APPENDIX T

Pokegama-Carnegie Plans
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APPENDIX T1

Pokegama-Carnegie Wetland Complex
Practicable Alternatives Analysis
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ENBRIDGE Energy, Limited Partnership and Enbridge Pipelines (Southern Lights) L.L.C.

Alberta Clipper and Southern Lights Diluent Pipeline Projects

Pokégama-Carnegie Wetland Complex
Practicable Alternatives Analysis

April 2009
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**Attachments**

Attachment A  Preferred Route Maps  
Attachment B  Route Variation PC1 Maps  
Attachment C  Route Variation PC2 Maps  
Attachment D  Route Variation PC3 Maps  
Attachment E  Excerpts of Alberta Clipper and Southern Lights Diluent Commercial Agreements  
Attachment F  J.D. Hair & Associates, Inc. - “Horizontal Directional Drilling for Utility and Pipeline  
               Applications”
1.0 Introduction

On November 21, 2008, Enbridge Energy, Limited Partnership and Enbridge Pipelines (Southern Lights) L.L.C. (referred to herein as “Enbridge”) submitted a Section 404 Clean Water Act individual permit application and a Section 10 Rivers and Harbors Act permit application for the Alberta Clipper and Southern Lights Diluent Pipeline Projects (referred to herein as the “Project”) to the St. Paul District of the Army Corps of Engineers (“ACOE”). Furthermore, on February 3, 2009, Enbridge submitted a Construction Consolidated Permit Application to the Wisconsin Department of Natural Resources (“Wisconsin DNR”) for the following permits:

- Temporary Bridges (Wis. Stat. §30.123, Section 404 Clean Water Act);
- Grading (Wis. Stat. §30.19, Section 404 Clean Water Act);
- Utility Crossing (Wis. Stat. §§ 30.20 and 30.12, Section 404 Clean Water Act); and
- Wetland Water Quality Certifications (Section 401 Clean Water Act).

Enbridge provided additional supplementary wetland and waterbody impact documentation in support of the ACOE and Wisconsin DNR applications on March 5, 2008 to demonstrate compliance with ACOE permit rules, Environmental Protection Agency (“EPA”) Section 404(b)(1) Guidelines (“Guidelines”), Wisconsin Administrative Code § NR 103.07(2), and other applicable laws and policies.

The ACOE considers several statutes, regulations and policies in making its individual permit decisions, including principally, (i) ACOE permit regulations and public interest review policy, and (ii) the EPA Guidelines. The Guidelines require avoidance of impacts to the aquatic ecosystem to the maximum extent practicable and minimization and compensation for unavoidable impacts. Wisconsin Administrative Code § NR 103.07(2) provides that a “practicable alternative” is one “available and capable of being implemented after taking into consideration cost, available technology and logistics in light of overall project purpose.”

At the request of the Wisconsin DNR on October 21, 2008, Enbridge conducted an office review of available information in support of a broad analysis of potential alternatives to the preferred co-location with existing Enbridge pipelines in Wisconsin. This information was supplied to the ACOE and the Wisconsin DNR on February 3, 2009. To more specifically address concerns with collocating along Enbridge’s existing corridor through the Pokegama-Carnegie Wetland Complex (Enbridge’s “Preferred Route”), the ACOE and Wisconsin DNR requested that Enbridge conduct a more detailed practicable alternatives analysis in this area. The Pokegama-Carnegie Wetland Complex is an Area of Special Natural Resource Interest (“ANSRI”), a portion of which was designated a State Natural Area in 2006 (refer to Figure 1-1). Enbridge understands that no management plan exists at this time for the Pokegama-Carnegie State Natural Area. At present, there are two non-Enbridge pipeline corridors that also traverse portions of the State Natural Area. Furthermore, on June 1, 2008 the State of Wisconsin nominated the St. Louis River Freshwater Estuary for designation as a Natural Estuarine Research Reserve (“NERR”) through the National Oceanic and Atmospheric Administration (NOAA). The Wisconsin DNR-owned portion of the Pokegama-Carnegie Wetlands State Natural Area, which includes one existing non-Enbridge pipeline corridor, was included in the nomination area.

The proceeding sections evaluate avoidance alternatives and impact minimization options for pipeline construction in and near the Pokegama-Carnegie Wetland Complex.
Figure 1.1
Pokegama-Carnegie Wetland Complex
Site Location
2.0 Avoidance of the Pokegama-Carnegie Wetland Complex

Wisconsin has identified the Pokegama Carnegie Wetland Complex (“PC”) as a designated ASNRI pursuant to Wis. Admin. Code § NR 1.05. Portions of the ASNRI were designated as State Natural Area No. 516 in 2006. The PC ASNRI is a two-unit land feature consisting of a large tag alder swamp on relatively level fine-textured clayey-soils. Four existing Enbridge pipelines traverse both units and are contained within a permanently maintained corridor that was established in 1950, well before the SNA designation in 2006. The two units are separated by a railroad yard, which is not a designated SNA or ASNRI. As previously noted, two additional non-Enbridge pipeline corridors exist within the PC ASNRI.

In consultation with the Wisconsin DNR and ACOE, Enbridge identified three route variations to potentially avoid the PC (Route Variations PC1, PC2, and PC3, refer to the Overview Map included in Attachment A). Route variations differ from system or corridor alternatives in that they are intended to resolve or reduce construction impacts to localized, specific resources, such as wetlands, recreational lands, residences, landowner requests, and terrain conditions. Several factors are considered in identifying and evaluating route variations, including construction length, land requirements, the potential for reducing or minimizing impacts to natural resources, and addressing landowner concerns.

Enbridge proposes to use a 140-foot wide construction corridor along most of the route to ensure safe excavations, allow adequate room for topsoil and subsoil segregation, provide for temporary material storage, and provide a working area for equipment and pipe stringing/assembly. The construction corridor is within Enbridge’s existing permanent easement ROW and is comprised of existing permanently maintained area, new permanently maintained area, and temporary workspaces. The construction corridor is divided between the spoil side (area used to store topsoil and excavated materials) and the working side (equipment work area and travel lane). The spoil side is located within Enbridge’s existing permanently maintained corridor and the working side is generally located outside of Enbridge’s existing permanently maintained corridor (refer to Figures 2-1 and 2-2).

Each of the route variations will require a construction corridor of 140 feet in width, which includes 75 feet of new permanent ROW. 75 feet of permanent ROW is required to establish adequate spacing between the pipelines and an adequate encroachment buffer on either side of the pipelines. In wetlands, the construction corridor is 125 feet in width, which also includes 75 feet of new permanent ROW. The Preferred Route generally requires an extension of the existing 125 foot-wide corridor by 50 feet where the pipelines are located on the south side of the existing pipelines and 25 feet where they are located on the north side. Therefore, the amount of new disturbed lands is reduced in the Preferred Route.

The alternative analysis focused on minimizing the length of the pipeline to the extent practicable, while also minimizing the environmental impacts to specific resources. For context, each mile of the proposed Project along any of the route variations would generally impact approximately 17 acres during construction and 9 acres during operation (exact acreage is dependent on exact construction methods, workspaces, access roads, etc.). By comparison, each mile of the proposed route through the PC would generally impact 6 acres of temporary work space and 1.2 acres of new permanently maintained area during operation. It is impossible to avoid all resources due to the extent, shape, and prevalence of many resources.

Consideration of potential route variations was also influenced by control points established by Enbridge. Control points at specific locations along the pipeline route serve to anchor the route, thereby defining specific portions of the final route. To minimize the length of each route variation and to provide a basis for a side-by-side comparison of impacts, the primary control points were identified at South Irondale Road and Tower Avenue in the City of Superior. The existing Enbridge ROW and Preferred Route approximates a
straight line connecting the control points. Route Variations PC1, PC2, and PC3 consist of greenfield routes generally following existing road or utility corridors.

To provide an objective comparison, the Preferred Route and the route variations were evaluated using WWI Data, USGS stream data, and other published data, in lieu of using known field data for the Preferred Route. Most impacts are reported as a linear measurement in lieu of an area measurement; with the exception of temporary and permanent impacts to wetlands. Permanent wetland impacts for the route variations were calculated using the proposed 75-foot-wide permanent ROW. The Preferred Route permanent impacts take into account the overlap with Enbridge's existing permanent corridor. New permanent impacts are based on the new permanently maintained area of 10 feet where the route is to the north of the existing pipelines and 25 feet where the route is to the south of the existing pipelines. Because trees and shrubs would not be allowed to fully regenerate within the permanently maintained area, impacts to forested wetlands would be long-term and represent a conversion of forested wetlands to scrub-shrub or emergent wetlands.
TYPICAL EXISTING ROW BOUNDARY DEFINED BY LOCATION OF SOUTHERN MOST PIPELINE: UP TO 25 FEET TO THE SOUTH AND 100 FEET TO THE NORTH.

TEMPORARY WORKSPACE ADJACENT TO NEW ADDITIONAL PERMANENT ROW WILL BE REQUIRED TO INSTALL THE PIPELINE(S). TYPICALLY 65' IN WIDTH AND THE LENGTH OF THE ROW WILL BE RENTED FROM LANDOWNERS. ADDITIONAL TEMPORARY WORKSPACE AT CIVIL AND ENVIRONMENTAL CROSSINGS OF UP TO 75' IN WIDTH AND UP TO 300' IN LENGTH ON EACH SIDE OF THE CROSSING WILL BE RENTED.

**Figure 2.1**

Alberta Clipper and Southern Lights Diluent Projects

Typical Right-of-Way Configuration North of Existing Lines

(Wisconsin Only)
For environmental review purposes only.

Typical existing row boundary defined by location of northern most pipeline: 25 feet to the north and 100 feet to the south.

Temporary workspace adjacent to new additional ROW will be required to install the pipeline(s). Typically 65' in width and the length of the ROW will be rented from landowners. Additional temporary workspace at civil and environmental crossings of up to 75' in width and up to 300' in length on each side of the crossing will be rented.

Figure 2.2
Alberta Clipper and Southern Lights Diluent Projects
Typical Right-of-Way Configuration South of Existing Lines
(Wisconsin Only)
The alternatives analysis for the PC specifically focused on the following factors:

- Length of pipeline;
- Adjacent to existing ROW;
- Wisconsin Wetland Inventory ("WWI") mapped wetlands (by wetland type). An aerial review was made of the project areas to determine if a forest cover was still remaining within WWI-designated forested/scrub-shrub wetlands. It was noted that along the Preferred Route a designation of forested/scrub-shrub WWI wetlands overlapped Enbridge’s existing maintained corridor. Within this corridor, the acreage for this wetland type was accounted for in the Scrub-Shrub category;
- Wetlands within the City of Superior that are indicated as “Protected” in the Special Area Management Plan (“SAMP”);
- Priority Wetlands as identified by the March 2000 Data Compilation and Assessment of Coastal Wetlands of Wisconsin’s Great Lakes, Pub. ## ER-002-00;
- Perennial and intermittent waterbodies (including major, impaired, Priority Navigable Waterway (“PNW”), ASNRI);
- Wild Rice production area drainages as identified by the WDNR and Great Lakes Indian Fish and Wildlife Commission;
- Named ASNRI lands;
- State Natural Areas;
- County Forest land;
- WDNR-managed lands;
- Superior Municipal forest;
- Managed Forest Law tracts;
- High Consequence Areas (“HCAs”) (HCAs are areas identified by the U.S. Department of Transportation (“US DOT”) where the potential consequences of a pipeline accident may be significant or may do considerable harm to people and their property);
- Structures within 100 feet of the centerline;
- Land Use (“WISCLAND”);
- Landowners affected;
- Private land tracts;
- Public land tracts;
- Roads and railroads crossed;
- All-terrain vehicle (“ATV”) and snowmobile trails crossed;
- Constructability issues;
- Logistical constraints; and
- Construction and right-of-way easement acquisition costs.

Enbridge completed a detailed evaluation of each route variation based on the above-referenced factors. Comprehensive results are provided in Tables 2.0-1. In addition to the summary table, maps of each route variation have been prepared and are included in Attachments A through D. These maps include: wetlands and waterbodies, sensitive water features, sensitive land features, HCAs, land use, and property boundaries for each route variation.
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<th>Source</th>
<th>Unit</th>
<th>Preferred Route</th>
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<th>Route Variation PC 2</th>
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Table 2.0-1
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<td>High Consequence Areas</td>
<td>US DOT, Office of Pipeline Safety</td>
<td>Length Crossed (mi)</td>
<td>0.81</td>
<td>3.02</td>
<td>0.83</td>
<td>0.78</td>
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<td>Ecologically Sensitive Areas</td>
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<td>0.00</td>
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<td>Highly Populated Areas</td>
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<td>Length Crossed (mi)</td>
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<tr>
<td>Structures within 100 feet of the Proposed Centerline</td>
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<td>6</td>
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<td>Length Crossed (mi)</td>
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<td>Forest (Mixed Deciduous / Coniferous)</td>
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<td>Forested Wetland (Coniferous)</td>
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<td>Length Crossed (mi)</td>
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<td>Grassland</td>
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<td>Shrubland</td>
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<tr>
<td>Urban / Developed (High Intensity Urban)</td>
<td>WDNR WiscLand</td>
<td>Length Crossed (mi)</td>
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<td>0.00</td>
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Table 2.0-1
Pokegama-Carnegie Wetland Complex Route Variation Evaluation

<table>
<thead>
<tr>
<th>Environmental and Construction Factors</th>
<th>Source</th>
<th>Unit</th>
<th>Preferred Route</th>
<th>Route Variation PC 1</th>
<th>Route Variation PC 2</th>
<th>Route Variation PC 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Urban / Developed (Low Intensity Urban)</td>
<td>WDNR WiscLand</td>
<td>Length Crossed (mi)</td>
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<td>0.03</td>
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<td>Wetland (Lowland Shrub: Broad-leaved Deciduous)</td>
<td>WDNR WiscLand</td>
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<td>2.74</td>
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<td>Number of Landowners</td>
<td>Douglas County</td>
<td>Number</td>
<td>18</td>
<td>25</td>
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<tr>
<td>Private Land Tracts Crossed</td>
<td>Douglas County</td>
<td>Number</td>
<td>19</td>
<td>34</td>
<td>37</td>
<td>65</td>
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<tr>
<td>Public Land Tracts Crossed</td>
<td>Douglas County</td>
<td>Number</td>
<td>13</td>
<td>80</td>
<td>28</td>
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<tr>
<td>Total Number of Tracts Crossed</td>
<td>Douglas County</td>
<td>Number</td>
<td>32</td>
<td>114</td>
<td>65</td>
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<tr>
<td>Roads Crossed</td>
<td>ESRI Street Map</td>
<td>Number</td>
<td>4</td>
<td>7</td>
<td>6</td>
<td>9</td>
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<tr>
<td>Railroads Crossed</td>
<td>ESRI Street Map</td>
<td>Number</td>
<td>2</td>
<td>4</td>
<td>4</td>
<td>9</td>
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<tr>
<td>Known Areas of Contamination (e.g., Superfund sites)</td>
<td>WDNR Superfund Sites in Wisconsin</td>
<td>Number</td>
<td>0</td>
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<tr>
<td>ATV Trails Crossed</td>
<td>WDNR</td>
<td>Number</td>
<td>2</td>
<td>2</td>
<td>3</td>
<td>3</td>
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<tr>
<td>Snowmobile Trails Crossed</td>
<td>WDNR</td>
<td>Number</td>
<td>1</td>
<td>2</td>
<td>2</td>
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</table>

**Cost Analysis**

<table>
<thead>
<tr>
<th></th>
<th>Enbridge Contractor</th>
<th>$</th>
<th>$1,558,656</th>
<th>$2,198,592</th>
<th>$2,185,928</th>
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<tbody>
<tr>
<td>20-inch Pipeline Cost$</td>
<td>Enbridge Contractor</td>
<td>$</td>
<td>$3,636,864</td>
<td>$5,130,048</td>
<td>$5,100,480</td>
<td>$6,261,024</td>
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<tr>
<td>36-inch Pipeline Cost$</td>
<td>Enbridge Contractor</td>
<td>$</td>
<td>$2,857,536</td>
<td>$4,030,752</td>
<td>$4,007,520</td>
<td>$4,919,376</td>
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<tr>
<td>20-inch Pipeline Installation Cost$</td>
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<td>$6,052,781</td>
<td>$8,537,866</td>
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<td>$10,420,133</td>
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<tr>
<td>36-inch Pipeline Installation Cost$</td>
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<td>$</td>
<td>Not applicable</td>
<td>$5.2 Million</td>
<td>$4.8 Million</td>
<td>$5.6 Million</td>
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<tr>
<td>Incremental ROW Acquisition Costs$</td>
<td>Enbridge ROW Staff</td>
<td>$</td>
<td></td>
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<td></td>
<td></td>
</tr>
</tbody>
</table>

*Additional Costs*
### Table 2.0-1
Pokegama-Carnegie Wetland Complex Route Variation Evaluation

<table>
<thead>
<tr>
<th>Environmental and Construction Factors</th>
<th>Source</th>
<th>Unit</th>
<th>Preferred Route</th>
<th>Route Variation PC 1</th>
<th>Route Variation PC 2</th>
<th>Route Variation PC 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>36-inch Pipeline Railroad Crossing Costs(^8)</td>
<td>Enbridge Contractor</td>
<td>$</td>
<td>$180,000</td>
<td>$360,000</td>
<td>$360,000</td>
<td>$810,000</td>
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<tr>
<td>20-inch Pipeline Railroad Crossing Costs(^8)</td>
<td>Enbridge Contractor</td>
<td>$</td>
<td>$120,000</td>
<td>$240,000</td>
<td>$240,000</td>
<td>$540,000</td>
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<tr>
<td>36-inch Pipeline Road Crossing Costs(^9)</td>
<td>Enbridge Contractor</td>
<td>$</td>
<td>$360,000</td>
<td>$630,000</td>
<td>$540,000</td>
<td>$810,000</td>
</tr>
<tr>
<td>20-inch Pipeline Road Crossing Costs(^9)</td>
<td>Enbridge Contractor</td>
<td>$</td>
<td>$240,000</td>
<td>$420,000</td>
<td>$360,000</td>
<td>$540,000</td>
</tr>
<tr>
<td>Number of Guided Bore Crossings(^10)</td>
<td>Enbridge Contractor</td>
<td>Number</td>
<td>2</td>
<td>8</td>
<td>6</td>
<td>13</td>
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<tr>
<td>20-inch Pipeline Guided Bore Crossing Costs</td>
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<td>$250,000</td>
<td>$1,000,000</td>
<td>$750,000</td>
<td>$1,625,000</td>
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<tr>
<td><strong>Total Route Cost</strong></td>
<td></td>
<td></td>
<td>$14,931,837</td>
<td>$27,423,258</td>
<td>$26,832,584</td>
<td>$30,208,829</td>
</tr>
</tbody>
</table>

1. The adjacent ROWs include existing pipeline, road, power line, and railroad corridors. The route variations would not overlap with any of the existing ROWs.
2. All wetlands impacted have the hydrologic modifier “Wet soil, Palustrine” and are defined as “Areas which are wetlands, but do not appear to have surface water for prolonged periods of time”.
3. The Preferred Route permanent impacts take into account the overlap with Enbridge’s existing permanently maintained corridor. New permanent impacts represent the new permanently maintained area of 10 feet where the route is to the north of the existing pipelines and 25 feet where the route is to the south of the existing pipelines. All permanent impacts for the Route Variations are based on a new 75-foot permanent ROW.
4. Based on temporary workspace of 50 feet in wetlands.
5. This represents the cost to purchase the pipe and is based on actual current costs ($140 per foot 36-inch and $60 per foot 20-inch). This does not include heavier wall pipe required for certain crossings (roads, railroads, HDD, etc.).
6. The baseline installation costs for 20-inch and 36-inch diameter pipelines are $580,800 and $1,230,240 per mile, respectively.
7. Incremental ROW acquisition costs were determined by Enbridge ROW staff based on land use, potential structure relocation, timber costs, appraisals and title work, and manpower. The figures represent minimum estimated costs that assume that condemnation authority is obtained and the land rights are acquired on the basis of fair market value. Acquisition costs would likely increase significantly if condemnation authority is not obtained. The Preferred Route has already been secured; therefore, there are no additional acquisition costs.
8. 200 feet was used for all crossings, which is typical for the majority of railroad crossings. The cost per foot for the 36-inch and 20-inch diameter pipe is $450 and $300, respectively.
9. 200 feet was used for all crossings, which is typical for the majority of road crossings. The cost per foot for the 36-inch and 20-inch diameter pipe is $450 and $300, respectively.
10. The guided bore installation method is only applicable to the 20-inch diameter Southern Lights pipeline. The costs assume that all waterbodies would be crossed using the guided bore method. Each crossing was assumed to require 500 feet, which is the typical minimum length for guide bore crossings of waterbodies with 20-inch diameter pipe, at a cost of $250 per foot.
2.2  **Route Variation PC1**

Route Variation PC1 begins at the location where the Project crosses South Kimmes Road. At this intersection, the route heads north, following South Irontale Road to the City of Oliver. At the City of Oliver, the route turns to the east and then north towards old Highway 105. The corridor continues east along Old Highway 105 for approximately 2.5 miles at which point the route turns south to intersect with Enbridge’s existing corridor. Maps for Route Variation PC1 are found in Attachment B. A summary of Route Variation PC1 as compared to the Preferred Route is provided below.

2.2.1  **Environmental and Land Use Considerations**

Route Variation PC1 as compared to the Preferred Route results in the following reductions:

- Avoidance of both units of the Pokegama-Carnegie Wetlands State Natural Area and partial avoidance of the PC ASNRI;
- A reduction of temporary wetland impacts;
- A reduction of temporary and permanent impacts to mixed forested (needle-leaved evergreen)/scrub/shrub (broad-leaved deciduous) wetland impacts;
- A reduction of temporary impacts to scrub/shrub wetlands;
- A reduction of structures within 100 feet of the centerline of the proposed centerline of the pipelines; and
- Reduction in county forest areas crossed by 2.67 miles.

Route Variation PC1 results in the following additional impacts as compared to the Preferred Route:

- A 73 percent increase of wetland impacts due to the establishment of a new, permanent ROW;
- Substantial permanent and temporary impacts (94 and 66 percent increase) to mixed forested (broad-leaved deciduous)/scrub/shrub (broad-leaved deciduous) wetlands;
- A 68 percent increase of permanent impacts to scrub/shrub wetlands;
- An additional 6 waterbody crossings (8 total), all of which are wild rice production area drainages;
- An additional 5 WDNR-mapped ASNRI and PNW waterbody crossings;
- Increase in the crossing of HCAs by 2.21 miles;
- Increase in forest land crossed by 1.1 miles;
- Increase of 3 new road crossings; and
- Create a new pipeline corridor immediately adjacent to the City of Oliver in addition to Enbridge’s current corridor through the Town of Saunders, thus establishing a new HCA segment. Furthermore, the risk of third-party excavation damage increases as the result of pipelines being adjacent to municipal boundaries.

Route Variation PC1 would result in an increase to temporary and permanent impacts as compared to the Preferred Route. Because this alternative requires the creation of a new greenfield corridor, this alternative results in two permanently maintained areas, as opposed to one. Multiple corridors increase the potential for habitat fragmentation, an increase in new forest land crossed, and an increase in HCAs impacted. While there are no regulatory requirements to avoid HCAs during routing, they are considered sensitive areas by the US DOT as evidenced by the supplemental safety requirements and risk-based integrity measures for HCAs contained in 49 CFR Part 195. The enhanced requirements for protecting HCAs indicate that these areas should be avoided to the extent possible when determining the route for a new pipeline.
The most notable increased impacts as compared to the preferred route include 6.52 acres of mixed forested/scrub/shrub and 3.29 acres of scrub/shrub wetlands that would be converted to emergent/wet meadow wetlands along the new permanently maintained ROW.

All eight waterbodies crossed are wild rice production area drainages. The actual wild rice production areas are located within bays of the St. Louis River. In addition, 7 of the 8 waterbodies are designated as ANSRI and PNW. There is increased risk of sedimentation impacting the wild rice production areas as compared to the Preferred Route and, thus, this alternative carries a greater risk of affecting the abundance or habitat of wild rice.

Enbridge reviewed aerial photography and topographic maps of Route Variation PC1 and identified several more deeply incised, perennial and seasonal streams along South Irondale Road as well as the Little Pokegama River on the northern portion of the route. The potential for erosion in these areas is higher than the Preferred Route, which is relatively flat with the exception of the Pokegama River crossing.

This variation abuts two portions of the St. Louis River Estuary lands that have been nominated for designation as a NERR; whereas the Preferred Route at its closest point is approximately one third of a mile south and in most places several miles to the south and west of the proposed St. Louis Estuary lands. Therefore, given its proximity, Route Variation PC1 has significantly higher potential for erosion and possible slope failure and potential sediment-release impacts to the St. Louis River Estuary than the Preferred Route.

The Managed Forest Law (“MFL”) was enacted in Wisconsin in 1985 to allow private landowners to obtain a tax relief benefit by enrolling their forested land as MFL land (similar in nature to the Conservation Reserve Program administered by the Natural Resource Conservation Service). The MFL is a free and voluntary enrollment, with very specific criteria required for enrollment. The predecessor to the MFL program is the Forest Crop Law (“FCL”) program, which is a landowner incentive program that encourages long-term, sustainable management of private woodlands by reducing and deferring property taxes. The FCL program was enacted in 1927 and enrollment was closed on January 1, 1986. Enbridge identified one property enrolled in one of these programs along Route Variation PC1. By comparison, no MFL properties have been identified along the Preferred Route. Enbridge would need to work with the potentially affected landowner to determine if any impacts to MFL lands will occur as a result of construction activities and compensate them accordingly if their status is affected.

### 2.2.2 Constructability Issues

Enbridge conducted a desk-top review of topographic maps as well as a field review of portions of Route Variation PC1 that are accessible from public ROWs. During this review, Enbridge identified several locations with steep slopes along South Irondale Road that require alternative construction techniques (referred to as two-toning) to ensure safe working conditions for construction workers. Terraces are cut into the side slope, one for equipment to operate from and one for the pipeline trench. A photograph of the preparations of the terraces is provided on the following page. Two-toning requires more soil to be exposed during construction than typical trenching methods; therefore, there is an increased risk of erosion and sedimentation issues. Additional temporary workspace may be required in these areas to facilitate stable terrace slopes; however, field surveys are needed to verify and Enbridge does not have permission to access these affected properties at this point in time. Therefore, the typical 140-foot construction ROW was applied.
2.2.3 Logistical Constraints

The addition of new pipeline corridors also presents additional operational logistical concerns. For instance, Enbridge is required by the US DOT to implement and maintain a public awareness and damage prevention program. Therefore, the new additional 25 landowners would need to be included in this program. Furthermore, the new corridor also requires routine aerial inspection and vegetation maintenance.

In addition, Enbridge currently has easement agreements with private and public landowners for the Preferred Route, which Enbridge acquired without condemnation authority from Wisconsin Public Service Commission (“WPSC”). A major deviation in the Wisconsin portion of the route at this stage would creating a new pipeline ROW and impacting new lands and landowners and in all likelihood would require Enbridge to apply for condemnation rights through the WPSC. The delay incurred by the WPSC process places the targeted in-service date in jeopardy and, thus, does not meet the overall project purpose and need. The WPSC process and implications of the resulting delays to Enbridge’s commitments to its shippers are discussed in the following sections.
2.2.3.1 Power of Eminent Domain

Enbridge is not commercially regulated by the WPSC, and, therefore, it does not require a certificate of public convenience and necessity (“CPCN”) to construct pipelines or associated facilities. However, a finding by the WPSC that the Project is in the public interest is required for Enbridge to obtain the power of eminent domain (authority to condemn) to acquire land rights from private individuals, as provided in Wis. Stat. Sec. 32.03(13). The public interest/condemnation process consists of the following procedures and general timeline:

**Step 1:** Prepare application. Enbridge prepares an application pursuant to Wis. Stat. Sec. 32.03(13) and WPSC general guidelines. An accelerated preparation timeframe for such an application is estimated to be approximately 10 to 12 weeks.

**Step 2:** File application with WPSC. There is no statute or administrative rule governing the timeline for WPSC review and processing of the public interest determination application. However, for Enbridge’s Southern Access Stage 1 project, the need for a public interest determination was limited to 1.21 miles of ROW, and the review process extended for 9 months until final approval was obtained from WPSC. Enbridge’s Southern Access Stage 2 project included a filing for 22 miles of ROW, and the review process also extended for 9 months until final approval was obtained from WPSC.

**Step 3:** Application reviewed, processed and noticed. Following receipt of an application, WPSC issues a Notice of Proceeding. However, there is no statutory timeline for issuance of the Notice following receipt of the application. The expectation is that the WPSC will generally follow the procedures for processing applications of regulated entities established in Wis. Stat. Sec. 196.49 (applicable to natural gas pipelines), which provides for a 60 day period to issue the Notice of Proceeding. There is no limit on the review/approval period by WPSC. If WPSC determines the application requires a public hearing (“contested case”), there is no certainty on the time required to process the application. Much will depend on the number of persons seeking to intervene and the amount of pre-hearing discovery that is permitted. It appears likely the least amount of time the WPSC would take to process an application is 6 months, with the more likely time period being in excess of 1 year from the date of application.

**Step 4:** Initiate Condemnation. Enbridge may not initiate condemnation proceedings until WPSC issues the requested public interest determination. Because of the detailed condemnation procedures and notice requirements to obtain access to property for purposes of construction (including the necessity for a period of good faith negotiations with the landowners), it is expected that access would not be available until a minimum of 5 to 6 months following initiation of the condemnation process if Enbridge is allowed to construct before a final determination of the amount of just compensation a landowner is entitled to receive. See Wis. Stat. § 32.12(1) (“Quick Take”). If Quick Take is not allowed, access to construction could be delayed 1 to 2 years, if not longer.

The total elapsed time period from filing of application to access to property is expected to range from a minimum of 15 months (if Quick Take is allowed) to 24 months. In Enbridge’s experience, impasse with landowners is often reached over various issues and it becomes necessary to initiate a minimum number of condemnation proceedings to establish an approved route. Therefore, any alternative “greenfield” route that deviates from the current Preferred Route that has been acquired by Enbridge should be assessed with the assumption that the route will not be obtained without the passage of time necessary to prepare and process the public interest determination application with WPSC and complete the condemnation process.
2.2.3.2 Enbridge Shipper Commitments

Enbridge negotiated with the Canadian Association of Petroleum Producers (CAPP) for Alberta Clipper and the customers that entered into pipeline capacity agreements with Southern Lights to develop commercial terms that would govern shipments on the pipelines. CAPP has approximately 140 members, who account for more than 95 percent of Canada’s oil and gas production. Through its committees, CAPP negotiates with pipelines to ensure fair pipeline transportation rates and practices. Enbridge and CAPP reached a final agreement on commercial terms for the Alberta Clipper pipeline on June 27, 2008. By order dated August 28, 2008, the Federal Energy Regulatory Commission (“FERC”) found the terms of agreement to be in the public interest and approved Enbridge’s proposal to recover the project capital costs. The Southern Lights Diluent pipeline serves a different commercial purpose and was not negotiated through CAPP. Contracts with the shippers agreeing to long term capacity commitments for the Southern Lights Diluent pipeline were finalized in March 2007. By order dated December 31, 2007, FERC approved Enbridge’s proposal for recovery of the project capital costs. The commercial agreements for these projects backstop Enbridge’s construction of the pipelines and include a FERC-regulated negotiated cost-of-service rate (Southern Lights Diluent) and an incremental tariff rate surcharge that can be added to existing rates (Alberta Clipper). These mechanisms allow the capital costs required to construct the Alberta Clipper and Southern Lights Diluent pipelines to be recovered via the FERC-approved tariff rates charged shippers on the respective pipelines. Shippers include producers and refiners (and marketers that connect these two parties) that include transportation rates in the costs of the final finished products paid for by the end consumer. Increased costs paid by shippers will, in whole or in part, be passed on to end users of refined products, such as Wisconsin consumers. Any delays of the targeted in-service date of July 1, 2010 as agreed upon with the shippers will also result in significant impacts to the Project and, due to the commercial agreements with shipper, risk cancellation. Excerpts of the FERC-approved agreements between Enbridge and its shippers for the Alberta Clipper and Southern Lights Diluent pipelines are included in Attachment E to evidence the commercial support for the pipelines and the consequences of delayed in-service dates.

