DISCUSSION PAPER

ON

System Supply in Ontario

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I. Introduction

The purpose of this paper is to provide an overview of the current market structure and operation for system supply and to lay out potential options for change. System supply (or system gas, the two terms are used interchangeably) refers to the sale of gas by local distribution companies (LDCs) primarily to their core, typically small volume customers. This is in contrast to the sale of gas made by independent marketers to LDC customers or the direct purchase of gas by many large volume customers. Whatever the source of the gas, the LDCs continue to provide the necessary gas distribution and related services involved in operating a distribution network. The broad questions about system supply are whether it would be in the public interest for LDCs to continue in the system supply function or how that function should be re-defined or changed. Driving these questions are ongoing concerns expressed by stakeholders regarding certain inefficiencies in the current market structure, the cost and length of the regulatory review process, and unfair competitive advantage afforded to the LDCs due to a lack of transparency and cost allocation issues. For the future, the on-going changes in the North American gas market including Ontario will have a major impact on market efficiency. Questions will also arise about the structure of the network functions, or ancillary services, that the LDCs also provide as part of their distribution franchise.

Making changes to the current regulatory approach, if warranted, requires addressing several issues.

1. Would unbundling these services be an improvement and how would one know?
2. Is the present system consistent with developments in the market?
3. Does LDC involvement in system supply decrease competition and choice?
4. Will the market make necessary infrastructure investments under an unbundled system?

The purpose of this paper is not to answer these questions but rather to develop a starting point for beginning to address the issues they raise. The appropriate regulatory approach to system supply depends on understanding the interrelationships of upstream gas supply fundamentals, the system infrastructure, consumer demand, and the competitive options to system supply. Consequently, this paper begins with a description of the current gas market and gas market trends. We next address how system supply operates in Ontario in some detail. Next we describe how system supply operates in markets and jurisdictions where changes to traditional approaches have been implemented. Finally, we propose several alternative structures and discuss the issues they raise. This paper is intended to be a starting point for discussion of these potential regulatory outcomes.

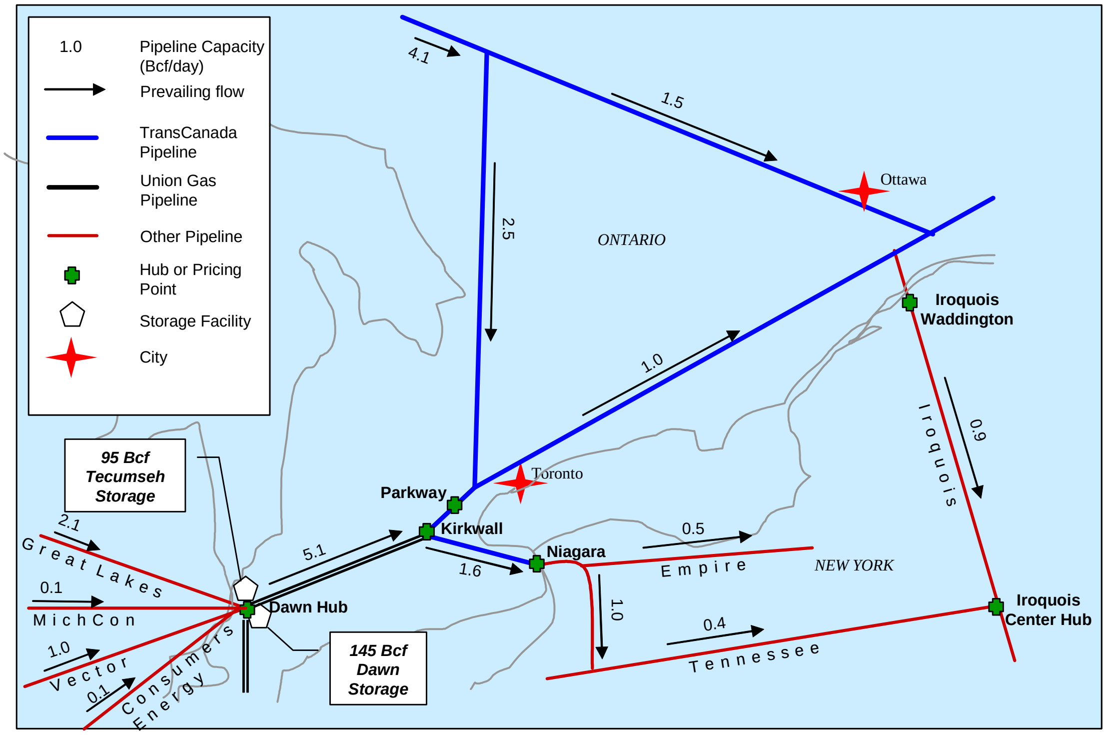
II. Overview of Gas Supply for Ontario

Changes to the current approach to system supply should take into account the ongoing changes in North American gas markets that will affect where gas will come from, how it is delivered and changes to consumption patterns. The two principal developments in the market include the maturing North American resource base which is leading to shifts in the sources of gas and transportation patterns, and the continued growth of gas demand in the power generation sector, particularly in Canada where the government's commitment to the Kyoto Protocol will lead to the increased use of gas to replace coal-fired generation.

The Province of Ontario is Canada's largest consuming gas market, with a total market size approaching 1 trillion cubic feet (Tcf) annually, or a little under 3 billion cubic feet per day (Bcf). Over 95 percent of Ontario's supply comes from outside the province, principally from the Western Canadian Sedimentary Basin (WCSB), with additional supplies from the U.S. and small amounts of Ontario production.

Natural gas enters the Province over the northern mainline of TransCanada Pipe Line (TCPL) and through the Dawn Hub in southwestern Ontario. TCPL's northern mainline has a capacity of 4 Bcf per day at the Manitoba border, being directly interconnected with the WCSB. Dawn Hub has a receipt capacity of about 3.9 Bcf per day from pipelines crossing the border and 1.2 Bcf per day from storage. Three major border crossings connect Dawn with ANR Pipeline, MichCon, Great Lakes Gas Transmission (GLGT – 50% owned by TCPL), CMS (formerly Panhandle), Trunkline, and Vector (connecting through Chicago to the Alliance and Northern Border systems). Dawn also has multiple pipeline takeaway interconnections. The Parkway interconnect with Enbridge and TCPL has an easterly capacity of 5.1 Bcf per day. The Kirkwall interconnect to the Tennessee, Empire and National Fuel systems in New York has a capacity of 1.6 Bcf per day. Dawn also can deliver gas into Michigan at St. Clair, Bluewater, and Ojibway (200 MMcf per day each). The excess of pipeline capacity over Ontario's needs is used to transport and deliver gas to the U.S. and Quebec. About 60 percent of the gas entering Ontario is moved across the province into these markets. Dawn is also the location of large concentrations of underground storage capacity, estimated at about 240 Bcf. Through the pipelines feeding Dawn from the U.S., Ontario has access to another 600 Bcf of underground storage in Michigan.

