## 2.0 PROJECT OVERVIEW

This Project overview provides summary information about:

- the background and scope of the Project
- content and organization of this Consolidated Application
- regulatory context
- main Project components and activities
- the transfer of existing natural gas facilities required for the Project
- the economic feasibility of the Project, including:
  - crude oil supply and markets
  - transportation and tolls
  - financing
- engineering and design considerations
- preliminary cost estimates and scheduling
- management systems and operations
- land and landowner consultation
- Aboriginal and community engagement
- environmental and socio-economic assessment (ESA)
- risk assessment
- decommissioning and abandonment
- supporting documents

## 2.1 BACKGROUND

### 2.1.1 Chronology of Events

In 2011, TransCanada began investigating the feasibility of transporting additional crude oil production from the WCSB to major markets such as eastern Canada, the United States (US) East Coast, the US Gulf Coast, Europe and Asia. Preliminary discussions were held with prospective oil shippers and, through the subsequent months, TransCanada developed a conceptual project which considered various ways to accomplish it, including the potential acquisition and conversion of existing natural gas facilities to crude oil service.

Commercial discussions with prospective shippers took place through 2012 and early 2013 regarding potential delivery points, timing, tolls and terms of service. Following those discussions, TransCanada, on behalf of Energy East, announced plans in April 2013 to hold a binding open season to obtain firm commitments from interested parties. In early August 2013, TransCanada announced that the open season had resulted in sufficient long-term shipping commitments to proceed with a project.

On 30 October 2014, Energy East and TransCanada applied to the Board for approvals to construct and operate the Project (Original Application or Application).

The Application included information on a proposed Cacouna marine terminal and related facilities near Cacouna, Québec.

### 2.1.2 Application Amendment

On 28 November 2014, the *Committee on the Status of Endangered Wildlife in Canada* (COSEWIC) recommended a re-designation of the St. Lawrence Estuary population of beluga whales from a threatened to an endangered species. Energy East responded by immediately suspending any investigative work related to the Cacouna marine terminal and facilities while it assessed the implications of the COSEWIC recommendation. Energy East notified the Board of this development in its first quarterly supplemental report.

On 2 April 2015, Energy East and TransCanada advised the Board of a decision not to proceed with the Cacouna marine terminal as part of the Project, and that the Application would be amended following an evaluation of the viability of other options for siting a marine terminal and oil storage facility. Energy East and TransCanada further advised that the amendment was planned for filing in fourth quarter 2015.[1]

In late August 2015, TransCanada and Energy East filed with the Board an agreement in principle, and in October 2015 a final agreement reached with three local distribution companies in Eastern Canada (LDC Energy East Agreement), which addresses various matters relating to the Energy East and Eastern Mainline projects (see Section 2.3.1).[2] The LDC Energy East Agreement addresses concerns raised in respect of the Project by the LDCs and defines the economic benefit and capacity available on the TransCanada Mainline after completion of the Project and the EMP.

On 5 November 2015, TransCanada announced on behalf of Energy East, that the Application would be amended to remove a Québec port from the scope of the Project (Application Amendment or Amendment), and to focus on connections to the Canaport Energy East marine terminal, two refineries in Québec, and one refinery in New Brunswick.

The Application Amendment reflecting the removal of the Cacouna marine terminal and the impact of the LDC Energy East Agreement was filed with the Board on 17 December 2015.

1 See –NEB Exhibit No. A6933-1.
2 See Appendix 2-2, Transfer Agreement between TransCanada and Energy East – First Amending Agreement (Attachment – LDC Energy East Agreement)

### 2.1.3 Supplemental Reports

Through the course of 2015, five supplemental reports, totalling over 25,000 pages, were also filed:

- Supplemental Report No. 1 , filed 30 January 2015
- Supplemental Report No. 2 , filed 2 April 2015
- Supplemental Report No. 3 , filed 30 June 2015
- Supplemental Report No. 4 , filed 30 September 2015
- Supplemental Report No. 5 , filed 17 December 2015

### 2.1.4 Consolidated Application

On 3 February 2016, the Board directed Energy East to file a consolidated version of the Application that included the supplemental reports and the Application Amendment (Consolidated Application). It also directed that, prior to filing the Consolidated Application, Energy East submit a structural map, a proposed detailed table of contents (TOC) for the consolidation, and a plan in respect of future supplemental filings and updates. The TOC and other materials were filed on 26 February 2016 and were addressed by the Board with comments in a letter to Energy East dated 21 March 2016.[3]

In accordance with Energy East's filing of 26 February 2016, this Consolidated Application amalgamates the material information from the Original Application, supplemental reports, and Amendment. In addition, and in alignment with the aims of consolidation as the Board has described, contents of a previously contemplated Supplemental Report No. 6 have also been included.

Through 2015, Energy East and TransCanada responded to five rounds of information requests (IRs) from the Board. The responses to these IRs have not been incorporated into the Consolidated Application, except where needed to enhance clarity or update original text with either correct or more current information. In most cases, footnote references to the applicable IRs are provided with this filing.

For further ease of reference, the general contents of the Consolidated Application and this overview section are presented in much the same order as they were in the original application and in each of Energy East's supplemental reports to the Board. That order is:

- Consolidated Application Volume 1 – Application and Project Overview
- Consolidated Application Volume 2 – Sale and Purchase of Mainline Assets (Section 74 Application)
- Consolidated Application Volume 3 – Commercial

[3] See NEB Exhibit Nos. A7f5676-1 and A76011-2, respectively.

- Consolidated Application Volume 4 – Pipeline Design
- Consolidated Application Volume 5 – Conversion Design
- Consolidated Application Volume 6 – Facility Design
- Consolidated Application Volume 7 – Construction and Operations
- Consolidated Application Volume 8 – Land
- Consolidated Application Volume 9 – Community Engagement
- Consolidated Application Volume 10 – Aboriginal Engagement
- Consolidated Application Volume 11 – Environmental and Socio-Economic Assessment (ESA) Overview
- Consolidated Application Volume 12 – Project Risk Assessment
- Consolidated Application Volume 13 – Overview and Detailed Route Maps

For additional information on the contents of this Consolidated Application, including the consolidated ESA for the Project, refer to the Structural Map and Table of Contents that are provided in the Contents section of this Volume 1.

#### 2.1.5 Supplemental Information

The information in this Consolidation Application is based on preliminary design, as supported by results from engineering assessments, field investigations, and engagement and consultation programs.

Additional engineering, stakeholder, and Aboriginal engagement informing detailed design and mitigation of Project effects will occur as the Board's regulatory process continues to unfold. This will generate additional information and reports, such as those detailing seasonal environmental surveys or traditional knowledge (TK) studies. These reports and studies, or summaries of them as appropriate, are currently anticipated to be filed in routine course, upon their completion either individually or together in groups, during the second half of 2016.

One supplemental filing is currently scheduled for filing by 30 June 2016.[4] Beyond this filing, Energy East will provide additional information in accordance with any timetable of events the Board issues as part of a Hearing Order, or as the Board may otherwise allow.

[4] See Energy East's supplemental filing plan, which was included as Attachment C to Energy East's response to the Board's directions dated 3 February 2016 (NEB Exhibit No. A75676-1).

## 2.2 CONSOLIDATED APPLICATION VOLUME 1 – APPLICATION AND PROJECT OVERVIEW

### 2.2.1 Regulatory Relief, Context and Standard

#### 2.2.1.1 Energy East

The Energy East Pipeline will be a federal work and undertaking that will be subject to NEB regulation for its entire life cycle, from planning and design, through construction and operation to abandonment.

Energy East requires pipeline facilities that reach from Alberta, across the Prairie provinces and northern Ontario, to Québec and New Brunswick. The existence of natural gas facilities that are not required for gas transportation service on a firm contract basis presents an opportunity to both re-purpose those facilities and proceed with the Project in a way that is economically feasible, environmentally responsible and achievable in a timely way.

The Project scope, as applied for in this Consolidated Application, includes:

- the purchase and conversion of approximately 3,000 km of TransCanada's existing natural gas pipeline facilities
- the construction and operation of approximately 1,500 km of new oil facilities along with pipeline laterals and connections, pump stations and custody transfer metering stations
- the construction and operation of three oil storage tank terminals and one new marine terminal

As designed, the Energy East Pipeline will enable Energy East to ship up to approximately 175,000 $m^3$/d (1.1 million bbl/d) of growing crude oil supply from western Canada to eastern Canadian refineries. These refineries have historically been heavily reliant on imported oil. The Project’s marine terminal will provide increased market diversity for this crude oil supply by enhancing access to markets in the US and overseas.

Initial shipments on the Energy East Pipeline are anticipated in fourth quarter 2021.

Energy East requires various approvals for the Project’s construction and operation under Parts I, III, IV and V of the NEB Act. In addition, Energy East will need various permits and authorizations under federal and provincial legislation for activities that are ancillary to, but necessary for, construction and operation of the Energy East Pipeline. These non-NEB regulatory permits and authorizations are expected to be in place, as required, to meet the construction schedule and planned in-service dates for the Project. Energy East will keep the Board informed as to the progress and receipt of those approvals.

For additional information on the NEB approvals that are being requested by Energy East, see Volume 1, Energy East Project and Asset Transfer Applications, and Volume 2, Sale and Purchase of Mainline Assets (section 74 Application).

The primary non-NEB regulatory permits and authorizations along with a preliminary receipt schedule are listed in Volume 7, Section 2.14: Regulatory Authorizations Required for Construction.

#### 2.2.1.2 TransCanada PipeLines Limited

TransCanada will require various approvals under Parts I, IV and V of the NEB Act, including NEB approval to sell certain existing natural gas assets of the TransCanada Mainline (portions of Lines 100-3 and 100-4 of the Prairies and Northern Ontario lines and all of Line 1200-2 of the North Bay Shortcut).

Additionally, in a related but separate application, TransCanada is applying for approval under Part III of the NEB Act to install new natural gas facilities along its existing Montréal Line in southeastern Ontario (Eastern Mainline Project or EMP). These facilities, which are centrally located where regional gas demand is greatest, will enable TransCanada to continue to meet service obligations, as well as accommodate new firm service requests after the TransCanada gas assets are transferred to Energy East. TransCanada will also require approvals as part of this Consolidated Application to give effect to the LDC Energy East Agreement which defines the economic benefit and capacity available on the TransCanada Mainline after completion of the Project and the Eastern Mainline Project.

#### 2.2.1.3 Regulatory Standard

The applicable regulatory standard is the public interest.

The Board is an independent federal agency established by the Parliament of Canada to regulate international and interprovincial aspects of the oil, gas and electric utility industries. It states that *its purpose is to regulate pipelines, energy development and trade in the public interest*.[5] (*emphasis added*)

The Board's public interest purpose is founded in its statutory *mandate*. For example, paragraph 12(1)(b) of Part I of the NEB Act sets out the Board's broad jurisdiction to make orders in the public interest:

> Jurisdiction
>
> 12. (1) The Board has full and exclusive jurisdiction to inquire into, hear and determine any matter …

[5] National Energy Board Home Page "Who We Are and Our Governance": www.neb.gc.ca.

> (b) where it appears to the Board that the circumstances may require the Board, *in the public interest*, to make any order or give any direction, leave, sanction or approval that by law it is authorized to make or give, or with respect to any matter, act or thing that by this Act or any such regulation, certificate, licence, permit, order or direction is prohibited, sanctioned or required to be done. (*emphasis added*)

Several other sections of the NEB Act make specific reference to the public interest, but it is clear that the Board takes the view that consideration of the public interest is applicable to all Board decisions.

Chapter 1 of the Filing Manual, issued in 2004 and amended various times since, applies to all applications. Section 1.1 of Chapter 1 provides:

> The National Energy Board's … *purpose is to promote safety, environmental protection and economic efficiency in the Canadian public interest* through its regulation of pipelines, energy development and trade as mandated by Parliament. As a result, companies … are required to obtain the Board's approval to, among other things:
>
> - add new facilities or modify or abandon existing facilities;
> - export or import oil and gas products; and
> - set tolls and tariffs.
>
> When seeking approval, applicants must submit applications or information filings (collectively referred to as filings) to the Board that are complete and enable the Board to:
>
> - evaluate the overall public good that the request can create as well as its negative aspects;
> - weigh the impacts;
> - make an informed decision that balances, among other things, the economic, environmental and social interests at that point in time.[6]

Courts and regulators have found that there is no precise definition of what constitutes the public interest, nor are there firm criteria for determining the public interest that could be applied in every situation. The public interest is not a question of law or fact but is an opinion that necessarily involves accommodation of conflicting interests.

The NEB has held that the NEB Act provides the Board with flexibility and broad powers, but the Board must interpret and implement the NEB Act in ways that

[6] *Filing Manual*, page 1-1. See also National Energy Board Annual Report 2013 to Parliament, page 47.

serve the Canadian public interest.[7] It has gone on to describe the nature of the Canadian public interest in the following terms:

> The public interest is inclusive of all Canadians and refers to a balance of economic, environmental and social interests that change as society's values and preferences evolve over time. As a regulator, the Board must estimate the overall public good a project may create and its potential negative aspects, weigh its various impacts, and make a decision.[8]

A previous Chairman of the NEB has stated:

> Although there is no precise definition of the public interest, it is clear that the public interest embodies the concept of "the greatest good for the greatest number." [9]

The Board recognized the "marked shift in most western economies" in the 1980s and 1990s to increased reliance on market forces in place of government decision-making with the consequence that the world of energy regulation became one where business makes investment decisions and governments set conditions under which investments can proceed.[10] The change was manifested in public interest-based approvals by the NEB of competing pipelines (including the Express, Alliance and Vector pipelines) in the evolution to an energy transmission pipeline market in Canada that is characterized by competition.[11]

The last Chairman of the NEB reiterated the Board's view of its public interest mandate. He indicated that the public interest:

> "…is something the NEB takes seriously and through our Reasons for Decisions we have communicated our thinking."

He further noted:

> "Since 1959, the NEB has been a quasi-judicial tribunal with independent authority in making decisions within its mandate. The legislators at the time were visionary in use of language within the Act by using a phrase "in the public interest."

[7] National Energy Board Reasons for Decision OH-1-2009, TransCanada Keystone Pipeline GP Ltd. (Keystone XL), page 78.
[8] Ibid, citing National Energy Board Reasons for Decision GH-1-2006, page 10.
[9] *The Regulator's Role—Promoting the Public Interest, Notes for a Presentation* by Mr. Kenneth Vollman, Chairman, National Energy Board, World Forum on Energy Regulation, May 24, 2000, Montréal, QC.
[10] Ibid, page 1.
[11] *The Future of Natural Gas Pipeline Regulation in Canada,* presented to Industrial Gas Users Association 2000 Natural Gas Conference, Toronto, Ontario by Jean-Paul Théorêt, Board Member, National Energy Board, November 14 and 15, 2000 (Théorêt Speech).

> What does decision making in the public interest mean? The NEB has defined "public interest" as "inclusive of all Canadians, and refers to the balance of economic, environmental and social interests that changes as society's values and preferences evolve over time. As a regulator, the Board weighs the relevant impacts on these interests when making decisions.[12]

The Board has explicitly stated that it has a responsibility "to regulate pipeline tolls in the public interest"[13] and that it must give "due weight" to the overall public interest in making determinations under its NEB Act Part IV jurisdiction, which relates to tolls and tariffs.[14]

In this context, the NEB has also stated explicitly that the regulatory standard applicable to an application to transfer facilities is the public interest. The Board must consider all factors relevant to the public interest including, but not limited to, the interests of gas and oil shippers, producers and consumers.[15] The Board further held that the standard is not "no harm" to shippers.[16] It also reiterated that shippers on pipelines have no acquired rights[17] to be protected from cost increases or entitlement to spare capacity. Shippers are entitled to receive the service for which they have contracted: they are not entitled to specific facilities.[18]

The Board went on to express its belief that regulation should emulate competition and should encourage actions and decisions that would enhance efficiency, improve competition and respond to market needs, but in doing so should be in keeping with the public interest.[19]

In the result, consideration of the Canadian public interest is the overriding standard to be applied by the NEB in the determination of whether to approve the Project, including the construction, transfer and operation of pipeline facilities.