2.2.3.3 Other Public Interest Considerations

The Route Variation analysis primarily focuses on environmental comparisons; however, regulatory review of projects also takes into consideration impacts to the public interest. Significant delays in attaining the in-service date of the Project or, at worst cancellation of the Project, will significantly impact consumers and the public. As an example, the 13 miles of the Alberta Clipper pipeline that is situated in Wisconsin is only a small portion of the 1,000 miles of the entire Alberta Clipper project. Furthermore, Canada, North Dakota and Minnesota have all deemed the project to be needed pursuant to their respective governmental requirements.1

While the primary purpose and need for the Project has been affirmed by Canada, the United States, North Dakota and Minnesota based on energy demand and supply, there are other economic considerations should the in-service date not be met or, at worst, regulatory delays result in cancellation of the Project. For example, construction of international projects of this magnitude requires a large workforce. This large

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1 On December 31, 2007, in conjunction with approval of the separate LSr project subsequently constructed in North Dakota and Northern Minnesota in 2008, the North Dakota Public Service Commission concluded in Order PUC 07 018 that the North Dakota portion of the Alberta Clipper pipeline serves the public interest by meeting a regional need for access to increased supplies of crude oil.

The Canadian Energy Board and the Canadian Governor in Council approved the Canadian portion of the Project in May 2008, concluding the Project will serve the public necessity and convenience. The Minnesota Public Utilities Commission issued an order granting the Project a Certificate of Need for the Minnesota portion of the Project on December 28, 2008.
workforce must be retained and scheduled significantly in advance of any anticipated start of construction date. For this Project, Enbridge must contract to retain and schedule construction workers in two countries, crossing three states in the United States. Accordingly, Enbridge has already entered into contracts with its major construction contractors that together will employ at the peak of construction some 2,000 workers in this region. A good portion of the support and workers will be based in Douglas County, Wisconsin to construct the stations, tanks and pipelines that are associated with the Project. The economic benefits of construction, especially during these months of severe regional and economic downturns, should not be ignored. For example, upon completion of these projects the incremental property tax revenue paid to Douglas County and Wisconsin is estimated at $4,700,000 per year.

2.2.4 Construction and Right-of-Way Acquisition Costs

Enbridge calculated the costs associated with construction and acquisition of new ROW for Route Variation PC1, as presented in Table 2.0-1. The total cost of Route Variation PC1 is at least 45.5 percent higher than the portion of the Preferred Route within the area subject to this evaluation.

2.3 Route Variation PC2

Route Variation PC2 begins at the location where the Project crosses the Northern Natural Gas Company’s ROW. The route abuts the Northern Natural Gas ROW until it intersects with old Highway 105. The route continues east along Old Highway 105 for approximately 2.5 miles at which point the corridor turns south to intersect with Enbridge’s existing corridor. Maps for Route Variation PC2 are found in Attachment C. A summary of Route Variation PC2 as compared to the preferred route is provided below.

2.3.1 Environmental and Land Use Considerations

Route Variation PC2 as compared to the preferred route results in the following reductions:

- Partial avoidance of the PC ASNRI;
- A reduction of temporary and permanent impacts to mixed forested (needle-leaved evergreen)/scrub/shrub (broad-leaved deciduous) wetlands;
- A reduction of temporary impacts to scrub/shrub wetlands;
- A reduction of structures located within 100 feet of the centerline of the pipelines; and
- Reduction in county forest areas crossed by 0.90 mile.

Route Variation PC2 results in the following increased impacts as compared to the Preferred Route:

- An 84 percent increase to permanent wetland impacts due to establishing a new permanent pipeline corridor;
- Substantial permanent and temporary impacts (96.3 and 74 percent) to mixed forested (broad-leaved deciduous)/scrub/shrub (broad-leaved deciduous) wetlands;
- New temporary and permanent impacts to mixed forested (needle-leaved evergreen)/scrub/shrub (broad-leaved deciduous) wetlands;
- New temporary and permanent impacts to mixed scrub/shrub (broad-leaved deciduous)/emergent/wet meadow wetlands;
- A 66 percent increase of permanent impacts to scrub/shrub wetlands;
- An additional 4 waterbody crossings (6 total), all of which are wild rice production area drainages, and 5 are designated as ANSRI and PNW;
- An additional3 WDNR-mapped ASNRI waterbody crossings;
• An additional 0.01 mile of HCAs crossed; and
• An increase in forest land crossed by 0.64 mile.

Route Variation PC2 would result in an increase to temporary and permanent impacts as compared to the Preferred Route. A portion of this alternative would require the establishment of a new permanent ROW. Additional new ROW potentially increases the habitat fragmentation and sedimentation as a result of the greenfield corridor, an increase in new forest land crossed, and an increase in HCAs impacted. While there are no regulatory requirements to avoid HCAs during routing, they are considered sensitive areas by the US DOT and should be avoided to the extent possible as evidenced by the supplemental safety requirements and risk-based integrity measures for HCAs contained in 49 CFR Part 195. The enhanced requirements for protecting HCAs indicate that these areas should be avoided to the extent possible when determining the route for a new pipeline.

The most notable increased impacts as compared to the Preferred Route include 21.33 acres of mixed forested/scrub/shrub and 3.82 acres of scrub/shrub wetlands that would be converted to emergent/wet meadow wetlands along the new permanently maintained ROW.

All six waterbodies crossed are wild rice production area drainages. The actual wild rice production areas are located within bays of the St. Louis River. In addition, 5 of the 6 waterbodies are designated as ANSRI and PNW. There is increased risk of sedimentation impacting the wild rice production areas as compared to the Preferred Route and, thus, this alternative carries a greater risk of affecting the abundance or habitat of wild rice.

This variation abuts one portion of the St. Louis River Estuary lands that have been nominated for designation as a NERR; whereas the Preferred Route at its closest point is approximately one third of a mile south and in most places several miles to the south and west. Therefore, given its proximity, Route Variation PC2 has significantly higher potential for erosion and possible slope failure and potential sediment-release impacts to the St. Louis River Estuary than the Preferred Route.

The MFL was enacted in Wisconsin in 1985 to allow private landowners to obtain a tax relief benefit by enrolling their forested land as MFL land (similar in nature to the Conservation Reserve Program administered by the Natural Resource Conservation Service). The MFL is a free and voluntary enrollment, with very specific criteria required for enrollment. The predecessor to the MFL program is the FCL program, which is a landowner incentive program that encourages long-term, sustainable management of private woodlands by reducing and deferring property taxes. The FCL program was enacted in 1927 and enrollment was closed on January 1, 1986. Enbridge identified two properties enrolled in the MFL program along Route Variation PC2. By comparison, no MFL properties have been identified along the Preferred Route. Enbridge would need to work with the potentially affected landowners to determine if any impacts to MFL lands will occur as a result of construction activities and compensate them accordingly if their status is affected.

2.3.2 Constructability Issues

Route Variation PC2 includes a crossing of a foreign (non-Enbridge) underground pipeline which would require considerable coordination with the other pipeline operator to ensure that construction procedures, pipeline design, and cathodic protection does not affect the integrity of their pipeline.

There are no roads, public or private, between South Irondale Road and the railroad tracks (approximately three miles). Therefore, given the amount of wetlands in this area, a mat road approximately three miles long is necessary.
2.3.3 Logistical Constraints

Route Variation PC2 would require land rights from 25 landowners owning 65 tracts; therefore, Enbridge must acquire these rights through consensual negotiations with the landowners or file an application for condemnation rights with the WPSC. As discussed in Section 2.2.3.1, this would delay the Project for a minimum of 15 months and as much as 24 months, which has significant implications to Enbridge’s commitments to its shippers as discussed in Section 2.2.3.2. Furthermore, the other public interest considerations discussed in Section 2.2.3.3 also apply to Route Variation PC2.

The addition of new pipeline corridors also presents additional operational logistical concerns. For instance, Enbridge is required by the US DOT to implement and maintain a public awareness and damage prevention program. Therefore, the new additional 25 landowners would need to be included in this program. Furthermore, the new corridor also requires routine aerial inspection and vegetation maintenance.

2.3.4 Construction and Right-of-Way Acquisition Costs

Enbridge calculated the costs associated with construction and acquisition of new ROW for Route Variation PC2, as presented in Table 2.0-1. The total cost of Route Variation PC2 is at least 44 percent higher than the Preferred Route within the area subject to this evaluation.

2.4 Route Variation PC3

Route Variation PC3 begins at the location where the Project crosses South Kimmes Road. At this intersection, the route turns south following South Kimmes Road to Great Lakes Gas’ ROW. The route abuts the Great Lakes Gas ROW until it intersects with County Road C. At County Road C the route turns north, paralleling the road until it intersects Enbridge’s existing corridor. Maps for Route Variation PC3 are found in Attachment C. A summary of Route Variation PC3 as compared to the Preferred Route is provided below.

2.4.1 Environmental and Land Use Considerations

Route Variation PC3 compared to the Preferred Route results in the following reductions:

- Avoidance of the PC;
- A reduction of temporary and permanent impacts to mixed forested (needle-leaved evergreen)/scrub/shrub (broad-leaved deciduous) wetlands;
- A reduction of temporary impacts to scrub/shrub wetlands; and
- Reduction in county forest areas crossed by 1.69 mile.

Route Variation PC3 results in the following increased impacts as compared to the Preferred Route:

- An 85 percent increase in wetland impacts due to the creation of a new, permanent ROW
- Substantial permanent and temporary impacts (96 and 71 percent increase) to mixed forested (broad-leaved deciduous)/scrub/shrub (broad-leaved deciduous) wetlands;
- New temporary and permanent impacts to forested (broad-leaved) wetlands;
- New temporary and permanent impacts to mixed scrub/shrub (broad-leaved deciduous)/emergent/wet meadow wetlands;
- A 71 percent increase of permanent impacts to scrub/shrub wetlands;
- New permanent and temporary impacts to emergent/wet meadow wetlands;
• An additional 11 waterbody crossings (13 total); all wild rice production area drainages;
• 11 WDNR-mapped ASNRI and PNW waterbody crossings;
• New crossing of WDNR-managed lands (0.02 miles);
• Increase in forest land crossed by 0.56 mile;
• 5 additional structures within 100 feet of the centerline of the pipelines;
• Increase of 5 new road crossings;
• Increase of 7 railroad crossings; and
• An additional 1 ATV trail crossing.

Route Variation PC3 would result in an increase to temporary and permanent impacts as compared to the Preferred Route. This alternative would require the establishment of a new permanent ROW which potentially increases the habitat fragmentation and sedimentation as a result of the new greenfield corridor, and there is an increase in new forest land crossed.

The most notable increased impacts as compared to the Preferred Route include 2.72 acres of forested (broad-leaved) deciduous wetland, 19.49 acres of mixed forested/scrub/shrub, and 4.51 acres of scrub/shrub wetlands would be converted to emergent/wet meadow wetlands along the new permanently maintained ROW.

2.4.2 Constructability Issues

No noteworthy constructability issues were identified associated with pipeline construction along Route Variation PC3 (based on desktop analysis and field reviews). In addition, it parallels many public roads; therefore, access to the ROW is not a concern.

2.4.3 Logistical Constraints

Route Variation PC3 would require land rights from 37 landowners owning 82 tracts; therefore, Enbridge must acquire these rights through consensual negotiations with the landowners or file an application for condemnation rights with the WPSC. As discussed in Section 2.2.3.1, this would delay the Project for a minimum of 15 months and as much as 24 months, which has significant implications to Enbridge’s commitments to its shippers as discussed in Section 2.2.3.2. Furthermore, the other public interest considerations discussed in Section 2.2.3.3 also apply to Route Variation PC2.

The addition of new pipeline corridors also presents additional operational logistical concerns. For instance, Enbridge is required by the US DOT to implement and maintain a public awareness and damage prevention program. Therefore, the new additional 37 landowners would need to be included in this program. Furthermore, the new corridor also requires routine aerial inspection and vegetation maintenance.

2.4.4 Construction and Right-of-Way Acquisition Costs

Enbridge calculated the costs associated with construction and acquisition of new ROW for Route Variation PC3, as presented in Table 2.0-1. The total cost of Route Variation PC3 is at least 50.6 percent higher that the Preferred Route within the area subject to this evaluation.

2.5 Conclusions

There is no practicable alternative to the Preferred Route that will avoid wetland impacts and achieve the overall project purpose. As documented on Table 2.0-1, the Preferred Route results in significantly less permanent wetland impacts than any of the alternative routes. It also results in fewer temporary impacts than
routes PC-2 and PC-3. Complete avoidance of all aquatic resources is not possible as pipelines are a continuous, linear project. However, co-location allows for a reduction in the overall acreage of permanent wetland impact. The co-location to the north minimizes impacts to the PC ASNRI as it utilizes a larger area of existing permanently maintained corridor. The permanent wetland acreage calculations for the Preferred Route take into account the 50 foot overlap of the new proposed permanently maintained area with the existing permanently maintained area in Enbridge’s ROW. The 75-foot-wide permanent ROW is required for Route Variations PC1, PC2 and PC3 even if they are adjacent to existing utility or road corridors as the easements would not overlap. In these variations permanent wetland impacts would occur within the entire 75-foot-wide permanent ROW.

The PC ASNRI contains large or multiple populations of rare plants that are interspersed throughout the complex. In general, these species require some type of disturbance regime, either natural or man-made, to mimic natural disturbance that reduces competition and enables these populations to exist. Enbridge has proposed a restoration plan that takes advantage of the mimicking of construction activities to that of a natural disturbance. With the proposed restoration of hydrologic features, control of seeding and a two-phase restoration program, Enbridge anticipates the community and its rare plant species populations will be enhanced as a result of construction, restoration and maintenance activities along the Preferred Route. Enbridge’s 2002 Terrace 3 project crossed the PC ASNRI and SNA in the area to be crossed by the Preferred Route and illustrates this point. In general, rare plant survey data shows that rare plant communities found in the 2008 surveys coincide with the locations of the communities identified during the Terrace 3 surveys. Furthermore, the results not only show successful regeneration of rare plant species since the Terrace 3 construction, but in fact illustrate the expansion of some of those communities. Therefore, as demonstrated with the Terrace 3 project, the wetlands in PC ASNRI recover well and the rare plants in this area actually thrive on the disturbance caused by the pipeline construction. Thus, the use of the Preferred Route should not be considered inconsistent with or injurious to the natural values of the state natural area and will not result in a significant adverse impact to the wetland functional values in the PC ASNRI.

The Preferred Route also results in fewer roadway and railroad crossings than any of the alternatives. In addition, the Preferred Route through the PC ASNRI does not require impacts to the Town of Oliver that are associated with variation PC-1, does not require impacting any lands in the managed forest program, and does not impose new land use restrictions on landowners whose properties are not otherwise impacted by Enbridge’s existing pipeline corridor. While Alternative PC-1 partially avoids the PC ASNRI and SNA, it is closer to the proposed St. Louis Estuary lands than the Preferred Route, which increases the potential for sedimentation to the St. Louis Estuary, and would require the creation of a new permanently maintained ROW.

Moreover, co-location with existing utilities is typically presumed to be a least environmentally damaging practicable alternative for pipeline construction. Although siting of liquid pipelines is not regulated by the FERC, their regulations (18 CFR §380.15[d][1]) pertaining to natural gas pipeline siting and maintenance requirements state that the use, widening, or extension of existing rights-of-way must be considered in locating proposed facilities. Furthermore, Enbridge’s proposed use of an existing pipeline corridor is consistent with the goals of Wisconsin’s energy policy found in Section 1.12 of the Wisconsin Statutes. See Wis. Stat. §1.12 (6)(a) (co-locating new electric transmission lines within existing utility corridors is declared to be the preferred practice in Wisconsin). Wisconsin’s energy policy requires that new electric transmission lines first utilize existing utility corridors. While this provision is not directly applicable to pipelines, the goal of limiting environmental impacts through the use of existing corridors is applicable.

Furthermore, requiring any of the three re-route alternatives will significantly delay the Project and could result in cancellation. Such a result would not be in the public interest. Even if cancellation did not result, the additional costs render none of the three variations to be a practicable alternative when considered in light of
the fact that the re-route alternatives do not materially reduce environmental impacts when compared to the Preferred Route.
3.0 Minimization of Impacts to the Pokegama-Carnegie Wetland Complex

As discussed in Section 2.5, there is no practicable alternative to the Preferred Route that would result in less impact to wetlands. Therefore, Enbridge evaluated potential alternatives to minimize impacts to the PC. Details of the various potential minimization techniques are provided in the following sections.

3.1 Potential Minimization by Specialized Construction Techniques

Installing a pipeline using horizontal directional drilling (HDD) involves placing a drill unit on one side of the feature to be crossed (waterbody, wetland, road, etc.). A small-diameter pilot hole is drilled under the feature to be crossed along a prescribed profile. After the pilot hole has been completed, the hole is sequentially enlarged using reamers until the desired hole is established to accommodate the desired pipeline diameter. Drilling mud (bentonite clay and water slurry) is circulated through the drill stem pipe to power the cutting tool. The mud is also circulated through the drill hole to remove cuttings and maintain the integrity of the hole. Water from an approved source is used to prepare the slurry of drilling mud, and will be appropriated according to applicable permits. During drilling operations, drilling mud and slurry is stored back in an earthen berm sediment control structure, in tanks, or by other methods so that it does not flow into adjacent wetlands/waterbodies or off the workspace. After the pipe is in place, excess drilling mud and slurry will be spread over an upland area approved by Enbridge and the landowner, or hauled off site to an Enbridge approved disposal location. The pipe section that will be pulled through the hole is typically strung and assembled on the exit side of the drilling operation, and may require additional workspace (false ROW) to properly assemble. Once the pipe segment is assembled, it is pulled through the hole by the drilling/bore rig and welded to the adjoining sections of pipe on each side of the feature.

HDD methods are typically used for deeper and/or broader waterbodies with high discharge volumes, areas with unstable approach slopes, and areas with sensitive habitat and are restricted by substrate types, slope, and landform constraints.

The guided bore crossing method is very similar to the HDD method but is used for shorter distances, smaller diameter pipelines, and may or may not use drilling mud. The use of drilling mud during a guided bore crossing is dependent on the nature of the subsurface materials that would be encountered during the crossing as well as the length of the crossing. The substrate must be such that it will provide buoyancy control to the empty pipe.

HDD and guided bores are restricted by the geometry of the bore path, the size of the pipe, certain geological settings that present obstacles that can deflect the drill bit (boulders and rocks in till) or prevent drilling altogether (voids to continuous cobble), and horsepower of the drilling machinery. Under optimal conditions:

- HDDs for the Alberta Clipper pipeline have an effective minimum and maximum length of approximately 1,300 and 6,000 feet due to required bore geometry and drilling equipment horsepower, respectively. As the length of the HDD segment increase, the risk of failure to pull the pipe pilot hole increases.

- HDDs for the Southern Lights Diluent pipeline have a minimum and maximum length of 700-800 and 6,000 feet, respectively due to required bore geometry and drilling equipment horsepower, respectively.
• Under optimal conditions, the minimum and maximum length for a guided bore of the 20-inch Southern Lights Diluent line is 200-250 and 700-800 feet respectively. Guided bores are not appropriate for the 36-inch Alberta Clipper pipeline due to the greater limitations associated with bending a larger pipe diameter.

• Steep slopes on the entry (going in) and exit (leaving) locations for the bore will change the minimum and maximum bore lengths accordingly.

The proposed route through the PC is approximately 18,000 feet in length. Utilization of guided bores is not practicable as it is not appropriate for the 36-inch diameter Alberta Clipper pipeline and would required a minimum of 22 individual bores for the Southern Lights Diluent pipeline. Therefore, at the request of the ACOE and the Wisconsin DNR, Enbridge evaluated the potential of crossing the PC utilizing HDD techniques.

3.1.1 Horizontal Directional Drilling Evaluation

Enbridge prepared a conceptual plan for HDD installation of the Alberta Clipper and Southern Lights pipelines through the Pokegama-Carnegie Wetland Complex based on the following assumptions/limitations in accordance with J.D. Hair & Associates, Inc. “Horizontal Directional Drilling for Utility and Pipeline Applications” guidance document dated October 2007, which is included as Attachment F for reference:

• Pokegama-Carnegie Wetland Complex begins at MP 1091.7 and ends at MP 1094 (approximately 3.3 miles or 17,424 feet.
• Each drill segment is installed at the maximum length allowable (6,000 feet) using a 217,000 Newton-meter torque drill rig. Therefore, three 6,000-foot long (linear) segments for each pipeline are required (six total drill segments three each for Alberta Clipper and Southern Lights Diluent pipelines, respectively).
• An approximately 300 foot long excavation is required for each pipeline in between HDD segments to connect them.
• The duration to install each pipeline segment is approximately 65 consecutive days.
• Each pipeline string is fabricated in its entirety prior to installation.
• The Southern Lights Diluent pipeline is installed 25 feet north of the northern most existing line and the Alberta Clipper pipeline is installed 25 feet north of the Southern Lights Diluent pipeline.
• The clay soil layer is up to 180 feet thick, based upon information provided by the ACOE and Wisconsin DNR local representatives.
• Water appropriation is required at each entry point to prepare the slurry of drilling mud.
• Extra temporary workspace is required at each entry/exit point for equipment, dewatering pumps, generators, and the drilling mud containment. The amount of extra temporary workspace varies depending on location. A typical extra temporary workspace configuration is provided on page 14 of Attachment D.
• Access for drilling rigs, delivery of consumables and labor would be required to each drill site

A conceptual plan and profile for the HDD sequence is provided on the following page (refer to Figure 3.1.1-1). As previously mentioned, each pipe segment requires the equivalent length of temporary (false) ROW to facilitate welding prior to installation. Therefore, due to physical constraints (homes, Kimmes and South Irondale Roads to the west and the Pokegama River to the east), the temporary (false) ROW must be located within the PC as illustrated on Figure 3.1.1-1. Each segment would be installed as follows:

1. The entry point for Segment #1 is located at MP 1094, which is approximately 2,112 feet from the Pokegama River. A 250 foot by 150 foot extra temporary workspace is required at this location. The
entry point can be accessed from a road that terminates at the Town of Superior’s waste water lagoons. The exit point is located approximately 720 feet west of the Canadian National rail yard. An approximately 11,800 foot timber mat road is required to access the exit point. This mat road must be installed prior to commencing the first HDD segment and would remain in place until the final segment is complete to allow drilling equipment, stringing trucks, excavators, personnel, and other related equipment.

2. The Southern Lights Diluent pipe for Segment #3 is strung and welded along the temporary (false) ROW from the exit point of Segment #1 west toward the exit point of Segment #2 and installed.

3. An approximately 300 foot long section of pipeline must be traditionally installed to connect Segment #1 to Segment #2.

4. The Southern Lights Diluent pipe for Segment #2 is strung and welded along the temporary (false) ROW from the exit point of Segment #2 west toward the entry point of Segment #3 and installed.

5. An approximately 300 foot long section of pipeline must be traditionally installed to connect Segment #1 to Segment #2.

6. Due to the homes located north and south of Kimmes Road and South Irondale Road to west, there the Southern Lights Diluent pipe for Segment #3 is strung and welded along the temporary (false) ROW from the exit point of Segment #2 east toward the entry point of Segment #3 and installed.

7. Steps 2 through 6 are then repeated for the Alberta Clipper pipeline.

8. Assuming that each segment for each pipeline requires 65 days to install, the entire HDD sequence require approximately 390 days to complete.
Figure 3.1.1-1  Pokegama - Carnegie Wetland Complex
PRELIMINARY DRAFT - CONCEPTUAL HDD PLAN
3.1.1.1 Advantages

Advantages of HDD include:

- No sediment release unless an inadvertent release of drilling mud (frac-out) occurs;
- Minimal excavations;
- Impacts would be restricted to entry and exit areas, false right-of-way for pipe string make-up, and access roads.
- Less temporary clearing acres; and
- Not likely to adversely affect habitat unless frac-out occurs.

3.1.1.2 Disadvantages

Disadvantages of HDD include:

- Relatively large adjacent work areas are required at both the drill entrance and exit locations;
- Unknown subsurface features (e.g. boulders, fractures, unconsolidated material) can compromise the success of the drill;
- Significant amounts of water are required to create the drilling mud, which would need to be hauled to the drill segment entry points or from temporary dewatering wells as there is no surface water body in close proximity. Installation of temporary dewatering wells could impact the hydrology of the wetlands as the appropriation would be consumptive;
- In the event that a drilling segment is unsuccessful, any further attempts must be located a minimum of 25 feet north of the failed section;
- Disposal of drilling fluid must be accounted for;
- Location and extent of frac-outs cannot be predicted;
- If a frac-out occurs, it is unlikely that any topsoil could be salvaged during drilling fluid recovery activities;
- Length of time to accomplish (approximately 390 days versus three weeks to one month by traditional construction methods);
- An approximately 11,800 foot timber mat road must remain within the PC for over one year to allow daily equipment access, fueling and dewatering activities;
- Access to the ATV/snowmobile trail that transects the ROW would be restricted due to the mat road.
- Fuel must be transported by tanker truck to the drill rigs along the timber mat road, which would occur on a frequent basis during the 390 day drilling program. Therefore, there is a higher potential for diesel fuel releases within wetlands along the timber mat access road;
- In order to meet the targeted July 1, 2010 in-service date, HDD activities need to commence by June 1, 2009;
- Due to the length and magnitude of completing six HDDs, the six residences along Kimmes Road would experience a significant increase in disruption;
- Road restrictions in the spring of 2010 could prohibit activities for up to two months if equipment cannot be transported on South Irondale or Kimmes Roads; therefore, the final HDD segment could be delayed (390 days total to 450 days);
- In general, Enbridge has experienced difficulties securing sufficient drilling contractor resources. Therefore, a drilling program of this magnitude could be prohibitive from a contractor perspective;
- Successful installation using the HDD or guided bore method cannot be guaranteed. If unsuccessful, the pipelines must be installed using traditional open trench methods; and
• If an internal inspection identifies an anomaly once a pipeline is operational that has been installed using HDD, it cannot be repaired as it is too deep to excavate; therefore, it must be abandoned in place and a new pipeline must be installed either by another HDD or traditional construction techniques.

### 3.1.1.3 Costs

A summary of the estimated incremental cost incurred to the Project to install the Alberta Clipper and Southern Lights Diluent pipelines by HDD is provided in Table 3.1.1.3-1. Cost information is based on actual costs for the Southern Access Stages I and II projects, and the LSr project. The costs were provided by Precision Pipeline, who is the contractor for the Wisconsin portion of the Alberta Clipper and Southern Lights Pipeline Projects. The total estimated cost to the Project to install both pipelines by HDD is $16,864,400, as opposed to $6,088,936 for traditional construction techniques (a 64 percent increase).

#### Table 3.1.1.3-1

<table>
<thead>
<tr>
<th>Cost Category</th>
<th>20-inch Pipeline Installation (per foot)</th>
<th>20-inch Pipeline Installation Cost</th>
<th>36-inch Pipeline Installation (per foot)</th>
<th>36-inch Pipeline Installation Cost</th>
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<td>$110</td>
<td>$1,952,720</td>
<td>$233</td>
<td>$4,136,216</td>
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<tr>
<td>Horizontal Directional Drill Installations</td>
<td>$350</td>
<td>$6,213,200</td>
<td>$600</td>
<td>$10,561,200</td>
</tr>
</tbody>
</table>

1. Assumes a crossing length of 17,752 feet.

### 3.1.1.4 Conclusions

HDD installation of the Alberta Clipper and Southern Lights pipelines through the PC is not practicable as it does not avoid impacts to wetlands, does not completely avoid open trench construction, jeopardizes the Project in-service date, and is cost prohibitive. Additional environmental concerns are associated with the HDD installations that are not associated with the traditional installation method. A water source is needed for the creation of drilling mud, which would require temporary dewatering wells that could adversely impact the wetlands. The HDD method creates drilling mud waste that must be properly disposed. A timber mat road must remain in place during the entire HDD process to transport the large numbers of fuel trucks needed for the project. The increase in number of fuel trucks results in an increase risk of fuel spills. While the HDD installation requires fewer direct wetland impacts than the traditional method, 300 foot segments of open trench installation is needed to connect the pipe segments installed by HDD. Therefore, some direct impacts are unavoidable. Finally, the success of the HDD installation cannot be guaranteed. Therefore, it may be that the portions of the HDD that were not successful would need to be abandoned in place and new pipe installed resulting in additional impacts.
Figure 3.2
Alberta Clipper and Southern Lights Diluent Projects
Typical Wetland Right-of-Way Configuration in
The Pokegama-Carnegie Wetland Complex
(Wisconsin Only)

- Typical existing row boundary defined by location of southern most pipeline: up to 25 feet to the south and 100 feet to the north.
- Temporary workspace adjacent to new additional ROW will be required to install the pipeline(s). Typically 50' in width in wetlands and the length of the ROW will be rented from landowners. Additional temporary workspace at civil and environmental crossings of up to 75' in width and up to 300' in length on each side of the crossing will be rented.
3.2 Minimization by Reconfiguration of the Construction ROW and Pipeline Spacing

Initially, Enbridge intended to install the new pipelines south of the existing corridor between mileposts 1090.6 and 1094.1 using: (1) an industry standard 25-foot separation between pipelines, (2) a 125-foot wide construction corridor, and (3) adding an additional 50 feet of permanently maintained corridor to the existing permanently maintained corridor width (refer to Figures 2.1 and 2.2). This configuration would have extended the existing corridor from 125 to 175 feet by adding an additional 50 feet of permanently maintained corridor to the south. Enbridge reviewed the workspace configuration within the PC and identified an alternative construction configuration to further minimize the impacts to wetlands within this area. By moving the new pipelines to the north, reducing the spacing between pipelines, and reducing the operational buffer, Enbridge effectively reduces the originally proposed new additional permanently maintained corridor from 50 feet to 10 feet within the PC. (Figure 3.2) resulting in a substantial reduction in scrub-shrub and forested wetland impacts. While these alternative techniques reduce the environmental impacts, they also increase the possibility of a reduction in the overall margin of safety and integrity for the pipelines in operations mode. Therefore, they are techniques that are considered and implemented only in limited site specific circumstances as explained further below.

3.3 Minimization by Decreasing Line Separation, Construction ROW, and Permanently Maintained Corridor Widths

Between milepost 1090.6 and 1093.8, Enbridge will reduce the spacing between the pipelines from 25 feet to 20 feet as a result of the predominance of compact, fine-textured clay that Enbridge believes will allow a reduction in line separation without reducing pipeline integrity and constructability issues that are typical of looser, less cohesive sediments. The existing maintained permanent ROW is 125 feet, which extends 50 feet to the north of the northernmost pipeline (Line 4). The Southern Lights Diluent pipeline will be installed 20 feet north of Line 4 and the Alberta Clipper pipeline will be installed 20 feet north of the Southern Lights Diluent pipeline (Figure 3.2).

In addition, Enbridge proposes to reduce the originally proposed 25-foot buffer to be maintained north of the Alberta Clipper pipeline to 20 feet. Enbridge is able to reduce the buffer in this area due to the current land use to the north of the pipelines. The typical 25-foot buffer between the outermost pipeline is necessary to help prevent the encroachment of adjoining landowners (structures, excavation, etc.), which is a significant safety concern. However, development by adjoining landowners within this area is highly unlikely, as it is currently Douglas County Forest. Therefore, Enbridge is agreeable to reducing the buffer to 20 feet instead of the typical 25 feet (Figure 3.2).

3.4 Minimization of Temporary Impacts by Developing and Implementing a Construction, Restoration, and Maintenance Plan

Site-specific modifications to construction, restoration, and operations procedures will further minimize and/or eliminate impacts to the sensitive resources contained within the PC. Enbridge has drafted a site-specific construction, restoration, and maintenance plan for the Pokegama-Carnegie Wetland Complex that was submitted previously under separate cover, which provides essential background and describes site-specific modifications to standard wetland and waterbody crossing procedures that will minimize and/or eliminate adverse impacts that could result from the Project construction.
Attachment A

Preferred Route Maps
Alberta Clipper and Southern Lights Pipeline Projects
Pokegama-Carnegie Wetland Complex Alternatives
Preferred Route

This information is for environmental review purposes only.

