Keystone XL Assessment – No Expansion Update

Prepared by Ensys Energy & Navigistics Consulting

For the U.S. Department of Energy & the U.S. Department of State

Final Report

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Disclaimer

Abbreviations & Acronyms Used in this Report

bbl	barrel
b/d	barrels per day
mbd	million barrels per day
tpa	tonnes per annum
mtpa	million tonnes per annum
DOE	Department of Energy
DOS	Department of State
EPA	Environmental Protection Agency
GIWW	Gulf Intracoastal Waterway
PADD	Petroleum Administration for Defense Districts
BC	British Columbia
CAPP	Canadian Association of Petroleum Producers
NEB	Canadian National Energy Board
SCO	Synthetic crude oil
WC	Western Canada
WCSB	Western Canadian Sedimentary Basin
WORLD	EnSys World Oil Refining Logistics & Demand Model

1 Executive Summary

1.1 Prior Analysis

In June 2010, EnSys Energy was contracted by the Department of Energy Office of Policy & International Affairs to conduct an evaluation of the impacts of the proposed Keystone XL pipeline on U.S. and global refining, trade and oil markets. Keystone XL would bring additional Canadian crudes, including oil sands, into the U.S. and also transport Bakken and other domestic U.S. crudes. In the study, released in December 2010, EnSys evaluated a number of alternative pipeline outlooks. These included so-called "No Expansion" scenarios in which all or most pipeline capacity to move Western Canadian crudes was "frozen" at 2011 levels, Keystone XL was not allowed and other pipeline projects/expansions were totally or partially restricted.

The No Expansion scenarios as studied in 2010 imposed pipeline restrictions that were permanent and also – implicitly - did not allow for any expansion of rail and barge modes. Under the Total No Expansion scenario, literally no capacity expansion was allowed beyond that now onstream in 2011. Under the Partial No Expansion scenario, expansion of the existing Trans Mountain line to the British Columbia coast was allowed as were additions to domestic U.S. pipeline capacity from the Midwest (PADD2) to the Gulf Coast (PADD3). All the scenarios considered focused on pipeline developments and implicitly assumed little or no expansion of WCSB crude oil movements by non-pipeline transport modes within Canada and the USA. In our report, EnSys stated that we felt the probability of either a Total or a Partial No Expansion scenario obtaining and persisting over time was low, in large part because non-pipeline modes would come into play.

1.2 Requested Update on Likelihood of "No Expansion"

The Departments of Energy and State have requested that we revisit these No Expansion scenarios and reassess in more depth the factors that could render them probable or improbable. At the time EnSys was undertaking its analysis for the Department of Energy in mid/late 2010, the congestion relating to Canadian and U.S. domestic crudes and centered on Cushing was still intermittent in terms of its impact on crude prices. Since early 2011, this congestion has become structural. It is depressing prices on a sustained basis for Canadian heavy and inland WTI grades relative to those for internationally traded marker crudes such as Brent and Mayan. These exceptional differentials are acting as economic drivers that are spurring a range of actions by industry, actions that are akin to how industry could react under a "No Expansion" scenario. Key effects to date have included an increase in domestic pipeline proposals, including ones that involve existing line or right-of-way, and rapid increases in rail and barge movements and projects. While our 2010 analysis incorporated most of the now-known pipeline projects, our modeling premises were set mainly in the third quarter of 2010, too early to capture the upsurges in rail and barge activity that are now occurring largely because of the sustained "Cushing/Canadian" congestion that set in early this year.

This report presents our findings based on our updated assessment of the developments that would have to not occur in order for a No Expansion scenario to occur. In summary, we believe a Total No Expansion scenario which freezes at current levels all capacity – across all modes - to transport Western Canadian crudes to market is essentially implausible. In order to obtain, such a scenario would require a total cessation of developments across several classes of crude transport, namely:

1. New pipeline projects, including both cross-border and pipelines that would lie entirely within either the USA or Canada
2. Modifications to existing pipeline systems, such as expansions or reversals
3. Expansions in rail, barge and tanker shipping (which would tend to become more economically attractive under any moratorium on pipeline expansions).

1.3 Types and Levels of Alternatives to Pipelines

In effect these three levels can be viewed as a pyramid as per Exhibit 1-1. At the top level, (Tier 1), are major new pipeline projects. These are few in number. They have the advantages of scale and low per barrel tariff rates but have the disadvantages of high capital cost, also of requiring a high level of commitment by shippers. They have a potentially high level of permitting complexity and difficulty, and associated long lead time to implement. In the context of WCSB crude exports, there are two primary projects in this category – Keystone XL and Northern Gateway. Both are the subject of intense debate.

At the second level, (Tier 2), are a number of projects which would modify existing pipelines. Compared to major new lines, these are larger in number, generally somewhat smaller in scale and capital cost, potentially are easier with respect to permitting and have shorter timescale.

At the third level, (Tier 3), options to expand transport via rail, barge and tanker have potentially the lowest scale/capacity – per individual unit of movement - and the highest per barrel transport costs but the lowest capital costs, easiest permitting, shortest times to implementation and highest number of options.

A key parameter in our update involved assessing whether the Tier 2 and Tier 3 options could deliver the same scale of transport capacity in aggregate as would the Tier 1 projects. This is particularly critical with respect to the rail, barge and tanker modes as these would be the only ones capable of expansion in a "Total No Expansion" situation.

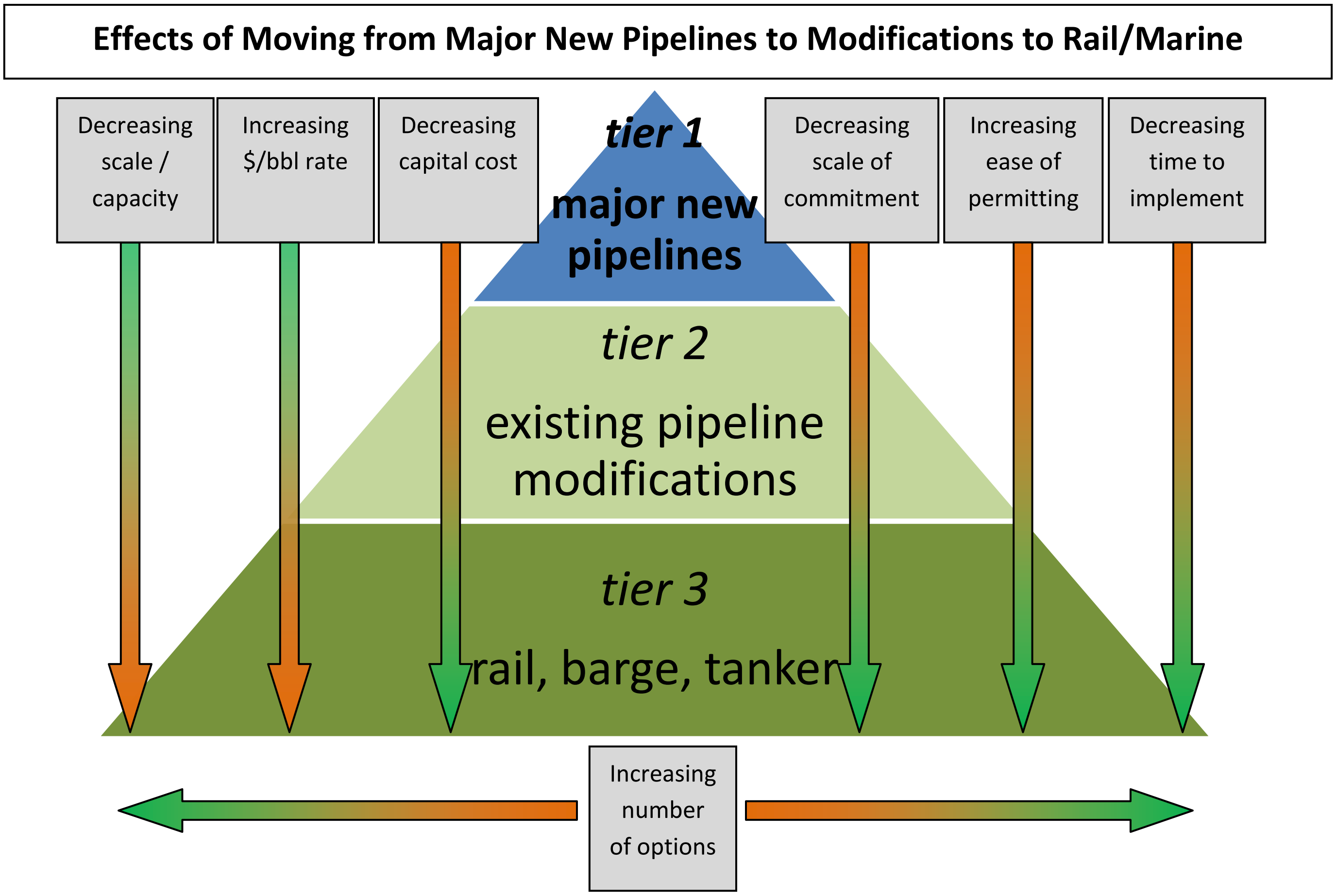

Exhibit 1-1

1.4 Updated Assessment of Alternatives

The June 2011 "Growth" projection by the Canadian Association of Petroleum Producers (CAPP) has higher levels of future WCSB supply than those EnSys used for our 2010 Keystone XL Assessment which were based on the CAPP 2010 Growth outlook[1]. Applying this new production projection to the Total No Expansion scenario evaluated in our 2010 analysis, while maintaining all other underlying assumptions unchanged, would mean present available pipeline capacity out of WCSB would be fully utilized before rather than after 2020 and that, by 2030, the level of WCSB production shut-in would be around 1.4 mbd as opposed to the 0.75 mbd previously estimated[2]. Under the Partial No Expansion

[1] Compared to the CAPP 2010 Growth Outlook used by EnSys for Keystone XL Assessment, the CAPP 2011 Growth Outlook has WCSB supply to markets 0.085 mbd higher by 2015, 0.46 mbd by 2020, 0.57 mbd by 2025 and an estimated 0.65 – 0.7 mbd higher by 2030.

