ONTARIO ENERGY BOARD

NATURAL GAS ELECTRICITY INTERFACE REVEW
EB-2005-0551

DIRECT EVIDENCE
of
MARK P. STAUFT

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I. INTRODUCTION AND OVERVIEW

Q. Please state your name and identify the parties that are sponsoring your testimony in this proceeding.

A. My name is Mark Stauft. The organizations that have retained me in these proceedings are: the Industrial Gas Users Association, the Association of Major Power Consumers in Ontario, the Consumers Council of Canada, the Vulnerable Energy Consumers Coalition, the Schools Energy Coalition, the City of Kitchener, and the Canadian Manufacturers and Exporters Inc., hereinafter referred to as the "Sponsoring Parties".

Q. Please describe your qualifications and experience.

A. A summary of my qualifications and experience is set out in Appendix 1.

Q. What is the purpose of your testimony in this proceeding?

A. The Sponsoring Parties have asked me to consider and provide my views on the storage-related issues that the Ontario Energy Board ("Board") has indicated it wishes to examine in this proceeding. In responding to that request in this evidence, I analyze and provide my views on the general issue of whether it would be appropriate for the Board to refrain, in whole or in part, from regulating the rates charged by Union Gas Limited ("Union") and Enbridge Gas Distribution Inc. ("EGDI") (collectively, the "Utilities") for gas storage services provided by the Utilities. That issue turns primarily on the question of whether, as against Ontario consumers, the Utilities have market power in relation to storage services.

I also analyze and make recommendations in relation to issues around whether, and on what terms, it would be reasonable for the Board to depart from a traditional cost of service approach for the purpose of regulating storage rates, either in relation to certain classes of customers or certain services, if my conclusion is that the Utilities have market power in the storage services market in Ontario. This testimony sets out my analysis and conclusions in relation to these issues.

Q. Please summarize your conclusions.

A. As an initial matter, I discuss certain issues around the interrelationship between storage prices and bundled utility sales and transportation services. My conclusion in relation to those issues is that before the storage services components of the bundled services EGDI and Union provide to their customers can be priced at anything other than cost, customers who utilize those bundled services must have available to them unbundled services that are comparable in terms of both quality and cost to the bundled services that they currently purchase from EGDI and Union. Since this situation does not currently exist for either Union or EGDI, there is no principled basis upon which the charges for the storage services component of bundled services can be anything other than cost-based charges at this time.

As to whether, as against Ontario consumers, the Utilities have market power in relation to storage services, my conclusion, based on the empirical evidence that is available and an application of the standard framework for analyzing market power issues, is that the Ontario Utilities have significant market power in the storage market. As a general matter, it would therefore not be appropriate for the Board to refrain in whole or in part from regulating the Utilities' storage prices.

With respect to the question of whether it would nevertheless be appropriate to allow market pricing of storage services for some classes of customers, in spite of the fact that the Utilities have significant market power in relation to storage, I do not see any rational basis for distinguishing between different classes of customers with respect to whether they should be charged cost-based or market rates for storage services. However, I believe that a reasonable argument can be made that, in relation to non-renewable short-term (i.e. one year or less) storage services, it would be appropriate to continue something similar to the current regime, under which the Utilities are allowed to charge market prices for such services, with revenues in excess of costs credited to the Utilities' revenue requirements in a manner determined by the Board.

Q. How is the remainder of this evidence organized?

A. The remainder of this evidence is organized into six Parts. Part II describes in detail the issues to be addressed, and discusses in general terms the conceptual framework that is applicable.

Part III discusses issues related to bundled Utility services. Any regulatory forbearance in relation to storage prices would have implications for the pricing of bundled services, and Part III discusses those implications.

Part IV examines the implications of observed market prices for storage in relation to market power issues.

Part V deals with the application of the conventional market power analysis framework to the facts in this case.

Part VI addresses issues related to possible mechanisms under which some customers would be entitled to cost based rates for storage, while others would be charged market prices for storage.

Part VII briefly addresses issues related to storage development.

II. <u>ISSUES, BACKGROUND, AND CONCEPTUAL FRAMEWORK</u>

A. <u>Definition of Issues</u>

Q. How has the Board formulated the issues related to the regulation of storage that you are addressing here?

A. In its December 29, 2005 Notice of Proceeding under file EB-2005-0551 the Board indicated that it has commenced this proceeding on its own motion to determine, *inter alia*:

> *"whether to refrain, in whole or part, from exercising its power to regulate the rates charged for the storage of gas in Ontario by considering*

> *whether, as a question of fact, the storage of gas in Ontario is subject to competition sufficient to protect the public interest."*

In Procedural Order No. 1 issued January 24, 2006 the Board set out the issues that it wishes to examine in relation to storage in more detail, as follows:

> *Should the Board refrain, in whole or part, from exercising its power to regulate the rates charged for the storage of gas in Ontario? In making this determination, the Board will have regard to a number of considerations, including:*
>
> 1. *Do gas utilities (and/or their affiliates) either collectively or individually have market power in the provision of storage services for all or some categories of customers in Ontario?*
>
> 2. *If gas utilities (and/or their affiliates) do have market power in storage, is it appropriate for them to charge "market rates" for transactional and long term storage services?*
>
> 3. *If gas utilities (and/or their affiliates) do not have market power, is it in the public interest that all or some customers continue to pay storage rates at cost as opposed to market rates? How should the extra revenue from storage services at market rates be allocated?*
>
> 4. *If the Board determines, based on considerations of market power and the public interest more generally, that some customers should pay for storage services at cost and others should pay for storage services at market prices, how should the line be drawn between the two types of customers, and, specifically, should there be a constraining allocation of physical storage facilities to some types of customers based on measures such as aggregate excess or whether customers are considered "in-franchise" or "ex-franchise"? How should the extra revenue from storage services at market rates be allocated?*

B. Market Power and the Need for Regulation

Q. Please explain what market power is and discuss the relationship between that concept and the regulation of utilities.

A. Market power is normally defined as the ability of a firm to profitably increase the price of its product above the competitive level for a sustained period. The exercise of market power can lead to distributional effects that society regards as unfair, and to inefficient uses of resources. Under competitive conditions, the market price of a product is determined by the interplay of market forces at a level that reflects, roughly speaking, the cost of producing the product, including a market return on capital employed in the production process. Firms that face effective competition are unable to increase the prices of their products above that level on a sustained basis because if they attempt to do so other firms will compete their customers away, with the result that the firm attempting to charge an above-market price will ultimately reduce its profit rather than increase it.

Market power therefore arises where a firm faces few or no effective competitors, and where customers therefore do not have adequate competitive alternatives to the firm's product. It is often associated with industries that are "natural monopolies", i.e. industries in which unit costs decline continuously over a wide range of output levels, relative to the market demand curve, and in which the most efficient organization of the industry therefore involves a single firm. Market power can also arise as a result of other barriers to competitive entry, e.g.

governmental or regulatory restrictions on entry. Utility industries are usually thought to exhibit natural monopoly characteristics.

Q. Is economic regulation of certain industries a response to the potential exercise of market power?

A. Yes, especially for industries, like the utility industry, whose natural monopoly character implies that the most efficient organization of the industry involves very few firms. With economic regulation that benefit can be preserved, while at the same time prices and output levels can be made to reasonably reflect the efficient levels that would be seen if the industry were competitive. Economic regulation is therefore commonly referred to as a substitute for competition, with its goal being to replicate, as closely as possible, the pricing and output results that would be observed if the industry in question were competitive. In the North American utility context, the relevant statutes usually require the regulator to ensure that rates are "just and reasonable" and "not unjustly (or 'unduly') discriminatory". The typical approach to achieving that goal is to prescribe "cost-based" prices for utility services, which involves setting prices at a level that is calculated to recover for the utility its costs of providing service, including a "fair return", which is usually conceived of as reflecting the firm's risk adjusted cost of capital.

Q. The Board's list of issues suggests that it is considering refraining from exercising its power to regulate the prices of storage services provided by the Utilities. What would refraining from exercising a power to regulated storage rates involve, in your view?

A. I am assuming that the Board is considering whether it would be in the public interest for it to completely withdraw from its role of supervising the prices charged by the Utilities for all, or possibly some, of their storage services. If the Board did that, the Utilities would be entitled to charge whatever prices for storage services they considered would be profit-maximizing from their perspective, subject to laws of general application like the *Competition Act*. In what follows I will refer to prices or rates charged by the Utilities on that basis as "market rates" or "market prices".

Q. If the Utilities are allowed to charge market rates for all of their storage services, would you expect them to assume all risks associated with the costs that they incur for the purpose of providing storage services?

A. My assumption is that if the Board elected to refrain from exercising its power to regulate storage rates, all storage related costs would be eliminated from the Utilities' revenue requirements, and all storage revenues and associated returns would be retained by the Utilities.

Q. If the goal of regulation is to replicate the pricing and investment outcomes that would be seen under competitive conditions, what purpose would be served by the Board refraining from exercising its regulatory powers in relation to storage, or any other utility service?

A. Although the goal of utility regulation is generally to replicate competitive outcomes, it is unlikely to be a perfect substitute for effective competition. There are incremental costs involved with adopting economic regulation as a response to market power. The regulatory process itself involves certain costs, for example, although those may be minor in comparison to the total costs of the regulated entity. Regulators can make mistakes in relation to utility costs that have some inherent uncertainty associated with them, e.g. cost of capital, or appropriate depreciation rates. Traditional rate-base, cost of service regulation may create incentives for over-investment in capital equipment, and may fail to create appropriate incentives for efficient behavior in relation to operations and maintenance expenditures, for example. Utility regulatory regimes typically restrict market entry by potential competitors, e.g. through the granting of franchises or the restrictive exercise of certificate jurisdiction, which may prevent or inhibit technological or service-related innovation. The mechanics of maintaining prescribed prices and enforcing non-discrimination requirements may prevent regulated utilities from responding as flexibly as competitive firms would to customer needs in relation to service attributes and pricing structures.

Given the potential for these costs to exist, it is reasonable to suggest that, if regulation can be shown to be unnecessary in a given case, because without it customers would continue to pay just, reasonable, and not unjustly discriminatory rates purely as a result of the operation of market forces, then there will be a net benefit to society from ceasing to regulate the firm or service in question.

C. Framework for Analysis of Market Power

Q. Given this background discussion, what standards ought to be applied in determining whether, in relation to storage services offered by the Utilities, it would be appropriate for the Board to refrain from regulating the rates for those services?

A. My understanding is that the explicit granting of forbearance power to the Board is a relatively recent development, and that the Board has never had occasion to consider whether it should refrain from exercising its regulatory powers. The statutory standard is set out in s.29(1) of the *Ontario Energy Board Act 1998* ("OEB Act") as follows:

> On an application or in a proceeding, the Board shall make a determination to refrain, in whole or part, from exercising any power or performing any duty under this Act if it finds as a question of fact that a licensee, person, product, class of products, service or class of services is or will be subject to competition sufficient to protect the public interest. (1998, c. 15, Sched. B, s. 29 (1)).

This provision appears to leave the Board with considerable discretion in relation to the circumstances in which it can lawfully find that a particular service, e.g. in this case gas storage service, is subject to competition "sufficient to protect the public interest".

In the absence of previous decisions from the Board on this topic, it is useful to consider the standards applied by other regulatory tribunals when they have been faced with questions about whether they should forbear from regulating particular firms, facilities, or services. In Canada, the Canadian Radio and Telecommunications Commission ("CRTC") has, and has exercised, a forbearance power similar to the Board's in relation to the CRTC's regulation of telecommunications companies. In the U.S., the Federal Energy Regulatory Commission ("FERC") has jurisdiction to allow interstate pipelines (including storage operators) under its jurisdiction to charge what the FERC refers to as "market based rates". Although as a technical matter the FERC's practice of allowing some firms to charge market based rates is slightly different from the forbearance power that is explicitly provided for in s.29 of the OEB Act, the economic and practical result is generally the same.[1]

For both the CRTC and the FERC the basic test for whether it is appropriate for the agency to refrain from exercising its rate-making power in relation to a particular service or set of services is whether the firm that provides the service will be able to exercise market power in relation to it. Although there may be nuances to this in particular cases, the basic rule is that if the firm is able to exercise market power in relation to the service, the CRTC will not refrain from exercising its regulatory powers, and the FERC will not grant the firm market based rate authority. At the FERC, the burden is on the applicant for market based rate authority to show that it lacks market power.