---

[12] November 2009 speech entitled *"Energy Regulation in Canada, 50 Years in the Public Interest,"* Gaétan Caron, Chair and Chief Executive Officer of the Board.

[13] National Energy Board Reasons for Decision, In the Matter of TransCanada PipeLines Limited, RH-4-91, Tolls, March 1992, at PDF Page 54 of 85. See also National Energy Board Reasons for Decision Enbridge Pipelines Inc., RH-1-2005, Tolls, (June 2005).

[14] National Energy Board Reasons for Decision, In the Matter of TransCanada PipeLines Limited, RH-1-88, Phase I, Tolls, November 1988, at PDF Page 20 of 107.

[15] MH-1-2006 Decision, Chapter 5: The Board's Views on the Transfer and the Public Interest, pages 55–56 and Chapter 2, pages 14–16.

[16] MH-1-2006 Decision, page 16: "…adopting the proposed no harm test would be contrary to the long list of Board and Court authorities that have decided that the Board has wide discretion to determine what is relevant to the exercise of its mandate."

[17] MH-1-2006 Decision, page 51.

[18] MH-1-2006 Decision, page 55.

[19] MH-1-2006 Decision, page 58.

### 2.2.2 Main Project Components

The Project includes the following main components:

- new mainline, converted lines, two laterals and a connection pipeline totalling approximately 4,516 km of 1,067 mm (NPS 42) pipe
- a lateral consisting of approximately 58 km of 406 mm (NPS 16) pipe
- pipeline-related facilities, including:
  - 71 pump stations (70 mainline and one lateral)
  - tank terminals and related facilities at Hardisty, AB, Moosomin, SK, and Saint John, NB
  - marine terminal and loading facilities at Saint John, NB
  - custody transfer metering facilities at receipt and delivery locations
  - pressure control valve station near Burstall, SK
- pipeline appurtenances, including:
  - over 500 valves within the pipeline right-of-way (ROW) and at pump stations
  - launching and receiving facilities for cleaning and in-line inspection (ILI) of the new mainline, laterals and terminal connections
  - cathodic protection (CP) systems
  - communications and control systems

Temporary infrastructure will be required during construction. Construction-related infrastructure is typically developed on temporary workspace (TWS) and includes access, stockpile sites and laydown areas, borrow sites and dugouts, contractor yards, warehouses and construction camps.

Pump stations, delivery meter stations, tank terminals and the marine terminal will require new permanent access roads or approaches for operational purposes. This access will be developed and used temporarily for construction before being completed for permanent use prior to operations. Mainline valves (MLVs) may require permanent access, including helicopter landing areas for remote sites.

New electrical power lines will be required to operate most of the new pump stations, tank and marine terminal and valve sites. These lines are expected to be constructed, owned and operated by independent regulated power providers. The exception will be at eight pump stations in northern Ontario where electrical utility infrastructure is not available and on-site power generation is planned.

Figure 2-1 shows the pipeline route and main components. For applicable company and industry codes and standards, refer to Appendix 1-1 and Section 2.9.1 below.

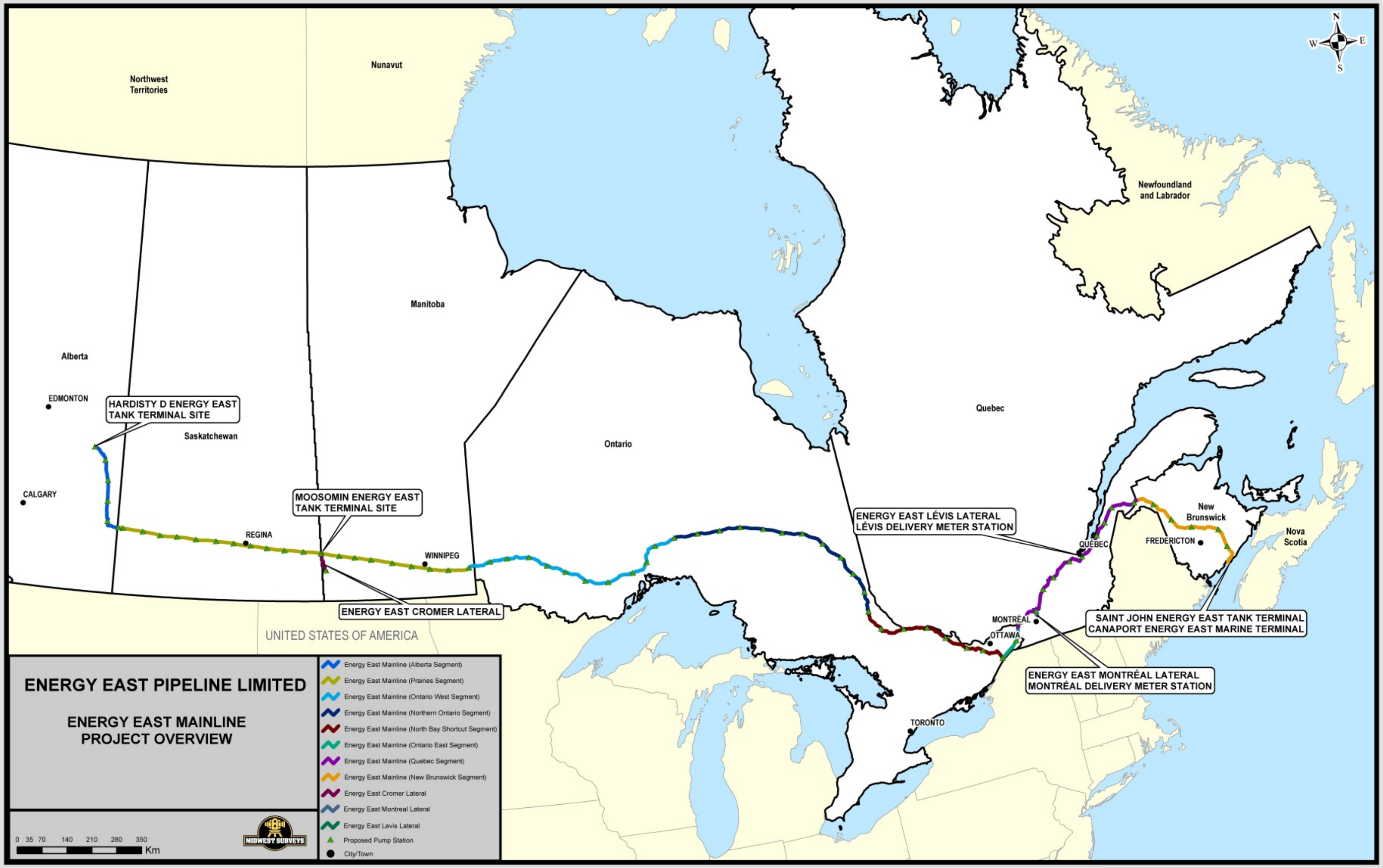


**Figure 2-1: Overview of Energy East Pipeline Route and Main Components (CA Rev. 0)**

For a breakdown of the main Project components by province, refer to Section 5.0, Provincial Profiles, of this Consolidated Application volume. See also Sections 2.5, 2.6, and 2.7 below for additional information on the respective new pipeline, conversion, and facility designs for the Project.

Volume 13 provides aerial overview and detailed route maps of the Energy East Pipeline.

### 2.2.3 Estimated Capital Cost

Table 2-1 provides a current estimate of the capital costs of the Project in 2013 dollars.

**Table 2-1: Capital Cost Estimate (CA Rev. 0)**

| Component | Capital Cost ($ million) |
|---|---|
| **Pipeline** | |
| New Pipelines | 6,439 |
| Conversion Pipelines | 1,950 |
| Pump Stations | 4,354 |
| Tank Terminals and Delivery Meter Stations | 1,880 |
| Marine Terminals | 1,025 |
| **Sub-total** | **15,648** |
| Transfer Price for Gas Assets | 1,478 |
| AFUDC | 2,220 |
| **Total** | **19,346** |

### 2.2.4 Project Justification

Energy East has commissioned independent expert reports on the economic, social and environmental effects of the Project and the overall public interest served by the Project, the Asset Transfer and the related but separate Eastern Mainline Project. The reports conclude that there will be positive benefits from the Project, the Asset Transfer and the EMP.

The reports are outlined in Volume 1, Section 3.3: Evidentiary Support for the Public Interest Determination, and are appended as follows:

- Conference Board of Canada (CBoC) – *Energy East Pipeline Project: Understanding the Economic Benefits for Canada and its Regions, October 2015* (Appendix 1-2)
- Concentric Energy Advisors, Inc. (Concentric) – *Direct Evidence of John J. Reed, ~~November 2015 Update~~June 2016* (Appendix 1-3)

- Roland Priddle – *The Energy East Project and the Canadian Public Interest: A Significant and Strategic Element of National Infrastructure, Updated November 2015* (see Appendix 1-4)

These reports reflect the current scope and cost of the Project, and augment third-party economic effects assessments of Energy East and the EMP that were prepared by Nichols Applied Management/Stantec Consulting Ltd. (Nichols) and Golder Associates Ltd. (Golder), respectively. The Nichols assessment is provided in Volume 16 of the consolidated ESA, while the Golder assessment is appended to the Concentric report in Appendix 1-3.[20]

### 2.2.5 Section 58 Exemption

To maintain the construction schedule and staged in-service dates for the Project, exemptions from the detailed route process are being sought under section 58 of the NEB Act as part of the Consolidated Application. The requested exemptions are for:

- temporary construction-related infrastructure
- activities and works in support of converting the required TransCanada gas assets to oil service
- pump stations along the Project's converted pipeline segments
- Hardisty D and Saint John tank terminals and related facilities

The activities and works proposed for relief under section 58 will only be undertaken on lands where the requisite land rights are in place and only then, after the Board has issued a CPCN for the entire Project and subject to any further regulatory direction, applicable pre-construction conditions have been satisfied.

## 2.3 CONSOLIDATED APPLICATION VOLUME 2 – SALE AND PURCHASE OF MAINLINE ASSETS

As described in Volume 2 of this Consolidated Application, TransCanada and Energy East, as general partner on behalf of Energy East Pipeline Limited Partnership, have entered into an agreement governing the transfer of the TransCanada gas assets, the Transfer Agreement. The assets proposed to be transferred include approximately 3,000 km of 1067 mm (NPS 42) pipeline.

[20] To reflect an increase in the estimated capital cost of the EMP, Golder refreshed the Statistics Canada Inter-Provincial Input-Output Model economic modelling in an additional report dated March ~~1~~ 2016. The March 2016 report is provided in Appendix 1-3 of this Consolidated Application (see Attachment~~s B to~~ D to the ~~Golder~~Concentric report).

### 2.3.1 LDC Energy East Agreement

In late August 2015, TransCanada and Energy East filed with the Board an agreement in principle reached with three local distribution companies in Eastern Canada, which addresses various matters relating to the Energy East and Eastern Mainline projects.[21]

In October 2015, the formalized LDC Energy East Agreement was filed.[22] The LDC Energy East Agreement addresses concerns raised in respect of the Project by the LDCs and defines the economic benefit and capacity available after the Asset Transfer to Energy East and construction of the EMP for TransCanada Mainline shippers in the Eastern Triangle. In particular, the LDC Energy East Agreement addresses:

- the design requirement in the Affected Area[23] of the Eastern Triangle to meet all firm service requirements plus 50 TJ/d of additional capacity (the Design Requirement)
- financial benefits of at least $100 million, on a net present value (NPV) basis in the total cost in the Eastern Triangle to the end of 2050. This benefit will be met by adjusting the "acquisition premium" portion of the Asset Transfer Price (Acquisition Premium) that will be paid by Energy East.
- the EMP capital costs added to the Eastern Triangle rate base will not exceed $2.1 billion. Any excess will be added to the Acquisition Premium, the effect of which is that Energy East will assume the capital cost overrun risk associated with the EMP.

### 2.3.2 Asset Transfer Agreement

Under the Transfer Agreement, the TransCanada gas assets will be transferred in stages based on the Energy East construction schedule, for a total transfer price of approximately $1.5 billion.

### 2.3.3 Acquisition Price

With respect to the acquisition cost of the gas pipeline facilities, Energy East will pay a purchase price estimated at $1.5 billion to TransCanada comprised of net book value (NBV), estimated at $744 million on the transfer dates in 2018 and 2019 and an Acquisition Premium estimated at $734 million. The calculation of the

[21] See NEB Exhibit No. A72297-1.

[22] See Appendix 2-2 of Volume 2 for the LDC Energy East Settlement Agreement, which is attached to the Transfer Agreement between TransCanada and Energy East – First Amending Agreement. Refer also to NEB Exhibit No. A73732-1.

[23] This term is defined as the domestic markets of the Enbridge EDA, Union EDA, GMIT EDA, KPUC EDA, and the export markets at Cornwall, East Hereford, Iroquois, Naperville, and Phillipsburg.

Acquisition Premium reflects the terms of the LDC Energy East Agreement, which is detailed in Volume 2, Section 4.3: Rate Base, Revenue Requirement and Tolls.

The acquisition cost will be included in the Energy East rate base; however, a portion of those costs will be excluded for the purposes of establishing the Energy East fixed tolls. The portion of the acquisition cost that will be included in the calculation of Energy East's fixed toll will be no more than $1 billion depending on the final acquisition cost.

### 2.3.4 Effects of the Transfer on the TransCanada Mainline Shippers

The transfer of the TransCanada gas assets, in combination with the EMP facilities, is expected to reduce costs that gas shippers would have otherwise incurred. On a net present value basis, these cost savings have been calculated to reflect the LDC Energy East Agreement and are estimated at over $500 million for Mainline shippers as a whole to 2050. Of this amount, the savings are approximately $400 million for Western Mainline shippers and $100 million for shippers in the Eastern Triangle, estimated over the same period.

### 2.3.5 Impact on Rate Base, Revenue Requirement and Tolls

The evidence in Volume 2, Section 4.4: Rate Base, Revenue Requirement and Tolls, provides support and justification for the Asset Transfer and the EMP. It demonstrates the benefits that are provided to Mainline shippers and the public interest justification for both Energy East and the EMP in conjunction with the LDC Energy East Agreement. The evidence explaining the impact on the Mainline rate base, revenue requirement and tolls can be found in Volume 2, Section 4.4.[24] The public interest discussion can be found in Volume 2, Section 8.0: Public Interest of Asset Transfer.

### 2.3.6 Consultation with Commercial Third Parties

In Volume 2, Section 7.4, Energy East describes the consultation with Mainline shippers and their expressed concerns up until the filing of the Application in October 2014. Since that time, TransCanada has continued to pursue opportunities to resolve the expressed concerns. The August 2015 LDC Energy East Agreement and Settlement Term Sheet led to the 30 October 2015 Definitive Agreement which addresses the issues and concerns raised by Ontario and Québec natural gas customers.

The August Term Sheet was provided to Mainline shippers and the Board on 24 August 2015.[25] It was presented to the Mainline Tolls Task Force (TTF) on

[24] Refer to Section 4.4.3.1: Pipeline Abandonment Cost Implications for a discussion of the effects of the Asset Transfer and the EMP on the Mainline abandonment cost estimate.
[25] See NEB Exhibit No. A72297-1.