[2] EnSys' 2010 Keystone XL Assessment evaluated various pipeline scenarios and two U.S. demand growth scenarios against a single outlook for WCSB supply, that of the 2010 CAPP Growth outlook.

scenario with the 2011 CAPP production projection, WCSB production would be affected before rather than after 2025 and production shut-in by 2030 would be around 0.9 mbd versus the 0.25 mbd in our original analysis. Growth in U.S. domestic production in the Bakken could add to the competition for space on the existing cross-border pipelines. To the extent it did, it would increase potential WCSB shut-in beyond the levels stated above.

Against this, Exhibit 1-2 summarizes the potential options we now believe exist for alternative transport and processing developments under both Total and Partial No Expansion scenarios. Broadly, under a Total No Expansion scenario, we see rail supported by barge, tanker and direct upgrading to product as able to deliver sufficient capacity to avert any WCSB shut-in through – and potentially beyond - 2030.

Projects recently fully approved will upgrade 0.15 mbd of mainly Alberta Royalty-in-Kind bitumen directly to finished products. This capacity was not in our past analysis and cuts the 2030 potential shut-in from 1.4 to 1.25 mbd.

Rail is seen as having the ability to provide the remaining 1.25 mbd capacity, potentially significantly more if needed. To generate 1.25 mbd of additional capacity to move WCSB crudes by rail by 2030 would entail adding around 100,000 b/d of capacity each year over a 10 to 15 year period. This rate of capacity addition is well below the 250,000 b/d per year expansion being achieved today in the Bakken and equates to adding only 1-2 unit trains per day out of WCSB each year from around 2016 to 2030. Our assessment is this level of expansion lies well within the capability of the rail system to expand capacity over time. Options include expansion to ports on the BC coast, several border crossings into the USA, whence delivery can be achieved to the Gulf Coast and other regions within the U.S.; also rail to Eastern Canada. These sets of routes would use existing rail lines, and as such require essentially no permitting. WCSB crude oils, including DilBit and raw bitumen, have been shipped for some time via rail. Movements are already occurring on the routes to several destinations in the USA and to Eastern Canada.

Barge can play an important supporting role to deliver WCSB – and domestic crudes – from PADD2 to PADD3. Barge can act in concert with cross-border pipelines, lifting WCSB and other crudes from pipeline termini in PADD2 then taking the crudes down to PADD3. Barge can thus provide a means to bypass PADD2 to PADD3 pipeline bottlenecks, allowing WCSB and Lower 48 crudes to flow to the Gulf Coast in volume and enabling existing cross-border pipeline capacity to be fully utilized. Barge movements between PADD2 and PADD3 have increased rapidly since late 2010 to a level of 50,000 b/d by mid 2011. Our assessment is that this level of activity can be increased at least tenfold, with little difficulty in adding the necessary barge, towboat and dock/transfer capacity.

Tanker could provide the means to take WCSB crudes via the Great Lakes to refineries in the U.S., Eastern Canada and, beyond, to international markets in the Atlantic Basin. This would entail either extending pipelines within Canada to the Great Lakes and/or adding rail shipments. Given those extensions, there is no significant constraint on the volumes of WCSB crudes that could be moved by tanker across the Great Lakes (a region that comprises some 2 million b/d of combined U.S. and Canadian refining capacity). In addition, crude oil delivered to the Chicago area could be taken onward by barge to refineries on the U.S. Gulf Coast. Another route that would bypass pipeline constraints would entail using rail to the BC coast plus tanker to move WCSB crudes to the U.S. Gulf and West Coasts as well as to other markets in the Pacific Basin.

Should rising domestic production from the Bakken and other shale plays increase the utilization of pipelines and cut surplus capacity below that estimated here, we believe there is scope across rail and marine options to provide alternatives that, *inter alia,* could reach and exceed the scale of the Keystone XL pipeline such that neither WCSB nor domestic U.S. production would be shut in, other than possibly for short periods as is happening today. All told, our assessment is that rail, barge and tanker combined could, over time, add at least 2 million b/d of capacity to support WCSB crude oil exports under a "Total No Expansion" scenario. Optimistic assumptions lead to a level appreciably higher.

A Partial No Expansion situation (i.e. one where there were no wholly new pipelines) would bring in to play the potential to augment existing pipelines via either direct expansion, reversal and/or use of existing rights-of-way/pipeline corridors to lay down new physical line. Here, there are a number of known projects that can add significantly to capacity, both to the BC coast, cross-border and from PADD2 to PADD3. If all projects in this category were to go ahead, the total capacity added would be of the order of 2 million b/d. In addition, there is potential to expand or reverse existing lines where no project has been announced.

Potential for Main Alternative Transport Developments under No Expansion Scenarios

Mode	Potential		
	Total No Expansion	**Partial No Expansion**	Notes
Existing Pipelines			
To BC coast	Already at maximum	Expandable	1
Cross-border	Available spare capacity only	Expandable	2, 3
PADD2 to PADD3	Already at maximum	Expandable	4
Rail			
To BC coast	Yes	Yes	
Cross-border	Yes	Yes	
PADD2 to PADD3	Yes	Yes	
Internally to Eastern Canada & Great Lakes	Yes	Yes	
Barge/Tanker			
To BC coast	n.a.	n.a.	
Cross-border western U.S.	n.a.	n.a.	
PADD2 to PADD3	Yes	Yes	
Great Lakes to Eastern Canada	Yes	Yes	
Great Lakes to U.S. refineries on the Lakes	Yes	Yes	
Great Lakes to U.S. Gulf Coast refineries via onward barge	Yes	Yes	
Upgrading	Yes	Yes	5

Notes:

1. Trans Mountain excluding Northern Leg.
2. Existing spare capacity cross-border.
3. Alberta Clipper expansion of 0.35 mbd, possible expansions on other lines.
4. Including Double E, Magellan Longhorn reversal, Enbridge Monarch. Expansions/reversals possible on other lines.
5. Upgrading of at least 0.15 mbd per North West Redwater Partnership.

Exhibit 1-2

1.5 Core Conclusion and Specific Findings

Our core conclusion from this review is that, while it may be possible to cause one or two major new pipeline projects (Tier 1) to be halted, it is difficult to conceive how a No Expansion scenario could be sustained by preventing all of the increasing number of options as one moves from new to existing pipelines (Tier 2) and on to rail/barge/tanker options (Tier 3). We maintain this conclusion recognizing that the higher 2011 CAPP projection for WCSB supply would likely lead to all currently existing cross-border pipeline capacity being fully utilized before rather than after 2020.

Specific findings and conclusions include the following.

Potential from Existing Pipelines

1. Significant activity exists in both proposals for new pipelines and also for expansions to and reversals of existing pipelines. The proposals relating to existing lines add up to substantial potential for additional capacity. If all the announced projects were built, they would add approximately 2 million b/d of new capacity that could be utilized under a Partial No Expansion scenario. This could include 0.4 million b/d to the BC Coast, at least 0.35 million b/d cross-border, close to 1 million b/d from PADD2 to PADD3, also over 0.2 million b/d from PADD2 to Eastern Canada.

2. While new cross-border pipeline capacity, such as for Keystone Mainline and Keystone XL, requires high level permits and can be subject to extended delays, proposals for modifications to existing pipelines, whether cross-border or domestic, tend to not meet such difficulties. Many of the current pipeline projects entail existing lines and/or rights-of-way.

3. In addition to announced projects for pipeline modifications, there is potential for additional expansions and reversals that may be implemented in any event over time and which could be brought to bear in a No Expansion situation. While indeterminate, a combination of expansions and reversals could add several hundred thousand barrels per day of PADD2 to PADD3 capacity. Appreciable cross-border expansion may also be achievable.

Potential from Rail

4. There is significant activity in new capacity for rail shipment. Actual projects being put in place mainly relate to U.S. Bakken and other domestic crude movements but activity to transport WCSB crudes by rail is also growing. Rail developments are occurring at the aggregate level of hundreds of thousands of barrels per day, i.e. at substantial, not minor,

scale. By the end of 2012, projected rail takeaway capacity from the Bakken is expected to exceed 700,000 b/d. To accommodate this, receiving terminals are being built in Oklahoma, Louisiana, Texas, California and elsewhere. These developments, adding substantial rail capacity in a short period of time, indicate what could be done for WCSB crude oil exports in a "No Expansion" situation. At the same time, interest in shipping WCSB crudes by rail is growing. Canadian rail companies are already moving WCSB crude oil by rail to the Gulf and West Coasts and to Ontario.

5. While moving light crudes via rail is more straightforward, the technology for moving oil sands bitumen is available. Options include dilution (as in DilBit) but also heating with no dilution. Industry experience in moving heavy crudes ranges from years of shipping oil sands bitumen in relatively small volumes within Canada and to U.S. refineries, (including recent tests), to shipping asphalt via rail, to foreign experience of moving large volumes of heavy crudes via rail. Shipping using heating requires insulated rail cars but obviates the need to blend in and ship diluent, cutting net costs per barrel of bitumen moved relative to those for shipping DilBit via pipeline (or rail).

6. Comparison of rail and pipeline economics cannot be based solely on "per barrel" tariffs. To move conventional crudes, rail has typically cost up to 50% more "per barrel" than movement by pipeline. However, several additional factors are tending to weigh in favor of rail, supporting today's growing interest in use of this mode to transport Bakken, WCSB and other crudes. Firstly, increases in rail movements can generally use existing mainline tracks. "Unit train" technology is improving rail economics. The investment to establish one loading and one discharge terminal is a fraction of that for a major pipeline. Projects have shorter lead times (12 – 18 months) and do not appear to incur the permitting difficulties associated with those for pipelines. Thus rail projects can be easier to implement and are more "scalable". A typical modern "unit-train" terminal will have an initial capacity of one unit train per day, equivalent to around 65,000-80,000 b/d, and may be expandable to two up to even ten unit trains per day. Rail also offers faster transit times to market (claims are for 8-10 days from Alberta to the Gulf Coast versus 40-50 via pipeline). Required contract commitment periods are shorter, often 1-5 years versus 10+ years for pipeline, and rail offers more flexibility in determining destinations based on market conditions.

