dividend yield and expected growth component that can be added to obtain the DCF expected rate of return. Further, Dr. Vander Weide notes that the quarterly DCF cost of equity is given by the equation:

$$k = \left[\frac{d_0 (1+g)^{\frac{1}{4}}}{P_0 (1-FC)} + (1+g)^{\frac{1}{4}} \right]^4 - 1.$$

In responding to this request, Dr. Vander Weide also notes that there is a typographical error in Dr. Vander Weide's filed written evidence; the "$(1 + g)^{1/4}$" term in this equation was inadvertently omitted. The typographical error does not affect the underlying calculations in Dr. Vander Weide's evidence.

c) Please provide a separate regression analyses based on the difference between the dividend yield and the long bond yield and the growth component and the long bond yield equivalent to the equation on page 20, complete with all the underlying statistics.

Response:

Since the quarterly DCF equation used to estimate the cost of equity in Exhibit 5 and Exhibit 6 cannot be broken down into the sum of the dividend yield and the growth rate, such a regression analysis would provide no meaningful information regarding Dr. Vander Weide's regressions. In addition, Dr. Vander Weide only posits that the risk premium, that is, the difference between the cost of equity and the yield on long-term Treasury bonds, is related to interest rates. He does not hypothesize that either the premium of the dividend yield over the interest rate or the premium of the growth rate over the interest rate is related to the level of interest rates.

d) Please provide the basic regression statistics attached to the latest DCF utility risk premium estimate of 4.40% and explain in detail why this is not the best estimate of the utility risk premium in the US.

Response:

Dr. Vander Weide does not understand the reference to a 4.40 percent "latest DCF utility risk premium estimate." Dr. Vander Weide does not refer to a 4.40 percent utility risk premium at pages 18 – 20 of his written evidence. As discussed on page 20 of Dr. Vander Weide's written evidence, the forward-looking, or ex ante, risk premium, based on the relationship between the DCF cost of equity and interest rates, is in the range 7.5 percent to 8.0 percent. As shown in Exhibit 5 and Exhibit 6, the "latest," that is, February 2009, DCF-based risk premium for the electric utilities is 8.71 percent; and for the natural gas utilities, 7.72 percent.

e) Please explain why estimating a regression equation on historic data and using a forecast interest rate is "better" than simply using the latest DCF estimate.

Response:

Dr. Vander Weide does not believe that 'estimating a regression equation on historic data and using a forecast interest rate" is necessarily "better" than simply using the latest DCF estimate. Instead, Dr. Vander Weide believes that his ex ante risk premium analyses and his DCF analyses provide independent estimates of the required risk premium and cost of equity. The ex ante risk premium analysis is different from a direct DCF estimate of the cost of equity in that it considers the relationship between the DCF-based risk premium and interest rates, whereas the latest DCF estimate does not consider that relationship.

JIESC/BCOAPO/CEC-TGI-60.

TOPIC: **DCF Implied Risk Premiums**

REFERENCE: **Evidence of Dr. Vander Weide, Page 18 & Page 54**

REQUEST:

a) Dr. Vander Weide uses a quarterly dividend discount model. Please provide all evidentiary support for the assumption that utilities increase their dividends on a quarterly basis.

Response:

The dividends for the firms in Dr. Vander Weide's sample are paid quarterly but do not increase quarterly. However, from more than 30 years of experience in using the DCF Model, Dr. Vander Weide has found that the results of assuming that dividends are paid quarterly and increase quarterly are not significantly different from the results of assuming that dividends are paid quarterly and increase annually. Given the insignificant difference between the two results, it is advantageous to use an equation that assumes that dividends are paid quarterly and increase quarterly because it reduces the data collection effort significantly.

b) Please provide the quarterly dividend for TransCanada, Enbridge Inc, Canadian Utilities, Emera and Fortis since 2000.

Response:

Dr. Vander Weide did not conduct a DCF analysis for TransCanada, Enbridge, Inc., Canadian Utilities, Emera, and Fortis because it is difficult to obtain a reasonable number of analysts' growth forecasts for these companies. Furthermore, information on the dividend payments of these companies is publicly available.

c) Please provide any published academic literature that supports the application of a quarterly dividend discount model to determine the fair ROE for a utility.

Response:

The DCF Model is based on the assumption that a company's stock price is equal to the present value of its expected future dividends. When dividends are paid quarterly, the quarterly DCF model is the only DCF model that equates a company's stock price to the present value of its expected future dividends. This simple fact is so obvious that it would not be a suitable topic for a published academic article.

d) Please indicate whether awarding a fair ROE based on the current annual dividend updated by its annual growth rate allows the investor to earn a quarterly rate of return by reinvesting the quarterly dividend.

Response:

Dr. Vander Weide's studies indicate that calculating the cost of equity using an annual DCF model where the current annualized dividend is multiplied by one plus the annual growth rate produces results that are generally similar to the results of applying a quarterly model. Thus, while the quarterly model is theoretically correct, the difference between the results of the quarterly model and a correctly applied annual model is generally immaterial.

JIESC/BCOAPO/CEC-TGI-61.

TOPIC: **Standard Deviation Risk Assessments**

REFERENCE: **Evidence of Dr. Vander Weide, Page 23**

REQUEST:

a) Please indicate any research Dr. Vander Weide is aware of (with relevant citations) that bases risk assessments on the ratio of two standard deviations for undiversified portfolio's.

Response:

Please see response to BCUC 1.14.5.1.

b) Please indicate that if the standard deviation of the utilities sub index were higher due to fully diversifiable risk factors, such as interest rate changes, then this risk assessment process overstates utility risk. If not agreed, why not?

Response:

The use of the standard deviation of the utilities index may slightly overstate the risk of investing in utility stocks. However, the evidence on the relative standard deviation of utility stock returns to the standard deviation of the S&P/TSX Composite stock returns is consistent with the evidence that utility investors have earned higher returns than investors in the S&P/TSX Composite. In contrast the intervenors' traditional low beta estimates for Canadian utilities (for example, beta estimate of approximately 0.50) are not consistent with the evidence that Canadian utility stock investors have earned higher returns than investors in the S&P/TSX Composite over two long time periods, 1956 – 2008 and 1983 – 2008.

c) In Table 3 please regress the returns of the BMO and TSX utility index on both the TSX market return and the return on the long Canadian bond obtained from the same Canadian Institute of Actuaries data base that Dr. Vander Weide used to obtain yield estimates and report the results and relevant statistics.

Response:

Dr. Vander Weide did not regress the returns of the BMO CM and S&P/TSX utilities index on both the TSX market return and the return on the long Canadian bond obtained from the same Canadian Institute of Actuaries data base because such a study would not provide relevant information for this proceeding. First, as discussed in response to BCUC IR 1.14.5, Dr. Vander Weide does not believe that utility stock investors are interested in short-run correlations between utility stock returns and composite market returns. Second, Dr. Vander Weide does not believe that the return on long Canada bonds is a reasonable measure of the risk-free rate of interest. Dr. Vander Weide notes that if JIESC/BCOAPO/CEC are interested in this information, they can easily conduct such a regression.

d) Given c) above does Dr. Vander Weide believe that utilities are interest rate sensitive investments and does he believe this risk is priced by investors?

Response:

Yes. Any interest rate sensitivity of utility stocks is likely to be reflected in the stock price. Please also see response to JIESC/BCOAPO/CEC IR 1.54(a).

JIESC/BCOAPO/CEC-TGI-62.

TOPIC: **TGI Yield Spreads**

REFERENCE: **Evidence of Dr. Vander Weide, Page 25**

REQUEST:

a) Please update Dr. Vander Weide's estimate of the current and forecast long Canada (30 year) bond yield and the yield on TGI's long term debt.

Response:

As of July 13, 2009 RBC Capital Markets indicated that the long-term Canada bond yield was 3.86% and a new issue credit spread would be approximately 1.80%, for an estimated TGI debt yield of 5.66%.

The long-term Government of Canada bond yield forecast utilizing the consensus forecast released the week of July 13, 2009 is 4.140% derived as follows:

ROE Calculation Date	2009 Jul	
1. Ten Year Canada bond yield forecast - 3 month	3.500	a
Ten Year Canada bond yield forecast - 12 month	3.800	b
10 year bonds - Average of 3 & 12 month forecast	3.650	c=(a+b)/2
2. Add 10 year / 30 year Bond Yield Spread (these are actual spreads from prior month)	0.490	d
3. Equals Forecast Yield on 30 year Canada bonds	4.140	e=c+d

Assuming a new issue credit spread as indicated above of 1.80%, a forecast long term debt yield would be 5.94%.

b) Has the decline in TGI's spread over the long Canada bond yield since the time of Dr. Vander Weide's testimony caused him to reconsider his recommendations?

Response:

No. Dr. Vander Weide has conducted six tests of the validity of the AAM ROE Formula, and only one of those tests depends on the relationship between the interest rate on TGI's long-term debt and the long Canada bond yield. His other five tests continue to demonstrate that the AAM ROE Formula does not provide a fair rate of return for TGI. In addition, Dr. Vander Weide notes that, even absent his other five tests, that the AAM ROE Formula result declined when interest rates on TGI's bonds increased is evidence that the AAM ROE Formula is not generally valid.

c) If TGI's spread tightened back to the 120 bps level and the long Canada bond yield increased to 4.5%, both consistent with a strong economy, would Dr. Vander Weide accept that the BCUC formula ROE was fair and reasonable? If not agreed, why not?

Response:

Dr. Vander Weide does not accept that the AAM ROE Formula is fair and reasonable. As described in his written evidence, Dr. Vander Weide provides six tests of the reasonableness of the results provided by the AAM ROE Formula. Five of these tests continue to demonstrate that the AAM ROE Formula does not produce a fair rate of return for TGI. Further, even if TGI's spread tightens back to the 120 bps level, there is no guarantee that this spread will remain in the future. Thus, Dr. Vander Weide's sixth test also demonstrates that the AAM ROE Formula is not generally valid.

JIESC/BCOAPO/CEC-TGI-63.

TOPIC: **Utility WACC**

REFERENCE: **Evidence of Dr. Vander Weide, Page 38, Table 7**

REQUEST:

a) Please confirm that in estimating the utility WACC Dr. Vander Weide recommends any combination of debt and equity that results in a WACC of 8.0%.

Response:

Dr. Vander Weide specifically recommends that TGI be awarded an allowed ROE 11.0 percent on an equity base of 40 percent (see Vander Weide Written Evidence, page 38, Answer 116).

b) Please calculate the ATWACC, that is the cost of equity and the after tax cost of debt, using a 30% tax rate with TGI's 35% common equity ratio, his suggested 40% and 50%. Which of these capital structures would ratepayers prefer given that he is indifferent between them?

Response:

Dr. Vander Weide's recommendation that TGI be awarded an 11.0 percent ROE on an equity base of 40.0 percent is based on his calculation of the average 8.0 percent allowed WACC for U. S. utilities rather than on an ATWACC calculation. The average allowed return is best expressed in terms of a WACC because taxes are treated as an operating expense for rate making purposes.

In addition, Dr. Vander Weide has not stated that he is "indifferent between" capital structures that generate the same ATWACC.

c) In the recent Albert Utilities Commission Dr. Vander Weide provided testimony with Drs. Kolbe and Vilbert on behalf of NGTL. Can Dr. Vander Weide confirm that they proposed any combination of debt and equity that kept the ATWACC constant?

Response:

Cannot confirm. Dr. Vander Weide recalls that Drs. Kolbe and Vilbert proposed any combination of debt and equity that kept the ATWACC constant within the range of debt and equity percentages for which the ATWACC is constant.

d) Is it possible for ATWACC and WACC both to remain constant as the debt ratio is varied for a taxable firm? If not can Dr. Vander Weide explain in detail why he recommends keeping the WACC, rather than the ATWACC constant?

Response:

No. Dr. Vander Weide proposes keeping the WACC constant because his analysis is based on average allowed returns and average allowed capital structures of U. S. utilities. The WACC is more appropriate for expressing the allowed returns for utilities because taxes are treated as an operating expense in utility rate making. In short, the cost of debt is treated on a before-tax basis in utility rate making.

Attachment 6a

Terasen Gas Inc.

Approved Rate Base Deferrals

As at December 31

Line No.	Particulars	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
Volume and Gas Cost Related Deferrals																
1	Midstream Cost Reconciliation Account (MCRA)	✓	✓	✓	✓	✓										
2	Commodity Cost Reconciliation Account (CCRA)	✓	✓	✓	✓	✓										
3	MCRA Interest	✓	✓	✓	✓	✓										
4	CCRA Interest	✓	✓	✓	✓	✓										
5	Gas Cost Reconciliation Account (GCRA)						✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
6	CGRA Interest						✓	✓	✓	✓	✓	✓				
7	Revenue Stabilization Adjustment Mechanism (RSAM	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
8	RSAM Interest	✓	✓	✓	✓	✓	✓									
9	Revelstoke Propane Cost	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
10	SCP Net Mitigation Revenues	✓	✓	✓	✓	✓	✓	✓	✓	✓						
11	SCP West to East Transmission	✓	✓	✓	✓	✓	✓	✓	✓							
12	SCP PG&E Contract Cancellation	✓	✓	✓	✓	✓	✓									
13	Deferred 2000 SCP Cost of Service			✓	✓	✓	✓	✓	✓							
14	Non-Core Margin Deferral										✓	✓	✓	✓		
15	Offsystem Sales Coordination Center											✓	✓	✓	✓	✓
16	1993 Industrial Margin Shift														✓	✓
17	T-Service Lost Margin														✓	✓
18	Buy/Sell Incremental Admin Costs								✓	✓	✓	✓	✓	✓	✓	✓
19	ABC T-Service								✓	✓	✓					
Energy Policy Related Deferrals																
20	Demand Side Management	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
21	Demand Side Management - DRIA				✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		
22	NGV Conversion Grants	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
23	NGV Compression Equipment Recovery	✓	✓	✓	✓	✓	✓	✓	✓	✓						
24	NGV Fuelling Probe										✓	✓	✓	✓	✓	✓
25	Burner Tip Service					✓	✓	✓	✓	✓	✓	✓	✓			
26	Water Heater Grants						✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
27	BC 21 Power Smart Program								✓	✓	✓	✓	✓	✓	✓	
28	Residential Thermostat Pilot Program										✓	✓	✓	✓	✓	✓
29	Appliance Insurance Program														✓	✓
30	Deferred Service Line Installation Fee	✓														
Uncontrollable Items																
31	Deferred Interest	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
32	Deferred Interest - funding benefits via Customer Dep	✓	✓	✓	✓	✓										
33	Property Tax Deferral	✓	✓	✓	✓	✓	✓	✓			✓	✓	✓	✓	✓	
34	Bad Debt Allowance for Rates 14 & 14A	✓	✓	✓	✓	✓										
35	Pension Variance	✓	✓	✓	✓	✓										
36	Insurance Variance	✓	✓	✓	✓	✓										
37	BCUC Levies	✓	✓	✓	✓	✓										
38	OSC Certification Compliance	✓	✓	✓	✓	✓										
39	IFRS Conversion Costs	✓														
40	Olympics Security Costs Deferral	✓														
41	BC Energy Council Levies															✓
Tax-related Deferrals																
42	SCP Tax Reassessment	✓	✓	✓												
43	CCT Assessment	✓	✓	✓	✓	✓	✓	✓								
44	2006 LCT Elimination	✓	✓	✓												
45	Carbon Tax Implementation	✓														
46	Carbon Tax Cost of Service	✓														
47	2005 BC Tax Rate Reduction Deferral			✓	✓											
48	Overheads Charge - Income Tax Refund			✓	✓	✓	✓	✓	✓	✓						
49	CIAOC Software Tax Savings/OH Change			✓	✓	✓	✓	✓	✓	✓						
50	CCT Deferral			✓	✓	✓	✓	✓	✓							
Reorganization/Amalgamation Cost Deferrals																
51	Terasen Gas Squamish (TGS) O&M Variance	✓	✓													
52	TGS Amalgamation	✓	✓													
53	Organizational Restructuring Costs								✓	✓	✓	✓	✓	✓	✓	
54	1997 - 2000 Restructuring costs										✓	✓	✓			
55	Corporate Reorganization														✓	✓
Hearing Costs																
56	ROE Hearing 2005	✓	✓	✓	✓											
57	2003 Revenue Requirement		✓	✓	✓	✓	✓	✓								
58	2004 - 2007 Revenue Requirements		✓	✓	✓	✓	✓									
59	Future Revenue Requirements		✓	✓												
60	2001 Rate Design						✓	✓	✓							
61	1998 - 2002 Revenue Requirements								✓	✓	✓	✓	✓			
62	ROE Hearing Costs								✓	✓	✓					
63	1999- 2000 Rate Design									✓						
64	Integrated Resource Plan										✓	✓	✓	✓	✓	✓
65	1996 Rate Design												✓	✓		
66	MX Hearing Costs												✓	✓		
67	1995 IRP Participant Awards												✓	✓		
68	1997 CPCN CCA												✓			
69	1996 - 1997 Revenue Requirements													✓	✓	
70	Rate Design - Phase B														✓	✓
71	1994 - 1995 Revenue Requirements														✓	✓
72	1992 Revenue Requirements														✓	✓
Coastal Facilities																
73	Extraordinary Plant Loss - Lochburn			✓	✓	✓	✓	✓	✓							
74	Relocation					✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	
75	Fraser Valley NBV Amortization					✓	✓	✓	✓	✓						
76	Noncapital Finance Costs						✓	✓	✓	✓						
77	Lochburn NBV Amortization										✓	✓	✓	✓	✓	
78	Preliminary Investigation											✓	✓	✓	✓	
Other																
79	Earnings Sharing Mechanism	✓	✓	✓	✓			✓	✓	✓	✓					
80	Other Post Employment Benefit Funding (OPEB)	✓	✓	✓	✓	✓	✓	✓	✓	✓						
81	Vehicle Lease Deferral		✓	✓	✓											
82	BC Hydro Service Agreement Costs						✓	✓	✓	✓	✓	✓			✓	✓
83	ABC T Project Requirements Phase						✓	✓	✓							
84	Salmon Arm Reinforcement							✓	✓	✓						
85	Local Gas Development								✓	✓	✓	✓	✓	✓	✓	✓
86	Fraser Valley Gas Exploration								✓	✓	✓	✓	✓	✓	✓	✓
87	Westar Receivable								✓	✓	✓	✓	✓	✓	✓	✓
88	Burrard Thermal									✓	✓					
89	Recovery of Non-Utility Service											✓	✓	✓	✓	✓
90	Gain on Sale of Kamloops Property												✓	✓	✓	

Attachment 22d

Debt Capital Markets

Weekly Market Update

July 17, 2009

Economic Highlights

The June FOMC minutes strongly suggest the Fed will not raise rates for some time, barring a quick snap-back in growth. Two nuggets of information mined from the minutes are the Fed's economic forecasts and its assumptions about "potential" growth (2.6%-2.8%) and the "natural" rate of unemployment (4.8%-5.0%). These reveal when policymakers think the economy will return to full capacity and disinflation pressures will subside. Although the Fed expects the recession to end soon, it also sees a soft recovery initially. Consequently, the unemployment rate is expected to remain near 9¾% in late 2010. Only when growth strengthens to just over 4% (1½ percentage points faster than potential) will the jobless rate begin to drop substantively to 8½% by late 2011. The Fed's published annual forecasts end in 2011. However, even if growth remains at this high rate for several more years, surplus labour will persist until late 2014. In fact, the minutes state that most policymakers think it may take "five or six years" to achieve full employment, and several thought it could take longer. Considering the lagged effect of policy on growth, policymakers will need to return the fed funds rate to a more neutral 4%-to-5% about two years before the unemployment gap closes—or late 2012. If rates begin to climb next summer, as we expect, it will take more than two years to renormalize policy—longer than the last two cycles (about two years in 2004-2006 and one year in 1994), but clearly warranted by the massive amount of slack. Of course, the slack could vanish sooner than the Fed expects, as industry restructuring may slash capacity more than expected and worker retraining may lift the natural unemployment rate. Still, the inescapable conclusion is that interest rates may stay put until well into 2010 (if not 2011) and will then rise at a turtle's pace. Adding credence to this view, the minutes stated that the Fed's staff expects monetary policy to "remain stimulative" in 2011 and 2012 because of the still-large output gap and the need to offset fading fiscal stimulus. While this doesn't mean the Fed won't begin to raise rates before 2011, it does suggest it won't be in a hurry to renormalize policy. The combination of solid economic growth yet gradual tightening beyond 2010 could provide a favourable backdrop for corporate bonds and equities.

Corporate Debt Highlights

Credit and equity markets continued to show strength over the past week fuelled by strong earnings by US banks and industrials and better than expected North American economic releases. The ongoing saga around CIT's future has been percolating in the background but has not had much impact on the positive sentiment that has been fuelling the recovery story. Canadian credit markets have been particularly strong this past week in a relatively illiquid summer market that has seen spreads gap in between 10 to 25bps. Looking ahead to next week, barring supply pressures we look to earnings and equities to continue to provide direction in credit markets.

Primary issuance activity was limited to two very well received transactions by Hydro One and Bank of Nova Scotia. Hydro One (A+,AH) was first to market with C$300 MM 31 year issue pricing at 162 bps vs Canada's, flat to secondaries, and tightening in by 5bps on the break. The BMO joint led transaction was broadly distributed across 49 buyers with non-lead orders in the 20% range. Bank of Nova Scotia followed with an upsized C$1 B 5 year senior note issue (AA-, AA) which priced at 100 bps vs Canada's and saw investor fills in the 40-50% range. Senior bank spreads have tightened in materially over the past two months and are now at levels last seen in September 2007. Moreover, with benchmark yields remaining low, the issue came at an attractive coupon of 3.43%. As the Canadian banks have embraced the mortgage purchase operations this year, BNS has been an outlier by being the only Canadian bank to be an active senior note issuer.

Government Debt Highlights

There were no new provincial issues this week. Ongoing secondary market buying helped narrow spreads by ~3 bps across the curve on the week; we closed the Ontario benchmarks at 63 (Sep/14's), 86 (Jun/19's), and 83 (Jun/39's). CMB spreads were similarly several bps tighter across the curve this week – we closed the Jun/14's at +32 over the Cda Jun/14's, narrower by 5 bps on the week.

At its purchase operation Wednesday, CMHC bought $2.33bn out of a maximum $4 bn of 5yr fixed-rate NHA MBS at an average 3.13%, ~20 bps back of a comparable 5yr CMB at the time. This continues the string of undersubscribed CMHC purchase operations dating from February, although the amount purchased this time exceeds the $1.38 bn and $1.49 bn CMHC purchased at its two previous fixed-rate operations. On the same day, Canada re-opened its Dec/14's for $3 bln, in a well-received auction (tail was 0.6 bps and cover 2.19x).

Swap Market Highlights

Market sentiment has shifted 180 degrees since the end of last week as stocks and bond yields pressed meaningfully higher. Rates are higher across the curve from 10-15bps in Canada and 30-40bps in the US. Swap spreads have not moved significantly in Canada but about 5bps higher in the US. As long as the good news/earnings keep rolling in, rates are going to continue northbound.

Current Market Rates (mid)

	C$ Swap Spreads		US$ Swap Spreads		C$ / US$ Basis		€ / US$ Basis	
Term	Close	*1 Wk Chg.*	Close	*1 Wk Chg.*	Close	*1 Wk Chg.*	Close	*1 Wk Chg.*
2	4bps	4bps	46bps	8bps	14bps	(1bps)	(33bps)	(2bps)
5	13bps	0bps	48bps	7bps	14bps	0bps	(30bps)	(4bps)
10	15bps	(0bps)	24bps	6bps	13bps	1bps	(19bps)	(4bps)
30	44bps	(1bps)	(20bps)	7bps	(20bps)	(3bps)	1bps	(3bps)

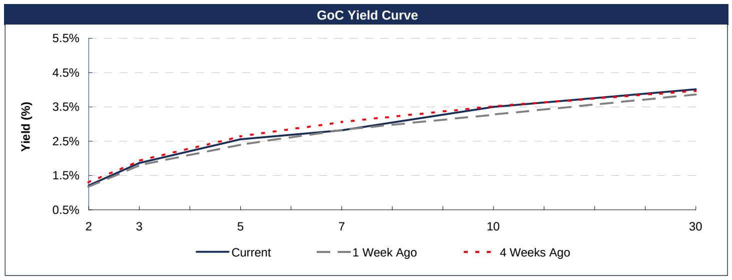
C$ Short Term Rates

	BoC O/N Rate	1 Month BA	2 Month BA	3 Month BA
Close	0.250%	0.394%	0.410%	0.436%
1 Wk Chg.	*0.00 bps*	*0.1 bps*	*0.0 bps*	*0.0 bps*

US$ Short Rates

	Fed Funds Rate	1 Week LIBOR	1 Month LIBOR	3 Month LIBOR
Close	0.250%	0.267%	0.286%	0.504%
1 Wk Chg.	*0.00 bps*	*-0.4 bps*	*-0.6 bps*	*-0.1 bps*

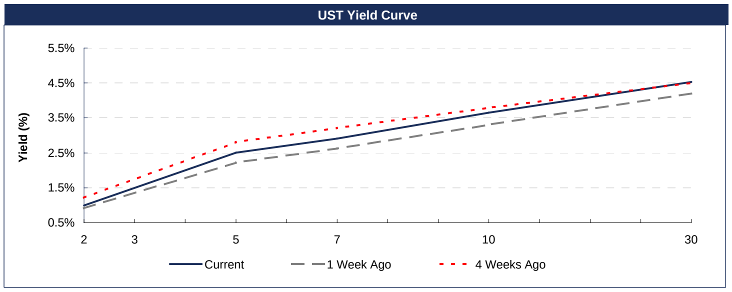
GoC Yield Curve



GoC Yields

	2 yrs	5 yrs	10 yrs	30 yrs
Close	1.21%	2.55%	3.50%	4.01%
1 Wk Chg.	*5bps*	*15bps*	*22bps*	*15bps*

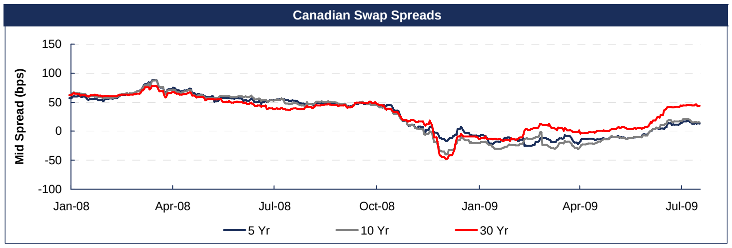
UST Yield Curve



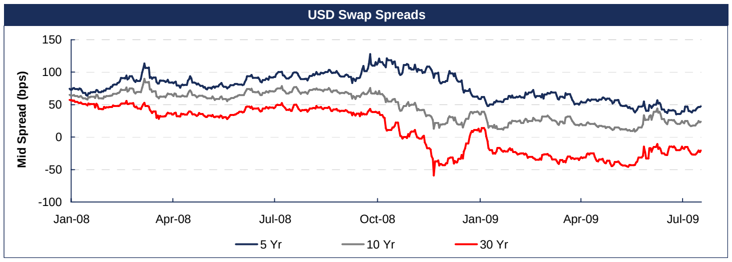
UST Yields

	2 yrs	5 yrs	10 yrs	30 yrs
Close	1.00%	2.51%	3.65%	4.53%
1 Wk Chg.	*9bps*	*29bps*	*34bps*	*33bps*

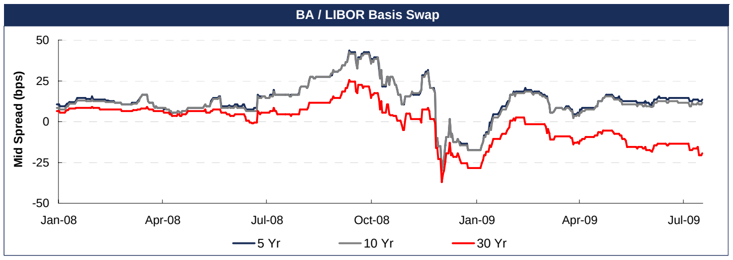
Canadian Swap Spreads



USD Swap Spreads



BA / LIBOR Basis Swap



Debt Capital Markets

Weekly Market Update

July 17, 2009

Domestic New Issuance

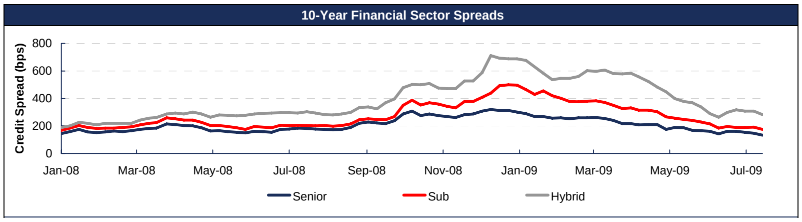
Issuer / Ratings (DBRS/S&P/Moody's)	Corporate / Government	Pricing Date	Amount ($MM)	Term	Coupon	Benchmark	Spread (bps) (1)
Hydro One Inc. (AH/A+/Aa3)	Corporate	13-Jul-09	300	31	5.490%	GoC 5.00% 06/01/2037	162
Bank of Nova Scotia (AA/AA-/Aa1)	Corporate	13-Jul-09	1,000	5	3.430%	GoC 3.00% 06/01/2014	100

(1) Spread to Bench for Government issuance and spread to interpolated Curve for Corporate issuance

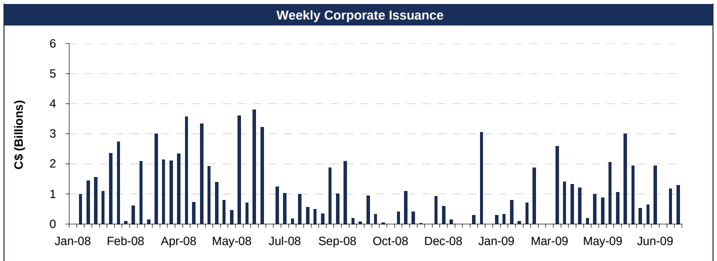
Indicative Generic Pricing

Credit Type	A Corporate		BBB Corporate		AA Senior Bank		AA Subordinated Bank	
Term	5-Year	10-Year	5-Year	10-Year	5-Year	10-Year	10nc5	15nc10
GoC Bench	CAN 3 06/14	CAN 3.75 06/19	CAN 3 06/14	CAN 3.75 06/19	CAN 3 06/14	CAN 3.75 06/19	CAN 3 06/14	CAN 3.75 06/19
GoC Yield	2.55%	3.50%	2.55%	3.50%	2.55%	3.50%	2.55%	3.50%
Credit Spread	*220bps*	*248bps*	*260bps*	*290bps*	*87bps*	*132bps*	*147bps*	*175bps*
Coupon *Including curve adj*	4.79%	5.99%	5.19%	6.41%	3.46%	4.83%	4.06%	5.26%
vs. 3m BA	*212bps*	*237bps*	*252bps*	*279bps*	*79bps*	*121bps*	*139bps*	*164bps*
vs. 3m $LIBOR	*198bps*	*225bps*	*238bps*	*267bps*	*65bps*	*109bps*	*125bps*	*152bps*

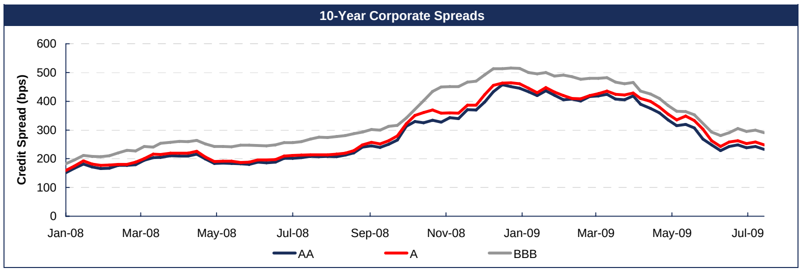
10-Year Financial Sector Spreads



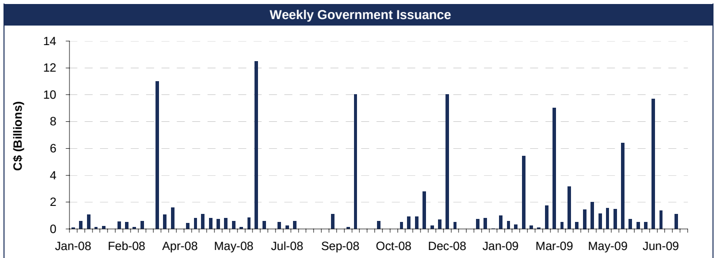
Weekly Corporate Issuance



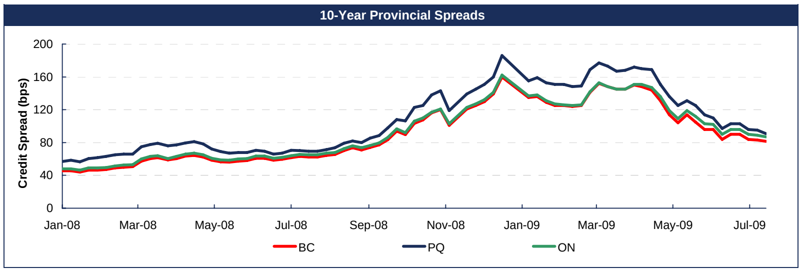
10-Year Corporate Spreads



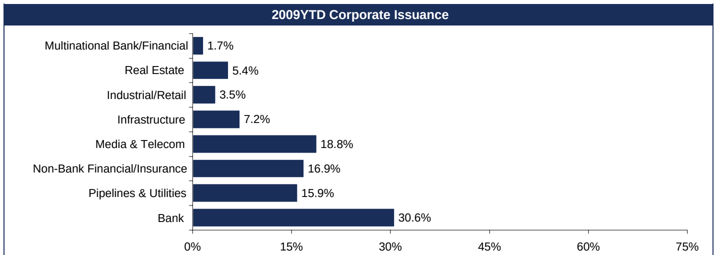
Weekly Government Issuance



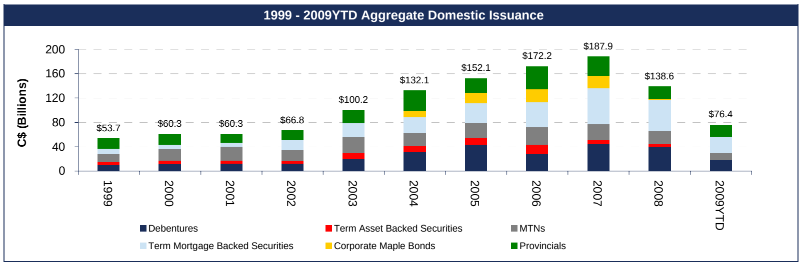
10-Year Provincial Spreads



2009YTD Corporate Issuance



1999 - 2009YTD Aggregate Domestic Issuance



Recent BMO CM-led/co-led Debt Deals

hydroOne	Yellow Pages Group	GazMétro la vie en bleu	Bell		CANADA HOUSING TRUST
$300 million	$260 million	$100 million	$1 billion	$300 million	$5.6 billion
Medium Term Notes Due 2040	Medium Term Notes Due 2015	Medium Term Notes Due 2019	Medium Term Notes Due 2014	Debentures Due 2040	Canada Mortgage Bonds Due 2018 FRN Due 2014
Joint Lead & Joint Bookrunner *July 2009*	Joint Lead & Joint Bookrunner *June 2009*	Lead & Bookrunner *June 2009*	Joint Lead *June 2009*	Co-Lead *May 2009*	Joint Lead *May 2009*

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Debt Capital Markets

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Debt Capital Markets

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Attachment 26b

Bank	City	State	Date of Closing
Founders Bank	Worth	IL	02-Jul-09
Millennium State Bank of Texas	Dallas	TX	02-Jul-09
First National Bank of Danville	Danville	IL	02-Jul-09
Elizabeth State Bank	Elizabeth	IL	02-Jul-09
Rock River Bank	Oregon	IL	02-Jul-09
First State Bank of Winchester	Winchester	IL	02-Jul-09
John Warner Bank	Clinton	IL	02-Jul-09
Mirae Bank	Los Angeles	CA	26-Jun-09
MetroPacific Bank	Irvine	CA	26-Jun-09
Horizon Bank	Pine City	MN	26-Jun-09
Neighborhood Community Bank	Newnan	GA	26-Jun-09
Community Bank of West Georgia	Villa Rica	GA	26-Jun-09
First National Bank of Anthony	Anthony	KS	19-Jun-09
Cooperative Bank	Wilmington	NC	19-Jun-09
Southern Community Bank	Fayetteville	GA	19-Jun-09
Bank of Lincolnwood	Lincolnwood	IL	05-Jun-09
Citizens National Bank	Macomb	IL	22-May-09
Strategic Capital Bank	Champaign	IL	22-May-09
BankUnited, FSB	Coral Gables	FL	21-May-09
Westsound Bank	Bremerton	WA	08-May-09
America West Bank	Layton	UT	01-May-09
Citizens Community Bank	Ridgewood	NJ	01-May-09
Silverton Bank, NA	Atlanta	GA	01-May-09
First Bank of Idaho	Ketchum	ID	24-Apr-09
First Bank of Beverly Hills	Calabasas	CA	24-Apr-09
Michigan Heritage Bank	Farmington Hills	MI	24-Apr-09
American Southern Bank	Kennesaw	GA	24-Apr-09
Great Basin Bank of Nevada	Elko	NV	17-Apr-09
American Sterling Bank	Sugar Creek	MO	17-Apr-09
New Frontier Bank	Greeley	CO	10-Apr-09
Cape Fear Bank	Wilmington	NC	10-Apr-09
Omni National Bank	Atlanta	GA	27-Mar-09
TeamBank, NA	Paola	KS	20-Mar-09
Colorado National Bank	Colorado Springs	CO	20-Mar-09
FirstCity Bank	Stockbridge	GA	20-Mar-09
Freedom Bank of Georgia	Commerce	GA	06-Mar-09
Security Savings Bank	Henderson	NV	27-Feb-09
Heritage Community Bank	Glenwood	IL	27-Feb-09
Silver Falls Bank	Silverton	OR	20-Feb-09
Pinnacle Bank of Oregon	Beaverton	OR	13-Feb-09
Corn Belt Bank & Trust Co.	Pittsfield	IL	13-Feb-09
Riverside Bank of the Gulf Coast	Cape Coral	FL	13-Feb-09
Sherman County Bank	Loup City	NE	13-Feb-09
County Bank	Merced	CA	06-Feb-09
Alliance Bank	Culver City	CA	06-Feb-09
FirstBank Financial Services	McDonough	GA	06-Feb-09

Ocala National Bank	Ocala	FL	30-Jan-09
Suburban FSB	Crofton	MD	30-Jan-09
MagnetBank	Salt Lake City	UT	30-Jan-09
1st Centennial Bank	Redlands	CA	23-Jan-09
Bank of Clark County	Vancouver	WA	16-Jan-09
National Bank of Commerce	Berkeley	IL	16-Jan-09
Sanderson State Bank	Sanderson	TX	12-Dec-08
Haven Trust Bank	Duluth	GA	12-Dec-08
First Georgia Community Bank	Jackson	GA	05-Dec-08
PFF Bank & Trust	Pomona	CA	21-Nov-08
Downey Savings & Loan	Newport Beach	CA	21-Nov-08
Community Bank	Loganville	GA	21-Nov-08
Security Pacific Bank	Los Angeles	CA	07-Nov-08
Franklin Bank, SSB	Houston	TX	07-Nov-08
Freedom Bank	Bradenton	FL	31-Oct-08
Alpha Bank & Trust	Alpharetta	GA	24-Oct-08
Meridian Bank	Eldred	IL	10-Oct-08
Main Street Bank	Northville	MI	10-Oct-08
Washington Mutual Bank	Henderson	NV	25-Sep-08
Washington Mutual Bank FSB	Park City	UT	25-Sep-08
Ameribank	Northfork	WV	19-Sep-08
Silver State Bank	Henderson	NV	05-Sep-08
Integrity Bank	Alpharetta	GA	29-Aug-08
Columbian Bank & Trust	Topeka	KS	22-Aug-08
First Priority Bank	Bradenton	FL	01-Aug-08
First Heritage Bank, NA	Newport Beach	CA	25-Jul-08
First National Bank of Nevada	Reno	NV	25-Jul-08
IndyMac Bank	Pasadena	CA	11-Jul-08
First Integrity Bank, NA	Staples	MN	30-May-08
ANB Financial, NA	Bentonville	AR	09-May-08
Hume Bank	Hume	MO	07-Mar-08
Douglass National Bank	Kansas City	MO	25-Jan-08
Miami Valley Bank	Lakeview	OH	04-Oct-07
NetBank	Alpharetta	GA	28-Sep-07

National City was bought by PNC in October 2008
Wachovia was bought by Wells Fargo in October 2008

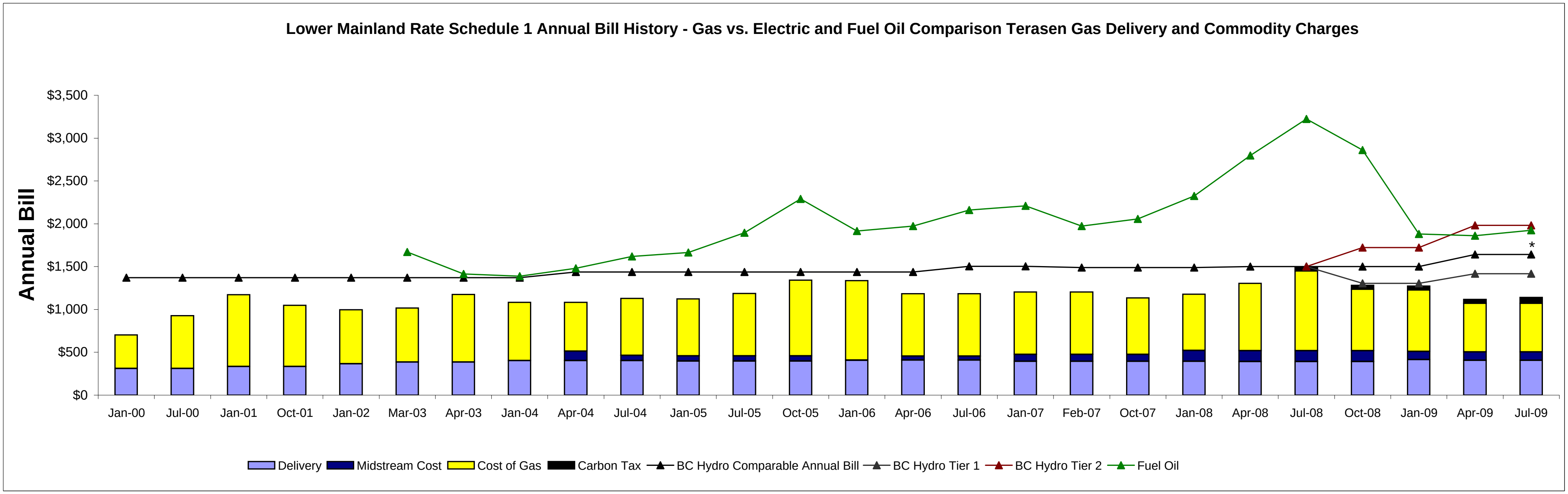
Attachment 32c

DateEntered	p_IssuerName	10yr	30yr
02-Jan-07	Terasen Gas Inc.	70	130
08-Jan-07	Terasen Gas Inc.	75	135
15-Jan-07	Terasen Gas Inc.	73	133
22-Jan-07	Terasen Gas Inc.	70	130
29-Jan-07	Terasen Gas Inc.	69	128
05-Feb-07	Terasen Gas Inc.	68	127
12-Feb-07	Terasen Gas Inc.	68	127
19-Feb-07	Terasen Gas Inc.	68	127
26-Feb-07	Terasen Gas Inc.	68	126
05-Mar-07	Terasen Gas Inc.	58	118
12-Mar-07	Terasen Gas Inc.	62	117
19-Mar-07	Terasen Gas Inc.	64	119
26-Mar-07	Terasen Gas Inc.	64	119
02-Apr-07	Terasen Gas Inc.	64	119
09-Apr-07	Terasen Gas Inc.	64	119
16-Apr-07	Terasen Gas Inc.	64	119
23-Apr-07	Terasen Gas Inc.	65	120
30-Apr-07	Terasen Gas Inc.	65	120
07-May-07	Terasen Gas Inc.	65	120
14-May-07	Terasen Gas Inc.	65	120
22-May-07	Terasen Gas Inc.	65	119
28-May-07	Terasen Gas Inc.	64	118
04-Jun-07	Terasen Gas Inc.	64	117
11-Jun-07	Terasen Gas Inc.	65	120
18-Jun-07	Terasen Gas Inc.	65	120
25-Jun-07	Terasen Gas Inc.	65	120
03-Jul-07	Terasen Gas Inc.	67	122
09-Jul-07	Terasen Gas Inc.	67	122
16-Jul-07	Terasen Gas Inc.	67	122
23-Jul-07	Terasen Gas Inc.	67	122
30-Jul-07	Terasen Gas Inc.	70	125
07-Aug-07	Terasen Gas Inc.	70	125
13-Aug-07	Terasen Gas Inc.	80	125
20-Aug-07	Terasen Gas Inc.	80	125
27-Aug-07	Terasen Gas Inc.	80	125
04-Sep-07	Terasen Gas Inc.	81	126
10-Sep-07	Terasen Gas Inc.	86	131
17-Sep-07	Terasen Gas Inc.	95	135
24-Sep-07	Terasen Gas Inc.	95	140
01-Oct-07	Terasen Gas Inc.	95	140
09-Oct-07	Terasen Gas Inc.	90	135
15-Oct-07	Terasen Gas Inc.	90	135
22-Oct-07	Terasen Gas Inc.	93	138
29-Oct-07	Terasen Gas Inc.	93	138
05-Nov-07	Terasen Gas Inc.	93	138
13-Nov-07	Terasen Gas Inc.	98	143

19-Nov-07	Terasen Gas Inc.	98	143
26-Nov-07	Terasen Gas Inc.	100	145
03-Dec-07	Terasen Gas Inc.	100	145
10-Dec-07	Terasen Gas Inc.	100	145
17-Dec-07	Terasen Gas Inc.	100	140
24-Dec-07	Terasen Gas Inc.	100	140
31-Dec-07	Terasen Gas Inc.	100	140
07-Jan-08	Terasen Gas Inc.	100	140
14-Jan-08	Terasen Gas Inc.	115	155
21-Jan-08	Terasen Gas Inc.	137	157
28-Jan-08	Terasen Gas Inc.	137	157
04-Feb-08	Terasen Gas Inc.	137	157
11-Feb-08	Terasen Gas Inc.	137	157
19-Feb-08	Terasen Gas Inc.	139	159
25-Feb-08	Terasen Gas Inc.	140	160
03-Mar-08	Terasen Gas Inc.	140	155
10-Mar-08	Terasen Gas Inc.	150	165
17-Mar-08	Terasen Gas Inc.	153	168
24-Mar-08	Terasen Gas Inc.	153	168
31-Mar-08	Terasen Gas Inc.	153	168
07-Apr-08	Terasen Gas Inc.	151	166
14-Apr-08	Terasen Gas Inc.	155	175
21-Apr-08	Terasen Gas Inc.	155	175
28-Apr-08	Terasen Gas Inc.	150	170
05-May-08	Terasen Gas Inc.	145	165
12-May-08	Terasen Gas Inc.	145	165
20-May-08	Terasen Gas Inc.	145	165
26-May-08	Terasen Gas Inc.	140	160
02-Jun-08	Terasen Gas Inc.	140	160
09-Jun-08	Terasen Gas Inc.	140	160
16-Jun-08	Terasen Gas Inc.	140	160
23-Jun-08	Terasen Gas Inc.	140	160
30-Jun-08	Terasen Gas Inc.	145	170
07-Jul-08	Terasen Gas Inc.	145	170
14-Jul-08	Terasen Gas Inc.	150	175
21-Jul-08	Terasen Gas Inc.	150	175
28-Jul-08	Terasen Gas Inc.	145	170
05-Aug-08	Terasen Gas Inc.	145	170
11-Aug-08	Terasen Gas Inc.	145	170
18-Aug-08	Terasen Gas Inc.	150	175
25-Aug-08	Terasen Gas Inc.	155	180
02-Sep-08	Terasen Gas Inc.	160	185
08-Sep-08	Terasen Gas Inc.	160	185
15-Sep-08	Terasen Gas Inc.	170	195
22-Sep-08	Terasen Gas Inc.	180	205
29-Sep-08	Terasen Gas Inc.	195	220
06-Oct-08	Terasen Gas Inc.	250	290

14-Oct-08	Terasen Gas Inc.	250	290
20-Oct-08	Terasen Gas Inc.	320	360
27-Oct-08	Terasen Gas Inc.	310	345
03-Nov-08	Terasen Gas Inc.	285	310
10-Nov-08	Terasen Gas Inc.	290	310
17-Nov-08	Terasen Gas Inc.	290	310
24-Nov-08	Terasen Gas Inc.	290	310
01-Dec-08	Terasen Gas Inc.	295	325
08-Dec-08	Terasen Gas Inc.	335	350
15-Dec-08	Terasen Gas Inc.	335	350
22-Dec-08	Terasen Gas Inc.	355	380
29-Dec-08	Terasen Gas Inc.	355	380
05-Jan-09	Terasen Gas Inc.	355	380
12-Jan-09	Terasen Gas Inc.	325	340
19-Jan-09	Terasen Gas Inc.	325	340
26-Jan-09	Terasen Gas Inc.	315	330
02-Feb-09	Terasen Gas Inc.	305	320
17-Feb-09	Terasen Gas Inc.	295	310
23-Feb-09	Terasen Gas Inc.	275	290
02-Mar-09	Terasen Gas Inc.	275	290
09-Mar-09	Terasen Gas Inc.	275	295
16-Mar-09	Terasen Gas Inc.	265	290
23-Mar-09	Terasen Gas Inc.	265	290
30-Mar-09	Terasen Gas Inc.	265	290
06-Apr-09	Terasen Gas Inc.	265	290
13-Apr-09	Terasen Gas Inc.	250	275
21-Apr-09	Terasen Gas Inc.	250	275
27-Apr-09	Terasen Gas Inc.	240	270
05-May-09	Terasen Gas Inc.	220	260
12-May-09	Terasen Gas Inc.	210	250
19-May-09	Terasen Gas Inc.	190	230
25-May-09	Terasen Gas Inc.	170	210

Source: RBC Capital Markets, *Indicative New Issue Pricing*



Assumes:

Natural gas use of 95 GJ

Efficiency of gas equipment is 90% relative to 100% for electricity

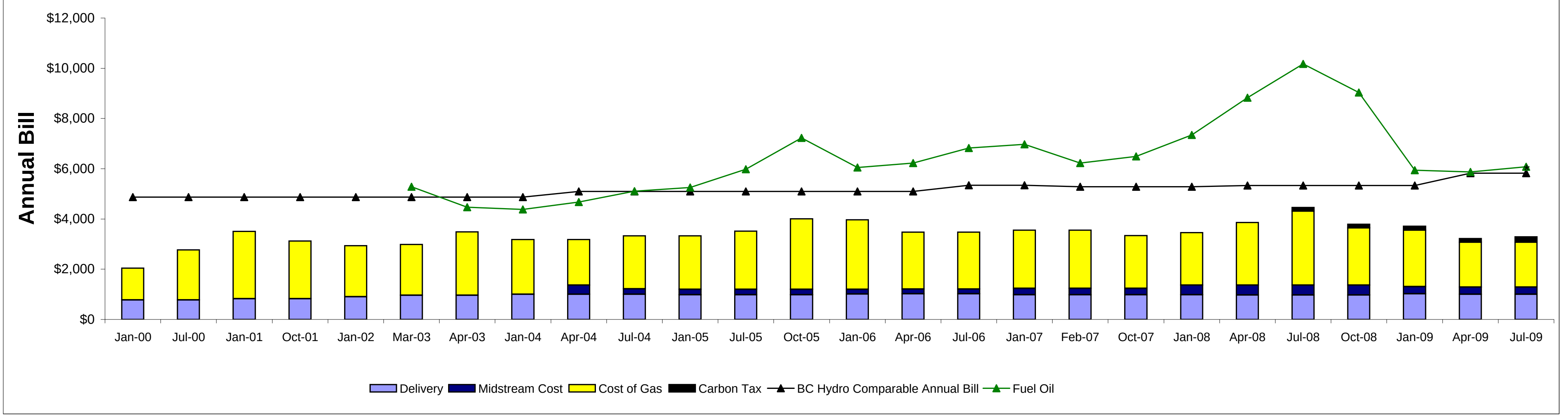
Terasen Gas amount includes the basic charge

BC Hydro amount does not include basic charge since a household already pays the basic electric charge for non-heating use

**Calculated BC Hydro rate based on the F2009-2010 RRA approved increase of 8.74% (inclusive of the applicable 1% rate rider)*

Fuel Oil information is obtained from the MJ Ervin & Associates Weekly Pump Price Survey. This survey is published on MJ Ervin's website weekly, and tracks the retail furnace oil rates (in addition to gasoline, diesel, and propane) across Canada. Terasen only has this data dating back to March 2003.

Lower Mainland Rate Schedule 2 Annual Bill History - Gas vs. Electric and Fuel Oil Comparison Terasen Gas Delivery and Commodity Charges



Assumes:

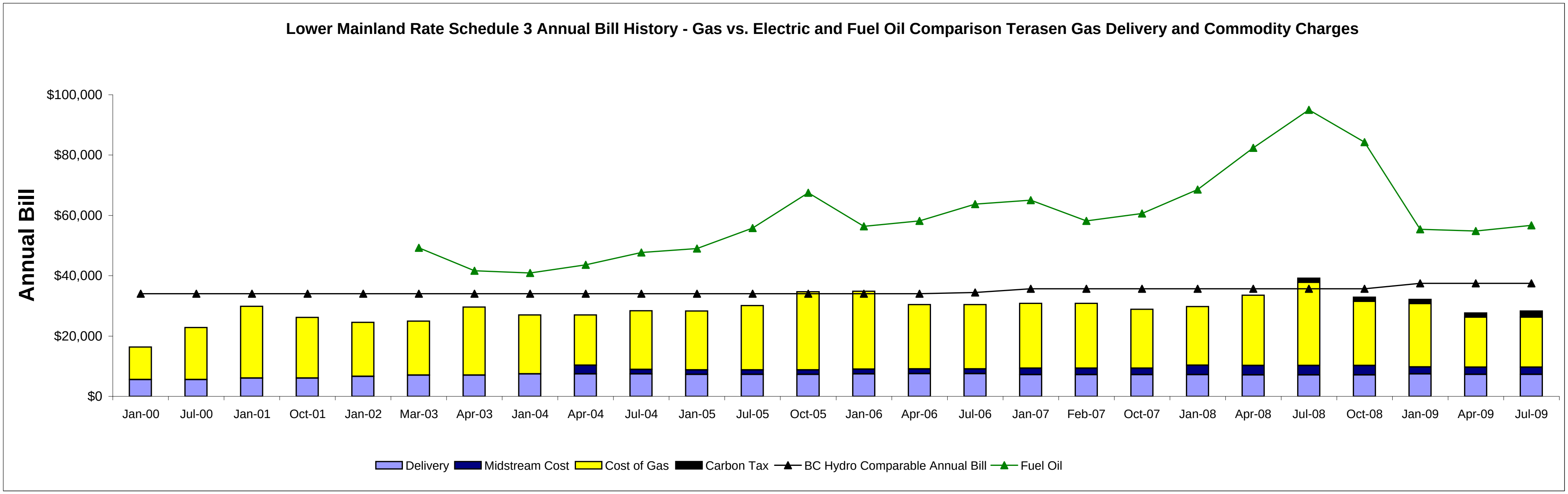
Natural gas use of 300 GJ

Efficiency of gas equipment is 90% relative to 100% for electricity

Terasen Gas amount includes the basic charge

BC Hydro amount does not include basic charge since a household already pays the basic electric charge for non-heating use

Fuel Oil information is obtained from the MJ Ervin & Associates Weekly Pump Price Survey. This survey is published on MJ Ervin's website weekly, and tracks the retail furnace oil rates (in addition to gasoline, diesel, and propane) across Canada. Terasen only has this data dating back to March 2003.



Assumes:

Natural gas use of 2800 GJ

Efficiency of gas equipment is 90% relative to 100% for electricity

Terasen Gas amount includes the basic charge

BC Hydro amount does not include basic charge since a household already pays the basic electric charge for non-heating use

Fuel Oil information is obtained from the MJ Ervin & Associates Weekly Pump Price Survey. This survey is published on MJ Ervin's website weekly, and tracks the retail furnace oil rates (in addition to gasoline, diesel, and propane) across Canada. Terasen only has this data dating back to March 2003.

Attachment 34c

TERASEN GAS INC.

SURREY BRITISH COLUMBIA

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS

RELATED TO GAS PLANT

AT DECEMBER 31, 2007

Gannett Fleming
Valuation and Rate Division

Harrisburg, Pennsylvania   Calgary, Alberta   Valley Forge, Pennsylvania

Gannett Fleming

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Suite 277
200 Rivercrest Drive S.E.
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www.gannettfleming.com

October 10, 2008

Terasen Gas Inc.
16705 Fraser Highway
Surrey, British Columbia V4N 0E8

Attention: Mr. James Wong
Director, Finance and Planning

Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the gas plant of Terasen Gas Inc. at December 31, 2007. The depreciation study has developed depreciation rates for the Mainland, Vancouver Island, and Whistler systems. Our report presents a description of the methods used in the estimation of depreciation, the statistical analyses of service life and net salvage, and the summary and detailed tabulations of annual and accrued depreciation.

We gratefully acknowledge the assistance of Terasen Gas Inc. personnel in the completion of the study.

Respectfully submitted,

GANNETT FLEMING, INC.

LARRY E. KENNEDY
Director, Canadian Services
Valuation and Rate Division

/LEK

CONTENTS

PART I. INTRODUCTION

PART II. METHODS USED IN THE ESTIMATION OF DEPRECIATION

PART III. RESULTS OF STUDY

PART IV. SERVICE LIFE STATISTICS

PART V. DETAILED DEPRECIATION CALCULATIONS

PART I. INTRODUCTION

TERASEN GAS INC.

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO GAS PLANT
AT DECEMBER 31, 2007

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study conducted by Gannett Fleming, Inc. ("Gannett Fleming") for Terasen Gas Inc. (Terasen) to determine the annual depreciation accrual rates and amounts for book and ratemaking purposes applicable to the original cost of gas plant at December 31, 2007. Separate annual accrual rates have been developed for the provision applicable to the average service life and net salvage components of depreciation expense for each of the Terasen Gas Inc., Terasen Gas Vancouver Island, and Terasen Gas Whistler systems.

The depreciation accrual rates presented herein are based on generally-accepted methods and procedures for calculating depreciation. The service life estimates were based on analyses incorporating data through December 31, 2007, a review of Company practices and outlook as they relate to plant operation and retirement, and the service life and net salvage estimates for other gas transmission and distribution companies.

Part I, Introduction, of this report, contains statements with respect to the scope and plan of the report and the basis of the study. Part II, Methods Used in the Estimation of Depreciation, presents the methods used in the estimation of average service lives, survivor curves and net salvage, and in the calculation of depreciation. Part III, Results of Study, presents a summary of annual and accrued depreciation. Part IV, Service Life

Statistics presents the statistical analyses of service life. Part V, Detailed Depreciation Calculations presents the detailed tabulations of annual and accrued depreciation.

BASIS OF THE STUDY

Depreciation. The annual and accrued depreciation were calculated by the straight line method using the average service life procedure and applied on a remaining life basis. The calculations of composite remaining life and annual depreciation accrual amounts were based on attained ages and estimated service life and net salvage characteristics for each depreciable group of assets.

Service Life and Net Salvage Estimates. The method of estimating service lives consisted of compiling the service life history of the plant accounts and subaccounts, reducing this history to trends through the use of Retirement Rate Method of analysis as further described in Part III of this report, and then applying judgment to make a final estimate of average service life. The results of the statistical analysis resulted in the forecasting of the trend of survivors for each depreciable group on the basis of interpretations of past trends and consideration of Company plans for the future. The combination of historical trend and the estimated future trend yielded a complete pattern of life characteristics from which the average service life was derived.

The service life estimates used in the depreciation calculations incorporated historical data compiled from the property records of the Company. Such data included plant additions, retirements, transfers and other activity from 1958 through 2007. A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirement were obtained through discussions with operating and management personnel, and through a tour of company facilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for gas plant. Iowa type survivor curves were used to depict the estimated survivor curves. The estimates of net salvage were based on judgment which incorporated analyses of available historical data, a review of policies and outlook with management, a general knowledge of the gas utility industry, and comparison of the net salvage estimates from studies of other gas utilities. The estimates of net salvage are expressed as the average net percent of the investment to be incurred or recovered upon its retirement. In order to comply with announcements from the Canadian Accounting Standards Board relating to the implementation of the International Financial Reporting Standards ("IFRS"), Terasen has asked Gannett Fleming to develop separate annual accrual and accumulated depreciation calculations related to the requirements for net salvage. A summary of the calculations relating specifically to the net salvage requirement is presented in the Results section of this report.

RECOMMENDATIONS

The calculated annual depreciation accrual rates set forth herein apply specifically to gas plant as of December 31, 2007. Continued surveillance and periodic revisions are required to maintain use of appropriate depreciation rates. The survivor curves, amortization periods and net salvage percents determined in this study should be the basis for periodic recalculations. Complete depreciation studies which re-evaluate these parameters should be performed every three to five years.

PART II. METHODS USED IN THE ESTIMATION OF DEPRECIATION

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DEPRECIATION

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy and obsolescence.

Service Value, in public utility regulation, means the difference between original cost and the net salvage value of gas plant.[1] Net Salvage Value is considered to be the amount received for property retired less any expenses incurred in connection with the sale of the asset, or in preparing the asset for sale.[2] As such, the depreciation study completed by Gannett Fleming and as presented in this report has developed annual accrual rates applicable to both the recovery of the original costs and separately for the net salvage component of the utility assets in service as at December 31, 2007.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal

[1] Federal Energy Regulatory Commission, Natural Gas Act, Part 201-Uniform System of Accounts Prescribed for Natural Gas Companies subject to the Provisions of the Natural Gas Act, Page 516-Definitions.
[2] Ibid, footnote 1

amount of cost to each year of service life. This method is known as the straight line method of depreciation.

The calculation of annual depreciation based on the straight line method requires the estimation of average life and salvage and the selection of group depreciation procedures. These subjects are discussed in the sections that follow.

ESTIMATION OF SURVIVOR CURVES

Average Service Life. The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages. A discussion of the general concept of survivor curves is presented. Also, the Iowa type survivor curves are reviewed.

Survivor Curves. The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval and is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

Iowa Type Curves. The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family.

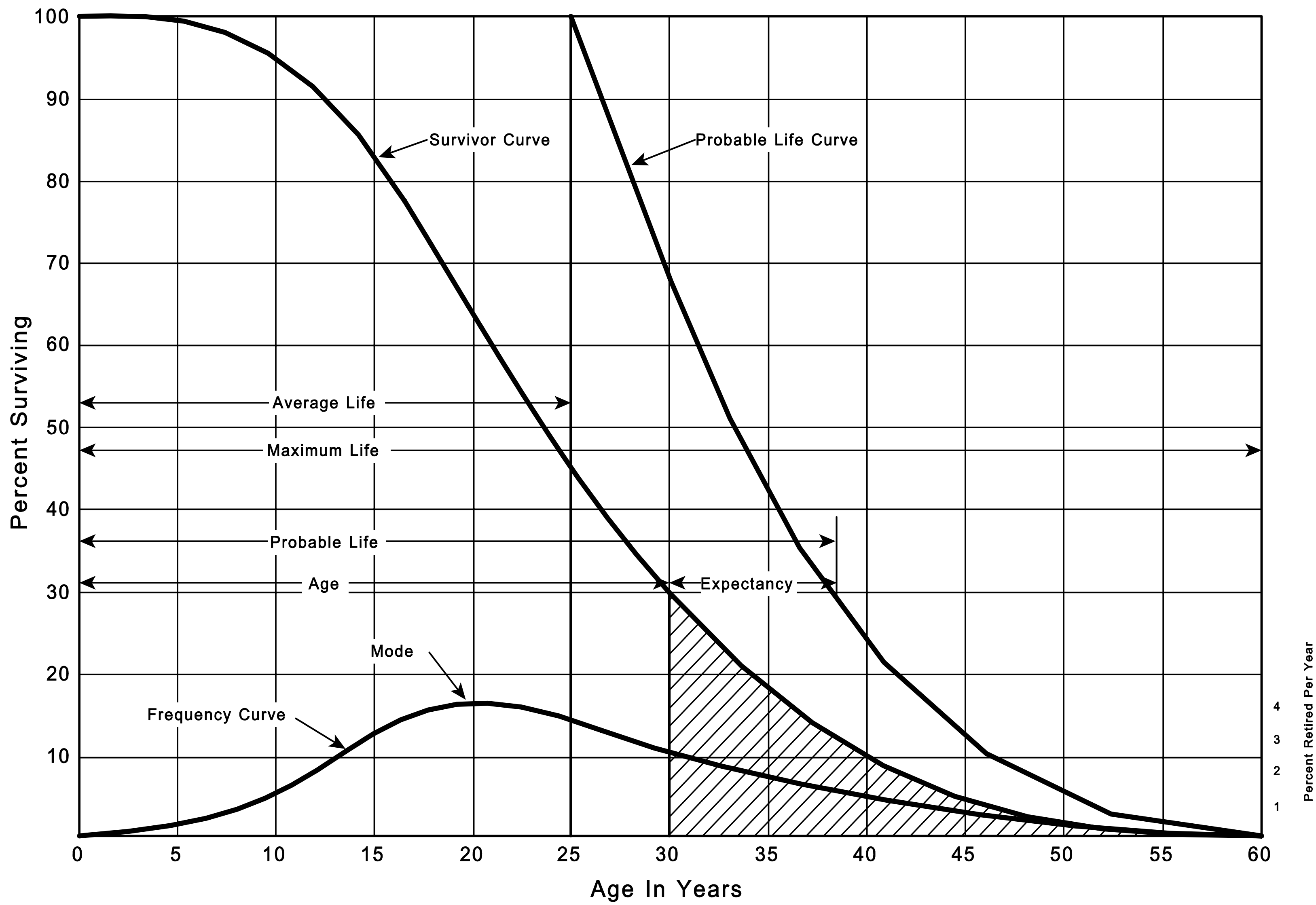

Figure 1. A Typical Survivor Curve and Derived Curves

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.[3] These type curves have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[4] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis[5] presenting his development of the fourth family consisting of the four O type survivor curves.

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[3] Winfrey, Robley. Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.

[4] Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

[5] Couch, Frank V. B., Jr. "Classification of Type O Retirement Characteristics of Industrial Property." Unpublished M.S. thesis (Engineering Valuation). Library, Iowa State College, Ames, Iowa. 1957.

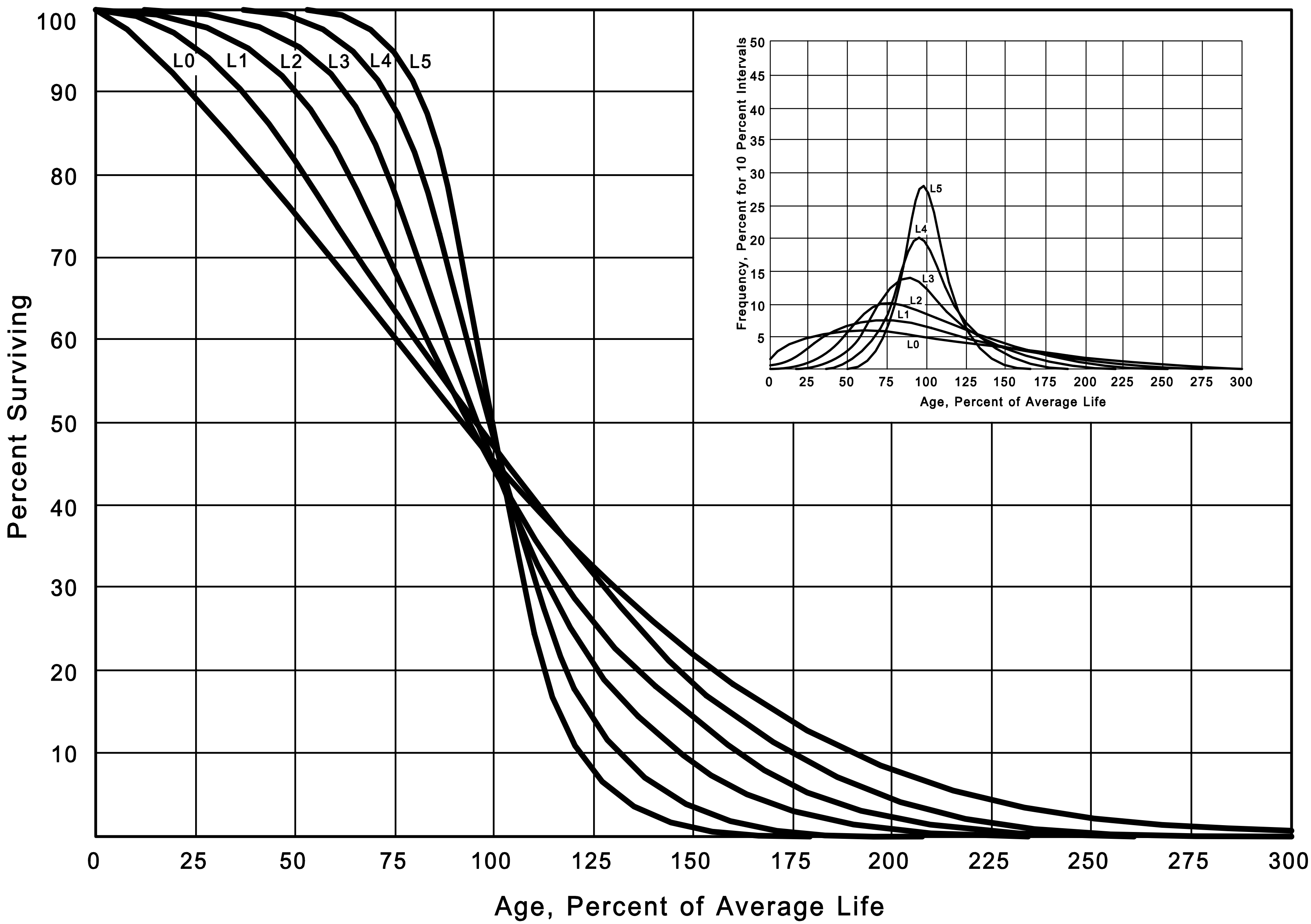

Figure 2. Left Modal or "L" Iowa Type Survivor Curves

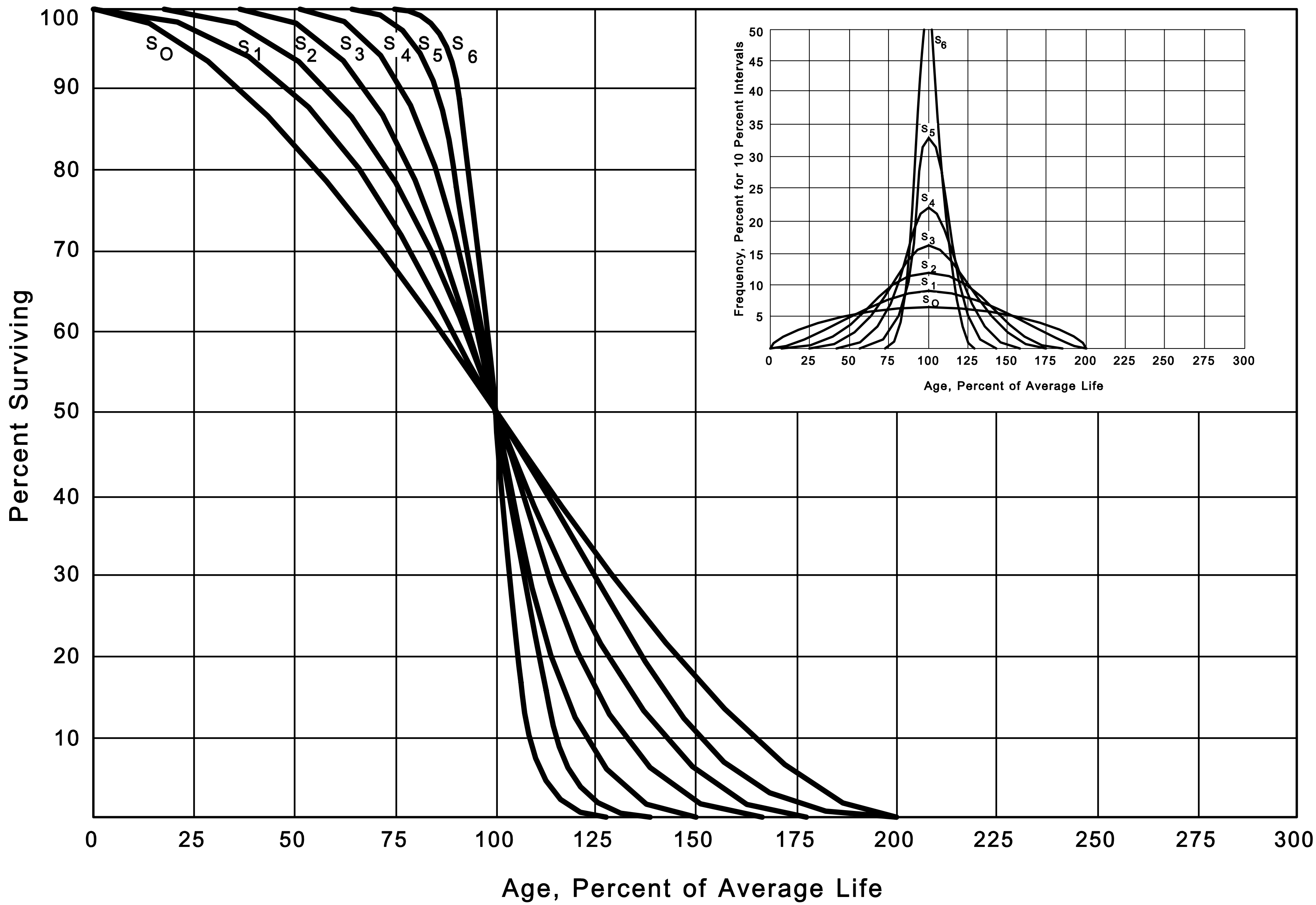

Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

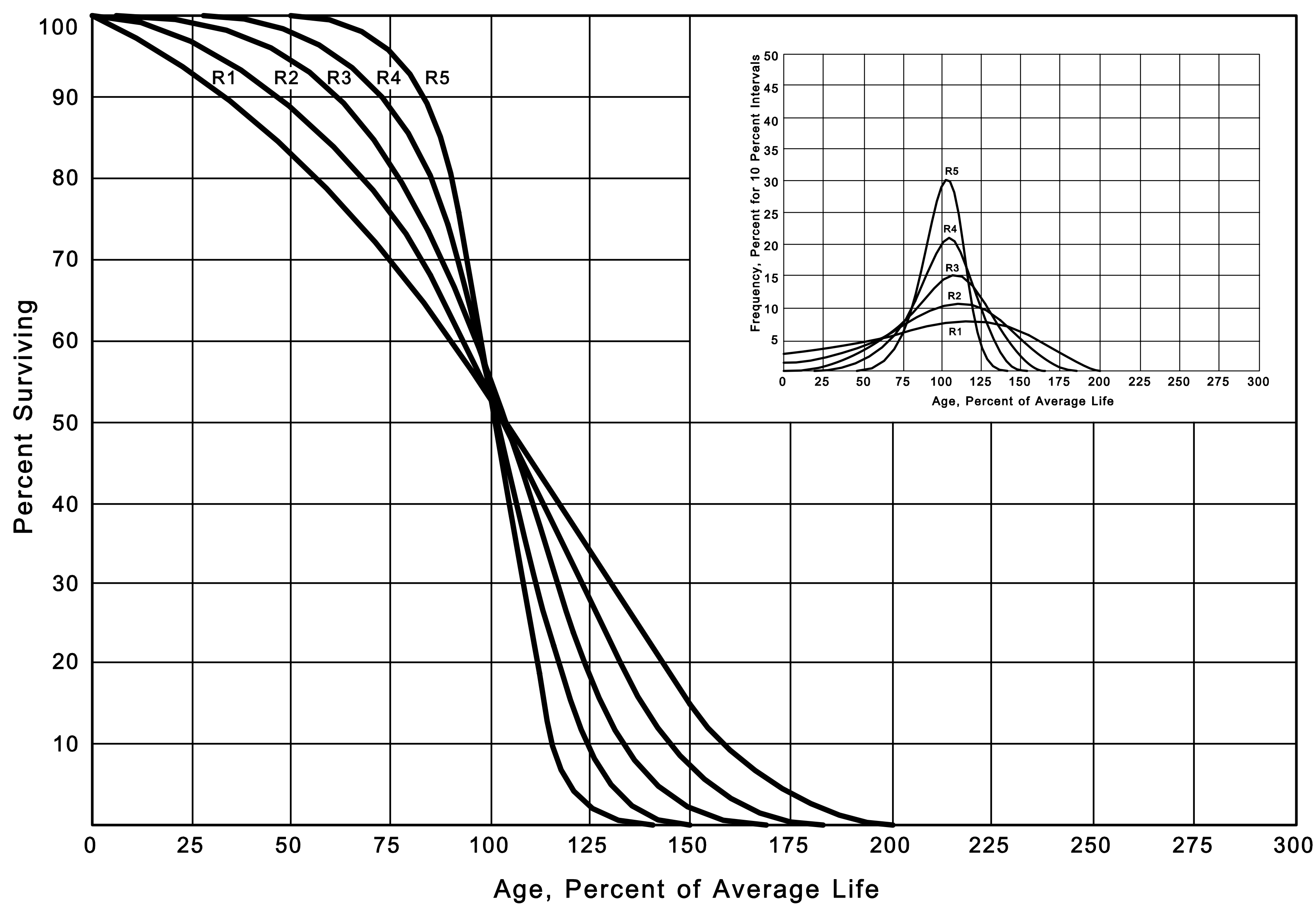

Figure 4. Right Modal or "R" Iowa Type Survivor Curves

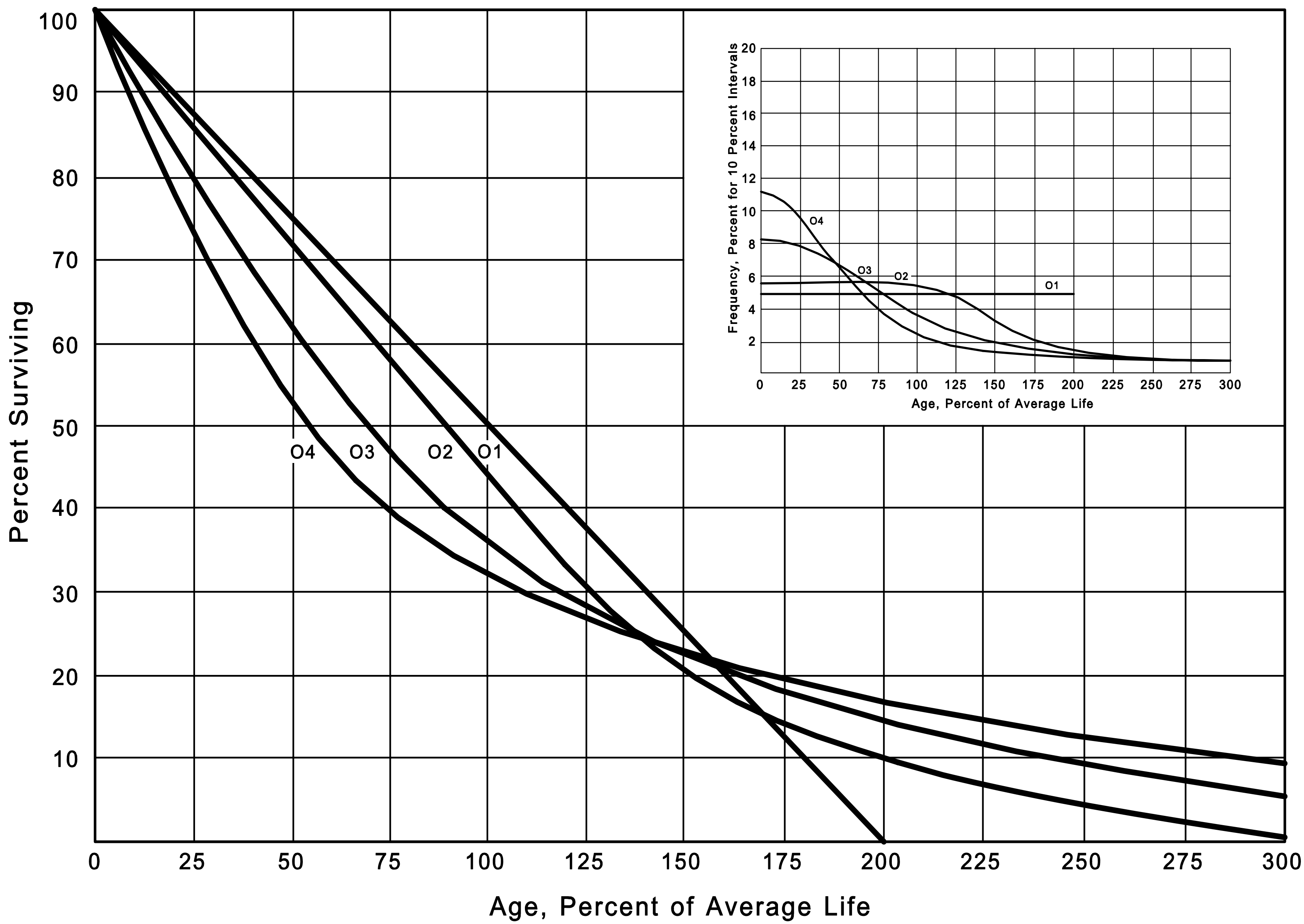

Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

Retirement Rate Method of Analysis. The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available or for which aged accounting experience is developed by statistically aging unaged amounts and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text, and is also explained in several publications, including "Statistical Analyses of Industrial Property Retirements,"[6] "Engineering Valuation and Depreciation,"[7] and "Depreciation Systems."[8]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginnings of the age intervals during the same period. The period of observation is referred to as the experience band, and the band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

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[6]Winfrey, Robley, Supra Note 3.

