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2006-03-20

VIA EMAIL and COURIER

Mr. John Zych
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, ON M4P 1E4

Dear Mr. Zych:

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

As per Procedural Order No. 2 dated February 28, 2006 attached please find ten copies of the evidence of Enbridge Gas Distribution Inc. as outlined in Appendix A of said procedural order. Soft copies in MS Word and searchable Adobe PDF format are also being filed with the Ontario Energy Board on CD.

Yours truly,

Malini Giridhar
Manager, Rate Research and Design

Attachment

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

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C – PROPOSED TARIFFS FOR POWER GENERATION CUSTOMERS

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OVERVIEW AND BACKGROUND

1. The evidence in this proceeding addresses Enbridge Gas Distribution's (or the "Company") proposals for balancing, storage and distribution services, and rates to meet the needs of gas-fired power generation customers.

2. First, the Company's evidence outlines current capabilities for managing its gas supply and storage portfolio, and addresses the anticipated needs and demands of gas-fired power generation customers. Second, the evidence addresses operational barriers, issues and costs that impact the Company's ability to offer the types of rates and services sought by these new customers. Third, following the context-setting sections, the Company's evidence sets out proposed tariffs, along with some additional service offerings, for power generation customers.

3. The Company believes it is helpful to briefly examine processes that have led to this Natural Gas Electricity Interface Review ("NGEIR") generic proceeding. This will outline the context within which rates and services for power generation customers will be developed.

4. Initially, Enbridge Gas Distribution believed that power generation customers required unbundled load balancing and storage services under the Rate 300 family of rates. Hence, the Company undertook to develop rates consistent with the settlement in its RP-2003-0203 Rate Case, dated June 17, 2004, and agreed to consider comprehensive changes to Rates 300, 305, 310 and 315 for its next rate case. Specifically, Enbridge Gas Distribution agreed to review the following:
    - Combined multi-facility delivery, storage and load balancing options;

- Flexibility in delivery area, minimum annual volumes, daily delivery obligations, provision of fuel, and choice between bundled and unbundled services; and
- Term differentiated rates.

5. To develop new rates to reflect these considerations, Enbridge Gas Distribution initiated a consultative process with existing and potential customers, including power generators.

6. The Company obtained both direct and indirect input from power generation customers about their wants and needs. The results of the consultative process indicated unique load characteristics and service requirements for these customers, thus necessitating a different approach than that used for conventional large customers.

7. These findings coupled with the guidance resulting from the NGEIR report by Board Staff led Enbridge Gas Distribution to conclude that the requirements of power generation customers necessitate the following:
    - New upstream services from its upstream providers: Union Gas Limited ("Union") and TransCanada PipeLines ("TCPL");
    - New communication protocols among the Independent Electricity System Operator ("IESO"), merchant power plants, Enbridge Gas Distribution, and its upstream providers;
    - New distribution infrastructure investment including storage service enhancements; and
    - Appropriate pricing mechanisms and contract provisions designed to minimize cost and service quality impacts on existing customers.

8. The Company proposes that the design of new rate offerings reflect the Board's accepted cost allocation and rate design principles for distribution service, while recognizing the competitive aspects of upstream transport, balancing and storage services.

9. To tailor the rate development to power generation customers, Enbridge Gas Distribution undertook a separate process designed to meet their unique requirements. An internal cross-functional team, using ongoing dialogue with power generation customers and other stakeholders (including NGEIR), expanded the scope of Rate 125 – Extra Large Firm Transportation Service ("Rate 125") and developed Rate 316 – High Deliverabity Gas Storage Service (Customer Arranged Transport) ("Rate 316"). Enbridge Gas Distribution's draft proposal for both rates was circulated to existing and potential customers, as well as other stakeholders.

10. On January 26, 2006, the Company invited interested stakeholders to discuss the provisions of each rate schedule, ask questions about rate operation, and provide suggestions regarding various rate terms and provisions. The Company has since modified, to the extent possible, its draft proposals to incorporate suggested changes from the participants as well as outcomes of further internal analysis. A copy of the modified draft proposals is attached as part of the Company's proposal for Rates 125 and 316 in Exhibit C of this evidence.

11. The Company anticipates that this NGEIR proceeding will provide a conceptual framework for determining service offerings and rates for power generation customers. It will achieve that by balancing customers' requirements with the cost of meeting those requirements and by taking into

account the systemic challenges and the impacts new rates and services may have on other customers. The Company does not believe, however, that the NGEIR proceeding is the appropriate forum for actually setting and determining rates for power generation customers. The Company proposes that this should be accomplished through a rate proceeding to ensure that all relevant cost allocation and other impacts are accounted for in the context of the Company's entire operations and rate structure. Indeed, given that at least one customer will likely require service in 2007, the Company believes that the rates should be set in its Fiscal 2007 Rate Case. The Company is prepared to work with parties to arrive at an appropriate process to accomplish this.

B1

CURRENT EXPERIENCE

1. The purpose of this evidence is to provide background information regarding the manner in which Enbridge Gas Distribution manages its gas supply portfolio and the associated responsibilities for both Enbridge Gas Distribution and its customers that must be met to ensure supply disruptions do not occur. This is intended to provide context for the factors that must be considered in the design and development of new rates to serve power generation customers and other qualified customers.

2. Enbridge Gas Distribution has a long history in meeting the gas supply needs of its customers. In 2005, Enbridge Gas Distribution distributed approximately 2 057.3106m3 (425.6 Bcf) of natural gas to more than 1.7 million customers within Ontario. These volumes were distributed to both system gas customers, who rely on Enbridge Gas Distribution for their supply (approximately 4 757.4 10^6m^3 or 167.9 Bcf), and direct purchase customers, who arrange their own supply (approximately 7 300 10^6m^3 or 257.7 Bcf).

Load Balancing

3. Currently, all direct purchase customers rely on Enbridge Gas Distribution to provide bundled distribution services. The bundled services include load balancing, which allows the direct purchase customer to deliver equal installments of gas throughout the year with the Company assuming responsibility for managing any daily variances in demand. The direct purchase customer is responsible for ensuring that all of its gas deliveries are made to Enbridge Gas Distribution at a designated delivery area and that on an annual basis the total gas they have consumed equals the gas they have delivered. Any annual variance between deliveries and consumption must be

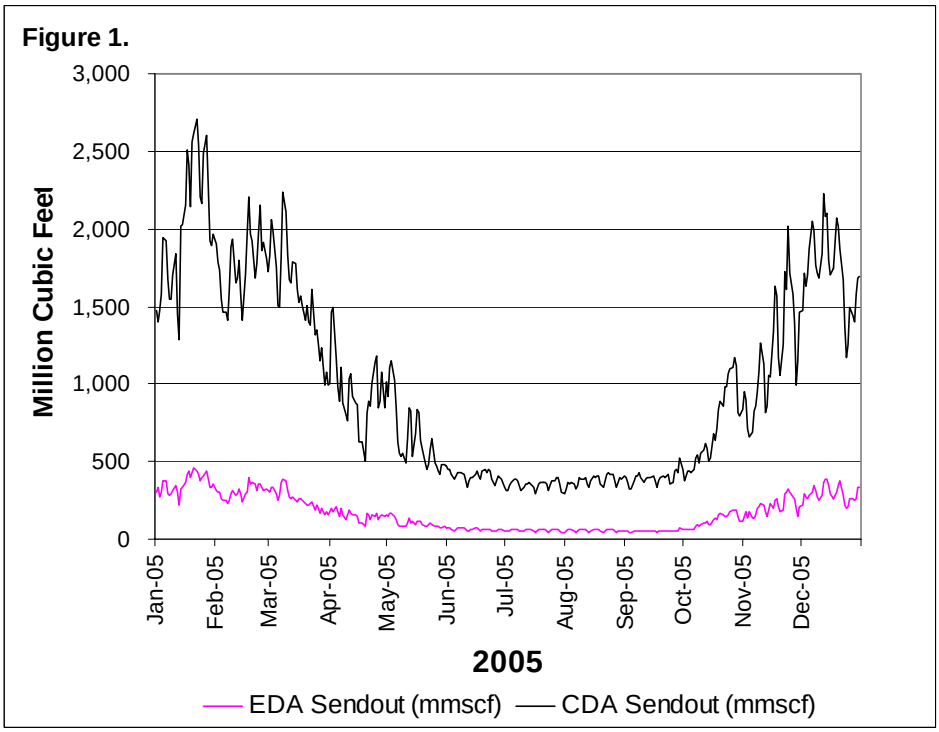
balanced, either through incremental deliveries ("makeup"), reducing deliveries to dispose of the excess gas that has been delivered ("suspensions"), or by transacting to transfer their imbalance to another direct purchase customer within the Enbridge Gas Distribution franchise area ("title transfer").

4. Direct purchase customers can meet their annual balancing requirement by either undertaking these balancing activities during the course of their contract, or at the end of the contract year when the final imbalance is known. While Enbridge Gas Distribution does have some operational conditions that limit the availability of certain balancing transactions during certain periods of time (e.g., suspensions during the peak winter months), direct purchase customers can generally choose when they will balance their annual imbalance.

5. In contrast, Enbridge Gas Distribution assumes responsibility for balancing the demands of its system gas customers and bundled direct purchase customers on a daily basis. As Figure 1 demonstrates, there is significant variability in these daily demands over the course of the year due to the high proportion of distribution volumes that are weather sensitive.

Figure #1

Daily Demand in Enbridge CDA & EDA



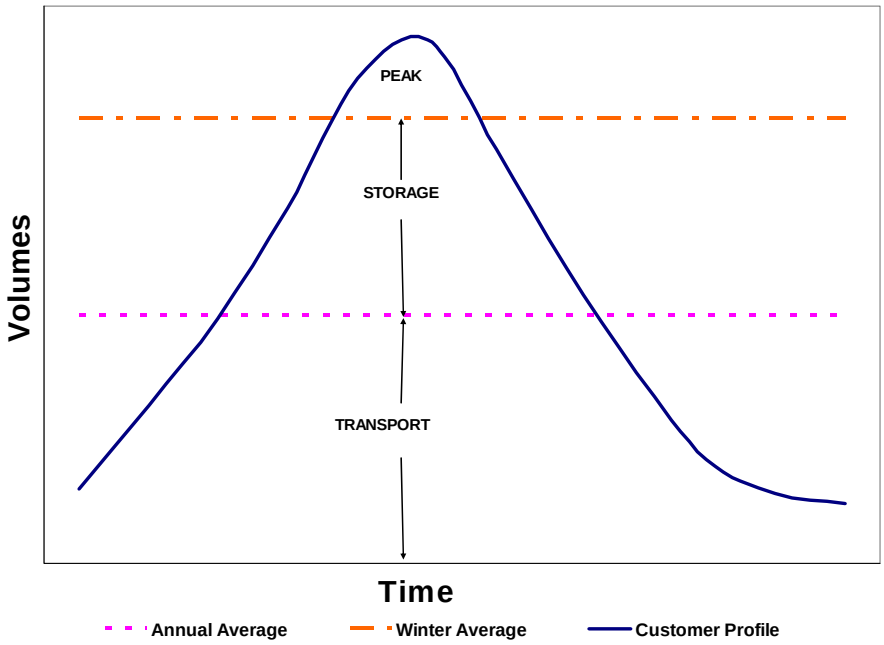
The Company manages these daily variations in demand through a portfolio of transportation, storage and supply. Enbridge Gas Distribution uses a variety of transportation contracts to move gas to the markets; these contracts include long-haul and short-haul transportation with TCPL, and transportation contracts with Alliance Pipeline L.P ("Alliance"), Vector Pipeline L.P ("Vector"), Union, and other transporters. These contracts have been sized to meet the requirements of existing distribution customers. The long-haul TCPL and Alliance contracts are used to move supply acquired in Western Canada to the east. Vector contracts are used both to transport the gas moved on Alliance to Chicago and moved east to Dawn and also to transport supply that is acquired in Chicago to Dawn. The Company's short-haul contracts with

Union and TCPL are used for transporting gas between Dawn and the Company's franchise areas. This gas includes the supplies transported on Vector and gas that the Company holds in storage. Enbridge Gas Distribution owns and operates storage within southwestern Ontario and contracts for additional storage capacity to enable high load-factor utilization of its long-haul transportation capacity. From a supply perspective, spot purchases, peaking contracts, and the availability of supply from interruptible customers provide additional tools to allow the Company to meet daily demand throughout the year.

6. As Figure 2 demonstrates, these various supply tools are used in combination to meet the profile of customer demand during the winter months and in peak consumption situations. On peak days the Company also relies on peaking contracts and the availability of supplies from curtailed large volume customers.

Figure 2

Sources of Supply for System Demand



7. It is important to note that the balancing performed by the Company has to occur within two distinct delivery areas of the TCPL system, Enbridge Gas Distribution's Central Delivery Area ("CDA"), which is the Greater Toronto Area ("GTA") and Niagara Peninsula) and the Enbridge Gas Distribution Eastern Delivery Area ("EDA ") (Ottawa and surrounding area). This balancing requires specific transportation and supply to manage the demands of each of these delivery areas. Each has its own unique costs. For example, the cost of moving gas to storage in the summer and from storage in the winter is higher to the EDA than the CDA due to its distance from storage. Gas cannot move without some cost between the Enbridge Gas Distribution delivery areas.

Witnesses: D. Charleson
J. Grant

8. In addition to the daily variability in demand, real time flows on the distribution system are highly variable with significant changes being seen on an hourly basis. This is particularly prevalent in the winter. Flows will typically reduce overnight, then increase rapidly during the early morning hours by 50 to 150% or more due to start up of residential furnaces, water heater load, and commercial operations starting up for the day. This is commonly referred to as the "morning lift". By 9:00 a.m. the load begins to decrease again. As daytime temperatures increase, the afternoon gas demand decreases. Later in the afternoon and into the evening, as residents return home, residential furnace load increases once again, though not as dramatically as the morning peak, until the evening demand drops off once again. All of this variability in demand must be managed within the nomination windows that are made available by the upstream transporters that move gas to the distribution system.

9. Currently, upstream transporters allow for nominations based on the four standard North American Energy Standards Board ("NAESB") nomination windows. These windows are:

Nomination	Time	Gas Day Flow
Timely	13:00 EST	10:00 Next Day
Evening Cycle	19:00 EST	10:00 Next Day
Intraday 1	11:00 EST	18:00 Same Day
Intraday 2	18:00 EST	22:00 Same Day

In addition to the standard windows, the Company also has access to four additional nominations from TCPL that are associated with its Storage Transportation Service

("STS") and from Union with its M12 transportation service. These provide the opportunity to nominate gas to or from storage on TCPL and Union. These windows are:

Nomination	Time	Gas Day Flow
STS 1	10:00 EST	12:00 Same Day
STS 2	11:30 EST	18:00 Same Day
STS 3	23:00 EST	02:00 Same Day
STS 4	04:00 EST	06:00 Same Day

The STS windows allow a finite adjustment of storage supplies, based on the volume of STS service contracted, to fine tune the supply to match demand on a daily basis. The fact that they occur later in the gas day provides improved opportunities for adjusting nominations for the purpose of keeping within pipeline tolerances load balancing prior to the end of the gas day.

10. The available nomination windows have traditionally been adequate for the gas industry for the following reasons:

- Natural gas can be stored in reservoirs and in line pack. Traditional changes in hourly demand for existing customer load has been incorporated into the existing system design and can be accommodated in the current number of nomination windows;

- While gas can be stored in line pack, natural gas travels relatively slowly (typically 15 to 50 km/hr), and gas controllers must prepare the system for anticipated changes well ahead of the actual demand as gas takes several hours to physically

travel from storage at Dawn to the delivery area in the CDA, or longer to the EDA. These changes are nominated on the provided windows; and

- Forecasting demand of traditional natural gas customers is relatively predictable.

11. While industry has managed the system effectively using these nomination windows, there are still limitations with them:

    - The timing of the last window within the gas day (which ends at 10:00 a.m.) does not allow for adjustments to be made for sudden changes in demand that may occur during the morning lift, which can be impacted dramatically by a shift in the weather from the expectations in place at the last nomination window; and

    - Under current operating conditions, gas shippers cannot increase their nominations after the Timely Window on a firm basis. The timely nomination and each subsequent nomination establish the maximum amount of capacity that the transportation company reserves to move the shippers gas. The non-reserved capacity is marketed by the transportation company for use by other services. The shipper will only be able to increase their nomination if the transportation company still has that capacity available.

12. The Company must work within these nomination windows and their limitations to manage the variability of overall demands of the distribution system on a daily basis.

Storage

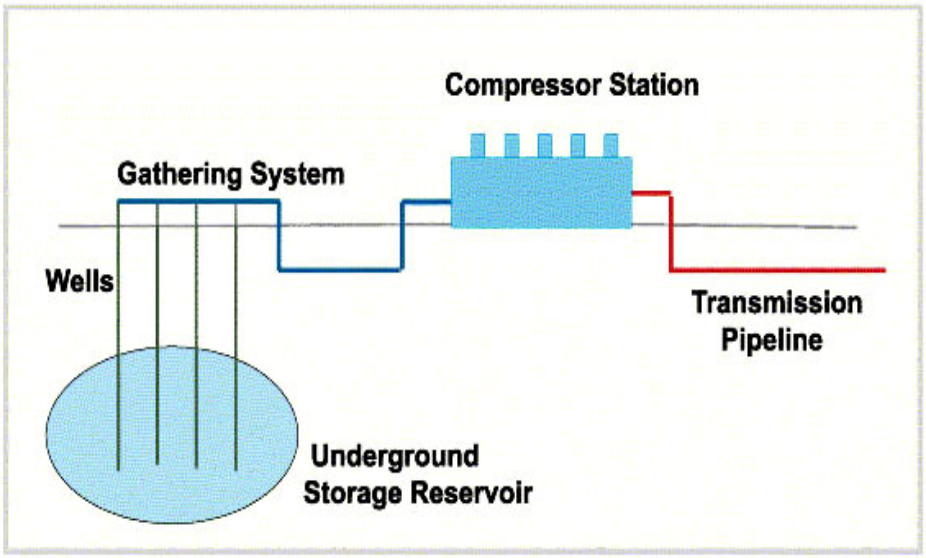
13. Enbridge Gas Distribution owns and operates the second largest gas storage business in Ontario. It is commonly referred to as the Tecumseh storage operation and it has been operating for over 40 years. Total annual turnover approximates 98 Bcf, with 6.7 Bcf of this capacity under contract with Union. The current peak deliverability of the system is 2 Bcf per day.

14. The following schematic diagram illustrates the generic components that make up storage systems. These components include the reservoir, the wells which access

the reservoir, the gathering line system to take the gas to some central point, the compression used on injection and withdrawal, and finally the transmission line system to get the gas to its market point. To be effective as a storage operation each of the components must be integrated into an operating "symphony", and each component must undergo engineering analysis and due diligence prior to any capacity or deliverability upgrades.

Figure 3

Storage System Components

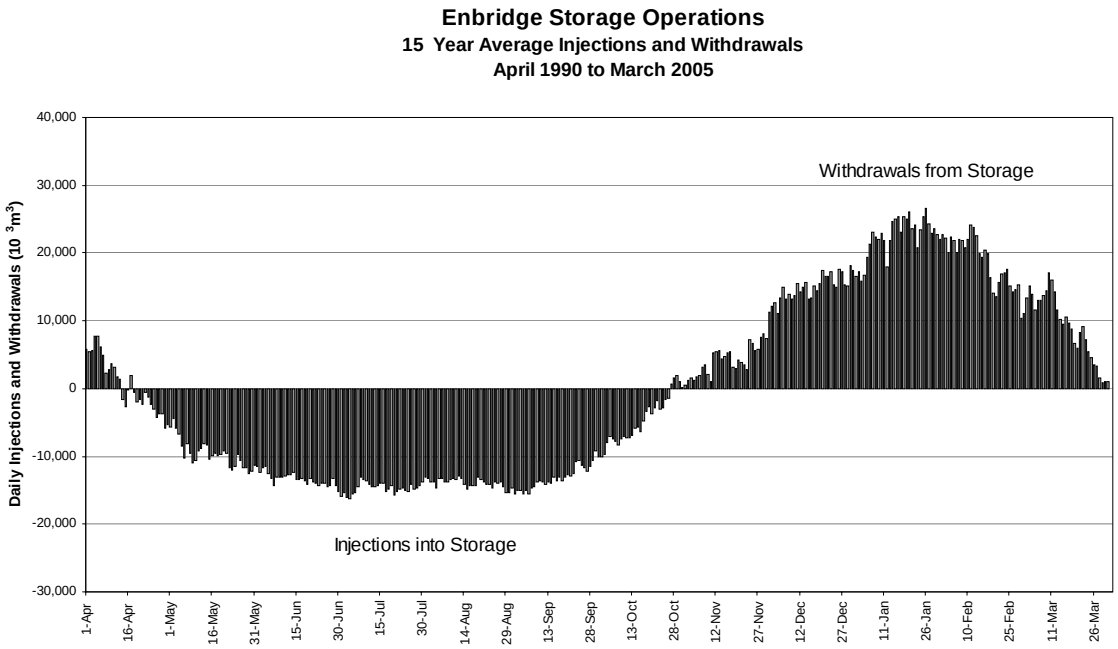


15. The existing capacity and deliverability at the Tecumseh storage facility, net of the Union contract, is utilized to help meet the load balancing needs of existing in-franchise customers of Enbridge Gas Distribution. In fact, the Company's distribution system requires more than the Tecumseh facility to meet its storage

needs and has, for many years, contracted for 20 Bcf of additional storage with Union.

16. A depiction of Tecumseh's 15 year average annual injection and withdrawal profile is shown below.

Figure 4



17. As is evident, the operation follows a reasonably predictable single injection and withdrawal cycle throughout the year, with daily variations being the greatest in the winter months when weather patterns affect storage withdrawals. This profile ensures that pipeline utilization is optimized for the distribution system throughout the year. The impact of gas-fired generation on the withdrawal cycle is likely to be

coincident with the peak withdrawal period (system peak days). The impact of gas-fired generation on the injection cycle is likely to be felt most at the end of the injection period because storage is close to full capacity at that time.

18. In the context of the NGEIR proceeding, the most significant question from a storage standpoint relates to whether the existing Tecumseh system can respond effectively to the flexible/high deliverability/fast response requirements of potential gas fired generation customers, should it be required to do so. In order to answer this question, the Company has estimated likely incremental space and deliverability requirements of the gas-fired generation market, reviewed any existing constraints in the storage system, and designed a capital program to address the market's needs. This topic is discussed in detail in evidence, under the heading "Operational Characteristics, Issues and Proposed Solutions: Storage" (Exhibit B1, Tab 3, Schedule 2).

POWER GENERATION CUSTOMERS: CHARACTERISTICS AND NEEDS

1. In order to undertake the process of examining and designing rates for power generation customers, Enbridge Gas Distribution has looked into the characteristics and needs of those potential customers in its franchise area. This section describes the load characteristics of power generation customers and discusses the rate and service requirements for these customers.

2. Based on industry announcements to date and other possible future developments in the power industry, Enbridge Gas Distribution has proceeded with studies assuming 2,000 MW of gas-fired capacity in the Enbridge franchise, at a collective daily maximum gas demand of 400 MMcfd.

3. These developments include the following:

    - The OPA has signed an Accelerated Clean Energy Supply contract with Goreway Station in Brampton pursuant to a directive issued by the Ontario Ministry of Energy. The facility is expected to operate in a simple cycle mode from May through September, 2007, with full commercial operation as a 900 MW combined cycle facility scheduled for July, 2008.

    - The Ministry of Energy has issued a directive to the OPA to negotiate an Accelerated Clean Energy Supply contract with the Portlands Energy Centre (PEC), in downtown Toronto. Timelines and possible operation modes for this plant are uncertain at this time. The PEC facility may require gas for commissioning in Spring, 2008, and operate in a simple cycle mode in Summer, 2008. The facility may then be expanded to a 550 MW combined cycle plant for Summer, 2009.

    - Other than Goreway Station and PEC, load from other gas-fired generation in the Enbridge franchise represents the Company's best estimate based on announced procurement initiatives. A "peaker" plant in Northern York Region has been discussed in OPA documents, but the procurement process has not started. Commissioning could take place between 2008 and 2010 and size may range from 100 to 300 MW.

Witness: E. Chin
E. Overcast

- The procurement process for 1000 MW in West GTA has commenced, but it is currently difficult to assess whether it will be situated in the Union or Enbridge Gas Distribution franchise area. These plant or plants are expected to be in service in 2008/9.

4. The absolute magnitude of gas-fired capacity requiring storage services to be developed in the Enbridge Gas Distribution franchise over the next decade is uncertain. Based upon current information in the marketplace the Company estimated that 2,000 MW was a sound estimate moving forward. A chart setting out the potential power generation customers in the Company's franchise area and their projections of capacity, in MW, is set out below:

Table 1

Forecast of new gas-fired generation in Enbridge Gas Distribution franchise (MW)

	2007	2008	2009	2010	2011	2012	2013	2014
Goreway	600	900	900	900	900	900	900	900
Downtown		300	550	550	550	550	550	550
York Region		200	200	200	200	200	200	200
West GTA, CHP, etc.			350	350	350	350	350	350
Other					?	?	?	?
Total	600	1400	2000	2000	2000	2000	2000	2000

As discussed below, and in more detail in the Operational Barriers section that follows, power generation customers have demands that are different, and likely less predictable, than others of Enbridge Gas Distributions large customers.

5. In estimating gas-fired generation demand the Company used an industry 'rule of thumb' that a 500 MW combined-cycle gas-fired plant requires a daily gas supply in the order of 100 MMcf, or 2.833 106m3, (assuming a full firm peak load).

6. As stated previously, the Company estimated that a high level forecast of 2,000 MW capacity development over the next decade was a sound estimate moving forward. Using the rule of thumb from above, this level of capacity equates to an approximate collective daily gas demand of up to 400 MMcfd, or 11.331 10^6m^3 over 24 hours.

7. Comparisons are provided below (in 10^6m^3) of ;

   - an annual gas load for 2,000 MW gas fired intermediate generation at a 40% load factor versus the Enbridge Gas Distribution 2006 annual design demand, and

   - a collective 24 hour daily demand versus the Company forecasted 2006 design peak day demand. Peak day demand governs system design.

