DISCUSSION PAPER

ON

Gas Storage in Ontario

Presented By

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I. Introduction

The purpose of this paper is to provide an overview of the current market structure and operation of underground natural gas storage in Ontario. Underground storage is an important element of natural gas pipeline systems, especially for markets with large winter demand for heating. Underground storage usually consists of depleted gas fields where storage operators take pipeline gas and inject it during the summer months and withdraw gas during the winter months. This pattern of use allows pipelines upstream of storage to operate at high load factors year round, despite the large swings in seasonal demand. Pipeline systems integrated with market area underground storage can be sized optimally and thus lower their overall costs. Storage operations therefore are highly integrated with pipeline transportation, and as such, storage historically has been owned and operated by the long haul pipelines (in the U.S.) and by local distribution companies (LDCs) as has been the case in Ontario. Pipelines and distributors use storage to meet swings in demand, manage pipeline line pack, and to offer various storage services to customers. Although historically integrated, several international examples demonstrate that storage can be unbundled from transmission and distribution as long as competitive market mechanisms serve to integrate the operation of storage with the rest of market operations.

Storage also plays an important role in the day-to-day operations of natural gas and pipeline systems. The North American gas market is seeing an increase in high-deliverability storage that is used to manage rapid fluctuations in gas demand and steep diurnal load profiles, particularly those experienced by gas-fired power generation plants. These storage fields provide opportunities to rapidly adjust injections and withdrawals in order to meet power plant operations and to help manage flows on the pipeline and distribution systems during the day.

The appearance of independent, third party storage in recent years has been made possible by the withdrawal of pipelines from the merchant function and the rise of open access transportation. Third party operators can offer storage services independently of pipelines or LDCs, provided that there is adequate pipeline access and pipeline tariffs that do not render such services uneconomic or unworkable. These third party storage operations can operate under cost-of-service or market-based rates. The broad question about storage before the Ontario Energy Board is whether it would be in the interest of stakeholders to promote independent storage in Ontario, even to the point that the LDCs exit the storage service business. Behind the question are ongoing concerns expressed by stakeholders that efficiency could be improved, that customers lack access to new storage, that pricing is discriminatory and does not reflect the value of storage, and that the current approach discourages innovation and the development of additional storage services. Such questions also tend to draw into the discussion the role and operation of pipeline transportation and distribution that is a necessary element of storage services.

Making changes to the current structure of storage operations, if warranted, requires addressing several issues.

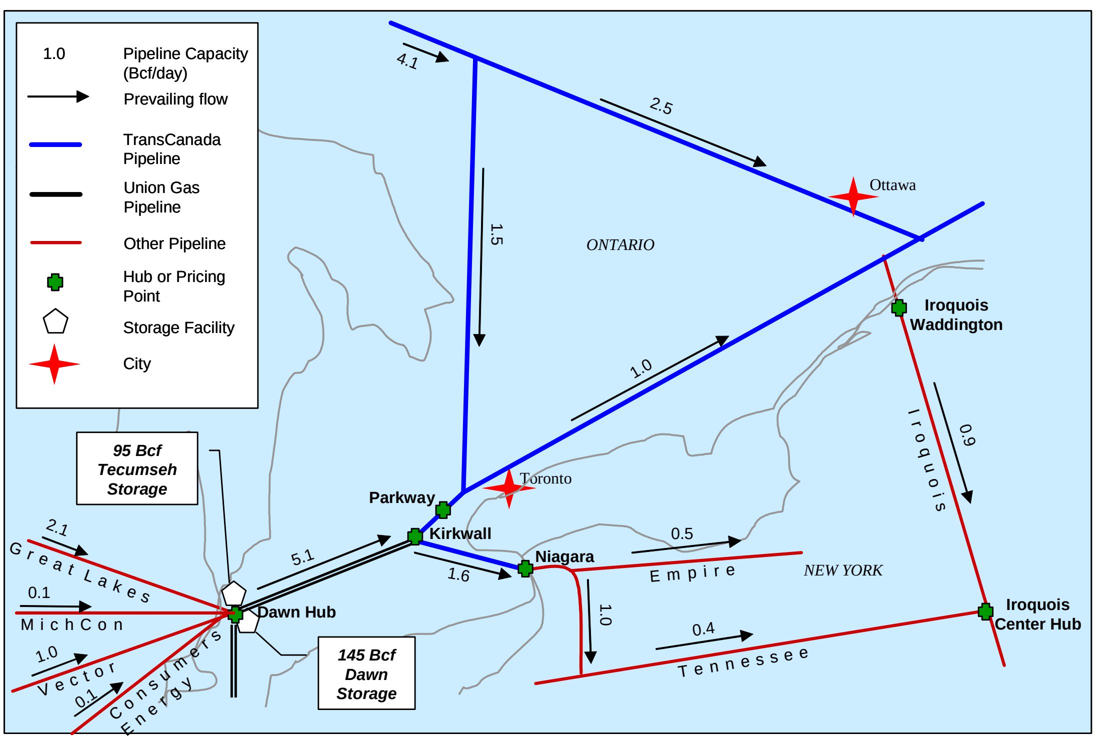
1. Does LDC involvement in storage decrease competition, distort pricing, and limit service choices?
2. Would requiring LDCs to exit the storage function reduce barriers to entry, drive down costs, and stimulate competition?
3. Is the present system consistent with developments in the market?
4. Will the market make necessary infrastructure investments under alternative storage structures?

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 storage depends on understanding the interrelationships of upstream gas supply fundamentals, the system infrastructure, consumer demand, and the competitive options to LDC-owned storage. Consequently, this paper begins with a description of the current gas market and gas market trends. We next address how storage operates in Ontario in some detail. Next we describe how storage 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 Ontario's Gas Market and Storage

Changes in the current approach to the structure and regulation of storage should take into account the ongoing developments in the North American gas market and in Ontario. As the North American resource base matures, more gas will be produced from unconventional resources, from different basins and from LNG imports. Ontario's integration with the U.S. market through pipeline interconnections at Dawn, combined with the expiration of long-term contracts on TransCanada Pipe Line (TCPL) can lead to more gas moving through southwestern Ontario in the future. At the same time, there will be continued growth of gas demand in the power generation sector, particularly in Canada where the government's commitment to the Kyoto Protocol. This will affect Ontario by increasing the demand for gas and depending on where the power plants are located, can have dramatic effects on pipeline and storage operations.

Exhibit 1. Ontario Gas System Schematic



The Province of Ontario is Canada's largest consuming gas market, at one trillion cubic feet (1 Tcf) annually, or a little under three billion cubic feet per day (3 Bcf). Natural gas enters the Province over the northern mainline of 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 3.5 Bcf per day from storage. Three major border crossings that connect Dawn with ANR Pipeline, MichCon, Great Lakes Gas Transmission (GLGT – 50 percent owned by TCPL), CMS (formerly Panhandle), Trunkline, and Vector (connecting through Chicago to the Alliance and Northern Border systems and which is jointly owned by Enbridge and DTE). 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 million cubic feet 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.