[7]Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note

[8]Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

Schedules of Annual Transactions in Plant Records. The property group used to illustrate the retirement rate method is observed for the experience band 1998-2007 during which there were placements during the years 1993-2007. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Tables 1 and 2 on the following pages. In Table 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the dollars invested in 1993 were retired in 1998. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Table 1 immediately above the stairstep line drawn on the table beginning with the 1998 retirements of 1993 installations and ending with the 2007 retirements of the 2002 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

$$10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.$$

TABLE 1. RETIREMENTS FOR EACH YEAR 1998-2007
SUMMARIZED BY AGE INTERVAL

Experience Band 1998-2007

Placement Band 1993-2007

Year Placed	Retirements, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1993	10	11	12	13	14	16	23	24	25	26	26	13½-14½
1994	11	12	13	15	16	18	20	21	22	19	44	12½-13½
1995	11	12	13	14	16	17	19	21	22	18	64	11½-12½
1996	8	9	10	11	11	13	14	15	16	17	83	10½-11½
1997	9	10	11	12	13	14	16	17	19	20	93	9½-10½
1998	4	9	10	11	12	13	14	15	16	20	105	8½-9½
1999		5	11	12	13	14	15	16	18	20	113	7½-8½
2000			6	12	13	15	16	17	19	19	124	6½-7½
2001				6	13	15	16	17	19	19	131	5½-6½
2002					7	14	16	17	19	20	143	4½-5½
2003						8	18	20	22	23	146	3½-4½
2004							9	20	22	25	150	2½-3½
2005								11	23	25	151	1½-2½
2006									11	24	153	½-1½
2007	—	—	—	—	—	—	—	—	—	13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

TABLE 2. OTHER TRANSACTIONS FOR EACH YEAR 1998-2007
SUMMARIZED BY AGE INTERVAL

Experience Band 1998-2007 | Placement Band 1993 -2007

Year Placed (1)	1998 (2)	1999 (3)	2000 (4)	2001 (5)	2002 (6)	2003 (7)	2004 (8)	2005 (9)	2006 (10)	2007 (11)	Total During Age Interval (12)	Age Interval (13)
	Acquisitions, Transfers and Sales, Thousands of Dollars During Year											
1993	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
1994	-	-	-	-	-	-	-	-	-	-	-	12½-13½
1995	-	-	-	-	-	-	-	-	-	-	-	11½-12½
1996	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
1997	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
1998		-	-	-	-	-	-	-	-	-	(5)	8½-9½
1999		-	-	-	-	-	-	-	-	-	6	7½-8½
2000			-	-	-	-	-	-	-	-	-	6½-7½
2001				-	-	-	-	(12)[b]	-	-	-	5½-6½
2002					-	-	-	-	22[a]	-	-	4½-5½
2003						-	-	(19)[b]	-	-	10	3½-4½
2004							-	-	-	-	-	2½-3½
2005								-	-	(102)[c]	(121)	1½-2½
2006									-	-	-	½-1½
2007											-	0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses denote Credit amount.

In Table 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement. The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Table 3 on page II-16 .

The surviving plant at the beginning of each year from 1998 through 2007 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Table 3 for each successive year following the beginning balance or addition are obtained by adding or subtracting the net entries shown on Tables 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2003 are calculated in the following manner:

Exposures at age 0	= amount of addition	= $750,000
Exposures at age ½	= $750,000 - $ 8,000	= $742,000
Exposures at age 1½	= $742,000 - $18,000	= $724,000
Exposures at age 2½	= $724,000 - $20,000 - $19,000	= $685,000
Exposures at age 3½	= $685,000 - $22,000	= $663,000

TABLE 3. PLANT EXPOSED TO RETIREMENT
JANUARY 1 OF EACH YEAR 1998-2007
SUMMARIZED BY AGE INTERVAL

Experience Band 1998-2007

Placement Band 1993-2007

	Exposures, Thousands of Dollars											
	Annual Survivors at the Beginning of the Year										Total at	
Year Placed	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	Beginning of Age Interval	Age Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1993	255	245	234	222	209	195	239	216	192	167	167	13½-14½
1994	279	268	256	243	228	212	194	174	153	131	323	12½-13½
1995	307	296	284	271	257	241	224	205	184	162	531	11½-12½
1996	338	330	321	311	300	289	276	262	242	226	823	10½-11½
1997	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
1998	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
1999		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2000			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2001				580[a]	574	561	546	530	501	482	3,057	5½-6½
2002					660[a]	653	639	623	628	609	3,789	4½-5½
2003						750[a]	742	724	685	663	4,332	3½-4½
2004							850[a]	841	821	799	4,955	2½-3½
2005								960[a]	949	926	5,719	1½-2½
2006									1,080[a]	1,069	6,579	½-1½
2007										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a] Additions during the year.

For the entire experience band 1998-2007, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Table 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table. The original life table, illustrated in Table 4 on page II-18, is developed from the totals shown on the schedules of retirements and exposures, Tables 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15				
Exposures at age 4½	=	3,789,000				
Retirements from age 4½ to 5½	=	143,000				
Retirement Ratio	=	143,000	÷	3,789,000	=	0.0377
Survivor Ratio	=	1.000	-	0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15)	x	(0.9623)	=	84.83

TABLE 4. ORIGINAL LIFE TABLE

CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 1998-2007 Placement Band 1993-2007

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval (1)	Exposures at Beginning of Age Interval (2)	Retirements During Age Interval (3)	Retirement Ratio (4)	Survivor Ratio (5)	Percent Surviving at Beginning of Age Interval (6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
14.5					35.66
Total	44,780	1,606			

Column 2 from Table 3, Column 12, Plant Exposed to Retirement.
Column 3 from Table 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 Divided by Column 2.
Column 5 = 1.0000 Minus Column 4.
Column 6 = Column 5 Multiplied by Column 6 of the Preceding Age Interval.

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Tables 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless.

The original survivor curve is plotted from the original life table (column 6, Table 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

Field Trip. In order to be familiar with the Company and observe a representative portion of the plant, a field trip was conducted. As described in the next section of this report, a number of operational interviews were conducted before and after the field trips. In this manner, the knowledge gained during the operational interviews could be enhanced through the physical inspection of plant. Additionally, a number of questions that arose during the field trips were discussed during operational discussions following the site inspections. A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements were obtained during the field trip. This knowledge and information were incorporated in the interpretation and extrapolation of the statistical analyses.

The following is a list of the locations visited during the field trip.

- Surrey Operations Center
- Huntingdon Metering Station
- Langley Compressor Station
- Coquitlam Metering Station
- Tilbury LNG Plant

Operational Interviews. Interviews and discussions were held with a number of operational and engineering groups. The interviews and discussions assisted Gannett Fleming in the understanding of the historic forces of retirement that have resulted in the statically developed average service life indications and on the anticipated future forces of retirement. Based on these discussions, Gannett Fleming is better able to determine if the results of the retirement rate analysis should be adjusted to better reflect the future forces of retirement, or changes in technology. Additionally, operational interviews provide information regarding the reuse practices and policies and cost of retirement information. Interviews with budgeting departments provided insight into upcoming capital programs which may include significant retirement of assets.

The following groups were interviewed by Gannett Fleming during the Depreciation Study:

- Vancouver Island System Operations
- Fleet Management
- Metering
- Transmission
- Compression
- Capital Expenditure Budgeting
- Distribution Stations
- Inventory

The information gained from these interviews was used in combination with the retirement rate study, comparisons to peers and the experience of Gannett Fleming in the final determination of average service life estimates and net salvage percentages.

Survivor Curve Judgments. Each retirement rate analysis resulted in a life table which, when plotted, formed an original survivor curve. Each original survivor curve, as plotted from the life table, represents the average survivor pattern experienced by several vintage groups during the experience band studied. Inasmuch as this survivor pattern does not necessarily describe the life characteristics, interpretation of the original survivor curves is required to use them as valid considerations in service life estimation. Iowa type curves were used in these interpretations. The survivor curve estimates were based on judgment which considered a number of factors as discussed above. The primary factors were the statistical analysis of data, current policies and outlook as determined during conversations with management and the field trip, and survivor curve estimates from previous studies of this Company and other gas distribution companies. The specific factors for the largest accounts follow.

Account 475 – Distribution Mains, is the largest account studied and represents 25% of Terasen's depreciable plant. The retirements, additions and other plant transactions for the period 1958 through 2007 were analyzed by the retirement rate method. The original and smooth survivor curves are plotted on page lV-47. Typical service lives for distribution mains range from 50 to 65 years.

In previous studies Gannett Fleming recommended the Iowa 60-R2.5. Since the last study, this account has continued to incur retirements at a consistent rate which provide for a reliable statistical indication of average service life characteristics. To date, this account has experienced over $27 million of retirement actively. Discussions with operating and engineering staff have not indicated any specific reasons to believe that the future retirement trends in this account will be significantly different than either historic pattern. Furthermore, operations staff have indicated that it would be expected that the life of the

Terasen distribution mains would be in the range of other industry peers. Typical service lives for distribution mains range from 50 to 65 years.

The retirement rate analysis indicates a significant rate of retirement activity as plant reaches 50 years of age, with large retirement rates through to age 75. In order to better fit to this retirement pattern, Gannett Fleming has recommended the Iowa 60-R3 survivor curve to better reflect the trend towards increased retirement rates beyond age 50 as compared to the previous estimate of the 60-R2.5. This minor increase in the mode of the Iowa curve provides a reasonable interpretation of the original survivor curve, and falls within the range of typical service lives for this account and is therefore recommend for this account.

Account 465, Transmission Mains, represents approximately 23% of the depreciable plant studied. The retirements, additions and other plant transactions for the period 1957 through 2007 were studied. The original survivor curve as plotted on page IV-20 indicates only a modest level of retirements through age 45. Typical service lives for transmission mains range from 50 to 70 years. The previously approved estimate for this account was the Iowa 65-R3 based primarily on industry trends.

The Retirement Rate Analysis as presented at page IV-21 of this report and discussions with the operations and engineering staff have indicted that to date the pipe has experienced only a limited level of retirement activity. However, the retirement activity to date of over $9 Million of originally installed cost, has provided some data upon which a life analysis can be made, particularly when combined with the experience of the operations staff. Operations staff has indicated that the original 12-inch system installed in 1957 is not cathodically protected. However the cathodic protection was started in the late 1960's with the installation of the 10-inch lines. Terasen does inspect the transmission lines using inspection pigs through an on-going inspection program. Recent inspections have indicated some corrosion in the 10-inch line. In previous studies Gannett Fleming recommended an Iowa 65-R3 curve. However, the average service life in this study has been shortened to an Iowa 60-R3 to better fit the historic retirement activity, and to recognize the anticipated increased level of retirements in future years due to the potential of corrosion in the 10-inch line. The Iowa 60-R3 survivor curve, selected in this study to represent the life characteristics for this account, is within the typical range of lives used for transmission mains in the industry, and conforms to the expectations of management.

Account 473, Distribution Services, represents 18% of Terasen's depreciable plant. The retirements, additions and other plant transactions for the period 1959 through 2007 were analyzed by the retirement rate method. The original and smooth survivor curves are plotted on page IV-40.

In previous studies Gannett Fleming recommended the Iowa 55-R1. Since the last study, this account has continued to incur retirements at a consistent rate, which provides for a reliable statistical indication of average service life characteristics. To date, this account has experienced over $44 million of retirement activity. Discussions with operating and engineering staff have not indicated any specific reasons to believe that the future retirement trends in this account will be significantly different than historic patterns. Furthermore, operations staff have indicated that it would be expected that the life of the Terasen distribution services would be in the range of other industry peers. Typical service lives for distribution services range from 40 to 60 years.

The retirement rate analysis indicates a significant rate of retirement activity as plant reaches 45 years of age, with large retirement rates through to age 70. In order to better fit to this retirement pattern, Gannett Fleming has recommended the Iowa 55-R2.5 survivor curve to better reflect the trend toward increased retirement rates beyond age 40, as compared to the previous estimate of the Iowa 55-R1. This minor increase in the mode of the Iowa curve provides a reasonable interpretation of the original survivor curve, and falls within the range of typical service lives for this account and is, therefore recommended for this account.

Account 478.1, Meters, represents 6% of Terasen's depreciable plant. The retirements, additions and other plant transactions for the period 1963 through 2007 were analyzed by the retirement rate method. The original and smooth survivor curves are plotted on page IV-60. Typical service lives for gas distribution services range from 15 to 30 years. In recent years, the gas distribution industry has been moving toward increased used of digital metering and Automated Meter Reading (AMR) technology. The impact of the changed technology on the average service life of meters has not yet been witnessed.

Previous Gannett Fleming studies have recommended a 25-R2-Iowa curve to represent the retirement characteristics for this account. During the period since the last study, Terasen Gas has entered into a program to replace the older electro-mechanical meters with newer technology digital metering equipment. Furthermore, Terasen is testing AMR technology through a residential test program. The impact of the new metering technology and potential for the implementation of AMR is unknown, but may cause a future retirement program to replace a significant portion of the investment in this account. It is anticipated that the retirement activity caused by the program nature of the conversion will result in an increased number of retirements at a younger age. However, until these programs are more certain and the results of the AMR projects are known, Gannett Fleming does not recommend large changes in the average service life of this account due to this introduction of new technology in this account.

Effective January 1, 2007, Terasen made a significant policy change regarding the manner in which meter related costs are capitalized. The revised policy has two key components, as follows:

- Meter repair and inspection costs incurred in the meter shop will no longer be capitalized, and the costs will be considered as operating costs and
- Field costs associated with residential meter exchanges will now be capitalized, where the old meter is expected to be retired.

The above changes in capitalization policy will not have any material impact with regard to average service life estimates. The policy to charge the repair of meters in the meter shop to operating cost could have a slight lengthening impact on average service life, as any potential retirement of a portion of the asset will no longer occur. However small retirements for replaced parts on the meter have not historically been recorded and, therefore, no charge in average service life is expected due to this change.

The retirement rate analysis for this account, as presented at page IV-61, indicates retirement activity throughout the accounts life constant with an Iowa 25-R2 shape. While this account is experiencing significant change in both the capitalization policies and in the technology associated with the assets within this account, the impacts of these changes are not known at this time. Therefore, absent any empirical data to support a shortening of the average service life estimate, the 25-R2 has been selected for this account. This account will be closely monitored over the next few years to determine if a shortening of the average service life estimate becomes necessary.

Account 466, Compression Equipment, represents less than 4% of the depreciable plant studied. The retirements, additions and other plant transactions for the period 1970 through 2007 were analyzed by the retirement rate method. The original survivor curve as plotted on page IV-23 indicates only a modest level of historical retirements through age 15, and a significantly faster rate of retirement from ages 16 through 21. Plant surviving past age 21 appears to be at a much slower pace.

In previous depreciation studies, Gannett Fleming has recommended a 30-R2.5 Iowa curve. Typical service lives for compression equipment range from 25 to 35 years. The compression units, utilized by Terasen are Solar units which have proven to be reliable both at Terasen and within the industry as a whole. As such, it is expected that these units would perform at the longer end of the range of average service lives. However, the high rate of retirement ratios at approximately age 20 need to be recognized. Gannett Fleming recommends a slight lengthening of the average service life to 33 years to deal with the company and industry experience with the compression units in use, and an increase in the mode of the Iowa curve from a Iowa R2.5 to an Iowa R3 to deal with the period of high retirement ratios. As such, an adjustment to the Iowa 33-R3, selected in this study, provides a reasonable interpretation of the historical data, and is within the range of lives used in the industry and anticipated by management.

Account 477.1, Measuring and Regulators, represents 2% of the depreciable plant studied. The retirements, additions and other plant transactions for the period 1962 through 2007 were analyzed by the retirement rate method. The original survivor curve as plotted on page IV-52 indicates only a relatively constant rate of historical retirements through age 35, at which point the amount of plant exposed to retirement becomes minimal. As such, in the analysis of this account, Gannett Fleming has fit to the retirement experience from age 0 through to age 35. Over this period, most significant retirements occur from age 0 through age 17.

Gannett Fleming has previously recommended the Iowa 29-R2 curve for this account. However, given the high rate of retirements beginning at age 0 and the minimal amount of plant remaining in service after age 35, Gannett Fleming is recommending a reduction to this average service life. A reduction in the average service life estimate to the Iowa 25-R2, selected in this study, provides a reasonable interpretation of the historical data, and is within the range of lives which used in the industry which range from 20 to 30 years.

The survivor curves for the remaining accounts were based on similar considerations of historical analysis, management outlook and estimates of this company and other gas distribution companies.

ESTIMATION OF NET SALVAGE

Appropriate depreciation policies should provide for the recovery of the service value of assets in regulatory service over the period of time for which the assets being depreciated are forecast to be in service. This concept has been held by numerous regulatory jurisdictions throughout North America for many years. The concept of service value to include both the original costs of the asset and the net salvage costs incurred at the time of retirement of the asset is also widely held.[9] As such, in the completion of the depreciation study for Terasen Gas, Gannett Fleming has developed appropriate net salvage rates, which when applied to the original cost of plant in service, will result in the provision of funds estimated to be required at the time of retirement.

[9] For example as identified by the FERC as noted in footnote 2 to this report and in the General Instructions to the Canadian Gas Association Uniform Classification of Accounts for Natural Gas Utilities under the Jurisdiction of the Public Utilities Board of the Province of Alberta, page 8

The recovery of the estimated costs of retirement (net of any potential salvage proceeds realized from the sale of assets to third parties or from reuse within the utility) over the period of time that the asset is providing utility service provides generational equity wherein the toll payers receiving the benefit of an asset in service fund the total cost of the asset, including the eventual costs of retirement of the asset.

Recently, the Canadian Accounting Standards Board has announced that Canadian Generally Accepted Accounting Principles (GAAP) will cease to exist as of 2011. From that date forward, companies will be required to report under International Financial Reporting Standards ("IFRS"). One of the areas of change relate to the depreciation of assets relating to net salvage requirements. In order to comply with these new standards, Terasen Gas has asked that Gannett Fleming prepare separate depreciation accrual rates specifically applicable to the net salvage requirements. As such, Table 1, as presented in the Results section of this report, provides for the recovery of the original cost of assets in service; and Table 2 separately provides for the recovery of the estimated costs of retirement. It is the recent experience of Gannett Fleming that regulated Canadian Utilities are complying with the IFRS in this manner.

The estimates of net salvage recommended in this report were primarily based on judgment which considered a number of factors. The primary factors were knowledge of the company's plans and operating practices as determined during the field trip and discussions with operating, engineering and budgeting staff, a general knowledge of the natural gas industry, and review of the net salvage estimates of other gas companies. The estimates of net salvage are expressed as the average net percent of the cost of plant.

CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

Group Depreciation Procedures. When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because normally all of the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, the average service life and equal life group procedures.

In the average service life procedure, the rate of annual depreciation is based on the average service life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to the average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

In the equal life group procedure, also known as the unit summation procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life unit. Although the equal life group procedure is superior to the average service life procedure in matching depreciation expense and consumption of service value, the average service life procedure was used in order to conform to past Company practices and for consistency with practices of other companies regulated by the British Columbia Utilities Commission.

CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is proposed for certain General Plant accounts that represent numerous units of property, but a very small portion of depreciable gas plant in service. The accounts and their amortization periods are as follows:

Account		Amortization Period Years
401	Franchises and Consents	40
402	Intangible Plant	40
483.1	Computer Hardware	5
483.2	Computer Software	5
483.3	Office Equipment	15
483.4	Office Furniture	20
486	Small Tools/Equipment	20
487.2	NGV Cylinders	15
488.1	Telephone Equipment	15
488.2	Radio Equipment	15

The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the original cost by the period of amortization for the account for those vintages with an age less than the amortization period. In order to develop amortization rates that reflect the period over which the assets render service, the accumulated depreciation accounts have been adjusted for the purposes of this study to remove any amounts other than the accumulated depreciation related to the assets currently in service. As a result, the amortization rate as recommended in this report represent the pure amortization rate without any other accumulated depreciation adjustments.

Use of the amortization method of accounting generally includes the retirement of the investment in these accounts at the expiry of the amortization period. As such, no investment is retired prior to the expiry of the period and all investment is retirement at the end of the period, regardless of when the items are physically removed from service. As part of the review of the general plant accounts for this study, the amortization rates only considered the investment that is within the recommended amortization period.

PART III. RESULTS OF THE STUDY

PART III. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculation of the composition remaining lives and the determination of the annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revision are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage, and for the change of the composition of property in service.

The annual accrual rates and the accrued depreciation were calculated in accordance with the straight line average service life method of depreciation based on estimates which reflect consideration of current historical evidence and expected future conditions. The calculated accrued depreciation represents that portion of the depreciable cost which will not be allocated to future annual expense through depreciation accruals if current forecasts of service life and salvage materialize and are used as a basis for straight line average service life depreciation accounting.

DESCRIPTION OF DEPRECIATION TABULATIONS

A summary of the results of the study, as applied to the original cost of gas plant of Terasen Gas Inc., Terasen Gas Vancouver Island, and Terasen Gas Whistler as at December 31, 2007, is presented in Tables 1 and 2 attached to this report. Table 1 sets forth the original cost, the booked accumulated depreciation amounts, and the required future accruals prior to consideration of the net salvage provision for Terasen Gas Inc., Terasen Gas Vancouver Island, and Terasen Gas Whistler. As such, Table 1 for each system provides for the recovery of the original costs of the assets within each system.

Table 2 presents the calculations related to the recovery of the net salvage requirements for each of the same three systems.

The service life estimates were based on judgment that incorporated statistical analysis of retirement data, discussions with management and operating staff, and consideration of estimates made for other gas companies as discussed in Part II of this report. For each depreciable group analyzed by the retirement rate method, a chart depicting the original and estimated survivor curves followed by a tabular presentation of the original life table plotted on the charts is presented starting at page lV-2. The survivor curve estimated for the depreciable groups is shown as a dark smooth curve on the charts. Each smooth curve is denoted by a numerical average service life indication followed by the curve type designation. The numeral used is the average life derived from the entire curve from 100 percent to zero percent surviving. The titles of each chart indicate the group, the symbol used to plot the points of the original life table, and the experience and placement bands of the life tables that are plotted. The experience band indicates the range of years fro which retirements were used to develop the stub survivor curve. The placements indicate, for the related experience band, the range of years of installations which appear in the experience.

The tables of the calculated annual and accrued depreciation are presented in account sequence in the section beginning on V-2**.** With the exception of the general plant accounts, the tables are first presented for all of the Terasen Gas Inc. accounts, followed by all of the Terasen Gas Vancouver Island accounts and then for all accounts related to Terasen Gas Whistler. Each table indicates the estimated survivor curve and net salvage percent for the account;and sets forth, for each installation year, the original cost, the calculated annual accrual rate and amount, and the calculated accrued depreciation factor and amount.

As previously indicated the amortization rates for general plant accounts, as developed in this report are based on adjusted gross plant in service and accumulated depreciation balances. As these amortization rates for the general plant accounts are developed as a pure rate the aged plant surviving balances for only the investment within the amortization period has been considered. Therefore the general plant accounts are not included in the detailed depreciation calculation pages beginning at page V-2 of this report.

TERASEN GAS INC.

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2007
DEPRECIATION RELATED TO LIFE

	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2007	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	Intangible Plant								
401.0	Franchises and Consents	40-SQ	0	99,236	47,482	51,754	19,611	19.76	2.6
402.0	Intangible Plant	40-SQ	0	772,555	205,894	566,661	16,526	2.14	34.3
402.1	Plant Acquisitions and Adjustments	40-SQ	0	62,457	25,521	36,936	14,774	23.66	2.5
	Total Intangible Plant			**934,248**	**278,897**	**655,351**	**50,912**	**5.45**	
	Manufacturing Plant								
432.0	Manufacturing Gas Structures	40-SQ	0	450,708	85,863	364,845	14,783	3.28	24.7
433.0	Manufacturing Gas Equipment	20-SQ	0	145,939	42,710	103,229	9,196	6.30	11.2
434.0	Manufacturing Gas Holders	40-SQ	0	357,586	158,645	198,941	13,939	3.90	14.3
436.0	Manufacturing Gas Compressor Equipment	25-SQ	0	53,309	20,072	33,237	2,642	4.96	12.6
437.0	Manufacturing Gas Measuring/Regulating Equipment	20-SQ	0	309,447	133,516	175,931	60,354	19.50	2.9
	Total Manufacturing Plant			**1,316,989**	**440,806**	**876,183**	**100,914**	**7.66**	
	LNG Plant								
442.0	LNG Gas - Structures	25-R3	-10	4,779,018	1,702,128	3,076,890	174,645	3.65	17.6
443.0	LNG Gas - Equipment	40-R3	-20	16,495,801	6,943,654	9,552,147	360,024	2.18	26.5
449.0	LNG Gas - Other Equipment	35-R3	-10	18,936,395	7,463,537	11,472,858	635,510	3.36	18.1
	Total LNG Plant			**40,211,214**	**16,109,319**	**24,101,895**	**1,170,178**	**2.91**	
	Transmission Plant								
462.0	TP - Compressor Structures	30-R4	-5	14,587,984	4,178,048	10,409,936	559,824	3.84	18.6
463.0	TP - Measuring/Regulating Structures	30-R2.5	-5	4,839,702	971,868	3,867,834	206,759	4.27	18.7
464.0	TP - Other Structures	35-R3	-5	5,842,863	956,201	4,886,662	168,227	2.88	29.0
465.0	TP - Transmission Pipeline	60-R3	-10	700,388,612	141,662,619	558,725,993	11,422,619	1.63	48.9
466.0	TP - Compressor Equipment	33-R3	-10	106,301,110	26,281,352	80,019,758	3,380,640	3.18	23.7
467.1	TP - Measuring/Regulating Equipment	25-R2.5	-5	27,913,211	4,286,756	23,626,455	2,005,641	7.19	11.8
467.2	TP - Telementry Equipment	17-R2	0	6,065,331	4,836,167	1,229,164	80,580	1.33	15.3
467.3	TP - Measurement/Regulating Equipment	25-R2.5	-5	38,716	4,753	33,963	1,551	4.01	21.9
468.0	TP - Communications Equipment	15-R2	0	345,886	197,658	148,228	18,393	5.32	8.1
	Total Transmission Plant			**866,323,415**	**183,375,422**	**682,947,993**	**17,844,235**	**2.06**	
	Distribution Plant								
472.0	DS - Structures	28-L1	-5	13,845,551	2,398,305	11,447,246	498,573	3.60	23.0
473.0	DS - Services	55-R2.5	-50	578,026,320	51,399,770	526,626,550	13,004,730	2.25	40.5
473.01	LILO - DS - Services	40-SQ	-50	43,302,554	9,662,455	33,640,099	952,600	2.20	35.3
474.0	DS - Meters/Regulators Installations	30-R2	0	127,327,914	5,285,163	122,042,751	6,636,365	5.21	18.4
474.01	LILO - DS - Meters/Regulators Installations	30-SQ	0	16,070,133	7,123,947	8,946,186	352,434	2.19	25.4
475.0	DS - Mains	60-R3	-20	790,729,371	174,026,268	616,703,103	14,917,469	1.89	41.3
475.01	LILO - DS - Mains	40-SQ	-20	39,743,548	11,665,494	28,078,054	793,861	2.00	35.4
476.0	DS - NGV Fuel Equipment	15-R3	0	570,858	229,823	341,035	142,932	25.04	2.4
477.1	DS - Meters/Regulators Additions	25-R2	0	72,654,480	10,952,419	61,702,061	4,157,541	5.72	14.8
477.2	DS - Telemetry	20-R2.5	0	5,527,676	5,277,715	249,961	13,802	0.25	18.1
477.3	DS - Measuring/Regulating Equipment	15-R2.5	-5	163,151	174,677	(11,526)	-	-	1.0
478.1	DS - Meters	25-R2	0	180,537,629	35,702,962	144,834,667	9,587,890	5.31	15.1
478.11	LILO - DS Meters	25-SQ	0	10,026,726	3,351,178	6,675,548	329,852	3.29	20.2
478.2	DS - Instruments	30-R3	0	10,942,940	2,021,854	8,921,086	440,896	4.03	20.2
	Total Distribution Plant			**1,889,468,851**	**319,272,030**	**1,570,196,821**	**51,828,944**	**2.74**	
	General Plant								
482.1	Structures (Frame)	25-R2	0	5,637,521	1,681,346 *	3,956,175	207,130	3.67	19.1
482.2	Structures(Masonry)	25-R2	0	81,459,403	7,241,295 *	74,218,108	3,563,039	4.37	20.8
483.1	Computer Hardware	5-SQ	0	13,863,764	7,255,376 *	6,608,388	2,772,091	20.00	2.4
483.20	Computer Software (8 Years)	8-SQ	0	71,038,304	42,948,228 *	27,825,480	8,878,583	12.50	3.1
483.21	Computer Software (5 Years)	5-SQ	0	6,787,308	1,111,596 *	5,675,712	1,357,176	20.00	4.2
483.3	Office Furniture and Equipment	15-SQ	0	4,248,230	2,296,043 *	1,952,187	283,336	6.67	6.9
483.4	Furniture	20-SQ	0	20,073,829	10,519,950 *	9,553,879	1,004,614	5.00	9.5
484.0	Vehicles	6-L1	20	695,457	486,610	208,847	53,551	7.70	3.9
485.1	Heavy Work Equipment	15-R2	15	189,165	48,520	140,645	12,558	6.64	11.2
485.2	Heavy Mobile Equipment	15-L2.5	10	312,945	15,682	297,263	26,541	8.48	11.2
486.0	Small Tools/Equipment	20-SQ	0	32,034,924	14,362,213 *	17,672,711	1,600,789	5.00	11.0
487.2	NGV Cylinders	15-SQ	0	24,167	2,705	21,462	1,612	6.67	13.3
487.3	VRA's	10-SQ	0	-	-	-	-	-	0.0
488.1	Telephone Equipment	15-SQ	0	10,450,131	5,124,276 *	5,325,855	696,554	6.67	7.6
488.2	Radio Equipment	15-SQ	0	4,992,872	1,639,789 *	3,353,083	332,977	6.67	10.1
	Total General Plant			**251,808,020**	**94,733,629**	**156,809,795**	**20,790,553**	**8.26**	
	TOTAL DEPRECIABLE PLANT			**3,050,062,737**	**614,210,103**	**2,435,588,038**	**91,785,736**	**3.01**	**27.8**

(*) indicates that the historic gain/loss on retirments have been removed from the depreciation rate calcuation.

TERASEN GAS (VANCOUVER ISLAND) INC.

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2007
RELATED TO LIFE

	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2007	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	Intangible Plant								
401.0	Franchises and Consents	40-SQ	0	189,777	50,063	139,714	5,942	3.13	23.5
402.0	Intangible Plant	40-SQ	0	1,194,037	416,142	777,895	27,411	2.30	28.4
	Total Intangible Plant			**1,383,814**	**466,205**	**917,609**	**33,353**	2.41	
	Transmission Plant								
462.0	TP - Compressor Structures	30-R4	-5	10,148,764	2,219,551	7,929,213	377,905	3.72	21.0
463.0	TP - Measuring/Regulating Structures	30-R2.5	-5	6,056,273	1,727,823	4,328,450	173,666	2.87	24.9
464.0	TP - Other Structures	35-R3	-5	129,495	8,233	121,262	3,716	2.87	32.6
465.0	TP - Transmission Pipeline	60-R3	-10	221,257,782	49,586,037	171,671,745	3,820,531	1.73	44.9
466.0	TP - Compressor Equipment	33-R3	-10	45,122,851	8,411,858	36,710,993	1,439,026	3.19	25.5
467.1	TP - Measuring/Regulating Equipment	25-R2.5	-5	10,307,745	1,680,672	8,627,073	576,175	5.59	15.0
468.0	TP - Communications Equipment	15-R2	0	2,348,555	871,937	1,476,618	236,600	10.07	6.2
	Total Transmission Plant			**295,371,465**	**64,506,111**	**230,865,354**	**6,627,619**	2.24	
	Distribution Plant								
472.0	DS - Structures	28-L1	-5	1,455,159	569,949	885,210	46,671	3.21	19.0
473.0	DS - Services	55-R2.5	-50	122,548,256	14,742,217	107,806,039	2,345,649	1.91	46.0
474.0	DS - Meters/Regulators Installations	30-R2	0	15,569,726	3,855,682	11,714,044	537,563	3.45	21.8
475.0	DS - Mains	60-R3	-20	201,067,397	39,794,709	161,272,688	3,250,614	1.62	49.6
477.1	DS - Meters/Regulators Additions	25-R2	0	5,015,290	1,778,305	3,236,985	230,620	4.60	14.0
478.1	DS - Meters	25-R2	0	10,881,716	2,815,662	8,066,054	475,005	4.37	17.0
	Total Distribution Plant			**356,537,544**	**63,556,524**	**292,981,020**	**6,886,122**	1.93	
	General Plant								
482.2	Structures	25-R2	0	4,026,481 *	1,208,562	2,817,919	175,681	4.36	16.0
483.1	Computer Hardware	5-SQ	0	1,924,079 *	1,051,969	872,110	384,868	20.00	2.3
483.2	Computer Software (8 years)	8-SQ	0	15,758,816 *	3,299,262	12,459,554	1,969,890	12.50	6.3
483.2	Computer Software (5 years)	5-SQ	0	-	-	-	-	20.00	5.0
483.3	Office Furniture and Equipment	15-SQ	0	2,263,540 *	1,997,434	266,106	151,025	6.67	1.8
483.4	Furniture	20-SQ	0	59,597 *	7,113	52,484	2,980	5.00	17.6
484.0	Vehicles	6-L1	20	4,040,002 *	1,254,919	2,785,083	722,273	17.88	3.9
485.1	Heavy Work Equipment	15-R2	15	396,033 *	229,168	166,865	25,108	6.34	6.6
485.2	Heavy Mobile Equipment	15-L2.5	10	378,433 *	34,046	344,387	27,814	7.35	12.4
486.0	Small Tools/Equipment	20-SQ	0	5,540,499 *	2,610,915	2,929,584	277,160	5.00	10.6
488.1	Telephone Equipment	15-SQ	0	1,188,352 *	819,726	368,626	79,274	6.67	4.7
	Total General Plant			**35,575,832**	**12,513,114**	**23,062,718**	**3,816,072**	10.73	
	TOTAL DEPRECIABLE PLANT			**688,868,655**	**141,041,954**	**547,826,701**	**17,363,166**	**2.52**	**27.6**

(*) indicates that the historic gain/loss on retirments have been removed from the depreciation rate calcuation.

TERASEN GAS (WHISTLER) INC.

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2007

DRAFT - DEPRECIATION RELATED TO LIFE

	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2007	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	Intangible Plant								
401.0	Franchises and Consents	40-SQ	0	8,239	1,643	6,596	338	4.11	19.5
	Total Intangible Plant			**8,239**	**1,643**	**6,596**	**338**		
	Transmission Plant								
431.0	Mfg. Gas Land Rights	75-R4	0	3,625	637	2,988	50	1.38	59.8
432.0	Mfg. Gas Structures	40-SQ	0	2,878,938	924,528	1,954,410	71,840	2.50	27.2
433.0	Mfg. Gas Equipment	20-SQ	0	1,695,048	513,036	1,182,012	243,212	14.35	4.9
434.0	Mfg. Gas Holders	40-SQ	0	2,108,175	324,441	1,783,734	57,767	2.74	30.9
436.0	Mfg. Gas Compressor Equipment	25-SQ	0	37,896	11,420	26,476	1,961	5.18	13.5
437.0	Mfg. Gas Meas / Regulating Equipment	20-SQ	0	343,591	11,194	332,397	45,212	13.16	7.4
	Total Transmission Plant			**7,067,273**	**1,785,256**	**5,282,017**	**420,043**		
	Distribution Plant								
471.0	DS - Land Rights	75-R4	0	86,987	9,315	77,672	1,217	1.40	63.8
472.0	DS - Structures	28-L1	-5	205	92	113	7	3.26	16.9
473.0	DS - Services	55-R2.5	-50	2,890,836	331,381	2,559,455	55,993	1.94	45.7
474.0	DS - Meters/Regulators Installations	30-R2	0	808,837	241,338	567,499	26,972	3.33	21.0
475.0	DS - Mains	60-R3	-20	6,836,226	1,188,751	5,647,475	113,392	1.66	49.8
477.1	DS - Meters/Regulators Additions	25-R2	0	13,717	6,678	7,039	631	4.60	11.2
478.1	DS - Meters	25-R2	0	500,227	107,784	392,443	23,290	4.66	16.9
	Total Distribution Plant			**11,137,035**	**1,885,339**	**9,251,696**	**221,503**		
	General Plant								
482.1	Structures(Masonry)	25-R2	0	8,128	3,079	5,049	358	4.41	14.1
483.3	Office Furniture and Equipment	15-SQ	0	19,484	16,935 *	2,549	1,301	6.67	2.0
484.0	Vehicles	6-L1	20	64,260	20,018 *	44,242	10,289	16.01	4.3
485.1	Heavy Work Equipment	15-R2	15	77,949	58,554	19,395	3,610	4.63	5.4
486.0	Small Tools/Equipment	20-SQ	0	175,900	92,846 *	83,054	8,789	5.00	9.5
488.1	Telephone Equipment	15-SQ	0	45,832	41,174 *	4,658	3,058	6.67	1.5
	Total General Plant			**391,553**	**232,606**	**158,947**	**27,404**		
	TOTAL DEPRECIABLE PLANT			**18,604,100**	**3,904,844**	**14,699,256**	**669,288**	**3.60**	**22.1**

(*) indicates that the historic gain/loss on retirments have been removed from the depreciation rate calcuation.

TERASEN GAS INC.

TABLE 2. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2007
DEPRECIATION RELATED TO NET SALVAGE

	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2007	BOOK DEPRECIATION RESERVE	FUTURE NET SALVAGE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	Intangible Plant								
401.0	Franchises and Consents	40-SQ	0	99,236	-	-	-	-	
402.0	Intangible Plant	40-SQ	0	772,555	-	-	-	-	
402.1	Plant Acquisitions and Adjustments	40-SQ	0	62,457	-	-	-	-	
	Total Intangible Plant			**934,248**	**-**	**-**	**-**		
	Manufacturing Plant								
432.0	Manufacturing Gas Structures	40-SQ	0	450,708	-	-	-	-	
433.0	Manufacturing Gas Equipment	20-SQ	0	145,939	-	-	-	-	
434.0	Manufacturing Gas Holders	40-SQ	0	357,586	-	-	-	-	
436.0	Manufacturing Gas Compressor Equipment	25-SQ	0	53,309	-	-	-	-	
437.0	Manufacturing Gas Measuring/Regulating Equipment	20-SQ	0	309,447	-	-	-	-	
	Total Manufacturing Plant			**1,316,989**	**-**	**-**	**-**		
	LNG Plant								
442.0	LNG Gas - Structures	25-R3	-10	4,779,018	168,342	309,560	17,571	0.37	17.6
443.0	LNG Gas - Equipment	40-R3	-20	16,495,801	1,422,194	1,876,966	70,743	0.43	26.5
449.0	LNG Gas - Other Equipment	35-R3	-10	18,936,395	738,152	1,155,488	64,005	0.34	18.1
	Total LNG Plant			**40,211,214**	**2,328,688**	**3,342,014**	**152,319**		
	Transmission Plant								
462.0	TP - Compressor Structures	30-R4	-5	14,587,984	219,897	509,502	27,400	0.19	18.6
463.0	TP - Measuring/Regulating Structures	30-R2.5	-5	4,839,702	51,151	190,834	10,201	0.21	18.7
464.0	TP - Other Structures	35-R3	-5	5,842,863	50,326	241,817	8,325	0.14	29.0
465.0	TP - Transmission Pipeline	60-R3	-10	700,388,612	14,010,589	56,028,272	1,145,444	0.16	48.9
466.0	TP - Compressor Equipment	33-R3	-10	106,301,110	2,599,255	8,030,856	339,284	0.32	23.7
467.1	TP - Measuring/Regulating Equipment	25-R2.5	-5	27,913,211	225,619	1,170,042	99,324	0.36	11.8
467.2	TP - Telementry Equipment	17-R2	0	6,065,331	-	-	-	-	
467.3	TP - Measurement/Regulating Equipment	25-R2.5	-5	38,716	250	1,686	77	0.20	21.9
468.0	TP - Communications Equipment	15-R2	0	345,886	-	-	-	-	
	Total Transmission Plant			**866,323,415**	**17,157,087**	**66,173,009**	**1,630,056**		
	Distribution Plant								
472.0	DS - Structures	28-L1	-5	13,845,551	126,227	566,051	24,654	0.18	23.0
473.0	DS - Services	55-R2.5	-50	578,026,320	25,316,304	263,696,856	6,511,837	1.13	40.5
473.01	LILO - DS - Services	40-SQ	-50	43,302,554	4,759,119	16,892,158	478,342	1.10	35.3
474.0	DS - Meters/Regulators Installations	30-R2	0	127,327,914	-	-	-	-	
474.01	LILO - DS - Meters/Regulators Installations	30-SQ	0	16,070,133	-	-	-	-	
475.0	DS - Mains	60-R3	-20	790,729,371	35,643,935	122,501,939	2,963,207	0.37	41.3
475.01	LILO - DS - Mains	40-SQ	-20	39,743,548	2,389,318	5,559,392	157,183	0.40	35.4
476.0	DS - NGV Fuel Equipment	15-R3	0	570,858	-	-	-	-	
477.1	DS - Meters/Regulators Additions	25-R2	0	72,654,480	-	-	-	-	
477.2	DS - Telemetry	20-R2.5	0	5,527,676	-	-	-	-	
477.3	DS - Measuring/Regulating Equipment	15-R2.5	-5	163,151	9,194	(1,036)	-	-	1.0
478.1	DS - Meters	25-R2	0	180,537,629	-	-	-	-	
478.11	LILO - DS Meters	25-SQ	0	10,026,726	-	-	-	-	
487.2	DS - Instruments	30-R3	0	10,942,940	-	-	-	-	
	Total Distribution Plant			**1,889,468,851**	**68,244,097**	**409,215,359**	**10,135,222**		
	General Plant								
482.1	Structures (Frame)	25-R2	0	5,637,521	-	-	-	-	
482.2	Structures(Masonry)	25-R2	0	81,459,403	-	-	-	-	
482.3	Structures (Leased)	20-R1	0	1,586,223	-	-	-	-	
483.1	Computer Hardware	5-SQ	0	13,863,764	-	-	-	-	
483.20	Computer Software (8 Years)	8-SQ	0	71,038,304	-	-	-	-	
483.21	Computer Software (5 Years)	5-SQ	0	6,787,308	-	-	-	-	
483.3	Office Furniture and Equipment	15-SQ	0	4,248,230	-	-	-	-	
483.4	Furniture	20-SQ	0	20,073,829	-	-	-	-	
484.0	Vehicles	6-L1	20	695,457	(97,322)	(41,769)	(10,710)	(1.54)	3.9
485.1	Heavy Work Equipment	15-R2	15	189,165	(7,401)	(20,974)	(1,873)	(0.99)	11.2
485.2	Heavy Mobile Equipment	15-L2.5	10	312,945	40,502	(71,797)	(6,410)	(2.05)	11.2
486.0	Small Tools/Equipment	20-SQ	0	32,034,924	-	-	-	-	
487.2	NGV Cylinders	15-SQ	0	24,167	-	-	-	-	
487.3	VRA's	10-SQ	0	-	-	-	-	-	
488.1	Telephone Equipment	15-SQ	0	10,450,131	-	-	-	-	
488.2	Radio Equipment	15-SQ	0	4,992,872	-	-	-	-	
	Total General Plant			**253,394,243**	**(64,221)**	**(134,540)**	**(18,993)**		
	TOTAL DEPRECIABLE PLANT			**3,051,648,960**	**87,665,651**	**478,595,842**	**11,898,605**	**0.39**	

TERASEN GAS (VANCOUVER ISLAND) INC.

TABLE 2. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2007

DEPRECIATION RELATED TO NET SALVAGE

	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2007	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	Intangible Plant								
401.0	Franchises and Consents	40-SQ	0	189,777	-	-	-	-	0.0
402.0	Intangible Plant	40-SQ	0	1,194,037	-	-	-	-	0.0
	Total Intangible Plant			**1,383,814**	**-**	**-**	**-**		
	Transmission Plant								
462.0	TP - Compressor Structures	30-R4	-5	10,148,764	116,818	390,620	18,617	0.18	21.0
463.0	TP - Measuring/Regulating Structures	30-R2.5	-5	6,056,273	90,938	211,876	8,501	0.14	24.9
464.0	TP - Other Structures	35-R3	-5	129,495	433	6,042	185	0.14	32.6
465.0	TP - Transmission Pipeline	60-R3	-10	221,257,782	4,904,113	17,221,665	383,266	0.17	44.9
466.0	TP - Compressor Equipment	33-R3	-10	45,122,851	831,942	3,680,343	144,265	0.32	25.5
467.1	TP - Measuring/Regulating Equipment	25-R2.5	-5	10,307,745	88,456	426,931	28,513	0.28	15.0
468.0	TP - Communications Equipment	15-R2	0	2,348,555	-	-	-	-	0.0
	Total Transmission Plant			**295,371,465**	**6,032,700**	**21,937,477**	**583,347**		
	Distribution Plant								
472.0	DS - Structures	28-L1	-5	1,455,159	29,997	42,761	2,254	0.15	19.0
473.0	DS - Services	55-R2.5	-50	122,548,256	7,261,092	54,013,036	1,175,218	0.96	46.0
474.0	DS - Meters/Regulators Installations	30-R2	0	15,569,726	-	-	-	-	0.0
475.0	DS - Mains	60-R3	-20	201,067,397	8,150,724	32,062,755	646,257	0.32	49.6
477.1	DS - Meters/Regulators Additions	25-R2	0	5,015,290	-	-	-	-	0.0
478.1	DS - Meters	25-R2	0	10,881,716	-	-	-	-	0.0
	Total Distribution Plant			**356,537,544**	**15,441,813**	**86,118,552**	**1,823,730**		
	General Plant								
482.2	Structures	25-R2	0	4,026,481	-	-	-	-	0.0
482.3	Structures (Leased)	20-R1	0	1,338,776	-	-	-	-	0.0
483.1	Computer Hardware	5-SQ	0	1,924,079	-	-	-	-	0.0
483.2	Computer Software	5-SQ	0	15,810,140	-	-	-	-	0.0
483.3	Office Furniture and Equipment	15-SQ	0	2,263,540	-	-	-	-	0.0
483.4	Furniture	20-SQ	0	59,597	-	-	-	-	0.0
484.0	Vehicles	6-L1	20	4,040,002	(250,984)	(557,016)	(144,454)	(3.58)	3.9
485.1	Heavy Work Equipment	15-R2	15	396,033	(34,958)	(24,447)	(3,678)	(0.93)	6.6
485.2	Heavy Mobile Equipment	15-L2.5	10	378,433	(3,374)	(34,469)	(2,784)	(0.74)	12.4
486.0	Small Tools/Equipment	20-SQ	0	5,540,499	-	-	-	-	0.0
488.1	Telephone Equipment	15-SQ	0	1,188,352	-	-	-	-	0.0
	Total General Plant			**36,965,932**	**(289,316)**	**(615,933)**	**(150,917)**		
	TOTAL DEPRECIABLE PLANT			**690,258,755**	**21,185,197**	**107,440,097**	**2,256,160**	**0.33**	

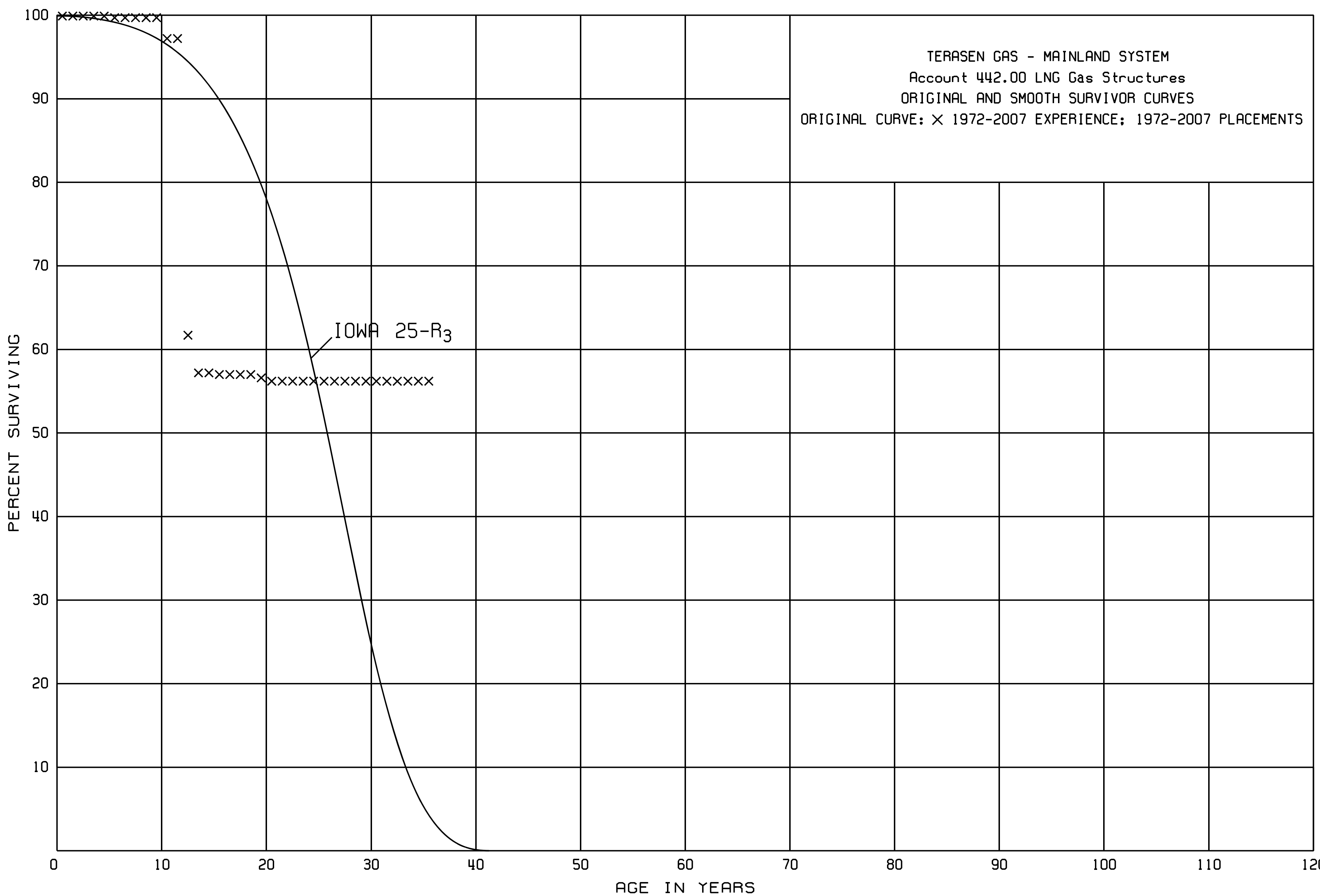
TERASEN GAS (WHISTLER) INC.

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2007

DRAFT - DEPRECIATION RELATED TO NET SALVAGE

	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2007	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	Intangible Plant								
401.0	Franchises and Consents	40-SQ	0	8,239	-	-	-	-	0.0
	Total Intangible Plant			**8,239**	**-**	**-**	**-**		
	Transmission Plant								
431.0	Mfg. Gas Land Rights	75-R4	0	3,625	-	-	-	-	0.0
432.0	Mfg. Gas Structures	40-SQ	0	2,878,938	-	-	-	-	0.0
433.0	Mfg. Gas Equipment	20-SQ	0	1,695,048	-	-	-	-	0.0
434.0	Mfg. Gas Holders	40-SQ	0	2,108,175	-	-	-	-	0.0
436.0	Mfg. Gas Compressor Equipment	25-SQ	0	37,896	-	-	-	-	0.0
437.0	Mfg. Gas Meas / Regulating Equipment	20-SQ	0	343,591	-	-	-	-	0.0
	Total Transmission Plant			**7,067,273**	**-**	**-**	**-**		
	Distribution Plant								
471.0	DS - Land Rights	75-R4	0	86,987	-	-	-	-	0.0
472.0	DS - Structures	28-L1	-5	205	5	5	0	0.15	16.9
473.0	DS - Services	55-R2.5	-50	2,890,836	163,218	1,282,200	28,051	0.97	45.7
474.0	DS - Meters/Regulators Installations	30-R2	0	808,837	- 0	- 0	- 0	-	0.0
475.0	DS - Mains	60-R3	-20	6,836,226	243,479	1,123,766	22,563	0.33	49.8
477.1	DS - Meters/Regulators Additions	25-R2	0	13,717	- 0	-	-	-	0.0
478.1	DS - Meters	25-R2	0	500,227	-	-	-	-	0.0
	Total Distribution Plant			**11,137,035**	**406,702**	**2,405,971**	**50,614**		
	General Plant								
482.1	Structures(Masonry)	25-R2	0	8,128	-	-	-	-	0.0
483.3	Office Furniture and Equipment	15-SQ	0	19,484	-	-	-	-	0.0
484.0	Vehicles	6-L1	20	64,260	(3,336)	(9,516)	(2,213)	(3.44)	4.3
485.1	Heavy Work Equipment	15-R2	15	77,949	(8,932)	(2,760)	(514)	(0.66)	5.4
486.0	Small Tools/Equipment	20-SQ	0	175,900	-	-	-	-	0.0
488.1	Telephone Equipment	15-SQ	0	45,832	-	-	-	-	0.0
	Total General Plant			**391,553**	**(12,268)**	**(12,276)**	**(2,727)**		
	TOTAL DEPRECIABLE PLANT			**18,604,100**	**394,434**	**2,393,695**	**47,888**	**0.26**	

SERVICE LIFE STATISTICS


TERASEN GAS - MAINLAND SYSTEM
Account 442.00 LNG Gas Structures
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1972-2007 EXPERIENCE; 1972-2007 PLACEMENTS
IOWA 25-R3
PERCENT SURVIVING
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120
AGE IN YEARS

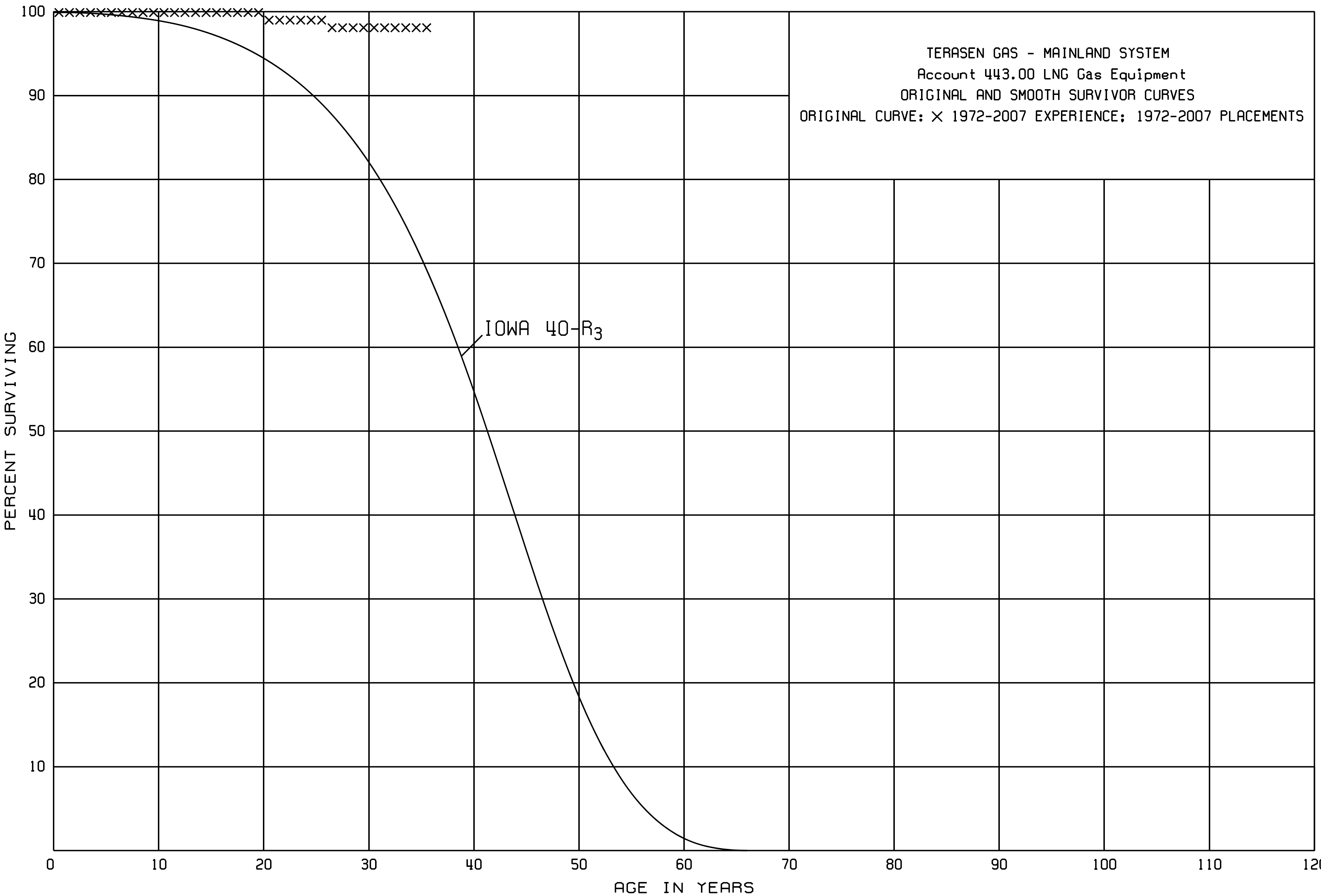
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 442.00 LNG GAS STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1972-2007 EXPERIENCE BAND 1972-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,611,718		0.0000	1.0000	100.00
0.5	5,422,288		0.0000	1.0000	100.00
1.5	5,402,758		0.0000	1.0000	100.00
2.5	4,613,619		0.0000	1.0000	100.00
3.5	3,917,493		0.0000	1.0000	100.00
4.5	3,877,256	11,458	0.0030	0.9970	100.00
5.5	3,713,054		0.0000	1.0000	99.70
6.5	3,654,427		0.0000	1.0000	99.70
7.5	3,423,460		0.0000	1.0000	99.70
8.5	2,570,431	1,000	0.0004	0.9996	99.70
9.5	2,522,805	61,358	0.0243	0.9757	99.66
10.5	1,869,913		0.0000	1.0000	97.24
11.5	1,831,056	669,121	0.3654	0.6346	97.24
12.5	1,031,517	74,954	0.0727	0.9273	61.71
13.5	882,333		0.0000	1.0000	57.22
14.5	874,240	2,477	0.0028	0.9972	57.22
15.5	751,004		0.0000	1.0000	57.06
16.5	749,079		0.0000	1.0000	57.06
17.5	748,737	1,959	0.0026	0.9974	57.06
18.5	736,840	6,000	0.0081	0.9919	56.91
19.5	690,981	4,373	0.0063	0.9937	56.45
20.5	406,524		0.0000	1.0000	56.09
21.5	406,524		0.0000	1.0000	56.09
22.5	373,294		0.0000	1.0000	56.09
23.5	373,294		0.0000	1.0000	56.09
24.5	371,581		0.0000	1.0000	56.09
25.5	337,361		0.0000	1.0000	56.09
26.5	281,400		0.0000	1.0000	56.09
27.5	266,336		0.0000	1.0000	56.09
28.5	242,968		0.0000	1.0000	56.09
29.5	239,234		0.0000	1.0000	56.09
30.5	239,234		0.0000	1.0000	56.09
31.5	239,234		0.0000	1.0000	56.09
32.5	239,234		0.0000	1.0000	56.09
33.5	239,234		0.0000	1.0000	56.09
34.5	236,738		0.0000	1.0000	56.09
35.5					56.09



TERASEN GAS - MAINLAND SYSTEM
Account 443.00 LNG Gas Equipment
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1972-2007 EXPERIENCE; 1972-2007 PLACEMENTS
IOWA 40-R3
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120

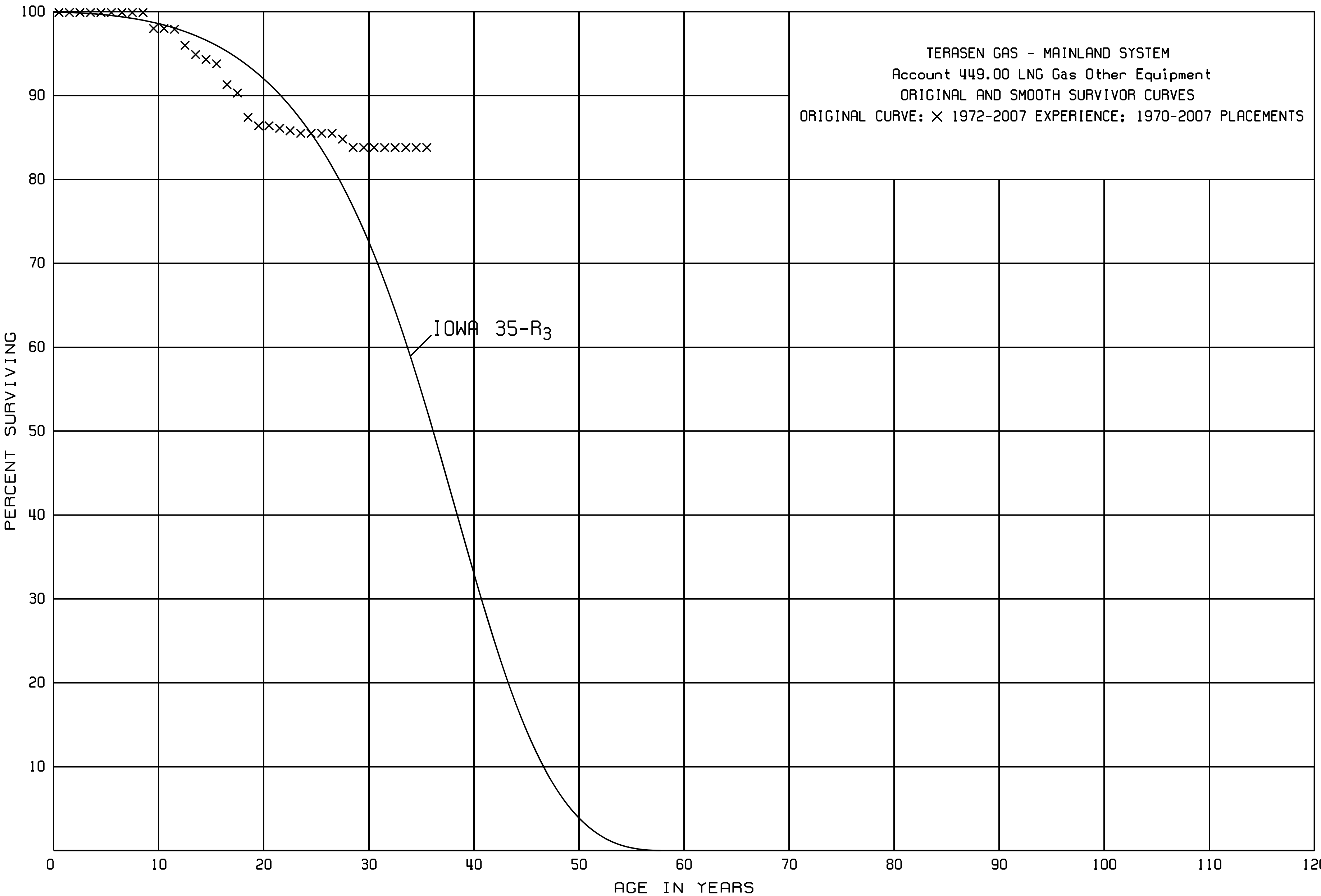
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 443.00 LNG GAS EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1972-2007 EXPERIENCE BAND 1972-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	16,661,182		0.0000	1.0000	100.00
0.5	16,660,797		0.0000	1.0000	100.00
1.5	16,608,373		0.0000	1.0000	100.00
2.5	16,550,203		0.0000	1.0000	100.00
3.5	15,658,256		0.0000	1.0000	100.00
4.5	15,524,004	1,000	0.0001	0.9999	100.00
5.5	10,288,394		0.0000	1.0000	99.99
6.5	10,288,394		0.0000	1.0000	99.99
7.5	10,288,394		0.0000	1.0000	99.99
8.5	9,644,196		0.0000	1.0000	99.99
9.5	9,644,196	12,708	0.0013	0.9987	99.99
10.5	9,560,685		0.0000	1.0000	99.86
11.5	9,297,826		0.0000	1.0000	99.86
12.5	9,297,826		0.0000	1.0000	99.86
13.5	9,296,283		0.0000	1.0000	99.86
14.5	9,193,420		0.0000	1.0000	99.86
15.5	9,188,597		0.0000	1.0000	99.86
16.5	9,159,007		0.0000	1.0000	99.86
17.5	9,143,573		0.0000	1.0000	99.86
18.5	9,140,232	44,685	0.0049	0.9951	99.86
19.5	9,082,459	79,648	0.0088	0.9912	99.37
20.5	2,941,311		0.0000	1.0000	98.50
21.5	2,941,311		0.0000	1.0000	98.50
22.5	2,941,311		0.0000	1.0000	98.50
23.5	2,941,311		0.0000	1.0000	98.50
24.5	2,941,311		0.0000	1.0000	98.50
25.5	2,941,311	27,340	0.0093	0.9907	98.50
26.5	2,913,971		0.0000	1.0000	97.58
27.5	2,913,971		0.0000	1.0000	97.58
28.5	2,913,971		0.0000	1.0000	97.58
29.5	2,913,971		0.0000	1.0000	97.58
30.5	2,913,971		0.0000	1.0000	97.58
31.5	2,913,971		0.0000	1.0000	97.58
32.5	2,913,971		0.0000	1.0000	97.58
33.5	2,913,971		0.0000	1.0000	97.58
34.5	2,901,446		0.0000	1.0000	97.58
35.5					97.58


TERASEN GAS - MAINLAND SYSTEM
Account 449.00 LNG Gas Other Equipment
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1972-2007 EXPERIENCE; 1970-2007 PLACEMENTS
IOWA 35-R3
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120

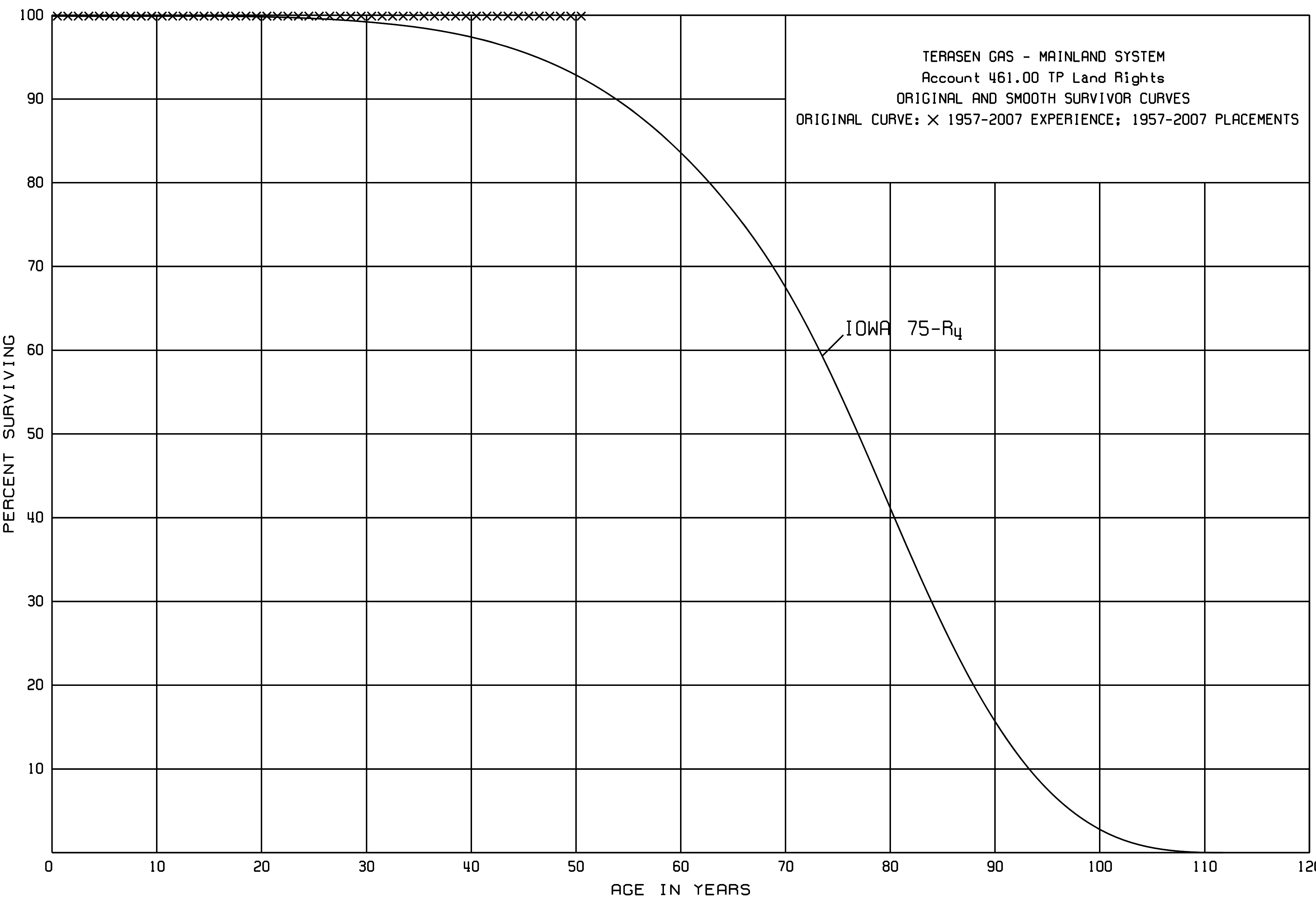
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 449.00 LNG GAS OTHER EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1970-2007 EXPERIENCE BAND 1972-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	20,548,251	500	0.0000	1.0000	100.00
0.5	20,339,960		0.0000	1.0000	100.00
1.5	20,096,893	1	0.0000	1.0000	100.00
2.5	17,965,859	12	0.0000	1.0000	100.00
3.5	17,723,075	48	0.0000	1.0000	100.00
4.5	17,483,718	22	0.0000	1.0000	100.00
5.5	16,591,336	18	0.0000	1.0000	100.00
6.5	16,591,318	15	0.0000	1.0000	100.00
7.5	16,293,582	8,344	0.0005	0.9995	100.00
8.5	15,882,726	303,785	0.0191	0.9809	99.95
9.5	15,539,021	53,798	0.0035	0.9965	98.04
10.5	15,073,320	25,930	0.0017	0.9983	97.70
11.5	14,447,991	286,493	0.0198	0.9802	97.53
12.5	10,557,321	123,449	0.0117	0.9883	95.60
13.5	10,140,987	67,845	0.0067	0.9933	94.48
14.5	8,787,176	41,927	0.0048	0.9952	93.85
15.5	8,150,923	215,295	0.0264	0.9736	93.40
16.5	7,294,125	85,676	0.0117	0.9883	90.93
17.5	6,935,302	217,876	0.0314	0.9686	89.87
18.5	6,547,727	71,537	0.0109	0.9891	87.05
19.5	6,473,096	39,819	0.0062	0.9938	86.10
20.5	6,433,277	27,751	0.0043	0.9957	85.57
21.5	6,347,488	21,715	0.0034	0.9966	85.20
22.5	6,285,474	20,000	0.0032	0.9968	84.91
23.5	6,220,160		0.0000	1.0000	84.64
24.5	6,204,562		0.0000	1.0000	84.64
25.5	6,167,258	9	0.0000	1.0000	84.64
26.5	6,165,610	54,471	0.0088	0.9912	84.64
27.5	6,111,064	67,164	0.0110	0.9890	83.90
28.5	6,043,468		0.0000	1.0000	82.98
29.5	6,043,281		0.0000	1.0000	82.98
30.5	6,042,240		0.0000	1.0000	82.98
31.5	6,030,043		0.0000	1.0000	82.98
32.5	6,030,043		0.0000	1.0000	82.98
33.5	6,016,004		0.0000	1.0000	82.98
34.5	5,851,651		0.0000	1.0000	82.98
35.5					82.98


TERASEN GAS - MAINLAND SYSTEM
Account 461.00 TP Land Rights
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1957-2007 EXPERIENCE; 1957-2007 PLACEMENTS
IOWA 75-R4
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
110
120

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 461.00 TP LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1957-2007 EXPERIENCE BAND 1957-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	42,840,570	6	0.0000	1.0000	100.00
0.5	42,637,239	6,456	0.0002	0.9998	100.00
1.5	37,595,011	1,448	0.0000	1.0000	99.98
2.5	37,552,211		0.0000	1.0000	99.98
3.5	36,590,595		0.0000	1.0000	99.98
4.5	29,302,090		0.0000	1.0000	99.98
5.5	24,549,137		0.0000	1.0000	99.98
6.5	21,747,788		0.0000	1.0000	99.98
7.5	9,384,687		0.0000	1.0000	99.98
8.5	9,384,687		0.0000	1.0000	99.98
9.5	9,175,875		0.0000	1.0000	99.98
10.5	8,888,191		0.0000	1.0000	99.98
11.5	8,188,998		0.0000	1.0000	99.98
12.5	7,714,724		0.0000	1.0000	99.98
13.5	6,493,268		0.0000	1.0000	99.98
14.5	5,373,917		0.0000	1.0000	99.98
15.5	2,931,981	1,089	0.0004	0.9996	99.98
16.5	2,879,483		0.0000	1.0000	99.94
17.5	2,847,966		0.0000	1.0000	99.94
18.5	2,806,481		0.0000	1.0000	99.94
19.5	2,795,855		0.0000	1.0000	99.94
20.5	2,694,994		0.0000	1.0000	99.94
21.5	2,171,584		0.0000	1.0000	99.94
22.5	2,149,349		0.0000	1.0000	99.94
23.5	2,145,553		0.0000	1.0000	99.94
24.5	2,100,686		0.0000	1.0000	99.94
25.5	2,053,926		0.0000	1.0000	99.94
26.5	2,015,880		0.0000	1.0000	99.94
27.5	2,012,397		0.0000	1.0000	99.94
28.5	1,878,619		0.0000	1.0000	99.94
29.5	1,753,224		0.0000	1.0000	99.94
30.5	1,697,344		0.0000	1.0000	99.94
31.5	1,152,779		0.0000	1.0000	99.94
32.5	1,087,991		0.0000	1.0000	99.94
33.5	1,066,795		0.0000	1.0000	99.94
34.5	1,058,745		0.0000	1.0000	99.94
35.5	814,475		0.0000	1.0000	99.94
36.5	786,510		0.0000	1.0000	99.94
37.5	782,286		0.0000	1.0000	99.94
38.5	764,147		0.0000	1.0000	99.94

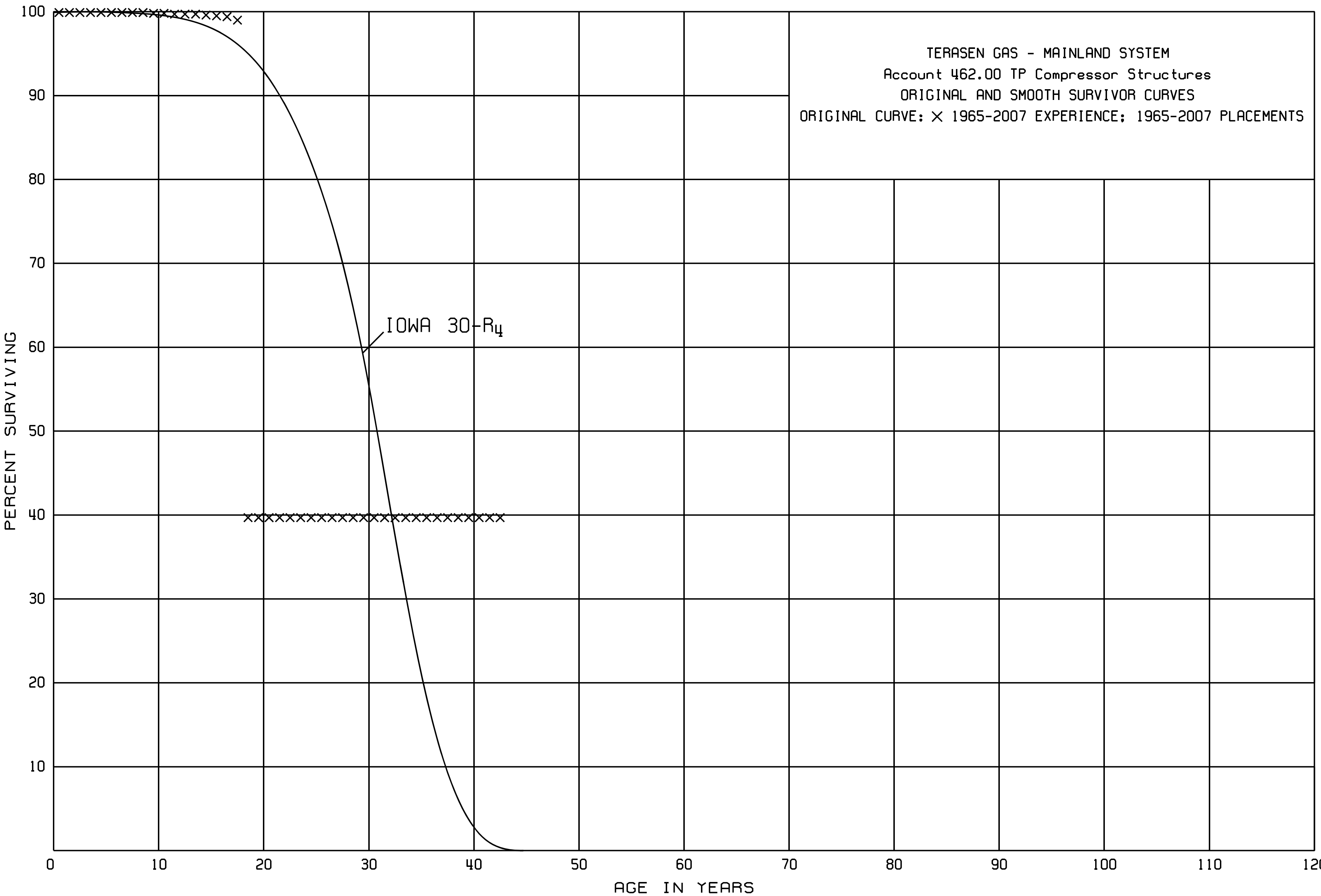
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 461.00 TP LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1957-2007 EXPERIENCE BAND 1957-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	747,059		0.0000	1.0000	99.94
40.5	744,323		0.0000	1.0000	99.94
41.5	743,099		0.0000	1.0000	99.94
42.5	733,552		0.0000	1.0000	99.94
43.5	708,502		0.0000	1.0000	99.94
44.5	666,092		0.0000	1.0000	99.94
45.5	663,904		0.0000	1.0000	99.94
46.5	647,244		0.0000	1.0000	99.94
47.5	628,251		0.0000	1.0000	99.94
48.5	1,089		0.0000	1.0000	99.94
49.5	1,089		0.0000	1.0000	99.94
50.5					99.94