DATE: 04/01/09 DRAWN BY: RGCutting
REVISED: 04/01/09

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1:32,000

Preferred Route
Contaminated Site
Commercially Navigable Water
EPA DW Region 5
National OPA
National ESA Enbridge
National HPA
National DW Enbridge

Miles
0 0.5 1
0 1 2
Alberta Clipper and Southern Lights Pipeline Projects
Pokegama-Carnegie Wetland Complex Alternatives
Preferred Route

This information is for environmental review purposes only.

0.51 Miles

DATE: 04/01/09 REVISED: 04/01/09 DRAWN BY: RG Cutting
Alberta Clipper and Southern Lights Pipeline Projects
Pokegama-Carnegie Wetland Complex Alternatives
Preferred Route
St. Louis
Douglas
Alberta Clipper and Southern Lights Pipeline Projects
Pokegama-Carnegie Wetland Complex Alternatives
Preferred Route

This information is for environmental review purposes only.

0.51 Miles

Preferred Route
Lake Superior Basin Priority Site
ASNRI
Wild Rice Area
ASNRI Waterbodies
Priority SAMP Wetland
NERR Boundary
NERR Core Area
Wetland Mitigation Site

DATE: 04/01/09 DRAWN BY: MLTeichert
REVIEWED: 04/01/09

M:\Clients\D-F\EEL\Alberta_Clipper\ArcGIS\2009\WI_Alternatives\WI_Overview_Water2.mxd

1:32,000
Attachment B

Route Variation PC1 Maps
St. Louis

Douglas

Alberta Clipper and Southern Lights Pipeline Projects
Pokegama-Carnegie Wetland Complex Alternatives
Alternative 1

This information is for environmental review purposes only.
Alberta Clipper and Southern Lights Pipeline Projects

Pokegama-Carnegie Wetland Complex Alternatives

Alternative 1

This information is for environmental review purposes only.
Alberta Clipper and Southern Lights Pipeline Projects
Pokegama-Carnegie Wetland Complex Alternatives
Alternative 1

This information is for environmental review purposes only.
Alberta Clipper and Southern Lights Pipeline Projects
Pokégama-Carnegie Wetland Complex Alternatives
Alternative 1

PC Alternative 1

Wetland Mitigation Site

Priority SAMP Wetland

NERR Core Area

NERR Boundary

ASNRI Waterbodies

ASNRI

Wild Rice Area

Lake Superior Basin Priority Site
Attachment C

Route Variation PC2 Maps
Alberta Clipper and Southern Lights Pipeline Projects
Pokegama-Carnegie Wetland Complex Alternatives
Alternative 2

This information is for environmental review purposes only.

PC Alternative 2
Contaminated Site
Commercially Navigable Water

EPA DW Region 5
National OPA
National DW Enbridge
National HPA
National ESA Enbridge
National OPA

DATE: 04/01/09 REVISED: 04/01/09 DRAWN BY: RGCutting
St. Louis

Douglas

Alberta Clipper and Southern Lights Pipeline Projects

Pokegama-Carnegie Wetland Complex Alternatives

Alternative 2

This information is for environmental review purposes only.

PC Alternative 2  Waterbodies
Wisconsin Wetland Inventory

DATE: 04/01/09 DRAWN BY: MLTeichert
REVISED: 04/01/09

1:32,000

Alberta Clipper and Southern Lights Pipeline Projects
Pokegama-Carnegie Wetland Complex Alternatives
Alternative 2
Alberta Clipper and Southern Lights Pipeline Projects
Pokegama-Carnegie Wetland Complex Alternatives
Alternative 2
Alberta Clipper and Southern Lights Pipeline Projects
Pokegama-Carnegie Wetland Complex Alternatives
Alternative 3
Alberta Clipper and Southern Lights Pipeline Projects
Pokegama-Carnegie Wetland Complex Alternatives
Alternative 3
Attachment E

Excerpts of Alberta Clipper and Southern Lights Diluent Commercial Agreements
August 28, 2008

In Reply Refer To:
Enbridge Energy, Limited Partnership
Docket No. OR08-12-000

Enbridge Energy, Limited Partnership
1330 Connecticut Avenue, NW
Washington, DC 20036

Attention:  Steven Reed
Attorney for Enbridge Energy, Limited Partnership

Reference:  Approval of Offer of Settlement

Dear Mr. Reed:

1. On June 27, 2008, Enbridge Energy, Limited Partnership (Enbridge Energy),\(^1\) with the support of the Canadian Association of Petroleum Producers (CAPP),\(^2\) filed an Offer

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\(^1\) Enbridge Energy states that it operates the U.S. portion of the Enbridge System, which is a major crude oil pipeline system providing transportation of Western Canadian oil to the U.S. Midwest and points in Eastern Canada and New York State. Enbridge Energy states that this portion, which is commonly referred to as the Lakehead System, is subject to the jurisdiction of this Commission. Enbridge Energy further states that the Canadian portion of the Enbridge System is operated by Enbridge Pipelines Inc. (EPI) and is regulated by the National Energy Board (NEB) in Canada. According to Enbridge Energy, EPI has received approval from the NEB for the Canadian aspects of this project. (Enbridge Pipelines Inc., Alberta Clipper Project, Docket No. OH-4-2007 (Feb. 2008). Enbridge Energy states that construction of the Canadian portion of the Alberta Clipper will commence in August 2008.

\(^2\) Enbridge Energy states that CAPP producer members account for more than 95 percent of Canada’s oil and gas production and that approximately 97 percent of the crude petroleum transported on the Enbridge System originates in Canada.
of Settlement (Settlement) under the Facilities Surcharge mechanism previously approved by the Commission.\(^3\) By this Settlement, Enbridge Energy seeks Commission approval to implement an additional component of the Facilities Surcharge to permit recovery by Enbridge Energy of the costs of a planned expansion of its mainline capacity from the international border near Neche, North Dakota, to Superior, Wisconsin (the Alberta Clipper Project). Enbridge Energy explains that this Settlement pertains to the recovery of costs associated with the expansion of mainline capacity on the Lakehead System. Enbridge Energy emphasizes that both parties seek Commission approval of the Settlement as a whole because they agreed to it as a package deal.

2. Flint Hills Resources, LP submitted comments stating that it does not object to the Settlement. No other persons filed comments or objections to the Settlement. The Commission finds that the subject Settlement is uncontested, and is approving it as it appears fair and reasonable and in the public interest.

3. Enbridge Energy explains that the proposed expansion of the Lakehead System in the U.S. is a significant part of the larger Alberta Clipper Project, but clarifies that the Commission is not being asked to determine any regulatory issues relating to the Canadian portion of the expansion project, which has been approved by the NEB. Because of substantial investment in new facilities to develop Western Canada’s abundant crude oil resources, Enbridge Energy anticipates an increase in the supply of Canadian crude oil available for export to U.S. markets. According to Enbridge Energy, this will require significant transportation infrastructure expansion, and the Alberta Clipper Project will improve the pipeline system’s upstream capability to balance the increased capacity available from the Southern Access Mainline Expansion between Superior, Wisconsin, and Flanagan, Illinois, which the Commission addressed in accepting a previous offer of settlement.\(^4\) Because the Alberta Clipper Project involves a coordinated expansion of capacity in both Canada and the U.S., Enbridge Energy emphasizes that, on both sides of the border, the system will initially be able to transport an additional 450,000 barrels per day (bpd), with the potential for expansion up to 800,000 bpd.

4. Enbridge Energy states that the U.S. portion of the project includes approximately 325 miles of new 36-inch pipeline between the International Border and Superior, Wisconsin, along with three new pump stations at existing pump locations and five 250,000-barrel breakout tanks at Superior. Enbridge Energy estimates that the cost of the U.S. portion to be recovered through the Facilities Surcharge is approximately $1.1 billion in 2007 U.S. dollars (all of which will be incurred and recovered solely by


Docket No. OR08-12-000

Enbridge Energy). However, Enbridge Energy explains that the Canadian portion of the project will add approximately 665 miles of new pipeline from Hardisty, Alberta, to the International Border at a cost of approximately $2.0 billion in 2007 Canadian dollars (to be incurred and recovered by ENP). Enbridge Energy projects that the entire project will be completed and placed in service between January 1, 2010, and July 1, 2010.

5. Because the Alberta Clipper Project will enhance service to all shippers, Enbridge Energy states that it has agreed with CAPP that the costs associated with the expansion should be borne by shippers to all delivery points on the Lakehead System in accordance with Enbridge Energy’s existing distance-based rate design, which is consistent with Commission precedent for oil pipelines. Enbridge Energy emphasizes that, as a common carrier, it is open to all shippers nominating oil on the pipeline and that the project will help relieve existing capacity constraints, thereby benefitting the entire system and, further, that with the surcharge applicable across the system, all shippers will pay in accordance with their usage of the system.

6. Enbridge Energy details the specific terms of the surcharge calculation in Exhibit I attached to its filing. It states that, in general, it will recover the cost of service of the U.S. portion of the project through a surcharge that will be included in the Facilities Surcharge added to the indexed base rates and other existing surcharges currently in effect for Enbridge Energy. Enbridge Energy states that the surcharge will be calculated on a cost-of-service basis and true-up annually in a manner similar to the treatment of current surcharges under the Facilities Surcharge Mechanism at such time as the Alberta Clipper facilities go into service, based on an estimate of the first year’s projected costs and throughput volumes. Thereafter, continues Enbridge Energy, on April 1 of each succeeding year, Enbridge Energy will adjust the surcharge to true-up the prior year’s costs and throughput volumes to actual data and to reflect the projected costs and throughput volumes for the then-current year in accordance with the term sheet. Enbridge Energy adds that the Alberta Clipper surcharge will remain in effect for fifteen years. Enbridge Energy states that CAPP has agreed to the terms of the cost-of-service calculation supporting the surcharge.

7. The Commission approves the Settlement, finding that it appears fair, reasonable, and in the public interest. Approval of the Settlement does not constitute approval of any other project beyond the scope of this proceeding. The Commission’s approval of the

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Docket No. OR08-12-000

Settlement does not constitute acceptance of, or precedent regarding, any principle or issue in this proceeding.

By direction of the Commission.

Kimberly D. Bose,
Secretary.
June 27, 2008

The Hon. Kimberly D. Bose  
Secretary  
Federal Energy Regulatory Commission  
888 First Street, NE  
Washington, DC 20426

Re: Enbridge Energy, Limited Partnership,  
Docket No. OR08-____-000  
Offer of Settlement

Dear Secretary Bose:

Attached for filing is an Offer of Settlement submitted by Enbridge Energy, Limited Partnership, a common carrier oil pipeline, with the support of the Canadian Association of Petroleum Producers. Because no proceeding is currently ongoing in which this Offer of Settlement can be docketed, Enbridge Energy requests that an OR docket be established for consideration of this proposed settlement.

Under 18 C.F.R. § 385.602(f)(2) (2007), comments on this Offer of Settlement are due within 20 days of the date of this filing, which is July 17, 2008. Thank you.

Sincerely,

/s/ Steven Reed  
Steven Reed
OFFER OF SETTLEMENT

Pursuant to 18 C.F.R. § 385.602 (2007), Enbridge Energy, Limited Partnership ("Enbridge Energy"), a common carrier oil pipeline regulated by the Commission, hereby submits this Offer of Settlement under the Facilities Surcharge mechanism approved by the Commission in Enbridge Energy, Limited Partnership, 107 FERC ¶ 61,336 (2004) ("Facilities Surcharge Order"). With the support of the Canadian Association of Petroleum Producers ("CAPP"), an association that represents the producers of virtually all of the crude petroleum transported by Enbridge Energy,\(^1\) the settling parties seek Commission approval to implement an additional component of the Facilities Surcharge to permit recovery by Enbridge Energy of the costs of a planned expansion of its mainline capacity from the international border near Neche, North Dakota to Superior, Wisconsin (the "Alberta Clipper project").

Enbridge Energy operates the U.S. portion of the Enbridge System, which is a major crude oil pipeline system providing transportation of Western Canadian oil to the U.S. Midwest and points in Eastern Canada and New York State.\(^2\) The Canadian portion of the Enbridge System originates in Canada. Affidavit of László Varsányi ("Varsányi Aff.") at ¶ 9 (Exhibit IV hereto).

\(^1\) CAPP producer members account for more than 95 percent of Canada’s oil and gas production. Approximately 97 percent of the crude petroleum transported on the Enbridge System originates in Canada. Affidavit of László Varsányi ("Varsányi Aff.") at ¶ 9 (Exhibit IV hereto).

\(^2\) Components of the Enbridge System, including the planned Alberta Clipper project, are depicted on the map attached as Exhibit III hereto.
System is operated by Enbridge Pipelines Inc. ("EPI") and is regulated by the National Energy Board ("NEB") in Canada. The U.S. portion, which is commonly referred to as the "Lakehead System," is operated by Enbridge Energy subject to this Commission's jurisdiction. This Offer of Settlement pertains solely to the Lakehead System, and in particular to the recovery of costs associated with the expansion of mainline capacity on that system.\(^3\)

The agreement between Enbridge Energy and CAPP, embodied in the Alberta Clipper U.S. Term Sheet attached hereto as Exhibit I, is explained in detail below. Enbridge wishes to emphasize at the beginning that the terms of the agreement were the result of negotiations, and that both parties accepted it as a package deal. The terms of the agreement are interconnected, and neither party would necessarily have entered into the agreement if certain provisions were changed or absent. Varsányi Aff., Ex. IV, at ¶ 12. Therefore it is important to both parties that the Commission accept the settlement as a whole.

This Offer of Settlement is being filed now in order to give public notice of the addition of the Alberta Clipper project component to the Facilities Surcharge and to request approval to implement the new component when the Alberta Clipper project facilities are placed in service. Construction of the Canadian portion of Alberta Clipper will commence in August 2008.

**EXPLANATORY STATEMENT**

I. **Overview of Facilities Surcharge Mechanism**

The Facilities Surcharge, as approved by the Commission in the *Facilities Surcharge Order*, allows Enbridge Energy to recover the costs associated with particular shipper-requested projects through an incremental surcharge added to the existing base rates and other

\(^3\) EPI has made an application to the NEB and received approval with respect to the Canadian aspects of this project. *Enbridge Pipelines Inc., Alberta Clipper Project*, Docket No. OH-4-2007 (Feb. 2008).
Commission-approved surcharges already in effect. The Facilities Surcharge Mechanism is intended to be a transparent, cost-of-service-based tariff mechanism that will be trued-up each year to actual costs and throughput and that will therefore not be subject to adjustment either upwards or downwards under indexing. *Facilities Surcharge Order at P 2.*

The particular projects to be included are determined as the result of a negotiating process between Enbridge Energy and CAPP. As described in the Affidavit of László Varsányi (attached hereto as Exhibit IV), CAPP represents the upstream oil and natural gas industry in Canada. With approximately 140 member companies that produce more than 95 percent of Canada’s crude oil, CAPP, through its committees, negotiates with pipelines to ensure fair pipeline transportation practices and rates. *See Varsányi Aff., Ex. IV, at ¶ 9.* CAPP’s letter of support for the Alberta Clipper Project and the related surcharge terms is attached as Exhibit 11.

At the time of the establishment of the Facilities Surcharge, Enbridge Energy and CAPP had identified four specific projects for inclusion in the original surcharge. *4 Facilities Surcharge Order at P 3.* However, the Facilities Surcharge framework was expressly designed to be open-ended, and the Commission accepted Enbridge Energy’s proposal “to submit for Commission review and approval, future agreements resulting from negotiations with CAPP where the parties have agreed that recovery of the costs through the Facilities Surcharge is desirable and appropriate.” *Id.* at P 1. Thus, a supplemental Offer of Settlement was approved on March 16, 2006 for the Southern Access Mainline Expansion as consistent with the intent of the Facilities.

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4 The first four projects were: (1) Superior Manifold Modification Project; (2) Griffith Hartsdale Transfer Lines Project; (3) Hartsdale Tank Charge; and (4) Line 17 Expansion Project (Toledo).
Surcharge framework as previously approved by the Commission. Three additional agreements were submitted for inclusion in the Facilities Surcharge effective April 1, 2008.

II. The Alberta Clipper Expansion

As noted above, the proposed expansion of the Lakehead System in the U.S. is a significant part of a larger project known as Alberta Clipper. This section will describe the overall Alberta Clipper project in order to provide the Commission a context for the U.S. portion, which is the subject of this Offer of Settlement. This information is intended to aid the Commission in understanding the systemwide benefits of the U.S. portion of Alberta Clipper and should not be read to suggest that the Commission is being asked to determine any regulatory issues relating to the Canadian portion of this expansion project, which has already been approved by the NEB.

Based on the substantial capital investment currently being made in new facilities to develop Western Canada’s abundant oil sands resources, as well as the continuing development of Canadian heavy oil reserves, Enbridge Energy anticipates an increase in the supply of Canadian crude oil available for export to U.S. markets. Varsányi Aff. Ex. IV, at ¶ 6. The Commission has previously taken notice of this “expected significant increase in Western Canadian crude oil production over the next decade” and the associated benefits to domestic refiners of having access to this source of refinery feedstock to offset declining domestic crude oil production in the Mid-Continental area. Enbridge Energy Co., Inc., 110 FERC ¶ 61,211 at P 3

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5 The fifth agreement, Southern Access Mainline Expansion, was approved in Enbridge Energy, Limited Partnership, 114 FERC ¶ 61,264 (2006).

6 The three additional agreements were filed as a tariff, docketed as IS08-153-000, to become effective April 1, 2008. On April 17, 2008, the Commission published a notice of the amendment under docket number OR08-10-000, providing a 20-day comment period. No comments were filed, and that docket remains pending at this time.
(2005). The Alberta Clipper project is prompted in large part by the projected need for significant infrastructure expansion in coming years to transport the expected increase in Canadian crude oil imports to the U.S. (offsetting supplies otherwise required from more volatile sources overseas). It also increases Enbridge Energy’s upstream capability to balance the increased capacity available from the Southern Access Mainline Expansion between Superior, Wisconsin and Flanagan, Illinois, which was the subject of a previous offer of settlement approved by the Commission. *Enbridge Energy, Ltd. P’ship*, 114 FERC ¶ 61,264 (2006).

As discussed in the Varsányi Affidavit, at ¶¶ 2-5, the Alberta Clipper project as a whole involves a coordinated expansion of the capacity of the Enbridge System (both in Canada and the U.S.) from Hardisty, Alberta to Superior, Wisconsin. On both sides of the international border, the system will initially be able to transport an additional 450,000 barrels per day (“bpd”), eventually expandable up to 800,000 bpd. Specifically, when the project is completed, EPI will have additional incremental capacity between Hardisty, Alberta and the international border near Neche, North Dakota, *id.* at ¶ 3, and Enbridge Energy will have additional incremental capacity from the international border to Superior, Wisconsin (and points south). *Id.* at ¶ 4.

The U.S. portion of Alberta Clipper includes approximately 325 miles of new 36-inch pipeline between the international border and Superior along with three new pump stations at existing pump locations and five 250,000-barrel breakout tanks at Superior. *Id.* The current estimate of the cost of the U.S. portion to be recovered through the Facilities Surcharge is approximately $1.1 billion in 2007 U.S. dollars (all of which will be incurred and recovered solely by Enbridge Energy). *Id.* at ¶ 5. The expansion project’s Canadian portion will add approximately 665 miles of new pipeline from Hardisty, Alberta to the international border. *Id.* at ¶ 3. The Canadian portion costs are estimated to be approximately $2.0 billion in 2007.
Canadian dollars (to be incurred and recovered by EPI). Id. at ¶ 5. The entire project is expected to be completed and placed into service between January 1, 2010 and July 1, 2010. Id. The map attached hereto as Exhibit III shows the planned expansion project.

Completion of the total Alberta Clipper project will create a new 990-mile pipeline with approximately 450,000 bpd of incremental capacity, upgradeable to 800,000 bpd. This new pipeline will substantially increase the capability of the Lakehead System and other Enbridge pipelines to transport Canadian crude oil production to Chicago, Illinois, Cushing, Oklahoma, eastern PADD II, and potentially PADD III markets in the future, avoiding what would otherwise become a bottleneck that would significantly inhibit the access of Canadian crude to these important markets. The U.S. portion of Alberta Clipper will be fully integrated into the Lakehead System both operationally and from a rate perspective, as more fully discussed below.

III. Public Interest And Shipper/Producer Benefits Of The Proposed Alberta Clipper Project

As described in detail in the Varsányi Affidavit, the principal benefit of the Alberta Clipper project will be increased capacity. Id. at ¶ 6. As noted above, the construction of the Southern Access Mainline Expansion pipeline, which extends south from Superior to serve the Chicago, Cushing and other markets, needs to be balanced by creation of equivalent new capacity upstream of Superior. Id. at ¶ 7. The Alberta Clipper project will benefit all shippers by offering sufficient capacity to relieve bottlenecks and avoid projected apportionment of scarce capacity.

Among the other significant benefits of the Alberta Clipper project are:

- balanced capacity across the mainline system;
- improved utilization of existing infrastructure;
- improved crude quality; and
operational synergies in the form of reduced power consumption per barrel and lower operating costs.

As explained by Mr. Varsányi, the benefit of balanced capacity is significant because the Enbridge mainline system has multiple lines coming into Superior, Wisconsin, where the system splits into one line going north of Lake Michigan and several lines going south towards Chicago. If there is greater aggregate capacity upstream of Superior than downstream (or vice versa), then a portion of Enbridge's overall capacity cannot be efficiently utilized. Through Alberta Clipper, the upstream and downstream capacity will be brought into alignment, which permits highly efficient utilization of the full system capacity. *Id.* at ¶ 7. The balanced capacity thus improves utilization of existing infrastructure, which benefits all shippers by maximizing the throughput that can be transported through facilities that are already in place.

Alberta Clipper will also facilitate various operational efficiencies. By adding an additional large capacity line between Hardisty and Superior, Enbridge will be able to reallocate crude streams between the available pipelines to increase crude separation (leading to improved crude quality) and to reduce power costs per barrel (which tend to be driven up when heavier crudes are moved in smaller diameter pipelines). *Id.* at ¶ 8. The allocation of crude streams reduces power costs per barrel, because the addition of the new pipeline will allow two larger diameter pipelines to be allocated to heavy crude oil service. This allocation assures that neither heavy oil line will be at the extreme end of its power curve, where the per-unit cost of moving an incremental barrel of oil is highest. This will result in lower power costs per barrel overall. In addition, the construction of Alberta Clipper will allow another of the upstream lines to be allocated to conventional and synthetic light crude oil service.
IV. Terms of the Proposed Surcharge -- Overview

Because the Alberta Clipper project will enhance service to all shippers, Enbridge Energy and CAPP have agreed that the costs associated with the expansion should be borne by shippers to all delivery points on the Lakehead System in accordance with Enbridge Energy's existing distance-based rate design. This rate design is consistent with Commission precedent for oil pipelines. See, e.g., SFPP, L.P., 102 FERC ¶ 61,089 at PP 14-18, order denying reh'g, 104 FERC ¶ 61,163 at PP 10-11 (2003); Colonial Pipeline Co., 116 FERC ¶ 61,078 at PP 54-57 (2006), order denying reh'g, 119 FERC ¶ 61,183 at PP 13-19 (2007); Calnev Pipe Line LLC, 120 FERC ¶ 61,073 at PP 13, 30 (2007). As a common carrier, Enbridge Energy is open to all shippers nominating oil to the pipeline. With increasing nominations expected in coming years, any shortage of capacity at the origination of the Lakehead System would necessarily affect shippers across the board. The Alberta Clipper project will help relieve existing capacity constraints, thereby providing benefits to the system as a whole. Accordingly, CAPP and Enbridge Energy have agreed to a surcharge that will apply across the system so that all shippers pay in accordance with their usage of the system.

The specific terms of the surcharge calculation are set forth in Exhibit I attached hereto and are explained in detail in the section-by-section description set forth in Part V below. In general, Enbridge Energy will recover the cost of service of the U.S. portion of the Alberta Clipper project through a surcharge, which will be included in the Facilities Surcharge added to the indexed base rates and other existing surcharges currently in effect for Enbridge Energy. The surcharge will be calculated on a cost of service basis and trued-up annually in a similar manner to the existing surcharges under the Facilities Surcharge mechanism. In particular, Enbridge Energy will include Alberta Clipper in the Facilities Surcharge Mechanism at such time as the Alberta Clipper facilities go into service, based on an estimate of the first year's projected costs.
and throughput volumes. Thereafter, on April 1 of each succeeding year, Enbridge Energy will adjust the surcharge to true-up the prior year’s costs and throughput volumes to actual data and to reflect the projected costs and throughput volumes for the then-current year in accordance with the term sheet. The Alberta Clipper surcharge will remain in effect for 15 years.

As set forth in Exhibit I, the terms of the cost-of-service calculation supporting the surcharge have been agreed upon between CAPP and Enbridge Energy. Enbridge Energy will use the Commission’s Opinion No. 154-B methodology, but employing a stipulated capital structure that will remain fixed at 55 percent equity, 45 percent debt. The stipulated annual depreciation rate for long-lived assets will be based on a 30-year life (subject to possible future adjustment if Enbridge Energy’s overall depreciation rates change). The stipulated cost of debt for each year will be the weighted average long-term cost of debt incurred by Enbridge Energy for the Alberta Clipper project. The stipulated cost of equity will be fixed at the NEB multi-pipeline rate plus 225 basis points. The tax allowance component of the cost of service will be determined each year in accordance with the FERC’s tax allowance policy in effect in such year.

As described in the Varsáni Affidavit, the Alberta Clipper term sheet contains a number of innovative terms regarding cost recovery that are designed to provide Enbridge Energy with incentives to construct and operate the pipeline in an efficient manner. Varsáni Aff., Ex. IV, at ¶¶ 15-16. With respect to capital costs, the parties have created two categories: “non-controllable costs” that are to be included in the surcharge calculation in full and “controllable costs” that are subject to a negotiated risk-sharing mechanism. In particular, if the controllable costs for the U.S. portion of Alberta Clipper exceed $806.28 million, a portion of the excess is

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excluded from rate base (i.e., 25 percent of the excess up to $982.77 million and 50 percent of the excess above that level is excluded if there are controllable cost overruns). On the other hand, if the controllable costs are less than $806.28 million, then an incremental amount is added to the rate base within the negotiated surcharge formula (i.e., 25 percent of the saved costs between $806.28 million and $626.77 million and 50 percent of the savings below $626.77 million). This balanced mechanism provides a strong incentive to the pipeline to minimize controllable capital costs, while protecting shippers against unplanned cost overruns. See id. at ¶ 15.

Similarly, for operating expenses there is a mechanism to encourage greater cost efficiency on the carrier’s part. Id. at ¶ 16. Power costs (which are treated as noncontrollable) are flowed-through to the surcharge on an annual basis. However, all other operating expenses are subject to a modified index approach, with a periodic resetting of the base cost estimate based on actual experience. Thus, operating expenses (other than power costs) are estimated in the initial year and escalated annually for three five-year periods. The escalation factor used to calculate operating expenses will be a five-year average of the producer price index ("PPI") plus 50 percent of any amount by which the FERC index varies from the PPI. The operating expenses are re-based every five years using the average actual operating expenses from the prior two years. Thus, any cost savings achieved by the pipeline are eventually flowed through to shippers, but in the short run the pipeline is encouraged to operate in a cost-effective manner, similar to the incentives provided by the Commission’s overall indexing methodology.
V. Section-by-Section Explanation of Term Sheet\textsuperscript{8}

The Alberta Clipper U.S. Term Sheet provides as follows:

- **Preface:** Defines terms in the agreement.

- **Paragraph One:** Sets forth the scope of the project in the U.S. as 325 miles of new 36-inch pipeline from Neche to Superior with an initial annual capacity of 450,000 bpd expandable up to 800,000 bpd, assuming 100 percent heavy crude service, with a target service in service date of July 1, 2010. *See also Ex. I, Schedule A.*

- **Paragraph Two:** Sets the term of the agreement at 15 years from its in-service date and requires renegotiation beginning two years before the end of the term, which is subject to dispute resolution if the parties have not reached agreement after one and a half years.

- **Paragraph Three:** Sets the formula for calculating the revenue required to be covered by the surcharge, which is the Commission’s Opinion No. 154-B methodology using the following stipulated inputs:
  
  (a) 45 percent debt and 55 percent equity capital structure;

  (b) rate base consisting of the following:

  (i) all reasonable capital costs subject to risk sharing in Paragraphs 5 and 7;

  (ii) stipulated annual maintenance capital costs for each year of the term, *see Ex. I, Schedule B;*

  (iii) stipulated pipeline integrity capital costs for each year of the term, *see Ex. I, Schedule C;\textsuperscript{9}

  (iv) a monthly calculated allowance for funds using during construction ("AFUDC") using a specified formula, *see Ex. I, Schedule D;*

  (v) an allowance for working capital (1/12 of annual operating expenses plus annual power costs); and

\textsuperscript{8} This summary explanation of the term sheet is provided solely for the convenience of the Commission in reviewing the Offer of Settlement. In the event of any dispute, the language of the term sheet is intended to prevail over this or any other summary description.

\textsuperscript{9} Unscheduled pipeline integrity capital costs are permitted only for "sabotage or annual replacement of pipe" in excess of a specified length. *See Ex. I at 5 (Paragraph 3(b)(iii)(2)).
(vi) straight-line depreciation (costs in accounts 152-161) over a 30-year period unless the FERC approves a longer period for new long-lived assets;

(c) annual return on equity ("ROE") equal to the NEB multi-pipeline rate plus 225 basis points. If the NEB stops using such a rate, the parties have 90 days to agree to a new rate; otherwise, the ROE for Alberta Clipper Canada will apply;

(d) weighted average cost of long-term debt incurred by Enbridge Energy for the Alberta Clipper project;

(e) an income tax allowance under the Commission’s then-current policy;

(f) operating expenses consisting of:

(i) estimated general operating, maintenance and administrative expenses escalated annually using the FERC escalation factor (or if no longer in existence or not based on PPI, EELP’s reasonable proxy that may be approved by FERC) based on three consecutive periods of five years and re-based every five years using the average actual operating expenses from the prior two years x 150 percent of applicable escalation factor; property taxes will be treated similarly, except will be re-based using actual property taxes during the last year of each five-year period; see also Ex. I, Schedules E and F;

(ii) power costs on a flow through basis;

(iii) annual pipeline integrity costs as stipulated in Schedule G, see Ex. I, Schedule G, plus certain specified unscheduled pipeline integrity operating expenses; and

(iv) other recoverable operating expenses resulting from changes in legislation, regulations, orders, etc., provided that costs arising from “non-mandatory guidelines” are subject to CAPP approval.

* Paragraph Four: Provides that the revenue requirement shall be recovered through the facilities surcharge framework based initially on projected costs and throughputs and true-up every April 1 using actuals. The final true-up will be performed within three months after the expiration of the agreement, which will be recovered or credited over the following year. See also Ex. I, Schedule II. 
- Paragraph Five: Sets forth the capital cost risk-sharing mechanism based on a probabilistic analysis of controllable and non-controllable costs, which permits inclusion of all non-controllable costs, but excludes or includes set percentages of controllable costs to the extent they meet or exceed certain thresholds.

- Paragraph Six: Provides that the Lakehead System rules and regulations tariff applies.

- Paragraph Seven: Targets an in-service date of July 1, 2010 subject to unavoidable events or regulatory delays, which defer the in-service date; otherwise a delay will result in $230,136.98 per day deduction from the rate base.

- Paragraph Eight: Provides for testing of the initial capacity to confirm actual operating capacity. To the extent the capacity is below the target, the percentage it is below capacity will be deducted from rate base until the capacity is restored.

- Paragraph Nine: Provides CAPP the right, upon reasonable written notice, to review and audit Alberta Clipper’s proposed expense procedures and allocation of controllable versus non-controllable costs. An audit of capital costs is also available within two years of in-service date. Within one year of re-basings, an audit of operating costs and property taxes is also available.