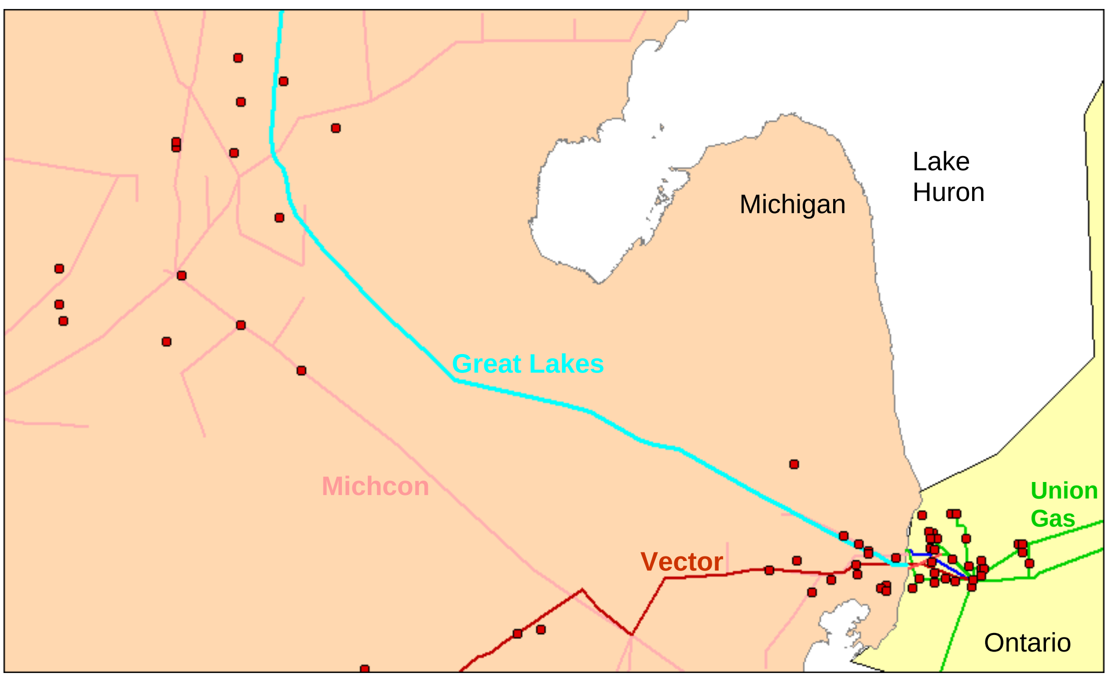
Ontario's two major distribution companies are Enbridge Gas Distribution (Enbridge) and Union Gas (Union). Other smaller systems include Natural Resource Gas, the City of Kitchener, and the City of Kingston. Union serves 1.2 million customers delivering 525 Bcf per year. Union also transports 730 Bcf 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.

The vast majority of Ontario's underground storage, approximately 240 Bcf, is located in and around Dawn. Through the pipelines feeding Dawn from the U.S., Ontario has access to another 600 Bcf of underground storage in Michigan. Union and Enbridge own the bulk of Ontario's storage. The largest storage facility in Canada is Union's Dawn facility, which has a working gas capacity of 145 Bcf and a maximum delivery capability of 2.0 Bcf per day. Enbridge's Tecumseh Gas Storage is just north of the

Dawn Hub has a working gas storage of approximately 95 Bcf, and a delivery capability of 1.5 Bcf per day.

The Dawn storage facility is located at the interconnection of the Vector, TCPL (Great Lakes Gas Transmission in Michigan), and Union gas pipelines. Tecumseh is interconnected with ANR/MichCon through Enbridge's Link pipeline at Corunna, just west of Tecumseh. Tecumseh is tied into Dawn. Michigan storage fields are accessible also through Dawn and the pipelines feeding Dawn, however, storage deliveries to Ontario from Michigan have the potential to be constrained due to a fixed capacity from Dawn to Parkway (from Dawn, all gas moves on the Union system to Parkway and Kirkwall). Pipeline capacity from Michigan (3.9 Bcf per day) and storage capacity at Dawn and Tecumseh (3.5 Bcf per day) exceed the 5.1 Bcf per day capacity on Union's Dawn to Parkway system.

Exhibit 2. Storage in Ontario and Michigan



Ontario and Canada are highly integrated in the North American natural gas market through the numerous pipeline interconnections. Gas prices in Ontario reflect not only conditions there but broad, North American gas market developments. Due to the expansion of pipeline capacity into Dawn, gas prices in Ontario are highly correlated with gas prices in Chicago and by extension Henry Hub. Correlations are similarly high with AECO, and other market hubs in the eastern U.S. Regulatory market reforms in Ontario will be undertaken in the face of broad trends in the industry, and to some extent should anticipate developments.

Two developments in the North American market will have a potentially significant impact on gas supply and demand in Ontario and ultimately on storage operations.

1. Changing regional supply patterns tied to declining production from the Western Canadian Sedimentary Basin (WCSB)
2. Changing demand patterns driven by expected increases in gas-fired generation

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 similar declines in conventional production in the U.S. Like Canada, this will lead to more development in unconventional resources – coal bed methane, deep tight sands, and very deep offshore Gulf of Mexico. These unconventional resources will come at higher cost, thus the NPC expects a substantial expansion of liquefied natural gas (LNG) as well as Alaska natural gas development to offset substantial declines in gas production in the lower 48 United States and declining exports from Canada.

The major effects of these changes will be higher and more volatile natural gas prices and potential shifts in gas flow patterns generally. More gas will enter the North

[1] National Energy Board, 2003 Canada's Energy Future
[2] National Petroleum Council, Balancing Natural Gas Policy, Fueling the Demands of a Growing Economy, 2003

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 River 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, since it is a strategic interconnection with supply from the west and Gulf Coast. This could require a reconfiguration of pipeline capacity, particularly over Union towards Parkway, and perhaps rate restructuring on TCPL.

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 and creates the necessity to manage line pack, storage, and system balancing aggressively and in ways that will affect total costs and services throughout the system.

Large increases in gas-fired power generation will change the seasonal profile of the gas load. The exact nature of this change is uncertain. While Canada has a bimodal, dual peak electric load (i.e., comparable electric load peaks in winter and summer), the shape of natural gas demand for electricity is also tied to US electric markets, seasonal hydro flows, and the price of gas. It can be said, however, that increasing electric gas use will increase overall demand levels, make the winter peak higher, and create a new summer gas peak. The summer gas peak has already manifested in the North American gas market and can be observed in gas price patterns over the past four years. As a result of the changing seasonal pattern, the storage injection period will be shortened to mostly occur in the spring and fall, and summer storage withdrawals will increase. This will likely favour increasing deliverability of storage.