TERASEN GAS - MAINLAND SYSTEM
Account 462.00 TP Compressor Structures
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1965-2007 EXPERIENCE; 1965-2007 PLACEMENTS
IOWA 30-R4
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 462.00 TP COMPRESSOR STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2007 EXPERIENCE BAND 1965-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	15,027,655		0.0000	1.0000	100.00
0.5	14,976,676		0.0000	1.0000	100.00
1.5	14,970,807	1,338	0.0001	0.9999	100.00
2.5	14,928,636		0.0000	1.0000	99.99
3.5	14,628,921	1,225	0.0001	0.9999	99.99
4.5	14,442,774	7,893	0.0005	0.9995	99.98
5.5	12,947,199	6,379	0.0005	0.9995	99.93
6.5	12,476,014	2,414	0.0002	0.9998	99.88
7.5	8,977,459	659	0.0001	0.9999	99.86
8.5	8,976,800	3,363	0.0004	0.9996	99.85
9.5	8,972,739	3,380	0.0004	0.9996	99.81
10.5	8,786,769	6,438	0.0007	0.9993	99.77
11.5	8,433,255		0.0000	1.0000	99.70
12.5	7,502,427	1,162	0.0002	0.9998	99.70
13.5	2,364,324	2,977	0.0013	0.9987	99.68
14.5	913,493	683	0.0007	0.9993	99.55
15.5	710,205	461	0.0006	0.9994	99.48
16.5	696,786	3,140	0.0045	0.9955	99.42
17.5	664,972	398,159	0.5988	0.4012	98.97
18.5	264,222		0.0000	1.0000	39.71
19.5	259,073		0.0000	1.0000	39.71
20.5	256,210		0.0000	1.0000	39.71
21.5	255,552		0.0000	1.0000	39.71
22.5	254,237		0.0000	1.0000	39.71
23.5	253,996		0.0000	1.0000	39.71
24.5	253,996		0.0000	1.0000	39.71
25.5	252,750		0.0000	1.0000	39.71
26.5	252,750		0.0000	1.0000	39.71
27.5	252,135		0.0000	1.0000	39.71
28.5	251,101		0.0000	1.0000	39.71
29.5	250,041		0.0000	1.0000	39.71
30.5	249,974		0.0000	1.0000	39.71
31.5	248,621		0.0000	1.0000	39.71
32.5	244,183		0.0000	1.0000	39.71
33.5	239,876		0.0000	1.0000	39.71
34.5	25,606		0.0000	1.0000	39.71
35.5	25,606		0.0000	1.0000	39.71
36.5	25,606		0.0000	1.0000	39.71
37.5	25,606		0.0000	1.0000	39.71
38.5	23,839		0.0000	1.0000	39.71

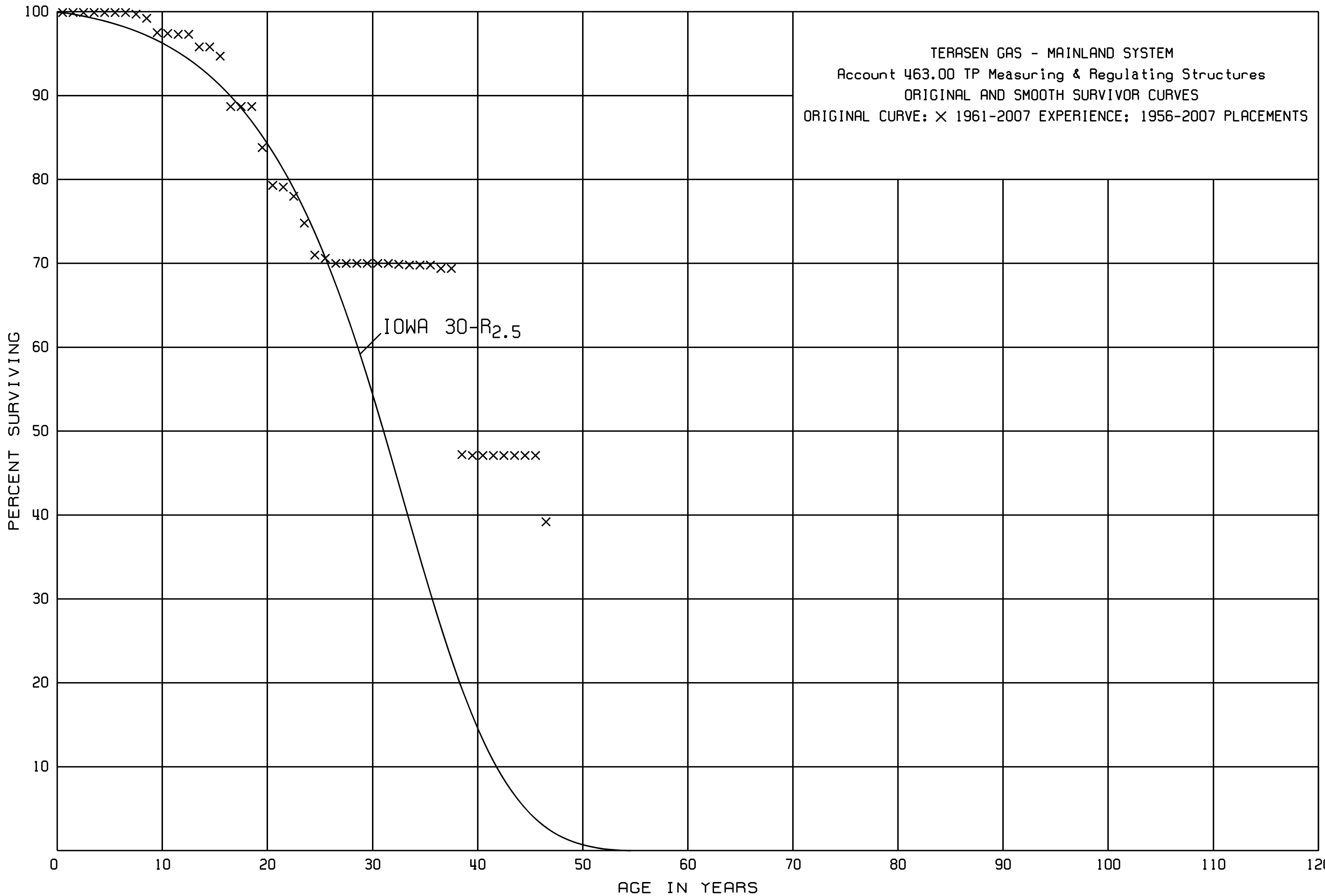
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 462.00 TP COMPRESSOR STRUCTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1965-2007 EXPERIENCE BAND 1965-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	23,839		0.0000	1.0000	39.71
40.5	21,757		0.0000	1.0000	39.71
41.5	14,750		0.0000	1.0000	39.71
42.5					39.71


TERASEN GAS - MAINLAND SYSTEM
Account 463.00 TP Measuring & Regulating Structures
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1961-2007 EXPERIENCE; 1956-2007 PLACEMENTS
IOWA 30-$R_{2.5}$
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 463.00 TP MEASURING & REGULATING STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2007 EXPERIENCE BAND 1961-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,259,839	53,753	0.0102	0.9898	100.00
0.5	5,192,789	3	0.0000	1.0000	98.98
1.5	5,072,056	23	0.0000	1.0000	98.98
2.5	4,875,405	142	0.0000	1.0000	98.98
3.5	4,146,196	167	0.0000	1.0000	98.98
4.5	3,920,230	617	0.0002	0.9998	98.98
5.5	3,221,733	244	0.0001	0.9999	98.96
6.5	3,199,270	6,386	0.0020	0.9980	98.95
7.5	2,875,855	14,641	0.0051	0.9949	98.75
8.5	2,812,311	48,726	0.0173	0.9827	98.25
9.5	2,760,860	4,013	0.0015	0.9985	96.55
10.5	2,651,554	544	0.0002	0.9998	96.41
11.5	2,381,684	437	0.0002	0.9998	96.39
12.5	2,376,471	36,190	0.0152	0.9848	96.37
13.5	2,141,458	955	0.0004	0.9996	94.91
14.5	1,975,788	22,233	0.0113	0.9887	94.87
15.5	1,516,535	97,354	0.0642	0.9358	93.80
16.5	813,392	113	0.0001	0.9999	87.78
17.5	813,279	59	0.0001	0.9999	87.77
18.5	811,168	46,351	0.0571	0.9429	87.76
19.5	574,001	31,956	0.0557	0.9443	82.75
20.5	532,633	1,643	0.0031	0.9969	78.14
21.5	454,529	6,227	0.0137	0.9863	77.90
22.5	436,652	18,950	0.0434	0.9566	76.83
23.5	412,688	22,385	0.0542	0.9458	73.50
24.5	370,484	1,851	0.0050	0.9950	69.52
25.5	341,013	3,000	0.0088	0.9912	69.17
26.5	311,995		0.0000	1.0000	68.56
27.5	261,651		0.0000	1.0000	68.56
28.5	258,208		0.0000	1.0000	68.56
29.5	232,796		0.0000	1.0000	68.56
30.5	228,405		0.0000	1.0000	68.56
31.5	227,978	622	0.0027	0.9973	68.56
32.5	217,675	322	0.0015	0.9985	68.37
33.5	192,290		0.0000	1.0000	68.27
34.5	179,981		0.0000	1.0000	68.27
35.5	149,498	1,000	0.0067	0.9933	68.27
36.5	147,745		0.0000	1.0000	67.81
37.5	147,734	54,267	0.3673	0.6327	67.81
38.5	92,825	230	0.0025	0.9975	42.90

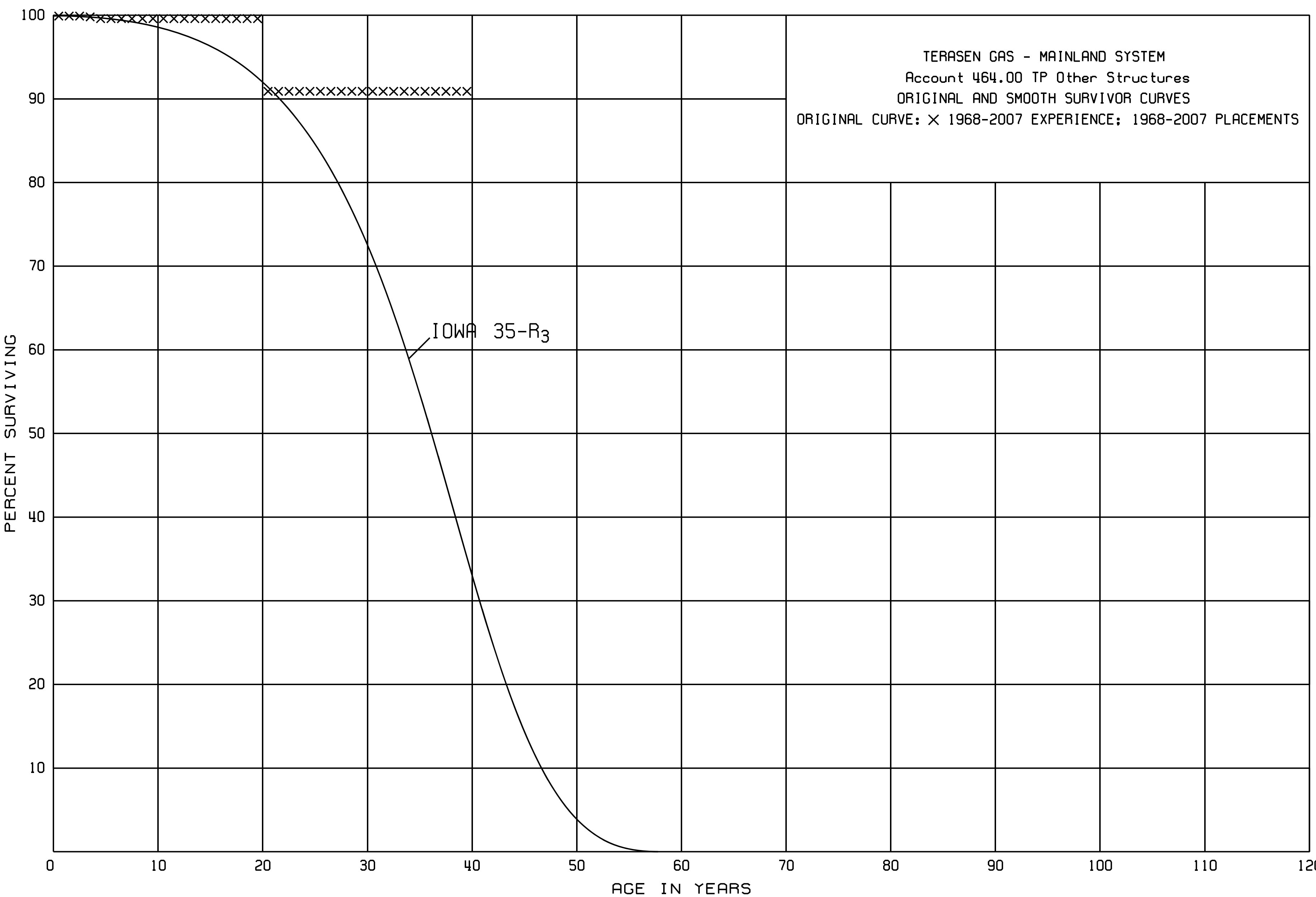
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 463.00 TP MEASURING & REGULATING STRUCTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-2007 EXPERIENCE BAND 1961-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	84,912		0.0000	1.0000	42.79
40.5	83,040		0.0000	1.0000	42.79
41.5	77,964		0.0000	1.0000	42.79
42.5	68,986		0.0000	1.0000	42.79
43.5	38,164		0.0000	1.0000	42.79
44.5	7,072		0.0000	1.0000	42.79
45.5	6,016	4,697	0.7808	0.2192	42.79
46.5					9.38


TERASEN GAS - MAINLAND SYSTEM
Account 464.00 TP Other Structures
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1968-2007 EXPERIENCE; 1968-2007 PLACEMENTS
IOWA 35-R3
PERCENT SURVIVING
AGE IN YEARS

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 464.00 TP OTHER STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1968-2007 EXPERIENCE BAND 1968-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,868,546		0.0000	1.0000	100.00
0.5	5,644,144		0.0000	1.0000	100.00
1.5	5,623,013	7,358	0.0013	0.9987	100.00
2.5	5,269,962	4,055	0.0008	0.9992	99.87
3.5	4,874,834	7,453	0.0015	0.9985	99.79
4.5	4,857,954		0.0000	1.0000	99.64
5.5	4,288,858		0.0000	1.0000	99.64
6.5	388,211		0.0000	1.0000	99.64
7.5	315,371		0.0000	1.0000	99.64
8.5	229,494		0.0000	1.0000	99.64
9.5	229,494		0.0000	1.0000	99.64
10.5	219,440		0.0000	1.0000	99.64
11.5	147,539	70	0.0005	0.9995	99.64
12.5	138,887		0.0000	1.0000	99.59
13.5	122,239		0.0000	1.0000	99.59
14.5	104,728		0.0000	1.0000	99.59
15.5	104,447		0.0000	1.0000	99.59
16.5	78,597		0.0000	1.0000	99.59
17.5	75,990		0.0000	1.0000	99.59
18.5	74,317		0.0000	1.0000	99.59
19.5	66,277	6,746	0.1018	0.8982	99.59
20.5	46,272		0.0000	1.0000	89.45
21.5	46,272		0.0000	1.0000	89.45
22.5	46,272		0.0000	1.0000	89.45
23.5	44,804		0.0000	1.0000	89.45
24.5	35,935		0.0000	1.0000	89.45
25.5	29,189		0.0000	1.0000	89.45
26.5	26,979		0.0000	1.0000	89.45
27.5	26,979		0.0000	1.0000	89.45
28.5	16,153		0.0000	1.0000	89.45
29.5	9,838		0.0000	1.0000	89.45
30.5	9,838		0.0000	1.0000	89.45
31.5	9,838		0.0000	1.0000	89.45
32.5	7,846		0.0000	1.0000	89.45
33.5	7,846		0.0000	1.0000	89.45
34.5	1		0.0000	1.0000	89.45
35.5	1		0.0000	1.0000	89.45
36.5	1		0.0000	1.0000	89.45
37.5	1		0.0000	1.0000	89.45
38.5	1		0.0000	1.0000	89.45

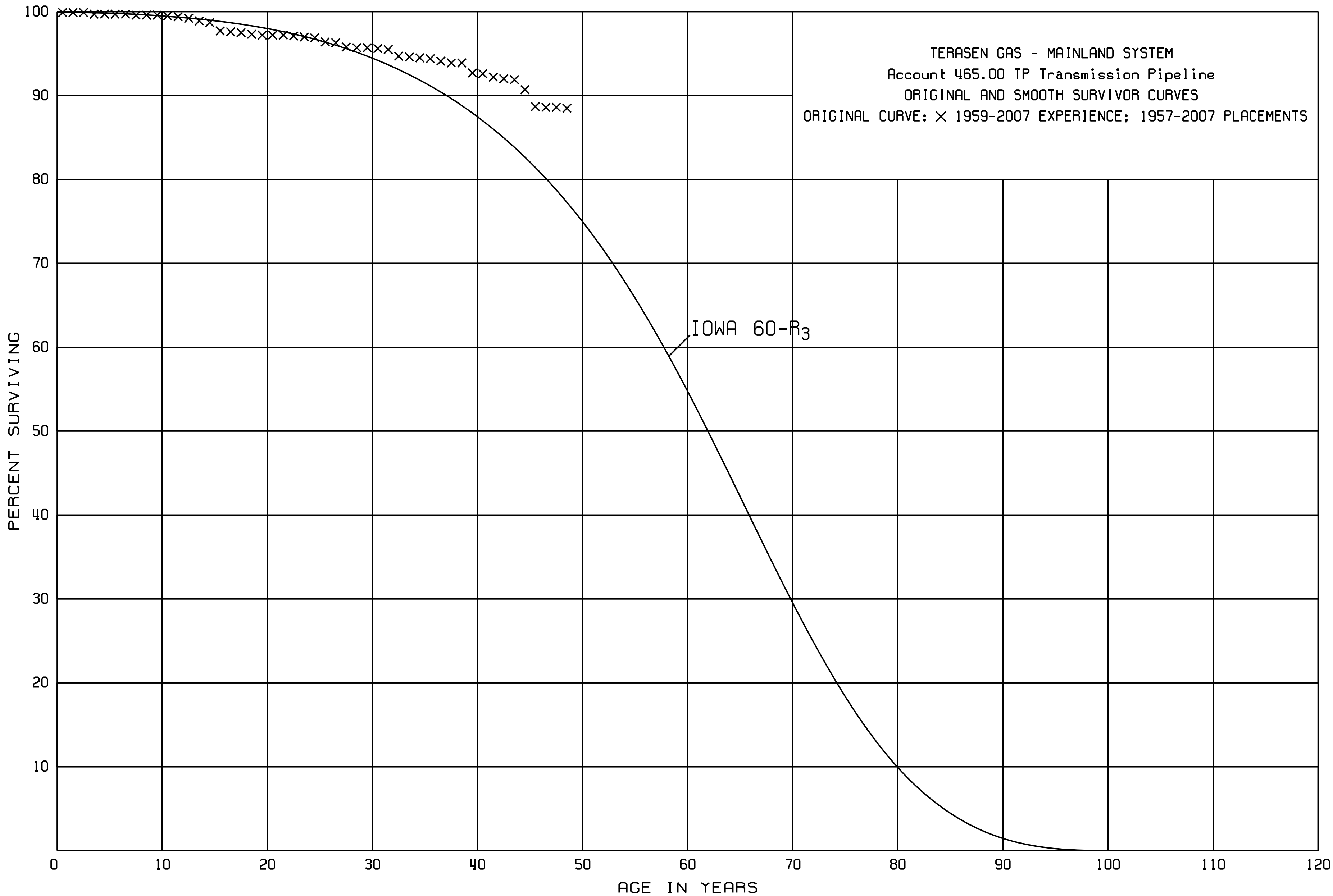
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 464.00 TP OTHER STRUCTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1968-2007 EXPERIENCE BAND 1968-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5					89.45


TERASEN GAS - MAINLAND SYSTEM
Account 465.00 TP Transmission Pipeline
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1959-2007 EXPERIENCE; 1957-2007 PLACEMENTS
IOWA 60-R3
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 465.00 TP TRANSMISSION PIPELINE

ORIGINAL LIFE TABLE

PLACEMENT BAND 1957-2007 EXPERIENCE BAND 1959-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	710,021,640	20,950	0.0000	1.0000	100.00
0.5	705,049,533	340,793	0.0005	0.9995	100.00
1.5	695,895,621	211,413	0.0003	0.9997	99.95
2.5	686,157,947	1,460,744	0.0021	0.9979	99.92
3.5	639,361,750	336,937	0.0005	0.9995	99.71
4.5	631,681,268	38,596	0.0001	0.9999	99.66
5.5	617,414,839	68,177	0.0001	0.9999	99.65
6.5	566,538,751	235,985	0.0004	0.9996	99.64
7.5	242,800,064	165,840	0.0007	0.9993	99.60
8.5	237,457,599	55,545	0.0002	0.9998	99.53
9.5	227,031,573	143,272	0.0006	0.9994	99.51
10.5	223,930,940	133,324	0.0006	0.9994	99.45
11.5	220,276,844	563,904	0.0026	0.9974	99.39
12.5	211,584,655	581,312	0.0027	0.9973	99.13
13.5	178,834,487	224,700	0.0013	0.9987	98.86
14.5	171,845,127	1,685,360	0.0098	0.9902	98.73
15.5	116,971,803	119,753	0.0010	0.9990	97.76
16.5	112,848,517	100,429	0.0009	0.9991	97.66
17.5	111,361,097	198,990	0.0018	0.9982	97.57
18.5	110,430,601	117,708	0.0011	0.9989	97.39
19.5	109,067,049	26,736	0.0002	0.9998	97.28
20.5	106,242,805	14,452	0.0001	0.9999	97.26
21.5	100,589,616	15,287	0.0002	0.9998	97.25
22.5	99,702,928	92,276	0.0009	0.9991	97.23
23.5	97,752,281	94,207	0.0010	0.9990	97.14
24.5	86,739,856	419,671	0.0048	0.9952	97.04
25.5	83,902,990	97,195	0.0012	0.9988	96.57
26.5	81,925,419	363,542	0.0044	0.9956	96.45
27.5	80,620,153	45,162	0.0006	0.9994	96.03
28.5	67,593,683	32,232	0.0005	0.9995	95.97
29.5	66,384,927	46,659	0.0007	0.9993	95.92
30.5	61,737,588	14,892	0.0002	0.9998	95.85
31.5	43,586,458	267,087	0.0061	0.9939	95.83
32.5	43,014,181	51,768	0.0012	0.9988	95.25
33.5	42,869,093	16,491	0.0004	0.9996	95.14
34.5	42,379,848	82,737	0.0020	0.9980	95.10
35.5	34,074,986	82,773	0.0024	0.9976	94.91
36.5	33,126,177	112,003	0.0034	0.9966	94.68
37.5	32,098,937		0.0000	1.0000	94.36
38.5	30,627,387	295,708	0.0097	0.9903	94.36

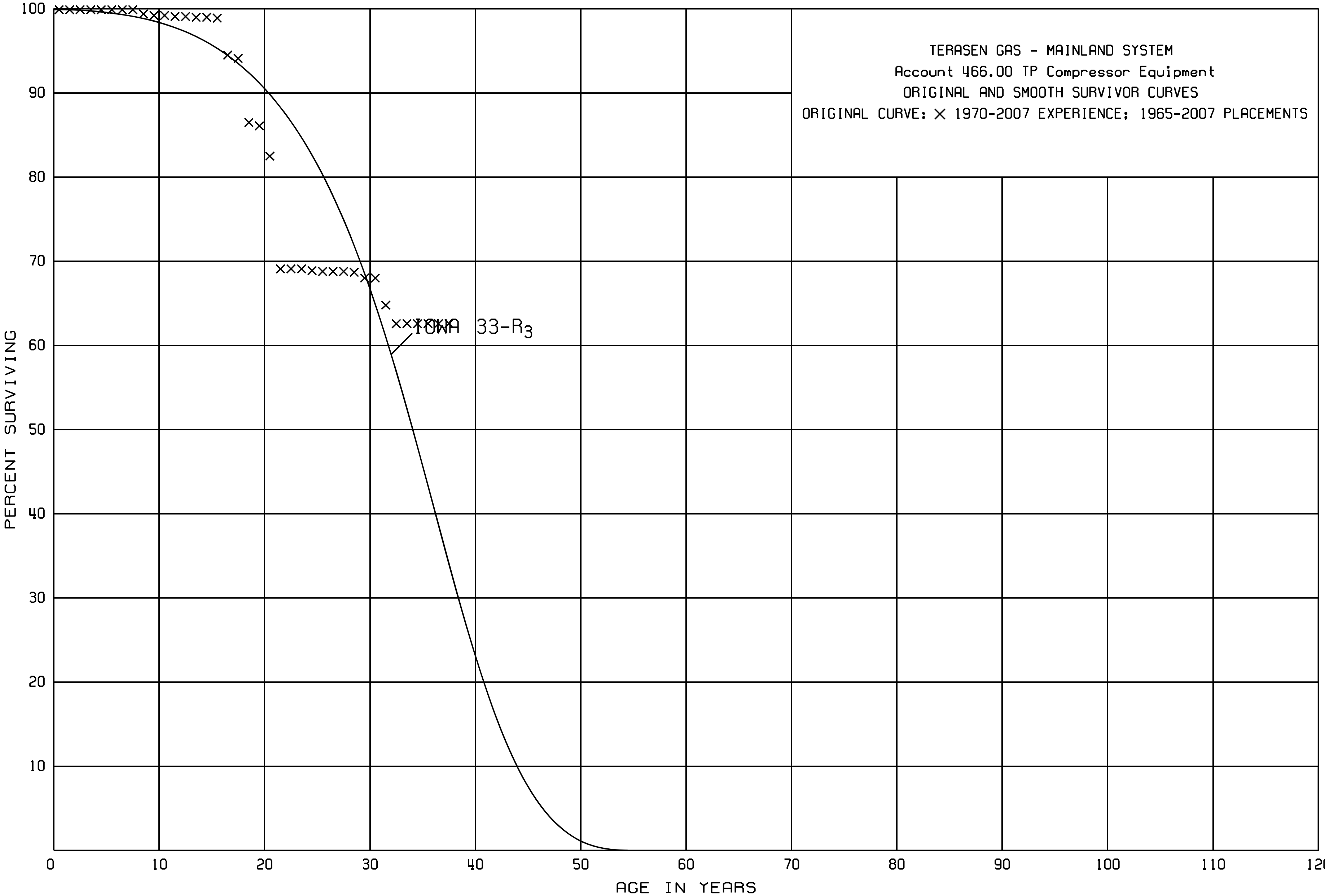
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 465.00 TP TRANSMISSION PIPELINE

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1957-2007 EXPERIENCE BAND 1959-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	29,398,793	24,571	0.0008	0.9992	93.44
40.5	28,892,563	98,214	0.0034	0.9966	93.37
41.5	24,836,051	39,589	0.0016	0.9984	93.05
42.5	24,740,300	30,563	0.0012	0.9988	92.90
43.5	24,091,356	200,880	0.0083	0.9917	92.79
44.5	14,407,521	327,084	0.0227	0.9773	92.02
45.5	14,080,437	17,760	0.0013	0.9987	89.93
46.5	13,975,092	41,389	0.0030	0.9970	89.81
47.5	13,933,703	5,119	0.0004	0.9996	89.54
48.5					89.50


TERASEN GAS - MAINLAND SYSTEM
Account 466.00 TP Compressor Equipment
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1970-2007 EXPERIENCE; 1965-2007 PLACEMENTS
IOWA 33-R3
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120

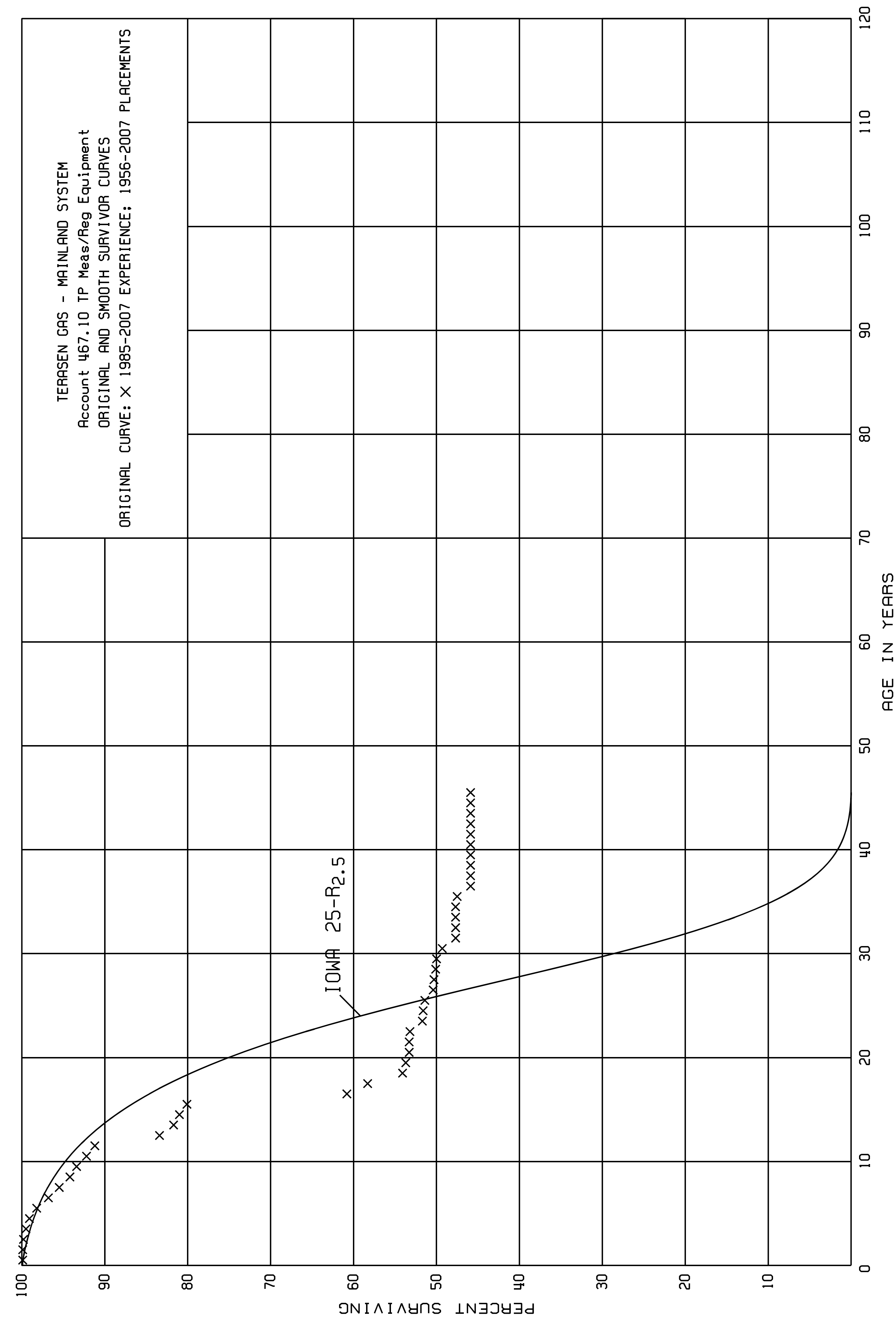
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 466.00 TP COMPRESSOR EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2007 EXPERIENCE BAND 1970-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	107,685,714	35	0.0000	1.0000	100.00
0.5	107,670,999	556	0.0000	1.0000	100.00
1.5	107,655,591	758	0.0000	1.0000	100.00
2.5	106,154,135	2,978	0.0000	1.0000	100.00
3.5	102,943,650	1,513	0.0000	1.0000	100.00
4.5	102,614,320	16,949	0.0002	0.9998	100.00
5.5	97,155,610	23,569	0.0002	0.9998	99.98
6.5	92,069,850	18,547	0.0002	0.9998	99.96
7.5	40,615,156	234,417	0.0058	0.9942	99.94
8.5	40,336,886	62,334	0.0015	0.9985	99.36
9.5	40,129,147	5,855	0.0001	0.9999	99.21
10.5	38,004,445	41,588	0.0011	0.9989	99.20
11.5	36,653,394	11,150	0.0003	0.9997	99.09
12.5	32,389,126	13,910	0.0004	0.9996	99.06
13.5	10,855,443	5,619	0.0005	0.9995	99.02
14.5	6,327,641	3,876	0.0006	0.9994	98.97
15.5	3,877,376	171,537	0.0442	0.9558	98.91
16.5	3,580,372	17,640	0.0049	0.9951	94.54
17.5	3,517,288	284,588	0.0809	0.9191	94.08
18.5	3,210,898	12,182	0.0038	0.9962	86.47
19.5	3,184,745	135,051	0.0424	0.9576	86.14
20.5	2,966,404	480,963	0.1621	0.8379	82.49
21.5	2,470,175	510	0.0002	0.9998	69.12
22.5	2,460,683	85	0.0000	1.0000	69.11
23.5	2,453,433	9,084	0.0037	0.9963	69.11
24.5	2,396,588	374	0.0002	0.9998	68.85
25.5	2,387,470	1,436	0.0006	0.9994	68.84
26.5	2,380,662	655	0.0003	0.9997	68.80
27.5	2,379,523	4,049	0.0017	0.9983	68.78
28.5	2,366,825	22,073	0.0093	0.9907	68.66
29.5	1,726,115		0.0000	1.0000	68.02
30.5	1,681,768	79,374	0.0472	0.9528	68.02
31.5	880,910	29,977	0.0340	0.9660	64.81
32.5	850,485		0.0000	1.0000	62.61
33.5	651,741		0.0000	1.0000	62.61
34.5	6,993		0.0000	1.0000	62.61
35.5	6,687		0.0000	1.0000	62.61
36.5	6,687		0.0000	1.0000	62.61
37.5					62.61


TERASEN GAS - MAINLAND SYSTEM
Account 467.10 TP Meas/Reg Equipment
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1985-2007 EXPERIENCE: 1956-2007 PLACEMENTS
IOWA 25-R2.5
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
110
120

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 467.10 TP MEAS/REG EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2007 EXPERIENCE BAND 1962-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	33,033,385	178,113	0.0054	0.9946	100.00
0.5	31,864,817	11,633	0.0004	0.9996	99.46
1.5	31,390,643	28,212	0.0009	0.9991	99.42
2.5	30,714,407	68,444	0.0022	0.9978	99.33
3.5	27,703,599	105,624	0.0038	0.9962	99.11
4.5	23,942,432	378,143	0.0158	0.9842	98.73
5.5	21,170,312	288,749	0.0136	0.9864	97.17
6.5	20,460,308	247,391	0.0121	0.9879	95.85
7.5	16,974,438	212,557	0.0125	0.9875	94.69
8.5	16,620,168	129,336	0.0078	0.9922	93.51
9.5	16,294,703	226,671	0.0139	0.9861	92.78
10.5	14,858,083	144,388	0.0097	0.9903	91.49
11.5	12,600,649	942,895	0.0748	0.9252	90.60
12.5	10,391,814	188,092	0.0181	0.9819	83.82
13.5	9,239,359	89,387	0.0097	0.9903	82.30
14.5	7,241,261	67,497	0.0093	0.9907	81.50
15.5	5,545,851	1,063,422	0.1918	0.8082	80.74
16.5	4,027,004	122,841	0.0305	0.9695	65.25
17.5	3,558,961	200,554	0.0564	0.9436	63.26
18.5	3,083,734	69,455	0.0225	0.9775	59.69
19.5	2,957,024	148,825	0.0503	0.9497	58.35
20.5	2,725,753	1,217	0.0004	0.9996	55.41
21.5	2,631,204	4,690	0.0018	0.9982	55.39
22.5	2,509,193	69,034	0.0275	0.9725	55.29
23.5	2,403,347	3,170	0.0013	0.9987	53.77
24.5	2,258,647	8,004	0.0035	0.9965	53.70
25.5	2,111,721	43,788	0.0207	0.9793	53.51
26.5	1,976,805	1,249	0.0006	0.9994	52.40
27.5	1,734,176	7,442	0.0043	0.9957	52.37
28.5	1,715,078	3,232	0.0019	0.9981	52.14
29.5	1,432,123	21,090	0.0147	0.9853	52.04
30.5	1,374,426	44,228	0.0322	0.9678	51.28
31.5	1,234,965	800	0.0006	0.9994	49.63
32.5	1,196,889		0.0000	1.0000	49.60
33.5	1,168,629		0.0000	1.0000	49.60
34.5	1,160,038	4,450	0.0038	0.9962	49.60
35.5	1,071,230	37,550	0.0351	0.9649	49.41
36.5	1,012,838		0.0000	1.0000	47.68
37.5	995,870		0.0000	1.0000	47.68
38.5	837,740		0.0000	1.0000	47.68

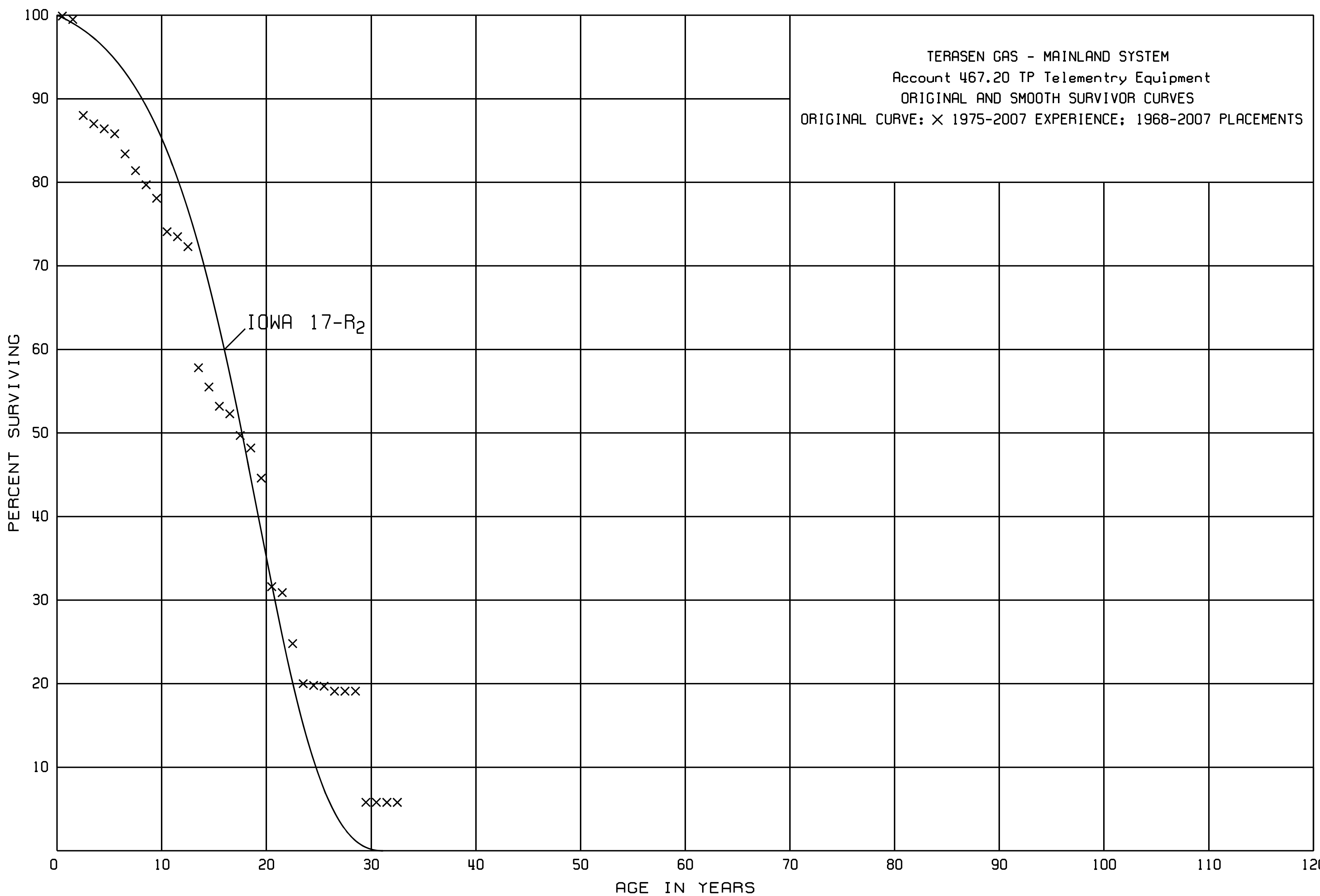
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 467.10 TP MEAS/REG EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-2007 EXPERIENCE BAND 1962-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	767,195		0.0000	1.0000	47.68
40.5	751,154		0.0000	1.0000	47.68
41.5	695,296		0.0000	1.0000	47.68
42.5	657,056		0.0000	1.0000	47.68
43.5	427,788		0.0000	1.0000	47.68
44.5	8,842		0.0000	1.0000	47.68
45.5					47.68


TERASEN GAS - MAINLAND SYSTEM
Account 467.20 TP Telementry Equipment
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1975-2007 EXPERIENCE; 1968-2007 PLACEMENTS
IOWA 17-R2
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120

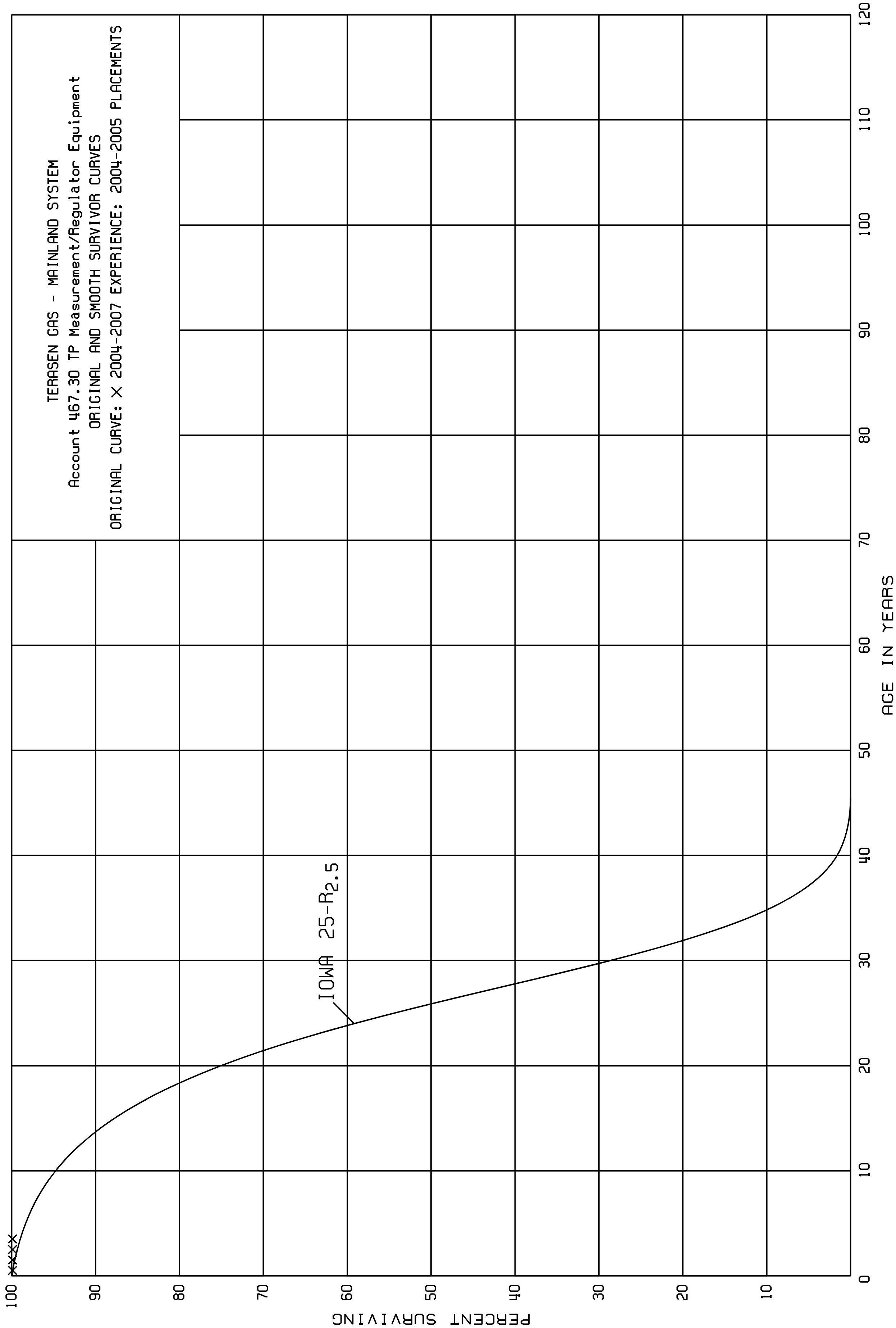
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 467.20 TP TELEMENTRY EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1968-2007 EXPERIENCE BAND 1975-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	10,511,831	12,004	0.0011	0.9989	100.00
0.5	10,941,836	36,864	0.0034	0.9966	99.89
1.5	9,832,518	978,712	0.0995	0.9005	99.55
2.5	8,852,632	83,348	0.0094	0.9906	89.64
3.5	8,443,286	53,985	0.0064	0.9936	88.80
4.5	8,275,516	56,148	0.0068	0.9932	88.23
5.5	8,128,708	185,424	0.0228	0.9772	87.63
6.5	7,526,552	1,223,566	0.1626	0.8374	85.63
7.5	5,896,137	118,502	0.0201	0.9799	71.71
8.5	4,991,706	95,520	0.0191	0.9809	70.27
9.5	4,678,987	235,426	0.0503	0.9497	68.93
10.5	4,222,990	35,095	0.0083	0.9917	65.46
11.5	4,128,120	61,252	0.0148	0.9852	64.92
12.5	3,840,952	962,585	0.2506	0.7494	63.96
13.5	2,703,687	110,366	0.0408	0.9592	47.93
14.5	2,063,243	84,253	0.0408	0.9592	45.97
15.5	1,850,930	32,222	0.0174	0.9826	44.09
16.5	1,696,445	81,868	0.0483	0.9517	43.32
17.5	1,606,631	47,800	0.0298	0.9702	41.23
18.5	1,546,075	116,783	0.0755	0.9245	40.00
19.5	1,369,200	394,389	0.2880	0.7120	36.98
20.5	905,392	19,690	0.0217	0.9783	26.33
21.5	362,152	68,456	0.1890	0.8110	25.76
22.5	279,707	51,529	0.1842	0.8158	20.89
23.5	189,651	1,790	0.0094	0.9906	17.04
24.5	162,457	804	0.0049	0.9951	16.88
25.5	135,025	3,628	0.0269	0.9731	16.80
26.5	103,693		0.0000	1.0000	16.35
27.5	70,875		0.0000	1.0000	16.35
28.5	68,725	47,907	0.6971	0.3029	16.35
29.5	20,818		0.0000	1.0000	4.95
30.5	15,840		0.0000	1.0000	4.95
31.5	8,837		0.0000	1.0000	4.95
32.5					4.95


TERASEN GAS - MAINLAND SYSTEM
Account 467.30 TP Measurement/Regulator Equipment
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 2004-2007 EXPERIENCE; 2004-2005 PLACEMENTS
IOWA 25-R2.5
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120

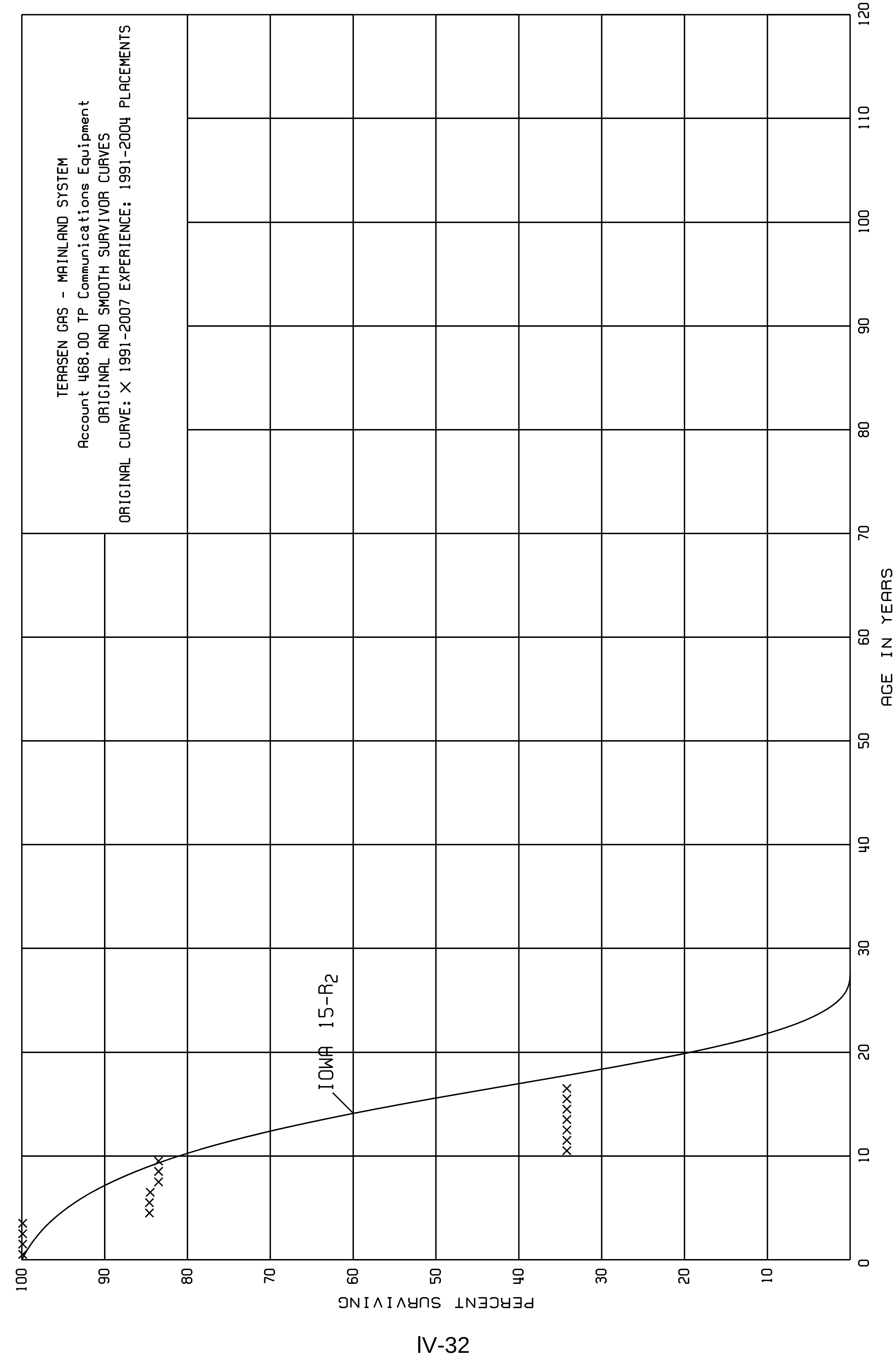
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 467.30 TP MEASUREMENT/REGULATOR EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 2004-2005 EXPERIENCE BAND 2004-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	38,716		0.0000	1.0000	100.00
0.5	38,716		0.0000	1.0000	100.00
1.5	38,716		0.0000	1.0000	100.00
2.5	32,220		0.0000	1.0000	100.00
3.5					100.00


TERASEN GAS - MAINLAND SYSTEM
Account 468.00 TP Communications Equipment
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1991-2007 EXPERIENCE; 1991-2004 PLACEMENTS
IOWA 15-R_2
AGE IN YEARS
PERCENT SURVIVING

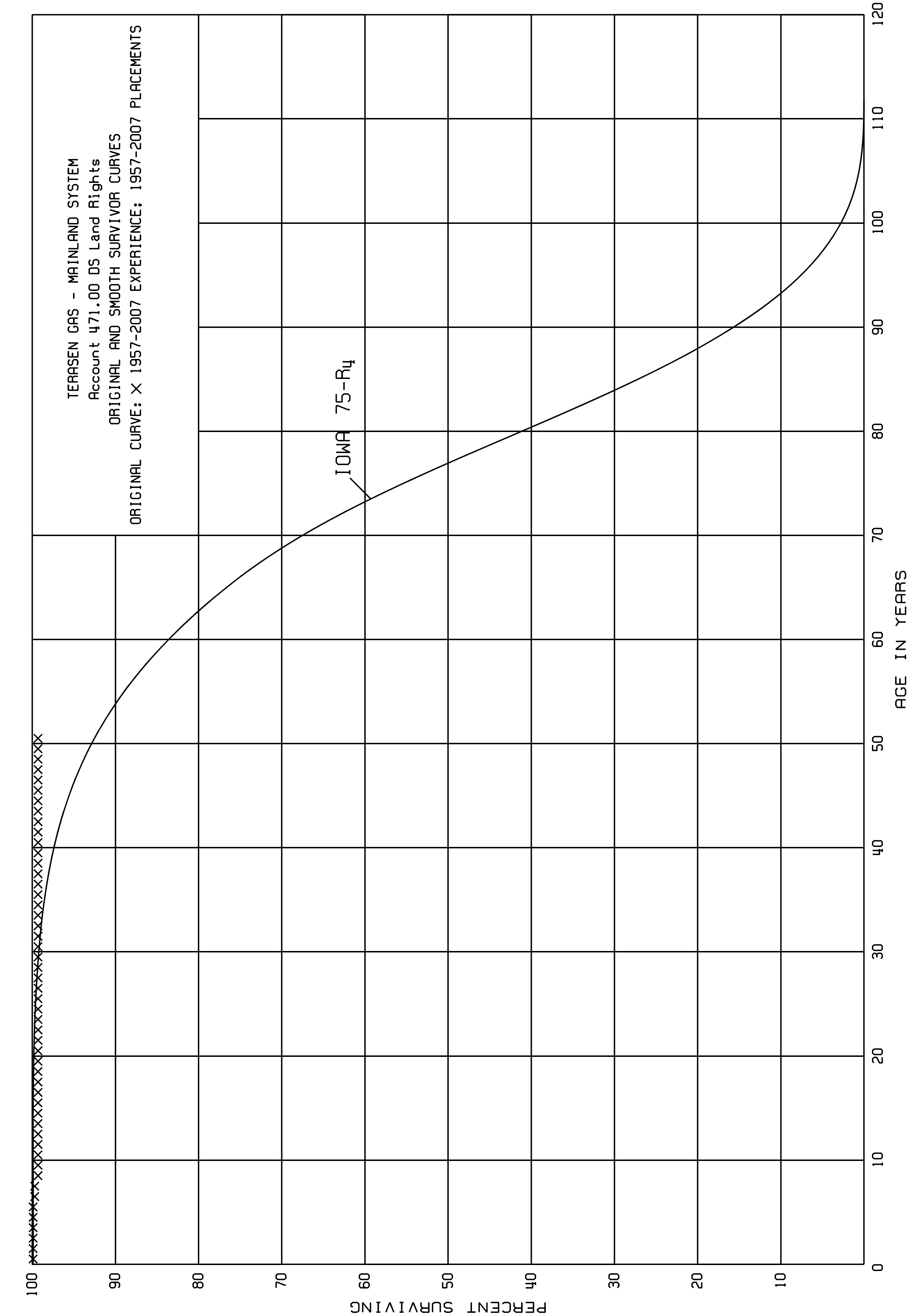
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 468.00 TP COMMUNICATIONS EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1991-2004 EXPERIENCE BAND 1991-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	686,641		0.0000	1.0000	100.00
0.5	686,641		0.0000	1.0000	100.00
1.5	686,641		0.0000	1.0000	100.00
2.5	686,641	106	0.0002	0.9998	100.00
3.5	665,988	101,196	0.1519	0.8481	99.98
4.5	564,792		0.0000	1.0000	84.79
5.5	558,798	849	0.0015	0.9985	84.79
6.5	399,999	4,374	0.0109	0.9891	84.66
7.5	395,625		0.0000	1.0000	83.74
8.5	390,402		0.0000	1.0000	83.74
9.5	390,402	225,386	0.5773	0.4227	83.74
10.5	160,896	4,902	0.0305	0.9695	35.40
11.5	127,711	3,942	0.0309	0.9691	34.32
12.5	103,814		0.0000	1.0000	33.26
13.5	13,501		0.0000	1.0000	33.26
14.5	11,614		0.0000	1.0000	33.26
15.5	5,633		0.0000	1.0000	33.26
16.5					33.26


TERASEN GAS - MAINLAND SYSTEM
Account 471.00 DS Land Rights
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1957-2007 EXPERIENCE; 1957-2007 PLACEMENTS
IOWA 75-R4
AGE IN YEARS
PERCENT SURVIVING
0
10
20
30
40
50
60
70
80
90
100
110
120

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 471.00 DS LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1957-2007 EXPERIENCE BAND 1957-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,042,577		0.0000	1.0000	100.00
0.5	856,856		0.0000	1.0000	100.00
1.5	712,366		0.0000	1.0000	100.00
2.5	712,366		0.0000	1.0000	100.00
3.5	688,062		0.0000	1.0000	100.00
4.5	662,758		0.0000	1.0000	100.00
5.5	552,274	1,493	0.0027	0.9973	100.00
6.5	493,008		0.0000	1.0000	99.73
7.5	477,059	1,878	0.0039	0.9961	99.73
8.5	474,380		0.0000	1.0000	99.34
9.5	474,380		0.0000	1.0000	99.34
10.5	449,182		0.0000	1.0000	99.34
11.5	446,448		0.0000	1.0000	99.34
12.5	435,870	305	0.0007	0.9993	99.34
13.5	417,937		0.0000	1.0000	99.27
14.5	389,475		0.0000	1.0000	99.27
15.5	382,716		0.0000	1.0000	99.27
16.5	375,961		0.0000	1.0000	99.27
17.5	316,208		0.0000	1.0000	99.27
18.5	279,156		0.0000	1.0000	99.27
19.5	257,690		0.0000	1.0000	99.27
20.5	236,487		0.0000	1.0000	99.27
21.5	229,233		0.0000	1.0000	99.27
22.5	199,837		0.0000	1.0000	99.27
23.5	150,565		0.0000	1.0000	99.27
24.5	80,008		0.0000	1.0000	99.27
25.5	50,453		0.0000	1.0000	99.27
26.5	42,962		0.0000	1.0000	99.27
27.5	40,994		0.0000	1.0000	99.27
28.5	35,990		0.0000	1.0000	99.27
29.5	33,276		0.0000	1.0000	99.27
30.5	32,689		0.0000	1.0000	99.27
31.5	30,378		0.0000	1.0000	99.27
32.5	28,150		0.0000	1.0000	99.27
33.5	24,513		0.0000	1.0000	99.27
34.5	22,379		0.0000	1.0000	99.27
35.5	21,027		0.0000	1.0000	99.27
36.5	20,195		0.0000	1.0000	99.27
37.5	17,405		0.0000	1.0000	99.27
38.5	16,161		0.0000	1.0000	99.27

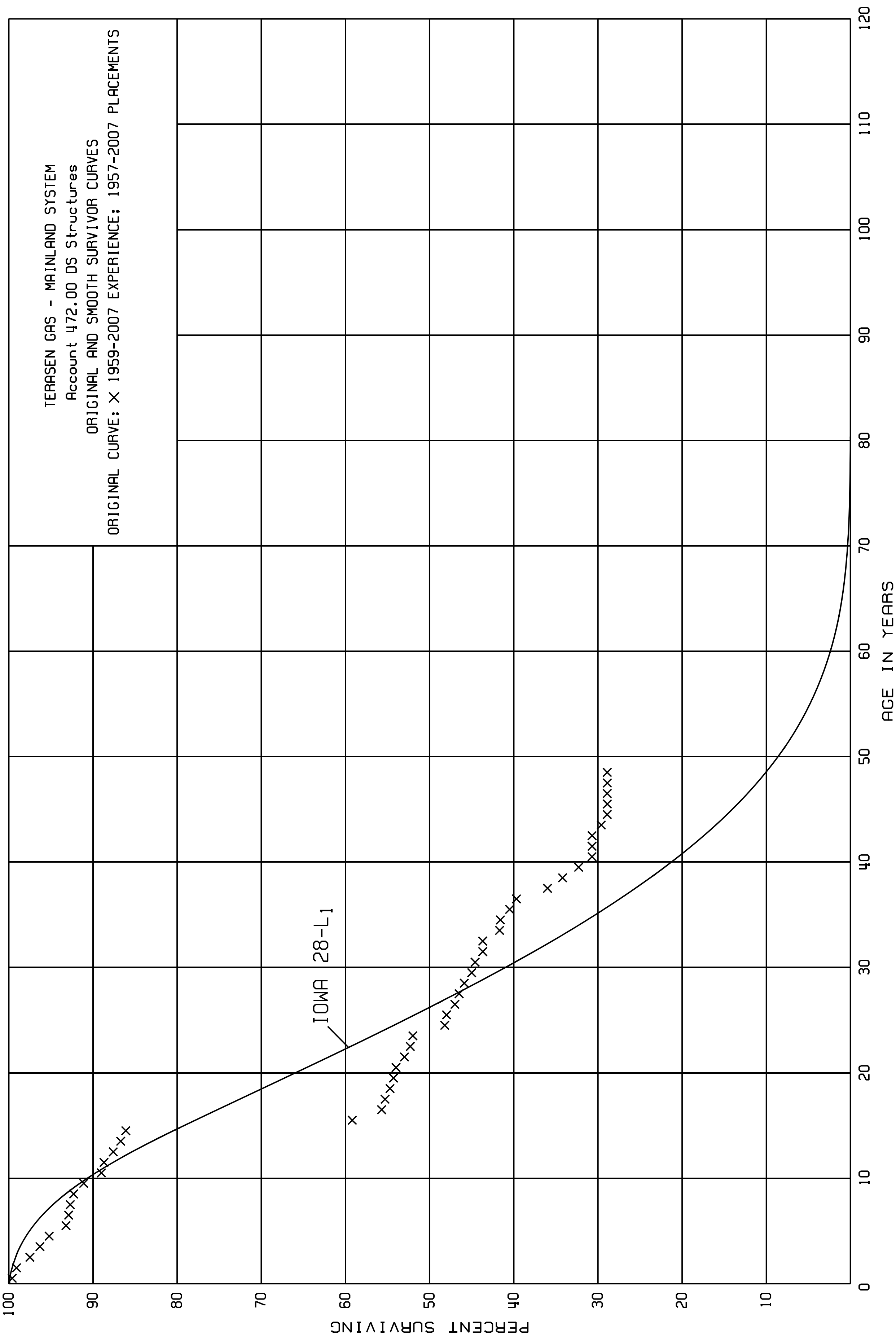
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 471.00 DS LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1957-2007 EXPERIENCE BAND 1957-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	16,048		0.0000	1.0000	99.27
40.5	16,039		0.0000	1.0000	99.27
41.5	15,041		0.0000	1.0000	99.27
42.5	14,126		0.0000	1.0000	99.27
43.5	8,898		0.0000	1.0000	99.27
44.5	6,289		0.0000	1.0000	99.27
45.5	5,900		0.0000	1.0000	99.27
46.5	5,585		0.0000	1.0000	99.27
47.5	5,512		0.0000	1.0000	99.27
48.5	1,089		0.0000	1.0000	99.27
49.5	1,089		0.0000	1.0000	99.27
50.5					99.27


TERASEN GAS - MAINLAND SYSTEM
Account 472.00 DS Structures
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1959-2007 EXPERIENCE; 1957-2007 PLACEMENTS
IOWA 28-L1
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 472.00 DS STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1957-2007 EXPERIENCE BAND 1959-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	15,882,195	84,448	0.0053	0.9947	100.00
0.5	14,904,990	69,297	0.0046	0.9954	99.47
1.5	12,239,593	186,402	0.0152	0.9848	99.01
2.5	9,231,102	109,637	0.0119	0.9881	97.51
3.5	7,877,709	96,769	0.0123	0.9877	96.35
4.5	7,542,209	155,256	0.0206	0.9794	95.16
5.5	7,292,571	21,892	0.0030	0.9970	93.20
6.5	6,730,364	19,195	0.0029	0.9971	92.92
7.5	6,360,058	23,530	0.0037	0.9963	92.65
8.5	5,923,312	77,077	0.0130	0.9870	92.31
9.5	5,592,357	130,422	0.0233	0.9767	91.11
10.5	4,805,359	18,301	0.0038	0.9962	88.99
11.5	3,812,262	45,998	0.0121	0.9879	88.65
12.5	2,883,937	31,051	0.0108	0.9892	87.58
13.5	2,391,178	15,044	0.0063	0.9937	86.63
14.5	2,194,141	698,327	0.3183	0.6817	86.08
15.5	1,321,550	80,462	0.0609	0.9391	58.68
16.5	1,063,578	8,733	0.0082	0.9918	55.11
17.5	1,020,877	10,401	0.0102	0.9898	54.66
18.5	954,342	7,454	0.0078	0.9922	54.10
19.5	924,635	5,074	0.0055	0.9945	53.68
20.5	840,976	15,987	0.0190	0.9810	53.38
21.5	790,397	10,791	0.0137	0.9863	52.37
22.5	707,382	4,553	0.0064	0.9936	51.65
23.5	639,293	48,767	0.0763	0.9237	51.32
24.5	462,835	1,715	0.0037	0.9963	47.40
25.5	402,331	8,894	0.0221	0.9779	47.22
26.5	351,529	4,459	0.0127	0.9873	46.18
27.5	332,044	4,813	0.0145	0.9855	45.59
28.5	327,191	6,623	0.0202	0.9798	44.93
29.5	318,589	2,822	0.0089	0.9911	44.02
30.5	311,966	6,871	0.0220	0.9780	43.63
31.5	296,608	331	0.0011	0.9989	42.67
32.5	289,219	14,257	0.0493	0.9507	42.62
33.5	261,440	11,401	0.0436	0.9564	40.52
34.5	233,036	6,718	0.0288	0.9712	38.75
35.5	220,048	5,185	0.0236	0.9764	37.63
36.5	208,825	23,097	0.1106	0.8894	36.74
37.5	185,502	10,848	0.0585	0.9415	32.68
38.5	174,591	11,575	0.0663	0.9337	30.77

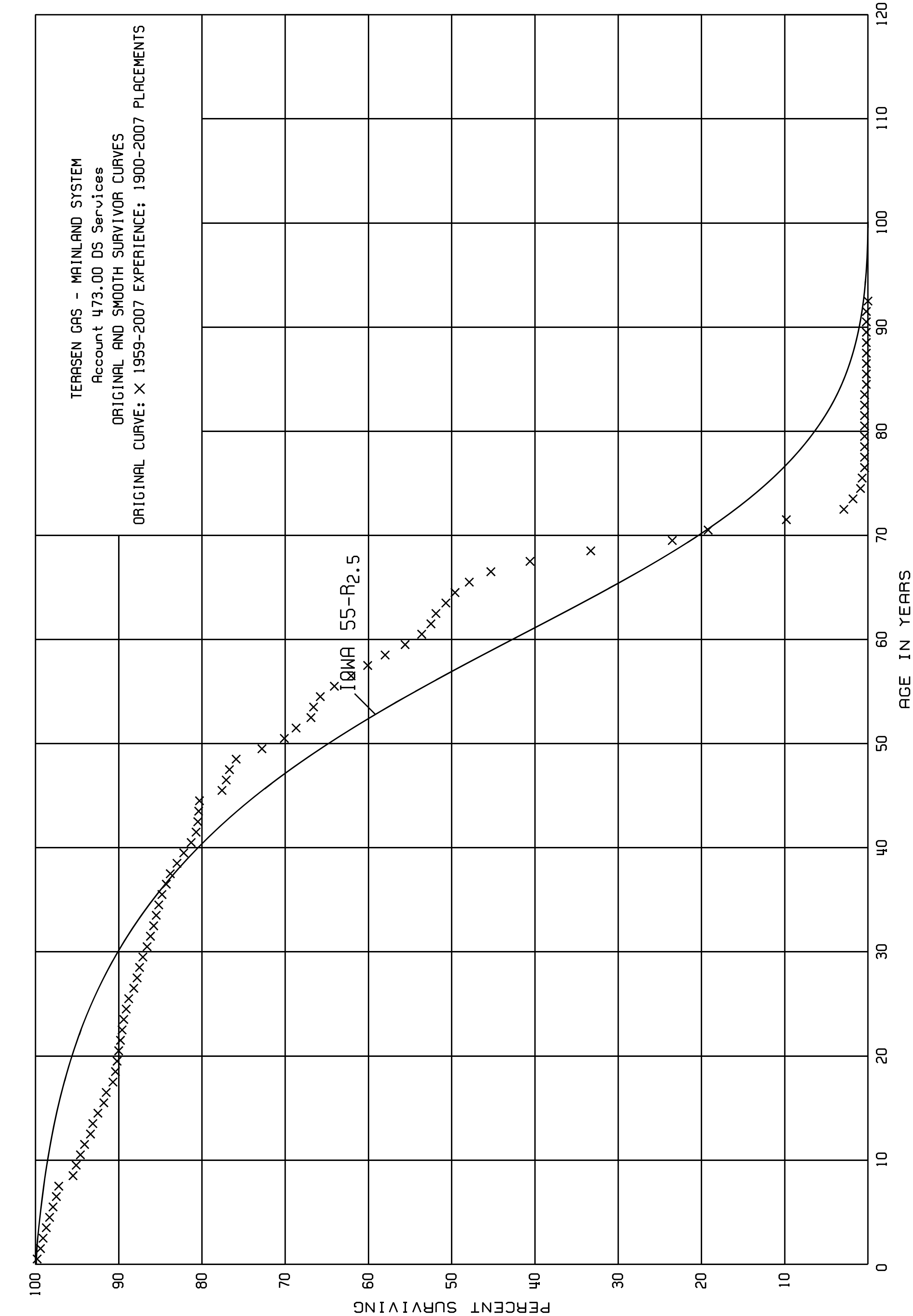
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 472.00 DS STRUCTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1957-2007 EXPERIENCE BAND 1959-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	162,707	9,976	0.0613	0.9387	28.73
40.5	151,406		0.0000	1.0000	26.97
41.5	149,584		0.0000	1.0000	26.97
42.5	115,862	5,444	0.0470	0.9530	26.97
43.5	107,997	3,313	0.0307	0.9693	25.70
44.5	76,174		0.0000	1.0000	24.91
45.5	75,970		0.0000	1.0000	24.91
46.5	3,509		0.0000	1.0000	24.91
47.5	3,509		0.0000	1.0000	24.91
48.5					24.91


TERASEN GAS - MAINLAND SYSTEM
Account 473.00 DS Services
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1959-2007 EXPERIENCE; 1900-2007 PLACEMENTS
IOWA 55-R2.5
AGE IN YEARS
PERCENT SURVIVING
0
10
20
30
40
50
60
70
80
90
100
110
120

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 473.00 DS SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2007 EXPERIENCE BAND 1959-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	635,067,865	11,950,504	0.0188	0.9812	100.00
0.5	594,487,067	2,170,951	0.0037	0.9963	98.12
1.5	566,347,528	2,047,542	0.0036	0.9964	97.76
2.5	527,774,624	1,920,410	0.0036	0.9964	97.41
3.5	469,614,949	1,750,580	0.0037	0.9963	97.06
4.5	454,651,688	1,987,944	0.0044	0.9956	96.70
5.5	449,158,345	1,752,533	0.0039	0.9961	96.27
6.5	438,268,729	1,884,250	0.0043	0.9957	95.89
7.5	432,728,171	7,643,365	0.0177	0.9823	95.48
8.5	421,072,834	1,478,324	0.0035	0.9965	93.79
9.5	406,986,507	2,238,124	0.0055	0.9945	93.46
10.5	389,485,375	2,277,817	0.0058	0.9942	92.95
11.5	370,833,922	2,604,261	0.0070	0.9930	92.41
12.5	341,164,431	1,507,017	0.0044	0.9956	91.76
13.5	312,046,975	2,306,460	0.0074	0.9926	91.36
14.5	278,308,639	2,076,731	0.0075	0.9925	90.68
15.5	251,008,025	1,783,370	0.0071	0.9929	90.00
16.5	225,643,712	2,167,363	0.0096	0.9904	89.36
17.5	200,975,521	490,170	0.0024	0.9976	88.50
18.5	179,972,320	444,503	0.0025	0.9975	88.29
19.5	163,674,630	359,984	0.0022	0.9978	88.07
20.5	144,937,874	341,087	0.0024	0.9976	87.88
21.5	131,771,718	362,344	0.0027	0.9973	87.67
22.5	117,522,861	294,202	0.0025	0.9975	87.43
23.5	103,221,381	302,482	0.0029	0.9971	87.21
24.5	90,063,857	312,274	0.0035	0.9965	86.96
25.5	74,242,925	503,390	0.0068	0.9932	86.66
26.5	63,005,937	306,312	0.0049	0.9951	86.07
27.5	54,989,603	221,084	0.0040	0.9960	85.65
28.5	49,869,357	207,224	0.0042	0.9958	85.31
29.5	43,037,618	237,460	0.0055	0.9945	84.95
30.5	36,679,245	187,572	0.0051	0.9949	84.48
31.5	32,683,571	153,538	0.0047	0.9953	84.05
32.5	28,539,992	89,404	0.0031	0.9969	83.65
33.5	25,022,157	88,381	0.0035	0.9965	83.39
34.5	22,209,195	108,889	0.0049	0.9951	83.10
35.5	20,149,318	107,452	0.0053	0.9947	82.69
36.5	18,114,476	119,655	0.0066	0.9934	82.25
37.5	16,204,857	142,053	0.0088	0.9912	81.71
38.5	14,704,119	146,815	0.0100	0.9900	80.99

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 473.00 DS SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2007 EXPERIENCE BAND 1959-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	13,463,166	151,925	0.0113	0.9887	80.18
40.5	12,138,794	88,517	0.0073	0.9927	79.27
41.5	10,933,166	24,995	0.0023	0.9977	78.69
42.5	9,854,838	13,538	0.0014	0.9986	78.51
43.5	8,696,302	11,054	0.0013	0.9987	78.40
44.5	2,186,796	73,583	0.0336	0.9664	78.30
45.5	1,944,860	11,907	0.0061	0.9939	75.67
46.5	1,932,953	18,523	0.0096	0.9904	75.21
47.5	1,757,656	18,535	0.0105	0.9895	74.49
48.5	104,710	4,332	0.0414	0.9586	73.71
49.5	100,378	3,712	0.0370	0.9630	70.66
50.5	96,666	1,900	0.0197	0.9803	68.05
51.5	94,766	2,469	0.0261	0.9739	66.71
52.5	92,297	389	0.0042	0.9958	64.97
53.5	91,908	1,189	0.0129	0.9871	64.70
54.5	90,719	2,258	0.0249	0.9751	63.87
55.5	88,461	2,800	0.0317	0.9683	62.28
56.5	85,661	2,689	0.0314	0.9686	60.31
57.5	82,972	2,938	0.0354	0.9646	58.42
58.5	80,300	3,372	0.0420	0.9580	56.35
59.5	76,928	2,777	0.0361	0.9639	53.98
60.5	74,151	1,500	0.0202	0.9798	52.03
61.5	72,651	777	0.0107	0.9893	50.98
62.5	71,874	1,686	0.0235	0.9765	50.43
63.5	70,188	1,480	0.0211	0.9789	49.24
64.5	68,708	2,377	0.0346	0.9654	48.20
65.5	66,331	3,544	0.0534	0.9466	46.53
66.5	62,787	6,635	0.1057	0.8943	44.05
67.5	56,152	10,001	0.1781	0.8219	39.39
68.5	46,151	13,679	0.2964	0.7036	32.37
69.5	32,472	5,866	0.1806	0.8194	22.78
70.5	26,606	13,087	0.4919	0.5081	18.67
71.5	13,519	9,566	0.7076	0.2924	9.49
72.5	3,953	1,500	0.3795	0.6205	2.77
73.5	2,453	1,200	0.4892	0.5108	1.72
74.5	1,253	287	0.2291	0.7709	0.88
75.5	966	400	0.4141	0.5859	0.68
76.5	566		0.0000	1.0000	0.40
77.5	566		0.0000	1.0000	0.40
78.5	566		0.0000	1.0000	0.40