- Paragraph Ten: Provides that any new contract carriage projects will not use the mainline system without CAPP approval and that any new common carrier projects affecting the term sheet will be negotiated with CAPP.

- Paragraph Eleven: Provides for recovery of other capital costs resulting from legislation, regulations, etc. by a governmental body.

- Paragraph Twelve: Sets forth dispute resolution provisions.

- Paragraph Thirteen: Provides for crediting to the Alberta Clipper surcharge of revenue otherwise retained by Enbridge Energy in connection with the Southern Access Mainline Expansion project for “qualifying volumes” above 400,000 bpd.

- Paragraph Fourteen: Requires approval by the NEB and FERC.

- Paragraph Fifteen: Provides that the Term Sheet is an integrated agreement that is intended to be approved as a negotiated package.
COMMUNICATIONS

Communications regarding this Offer of Settlement should be addressed to:

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10 Enbridge Energy requests, to the extent necessary, a waiver of Rule 203(b)(3), 18 C.F.R. § 385.203(b)(3), limiting to two names the persons upon whom service is to be made.
CONCLUSION

For the reasons set forth above, Enbridge Energy respectfully requests that, pursuant to 18 C.F.R. § 385.602, the Commission approve the settlement between Enbridge Energy and CAPP embodied in the term sheet and permit the Alberta Clipper surcharge under the Facilities Surcharge mechanism to take effect at such time as the relevant facilities are placed in service, as requested herein.11 As with the original Offer of Settlement that resulted in the Facilities Surcharge Order, Enbridge Energy proposes that the Commission follow its Rule 602 procedures for processing this Offer of Settlement. In particular, parties seeking to comment on any aspect of the proposed settlement should be required to do so within 20 days of the date of the filing of this Offer of Settlement (Rule 602(0)(2)).12 Reply comments would then be due 10 days later. Following receipt of comments and reply comments, if any, the Commission should proceed to consider and accept this Offer of Settlement, as requested above.

Respectfully submitted,

/s/ Steven Reed
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Counsel for Enbridge Energy, Limited Partnership

June 27, 2008

11 Enbridge Energy requests that the Commission waive the filing requirements under 18 C.F.R. §§ 342.1, 342.3(a), and 342.4 to the extent necessary to facilitate the filing of this proposed surcharge. The Commission’s approval of this Offer of Settlement will not constitute approval of, or precedent regarding, any principle or issue settled.

12 For convenience, a form of Notice of Settlement is attached hereto.
Alberta Clipper U.S. Term Sheet

This term sheet sets forth certain terms concerning the U.S. segment of the proposed expansion of the EELP System in the U.S. and Mainline System in Canada, which expansion is referred to as "Alberta Clipper", which involves construction of a new pipeline to transport heavy crude petroleum from Hardisty, Alberta to Superior, Wisconsin.

For purposes of this term sheet:

"Alberta Clipper Canada" means the Canadian segment of Alberta Clipper.


"Alberta Clipper U.S." means the U.S. segment of Alberta Clipper.

"Allowance for Funds Used During Construction" or "AFUDC" means the allowance referenced in Paragraph 3(b)(vi) hereof.

"Allowance for Working Capital" means the allowance described in Paragraph 3(b)(v) hereof.

"CAPP" means the Canadian Association of Petroleum Producers.

"Capital Costs" means all costs incurred by EELP in seeking and obtaining regulatory approval for and in the development, design, procurement, installation, construction and commissioning of Alberta Clipper U.S.

"CFR" means the U.S. Code of Federal Regulations, as amended from time to time.

"Controllable Costs" means the Capital Costs of Alberta Clipper U.S., excluding the Non-Controllable Costs.

"Cost of Debt" means the cost of debt described in Paragraph 3(d) hereof.

"Dollars" or "$" means U.S. dollars.

"EELP" means Enbridge Energy, Limited Partnership.

"EELP System" means the crude oil and liquid petroleum pipeline that extends from the international border near Neche, North Dakota to the international border near Marysville, Michigan with an extension across the Niagara River into
the Buffalo, New York area, owned by EELP and regulated by the FERC, as such pipeline may be expanded or modified from time to time.

"EEP" means Enbridge Energy Partners, L.P.

"Enbridge" means EPI and EELP collectively.

"EPI" means Enbridge Pipelines Inc.

"Escalation Factor" means the sum of (a) the percent change (expressed as a decimal) in the PPI published in May of any year from the PPI published in the immediately preceding May, plus (b) fifty percent (50%) of any amount by which the Index promulgated by the FERC under 18 CFR § 342.3, varies from PPI.

"FERC" means the U.S. Federal Energy Regulatory Commission.


"FSM" means the Facilities Surcharge Mechanism that is under negotiation between EELP and CAPP and that is the subject of an offer of settlement between EELP and CAPP approved by the FERC on June 30, 2004 in Docket No. OR04-2-000, as amended from time to time by agreement between EELP and CAPP.

"In-Service Date" means the date upon which Alberta Clipper Canada is able to accept oil.

"Investment Dealer" means a U.S. based investment dealer reasonably considered to be a market maker for investment grade U.S. pipeline debt securities including Banc of America Securities, Citigroup Global Markets, Deutsche Bank Securities, Merrill Lynch and Wachovia Capital Markets (or their respective successors).

"Mainline System" means the crude oil and liquid petroleum pipeline that extends from Edmonton Alberta to the U.S. border near Gretna, Manitoba and includes Alberta Clipper Canada as well as all of the EPI pipeline operations regulated by the Canadian National Energy Board, including all facilities and operations associated with the Terrace Expansion (but not including Line 8 or Line 9), as such system may be expanded or modified from time to time.

"Maintenance Capital Costs" means the costs described in Paragraph 3(b)(ii) hereof.
"NEB" means the Canadian National Energy Board.

"Non-Controllable Costs" means the Capital Costs for which estimates are set forth in Part I of Schedule I attached to this term sheet.

"Parties" means CAPP and EELP collectively; "Party" means either CAPP or EELP.

"Pipeline Integrity Capital Costs" means the costs described in Paragraph 3(b)(ii) hereof.

"PPI" means the final Producer Price Index for Finished Goods (PPI-FG) published by the U.S. Bureau of Labor Statistics in May of each year.

"ROE" has the meaning set forth in Paragraph 3(c) hereof.

"S&P" means Standard & Poor's Rating Services (or its successor).

Certain other terms are defined elsewhere in this term sheet. In addition, the word "including" means "including without limitation," and the word "hereof" refers to this term sheet as a whole.

1. **Project Scope**

   The project scope of Alberta Clipper U.S. is described in Schedule A attached to this term sheet. The project will include all necessary infrastructure to manage the transportation of 450,000 barrels per day of heavy capacity on Alberta Clipper U.S. under ordinary operating conditions and all terminal and related facilities (not including delivery tankage) to facilitate such transportation.

2. **Term**

   (a) The term of this term sheet (the "Term") will commence on the date of a duly authorized letter of support from CAPP, fully endorsing this term sheet and will continue until the fifteenth anniversary of the In-Service Date of Alberta Clipper U.S.

   (b) 24 months prior to the expiration of the Term, the Parties will begin negotiating a new agreement that will become effective upon expiry of this term sheet. If the Parties do not reach a new agreement at least 6 months prior to expiry of this term sheet, the terms of the new agreement shall be subject to the dispute resolution provisions set forth in Paragraph 12 hereof.
3. Revenue Requirement

Alberta Clipper U.S.' revenue requirement (the "Revenue Requirement"), which will be recovered as a surcharge, will be calculated in accordance with FERC Opinion 154-B, using the amounts provided for herein as relevant input.

The Revenue Requirement shall be calculated as set forth in this Paragraph 3.

(a) Capital Structure

The capital structure will be a stipulated capital structure consisting of 45% debt and 55% equity.

(b) Rate Base

The rate base of Alberta Clipper U.S. will (except as provided in Paragraphs 5 and 7 below) comprise all Capital Costs, Maintenance Capital Costs, Pipeline Integrity Capital Costs, the Allowance for Funds Used During Construction, the Allowance for Working Capital, and deferred earnings and accumulated deferred income tax adjustment (as calculated pursuant to FERC Opinion 154-B or subsequent decisions), less cumulative depreciation, subject to the provisions of Paragraph 8 below.

The capital structure specified in Paragraph 3(a) will be applied to the rate base for calculation of the Equity Return and Cost of Debt.

(i) Capital Costs

Except as provided in Paragraph 5 below, all reasonable Capital Costs will be capitalized and included in the rate base.

(ii) Maintenance Capital Costs

Maintenance capital costs will be capitalized and included in the rate base. The amounts that will be included in the rate base for maintenance capital costs for the Term will be fixed per Schedule B attached hereto.
(iii) Pipeline Integrity Capital Costs

(1) Scheduled pipeline integrity related capital costs for the Alberta Clipper U.S. will be capitalized and included in the rate base subject to the maximum amounts set forth in Schedule C attached hereto.

(2) There will also be capitalized and included in the rate base any unscheduled pipeline integrity capital costs for Alberta Clipper U.S. resulting from sabotage or annual replacement of pipe in excess of the product of (a) five miles, and (b) the ratio that Alberta Clipper U.S. bears to the total length of Alberta Clipper, where repair methods (such as sleeve repair) cannot be suitably implemented.

(iv) Allowance for Funds Used During Construction ("AFUDC")

Subject to Paragraph 5 below, AFUDC will be calculated on a monthly basis by multiplying the cost of the construction work in progress, including any existing AFUDC balance, by a rate equal to EELP's weighted average cost of capital using the capital structure specified in Paragraph 3(a), 1/12th of the annual ROE specified in Paragraph 3(c), and 1/12th of EELP's annual weighted average cost of debt including short term debt borrowed under EEP's commercial paper program or drawn under EEP's bank credit and on-lent to EELP via intercompany debt on terms that are substantially the same as the terms of EEP's short-term debt specifically attributed to the Alberta Clipper U.S. cost of construction work in progress. If, on the date upon which the interest rate is specified for any short-term debt amount outstanding, EEP's long-term debt is rated lower than BBB by S&P, the interest cost shall be set at the corresponding short-term interest cost stipulated within EEP's bank credit facility agreement, as amended, for EEP as a BBB rated entity by S&P.

An example of the calculation of AFUDC using illustrative numbers is set forth in Schedule D attached hereto.
(v) Allowance for Working Capital

An amount equal to one twelfth (1/12) of the sum of (1) the annual Operating Expenses described in Paragraph 3(f) hereof, plus (2) the annual power costs described in Paragraph 3(f) hereof will be included in the rate base as an allowance for working capital. If the annual Operating Expenses and power costs increase, one twelfth (1/12) of the annual increase shall be added to the allowance for working capital included in the rate base. If the annual Operating Expenses and power costs decrease, one twelfth (1/12) of the annual decrease shall be subtracted from the allowance for working capital included in the rate base.

(vi) Depreciation

All items included in the rate base, except for the Allowance for Working Capital, will be subject to depreciation. Costs that fall within accounts 152 through 161 of 18 CFR Part 352 will be depreciated as follows:

1. All such initial costs will be depreciated on a straight line basis over a 30 year period (i.e., 3 1/3% p.a.), beginning with the in-service date of Alberta Clipper;

2. All such costs incurred after the in-service date of Alberta Clipper will be depreciated on a straight line basis over a 30 year period (i.e., 3 1/3% p.a.), beginning with the date of installation of such items; and

3. In the event that, during the Term, any periodic depreciation studies of Long Lived Assets are, subject to any approval or comment rights that CAPP may have under the Alberta Clipper Canada Settlement, submitted by EELP to the FERC, which (a) extend the economic planning horizon beyond 2040, and (b) are accepted by the FERC, then the depreciation of Long Lived Assets will be based on that new expected economic life. In the event that, during the Term, any periodic depreciation studies of items that are not Long Lived Assets are,
subject to any approval or comment rights that
CAPP may have under the Alberta Clipper
Canada Settlement, submitted by EELP to the
FERC, which are accepted by the FERC then
the depreciation of such assets will be based
on the expected economic life approved by the
FERC.

(c) Return on Equity

The annual return on equity ("ROE") for Alberta Clipper U.S.
will be equal to the NEB multi-pipeline rate plus a 225 basis
point adjustment. If the NEB ceases to publish a multi-
pipeline rate during the Term, the Parties will meet to agree
on a new benchmark to which will be applied the 225 basis
point adjustment (or such other basis point adjustment as
shall result in an ROE that is reasonably equivalent to the
NEB multi-pipeline rate plus 225 basis points). If such
agreement is not forthcoming within 90 days, then the ROE
for Alberta Clipper Canada, as determined pursuant to the
provisions of the Alberta Clipper Canada Settlement, will
apply to Alberta Clipper U.S.

(d) Cost of Debt

(i) The Cost of Debt will be the weighted average cost of
long-term debt incurred by EEP, and on-lent to EELP
via intercompany debt on terms that are substantially
the same as the terms of the EEP debt. EEP, acting
reasonably, will seek to issue the Alberta Clipper U.S.
long-term debt at points of time either shortly before
or shortly after the In-Service Date in order to take
advantage of suitable market conditions. EEP will
issue debt securities in notional sizes and maturities
that seek to minimize refinancing risks while
managing total interest cost. Issuances of EEP debt
securities will be specifically attributed to Alberta
Clipper U.S., in whole or in part, to match the
aggregate debt component of the Alberta Clipper U.S.
rate base. EELP will notify CAPP within fifteen
business days after the receipt of proceeds of such
debt.

(ii) To the extent any Alberta Clipper U.S. long-term debt
matures during the Term, the interest cost of the then-
issued refinancing debt will be incorporated into the
Cost of Debt. Unless the Cost of Debt is determined
in accordance with Section 3(d)(i), EELP will actively manage the issuance of the appropriate amount of debt associated with Alberta Clipper U.S. in a commercially reasonable manner throughout the Term.

(iii) If, on the closing date of any such debt security issuance specifically attributed to Alberta Clipper U.S., the specific long-term debt security issued by EEP is rated lower than BBB by S&P, EELP shall promptly endeavor to obtain from five (5) Investment Dealers an indicative quote (or quotes, in the case of multiple tranches of debt securities) representing the all-in cost of debt issued by a US pipeline company with an S&P rating of BBB, where the terms of the indicative debt match those of the specific long-term debt security issued by EEP. Upon receipt of the five (5) Investment Dealer indicative quotes, an average cost of debt will be calculated excluding the highest and lowest indicative quoted costs of debt, and this average Cost of Debt will apply in lieu of the Cost of Debt determined in accordance with clause (i) above. If EELP is unable, using reasonable effort, to obtain at least three (3) Investment Dealer indicative quotes, the Parties shall endeavor to agree upon the appropriate Cost of Debt. If the Parties are unable to reach agreement on the Cost of Debt, the Cost of Debt shall be subject to the dispute resolution provisions set forth in Paragraph 12 hereof.

(iv) The Cost of Debt shall not be determined on a project financing basis.

(e) **Income Tax Allowance**

An allowance for federal and state income taxes will be based on the applicable earnings amount, statutory tax rates, and the normalized methodology for accounting for income taxes.

If the FERC modifies its tax allowance policy, an allowance for federal and state income taxes will be determined each year in accordance with the FERC’s tax allowance policy in effect in such year for pipelines comparable to EELP.
(f) Operating Expenses

(i) General Operating, Maintenance and Administrative Expenses

(1) EELP will estimate the initial annual operating, maintenance and administrative costs (collectively, "Operating Expenses") of Alberta Clipper U.S., including a separate line item for property taxes (as addressed in Paragraph 3(f)(i)(4) below), but excluding power costs and pipeline integrity maintenance and operating expenses. That estimate will apply for the initial year of operation. Thereafter, Operating Expenses for Alberta Clipper U.S. will be escalated annually using the Escalation Factor, for three consecutive periods of five year commencing on the in-service date of Alberta Clipper.

General and Administrative Expenses provided for in the estimate of Operating Expenses will be included according to the methodology used by EELP as of the date of this term sheet, as amended from time to time by EELP.

(2) If FERC either ceases to promulgate an index or promulgates an index that is not based on PPI, the Escalation Factor shall be modified to mean the reasonably equivalent proxy selected by EELP in its reasonable discretion. If CAPP does not approve the selected substitute as a reasonably equivalent proxy, CAPP shall be entitled to refer the substitution to the FERC, which shall either confirm EELP's selection or select an alternative proxy that the FERC deems to be a better equivalent to the Escalation Factor as defined at the beginning of this term sheet.

(3) Operating Expenses (excluding property taxes) will be re-based at the end of each five year period (i.e., on the fifth and tenth anniversaries of the in-service date of Alberta Clipper), based on the product of (a) the average of actual Operating Expenses during the last two years
of each such five year period, multiplied by (b) 150% of the then-applicable Escalation Factor.

(4) EELP will estimate the initial annual property taxes for Alberta Clipper U.S. Property taxes will be re-based at the end of each five year period (i.e., on the fifth and tenth anniversaries of the in-service date of Alberta Clipper) based on actual property taxes during the last year of each five year period. If, for any year after the first year of each five year period, the actual property taxes for Alberta Clipper U.S. are less or more than EELP’s estimate or escalated estimate of property taxes, such positive or negative variance shall be split equally between EELP and the Alberta Clipper U.S. shippers.

An illustrative, non-binding schedule of Operating Expenses, including property taxes, for the first year of service of Alberta Clipper U.S. is attached as Schedule E to this term sheet.

An illustration of the re-basing of Operating Expenses and property taxes is attached as Schedule F to this term sheet.

(ii) Power Costs

Power will be charged on a flow-through basis.

(iii) Pipeline Integrity

(1) Scheduled pipeline integrity operating expenses for Alberta Clipper U.S. will be fixed per Schedule G attached to this term sheet.

(2) Any unscheduled pipeline integrity operating expenses for Alberta Clipper U.S. resulting from sabotage or annual replacement of pipe in excess of the product of (a) five miles, and (b) the ratio that Alberta Clipper U.S. bears to the total length of the Alberta Clipper, where repair methods (such as sleeve repair) cannot be suitably implemented, will be included.
(iv) **Other (Operating Expense) Recoverables**

Operating Expenses resulting from legislation, regulations, orders, directions or non-mandatory guidelines by any government authority which result in changes to health, safety, environmental, security, anti-terrorism and taxation requirements, practices or procedures for EELP will be included in the Revenue Requirement; provided that the inclusion in the Revenue Requirement of Operating Expenses resulting from compliance with non-mandatory guidelines shall be subject to agreement with CAPP.

4. **Revenue Requirement Adjustment**

The Revenue Requirement of Alberta Clipper U.S. will be recovered through the facilities surcharge, which is part of the system-wide rates of the EELP system. EELP will, at the time Alberta Clipper goes into service, file the surcharge based on the first year's projected costs and EELP throughput volumes. Thereafter, in addition to the re-basings and adjustments provided for in Paragraphs 3(b) and 3(f) of this term sheet, on April 1 of each succeeding year, EELP will adjust the surcharge to reflect (i) any over-collections or under-collections resulting from actual EELP throughput volumes in the immediately preceding year being more or less than projected throughput volumes for such year, (ii) any over-collections or under-collections resulting from actual costs in the immediately preceding year being less or more than projected costs for such year, and (iii) projected costs and EELP throughput volumes for the then-current year. Such true-ups will reflect carrying charges at a rate equal to the average of the 12 monthly bank rates for the prior year published as Series V122530 by the Bank of Canada on its website, or any successor thereto. EELP will perform a final true-up of actual to projected costs and throughput volumes within three months after the expiration of the Term. If the final true-up discloses a difference between the projected costs and throughput volumes and the actual data, such difference (negative or positive) shall be recovered or credited on throughput volumes over the following twelve month-period.

An illustration of the EELP rate structure will be finalized by the Parties and attached to this term sheet as Schedule H on or before October 15, 2007.

5. **Capital Cost Risk Sharing**

(a) **Schedule I** attached to this term sheet sets forth the results of a probabilistic analysis of the Controllable Costs and Non-
Controllable Costs, based on the May, 2007 estimate, to determine the P10, P55, and P90 amounts to be utilized in this Paragraph 6.

(b) The full amount of actual Non-Controllable Costs for Alberta Clipper U.S. (including AFUDC thereon) will be included in the Alberta Clipper U.S. rate base.

The Capital Costs included in the Alberta Clipper U.S. rate base for actual Controllable Costs will be calculated as provided below.

(i) If actual Controllable Costs for Alberta Clipper U.S. (such costs, "ACC") incurred in construction are equal to or greater than the P90 amount set forth in Part 2 of Schedule 1, the amount to be included for Controllable Costs shall equal:

\[ \bullet \ P55 + (0.75 \times (P90 - P55)) + (0.50 \times (ACC - P90)) \]

(ii) If ACC incurred in construction are less than the P90 amount but greater than the P55 amount set forth in Part 2 of Schedule 1, the amount to be included for Controllable Costs shall equal:

\[ \bullet \ P55 + 0.75 \times (ACC - P55) \]

(iii) If ACC incurred in construction are less than the P55 amount but greater than the P10 amount set forth in Part 2 of Schedule 1, the amount to be included for Controllable Costs shall equal:

\[ \bullet \ ACC + 0.25 \times (P55 - ACC) \]

(iv) If ACC incurred in construction are equal to or less than the P10 amount set forth in Part 2 of Schedule 1, the amount to be included for Controllable Costs shall equal:

\[ \bullet \ ACC + (0.25 \times (P55 - P10)) + (0.50 \times (P10 - ACC)) \]

No AFUDC will be included in the Alberta Clipper U.S. rate base on the amount of ACC that is excluded from such rate base through the application of the foregoing risk sharing mechanisms.

Illustrations of the foregoing risk sharing mechanisms are set forth in Schedule 1 attached to this term sheet.
6. Rules and Regulations

Alberta Clipper U.S. will be subject to the Rules and Regulations Tariffs of EELP for the EELP System, as amended from time to time.

7. In-Service Date

(a) The targeted In-Service Date of Alberta Clipper U.S. is July 1, 2010 (the “Targeted Date”) and EELP will use commercially reasonable efforts to achieve the Targeted Date. As of the date of this term sheet, subject to timely receipt of all necessary governmental authorizations, orders, certificates, licenses, permits and approvals, EELP proposes to commence construction of Alberta Clipper U.S. in August, 2008. If commencement of construction of Alberta Clipper U.S. is delayed beyond August, 2008 (or any replacement date selected by EELP for the commencement of construction), or if the actual In-Service Date is delayed to a date that is later than the Targeted Date set forth above, in either case, as a result of any Unavoidable Event or Regulatory Delay, then, the Targeted Date shall be deferred by one day for each day of such delay.

For the purposes of this term sheet:

“Unavoidable Event” shall mean: (1) compliance with acts, orders, regulations, or requests of any governmental authority or any person purporting to act therefore; (2) insurrections, wars, rebellion, riots, strikes, or labor disruptions; (3) action of the elements not reasonably preventable or accidental disruption; (4) breakdown of production or transportation facilities that is not reasonably preventable; (5) any event that is an “Unavoidable Event” as defined in the Alberta Clipper Canada Settlement; and (6) any other cause, whether or not of the same class or kind, reasonably beyond EELP’s control.

“Regulatory Delay” shall mean any problems or delays in obtaining governmental or regulatory authorizations, orders, certificates, licenses, permits and approvals required or desirable in connection with the construction of Alberta Clipper.

(b) For any day after the Targeted Date that Alberta Clipper U.S. is not available to accept oil, an amount equal to (i) $7 million, multiplied by (ii) 12, divided by (iii) 365 will be
deducted from the Capital Costs included in Alberta Clipper U.S.' rate base.

8. Initial Capacity Verification Process

(a) The capacity provided by Alberta Clipper may be tested to confirm the actual operating capacity after the project is completed. Any such test will be performed by EELP at the time or times requested in writing by CAPP, except that no such test shall be performed at any time when either Alberta Clipper U.S. or Alberta Clipper Canada is subject to an Unavoidable Event. Subject to the immediately preceding sentence, EELP will be required to conduct the test within two months of receiving the notice from CAPP unless another date is mutually agreed upon.

(b) The capacity test parameters will be consistent with the Terrace agreement (a 72 hour test targeting operating capacity, and EELP has the option to retest).

(c) Subject to Unavoidable Event exceptions, over the 72 hour period the line must achieve 105.5% of annual capacity of 450,000 barrels per day, adjusted for seasonal temperatures, consistent with the test parameters set forth in the Terrace agreement (the "Target Capacity").

(d) If the Target Capacity cannot be achieved for the test period (other than by reason of an Unavoidable Event), then, until capacity of Alberta Clipper is restored to at least the Target Capacity, Alberta Clipper U.S.' rate base will be reduced by a fraction, the numerator of which is the amount by which capacity is less than the Target Capacity and the denominator of which is the Target Capacity.

9. Audit and Review

(a) Audit/Review of Cost Allocation

Upon reasonable written notice to EELP by CAPP, but subject to EELP's confidentiality obligations to third parties, CAPP may elect to conduct the following review and audit, upon and subject to the terms set forth in this Paragraph 9:

(i) Prior to issuance of FERC's approval of Alberta Clipper U.S., a review of (y) EELP's proposed procedures to ensure that expenses of Alberta Clipper U.S. will be appropriately coded and (z) EELP's proposed allocation of Capital Costs between
Controllable Costs and Non-Controllable Costs. The review will include each segment as defined in EELP's costing documents;

(ii) On or before the second anniversary of the In-Service Date of Alberta Clipper U.S., an audit of the Capital Costs of Alberta Clipper U.S. The range of such audit shall cover such data as shall be needed to reasonably confirm whether inclusion of Capital Costs has been appropriate and whether all Capital Costs components have been fairly allocated; and

(iii) Not later than one year after the effective date of any re-basings of Operating Costs and property taxes of Alberta Clipper U.S., audits of such re-basings. The range of any such audit shall cover such data as shall be needed to reasonably confirm whether expenses have been fairly allocated for the purposes of re-basing the Operating Costs and property taxes. No more than one audit shall be conducted for each re-basing.

(b) CAPP Auditors

For purposes of performing the review and audit functions described in Paragraph 9(a) hereof, independent parties will be selected by CAPP, subject to EELP's approval, which approval shall not be unreasonably withheld (the "Auditors"). EELP will not withhold approval of independent auditors selected by CAPP and approved by EPI pursuant to the Alberta Clipper Canada Settlement, provided such independent auditors are properly qualified and licensed in the applicable jurisdictions to perform the review and/or audits, as applicable, described in this Paragraph 9. The review and audits shall each be conducted during normal business hours. EELP will provide the Auditors with reasonable access to EELP source data necessary for the conduct of the review and audit. The Auditors will maintain confidentiality and not disclose source data reasonably identified by EELP as confidential. Source data which is subject to any form of legal privilege will not be made available.

(c) Conduct of Review/Audit

With respect to the review and audits described in Paragraph 9(a), each of the Auditors will:

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execute and deliver a confidentiality agreement with EELP prior to commencing the review and another confidentiality agreement prior to commencing each audit. Each such confidentiality agreement shall be in form and substance acceptable to EELP;

(ii) subject to (iii) below, for purposes of the review described in Paragraph 9(a)(i) and the audit described in Paragraph 9(a)(ii) have access to all historical EELP source data regarding Capital Cost expenditures, and for purposes of the audits described in Paragraph 9(a)(iii) have access to a maximum of two years of historical EELP source data; and

(iii) have access to EELP auditors’ working papers, where EELP is able, through its use of reasonable commercial efforts, to cause the disclosure of such working papers to CAPP.

(d) No Further Reviews or Audits

Upon completion of the review described in Paragraph 9(a)(i) and audits described in Paragraphs 9(a)(ii) and (iii), and upon resolution of any issues arising as a result of such review and/or audit, no further review or audit shall be conducted by CAPP pursuant to this Paragraph 9.

The CAPP review will be deemed to be complete no later than one year following the execution of the confidentiality agreement required by EELP for the review unless otherwise agreed to by CAPP and EELP. Each CAPP audit will be deemed to be complete no later than one year following the execution of the confidentiality agreement required by EELP for such audit unless otherwise agreed to by CAPP and EELP.

10. Upstreaming

Any New Enbridge Pipeline that is a project for contract carriage will not use any Mainline System facilities without the prior approval of CAPP, but will otherwise have no impact on this term sheet. Adjustments to this term sheet in connection with any New Enbridge Pipeline that is a common carrier project will be negotiated between EELP and CAPP prior to the construction of such project. For the purposes of this Paragraph 10, a “New Enbridge Pipeline” means a pipeline for transportation of volumes of heavy crude out of the Western Canada Sedimentary Basin in which Enbridge Inc., EELP or an entity that is owned by Enbridge Inc. or EELP
has at least a 50% ownership interest and that is constructed after the date of this term sheet.

11. Other (Capital Cost) Recoverables

Capital costs incurred by EELP in connection with Alberta Clipper U.S. resulting from legislation, regulations, orders or directions or non-mandatory guidelines by any government authority which result in changes to EELP's health, safety, environmental, security, anti-terrorism and taxation requirements, practices or procedures will be recovered through the FSM.

12. Dispute Resolution

(a) In the event of a dispute arising out of or relating to this term sheet (a "Dispute"), the Party wishing to initiate dispute resolution shall give written notice (the "Dispute Notice") to the other Party of the Dispute and outline in reasonable detail the relevant information concerning the Dispute. Within 14 days following receipt of the Dispute Notice, the Parties will each appoint representatives to meet to discuss and attempt to resolve the Dispute. Such representatives shall be individuals that are technically qualified to appreciate and assess the Dispute and have authority to negotiate the Dispute. If the Dispute is not settled within 90 days of receipt of the Dispute Notice, the negotiations will be deemed to have failed.

(b) If the Dispute is not resolved pursuant to the process in (a) above, the Dispute may be referred to the FERC by either Party, for binding resolution on an expedited basis.

(c) For the avoidance of doubt, it is expressly agreed that the reference in certain paragraphs of this settlement to dispute resolution pursuant to this Paragraph 12 is included so that there is a fallback where no agreement is reached between the Parties on certain items. All provisions of this settlement are, however, subject to the dispute resolution provisions of this Paragraph 12, whether or not such provisions expressly reference these provisions.

13. Revenue Credit

EELP will credit to the Revenue Requirement for the Alberta Clipper U.S. surcharge the portion of the revenue otherwise retained by EELP pursuant to Paragraph 6 of Exhibit III to the Offer of Settlement in FERC Docket No. OR06-3-000 (the "Retained Revenues"); provided, however, that such revenue credit would not apply unless and until the Southern Access
Mainline Expansion Qualifying Volume (as defined in Paragraph 5(d)(2) of Exhibit III) exceeds 400,000 barrels per day and then only to the extent of the overage.

14. **Condition to Implementation**

Implementation of this term sheet will be subject to (i) approval of the FERC of this term sheet, and (ii) approval by the NEB of the Alberta Clipper Canada Settlement.

15. **Interpretation**

The Parties have concluded the Alberta Clipper U.S. Term Sheet on a negotiated basis based on all of the components reflected herein. The Parties have agreed that no individual component(s) of this term sheet is to be construed as representing the position of either Party. No element of this term sheet is to be considered acceptable to either Party in isolation from all other aspects of this term sheet. The Parties' intent is that this term sheet is to be viewed as a whole and that there should be no prejudice to the positions of either Party in the future when the Term expires.
Project Scope for Alberta Clipper U.S.

Project Description

New 36 inch pipeline from near Neche, North Dakota to Superior WI with initial annual capacity of 450,000 bpd and designed for an ultimate annual capacity of 800,000 bpd, assuming 100% heavy crude service. The targeted in service date is July 1st, 2010.

US Overview

- Approximately 325 miles of new 36-inch diameter pipeline from the Canada-United States border near Neche, North Dakota to Superior, WI.
- 3 new pump stations at existing station locations
- Pump stations shall be designed such that flow of 450 kbpdp can be maintained with the loss of a single pump unit.

