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**BRITISH COLUMBIA
UTILITIES COMMISSION**

**ORDER
NUMBER** G-64-04

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**IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473**

and

**An Application by Terasen Gas Inc.
for Approval of Market-Based Commodity Rates for Rate Schedules 7, 10, 14 and 14A
for the 2004/05 Gas Contract Year**

BEFORE: L.F. Kelsey, Commissioner)
R.J. Milbourne, Commissioner) July 9, 2004
P.E. Vivian, Commissioner)

O R D E R

WHEREAS:

- A. By Commission Order No. G-25-03 dated April 14, 2003, the Commission approved market-based gas commodity rates, effective November 1, 2003 for BC Gas Utility Ltd. (now Terasen Gas Inc. ["Terasen Gas"]) for Rate Schedule 7 – General Interruptible Service, Rate Schedule 10 – Large Volume Interruptible Sales, and Rate Schedules 14 and 14A – Term and Spot Gas Sales; and
- B. On March 17, 2004, Terasen Gas requested approval of market-based gas commodity rates, effective November 1, 2004, for Rate Schedules 7, 10, 14 and 14A (the "Application"); and
- C. Terasen Gas provided copies of the Application to interested parties, and several interested parties raised concerns about the Application that were largely related to Rate Schedules 14 and 14A; and
- D. Commission Letter No. L-20-04 established a Workshop for the Application on April 2, 2004; and
- E. Commission Order No. G-37-04 established a written hearing process and a Regulatory Agenda and Timetable for the Application; and
- F. Absolute Energy Inc. ("Absolute"), CEG Energy Options Inc. ("CEG") and Direct Energy Business Services ("Direct") filed evidence and, along with Terasen Gas, responded to information requests. Absolute, CEG, Direct, R.T. O'Callaghan & Associates, Inc. and Terasen Gas filed Written Argument. The written hearing process concluded with the filing of Terasen Gas' Reply Argument on June 11, 2004; and
- G. The Commission has considered the Application and the submissions received in the written hearing process and is satisfied that market-based rate arrangements for Rate Schedules 7, 10, 14 and 14A should be approved for the gas contract year commencing November 1, 2004 and ending October 31, 2005 ("the 2004/05 gas contract year"), as set out in the Reasons for Decision attached as Appendix A to this Order.

**BRITISH COLUMBIA
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NOW THEREFORE the Commission orders as follows for Terasen Gas for the 2004/05 gas contract year:

1. The Commission approves the Rate Schedules 14 and 14A tariffs, generally as set out in the Application including the Swing Premium under the Annual Fixed Price Option of \$0.93 per gigajoule, except that the Market Factor Premium will be the greater of \$0.06 per gigajoule or actual transaction cost and the Gas Management Fee under Rate Schedule 14A will be \$0.05 to \$0.09 per gigajoule.
2. The Commission approves the extension of the Rate Schedule 10 tariff without material change, as set out in the Application.
3. The Commission approves the extension of the Rate Schedule 7 tariff with the elimination of the Index Rate Option, as set out in the Application.
4. Terasen Gas will comply with the other directions set out in the Reasons for Decision that accompanies this Order.
5. Terasen Gas will file a report for Rate Schedules 14 and 14A within 30 days of the end of each month that summarizes gas purchase and sales quantities, and costs and revenue for each rate option for the month.
6. The Commission will accept, subject to timely filing, Gas Tariff Rate Schedules in accordance with this Order and Reasons for Decision.
7. Terasen Gas will provide a copy of this Order and Reasons for Decision to all intervenors and interested parties to the Application and the written hearing, and to customers of Rate Schedules 7, 10, 14 and 14A.

DATED at the City of Vancouver, in the Province of British Columbia, this *9th* day of July 2004.

BY ORDER



L.F. Kelsey
Commissioner

Attachments

TERASEN GAS INC.
MARKET-BASED COMMODITY RATES UNDER RATE SCHEDULES 7, 10, 14 AND 14A
APPLICATION FOR THE 2004/05 GAS CONTRACT YEAR

REASONS FOR DECISION

1.0 INTRODUCTION

Terasen Gas Inc. (“Terasen Gas”, “Utility”, formerly BC Gas Utility Ltd. “BC Gas”) has sold natural gas at market-based commodity rates to its transportation service customers since the early 1990’s. The February 21, 1992 BC Gas Inc. Phase A Rate Design Decision anticipated the sale of surplus or “valley” gas that is available under baseload contracts to interruptible customers. Page 23 of the Phase A Decision determined:

“The Commission accepts BC Gas’ proposition that the excess or valley gas used to serve interruptible customers is essentially an asset of the Core Market. ...it is clear that interruptible sales should be priced in such a way as to maximize the benefits to the Core Market.”

Core Market referred to utility sales customers who received bundled or burner-tip service, which for the most part was firm service. The Phase A Decision approved Rate Schedule 10 for interruptible gas sales and Rate Schedule 13 for interruptible peaking and backstopping gas sales. Both schedules provided for the delivery of gas to customers at the interconnection of the pipeline systems of Terasen Gas and Westcoast Energy Inc. (“Westcoast”, now known as Duke Energy Gas Transmission).

The October 25, 1993 BC Gas Phase B Rate Design approved Rate Schedule 14 as a separate rate schedule for interruptible backstopping sales. The Phase B Decision also approved several bundled or burner-tip schedules, including Rate Schedule 7 for small volume interruptible sales. Thereafter, BC Gas applied annually for approval of market-based commodity rates under Rate Schedules 7 and 10 and more recently 14, and the rate options offered have evolved as the natural gas market in the area developed.

Since 1992, BC Gas has sold valley gas that is surplus to the needs of its firm sales customers to on-system and off-system interruptible customers. The revenue from these sales mitigated the demand charges paid by Core Market customers, and for several years the gas provided a useful source of interruptible, but reasonably reliable, supply for on-system industrial customers. In the mid 1990’s, the gas markets at Huntingdon/Sumas and Westcoast Station Number 2 became more liquid, with more marketers present and more supply options available. The increased market liquidity meant industrial customers had more supply alternatives available to them, including fixed price contracts.

To preserve the market for its surplus Core Market supply, in its 1996 Rate Design Application BC Gas proposed the reconstruction of Rate Schedule 14 as an on-system commodity sales option whereby the Utility could negotiate supply and price terms that would meet the needs of a particular industrial customer. The Canadian Independent Gas Marketers Association expressed concern that the Rate Schedule 14 proposal would result in anti-competitive behaviour on the part of the Utility and discrimination towards customers. The Commission concluded that the revisions to Rate Schedule 14 were unlikely to result in anti-competitive behaviour or rates that were in any way discriminatory towards customers, and by Order No. G-98-96 approved a Negotiated Settlement that included the revisions.

Rate Schedule 14 as approved by Order No. G-98-96 required the filing of the sales contracts with individual customers for Commission approval of the sales rates and other terms. In part to facilitate the administration of these sales, Order No. G-90-98 identified a number of market-based commodity pricing options that a customer could select.

By 2000, the ongoing shaping of its gas supply portfolio materially reduced the amount of surplus baseload gas that BC Gas had available for interruptible sales. For 2000/01, Order No. G-83-00 approved significant changes to Rate Schedule 10 to recognize the lower reliability of the supply. The Order also permitted BC Gas to offer firm gas supply under Rate Schedule 7 and Rate Schedule 14, with rates designed to recover the cost of the gas that BC Gas purchased to make these sales.

Commission Order No. G-32-02 approved Rate Schedule 14A for the 2002/03 gas year. This schedule applies when BC Gas performs the nominating and balancing functions that Shipper Agents typically perform for customers or groups of customers.