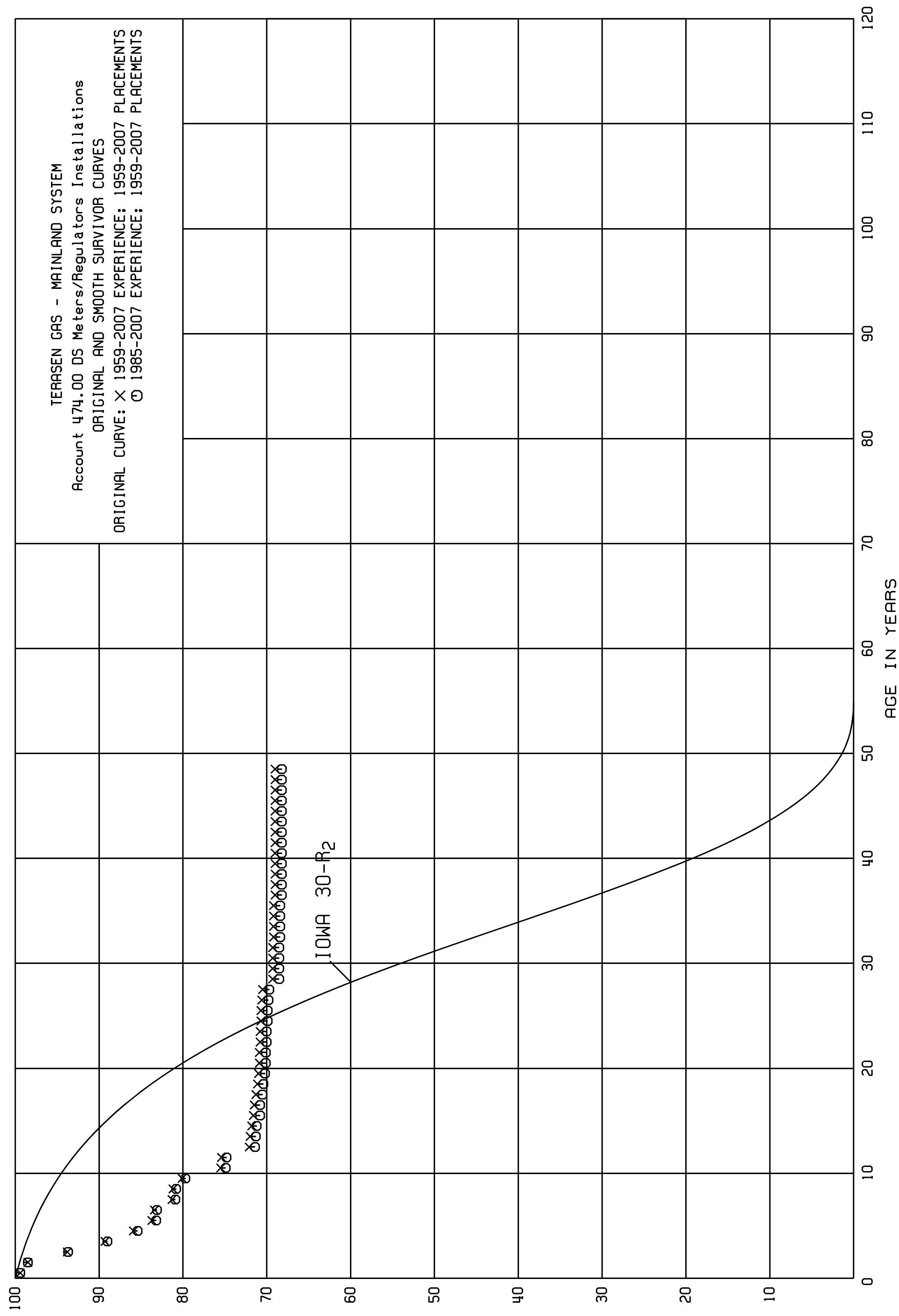
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 473.00 DS SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2007 EXPERIENCE BAND 1959-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	566		0.0000	1.0000	0.40
80.5	566		0.0000	1.0000	0.40
81.5	566		0.0000	1.0000	0.40
82.5	566		0.0000	1.0000	0.40
83.5	566	300	0.5300	0.4700	0.40
84.5	266		0.0000	1.0000	0.19
85.5	266		0.0000	1.0000	0.19
86.5	266		0.0000	1.0000	0.19
87.5	266		0.0000	1.0000	0.19
88.5	266		0.0000	1.0000	0.19
89.5	266		0.0000	1.0000	0.19
90.5	266		0.0000	1.0000	0.19
91.5	266	266	1.0000	0.0000	0.19
92.5					0.00


TERASEN GAS - MAINLAND SYSTEM
Account 474.00 DS Meters/Regulators Installations
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1959-2007 EXPERIENCE; 1959-2007 PLACEMENTS
○ 1985-2007 EXPERIENCE; 1959-2007 PLACEMENTS
IOWA 30-R2
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
110
120

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 474.00 DS METERS/REGUALTORS INSTALLATIONS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1959-2007 EXPERIENCE BAND 1959-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	168,642,607	2,077,182	0.0123	0.9877	100.00
0.5	158,066,271	1,369,064	0.0087	0.9913	98.77
1.5	147,881,550	6,485,618	0.0439	0.9561	97.91
2.5	130,211,618	5,957,576	0.0458	0.9542	93.61
3.5	117,016,822	4,324,847	0.0370	0.9630	89.32
4.5	108,914,676	2,601,505	0.0239	0.9761	86.02
5.5	101,213,879	3,098,950	0.0306	0.9694	83.96
6.5	97,904,547	2,340,498	0.0239	0.9761	81.39
7.5	93,816,917	124,250	0.0013	0.9987	79.44
8.5	86,119,915	1,120,230	0.0130	0.9870	79.34
9.5	81,731,741	4,526,383	0.0554	0.9446	78.31
10.5	68,089,480	4,239,131	0.0623	0.9377	73.97
11.5	57,611,966	2,512,901	0.0436	0.9564	69.36
12.5	45,642,876	64,060	0.0014	0.9986	66.34
13.5	34,612,894	61,823	0.0018	0.9982	66.25
14.5	30,733,300	125,098	0.0041	0.9959	66.13
15.5	27,602,419	33,516	0.0012	0.9988	65.86
16.5	17,049,075	51,009	0.0030	0.9970	65.78
17.5	14,725,611	21,479	0.0015	0.9985	65.58
18.5	13,112,848	23,810	0.0018	0.9982	65.48
19.5	11,330,464	16,054	0.0014	0.9986	65.36
20.5	9,470,069	7,673	0.0008	0.9992	65.27
21.5	8,765,095	5,656	0.0006	0.9994	65.22
22.5	7,997,205	3,514	0.0004	0.9996	65.18
23.5	7,362,578	5,013	0.0007	0.9993	65.15
24.5	6,825,145	2,589	0.0004	0.9996	65.10
25.5	5,965,675	10,102	0.0017	0.9983	65.07
26.5	5,317,211	2,737	0.0005	0.9995	64.96
27.5	4,966,747	91,069	0.0183	0.9817	64.93
28.5	4,489,790	651	0.0001	0.9999	63.74
29.5	3,946,097	600	0.0002	0.9998	63.73
30.5	3,534,903		0.0000	1.0000	63.72
31.5	3,168,354	5,825	0.0018	0.9982	63.72
32.5	2,922,737		0.0000	1.0000	63.61
33.5	2,685,650		0.0000	1.0000	63.61
34.5	2,515,608		0.0000	1.0000	63.61
35.5	2,390,393	4,281	0.0018	0.9982	63.61
36.5	2,307,161		0.0000	1.0000	63.50
37.5	2,143,276		0.0000	1.0000	63.50
38.5	2,115,710		0.0000	1.0000	63.50

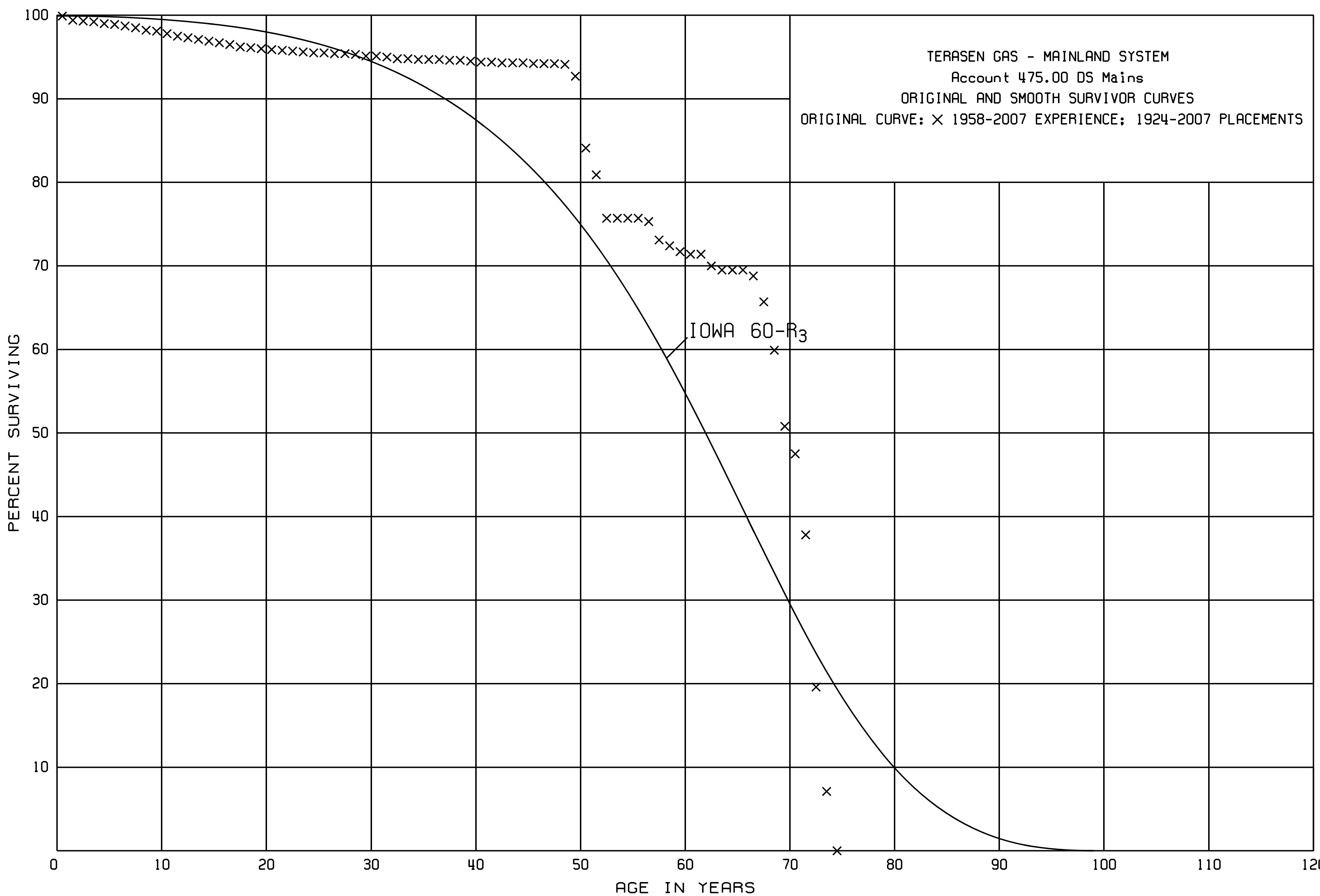
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 474.00 DS METERS/REGUALTORS INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1959-2007 EXPERIENCE BAND 1959-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,851,729		0.0000	1.0000	63.50
40.5	1,711,294		0.0000	1.0000	63.50
41.5	1,508,982		0.0000	1.0000	63.50
42.5	1,362,368		0.0000	1.0000	63.50
43.5	1,172,656		0.0000	1.0000	63.50
44.5	1,054,380		0.0000	1.0000	63.50
45.5	986,853		0.0000	1.0000	63.50
46.5	394,658		0.0000	1.0000	63.50
47.5	303,837		0.0000	1.0000	63.50
48.5					63.50


TERASEN GAS - MAINLAND SYSTEM
Account 475.00 DS Mains
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1958-2007 EXPERIENCE; 1924-2007 PLACEMENTS
IOWA 60-R3
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 475.00 DS MAINS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1924-2007 EXPERIENCE BAND 1958-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	820,496,102	494,414	0.0006	0.9994	100.00
0.5	799,446,119	4,137,861	0.0052	0.9948	99.94
1.5	761,659,663	1,070,191	0.0014	0.9986	99.42
2.5	729,896,442	848,405	0.0012	0.9988	99.28
3.5	645,214,168	955,796	0.0015	0.9985	99.16
4.5	627,438,680	901,909	0.0014	0.9986	99.01
5.5	619,824,953	1,045,535	0.0017	0.9983	98.87
6.5	608,219,386	2,603,245	0.0043	0.9957	98.70
7.5	593,289,469	1,619,961	0.0027	0.9973	98.28
8.5	577,494,807	794,042	0.0014	0.9986	98.01
9.5	563,924,893	1,968,312	0.0035	0.9965	97.87
10.5	546,902,643	1,345,143	0.0025	0.9975	97.53
11.5	531,124,425	1,440,980	0.0027	0.9973	97.29
12.5	496,756,164	860,957	0.0017	0.9983	97.03
13.5	468,502,748	1,001,506	0.0021	0.9979	96.87
14.5	442,689,861	1,175,399	0.0027	0.9973	96.67
15.5	417,765,394	1,526,639	0.0037	0.9963	96.41
16.5	403,741,862	1,481,510	0.0037	0.9963	96.05
17.5	384,980,078	518,666	0.0013	0.9987	95.69
18.5	374,479,889	510,726	0.0014	0.9986	95.57
19.5	361,701,850	252,680	0.0007	0.9993	95.44
20.5	340,630,823	214,556	0.0006	0.9994	95.37
21.5	320,866,014	399,887	0.0012	0.9988	95.31
22.5	305,484,702	328,028	0.0011	0.9989	95.20
23.5	287,302,642	388,048	0.0014	0.9986	95.10
24.5	257,662,602	130,255	0.0005	0.9995	94.97
25.5	230,065,119	130,714	0.0006	0.9994	94.92
26.5	212,756,034	155,972	0.0007	0.9993	94.86
27.5	196,798,874	208,191	0.0011	0.9989	94.79
28.5	181,770,863	239,923	0.0013	0.9987	94.69
29.5	167,300,254	153,729	0.0009	0.9991	94.57
30.5	153,362,782	149,544	0.0010	0.9990	94.48
31.5	137,192,155	278,684	0.0020	0.9980	94.39
32.5	125,561,095	53,444	0.0004	0.9996	94.20
33.5	115,615,819	81,825	0.0007	0.9993	94.16
34.5	108,827,831	30,086	0.0003	0.9997	94.09
35.5	102,471,007	34,729	0.0003	0.9997	94.06
36.5	95,649,702	54,091	0.0006	0.9994	94.03
37.5	87,389,622	67,098	0.0008	0.9992	93.97
38.5	81,441,128	37,821	0.0005	0.9995	93.89

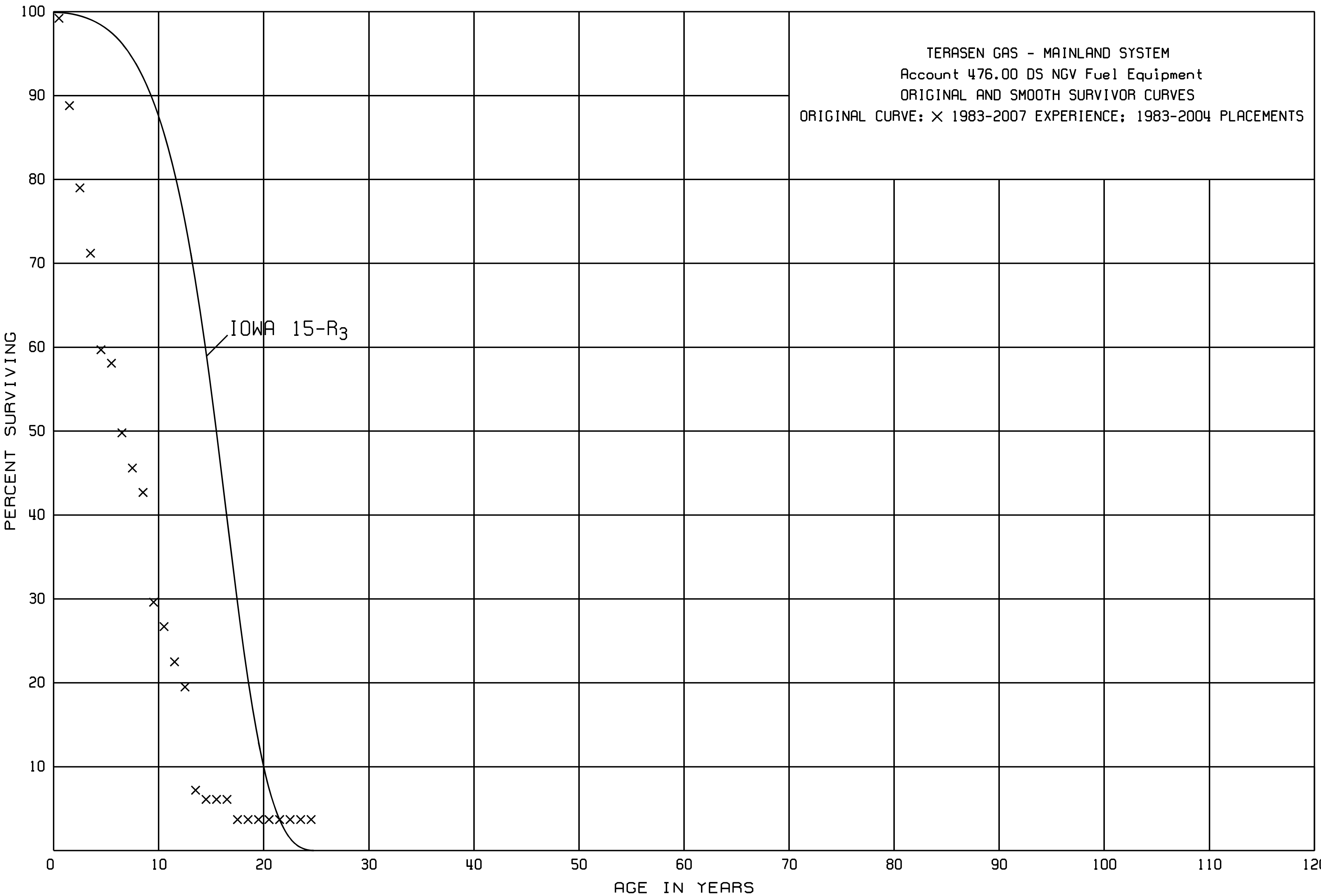
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 475.00 DS MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1924-2007 EXPERIENCE BAND 1958-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	75,636,460	87,621	0.0012	0.9988	93.84
40.5	70,697,210	44,705	0.0006	0.9994	93.73
41.5	66,696,300	38,710	0.0006	0.9994	93.67
42.5	62,885,719	16,181	0.0003	0.9997	93.61
43.5	59,532,844	1,355	0.0000	1.0000	93.58
44.5	5,902,004	24,392	0.0041	0.9959	93.58
45.5	5,626,157	23,046	0.0041	0.9959	93.20
46.5	5,500,009	12,522	0.0023	0.9977	92.82
47.5	5,309,352	22,193	0.0042	0.9958	92.61
48.5	221,795	3,399	0.0153	0.9847	92.22
49.5	153,664	14,173	0.0922	0.9078	90.81
50.5	139,491	5,340	0.0383	0.9617	82.44
51.5	134,151	8,589	0.0640	0.9360	79.28
52.5	125,562		0.0000	1.0000	74.21
53.5	125,562	54	0.0004	0.9996	74.21
54.5	125,508		0.0000	1.0000	74.18
55.5	125,508	621	0.0049	0.9951	74.18
56.5	124,887	3,684	0.0295	0.9705	73.82
57.5	121,203	1,132	0.0093	0.9907	71.64
58.5	120,071	1,196	0.0100	0.9900	70.97
59.5	118,875	484	0.0041	0.9959	70.26
60.5	118,391		0.0000	1.0000	69.97
61.5	118,391	2,400	0.0203	0.9797	69.97
62.5	115,991	732	0.0063	0.9937	68.55
63.5	115,259	104	0.0009	0.9991	68.12
64.5	115,155		0.0000	1.0000	68.06
65.5	115,155	1,051	0.0091	0.9909	68.06
66.5	114,104	5,097	0.0447	0.9553	67.44
67.5	109,007	9,619	0.0882	0.9118	64.43
68.5	99,388	15,233	0.1533	0.8467	58.75
69.5	84,155	5,371	0.0638	0.9362	49.74
70.5	78,784	16,139	0.2049	0.7951	46.57
71.5	62,645	30,099	0.4805	0.5195	37.03
72.5	32,546	20,729	0.6369	0.3631	19.24
73.5	11,817	11,817	1.0000	0.0000	6.99
74.5					0.00


TERASEN GAS - MAINLAND SYSTEM
Account 476.00 DS NGV Fuel Equipment
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1983-2007 EXPERIENCE; 1983-2004 PLACEMENTS
IOWA 15-R3
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120

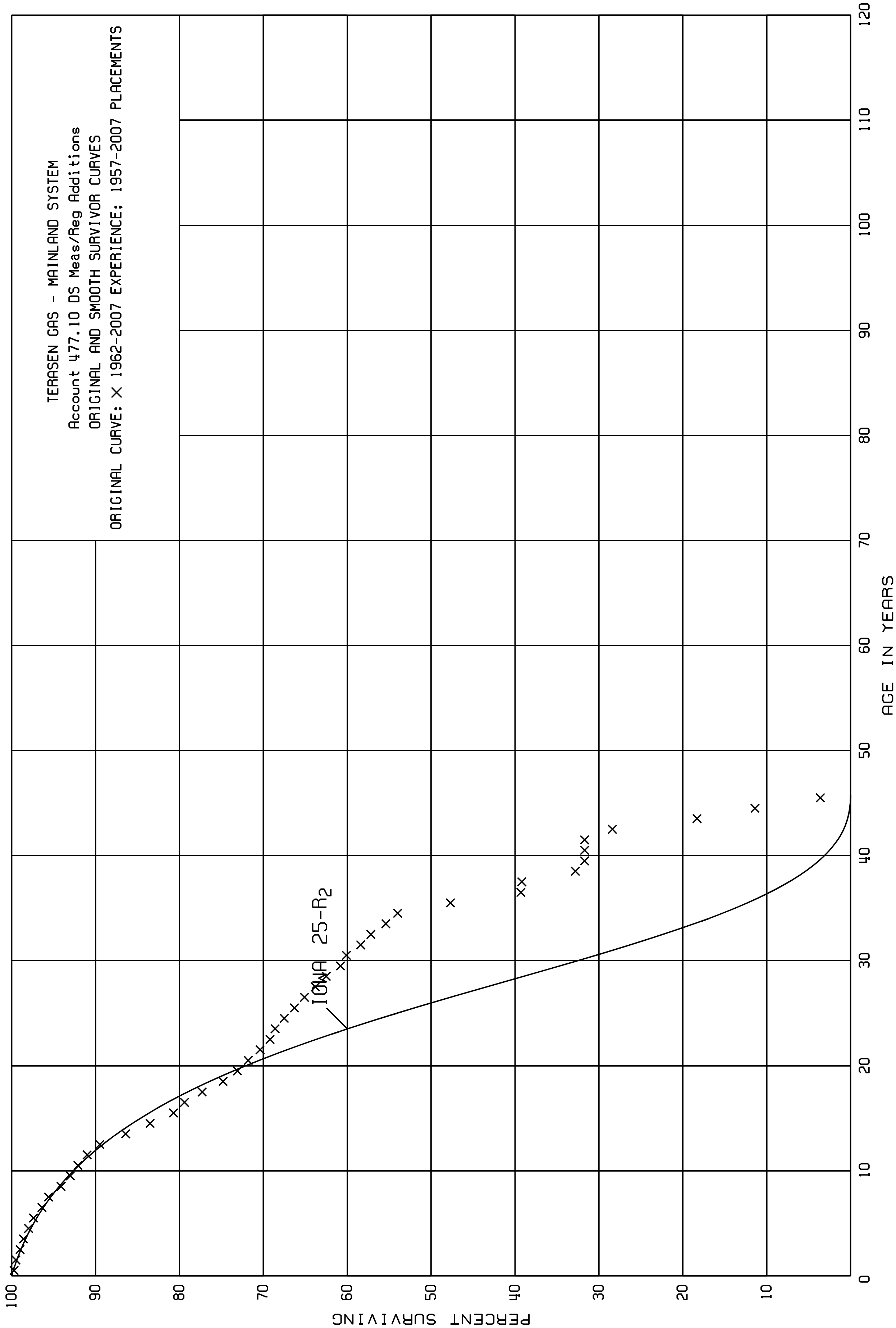
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 476.00 DS NGV FUEL EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1983-2004 EXPERIENCE BAND 1983-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	9,828,122	83,579	0.0085	0.9915	100.00
0.5	9,744,543	1,013,464	0.1040	0.8960	99.15
1.5	8,731,079	969,105	0.1110	0.8890	88.84
2.5	7,761,974	765,596	0.0986	0.9014	78.98
3.5	6,951,034	1,125,829	0.1620	0.8380	71.19
4.5	5,825,204	156,311	0.0268	0.9732	59.66
5.5	5,668,893	808,111	0.1426	0.8574	58.06
6.5	4,853,617	407,191	0.0839	0.9161	49.78
7.5	4,446,426	278,800	0.0627	0.9373	45.60
8.5	4,164,864	1,279,856	0.3073	0.6927	42.74
9.5	2,814,847	278,533	0.0990	0.9010	29.61
10.5	2,520,308	399,241	0.1584	0.8416	26.68
11.5	2,112,617	273,868	0.1296	0.8704	22.45
12.5	1,838,748	1,159,465	0.6306	0.3694	19.54
13.5	663,766	99,250	0.1495	0.8505	7.22
14.5	553,248		0.0000	1.0000	6.14
15.5	419,864		0.0000	1.0000	6.14
16.5	394,453	159,063	0.4032	0.5968	6.14
17.5	209,486		0.0000	1.0000	3.66
18.5	128,961		0.0000	1.0000	3.66
19.5	123,543		0.0000	1.0000	3.66
20.5	63,918		0.0000	1.0000	3.66
21.5	49,754		0.0000	1.0000	3.66
22.5	26,337		0.0000	1.0000	3.66
23.5	17,290		0.0000	1.0000	3.66
24.5					3.66


TERASEN GAS - MAINLAND SYSTEM
Account 477.10 DS Meas/Reg Additions
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1962-2007 EXPERIENCE; 1957-2007 PLACEMENTS
IOWA 25-R2
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
110
120

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 477.10 DS MEAS/REG ADDITIONS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1957-2007 EXPERIENCE BAND 1962-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	83,189,737	203,097	0.0024	0.9976	100.00
0.5	78,887,598	165,897	0.0021	0.9979	99.76
1.5	70,980,849	381,934	0.0054	0.9946	99.55
2.5	65,427,264	306,107	0.0047	0.9953	99.01
3.5	58,835,472	311,210	0.0053	0.9947	98.54
4.5	52,218,074	324,304	0.0062	0.9938	98.02
5.5	49,149,030	498,660	0.0101	0.9899	97.41
6.5	45,071,304	703,748	0.0156	0.9844	96.43
7.5	40,220,438	621,603	0.0155	0.9845	94.93
8.5	37,988,789	460,330	0.0121	0.9879	93.46
9.5	36,030,943	402,612	0.0112	0.9888	92.33
10.5	33,025,919	426,415	0.0129	0.9871	91.30
11.5	29,591,616	486,164	0.0164	0.9836	90.12
12.5	24,376,494	837,207	0.0343	0.9657	88.64
13.5	21,450,308	796,664	0.0371	0.9629	85.60
14.5	18,226,541	588,495	0.0323	0.9677	82.42
15.5	16,330,477	257,430	0.0158	0.9842	79.76
16.5	14,695,173	424,218	0.0289	0.9711	78.50
17.5	13,621,977	619,002	0.0454	0.9546	76.23
18.5	12,498,285	281,605	0.0225	0.9775	72.77
19.5	12,101,887	298,941	0.0247	0.9753	71.13
20.5	11,797,125	223,461	0.0189	0.9811	69.37
21.5	11,195,222	221,005	0.0197	0.9803	68.06
22.5	10,519,534	85,348	0.0081	0.9919	66.72
23.5	9,898,742	152,971	0.0155	0.9845	66.18
24.5	8,226,598	152,856	0.0186	0.9814	65.15
25.5	7,813,690	138,396	0.0177	0.9823	63.94
26.5	7,425,389	141,189	0.0190	0.9810	62.81
27.5	6,436,230	124,663	0.0194	0.9806	61.62
28.5	5,441,615	147,495	0.0271	0.9729	60.42
29.5	4,699,354	60,773	0.0129	0.9871	58.78
30.5	2,731,015	81,643	0.0299	0.9701	58.02
31.5	1,953,767	45,452	0.0233	0.9767	56.29
32.5	1,630,026	58,775	0.0361	0.9639	54.98
33.5	1,538,891	42,119	0.0274	0.9726	53.00
34.5	1,345,814	180,319	0.1340	0.8660	51.55
35.5	1,055,499	219,785	0.2082	0.7918	44.64
36.5	753,215	2,938	0.0039	0.9961	35.35
37.5	724,237	133,842	0.1848	0.8152	35.21
38.5	377,306	16,923	0.0449	0.9551	28.70

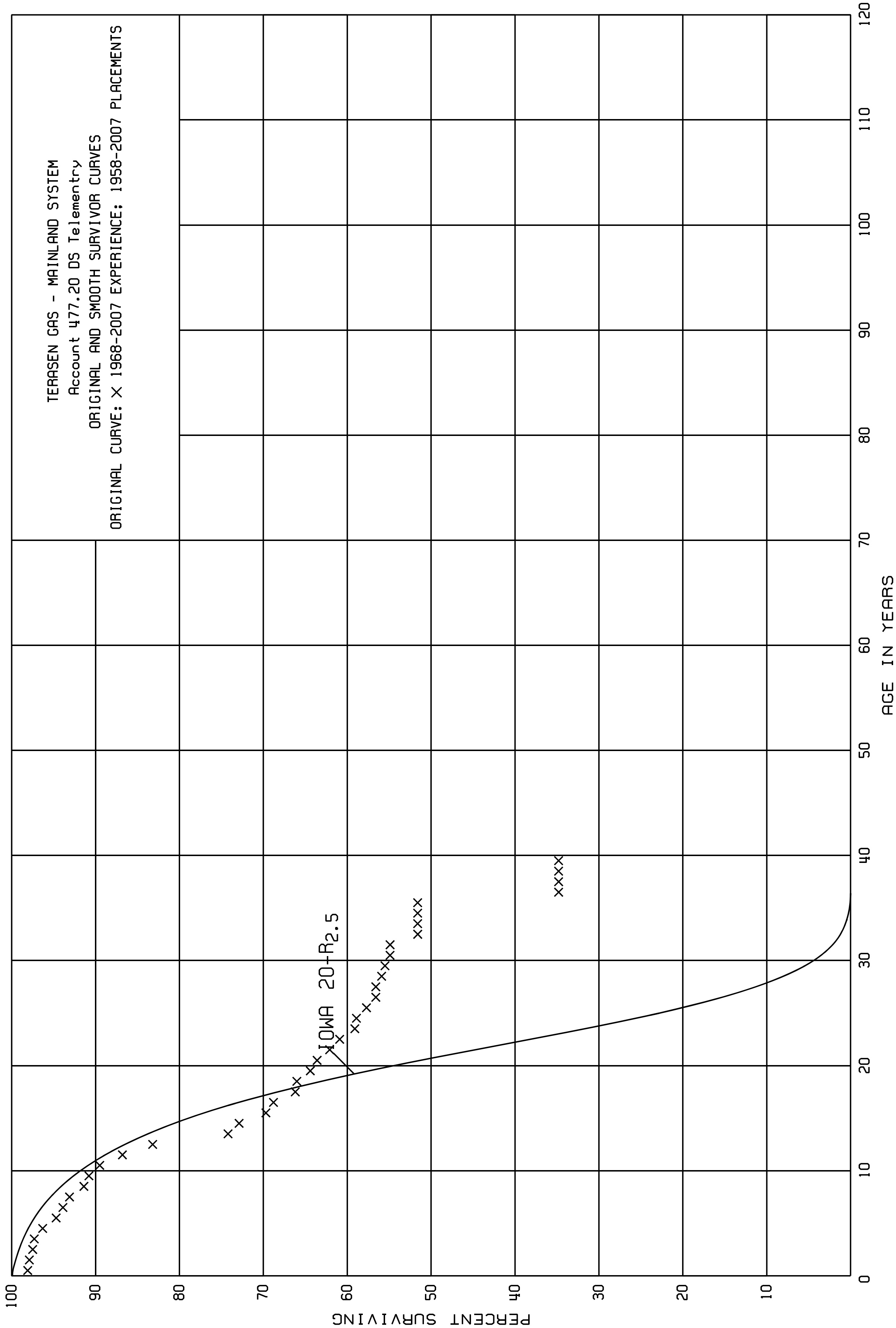
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 477.10 DS MEAS/REG ADDITIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1957-2007 EXPERIENCE BAND 1962-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	346,170		0.0000	1.0000	27.41
40.5	275,743		0.0000	1.0000	27.41
41.5	221,265	22,833	0.1032	0.8968	27.41
42.5	113,465	40,318	0.3553	0.6447	24.58
43.5	35,986	13,615	0.3783	0.6217	15.85
44.5	20,347	13,855	0.6809	0.3191	9.85
45.5					3.14


TERASEN GAS - MAINLAND SYSTEM
Account 477.20 DS Telementry
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1968-2007 EXPERIENCE; 1958-2007 PLACEMENTS
IOWA 20-R2.5
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 477.20 DS TELEMENTRY

ORIGINAL LIFE TABLE

PLACEMENT BAND 1958-2007 EXPERIENCE BAND 1968-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,476,461	122,183	0.0189	0.9811	100.00
0.5	6,321,833	9,348	0.0015	0.9985	98.11
1.5	6,123,789	28,437	0.0046	0.9954	97.96
2.5	5,978,847	13,274	0.0022	0.9978	97.51
3.5	5,712,591	58,975	0.0103	0.9897	97.30
4.5	5,215,131	83,246	0.0160	0.9840	96.30
5.5	4,809,046	40,873	0.0085	0.9915	94.76
6.5	4,512,167	39,288	0.0087	0.9913	93.95
7.5	4,174,828	78,848	0.0189	0.9811	93.13
8.5	3,808,058	25,079	0.0066	0.9934	91.37
9.5	3,692,231	50,564	0.0137	0.9863	90.77
10.5	3,421,835	103,857	0.0304	0.9696	89.53
11.5	1,963,013	82,549	0.0421	0.9579	86.81
12.5	1,039,885	115,858	0.1114	0.8886	83.16
13.5	649,380	11,280	0.0174	0.9826	73.90
14.5	548,808	25,213	0.0459	0.9541	72.61
15.5	483,407	6,444	0.0133	0.9867	69.28
16.5	372,306	15,147	0.0407	0.9593	68.36
17.5	320,696	1,115	0.0035	0.9965	65.58
18.5	305,293	7,956	0.0261	0.9739	65.35
19.5	255,348	3,583	0.0140	0.9860	63.64
20.5	234,939	5,962	0.0254	0.9746	62.75
21.5	228,977	5,115	0.0223	0.9777	61.16
22.5	177,631	6,133	0.0345	0.9655	59.80
23.5	158,500	425	0.0027	0.9973	57.74
24.5	101,075	2,588	0.0256	0.9744	57.58
25.5	98,487	2,374	0.0241	0.9759	56.11
26.5	96,113		0.0000	1.0000	54.76
27.5	92,766	1,472	0.0159	0.9841	54.76
28.5	65,707	643	0.0098	0.9902	53.89
29.5	64,252	955	0.0149	0.9851	53.36
30.5	51,862		0.0000	1.0000	52.56
31.5	49,795	4,517	0.0907	0.9093	52.56
32.5	30,258		0.0000	1.0000	47.79
33.5	21,896		0.0000	1.0000	47.79
34.5	21,896		0.0000	1.0000	47.79
35.5	21,896	15,313	0.6994	0.3006	47.79
36.5	6,583		0.0000	1.0000	14.37
37.5	6,583		0.0000	1.0000	14.37
38.5	6,583		0.0000	1.0000	14.37

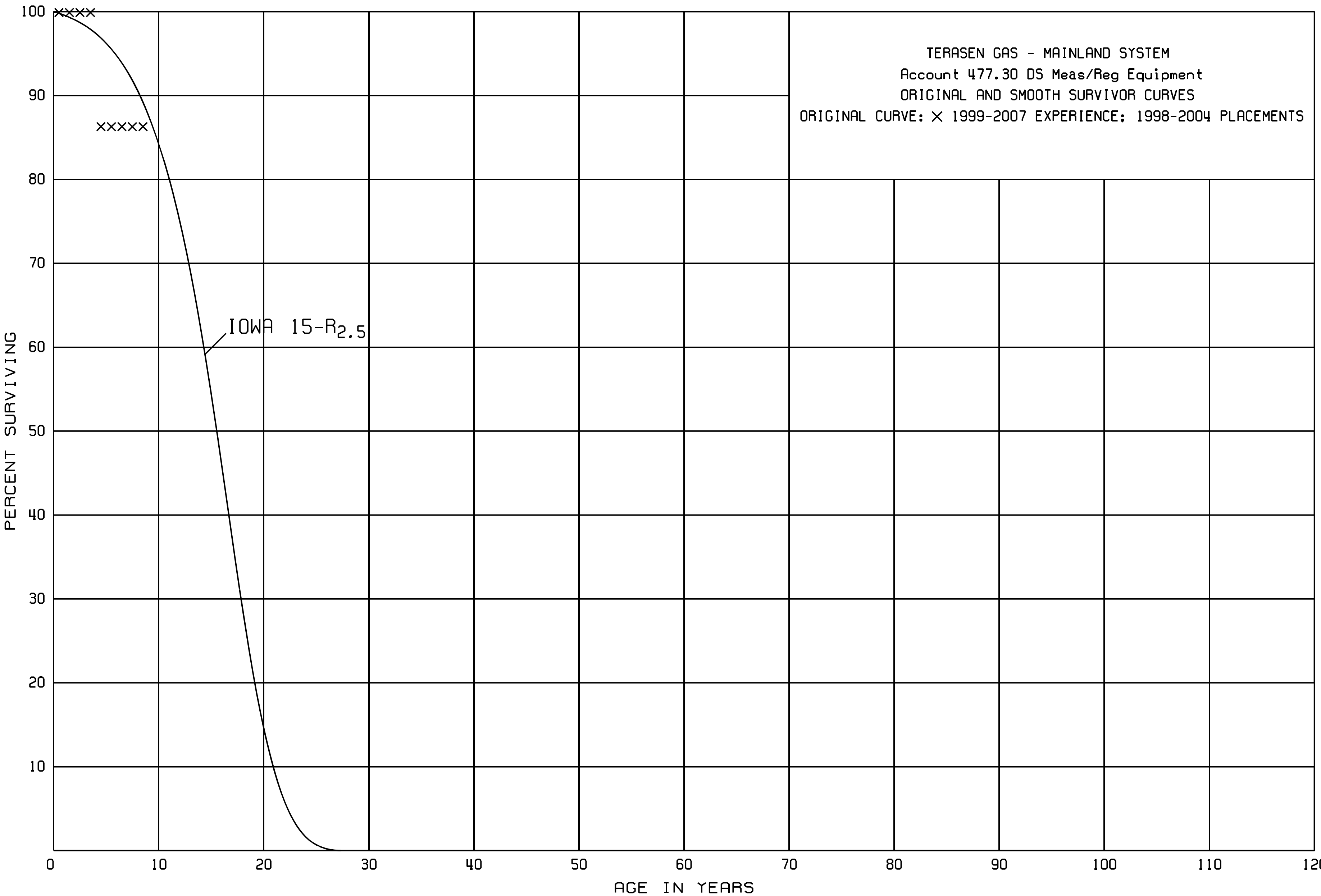
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 477.20 DS TELEMENTRY

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1958-2007 EXPERIENCE BAND 1968-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5					14.37


TERASEN GAS - MAINLAND SYSTEM
Account 477.30 DS Meas/Reg Equipment
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1999-2007 EXPERIENCE; 1998-2004 PLACEMENTS
IOWA 15-R2.5
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120

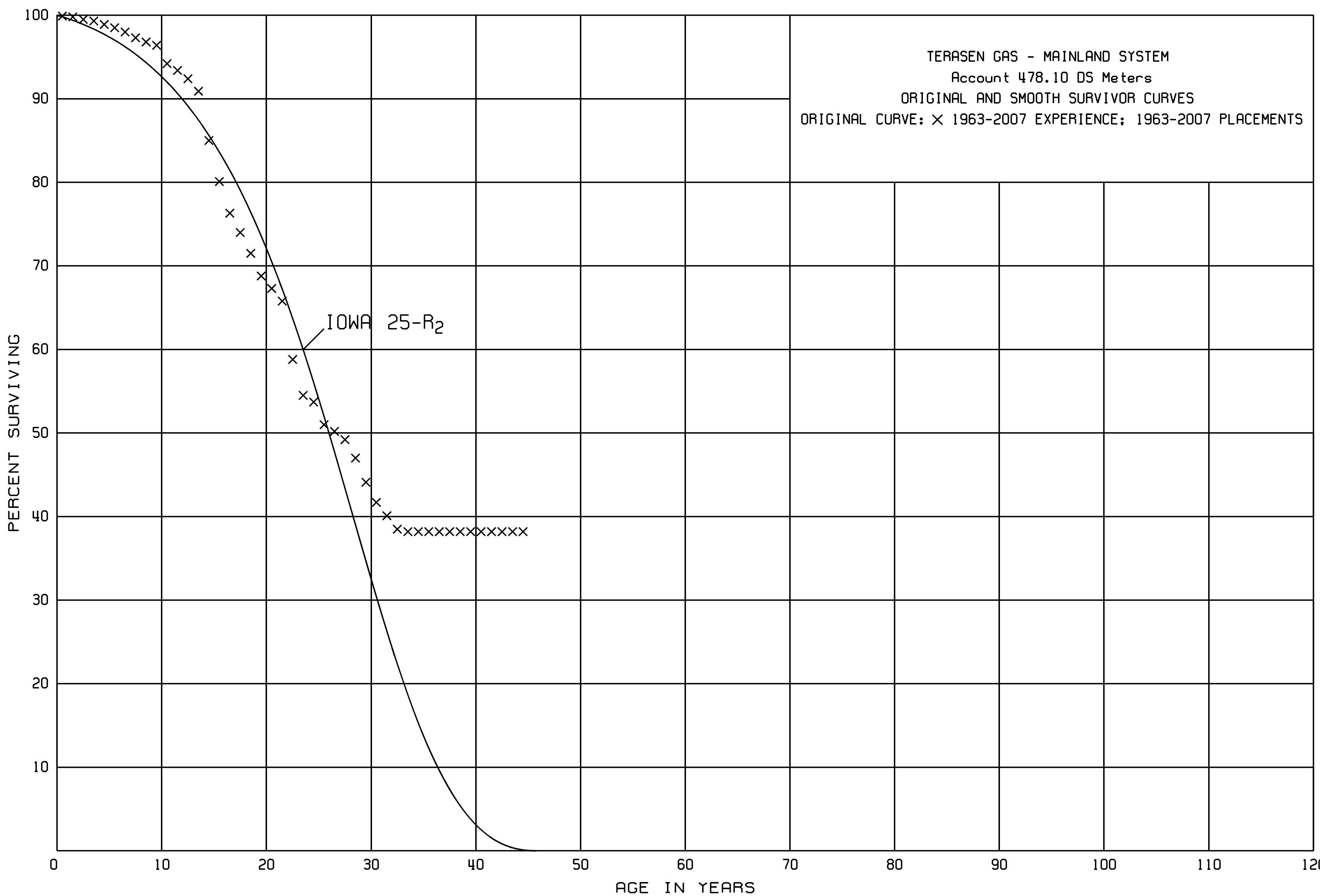
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 477.30 DS MEAS/REG EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1998-2004 EXPERIENCE BAND 1999-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	163,151		0.0000	1.0000	100.00
0.5	181,177		0.0000	1.0000	100.00
1.5	181,177		0.0000	1.0000	100.00
2.5	181,177		0.0000	1.0000	100.00
3.5	131,954	18,026	0.1366	0.8634	100.00
4.5	113,928		0.0000	1.0000	86.34
5.5	113,928		0.0000	1.0000	86.34
6.5	69,864		0.0000	1.0000	86.34
7.5	68,203		0.0000	1.0000	86.34
8.5					86.34


TERASEN GAS - MAINLAND SYSTEM
Account 478.10 DS Meters
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1963-2007 EXPERIENCE; 1963-2007 PLACEMENTS
IOWA 25-R2
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 478.10 DS METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1963-2007 EXPERIENCE BAND 1963-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	216,988,388	138,559	0.0006	0.9994	100.00
0.5	208,074,105	236,806	0.0011	0.9989	99.94
1.5	199,581,712	592,737	0.0030	0.9970	99.83
2.5	186,997,652	414,251	0.0022	0.9978	99.53
3.5	163,103,359	644,923	0.0040	0.9960	99.31
4.5	151,174,200	692,385	0.0046	0.9954	98.91
5.5	142,714,421	583,546	0.0041	0.9959	98.46
6.5	138,575,217	1,090,652	0.0079	0.9921	98.06
7.5	130,164,875	648,895	0.0050	0.9950	97.29
8.5	122,321,622	586,739	0.0048	0.9952	96.80
9.5	115,540,707	2,632,467	0.0228	0.9772	96.34
10.5	106,492,660	894,332	0.0084	0.9916	94.14
11.5	98,301,116	1,327,729	0.0135	0.9865	93.35
12.5	87,444,091	1,800,321	0.0206	0.9794	92.09
13.5	79,231,429	5,509,893	0.0695	0.9305	90.19
14.5	68,395,402	4,028,692	0.0589	0.9411	83.92
15.5	59,382,313	2,920,237	0.0492	0.9508	78.98
16.5	52,174,775	1,854,859	0.0356	0.9644	75.09
17.5	37,655,766	1,525,223	0.0405	0.9595	72.42
18.5	22,220,962	1,132,813	0.0510	0.9490	69.49
19.5	21,056,945	531,930	0.0253	0.9747	65.95
20.5	20,080,057	430,526	0.0214	0.9786	64.28
21.5	18,312,954	1,852,532	0.1012	0.8988	62.90
22.5	15,777,524	1,113,792	0.0706	0.9294	56.53
23.5	13,585,073	924,184	0.0680	0.9320	52.54
24.5	12,660,889	630,836	0.0498	0.9502	48.97
25.5	10,654,063	179,868	0.0169	0.9831	46.53
26.5	9,361,897	187,992	0.0201	0.9799	45.74
27.5	7,869,857	348,232	0.0442	0.9558	44.82
28.5	6,852,543	421,739	0.0615	0.9385	42.84
29.5	5,235,755	287,219	0.0549	0.9451	40.21
30.5	3,925,523	152,679	0.0389	0.9611	38.00
31.5	2,901,975	114,772	0.0395	0.9605	36.52
32.5	2,216,104	18,397	0.0083	0.9917	35.08
33.5	1,687,544		0.0000	1.0000	34.79
34.5	1,285,658		0.0000	1.0000	34.79
35.5	1,008,534		0.0000	1.0000	34.79
36.5	793,837		0.0000	1.0000	34.79
37.5	627,456		0.0000	1.0000	34.79
38.5	488,603		0.0000	1.0000	34.79

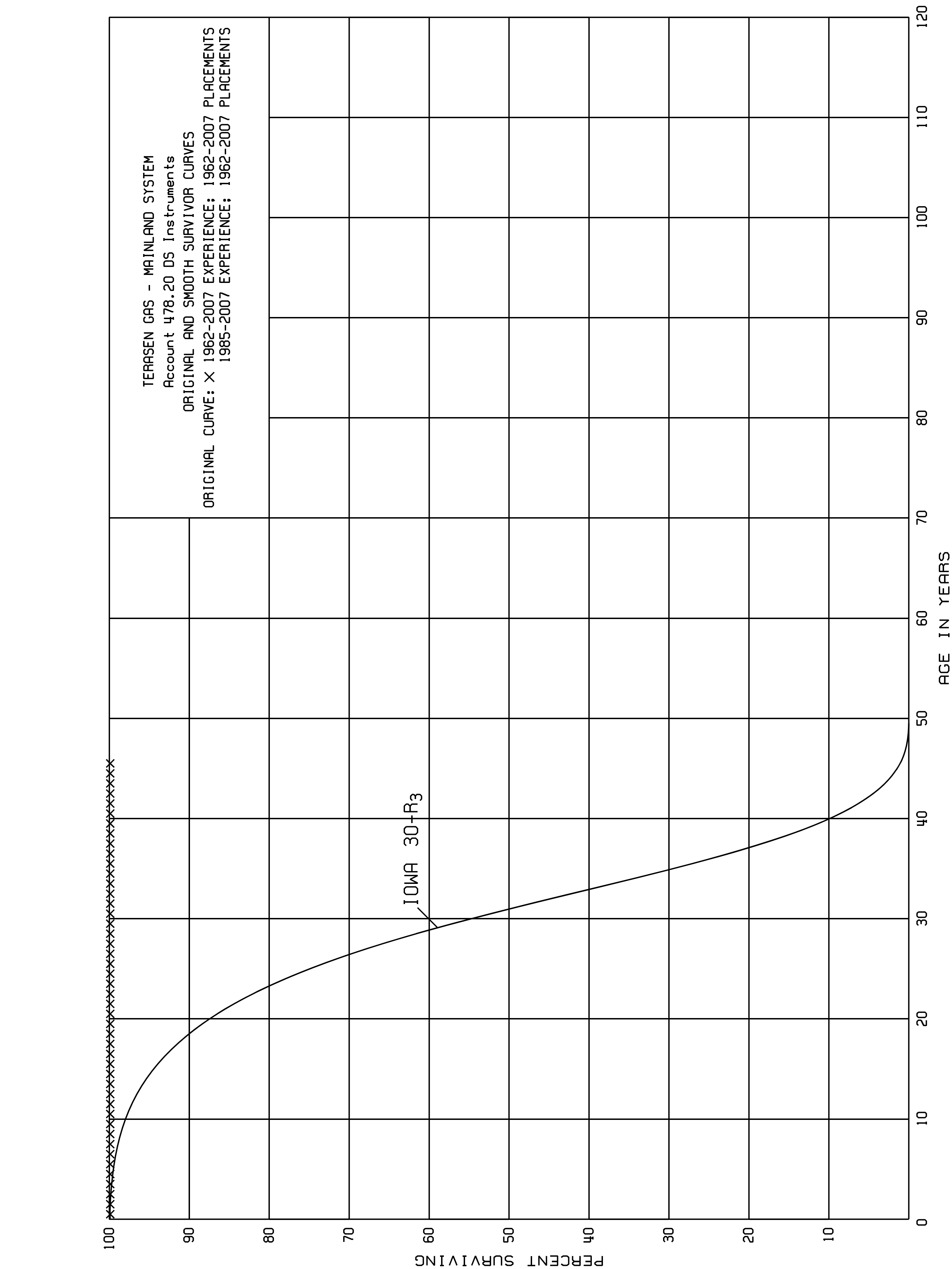
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 478.10 DS METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1963-2007 EXPERIENCE BAND 1963-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	388,434		0.0000	1.0000	34.79
40.5	312,070		0.0000	1.0000	34.79
41.5	246,748		0.0000	1.0000	34.79
42.5	176,540		0.0000	1.0000	34.79
43.5	130,782		0.0000	1.0000	34.79
44.5					34.79


TERASEN GAS - MAINLAND SYSTEM
Account 478.20 DS Instruments
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1962-2007 EXPERIENCE; 1962-2007 PLACEMENTS
1985-2007 EXPERIENCE; 1962-2007 PLACEMENTS
IOWA 30-R3
PERCENT SURVIVING
AGE IN YEARS

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 478.20 DS INSTRUMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1962-2007 EXPERIENCE BAND 1962-2007
PLACEMENT BAND 1962-2007 EXPERIENCE BAND 1985-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	21,389,210		0.0000	1.0000	100.00
0.5	20,496,137		0.0000	1.0000	100.00
1.5	19,845,790		0.0000	1.0000	100.00
2.5	18,494,595		0.0000	1.0000	100.00
3.5	15,469,956		0.0000	1.0000	100.00
4.5	13,467,973		0.0000	1.0000	100.00
5.5	12,805,462		0.0000	1.0000	100.00
6.5	12,121,185		0.0000	1.0000	100.00
7.5	11,663,394		0.0000	1.0000	100.00
8.5	11,011,019		0.0000	1.0000	100.00
9.5	10,958,105		0.0000	1.0000	100.00
10.5	10,203,593		0.0000	1.0000	100.00
11.5	8,960,577		0.0000	1.0000	100.00
12.5	7,394,242		0.0000	1.0000	100.00
13.5	5,582,817		0.0000	1.0000	100.00
14.5	3,953,902		0.0000	1.0000	100.00
15.5	2,541,332		0.0000	1.0000	100.00
16.5	1,900,982		0.0000	1.0000	100.00
17.5	1,583,411		0.0000	1.0000	100.00
18.5	1,452,219		0.0000	1.0000	100.00
19.5	1,205,556		0.0000	1.0000	100.00
20.5	1,041,114		0.0000	1.0000	100.00
21.5	1,002,441		0.0000	1.0000	100.00
22.5	993,342		0.0000	1.0000	100.00
23.5	988,636		0.0000	1.0000	100.00
24.5	257,100		0.0000	1.0000	100.00
25.5	210,422		0.0000	1.0000	100.00
26.5	171,404		0.0000	1.0000	100.00
27.5	142,316		0.0000	1.0000	100.00
28.5	124,772		0.0000	1.0000	100.00
29.5	105,614		0.0000	1.0000	100.00
30.5	83,936		0.0000	1.0000	100.00
31.5	65,158		0.0000	1.0000	100.00
32.5	52,354		0.0000	1.0000	100.00
33.5	41,082		0.0000	1.0000	100.00
34.5	26,706		0.0000	1.0000	100.00
35.5	18,188		0.0000	1.0000	100.00
36.5	10,286		0.0000	1.0000	100.00
37.5	7,932		0.0000	1.0000	100.00
38.5	5,748		0.0000	1.0000	100.00

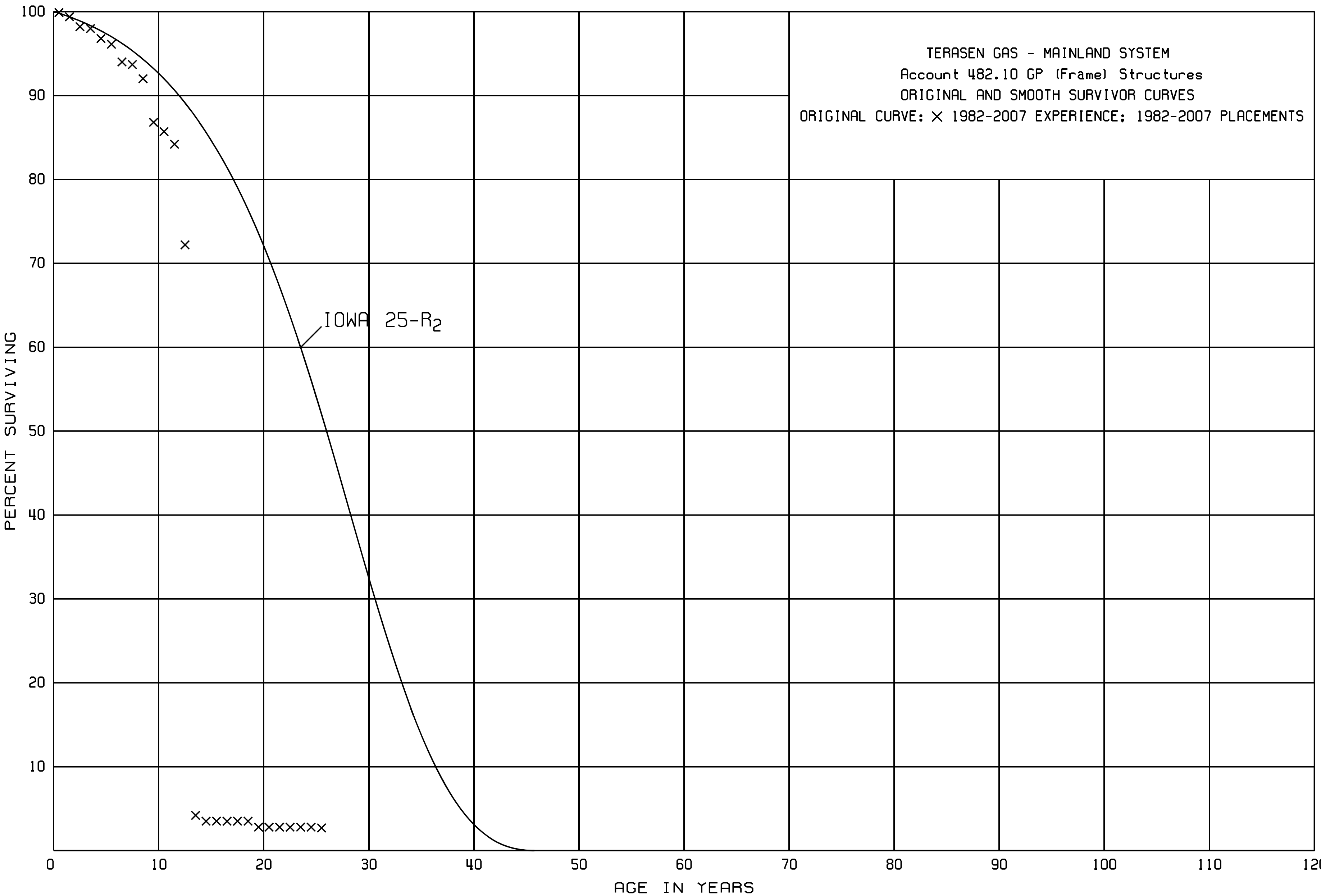
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 478.20 DS INSTRUMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1962-2007 EXPERIENCE BAND 1962-2007
PLACEMENT BAND 1962-2007 EXPERIENCE BAND 1985-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	4,580		0.0000	1.0000	100.00
40.5	2,898		0.0000	1.0000	100.00
41.5	1,674		0.0000	1.0000	100.00
42.5	1,172		0.0000	1.0000	100.00
43.5	624		0.0000	1.0000	100.00
44.5	202		0.0000	1.0000	100.00
45.5					100.00


TERASEN GAS - MAINLAND SYSTEM
Account 482.10 GP (Frame) Structures
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1982-2007 EXPERIENCE; 1982-2007 PLACEMENTS
IOWA 25-R2
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120

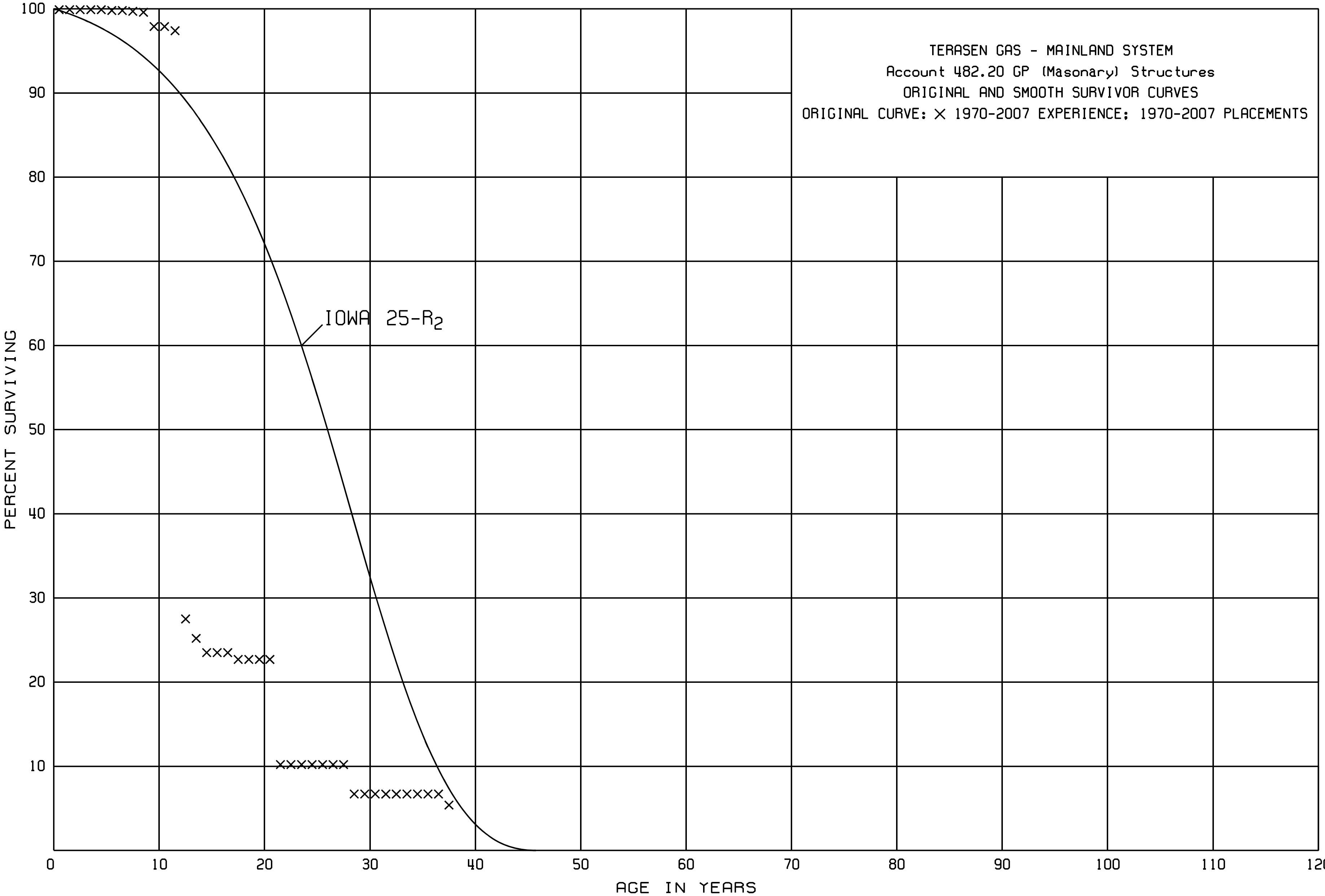
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 482.10 GP (FRAME) STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1982-2007 EXPERIENCE BAND 1982-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	12,622,325	1,593	0.0001	0.9999	100.00
0.5	12,546,015	74,690	0.0060	0.9940	99.99
1.5	12,125,984	178,592	0.0147	0.9853	99.39
2.5	11,679,139	19,013	0.0016	0.9984	97.93
3.5	11,590,003	82,123	0.0071	0.9929	97.77
4.5	11,031,333	118,358	0.0107	0.9893	97.08
5.5	10,409,719	228,606	0.0220	0.9780	96.04
6.5	9,886,427	28,183	0.0029	0.9971	93.93
7.5	8,107,013	155,188	0.0191	0.9809	93.66
8.5	6,466,915	364,249	0.0563	0.9437	91.87
9.5	6,100,060	75,021	0.0123	0.9877	86.70
10.5	6,023,927	108,137	0.0180	0.9820	85.63
11.5	5,813,234	822,678	0.1415	0.8585	84.09
12.5	4,945,988	4,635,312	0.9372	0.0628	72.19
13.5	245,018	36,088	0.1473	0.8527	4.53
14.5	205,522		0.0000	1.0000	3.86
15.5	169,684		0.0000	1.0000	3.86
16.5	169,684		0.0000	1.0000	3.86
17.5	165,440		0.0000	1.0000	3.86
18.5	160,359	28,873	0.1801	0.8199	3.86
19.5	131,486		0.0000	1.0000	3.16
20.5	131,486		0.0000	1.0000	3.16
21.5	131,486		0.0000	1.0000	3.16
22.5	130,339		0.0000	1.0000	3.16
23.5	130,339	24,783	0.1901	0.8099	3.16
24.5	104,546	3,316	0.0317	0.9683	2.56
25.5					2.48


TERASEN GAS - MAINLAND SYSTEM
Account 482.20 GP (Masonary) Structures
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1970-2007 EXPERIENCE; 1970-2007 PLACEMENTS
IOWA 25-R2
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
110
120

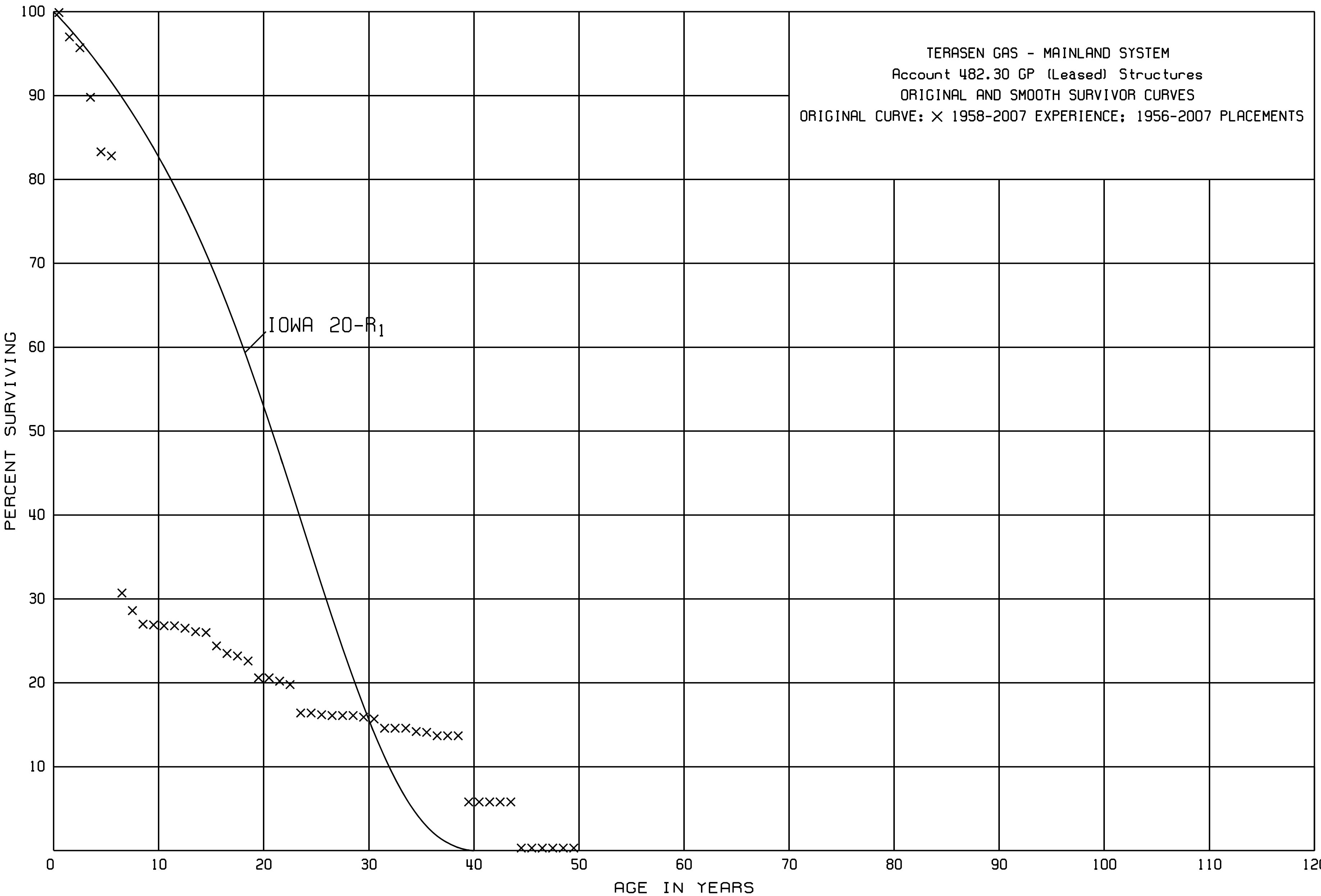
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 482.20 GP (MASONARY) STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1970-2007 EXPERIENCE BAND 1970-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	82,810,510	12,000	0.0001	0.9999	100.00
0.5	79,928,505	40,054	0.0005	0.9995	99.99
1.5	78,159,370	396	0.0000	1.0000	99.94
2.5	30,154,615		0.0000	1.0000	99.94
3.5	28,167,050	6,229	0.0002	0.9998	99.94
4.5	26,962,742	32,473	0.0012	0.9988	99.92
5.5	26,277,945	4,411	0.0002	0.9998	99.80
6.5	25,886,248	71,887	0.0028	0.9972	99.78
7.5	25,311,035	34,252	0.0014	0.9986	99.50
8.5	5,301,676	20,139	0.0038	0.9962	99.36
9.5	5,281,537		0.0000	1.0000	98.98
10.5	5,243,429	6,520	0.0012	0.9988	98.98
11.5	5,120,528	856,492	0.1673	0.8327	98.86
12.5	333,599	27,312	0.0819	0.9181	82.32
13.5	304,382	20,937	0.0688	0.9312	75.58
14.5	283,151		0.0000	1.0000	70.38
15.5	283,151		0.0000	1.0000	70.38
16.5	283,151	10,000	0.0353	0.9647	70.38
17.5	273,151		0.0000	1.0000	67.90
18.5	273,151		0.0000	1.0000	67.90
19.5	273,151		0.0000	1.0000	67.90
20.5	273,151	150,222	0.5500	0.4500	67.90
21.5	122,929		0.0000	1.0000	30.56
22.5	122,929		0.0000	1.0000	30.56
23.5	122,929		0.0000	1.0000	30.56
24.5	122,929		0.0000	1.0000	30.56
25.5	122,929		0.0000	1.0000	30.56
26.5	122,929		0.0000	1.0000	30.56
27.5	122,929	42,784	0.3480	0.6520	30.56
28.5	80,145		0.0000	1.0000	19.93
29.5	80,145		0.0000	1.0000	19.93
30.5	80,145		0.0000	1.0000	19.93
31.5	80,145		0.0000	1.0000	19.93
32.5	80,145		0.0000	1.0000	19.93
33.5	80,145		0.0000	1.0000	19.93
34.5	80,145		0.0000	1.0000	19.93
35.5	80,145		0.0000	1.0000	19.93
36.5	80,145	15,000	0.1872	0.8128	19.93
37.5					16.20


TERASEN GAS - MAINLAND SYSTEM
Account 482.30 GP (Leased) Structures
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1958-2007 EXPERIENCE; 1956-2007 PLACEMENTS
IOWA 20-R1
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 482.30 GP (LEASED) STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2007 EXPERIENCE BAND 1958-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	19,418,199	10,661	0.0005	0.9995	100.00
0.5	19,380,913	574,758	0.0297	0.9703	99.95
1.5	19,760,003	268,855	0.0136	0.9864	96.98
2.5	19,478,133	1,200,376	0.0616	0.9384	95.66
3.5	18,272,955	1,319,923	0.0722	0.9278	89.77
4.5	16,941,680	128,357	0.0076	0.9924	83.29
5.5	16,813,323	10,588,198	0.6298	0.3702	82.66
6.5	6,220,604	441,500	0.0710	0.9290	30.60
7.5	5,490,866	305,690	0.0557	0.9443	28.43
8.5	5,185,176	21,557	0.0042	0.9958	26.85
9.5	5,163,619	5,655	0.0011	0.9989	26.74
10.5	5,157,964	10,984	0.0021	0.9979	26.71
11.5	5,146,980	54,002	0.0105	0.9895	26.65
12.5	5,092,977	66,560	0.0131	0.9869	26.37
13.5	5,026,417	23,554	0.0047	0.9953	26.02
14.5	5,002,863	314,059	0.0628	0.9372	25.90
15.5	4,688,804	168,721	0.0360	0.9640	24.27
16.5	4,271,919	46,271	0.0108	0.9892	23.40
17.5	4,225,648	112,042	0.0265	0.9735	23.15
18.5	4,078,019	355,339	0.0871	0.9129	22.54
19.5	3,722,680		0.0000	1.0000	20.58
20.5	3,722,680	82,176	0.0221	0.9779	20.58
21.5	3,638,100	74,239	0.0204	0.9796	20.13
22.5	3,549,103	600,904	0.1693	0.8307	19.72
23.5	2,948,199	2,439	0.0008	0.9992	16.38
24.5	2,945,760	40,043	0.0136	0.9864	16.37
25.5	2,905,717	10,000	0.0034	0.9966	16.15
26.5	2,895,717	3,175	0.0011	0.9989	16.10
27.5	2,874,069	11,243	0.0039	0.9961	16.08
28.5	2,862,826	27,762	0.0097	0.9903	16.02
29.5	2,762,082	37,125	0.0134	0.9866	15.86
30.5	2,724,957	188,202	0.0691	0.9309	15.65
31.5	2,406,815		0.0000	1.0000	14.57
32.5	2,254,070		0.0000	1.0000	14.57
33.5	2,205,137	65,724	0.0298	0.9702	14.57
34.5	2,136,556	20,001	0.0094	0.9906	14.14
35.5	1,865,887	46,646	0.0250	0.9750	14.01
36.5	1,819,241	4,224	0.0023	0.9977	13.66
37.5	1,814,570		0.0000	1.0000	13.63
38.5	1,814,506	1,046,586	0.5768	0.4232	13.63

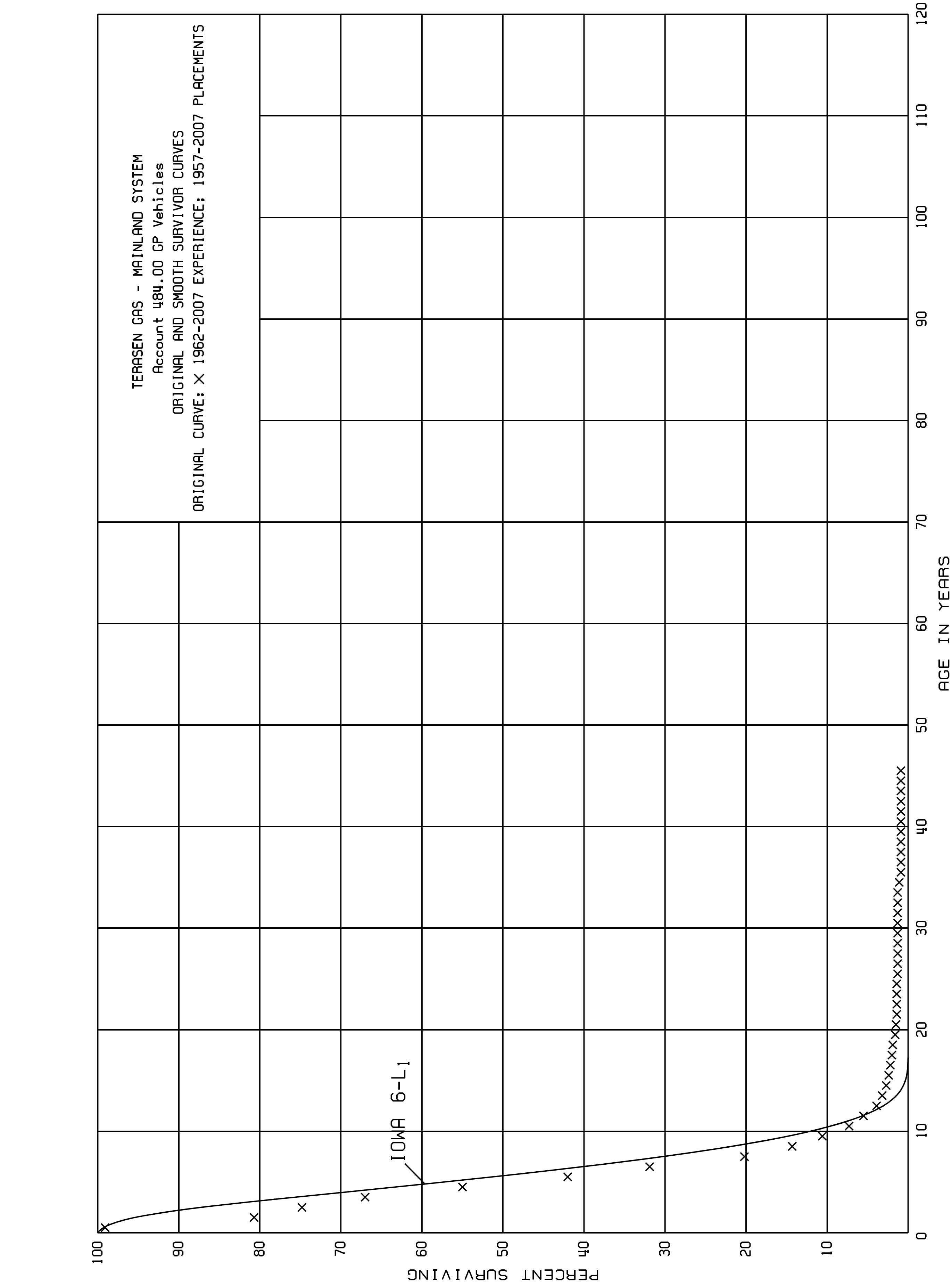
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 482.30 GP (LEASED) STRUCTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-2007 EXPERIENCE BAND 1958-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	767,920		0.0000	1.0000	5.77
40.5	688,841		0.0000	1.0000	5.77
41.5	687,780		0.0000	1.0000	5.77
42.5	548,246		0.0000	1.0000	5.77
43.5	547,167	510,642	0.9332	0.0668	5.77
44.5	13,040		0.0000	1.0000	0.39
45.5	13,040		0.0000	1.0000	0.39
46.5	8,959		0.0000	1.0000	0.39
47.5	8,959		0.0000	1.0000	0.39
48.5	8,959		0.0000	1.0000	0.39
49.5					0.39



TERASEN GAS - MAINLAND SYSTEM
Account 484.00 GP Vehicles
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1962-2007 EXPERIENCE; 1957-2007 PLACEMENTS
IOWA 6-L1
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
110
120

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 484.00 GP VEHICLES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1957-2007 EXPERIENCE BAND 1962-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	18,833,012	168,249	0.0089	0.9911	100.00
0.5	18,665,013	3,452,073	0.1849	0.8151	99.11
1.5	15,060,901	1,095,929	0.0728	0.9272	80.78
2.5	14,176,392	1,474,471	0.1040	0.8960	74.90
3.5	12,698,175	2,277,560	0.1794	0.8206	67.11
4.5	10,365,445	2,447,929	0.2362	0.7638	55.07
5.5	7,866,694	1,883,021	0.2394	0.7606	42.06
6.5	5,945,543	2,181,178	0.3669	0.6331	31.99
7.5	3,759,340	1,097,499	0.2919	0.7081	20.25
8.5	2,661,841	692,144	0.2600	0.7400	14.34
9.5	1,946,555	607,011	0.3118	0.6882	10.61
10.5	1,326,711	326,996	0.2465	0.7535	7.30
11.5	952,167	270,453	0.2840	0.7160	5.50
12.5	674,644	133,758	0.1983	0.8017	3.94
13.5	537,097	83,561	0.1556	0.8444	3.16
14.5	447,905	44,020	0.0983	0.9017	2.67
15.5	388,514	27,336	0.0704	0.9296	2.41
16.5	337,965	36,543	0.1081	0.8919	2.24
17.5	276,887	10,589	0.0382	0.9618	2.00
18.5	266,298	41,165	0.1546	0.8454	1.92
19.5	212,704	10,920	0.0513	0.9487	1.62
20.5	190,962	19,252	0.1008	0.8992	1.54
21.5	146,449	1,254	0.0086	0.9914	1.38
22.5	134,689	367	0.0027	0.9973	1.37
23.5	120,740		0.0000	1.0000	1.37
24.5	111,110	3,721	0.0335	0.9665	1.37
25.5	107,389		0.0000	1.0000	1.32
26.5	97,310		0.0000	1.0000	1.32
27.5	86,584	384	0.0044	0.9956	1.32
28.5	82,393		0.0000	1.0000	1.31
29.5	82,393		0.0000	1.0000	1.31
30.5	82,393	3,441	0.0418	0.9582	1.31
31.5	66,294		0.0000	1.0000	1.26
32.5	66,294	385	0.0058	0.9942	1.26
33.5	60,675	7,823	0.1289	0.8711	1.25
34.5	40,009	8,840	0.2210	0.7790	1.09
35.5	19,677		0.0000	1.0000	0.85
36.5	11,128		0.0000	1.0000	0.85
37.5	9,741		0.0000	1.0000	0.85
38.5	9,741		0.0000	1.0000	0.85