Terminal Scope

**Clearbrook**
- 30-inch delivery piping to main manifold with manifold connections
- 1 control valve

**Superior**
- Breakout tankage 5 X 200,000 bbls (working volume)
- 36-inch tank lines from each tank to new field booster pump manifold
- 36-inch line from tank manifold to central and heavy manifolds for connections to:
  - Southern Access Expansion (Line 61)
  - Line 6A
- Booster pumps ([3] X 1000HP)
CONFIDENTIAL

June 28, 2007

Mr. Richard Bird
President
Enbridge Pipelines Inc.
3000, 425 – 1st Street S.W.
Calgary, Alberta T2P 3L8

Dear Mr. Bird:

Re: Enbridge Pipelines’ Alberta Clipper Expansion Project

This letter confirms that pursuant to Paragraph 2 of the Alberta Clipper US Term Sheet dated June 28, 2007 between Enbridge Energy, Limited Partnership and the Canadian Association of Petroleum Producers (the “Alberta Clipper US Term Sheet”), the Canadian Association of Petroleum Producers supports the Alberta Clipper US Term Sheet and the development of a new 36" pipeline from Hardisty to Superior, with the necessary ancillary facilities, known as the Alberta Clipper Expansion Project. This will add an initial 450,000 barrels per day capacity, is targeted to be in-service by July 1, 2010 and allows expansions up to 800,000 barrels per day. Alberta Clipper will be integrated with, and form part of, the existing Enbridge Mainline system in Canada and the EEP Lakehead system in the US. The terms for the US segment of the Alberta Clipper Expansion Project are more fully described in the Alberta Clipper US Term Sheet.

Sincerely,

Greg Stringham
Vice President, Markets and Fiscal Policy
UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION

Enbridge Energy, Limited Partnership  

Docket No. OR08-__

AFFIDAVIT OF LÁSZLÓ VARSÁNYI

1. My name is László Varsányi. I have been employed by Enbridge Pipelines since 1998. I am currently the Commercial Manager, Capacity Development, in which position I am responsible for business development activities related to the company’s mainline pipeline system. I am submitting this affidavit in support of the Offer of Settlement filed by Enbridge Energy, Limited Partnership (“Enbridge Energy”) regarding the Alberta Clipper project. I have responsibility for the commercial development of this project, and this affidavit explains the characteristics of the project, the benefits expected from the project, and the rate treatment that has been agreed upon by Enbridge Energy and the Canadian Association of Petroleum Producers (“CAPP”).

I. The Alberta Clipper Project

2. The Alberta Clipper project will be a new 36-inch pipeline with an initial annual capacity to transport approximately 450,000 barrels per day (“bpd”) of heavy crude oil from Hardisty, Alberta to Superior, Wisconsin with delivery capability to Clearbrook, Minnesota. A map of the planned pipeline is included as Exhibit III to the Offer of Settlement. Alberta Clipper is designed to be expandable to an annual capacity of approximately 800,000 bpd of heavy crude through addition of added pumping power.
3. The portion of the pipeline from Hardisty to the international border (approximately 665 miles) will be an expansion of the Enbridge Mainline System owned by Enbridge Pipelines Inc. ("EPI"). The Canadian portion is regulated by the Canadian National Energy Board ("NEB"). On February 22, 2008, the NEB approved construction of the Canadian portion of Alberta Clipper, and accepted the rate terms included in the agreement between EPI and CAPP. *Enbridge Pipelines Inc., Alberta Clipper Project*, Docket No. OH-4-2007, at 53 (Feb. 2008).

4. The portion of the pipeline in the United States will run approximately 325 miles from the international border near Neche, North Dakota to Superior, Wisconsin. It will be an expansion of the Lakehead System owned and operated by Enbridge Energy, and will run alongside the existing system.¹ Alberta Clipper will be fully integrated into the Lakehead System. In addition to the pipeline, the project in the United States includes three new pump stations at existing station locations.² There will be new tankage at the terminal at Superior consisting of five new breakout tanks, each with a working volume of 200,000 barrels.³

5. The estimated cost of the U.S. portion of Alberta Clipper is $1.1 billion in 2007 U.S. dollars. The estimated cost of the Canadian portion is $2.0 billion in 2007 Canadian dollars (incurred by EPI). The targeted in-service data for shipments through Alberta Clipper is between January 1, 2010 and July 1, 2010. The construction of the Canadian portion of will begin in August 2008.

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¹ The Lakehead System is a major crude oil pipeline system providing transportation of Western Canadian oil to the U.S. Midwest and points in Eastern Canada and New York State.

² The pump stations shall be designed to maintain a flow of 450,000 bpd even if one of the pump stations is not operating.

³ The tanks have a nominal capacity of 250,000 barrels.
II. Benefits of Alberta Clipper

6. Enbridge Energy anticipates a major increase in the supply of crude oil from Western Canada available for export to the United States because of the substantial capital investment being made in new facilities in the oil sands region, which has been recognized by the Commission. Alberta Clipper will benefit U.S. refiners by providing access to that crude oil, which is more attractive than crude oil from volatile overseas sources and more plentiful than declining local U.S. domestic crude production. The Alberta Clipper pipeline will provide direct access to the Murphy refinery at Superior, Wisconsin, and indirectly to the Flint Hills and Marathon refineries at St. Paul, Minnesota. Through the Enbridge mainline and other Enbridge operated pipelines, the additional capacity unlocked by Alberta Clipper will also increase access to Canadian crude for refineries in Chicago, Illinois, Toledo, Ohio, Detroit, Michigan, and Warren, Pennsylvania. Connecting pipelines will also allow these volumes to access the crude oil pipeline hub at Patoka, Illinois from which volumes can move east to three Marathon refineries and the Husky refinery in Lima, Ohio; west to ConocoPhillips’s Wood River, Illinois facility; or to PADD III markets at the U.S. Gulf Coast.

7. Alberta Clipper will also benefit Enbridge Energy’s ability to balance capacity on its system. Enbridge is currently undertaking the Southern Access Mainline Expansion, which will increase the capacity available on its system downstream of Superior by 400,000 bpd, with an in-service target of Q1-2009.\(^4\) Alberta Clipper will provide an increase in capacity upstream of Superior, Wisconsin, which is necessary to balance the expanded downstream capacity. A balance between upstream and downstream capacity is necessary to promote efficient utilization

\(^4\) A settlement regarding the Southern Access Mainline Expansion was approved by the Commission at 114 FERC ¶ 61,264 (2006).
of total system capacity. By promoting efficient system utilization, Alberta Clipper will benefit all shippers, by maximizing the throughput available through existing infrastructure.

8. Other benefits of Alberta Clipper are related to the use and configuration of upstream pipelines. The Enbridge mainline system currently has three crude oil pipelines coming into Superior. At Superior, the system will have one line going north of Lake Michigan and three lines going south towards Chicago (once the Southern Access Mainline Expansion is completed). With Alberta Clipper, there will be four crude oil lines into and out of Superior, Wisconsin. The additional flexibility provided by the fourth upstream crude oil line will allow Enbridge Energy to allocate crude streams to particular pipelines in order to increase crude separation, which leads to improved crude quality. In addition, flexibility in allocating crude oil between pipelines will also reduce power costs. The addition of the new pipeline will allow two larger diameter pipelines to be allocated to heavy crude oil service, thereby assuring that neither heavy oil line will be at the extreme end of its power curve, where the per-unit cost of moving an incremental barrel of oil is highest. This will result in lower power costs per barrel overall. In addition, the construction of Alberta Clipper will allow another of the upstream lines to be allocated to conventional and synthetic light crude oil service. The addition of the fourth crude oil line will provide system flexibility to allocate lines by crude oil stream to move the crude oil streams or grades expected to be produced.

III. Agreed Upon Terms for Rate Treatment of the U.S. Portion of Alberta Clipper

9. As it has in the past, Enbridge Energy negotiated with CAPP to develop the commercial terms that would govern shipments on the pipeline. CAPP has approximately 140

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5 There is a fourth line into Superior, designated as Line 1, that transports refined products in Canada as well as natural gas liquids and small amounts of crude oil as buffer material.
members, who account for more than 95 percent of Canada's oil and gas production.

Approximately 97 percent of the crude petroleum transported on the Enbridge system originates in Canada. Through its committees, CAPP negotiates with pipelines to ensure fair pipeline transportation rates and practices.

10. The parties agreed to treat Alberta Clipper as a project to be covered by the Facilities Surcharge Mechanism. That negotiated framework – approved by the Commission in 2004 (107 FERC ¶ 61,336) – allows for the recovery of the cost of shipper-requested projects. The mechanism provides for a cost-of-service surcharge that can be added to existing rates, with annual true-ups. The Commission has approved the recovery of the cost of five projects under the framework, and the approval of three additional projects is pending.\(^6\)

11. Enbridge Energy and CAPP have agreed on a term sheet that sets forth the terms of the rate treatment for the Albert Clipper project. The term sheet, which was signed on June 28, 2007, has a 15-year term. Essentially CAPP, as the representative of Lakehead shippers, has agreed that a surcharge in the form prescribed in the term sheet can be added to Lakehead's existing indexed base rates and prior surcharges. The term sheet is attached as Exhibit I to the Offer of Settlement, and CAPP's letter of support is attached as Exhibit II.

12. The terms contained in the rate sheet are the result of negotiations between Enbridge Energy and CAPP, and both parties accepted it as a package deal. The terms of the agreement are interconnected, and neither party would necessarily have entered the agreement if certain provisions were changed or absent.

\(^6\) Enbridge Energy filed the surcharge for the three additional projects in tariff form, docketed as IS08-153-000, to become effective April 1, 2008. On April 17, 2008, the Commission published a notice of the amendment under docket number OR08-10-000, providing a 20 day comment period. No comments were filed, and that docket remains pending at this time.
13. The costs of Alberta Clipper will be recovered via a surcharge on all shippers, reflecting the benefit provided to all shippers by the increased capacity. The surcharge will be true-up every year, in accordance with the terms of the term sheet. Enbridge Energy will file the surcharge when the facilities go into service, based on a projection of the first year’s costs and throughput volumes. On April 1 of each year, Enbridge Energy will adjust the surcharge to true-up the prior year’s costs and volumes with actual data, and to reflect the projected costs and volumes for the current year. The surcharge will be in effect for the 15 year term of the agreement.

14. The surcharge will be calculated using the Commission’s Opinion No. 154-B methodology, with stipulated inputs. The essential terms of those inputs are:

- Capital structure of 45 percent debt / 55 percent equity.
- Return on equity equal to the NEB multi-pipeline rate plus 225 basis points. The term sheet specifies the procedures to be used if the NEB discontinues the multi-pipeline rate.
- Cost of debt will be equal to the weighted average cost of long-term debt incurred by Enbridge Energy for the Alberta Clipper project.
- Components of rate base will be subject to straight-line depreciation over 30 years. That may be adjusted if periodic depreciation studies show that Alberta Clipper has an economic planning horizon beyond 2040.
- Income tax allowance is based on the normalized methodology for accounting for income taxes, and FERC’s then-current tax allowance policy for pipelines similar to Enbridge Energy.

15. The term sheet includes a number of innovative terms that are designed to provide Enbridge Energy incentives to construct and operate the pipeline in an efficient manner. With respect to capital costs, the parties have distinguished “Non-Controllable Costs” from “Controllable Costs.” The full amount of Non-Controllable Costs will be included in the rate

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7 The complete set of terms can be found in Paragraph 3 of the term sheet. Ex. 1 at 4-11.
base. However, there is an incentive for Enbridge Energy to reduce the level of Controllable Costs. The amount of Controllable Costs that will be recovered is based upon a formula included in the term sheet. Paragraph 5(b) & Schedule J.\textsuperscript{8} Such a feature provides an incentive to the pipeline to minimize controllable costs while protecting shippers from unplanned cost overruns.

16. Operating expenses (other than power costs and pipeline integrity costs\textsuperscript{9}) will be estimated prior to the beginning of operations. Operating expenses will be adjusted each year, according to an indexing method identified in the term sheet. Paragraph 3(f)(i)(3) & 3(f)(i)(4), Ex. I at 9-10. The operating expenses are re-based every five years using the average actual operating expenses from the prior two years. This mechanism will allow cost savings to be passed along to the shippers, while providing incentives to the pipeline to operate in a cost-effective manner.

\textsuperscript{8} Ex. I at 12 & 28-29. The agreement is balanced around an estimate of $806.28 million. If the controllable costs for the U.S. portion of Alberta Clipper exceed $806.28 million, a portion of the excess is excluded from rate base (\textit{i.e.}, 25 percent of the excess up to $982.77 million and 50 percent of the excess above that level is excluded if there are controllable cost overruns). On the other hand, if the controllable costs are less the $806.28 million, then an incremental amount is added to the rate base within the negotiated surcharge formula (\textit{i.e.}, 25 percent of the saved costs between $806.28 million and $626.77 million and 50 percent of the savings below $626.77 million).

\textsuperscript{9} Power costs will be flowed through. Pipeline integrity costs will be assessed pursuant to the term sheet. Paragraph 3(f)(iii), Ex. I at 10.
I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and accurate.

Executed on June 27, 2008.

László Varsányi
121 FERC ¶ 61,310
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
SueDeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

Enbridge Pipelines (Southern Lights) LLC

Docket No. OR07-15-000

ORDER ON PETITION FOR DECLARATORY ORDER

(Issued December 31, 2007)

1. On July 20, 2007, Enbridge Pipelines (Southern Lights) LLC (Enbridge Southern
Lights) filed a petition for a declaratory order. Enbridge Southern Lights asks the
Commission to approve the proposed rate structure for the U.S. portion of the planned
Southern Lights Pipeline,\(^1\) which will transport light liquid hydrocarbons (diluent) from
Chicago, Illinois, to Edmonton, Alberta, for use in transporting heavy crude petroleum
produced from Canada’s oil sands.

2. Enbridge Southern Lights states that it is targeting a July 1, 2010 in-service date
for the Southern Lights Pipeline. According to Enbridge Southern Lights, this
construction schedule requires that necessary capital expenditures occur in 2007,
accelerating in 2008 and 2009. Enbridge Southern Lights anticipates a ruling on the NEB
application in late 2007, and it seeks similar timing from the Commission in this
proceeding.

3. The petition is unopposed, and the Commission grants the petition to the extent
discussed below.

\(^1\) Enbridge Southern Lights explains that approval of the Canadian portion of the
pipeline currently is pending before the National Energy Board of Canada (NEB) in
Enbridge Southern Lights states that it and a Canadian entity, Enbridge Southern Lights
LP (Southern Lights Canada), are subsidiaries of Enbridge Pipelines Inc. (Enbridge), a
Canadian liquids pipeline company that owns and operates an extensive system in
Canada.
Background and Overview of Petition

4. Enbridge Southern Lights emphasizes that Canadian production has been the single largest source of crude oil imported to the United States for a number of years and that the Canadian Association of Petroleum Producers (CAPP) predicts that the Canadian oil sands production will almost double by 2020. However, Enbridge Southern Lights states that, for this production to reach U.S. markets via pipeline, it must be diluted with a less dense, low viscosity material known as diluent. Enbridge Southern Lights further explains that the main source of diluent used in the transportation of Canadian oil sands production has been the condensates produced with natural gas, although the anticipated decline of conventional natural gas production in western Canada means that the associated condensate production also will decline, leaving an unmet demand for diluent, and prompting the Canadian producers to seek other sources of that product. Enbridge Southern Lights also asserts that its market research identified possible U.S. sources for diluent and concluded that the total potential U.S. diluent supply volume for the Southern Lights Pipeline could reach approximately 450,000 bpd without affecting the prices of petroleum products.

5. Enbridge Southern Lights submits that the Southern Lights project offers substantial benefits to the public and to shippers. Enbridge Southern Lights maintains that the increased supply of diluent to western Canada will increase competition for diluent in that market and, in turn, will facilitate economic, efficient production and transportation of oil sands crude. Further, states Enbridge Southern Lights, this will allow synthetic crude oil to be put to higher value uses, such as in existing refineries, which could relieve these refineries from being forced to make substantial investments to meet enhanced product specifications. Enbridge Southern Lights also cites other likely benefits, including increased availability of western Canadian oil sands production to the U.S., which will lessen U.S. reliance on sources from less stable countries, help to offset declining U.S. production levels, and minimize the need for tanker transportation of oil into the U.S.

6. Enbridge Southern Lights explains that the Southern Lights Pipeline will consist of two interconnected pipelines: (1) the U.S. portion, which will be built and operated by Enbridge Southern Lights and will extend from Chicago to the international border near Neche, North Dakota, and (2) the connecting pipeline in Canada, which will be built and operated by Southern Lights Canada and will extend from the international border to Edmonton, Alberta. Enbridge Southern Lights states that the capacity of the Southern Lights Pipeline will be approximately 180,000 barrels per day (bpd).²

² Enbridge Southern Lights states that the Affidavit of Don Thompson, Director of Light Product Development for Enbridge, which is attached as Exhibit B to its petition,
Docket No. OR07-15-000

7. Enbridge Southern Lights further explains that the U.S. portion of the pipeline will consist of two principal components: (1) a new line from Chicago to Clearbrook, Minnesota, which will be approximately 675 miles of 20-inch pipeline following existing right-of-way used by other Enbridge pipelines, and (2) the existing line from the international border to Clearbrook consisting of the 135-mile, 18-inch Line 13 that currently is part of the Lakehead system (owned and operated by Enbridge Energy Limited Partnership (Enbridge LP)). Enbridge Southern Lights states that the line from the international border to Clearbrook is used for the transportation of western Canadian crude oil from the border to Chicago and other midwestern markets.

8. Enbridge Southern Lights states that it will acquire and reverse Line 13 to integrate it into the new Southern Lights Pipeline. However, Enbridge Southern Lights states that, to prevent a reduction in the annual capacity of the Lakehead System, it will construct a new line from Clearbrook to the border to replace Line 13 (the Light Sour Pipeline or LSR) and will make certain improvements to Enbridge LP's Line 2 (together, the Replacement Facilities). Enbridge Southern Lights asserts that the Replacement Facilities will provide a modest increase in annual capacity for the Lakehead system and that each company's rate base will reflect its own expenditures incurred in providing service to its shippers.³ Enbridge Southern Lights also states that Southern Lights Canada will receive the Canadian portion of Line 13 and, in return, will construct a segment of the new LSR line from Cromer, Manitoba, to the international border.

9. Enbridge Southern Lights explains that Enbridge conducted a widely-publicized open season from May 30 through July 24, 2006. Enbridge Southern Lights describes the materials made available to current and prospective shippers, including the proposed Transportation Services Agreement (TSA),⁴ an estimate of capital costs, a pro forma rate provides complete details about the origins and nature of the project, the process Enbridge Southern Lights followed to secure supporting commitments, and the potential benefits to shippers and to the public interest. Petition for Declaratory Order of Enbridge Pipelines (Southern Lights) LLC, July 20, 2007 at Ex. B.

³ Enbridge Southern Lights states that, for an interim period after the like-kind exchange, it will lease Line 13, which will remain in southbound crude oil service. According to Enbridge Southern Lights, this will provide Lakehead shippers an increase in annual capacity of approximately 219,000 bpd. Petition for Declaratory Order of Enbridge Pipelines (Southern Lights) LLC, July 20, 2007 at Ex. B ¶ 21. Enbridge Southern Lights plans to file a separate application for Commission approval to include the cost of the Line 13 lease in its mainline tariff rates during the interim period based on cost parameters agreed to with CAPP. However, Enbridge Southern Lights notes that the relief sought in this petition is not contingent on the separate application.

⁴ The pro forma TSA is attached to the petition as Exhibit C.
model that explains the development of prospective rates, a market study, draft rules and regulations, a draft commodity specification practice, and a proposed pipeline equalization practice.\textsuperscript{5}

10. Enbridge Southern Lights asserts that it has shipper commitments to transport 77,000 bpd during the 15-year TSA term at committed rates that will recover the discounted level of cost for the pipeline.\textsuperscript{6} In addition, Enbridge Southern Lights points out that committed shippers will receive a 50-percent discount from the uncommitted rate in addition to other concessions for their long-term volume commitments. For example, continues Enbridge Southern Lights, until the end of the 10\textsuperscript{th} year of the initial 15-year term, committed shippers will have the option to extend the terms of their TSAs for an additional 15 years. Enbridge Southern Lights also emphasizes that the committed shippers agreed to pay an uncommitted tariff rate for volumes transported in excess of their committed volumes (the minimum committed volume is 5,000 bpd).\textsuperscript{7}

11. Enbridge Southern Lights summarizes the essential terms of the TSA as follows:

Committed shippers agree to ship their committed volumes or pay the committed tariff rates for the committed volumes over the 15-year term.

Committed shippers have the right, during the first 10 years, to extend the initial TSA term by 15 years at the same or reduced volumes.

Committed shippers agree to ship volumes in excess of their minimum commitment at two times the committed rate (uncommitted rate).

\textsuperscript{5} Enbridge Southern Lights explains that the pipeline equalization practice will compensate shippers for differences in the quality of diluent tendered to the pipeline for transportation.

\textsuperscript{6} Enbridge Southern Lights states that, following the initial open season, one party exercised its No-Fault Termination Right under the TSA, which gave it the right to terminate the contract by paying its pro-rata share of development costs up to that time. Enbridge Southern Lights explains that Enbridge then allowed the other committed shippers an opportunity to terminate, but none did. Therefore, continues Enbridge Southern Lights, after additional prospective shippers inquired about becoming committed shippers, Enbridge conducted a second open season ending March 28, 2007, although it did not secure any additional commitments.

\textsuperscript{7} Enbridge Southern Lights states that, if a committed shipper does not ship the minimum committed volume each month, it will be subject to a deficiency payment.
Committed rates incorporate the following principles:

Enbridge Southern Lights will set prospective rates annually based on an estimate of its costs.

Capital costs will include costs to transfer Line 13 to Enbridge Southern Lights and to modify it for new use as a diluent pipeline, costs to construct the LSR line, and costs to construct the new diluent line from Chicago to Clearbrook.

The discounted cost-of-service assumes a capital structure of 30 percent equity and 70 percent debt and a base annual equity rate of return (ROE) of 12 percent (adjusted according to the final capital cost of the project in comparison to the estimated capital cost established in September 2006).

Depreciation expense is based on a stipulated depreciation schedule resulting in a more levelized cost-of-service in real terms.

All rates are determined for movements between Chicago and the international border; shorter distance movements (if any) pay the same rate but will be credited with avoided power costs.

After the end of each year, Enbridge Southern Lights will refund to or recover from each shipper any rate differential between estimates and actual costs.

Enbridge Southern Lights will credit all uncommitted revenues to the committed and uncommitted shippers up to 90 percent of pipeline annual capacity.

Enbridge Southern Lights will retain 25 percent of any incremental revenues associated with volumes above 162,000 bpd (90 percent of annual capacity of 180,000).
12. Finally, Enbridge Southern Lights states that the Commission has recognized the need for new pipeline infrastructure and has expressed its support for such projects, including the following recent statement:

The Commission has recognized the need for investment in energy transportation infrastructure whether for electric power, natural gas or oil, to meet the nation’s growing demand for energy. Further, the Commission also has recognized that certain rate treatments are appropriate to encourage this needed investment in infrastructure.

Notice, Interventions, and Comments

13. Notice of Enbridge Southern Lights’ filing was issued on July 27, 2007. Interventions and protests were due August 10, 2007. The Alberta Department of Energy, CAPP, and Statoil North America, Inc. filed motions to intervene. BP Products North America, Inc. filed comments in support of the petition, but did not file a motion to intervene. No one filed a protest.

Discussion

14. Enbridge Southern Lights seeks certain assurances that it contends are necessary to justify the approximately $1.0 billion capital investment required for the U.S. portion of the Southern Lights project. In particular, Enbridge Southern Lights asserts that it

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9 Enbridge Southern Lights cites Colonial Pipeline Co., 116 FERC ¶ 61,078, at P 44 (2006) (Colonial); see also Rate Regulation of Certain Natural Gas Storage Facilities, 115 FERC ¶ 61,343, at P 91 (goal of creating a regulatory environment that will promote infrastructure), order on reh’g, 117 FERC ¶ 61,190 (2006). Enbridge Southern Lights adds that the Commission has created incentives to develop needed infrastructure in other industries. See Promoting Transmission Investment Through Pricing Reform, Order No. 679, FERC Stats. &Regs. ¶ 31,222 (2006), reh’g granted in part, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236, reh’g denied, 119 FERC ¶ 61,062 (2007) (issuing rules to promote investment in bulk power transmission system).

10 Statoil North America, Inc. also provided comments in support of the petition.

11 Enbridge Southern Lights states that an additional $300 million will be invested by Southern Lights Canada for the Canadian portion of the project.
needs clear assurance the terms of the TSA will control and that the Southern Lights rates will not be subject to the Commission's indexing regulations or subject to challenge on the basis that certain elements of the Schedule B cost-of-service principles depart from standard Commission ratemaking approaches. Enbridge Southern Lights emphasizes that the Commission has recognized the value of providing advance rate guidance for such projects through the declaratory order mechanism.\textsuperscript{12} Further, Enbridge Southern Lights maintains that the Commission previously has been flexible in accepting rate provisions:

The Commission has neither considered nor treated its rate methodologies as limiting its ratemaking approach or constraining it from exploring and adopting other rate approaches that are more fitting in particular circumstances to ensure that a just and reasonable rate results. The Commission has, in fact, used approaches outside its defined methodologies when circumstances have warranted.\textsuperscript{13}

\textbf{A. Rate of Return}

15. Enbridge Southern Lights explains that the TSA provides that committed rates will be calculated annually using 77,000 bpd of committed volumes as the throughput level (subject to the revenue credit for uncommitted volumes). Enbridge Southern Lights cites \textit{Express Pipeline Partnership}, 76 FERC ¶ 61,245, at 62,253 (1996):

[It] is better to address these issues \{term rate structure and validity of proposed rates\} in advance of an actual tariff filing than to defer until the rate filing is made, when the decision-making process would be constrained by the deadlines inherent in the statutory filing procedures. The public interest is better served by a review of the issues presented before a filing to put the rates into effect.

Enbridge Southern Lights adds that, on rehearing, the Commission concluded that "issuing a declaratory order \{is\} procedurally appropriate for a new oil pipeline entrant, such as Express, because it needs to acquire and guarantee financing in order to begin construction." \textit{Express Pipeline Partnership}, 77 FERC ¶ 61,188, at 61,755 (1996). \textit{See also Colonial Pipeline Co.}, 116 FERC ¶ 61,078, at P 9 (2006) (declaratory order prior to $1 billion expansion); \textit{Enbridge Energy Co., Inc.}, 110 FERC ¶ 61,211 (2005) (Spearhead Order); \textit{Plantation Pipe Line Co.}, 98 FERC ¶ 61,219 (2002).

\textsuperscript{12} \textit{Colonial Pipeline Co.}, 119 FERC ¶ 61,183, at P 23 (2007).
acknowledges that, in the Spearhead Order, the Commission suggested that the pipeline should be required to use its initial design capacity to set its first year rate,14 but Enbridge Southern Lights contends that this requirement should not apply to the proposed Southern Lights line.15 Enbridge Southern Lights also explains that, in the Spearhead Order, the Commission expressed concern that use of a lower projected throughput figure to set initial rates could permit the pipeline to over-recover its costs.16 However, Enbridge Southern Lights claims that its proposed rate methodology includes a mechanism to prevent such an over-recovery.

16. Enbridge Southern Lights explains that the TSA provides for adjusting the ROE based on Enbridge Southern Lights' performance in controlling construction costs. Specifically, continues Enbridge Southern Lights, the base ROE is set at a 12-percent nominal level, which will be adjusted depending on whether the project’s final capital cost is above or below an agreed capital cost estimate, with an upward ceiling of 14 percent nominal and a downward floor of 10 percent nominal.17


15 Enbridge Southern Lights cites Calnev Pipe Line LLC, 120 FERC ¶ 61,073, at P 28 (2007) ("The Commission recognizes that by sizing its expansion pipeline to meet future demands, Calnev is attempting to build its project in a cost effective and efficient manner.") Enbridge Southern Lights points out that the Commission’s oil pipeline regulations provide that, when a carrier is establishing rates for a new service, “the test period will be based on a 12-month projection of costs and revenues.” 18 C.F.R. § 346.2(a)(3) (2007).


17 Enbridge Southern Lights recognizes that it faces the risk that it may receive an ROE lower than that authorized for other pipelines. Enbridge Southern Lights cites Texaco Refining and Marketing, Inc. v. SFPP, L.P., 117 FERC ¶ 61,285, at P 30 (2006) (approved nominal ROEs of 14.18 percent and 13.63 for two test years). Enbridge Southern Lights also recognizes that it will have the opportunity to earn a higher ROE. It states that, even at the high end, the nominal ROE in the TSA would fall within the zone of reasonableness that the Commission has accepted for other comparably risky projects. Enbridge Southern Lights observes that, in a recent case involving a billion-dollar pipeline expansion, for example, the Commission indicated that the risks of that project merited an ROE at the high end of the zone of reasonableness:

(continued...)
17. Commission Analysis. In Opinion No. 154-B, the Commission stated that “the equity rate of return should be determined on a case-specific basis with reference to the risks and corresponding cost of capital associated with the oil pipeline whose rates are in issue.” In this case, Enbridge Southern Lights and the committed shippers have agreed to a base nominal ROE of 12 percent, which can be adjusted upward to as much as 14 percent or downward to a potential floor of 10 percent, depending on the final capital costs of the project. This gives Enbridge Southern Lights a strong incentive to control construction costs. However, Enbridge Southern Lights argues that the supply and demand risks of the project warrant a nominal 14-percent ROE for the uncommitted rates, especially as compared to recent Commission decisions relating to less risky Greenfield natural gas pipelines, where the Commission approved similar rates.

18. As it did in Colonial, the Commission finds here that several factors support Enbridge Southern Lights’ request for an ROE at the upper end of the range of reasonableness, including the size and scope of the multistate and international project, the approximately $1.3 billion investment requirement, and the length of time necessary to complete the project. Additionally, Enbridge Southern Lights has elected to build major new facilities with no guarantee that the projected throughput will be achieved.

We believe that a number of factors support Colonial’s request for an ROE toward the upper end of the zone of reasonableness. For example, the length and scope of the project will present substantial challenges, even if Colonial is able to site the expansion mainly in the existing right-of-way. The project also requires an enormous investment, and thereby presents the financing challenges not faced by the ordinary upgrade. The size of the investment, the challenges of constructing a multistate project, and the time for completion of the project (four years) all support the request for an ROE toward the upper end of the range of reasonableness. Finally, Colonial has no obligation to expand its system but has voluntarily chosen to build major new facilities, with no guarantee that the throughput would be fully used.


However, as in Colonial, the Commission will not approve a specific ROE in this proceeding.\textsuperscript{20} Instead, Enbridge Southern Lights must propose and support the ROE or the range it believes is necessary when it files to implement its actual initial rates.

B. Debt-Equity Ratio

19. Enbridge Southern Lights asks the Commission to authorize a fixed capital structure of 70-percent debt and 30-percent equity for its committed rates, although it acknowledges that it could not obtain this capital structure without the shipper volume commitments. While it expects to achieve the 70-percent debt level of financing, Enbridge Southern Lights maintains that it will calculate the committed shippers’ rates on that basis even if it does not reach that level of debt. Enbridge Southern Lights cites the Colonial decision, contending that the Commission indicated there that it could approve a capital structure with 71-percent equity if the pipeline could support it.\textsuperscript{21}

20. Commission Analysis. The Commission will not authorize a specific equity/debt ratio in this order. Enbridge Southern Lights requests a capital structure that is at the high end of the range of capital structures the Commission has authorized in other proceedings. The Commission will defer its decision on the proper capital structure for Enbridge Southern Lights until it is able to determine the justness and reasonableness of a particular capital structure at the time the pipeline files for approval of the actual rates that it will charge.