Q. Is there an established framework for evaluating whether a firm has or will be able to exercise market power?

A. Yes, at least in general terms. Both the CRTC and the FERC have explained in some detail the analytical models that they will apply when considering

[1] When the FERC grants market based rate authority to an applicant I do not understand it to be in any sense relinquishing its jurisdiction to regulate the applicant, and it clearly retains jurisdiction to condition its approvals in any way it thinks appropriate, maintain reporting requirements, entertain complaints under s.5 of the Natural Gas Act with respect to the rates charged by the applicant, and generally to perform all of the functions that it is authorized by the Natural Gas Act to perform.

forbearance questions or applications for market based rates[2]. Although the approaches differ in their details, they are in substance very similar. I believe that it is fair to summarize the basic inquiry that is undertaken by both agencies as being directed to determining whether purchasers of the service in question will have available to them, within a reasonably short time, alternative products or services that are available in sufficient quantities, are priced low enough, and that are of sufficiently similar quality, that the ability of those customers to switch suppliers will prevent the firm in question from increasing its price relative to the regulated level by a significant amount for a sustained period.

As a means of organizing this overall inquiry, both agencies have described essentially a three-step process. The first step is to define the relevant market, in terms both of the relevant product market, and the relevant geographic market. The relevant product market is the set of products available in the market that are good substitutes for the price-regulated product for which forbearance is being sought. The relevant geographic market is, roughly, the geographic area within which alternative products are available and in which the regulated product competes.

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[2] See "Review of Regulatory Framework", Telecom Decision CRTC 94-19, September 16, 1994 and "Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines" (1996), 74 F.E.R.C. P61,076 ("Rate Design Policy Statement")

The second step in the process is to conduct an analysis of market concentration in the relevant product and geographic markets. A highly concentrated market, i.e. a market in which there are few sellers, tends to suggest that firms operating in that market have market power, with the most extreme case being the situation in which a single firm is a monopolist, i.e. has no competitors at all. This analysis involves consideration of both the applicant's own market share, which is an indicator of its ability to increase the price of its output acting on its own, and also the overall number and market shares of the firms in the market, which is an indicator of the applicant's ability to increase price acting in concert with others. This step is essentially a "screening" exercise, in that where a low market concentration is found that is normally good evidence that the applicant lacks market power, whereas where the market is highly concentrated that fact suggests the existence of market power and indicates the need for closer scrutiny.

The third stage in the analysis is referred to by FERC as a consideration of "other factors", of which the most important is the ease with which competitors can enter and exit the market. Even in a highly concentrated market the incumbent firms may not be able to exercise market power if new competitors will be able to enter the market with good alternatives to the applicant's product quickly and at comparable cost. In that case, just the threat of market entry by effective competitors may be sufficient to prevent the applicant and the other incumbent firms from exercising market power, since they will know that any attempt to do so will be met with a strong competitive response and, as a result, a significant loss of revenues and profits.

Q. As you have described it, this three-step framework for analyzing market power appears to involve a number of qualitative judgments and measures. Have the two tribunals attempted to establish measurable, quantitative standards for determining whether a firm does or does not have market power?

A. Both the CRTC and the FERC have established guidelines for some of the parameters involved in the overall analysis, but even where that has been done they typically emphasize that these are only guidelines, and that ultimately the agency will consider all of the facts together in making its decision. There is no "bright line", mathematical test for market power.

In Part V below, where I discuss in more detail the application of the prospective analytical framework that I have described to the facts in this case, I will also discuss some of the quantitative measures, and threshold values for those measures, that are typically considered by the agencies. However, there is one quantitative issue that is critical to the proper analysis of the issue in this case, and that it is therefore appropriate to discuss at this point.

Q. What is that issue?

A. As I have expressed it, the definition of market power involves the firm in question being able to "significantly" increase the price of its product above the "competitive level". This somewhat vague language raises the question, first, of what we mean by the "competitive level" and, second, the question of what will constitute a "significant" increase relative to that level. For a regulated firm that is seeking relief from price regulation, there is no observable "competitive" price level for its product, because its prices are set by the regulator rather than by a competitive market. With respect to the question of what will constitute a "significant" price increase, the language that I have used assumes that there is some flexibility in relation to determining whether any predicted or possible price increase, relative to whatever we determine the "competitive level" to be, is acceptable. Both of these concepts require further definition.

Q. In this context, how are the "competitive level" and a "significant" price increase normally defined, and how in your view should they be defined for the purposes of this proceeding?

A. In its Rate Design Policy Statement[3] the FERC established a 10% threshold for expected price increases in cases where a pipeline is seeking market based rate

[3] See footnote 2.

authority, stating that "[t]he Commission believes that if a company can sustain an increase in its rates in the order of 10 percent or more without losing significant market share, the company is in a position to exercise market power to the detriment of the public interest."

It is clear from the discussion leading to that conclusion that the maximum permissible price increase that the Commission has in mind is an increase *relative to* the company's cost based regulated maximum rates. It is also clear from that discussion that the Commission believes that the level of price increase that a company can sustain relative to its cost based rates is a direct function of the cost of the competing services that are identified as potential alternatives to the company's service. This is the economically correct analysis, because it is the cost of the available alternatives that constrains the price that can be charged by the utility. If a customer is presented with a utility's proposed market rate, it will accept that proposed rate, regardless of whether the rate is higher than the utility's cost-based rate would be, as long as the proposed rate is marginally lower than the cost of the customers' next best alternative. The all-in cost of the competing alternatives is therefore a direct determinant, and a good predictor, of what a utility's market rates will turn out to be.

In my view, something like the FERC's approach, under which alternatives are evaluated with respect to whether they are a "good alternative" in terms of cost by reference to whether their cost is at most some modest premium to the utility's cost-based regulated rate, is entirely appropriate. Such an approach is consistent with the purpose of regulation, which is to protect the public from exploitation at the hands of utilities that possess market power, and with the rationale for potentially refraining from exercising that regulatory power. The purpose of regulation is to ensure that the prices of utility services are constrained to a just and reasonable level, which most jurisdictions define as the cost-based level. Just and reasonable rates at a cost-based level replicate as nearly as practicable the market result that would be seen under competitive conditions, i.e. in the absence of market power. The major premise of forbearing from regulation in any given case is that regulation is *unnecessary* in that case because competition will be effective in constraining utility prices to roughly the same level as the just and reasonable regulated level. A policy that allowed expected price increases with forbearance of 30%, 50%, or 100%, relative to the cost-based level, would be inconsistent with that premise.

Q. In general terms, is it instructive to consider CRTC and FERC decisions related to regulatory forbearance and applications for market based rates in the context of this proceeding?

A. Although the statutory regime to which the CRTC is subject resembles the Board's more than the FERC's does, my view is that the factual circumstances that arise in CRTC cases are sufficiently dissimilar from the factual circumstances surrounding gas storage in Ontario that CRTC decisions are not helpful for these purposes at anything other than the most conceptual level. FERC decisions on applications for market based rates for storage facilities, however, address essentially the same issues that the Board is addressing in this proceeding.

Q. Can you describe in general terms the types of applications the FERC has received for market based rate authority in relation to storage, and what decisions it has made?

A. Most of the applications for market based rate authority for storage services that the Commission has received relate to new, relatively small-scale storage developments in areas where significant storage infrastructure already exists. In the Ontario context, these would be analogous to applications for market rates by independent developers of new and relatively small storage facilities in Ontario. The FERC has approved such applications more often than not. As far as I am aware, however, the Commission has not received, much less approved, applications for market based rate authority for large-scale market area storage facilities owned by the large interstate pipelines like ANR Pipeline Company, Natural Gas Pipeline Company of America, Dominion Transmission, or Transcontinental Pipeline, for whom storage facilities are a major part of their transportation undertaking. In the Ontario context those would be analogous to the Utilities' storage facilities. I assume that none of those interstate pipelines has even applied for market based rate authority for their storage services because they know that the FERC would not grant it in their circumstances.

III. ISSUES RELATED TO BUNDLED SERVICES

A. Definition of Bundled Services

Q. What are "bundled services"?

A The term "bundled services" refers to Utility services provided directly to end-use customers that are in substance a combination of services provided using discrete sets of utility assets. For example, the Utilities provide residential and small commercial customers with conventional utility gas sales service. Under that service the customer simply receives gas supply delivered to its facilities in response to whatever its requirements happen to be, and pays a prescribed rate for that delivered gas. In order to provide sales service, however, the Utility performs a number of functions, utilizes a number of different assets, and effectively provides in "bundled" form a number of different services. As part of the Utility sales service, the Utilities provide gas, first of all, that they purchase in the market, and that they may transport on upstream pipeline systems. The Utilities also provide, as part of gas sales service, pure distribution service using the distribution pipelines that they own, and storage service using the storage assets that they own.

B. Bundled Services and Market Power

Q. Why are bundled services relevant to issues related to the market power of the Utilities in the storage market?

A. Suppose that we assume, for the purposes of this discussion, that the Utilities do not have market power in relation to storage services. A finding that the Utilities lack market power in relation to storage entails a finding that there are competitive alternatives to Utility-owned storage that are available in sufficient quantities, at a sufficiently low cost, and that are of sufficiently high quality, that customers can switch to those alternatives if the Utilities attempt to increase their storage prices above a just and reasonable level. Those alternatives, however, are necessarily available to customers only at the inlet to, or upstream of, the Utilities' distribution systems, and it is only at such points that the competitive market for storage, if it exists at all, will be found.

Even if we can satisfy ourselves that a firm lacks market power in relation to one product on a "stand-alone" basis, e.g. that the Utilities lack market power in the market for storage at the inlet to their distribution systems, the firm will nevertheless still be able to exercise market power in relation to that product if the product is a necessary component of, or is otherwise tied to, some other product in relation to which the firm does have market power.

To illustrate that principle in the context of storage and bundled Utility services, consider what the practical implementation of a decision by the Board to refrain from regulating storage rates would involve. There is no suggestion, as far as I am aware, that the Utilities lack market power in relation to distribution services, including, for example, city-gate "bundled T" arrangements. Under such arrangements, customers or their agents are obliged to deliver to the Utility, at the Utility city-gate, a daily quantity of gas equal to the customers' annual average daily usage. The Utility then takes that supply and effectively provides seasonal storage service to the customer by injecting a portion of the delivered daily quantity into storage during off-peak periods and then withdrawing the stored gas from storage and delivering it to the customer during later peak periods. The Utilities charge a single, regulated, bundled rate for the overall service.

If the Utilities are allowed to charge market rates for the storage service that is embedded in their sales and bundled T services, the practical result will be that the Utilities will be able to set the price of the overall bundled service at whatever level they choose, i.e. they will be able to charge market rates for those services as well as for storage. While the Board will presumably continue to prescribe the components of the bundled rates associated with, e.g. pure distribution service, the fact is that the Utility will be able to set the overall rate for the bundled service at whatever profit maximizing level it chooses by adjusting the amount of the storage component, over which it has sole control. In practical terms, if the Board refrains from regulating prices for storage services, it will also refrain from regulating prices for bundled services that involve storage.