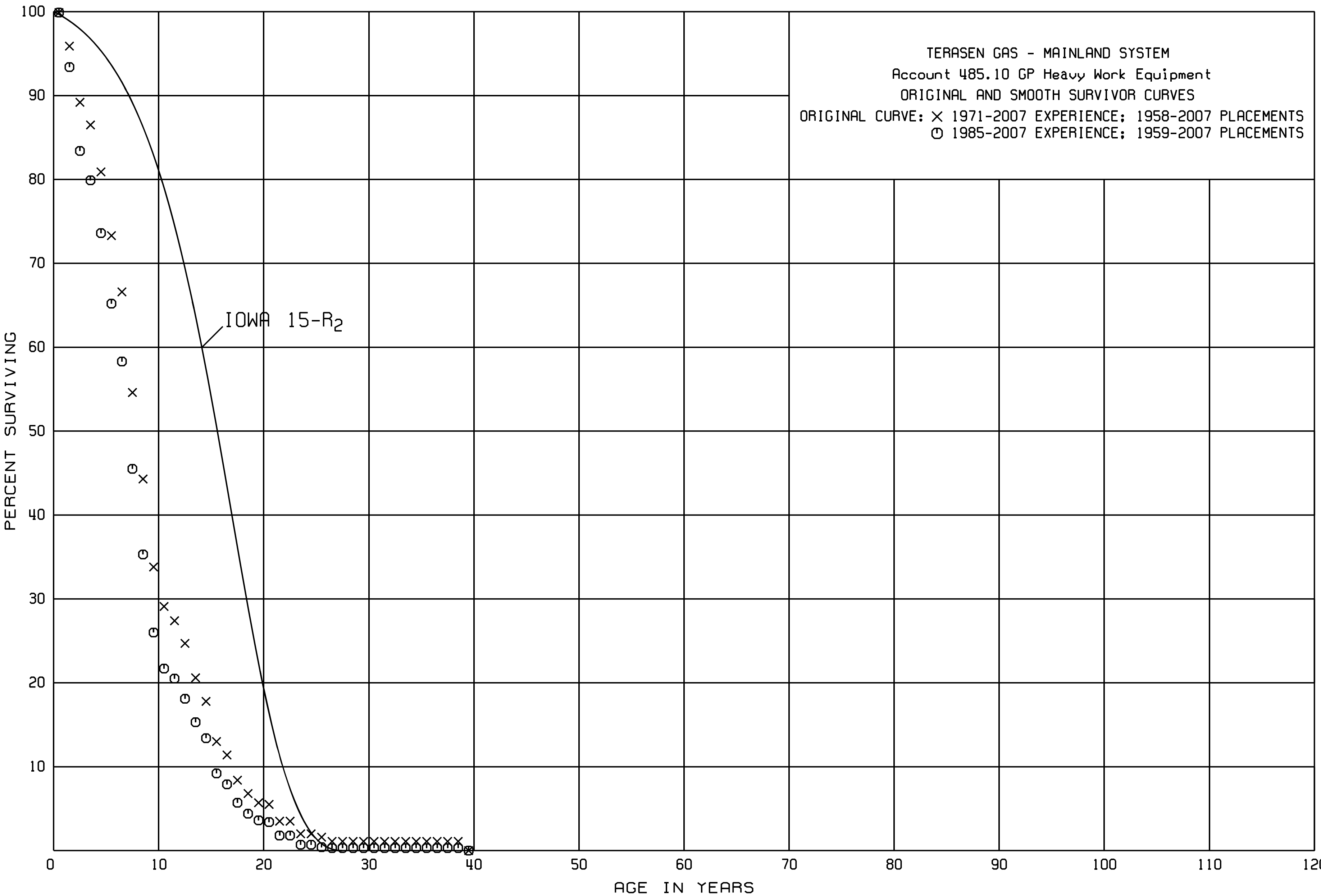
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 484.00 GP VEHICLES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1957-2007 EXPERIENCE BAND 1962-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	9,741		0.0000	1.0000	0.85
40.5	9,741		0.0000	1.0000	0.85
41.5	9,741		0.0000	1.0000	0.85
42.5	9,741		0.0000	1.0000	0.85
43.5	9,741		0.0000	1.0000	0.85
44.5	9,741		0.0000	1.0000	0.85
45.5					0.85


TERASEN GAS - MAINLAND SYSTEM
Account 485.10 GP Heavy Work Equipment
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1971-2007 EXPERIENCE; 1958-2007 PLACEMENTS
⊙ 1985-2007 EXPERIENCE; 1959-2007 PLACEMENTS
IOWA 15-R2
PERCENT SURVIVING
AGE IN YEARS

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 485.10 GP HEAVY WORK EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1958-2007 EXPERIENCE BAND 1971-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,234,498	30,338-	0.0246-	1.0246	100.00
0.5	1,259,438	67,371	0.0535		
1.5	1,266,255	74,412	0.0588		
2.5	1,191,843	92,093	0.0773		
3.5	1,099,750	70,598	0.0642		
4.5	981,538	92,838	0.0946		
5.5	782,982	71,883	0.0918		
6.5	711,100	128,131	0.1802		
7.5	582,969	109,889	0.1885		
8.5	473,574	112,132	0.2368		
9.5	361,443	49,894	0.1380		
10.5	311,549	18,456	0.0592		
11.5	305,203	30,434	0.0997		
12.5	274,770	45,607	0.1660		
13.5	229,163	30,871	0.1347		
14.5	198,292	53,676	0.2707		
15.5	144,616	18,288	0.1265		
16.5	126,328	32,705	0.2589		
17.5	93,623	18,334	0.1958		
18.5	75,289	11,438	0.1519		
19.5	63,851	2,493	0.0390		
20.5	61,358	22,597	0.3683		
21.5	38,761		0.0000		
22.5	38,761	16,706	0.4310		
23.5	22,055		0.0000		
24.5	22,055	4,653	0.2110		
25.5	17,402	4,800	0.2758		
26.5	12,602		0.0000		
27.5	12,602		0.0000		
28.5	12,602		0.0000		
29.5	12,602		0.0000		
30.5	12,602		0.0000		
31.5	12,602		0.0000		
32.5	12,602		0.0000		
33.5	12,602		0.0000		
34.5	12,602		0.0000		
35.5	12,602		0.0000		
36.5	12,602		0.0000		
37.5	12,602		0.0000		
38.5	12,602	12,109	0.9609		

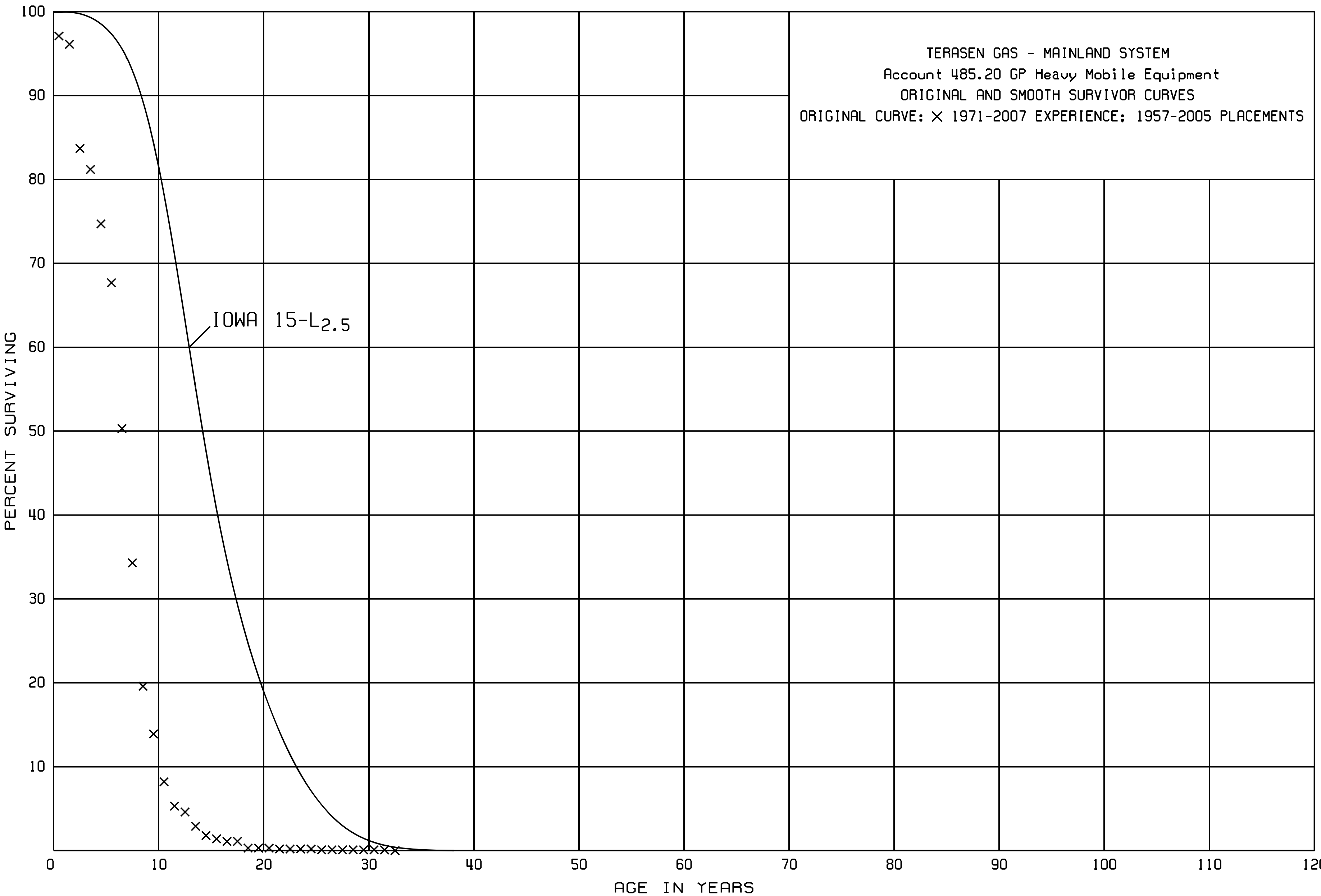
TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 485.10 GP HEAVY WORK EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1958-2007 EXPERIENCE BAND 1971-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	493	493	1.0000		
40.5					


TERASEN GAS - MAINLAND SYSTEM
Account 485.20 GP Heavy Mobile Equipment
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1971-2007 EXPERIENCE; 1957-2005 PLACEMENTS
IOWA 15-L2.5
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
110
120

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 485.20 GP HEAVY MOBILE EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1957-2006 EXPERIENCE BAND 1971-2007

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,354,088	95,241	0.0284	0.9716	100.00
0.5	3,270,618	33,718	0.0103	0.9897	97.16
1.5	3,249,813	450,545	0.1386	0.8614	96.16
2.5	2,815,517	84,272	0.0299	0.9701	82.83
3.5	2,498,442	201,081	0.0805	0.9195	80.35
4.5	2,308,082	214,821	0.0931	0.9069	73.88
5.5	2,107,037	541,439	0.2570	0.7430	67.00
6.5	1,563,346	498,677	0.3190	0.6810	49.78
7.5	1,071,728	459,036	0.4283	0.5717	33.90
8.5	587,152	170,918	0.2911	0.7089	19.38
9.5	416,234	170,797	0.4103	0.5897	13.74
10.5	246,173	86,107	0.3498	0.6502	8.10
11.5	167,403	24,538	0.1466	0.8534	5.27
12.5	166,797	60,683	0.3638	0.6362	4.50
13.5	113,451	41,190	0.3631	0.6369	2.86
14.5	72,261	16,144	0.2234	0.7766	1.82
15.5	56,117	11,951	0.2130	0.7870	1.41
16.5	44,166	1,419	0.0321	0.9679	1.11
17.5	42,747	29,983	0.7014	0.2986	1.07
18.5	12,764		0.0000	1.0000	0.32
19.5	12,764	1	0.0001	0.9999	0.32
20.5	12,763	4,280	0.3353	0.6647	0.32
21.5	8,483	1,812	0.2136	0.7864	0.21
22.5	6,671		0.0000	1.0000	0.17
23.5	6,671	323	0.0484	0.9516	0.17
24.5	6,348	1,079	0.1700	0.8300	0.16
25.5	5,269	74	0.0140	0.9860	0.13
26.5	5,195	1,509	0.2905	0.7095	0.13
27.5	3,686		0.0000	1.0000	0.09
28.5	3,686	729	0.1978	0.8022	0.09
29.5	2,957		0.0000	1.0000	0.07
30.5	2,957		0.0000	1.0000	0.07
31.5	2,957	2,957	1.0000	0.0000	0.07
32.5					0.00

DETAILED DEPRECIATION CALCULATIONS

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 402.00 INTANGIABLE PLANT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
1999	85,000.00	18,063	33,511	51,489	31.50	1,635
2002	622,698.65	85,621	158,847	463,852	34.50	13,445
2003	64,856.13	7,296	13,536	51,320	35.50	1,446
	772,554.78	110,980	205,894	566,661		16,526
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					34.3	2.14

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 402.10 PLANT ACQUISITIONS AND ADJUSTMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
1970	62,457.00	58,553	25,521	36,936	2.50	14,774
	62,457.00	58,553	25,521	36,936		14,774
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					2.5	23.65

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 432.00 MFG. GAS STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
1990	280,640.00	122,780	62,911	217,729	22.50	9,677
1991	75,194.00	31,018	15,893	59,301	23.50	2,523
1992	4,909.00	1,902	975	3,934	24.50	161
1997	2,867.00	753	386	2,481	29.50	84
1998	1,958.00	465	238	1,720	30.50	56
1999	5,724.00	1,216	623	5,101	31.50	162
2000	13,055.64	2,448	1,254	11,802	32.50	363
2001	471.58	77	39	433	33.50	13
2002	32,022.36	4,403	2,256	29,766	34.50	863
2003	1,122.58	126	65	1,058	35.50	30
2004	18,762.52	1,642	841	17,922	36.50	491
2005	9,289.79	581	298	8,992	37.50	240
2006	4,221.66	158	81	4,141	38.50	108
2007	470.26	6	3	467	39.50	12
	450,708.39	167,575	85,863	364,847		14,783
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					24.7	3.28

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 433.00 MFG. GAS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
1994	5,019.00	3,388	2,299	2,720	6.50	418
1996	11,343.00	6,522	4,425	6,918	8.50	814
1997	6,421.00	3,371	2,287	4,134	9.50	435
1999	108,000.64	45,900	31,143	76,858	11.50	6,683
2000	5,687.97	2,133	1,447	4,241	12.50	339
2002	3,008.60	827	561	2,448	14.50	169
2005	6,458.40	807	548	5,910	17.50	338
	145,938.61	62,948	42,710	103,229		9,196

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 11.2 6.30

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 434.00 MFG. GAS HOLDERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
1972	103,239.00	91,625	73,338	29,901	4.50	6,645
1990	224,319.00	98,140	78,553	145,766	22.50	6,478
1991	15,624.00	6,445	5,159	10,465	23.50	445
2001	9,757.73	1,586	1,269	8,489	33.50	253
2004	4,646.00	407	326	4,320	36.50	118
	357,585.73	198,203	158,645	198,941		13,939

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 14.3 3.90

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 436.00 MFG. GAS COMPRESSOR EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 25-SQUARE						
NET SALVAGE PERCENT.. 0						
1972	1,383.00	1,383	1,383			
1995	47,989.00	23,995	17,384	30,605	12.50	2,448
1996	3,907.00	1,797	1,302	2,605	13.50	193
2004	30.00	4	3	27	21.50	1
	53,309.00	27,179	20,072	33,237		2,642

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 12.6 4.96

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 437.00 MFG. GAS MEASURING & REGUALTING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
1972	11,581.00	11,581	11,581			
1990	226,393.00	198,094	98,351	128,042	2.50	51,217
1991	21,648.41	17,860	8,867	12,781	3.50	3,652
1992	30,767.00	23,844	11,838	18,929	4.50	4,206
1994	4,012.00	2,708	1,344	2,668	6.50	410
2001	605.49	197	98	507	13.50	38
2003	7,327.08	1,649	819	6,508	15.50	420
2004	7,112.00	1,245	618	6,494	16.50	394
2006	1.02			1	18.50	
	309,447.00	257,178	133,516	175,930		60,337

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 2.9 19.50

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 442.00 LNG GAS STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-R3						
NET SALVAGE PERCENT.. -10						
1972	236,738.00	243,120	258,661	1,751	1.66	1,055
1973	2,496.00	2,535	2,697	49	1.92	26
1978	3,734.00	3,567	3,795	312	3.29	95
1979	23,368.00	21,983	23,388	2,317	3.62	640
1980	15,064.00	13,926	14,816	1,754	3.99	440
1981	55,961.00	50,772	54,018	7,539	4.38	1,721
1982	34,220.00	30,400	32,343	5,299	4.81	1,102
1983	1,713.00	1,486	1,581	303	5.28	57
1985	33,230.00	27,283	29,027	7,526	6.34	1,187
1987	280,084.00	215,295	229,058	79,034	7.53	10,496
1988	39,859.24	29,499	31,385	12,460	8.18	1,523
1989	9,938.00	7,058	7,509	3,423	8.86	386
1990	342.00	232	247	129	9.57	13
1991	1,925.00	1,245	1,325	793	10.30	77
1992	120,759.00	74,122	78,860	53,975	11.05	4,885
1993	8,093.00	4,690	4,990	3,912	11.83	331
1994	74,230.00	40,402	42,985	38,668	12.63	3,062
1995	130,418.00	66,278	70,515	72,945	13.45	5,423
1996	38,857.00	18,311	19,482	23,261	14.29	1,628
1997	591,534.00	256,371	272,759	377,928	15.15	24,946
1998	46,626.00	18,423	19,601	31,688	16.02	1,978
1999	853,029.00	303,644	323,054	615,278	16.91	36,385
2000	230,967.28	72,967	77,631	176,433	17.82	9,901
2001	58,626.64	16,122	17,153	47,336	18.75	2,525
2002	152,744.47	35,754	38,039	129,980	19.68	6,605
2003	40,236.73	7,737	8,232	36,028	20.63	1,746
2004	696,126.26	104,447	111,123	654,616	21.59	30,320
2005	789,138.14	85,069	90,507	777,545	22.55	34,481
2006	19,530.75	1,263	1,344	20,140	23.53	856
2007	189,429.68	4,084	4,345	204,028	24.51	8,324
	4,779,018.19	1,758,085	1,870,470	3,386,450		192,214
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					17.6	4.02

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 443.00 LNG GAS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R3						
NET SALVAGE PERCENT.. -20						
1972	2,901,446.00	2,574,743	2,941,441	540,294	10.42	51,852
1973	12,525.00	10,892	12,443	2,587	11.01	235
1987	6,061,499.92	3,436,870	3,926,353	3,347,447	21.10	158,647
1988	13,088.00	7,094	8,104	7,602	21.93	347
1989	3,341.00	1,726	1,972	2,037	22.78	89
1990	15,434.00	7,579	8,658	9,863	23.63	417
1991	29,590.00	13,766	15,727	19,781	24.49	808
1992	4,823.00	2,117	2,419	3,369	25.37	133
1993	102,863.19	42,400	48,439	74,997	26.26	2,856
1994	1,543.00	595	680	1,172	27.15	43
1996	262,859.00	86,901	99,277	216,154	28.98	7,459
1997	70,803.00	21,453	24,508	60,456	29.90	2,022
1999	644,197.83	159,014	181,661	591,376	31.77	18,614
2002	5,234,609.74	841,725	961,604	5,319,928	34.64	153,578
2003	134,252.28	17,721	20,245	140,858	35.60	3,957
2004	891,947.15	91,728	104,792	965,545	36.57	26,403
2005	58,170.10	4,272	4,880	64,924	37.55	1,729
2006	52,423.59	2,309	2,638	60,270	38.53	1,564
2007	384.99	6	7	455	39.51	12
	16,495,800.79	7,322,911	8,365,848	11,429,115		430,765

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 26.5 2.61

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 449.00 LNG GAS OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R3						
NET SALVAGE PERCENT.. -10						
1972	5,851,651.00	5,180,993	4,613,881	1,822,935	6.83	266,901
1973	164,353.00	143,076	127,415	53,373	7.30	7,311
1974	14,039.00	12,001	10,687	4,756	7.80	610
1976	12,197.00	10,017	8,921	4,496	8.87	507
1977	1,041.00	836	744	401	9.45	42
1978	187.00	147	131	75	10.05	7
1979	432.00	330	294	181	10.67	17
1980	75.00	56	50	33	11.32	3
1981	1,639.00	1,185	1,055	748	11.99	62
1982	37,304.00	26,168	23,304	17,730	12.68	1,398
1983	15,598.00	10,593	9,433	7,725	13.39	577
1984	45,314.00	29,738	26,483	23,362	14.12	1,655
1985	40,299.00	25,507	22,715	21,614	14.86	1,455
1986	58,038.37	35,330	31,463	32,379	15.63	2,072
1988	3,094.00	1,731	1,542	1,861	17.20	108
1989	169,698.70	90,665	80,741	105,928	18.00	5,885
1990	273,147.00	138,813	123,618	176,844	18.83	9,392
1991	641,503.00	309,288	275,433	430,220	19.66	21,883
1992	594,325.70	270,656	241,030	412,728	20.51	20,123
1993	1,285,966.00	550,406	490,159	924,404	21.38	43,237
1994	292,885.04	117,368	104,521	217,653	22.25	9,782
1995	3,604,177.00	1,343,601	1,196,530	2,768,065	23.14	119,623
1996	599,398.91	206,439	183,842	475,497	24.04	19,779
1997	411,903.00	130,083	115,844	337,249	24.95	13,517
1998	39,920.00	11,457	10,203	33,709	25.87	1,303
1999	402,512.00	103,739	92,384	350,379	26.80	13,074
2000	297,720.88	67,922	60,487	267,006	27.74	9,625
2002	892,360.07	150,086	133,658	847,938	29.65	28,598
2003	239,308.75	33,010	29,397	233,843	30.61	7,639
2004	242,772.49	26,091	23,235	243,815	31.58	7,721
2005	2,131,032.77	164,090	146,128	2,198,008	32.55	67,527
2006	310,240.45	14,333	12,764	328,500	33.53	9,797
2007	262,261.93	4,039	3,597	284,891	34.51	8,255
	18,936,395.06	9,209,794	8,201,689	12,628,346		699,485

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 18.1 3.69

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 461.00 TP LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1957	1,089.00	694	93	996	27.23	37
1959	627,162.00	385,893	51,803	575,359	28.85	19,943
1960	18,993.00	11,477	1,541	17,452	29.68	588
1961	16,660.00	9,883	1,327	15,333	30.51	503
1962	2,188.00	1,273	171	2,017	31.35	64
1963	42,410.00	24,195	3,248	39,162	32.21	1,216
1964	25,050.00	14,005	1,880	23,170	33.07	701
1965	9,547.00	5,227	702	8,845	33.94	261
1966	1,224.00	656	88	1,136	34.81	33
1967	2,736.00	1,434	193	2,543	35.70	71
1968	17,088.00	8,751	1,175	15,913	36.59	435
1969	18,139.00	9,071	1,218	16,921	37.49	451
1970	4,224.00	2,061	277	3,947	38.40	103
1971	27,965.00	13,303	1,786	26,179	39.32	666
1972	244,270.00	113,219	15,199	229,071	40.24	5,693
1973	8,050.00	3,632	488	7,562	41.16	184
1974	21,196.00	9,299	1,248	19,948	42.10	474
1975	64,788.00	27,606	3,706	61,082	43.04	1,419
1976	544,565.00	225,232	30,235	514,330	43.98	11,695
1977	55,880.00	22,402	3,007	52,873	44.93	1,177
1978	125,395.00	48,691	6,536	118,859	45.88	2,591
1979	133,778.00	50,234	6,743	127,035	46.84	2,712
1980	3,483.00	1,263	170	3,313	47.80	69
1981	38,046.00	13,305	1,786	36,260	48.77	743
1982	46,760.00	15,753	2,115	44,645	49.73	898
1983	44,867.00	14,532	1,951	42,916	50.71	846
1984	3,796.00	1,180	158	3,638	51.68	70
1985	22,235.00	6,624	889	21,346	52.66	405
1986	523,410.00	149,067	20,011	503,399	53.64	9,385
1987	100,861.00	27,404	3,679	97,182	54.62	1,779
1988	10,626.00	2,749	369	10,257	55.60	184
1989	41,485.00	10,185	1,367	40,118	56.59	709
1990	31,517.00	7,321	983	30,534	57.58	530
1991	51,409.00	11,264	1,512	49,897	58.57	852
1992	2,441,936.00	502,795	67,495	2,374,441	59.56	39,866

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 461.00 TP LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1993	1,119,351.00	215,699	28,956	1,090,395	60.55	18,008
1994	1,221,456.00	219,251	29,432	1,192,024	61.54	19,370
1995	474,274.00	78,872	10,588	463,686	62.53	7,415
1996	699,193.00	106,907	14,351	684,842	63.53	10,780
1997	287,684.00	40,189	5,395	282,289	64.52	4,375
1998	208,812.00	26,394	3,543	205,269	65.52	3,133
2000	12,363,101.40	1,235,074	165,797	12,197,304	67.51	180,674
2001	2,801,348.93	242,317	32,529	2,768,820	68.51	40,415
2002	4,752,952.33	347,916	46,705	4,706,247	69.51	67,706
2003	7,288,504.96	436,581	58,607	7,229,898	70.51	102,537
2004	961,616.85	44,908	6,028	955,589	71.50	13,365
2005	41,352.00	1,377	185	41,167	72.50	568
2006	5,035,771.66	100,715	13,520	5,022,252	73.50	68,330
2007	203,324.84	1,362	183	203,142	74.50	2,727
	42,831,570.97	4,849,242	650,968	42,180,603		646,756

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 65.2 1.51

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 462.00 TP COMPRESSOR STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R4						
NET SALVAGE PERCENT.. -5						
1965	14,750.00	15,136	12,183	3,305	0.68	3,305
1966	7,007.00	7,137	5,745	1,612	0.90	1,612
1967	2,082.00	2,103	1,693	493	1.14	432
1969	1,767.00	1,755	1,413	442	1.63	271
1973	214,270.00	204,510	164,608	60,376	2.73	22,116
1974	4,307.00	4,064	3,271	1,251	3.04	412
1975	4,438.00	4,135	3,328	1,332	3.38	394
1976	1,353.00	1,243	1,000	421	3.75	112
1977	67.00	61	49	21	4.16	5
1978	1,060.00	941	757	356	4.63	77
1979	1,034.00	899	724	362	5.15	70
1980	615.00	523	421	225	5.72	39
1982	1,246.00	1,003	807	501	7.00	72
1984	241.00	182	146	107	8.39	13
1985	1,315.00	961	773	608	9.12	67
1986	658.00	464	373	318	9.87	32
1987	2,863.00	1,939	1,561	1,445	10.65	136
1988	5,149.00	3,341	2,689	2,717	11.46	237
1989	2,591.00	1,606	1,293	1,428	12.29	116
1990	28,674.00	16,921	13,620	16,488	13.14	1,255
1991	12,958.00	7,252	5,837	7,769	14.01	555
1992	202,605.00	107,006	86,128	126,607	14.91	8,491
1993	1,447,854.00	718,621	578,411	941,836	15.82	59,535
1994	5,136,941.00	2,382,436	1,917,600	3,476,188	16.75	207,534
1995	930,828.00	401,015	322,773	654,596	17.69	37,004
1996	347,076.00	138,010	111,083	253,347	18.64	13,592
1997	182,590.00	66,469	53,500	138,220	19.60	7,052
1998	698.00	230	185	548	20.57	27
2000	3,496,140.59	912,965	734,837	2,936,111	22.54	130,262
2001	464,805.91	105,272	84,733	403,313	23.53	17,140
2002	1,487,682.78	285,390	229,708	1,332,359	24.52	54,338
2003	184,921.95	29,067	23,396	170,772	25.51	6,694
2004	299,714.76	36,600	29,458	285,242	26.51	10,760
2005	40,833.27	3,571	2,874	40,001	27.50	1,455
2006	5,868.95	308	248	5,914	28.50	208

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 462.00 TP COMPRESSOR STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R4						
NET SALVAGE PERCENT.. -5						
2007	50,978.72	894	720	52,808	29.50	1,790
	14,587,983.93	5,464,030	4,397,945	10,919,439		587,210
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					18.6	4.03

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 463.00 TP MEASURING & REGULATING STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R2.5						
NET SALVAGE PERCENT.. -5						
1961	1,318.90	1,276	808	577	2.36	244
1962	1,056.00	1,013	642	467	2.58	181
1963	31,092.00	29,601	18,748	13,899	2.80	4,964
1964	30,822.00	29,104	18,434	13,929	3.02	4,612
1965	8,978.00	8,406	5,324	4,103	3.25	1,262
1966	5,076.00	4,712	2,984	2,346	3.48	674
1967	1,872.00	1,722	1,091	875	3.72	235
1968	7,683.00	7,002	4,435	3,632	3.96	917
1969	642.00	579	367	307	4.22	73
1970	11.00	10	6	6	4.48	1
1971	752.65	665	421	369	4.77	77
1972	30,483.00	26,598	16,846	15,161	5.07	2,990
1973	12,309.00	10,602	6,715	6,209	5.39	1,152
1974	25,063.00	21,282	13,479	12,837	5.74	2,236
1975	9,681.00	8,094	5,127	5,038	6.11	825
1976	427.00	351	222	226	6.51	35
1977	4,391.00	3,544	2,245	2,366	6.94	341
1978	25,412.00	20,100	12,731	13,952	7.40	1,885
1979	3,443.00	2,664	1,687	1,928	7.89	244
1980	50,344.00	38,044	24,096	28,765	8.41	3,420
1981	26,018.00	19,170	12,142	15,177	8.95	1,696
1982	27,620.00	19,799	12,540	16,461	9.52	1,729
1983	19,819.00	13,791	8,735	12,075	10.12	1,193
1984	5,014.00	3,380	2,141	3,124	10.74	291
1985	11,650.00	7,593	4,809	7,424	11.38	652
1986	76,461.00	48,034	30,423	49,861	12.05	4,138
1987	9,412.00	5,689	3,603	6,280	12.73	493
1988	190,815.98	110,657	70,087	130,270	13.43	9,700
1989	2,051.70	1,137	720	1,434	14.16	101
1991	605,789.00	304,236	192,694	443,384	15.65	28,331
1992	437,019.94	207,731	131,571	327,300	16.42	19,933
1993	164,715.34	73,729	46,698	126,253	17.21	7,336
1994	198,822.66	83,443	52,850	155,914	18.01	8,657
1995	4,776.00	1,867	1,183	3,832	18.83	204
1996	269,326.15	97,479	61,740	221,052	19.66	11,244

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 463.00 TP MEASURING & REGULATING STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R2.5						
NET SALVAGE PERCENT.. -5						
1997	105,293.29	34,969	22,148	88,410	20.51	4,311
1998	2,725.00	824	522	2,339	21.36	110
1999	48,902.39	13,299	8,423	42,925	22.23	1,931
2000	317,028.88	76,463	48,429	284,451	23.11	12,309
2001	22,219.49	4,666	2,955	20,375	24.00	849
2002	697,879.87	124,572	78,901	653,873	24.90	26,260
2003	280,066.34	41,082	26,020	268,050	25.81	10,386
2004	729,066.54	83,442	52,850	712,670	26.73	26,662
2005	201,325.18	16,552	10,484	200,907	27.65	7,266
2006	121,730.27	6,007	3,804	124,013	28.59	4,338
2007	13,297.68	219	139	13,824	29.53	468
	4,839,702.25	1,615,199	1,023,019	4,058,670		216,956

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 18.7 4.48

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 464.00 TP OTHER STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R3						
NET SALVAGE PERCENT.. -5						
1968	1.00	1	1			
1973	7,845.00	6,519	6,307	1,930	7.30	264
1975	1,992.00	1,594	1,542	550	8.32	66
1978	6,315.00	4,727	4,573	2,058	10.05	205
1979	10,826.00	7,901	7,644	3,723	10.67	349
1981	2,210.00	1,525	1,475	846	11.99	71
1982	6,746.00	4,517	4,370	2,713	12.68	214
1983	8,869.00	5,750	5,563	3,749	13.39	280
1984	1,468.00	920	890	651	14.12	46
1987	13,258.53	7,398	7,158	6,763	16.40	412
1988	8,040.00	4,294	4,154	4,288	17.20	249
1989	1,673.00	853	825	932	18.00	52
1990	2,607.00	1,265	1,224	1,513	18.83	80
1991	25,850.00	11,897	11,510	15,633	19.66	795
1992	281.00	122	118	177	20.51	9
1993	17,511.00	7,154	6,922	11,465	21.38	536
1994	16,648.00	6,368	6,161	11,319	22.25	509
1995	8,582.00	3,054	2,955	6,056	23.14	262
1996	71,901.00	23,638	22,870	52,626	24.04	2,189
1997	10,054.00	3,031	2,933	7,624	24.95	306
1999	85,877.00	21,127	20,441	69,730	26.80	2,602
2000	72,839.66	15,862	15,347	61,135	27.74	2,204
2001	3,900,647.49	738,451	714,457	3,381,223	28.69	117,854
2002	569,095.64	91,365	88,396	509,154	29.65	17,172
2003	9,427.20	1,241	1,201	8,698	30.61	284
2004	391,073.47	40,118	38,814	371,813	31.58	11,774
2005	345,692.77	25,408	24,582	338,395	32.55	10,396
2006	21,130.43	932	902	21,285	33.53	635
2007	224,402.12	3,299	3,192	232,430	34.51	6,735
	5,842,863.31	1,040,331	1,006,527	5,128,479		176,550
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					29.0	3.02

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 465.00 TP TRANSMISSION PIPELINE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R3						
NET SALVAGE PERCENT.. -10						
1959	13,928,583.88	10,590,181	11,321,433	4,000,009	18.53	215,867
1961	87,585.07	64,483	68,936	27,408	19.84	1,381
1963	9,482,954.69	6,746,933	7,212,809	3,218,441	21.19	151,885
1964	618,381.66	432,076	461,911	218,309	21.89	9,973
1965	56,161.71	38,506	41,165	20,613	22.60	912
1966	3,958,297.90	2,661,678	2,845,467	1,508,661	23.32	64,694
1967	481,659.13	317,471	339,392	190,433	24.05	7,918
1968	932,886.52	602,160	643,739	382,436	24.79	15,427
1969	1,471,549.74	929,946	994,159	624,546	25.53	24,463
1970	915,237.43	565,598	604,653	402,108	26.29	15,295
1971	866,035.79	522,999	559,112	393,527	27.06	14,543
1972	8,222,124.44	4,847,765	5,182,503	3,861,834	27.84	138,715
1973	472,754.05	271,871	290,644	229,385	28.63	8,012
1974	93,320.09	52,322	55,935	46,717	29.42	1,588
1975	305,189.74	166,579	178,081	157,628	30.23	5,214
1976	18,136,238.40	9,629,799	10,294,736	9,655,126	31.04	311,054
1977	4,600,679.99	2,373,491	2,537,380	2,523,368	31.86	79,202
1978	1,176,523.29	589,109	629,787	664,389	32.69	20,324
1979	12,981,308.30	6,300,089	6,735,110	7,544,329	33.53	225,002
1980	941,723.69	442,328	472,871	563,025	34.38	16,377
1981	1,880,376.32	853,841	912,799	1,155,615	35.23	32,802
1982	2,417,194.71	1,059,577	1,132,741	1,526,173	36.09	42,288
1983	10,918,218.25	4,611,855	4,930,303	7,079,737	36.96	191,551
1984	1,858,371.52	754,926	807,054	1,237,155	37.84	32,694
1985	871,401.63	339,995	363,472	595,070	38.72	15,369
1986	5,638,737.08	2,107,647	2,253,180	3,949,431	39.61	99,708
1987	2,797,507.73	999,494	1,068,509	2,008,750	40.51	49,587
1988	1,245,843.79	424,559	453,875	916,553	41.41	22,134
1989	731,505.75	237,132	253,506	551,150	42.32	13,023
1990	1,386,991.22	426,125	455,549	1,070,141	43.24	24,749
1991	4,003,532.62	1,162,626	1,242,905	3,160,981	44.16	71,580
1992	53,187,964.17	14,550,631	15,555,352	42,951,409	45.08	952,782
1993	6,764,659.91	1,733,782	1,853,500	5,587,626	46.02	121,417
1994	32,168,855.96	7,689,322	8,220,269	27,165,473	46.96	578,481
1995	8,128,285.34	1,803,423	1,927,949	7,013,165	47.90	146,413

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 465.00 TP TRANSMISSION PIPELINE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R3						
NET SALVAGE PERCENT.. -10						
1996	3,520,771.61	719,575	769,262	3,103,587	48.85	63,533
1997	2,957,361.54	553,027	591,213	2,661,885	49.80	53,452
1998	10,370,480.20	1,759,041	1,880,503	9,527,025	50.75	187,725
1999	5,176,624.61	786,950	841,289	4,852,998	51.71	93,850
2000	323,502,703.03	43,414,063	46,411,802	309,441,171	52.68	5,873,978
2001	50,807,910.87	5,913,025	6,321,319	49,567,383	53.65	923,903
2002	14,227,832.95	1,403,860	1,500,796	14,149,820	54.62	259,059
2003	7,343,545.58	593,726	634,723	7,443,177	55.59	133,894
2004	45,335,453.20	2,857,494	3,054,804	46,814,195	56.56	827,691
2005	9,526,260.60	429,634	459,300	10,019,587	57.54	174,133
2006	8,939,870.11	242,896	259,668	9,574,189	58.52	163,605
2007	4,951,156.50	44,659	47,743	5,398,529	59.51	90,716
	700,388,612.31	145,618,269	155,673,208	614,754,267		12,567,963
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					48.9	1.79

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 466.00 TP COMPRESSOR EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

SURVIVOR CURVE.. IOWA 33-R3
NET SALVAGE PERCENT.. -10

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1970	6,687.00	6,279	5,594	1,762	4.83	365
1972	306.00	280	249	88	5.57	16
1973	644,747.84	580,499	517,135	192,088	5.99	32,068
1974	198,744.58	176,032	156,817	61,802	6.43	9,612
1975	447.00	389	347	145	6.90	21
1976	721,484.00	615,700	548,494	245,138	7.40	33,127
1977	44,347.00	37,074	33,027	15,755	7.92	1,989
1978	618,637.00	505,612	450,422	230,079	8.48	27,132
1979	8,649.00	6,902	6,149	3,365	9.06	371
1980	484.00	376	335	197	9.67	20
1981	5,372.00	4,065	3,621	2,288	10.30	222
1982	8,744.00	6,424	5,723	3,895	10.96	355
1983	47,761.00	34,007	30,295	22,242	11.64	1,911
1984	7,165.00	4,935	4,396	3,486	12.34	282
1985	8,982.00	5,970	5,318	4,562	13.06	349
1986	15,266.00	9,770	8,704	8,089	13.80	586
1987	83,290.00	51,197	45,609	46,010	14.56	3,160
1988	13,971.00	8,230	7,332	8,036	15.33	524
1989	21,802.00	12,267	10,928	13,054	16.12	810
1990	45,444.00	24,344	21,687	28,301	16.93	1,672
1991	125,467.00	63,776	56,815	81,199	17.75	4,575
1992	2,446,389.00	1,175,172	1,046,897	1,644,131	18.59	88,442
1993	4,522,183.00	2,043,981	1,820,872	3,153,529	19.44	162,219
1994	21,519,773.01	9,101,788	8,108,291	15,563,459	20.31	766,295
1995	4,253,118.00	1,675,814	1,492,892	3,185,538	21.18	150,403
1996	1,309,463.20	476,632	424,606	1,015,804	22.08	46,006
1997	2,118,847.00	707,610	630,371	1,700,361	22.98	73,993
1998	145,405.00	44,161	39,341	120,605	23.89	5,048
1999	43,853.00	11,958	10,653	37,585	24.82	1,514
2000	51,436,146.91	12,413,600	11,058,604	45,521,158	25.76	1,767,126
2001	5,062,190.94	1,063,009	946,977	4,621,433	26.70	173,087
2002	5,441,761.30	970,320	864,406	5,121,531	27.65	185,227
2003	613,683.56	89,782	79,982	595,070	28.61	20,799
2004	3,226,723.55	367,717	327,579	3,221,817	29.58	108,919
2005	1,501,255.90	122,533	109,158	1,542,223	30.55	50,482

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 466.00 TP COMPRESSOR EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 33-R3						
NET SALVAGE PERCENT.. -10						
2006	17,512.11	857	764	18,499	31.53	587
2007	15,007.23	244	217	16,291	32.51	501
	106,301,110.13	32,419,306	28,880,607	88,050,615		3,719,815

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 23.7 3.50

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 467.10 TP MEAS/REG EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-R2.5						
NET SALVAGE PERCENT.. -5						
1962	8,842.00	9,191	4,078	5,206	0.25	5,206
1963	418,946.00	431,095	191,268	248,625	0.50	248,625
1964	229,268.00	233,413	103,561	137,170	0.76	137,170
1965	38,240.00	38,498	17,081	23,071	1.03	22,399
1966	55,858.00	55,578	24,659	33,992	1.31	25,948
1967	16,041.00	15,785	7,003	9,840	1.57	6,268
1968	70,545.00	68,739	30,498	43,574	1.80	24,208
1969	158,130.00	152,621	67,715	98,322	2.02	48,674
1970	16,968.00	16,220	7,196	10,620	2.24	4,741
1971	20,842.00	19,731	8,754	13,130	2.46	5,337
1972	84,358.00	79,045	35,071	53,505	2.69	19,890
1973	8,591.19	7,967	3,535	5,486	2.92	1,879
1974	28,260.00	25,922	11,501	18,172	3.16	5,751
1975	37,276.00	33,801	14,997	24,143	3.41	7,080
1976	95,233.00	85,315	37,853	62,142	3.67	16,932
1977	36,607.00	32,364	14,359	24,078	3.95	6,096
1978	279,723.08	243,779	108,160	185,549	4.25	43,659
1979	11,656.00	9,997	4,435	7,804	4.58	1,704
1980	241,380.00	203,469	90,275	163,174	4.93	33,098
1981	91,127.28	75,322	33,419	62,265	5.32	11,704
1982	138,922.85	112,319	49,834	96,035	5.75	16,702
1983	141,529.99	111,693	49,556	99,050	6.21	15,950
1984	36,812.00	28,294	12,553	26,100	6.70	3,896
1985	117,321.00	87,561	38,849	84,338	7.23	11,665
1986	93,331.39	67,462	29,932	68,066	7.79	8,738
1987	82,446.18	57,551	25,534	61,034	8.38	7,283
1988	57,254.66	38,475	17,071	43,046	9.00	4,783
1989	274,673.53	177,082	78,568	209,839	9.65	21,745
1990	345,202.00	212,838	94,432	268,030	10.32	25,972
1991	455,424.96	267,407	118,643	359,553	11.02	32,627
1992	1,627,913.01	906,617	402,248	1,307,061	11.74	111,334
1993	1,908,711.42	1,003,677	445,312	1,558,835	12.48	124,907
1994	964,362.54	476,723	211,513	801,068	13.23	60,549
1995	1,265,940.47	584,333	259,257	1,069,980	14.01	76,373
1996	2,113,045.74	904,341	401,238	1,817,460	14.81	122,718

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 467.10 TP MEAS/REG EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-R2.5						
NET SALVAGE PERCENT.. -5						
1997	1,209,948.87	476,671	211,489	1,058,957	15.62	67,795
1998	196,129.11	70,348	31,212	174,724	16.46	10,615
1999	141,713.25	45,830	20,334	128,465	17.30	7,426
2000	3,238,478.61	930,350	412,778	2,987,625	18.16	164,517
2001	421,255.69	105,449	46,786	395,532	19.04	20,774
2002	2,393,976.35	509,773	226,176	2,287,499	19.93	114,777
2003	3,655,542.79	640,232	284,058	3,554,262	20.83	170,632
2004	2,942,363.73	402,868	178,745	2,910,737	21.74	133,889
2005	685,574.05	67,378	29,894	689,959	22.66	30,448
2006	466,991.02	27,655	12,270	478,071	23.59	20,266
2007	990,454.53	19,552	8,675	1,031,302	24.53	42,042
	27,913,211.29	10,170,331	4,512,375	24,796,496		2,104,792
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					11.8	7.54

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 467.20 TP TELEMENTRY EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 17-R2						
NET SALVAGE PERCENT.. 0						
1975	8,837.00	8,837	8,837			
1976	7,003.00	6,978	7,003			
1977	4,978.00	4,899	4,978			
1979	2,150.00	2,048	2,150			
1980	32,818.00	30,714	32,818			
1981	27,704.00	25,454	27,704			
1982	26,627.93	24,013	26,628			
1983	25,404.18	22,475	25,404			
1984	38,527.10	33,407	38,527			
1985	13,989.04	11,874	13,989			
1986	523,549.34	434,232	523,549			
1987	69,419.00	56,188	69,419			
1988	60,092.00	47,298	60,092			
1989	12,756.00	9,732	12,756			
1990	7,946.00	5,857	7,946			
1991	122,263.00	86,733	122,263			
1992	128,060.26	86,927	128,060			
1993	530,077.88	343,013	530,078			
1994	174,680.06	107,061	174,680			
1995	225,916.00	130,376	225,916			
1996	59,774.84	32,207	59,775			
1997	220,571.15	110,153	220,571			
1998	217,198.82	99,520	217,199			
1999	785,928.87	326,396	785,929			
2000	406,849.42	151,023	406,849			
2001	422,744.92	137,519	418,694	4,051	11.47	353
2002	91,796.90	25,593	77,921	13,876	12.26	1,132
2003	120,202.27	27,719	84,394	35,808	13.08	2,738
2004	325,998.07	59,071	179,849	146,149	13.92	10,499
2005	159,042.52	20,771	63,240	95,803	14.78	6,482
2006	1,137,481.59	89,634	272,902	864,580	15.66	55,209
2007	74,943.49	1,986	6,047	68,896	16.55	4,163
	6,065,330.65	2,559,708	4,836,167	1,229,163		80,576

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 15.3 1.33

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 467.30 TP MEASUREMENT/REGULATOR EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-R2.5						
NET SALVAGE PERCENT.. -5						
2004	32,220.01	4,412	4,371	29,460	21.74	1,355
2005	6,496.05	638	632	6,189	22.66	273
	38,716.06	5,050	5,003	35,649		1,628

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 21.9 4.20

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 468.00 TP COMMUNICATIONS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-R2						
NET SALVAGE PERCENT.. 0						
1991	5,633.00	4,326	5,063	570	3.48	164
1992	5,981.00	4,418	5,171	810	3.92	207
1993	1,887.17	1,335	1,563	324	4.39	74
1994	90,312.50	60,753	71,107	19,206	4.91	3,912
1995	19,955.41	12,692	14,855	5,100	5.46	934
1996	28,283.00	16,876	19,752	8,531	6.05	1,410
1997	4,120.00	2,285	2,674	1,446	6.68	216
1999	5,223.00	2,423	2,836	2,387	8.04	297
2001	157,949.54	57,699	67,533	90,417	9.52	9,498
2002	5,994.21	1,878	2,198	3,796	10.30	369
2004	20,547.00	4,192	4,906	15,641	11.94	1,310
	345,885.83	168,877	197,658	148,228		18,391
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					8.1	5.32

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 471.00 DS LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1957	1,089.00	694	9	1,080	27.23	40
1959	4,423.00	2,721	36	4,387	28.85	152
1960	73.00	44	1	72	29.68	2
1961	315.00	187	2	313	30.51	10
1962	389.00	226	3	386	31.35	12
1963	2,609.00	1,488	20	2,589	32.21	80
1964	5,228.00	2,923	38	5,190	33.07	157
1965	915.00	501	7	908	33.94	27
1966	998.00	535	7	991	34.81	28
1967	9.00	5		9	35.70	
1968	113.00	58	1	112	36.59	3
1969	1,244.00	622	8	1,236	37.49	33
1970	2,790.00	1,362	18	2,772	38.40	72
1971	832.00	396	5	827	39.32	21
1972	1,352.00	627	8	1,344	40.24	33
1973	2,134.00	963	13	2,121	41.16	52
1974	3,637.00	1,596	21	3,616	42.10	86
1975	2,228.00	949	12	2,216	43.04	51
1976	2,311.00	956	13	2,298	43.98	52
1977	587.00	235	3	584	44.93	13
1978	2,714.00	1,054	14	2,700	45.88	59
1979	5,004.00	1,879	25	4,979	46.84	106
1980	1,968.00	714	9	1,959	47.80	41
1981	7,491.00	2,620	35	7,456	48.77	153
1982	29,555.00	9,957	131	29,424	49.73	592
1983	70,557.00	22,853	301	70,256	50.71	1,385
1984	49,272.00	15,319	202	49,070	51.68	949
1985	29,396.00	8,757	115	29,281	52.66	556
1986	7,254.00	2,066	27	7,227	53.64	135
1987	21,203.00	5,761	76	21,127	54.62	387
1988	21,466.00	5,553	73	21,393	55.60	385
1989	37,052.00	9,096	120	36,932	56.59	653
1990	59,753.00	13,881	183	59,570	57.58	1,035
1991	6,755.00	1,480	19	6,736	58.57	115
1992	6,759.00	1,392	18	6,741	59.56	113

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 471.00 DS LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1993	28,462.00	5,485	72	28,390	60.55	469
1994	17,628.00	3,164	42	17,586	61.54	286
1995	10,578.00	1,759	23	10,555	62.53	169
1996	2,734.00	418	6	2,728	63.53	43
1997	25,198.00	3,520	46	25,152	64.52	390
1999	801.00	91	1	800	66.52	12
2000	15,948.50	1,593	21	15,928	67.51	236
2001	57,773.96	4,997	66	57,708	68.51	842
2002	110,483.55	8,087	107	110,377	69.51	1,588
2003	25,303.91	1,516	20	25,284	70.51	359
2004	24,304.22	1,135	15	24,289	71.50	340
2006	144,490.31	2,890	38	144,452	73.50	1,965
2007	185,720.55	1,244	16	185,705	74.50	2,493
	1,038,901.00	155,369	2,046	1,036,856		16,780

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 61.8 1.62

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 472.00 DS STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 28-L1						
NET SALVAGE PERCENT.. -5						
1959	3,509.00	2,679	2,602	1,082	7.64	142
1961	72,460.67	54,073	52,526	23,558	8.10	2,908
1962	204.00	150	146	68	8.34	8
1963	28,510.93	20,773	20,179	9,757	8.57	1,139
1964	2,421.00	1,741	1,691	851	8.82	96
1965	33,722.00	23,950	23,265	12,143	9.06	1,340
1966	1,822.00	1,277	1,240	673	9.31	72
1967	1,324.75	916	890	501	9.57	52
1968	309.00	211	205	119	9.82	12
1969	63.00	42	41	25	10.09	2
1970	225.77	149	145	92	10.35	9
1971	6,038.88	3,936	3,823	2,518	10.62	237
1972	6,269.19	4,020	3,905	2,678	10.90	246
1973	17,003.16	10,724	10,417	7,436	11.18	665
1974	13,522.49	8,387	8,147	6,052	11.46	528
1975	7,057.46	4,301	4,178	3,232	11.75	275
1976	8,487.00	5,079	4,934	3,977	12.04	330
1977	3,801.00	2,232	2,168	1,823	12.34	148
1978	1,979.00	1,139	1,106	972	12.65	77
1979	40.27	23	22	20	12.95	2
1980	15,026.00	8,300	8,063	7,714	13.27	581
1981	41,908.30	22,644	21,996	22,008	13.59	1,619
1982	58,789.49	31,043	30,155	31,574	13.92	2,268
1983	127,690.99	65,844	63,960	70,116	14.25	4,920
1984	63,535.00	31,948	31,034	35,678	14.59	2,445
1985	72,224.00	35,370	34,358	41,477	14.94	2,776
1986	34,592.09	16,486	16,014	20,308	15.29	1,328
1987	78,585.24	36,397	35,356	47,159	15.65	3,013
1988	22,252.77	10,005	9,719	13,646	16.01	852
1989	56,134.23	24,437	23,738	35,203	16.39	2,148
1990	33,968.35	14,306	13,897	21,770	16.77	1,298
1991	177,509.21	72,150	70,086	116,299	17.16	6,777
1992	174,263.79	68,232	66,280	116,697	17.56	6,646
1993	181,993.00	68,449	66,491	124,602	17.97	6,934
1994	461,707.85	165,848	161,103	323,690	18.42	17,573

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 472.00 DS STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 28-L1						
NET SALVAGE PERCENT.. -5						
1995	882,327.15	301,743	293,111	633,333	18.88	33,545
1996	974,795.56	314,737	305,733	717,802	19.39	37,019
1997	656,575.98	198,686	193,002	496,403	19.93	24,907
1998	253,877.77	71,415	69,372	197,200	20.50	9,620
1999	413,216.00	106,604	103,554	330,323	21.12	15,640
2000	351,110.21	81,770	79,431	289,235	21.79	13,274
2001	540,315.38	111,651	108,457	458,874	22.49	20,403
2002	94,381.32	16,847	16,365	82,735	23.24	3,560
2003	238,731.61	35,545	34,528	216,140	24.03	8,995
2004	1,243,756.11	146,919	142,716	1,163,228	24.85	46,810
2005	2,822,089.66	242,389	235,454	2,727,740	25.71	106,096
2006	2,625,507.90	136,736	132,823	2,623,960	26.61	98,608
2007	939,915.47	16,580	16,106	970,805	27.53	35,264
	13,845,551.00	2,598,883	2,524,532	12,013,296		523,207

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 23.0 3.78

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 473.00 DS SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R2.5						
NET SALVAGE PERCENT.. -50						
1959	1,634,411.62	1,717,848	643,746	1,807,871	16.46	109,834
1960	156,773.15	162,378	60,850	174,310	17.02	10,241
1962	168,653.39	169,269	63,432	189,548	18.20	10,415
1963	6,498,451.95	6,415,922	2,404,303	7,343,375	18.80	390,605
1964	1,144,998.32	1,111,049	416,355	1,301,142	19.42	67,000
1965	1,053,332.83	1,003,774	376,154	1,203,845	20.06	60,012
1966	1,117,110.75	1,044,945	391,583	1,284,083	20.70	62,033
1967	1,172,448.14	1,075,604	403,072	1,355,600	21.36	63,464
1968	1,094,424.36	984,161	368,805	1,272,832	22.03	57,777
1969	1,358,684.16	1,196,525	448,386	1,589,640	22.71	69,997
1970	1,790,364.40	1,542,847	578,167	2,107,380	23.40	90,059
1971	1,927,389.49	1,624,211	608,657	2,282,427	24.10	94,707
1972	1,950,987.89	1,606,346	601,962	2,324,520	24.81	93,693
1973	2,726,081.27	2,190,952	821,037	3,268,085	25.53	128,010
1974	3,435,997.20	2,692,963	1,009,161	4,144,835	26.26	157,838
1975	4,002,328.41	3,056,378	1,145,347	4,858,146	27.00	179,931
1976	3,816,067.83	2,836,292	1,062,872	4,661,230	27.75	167,972
1977	6,135,291.93	4,433,975	1,661,588	7,541,350	28.50	264,609
1978	6,634,215.83	4,655,229	1,744,501	8,206,823	29.27	280,383
1979	4,906,496.79	3,338,380	1,251,025	6,108,720	30.05	203,285
1980	7,713,966.09	5,085,432	1,905,715	9,665,234	30.83	313,501
1981	10,735,975.04	6,845,794	2,565,393	13,538,570	31.62	428,165
1982	15,510,536.99	9,550,613	3,578,997	19,686,808	32.42	607,243
1983	12,856,328.50	7,632,802	2,860,316	16,424,177	33.23	494,258
1984	14,008,455.18	8,003,731	2,999,318	18,013,365	34.05	529,027
1985	13,887,212.61	7,624,080	2,857,048	17,973,771	34.87	515,451
1986	12,827,846.70	6,751,937	2,530,221	16,711,549	35.70	468,111
1987	18,380,543.14	9,252,765	3,467,382	24,103,433	36.54	659,645
1988	15,856,525.19	7,620,646	2,855,761	20,929,027	37.38	559,899
1989	20,514,619.42	9,376,207	3,513,640	27,258,289	38.24	712,821
1990	22,504,328.09	9,765,753	3,659,619	30,096,873	39.09	769,938
1991	23,583,201.63	9,675,008	3,625,613	31,749,189	39.96	794,524
1992	25,225,471.89	9,747,122	3,652,637	34,185,571	40.83	837,266
1993	31,432,265.37	11,391,053	4,268,683	42,879,715	41.71	1,028,044
1994	27,612,206.69	9,343,971	3,501,560	37,916,750	42.59	890,274

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 473.00 DS SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R2.5						
NET SALVAGE PERCENT.. -50						
1995	27,067,030.42	8,505,814	3,187,469	37,413,077	43.48	860,466
1996	16,377,848.05	4,743,844	1,777,708	22,789,064	44.38	513,499
1997	15,266,040.35	4,046,264	1,516,297	21,382,764	45.28	472,234
1998	12,616,878.78	3,035,621	1,137,569	17,787,749	46.18	385,183
1999	4,020,841.39	867,295	325,010	5,706,252	47.09	121,178
2000	3,661,268.49	698,021	261,576	5,230,327	48.01	108,942
2001	9,143,146.59	1,514,105	567,396	13,147,324	48.93	268,697
2002	3,513,499.78	493,295	184,857	5,085,393	49.85	102,014
2003	13,215,743.72	1,520,471	569,782	19,253,834	50.78	379,162
2004	56,242,919.97	5,044,990	1,890,560	82,473,820	51.71	1,594,930
2005	36,583,227.72	2,343,156	878,074	53,996,768	52.65	1,025,580
2006	26,155,684.85	1,012,225	379,322	38,854,205	53.58	725,162
2007	28,788,197.65	367,050	137,548	43,044,748	54.53	789,377
	578,026,320.00	204,718,113	76,716,074	790,323,408		19,516,456
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					40.5	3.38

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 473.01 LILO DS SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. -50						
2001	13,037,587.25	3,177,912	5,942,665	13,613,716	33.50	406,380
2002	8,263,418.29	1,704,330	3,187,081	9,208,046	34.50	266,900
2003	369,203.42	62,303	116,506	437,299	35.50	12,318
2004	19,720,905.69	2,588,369	4,840,225	24,741,134	36.50	677,839
2005	1,911,439.24	179,197	335,097	2,532,062	37.50	67,522
	43,302,553.89	7,712,111	14,421,574	50,532,257		1,430,959
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					35.3	3.30

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 474.00 DS METERS/REGULATORS INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R2						
NET SALVAGE PERCENT.. 0						
1959	303,837.00	284,179	40,645	263,192	1.94	135,666
1960	90,821.00	84,073	12,025	78,796	2.23	35,335
1961	592,195.00	542,451	77,585	514,610	2.52	204,210
1962	67,527.00	61,200	8,753	58,774	2.81	20,916
1963	118,276.00	106,058	15,169	103,107	3.10	33,260
1964	189,712.00	168,275	24,068	165,644	3.39	48,863
1965	146,614.00	128,624	18,397	128,217	3.68	34,842
1966	202,312.00	175,465	25,096	177,216	3.98	44,527
1967	140,435.00	120,353	17,214	123,221	4.29	28,723
1968	263,980.65	223,512	31,968	232,013	4.60	50,438
1969	27,566.00	23,045	3,296	24,270	4.92	4,933
1970	163,885.65	135,156	19,331	144,555	5.26	27,482
1971	78,951.00	64,187	9,180	69,771	5.61	12,437
1972	125,215.00	100,297	14,345	110,870	5.97	18,571
1973	170,042.00	133,993	19,164	150,878	6.36	23,723
1974	237,087.00	183,742	26,280	210,807	6.75	31,231
1975	239,792.00	182,482	26,100	213,692	7.17	29,804
1976	366,549.00	273,556	39,126	327,423	7.61	43,025
1977	410,594.00	300,267	42,946	367,648	8.06	45,614
1978	543,042.00	388,438	55,557	487,485	8.54	57,083
1979	385,888.00	269,736	38,579	347,309	9.03	38,462
1980	347,727.00	237,045	33,904	313,823	9.55	32,861
1981	638,361.23	423,680	60,597	577,764	10.09	57,261
1982	856,881.00	552,945	79,085	777,796	10.64	73,101
1983	532,420.00	333,455	47,693	484,727	11.21	43,241
1984	631,113.00	382,644	54,728	576,385	11.81	48,805
1985	762,234.00	446,669	63,885	698,349	12.42	56,228
1986	697,301.00	393,975	56,349	640,952	13.05	49,115
1987	1,844,341.00	1,002,768	143,422	1,700,919	13.69	124,245
1988	1,758,574.00	916,745	131,118	1,627,456	14.36	113,333
1989	1,591,284.00	793,573	113,502	1,477,782	15.04	98,257
1990	2,272,455.00	1,081,007	154,612	2,117,843	15.73	134,637
1991	10,519,828.00	4,754,962	680,083	9,839,745	16.44	598,525
1992	3,005,783.55	1,285,574	183,870	2,821,914	17.17	164,351
1993	3,817,770.63	1,538,562	220,054	3,597,717	17.91	200,878

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 474.00 DS METERS/REGULATORS INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R2						
NET SALVAGE PERCENT.. 0						
1994	10,965,922.37	4,145,119	592,860	10,373,062	18.66	555,898
1995	9,456,189.04	3,331,415	476,479	8,979,710	19.43	462,157
1996	6,238,383.00	2,035,584	291,141	5,947,242	20.21	294,272
1997	9,115,878.00	2,734,763	391,142	8,724,736	21.00	415,464
1998	3,267,944.30	892,149	127,600	3,140,344	21.81	143,986
1999	7,572,752.34	1,860,625	266,118	7,306,634	22.63	322,874
2000	1,747,132.29	380,875	54,475	1,692,657	23.46	72,151
2001	210,381.53	39,972	5,717	204,665	24.30	8,422
2002	5,099,292.51	824,556	117,933	4,981,360	25.15	198,066
2003	3,777,299.12	502,381	71,854	3,705,445	26.01	142,462
2004	7,237,219.42	752,671	107,651	7,129,568	26.88	265,237
2005	11,184,313.61	835,468	119,494	11,064,820	27.76	398,589
2006	8,815,657.85	396,705	56,739	8,758,919	28.65	305,721
2007	8,499,153.91	127,487	18,234	8,480,920	29.55	287,002
	127,327,914.00	36,952,463	5,285,163	122,042,752		6,636,284

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 18.4 5.21

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 474.01 LILO DS METERS/REGULATORS INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 30-SQUARE						
NET SALVAGE PERCENT.. 0						
2001	6,523,815.00	1,413,711	3,847,174	2,676,641	23.50	113,900
2002	1,599,767.44	293,237	797,995	801,772	24.50	32,725
2003	8,985.21	1,348	3,668	5,317	25.50	209
2004	7,435,013.87	867,666	2,361,206	5,073,808	26.50	191,464
2005	502,351.85	41,846	113,877	388,475	27.50	14,126
2006	199.63	10	27	173	28.50	6
	16,070,133.00	2,617,818	7,123,947	8,946,186		352,430
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					25.4	2.19

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 475.00 DS MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R3						
NET SALVAGE PERCENT.. -20						
1958	64,732.00	54,515	41,502	36,176	17.89	2,022
1959	5,065,364.27	4,201,416	3,198,514	2,879,923	18.53	155,419
1960	178,134.81	145,422	110,709	103,053	19.18	5,373
1961	103,101.67	82,807	63,040	60,682	19.84	3,059
1962	251,454.49	198,609	151,200	150,545	20.51	7,340
1963	53,629,486.09	41,625,062	31,688,918	32,666,465	21.19	1,541,598
1964	3,336,693.39	2,543,361	1,936,246	2,067,786	21.89	94,463
1965	3,771,871.16	2,821,209	2,147,770	2,378,475	22.60	105,242
1966	3,956,205.35	2,902,114	2,209,363	2,538,083	23.32	108,837
1967	4,851,628.70	3,488,515	2,655,786	3,166,168	24.05	131,649
1968	5,766,846.63	4,060,783	3,091,450	3,828,766	24.79	154,448
1969	5,881,396.98	4,054,635	3,086,770	3,970,906	25.53	155,539
1970	8,205,989.52	5,532,150	4,211,594	5,635,593	26.29	214,363
1971	6,786,576.10	4,470,996	3,403,743	4,740,148	27.06	175,172
1972	6,326,738.05	4,069,358	3,097,979	4,494,107	27.84	161,426
1973	6,706,163.36	4,207,179	3,202,901	4,844,495	28.63	169,210
1974	9,903,648.41	6,057,468	4,611,515	7,272,863	29.42	247,208
1975	11,373,106.01	6,772,002	5,155,486	8,492,241	30.23	280,921
1976	16,059,007.26	9,302,019	7,081,573	12,189,236	31.04	392,694
1977	13,795,334.73	7,764,014	5,910,699	10,643,703	31.86	334,077
1978	14,246,170.27	7,781,828	5,924,260	11,171,144	32.69	341,730
1979	14,830,068.13	7,851,631	5,977,401	11,818,681	33.53	352,481
1980	15,806,676.98	8,099,341	6,165,981	12,802,031	34.38	372,369
1981	17,180,005.41	8,510,287	6,478,832	14,137,174	35.23	401,282
1982	27,467,464.98	13,134,942	9,999,555	22,961,403	36.09	636,226
1983	29,252,096.01	13,479,366	10,261,763	24,840,752	36.96	672,098
1984	17,854,763.66	7,912,517	6,023,753	15,401,963	37.84	407,029
1985	14,981,425.71	6,376,694	4,854,540	13,123,171	38.72	338,925
1986	19,552,653.18	7,972,790	6,069,639	17,393,545	39.61	439,120
1987	20,818,831.26	8,114,348	6,177,406	18,805,192	40.51	464,211
1988	12,268,214.04	4,560,831	3,472,134	11,249,723	41.41	271,667
1989	9,981,941.50	3,530,014	2,687,379	9,290,951	42.32	219,540
1990	17,282,119.80	5,792,275	4,409,625	16,328,919	43.24	377,635
1991	12,499,738.11	3,959,917	3,014,662	11,985,024	44.16	271,400
1992	23,749,688.70	7,087,857	5,395,944	23,103,682	45.08	512,504

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 475.00 DS MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R3						
NET SALVAGE PERCENT.. -20						
1993	24,811,382.07	6,937,262	5,281,297	24,492,361	46.02	532,211
1994	27,392,512.11	7,142,871	5,437,826	27,433,189	46.96	584,182
1995	32,927,281.51	7,969,719	6,067,301	33,445,437	47.90	698,235
1996	14,443,045.72	3,220,221	2,451,536	14,880,119	48.85	304,608
1997	15,072,250.40	3,074,739	2,340,781	15,745,919	49.80	316,183
1998	12,776,419.92	2,364,149	1,799,813	13,531,891	50.75	266,638
1999	14,198,112.06	2,354,615	1,792,555	15,245,179	51.71	294,821
2000	12,329,027.32	1,804,970	1,374,113	13,420,720	52.68	254,759
2001	10,560,031.82	1,340,702	1,020,669	11,651,369	53.65	217,174
2002	6,732,323.96	724,667	551,685	7,527,104	54.62	137,809
2003	16,820,588.94	1,483,576	1,129,438	19,055,269	55.59	342,782
2004	83,833,868.55	5,764,417	4,388,417	96,212,225	56.56	1,701,065
2005	30,715,324.80	1,511,194	1,150,463	35,707,927	57.54	620,576
2006	33,679,365.29	998,256	759,966	39,655,272	58.52	677,636
2007	20,652,499.81	203,221	154,711	24,628,289	59.51	413,851
	790,729,371.00	275,412,851	209,670,203	739,205,039		17,880,807
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					41.3	2.26

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 475.01 LILO DS MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. -20						
1983	5.21	4	6			
1985	2.37	2	3			
2001	12,448,127.66	2,427,385	6,021,977	8,915,776	33.50	266,143
2002	6,921,230.51	1,142,003	2,833,137	5,472,340	34.50	158,619
2003	307,406.83	41,500	102,955	265,933	35.50	7,491
2004	18,314,092.18	1,922,980	4,770,624	17,206,287	36.50	471,405
2005	1,752,682.79	131,451	326,110	1,777,109	37.50	47,390
	39,743,547.55	5,665,325	14,054,812	33,637,445		951,048
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					35.4	2.39

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 476.00 DS NGV FUEL EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-R3						
NET SALVAGE PERCENT.. 0						
1983	17,290.01	17,048	9,009	8,281	0.21	8,281
1984	9,047.00	8,782	4,641	4,406	0.44	4,406
1985	23,417.00	22,340	11,806	11,611	0.69	11,611
1986	14,163.49	13,275	7,015	7,148	0.94	7,148
1987	59,625.11	54,855	28,989	30,636	1.20	25,530
1988	5,417.91	4,891	2,585	2,833	1.46	1,940
1989	80,524.98	71,184	37,618	42,907	1.74	24,659
1990	25,904.79	22,382	11,828	14,077	2.04	6,900
1991	25,410.47	21,363	11,289	14,121	2.39	5,908
1992	133,384.07	108,481	57,328	76,056	2.80	27,163
1993	11,268.63	8,812	4,657	6,612	3.27	2,022
1994	15,517.24	11,587	6,123	9,394	3.80	2,472
1996	8,449.94	5,611	2,965	5,485	5.04	1,088
1997	16,006.59	9,881	5,222	10,785	5.74	1,879
1998	70,160.65	39,851	21,059	49,102	6.48	7,577
1999	2,761.71	1,425	753	2,009	7.26	277
2001	7,164.57	2,909	1,537	5,628	8.91	632
2004	45,344.05	10,216	5,399	39,945	11.62	3,438
	570,858.21	434,893	229,823	341,036		142,931
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					2.4	25.04

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 477.10 DS MEAS/REG ADDITIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-R2						
NET SALVAGE PERCENT.. 0						
1962	6,492.00	6,427	3,227	3,265	0.25	3,265
1963	2,023.38	1,983	996	1,027	0.50	1,027
1964	37,162.24	36,033	18,091	19,071	0.76	19,071
1965	84,966.94	81,466	40,901	44,066	1.03	42,783
1966	54,478.00	51,623	25,918	28,560	1.31	21,802
1967	70,427.00	65,948	33,110	37,317	1.59	23,470
1968	14,212.18	13,143	6,599	7,613	1.88	4,049
1969	213,088.95	194,593	97,698	115,391	2.17	53,176
1970	26,040.17	23,478	11,787	14,253	2.46	5,794
1971	82,498.87	73,424	36,863	45,636	2.75	16,595
1972	109,996.86	96,577	48,488	61,509	3.05	20,167
1973	150,957.86	130,730	65,635	85,323	3.35	25,470
1974	32,359.89	27,635	13,874	18,486	3.65	5,065
1975	278,289.30	234,097	117,531	160,758	3.97	40,493
1976	695,605.04	575,961	289,168	406,437	4.30	94,520
1977	1,907,565.74	1,552,759	779,582	1,127,984	4.65	242,577
1978	594,766.68	475,575	238,768	355,999	5.01	71,058
1979	869,952.12	682,390	342,602	527,350	5.39	97,839
1980	847,969.49	651,241	326,964	521,005	5.80	89,828
1981	249,905.08	187,629	94,201	155,704	6.23	24,993
1982	260,051.52	190,566	95,676	164,376	6.68	24,607
1983	1,519,173.31	1,084,082	544,277	974,896	7.16	136,159
1984	535,443.21	371,383	186,457	348,986	7.66	45,560
1985	454,682.96	305,911	153,586	301,097	8.18	36,809
1986	378,442.29	246,290	123,653	254,789	8.73	29,185
1987	5,821.32	3,656	1,836	3,985	9.30	428
1988	114,792.36	69,381	34,834	79,958	9.89	8,085
1989	504,689.91	292,720	146,964	357,726	10.50	34,069
1990	648,978.63	359,794	180,639	468,340	11.14	42,041
1991	1,377,874.01	727,517	365,259	1,012,615	11.80	85,815
1992	1,307,568.50	655,353	329,028	978,541	12.47	78,472
1993	2,427,102.88	1,148,505	576,621	1,850,482	13.17	140,507
1994	2,088,980.15	929,178	466,505	1,622,475	13.88	116,893
1995	4,728,957.70	1,965,355	986,731	3,742,227	14.61	256,141
1996	3,007,888.98	1,159,842	582,313	2,425,576	15.36	157,915

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 477.10 DS MEAS/REG ADDITIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-R2						
NET SALVAGE PERCENT.. 0						
1997	2,602,412.08	923,336	463,572	2,138,840	16.13	132,600
1998	1,497,515.68	484,596	243,297	1,254,219	16.91	74,170
1999	1,610,046.31	470,134	236,037	1,374,009	17.70	77,628
2000	4,147,117.96	1,076,592	540,516	3,606,602	18.51	194,846
2001	3,579,066.92	810,301	406,822	3,172,245	19.34	164,025
2002	2,744,739.69	529,186	265,684	2,479,056	20.18	122,847
2003	6,334,196.61	1,005,870	505,010	5,829,187	21.03	277,184
2004	6,452,427.01	802,682	402,997	6,049,430	21.89	276,356
2005	6,046,234.55	541,743	271,989	5,774,246	22.76	253,701
2006	7,862,349.96	424,567	213,159	7,649,191	23.65	323,433
2007	4,089,167.71	73,605	36,954	4,052,214	24.55	165,060
	72,654,480.00	21,814,857	10,952,419	61,702,062		4,157,578
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					14.8	5.72

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 477.20 DS TELEMENTRY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-R2.5						
NET SALVAGE PERCENT.. 0						
1968	6,582.76	6,583	6,583			
1974	8,362.36	7,961	8,362			
1975	15,020.02	14,096	15,020			
1976	2,066.66	1,916	2,067			
1977	11,435.00	10,474	11,435			
1978	811.75	735	812			
1979	25,587.00	22,862	25,587			
1980	3,346.63	2,952	3,347			
1983	56,999.71	48,079	57,000			
1984	12,998.00	10,769	12,998			
1985	46,230.22	37,516	46,230			
1987	16,826.00	12,998	16,826			
1988	41,988.83	31,471	41,989			
1989	14,287.73	10,344	14,288			
1990	36,463.69	25,415	36,464			
1991	104,656.77	69,911	104,657			
1992	40,187.99	25,600	40,188			
1993	89,292.30	53,933	89,292			
1994	274,646.59	156,549	274,647			
1995	840,579.65	448,870	840,580			
1996	1,354,965.10	673,418	1,354,965			
1997	219,831.55	100,903	219,832			
1998	106,061.66	44,493	106,062			
1999	287,922.67	109,123	287,923			
2000	298,050.06	100,592	298,050			
2001	256,006.66	75,522	256,007			
2002	322,838.61	81,194	322,839			
2003	438,484.62	90,986	438,485			
2004	257,499.74	41,844	207,877	49,623	16.75	2,963
2005	116,504.03	13,573	67,429	49,075	17.67	2,777
2006	188,696.60	13,303	66,088	122,609	18.59	6,595
2007	32,445.04	762	3,786	28,659	19.53	1,467
	5,527,676.00	2,344,747	5,277,715	249,966		13,802
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					18.1	0.25

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 477.30 DS MEAS/REG EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-R2.5						
NET SALVAGE PERCENT.. -5						
1999	68,202.71	35,140	99,613	28,000-		
2000	1,661.74	767	2,174	429-		
2001	44,063.55	17,859	50,626	4,359-		
2004	49,223.00	11,097	31,458	20,226		
	163,151.00	64,863	183,871	12,562-		
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					0.0	0.00

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 478.10 DS METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-R2						
NET SALVAGE PERCENT.. 0						
1963	130,782.00	128,166	76,689	54,093	0.50	54,093
1964	45,758.00	44,367	26,547	19,211	0.76	19,211
1965	70,208.00	67,315	40,278	29,930	1.03	29,058
1966	65,322.00	61,899	37,038	28,284	1.31	21,591
1967	76,364.00	71,507	42,787	33,577	1.59	21,118
1968	100,169.00	92,636	55,429	44,740	1.88	23,798
1969	138,853.00	126,801	75,872	62,981	2.17	29,024
1970	166,381.00	150,009	89,759	76,622	2.46	31,147
1971	214,697.00	191,080	114,334	100,363	2.75	36,496
1972	277,124.00	243,315	145,589	131,535	3.05	43,126
1973	401,886.00	348,033	208,247	193,639	3.35	57,803
1974	510,163.00	435,679	260,691	249,472	3.65	68,348
1975	571,099.00	480,408	287,455	283,644	3.97	71,447
1976	870,869.00	721,080	431,462	439,407	4.30	102,188
1977	1,023,013.00	832,733	498,270	524,743	4.65	112,848
1978	1,195,049.00	955,561	571,765	623,284	5.01	124,408
1979	669,082.09	524,828	314,034	355,048	5.39	65,872
1980	1,304,048.00	1,001,509	599,258	704,790	5.80	121,516
1981	1,112,298.00	835,113	499,694	612,604	6.23	98,331
1982	1,375,989.99	1,008,325	603,337	772,653	6.68	115,667
1984	1,078,658.00	748,157	447,664	630,994	7.66	82,375
1985	682,897.50	459,453	274,916	407,982	8.18	49,876
1986	1,336,577.20	869,844	520,476	816,101	8.73	93,482
1987	444,957.22	279,433	167,200	277,757	9.30	29,866
1988	31,204.41	18,860	11,285	19,919	9.89	2,014
1989	13,909,580.23	8,067,557	4,827,266	9,082,314	10.50	864,982
1990	12,664,150.41	7,021,005	4,201,056	8,463,094	11.14	759,703
1991	4,287,300.19	2,263,695	1,354,494	2,932,806	11.80	248,543
1992	4,984,397.72	2,498,180	1,494,800	3,489,598	12.47	279,839
1993	5,326,133.70	2,520,326	1,508,051	3,818,083	13.17	289,908
1994	6,412,340.40	2,852,209	1,706,635	4,705,705	13.88	339,028
1995	9,529,296.37	3,960,376	2,369,712	7,159,584	14.61	490,047
1996	7,297,211.57	2,813,805	1,683,655	5,613,557	15.36	365,466
1997	6,415,580.11	2,276,248	1,362,005	5,053,575	16.13	313,303
1998	6,194,175.59	2,004,435	1,199,365	4,994,811	16.91	295,376

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 478.10 DS METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-R2						
NET SALVAGE PERCENT.. 0						
1999	7,194,358.96	2,100,753	1,256,997	5,937,362	17.70	335,444
2000	7,319,689.15	1,900,191	1,136,989	6,182,700	18.51	334,019
2001	3,555,658.64	805,001	481,677	3,073,982	19.34	158,944
2002	7,767,394.52	1,497,554	896,070	6,871,325	20.18	340,502
2003	11,284,235.86	1,791,937	1,072,215	10,212,021	21.03	485,593
2004	23,480,041.88	2,920,917	1,747,746	21,732,296	21.89	992,796
2005	11,991,323.59	1,074,423	642,887	11,348,437	22.76	498,613
2006	8,255,587.28	445,802	266,748	7,988,839	23.65	337,794
2007	8,775,723.42	157,963	94,518	8,681,205	24.55	353,613
	180,537,629.00	59,668,488	35,702,962	144,834,667		9,588,216

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 15.1 5.31

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 478.11 LILO DS METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 25-SQUARE						
NET SALVAGE PERCENT.. 0						
2001	3,466,791.00	901,366	1,546,614	1,920,177	18.50	103,793
2002	1,819,445.41	400,278	686,819	1,132,626	19.50	58,083
2004	4,434,310.44	620,803	1,065,209	3,369,101	21.50	156,702
2005	306,178.84	30,618	52,536	253,643	22.50	11,273
	10,026,725.69	1,953,065	3,351,178	6,675,547		329,851

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 20.2 3.29

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 478.20 DS INSTRUMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. 0						
1962	101.00	97	61	40	1.25	32
1963	211.00	200	126	85	1.50	57
1964	274.00	258	162	112	1.76	64
1965	251.00	234	147	104	2.02	51
1966	612.00	566	356	256	2.27	113
1967	841.00	770	484	357	2.53	141
1968	584.00	530	333	251	2.79	90
1969	1,092.00	981	617	475	3.06	155
1970	1,177.00	1,046	658	519	3.33	156
1971	3,951.00	3,474	2,184	1,767	3.62	488
1972	4,259.00	3,702	2,327	1,932	3.92	493
1973	7,188.00	6,169	3,878	3,310	4.25	779
1974	5,636.00	4,772	3,000	2,636	4.60	573
1975	6,402.00	5,339	3,356	3,046	4.98	612
1976	9,389.00	7,706	4,845	4,544	5.38	845
1977	10,839.00	8,736	5,492	5,347	5.82	919
1978	9,579.00	7,570	4,759	4,820	6.29	766
1979	8,772.00	6,787	4,267	4,505	6.79	663
1980	14,544.00	10,991	6,910	7,634	7.33	1,041
1981	19,509.00	14,378	9,039	10,470	7.89	1,327
1982	23,339.00	16,741	10,525	12,814	8.48	1,511
1983	365,768.00	254,831	160,205	205,563	9.10	22,589
1984	2,353.00	1,588	998	1,355	9.75	139
1985	4,600.00	3,001	1,887	2,713	10.43	260
1986	19,442.00	12,235	7,692	11,750	11.12	1,057
1987	82,358.00	49,851	31,340	51,018	11.84	4,309
1988	123,457.00	71,691	45,070	78,387	12.58	6,231
1989	65,902.00	36,595	23,006	42,896	13.34	3,216
1990	159,206.00	84,268	52,977	106,229	14.12	7,523
1991	320,467.00	161,195	101,339	219,128	14.91	14,697
1992	706,831.00	336,452	211,518	495,313	15.72	31,508
1993	815,046.00	365,385	229,708	585,338	16.55	35,368
1994	907,688.00	381,229	239,668	668,020	17.40	38,392
1995	785,297.00	307,287	193,183	592,114	18.26	32,427
1996	625,102.00	226,287	142,260	482,842	19.14	25,227

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 478.20 DS INSTRUMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. 0						
1997	380,074.00	126,299	79,401	300,673	20.03	15,011
1998	29,658.00	8,966	5,637	24,021	20.93	1,148
1999	330,882.00	89,901	56,518	274,364	21.85	12,557
2000	234,314.86	56,400	35,457	198,858	22.78	8,729
2001	346,927.98	72,751	45,737	301,191	23.71	12,703
2002	335,641.68	59,744	37,559	298,083	24.66	12,088
2003	1,008,263.64	147,206	92,544	915,720	25.62	35,742
2004	1,522,073.91	173,516	109,085	1,412,989	26.58	53,160
2005	687,266.98	56,150	35,300	651,967	27.55	23,665
2006	508,057.41	24,895	15,651	492,406	28.53	17,259
2007	447,712.81	7,298	4,588	443,125	29.51	15,016
	10,942,940.27	3,216,068	2,021,854	8,921,087		440,897
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					20.2	4.03

TERASEN GAS - (VANCOUVER ISLAND) INC.