C. Depreciation

21. Enbridge Southern Lights states that the proposed Southern Lights rate structure employs a stipulated depreciation profile to calculate rates, essentially spreading out the depreciation so that it will produce a more stable rate pattern over time. Enbridge Southern Lights explains that the depreciation schedule specifies a series of differing (i.e., sculpted) depreciation rates that will recover 60 percent of the initial rate base over the first 15 years of the pipeline’s life, starting with lower percentages and increasing the percentages during the TSA’s initial term. Enbridge Southern Lights further states that the schedule reverts to a straight-line depreciation after the initial 15-year term, at which point the remaining depreciation will be spread using straight-line depreciation. Enbridge Southern Lights contends that this approach prevents front-end rate shock and provides rate stability for shippers by leveling the rates in real terms. Enbridge Southern Lights contends that this creates an incentive for shippers to begin shipping earlier, versus a straight-line schedule under which early shippers pay the highest rates. Enbridge


\textsuperscript{21} Id. at P 62.
Southern Lights argues that this will aid the pipeline in obtaining the long-term commitments that will make the project feasible.\textsuperscript{22} Enbridge Southern Lights also requests a waiver of the Uniform System of Accounts to permit recording of the sculpted depreciation for Form 6 reporting purposes and in any rate matter that may arise with respect to rates charged during the initial term of the TSA.\textsuperscript{23}

22. Enbridge Southern Lights points out that the Commission has not always required oil pipelines to set rates based on straight-line depreciation. For example, Enbridge Southern Lights cites \textit{Kupurak Transportation Co.}, in which the Commission reversed an Initial Decision that adopted straight-line depreciation over the 27-year useful life of the assets, finding instead that the unit-of-throughput (UOT) method was appropriate.\textsuperscript{24} In that case, continues Enbridge Southern Lights, the Commission found that a stipulation adequately established the life of the fields served and the probable future throughput of the pipeline. Enbridge Southern Lights also cites \textit{Georgia Strait Crossing Pipeline LP}, where one shipper negotiated to pay a rate for the entire capacity of the planned pipeline.\textsuperscript{25}

23. Enbridge Southern Lights states that, in \textit{Kern River Gas Transmission Co.},\textsuperscript{26} the Commission described Kern River's depreciation approach as follows: "Generally, under

\textsuperscript{22} Enbridge Southern Lights cites \textit{Greenbrier Pipeline Co.}, 101 FERC ¶ 61,122, at P 115 (2002), \textit{reh'g denied}, 103 FERC ¶ 61,024 (2003) ("Greenbrier indicates it is willing to accept lower rates, and thus, lower return in the early years of its project from customers willing to enter into a long-term agreement in exchange for the certainty and stability provided by the long-term agreements.").


\textsuperscript{24} 55 FERC ¶ 61,122, at 61,380-81 (1991). Enbridge Southern Lights states that the Commission also approved levelized rates in \textit{Express Pipeline Partnership}, 76 FERC ¶ 61,245, at 62,257-58 (1996). ("During the first two years of operation, Express' rates generate revenues below what would normally be allowed under traditional cost-based ratemaking ..." The Commission approved the rate "because without the rate incentives essential to attract those willing to make term commitments, the project might not be built at all."). \textit{See also Colonial Pipeline Co.}, 89 FERC ¶ 61,095 (1999) (levelized initial three-year rate).


\textsuperscript{26} 117 FERC ¶ 61,077 (2006).
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Kern River’s levelization methodology, annual depreciation recovery in rates starts very low and increases during the levelization period as the return component of the cost-of-service decreases (in tandem with the declining total rate base) to obtain a constant or ‘level’ annual cost of service.” 27 Further, states Enbridge Southern Lights, the Commission recognized that such a system provides advantages to both the pipeline and the shippers. 28

24. **Commission Analysis.** Although the Commission has approved a deviation from the straight-line method of depreciation, it has done so only when the pipeline sought to use UOT because its crude oil supply was from a limited reserve area. 29 In this petition, Enbridge Southern Lights has not fully supported its request for sculpted depreciation rates. In particular, it has not explained why sculpted depreciation is necessary to foster investment in the pipeline project or how it will impact the pipeline’s rates. Enbridge Southern Lights may renew its proposal for sculpted depreciation at the time it submits its rate filing; however, it must demonstrate that the proposed depreciation method is based on the projected economic or physical life of the project and must analyze the impact of the proposed depreciation method on its proposed initial rates.

D. **Rate Design**

25. Enbridge Southern Lights maintains that the significant rate design issue in the TSA cost-of-service formula is the provision setting the uncommitted rate at twice the level of the committed rate. According to Enbridge Southern Lights, the purpose of this provision is to distribute the agreed cost-of-service between the committed and uncommitted shippers according to their respective contributions to the initial development and construction of the pipeline. Enbridge Southern Lights reiterates that it is not seeking Commission approval for any specific rate to be charged to the committed or uncommitted shippers in advance of the actual annual tariff filings to be made once the pipeline is in operation, but instead is now seeking approval of the proposed rate design. Accordingly, Enbridge Southern Lights asks the Commission to consider whether it is

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27 *Id.* at P 40.

28 *Id.* at P 40-41 (“traditional rate design rates start high”). Enbridge Southern Lights further states that the Commission has approved rate levelization in novel circumstances, such as for a pipeline serving an LNG facility. *E.g.* Tractebel Calypso Pipeline, LLC, 106 FERC ¶ 61,273, at P 8 (2004).

reasonable, as a matter of regulatory policy, for the uncommitted shippers to bear such a higher proportionate share of the costs on a unit basis.\textsuperscript{30}

26. Enbridge Southern Lights emphasizes that the committed shippers have agreed to pay the uncommitted rates for any volumes transported in excess of their minimum monthly commitments. Therefore, reasons Enbridge Southern Lights, the uncommitted rates constitute negotiated rates as contemplated by the Commission’s regulations.\textsuperscript{31} However, Enbridge Southern Lights also asserts that the uncommitted rates are supported by two other considerations. First, states Enbridge Southern Lights, the revenue-sharing formula for calculating both the committed and the uncommitted rates ensures that the total revenues ultimately collected from committed and uncommitted shippers will not exceed the agreed cost-of-service each year. Second, continues Enbridge Southern Lights, after the annual true-up adjustment, the uncommitted rates will be lower than the benchmark Opinion No. 154-B rates that the uncommitted shippers would be charged under more traditional cost-of-service assumptions and a traditional rate design approach.

27. Enbridge Southern Lights explains that the committed rate will be determined each year as provided in the TSA, and the uncommitted rate then will be set at two times the level of the committed rate. However, Enbridge Southern Lights states that, except in certain limited circumstances, all revenues from uncommitted movements will be credited at the end of the year against both the committed and uncommitted rates, and appropriate refunds will be paid to each group of shippers in proportion to the rates paid, thereby preserving the 50-percent discount. According to Enbridge Southern Lights, while the committed and uncommitted shippers will share in paying the agreed cost-of-service of the pipeline, after revenue sharing is implemented, the uncommitted shippers will pay a higher proportion of the costs on a unit basis. Enbridge Southern Lights maintains that this reflects the different market risks borne by the committed and uncommitted shippers if the market for transportation of diluent does not develop as expected. Enbridge Southern Lights contends that the Commission previously has accepted the principle that committed shippers are not similarly situated as compared to

\textsuperscript{30} Enbridge Southern Lights states that, as with the committed rates, it is essential that the Commission’s indexing rules be waived with respect to the uncommitted rates for Southern Lights. Enbridge Southern Lights states that, because the uncommitted rates vary annually based on the committed rates (which in turn are based on annual costs), the uncommitted rates will not necessarily track the general oil pipeline index. Enbridge Southern Lights explains that the intent is that the uncommitted rates will be exempt from indexing (up or down) so long as they are set in conformity with the TSA formula.

\textsuperscript{31} 18 C.F.R. § 343.2(b) (2007).
uncommitted shippers and that providing rate discounts to the shippers that made initial financial and volume commitments is nondiscriminatory where, as here, the offer was open to all potential shippers.\textsuperscript{32}

28. Enbridge Southern Lights submits that the uncommitted rates calculated pursuant to the TSA (after all adjustments) are lower than the just and reasonable rates that would apply to uncommitted movements under the Commission's standard Opinion No. 154-B rate model, using accepted inputs for cost of capital items and a revenue credit mechanism that takes the discounted rates into account. However, continues Enbridge Southern Lights, if the uncommitted rates were to be challenged, the appropriate framework for evaluating that challenge would be the Commission's Opinion No. 154-B methodology.\textsuperscript{33}

29. \textit{Commission Analysis.} Enbridge Southern Lights did not use the pipeline's design capacity to derive the committed rates. Instead, it utilized the volumes committed by shippers during the open season and projected spot volumes,\textsuperscript{34} claiming that this constitutes 90 percent of the pipeline's annual capacity. As the Commission stated in the Spearhead Order:

> Commission precedent generally dictates the use of actual design capacity for initial rates on a new pipeline, and a pipeline is placed at risk for the costs of unsubscribed capacity based on actual capacity. The Commission made an exception to this policy in the case of Crossroads Pipeline Co. (Crossroads), in which the pipeline filed an application to acquire an oil pipeline and convert it to a gas pipeline for transportation of gas in the

\textsuperscript{32} Enbridge Southern Lights cites \textit{e.g.}, Mid-America Pipeline Co., LLC, 115 FERC ¶ 61,258, at P 16 and n.7 (2006) (acknowledging that "incentive rates have been structured to preserve the rate differential between the incentive rate and the otherwise generally-applicable rate" and that such an agreement "might include a guarantee to [the committed shipper] that its Incentive Program rate would remain below the generally-applicable rate"). Enbridge Southern Lights cites Enbridge Energy Co., Inc., 110 FERC ¶ 61,211, at P 38 (2005) (applying Express Pipeline Partnership, 76 FERC ¶ 61,245 (1996)). See also Plantation Pipe Line Co., 98 FERC ¶ 61,219 (2002); Mid-America Pipeline Co., 93 FERC ¶ 61,306, at 62,048-49 (2000).


\textsuperscript{34} See Petition for Declaratory Order of Enbridge Pipelines (Southern Lights) LLC, Ex. D, Statement G of Exhibit Nos. RGV-2 and RGV-3.
interstate market. In that case, the Commission concluded that it was appropriate to use projected throughput in light of safeguards implemented by Crossroads to prevent over-recovery.\(^{35}\)

30. Calculating Enbridge Southern Lights' initial rate for committed volumes on the basis of the pipeline's design capacity (10 percent more volumes than the 90 percent used by Enbridge Southern Lights) would produce a rate lower than under Enbridge Southern Lights' proposed method. However, no one has challenged the proposed method; therefore, the Commission will accept it. Similarly, no one has opposed setting the uncommitted rate. Accordingly, the Commission likewise will accept this aspect of Enbridge Southern Lights' proposal.

31. Enbridge Southern Lights' proposal is fully supported by CAPP and the committed shippers, and no one has protested it. Moreover, all potential shippers had an opportunity during the open season to commit volumes and establish a 50-percent tariff rate discount. Accordingly, the Commission finds that the proposed rate structure does not violate the antidiscrimination or undue preference provisions of the Interstate Commerce Act (ICA) because the rate discount was made available to all interested shippers and reflects the differences in service between firm and non-firm shippers. The Commission will, of course, review the actual rates at the time Enbridge Southern Lights files a tariff to implement those rates, to ensure that they are just and reasonable.

**E. Costs Included in Rate Base**

32. Enbridge Southern Lights asks that it be permitted to include in the rate base the costs associated with the expected benefits of the proposed asset swap in which it would acquire an existing pipeline (Line 13) in exchange for a new line to be constructed for the Lakehead System. Enbridge Southern Lights maintains that the exchange is highly beneficial to Southern Lights shippers when the Canadian portion of the asset is considered because the cost of the LSR line in Canada is substantially lower than the cost of a new line from the international border to Edmonton. Further, continues Enbridge Southern Lights, there is also a benefit to Lakehead's shippers in that the replacement LSR pipeline will increase annual capacity without a corresponding increase in rate base on the Lakehead System.

33. Enbridge Southern Lights contends that, while this asset swap might appear to resemble the type of purchase price adjustment seen in cases such as Longhorn Partners

\(^{35}\) Enbridge Energy Company, Inc., 110 FERC \(\text{¶} 61,122\), at P 44 (2005) (footnotes omitted). The Commission also noted that Crossroads agreed to file a major section 4 rate proceeding if its annual firm demand level exceeded its rate design level.
Pipeline\textsuperscript{36} and Rio Grande Pipeline Co. v. FERC\textsuperscript{37} (where a purchasing entity seeks to include the purchase price paid for an asset, rather than the seller’s depreciated original cost, in the buyer’s rate base), it is distinctly different. Enbridge Southern Lights emphasizes that this is not an attempt to write up an asset, but that it is seeking to include in its rate base only the construction costs it will actually incur.

34. Enbridge Southern Lights acknowledges that the concern behind the general rule against purchase price adjustments is that one pipeline company will sell an asset to another pipeline company at an inflated price so that the second company can achieve a higher rate base than it would otherwise, causing that line’s shippers to pay twice for the same asset. However, Enbridge Southern Lights contends that this is not the situation here; it seeks only to avoid having the same shippers pay twice. Enbridge Southern Lights explains that, by allowing Lakehead to retain its current rate base, Lakehead’s shippers will not be paying higher rates and will not be subsidizing the construction of the new diluent line; rather, once Southern Lights goes into service, the Lakehead rates will be the same as they would have been without the asset swap.

35. Enbridge Southern Lights argues that this asset swap meets the Commission’s “benefits exception” test, which permits a purchased asset to “be included in the rate base at the full purchase price if the purchaser can demonstrate that: (1) the acquired facility is being put to new use, and (2) the purchase price is less than the cost of constructing a comparable facility.”\textsuperscript{38} According to Enbridge Southern Lights, Line 13 will be put to an entirely new use because it will be moving a different product in a different direction to a different market serving different shippers.\textsuperscript{39} In addition, continues Enbridge Southern Lights, when the entire transaction on both sides of the border is considered, there is clearly an overall benefit to both the Southern Lights shippers and the Lakehead shippers.

36. \textit{Commission Analysis}. As a result of this proposed asset swap, Enbridge Southern Lights would include in its rate base the following capital costs: (1) construction costs of the new 20-inch diluent pipeline and facilities from Chicago to Clearbrook, Minnesota; (2) construction costs of the Replacement Facilities for Enbridge LP’s Lakehead system;

\textsuperscript{36} 82 FERC ¶ 61,146 (1998).

\textsuperscript{37} 178 F.3d 533 (D.C. Cir. 1999).

\textsuperscript{38} Enbridge Southern Lights cites Rio Grande Pipeline Co. v. FERC, 178 F.3d 533, 536-37 (D.C. Cir. 1999).

\textsuperscript{39} Enbridge Southern Lights cites Enbridge Energy Co., Inc., 110 FERC ¶ 61,211, at P 27-32 (2005) (upholding use of Spearhead pipeline purchase price as new use where line reversed, new products, and new shippers were involved).
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and (3) costs to transfer Line 13 to Enbridge Southern Lights, including reversing the flow and modifying the crude pipeline for use as a diluent pipeline.

37. The Commission finds that Enbridge Southern Lights has demonstrated that this proposal is the most efficient and equitable choice for Southern Lights, Lakehead, and all of their shippers. The potential benefits cited by Enbridge Southern Lights support this decision.

38. The Commission also finds that the proposed asset swap meets the Commission’s criteria for such an action. The Commission’s “benefits exception” test permits a purchased asset to “be included in the rate base at the full purchase price if the purchase can demonstrate that: (1) the acquired facility is being put to new use, and (2) the purchase price is less than the cost of constructing a comparable facility.” Line 13 will be put to new use, moving diluent instead of crude oil, and in a new direction because of the reversal, thereby serving a different market with different shippers. Accordingly, the Commission will allow Enbridge Southern Lights to include the purchase price adjustment in its rate base. This arrangement benefits shippers by assuring they will not pay twice for the same asset and benefits the public interest by providing a means to help transport the vast Canadian oil reserves and increase U.S. refiners’ security of supply.

F. Rate from Chicago to International Border

39. Enbridge Southern Lights states that the TSA establishes a single rate for shipments in the U.S. To the extent there may be any short-haul U.S. movements, Enbridge Southern Lights explains that those shippers will pay the applicable Chicago-to-border rate adjusted for any power cost savings associated with the movements. Further, states Enbridge Southern Lights, the power costs savings adjustment will ensure that any shippers who transport diluent from origins other than Chicago will be credited with the variable costs (essentially power and drag reducing agent costs) that are avoided due to the shorter distance of haul. Enbridge Southern Lights submits that the Commission has

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40 Rio Grande Pipeline Co. v. FERC, 178 F.3d 533, 536-37 (D.C. Cir. 1999).

accepted such rates in other cases and generally has avoided establishing a bright line between cases in which such rates are appropriate and cases in which a distance-based rate is required.\textsuperscript{42}

40. Enbridge Southern Lights asks the Commission to accept the single rate it proposes. First, states Enbridge Southern Lights, it is speculative whether any shipper will want to move diluent from an origin point north of Chicago. Enbridge Southern Lights also asserts that the Commission does not require distance-based rates on the basis of speculative shippers.\textsuperscript{43} Enbridge Southern Lights also submits that the Commission has been flexible in accepting non-distance based rates, as reflected in its gas pipeline precedents.\textsuperscript{44} In the instant case, continues Enbridge Southern Lights, the rate reasonably reflects variations in the cost of providing service because any shipper who chooses to ship over a portion of the pipeline will be credited the savings in power cost not incurred by moving the shorter distance. Because the partial shipper will only pay for the variable power costs it incurred, the rate reasonably accommodates material variations in variable costs.\textsuperscript{45} Finally, Enbridge Southern Lights argues that the pipeline was planned, accepted, and launched as a pipeline from Chicago to Edmonton, and it would not have been built on any shorter path. According to Enbridge Southern Lights, because all shippers benefit from the existence of the pipeline, they cannot be heard to argue that they should bear only the cost of a shorter pipeline, one which neither Enbridge Southern Lights nor its committed shippers would have accepted.

41. Commission Analysis. The Commission finds this proposal acceptable. Enbridge Southern Lights planned the Southern Lights project and held the associated open season

\textsuperscript{42} Enbridge Southern Lights cites Greenbrier Pipeline Co., LLC, 101 FERC ¶ 61,122, at P 77 (2002).

\textsuperscript{43} Enbridge Southern Lights cites Entegra Gas Pipeline Inc., 113 FERC ¶ 61,327, at P 29 and n.21 (2005).

\textsuperscript{44} Enbridge Southern Lights cites Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 436, FERC Stats. & Regs. ¶ 30,665, at 31,538 (1985); see also Northwest Pipeline Corp., 82 FERC ¶ 61,158, at 61,578 (1998).

\textsuperscript{45} Enbridge Southern Lights cites Gulf South Pipeline Co., LP, 111 FERC ¶ 61,463, at P 4 (2005) (allowing pipeline to eliminate fuel charge “on specified transactions posted on its website where, based on Gulf South’s operational experience, no incremental fuel is expected to be consumed in the transaction on an aggregate basis at a matrix of receipt and delivery point pairs”).
on the premise that its diluent shipments would originate in Chicago. By offering a power cost savings to potential future short-haul movements, Enbridge Southern Lights reasonably reduces the rates for such movements.

G. Annual True-Up

42. Enbridge Southern Lights states that the TSA establishes an annual true-up of any differences between estimated and actual revenues and costs, which also will include a credit for any uncommitted revenue received during the year up to 90 percent of the annual capacity of 180,000 bpd (and 75 percent of uncommitted revenues). Enbridge Southern Lights asks the Commission to approve the annual true-up mechanism. If Enbridge Southern Lights finds that it has over-collected, it states that it will issue a refund to each shipper based on the volume transported. Similarly, if Enbridge Southern Lights finds that it has undercollected, it states that it will send an invoice to each affected shipper. Enbridge Southern Lights contends that this annual true-up will benefit shippers because it avoids over-collection by the pipeline, thereby assuring a proper matching of burdens and benefits. Moreover, continues Enbridge Southern Lights, the true-up mechanism is fair as among shippers because the amount of the refund or the adjusted invoice is proportional to their actual volumes during the calendar year for which the true-up is being made.

43. Enbridge Southern Lights cites other Commission orders involving true-ups. For example, Enbridge Southern Lights states that Southern Company has reported to the Commission its annual refunds or surcharges due under its formula rates accepted by the Commission. Additionally, continues Enbridge Southern Lights, the Commission recently accepted a settlement in which Enbridge Pipelines (North Dakota) LLC was permitted to impose a surcharge to support a mainline expansion, subject to an annual true-up of the surcharge. Enbridge Southern Lights also points to a settlement under which an oil pipeline's Hurricane Recovery Surcharge is subject to a true-up that could result in the pipeline issuing refunds to the shippers and a Mid-America Pipeline Company security surcharge true-up that involved the possibility of refunding or invoicing shippers. Enbridge Southern Lights contends that, because the terms of the


true-up will be explicitly set forth in the tariff, using such a prior period adjustment does not violate the filed rate doctrine because any shipper choosing to ship uncommitted volumes will be on notice of the possibility of refunds and charges.

44. Enbridge Southern Lights also points out that the Commission has accepted revenue sharing arrangements similar to the 75/25 revenue sharing proposed here when annual volumes exceed an average of 162,000 bpd. According to Enbridge Southern Lights, where contracts make assumptions about the effective annual capacity of a gas pipeline, the shippers generally cannot challenge those risk allocations after the fact.

49 Enbridge Southern Lights cites Mid-America Pipeline Co., LLC, 115 FERC ¶ 61,384, at P 5 (2006) ("MAPL states it will refund or invoice its shippers on a pro-rata basis for barrels shipped during the Recovery Period. If this true-up amount is within one percent of the costs incurred, MAPL will not make any additional collections or refunds.").

50 Enbridge Southern Lights cites TransColorado Gas Transmission Co., 112 FERC ¶ 61,135, at P 11 (2005) (in a case involving true-ups of gas quantities, "there is no violation of the filed rate doctrine or the rule against retroactive rate making because the shippers are on notice that the pipeline is entitled to recover these costs"). Enbridge Southern Lights also cites Canadian Association of Petroleum Producers v. FERC, 254 F.3d 289, 299 (D.C. Cir. 2001) ("So long as the parties had adequate notice that surcharges might be imposed in the future, imposition of surcharges does not violate the filed rate doctrine."); Louisiana Public Service Commission v. FERC, 482 F.3d 510, 520 (D.C. Cir. 2007) (same as for refunds).


52 Enbridge Southern Lights cites Cheyenne Plains Gas Pipeline Co., L.L.C., 108 FERC ¶ 61,052, at P 12 (2004) (clarifying that pipeline could amend agreements to divide revenue 50/50 with negotiated rate shippers); Entegra Gas Pipeline Inc., 113 FERC ¶ 61,327, at P 16-17 (2005) (allowing 50/50 split which was included in open season materials, included in pro forma tariff and also in precedent agreement).

53 Enbridge Southern Lights cites Mojave Pipeline Co., 81 FERC ¶ 61,150, at 61,684 (1997) ("As with several of the prior rulings, the Commission finds that the relevant contracts and rates allocated the risk of the Btu gas content between Mojave and its shippers at the beginning of the project. There is no overriding policy reason to interfere with this contractual relationship."). See also High Island Offshore System, (continued...)
and in this case, the division of revenues above 162,000 bpd is the parties’ means of allocating the risk that the pipeline’s full annual capacity will not be used and making up for some of the discounts to the agreed cost-of-service. However, Enbridge Southern Lights emphasizes that, even with this incentive, it will not recover more than its properly calculated cost-of-service using traditional application of the Opinion No. 154-B methodology.

45. Commission Analysis. The Commission finds that this proposed mechanism will guarantee that Enbridge Southern Lights will not be over-recovering its costs and at the same time will ensure that Enbridge Southern Lights is appropriately compensated for its capital investment and its associated risk. The Commission thus concludes that this mechanism will result in rates that are just and reasonable.

The Commission orders:

Enbridge Northern Lights’ petition for a declaratory order is granted to the extent discussed in the body of this order.

By the Commission.

(SEAL)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

66 FERC ¶ 61,378, at 62,268 (1994) (in wake of gas pipeline restructuring, when projections of use of interruptible service were uncertain, Commission required “the pipeline to establish a 90/10 revenue sharing mechanism under which the pipeline is allowed to retain 10 percent of all revenues in excess of allocated costs to give the pipeline an incentive to market interruptible service”); Discovery Gas Transmission LLC, 108 FERC ¶ 61,060, at P 13 (2004).
July 20, 2007

BY HAND DELIVERY

Hon. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Enbridge Pipelines (Southern Lights) LLC,
Docket No. OR07-15-000
Petition for Declaratory Order

Dear Secretary Bose:

Enclosed for filing are the original and fourteen (14) copies of the Petition for Declaratory Order of Enbridge Pipelines (Southern Lights) LLC, together with a check for the filing fee in the amount of $20,940 made payable to the Treasurer of the United States.

Also enclosed is a form of notice of filing, together with a 3.5" disk containing an electronic version of the form of notice.

Please date-stamp the enclosed duplicate originals and return them to our messenger for our files.

Sincerely,

Steven Reed

Enclosures
EXPEDITED DECISION REQUESTED

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Enbridge Pipelines (Southern Lights) LLC

Docket No. OR07-__

PETITION FOR DECLARATORY ORDER
OF ENBRIDGE PIPELINES (SOUTHERN LIGHTS) LLC

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July 20, 2007
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EXPEDITED DECISION REQUESTED

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Enbridge Pipelines (Southern Lights) LLC
Docket No. OR07--

PETITION FOR DECLARATORY ORDER
OF ENBRIDGE PIPELINES (SOUTHERN LIGHTS) LLC

Pursuant to Rule 207(a)(2) of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.207(a)(2) (2006), Enbridge Pipelines (Southern Lights) LLC (“EPSL”) respectfully petitions the Commission to issue a declaratory order confirming the proposed rate structure for the planned Southern Lights Pipeline, which will transport light liquid hydrocarbons from Chicago, Illinois to Edmonton, Alberta for use as a diluent for heavy crude petroleum produced from Canada’s oil sands.¹ Because of the time-sensitive nature of this project and the expected timing of other regulatory approvals, EPSL respectfully requests a Commission decision on its petition on or before December 31, 2007.

1. EXECUTIVE SUMMARY

As the Commission has noted in several orders, production of heavy oil and bitumen from the oil sands reserves in Western Canada has been growing rapidly over the past several

¹ EPSL is only seeking Commission rulings with respect to the portion of the Southern Lights Pipeline that will be built and operated in the United States. Approval of the Canadian portion of the pipeline is currently pending before the National Energy Board of Canada (“NEB”) in Enbridge Southern Lights GP Inc., NEB File No. OF-Fac-Oil-E242-2007-01-01. Both EPSL and the Canadian entity (Enbridge Southern Lights LP (“Southern Lights Canada”)) are subsidiaries of Enbridge Pipelines Inc. (“Enbridge”), a Canadian liquids pipeline company that owns and operates an extensive system in Canada.
years and is expected to increase even more in the future.\textsuperscript{2} To make the heavy oil and bitumen transportable by pipeline, it is necessary to reduce the density and lower the viscosity by diluting it with a low density, low viscosity hydrocarbon. Accordingly, in order to enable the current projections of oil sands production to get to market there is a need for a significant increase in diluent. The amount of diluent required significantly exceeds the available supply of conventional diluent in Alberta, including traditional wellhead natural gas condensate. To address this challenge, a number of prospective shippers approached Enbridge about building a pipeline to export diluent from the United States into Canada.

The Southern Lights Pipeline project, which is estimated to cost approximately $1.3 billion in total,\textsuperscript{1} was developed by Enbridge to meet this need. Through an extensive open season process, Enbridge solicited shippers to provide financial support for this pipeline by making long-term volume commitments. Those commitments, and the terms on which EPSL would offer service, are embodied in a Transportation Services Agreement ("TSA") that was executed by each committed shipper. As a result of those commitments, and subject to necessary regulatory approvals in the U.S. and Canada, Enbridge is prepared to move forward with this pipeline proposal. The importance of this project to the U.S. petroleum market and U.S. energy security generally cannot be overstated. An enhanced supply of diluent in Western Canada is critical to support the projected increase in Canadian oil available for export to the U.S. market. The support of the committed shippers demonstrates that Southern Lights is an efficient, market-responsive solution to this problem, which strongly merits the support of regulators in both the U.S. and Canada.

\textsuperscript{2} E.g., Order on Petition for Declaratory Order, Enbridge Energy Co., Inc., 110 FERC ¶ 61,211 at P3 (2005).

\textsuperscript{1} All dollar figures in this Petition and accompanying Affidavits are stated in U.S. dollars.
To make this complex project economically viable, EPSL seeks certain assurances with respect to the tariff rates to be charged for service through the U.S. portion of Southern Lights. Specifically, in this Petition, EPSL requests the following rulings:

1. That the terms of the TSA entered into by the committed shippers on Southern Lights (including specifically the agreed-upon capital structure and adjustable rate of return for the committed rates) will be upheld and applied during the agreed term of the TSA as between EPSL and the committed shippers;

2. That the rate design embodied in the TSA, which is used to determine both the committed rates and the uncommitted rates, will be upheld and applied during the term of the TSA;

3. That EPSL will be permitted to use the agreed-upon depreciation schedule to calculate the rates during the initial 15-year TSA term;

4. That EPSL will be permitted to include in the rate base of Southern Lights costs associated with the exchange of a new line to be constructed by EPSL for an existing pipeline held by Enbridge Energy, Limited Partnership ("EELP") that will form part of the route of Southern Lights;

5. That EPSL will be permitted to charge a single rate from Chicago to the U.S.-Canada border with a credit to reflect power cost savings for transportation from any intermediate origin points that may be established in the future; and

6. That EPSL will be permitted to true-up its Southern Lights tariff collections on an annual basis to reflect various credits to shippers as discussed further below.¹

¹ The true-up will have two primary components: (1) an adjustment to true-up estimated costs and revenues to actual data and (2) a credit to the cost of service for revenues from uncommitted movements.
EPSL requests the assurance of a declaratory order on these points in order to justify the substantial capital investment (totaling more than $1.0 billion in the U.S. alone) required to construct the Southern Lights Pipeline. As discussed below, the requested rulings are well-grounded in Commission precedent and the factual circumstances of this pipeline project. Commission confirmation of these points will facilitate the construction and operation of this new pipeline, which (as noted above) promises substantial economic and other benefits for Canadian oil producers, U.S. refiners, and the U.S. petroleum market. Notably, the Canadian Association of Petroleum Producers ("CAPP"), which is the principal representative of the producers of oil in Canada, is supportive of the Southern Lights project, as evidenced in Exhibit A hereto.

II. BACKGROUND

A. Overview of the Southern Lights Project

The nature and purpose of the Southern Lights project are explained in greater detail in the Affidavit of Don Thompson ("Thompson Affidavit"), which is attached as Exhibit B to this Petition. Mr. Thompson, who is the Director, Light Product Development at Enbridge, describes the origins of the project, the nature of the project, the process EPSL followed to secure commitments to support the project, and the benefits the project offers both to shippers and to the public interest.

Southern Lights will consist of two interconnected pipelines, one in the United States and one in Canada. The U.S. portion, to be built and operated by EPSL, will extend from Chicago to the international border near Neche, North Dakota. Thompson Aff., Exh. B at ¶ 2 & 19. The

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The Commission waives the filing requirements under 18 C.F.R. §§ 342.1, 342.3(a), and 342.4 to the extent necessary to facilitate the filing of the rates authorized by the Commission's declaratory order.
connecting pipeline in Canada will be built and operated by Southern Lights Canada, id. at ¶ 2; it will extend from the international border to Edmonton, Alberta. Id. at ¶ 19. As described by Mr. Thompson, the annual capacity of the new Southern Lights Pipeline will be approximately 180,000 barrels per day ("bpd"). Id.

Construction of the U.S. portion of Southern Lights will consist of two principal components. From Chicago to Clearbrook, Minnesota, EPSL will build approximately 675 miles of new 20-inch pipeline following existing right of way used by other Enbridge pipelines. From Clearbrook to the international border, EPSL will acquire the existing 135-mile, 18-inch Line 13, which is presently part of the Lakehead System (owned and operated by EELP) that transports Western Canadian crude oil from the border to Chicago and other mid-western markets. Line 13 will be reversed and integrated into the new Southern Lights Pipeline. Id. To prevent a reduction in the annual capacity of the Lakehead System, EPSL will construct a new line from Clearbrook to the border to replace Line 13 (the Light Sour Pipeline or "LSR") and certain improvements will be made to EELP's Line 2 (together, the "replacement facilities"). The replacement facilities will provide a modest increase in annual capacity for the Lakehead System and be better suited to the hydrocarbons being moved on the Lakehead System than the existing 18-inch Line 13. Id. at ¶ 23.