The Province released its Energy Plan entitled “Energy for our Future, A Plan for BC” in November 2002. Policy Action No. 19 addresses unbundling for low volume customers, so that gas marketers will be able to sell gas to customers who do not consume sufficient quantities for transportation service to be viable. Policy Action No. 19 also provides:

“In addition, the requirement for large natural gas customers to file their supply contracts with the commission will be removed since the high-volume direct sales market is now mature and a high level of regulatory oversight is no longer needed.”

This change reduced the administrative burden for gas sales to large transportation service customers.

2.0 APPLICATION AND REVIEW PROCESS

On March 17, 2004, pursuant to section(s) 60 and 61 of the Utilities Commission Act (“UCA”) Terasen Gas filed its annual application seeking approval for Rate Schedules 7, 10, 14 and 14A and the related market-based commodity rates for the 2004/05 gas year commencing November 1, 2004 (the “Application”). The Application requested the continuation of these rate schedules generally in their current form, with some relatively small changes for each schedule that will be addressed in subsequent chapters of these Reasons.

Several gas marketers raised concerns about the Application that were virtually entirely related to Rate Schedules 14 and 14A. The marketers were concerned that the current Rate Schedule 14 and 14A terms may be an impediment to the development of a competitive gas commodity market in British Columbia, that Core Market customers may be subsidizing the rate offering and that Terasen Gas may be inappropriately using customer information.

Pursuant to Commission Letter No. L-20-04 a Workshop took place on April 2, 2004 providing a forum where Terasen Gas explained the Application, particularly Rate Schedules 14 and 14A and the proposed changes to these rate schedules. Marketers and customers were presented with the opportunity to express their concerns and views on the rate schedules. After the Workshop, the parties provided written comments on the process that the Commission should use to review the Application.

Order No. G-37-04 established a written hearing process and a Regulatory Agenda and Timetable for the Application. Three intervenors, Absolute Energy Inc. (“Absolute”), CEG Energy Options Inc. (“CEG”) and Direct Energy Business Services (“Direct”), filed direct evidence. Terasen Gas and each of the foregoing three intervenors responded to Information Requests. Terasen Gas filed Written Argument on Rates Schedules 7, 10, 14 and 14A following which Absolute, CEG and Direct, along with R.T. O’Callaghan & Associates, Inc. provided written comments or Final Argument. The written hearing process concluded with the filing of Terasen Gas’ Reply Argument on June 11, 2004. A List of Intervenors who registered in the written hearing process is Attachment 1 to these Reasons. The List of Exhibits is Attachment 2.

3.0 MARKET-BASED COMMODITY SALES IN A COMPETITIVE MARKETPLACE

The approval by the Commission of Rate Schedules 7, 10, 14 and 14A is a discretionary matter as this market is also served by unregulated gas suppliers in a competitive business environment. The continuance of these regulated rate schedules based on a need and/or a demand in the market is therefore a matter of interest for the Commission. As noted above, the Commission has from time-to time received comment from gas marketplace participants and the stakeholders of the utility in the course of its reviews of Rate Schedules 7, 10, 14 and 14A. In the main, the focus of comment has been on Rate Schedules 14 and 14A, with increasing concern raised by the gas marketers who are in direct competition with Terasen Gas as to their “inability to compete,” given the cost structure and risk mitigation characteristics of Terasen Gas’ offerings. Equally, the stakeholders who utilize the offerings, including marketers who perform the shipper agent role for groups of customers under Rate Schedule 14, are strongly supportive of maintaining the status quo. These respective positions have become more entrenched with the passage of time, as the submissions to the Commission in the course of this hearing process forcefully record.

As the Commission has noted in its past decisions regarding these Rate Schedules, it is considered to be in the public interest that there be a robust, liquid, and sustainable gas marketplace, and that customers have choice as to their gas commodity supplier and the terms and conditions under which gas is provided. Also, the Core Market customers of the Utility must not be adversely impacted by activities under these rate schedules.

In the course of the proceeding, evidence was filed which quantified the rapid growth in unbundled gas supply to the customers eligible for Rate Schedules 14 and 14A. From the 2001/2002 gas year through the 2003/2004 year, Rate Schedule 14 and 14A activity increased 638 percent by number of customers, and 325 percent by volume supplied (Exhibit B-1, p. 4). The comparable indicators for Direct are 305 percent and 152 percent, respectively (Exhibit C6-5, Absolute IR 1). The increase in Direct’s customers and sales were approximately one-half the growth of Terasen Gas, and furthermore the majority of its growth occurred between the 2001/2002 and 2002/03 years, with stagnant growth from 2002/2003 to 2003/2004. No sales statistics were provided by other marketers either in support of their position or in opposition to the Terasen Gas position. Direct submits that its competitive position is adversely impacted by the “systematic bias” enjoyed by Rate Schedule 14 and 14A service through “the single bill model, cost allocation methodology, and incumbent position of Terasen Gas ...” (Exhibit C6-6, BCUC IR 1).

Independent marketers made submissions that the objective of a competitive marketplace for gas commodity supply can only be realized if either Rate Schedule 14 or 14A are withdrawn (Direct), or restricted to end users only (CEG) or alternatively Terasen Gas is directed to conduct those activities under the aegis of a non-regulated entity (Direct). Avista Energy Canada, Ltd. (“Avista”) in its submission notes that “We remain concerned, however, about peak day treatment, allocation of overhead, market access, and conflict of interest” (Exhibit E5-2). Atlin Energy Management Inc., in its letter of comment, expressed similar concerns (Exhibit C4-2).

In response, both Terasen Gas and Absolute submit that Rate Schedules 14 and 14A are fairly and even handedly applied and go towards furthering competition, as opposed to constraining it. Extensive customer support for the continuing of Rate Schedules 14 and 14A was received. No submissions were received on behalf of other stakeholders of the Utility.

Commission Determination

The Commission is of the view that there may not be a long term future for the continuation of Rate Schedules 14 and 14A, as other participants offer similar supply options to customers. However, discontinuance of these rate schedules would require sufficient notice for customers to make alternative supply arrangements in an orderly manner. The Commission is persuaded that the Application has merit notwithstanding considerable argument by competitors opposing Rate Schedules 14 and 14A. There is also strong support for their continuation.

The Commission determines that the interests of customers, marketers and the Utility are best served by making Rate Schedules 14 and 14A supply available for the 2004/05 gas year, and approves the continuation of the rate schedules. The terms of Rate Schedules 14 and 14A for 2004/05 will be discussed in detail in Chapter 4.

Nevertheless, the Commission considers that several aspects of the rate schedules should be reviewed if the service offering is to continue for the longer term. The Commission has reviewed the principal concerns that Intervenor raised, and has considered them in the sections which immediately follow.

3.1 Single Billing

Direct submits that:

“Terasen Gas is the only Marketer that has the ability to provide the customer with a single invoice. This provides a clear competitive advantage... Competitive Marketers must provide their own commodity billing at their expense. Terasen Gas must either provide this same single invoice function to all Marketers, or cease providing this functionality for Rate 14/14A service” (Exhibit C 6-2, item 5).

In a response Terasen Gas notes that “single monthly billing is an option in many deregulated or partially deregulated industries,” and cites examples (Exhibit C6-7, p. 3). Terasen Gas then questions “...the value of the premium that (Direct) would attribute to the convenience of a single bill for large commercial and industrial customers...”. Direct “is of the view that it is difficult to quantify...but coupled with the other advantages inherent in rates 14/14A, the additional convenience is a factor in a customer’s decision regarding the selection of a service provider.”