	Current Demand	2000 MW Generation	% Increase
Peak Day	105.6	11.3	10.7%
Annual Design	13509.8	1654.3	12.2%

9. The above forecast of the demands of gas fired generation customers in the Company's franchise area is only a rough estimate of what those demands will actually be. In addition to quantum of generating capacity, a number of other factors affect the gas load requirements for power generation customers. Important factors include the type of generation: baseload, intermediate or peaking capacity; the type of technology, the availability of alternate fuel; the percentage of gas-fired generation on the electricity system; minimum electrical load characteristics, incremental heat rates and so forth. These factors help to determine both the normal operating mode for the units as well as the emergency operating characteristics. The variation in operation of the generator determines the impact on the management of the gas delivery system. In addition, the size of facilities used to serve the load including system pressure and the location of the generator within the system impact planning

requirements and the costs incurred to serve the load. Distribution system operation requires plans that manage not only the day-to-day normal operations of generators but must also plan particularly for emergency operation. Finally, the impact on the gas delivery system depends on whether the service is firm or interruptible, the season of the year and underlying system capacity requirements.

10. Different types of power generation plants will impact the Company's operation in different ways. Baseload power plants are designed to run continuously. Given their design, stresses on the gas system occur when a forced outage occurs and gas deliveries to the plant do not match the gas flowing to the system with resulting system pressure increases. Dispatchers and plant operators should know the startup schedules in advance and coordinate gas deliveries to maintain reliable operation of the gas delivery system.

11. Peaking units, on the other hand, (particularly gas-fired turbines that are based on aircraft engine technology) operate on very little advance notice. The startup times for peaking units are short, usually from one to a few minutes. The lack of notice and the requirement to ramp up within minutes to maximum output rating has implications for the natural gas system. Depending on the size of the unit at a location, the increase in gas consumption imposed in this operating mode is large relative to the system load. The gas dispatch must respond to maintain system pressure. Tools available to respond to rapid startup include line pack, storage and pipeline supplies. Each gas system responds differently given the resources available and the magnitude of those resources. Predicting the actual operation of gas turbines proves difficult because of the underlying variables that influence electric dispatch including weather, forced outages, transmission congestion/redispatch, hydroelectric availability and system operating conditions. Thus, peaking units that require firm service create the most stress for gas system operation for the above reasons.

Witness: E. Chin
E. Overcast

12. Intermediate plants run on a more limited schedule. Where intermediate units use gas-fired combined cycle technologies the impact on the gas system mirrors the impact of gas fired peaking units. Where intermediate units are older baseload units, the impact on the gas system mirrors baseload units.

13. For gas-only peaking facilities, the operating characteristics mean that scheduling the daily gas deliveries for operation is difficult on a day ahead basis. Scheduling intermediate units typically exhibits more advance notice and regular operation with the exception noted above. For each technology, the shape of the incremental heat rate curve determines the gas consumption changes that occur over the course of a gas day. While these changes are not as large as those that occur with startup or shutdown, the gas system dispatch must still manage the pressure changes to maintain reliability. Given these operating characteristics, the coordination between the power plant operators, the gas distribution system and the pipeline operators is critical. Further, it illustrates that upstream pipeline and storage operators determine distribution flexibility.

14. The availability of alternate fuels reduces the stress experienced by the gas system. Where alternate fuels satisfy the customers' fuel requirements under unplanned and unscheduled operations, the gas system reliability remains unaffected. In addition, customers with alternate fuel capability do not require firm upstream assets to provide service. Alternate fuel capability also improves electric reliability, especially under extreme conditions.

15. While the quantum and type of gas fired generation in Enbridge's franchise area is not known with certainty, the above discussion highlights the fact that power generation customers differ from other large industrial customers. The principal

differences between power generators and other large industrial customers include the following:

- Power generation loads vary substantially from day to day and hour to hour. The load ranges from zero to maximum contract demand in a matter of minutes or hours. Similarly, the load also ranges from maximum contract demand to zero in a matter of minutes. Conversely, industrial customers are able to plan reliably on a day ahead basis;

- Power generation loads exhibit far less predictability due to external factors not typical for industrial customers;

- Power generation loads require frequent nominations to balance deliveries and consumption;

- Power generation loads tend to be larger than all but a few of the very largest industrial loads;

- Power generation loads impose greater operating risk on the utility because, unlike existing customers, they are likely to all be on or off at the same times; and

- Power generation loads bid to the market based on marginal costs reducing the benefits of storage for managing gas supply costs but not for managing load variations.

16. These differences in load characteristics create unique services requirements for power generators. These requirements also place a burden on the gas distribution system operators to manage a system with greater daily load variability and unpredictability. Closer and timelier contacts between the Company and power generation customers represent important differences that Enbridge Gas Distribution recognized early on in the process of developing rates to serve these customers.

17. As explained in the “Overview and Background” piece of this evidence, Enbridge Gas Distribution has concluded that power generation customers require a separate set of rates and service offerings. These proposed new rates and service offerings are detailed in Exhibit C of this evidence. These rates and service offerings, while

not limited to power generators, reflect the service requirements that Enbridge Gas Distribution believes it may reasonably offer. Many of the concepts used in the proposed rates require new service offerings from upstream providers. Enbridge Gas Distribution's proposals also reflect a set of assumptions about the regulatory principles that must be respected. Finally, Enbridge Gas Distribution's proposals use estimates of costs based on a variety of assumptions related to operations of its system and the power generators. To the extent that actual operations invalidate these assumptions rate modifications as to cost and terms of service will change.

18. Over the past six months, Enbridge Gas Distribution has been active in meeting and consulting with potential power generation customers in order to understand their needs. Through this consultation process, as well as through the NGEIR process, potential power generation customers have indicated that they would like the Company to examine and offer a number of services including:

- Separate unbundled distribution and load balancing/storage.
- Facilitate flexibility offered by upstream pipelines (e.g., multi same-day nominations.)
- No-notice storage services
- High deliverability storage services
- Park and loan services
- Load balancing service over and above the 2% tolerance which is less punitive than the 150% cash out.
- Services which optimize costs (e.g. allow customer to pack in winter etc).

The Company has endeavoured to develop services that incorporate as many of these attributes as possible. These services may evolve over time.

19. As a result of the Board's NGEIR process in the fall of 2005, the Board issued the Notice of Proceeding in this matter. Procedural Order No. 1 stated that the Board would consider whether it should order new rates for services to gas power generation customers. The Board directed Enbridge Gas Distribution (and Union) to file proposed tariffs for the provision of the following services:

    - More frequent nomination windows for distribution, storage and transportation that correspond with the nominations of upstream pipelines that connect to the Ontario gas system.
    - Firm high deliverability service from storage with customer options for 1.2%, 5% and 10% deliverability.
    - Gas storage and distribution offered as discrete services.
    - Inter-franchise movement of gas (i.e., the ability to access services across Ontario, whether to a customer's own account or as a sale to a third party).
    - Redirection of gas to a different delivery area on short notice (i.e., the ability to redirect or acquire gas on short notice to a different delivery area).
    - The ability to transfer the title of gas in storage (i.e., the title transfer in gas storage is treated as an administrative matter instead of a physical withdrawal or injection of gas).

20. Through this evidence, Enbridge Gas Distribution has endeavored to address and respond to as many of the services listed above as possible. In fact, Enbridge Gas Distribution has made efforts to go beyond the services mandated by the Board and to also examine some additional services requested by potential power generation customers.

OPERATIONAL CHARACTERISTICS AND ISSUES: LOAD BALANCING

1. The introduction of significant gas-fired power generation into the Company's distribution system represents a shift from the traditional demand profile within the Company's franchise areas. As Figure 1 in the "Current Experience" section (Exhibit B, Tab 1, Schedule 1) of this evidence shows, the current Enbridge Gas Distribution load profile reflects peak consumption in the winter that is then followed by lower "baseload" consumption during the summer months. Gas-fired power generation is likely to peak coincident with the existing winter peaks and also with the Company's traditionally low demand periods during the summer. The coincident peaks will have the effect of raising the peak distribution volumes experienced by the utility. The introduction of summer peaks to the distribution profile will require summer volumes to be managed in a manner that is able to respond to these peaks. These gas-fired generation peaks have the potential to represent a significant portion of the current throughput in the Enbridge Gas Distribution franchise. The table below shows comparisons (in 10^6m^3) between the forecast 2006 summer and winter daily loads of the Enbridge Gas Distribution GTA and the approximate volume consumed by a 16 hour burn of 2,000 MW of gas-fired generation.

Table 1

Impact of Gas Fired Generators on Current Demand

	Current Demand 10^6m^3	2000 MW Generation (16 hours burn) 10^6m^3	% Increase
Summer			
Average Day (April through October)	15.6	7.6	48
Minimum Day (June through August)	13.9	7.6	55
Winter			
Average Day (November through March)	43.9	7.6	17
Peak Day (November through March)	100.5	7.6	7.6

Witness: D. Charleson

2. In additional to the impact on daily peak demand, the introduction of gas-fired generation is also expected to impact the hourly peak flows. The hourly peak flows in the gas industry are nearly identical to that of the electric industry, and the consensus is, the majority of incremental power generation to feed the peak electricity demand will likely come from gas-fired generation. The gas utility is currently designed for peak winter conditions, as are contracted transportation quantities. The tariff of the upstream transportation provider stipulates all deliveries shall be as uniform as possible throughout the day and are to be within ±5% of the scheduled daily quantities. The transportation provider designs their systems to this basic parameter. However, the current demand fluctuations within the utility, especially during the "morning lift" puts stress on this parameter. Adding a large concurrent peak load will likely stress the natural gas system even further. The Company will find it challenging to adequately manage this new demand.

3. While the Company's distribution system is designed to meet peak conditions, it will still be essential that load balancing is planned for to ensure adequate supplies are available to the distribution system. Whether the load balancing is performed by Enbridge Gas Distribution, the customer, or other market participants, ensuring that supplies are delivered to match the daily consumption is critical to the successful operation of the distribution system

4. Load balancing can take several forms:
   (i) the end of day difference between nominated flow and consumption at the plant;
   (ii) partial source of gas supply for the day;
   (iii) temporary source of gas supply during the day while the power plant makes arrangements for their own supply; and

(iv) providing line pack to handle variations in demand during the day.

5. To effectively serve the power generation market, the upstream services and nomination windows must recognize and support the operating challenges that this class of customer faces. Gas cannot be made available into Enbridge Gas Distribution's franchise area by any means other than those provided by upstream transportation companies. The potential unpredictability of the gas-fired generation loads requires more frequent nomination windows for upstream storage and transportation to perform load balancing services. Nomination windows should be aligned across upstream providers to provide congruent services between the storage pool and a customer's facility. Without services that align with these needs, it will be very difficult for any market participant to provide load balancing services at a reasonable cost.

6. To provide load balancing services, the upstream services available play a critical role. The contracted upstream services are used to manage volumes that have been delivered to Enbridge Gas Distribution's franchise area. Given that there is no storage imbedded within the Company's franchise area that can be used for balancing, upstream deliveries are the only mechanism that Enbridge Gas Distribution, its customers, or other market participants have available to meet the demands of customers. These upstream services must be compatible with the services that the market is looking for.

7. Given the less predictable nature of the power generator load and the fact that the electric day is not aligned with the gas day, one critical aspect of upstream services that are required will be the reservation of capacity. The Ontario electric day is parallel to the calendar day, running midnight to midnight. Bidding for power generation occurs hourly and generation is dispatched in near real time. This does

not align with the gas day, which is a North American standard and which runs from 10:00 a.m. one day to 10:00 a.m. the next day on a full day ahead basis. Gas fired generators will be required to nominate supplies as early as possible to ensure that fuel supply is in place on supply pipelines. The fact that the most significant gas demand from existing gas customers, which occurs during the "morning lift" at the end of the gas day, coincides with the early stages of the electric day further emphasizes the importance of power generators having supply in place. The distribution system has its least supply flexibility at this time of the day. As the first bidding for electric generation occurs after the current gas day begins, some form of capacity reservation on pipelines will be required to allow generators to make the necessary supply deliveries as it would allow for an increased nomination up to the contracted level on a firm basis. Also, dispatch of gas-fired generation will be hourly and real time. Scheduling adjustments of fuel supply throughout the day will be required on upstream gas pipelines.

8. As described earlier in this evidence, the current nomination process does not allow for nominations to be increased on a firm basis. If a power generator customer needed load balancing due to an unplanned requirement to generate, the Company, power generator, or any other market participant would not be in a position to do this on a firm basis if it cannot increase its nominations to the delivery area on a firm basis. The service could only be provided on a best efforts basis. The availability of additional nomination windows is also required to facilitate the adjustment of deliveries later in the gas day, specifically closer to the timing of the morning lift.

9. Also, load balancing for gas-fired generation could lead to more frequent changes in storage operations. Storage is expected to play an important role in providing load balancing services to power generators, similar to the key role it plays in load balancing the conventional loads and demands of Enbridge Gas Distribution's

customers. It provides intra-day access to supplies that may be needed to meet increased demand, or provides a location to receive gas that is not required within the distribution system. Currently, storage operations nominations are typically adjusted only one to three times each day, and the storage system is able to operate at relatively stable rates over the day. More frequent nominations could lead to more frequent changes between injection and withdrawal, or simply a reduction/increase in the amount of gas being injected or withdrawn. These direction changes or reductions or increases in gas rates could lead to compressor units experiencing more starts and stops or changes in pools being utilized. This could lead to additional maintenance issues and maintenance costs. Operational barriers and issues related to storage are discussed in more detail in the next section of the Company's evidence.

10. There may also be times of the year where balancing abilities of storage may be limited. These would likely occur in the spring or fall when storage inventories are at their lowest or highest and the system is operating close to its limits. If additional withdrawals are required to meet balancing in the spring, this could further tax the system that has limited deliverability remaining at that time of the year. The same can be said for fall injections when little space is available to manage incremental injections.

11. The largest impact on storage may be in terms of deliverability and injectability, rather than capacity. To be able to balance the power generation load, the issue of how quickly the gas can be injected or withdrawn will be more important than the amount of space which will have to be reserved for balancing services. This notion of improved injection and withdrawal capacity will drive some of the improvements which are necessary in the storage system to meet this demand. In addition, inventory management will become a more important focus so that storage

operations can ensure it can deliver at the required level of service every day. This may mean that more attention will have to be paid to storage balances in the pools that provide high deliverability and injectability as opposed to the balances which would be in the pools closer to system average capabilities.

12. An additional operational consideration is the differences in supplying customers in different Enbridge Gas Distribution franchise areas. Supplying gas to customers in the EDA and CDA are quite different. In the CDA, gas customers are fed by two very robust gas systems, TCPL and Union. As well, the CDA is closer to storage. The closer a distribution utility is to a large storage reservoir; the easier it is to make supply adjustments. By comparison, the EDA is only supplied by TCPL and it is further from storage.

13. As the EDA is nearing the end of the TCPL system, the pipeline capacity is reduced, and flows are often subject to the takes and restrictions of upstream customers. Demand in the EDA is also highly volatile. There is less commercial base load, higher residential load subject to peaking, colder winter temperatures, and overall greater sensitivity to changes in weather and temperature. Adding an additional volatile demand in the EDA with concurrent peaks is a large challenge.

14. Based on discussions that the Company has had within the industry, it is expected that these gas fired power generation customers will not operate independently and will be looking to the gas utilities to provide some form of Load Balancing service. This has led to the inclusion of a load balancing provision in the design of the proposed Rate 125 service (Exhibit C, Tab 2, Schedule 1). However, for the Company to effectively provide these services, alignment of the upstream services in the manner described above is critical to Enbridge Gas Distribution's proposal. Incompatible upstream services will make it difficult, if not impossible, to load balance

this class of customers or provide any efficiency over the customer assuming full responsibility for doing this themselves.

15. The introduction of these services by Enbridge Gas Distribution will require careful planning. Load Balancing services have to be factored into overall system demand, the necessary contractual arrangements have to be in place with upstream service providers, and storage capacity considerations have to be made. In order to provide balancing to a power generator, the Company must be aware of, or be able to forecast, the customer's balancing requirements and the means available to provide the balancing.

16. As described earlier in this evidence, Enbridge Gas Distribution has a long history of managing the overall demand of its customers. This has been done through developing an understanding of its customers' load profiles and the impact of weather on demand. With any new load, the expectation for demand has to be factored into the daily planning to meet the load. The addition of load balancing for gas-fired power generators is no different. An understanding of the load profile for these customers needs to be developed so that appropriate planning can be done. It is not expected that these loads will have a conventional or completely predictable load profile. While certain loads would be expected to be weather-sensitive there is also the potential for loads to occur during periods when other sources of generation may not be on-line and additional gas-fired generation is required. The variability and difficulty in projecting when these loads may occur will make communication within the natural gas and electricity industries critical to allowing the utility to effectively manage potential variances between deliveries from the power generators and their demand. This communication needs to include the exchange of information between the customer, the IESO, Enbridge Gas Distribution, and upstream transporters.

17. Enbridge Gas Distribution expects that it will require additional transportation and storage services to provide load balancing services for these new customers. The Company may need to contract for incremental upstream transportation services that allow for the flexibility necessary to meet the balancing demands of this class of customer. This flexibility includes providing access to additional nomination windows and the reservation of capacity to the delivery area to be balanced, either the CDA or EDA depending on the customer. Additional storage flexibility and deliverability will also be required to allow the Company to access supplies that are needed to balance the load. This would include the ability to nominate from storage at the same windows as the transportation services and having higher deliverability to provide access to an increased volume of gas from storage on a given day. Without adequate incremental transport with enhanced flexibility, the Company would have to rely on seasonal restrictions, suspension of balancing on system constraint days and the ability to terminate service to the customer to ensure system integrity is maintained. The Company's review of load balancing options is contained at Exhibit C, Tab 2, Schedule 1.

18. The Company expects that it will incur incremental costs associated with the contracted transportation capacity and the development of, or obtaining access to, higher deliverability storage. Enbridge Gas Distribution will not be in a position to determine or control the unit costs associated with incremental transportation capacity as these costs will be determined by the upstream transporter. Similarly the costs associated with higher deliverability from storage will also be dependent on the amount of storage capacity the Company will require to meet these needs. The volume of transportation or storage capacity required to meet these demands will be dependent on loads that need to be balanced. The Company expects to gain efficiencies in the provision of these services through the coordination of these load balancing activities with the load balancing that it performs for other customers within

the delivery areas. There is also the potential that additional efficiencies can be gained by encouraging customers to behave in a counter seasonal manner, packing gas in the winter, which would assist in meeting the higher seasonal demand, and drafting in the summer, which would reduce the volume of gas to be transferred to storage. To the extent that these types of efficiencies can be achieved, it is expected that all distribution customers will benefit from them.

OPERATIONAL CHARACTERISTICS, ISSUES AND PROPOSED SOLUTIONS: STORAGE

Characteristics and Issues

1. This evidence addresses proposed enhancements to storage that would be required to provide high deliverability storage service to power generators and other customers. Enbridge Gas Distribution's gas storage operations group ("Tecumseh") has based these proposed enhancements on deliverability requirements articulated by power generators and as directed by the Board. As noted at Exhibit B, Tab 3, Schedule 1, because Tecumseh storage does not reside within the Enbridge Gas Distribution franchise area, complementary transport services from Union and TCPL are required.

2. The first step in the Company's investigation of storage enhancements involved estimating the incremental space and deliverability required for the gas-fired generation market in the Enbridge Gas Distribution franchise. Gas usage by these gas-fired generators can vary significantly depending on their operating modes, equipment choices and decisions relating to gas supply and load balancing.

3. To establish a forecast of gas usage, the Company first used an industry 'rule of thumb' which assumes that a 500 MW combined-cycle gas-fired plant requires a daily gas supply in the order of 100 MMcf (assuming a full firm peak load).

4. This number was then multiplied by the estimated size of the market which, based upon current information in the marketplace, is estimated to be 2,000 MW in the Enbridge Gas Distribution franchise. This level of capacity equates to an approximate collective daily gas demand of up to 400 MMcfd.

5. It was further assumed that gas-fired generators would be interested in a daily deliverability from storage equating to as much as half of their daily gas demand. This would allow a generator the flexibility to inject or withdraw up to 50% of their gas supply requirements on a given day, and would result in a total market need for up to 200 MMcfd of incremental deliverability from storage.

6. Flowing from the Board's 2005 NGEIR process, gas-fired generators have expressed a desire for high deliverability services from storage (where daily deliverability is expressed as a percentage of the total storage space allotted for a given service). The Board's subsequent Procedural Orders confirm this need and call for high deliverability services of up to 10%, which is much greater than the traditional 1.2% deliverability from storage.

7. If the daily deliverability requirement is about 200 MMcfd, and represents 10% of total space, the resulting total space required by gas-fired generators would therefore be about 2 Bcf. Other variations on hours of operation and desired deliverability are shown in the table below.

Capacity (MW)	Hourly flow (MMcfh)	Hours per Day	Daily Gas Burn (MMcfd)	% Plant Burn from Storage	Daily Storage Requirement (MMcfd)	Deliverability %	Total Space Requirement (Bcf)
2000	16.7	24	400	25%	100	10%	1.0
2000	16.7	24	400	35%	140	10%	1.4
2000	16.7	24	400	50%	200	10%	2.0
2000	16.7	24	400	25%	100	5%	2.0
2000	16.7	24	400	35%	140	5%	2.8
2000	16.7	24	400	50%	200	5%	4.0
2000	16.7	16	267	25%	67	10%	0.7
2000	16.7	16	267	35%	93	10%	0.9
2000	16.7	16	267	50%	133	10%	1.3
2000	16.7	16	267	25%	67	5%	1.3
2000	16.7	16	267	35%	93	5%	1.9
2000	16.7	16	267	50%	133	5%	2.7

8. The Company's investigation of current operational barriers continued with a review of the existing constraints in the Tecumseh gas storage system.

9. The Tecumseh system has a number of existing restrictions that limit its overall capabilities. These restrictions create issues that affect service to those customers who require incremental space and, most importantly, fast-response incremental deliverability. The more significant restrictions are as follows:

    a) Tecumseh transmission pipeline limitations exist due to a bottleneck on the NPS 30 lines connecting at Dawn. This bottleneck occurs at the point of tie-in with the NPS 16, Sombra Transmission system;

    b) Maximum operating pressure ("MOP") limitations exist on various transmission, gathering and header piping components thereby restricting the ultimate flow and capacity in the system;

c) There are four transmission pipelines near the Tecumseh system (Union, TCPL/Great Lakes, Link, Vector), however only three of these are connected to Tecumseh and allow receipt of gas into the system;

d) The Tecumseh Wilkesport Transmission Line, which connects four separate storage pools and a compressor station, is a single NPS 16 sized line, thereby severely limiting the capabilities of this part of the system;

e) The Enbridge Gas Distribution Storage System has approximately 43,000 hp of compression with only 10,100 hp capable of compressing to over 8.28 mPa (1200 psig). Additional compression is required to assist in meeting deliverability issues;

f) Three of the oldest storage reservoirs within the Enbridge Gas Distribution system have surface facilities with operating and MOP characteristics that have historically limited their capacity;

g) The deliverability and rate of injection is limited on some reservoirs due to the connecting pipeline characteristics (size, MOP), number of wells filling/draining the pool or the characteristics of the reservoir (porosity, permeability); and

h) Drawdown limitations exist on the system and this limits the pressure differential between the plant and the wellhead. The purpose of these limitations is to minimize well bore damage and to control the drawing of reservoir liquids or solids into the balance of the storage system.

Proposed Storage Solutions

10. As noted above, the gas-fired generator market requires unique and significant storage services. Such services are important to ensure that gas-fired generator's can react quickly to requirements that are anticipated to be placed upon them by the organization that will dispatch these plants (IESO).

11. Enbridge Gas Distribution's proposed storage solutions must therefore keep these priorities in mind and be a part of the overall solution that addresses the need to add this gas fired capacity to the GTA in the 2007 to 2008 time period.

12. Keeping these priorities in mind, the Company's proposed storage build program that is described below will need to undergo all OEB regulatory approvals on an expedited basis, with fairness to all and regulatory scheduling flexibility being the keys to success.

13. The OEB's NGEIR proceeding is a very timely one which can deal with the vast majority of the critical regulatory issues that need to be addressed for the proposed storage solution. While no rate order or leave to construct approval is anticipated by the Company in this proceeding, Enbridge Gas Distribution believes that a Decision from the Board that supports the purpose and need for its proposed storage build program, specifies the timing for the build, and deals with ratepayer fairness issues (including the issue of whether the new Rate 316 unbundled storage service should be priced at market rates), accomplishes these goals.

14. Such strong direction from the Board in the NGEIR proceeding will allow for the timely completion of the following processes;

    a) the timely execution of an open season process that will establish prices (spring/summer 2006) and award a contract (fall 2006);

    b) the timely filing of various leave to construct applications with the OEB (July and August 2006);

    c) the timely filing and approval of well license applications with the Ministry of Natural Resources and, if necessary, the OEB in November 2006; and

d) the expedited approval of any rate making implications of the build in the Company's 2007 Rate Case.

15. These regulatory timelines are shown within the context of the overall build schedule in a Gantt chart found in an appendix at the end of this portion of the Company's evidence.

The Planning Process

16. The Tecumseh limitations noted earlier, along with other assumptions and metering constraints, were taken into consideration by the Company's storage simulation modeling system (Advantica's Synergee Gas software version 3.36). This software is utilized for overall pool planning and scheduling, pipeline sizing, high level engineering design and general compression modeling. The model has been run to simulate the changes that are necessary at Tecumseh to develop as much as 2 Bcf of capacity, and at least 200 Mmcfd of incremental deliverability.

17. The specific objective of the simulation was to determine whether there are improvements to Tecumseh's existing performance curves that can be made by adding new capacity and deliverability in an integrated fashion and at reasonable cost. At the same time, there is an overall constraint that the Company has imposed on the exercise, which is that service to existing Enbridge Gas Distribution ratepayers should be maintained such that they are held harmless by any expansion or revisions to the way in which the system is operated for the new services.

18. The following system improvements represent an optimal design which, when integrated with the existing manner in which the system is operated, should result in

service to qualifying Rate 125/316 customers, and a continuation of existing service to all other Enbridge Gas Distribution customers.