The new LSR line built by EPSL will be exchanged for Line 13 upon completion. As discussed further below, when the transaction is fully implemented, the intent is that EELP will have a modest increase in annual capacity to transport crude oil and will retain its original rate base as though Line 13 had remained in southbound crude service.14 EPSL will include in its rate

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14 As discussed in the Thompson Affidavit, for an interim period after the like-kind exchange Line 13 will be leased to EELP and will remain in southbound crude oil service, which will provide Lakehead shippers with an increase in annual capacity of approximately 219,000
base the cost to construct the replacement facilities (adjusted for costs recovered from EELP during the interim period). Thus, the rate base for each company will appropriately reflect that company's expenditures incurred in providing service to its own shippers. *Id.* at ¶ 20. In Canada, Southern Lights Canada will receive the Canadian portion of Line 13, which extends from the international border to Edmonton, Alberta. In return, it will construct a segment of the new LSR line from Cromer, Manitoba to the international border, a significantly shorter distance. *Id.* at ¶ 15. Thus, on an overall basis, Southern Lights shippers will be substantially benefited by the proposed line swap.

**B. Open Season**

To be economically feasible, this project requires substantial long-term financial support from prospective shippers in the form of term volume commitments obligating the committed shippers to bear virtually all of the pipeline's costs in the event that no other volumes are transported in any given year of the TSA term. On May 30, 2006, Enbridge launched an open season for the Southern Lights project. As described by Mr. Thompson, the open season was widely publicized and notices were emailed to more than 30 entities, including existing Enbridge shippers, interested parties and potential Southern Lights shippers. In addition, the open season materials were posted on the Enbridge website. Those materials included: the formal notice of Open Season, an Open Season PowerPoint presentation, the proposed TSA,\(^7\) a summary of the

\[\begin{align*}
\text{bpd} & \quad \text{Thompson Aff., Exh. B at ¶ 21. The expectation is that EELP will file a separate application for Commission approval to include the cost of the Line 13 lease in its mainline tariff rates during the interim period based on cost parameters agreed to with CAPP. *Id.* at ¶ 22. The relief sought in this Petition is not contingent on that separate EELP application. *Id.*}
\end{align*}\]

\(^7\) The pro forma TSA is attached hereto as Exhibit C. This pro forma TSA has been modified to reflect amendments made after the first open season and entered into by all committed shippers. The amendments modified Section 12.01.03 of the TSA and replaced the original version of Sections 14(c)(vi) and 15 of Schedule B to the TSA. The version attached as Exhibit C embodies the TSA as presented to shippers in the second open season discussed below.
proposed TSA terms, an estimate of capital costs, a pro forma rate model that translated the various cost inputs into prospective rates, a market study conducted by Muse Stancil on the availability of diluent in the United States, draft Rules and Regulations, a draft commodity specification practice, and a proposed pipeline equalization practice. All prospective Southern Lights shippers had a substantial and equal opportunity to participate in the open season, which ended on July 24, 2006. Thompson Aff., Exh. B at ¶ 24.

Subsequent to the initial open season, EPSL received notice that one party had exercised its No-Fault Termination Right under the TSA, which gave it the right to terminate the contract by paying its pro-rata share of development costs up to that time. Because of that termination, the other committed shippers were afforded an opportunity to terminate, but did not. Later, EPSL was approached by a number of new prospective shippers about the potential to participate in the Southern Lights project as a committed shipper. To ensure all prospective shippers were given a full opportunity to participate, EPSL conducted a second open season, which ended on March 28, 2007. Despite substantial interest in the project, no further commitments were secured during the second open season. Id. at ¶ 26. Thus, at present, EPSL has shipper commitments to transport 77,000 bpd over the 15-year TSA term at committed rates that recover the discounted level of cost for the pipeline agreed to by EPSL and the committed shippers. Id. at ¶ 27.

Under the terms of the TSA, EPSL agreed to provide transportation of a commingled diluent stream in exchange for a 15-year transportation commitment from shippers. Committed shippers agreed to pay a committed tariff rate for all committed volumes and an uncommitted

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*The pipeline equalization practice provides a means to compensate shippers for differences in the quality of diluent tendered to the pipeline for transportation in the commingled diluent stream.*
tariff rate for volumes transported in excess of the committed volumes. The TSA set the minimum committed volume at 5,000 bpd. Up until the end of the tenth year of the initial 15-year commitment, the TSA permits committed shippers to extend the TSA term another 15 years. Thompson Aff., Exh. B at ¶ 27.

In exchange for their long-term throughput commitments, committed shippers will receive a substantial discount relative to uncommitted rates for the term of the TSA. In effect, the TSA fixes the uncommitted rates so that the committed rate constitutes a 50% discount from the uncommitted rate.10 Id. at ¶ 27. The TSA provides comprehensive agreed-upon terms for the committed tariff rates based on a cost-of-service model using stipulated inputs that are, in some cases, more conservative than those EPSL believes it could justify under standard Commission policies and practices. These terms were specifically designed as concessions to the committed shippers to induce them to make long-term volume commitments to support the Southern Lights project; they are not intended to bind EPSL in any other context, including a future rate challenge brought by a third party. Id. at ¶ 29.

C. Market Overview

As a part of its decision making process in support of the Southern Lights project, Enbridge performed a thorough analysis of the markets for Canadian oil and for U.S. and

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9 This commitment takes the form of a "ship-or-pay" commitment, meaning the shipper must ship the minimum committed volume each month or else pay a deficiency payment equal to the tariff rate multiplied by the volume by which the shipper fell short of meeting its monthly commitment. See TSA, Exh. C at ¶ 3.01.

10 Pursuant to the TSA, the committed rates are set at a fixed 50% discount from the uncommitted rates charged to shippers that did not make a volume commitment in support of the pipeline. All revenues from transportation are credited against the cost-of-service, up to 162,000 bpd (i.e., 90% of the pipeline's annual capacity). See TSA, Exh. C, Schedule B, ¶ 14(c)(vi). At usage rates above 162,000 bpd, incremental revenues are credited 75% to the committed and uncommitted shippers and 25% to EPSL, in recognition of EPSL's agreement to utilize a discounted cost-of-service to establish committed rates, as well as to provide an incentive to the pipeline to maximize throughput to the benefit of all parties.

Mr. Thompson notes that Canadian crude oil production has been the single largest source of oil imported to the United States for a number of years. Id. at ¶ 4. Those crude oil imports support an integral part of the nation’s energy security strategy, which is to diversify its oil sources and rely on imports from politically stable oil producing nations. According to CAPP’s forecast, Canadian oil production is expected to almost double from 2007 levels by 2020. Id. at ¶ 7. In order for Canadian oil sands production to reach markets, which are primarily in the United States, by the most economical and environmentally-preferred transportation means (i.e., via pipeline), it must be diluted with a less dense, low viscosity material. Id. at ¶ 4. The main source of diluent used to support transportation of oil sands production from Western Canada to market has been natural gas condensates produced with natural gas. Id.

1. Diluent Market in Western Canada

The projected decline of conventional natural gas production in Western Canada implies that production of condensates associated with that production will decline, leaving unmet demand for diluent. Thompson Aff., Exh. B at ¶ 4. Canadian producers are therefore looking for other substantial sources of diluent to transport the oil sands production, including importing condensate via railroad, which is more expensive and historically more hazardous than pipeline transportation. In recognition of the need for an alternative supply of diluent, CAPP (as the representative of the Canadian producers) is supportive of Enbridge’s Southern Lights project. See Exhibit A.
2. Diluent Market in the Midwest

The Muse Stancil report identified potential sources for diluent supply within the United States. Thompson Aff., Exh. B at ¶ 11. Muse Stancil considered possible sources, and found three in light hydrocarbon streams from refineries, natural gasoline produced at natural gas liquids fractionators, and natural gasoline imported to the United States. Muse Stancil concludes that the total potential U.S. diluent supply volume for Southern Lights could reach approximately 450,000 bpd without affecting the prices of petroleum products. Id.

III. BENEFITS OF THE SOUTHERN LIGHTS PROJECT

As set forth in more detail in Mr. Thompson’s Affidavit, the Southern Lights project offers substantial benefits both to the public and to shippers. Thompson Aff., Exh. B at ¶¶ 35-37. The Southern Lights project was initiated at the request of prospective shippers who were interested in facilitating transportation of oil sands production out of Canada. Id. at ¶ 4.

The most direct public interest benefit is to increase the supply of diluent to Western Canada. Adding a new source of diluent supply in Western Canada increases competition for diluent in that market. Increased diluent supply and competition facilitate economic and efficient production and transportation of oil sands crude. It also allows synthetic crude oil to be put to higher value uses including being run in existing refineries, thereby potentially relieving those refineries from being forced to make substantial investments in hardware to meet ever-tightening product specifications. Id. at ¶¶ 35-36.

By increasing the likelihood that Western Canadian oil sands production will be produced, the increased supply of diluent also enhances the amount of oil sands production available to the United States. The increased competition in the diluent market could also help to make the cost of Canadian oil sands crude more competitive with oil from other countries. The more oil that the U.S. can import from politically stable, democratically governed countries, such
as Canada, the less it has to import from less stable countries. That increases both the United States’ energy supply and its overall national security. Canadian production helps to offset the U.S.’s declining domestic production levels and minimizes the need for tanker transportation of oil into the United States, which is perceived to be less environmentally attractive. Finally, it increases the markets available for U.S. condensate production and natural gasoline products. Id. at ¶ 37.

The Commission has repeatedly noted the need for new pipeline infrastructure, and stated that it is seeking to promote that development. 11 As it recently stated:

The Commission has recognized the need for investment in energy transportation infrastructure whether for electric power, natural gas or oil, to meet the nation’s growing demand for energy. Further, the Commission also has recognized that certain rate treatments are appropriate to encourage this needed investment in infrastructure.

Colonial Pipeline Co., 116 FERC ¶ 61,078 at P 44 (2006); see also Rate Regulation of Certain Natural Gas Storage Facilities, 115 FERC ¶ 61,343 at P 91 (2006) (“goal of creating a regulatory environment that will promote infrastructure”), order on reh’g, 117 FERC ¶ 61,190 (2006). In other industries, it has tried various means of creating incentives to develop needed infrastructure. See also Promoting Transmission Investment Through Pricing Reform, 71 Fed. Reg. 43,294 (July 31, 2006), reh’g granted in part, 72 Fed. Reg. 1152 (Jan. 10, 2007), reh’g denied, 119 FERC ¶ 61,062 (2007) (issuing rules to promote investment in bulk power transmission system). In EPSL, the market participants have planned a pipeline that will help reduce the U.S.’s dependence on oil imports from less stable countries and increase its national security. The Commission has the opportunity to promote these benefits by approving the rate

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structure for the Southern Lights Pipeline, thus facilitating construction of this much-needed project.

IV. DISCUSSION

The central assurance that EPSL seeks from the Commission in advance of full construction of the Southern Lights Pipeline is that the agreed-upon terms of the TSA will govern the determination of the Southern Lights tariff rates for the term of the TSA and that those terms will not be overridden by contrary or evolving Commission rules or policies meant to apply to liquids pipelines generally. The Petition first will explain why an expeditious declaratory order is warranted. It then will explain the specific elements of the TSA for which EPSL is seeking approval and the reasons why the application of those terms is reasonable and compatible with Commission regulatory policy.

A. EPSL Needs an Expeditious Declaratory Order to Proceed with the Southern Lights Pipeline

EPSL is seeking a declaratory order accepting the proposed rate structure for the Southern Lights Pipeline to justify the substantial capital investment needed to bring this project to completion. The total cost of the construction (including the reversal and replacement of Line 13) is approximately $1.0 billion for the U.S. portion of the pipeline.\footnote{An additional $300 million will be invested by Southern Lights Canada for the Canadian portion of the project.} To support that level of investment, EPSL needs assurance that its proposed rate structure is lawful and will be accepted when the pipeline goes into service. Thompson Aff., Exh. B at ¶ 38.

The Commission has recognized in past cases the appropriateness of providing advance rate guidance for projects of this nature through the declaratory order mechanism. For example, in the case of the Express Pipeline System – another project involving a new pipeline across the
international boundary between the U.S. and Canada – the Commission issued a declaratory order over the objection of parties who argued the issues should be deferred until the pipeline was actually built. The Commission noted there:

[It is better to address these issues [term rate structure and validity of proposed rates] in advance of an actual tariff filing than to defer until the rate filing is made, when the decisionmaking process would be constrained by the deadlines inherent in the statutory filing procedures. The public interest is better served by a review of the issues presented before a filing to put the rates into effect.]

On rehearing, the Commission added that “issuing a declaratory order [is] procedurally appropriate for a new oil pipeline entrant, such as Express, because it needs to acquire and guarantee financing in order to begin construction.” This Petition is very similar to Express and other recent orders in that the new Southern Lights pipeline needs advance Commission guidance to justify a major capital expenditure. See also Colonial Pipeline Co., 116 FERC ¶ 61,078 at P 9 (2006) (declaratory order prior to $1 billion expansion); Enbridge Energy Co., Inc., 110 FERC ¶ 61,211 (2005); Plantation Pipe Line Co., 98 FERC ¶ 61,219 (2002).

EPSL respectfully requests that the Commission provide the rulings sought in this Petition by no later than December 31, 2007. In order to meet the service needs of its committed shippers, Enbridge is targeting an in-service date for the Southern Lights Pipeline of July 1, 2010. As described by Mr. Thompson, this ambitious construction schedule requires that certain capital expenditures occur in 2007, with an accelerating level of expenditure in 2008 and 2009. Thompson Aff., Exh. B at ¶ 39. Enbridge has applications pending before the NEB for approval of the portion of the pipeline in Canada, as well as before the U.S. Department of State for a Presidential Permit for the international border crossing. A ruling on the NEB application is


14 Express Pipeline P’ship, 77 FERC ¶ 61,188 at 61,755 (1996).
expected in late 2007. A decision by this Commission on the same time schedule would facilitate a decision by EPSL to proceed with construction in a timely and efficient manner, so that Southern Lights shippers can obtain this needed service at the earliest possible date. \textit{Id.}

\textbf{B. EPSL Requests Assurance That the Agreed-Upon Terms of the TSA for Southern Lights' Committed Rates Will Be Upheld}

The Southern Lights Pipeline is an extraordinarily complex and ambitious undertaking, designed to bring substantial benefits to Canadian oil producers, U.S. refiners of heavy Canadian crude oil and the general public. Because of the unusual nature and risk associated with this project, Enbridge determined from an early stage that the commercial terms for the project required substantial backstopping by the committed shippers. Prospective committed shippers of diluent would be required to provide financial backing for the project in the form of long-term volume commitments, assuring the pipeline of sufficient revenues to justify the enormous investment involved. In addition, that financial backing is intended to permit EPSL to enter into a project financing arrangement whereby the proportion of debt available to the project is significantly higher and at a lower interest rate than would be available without the backstopping. Thompson Aff., Exh. B at ¶ 32-33. In return for making that commitment, the committed shippers quite reasonably sought assurances about the level of the tariff rates they would be required to pay over the term of the TSA, as well as the rates to be charged to future "walk-up shippers" who choose to use the pipeline's services without having provided volume commitments before construction. \textit{Id.} at ¶ 28-29. These intertwined goals were met in the TSA that committed shippers executed during the Southern Lights open season.

The unique features of the TSA emerged from discussions with potential shippers regarding terms that would make the project sufficiently viable that it could be built. The Commission should accept these unique features because, as will be demonstrated below, they
are tied to the facts of this project and are compatible with the Commission's precedents. The Commission has very recently recognized that it is not limited to accepting "cookie-cutter" rate provisions, but is chartered by Congress with the flexible authority to prescribe a rate that is just and reasonable in particular circumstances. "The Commission has neither considered nor treated its rate methodologies as limiting its ratemaking approach or constraining it from exploring and adopting other rate approaches that are more fitting in particular circumstances to ensure that a just and reasonable rate results." Colonial Pipeline Co., 119 FERC ¶ 61,183 at P 23 (2007). The EPSL diluent pipeline project is necessary to promote the development of the Canadian oil sands, and the Commission is empowered to take a flexible approach in setting rates that make the project possible. See id. at P 24.

For the Commission's reference, a pro forma copy of the TSA as agreed to by the committed shippers is attached to this Petition as Exhibit C.\(^{15}\) Although the agreement is complex, its essential terms can be summarized as follows:

- **Committed shippers agree to ship their committed volumes or pay the committed tariff rates for the committed volumes over the 15-year term (Exh. C, TSA §§ 3.01 & 7.01);**

- **Committed shippers have the right, during the first 10 years, to extend the initial term by 15 years at the same or reduced volumes (id. at § 5.03);**

- **Committed shippers agree to ship volumes in excess of their minimum commitment at two times the committed rate (the "uncommitted rate") (id. at § 6.03);**

- **Committed rates incorporate the following principles:**

  - EPSL will set prospective rates annually based on an estimate of its costs (Id. at Schedule B, § 14(a));

\(^{15}\) See note 7, supra. Only a small portion of the lengthy agreement is directly relevant to this Petition. The parts of interest to the Commission are concentrated in Sections 2 through 7 and in Schedule B (Tariff Rate Principles).
Capital costs will include costs to transfer Line 13 to EPSL and modify it for new use as a diluent pipeline, costs to construct the LSR line, and costs to construct the new diluent line from Chicago to Clearbrook (Id. at Schedule B, § 3);

The discounted cost-of-service assumes a capital structure of 30 percent equity and 70 percent debt and a base annual equity rate of return of 12 percent (adjusted according to the final capital cost of the project in comparison to the estimated capital cost established in September 2006) (Id. at Schedule B, §§ 8 & 9);

Depreciation expense is based on a stipulated depreciation schedule resulting in a more levelized cost-of-service in real terms (Id. at Schedule B, § 11 and Schedule D);

All rates are determined for movements between Chicago and the international border; shorter distance movements (if any) pay the same rate but will be credited with avoided power costs (Id. at Schedule B, § 14);

EPSL will, after the end of each year, refund to or recover from each shipper any rate differential between estimates and actual costs (Id. at Schedule B, § 14(b));

EPSL will credit all uncommitted revenues to the committed and uncommitted shippers up to 90% of pipeline annual capacity (Id. at Schedule B, § 14(c)(vi)); and

EPSL retains 25% of any incremental revenues associated with volumes above 162,000 bpd (90% of annual capacity of 180,000 bpd) (Id. at Schedule B, § 15).


Because of the interlocking nature of the various major components of the TSA, it is important both to EPSL and to committed shippers that the entire package of terms be enforced and applied as agreed. In the case of the committed shippers, this means that their rates will be calculated initially, and adjusted each year during the term of the TSA, in accordance with the cost-of-service principles embodied in Schedule B to the TSA. In particular, it is important that
there be a clear assurance that the rates on Southern Lights will not be subject to the Commission's indexing regulations, nor will they be subject to challenge on the ground that specific elements of the Schedule B cost-of-service principles depart from the parameters that would otherwise apply under standard Commission ratemaking rules or policies for oil pipelines. As further discussed below, the provisions of Schedule B are generally consistent with (although in a number of respects more conservative than) standard Commission ratemaking principles, and thus do not lead to unreasonable rate levels for committed shippers. However, to avoid uncertainty and the potential of future unpredictable litigation, Enbridge requests assurance that the Commission will uphold the rates derived from the Schedule B cost-of-service, which the committed shippers have agreed to pay, without challenge by the committed shippers. This is not a request that the Commission approve specific rates, but that the Commission approve the rate principles and methodology contemplated in the TSA.

The TSA mandates that the committed rates will be calculated annually using the 77,000 bpd committed volume as the throughput level (subject to the revenue credit discussed above for uncommitted volumes). In a declaratory order for another Enbridge pipeline, the Commission suggested that an oil pipeline should be required to use its initial design capacity to set its first year rate. *Enbridge Energy Co., Inc.*, 110 FERC ¶ 61,211 at P 46 (2005) (“Spearhead Order”). This criterion should not apply to the proposed Southern Lights line. All of the cases the Commission cited in support of the Spearhead Order involved natural gas pipelines, not oil pipelines. As the Commission has recently observed, natural gas pipeline concepts do not necessarily apply to oil pipeline regulation under the ICA. *Colonial Pipeline Co.*, 119 FERC ¶ 61,138 (1995); *Great Lakes Transmission Limited P'ship*, 66 FERC ¶ 61,118 (1994); *Equitran, Inc.*, 63 FERC ¶ 61,070 (1993); *Ark. W. Pipeline Co.*, 63 FERC ¶ 61,006 (1993).
61, at P 19 (2007). Natural gas pipelines are required to apply for a certificate of public convenience and necessity prior to beginning operations, which typically requires a showing that the planned capacity is actually necessary. There is no such requirement for oil pipelines. Accordingly, there is no reason to assume that an oil pipeline will necessarily begin operations at full capacity, since such pipelines are frequently sized to handle anticipated future demand and not simply the first-year demand. Calnev Pipe Line LLC, Order on Petition for Declaratory Order, Docket No. OR07-10 at P 28 (July 20, 2007) (“The Commission recognizes that by sizing its expansion pipeline to meet future demands Calnev is attempting to build its project in a cost effective and efficient manner.”).17

In the Spearhead Order, the Commission expressed concern that use of a lower projected throughput figure to set initial rates could permit the pipeline to over recover its costs. 110 FERC ¶ 61,211 at P 46. However, the rate methodology Southern Lights proposes includes a self-correcting mechanism that is designed to prevent such an over recovery. As explained below, the Southern Lights TSA includes a true-up of actual revenues to the agreed cost-of-service,18 with excess revenues being credited back to all shippers. In this way, shippers are protected from the prospect of over recovery by the pipeline as a result of overly conservative throughput projections. Therefore, the principles in the Spearhead Order, to the extent that they are applicable to oil pipelines, should not apply here.

The TSA also stipulates that the committed rates will be calculated using a fixed capital structure of 70 percent debt and 30 percent equity, which reflects the proposed project financing.

17 Notably, the Commission’s oil pipeline regulations provide that when a carrier is establishing rates for a new service, “the test period will be based on a 12-month projection of costs and revenues.” 18 C.F.R. § 346.2(a)(3).

18 The term “agreed cost-of-service” refers to the cost-of-service the parties agreed to in the TSA.
As discussed in the Thompson Affidavit, this capital structure was an agreed-upon term of the TSA that has no relation to the capital structure the pipeline would have been able to obtain in the absence of shipper volume commitments. Thompson Aff., Exh. B at ¶¶ 30, 32. EPSL expects that it will be able to achieve the 70 percent debt level of financing based upon the committed shipper financial commitments it has obtained. However, even if it is unable to do so, EPSL has agreed to calculate the committed shippers' rates on that basis. Id.

The return on equity ("ROE") provision in the TSA is an incentive mechanism that adjusts the ROE based on EPSL's performance in controlling construction costs. The base ROE in the TSA starts at a 12% nominal ROE level. The base ROE is then adjusted depending upon whether the project's final capital cost is above or below an agreed-upon capital cost estimate, with an upward ceiling of 14% nominal and a downward floor of 10% nominal. Exh. C.

Schedule B, App. I. This formula, which was expressly agreed to by the committed shippers, provides a strong incentive to EPSL to control construction costs and is reasonable in light of the risks of the endeavor, the first ever cross-border diluent pipeline to the Canadian oil sands. However, it does expose EPSL to the risk that it may receive an ROE well below the ROE's typically granted to other oil pipelines. On the other hand, EPSL can do better than the base ROE of 12% if it keeps its construction costs low relative to the agreed-upon estimate, which would substantially benefit shippers by reducing the capital costs to be included in rate base.  

\[ 19 \text{ E.g., Texaco Refining and Mktg., Inc. v. SFPP, L.P., 117 FERC ¶ 61,285 at P 30 (2006) (nominal 14.18\% and 13.63\% ROE for two test years approved).} \]

\[ 20 \text{ Even at the high end, the nominal ROE in the TSA would fall within the zone of reasonableness that the Commission has accepted for other comparably risky projects. In a recent case involving a billion-dollar pipeline expansion, for example, the Commission indicated that the risks of that project merited an ROE at the high end of the zone of reasonableness.} \]

We believe that a number of factors support Colonial's request for an ROE toward the upper end of the zone of reasonableness. For
The Commission should find that the agreement of sophisticated shippers, not affiliated with Enbridge, to pay the committed rates resulting from the TSA is sufficient to permit those rates to be filed and charged. The Commission's regulations expressly allow for accepting an initial negotiated rate with a non-affiliated shipper. 18 C.F.R. § 342.2. Moreover, the Commission has indicated in other contexts that sophisticated oil pipeline shippers should be held to their agreements and need not be protected by regulatory fiat. In a case involving SFPP, the Commission rejected an attempt by shippers to seek a refund on a rate they had agreed to pay, noting that "the charge was established by negotiation, and the contracts were entered into voluntarily by the parties." SFPP, L.P., 86 FERC ¶ 61,022 at 61,075 (1999) (subsequent history omitted). Where sophisticated shippers, aware of their rights under the ICA, had negotiated a detailed contract, and there were no obstacles to challenging the rate, a subsequent challenge was "arguably little more than an attempt to avoid a previously negotiated contract, agreements the Commission has held are lawful under the ICA." Id. The Commission has respected the ability of shipping parties to bind themselves to contracts, without the need of Commission interference in the trade-offs made in that process. Kern River Gas Transmission Co., 117 FERC ¶ 61,077 at P 64 & n.113 (2006) (choices made by two classes of shippers were accorded the "sanctity of example, the length and scope of the project will present substantial challenges, even if Colonial is able to site the expansion mainly in the existing right of way. The project also requires an enormous investment, and thereby presents financing challenges not faced by the ordinary upgrade. The size of the investment, the challenges of constructing a multi-state project, and the time for completion of the project (four years) all support the request for an ROE toward the upper end of the range of reasonableness. Finally, Colonial has no obligation to expand its system but has voluntarily chosen to build major new facilities, with no guarantee that the throughput would be fully used.

Colonial Pipeline Co., 116 FERC ¶ 61,078 at P 59.
The Commission should, therefore, accept the committed rates as just and reasonable as between EPSL and the committed shippers.

C. EPSL Requests Assurance That the Rate Design Embodied in the TSA Will Be Upheld As to the Uncommitted Rates

The specific rate design issue of significance in the TSA cost-of-service formula is the provision setting the uncommitted rate at two times the level of the committed rate. Exh. C. TSA, Schedule B, § 14(a)(ii). The general purpose of this provision is to determine the distribution of the agreed-upon cost-of-service as between the committed and uncommitted shippers in light of their respective contributions to the initial development and construction of the pipeline. To be clear, EPSL is not seeking Commission approval for any specific rate to be charged to the committed or uncommitted shippers in advance of the actual annual tariff filings to be made once the pipeline is in operation. Rather, it is asking for approval of the principle that the rate design embodied in the TSA will be applied to determine the allocation of the cost-of-service among the two groups of shippers. Thus, what the Commission should be concerned about here is not the absolute level of the uncommitted rate in any given year, but the question whether it is reasonable, as a matter of regulatory policy, for the uncommitted shippers to bear a higher proportionate share of the costs on a unit basis as embodied in the two-to-one ratio of the uncommitted rate to the committed rate.

21 See also Revisions to Oil Pipeline Regulations Pursuant to the Energy Policy Act of 1992, 58 Fed. Reg. 58,753, 58,765 (Nov. 4, 1993) ("in furtherance of the Commission's policy to encourage settlements," initial rates could be established "through agreement of the pipeline and potential shippers, at least one of which must not be affiliated with the pipeline").

22 As with the committed rates, it is essential that the Commission's indexing rules be waived with respect to the uncommitted rates for Southern Lights. Since the uncommitted rates vary annually based on the committed rates (which in turn are based on annual costs), the uncommitted rates will not necessarily track the general oil pipeline index. The intent is that the uncommitted rates will therefore be exempt from indexing (up or down) so long as they are set in conformity with the TSA formula.
Regarding the uncommitted rates, as noted in Section B above, the committed shippers agreed in the TSA to pay the uncommitted rates for any volumes transported in excess of their minimum monthly commitment. The uncommitted rates thus constitute negotiated rates within the Commission’s regulatory framework. 18 C.F.R. § 342.2(b). In addition, the uncommitted rates are supported by two other considerations.

First, the revenue-sharing formula for calculating both the committed and the uncommitted rates ensures that the total revenues ultimately collected from committed and uncommitted shippers will not exceed the agreed-upon cost-of-service under the TSA each year. Second, according to the Affidavit of Mr. Robert G. Van Hoecke (Exhibit D hereto), the uncommitted rates, after the annual true-up adjustment, will be lower than the benchmark Opinion 154-B rates the uncommitted shippers would be charged under a more traditional set of cost-of-service assumptions and rate design approach.

1. Commission Precedent Supports the Proposed Rate Design

The uncommitted rates are proper because they do no more than allow EPSL to recover its agreed-upon (i.e., discounted) cost-of-service. The committed rate is determined each year based on the TSA. The uncommitted rate is then automatically calculated at two times the level of the committed rate. However, except as described in footnote 10, all revenues from uncommitted movements are credited at the end of the year against both the committed and uncommitted rates and appropriate refunds are paid to each group of shippers in proportion to the rates paid, so that the 50% discount is preserved. The end result is that the committed and uncommitted shippers share in paying the agreed-upon cost-of-service of the pipeline, but after

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23 As mentioned above, if volumes exceed 162,000 bpd, a portion of the incremental uncommitted revenue will accrue to EPSL in recognition of its cost-of-service concessions and as an incentive to maximize throughput.
revenue sharing the uncommitted shippers pay a higher proportion of the cost on a unit basis.

The differential between the committed and uncommitted rates (i.e., the fact that the uncommitted rate is exactly two times the level of the uncommitted rate) is a rate design element for spreading the agreed-upon cost-of-service between committed and uncommitted shippers and is fair in light of the heightened risk taken on by committed shippers through their long-term volume commitments and the flexibility afforded to uncommitted shippers who are free on a monthly basis to choose whether to use the transportation service provided by Southern Lights.

The differential allocation of costs also reflects the different risks borne by the committed and uncommitted shippers with respect to the possibility that the market for transportation of diluent from the U.S. into Canada will not develop as expected during the term of the TSA. As Mr. Van Hoecke states:

Under this rate structure, the TSA establishes a 50 percent tariff rate discount on committed volumes, relative to the uncommitted tariff rate. That agreed-upon discount is readily justified if one considers the alternatives available to potential shippers on Southern Lights. Those shippers could have chosen to withhold their commitment in the expectation that the line would be built with the support of other shippers; that is, that they would receive service without incurring the costs of commitment. The 50 percent discount represents the benefit that the Committed Shippers required to justify the cost they incur by assuming certain market risks and by providing the financial surety that will enable Southern Lights to be constructed. To the extent a Committed Shipper makes movements in excess of its commitment, it will pay the higher uncommitted spot rate on those volumes. None of the Committed Shippers is affiliated in any way with EPSL; the contract is entirely arms-length. These considerations strongly suggest that the 50 percent discount for the committed volumes that EPSL requests in the Petition is the inducement necessary to garner commitments and build the pipeline.


In a number of cases, the Commission has accepted the principle that committed shippers are not similarly situated to uncommitted shippers, and that provision of rate discounts to those
shippers that made initial commitments is therefore nondiscriminatory where, as here, the offer was open to all. See, e.g., Mid-America Pipeline Co., L.L.C. 115 FERC ¶ 61,258 at P16 & n. 7 (2006) (acknowledging that "incentive rates have been structured to preserve the rate differential between the incentive rate and the otherwise generally-applicable rate" and that such an agreement "might include a guarantee to [the committed shipper] that its Incentive Program rate would remain below the generally-applicable rate"). For its Spearhead pipeline, Enbridge held an open season to allow committed shippers to obtain a rate that was discounted from the rate subsequently available to uncommitted shippers. The Commission found that there had been a "transparent open season" for capacity, and relied on a prior case recognizing that discounting committed rates from uncommitted rates was nondiscriminatory because "such rates ... reflected relevant differences ... between term and uncommitted shippers." Enbridge Energy Co., Inc., 110 FERC ¶ 61,211 at P 38 (applying Express Pipeline P'ship, 76 FERC ¶ 61,245 (1996)). Just as the Spearhead discount for committed rates was nondiscriminatory, the discount is nondiscriminatory here where there has been an open season and the committed shippers provide substantial benefits to the pipeline that uncommitted shippers do not provide. See also Plantation Pipe Line Co., 98 FERC ¶ 61,219 (2002); Mid-America Pipeline Co., 93 FERC ¶ 61,306 at 62,048-49 (2000).