9 September 2015 and the Definitive Agreement was presented to the Mainline TTF on 12 November 2015.[26] Individual customer meetings have taken place since November 2015 to further discuss the details and benefits of this agreement.

For additional information on consultation with Mainline shippers, refer to Section 7.4: Commercial Third-Party Notification in Volume 2.

#### 2.3.7 Transportation Capacity and Eastern Mainline Project

The EMP, in addition to existing facilities in the Eastern Triangle, will be designed to meet the Design Requirement of 2,714 TJ/d. Firm service requests from customers arising from the 2016 and 2017 new capacity open seasons (NCOS), and implementation of the Term-Up Provision and turnback commercial processes have resulted in Mainline firm service requirements of 2,644 TJ/d. Additionally, the LDC Energy East Agreement requires an additional 50 TJ/d of capacity for a total Design Requirement for the EMP of 2,714 TJ/d at an estimated cost of $2.1 billion.

#### 2.3.8 Eastern Mainline Project Application

In a related but separate application on 30 October 2014, TransCanada applied for approval under Part III of the NEB Act of the EMP, consisting of new natural gas facilities along its existing Montréal Line in southeastern Ontario.[27] These facilities, which are centrally located where regional gas demand is greatest, will enable TransCanada to continue meeting its existing firm service obligations, as well as providing a direct path to Marcellus and Utica supply options.

An amendment to the EMP application was filed in December 2015[28] to include additional gas facilities to accommodate the Design Requirement arising from:

- an increase in firm service requirements from the 2017 NCOS
- the results of the turnback process and Term-Up Provision being applied to existing contracts in the Affected Area
- the LDC Energy East Agreement

Energy East's Consolidated Application Volume 2 contains information on commercial matters underpinning the EMP and supporting the asset transfer portion of this Consolidated Application. This commercial information includes:

- impact of the EMP project cost of $2.1 billion on TransCanada Mainline rate base, revenue requirement and tolls
- gas supply and markets in Eastern Canada and the Northeast US

[26] See NEB Exhibit No. A73732-1.
[27] See NEB Exhibit Nos. A63940 and A63951,
[28] See NEB Exhibit Nos. A74778, A74787, and A74788.

- transportation contracts and system design alternatives
- commercial third-party notification

### 2.3.9 Gas Supply and Market Outlook

In Volume 2, Section 4.3, Energy East includes a TransCanada gas supply and demand outlook for the Eastern Triangle. This evidence is augmented in Volume 2, Section 5.0: Natural Gas Supply, Markets, and Throughput Forecast, with an overview of the gas supply available to the Eastern Triangle, an outlook for the gas markets served by the EMP a throughput forecast for the Mainline, and a flow balance for the Affected Area. The supply and market evidence provides justification for both the EMP and Mainline Asset Transfer.

## 2.4 CONSOLIDATED APPLICATION VOLUME 3 – COMMERICAL

### 2.4.1 Transportation Service Agreements

As described in Volume 3 of this Consolidated Application, Energy East received long-term shipping commitments by way of executed transportation service agreements (TSAs) through the initial open season in 2013 of 144,000 $m^3$/d (905,000 bbl/d). In July 2014, Energy East held a second open season. This subsequent open season was fully subscribed and in November 2014, binding TSAs were executed for an additional 14,000 $m^3$/d (90,000 bbl/d) of firm shipping commitments. In the result, a total of 158,000 $m^3$/d (995,000 bbl/d) of volume is now committed under executed TSAs for an average term of 19 years.

As discussed in Sections 2.1 and 2.2 of Volume 3, Energy East has been working with its shippers on amendments to the TSAs, as necessary. Shippers with a contract delivery point of Montréal and Québec City (i.e., the Base TSAs) were asked to remove reference to a Québec marine terminal from their TSAs, whether by maintaining a Québec City (refinery) contract delivery point or by changing the contract delivery point under their TSA to Saint John, NB.

As at the date of this Consolidated Application filing, 134,300 $m^3$/d (845,000 bbl/d) of volumes are underpinned by TSAs reflecting either:

- a contract delivery point of Québec City (i.e., a refinery without the marine and tank terminal in Québec), or
- a contract delivery point of Saint John, New Brunswick

Volumes in the amount of 23,900 $m^3$/d (150,000 bbl/d) remain under contract pursuant to the unamended Base TSAs. Commercial discussions with affected shippers are ongoing in relation to delivery to Saint John or continued evaluation of other delivery options.

### 2.4.2 Transportation Terms and Tolls

The tolling methodology that is reflected in the TSAs is negotiated and provides committed shippers with long-term price certainty to ship on the Energy East Pipeline. Of the capacity, 14,000 $m^3$/d (90,000 bbl/d) will be reserved for uncommitted service in order to satisfy common carrier regulatory requirements.

For additional information including a description of the negotiated toll design and illustrative tolls, see Volume 3, Section 2.4: Negotiated Tolls.

### 2.4.3 Crude Oil Supply and Markets

Energy East has provided a crude oil supply and market analysis which is included in Consolidated Application Volume 3, Section 3.0: Supply and Markets.

The supply and market analysis shows that Canadian crude oil production will continue to grow to meet demand, but at a slower rate than previously anticipated. This confirms that additional oil transportation capacity from Western Canada continues to be required to provide secure and diverse market access for both producers and consumers.

As part of the supply and market analysis, Energy East engaged an independent third-party consultant, IHS Inc. (IHS), to develop a report on the crude oil supply and market outlook and related issues relevant to the Project. The IHS report reflects the current outlook including the impact of the decline in crude oil price and the corresponding producer netbacks.

The IHS report estimates that western Canadian supply will increase from 588,000 $m^3$/d (3.7 million bbl/d) in 2014 to 938,000 $m^3$/d (5.9 million bbl/d) by the year 2030. In addition to its own forecast, the IHS report references the Canadian Association of Petroleum Producers (CAPP) 2015 crude oil production forecast, which is slightly higher, by 32,000 $m^3$/d (200,000 bbl/d) than that of IHS.

The CAPP and IHS forecasts both indicate that supply growth in Western Canada will require access to new and diverse markets, including:

- the refining market in Québec, which has a capacity of 64,000 $m^3$/d (402,000 bbl/d) and is currently importing 81% of its requirements
- the refining market in Atlantic Canada, which has a capacity of 66,000 $m^3$/d (415,000 bbl/d) and is currently importing 83% of its requirements
- the refining market in the US East Coast Petroleum Administration for Defence District (PADD) I region, which has capacity of 211,000 $m^3$/d (1.33 million bbl/d) and is currently importing 60% of its requirements, of which, 45% is from Canada
- the refining market in the USGC PADD III region, which is accessible by tanker

- international refining markets, including Europe and India

The analyses of supply and demand for oil show that additional oil transportation capacity from Western Canada is required. This conclusion is supported by long-term binding commitments for shipments on the Energy East Pipeline.

For the supply and market analysis and IHS report, see Consolidated Application Volume 3, Appendix 3-6: Supply and Market Study for the Energy East Project.

### 2.4.4 Financing

Financing for the Project will be provided primarily by TransCanada. TransCanada and its parent company, TransCanada Corporation, are well-positioned to finance TransCanada's current capital program, including the Project.

For additional information, see Volume 3, Section 4.2: Financing Capacity.

## 2.5 CONSOLIDATED APPLICATION VOLUME 4 – PIPELINE DESIGN

In designing, building and operating the Energy East Pipeline, Energy East will focus on managing, mitigating and reducing hazards and potential risks to safety and the environment. The Energy East Pipeline includes:

- the Energy East Mainline
- three pipeline laterals (Cromer, Montréal and Lévis)
- the terminal connection laterals at the Energy East complex near Saint John, NB (Energy East Complex), together known as the Saint John Connection
- ancillary pipeline facilities (e.g., valves, CP and ILI facilities, and communications and control systems)

Safety and environmental protection measures will be incorporated into the design of the pipeline and facilities to prevent and reduce the potential for accidents and malfunctions. These measures will help ensure that the Project meets or exceeds industry standards, specifications and best practices.

Once design and construction of the Energy East Pipeline is complete, Energy East will follow TransCanada's integrated health, safety and environmental management system.

### 2.5.1 Mainline Segments

The Energy East Mainline is comprised of eight mainline segments that will together create a direct connection or 'bullet line' for crude oil shipments from Hardisty, Alberta to Saint John, New Brunswick.

The Energy East Mainline is further sub-divided into 73 pipeline sections. Pipeline sections extend between pump stations and are named for the upstream station, except at the Québec borders, where sections start or end, and at the Burstall pressure control valve station, where the Alberta and Prairies segments connect.

Four of the Energy East Mainline segments will be newly built pipelines – Alberta, Ontario East, Québec and New Brunswick. Four will be converted portions of three existing TransCanada Mainline gas lines – the Prairies Line, Northern Ontario Line, and North Bay Shortcut.[29] These lines were selected for conversion because they had the requisite pipe diameter (1067 mm/NPS 42) and were best situated to facilitate construction. The total length of the gas lines proposed for conversion is approximately 3,000 km.

The segments comprising the Energy East Mainline are summarized in more detail from west to east in Section 4.0: Provincial Profiles of this volume. The profiles in Section 4.0 also provide the names and lengths of the pipeline sections.

For additional information, refer to Sections 3.1 to 3.4 of Volume 4 for details on the new mainline segments and to Sections 1.1 and 4.0 of Volume 5 for the conversion segments.

### 2.5.2 Laterals and Terminal Connection Pipelines

The laterals and connection pipelines required for the Energy East Pipeline are, from west to east:

- Cromer Lateral, comprised of approximately 58 km of 406 mm (NPS 16) pipe from the Cromer pump station to the Prairie receipt point at a new tank terminal near Moosomin, SK (Moosomin tank terminal)
- Montréal Lateral, anticipated to be comprised of 16 to 17 km of 1067 mm (NPS 42) pipe from the Québec Segment to a stand-alone delivery meter station at an existing refinery on the Island of Montréal, QC (Montréal delivery meter station)
- Lévis Lateral, comprised of approximately 8 km of 1067 mm (NPS 42) pipe from the Québec Segment to a stand-alone delivery meter station at an existing refinery approximately 10 km west of Lévis, QC (Lévis delivery meter station)
- Saint John Connection, comprised of:
    - two 1067-mm aboveground oil pipelines spanning approximately 1,500 m that are required to connect the Saint John tank terminal to the Canaport Energy East marine terminal

[29] Once converted, the four segments are the Prairies Segment, the Ontario West Segment, the Northern Ontario Segment and the North Bay Shortcut Segment.

- two 610-mm aboveground vapor pipelines spanning approximately 900 m to connect the Canaport Energy East marine terminal and an auxiliary equipment area
- a 914-mm pipeline spanning 500 m to connect the Saint John tank terminal to the Irving Oil Canaport tank terminal

For additional site-specific information on the Cromer, Montréal and Lévis laterals, see Volume 4, Sections 3.5 to 3.7, respectively. Refer to Volume 4, Section 3.8 for details on the Saint John Connection.

### 2.5.3 Pipeline Routing

Energy East applied TransCanada's criteria in selecting the route for the new mainline, laterals and connection pipelines. These criteria reflect industry best practices in pipeline routing by:

- paralleling existing linear disturbances where practical
- reducing the number and complexity of watercourse crossings
- where feasible, avoiding areas with:
  - unstable terrain or problem soils
  - known occurrences of provincially or federally listed species
  - specific status such as parks, protected areas, cemeteries and historic sites
  - concentrations of rural residences and urban developments
  - cultural importance to First Nations and Métis
- considering input from First Nations and Métis communities and organizations, landowners and other stakeholders
- consulting with regulatory agencies to understand issues that may need to be addressed in the routing process

By applying these routing criteria, Energy East has routed the new pipelines such that approximately 52% of the total new mainline ROW required for the Project follows existing linear developments and disturbances, including their easements.

Parallel versus non-parallel ROW along the Energy East Mainline is summarized below on Table 2-2 and depicted on Figure 2-2.

The route selected for each new mainline segment, lateral, and connection pipeline is described in Volume 4, Section 3: Pipeline-Specific Information. The descriptions include details on parallel routing for all but the Saint John Connection, which will be located at the Energy East Complex.[30]

[30] For a map of the Energy East Complex, see Figure 5-5 of Volume 6, Section 5.5: Saint John Tank Terminal.

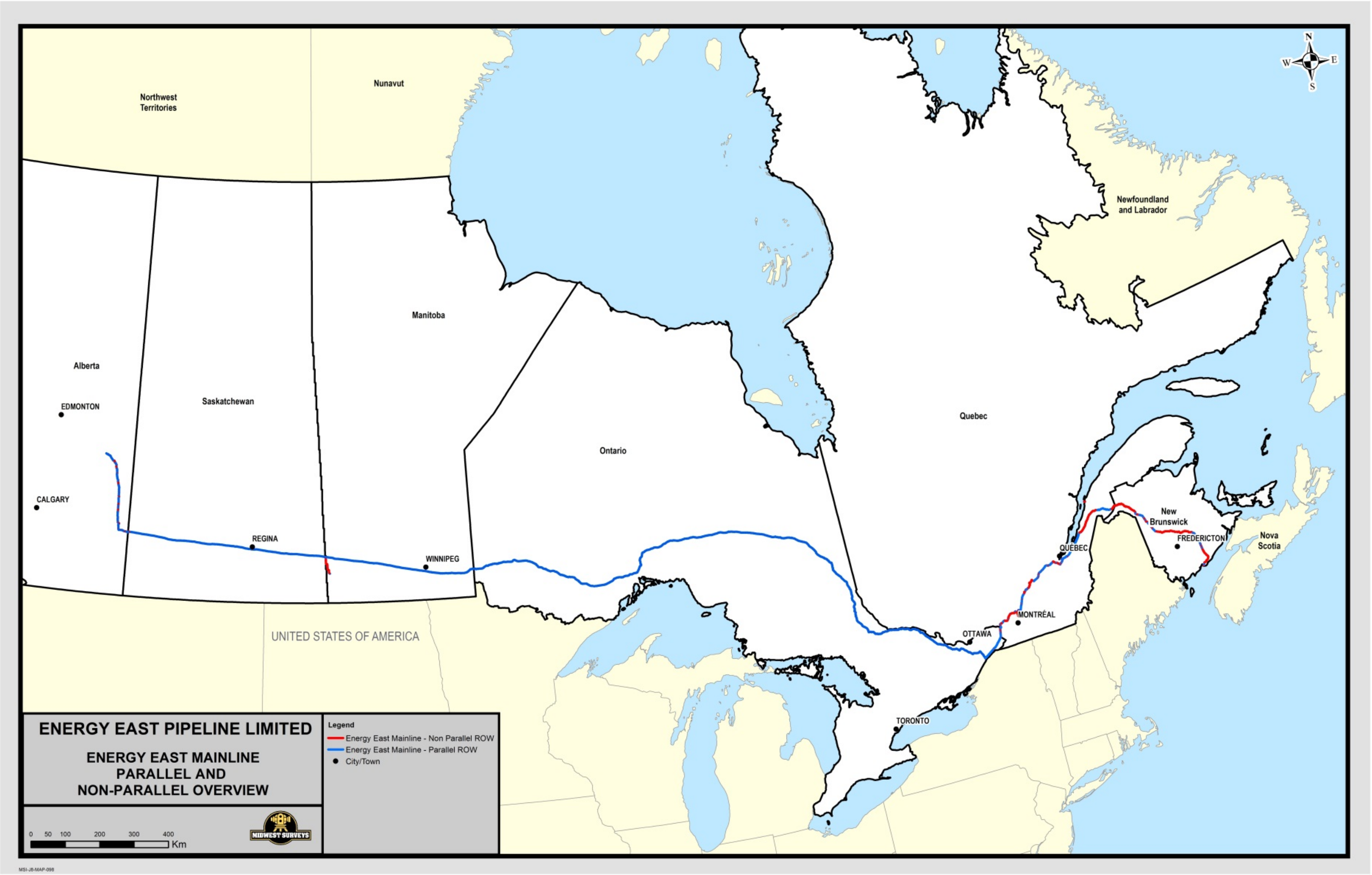


**Figure 2-2: Locations of Parallel and Non-Parallel Right-of-Way along the Energy East Mainline (CA Rev. 0)**

For additional information, see Volume 4, Section 2.2: Route Selection Criteria and Volume 11, Section 2.1: Pipeline Routing. See also ESA Volume 14, Section 4: Routing and Site Selection.