Increasing Capacity

19. There are two basic ways in which turnover capability can be increased in the existing Tecumseh system. The first method involves a permanent pressure elevation in select pools, where such an elevation can be accommodated without a major re-engineering of the "top-side" facilities. The second method involves the introduction of fresh gas into the storage system for purposes of multi- cycling it at non – critical times of the year when it does not interfere with the utility's needs. Such multi-cycling serves to increase the effective turnover of gas, however, it does not add capacity to the system.

20. The first method is complicated by one or more of the above-noted limitations, and the second method is complicated by the fact that the introduction of fresh gas into the system may be possible for parts of the year but will most definitely be limited at other times of the year. Multi-cycling, in and of itself, would therefore only be an interruptible source of new turnover capability.

21. The proposed solution of Enbridge Gas Distribution is a combination of a pressure elevation and the introduction of another pipeline path into Tecumseh for multi-cycling purposes.

22. With respect to the pressure elevation, Enbridge Gas Distribution proposes to delta pressure two of its existing and oldest storage reservoirs, located in the north section of the system in Moore Township, to a pressure that matches the maximum operation pressure ("MOP") of the surface facilities (wellhead and pipelines). The

increase in pressure of gas stored in the reservoir will result in an incremental increase in total storage capacity of approximately 56.7 $10^6 m^3$ (2 Bcf).

23. The pools targeted for delta pressuring (Seckerton and Corunna) are subject to due diligence as part of this project planning process. An integrity review of surface facilities by the Company's Storage Engineering Department is underway to verify that all downstream pipeline and fittings are suited for the higher MOP pressure. This review includes a verification of pipeline and fittings specifications as well as internal inspection of the main gathering system.

24. The internal inspection component of the gathering lines associated with reservoirs targeted for delta pressuring began in the fall of 2005. The preliminary results of the internal inspection indicate only minor anomalies with no repairs required. The completion of inspection will take place in the spring of 2006 with final results expected in summer. Investigative digs will be scheduled for summer 2006 on the inspected lines to verify anomaly size and depth, perform further analysis and complete any required repairs.

25. Well integrity is also included in the due diligence process. Wells in the pools are undergoing internal inspection of casing pipe and pressure tests to verify the pressure rating of materials. If necessary, wellhead upgrades would be performed to ensure all wellhead components are rated to the proposed elevated pressure. To date, the well integrity process is approximately 50% complete and has shown positive results, with no remedial work required to date.

26. The multi-cycling component of the capacity plan involves a pipeline tie-in to the Vector system at the Tecumseh Sombra compression facility. This pipeline tie-in will be integrated with other aspects of the proposed deliverability build program

that will allow for high rates of injection and withdrawal, primarily into the south end of the system but integrated with the entire operation.

Increasing Deliverability

27. Enhancing the deliverability characteristics of the Tecumseh system, and doing so on both a ratcheted and un-ratched basis (as explained in Exhibit C, Tab 3, Schedule 1) presents the biggest challenge for Rate 316 service. The deliverability plan involves a number of components which need to be operated in an integrated fashion, and these are summarized below.

Sombra Transmission Tie-In

28. This aspect of the proposed deliverability project involves an extension and dedicated entry point for the NPS 16 Sombra Transmission Line into the Union Gas Dawn delivery and receipt point located in Dawn Township. Presently, Sombra Transmission Line connects into the bottom section of the Twin NPS 30 Tecumseh Station to Dawn Transmission Lines. These lines become bottlenecked at this connection point, thereby restricting the total potential delivery into Dawn. The tie-in consists of 0.6 km of NPS 16 pipeline and an ultrasonic meter.

29. Inside Union's Dawn yard, the NPS 16 extension will connect into two different headers. Two connection points provide Enbridge Gas Distribution Storage Operation with more flexibility to move gas in and out of the Enbridge Gas Distribution system from Dawn. Enbridge Gas Distribution is coordinating with Union to ensure that both the proposed NPS 16 line connections and the Dawn yard work planned for 2007 are completed efficiently.

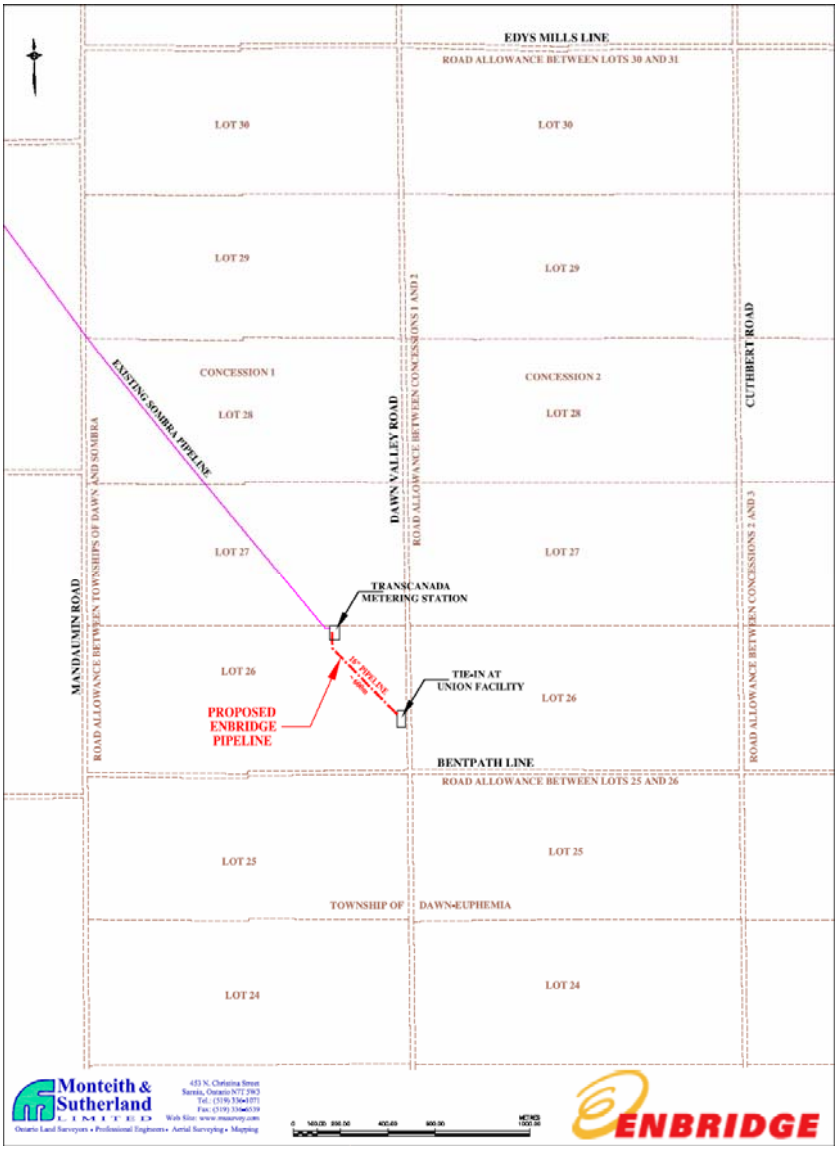
30. The dedicated tie-into Dawn will remove the existing transmission bottleneck and will provide the additional 5.7 $10^6 m^3$/day (200 Mmcfd) of deliverability in and out of

the Tecumseh storage system at the Dawn receipt/delivery point. This is equivalent to the maximum rate of injection/withdrawal within the proposed rates (10% of 56.7 $10^6 m^3$ (2 Bcf)).

31. In addition to the deliverability gained, a separate tie-in of the Sombra Transmission Line provides the Tecumseh storage system with a secondary route for delivery and receipt of gas from Dawn in the event of loss of the Tecumseh Station to Dawn Transmission Lines. Today, the loss of one or both of the NPS 30 Tecumseh to Dawn Transmission lines due to damage or other events, would either create a significant restriction on gas flow from storage (in the case of one line), or put Tecumseh temporarily out of service (in the case of two lines). The additional security of supply resulting from the separate Sombra Transmission connection into Dawn is beneficial to all customers within the Enbridge Gas Distribution Gas Distribution system.

32. The following schematic shows the proposed Sombra Transmission tie-in.

Sombra Transmission Tie-In



33. While the Sombra tie-in creates additional flow capability between the remote Sombra compressor station and Dawn, there are other aspects of the storage system, such as well and reservoir deliverability, transmission line capacity into and within the Tecumseh storage system, and compression that are necessary to move gas, at a fast rate, from the reservoirs to the Dawn delivery point to meet the needs

of Rate 316 customers. The next features of the Company's proposed build program address these aspects.

Wilkesport Transmission Looping

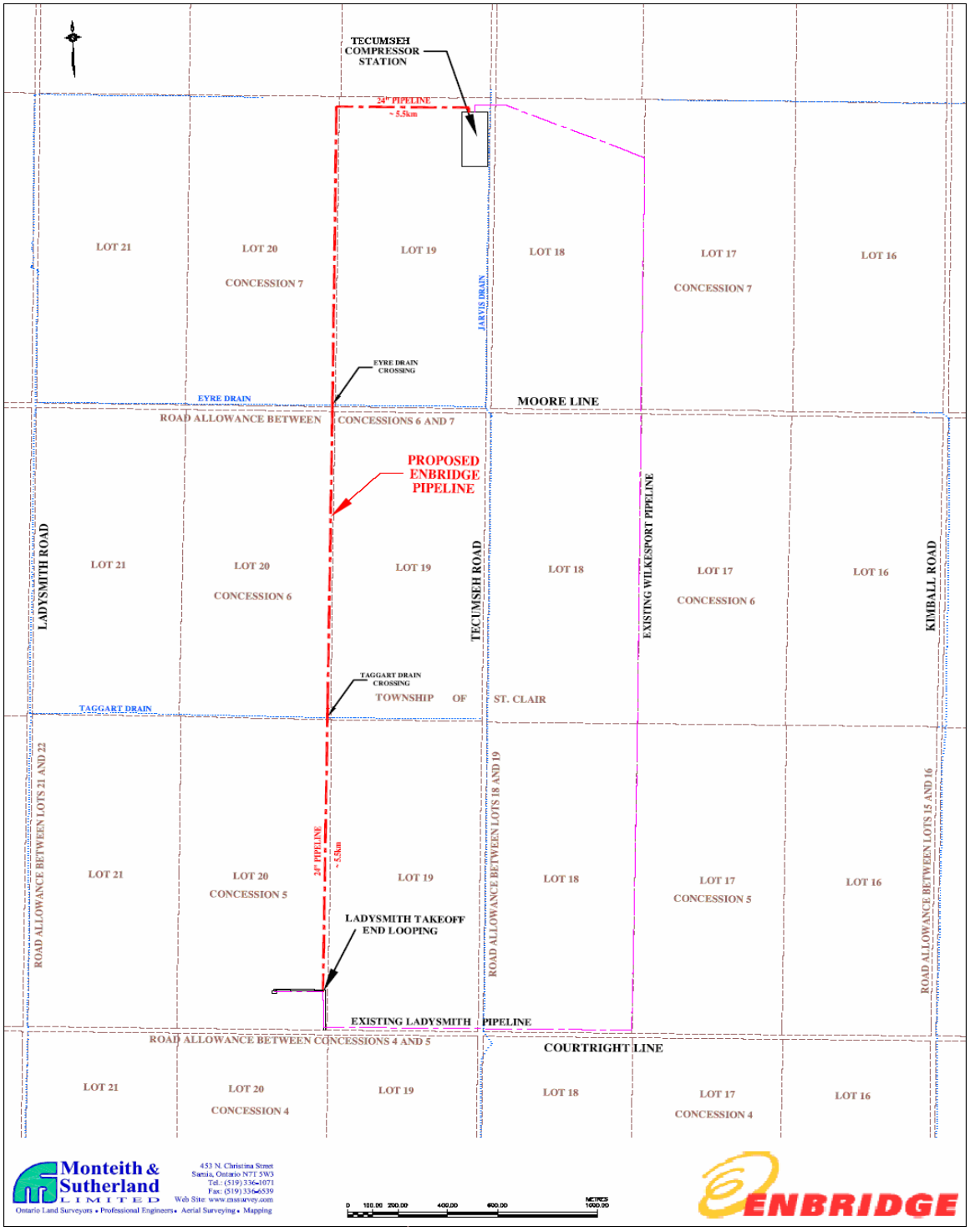
34. In order to provide the deliverability specified in the proposed Rate 316 service and at the same time maintain Tecumseh's deliverability commitments to all other ratepayers in the Enbridge Gas Distribution system, every day of the year, it is necessary to enhance the coordination of pools in the north part of the Tecumseh system with those in the south part of the Tecumseh system. This is accomplished, in part, by looping a section of the Wilkesport transmission line.

35. A 5.5 km section of the Wilkesport transmission line would be looped with a proposed NPS 24 pipeline to be installed between the main Tecumseh Compressor Station and the Ladysmith reservoir gathering system connection, located in Moore Township.

36. The addition of the looped pipeline would provide further operational flexibility and flow due to the fact that gas from two connected reservoirs can be transported through the Wilkesport Line simultaneously, despite a pressure differential between the pools, because the gas from each pool would be assigned to one of the two lines. Presently, without the looped section of the Wilkesport Transmission Line, gas moving from a reservoir at a lower pressure would be restricted from entering the transmission line until another pool of higher pressure also flowing into the line dropped to the same pressure with the reduction of its pool inventory. This situation ultimately limits the flow of gas within the Tecumseh storage system.

37. The following diagram provides a schematic of the proposed Wilkesport Looping.

Wilkesport Transmission Looping



Witness: J. Grant

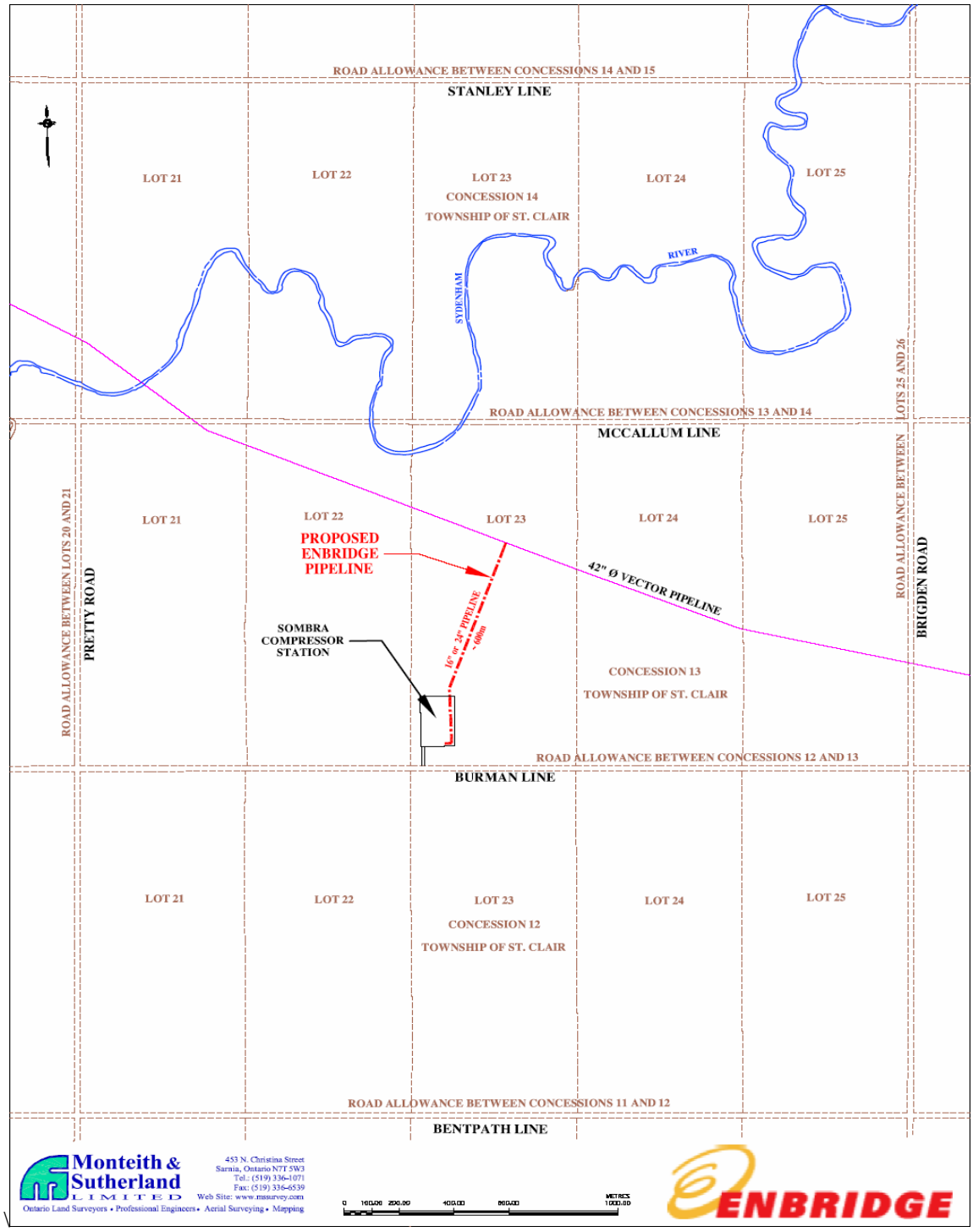
Vector Tie-In

38. Vector has not been approached yet as to this aspect of the storage proposal, however, subject to future discussions and an agreement with Vector, Enbridge Gas Distribution is proposing a connection to the Vector Line at the Sombra Station in Sombra Township. As indicated earlier, this connection would bring fresh supply transmission gas into the Tecumseh storage system. The proposed tie-in allows for cycling the Vector sourced gas into high deliverability peaking pools during the storage withdrawal season. By cycling peaking pools with supply transmission gas, there is a short term gain in storage inventory as well as a significant gain in deliverability from the peaking pool once it is refilled.

39. The Vector Tie-In also provides Enbridge Gas Distribution Storage with an alternative source of gas supply providing operational flexibility and redundancy in the event of a supply restriction on an existing supply transmission pipeline.

40. The Vector Tie-In will include 0.5 km of NPS 20 pipeline and an ultrasonic meter extending from the Vector Pipeline to the Sombra Station. (Lot 23, Concession 13 in Sombra township). The following diagram provides a schematic of the proposed Vector Tie-In.

Vector Tie-In



Witness: J. Grant

Additional Sombra Compression

41. Cycling gas through high deliverability pools can improve the overall system deliverability. Gas used to fill a high deliverability pool can come from many sources such as TCPL, Vector (pending the previously noted tie-in project), or from a lower deliverability pool. Currently a restriction in cycling pools results from the time that it takes to both empty and refill a high deliverability pool. These restrictions do not allow for a fast response to a Rate 316 customer. In order to improve the abilities of the pools in the southern part of the Tecumseh storage system, it is necessary to alleviate the compressor constraints at the Sombra compressor station. This will be accomplished by the addition of 1200 horsepower of compression at the Sombra Compressor Station.

Reservoir Simulation and Horizontal Well Drilling

42. A final step in the deliverability enhancement process involves an assessment of what needs to be done to enhance deliverability into and out of the reservoirs by way of new wells.

43. A detailed reservoir simulation process, utilizing an outside consultant with expertise in this area, will be conducted in 2006 and is required to determine the optimal design for this aspect of the build program and to develop a well drilling program. The reservoir simulation will help identify where the wells should be located, and what impact, if any, those new wells may have on the existing wells. These results will be combined with simulation of surface facilities to provide deliverability estimates back to the compressor station.

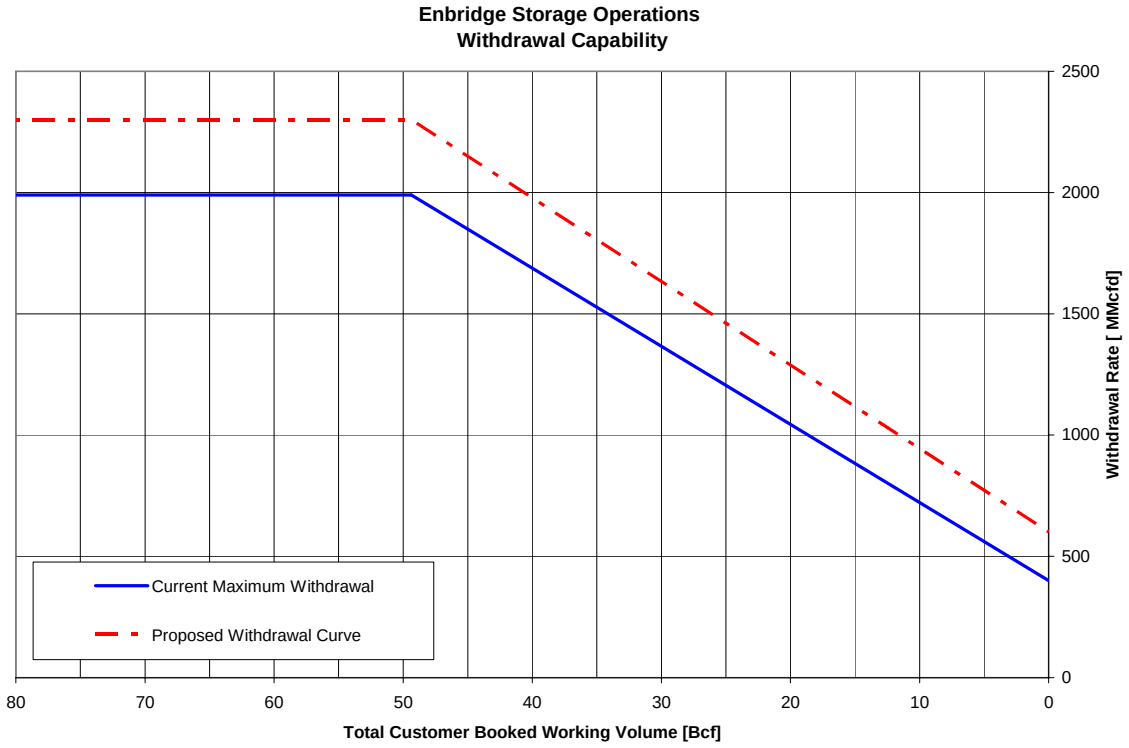
44. While the final number of new wells and their location has yet to be determined, a high level assumption has been made that as many as 8 new horizontal wells will be necessary in order to move the gas into and out of the reservoirs at rates that

match the requirements of a gas fired generator or other qualifying Rate 316 customer. The working assumption is that the wells that will be added to the reservoirs will provide deliverability in the order of the average of the other wells in that reservoir. By adding wells with average deliverability into the planning assumptions, it has been possible to estimate the new pool flow characteristics as an aggregate.

Resulting Impact On Tecumseh Performance Curves

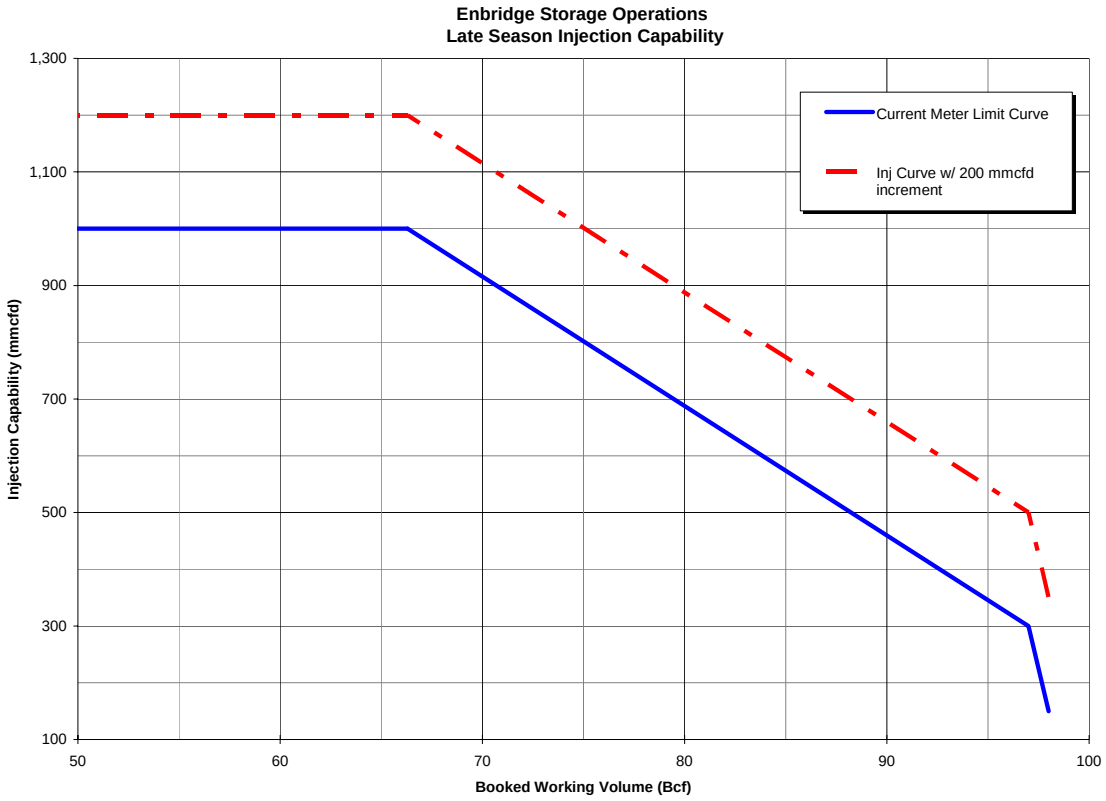
45. Upon completion of the proposed build program, the current estimate of the impact on the Tecumseh total storage curves is discussed below, subject to final analysis.

46. The following chart shows the impact of the proposed build program on Tecumseh's total withdrawal curve (ie. prior to allowing for any loss of critical unit (LCU) protection and the contract to Union).



47. The solid line above represents the current maximum withdrawal at Tecumseh and the dashed line represents the total deliverability after all of the proposed build phases are taken into account. Additional withdrawal capability is evident regardless of the total working volumes in the system. Therefore, the proposal allows Rate 316 to be offered on a firm basis to qualifying customers without impacting the rest of Enbridge Gas Distribution customers.