ACCOUNT 401.00 FRANCHISES AND CONSENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
1991	187,221.94	77,229	49,429	137,793	23.50	5,864
1992	2,554.74	990	634	1,921	24.50	78
	189,776.68	78,219	50,063	139,714		5,942
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					23.5	3.13

TERASEN GAS - (VANCOUVER ISLAND) INC.

ACCOUNT 402.00 INTANGIABLE PLANT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
1991	694,036.53	286,290	335,560	358,477	23.50	15,254
2002	500,000.00	68,750	80,582	419,418	34.50	12,157
	1,194,036.53	355,040	416,142	777,895		27,411

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 28.4 2.30

TERASEN GAS - (VANCOUVER ISLAND) INC.

ACCOUNT 461.00 TP LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1991	4,796,701.53	1,050,957	816,613	3,980,089	58.57	67,954
1992	44,432.00	9,149	7,109	37,323	59.56	627
1993	417,105.00	80,376	62,454	354,651	60.55	5,857
1994	1,620.00	291	226	1,394	61.54	23
1995	15,818.00	2,631	2,044	13,774	62.53	220
1996	159,889.08	24,447	18,996	140,893	63.53	2,218
1997	277,167.23	38,720	30,086	247,081	64.52	3,830
1998	19,894.42	2,515	1,954	17,940	65.52	274
1999	588,158.17	66,521	51,688	536,470	66.52	8,065
2000	104,516.74	10,441	8,113	96,404	67.51	1,428
2001	58,232.34	5,037	3,914	54,318	68.51	793
2002	123,554.28	9,044	7,028	116,526	69.51	1,676
2006	1,699.99	34	26	1,674	73.50	23
2007	82,370.22	552	429	81,941	74.50	1,100
	6,691,159.00	1,300,715	1,010,680	5,680,478		94,088
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					60.4	1.41

TERASEN GAS - (VANCOUVER ISLAND) INC.

ACCOUNT 462.00 TP COMPRESSOR STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R4						
NET SALVAGE PERCENT.. -5						
1991	1,839,678.93	1,029,576	779,612	1,152,051	14.01	82,231
1992	70,386.00	37,174	28,149	45,756	14.91	3,069
1993	6,445.00	3,199	2,422	4,345	15.82	275
1994	25,252.00	11,711	8,868	17,647	16.75	1,054
1997	67,885.45	24,713	18,713	52,567	19.60	2,682
1998	2,600,005.52	858,041	649,723	2,080,283	20.57	101,132
1999	2,354,622.49	696,462	527,372	1,944,982	21.55	90,254
2000	918,083.31	239,744	181,538	782,449	22.54	34,714
2001	95.56	22	17	83	23.53	4
2002	816,975.38	156,724	118,674	739,150	24.52	30,145
2005	28,186.00	2,465	1,867	27,728	27.50	1,008
2006	20,573.30	1,080	818	20,784	28.50	729
2007	1,400,575.25	24,559	18,596	1,452,008	29.50	49,221
	10,148,764.19	3,085,470	2,336,369	8,319,833		396,518
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					21.0	3.91

TERASEN GAS - (VANCOUVER ISLAND) INC.

ACCOUNT 463.00 TP MEASURING & REGULATING STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R2.5						
NET SALVAGE PERCENT.. -5						
1991	2,115,960.41	1,062,667	1,463,920	757,838	15.65	48,424
1996	5,526.35	2,000	2,755	3,048	19.66	155
1997	78,158.95	25,958	35,759	46,308	20.51	2,258
1998	52,010.54	15,728	21,667	32,944	21.36	1,542
1999	514,828.00	140,007	192,872	347,697	22.23	15,641
2000	31,664.89	7,637	10,521	22,727	23.11	983
2002	36,872.29	6,582	9,067	29,649	24.90	1,191
2006	199,826.49	9,861	13,585	196,233	28.59	6,864
2007	3,021,424.77	49,808	68,615	3,103,881	29.53	105,109
	6,056,272.69	1,320,248	1,818,761	4,540,325		182,167
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					24.9	3.01

TERASEN GAS - (VANCOUVER ISLAND) INC.

ACCOUNT 464.00 TP OTHER STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R3						
NET SALVAGE PERCENT.. -5						
2005	118,949.64	8,743	8,233	116,664	32.55	3,584
2006	10,372.03	457	430	10,461	33.53	312
2007	172.96	3	3	179	34.51	5
	129,494.63	9,203	8,666	127,304		3,901
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					32.6	3.01

TERASEN GAS - (VANCOUVER ISLAND) INC.

ACCOUNT 465.00 TP TRANSMISSION PIPELINE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

SURVIVOR CURVE.. IOWA 60-R3
NET SALVAGE PERCENT.. -10

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1991	204,227,999.37	59,307,811	52,961,013	171,689,786	44.16	3,887,903
1992	2,494,449.68	682,407	609,380	2,134,515	45.08	47,349
1993	439,615.00	112,673	100,615	382,962	46.02	8,322
1994	315,663.00	75,453	67,378	279,851	46.96	5,959
1995	113,197.00	25,115	22,427	102,090	47.90	2,131
1996	294,612.96	60,213	53,769	270,305	48.85	5,533
1997	226,554.21	42,366	37,832	211,378	49.80	4,245
1998	34,065.12	5,778	5,160	32,312	50.75	637
1999	209,509.18	31,850	28,442	202,018	51.71	3,907
2000	713,580.65	95,763	85,515	699,424	52.68	13,277
2001	1,196,533.66	139,253	124,351	1,191,836	53.65	22,215
2002	2,969,983.86	293,048	261,688	3,005,294	54.62	55,022
2003	337,302.89	27,271	24,353	346,680	55.59	6,236
2005	1,355,812.00	61,147	54,603	1,436,790	57.54	24,970
2006	163,254.63	4,436	3,961	175,619	58.52	3,001
2007	6,165,649.24	55,614	49,663	6,732,551	59.51	113,133
	221,257,782.45	61,020,198	54,490,150	188,893,411		4,203,840

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 44.9 1.90

TERASEN GAS - (VANCOUVER ISLAND) INC.

ACCOUNT 466.00 TP COMPRESSOR EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 33-R3						
NET SALVAGE PERCENT.. -10						
1991	10,829,243.36	5,504,613	4,688,626	7,223,542	17.75	406,960
1992	617,142.00	296,457	252,511	426,345	18.59	22,934
1993	335,259.00	151,534	129,071	239,714	19.44	12,331
1994	147,313.00	62,306	53,070	108,974	20.31	5,366
1995	255,900.00	100,830	85,883	195,607	21.18	9,235
1996	580,381.49	211,253	179,938	458,482	22.08	20,765
1997	1,180,372.98	394,197	335,762	962,648	22.98	41,891
1998	5,571,255.17	1,692,046	1,441,223	4,687,158	23.89	196,197
1999	7,106,963.03	1,937,998	1,650,715	6,166,944	24.82	248,467
2000	341,290.14	82,367	70,157	305,262	25.76	11,850
2001	157,418.52	33,056	28,156	145,004	26.70	5,431
2002	68,728.43	12,255	10,438	65,163	27.65	2,357
2005	995,220.00	81,230	69,189	1,025,553	30.55	33,570
2006	510,627.94	24,995	21,290	540,401	31.53	17,139
2007	16,425,736.38	267,411	227,771	17,840,539	32.51	548,771
	45,122,851.44	10,852,548	9,243,800	40,391,336		1,583,264

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 25.5 3.51

TERASEN GAS - (VANCOUVER ISLAND) INC.

ACCOUNT 467.10 TP MEAS/REG EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-R2.5						
NET SALVAGE PERCENT.. -5						
1991	4,464,916.27	2,621,620	1,184,501	3,503,661	11.02	317,937
1992	77,407.00	43,110	19,478	61,799	11.74	5,264
1993	51,286.00	26,968	12,185	41,665	12.48	3,339
1994	74,109.00	36,635	16,552	61,262	13.23	4,631
1996	42,594.79	18,230	8,237	36,488	14.81	2,464
1997	156,070.63	61,486	27,781	136,093	15.62	8,713
1998	795,811.49	285,442	128,968	706,634	16.46	42,930
1999	1,595,372.93	515,944	233,114	1,442,028	17.30	83,354
2000	134,094.41	38,523	17,405	123,394	18.16	6,795
2001	7,834.35	1,961	886	7,340	19.04	386
2002	509,953.69	108,590	49,063	486,388	19.93	24,405
2004	231,588.33	31,709	14,327	228,841	21.74	10,526
2005	491,065.71	48,262	21,806	493,813	22.66	21,792
2006	1,114,523.26	66,002	29,821	1,140,428	23.59	48,344
2007	561,117.44	11,076	5,004	584,169	24.53	23,814
	10,307,745.30	3,915,558	1,769,128	9,054,003		604,694

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 15.0 5.87

TERASEN GAS - (VANCOUVER ISLAND) INC.

ACCOUNT 468.00 TP COMMUNICATIONS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-R2						
NET SALVAGE PERCENT.. 0						
1991	1,014,626.95	779,233	552,315	462,312	3.48	132,848
1997	122,787.93	68,110	48,276	74,512	6.68	11,154
1998	116,792.80	59,564	42,219	74,574	7.35	10,146
1999	180,141.42	83,586	59,245	120,896	8.04	15,037
2000	37,020.67	15,375	10,898	26,123	8.77	2,979
2001	8,082.15	2,952	2,092	5,990	9.52	629
2002	165,788.13	51,941	36,815	128,973	10.30	12,522
2003	625,406.37	162,168	114,944	510,462	11.11	45,946
2005	4,921.00	725	514	4,407	12.79	345
2006	72,978.00	6,517	4,619	68,359	13.66	5,004
2007	9.34			9	14.55	1
	2,348,554.76	1,230,171	871,937	1,476,617		236,611
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					6.2	10.07

TERASEN GAS - (VANCOUVER ISLAND) INC.

ACCOUNT 471.00 DS LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

SURVIVOR CURVE.. IOWA 75-R4
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1990	2,265.83	526	444	1,822	57.58	32
1991	243,294.67	53,306	44,969	198,326	58.57	3,386
1992	167,375.80	34,463	29,073	138,303	59.56	2,322
1993	53,789.07	10,365	8,744	45,045	60.55	744
1994	123,901.44	22,240	18,761	105,140	61.54	1,708
1995	107,699.74	17,910	15,109	92,591	62.53	1,481
1996	53,581.10	8,193	6,912	46,669	63.53	735
1997	152,127.54	21,252	17,928	134,200	64.52	2,080
1998	142,216.70	17,976	15,164	127,053	65.52	1,939
1999	215,415.41	24,363	20,552	194,863	66.52	2,929
2000	150,291.08	15,014	12,666	137,625	67.51	2,039
2001	56,285.13	4,869	4,107	52,178	68.51	762
2002	98,383.52	7,202	6,076	92,308	69.51	1,328
2003	142,982.84	8,565	7,225	135,758	70.51	1,925
2005	74,436.00	2,479	2,091	72,345	72.50	998
2006	45,864.36	917	774	45,090	73.50	613
2007	200.00	1	1	199	74.50	3
	1,830,110.23	249,641	210,596	1,619,515		25,024

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 64.7 1.37

TERASEN GAS - (VANCOUVER ISLAND) INC.

ACCOUNT 472.00 DS STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 28-L1						
NET SALVAGE PERCENT.. -5						
1991	244,456.26	99,360	120,309	136,370	17.16	7,947
1992	58,312.46	22,832	27,646	33,582	17.56	1,912
1993	77,316.46	29,079	35,210	45,972	17.97	2,558
1994	303,680.20	109,083	132,082	186,782	18.42	10,140
1995	488,111.02	166,927	202,121	310,396	18.88	16,440
1997	153,909.18	46,574	56,394	105,211	19.93	5,279
1998	7,606.07	2,140	2,591	5,395	20.50	263
1999	21,650.99	5,586	6,764	15,970	21.12	756
2000	10,165.74	2,367	2,866	7,808	21.79	358
2003	61,612.53	9,173	11,107	53,586	24.03	2,230
2005	26,098.00	2,242	2,714	24,689	25.71	960
2006	2,240.00	117	142	2,210	26.61	83
	1,455,158.91	495,480	599,946	927,971		48,926
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					19.0	3.36

TERASEN GAS - (VANCOUVER ISLAND) INC.

ACCOUNT 473.00 DS SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R2.5						
NET SALVAGE PERCENT.. -50						
1990	3,779,974.48	1,640,320	1,213,863	4,456,099	39.09	113,996
1991	3,982,134.24	1,633,671	1,208,942	4,764,259	39.96	119,226
1992	13,865,374.10	5,357,581	3,964,695	16,833,366	40.83	412,279
1993	12,921,975.02	4,682,924	3,465,438	15,917,525	41.71	381,624
1994	12,073,816.38	4,085,779	3,023,542	15,087,183	42.59	354,242
1995	10,753,624.16	3,379,326	2,500,755	13,629,681	43.48	313,470
1996	6,765,595.93	1,959,655	1,450,176	8,698,218	44.38	195,994
1997	799,501.62	211,908	156,815	1,042,437	45.28	23,022
1998	781,902.07	188,126	139,216	1,033,637	46.18	22,383
1999	7,473,715.77	1,612,080	1,192,965	10,017,609	47.09	212,733
2000	6,831,403.25	1,302,407	963,802	9,283,303	48.01	193,362
2001	4,932,966.43	816,899	604,518	6,794,932	48.93	138,870
2002	6,084,229.47	854,226	632,141	8,494,203	49.85	170,395
2003	10,137,644.35	1,166,336	863,107	14,343,360	50.78	282,461
2005	7,918,109.00	507,155	375,303	11,501,861	52.65	218,459
2006	6,309,443.89	244,175	180,693	9,283,473	53.58	173,264
2007	7,136,846.33	90,995	67,338	10,637,931	54.53	195,084
	122,548,256.49	29,733,563	22,003,309	161,819,077		3,520,864

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 46.0 2.87

TERASEN GAS - (VANCOUVER ISLAND) INC.

ACCOUNT 474.00 DS METERS/REGUALTORS INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R2						
NET SALVAGE PERCENT.. 0						
1990	742,537.09	353,225	323,658	418,879	15.73	26,629
1991	751,187.52	339,537	311,116	440,072	16.44	26,768
1992	1,574,688.05	673,494	617,119	957,569	17.17	55,770
1993	1,525,841.74	614,914	563,442	962,400	17.91	53,735
1994	1,521,656.27	575,186	527,040	994,616	18.66	53,302
1995	1,277,332.35	450,004	412,336	864,996	19.43	44,519
1996	781,484.51	254,998	233,653	547,832	20.21	27,107
1997	75,742.91	22,723	20,821	54,922	21.00	2,615
1998	25,082.57	6,848	6,275	18,808	21.81	862
1999	973,144.55	239,102	219,088	754,057	22.63	33,321
2000	780,692.15	170,191	155,945	624,747	23.46	26,630
2001	443,981.75	84,357	77,296	366,686	24.30	15,090
2002	553,059.91	89,430	81,944	471,116	25.15	18,732
2003	1,543,512.88	205,287	188,104	1,355,409	26.01	52,111
2005	1,164,127.00	86,960	79,681	1,084,446	27.76	39,065
2006	470,507.13	21,173	19,401	451,106	28.65	15,745
2007	1,365,147.92	20,477	18,763	1,346,385	29.55	45,563
	15,569,726.30	4,207,906	3,855,682	11,714,046		537,564

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 21.8 3.45

TERASEN GAS - (VANCOUVER ISLAND) INC.

ACCOUNT 475.00 DS MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R3						
NET SALVAGE PERCENT.. -20						
1990	13,732,535.87	4,602,597	5,248,011	11,231,032	43.24	259,737
1991	20,915,301.69	6,625,968	7,555,116	17,543,246	44.16	397,266
1992	3,779,397.75	1,127,923	1,286,090	3,249,187	45.08	72,076
1993	19,091,048.54	5,337,857	6,086,375	16,822,883	46.02	365,556
1994	21,151,335.63	5,515,422	6,288,840	19,092,763	46.96	406,575
1995	16,148,455.92	3,908,572	4,456,664	14,921,483	47.90	311,513
1996	13,717,022.46	3,058,347	3,487,214	12,973,213	48.85	265,572
1997	15,691,304.76	3,201,026	3,649,900	15,179,666	49.80	304,813
1998	11,684,546.65	2,162,109	2,465,298	11,556,158	50.75	227,708
1999	12,458,692.32	2,066,150	2,355,883	12,594,548	51.71	243,561
2000	10,454,969.92	1,530,608	1,745,242	10,800,722	52.68	205,025
2001	7,865,916.30	998,657	1,138,697	8,300,403	53.65	154,714
2002	4,073,751.43	438,499	499,989	4,388,513	54.62	80,346
2003	11,016,780.14	971,680	1,107,937	12,112,199	55.59	217,884
2005	5,530,109.59	272,081	310,235	6,325,897	57.54	109,939
2006	4,854,591.30	143,890	164,067	5,661,443	58.52	96,744
2007	8,901,636.55	87,592	99,875	10,582,089	59.51	177,820
	201,067,396.82	42,048,978	47,945,433	193,335,445		3,896,849

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 49.6 1.94

TERASEN GAS - (VANCOUVER ISLAND) INC.

ACCOUNT 477.10 DS MEAS/REG ADDITIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-R2						
NET SALVAGE PERCENT.. 0						
1991	1,083,016.84	571,833	468,874	614,143	11.80	52,046
1992	1,563,640.09	783,696	642,591	921,049	12.47	73,861
1993	217,116.81	102,740	84,241	132,876	13.17	10,089
1994	816,689.55	363,264	297,858	518,832	13.88	37,380
1995	234,980.23	97,658	80,075	154,905	14.61	10,603
1996	215,709.30	83,178	68,202	147,507	15.36	9,603
1997	77,814.96	27,609	22,638	55,177	16.13	3,421
1998	24,023.94	7,774	6,374	17,650	16.91	1,044
1999	344,964.17	100,730	82,593	262,371	17.70	14,823
2000	26,150.94	6,789	5,567	20,584	18.51	1,112
2001	20,730.26	4,693	3,848	16,882	19.34	873
2003	37,986.51	6,032	4,946	33,041	21.03	1,571
2006	179,424.98	9,689	7,944	171,481	23.65	7,251
2007	173,041.57	3,115	2,554	170,488	24.55	6,945
	5,015,290.15	2,168,800	1,778,305	3,236,986		230,622
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					14.0	4.60

TERASEN GAS - (VANCOUVER ISLAND) INC.

ACCOUNT 478.10 DS METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-R2						
NET SALVAGE PERCENT.. 0						
1990	212,403.92	117,757	97,550	114,854	11.14	10,310
1991	259,968.27	137,263	113,709	146,259	11.80	12,395
1992	1,005,894.76	504,154	417,641	588,254	12.47	47,174
1993	979,710.77	463,599	384,045	595,666	13.17	45,229
1994	1,468,672.98	653,266	541,165	927,508	13.88	66,823
1995	85,057.15	35,350	29,284	55,773	14.61	3,817
1996	897,465.05	346,063	286,678	610,787	15.36	39,765
1997	869,282.84	308,422	255,496	613,787	16.13	38,053
1998	24,282.56	7,858	6,510	17,773	16.91	1,051
1999	818,787.19	239,086	198,059	620,728	17.70	35,069
2000	431,647.90	112,056	92,827	338,821	18.51	18,305
2001	389,419.12	88,164	73,035	316,384	19.34	16,359
2002	415,059.06	80,023	66,291	348,768	20.18	17,283
2003	1,239,465.03	196,827	163,051	1,076,414	21.03	51,185
2005	726,790.00	65,120	53,945	672,845	22.76	29,563
2006	690,854.56	37,306	30,904	659,951	23.65	27,905
2007	366,954.40	6,605	5,472	361,482	24.55	14,724
	10,881,715.56	3,398,919	2,815,662	8,066,054		475,010

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 17.0 4.37

TERASEN GAS - (WHISTLER) INC.

ACCOUNT 401.00 FRANCHISES AND CONSENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE NET SALVAGE PERCENT.. 0						
1987	8,238.78	4,222	1,643	6,596	19.50	338
	8,238.78	4,222	1,643	6,596		338
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					19.5	4.10

TERASEN GAS - (WHISTLER) INC.

ACCOUNT 431.00 MFG. GAS LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1990	2,430.15	565	468	1,962	57.58	34
1993	225.00	43	36	189	60.55	3
1995	970.00	161	133	837	62.53	13
	3,625.15	769	637	2,988		50
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					59.8	1.38

TERASEN GAS - (WHISTLER) INC.

ACCOUNT 432.00 MFG. GAS STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
1990	156,868.22	68,630	68,881	87,987	22.50	3,911
1991	225,697.77	93,100	93,440	132,258	23.50	5,628
1992	1,335,708.59	517,587	519,477	816,232	24.50	33,316
1993	299,848.93	108,695	109,092	190,757	25.50	7,481
1994	93,944.72	31,706	31,822	62,123	26.50	2,344
1995	4,460.68	1,394	1,399	3,062	27.50	111
1996	3,629.77	1,044	1,048	2,582	28.50	91
1998	7,884.48	1,873	1,880	6,004	30.50	197
1999	6,879.79	1,462	1,467	5,413	31.50	172
2000	249,020.93	46,691	46,861	202,160	32.50	6,220
2001	66,855.76	10,864	10,904	55,952	33.50	1,670
2002	209,513.35	28,808	28,913	180,600	34.50	5,235
2003	4,162.94	468	470	3,693	35.50	104
2005	31,963.00	1,998	2,005	29,958	37.50	799
2006	182,499.15	6,844	6,869	175,630	38.50	4,562
	2,878,938.08	921,164	924,528	1,954,411		71,841
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					27.2	2.50

TERASEN GAS - (WHISTLER) INC.

ACCOUNT 433.00 MFG. GAS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
1990	86,712.76	75,874	31,045	55,668	2.50	22,267
1991	3,696.12	3,049	1,248	2,448	3.50	699
1992	893,830.60	692,719	283,439	610,392	4.50	135,643
1993	575,777.34	417,439	170,803	404,974	5.50	73,632
1994	21,264.78	14,354	5,873	15,392	6.50	2,368
1995	4,353.30	2,721	1,113	3,240	7.50	432
1997	61,117.84	32,087	13,129	47,989	9.50	5,051
1998	266.08	126	52	214	10.50	20
2001	47,515.08	15,442	6,318	41,197	13.50	3,052
2006	514.00	39	16	498	18.50	27
	1,695,047.90	1,253,850	513,036	1,182,012		243,191

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 4.9 14.35

TERASEN GAS - (WHISTLER) INC.

ACCOUNT 434.00 MFG. GAS HOLDERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
1990	133,013.22	58,193	40,267	92,746	22.50	4,122
1992	309,975.11	120,115	83,114	226,861	24.50	9,260
1993	46,294.72	16,782	11,612	34,683	25.50	1,360
1994	4,590.00	1,549	1,072	3,518	26.50	133
1998	39,582.73	9,401	6,505	33,078	30.50	1,085
1999	110.19	23	16	94	31.50	3
2000	667,258.16	125,111	86,572	580,686	32.50	17,867
2001	517,587.18	84,108	58,199	459,388	33.50	13,713
2002	389,763.85	53,593	37,084	352,680	34.50	10,223
	2,108,175.16	468,875	324,441	1,783,734		57,766

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 30.9 2.74

TERASEN GAS - (WHISTLER) INC.

ACCOUNT 436.00 MFG. GAS COMPRESSOR EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 25-SQUARE						
NET SALVAGE PERCENT.. 0						
1990	250.80	176	116	135	7.50	18
1996	34,428.08	15,837	10,415	24,013	13.50	1,779
1997	3,216.68	1,351	889	2,328	14.50	161
	37,895.56	17,364	11,420	26,476		1,958

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 13.5 5.17

TERASEN GAS - (WHISTLER) INC.

ACCOUNT 437.00 MFG. GAS MEASURING REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
1990	60,363.69	52,818	4,032	56,332	2.50	22,533
1992	2,822.83	2,188	167	2,656	4.50	590
1993	4,433.73	3,214	245	4,189	5.50	762
1994	15,127.59	10,211	779	14,349	6.50	2,208
1995	7,001.96	4,376	334	6,668	7.50	889
1996	24,492.15	14,083	1,075	23,417	8.50	2,755
1997	115.18	60	5	110	9.50	12
2000	46,432.12	17,412	1,329	45,103	12.50	3,608
2001	91,605.36	29,772	2,273	89,332	13.50	6,617
2003	7,540.22	1,697	129	7,411	15.50	478
2004	13,873.92	2,428	185	13,689	16.50	830
2005	63,170.00	7,896	603	62,567	17.50	3,575
2006	6,612.27	496	38	6,574	18.50	355
	343,591.02	146,651	11,194	332,397		45,212

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 7.4 13.16

TERASEN GAS - (WHISTLER) INC.

ACCOUNT 471.00 DS LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1990	8,806.35	2,046	1,480	7,326	57.58	127
1991	2,017.06	442	320	1,697	58.57	29
1992	2,324.25	479	346	1,978	59.56	33
1993	10,026.94	1,932	1,397	8,630	60.55	143
1994	17,669.36	3,172	2,295	15,374	61.54	250
1995	4,753.00	790	571	4,182	62.53	67
1996	3,570.01	546	395	3,175	63.53	50
1997	3,965.63	554	401	3,565	64.52	55
1998	3,351.70	424	307	3,045	65.52	46
1999	4,369.67	494	357	4,013	66.52	60
2000	8,879.74	887	642	8,238	67.51	122
2001	3,282.33	284	205	3,077	68.51	45
2002	6,532.32	478	346	6,186	69.51	89
2003	3,402.48	204	147	3,255	70.51	46
2004	1,151.29	54	39	1,112	71.50	16
2005	2,592.00	86	63	2,529	72.50	35
2006	293.20	6	4	289	73.50	4
	86,987.33	12,878	9,315	77,671		1,217
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					63.8	1.40

TERASEN GAS - (WHISTLER) INC.

ACCOUNT 472.00 DS STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 28-L1						
NET SALVAGE PERCENT.. -5						
1991	167.58	68	79	97	17.16	6
1992	37.57	15	18	21	17.56	1
	205.15	83	97	118		7
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					16.9	3.41

TERASEN GAS - (WHISTLER) INC.

ACCOUNT 473.00 DS SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R2.5						
NET SALVAGE PERCENT.. -50						
1990	366,514.63	159,049	109,229	440,543	39.09	11,270
1991	29,452.88	12,083	8,298	35,881	39.96	898
1992	87,832.22	33,938	23,307	108,441	40.83	2,656
1993	200,435.31	72,638	49,885	250,768	41.71	6,012
1994	138,362.07	46,822	32,156	175,387	42.59	4,118
1995	242,546.16	76,220	52,345	311,474	43.48	7,164
1996	210,226.02	60,892	41,818	273,521	44.38	6,163
1997	266,737.15	70,699	48,553	351,553	45.28	7,764
1998	158,619.90	38,164	26,210	211,720	46.18	4,585
1999	181,476.04	39,144	26,883	245,331	47.09	5,210
2000	170,417.75	32,490	22,313	233,314	48.01	4,860
2001	120,007.41	19,873	13,648	166,363	48.93	3,400
2002	145,592.44	20,441	14,038	204,351	49.85	4,099
2003	180,352.60	20,750	14,250	256,279	50.78	5,047
2004	51,368.23	4,608	3,165	73,887	51.71	1,429
2005	59,993.00	3,843	2,639	87,351	52.65	1,659
2006	190,925.43	7,389	5,074	281,314	53.58	5,250
2007	89,976.66	1,147	788	134,177	54.53	2,461
	2,890,835.90	720,190	494,599	3,841,655		84,045

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 45.7 2.91

TERASEN GAS - (WHISTLER) INC.

ACCOUNT 474.00 DS METERS / REGULATORS INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R2						
NET SALVAGE PERCENT.. 0						
1990	153,353.90	72,950	72,879	80,475	15.73	5,116
1991	16,941.71	7,658	7,651	9,291	16.44	565
1992	31,063.77	13,286	13,273	17,791	17.17	1,036
1993	43,452.24	17,511	17,494	25,958	17.91	1,449
1994	38,808.20	14,669	14,655	24,153	18.66	1,294
1995	46,380.66	16,340	16,324	30,057	19.43	1,547
1996	45,095.62	14,715	14,700	30,396	20.21	1,504
1997	62,955.92	18,887	18,868	44,088	21.00	2,099
1998	66,159.06	18,061	18,043	48,116	21.81	2,206
1999	54,627.05	13,422	13,409	41,218	22.63	1,821
2000	41,971.77	9,150	9,141	32,831	23.46	1,399
2001	28,803.36	5,473	5,468	23,335	24.30	960
2002	30,673.05	4,960	4,955	25,718	25.15	1,023
2003	76,840.80	10,220	10,210	66,631	26.01	2,562
2004	24,149.87	2,512	2,510	21,640	26.88	805
2005	7,407.00	553	552	6,855	27.76	247
2006	20,146.73	907	906	19,241	28.65	672
2007	20,006.39	300	300	19,706	29.55	667
	808,837.10	241,574	241,338	567,500		26,972

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 21.0 3.33

TERASEN GAS - (WHISTLER) INC.

ACCOUNT 475.00 DS MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R3						
NET SALVAGE PERCENT.. -20						
1990	1,481,548.46	496,556	509,605	1,268,253	43.24	29,331
1991	95,296.76	30,190	30,983	83,373	44.16	1,888
1992	367,215.48	109,592	112,472	328,187	45.08	7,280
1993	87,449.42	24,451	25,094	79,845	46.02	1,735
1994	182,140.82	47,495	48,743	169,826	46.96	3,616
1995	415,392.63	100,542	103,184	395,287	47.90	8,252
1996	223,213.77	49,768	51,076	216,781	48.85	4,438
1997	186,645.53	38,076	39,077	184,898	49.80	3,713
1998	330,836.75	61,218	62,827	334,177	50.75	6,585
1999	30,965.42	5,135	5,270	31,889	51.71	617
2000	850,303.39	124,484	127,755	892,609	52.68	16,944
2001	2,031,117.51	257,871	264,648	2,172,693	53.65	40,498
2002	317,258.04	34,150	35,048	345,662	54.62	6,328
2003	95,175.93	8,395	8,616	105,595	55.59	1,900
2004	58,793.57	4,043	4,149	66,403	56.56	1,174
2005	57,901.00	2,849	2,924	66,557	57.54	1,157
2006	24,971.74	740	759	29,207	58.52	499
	6,836,226.22	1,395,555	1,432,230	6,771,242		135,955

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 49.8 1.99

TERASEN GAS - (WHISTLER) INC.

ACCOUNT 477.10 DS MEAS/REG ADDITIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-R2						
NET SALVAGE PERCENT.. 0						
1990	13,644.21	7,564	6,653	6,991	11.14	628
1996	73.00	28	25	48	15.36	3
	13,717.21	7,592	6,678	7,039		631

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 11.2 4.60

TERASEN GAS - MAINLAND SYSTEM

ACCOUNT 401.00 FRANCHISES AND CONSENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
1959	2,931.00	2,931	2,931			
1960	88,488.00	88,488	88,488			
1962	4,804.00	4,804	4,804			
1963	230.00	230	230			
1964	50.00	50	50			
1969	848.00	816	16,434-	17,282	1.50	11,521
1970	452.00	424	8,539-	8,991	2.50	3,596
1971	260.00	237	4,773-	5,033	3.50	1,438
1972	300.00	266	5,358-	5,658	4.50	1,257
1973	50.00	43	866-	916	5.50	167
1976	823.00	648	13,051-	13,874	8.50	1,632
	99,236.00	98,937	47,482	51,754		19,611

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT.. 2.6 19.76

TERASEN GAS - (WHISTLER) INC.

ACCOUNT 478.10 DS METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2007

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUT. BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-R2						
NET SALVAGE PERCENT.. 0						
1990	55,769.39	30,919	21,437	34,332	11.14	3,082
1991	9,071.74	4,790	3,321	5,751	11.80	487
1992	21,032.62	10,542	7,309	13,724	12.47	1,101
1993	16,940.55	8,016	5,558	11,383	13.17	864
1994	19,837.86	8,824	6,118	13,720	13.88	988
1995	35,839.01	14,895	10,327	25,512	14.61	1,746
1996	30,796.86	11,875	8,233	22,564	15.36	1,469
1997	52,366.75	18,580	12,882	39,485	16.13	2,448
1998	30,235.35	9,784	6,784	23,451	16.91	1,387
1999	33,880.58	9,893	6,859	27,022	17.70	1,527
2000	29,972.13	7,781	5,395	24,577	18.51	1,328
2001	21,111.96	4,780	3,314	17,798	19.34	920
2002	14,189.36	2,736	1,897	12,292	20.18	609
2003	37,333.67	5,929	4,111	33,223	21.03	1,580
2005	59,413.00	5,323	3,691	55,722	22.76	2,448
2006	5,726.30	309	214	5,512	23.65	233
2007	26,710.30	481	334	26,376	24.55	1,074
	500,227.43	155,457	107,784	392,444		23,291
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..					16.8	4.66

MANAGEMENT'S DISCUSSION & ANALYSIS
FOR THE THREE MONTHS ENDED MARCH 31, 2009
DATED APRIL 30, 2009

The following discussion of the financial condition and the results of operations of Terasen Gas Inc. ("Terasen Gas" or the "Company") should be read in conjunction with the Company's annual audited consolidated financial statements and related notes together with Management's Discussion and Analysis ("MD&A") at December 31, 2008 and the unaudited interim consolidated financial statements and related notes for the period ended March 31, 2009.

The financial data included in the discussion provided in this report has been prepared in accordance with Canadian generally accepted accounting principles, and all dollar amounts are in Canadian dollars.

FORWARD LOOKING STATEMENT

Certain statements contained in this Management Discussion & Analysis contain forward-looking information within the meaning of applicable securities laws in Canada ("forward-looking information"). The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words.

The forward-looking information in this Management Discussion & Analysis includes, but is not limited to, statements regarding: the Company's expectation to generate sufficient cash from operations to meet its working capital needs; the Company's expected capital expenditures in 2009; and the Company's belief that changes in consumption levels and changes in the commodity cost of natural gas do not materially impact earnings as a result of regulatory deferral accounts..

The forecasts and projections that make up the forward-looking information are based on assumptions, which include but are not limited to receipt of applicable regulatory approvals and requested rate orders; no significant operational disruptions or environmental liability as a result of a catastrophic event or environmental upset, the competitiveness of natural gas pricing when compared with alternate sources of energy, continued population growth and new housing starts, the availability of natural gas supply, access to capital including no material adverse ratings actions by credit ratings agencies; interest rates; the ability to hedge certain risks including no counterparties to derivative instruments failing to meet obligations; and no material change in pension expense or funding requirements.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory approval and rate orders risk; operational disruptions and environmental risk; price competitiveness risk including the impact of carbon taxes or other environmental policies of government; changes in economic conditions including population changes and declining housing starts; natural gas supply risks; capital and credit ratings risk including material adverse ratings actions by credit ratings agencies, interest rate risk; counterparty credit risk including counterparties to derivative instruments failing to meet obligations; and pension expense and funding risk., For additional information with respect to these risk factors, reference should be made to the section entitled "Commitments, Events, Risks, and Uncertainties" in the Company's MD&A for the year ended December 31, 2008

All forward-looking information in this Management Discussion & Analysis is qualified in its entirety by this cautionary statement and, except as required by law, the Company undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

FIRST QUARTER 2009 RESULTS

During the first quarter of 2009, revenues increased by $29.0 million, compared to the corresponding period in 2008. Cost of natural gas changed on a year-over-year basis, up $24.8 million in the first quarter. Higher revenues and cost of natural gas for the three months ended March 31, 2008 reflects higher consumption in the current quarter due to cooler weather on a year-over-year basis which is partially offset by a lower allowed return on equity described below. Changes in consumption levels and changes in the commodity cost of natural gas do not materially impact earnings as a result of regulatory deferral accounts.

As noted in the Company's annual 2008 Management's Discussion and Analysis, the allowed Return on Equity ("ROE") for 2009 for Terasen Gas has been set at 8.47% (8.62% in 2008). In addition, the deemed equity component for Terasen Gas was set at 35.01% for 2009, unchanged from 2008. The change in the earnings from the segment is mainly attributable to a lower ROE in 2009 compared to 2008. The change in the earnings is mainly attributable to a lower ROE in 2009 compared to 2008.

For the three months ended March 31, 2009, Terasen Gas net customer additions were 1,569, bringing the total number of utility customers to 835,780 at March 31, 2009. The net increase of 1,569 customers for the first three months of 2008 is lower than the 1,702 net new customers reported in the same period of 2008. The weakening housing and construction markets contributed to lower net customers additions in 2009 compared to 2008. In addition, the growth in multi-family housing impacted net additions as natural gas use is less prevalent in this type of dwelling.

For the three months ended March 31, 2009, operation and maintenance expenses increased by $4.8 million as compared with the corresponding period of 2008. The increase in operation and maintenance expenses was a result of higher labour and benefits costs compared to the comparable period in the prior year. For the three months ended March 31, 2009, depreciation and amortization increased by $1.1 million, as compared with the corresponding period of 2008. The increase in depreciation is due to net capital assets additions in 2008. Income taxes for the first three months of 2009 were slightly lower than the same period of 2008 as a result of lower income before tax and a lower effective tax rate compared to 2008 due to the lower enacted federal and provincial tax rates.

Every three months, Terasen Gas reviews natural gas commodity price with the British Columbia Utilities Commission ("BCUC") in order to ensure the flow-through rates charged to customers are sufficient to cover the cost of purchasing natural gas and propane. As approved by the BCUC, the commodity rate for natural gas was unchanged during the first quarter of 2009 while the commodity rate for propane decreased, effective January 1, 2009. Effective April 1, 2009, the BCUC approved decreases in the commodity rate for natural gas. The commodity cost of natural gas is a flowed through to customers without markup. In December 2008, the BCUC approved customer delivery rate increases by approximately six percent at Terasen Gas. Customer delivery rates for 2009 also reflect the decrease in the allowed ROE for 2009 to 8.47 per cent resulting from the application of automatic ROE adjustment mechanisms. Terasen Gas is currently preparing rate applications related to 2010 which are anticipated to be filed with the BCUC during the summer of 2009. The BCUC approval of rates for 2010 and future years will be required as the current Performance Based Rate Plan ("PBR") agreements expire at the end of 2009. in addition, Terasen Gas will be applying to the BCUC for a review of the current generic ROE adjustment mechanism and the deemed equity component of its capital structure.

In April 2009, Terasen Gas received approval from the BCUC for its new $41.5 million Energy Efficiency and Conservation program to provide customers enhanced incentives to manage their natural gas consumption, reduce their energy costs and lower their greenhouse gas emissions. The program is expected to begin in the summer of 2009.

QUARTERLY FINANCIAL INFORMATION

(In millions of dollars)	2009	2008			2007			
	Mar	Dec	Sept	June	Mar	Dec	Sept	June
Revenues	$592.8	$537.0	$ 227.7	$336.1	$ 563.8	$ 484.6	$ 187.4	$ 293.3
Net earnings (loss)	50.8	43.3	(6.3)	3.9	50.6	40.7	(12.1)	2.8

SEASONALITY

Because of natural gas consumption patterns, the natural gas transmission and distribution operations of Terasen Gas normally generate higher net earnings in the first and fourth quarters and lower net earnings in the second quarter, which are partially offset by net losses in the third quarter. As a result, interim earnings statements are not indicative of earnings on an annual basis.

LIQUIDITY AND CAPITAL RESOURCES

Terasen Gas expects to generate sufficient cash from operations to meet its working capital needs and to maintain its financial liquidity and flexibility. The Company's liquidity and capacity to access capital markets to maintain operations, refinance debt and fund growth remains substantially unchanged since December 31, 2008.

CONSOLIDATED CASH FLOW

Cash from operations refers to cash generated before the impact of working capital changes. Cash from operations for the three months ended March 31, 2009 was $71.5 million compared to $73.0 million in the corresponding period of 2008. Cash from operations has not materially changed on a year over year basis.

Between December 31, 2008 and March 31, 2009, inventories of gas in storage and supplies, current portion of rate stabilization accounts, accounts payable and accrued liabilities, excluding the mark to market on gas derivatives, have declined while accounts receivable has increased as a result of the typical seasonal increase in natural gas consumption and the use of inventories of gas in storage during the period. Due to the lesser impact of these changes in 2009 as compared to 2008, cash flow generated from operating activities has decreased.

CAPITAL EXPENDITURES

For the three month period ended March 31, 2009, capital expenditures totalled $30.1 million, up from $27.5 million in the first quarter of 2008.

There have been no material changes to Terasen's planned capital expenditures from those reported in the Company's Annual 2008 Management's Discussion and Analysis.

FINANCING ACTIVITIES

On February 24, 2009, Terasen Gas issued $100.0 million of 30-year 6.55% unsecured debentures. The net proceeds are being used to repay credit-facility borrowings incurred in support of working capital requirements and capital expenditures, and to repay $60 million of unsecured debentures that mature in June 2009.

On May 13, 2008, Terasen Gas issued $250.0 million of Medium Term Note Debentures at a coupon interest rate of 5.80%. The proceeds were used to repay current debt maturities of $188 million which matured on June 2, 2008 and the remainder of the proceeds were used to pay down Terasen Gas' operating line.

During the first quarter of 2009, Terasen Gas declared dividends of $11.5 million compared to dividends of $54.0 million in the corresponding period in 2008.

CONTRACTUAL OBLIGATIONS

The Company has entered into operating leases for certain building space and natural gas transmission and distribution assets. In addition, the Company enters into gas purchase contracts. The following table sets forth the Company's operating lease, gas purchase obligations and employee benefit plans due in the twelve month period beginning April 1 as indicated:

(In millions of dollars)	Operating leases	Purchase obligations	Employee benefit plans	Total
2009/10	$ 15.4	$ 210.1	$ 7.7	$ 233.2
2010/11	15.0	23.6	5.1	43.7
2011/12	14.6	14.4	-	29.0
2012/13	14.2	-	-	14.2
2013/14	13.2	-	-	13.2
2014 and thereafter	82.3	-	-	82.3
	$ 154.7	$ 248.1	$ 12.8	$ 415.6

Gas purchase contract commitments are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect at March 31, 2009.

FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets as at March 31, 2009 compared to December 31, 2008.

Balance Sheet Item	Increase (Decrease) ($ millions)	Explanation
Other assets	$ 265.3	The increase in other assets is due to the adoption of CICA S. 3465, ***Income taxes***, Other assets captures the regulated assets related to recovering the future income tax liability from rate-payers.
Future income taxes	222.4	The increase in future income taxes is due to the adoption of CICAS. 3465, ***Income taxes***, on rate regulated operations effective January 1, 2009.
Long-term debt (including current portion)	99.2	The increase is due to the issuance of Medium Term Notes during the quarter.
Inventories of gas in storage and supplies	(128.5)	The decrease is mainly due to a drawdown of gas in storage used during the winter consumption months.
Short-term notes	(170.5)	The decrease is due to the repayment of borrowings with proceeds from the issuance of Medium Term Debentures plus the decline in borrowings in Terasen Gas due to seasonality.

LINES OF CREDIT

As at March 31, 2009, the Company had lines of credit in place under its unsecured committed revolving credit facility totalling $500.0 million to finance cash requirements. These lines enable the Company to borrow directly from its bankers, issue bankers' acceptances and support commercial paper. Bank lines of $388.5 million were unutilized at March 31, 2009. Utilized lines are used for short term borrowings and letters of credit. Virtually all short-term cash needs are funded through commercial paper and bankers' acceptances in the Canadian market at rates generally below bank prime. The Company has ten letters of credit outstanding totalling $43.5 million which primarily relate to unfunded pension plans.

CREDIT RATINGS

There have been no other changes to the Company's credit ratings from those reported in the annual 2008 Management's Discussion and Analysis.

DIVIDENDS

During the first quarter of 2009, Terasen Gas declared a dividend of $11.5 million compared to a dividend of $54.0 million declared in the first quarter of 2008.

TRANSACTIONS WITH RELATED PARTIES

The Company reimbursed its parent for management services under a shared-services agreement totalling $2.1 million (2008 – $2.1 million) for the three months ended March 31, 2009. The Company charged $1.6 million (2008 – $1.6 million) to affiliated companies for management services during the three months ended March 31, 2009.

The Company received $0.8 million (2008 - $0.8 million) for the three months ended March 31, 2009 from Terasen Gas (Vancouver Island) Inc., a subsidiary of Terasen Inc., for transporting gas through the Company's pipeline system.

The Company paid $11.7 million (2008 – $11.3 million) during the three months ended March 31, 2009 for customer care and billing services to a limited partnership in which Terasen Inc. owns a 30 percent interest.

The Company's indirect parent, Fortis Inc., grants stock options to certain employees of the Company under its stock option plans. For the period ended March 31, 2009, the Company was charged, and recorded an expense of $0.1 million (2008 - $0.1 million) for the fair value of the stock compensation granted by Fortis Inc.

Related party transactions are measured at the exchange amount.

FINANCIAL AND OTHER INSTRUMENTS

FAIR VALUE ESTIMATES

	March 31, 2009		December 31, 2008	
	Carrying Value	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Held for trading				
Cash and short-term investments [1]	**$ 17.4**	**$ 17.4**	$ 13.1	$ 13.1
Loans and receivables				
Accounts receivable [1,2]	**388.3**	**388.3**	345.9	345.9
Long-term receivables[1,2]	**9.0**	**9.0**	9.1	9.1
Other financial liabilities				
Short-term notes [1,2]	**68.0**	**68.0**	238.5	238.5
Accounts payable and accrued liabilities [1,2]	**370.6**	**370.6**	365.9	365.9
Long-term debt, including current portion [3,4,5]	**1,500.9**	**1,555.8**	1,401.7	1,454.2

[1] Due to the nature and/or short-term maturity of these financial instruments, carrying value approximates fair value.
[2] Carrying value approximates amortized cost.
[3] Carrying value is measured at amortized cost using the effective interest rate method.
[4] Carrying value at March 31, 2009 is net of unamortized deferred financing costs of $13.7 million (2008 - $12.8 million). The majority of the Company's long-term debt relates to regulated operations which enables the Company to recover the existing financing charges through rates or tolls.
[5] Fair value is calculated by discounting the future cash flow of each debt issue at the estimated yield to maturity for the same or similar issues at March 31, 2009, or by using available quoted market prices.

Fair value estimates are made at a specific point in time, based on relevant market information and information about the financial instrument. These estimates cannot be determined with precision as they are subjective in nature and involve uncertainties and matters of judgment.

Derivative Instruments

The Company hedges its exposure to fluctuations in natural gas prices through the use of derivative instruments. The table below indicates the valuation of the derivative instruments as at March 31, 2009.

Asset (Liability)			March 31, 2009		December 31, 2008	
December 31	Number of swaps and options	Term to maturity (years)	Carrying Value	Fair Value	Carrying Value	Fair Value
Natural Gas						
Commodity Swaps and Options	151	Up to 2.5	**$ (153.5)**	**$ (153.5)**	$ (70.7)	$ (70.7)
Gas purchase contract premiums	30	Up to 2.5	**1.5**	**1.5**	(6.2)	(6.2)

The natural gas derivatives fair value reflects only the value of the natural gas derivatives and not the offsetting change in value of the underlying future purchases of natural gas. These fair values reflect the estimated amounts the Company would receive or pay to terminate the contracts at the stated dates. The natural gas derivatives fair values have been determined using published market prices for natural gas commodities.

The derivatives entered into by the Company relate to regulated operations and any resulting gains or losses are recorded in rate stabilization accounts, subject to regulatory approval, and passed through to customers in future rates.

CHANGES IN ACCOUNTING POLICIES AND FUTURE PRONCOUNEMENTS

CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2009, the Company adopted the following new accounting standards issued by the Canadian Institute of Chartered Accountants ("CICA").

a) Section 3064, ***Goodwill and Intangible Assets,*** which replaces Section 3062, ***Goodwill and Other Intangible Assets***, and Section 3450, ***Research and Development Costs***, establishes standards for the recognition, measurement and disclosure of goodwill and other intangible assets. The standard requires that this section be applied on a retrospective basis. As a result, the Company has reclassified the net book value of land and transmission rights, certain computer software costs and franchise costs. As at December, 31, 2008, the net book value of intangible assets was increased by $73.8 million and the net book value of property, plant and equipment was reduced by $73.8 million.

b) Rate-Regulated Operations: Effective January 1, 2009, the Accounting Standards Board ("AcSB") amended: (i) CICA Handbook Section 1100, ***Generally Accounted Accounting Principles*** removing the temporary exemption providing relief to entities subject to rate regulation from the requirement to apply the Section to the recognition and measurement of assets and liabilities arising from rate regulation; (ii) Section 3465, Income Taxes to require the recognition of future income tax liabilities and assets as well as offsetting regulated assets or liabilities.

   Prior to January 1, 2009, the Company used the taxes payable method of accounting for income taxes. As a result of the amendments to Section 3465, ***Income Taxes,*** on January 1, 2009, regulatory assets related to future income taxes included in deferred charges increased by $266.4 million, future income tax liabilities increased by $242.4 million, and opening retained earnings was adjusted by $14.5 million, respectively. Included in the amounts are the future income tax effects of the subsequent settlement of the related regulatory assets and liabilities through customer rates and the separate disclosure of future income tax assets and liabilities.

   Effective January 1, 2009, with the removal of the temporary exemption in Section 1100, the Company must now apply Section 1100 to the recognition of assets and liabilities arising from rate regulation. Certain assets and liabilities arising from rate regulation continue to have specific guidance under a primary source of Canadian GAAP that applies only to the particular circumstances described therein, including those arising under Section 1600, ***Consolidated Financial Statements***, Section 3061, ***Property, Plant and Equipment***, Section 3465***, Income Taxes***, and Section 3475, ***Disposal of Long-Lived Assets and Discontinued Operations***. The assets and liabilities arising from rate regulation, as described in Note 4 to the 2008 Consolidated Financial Statements, do not have specific guidance under a primary source of Canadian GAAP.

Therefore, Section 1100 directs the Company to adopt accounting policies that are developed through the exercise of professional judgment and the application of concepts described in Section 1000, ***Financial Statement Concepts***. In developing these accounting policies, the Company may consult other sources including pronouncements issued by bodies authorized to issue accounting standards in other jurisdictions. Therefore, in accordance with Section 1100, the Company has determined that its regulatory assets and liabilities qualify for recognition under Canadian GAAP and this recognition is consistent with US Statement of Financial Accounting Standards No. 71, ***Accounting for the Effects of Certain Types of Regulation***. Therefore, there was no effect on the Company's consolidated financial statements as at January 1, 2009 due to the removal of the temporary exemption in Section 1100.

c) Emerging Issues Committee ("EIC") – 173, ***Credit Risk and the Fair Value of Financial Assets and Financial Liabilities***, requires that the Company's own credit risk and the credit risk of its counterparties be taken into account in determining the fair value of a financial instrument. The Company's consolidated financial statements are not materially impacted from applying this new standard.

FUTURE ACCOUNTING PRONOUNCEMENTS

Business Combinations: Effective January 1, 2010, the Company will be early adopting the new CICA Handbook Section 1582, ***Business Combinations,*** together with Section 1601, ***Consolidated Financial Statements*** and Section 1602, ***Non-controlling Interests.*** These new standards were issued by the AcSB in January 2009 to be effective for fiscal years beginning on or after January 1, 2011 with early adoption permitted. As a result of adopting Section 1582, changes in the determination of the fair value of the assets and liabilities of the acquiree will result in a different calculation of goodwill. Such changes include the expensing of acquisition-related costs incurred during a business acquisition, rather than recording them as a capital transaction, and the disallowance of recording restructuring accruals. The adoption of these standards is not expected to have a material impact on the Company's earnings, cash flows or financial position.

Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The adoption of Section 1601 and 1602 will result in non-controlling interests being presented as a component of equity, rather than as a liability on the consolidated balance sheet. Also, net income and components of other comprehensive income attributable to the owners of the parent and to the non-controlling interests are required to be separately disclosed on the income statement. The adoption of Section 1601 and 1602 is not expected to have a material impact on the Company's earnings, cash flows or financial position.

International Financial Reporting Standards ("IFRS"): In February 2008, the AcSB confirmed that the use of IFRS will be required in 2011 for publicly accountable enterprises in Canada. In March 2009, the AcSB issued a second IFRS Omnibus Exposure Draft confirming that publicly accountable enterprises be required to apply IFRS, in full and without modification, on January 1, 2011.

On June 27, 2008 the Canadian Securities Administrators ("CSA") issued Staff Notice 52-321, ***Early Adoption of IFRS*** which indicated that the CSA would be prepared to grant an exemption to allow Canadian financial statement issuers to adopt IFRS early on a case-by-case basis, provided that they could demonstrate that they met certain conditions. Terasen Gas is not planning to early adopt IFRS.

The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Company for its year ended December 31, 2010, and of the opening balance sheet as at January 1, 2010. The AcSB proposes that CICA Handbook Section - ***Accounting Changes***, paragraph 1506.30, which would require an entity to disclose information relating to a new primary source of GAAP that has been issued but is not yet effective and that the entity has not applied, not be applied with respect to the IFRS Omnibus Exposure Draft.

Terasen Gas is continuing to assess the financial reporting impacts of the adoption of IFRS and, at this time, the impact on future financial position and results of operations is not reasonably determinable or estimable. Terasen Gas does anticipate a significant increase in disclosure resulting from the adoption of IFRS and is continuing to assess the level of disclosure required as well as systems changes that may be necessary to gather and process the required information.

Terasen Gas commenced its IFRS conversion project in 2007 and has established a formal project governance structure which includes the audit committees, senior management and a project team. Overall project governance, management and support are coordinated by Fortis. Regular reporting occurs to the Audit Committee of the Board of Directors. An external expert advisor has been engaged to assist in the IFRS conversion project.

The Terasen Gas IFRS conversion project consists of three phases: Scoping and Diagnostics, Analysis and Development, and Implementation and Review.

Phase One: Scoping and Diagnostics, which involved project planning and staffing and identification of differences between current Canadian GAAP and IFRS, has been completed. The resulting identified areas of accounting difference of highest potential impact to the Company, based on existing IFRS, are rate-regulated accounting, property plant and equipment, intangible assets, provisions and contingent liabilities, employee benefits, impairment of assets, income taxes, and initial adoption of IFRS under the provisions of IFRS 1 ***First-Time Adoption of IFRS***.

Phase Two: Analysis and Development is nearing completion, and involves detailed diagnostics and evaluation of the financial impacts of various options and alternative methodologies provided for under IFRS; identification and design of operational and financial business processes; initial staff and audit committee training; analysis of IFRS 1 optional exemptions and mandatory exceptions to the general requirement for full retrospective application upon transition to IFRS; summarization of 2011 IFRS disclosure requirements; and development of required solutions to address identified issues.

The Company has completed a preliminary assessment of the impacts of adopting IFRS; however a final assessment cannot be completed at this time pending the outcome of the project on rate-regulated activities that was recently added to the International Accounting Standards Board ("IASB") technical agenda. The IASB is expected to issue an exposure draft addressing rate-regulated activities during the third quarter of 2009.

It is anticipated that the adoption of IFRS will have an impact on information systems requirements. The Company is assessing the need for system upgrades or modifications to ensure an efficient conversion to IFRS. As part of Phase Two, information systems plans are being prepared for implementation in Phase Three. The extent of the impact on the Company's information systems is not reasonably determinable at this time.

Phase Three: Implementation and Review, expected to commence mid-year 2009, will involve the execution of changes to information systems and business processes; completion of formal authorization processes to approve recommended accounting policy changes; and further training programs across the Company's finance and other affected areas, as necessary. It will culminate in the collection of financial information necessary to compile IFRS-compliant financial statements and reconciliations; embedding of IFRS in business processes; and, audit committee approval of IFRS-compliant financial statements.

Terasen Gas will continue to review all proposed and continuing projects of the International Accounting Standards Board, closely monitor any International Financial Reporting Interpretations Committee initiatives with the potential to impact rate-regulated accounting under IFRS, and will participate in any related processes, as appropriate.

RISK ASSESSMENT AND CRITICAL ACCOUNTING ESTIMATES

Except as discussed below, the risk profile and critical accounting estimates of Terasen Gas remains substantially unchanged from the profile outlined in Terasen Gas' 2008 Annual Management's Discussion and Analysis.

INCOME TAXES

Income taxes are determined based on estimates of the Company's current income taxes and estimates of future income taxes resulting from temporary differences between the carrying value of assets and liabilities in the consolidated financial statements and their tax values. The use of estimation with respect to recording future income taxes has increased due to the adoption by the Company of amended CICA Handbook Section 3465, ***Income Taxes***, effective January 1, 2009. A future income tax asset or liability is determined for each temporary difference based on the future tax rates that are expected to be in effect and management's assumptions regarding the expected timing of the reversal of such temporary differences. Future income tax assets are assessed for the likelihood that they will be recovered from future taxable income. To the extent recovery is not considered more likely than not, a valuation allowance is recorded and charged against earnings in the period that the allowance is created or revised. Estimates of the provision for income taxes, future income tax assets and liabilities and any related valuation allowance might vary from actual amounts incurred.

ADDITIONAL INFORMATION

Additional information relating to Terasen Gas Inc, including its Annual Information Form is available on SEDAR at www.sedar.com.

Attachment 35c

No securities commission or similar authority in Canada has in any way passed upon the merits of these securities and any representation to the contrary is an offence. This prospectus supplement, together with the short form base shelf prospectus dated December 10, 2003 to which it relates, as amended or supplemented, and each document incorporated or deemed to be incorporated by reference in the short form base shelf prospectus, constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities.

Prospectus Supplement dated March 11, 2004 to the
Short Form Base Shelf Prospectus dated December 10, 2003

TERASEN GAS INC.
$700,000,000
MEDIUM TERM NOTE DEBENTURES
(Unsecured)

Change with respect to Ratings

After reassessing its relationship with Standard & Poor's Ratings Services, a division of the McGraw-Hill Companies (Canada) Corporation ("S&P"), Terasen Gas Inc. (the "Company" or "Terasen Gas") has discontinued the engagement of S&P to provide credit ratings in respect of the Company's medium term note program, including the medium term note debentures ("MTN Debentures") to be issued thereunder.

The Company is continuing its engagement of Moody's Investors Services Inc. ("Moody's") and Dominion Bond Rating Service Limited ("DBRS") and the Company's credit ratings on its MTN Debentures of A2 from Moody's and A from DBRS have not been changed.

Documents Incorporated by Reference

The following documents are, as of the date of this prospectus supplement, deemed to be incorporated by reference into the accompanying short form base shelf prospectus of Terasen Gas dated December 10, 2003 solely for the purpose of the MTN Debentures issued thereunder:

1. This Prospectus Supplement dated March 11, 2004.

Attachment 35f

CAPITAL STRUCTURE RATIOS
OF CANADIAN UTILITIES WITH RATED DEBT
(2008)

	Long-Term Debt 1/	Short-Term Debt	Preferred Stock 2/	Common Stock Equity 3/
Government Owned Utilities				
Enersource 4/	57.5%	0.0%	0.0%	42.5%
ENMAX Corp.	37.3%	4.6%	0.0%	58.1%
EPCOR Utilities Inc.	50.3%	2.6%	2.3%	44.8%
Hamilton Utilities 4/	35.4%	0.0%	0.0%	64.6%
Hydro One Inc.	54.5%	0.0%	2.9%	42.6%
Hydro Ottawa Holding Inc. 4/	43.8%	4.3%	0.0%	51.9%
London Hydro 4/	36.5%	0.0%	0.0%	63.5%
Toronto Hydro	55.2%	0.0%	0.0%	44.8%
Veridian 4/	40.4%	0.0%	0.0%	59.6%
Electric Utilities				
Altalink LP	61.7%	0.0%	0.0%	38.3%
CU Inc	56.6%	0.0%	5.2%	38.3%
FortisAlberta	60.0%	0.5%	0.0%	39.4%
FortisBC	59.1%	0.0%	0.0%	40.9%
Maritime Electric	53.6%	6.2%	0.0%	40.2%
Newfoundland Power	53.4%	0.0%	1.1%	45.5%
Nova Scotia Power	54.3%	0.8%	4.7%	40.1%
Gas Distributors				
Enbridge Gas Distribution	44.2%	18.1%	1.9%	35.8%
Gaz Metro	64.0%	2.0%	0.0%	34.0%
Pacific Northern Gas	45.6%	1.8%	3.0%	49.6%
Terasen Gas	55.7%	9.5%	0.0%	34.8%
Terasen Gas (Vancouver Is.)	46.3%	18.2%	0.0%	35.5%
Union Gas	56.1%	8.1%	2.6%	33.2%
Pipelines				
Enbridge Pipelines	52.7%	7.0%	0.0%	40.4%
Nova Gas Transmission Ltd.	61.4%	0.6%	0.0%	38.0%
Trans Quebec & Maritimes 4/	69.8%	0.0%	0.0%	30.2%
TransCanada Pipelines	54.1%	5.0%	1.2%	39.7%
Westcoast Energy	52.6%	1.2%	4.9%	41.3%
Medians				
Government Owned Electric T&D	**43.8%**	**0.0%**	**0.0%**	**51.9%**
Government Owned Electric Integrated	**43.8%**	**3.6%**	**1.1%**	**51.5%**
Private Electric T&D	**60.0%**	**0.0%**	**0.0%**	**39.4%**
Private Electric Integrated	**55.5%**	**0.4%**	**2.4%**	**40.2%**
All Private Electric	**56.6%**	**0.0%**	**0.0%**	**40.1%**
Private Gas Distributors	**51.0%**	**8.8%**	**1.0%**	**35.2%**
Private Pipelines	**54.1%**	**1.2%**	**0.0%**	**39.7%**
All Government Owned Companies	**43.8%**	**0.0%**	**0.0%**	**51.9%**
All Private Companies	**55.0%**	**1.5%**	**0.0%**	**38.9%**

1/ Includes current portion of long-term debt and preferred securities classified as debt.
2/ Includes minority interest in preferred shares of subsidiary companies and preferred securities .
3/ Includes minority interest in common shares of subsidiary companies.
4/ 2007 data.

Source: Annual Reports to Shareholders

FINANCIAL METRICS
FOR CANADIAN UTILITIES WITH RATED DEBT
2005-2007

Company	EBIT Coverage	FFO/ Total Debt	FFO Coverage [1/]
Government Owned Utilities			
Enersource	2.2	14.9	3.2
ENMAX Corp.	8.2	18.0	3.9
EPCOR Utilities Inc.	2.8	20.3	3.6
Hamilton Utilities	3.2	32.2	4.9
Hydro One Inc.	2.8	14.5	3.4
Hydro Ottawa Holding Inc.	3.5	22.3	5.3
London Hydro	2.9	20.9	4.0
Toronto Hydro	2.3	17.7	3.5
Veridian	3.4	29.5	4.2
Electric Utilities			
AltaLink L.P.	1.9	12.6	3.1
CU Inc.	2.5	17.1	3.4
FortisAlberta Inc.	2.2	14.3	4.2
FortisBC Inc.	2.1	10.4	2.7
Maritime Electric	2.7	13.5	2.8
Newfoundland Power	2.3	14.1	2.7
Nova Scotia Power	2.5	13.8	3.4
Gas Distributors			
Enbridge Gas Distribution	2.1	11.5	2.6
Gaz Metropolitain	2.5	20.9	5.0
Pacific Northern Gas	2.4	12.5	2.5
Terasen Gas	2.0	9.1	2.4
Terasen Gas (Vancouver Is.)	2.8	10.3	3.1
Union Gas	2.1	12.4	2.8
Pipelines			
Enbridge Pipelines	3.3	16.9	3.5
Nova Gas Transmission Ltd.	2.4	19.0	3.2
Trans Quebec & Maritimes	2.4	10.4	2.7
TransCanada PipeLines Ltd.	2.5	14.3	2.8
Westcoast Energy Inc.	2.2	17.0	3.2
Medians			
Government Owned Electric T&D	**2.9**	**20.9**	**4.0**
Government Owned Electric Integrated	**5.5**	**19.2**	**3.7**
Private Electric T&D	**2.2**	**14.1**	**3.1**
Private Electric Integrated	**2.5**	**13.7**	**3.1**
All Private Electric	**2.3**	**13.8**	**3.1**
Private Gas Distributors	**2.3**	**12.0**	**2.7**
Private Pipelines	**2.4**	**16.9**	**3.2**
All Government Owned Companies	**2.9**	**20.3**	**3.9**
All Private Companies	**2.4**	**13.7**	**3.0**

[1/] S&P defines Funds from Operations as follows:
FFO = (income from continuing operations + depreciation & amortization + deferred income taxes – AFUDC).

Source: Annual Reports to Shareholders and Standard and Poor's

Attachment 35g

DEBT RATINGS AND FINANCIAL METRICS FOR S&P RATED U.S. NATURAL GAS UTILITIES

	S&P									
				Average 2005-2007 [1/]						
Name	Debt Rating	Business Profile	Financial Profile	Debt Ratio	EBIT Coverage	FFO/Debt	FFO Coverage	Moody's Debt Rating	Common Equity Ratio (2008) [2/]	Average ROE 2006-2008
Nicor Gas	AA	Excellent	Intermediate	47.1	2.7	19.7	4.7	na		
Nicor Inc.	AA	Excellent	Intermediate	45.3	3.9	28.3	6.0	A3	44.0	14.2
Northwest Natural Gas Co.	AA-	Excellent	Intermediate	53.4	3.6	21.2	4.4	A3	45.3	11.5
Washington Gas Light Co.	AA-	Excellent	Intermediate	50.8	4.6	24.1	5.5	A2	49.9	10.9
WGL Holdings Inc.	AA-	Excellent	Intermediate	52.8	4.6	22.2	5.3	na	51.7	10.8
NSTAR Gas Co.	A+	Excellent	Intermediate	45.2	4.5	-5.4	3.6	na		
KeySpan Energy Delivery Long Island	A	Excellent	Intermediate	na	na	na	na	na		
KeySpan Energy Delivery New York	A	Excellent	Intermediate	na	na	na	na	na		
Laclede Gas Co.	A	Excellent	Intermediate	60.0	2.3	13.8	3.1	Baa1	34.0	9.7
Laclede Group	A	Excellent	Intermediate	57.9	3.0	17.7	3.6	na	44.5	13.9
New Jersey Natural Gas	A	Excellent	Intermediate	42.8	5.4	24.2	5.5	A1	51.2	13.9
Northern Natural Gas Co.	A	Excellent	Intermediate	na	na	na	na	A2		
Piedmont Natural Gas Co. Inc.	A	Excellent	Intermediate	50.5	3.9	24.9	4.9	A3	41.9	11.8
Southern California Gas Co.	A	Excellent	Intermediate	56.2	4.6	30.6	6.4	A2	50.9	16.0
AGL Resources Inc.	A-	Excellent	Intermediate	58.2	3.7	19.6	4.4	A3	39.4	13.2
Atlanta Gas Light Co.	A-	Excellent	Intermediate	na	na	na	na	A3		
Boston Gas Co.	A-	Excellent	Intermediate	na	na	na	na	A2		
Colonial Gas Co.	A-	Excellent	Intermediate	na	na	na	na	A2		
Indiana Gas Co. Inc.	A-	Excellent	Intermediate	48.0	2.8	16.4	3.6	Baa1		
KeySpan Corp.	A-	Excellent	Intermediate	61.8	3.5	16.3	3.5	Baa1		
Peoples Energy Corp.	A-	Excellent	Intermediate	na	na	na	na	Baa1		
Peoples Gas Light & Coke Co. (The)	A-	Excellent	Intermediate	45.8	3.8	14.1	3.1	na		
Public Service (North Carolina) 4/	A-	Excellent	Aggressive	42.1	2.9	14.3	3.3	A3	58.3	5.3
Vectren Corp.	A-	Excellent	Intermediate	58.4	2.8	17.1	4.0	na	42.2	10.4
Vectren Utility Holdings Inc.	A-	Excellent	Intermediate	53.7	2.9	19.0	4.1	Baa1	48.2	9.4
Wisconsin Gas LLC	A-	Excellent	Intermediate	na	na	na	na	A1		
Atmos Energy Corp.	BBB+	Excellent	Aggressive	59.6	2.6	16.6	3.7	Baa2	45.4	9.1
Connecticut Natural Gas Corp.	BBB+	Excellent	Intermediate	na	na	na	na	Baa1		
Questar Gas Co.	BBB+	Satisfactory	Intermediate	51.9	3.5	22.7	4.4	A3	45.6	11.2
South Jersey Gas Co.	BBB+	Excellent	Aggressive	49.6	3.8	17.7	3.9	Baa1	49.5	10.2
Southern Connecticut Gas Co.	BBB+	Excellent	Intermediate	na	na	na	na	Baa1		
Alabama Gas Corp.	BBB	Satisfactory	Intermediate	46.6	4.3	33.9	5.8	A1	53.4	13.1
Energen Corp.	BBB	Satisfactory	Intermediate	42.4	8.4	52.7	9.3	Baa3	75.4	23.2
Michigan Consolidated Gas Co.	BBB	Excellent	Aggressive	na	na	na	na	Baa1	38.5	8.6
National Fuel Gas Co.	BBB	Satisfactory	Intermediate	50.3	4.8	33.3	6.2	Baa1	59.3	16.3
Yankee Gas Services Co.	BBB	Excellent	Aggressive	na	na	na	na	Baa2		
Bay State Gas Co.	BBB-	Excellent	Aggressive	na	na	na	na	na		
Northern Indiana Public Service Co.	BBB-	Excellent	Aggressive	na	na	na	na	Baa2		
Southwest Gas Corp.	BBB-	Strong	Aggressive	62.3	2.2	17.0	3.8	Baa3	43.5	8.3
SourceGas LLC	BB+	Excellent	Highly leveraged	na	na	na	na	Ba1		
Mean	**A-**	**Excellent**	**Intermediate**	**51.7**	**3.8**	**21.3**	**4.6**	**A3**	**48.2**	**12.0**
Median	**A-**	**Excellent**	**Intermediate**	**50.8**	**3.7**	**19.6**	**4.4**	**A3**	**45.6**	**11.2**

[1/] S&P Credit Stats
[2/] Equity ratio based on total capital.
[3/] ROE and equity ratio for New Jersey Resources Corp.
[4/] Common equity ratio is 2007, and average ROE is for 2005-2007.