Commission Determination

Noting that Terasen Gas does not address the practicalities of Direct’s request in argument, and given the Commission’s view that fostering a competitive marketplace for the supply of commodity gas is desirable, the Commission requests that Terasen Gas work with the independent marketers to establish a commercially reasonable basis for accomplishing the objective of enabling “the same single invoice function to all marketers,” and to report progress to the Commission within 6 months of the date of these Reasons for Decision.

3.2 Cost Allocation

The methodology employed by Terasen Gas to compute its costs and therefore its Gas Management Fee and also the degree to which the methodology affects the dynamics of the market place are the subject of differing opinions.

On the matter of Gas Management Fees and the makeup thereof, Terasen Gas is of the view that “The management fees collected through RS14 and RS14A recover all costs associated with providing the R14/14A option. These costs include; a portion of the Key Account Managers’ salaries, as well as overhead costs such as

bad debt allowance, billing, credit reviews and purchasing physical and financial contracts” (Exhibit B-1, pp. 13, 14).

Terasen Gas was asked for its view on “whether the proposed fees are higher, lower or about the same as the fees charged by marketers for the equivalent services.” The Utility responded: “Terasen Gas has no specific information related to the fees charged by any of the marketers, but understands that its fee schedule falls within a reasonable range of what customers would expect to have to pay marketers for equivalent services.” (Exhibit B-3, BCUC IR 7.6)

The position of marketers as expressed by CEG is: “The costs of the Schedule 14 program are presented by Terasen as cost based. Terasen is able to leverage its considerable expertise and infrastructure to present marginal cost of delivery that is not market based and results in a considerable cost advantage on a stand alone basis” (Exhibit C1-4, pg. 3).

CEG states:

“These customers will be capable of determining the economics of remaining on transport and working with a marketer versus going back to a Utility option. CEG believes the elimination of the Schedule 14 program would not materially affect the economics of remaining on transport for any of the current Schedule 14 customers. The only customers that may migrate back to the Utility are those who prefer the safety of a regulated price environment and this should be a minority” (Exhibit C1-6, BCUC IR 7).

Direct states: “(c) DEBS [Direct] would price all products and services competitively, and with a view to recovering its stand-alone costs. Therefore, DEBS is of the view that it’s’ management fee structure would likely be higher than Terasen Gas’ current Rate 14/14A management fee in the short term” (Exhibit C6-7, Terasen Gas IR 2).

On the other hand, Direct also submits: “Terasen Gas’ response to BCUC Information Request 7.4 demonstrates that the Rate 14/14A management fee is calculated on an incremental basis. Competitive marketers must set their fees based on a fully allocated stand-alone cost structure. The ability of Terasen Gas to rely on the use of assets and personnel embedded in regulated rates, at the incremental cost of those assets and personnel, conveys a significant advantage to Terasen Gas” (Exhibit C6-8, p. 1). By “fully allocated” Direct means that Gas Management Fees should be based on a stand-alone methodology similar to the situation of a marketer. According to Direct, competitive marketers are likely to face higher costs since they must provide “on call” service, may not be able to obtain part-time services as needed and must provide back-up. This is a somewhat

different meaning of “fully allocated” costs than that which applies for a utility fully allocated cost of service study (Exhibit C6-4, pp. 1-2; Exhibit C6-6, BCUC IR 2).

CEG submits:

“The second fundamental reason for the success of the Schedule 14 program is that Schedule 14 products are priced similar or lower than competing marketer offerings. This makes it difficult for a marketer to attract customers. CEG has come across a number of Schedule 14 customers who have stated that they have no intention of even entertaining a competitive offer from a competitor because of the comfort and belief that Terasen Schedule 14 will be the lowest and most secure supply available on the market. There is no question that Terasen has the ability to do this using its “efficiency gains” or marginal cost allocations for fees” (Exhibit C1-5, p. 3).

On the other hand, Absolute expresses the view that “Schedule 14 provides an important service to support the development of a fair, transparent marketplace, and one that in no way impedes competition, but indeed supports and facilitates it” (Exhibit C2-6, p.1).

Commission Determination

The Gas Management Fee is of course only one cost component in the total cost of the commodity and the management of its acquisition and delivery to the customer. It is significant however and when originating in a regulated entity must be calculated in a way that is transparent, understood and reasonable so as to not cross subsidize between classes of service. The Commission Panel is not convinced by the evidence before it that the current methodology and content for calculating an appropriate Gas Management Fee is fully comprehensive in the circumstances.

On the other hand, in spite of the considerable comments from marketers on the topic, the Commission Panel is equally unconvinced by the evidence that, when taken in total with other Rate Schedule 14 and 14A costs, a material competitive advantage to Rate Schedules 14 and 14A is the result. Moreover, to fulfill its responsibilities under the UCA, the Commission must concern itself primarily with the identification and recovery of costs for a class of service, in this case the make-up and appropriateness of Gas Management Fees charged to Rate Schedules 14 and 14A customers.

Gas Management Fees for 2004/05 will be discussed in Chapter 4.

To establish a better-understood and comprehensive basis for Gas Management Fees for future years, the Commission Panel directs Terasen Gas, within six months, to prepare and file a detailed and appropriately supported fully allocated cost of service analysis for the provision of Rate Schedules 14 and 14A. For clarity, the analysis should be an allocation of Terasen Gas costs, rather than an attempt to ascertain the cost for a stand-alone entity to provide an equivalent service. Staffing and other utility costs that relate to margin revenue requirements should be reported separately from those that are included in Core Administration Costs. This filing should be supported by a statement by Terasen Gas' Internal Audit Department confirming the result of the study is complete, fully reflects all costs attributable to the provision of Rate Schedules 14 and 14A and is compliant with the Terasen Gas Transfer Pricing Policy. This will provide a detailed and useful base of information for the Terasen Gas application for the 2005/06 gas contract year.

3.3 Risk Containment – Bad Debt Allowance

There are certain risks inherent in the provision of Rate Schedules 14 and 14A or a like service. In this proceeding there is no disagreement on the nature of these risks. They are credit risk and the costs associated with daily swing volumes in order to provide a fixed price for a contracted term. Where there is disagreement is in the costing of these risks and which party ultimately bears the risk.

On the matter of credit risk, Terasen Gas referenced its credit review process in the Application and indicated it “has not incurred any bad debt from RS14 and RS14A customers over the past three contract years” (Exhibit B-1, p. 13). Terasen Gas is however proposing an Industrial Bad Debt Allowance account to capture the cost of any bad debt incurred by the RS 14/14A group of customers:

“This allowance account is funded by a portion of the RS14 and RS14A Gas Management Fees collected. The calculated bad debt on RS14 and RS14A accounts is 0.3 percent of total revenues. As RS14 and RS14A have not incurred any bad debt to date, the determination of the 0.3% bad debt allowance is calculated from the bad debt incurred by transportation customers as a percentage of revenues received. This may be a conservative calculation as the past two contract years have yielded bad debt of 0.07% and 0.19%” (Exhibit B-1, p. 13).

There was no disagreement from Intervenors with the quantum of the Bad Debt Allowance and the proposal seems reasonable to the Commission Panel. However the disposition of the Bad Debt Allowance is another matter. This proposed account has been variously referred to as an Industrial Bad Debt Allowance account (Exhibit B-1, p. 13), a Bad Debt Allowance deferral account (Exhibit B-3, BCUC IR 6.3), and a Bad Debt Allowance account (Exhibit B-3, BCUC IR 6.5). It is not clear therefore if Terasen intends this account to be a

deferral account or an operating account. The implications of the type of account are quite different. A deferral account balance would remain from year to year with disposition subject to Commission approval while an operating account balance would be incorporated into operating results and would be subject to the established profit sharing mechanism. Terasen proposes that the account be included in rate base. This would seem to indicate that the proposed accounting treatment would be as a deferral account. In the event that the account was an operating account, account balances would be subject to the established profit share mechanism and would be shared between utility customers and shareholders.