48. The chart below represents the injection curves for Tecumseh with and without the proposed build program. The same considerations need to be made for these injection curves as were made for the withdrawal curves.



49. The solid line represents the current maximum injection rate of injection, and the dashed line represents the total deliverability after all of the proposed build phases are taken into account. Additional injection capability is evident regardless of the total working volumes in the system. Therefore, the proposal allows Rate 316 to be offered on a firm basis to qualifying customers without impacting the rest of the Company's customers.

50. The above sections of evidence have detailed the proposed build program for rate 125 enhancements as well as for the Rate 316 service. The following four sections of this evidence discuss landowner and environmental matters, an estimate of capital expenditures and incremental O&M costs, project timing, and finally a process for pricing the value of the Rate 316 services.

Witness: J. Grant

Landowner Considerations

51. The persons affected by these proposed storage enhancements include landowners, tenants, mortgage holders and those who hold encumbrances of the lands located within the pipeline routes, and the municipalities with jurisdiction over the lands of the proposed pipeline routes. Enbridge Gas Distribution is working on addressing landowner concerns.

Environmental Considerations

52. An environmental study will be undertaken and filed as part of leave to construct applications related to the proposals detailed above.

Capital Expenditures

53. The total capital cost of the proposed projects is approximately $26.2 Million, excluding IDC & overheads. These capital costs are broken down as follows:

Project Component	**Capital Cost**
Reservoir Delta Pressuring	0.6
Sombra Transmission Tie-In	2.3
Wilksport Looping	8.4
Vector Tie-In	1.2
Sombra Compression	5.0
Horizontal Well Drilling	8.7
Total	26.2

Incremental O&M

54. The introduction of storage facility enhancements for Rate 316 and 125 customers will result in an incremental increase in O&M costs for the Company's Storage Operations.

55. With the potential of gas-fired generators's contracting for Rate 316 service, there will be a requirement for more frequent nomination windows to allow the power generator to meet its obligation to the power grid system. Due to the expected increase in the frequency of nomination windows in a 24 hour period, there will be a requirement for additional operators to receive the revised nominations and adjust the system to meet the new nomination requirements. There will also be increased communication with gas control and interfacing pipelines: Union, TCPL, and Vector.

56. The proposed enhancement projects additions will also cause O&M cost increases. New pipelines will be required to be part of the pipeline integrity program that includes annual leak survey and corrosion survey as well as internal inspection.

57. Surface facility additions will require lease payments to landowners, compressor additions will require maintenance and have lubricating oil requirements and meter additions will need regular meter calibration and maintenance.

58. Well additions will be included in the well integrity program, undergoing regular vertilogs and well inspection and maintenance.

59. A summary of these incremental O&M costs is shown in the table below.

Annual Incremental O&M Impact

Activity	Detail	Total Cost ($000)
Pipeline Integrity	Leak & Corrosion Survey, Internal Inspection, ROW Clear	25
Well Integrity	Vertilogs, Well Inspection	60
Land Payments	Lease Payment, Wellhead Payment, Laneway Payment	12
Compressor Maintenance	Misc. Compressor Maintenance, Oil Changes	28
Vector Tie-In	Vector Maintenance Agreement	10
Sombra Transmission Tie-In	Meter Calibration & Maintenance, Pipeline Integrity	15
Operations Staff Additions	Coverage of More Frequent Nomination Windows	130
Total		280

Timing of the Capital Projects

60. A detailed GANTT chart which sets out timelines and key steps in the Company's proposed storage build project is found in an appendix at the end of this section of evidence.

61. The planning phase of the delta pressuring process is ongoing with the majority of internal inspections completed on the associated gathering lines and well work completed in the Corunna Reservoir in 2005. The completion of the remainder of

the gathering line inspection, integrity digs, material specification review and well work in the Seckerton Reservoir will be completed throughout the 2006 calendar year according to the milestone dates identified on the Gantt Chart.

62. In order to meet the needs of Rate 316 customers, construction on the Company's proposals is scheduled to begin in the spring of 2007. Long delivery material such as pipeline valves will be required to be ordered up to 6 months in advance of construction to allow for the construction time line to be met.

63. A summary of key milestones in the Company's proposed build program is found in the following chart.

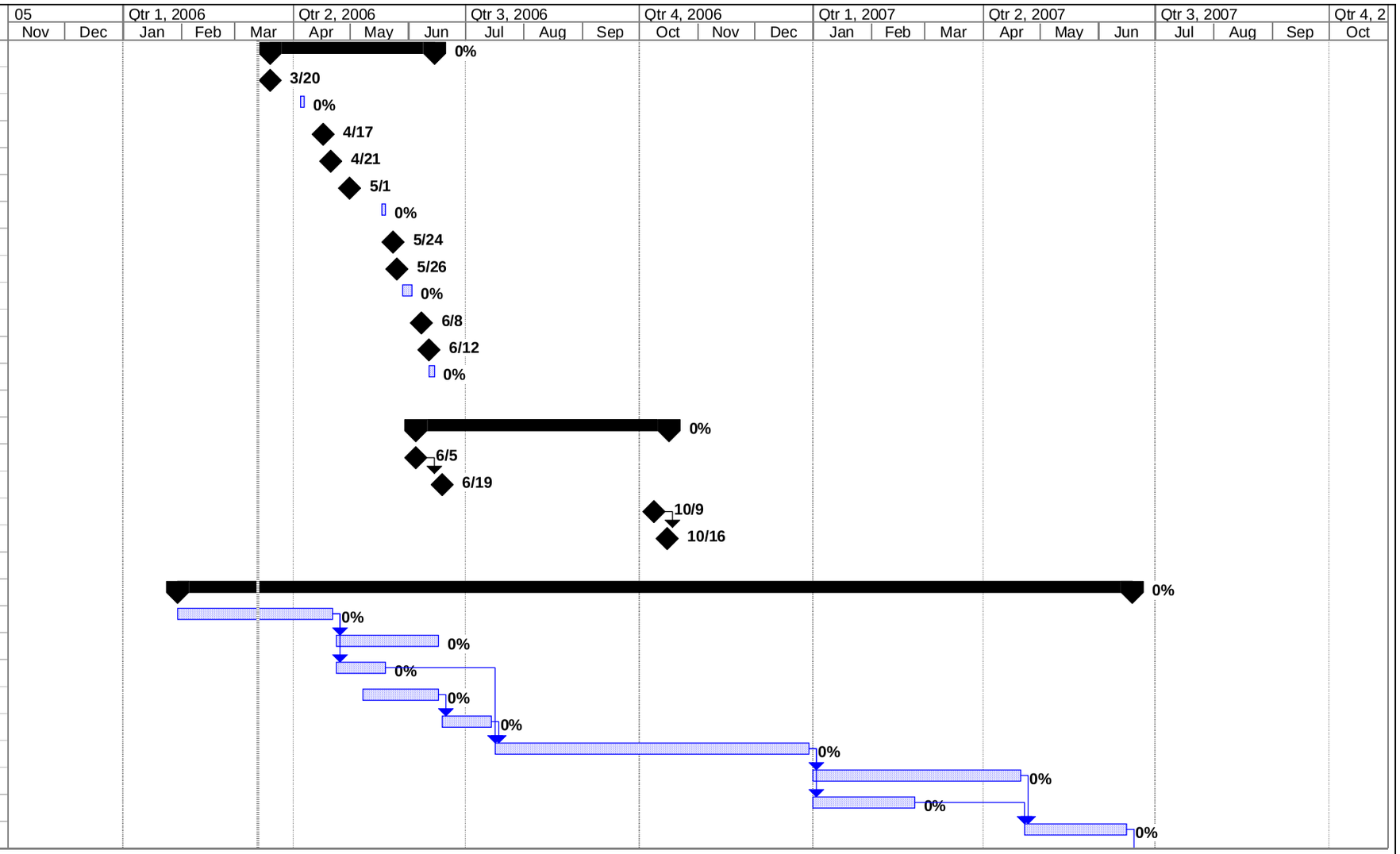
Project	Leave to Construct Application Date	Construction Start Date	In Service Date	Gantt Chart Reference
Reservoir Delta Pressuring	N/A	N/A	December, 2006	N/A
Sombra Transmission Tie-In	July, 2006	August, 2007	December, 2007	Line 10
Wilkesport Transmission Looping	August, 2006	March, 2007	April, 2007	Line 34
Vector Tie-In	July, 2006	May, 2007	June, 2007	Line 22
Sombra Compression	N/A	September, 2007	January, 2008	Line 48
Horizontal Well Drilling	November, 2006	March, 2007	October, 2007	Line 67

Summary And Conclusions

119. The Company's existing gas storage system is not currently able to meet the anticipated storage service needs of the gas fired generators.

120. As a result, Enbridge Gas Distribution Gas Distribution is proposing a capital expenditure program in the 2007 year such that service to this market could soon commence under a new unbundled storage service (Rate 316) and an enhanced Rate 125.

ID	Task Name
1	**Regulatory (NGEIR) Process**
2	File Evidence
3	Technical Conference
4	File Responses
5	File Rate Evidence
6	File Other Evidence
7	Technical Conference
8	Respond to Undetakings
9	Reply Evidence
10	Settlement Conference
11	Settlement Proposal
12	Settlement Proposal Presentation
13	Settlement Proposal Hearing
14	
15	**Open Season Bid Process**
16	Open for Non-Binding Bids
17	Receive Non-Binding Responses
18	Open for Binding Bids
19	Receive Binding Responses
20	
21	**Sombra NPS16 Transmission Tie-In**
22	Economic Feasibility Study
23	Land Negotiations
24	Environmental Screening
25	Design
26	Bid Process
27	OEB Application (Leave to Construct)
28	Procurement
29	Legal Approval & Contract Negotiation
30	Construction



Project: EGS Growth Projects 2007
Date: Mon 3/13/06

Critical	Split	Baseline Milestone	Project Summary
Critical Split	Task Progress	Milestone	External Tasks
Critical Progress	Baseline	Summary Progress	External Milestone
Task	Baseline Split	Summary	Deadline

Filed: 2006-03-20
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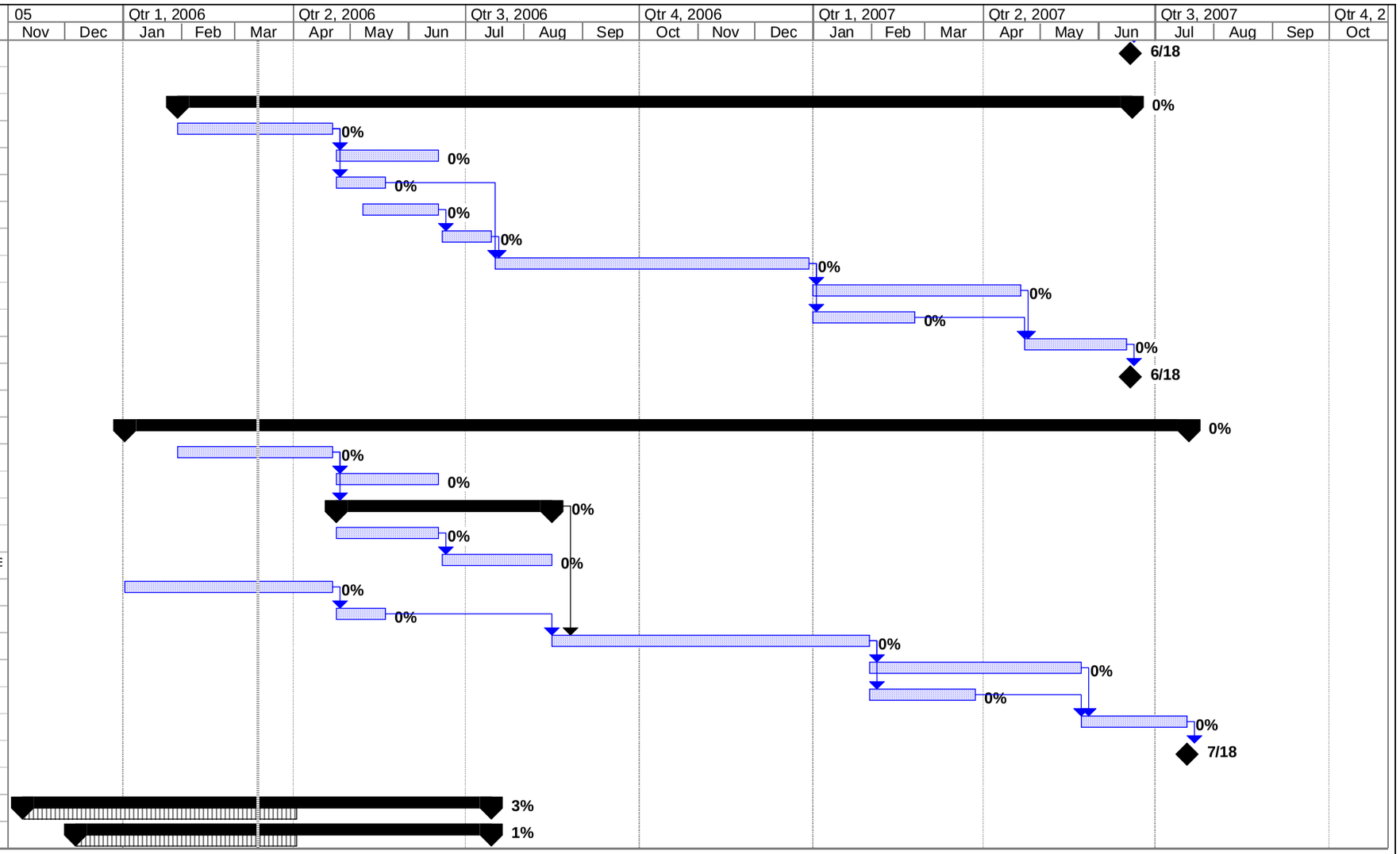
ID	Task Name
31	In-Service
32	
33	**Vector Tie In**
34	Economic Feasibility Study
35	Land Negotiations
36	Environmental Screening
37	Design
38	Bid Process
39	OEB Application (Leave to Construct)
40	Procurement
41	Legal Approval & Contract Negotiation
42	Construction
43	In-Service
44	
45	**Wilkesport Transmission Pipeline Looping**
46	Economic Feasibility Study
47	Land Negotiations
48	**Environmental Report**
49	Environmental Assessment
50	Ontario Pipeline Co-ordinating Committee
51	Design
52	Bid Process
53	OEB Application (Leave to Construct)
54	Procurement
55	Legal Approval & Contract Negotiation
56	Construction
57	In-Service
58	
59	**Pipeline & Facilities Integrity Review**
60	**Seckerton Pool Line**



Project: EGS Growth Projects 2007
Date: Mon 3/13/06

Critical	Split	Baseline Milestone	Project Summary		
Critical Split	Task Progress	Milestone	External Tasks		
Critical Progress	Baseline	Summary Progress	External Milestone		
Task	Baseline Split	Summary	Deadline		

Filed: 2006-03-20
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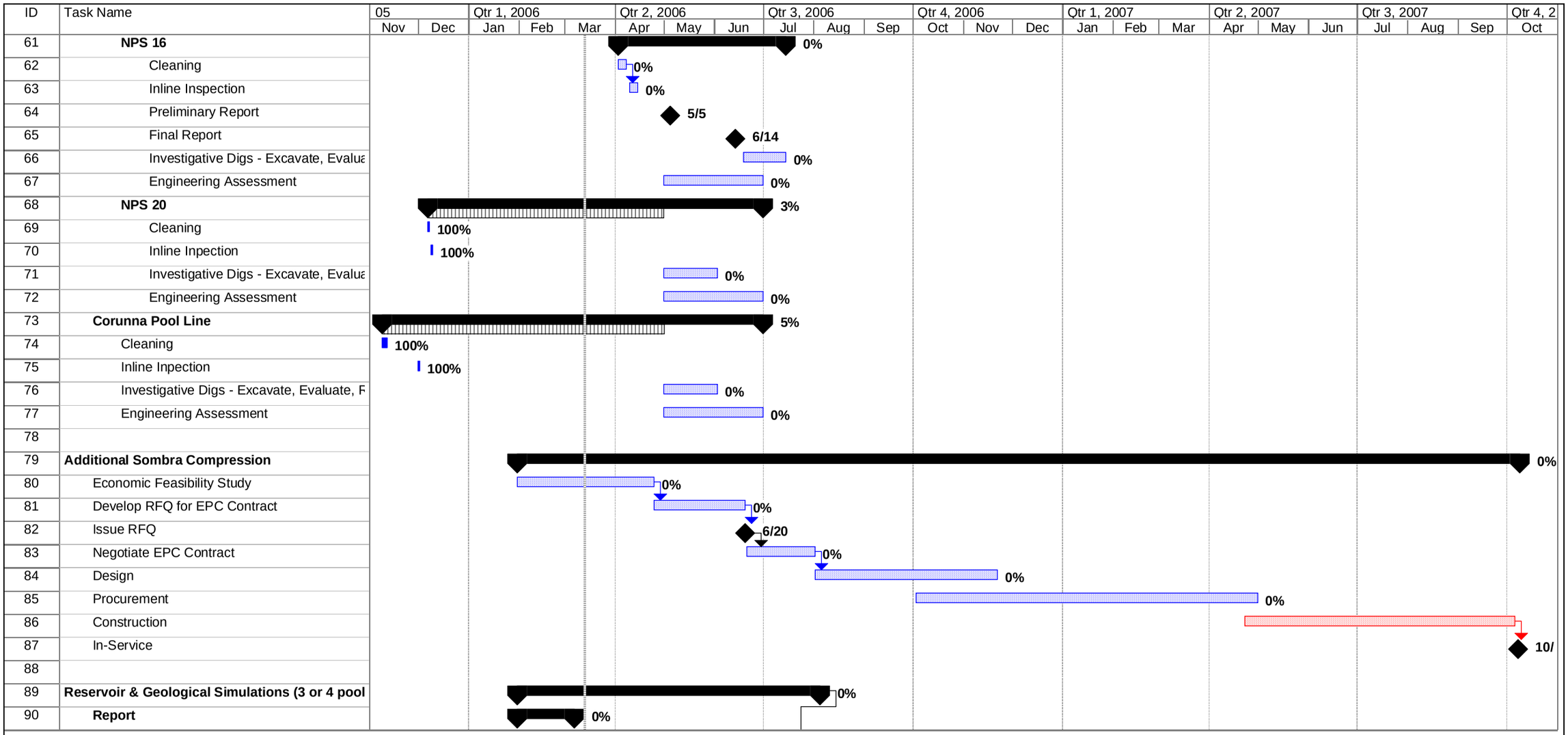
ID
Task Name
05
Qtr 1, 2006
Qtr 2, 2006
Qtr 3, 2006
Qtr 4, 2006
Qtr 1, 2007
Qtr 2, 2007
Qtr 3, 2007
Qtr 4, 2
Nov Dec Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec Jan Feb Mar Apr May Jun Jul Aug Sep Oct
61 NPS 16
62 Cleaning
63 Inline Inspection
64 Preliminary Report
65 Final Report
66 Investigative Digs - Excavate, Evalua
67 Engineering Assessment
68 NPS 20
69 Cleaning
70 Inline Inpection
71 Investigative Digs - Excavate, Evalua
72 Engineering Assessment
73 Corunna Pool Line
74 Cleaning
75 Inline Inpection
76 Investigative Digs - Excavate, Evaluate, F
77 Engineering Assessment
78
79 Additional Sombra Compression
80 Economic Feasibility Study
81 Develop RFQ for EPC Contract
82 Issue RFQ
83 Negotiate EPC Contract
84 Design
85 Procurement
86 Construction
87 In-Service
88
89 Reservoir & Geological Simulations (3 or 4 pool
90 Report
0%
0%
0%
5/5
6/14
0%
0%
3%
100%
100%
0%
0%
5%
100%
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6/20
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10/
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0%
Project: EGS Growth Projects 2007
Date: Mon 3/13/06
Critical
Critical Split
Critical Progress
Task
Split
Task Progress
Baseline
Baseline Split
Baseline Milestone
Milestone
Summary Progress
Summary
Project Summary
External Tasks
External Milestone
Deadline
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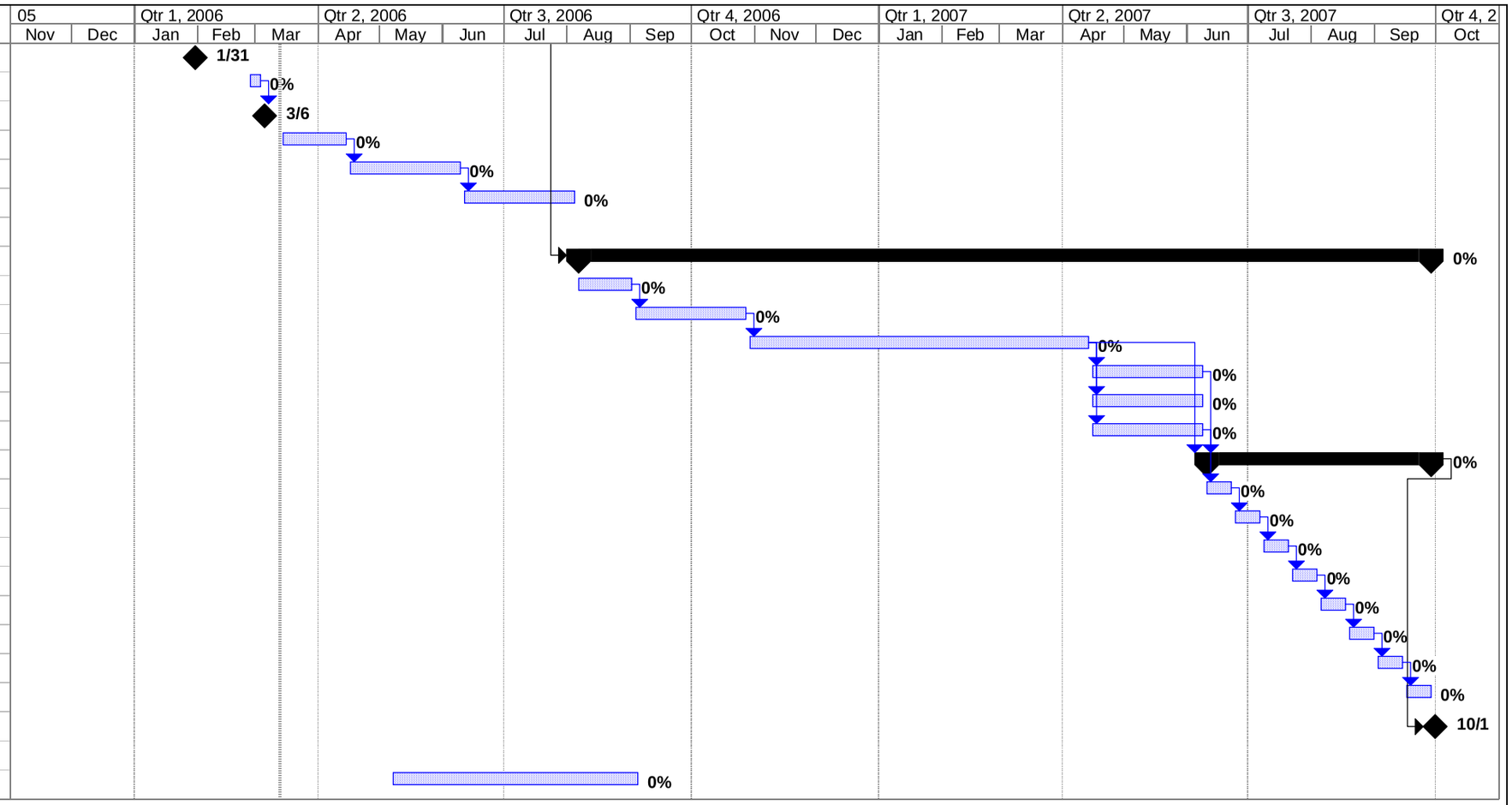
ID	Task Name
91	Issue RFQ
92	Evaluate Responses
93	Issue Contract
94	Construct Model
95	Simulations
96	Optimization
97	
98	**Drill Horizontal Wells**
99	Bid Process
100	CR Approval Process
101	OEB Approval Process
102	Procurement
103	Lease Construction
104	Land Negotiations
105	**Drill 8 Wells**
106	Drill Well 1
107	Drill Well 2
108	Drill Well 3
109	Drill Well 4
110	Drill Well 5
111	Drill Well 6
112	Drill Well 7
113	Drill Well 8
114	In-Service
115	
116	**Oilfield Workovers**



Project: EGS Growth Projects 2007
Date: Mon 3/13/06

Critical
Critical Split
Critical Progress
Task
Split
Task Progress
Baseline
Baseline Split
Baseline Milestone
Milestone
Summary Progress
Summary
Project Summary
External Tasks
External Milestone
Deadline

Filed: 2006-03-20
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OPERATIONAL CHARACTERISTICS, ISSUES AND PROPOSED SOLUTIONS: RATE IMPLEMENTATION

1. This evidence addresses the business process and systems changes required in order to implement the rates and services contemplated within the scope of the NGEIR proceeding. These changes are required to accommodate the differing operating parameters and contractual rights associated with bundled versus unbundled rates and services. The evidence provides a high level cost and time estimate for manual and automated solutions. Customers that would contract for unbundled service include power generators and other industrial customers.

2. At a high level, there are three key areas of change which distinguish the provision of unbundled rates and services from that of the bundled rates and services currently being offered: (1) system measurement issues – such as more frequent metering data (possibly hourly), and the infrastructure changes required to gather and record this data; (2) operating parameters – such as supporting hourly nominations, tracking and reporting daily and cumulative volumetric imbalances, the calculation of daily and cumulative imbalance charges, and the modifications to existing information systems that are required to effectively monitor compliance with these parameters; and (3) billing implications – such as the application of the new unbundled rate structures, and its compliance parameters and the related billing system modifications required to support these changes.

3. In February 2006, Enbridge Gas Distribution retained Sapient Canada Inc. to prepare an Impact Assessment of the changes that may be required to implement the proposed NGEIR requirements. Specifically, the objectives of this engagement were to: (1) assist in identifying high level system changes and/or manual processes to support unbundled rates and services; and (2) assist in building a

preliminary resource estimate and a high level timeline to analyses, design, and implement these system changes. A copy of Sapient's Impact Assessment follows this section of the narrative evidence.