In addition, electric load will impact the diurnal profile of Ontario gas use. Much of the electric load will be concentrated between 6 or 7 AM to 10 or 11 PM. With more dramatic diurnal gas load fluctuations, storage may need to play an increased roll in daily load balancing (in addition to more careful use of line pack).

Considering Ontario's gas storage in this context, it is important to remember that storage serves three primary purposes: 1) managing variation on seasonal load patterns, 2) balancing daily load, and 3) rapid cycling to meet volatile gas loads or make arbitrage gains from short-term price volatility. All of these purposes tie back to the basic need to have gas stored and available when needed. In open and competitive markets, storage can be generalized as a tool for inter-temporal arbitrage that serves to reduce volatility and make real time supply and demand meet.

Historically, Ontario's storage was developed by the LDCs to provide seasonal and daily load balancing for utility consumers. Moving forward in an integrated North American market the role of storage is broadening to cover a range of services. These services are simply repackaging of the basic intertemporal function of storage:

- Basic storage of gas to be withdrawn in the future
- Park and Loan service, where the storage owner allows the shipper to store excess gas during gas oversupply and buy gas during undersupply periods
- Load Balancing
- No-Notice Service, where shippers buy gas (at very high prices) from the LDC, storage owner, or pipeline operator

Storage serves as a natural hedge to price volatility. Higher gas price volatility creates a significant incentive for LDCs, marketers and direct gas buyers to procure storage and use it to reduce the impact of dramatic gas price fluctuations. Increasing gas price volatility has changed the focus of storage from operational (meeting seasonal and daily gas load) to financial (managing/reducing gas price swings).

According to the recent National Petroleum Council report (NPC, 2003) the North American market will need 700 Bcf of new storage by 2025 (incremental to current capacity of 4,500 Bcf). Over 50 Bcf of storage is projected in Eastern Canada, including Ontario, Quebec and the Maritime provinces. With significant increases in demand for new storage, it is therefore important to consider how storage in Ontario is regulated and priced in current usage.

III. Issues in the Regulation of Storage

Today, Ontario has two flavors of storage: in-franchise and ex-franchise. In-franchise storage service is storage available to the LDCs' franchise customers. It can be bundled or unbundled. Most important, it is offered at embedded, heavily depreciated, cost-of-service (COS) rates, and therefore is cheap compared to market-based storage. Ex-franchise storage service is an unbundled service, available to those who are not the LDC's franchise customers. It is priced at market-based rates, and typically is priced at a 30 percent to 50 percent premium to the COS rates. Ex-franchise storage services include inter-utility transactions (i.e., Union sells storage service to other utilities at market rates), new LDC peak storage offerings, and parking (short-term) services. Although the majority of Ontario load is in-franchise, a growing ex-franchise storage market is emerging in Ontario. Thus, most of the issues surrounding whether the current system should be changed concern the consequences of low cost storage franchise service.

There is no cost basis to account for the differences between in-franchise and ex-franchise storage service. Both types of storage services are provided from using the same storage facilities, fields, and pipelines. Union or Enbridge's marketing affiliates offer storage at cost for in-franchise use, but at market prices to ex-franchise uses. The amount of storage needed for in-franchise use is determined by Union and Enbridge, and the remainder is available for sale at market-based rates. For Union, roughly half of their storage capacity is at market-based rates and half at cost of service rates. This market-based storage at Dawn has been critical to making Dawn a liquid trading hub where market participants can buy, sell, and store gas. Some of the profits from market-based sales are returned to the regulated company and credited towards the cost of service.

Under the in-franchise service, buyers of the service (which can include marketers and direct gas purchasers) can contract for a bundled or unbundled service. Most choose the bundled service, which supplies transportation, distribution, and load balancing in a single service. Some marketers and large direct gas buyers will purchase a range of unbundled services, which require the shipper to nominate their own transportation and storage to balance daily supply and demand.

Under bundled services, the shipper has responsibility for supplying sufficient natural gas over large time blocks and the LDC has responsibility for balancing daily load with supply. Periodically, the LDC reconciles each shipper's load with supply and shippers have a fixed period to zero out imbalance accounts. These are sometimes called *balancing points* (one per year has been the convention, but the LDCs are moving to more frequent two and three point balancing systems). Infrequent balancing is simple for the counterparties to implement.

Under unbundled services, shippers pay lower overall rates but take on responsibility for daily nominations and balancing. 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 that are more than 2 percent 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 some other markets. Unbundled services also set maximum daily injection and withdrawal rates, and maximum storage balances governing each shipper's storage nominations. Unbundled storage carries sufficient additional burdens such that only large, predictable gas consumers have found the discounted rates a big enough incentive to compensate for increased risk and responsibility.

Although the vast majority of Ontario load is "in-franchise," a growing ex-franchise storage market is emerging in Ontario. The market is made up of three primary groups:

1. Shippers (U.S. or Canada) taking physical positions for hedging or to capture arbitrage opportunities and to manage long-haul gas transportation

2. Large in-franchise gas consumers whose demand for storage exceeds the storage allocated by the LDC at COS rates
3. LDCs purchasing storage from each other

These ex-franchise parties pay market-based rates for storage where prices are determined through bilateral agreements. The bilateral market is supplied by excess LDC storage capacity and the release of capacity from in-franchise and ex-franchise storage consumers.

The role of storage in reducing volatility in the market is significant. Seasonally, storage allows the owners to purchase gas during the spring, summer, and fall when prices are lower and when capacity to market is under-utilized, and deliver this gas to market during the winter when prices are higher and upstream capacity may be limited. Storage also plays a role on shorter time frames to help reduce volatility in the market. For example, natural gas demand will typically have a profile that varies by the day of the week where holidays and weekends experience less demand than weekdays. A typical profile in the summer for a storage operator will have high injections into storage during low demand periods (e.g., weekends) and low injections during days with higher demand and possibly higher prices. In the winter, withdrawals from storage may be lower during the weekends than during the week as well as being lower on warmer days.

Some storage including high deliverability storage allows for withdrawals during the off peak season (e.g., summer) and injections during the winter. More flexibility in the storage operations allows for tighter management of the resource with less contingency required for the later parts of the winter season. Also, greater ability to take advantage of arbitrage opportunities can provide benefits to Ontario overall. Demand and weather patterns vary considerably throughout North America and days with high demand in Ontario can correspond to low demand in other areas. This load diversity leads to less reliance on storage and more on direct supply.

A key issue going forward for storage regulation in Ontario is new storage and storage capacity expansion. Storage capacity could come from multiple parties including Union and Enbridge, independent storage merchants, and U.S. storage operators in Michigan. New storage development faces multiple cost and regulatory hurdles:

- Access to the transportation to and from the storage fields (such as from Dawn to Parkway during peak periods)
- Tolling structures
- Regulation of the storage operations

Although these are significant hurdles for new storage, it is not clear that the hurdles should be lowered, how to lower the hurdles, and who should bear the costs of the necessary transmission investments, if not the storage developer. In other jurisdictions, which we discuss in the next section, the predominant approach has been to let storage developers and their customers bear the costs of gaining access to the transportation system, while attempting to minimize the regulatory burden.

