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2006-05-26

VIA EMAIL and COURIER

Mr. Peter O'Dell
Assistant Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, ON M4P 1E4

Dear Mr. O'Dell:

Re: Board File No.: EB-2005-0551
Natural Gas Electricity Interface Review Issues and Storage Regulation
Reply Evidence of Enbridge Gas Distribution Inc.

Please find attached ten copies of the reply evidence of Enbridge Gas Distribution in response to Procedural Order No. 2

Specifically, the evidence being filed by Enbridge Gas Distribution includes the following:

F-1-1	Load Balancing
F-1-2	Title Transfers
F-2-1	Reply to APPrO Evidence
F-3-1	Storage Regulation

Also included is an updated index of the evidence of Enbridge Gas Distribution filed to date.

Yours truly,

David Stevens
Acting Senior Counsel, Regulatory

Attachment

cc: Mr. F. D. Cass, Aird & Berlis (via email and courier)
EB-2005-0551 Interested Parties (via email)

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F– REPLY EVIDENCE

REPLY EVIDENCE – LOAD BALANCING

1. In the evidence it has already filed, Enbridge Gas Distribution has identified two key considerations that directly affect the Company's ability to provide load balancing for power generation customers (or other qualifying customers): (i) the reservation of upstream transportation capacity to allow for nominations to be increased on a firm basis, and (ii) the availability of additional nomination windows to facilitate the adjustment of deliveries later in the gas day (Exhibit B, Tab 3, Schedule 1, para. 17). A further qualification of these upstream capabilities was that they would be available for deliveries made to the delivery area (ibid). This transportation service flexibility is necessary to allow Enbridge Gas Distribution to be responsive to the balancing needs of these customers and adjust its supplies in the delivery area on a firm basis.

2. Both Union Gas ("Union") and TransCanada Pipelines ("TCPL") have filed evidence in this proceeding that outlines their transportation service proposals that are intended to address the needs of power generators. To effectively provide load balancing services, Enbridge Gas Distribution expects to need to be able to use services from both Union and TCPL.

Union Gas F24-T Proposal

3. Union has introduced four new services in its evidence that are designed to support power generation customers. These service proposals are:
   i) F24-T;
   ii) Upstream Pipeline Balancing Service ("UPBS");
   iii) Downstream Pipeline Balancing Service ("DPBS"); and
   iv) F24-S.

While each of these services provides a degree of flexibility for a power generation customer to meet their needs, Enbridge Gas Distribution views the F24-T service as providing the flexibility it requires to move supply between storage and Parkway for the purpose of providing load balancing services.

4. The F24-T service provides both reservation of capacity and additional nomination windows. The 10 nomination windows proposed by Union are, in Enbridge Gas Distribution's view, sufficient to enable the Company to effectively move gas between storage and Parkway for the purpose of load balancing its delivery areas. The timing of these windows was developed through discussions between the two companies. As the Company indicated during the Technical Conference, Enbridge Gas Distribution believes that the Union proposal provides what is needed by the Company (April 6, 2006, Tr. 159).

5. Given that Union is unable to transport gas from Parkway to the Enbridge CDA or Enbridge EDA, Enbridge Gas Distribution must still rely on upstream transportation services from TCPL to move gas into its delivery areas. Without compatible services from TCPL that allow for the reservation of capacity to the delivery area with similar nomination windows, the F24-T service on its own is inadequate in supporting the Company's load balancing requirements.

<u>TCPL FT-SN Proposal</u>

6. TCPL has filed evidence in this proceeding regarding two services that it is proposing to serve the power generation market: FT-SN, a short notice firm transportation service, and SNB, a short notice balancing service. TCPL has also filed an application with the NEB seeking approval for the addition of FT-SN and SNB to its portfolio of service. As a result, these services remain proposals and it is not certain if they will become available to customers in their current state.

7. The SNB service is intended to provide an intra-day balancing service that is expected to support the effective operation of FT-SN by providing access to alternative supply on a short notice basis (TCPL evidence, Issue I, page 10, A10). While SNB service may provide some benefits to power generators, Enbridge Gas Distribution does not see this service as being necessary for the purpose of the Company providing load balancing services. As a result, the focus of this reply evidence is on the proposed FT-SN service.

8. FT-SN is a short notice firm transportation service that provides reservation of the contracted transportation capacity and allows for nominations to be changed every 15 minutes (TCPL evidence, Issue I, page 3, A7). Two additional attributes of this service are the requirement for deliveries to be made to a separate distributor delivery area and for the delivery location to have flow control valves that can be remotely operated by TCPL (TCPL evidence, Issue I, pages 8–10).

9. TCPL has indicated that while a separate distributor delivery area is a requirement of the FT-SN service, this should not preclude power generators, or other interested shippers, from contracting for this service if they are not located within reasonable proximity of the TCPL system, but are instead “embedded” within an LDC’s distribution franchise. For these embedded shippers, a unique delivery area and flow control valve would still be required, but the gas flowing from the flow control valve can be connected in the LDC distribution system for delivery to the customer’s plant (May 16, 2006, Tr. 112 and 141).

Rate 125 Implications of FT-SN

10. Enbridge Gas Distribution notes that both the FT-SN and SNB services proposed by TCPL will require NEB approval prior to them becoming available to TCPL shippers. TCPL currently has an application before the NEB, but it is uncertain whether the services will be approved in their current form. TCPL has indicated that it expects

an NEB decision on its service proposals some time in 2006 (May 16, 2006, Tr. 78). Enbridge Gas Distribution's reply evidence is based on the services as they have been laid out within TCPL's evidence in the NGEIR proceeding. Any changes that may be made to these services as the result of an NEB proceeding may result in changes to the implications the Company currently sees from these services.

11. As indicated above, the Company does not see the SNB service proposed by TCPL as playing a role in Enbridge Gas Distribution's ability to provide load balancing services to power generation or other qualifying customers. There are, however, implications to the Company's proposed limited balancing services arising from the FT-SN service as it is currently proposed.

12. TCPL's evidence makes a distinction between two types of FT-SN customers: those that are served by a dedicated connection to the TCPL system; and those that are embedded within a distributor's franchise area. This distinction has a direct impact on the ability of Enbridge Gas Distribution to provide load balancing services.

13. For power generators using the proposed FT-SN service that are served by a dedicated connection to the TCPL system, Enbridge Gas Distribution will not be able to provide any load balancing services. This would include the provision of a 2% balancing tolerance within Rate 125. FT-SN service requires daily balancing between deliveries and consumption at the unique delivery point established for the FT-SN service. Since this delivery point is not able to use any other TCPL services (May 16, 2006, Tr. 98), Enbridge Gas Distribution would have no means other than contracting for FT-SN service itself to that same delivery point as a means of balancing the deliveries and consumption for that customer. This would in essence result in either a duplication of contracted capacity to that delivery point, with the customer holding the capacity they require to meet their peak hourly flow and Enbridge Gas Distribution holding capacity to meet the maximum balancing that is to

be provided, or in the customer assigning a portion of their capacity to Enbridge Gas Distribution for balancing purposes. If the customer were to assign this capacity, it would either reduce their ability to meet their peak hourly demand on their own (Enbridge Gas Distribution would have to make deliveries on their behalf to meet the peak) or require the customer to over-contract for the capacity they require.