Terasen Gas has asserted a number of times that it has no profit motive with respect to its provision of Rate Schedules 14 and 14A. The following are some examples of those assertions: “RS 14 services provides Terasen Gas with no meaningful profit motivation” (Exhibit B-3, BCUC IR 3.2), “Terasen Gas has absolutely no motivation for capturing a share of the Industrial commodity sales” (Exhibit B-5, p. 4), “Because Terasen Gas has no profit incentive with respect to Rate Schedules 14/14A” (Exhibit B-6, p. 2), “the company’s profitability is not impacted directly by the share of the Market that uses Rate Schedules 14/14A” (Exhibit B-6, p. 3).

Commission Determination

Including a Bad Debt charge in the Gas Management Fee attributes the credit risks associated with these rate schedules to Rate Schedule 14 and 14A customers and relieves other customer categories or classes of service of this risk. It is therefore an effective risk management strategy. The Terasen Gas credit granting policies have been effective in managing credit loss performance and the creation of a bad debt allowance should not result in a relaxation of Terasen Gas credit granting policies. The Commission Panel is of the view however that the proposed Bad Debt Allowance should be recorded in a deferral account against which any credit losses should be charged.

The Panel approves the establishment of a Bad Debt Allowance Deferral Account to capture both the allowance as it is collected and bad debts as they are experienced. The requested quantum of the Bad Debt Allowance of 0.3 percent is approved. The account balance will be included in rate base and Terasen Gas will provide the Commission with an annual report on account transactions and balances. Terasen Gas is to maintain or strengthen current credit granting policies and procedures. Adjustments to the Bad Debt Allowance and disposition of any surplus in the Bad Debt Allowance Deferral Account will be reviewed by the Commission at a future time.

3.4 Risk Containment – Swing Premium

There was intervenor disagreement on the matter of the risks associated with a group's daily swing volumes in order to provide a fixed price for the year. A Swing Premium for Annual Fixed Rate Option sales was developed to minimize this risk with the revenue going to the benefit of Core Market customers. The Application proposes a modified, more conservative methodology for the calculation of the Swing Premium for 2004/05. Intervenor disagreement lies not with the proposed revision to the calculation but rather with the scenario on which the calculation is based not being "worst case." Another more philosophical difference was the transfer of risk to core customers where in a competitive environment the risk would be borne by shareholders.

According to CEG:

"CEG asked Terasen to quantify what the worst case scenario(s) would be for actual costs of the schedule 14 swing premium customer obligations. CEG requested Terasen consider a design year demand scenario consistent with how the current firm portfolio is developed and to use daily index prices consistent with what was experienced in December of 2000 at Sumas. Terasen declined to develop or provide this analysis or dispute that this scenario could or could not occur. While CEG would agree that the current Terasen swing premium is priced appropriately, under the assumptions put forward by CEG above it is certain in CEG's opinion, that the actual costs of the program would far exceed the swing premium cost in this potential scenario. Therefore, CEG has stated that swing premium surplus revenues are not guaranteed in any given year and that the swing premium does or should be priced to anticipate this worst case scenario" (Exhibit C1-6, BCUC IR 5).

Direct Energy submits:

"Terasen Gas has provided evidence to show that core consumers have benefited from the existence of rate 14/14A, and has stated that the potential for under collection in any year is remote. This, however, underscores another fundamental issue that the BCUC must address, and that is that the core market does backstop Rate 14/14A service. Ultimately, all risks associated with provision of commodity service in the competitive market by Terasen Gas are borne by core customers. This is a fundamental flaw in market design that results in an uneven playing field. The shareholders of competitive marketers assume all risks of providing commodity service, and do not have the luxury of offloading this risk onto regulated customers" (Exhibit C6-8, p. 1).

Terasen Gas replied that the risk borne by Core Market customers through Rate Schedules 14 and 14A are no greater than, and may in fact be less, than the risks associated with servicing all other transportation customers. The Utility submitted "The conservative approach taken with respect to all aspects of the services virtually assures continued full cost recovery" (Exhibit B-6, p. 2). Core customers do have potential exposure however:

“Terasen Gas agrees it is possible that the Swing Premium may not cover the total actual costs on any given day, but concludes that the probability of under recovery over the year is extremely remote” (Exhibit B-5, p. 4).

Terasen Gas noted that Rate Schedule 14 and 14A customers are required to pay an annual premium for services that other transportation customers and marketers currently receive at no cost under their transportation rate schedules (Exhibit B-5, p. 5). The Commission Panel notes that the statement relates to the Swing Premium, which only Annual Fixed Rate Option customers pay. Rate Schedule 14 and 14A sales potentially expose Core Market customers to price risks related to daily swing volumes and also to the cost of providing the Midstream storage and other physical resources that are needed to balance day to day variations in load. The Swing Premium that Annual Fixed Rate Option customers pay compensates for these price risks and costs.

It is not clear why no Swing Premium should apply to other Rate Schedule 14 and 14A customers. Terasen Gas believes that no Swing Premium should be charged to customers participating in the Term Fixed Rate Option and the Daily Index Option because Terasen Gas has not guaranteed a fixed price for those customers. They are susceptible to any price fluctuations above their locked-in quantities (Exhibit B-3, BCUC IRs 5.6, 5.7).

Customers can select the Term Fixed Rate Option for up to 85 percent of their expected average daily consumption for the period, and the Term Fixed Rate and Monthly Index Option in combination for up to 90 percent. Additional sales are charged at the Daily Index Rate. In response to an Information Request, Terasen Gas provided monthly load profiles for typical Rate Schedule 23 and 25 customers, but did not discuss why 85 and 90 percent are the appropriate levels to prevent the transfer of risk (Exhibit B-3, BCUC IR 5.7).

The Application shows in graphical form how the actual load of a customer can vary from day to day (Exhibit B-1, p. 5). (This graph is for the Annual Fixed Rate Option but should also be representative of other Rate Schedule 14 and 14A customers). When a customer’s actual consumption is less than the expected consumption, the excess supply is recorded in the customer’s balancing account and returned at a future time. Core Market customers would appear to be exposed to price risk by these transactions. Furthermore, the Midstream physical assets that are needed to balance day to day variation in load are a cost to Core Market customers.

Terasen Gas acknowledges that transportation customers served under Rate Schedules 22, 23, 25 and 27 do not pay any charge for the use of Midstream resources. The Utility considers the transportation service model to be fundamentally different from the Essential Services Model, and notes that an objective of the Commodity Unbundling and Customer Choice Program was for it to have no impact on the terms of service for transportation

customers. Terasen Gas has not performed comprehensive analysis to determine what Midstream resources are used by transportation customers (Exhibit B-3, BCUC IR 1.8).

Commission Determination

While the Commission Panel agrees that in a commercial environment the shareholder ultimately bares the risk, business risk is in the first instance limited to a level acceptable to shareholders through risk management strategies. In a regulated utility environment this type of risk is borne by the customer but the effect of the risk is mitigated and smoothed through business strategies, pricing strategies and deferral accounts. In the case of Rate Schedules 14 and 14A the pricing strategy in terms of the proposed calculation of the Swing Premium appears to have been determined to provide significant benefit to core customers in a good year and reasonable protection to those same customers in a volatile year. The amount of the Swing Premium for 2004/05 will be discussed in Chapter 4.

Although the transportation service model is different from the Essential Services Model, it is not clear to the Commission Panel why the allocation of costs related to price risk exposure and Midstream assets should not be consistent across the two models. Also, the full allocation of costs to Rate Schedules 14 and 14A requires consideration of both the price risk exposure and the cost of physical Midstream resources.