7. Costs for shipping via rail are closer to those for pipeline if the product shipped does not include diluent or the diluent can be recycled. Although the costs per barrel of shipping conventional light crude oil long distance via rail versus via pipeline are estimated to be up to 50% higher than those for pipeline, the added cost of shipping heavy, higher viscosity crudes by pipeline, including DilBit, narrows the gap. In addition, use of rail could (a) enable undiluted bitumen to be moved or (b) enable separated diluent to be backhauled to Western Canada and recycled, again reducing costs. On a straight barrel for barrel basis, using rail rather than pipeline to ship DilBit from Western Canada to the U.S. Gulf Coast

could increase costs from around \$7/bbl via pipeline to around \$10/bbl via rail, but approximately \$2-\$4/bbl[3] could be saved moving undiluted bitumen versus moving DilBit. Thus, per net barrel of bitumen moved, costs for shipping via rail are closer to those for pipeline. Adding any back-haul of diluent makes rail more economic than pipeline. Rail's incremental costs, which may be nil when shipping bitumen, do not appear to be high enough to deter widespread use of rail in any "No Expansion" situation.

8. The U.S. and Canadian rail systems are currently operating well below pre-recession peak levels. Consequently, spare capacity exists today to expand rail movements of crude oil both to the BC coast and elsewhere within Western Canada. Critically, there is also capacity available cross-border from Canada into the USA and to multiple destinations inside the U.S., ranging from California to the Gulf Coast.

9. Capacity, in terms of ability to run additional crude oil trains, could tighten over time as economic growth leads to increased total rail traffic. However, in both the USA and Canada, rail shipments of crude oil comprise a very small proportion (2% or less) of total rail freight. This suggests that gradual increases over time, such as would be anticipated in a "No Expansion" situation, could be handled - and would be achieved using existing track. (All 700,000+ b/d planned Bakken rail takeaway capacity will use existing mainline tracks.) Capacity to construct rail cars is a second critical factor. Production and apparently capacity in North America was cut because of the recession but there are indications of additions to manufacturing capacity in 2011. Thus, while rail car manufacturing capacity could act as a constraint in the event of a sudden surge in demand, we would not expect this to be the case to meet the gradual increase in rail traffic we would anticipate under any "No Expansion" scenario. Also, the U.S. and Canadian rail sectors have a history of expanding to meet clearly defined demand increases.

10. While we have not been able to conduct a full appraisal of rail capacity, on the basis that capacity to deal with a "No Expansion" situation could be built up progressively (in line with growing WCSB crude production)[4], rather than precipitately, EnSys estimates the rail systems of Canada and the USA could add the necessary rail cars and terminals. EnSys estimates the ability could be developed over time to move substantial volumes via rail to BC ports, cross border from WCSB into the USA and within the USA, also out to Eastern Canada, using existing main lines. To deliver around 1.25 mbd of additional WCSB export capacity by 2030, the level estimated as needed under an update of our Total No Expansion case, would entail capacity addition well within the bounds of the rail industry's potential. It would equate to adding around 100,000 b/d per year, equal to 1-2 unit trains per day,

[3] DilBit typically includes 25 -30% diluent. Removing this would thus save around \$2.50 - \$4.50 /bbl versus shipping DilBit. However, some cost for heating has to be allowed for, hence the estimated net saving versus DilBit of around \$2-\$4/bbl.

[4] Existing excess cross-border pipeline capacity together with growing ability to move crude by barge from PADD2 to PADD3 provides somewhat of a buffer and lead time. Rail expansion would not need to start until after 2015.

each year over a period of 10-15 years starting around 2016. This compares to over 250,000 b/d being added now per year for Bakken takeaway.

11. For shipment of WCSB crudes, including DilBit, via rail, we understand no additional or special rail car or terminal equipment would be needed. Cars and terminals would be inter-operable between conventional crudes and DilBit. To ship raw bitumen, insulated rail cars with heaters would be needed; also steam or other heating at off-loading terminals. The technology for this, though, is essentially identical to that for shipping asphalt by rail, a practice that has been in existence for many years. Canadian rail companies are already shipping raw bitumen as well as DilBit to markets in the USA.

Potential from Barge and Tanker

12. Significant activity is occurring to move both domestic U.S. and WCSB crudes by barge to the Gulf Coast, generally in combination with pipeline. Since 2009, movements from PADD2 to PADD3 via tanker and barge have increased from 10,000 to 50,000 b/d. The focus is on moving both Lower 48 and WCSB crudes to the Gulf Coast. Costs are estimated at 40 – 100% more than those for pipeline, with the upper end of the range applying where short haul truck is required to link pipeline to barge. Over time, we estimate the scale of barge movements from PADD2 to PADD3 could be increased to at least 0.5 million b/d, potentially higher.

13. Barge has limited potential to move crudes cross-border but, within the U.S., has the ability to move substantial volumes of crude oil. In any "No Expansion" situation, barge could thus play a valuable role (as now) in bypassing and alleviating pipeline constraints to move both WCSB and domestic crudes within the USA to market.

14. In a "No Expansion" situation, waterborne movements could also be developed across the Great Lakes to access refineries in the USA, Eastern Canada and internationally via onward tanker shipment.

15. Shipping DilBit via barge or tanker requires no special facilities. Shipping raw oil sands bitumen can be undertaken by undertaking limited modifications. Both barges and tankers would need to be fitted with thermal oil heating systems that can maintain the higher temperatures needed to keep raw bitumen liquid. Tank insulation would also generally be undertaken depending on the assessed heat savings. Suitably outfitted barges and tankers would thus be able to ship oil neat sands bitumen and eliminate the diluent that comprises 25-30% of DilBit. As with rail, the saving in avoided diluent shipping (and back-haul) costs would more than offset the additional equipment and heat costs on a per barrel of bitumen basis.

Economics

16. As discussed above, while the per barrel tariff costs of moving conventional light crude oil by rail or barge are generally higher than those for shipping via pipeline, cost differentials narrow or can even reverse when shipping oil sands. Consequently, we do not see cost deterring rail, barge and tanker expansion in any form of "No Expansion" situation. Indeed, the rapid developments occurring in both rail and barge in today's constrained U.S. domestic market are evidence that such movements are attractive when there is inadequate pipeline capacity to meet market demand for transport. We are, in effect, living in a "No Expansion" situation right now, and it is telling us how the industry can react. Moreover, under any "No Expansion" scenario, (a) the opportunity cost economics of averting production shuts-ins would make the higher costs of rail and barge more acceptable and (b) tariffs on pipelines would almost inevitably rise, narrowing the gap between pipeline and alternative modes.

17. Under "No Expansion" there would substantial incentives to WCSB producers to relieve logistics constraints. Today's Cushing constraints are creating imbalances in the market, as evidenced by discounts versus normal conditions which, for WCSB heavy grades, are around $10/bbl. In 2005-2008, when inadequate export capacity was leading to marginal shut-ins, discounts were in the $10 - $20/bbl range. These discounts apply to the total volume of WCSB heavy crudes. Based on our updated assessment of our 2010 Total No Expansion scenario, which assumed no rail or barge or tanker options were available in addition to assuming no further pipeline development, WCSB shut-in volumes are projected at around 1.4 mbd in 2030 out of around 4 mbd total WCSB heavy crude supply[5]. Thus, versus an average price of say $100/bbl in normal market conditions, this situation would cost WCSB producers 1.4 * $100/bbl in lost production revenue + 2.6 * (say) $15/bbl discount on the crudes still being produced, a total of around $179 million per day, $65 billion per year. The cost to avoid those discounts would be that of transporting to market the 1.4 mbd for which no further pipeline capacity would be available. Our estimates are that 1.4 mbd of WCSB crude oil could be moved to market by rail or barge or tanker at a (present day) average cost of around $10/bbl for transport. So in the absence of additional pipeline capacity, incurring $14 million per day in incremental transport costs using other modes would avert $179 million per day of lost revenues in 2030. Even if transport costs for rail, barge and tanker were appreciably higher, there would still be an overriding incentive to use those modes to avoid production shut-in.

Potential from Upgrading Directly to Product

[5] This figure is the sum of 3.09 million b/d of heavy WCSB oil sands grades plus 0.09 million b/d of heavy WCSB conventional grades, as projected for 2030 in our 2010 Keystone XL Assessment, plus an estimated 0.65 – 0.7 million b/d of incremental heavy WCSB oil sands supply in 2030 to reflect the higher WCSB supply projected in the CAPP June 2011 Growth outlook.

18. In addition to transport options, WCSB producers have the ability to upgrade oil sands bitumen all the way to finished products within Alberta and to export product in place of bitumen. The first in a series of such upgraders has just received final approvals and is moving into the construction phase. The three upgrading refineries that will be built in phases will process 150,000 b/d of bitumen which otherwise would have been exported. Any "No Expansion" scenario could increase the incentives for expanding such capacity[6]. To the extent this happens, and leads to export of product not bitumen to the USA, it will shift refinery/upgrading processing, investment, jobs and "value-added" from the USA to Canada.

Permitting

19. Expanding movements by rail on existing track, or expanding barge movements on inland waterways, requires essentially no permits for the movements themselves, only for the vessels and other equipment to be in compliance with regulations. Critically, this applies to cross-border as well as domestic movements. (Installing new rail track cross-border would require permitting by the Department of State but, as indicated above, we estimate significant potential exists for expanding cross-border oil movements using existing track before reaching such a point.)
20. Similarly, obtaining permits to expand or reverse existing pipelines (including cross-border), or to install new line on existing right of way, is generally easier than obtaining permits for wholly new pipelines.
21. In short, permitting difficulties are unlikely to (be a means to) significantly constrain either modifications to existing pipelines or expansions to rail and barge traffic.

Bottom Line

Taken together, these (a) comprise potentially numerous development options, not just a few, (b) many of them require only limited investment and/or permitting and (c) they can be achieved at high volume, potentially well above the 1.4 million b/d or so of total capacity that could be required by 2030 under a No Expansion scenario. Again, while it is possible to conceive of a situation wherein one or two large scale developments are prevented, it is correspondingly almost impossible for us to conceive of a situation where a wide range of pipeline expansions/reversals and projects along existing rights-of-way, rail and barge terminal developments and movements in the U.S./Canadian crude oil supply system are

[6] The products from the upgraders, primarily diesel, will likely still have to be exported and suitable means developed. However, this will reduce the barrels of oil sands exported.

all prevented from occurring. The body of this Report reviews in detail the potential for such developments, including upgrading directly to products, that leads us to this conclusion.