14. Whether Enbridge Gas Distribution acquired its own FT-SN service to the point or received an assignment of capacity from the customer, the Company would not be able to provide any efficiency to the customer by balancing this load against deliveries to the broader delivery area (the CDA or EDA). Currently, Enbridge Gas Distribution relies on a certain variability in demand within its franchise areas as a means of limiting the costs associated with balancing customers loads. On any given day, the Company is able to net the under-deliveries to customers that consume more than expected against the over-deliveries to customers that consume less than expected. To the extent that these trade-offs do not balance out, the Company is also able to adjust its overall nominations to the broad delivery area and use other transportation services such as IT and STS as a means of moving gas into or away from the delivery area. Enbridge Gas Distribution has additional flexibility in the CDA by managing deliveries into its distribution system at Parkway under its M12 contracts with Union. Enbridge Gas Distribution is also able to use its Limited Balancing Arrangements (LBAs) with TCPL as a means of managing imbalances in the delivery area within the tolerances allowed by TCPL. All of these tools that are available to the broader delivery area provide a higher degree of flexibility than what can be offered at a distinct delivery point as required by FT-SN for a directly connected customer. In these situations, the only real option is FT-SN to that point.

15. During the Technical Conference, Mr. Frew of TCPL indicated that it was possible that an FT service could also be contracted for by an FT-SN customer and an additional meter would be added to serve a direct connect customer. This meter

could then be connected downstream of the flow control valve on the dedicated line (May 16, 2006, Tr. 99). If TCPL were to allow such a connection, the load balancing provisions of Rate 125 could apply to a direct connect customer as this may provide a means of allowing deliveries to the broader delivery area to be used for balancing the direct connect FT-SN shipper's load. However, it would represent a duplication of metering facilities and require other incremental facilities to provide the service to the power generator. To the extent that these additional facilities are required, this would reduce the feasibility of connecting the customer. If the connection was rendered uneconomic, a capital contribution might be required from the customer to offset these additional costs.

16. For power generators using the proposed FT-SN service that are embedded within the Enbridge Gas Distribution delivery area, Enbridge Gas Distribution will be able to provide the load balancing services proposed in Rate 125. Since the customer would still be served off of the broader Enbridge Gas Distribution distribution system, the Company would have the means of balancing the loads of these customers to the thresholds specified in its Rate 125 proposal using similar approaches to those currently used to balance the loads of other customers. The efficiencies that can be gained from the broader delivery would be made available to these customers.

17. As a result of TCPL's FT-SN proposal, Enbridge Gas Distribution will be filing an updated rate schedule for Rate 125 to differentiate the services that can be made available to customers depending on the upstream services they have contracted for and the manner in which they are connected to the transmission system.

REPLY EVIDENCE – TITLE TRANSFERS

1. Enbridge Gas Distribution has proposed in its evidence that transactions under the Enhanced Title Transfer ("ETT") service be executed at Dawn (Exhibit C, Tab 4, Schedule 1, para. 6). The principal driver for this consideration was the Company's belief that the degree of liquidity at Dawn and its role within the Union Gas system best facilitates the transfer of gas between utilities (ibid). The Company proposed an administration charge for all customers using this service. Furthermore, for direct purchase customers using a bundled service, there would be a "Bundled Service Charge" that was equivalent to the absolute difference between the Eastern Zone and Southwest Zone Firm Transportation tolls approved by the National Energy Board (Exhibit C, Tab 4, Schedule 3).

2. In its evidence, APPrO proposes that title transfers under the ETT service be allowed at other points, in addition to Dawn (APPrO Evidence, Section 4.4 (d)). During the Technical Conference, Mr. Rosenkranz clarified that APPrO didn't have any specific recommendations on what other points should be permitted, but that "when services are offered, they should be offered in such a way that is as generic and expansive as reasonably possible." (May 17, 2006, Tr. 66). APPrO acknowledged that determining an appropriate rate for bundled service customers for points other than Dawn may be "somewhat problematic" (ibid), but believed it "was more straightforward as an administrative issue for other types of services" (ibid).

3. Enbridge Gas Distribution believes that the position of APPrO does not take into consideration some of the operational implications or costs associated with facilitating ETT transactions. For a customer to be in a position that would require them to enter into an inter-franchise title transfer, they would have to have either over-delivered or under-delivered gas supply to the Local Distribution Companies

("LDC"). The LDC would then have to either bring in additional supplies to the delivery area or move supplies away from the delivery area on that day to balance the total load for the delivery area. While the LDC might be able to facilitate this by virtue of other customers within the delivery area having imbalances in the opposite direction, at the end of the day the delivery area would have to be brought into balance and the excess or shortfall in gas would have to be made up. For any gas that could not be balanced against other loads, the likely source or destination for that gas is Dawn. Enbridge Gas Distribution believes that this would likely also be the case for other utilities in Ontario.

4. When the customer requests the ETT transaction at a point other than Dawn, the two utilities participating in the transaction would have to ensure they had sufficient supply at that point to execute the title transfer. This would likely require each utility to either move gas to or from Dawn or their franchise area to this common point for the purpose of executing the transaction, at some cost. This cost has not been contemplated in the derivation of the costs associated with providing the proposed service. Furthermore, the costs would likely vary depending on the point in question, making it difficult to define within a tariff.

5. Given the liquidity at Dawn and the costs and challenges associated with trying to facilitate an inter-franchise title transfer at points other than Dawn, Enbridge Gas Distribution does not believe it is necessary, or in the best interest of all ratepayers, to facilitate ETT transactions at any point other than Dawn.

REPLY EVIDENCE: RESPONSE TO APPrO EVIDENCE (RATES 125 and 316)

1. APPrO's evidence includes 11 proposals that it believes will benefit gas fired generators and other customers by reducing their supply costs. Of these, several proposals relate to upstream transport services that the Company does not provide. However, the Company has offered to make available to its customers all enhancements to transport services that are made available to it. To the extent that some of these requirements, such as hourly nominations and firm reservation of capacity also relate to storage services, the Company's proposals include them. In the following evidence, the Company sets out its response to APPrO's comments on its Rate 125 and Rate 316 proposals.

Rate 125

2. APPrO's evidence suggests that the minimum applicability for Rate 125 must be lowered to allow small generators to take service on Rate 125 and that Rate 125 must allow for negotiated outcomes that include incremental pricing and longer term rate certainty. APPrO also asserts the Company's cashout provisions are not reasonable and that greater clarity is required with respect to the load balancing provisions of Rate 125.

(i) Minimum Contract Demand for Rate 125

3. At page 61 of its evidence, section 4.4, APPrO suggests that the minimum daily quantity of 600 000 m^3 required to be eligible for service under Rate 125 is too high and that the rate does not take account of the needs of smaller generators which may otherwise have the same needs. At the Technical Conference (May 17, 2006, Tr. 57, line 10), the APPrO panel suggested that a minimum threshold of 300 000 m^3 is more appropriate. APPrO also acknowledged that the "needs of smaller generators" is fundamentally an issue of cost, not access to services. (Tr. 57, line 1)

Importantly, the cost difference between Rate 125 and Rate 300 is small, particularly when compared to the cost of gas commodity.

4. In its Undertaking response #24 in this proceeding, the Company outlined all the reasons why Rate 125 has a minimum threshold of 600 000 m^3 and the impact on other customers of reducing the applicability to 300 000 m^3. In particular the Company identified the fact that Rate 125 has certain features that make the rate robust against bypass. Lowering the threshold would dilute this robustness, and customers currently served from other than extra-high pressure mains may become eligible for the rate. This alters the cost basis, increases the opportunity for bypass and violates the APPrO principle that utility services contribute to economic efficiency of both the gas and electric market.

5. The argument for a lower contract demand to accommodate smaller power generators provides no factual foundation that such lower minimum demands are needed or that those lower limits remain cost based. Depending on heat rate and technology, plants that are as small as 100MW may qualify for Rate 125.