**Table 2-2: Parallel and Non-Parallel ROW on the Energy East Mainline (CA Rev. 0)**

| Name | Original Parallel ROW (km)[1] | Current Parallel ROW (km)[1] | Original Total ROW (km)[1] | Current Total ROW (km)[1] | Original Parallel ROW (%)[2,3] | Current Parallel ROW (%)[2,3] |
|---|---|---|---|---|---|---|
| Alberta Segment | 234 | 233 | 284 | 284 | 82 | 82 |
| Ontario East Segment | 81 | 94 | 104 | 106 | 78 | 89 |
| Québec Segment | 386 | 329 | 693 | 625 | 56 | 53 |
| New Brunswick Segment | 110 | 92 | 407 | 412 | 27 | 22 |
| **Total** | 811 | 748 | 1,488 | 1,427 | 85 | 52 |

Note:
1. This table is based on preliminary design. Final locations will be subject to further engineering and environmental site evaluations, geotechnical assessments, Aboriginal, landowner and stakeholder engagement, land acquisition and consultation with regulatory authorities.
2. The numbers in this column are rounded and based on horizontal grid measurements.
3. The percentages in this column are rounded.

### 2.5.4 Pipeline Valves

Pipeline valves will be installed at pump stations and within the pipeline ROW at select watercourse crossings, environmentally sensitive areas, and other locations as needed to facilitate operations. Valve sites are named for the pipeline section, lateral or connection on which they are located.

An engineering assessment (EA) was undertaken in accordance with CSA Z662-15, which describes the iterative process for valve siting developed by Energy East to determine the number and spacing of “shutoff” valves on the Project’s pipelines. The process involves numerous steps and a multi-disciplinary team of engineering, environmental and emergency response specialists. It is intended to reduce potential risks to the public and the environment. For additional information on the valve placement process and the EA, see Volume 4, Section 2.11 and Appendix 4-13.

## 2.6 CONSOLIDATED APPLICATION VOLUME 5 – CONVERSION DESIGN

The TransCanada Mainline natural gas pipelines to be transferred to Energy East and converted to oil service include approximately:

- 940 km of Line 100-3 on Northern Ontario Line
- 1,640 km of Line 100-4 on the Prairies Line and Northern Ontario Line
- 420 km of Line 1200-2 on the North Bay Shortcut

Figure 2-3 provides a schematic of the gas pipelines to be converted to oil service.

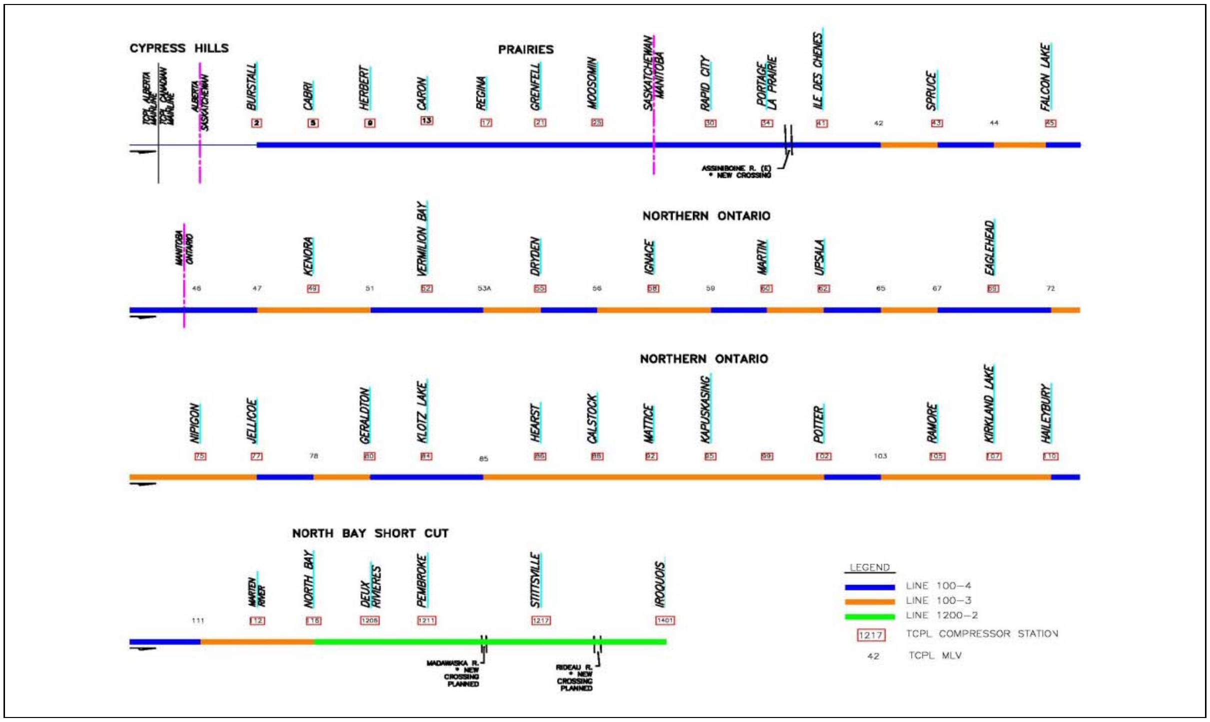


**Figure 2-3: Schematic of Conversion Segments (CA Rev. 0)**

Conversion activities will be scheduled to avoid interrupting TransCanada's gas service obligations on the TransCanada Mainline. These activities will involve:

- assessing the condition of the pipe to be converted, including ILI inspections and where required, pipe repairs and replacements
- isolating the pipelines to be converted from the existing TransCanada gas facilities
- constructing the new facilities needed to put the pipelines to be converted into oil service

The conversion activities and works anticipated are generally routine in nature and will take place primarily on TransCanada-owned, leased or licensed property or on existing pipeline ROW for which an approved and certified plan, profile and book of reference is in place. Most are of a type that would otherwise satisfy the criteria established in the Board's Section 58 streamlining order (XG/XO-100-2012), decommissioning exemption order (XG/XO-100-2008), or its Operations and Maintenance Requirements and Guidance Notes.[31]

For details on the nature of the proposed conversion activities, see Volume 5, Sections 3 and 4, and Appendix 5-4, Scope of Work.

[31] Operations and Maintenance Activities on Pipelines Regulated Under the *National Energy Board Act*: Requirements and Guidance Notes – January 2013, as amended.

### 2.6.1 Pipe Condition Assessment – Conversion Segments

To demonstrate that the pipe proposed for conversion from natural gas to oil service will be suitable for the intended service, an engineering assessment of the pipe condition has been completed and is provided with this Consolidated Application. Refer to Volume 5, Section 2.0: Pipeline Condition, for a summary of the EA and to Appendix 5-1 for the EA.

The EA confirms that the pipelines to be converted have or will be inspected using ILI technology before the conversion segments are removed from gas service. Once the ILI assessments are completed, and before the pipelines are removed from gas service, Energy East will develop a remediation plan to address issues that may be identified through the ILI assessments. This remediation plan will be submitted to the Board, as described in Volume 5, Section .3: Conversion Integrity Program.[32]

### 2.6.2 Pipe Condition Assessment – TransCanada Lines Remaining in Gas Service

TransCanada has assessed the potential effects of conversion on the TransCanada Mainline pipelines that will remain in gas service after conversion and has developed a short and longer term maintenance plan.

This plan is designed to ensure that the remaining gas assets continue to meet commercial requirements and will be operated in a safe and reliable manner after conversion. It will be implemented within the framework of TransCanada's gas integrity management plan (IMP), its associated processes and procedures, and the annual pipeline maintenance plan (PMP). See Figure 2-4 for a schematic of the gas and liquid IMP.

For the Prairies Line and North Bay Shortcut, no changes to the ongoing PMP will be required as part of the plan. Changes will be required to the PMP for the NOL, where integrity assessments will be accelerated for Line 100-1 and Line 100-2.

For additional information on the integrity plan for the TransCanada Mainline pipelines remaining in service after conversion, see Volume 5, Section 5.0: Gas Pipeline Integrity Plan.

[32] As indicated in Section 2.3 of Volume 5, the Project's schedule has been refreshed such that an updated estimate of investigative digs will be developed (see Section 2.8.4 below). Energy East will advise the Board once the program schedule update is completed and at that time, will further advise the Board of a revised target filing date for the remediation plan (previously known as Supplemental Report Item SR 7-2). As directed by the Board in its 21 March 2016 letter (NEB Exhibit No. A76011-1) the plan will also be assigned an appendix placeholder number (see appendices 5-36 to 5-40 on Table 1-5, Section 1.2.4: Supporting Documents, Volume 5).

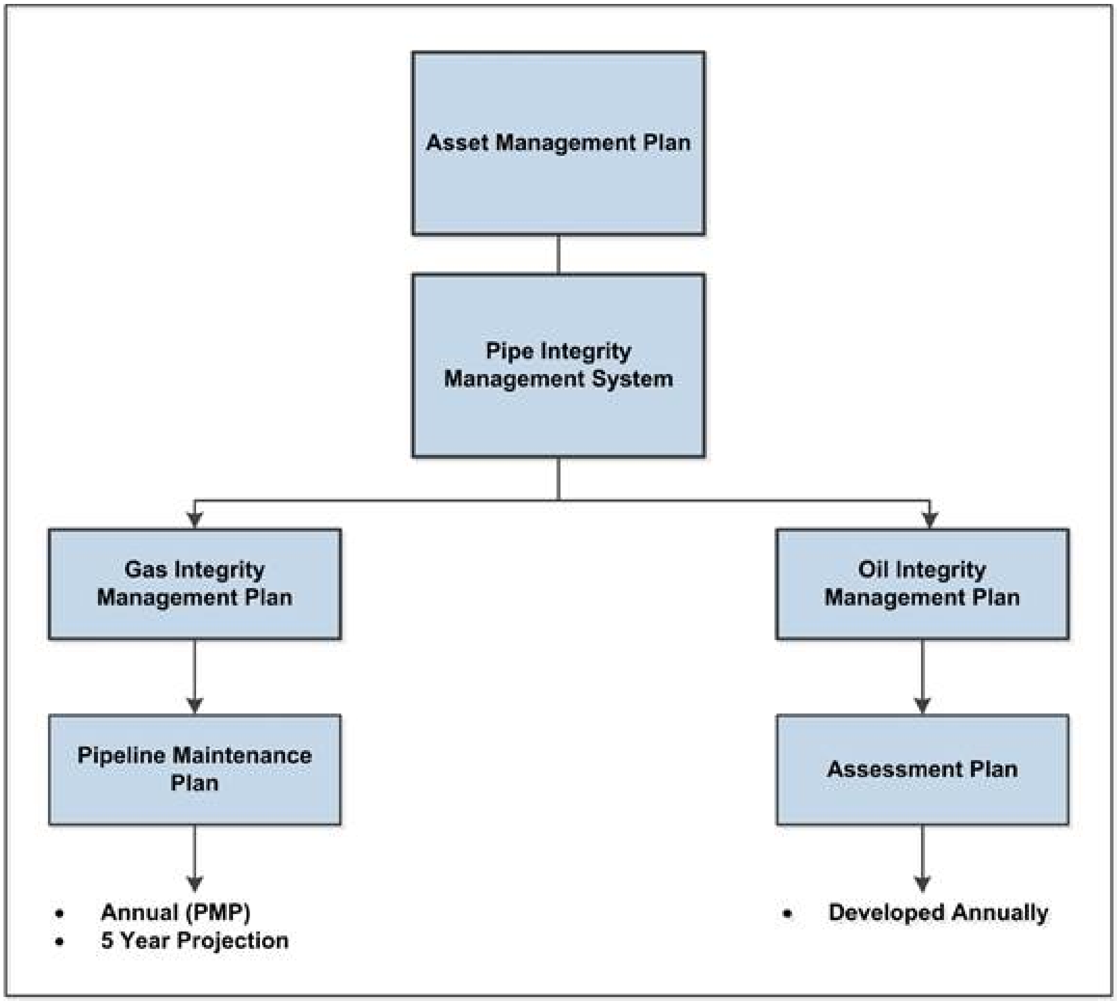


**Figure 2-4: Schematic of Integrity Management Process (CA Rev. 0)**

## 2.7 CONSOLIDATED APPLICATION VOLUME 6 – FACILITY DESIGN

### 2.7.1 Pump Stations

Seventy-one pump stations will be required for the Project, including 70 mainline stations at intervals of approximately 65 km along the pipeline, and one on the Cromer Lateral. These stations provide pressure to the oil to compensate for pressure losses along the pipeline due to friction. Stand-alone station sites will typically have a footprint of 8 ha to 10 ha. Additional area will be required for permanent site access.

Of the 71 total pump stations, up to 62 will be supplied with power sourced from utility companies. The remaining eight stations, located in northern Ontario, will be supplied with power produced by on-site gas turbine-driven generators. The standard pump station layouts for the Project have been designed to facilitate safe construction and station accessibility for future operations and maintenance activities.

For additional information, see Volume 6, Sections 2.0 and 3.0 and Volume 7, Section 3.3: Pump Station Construction.

### 2.7.2 Oil Storage Tank Terminals

The Project requires three new tank terminals with storage tanks of various sizes to meet its commercial and operational needs. These terminals include the following:

- Hardisty D tank terminal near Hardisty, Alberta
- Moosomin tank terminal near Moosomin, Saskatchewan
- Saint John tank terminal near Saint John, New Brunswick

The terminals at Hardisty and Moosomin will be receipt locations where oil is accumulated in batches for delivery to the Energy East Pipeline. The terminal at Saint John will be the delivery location for oil batches from the Energy East Pipeline.

Safety and environmental protection measures will be built into the design of the tank terminals (see Volume 6, Section 4.1: Safety and Environmental Protection).

The Hardisty D tank terminal and related facilities will be installed on an existing industrial complex on TransCanada-owned property immediately north of the Hardisty A, B and C tank terminals. This location reduces environmental footprint by allowing for shorter interconnecting pipelines, power lines, and access roads. It also allows the shared use of infrastructure. The terminal will take up to three years to construct and will be used as the primary source of oil for line fill and commissioning of the entire Project.

The Saint John tank terminal and related facilities will be located on lands leased from a subsidiary of Irving Oil. These lands are located within an existing industrial area that includes the Canaport LNG (liquefied natural gas) terminal and Irving Canaport, a marine deepwater crude receiving terminal. Tank lots will be tiered into groups in accord with natural site topography, which reduces the developmental footprint and decreases blasting and civil development requirements

For additional information on the tank terminals, see Volume 6, Sections 4 and 5, and Volume 7, Section 3.5: Tank Terminal Construction.

