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December 14, 2016

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms. Walli:

RE: EB-2016-0186 – Written Submissions of London Property Management Association

Please find attached LPMA's written submissions with respect to the above noted proceeding.

Sincerely,

Randy Aiken

Randy Aiken
Aiken & Associates
Encl.

cc: Karen Hockin, Union Gas Limited (e-mail)
Intervenors (e-mail)

EB-2016-0186

Union Gas Limited

Application for approval to construct a natural gas pipeline in the Township of Dawn Euphemia, the Township of St. Clair and the Municipality of Chatham-Kent and approval to recover the cost of the pipeline.

SUBMISSIONS
OF
LONDON PROPERTY MANAGEMENT ASSOCIATION

A. INTRODUCTION

Union Gas Limited ("Union") filed an application with the Ontario Energy Board ("OEB" or "Board") on June 10, 2016 for:

1. Leave to construct 40 kilometres of 36 inch diameter pipeline from Union's Dawn Compressor Station in the Township of Dawn-Euphemia to its Dover Transmission Station in the Municipality of Chatham-Kent ("the Project") pursuant to section 90 of the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Schedule B ("Act"),

2. Approval of the recovery of costs associated with the construction of the Project pursuant to section 36 of the Act,

3. Approval to calculate the Project's revenue requirement and resulting rates based on a 20 year depreciation term, and

4. Approval of an accounting order to establish a Panhandle Reinforcement Deferral Account pursuant to section 36 of the Act.

An oral hearing was held in Toronto on November 22 and 23, 2016 during which all issues were heard, with the exception of the landowner issues. The landowner issues, which are found in the OEB Decision on Issues List dated August 24, related to issues 6, 7, 8, 9 and 12. The oral hearing covered issues 1, 2, 3, 4, 5, 10, 11 and 12.

The following are the submissions of the London Property Management Association ("LPMA") on some of the issues covered at the oral hearing. LPMA is not making any submissions with respect to the landowner issues or on the issues related to the environmental guidelines, consultation with indigenous communities or the appropriate conditions.

B. SUBMISSIONS ON ISSUES

1. Are the proposed facilities needed?

LPMA submits that there is a need for the facilities. Moreover, LPMA further submits that the need is for the 2017/2018 winter, as forecast by Union.

As shown in Table 5-1 in Exhibit A, Tab 5, the Union Panhandle system is at capacity for the winter of 2016/2017. This is the result of the increase in capacity that resulted from the Leamington Expansion projects and the increase in system demand for firm service that was taking place in virtually all of the rate classes shown in Table 5-1.

The project proposed by Union would increase the design day capacity of the Panhandle System from the current 565 TJ/day to 671 TJ/day. Based on the forecast provided in Table 5-1, this capacity is forecast to be used up in five years.

LPMA submits that there is no evidence on the record in this proceeding to refute the growth forecasts of Union over this five year period. As a result, LPMA submits that the Board should accept the need for this project.

The question then arises that even if the facilities are needed, can they project be deferred for a year or two? LPMA submits that based on the evidence in this proceeding, the answer to this question is an emphatic no.

As shown in Table 5-1, the system demand is forecast to increase by 106 TJ/day between the winter of 2016/2017 and 2021/2022. More than one-half of this increase, or 58 TJ/day is forecast to take place in the in the first year. These increases, and the geographic areas where they are coming from is shown in the response to a BOMA interrogatory in Exhibit B.BOMA.3 (d). The increase is coming mainly from the Leamington/Kingsville and Windsor areas, but there are also increases forecast for Chatham-Kent, Tecumseh and Lakeshore.

Similarly, the majority of the 58 TJ/day increase in the first year is coming from customers that want to firm up interruptible service. This accounts for approximately 46

TJ/day (Tr. Vol. 1, page 53, lines 6-13). This interruptible to firm service was not only in the Leamington/Kingsville area, but also in Windsor and was not confined to the greenhouse industry (Tr. Vol. 1, page 53, lines 14-23).

Union has indicated that it already has about 38 TJ/day of the 58 TJ/day increase forecast for the 2017/2017 winter design day from committed customers where the contracting process is starting (Tr. Vol. 1, page 52). In addition to this committed volume, Union also indicated that there was another 13 TJ/day where they had a strong level of confidence that a large portion would be proceeding (Tr. Vol. 1, page 63).

LPMA submits that even if the customers who have requested or expressed an interest in firming up some or all of their interruptible service could be convinced to wait for another year or two, there is still additional demand from general service customers, including residential and commercial customers, as well as demand from new contract customers that total 12 TJ/day in the first year.