4. The main focus of the Impact Assessment centers on the changes required to the EnTRAC application. This system allows customers to electronically transact, report, account, and contract for services with Enbridge Gas Distribution. However, the business rules inherent in EnTRAC currently support the management of bundled rates and services only. The expectation is that modifications to EnTRAC will be the major driver for the timeline estimates, given the extensive number of changes required to support unbundled rates and services.

5. With respect to the EnTRAC application only, Sapient has estimated that the cost associated with the necessary modifications is $2.3 to 4.0 million. In addition, the annual operating costs to support this new functionality are estimated to be in the range of $300,000 to $500,000/year. The above costs represent system-related and system support expenditures only, and exclude any costs associated with items such as user training, legal, and communication.

6. Sapient also identified the manual business processes that would need to be adopted in the absence of making the required system changes through EnTRAC. That is, to define the requirements for manually monitoring, reporting, and billing for the unbundled rates and services. These requirements are detailed in Section 5 of the Impact Assessment.

7. In the event that only a limited number of customers opt for unbundled rates and services, it may be feasible, in the immediate term, to manage these services by way of manual processes. However, this methodology is definitely not scalable for

more than a handful of customers and, in any event, would require additional resources in order to implement. This is due to the sheer volume of data tracking and monitoring, the number of handoffs of the data across numerous departments for input, the frequency of balancing provisions, and the complexity of calculating and billing the rates and compliance-related charges. Under these circumstances, the potential risk of human error is high and such errors could have significant repercussions, both from a volumetric standpoint and a financial standpoint.

8. From a cost perspective, preliminary estimates indicate a one-time set-up cost of approximately $200,000 to $300,000 for system changes and the creation of manual processes, as well as a tracking mechanism. In addition, there are ongoing costs of $250,000 to $325,000/year associated with manually processing and managing the new rates and services.

9. As part of the Impact Assessment, a high level timeline was created for the design, implementation, and testing of the EnTRAC system changes. Each system change that was identified was analysed and a level of effort (in person days) was derived and then summed to determine the total amount of time required. Based on this analysis, it will take 43 weeks to complete all of the stages from design to full implementation of the EnTRAC system changes. A timeline depicting this process is included as part of the Impact Analysis.

10. EnTRAC, however, is not the only system that would require modifications or enhancements as a result of the implementation of unbundled rates and services. There are a number of other systems that would also be impacted, including those that support billing, metering, nominations, and customer relationship management. Some of the changes that are required are discussed in the Impact Assessment.

11. Enbridge Gas Distribution's billing service provider has estimated at a high level that an automated solution would require a one-time implementation cost of approximately $300,000, with an ongoing cost of $150 per bill. The expected time line for implementation is 26 weeks. The cost estimate assumes that all charges are calculated by Enbridge Gas Distribution and transferred to the billing service provider. Cost and time estimates for System Measurement and Nomination systems were not available at the time of writing this evidence. As a result, the Company will bring forward this information at or before the scheduled Technical Conference.

12. An automated solution is the only viable long term solution for scalability, data integrity and governance reasons. However, the automated solution cannot be designed and implemented until after the Company receives approvals for its rates and associated terms and conditions. The Company realizes the importance of implementing unbundled rates as soon as possible, particularly for existing customers who wish to avail of unbundled rates. The Company proposes to take a two step approach. A manual solution would be designed first. This would facilitate earlier implementation. Also, it would allow for testing of the business rules in the first year of implementation. An automated solution would then be designed to incorporate lessons learned through the manual process. Such an approach would also have other benefits in terms of managing the risks associated with other major systems implementations for GDAR compliance and the new Customer Information System ("CIS") system.

13. The cost of the proposed two step approach cannot be determined due to several unknowns at this point. These include the specific form and content of rates that will eventually be approved, the approval date, the preferred implementation date and the number of customers that would wish to take unbundled rates. The

estimation of costs cannot begin until the decision in this proceeding is known. Therefore, Enbridge Gas Distribution requests that a deferral account be established to record all costs associated with the provision of these services. The Company anticipates that the Board would allow recovery of these costs from all customers similar to EnTrac and GDAR as these processes and system enhancements are market enabling in nature.

NGEIR Impact Analysis

March 17, 2006

1 Table of Contents

2 Revision History

Date	Version	Description	Author
February 1, 2006	0.1	Initial draft	Corey Webster, Sapient
February 10, 2006	0.2	Populated EnTRAC System Changes section	Corey Webster, Sapient
February 10, 2006	0.3	Added assumptions, issues, next steps	Corey Webster, Sapient
February 11, 2006	0.4	Added other system changes, manual changes and additional assumptions, issues and next steps	Jayender Rajagopal, Sapient
February 12, 2006	0.5	Added overview and approach	Corey Webster, Sapient
February 14, 2006	0.6	Added scope description	Corey Webster, Sapient
February 14, 2006	0.7	Added abbreviations appendix	Corey Webster, Sapient
February 15, 2006	0.8	As per Malini's feedback, added additional verbiage to overview; expanded MSA Termination verbiage	Corey Webster, Sapient
February 15, 2005	0.9	Added timeline	Corey Webster, Sapient
February 16, 2005	1.0	Reviewed the document and made edits to the overview & timeline section	Mudit Kapur, Sapient
February 17, 2006	1.1	Updated overview and scope based on feedback from walkthrough with Malini G., Jody S. and Andrew W.	Corey Webster, Sapient
February 20, 2006	1.2	Updated manual changes section based on feedback from Andrew W	Jayender Rajagopal, Sapient

3 Introduction

3.1 Overview

Enbridge Gas Distribution has a core set of information systems & processes in place that allows Enbridge to meet the requirements of its consumer base. Over the years, Enbridge has kept pace with the evolving marketplace and changes in regulations by modifying and/or replacing these systems & processes as required. The aim of such initiatives has been to keep all internal procedures and information systems in sync with the changing regulatory & consumer demand landscape.

In view of the functional norms proposed by the Ontario Energy Board (OEB) for gas-fired generators (and other eligible customers) under the notification issued on December 29, 2005 under file number EB-2005-0551, Enbridge may be required to make some modifications and enhancements to its key information systems and processes.

A summary of events leading up to the current state of the NGEIR initiative is listed below:

- March 30, 2005: OEB issued a report on Natural Gas Regulation in Ontario. An "important & immediate priority" was to ensure that NG infrastructure could meet the demands created by new gas–fired generators
- March to November, 2005: OEB initiated the Natural Gas Electricity Interface Review (NGEIR) to examine regulatory treatment of NG infrastructure & services
- November 21, 2005: NGEIR report released for stakeholder comment
- December 29, 2005: Board initiated a proceeding of its own accord to determine
  - if it should order new rates for gas-fired generators and
  - whether it should refrain from regulating rates for storage of gas
- March 1, 2006: EGD & UG asked to file evidence on the above

This document presents a high level overview of the potential system and process changes based on the above in order to support Enbridge's evidence filing on board notification on NGEIR.

The document also includes a draft timeline for EnTRAC changes which is anticipated to be most impacted by the proposed functional changes. This is based on the current understanding of the scope of proposed functional changes.

3.2 Audience

Primary Audience: Malini Giridhar & the NGEIR Working Group at EGD
Secondary Audience: Other departments at EGD who may be impacted by NGEIR

3.3 Scope

This document's primary focus is on changes to the EnTRAC and ABSU systems and potential manual processes related to the NGEIR initiative. This includes changes to EnTRAC interfaces to other systems but does not deal with potential changes to downstream systems such as UCIR or RAVE. It is assumed that any changes to these other systems will not have a significant impact on the implementation timeline.

The manual changes presented in this document are independent of the system changes. They are presented as an alternative to an automated solution. Even though a combination of automated and manual processes is feasible, this document does not address a recommended approach.

3.4 Approach

Sapient was engaged to conduct workshop sessions aimed at accomplishing the following objectives:

- Assist in identifying high level system changes and/or manual processes required to support proposed NGEIR requirements
- Build a preliminary estimate to come up with an implementation timeline
  - Needs to factor in current large initiatives impacting EGD i.e. CIS Program, GDAR compliance.

Prior to the workshop, interviews with workshop participants were conducted with the purpose of closing on an approach for the workshop sessions. Workshop sessions were held over a period of three days and involved experts from the key business areas affected by NGEIR. A list of workshop participants can be found in the Key Contacts section of this document.

4 Summary of System Changes

4.1 EnTRAC

What follows is an analysis of EnTRAC system changes. The changes have been grouped into three main areas of functionality: contract management; gas management; and charges and reconciliation (billing). Each section conforms to the following format:

<Heading>

<Category> **<System Change>**

4.1.1 Contract Management

Master Service Agreement (MSA) Management

Termination	In the bundled world, contracts under an MSA move to system gas if the MSA gets terminated. But since unbundled contracts cannot move directly to system gas, they will need to be terminated if the MSA gets terminated.

Pool Management

Pool creation	'Unbundled pools' need to be created which can only have accounts on unbundled rates
MDV (establishment & re-establishment)	Unbundled pools should not be picked up for MDV calculation or re-establishment
FT (election, allocation, turnback and assignment at a pool level)	FT related functionality needs to be unavailable for unbundled pools

LVC

LVC Access to EnTRAC is for the viewing of consumption information only	Unbundled customers need the ability to view their consumption information daily and/or hourly
Adding/Editing LVC relationships	Need to accommodate unbundled rates

Large Volume Distribution & Storage Contracting

Creation of contract document	Need functionality to create unbundled contracts and storage contracts including the various contract parameter details (e.g. MCI for rate 125, deliverability for rate 316)
Renewal of distribution contract including roll over	Need to implement for unbundled rates
Termination	Change to accommodate unbundled rate parameters

Associating an account to one or two distribution contracts	Unbundled distribution rates cannot be combinations, however an account can have a rate 125 and a rate 316 contract simultaneously
Search for Contracts	Search parameters need to change for unbundled rates (e.g. rate dropdown and inclusion of storage contract)

Account/Consumer Management

Account movement	Need to ensure that unbundled customers cannot move to system gas and can only move from one unbundled pool to another. This would also impact corresponding STR functionality (e.g. vendor to vendor STR, vendor initiated vendor to system gas STR)
Quasi-adds	Unbundled customers can be quasi added any time as there is no MDV for the pool
Price Point Group (PPG) - Account association	Need to enforce that these accounts cannot have price point groups

Security Deposit

Enter security deposit	Needs to be enabled for unbundled customers. Note that calculating (and if applicable, re-calculating) the deposit amount will be manually done and entered into EnTRAC
View security deposit	Need to compute and store security deposit for MSAs with unbundled pools, show updated exposure if contracts are added/dropped. Need ability to view the deposit amount and tolerance percentages
Notifications	Needs to be enabled for unbundled customers with notifications being sent upon changes to either the deposit amount or the current exposure
Thresholds	Needs to be enabled for unbundled customers
Validations based on STRs	Need to re-calculate exposure if new contracts are added, validate against the tolerance level for that customer and accept/reject the STR

Billing Demand Volumes

Ability to edit/view billing demand volume for LVDCs	Need to view the reestablished contract demand (if the consumption goes more than the contract demand)

Data Migration

Migrating existing unbundled customers	Spreadsheets need to be populated with relevant data for any Rate 3xx and Rate 125 customers and need to be migrated

4.1.2 Gas Management

Nominations

Nominations	Changes to nomination screens to account for nominations from storage contracts; changes to nomination screens to support multiple nomination windows; ability to update storage capacity for each of the storage contract (based on ratchets) including updates to deliverability level for storage contracts, based on storage nominations; removal of rules corresponding to MDV; addition of fields to accommodate for UFG, etc.
Automatic notifications if nomination has not been submitted by deadline	Need to remove this rule for unbundled nominations
Ability to copy forward and/or edit an existing nomination	Need to remove editing functionality. Would be done by overriding the existing nomination
Fuel ratio	Need to change existing screen to accommodate storage, transport & UFG as well
Fuel volumes	In addition to TCPL fuel volumes, now need to calculate storage fuel volume (and may need to include fuel for transport nominations, if applicable)
Nominations from EnTRAC to Altra	Need a new interface to submit nomination information to Altra on a near-real-time basis. Also, EnTRAC should only send nominations that will actually flow, instead of all nominations (which may imply that these may need to be held until the deadline and only then sent across). Need to split this at an account level if FTSN comes into play.
Report of submitted nominations	This is required only if there isn't an automated interface to submit nomination information to Altra
Query for nominations	EOS needs the ability to search for nominations present in EnTRAC for a given day and time
Allowance	Need to change nomination screens to allow secondary delivery points

Load Balancing

View daily imbalances	Ability to refresh imbalances (instantly in the event of a nomination and also whenever consumption and delivery information are received); also includes the ability to view storage contract balance and cumulative imbalance at a daily level
Title Transfer Request between pools at a pool level	Ability to title transfer between storage contracts (factoring in deliverability levels); ability to do a title transfer from unbundled BGA to a bundled pool and vice versa; ability to submit half a title transfer transaction for cross-franchise transfers
Allowances for suspensions/make-ups	Need to accommodate different validation rules for nominations factoring in storage contracts and OFO days
Make-ups/Suspensions	Change to load balancing screens to allow nominations to/from BGA

Ability to override load balancing request transactions that violate business rules	Need to accommodate this (exact functionality is to be determined based on business rules)

Deliveries

Account-level deliveries	Need to change the delivery engine to allocate deliveries to accounts based on pool-level deliveries obtained from the Altra-EnTRAC interface
Delivery confirmation report	Need a delivery confirmation report from EnTRAC based on a comparison of nominated and delivered volumes

Consumptions

Measurements & final meter reads	Need a new interface to poll the ftp server for hourly consumptions from Metretek

Non-Compliance

Calculation of non-compliance volumes (e.g. unauthorized overrun)	Need to change the compliance engine based on new rules for unbundled rates

Prior Period Adjustments (PPA)

Consumption adjustments	Reading the PPA could either be from LVTS (similar to current state) or could entail a change if EnTRAC needs revised consumptions from Metretek (with logic to understand that revised reads are present in the file).
Delivery adjustments	Need to apply delivery adjustments at an account level instead of at a pool level
Non-compliance adjustments	Need the ability to recalculate non-compliance volumes due to consumption and delivery adjustments

BGA Calculation & Disposition

Imbalance reports	Need reporting ability at an account level potentially on a daily basis; also need to report storage balance (with access to the storage group and customers)
Gas purchase/sale (manual as well as EnTRAC initiated)	Need to make three main changes a) manage at an account level instead of at a pool level b) accommodate gas purchase/sale for amounts in excess of daily as well as cumulative imbalances (after accounting for tiers) c) need automatic gas purchase/sale for accounts with cumulative imbalance as well as storage contracts with a balance after settlement period is over
Automatic title-transfer into current year's BGA	Need to accommodate title transfers at an account level and with shortened timelines
Imbalance adjustments	Potential requirement to update the imbalance of an account using the adjustment screen. May need to change the screen to contain certain rules/checks

Curtailments

Curtailment events	Need changes to the setup screen (e.g. CDS is no longer applicable)
BGA related processes	Need changes to allow waiving of charges
CDS	Need changes to exclude contracts from having CDS nominations (and therefore CDS deliveries and CDS BGA)
Curtailment Gas Purchase	Need changes to ensure all gas delivered is purchased as CGP and that there is no penalty (because there is no fixed amount that customers need to deliver unlike the bundled world)
Curtailment Report	Need changes to exclude for unbundled pools

Operational Flow Order (OFO) Days

Setup	New screen to allow setup (similar to curtailment events)
Business rule changes in other components	Changes to business rules to nominations, load balancing and BGA disposition transactions based on OFO days

4.1.3 Charges and Reconciliation

Rate Management	Need to add NGEIR introduced rates
Remittance Reports	No offsetting of charges against remittance therefore there is no need for remittance report. Will maintain current state similar to non-ABC pools. Need to include cross-franchise title transfer financial impacts into this report.
ABC Balance Adjustment	No need for this for unbundled rates. We would still need volumetric reconciliation and subsequent financial reconciliation (e.g. arising out of BGA disposition).
Prior Period Adjustments	No change if we get adjustment volume/dollar amount from LVTS (would include ABSU system changes to include the new rates). The charges engine would need to change to account for automatic re-calculation of non-compliance amounts due to consumption and delivery adjustments.

4.1.4 Common

Security Roles	Modification to the security roles matrix to allow for new user groups to access EnTRAC (e.g. Rate 125 LVCs to nominate and also access to the storage group)
Information Architecture	Addition of new screens and access based on roles would necessitate navigation changes
FAQs/Help	Need to add additional training material that would be available to users via EnTRAC
Homepages	Modifications to existing homepages to show additional information for unbundled rates

4.2 ABSU (LVB, LVTS, CIS)

Rate Setup and Security Deposit	Add new rates to the rate table and the revenue class table (LVB, CIS, LVTS)
Bill Calculation	No change for - distribution charge - monthly customer charge (assume it is fixed and not negotiable on a per customer basis) - demand charge (assume it is fixed) - no commodity charge Change to LVB for - Tier 1/Tier 2 fees (and potentially others) - Non-compliance (potential change)
Bill Print	Depending on format of gas charge components and messages (and length of fields), there could be changes. Adding new components is not a limitation.
Collections	May involve potential changes to LVAX if we would want to use it. Monitoring needs to be more aggressive for the power generators but there shouldn't be any system changes
Adjustments	Change to LVTS to accommodate the unbundled rates
Orders	No change (except for possibly meter information to go into CIS)
GL Posting	Need to change 'reporting system' to handle new revenue classes. Also need changes to Revist.

4.3 Altra

Ability to pass regular nomination to Altra	Altra change to accept nomination information through an interface instead of through data entry

4.4 System Measurement

Frequency of reads	AMR programming change to send hourly consumption for unbundled rates to Metretek
Consumption	New interface from Metretek to FTP server to provide hourly consumption information

4.5 Enterprise Sales Maker (ESM)

Contact/contract information in ESM	ESM may need to change depending on exact scope of what information needs to be captured for unbundled customers

5 Summary of Manual Changes

This section lists out the manual processes that would need to be followed if unbundled rates were to be supported by Enbridge and ABSU.

Id	Activity	Description	Department
Contract Management			
1	MSA	Account executives would need to manage (create, search, terminate) MSA information in a separate spreadsheet.	Strategic and Key Accounts
2	Security deposit	Account executives would need to track letter of credit (security deposit) and update this sheet as and when contracts get added to an MSA. This needs to be accessible to CSC	Strategic and Key Accounts
3	Contracts (LVDC and Storage)	Customers would sign new contract documents for unbundled rates and send them to account executives. The account executives would need to manage (create, edit, terminate, search) distribution & storage contracts and their parameters (rates 125, 300, 305, 315, 316) by using a separate spreadsheet. This would need to be accessible by several groups including CSC, EOS, Storage and ABSU	Strategic and Key Accounts
4	LVC Relationships	The CM group would need a spreadsheet to create, edit and terminate LVC relationships	Strategic and Key Accounts
5	Pools	Customers would call the contract management group to setup a pool under an MSA. The CM group would need a separate spreadsheet to track pool term information (creation, termination, early termination, renewal, searches)	Strategic and Key Accounts
6	Account association	Customers would need to send a form to associate accounts to pools. Account executives would need to track pool-account associations in a separate spreadsheet. This would need to be accessible by several groups including CSC and EOS.	Strategic and Key Accounts
7	M12 FT Transoprts	The account executives would need to track FT transports on the M12 (if transportation were brought into scope). This would need to be accessible by several groups including CSC and EOS.	Strategic and Key Accounts
Gas Management and Charges & Reconciliation			
8	Fuel Ratio, Allowance	EOS would need to update a spreadsheet with the fuel ratio (storage, transport, UFG) and other allowances for a given day. This needs to be accessible by CSC	EOS
9	Nominations	In order for gas flow to commence, the customer would send a paper nomination to EOS for (different nominations for storage, distribution and transportation). EOS would enter the nominations into Altra and use existing processes to match with Altra and send to the storage group. Rescinding, overriding, editing nominations will be handled by EOS	EOS
10	Make-ups & Suspensions	Customers would need to submit make-up/suspension request forms to CSC. These need to be tracked in a spreadsheet. CSC would validate and send the	Contract Support and Compliance

		approved requests to EOS	
11	Title Transfers	Customers would need to submit title transfer forms to CSC. These need to be tracked in a spreadsheet that can be accessed by the storage group as well	Contract Support and Compliance
12	Gas Purchase/Sale	Customers would need to submit GP/GS forms to CSC in order to adjust their BGA during a contract term or zero it out at the end of a contract term. These transactions need to be tracked in a spreadsheet.	Contract Support and Compliance
13	Deliveries	The nominations/deliveries would be tracked in a nomination/delivery spreadsheet and would be updated 24X7 by EOS (the information would come from Altra). This would need to be accessible by CSC.	EOS
14	Consumptions	Consumptions would need to be updated at an hourly level (using extracts from Metretek) and shared across multiple groups – EOS (gas control & nominations), EGS (gas supply and transportation), CSC, Key Accounts, and Storage.	System Measurement
15	Non-compliance	Non-compliance volumes & dollars would need to be calculated at an hourly level (automatically populated using formulae). The group responsible for updating the consumption sheet would need to monitor the compliance tracker and escalate if needed	Contract Support and Compliance
16	PPA	A PPA tracker would need to be put in place to track volumetric and dollar adjustments. These would then need to get applied to imbalance reports	Contract Support and Compliance
17	OFO days	An OFO day tracker would need to be put in place to track operational flow order days	Contract Support and Compliance
18	Rate management	A unit rates table would need to be put in place to hold GP/GS prices, Tier 1 and Tier 2 rates, etc.	Contract Support and Compliance
19	Curtailments	A curtailment tracker would need to be put in place to track curtailment events and specific contracts being curtailed. This would also be used to track CGP (customers would need to send forms if they elect for CGP)	Contract Support and Compliance
20	Imbalance and storage balance reports	Deliveries and consumptions would be used to calculate volumetric and financial imbalances. Imbalances and storage balance reports would need to be posted to a secure website or emailed to customers. It would need to be at a daily level (broken by hour), a monthly level (broken by day) and a yearly level (broken by month)	Contract Support and Compliance
21	Miscellaneus adjustments	For miscellaneous adjustments, CSC would need to update existing GM/CR spreadsheets with comments.	Contract Support and Compliance
22	Financial summary	CSC would need to maintain one spreadsheet to capture a. Contract information with rates b. Summary of volumetric information c. Charge calculation & totals for the month/year per contract This spreadsheet would need details at a daily level. It	Contract Support and Compliance

		needs some edits, would be protected and would need renewal/approval	
23	Handoff to ABSU	Forms would need to be put together to collate consumption and compliance amounts to be sent by CSC to ABSU for billing.	Contract Support and Compliance
24	Validation & reconciliation	A reconciliation and validation process would be put in place for CSC to check a. Consumptions received versus the volumes that the system measurement group has b. Deliveries received versus the volumes in Altra c. Volumes being billed by ABSU	Contract Support and Compliance
Billing			
25	Billing and management of cancellation/rebilling	CSC would calculate charge and pass off to KAB to bill. KAB would manage cancel/re-bills manually. In case of adjustments, either a revised bill could be sent the same month, or an adjustment could be added to next month's bill. KAB would manage payment processing and collection and would maintain a spreadsheet of balance outstanding and payment details per contract. This needs to be accessible to CSC.	Contract Support and Compliance/ Key Account Billing
26	Reuse existing templates for generating bills	KAB would use existing bill templates to print bills (which will also have outstanding balances)	Key Account Billing
27	Manual posting of charges to GL	A manual posting to GL would need to be done by EGD (segregated by the different types of charges) a. Post amount owing once the bill is sent b. Post receivable once payment is received	Customer Support

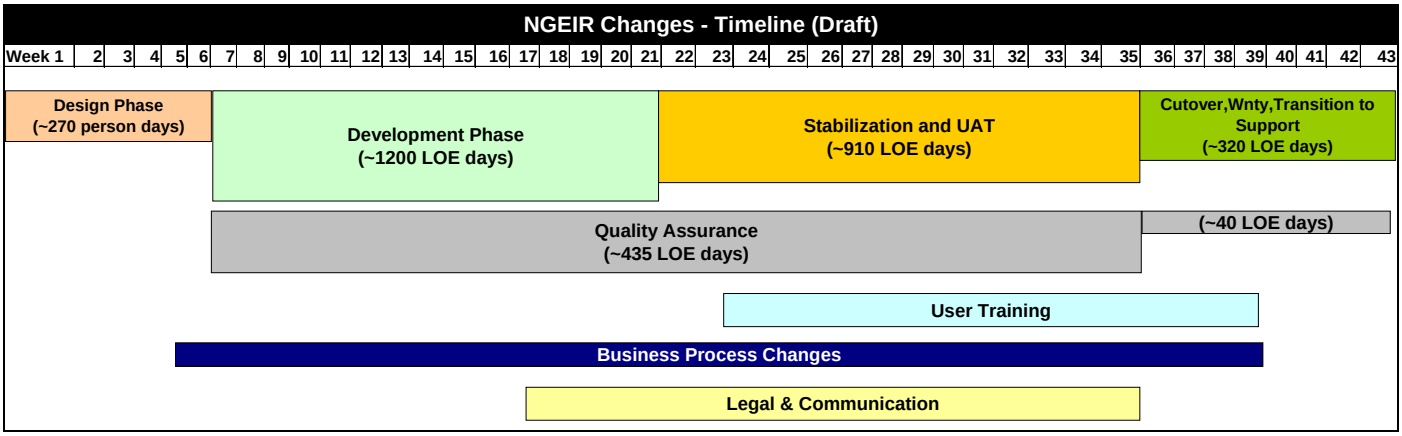
Key Assumptions:

1. Existing processes for other aspects (premise setup, account setup, meter and service orders, bill calculation, payment processing, collections) would continue in current manual form
2. Any notifications would be done via email
3. Information could be tracked either in an Excel spreadsheet or in an Access database (for purposes of estimating effort, it's assumed that spreadsheets are used)
4. Spreadsheet access to other groups would be defined later
5. Internal reporting will be defined later
6. Manual changes will entail system changes since EnTRAC would need to prevent unbundled accounts from being sent over from LVB

6 Timeline

This section discusses a suggested timeline for design, implementation and testing of the EnTRAC system changes.
Each system change identified in this document was analyzed and a level of effort (LOE) number in person days was applied to each. These numbers were summed to arrive at a core development LOE.
This was followed by applying metrics for design & post development phases based on past experience with EnTRAC releases, to arrive at the level of effort required for each phase.