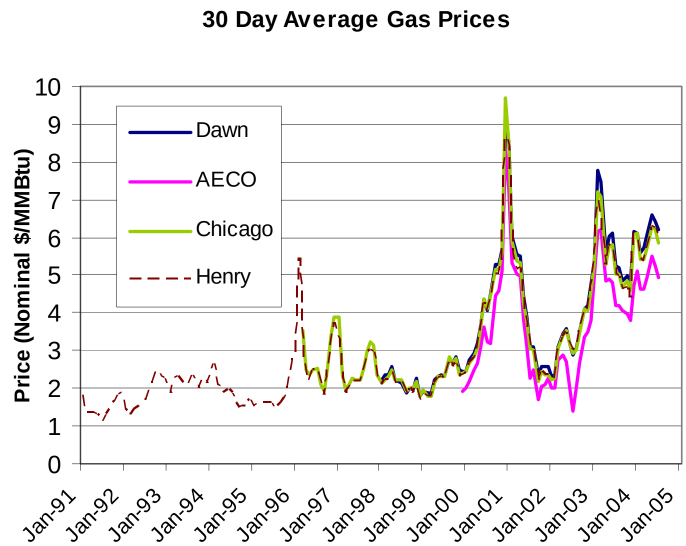
Exhibit 1. Ontario Gas System Schematic

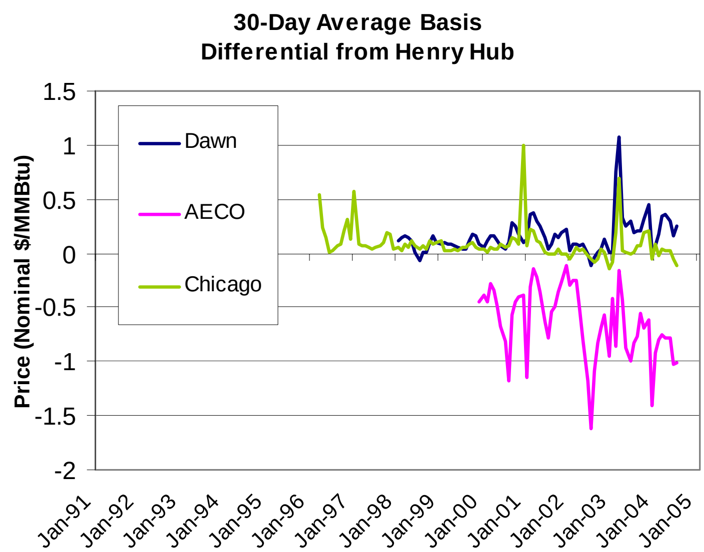


Ontario's two major distribution companies are Enbridge Gas Distribution (Enbridge) and Union Gas Limited (Union). Other smaller systems include Natural Resource Gas, the City of Kitchener, and the City of Kingston. Union serves 1.2 million customers delivering 525 Bcf per year. Union also transports 730 Bcf on behalf of others, with much of this flowing to the U.S. Enbridge sells about 162 Bcf per year of gas to 1.7 million customers and transports an additional 296 Bcf per year.

Ontario and Canada are highly integrated in the North American natural gas market. Gas prices in Ontario reflect not only conditions there but broad, North American gas market developments. Gas prices in Ontario are highly correlated with gas prices in Chicago, Henry Hub, AECO, and other market hubs in the U.S. Regulatory market reforms in Ontario should take into account trends and developments in the overall market in order to create a system that is flexible to changing gas supplies and demands.

Exhibit 2. Natural Gas Prices in Ontario-Relevant Hubs





From a pricing standpoint, the Ontario gas market has evolved dramatically over the past decade. Beginning in the mid nineties, the Dawn trading hub emerged as a frequently tracked, increasingly liquid, and transparent market price in the Ontario gas market. The large amount of nearby storage, combined with a convergence of pipelines linking the U.S. and Ontario gas market made Dawn the most liquid trading location in Ontario.

The result has been a very high correlation between gas prices at Dawn and Henry Hub of between 0.98 and 0.99. This suggests that Dawn is now more highly integrated with U.S. markets, both Henry Hub and Chicago, than with AECO. As the exhibit to the right shows, the basis between Dawn and Henry Hub closely matches that of Chicago, as one would expect given the Vector interconnect. With the increased capacity into Dawn from the U.S. one would expect the Dawn price to increasingly reflect Henry Hub prices and volatility, as is apparent in the graphs and continuing integration with U.S. Midwestern and Gulf Coast markets.

Three developments in the North American market will have a potentially significant impact on gas supply and flows in Ontario:

- Changing regional supply trends
- Increasing power sector gas demand
- High and volatile natural gas commodity prices

WCSB conventional production has plateaued and begun to decline. Since 1990, WCSB well productivity has fallen from 1.6 Bcf per well to less than 0.4 Bcf. The National Energy Board expects total production from the WCSB to decline from about 16 Bcf per day in 2001 to about 14 Bcf per day by 2025, with substantial declines in conventional production, being partially offset by coal bed methane production and Mackenzie Delta gas supply.[1] This outlook is consistent with the recent U.S. National Petroleum Council Report[2] that forecasts a substantial expansion of liquefied natural gas (LNG) as well as Alaska natural gas development to offset substantial decline in gas production in the lower 48 United States and declining exports from Canada.

The major effect of these changes will be a change in the gas flow patterns generally. More gas will enter the North American network from the U.S. Rockies. Depending on where LNG import terminals are built, gas flow patterns could change substantially in the northeast. Two Quebec projects have been proposed in the St. Lawrence that could meet local demand growth. Two LNG projects proposed in the Maritimes Provinces would supply the Northeast U.S. and back out some WCSB supply. Should an Alaska gas pipeline be developed it could either terminate in Alberta or in the U.S., with very different flow patterns evolving. It is likely, however, that over time more gas could enter the province through Dawn. This will require a reconfiguration of pipeline capacity, particularly over Union towards Parkway, and perhaps rate restructuring on TCPL.

[1] NEB, 2003 Canada's Energy Future
[2] NPC, 2003

The second significant development is the expected growth in gas fired electric power generation. In Ontario, the growth of gas demand for power generation will be driven in large part by the adoption of the Kyoto Protocol and the proposed phase out of coal fired generation. Adding substantial amounts of gas fired generation units to the current pipeline system will increase overall gas consumption in Ontario, but more importantly would have significant effects on the infrastructure and pipeline operations. Power demand for gas results in large swings in consumption increasing the challenge of system balancing and changing the use of storage and line pack. These changes will affect total costs and services throughout the system.

The third development is high and volatile natural gas prices driven by the increasingly tight balance between supply and demand. High gas prices should increase regulators' focus on price signals and demand response to help stem increasing consumer gas costs. Encouraging the optimal use of scarce gas resources (optimal use includes meeting consumer demand and environmental protection) should be the paramount regulatory concern. Efficient price signals will ensure that gas supplies are optimally utilized and that investors in storage and pipelines supply the necessary infrastructure to meet rapidly cycling electric power gas load.

These developments could lead to a re-alignment of pipeline capacity into and through Ontario. As more gas enters Dawn, expansion may be needed between Dawn and Parkway, which according to some stakeholders is already experiencing constraints. Additional power generation will require local pipeline facility upgrades with implications for rates for all customers. The concentration of storage in western Ontario limits the access of eastern customers to this storage. Thus, regulatory initiatives that address system supply, storage, and ancillary services will have to reflect these developments and consider the long-haul pipeline transportation allocations of shifting markets between system supply and marketers and between Dawn and TCPL.

III. System Supply

Beginning in 1985, the wholesale gas market was opened to competition from third party gas marketers. Retail competition proceeded to gradually take hold through the early nineties. LDCs supply system gas to consumers who did not switch to a marketer, or who have defaulted or switched back to the LDCs for a range of reasons. The overall market share of system gas has changed since 1985, and today stands at more than one third of gas volume and approximately sixty percent of customers.