6. Smaller generators, who do not qualify for Rate 125 impose lower operating risks for the Enbridge Gas Distribution Gas Distribution distribution system, receive service under Rate 300 and benefit from the more favorable service options under that rate such as the delivered storage under Rate 315. As such these customers pay a higher distribution charge but also benefit from the greater flexibility in balancing provisions. Reducing the minimum contract demand for Rate 125 represents an inefficient and unnecessary alteration of the total service package offered by Enbridge Gas Distribution Gas Distribution. It is inefficient because it alters the cost structure of Rate 125 and dilutes its robustness against bypass and unnecessary because it responds to a non-existent problem.

(ii) Negotiated Rates

7. At the Technical Conference (May 16, 2006, Tr. 215), APPrO's panel provided examples of negotiated rates. One such example would allow for rates that are fixed over a period of time. APPrO also claimed that offering such rates was not linked to incentive rate making and could be offered without harming other customers. APPrO further clarified that in such instances these rates could be set at a premium above cost based rates to obtain rate certainty. The Company has no objection, in principle, to rate setting in this manner as long as the mechanisms for setting premiums over current costs are adequately compensatory for the added business risk from offering rate certainty over extended periods of time. The Company also believes that the existence of negotiated rates approved by the Board should not be the basis for future disallowance of costs to the extent that changes in costs cause such rates to be less than fully compensatory.

(iii) Cashout Provisions for Load Balancing

8. Rate 125 provides for a cashout process for imbalances under a variety of conditions. APPrO states that Enbridge Gas Distribution has not demonstrated that its cashout penalties are reasonable. At the Technical Conference, APPrO suggested that penalties should be linked to the cost of managing the imbalance caused by a customer's non conformance (May 17, 2006, Tr. 58) while simultaneously acknowledging that penalty provisions should include disincentives and that if they are set correctly, they would not apply since the customer would have complied (Tr. 61, line 12). Finally, APPrO also suggested that penalties have to go hand in hand with available options to avoid them.

9. Enbridge Gas Distribution is committed to the principle of assuring no adverse impact on other customers as part of its filing. The cashout penalties represent an

important element of that commitment. Conceptually, the cashout mechanism design aims to produce behaviors that protect the system from both a reliability perspective and a cost perspective.

10. APPrO acknowledges that the enhancements to Rate 125 provide greater ability to manage imbalances. Under its proposal, Enbridge Gas Distribution would provide all the upstream transport flexibility available to it and permit the customer to nominate and use storage assets in conjunction with pipeline supplies. The customer takes the responsibility to manage its system without imposing costs, reliability related or gas commodity related, on the other customers. The cashout level only applies above a ten percent imbalance related to the maximum contractual imbalance as opposed to the nominated delivery on a day, if the imbalance is in the direction of seasonal constraints. If the imbalance is the opposite direction to seasonal constraints the customer may have an imbalance equal to the maximum contractual imbalance. Put together, these tolerances allow for a draft capability of 6% (equivalent to 1.5 hours of continuous drafting) and a pack capability of 14 hours in the winter. In no instance is a customer that is integrated with the distribution system expected to balance exactly. Accordingly, the customer is provided with all the tools available to Enbridge Gas Distribution to manage their daily imbalances.

11. Further, Enbridge Gas Distribution is unable to confirm that APPrO desires an increase in the tolerances for Rate 125 (Tr. 61, Line 2). Rather, APPrO emphasizes that if upstream services are available to power generators they may not be as concerned about penalties (Tr. 62, Line 22).

12. Where the customer drafts the system during the winter, beyond a planned tolerance level, the potential for price arbitrage exists as does the threat to system

reliability. The reliability and costs concerns related to power generation are unique in the sense that the magnitude of the load and the variability of the load challenge the traditional operating parameters of the system. APPrO recognizes the unique load characteristics of electric generation without any apparent concern for the impact on the operation of the gas delivery system. To discourage behavior that potentially increases the cost of gas for customers purchasing gas from Enbridge Gas Distribution, the Company proposed a cashout mechanism. Without a meaningful penalty (an effective zero cashout price that passes through the spot cost of gas, for example), no deterrent exists to damaging behavior that raises costs for captive customers and jeopardizes reliability. Conceptually, the lowest cost for meeting the imbalance requirement is the spot cost of gas commodity. The highest cost for this service cannot be known with certainty because drafting in the winter creates the potential for system outages and these costs substantially exceed the proposed penalty amount. Even with very high penalties, there is no assurance that the deterrent to adverse behavior is effective, particularly where the power generator bids based on the expected penalty.

13. Enbridge Gas Distribution set the cashout rate at 150% of the highest daily index price for drafting the system in the winter and at 50% of the lowest index price for packing the system in the summer. These levels are consistent with cashout provisions used by Local Distribution Companies (“LDC”) in other jurisdictions such as Pacific Gas and Electric cited by APPrO. In addition, as fully discussed in evidence (Exhibit B, Tab 4, Schedule 1, Page 5), Enbridge Gas Distribution believes that the cashout mechanism and the levels strike the appropriate balance to deter opportunism and to protect system reliability. In the event that customers jeopardize the system, Enbridge Gas Distribution needs other tools such as automatic shut off/flow control valves.

(iv) Clarity with respect to Load Balancing provisions and OFO Days

14. APPrO asserts that greater clarity is required with respect to the proposed load balancing provisions of Rate 125 and Operational Flow Order (“OFO”) days.

15. During the Technical Conference, APPrO expressed concern with the proposed tolerance for load balancing under Rate 125. Mr. Kelly indicated that the proposal related to the balancing provisions was “a small step in the right direction of what the generators are looking for. But, in and of itself, it is not sufficient.” (May 17, 2006, Tr. 60). Enbridge Gas Distribution acknowledges that there are some limitations associated with limited balancing service it has proposed in its evidence. As Enbridge Gas Distribution outlined in paragraph 6 of Exhibit C, Tab 2, Schedule 1, a number of potential alternatives for providing a limited balancing service were reviewed. Each of these alternatives required differing levels of incremental assets and provided different characteristics.

16. Based on feedback that was received from power generators during the stakeholder process, the Company deduced that these customers were looking for a low cost service that still provided a degree of flexibility. It was on this basis that the Company brought forward its proposal to provide the load balancing services based on its Option 1.

17. Enbridge Gas Distribution is not averse to offering increased load balancing services. It must, however, be recognized that with more flexibility comes more cost. Providing enhanced services from Option 1 will likely require the Company to invest in incremental assets, including additional transportation that provides for the reservation of capacity. To the extent that these incremental assets are secured solely for the purpose of providing less restrictive load balancing options for Rate 125, the costs must be borne by the customers that would benefit.

18. As shown at Exhibit C ,Tab 2, Schedule 3, page 5, the Company proposes that Maximum Contractual Imbalance (“MCI”) for customers served under Rate 125 shall be less than or equal to 60% of the customer’s Contract Demand.

19. The Company determined that limiting the MCI to 60% of the customer’s Contract Demand would allow for a low cost, limited balancing service that utilizes system diversity and few incremental assets. Such an approach, however, requires seasonal restrictions on balancing to minimize cost consequences on bundled customers and probability of system outages. Nevertheless, the proposed service provides substantial balancing flexibility for power generators and other very large customers.

20. Based on the forecast size of potential power generation customers (and other eligible customers) anticipated to take Rate 125 service in the next five years, the Company expects it would be able to load balance such customers at an MCI that equals 60% of Contract Demand. The Company believes that this addresses APPrO’s concerns regarding the setting of the MCI in an objective, transparent and non-discriminatory manner.

21. As discussed in paragraph 17 above, the Company would like to stress it is not averse to increasing the proposed load balancing service if customers are willing to pay higher cost of providing a more flexible service. Setting the MCI at a higher percentage of the customer’s Contract Demand would likely require the Company to move off Load Balancing Option 1 and acquire incremental assets to provide enhanced balancing to Rate 125 customers. This would facilitate increased flexibility, but at a higher cost.