This view, that it is essentially not feasible to constrain the U.S./Canadian logistics system from taking oil sands to markets, other than possibly for short periods as is happening now, is entirely consistent with the perspective we expressed in our original Keystone XL Assessment, except that this update corroborates that view with a much greater level of detail and a more complete range of options that could be employed in the event of a “No Expansion” situation.

2 Background

2.1 Keystone XL Assessment Report

2.1.1 Scenarios Examined

In our 2010 Keystone XL Assessment for the Department of Energy, EnSys developed and analyzed a series of scenarios using our WORLD model to explore the potential impact of KXL being built, of No KXL (not built) and of No Expansion in pipeline capacity. Variants were applied for each of these pipeline availability scenarios at the time of the report. These scenarios are represented in Exhibit 2-1.

Base Scenario		**Variant**
KXL (is built)	KXL	Trans Mountain TMX 2 and 3 expansion go ahead; U.S. domestic PADD2 to U.S. Gulf Coast expansion allowed
	KXL+Gateway	TMX2 and 3 and Northern Gateway go ahead; U.S. domestic PADD2 to U.S. Gulf Coast expansion allowed
	KXL no TMX	No TMX 2 and 3 or Northern Gateway i.e. no expansion to west coast of Canada; U.S. domestic PADD2 to U.S. Gulf Coast expansion allowed
No KXL (no built)	No KXL	Trans Mountain TMX2 and 3 expansion go ahead; U.S. domestic PADD2 to U.S. Gulf Coast expansion allowed
	No KXL HiAsia	High level of expansion to Asia: TMX2, 3, Northern Gateway, Northern Leg; U.S. domestic PADD2 to U.S. Gulf Coast expansion allowed
No Expansion	***Total***	**No Expansion of pipelines at all beyond current projects under construction**
	Partial	**No expansion except TMX 2,3 and U.S. domestic PADD2 to U.S. Gulf Coast**

Exhibit 2-1

In this update we focus on the No Expansion scenario and its two variants:

***Total* No Expansion scenario assumptions**

- No pipeline expansion at all allowed beyond lines that are in operation as of 2010. Thus Alberta Clipper, Keystone Mainline and Keystone Extension to Cushing are allowed but otherwise there are no further expansions:
  - No KXL
  - No PADD2 to PADD3 line expansions
  - No TMX 2,3 or other lines WCSB to BC
  - However, full utilization of existing pipelines was allowed.

***Partial* No Expansion scenario assumptions**

  - Same input assumptions as Total No Expansion case except that expansions to pipeline capacity along two existing routes were allowed, Trans Mountain TMX 2 and 3 and domestic U.S. line expansions from PADD2 to PADD3.

2.1.2 No Expansion Conclusion

With respect to the Total No Expansion Scenario, we concluded in our Keystone XL Assessment Report as follows:

"Production levels of oil sands crudes would not be affected by whether or not KXL was built. WCSB production would only be impacted (relative to the CAPP 2010 projection used in the study) if there were no further pipeline expansion out of WCSB and within the USA beyond projects currently under construction. Even then, because of existing available line capacity, oil sands production would not begin to be curtailed until after 2020. Versus the base projections, WCSB production would be curtailed by approximately 0.8 mbd by 2030. Since, to occur, such a scenario would have to entail no expansion of (a) pipelines entirely within Canada that could take WCSB crudes from Alberta to the British Columbia coast, (b) existing cross-border lines from WCSB to the U.S., (c) existing internal domestic U.S. pipelines that could take WCSB crudes to market within the U.S. - and to eastern Canada and (d) alternative proven transport modes, namely rail possibly supported by barge, the scenario is considered unlikely."

This update re-examines our prior conclusion that the probability of a No Expansion scenario materializing and being sustained would be low. In the body of this report, we update our view on the different classes of transport development (and also upgrading), all of which would have to not come about for a No Expansion scenario to occur. All the scenarios considered in our previous study focused on pipeline developments and implicitly assumed little or no expansion of WCSB crude oil movements by non-pipeline transport modes within Canada and the USA. In the update below, we examine all modes that could play a role, thus pipeline and tanker as before, but also, in detail, rail and barge.

2.2 Developments since Initial Report

Since EnSys' DOE analysis was completed, "Cushing/Canadian congestion" has become structural in that discounted prices for WTI and other inland Lower 48 crudes versus coastal and international grades (LLS, Brent etc.) have become persistent. Similarly, discounts for heavy WCSB grades versus international markets such as Mayan have become sustained. The question of exporting WCSB crudes to market, and how that could react and evolve under any "No Expansion" scenario, is therefore part of a larger issue as both WCSB and Lower 48 crude streams would be impacted. In many instances, transport developments affect and are closely inter-twined with both sources of crude. For example, increasing Bakken takeaway capacity via rail potentially reduces the need to move Bakken crude into existing pipelines which therefore would have additional space to move WCSB crudes. Expansion of pipeline and/or non-pipeline modes to take more crude to the Gulf Coast would impact the prices of both WCSB and Lower 48 crude oils. This report therefore considers developments relating to both sources of crude.

Equally important, the period of congestion that is occurring today is providing insights into how the industry reacts to a "pipeline constrained" situation. As discussed in detail in the body of the report, the industry's reaction is is to take vigorous action, a series of project developments ranging from (mainly) existing pipelines to rail to barge, all of which will act to increase flows to markets with higher prices (including notably the Gulf Coast) in the face of pipeline constraints and delays.

While our 2010 analysis incorporated most of the now-known pipeline projects, our modeling premises were set mainly in the third quarter of 2010, too early to capture the upsurges in rail and barge activity that are now occurring largely because of the sustained "Cushing/Canadian" congestion that set in early this year. Consequently, the 2010 analysis focused predominantly on pipeline potential. This update takes account of transport developments and potential, both including and outside of pipeline modes.

2.3 Focus of Update

To develop this update, EnSys undertook extensive online and literature research. To further cross-check the status and potential for the transport and processing options considered, we contacted and obtained feedback from the following organizations: Enbridge, Kinder Morgan, TransCanada, LOOP, Shell (as operator for Capline), Enterprise Products Partners, Magellan, BNSF, CN Rail, EDOG Rail LLc, NuStar Energy L.P., Rangeland LLc, Cambridge Systematics, North Dakota Pipeline Authority, Government of Alberta Director for International Logistics; also, in the marine sector: Kirby Corporation, Ingram Barge Company, Southern Towing Company, SCF Marine, Army Corps of Engineers, Marathon Oil Company, Petro Source Terminals, Port of Catoosa, OK, American Commercial Lines, Canal Barge, Bollinger Shipyards, Inc.

While we have attempted to present a fully updated and expanded assessment of existing WCSB crude oil transport and related options, it is clear the situation is dynamic. There have been important developments, for instance on new pipeline and rail announcements, since the bulk of our prior analysis was completed in the fourth quarter of 2010. Equally, it is clear the situation is going to continue to change and develop at a quite rapid pace. This update represents a best estimate of the current situation and outlook as of early third quarter 2011.

2.4 Update Exclusions

EnSys is fully aware of the debate surrounding oil sands production and transport regarding environmental, jobs and economic impacts. A "No Expansion" scenario would lead to shifts between transport modes and could therefore have significant effects across all three categories. We have not, however, attempted in this report to assess the relative environmental and safety records of the different transport modes covered or the GHG emissions, macroeconomic or jobs implications of potential shifts from one mode to others. Our focus has been on the potential routing, volume /capacity, microeconomics and permitting aspects of the modes considered. Further, although we have reviewed and commented on the comparative economics for moving crude oils by different transport modes, we have not made an assessment of potential impacts on total shipping costs, delivered costs of crude oil or investments in different transport sectors under a "No Expansion" scenario.

3 Transport Developments that Would Need to Not Occur for "No Expansion" Conditions to Exist

As discussed above, several classes of projects that could transport WCSB crudes would all need to not occur for a No Expansion scenario to occur. The 2010 EnSys Keystone XL Assessment Report laid out detail on projects relevant to transporting WCSB, and also Bakken, crudes. As discussed in Section 2.2, the focus was on pipeline developments; rail and barge were not included aside from then known expansions in Bakken rail takeaway capacity. (See Exhibit 7-4 in the Appendix to this report showing Bakken takeaway capacity assessed in our 2010 analysis.)

Set out below is our updated review of each class of project, this time covering rail and barge in detail as well as pipeline. While rail and barge movements are usually not economically competitive relative to pipeline, in a scenario in which pipeline expansions were constrained, they would become more attractive on an "opportunity cost" basis and so are highly relevant to whether a No Expansion scenario is plausible. Also relevant is the degree of permitting that would have to be obtained for a project to proceed. As a cross-border pipeline, Keystone XL, like Keystone Mainline, Alberta Clipper and others before it, requires approval at the level of both the Canadian National Energy Board and the U.S. Department of State. Compared to major new cross-border pipelines, the permitting scope and difficulty tends to be less for projects that are domestic, smaller, based on modes other than pipeline, and – especially – involve modifying existing facilities and/or using existing rights of way.

The Total No Expansion scenario would by definition prohibit all construction of pipelines that could support WCSB crude oil transport and export, both within the U.S.A. and Canada and cross-border, including Keystone XL. Exhibit 3-1 below comprises an update of a similar table (Table 3-3) contained in EnSys' 2010 Keystone XL Assessment for the U.S. DOE summarizing proposed projects which would support exports of WCSB crude oils. Exhibit 3-1 distinguishes between projects that would entail new pipelines (Tier 1) and those which would modify existing lines (Tier 2). The following commentary provides an update and review of the status of each current project.

In addition to the announced projects set out in Exhibit 3-1, the sub-sections below also describe the potential that could exist for potential additional pipeline modifications, i.e. for developments that are not formal projects but which, based on either industry information or EnSys judgment and experience, might occur.