Although stakeholder sentiment indicates a continued role for system gas, concerns were raised in three areas: the efficiency of the current system in providing price signals; whether pricing could be made more transparent in terms of the services provided by LDCs and by marketers; and potential cross subsidization that may occur where LDCs are providing services under the system supply (or ancillary functions) that may not reflect the true costs imposed by certain types of customers. Specific suggestions made by stakeholders include:

- System Gas accounts could be structured in a way that make cost accounting consistent with the total costs incurred by direct marketers making sure that the appropriate costs are included in the system gas charges. They could be structured to:
    - Include the same billing charges
    - Require the same balancing as direct marketers with these balancing costs included in the system gas costs
- The pricing of system gas could be modified to:
    - Be more timely in order to better show the price of gas to consumers and reduce gas cost variances
    - Allow more options so that system gas customers can more easily manage their price risk
    - Have QRAM difference accounts managed on a more or less timely basis

System Gas Functions

Since system supply is a bundle of services, each needs to be understood independently to make an assessment of potential changes to market structures, regulations, and bundling. Later in this paper we examine Ontario's approach to the components listed below in the context of experiences in other jurisdictions.

The system gas function includes several services that mirror activities by direct marketers and some services provided for both system gas and direct marketers. The LDC also provides services for the system as a whole. These LDC and system gas services follow:

- Mirror direct marketer functions to system gas customers:
    - Purchase natural gas supply at gas market hubs (e.g., AECO, Henry Hub, Dawn, Chicago)
    - Purchase upstream transportation to move gas from purchase point to Ontario delivery points (e.g., TCPL to Ontario, Alliance and Vector from BC/Alberta to Dawn)
    - Resolve imbalances in annual and, in the future, seasonal loads
    - Provide support to customers (e.g., call line, resolve billing disputes)
    - Provide billing of gas purchase costs
- Provided to all customers:
    - Day-to-day and seasonal load balancing
    - Metering
    - Billing of storage, balancing, and distribution costs and management of credit
    - Act as server of last resort
- LDC system wide services:
    - Manage the day-to-day operations of the distribution system for reliability and achieve required system operational goals
    - Provide for safety and system integrity
    - Expand the system to meet increased demands and service new market areas

- Other services such as the promotion of natural gas in the market, demand side management activities, and other services intended to be in the interest of the public good

System Gas Pricing

System gas and marketer gas have inherently different pricing approaches. System gas employs a QRAM to pass through commodity charges to consumers. As the name suggests, the QRAM uses a quarterly rate adjustment to track natural gas commodity prices. QRAM works as follows:

- Every three months the price of gas is set based on a 12-month forecast of commodity prices. Union and Enbridge recently switched to using a 21-day average of the 12-month NYMEX strip to develop the 12-month forecast.
- The difference from the actual cost of gas and the forecast cost for the previous 3 months is tracked and entered into a Purchase Gas Variance Account (PGVA).
- Along with the reforecast of prices every three months, Union and Enbridge establish a rate adjustment that is intended to zero out the PGVA over time. Union spreads the PGVA over projected consumer gas consumption for the following 12 months. Enbridge spreads the variance account across projected gas use for the remaining months of the gas fiscal year (which ends on October 31).

It is important to note that Enbridge and Union report the QRAM differently on customer bills. Union aggregates the PGVA and commodity charge into a single bill line item whereas Enbridge reports the two separately. The Enbridge approach is more complicated but allows for a more representative price to compare against marketer offerings.

The QRAM process is working much better than the previous system, which adjusted rates annually and cleared purchase gas variance accounts through a one time end-of-year lump sum payment from or credit to customers. Still, there are aspects of the system that should be examined:

- QRAM mutes price volatility and prevents consumers from responding to the real-time gas price.
- The QRAM is not automatic. In some instances the LDCs have left rates alone if they are not dramatically out of line. This creates potential for manipulation of the process.
- Even with the movement to quarterly adjustments, the QRAM allocates the PGVA not to the customer base that used the gas but to the usage in the future. This can lead to market inefficiencies and can raise issues with respect to fairness and equity.
- The rules for how the LDCs can forward contract for gas in order to reduce volatility to consumers.
- The desire by some customers to have a fixed price offering from system gas.

Marketers have flexibility to structure gas prices in ways that meet consumer preferences. They are responsible for getting the gas to the LDC and must purchase transportation to do so. A typical arrangement is that a marketer purchases natural gas supplies (say from Alberta), arranges to get the gas to Ontario through TCPL or Alliance and Vector, and marks up these costs with overhead costs and a profit margin to get the price offered to consumers. This price replaces the QRAM on system gas consumers' bills. Marketers have flexibility in how they manage their risk and will use financial and other instruments to do so.

Transparency, cross-subsidization, and equity issues arise from the pricing of system gas to consumers.

- The QRAM charges do not include the full set of LDC administrative costs, billing costs (similar to those charged to direct marketers), and credit costs, and may put direct marketers at a disadvantage.

- Direct marketers are required to balance their accounts annually and in the future, at multiple points during the year. This may create costs for the direct marketers but it is not clear that the actions for system gas are equivalent and create the same costs for system gas customers.
- Direct marketers have more flexibility in their charging mechanism and can offer more options to consumers but even so, limitations in LDC billing systems that some of these marketers use can limit this flexibility, e.g., index or variable pricing are not available.

Cross subsidization can occur in several places. If the system gas charges do not include the same charges as with the marketers, then these costs must be recovered by the LDC elsewhere – potentially in the distribution charges which are then charged to all customers. Second, the LDCs have significant flexibility in managing their storage assets and one important reason for requiring multiple balancing points is to reduce the risk of running out of storage in March and April. A prudent strategy would incorporate contingencies for a late cold spell into the customer's annual load profile. But all customers, both those of marketers and those of LDCs on system gas, should receive the same treatment, otherwise the contingency planning for one group could be used to subsidize seasonal load profile for the other group.

Load Balancing

Ontario's bundled approach to system gas puts the load balancing role under the LDC. LDCs own and operate the distribution and storage infrastructure in Ontario to provide the balancing service.

Marketers and direct gas purchasers have two principal options for how they can contract with the LDCs. The predominant option taken is to purchase a bundled service, which supplies transportation, distribution, and load balancing service in a single charge. Alternatively, marketers and large direct gas buyers can purchase unbundled service, which requires the consumer to use storage and supplies to balance supply and demand on a daily basis.

In the bundled service, the LDC employs storage, line pack, and short term gas purchases receipts with deliveries in close to real time. The direct consumers' and marketers' obligation is only to supply sufficient gas to meet demand over large time blocks. The current system requires balancing only on the anniversary of each contract (typically October 31st). Union and Enbridge are moving to 3 and 2 point balancing systems, respectively.

In the unbundled service, shippers pay a lower rate, but are required to nominate and balance on a daily basis. The unbundled contract sets several parameters governing the counterparty's transactions. Each shipper nominates a requested delivery amount on a day-ahead basis. The LDC determines if it can be met and establishes an "Authorized Quantity," less than or equal to the nomination. Actual amounts shipped above the authorized quantity are deemed "Unauthorized Overruns" for which the shipper pays an imbalance charge. The system is asymmetric, so under-runs do not earn a corresponding credit, nor can they be traded on a bilateral market as is the case in the UK, Georgia, Victoria (Australia), and other markets. The Unbundled T service also sets maximum daily injection and withdrawal rates and maximum storage balances governing each shipper's storage nominations. Unbundled storage carries sufficient additional burdens that only large, predictable gas consumers have found the discounted rates a big enough incentive to compensate for the increased risk and responsibility.

Beginning in February 2005, Union will use a three point balancing system to synchronize market supply and demand throughout the course of the year. This system was the target of significant discussion in stakeholder interviews and is an aspect of the system that needs careful consideration. As system supplier, LDCs provide real-time balancing to the entire market. Marketers supply gas to meet a projected load profile and LDCs absorb deviations from the forecast load (imbalances) by using storage, line pack, and peak shaving. Over time, imbalances accrue that need to be reconciled to keep account balances net zero over time. Ontario is moving to a multiple point balancing system. A winter balancing point (February 28th), a summer balancing point (Union only on September 30th) and a balancing point at the end of the contract year. LDCs compare actual gas demand with projected marketer demand—which is what marketers target to supply to LDCs—to estimate imbalances. The marketer is notified roughly 4 weeks prior to the balancing points and has that period to clear imbalance accounts (e.g., supply extra gas from the spot market if the imbalance is negative).