Union's evidence is clear that it cannot add any new customers to the system without expanding the capacity on the Panhandle system. This was emphasized in the following response to a question about the implications of a two or three year deferral in the project (Tr. Vol. 1, page 40):

> *MR. ISHERWOOD: So a delay in the project beyond November 1, 2017, in service would mean we cannot firm up the customers that we have been talking about at Leamington. We cannot firm up the customers in Windsor.* ***We can't attach any new customers in anywhere in the Panhandle system. We can't attach residential, commercial.***
>
> *So it is not a matter of delay of two years, three years.* ***If we delay past November 1st, we just physically are out of capacity. So it would mean no firming up. It would mean no new customers.*** (emphasis added)

When asked if without the transmission reinforcement or some other alternative with similar impacts on design day capacity it was Union's position was that it could not do any more distribution system expansion or connections on the Panhandle system, Mr. Isherwood replied that was correct as of November 1, 2017 and that this was supported by Union's actions in 2016 where it has denied requests that have been received to go from interruptible to firm service (Tr. Vol. 1, page 54).

LPMA submits that asking customers to defer switching from interruptible service to firm service is not a reasonable approach. Nor is it reasonable to deny service to new residential and commercial customers.

LPMA submits that the need is real and immediate and the project should be approved by the Board.

LPMA submits that the Board should give Union direction with respect to any further facilities to serve growth forecast beyond 2021/2022 winter shown in Table 5-1 in Exhibit A, Tab 5. In particular, Union has indicated it expects further design day requirements through to the 2034 period, as shown in Table 5-2 of the same exhibit. This forecasted growth is 99TJ/day between 2022 and 2034. In other words, the forecast is for less growth (99 TJ/day versus 106 TJ/day) over a longer period (13 years versus 5 years). This growth in the design day is, on average, about 7.5 TJ/day per year over the 2022 to 2034 period, a stark contrast to the 58TJ/day increase in 2017, and 10 to 15 TJ/day in 2018 to 2021.

While LPMA agrees with Union that brining in additional gas through Ojibway is not preferable or feasible at this time, LPMA submits that the Board should ensure that Union continues to evaluate this option going forward beyond 2021. With slower increases forecast in design day needs beyond 2021 and with a significant lead time in order to fully evaluate options other than more facilities in the ground and more assets in rate base, LPMA submits that Union should be directed to fully investigate other alternatives well in advance of the 2021 timeframe and to report back on those alternatives to all interested parties before bringing forward any facilities application. These alternatives should include, but not be limited to, increasing Ojibway firm obligated deliveries and DSM related programs that could reduce design day demand or shift load from design day to off peak days, with a special emphasis on the greenhouse/agricultural sector.

2. Do the proposed facilities meet the OEB's economic tests as outlined in the Filing Guidelines on the Economic Tests for Transmission Pipeline Applications, dated February 21, 2013, as applicable?

LPMA submits that the proposed facilities do meet the OEB's economic tests as outline in the Filing Guidelines on the Economic Tests for Transmission Pipeline Applications, dated February 21, 2013.

Union's evidence on this is found in Exhibit A, Tab 7. The three-stage analysis employed by Union is consistent with the OEB recommendations from the E.B.O. 134 Report on System Expansions and is consistent with the methodology used by Union in past Dawn to Parkway system facility expansions.

The Stage 1 analysis is a discounted cash flow ("DCF") analysis that is specific to Union. For this project the net present value of the project has a profitability index of less than 1.0. The net present value has been calculated to be -$212 million over a 20 year period (Table 7-1).

Since the Stage 1 analysis has a profitability index of less than 1.0, Union completed a Stage 2 benefit/cost analysis that quantifies benefits and costs to Union's customers as a result of the project. Union estimated the energy cost savings that will accrue to their in-franchise customers as a result of using natural gas instead of another fuel to meet their energy requirements. The calculated net present value of these benefits is approximately $805 million.

While LPMA may not agree with all of the assumptions used to calculate the net present value of the benefits – which are shown in Exhibit A, Tab 7, Schedule 5 – LPMA submits that the cost savings for customers under any reasonable set of assumptions, will still be well in excess of the $212 million shortfall in the Stage 1 analysis.