As long as the Utility has market power in relation to bundled services, which *prima facie* it does since no one else can provide bundled service to customers in the Utilities' respective franchise areas, it will be able to use that market power to extract an above-cost price for the storage component of the bundled service, *even if* it would be unable to extract an above-cost price for unbundled storage service provided at Dawn.

C. Requirement for Comparable Unbundled Services

Q. Given that no other party can provide distribution service to customers in the Utilities' respective franchise areas, how can this difficulty be avoided?

A. In order for the market prices charged by the Utilities for bundled services, if the Board refrained from regulating storage rates generally, to be constrained at a just and reasonable cost-based level customers must have an alternative to the bundled service that is priced on a cost basis. The only possible alternative is "unbundled" services provided by the same Utility.

Faced with market rates for bundled sales and delivery services, the only way a customer can assure itself that gas will be delivered to its facilities at a just and reasonable cost-based price is to separately purchase storage service at the inlet to the Utility system (which we have assumed for these purposes will be priced at a just and reasonable level as a result of competition in the storage market) and combine it with pure distribution service provided at a regulated cost-based price. Where the bundled service in question is a sales service, the customer must also be able to obtain an adequate gas supply as a substitute for the Utilities' supply.

Q. Are there conditions that must be satisfied in order for the unbundled alternative to provide an effective constraint on the Utilities' pricing of bundled services?

A. Yes. At a minimum, in order for unbundled services to provide an effective constraint on the Utilities' market prices for bundled services, the unbundled services must be equivalent in quality to the bundled service, and must be equivalent in cost to the bundled service, assuming that the bundled service is priced in a way that reflects competitive prices for storage. Note in particular that the relevant "cost" for the unbundled service includes *all* of the costs incurred by the customer in using the unbundled service, including whatever costs are associated with contracting for and managing the unbundled services on a day to day basis, and any expected costs arising from, for example, daily balancing charges under the unbundled distribution service in cases where deliveries differ from nominated amounts. Stated in very general terms, the minimum condition for unbundled services to provide an effective constraint on the Utilities market power in relation to bundled services, and therefore the minimum condition for allowing the Utilities to charge market rates for storage services embedded in bundled services, is that the unbundled services must be "comparable" to the bundled services in all significant respects.

Q. Do the Utilities offer suitable and comparable unbundled services now?

A. My understanding is that EGDI does not offer fully unbundled delivery services at all. As far as I am aware neither of the Utilities offers any form of unbundled gas commodity sales service. An unbundled sales service would involve the Utilities supplying gas to customers, at a cost-based rate, at the inlet to the Utilities' systems. Unbundled customers who wished to remain sales customers of the Utilities would then combine that supply delivered at the city-gate with unbundled storage purchased from the Utilities, or their competitors, and unbundled distribution service. If "comparability" is to be a condition of allowing market rates for storage, it could be argued that the Utilities must be forced to develop and provide cost-based city-gate sales services, in order to ensure that customers who want to purchase gas from the Utilities will be able to do so without having to use bundled transportation arrangements.

With respect to pure delivery services, it is my understanding that Union currently make unbundled storage and distribution services available for most of its customer classes, other than sales customers. However, it is also my understanding that very few, if any, general service customers actually purchase those services. This is strong evidence that the bundled and unbundled services are not comparable, and in fact that the unbundled services that do exist are inferior to the bundled services in some respect, e.g. they are of inferior quality, or (perhaps more likely) they have a higher all-in cost once all cost factors are accounted for.

Q. In general terms, what would be involved in demonstrating that existing or proposed unbundled services are comparable to the available bundled services?

A. To begin with, it must be recognized that in an environment where they were allowed to charge market rates for their storage services the Utilities would have an incentive to ensure that their bundled and unbundled services are not comparable, and in fact that unbundled services are less valuable than bundled services. The amount by which the value of bundled services exceeds the value of unbundled services, from the customers' perspective, is, in principle, the amount by which the Utilities will be able to increase the price of the storage component of the bundled services above the competitive level, even if the storage market is competitive upstream of the Utilities' systems. Given the Utilities' familiarity with their systems and costs, and their potential ability to affect the value of services simply through their day-to-day operating practices, it may be very difficult for the Board or interveners to establish comparable services.

Another important point here is that a part of the all-in cost of using unbundled services is likely to be costs incurred directly by the customers, in the form of additional management and administration costs and added risks associated with, for example, balancing charges. These may be different for different customers, and may be difficult to quantify. Moreover, the fact that those costs are not included in the Utilities rates means that, in order for bundled and unbundled services to be comparable on an all-in basis from the perspective of customers, the Utilities' unbundled services would have to be priced at a discount to their bundled services, with the discount being equal to an estimate of the additional customer costs associated with using unbundled services. This may be problematic from the perspective of preventing unjust discrimination, particularly if the Utilities could show that in fact it is more costly from their perspective to provide unbundled services than bundled services.

IV. OBSERVED MARKET PRICES AS EVIDENCE OF MARKET POWER

A. Relevance of Observed Market Prices

Q. Returning to the issue of whether the Utilities have market power in the upstream wholesale storage market, you have characterized the market power analyses conducted by the FERC, for example, as "prospective". What do you mean by that?

A. The FERC's market power analyses are directed at predicting, before the fact, whether an applicant will be able to exercise market power if it is permitted to charge market based rates for some service that it provides. If market based rates are approved, the Commission will be in a position to observe in the market whether the prediction arising from the before-the-fact analysis was correct, but at the time the analysis is done there is no direct market evidence of whether the applicant has market power.

B. Level of Observed Market Prices

Q. In the present case, do we have direct market evidence of whether the Utilities have market power in the wholesale storage market?

A. Yes we do. Under the current regime a portion of the storage capacity owned by the Utilities, especially Union, is not required for their in-franchise uses and is sold at essentially market rates to "ex-franchise" customers. My understanding is that, of the approximately 150 Bcf of storage capacity owned by Union, approximately 70 Bcf is sold under these market-priced arrangements. Of that 70 Bcf, approximately 42 Bcf is sold to other utilities, principally EGDI and Gaz Metropolitain ("GMi") under long term arrangements, while the remainder is sold under various arrangements to various third parties, including marketers[4].

Technically this scheme does not involve "market rates" as I have defined them, since in some cases I understand that there are upper and lower limits on the market prices that can be charged, the costs associated with the storage that is sold at market rates remain in the Utilities' regulated revenue requirements, and the revenues from such sales are accounted for and partially flowed back to system customers. Nevertheless, from the market's perspective the prices charged for these services are essentially unregulated, and provide very good evidence of

[4] See "Analysis of Competition in Natural Gas Storage Markets for Union Gas Limited", Energy and Environmental Analysis, Inc., October 28, 2004 (the "EEA Study"), at page 14. This study formed part of the record in the Board's Natural Gas Forum proceeding, and was referred to in the Board's final Natural Gas Forum Report ("NGF Report")

what the market result would be if the Board was to refrain from exercising its power to regulate storage rates generally.

Q. What market results have been observed with respect to the pricing of storage for ex-franchise customers?

A. Although precise data appears to be difficult to obtain, my understanding, and the general consensus, seems to be that the market price for Utility storage is, and has consistently been, considerably higher than the cost based rate that would otherwise be charged for those services. The Board's Natural Gas Forum ("NGF") Report suggested that the premium for market priced storage over the cost based rate is and has been in the range of 30% to 50%. My understanding is that most market participants consider that estimate of the market premium to be low, and I am informed that for the current year the market value of Utility storage sold at market prices under one-year arrangements is in fact a multiple of the cost based rate.

Further evidence of the extent of the market premium was recently provided by EGDI at the April technical conference in this proceeding. I am advised that at that conference EGDI indicated that under a long term market-priced arrangement that it recently entered into with Union the premium to a cost based rate is in the order of $0.50/GJ. As discussed below, such a rate probably represents approximately a 100% premium to the cost-based level.

In its response to Undertaking 16 given at the same technical conference Union explained its understanding of the economic basis for the determination of market prices for its storage, based on an analysis of prospective summer/winter gas price differentials. The illustrative example provided by Union resulted in a predicted market value of about US$0.97/MMBtu, which again reflects at least a 100% premium to the cost-based level.[5]

C. Implications of Observed Market Prices for Market Power Analysis

Q. Does this information constitute evidence that the Utilities, in particular Union, have market power in the wholesale storage market?

A. Yes, it is clear evidence of market power. As I have explained, the relevant test for market power should be whether the utility in question will be able to increase

[5] Although I agree with Union's analysis of market prices for storage being a function of forward-looking market area winter/summer gas price differentials, a complete analysis would recognize that those differentials are themselves a function of the cost and availability of storage capacity. For example, if the Utilities withheld a significant amount of storage capacity from the market winter/summer price differentials in the market area would increase dramatically, thereby driving up the "value" of storage on Union's analysis. Similarly, if there were excess storage capacity available in the market, the price of storage would be bid down, which would tend to compress the winter/summer gas price differential. It is also possible that if the storage business in Ontario were workably competitive, i.e. characterized by numerous small storage operators competing actively for market share, storage prices would reflect the cost of providing storage service as reflected in Union's cost-based storage rates, and the winter/summer price differential would reflect that cost as well.

its rates by something in the order of 10%, relative to its conventionally determined cost-based rates. In the present case, that experiment has been conducted, albeit on a smaller scale than if the Utilities had been allowed to charge market rates for all of their storage, and the market result was that the Utilities have sufficient market power to charge rates that are apparently at least 50%, and more likely 100%, higher than cost, even under long term arrangements. In my view that is unambiguous evidence that the Utilities have market power in relation to storage, and strictly speaking it is unnecessary to even conduct the type of prospective analysis that the FERC conducts when it attempts to predict whether a company will be able to exercise market power if it is given market based rate authority. There is no need to predict the result, since we already know what it is.

Q. Would the market power that the Utilities, and in particular Union, have in the wholesale storage market likely be less if they were allowed to sell all of their storage at market prices?

A. No. The most likely result, if the Utilities were allowed to charge market rates for all of their storage, would be average storage prices that are *higher*, and perhaps much higher, than the significant premium to cost that has been observed already.

Q. Please explain the basis for that conclusion.

A. Firms that have market power, even pure monopolists, are still subject to the demand curve for the product in question. With most products, different customers will value the product differently. Some will value it a great deal, and will be very insensitive to the price charged for it. Others will value it less, and will be much more sensitive to price. Some will not value it at all, and will not buy the product at any price. The familiar market demand function describes this range of consumer preferences, by showing the total amount of the product that will be purchased at any given price level. Demand curves typically slope downward, so that as the price of a product declines more customers are prepared to purchase it.

The storage customers that currently receive storage service (usually indirectly through bundled delivery services) at regulated rates are generally customers for whom storage is a critical input in order for them to be served with gas during the winter period. The primary use of storage in Ontario is as a seasonal load balancing tool, since the existing upstream pipeline infrastructure is not capable of meeting all peak season demands by itself, and the overall delivery system must be augmented with storage in order for all customers to be physically served with gas. The regulated storage customers that rely on storage for this seasonal load balancing service will tolerate very high storage prices because they need the service badly and there is no adequate substitute for it.

The marketers who purchase storage at market prices from Union at Dawn, on the other hand, do not have the same physical dependence on storage that captive distribution customers have, and are much more sensitive to price. In fact there will be a cap on the prices that such parties will be willing to pay for storage service, where the cap is roughly equal to the differential between summer and winter Dawn prices in the forward gas market, plus a small premium. That cap is an absolute limit on Union's ability to exercise any market power that it has over those customers. As against captive heating load distribution customers, however, that limit will be much higher, since those customers must have storage service, almost regardless of price. The potential for Union to exploit its market power in the storage market would therefore be much greater if it was able to charge market rates to heating load customers with highly inelastic demands, rather than simply to marketers who are much more price sensitive. We already know that Union is able to exercise market power as against its most price sensitive, least captive customers, and if was able to charge market rates to its most captive, least price sensitive customers the observed market prices for storage could only be higher than the premium to the competitive level that already exists.