Ontario's approach to balancing has advantages insofar as gas is flowing reliably. Also, keeping the balancing role under the LDC keeps the information and transaction costs relatively low. Putting the balancing role under the LDC (the most aggregate point in the supply/demand chain) also maximizes the effect of load diversity, which helps to naturally balance load across consumers with different daily, weekly, and seasonal profiles.

However, several potential problems exist in this system. First, socializing balancing costs to the LDC probably creates inefficiencies in the operation of the market that could be squeezed out if a market-based balancing system were to be employed. Such inefficiencies could include the utilization of more storage available at supply locations (e.g., Texas, Alberta), use of alternate fuels during peak periods, and revising use patterns (particularly with large industrial users) in order to minimize overall costs. Market based systems could include more unbundled services with more flexibility for customers to utilize and trade these services and perhaps even a spot market for consumers and marketers to trade potential daily, intra-daily, or monthly imbalances. Second, moving to the more frequent three point balancing still allows users to game the system by incurring large imbalance accounts. In general, the less frequent the balancing requirement, the greater the opportunity there is for users with large swings in gas takes to impose costs on the overall system and its customers. Third, the timing of reconciliation currently occurs each February when spot gas prices are frequently high. To clear imbalances, marketers must enter the spot market to acquire make-up gas volumes.

Another issue has come up with the existing one point and proposed three point balancing: with the current profiling mechanism, there is risk to the LDCs of utilizing all of the storage after February 28 but before the end of the winter season, especially if there is an unseasonably cold March and early April. The profiling used to determine imbalances that need to be made up by the end of February are:

- Based on expected loads of the customers and do not necessarily include contingencies for an unseasonably high demand period in late March and April.
- Are estimated in early February and may not account for unseasonably high demand in February

This leaves the LDC with storage managed to expected loads with the potential for being short during high demand periods.

Typically, in other markets, those managing storage assets leave a contingency volume of working gas in storage in March and April to mitigate the risk of an unseasonably cold weather patterns. Customers or direct marketers with the ability to modify their profiles to include contingencies or use unbundled load balancing services could use this to minimize their costs and reduce the risk of incurring high balancing costs in March and April. The explicit ability for consumers and marketers to track and reduce imbalances earlier will also help them manage their costs overall. Requiring this reduces the ability of the LDCs, marketers, and customers to game the system.

IV. System Supply in Other Jurisdictions

This section provides a summary of system supply approaches in Georgia, California, and the United Kingdom to provide some insights into the experiences in other markets. A brief discussion of the State of Victoria, Australia is also provided as its approach to resolving balancing issue is unique. A full survey of other jurisdictions was not undertaken; nevertheless, these three suggest a range of alternative approaches and experiences relevant to Ontario. The focus of this discussion is on how these jurisdictions have structured the gas supply function, and how they have addressed issues of system supply, seller of last resort, load balancing, and billing.

State of Georgia, U.S.A.

Background

In 1997, the Georgia General Assembly passed a bill that deregulated the natural gas industry in Georgia. Although the physical network of supply owned by Atlanta Gas and Light Company (AGL) would remain regulated, deregulation was introduced into the marketing of natural gas to consumers. Currently there are about 11 marketers supplying gas to AGL customers.

System Supply

Unlike most jurisdictions in the U.S., Georgia has eliminated the system supply function. When deregulation was first implemented, customers were given a period of time to choose a marketer before they would be randomly assigned to a marketer (based on the marketer's market share at the time). The rapid transition to deregulation and combined with market dynamics created a number of problems. Marketers were unprepared for the influx of consumers, a situation exacerbated by record cold temperatures during the winter of 2000/2001. The cold winter led to high gas prices right when deregulation was beginning to show pricing benefits. Many customers were unable to pay their bills, contributing to the bankruptcy of marketers and a reduction in the number of marketers from and initial set of 20 to 11. Currently, the top four marketers command approximately 94 percent of the marketplace.

Seller of Last Resort

In all other markets in the U.S. that have allowed marketers to compete with local gas utilities, the local utility is given the responsibility of seller of last resort (SOLR). Usually when the utility acts as the SOLR, the utility's price remains regulated while the marketers' prices are deregulated. In such cases, the utility's price serves as the price cap that marketers are able to charge. However, in Georgia, AGL no longer serves this function.

Instead, the SOLR is selected by the Georgia Public Service Commission (GPSC) through a competitive bid process. SCANA Energy (Regulated Division) is the current SOLR. The SOLR serves low-income consumers and those who are high credit risk and thus are unable to obtain service from another marketer. Georgia has a Universal Service Fund, which is primarily funded by large industrial gas users, that provides lifeline support to consumers and is used to reimburse SCANA for non-payment.

Load Balancing

Georgia has both daily and monthly load balancing with corresponding daily and monthly cash outs. Marketers can trade imbalances with each other on a bilateral market to avoid/reduce imbalance charges. The price of gas purchased or sold for balancing is based on the monthly average price as posted by AGL.

Billing

Marketers are in charge of billing Georgia customers.

Consumer Bill of Rights

Due to the high level of customer dissatisfaction and confusion during the initial years of deregulation a Consumer Bill of Rights was adopted in 2002. The Bill requires enhanced regulation of marketer billing and contract procedures and requires marketers to handle customer complaints in a timely fashion. It also requires the PSC to supervise AGL's quality of service to marketers in the form of timely meter readings and switching procedures.

State of California, U.S.A.

Background

California is similar to Ontario from both a gas supply and regulatory perspective. California imports the majority (~82%) of gas consumed. California's imported gas supplies come from the Southwest (42%), Rockies (14%) and Canada (26%), while 18 percent is produced in state. California—like Ontario—has adopted a hybrid approach to gas regulation, deregulating some aspects of the industry, while preserving cost of service regulation in others.

Alongside U.S. federal initiatives to open up wellhead and transportation services, the California Public Service Commission (CPUC) also established a new regulatory framework for California. The largest gas users were now able to set up their own gas purchasing arrangements. The CPUC split customers into two groups – core and non-core. Core customers comprised residential and small commercial customers who continued to receive vertically integrated services from a regulated utility. Non-core customers comprised large commercial, industrial and electricity generation customers who were given the option to buy their gas either directly from the producer or from a marketer, with the utility delivering the gas to the customer. As such, non-core customers were no longer responsible for paying for the interstate pipeline capacity that the utilities had obtained for all their customers.

System Supply/Seller of Last Resort

By the early 1990s, core customers were also given the option to purchase their gas from a marketer rather than the gas utility. Similar to most US states that have adopted retail choice for gas, consumers have the choice to purchase gas from marketers, but can still purchase system gas (i.e., gas from the regulated utility) at cost of service rates. The CPUC regulates the California utilities' natural gas rates and natural gas services including in-state transportation over the utilities' transmission and distribution pipeline systems, storage, procurement, metering and billing. The local utilities still function as provider of last resort.

Load Balancing

Core retail marketers have the option for monthly or daily balancing in California. Non-core customers (or marketers operating on their behalf) nominate and balance daily. Although core marketers will receive a small credit for daily balancing and daily balancing has been an option for about 18 months, currently no one does daily balancing for core gas customers. Bilateral markets exist for load balancing so that marketers can trade with each other. At the end of the month the utilities use a cash out mechanism for imbalances. The cash out mechanism uses the highest price in the previous month multiplied by 150% for imbalances greater than 5% and the highest price in the previous month multiplied by 200% for imbalances greater than 10%. Since California does not have daily meters for core customers, balancing is done based on the proportion that each marketer has of the forecasted loads. Actual meter reads are reconciled two months later but no cash out occurs at that time. Instead it is rolled forward. Non-core customers generally have real-time metering, thus balancing is done based on metered consumption.