22. The design of the load balancing provisions in Rate 125 incorporate the ability to declare an OFO day to protect the reliability of the system on certain days where particular conditions described in the rate schedule (Exhibit C, Tab 2, Schedule 3, page 5) potentially limit system flexibility. The Company is proposing to provide 24 hours notice for an OFO day to permit customers to manage nominations within the tighter tolerances on those days. Similar to a curtailment request, the 24 hour OFO notice would provide information concerning the need for OFO and affected rate class(es). The Company would like to emphasize that by over nominating gas on an OFO day, the customer incurs no load balancing charges on a winter OFO day. Likewise, by under nominating gas in the summer, the customer incurs no load balancing charges on a summer OFO day.

23. The load balancing provisions work together with cashout penalties and balancing charges specific to OFO days and permit the Company to provide flexibility for customers while maintaining system reliability. By permitting a separate set of provisions for the most critical days from a system operating perspective, the Company can permit greater flexibility on less critical days.

24. The trade off between flexibility and cost for balancing service also applies to circumstances that for call for an OFO. As pointed out in paragraph 21 above, if the Company acquired incremental assets solely for the purpose of providing load balancing to Rate 125 customers then the load balancing flexibility would increase, and so would the cost. At the same time, the use of such assets could reduce the number of OFO days the Company would otherwise need to call under its Load Balancing Option 1. This would reduce upstream constraints resulting in less OFO days, but would not alleviate OFO days related to equipment or pipeline failures.

Rate 316

(i) Storage Allocation Methodology

25. At the May 16th Technical Conference, APPrO recommended a storage allocation methodology for power generators. Enbridge Gas Distribution understands that the methodology advocated by APPrO is based on the following principles:

(a) A power generator should receive an entitlement of deliverability that would allow it to meet the entire imbalance between supply and consumption over a 24 hour period from storage.

(b) The associated storage space would be determined assuming that 10% deliverability is available.

(c) Of its total entitlement, the power generator would pay rolled in rates for the standard 1.2% deliverability.

(d) The power generator would pay incremental cost for the balance of its entitlement (i.e. the additional deliverability of 8.8%).

26. While Enbridge Gas Distribution acknowledges that the current Board approved methodology for allocating cost based storage may not yield a level of storage that is sufficient for power generators, the Company is concerned that APPrO's proposal would result in excessive allocation of cost based storage to power generators and excessive demand for storage assets.

27. Firstly, in its evidence at page 40, section 3.7, and elsewhere APPrO states that storage should not be expected to absorb all potential imbalances, and consumers need to have other tools in addition to storage to help prevent large imbalances from occurring. However, APPrO's recommended methodology to determine its storage entitlement assumes that the entire imbalance between deliveries and consumption is either injected into storage or withdrawn from storage, with no

recognition of the fact that the customer may choose to either sell, divert or purchase additional supplies. Further, APPrO does not believe that any restrictions on the use of this storage are appropriate, nor would gas fired generators commit to sharing any profits from remarketing cost based storage at a higher price (May 17, 2006, Tr. 45, line 12).

28. Secondly, bundled customers do not receive an allocation of storage that meets their entire balancing requirements from storage. The current Board approved formula for allocation of cost based storage is designed to meet average seasonal balancing requirements, not maximum balancing requirements as proposed by APPrO for gas fired generators. There is therefore an incongruence between the Board approved methodology and APPrO's methodology in terms of outcomes. Enbridge Gas Distribution would be willing to consider alternative methodologies that permit greater congruence between cost based allocation methodologies for existing customers and power generators.

29. Finally, Enbridge Gas Distribution agrees with APPrO that 1.2% deliverability associated with the space allocation methodology should be available at system average cost. Enbridge Gas Distribution submits, however, that in a non-forbearance scenario, higher deliverability services should be priced at market, with any premium above cost being attributed to utility shareholders. Enbridge Gas Distribution is open to discussing a possible sharing of this premium with ratepayers to ensure: (i) that the economics of building the rate 316 capabilities in its storage system are attractive to the utility, and (ii) create a win/win outcome for power generators and other ratepayers, subject to Board approval.

(ii) Maintaining Gas System Integrity with Power Generator Flexibility

30. Enbridge Gas Distribution discussed at length the impact of flexibility for gas generators and the potential impact on system reliability. The APPrO evidence omits concerns over reliability for the gas delivery systems. The APPrO evidence discusses at length the needs of the power generation market to maintain electric system reliability. For example, APPrO states in its evidence that (Section 2.2.3(vi), page 17):

> (T)here is a direct link between the flexibility of service offerings in the gas market and the reliability of the power grid. Inflexible gas service offerings increase the risk in the Ontario electricity system. Accordingly, it is necessary that dispatchable gas-fired generators have access to transportation and balancing services that will enable them to contribute to the required reliability of Ontario's electricity system.

31. Enbridge Gas Distribution recognizes the importance of electric reliability and to the extent that electric reliability does not jeopardize the gas system reliability supports flexible services. As discussed by Enbridge Gas Distribution (Exhibit B, Tab 4, Schedule 1, Page 3):

> At the extreme, large imbalances cause the system to lose pressure and experience system failure. The consequences of system failure due to loss of pressure impose significant economic costs on all customers and the restoration process requires days or weeks depending on the number of customers losing service. Unbundled services must be designed to minimize the risk of system outages. Risk management includes both the assessment of the cost and the probability of the outcome.

32. The issue of flexibility requires an assessment of the cost of system outages on both customers and the utility. System restoration costs for gas distribution represent the largest single cost risk for an LDC. Enbridge Gas Distribution's testimony describes in detail the costs and impacts of a system outage.

The reliability of the gas delivery system provides the single most paramount constraint on the limits of flexibility. All flexibility for power generation faces limits of cost for new facilities or services and the critical requirement for the power generator customers to manage their gas consumption to avoid adverse gas system impacts. The proposed Rates 125, 300, 315 and 316 represent a careful and comprehensive set of proposals that permit Enbridge Gas Distribution to provide as much of the flexibility and cost-based rates as possible while protecting the reliability and economics of gas service for all customers served by the Company's system.

REPLY EVIDENCE – STORAGE REGULATION

Q. What are your name, title, and business address?

A. My name is Richard G. Smead. I am a director in the energy practice of Navigant Consulting Inc. (NCI). My business address is 909 Fannin Street, Suite 1900, Houston, Texas 77010.

Q. For whom are you testifying in this proceeding, and in what role?

A. I am testifying for Enbridge Gas Distribution, as an expert in the natural gas pipeline business.

Q. Have you previously offered evidence in this proceeding?

A. Yes. I sponsored NCI's expert report filed as direct evidence by Enbridge Gas Distribution (Exhibit E, Tab 3, Schedule 1), and participated as a witness in the Technical Conference held from 16 May to 19 May. My *curriculum vitae* is being submitted in the context of that conference, and I summarized my relevant qualifications during direct examination.

Q. What is the purpose of your prepared reply testimony?

A. The purpose of my testimony is to respond to two expert witnesses in this proceeding, Ms. Bruce M. McConihe for the Staff of the Ontario Energy Board (OEB) and Mr. Mark P. Stauft for the Industrial Gas Users' Association (IGUA) and various other end users of natural gas in Ontario.

Q. What conclusions of Ms. McConihe and Mr. Stauft will you address?

A. Both witnesses have conducted analyses by which they conclude that Ontario storage markets, particularly those served by Enbridge Gas Distribution and Union Gas (Union), are not sufficiently competitive to justify market pricing of storage services. This conclusion is diametrically at variance with the conclusion NCI reached in reviewing the work performed for Union by Energy and Environmental Analysis Inc. (EEA), and in making its own independent qualitative review of the Ontario market. Our conclusions were included in the direct evidence filed by Enbridge Gas Distribution. My reply evidence addresses the reasons that these various experts reached different conclusions, and what I will show to be certain infirmities in the analyses of Ms. McConihe and Mr. Stauft.