V. PROSPECTIVE ANALYSIS OF MARKET POWER

A. **<u>Purpose of Analysis</u>**

Q. **Given the conclusion set out in Part IV, is it necessary or useful to conduct a conventional prospective analysis of whether the Utilities will be able to exercise market power if they are allowed to charge market rates for storage?**

A. While it may not be necessary to do so, I believe that it is useful to consider the conventional analysis because the result of that analysis is completely consistent with, and in fact predictive of, the market results that have been observed, and therefore with the conclusion that the Utilities have market power in relation to storage.

Q. **Have you conducted quantitative studies of what volumes of alternative storage are available, and the costs of that storage?**

A. While data on overall storage and transportation capacities is available, comprehensive and detailed information on contract levels, customer identities or descriptions, contract terms, un-contracted capacity, and applicable rates is difficult to obtain. Normally, and certainly before the FERC, the burden is on an applicant for market based rate authority to demonstrate the existence of sufficient competitive alternatives to its service to show that it lacks market power. It would not be normal, or in my view fair, to require parties like my clients to demonstrate positively that the Utilities have market power, in order to dissuade the Board from refraining from exercising its power to regulate storage rates.

Nevertheless, some capacity and rate information is available, and I believe that it, in combination with an analysis of the overall structure of the storage and transportation infrastructure in Ontario and adjacent jurisdictions, is more than sufficient to justify the conclusion that the Utilities have market power, and therefore to explain the market results that were discussed in Part IV.

B. Definition of Product Market

Q. As you have discussed, the first step in a market power analysis is the definition of the product and geographic markets that are to be considered. How would you define the product market in this case?

A. As a general matter, the product market is defined as the product that is being produced by the applicant for market based rates, together with any other products that are good substitutes for it. In the past the FERC has generally considered the product market to be simply gas storage having similar operational characteristics, e.g. similar injection/withrawal cycles. In a recent Notice of Proposed Rulemaking in Docket RM-05-23-000 the Commission proposed to relax its market power analysis slightly in order to allow applicants to include consideration of certain non-storage alternatives to storage in the analysis. The cited examples include LNG facilities and excess or uncontracted pipeline capacity. The Commission has not issued a final rule in this docket.

Although I do not dispute that it may be appropriate in certain fact situations to explicitly include consideration of, for example, LNG facilities and uncontracted pipeline capacity in a market power analysis related to storage, I do not believe that in this case there are any such alternatives. As far as I am aware there are no LNG facilities planned for southern Ontario, and in any event any LNG facilities that might be constructed in Canada (I understand that at least two such facilities are proposed for Quebec) will not be in service for many years. With respect to pipeline capacity, there is no significant amount of uncontracted pipeline capacity into Ontario. In this case, we are limited to considering only other storage facilities as alternatives to the Utilities' storage.

C. <u>Definition of Geographic Market</u>

Q. You have also indicated that it is necessary to define the geographic market for which the analysis is to be conducted. What considerations arise in connection with the definition of the geographic market?

A. The CRTC has defined the geographic market as "the smallest…geographic area in which a firm with market power can profitably impose a sustainable price increase."[6] The FERC appears to define the relevant geographic market as the geographic area within which there are good alternatives to the applicant's service. In fact there are two related but nevertheless distinct geographical issues related to our inquiry:

1) What is the geographic area within which the firm could exercise market power, and for which we want to predict its ability to exercise market power?

2) What is the geographic area within which there are competitive alternatives to the firm's services, such that those alternatives could constrain the firm's market based prices?

With respect to the first question, the issue in this case is clearly one of whether the Utilities are able to exercise market power in relation to storage as against Ontario consumers. The Board is presumably not interested in the question of whether the Utilities can exercise market power in the storage market as against Michigan consumers. More to the point, a demonstration that the Utilities lack market power in the storage market as against Michigan consumers would not justify allowing market rates for services provided to Ontario consumers, if the

[6] See Telecom Decision CRTC 94-19, supra note 2, at 34.

Utilities have market power over Ontario consumers. It is Ontario consumers that the Board is charged with protecting.

With respect to the second question, the fact that we are only concerned here with the Utilities' market power as against Ontario consumers does not necessarily imply that we should not consider ex-Ontario storage alternatives for the purpose of determining whether to allow the Utilities to charge market rates. If those alternatives can be predicted to constrain the Utilities' rates to a just and reasonable level, then it is appropriate to consider them.

Q. If we did not consider ex-Ontario storage facilities to be competitive alternatives to Utility storage, what would that imply for the market power analysis?

A. If the relevant geographic market is defined to include only Ontario, it is clear that when we proceed to the consideration of market concentration measures the only possible conclusion is that the Utilities have overwhelming market power. My understanding is that Union alone has over 60% of the available capacity, and Union together with EGDI control essentially all of the available capacity. Under any possible market concentration analysis, whether based on simple one-firm market shares, four-firm concentration, or a Herfindahl-Hirshman Index ("HHI") calculation, there is no plausible argument that the Utilities do not have very significant market power.[7] In order to proceed any further with the analysis, we must at least consider the potential effects of ex-Ontario storage. As discussed below, I do not believe that extending the analysis in that way ultimately changes the conclusion, but in order to ensure that we have fairly considered all of the possibilities it is necessary to examine ex-Ontario storage.

Q. Please describe in general terms the storage capacity that exists in the general area of Ontario, and its potential for constraining market prices charged by the Utilities for storage.

A. In the EEA Study that is referenced above in footnote 4, Energy and Environmental Analysis Inc. ("EEA") described in some detail the storage infrastructure that exists in areas of the U.S. that are, in EEA's view, sufficiently proximate to Ontario that a consideration of infrastructure in those areas is relevant to the issue of whether the Utilities have market power. EEA actually considered two definitions of the market area, which they referred to as "core" and "non-core". The core area includes basically all of Michigan, Chicago-area storage, and National Fuel Gas Supply Corporation ("NFG") storage facilities in New York. Within the core area, they identified approximately 1,150 Bcf of storage working gas capacity, having peak delivery capacity of about 25.6 Bcf/d. The larger area that includes the "non-core" area adds to the core area about 730

[7] See discussion below at page 45 of market concentration standards. The HHI for the Utilities in the Ontario market is approximately .53, which is well in excess of the .18 level that the FERC considers to be indicative of market power.

Bcf of working gas capacity and about 13.5 Bcf/d of peak deliverability, all of it located in New York, Pennsylvania, and West Virginia. These numbers all include Union capacity of 150 Bcf, with deliverability of 2.3 Bcf/d, and EGDI capacity of 92 Bcf, with deliverability of 1.8 Bcf/d.

EEA goes on to calculate, based on this data, various concentration ratios and HHI measures, and predictably finds that in the geographic market areas that it has identified the ratios are below the thresholds commonly applied by the FERC in market based rate cases and by the Canadian competition authorities when they examine proposed mergers. From this EEA concludes that Union does not have market power in the relevant storage market.

Q. **Does the EEA analysis address the issue that you believe needs to be addressed in this proceeding?**

A. No. As I have explained, we are not interested in whether Union has market power over storage customers in Chicago, New York, or Michigan. Nor are we interested in whether Nicor has market power over Ontario storage consumers. The question is whether the Utilities can exercise market power in relation to storage as against Ontario consumers. In order to examine that issue, the question is whether the storage alternatives identified by EEA in Michigan, New York, Chicago, etc. are viable competitive alternatives to Utility storage for the Utilities' existing Ontario customers. In order for them to be viable competitive alternatives, i.e. alternatives whose existence will constrain any market prices charged by the Utilities to Ontario customers to a just and reasonable cost-based level, they must be shown to be available to Ontario consumers in sufficient quantities, and at a sufficiently low price, and with sufficient reliability and quality, that they will prevent the Utilities from increasing their prices above the competitive level.

Q. You have already discussed the issue of what will constitute a "sufficiently low price" for these purposes, and suggested that the price of the alternatives must be within 10% of the cost of Utility storage, adopting the FERC standard. Do you have any other comments on that issue?

A. The only comment I would add is that the price or cost of the alternatives must be measured *at the inlet to the Utilities' systems,* i.e. at the same point at which the Utilities' storage is available to customers. This means that any cost calculation must include the cost of pipeline transportation necessary to deliver gas to the alternative storage facility, and to transport it from that facility to Dawn, or possibly Kirkwall in the case of alternative facilities accessible through Niagara.

Q. Do you have any comments in relation to the requirement that the alternatives be comparable to the Utilities' storage in terms of quality and reliability?

A. The Utilities' storage is available to customers on a firm basis, by and large, so any alternative that is claimed to be comparable must also be available on a firm basis into the Utilities' systems. This is especially relevant to transportation issues, since it implies that customers must be able to access firm transportation capacity into storage and from storage to Dawn or Kirkwall.

Q. Finally, do you have any comments on the issue of what will constitute "sufficient quantities" of alternative storage capacity, if that capacity is to be effective at constraining the Utilities market power?

A. It does not appear that there is any firm rule applied by other regulatory authorities in relation to this issue. It is likely not appropriate, or necessary, to require a demonstration that the alternative storage suppliers could immediately supply 100% of the Ontario storage market, i.e. 240 Bcf of capacity, with 4.1 Bcf/d of deliverabilty. On the other hand, it is also clear that 25 Bcf of alterative storage capacity, with 0.4 Bcf/d of deliverability, would have little effect on the ability of the Utilities to charge above-cost market rates.

One way to think about this issue is to consider what amount of available alternative storage capacity and deliverability would be necessary to reduce the market shares of the Utilities to "acceptable" levels, if it were all actually used. The Competition Bureau, in its merger enforcement guidelines, suggests that a 35% market share for a single firm, and a 4-firm concentration ratio of 65%, are essentially the upper limits on what the Bureau will consider as being unlikely to be associated with market power. The FERC considers an HHI of .18 or below to be generally indicative of a lack of market power. An HHI of .18 is consistent with a market structure in which there are five or six roughly equal-sized competing firms, i.e. a market in which any two firms will have only a 30-40% market share between them. Based on these general tests, which are themselves only guidelines, I think it is reasonable for these purposes, and conservative, to consider the issue in terms of whether there are sufficient good alternatives to the Utilities' storage, for Ontario customers, that in theory they could reduce the Utilities' market share in Ontario to 50%. This implies available firm storage of about 120 Bcf of capacity, and about 2.0 Bcf/d of deliverability, delivered on a firm basis at Dawn or Kirkwall.

I acknowledge that arguments could likely be made for higher or lower thresholds, but for discussion purposes I believe that these are reasonable. As the discussion that follows makes clear, the actual amount of alternative storage that is physically available to Ontario consumers at a reasonable price is in fact probably very close to zero, or at any rate a small fraction of the 120 Bcf and 2.0 Bcf/d amounts.

D. Economics of Storage Utilization

Q. Do you have any general comments on the economics of storage outside Ontario?

A. When we are considering the potential for U.S. storage facilities to provide meaningful and effective competition to the Utilities in the Ontario market, it is important to understand the overall structure of the delivery system, and the underlying economics of using storage services.

The basic function of storage in the Ontario market is seasonal load balancing. Total gas demand is higher in winter than in summer. Without storage, it would be necessary for Ontario consumers to contract for, directly or indirectly, and on a year-round basis, sufficient upstream pipeline capacity from producing areas, i.e. primarily Alberta, to meet the winter peak demand. With storage, a large part of that long haul pipeline commitment can be avoided, because the Utilities are able to contract for upstream pipeline capacity sufficient to transport only the average daily demand over the year. During the summer the amount they ship to Ontario is greater than actual consumption, and the excess is injected into storage. During the winter, the pipeline capacity is used to meet actual consumption, and is supplemented by gas withdrawn from storage and transported to consuming areas.