LDCs supply subsidiaries operate on the same basis as other marketers who sell gas to consumers. All sellers of gas are responsible for balancing their accounts with the distribution network. Marketers (including the LDC affiliates) are allowed to trade with other marketers to rectify imbalances with the distribution entity. The distribution pipeline, even though it is a sister company to the LDC supply affiliate, operates as an independent distribution company.

Billing

The choice of billing structure is left to the marketer in California. There are three options:

- Marketers can issue a consolidated bill that includes LDC charges,
- LDCs can issue a consolidated bill that includes marketer charges,
- Marketers and LDCs can issue separate bills.

United Kingdom

Background

The UK natural gas market began restructuring in 1986 when British Gas (BG) was privatized. Prior to the restructuring, BG was a vertically integrated monopoly, supplying transportation, distribution, and commodity. At that time, the Office of Gas Supply (Ofgas), now the Office of Gas and Electricity Markets (Ofgem), was formed to regulate the industry. By 1992, alternative suppliers entered the UK gas market as competition was opened up to large industrial and commercial customers. However, British Gas remained the sole gas supplier to residential customers until the passage of the 1995 Gas Act. This Act opened the rest of the natural gas market to competition. By mid-1998 the entire UK market was open to competition.

The gas industry in the UK consists of five functional groups: producers, shippers, the National Grid Transco (NGT), suppliers, and customers. There is competition at all levels except the NGT which is the national transmission monopoly. Licenses are issued to companies to produce, ship, and supply gas. While there are companies that specialize, some companies perform more than one function; and large customers may purchase directly from producers and ship the gas to themselves. Simply put, however, shippers buy from producers, and sell to suppliers who retail gas to customers. Pipeline capacity can be acquired through a series of auctions for up to 15 years. NGT is responsible for ensuring that the system remains in balance and purchases or sells gas as needed to ensure that supply meets demand every day.

British Gas (BG) remains the dominant supplier in the UK market. There is considerable active switching between gas suppliers. In studies performed by Ofgem, price is the main reason why customers have switched. In addition, research has shown that suppliers lose customers when they raise their prices illustrating that competition is working well in the UK market. Despite the switching, BG's share of domestic gas customers has hovered around 60 percent of customers, as shown in Exhibit 3.

Exhibit 3. BG's share of domestic gas customers over time (%)

Date	BG	New Entrants
Sep-98	84	16
Sep-99	75	25
Sep-00	71	29
Sep-01	67	33
Sep-02	64	36
Sep-03	62	38
Dec-03	61	39

Source: Ofgem/Domestic Gas Suppliers

System Supply/Seller of Last Resort

The concept of system supply no longer exists in the UK. Although the former utility, British Gas, still holds the largest market share, BG fills the same supplier/marketer function as any other company in the UK, but with better name recognition.

This regulatory model is interesting in that the utility was taken out of the LDC role and put into a marketer role, in contrast to the Georgia approach of stripping the LDC of any gas sales function. The UK also handles the seller of last resort function differently. Ofgem designates a supplier to serve the last resort function. The SOLR rate is based on the price of firm/contract gas.

Load Balancing

Retailers and direct purchasers (shippers) in the UK are responsible for managing supply, transportation and storage to meet daily gas load. While NGT does provide balancing services to the network, the UK gas balancing regime provides shippers with incentives to balance demand and supply at the end of the gas day through the cash out mechanism. Shippers who are long (short) gas are cashed out at the lowest (highest) price at which NGT has sold (bought) gas on the day commodity market (OCM). These cash out prices are the system marginal sell price and the system marginal buy price respectively. In the event that NGT has not taken any balancing actions, cash out prices are determined using fixed differentials that are added to the system average price (SAP) which is the weighted average price of gas traded on the OCM. The fixed differentials are based on the cost of storage.

Billing

Marketers are in charge of billing UK customers

Victoria, Australia

Although this paper does not review all aspects of the Victoria market, we do note the most innovative and unique feature of Victoria's market: the implementation of market-based optimization of storage, line pack, and real-time balancing. Given the expectations about growth of electricity demand in Ontario, the Victoria approach may be instructive.

The Victoria market represents the extreme, market-driven end of the policy spectrum, maximizing the use of markets and minimizing the role of regulatory intervention. In particular, Victoria has opted to facilitate market forces to optimize the real-time balancing of supply and demand. This is in contrast to leaving real-time balancing up to the LDC, as is the case in Ontario or even to the NGT as is the case in the UK.

As background, Victoria is similar to the UK in that there are suppliers, shippers, and consumers subject to choice and competitive forces. Storage is open to competition and charged at market-based rates (it should be noted that Victoria had limited storage prior to market restructuring, so there were no equity issues and limited vested interests).

The unique aspects of Victoria's market is the level of market control over the system, the intended evolution of the market, and the market clearing engine (MCE) in use for facilitating bids, nominations, inputs and offtakes, etc. Working simultaneously through the MCE, shippers optimize the supply, transportation, storage, and line-pack on an hourly basis by bidding how much gas they will provide or take at a schedule of prices. The MCE then matches offers and clears the market. Users quickly understand the value of deliverability through the hourly price signals. This system operates in parallel to long term bilateral contracting arrangements. In the current market design, gas supply (or storage gas) used to resolve constraints only during certain parts of the day can be compensated at higher prices than the computed market price. As the market evolves, the time resolution of optimization is likely to increase and the market will include specific trading of line-pack, day-to-day and within the day. The MCE has the capability to perform hourly optimization, but the current plan is to evolve from the daily balancing currently in place to 8-hour balancing. This increase in frequency will help to handle diurnal power generation demand swings.

Exhibit 4. Overview of System Gas Treatments

Service	Ontario	UK	Georgia	California	Victoria
System Gas Commodity	LDC provides	NA	NA	LDC **Affiliate** Provides; Most residential customers remain with LDC	
Seller of Last Resort	LDC/System Supplier provides services and the cost spread across all rate payers	Ofgem appoints a SOLR. Prices are based on the deemed contract price	SOLR function provided by marketer through a competitive bidding process.	LDC Affiliate provides. Cost of service rates	
Load Balancing	LDC provides under bundled service; Shippers cash out on a annual (soon to be seasonal basis). Costs of LDC purchases to balance supply & demand are socialized across all consumers Unbundled service customers nominate and balance daily.	Shippers nominate and balance (cash out) daily NGT purchases or sells gas as needed to ensure that supply meets demand every day and levies charges for imbalance actions.	Large customers nominate and balance daily Retail marketers nominate and cash out on a daily basis, but balance on a monthly basis. AGL purchases or sells gas as needed to make demand equal supply and charges prices back to the large customer/retail marketer at the average daily/monthly price.	Marketers and LDC Affiliate Balance on a monthly basis for core customer load Non-core balances daily LDC buy and sells gas to make up imbalances and assesses penalties	Shippers nominate and balance daily (moving to 8-hr balancing) The independent network operator (VENCorp) charges the spot price of gas for imbalances
Distribution	LDC provides; Rates depend on volume and location	NGT provides; Charges are subject to rate controls that are reviewed every 5 years or so by Ofgem	LDC (Atlanta Gas Light Company) provides under cost of service rates	LDC Provides	
Billing	LDC provides; Marketers show up under commodity charge	Marketer Provides	Marketers provide	Up to the Marketer: the marketer can provide a consolidated bill with the utility's charges, the utility can provide a consolidated bill with the marketer's charges or the customer can be dual billed.	