Under the current system, it is unclear how well the market for storage is functioning, and in fact, storage appears to be an inefficient market. The wide price spread between the lower COS priced and the higher market priced storage (30 percent to 50 percent based on Union’s published rates) indicates that in-franchise consumers are probably over consuming storage because it is cheap, which means less is available for the market, thus keeping market prices higher. Second, the lack of new storage would indicate that either the cost of new storage is higher than consumers would be willing to pay, or that utilities are able to exercise market power to keep competition out (e.g., transportation arrangements that advantage the LDC over competitors).

IV. Storage in Other Jurisdictions

This section provides a summary of storage and transportation approaches in the U.S. interstate storage system, regulated by the Federal Energy Regulatory Commission (FERC), the State of California, the United Kingdom, and Victoria, Australia. In each of these jurisdictions storage has undergone major restructuring with potential insights for Ontario.

Interstate Storage, U.S.A.

FERC's Order 636 removed long haul, interstate pipelines from the merchant sales function and restricted their activities to transportation (including storage) of natural gas under rules requiring open access. A key element of the restructuring of the industry was the unbundling of pipeline services into transportation, storage, and other services and the provision for a secondary market in pipeline and storage capacity. At the same time FERC revised pipeline rate design into a straight-fixed-variable formula, where all fixed costs were put in the demand charge and all variable costs in the commodity rate. Before this revision some fixed costs were recovered in the volumetric commodity portion of the rate. If anything, it was the latter action that led to an increased interest in storage, since it made plain the high cost of long haul transportation for meeting short-term seasonal peak demand. Thus the unbundling of services and the more explicit representation of costs allowed shippers to bundle their own services to meet their needs.

Pipelines still offer storage services under cost of service rates. Independent storage developers can also offer storage services, and in recent years a number of independent storage operators have entered the market. In considering storage offerings in a competitive context it is useful to review how FERC addresses the certification of independent storage and how it evaluates market-based rates for storage.

Storage operators (independent or pipeline affiliated) offering services in interstate commerce must receive a certificate of public convenience and necessity from FERC to construct and implement the storage service. FERC issued a Policy Statement in 1999[3] presenting its guidelines for establishing when a new project would meet the public interest test. FERC's stated goal is to give appropriate consideration to the enhancement of competitive transportation alternatives; to defend against the possibility of overbuilding; to avoid the subsidization by existing customers; to ensure the applicant's responsibility for unsubscribed capacity; and to avoid unnecessary exercise of eminent domain or other disruptions to the environment. The threshold requirement for a project is that the sponsor must be prepared to financially support the project without relying on its subsidization by existing customers. Clearly new, independent storage operators do not rely on current customers to subsidize construction of new projects; and independent storage operators bear the risk of unsubscribed capacity. FERC also weighs the adverse impacts of the new project on existing pipelines, their customers, landowners, and communities and the environment with the public benefits of the services being offered. In a decision granting a certificate to the Wyckoff Storage Project (Steuben County, New York), FERC described these public benefits as

> *. . . the ability to provide storage services to shippers, suppliers, and markets, to serve a growing market for firm and interruptible storage services, that will meet the needs of the gas-fired electric generation market, help prospective customers meet peak period needs, minimize pipeline imbalances, and enhance load factors responsive to intra-month swings. Thus the project will provide markets with greater storage and transportation options and enhance customers' capabilities to manage gas supplies*.[4]

[3] Certification of New Interstate Natural Gas Pipeline Facilities, 88 FERC 61,227 (1999), order clarifying statement of policy, 90 FERC 61,128 (2000).
[4] Order Issuing Certificates, Wyckoff Gas Storage Company, LLC, Docket No. CP03-33-000, October 6, 2003.

Rates for independent storage can be at cost-of-service or market-based, depending on whether FERC finds that the storage operator can exercise market power. Pipelines also can seek market-based rates under the same terms. The analytical framework for the evaluation of market based rate proposals was provided by FERC in its 1996 Alternative Rate Policy Statement.[5] The consideration of market power addresses two questions: whether the storage operator can withhold or restrict services and thereafter increase price by a significant amount for a significant period of time; and whether the storage operator can discriminate unduly in price or terms and conditions. The market power test has three elements: define the relevant market; measure the market share and market concentration; and evaluate other relevant factors. In seeking market-based rates, applicants must address each of these elements to the satisfaction of FERC.

Determining the relevant market includes an examination of the services offered and the suppliers of those services that would be alternatives to the services being offered by the applicant seeking market-based rate treatment. The key is the substitutability of these alternatives in a timely manner and adequate quantity, such that their presence would restrain the storage provider from exercising market power. (There is necessarily a geographic dimension to the definition of the relevant market.)

Once the relevant market is defined, then the second element of the market power test is the analysis of market share and market concentration. Market share refers to the percentage of the capacity to serve the market. In the Wyckoff Storage case, FERC examined the company's share of working gas capacity and peak day deliverability. FERC also considers the applicant's affiliates in calculating the applicant's share of the market. Wyckoff Storage has a 1.2 percent share of working gas capacity and 3.8 percent share of deliverability. An affiliate's capacity is included in the applicant's market share calculation when the affiliate controls the applicant, is controlled by the applicant, or is under common control with the applicant by a third party. (This was relevant in the Wyckoff case since National Fuel Gas Company, a pipeline and storage

[5] Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, 74 FERC 61,076.

operator in the region, held a minority, non-voting interest in Wyckoff, which FERC found did not meet the affiliate test.)

To calculate the market concentration, FERC employs the Herfindahl-Hirschman Index (HHI), a commonly accepted measure of market concentration. It is calculated by squaring the market share of each firm competing in the market and then summing the resulting numbers. For example, for a market consisting of four firms with shares of thirty, thirty, twenty and twenty percent, the HHI is 2600 ($30^2 + 30^2 + 20^2 + 20^2 = 2600$). The HHI takes into account the relative size and distribution of the firms in a market and can be very small when a market consists of a large number of firms of relatively equal size. The HHI increases both as the number of firms in the market decreases and as the disparity in size between those firms increases. Markets in which the HHI is between 1000 and 1800 points are considered to be moderately concentrated and those in which the HHI is in excess of 1800 points are considered to be concentrated. In Wyckoff, the concentration was significant: an HHI of 2,382 for working gas and 2,267 for peak day deliverability. However, this concentration was due to the presence of large, regulated storage service providers in the relevant market. Thus, FERC found that Wyckoff would have incentives to market its services at or below regulated rates.