Of the projects listed in Exhibit 3-1, nearly all would be designed to carry WCSB crudes, including DilBit. Projects definitely is this category would be the Enbridge and Kinder Morgan projects to the BC coast, Keystone XL, the expansion of Alberta Clipper, any expansion to Keystone Mainline, Enbridge Monarch / "full pass solution", possibly Double E, Keystone East and possibly Line 9 reversal. Magellan Longhorn reversal is the one listed project that would be specifically designed to carry light crudes since it would take Permian Basin production to the Gulf Coast.

Summary of Proposed Pipeline Projects Supporting WCSB Exports

Pipeline Project	Origin	Destination	Project Type	Current / Initial Capacity bpd	Expansion Possible to	Completion as Listed by Operator	Status
"Tier 1" New Pipelines							
WCSB West to BC Coast							
Enbridge Northern Gateway (1)	Edmonton	Kitimat BC	New	525,000	800,000	2016/17	Proposal submitted to NEB Joint Review Panel May, 2010 - In Review
WCSB Cross Border to US PADD-3							
Transcanada Keystone XL	Hardisty AB	Port Arthur / Houston TX	New	700,000	830,000	Q1-2013	NEB Approved March 2010 -Pending Presidential Permit
Domestic Pipelines PADD-2 to PADD-3							
None announced for wholly new lines							
"Tier 2" Existing Pipelines / Rights of Way							
WCSB West to BC Coast							
Kinder Morgan Transmountain TMX2	Edmonton	Vancouver BC	Expansion	300,000	380,000	2015/16	Decision depends on outcome on open season to be held 3/4Q 2011
Kinder Morgan Transmountain TMX3 (less power)	Edmonton	Vancouver BC	Expansion	380,000	540,000	2016/18	" "
Kinder Morgan Transmountain TMX3 (full power)	Edmonton	Vancouver BC	Expansion	540,000	700,000	2016/18	" "
Kinder Morgan Northern Leg	Edmonton	Kitimat BC	Expansion/ New	400,000	n.a.		On hold, longer term proposal
WCSB Cross Border to US PADD-3							
Enbridge "full pass solution"							See Monarch project
WCSB Cross Border to US PADD-2							
Enbridge Alberta Clipper	Hardisty	Clearbrook MN	Expansion	450,000	800,000	n.a.	Will depend on market conditions
Transcanada Keystone Mainline	Hardisty	Wood River / Patoka IL		590,000		Jul 2010	Operational
Domestic Pipelines PADD-2 to PADD-3							
Magellan Longhorn Reversal	El Paso, West Texas	Houston TX	Reversal	135,000	225,000	Q4-2012	Pending results of open season
Enterprise Products Partners / Energy Transfer Partners Double E	Cushing OK	Houston TX	Existing right of way / line	450,000	n.a.	Q4-2012	Pending results of open season
Enbridge Monarch Cushing to Gulf (2)	Cushing OK	Houston TX	New line using existing right of way	370,000	480,000	Q4-2012	Proposed mid 2010
"Tier 2" Existing Pipelines / Additional PADD2 Onward Extensions							
PADD-2 to Eastern Canada							
Line 9 Reversal Phase I	Sarnia, Ontario	Westover, Ontario	Reversal	50,000	-	Q2-2012	Under consideration
Line 9 Reversal Phase II	Sarnia, Ontario	Montreal, Quebec	Reversal	240,000	-	After 2012	Will depend on market conditions
PADD-2 Internal							
Keystone East	Patoka, IL	Lima & Toledo, OH, possibly Detroit, MI	Extension	300,000	-	2017	Depends on Keystone XL going ahead

Notes

1. Northern Gateway Project also includes a 193,000 bpd pipeline to import condensate (diluent) from Kitimat to Edmonton
2. Listed capacities are for light sweet crude. For 22 API heavy crude, stated capacities are 250,000 bpd initial and 325,000 eventual

Exhibit 3-1

The Tier 2 proposals relating to existing lines add up to substantial potential for additional capacity. If all the announced Tier 2 projects in Exhibit 3-1 were built, they would add approximately 2 million b/d of new capacity that could be utilized under a Partial No Expansion scenario. This could include 0.4 million b/d to the BC Coast, at least 0.35 million b/d cross-border, close to 1 million b/d from PADD2 to PADD3, also over 0.2 million b/d from PADD2 to Eastern Canada.

3.1 "Tier 1" Projects for Major New Pipelines

With the recent completion of the Enbridge Alberta Clipper and the TransCanada Keystone Mainline projects, there remain two projects for wholly new pipelines to export WCSB crudes, namely Enbridge Northern Gateway and TransCanada Keystone XL.

3.1.1 WCSB West To BC Coast

3.1.1.1 Enbridge Northern Gateway

The Enbridge Northern Gateway pipeline would run from Edmonton to the BC port of Kitimat and thence enable export via tanker up to Very Large Crude Carrier (VLCC) size to destinations in Asia and elsewhere[7]. Initial capacity is stated as 525,000 b/d expandable to 800,000 b/d.

Because of widely reported resistance to the project by First Nations and other groups, EnSys took the view in our 2010 Keystone XL Assessment that, if built, Northern Gateway would likely come on stream well after start up dates then being put forward by Enbridge of around 2016/2017.

EnSys' view is that this project continues to face major hurdles which still render its timing uncertain. However, the approval process is moving ahead. Following Enbridge's formal application to the Canadian National Energy Board (NEB) in May 2010, the NEB filed a hearing order in Spring 2011 for which Enbridge completed filing written evidence in July. Oral hearings on Northern Gateway are expected to start early in 2012 and to take potentially one and a half years. Thus, it is possible the NEB may have made a decision on Northern Gateway approximately two years from the time of this report. Should that decision be positive, and should it be accompanied by any and all other approvals and agreements necessary to enable the project to proceed, Enbridge estimates pipeline start-up could be around 2017.

[7] A VLCC crude oil tanker, typically has a capacity of around 250,000 deadweight tons, equivalent to around 1.5 million barrels.

It is also evident that there are active efforts at the government level in Canada to move Northern Gateway forward as a means to access Asian markets, which are seen by the government as vital to Canada's ability to exploit its oil and gas resources[8]. In addition, the Chinese government and national oil companies, while continuing to invest heavily in Canadian oil sands and Northern Gateway financing[9], are reported as being in active discussions with Canadian officials and keen to offer both financial and technical assistance. It appears that the desire to diversify market options by getting WCSB crudes to the Pacific Coast in order to access growing Asian markets is leading to a greater emphasis in Canada on the projects that would take WCSB streams west. Non-approval of Keystone XL would, in our view, reinforce this movement, further galvanizing Canadian government authorities, shippers and producers to deal with the challenges of building Northern Gateway, and for that matter Trans Mountain TMX expansions and Northern Leg.

3.1.2 WCSB Cross-Border to U.S. Gulf Coast (PADD3)

3.1.2.1 Keystone XL

The most significant permit required for the Keystone XL pipeline is that from the Department of State which would authorize the line's border crossing from Canada into the U.S.A. Keystone XL, however, comprises two physical construction projects. As illustrated in Exhibit 7-3, a northern segment would be built from Hardisty to Steele City, Nebraska. Here it would tie in to the just completed segment from Steele City to Cushing. The second construction project would entail building a new line from Cushing to the Gulf Coast. Both northern and southern construction projects are described by TransCanada as "shovel ready". Initial stated capacity for Keystone XL is 700,000 b/d. Potential eventual capacity of 900,000 b/d has now been revised down by TransCanada to 830,000 b/d.

TransCanada has consistently presented Keystone XL as an integrated project and pipeline from Hardisty, Alberta, to the Gulf Coast. We note though that, should a cross-border permit be denied, TransCanada could consider building only the southern line segment[10]. This would be a domestic line internal to the U.S. As such, it would still require a range of permits, as from the states it would pass through, but it would not require the Department of State permit. The southern segment would provide

[8] There is also an active project to export Canadian natural gas as LNG from Kitimat, BC.

[9] Adding to over $5 billion in prior investments, on July 20th, CNOOC agreed to buy Canadian oil sands producer, Opti Canada Inc. for $2.1 billion.

[10] TransCanada executives told investment analysts in February 2011 that building the southern segment is "obviously something that we would consider" if the permit is denied. They also cautioned though that building solely the southern segment would not be economic (unless pipeline capacity into Cushing from WCSB and elsewhere were sufficient to largely fill the southern segment). http://www.platts.com/weblog/oilblog/2011/02/18/keystone_xl_oil.html

potentially 590,000 - 700,000 b/d of capacity to take crudes from Cushing to the Gulf Coast[11]. As could other potential projects (see below), the line would likely move U.S. domestic Lower 48 crudes and help alleviate the Cushing to Gulf Coast bottleneck. The line would likely also be able to carry WCSB crudes as current and reversible line capacity also exists to move WCSB crudes to Cushing[12] whence they could link in to this southern Keystone XL segment to the Gulf Coast.

3.1.3 Domestic Pipelines PADD2 to PADD3

At present, there are no announced projects for wholly new pipelines that would bring crude from Cushing to the Gulf Coast. The projects that do exist all entail either existing lines or existing rights-of-way and are described in Section 3.2.4.

3.2 "Tier 2" Projects Entailing Existing Pipelines / Rights of Way

Several of the projects reviewed in our 2010 Keystone XL Assessment analysis concerned expansions of existing pipelines and/or use of existing rights-of-way. They included projects entirely within Canada, from Canada to the U.S. cross-border and entirely within the U.S.A., notably from PADD2 to PADD3. Since the time of our Report, further projects have been announced. This update confirms the views expressed in our 2010 Keystone XL Assessment report that (a) under No KXL scenarios, there exists a range of options for alternative pipeline projects that over time would bring into existence broadly comparable capacity and (b) under No Expansion scenarios, there is a series of announced and potential projects that could be undertaken, solely on existing lines and rights-of-way, that could add significant pipeline capacity and that would not have the permitting challenges associated with wholly new pipelines.

[11] The current capacity of the Cushing Extension segment is 590,000 b/d.