V. Policy Issues and Potential End States

In this section, we first discuss policy issues with Ontario's current regulatory approach and propose three potential end states: the status quo, a completely unbundled system with the LDCs exiting the system supply function, and a middle ground/hybrid regulatory approach. Finally, we discuss the implications that reforms of system supply would have for ancillary services.

A. Policy Issues

Stakeholders overall saw value in the LDC providing system gas and do not want to see it eliminated. Some stakeholders perceive system gas as providing the following market services:

- Supplier of last resort
- Provide basis for some long-term contracts on upstream capacity as seen with the LDC upstream commitments
- Provide basis for long-term supply in North America
- Supply options for customers who do not want longer term deals or who want to stay with the utility
- Provides a vehicle to promote natural gas in Ontario by maintaining communication between the LDCs and existing customers and providing a default for customers in new developments.

But not all stakeholders agree that the LDC is the appropriate entity to provide these services. For example, the value of LDCs owning system gas for expanding upstream capacity into Ontario is controversial with stakeholders using the same examples to argue for and against the statement. An example would be the construction of the Alliance pipeline. Some have argued that the LDCs with system gas provided key support in terms of long-term commitments. Others argued that it was the commitments of the unregulated parents that are being referenced here. The role of the LDCs in supporting long-term supply in North America has also been proposed as important in the market. Others have argued that the supply market in North America is well capitalized and that LDC support is unnecessary. Stakeholders identified six aspects of the system supply function that should be addressed in any potential restructuring:

- QRAM
- Cost accounting
- Billing
- Long term supply, upstream transportation, and storage
- Load balancing and deviations
- System gas consumer choice

Below we briefly discuss each of these elements, elaborating on the key point and implications of each.

QRAM: A considerable amount of regulatory oversight goes into the QRAM process to ensure the proper and appropriate pass through and recovery of gas costs. Alternatives to QRAM or suggestions of improvements to QRAM were suggested by stakeholders. These alternatives included

- Methods for recovering deviation charges (i.e., when actual prices paid for gas deviate from the forecast used in the commodity charge)
- Changing the period of QRAM pricing in order to reduce deviation charges
- Making the QRAM process consistent province wide
- Make the prices seen by consumers be more reflective of actual market prices

The current methods for recovering deviation charges can lead to inefficiencies in the market. Adjusting the future rates to account for past deviations creates a disconnect between cost and cause (i.e., cost of consumption lags actual consumption decisions). It also provides for an ongoing price for system gas inconsistent with actual market prices. An alternative is to charge customers retroactively for the deviations. This has some historic precedent but raises a whole new set of issues. Customers had made decisions based on the published QRAM which may not be optimal given the deviation charges.

Prior to the QRAM system, rate adjustments were roughly annual (or when big variances accrued). The QRAM's higher frequency helps to reduce the deviation account, which is increasingly important given the volatility of gas prices. Alternatives would be to further increase the frequency of rate adjustments, perhaps moving to monthly changes; however, for such alternatives to be workable the regulatory process (currently substantial) would need to be reduced by making the rate adjustment more formulaic.

Currently the two major LDCs are moving towards a more consistent QRAM process. Requiring a consistent QRAM process province wide could provide some benefits overall in the regulatory process and to customers province-wide.

Another issue to address is the fact that while the QRAM process is set up to track market prices, it does so only for longer-term prices and does not capture the daily volatility in the market. Prices that capture this volatility should provide for a more efficient market and allow participants to better manage their supply costs. Conversely, customers have the option to purchase gas directly in the market and balance their own portfolios. Those who stay with system gas are mostly small volume customers who do not have the ability to manage their load on a daily basis and have no need to see day-to-day volatility.

More detailed analysis of the recovery process needs to be made in order to assess the value of any of these proposals. Currently, stakeholders appear to be comfortable with the quarterly process. Any proposal to change the current approach would have to be based on quantification of the benefits of a particular approach.

Cost Accounting: System supply costs include the cost of the commodity gas and limited overhead costs, which the LDCs pass through to customers. Other overhead costs associated with the purchase, scheduling, and management of gas supply are covered in the distribution and upstream transportation charges. As such it is difficult to compare the value of system supply with marketer supply. Marketer commodity charges must reflect the overhead costs of sourcing, purchase, and management of the gas function, including return. There is the question, therefore, of whether the two types of gas are equivalent, and whether there is a level playing field, necessary for a viably competitive market where consumers choose based on prices and services. Currently, the advantage marketers have is the ability to offer term supply at fixed prices, which LDCs cannot provide. Does this offset the price advantage of system supply? And is it appropriate in any case?

Several possible system-gas cost accounting modifications have been identified to put direct marketers and system gas on a more equal footing. One option is to modify the gas supply account to capture the equivalent costs in the system gas purchased gas account as incurred by direct marketers and to make sure that these costs are not recovered in the rate process through other means such as distribution charges. The effect of this change would be to reduce the underlying transportation, storage, and distribution charges, and increase system gas supply rates. This reallocation would reduce the delivery cost to marketer's customers and increase system gas prices to some degree (as well as changing the rate allocations within the system gas bill). Such rate impacts will no doubt be somewhat contentious.

An alternative approach would be to set up an LDC affiliate to provide system gas, as in California. The affiliate would provide system supply gas, serve as the supplier of last resort, and provide all of the functions of marketers. The LDC would continue to serve as the distributor of gas, provide balancing and other ancillary services. The question remains whether the LDC affiliate would be allowed to offer fixed price term gas supply. If not, then the QRAM mechanism would remain in place, but the costs of the gas would have to include the costs borne by independent marketers. Such an approach would be simpler from a cost accounting standpoint, but may raise cost redundancy issues. The purpose of the affiliate is to reduce cross-subsidization, whereby all of the costs of the affiliate (and profit margin) would end up in the system gas rate. The problem may arise, however, that in setting up the affiliate certain management and overhead functions are duplicated and that overall costs could increase.

Consolidated Billing: A key concern in the market is access to customers and customer billing. LDCs argue that they need access in order to provide information to customers concerning their operations, safety, and their bills. Some direct marketers would like sole access in order to better manage customer billing requests and to reduce duplication of billing since some provide other services that need to be billed. A key concern for marketers is access to billing information in order to respond to customer queries.

Certainly both sides of the argument have merit and examples of both approaches exist in other markets. For smaller customers, it is generally not desirable to have multiple bills although there is precedent for this in other types of markets (e.g., telecommunications). Two areas for potential modification have been identified here:

- Provide marketers with more timely and better access to customer bills through automated data exchange.
- Provide marketers with the ability to provide consolidated billing conditioned with requirements for LDC information be included with the bills.

Both of these modifications are likely to provide overall benefits. Direct marketers with their own billing could provide different types of products to consumers with much different types of pricing. (Vendor Consolidated (VC) billing is provided under the Gas Distribution Access Rule, however, VC billing has not been implemented pending a court decision. The Board issued a proposed exemption to VC billing and is proposing implementation for VC billing in February 1, 2005.)

Long term gas supply, upstream transportation, and storage: The LDCs and others have argued that LDCs' involvement with system gas underpins an important role LDCs have in assuring a long term market for gas supply as well as a market basis for investments in upstream transportation and storage to serve their system supply obligations. Without this long-term commitment to markets that LDCs have, there would be more reluctance to invest in the infrastructure to provide security of supply over the long run. The importance of this LDC role is arguable and LDC long-term contracting creates inter-temporal equity and cost allocation issues in the market.