2. The Uncommitted Rates Will Be Lower Than Rates Supported by an Opinion 154-B Analysis Using Accepted Inputs

The second consideration showing that the proposed committed/uncommitted rate structure is reasonable is Mr. Van Hoecke's showing that across a wide range of throughputs, the uncommitted rates that result from the TSA (after all adjustments) are lower than the just and reasonable rates that would apply to uncommitted movements under the Commission's standard Opinion 154-B rate model, using accepted inputs for cost of capital items and a revenue credit
mechanism that takes the discounted rates into account. Van Hoecke Aff., Exh. D at ¶ 24 & Figure 1.

As Mr. Van Hoecke explains, if the uncommitted rates were to be challenged, the appropriate framework to evaluate that challenge would be the Commission's Opinion No. 154-B methodology. Id. at ¶ 16. Opinion No. 154-B has been the Commission's standard methodology for setting oil pipeline rates since 198521 and is further codified in the Commission's cost-of-service regulations at 18 C.F.R. Part 346. The Commission's regulations clearly permit an oil pipeline to defend its rates on an Opinion No. 154-B basis, regardless of whether those rates were initially filed as cost-of-service rates, negotiated rates, market-based rates, settlement rates, or indexed rates.22 See, e.g., Magellan Pipeline Co., LLC, 105 FERC ¶ 61,390 at P 10 (2003) (protested rates not set under Opinion 154-B can be defended with a 154-B cost-of-service); Express Pipeline Partnership, 76 FERC ¶ 61,245 at 62,250. Even before a rate is protested, an Opinion 154-B cost-of-service calculation is the appropriate alternative to evaluate whether a rate is just and reasonable.

In undertaking an Opinion 154-B analysis of the uncommitted rates, Mr. Van Hoecke noted that the assumptions and contractual agreements set forth in the TSA are not relevant to uncommitted shippers. Rather, it is necessary to determine what the appropriate inputs should be for such an analysis. Id. at ¶¶ 9, 16. With respect to rate of return and capital structure, the appropriate inputs for purposes of performing an Opinion 154-B analysis would be the rate of return and capital structure of the pipeline in the absence of the term volume commitments provided by committed shippers. Id. at ¶ 21. Professor J. Peter Williamson, an expert on cost of


22 18 C.F.R. Part 342.
capital and other financial regulatory matters, whose Affidavit is attached hereto as Exhibit E, has determined that those commitments must be disregarded because, without the committed shippers’ guarantees, EPSL would have required a much higher rate of return to offset the risks of undertaking the project than the rate of return agreed to with the committed shippers, who are in essence underwriting the success of the project by committing to cover all of the costs set forth in the TSA, including a specified level of return. Williamson Aff., Exh. E at ¶¶ 14-15.

Similarly, the capital structure of the project would be much different if EPSL were to go to the open market for debt without having any shipper commitments in place. In the absence of shipper commitments, EPSL’s capital structure would more likely reflect that of the bitumen producers — who would have been the most likely alternative candidates to undertake such a project — rather than the capital structure stipulated in the TSA. Id. at ¶¶ 13 & 26. In other words, as Mr. Thompson confirmed, EPSL would have needed much more equity capital and a significantly higher return on equity to undertake the Southern Lights project in the absence of shipper commitments. Thompson Aff., Exh. B at ¶ 33. A proper Opinion No. 154-B analysis should reflect that reality, rather than EPSL’s contractual agreement with committed shippers. Van Hoecke Aff., Exh. D at ¶ 16.

In determining what cost of capital EPSL might expect in the absence of shipper commitments, Professor Williamson evaluated the project’s risks. He notes:

I believe it is clear that, putting to one side the volume commitments provided by the committed shippers, the risk of Southern Lights is significantly greater than the risk in the average oil pipeline. The subject pipeline is designed to enable the producers of bitumen in Alberta to move the bitumen and diluent mix to the U.S. Midwest. The pipeline will therefore be subject to risks associated with both sides of the two markets (1) the supply of suitable diluents in the Mid-Continent and demand for them in the oil sands region of Alberta and (2) the supply of bitumen in Alberta and its demand at U.S. refineries. In Alberta, the only use
for the diluents is to enable the economical shipment of bitumen south to the U.S. The alternative uses that exist for diluent in gasoline blending and ethylene production in the U.S. would not be available in Alberta.

In particular, if the production of heavy oil and bitumen from the oil sands reserves in Western Canada does not develop as forecast, or if diluent is available from alternative sources more economically than from U.S. imports via the Southern Lights Pipeline, or if the supply of diluent in the U.S. were to be restricted or prove to be inadequate, a pipeline without shipper financial commitments could be in serious trouble.

Williamson Aff., Exh. E at ¶¶ 11-12.

Because of that heightened risk, Professor Williamson has determined that a minimum rate of return and capital structure for the Southern Lights project (without shipper commitments) would be a 14 percent nominal ROE and an equity ratio of 70 percent.

Williamson Aff., Exh. E at ¶¶ 20, 27. Professor Williamson arrives at the 14 percent ROE by comparing the Southern Lights project to recent Commission decisions for less risky "Greenfield" gas pipelines, where the Commission approved similar rates. *Id.* at ¶ 16, citing *Corpus Christi LNG, Cheniere Corpus Christi Pipeline Co.*, 111 FERC ¶ 61,081 (2005) (accepting 14 percent cost of equity); *Ingleside Energy Center L.L.C., San Patricio Pipeline L.L.C.*, 112 FERC ¶ 61,101 (2005) (same); see also *ANGTS*, 7 FERC ¶ 61,237 (1979) (approving 2 percent above cost of equity for an average pipeline). To support his recommended 70 percent equity capital structure, Professor Williamson refers to the Commission's recent decision in *Colonial Pipeline Co.*, 116 FERC ¶ 61,078, where a capital structure of 71 percent equity was referred to approvingly, as well as to the capital structures of the Western Canadian oil sands producers as a group, who would have been the parties most likely to have undertaken the Southern Lights project if EPSL had not done so. *Id.* at ¶ 22. Professor Williamson's analysis supports at least a 70 percent equity capital structure for EPSL in the absence of shipper
throughput guarantees. Id. at ¶ 27. Employing the 14 percent nominal ROE, Mr. Van Hoecke calculates a pro forma Opinion No. 154-B cost-of-service using both a capital structure of 70 percent equity (based on Professor Williamson’s recommendation) and, to be conservative, a capital structure of 55 percent equity. Van Hoecke Aff., Exh. D at ¶ 21 & Table 2.

Once the Opinion No. 154-B inputs he is using have been established, Mr. Van Hoecke uses a revenue credit mechanism to determine the uncommitted rate. Van Hoecke Aff., Exh. D at ¶ 18. Since the committed shippers bear a significant portion of the risk associated with the project, the TSA structure provides them with a substantial rate discount. Conversely, those uncommitted shippers that do not bear that risk are not entitled to a free ride; as explained by Mr. Van Hoecke, they should be required to pay a rate higher than would be expected under traditional average cost pricing. Id. at ¶ 15. The Commission has accepted a similar conclusion in Lac de Neige Pipeline Co., 114 FERC ¶ 61,335 at P 10 & n.4 (2006), reh'g denied. 119 FERC ¶ 61,236 (2007), where it specifically approved allocating the cost-of-service between discounted and undiscounted shippers through a revenue credit. Here, Mr. Van Hoecke has calculated the total Opinion 154-B revenue requirement and deducted from it the revenues anticipated from the discounted committed volumes (i.e., 77,000 bpd). Assuming varying levels of uncommitted volumes, the remaining cost-of-service is recovered from those uncommitted volumes to arrive at an uncommitted rate. Id. at ¶ 18. As Mr. Van Hoecke’s analysis shows, the benchmark Opinion 154-B rate exceeds the final uncommitted rate that would result from those same throughput levels under the TSA. In other words, at every point on the continuum, the benchmark Opinion No. 154-B rate is higher than the adjusted uncommitted rate under the TSA. Id. at ¶ 24.
Accordingly, the Commission should conclude that the uncommitted rates established under the rate design mechanism set forth in the TSA are permissible in principle (subject to proper implementation of the TSA formula in EPSL’s annual rate filings). The fact that the uncommitted rate level exceeds that of the committed rate is the result of a choice the uncommitted shippers made not to participate in the open season offering. Setting the committed rates at a 50% discount from the uncommitted rates does not subject uncommitted shippers to unreasonable or unduly discriminatory tariffs and the Commission should therefore approve the rate design methodology.

D. EPSL Requests Assurance That the Construction Costs of the Replacement Line and the Reversal Costs of Line 13 Will Be Included in the Southern Lights Rate Base

As Messrs. Van Hoecke and Thompson describe more fully, EPSL is proposing to conduct an asset swap in which EPSL would acquire an existing pipeline (Line 13) from EELP’s Lakehead System in exchange for a new line constructed for the Lakehead System. Van Hoecke Aff., Exh. D at ¶ 26; Thompson Aff., Exh. B at ¶¶ 15 & 20-23. Such an asset swap is "the most efficient and the most equitable choice" for Southern Lights, Lakehead, and all of their shippers. Van Hoecke Aff., Exh. D at ¶ 30.

As Mr. Thompson explains, the asset swap is neutral for Southern Lights shippers in the U.S. since the existing Line 13 in the Lakehead System can provide the same level of service for Southern Lights as a new line would, and the cost of the new LSR line will be charged to Southern Lights. Thompson Aff., Exh. B at ¶ 20. However, the exchange of Line 13 for the new LSR line is highly beneficial to Southern Lights shippers when the Canadian portion of the asset is considered because the cost of the LSR line in Canada is substantially lower than the cost of a
new line from the international border to Edmonton. Since the Southern Lights shippers in the
U.S. are the same as those in Canada, the line swap results in an overall benefit to Southern
Lights shippers. Van Hoecke Aff., Exh. D at ¶ 30. There is also a benefit to Lakehead’s
shippers in that the replacement LSR pipeline will increase annual capacity without a
 corresponding increase in rate base on the Lakehead System. Id. Thus, the asset swap will
result in rates that proportionally represent the costs each group of shippers ought to bear; that is,
the costs associated with the service provided to them.

As explained in the Van Hoecke Affidavit, while at first blush this asset swap
configuration might appear to resemble the type of purchase price adjustment seen in cases such
as Longhorn Partners Pipeline26 and Rio Grande Pipeline Co. v. FERC27 (where a purchasing
entity seeks to include the purchase price paid for an asset, rather than the seller’s depreciated
original cost, in the buyer’s rate base), it is distinctly different. This is not an attempt to write up

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26 As explained in the Thompson Affidavit, the LSR line in Canada will run from
Cromer, Manitoba to the Canada-U.S. border, a distance of only 178 miles. In exchange,
Southern Lights Canada will receive the Canadian portion of Line 13, which extends from the
border to Edmonton, Alberta a distance of 774 miles. Thus, the new construction in Canada
under the proposed exchange should be roughly 23% as much as building a new line for the
entire distance, thus saving the Southern Lights shippers hundreds of millions of dollars.
Thompson Aff., Exh. B at ¶ 15.

27 CAPP, as the representative of the companies whose production is transported by the
Lakehead System, has specifically agreed to the terms of this asset swap. See Exhibit A. As
noted above, CAPP has also agreed to terms on which the interim costs of the Line 13 lease can
be recovered in Lakehead’s mainline tariff rates during the period when Line 13 is still in
southbound crude service, reflecting the fact that the replacement facilities, plus Line 13, will
provide Lakehead shippers with a temporary increase in capacity to Clearbrook of approximately
219,000 bpd. Id. The mechanism for implementing that agreement will be the subject of a
separate application to be filed by FELP at a later time.


29 178 F.3d 533 (D.C. Cir. 1999).
an asset, since EPSL is seeking to include only the construction costs it will actually incur in its rate base. Van Hoecke Aff., Exh. D at ¶ 31-33.

The concern behind the general rule against purchase price adjustments is that one pipeline company will sell an asset to another pipeline company at an inflated price so that the second company can achieve a higher rate base than it would otherwise, and thus that line’s shippers would be paying twice for the same asset.\textsuperscript{30} That is not the situation here. In this case, EPSL’s goal is to avoid having the same shippers pay twice. By allowing Lakehead to retain its current rate base, Lakehead’s shippers will not be paying higher rates and will not be subsidizing the construction of the new diluent line; rather, once Southern Lights goes into service, the Lakehead rates will be the same as they would have been without the asset swap.\textsuperscript{31} In the same way, it is only fair that the Southern Lights shippers pay the actual costs of constructing the new substitute for Line 13. As Mr. Van Hoecke notes, “shippers on both Lakehead and the planned Southern Lights pipeline are better off than they would be under alternative arrangements.” \textit{Id.} at ¶ 33.

Even if the Commission were to analyze this asset swap under the guidance of \textit{Longhorn} and \textit{Rio Grande}, this asset swap would clearly meet the Commission’s “benefits exception” test. The benefits exception permits a purchased asset to “be included in the rate base at the full purchase price if the purchaser can demonstrate that: 1) the acquired facility is being put to new use, and 2) the purchase price is less than the cost of constructing a comparable facility.” \textit{Rio Grande}, 178 F.3d at 536-37. The proposed transaction clearly meets both criteria. Line 13 will be put to an entirely new use, since it will be moving a different product in a different direction.

\textsuperscript{30} \textit{Texaco Refining \\& Mktg., Inc.}, 108 FERC ¶ 63,036 at P 337 (2004).

\textsuperscript{31} For the interim period, see note 27, \textit{supra}. 
to a different market servicing different shippers. Van Hoecke Aff., Exh. D at ¶ 32. See also Enbridge Energy Co., Inc., 110 FERC ¶ 61,211 at PP 27-32 (upholding use of Spearhead pipeline purchase price as new use where line reversal, new products and new shippers were involved). In addition, when the entire transaction on both sides of the border is considered, there is clearly an overall benefit to both the Southern Lights shippers and the Lakehead shippers, for the reasons described above.12

E. EPSL Requests Approval to Use the Stipulated Depreciation Rates Contained in the TSA for Accounting and Rate Purposes During the Initial Term of the TSA

The rate structure included in the TSA uses a stipulated depreciation profile to calculate rates, essentially spreading out the depreciation to produce a more stable rate pattern over time. The depreciation schedule specifies a series of differing (i.e., sculpted) depreciation rates that result in recovery of 60% of the initial rate base over the first 15 years of the pipeline's life, starting with small percentages and increasing over time.13 Use of sculpted depreciation prevents front end rate shock, and provides rate stability for shippers by tending to levelize the rates in

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12 The Commission has in the past expressed some reservation about a seller retaining an ownership interest in the sold asset in the context of a purchase price adjustment. In Rio Grande, the D.C. Circuit rejected the notion of a per se rule prohibiting a purchase price adjustment when a seller acquires some interest in the purchaser. 178 F.3d at 542-43. In any event, the Commission should not be concerned about any such retained interest in this case. First, neither EPSL nor EELP (the owner of the Lakehead System) has or will have an ownership interest in the other. While it is true that both companies are affiliated with the same ultimate parent company, EELP is a publicly traded master limited partnership with a substantially different ownership structure from EPSL, which is a wholly owned Enbridge subsidiary. Second, the intent behind the scrutiny of affiliated transactions is to prevent self-dealing. EPSL has demonstrated that this transaction was negotiated with the goal of achieving a fair result for both companies (and their shippers), and it has the express approval of CAPP. As a result, no concern should arise about self-dealing.

13 The schedule reverts to a straight-line depreciation after 15 years at which point the remaining depreciation is spread using straight-line depreciation (illustrated in the TSA for years 16 and 17). See Exh. C, Schedule D.
real terms. The effect of the schedule is to deprecate a smaller percentage of the rate base when the assets have their greatest value, with the percentage increasing as the value decreases. This creates an incentive for shippers to begin shipping earlier, as compared to a straight-line schedule under which early shippers pay the highest rates. Van Hoecke Aff., Exh. D at ¶ 25. For the pipeline, it is a means of obtaining long-term commitments to make the project feasible. See Greenbrier Pipeline Co., L.L.C., 101 FERC ¶ 61,122 at P 115 (2002), reh’g denied, 103 FERC ¶ 61,024 (2003) (“Greenbrier indicates it is willing to accept lower rates, and thus, lower return in the early years of its project from customers willing to enter into a long-term agreement in exchange for the certainty and stability provided by the long-term agreements.”). Of course, the committed shippers were free to accept by contract the depreciation schedule. “TriState is free to structure its actual contracts in such a way as to contractually obligate its customers to pay additional amounts (amounts above the specified fixed rate) at a later date for services previously provided.” TriState Pipeline, L.L.C., 88 FERC ¶ 61,328 at 62,008 (1999), vacated after applicant withdrew application, 90 FERC ¶ 61,258 (2000).

Levelized rates were also approved in Express Pipeline P’ship, 76 FERC ¶ 61,245 at 62,257-58. “During the first two years of operation, Express’ rates generate revenues below what would normally be allowed under traditional cost-based ratemaking....” The Commission approved the rate “because without the rate incentives essential to attract those willing to make term commitments, the project might not be built at all.” See also Colonial Pipeline Co., 89 FERC ¶ 61,095 (1999) (levelized initial three-year rate).
Here, the Commission should accept the sculpted depreciation for the committed rates, as it has been willing to do in the case of other projects. In *Georgia Strait Crossing Pipeline L.P.* 98 FERC ¶ 61,271 (2002), for example, one shipper (Powerex) had negotiated to pay a rate for the entire capacity of the planned pipeline. *Id.* at 62,050. Georgia Strait planned to use straight-line depreciation for book purposes, but obtained approval from the Commission to use a depreciation profile to levelize the negotiated rates with Powerex. *Id.* at 62,056; *see also Northwest Pipeline Corp.*, 116 FERC ¶ 61,151 at P 28 (2006); *Millenium Pipeline Co., L.L.C.*, 117 FERC ¶ 61,319 at P 131 (2006).

To be consistent, the Commission should also approve the sculpted depreciation for the uncommitted rates, as it has done in other pipeline cases. In *Kern River Gas Transmission Co.*, 117 FERC ¶ 61,077 (2006), for example, the Commission described Kern River’s depreciation approach as follows: “Generally, under Kern River’s levelization methodology, annual depreciation recovery in rates starts very low and increases during the levelization period as the return component of the cost-of-service decreases (in tandem with the declining total rate base) to obtain a constant or ‘level’ annual cost of service.” *Id.* at P 40. According to the *Kern River* order, such a system provided advantages to both the pipeline and the shippers:

The benefits of using a levelized methodology are that shippers benefit from rates being lower during the early years after the project goes into service, than they would be under a traditional rate design. The pipeline benefits by securing construction loans as well as competing with other well established pipelines in the area charging low rates.
Id.; see also id. at P-41 ("traditional rate design rates start high"). Using the sculpted
depreciation found in the TSA’s will tend to produce the same benefits for EPSL and its shippers
as it produced for Kern River and its shippers.37

The Commission has also long accepted rate-levelization for electric utilities.

We believe that a levelized approach is preferable. A levelized
charge is not time sensitive and thus establishes an appropriate
benchmark for rates which will be in effect over an indefinite
period. It thus promotes rate stability without regard to the
customer or the time of the transaction. A nonlevelized rate,
however, must be revised periodically, since it front-loads the
recovery of capital costs, i.e., over time, depreciation reduces the
investment base, and the rate necessary to provide a reasonable
contribution to the seller’s fixed costs declines.

Jersey Cent. Power & Light Co., 38 FERC ¶ 61,275 at 61,927 (1987). In that context, the
Commission has recognized that the amount recovered by the utility is the same under either
formulation.

Under a levelized method, the capital recovery component of the
rates does not vary from year to year... Thus, in the early years of
a facility’s service life, nonlevelized rates will be higher than
levelized rates and, in the later years of the facility’s service life,
nonlevelized rates will be lower than levelized rates. However,
under either approach, the utility recovers, on a net present value
basis, the identical capital costs, i.e. depreciation, return on rate
base and income taxes.

Maine Public Serv. Co., 71 FERC ¶ 61,249 at 61,954 n.4 (1995); id. at 61,956 ("Both methods
are equivalent, and recover the same transmission costs. The only difference is the timing of cost
recovery.").

Finally, because the committed and uncommitted rates will both be determined using
sculpted depreciation, EPSL requests approval to use the agreed-upon depreciation both for

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37 The Commission should also note that it has approved rate levelization in novel
circumstances, such as for a pipeline serving an LNG facility. E.g., *Tractebel Calypso Pipeline,*
Form 6 reporting purposes and in any rate matter that may arise with respect to rates charged during the initial term of the TSA. In other words, to keep its accounting and ratemaking depreciation consistent, EPSL asks for a waiver of the Uniform System of Accounts to permit recording of the sculpted depreciation for both purposes. See 18 C.F.R. Part 352, Gen'l Inst. 1-8.

F. EPSL Requests Approval to Charge Rates for All U.S. Shipments Adjusted for Saved Power Costs

As explained by Mr. Thompson, the Southern Lights Pipeline is being constructed to support diluent shipments from Chicago to Edmonton. Thompson Aff., Exh. B at ¶ 2. In recognition of that fact, EPSL currently intends to charge a single rate for shipments in the U.S. as provided in the TSA. Exh. C, §§ 6.02, 6.03. To the extent there may be any short-haul U.S. movements in the future, these shippers would pay the applicable Chicago-to-border rate adjusted for any power cost savings associated with those movements. TSA, Exh. C, Schedule B, § 14(c)(iii). The power costs savings adjustment will ensure that any shippers who transport diluent from origins other than Chicago will be credited with the variable cost savings (essentially power and drag reducing agent ("DRA") costs) that are avoided due to the shorter distance of haul. Exh. C, Schedule B, § 14. As Mr. Van Hoecke explains, this approach is reasonable because a power cost adjustment directs savings to shippers who move a shorter distance. Van Hoecke Aff., Exh. D at ¶ 34.

The Commission has accepted such rates in other cases, and has generally avoided establishing a bright line between cases in which such rates are appropriate and cases in which a distance-based rate is required. Greenbrier Pipeline Co., LLC, 101 FERC ¶ 61,122 at P 77. The Commission should accept the rate structure proposed here for three reasons.

First, it is speculative whether any shipper will want to move diluent from an origin point north of Chicago. The pipeline is being built on the basis that committed shippers have agreed to
ship 77,000 barrels per day across the whole length of the pipeline. It is not certain there will be any additional shippers, and it is entirely speculative whether a future uncommitted shipper would want to ship diluent over only a portion of the pipeline. The Commission does not require distance-based rates on the basis of speculative shippers. *Entrega Gas Pipeline Inc. v. FERC* [61,327 at P 29 & n.21 (2005)].

Second, the Commission has been flexible in accepting non-distance based rates, as reflected in its gas pipeline precedents. The gas regulations require that "[a]ny rate filed for service subject to this section must reasonably reflect any material variation in the cost of providing the service due to . . . the distance over which the transportation is provided." 18 C.F.R. § 284.10(c)(1)(i) (formerly § 284.7). However, when it issued those regulations, the Commission noted that they do not necessarily require a mileage-based rate. In adopting the regulation, it stated:

> The commenters' arguments are based on the assumption that we have required that rates for all self-implementing services to be mileage-based or be time-of-service based. This is not quite the case. The Final Rule requires that the rate reasonably reflect any material variations in the cost of providing service. The cost issues will be determined on an individual case-by-case basis. It is only the general standard which is imposed in the rule.

*Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, 50 Fed. Reg. 42,408, 42,450 (Oct. 18, 1985); see also *Northwest Pipeline Corp. v. FERC* [61,158 at 61,578 (1998)].

Here, the rate reasonably reflects variations in the cost of providing service because any shipper who chooses to ship over a portion of the pipeline will be credited the savings in power cost not incurred by moving the shorter distance. Exh. C, Schedule B, § 14(c)(iii). (An example of the calculation is included in Exh. C, Schedule D.) Because the partial shipper will only pay for the variable power costs it incurred, the rate reasonably accommodates material variations in variable costs. *Cf. Gulf South Pipeline Co. L.P. v. FERC* [61,463 at P 4 (2005) (allowing
pipeline to eliminate fuel charge "on specified transactions posted on its website where, based on Gulf South's operational experience, no incremental fuel is expected to be consumed in the transaction on an aggregate basis at a matrix of receipt and delivery point pairs".

Third, the burden is on a prospective shipper to identify a cost that varies by distance for which it should not be held responsible. *Greenbrier Pipeline Co., LLC*, 101 FERC ¶ 61,122 at P 77 ("Saltville has not articulated "any material variation in the cost of providing the service".")

Here, the pipeline was planned, accepted and launched as a pipeline from Chicago to Edmonton. It would not have been built on any shorter path. Because all shippers benefit from the existence of the pipeline, they cannot be heard to argue that they should only bear the cost of a shorter pipeline, one which neither EPSL nor its committed shippers would have accepted.

**G. EPSL Requests Approval for the True-Up Mechanism in the TSA That Provides for an Annual Reconciliation of Actual Costs and Uncommitted Revenues**

The TSA contemplates an annual true-up of any differences between estimated and actual revenues and costs. Exh. C, Schedule B at § 14. This adjustment will also include a credit for any uncommitted revenue received during the year up to 90% of annual capacity of 180,000 bpd (and 75% of uncommitted revenues above 90%). Exh. C, Schedule B at § 14(e)(vi). EPSL asks the Commission to declare that the true-up and revenue credit mechanism is permissible in the unique circumstances of this pipeline.

With respect to the annual true-up mechanism, the Commission should approve that mechanism as being consistent with Commission policy and the filed rate doctrine. The terms of the true-up mechanism will be fully set forth in the tariff, so that all shippers are on notice of the potential year-end adjustment of their annual rates. If EPSL finds that it has over-collected, it will issue a refund to each shipper based on the volume transported. If EPSL finds it has under-collected, it will send an invoice to each shipper. Mr. Van Hoecke provides an example of how
the true-up will operate in his affidavit. Van Hoecke Aff., Exh. D at ¶ 36 & Table 3. The annual true-up envisioned by the TSA is highly beneficial to shippers, since it avoids ultimate over-collection by the pipeline, thereby assuring a proper matching of burdens and benefits. Id. at ¶ 35. The true-up mechanism is also fair as among shippers because the amount of the refund (or, if need be, the adjusted invoice) is proportional to their actual volumes during the calendar year for which the true-up is being made.38

Similar true-ups have been accepted in other cases. For example, Southern Company has reported to the Commission its annual refunds or surcharges due under its formula rates, accepted by the Commission in Southern Company Services, Inc., 105 FERC ¶ 61,019 (2003). See Southern Company Services, Inc., 117 FERC ¶ 61,308 at P 7 n.9 (2006). The Commission recently accepted a settlement in which Enbridge North Dakota was permitted to impose a surcharge to support a mainline expansion, subject to an annual true-up of the surcharge. Enbridge Pipelines (North Dakota) LLC, 117 FERC ¶ 61,131 (2006) (Office Director Order). And the Commission recently accepted a settlement under which an oil pipeline’s Hurricane Recovery Surcharge is subject to a true-up that could result in the pipeline issuing refunds to the shippers. Chevron Pipe Line Co., 117 FERC ¶ 61,144 (2006). The Mid-America Pipeline security surcharge true-up also involved the possibility of refunding or invoicing shippers. Mid-America Pipeline Co., LLC, 115 FERC ¶ 61,384 at P 5 (“MAPL states it will refund or invoice its shippers on a pro-rata basis for barrels shipped during the Recovery Period. If this true-up amount is within one percent of the costs incurred, MAPL will not make any additional collections or refunds.”).

38 This avoids the potential inequity that may arise when the true-up is rolled into the subsequent year’s rates if a particular shipper has substantial volumes in one period but not the next.
Because the terms of the true-up will be explicitly set forth in the tariff, using such a prior-period adjustment does not violate the filed rate doctrine. *TransColorado Gas Transmission Co.*, 112 FERC ¶ 61,135 at P 11 (2005) (in a case involving true-ups of gas quantities, "there is no violation of the filed rate doctrine or the rule against retroactive rate making because the shippers are on notice that the pipeline is entitled to recover these costs"). “So long as the parties had adequate notice that surcharges might be imposed in the future, imposition of surcharges does not violate the filed rate doctrine,” *Canadian Ass'n of Petroleum Producers v. FERC*, 254 F.3d 289, 299 (D.C. Cir. 2001); *Louisiana Public Service Comm'n v. FERC*, 482 F.3d 510, 520 (D.C. Cir. 2007) (same as for refunds). Any shipper choosing to ship uncommitted volumes will be on notice of the possibility of refunds and charges. *Public Utilities Comm'n of California v. FERC*, 254 F.3d 250, 254 & n.3 (D.C. Cir. 2001) (charges under formula rate contained in tariff do not violate filed rate doctrine). In short, both charges and refunds pursuant to a true-up announced in a tariff are consistent with the filed rate doctrine. *BP West Coast Products, L.L.C. v. SFPP, L.P.*, 120 FERC ¶ 61,014 at P 5 (2007).

With respect to the uncommitted revenue credit, as discussed above, this mechanism generally ensures that EPSL will not over-recover the agreed-upon cost-of-service and is therefore highly beneficial to both committed and uncommitted shippers. With respect to the 75/25 revenue sharing when annual volumes exceed an average of 162,000 bpd, similar divisions of incremental revenue to provide pipelines with incentives have been accepted in other contexts. *E.g.*, *Cheyenne Plains Gas Pipeline Co., L.L.C.*, 108 FERC ¶ 61,052 at P 12 (2004) (clarifying that pipeline could amend agreements to divide revenue 50/50 with negotiated rate shippers); *Entrega Gas Pipeline Inc.*, 113 FERC ¶ 61,327 at PP 16-17 (2005) (allowing 50/50 split which was included in open season materials, included in *pro forma* tariff, and in precedent agreement).
Where contracts make assumptions about the effective annual capacity of a gas pipeline, the shippers generally cannot challenge those risk allocations after the fact. "As with several of the prior rulings, the Commission finds that the relevant contracts and rates allocated the risk of the Btu gas content between Mojave and its shippers at the beginning of the project. There is no overriding policy reason to interfere with this contractual relationship." Mojave Pipeline Co., 81 FERC ¶ 61,150 at 61,684 (1997). The division of revenues above 162,000 bpd is the parties' means of allocating the risk that the pipeline's full annual capacity will not be used and making up for some of the discounts to the agreed-upon cost-of-service. Van Hoecke Aff., Exh. D at ¶ 39. Moreover, as demonstrated in Mr. Van Hoecke's pro forma cost-of-service calculations, even with this incentive EPSL will not recover more than its properly calculated cost-of-service using traditional application of the Opinion No. 154-B methodology. Id.

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See also High Island Offshore System, 66 FERC ¶ 61,378 at 62,268 (1994) (in wake of gas pipeline restructuring, when projections of use of interruptible service were uncertain, Commission required "the pipeline to establish a 90/10 revenue sharing mechanism under which the pipeline is allowed to retain 10 percent of all revenues in excess of allocated costs to give the pipeline an incentive to market interruptible service"); Discovery Gas Transmission L.L.C., 108 FERC ¶ 61,060 at P 13 (2004).
V. COMMUNICATIONS

The following persons are authorized to receive service and communications in this proceeding on behalf of EPSL:

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VI. CONCLUSION

For the foregoing reasons, EPSL respectfully requests a declaratory order regarding the Southern Lights Pipeline incorporating the rulings listed in the Executive Summary of this Petition.

Respectfully submitted

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EPSL requests, to the extent necessary, a waiver of Rule 203(b)(3). 18 C.F.R. § 203(b)(3), limiting to two names the persons upon whom service is to be made.