Note that, under this general scheme, it is necessary for customers to hold (a) firm long-haul transportation at a level equal to annual average demand, (b) storage capacity, and (c) firm "short-haul" transportation sufficient to transport the excess of the winter demand over the average annual demand, i.e. gas withdrawn from storage, from storage facilities to consuming areas. In Ontario, that short haul capacity is, basically, the Union Dawn/Trafalgar system, together with market area capacity on the TransCanada system sufficient to deliver storage volumes downstream of the Dawn/Trafalgar system to, for example, GMi.

This scheme makes economic sense as long as the cost of the avoided long-haul transportation capacity, i.e. TransCanada capacity equal to the excess of peak demand over annual average demand, is greater than the cost of the storage itself, plus the cost of the short haul capacity necessary to move gas withdrawn from storage to consumers. In Ontario, the scheme works because even with the added cost of the storage facilities, the transportation saving that results from effectively substituting Dawn/Trafalgar capacity for TransCanada Mainline capacity (i.e. to transport the excess of peak demand over annual average demand) more than offsets the cost of the storage.

The key variable in this scheme is the proximity of the storage facility to the area where the gas is ultimately consumed. The closer the storage is to the consuming market, the greater the transportation saving from substituting short-haul transportation for long-haul transportation for the excess of peak over average demand. The more remote the storage is from the consuming market, the greater the cost of the necessary short-haul transportation, and the less the transportation saving. At the limit, e.g. if the storage was in Alberta, and the "short-haul" transportation used to move the excess of peak over average demand was simply long-haul TransCanada Mainline capacity, there would be no saving at all, and essentially no point in incurring incremental storage costs.

This point is relevant to the issue we are considering because all of the U.S. storage facilities that we are considering as potential competitive alternatives to Utility storage are farther away from the consuming area than the Utilities' storage is. As a result, attempting to substitute storage at those facilities for Utility storage will *inevitably* require Ontario customers to incur costs for incremental short-haul transportation capacity that they do not have to pay for if they use Utility storage. The extent of this effect will vary according to what storage and transportation arrangements are made, and the effect could conceivably be offset by other cost factors, but the general result is that if unit storage costs, unit gas costs, and unit transportation costs per GJ-km are the same, U.S. storage will be more expensive for Ontario consumers than Ontario storage.

Q. Is this general principle reflected in the overall design of the storage and transportation infrastructure in eastern North America?

A. Yes it is, and that is a very important point. For all market areas where storage is used to meet peak demand, the fact is that the transportation infrastructure has over time been designed and built for the purpose of accommodating required average and peak gas flows given the storage capacity that is available and the established pattern of use for that storage. I have mentioned that the transportation infrastructure in Ontario has been designed and built specifically to accommodate the need for gas withdrawn from storage to be delivered to consuming areas during the winter. In the U.S., as examples of the same principle, the ANR and Natural Gas Pipeline systems both utilize market area storage (in Michigan in the case of ANR, and in the Chicago area in the case of Natural). Those pipeline systems have been designed to transport average day quantities of gas from producing regions to storage facilities in Michigan and Chicago, respectively, but to also transport additional quantities, i.e. volumes withdrawn from storage, along the much shorter paths from the Michigan and Chicago area storage facilities to consumers in Chicago, Wisconsin, and Michigan.

Q. Why is this relevant to the issue that we are considering here?

A. The point is that the existing transportation infrastructure has *not* been designed and built for the purpose of transporting gas into and out of U.S. storage facilities from, or for ultimate use in, Ontario, or for that matter anywhere in Canada. In particular, the pipeline infrastructure that delivers gas to Ontario, i.e. primarily the TransCanada and Vector systems, has been designed and installed for the primary purpose of delivering required *annual* quantities of gas to Ontario, not quantities of gas stored in U.S. storage facilities and transported to Ontario to meet peak demand during the winter.

The result is that it would be very surprising to find that the existing pipeline infrastructure can accommodate anywhere near the amounts of peak period storage withdrawals from U.S. storage facilities, for delivery to Dawn or Kirkwall, that would be necessary in order for U.S. storage facilities to be genuinely competitive with the Utilities' storage. Using the rough 50% market share measure discussed above, the incremental requirement, over and above the requirement for average day deliveries, would be some 2.0 Bcf/d. The firms that design and build pipeline infrastructure do not purposely build such massive amounts of infrastructure purely in the hope that some day Ontario consumers might be motivated to use Michigan, New York, or Chicago storage facilities in preference to the ample amounts of Ontario storage that already exist.

E. Adequacy of Potential Alternatives to Utility Storage

Q. Turning now to an examination of the adequacy of potential alternatives to Utility storage, what issues need to be addressed?

A. Three issues need to be considered:

1) The availability of existing storage and transportation infrastructure that may provide alternatives to the Utilities' storage services,

2) The cost of existing storage and transportation infrastructure that may provide alternatives to the Utilities' storage services, and

3) The potential for market entry by new competitors, in the form of new storage and transportation infrastructure.

1. Availability of Storage and Transportation Capacity

Q. With respect to the first of these issues, in particular in relation to the availability of U.S. storage capacity that can potentially compete with the Utilities' storage, what information do you have?

A. The storage facilities identified by EEA can be categorized into three broad groups. Some, including those operated by ANR Pipeline Company ("ANR"), ANR Storage Company ("ANR Storage"), Natural Gas Pipeline Company of America ("Natural"), NFG, Dominion Transmission, and Columbia Transmission, are owned and operated by interstate pipeline companies that are regulated by the FERC. Others, like those operated by Michigan Consolidated Gas Company (Michcon), CMS Energy, Nicor, and Northern Indiana Public Service ("NIPSCO"), are owned and operated by local distribution companies that are regulated at the State level. Others, like the Washington 10 facility, are basically newer merchant storage providers that, while they may be regulated at some level, provide services using facilities that were not originally developed in conjunction with particular pipeline or distribution systems.

Reliable information concerning available capacity on distributor-owned and merchant storage facilities does not appear to be easily available. However, interstate pipelines subject to the FERC's jurisdiction are required to make information about available capacity on their systems publicly available through their web-sites.

At the present time, none of ANR, ANR Storage, Natural, or NFG has un-subscribed storage capacity.

Q. Is it possible to infer from this any information about the expected level of un-subscribed capacity on the LDC storage systems?

A. First, the Chicago area distributors are Natural's main customers. They rely on both storage that they own and operate themselves, and on contract storage that they purchase from Natural, in order to serve their distribution customers. It seems unlikely that the Chicago area distributors would contract for Natural's storage, to the point where Natural is fully subscribed, if they had significant amounts of excess capacity on their own storage systems.

My understanding is that Michcon and CMS are not highly dependent on interstate pipeline storage, so the same reasoning does not necessarily apply to them. Nevertheless, it is reasonable to assume that, if there is unsubscribed storage capacity available on the Michigan LDC systems, it must only be available at a cost that is greater than the cost of interstate pipeline storage from, e.g., ANR or ANR Storage. Otherwise, customers would migrate to the LDC systems, leaving whatever excess capacity is available in the market as unsubscribed capacity on the interstate pipeline storage systems.

Q. Even if there is little or no U.S. storage capacity available now to compete with the Utilities, would Ontario customers not have an opportunity to

compete for and acquire such capacity over time, as existing contracts expire?

A. That is possible. However, an important consideration here is that LDC's like Michcon, CMS, and Nicor, and for that matter pipelines like ANR, ANR Storage, Natural, and NFG, are not pure merchant storage providers who are able to sell service to whoever asks for it first, or is willing to pay the most for it. These companies are all regulated entities, and they all have customers that they are legally obliged to provide service to under most conditions. That is particularly true of the distribution utilities. Their storage facilities have been developed primarily for the purpose of serving their own in-franchise customers, and they are not free to sell that capacity to Ontario industrials, or Ontario marketers, and tell their own customers to go away and buy competitive storage from Union, for example. Even the interstate pipelines like ANR, Natural, and NFG almost certainly have certificate obligations to continue to provide service to their captive customers (i.e. customers willing to pay maximum rates) for as long as those customers want the service.

Although there may be some utility and pipeline storage that is genuinely "in the market" from time to time, and there are facilities like Washington 10 and Blue Lake in Michigan that are primarily merchant storage providers, the capacity that could even conceivably be available on that basis to Ontario consumers is likely a small fraction of the working gas capacity listed in the EEA report. Although I have not attempted to quantify that fraction, my view is that if the Utilities want to apply for market based rate authority they should be obliged to identify it themselves and provide that information to the Board.

Q. What information is available about the availability of short-haul transportation capacity that would be necessary for the purpose of transporting Ontario storage volumes into and out of U.S. storage facilities?

A. The main routes over which large volumes of storage withdrawals could be transported into Ontario are the Great Lakes system, for gas from Michigan storage facilities, the Vector system, for gas from Chicago-area storage facilities, and the various pipelines that interconnect with TransCanada at Niagara, for gas from New York/Pennsylvania storage facilities. While other transmission systems exist, e.g. Blue Lake, and the St. Clair pipeline, my understanding is that they are small and therefore unlikely to be a significant factor in the Ontario market.

On the Great Lakes system, there is currently no unsubscribed capacity available from Emerson to the eastern part of the system, but about 32,000 GJ/d of capacity available from the Farwell interconnect with ANR/Michcon to St. Clair, and about 160,000 GJ/d available from Muttonville to St. Clair.

My understanding is that the Vector mainline is fully subscribed, and that Vector has filed an application with the FERC for approval of a compression-related expansion that will increase the mainline capacity from 1.0 Bcf to 1.2 Bcf in 2007. It appears that the expansion is underpinned by long term contractual commitments, so that the system can be expected to remain fully subscribed.

With respect to the National Fuel system at Niagara, identified by the EEA report as the most economical Niagara alternative, NFG's website indicates that it has no Firm Storage Transportation ("FST") capacity available anywhere on its system, nor does it have any conventional Firm Transportation ("FT") capacity from Niagara.

2. Cost of Alternative Storage and Transportation Capacity

Q. With respect to the second issue identified above, the cost of alternative storage and short-haul transportation capacity, if it were available, what analyses have you conducted?

A. Part of the difficulty with analyzing this question is that there are numerous potential alternatives available, and numerous strategies that could be pursued by customers for accessing alternatives to Utility storage. As a general matter, it appears that the cost of alternative storage is significantly higher than the cost of Union storage, with the premium being 50% or more in most cases. Moreover, the additional cost of short-haul transportation necessary to transport storage volumes into U.S. storage facilities and from those facilities to Ontario imposes a further cost burden that is generally equal to or more than the cost of Union storage itself. The end result is that the cost to Ontario customers of using alternative U.S. storage and transportation arrangements, if capacity were available, would be a multiple of the cost of Union storage, not a 10% premium to it.

For the purposes of illustrating this, I have examined the costs that would be involved in using alternative U.S. storage facilities under three scenarios. The three scenarios reflect, in broad terms, three of the major alternative strategies that customers could employ for accessing U.S. storage. They are:

1) Michigan storage from ANR Storage, with transportation on Great Lakes

2) Chicago-area storage from Natural, with transportation on Vector

3) New York storage from National Fuel, with transportation on the National Fuel transmission system.

I have compared the costs of these alternative arrangements with the costs of Union storage, evaluated on the same basis. A detailed description of the methodology and assumptions employed, together with the calculations, is set out in Appendix 2.

Q. Can you summarize the results of your analysis?

A. The results of the analysis are summarized in the following Table. All values are in Cdn$/GJ of storage space contracted for.