LDCs currently purchase gas under a variety of pricing formulas, including spot purchases, first of month index price purchasing, and relatively short term multi-month or one-year fixed price or forward price purchases. LDCs perform some limited moderate term gas supply contracting in order to reduce volatility in the system gas costs and overall deviation charges. This hedging is appropriate if it falls within the overall time frame of the QRAM process and recovery of deviation charges. Commitments to gas supply contracts for periods longer than one quarter or one year can result in commitments to gas supply that may be priced out of the market in the future and thus lock in deviations in the system gas purchased gas account. Such pricing provides incentives for customers to switch into and out of system gas to take advantage of price anomalies. This behavior can reduce the value of the lower costs to existing system gas customers, or lead to problems in cost recovery for the LDCs.

An alternative that the LDCs purchase gas only on the daily spot market or use prices indexed to the spot market reduces inter-temporal distortion due to long-term contracts but may increase volatility in the deviation charges which are recovered not at the time of consumption but in the future. Since the QRAM process does not reflect daily prices but annual prices, this restriction on risk management is not entirely appropriate.

The question remains whether the LDC system supply function is the ultimate guarantor for the investment in upstream gas resource development and long haul gas pipeline capacity. That LDCs are precluded from entering into long term gas supply contracts under the QRAM system argues that the regulators have not seen long term contracts as necessary for the continued development of long term supply. (Prior to the appearance of the spot market gas supply, contracts were long term, precisely to support the huge investment in infrastructure necessary for retail delivery of gas to eastern markets.) Retail unbundling and the dilution of the system supply obligation in Ontario also appear not to have affected long term supply security. Nevertheless, it is possible that new supply sources, such as LNG, would need LDC commitment to system supply as a guarantee for investment to bring the new supply on line.

It remains to be seen whether there is a similar argument to be made against LDCs making long term commitments to pipeline capacity in the future, once the current service agreements are up for renewal. Using the same arguments, regulators could insist that regulated LDCs not acquire long term transportation over a single pipeline, but rather spread their capacity across both TCPL and Dawn to ensure market access and in anticipation of changes in flows, sources of gas supply, and the introduction of LNG supply. And it may be found that 20 year firm transportation contracts are not desirable in the face of future supply source uncertainty.

Evidence from other jurisdictions suggests, rather, that it is not the system supply function that guarantees upstream commitments to infrastructure and gas resources, but the presence of a one Tcf (and with more gas-fired electricity generation, growing) gas market in Ontario that will ensure future service. A notable trend in pipeline capacity expansions in North America in the last 15 years has been the supplier support of new pipe, not the buyer support. What has driven gas supply and pipeline capacity is the presence of a market, whoever serves it.

Not allowing for LDC long-term contracting for upstream transportation and allowing only short term contracting could lead to increased volatility over time in cost of acquiring gas in Ontario. Some level of long-term contracting for upstream capacity is appropriate. Long-term contracts can lead to stranded costs and pricing inefficiencies if supply sources should change.

The optimal approach is to allow for a mix of long and short term contracting to meet system supply so that the contract levels can adjust rapidly to marginal changes in the system gas customer base. Reducing the requirements for capacity assignments to direct marketers will help improve the mobility of the customer base and overall efficiency in the market.

A more immediate issue for upstream pipeline capacity is managing the responsibilities for contracted capacity as customers move between marketers and the LDCs. This creates stranded costs and the responsibility for those costs.

The role of the LDC and system gas on the storage market is more complex. The possibility of a competitive storage market in Ontario is real for a number of reasons:

- Excess storage availability
- Potential inefficiencies in the current management of the storage assets
- Integration with the U.S. markets and access to storage in Michigan

Some arguments against reducing the regulation of storage, particularly the pricing of the storage assets are:

- The LDC storage assets were financed in part by the rate payers
- Storage in Ontario would be concentrated in too few owners leading to market power opportunities

Many of these issues will be dealt with in the storage and transportation paper, but the arguments against deregulating the pricing of storage assets could be addressed and opportunities do exist to improve the efficient use of storage for system gas customers and for customers not on system gas utilizing LDC storage assets.

Load Balancing and Deviations: Compared to other gas markets, the process for balancing load and addressing deviations in customer loads from forecasts is lax in some sense but quite severe in others. Currently, the LDCs require direct marketers to address deviations in load at the anniversary date of the direct marketer's contracts. For larger customers, more frequent balancing was allowed and in some cases encouraged. This approach created problems for the LDCs during high demand years and a three point balancing approach is being implemented in 2005.

Most other markets require monthly balancing and some require daily and even intra-daily balancing. Markets with daily or intra-daily balancing require more active management of supply and storage by the customers or direct marketers.

One issue with the proposed three point balancing approach is that is likely to require most of the market to make balancing adjustments at the same time of the year at a point when prices are likely to be at their highest. More analysis is required but a balancing approach that keeps track of deviations more often and allows for, or requires, participants to start adjusting earlier is more likely to lead to less disruptions in the market. Also, specific rules for addressing imbalances and requirements to follow these rules are less likely to create opportunities for gaming the system and using the imbalance accounts to take advantage of optionality in the gas market. Marketers and system gas should also have the ability to reduce imbalances through bilateral trades with other parties, thus reducing the cost overall of managing imbalances and removing the LDC from having to serve as a central clearinghouse. Bilateral trading would also require an equitable treatment of positive and negative imbalances.

More flexibility in the profiling should also be considered to allow for marketers and the LDC to manage the risk of over-utilizing storage before the end of the winter period. These could be a contingency adder to the profile in November through February with a matching reduction in March and April. Consideration should also be made to tie LDC balancing costs in March and April directly to imbalances in the system gas accounts and with non-system gas accounts.

Another issue has to do with equity between direct marketers and system gas. The argument is that system gas should have to respond to the same balancing requirements as direct marketers and that these costs should be included in the system gas purchases gas costs. This issue should be considered with the proposal above.

System Gas Customer Choice: The LDCs have provided arguments that system gas customers would like to see less volatility than the QRAM and longer term fixed price options should be made available to them. Others argue that the direct marketers provide these services.

The problem with the LDCs providing fixed price offerings is that they are then competing with the direct marketers and must market these offerings. They must also address deviations from the price charged to these customers and the cost of acquiring this gas. The complexity of these transactions, the transparency of the process and potential for shifting costs to and from accounts to reduce the impact of the deviations on the LDCs argue against this proposal.

Alternatives to this could be available. In some markets, deregulated entities compete for the ability to supply the equivalent of the system gas supply to the market. The LDC could offer a one-year fixed price contract and let unregulated entities compete to provide the supply and provide this option to system gas customers. This way, the cost of marketing is simply a selection process by customers on their bills (as an option) and the risk of deviations is incurred by the unregulated suppliers. These unregulated suppliers would then be responsible for providing supply to Ontario as with direct marketers and for addressing imbalances in the same manner and would also be assessed the same billing and other charges that direct marketers see from the LDC.

One problem with this approach is that is not completely dissimilar to the services provided by a direct marketer and will compete with the direct marketers where the marketing costs are much lower.

B. Potential System Gas End States

Option 1. Status Quo System Gas:

Most stakeholders believe that continuing to have the LDCs fulfill the system gas role is a reasonable and workable policy outcome. The status quo approach would maintain the current system, with three key changes.

First, the QRAM would be made uniform, formulaic, and automatic. The current system varies between the LDCs, the calculation leads to perpetual rate filings, and the utilities sometimes choose not to adjust rates and the QRAM if the adjustment is small. To make the QRAM more workable the OEB could adopt a single standardized approach. This approach needs to be highly formulaic to avoid excessive rate hearings. The approach would have consistent billing requirements (versus Union burying the PGVA into the commodity charge). Each utility would be required to update the QRAM each quarter, regardless of the size of the change, in order to prevent manipulation of the process.[3]

Second, system supply function and obligations would be made explicit and permanent. Under current rules, the LDCs future role as suppliers of system gas is left ambiguous and marketers allegedly have used the ambiguity as a argument against system supply as a secure and reliable supply. If system gas is deemed in the interest of Ontario gas customers, there is little reason to keep its ongoing role uncertain.