Union also undertook a Stage 3 analysis that deals with other public interest considerations such as employment, utility taxes, employer health taxes and environmental benefits. Union calculated these benefits to be approximately $296 million (Exhibit A, Tab 7, pages 6-9). Again, while LPMA believes that this figure may be high, it is most likely at least equal to or greater than the Stage 1 analysis shortfall of $212 under any reasonable assumptions.

In summary, LPMA submits that the proposed facilities meet the OEB's economic tests as outlined in the Filing Guidelines on the Economic Tests for Transmission Pipeline Applications under any reasonable set of assumptions.

3. What are the potential short-term and long-term rate impacts to customers? Are these costs and rate impacts to customers appropriate?

The Board is being asked to determine if the cost and rate impacts to customers that result from not only the costs associated with the project, but also associated with changes to the cost allocation methodology and the depreciation period associated with this project, are appropriate.

LPMA submits that in order to determine this, the impact of each of the three components of the increase need to be known.

As shown in the response to an LPMA interrogatory, the delivery rate impact on some rate classes is significant. In Exhibit B.LPMA.24, Attachment 1, the delivery rate impacts are shown for all rate classes of Union's proposal, which includes the cost of the project, the depreciation rate change and the cost allocation change. The range of impacts is quite wide, ranging from a decrease of 0.6% to an increase of 26.7%.

LPMA members are served under several different rates, notably M1, M2 and M4. As shown in the response to the above noted interrogatory, the delivery rate impact for an M1 customer is 2.3% or more than $8 per year. For an M2 customer, the increase is 6.2% to 7.7%, or between $205 and $820 per year. For an M4 customer, the increase is 24.3% to 26.7%, or about $9,000 for a small M4 customer to more than $74,000 for a large M4 customer. No matter how you look at it, these increases are significant.

a) No Change to Cost Allocation or Depreciation

The response to the undertaking provided in Attachment 1 of Exhibit J1.2 shows the corresponding increases for all rate classes that are solely attributable to the project costs. That is, there is no change in either the depreciation rates or the cost allocation methodology from the Board approved rates and methodology from Union's last cost of service rebasing application.

There is still a very wide range of delivery rate impacts, ranging from a decrease of 1.4% to an increase of 27.7%. However, the impact on the different rate classes is significant. As an example, the increase in the M1 rate class is only 0.6% or $1.93 per year, less than 25% of the increase under the Union proposal. The M2 rate increase is 2.0% to 2.6%, or $66 to $274 a year, roughly 33% of the Union proposal. Similarly, the M4 rate increase is 5.2% to 5.8%, or $1,960 to $15,990 for small and large M4 customers, respectively. These increases are only about 20% of those under the Union proposal.

Given the significant difference in the rate impacts of different rate classes, LPMA submits that the Board should only approve the depreciation rate change and/or the cost allocation methodology change if they are reasonable on their own.

b) Depreciation Change

Union is proposing to shorten the depreciation period from around 50 years to 20 years for the non-land capital costs associated with the Panhandle project. This adds about $3.5 million to the depreciation expense in 2017 and $7.4 million in 2018 (Exhibit J1.3).

Union indicates in their evidence (Exhibit A, Tab 3, page 7) that the uncertainty created by Ontario's Cap and Trade program and the Climate Change Action Plan ("CCAP") has driven the need for it to calculate the revenue requirement and resulting rate impacts based on an estimated 20 year useful life of the project. This 20 year useful life better aligns the cost, according to Union, with the timing of the reported restrictions and potential elimination of natural gas heating in homes and businesses in the CCAP.

In Exhibit B.LPMA.17, Attachment 1, Updated Union calculated the net present value of the at the end of each 10, 20, 30, 40 and 50 years of the revenue requirement based on the current Board approved depreciation rates and that proposed by Union as part of this application. In that response, Union showed both the net present value of the revenue requirement and the remaining undepreciated rate base under both of the depreciation scenarios.

Under the assumption that ratepayers would have to pay for any undepreciated assets remaining in rate base when they are no longer used or useful, ratepayers would be better off under Union's proposed 20 year depreciation rate than then current Board approved depreciation rate in the short term, but worse off in the long term. This can be seen by adding lines 1 and 3 in the updated Attachment 1 to Exhibit B.LPMA.17 and comparing that figure to the sum of lines 2 and 4. At the end of 10 years the sum of the net present value of the revenue requirement and the undepreciated rate base is \$308 million under Union's proposal, while \$325 million under the status quo. In other words, Union's proposal for a shorter depreciation period costs ratepayers less. This is true for the net present values and undepreciated rate base at the end of 20, 30 and 40 years. However, at the end of the 50 year period (the normal depreciation life), the cost to ratepayers of Union's proposal is \$250 million while that of the status quo approach is \$235 million. Ratepayers would be worse off under Union's proposal.