The timeline represents a high level estimate and will need to be re-evaluated/iterated after scope is closed.



Key Assumptions:

7. The plan presented above is based on an understanding of scope to date and assumes a reasonable team size in each phase. A more detailed plan will need to drawn up once the functional changes are crystallized. It is suggested that the plan be drawn up in a phased manner i.e. for the design phase first followed by implementation once the design is completed.
8. The plan assumes a sequenced project, decisions on executing the project in phases or iterations will impact the above plan
9. The plan assumes adequate availability of resources with required skill sets through all phases.
10. EGD team members will play an integral part of the design and implementation team, and will be responsible for preparation and deliverable effort on their assigned component.
11. ABSU and other system experts will be available on an as needed basis.

7 Assumptions / Issues / Next steps

7.1 Assumptions

1. EnTRAC would not allow a customer to nominate using another MSA A&C's storage contract
2. Unbundled customer won't have rentals (impact to LVRB)
3. There would be no changes to LVIRA
4. Controls would be built into any manual process
5. Title transfers from storage contracts to pools or vice-versa will not be allowed
6. Rescinds of load balancing nominations can be facilitated through edits and by submitting regular nominations
7. Deliveries from Altra will continue to arrive into EnTRAC at a daily level at a pool level, EnTRAC will then split them at an account level
8. No ABC-T service for all unbundled rates
9. We can pool different unbundled rate contracts together
10. A title transfer would be validated based on deliverability levels, i.e. a customer with 5% of 100 units cannot transfer more than 5 units in a given day (irrespective of the number of title transfers he submits for a given day)
11. Re-direction of gas at short notice is out of scope since it requires customers to negotiate and nominate to upstream transportation pipelines and not EGD
12. Transportation is out of scope (i.e. no FT assignment/turnback) until Enbridge decides to acquire capacity on the M12
13. Cross-franchise transfers would only partly be facilitated by a system such as EnTRAC. EGD would still need to manually track them, talk to Union to complete the transfer and then, maybe once a month, submit a name change nomination through EOS for physical movement between the Enbridge franchise area and Dawn for all title transfers in that month
14. LSDS will continue to handle security deposit information at ABSU the way it does today, irrespective of whether a system change is proposed or the manual route is established
15. Other system changes can be done in the same timeframe as EnTRAC system changes
16. External system changes may necessitate interfaces to/from EnTRAC, resulting in changes to the timeline/resource plan
17. A completely manual solution will still require some changes to EnTRAC (e.g. the interfaces would need to stop sending unbundled accounts from LVB to EnTRAC)

7.2 Issues

1. How are customers going to get set up? If they are captured in EnVision, system measurement will not know unless manually notified
2. Should EGD be handling billing of the new customer or should ABSU do it? Who handles payment procedure and collection? [Malini G]
3. Currently, if a new customer is setup on direct purchase, how does EnTRAC know which pool to associate that account with? [Swaroop G]
4. LVB (and LSDS?) system has limitations in terms of monthly bill, volume and payment processing amounts. Find out what they are. [Sam B]
5. Would power generator meters have a new type (and potentially other information) that needs to go into CIS via EnMAR? [Barry G].
6. Does EnTRAC send special mailing address to LVB? (needed to know where to send bill) [Swaroop G]
7. Do we allow nomination from BGA and with zero delivery on an OFO day? [Malini G]
8. Would an OFO apply globally or can it apply to specific customers or specific delivery areas? [Malini G]
9. The storage group would not want early termination of storage contracts because of investment in physical assets. Can we enforce this? [Brian B]

10. It is not standard practice for the storage group to allow rollover of storage contracts. Even if this is done, there wouldn't be any issues but is it something we want to pursue for storage contracts? [Brian B]
11. The storage group wants the ability to accept or reject title transfers. Would this affect timeliness of executing the transfer? If this is needed, a mechanism needs to be put in place to notify customers of the status of their title transfers [Malini G]
12. Should security deposit be stored at an MSA level or at an account level? [Malini G]

7.3 Risks

1. The IT group that manages Altra have said in the past that they typically don't allow other systems to write to the Altra database. In that case, the interface from EnTRAC to Altra to submit nominations may not be viable and a different approach may have to be pursued. This different approach may not be able to facilitate nomination transfer to Altra in a timely manner if there is a need to support multiple nomination windows in a day
2. Changes to legacy applications (e.g. LVB) that NGEIR may warrant, are potentially risky
3. Manual processes may be feasible from a cost-perspective but may be risky from an operational perspective even for a small customer base since they need to be worked on several times during a day

7.4 Next Steps

1. Need to include downstream system changes in cost/time estimate (e.g. UCIR and RAVE) [Malini G]
2. Factor in complexity of LVB changes. Also keep in mind the replacement project while closing on scope of ABSU changes. [Malini G]
3. Identify reasons (e.g., financial risk) as to why we aren't providing ABC service for unbundled rates [Malini G]
4. FT needs to be considered for Union M12, if it is brought into scope [Malini G]
5. Need mechanism to allow external customers access to their consumption information (especially important for manual processes) [Andrew W]
6. Need to resolve how to handle transportation as a service [Andrew W]
7. Confirm how the existing 305 adjustments are getting posted [Sam B]
8. Find out if changes to revenue class table need to be made [Sam B]
9. Seems like frequency of payment may not be an issue (i.e. bill on 1st as well as 15th), but need to verify [Sam B]
10. Process exists to notify EGD in case of default on payment but not on a regular basis where bill payment history is sent to EGD. Do we need this report? [Andrew W]
11. Walk through financial exposure process flow [Andrew W]
12. Follow up with Kent/Jim about the nomination confirmation process [Andrew W]
13. UFG needs to be considered for title transfers between bundled pools and unbundled BGAs [Andrew W]

8 Key Contacts

1) *Andrew Welburn, Contract Support and Compliance, EGD*
2) *Barry Goulah, Systems Measurement, EGD*
3) *Brian Burke, Key Accounts, EGD*
4) *Herman Medeiros, Systems Measurement, EGD*
5) *Ian MacRobbie, Engineering (Storage), EGD*
6) *Jackie Collier, Rate Research & Design, EGD*
7) *Jim Huber, EOS, Enbridge*
8) *Jody Sarnovsky, Strategic and Key Accounts, EGD*
9) *Kent Wirth, EOS, Enbridge*
10) *Malini Giridhar, Rate Research & Design, EGD*
11) *Sam Beninato, ABSU*
12) *Corey Webster, Sapient*
13) *Jayender Rajagopal, Sapient*
14) *Jitesh Sharma, Sapient*
15) *Swaroop George, Sapient*

9 Appendix A

9.1 Acronyms and Abbreviations

Acronym	Name
ABSU	Accenture Business Services for Utilities
BGA	Banked gas account
EGD	Enbridge Gas Distribution
KAB	Key Account Billing
MCI	Maximum Contractual Imbalance
MDV	Mean Daily Volume
MSA	Master Service Agreement
OFO	Operational Flow Order
PPA	Prior Period Adjustment
PPG	Price Point Group
STR	Service Transaction Request
UFG	Unaccounted For Gas

NGEIR EGD Manual Effort - Effort & Cost Summary

I **Setup Effort**

Functional Track	Design & Development (person days)	Notes
Contract Management	50	
Gas Management	70	
Charges & Reconciliation	20	
Total	**140**	

II **Total Setup Effort Estimate**

Category	Multiplier	Effort (person days)	Notes
Design + Development (D&I) phase		140	Derived from Table I
Manual Process Testing	50%	70	Assumes testing and defect fixing done by EGD business
Project Management effort	15%	31.5	Oversight/supervision to ensure 3rd party co-ordination
Associated system changes		112	This is to prevent unbundled accounts from getting into EnTRAC (includes design, development, testing, infra, QA, oversight for EnTRAC changes)
User Training			Not included in estimate
Legal & Communication			Not included in estimate
Others			Not included in estimate
Contingency	20%	48.30	Based on EGD project estimates
Total Manual Effort		**290**	**this excludes associated system changes**

III **Ongoing Effort**

Functional Track	Maintenance (FTE)	Notes
Contract Management	0.5	primarily for pools, account assoc, termination, renewal
Gas Management	4	3 - noms + LB + BGA, 1 - Non Compl + PPA
Charges & Reconciliation	0.5	primarily for ABSU validation of billing, security deposit
Total	**5**	

IV **Setup (Manual) Cost Estimate**

	Low	High	Notes
Salary ($/year)	$57,500	$57,500	Low case assumes 2 FTE's involved in setup; high case assumes 3
			Blended rate used - clerk and analyst
Total Setup Cost ($)	**$127,918**	**$191,877**	**this is a one-time cost to setup manual processes/spreadsheets**

V **Setup (EnTRAC change) Cost Estimate**

	Low	High	Notes
Rate ($)	$700	$1,000	
Total Setup Cost ($)	**$78,400**	**$112,000**	**this is a one-time cost to change EnTRAC**

VI **Ongoing Cost Estimate**

	Low	High	Notes
Salary ($/year)	$50,000	$65,000	Low case assumes all clerks; high case assumes all analysts
Total Cost per year ($)	**$250,000**	**$325,000**	**this is an annual cost**

Assumptions

The effort/cost does not include ABSU manual changes

FTEs perform administrative work and aren't supervisors (this is for ongoing work only; oversight is needed for initial setup)

Number of customers to manage is <= 10

Spreadsheets are as automated as possible

All manual processes are managed using spreadsheets & emails (not access databases or any other systems)

UCIR, RAVE, and other downstream systems wanting information to the manual data is not taken into account

Sapient

NGEIR EnTRAC - Effort & Cost Summary

I **Effort By Functional Area**

Functional Track	Design & Development (person days)	Notes
Contract Management	295	Based on metrics derived from past EnTRAC releases
Gas Management	512	
Charges & Reconciliation	90	
Common	78	
Total	**975**	

II **Total Effort Estimate**

Category	Multiplier	Effort (person days)	Notes
Design + Development (D&I) phase		975	Derived from Table I
Stabilization & Acceptance phase	70%	682.5	Based on actuals observed on EnTRAC releases over the past years and subjective assessment of scope clarity which exists today
DB Mgmt, Infrastructure effort	25%	243.75	
Quality Assurance effort	50%	487.5	
Project Management effort	15%	358.31	
User Training			Not included in estimate
Business Process Changes			Not included in estimate
Legal & Communication			Not included in estimate
Others			Not included in estimate
Contingency	20%	549.41	Based on EGD project estimates
Total		**3296**	

III **Initial Development Cost Estimate**

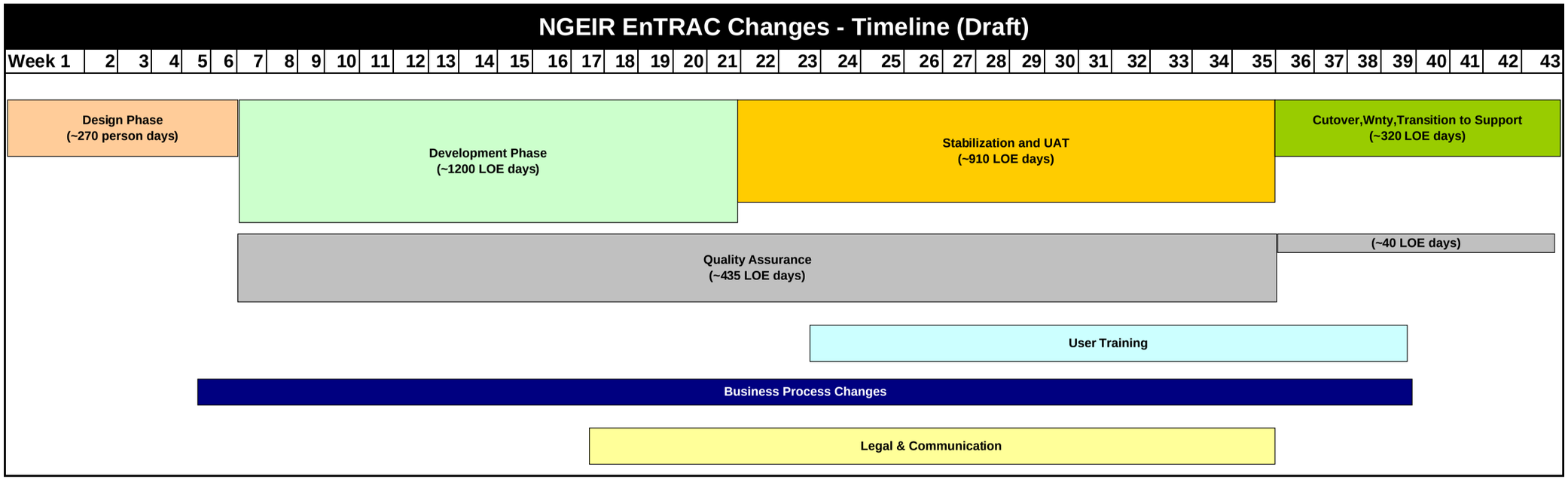
	Low	High
Rate ($/person day)	700	1200
Total Cost ($)	**$2,307,200**	**$3,955,200**

IV **Ongoing Support Cost Estimate**

	Low	High	Notes
Number of Resources	2	2	No oversight, since they'll be rolled into the existing support team
Rate ($/person day)	700	1200	1 resource on GM/Interfaces and 1 on CM/CR/Interfaces
Total Cost ($ per year)	**$308,000**	**$528,000**	**Assumes 220 work days per year**

Assumptions

The cost does not include hardware/software costs that may arise out of upgrades to the existing hardware to support the new requirements



Assumptions

1. The plan presented above is based on an understanding of scope to date & assumes a reasonable team size in each phase. A more detailed plan will need to drawn up once the functional changes are crystallised. It is suggested that the plan be drawn up in a phased manner i.e. for the design phase first followed by implementation once the design is completed.
2. The plan assumes a sequenced project, decisions on executing the project in phases or iterations will impact the above plan
3. The plan assumes adequate availability of resources with required skill sets through all phases.

RATE DESIGN PRINCIPLES AND PRICING APPROACHES

1. The purpose of this evidence is to address pricing principles for natural gas distribution, load balancing and storage services. One of the main objectives of pricing is to obtain economically efficient outcomes. Inefficient outcomes include failure of load balancing prices to maintain supply demand balance leading to system outages, or prices for services that create asymmetric windfalls for some market participants, while imposing undue burden on others.

2. One of the main objectives of pricing is to promote economically efficient decision making by producers and consumers of goods and services. In general, markets determine how prices are set and decisions are made. In a competitive market, firms invest when price levels and expected demand support the cost of the new investment. Ease of market entry and exit constrains prices and profit. In such markets, economically efficient prices also result in fair and equitable outcomes for consumers. For some markets, barriers to entry are caused by aspects of industry structure such as economies of scale, high levels of fixed capacity investment, and network economies.

3. In natural gas delivery, barriers to market entry arise from its capital intensive nature, and economies of scale and network. Since markets cannot discipline price, regulation of natural gas distribution serves the public interest.

4. Regulation determines both the level and the types of prices customers pay for natural gas delivery and other regulated services. The existence of common and joint facilities to serve multiple users requires regulatory bodies to establish pricing principles. These rely on cost allocation and acceptable revenue to cost ratios to

establish rates to serve various customer classes. Regulators also develop policies to provide fair access to services.

5. Service expansion to include new customers and services requires application of the regulatory approved framework for investment decision making. The Ontario Energy Board ("Board") has adopted a framework that assesses the net benefit of system expansion and ensures that existing customers bear no undue burden from the addition of new customers and services. Thus, any determination regarding service relies not just on market clearing prices but also upon a series of regulatory precedents and prescribed policies. This framework is collectively referred to as cost-based pricing. In a competitive market, on the other hand, price, or willingness to pay, is the sole arbiter of who gets service, how much, when, and at what cost. Pricing in competitive markets is also referred to as value-based pricing.

6. Regulators recognize that not all aspects of the gas industry need to be regulated to the same extent. While it is recognized that gas distribution is a monopoly service, upstream services such as gas supply, transport, storage and balancing have varying degrees of competitive aspects. Accordingly, the Board has mandated varying levels of unbundling of services. In these market segments, where regulation intersects with competition, concepts of cost-based and value-based pricing apply to ensure economically efficient outcomes.

7. Most large volume customers in Enbridge Gas Distribution's franchise exercise the option of purchasing their own commodity and arranging transportation to the Enbridge Gas Distribution city gate. Enbridge Gas Distribution is in the process of fully unbundling upstream transport from its service offerings through a phase-in of certain cost allocation changes which will fully take effect in October 2007. The

NGEIR proceeding addresses further unbundling of balancing and storage services from distribution services for power generation and large industrial customers.

8. In general, under bundled service, the utility must ensure that the system operates in balance (gas deliveries match gas consumption) to preserve the safety and reliability of the system. The utility accepts the obligation to procure the required assets to provide reliable service. Assets include a portfolio of gas supply contracts, storage services and pipeline delivery services required to satisfy the design day load requirements of customers and to meet the annual gas consumption under design weather conditions. The utility manages the assets to optimize the value for customers and recover the associated costs from customers.

9. Under unbundled service, market participants contract for the tools to balance their individual loads. Price, or willingness to pay, is the mechanism used to ensure that supply demand balance is maintained. However, if price changes were insufficient to maintain balance, there are serious operational consequences for the system operator. Since the gas system operates as a whole, the failure of an individual customer to appropriately balance creates reliability risks for all customers. 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.

10. Unlike electric service where power outages are restored often in minutes and occasionally in days, a gas system outage requires the execution of an elaborate and lengthy system restoration plan. In general, the restoration of gas service requires the physical isolation of the affected portion of the system. In addition, all of the meters in the affected area must be shut off by hand to prevent unsafe conditions for the customers and to permit the system to be re-pressurized. Once the system pressure has been restored, service must be restored to each customer, one at a time. To restore service requires that all of the interior gas equipment be inspected and pilot lights relit. This process is time-consuming and is most likely to occur when outside temperatures are extremely low and customer demands are at their peak.

11. The direct cost of service restoration for the utility is significant because of the number of trips to each customer's premise and the activities involved with each trip. For example, an outage affecting 100,000 customers, or approximately 5% of Enbridge Gas Distribution's customers, has a restoration cost of $12 million if the two trips to the customer's premise, as well as other activities cost as little as $120 per location. The timing of restoration would be affected by availability of qualified personnel. The economic cost to customers is likely far more than the costs to the utility. These costs include the losses associated with businesses being unable to operate, damages to inventory and equipment, and so forth. For residential customers, the damages include the impact of freezing on the contents of the dwelling and the need to relocate during the outage. In addition, the social costs include lost wages. It is reasonable to conclude that electric system outages cost society less than gas system outages.

12. Because the cost consequences of natural gas system outages are very high, new services must be designed to take outage probability into account. Economically efficient pricing must reduce the probability of system outages rather than increase it. Accordingly, in considering the requirements for unbundled service to power generators, the utility must insist that unbundled customers balance their loads and resources on a daily basis. The primary mechanism to incent customers to balance their loads is to have financial penalties for non-compliance. In general, these financial incentives must take the form of cash out provisions that are a multiple of the expected costs of balancing the system. In situations which could result in compromised integrity of the system, the utility must have the ability to terminate service to the customer. The Company's rate schedules currently incorporate market based financial penalties to induce conformance.

13. In stakeholder meetings, customers indicated that they do not want exclusive reliance on the market and their own arrangements for balancing services. Customers wish to minimize exposure to the financial and contractual penalties explained above. At the same time, they wish to maintain some upside exposure by managing their storage and gas supply options.

14. In other words, while customers want the tools to minimize cost through active gas management, they also want some "insurance" from Enbridge Gas Distribution in the form of a semi-bundled, no-notice balancing offering. The cost of providing this service would vary based on system operating conditions and the resources available to provide the service.

15. Enbridge Gas Distribution has reviewed potential alternatives for providing a limited balancing service. Such a service would allow a certain degree of imbalance

between the customer's deliveries and consumption on a daily basis. Based on that review (Exhibit C, Tab 2, Schedule 1), Enbridge Gas Distribution determined that various options present trade-offs between cost and reliability and between flexibility and restrictions.

16. For instance, the use of dedicated assets, reserved capacity, and some level of redundancy in assets improves reliability and reduces required restrictions on balancing services. Such a service requires high fixed charges and costs that duplicate certain of those borne directly by the customer. On the other hand, a lower cost, lower quality service offering with greater operating restrictions that uses system diversity and optimizes existing assets, requires lower fixed costs and lower payments than market-based services most of the time.

17. The pricing of the load balancing service must incorporate the following four principles. First, the costs of any incremental assets used to provide the service must be recovered from the users of this service. Second, system enhancements that benefit all customers should be borne by all customers. Third, to the extent system diversity and existing assets are utilized; the price must be set to offset any revenues the utility would have otherwise shared with its customers through transactional services activities. Finally, market based penalties and contract provisions must be used to ensure that power generation customers operate within the parameters of the limited balancing service. The Company believes that in conjunction, these four principles would ensure no undue burden is placed on existing customers from the provision of a limited balancing service for power generators.

18. Pricing of storage service must also recognize cost based and value based pricing principles. With respect to storage service, the Board ordered the Company and Union to file three alternatives for pricing storage. Two of the alternatives require cost-based rates while one alternative permits market-based pricing. The use of cost based storage for existing assets and deliverability represents current regulatory policy. The service desired by power generators and proposed by Enbridge Gas Distribution, outlined in Exhibit C, Tab 3, Schedule 1**,** requires different characteristics than the existing portfolio of storage service. These include higher than standard deliverability and access on a firm year-round basis (unratcheted service). The Board has identified cost-based pricing for these new services as one option to be considered.

19. The Company recognizes the value of higher deliverability storage for end-use power generation customers and for the Company's bundled customers. For bundled customers, the value of higher injection capability and deliverability produces a different set of benefits compared to existing storage service. The greatest value of this service occurs when market constraints exist. The ability to withdraw large volumes of gas from storage on a peak day displaces more expensive peaking supplies and higher priced spot purchases. The higher injection capability enhances storage benefits by creating more flexibility in the use of storage. This flexibility creates economic value that exceeds the cost basis for the service, particularly for customers who choose the unbundled service offering. In this context, the Company does not consider pricing high deliverability storage service on a cost basis appropriate. Cost based pricing for high deliverability could lead to economically inefficient outcomes for the reasons outlined below. The process for offering high deliverability storage at a market price follows.

20. High deliverability storage has market alternatives. These include contracting for peaking supplies and purchasing spot gas on a daily basis either at a liquid market or in the delivery area from customers who may be long on deliveries. Providing a cost-based rate for high deliverability storage when competitive alternatives exist could result in a windfall for unbundled customers through substitution. In addition, it could result in a misallocation of the service. Failure to reflect the value of the service permits unbundled customers to elect too much of the service resulting in reduced benefits for bundled customers. Also, the provision of this service is made possible by enhancements to storage assets that have been built under regulation. The Board has previously recognized that the combination of regulated and market-based services from regulatory assets requires a sharing of benefits.

21. For the above reasons, cost-based pricing for high deliverability storage could lead to economically inefficient outcomes. The market pricing option for high deliverability storage represents a sound basis for sharing the benefits of both the investment in storage and the required operations between bundled customers, unbundled customers, and shareholders.

22. The Company submits that a market price for Rate 316 is best determined by an open bidding process that solicits bids from all interested parties who meet pre-qualifying conditions. A floor price would be established based on the higher of the cost of developing storage or the value to bundled customers. The use of the open season for enhanced storage services does not in any way pre-judge or limit the Board's later consideration of how any premium is to be disposed off. The Board has historically placed such premiums in a deferral account pending disposition. The Company submits that this approach would be appropriate in this instance.

23. In conclusion, the Company proposes that its distribution, balancing and storage services be priced to reflect cost of service, value of service, and established principles of fair access to service where appropriate. The Company believes that a combination of these approaches is necessary to drive economically efficient outcomes.

C1

PROPOSED TARIFFS FOR POWER GENERATION CUSTOMERS: OVERVIEW

1. Enbridge Gas Distribution has developed two proposed rates for service to power generators. Rate 125 - Extra Large Firm Transportation Service ("Rate 125") and Rate 316 - High Deliverability Gas Storage Service (Customer Arranged Transport) ("Rate 316") constitute the service offerings. As outlined in the preceding evidence, these service offerings are the outcome of extensive discussions with power generation customers, generally accepted rate principles, the operational constraints discussed above, the Board's Procedural Orders in this proceeding, and the assumptions regarding services availability from upstream providers.

2. The following sections provide a description of the conceptual framework for the proposed rates, and then also discuss some additional services, as mandated by the Board in this proceeding, that could be offered to power generation customers.

3. As stated in Exhibit A, Tab 1, Schedule 1, the Company anticipates that this NGEIR proceeding will provide a conceptual framework for determining service offerings and rates for power generation customers by balancing customers' requirements with the cost of meeting those requirements and by taking into account the systemic challenges and the impacts new rates and services may have on other customers. The Company does not believe, however, that the NGEIR proceeding is the appropriate forum for actually setting and determining rates for power generation customers.

RATE 125

1. Rate 125 was first introduced and approved by the Ontario Energy Board in the context of Enbridge Gas Distribution's 2000 Rate Case (RP-1999-001) in order to respond to opportunities for natural gas fuelled cogeneration and power generation in anticipation of the deregulation of the electricity market in Ontario. Rate 125 provides unbundled distribution service from Enbridge Gas Distribution's city gate to the customer's premise.

2. At its inception, the applicability section of Rate 125 stipulated a minimum annual volume of 200 million cubic metres, a minimum contract demand of 609 thousand cubic metres per day, and a minimum load factor requirement of 90 percent. In its 2001 Rate Case (RP-2000-0040), Enbridge Gas Distribution subsequently applied and received approval from the Board to remove the minimum load factor requirement of 90 percent. This amendment was requested on the ground that the rate was originally designed for cogeneration projects and as further developments of the electricity market unfolded, Rate 125 was too restrictive for gas fired power plants that intended to sell all or most of their output to the power grid. These plants would have no assurance regarding their operating profile as this will ultimately depend on each plant's success in bidding to supply power into the Ontario grid.