### 2.7.3 Canaport Energy East Marine Terminal

The Canaport Energy East marine terminal will be located in an existing industrial area on the western shore of the Bay of Fundy, southeast of the city of Saint John. The siting of this facility was subject to a selection process that evaluated differing sites along the Bay of Fundy near Saint John, NB. Various criteria were applied in evaluating alternatives, including navigational requirements, environmental features, proximity to the Project’s pipeline facilities, and socio-economic considerations.

The marine terminal will be constructed for the Project to load crude oil onto oil tankers from the Saint John tank terminal, and will be able to accommodate the berthing and loading of Aframax, Suezmax, and very large crude carrier (VLCC) oil tankers. It has been designed to safely operate within the prevailing climatic and marine conditions experienced within the Bay of Fundy, including the use of oil loading arms that can operate over the wide variance of tidal fluctuations that exist at the marine terminal.

The marine terminal will be able to concurrently load two vessels through two marine loading systems, including two 1067 mm (NPS 42) pipelines from the Saint John tank terminal to the marine terminal and a manifold above both berths.

Energy East anticipates that approximately 281 tankers will call on the Canaport Energy East marine terminal per year.

For additional site-specific information, see Volume 6, Sections 7 and Volume 7, Section 3.6: Marine Terminal Construction.

For a more detailed discussion of the site selection process, see Volume 11, Section 2.1.3: Alternative Means of Carrying Out the Project – Marine Terminal Siting.

### 2.7.4 Custody Transfer Metering Facilities

Energy East requires custody transfer metering facilities at the following locations:

- Hardisty D tank terminal within the existing industrial complex
- Cromer pump station at the start of the Cromer Lateral
- Montréal delivery meter station at the terminus of the Montréal Lateral
- Lévis delivery meter station at the terminus of the Lévis Lateral
- Saint John tank terminal

Oil flowing into the Energy East system will be metered at the Hardisty D tank terminal and at the Cromer pump station. Oil flowing out of the system will be metered at the Montréal and Lévis delivery meter stations, and at the Saint John tank terminal.

The Saint John tank terminal will have three meter banks in total with two be used to accommodate concurrent loading at both Canaport Energy East marine terminal berths and the other is needed to measure deliveries to the existing Irving Canaport tank terminal. Each meter bank consists of several meter runs and headers.

For a general and site-specific description of the custody transfer metering facilities, see Volume 6, Sections 7 and 8 and Volume 7, Section 3.4: Meter Station Construction.

## 2.8 CONSOLIDATED APPLICATION VOLUME 7 – CONSTRUCTION AND OPERATIONS

### 2.8.1 Temporary Infrastructure

In Volume 7 of this Consolidated Application, Energy East describes the temporary infrastructure and activities that will be required for construction of the Project, including for:

- construction camps
- pipe stockpiles and laydown areas
- temporary access such as:
    - approaches to gain access to pipeline ROW and facilities
    - roads to gain access to pipeline ROW and facilities
    - bridges over watercourse crossings, ravines, and wet areas
    - travel lanes on the pipeline ROW
- equipment storage and office areas
- borrow sites and dugouts
- beaver dam removals

Previously disturbed areas will be used for temporary infrastructure sites, where available and practical. New or expanded sites for stockpiles and laydown areas will be developed near the pipeline ROW and facility sites, or along existing roads and railway sidings. Camps will be developed in areas where the anticipated workforce exceeds available space in existing accommodation. Consultation with local authorities on accommodation options is ongoing. Approximately 17 self-contained construction camps were and continue to be anticipated for the entire Project, including large camps and smaller more mobile camps or lodges.

For additional information on the temporary infrastructure required for construction of the Project, see Volume 7, Section 2.9.

### 2.8.2 Blasting Management

Energy East anticipates that portions of the pipeline corridor in Ontario, Québec and New Brunswick will require blasting to excavate the pipeline trench or to grade the ROW during construction. Blasting may also be required at tank terminals, pump stations, and will be required at the marine terminal to facilitate grading of the sites.

Accordingly, a blasting management program is being developed. As part of this program, a preliminary blasting management plan has been completed and is provided in Appendix 7-3 of Volume 7. This preliminary plan details, among other things, a phased approach that includes:

- desktop studies
- terrain assessments
- field assessments

- area-based plan development
- stakeholder notification
- safety
- environmental protection

The preliminary plan incorporates learnings from the desktop reviews and field programs that also support the acid rock drainage mitigation plan described in Section 2.9.3 below. Refer also to Volume 4, Section 2.9 and Appendix 4-9.

### 2.8.3 Preliminary Construction Schedule

Volume 7 includes a preliminary multi-year construction plan for the Project that accounts for the anticipated interim regulatory measures and timelines that were announced by the Government of Canada on 27 January 2016. [33]

The preliminary plan is contingent on anticipated regulatory approvals, permits and authorizations being obtained in time for construction activity to begin in the third quarter of 2018 leading to an earliest in-service date of fourth quarter 2021 (see Figure 2-5).

Opportunities to optimize the construction schedule have and will be pursued throughout the Project development and regulatory review process. For more detailed information on the preliminary construction plan see Volume 7: Section 2.5: Construction Schedule.

### 2.8.4 Management Systems

Energy East will employ TransCanada's existing and evolving management systems to effectively manage and reduce risk over the life-cycle of the entire Project. These systems include:

- asset and capital planning management, including the integrity management
- integrated health, safety and environmental (HS&E) management
- emergency preparedness and response
- quality management
- security management

For more details on these management systems, see below and also Volume 7: Construction and Operations, Section 4: Operations.

[33] The NEB has since confirmed extended time limits for the Energy East and Eastern Mainline applications (see NEB Exhibit No. A76589). The confirmation, dated 22 April 2016, extends the time limits for each application to 21 months from the date of the NEB's completeness determination.

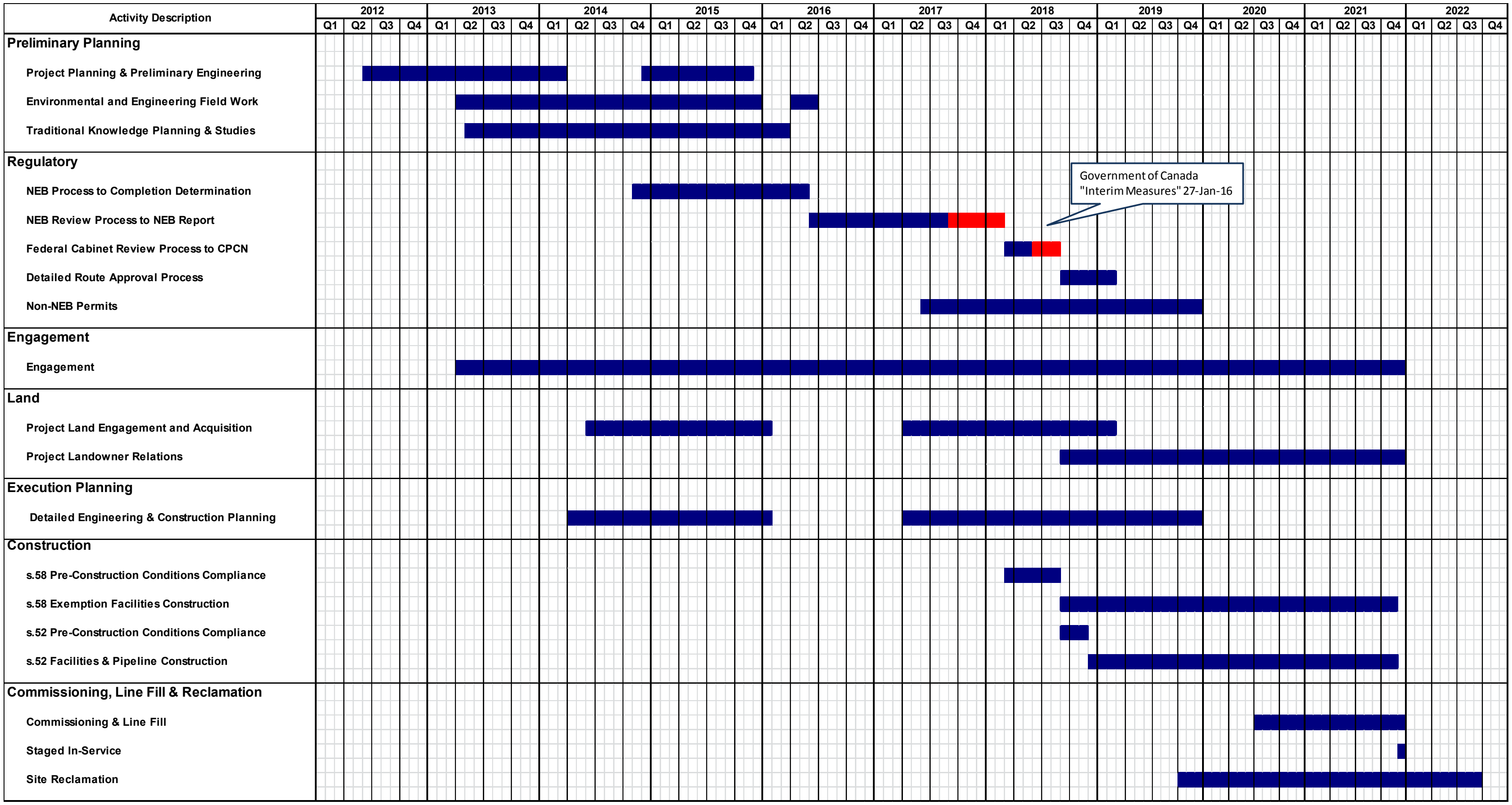


**Figure 2-5: Preliminary Schedule for the Energy East Project (CA Rev.0)**

### 2.8.5 Asset Management System

The TransCanada asset management system includes TransCanada's IMP for managing pipelines and the facility integrity and reliability management program for managing facilities.

During design and through construction of the Project, Energy East, as part of IMP, will identify potential threats to pipe integrity and develop recommendations for mitigation, including corrosion prevention, inspections and pipeline routing.

Between construction and operations, Energy East will perform inspections for construction-related damage to the pipe. Inspections will include the use of ILI tools, as the pipeline will be designed to facilitate their use along its entire length. Any construction damage will be assessed and repaired where necessary.

In the first year of operations, Energy East will again inspect the pipeline through the use of ILI tools to establish baseline integrity data. Based on the results of this inspection, and drawing on available construction and environmental information, a pipeline maintenance plan will be developed for future integrity assessments, either by ILI or other means. This plan will be implemented, and reviewed on an annual basis, throughout the operations phase of the Project.

Activities for managing threats identified by the facility integrity and reliability management process for facility equipment will be captured in annual maintenance plans or general plant maintenance capital projects.

### 2.8.6 Integrated Health, Safety and Environmental Management System

Energy East will adopt TransCanada's occupational health, safety, and environment management system and the supporting safety and environmental protection programs for the Project (HS&E framework). The HS&E management system conforms to industry standards and is aligned with the management system requirements outlined in the *National Energy Board Onshore Pipeline Regulations* (OPR).

During construction, Energy East will follow TransCanada's contractor safety management program, which provides guidance on audit and safety inspection requirements in accordance with HS&E framework. Energy East will require its prime contractors to develop safety management plans for their respective portions of the Project. These plans must incorporate the regulations, policies, and safety targets that are outlined in the contract tender documents and represent Energy East's expectations for safety through construction of the Project.

Environmental mitigation measures and commitments will be implemented during construction in accordance with the EPPs for the Project. The EPPs will include general and site-specific environmental protection measures that have been developed based on TransCanada's past project experience, feedback obtained during engagement activities and current industry best management practices. Environmental compliance will be facilitated through the sharing of information, orientations and training, the hiring of qualified staff, onsite inspection of activities, and the ongoing use of environmental commitment tracking lists.

#### 2.8.7 Emergency Management

Energy East will use TransCanada's emergency management program to oversee the emergency preparedness and response plans and programs for the Project. Project-specific emergency response plans (ERPs) will be developed for the Energy East Pipeline, pump stations, tank terminals, and marine terminal.

The Project ERPs will be developed in consultation with emergency service agencies, including local, provincial and federal agencies, and Aboriginal groups. Energy East will distribute the ERPs to applicable emergency service agencies, as necessary, before Project commissioning.

In addition, the Canaport Energy East marine terminal will have a dedicated emergency response capacity due to its designation as an oil handling facility under the *Canada Shipping Act*. The marine terminal will have a contract in place with Atlantic Environmental Response Team Inc. (ALERT) to provide additional equipment and personnel if a response situation requires such assistance.

For additional information see Volume 7, Section 6.0: Emergency Preparedness and Response.

#### 2.8.8 Quality Management

The quality management team for Energy East will develop an overarching construction quality management plan for the Project. This plan will be used to ensure that the goods and services acquired for and used by the Project, including construction, meet or exceed TransCanada quality requirements. The plan will also specify audit and inspection plans for construction.

The quality objectives that have been established for this Project are as follows:

- engineering designs are clearly documented, consistent with acceptable design standards and in accordance with operating performance requirements
- all work complies with applicable acts, regulations, statutes, permitting requirements and generally accepted engineering practices
- equipment and materials are procured and installed in a manner consistent with the engineering design
- documentation providing objective evidence of conformance to the requirements is maintained and records are retained

- compliance with TransCanada's proprietary quality management system is maintained

### 2.8.9 Security Management

Energy East will implement TransCanada's corporate security policy and programs for the Project. These policies and programs are aligned to the CSA Standard Z246.1 for security management.

During construction of the Project, security management will be governed by the TransCanada corporate security policies and programs, and through a TransCanada operating procedure (TOP) that governs construction security. The TOP details TransCanada's security expectations and plan elements for the prime construction contractors on the Project. Energy East will audit the prime contractor plans to ensure compliance with the TransCanada TOP.

Consistent with this standard, security assessments will be conducted and documented on an ongoing basis, and security management plans will be developed and implemented for the Project. The TransCanada TOP will also be used to govern security management during the operations phase.

### 2.8.10 Operations – Project Facilities

Project facilities will be controlled, monitored, and operated remotely by controllers in the oil Operations Control Center (OCC) using a supervisory control and data acquisition (SCADA) system. The OCC will be staffed 24 hours a day, seven days a week and the SCADA system has redundancy in its design.

The Project facilities will be protected from high-pressure conditions through a variety of systems operating through both the SCADA system and local facility controls (programmable logic controller and variable frequency drive systems), which are used to maintain pressure and suction within normal operating limits at pump stations (see Volume 6, Sections 2 and 3). The design of appropriate facility control systems will be advanced through detail engineering.

The SCADA system will alert OCC controllers whenever a local facility control system detects operations that are outside pre-determined limits. Operating procedures will be used to govern how the controllers respond to these alarms, with priority on ensuring the continued safety and integrity of the pipeline and associated facilities.

An emergency shutdown system (ESD) will be employed to protect the pipeline and related facilities. The ESD system can be initiated through either field-based push buttons located at all facilities, facility programmable logic controllers, or by the OCC through the SCADA system. Should an ESD be triggered, local field staff will be required to investigate the source of the ESD and clear the ESD locally before operations can resume at the facility. The design of appropriate facility control systems will be advanced through detail engineering.

A leak detection strategy will be implemented for the Project, which uses both real-time and non-real-time methods. The purpose of the leak detection strategy is to ensure methods are in place that will contribute to the certain and timely detection of a release in order to support and inform appropriate pipeline control and emergency response actions.

Based on a hydraulic analysis of the current design information, and subject to refinement during detailed design, pipeline shutdowns (including pump shutdown and valve closure to isolate sections) are expected to be completed within eight minutes of initiation of a shutdown.