If the undepreciated rate base is ignored and it is not recovered from ratepayers, then ratepayers would be worse off over all periods under Union's proposal. This is illustrated by the fact that line 1 in Attachment 1 is always higher than line 2.

However, as noted in the response to Exhibit J2.2, the discount rate used in the analysis was Union's pre-tax weighted average cost of capital of 6.93%. LPMA agrees that this discount rate is appropriate from the perspective of Union as the utility. However, LPMA submits that it is not an appropriate discount rate from the perspective of the customer.

Union has used a social discount rate of 3.0% in the response to Exhibit J2.2. LPMA submits that this is a more appropriate discount rate from the perspective of ratepayers, including LPMA members. The 3.0% is close to the current rate for fixed mortgages of terms 1 to 5 years. This is the relevant rate for LPMA members.

In Attachment 1 to Exhibit J2.2, Union has included lines 5 and 6 that add the net present value of the revenue requirement and the undepreciated rate base at the end of the same time periods as in Exhibit B.LPMA.17. This shows that the cost to ratepayers is lower under Union's proposal for all the periods shown. For example, at the end of 10 years, Union's proposal results in ratepayer costs of $351 million as compared to $355 million under the status quo depreciation rates. This ratepayer benefit of $4 million increases to $62 million at the end of 20 years and to $66 million by the end of 50 years. Assuming the costs of any stranded assets are recovered from ratepayers, which is highly likely, Union's proposal is not only better for ratepayers in the short-term but also better for them in the long-term.

Under the scenario where ratepayers do not assume the cost of the undepreciated assets, Union's proposal has a higher cost to ratepayers through about 30 years, but beyond that length of time, Union's proposal results in lower net present values of the revenue requirement than the status quo. At the end of 50 years, the cost to ratepayers of Union's proposal is $341 million, compared to $396 million under the status quo. These figures are shown on lines 1 and 2 of Attachment 1 to Exhibit J2.2. Ratepayers would be worse off in the short-term, but better off in the long-term.

Given that the net present value of the costs to ratepayers of Union's proposal to use a 20 year depreciation period are less than that under the status quo Board approved depreciation rate, LPMA supports the use of the shorter depreciation period.

The savings to customers are the result of lower returns over the life of the asset. As shown on lines 1(a), 1(b), 1(c), 2(a), 2(b) and 2(c) in Attachment 1 to Exhibit J2.2, the net present value of the depreciation expense is about $60 million higher for ratepayers under Union's proposal. However, this is more than offset by a net present value of the return that is about $110 million lower under Union's proposal. LPMA further notes that the depreciation difference is essentially fixed, while the return component benefit to ratepayers is probably understated because it is based on current low rates of debt and return on equity that are not likely to persist for the next 50 years. Said differently, if the cost of capital increases from the historically low levels that exist today, the accelerated depreciation of the rate base under the Union proposal would save ratepayers more money from that shown in the attachment.

LPMA submits that the Board should approve the shorter depreciation period for the costs associated with this project because they reduce the risk to Union that has resulted from the Cap and Trade program and from the CCAP, while at the same time reducing the total overall net present costs to ratepayers. This is a win – win situation.

c) Cost Allocation Change

The cost allocation change proposed by Union has a bigger impact on the rate impacts than that of the depreciation change. This can be seen in the response in Exhibit B.LPMA.24, Attachment 1 and Exhibit J1.2.

As shown in these attachments, the increase for an M1 residential customer of the project alone (i.e. no change to depreciation rate or to cost allocation methodology) is $1.93 (Exhibit J1.2, Attachment 1). With no change to the cost allocation methodology, but using the proposed 20 year depreciation rate the impact on the M1 residential customer is $3.79 (Exhibit B.LPMA.24, Attachment 1, page 2 of 4), an increase of $1.86. With no change to the depreciation rate, but using the proposed cost allocation the impact on the M1 residential customer is $5.15 (Exhibit B.LPMA.24, Attachment 1, page 3 of 4), an increase of $3.22.

Union provides its rationale for the proposed change in the cost allocation methodology in Attachment 2 to Exhibit J1.2.