3. The approach undertaken in the derivation of Rate 125 was based on the ratemaking principles considered by the Board for the approval of all other customer rate classes. These principles included the use of postage stamp rates, class rate-making, and the use of an embedded average cost approach. The costs allocated to Rate 125 include return and taxes, operating and maintenance costs, and depreciation associated with extra high pressure mains, meters, and services. No

costs were allocated for the high pressure or low pressure distribution network. A typical customer under this rate would require service off the Company's extra high pressure (i.e. transmission pressure) network. The level of Rate 125 was set such that it entirely recovers its fully allocated costs.

4. In subsequent discussions, potential Rate 125 customers expressed a desire for more flexibility in the rate, given the uncertainties of the deregulated electricity market and the distinctive nature of merchant power plants. The specific areas that were discussed related to the existing terms and conditions pertaining to the requirement for system wide unaccounted for gas in the case of dedicated lines, as well as the consideration for the establishment of authorized demand overrun provision within Rate 125. Consideration of these issues took place and Enbridge Gas Distribution filed an amended Rate 125 schedule on October 8, 2002 as part of its 2003 Rate Case proceeding. There are no customers currently taking service on Rate 125.

5. Under the current Rate 125, customers are required to balance deliveries and consumption within a 2% tolerance. Any imbalance in excess of 2% is cashed out based on the price of gas on the day. In this proceeding, based on stakeholder feedback, Enbridge Gas Distribution is expanding the scope of Rate 125 from a pure unbundled distribution rate to include a default balancing provision. The service allows a certain degree of imbalance between the customer's deliveries and consumption on a daily basis. The provision is default in the sense that a customer who is always in balance within +/- 2%, would only incur fixed distribution charges and no balancing charges. Failure to remain within expanded balancing limits will still trigger cashout provisions.

6. Enbridge Gas Distribution has reviewed potential alternatives for providing a limited balancing service. In all instances the Company would require the use of storage assets and pipeline capacity to provide load balancing service in the franchise area. However, depending on the level of incremental assets and their characteristics, there would be different trade-offs between cost and quality and between flexibility and restrictions. In a low cost offering that utilizes system diversity and few incremental assets, some restrictions on balancing may be required to minimize cost consequences on bundled customers and the probability of system outages. On the other hand, if there is full reservation of capacity for power generation customers and no reliance on system diversity, restrictions may be reduced significantly without compromising system integrity, albeit at a higher cost. The table below lays out the options and the associated tradeoffs.

Load Balancing Options

Option	Cost	Enhanced Storage	Enhanced Transport	Use of System Diversity	Service Restrictions	Imbalance Charges	Nature of Service
1	Low	Yes	None	High	Seasonal and OFO	Variable	Default
2	Medium	Yes	Partial	Low	Some	Fixed/Variable	Contracted
3	High	Yes	Full reservation of capacity	None	Low	Fixed/Variable	Contracted

7. Option 1 in the above table provides a lower quality and lower cost service. The service relies on high deliverability storage but no incremental pipeline capacity to

balance the customer. This can be done by optimizing existing assets and encouraging power generation customers to act in a counter seasonal manner i.e. pack gas in the winter and draft in the summer. For example, customers would have a limited ability to draft in the winter. On some system constraint days, identified as Operational Flow Order ("OFO") days, the customer would not be allowed to draft the system. To the extent LBA charges are imposed by the pipeline, and power generation customers have contributed to the imbalance, they would partake in the sharing of the charges. Such a service would trade greater availability and flexibility for lower cost. Such a service would be default in nature and use variable charges as opposed to fixed charges.

8. Option 3 provides a higher quality balancing service at a higher cost. The service relies on high deliverability storage and enhanced pipeline services (reserved pipeline capacity with more nomination windows). The need to manage hourly swings (Exhibit B, Tab 2, Schedule 1) may require the Company to obtain upstream reserved capacity equal to the 24 times the customer's hourly flow. Such a service if elected by customers may be more economical on a bundled basis. If the customer wished to manage its transport in addition to supply arrangements, the balancing service could result in complete duplication of transport assets. Also, this service would require a longer term commitment to take balancing service from Enbridge Gas Distribution and commitment to paying fixed/demand charges to mirror pipeline charges paid by Enbridge. The cost of this service is estimated to be in excess of $30M per year.

9. The differentiator between the two options is the nature of the transport arrangement between storage and the Company's franchise area. Option 2 is a proxy for options that would lie between Option 1 and 3. These could include a

substitution of enhanced transport services for a portion of the current transport arrangements combined with some level of incremental capacity. These options would allow the Company to reduce exposure to LBA charges, however unless incremental transport capacity is fully sized for the customer's hourly flow requirements, restrictions in the form of OFO days may still apply. The Company would use simulation models to determine the mix of enhanced incremental capacity that would be required. This analysis would determine to a better extent the cost of providing this service.

10. The Company's proposal is based on Option 1. Paragraphs 6 to 9 above have laid out the operational issues and the costs of providing a balancing service at a conceptual level. Under the proposed solution there are few rate implications for existing customers**.** To the extent the Company is able to offer synergies between its bundled customers and unbundled customers, lower costs result for both categories of customers. Power generators pay for incremental costs and contribute revenues when system assets are optimized. Counter seasonal actions by power generators would benefit existing customers. In some instances, these actions could be over compensatory (i.e.,excessive packing on an OFO Day that results in LBA charges for over delivery) and result in some costs to existing customers. In most instances, cash out provisions are expected to incent appropriate balancing actions by unbundled customers. The cash out provision prevents the customer from using high cost gas on one day and subsequently replacing that gas through a make-up nomination using lower cost gas. The design of the cash out feature assures that Rate 125 customers do not impose costs on bundled customers and protecst system integrity. To the extent a customer's imbalance threatens system integrity, Enbridge Gas Distribution would use its termination right as the ultimate tool to maintain system integrity. The Company's

ability to offer this load balancing service is conditional on appropriate upstream services being available to the Company and its customers (Exhibit B, Tab 2, Schedule 1). The specific features of the balancing service are outlined at Exhibit C, Tab 2, Schedule 1.

11. The section below provides a brief description of the characteristics of Rate 125 as presented at Exhibit C, Tab 2, Schedule 2. The schedule contains general provisions for the rate and some language to clarify requirements. The rate includes certain price parameters where the Company used existing data to make reasonable estimates. As noted above, final prices would be an outcome of the next rates case.

12. The proposed Rate 125 contains the following provisions:
    (a) Availability
    (b) Character of Service
    (c) Monthly Customer Charge
    (d) Monthly Contract Demand Charge
    (e) Commodity Charge
    (f) Monthly Minimum Bill
    (g) Unaccounted for Gas ("UFG") Adjustment
    (h) Nominations
    (i) Load Balancing
    (j) Authorized Demand Overrun
    (k) Unauthorized Demand Overrun
    (l) Unauthorized Supply Overrun
    (m) Term of Contract
    (n) Right to Terminate Service

13. The following describes the provisions:

a. Availability

Service under this rate schedule is available to a customer who contracts for gas transportation service on the distribution system and who has installed automatic meter reading capability as a condition of service. The service contemplated under this rate is for a single terminal location served using extra high pressure main. In order to assure consistency between the underlying cost of this rate and the facilities actually used to provide distribution service, there is a minimum contract demand provision of 600,000 cubic metres. There is no minimum commodity requirement so that large peaking power generation customers are not precluded from access to service under this rate. Customers who do not qualify for this service will be able to receive unbundled distribution service under the Rate 300 family of services.

b. Character of Service

Rate 125 provides for firm service subject to the contract demand and the maximum hourly demand equal to 1/24 of the contract demand. This feature ensures that the distribution system is sized to meet all operating conditions including system peak hourly demand. Firm service under this schedule is subject to the terms and conditions contained in the customer contract.

c. Rate Charges (including items c to f from the list of services)

The distribution component of the rate consists of a customer charge and a demand charge. The customer charge recovers customer related costs. The contract demand charge recovers cost associated with extra high pressure mains. There is no commodity cost for distribution service under the schedule. The minimum bill is the sum of the customer charge plus the applicable contract demand charge. The contract demand charge is an annual charge. On the rate schedule, the demand charge is depicted as a monthly charge payable twelve times a year.

g. The UFG Charge

The UFG provision has two options. Where a customer's service is from the Company's gas distribution network, the UFG provision reduces the volume of gas delivered to its system by the UFG factor as determined from time-to-time. This adjustment means that the customer receives less gas at the customer's meter than is confirmed as a delivery to the system. In the event that the customer receives dedicated service there is no UFG adjustment because the metering occurs at the location of interconnection with the Enbridge Gas Distribution system.

h. Nomination Requirements

Enbridge Gas Distribution has provided for all of the nomination flexibility available to the customer on the upstream pipeline. Nominations are daily and the customer may change nominations in accordance with pipeline nomination windows. Nominations always equal confirmed upstream nominations. There is substantial delivery area flexibility including the ability to nominate secondary delivery areas, when system operating conditions permit, and to combine

nominations within a given delivery area such as CDA or EDA where the customer has more than one terminal location.

i. Load Balancing Requirements

Load balancing is a default provision under the rate schedule that applies only to the extent that gas deliveries, adjusted for UFG, do not match gas consumption at the customer's meter. The default balancing applies up to a limit called the Maximum Contractual Imbalance ("MCI") which would be fixed for the contract period. The MCI may be less than or equal to the customer's CD, based on the Company's assessment. The daily and cumulative imbalance could be up to the MCI, subject to certain restrictions. These restrictions are symmetric in nature, in that they encourage the customer to pack the system in winter and draft the system in summer. Cash out provisions apply if seasonal restrictions and the MCI are breached.

When a customer uses the balancing provisions, two charges are applicable: the daily balancing charge and the cumulative balancing charge. The daily imbalance charge is based on storage injection and withdrawal charges and transport fuel costs and an allocation of pipeline CBA charges, if any. The cumulative imbalance charge is derived by unitizing storage space and demand charges and associated transport demand charges.

The daily balancing charge consists of two tiers. For each tier, the measure for imbalance is against the MCI. The Tier 1 charge applies to daily balances, whether positive or negative, greater than 2% but less than 10% of the customer's MCI. There are no charges for an imbalance that is less than +/- 2% of MCI. This provision, using an MCI, provides for a greater maximum imbalance

than one that measures imbalance against the daily nomination. This feature specifically addresses power generators' concerns related to more flexibility in daily balancing. On a daily basis, the Company provides the 10% of MCI as a no notice service and treats the service for costing purposes as a no notice storage withdrawal or injection.

The Tier 2 charge applies to daily imbalances equal to or greater than 10%. Tier 2 imbalances are subject to seasonal restrictions. During the winter season the customer may draft the system only up to 10% of MCI. A daily draft imbalance greater than 10% is subject to cash out. During the summer season, the customer may draft the system up to the MCI. A daily pack imbalance greater than 10% may be subject to cash out.

In some instances, the Company may suspend balancing provisions that could worsen system constraints. The Company may issue an OFO day, at 24 hours notice in the summer or winter (for definition of OFO day, see Exhibit C, Tab 2, Schedule 2, Item 14). On a winter OFO day, the customer cannot draft the system but may pack the system. On a summer OFO day, the customer cannot pack the system but may draft the system. On such days, daily and cumulative charges are waived if the customer's imbalance is in the desired direction (i.e., mitigates system constraints). If the customer's imbalance worsens system constraints, cash out provisions apply. If cash out provisions are ineffective in imposing compliance, the Company reserves the right to terminate service as explained at Item n. below.

As noted above, the customer's cumulative imbalance may range from +/-MCI. Cumulative imbalance charges apply; however, the customer has other means to

manage imbalances. These include the ability to title transfer to a storage account or trade imbalances. The customer is required to clear the cumulative imbalance within five days after the end of each month. Also, if the Company declares an OFO day in the winter, the customer has 24 hours notice to bring a negative cumulative imbalance to 10% of MCI. Failure to reduce the negative imbalance to 10% of MCI would result in a cash out of the excess. In the summer, the Company may exercise the right to require a customer to bring a positive cumulative imbalance to 10% of the MCI.

j. Authorized Demand Overrun

Authorized demand overrun service provides a limited opportunity for the customer to exceed contract demand at the sole discretion of the Company. Once authorized, amounts in excess of the contract demand plus UFG equal authorized demand overrun plus UFG. Authorization of a demand overrun assumes that the customer will deliver gas equal to the contract demand, the authorized overrun amount at the meter plus UFG for total deliveries. Any consumption above the authorized demand overrun is unauthorized supply overrun. The bill for this service equals 12/365 times the applicable demand charge for service under this rate times the authorized overrun. Based on terms of the Service Contract, requests beyond five days will establish a new contract demand and be subject to the higher annual charge for twelve months.

k. Unauthorized Demand Overrun

The unauthorized demand overrun provision applies when a customer exceeds the maximum hourly or daily contract demand. Any amount of unauthorized demand may establish a new contract demand where local facilities permit. In any case, the customer will be subject to a charge of 120% of the applicable

annual contract demand charge times the volume of gas taken in excess of the contract demand. In addition, all excess consumption plus the applicable UFG equals unauthorized supply overrun. The unauthorized supply overrun billing provision applies as well.

l. Unauthorized Supply Overrun

Unauthorized supply overrun equals any gas consumed above levels explicitly authorized by Enbridge Gas Distribution under either the contract demand provision or an authorized demand overrun. The rate applicable to unauthorized supply overrun is 150% of the maximum daily index price applicable for such day.

m. Term of Contract

The term of contract provides for a minimum of one year and longer if necessary to assure the recovery of the costs dedicated to the customer's service.

n. Right to Terminate Service

The Company's standard contract includes language that permits service termination. Inclusion of this feature in the rate schedule reflects the substantial risk imposed on the Company and its bundled customers from service to power generators in the event the power generator fails to abide by the requirements of the rate. The Company requires the right and indeed the duty to terminate service where customer operations threaten the safety and reliability of the system. The provision permits the Company to terminate service under emergency conditions rather than incur the cost of restoring service to affected customers.

14. A sample bill calculation illustrates the basic operation of Rate 125 using nominations and actual consumption. The calculations use several consecutive days to demonstrate the various load balancing provisions.

Rate 125 Illustrative Example
Season: Winter

Day	Net Nomination	Consumption	Daily Imbalance	Daily Imbalance Fees	Cumulative Imbalance	Cumulative Imbalance Fees
			MCI=+/-100		MCI=+/-100	
1	80	80	0	0	0	0
2	80	90	-10	-8 x Tier 1 Fee	-10	-10 x CI Fee
3	100	80	20	8 x Tier 1 Fee 10 x Tier 2 Fee	10	10 x CI Fee
4	0	100	-100	-8 x Tier 1 Fee -90 Cash Out	0	0
5	80	100	-20	-8 x Tier 1 Fee -10 Cash Out	-10	-10 x CI Fee
6	100	80 24 Hour Notice Issued	20	8 x Tier 1 Fee 10 x Tier 2 Fee	10	10 x CI Fee
7*	85	80 OFO Day	5	0	15	10 x CI Fee
8	0	110 Unauthorized	-110	-8 x Tier 1 Fee -90 Cash Out -10 UOG	5	5 x CI Fee

Note: No Daily Imbalance fees for imbalances up to 2% MCI = +/- 2
Note: Day 7*: No Daily or Cumulative Imbalance fee for over deliveries on OFO day!

15. On Day 1, the customer balances and no charge results. On Day 2, the customer drafts the system for ten units. With an MCI of 100 units, the customer incurs only Tier 1 charges for daily imbalance because the customer is within the ten percent MCI tolerance band. The customer bears no charge for the first two percent of MCI under the daily balancing charge (2 units) and pays for eight units of daily imbalance. The customer also creates a cumulative imbalance of ten units and pays for that service at the cumulative imbalance rate. On Day 3, the customer delivers excess gas of 20 units. The 20 units receives the daily charge for Tier 1 (8

units as calculated above) and 10 units at Tier 2. The customer's cumulative imbalance changes from a negative 10 units to a positive 10 units subject to the cumulative charge. On Day four (a winter season day), the customer drafts the system for 100 units. In the winter, customer drafts in excess of ten percent MCI are subject to immediate cash out. The daily imbalance fee applies to eight units as discussed above. The cumulative imbalance returns to zero. Each day following illustrates other provisions such as waiving the daily balancing fee for over deliveries on an operational flow order day and the use of unauthorized overrun gas. Each feature causes customers to protect the integrity of the system by managing gas deliveries and consumption to match as closely as possible. Customers who successfully manage their daily imbalances realize benefits of the unbundled rate. Failure to mange successfully, increases costs, and under extreme conditions may result in service termination.

ENBRIDGE GAS DISTRIBUTION

PROPROSED TARIFFS FOR POWER GENERATION CUSTOMERS

Rate 125 – Extra Large Firm Distribution Service

1. Availability:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation to a single Terminal Location of a specified maximum daily volume of natural gas of not less than 600,000 m^3. The Service under this rate requires Automatic Meter Reading (AMR) capability.

2. Character of Service:

The Service shall be continuous (firm) except for events specified in the Service Contract including force majeure. The Applicant is neither allowed to take a daily quantity of gas greater than the Contract Demand (CD) nor an hourly amount in excess of the Contract Demand (CD) divided by 24, without the Company's prior consent.

3. Monthly Customer Charge: TBD (Note: The charge will reflect unbundled rate implementation costs.)

4. Monthly Contract Demand (CD) Charge: Approx. 8.5 c/m^3

5. Commodity Charge: Not Applicable.

6. Monthly Minimum Bill: The Monthly Customer Charge plus the Monthly Contract Demand (CD) Charge.

7. Unaccounted for Gas (UFG) Adjustment Factor:

The amount of gas delivered to the EGD system on behalf of the customer will be reduced by X% (UFG adjustment factor) for delivery to the customer's meter. In the case of a Dedicated Service the Unaccounted for Gas volume requirement is not applicable.

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8. Nominations:

Customer shall nominate gas delivery daily based on the gross commodity delivery required to serve the customer's daily load plus the UFG. Customers may change daily nominations based on the nomination windows within a day as defined by the customer contract with TransCanada PipeLines (TCPL) or Union Gas Limited.

Schedule of nominations under Rate 125 has to match upstream nominations. There is no way to provide more flexibility than exists upstream of the EGD gas distribution system. Where the customer's nomination does not match the confirmed upstream nomination, the nomination will be confirmed at the upstream value.

Customer may nominate gas to a contractually specified Primary Delivery Area that may be EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA). The Company may accept deliveries at a Secondary Delivery Area such as Dawn, at its sole discretion. Quantities of gas nominated to the system cannot exceed Contract Demand (CD), unless Make-up Gas or Authorized Overrun is permitted.

Customers with multiple Rate 125 contracts within a Primary Delivery Area may combine nominations subject to system operating requirements and subject to the Contract Demand (CD) for each Terminal Location. For combined nominations the customer shall specify the quantity of gas to each Terminal Location and the order in which gas is to be delivered to each Terminal Location. The specified order of deliveries shall be used to administer Load Balancing Provisions to each Terminal Location. When system conditions require delivery to a single Terminal Location only, nominations with different Terminal Locations may not be combined.

9. Load Balancing:

Any difference between actual daily-metered consumption and the actual daily volume of gas delivered to the system under this rate less the UFG shall be subject to the Load Balancing Provisions (Item 15).

10. Authorized Demand Overrun:

The Company may, at its sole discretion, authorize consumption of gas in excess of the Contract Demand (CD) for limited periods within a month, provided local distribution facilities have sufficient capacity to accommodate higher demand. In such circumstances, customer shall nominate gas delivery based on the gross commodity delivery (the sum of the customer's CD and the authorized

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overrun amount) required to serve the customer's daily load, including quantities of gas in excess of the Contract Demand (CD), plus the UFG. In the event that gas usage exceeds the gas delivery on a day where demand overrun is authorized, the excess gas consumption shall be deemed Supply Overrun Gas.

The rate applicable to Authorized Demand Overrun shall equal the applicable Monthly Demand Charge times 12/365. Such service shall not exceed 5 days in any contract year. Based on terms of Service Contract, requests beyond 5 days will constitute a request for a new Contract Demand (CD) level with retroactive charges. The new Contract Demand (CD) level may be restricted by the capability of the local distribution facilities to accommodate higher demand.

Automatic authorization of transportation overrun will be given in the case of Dedicated Service to the Terminal Location provided that pipeline capacity is available and subject to a maximum volume as specified in the Service Contract.

11. Unauthorized Demand Overrun:

Any gas consumed in excess of the Contract Demand (CD) and/or maximum hourly flow requirements, if not authorized, will be deemed to be Unauthorized Demand Overrun gas. Unauthorized Demand Overrun gas may establish a new Contract Demand (CD) effective immediately and shall be subject to a charge equal to 120 % of the applicable monthly charge for twelve months of the current contract term, including retroactively based on terms of Service Contract. Based on capability of the local distribution facilities to accommodate higher demand, different conditions may apply as specified in the applicable Service Contract. Unauthorized Demand Overrun gas shall also be subject to Unauthorized Supply Overrun provisions.

12. Unauthorized Supply Overrun:

Any gas deemed to be Unauthorized Overrun gas shall be subject to cash out at the rate of 150% of the highest daily index cost of gas.

13. Term of Contract:

A minimum of one year. A longer-term contract may be required if incremental contracts/assets/facilities have been procured/built for the customer. Migration from an unbundled rate to bundled rate may be restricted subject to availability of adequate transportation and storage assets.

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14. Load Balancing Provisions (Applicable to Rate 125):

Load Balancing Provisions shall apply at the customer's Terminal Location or at the location of the meter installation for a customer served from a dedicated facility.

In the event of an imbalance any excess delivery above the customer's actual consumption or delivery less than the actual consumption shall be subject to the Load Balancing Provisions.

Definitions:

Aggregate Delivery:

The Aggregate Delivery for a customer's account shall equal the sum of the confirmed nominations of the customer for delivery of gas to the applicable delivery area from all pipeline sources.

Applicable Delivery Area:

The Applicable Delivery Area for each customer shall be specified by contract as a Primary Delivery Area. Where system-operating conditions permit, the Company, in its sole discretion, may accept a Secondary Delivery Area as the Applicable Delivery Area by confirming the customer's nomination of such area. Confirmation of a Secondary Delivery Area for a period of a gas day shall cause such area to become the Applicable Delivery Area for such day. Where delivery occurs at both a Terminal Location and a Secondary Delivery Area on a given day, the sum of the confirmed deliveries may not exceed Contract Demand (CD), unless Demand Overrun and/or Make-up Gas is authorized.

Primary Delivery Area:

The Primary Delivery Area shall be delivery area such as EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA).

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Secondary Delivery Area:

A Secondary Delivery Area may be a delivery area such as Dawn where the Company, at its sole discretion, determines that operating conditions permit gas deliveries for a customer.

Actual Consumption:

The Actual Consumption of the customer shall be the metered quantity of gas consumed at the customer's Terminal Location or in the event of combined nominations at the Terminal Locations specified.

Net Available Delivery:

The Net Available Delivery shall equal the Aggregate Delivery times one minus the annually determined percentage of Unaccounted for Gas (UFG) as reported by the Company.

Daily Imbalance:

The Daily Imbalance shall be the absolute value of the difference between Actual Consumption and Net Available Delivery.

Cumulative Imbalance (also referred to as Banked Gas Account):

The Cumulative Imbalance shall be the sum of the difference between Actual Consumption and Net Available Delivery since the date the customer last balanced or was deemed to have balanced its cumulative imbalance account.

Maximum Contractual Imbalance:

The Maximum Contractual Imbalance shall be less than or equal to the customer's Contract Demand (CD).

Winter and Summer Seasons:

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The winter season shall commence on the date that the Company provides notice of the start of the winter period and conclude on the date that the Company provides notice of the end of the winter period. The summer season shall constitute all other days.

Operational Flow Order:

An Operational Flow Order (OFO) shall constitute an issuance of instructions to protect the operational capacity and integrity of the Company's system, including distribution and/or storage assets, and/or connected transmission pipelines.

Circumstances that would call for an OFO would include but not be limited to:

- Capacity constraint on the system, or portions of the system, or upstream systems, that are fully utilized;
- Conditions where the potential exists that forecasted system demand plus reserves for short notice services provided by the Company and allowances for power generation customers' balancing requirements would exceed facility capabilities and/or provisions of 3rd party contracts;
- Pressures on the system or specific portions of the system are too high or too low for safe operations;
- Storage system constraints on capacity or pressure or caused by equipment problems resulting in limited ability to inject or withdraw from storage;
- Pipeline equipment failures and/or damage that prohibits the flow of gas;
- Any and all other circumstances where the potential for system failure exists.

14.1 Daily Balancing Fee

On any day where the customer has a Daily Imbalance the customer shall pay a Daily Balancing Fee equal to:

(Tier 1 Quantity X Tier 1 Fee) + (Tier 2 Quantity X Tier 2 Fee) + (Applicable Penalty Fee for Imbalance in excess of the Maximum Contractual Imbalance X the amount of Daily Imbalance in excess of the Maximum Contractual Imbalance)

Where Tier 1 and 2 Fees and Quantities are set forth as follows:

Tier 1 = Daily Imbalance of greater than 2% but less than 10% of the Maximum Contractual Imbalance and shall be subject to a charge of approx. 0.5 c/m^3.

(Note: This charge will be based on injection and withdrawal charges plus any transportation charges associated with storage injection or withdrawal. This charge will be impacted by commodity prices as it would include short haul transport fuel.)

Tier 2 = Daily Imbalance of greater than 10% but less than the Maximum Contractual Imbalance shall be subject to a charge of approx. 0.6 c/m^3.

(Note: This charge will equal the sum of 120% of the injection and withdrawal charges plus any transportation charges associated with storage injection or withdrawal. This charge will be impacted by commodity prices as it would include short haul transport fuel.)