Q. What is your overall reaction to the evidence of Ms. McConihe and Mr. Stauft?

A. Both witnesses have produced extensive, detailed analyses to support their assertions, but two aspects of both greatly simplify a high-level reaction. First, the conclusion that the various services provided at Dawn, Ontario are not fully competitive flies in the face of my industry experience—Dawn is well known as one of the most competitive market hubs in North America. Frankly, the notion that Dawn is not fully competitive is a stunning departure from the common perception of the industry. Second, although both witnesses go into great detail in performing their market analyses once they have defined the relevant market, both base their entire logical structures on initial, "lynchpin" assertions that, if not valid, cause the entire analyses to collapse.

Q. What experience or evidence do you have that Dawn is seen by the natural gas industry as a fully competitive market hub?

A. First, Dawn has routinely been viewed by industry analysts and the trade press as a major pricing point in the North American gas market. This is because sales into Dawn and purchases from Dawn are of strong interest to market participants throughout the industry. Such interest would not exist if Dawn were in any way an isolated market. Second, my own experience as an officer of ANR Pipeline Company was fully consistent with the perception of the industry, that Dawn is a major competitive market point in the North American gas industry. ANR Pipeline Company interacts daily with the Dawn hub, competing in both directions across the border for storage business.

Q. Have U.S. regulators recognized the competitive nature of Dawn?

A. Yes. For example, in June 2005, the Staff of the Federal Energy Regulatory Commission (FERC) Office of Market Oversight and Investigation issued their "2004 State of the Markets Report." There, at page 161 of the report, the FERC Staff said:

> The Dawn Hub is an increasingly important link that integrates gas produced from multiple basins for delivery to

> customers in the Midwest and Northeast .. . . Dawn has many of the attributes that customers seek as they structure gas transactions at the Chicago Hub: access to diverse sources of gas production; interconnection to multiple pipelines; proximity to market area storage; choice of seasonal and daily park and loan storage services; liquid trade markets and transparent pricing; and opportunities to reduce long-haul pipeline capacity ownership by purchasing gas at downstream liquid hubs.

The FERC staff's assessment of the importance of, and dynamic market characteristics around Dawn, is fully consistent with the industry perception that I share, and quite inconsistent with the picture painted by Ms. McConihe and Mr. Stauft.

Q. What are the initial "lynchpin" assertions in the evidence of the two witnesses that are critical to their findings?

A. In the case of Ms. McConihe, that assertion is simple: That there is no transmission capability for services from the United States to compete with Ontario services. Mr. Stauft similarly asserts an inability for competitive supplies to be transported across the border, but also asserts that U.S. storage is unavailable in the quantities necessary to compete meaningfully, and that the combined cost of U.S. storage and the associated transportation, if it were available, would greatly exceed the competitive price for storage service in Ontario—and thus would not be a meaningful substitute for that storage service. Further, throughout his evaluation, Mr. Stauft relies extensively on an assertion made early in his evidence (Stauft evidence, pages 17-18), that the threshold for determining whether prices are competitive is the cost-of-service rate—that any market in which a competitor's price can exceed that competitor's average level of accounting cost by 10 percent or more is *per se* uncompetitive.

Q. You indicated that these various assertions are "lynchpins," upon which the entirety of each witness's analysis rests. Please explain.

A. The entirety of each witness' analysis depends upon the confinement of all quantitative factors, market-entry dynamics, etc. to Ontario. Any significant expansion of the relevant geographic market beyond Ontario, especially into Michigan or New York, brings into play massive storage operations and the entire U.S. interstate-pipeline network. If the relevant geographic market is so expanded, all quantitative measures of market concentration, market share, etc. strongly confirm robust competition—as is amply demonstrated by EEA. Accordingly, it is the two witnesses' assertions of an inability of U.S. storage and other services to provide competitive alternatives to Ontario that allow the two witnesses to reach quantitative measures that indicate the existence of market power. Additionally, Mr. Stauft has placed a great deal of reliance on the premise that average-cost regulated rates must be the threshold from which all prices are measured, to determine market power. This reliance distorts each comparison he makes, whether dealing with in-province market storage or with competitive U.S. storage. If open-market competitive prices are used for the threshold, rather than average-cost-based regulated rates, any valid comparison shows a normal competitive market.

Q. Turning first to Ms. McConihe, is she correct that transportation constraints act to isolate the Ontario market from northern U.S. markets?

A. No. Ms. McConihe apparently did not perform the analysis of available pipeline capacity herself, but rather subcontracted it to Ben Schlesinger Associates (McConihe evidence, page 25). Thus, it is not entirely clear how broad-based the inquiry was, beyond the specific pipelines and contracts listed. However, as presented in Ms. McConihe's evidence, the formulation and analysis of how storage gas gets to a market such as Dawn disregards the way today's dynamic natural gas industry really works. When all the vehicles and mechanisms used by the industry for markets to communicate with each other are taken into account, it is apparent that there is ample ability for storage and other services in the United States to provide meaningful competition for Ontario storage.

Q. What "vehicles and mechanisms" did Ms. McConihe fail to take into account?

A. In reviewing only the availability of uncommitted firm transportation, Ms. McConihe failed to take into account multiple ways in which the natural gas industry moves gas between markets. Six examples of such mechanisms, with brief summaries of what each represents, are as follows:

1. **Capacity Release**--Where all capacity is subscribed, the secondary shipper purchases capacity (short-term or long-term) from the holders of that capacity. In the US, all interstate pipelines are required to allow and even to facilitate this, although it means that the shippers are competing directly with the pipeline's sale of services.

2. **Pipeline Interruptible Transportation**--If any firm capacity is unused but not released for resale by the shipper, pipelines are required to offer the unused capacity for sale, in electronic postings that are updated four times per day.

3. **Buy-Sell Transactions** --Gas is sold upstream of constrained capacity and bought back downstream of the constraint. How it gets there is the buyer/seller's problem, not necessarily forward haul through the constraint.

4. **Displacement** --Gas is dropped off where needed from flowing supplies, then made up downstream through the use of storage. This creates virtual transport in the opposite direction of physical flow.

5. **General Use of Load Diversity**--Careful management of diverse loads allows the use of "holes" in capacity created when one load drops off and another needs the capacity. This can allow for a double use of firm assets, and thus create apparent capacity in excess of stated and committed levels.

6. **In-Field Purchase and Sale**--Gas is sold in-place in one storage field and purchased in-place in another storage field, in such a way that both buyers and sellers optimize the location of where they own gas in storage, relative to the transportation means available to their target markets.

Q. Can these various mechanisms operate to deliver storage gas if outgoing firm transportation is fully contracted to others?

A. Yes. The general business structure that has evolved under FERC regulation in the United States virtually always includes the full subscription of available firm transportation. There are two reasons this has happened under industry practice and FERC policy. First, pipelines will not build new systems or expansions unless such capacity is supported by firm contractual commitments. Second, the FERC's restructuring policy in place since 1993 emphasizes placing capacity control in the hands of shippers, rather than of the pipelines themselves. Thus, full contractual subscription of firm capacity merely indicates that the commercial control of that capacity—the opportunity to use it or resell it—resides in the hands of the primary customer rather than of the pipeline. Such subscription does not necessarily give any indication of the <u>availability</u> of the capacity. The six examples of transportation mechanisms other than primary firm transportation contracts listed earlier are the ways in which gas may be moved by any party, regardless of whether that party holds any firm capacity in its own right.