[12] The Enbridge Mainline system takes WCSB crudes as far as Chicago and on to Patoka, Illinois (via the 100,000 b/d Mustang pipeline). From Chicago, the 190,000 b/d Spearhead line takes mainly heavy WCSB crudes to Cushing. In addition, one or more of the lines that currently run northeast from Cushing could potentially be reversed to add to the capacity into Cushing. The Enbridge Ozark line, (230,000 b/d), runs from Cushing to Wood River near Patoka Illinois, the BP line (100,000 b/d) runs from Cushing to Chicago; the Chicap, (360,000 b/d), runs from Patoka to Chicago. As an example, the Enbridge Spearhead line used to run south-north. It was reversed by Enbridge in 2006 to run north-south and was subsequently expanded from 125,000 to the current 190,000 b/d.

3.2.1 WCSB West To BC Coast

3.2.1.1 Kinder Morgan Trans Mountain and Northern Leg

As shown in Exhibit 7-1, the Trans Mountain is an existing pipeline that runs from Edmonton to the Vancouver area where one spur feeds a local refinery at Burnaby, a second runs south to refineries in Washington state and a third leads to the Westridge Dock marine terminal in Port Metro Vancouver harbor. Kinder Morgan expanded the Trans Mountain Pipeline in 2008 (the so-called TMX1 expansion) to reach its current capacity of 300,000 b/d.

Kinder Morgan has proposed a change to the service offered via the existing Trans Mountain facilities to allow "firm service" contracts for shipment over the Westridge dock. Shippers have committed to lift 54,000 b/d of WCSB crude from the dock via tanker under ten year contracts. As of August 2011, Kinder Morgan is awaiting approval from the NEB for this application. This initiative is seen as a first step to gauging level of interest for expanding throughput to new markets overseas. A second step planned by Kinder Morgan is a binding open season to be held in late 2011 to gauge the interest and scope for physical expansion of the pipeline and shipment system. As indicated in Exhibit 3-1, TMX expansions can increase Trans Mountain capacity in stages from the current 300,000 b/d to a total capacity of 700,000 b/d to Vancouver.

At the 700,000 b/d capacity level, Kinder Morgan indicates that 250,000 b/d of capacity would be allocated to feeding the local BC and Washington State markets and refineries and that dock capacity would be 450,000 b/d. The expansion in dock use from today's level of around 75,000 b/d would be accompanied by channel dredging to enable the port to take Suezmax (1 million barrel) tankers in place of today's limit of Aframax (650,000 barrel) tankers. According to Kinder Morgan estimates, crude tanker arrivals could rise from the 2010 level of 71 out of 2832 total vessel arrivals (3%) in Port Metro Vancouver to 288 out of 3,500 (8%) in 2016/2017 with a full build out to 700,000 b/d. The 2016/2017 date for the expansion(s) to be in service is based on a 2012 decision followed by pre-permitting and regulatory approvals that are anticipated to take between 2.5 to 3.5 years, plus 1.5 to 3 years for construction, depending on the scale of expansion.

In addition to expanding up to 700,000 b/d to Vancouver, Kinder Morgan has put forward a longer term option of building a spur from part way along the Trans Mountain line northwest to the deep-water port of Kitimat. That expansion would follow the existing Trans Mountain right-of-way to Rearguard, BC and then cut northwest to Kitimat along a route which, we understand, would require new right-of-way.

In summary, several options exist to expand Trans Mountain in stages from the current 300,000 b/d to 700,000 and even on to 1.1 million b/d - and there is evidence of active interest in Trans Mountain expansion[13]. The extent of any future expansion is not certain but the picture should be clearer by the first half of 2012.

3.2.2 WCSB Cross-Border to U.S. Gulf Coast (PADD3)

3.2.2.1 Enbridge "Full Pass Solution"

As discussed below, the Enbridge see their Monarch pipeline project as potentially forming part of a "full pass solution" to take WCSB crudes to the Gulf Coast.

3.2.3 WCSB Cross-Border to U.S. Interior (PADDs 2,4)

3.2.3.1 Enbridge Alberta Clipper

Brought into operation in October 2010, the Enbridge Alberta Clipper[14] effectively extends capacity on the Enbridge Mainline system of pipelines that run from Alberta into PADD2. Current capacity is 450,000 b/d but the pipeline is listed as being expandable by 350,000 b/d to a potential 800,000 b/d. EnSys understands from the Department of State that expansion of Alberta Clipper would likely not require any significant new permits and/or significant changes to its Presidential permit. Enbridge's understanding is that little or no new permitting would be necessary for the expansion to proceed, including in respect to the line's Presidential permit, since expansion would be achieved solely by adding horsepower at existing pumping stations.

3.2.3.1 Possible Additional Pipeline Modifications

In addition to potential Alberta Clipper expansion, there could be possibilities to partially expand other existing cross-border pipelines.

Enbridge Mainline

The Enbridge Mainline comprises a system of pipelines, with total capacity just over 2 million b/d, that bring WCSB crudes cross-border into the USA. Between 2008 and 2010, the system was expanded by

[13] In addition to the Firm Service commitments, the line has reportedly been heavily over-subscribed since late 2010.
[14] Also now known as Enbridge Line 67.

185,000 b/d. According to Enbridge, most of the lines in the system are at or near their maximum capacity, i.e. they may possess some further expansion potential but it is likely to be limited.

Keystone Mainline

The new Keystone Mainline had initial capacity of 435,000 b/d and has already been expanded to 590,000 b/d. EnSys is not aware of any plans by TransCanada to further expand the line. According to TransCanada, expansion of Keystone Mainline is, however, feasible. This could not be achieved solely via adding pumping capacity; it would entail looping the line.

Express-Platte

The Kinder Morgan Express-Platte pipeline system comprises the 280,000 b/d Express line which runs south from Hardisty to Casper, Wyoming, and then feeds into the 140,000 b/d Platte line which runs southeast to Wood River, Illinois. According to the June 2011 CAPP Report, Express does not operate at capacity due to the lower capacity of the Platte line. In addition, WCSB crudes are now increasingly competing with Bakken crudes for space on the Platte. Consequently, in 2010, the Express took in 200,000 b/d of WCSB crude at Hardisty, leaving 80,000 b/d of capacity unused.

Modifications to the Express and/or Platte lines themselves and/or to the types of crude processed at linked refineries or to other facilities providing Bakken takeaway capacity could all act to increase the effective cross-border capability of the Express-Platte system. Recent Kinder Morgan presentations refer to “expansion options to take Platte barrels to Patoka or Cushing”. Based on pipeline tariff information in the CAPP Report, June 2011, Appendix C, the Express-Platte system enjoys an appreciable economic advantage for shipping to Wood River versus Enbridge and Keystone routes. Versus tolls for heavy crude from Hardisty to Wood River on the latter lines of around $5.30/bbl, that for the same routing on Express-Platte is $2.25/bbl[15], indicating economic incentives to expand the Express-Platte system.

As discussed in Section 3.4, a further incentive to expand Express-Platte, and other lines feeding into Wood River, Illinois, is that the Wood River terminal can act as a transfer point for crude oil onto barges which can then go to refineries along the Gulf Coast. Such barge traffic is already expanding as a means to bypass pipeline constraints from PADD2 to PADD3.

Rangeland and Milk/Bow River

The Rangeland and Bow River/Milk River pipelines owned by Plains All American and Inter-Pipeline run from respectively Edmonton and Hardisty cross-border to Cutbank, Montana, where they join the Western Corridor pipeline system to Casper, Wyoming. The 85,000 b/d Rangeland line has the capability to transport light crude oils, condensates and butane. Recent reported throughput was 52,000 b/d. The Bow River line has stated capacity of 129,000 b/d.

[15] 10 year committed toll.

EnSys is not aware of any plans to expand any of the above pipelines. However, there very often is potential for expansion via boosting power at existing pumping stations, adding new pumping stations and/or looping the whole line or sections. In addition and potentially more significant, existing pipelines constitute established pipeline corridors / rights-of-way which frequently can be used to install new parallel lines with permitting that is easier than for a wholly new route and line.

3.2.4 Domestic Pipelines PADD2 to PADD3

3.2.4.1 Enterprise/Energy Transfer Double E

Enterprise Products Partners L.P. and Energy Transfer Partners, L.P. have announced a 50:50 joint venture to build a 450,000 b/d pipeline, named Double E, from Cushing to the Gulf Coast with stated "connectivity to multiple facilities at the points of origin and destination, including access to locations along the Gulf of Mexico that offer marine terminal loading capabilities". Enterprise and Energy Transfer extended a binding open season commitment period to end on July 29th, 2011. The stated in-service date is fourth quarter 2012 subject to sufficient customer commitments and required approvals. The partners state that the 584 mile Double E pipeline would use 230 miles of existing natural gas pipeline owned by Energy Transfer that would be converted to crude oil use and require 354 miles of new construction but which would follow existing pipeline corridors. It is not evident to EnSys whether the Double E line would carry both light and heavy crudes, including DilBit, but we would expect it to be capable of transporting both[16].

3.2.4.2 Magellan Longhorn Reversal

As of June 2011, Magellan Midstream Partners, L.P. was reported as assessing the potential reversal of the eastern leg of its Longhorn pipeline and its conversion from products to crude oil service. The reversed line would carry growing Permian Basin light crude production to Houston. The effect of the reversal would be to relieve supply pressure on Cushing which, otherwise, would continue to receive the Permian Basin barrels. Stated capacity of the reversed line is 135,000 b/d expandable to 225,000 b/d. Magellan has estimated associated capital costs at $275 million to implement 135,000 b/d of capacity and $80 - $150 million additional to expand to 225,000 b/d. The company was reported as proceeding with the US Pipeline and Hazardous Materials Safety Administration and other regulators on permitting

[16] The TransCanada Keystone Mainline carries WCSB crudes including DilBit. The Canadian portion of this line included construction of 232 miles of new pipeline and the conversion of 537 miles of existing Transcanada pipeline from natural gas to crude oil transmission. This suggests the Double E line should also be capable of carrying DilBit.

and an environmental assessment and "expecting to announce contracts sufficient to proceed in the near future".

3.2.4.1 Enbridge Monarch

Enbridge is actively considering a project for a pipeline, Monarch, to take potentially both light U.S. domestic crudes and heavy WCSB crudes from Cushing to Houston. As of the time of this report, Enbridge was at the stage of working with shippers to gauge potential interest. In the event there is sufficient interest, Enbridge plans to undertake a formal open season for commitments this Fall. Line capacity could be anywhere in the range of 200,000 b/d to 500,000 b/d, depending on the outcome of the open season. While the pipeline itself would be new, it would follow and use existing rights-of-way[17].