As LPMA understands the cost allocation issue and the proposed change, Union's last cost of service proceeding used a joint allocator of the Panhandle system design day demands and the St. Clair system design day demands. It appears that this was done for simplicity purposes, even though the customer mix in terms of design day demands is significantly different between the two systems. This is illustrated in the table on page 3 of 4 in Attachment 2 to Exhibit J1.2. By way of examples, Raye M1 represents only 7% of the design day demand on the St. Clair system as compared to 40% on the Panhandle system, while Rate T2 represents 82% of the design day demand on the St. Clair system as compared to only 23% on the Panhandle system. The use of the joint allocator was made possible by the fact that both systems are significantly depreciated and represent small amounts of transmission related rate base. In the EB-2011-0210 rebasing application the remaining rate base associated with these two systems was about $28 million.

Union argues that given the significant increase in rate base of about $260 million and the fact that all of this is for the Panhandle system, it is no longer appropriate to use the joint allocator for both systems to allocate the costs for this one system.

LPMA agrees that each transmission system should be allocated based on its design day demand customer mix if the mix of customers is significantly different in each system and the costs are significantly different for each system. For example, it would make no sense to allocate the Panhandle system costs based on the design day demands of the Dawn to Parkway system or some joint allocator of the Panhandle system and the Dawn to Parkway system. The costs are significantly different and the mix of customers served are significantly different from one system to the other. In a similar fashion, LPMA submits that it makes no sense to continue to use the joint allocator that includes the St. Clair system. The costs are now significantly different and the evidence shows that the mix of customers is also significantly different on these two systems.

Having agreed that a separate allocator for the Panhandle system is appropriate and justified, the question for LPMA is whether or not this proposed change is reasonable and justified under the current IRM regime, especially given that the impact is really only for one full year, 2018. Union will rebase for 2019 rates, and the impact in 2017 is small given the in-service date of November 1, 2017.

If this was the only cost allocation change that was likely to take place at the rebasing application, then the change now might be justified. However, at this time, the magnitude of any proposed cost allocation changes at rebasing are not known.

What is known, however, is that Union also has an "Other Transmission" allocator in its cost allocation model. In the last rebasing application the assets allocated using this allocator were approximately $225 million, close to the costs for the Panhandle system. Union explained that this allocator was used for all the transmission lines in Union South, excluding the Panhandle system, St. Clair system and Dawn to Parkway system. Union also confirmed that were at least two other lines that would be included under this common allocator – the Dominion line and the Owen Sound line (Tr. Vol. 1, page 123).

As part of the rebasing application, LPMA would expect that Union would investigate the decoupling of these two transmission lines (and perhaps others that use the same allocator) in the same way that Union proposes to decouple the Panhandle and St. Clair system allocator into two to more accurately reflect the costs and mix of customers.

In addition, Union may bring forward other changes to the cost allocation model beyond the allocators for the transmission systems included in rate base. There may be changes to allocators that impact OM&A for example, or distribution rate base, or storage rate base.

The question that arises is whether or not the Board should accept a piecemeal change in the design day demand for some transmission systems, or wait until Union does a complete review of its transmission allocators for other systems such as the Dominion and Owen Sound lines and all other allocators used in the cost allocation model.

While LPMA believes that the Union proposal results in a more reasonable allocation of the Panhandle system costs, implementation of the proposed change now would result in increased costs allocated to some rate classes and decreased costs allocated to other rate classes and then in the rebasing application do the exact opposite. In effect by implementing only one allocation change at this time could result in rate instability for all rate classes when all other allocators are reviewed.

Cost allocation is a zero sum exercise. LPMA is concerned that changing only one aspect of the methodology could result in an allocation of costs that is biased because it is not based on a comprehensive review of all cost allocation methodologies.

LPMA recommends that the Board reject the proposed cost allocation changes until they can be dealt with as part of a comprehensive review of all cost allocation methodologies as part of the next rebasing application. LPMA further notes that this delay in the change in the allocation would only affect one full year of costs (2018) before Union rebases for 2019 rates. The impact on costs in 2017 is minimal given the projected in-service date late in 2017.

4. What are the facilities and non-facilities alternatives to the proposed facilities? Have these alternatives been adequately assessed and are any preferable to the proposed facilities, in whole or in part?

Based on Union's evidence and the issues raised throughout the proceeding, only two potential alternatives to Union's proposed project have been brought forward. The first of these alternatives is a NPS 30 pipeline from Dawn and the second is incremental deliveries at Ojibway, combined with incremental pipeline, station and compressor facilities.

a) 30 NPS Pipeline from Dawn

Union's evidence indicates that the capital costs for the NPS 30 pipeline alternative is virtually identical to its proposed project (Exhibit A, Tab 6, Schedule 1). The main difference between this alternative and the Union proposal is that instead of a 36 inch pipeline replacing the existing 16 inch line, a 30 inch line would be installed and the existing 16 inch line would remain in service. Union's proposal has higher capital costs associated with materials, labour and pipeline removal costs, but lower costs associated with land/land rights.