A key to the success of independent storage service is the ability to access pipeline transportation at rates that make the storage economic. New storage fields often require additional pipeline capacity expansion in order to feed the storage facility and make it available during peak demand hours. In certificating new storage, FERC will often certificate related pipeline facilities. Incremental additions to pipeline capacity to accommodate new customers are usually priced at the incremental cost-of-service, unless the new service would help reduce (or not unduly increase) costs to all customers. The customers purchasing storage capacity generally will also procure transportation capacity from the pipeline. The pipeline will either have coordinated with the storage developer to expand capacity on the pipe, or may have spare capacity to sell. Either way, the customer bears the cost of the transportation to and from the storage, in addition to whatever charges the storage developer charges for injections, withdrawals, and storage.

California, U.S.A

Alongside federal initiatives, the California Public Utility 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. By the early 1990s, core customers were also given the option to purchase their gas from marketers.

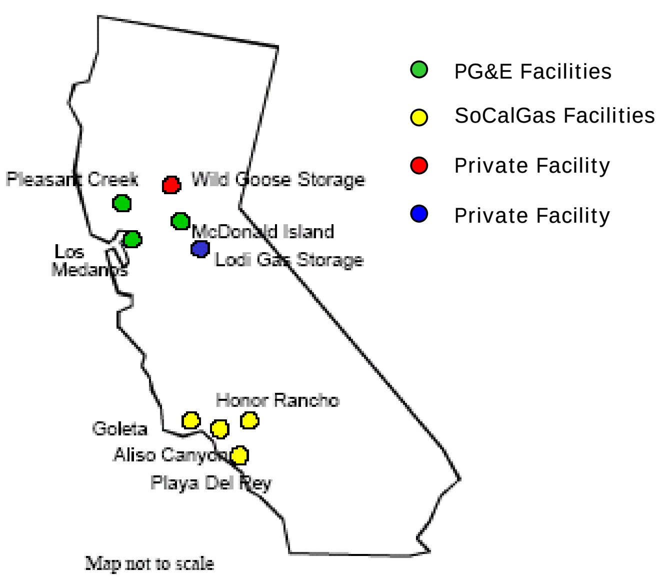
Most core customers still purchase their gas from regulated utilities. The CPUC regulates the California utilities' natural gas rates and natural gas services including in-state transportation over the utilities transmission and distribution pipeline system, storage, procurement, metering and billing. The local utilities still function as provider of last resort.

Southern California Gas (SoCalGas), the local gas utility in Los Angeles, owns all the storage facilities in southern California. San Diego Gas & Electric (Sempra) purchases its storage services from SoCalGas. Pacific Gas & Electric owns the remaining storage facilities in northern California.

In 1993, the CPUC unbundled non-core storage. Utilities were no longer responsible for ensuring that non-core customers had their storage requirements. As such, storage costs were removed from non-core rates. Non-core customers contract and pay for storage service on an unbundled basis. However, the utility distribution companies continue to provide storage as a bundled product to residential and commercial customers. In addition, specific storage reserve levels were also specified for the utilities' core customers. All storage built by the utilities is available to core and non-core customers at regulated rates. With regard to construction and expansion of storage facilities the CPUC adopted a "let the market decide" policy. This policy was based on the view that the prior regulated approach was not stimulating sufficient infrastructure investment in pipelines and storage. Regulators felt that if storage was needed, companies should be allowed to make the necessary investments to meet the demand.

As a result, two independent storage facilities were opened. The Wild Goose Storage and the Lodi Gas Storage facilities came online in 1999 and 2001 respectively. They are exempt from traditional cost-of-service ratemaking although they are subject to the regulatory jurisdiction of the Commission. They assume all the risk for the commercial performance of the facilities.

Natural Gas Storage Facilities in California



The 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.

Operation of the System, Storage, and Transportation

The UK takes an unbundled and liberalized approach to the natural gas market, with multiple parties involved at various stages of gas supply and delivery. Utilization and operation of the gas transportation system is governed by the "Network Code." Shippers arrange for the conveyance of gas over the national transmission system (NTS), distribution networks, or independent gas transporter (IGT) distribution networks to consumers. These shippers can either be large consumers or aggregators of many small customers (i.e., retailers). NGT owns and operates both the NTS and the IGTs. Independent gas transporters own and operate separate gas distribution networks that are attached to NGT and other IGT networks. Typically a distribution network is a monopoly in its service territory. Ofgem regulates all licensed gas transporters.

NTS transports gas from entry points (beach terminals and interconnectors) to gas distribution networks, large consumers connected directly to NTS, and storage facilities. A system of entry capacity auctions has been developed to provide an efficient mechanism for rationing capacity at entry points to the NTS. Because these auctions allow for the purchase of capacity for a period of up to 15 years, the prices also provide signals as to the pattern of demand in the longer-term. Shippers participate in the auctions to procure sufficient pipeline capacity to deliver gas directly to the consumer (if connected to the NTS) or to the distribution network.

Distribution networks take gas from the NTS and deliver it to connected system exit points and over 20 million consumers across Great Britain. Transco and independent gas transporters charge gas distribution fees that are included in the overall transportation prices charged to shippers (and then suppliers). Given the natural monopoly nature of gas transportation and distribution, Ofgem regulates NGT and other independent gas transporters through price controls which limit the amount of revenue that can be collected from customers. Regular price control reviews occur every five years and lay out the amount of revenue that it is allowed to recover through their charges. Transco's total allowed distribution revenue was approximately £2 billion for the financial year 2002/03. Transco charges account for 25-30 percent of a typical gas domestic bill.

The UK system places responsibility for supply, transportation, and storage nominations on the shipper. Having purchased sufficient capacity (pipe and storage), shippers must nominate and balance each day. The Network Code establishes a specific timeline for this process:

- Shippers must provide NGT with nominations for off-takes at the daily-metered (DM) sites by 1 pm on the day prior to the gas day
- By 4 pm on the prior day, shippers must provide BGT with nominations for inputs at each entry point
- From 5:30 pm that day until 3:59 am on the gas day, shippers can re-nominate their DM site gas off-takes and entry point gas inputs
- To provide information on gas demand, NGT issues forecasts for non-metered sites in each LDZ for each shipper at 2 pm, 7 pm and 2 am of the day before, and noon, 3 pm, 6 pm and 9:30 pm on the gas day

Storage

Within the overall network code governing gas transportation, the UK takes a very simple approach to natural gas storage, treating injections to storage just like any other off-take, withdrawals just like any other input, and leaving the pricing and development of new storage up to the market (for the most part).

The UK has underground and LNG gas storage totaling roughly 130 BCF, roughly 90% of which is underground storage. The bulk of underground storage capacity is concentrated in the Rough and Hornsea facilities. The Rough facility is a depleted gas field connected to the Easington terminal and has a total capacity of approximately 100 BCF. Hornsea is a salt cavern storage facility located in East Yorkshire with a capacity of roughly 12 BCF. As a salt cavern facility, East Yorkshire has relatively high deliverability. The ownership of both Rough and Hornsea has changed hands several times in recent years. Today, Scottish and Southern Energy (SSE) owns the Hornsea facility (acquired from Dynegy in September 2002) and Centrica (British Gas) owns the Rough facility (acquired from Dynegy in November 2002).