Emergency response, including dispatch of field personnel to the site, would be immediately initiated through TransCanada's emergency management system. In a worst case scenario of a rupture the target timeline is to detect and complete the shutdown and isolation of the pipeline (complete closure of the shut-off valves) within 13 minutes of the event.[34]

In all other instances, once an alarm is sounded indicating a potential leak, the OCC staff has a maximum of 10 minutes to conclusively explain the cause of the alarm as a non-leak using established procedures. When a leak cannot be ruled out by the controller, a pipeline shutdown is immediately initiated. If additional indications of a potential leak are noted at any point during the 10-minute period, the pipeline shutdown is immediately initiated, and the remainder of the 10-minute period for any further cause analysis is disposed of. Following the shutdown, field staff will be immediately dispatched to the site.

Local operations, inspections, maintenance, and emergency response, will be conducted as required, by competent field personnel in coordination with the OCC, and in accordance with TransCanada's operating procedures for routine and non-routine field operations and maintenance.

For additional information on SCADA, leak detection methods and ESD systems, see Volume 7, Sections 4.9 and 4.10, respectively.

[34] For further reference and information on timing associated with leak detection and shutdown activities, see Energy East's response to NEB 5.30 (NEB Filing ID: A4V8G6).

### 2.8.11 Marine Terminal Operations

The Canaport Energy East marine terminal will be operated by a subsidiary of Irving Oil on behalf of Energy East. The marine terminal is not unique or unusual in comparison with other marine terminals handling crude oil currently operating within the Bay of Fundy, with up to VLCC tankers visiting existing terminals.

#### 2.8.11.1 Marine Loading Operations

The Canaport Energy East marine terminal will be able to simultaneously load two tankers at berth. The marine terminal will be monitored and operated by qualified personnel and will be equipped with integrated automation and leak detection systems. The OCC will be responsible for controlling loading operations. However, the OCC cannot initiate loading operations until local marine terminal personnel provide their permission and determine that safe operating conditions exist.

A continuous three-point radio communication system will be in place to support the marine loading operations between the tanker, the berth operator at the marine terminal, and the OCC. Data pertaining to marine loading operations and vapour recovery systems will be collected and evaluated locally by the marine terminal and remotely by the OCC to ensure safe and reliable operations.

#### 2.8.11.2 Tanker Acceptance Program

To help ensure that tankers visiting the marine terminal meet appropriate safety standards and operate in an environmentally responsible manner, a Tanker Acceptance Program, better known as “TAP,” will be implemented by Energy East to ensure tankers scheduled to berth at the marine terminal meet the industry standards for safety and environmental protection and conform to the design limits of the marine terminal.

While marine activities associated with the two marine terminals are outside the Board’s jurisdiction, a comprehensive regulatory framework regulates marine activities within Canadian waters under the *Canada Shipping Act*. As the two marine terminals will not have a dedicated vessel fleet, marine activities associated with vessel traffic destined to, or from, either marine terminal is the responsibility of the ship owner and operator, including accidents or malfunctions. Energy East is responsible for ensuring the safety of the marine terminal operations.

#### 2.8.11.3 TERMPOL Process

To ensure that the marine vessel and marine terminal activities are as safe as possible, Energy East has voluntarily initiated separate Technical Review Process of Marine Terminal Systems and Transshipment Sites (TERMPOL) review.

The purpose of TERMPOL is to examine elements of a proposed oil handling marine terminals where there might be a risk of an oil spill (such as navigation and marine terminal design) and, where possible, allow the implementation of either design or operational safety measures to remove or reduce site-specific risks.

Upon the completion of the TERMPOL review process, Energy East will submit the TERMPOL Review Committee's reports to the Board, abide by TERMPOL Review Committee's recommendations, and will incorporate these recommendations into the operational procedures and manuals that will be developed prior to commencement of marine terminal operations.

Energy East has provided updated reports to Transport Canada to reflect the operational requirements at the Canaport Energy East marine terminal.

Energy East will provide an update to the Board in fourth quarter 2016 on the status of this review process, including on any additional commitments made through this process that have not been provided to the Board to-date (see Table 2-4: List of Appendices to Volume 1 – Application, Overview and Justification).

## 2.9 CONSOLIDATED APPLICATION VOLUMES 4, 5, 6 AND 7 — ENGINEERING DESIGN

### 2.9.1 Codes and Standards

Primary industry standards for the proposed pipeline and related facilities, as well as a current list of potentially applicable TransCanada specifications and standards, are listed in Appendix 1-1: Standards and Specifications (see Appendix Table 1-1A and Table 1-1B, respectively). A final list of applicable specifications and standards will evolve as Project planning progresses through detailed design, and as individual specifications and procedures are added, updated or replaced to incorporate legislative and regulatory changes, and technological advances. [35]

With the Canadian Standards Association (CSA) 15 June 2015 updating of standard CSA Z662, and the Board's supporting Information Advisory (NEB IA 2015-001), Energy East confirms that the detailed design and construction phases of the Project will comply with the OPR and CSA Z662-15.

For the operations phase of the Project, Energy East has entered into an operating services agreement with TransCanada. TransCanada's proprietary engineering standards, specifications, operating procedures and policies are expected to reflect and be compliant with both CSA Z662-15 and the OPR when Project operations commence. At any phase of the Project, if there are inconsistencies between the OPR and CSA Z662-15, the OPR will govern.

[35] For additional information regarding the review and update of TransCanada specifications and standards, see Energy East's response to NEB 5.10 (NEB Filing ID: A4V8G6).

The Project has been and continues to be assessed and designed for the potential effects of conditions not specifically addressed in CSA Z662. This is confirmed in written statements from a qualified professional engineer (see the Design Confirmation and Addendum provided in Volume 4, Appendices 4-2 and 4-3).

### 2.9.2 Geohazard Assessments

A two-phased geotechnical investigation program, including desktop studies and both aerial and ground reconnaissance, has been completed for the Energy East Pipeline alignment. Phase I assessments identified potential geohazards that might negatively affect pipeline construction and operation, as well as areas for further evaluation. Phase II assessments included ground reconnaissance and evaluation of hazards with moderate and high potential identified in the Phase I assessments.

All investigations focused on the following key design issues:

- slope stability
- scour at watercourse crossings
- faults and seismicity
- ground subsidence and other geohazards

Energy East has determined that standard and/or site-specific mitigation measures can be implemented to effectively address the geohazards potentially present along the pipeline alignment (see Volume 4, Section 2.7: Geohazard Assessment, and Appendices 4-4 to 4-8). Refer also to the pipeline-specific geohazard information provided in Sections 3.1 to 3.7.

Site-specific offshore geotechnical investigations have also been completed for the Canaport Energy East marine terminal. The work included field investigations and in-situ field tests at boreholes, as well as laboratory testing, engineering analyses and reporting. These offshore investigations will provide subsurface information and geotechnical parameters that are needed for the marine terminal structural foundation design. A report detailing the findings of the geotechnical investigation program is provided in Appendix 6-113. Refer also to Volume 6, Section 6.3.2.4: Seismic Consideration.

Site-specific geotechnical investigations for the other facilities associated with the pipeline, including pump stations, delivery meter stations, and tank terminals are planned or underway and will continue as engineering design and construction planning progresses.

If these geotechnical investigations indicate conditions that are not addressed in CSA Z662-15, Energy East will submit to the Board a report from a professional engineer and a description of the designs and measures required for safeguarding the affected facilities.

### 2.9.3 Acid Rock Management

Energy East is developing a plan for managing potentially acid-generating (PAG) bedrock at locations along the pipeline route in Québec and in New Brunswick.

Preliminary acid rock drainage (ARD) mitigation plans are provided for the Québec and New Brunswick segments. Refer to Appendices 4-9 and 4-10 of Volume 4, Pipeline Design.

Desktop studies providing a preliminary assessment of surficial geology and bedrock depths along the new pipeline route in Ontario, Québec and New Brunswick have also been completed. The results are found in Appendix 4-11: Terrain Mapping. The desktop studies identified several bedrock formations as having low, moderate or high potential for generating ARD. The desktop studies provide additional information to the ARD technical data report (TDR) that is included in ESA Volume 22.

### 2.9.4 Trenchless Watercourse Crossings

Preliminary and follow-up horizontal directional drill (HDD) feasibility reports have and continue to be completed in support of proposed watercourse crossings for the Project. These reports are appended to Volumes 4 and 5 of this Consolidated Application (see Table 1-1 of Volume 4 and Table 1-5 of Volume 5).

As shown on Table 2-3 below, feasibility reports have been prepared for 49 pipeline watercourse crossings. Forty-two of these crossings appear to be feasible for a trenchless crossing method, mostly by HDD. The remaining seven are not considered feasible for a trenchless crossing method and have instead been identified for site-specific trenched crossing designs.

Trenchless crossings avoid in-stream works and ditching activities in the beds and banks of watercourses. They are generally used for watercourses with flows, water depths and channel widths that cannot be effectively isolated, and can be installed in a number of different geotechnical conditions.

Trenched crossings include open cut and isolated crossing methods.

For additional information on trenchless and trenched crossing methods, refer to Volume 4, Sections 2.6.1 and 2.6.2, respectively. See also Volume 7, Section 3.1.8: Pipeline Watercourse Crossings.

**Table 2-3: Trenchless Watercourse Crossings along the Energy East Pipeline (CA Rev. 0)**

| Segment | Watercourse | Feasibility Report Finding[1] | Comment[1] |
|---|---|---|---|
| Alberta | Red Deer River | Feasible | Feasible based on preliminary geotechnical information. |
| | South Saskatchewan River | Feasible | Feasible based on preliminary geotechnical information. |
| Prairie | Assiniboine River | Not Feasible | Preliminary crossing method is now trenched. |
| North Bay Shortcut | Rideau River | Feasible | Findings accepted. Proceed to detailed design. |
| | Madawaska River | Feasible | Findings accepted. Proceed to detailed design. |
| Ontario East | Raisin River | Feasible | Feasible based on preliminary geotechnical information. |
| | Delisle River | Feasible | Feasible based on preliminary geotechnical information. |
| | Rigaud River | Feasible | Feasible based on preliminary geotechnical information. |
| Québec | Rivière des Outaouais | Not Feasible | Report on feasibility of alternative trenchless and contingency crossing methods planned for future filing. |
| | Rivière du Nord | Not Feasible | Geotechnical complete, trenchless deemed unfeasible. Proceed to detailed design as trenched crossing. |
| | Rivière l'Assomption | Feasible | Findings accepted. Proceed to detailed design. |
| | Rivière Bayonne | Feasible | Findings accepted. Proceed to detailed design. |
| | Rivière Chicot | Feasible | Findings accepted. Proceed to detailed design. |
| | Rivière Maskinongé | Feasible | Findings accepted. Proceed to detailed design. |
| | Rivière du Loup | Feasible | Findings accepted. Proceed to detailed design. |
| | Rivière Saint-Maurice | Feasible | Findings accepted. Proceed to detailed design. |
| | Rivière Batiscan | Feasible | Findings accepted. Proceed to detailed design. |
| | Rivière Sainte-Anne | Feasible | Findings accepted. Proceed to detailed design. |
| | Rivière Jacques-Cartier | Feasible | Findings accepted. Proceed to detailed design. |
| | St. Lawrence River | Tunnel Feasible | Tunnel feasibility report to be considered during detailed design. |
| | Rivière Beaurivage | Feasible | Findings accepted. Proceed to detailed design. |
| | Rivière Chaudière | Feasible | Findings accepted. Proceed to detailed design. |

**Table 2-3: Trenchless Watercourse Crossings along the Energy East Pipeline (CA Rev. 0) (cont'd)**

| Segment | Watercourse | Feasibility Report Finding | Comment |
|---|---|---|---|
| Québec (cont'd) | Rivière Etchemin | Not Feasible | Geotechnical complete. Trenchless deemed unfeasible. Proceed to detailed design as trenched crossing. |
| | Rivière du Sud | Feasible | Findings accepted. Proceed to detailed design. |
| | Rivière Bras Saint-Nicolas | Feasible | Trenchless crossing deemed feasible. Findings accepted. Proceed to detailed design. |
| | Rivière Trois-Saumons | Not Feasible | Preliminary crossing method is now trenched. |
| | Rivière Ouelle | Feasible | Findings accepted. Proceed to detailed design. |
| | La Grande Rivière | Not Feasible | Bore crossing deemed feasible. |
| | Rivière du Loup | Not Feasible | Bore crossing deemed feasible. |
| | Rivière Madawaska | Feasible | Findings accepted. Proceed to detailed design. |
| New Brunswick | Rivière Iroquois | Feasible | Findings accepted. Investigations for contingency crossing underway. |
| | Petite Rivière Iroquois | Feasible | Findings accepted. Investigations for contingency crossing underway. |
| | Rivière Verte | May be Feasible | Findings accepted. Proceed to detailed design. |
| | Salmon River (North) [3] | Feasible | Findings accepted. Proceed to detailed design. |
| | Tobique River [3] | Feasible | Findings accepted. Proceed to detailed design. |
| | Coal Creek [3] | Feasible | Findings accepted. Proceed to detailed design. |
| | Canaan River | Feasible | Findings accepted. Proceed to detailed design. |
| | Long Creek | Feasible | Findings accepted. Proceed to detailed design. |
| | Kennebecasis | Feasible | Findings accepted. Proceed to detailed design. |
| | Black River | Feasible | Findings accepted. Proceed to detailed design. |
| | Mispec River | Feasible | Findings accepted. Proceed to detailed design. |

**Table 2-3: Trenchless Watercourse Crossings along the Energy East Pipeline (CA Rev. 0) (cont'd)**

| Segment | Watercourse | Feasibility Report Finding | Comment |
|---|---|---|---|
| New Brunswick (cont'd) | Grande Rivière | Feasible | Trenchless crossing deemed feasible. Findings accepted. Proceed to detailed design. |
| | South Branch SouthWest Miramichi River | Feasible | Trenchless crossing deemed feasible. Findings accepted. Proceed to detailed design. |
| | Cains River | Feasible | Trenchless crossing deemed feasible. Findings accepted. Proceed to detailed design. |
| | Salmon River (South) | Feasible | Trenchless crossing deemed feasible. Findings accepted. Proceed to detailed design. |
| | Hammond River | Feasible | Trenchless crossing deemed feasible. Findings accepted. Proceed to detailed design. |
| Montréal Lateral (Alternative Routes 1 and 2)[2] | Rivière des Milles Iles | Feasible | Trenchless crossing deemed feasible. Findings accepted. Proceed to detailed design. |
| | Rivière des Prairies | Feasible | Trenchless crossing deemed feasible. Findings accepted. Proceed to detailed design. |
| Lévis Lateral | Rivière Etchemin (Lévis) | Not Feasible | Trenchless crossing deemed feasible. Findings accepted. Proceed to detailed design. |

Note:

1. This table is based on preliminary design. Final locations will be subject to further engineering and environmental site evaluations, geotechnical assessments, Aboriginal, landowner and stakeholder engagement, land acquisition and consultation with regulatory authorities.
2. Refer to Volume 4, Section 3.6: Montréal Lateral for additional information. See also Volume 13, Appendix 13-91, for a detailed route map.

## 2.10 CONSOLDIATED APPLICATION VOLUME 8 – LAND

### 2.10.1 Overall Land Requirements

The Project will require approximately 1,510 km of right-of-way (ROW) for new pipeline segments, including approximately:

- 281 km of pipeline ROW in Alberta
- 3 km of pipeline ROW in Saskatchewan
- 106 km of pipeline ROW in Ontario
- 625 km of pipeline ROW in Québec
- 412 km of pipeline ROW in New Brunswick
- 83 km of pipeline ROW for laterals and interconnections including the Cromer Lateral in MB and SK, the Montréal Lateral and Lévis Lateral in QC, and the Saint John Connection in NB

Segments of the TransCanada Mainline to be transferred to Energy East and converted for crude oil service will be located in existing ROW. Notwithstanding, a number of route realignments are required along these converted TransCanada Mainline segments to manage watercourse crossings, to route around specific facilities or for operability reasons and will require the following additional pipeline ROW:

- approximately 2.3 km of pipeline ROW in MB
- approximately 3 km of pipeline ROW in ON

In addition, the Project will also require land for facilities including, approximately:

- 682 ha for pump station sites
- 145 ha for tank terminal sites
- 3.3 ha of land and 14.8 ha of water lot for the Canaport Energy East marine terminal site

Beyond these specific requirements, the Project also will require the use of temporary workspace for construction activities.