The material difference between the projects is that Union's proposal eliminates the ongoing operating and maintenance costs associated with the existing 16 inch line related to future integrity and other maintenance costs associated with this line. These costs, which as shown in Exhibit A, Tab 6, Schedule 2, have an estimated net present value cost of about $12 million over a 20 year horizon.

Based on the virtually identical capital costs and the incremental $12 million in net present value costs associated with 16 inch line remaining in service, the Union proposal has a net present value cost to ratepayers of $212 million, while the 30 inch alternative has a cost of $224 million (Exhibit A, Tab 7, Table 7-1). Based on this information and evaluation, LPMA submits that the NPS 30 alternative is inferior to Union's proposal.

b) Incremental Ojibway Deliveries

The second alternative explored throughout the hearing was the impact of incremental deliveries at Ojibway, along with required capital costs for incremental pipelines, stations and compressors. There was discussion around a range of incremental deliveries at Ojibway that could serve part or all of the incremental design day demand on the Panhandle system.

LPMA has reviewed Union's December 1, 2016 Argument-in-Chief on this alternative found at pages 12 through 16 and accepts Union's argument that the proposed project is superior to any of the options related to incremental Ojibway deliveries.

LPMA has also had the opportunity to review the submissions of the Ontario Greenhouse Vegetable Growers ("OGVG") with respect to this issue. LPMA agrees with the OGVG submissions on the "Ojibway Alternatives".

LPMA is particularly opposed to any scenario where Union would be required to purchase additional gas for obligated deliveries at Ojibway for system gas customers. This requirement could significantly affect the flexibility of Union's gas supply portfolio and have potentially significant negative impacts on system gas customers and/or on rates for all customers.

The evidence in this proceeding is that purchasing gas at Ojibway is more expensive than purchasing gas delivered to Dawn. Prices at Ojibway also have the potential to be more volatile than at Union because Ojibway is not a liquid market, whereas Dawn is.

LPMA submits that it would be unfair to burden system gas customers with a higher and more volatile cost of gas if Union were required to purchase a greater proportion of its system gas at Ojibway. If the Board required Union to do this, some mechanism would need to be developed to keep system gas customers whole by allocating a portion of gas supply costs to system gas costs and a portion to transmission related costs.

LPMA submits that this could be a complicated exercise. Parties would need to know the price differential on a daily basis and the volume that flowed on each day. It would have to make assumptions about what Union would have done if it did not have to buy certain incremental amounts at Ojibway. It would also have to take into account the impact on system gas costs of potentially purchasing more gas at Ojibway during the winter and less during the summer because of facility constraints to move gas to storage during the summer period.

If an accurate estimate could be done, these costs and their potential volatility would be shifted to transmission costs and paid for by all customers. When added to the capital expenditures that Union estimates would still be required under the various levels of incremental Ojibway deliveries, it does not appear that the net present value of those costs would be significantly lower than that associated with Union's proposal. Unlike Union's proposal, however, the volatility in the costs would be increased.

11. Does the project meet the capital pass-through mechanism criterial for pre-approval to recover the cost consequences of the proposed facilities?

The EB-2013-0202 Settlement Agreement dated July 31, 2013 ("Settlement Agreement") that was accepted by the Board EB-2013-0202 Decision and Order dated October 7, 2013 set out eight criteria for the Y factor treatment for major capital projects. These eight criteria are set out at pages 19 through 22 of the Settlement Agreement and will not be repeated here. Union has included these criteria in the table found on pages 3 and 4 of Exhibit A, Tab 8.

LPMA submits that there are two topics that need to be addressed under this issue. The first relates to whether the project qualifies for Y factor treatment under the criteria set out in the Settlement Proposal and the second relates to the amount that should be included in the rate adjustment for each of 2017 and 2018.

a) Does the Project Qualify for Y Factor Treatment?

LPMA submits that the project does qualify for Y factor treatment based on the eight criteria set out in the Settlement Agreement.

LPMA notes that the criteria set out in Exhibit A, Tab 8, pages 3 and 4, show that each of the criteria agreed to in the Settlement Agreement has been met.