The UK has five LNG storage sites located around the country. Although a relatively small storage capacity relative to the underground storage, the LNG storage is located close to transportation constrained markets and is used to ensure reliable delivery of natural gas to these markets.

In general, storage facilities in the UK are treated like any other gas input or output. When injections are being made, the storage is nominated like any other gas offtake. When withdrawals are being made the storage is nominated like any other gas input. The market for storage is competitive, so owners/operators of storage can sell storage capacity to the highest bidder(s) and the holders of the storage capacity can optimize injections and withdrawals to best capitalize on market price swings (daily or seasonally).

While shippers and the NGT compete on the competitive market for the storage capacity, there are specific exceptions to this approach where reliability is of specific concern. One example is that NGT has special access to LNG facilities to provide sufficient operating margins. Another is that the NGT can require shippers to maintain specific stocks of gas at “Constrained LNG” facilities. These are a category of LNG storage facilities serving transportation constrained localities.

Under the Gas Act of 1986, licenses are not required for the operation and ownership of gas storage facilities. Competition continues to grow in storage facilities. Hatfield Moor and Hole House Farm became operational in 1999, and together these two storage facilities account for about 30 percent of the ‘Mid-Range’ Storage space and deliverability. In addition, a number of other storage projects have been proposed to come online between 2005 and 2008. These include Star Energy’s Humbly Grove and Welton facilities, Scottish Power’s Byley facility, Canatxx’s Flentwood facility and a joint venture between SSE and Statoil on the Aldrough facility. In total, these facilities are anticipated to provide an additional 66 Bcf of storage space to the existing 130 Bcf system and 4 Bcf/d deliverability to the existing 5 Bcf/d system.

The State of Victoria, Australia

In Australia, the State of Victoria undertook gas market restructuring in 1997. The state sold its monopoly transport and distribution of natural gas systems. An independent systems operator (ISO) was formed to operate a daily spot market and operate the pipeline system. Prior to the restructuring of the gas market, no storage existed in Victoria. Seasonal swings in load were managed through production and pipeline capacity. Daily swings in load were managed through line pack in the pipeline system.

The newly restructured market went into operation in March of 1999 and is unique for a gas market in many ways. Essentially the system operates like some power markets where shippers bid on supply and demand on a daily basis to meet their customer needs. This creates marginal prices that signal the value of gas daily. The advantage of this system has been high resolution price signals that transfer the costs of balancing, storage, transportation bottlenecks, and other system costs to the shippers and ultimately to the consumers. This leads to more efficient decision-making. Disadvantages of this system are that it does not send adequate long-term price signals to develop new transportation capacity and the system has high start-up and on-going information/transaction costs.

Most customers, except for large industrials, buy gas from retailers who ship volumes over the pipeline and manage nominations, balancing, and other requirements. Retailers nominate transportation capacity, storage injections, and storage withdrawals on a daily basis, and balance accounts at the end of the day through Victoria's cash-out mechanism. Similar to the UK, storage nominations are handled just like other supplies and demands in the market. Storage is treated either as a supply or demand depending on if gas is being injected or withdrawn. During withdrawals, the storage is bid into the market just like any other supply, and the retailer is required to nominate not only the supply but also the transportation to market. During injections, the storage acts like a demand/consumer requiring nominations of supply and transportation to move gas to the facility.

This sort of market structure could be useful as Ontario moves towards more gas fired generation with strong diurnal swings in demand for pipeline capacity and storage service. Some element of short term storage that makes use of both line pack and storage could be managed on a daily basis with a similar sort of bidding process.

Since market restructuring, there has been one large storage field developed in Victoria with a number of new fields under consideration. The existing and new fields were/will be privately financed and the storage assets revenues are entirely dependent upon daily and seasonal gas swings in the gas market.

Also, the State of Victoria is currently undergoing a review of the market and a number of changes have been proposed to improve price signals and allocation of costs for load balancing. The proposals for immediate change include multiple pricing points during the day to help manage and allocate load balancing costs and point to point transportation capacity rights with the ability to trade these rights and combined with penalties for exceeding them. Under the proposals, the market will eventually include multiple pricing points during the day (e.g., every 6 or 8 hours).

V. Policy Issues and Potential End States

Historically Ontario's storage resource was developed for seasonally-fluctuating in-franchise gas load. Over time, retail restructuring and unbundled transmission service have been introduced into the market. Along with the outlook for high levels of volatile electric gas load, the main policy questions concern whether the current system is well suited to the changed and changing circumstances of the market.

Ontario's approach to pricing storage raises questions of both fairness and efficiency. From a fairness perspective, new and existing in-franchise customers have access to cheap storage, limits the ability of other storage providers to market their storage. For example, new customers can make decisions on COS priced storage which does not reflect the marginal cost of storage to the utility providing the storage. In addition, more cost effective storage may be available from other sources to meet the marginal storage requirement. Inefficient decisions can also lead to the overall market price increasing to levels above what would be expected in a fully competitive market.

The current arrangement sends inefficient price signals. The regulated prices for in-franchise customers provide a competitive advantage to the LDCs and may discourage competition from the U.S. and independent operators in Ontario. It can create incentives that favour LDC storage even when the LDC must go to market and pay market rates for additional storage. For example, suppose a new Enbridge customer signs up for bundled service. Enbridge needs additional storage to satisfy the demand of the new customer and purchases that storage service at market rates from Union. Even though the marginal cost to Enbridge is the market price of storage, the added storage costs are rolled into Enbridge's total cost of storage and are spread across all Enbridge customers. The consumer faces a price signal based on the average cost, not the marginal cost, which is inefficient and imposes costs on other consumers in the system.

Transportation charges for moving gas to and from the storage field is a key issue. Currently, independent storage operators must pay the LDC postage stamp rates for both moving gas to and from storage, creating a double charge which is not reflected in the charges for LDC load balancing services. For storage to be competitive in Ontario, the transport and distribution charges for LDC storage and independent storage must be on an equal basis. Consideration should also be made to adjusting tolls to reflect the cost of the transport when the transport occurs and its impact on the system as a whole. In other markets, marketers using storage can take advantage of discounted rates during the summer in order to fill storage.

Access to transportation to and from the storage field is another key issue. Some of the newer storage fields proposed by independents in Ontario are in areas where access to transportation is limited or constrained, and options for expanding capacity are for the storage operator to build their own. At issue is whether the incentives for the LDC to expand their systems to integrate the new storage fields into their systems are sufficient, and if the competing position of the LDC or its affiliates provides dis-incentives. Also, constrained transportation capacity from Dawn to Parkway leaves independents with transportation that can be interrupted when the value of their asset is the greatest, substantially reducing the value of their storage.