The Commission Panel directs Terasen Gas, within six months, to file a comprehensive analysis of both of these costs (without an allowance for the no-charge balancing provided under transportation service tariffs) and recommendations regarding Swing Premiums that should apply for all Rate Schedule 14 and 14A Rate Options for 2005/06 that are based on a range of risk scenarios with related risk costs, from best case to worst case. In the report, the Utility should also review and comment on whether transportation customers in general provide adequate compensation to Core Market customers with respect to gas balancing.

3.5 20,000 GJ Cap on Sales

The maximum participation volume under Rate Schedules 14 and 14A of 20,000 GJ per day was the subject of question and comment by several parties. The cap currently applies only to the Annual Fixed Rate Option, and is well defined in section 2.3(c)(i) of Rate Schedules 14 and 14A:

“Availability of Firm Gas Supply under Annual Fixed Rate Option - Participation in Firm Gas Supply under the Annual Fixed Rate option will be available to Customers until August 31, 2004 subject to the following:

- i) The combined total Average Daily Consumption during the November to March period for all Customers who have already elected the Annual Fixed Rate option does not exceed 20,000 Gigajoules per Day based on their total Average Daily Consumption under Rate Schedules 14 and 14A.”

Current deliveries by Terasen Gas are well below this level as defined and therefore this matter is not, at this time, germane to the matters before the Commission Panel.

4.0 RATE SCHEDULES 14 AND 14A – TERM AND SPOT GAS SALES

Rate Schedules 14 and 14A provide for the sale of gas to on-system customers and marketers on a firm basis at the interconnection with the Westcoast system. A Rate Schedule 14 or 14A customer currently selects from the following rate options:

Annual Fixed Rate Option:	Annualized price based on the Sumas monthly forward prices for physical purchases, including a Market Factor and all transaction costs, that BC Gas fixed at approximately the time when the customer committed to the Annual Fixed Rate Option for 2003/04, plus a Swing Premium of \$0.84/GJ.
Term Fixed Rate Option:	Fixed price for a specified daily amount of gas for a period of months, that is BC Gas’ cost of fixing the forward physical purchase of the gas at Sumas, including a Market Factor of the greater of \$0.05/GJ or cost and all transaction costs. A customer can select the Term Fixed Rate Option for up to 85 percent of the customer’s expected consumption.
Monthly Index Rate Option:	Inside FERC Sumas monthly price, plus a Market Factor of the greater of \$0.05/GJ or cost. A customer can select the Monthly Index Rate Option and the Term Fixed Rate Option in combination for up to 90 percent of the customer’s expected consumption.
Daily Index Rate Option:	Gas Daily Sumas midpoint price, plus a Market Factor of the greater of \$0.05/GJ or cost.

The Daily Index Rate Option is used to supply spot gas to customers who have experienced gas supply failure for some reason, including customers who have been released from their marketer. Each customer must meet Terasen Gas’ credit requirements before such deliveries can begin (Exhibit B-3, BCUC IR 5.10). This option is used primarily to top up requirements under the Term Fixed Rate and Monthly Index Rate options.

Terasen Gas enters into firm physical supply contracts that are outside its Core Market supply portfolio for all fixed price volumes. Monthly Index Option volumes are purchased prior to the beginning of each month and Daily Index Option volumes are purchased two days prior to the flow date, to ensure the physical procurement of the gas. Physical supply is purchased for delivery at Sumas, so that no transportation capacity on the Westcoast system is required. Core Market Midstream resources are used to balance day to day differences between nominations and actual deliveries, consistent with the terms of the customers' transportation service agreements (Exhibit B-3, BCUC IR 4.5).

Customer Participation and Annual Volumes for Rate Schedules 14 and 14A are as follows:

Customer Participation	2001/02	2002/03	2003/04
Rate Schedule 14A	44	75	125
Rate Schedule 14	N/A	78	200
Total	44	153	325
Annual Volumes (GJs)	2001/02	2002/03	2003/04*
Rate Schedule 14A	1,295,945	1,236,501	2,093,275
Rate Schedule 14	N/A	1,289,021	3,413,480
Total	1,295,945	2,525,522	5,506,755

*2003/04 Volumes are estimated

4.1 Market Factor Premium

The Market Factor Premium currently is the greater of \$0.05 per gigajoule or cost. It compensates Terasen Gas for the premium paid to suppliers to ensure the firm supply of physical gas. Terasen Gas states that current physical premiums are US \$0.04 per MMBtu for winter 2004/05 and US \$0.01 per MMBtu for summer 2005, averaging \$0.03 per gigajoule. Market Factor Premiums are credited to gas cost accounts, and Core Market customers benefit from any difference between the Rate Schedule 14 and 14A Market Factor Premium and the premiums charged by gas suppliers.

Terasen Gas recommends a continuation of the current Market Factor Premium, but it is not clear whether the Utility wishes to limit the application of the premium to Daily and Monthly Index Rate Option purchases. The definition of Market Factor Premium indicates that it is the premium above indexed or fixed prices related to securing incremental supply, and since Terasen Gas buys incremental supply for all Rate Schedule 14 and 14A

sales, the Market Factor Premium should apply to all sales under these rate schedules. It may be the case that the Market Factor Premium is included in the prices that are determined under the Annual Fixed Rate Option and the Term Fixed Rate Option, but it would be more transparent to include it as a separate charge.

CEG stated that the Terasen Gas Market Factor Premiums are not excessive and are close to typical premiums seen in the marketplace (Exhibit C1-6, BCUC IR 5). However, CEG in its written evidence also stated that Core Administration Costs are approximately \$1.7 million per year (not including the capital costs of sophisticated management software and other overheads) and the Core Market load is approximately 120 petajoules per year. These numbers indicate the average Core Administration Cost is \$0.014 per gigajoule. Rate Schedule 14 and 14A sales of 5.5 petajoules per year are approximately 5 percent of the Core Market Load, and CEG proposed that 5 percent of Core Administration Costs should be allocated to these sales (Exhibit C1-4, Item 2).

In Reply Argument, Terasen Gas observed that the Core Administration Cost is now allocated between Commodity and Midstream Costs, and the Commodity portion is approximately \$475,000 per year. Terasen Gas argued that if for consistency one allocated other costs on a similar proportional basis, rather than a full cost basis in accordance with the Terasen Gas Transfer Pricing Policy, the result would be lower fees for Rate Schedule 14 and 14A customers (Exhibit B-6, p. 4).

Commission Determination

The Commission Panel notes that Terasen Gas must purchase and financially fix the prices of a relatively large number of smaller volumes of gas for Rate Schedules 14 and 14A. The Application states that Terasen Gas now has the ability to fix a term price for customer volumes that are less than 1,000 gigajoules per day if the Utility deems the volume can be transacted (Exhibit B-1, p. 12). Allocating costs on a volumetric basis may not appropriately represent the administration costs related to small volume transactions.

The evidence of Terasen Gas and CEG support a premium of \$0.05 per gigajoule to ensure the firm supply of physical gas. In addition, Core Administration Costs for activities related to Rate Schedules 14 and 14A appear to be approximately \$0.01 per gigajoule. In the report on costs related to the provision of Rate Schedules 14 and 14A that is discussed in Chapter 3, Terasen Gas will be expected to review the allocation of Core Administration Costs. Since Core Administration Costs are recovered in Commodity and Midstream Charges rather than in Delivery Charges, it is more appropriate to include this amount in the Market Factor Premium (which is credited to gas cost accounts) rather than in the Gas Management Fee. Rate Schedule 14 and 14A customers should continue to be responsible for costs that exceed the established premium amount.