Monarch would form part of an Enbridge "full pass solution" to bring WCSB crudes from Canada to the Gulf Coast. This "solution" would utilize existing spare capacity in Enbridge's Mainline system to the Chicago area. Then, depending on the level of commitment, Enbridge might need to expand existing line capacity from Chicago to Cushing to tie in to the Monarch line.

3.2.4.2 Possible Additional Pipeline Modifications

In addition to the above announced projects, there has been discussion of other possible pipeline reversals that could at some time be implemented to move crudes south from the Midwest / Midcontinent to the Gulf Coast as distinct from north as they do today. Three possible reversals are outlined below. Given that the U.S. has some 160,000 miles of crude oil pipelines and many large diameter gas lines it is possible more projects could emerge over time that would utilize existing facilities.

Seaway

As stated in our 2010 Keystone XL Assessment Report, the 30" Seaway crude oil pipeline runs north from Freeport, Texas, to Cushing. The line is owned by a 50:50 joint venture of Enterprise Products Partners and ConocoPhillips. It is rated at 350,000 b/d but is currently reported as underutilized. The partners have reportedly examined the feasibility and cost of reversing the line such that it would run from north to south. Recognizing pipeline wall thickness limitations, the north to south capacity could be nearer to 200,000 b/d running heavy crudes, somewhat higher with lighter crude grades. In February 2011, the

[17] According to Enbridge, a project announced in 2008 with BP to add capacity to the Gulf has now been subsumed into the Monarch project.

CEO of ConocoPhillips, (James Mulva), stated it was not in the company's interests to reverse the line[18]. Since then, ConocoPhillips has announced that the company will split into two separate entities, one for upstream (exploration and production), and one for downstream, (refining, marketing and distribution). This pending split has raised speculation that Seaway could be reversed if it becomes an asset of the upstream company - but would likely not be reversed if it goes into the downstream company. According to ConocoPhillips, the situation will become clearer later in 2011, although a recent comment by Mr. Mulva regarding Seaway's fate was that "it's probably downstream"[19].

Capline

The Capline system links in to the LOOP Louisiana Offshore Oil Terminal and carries both imported and Gulf of Mexico domestic offshore crudes north to the Patoka, Illinois, terminal complex. Capline comprises a single pipeline with 1.2 million b/d capacity. The owners are BP, Marathon, and Plains All American. As imports into the Midwest from Canada have grown, and now with rising Lower 48 production, so the volumes of crude moved via Capline have declined significantly over the past 5 years. Current utilization levels are reported at less than 50%.

There has been interest in reversing Capline and so this could be a future possibility for bringing additional volumes of domestic and WCSB crudes down to the Gulf Coast. It must be recognized though that the three owners would need to be in agreement. In the event the pipeline were reversed, LOOP and LOCAP would make the necessary modifications to handle the crude oil to support the needs of the connected pipelines and refiners.

Ozark

The Enbridge Ozark pipeline has 230,000 b/d of capacity and runs northeast from Cushing to Wood River, Illinois. With increasing volumes of WCSB and domestic crudes flowing south, this line could also be a candidate for future reversal. Alternatively, under a "No Expansion" scenario, it could take crude oil from Cushing to Wood River for loading on to barges to the Gulf Coast.

Pegasus

The 96,000 b/d ExxonMobil Pegasus pipeline currently comprises the only line that runs from PADD2 to the Gulf Coast. Looping and/or use of the right-of-way to install a parallel line could represent expansion options.

To reiterate a comment made regarding existing cross-border pipelines, EnSys is not aware of any firm plans to expand any of the above pipelines. However, there very often is potential for expansion via

[18] ConocoPhillips Not Interested in Reversing Seaway Pipeline, Aaron Clark, Bloomberg, February 15, 2011. http://www.bloomberg.com/news/2011-02-15/conocophillips-not-interested-in-reversing-seaway-pipeline.html.

[19] Conoco Split Raises Hope Of Seaway Reversal, Jerry A. DiColo of Dow Jones Newswires, First Enercast Financial, July 26, 2011. http://www.firstenercastfinancial.com/news/story/44094-conoco-split-raises-hope-seaway-reversal.

adding pumping stations and/or looping the whole line or sections. In addition and potentially more significant, existing pipelines constitute established pipeline corridors / rights-of-way which frequently can be used to install new parallel lines with permitting that is easier than for a wholly new route and line.

3.2.5 Potential Additional PADD2 Onward Extensions

A further category of projects would more indirectly support WCSB exports – and potentially also movements of Lower 48 crude – by providing onward extensions of existing lines in PADD2 to refineries in regions other than PADD3.

3.2.5.1 Line 9 Reversal (PADD2 to Eastern Canada & Beyond)

Enbridge has recently proposed reversing its 240,000 b/d Line 9 pipeline that currently runs from Montreal west to Sarnia. A Phase I proposal is to reverse the portion of the line between Sarnia and Westover, Ontario. Stated throughput would be 50,000 b/d on this segment. A possible Phase II would complete the reversal all the way east to Montreal. This would constitute a re-reversal as, prior to the late 1990's, the line used to run west to east. As a consequence, cost for this re-reversal is indicated as low.

Montreal is the connection point between Enbridge's Line 9 and the Portland Montreal Pipeline (PMPL) which runs westward from Portland, Maine, to Montreal. PMPL in fact comprises at least three pipelines which were constructed in World War II and which today have a rated total capacity of 525,000 b/d. Enbridge had previously considered a projected named Trailbreaker which would have reversed both Line 9 and PMPL. The intent was to carry WCSB crude oils east to open water at Portland, whence they could be shipped to refineries on the Canadian and U.S. East and Gulf Coasts and elsewhere. The project met resistance from groups opposed to the shipment of oil sands streams through PMPL, and Enbridge shelved it in 2009.

The continuing and rapid growth in Lower 48 production from the Bakken and elsewhere is arguably changing the situation versus that which applied in 2009, creating a growing incentive to move those crude oils east. Unlike WCSB heavies, they are conventional crudes which are light and sweet and more akin to those currently run by refineries in eastern Canada, the U.S. Northeast (PADD1) as well as in the Gulf Coast (PADD3). Over time, reversal of Line 9 and PMPL to carry light crudes may therefore become an option for which there is a growing rationale[20]. Carriage of light, conventional crude oils would presumably also meet with less opposition than carriage of oil sands streams.

[20] In EnSys' 2010 Keystone XL Assessment for the Department of Energy, we considered the Trailbreaker project but only as a means to carry (heavy) WCSB crudes. In that role, the project appeared to be uneconomic as it represented such a lengthy and circuitous route to market. However, moving light crudes to nearby refineries could be more attractive.

All options, starting with the Enbridge Phase I reversal, entail existing lines and add to the capacity to take U.S. domestic and/or WCSB crudes out of PADD2. Even if a reversal of Line 9 or Line 9 plus PMPL carried only conventional crude oils, it would open up "space" within the U.S. refining system for processing WCSB crudes and would thus indirectly support WCSB crude exports from Canada. Because PMPL comprises more than one physical line, it is possible to conceive of a situation where one or more of the lines is reversed to go east to Portland while other physical lines continue to take crude west to Montreal. Another possibility, given the total capacity and potential flexibility of the PMPL, is that, if both Line 9 and PMPL were reversed to flow entirely east, the excess capacity on PMPL above that of Line 9 could be fed by Great Lakes tanker or by rail movements of Lower 48 and/or WCSB crudes to Montreal. Those crudes could then move at up to 525,000 b/d on PMPL to Portland and thence to international markets.

Again, any "No Expansion" situation would render the opportunity cost economics of these and other potential projects more attractive than those which would apply under normal "business as usual" circumstances.

3.2.5.1 Keystone East (Illinois to Ohio and Michigan)

TransCanada is considering the option of extending its Keystone (Mainline) system east from Patoka, Illinois, through to Lima and Toledo, Ohio, with optional onward extension to Detroit if there is sufficient interest. They are also working to create a connection either in Saskatchewan or North Dakota for Bakken crude to enter Keystone Mainline[21]. While that connection could go ahead without Keystone East, TransCanada sees it as an enabler to Keystone East as the refineries in the target area receive Gulf Coast priced light crude through the Mid-Valley pipeline system (starting at Longview, TX) as well as through the Capline and Marathon pipeline systems. The commercial rationale is that facilitating greater quantities of Bakken or Canadian light oil to reach the refineries at Toledo, Lima, and Canton would allow those refineries to avoid buying Gulf Coast crude while providing a premium market for Bakken and Canadian light grades. While it is possible, TransCanada doubt that adding Bakken and other light crudes on Keystone Mainline to Keystone East would free much capacity on Keystone XL, this because they see the Keystone Mainline to Keystone East route as taking up growing production of Bakken and other light grades.

Stated capacity for Keystone East is 300,000 b/d. Stated timing is 2017 but this is fairly arbitrary. The project cannot happen before 2013 as it depends on capacity made available by Keystone XL. The space that the East project would utilize on Keystone Mainline would be freed up by the crude oil deliveries to Cushing being moved from Keystone (Mainline) over to the Keystone XL pipeline. TransCanada would shift 150,000 -200,000 b/d of WCSB crudes from Keystone Mainline to Keystone XL. This space could be used to base load the Keystone East project. Additionally, existing Keystone shippers to Patoka would

[21] This connection would, we understand be separate from the "Bakken Marketlink" that would be associated with Keystone XL.

then have the capability to also carry on past Patoka on Keystone East. Finally, the project would compete for short haul transportation from Patoka for volumes arriving via Mustang, Woodpat, or Capline. For these reasons, TransCanada has sized the Keystone East project a little larger than the volumes that would be moved over from the Keystone Mainline to Keystone XL. One intended result is to give enhanced flexibility to existing shippers and greater supply choices to refiners at Lima, Toledo and connected regions.

Capacity on the now operational Keystone Mainline would remain unchanged, thus Keystone East would require no modifications to the existing Keystone Mainline facilities. The project is a proposal, and timing for an open season has not been set.