Alternative	Storage Cost	Tptn Cost	Total	Premium	%
Union	.56	-	.56	-	-
Natural/Vector	.88	1.24	2.12	1.56	279%
National Fuel	.93	.78	1.71	1.15	205%
ANR/Great Lakes	.70	.85	1.55	.99	176%

Q. In these illustrative examples, what cost is being measured?

A. The cost being measured is the unit cost of storage and necessary transportation service per GJ of gas that is put into (and thus withdrawn from) storage using the assumptions outlined in Appendix 2. The analysis therefore takes account of load factor in storage and on associated transportation infrastructure. I have ignored for these purposes the cost of gas, the cost of long haul transportation necessary to transport gas to the storage facility, and the costs of transporting gas withdrawn from storage downstream from Dawn to Ontario consumers. In that way, a valid comparison can be drawn between the costs of alternative storage arrangements and the stand-alone cost of Union storage.

Q. Do any of the scenarios that you have examined involve the use of U.S.-sourced gas supply in place of western Canadian supply? If not, do you consider that such alternatives need to be considered?

A. The three scenarios all assume that the gas supply that is put into storage is sourced in western Canada. While substituting U.S. sourced supply from the Gulf Coast or the mid-continent, together with U.S. long-haul transportation from those areas, for Canadian supply transported via TransCanada or Alliance would change the overall economics of the arrangement, it would not affect the storage cost comparison that the analysis makes. Customers would still have to contract for U.S. storage capacity and for short-haul storage-related transportation capacity from those U.S. storage facilities to Ontario, and those are the costs that the analysis measures. If U.S. gas supply and U.S. long haul transportation were an available and economic alternative to western Canadian supply, that would be true independently of the storage arrangements that were made. The fact that Ontario's supply still comes predominantly from western Canada suggests that there is no economic advantage to using U.S. sourced supply, and in fact probably an economic disadvantage to doing so.

Q. Why have you chosen to examine the particular alternative storage and service providers identified in the table?

A. Those alternative service providers were chosen because information on cost-based rates for the services that they provide is readily available, because they are all FERC-regulated.

Q. As you have noted, the cost of storage alone in each of the scenarios appears to be considerably above the cost of Union storage. Can you comment on whether the consideration of FERC-regulated storage companies only is appropriate, given that other LDC-owned storage might be available?

A. It is doubtful that LDC-owned storage would be available at a cost less than the cost of storage provided by ANR, Natural, and NFG. The rate information that is readily available for Michcon and CMS indicates that, for both companies, contract storage arrangements can be negotiated, but with a maximum price for CMS of US$1.50/Dth, and a maximum price for Michcon of US$1.47/Dth. These maximum rates are well above the cost-based rates that are set out in the tariffs of the FERC-regulated entities. In fact, these are probably not cost-based rates at all, and it is reasonable to assume that they are simply maximum allowable negotiated prices for transactional services provided to non-utility customers that have been set on some more or less arbitrary basis. While it is therefore possible that under at least some market conditions storage would be available at some price less than these maximums, there is no reason to believe that storage would be available from these companies at rates less than the maximum rates charged by the FERC-regulated entities, given that ANR, Natural, and NFG are all fully contracted.

Q. The unit costs indicated for storage-related transportation in the above table all appear to be well in excess of the regulated rates charged by the specified pipelines. Please explain why that is the case.

A. The analysis is measuring the cost of storage-related short-haul transportation *per unit of stored gas*. That gas is only transported on the short-haul capacity from the storage facility to Ontario during the five months of the winter period. Moreover, the analysis assumes that customers will hold less storage space than they would need in order to fully utilize their entire withdrawal capacity each day during the winter, so short haul capacity to transport gas withdrawn from storage will not be used at a 100% load factor even during the winter. When transportation costs are adjusted to account for these load factor effects, the result is very high unit costs per GJ of stored gas.

This effect is seen most clearly in the Natural/Vector case, where the Vector short haul capacity is not used for injection purposes. Nevertheless, even in the ANR/Great Lakes and NFG cases, where I have assumed that the necessary short-haul capacity will be used for both injection and withdrawal purposes, the same analysis holds. While the capacity is used all year, it is used to transport the same stored volume twice, i.e. once into storage, and once out of storage, so the calculation of a unit rate *per unit of stored gas* must ignore the summer injection-related transportation.

Q. In the Natural/Vector scenario, would it not be realistic to assume that a customer that held year-round short haul capacity on Vector for storage withdrawal purposes would find some way to mitigate the stranding of its capacity during the summer months?

A. While it is possible that any individual customer could mitigate the costs of stranded capacity to some extent, in aggregate customers will not be able to do so to any significant degree.

The problem is that there is simply an insufficient market for gas, and therefore for the short-haul Vector capacity, during the summer. In the Vector situation, mitigation of the costs of stranded capacity would consist of using the capacity during the summer to move non-storage-related gas from Chicago to Dawn, but the reason customers enter into storage arrangements is that during the summer there is not sufficient consumption demand in Ontario to use up all of the gas that can be transported using existing pipeline entitlements. There is nowhere for the gas to go.

It is true that any individual customer in the situation I have described could perhaps utilize its summer Vector capacity to move gas into Ontario, essentially by displacing gas arriving in Ontario via another route, e.g. TransCanada, or another Vector shipper, for either consumption or injection into storage. However, in aggregate the amount of gas demand in Ontario during the summer, for both consumption and storage injection, is fixed. If the hypothetical Vector customer succeeded in capturing part of that demand, that would mean that an equal amount of summer flow on TransCanada (or on capacity held by another Vector shipper) would disappear. Since that capacity is also firm year-round capacity, there will be stranded summer capacity somewhere, and therefore high unit transportation costs for someone.

The point is that, if the transportation infrastructure upstream of Ontario were large enough to accommodate both the annual average requirements in Ontario and large flows of gas withdrawn from U.S. storage and transported to Ontario during the winter, it *must* be the case that there would be stranded transportation capacity into Ontario during the summer. That stranded capacity is an incremental cost of utilizing storage in the U.S. as a substitute for Utility storage, and any proper analysis of the cost of alternative storage must take it into account. The analysis set out in Appendix 2 does that by attributing or "allocating" the incremental cost to the hypothetical customer that uses the U.S. storage. While that cost could theoretically end up being borne by someone else, it will always exist for Ontario gas consumers as a group.

Q. Please summarize your conclusions with respect to whether alternative storage options, using existing facilities, would constitute good alternatives to Utility storage for the purpose of evaluating whether competition from those options would constrain the Utilities' market based rates to a just and reasonable level.

A. The cost-based rate for Utility storage at Dawn appears to be approximately $0.56/GJ. Applying the 10% cost threshold discussed earlier, the requirement is therefore for winter storage withdrawal volumes to be delivered to Dawn at an all-in cost of $0.62/GJ, taking into account the costs of the U.S. storage and the necessary incremental transportation capacity. I have also suggested that storage volumes must be deliverable to Dawn, at that cost, in significant quantities, e.g. 2.0 Bcf/d.

It is unlikely, first of all, and certainly it has not been demonstrated, that there is enough free storage capacity (i.e. capacity that is not already committed for the long term to utility and pipeline jurisdictional customers) in the U.S. areas to meet the 2.0 Bcf/d requirement, or indeed any amount even approaching that.

Second, it does not appear that there is anywhere nearly enough short haul transportation capacity available from Ontario to U.S. storage and back again to accommodate the storage injection and withdrawal volumes that we have said would be necessary to create a meaningful competitive threat to the Utilities.

Third, even if adequate storage capacity were shown to be available, its appears that the cost of that storage exceeds the $0.62/GJ pricing threshold by a considerable amount, without taking into account the costs of incremental transportation capacity that would be necessary to use the U.S. storage capacity.

Finally, even if adequate transportation capacity were available, the unit cost of that capacity would itself represent a significant premium to the cost of Utility storage, particularly if load factor effects are properly accounted for. Thus, on an "all-in" basis, the unit cost of using the U.S. alternatives is much higher than the cost of using Union storage.

The most reasonable conclusion to draw from all of this is that, as a practical matter, the expanded market area proposed in the EEA study includes essentially no genuinely viable competitive alternatives to the Utility storage, from the perspective of Ontario customers.

Q. What does this mean for the overall three step market power analysis?

A. If we proceed to the market concentration screening stage of the overall analysis, based on this information, the net result is that the screening process, assuming even a greatly expanded geographic market, yields essentially the same answer as it did when we assumed that the only alternatives were in Ontario: that the Utilities have overwhelming market power in the storage market.

3. __Potential for Competitive Market Entry__

Q. The third question that you identified above is that of whether it is reasonable to expect that new competitors would enter the market and provide effective competition for the Utilities, if the Utilities were allowed to

charge market rates for their storage services. Do you believe that to be likely?

A. No, for at least three reasons.

The first point is that the overall gas market in Ontario, and indeed in North America, is growing. The potential market growth in Ontario is discussed in the NGF Report, and is very significant. In order for infrastructure growth to create competitive pressure on the Utilities' storage, it would have to be in excess of whatever growth is required simply to meet increasing annual requirements.

The second point is that infrastructure growth, even if it could be used to provide competition for the Utilities' storage, would still have to be less expensive than the existing infrastructure in order to create genuine competitive pressure. Probably the fundamental issue with the competitiveness of existing U.S. storage and storage-related transportation in Ontario is that it is much more expensive than the Utilities' storage. New infrastructure will not be cheaper than the existing infrastructure, which is already too expensive to pose a meaningful competitive threat to the Utilities in the storage market.

The third point is that competitive entry in the natural gas storage and transportation industry is inherently difficult, time-consuming, expensive, and risky, and as a general matter it is not reasonable to believe that competitive entry in the form of new facilities, or the threat of competitive entry, would constrain the pricing behavior of the Utilities if they are allowed to charge market rates for storage.

Q. Please explain this last point in more detail.

A. The development of new natural gas pipeline and storage infrastructure involves very large "sunk" investments in long-lived capital equipment that cannot used for any other purpose once it is installed. As a result, the risk associated with competitive entry, where competitive entry is undertaken solely for the purpose of taking advantage of monopolistic prices in the market, and not in response to genuine growth in the market's overall requirement for the product in question, is extreme.

In the context of Ontario storage, consider what competitive entry would involve, and the reasonableness of the hypothesis that it would effectively constrain the prices that could be charged by the Utilities. The suggestion would be that, if the Utilities are given authority to charge market rates for their storage services, they will charge rates that exceed a just and reasonable level, i.e. a level that reasonably reflects the cost of providing the service. Those monopolistic prices would induce new market participants to install new storage and transportation infrastructure in order to compete customers away from the Utilities, and capture for themselves a portion of the economic rent that we assume the Utilities will be extracting through their above-cost prices.

Such a plan would involve a number of significant practical obstacles, including finding suitable geological formations, in the case of storage development, acquiring rights of way, completing a lengthy and expensive planning and certification process, and ensuring that the planned new facilities would be operationally and commercially integrated into the overall storage and transportation network, likely in the face of efforts by the Utilities to ensure that they would not be.

The most fundamental problem faced by such a new entrant, however, is that the new facilities, once constructed, will necessarily be excess to the actual requirements of the market. If they are not, i.e. if they simply meet growing demand, they will not have any effect on the ability of the Utilities to charge above-cost prices, because the new facilities will not create any genuine threat to the Utilities' volumes.

If the new facilities are excess to the market's requirement, the risk faced by the new entrant is that its attempt at market entry will fail, and its entire large sunk investment will be essentially lost. If, as is likely, the embedded cost of the new entrant's facilities is higher than the embedded cost of the Utilities' infrastructure, the Utilities will be able to ensure the failure of the new project simply by reducing their market rates to levels that are lower than those of the new entrant. They would be able to do that since such price levels would still be profitable for the Utilities.