The only criteria which can be called into question is the first criteria which requires a minimum increase or decrease of $5 million in net delivery revenue requirement for a single new project in any year under the IRM. Based on the 20 year depreciation period proposed by Union, the net delivery revenue requirement is $4.8 million in 2017 and $25.6 million in 2018.

However, the Settlement Agreement clearly states a number of requirements in calculating the net delivery revenue requirement. One of these is that the depreciation expense is to be calculated using the 2013 Board-approved depreciation rates.

Union has calculated the net delivery requirements using the Board-approved depreciation rates to be $0.1 million in 2017 and $16.1 million in 2018 (Exhibit A, Tab 8, page 3). This means that the project would still qualify under the criteria, since the 2018 net delivery requirement is in excess of $5 million.

One of the other requirements as set out on the Settlement Agreement in the calculation of the net delivery requirements is the use of the incremental delivery revenues associated with the project that are used as an offset to the delivery revenue requirement.

Union has included in the calculation of the incremental delivery revenues, only the transmission related margin associated with the project (Exhibit A, Tab 8, page 5, lines 10-12). LPMA submits that this underestimates the incremental delivery revenues. This issue is dealt with in further detail under the second topic under this issue below.

LPMA submits that even with the added incremental delivery revenue as discussed below, the net delivery requirement would still be in excess of $5 million in 2018 and thus qualify for the Y factor treatment.

As set out in the Settlement Agreement, in the event that the net delivery revenue requirements for neither 2017 nor 2018 exceed the $5 million threshold - for whatever reason - there is a deferral account that will capture the differences between the forecast annual net delivery revenue requirement and the actual net delivery revenue requirement for each year of the IRM term. If, at the end of the 2018 year, the actual net delivery revenue requirement has not exceeded the $5 million minimum for any year in which the project has been in service, then the project will be deemed to not have qualified and all amounts collected from ratepayers would be refunded to them through the deferral account mechanism.

Union has requested such a deferral account – the Panhandle Reinforcement Project Costs Deferral Account – in Schedule 8 of Exhibit A, Tab 8.

LPMA submits that there is a reasonable expectation that the project will have a net delivery revenue requirement in excess of the $5 million threshold. The Board should find that the project meets the criteria as set out in the Settlement Agreement and also approved the establishment of the requested deferral account.

b) Calculation of the Rate Adjustments

LPMA submits that the Board should not approve the rate adjustments as calculated by Union because they do not follow the approved calculation methodology set out in the Settlement Agreement. In particular, the calculation proposed by Union use a 20 year depreciation rate and does not include all of the incremental delivery revenues associated with the project.

The Settlement Agreement is very specific as how the rate adjustments are to be calculated. The following is taken from pages 19 and 20 of the Settlement Agreement (with emphasis added).

> *The **rate adjustment for each year will be based on the forecast net delivery revenue requirement impacts** for each specific year, subject to true-up to actual as discussed in subparagraph (viii) below.*
>
> ***In determining net delivery revenue requirement for any year, the following parameters will be applied**:*
>
> > ***• Depreciation expense will be calculated using 2013 Board-approved depreciation rates**;*
> >
> > *• Required return assumes a capital structure of 64% long-term debt and 36% common equity;*
> >
> > *• The incremental long-term debt cost will be calculated based on expected financing costs for the incremental borrowing required by the project, at market rates in effect at the time the project is approved;*

• The return will be calculated using the 2013 Board-approved return on equity of 8.93%;

• Income and other taxes related to the equity component of the return will be calculated using the 2013 Board-approved tax rate of 25.5%;

• Incremental delivery revenues associated with the project will be calculated as an offset to the delivery revenue requirement*;*

• For the in-service year, all components of the calculation except taxes (but including, without limitation, depreciation, cost of debt, and return) will be calculated only for the period from the month of in-service to the end of the year; and,

• Union agrees to make no changes to these parameters during the IRM term.

On page 18 of the Settlement Agreement it is stated that the net delivery revenue requirement impacts of projects will be treated as Y factors in each year of the IRM term. Union has interpreted the Settlement Agreement to have two different definitions of the net delivery revenue requirement. The definition quoted above, taken from pages 19 and 20 of the Settlement Agreement, in Union's view is only applicable to the threshold calculation. The definition to be applied to the net delivery revenue requirement referenced on page 18 of the Settlement Agreement has a different definition, according to Union Gas (Tr. Vol. 1, page 142). LPMA disagrees with Union's interpretation.