Source: S&P Research Insight, S&P: *Issuer Ranking: U.S. Natural Gas Distributors and Integrated Gas Companies, Strongest to Weakest, March 10, 2009* and S&P, Credit Stats, September 2008 and www.moodys.com

DEBT RATINGS AND FINANCIAL METRICS FOR S&P RATED U.S. ELECTRIC UTILITIES

	S&P									
				Average 2005-2007 [1/]						
Name	**Debt Rating**	**Business Profile**	**Financial Profile**	**Debt Ratio**	**EBIT Coverage**	**FFO/Debt**	**FFO Coverage**	**Moody's Debt Rating**	**Common Equity Ratio (2008)** [2/]	**Average ROE 2006-2008**
Madison Gas & Electric Co.	AA-	Excellent	Intermediate	50.8	4.6	20.5	5.4	Aa3	53.6	11.1
NSTAR	A+	Excellent	Intermediate	62.4	3.5	23.2	5.3	A2	36.8	13.5
Alabama Power Co.	A	Excellent	Intermediate	52.7	4.2	21.8	5.3	A2	42.5	13.4
Central Hudson Gas & Electric Corp.	A	Excellent	Intermediate	61.4	4.5	16.1	4.5	A2	43.7	9.3
Florida Power & Light Co.	A	Excellent	Intermediate	43.3	5.0	30.3	6.3	A1	56.0	10.9
FPL Group Inc.	A	Excellent	Intermediate	51.4	2.9	25.8	5.3	A2	40.6	13.7
Georgia Power Co.	A	Excellent	Intermediate	49.7	4.8	23.3	5.5	A2	46.5	13.7
Gulf Power Co.	A	Excellent	Intermediate	53.2	3.8	20.1	4.6	A2	42.9	12.4
Mississippi Power Co.	A	Excellent	Intermediate	47.0	6.9	44.7	11.3	A1	57.5	14.0
San Diego Gas & Electric Co.	A	Excellent	Intermediate	51.5	3.4	30.5	4.6	A2	53.3	14.0
Southern Co.	A	Excellent	Intermediate	56.4	3.6	21.3	5.1	A3	40.5	14.1
Consolidated Edison Co. of New York Inc.	A-	Excellent	Intermediate	54.1	3.0	15.5	3.6	A1	48.8	10.1
Consolidated Edison Inc.	A-	Excellent	Intermediate	57.1	2.9	14.7	3.6	A2	48.5	11.1
Dominion Resources	A-	Excellent	Aggressive	60.3	2.5	13.0	3.1	Baa2	36.3	18.3
Duke Energy Carolinas LLC	A-	Excellent	Intermediate	47.9	4.1	31.3	9.9	A3	na	na
Duke Energy Corp.	A-	Excellent	Intermediate	44.3	3.6	22.4	4.5	Baa2	59.2	7.1
Duke Energy Indiana Inc. 3/	A-	Excellent	Intermediate	55.0	3.1	17.4	4.4	Baa1	46.7	9.1
Duke Energy Kentucky	A-	Excellent	Intermediate	69.0	1.3	8.2	2.7	Baa1	na	na
Duke Energy Ohio Inc.	A-	Excellent	Intermediate	32.1	3.9	24.0	5.4	Baa1	na	na
MidAmerican Energy Co.	A-	Excellent	Aggressive	53.0	4.2	23.3	5.3	A2	43.4	14.6
Northern States Power (Wisconsin)	A-	Excellent	Intermediate	44.9	3.4	24.0	4.9	A3	51.3	9.3
PacifiCorp	A-	Excellent	Aggressive	55.6	2.8	16.8	3.8	Baa1	51.1	7.1
PPL Electric Utilities Corp.	A-	Excellent	Intermediate	52.3	3.4	20.4	4.1	Baa1	38.3	12.5
SCANA Corp.	A-	Excellent	Aggressive	57.5	2.4	19.6	4.3	Baa1	39.3	11.2
South Carolina Electric & Gas Co.	A-	Excellent	Aggressive	49.1	2.6	27.3	5.3	A3	44.9	9.5
Southern Indiana Gas & Electric	A-	Excellent	Intermediate	46.1	3.7	23.5	4.8	Baa1	na	na
Virginia Electric Power 3/	A-	Excellent	Aggressive	52.5	3.2	20.0	4.4	Baa1	47.1	6.5
Wisconsin Electric Power Co.	A-	Excellent	Intermediate	46.4	3.7	28.3	5.3	A1	46.7	11.1
Wisconsin Power & Light Co.	A-	Excellent	Intermediate	50.8	3.8	20.2	4.8	A2	53.7	10.0
Wisconsin Public Service Corp.	A-	Excellent	Aggressive	55.5	3.1	18.7	4.1	A1	54.2	10.1
ALLETE Inc.	BBB+	Strong	Intermediate	51.6	4.2	20.1	4.6	Baa1	57.8	11.7
Alliant Energy Corp.	BBB+	Excellent	Aggressive	54.8	2.7	19.5	4.0	NA	56.0	12.9
Carolina Power & Light Co. d/b/a Progress Energy Carolinas Inc.	BBB+	Excellent	Aggressive	57.2	4.2	23.3	5.5	A3	53.9	13.7
Energy East Corp.	BBB+	Excellent	Aggressive	60.1	2.2	14.5	3.0	Ba2	na	na
Florida Power Corp. d/b/a Progress Energy Florida Inc.	BBB+	Excellent	Aggressive	54.9	3.5	24.1	5.4	A3	41.1	11.8
Integrys Energy Group Inc.	BBB+	Excellent	Aggressive	52.6	2.8	12.4	3.3	Baa1	45.6	8.5
Interstate Power & Light Co.	BBB+	Excellent	Aggressive	51.3	3.8	23.5	4.5	A3	48.5	17.3
MidAmerican Energy Holdings Co.	BBB+	Excellent	Aggressive	66.1	2.3	13.0	3.0	Baa1	33.5	16.2
North Shore Gas Co.	BBB+	Excellent	Aggressive	45.6	4.5	20.6	4.9	A3	54.8	7.1
Northern States Power Co.	BBB+	Excellent	Aggressive	54.1	2.8	21.0	4.0	A3	49.8	10.2
OGE Energy Corp.	BBB+	Strong	Aggressive	52.7	4.6	23.5	5.0	Baa1	43.5	15.1
Oklahoma Gas & Electric Co.	BBB+	Excellent	Intermediate	44.6	5.0	27.7	5.4	A2	54.2	10.9
Oncor Electric Delivery Co. LLC	BBB+	Excellent	Intermediate	56.0	3.1	20.2	4.0	Baa2	55.1	3.7
Pacific Gas & Electric Co.	BBB+	Excellent	Intermediate	59.8	2.8	19.5	3.7	A3	44.7	12.5
Portland General Electric Co.	BBB+	Strong	Intermediate	53.3	2.3	20.2	3.8	Baa2	47.3	7.9
Progress Energy Inc.	BBB+	Excellent	Aggressive	58.5	2.2	15.9	3.7	Baa2	41.9	7.6
Public Service Co. of Colorado	BBB+	Excellent	Aggressive	52.2	2.6	16.8	3.6	Baa1	58.2	9.2
Sempra Energy	BBB+	Strong	Intermediate	49.9	4.2	26.6	4.9	Baa1	50.6	16.0
Southern California Edison Co.	BBB+	Excellent	Intermediate	55.3	3.3	26.7	4.5	A3	41.5	12.6
Southwestern Public Service Co.	BBB+	Excellent	Aggressive	54.6	2.2	14.6	3.4	Baa1	47.6	4.6
Wisconsin Energy Corp.	BBB+	Excellent	Aggressive	60.8	3.1	15.8	4.3	A3	41.2	11.2
Xcel Energy Inc.	BBB+	Excellent	Aggressive	61.5	2.2	16.7	3.5	Baa1	44.0	9.8
AEP Texas Central Co.	BBB	Excellent	Aggressive	73.4	1.3	4.1	1.5	Baa2	15.0	12.4
AEP Texas North Co.	BBB	Excellent	Aggressive	47.9	3.3	21.5	4.2	Baa2	44.6	9.1
American Electric Power Co. Inc	BBB	Excellent	Aggressive	62.5	2.4	16.3	3.5	Baa2	36.8	12.0
Appalachian Power Co.	BBB	Excellent	Aggressive	59.0	2.2	10.8	3.0	Baa2	41.2	7.1
Atlantic City Electric Co.	BBB	Excellent	Aggressive	52.1	3.0	22.1	3.4	Baa1	33.3	12.8
Baltimore Gas & Electric Co.	BBB	Strong	Intermediate	50.5	3.3	13.7	3.2	Baa2	35.1	6.5
CenterPoint Energy Houston Electric LLC	BBB	Excellent	Aggressive	49.8	3.2	29.4	4.0	Baa3	27.0	13.6
CenterPoint Energy Inc.	BBB	Excellent	Aggressive	84.0	1.9	14.6	2.9	Ba1	16.0	25.7
CenterPoint Energy Resources Corp.	BBB	Excellent	Aggressive	47.7	2.9	19.5	3.7	Baa3	46.4	9.1
Cleco Corp.	BBB	Strong	Aggressive	49.7	5.1	24.4	5.0	Ba2	47.5	11.7
Cleco Power LLC	BBB	Strong	Aggressive	52.2	3.3	18.5	4.3	Baa1	44.9	11.9
Cleveland Electric Illuminating Co.	BBB	Excellent	Aggressive	58.9	4.0	7.5	2.2	Baa3	44.9	18.3
Columbus Southern Power Co.	BBB	Excellent	Aggressive	57.4	4.6	21.6	5.0	A3	44.9	20.4
Dayton Power & Light Co.	BBB	Excellent	Aggressive	40.2	12.7	42.9	12.3	A2	61.6	20.6
Delmarva Power & Light Co.	BBB	Excellent	Aggressive	56.8	3.1	13.8	3.7	Baa2	44.7	7.5
Detroit Edison Co.	BBB	Excellent	Aggressive	65.1	2.9	15.7	3.9	Baa1	40.2	10.0
DPL Inc.	BBB	Excellent	Aggressive	66.6	3.2	18.7	3.8	Baa1	38.3	23.5
DTE Energy Co.	BBB	Excellent	Aggressive	61.6	1.9	13.1	3.4	Baa2	40.4	11.1
El Paso Electric Co.	BBB	Strong	Aggressive	56.7	2.9	21.8	4.6	Baa2	45.4	11.4
Entergy Arkansas Inc.	BBB	Strong	Aggressive	53.5	3.6	29.2	6.2	Baa2	42.9	7.9
Entergy Corp.	BBB	Strong	Aggressive	59.2	3.4	23.2	5.2	Baa3	38.8	14.6
Entergy Mississippi Inc.	BBB	Strong	Aggressive	56.0	2.9	32.4	6.3	Baa3	46.9	9.3
FirstEnergy Corp.	BBB	Excellent	Aggressive	61.3	3.0	15.5	3.4	Baa3	37.2	14.6
Great Plains Energy Inc.	BBB	Excellent	Aggressive	55.5	3.0	22.2	4.5	Baa3	44.0	9.4
Hawaiian Electric Co. Inc	BBB	Strong	Aggressive	59.9	2.3	15.6	3.9	Baa1	54.8	6.8
Hawaiian Electric Industries Inc.	BBB	Strong	Aggressive	62.4	2.4	14.1	3.5	Baa2	41.9	7.8
IDACORP Inc.	BBB	Strong	Aggressive	56.3	2.3	11.2	3.1	Baa2	47.8	8.3
Idaho Power Co.	BBB	Strong	Aggressive	56.6	2.7	11.2	3.1	Baa1	46.4	8.3
Indiana Michigan Power Co.	BBB	Strong	Aggressive	71.1	2.5	13.9	4.3	Baa2	42.5	9.7
ITC Holdings Corp.	BBB	Excellent	Aggressive	75.0	2.4	8.1	3.1	Baa3	29.2	12.1
Jersey Central Power & Light Co.	BBB	Excellent	Aggressive	29.3	4.5	22.0	4.2	Baa2	61.9	6.2
Kansas City Power & Light Co.	BBB	Excellent	Aggressive	49.6	3.6	27.7	5.6	Baa1	48.0	10.3
Kentucky Power Co.	BBB	Excellent	Aggressive	59.0	2.3	14.2	3.4	Baa2	41.7	8.2
Metropolitan Edison Co.	BBB	Excellent	Aggressive	44.5	3.6	9.2	2.5	Baa2	55.4	-0.9
Northeast Utilities	BBB	Excellent	Aggressive	57.5	1.9	8.7	2.5	Baa2	35.1	11.8
NorthWestern Corp.	BBB	Excellent	Aggressive	55.5	2.2	18.5	3.5	Baa2	45.9	6.8
Ohio Edison Co.	BBB	Excellent	Aggressive	52.7	4.1	18.5	4.2	Baa2	51.4	11.7
Ohio Power Co.	BBB	Excellent	Aggressive	58.6	3.1	16.5	4.1	A3	43.0	11.4
PECO Energy Co.	BBB	Excellent	Aggressive	53.7	7.8	22.8	5.8	A3	37.7	22.8
Pennsylvania Electric Co.	BBB	Excellent	Aggressive	40.6	3.3	10.2	2.8	Baa2	47.3	7.5
PEPCO Holdings Inc.	BBB	Strong	Aggressive	62.0	2.3	11.2	2.9	Baa3	41.4	7.7
Potomac Electric Power Co.	BBB	Excellent	Aggressive	56.5	2.7	18.5	4.0	Baa2	41.7	9.6

DEBT RATINGS AND FINANCIAL METRICS FOR S&P RATED U.S. ELECTRIC UTILITIES

	S&P									
				Average 2005-2007 [1/]						
Name	Debt Rating	Business Profile	Financial Profile	Debt Ratio	EBIT Coverage	FFO/Debt	FFO Coverage	Moody's Debt Rating	Common Equity Ratio (2008) [2/]	Average ROE 2006-2008
Public Service Co. of New Hampshire	BBB	Excellent	Aggressive	62.0	3.1	14.6	3.9	Baa2	39.6	9.5
Public Service Co. of Oklahoma	BBB	Excellent	Aggressive	60.1	1.4	17.2	4.0	Baa1	43.7	4.6
Public Service Electric & Gas Co.	BBB	Excellent	Aggressive	55.5	3.4	15.0	3.4	Baa1	41.4	10.2
Puget Sound Energy Inc.	BBB	Excellent	Aggressive	59.5	2.1	14.5	3.1	Baa3	38.0	7.9
Southwestern Electric Power Co.	BBB	Excellent	Aggressive	56.8	2.5	16.6	3.8	Baa3	43.8	9.0
System Energy Resources Inc.	BBB	Strong	Aggressive	51.7	4.1	23.4	4.7	Ba1	51.4	14.1
Toledo Edison Co.	BBB	Excellent	Aggressive	60.5	3.4	27.0	5.5	Baa3	53.9	15.9
Western Massachusetts Electric Co.	BBB	Excellent	Aggressive	61.4	2.8	8.5	3.0	Baa2	35.2	8.6
Allegheny Energy Inc.	BBB-	Strong	Aggressive	65.6	2.3	15.3	2.9	Ba3	40.2	16.5
Ameren Corp.	BBB-	Satisfactory	Aggressive	53.0	3.7	18.0	4.6	Baa3	45.6	8.8
Arizona Public Service Co.	BBB-	Strong	Aggressive	56.0	3.1	16.8	4.2	Baa2	49.7	8.4
Avista Corp.	BBB-	Strong	Aggressive	61.6	1.8	13.6	2.8	Baa3	45.5	6.9
Black Hills Corp.	BBB-	Satisfactory	Intermediate	51.4	2.8	22.6	4.2	Baa3	46.5	10.7
Black Hills Power Inc.	BBB-	Strong	Intermediate	44.1	3.3	25.2	4.1	Baa2	53.5	10.0
Central Illinois Light Co.	BBB-	Satisfactory	Aggressive	42.2	4.5	30.0	7.1	Ba1	51.3	10.8
Central Illinois Public Service Co.	BBB-	Strong	Aggressive	48.8	2.5	16.2	3.5	Ba1	45.4	4.1
CILCORP Inc.	BBB-	Satisfactory	Aggressive	58.0	1.5	9.7	2.7	Ba2	38.1	5.1
CMS Energy Corp.	BBB-	Excellent	Aggressive	76.6	1.4	8.9	2.4	Ba1	25.9	-0.6
Commonwealth Edison Co.	BBB-	Strong	Aggressive	43.8	3.7	10.6	2.9	Baa3	57.4	1.3
Edison International	BBB-	Strong	Aggressive	64.9	2.3	17.0	3.0	Baa2	40.2	14.5
Empire District Electric Co.	BBB-	Strong	Aggressive	54.4	2.3	17.4	3.7	Baa2	41.9	7.7
Entergy New Orleans Inc.	BBB-	Satisfactory	Aggressive	60.5	2.3	46.6	6.5	Ba2	41.9	11.4
Illinois Power Co.	BBB-	Strong	Aggressive	45.1	2.6	14.6	3.6	Ba1	45.5	2.1
NiSource Inc.	BBB-	Excellent	Aggressive	59.5	2.1	11.9	2.9	Baa3	38.4	4.5
Pinnacle West Capital Corp.	BBB-	Strong	Aggressive	56.8	2.8	15.5	3.8	Baa3	47.0	8.4
Tampa Electric Co.	BBB-	Excellent	Aggressive	53.0	3.1	21.1	4.2	Baa1	52.0	9.4
TECO Energy Inc.	BBB-	Excellent	Aggressive	70.0	1.8	14.3	3.0	Baa3	37.8	15.0
Union Electric Co. d/b/a AmerenUE	BBB-	Excellent	Aggressive	50.4	4.0	22.4	5.2	Baa2	45.5	9.6
Westar Energy Inc.	BBB-	Excellent	Aggressive	60.7	2.7	16.3	3.9	Baa3	45.2	10.0
Central Vermont Public Service Corp.	BB+	Excellent	Highly leveraged	73.3	1.5	12.1	3.0	Baa3	52.5	8.4
IPALCO Enterprises Inc.	BB+	Excellent	Highly leveraged	102.6	2.5	14.2	3.1	Ba2	na	na
Puget Energy Inc.	BB+	Excellent	Aggressive	59.3	2.0	13.2	2.9	Ba2	na	na
Tucson Electric Power Co.	BB+	Strong	Highly leveraged	72.6	1.8	17.5	3.1	Baa3	28.8	7.4
PNM Resources Inc.	BB-	Satisfactory	Highly leveraged	63.2	1.7	10.5	2.9	Ba2	40.3	-1.2
Public Service Co. of New Mexico	BB-	Satisfactory	Highly leveraged	57.9	2.0	9.8	3.1	Baa3	48.8	2.3
Texas-New Mexico Power Co.	BB-	Satisfactory	Highly leveraged	45.0	2.0	11.6	2.6	Baa3	56.1	1.6
Nevada Power Co.	BB	Excellent	Highly leveraged	56.9	2.2	12.3	2.7	Ba3	43.6	8.3
Sierra Pacific Power Co.	BB	Excellent	Highly leveraged	57.9	2.0	15.3	3.2	Ba3	38.6	7.8
Mean	**BBB**	**Excellent**	**Aggressive**	**55.9**	**3.1**	**18.8**	**4.2**	**Baa2**	**44.8**	**10.3**
Median	**BBB**	**Excellent**	**Aggressive**	**55.6**	**3.0**	**17.5**	**4.0**	**Baa2**	**44.9**	**10.0**

[1/] S&P Credit Stats

[2/] Equity ratio based on total capital.

[3/] Common equity ratio is 2007, and average ROE is for 2005-2007.

Source: Standard and Poor's Research Insight; S&P, *Issuer Ranking: U.S. Regulated Electric Utilities, Strongest to Weakest,* March 31, 2009;
S&P, *Credit Stats,* September 2008 and www.moodys.com

Attachment 35h

INDIVIDUAL COMPANY RISK DATA FOR BENCHMARK SAMPLE OF
US ELECTRIC AND GAS UTILITIES

	Value Line									S & P		Moody's	Average
	Safety	Earnings Predictability	Financial Strength	Forecast Common Equity Ratio 2010-2012	Forecast Return On Average Common Equity 2010-2012	Dividend Payout Forecast 2010-2012	Beta	Research Insight Beta 1/	Common Equity Ratio 2006	Business Profile	Debt Rating	Debt Rating 2/	Market/ Book Ratio 1994-2006
AGL Resources	2	75	B++	50.8%	14.2%	58.1%	0.95	0.58	42.7%	4	A-	A3	1.76
Consol. Edison	1	85	A++	50.5%	9.1%	70.6%	0.75	0.43	47.0%	2	A	A2	1.49
FPL Group	1	80	A+	51.0%	12.4%	51.8%	0.85	0.69	44.6%	5	A	A2	1.89
Integrys Energy	2	70	B++	49.5%	11.1%	65.7%	0.85	0.66	42.4%	5	A-	A3	1.62
New Jersey Resources	1	95	A	69.3%	10.7%	54.6%	0.80	0.39	50.2%	2	A+	na	2.19
NICOR Inc.	3	75	A	69.0%	13.2%	63.5%	1.30	0.99	50.7%	3	AA	A3	2.28
Northwest Nat. Gas	1	80	A	52.0%	11.6%	60.0%	0.75	0.44	48.1%	1	AA-	A3	1.56
NSTAR	1	95	A	55.5%	15.7%	58.3%	0.80	0.64	34.4%	1	A+	A2	1.74
Piedmont Natural Gas	2	80	B++	52.8%	11.2%	71.9%	0.80	0.60	47.0%	2	A	A3	2.00
SCANA Corp.	2	95	A	49.0%	11.1%	61.5%	0.85	0.70	43.4%	4	A-	A3	1.64
Southern Co.	1	95	A	44.0%	13.0%	74.0%	0.70	0.33	40.6%	4	A	A3	2.08
Vectren Corp.	2	70	A	51.0%	10.5%	71.5%	0.95	0.71	40.6%	4	A-	Baa1	1.91
WGL Holdings Inc.	1	65	A	64.5%	11.1%	63.3%	0.85	0.54	52.2%	3	AA-	A2	1.71
Mean	**2**	**82**	**A**	**54.5%**	**11.9%**	**63.4%**	**0.86**	**0.59**	**44.9%**	**3**	**A**	**A2**	**1.84**
Median	**1**	**80**	**A**	**51.0%**	**11.2%**	**63.3%**	**0.85**	**0.60**	**44.6%**	**3**	**A**	**A3**	**1.76**
Weighted Average	**1**	**86**	**A**	**50.0%**	**12.0%**	**64.6%**	**0.80**	**0.53**	**43.5%**	**4**	**A**	**A2**	**1.84**

1/ Calculated using monthly data against the S&P 500 (60 months ending June 2007); adjusted towards the market mean of 1.0.

2/ Rating for WGL Holdings is Washington Gas Light.

Source: Standard and Poor's Research Insight, Value Line (June 2007), www.Moodys.com,
Standard and Poor's, *Issuer Ranking: U.S. Integrated Utility And Merchant Power Companies, Strongest To Weakest* (July 24, 2007) and

DCF COST OF EQUITY FOR BENCHMARK SAMPLE OF US ELECTRIC AND GAS UTILITIES (BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)

Company	Annualized Last Paid Dividend (1)	Average Daily Closing Prices 7/15-8/15/2007 (2)	Expected Dividend Yield [1/] (3)	I/B/E/S Long-Term EPS Forecasts (4)	DCF Cost of Equity [2/] (5)
AGL Resources	1.64	38.77	4.4	4.5	8.9
Consolidated Edison	2.32	45.41	5.3	3.5	8.7
FPL	1.64	59.01	3.0	9.1	12.2
Integrys Energy	2.64	50.78	5.5	5.3	10.8
New Jersey Resources	1.52	48.91	3.2	4.5	7.7
Nicor Inc.	1.86	41.20	4.7	4.6	9.3
Northwest Nat. Gas	1.42	44.12	3.4	4.8	8.2
NSTAR	1.30	32.21	4.3	6.3	10.5
Piedmont Natural Gas	1.00	24.64	4.2	4.5	8.7
Scana	1.76	38.11	4.8	4.5	9.3
Southern Co.	1.61	34.87	4.8	4.6	9.4
Vectren	1.26	26.45	5.0	4.3	9.3
WGL Holdings Inc.	1.37	31.65	4.5	3.3	7.8
Mean	**1.64**	**39.70**	**4.4**	**4.9**	**9.3**
Median	**1.61**	**38.77**	**4.5**	**4.5**	**9.3**

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (4))
[2/] Expected Dividend Yield (Col (3)) + I/B/E/S Growth Forecast (Col (4))

Source: Standard and Poor's Research Insight, Yahoo.com and I/B/E/S (July 2007)

DCF COST OF EQUITY FOR BENCHMARK SAMPLE OF US ELECTRIC AND GAS UTILITIES (TWO STAGE MODEL)

Company	Annualized Last Paid Dividend	Average Daily Closing Prices 7/15-8/15/2007	I/B/E/S Long-Term EPS Forecasts	Stage 2 GDP Growth [1/]	DCF Cost of Equity [2/]
	(1)	(2)	(3)	(4)	(5)
AGL Resources	1.64	38.77	4.5	5.1	9.3
Consolidated Edison	2.32	45.41	3.5	5.1	10.0
FPL	1.64	59.01	9.1	5.1	8.4
Integrys Energy	2.64	50.78	5.3	5.1	10.6
New Jersey Resources	1.52	48.91	4.5	5.1	8.1
Nicor Inc.	1.86	41.20	4.6	5.1	9.7
Northwest Nat. Gas	1.42	44.12	4.8	5.1	8.3
NSTAR	1.30	32.21	6.3	5.1	9.5
Piedmont Natural Gas	1.00	24.64	4.5	5.1	9.2
Scana	1.76	38.11	4.5	5.1	9.8
Southern Co.	1.61	34.87	4.6	5.1	9.8
Vectren	1.26	26.45	4.3	5.1	9.9
WGL Holdings Inc.	1.37	31.65	3.3	5.1	9.2
Mean	**1.64**	**39.70**	**4.9**	**5.1**	**9.4**
Median	**1.61**	**38.77**	**4.5**	**5.1**	**9.5**

[1/] Consensus forecast nominal rate of GDP growth, 2009-18
[2/] Internal Rate of Return: I/B/E/S EPS forecast growth rate applies for first 5 years; GDP growth thereafter.

Source: Standard and Poor's Research Insight, Yahoo.com, Blue Chip *Economic Indicators* (March 2007) and I/B/E/S (July 2007)

ESTIMATE OF MARKET VALUE CAPITAL STRUCTURES FOR BENCHMARK SAMPLE OF US ELECTRIC AND GAS UTILITIES

Company	Stock Price (Average Daily Closing 7/16-8/15/2007) (1)	Book Value Per Share (Avg. 2005 and 2006) (2)	Market/Book Ratio (3) = (1)/(2)	Book Value Permanent Capital Common Equity Ratio 2006 (4)	Market Value Common Equity Ratio (Debt at Par) (5)=[(4)*(3)]/[(4)*(3)+(1-(4))]	Market Value Debt Ratio 1.0-Col.(7)
AGL Resources	38.77	19.99	1.94	49.8%	65.8%	34.2%
Consolidated Edison	45.41	30.38	1.49	48.4%	58.4%	41.6%
FPL	59.01	23.01	2.56	50.9%	72.6%	27.4%
Integrys Energy	50.78	33.95	1.50	53.4%	63.2%	36.8%
New Jersey Resources	48.91	19.20	2.55	65.2%	82.7%	17.3%
Nicor Inc.	41.20	18.90	2.18	63.7%	79.2%	20.8%
Northwest Nat. Gas	44.12	21.63	2.04	53.7%	70.3%	29.7%
NSTAR	32.21	14.59	2.21	39.7%	59.2%	40.8%
Piedmont Natural Gas	24.64	11.61	2.12	51.7%	69.4%	30.6%
Scana	38.11	23.80	1.60	47.2%	58.9%	41.1%
Southern Co.	34.87	14.82	2.35	46.2%	66.9%	33.1%
Vectren	26.45	15.24	1.74	49.3%	62.8%	37.2%
WGL Holdings Inc.	31.65	18.61	1.70	60.4%	72.2%	27.8%
Mean				**52.3%**	**67.8%**	**32.2%**

Sources: Schedule 14 for stock prices and Standard & Poor's Research Insight

Attachment 36a

CONSENSUS FORECASTS

Survey Date
June 8, 2009

Every month, Consensus Economics surveys over 240 prominent financial and economic forecasters for their estimates of a range of variables including future growth, inflation, interest rates and exchange rates. More than 20 countries are covered and the reference data, together with analysis and polls on topical issues, is rushed to subscribers by express mail and e-mail.

Contents

Survey Highlights

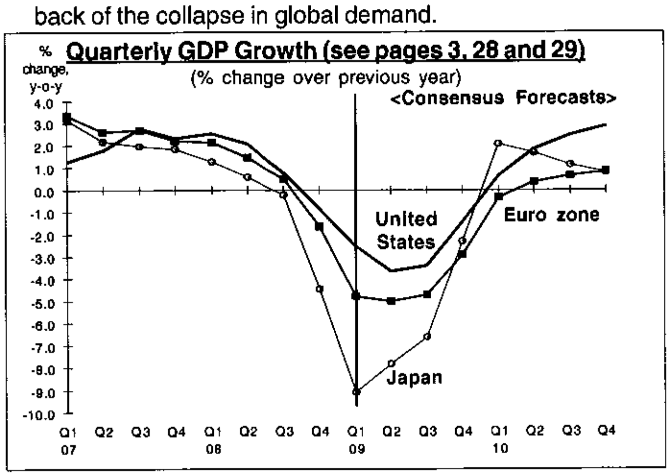
United States – Quarterly Real GDP Consensus Forecasts in December 2008 and March and June 2009

· % change, y-o-y	2009 Q1	Q2	Q3	Q4	2010 Q1	Q2	Q3	Q4
June 8, 2009*	-2.5	*-3.6*	*-3.4*	*-1.4*	*0.6*	*1.8*	*2.5*	*2.9*
% change, q-o-q	*-1.5*	*-0.5*	*0.1*	*0.4*	*0.6*	*0.7*	*0.7*	*0.8*
March 9, 2009*	-2.5	*-3.7*	*-3.5*	*-1.6*	*0.4*	*1.6*	*2.3*	*2.6*
Dec. 8, 2008*	-1.3	*-2.2*	*-1.8*	*-0.1*	*1.2*	*2.2*	-	-

- Our regular special survey of **Quarterly Forecasts** (pages 3, 28 and 29) shows projections up to the final quarter of 2010. We have also extended this quarterly theme to page 2, where we examine **significant changes in our quarterly forecasts** from December 2008, March 2009 and June (see box, above).

- In the **US**, many observers are optimistic that the worst of the recession has passed. As the chart (below) illustrates, the **US** recession is being outpaced by the **Euro zone** and, especially, **Japan**. On the employment front, May saw a smaller number of non-farm payroll losses, compared with previous months. However, the jobless rate soared to 9.4%, suggesting that the labour market retrenchment is not over.

- **Japanese** and **German** GDP forecasts continue to drop on the back of the collapse in global demand.



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Publisher: Philip M. Hubbard

	Average % Change on Previous Calendar Year																Annual Total	
	Gross Domestic Product		Personal Expenditure		Machinery & Equipment Investment		Pre - Tax Corporate Profits		Industrial Production		Consumer Prices		Industrial Product Prices		Average Hourly Earnings		Housing Starts (thousand units)	
	Produit Intérieur Brut		*Dépenses de Consommation des Ménages*		*Investissement Productif*		*Bénéfices des Sociétés avant Impôts*		*Production Industrielle*		*Prix à la Consommation*		*Prix des Produits Industriels*		*Rémunération Horaire Moyenne*		*Construction de Logements mises en chantier, milliers*	
Economic Forecasters	2009	2010	2009	2010	2009	2010	2009	2010	2009	2010	2009	2010	2009	2010	2009	2010	2009	2010
National Bank Financial	-1.5	2.5	-1.0	1.9	-10.4	4.1	-14.1	2.9	na	na	0.0	1.8	na	na	na	na	130	145
Conf Board of Canada	-1.7	2.5	0.2	2.1	-17.0	1.9	-32.0	8.8	na	na	0.5	2.6	-3.0	3.2	na	na	145	167
EDC Economics	-2.0	1.7	-1.4	1.3	-3.2	2.8	na	na	na	na	0.2	2.0	na	na	na	na	155	160
Informetrica	-2.1	2.4	0.0	2.0	-20.0	1.4	-27.0	5.0	-13.0	1.8	0.1	1.8	-1.5	1.5	3.0	2.8	126	150
Scotia Economics	-2.2	2.5	-0.6	1.8	-20.2	-0.9	-16.5	10.0	-7.7	2.2	0.4	1.9	na	na	na	na	135	150
IHS Global Insight	-2.3	2.3	-0.9	1.3	-20.1	-1.6	-36.8	26.5	-7.1	2.7	0.5	1.6	-1.9	2.2	na	na	138	166
Royal Bank of Canada	-2.4	2.5	-0.5	1.6	-20.1	1.7	-36.9	7.1	na	na	0.4	1.7	na	na	na	na	141	173
Toronto Dominion Bank	-2.4	1.7	-1.5	0.7	-23.6	-4.9	-38.8	6.9	na	na	0.2	1.5	na	na	na	na	125	130
BMO Capital Markets	-2.5	1.8	-0.7	1.7	-21.7	-3.6	-35.0	5.0	-8.4	1.0	0.5	1.8	-2.0	1.5	2.8	2.5	135	145
CIBC World Markets	-2.5	1.5	-0.4	1.9	-20.5	-2.2	-24.0	9.5	na	na	0.1	1.2	na	na	na	na	135	160
Desjardins	-2.6	1.6	-0.9	0.9	-17.4	2.6	-35.3	12.3	na	na	0.0	1.7	-2.0	1.6	2.5	1.0	126	130
Economap	-2.6	1.9	-0.7	1.8	-19.5	-2.0	-30.0	4.0	-9.0	1.0	0.5	1.8	-3.0	4.0	2.5	2.6	140	145
University of Toronto	-2.6	3.0	-1.2	1.5	-19.2	2.1	-34.9	22.8	na	na	0.3	2.3	na	na	na	na	136	162
Caisse de Depot	-2.6	2.1	-0.7	2.0	-18.2	1.4	na	na	na	na	0.1	1.6	na	na	na	na	131	152
Consensus (Mean)	-2.3	2.1	-0.7	1.6	-17.9	0.2	-30.1	10.1	-9.0	1.7	0.3	1.8	-2.2	2.3	2.7	2.2	136	153
Last Month's Mean	-2.5	2.0	-0.9	1.6	-12.8	-0.3	-26.0	8.8	-9.0	1.5	0.3	1.7	-2.8	1.7	2.7	2.2	138	156
3 Months Ago	-1.8	2.3	-0.5	1.8	-9.9	1.0	-21.7	8.2	-6.6	1.7	0.2	1.8	-3.4	1.4	2.6	2.4	154	161
High	-1.5	3.0	0.2	2.1	-3.2	4.1	-14.1	26.5	-7.1	2.7	0.5	2.6	-1.5	4.0	3.0	2.8	155	173
Low	-2.6	1.5	-1.5	0.7	-23.6	-4.9	-38.8	2.9	-13.0	1.0	0.0	1.2	-3.0	1.5	2.5	1.0	125	130
Standard Deviation	0.4	0.4	0.5	0.4	5.2	2.7	8.2	7.4	2.3	0.7	0.2	0.3	0.6	1.0	0.2	0.8	8	13
Comparison Forecasts																		
IMF (Apr. '09)	-1.9	1.7	-2.3	0.7	-8.0	1.3					-0.2	0.9						
OECD (Mar. '09)	-3.0	0.3	-2.2	0.1							-0.6	0.5						

Government and Background Data

Prime Minister - Mr. Stephen Harper (Conservative). **Government** - The Conservatives lead a minority government, with 143 out of 308 seats in parliament (155 seats are needed for a clear majority). **Next Election** - By 2013 (general election). **Nominal GDP** - C$1,536bn (2007). **Population** - 32.9mn (mid-year, 2007). **C$/$ Exchange Rate** - 1.064 (average, 2007).

Quarterly Consensus Forecasts

*Historical Data and Forecasts (bold italics) From Survey of **June 8, 2009***

	2008 Q3	Q4	2009 Q1	Q2	Q3	Q4	2010 Q1	Q2	Q3	Q4
Gross Domestic Product	0.3	-1.0	-2.1	***-2.7***	***-2.5***	***-1.0***	***0.6***	***2.0***	***2.7***	***3.2***
Personal Expenditure	3.0	0.2	-0.8	***-1.2***	***-0.9***	***0.3***	***1.0***	***1.5***	***1.9***	***2.1***
Consumer Prices	3.4	2.0	1.2	***-0.2***	***-0.8***	***0.7***	***1.4***	***1.7***	***1.8***	***1.9***

Percentage Change (year-on-year).

Historical Data

* *% change on previous year*	2005	2006	2007	2008
Gross Domestic Product*	3.0	2.9	2.5	0.4
Personal Expenditure*	3.7	4.1	4.6	3.0
Machinery & Eqpt Investment*	14.1	10.5	4.4	0.5
Pre - Tax Corporate Profits*	10.9	5.1	4.1	5.7
Industrial Production*	1.6	0.2	0.2	-4.1
Consumer Prices*	2.2	2.0	2.1	2.4
Industrial Product Prices*	1.5	2.3	1.6	4.3
Average Hourly Earnings*	3.1	2.6	4.6	3.5
Housing Starts, '000 units	225	227	228	211
Unemployment Rate, %	6.8	6.3	6.0	6.2
Current Account, C$ bn	25.9	20.3	15.6	8.1
Federal Govt Budget Balance, fiscal years, C$ bn	13.2	13.8	9.6	-2.6 *e*
3 mth Trsy Bill, % (end yr)	3.4	4.2	3.8	0.9
10 Yr Govt Bond, % (end yr)	4.0	4.1	4.0	2.9

e = consensus estimate based on latest survey

Year Average		Annual Total		Fiscal Years (Apr-Mar)		Rates on Survey Date 0.2%		Rates on Survey Date 3.5%	
Unemploy-ment Rate (%)		Current Account (C$ bn)		Federal Govt Budget Balance (C$ bn)		3 month Treasury Bill Rate (%)		10 Year Government Bond Yield (%)	
Taux de Chômage (%)		*Balance Courante (C$ md)*		*Balance Budgétaire (C$ md)*		*Rendement sur les Bons du Trésor de 3 mois %*		*Rendement des Obligat-ions d'État de 10 ans %*	
2009	2010	2009	2010	FY 09-10	FY 10-11	End Sep'09	End Jun'10	End Sep'09	End Jun'10
8.0	8.0	-17.1	4.5	na	na	0.3	1.4	3.5	4.1
8.3	9.4	-62.0	-64.0	-23.0	-31.0	0.4	1.5	2.3	2.8
8.5	8.2	-8.4	-2.5	na	na	na	na	na	na
8.6	8.7	-55.0	-5.0	-45.0	-36.0	0.3	1.0	3.6	4.0
8.5	8.9	-39.5	-34.5	-54.0	-42.0	0.3	1.1	3.6	4.5
8.5	9.8	-21.3	-30.8	na	na	0.2	0.5	3.6	3.7
8.5	9.0	-23.0	0.4	na	na	0.3	0.8	3.9	4.3
8.8	10.6	-12.6	7.9	-51.0	-45.3	0.2	0.6	2.8	3.0
8.6	9.0	-32.0	-35.0	-52.0	-40.0	0.2	0.5	3.4	4.0
8.3	9.0	-41.5	-35.0	na	na	0.2	0.3	3.4	3.7
8.7	9.3	-29.8	-8.5	-55.0	-35.0	0.3	0.8	3.0	4.5
8.7	9.0	-35.0	-30.0	-60.0	-45.0	0.2	0.3	3.5	3.9
8.5	8.7	-39.4	-36.0	na	na	0.2	0.7	3.3	3.5
8.5	9.0	-37.0	-31.0	-52.0	-37.0	0.3	0.8	2.8	3.3
8.5	9.0	-32.4	-21.4	-49.0	-38.9	0.3	0.8	3.3	3.8
8.5	9.1	-38.0	-29.1	-35.6	-33.6				
8.1	8.4	-31.6	-20.6	-34.0	-30.1				
8.8	10.6	-8.4	7.9	-23.0	-31.0	0.4	1.5	3.9	4.5
8.0	8.0	-62.0	-64.0	-60.0	-45.3	0.2	0.3	2.3	2.8
0.2	0.6	15.2	20.8	11.3	5.1	0.1	0.4	0.4	0.5
8.8	10.5								

Manufacturing Leads the Decline

GDP fell by 1.4% (q-o-q) in Q1, down from -0.9% in the previous quarter, on the back of deteriorating external and domestic demand. Investment in machinery and equipment was especially hard-hit by the fall-off in US and Canadian spending, declining by 10.5% over the previous quarter which brought the y-o-y rate down from a 10% fall in Q4 to a massive 19.5% decline. The 2009 forecast for investment this year has consequently been sharply downgraded from -12.8% last month to -17.9%. By comparison, Q1 personal expenditure fell by a relatively muted 0.8% in y-o-y terms, but this contrasts sharply with the 3.0% growth rate two quarters previously. Despite a boost in auto trade in March – which helped to lift overall retail sales month-on-month – the indicator painted a weakening picture of spending, with real retail purchases falling by 1.0% (q-o-q) over the first quarter. Employment indicators are also suffering on the back of the economic downturn, leaving consumption fundamentals shaky, as evidenced by our panel's quarterly forecasts (page 28).

However, it is the manufacturing sector which continues to drive the recession, with goods production in Q1 dropping by 4% (q-o-q) on the back of a 26% collapse in auto and parts output. According to the monthly GDP-by-industry report, the 0.3% (m-o-m) dip in activity in March was driven by a 1.0% fall in manufacturing and 1.9% loss in energy output. Meanwhile, March's factory report showed sales falling by 2.7% (m-o-m) as payback for February's 2.2% surge, which suggests that industry's retrenchment still has some way to go. While the relative stabilisation in US industrial indicators provides some hope going forward, a marked turnaround in the Canadian sector has yet to be evidenced.

Likelihood of a Bank of Canada Interest Rate Change

Our panel's estimated average probability of a change in the **overnight lending rate (0.25% on survey date) at or before the next key policy meeting (July 21, 2009)** is:

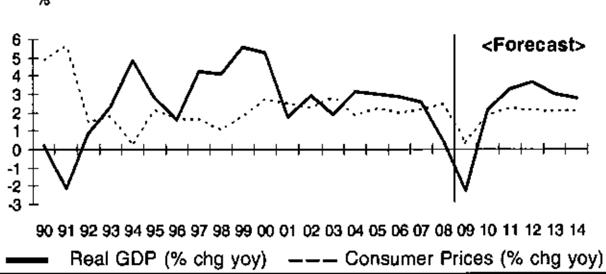
INCREASE		NO CHANGE		DECREASE	
1.4	+	97.8	+	0.8	= 100 %

Most likely rate change mentioned: None

Direction of Trade – First Half 2008

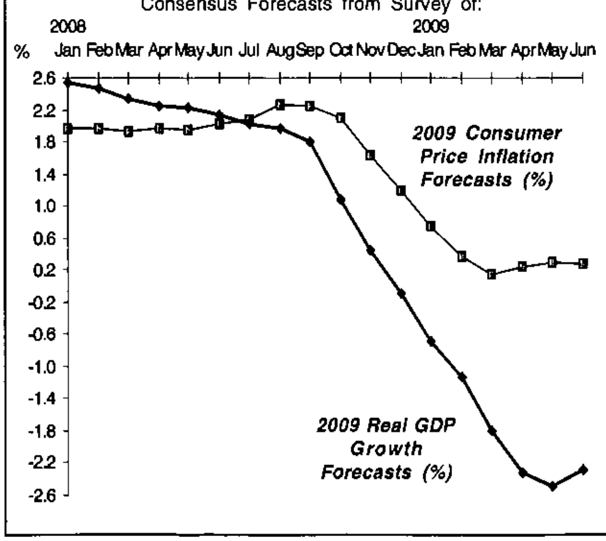
Major Export Markets (% of Total)		Major Import Suppliers (% of Total)	
United States	78.2	United States	53.6
United Kingdom	2.8	China	8.7
China	2.3	Mexico	3.9
Asia (ex. Japan)	*5.5*	*Asia (ex. Japan)*	*13.9*
Latin America	*2.7*	*Latin America*	*7.0*
Eastern Europe	*1.1*	*Africa*	*3.0*

Real Growth and Inflation



GDP Growth and Inflation Forecasts

Consensus Forecasts from Survey of:



Attachment 42a

	States Served	Type of Utility	Regulatory Climate	Moody's Reg Support Rating (Gas Only)	Test Year	Sales and Weather Normalization Features	Fuel/Gas Cost Recovery Assurance	Deferral Mechanisms
AGL Resources	Georgia	Gas LDC	Average 1	Baa	Forecast	Straight fixed variable rate (Georgia); Decoupling (Virginia); Weather Normalization (New Jersey and Tennessee)	Yes for all but Georgia where the company does not sell gas	Rider for Pipeline Replacement Costs (Georgia); rider for Environmental remediation liabilities (Georgia)
	Tennessee		Average 1		Historic with adjustment for known and measurable changes			
	New Jersey		Average 2		Partial forecast			
	Virginia		Above Average 3		Historic with adjustment for known and measurable changes			
Consolidated Edison	New York	Electric and Gas LDC	Average 3		Forecast	Revenue Decoupling (electric); weather normalization (gas)	Yes	True ups for OPEBS and environmental remediation expenses
Dominion Resources	Virginia	Vertically Integrated Electric and Gas LDC	Above Average 3		Historic with Adjustments		Yes	Legislation allows for rate adjustment clauses for environmental compliance costs, FERC approved transmission rates, conservation and energy efficiency programs
	West Virginia		Average 3		Historic with Adjustments			
	Ohio		Average2		Partial Forecast	Straight fixed variable (Ohio)		
	Pennsylvania		Average 3		Forecast			
Duke Energy	North Carolina	Vertically Integrated Electric and Gas LDC	Above Average 2		Historic with Adjustments		Yes	storm cost deferral, demand side management cost deferral, RTO cost deferral; pension expense deferral
	Ohio		Average 2		Partial Forecast	Straight fixed variable rate (gas Ohio)		
	Kentucky		Average 2		Historic with Adjustments			
	Indiana		Above Average 2		Historic with Adjustments			
	South Carolina		Average 1		Historic with Adjustments			
FPL	Florida	Vertically Integrated Utility	Above Average 2		Partial Forecast		Yes	Rate Riders for generation construction costs including pre-construction costs; securitized storm recovery costs;deferral for pension expense
New Jersey Resources	New Jersey		Average 2	Aaa	Partial Forecast	Decoupling	Yes	Deferrals for universal service fund; environmental remediation expenses; post retirement benefits;conservation incentive program
Northwest Nat. Gas	Oregon	Gas LDC	Average 3	Aaa	Partial or Full Forecast	Decoupling (Oregon)	Yes	deferral for pipeline integrity management program; pension expense deferral; environmental cost deferral
	Washington		Average 2		Historic with Adjustments			
NSTAR	Massachusetts	Electric and Gas LDC	Average 1		Historic with Adjustments	Generic order issued for gas and electric permitting development of plans for decoupling	Yes	provision for goodwill recovery;deferral for pension expense
Piedmont Natural Gas	North Carolina	Gas LDC	Above Average 2	Aaa	Historic with Adjustments	weather normalization;Customer utilization tracker (gas, NC)	Yes	deferrals for pension and retirement benefits expense, environmental remediation, demand side management; pipeline integrity expense; uncollected gas costs
	South Carolina		Average 1		Historic with Adjustments			
	Tennessee		Average 1		Historic with Adjustments			
Scana	South Carolina	Vertically integrated electric and gas	Average 1	Aaa	Historic with Adjustments	Weather normalization (gas, SC)	Yes	CWIP in rate base; storm damage reserve; deferrals for pension and employee benefit expense;environmental remediation expense; planned major maintenance
	North Carolina		Above Average 2		Historic with Adjustments	Customer utilitization tracker (gas, NC)		
Southern Co.	Georgia	Vertically Integrated electric	Average 1		Forecast		Yes	CWIP in rate base (Georgia); storm damage reserve;deferrals for pension and employee benefit expense, plant outage costs, environmental remediation costs; Rate Stabilization Mechanism (Alabama)
	Alabama		Above Average 2		Historic with Adjustments			
	Florida		Above Average 2		Partial Forecast			
	Mississippi		Above Average 2		Forecast			
Vectren	Indiana	Gas LDC and Vertically integrated	Above Average 2	Aa	Historic with Adjustments	Weather normalization (Indiana);	Yes	Employee benefit deferral; deferrals for demand side management expense and pipeline integrity expense
	Ohio		Average 2		Partial Forecast	Straight fixed variable rate design (gas, Ohio)		
WGL Holdings Inc.	Maryland	Gas LDC	Below Average 1	Baa	Partial Forecast	decoupling (MD)	Yes	trackers for pension and OPEB expenses
	D.C.		Average 2		Partial Forecast			
	Virginia		Above Average 3		Historic with Adjustments	Declining block structure (VA)		

Note: Historic with Adjustments means adjusted for known and measurable changes

Attachment 43a

REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)

Attachment 44b

HISTORIC UTILITY EQUITY RISK PREMIUMS

Canada
(1956-1981)

Utilities Index Return	Bond Total Return	Risk Premium
11.5	3.1	8.4

Utilities Index Return	Bond Income Return	Risk Premium
11.5	7.4	4.1

United States
(1947-1981)

S&P/Moody's Electric Index Return	Bond Total Return	Risk Premium
8.8	2.3	6.5

S&P/Moody's Electric Index Return	Bond Income Return	Risk Premium
8.8	5.0	3.8

S&P / Moody's Gas Distribution Index Return	Bond Total Return	Risk Premium
11.5	2.3	9.2

S&P / Moody's Gas Distribution Index Return	Bond Income Return	Risk Premium
11.5	5.0	6.5

Notes:
The Canadian Utilities Index is based on the Gas/Electric Index of the TSE 300 (from 1956 to 1987) and on the S&P/TSX Utilities Index from 1988-2008.

The S&P/Moody's Electric Index reflects S&P's Electric Index from 1947 to 1998 and Moody's Electric Index from 1999 to 2001. The 2002 to 2008 data were estimated using simple average of the prices and dividends for the utilities included in Moody's Electric Index as of the end of 2001. These utilities include American Electric Power, Centerpoint Energy, CH Energy, Cinergy, Consolidated Edison, Constellation, Dominion Resources, DPL, DTE Energy, Duke Energy, Energy East, Exelon, FirstEnergy, IDACORP, Nisource, OGE Energy, Pepco Holdings, PPL, Progress Energy, Public Service Enterprise Grp., Southern Co., Teco and Xcel Energy.

The S&P/Moody's Gas Distribution Index reflects S&P's Natural Gas Distributors Index from 1947 to 1984, when S&P eliminated its gas distribution index. The 1985-2001 data are for Moody's Gas index. The index was terminated in July 2002. The 2002-2008 returns were estimated using simple averages of the prices and dividends for the utilities that were included in Moody's Gas Index as of the end of 2001. These LDCs include AGL Resources, Keyspan Corp., Laclede Group, Northwest Natural, Peoples Energy and WGL Holdings.

Source: Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2009 Yearbook* ;
Ibbotson Associates, *Canadian Risk Premia Over Time Report 2008* ; Canadian Institute of Actuaries
Report on Canadian Economic Statistics 1924-2006 ; www.standardandpoors.com, *TSX Review*
Mergent Corporate News Reports, www.federal reserve.com

HISTORIC UTILITY EQUITY RISK PREMIUMS

Canada
(1982-2008)

Utilities Index Return	Bond Total Return	Risk Premium
12.4	12.4	0.0

Utilities Index Return	Bond Income Return	Risk Premium
12.4	8.2	4.2

United States
(1982-2008)

S&P/Moody's Electric Index Return	Bond Total Return	Risk Premium
13.4	12.2	1.2

S&P/Moody's Electric Index Return	Bond Income Return	Risk Premium
13.4	7.3	6.1

S&P / Moody's Gas Distribution Index Return	Bond Total Return	Risk Premium
12.8	12.2	0.6

S&P / Moody's Gas Distribution Index Return	Bond Income Return	Risk Premium
12.8	7.3	5.5

Notes:
The Canadian Utilities Index is based on the Gas/Electric Index of the TSE 300 (from 1956 to 1987) and on the S&P/TSX Utilities Index from 1988-2008.

The S&P/Moody's Electric Index reflects S&P's Electric Index from 1947 to 1998 and Moody's Electric Index from 1999 to 2001. The 2002 to 2008 data were estimated using simple average of the prices and dividends for the utilities included in Moody's Electric Index as of the end of 2001. These utilities include American Electric Power, Centerpoint Energy, CH Energy, Cinergy, Consolidated Edison, Constellation, Dominion Resources, DPL, DTE Energy, Duke Energy, Energy East, Exelon, FirstEnergy, IDACORP, Nisource, OGE Energy, Pepco Holdings, PPL, Progress Energy, Public Service Enterprise Grp., Southern Co., Teco and Xcel Energy.

The S&P/Moody's Gas Distribution Index reflects S&P's Natural Gas Distributors Index from 1947 to 1984, when S&P eliminated its gas distribution index. The 1985-2001 data are for Moody's Gas index. The index was terminated in July 2002. The 2002-2008 returns were estimated using simple averages of the prices and dividends for the utilities that were included in Moody's Gas Index as of the end of 2001. These LDCs include AGL Resources, Keyspan Corp., Laclede Group, Northwest Natural, Peoples Energy and WGL Holdings.

Source: Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2009 Yearbook* ;
Ibbotson Associates, *Canadian Risk Premia Over Time Report 2008* ; Canadian Institute of Actuaries *Report on Canadian Economic Statistics 1924-2006* ; www.standardandpoors.com, *TSX Review*
Mergent Corporate News Reports, www.federal reserve.com

Attachment 45e

Yearly Dividends Per Share

	AGL Resources	Consolidated Edison	Dominion	Duke	FPL	New Jersey Resources	Northwest Nat. Gas	NSTAR	Piedmont Natural Gas	Scana	Southern Co.	Vectren	WGL Holdings Inc.	Average	Dividend Growth Rate	Nominal US GDP	GDP Growth Rate
1970		0.45															
1971		0.45															
1972		0.45															
1973		0.45															
1974		0.26															
1975		0.30															
1976		0.40															
1977		0.50															
1978		0.55															
1979		0.61															
1980		0.67															
1981		0.74															
1982		0.84									0.83						
1983		0.94									0.86						
1984		1.06			0.93						0.92						
1985		1.20			0.97						0.98						
1986		1.34	0.92	0.66	1.01			0.87			1.03						
1987		1.48	1.00	0.69	1.05			0.90			1.07						
1988		1.60	1.04	0.72	1.09	0.58		0.91	0.37		1.07	0.57	0.93				
1989	0.95	1.72	1.08	0.76	1.13	0.61	1.07	0.91	0.40	1.23	1.07	0.62	0.97	0.96		100.00	
1990	0.99	1.82	1.12	0.80	1.17	0.65	1.10	0.76	0.42	1.26	1.07	0.66	1.01	0.99	2.40%	105.80	5.80%
1991	1.02	1.86	1.16	0.84	1.20	0.67	1.13	0.79	0.44	1.31	1.07	0.69	1.03	1.01	2.82%	109.30	3.31%
1992	1.03	1.90	1.20	0.88	1.22	0.68	1.15	0.82	0.46	1.34	1.10	0.72	1.06	1.04	2.66%	115.60	5.76%
1993	1.04	1.94	1.24	0.92	1.24	0.68	1.17	0.85	0.48	1.37	1.14	0.75	1.08	1.07	2.54%	121.40	5.02%
1994	1.04	2.00	1.28	0.96	0.94	0.68	1.17	0.88	0.51	1.41	1.18	0.77	1.10	1.07	0.23%	129.00	6.26%
1995	1.04	2.04	1.29	1.00	0.88	0.68	1.18	0.91	0.54	1.44	1.22	0.80	1.11	1.09	1.59%	134.90	4.57%
1996	1.06	2.08	1.29	1.04	0.92	0.69	1.20	0.94	0.57	1.47	1.26	0.83	1.13	1.11	2.46%	142.50	5.63%
1997	1.08	2.10	1.29	1.08	0.96	0.71	1.21	0.94	0.60	1.51	1.30	0.86	1.16	1.14	2.20%	151.40	6.25%
1998	1.08	2.12	1.29	1.10	1.00	0.73	1.22	0.94	0.64	1.54	1.34	0.90	1.19	1.16	1.89%	159.50	5.35%
1999	1.08	2.14	1.29	1.10	1.04	0.75	1.23	0.97	0.68	1.32	1.34	0.94	1.21	1.16	0.00%	169.00	5.96%
2000	1.08	2.18	1.29	1.10	1.08	0.76	1.24	1.00	0.72	1.15	1.34	0.74	1.23	1.15	-1.11%	179.00	5.92%
2001	1.08	2.20	1.29	1.10	1.12	0.78	1.25	1.03	0.76	1.20	1.34	1.03	1.25	1.19	3.43%	184.67	3.17%
2002	1.08	2.22	1.29	1.10	1.16	0.80	1.26	1.06	0.79	1.30	1.35	1.07	1.26	1.21	2.10%	190.90	3.37%
2003	1.11	2.24	1.29	1.10	1.20	0.83	1.27	1.08	0.82	1.38	1.38	1.11	1.27	1.24	2.14%	199.86	4.69%
2004	1.15	2.26	1.30	1.10	1.30	0.87	1.30	1.11	0.85	1.46	1.41	1.15	1.29	1.27	2.92%	213.08	6.62%
2005	1.30	2.28	1.34	1.17	1.42	0.91	1.32	1.16	0.91	1.56	1.48	1.19	1.31	1.33	4.76%	226.50	6.30%
2006	1.48	2.30	1.38	1.26	1.50	0.96	1.39	1.21	0.95	1.68	1.53	1.23	1.34	1.40	5.02%	240.29	6.09%
2007	1.64	2.32	1.46	0.86	1.64	1.01	1.44	1.30	0.99	1.76	1.59	1.27	1.36	1.43	2.36%	251.76	4.77%
2008	1.68	2.34	1.58	0.90	1.78	1.11	1.52	1.40	1.03	1.84	1.66	1.31	1.39	1.50	4.83%	260.39	3.43%

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.22310706
R Square	0.04977676
Adjusted R Square	-0.00611873
Standard Error	0.01565947
Observations	19

ANOVA

	df	*SS*	*MS*	*F*	*ignificance F*
Regression	1	0.000218375	0.0002184	0.890533	0.358552
Residual	17	0.004168721	0.0002452		
Total	18	0.004387096			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.03966366	0.017180501	2.3086436	0.033798	0.003416	0.0759113	0.003416	0.075911
GDP Growth Rate	-0.3065602	0.324855949	-0.94368	0.358552	-0.99195	0.3788259	-0.991946	0.378826

Attachment 49a

REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)

Attachment 49b

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Attachment 50b

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Entry auctions and strategic behavior under cross-market price constraints

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Abstract

We examine how universal service provisions and price restrictions across markets impact strategic entry and pricing. We develop a simple multi-market model with an oligopolistic (profitable) urban market and entry auctions for (unprofitable) rural service. Cross-market price restrictions induce a firm operating in both markets to become a 'softer' competitor, thus placing the firm at a strategic disadvantage. When we account for entry incentives and strategic bidding, the downstream strategic disadvantage becomes advantageous, leading to higher prices and profits. Price restrictions may also put outside firms, even relatively inefficient ones, at a strategic advantage. © 2002 Elsevier Science B.V. All rights reserved.

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1. Introduction

We observe many regulated market environments in which the variation of prices across markets and market segments is restricted. Typically, these price restrictions are associated with universal service goals and they arise when the

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price differentials expected to prevail in an unregulated setting are deemed unacceptable by policymakers. Familiar examples of industries with universal service requirements are postal delivery, railroad transport and telecommunications; related cross-market price constraints are also observed in a variety of other markets.[1] Liberalization in many regulatory environments, however, has exposed profitable markets to entry and competition. As discussed by Laffont and Tirole (2000) and others, liberalization has raised important questions regarding the coexistence of price constraints across markets, competition, and the goal of universal service, as many markets and segments are inherently unprofitable on a stand-alone basis.[2]

In a classic analysis, Leontief (1940) develops the theory of multi-market monopoly under cross-market price restrictions. Armstrong and Vickers (1993) introduce competition and examine the effects of price discrimination when an incumbent firm faces a (price-taking) entrant in a profitable market while the incumbent also serves customers in a separate market. A ban on price discrimination across the incumbent's markets, which is often part of a universal service requirement, causes the incumbent to be less aggressive in response to entry. The ban on price discrimination also has a significant impact on the scale of entry in equilibrium. We also examine the impact of cross-market price constraints (a ban on price discrimination) but introduce strategic interaction between competitors.

We focus on the issue of firm selection for a second, inherently unprofitable, 'rural' market and the strategic linkage to a profitable 'urban' market where there is oligopolistic competition. In particular, we examine the use of an auction to determine which firm will supply the unprofitable rural market. As discussed by Armstrong (2000) and Laffont and Tirole (2000), there is significant policy interest in the potential for awarding the right to serve markets via auctions in which bidders compete on requested subsidy levels.

We analyze the strategic implications of universal service requirements and related cross-market price restrictions with a simple model involving oligopoly competition and two markets. Oligopoly competition takes place in a profitable urban market and the resulting urban market price determines the ceiling (under

[1] Universal service provisions exist in several other markets (e.g., a Federal subsidy program was established following deregulation in the Airlines industry to support 'Essential Air Service' to rural, regional airports in the US). In general, cross-market price restrictions arise in a variety of contexts and, even when no formal entry auctions exist, strategic entry incentives may be affected: in international trade, anti-dumping provisions involve a comparison of prices across countries (Prusa, 1994); in pharmaceutical markets, countries often employ global reference pricing and link their domestic prices to those observed abroad (Lanjouw, 1997); and systems like Medicaid involve most-favored-customer rules (Scott Morton, 1997).

[2] According to Laffont and Tirole (2000), p. 218, ''Universal service is a knotty and explosive problem. It has been (or will be) a central issue in the political debate surrounding regulatory reform in all network industries and in most countries.''

universal service) for the rural market price. The strategic element that matters for our analysis is that urban market firms can influence or manipulate the relevant prices via their strategic choices. A homogeneous good duopoly with quantity-setting (as in Cournot competition) has this property and, for simplicity, we adopt this as the mode for strategic choice in the urban market.[3]

The rural market is inherently unprofitable due to a large fixed cost. Thus, no firm would independently seek to enter this market. Supply in this market is determined by the outcome of bidding in an upstream auction in which one firm becomes the single supplier to the rural market. Bids take the form of subsidy requirements and the selected firm is the low bidder (smallest subsidy).

The model provides a simple equilibrium framework for assessing the strategic implications of universal service requirements. First, we examine the direct impact of cross-market price constraints under universal service on prices, quantities and profits in each of the urban and rural markets. Next, we employ these market outcomes to analyze the bidding incentives for the rural market auction. The advantage of this approach is that market structure and bidding outcomes are endogenously determined by the underlying demand and cost structure. Finally, we extend the analysis to examine bidding competition and market structure when ‘outside’ firms (i.e., not active in the urban market) also bid in the rural market auction.

Our main results are as follows. With regard to direct effects on the two markets, we find that universal service requirements create a strategic link between the urban and rural market. This link arises because a firm that supplies both markets would like to set a rural price in excess of the oligopolistically determined urban price and, as a result, the reaction function of this firm shifts in the direction that makes this firm a ‘softer’ competitor in the urban market. The shift, which is downwards under quantity-setting, leads to higher equilibrium prices in both markets relative to unconstrained oligopoly competition. The ‘softer’ firm benefits in the rural market but it suffers in the urban market as the competing firm expands and earns higher profits. Thus, a firm supplying both markets is at a strategic disadvantage relative to an urban market competitor.

Equilibrium bidding and the resulting subsidy in the rural market auction must reflect this strategic disadvantage. Since a firm would prefer to ‘lose’ the rural auction and gain the stronger position in the urban market, the equilibrium subsidy contains a premium to compensate for the strategic disadvantage. As a result, once the subsidy is included, both firms earn higher profits relative to those under pure oligopoly competition in the urban market. The key insight is that the higher price under universal service leads to greater joint profits for the competitors and the auction, via the subsidy, allows a share of these gains to accrue to the firm that

[3] We also discuss how our results extend to other settings, such as differentiated price-setting (Bertrand) competition and quality competition.

supplies both markets. Thus, the strategic disadvantage created by universal service requirements is advantageous for urban market competitors once we account for the equilibrium incentives to bid for the rural market.

The presence of outside firms in the rural market auction affects bidding and the resulting market structure in several important ways. The critical feature is that an outside firm cannot directly affect the urban market price and, consequently, when an outside firm wins the auction, the strategic link between prices in the two markets disappears. This has an important implication for bidding incentives as the identity of the winning firm now matters to an incumbent urban market firm when it loses the rural auction. Among other results, we show when this leads to a less efficient outside firm winning the rural market auction.

Our analysis rests upon a price link across markets and is therefore closely related to the general issue of multimarket oligopoly. The idea that production in one market can affect strategic incentives in another market is emphasized by Bulow et al. (1985). The strategic link in our analysis, however, does not arise as a consequence of cost or demand interrelationships across markets. Indeed, we abstract away from any such interrelationship in order to focus exclusively on the strategic implications of the price restriction.

DeGraba (1987) also recognizes how cross-market price constraints can make firms softer competitors. The focus is different, however, as DeGraba shows that once firms become softer (price) competitors they may adjust their locations and, as a result, prices may decrease when a cross-market price constraint is present. In addition, he does not examine entry incentives, a primary consideration in our analysis.[4]

Our analysis involves an entry auction for determining the rural market supplier. Consequently, the issue of whether a multimarket oligopoly arises (an insider wins the auction) or not (an outsider wins) is determined endogenously. Further, the valuations of insiders and outsiders with respect to the rural market feature external effects: a losing bidder is affected by the identity of the winning bidder. Thus, our entry auction is related to recent work on auctions and, in particular, Jehiel and Moldovanu (1996, 2000) who examine bidding under external effects. In our case, the asymmetry of external effects is because an urban market insider prefers that a competing insider wins the auction rather than an outsider.

The basic model is described in Section 2 and analyzed in Section 3. In Section 4, we examine bidding when outside firms can participate. Section 5 discusses welfare effects. We consider extensions and conclude in Section 6.

[4] Our paper is also related to the problem of introducing competition into regulated markets (see Biglaiser and Ma, 1995; De Fraja, 1997; Laffont and Tirole, 1993; Wolinsky, 1997, who also provide additional references).

2. The Model

There are two markets, U (urban) and R (rural) and two firms, A and B. Demand in the U market is $D^{U}(p) = 1 - p$ and in the R market $D^{R}(p) = b(1 - p)$, where p is the market price and $b > 0$. Thus, while both markets have a common price intercept of $p = 1$, the slope coefficient of b allows rural demand to be smaller or larger than urban demand. In many situations, we expect the rural market to be the smaller market.[5]

The fixed cost of any given firm is $F^{U} > 0$ in market U and $F^{R} > 0$ in market R. There is a constant marginal cost $c \geqslant 0$, and this is the same for both firms and both markets.[6] Naturally, we assume that $c < 1$ so that, ignoring fixed costs, it is always profitable (and efficient) to supply some amount to each market.

2.1. Benchmarks

Consider first the case where the two firms compete in a Cournot fashion in the U market. Standard arguments yield a unique equilibrium with quantities $q^{c} = (1 - c)/3$, price $p^{c} = (1 + 2c)/3$, and per-firm profit

$$\pi^{c} = (1 - c)^{2}/9 - F^{U}. \tag{1}$$

We assume that the fixed cost in the U market is sufficiently low to allow $\pi^{c} > 0$.

Consider now a monopolist operating only in market R. The monopolist would maximize $Q(1 - Q/b) - cQ$ by choosing output $b(1 - c)/2$ with price $(1 + c)/2$ and profit

$$\Pi^{M} = b(1 - c)^{2}/4 - F^{R}. \tag{2}$$

We assume that F^{R} is sufficiently large that $\Pi^{M} < 0$. This assumption implies the need for subsidies if the government wants consumers in this market to be served.

2.2. The game

We consider a simple complete information game with the following timing.

1. Firms A and B choose bids s^{A} and s^{B}. These bids represent lump-sum subsidies that the firms ask from the government in order to serve market R.

[5] The analysis, which extends readily to linear demands with different intercepts, is streamlined by specifying a common intercept since this eliminates cases in which the price constraint does not bind.

[6] We assume that marginal cost is the same in order to focus on the effects of differences in demand and fixed costs across markets. Such differences are often substantial in reality.

2. The lowest bidder (smaller subsidy required) wins, receives a subsidy equal to the winning bid, incurs the fixed cost F^{R} and becomes a monopolist in the R market. 'Ties' among symmetric bidders are resolved by a coin toss and ties in other cases are resolved by awarding the rural market to the bidder with the highest payoff.[7] The price in the R market is determined as in 4 below.

3. Firms A and B choose quantities q_A and q_B for the U market. The price in the U market is then determined as $p^{U} = 1 - q_A - q_B$.

4. The monopolist in the R market can then choose a price that cannot exceed the price determined in the U market, that is, $p^{R} \leqslant p^{U}$.

5. Each firm's payoff is the sum of its profits in the two markets, including any subsidies.

We solve for a subgame perfect equilibrium of this game, focusing on pure strategy equilibria in the bidding stage.[8]

3. Analysis

We proceed from the end of the game-tree back towards the beginning.

3.1. Step 1: pricing in the R market

As we show below, the $p^{R} \leqslant p^{U}$ constraint is binding in equilibrium. In other words, the monopoly price in the R market is higher than the equilibrium price in the U market when one firm operates in both markets. Thus $p^{R} = p^{U}$.

[7] In a complete information setting, auction equilibria typically involve a tie either because bidders are symmetric or because the bidder with the strongest strategic position bids so that the next strongest bidder is indifferent between winning and losing. Our tie breaking rule follows the literature (see, e.g., Milgrom, 1987).

[8] Some remarks about the model are appropriate at this point. First, the adopted timing of events is the one that makes the cross-market constraint operate in a natural way. An alternative sequencing would be to have the firm that operates in both markets choose the quantities it supplies in each market at the same time that the other firm chooses its U market quantity. However, this would create the problem of how to impose the price constraint in the R market. Second, the multi-market firm should not be viewed as a price-taker in the R market. Given the cross-market price constraint, the firm is free to set any price in the R market up to the ceiling. More importantly, the ceiling is endogenous with respect to the firms' actions: the multi-market firm can and does adjust its U market choices to raise the ceiling price for the R market. Finally, the Cournot structure for the U market only serves to streamline the analysis and allows us to consider a homogeneous good for which the cross-market price constraint is unambiguous (R market buyers purchase the same good at the same price as U market buyers). As an alternative strategic mode, we could employ price setting (differentiated Bertrand). While, as noted below, this does not alter the basic strategic link between the U and R markets, it does introduce additional issues such as how to interpret the cross-market price constraint when products are differentiated.

3.2. Step 2: quantities supplied in the U market

Denote by q_1 the quantity supplied in the U market by the firm that only operates in the U market and by q_2 the quantity supplied in the U market by the firm that operates in *both* markets. Given the quantities supplied in the U market, the prices are $p^R = p^U = 1 - q_1 - q_2$. Then, market profits gross of fixed costs and subsidies are: for the firm that operates in both markets $[(1 - q_1 - q_2)q_2 - cq_2] + [(1 - q_1 - q_2)b(q_1 + q_2) - cb(q_1 + q_2)]$ or, equivalently, $(1 - q_1 - q_2 - c)[q_2 + b(q_1 + q_2)]$, and for the firm that operates only in the U market $(1 - q_1 - q_2 - c)q_1$.

We can then derive the reaction functions

$$r^1(q_2) = \frac{1 - c - q_2}{2} \quad \text{and} \quad r^2(q_1) = \frac{1 - c - q_1}{2} - \frac{bq_1}{2(1 + b)}, \tag{3}$$

which yield the equilibrium quantities

$$q_1^* = (1 + b)\frac{1 - c}{3 + 2b}, \quad q_2^* = \frac{1 - c}{3 + 2b}, \tag{4}$$

and equilibrium price

$$p^* \equiv 1 - q_1^* - q_2^* = \frac{(1 + b)(1 + c) + c}{3 + 2b} = p^U = p^R. \tag{5}$$

It is now easy to check that the price constraint is indeed binding:

Remark 1. *p^* is lower than the monopoly price in the R market.*

This follows directly from a comparison of p^* with the monopoly price $(1 + c)/2$ upon noting that $c < 1$. We now summarize how the outcome in the urban and rural markets under the price constraint compares with the benchmark of Cournot outcomes in the urban market. A direct comparison of the appropriate terms shows that:

Proposition 1. *Relative to the Cournot outcome, (i) when one of the U market firms also operates in the R market, equilibrium in the U market involves a higher price and lower aggregate quantity: $p^* > p^c$ and $q_1^* + q_2^* < 2q^c$, and (ii) the firm that operates in both markets supplies a lower quantity in the U market while the firm that operates only in the U market supplies a higher quantity: $q_2^* < q^c < q_1^*$.*

Intuitively, the firm that operates in both markets would like to relax the R market price constraint and, as a result, it would like a higher price in the U market. To accomplish this, it is willing to supply a lower (than the Cournot level) quantity in the U market. In other words, the firm that operates in the U market is now ‘softer’ (relative to Cournot competition). This is evident from the fact that

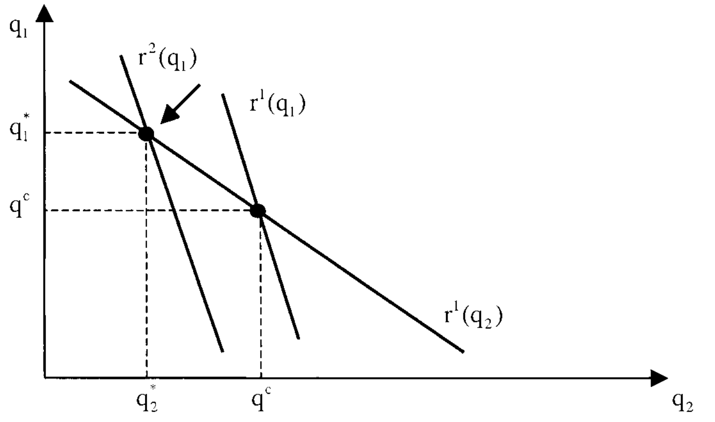

Fig. 1. Equilibrium quantities in the Urban market compared to the equilibrium with no cross-market constraints.

the reaction function r^2 lies below the reaction function under Cournot competition (see Fig. 1 and Eq. (3)). The U market competitor (firm 1) benefits from this effect and supplies a larger quantity.

Now, the equilibrium profit for the firm that operates only in the U market is

$$\pi_1^* = (p^* - c)q_1^* - F^U = \frac{(1+b)^2}{(3+2b)^2}(1-c)^2 - F^U \tag{6}$$

and profit for the firm that operates in both markets is

$$\begin{aligned}\pi_2^* &= (p^* - c)[q_2^* + b(1-p^*)] - F^U - F^R \\ &= \frac{(1+b)^3}{(3+2b)^2}(1-c)^2 - F^U - F^R.\end{aligned} \tag{7}$$

A direct comparison of (1), (6) and (7) yields the following result.

Lemma 1. *The profit of the firm that operates in both markets is lower than the per-firm U market Cournot profit and this, in turn, is lower than the profit of the firm that operates only in the U market*:

$$\pi_2^* < \pi^c < \pi_1^*. \tag{8}$$

The firm that operates in both markets has negative profit in the R market once we account for the fixed cost of F^R. Further, this firm supplies smaller quantity to the U market and has a lower profit there than its competitor. Thus $\pi_2^* < \pi_1^*$. $\pi^c < \pi_1^*$ follows from the fact that the firm that operates only in the U market increases both its price and its quantity when its competitor enters the R market.

Now, $\pi_2^* < \pi^c$ is true for two reasons. First, firm 2 has a loss in the R market. In addition, firm 2's profit in the U market decreases when it enters the R market. Note that when 2 enters the R market the quantity it supplies to the U market decreases but the price increases. Direct calculations show that its U market profit drops from π^c to $(p^* - c)q_2^* - F^U = (1+b)(1-c)^2/(3+2b)^2 - F^U$. This follows by noting that $(p^* - c)q_2^* - F^U$ is equal to π^c for $b = 0$ and is decreasing in b.

3.3. Step 3: equilibrium bids

The total payoffs as functions of the bids s^A and s^B (and assuming equilibrium behavior in the continuation of play) are

$$v^i(s^i, s^j) = \begin{cases} \pi_1^* & \text{if} \quad s^i > s^j \\ \pi_2^* + s^i & \text{if} \quad s^i < s^j \end{cases}, \quad i, j = \text{A, B},$$

where π_1^*, π_2^* are calculated as above. Note that the bids represent required subsidies and an 'aggressive' bid (one that increases the chance of winning the auction) is a low bid.

Now we can determine the equilibrium bids:[9]

Proposition 2. *In equilibrium, each firm requires a subsidy equal to*

$$s^* \equiv \pi_1^* - \pi_2^* = F^R - b\left[\frac{(1+b)(1-c)}{(3+2b)}\right]^2 \Big/ 25 \tag{9}$$

and wins the auction with probability $1/2$. *The total after-subsidy profit for each firm is* π_1^* (*which exceeds* π^c). *Further, the joint profit in the U market exceeds the Cournot level.*

A firm that operates only in the U market strictly prefers that its U market opponent also operates in the R market, because this makes the U market opponent a softer competitor in the U market. Consequently, the required subsidy in equilibrium is $\pi_1^* - \pi_2^*$, which is higher than $\pi^c - \pi_2^*$. In other words, the point of reference for the firm that loses the auction is not π^c but π_1^*. When a firm loses the auction then its competitor wins, and this is a desirable outcome for the firm. Thus, each firm is more 'demanding' with respect to the subsidy it requires.

[9] The proof is immediate. If it bids $s < s^*$, the firm wins the auction and receives total profit $s + \pi_2^* < s^* + \pi_2^* = \pi_1^*$. On the other hand, with a bid $s > s^*$ the firm loses the auction and has the same profit, π_1^*. Proposition 2 describes the unique pure-strategy outcome. A symmetric mixed strategy bidding equilibrium also exists, but it requires unbounded support for the bid distribution and so does not survive if there is a finite upper bound on the requested subsidy. For a related construction see Baye and Morgan (1999).

The fact that equilibrium profit exceeds the Cournot level (if there were no link between the markets) represents a key effect in our analysis. The desire of the government to provide service to consumers in the rural market, in conjunction with the requirement that the rural price not exceed the urban price, can create a perverse incentive for each firm to lose the auction for the rural market in order to gain the more profitable position of serving only the urban market. Equilibrium bidding then leads to a subsidy that compensates for the strategic disadvantage associated with winning. As a result, both firms ultimately benefit and earn profit π_1^* which exceeds π^c (the profit level when no price constraint is imposed on the R market or, equivalently, the profit when U market firms are not allowed to enter the R market). Further, the urban market has higher prices and lower quantities relative to those of unconstrained oligopoly competition (Cournot) in the urban market.

The effects described above are valid for much more general settings than the simple model presented here. In particular, they hold for standard Cournot models with nonlinear demand and costs.[10] Further, the main effect is still present if there are more than two U market firms, as long as these have market power (of course, as the market power of each firm decreases, the incentive to manipulate the price becomes weaker). Finally, the effects of the price restriction are not dependent on the specifics of quantity-setting as the strategic mode. In a differentiated price-setting competitive interaction, the reaction function of the firm operating in both will also shift in the direction (up in the case of price-setting) associated with being a softer competitor.

4. Outsiders allowed to bid for the Rural market

Thus far we have focused on the interaction between the (two) firms that are active in the U market. We now introduce the possibility of entry into the R market by a firm that is not active in the U market, an 'outside' firm, for short. The critical difference is that an outside firm cannot directly affect or manipulate the price in the U market. In addition to being a useful benchmark for understanding the incentives of U market incumbent firms to relax the cross-market price constraint, the question of whether an insider or an outsider is expected to win the auction is an important strategic issue for firms in these markets as well as for policymakers. Our inquiry includes the question of whether an inside incumbent or an outsider is more likely to request a smaller subsidy and win the auction, as well as that of determining the strategic impact of an outsider on the bidding behavior of inside firms.

In order to focus on the implications of differences in strategic positions, we

[10] A sufficient condition is to have downward sloping reaction functions with a unique, stable equilibrium. We thank a referee for this suggestion.

begin by abstracting away from any other differences between U market incumbent firms and outside firms; later, we discuss the impact of differences in technology. Thus, all firms face the same marginal cost of c and fixed cost of F^{R}. The game is as before with the only change being that outside firms can also submit bids at the same time as U market incumbents for the R market subsidy. We begin with the case of one outside firm and then proceed to the case of many outsiders (this corresponds to 'free entry' into the R market auction).

4.1. Comparing the profit differences

Consider first the subgame given that an outsider has won the bidding. In this case, neither of the duopolists in the U market has any cross-market incentive to manipulate the U market price. Thus, the price in the U market will be the Cournot price p^c, and each of these two firms will earn the Cournot profit, π^c. The price constraint binds on the outside firm and so p^c will also be the price in the R market.[11] The profit for the firm operating in the R market (before the subsidy) is then

$$(p^c - c)b(1 - p^c) - F^{\mathrm{R}} = \frac{2b}{9}(1 - c)^2 - F^{\mathrm{R}} \equiv -\tilde{\pi} < 0. \tag{10}$$

Thus, $\tilde{\pi}$ is the *loss* for the firm operating (only) in the R market. It follows that in order for the outsider to be willing to enter the R market, a subsidy of at least $\tilde{\pi}$ is necessary (the outsider's profit when not operating in the R market is normalized to zero).

In the subsequent analysis, we need to compare $\tilde{\pi}$ to $\pi_1^* - \pi_2^*$ (the bid subsidy demanded in equilibrium when only the U market incumbents can bid for the R market) and $\pi^c - \pi_2^*$ (the decrease in an insider's profit after entering the R market). From the previous analysis, a direct comparison of $\tilde{\pi}$ from (10), $\pi_1^* - \pi_2^*$ from (9), and $\pi^c - \pi_2^*$ from (1) and (7) yields:

Lemma 2. *(i)* $b \leqslant b_L \Leftrightarrow \tilde{\pi} \leqslant \pi^c - \pi_2^* < \pi_1^* - \pi_2^*$,*(ii)* $b_L < b \leqslant b_H \Leftrightarrow \pi^c - \pi_2^* < \tilde{\pi} \leqslant \pi_1^* - \pi_2^*$, *and (iii)* $b_H < b \Leftrightarrow \pi^c - \pi_2^* < \pi_1^* - \pi_2^* < \tilde{\pi}$, *where* $b_L \equiv (1 + \sqrt{13})/2 \simeq 2.3$ *and* $b_H \equiv 3(1 + \sqrt{2}) \simeq 7.24$.

Observe that in most applications we expect demand in the rural market to be less than demand in the urban market. Taking $b < 1$, the above result implies that an outsider will incur a smaller loss from supplying service to the rural market than will an urban market insider. Thus, assuming that production technologies and all other aspects of the firms are identical, outsiders are in a better strategic position to submit a more aggressive bid in the auction for the R market.

[11] Since $p^c < p^*$ and from Remark 1 the price constraint binds at p^*, it also binds at p^c.

4.2. Equilibrium

We begin with the case of a single outsider who can bid for the R market. This allows us to isolate the effect of an outsider from that of competition among outsiders.[12]

Proposition 3. *Suppose that one outsider and the two firms active in the U market participate in the R market subsidy auction.*

(i) If $b \leqslant b_L$, in equilibrium, all firms bid a subsidy of $\pi^c - \pi_2^*$ and the outsider wins. In equilibrium, the outsider has after subsidy profit $\pi^c - \pi_2^* - \tilde{\pi} > 0$, and each of the U market incumbents has profit π^c.

(ii) If $b_L < b \leqslant b_H$, in equilibrium, a U market incumbent wins with a bid of $\tilde{\pi}$, the outsider also bids $\tilde{\pi}$, and the other U market incumbent requires a subsidy higher than $\tilde{\pi}$. In equilibrium, the winning U market incumbent has after-subsidy profit $\tilde{\pi} + \pi_2^*$, the losing U market incumbent has profit π_1^*, and the outsider has zero profit.[13]

(iii) If $b_H < b$, in equilibrium, each of the U market incumbents bids $\pi_1^* - \pi_2^*$ and wins with probability $1/2$ while the outsider submits a higher bid.

Proof. (i) In this case, Lemma 2 implies $\tilde{\pi} \leqslant \pi^c - \pi_2^* < \pi_1^* - \pi_2^*$. The outsider does not want to raise its bid because it would lose the auction and its profit would drop from $\pi^c - \pi_2^* - \tilde{\pi} > 0$ to zero. It also does not want to lower its bid since this would only decrease its subsidy. A U market insider does not want to lower its bid because it would then win the auction and its profit would decrease: a bid $s < \pi^c - \pi_2^*$ yields after-subsidy profit $\pi_2^* + s$, which is lower than π^c. Finally, raising the bid would not affect an insider's profit.

(ii) In this case, $\pi^c - \pi_2^* < \tilde{\pi} \leqslant \pi_1^* - \pi_2^*$. The outsider would still lose the auction if it asks for a higher subsidy and thus its profit would remain zero. Its profit would be negative if it bid less than $\tilde{\pi}$ and won the auction. By submitting a lower than $\tilde{\pi}$ bid, the losing insider wins and its after subsidy profit drops to below $\tilde{\pi} + \pi_2^*$ which is lower than the original profit of π_1^*, since for these parameter values $\tilde{\pi} \leqslant \pi_1^* - \pi_2^*$. Finally, if the winning insider asked for a lower subsidy, it would only decrease its profit by the amount of the subsidy reduction. If it asked for a higher subsidy, it would lose the auction and the outsider would win. This deviation leads to a profit of π^c which is lower than the original profit, $\tilde{\pi} + \pi_2^*$

[12] In practice, a large asymmetry could render other potential outsider firms irrelevant to the bidding competition, as when a prior R market incumbent has legal control of essential facilities (see Laffont and Tirole (1993, p. 260)).

[13] In this case, there is no pure-strategy equilibrium where the outsider wins or where an insider wins and both insiders have the same bid. There is, however, a symmetric mixed strategy equilibrium in which each insider mixes between $\tilde{\pi}$ and an arbitrary higher bid. Details are available from the authors upon request.

because we have $\pi^c - \pi_2^* < \tilde{\pi}$. Thus, the proposed strategy profile is an equilibrium, with the losing insider making higher profit than the winning insider and the outsider disciplining the winning bid.

(iii) In this case, $\pi^c - \pi_2^* < \pi_1^* - \pi_2^* < \tilde{\pi}$. The outsider would make a large enough loss ($\tilde{\pi}$) if it entered the R market that its presence is irrelevant for the auction. The U market firms behave exactly as in Proposition 2. The outsider loses the auction and submits a high bid. If the outsider were to submit a bid lower than $\pi_1^* - \pi_2^*$, it would win the auction and its loss in the R market would be larger than the subsidy. □

Recall that we consider the case of small rural market demand to be the most likely scenario for most applications. Proposition 3(i) then implies that the strategic advantage of an outsider translates directly into the ability to win the R market auction at a subsidy level that involves a positive profit. Insiders then operate only in the U market. Note that it is the willingness of insiders to bid (and operate) in the R market that disciplines the bid subsidy and that, in equilibrium, the insiders are pushed to indifference.[14] In addition, a comparison of the profits for insiders indicates clearly that the insiders would prefer that outside firms be excluded from the rural market auction.