This phenomenon is an acknowledged and probably insuperable barrier to purely competitive entry in the gas pipeline and storage industry. The FERC, when it is considering applications for market based rate authority, does not consider the possibility of market entry through the construction of new facilities, other than very minor facilities, to be a factor that could constrain the pricing behavior of applicants, basically for this reason.[8]

To put this point in the context of my earlier discussion of the short-haul transportation capacity that would be required in order for storage alternatives in Michigan and Chicago to be workable alternatives, it is clear that essentially none of the necessary capacity exists now. In order for Ontario customers to have the ability to switch from Utility storage to Chicago storage, for example, in quantities that would create meaningful competitive pressure on the Utilities, someone would have to construct, for example, 500,000 GJ/d of transportation capacity from Chicago to Dawn, knowing that the new capacity is not needed to

[8] See Rate Design Policy Statement.

meet annual requirements in Ontario, knowing that the capacity will likely only be used in the winter under the best of circumstances, and knowing that if the Utilities are able to retain their existing storage market in the face of competition from the Chicago-area storage providers, the capacity will be entirely useless. Even if the FERC would certificate such a project, which is doubtful, no commercially sensible party, whether it was a pipeline sponsor or a shipper, would entertain it.

Q. Would it not be possible for new storage to be developed in Ontario that would have the effect of constraining the Utilities' market prices to a competitive level?

A. My understanding is that there is some potential for new storage facilities to be developed in Ontario. The Staff report on storage issues that was filed as part of the NGF process discusses that, but my understanding is that the expectation is for only modest amounts of new storage capacity to be developed in Ontario over even the next several years. Given that the NGF Report also forecasts significant growth in overall annual gas demand, and in the demand for storage capacity, over that period, it is unlikely that any incremental storage development will seriously undermine the market power of the Utilities. The business cases for new storage development are likely premised primarily on an expectation of market growth, rather than on any notion that the sponsors of the projects will be able to profit by competing existing market away from the Utilities.

Q. Please summarize your overall conclusion with respect to the issue of whether the Utilities have market power in relation to storage, and on the advisability of the Board refraining from regulating the rates that the Utilities charge for storage.

A. My overall conclusion is that the Utilities have, and will continue to have for the foreseeable future, overwhelming market power in the Ontario storage market. The Utilities have no meaningful competitors within Ontario. If we look beyond Ontario to adjacent areas in the U.S. where significant amounts of storage capacity exist, essentially none of that capacity provides effective competition to the Utilities from the perspective of Ontario customers. As a practical matter, competitive entry into the Ontario storage market is very unlikely.

Given these results, I do not believe that it would be appropriate for the Board to refrain from exercising its power to regulate the rates charged by the Utilities for storage services generally.

VI. CONTINUATION OF A COMBINED COST AND MARKET BASED REGIME FOR STORAGE REGULATION

A. Distinctions Based on Customer Class or Type

Q. In the List of Issues the Board indicates that it wishes to consider whether some customers should continue to pay for storage services at cost while others pay market prices for those services and, if so, how the line should be drawn between the two types of customers. Do you have any comments?

A. For the reasons that I have explained, my view is that all of the Utilities' customers are subject, to one degree or another, to the market power of the Utilities, in the sense that the Utilities have an ability to maintain the prices charged for storage services above a competitive cost based level for all customers. If the suggestion is that the Board nevertheless require the Utilities to charge cost based rates to some classes of customers, but allow them to charge higher market rates to others, the question arises of what principled basis there is for distinguishing between the affected classes of customers.

The usual and accepted basis for making a distinction between classes of customers in relation to utility rates is simply that the cost of providing service to one class is different than the cost of providing service to the other, but that rationale does not apply here. Because the Utilities operate their storage assets on an integrated basis it is not possible to identify any particular customers as being served through the use of particular facilities. More to the point, the proposed rate distinction is not between lower and higher rates based on differences in the cost of providing service, but between rates that are designed on the basis of cost and rates that are almost certainly above cost.

Q. Do you have any comments on the "in-franchise" versus "ex-franchise" distinction that has been used in the past?

A. The difficulty with using this distinction as the basis for different rate treatment is that it is not obvious why it is reasonable to protect in-franchise customers from the exercise of market power, but not ex-franchise customers. This problem is especially acute when we are considering ex-franchise customers whose end-use facilities are nevertheless still in Ontario. The Board's primary function in regulating the Utilities is to protect Ontario consumers against the market power of the Utilities, and it is not clear to me why it is appropriate to protect customers against the market power of the particular Utility in whose franchise area they happen to reside, but not protect those customers against the market power of Utilities in other parts of the province.

That is essentially what happens under the current arrangement, under which EGDI pays a market price for Union storage, while Union's own customers pay a lower cost-based rate. Those above-cost Union storage rates charged to EGDI are ultimately paid by EGDI's customers, so the net result is that Union's customers pay cost based storage rates while ECGI's customers pay storage rates that are higher than cost, and that reflect the exercise of market power by Union.

Where we are considering ex-franchise customers that are outside of Ontario, e.g. GMi, slightly different issues may arise, since the Board or the Ontario government might take the view that the Board should not be concerned with protecting customers outside Ontario against the market power of Ontario Utilities. This, however, is a policy or politically-driven distinction rather than a question of economics or regulatory theory.

From a regulatory perspective, the difficulty is with understanding why the question of whether a customer is "in-franchise" or "ex-franchise" has anything to do with whether it should be entitled to cost based rates, or will be forced to pay rates that reflect the exercise of market power. The same basic problem would exist with, for example, distinctions between "old" and "new" customers, large and small customers, or customers in one business and customers in other businesses – the distinction between customer classes is unrelated to the difference in rate treatment that is being proposed.

Q. What is your general conclusion in relation to proposals to distinguish between different classes of customers for the purpose of determining which customers should pay cost based rates and which should pay market rates?

A. Although these decisions may be influenced by policy considerations that are outside the normal regulatory sphere, as a matter of economics and regulatory theory I do not see any rational basis for protecting some customers from the exercise of market power through cost based rates, while exposing other customers to the potential exercise of market power by the Utilities.

B. <u>Distinctions Based on Type of Service</u>

Q. If it is not reasonable to distinguish between classes of customers for the purposes of determining which customers will be entitled to buy service at cost based rates and which will be required to pay market rates, would it be possible in your view to usefully distinguish between different types of *services* with respect to whether they should be priced on a cost or market basis?

A. Although this is an issue on which there may be reasonable arguments both ways, it may be reasonable to distinguish for these purposes between what I will call "core" services and "discretionary" services. Core services are long term, generally firm services provided to customers, or agents of customers, who have a permanent or long term need for storage service in order to meet their gas requirement needs. One could also characterize the types of services that I have in mind as "delivery-related" or "utility-related".

"Discretionary" services, on the other hand, which are essentially the same thing as "transactional services" as that term has been used in Ontario, are storage services that are used essentially for the purpose of commercially managing gas supply costs and risks, independently of any particular physical delivery requirement on the Utility systems.

As I have indicated, the basic function of storage in Ontario is to be a part of the overall delivery system for gas produced outside Ontario, since storage is an essential and economical substitute for upstream pipeline capacity. Some customers, however, primarily marketers and traders, contract for generally short term unbundled storage at Dawn primarily for the purpose of using it as part of their overall gas price risk management activities. That activity takes place upstream of the Utility systems, and is not in any direct way connected with the operation of the Utility systems or with issues related to the pricing or availability of delivery services to Utility customers. It is at least arguable that that function is outside the core mandate of the Board, in terms of the interests that the Board is charged with protecting, and that it therefore may be reasonable to allow departures from cost-based pricing for such storage uses.

Q. In practical terms how would this distinction be drawn?

A. In practical terms the distinction is probably between services provided under short term (one year or less) non-renewable storage contracts, which would be defined as "discretionary" or "transactional" services, and long term or renewable arrangements under which customers, directly or indirectly, have an ongoing entitlement to storage service. If that distinction were drawn, it could be appropriate to allow the Utilities to charge market prices for discretionary or transactional services, but require them to charge cost-based rates for all other storage services.

Q. If the Board were to allow the Utilities to charge market prices for discretionary or transactional storage services, would it be appropriate for the Utilities to retain all of the revenues in excess of cost generated from sales of those services?

A. No. Such services are provided using the integrated storage systems that have been developed by the Utilities for the purpose of providing the "core" or "utility-related" delivery services that would be priced on the basis of cost. Discretionary services are available only because, and to the extent that, the Utility storage infrastructure is not needed from time to time to perform the utility function. To the extent that excess revenues are generated by the sale of discretionary services, it is perfectly reasonable to flow those revenues back to utility customers, who would remain at risk for the costs of the temporarily excess storage facilities in the long run. More to the point, there is no reason to think that it is fair or appropriate to allow the Utilities to retain those excess profits.

Q. Are you aware of similar approaches being taken elsewhere?

A. The TransCanada Mainline system has for many years been allowed, and in fact required, to sell available interruptible and short term, non-renewable firm capacity at effectively market prices through a bidding process, although there is a bid floor that approximates the cost based rate. All revenues from those sales of discretionary services are flowed back to customers through the rate-setting mechanism.

VII. EFFICIENCY ISSUES RELATED TO COST BASED RATES

Q. Do your recommendations have any negative implications for the future development of storage infrastructure in Ontario by entities other than Union and EGDI?

A. I do not believe so. I am not suggesting that all new storage facilities be required to provide service at cost based rates.

As I understand the Board's practice it is to approve market rates for new, independently operated storage developments, and I do not take any issue with that policy. In the U.S., the FERC has followed a path that involves, for the most part, retaining cost based rates for established, large scale utility storage infrastructure, i.e. primarily the storage services offered by interstate pipelines, while approving market based rates for new storage projects in areas where significant storage infrastructure already exists. A policy of retaining cost based rates for Utility storage, given the overwhelming dominance of the Utilities in the Ontario storage market, while allowing incremental, and generally small-scale, development to proceed on the basis of market pricing is consistent with the FERC's approach, and with my overall market power analysis.

Q. How would your recommendation affect expansions of existing storage facilities by EGDI and Union, or their affiliates?

A. If an affiliate of Union or EGDI wished to independently develop and operate a new storage facility, it would have the same right to seek approval of market rates as any other storage developer. If the question relates to possible expansions of the existing integrated Utility storage facilities, e.g. through the addition of compression, it is true that it would not be possible to allow market rates for whatever capacity was made available by an expansion, if only because it would not be possible to identify "the capacity" that was made available, or the customers who use it.

Although this might make expansions less attractive than they otherwise would be, it must be remembered that cost based rates prescribed by the Board include a fair return that is intended to reflect the risk-adjusted cost of the capital invested in the Utility businesses. If the Board's determination of a fair return is correct, the Utilities will still have an incentive to invest in expansions of existing infrastructure, even if they would prefer to earn even higher monopolistic profits.

Q. **Does that conclude your testimony?**

A. Yes.

Mark P. Stauft

Mr. Stauft holds a Bachelor of Arts (Philosophy) degree from the University of Calgary, and a Bachelor of Laws degree, also from the University of Calgary. He has been a member of the Law Society of Alberta since 1986.

Since 2001 Mr. Stauft has been engaged in private practice as a regulatory consultant and regulatory counsel. During that period he has represented various clients before the Alberta Energy and Utilities Board in relation to matters involving various Alberta utilities, and before the National Energy Board in relation to matters involving the TransCanada PipeLines Limited Mainline system.

During that period he has also appeared as a witness on behalf of various clients in proceedings before the National Energy Board and the Ontario Energy Board, and provided advice to clients on a variety of regulatory issues.

From 1986 to 1999 Mr. Stauft was employed by TransCanada Gas Services ("TCGS")(formerly Western Gas Marketing Limited). During that period he held various positions of increasing responsibility in which he was responsible for directing TCGS's activities in pipeline and utility regulatory proceedings across North America. He represented the company, on a variety of regulatory issues, in proceedings before the National Energy Board, the Federal Energy Regulatory Commission, the Alberta Energy and Utilities Board, the Ontario Energy Board, and the Manitoba Public Utilities Board.