Third, the accounting for system gas purchased gas costs and requirements for balancing would be made consistent with direct marketer costs. These accounting changes would transfer administrative costs, risk management costs, the costs of acquiring supply, some billing charges for system gas to the purchased gas line of the system gas bill. Also, system gas would have the same balancing requirements as direct marketers.

[3] The observation has been made by some that if the QRAM is not updated each quarter, consumers do not have an accurate price to compare marketer gas against.

Other potential improvements would be to increase the points at which imbalances are estimated and to even out the period for adjusting to imbalances and to allow for contingencies in managing balances, especially in the March and April timeframe. An additional improvement could be timely resolution of the issues that would bring about consolidated billing.

Option 2. Hybrid System Gas Approach:

The Hybrid approach builds on the Status Quo option but takes it further. The QRAM would be standardized and system gas would be guaranteed for some finite period, if not permanently. Additional changes, however, would be implemented to increase consumer choice.

LDCs would be allowed to offer a discrete set of alternative gas offerings. For example, a one year fixed price gas contract, could be available to customers who seek more certainty in their bills, but who also prefer to purchase gas from the LDC. The supply for this offering could be tendered and provided by unregulated entities so that inter-temporal cost allocation issues could be avoided. Note that multiple entities could provide the service where all receive the marginal bid price. Care would be needed to allocate costs similar to those incurred by direct marketers and to require that they must resolve imbalances exactly like direct marketers and system gas.

Option 3. LDCs Exit System Gas:

Two of the jurisdictions reviewed have natural gas markets that operate successfully without LDCs providing system gas (Georgia and the UK). This is also an option for Ontario.

Removing LDCs from the system gas function would create a competitive situation where no one gas supplier would have an inherent advantage over any other. It would level the competitive playing field for supplying gas, force marketers to compete on price and services, and would tend to eliminate cross-subsidization of gas supply and other LDC functions (load balancing, distribution, billing). In theory this is the most efficient regulatory approach.

In practice, however, several potential problems arise that will need to be addressed to make this option work:

1. The Ontario market is currently dominated by two retail marketers, each of whom offers relatively few choices. Ontario regulations would need to complement this approach with affirmative actions to increase the number of parties and service offerings in the market.
2. LDCs leverage the system gas role to provide load balancing to the entire system. A complementary approach to ancillary services will need to be devised if LDCs exit system gas. Either this may require LDCs to purchase a minimum amount of gas to balance and maintain system integrity, or the creation of an unbundled service that marketers would have to purchase to ensure these activities.
3. Ontario LDCs, by virtue of their local market monopolies and captive customers, originally served as the ultimate underwriter to major long haul pipeline expansions and resource development. Taking the LDCs completely out of the gas supply role could force a reevaluation of upstream infrastructure requirements and how to guarantee them. The LDCs, operating as independent system operators (such as the UK's NGT), would have incentives for ensuring access to producing markets. More problematic will be the counterparty risks inherent in depending on marketers and others to secure upstream investments.
4. The market must have a supplier of last resort. Options in other markets include rules to assign customers to marketers. This can be by market area or through a rotating process. The license to market gas in the province includes a requirement to accept these customers.

C. Implications of End States

The LDCs internalize and socialize network externalities through their system gas function. As a result, the costs of discrete services such as load balancing, seller of last resort, etc., are blended into rates that limit price responsiveness and potentially lead to inefficient or unfair outcomes. The primary question affecting the unbundling decision is whether the increased complexity of market-based ancillary services would lead to high transaction and information costs that erode or overwhelm efficiency gains. Another issue is pricing and cost allocation for ancillary services such that prices send the right signals to the market, and cross subsidization and anti-competitive impacts are minimized. Other issues are the impact of cost of service regulation on the competitive pricing of these services, primarily load balancing.

In evaluating potential end states, the evolution of the gas market needs to be considered, particularly, the potential shift towards gas-fired generation in Ontario. This shift will create new strains on the system and will increase the importance of efficient resource allocation. This is especially true for load balancing services, which derive from storage, line pack, and peak shaving. Although Ontario has a large amount of storage at or near Dawn, the pricing and use of this storage will be a key concern. A separate paper is being prepared to go into greater detail on the storage question.

In terms of system gas, the previous discussions and options for system gas suggest that separating system gas and ancillary services is desirable in order to reduce cross-subsidization and to improve the playing field for direct marketers. This includes better accounting of costs and making system gas follow the same balancing rules as direct marketers. This may require additional capabilities for acquiring gas and storage volumes for maintaining system security which would then be allocated to and accounted for as a distribution cost.

The impact of increased power generation in Ontario utilizing natural gas is likely to reduce the seasonality overall of Ontario load and change the dynamics of the load balancing requirements for both system gas and for smaller, weather sensitive load served by direct marketers. Consideration of modifying the load balancing services to provide more flexibility to direct marketers (and to system gas) to take advantage of these opportunities is likely to improve the overall efficiency of the market. The impact of these opportunities may be limited by current abilities of larger consumers to manage their load and balances and would require more detailed analysis to understand the potential benefits.

The criteria for evaluating these proposed end states include the following.

1. The change creates more transparent rules and price signals and thus affords consumers a better basis on which to make choices.
2. The changes improve market efficiency
   a. Create more accurate price signals in the market (eliminate cross subsidization)
   b. Keep costs down
3. The changes reduce the need for regulatory oversight
4. The changes improve the ability of participants to manage risk in the market including price volatility
5. The changes will help protect consumers from unfair practices
6. The proposed changes are capable of being implemented without undue disruption
7. The changes anticipate macro-trends in the gas market

We have prepared the exhibit below as a straw man for considering the implications of the three options under the above criteria.

Exhibit 5. Evaluation of Options

Criteria	Option 1 Status Quo	Option 2 Hybrid	Option 3 Exit System Gas
1. Enhance transparency	+	+	++
2. Improve market efficiency	+	+	++
3. Reduce need for regulatory oversight	+	+	++
4. Enhance ability to manage risk	?	?	?
5. Protect consumers from unfair practices	+	+	?
6. Implemented without undue disruption	++	+	--
7. Accommodates macro trends	?	?	+

+ = probably positive impact; - = probably negative or no impact. ? = uncertain impact

All of the options as proposed would tend to enhance the transparency of services and rates, with Option 3 being the most effective. On the issue of market efficiency, again, all of the options would tend to improve pricing signals and we believe Option 3 would be more effective in keeping costs down by enhancing competition. Options 1 and 2 would contribute towards reducing regulatory oversight by virtue of making the QRAM formulaic and automatic, while Option 3 would substitute competitive forces for regulatory oversight. We are not sure how the options help manage risk. To the extent that the QRAM is automatic, and that pricing transparency and efficiency are improved, perhaps risk management can be made easier. On the other hand, there is nothing affirmative in these proposals that addresses risk management explicitly. On the protection of consumers, the first two options may be easier to accomplish with the retention of more oversight by regulators. For Option 3, without consumer education, market monitoring, and standards of conduct, the effect on consumer protection is less certain. In markets where competition has been implemented, there tends to be some abuse early in the transition, which is rectified later on. Clearly, the third option would be the greatest departure from current practice and would be most disruptive. Competitive markets would tend to be more accommodating to macro trends – the expansion of gas-fired power generation and the potential shift in sources of gas and flows over the pipeline network – because of the market discipline. Other actions by the OEB related to gas storage, pipeline capacity additions and other related issues may have greater implications than decisions on system supply.