Q. How feasible is it to observe or measure the use of such mechanisms?

A. Individually, such observation or measurement is difficult. Certain of the mechanisms, such as capacity release or pipeline interruptible service, result in transaction reporting to the FERC that, through detailed research, may be quantified. However, for the most part the mechanisms represent day-to-day responses of a fast-moving, flexible marketplace and are thus difficult to measure. This does not mean that the overall success of market-driven communication among market centers cannot be measured quantitatively. Such measurement is quite feasible, and in fact has been done for access to Dawn in this proceeding, by EEA.

Q. How has EEA performed such measurement?

A. In addition to examining the statistical correlation of Dawn gas prices with prices at various major U.S. market centers, EEA has thoroughly examined the price <u>basis differentials</u> between Dawn and the United States (EEA evidence, pages 39-43). EEA addressed its observations in the expert report filed for Union. The basis differentials were modest and stable, never exceeding $1.00US and more generally in the 20¢ to 50¢US range (EEA evidence, page 41, Table 6). The bottom line is that all aspects of behavior of the basis differentials are indicative of markets that communicate freely through the flexible availability of transportation between those markets. The sorts of modest, stable basis differentials observed by EEA are generally not able to be maintained in consuming markets that are actually subject to transportation constraints.

Q. Is there experience in the United States with the impact of real transportation constraints?

A. Yes. California in 2000-2001 and New England in 2004 were extreme examples of what happens when transportation constraints create strong buyer-to-buyer competition for the restricted supplies that are able to reach the delivery end of pipelines. The basis differentials from production area to the California border and to New England during those respective periods were well in excess of fifty dollars per million Btus. The California and New England experiences demonstrate that when transportation is truly not available the escalation in basis differentials is explosive.

Q. How does the experience at Dawn compare with these examples?

A. Dawn stands in sharp contrast with the California and New England experiences. The basis to Dawn measured by EEA has apparently never exceeded one dollar, and has generally been in the 20- to 50-cent range. The fact that a "blowout" similar to the constrained U.S. markets has not ever happened between the United States and Dawn demonstrates that the totality of traditional transportation and the various alternatives discussed above has continuously allowed gas to get where the market needs it in the required quantities.

Q. Aside from some degree of flexibility in the use of committed transportation, what fundamentals should be in place for there to be the wide range of delivery alternatives you have described?

A. The most important fundamental that should be in place is for large quantities of natural gas to be flowing in multiple directions around the affected market. In the case of Ontario in considering the availability of capacity from the United States, this would mean that it would be very helpful for large quantities of gas to be routinely flowing <u>from</u> Ontario to the United States. This would greatly enable such flexible options as displacement transportation.

Q. Do such flows exist?

A. Yes. Large quantities of natural gas exported from Canada to the United States pass through Ontario. According to the U.S. Energy Information Administration, the flow into the United States through Ontario points in 2004 amounted to 913 Billion cubic feet (Bcf), or approximately 2.5 Bcf per day ("US Natural Gas Imports and Exports: 2004," U.S. Department of Energy, Energy Information Administration, December 2005, page 1). Much of this gas could be used to create displacement transactions whereby the flowing gas would physically serve Ontario, while the U.S. markets for which the gas is destined could be physically served by gas held in U.S. storage for Ontario entities.

Q. In the case of your first two examples, capacity release and pipeline interruptible service, please discuss the relative reliability of these options.

A. First, released capacity is firm service—the secondary shipper steps into the shoes of the contract holder for the term of the release. Thus, the released service is fully as reliable as a primary firm contract. Second, pipeline interruptible service occurs when the pipeline is not fully utilized, but the firm subscribers have not released the unused capacity. Thus, interruptible service is fully reliable unless the holders of firm capacity simultaneously increase their utilization to the point that total physical capacity is constrained. As discussed earlier, judging from the basis-differential history, such total physical constraints do not appear to have affected the Ontario market. Accordingly, a shipper using interruptible service to support storage withdrawals into Dawn can expect very high reliability, especially if the shipper could flexibly move among alternative methods of delivery if one specific pipeline route begins to become congested.

Q. Please summarize your overall evaluation of Ms. McConihe's analysis.

A. Ms. McConihe's analysis hinges entirely upon the premise that U.S. alternatives to Ontario storage cannot reach Ontario because of the full subscription of firm transportation in cross-border pipelines. Once the many market-driven alternatives to primary firm transportation are considered, against the backdrop of market basis differentials that clearly show those alternatives to be working, Ms. McConihe's premise breaks down. Her relevant geographic market should be greatly expanded, to the area considered by EEA. Once that happens, Ms. McConihe's market-share and concentration ratios would look much more like EEA's, and thus her analysis would firmly support a finding of no market power in the Ontario markets where forbearance is sought.

Q. Turning to Mr. Stauft's analysis, you have noted that much of his evidence relies upon the use of a cost-based rate as the threshold for measuring market price increases. What is Mr. Stauft's authority for this threshold?

A. Mr. Stauft relies, apparently exclusively, upon language in the FERC's 1996 *Statement of Policy on Alternatives to Traditional Cost of Service Ratemaking for Natural Gas Pipelines*, Docket Nos. RM95-6 *et al.* (Policy Statement) (Stauft evidence, pages 13-18). There, in defining what was meant by market power, the FERC said that it had generally considered market power to be present if an applicant could increase prices by more than 10 percent without losing market share. In defining the threshold from which the 10 percent would be measured, the FERC did not say anything directly, but rather made an introductory reference to prior cases where it said it had used 15 per cent above cost-based rates as the measure of market power. Mr. Stauft relies on the combination of these statements by the FERC in its Policy Statement to provide the basic foundation for his argument that even the existing, authorized market-based pricing in Ontario demonstrates the existence of market power. Then, as he compares various U.S. tariff-based prices for alternatives with Ontario prices, Mr. Stauft continually returns to the notion that any price significantly in excess of average-cost regulated prices in Ontario is *per se* a non-competitive price.

Q. Is Mr. Stauft's characterization of FERC policy legitimate?

A. Mr. Stauft's recitation of what the FERC said in its Policy Statement is accurate. However, there are several problems with Mr. Stauft's interpretation of the FERC policy and with his degree of reliance on that interpretation. Fundamentally, the end result of Mr. Stauft's interpretation and reliance is a theory that would hold market power to exist for any low-cost competitor in any market, regardless of that competitor's size or the nature of the market.

Q. Has Mr. Stauft provided any further clarification as to his basis for relying upon cost-based tariff rates as the threshold for market-power tests of price differences?

A. Yes. In the Technical Conference held in May in this proceeding, Mr. Stauft indicated that the use of cost-based rates was a unique feature of regulated markets, in that the existing cost-based tariff rates would generally be the only observable "status quo" prices. He acknowledged that market-power tests as applied in the broader arena of merger approval etc. treat the competitive market price as the threshold (18 May 2006, Tr. 154-156).

Q. What is the relevance of Mr. Stauft's clarification to this proceeding?

A. Unlike the generic regulated-company situation in which Mr. Stauft indicated that the cost-based rate is the only "existing" price from which to measure price differences, the Ontario storage market has for some time included an active market-based segment of transactional storage services. Thus, the absence of a competitive market price which Mr. Stauft ascribes to regulated companies seeking market-based pricing is not a characteristic of the Ontario storage market. This means that Mr. Stauft's apparent pragmatic rationale for using cost-based prices does not pertain to Ontario.