### 2.10.2 Pipeline Requirements

Energy East will acquire additional ROW to construct, operate and maintain the new mainline segments, laterals and interconnections, and their associated facilities. The Project also intends to use TWS for construction of these pipelines and associated facilities.

The conversion pipeline will be located in existing ROW. The Project will acquire additional ROW along the conversion pipeline segments where required for new pipeline additions to route around existing TransCanada facilities, and route realignments outside existing ROW for new watercourse crossings or for constructability and operability reasons.

Mainline valves will be installed in the ROW on the new mainline segments, laterals and conversion pipeline segments. These valve sites are intended to be fenced and located within the boundaries of the pipeline ROW. The estimated surface area of each mainline valve site is approximately 0.04 ha.

Typically, for the construction of new pipeline, the Project will require a construction ROW (i.e., combined ROW and TWS) width of approximately 42 m on agricultural land and 32 m on forested land to accommodate transportation of personnel, vehicle movement, equipment storage and other safety and operational considerations. The construction ROW width could vary depending on design and constructability or environmental factors, or landowner considerations.

### 2.10.3 Facility Requirements

In addition to the ROW required for pipelines, Energy East requires land for the Canaport Energy East marine terminal, tank terminals, custody transfer metering facilities, pump stations, pressure control facilities, access roads and temporary infrastructure.

Land for the marine terminal will be acquired through a long term lease agreement, and the required rights to water lots through a long-term water lot lease. Three tank terminals are planned for installation on private land near Hardisty, AB, Moosomin, SK, and in Saint John, NB. Land requirements vary for each facility. New delivery meter stations are proposed at the termini of the Montréal and Lévis laterals to measure the volumes of crude oil delivered by the Energy East Pipeline to existing refineries, and again, land requirements vary for each such facility.

The Project requires new land rights for the 71 pump stations along the route. The required land rights are generally intended to be acquired by fee simple purchase. In the Province of Québec, land rights might be acquired by long-term lease agreements, which include an option to purchase.

Pressure control valve facilities will be installed near Burstall, SK, Cromer, MB, Île des Chênes, MB and Iroquois, ON. The pressure control facilities near Cromer, MB, Île-des-Chênes, MB and Iroquois, ON will be located in the proposed Cromer pump station site, Île-des-Chênes pump station site and Iroquois pump station site, respectively. The pressure control facility to be installed near Burstall will be sited outside of a pump station site. The need for additional pressure control facilities might be identified during detailed design.

The Project will require permanent access roads (between 7 m and 20 m wide) at the proposed pump stations, tank terminals, marine terminal and at some of the mainline valve sites. The intent is to acquire land rights by fee simple purchase where possible and access easement agreements, if required. Beyond this, stockpile sites, contractor yards and construction camp sites will be required during Project construction. Energy East will use existing disturbed areas where available and practical to help minimize impacts on previously undisturbed areas. As these sites will be temporary, permanent land rights are not required.

For more detail regarding specific and estimated land requirements for these facilities see Volume 8, Section 3.

### 2.10.4 Land Acquisition

The Project's land acquisition process began in 2013 and will continue for the next several years.

Notices pursuant to section 87(1) of the NEB Act have been and will be served on owners and occupants of lands proposed to be acquired for the Project. Additional Project-specific regulatory notifications have and will continue to be provided to owners of land, along with periodic newsletters detailing Project updates.

For further detail see Section 2.8.3: Preliminary Construction Schedule above, and Volume 8, Section 4.5: Land Acquisition Status.

### 2.10.5 Landowner Identification

Preliminary Project route maps were used to identify lands traversed by the pipeline and sites where facility locations are proposed. To identify landowners and occupants in or near the Project footprint, Energy East, among other things:

- prepared lists of landowners and registered occupants along the new pipeline segments by reviewing title information for each property
- identified landowners along the conversion pipeline segments using a TransCanada landowner database system
- reviewed title information to identify landowners and registered occupants where facilities will be sited
- reviewed title information to identify owners and registered occupants of lands not traversed by the proposed centreline of the Project where access is required to conduct surveys and examinations (Survey Lands)

Based on these and similar subsequent activities undertaken as appropriate, Energy East has determined there are 2,727 landowners along the new pipeline segments (i.e., owners of lands to be acquired for new pipeline segments) and 2,992 owners of land along the conversion pipeline segments. An additional 83 landowners have been identified for facilities sites. Occupants (registered and unregistered) continue to be identified.

Energy East continues to identify landowners where access is required to conduct necessary field surveys and examinations and where land will be acquired for Project requirements including route refinements.

### 2.10.6 Landowner Consultation

In addition to the stakeholder engagement principles and goals set out in Volume 9, Community Engagement, the goals of land consultation are to:

- share project information
- identify and address project-related landowner concerns
- support reaching agreements for land access and land rights necessary for Project construction, operations and maintenance

The land consultation program was developed to address different landowner contexts with respect to the Project on the conversion pipeline sections, the new pipeline segments, and facilities.

Three main activities are involved in land consultation:

- landowner identification and initial contact
- information sharing
- identifying and addressing project-related issues and concerns

The landowner consultation program has been designed to provide landowners with information and documentation in the language of their choice, English or French.

Consultation with landowner advocacy groups such as the Union des producteurs agricoles in Québec, as well as other regional landowner advocacy groups, has been incorporated into the land consultation program.

For additional information on the land acquisition and land consultation process for the Project, see Volume 8, Sections 4 and 5. See also Volume 7, Section 2.14: Regulatory Authorizations Required for Construction.

### 2.10.7 Issues and Concerns

Through consultation with landowners, specific issues and concerns are recorded, discussed and addressed.

For Energy East's summary of general landowner issues and concerns identified along the conversion and new pipeline segments, and Energy East's responses, see Volume 8, Section 5.3.1: Ongoing Issues Resolution.

## 2.11 CONSOLIDATED APPLICATION VOLUME 9 – COMMUNITY ENGAGEMENT

Energy East’s community engagement program was developed and is adapted according to the nature, location and effects of the Project, and to the interests, information needs and concerns of various stakeholders. The program recognizes the diversity of stakeholders and their interests across the Project, and is designed to provide stakeholders with opportunities to review project details, ask questions, and express comments and concerns. Information is shared and where feasible, Project-related concerns will be addressed through design or operational changes.

### 2.11.1 Scope

Engagement for Energy East extends across six provinces and includes outreach to approximately 580 municipalities, about 580 first responders, and 11 Canadian Armed Forces (CAF) Garrisons and Wings organizations.[36]

While many of the engagement activities are the same and overall Project information is consistent, information provided at the provincial level is tailored to Project components – either conversion or new pipeline and associated facilities – and recognizes stakeholder language preferences. Newsletters, email messages, materials, displays and open houses are provided in English, French or both languages, depending on community preferences.

For information on Energy East’s approach to identifying stakeholders for notification and engagement, see Volume 9, Section 2.2: Stakeholder Identification.

For information on the communication tools that are being used for engagement on the Project, refer to Volume 9, Section 2.5: Engagement Tools.

### 2.11.2 Engagement Activities

An overview of engagement activities, timelines, and the associated primary materials is provided in Volume 9, Section 3.1: Engagement Overview. The overview describes engagement activities from 1 April 2013 and 31 December 2015 across the Project. It also describes engagement with communities that were potentially affected by the removal of the Cacouna marine terminal and related facilities. This engagement extended into first quarter 2016.[37]

By December 2015, Energy East had hosted 116 community open houses attended by a total of 9,062 registered attendees. Refer to Volume 9, Section 3.2: Open Houses for details.

[36] Refer to Section 4.0: Provincial Profiles and Appendix 9-1: Municipal and Regional Authorities and Emergency Response Stakeholders for lists of municipalities that are engaged on the Project.
[37] Refer to Section 2.1.2, Application Amendment, of this Project overview for additional information.

Additionally, Energy East held "Safety and Emergency Response Information Days" in 23 communities from September 2015 to December 2015. More than 1,500 registered attendees took part in the events. For displays and materials at these events, see Appendix 9-82: Safety and Emergency Response Information Days Materials.

### 2.11.3 Engagement Outcomes

To date, the following information needs have been identified through community engagement activities:

- Project scope and design
- pipeline routing criteria
- the NEB process and how stakeholders can participate in it
- pipeline integrity measures
- pipeline safety procedures
- emergency preparedness and response[38]
- the environmental and socio-economic assessment process and study outcomes
- opportunities to become involved in the engagement program
- economic development and community investment opportunities

Beyond identification of information needs, Energy East tracks and follows up on community engagement activities and more specific comments, issues and interests raised by stakeholders. Refer to Appendices 9-4 to 9-10 for provincial summaries and tables.

The main topics of interest that have arisen through community engagement to-date include:

- protection of water sources and watercourse crossings
- pipeline safety, integrity and monitoring
- marine shipping effects
- potential operational effects of facilities (e.g., noise from the marine terminal, tank terminals and pump stations)
- environmental protection
- potential effects of a spill

### 2.11.4 Ongoing Engagement

Engagement program outreach and information sharing will continue throughout the NEB's regulatory process, as well as through construction. Energy East will continue to respond to questions and comments and identify and address community stakeholder issues.

[38] Refer to Section 4.2: Engagement with Emergency Responders for details.

During the operations phase, ongoing engagement activities for the Project will transition to TransCanada's Public Awareness Program. Please refer to Volume 7, Section 4: Operations, for a description of that program.

## 2.12 CONSOLIDATED APPLICATION VOLUME 10 – ABORIGINAL ENGAGEMENT

Energy East's Aboriginal engagement program was developed and is adapted according to the nature, location and potential effects of the Project, and to the interests and concerns of First Nation and Métis communities and organizations. It respects and, to the extent practical, follows the traditions and protocols specific to each Aboriginal group. It is guided by TransCanada's *Aboriginal Relations Policy*.

The Aboriginal engagement program is iterative and will be employed through the duration of the Project. It includes the following elements:

- sharing Project information
- gathering input, offering resources and establishing agreements to support the engagement process
- identifying opportunities and developing programs to support Project-related benefits or community-based initiatives
- responding to comments and questions
- identifying concerns and developing measures to avoid, mitigate or otherwise manage potential effects

As an integral part of the program, Energy East works collaboratively with First Nation and Métis communities and organizations to address Project-related concerns, including through design or operational changes where feasible. Energy East also provides communities and organizations with information on how their input has influenced the design of the Project and discusses with them proposed measures to avoid, mitigate, or otherwise manage potential effects.

### 2.12.1 Scope

Approximately 165 First Nation and Métis communities and organizations are currently engaged on the Project, as shown on Tables 2-1 to 2-7 of Volume 10, Section 2.4: Aboriginal Groups Identified for Engagement.

Engagement is typically with First Nation and Métis communities individually, although some Aboriginal groups prefer to be represented by a tribal council[39] or a

[39] Tribal Council is defined as: A group of First Nations with common interests who have voluntarily joined together to provide services to member First Nations. Aboriginal Affairs and Northern Development Canada website 2014: http://www.aadnc-aandc.gc.ca/eng/1386290996817/1386291051138.

provincial-territorial organization.[40] When directed to do so, Energy East communicates directly with the identified organization.

For information on Energy East's approach to identifying and confirming Aboriginal groups for notification and engagement, see Volume 10, Sections 2.2 and 2.3, respectively.

### 2.12.2 Engagement Activities

Engagement activities are conducted and materials are provided in English and/or French.

To implement the Aboriginal engagement program, Energy East employs a wide range of activities and communication tools to engage Aboriginal groups, including those used in the Project's community engagement program (see Volume 10, Section 2.8: Engagement Tools).

In addition, the following communication tools and activities are used specifically by the Project to engage Aboriginal groups:

- GIS data and shape files, on request
- oversize maps
- community information sessions and technical working groups

From April 2013 to December 2015, Energy East participated in approximately 2,800 meetings with Aboriginal groups.

To support the engagement process for the Project, Energy East has made available to First Nation and Métis communities and organizations different forms of agreement, including Letters of Agreement (LOA) and Communications and Engagement Funding Agreements (CEFA).[41] LOAs and CEFAs are described in Section 2.3.1: Funding Agreements.[42]

For a more detailed description and chronology of Energy East's engagement with Aboriginal groups and the sharing of information through these activities and tools, see Volume 10, Section 3.0: Program Implementation.

[40] Provincial-territorial organization is defined as: A federally recognized and federally funded entity that represents a group of First Nations communities or organizations in a defined regional context.

[41] For further information about the various forms of agreement that Energy East has made available, see Energy East's response to NEB 5.26(b) through (e). NEB Exhibit No. A74256-1.

[42] By December 2015, a total of 94 First Nation and Métis communities and organizations had received initial capacity funding through LOAs. Energy East is no longer actively offering LOAs. A total of 158 CEFAs were offered to Aboriginal groups between April 2013 and December 2015. By December 2015, 46 CEFA work plans were under negotiation, and 50 CEFAs had been executed with First Nation and Métis communities and organizations.

### 2.12.3 Engagement Outcomes

Aboriginal engagement information is collected and managed in a database designed to capture engagement efforts with each Aboriginal group. Comments, project-related issues, and concerns are tracked and followed up on.

Project-related issues of interest and concern that have been raised by First Nation and Métis communities and organizations through engagement from April 2013 to December 2015 are summarized in Section 6.0: Engagement Program Outcomes. These summaries are presented by province.

Topics of interest that have been raised by Aboriginal communities and organizations in more than one province include:

- pipeline integrity and safety
- potential effects of a spill and emergency response
- Project engagement and Crown consultation
- potential effects on treaty and Aboriginal rights
- economic development and participation in construction and reclamation
- potential effects on the environment (e.g., water, fish, wildlife, traditional use, marine and health)
- environmental protection
- mainline valve siting
- potential effects on commercial or traditional fishing activities
- marine shipping activities and potential cumulative effects

For a province-by-province summary of engagement with each Aboriginal community and organization through December 2015, see Appendices 10-3 to 10-152.

### 2.12.4 Traditional Knowledge

As part of the Aboriginal engagement process for the Project, Energy East is implementing a TK information-gathering program. The primary objective of the TK program is to gather TK information to assist in identifying potential effects of the Project on environmental and socio-economic elements of identified interest to engaged Aboriginal groups. The TK program is guided, among other things, by the goals of the Aboriginal engagement program for the Project.

TK information is gathered either through an Energy East- or community-facilitated approach. Through either approach , the TK information gathering program is framed by an established process and set of deliverables that consist of:

- scoping meetings
- a TK workplan and budget
- a TK protocol agreement

- an interim TK report
- a final TK report

The TK program began in June 2013 and by December 2015, Energy East had offered TK study protocol agreements to 109 Aboriginal communities and organizations. Thirteen of these were offered to organizations that represent more than one First Nation or Métis community for the purposes of engagement on Energy East. Refer to Table 4-1 of Section 4.3: Integration of Traditional Knowledge for information on the status of the TK program in December 2015.