In addition for Tier 2, instances where the Daily Imbalance represents an under delivery of gas during the winter season shall constitute an immediate cash out at 150% of the highest daily index cost of gas for all gas in excess of 10 % of Maximum Contractual Imbalance. Where the Daily Imbalance represents an over delivery of gas during the summer season, the Company reserves the right to cash out the excess delivery at 50% of the lowest daily index price of gas for all gas in excess of 10 % of Maximum Contractual Imbalance. The Company will issue a 24-hour advance notice to customers of its intent to impose cash out for over delivery of gas during the summer season.

The customers shall also pay any Load Balancing Agreement (LBA) charges imposed by the pipeline on days when the customer has a Daily Imbalance provided such imbalance matches the direction of the pipeline imbalance. LBA charges shall first be allocated to customers served under this rate. The system bears a portion of these charges only to the extent that the system incurs such charges based on its operation excluding the operation of customers under this rate schedule. In that event, LBA charges shall be prorated based on the relative imbalances.

Customer's Actual Consumption cannot exceed Net Available Delivery when the Company issues an Operational Flow Order in the winter. Net nominations must not be less than consumption at the Terminal Location. Any negative Daily Imbalance on a winter Operational Flow Order day shall be cashed out at the 150% of the highest daily index cost of gas. Customer's Net Available Delivery cannot exceed Actual Consumption when the Company issues an Operational Flow Order in the summer. Actual Consumption must not be less than net nomination at the Terminal Location. Any positive Daily Imbalance on a summer Operational Flow Order day shall be cashed out at the 50% of the lowest daily index cost of gas.

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The Company will waive Daily Balancing Fee and Cumulative Imbalance Charge on the day of an Operational Flow Order if the customer used less gas that the amount the customer delivered to the system during the winter season or the customer used more gas than the amount the customer delivered to the system during the summer season. The Company will issue a 24-hour advance notice to customers of Operational Flow Orders and suspension of Load Balancing Provisions.

14.2 Cumulative Imbalance Charges

Customers have the right to trade Cumulative Imbalances within a delivery area. Customers also have the right to title transfer gas from their Cumulative Imbalances Account (Banked Gas Account) into a storage account of the customer provided that the customer has space available in the storage account to accommodate the transfer.

Customers shall be permitted to nominate Make-up Gas, subject to operating constraints, provided that Make-up Gas plus Aggregate Delivery do not exceed Contract Demand (CD). The Company may, on days with no operating constraints, authorize Make-up Gas that, in conjunction with Aggregate Delivery, exceeds Contract Demand (CD).

The customer's Cumulative Imbalance cannot exceed its Maximum Contractual Imbalance, which may be less than or equal to the customer's Contract Demand (CD). In the event that the customer cannot title transfer gas from their Cumulative Imbalances Account (Banked Gas Account) in whole or in part to storage the Company proposes a cash-out mechanism for such instances.

The Cumulative Imbalance Fee shall be equal to approx. 2.0 c/m^3 per unit of imbalance. This fee shall be based on a pro-rata share of the capacity cost of the Company's Storage Service.

In addition, on any day that the Company declares an Operational Flow Order, negative Cumulative Imbalances greater than 10 % of Maximum Contractual Imbalance in the winter season shall be cashed out at 150% of the highest daily index cost of gas. The Company reserves the right to cash out positive Cumulative Imbalances greater than 10 % of Maximum Contractual Imbalance in the summer season at 50% of the lowest daily index cost of gas. The Company will issue a 24-hour advance notice to customers of Operational Flow Orders including cash out instructions for Cumulative Imbalances greater than 10 % of Maximum Contractual Imbalance.

The customer's Cumulative Imbalance shall be equal to zero within five (5) days after the end of each month.

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15. Right to Terminate Service

The Company reserves the right to terminate service to customers served hereunder where the customer's failure to comply with the parameters of this rate schedule jeopardizes either the safety or reliability of the gas system. The Company may, in its sole discretion, provide notice to the customer of such termination; however, no notice is required to alleviate emergency conditions.

RATE 316

1. Rate 316 provides for a highly flexible, high deliverability, natural gas storage service. Rate 316 permits both in-franchise and ex-franchise customers to contract for service under this rate. The Company believes that the combination of choices for both space and deliverability provides power generation customers a range of options for electing a suitable storage service. Customers, other than power generation customers, may also find this service attractive.

2. The operational issues, infrastructure requirements, and costs to provide this service are identified at Exhibit B, Tab 3, Schedule 2. The implementation timeline would be impacted by the timeline for storage infrastructure and the business process changes required to implement unbundled rates (Exhibit B, Tab 3, Schedule 3).

3. The pricing of this service includes cost based (regulated) and market based elements. The regulated rate only applies to in-franchise customers whose space and deliverability requirements are in accordance with current Board approved allocation methodology. This methodology allocates space based on an algorithm that takes in account the customer's seasonal load profile. Standard deliverability is 1.2% of allocated space and subject to ratchets. As outlined at Exhibit B, Tab 4, Schedule 1, the Company submits that revenues from the enhanced features of the proposed storage service should be recovered on market based rates. This would allow for benefit sharing between unbundled and bundled customers. Pricing premium high deliverability services at cost could result in windfalls to the subscribers of this service. It could also affect bundled customers adversely by allocating too much of a high value service to unbundled customers. This in turn

would force more expensive alternatives to high deliverability such as peaking contracts and spot purchases on bundled customers.

4. The section below provides a brief description of the features of Rate 316 as attached at Exhibit C, Tab 3, Schedule 2. The schedule contains general provisions for the rate and some language to clarify requirements. The rate includes certain price parameters where the Company used existing data to make reasonable estimates for the standard 1.2% deliverability offering. Market prices for the enhanced services are better determined through an open season process.

5. The proposed Rate 316 contains the following provisions:
   a. Availability
   b. Character of Service
   c. Monthly Customer Charge
   d. Storage Reservation Charge
   e. Monthly Minimum Bill
   f. Nominated Storage Service
   g. Unratcheted Deliverability Service
   h. Other provisions
   i. Term of Contract

6. The following describes the provisions:

   a. Availability

   The availability provision provides that a customer must contract for both storage space and storage deliverability at one of three tiers as separate options. This storage is not a delivered service and the customer must provide a separate pipeline transportation contract from storage to the Enbridge Gas Distribution delivery area that serves the customer's terminal location. In the event that the

customer electing service is not in the Company franchise area, the customer must provide delivery to the customer's location. This service is limited to confirmed pipeline deliveries. The availability provision also describes the three tiers of deliverability available for contract. Tier One service permits a maximum daily withdrawal of 1.2% of contracted space. Tier Two service permits a maximum daily withdrawal of 5%. Tier Three service permits a maximum daily withdrawal of 10%. All such withdrawals are subject to storage ratchets based on the actual quantity of gas in the customer storage account. This service requires daily nomination and the rate of injection or withdrawal is limited to 1/24th of the daily maximum right available.

b. Character of Service

This service may be either firm or interruptible. The status of the service depends on the nature of the pipeline delivery service the customer contracts for. Firm deliveries constitute firm service while interruptible deliveries constitute interruptible service.

c. Monthly Customer Charge

The monthly customer charge is designed to recover the customer related costs for providing unbundled services including the availability of the electronic bulletin board, managing nominations and confirmations, gas in storage accounting, managing injection and deliverability constraints, and posting information for customers regarding ratchets for storage. This charge represents the monthly management related costs for the service and applies to each customer.

d. Storage Reservation Charge

The storage reservation charge consists of the price bid for the service under the open season. There are several components to the price. First, there is a

storage space demand charge. This charge reserves the maximum space in storage allotted to the contract. This represents the maximum quantity of gas that the customer may hold in storage. There is also a tiered deliverability/injection demand charge associated with the elected tier of deliverability. These charges increase with the level of daily deliverability the customer selects. Finally, the service requires volumetric charges for activities under the service. The volumetric charges include charges for injection and withdrawal as well as a fuel charge applicable to the service. The customer charge and the volumetric charges reflect specific costs in addition to the price bid for service under the open season. The open season essentially sets the price for space and deliverability.

e. Minimum Bill

The monthly minimum bill equals the sum of the monthly customer and monthly demand charges.

f. Nominated Storage Provision

Nominated storage service provides that storage services up to the maximum injection or withdrawal must be nominated at Dawn. The provision also permits customers to transfer title to gas in storage, subject to certain restrictions as proposed at Exhibit C, Tab 4, Schedule 1. Finally, there may be periods when operational considerations limit either injection or withdrawal. With proper notice, the Company reserves the right to impose limits to ensure the storage system meets operating requirements.

g. Un-Ratcheted Storage Provision

The purpose of this provision is to permit a customer to select a level of storage withdrawal service that will not be subject to storage ratchets. Under this

provision, a customer will be able to withdraw up to the full amount of gas under the withdrawal tier so long as the customer has that amount of gas in storage. The premium for this service would be determined through an open season.

h. Other Provisions

The purpose of the other provision is to permit the Company to store its own gas and in the space contracted for by the customer in the event that the customer does not use all of the storage space. This provision is necessary to permit the Company to offer higher deliverability and to maintain system reliability. This provision provides further that Company use of storage space does not reduce the flexibility of the customer to inject or withdraw from storage gas owned by the customer.

i. Minimum Term of Contract

The minimum term of contract is one year. The Company reserves the right to require a longer-term contract where it must acquire additional contracts with 3rd parties, construct facilities, or make new capital investment in existing facilities to provide the requested service.

ENBRIDGE GAS DISTRIBUTION

PROPOSED TARIFFS FOR POWER GENERATION CUSTOMERS

Rate 316 – High Deliverability Gas Storage Service (Customer Arranged Transport)

1. Availability:

This rate requires a Service Contract that identifies the required storage space and deliverability tier. In addition, the customer must arrange for pipeline delivery service from Dawn to the Primary Delivery Area of the customer where the customer is served by Enbridge Gas Distribution, otherwise, the customer must provide delivery to the customer's preferred location. This service is not a delivered service and is only available when the relevant pipeline confirms the delivery.

A daily nomination for storage injection and withdrawal shall also be required.

The maximum hourly injections / withdrawals shall equal $1/24^{th}$ of the daily Storage Demand.

Customer contracts for a combination of storage space and deliverability. The deliverability tiers available represent the maximum withdrawal rate from the contract storage capacity. Tier One service permits a maximum daily withdrawal of 1.2%. Tier Two service permits a maximum daily withdrawal of 5%. Tier Three service permits a maximum daily withdrawal of 10%. All such withdrawals are subject to storage ratchets based on the actual quantity of gas in the customer storage account. Customer may also contract for un-ratcheted deliverability service where the Company permits maximum daily withdrawal on a year round basis provided the gas is available in the customer's storage.

2. Character of Service:

Service shall be firm when used in conjunction with firm transportation service. Service is interruptible when used in conjunction with interruptible upstream transportation service. All service is subject to contract terms and force majeure.

The service is nominated daily based on the available capacity and gas in storage up to the maximum contracted daily deliverability.

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3. **Monthly Customer Charge:** TBD (Note: This charge will reflect unbundled rate implementation costs.)

4. **Storage Reservation Charge** that is made up of:

    1. Storage Space Demand Charge: TBD (Minimum Charge: 0.0388 c/m^3 (based on Rate 330 as per Jan. 01, 2006 QRAM)

    2. Tiered Storage Deliverability/Injection Demand Charge:
       Tier 1 (1.2% Deliverability): TBD (Minimum Charge: 3.5502 c/m^3 (based on R330 as per Jan. 01, 2006 QRAM)
       Tier 2 (5% Deliverability): TBD
       Tier 3 (10% Deliverability): TBD

    3. Injection & Withdrawal Unit Charge: TBD (Minimum Charge: 0.3287 c/m^3 (based on R330 as per Jan. 01, 2006 QRAM)

    4. Fuel Ratio: TBD

All Storage Space and Deliverability/Injection Demand Charges are applicable monthly. Injection and withdrawal charges are applicable to each unit of gas injected or withdrawn based on daily nominations.

In addition, for each unit of injection or withdrawal there will be an applicable fuel charge adjustment expressed as a percent of gas.

5. **Monthly Minimum Bill**: The sum of the Monthly Customer Charge plus Monthly Demand Charges.

6. **Nominated Storage Service**:

The customer may elect to nominate all or a portion of the available withdrawal capacity for delivery to Dawn. Customers may transfer the title of gas in storage.

The Company reserves the right to limit injection and withdrawal rights based on storage system operating requirements.

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7. Un-ratcheted Deliverability Service

This service permits the customer to withdraw gas from storage on any day equal to the contract Tier withdrawal rate provided that the customer has at least the withdrawal amount in storage. Un-ratcheted withdrawal service is subject to an additional annual charge.

8. Other provisions:

If the customer elects to use the contracted storage capacity at less than the full volumetric capacity of the storage, the Company may inject its gas provided that such injection does not reduce the right of the customer to withdraw the full amount of gas injected on any day during the withdrawal season or to schedule its full injection right during the injection season.

9. Term of Contract:

A minimum of one year.

A longer-term contract may be required if incremental contracts/assets/facilities have been procured/built for the customer.

ADDITIONAL SERVICE OFFERINGS

1. The proposed rates set out in the previous sections address many of the services requested by power generation customers, as well as some of the services listed in Appendix A to Procedural Order No.2 in this proceeding.

2. This section addresses the remaining services listed in Appendix A to Procedural Order No.2. These services could be accessed by customers in conjunction with the services included in the proposed rates already discussed.

Inter-Franchise Movement of Gas

3. Inter-franchise movement of gas is the ability for direct purchase customers to transfer gas that they have delivered to one utility to another utility in a seamless manner. While all direct purchase customers have the ability to effectively transfer gas between franchise areas today using market services, there can be some challenges and limitations in the manner in which these types of transactions are conducted.

4. Enbridge Gas Distribution proposes that an Enhanced Title Transfer ("ETT") service be introduced to the suite of balancing services made available by Enbridge Gas Distribution. The availability of this service would be dependent on a comparable service offering being made available by the utility whose franchise area the customer wants to transfer the gas too. For existing bundled customers, the existing balancing services include the ability to "make-up" a shortfall in deliveries to a franchise area or dispose of excess deliveries through a "suspension" of deliveries. They can also title transfer gas within Enbridge Gas Distribution's franchise areas.

5. The proposed ETT service would provide a mechanism that could be used by all direct purchase shippers, both bundled and unbundled, to have the Company and other distributors in Ontario facilitate the inter-franchise movement of gas without having to acquire other services in the marketplace. Given the differences between the balancing requirements for bundled and unbundled customers, differences should exist in the ETT services based on the type of direct purchase customer.

6. Enbridge Gas Distribution proposes that the ETT transactions be executed at Dawn. Given the degree of liquidity at Dawn and its role within Union's system, the Company believes that this common point best facilitates the transfer of gas between utilities. Enbridge Gas Distribution and the other utility would have to determine the most appropriate method for the physical settlement of gas associate with these transactions. This settlement may have to occur at the time the transaction is executed, or it may be reasonable to settle the cumulative outcome of inter-franchise title transfers between the two utilities on a periodic basis.

7. Due to the fact that the title transfers will be exchanging gas at a point that differs from the delivery area specified within the direct purchase customer's contract, some form of charge for the ETT service needs to apply. The charge would serve two purposes; first to ensure that other ratepayers are not harmed by Enbridge Gas Distribution facilitating this transaction; and second to ensure there is no incentive for direct purchase customers to contract inappropriately.

8. The ability to freely move gas between two areas where there would otherwise be a market cost could lead parties to re-evaluate their contracted deliveries to one

franchise or another. If there is an economic benefit to under-delivering to one franchise while over-delivering to another, there is a strong incentive for the direct purchase customer, or their agent, to err on their deliveries in the direction to which there is the most benefit. It is important that the costs associated with the ETT service be structured in such a way that it does not incent this form of behaviour and that appropriate contracting and deliveries are made.

9. For direct purchase customers who are using a bundled service, the potential benefits associated with the ETT service would be dependent on the direction in which the gas is flowing. If the customer is over-delivered in the Enbridge Gas Distribution franchise area and is title transferring the gas to another utility, the customer has in effect used Enbridge Gas Distribution's storage for the purpose of delivering gas outside of Enbridge Gas Distribution's franchise area. If the customer is under-delivered to the Enbridge Gas Distribution franchise and is title transferring gas from another utility at Dawn, the customer has the opportunity to avoid the cost of transporting gas between Dawn and the Enbridge Gas Distribution delivery areas. Under each of these scenarios, the actual benefit the direct purchase customer may receive is difficult to determine, however, some form of charge is required to help ensure that appropriate contracting and deliveries are made with and to Enbridge Gas Distribution.

10. Enbridge Gas Distribution proposes that the charge for the ETT service would be based on the difference between the TCPL Southwest Zone and Eastern Zone tolls in place at the time of the transaction. This charge acts as a proxy for the costs that a customer would otherwise have had to incur to move the gas from Dawn to the Enbridge Gas Distribution delivery area in the case where they were under-delivered and recognizes the benefit a customer that has over-delivered may have

received from the Enbridge Gas Distribution storage. Since it is difficult to truly determine the value of this storage, the Company is proposing a charge that it believes encourages the appropriate behaviour, while also being easy to administer and simple for customers to understand. In addition to these volume-based charges, there would also be an administrative charge for using the service. The amount of this administrative charge should be determined in the course of an Enbridge Gas Distribution rate case.

11. For direct purchase customers who are using an unbundled service, there would strictly be the administrative fee associated with the ETT service. Given that unbundled customers are subjected to charges for an imbalance between deliveries and consumption, the potential costs associated with having to facilitate the inter-franchise title transfer would be recovered through these charges. Also, since imbalances must be settled in a short time-frame, there is little incentive for such customers to contract and deliver gas inappropriately.

12. The availability of ETT for direct purchase customers who are using a bundled service would have to take into consideration the implications to Enbridge Gas Distribution's supply portfolio. Given that the exchange of gas is proposed to occur at Dawn, the ETT service may impact Enbridge Gas Distribution's storage balances and deliverability. As a result, there may be periods where ETT service may not be available due to operational constraints. During the winter months, Enbridge Gas Distribution relies on gas from storage to meet the overall demands of its customers. Accepting ETT transactions that would negatively impact Enbridge Gas Distribution's storage balances or deliverability in relation to its supply plan would not be in the best interest of all customers. Similarly, accepting ETT transactions during the injection season may negatively impact the Company's ability to manage

the use of its firm transportation contracts at the high load factors at which they typically operate. As a result, there may be periods in time where the availability of the ETT service would be constrained, similar to limitations that exist today on the availability of "make-up" and "suspensions" for balancing.

13. Similar limitations would not be in place for direct purchase customers who are using unbundled services. Given that the imbalances and subsequent balancing transactions for these customers occur within a very short period of time, Enbridge Gas Distribution does not see the same implications that exist for customers using bundled services. While bundled service customers can have an imbalance occur in one season and then balance this in a different season, the imbalances that an unbundled customer may have will be balanced within the same month. This prevents seasonal inequities on the storage services from occurring for these ETT transactions. As a result, the Company does not foresee the need for any balancing limitations for unbundled service customers at this time.

14. The types of transactions being used to support the ETT service are those that are typically supported through the provision of Transactional Services ("TS"). These TS transactions would be similar to the market services available today that were discussed earlier in this evidence. As a result, the Company proposes that any non-administration charge revenue arising from the ETT service should be recorded as TS revenue. Some incremental resource and/or system changes will be required to support the processing of ETT transactions. The Company proposes that the administration charges would include the recovery of these costs and that the revenue generated from them would be recorded as other revenue. At this time it is

not possible to project the level of interest or activity that counterparties may have for the ETT service, which makes projecting both costs and revenues difficult.

15. Enbridge Gas Distribution expects that it would be able to implement the ETT service in a relatively short time frame following approval of the service by the Board. The initial implementation would have to rely on a manual process that would be put in place until such time as a more automated process could be implemented in EnTRAC. The Company does not anticipate that such a manual process could be sustained over the longer term. The extent of changes required to have EnTRAC support the ETT service is not known at this time. Once identified, however, these changes would have to be coordinated with other initiatives (e.g., GDAR implementation) that are already in progress and have specific delivery timeframes that cannot be compromised.

Redirection of Gas

16. The redirection of gas requires the use of upstream transportation services. Enbridge Gas Distribution, as a distribution utility, accepts gas at its gate stations for use within its distribution system. The Company and direct purchase customers must nominate gas with an upstream transportation service provider to move the gas to the delivery areas within the utility's franchise areas. There are currently upstream transportation services and market services that a direct purchase customer can use to effect a redirection of gas. These services are the same services that would be available to a utility. As such, Enbridge Gas Distribution does not see there being any benefit for the utility to establish a service that purely relies on services that participants in the marketplace can already avail themselves to. Any involvement by the utility would only add incremental administration costs to these services.

17. Given that the services are already available in the marketplace, Enbridge Gas Distribution does not foresee any operational implications or barriers in providing these services. Using the market services will not lead to any incremental costs or revenues for the utility, therefore there would be no rate implications to any existing or new customer group.

Title Transfer for Gas in Storage

18. In considering these title transfers for gas in storage, it is important to recognize that not all gas in storage is equal. While the physical molecules may be indistinguishable, the nature of the storage services that customers have contracted for will differ. These differences in contractual service parameters affect the value and cost of the storage services and the manner in which storage capacity has to be managed to meet the contractual commitments. It is critical that these differences be considered when contemplating whether the title transfer of gas in storage between parties is strictly an administrative matter, or if there are real cost implications and/or arbitrage opportunities created by an inappropriate mechanism.

19. When considering title transfers, it must also be recognized that not all storage reservoirs have the same level of deliverability. Some will operate at or below the system average, while others will have much higher deliverability. Enbridge Gas Distribution uses number of storage assets that include the Tecumseh storage facility, Chatham “D”, Crowland, and services that are currently contracted with Union at their Dawn facility. These assets have differing levels of deliverability. The higher deliverability reservoirs, which are located at Tecumseh and Crowland, will have to be used to backstop the high deliverability services. Similarly, the lower deliverability reservoirs will be used to backstop the lower deliverability services.

20. Enbridge Gas Distribution has to maintain its storage balances in different pools depending on the injection and delivery capability from the pool and the total injection and delivery requirements to which the Company is committed. The transfer of gas from one storage contract to another that has different injection or delivery requirement will change the overall commitment for Enbridge Gas Distribution and as a result the Company may have to move gas accordingly to meet the changed commitment.

21. Enbridge Gas Distribution believes that the most appropriate manner to address these issues is to differentiate between the manner in which the title transfers are conducted between contracts that have different contractual service parameters and those with identical service parameters. The contract service parameters which would be called in to question include the service level (e.g., 1.2%, 5%, or 10%), whether it is a ratcheted or unratcheted service, and whether the service is firm or interruptible. In all cases, these title transfers can only be provided on a firm basis at a flow rate that is equal to that of the more restrictive service level or contract of either of the parties involved. The transfer of title at flow rates above this may be done on a discretionary basis if operational conditions allow.

Contracts with Different Service Parameters

22. Enbridge Gas Distribution proposes that all title transfers between contracts that have different contractual service parameters or conditions take place above ground at Dawn. This would mean that one party would have to nominate to withdraw the gas and the other party would have to nominate to inject the gas. The Company believes that this is the most appropriate means of addressing these title transfers

due to the likely need for the physical movement of gas and differing values between different services.

23. The title transfer of gas in storage between contracts with different sets of service parameters or contract conditions will usually require the physical movement of gas. This movement of gas will be necessary so that the storage operator can maintain the contractually required injection or deliverability levels for both parties involved in the transfer. The parties would only be able to transfer gas on a firm basis at a flow rate determined by the contractual arrangements of the customer with the more restrictive contractual arrangements. This flow rate restriction is necessary due to the need to transfer the gas from one pool to another. Any transfers above these contractual arrangements would only be provided on a discretionary basis.

24. The following is an example to illustrate why this type of transaction must occur above ground at Dawn and why a physical movement of gas would be required: Assume that:

- Customer A has 1,000 units of contracted capacity with a 1.2% level of service and 1,000 units in storage.
- Customer B has 1,000 units of contracted capacity with a 10% level of service and 0 units in storage.
- Customer A wants to transfer 200 units of gas to Customer B.
- If this transfer were allowed to occur all in one block, then Customer B would immediately be entitled to two days of withdrawal up to their 100 unit per day limit. However, operationally the storage operator may only be able to withdraw 12 units per day depending on current storage balances and where the gas to serve Customer A was stored. It would be impossible for the operator to

guarantee the 100 unit per day level of service. In order to meet the contract obligations of Customer B, the gas will have to be moved from a low deliverability reservoir to a higher deliverability one. Gas that is moved from one reservoir to another has to occur above ground and would have to be nominated as being a withdrawal to Dawn by Customer A and as an injection from Dawn by Customer B.

- In addition, the transfer of gas in this example cannot take place in one 200 unit block. It can only occur on a firm basis at a flow rate of 12 units per day. Specific operational conditions may exist where a flow rate greater than 12 units can be authorized as an authorized overrun, but this would only be on a discretionary basis.

25. The charges associated with these title transfers between contracts with different contractual service parameters or conditions would include a withdrawal charge, injection charge, and an administrative fee.

Contracts with Identical Service Parameters

26. The title transfer of gas between contracts with identical service parameters will be able to occur underground in storage. If the contract service parameters (which as mentioned above include withdrawal and injection amounts, ratchet provisions, firm vs. interruptible) are the same, then there should not be a need to physically move gas from one reservoir to another and therefore no injection or withdrawal charges would apply. There would only be an administrative cost associated with these types of transactions.

27. Similar to transfers between contracts with different service parameters, the flow rate of transfer on a firm basis must abide by the lower flow rate of the two parties'

injection or withdrawal rate. This flow rate would be the absolute flow rate of gas, rather than the percentage level of service. There can be discretionary or authorized transfers above that firm flow rate when operational conditions will allow.

Conclusions

28. In all cases, title transfers will only occur at a firm flow rate equal to that of the more restrictive service level of either of the parties involved. Discretionary amounts may be allowed above that base amount if operational conditions would allow.

29. Title transfers between contracts with identical service parameters or conditions should be able to occur underground in storage. The charges involved in these transfers would be only an administrative fee for managing the contracts.

30. Title transfers between contracts with different service parameters or conditions will take place above ground at Dawn because the likelihood is high that such transfers will necessitate the physical movement of gas. Hence the charges involved would include an injection fee, a withdrawal fee, and an administrative fee.