Q. Please explain your concerns with Mr. Stauft's interpretation of the FERC's Policy Statement language.

A. First, the FERC did not say directly that market-power tests would be based upon price differences from cost-based rates. In the section of the Policy Statement deliberating what the <u>percentage</u> of allowable increase would be, examining a range from 5 percent to 15 percent in arriving at its presumptive 10 percent, the FERC merely made passing reference to prior decisions that had selected 15 percent above the cost-based tariff rate. An examination of the cases cited by the FERC for its passing reference reveals little debate over the threshold rate as opposed to the test percentage. In fact, in one of the cited opinions, *Williams Pipeline Company*, Opinion No. 391, the FERC went to great length to explain that the selection of a price-change threshold is a matter of considerable judgment, not a simple mechanical exercise. The FERC cites the U.S. Department of Justice's Merger Guidelines to support that premise, including the critical language in those guidelines—that price changes should be measured from "competitive levels." In short, the FERC's reference in the Policy Statement to earlier measurements from a cost-based tariff rate must be viewed in context as an indication of one possible approach but not a dispositive standard. This interpretation is strengthened by the nature of FERC statements of policy, which are more in the nature of guidance than rule. Accordingly, Mr. Stauft's interpretation of the FERC language as a black-letter standard to be applied in this proceeding is inappropriate, and his degree of reliance upon his interpretation is clearly not justified.

Q. You have indicated that Mr. Stauft's reliance upon cost-based rates as the threshold for market-power tests would create a situation in which any low-cost competitor could be found to have market power. Could this lead to perverse results?

A. Yes. Every competitive market is characterized by winners and losers, with the low-cost competitors frequently being the winners. Mr. Stauft's interpretation would call into question this most fundamental of competitive dynamics. Under his theory, a Dell Computer company successfully entering the market for personal computer hardware would be seen as having market power from the day it first existed, simply because its average costs were lower than the going price for computers. The New York City real estate market could be seen to be uncompetitive because going rental rates are considerably higher than the many properties subject to artificial rent controls.

Q. If measures of cost were to be used for testing competitive prices, would regulated cost-based rates be a valid representation of such cost?

A. No. Even in terms of cost, the use of the historical average cost levels that underlie regulated rates is completely inappropriate. As competitors increase or decrease production—that is, as they compete or do not compete—the only cost material to such decisions is marginal cost, the cost of the units produced or not produced. In the case of capital-intensive industries with long-term contracts, such as the natural gas industry, the relevant marginal cost would be long-run marginal cost, the cost of new or avoided capital commitments. This cost level is generally much higher than the average cost level that underlies regulated rates.

Q. Do you base these observations on training as an economist?

A. No, I base these observations upon my experience as a senior executive of major pipeline companies, wherein I participated in the daily decisions as to how to compete in various markets and frequent decisions as to how and where to make new capital investments. The analysis of company choices, customer choices, and competitive dynamics was exclusively a marginal-cost analysis throughout my three decades in the business. In addition, as noted earlier I chaired one of the Interstate Natural Gas Association of America (INGAA) task forces that contributed extensively to the FERC effort leading to its Policy Statement. Throughout that effort, there was extensive discussion among industry experts including economists as to what constituted competitive pricing. It was never suggested by any such experts that average-cost rates bore any relevance at all to competitive prices in economic terms. The only relevance that was ever recited was the role that cost-based rates could play as the “status quo” for customers under regulated services whose services were proposed to be repriced.

Q. Turning to Mr. Stauft’s quantification of competitive alternatives if the United States were considered, he indicates that all U.S. storage is committed under firm contracts, and thus would be unavailable to compete into Ontario (Stauft evidence, pages 51-55). Is his analysis correct?

A. No. As with firm transportation, the industry and FERC practice and standard are for firm customers to control storage capacity, but to do so in a market that encourages multiple uses of that storage. FERC's capacity release program applies equally to firm storage, and is used actively by the holders of capacity. In other words, any non-holder, such as an Ontario entity, can buy released storage on the market from those contract holders. Additionally, as with the transportation options discussed in response to Ms. McConihe, a variety of service options other than traditional storage might be purchased from capacity holders or even from the U.S. pipelines themselves.

Q. Are the committed U.S. storage volumes already completely spoken for in serving local utility markets?

A. No. I examined the index of customers for six U.S. pipeline companies that own storage relevant to Ontario: ANR Pipeline Company (which holds and markets ANR Storage Company's capacity), National Fuel Gas Supply Corporation, Columbia Gas Transmission Corporation, Tennessee Gas Pipeline Company, Natural Gas Pipeline Company of America, and Dominion Transmission, Inc. Of the more than one trillion cubic feet of storage working capacity operated by those six companies, approximately 25 percent, or 250Bcf, appears to be held by marketers or producers—sellers of gas and services, not utilities. I would consider much of this capacity as being in play on the market, and potentially available to compete into Ontario. Meanwhile, especially in the case of the marketers who hold firm storage capacity, it could be expected that multiple creative packages of services could be crafted, which might rely on storage to be provided but would not necessarily be traditional storage service. In other words, the profile of who holds and controls storage capacity in the areas adjacent to Ontario is highly indicative of a robust, flexible market for services to Ontario.

Q. Mr. Stauft performs a hypothetical calculation wherein he states that 120Bcf of competitive storage capacity would be required to bring the Enbridge Gas Distribution and Union market shares to levels he would consider competitive (Stauft evidence, pages 44-46). Is his calculation correct?

A. Under Mr. Stauft's terms, reducing the combined Enbridge Gas Distribution and Union market share to 50 percent, his calculation significantly overstates the competitive volume needed. Mr. Stauft bases his 120Bcf on a total market volume of approximately 240Bcf. However, he disregards the exclusion of existing in-franchise bundled customers from a competitively priced market, which exclusion has been proposed by both utilities and apparently supported by Mr. Stauft. Once these bundled utility volumes are set aside, the equivalent of Mr. Stauft's 240Bcf is approximately 70Bcf, and his theoretical 50-percent market-share volume would be 35Bcf, not 120Bcf. As noted, firm storage held on U.S. interstate pipelines with access to Ontario include approximately 250Bcf held by marketers and producers, over seven times as much capacity as Mr. Stauft's calculation indicates would confirm a competitive market. An economist would explain that the actual volume needed to reach Mr. Stauft's formulation of a competitive market would be much smaller, just enough to discipline prices at the margin.

Q. Does Mr. Stauft find, as does Ms. McConihe, that transportation access is inadequate to allow U.S. storage to compete in Ontario?

A. Yes. He follows a course similar to Ms. McConihe's, indicating that since firm transportation is fully subscribed on the various border-crossing pipelines, U.S. storage service would have no way of reaching Ontario (Stauft evidence, pages 55-56).

Q. Does Mr. Stauft offer any observations or analyses as to transportation availability beyond those offered by Ms. McConihe?

A. No. Thus, the response to Ms. McConihe is equally applicable to Mr. Stauft. His analysis has not taken into account the true dynamics of the U.S. natural gas industry, including the multiple ways that gas may be moved commercially. Similarly, he has not taken into account the clear evidence from cross-border basis differentials that there is no significant constriction of capacity into Ontario.

Q. You indicated that Mr. Stauft also contends that the cost of U.S. storage options significantly exceed Ontario prices, and thus cause U.S. storage not to be effective competition. Is his analysis valid?

A. No, Mr. Stauft's analysis suffers from three infirmities. First, as with his general evaluation of what is competitive and what is not, Mr. Stauft compares all of his calculated prices for U.S. storage with Union's average-cost-based rate, rather than with the competitive market price for Union's market-priced storage. Second, Mr. Stauft evaluates U.S. storage cost solely based upon tariff rates, which represent maximum levels rather than the price levels that can result from discounting and negotiated releases of capacity. Third, Mr. Stauft evaluates transportation cost based upon only one transportation assumption, that the shipper would sign up for new, year-round firm transportation for 100 percent of the storage volume held in the United States, rather than taking into account the multiplicity of transportation options that can be used (Stauft evidence, pages 58-59). The combined effect of these three infirmities distorts the picture from what is actually relative parity between U.S. and Ontario market storage to Mr. Stauft's representation of U.S. costs that range from

176% to 279% more expensive than Ontario storage (Stauft evidence, page 58).