TK information has been and will continue to be gathered through a variety of methods, including:

- workshops, map workshops, technical workshops
- one-on-one interviews
- aerial reconnaissance
- ground-based field work
- ongoing participation in monitoring and follow-up programs

For further information regarding the TK program, see Section 4:0: Traditional Ecological Knowledge and Traditional Land Use. See also ESA Volume 25, Traditional Land and Resource Use.

### 2.12.5 Community Investment, Employment and Contracting

Through community engagement, Energy East has developed and is supporting an Aboriginal community investment strategy for communities near its planned operations.

For further information on this initiative and for summaries of its outcomes through December 2015, see Volume 10, Section 5.3: Community Investment.

#### 2.12.5.1 Employment, Contracting and Capacity Development

Energy East supports local communities by providing contracting and employment opportunities to qualified Aboriginal and local businesses. Energy East is guided by TransCanada's *Aboriginal Contracting and Employment Program*, which is designed to fulfill commitments under the company's *Aboriginal Relations Policy*, and is applied in all TransCanada projects.

Energy East has developed an Aboriginal contracting plan that aligns with both of the TransCanada policies referred to above.

By December 2015, Energy East's Aboriginal contracting and employment team had participated in 384 meetings related to contracting and employment with Aboriginal leaders and in an additional 318 meetings with Aboriginal contractors, organizations and vendors.

To encourage and enable community participation in the Project, Energy East collaborates with local First Nation and Métis communities and organizations to identify training needs related to employment opportunities during the pre-construction, construction and post-construction phases of the Project.

For additional information on the Aboriginal engagement program as it relates to community investment, contracting and employment, as well as to capacity development and training, see Volume 10 Sections 5.1 to 5.3, respectively.

## 2.13 CONSOLIDATED APPLICATION VOLUMES 9 AND 10 — MARINE SHIPPING CONSULTATION

Through its community and Aboriginal engagement programs, Energy East has been and will continue to engage with users of the waterways on marine shipping matters pertaining to the Project.

Through engagement to December 2015, concerns have been raised with respect to marine terminal and shipping operations for the Project. These include:

- potential effects, including noise and increased shipping, on the right whale, blue whale, harbor porpoise, and fin whale
- potential effects of increased marine traffic on shipping lanes in the Bay of Fundy, and on the local fishing community and fishing grounds
- loss of fishing grounds to the marine terminal and surrounding area or in the event of an oil spill or accident
- potential odours and vapour emissions from the marine and tank terminals
- potential effects of an oil spill in the Bay of Fundy
- scope of the impact analysis on marine mammals and if porpoises are being sufficiently studied
- compatibility of emergency response plans with the fishing community’s needs
- emergency response capability in the Bay of Fundy and the impact of any dispersants used in emergency response on the Bay of Fundy marine life

For additional information on marine shipping engagement, refer to the provincial summaries for New Brunswick and Nova Scotia in Volume 9, Community Engagement (Appendices 9-9 and 9-10). Refer also to the individual Aboriginal community and organizational summaries that are included for New Brunswick and Nova Scotia in Volume 10, Aboriginal Engagement (Appendices 10-136 to 10-152).

## 2.14 CONSOLIDATED APPLICATION VOLUME 11 – ENVIRONMENTAL AND SOCIO-ECONOMIC OVERVIEW

Energy East retained Stantec Consulting Ltd. (Stantec) and Groupe Conseil UDA Inc. to conduct an ESA for the Project.

The ESA is supported by environmental field studies and includes environmental protection plans for the Project (see ESA Volume 21, Environmental Protection Plans). The EPPs will be updated as additional mitigation measures are identified during detailed design, and through ongoing fieldwork and engagement programs.

### 2.14.1 Assessment of Project Effects and Determination of Significance

The ESA considered both residual and cumulative effects in respect of the biophysical elements that it interacts with. It concludes that the Project could potentially have significant adverse residual effects on the following biophysical elements:

- vegetation and wetlands – two species of rare plants in Alberta, both of which are species-at-risk under the *Species at Risk Act*: tiny cryptanthe (endangered) and slender mouse-ear-cress (threatened)

The ESA also concludes that the Project could potentially have significant adverse cumulative effects on:

- woodland caribou – two of the proposed pump stations are in critical habitat of one caribou herd that is considered very likely to be not self-sustaining and the Project could result in residual effects that will contribute to the pre-existing significant adverse cumulative effects on woodland caribou
- golden-winged warbler in Manitoba and eastern whip-poor-will in Québec – the Project contributes to pre-existing significant adverse cumulative effects on these two species although the Project's contribution to these significant cumulative effects is predicted to be minimal[43]
- greenhouse gas emissions – the Project contributes to a pre-existing significant adverse effect of GHG emissions on climate change. The Project contribution on its own is small in the global context.

Energy East accepts the findings of the ESA to-date, and will adhere to the recommendations and mitigation measures ultimately identified in the ESA, including the EPPs for the Project.

[43] The cumulative assessment findings for the golden-winged warbler in Manitoba and eastern whip-poor-will in Québec are based on a qualitative assessment and represent updated findings in the ESA as part of the Consolidated Application.

### 2.14.2 Ecological and Human Health Risk Assessment

As a part of the ESA an ecological and human health risk assessment (EHHRA) was undertaken (see ESA Volume 24). The EHHRA evaluates both stochastically[44] and deterministically, the potential environmental effects of accidental credible worst case (larger) and smaller crude oil spills on:

- the marine environment at the Canaport Energy East marine terminal
- such effects during marine shipping of crude oil from the Canaport Energy East marine terminal to the limits of Canadian territorial waters

For the stochastic analysis of the potential environmental effects of crude oil spills in the Bay of Fundy, five main ecological habitat and receptor types were defined as follows:

- shoreline and near-shore habitat
- marine fish and supporting habitats
- marine reptiles and supporting habitats
- marine birds and supporting habitats
- mammals and supporting habitats

The results of the deterministic analyses provide a more detailed assessment of the potential environmental effects on ecological and human receptors of specific "credible worst case" crude oil spills.

For the detailed analysis and specific EHHRA conclusions, see ESA Volume 24.

### 2.14.3 Commitment, Follow-up and Monitoring

Energy East will develop follow-up and monitoring programs to measure and report on the success of mitigation measures to address potential significant adverse Project effects. It will also develop offset plans where appropriate, to address significant residual adverse Project effects. Offset plans will be developed in consultation with regulatory agencies and environmental offices.

### 2.14.4 Environmental Regulatory Consultation

Energy East has and will continue to work with regulatory agencies and environmental offices to develop mitigation measures to address Project effects to ensure:

- the Project does not contribute to a negative change in the current status of a species

[44] The term "stochastic" describes an approach to modelling whereby the range of potential outcomes to a question being investigated is explored by performing a large number of simulations under varying input conditions. In this way both the most likely outcome, as well as other possible outcomes, can be understood.

- Project activities are done in accordance with the objectives of recovery strategies for species-at-risk

For summaries of Energy East's engagement with federal, provincial and regional environmental offices see Consolidated Application Volume 11, Section 6: Environmental Regulatory Consultation.

### 2.15 CONSOLIDATED APPLICATION VOLUME 12 – PROJECT RISK ASSESSMENT

Energy East retained independent experts to provide a characterization of the risks associated with the operation of Project facilities and the potential liabilities that might consequentially arise as a result of the scenarios assumed as part of the risk assessment. This evidence, as provided in Volume 12, Risk Assessment, includes:

- for pipelines and related facilities:
  - Stantec Consulting Ltd., *Pipeline Risk Assessment: Identification and Categorization of Pipeline Segments Posing Potential Hazard to Highly Sensitive Receptors* (Appendix 12-1)
  - Triox Environmental Emergencies Inc. (Triox), *Worst Case Spill Scenario Cost Estimates – Pipeline* (Appendix 12-2)
  - Stantec Consulting Ltd. (Stantec), *Pipeline Spill Response Scenarios – Estimated Remediation Costs* (Appendix 12-3)
- for tank terminals, pump stations, and delivery meter stations:
  - Marsh Risk Consultants Inc., *Risk Assessment - Energy East Pipeline Ltd.: Tank Terminal Facilities* (Appendix 12-4)
  - Triox, *Credible Worst Case Spill Scenario – Cost Estimates: Facilities* (Appendix 12-5)
  - Stantec, Facilities *Spill Response Scenarios – Estimated Remediation Costs* (Appendix 12-6)
- for the Canaport Energy East marine terminal and marine shipping in the Bay of Fundy:
  - Det Norske Veritas (U.S.A) Inc., *Canaport Energy East Marine Terminal Risk Studies – Termpol Study Report: Element 3.15 Risk Assessment* (Appendix 12-7)
  - Atlantic Environmental Response Team (ALERT) Inc., *Marine Spill Response Costs – Canaport Energy East Terminal* (Appendix 12-8)
  - Stantec, *Marine Spill Response Scenarios – Estimated Remediation Costs* (Appendix 12-9)

Collectively, this body of evidence demonstrates that the risks posed by the Project to the environment and nearby local communities can be sufficiently and appropriately mitigated. It also demonstrates that Energy East has sufficient financial capacity to address and compensate third parties in the unlikely event that an incident of the magnitude assumed in the risk assessment was to occur.

Energy East has reviewed the evidence cited above and confirms that the majority of mitigation measures recommended are reflected in the current and preliminary design of the Project. Those not reflected in current design will be considered and implemented as appropriate during detailed design.

## 2.16 APPLICATION VOLUME 13 – OVERVIEW AND DETAILED ROUTE MAPS

Volume 13 of this Consolidated Application provides a full set of aerial overview and detailed route maps for the Project.

The maps in Volume 1, as well as the coordinates and distances that are cited in Volumes 1 to 8, are based on horizontal grid measurements. The ESA uses slack chainage measurements and as explained below, the distances in the ESA may differ somewhat from those presented in Volumes 1 to 13.

### 2.16.1 Map Content

The detailed route maps, which are presented at a scale of 1:50,000, include:

- the pipeline route at August-September 2015
- pipeline section names conforming to the location and naming of pump station locations, except as described in Section 2.5.1: Mainline Segments
- pump station and tank terminal locations
- intermediate mainline valve locations
- the Canaport Energy East marine terminal location
- watercourse crossings and crossing methodologies for the pipeline route at August-September 2015
- publicly-available spatial data on land ownership, designated protected areas, and municipal and regional boundaries
- the locations and boundaries of reserves under the *Indian Act*

The aerial overview maps, which are presented at a scale of 1:200,000, include:

- the pipeline route at August-September 2015
- pump station and tank terminal locations
- primary roads and railways
- watercourses and proposed trenchless watercourse crossing locations

- nearby cities and towns, including Energy East open house locations
- designated protected areas
- the locations and boundaries of reserves under the *Indian Act*

### 2.16.2 Horizontal vs Slack Chain Measurements

As stated above, the maps and distances in Volumes 1 to 13 are based on horizontal grid measurements, which reflect a two-dimensional representation based on a horizontal grid. The ESA reflects slack chainage measurements in its maps and distances, which account for three-dimensional topographic surfaces and are typically longer than horizontal grid measurements.

Generally, the differences between horizontal grid and slack chain measurements are less in flat areas and greater in areas where the topography is undulating, varied, or complex. Figure 2-6 illustrates the difference in distance measurements using horizontal grid versus slack chainage methods. When distance intervals such as kilometre post markers are plotted along each of these representations, they will appear in different locations.

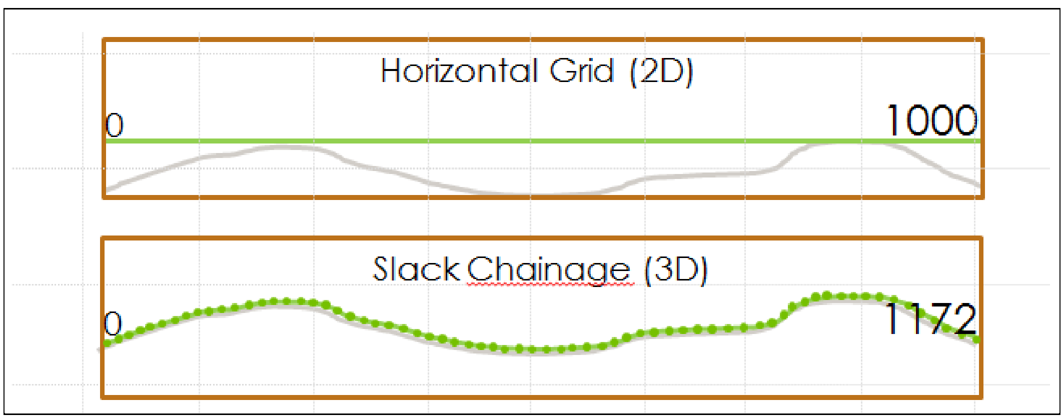


**Figure 2-6: Illustrative Horizontal Grid vs. Slack Chainage Measurements**

## 2.17 CONSOLIDATED APPLICATION VOLUMES 2, 3, 11 AND ESA VOLUME 14 — DECOMMISSIONING AND ABANDONMENT

The Project will be designed and maintained for a useful life in excess of 40 years. Any decision on the appropriate timing for decommissioning and abandonment will be influenced by future service requirements.

### 2.17.1 Energy East Project

For the purposes of this Consolidated Application, Energy East provides a Project abandonment cost estimate (ACE) of $914 million in accordance with the methodology described for TransCanada Keystone Pipeline GP Ltd. (Keystone) in the

Board's MH-001-2012 decision. Energy East intends to set-aside funds for the Project in a manner similar to the abandonment trust agreement provided for Keystone Pipeline (Canada).

For additional information on the ACE for Energy East, see Volume 3, Section 2.4.1.3: Decommissioning and Abandonment and to Appendix 3-5: Energy East Pipeline Draft Trust Agreement.

### 2.17.2 TransCanada Mainline

The Asset Transfer and addition of the EMP facilities will result in a net reduction to the ACE approved for the TransCanada Mainline. The estimated net impact of these two facility changes is a reduction of $362 million from the approved initial ACE of $2.38 billion.

For information on the effects of the Asset Transfer and EMP on the ACE for the TransCanada Mainline, refer to Section 4.4.3.1: Pipeline Abandonment Cost Implications.

### 2.17.3 Environmental Assessment

As decommissioning and abandonment are currently anticipated to occur in excess of 40 years into the future, a broad assessment was undertaken with respect to environmental impacts, informed by necessary assumptions. This assessment, including the determination of significance of any effects following mitigation and the significance of cumulative effects, is provided in the ESA (see ESA Volume 14, Section 8: Decommissioning and Abandonment).

## 2.18 SUPPORTING DOCUMENTS

Table 2-4 is a list of the supporting documents that are provided in this Consolidated Application volume.

**Table 2-4: List of Appendices to Volume 1: Application, Overview and Justification**

| Consolidated Appendix No. | Consolidated Appendix Name |
|---|---|
| Appendix 1-1 | Standards and Specifications (Industry  and Company) |
| Appendix 1-2 | Conference Board of Canada Report (October 2015) |
| Appendix 1-3 | Concentric Report (~~November 2015~~June 2016) (Attachment~~s~~ – ~~October 2014 Golder Report, November 2015 Update and~~ March 2016 Golder Report~~Update~~) |
| Appendix 1-4 | Priddle Report (November 2015) (Attachment – Footnote References) |
| Appendix 1-5 | Placeholder – Update on TERMPOL Process (Q4 2016) |
| Appendix 1-6 | Placeholder |
| Appendix 1-7 | Placeholder |

**Table 2-4: List of Appendices to Volume 1: Application, Overview and Justification (cont'd)**

| Consolidated Appendix No. | Consolidated Appendix Name |
|---|---|
| Appendix 1-8 | Placeholder |
| Appendix 1-9 | Placeholder |
| Appendix 1-10 | Placeholder |