There is only one definition of net delivery revenue requirement included in the Settlement Agreement and that definition is the excerpt from the agreement that has been reproduced above. There is no other definition of this term included in the agreement.

The fact that the statement that the rate adjustment for each year is based on the net delivery revenue requirement is included within one of the criteria does not mean that it is limited to the calculation of the threshold and not to be used for the calculation of the Y factor amount. If this were to be the case, a qualification would have been included in the statement that "In determining net delivery revenue requirement for any year, the following parameters will be applied:" with "In determining net delivery revenue requirement for any year, for the purposes of this criteria, the following parameters will be applied:". No such qualification of the calculation was included and therefore LPMA submits that the calculation of the net delivery revenue requirement that follows that statement is the one to be used for both purposes – the evaluation of whether the threshold has been met in the specific criteria and the rate adjustment to be included as a Y factor in each year.

As noted above, there are two instances where Union deviates from the calculation of the net delivery revenue requirement: the depreciation rate used and the calculation of the incremental delivery revenue.

The Settlement Agreement is very specific with respect to the depreciation expense, as highlighted in the above excerpt from the Settlement Agreement. The depreciation expense will be calculated using 2013 Board-approved depreciation rates. Union has failed to do this.

The Settlement Agreement is also very specific with respect to the incremental delivery revenues associated with a project. Delivery revenues include not only the transmission margin included in delivery rates that Union has included in the incremental revenue (Exhibit A, Tab 8, page 17), but also the distribution (monthly fixed charges, monthly demand charges and distribution volumetric) and storage rates that are included in delivery revenues.

LPMA submits that the incremental delivery revenues identified in the Settlement Agreement are not limited to the transmission portion of incremental delivery revenues. The agreement clearly encompasses all incremental delivery revenues.

LPMA also notes that Union's evidence is quite clear that without this project, Union will not be able to accommodate any requests to convert interruptible service to firm service. Firm service results in higher delivery revenues for Union than does interruptible service. Clearly the project will result in additional delivery revenue for Union as a result of the project.

Similarly, Union's evidence is clear that it cannot add any new general service (residential and commercial) or contract customers without the project being in service. As Mr. Isherwood stated, if the project is delayed past November 1, 2017, Union is physically out of capacity and it cannot firm up any customers and it cannot add any new customers (Tr. Vol. 1, page 40). In other words, all incremental delivery revenue generated beyond November 1, 2017 is associated with the project.

LPMA also notes that for 2017 and 2018, there should be no incremental distribution related costs incurred to serve the customer additions made possible by the project that are beyond the normal course of doing business for Union and that no aids to construction would be required (Tr. Vol. 1, pages 64-65). Beyond 2018 any changes would be reflected in the rebasing application.

Finally, in the calculation of the net delivery revenue requirement, Union agreed to make no changes to the parameters during the IRM term. Union has made changes. They have proposed to use a different depreciation rate and only a portion of the incremental delivery revenues.

Union's proposal would see all of the incremental delivery revenues, excluding the transmission component of delivery revenues flow to the bottom line to the benefit of the shareholder. If the earnings were sufficient to result in earnings sharing, ratepayers would get back a portion of these delivery revenues.

Union should only include the depreciation expense that is based on the Board approved depreciation rates from 2013. If the Board were to approve the accelerated depreciation proposed by Union, Union would be incur a larger expense than it could recover. The difference is $3.5 million in 2017 and $7.4 million in 2018 (Exhibit J1.3). This difference would decrease the amount of earnings sharing available to ratepayers and provide some relief to Union of the different amounts included in expenses and in the Y factor.

In summary, LPMA submits that the Board should direct Union to calculate the amounts to be included in the Y factor in accordance with the Settlement Agreement, specifically using the Board approved depreciation rates and the total incremental delivery revenues associated with the project.

If Union is unable to provide an estimate for each of 2017 and 2018 of the total incremental delivery revenues associated with the project at this time, LPMA submits that the Board should direct Union to track and provide the information needed to calculate the actual total incremental delivery revenues when the deferral account is trued up and cleared.

C. COSTS

LPMA requests that it be awarded 100% of its reasonably incurred costs. LPMA worked with other intervenors throughout the process to limit duplication while ensuring that the record was complete. LPMA discussed its preliminary submissions with a number of other parties to the proceeding and was provided with some of their preliminary submissions. This exchange of information helped to reduce the duplication in submissions.

ALL OF WHICH IS RESPECTFULLY SUBMITTED
December 14, 2016

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