The Commission Panel determines that the Market Factor Premium for 2004/05 will be the greater of \$0.06 per gigajoule or actual transaction cost and that it should be shown as a separate charge for all Rate Schedule 14 and 14A sales and separately reported in the Utility's monthly reports to the Commission.

4.2 Swing Premium

Annual Fixed Rate Option customers pay a Swing Premium that is currently \$0.84 per gigajoule of sales. The Reasons for Decision with Order No. G-32-02 described the 2001/02 Swing Premiums:

“Swing Premiums for 2001/02 of \$1.50/GJ for the winter and \$0.90/GJ for the summer, were calculated to recognize the cost of core market storage and peaking assets that are used to handle daily volumes that are greater or less than the Average Daily Consumption. The calculation did not consider the risk assumed by other sales customers in order to offer a firm one-year price under RS14, but also did not recognize the balancing provisions that transportation customers receive through transportation service schedules.”

In approving a Swing Premium of \$0.84 per gigajoule for 2002/03, the Commission stated:

“The Commission recognizes that the Swing Premium calculated by BC Gas may overstate the cost of handling demand swings for high load factor RS14 customers, but considers that core market customers must also be compensated for the risks associated with a firm one-year price.”

The Application states that the Swing Premium is “to cover-off any price variances in the Balancing Gas supply”, and proposes that the Swing Premium should be constructed to compensate the Core Market for the price of daily swing volumes under the Annual Fixed Rate Option. For 2004/05, the Utility proposes a calculation methodology that is based on a forecast winter Sumas Daily Index prices and price volatility. To be conservative, Terasen Gas used the Sumas Daily volatility factor of 2.3 that it calculated for winter 2000/01, which was the highest volatility experienced in the past five years. The volatility factor was used with winter 2004/05 forward prices and January 2004 volumes as that month had the highest winter peaking supply requirements since the Annual Fixed Rate Option was introduced. Terasen Gas calculated a Swing Premium of \$0.93 per gigajoule and requested that the premium be set at this amount for 2004/05 (Exhibit B-1, pp. 7, 8; Exhibit B-3, BCUC IR 4.6).

The Essential Services Model that was introduced as part of the Commercial Unbundling and Customer Choice process allocates the cost of Midstream resources like gas storage and transportation resources to Core Market customers. At the time the Application was filed, Lower Mainland Midstream charges were \$0.872 per gigajoule for Rate Schedules 5 and 7 and \$1.031 per gigajoule for Rate Schedule 3. (The current Midstream charges that went into effect May 1, 2004 were derived from other charges and do not fully reflect Midstream costs.) Terasen

Gas states that transportation customers do not use Midstream resources to the same extent or in the same way as bundled sales customers since Rate Schedules 14 and 14A gas is generally purchased at Sumas, and believes that the Swing Premium is not comparable to the Midstream charge (Exhibit B-3, BCUC IRs 1.2, 1.4, 1.7, 1.8, 4.10).

CEG stated that:

“Terasen’s current design of the swing premium for customers electing for the 100% fixed product is more fairly priced in comparison to other schedule 14 offerings and is also more consistent as it is a blanket price for all customers rather than a customized product.”

CEG agreed that the current Swing Premium is priced appropriately (Exhibit C1-6, Items 1, 5). Direct identified as a fundamental issue its concern that Core Market customers backstop Rate Schedules 14 and 14A service, but did not comment on the proposed Swing Premium amount.

Terasen Gas replied that “The conservative approach taken with respect to all aspects of the services virtually assures continued full cost recovery” (Exhibit B-6, p. 2).

Commission Determination

Rate Schedules 14 and 14A sales expose the Core Market to price risks related to daily swing volumes and also to the cost of providing the Midstream storage and other physical resources that are needed to balance day to day variations in load. The proposed Swing Premium of \$0.93 per gigajoule for Annual Fixed Rate Option customers can be viewed as a conservative (relatively high) estimate of the price risk exposure. Likewise Midstream charges in the \$0.872 to \$1.031 per gigajoule range probably overstate the appropriate Midstream charges for these customers. Taking both these considerations together, the proposed Swing Premium of \$0.93 per gigajoule for Annual Fixed Rate sales appears to be reasonable. The amount is a modest increase from the current Swing Premium, and no party opposed the increase.

Terasen Gas proposes that a zero Swing Premium continue to apply for to other Rate Schedule 14 and 14A rate options. Terasen Gas believes that no Swing Premium should be charged to customers participating in the Term Fixed Rate Option and the Daily Index Option because they are susceptible to any price fluctuations above their locked-in quantities (Exhibit B-3, BCUC IRs 5.6, 5.7). The Commission Panel accepts this proposal for 2004/05, but will require the matter to be reviewed for future years, as discussed in Chapter 3.

The Commission Panel approves a Swing Premium of \$0.93 per gigajoule for 2004/05 for the Annual Fixed Rate Option.

4.3 Gas Management Fees

Gas Management Fees relate to the services of Utility staff such as Key Account Managers whose costs form part of the Utility's margin revenue requirements that are almost entirely recovered from all customers in Delivery Charges. The Gas Management Fee revenue offsets part of these costs. The fees are currently \$0.02-\$0.08 per gigajoule for Rate Schedule 14 customers and \$0.04-\$0.08 per gigajoule for Rate Schedule 14A customers. Terasen Gas proposes to increase the fee ranges to \$0.03-\$0.08 per gigajoule and \$0.04-\$0.09 per gigajoule, respectively. With the significant increase in participation, Terasen Gas feels an increase in management fees is necessary to cover the costs of annual credit reviews for continuing and new customers.

The proposed increase would compress the differential between the minimum fees under the two rate schedules from \$0.02 to \$0.01 per gigajoule. The Reasons for Decision with Order No. G-32-02 that approved Rate Schedule 14A state:

“Although the provisions of RS14 generally should apply, it seems appropriate that the range of Gas Management fees of \$0.02 to \$0.08/GJ under RS14 should be adjusted to recognize the additional services provided by BC Gas under RS14A. In the absence of detailed evidence on the matter, a doubling of the minimum fee seems reasonable.”

Terasen Gas believes that a narrower differential on the lower end of the fee range is appropriate as the lower fees typically apply to large volume customers who require less administration and oversight. The Utility stated that the nomination and balancing function has required much less Key Account Managers' time than contract administration, credit reviews and purchase volume verification (Exhibit B-3, BCUC IR 7.5). However, Terasen Gas provided no material evidence in support of its request to compress the differential between the minimum fees under the two rate schedules.

Terasen Gas estimated total costs for 2004/05 of \$222,000, including a Bad Debt allowance of \$99,000 that was calculated as 0.3 percent of Rate Schedules 14 and 14A revenue. The other large cost is a portion of Key Account Managers' salaries which is allocated in accordance with the Terasen Gas Transfer Pricing Policy. The policy accounts for general overhead, a facilities charge, concessions, benefits, equipment and supervision. The average fees expected for 2004/05 is \$0.04 per gigajoule for Rate Schedule 14 and \$0.065 per gigajoule for Rate

Schedule 14A (Exhibit B-3, BCUC IR 7.4). Assuming 2004/05 sales volumes are similar to those in 2003/04, Gas Management Fee revenue will be approximately \$273,000.

Direct argued that the Terasen Gas Management Fee is calculated on an incremental basis, paying the increment cost of assets and personnel whose costs are embedded in regulated rates. Competitive marketers must set their fees based on a fully allocated stand-alone cost structure. CEG also argued that Terasen Gas used “marginal cost allocation” to set fees (Exhibit C1-5).