Expanded storage offerings will also be required to address future changes in the market, primarily the increase in gas-fired generation. The gas use for power generation could have both winter and summer peaks, and is likely to be primarily for the peak hours of the day. It will also include generation to support power systems reliability which leads to rapid changes in demand for gas that cannot be forecasted. As discussed earlier, the seasonal shifts in demand should change how the seasonal load balancing services are managed overall in Ontario with opportunities to reduce demand for seasonal storage[6]. At the same time, the power generation demand needs will need to be integrated into the gas market carefully through potential revisions to

[6] Seasonal storage demand may decline if power generation narrows the differential between summer and winter peaks. Demand for high deliverability storage and linepack may increase, however, since power generation gas load can vary significantly across hourly, daily, and monthly time frames.

pipeline tariffs, storage offerings, nominations schedules and procedures, and charging for deviations and imbalances.

From the stakeholder meetings, there are mixed concerns about storage issues and a wide range of conflicting views. For the most part, direct marketers and all but large industrial consumers do not want to bother with load management and want a simple system. Thus a bundled storage service that includes balancing and delivery certainty managed by the LDC is a perfectly adequate system. At the same time, it must be noted that storage is at COS rates with most of the storage depreciated, hence low rates which make it attractive to direct marketers and consumers.

The concerns of the storage operators and consumers focused primarily on access to transportation including transport during peak periods, transportation rates, equal competition with LDC storage, reducing regulatory burdens on storage fields, and fostering a more competitive market (given the dominance of Union and Enbridge in storage and transportation). With respect to the last point, two issues arise. The first issue is of keeping in-franchise storage management separate from unregulated affiliate activities. Under the current system, Union or Enbridge may have a competitive advantage since the unregulated affiliates also manage in-franchise storage and take advantage of added flexibility and optionality. A competitive advantage may also arise if the COS rate is subsidizing the unregulated affiliate's storage management. The market based storage does not require separate management infrastructure from the COS storage, so there is potential for the management costs to be born by the COS rates, thus reducing the underlying costs of the market-based storage. The second issue is that LDC storage ownership creates an inherent incentive for the LDCs to wield their control over the distribution system to keep new storage out.

While many stakeholders believe that the LDCs should be in the market with system gas and long-term storage, others feel that this is not the case. The support for unbundling storage appears mixed. Many consumers do not want to dilute the value of in-franchise storage by unbundling the service in a way that would increase costs. However, others recognize that storage use ought to be at prices that give proper price signals both to use it efficiently and to encourage investment in additional storage. The slowness in the expansion of storage by utilities is based, some believe, on utilities holding out for a higher rate of return on the development. Stakeholders also see a need to reduce regulatory barriers to development of new storage operations. Specific issues raised were:

- Regulation for new storage is too onerous
  - Need to regulate safety, and land-owner rights
  - Do not need regulation of pricing, go to market pricing
- There are opportunities for new storage in the market
  - Some feel that Enbridge has the capability to expand storage capacity by as much as 40 Bcf at a low incremental cost by increasing reservoir pressures
  - Other opportunities are either far from transport and/or market or are of small size
- New storage does not have fair access to market
  - Tolling arrangements on Union, increase costs significantly to independent storage operators and U.S. storage (postage stamp rate and charges for injection flows and withdrawal flows) and do not reflect the value of storage to the system
  - Limited capacity from Dawn to Parkway leaves storage operators with interruptible capacity only at Parkway, reducing the value of storage considerably (LDC storage receives 1st rights)
  - Management of the LDC storage assets though an unregulated affiliate along with the unregulated affiliate's assets leaves opportunities for unfair access to transport and distribution capacity and moving of costs from the unregulated entity to the regulated costs.

LDC storage has been financed and built to serve rate payers and is substantially depreciated. As such, it is very cheap to in-franchise customers. Although the property of the holding companies of Enbridge and Union, many view Ontario's storage assets—and consequently cheap storage rates—as both a provincial asset and a ratepayer entitlement. Regulatory actions that would affect the price of storage to in-franchise rate payers need to consider the equity implications with respect to the potential costs that would be imposed on rate payers. These costs may yield more efficient market performance, but could also yield a significant gain to the owners of storage (e.g., a shift to market-based storage prices would be more efficient, but would potentially increase Enbridge and Union storage profits).

Although viewed as a provincial asset, in operational terms, the assets really serve the North American market. This is consistent with serving Ontario consumers since a well-functioning North American market benefits all consumers. The challenge is in how to share the proceeds of profits made from storage assets that were financed with rate payer backing.

Storage from the U.S. can compete with market prices but not cost of service prices in most cases. There is thought to be considerable potential for low cost storage in Michigan, which could be utilized by Ontario, but expansions to transport capacity into Dawn and from Dawn to Parkway would be required.

Potential End States

We have identified three broad options. Within each, however, there can be variations.

Option 1. The *Status Quo*

This approach recognizes that the LDCs invested in and developed existing storage under cost-of-service regulation. This approach would keep the in-franchise and ex-franchise treatment of storage pricing. While future developments could cause current policies to be reexamined, the *status quo* approach is consistent with a wait-and-see regulatory strategy, where regulators come to the conclusion that the current arrangement does not need fundamental repair at this time. Even though the current system is inefficient, unfair, and not transparent, most customers like the current low price of storage. Major changes to the system would most likely be in anticipation of potential problems to come (e.g., large power generation gas load). Thus, the *status quo* option is inherently a reactive, rather than proactive strategy.

This approach could nevertheless recognize a role for independent storage. Ontario could take steps to make it easier to regulate independent storage operations and to improve their access to the gas system. This would also require a review of transportation tariffs to ensure non-discriminatory treatment of transport into and out of independent storage services. It would also include reviewing the role of unregulated affiliates in marketing storage and also managing the LDC storage assets.

In this option, the load balancing offering would also be expanded to include intra-day balancing options that could be used by power generators and other primarily large industrial users. These services would also allow for multiple nominations within the day, allowing the storage injection and withdrawal schedules to be modified. It would also provide for the LDC publishing available capacity to meet this service and managing linepack to address timing issues (although the services could have timing constraints built into them).

Option 1b. Structural Separation/ Separate Division

A possible variation on Option 1 would be the separation of storage assets to a division within the utility that is independent of the downstream distribution activities. This option would avoid the requirement for the determination of fair market value for the storage assets for legal and tax purposes, and continue the present regulatory oversight used for the integrated storage and distribution operations.

The advantage of this structure would be to clearly identify and account for all transactions for storage both from system gas and from other marketers. Storage rates would be separately regulated and could be shown as a separate charge on customers' bills. This structure also would delineate the load balancing options set out in Option I. Code of Conduct rules would govern the relationship of unregulated affiliates in marketing the use of storage. The separation of the assets to a division would require a clear segmentation of the cost associated with the management and operation of these facilities. In order to minimize any increase in cost, some allocation of management time and overhead cost would be required. These allocations could be reviewed periodically by the OEB through their rate making practices.