Suppose now that there are two or more outsiders. The only difference is that the presence of other outsiders disciplines the bid of each outsider and, therefore, in case (i) of the above Proposition, the winning bid cannot be higher than $\tilde{\pi}$.

Proposition 4. *Suppose that $n \geq 2$ outsiders and the two firms active in the U market participate in the R market subsidy auction. Then, if $b \leq b_L$, in equilibrium, all outsiders bid $\tilde{\pi}$ and each of the outsiders wins with probability $1/n$. Insiders can bid any number higher than $\tilde{\pi}$. In equilibrium, each outsider has after subsidy zero profit and each of the U market incumbents has profit π^c. If $b > b_L$ the equilibrium is as in Proposition 3.*

Propositions 3 and 4 suggest that, when firms are otherwise identical, an outsider is expected to win the auction when demand in the R market is not too large, whereas a firm active in the U market is expected to win if demand in the R market is high.

The key point here is that an outsider cannot manipulate the U market price, whereas a U market insider can. Therefore, an insider has an additional instrument at its disposal. We know that the price in the R market will be higher and the loss smaller if a U market insider operates there as compared to when an outsider does.

[14] In case (i) there is also a continuum of equilibria that differ from the one above in that the winning bid belongs to $[\tilde{\pi}, \pi^c - \pi_2^*)$. Similarly, in case (ii) there is also a continuum of equilibria with the winning bid in $[\pi^c - \pi_2^*, \tilde{\pi})$. Such equilibria are usually viewed in the literature as 'unreasonable' because they require the firm that submits the 'disciplining' bid to employ a weakly dominated strategy.

Thus, if firms are otherwise identical, it appears that a U market insider always has an 'advantage' relative to an outsider. How can we then find that an outsider may win the auction? This is because, firstly, the intuition described above is not valid is a strategic framework. When an insider also operates in the R market, the U market price is not manipulated against a given choice of the other U market competitor in the U market. Rather, the equilibrium in the U market is shifted as both competitors alter their choices. The source of this shift is that the firm operating in both markets now behaves according to the reaction function r^2 rather than r^1. Thus, the value of being able to manipulate the U market price depends on the downstream incentives of the firm and the resulting interaction with the U market rival.[15] Secondly, an insider's point of reference in case it loses the auction is different from that of an outsider. An insider strictly prefers that its U market competitor also operates in the R market and therefore requires the larger subsidy of $\pi_1^* - \pi_2^*$ rather than $\pi^c - \pi_2^*$ in order to give up the opportunity to face a softer competitor. Thus, in the event that it loses the auction, an insider will still care about the identity of the winner. An outsider faces no such concerns.

4.3. Different costs

The above results imply that a firm can often submit a more aggressive bid purely because it has a more favorable strategic position than another firm (even if firms are otherwise identical). These results also imply that a less efficient firm may be able to win the auction:

Remark 2. *An outside firm may win the rural market auction simply because it has a stronger strategic position, despite having higher production costs than inside firms.*

For concreteness, suppose that b is not too high, so that an outsider has a strategic advantage ($b < b_L$). In addition, we now allow for different costs. Let $\bar{c}$ be the unit cost for an outsider (the analysis so far has assumed $\bar{c} = c$). Clearly, for $\bar{c} < c$ the previous analysis implies that an outsider will win the auction. Suppose now that $\bar{c} > c$, so that the insiders are more efficient.[16] Propositions 3(i) and 4 remain valid for a range of $\bar{c}$ above c and an outsider will still win the R market

[15] The loss for an outsider that enters the R market is $\tilde{\pi}$. The corresponding loss for a U market insider is $\pi^c - \pi_2^*$. As shown above, the loss in the U market for a firm operating in both markets may be greater than its gain in the R market and therefore we could have $\tilde{\pi} < \pi^c - \pi_2^*$. Note that if the incumbent could commit not to decrease its U market output, its total profit could never fall below $\pi^c - \tilde{\pi}$. But the fact that a firm's reaction curve shifts once it enters the R market makes it possible for π_2^* to be below $\pi^c - \tilde{\pi}$.

[16] Insiders may be more efficient due to economies of scope across multiple markets. Other factors, however, such as labor and capital structure inherited from prior regulatory policy, may disadvantage an insider.

auction.[17] Thus, a (single) less efficient outsider is able to win the R market auction at a positive profit subsidy level whenever the advantage of a strong strategic position dominates the high cost disadvantage. Of course, with multiple outsiders, the bidding competition dissipates the profit from the subsidy, although an outsider still wins auction. Similar points apply for differences in fixed costs.

5. Welfare

It is useful to summarize here some basic welfare implications of our analysis. The discussion is based on our analysis of price and profit implications earlier in the paper. A first benchmark to which we can compare the policy of the cross-market price constraint and auction for the R market (and when only U markets insiders can bid for the R market) is an auction without any price constraint in the R market (then the winner of the auction charges the monopoly price in the R market — see Section 2.1). Compared to this benchmark, price falls to p^* from the monopoly level in the R market and it rises to p^* from the Cournot level in the U market (p^c). It is easy to verify that the increase in consumers' surplus in the R market is larger than the loss in the U market. The auction bid subsidy falls from Π^M (see (2)) to $\pi_1^* - \pi_2^*$, and both U market firms earn a higher profit level of π_1^*. Further, the sum of consumers surplus (over both markets) and profits (over the two firms) less the subsidy increases as the price constraint is introduced. Thus, for the familiar welfare measure consisting of a weighted average of these terms, introducing the price constraint will increase welfare as long as the weights on consumers surplus in the U compared to R market are not too far apart, a presumption which appears consistent with the goals of universal service.

Opening the auction to outsider bidding has direct welfare implications. Focus on the case of a 'small' R market. Then, outsider bidding causes the price to fall from p^* to p^c in both markets, directly benefiting consumers. Further, insider profits fall to π^c from π_1^* as does the auction subsidy. Clearly, allowing an outsider to bid for the R market in this setting breaks the strategic link with the U market. The outcome then is equivalent to a second benchmark for our analysis, that of a policy that fixes the R market price to p^c. Moving from one to multiple outsiders then disciplines the bidding of outside firms (and the resulting profit) without changing prices and consumers surplus or insider profits. Therefore (and although advice to policy makers cannot be precise if based only on a simple model like ours) it appears that, when there is a cross-market price constraint,

[17] This is because $\pi^c - \pi_2^*$ is independent while $\tilde{\pi}$ is decreasing in the outsider's marginal cost. At $\bar{c} = c$ we have $\tilde{\pi}$ less than $\pi^c - \pi_2^*$ by a finite amount. Thus, we must have $\tilde{\pi} \leqslant \pi^c - \pi_2^*$ for a range of $\bar{c}$ above c.

opening the auction to outsiders may help neutralize the adverse effect of firms' strategic behavior on consumer surplus.[18]

6. Extensions and conclusion

Our analysis shows how, when a firm operates in both markets, the incentive to relax the cross-market restriction makes the firm a 'softer' competitor and places the firm at a strategic disadvantage relative to other urban market competitors. Entry incentives must account for this disadvantage and strategic bidding results in an equilibrium subsidy that contains a compensating premium. Consequently, the downstream strategic disadvantage becomes advantageous for insiders, leading to higher prices and profits. Further, the existence of a strategic disadvantage for a firm operating in both markets makes it important to distinguish between inside and outside firms. An entry auction in this setting involves external effects: a losing inside firm is affected by the identity of the winning firm since this determines whether the losing firm will face a weak or a strong competitor in the urban market. Importantly, we find that an inefficient outside firm may win the rural market auction.

An assumption of the model that can be easily relaxed is that firms have the same technology. For example, the analysis can be reproduced in a straightforward way when the incumbents have different marginal costs. In this case we find that, as expected, it is the more efficient of the two firms that requires a smaller subsidy and enters the R market.

Further, the number of firms in the U market can be endogenized. Suppose that two Cournot competitors make positive profit in the U market but three would have a loss. If one of these two firms entered the R market, it would decrease its U market output and, thus, increase the U market price and its R market profit. But with the higher price in the U market it is conceivable that further entry in the U market has become profitable. This further entry creates a force that would tend to decrease the price back towards its original level. The analysis can be modified to include this case, with the incumbent firms taking into consideration the possibility of further entry when they choose their output levels. While we do not explicitly model this possibility in the paper, it is important to keep in mind with respect to entry and policy issues that, if the price increase in the U market is very high, additional firms may find it profitable to enter.

[18] Concerning our discussion of cost differences above, note that it is not obvious that the government should necessarily award the R market to the lowest bidder versus employing some type of bidder handicap system. The reason is that, although the outsider may require a larger subsidy to operate in the R market (if its cost is sufficiently higher), the price (in both markets) is lower when the outsider operates in the R market than the price when one of the U market insiders operates in the R market. Another way to think about this is that when a U market insider operates in the R market, there are additional market distortions.

Universal service provisions often also require that the quality of services in rural markets be comparable to that provided in urban markets. The logic of our model also applies to the case where quality is endogenous. This case is of interest since imposing a cross-market price constraint is less important if the quality levels are allowed to differ substantially, and is particularly important in markets with rapid technical change. The model could be modified as follows. Suppose that firms compete in both quantity and quality, and that the cross-market constraint dictates that the product has to be provided in the R market at a price not higher and a quality not lower than the U market levels.[19] Then, a firm operating in both markets may have an incentive to supply lower quality to the U market to increase profit in the R market.

Finally, we have not considered how the government finances the subsidy. In principle, of course, if welfare maximization is the goal, the government should choose some tax that minimizes the resulting distortions. Often, this subsidy can be financed by some tax on the firms operating in this industry, essentially creating a cross-subsidy from the profitable (U) to the unprofitable (R) segments of the market. For example, there may be a tax on the revenues of firms. The main idea is that firms contribute part of their revenues to this fund, and the collected revenue is used to finance the subsidy to firms serving the unprofitable segments of the market. Thus, it is of interest to discuss briefly how such a scheme might affect competition from the point of view of our model. In a formal treatment of the issue, the tax rate should be treated as endogenous (because the tax must produce sufficient revenue to cover the subsidy, that is, revenue should equal the winning bid in the R market auction). This has implications not only for bidding strategies, but also for the way competition takes place. Since the main goal of the paper is to examine how the cross-market price constraint affects the strategic behavior of firms rather than provide a detailed evaluation of different ways to finance the subsidy, we merely summarize here the main ways in which taxation may affect the firms' strategies.

Suppose that there is a revenue tax in the U market. First, concentrate on competition between the two insiders. Since U market profit (through revenues) is subject to taxation, for the firm that operates in both markets, it becomes more profitable at the margin to decrease supply in the U market. In other words, a revenue tax makes it more attractive for the firm to sacrifice its U market profit in order to decrease its loss in the R market and thus tends to further increase prices. Second, when firms determine their bids they realize that, at the margin, a higher bid implies that a higher tax rate will need to be imposed on the U market to finance the subsidy. Thus, the U market insiders have an incentive to submit a lower bid than otherwise. Furthermore, an outsider may want to submit a higher bid since increasing the tax rate only affects firms active in the U market. Thus,

[19] For a discussion of the effect of price regulation on a firm's quality offerings in oligopolistic markets, see Vander Weide and Zalkind (1981).

the fact that the tax rate is determined so that it finances the required subsidy may make the insiders willing to bid for a lower subsidy than otherwise, and introduces an additional difference between the strategic positions of insiders and outsiders.

The ideas presented here and our analysis are relevant for a number of markets. Deregulation and privatization policies, which typically involve some form of bidding procedure for entry, have been enacted in a number of countries and allow firms to enter and compete in profitable segments of an increasing number of markets. These policies often coexist with a concern of governments that service and supply must also be provided to less profitable segments of these markets. In this paper we have identified how such an environment can alter the strategic positions of inside and outside firms and assessed the implications for market competition and entry.

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Investor growth expectations: Analysts vs. history

Analysts' growth forecasts dominate past trends in predicting stock prices.

James H. Vander Weide and Willard T. Carleton

For the purposes of implementing the Discounted Cash Flow (DCF) cost of equity model, the analyst must know which growth estimate is embodied in the firm's stock price. A study by Cragg and Malkiel (1982) suggests that the stock valuation process embodies analysts' forecasts rather than historically based growth figures such as the ten-year historical growth in dividends per share or the five-year growth in book value per share. The Cragg and Malkiel study is based on data for the 1960s, however, a decade that was considerably more stable than the recent past.

As the issue of which growth rate to use in implementing the DCF model is so important to applications of the model, we decided to investigate whether the Cragg and Malkiel conclusions continue to hold in more recent periods. This paper describes the results of our study.

STATISTICAL MODEL

The DCF model suggests that the firm's stock price is equal to the present value of the stream of dividends that investors expect to receive from owning the firm's shares. Under the assumption that investors expect dividends to grow at a constant rate, g, in perpetuity, the stock price is given by the following simple expression:

$$P_S = \frac{D\,(1 + g)}{k - g} \tag{1}$$

where:

P_S = current price per share of the firm's stock;

D = current annual dividend per share;

g = expected constant dividend growth rate; and

k = required return on the firm's stock.

Dividing both sides of Equation (1) by the firm's current earnings, E, we obtain:

$$\frac{P_S}{E} = \frac{D}{E} \cdot \frac{(1 + g)}{k - g} \tag{2}$$

Thus, the firm's price/earnings (P/E) ratio is a non-linear function of the firm's dividend payout ratio (D/E), the expected growth in dividends (g), and the required rate of return.

To investigate what growth expectation is embodied in the firm's current stock price, it is more convenient to work with a linear approximation to Equation (2). Thus, we will assume that:

$$P/E = a_0(D/E) + a_1 g + a_2 k. \tag{3}$$

(Cragg and Malkiel found this assumption to be reasonable throughout their investigation.)

Furthermore, we will assume that the required

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rate of return, k, in Equation (3) depends on the values of the risk variables B, Cov, Rsq, and Sa, where B is the firm's Value Line beta; Cov is the firm's pretax interest coverage ratio; Rsq is a measure of the stability of the firm's five-year historical EPS; and Sa is the standard deviation of the consensus analysts' five-year EPS growth forecast for the firm. Finally, as the linear form of the P/E equation is only an approximation to the true P/E equation, and B, Cov, Rsq, and Sa are only proxies for k, we will add an error term, e, that represents the degree of approximation to the true relationship.

With these assumptions, the final form of our P/E equation is as follows:

$$P/E = a_0(D/E) + a_1g + a_2B + a_3Cov + a_4Rsq + a_5Sa + e. \quad (4)$$

The purpose of our study is to use more recent data to determine which of the popular approaches for estimating future growth in the Discounted Cash Flow model is embodied in the market price of the firm's shares.

We estimated Equation (4) to determine which estimate of future growth, g, when combined with the payout ratio, D/E, and risk variables B, Cov, Rsq, and Sa, provides the best predictor of the firm's P/E ratio. To paraphrase Cragg and Malkiel, we would expect that growth estimates found in the best-fitting equation more closely approximate the expectation used by investors than those found in poorer-fitting equations.

DESCRIPTION OF DATA

Our data sets include both historically based measures of future growth and the consensus analysts' forecasts of five-year earnings growth supplied by the Institutional Brokers Estimate System of Lynch, Jones & Ryan (IBES). The data also include the firm's dividend payout ratio and various measures of the firm's risk. We include the latter items in the regression, along with earnings growth, to account for other variables that may affect the firm's stock price.

The data include:

Earnings Per Share. Because our goal is to determine which earnings variable is embodied in the firm's market price, we need to define this variable with care. Financial analysts who study a firm's financial results in detail generally prefer to "normalize" the firm's reported earnings for the effect of extraordinary items, such as write-offs of discontinued operations, or mergers and acquisitions. They also attempt, to the extent possible, to state earnings for different firms using a common set of accounting conventions.

We have defined "earnings" as the consensus analyst estimate (as reported by IBES) of the firm's earnings for the forthcoming year.[1] This definition approximates the normalized earnings that investors most likely have in mind when they make stock purchase and sell decisions. It implicitly incorporates the analysts' adjustments for differences in accounting treatment among firms and the effects of the business cycle on each firm's results of operations. Although we thought at first that this earnings estimate might be highly correlated with the analysts' five-year earnings growth forecasts, that was not the case. Thus, we avoided a potential spurious correlation problem.

Price/Earnings Ratio. Corresponding to our definition of "earnings," the price/earnings ratio (P/E) is calculated as the closing stock price for the year divided by the consensus analyst earnings forecast for the forthcoming fiscal year.

Dividends. Dividends per share represent the common dividends declared per share during the calendar year, after adjustment for all stock splits and stock dividends). The firm's dividend payout ratio is then defined as common dividends per share divided by the consensus analyst estimate of the earnings per share for the forthcoming calendar year (D/E). Although this definition has the deficiency that it is obviously biased downward — it divides this year's dividend by next year's earnings — it has the advantage that it implicitly uses a "normalized" figure for earnings. We believe that this advantage outweighs the deficiency, especially when one considers the flaws of the apparent alternatives. Furthermore, we have verified that the results are insensitive to reasonable alternative definitions (see footnote 1).

Growth. In comparing historically based and consensus analysts' forecasts, we calculated forty-one different historical growth measures. These included the following: 1) the past growth rate in EPS as determined by a log-linear least squares regression for the latest year,[2] two years, three years, . . ., and ten years; 2) the past growth rate in DPS for the latest year, two years, three years, . . ., and ten years; 3) the past growth rate in book value per share (computed as the ratio of common equity to the outstanding common equity shares) for the latest year, two years, three years, . . ., and ten years; 4) the past growth rate in cash flow per share (computed as the ratio of pretax income, depreciation, and deferred taxes to the outstanding common equity shares) for the latest year, two years, three years, . . ., and ten years; and 5) plowback growth (computed as the firm's retention ratio for the current year times the firm's latest annual return on common equity).

We also used the five-year forecast of earnings per share growth compiled by IBES and reported in mid-January of each year. This number represents the consensus (i.e., mean) forecast produced by analysts from the research departments of leading Wall Street and regional brokerage firms over the preceding three months. IBES selects the contributing brokers "because of the superior quality of their research, professional reputation, and client demand" (IBES *Monthly Summary Book*).

Risk Variables. Although many risk factors could potentially affect the firm's stock price, most of these factors are highly correlated with one another. As shown above in Equation (4), we decided to restrict our attention to four risk measures that have intuitive appeal and are followed by many financial analysts: 1) B, the firm's beta as published by Value Line; 2) Cov, the firm's pretax interest coverage ratio (obtained from Standard & Poor's Compustat); 3) Rsq, the stability of the firm's five-year historical EPS (measured by the R^2 from a log-linear least squares regression); and 4) Sa, the standard deviation of the consensus analysts' five-year EPS growth forecast (mean forecast) as computed by IBES.

After careful analysis of the data used in our study, we felt that we could obtain more meaningful results by imposing six restrictions on the companies included in our study:

1. Because of the need to calculate ten-year historical growth rates, and because we studied three different time periods, 1981, 1982, and 1983, our study requires data for the thirteen-year period 1971-1983. We included only companies with at least a thirteen-year operating history in our study.
2. As our historical growth rate calculations were based on log-linear regressions, and the logarithm of a negative number is not defined, we excluded all companies that experienced negative EPS during any of the years 1971-1983.
3. For similar reasons, we also eliminated companies that did not pay a dividend during any one of the years 1971-1983.
4. To insure comparability of time periods covered by each consensus earnings figure in the P/E ratios, we eliminated all companies that did not have a December 31 fiscal year-end.
5. To eliminate distortions caused by highly unusual events that distort current earnings but not expected future earnings, and thus the firm's price/earnings ratio, we eliminated any firm with a price/earnings ratio greater than 50.
6. As the evaluation of analysts' forecasts is a major part of this study, we eliminated all firms that IBES did not follow.

Our final sample consisted of approximately sixty-five utility firms.[3]

RESULTS

To keep the number of calculations in our study to a reasonable level, we performed the study in two stages. In Stage 1, all forty-one historically oriented approaches for estimating future growth were correlated with each firm's P/E ratio. In Stage 2, the historical growth rate with the highest correlation to the P/E ratio was compared to the consensus analyst growth rate in the multiple regression model described by Equation (4) above. We performed our regressions for each of three recent time periods, because we felt the results of our study might vary over time.

First-Stage Correlation Study

Table 1 gives the results of our first-stage correlation study for each group of companies in each of the years 1981, 1982, and 1983. The values in this table measure the correlation between the historically oriented growth rates for the various time periods and the firm's end-of-year P/E ratio.

The four variables for which historical growth rates were calculated are shown in the left-hand column: EPS indicates historical earnings per share growth, DPS indicates historical dividend per share growth, BVPS indicates historical book value per share growth, and CFPS indicates historical cash flow per share growth. The term "plowback" refers to the product of the firm's retention ratio in the currennt year and its return on book equity for that year. In all, we calculated forty-one historically oriented growth rates for each group of firms in each study period.

The goal of the first-stage correlation analysis was to determine which historically oriented growth rate is most highly correlated with each group's year-end P/E ratio. Eight-year growth in CFPS has the highest correlation with P/E in 1981 and 1982, and ten-year growth in CFPS has the highest correlation with year-end P/E in 1983. In all cases, the plowback estimate of future growth performed poorly, indicating that — contrary to generally held views — plowback is not a factor in investor expectations of future growth.

Second-Stage Regression Study

In the second stage of our regression study, we ran the regression in Equation (4) using two different measures of future growth, g: 1) the best historically oriented growth rate (g_h) from the first-stage correlation study, and 2) the consensus analysts' forecast (g_a) of five-year EPS growth. The regression results, which are shown in Table 2, support at least

TABLE 1

Correlation Coefficients of All Historically Based Growth Estimates by Group and by Year with P/E

Current Year	Historical Growth Rate Period in Years: 1	2	3	4	5	6	7	8	9	10
1981										
EPS	−0.02	0.07	0.03	0.01	0.03	0.12	0.08	0.09	0.09	0.09
DPS	0.05	0.18	0.14	0.15	0.14	0.15	0.19	0.23	0.23	0.23
BVPS	0.01	0.11	0.13	0.13	0.16	0.18	0.15	0.15	0.15	0.15
CFPS	−0.05	0.04	0.13	0.22	0.28	0.31	0.30	0.31	−0.57	−0.54
Plowback	0.19									
1982										
EPS	−0.10	−0.13	−0.06	−0.02	−0.02	−0.01	−0.03	−0.03	0.00	0.00
DPS	−0.19	−0.10	0.03	0.05	0.07	0.08	0.09	0.11	0.13	0.13
BVPS	0.07	0.08	0.11	0.11	0.09	0.10	0.11	0.11	0.09	0.09
CFPS	−0.02	−0.08	0.00	0.10	0.16	0.19	0.23	0.25	0.24	0.07
Plowback	0.04									
1983										
EPS	−0.06	−0.25	−0.25	−0.24	−0.16	−0.11	−0.05	0.00	0.02	0.02
DPS	0.03	−0.10	−0.03	0.08	0.15	0.21	0.21	0.21	0.22	0.24
BVPS	0.03	0.10	0.04	0.09	0.15	0.16	0.19	0.21	0.22	0.21
CFPS	−0.08	0.01	0.02	0.08	0.20	0.29	0.35	0.38	0.40	0.42
Plowback	−0.08									

two general conclusions regarding the pricing of equity securities.

First, we found overwhelming evidence that the consensus analysts' forecast of future growth is superior to historically oriented growth measures in predicting the firm's stock price. In every case, the R^2 in the regression containing the consensus analysts' forecast is higher than the R^2 in the regression containing the historical growth measure. The regression coefficients in the equation containing the consensus analysts' forecast also are considerably more significant than they are in the alternative regression. These results are consistent with those found by Cragg and Malkiel for data covering the period 1961-1968. Our results also are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy–and–sell decisions.

TABLE 2

Regression Results
Model I

Part A: *Historical*

$P/E = a_0 + a_1 D/E + a_2 g_h + a_3 B + a_4 Cov + a_5 Rsq + a_6 Sa$

Year	$\hat{a}_0$	$\hat{a}_1$	$\hat{a}_2$	$\hat{a}_3$	$\hat{a}_4$	$\hat{a}_5$	$\hat{a}_6$	R^2	F Ratio
1981	−6.42*	10.31*	7.67*	3.24	0.54*	1.42*	57.43	0.83	46.49
	(5.50)	(14.79)	(2.20)	(2.86)	(2.50)	(2.85)	(4.07)		
1982	−2.90*	9.32*	8.49*	2.85	0.45*	−0.42	3.63	0.86	65.53
	(2.75)	(18.52)	(4.18)	(2.83)	(2.60)	(0.05)	(0.26)		
1983	−5.96*	10.20*	19.78*	4.85	0.44*	0.33	32.49	0.82	45.26
	(3.70)	(12.20)	(4.83)	(2.95)	(1.89)	(0.50)	(1.29)		

Part B: *Analysis*

$P/E = a_0 + a_1 D/E + a_2 g_a + a_3 B + a_4 Cov + a_5 Rsq + a_6 Sa$

Year	$\hat{a}_0$	$\hat{a}_1$	$\hat{a}_2$	$\hat{a}_3$	$\hat{a}_4$	$\hat{a}_5$	$\hat{a}_6$	R^2	F Ratio
1981	−4.97*	10.62*	54.85*	−0.61	0.33*	0.63*	4.34	0.91	103.10
	(6.23)	(21.57)	(8.56)	(0.68)	(2.28)	(1.74)	(0.37)		
1982	−2.16*	9.47*	50.71*	−1.07	0.36*	−0.31	119.05*	0.90	97.62
	(2.59)	(22.46)	(9.31)	(1.14)	(2.53)	(1.09)	(1.60)		
1983	−8.47*	11.96*	79.05*	2.16	0.56*	0.20	−34.43	0.87	69.81
	(7.07)	(16.48)	(7.84)	(1.55)	(3.08)	(0.38)	(1.44)		

Notes:
* Coefficient is significant at the 5% level (using a one-tailed test) and has the correct sign. T-statistic in parentheses.

Second, there is some evidence that investors tend to view risk in traditional terms. The interest coverage variable is statistically significant in all but one of our samples, and the stability of the operating income variable is statistically significant in six of the twelve samples we studied. On the other hand, the beta is never statistically significant, and the standard deviation of the analysts' five-year growth forecasts is statistically significant in only two of our twelve samples. This evidence is far from conclusive, however, because, as we demonstrate later, a significant degree of cross-correlation among our four risk variables makes any general inference about risk extremely hazardous.

Possible Misspecification of Risk

The stock valuation theory says nothing about which risk variables are most important to investors. Therefore, we need to consider the possibility that the risk variables of our study are only proxies for the "true" risk variables used by investors. The inclusion of proxy variables may increase the variance of the parameters of most concern, which in this case are the coefficients of the growth variables.[4]

To allow for the possibility that the use of risk proxies has caused us to draw incorrect conclusions concerning the relative importance of analysts' growth forecasts and historical growth extrapolations, we have also estimated Equation (4) with the risk variables excluded. The results of these regressions are shown in Table 3.

Again, there is overwhelming evidence that the consensus analysts' growth forecast is superior to the historically oriented growth measures in predicting the firm's stock price. The R^2 and t-statistics are higher in every case.

CONCLUSION

The relationship between growth expectations and share prices is important in several major areas of finance. The data base of analysts' growth forecasts collected by Lynch, Jones & Ryan provides a unique opportunity to test the hypothesis that investors rely more heavily on analysts' growth forecasts than on historical growth extrapolations in making security buy–and–sell decisions. With the help of this data base, our studies affirm the superiority of analysts' forecasts over simple historical growth extrapolations in the stock price formation process. Indirectly, this finding lends support to the use of valuation models whose input includes expected growth rates.

TABLE 3

Regression Results
Model II

Part A: *Historical*

$P/E = a_0 + a_1 D/E + a_2 g_h$

Year	$\hat{a}_0$	$\hat{a}_1$	$\hat{a}_2$	R^2	F Ratio
1981	−1.05	9.59	21.20	0.73	82.95
	(1.61)	(12.13)	(7.05)		
1982	0.54	8.92	12.18	0.83	167.97
	(1.38)	(17.73)	(6.95)		
1983	−0.75	8.92	12.18	0.77	107.82
	(1.13)	(12.38)	(7.94)		

Part B: *Analysis*

$P/E + a_0 + a_1 D/E + a_2 g_a$

Year	$\hat{a}_0$	$\hat{a}_1$	$\hat{a}_2$	R^2	F Ratio
1981	3.96	10.07	60.53	0.90	274.16
	(8.31)	(8.31)	(20.91)	(15.79)	
1982	−1.75	9.19	44.92	0.88	246.36
	(4.00)	(4.00)	(21.35)	(11.06)	
1983	−4.97	10.95	82.02	0.83	168.28
	(6.93)	(6.93)	(15.93)	(11.02)	

Notes:
* Coefficient is significant at the 5% level (using a one-tailed test) and has the correct sign. T-statistic in parentheses.

1 We also tried several other definitions of "earnings," including the firm's most recent primary earnings per share prior to any extraordinary items or discontinued operations. As our results were insensitive to reasonable alternative definitions of "earnings" we report only the results for the IBES consensus.

2 For the latest year, we actually employed a point-to-point growth calculation because there were only two available observations.

3 We use the word "approximately," because the set of available firms varied each year. In any case, the number varied only from zero to three firms on either side of the figures cited here.

4 See Maddala (1977).

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**Principles for Lifetime Portfolio Selection:
Lessons from Portfolio Theory***

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Abstract

Portfolio theory is concerned with developing general principles and practical models for making sound lifetime portfolio decisions. Much of the current research on portfolio theory emanates from the path-breaking mean-variance portfolio model of Nobel Laureate Harry Markowitz. Although the mean-variance model continues to be the most widely used portfolio model in financial practice, economists have devoted considerable effort to research on two additional models of portfolio behavior, the geometric mean model and the lifetime consumption-investment model. These models are also useful to investors because they offer significant additional insights into optimal portfolio behavior. The purpose of this paper is to review the major findings of the research literature on the mean-variance model, the geometric mean model, and the lifetime consumption-investment model, and, on the basis of this review, to develop a set of practical guidelines for making lifetime portfolio decisions.

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I. Introduction

1. An individual's savings and investment choices at various stages of life are among the most important decisions he or she can make. A person entering the workforce in 2008 can expect to work for approximately 40 to 45 years and to live in retirement for an additional 20 to 25 years. During his working life, an individual must accumulate sufficient assets not only to live comfortably in both good and bad economic times, but also to live comfortably in retirement. To achieve the goal of maximizing economic welfare over his expected lifetime, an individual consumer/investor should have a sound understanding of the basic economic principles of lifetime portfolio selection.

2. The lifetime consumption/investment decision problem is complex. Suppose an individual consumer/investor divides her expected remaining lifetime into N equal periods. At the beginning of period 1, she must allocate her wealth W_0 to consumption C_0 and investment W_0-C_0. Her wealth at the beginning of the next period, W_1, will depend on both the amount she chooses to invest at the beginning of period 1 and the return she earns on her investment. The consumer/investor recognizes that she will continue to make consumption/investment decisions at the beginning of each period of her life. Her goal is to maximize her expected utility from lifetime consumption. Since expected utility from lifetime consumption depends on consumption/investment decisions in every period of her life, and the opportunities in later periods depend on the results of decisions in earlier periods, the individual consumer/investor must potentially solve a complex N period optimization problem simply to make the correct consumption/investment decision at the beginning of period 1.

3. Portfolio theory is concerned with developing general principles and practical models for making sound lifetime portfolio decisions. Much of the current research on portfolio theory emanates from the path-breaking mean-variance portfolio model of Nobel Laureate Harry

Markowitz. Markowitz (1952, 1959) recommends that in making investment decisions, investors should explicitly recognize investment risk as measured by variance of return, as well as expected return. He describes how the variance of return on a portfolio of securities depends on the amount invested in each security, the variance of return on each security, and the correlation between the returns on each pair of securities. He also suggests that investors limit their choices to an efficient set of portfolios that provide the highest mean return for any level of variance and the lowest variance of return for any level of mean. By providing an intuitively appealing measure of portfolio risk and a framework for analyzing the basic risk/return tradeoff of portfolio decisions, Markowitz revolutionized both the theory and practice of portfolio management. For that reason, Markowitz is properly called the father of Modern Portfolio Theory.[1]

4. The beauty of the Markowitz mean-variance model lies in its blend of elegance and simplicity. Markowitz achieves elegance by providing investors a sophisticated tool for: (i) understanding how portfolio mix decisions affect portfolio risk; and (ii) determining those portfolios that provide an efficient combination of risk and return. He achieves simplicity by focusing solely on the economic trade-off between portfolio risk and return in a single-period world.[2]

5. Although the mean-variance model continues to be the most widely used portfolio model in financial practice, economists have devoted considerable effort to research on two additional models of portfolio behavior, the geometric mean model and the lifetime consumption-investment model. These models offer significant additional insights into optimal

[1] This paper is dedicated to Dr. Markowitz in celebration of his 80th birthday.

[2] Markowitz discusses many of the dynamic economic forces that affect lifetime consumption and investment decisions in the later chapters of Markowitz (1959). However, the economic forces described in this discussion are not incorporated directly in his single-period mean-variance model.

portfolio behavior. The purpose of this paper is to review the major findings of the research literature on the mean-variance model, the geometric mean model, and the lifetime consumption-investment model, and, on the basis of this review, to develop a set of practical guidelines for making lifetime portfolio decisions.

II. The Markowitz Mean-variance Model

6. Investors make portfolio decisions by selecting the securities to include in the portfolio and the amount to invest in each security. In making risky portfolio choices, the Markowitz mean-variance approach assumes that investors: (1) consider only the mean and variance of the probability distribution of portfolio and security returns; (2) for a given level of mean return, prefer a portfolio with a lower variance of return; and (3) for a given level of variance of return, prefer a portfolio with a higher mean return.

7. As Markowitz demonstrates, the above assumptions suggest that an investor's portfolio decision problem can be solved in three steps. First, an investor can estimate the mean and variance of return on each security and the correlation of returns on each pair of securities. Second, an investor can calculate the mean and variance of return on each feasible portfolio and determine an "efficient frontier" of portfolios that offer the lowest variance of return for any level of mean return and the highest mean return for any level of variance of return. Third, an investor can choose a portfolio on the efficient frontier. This paper will focus primarily on steps two and three.

A. Estimating the Mean and Variance of Portfolio Returns

8. Assume that there are N securities and that an investor allocates the proportion X_i of his wealth to security i. Let R_i denote the return on security i and R_p the return on the portfolio of N securities. Then:

$$R_p = R_1X_1 + R_2X_2 + \cdots + R_nX_n, \qquad (1)$$

where R_p and $R_1 \ldots R_n$ are random variables.

9. According to Equation (1), the portfolio return, R_p, is a weighted average of the returns on the securities in the portfolio. Formulas for calculating the mean and variance of a weighted sum of random variables are presented in most introductory probability texts. Using these formulas, the mean of the portfolio return, E_p, is given by:

$$E_p = E_1X_1 + E_2X_2 + \cdots + E_nX_n, \qquad (2)$$

where $E_1, \ldots, E_n$, are the mean, or expected, returns on the individual securities; and the variance of the portfolio return is given by:

$$V_p = \sum_i V_i X_i^2 + \sum_i \sum_{j>i} 2C_{ij} X_i X_j, \qquad (3)$$

where V_i is the variance of return on security i, and C_{ij} is the covariance of returns on security *i* and security *j*.

10. In the Markowitz mean-variance model, investment risk is measured by either the variance of the portfolio return or its equivalent, the standard deviation of portfolio return.[3] The formula for portfolio variance, Equation (3), can be used to provide insight on how investors can reduce the risk of their portfolio investment. Recall that the covariance of returns on security i and security j can be written as the product of the standard deviation of return on security i, SD_i, the standard deviation of the return on security j, SD_j, and the correlation of returns on securities i and j, ρ_{ij}:

$$C_{ij} = SD_i \times SD_j \times \rho_{ij}. \qquad (4)$$

[3] Variance and standard deviation of return are considered to be equivalent measures of risk because the standard deviation is the positive square root of the variance, and the positive square root is an order-preserving transformation. Thus, portfolios that minimize the variance of return for any level of mean return will also minimize the standard deviation of return for any level of mean return.

To simplify the analysis, assume that: (i) the variances on all securities are equal to the average security variance, $\overline{V}$; (ii) the correlation of returns on all securities i and j are equal to the average correlation of return, $\overline{\rho}$, on securities; and (iii) the investor allocates 1/N of his wealth to all securities.

11. Under these assumptions, the variance of return on the portfolio, V_p, can be written as:

$$V_p = \overline{V}(\frac{1}{N}) + \frac{N(N-1)}{N^2}\overline{V}\overline{\rho}. \tag{5}$$

The effect of variations in $\overline{V}$, $\overline{\rho}$, and N on portfolio variance, V_p, can be determined by calculating the partial derivative of V_p, with respect to each of these variables:

$$\begin{aligned} \frac{\partial V_p}{\partial \overline{V}} &= \frac{1}{N} + \frac{N(N-1)}{N^2}\overline{\rho} > 0 \quad \text{if} \quad \overline{\rho} \geq 0 \\ \frac{\partial V_p}{\partial \overline{\rho}} &= \frac{N(N-1)}{N^2}\overline{V} > 0 \\ \frac{\partial V_p}{\partial N} &= -\overline{V}(\frac{1}{N^2}) + \overline{V\rho}(\frac{1}{N^2}) = \overline{V}(\overline{\rho}-1)(\frac{1}{N^2}) \leq 0. \end{aligned} \tag{6}$$

These equations indicate that the portfolio variance of return can be reduced in three ways: (i) increasing the number of securities in the portfolio; (ii) choosing securities having returns that are less correlated with returns on other securities; and (iii) if $\overline{\rho}$ is greater than or equal to zero, choosing securities with low variance or standard deviation of returns.

12. The formulas for portfolio mean and variance, given by Equation (2) and Equation (3), require estimates of the mean, E_i, and variance, V_i, of return on each security, as well as the covariance, C_{ij}, of returns on each pair of securities. If there are N securities under

consideration, Equation (2) and Equation (3) require N mean estimates, N variance estimates, and N (N – 1)/2 distinct covariance estimates, for a total of 2N + N x (N-1)/2 estimates. To illustrate, assume that an analyst is considering 200 securities for possible inclusion in a portfolio. Then the analyst must estimate 200 mean values, 200 variance values, and 19,900 covariance values to implement the Markowitz mean-variance model. Without simplification, it is unlikely that the analyst could estimate these inputs cost effectively.

13. One way to reduce the large number of estimates required to implement the Markowitz mean-variance model is to apply the model to asset classes rather than to individual securities. For example, if the universe of securities is divided into large U.S. stocks, small U.S. stocks, global stocks, emerging market stocks, corporate bonds, long-term U.S. government bonds and Treasury bills, the number of input estimates would be reduced from 20,300 to 35. Given the importance of the asset mix decision and the significant reductions in required estimates obtainable by considering asset categories rather than individual securities, it is not surprising that the Markowitz model is frequently applied to asset categories rather than to individual securities.

14. Another way to reduce the input requirements of the Markowitz mean-variance model is to make one or more simplifying assumptions about the covariance structure of security returns. For example, if one assumes that: (i) the return on an individual security i is related to the return on a market index via the equation:

$$R_i = \alpha_i + \beta_i R_m + e_i \quad \text{for } i = 1, 2, \cdots, N \tag{7}$$

where R_i is the return on security i, R_m is the return on the market index, and e_i is a random error term; (ii) $E[e_i(R_m - \overline{R_m})] = 0$; and (iii) $E(e_i \times e_j) = 0$; then the means, variances, and covariances of securities' returns are given by:

$$E_i = \alpha_i + \beta_i E_m \tag{8}$$

$$V_i = \beta_i^2 V_m + V_{ei}, \tag{9}$$

$$C_{ij} = \beta_i \beta_j V_m. \tag{10}$$

15. Substituting Equations (8), (9), and (10) into Equations (2) and (3), we obtain the following equations for the mean and variance of return on a portfolio of securities:

$$E_p = \sum_i X_i (\alpha_i + \beta_i E_m) \tag{11}$$

$$V_p = \sum_i X_i^{\,2} \beta_i^2 V_m + \sum_i \sum_{j \neq i} X_i X_j \beta_i \beta_j V_m + \sum_i X_i^{\,2} V_{ei}. \tag{12}$$

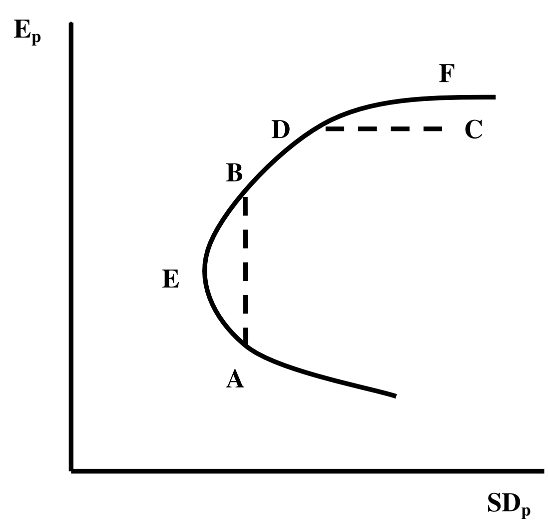
To estimate the mean and variance of return on any portfolio then, we need only to estimate the α_i, β_i, and V_{ei} inputs for each security and the expected return, E_m, and variance of return, V_m, on the market index. Thus, the total number of required estimates has been reduced from $2N + [N \times (N-1)]/2$ to 3N + 2. If the analyst is considering 200 securities for possible inclusion in a portfolio, the number of required estimates is reduced from 20,300 to 602.

B. The Feasible Set of Portfolios and the Efficient Frontier

16. The feasible set of portfolios is the set of all security allocations (X_1, … X_N) that satisfy the individual's portfolio constraints. An obvious portfolio constraint is that the sum of the proportion of wealth invested in all securities must equal 1. Other typical constraints are that the proportion invested in each security must be non-negative (that is, short selling is not allowed) and the investor will not invest more than a certain percentage of wealth in any one security.

17. The Markowitz mean-variance portfolio model allows an investor to translate all feasible portfolio proportions (X_1, … X_N) into feasible combinations of: (i) expected return and variance of return; or (ii) expected return and standard deviation of return. Figure I shows one such feasible set of E_p, SD_p, combinations. Consider portfolio A shown in Figure I. Rational Markowitz mean-variance investors would not choose to invest in portfolio A because they could achieve a higher expected return by investing in portfolio B without increasing the portfolio standard deviation. Similarly, rational investors would not invest in portfolio C because they could achieve a lower portfolio standard deviation by investing in portfolio D without sacrificing mean return. The efficient set of portfolios consists of all portfolios with the highest mean return for any given level of standard deviation of return and the lowest standard deviation of return for any given level of mean return. The curved line EBDF is the efficient frontier for the feasible set of risky portfolios shown in Figure I.

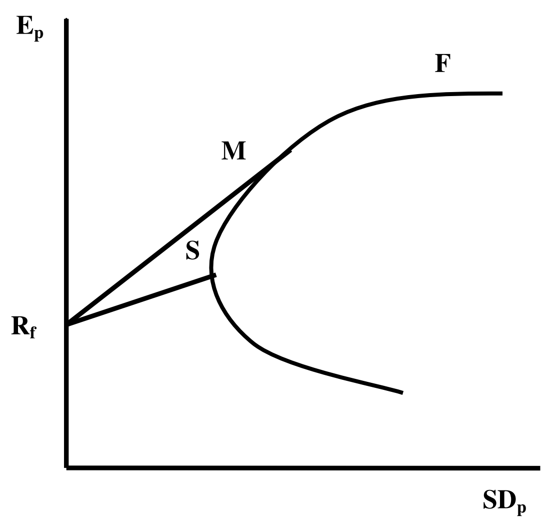
Figure I



C. The Effect of a Risk-free Security on the Shape of the Efficient Frontier

18. When all securities are risky, the efficient frontier typically has a shape similar to that shown in Figure I. Suppose now there exists a security with a risk-free rate of return, R_f. Since the risk-free security has zero variance, its mean-standard deviation combination lies on the vertical axis in mean-standard deviation space (see Figure II). In addition, the risk-free security must lie on the efficient frontier because there are no other securities with the same mean return and a lower standard deviation of return.

Figure II



19. To see how the shapes of the feasible set of securities and the efficient frontier change as a result of the presence of a risk-free security, consider a new portfolio consisting of the fraction X invested in a portfolio S of risky securities and a fraction (1-X) invested in the risk-free security. Because the return on the risk-free security has zero variance and is uncorrelated with the return on portfolio S, both the mean and standard deviation of return on the new portfolio are linearly related to the mean and standard deviation of return on portfolio S.[4]

[4] Specifically, $E_p = X \cdot E_s + (1 - X) R_f$ and $SD_p = X \cdot SD_s$.

Thus, the new portfolio lies somewhere on the straight line connecting R_f and S in Figure II, with its exact location depending on the fraction of wealth X invested in portfolio S.

20. Since the risky portfolio S in the above example is selected arbitrarily, the revised set of feasible portfolios consists of E_p, SD_p combinations lying on any line connecting R_f with a point such as S in the feasible set of risky portfolios. The slope of such a line is $(E_s - R_f)/SD_s$. Consider now the line connecting R_f with portfolio M in Figure II. The points on this line represent feasible portfolios with the fraction X invested in the risky portfolio M and the fraction (1-X) invested in the risk-free security. Since the slope $(E_M - R_f)/SD_M$ is greater than the slope $(E_s - R_f)/SD_s$ for any risky portfolio S, for any feasible portfolio not on the line connecting R_f and risky portfolio M, there exists a portfolio on the line connecting R_f and risky portfolio M with a higher mean return and the same standard deviation of return or the same mean return and a lower standard deviation of return. Thus, the points on the line connecting R_f and M are not only feasible but also efficient. Evidently, the new efficient frontier consists of the union of all points on the line connecting R_f and M and all points on the efficient frontier of risky securities between M and F.[5]

D. Identifying the Efficient Frontier

21. As noted above, the efficient set of portfolios consists of all portfolios with the highest mean return for a given level of variance or standard deviation and the lowest variance (standard deviation) for a given level of mean. Once the E_i, V_i, and C_{ij} inputs have been estimated, the analyst can calculate the mean-variance efficient frontier by solving the following optimization problem for all non-negative values of the parameter λ:

[5] This conclusion strictly applies only when the investor cannot finance risky investments with borrowing. If the investor can borrow as well as lend at the risk-free rate, the efficient frontier will consist of the entire straight line emanating from R_f and extending through the tangency point M on the efficient frontier of risky securities.

$$\begin{gathered}\text{Minimize } V_p - \lambda E_p \\ \text{with respect to } X_1, X_2 \cdots, X_N \\ \text{subject to } \sum_{\mathrm{i}} X_{\mathrm{i}} = 1 \\ X_i \geq 0; i = 1, \cdots, N.\end{gathered} \tag{13}$$

22. The above problem is called the standard mean-variance portfolio selection problem. Non-standard forms of the mean-variance portfolio selection problem include cases where: (i) additional linear constraints apply, and (ii) the amounts invested in one or more securities may be negative. Markowitz (1956, 1959, and 2000) describes efficient algorithms for solving both standard and non-standard versions of the mean-variance portfolio selection problem. These algorithms are used extensively in practical mean-variance portfolio analysis.

23. Elton, Gruber, and Padberg (1976, 1978) demonstrate that an alternative simple procedure can be used to select mean-variance efficient portfolios when the single-index model, Equation (7), is accepted as the best method of forecasting mean-variance portfolio inputs. Their simple procedure requires that securities be ranked based on the ratio of their expected excess return to their beta:

$$(E_i - R_f) \big/ \beta_i \tag{14}$$

where E_i is the expected return on security i, R_f is the return on the risk-free security, and β_i is the sensitivity of the return on security i to changes in the market index as measured by Equation (7). Elton, Gruber, and Padberg prove that all risky securities with an excess return to β ratio above a specific cut-off, C^*, should be included in a mean-variance efficient portfolio; and all risky securities with an excess return to β ratio below this cut-off value should be excluded. Formulas for C* for both the case where short sales are not permitted and the case where short sales are permitted are given in Elton, Gruber, and Padberg's papers.

E. Choosing the "Best" Portfolio on the Efficient Frontier

24. In the Markowitz mean-variance model, an investor should always choose a portfolio on the mean-variance efficient frontier. However, the investor's choice of the best portfolio on the efficient frontier depends on his or her attitude toward risk. Risk-averse investors will likely choose efficient portfolios near the minimum risk portfolio, E, on the efficient frontier in Figure I (or R_f on the efficient frontier in Figure II), while risk-tolerant investors will likely choose portfolios near the maximum mean portfolio, F.

25. But how does the investor actually make the choice of the "best" portfolio on the efficient frontier? It appears that there are two alternatives: direct choice, and investor utility functions. Direct choice involves a direct comparison of the mean and standard deviation of various portfolios on the efficient frontier. In the direct choice approach, the investor is simply presented with information on the means and standard deviations of various portfolios on the efficient frontier and asked to choose a preferred combination of mean and variance.

26. In contrast, investor utility functions involve an attempt to capture the investor's aversion to risk in the form of an investor-specific utility function:

$$U = E_p - kV_p, \tag{15}$$

where k is a parameter indicating the investor's aversion to risk, as measured by variance of return. In this approach, a portfolio advisor would estimate an investor's risk aversion parameter, k, from the investor's responses to a series of questions regarding the investor's attitude toward risk. Investors with high risk aversion would be assigned high values of k, while investors with low risk aversion would be assigned low values of k. The advisor would then calculate the utility, U, of each portfolio on the efficient frontier and recommend the portfolio with the highest utility.

27. In the tradition of Bernoulli (1738) and von Neuman and Morgenstern (1946), economists generally assume that investors wish to maximize their expected utility of wealth, an assumption that has allowed economists to derive a rich set of conclusions about investment behavior. However, practitioners have found that for most investors, utility functions are an impractical device for selecting portfolios. In their experience, they find that investors do not understand the concept of utility and are generally unable to provide the information required to determine their utility function analytically. While this conclusion probably explains the minimal use of utility functions in practical portfolio analysis, it does not rule out using utility functions to obtain practical insights into optimal investment policies for typical investors. Indeed, we demonstrate below how utility analysis has produced many useful guidelines for lifetime consumption-investment decision making.

F. Comments on the Mean-variance Model

28. The Markowitz mean-variance portfolio model has undoubtedly been one of the most influential models in the history of finance. Since its introduction in 1952, the mean-variance model has provided an intellectual foundation for much later research in finance. Because of its rich practical insights, the Markowitz model also continues to strongly influence practical financial management. Nonetheless, the mean-variance approach to portfolio selection is sometimes criticized because it implicitly assumes that information on a portfolio's mean return and variance of return is sufficient for investors to make rational portfolio decisions. Tobin (1958) notes that information on a portfolio's mean return and variance of return is only sufficient for rational portfolio decision making if: (i) the investor's utility function is quadratic; or (ii) the probability distribution of security returns is normal. Neither of these assumptions is likely to be strictly true.

29. Economists generally agree that a reasonable utility function should display non-satiety, risk aversion, decreasing absolute risk aversion, and constant relative risk aversion.[6] The problem with a quadratic utility function is that it displays satiety (that is, an investor with this utility function eventually prefers less wealth rather than more); and increasing absolute and relative risk aversion. Mossin (1968) demonstrates that the only utility functions that satisfy all four of the above desirable characteristics of utility functions are the logarithmic function, log W,[7] and the power function, $W^{1-\gamma}$. Thus, the assumption that it is rational for investors to evaluate risky choices based solely on the mean and variance of return cannot be strictly justified on the grounds that investors' utility functions are quadratic.

30. The other way to justify the assumption that investors base their risky choices solely on the mean and variance of returns is that security returns are normally distributed. But this justification is also problematic. The normal distribution is symmetric with a positive probability that returns can take any value on the real line. However, with limited liability, an investor can never lose more than his entire wealth—that is, $(1+r_t)$ must be greater than or equal to zero. In addition, the investor's multi-period return is the product of individual period returns, and the product of normally distributed variables is not normally distributed. Thus the rationality of relying solely on the mean and variance of portfolio returns cannot be strictly justified on the grounds that returns are normally distributed.

31. Markowitz (1959), Levy and Markowitz (1979), and Samuelson (1970), among other prominent economists, recognize that investor utility functions are unlikely to be quadratic and that security return distributions are unlikely to be normally distributed. However, they

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[6] The desirable attributes of utility functions are discussed more fully below.
[7] In this paper, we use the notation, log W, to indicate the natural logarithm of W.

defend the validity of the mean-variance approach to portfolio decision making based on the belief that one or more of the following statements is true:

- Within any interval, utility functions are approximately quadratic.
- Probability distributions can often be approximated by their first two moments.
- The mean-variance model, though not strictly rational, is nonetheless useful for investors because it provides information that investors find to be relevant and leads them to make better decisions than they would in the absence of the model.

Indeed, Markowitz and Levy and Markowitz demonstrate that many utility functions are approximately quadratic in any interval; Samuelson demonstrates that probability distributions can under fairly general conditions be approximated by their first two moments; and the prevalence of the mean-variance framework in practical decision making suggests that the mean-variance model is useful to investors.

III. The Geometric Mean Portfolio Model

32. As described above, Markowitz achieves simplicity in the mean-variance model by focusing on the economic trade-off between risk and return in a single-period world. However, many investors make portfolio decisions in a multi-period world where portfolios can be rebalanced periodically. For these investors, Latané (1959) recommends an alternative framework, the geometric mean portfolio model. He argues that the maximum geometric mean strategy will almost surely lead to greater wealth in the long run than any significantly different portfolio strategy, a result that follows from similar conclusions of Kelly (1957) in the context of information theory. Breiman (1960, 1961) states the precise conditions for which this result holds and develops additional properties of the geometric mean strategy. A recent news article

describes how two well-known fund managers, Edward Thorp and Bill Gross, have used the geometric mean portfolio strategy to improve the performance of their funds.[8]

A. The Geometric Mean Strategy and Long-run Wealth Maximization

33. Consider an investor who invests an amount, W_0, at the beginning of period 1 and earns a known rate of return on investment of $R_t = (1+r_t)$ in periods t = 1, …, T. If the investor reinvests all proceeds from his investment in each period, his wealth at the end of period T will be:

$$\begin{aligned} W_T &= W_0(1+r_1)(1+r_2)\cdots(1+r_T) \\ &= W_0 \prod_t R_t. \end{aligned} \tag{16}$$

Let G=(1+g) denote the investor's compound average, or geometric mean, return on his investment over the period from 1 to T. Then,

$$\begin{aligned} G &= [(1+r_1)(1+r_2)\cdots(1+r_T)]^{1/T} \\ &= \prod_t R_t^{1/T}. \end{aligned} \tag{17}$$

Since $W_T = W_0 G^T$, the investor's terminal wealth, W_T, will be maximized when the geometric mean return on investment, G, is maximized.

34. In practice, the returns $R_t = (1+r_t)$ for t = 1, …, T are uncertain at the time the investor makes the initial investment decision. Assume that the return on investment is independently and identically distributed, and that there are J possible outcomes for R. Let P_j denote the probability of obtaining the j^{th} return outcome. Then, the forward-looking geometric mean return on investment in this uncertain case is defined as:

[8] "Old Pros Size Up the Game, Thorp and Pimco's Gross Open Up on Dangers of Over-betting, How to Play the Bond Market," *The Wall Street Journal*, Saturday/Sunday, March 22-23, 2008.

$$G^E = \prod_j R_j^{P_j}. \quad \textbf{(18)}$$

In the geometric mean portfolio model, the investor's objective is to maximize the forward-looking geometric mean return on investment, G^E.

35. When analyzing a variable such as G or G^E that is equal to the product of other variables, it is frequently convenient to analyze the logarithm of the variable rather than the variable itself. From Equation (18), the log of G^E is equal to the expected log return on investment:

$$\begin{aligned} \log G^E &= \sum_j P_j \log R_j \\ &= E \log R. \end{aligned} \quad \textbf{(19)}$$

Because the log function is monotonically increasing throughout its domain, any portfolio that maximizes G^E will also maximize log G^E, and hence E log R. Thus, the geometric mean portfolio strategy is equivalent to a portfolio strategy that seeks to maximize the expected log return on investment, E log R.

36. Since the return on investment is assumed to be independently and identically distributed, the T values for R shown in the definition of G in Equation (17) can be considered to be a random sample of size T from the probability distribution for R. Let G^S denote the geometric mean return calculated from the random sample of size T from the probability distribution for R and log G^S denote the log of the sample geometric mean return. From Equation (17), log G^S is given by:

$$\log G^S = \frac{1}{T} \sum_t \log R_t. \quad \textbf{(20)}$$

According to the weak law of large numbers, the average of the sample values of a random variable will approach the expected value of the random variable as the sample size T approaches infinity. Presuming that the mean and variance of log R are finite, the weak law of large numbers assures that for any positive numbers ε and δ, no matter how small, there exists some positive number τ, perhaps large but nevertheless finite, such that for all T>τ,

$$\text{Prob}\left\{\left|\frac{1}{T}\sum_t \log R_t - E\log R\right| < \varepsilon\right\} \geq 1-\delta. \qquad \textbf{(21)}$$

An alternate notation for this condition is

$$\text{plim}\left(\frac{1}{T}\sum_t \log R_t\right) = E\log R, \qquad \textbf{(22)}$$

where plim denotes probability limit.

37. Let R^A denote the investor's returns under the maximum geometric mean strategy, and R^B denote the investor's returns under a significantly different strategy.[9] Then, from the above discussion, we know that:

$$\text{plim}\left(\frac{1}{T}\sum_t \log R_t^A\right) = E\log R^A, \qquad \textbf{(23)}$$

$$\text{plim}\left(\frac{1}{T}\sum_t \log R_t^B\right) = E\log R^B, \qquad \textbf{(24)}$$

and

$$E\log R^A > E\log R^B. \qquad \textbf{(25)}$$

Thus,

$$\text{plim}\left(\frac{1}{T}\sum_t \log R_t^A\right) > \text{plim}\left(\frac{1}{T}\sum_t \log R_t^B\right). \qquad \textbf{(26)}$$

[9] By "significantly different strategy," we mean a strategy that has a lower expected log return than the maximum geometric mean strategy.

This is turn implies that for T sufficiently large, it is virtually certain that $\left(\frac{1}{T}\right)\sum_t \log R_t^A$ will exceed $\left(\frac{1}{T}\right)\sum_t \log R_t^B$, and do so by an amount very nearly equal to (E log R^A – E log R^B) > 0. That is, in the long run, the investor will almost surely have greater wealth by using the geometric mean strategy than by using any significantly different strategy.

B. The Relationship between the Geometric Mean Strategy and the Log Utility Function

38. As shown above, the geometric mean portfolio strategy: (i) almost surely produces greater wealth in the long run than any significantly different strategy; and (ii) is equivalent to a strategy that seeks to maximize the expected log return. Further, Mossin (1968) demonstrates that for the log and power utility functions, maximizing the expected utility of return is equivalent to maximizing the expected utility of terminal wealth. Thus, for investors with log utility functions, the maximum geometric mean portfolio criterion is equivalent to the maximum expected utility of wealth criterion.

C. Desirable Properties of the Log Utility Function

39. For investors with log utility functions, the equivalence of the maximum geometric mean and the maximum expected log utility criteria is significant because log utility functions have many desirable properties. Among these properties are: (i) non-satiety; (ii) risk aversion; (iii) decreasing absolute risk aversion; (iv) constant relative risk aversion; (v) aversion to margin investing (that is, investing with borrowed money); and (vi) optimality of myopic decision making. Mossin (1968) demonstrates that the log and power functions are the only utility functions with all of these properties.

40. Non-satiety. Because the log utility function is increasing throughout its domain, investors with log utility functions always prefer more wealth to less, an attribute that economists refer to as "non-satiety." Although non-satiety would seem to be an obvious desirable property of a utility function, many utility functions do not possess this property, including the quadratic utility function.

41. Risk aversion. Consider the choice between (i) receiving \$W for certain and (ii) having a 50/50 chance of receiving either \$(W + C) or \$(W – C). Investors who choose alternative (i) over alternative (ii) are said to be risk averse, because these alternatives have the same expected value, but the second alternative has greater risk. Risk-averse investors choose alternative (i) because the difference in utility from receiving \$(W + C) rather than \$(W) is less than the difference in utility from receiving \$(W – C) rather than \$(W). That is, $U(W + C) - U(W) < U(W) - U(W - C)$. Evidently, risk-averse investors have utility functions characterized by $U''(W) < 0$.[10] Since the second derivative of log W is $-1/W^2$, investors with log utility functions are risk averse.

42. Decreasing absolute risk aversion. Although all risk-averse investors have utility functions characterized by $U''(W) < 0$, some investors are more risk averse than others. The intensity of an investor's aversion to risk is determined by the curvature of the investor's utility function, where curvature is measured by the ratio of $U''(W)$ to $U'(W)$. Specifically, Pratt (1964) and Arrow (1965) define the coefficient of absolute risk aversion by the equation:

$$ARA(W) = -\frac{U''(W)}{U'(W)}. \tag{27}$$

[10] We use the notation $U''(W)$ to indicate the second derivative of the utility function U with respect to its argument, W.

For small gambles, Pratt and Arrow demonstrate that ARA(W) determines the dollar amount an investor is willing to pay to avoid a fair gamble with the possibility of either winning or losing a constant absolute dollar amount, C. They argue that absolute risk aversion should decrease with wealth because rich investors would be relatively unconcerned with losing an amount, C, that would cause great concern for poor investors. For the log utility function, ARA(W) equals 1/W. Thus, log utility functions imply that absolute risk aversion declines as wealth increases.

43. Constant relative risk aversion. Pratt and Arrow define the coefficient of relative risk aversion by the equation:

$$RRA(W) = -\frac{WU''(W)}{U'(W)}. \tag{28}$$

For small gambles, they demonstrate that RRA(W) determines the fraction of wealth that an investor will pay to avoid a fair gamble with a possibility of winning or losing a specific fraction, C/W, of wealth. Economists generally believe that relative risk aversion should remain constant as wealth increases. This belief is consistent with the evidence that interest rates and risk premia have remained constant as average wealth has increased over time. Since RRA(W) equals 1 for the log utility function, log utility functions display constant relative risk aversion.

44. Aversion to investing on margin. Investors can frequently enhance their expected return on investment by investing on margin. However, margin investing is considered to be risky for individual investors because it can greatly increase both the variability of return on investment and the probability of bankruptcy. Investors with log utility functions are averse to margin investing because margin investing increases the probability that wealth will be less than some small value ε greater than zero; and their utility of wealth approaches minus ∞ as W approaches zero.

45. Optimality of myopic decision making. As noted above, lifetime portfolio selection is generally a complex problem that, because of its dynamic interdependence, can only be solved through sophisticated dynamic programming procedures. However, Mossin (1968), Samuelson (1969), and Merton (1969) demonstrate that investors with either log or power utility functions can solve their lifetime portfolio selection problem one period at a time. For these investors, the decision that maximizes the expected utility of wealth at the end of period t is the same as the t^{th} period decision resulting from a dynamic optimization procedure that considers the effect of the individual's t^{th} period decision on all future decisions. Myopic decision making is a highly desirable property of utility functions because it allows analytical solutions to problems that would otherwise be impossible to solve.

D. Solving the Geometric Mean Portfolio Problem

46. An optimal geometric mean portfolio consists of a set of securities, i = 1, … N, and the optimal proportion of wealth, X_i, to invest in each security. Let $R_i = (1 + r_i)$ denote the return on security i. Then the optimal geometric mean portfolio can be found by solving the following optimization problem:

$$\begin{gathered} \text{Maximize } E\left[\log \sum_{i=1}^{N} R_i X_i\right] \\ \text{with respect to } X_1, \cdots, X_N \\ \text{subject to } X_i \geq 0, i = 1, \cdots, N \\ \sum_{i=1}^{N} X_i = 1. \end{gathered} \tag{29}$$

47. Vander Weide, Peterson, and Maier (1977) establish conditions required for the existence of a solution to the geometric mean portfolio problem and provide computational methods for finding exact solutions when solutions do exist. Maier, Peterson, and Vander Weide

(1977) examine the solutions to a relatively large number of simulated geometric mean portfolio problems obtained with the aid of a numerically efficient nonlinear programming code embedded within a partitioning algorithm. They find that the number of risky securities in an optimal geometric mean portfolio depends on one's expectations concerning future market conditions and on the conditions under which borrowing is permitted. When borrowing is not permitted, the investor who believes the market will fall should invest in just one security; the investor who believes the market will remain unchanged should diversify among two securities; and the investor who believes the market will rise should diversify among four to seven securities.[11]

48. When borrowing is allowed, the geometric mean portfolio problem must be modified to assure that the investor will not go bankrupt. Avoidance of bankruptcy can be accomplished by requiring the investor to withhold sufficient capital from investment to cover interest and principal payments on the borrowing. In the modified geometric mean portfolio problem, the investor who believes the market will rise should choose the same securities in the same relative proportions as when no borrowing is allowed. Furthermore, the individual characteristics of securities contained in optimal geometric mean portfolios also depend on one's assumptions about market conditions and the availability of borrowing. If a rising market is anticipated, the investor should invest in securities for which β_i and σ_i are large, and for which α_i is small. If the market is expected to decline, the investor should invest in stocks with high α_i and low β_i and σ_i.

49. Maier, Peterson, and Vander Weide (1977) also describe several heuristic portfolio building rules that provide near-optimal solutions to the geometric mean portfolio problem, including a geometric mean rule, a reward-to-variability rule, a reward-to-non-

[11] These numbers of securities are obtained under the assumption that the investor has 100 securities from which to choose. If the investor can choose among a greater number of securities, the optimal number to hold is likely to increase.

diversifiable variability rule, and a Kuhn-Tucker rule. Each rule follows the same principle: rank each security on the basis of one criterion, and then allocate equal dollar amounts to several of the top-ranked securities. They find that the geometric mean rule, the reward-to-variability rule, and the Kuhn-Tucker rule provide reasonable approximations to the returns on the optimal geometric mean portfolio.

50. Of course, the geometric mean portfolio problem cannot be solved without appropriate data inputs. Maier, Peterson, and Vander Weide (1977) note that the data inputs to the geometric mean portfolio problem can be estimated by assuming that the distribution of the holding period return, R_i, is related to a market index, I, through the equation:

$$\log R_i = \alpha_i + \beta_i I + \varepsilon_i, \tag{30}$$

where I is defined as the expected value over all securities of the logarithm of the holding period return, α_i and β_i are constants, and ε_i is a normal random variable with mean zero and variance σ_i^2. The index I is considered a normal random variable whose parameters are chosen subjectively by the investor. Maier, Peterson, and Vander Weide (1982) develop an empirical Bayes estimation procedure for obtaining a simultaneous estimate of the three market model parameters of Equation (30) that makes use of more information than other estimates described in the literature.

E. Relationship between the Maximum Geometric Mean Return and the Mean and Variance of Return on a Portfolio

51. The geometric mean portfolio strategy is specifically designed for investors who wish to maximize their long-run wealth. Since the "long run" may be many years in the future, however, and mean-variance efficient portfolios have desirable short-run properties, it is natural to inquire whether the maximum geometric mean portfolio is mean-variance efficient.

Markowitz (1959) and Young and Trent (1969) address this inquiry by examining the expected value of several Taylor series approximations of either E log R or G. In discussing their methods and results, we will use the following notation:

μ_1	=	E(R)	=	the expected value or first moment of the probability distribution of R,
μ_2	=	$E(R- \mu_1)^2$	=	the variance or second central moment,
μ_3	=	$E(R- \mu_1)^3$	=	the skewness or third central moment, and
μ_4	=	$E(R- \mu_1)^4$	=	the kurtosis or fourth central moment.

52. The Taylor series approximation of log R centered around the mean value, μ_1, of R is given by:

$$\log R = \log \mu_1 + \frac{R-\mu_1}{\mu_1} - \frac{(R-\mu_1)^2}{2\mu_1^{\ 2}} + \frac{(R-\mu_1)^3}{3\mu_1^{\ 3}} - \frac{(R-\mu_1)^4}{4\mu_1^{\ 4}} + \cdots \qquad \textbf{(31)}$$

Taking expectations of both sides of Equation (31), and noting that E $(R - \mu_1) = 0$, we then have:

$$\mathrm{E}\log R = \log \mu_1 - \frac{\mu_2}{2\mu_1^{\ 2}} + \frac{\mu_3}{3\mu_1^{\ 3}} - \frac{\mu_4}{4\mu_1^{\ 4}} + \cdots \qquad \textbf{(32)}$$

53. Equation (32) provides several important insights about the relationship between the maximum geometric mean return and the mean and variance of return on a portfolio. First, if the third and higher moments of the probability distribution of R are "small" in relation to the first moment, E log R can be reasonably approximated by the expression:

$$\mathrm{E}\log R = \log \mu_1 - \frac{\mu_2}{2\mu_1^{\ 2}}. \qquad \textbf{(33)}$$

Second, if Equation (33) is a reasonable approximation for E log R, the geometric mean portfolio will be approximately mean-variance efficient because E log R will be maximized when the mean, μ_1, is maximized for any value of variance, μ_2, and the variance, μ_2, is minimized for any value of mean, μ_1. Third, if the third and higher moments of the probability distribution for R are not "small" in relation to the first moment, the geometric mean portfolio may not be mean-variance efficient. An example where the geometric mean portfolio is not mean-variance efficient is provided by Hakansson (1971).

54. To test whether the maximum geometric mean portfolio is approximately mean variance efficient, Markowitz (1959) examines the ability of two geometric mean approximations to E log R to predict the actual geometric mean return on nine securities and two portfolios over the period 1937 to 1954. The two geometric mean approximations include:[12]

$$G(1) \quad = \quad \mu_1 - \frac{\mu_1^{\;2} + \mu_2^{\;2}}{2}, \text{ and}$$

$$G(2) \quad = \quad \log \mu_1 - \frac{\mu_2}{2\mu_1^{\;2}}.$$

He finds that G(1) consistently underestimates the geometric mean return on the nine securities and two portfolios over the period, with an average error of eight percent. However, G(2) performs significantly better than G(1). It slightly overestimates the actual geometric mean return with an average error of only 1.7 percent. From his analysis of these approximations, Markowitz suggests that G(2) be used to estimate the geometric mean return for each portfolio on the mean-variance efficient frontier. He advises investors never to choose portfolios on the mean variance efficient frontier with greater single-period means than the optimal geometric mean portfolio because such portfolios will have higher short-run variance than the optimal geometric mean portfolio and less wealth in the long run.

55. Using methods similar to Markowitz, Young and Trent (1969) empirically test the ability of five geometric mean approximations to predict the actual geometric mean return on

[12] G(1) is derived from a Taylor series approximation centered on R = 1, while G(2) is the approximation shown in Equation (33).

233 securities and various portfolios based on these securities. The five geometric mean approximations include:[13]

$$G(1) = (\mu_1^2 - \mu_2)^{1/2},$$

$$G(2) = \mu_1 - \frac{\mu_2}{2\mu_1},$$

$$G(3) = \mu_1 - \frac{\mu_2}{2},$$

$$G(4) = \mu_1 - \frac{\mu_2}{2\mu_1} + \frac{\mu_3}{3\mu_1^2}, \text{ and}$$

$$G(5) = \mu_1 - \frac{\mu_2}{2\mu_1} + \frac{\mu_3}{3\mu_1^2} - \frac{\mu_4}{4\mu_1^3}.$$

Using monthly holding period returns for the time period January 1957 to December 1960 and annual holding period returns for the period January 1953 to December 1960, they demonstrate that geometric mean approximations such as G(2) and G(3), based only on the mean and variance of the probability distribution of R, provide predictions of geometric mean returns that differ on average from actual geometric mean returns by 0.5 percent. Thus, for their data set, we may conclude that maximum geometric mean portfolios are highly likely to be mean-variance efficient.

F. Comments on the Geometric Mean Portfolio Model

56. The geometric mean portfolio strategy is designed for investors who seek to maximize the expected value of their wealth in the long run. However, Merton and Samuelson (1974) demonstrate that maximizing the expected value of long-run wealth is not the same as maximizing the expected utility of long-run wealth. Since wealth at the end of a typical lifetime

[13] These approximations are derived from the Taylor series expansion of G centered around the mean value of R.

is variable, investors who are more risk averse than investors with log utility functions may prefer an alternative investment strategy that provides a stronger hedge against values of wealth that are less than the expected value of long-run wealth.

IV. Lifetime Consumption-Investment Model

57. The mean-variance and geometric mean portfolio models are designed to help investors choose the optimal proportions of wealth to invest in each security, based only on information regarding the probability distributions of returns on securities. If the probability distributions of returns are assumed to be independently and identically distributed, these models will recommend that the proportion of wealth invested in each security remain constant over the investor's lifetime. However, a constant proportion investment strategy is inconsistent with conventional wisdom that investors, as they age, should lower the proportion of wealth invested in risky stocks versus less risky bonds. The lifetime consumption-investment model is designed to help investors understand the conditions under which their optimal investment policy might change over their lifetimes, even if their probability beliefs remain constant.

58. Interest in lifetime consumption-investment models began in the late 1960s. Important early papers include Samuelson (1969), Merton (1969), Mossin (1968), and Hakansson (1969, 1970). Important later papers include Viceira (2001), Heaton and Lucas (2000), Koo (1998, 1999), Campbell, Cocco, Gomes, and Maenhout (2001), Bodie, Merton, and William Samuelson (1992), and Campbell and Cochrane (1999). Campbell and Viceira (2002) contains an excellent discussion of lifetime consumption-investment models, as well as a review of the literature on this important topic.

A. The Standard Lifetime Consumption-Investment Model

59. Consider an individual who must choose the amounts to consume, C_t, the fraction of wealth to invest in risky assets, w_t, and the fraction of wealth to invest in a risk-free asset, $(1 - w_t)$, at the beginning of each period (t = 0, 1, …, T). Assume that the individual's goal is to maximize the expected present value of the utility from lifetime consumption and that wealth must be either consumed or invested in each period. Let Z_t denote the random return on the risky asset, ρ the investor's discount rate, and r, the return on the risk-free asset. Then, the individual's standard lifetime consumption-investment problem can be stated as:[14]

$$
\begin{gathered}
\text{Max } E\left[\sum_{t=0}^{T}(1+\rho)^{-t}U(C_t)\right] \\
\text{with respect to } C_t, w_t \\
\text{subject to } \mathrm{C}_t = \left[W_t - \frac{W_{t+1}}{(1+r)(1-w_t)+w_t Z_t}\right] \\
W_0 \text{given, } \mathrm{W}_{\mathrm{T+1}} \text{ prescribed.}
\end{gathered}
\tag{34}
$$

B. Analysis of the Optimal Lifetime Consumption-Investment Strategy

60. The standard formulation of the lifetime consumption-investment problem is difficult to solve without some simplifying assumptions. In his first paper on this subject, Samuelson (1969) assumes that (i) the individual's utility function displays constant relative risk aversion, that is, the utility function is either a log or power function; and (ii) the probability distribution for Z_t is independently and identically distributed. To his surprise, he finds that the optimal proportion to invest in the risky asset is constant under these assumptions. Thus, under the standard assumptions, the lifetime consumption-investment model produces the same

[14] This formulation is taken from Samuelson (1969).

constant proportion recommendation as the mean-variance and geometric mean models. Merton, Leland, Mossin, and Hakansson reach similar conclusions.

61. However, Samuelson (1989), Bodie, Merton, and William Samuelson (1992), and the authors of later papers cited above, demonstrate that when the standard assumptions of the lifetime consumption-investment model are modified to include non-tradable human wealth,[15] subsistence levels of consumption, and mean-reverting probability distributions of returns, the conclusion that the percentage invested in risky assets is constant must be modified. Since the literature on the effect of these additional variables on the optimal solution to the lifetime consumption-investment problem is complex, we limit our discussion here to a brief summary of relevant conclusions.

62. Non-tradable human wealth. The effect of human wealth on an individual's optimal investment strategy depends on whether human wealth is riskless or risky. Assume first that human wealth is riskless, that is, that the present value of an individual's future income is certain. Since riskless human wealth is equivalent to an implicit investment in a riskless asset, the investor should adjust the proportion of financial wealth, F_t, invested in risky assets to reflect the investor's implicit additional holding of riskless assets. When human wealth is riskless, Campbell and Viceira demonstrate that the optimal proportion of financial wealth, F_t, to invest in risky assets is an increasing function of the ratio of human wealth to financial wealth, H_t/F_t. This ratio will typically vary over an individual's lifetime.

63. For young investors, the ratio of human wealth to financial wealth will typically be high because the young investor (i) can expect to earn labor income for many years to come;

[15] Human wealth, H_t, reflects the expected present value of an individual's future income. Human wealth is non-tradable because the legal system forbids trading in claims on an individual's future income. Financial wealth, F_t, reflects the current market value of an individual's financial assets, that is, stocks and bonds. Total wealth, W_t, is equal to H_t plus F_t.

and (ii) has not had much time to accumulate financial wealth. Thus, young investors should allocate a relatively large percentage of financial wealth to risky assets. In contrast, for investors nearing retirement, the ratio of human wealth to financial wealth will typically be low. Thus, when human wealth is riskless, the percentage of financial wealth invested in risky assets should decline with age.

64. Assume now that labor income, and hence human wealth, is risky. If labor income is uncorrelated with the return on risky assets, the investor with human wealth should still invest a greater percentage of financial wealth in risky assets than the investor without human wealth. However, the percentage invested in risky assets should decrease with increases in the variance of labor income, that is, investors with high variance in labor income should reduce the percentage of financial wealth invested in risky assets to hedge some of the risk of their labor income.

65. If, on the other hand, labor income is perfectly positively correlated with the return on one or more risky financial assets, human wealth is an implicit investment in these financial assets. In this case, the investor should either increase the percentage of financial wealth invested in the riskless asset or diversify into risky assets that are uncorrelated with labor income. This latter conclusion applies to all individuals who hold a high percentage of financial wealth in the stock of their employer.

66. Human wealth also affects the optimal percentage of financial wealth to invest in risky assets through the investor's ability to vary his or her work effort. If the investor can increase work effort to offset losses on financial assets, the optimal percentage of financial wealth to invest in risky assets will increase.

67. Subsistence levels of consumption. The optimal percentage of financial wealth to invest in risky assets also depends on the investor's desire to maintain a minimum level of consumption. A minimum level of consumption may be thought of as negative income because a certain part of income must be set aside to assure the minimum level of consumption. Samuelson (1989) establishes that as the investor nears retirement, the investor should increase the allocation of financial wealth to risk-free bonds in order to assure a minimum level of consumption in retirement. The shift towards risk-free bonds arises as a result of the investor's need to provide a steady income stream in retirement to cover the minimum level of consumption. However, Merton (1969) notes that young investors may also have a need to assure a minimum level of consumption in the face of uncertain human and financial wealth. He establishes that this need would also shift the optimal portfolio of young investors toward riskless bonds. Constantinides (1990) and Campbell and Cochran (1999) analyze the case where the minimum level of consumption itself may depend on either the individual's prior consumption habits or the consumption norms of society.

68. Mean-reverting probability distribution of returns. Samuelson (1989) demonstrates that when asset returns are mean reverting, investors with long investment horizons should invest more in risky assets than investors with short investment horizons. Campbell, Cocco, Gomes, Maenhout, and Viceira (2001) show that if asset returns are mean reverting, investors should reduce the percentage of financial wealth invested in risky assets when the returns on risky assets have recently been above the long-run mean return and increase the percentage of financial wealth invested in risky assets when returns on risky assets have recently been below the long-run mean return. Thus, investors who believe that returns on risky assets

are mean reverting should also vary the percentage of financial wealth invested in risky assets with the status of the capital markets.

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Attachment 51a

Attachment 59a

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