Terasen Gas replied that its fees for service fully recover all costs for the services provided. Furthermore, the Utility argues that the conservative approach taken with respect to the full allocation of personnel and overhead and the coverage of Bad Debt for Rate Schedules 14 and 14A means that full cost recovery is assured and competitors face no unfair pricing impediments (Exhibit B-5, p. 2).

The evidence indicates that the Gas Management Fee fully recovers the costs to administer these sales, providing utility personnel and services requirements are accurately represented by the usage that has been identified for administering Rate Schedule 14 and 14A activities. There is no indication that Terasen Gas included an allowance for standby costs.

No party expressed concern that the proposed Gas Management Fees are excessive.

Commission Determination

The Commission Panel accepts the proposal to increase Gas Management Fees to fully cover the cost of credit reviews, but considers that the increase should also be reflected in the minimum fee for Rate Schedule 14A. **The Commission Panel approves Gas Management Fees for 2004/05 as proposed in the Application, except that the range for Rate Schedule 14A will be \$0.05 - \$0.09 per gigajoule to maintain the differential in minimum fees between the rate schedules.**

4.4 Hedging Agreement

Rate Schedules 14 and 14A currently include a Customer Term Sheet through which a customer indicates its requested fixed quantity and maximum price. The sheet must be completed when the customer returns the Sales Agreement, and both customers and Terasen Gas have found that it does not offer sufficient flexibility in the volatile gas commodity market. Terasen Gas proposes to replace the Customer Term Sheet with a Hedging

Agreement that is separate from the Sales Agreement. The customer will be able to return the Hedging Agreement to Terasen Gas whenever it wishes to implement a gas purchase transaction.

No party raised a concern regarding the Hedging Agreement.

Commission Determination

The Commission Panel has some concern that the increased flexibility for customers may increase Terasen Gas' administration costs, and will expect the Utility to consider this when it reviews the allocation of costs for the Gas Management Fee. **The Commission Panel approves the Hedging Agreement as proposed in the Application.**

4.5 Inventory Management

A group of Rate Schedule 14 customers may source all its supply exclusively from Terasen Gas, or from Terasen Gas and other suppliers. When the group's Shipper Agent is able to nominate supply from a source other than Terasen Gas, inventory management is dealt with on a "non-exclusive" basis. To eliminate potential "gaming" of supply, all volumes purchased through Rate Schedule 14 is on a take-or-pay basis and is deemed to be the first gas taken through the meter set. The group's Shipper Agent is responsible for allocating all nominated volumes and managing the customers' inventory accounts.

A group of Rate Schedule 14 or 14A customers who have chosen to purchase all their gas supply from Terasen Gas are referred to as an "exclusive" group. Currently, these customers are billed based on consumed volumes, rather than nominated volumes like non-exclusive groups. If a customer does not consume all of its Term Fixed Rate volume, Terasen Gas reconciles these volumes at the Daily Index Rate pursuant to the Monetization Band clause in the Sales Agreements. If a customer does not use gas on a day when the Daily Index Rate was greater than the Term Fixed Rate, the customer receives the net proceeds on up to 20 percent of the Term Fixed Rate volume.

Terasen Gas has concluded that the current reconciliation method for exclusive groups is not consistent with inventory management practices in the market place and proposes to discontinue it. The utility proposes that all Term Fixed Rate and Index Rate Option supplies for Rate Schedules 14 and 14A will be on a take-or-pay basis for the 2004/05 gas year. Customers that participate in the Term Fixed Rate and Index Rate Options will be

subject to all the balancing provision that is set out in their Transportation Agreements. Balancing Service Charges and Unauthorized Overrun Charges as set out in their Transportation Agreements will also apply.

The proposed change to inventory management for exclusive groups means that there is no longer a requirement to monetize excess volumes. Instead, any volumes that are in excess of the customer's consumption on the day will be allocated to the customer's inventory account. Terasen Gas proposes to remove the Monetization Band clause from the Sales Agreements.

In a submission dated February 4, 2004, Avista raised concerns about current nominations and inventory management practices under Rate Schedules 14 and 14A (Exhibit E5-1, pp. 2, 3). In a submission dated March 18, 2004, Direct expressed concern about Terasen Gas providing marketers with balancing services, stating that marketers who select this service effectively become sales representatives for the utility (Exhibit E-7, point 4b). No comments were received regarding the changes to Inventory Management that Terasen Gas proposes for 2004/05 in the Application.

Commission Determination

The Commission Panel considers that the proposed changes to Inventory Management will better align the practices for Rate Schedule 14 and 14A customers with those for other transportation customers. **The changes to Inventory Management and the removal of the Monetization Band clause are approved.**

5.0 RATE SCHEDULE 10 – LARGE VOLUME INTERRUPTIBLE SALES

Rate Schedule 10 provides for the sale of surplus Core Market gas to on-system customers and marketers on an interruptible basis at the interconnection with the Westcoast system. A Rate Schedule 10 customer currently selects from the following two price alternatives by providing Terasen Gas with written notification at least five business days prior to the start of a month. During the winter months of November through March, the Monthly Index Option rate includes a 3 percent discount to reflect the interruptible nature of the gas supply.

Daily Index Option: Gas Daily Sumas midpoint price for the day.

Monthly Index Option: Inside FERC Sumas monthly price, less 3 percent in the winter and without a discount in the summer.

The availability of excess gas supply for Rate Schedule 10 sales is determined on a daily basis by the Midstream Group within Terasen Gas' Gas Supply Department. For the current gas year to date (November 1, 2003 through April 13, 2004), two customer groups have consumed 115 TJ under the Monthly Index Option and eight customer groups have consumed 198 TJ under the Daily Index Option (Exhibit B-3, BCUC IR 2.1).

The Application requests a continuation of Rate Schedule 10 with its present terms. To provide more flexibility for customers to adjust their nominations month to month, Terasen Gas proposes to remove the Customer Term Sheet and replace it with the utility's on-line nomination system known as the Web Information & Nomination System ("WINS"). Terasen Gas confirmed that the provisions of the tariff requiring a customer to select between the Daily and Monthly Index Options prior to the start of a month will continue to apply (Exhibit B-3, BCUC IR 2.4).

Terasen Gas defends the 3 percent winter discount under the Monthly Index Option on the basis that, while the customer must take gas if it is available, the utility can curtail the deliveries during periods of high demand. The utility does not believe there would be value in testing the amount of the winter discount, considering the relatively small volume that customers are buying under the current terms of this option. Customers selected the Monthly Index Option for 37 percent of Rate Schedule 10 sales to date this year.

Commission Determination

The Commission Panel considers that the proposed rate options each reasonably represent the competitive market value of the gas. **The Commission Panel approves Rate Schedule 10 for 2004/05 as applied for in the Application.**

6.0 RATE SCHEDULE 7 – GENERAL INTERRUPTIBLE SERVICE

Rate Schedule 7 provides interruptible bundled (burner-tip) service to customers who have the ability to switch to alternate fuels. Although the delivery service is interruptible and can be curtailed in times of capacity constraints on the Terasen Gas system, the supply of the gas commodity is considered to be firm. Currently each customer makes an annual election of one of the following two pricing alternatives:

Fixed Rate Option: Rate Schedule 5 Commodity Cost Recovery Charge, Midstream Cost Recovery Charge and related Gas Cost Riders.

Daily Index Option: Gas Daily Sumas midpoint price, plus a Market Factor of the greater of \$0.05/GJ or cost as the current cost premium for purchasing firm physical gas supplies.