From 1999-2000 Mr. Stauft was employed by TransCanada PipeLines Limited, where he was responsible for directing the company's regulatory activities in relation to the TransCanada Mainline system.

A summary of the testimony that Mr. Stauft has presented before regulatory tribunals in Canada and the United States is attached.

Mark P. Stauft
Written and Oral Testimony

2004 – National Energy Board, TransCanada PipeLines Limited, Application for Approval of a New Receipt and Delivery Point at North Bay Junction and Associated Tolls, Hearing Order RH-3-2004. Filed written direct testimony and Information Request responses on behalf of the Cogenerators Alliance, a group of electric generators in Ontario. The testimony addressed the toll design implications of the pipeline's proposal and measures to avoid unjust toll discrimination. Testified before the Board.

2004 – National Energy Board, TransCanada PipeLines Limited, Application for Approval of 2004 Mainline Tolls and Tariffs, Hearing Order RH-2-2004, Phase 1. Filed written direct testimony and Information Request responses on behalf of the Cogenerators Alliance and Coral Energy. The testimony addressed appropriate forecasting methodologies for OM&A expenses, the prudence of the pricing and management of affiliate transactions involving Great Lakes transmission capacity and compressor waste heat provided to TransCanada's power generation affiliate, fuel incentive mechanisms, deferral accounts, and market based pricing of TransCanada's proposed FT-NR service. Testified before the Board.

2003 – National Energy Board, TransCanada PipeLines Limited, Application for Approval of 2003 Mainline Tolls and Tariffs, Hearing Order RH-1-2002. On behalf of the Firm Shippers Group (Mirant Canada, Coral Energy, PG&E National Energy Group and Energy East), filed written direct testimony, reply testimony, and Information Request responses on depreciation issues, economic life of facilities, other cost of services issues, various toll design issues, and service design issues related to shipper flexibility. Testified before the Board.

2002 – Ontario Energy Board, Enbridge Consumers Gas, Application for Approval of Fiscal 2002 Rates, Docket No. RP-2001-0032. On behalf of the Consumers Association of Canada, filed written direct testimony and interrogatory responses on upstream pipeline issues, and testified before the Board.

2002 – National Energy Board, TransCanada PipeLines Limited, Fair Return Application, Hearing Order RH-4-2001. On behalf of Mirant Canada, filed written direct testimony on market power and business risk issues and testified before the Board.

2001 – Ontario Energy Board, Enbridge Consumers' Gas, Application for Approval of Fiscal 2001 Rates, Docket No. RP-2000-0040. On behalf of the Coalition for Efficient

Energy Distribution, filed written direct testimony on upstream pipeline transportation issues.

2000 – National Energy Board, AEC North Suffield Pipeline Ltd., Application for a Certificate to Construct Facilities, Hearing Order GH-2-2000. Filed written direct testimony on behalf of NOVA Gas Transmission Limited and testified before the Board.

2000 – Ontario Energy Board, Union Gas Limited, Application for Approval of Performance Based Rates and Unbundling of Services, Docket No. RP–1999-0017. Filed written testimony on unbundling of upstream transportation and testified before the Board.

1999/2000 – National Energy Board, TransCanada PipeLines Limited, Application for Approval of Changes to the IT and STFT Toll Schedules, Hearing Order RH-1-99. Filed the Application and written direct and reply testimony and testified before the Board.

1999 – Ontario Energy Board, Enbridge Consumers' Gas, Docket No. RP-1999-0001. Filed written direct testimony on unbundling issues. Oral hearing of unbundling issues adjourned *sine die*.

1998 – Federal Energy Regulatory Commission, Northern Natural Gas Company, Docket No. RP-98-203. Filed written Answering Testimony on rate design and cost allocation issues.

1997 – National Energy Board, TransCanada PipeLines Limited, Application for Approval of 1998 Facilities, Hearing Order GH-2-97. Filed Information Request Response on market issues and testified before the Board.

1997 – Ontario Energy Board, Request for Comments Concerning Legislative Change, E.B.O. 202. Filed written comments and testified before the Board.

1997 – Federal Energy Regulatory Commission, Iroquois Gas Transmission System L.P., Docket No. RP-97-126. Filed written Cross-Answering Testimony on certain rate design and cost allocation issues, and testified before the presiding Administrative Law Judge.

1997 – Alberta Energy and Utilities Board, NOVA Gas Transmission Limited, Application for approval of a load retention service. Filed written direct evidence and testified before the Board.

1996 – Federal Energy Regulatory Commission, Northern Natural Gas Company, Docket No. RP95-185. Filed written Answering Testimony on rate design issues.

1996 – Manitoba Public Utilities Board, Review of Natural Gas Supply Procurement, Storage, and Transmission Functions of Centra Gas Manitoba, Inc. Filed written direct and reply testimony and testified before the Board.

1996 – Alberta Energy and Utilities Board, Gulf Canada Limited, Application to Construct Facilities. Filed written evidence on Gulf's "sidestreaming" extraction proposal and testified before the Board.

1995/96 – Alberta Energy and Utilities Board, NOVA Gas Transmission Limited, 1995 General Rate Application. Filed written testimony on tariff issues and testified before the Board.

1995/96 – Federal Energy Regulatory Commission, ANR Pipeline Company, Docket No. RP94-43. Filed written Direct, Cross Answering, and Surrebuttal Testimony on rate design and cost allocation issues, and testified before the presiding Administrative Law Judge.

1994 – National Energy Board, Western Gas Marketing Limited, Application for a Gas Export License. Hearing Order GH-3-94. Testified before the Board on market issues.

1994 – Federal Energy Regulatory Commission, Natural Gas Pipeline Company of America, Docket No. RP93-36. Filed written Direct and Answering Testimony on rate design and cost allocation issues.

1994 – Federal Energy Regulatory Commission, Tennessee Gas Pipeline Company, Docket No. RP91-203. Filed written Answering Testimony on Niagara Spur Charge issue.

1993 – Ontario Energy Board, Inquiry Concerning Impediments to the Direct Purchase of Natural Gas. Filed written testimony and testified before the Board.

1992 – Manitoba Public Utilities Board, Inquiry Concerning the Offering of Direct Purchase Options to Residential Customers. Filed written testimony and testified before the Board.

APPENDIX 2
To
Direct Evidence of Mark P. Stauft
EB-2005-0551

ILLUSTRATIVE STORAGE AND TRANSPORTATION COSTS FOR POSSIBLE U.S. ALTERNATIVES TO UNION GAS LIMITED STORAGE SERVICES IN ONTARIO

- Four cases are considered:

    1) Union unbundled storage service under the "U" series of rates

    2) Michigan storage with ANR Storage Company ("ANR Storage") storage service and connecting transportation via Great Lakes Gas Transmission ("Great Lakes") to St. Clair

    3) Chicago-area storage with Natural Gas Pipeline Company ("NGPL") storage service and connecting transportation via Vector Pipeline ("Vector") to Dawn

    4) New York storage with National Fuel Gas ("NFG") storage service and connecting transportation via the NFG transmission system to Niagara

- In each case, it is assumed that the customer will hold 10,000 GJ/d (9,488 Dth/d) of injection and withdrawal capacity, and storage space consistent with withdrawal capacity equal to 1.2% of reserved space. This equates to 833,333 GJ (790,639 Dth) of storage space.

- In each of the non-Union cases, it is assumed that the customer will hold 10,000 GJ/d (9,488 Dth/d) of annual firm transportation capacity on the pipeline connecting the storage facility to Dawn (Niagara in the NFG case).

- Costs associated with long-haul transportation upstream of storage, short-haul transportation downstream of Dawn/Niagara to consumers, and fuel supplied for the storage services are ignored since they are common to all of the cases. Fuel costs on short-haul transportation connecting the non-Union storage facilities to Dawn/Niagara are included because they are incremental to the base Union storage case.

- The rates shown are maximum tariff rates for the relevant services. The conversion factor for energy units is 1 Dth = 1.054 GJ. The US$/Cdn$ exchange rate is assumed to be Cdn$1.00 = US$0.88. The cost of fuel is assumed to be $6.00/GJ (US$5.56/Dth).

- For each case, a cost per unit of stored gas (i.e. per unit of storage space) is calculated, assuming a single injection/withdrawal cycle over the year. For the Union case, the unit cost reflects storage costs alone, while in the non-Union cases separate unit costs for storage service and associated transportation services are calculated and then totaled to obtain a total unit cost.

Case 1 - Union

Charge	**Volume**	**Rate**	**Annual Cost**
Space Demand	833,333	.022	219,000
W/d Demand	10,000	.929	111,480
Inj Demand	10,000	.929	111,480
Inj/W/d Commodity	1,666,666	.013	21,667
Total Annual Storage Charge			463,627
Unit Storage Cost		**$0.56**	

Case 2 – ANR Storage/GLGT

It is assumed that the customer holds GLGT eastern zone FT capacity, and uses it to transport injection volumes from St. Clair to ANR Storage and withdrawal volumes from ANR Storage to St. Clair. No costs are assumed for transportation between St. Clair and Dawn, or between GLGT and ANR Storage. A zero fuel ratio assumed for backhaul injection-related transportation on GLGT from St. Clair to ANR Storage.

Storage charges – ANR Storage FST

Space Demand	790,639	.0245	232,448
Capacity Demand	9,448	2.40	272,102
Commodity	1,581,278	.00804	12,713
Total Annual Storage Charge (Cdn$)			587,799
Unit Storage Cost (Cdn$/GJ)		$0.70	

Transportation Charges – GLGT FT

Reservation	9,448	5.189	588,308
Commodity	1,581,278	.00464	7,337
Fuel (forehaul)	790,639	0.7%	30,771
Total Annual Transportation Charge (Cdn$)			711,836
Unit Transportation Cost (Cdn$/GJ)		$0.85	
Total Unit Cost – Storage and Transportation		**$1.55**	

Case 3 – NGPL/Vector

It is assumed that injections are made with gas transported on Alliance, and that there is no cost to move injection volumes from Alliance to NGPL storage. Delivery of storage withdrawal volumes to NGPL delivery points is included in the DSS storage rate. The Vector shipper is assumed to pay the maximum negotiated rate that is applicable to original shippers, and that rate is assumed to include transport on the Vector Canada system. Note that Vector's current maximum cost-based recourse rate is approximately US$0.32/Dth.

Storage Charges – NGPL DSS Service

Capacity Demand	9,448	5.70	646,243
Total Annual Storage Charge (Cdn$)			734,367
Unit Storage Cost (Cdn$/GJ)		$0.88	

Transportation Charges – Vector FT-1 (Negotiated Rate)

Demand	9,448	.25 (per day)	862,130
Commodity	0		0
Fuel	790,639	1.03%	45,278
Total Annual Transportation Charge (Cdn$)			1,031,145
Unit Transportation Cost (Cdn$/GJ)		$1.24	
Total Unit Cost – Storage and Transportation		**$2.12**	

Case 4 – NFG

It is assumed that injection volumes are delivered to Niagara via a no-cost diversion on TransCanada. There will be a charge on TransCanada to transport withdrawal volumes from Niagara to the Utility systems, e.g. Kirkwall, which is not included. However, it is assumed that that cost would be offset by avoided Dawn/Trafalgar charges.

Storage Charges – NFG FSS

Space Demand	790,639	.0432	409,867
Capacity Demand	9,448	2.1556	244,393
Inj/W/d Commodity	1,581,278	.0157	24,826
Total Annual Storage Charge (Cdn$)			771,689
Unit Storage Cost (Cdn$/GJ)		$0.93	

Transportation Charges – NFG FTS

Demand	9,448	3.3612	381,079
Commodity	1,581,278	.0081	12,808
Fuel	1,581,278	2.0%	175,838
Total Annual Transportation Charge (Cdn$)			647,414
Unit Transportation Cost (Cdn$/GJ)		$0.78	
Total Unit Cost – Storage and Transportation		**$1.71**	