Q. What storage price does Mr. Stauft use as the Ontario price with which alternatives should be compared?

A. Mr. Stauft uses 56¢, the average-cost-based rate applicable to Union's in-franchise customers, for most of whom forbearance is not proposed at this time (Stauft evidence, page 58).

Q. Does Mr. Stauft identify a representative market price for the Union storage that is not presently subject to regulated rates?

A. Yes. Mr. Stauft acknowledges that it is difficult to identify a single price, but ultimately arrives at a price of 91.7¢ (his filed evidence cites 97¢, but he adjusted this to 91.7¢ at the Technical Conference (18 May 2006, Tr. 133). As discussed earlier in my testimony, it is this sort of open-market competitive rate that must be used as the threshold for assessing market power, and—most importantly for Mr. Stauft's comparisons—it is this price level that must be used for the comparison of cross-border alternatives.

Q. What tariff rates did Mr. Stauft identify for U.S. storage providers?

A. Mr. Stauft focused on the interstate-pipeline providers of storage service. He derived prices based upon tariff rates for ANR Storage Company (ANR Storage), Natural Gas Pipeline Company of America (NGPL), and National Fuel Gas Supply (National Fuel). The prices he derived ranged from 79¢Cdn per GJ for ANR Storage, to 88¢Cdn per GJ for NGPL, to 93¢Cdn per GJ for National Fuel. All are based upon the cost-based tariffs of these companies (Stauft evidence, Appendix 2).

Q. Do Mr. Stauft's calculations appear to be accurate?

A. Yes. Both in his interpretation of the tariffs and in his conversions to GJ rates in Canadian dollars, Mr. Stauft appears to have accurately calculated the unit cost of full-rate firm storage service for these interstate pipeline companies.

Q. Did Mr. Stauft derive similar costs for storage providers other than interstate pipeline companies, such as local distribution companies (LDCs)?

A. Generally, Mr. Stauft took the position that it was unlikely that the LDC storage costs are lower than the interstate-pipeline costs, but he did not offer any significant evidence to that effect. He did recite the maximum rates for CMS Energy (CMS) and Michigan Consolidated Gas Company (MichCon), but acknowledged that the actual rates paid could be negotiated at lower levels (Stauft evidence, pages 60-61).

Q. Did Mr. Stauft overlook any aspect of the pricing of the storage providers he examined?

A. Yes. As to the interstate providers, Mr. Stauft overlooked the fact that, just like the stated rates for CMS and MichCon, the tariff rates are ceilings, with a full ability to negotiate lower levels. He also appeared to disregard the use of FERC's capacity-release program as to storage, whereby existing holders of firm space could resell that space at rates negotiated up to the maximum tariff levels.

Q. As to the LDC storage providers, do you have any information as to the outcome of the below-maximum negotiations acknowledged by Mr. Stauft?

A. Yes. The maximum prices cited by Mr. Stauft are $1.50US per MMBtu for CMS and $1.47US per MMBtu for MichCon (Stauft evidence, page 60). We have reviewed Michigan Public Service Commission (MPSC) decisions reciting actual market storage revenue levels, and through informal review with the MPSC staff have assessed the ongoing situation there. In 1993 and 2005 public decisions as to MichCon, the MPSC accepted unit revenue levels of 48¢US and 18¢US, respectively, although the latter amount related to "lower-quality" services. The informal discussions with the MPSC staff have indicated that in fact the market levels observed in the 1993 decision generally continue to this day, with unit revenue somewhere in the 40¢ to 50¢US range. It would be expected that the market value of CMS storage, and the market value of resold interstate-pipeline storage in the area would track these price levels. Using the upper end of this range, this would translate to 54¢Cdn per GJ, 25¢Cdn lower than the lowest of the interstate-pipeline tariff rates that Mr. Stauft assessed (ANR Storage), and 39¢Cdn lower than the highest that he assessed (National Fuel). Accordingly, Mr. Stauft's conclusion that U.S. storage is "out of the market" in Ontario does not appear to be correct.

Q. Does a market price of 50¢US for storage in this area correspond with your experience?

A. Yes. Generally, storage sold into high-value markets, such as that used for peak-day coverage of local utilities, could be expected to command the full tariff rates, but for storage sold in the competitive market, 50¢US is the "rule of thumb" price that we used for planning purposes during my tenure in pipeline senior management.

Q. In determining the total delivered cost of storage service, what levels of transportation cost did Mr. Stauft associate with the various sources of storage service?

A. Mr. Stauft derived the following transportation costs for the three interstate-pipeline storage services that he examined: ANR Storage—85¢Cdn per GJ; NGPL--$1.24Cdn per GJ; and National Fuel—78¢Cdn per GJ. This translates to 79¢US per MMBtu, $1.15US per MMBtu, and 72¢US per MMBtu respectively, and is meant to represent the cost of transportation both to and from U.S. storage (Stauft evidence, Appendix 2).

Q. Is Mr. Stauft's derivation valid?

A. Mr. Stauft's derivation is valid for what it represents: the unit cost at a low load factor for a maximum-tariff-rate annual commitment to primary firm transportation on the subject pipelines. However, as with the assessment of transportation availability in the first place, this is not the service I would expect to use for the injection and withdrawal of U.S. storage to compete at Dawn. Thus, while Mr. Stauft's derivation may be valid for what it represents, it represents the wrong thing.

Q. What would be the injection and redelivery transportation cost, through the various mechanisms that might be used for access to U.S. storage?

A. All of the six mechanisms recited in responding to Ms. McConihe's evidence are market-driven. That is, the services are either provided under tariffs that provide for discounting to market value (capacity release and interruptible service), or their cost is directly determined by market commodity values (buy-sell, displacement, use of load diversity, and in-field transfers). Accordingly, each service is directly driven by the market value of transferring gas from one point to another, which is the price basis differential. This means that the cost of the actual injection and redelivery transportation services that are used in the marketplace will be determined by the relevant basis differentials at the time each transportation transaction occurs. The combined injection and redelivery cost would be the summation of the two seasons' activities. Using Michigan as an example (based upon the MichCon city gate prices reported by EEA for the last six winters and seven summers), the average basis-driven cost of injection and redelivery transportation over the last seven years would have been on the order of 16¢ US. I would expect some transactional premium to be added to this in both directions, on the order of 5¢, which would bring the total cost to 26¢US. This compares with Mr. Stauft's assessment of transportation cost to and from ANR Storage, in the same area, of 79¢US.

Q. What is the combined impact of your assessment of market forces on U.S. storage and transportation cost?

A. At 50¢US for storage and 26¢US for transportation, the total cost of using U.S. storage would be 76¢US per MMBtu, or 82¢Cdn per GJ. This compares very favorably with the competitive storage market in Ontario. Thus, Mr. Stauft's overall assessment that U.S. storage is not price-competitive with Ontario storage is incorrect, in that it is based upon tariff prices that the market will not pay.

Q. Please summarize your overall review of Ms. McConihe's and Mr. Stauft's analyses.

A. Both witnesses have based their economic analyses of market power on faulty assumptions: that gas cannot get from the United States to Ontario, that a market cannot be workably competitive if it is priced above average cost, and that U.S. storage and transportation are not priced competitively with Ontario storage. When these assumptions are adjusted to reflect the actual operation of the dynamic market between the United States and Dawn (and when the proper comparison of prices is made, with competitive market prices in Ontario), both witnesses' narrow definitions of the relevant geographic market must be expanded, to the point that their revised concentration and market-share calculations would show an absence of market power.