Terasen Gas manages Rate Schedule 7 demands as part of its Core Market supply portfolio. There are currently five customers subscribing to Rate Schedule 7, with an approximate daily consumption of 250 GJ per day. Four of the five current customers receive service under the Fixed Rate Option and one is under the Daily Index Option. Discussions with Rate Schedule 7 customers have indicated a general level of satisfaction with this rate schedule.

Application proposes to eliminate the Index Rate Option for 2004/05, on the basis that it is inconsistent with the Essential Services Model for Commodity Unbundling that the Commission has approved to provide unbundled service to commercial customers. Terasen Gas argues that the Daily Index Option implies purchasing 100 percent of gas requirements for the option at Sumas, which would be a departure from the delivery allocation requirement under the Essential Services Model. Terasen Gas stated that a different Midstream Cost Recovery Charge would need to be calculated for the rate option, and that the consistency of the application of the Essential Services Model to all bundled sales customers would be compromised. Terasen Gas argued that it is more appropriate to discontinue the Daily Index Option rate offering than to make some compromise for only one customer (Exhibit B-3, BCUC IR 1.2; B-5, p. 1).

The only customer who currently uses the Daily Index Option has been informed of the proposal to eliminate the option and did not provide any comments on the matter (Exhibit B-3, BCUC IR 1.1). No intervenor in the proceeding raised any concerns with respect to Rate Schedule 7.

Commission Determination

The Commission Panel concurs with Terasen Gas' request to eliminate the Index Rate Option for Rate Schedule 7, and approves Rate Schedule 7 for 2004/05 as applied for in the Application.

Terasen Gas Inc. - Rate Schedules 7, 10, 14 and 14A 2004-05 Gas Contract Year – Intervenors

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Terasen Gas Inc.
Application for Rate Schedules 7, 10, 14 and 14A
November 1, 2004 through October 31, 2005 Gas Contract Year

EXHIBIT LIST

Exhibit No.	Description
A-1	Commission Order No. G-37-04 and cover letter dated April 15, 2004
A-2	Letter No. L-20-04 dated March 24, 2004 confirming Workshop on Rate Schedules 7, 10, 14 and 14A November 1, 2004 through October 31, 2005 Gas Contract Year
A-3	Commission Information Request No. 1 dated April 8, 2004 on Rate Schedules 7, 10, 14 and 14A for 2004/05 Gas Year
A-4	Commission response dated May 14 to Absolute Energy Inc.'s Written Evidence dated May 7, 2004 on Rate Schedules 7, 10, 14 and 14A
A-5	Commission response dated May 14 to CEG Energy Options Inc.'s Written Evidence dated May 7, 2004 on Rate Schedules 7, 10, 14 and 14A
A-6	Commission response dated May 14 to Direct Energy Marketing Limited's Written Evidence dated May 7, 2004 on Rate Schedules 7, 10, 14 and 14A
B-1	Terasen Gas Inc. Application dated March 17, 2004 on Rate Schedules 7, 10, 14 and 14A for the November 1, 2004 through October 31, 2005 Gas Year
B-2	Terasen Gas Inc. submit written comment dated April 6, 2004
B-3	Terasen Gas Inc. April 23, 2004 Responses to Information Requests from British Columbia Utilities Commission, CEG Energy Options Inc., and Avista Energy Canada Ltd.
B-4	Terasen Gas Inc. May 14, 2004 Information Requests for Direct Energy Business Services
B-5	Terasen Gas Inc. May 28, 2004 Written Argument on Rate Schedules 7, 10, 14 and 14A
B-6	Terasen Gas Inc. June 11, 2004 Reply Argument to Direct Energy Business Services and CEG Energy Options Inc.

- C1-1 **CEG Energy Options Inc.** – Notice of Intervention dated April 22, 2004
- C1-2 Information Request No. 1 from CEG Energy Options Inc. dated April 16, 2004
- C1-3 E-mail from CEG Energy Options Inc. dated April 7, 2004 supporting the recommended timelines of the Schedule 14 program
- C1-4 CEG Energy Options Ltd. – Written Evidence dated May 10, 2004
- C1-5 CEG Energy Options Inc – Letter dated June 4, 2004 commenting on the Schedule 14 program
- C1-6 CEG Energy Options Inc. – Letter dated May 21, 2004 Response to Commission questions dated May 14, 2004 based on CEG Written Evidence dated May 10, 2004
- C2-1 **Absolute Energy Inc.** – Notice of Intervention dated April 23, 2004 on behalf of its clients: Hot House Growers Inc.; Sun-Rype Products Ltd.; Ritchie-Smith Feeds, Inc.; ABC Linen Supply Ltd.; and Sure Crop Feeds Inc.
- C2-2 Response to Request for Comments from Absolute Energy Inc. dated April 6, 2004
- C2-3 Absolute Energy Inc. letter dated May 7, 2004 submitting Written Evidence
- C2-4 Absolute Energy Inc. – May 14, 2004 Response to Written Evidence provided by Direct Energy Business Services dated May 7, 2004
- C2-5 Absolute Energy Inc. – May 21, 2004 Response to Information Request of BCUC
- C2-6 Absolute Energy Inc. – Final Argument dated June 4, 2004
- C3-1 **R.T. O’Callaghan & Associates, Inc.** – Notice of Intervention dated April 23, 2004
- C3-2 R.T. O’Callaghan & Associates, Inc. – Comments on Rate Schedule 14 and 14A (Rate 14) dated June 4, 2004
- C4-1 **Atlin Energy Management Inc.** – Notice of Intervention dated April 22, 2004
- C4-2 Response to Commission Request from Atlin Energy Management Inc. dated April 7, 2004
- C5-1 **BP Canada Energy Company** – Notice of Intervention dated April 15, 2004
- C6-1 **Direct Energy Marketing Limited** – Notice of Intervention dated April 22, 2004

- C6-2 Response to Request for Comments from Direct Energy Marketing Limited dated April 6, 2004
- C6-3 Direct Energy Marketing Limited – Letter dated April 14, 2004 indicating no additional Information Requests
- C6-4 Direct Energy Marketing Limited – Evidence pertaining to Rate Schedules 7, 10, 14, 14A dated May 7, 2004
- C6-5 Direct Energy Marketing Limited – Response to IR from Absolute Energy
- C6-6 Direct Energy Marketing Limited – Response to IR from BCUC
- C6-7 Direct Energy Marketing Limited – Responses to IR from Terasen Gas
- C6-8 Direct Energy Marketing Limited – Written Argument dated June 4, 2004
- C7-1 **Ministry of Energy and Mines** – Notice of Intervention dated April 30, 2004

- D-1 Hot House Growers Inc. – Request for Interested Party status dated April 22, 2004
- D-2 Sun-Rype Products Ltd. – Request for Interested Party status dated April 22, 2004
- D-3 Ritchie-Smith Feeds, Inc. – Request for Interested Party status dated April 22, 2004
- D-4 ABC Linen Supply Ltd. – Request for Interested Party status dated April 22, 2004
- D-5 Sure Crop Feeds Inc. – Request for Interested Party status dated April 22, 2004

- E-1 Letter from Sorrento Nurseries Ltd. Dated January 22, 2004
- E-2 Letter from Montecito Towers dated January 23, 2004
- E-3 Letter from Best Western Sands Hotel dated January 27, 2004
- E-4 Letter from Plaza 500 Hotel & Convention Centre dated January 28, 2004
- E5-1 Letter from Avista Energy Canada Ltd. dated February 4, 2004
- E5-2 Submission from Avista Energy Canada Ltd. dated April 6, 2004
- E-6 Letter from CEG Energy Options Inc. dated March 16, 2004
- E-7 Letter from Direct Energy dated March 18, 2004
- E-8 Letter from Radke Bros. Construction Ltd. dated April 2, 2004