Option 2. Market Based Storage with Divestiture

Full divestiture would be consistent with a full LDC exit from the system gas business, but it is not necessary[7]. Under this approach, LDCs would either sell off their storage to independent storage operators or transfer storage to un-regulated affiliates. The proceeds from the sales would be split between shareholders and rate payers. Thereafter, storage would be priced at market-based rates and not be differentiated for both in-franchise and ex-franchise customers. These market rates would send efficient price signals to consumers of storage and would automatically internalize market trade-offs between storage and interruptible demand (interruptible consumers need less storage). Buyers of storage would be direct purchasers of gas (including electric power generators) and marketers.

Should the LDCs remain in the system supply business, however, they would be required to purchase storage to meet the system gas needs. Some residual storage would also be required to remain with the LDC to ensure system integrity. This storage could be purchased through contracting and would help manage diurnal profiles in load; mitigate marketer and customer forecast error; mitigate delivery imbalances from upstream transportation; and address timing of flows within the provinces' transport and distribution systems. Imbalances would be penalized so that all parties have appropriate incentives to resolve imbalances quickly. Customers purchasing gas directly, marketers, or in the case of system gas, the LDC, would be responsible for managing their imbalances and storage volumes on a day-to-day basis and could receive significant penalties for not managing their balances appropriately. Preferential access to storage would only be required during situations where system security would be threatened.

[7] Full divestiture of storage assets and removal of LDCs from the system gas function are both moves toward a system operator role for LDCs and a fully unbundled competitive market.

In other markets, such as Victoria, Australia, marketers aggregate customer load, contract for supply, transportation, and storage, and manage both the daily forecasting and bidding requirements in the market as well as settlements that occur daily and monthly. In Victoria, market participants must clear their imbalances daily. In the U.S., the process varies considerably with most markets requiring at minimum, balancing monthly, but with many having daily and in some cases hourly requirements.

Asset planning and management of the daily processes does require sophistication and an operational staff making aggregation attractive to customers as a service and to marketers as a business opportunity. In the U.S. markets, larger consumers and marketers own their own storage or contract for storage and manage this storage on a daily basis. The U.S. has seen significant increases in privately developed storage and all storage in Victoria, Australia were and are being privately developed.

All users of storage would be required to pay the same transport and distribution tariffs, which could vary, based on location and type of service. The purchasing of storage by LDCs from either independents or regulated affiliates would need to be structured in such a way as not to provide unfair advantages to unregulated affiliates.

The option would need to be supplemented with a careful analysis of the storage market after divestiture. Currently, the storage in Ontario is dominated by Union and Enbridge with Union holding the majority of the excess storage capacity. Any divestiture or shift to an unregulated affiliate would need to be accompanied by rules governing concentration of the assets.

This option would also include the same flexible balancing service for large users (primarily power generators and large industrial users) as proposed in Option 1.

Option 3. Mixed or Hybrid Solution:

A hybrid approach would be aimed at reserving cost of service for small customers and market-based storage for large, more sophisticated customers and for new customers generally. This approach is intended to avoid a situation where large new in-franchise electric power loads that impose incremental costs on the system would benefit from COS storage rates and be subsidized by current system customers. This approach would also gradually retire COS storage and convert it to market-based storage.

Existing COS based storage that is needed to meet grandfathered load is kept at COS rates offered by the LDCs. All storage that is surplus to grandfathered load requirements would be auctioned to unregulated LDC affiliates or to new independent storage operators. (Proceeds from the sales could be split between shareholders and customers through rate adjustments.) Marketers, who supply grandfathered load, would receive an allocation of COS storage, which the LDC would continue to operate. All storage needed to meet new customer growth would be priced at market and offered by LDC unregulated affiliates or by independent storage operators. Where the LDCs experience load growth from existing, grandfathered customers, which would require additional storage capacity, such capacity would have to be acquired on the open market. When grandfathered load leaves the system, the storage dedicated to that load potentially could be reallocated to the non-COS storage services, if the practical difficulties of this approach could be worked out.

A key aspect of this approach would be the encouragement of new independent storage operators to enter into the Ontario storage market. Buyers of non-grandfathered storage would have a choice among storage providers. Marketers would be free to bundle independent storage with delivery service on the LDC.

The LDC would have to retain some storage to support system management. This could remain at COS rates.

Implications of End States

Maintaining the *status quo* recognizes that LDCs have developed existing storage under a pricing regime that guaranteed the recovery of costs and a fair return on investment. Under this regime, the original storage investment has been greatly depreciated, such that today, rates are below the long run replacement cost of storage services. The major issue facing decision makers with respect to storage is whether this situation is sustainable in the face of a growing presence in the market for gas-fired power generation specifically and a general growth in demand for storage services. At present, there has been little demonstration that the current arrangement needs to be altered, except from would be providers of new storage services and from the current sellers of this under priced resource.

In considering the *status quo,* regulators will have to address fairness and efficiency considerations. Should the current system treat all customers of similar characteristics the same (it does not where market-based storage is sold by one LDC for in-franchise uses in a second LDC)? Looking ahead, how will the current system operate to meet new demands on storage services? Are the price signals present to make correct investments?

Changes in the *status quo* should be aimed at encouraging new storage services, whether offered by the LDCs or by new storage operators. A two-tier hybrid pricing approach (COS and market based) could encourage new suppliers of storage while maintaining the current system for small customers. This new storage service could originate in Ontario or in Michigan with transportation rights. There is no reason why market based storage cannot coexist with COS storage as long as the regulators can develop guidelines to protect against the use of market power.

Full divestiture would be consistent with full LDC exit from the system gas business. This may not have to be the case, where the LDC retains through an affiliate a marketer function or retains a core system supply service. The key would be that storage services would be offered on a similar basis to all users – LDC system supply function, marketers, direct purchasers, electric generators. A corollary to this competitive system would be to allow a secondary market for storage. Any divestiture would have to be accomplished through an auction, with some agreement on the distribution of the benefits of the sales.

Below we present some criteria for evaluating the proposed end states. This is followed by a straw man ranking of the end states in the interest of furthering discussion in the Natural Gas Forum.

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

Exhibit 5. Evaluation of Options

Criteria	*Option 1* Status Quo	*Option 1b* Structural Separation	*Option 2* Market Based with Divestiture	*Option 3* Hybrid Solution
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

Determining the optimal policy choice for storage is ultimately a matter of trade-offs. Examining the table above it is clear that the trend to achieving higher efficiency, transparency, and flexibility requires market disruption. The market-based system with divestiture offers a long-term solution for storage since it sends the most efficient price signals and is adaptable to changing market dynamics. Given Ontario's push to add new power generation capacity, making some movement towards market-based storage may be advisable.

On the other hand, COS storage is cheap in Ontario and the shift to market-based storage would be disruptive; this may account for the lack of consumer stakeholder interest in a change from the current system. The *status quo* option may be preferable if minimizing disruption is a higher priority than maximizing efficiency, especially given how abundant storage is in the Ontario market.

Taking a hybrid approach would reduce the disruption, while sacrificing some efficiency and requiring continued regulatory oversight. Overall, however, the hybrid approach anticipates the changing dynamics in market.