TransCanada is looking at the option of co-locating the majority of the Keystone East right-of-way with other pipelines but route details are likely to change if and as the project progresses.

3.2.6 Projects Timing and Open Seasons

As of the date of this report, a number of projects are at a point where decisions - or at least increased clarity on intentions - are likely to emerge. In other words, the picture regarding which of the main currently listed pipeline modification projects will go ahead and when is likely to progressively clarify over the next several months. This should lead to a clearer sense by early 2012 of firm capacity additions and timing. The projects that fall into this group (aside from Keystone XL) include:

- Trans Mountain TMX 2, 3 expansions,
- Enbridge Monarch, which Enbridge is now approaching as a potential component of a "full pass solution" to take WCSB crudes from Canada to the Gulf Coast, as well as a means to move domestic U.S. crudes out of Cushing,
- Magellan Longhorn reversal,
- Enterprise / Energy Transfer Double E.

By later this year, Magellan should have announced a firm decision on Longhorn reversal, the results of the Double E open season will be known and open seasons are likely to have been undertaken for Monarch and Trans Mountain.

3.3 "Tier 3" Projects & Potential for Rail Transportation

A review of the U.S. and Canadian rail sectors points to industries that (a) have highly developed infrastructures to reach essentially anywhere within the USA and Canada, including cross-border, (b) have current excess capacity within that infrastructure and (c) are run by well established private sector companies that are able to react, invest and modify their operations including with respect to the transportation of crude oil. Further, the evidence of the Bakken is that rail takeaway capacity can be expanded quickly and to levels in the range of at least 0.5-1 million b/d. Rail and logistic companies can build facilities within a year to eighteen months and contracts usually are between 3 to 5 years granting flexibility to this industry.

In Canada, modest volumes of crude oil (tens of thousands of b/d) have been shipped by rail for many years. Today the country's railroad companies are focusing on moving WCSB crude including oil sands. Volumes are starting to rise and shipments of conventional crudes, DilBit and undiluted bitumen are already occurring to several parts of the U.S. and to Eastern Canada. Over the longer term, EnSys estimates substantial potential to move WCSB crudes out of Canada by rail, both via the BC coast and cross-border directly into the USA. Prospective levels could reach or well exceed 1 million b/d, especially under a "No Expansion" situation which limited pipeline options.

Moving conventional crude oils and DilBit via rail is being undertaken routinely and requires no special equipment; terminals and tank cars can equally handle both. Rail also provides the option to ship raw bitumen (using heating). This requires additional facilities at off-loading terminals but has the advantage that eliminates shipping (and back-hauling) of diluent.

In short, rail is already responding to market needs to move crude oil in large volumes of hundreds of thousands of barrels per day and has the potential to do so under a No Expansion scenario.

3.3.1 Shipping Crude Oil & Oil Sands via Rail

As mentioned above, standard rail cars and terminals have the ability to handle both conventional light and heavy crudes and DilBit and are inter-operable between these. Unlike pipeline, rail also offers the option to ship oil sands in the form of undiluted bitumen. The technology is well established as it is essentially that of shipping asphalt via rail, which has been done for years. It entails (a) using rail cars that are insulated and which contain steam heating coils and (b) having steam available at the off-loading terminal to as necessary reheat the bitumen so that it flows and can be off-loaded.

In comparison, in order to be shipped by pipeline, bitumen has to be combined with diluents or synthetic crudes to lower its viscosity to acceptable levels. This adds to costs since the diluent must be shipped through the line in addition to the bitumen and must increasingly be shipped from destination back to origin to be reused. Claimed advantages of shipping oil sands via rail are that the shipper has options which can cut costs, basically a choice to ship either with diluent as DilBit – but potentially with the opportunity to ship back diluent on the return leg - or to transport heated bitumen in insulated railcars, thereby avoiding the use and cost of diluent.

As further discussed in Section 4, the typical situation is that light conventional crude is cheaper to ship via pipeline than via rail. With heavy crudes the economics move closer because of the generally higher pipeline tariffs to move heavy crude because of its higher viscosity. With DilBit, the same economics apply as for heavy crude except that rail provides the opportunity to back-haul diluent. In that circumstance, rail can be cheaper. Similarly, shipment of raw bitumen via rail is claimed to be competitive with or cheaper than pipeline per barrel of net bitumen.

In addition, while tariff per barrel of crude oil shipped is a key factor in comparing the economics of rail versus pipeline, as discussed below and in Section 4, it is by no means the only factor. Relative advantages of rail, in terms of lower capital costs per unit of capacity, ability to scale capacity, shorter lead times and less permitting difficulty, flexibility to reach different destinations, shorter transit times from source to destination, shorter contract commitment periods are factors evident today which are contributing to a rapidly growing interest in transit by rail.

In broad terms, rail has an advantage in that many existing rail tracks are available to be used throughout the USA and Canada and that, as detailed below, there appears to be spare capacity on these. Another key factor which must not be overlooked in establishing total capacity to move crudes, including WCSB DilBit and raw bitumen, by rail is availability of rail tank cars. To make a shipment from say Hardisty to the Gulf Coast using a "unit train" of approximately 100 cars requires a total inventory of 2,000 rail cars on the basis of shipping one train per day and an each-way in transit time of 8 days. This is because, to load and unload one train per day, requires a continuous "loop" of unit trains to be in operation such that, on any one day, one train is loading, one is unloading, 8 are transit to the unloading terminal and 8 are returning to the loading terminal, for a total of 20 trains in operation.

Under a sudden expansion of rail movements, tank car availability could be an issue but, as discussed in Section 3.3.5, tank car manufacturers are responding to the Bakken surge. Overall, we do not see ability to manufacture rail cars, including with insulation and heating for raw bitumen, to be a constraint in any progressive build-up of rail capacity as could apply under a "No Expansion" situation.

3.3.2 Rail Sector Overview - USA

3.3.2.1 History & Capacity

Since 1980 when the U.S. freight rail industry was partially deregulated by the Staggers Act, the industry has gone through a major transformation. Private freight rail investments modernized the industry. The

Association of American Railroads estimates that $480 billion dollars have been spent to maintain and modernize railroad infrastructure between 1980 and 2010. It is this investment, building on a legacy that dates back to the nineteenth century, that has led to and now maintains and operates, a 140,000 mile national rail network[22].

As a consequence and component of the recent recession, the railroad industry went through a downturn during the last part of 2008 and all of 2009 then started showing signs of recovery by the second quarter of 2010. (See Exhibit 3-2.) Preliminary data for the beginning of 2011 suggest that economic recovery is continuing throughout this industry but that freight activity has not returned to the peak levels reached in 2006. In that year, average weekly U.S. rail carloads were running at around 330,000. Data for 2010 and the beginning of 2011 indicate shipment levels still 10 - 12% below those in 2006.

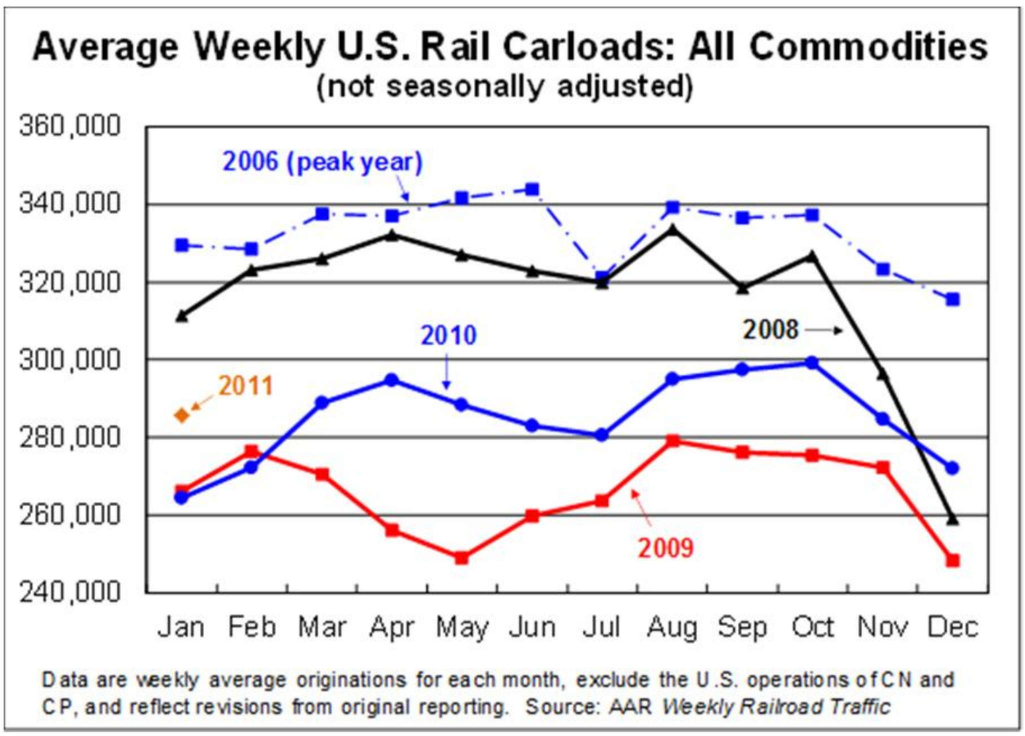

Exhibit 3-2

Analysis by Cambridge Systematics, Inc. further supports the view that the U.S. system currently has excess capacity. In September 2007, a study requested by the Association of American Railroads and prepared by Cambridge Systematics, Inc. presented an overview of U.S. railroad infrastructure with the aim of estimating the capital investments needed to meet expected demand though 2035[23]. Cambridge Systematics divided the continental U.S. Class I railroad network into primary corridors. Activities on

[22] Great Expectations 2011, Freight Rail's Role in U.S. Economic Recovery, Association of American Railroads, 2011.
[23] National Rail Freight Infrastructure Capacity and Investment Study, Cambridge Systematics, September 2007.

these corridors in terms of freight and passenger trains per day were based on 2005 Surface Transportation Board Carload Waybill data. These data were used to build the maps referenced below.

Based on this study, in 2005, railroad utilizations, both cross-border and throughout much of the U.S., were running below capacity. In Exhibit 3-3, taken from the Cambridge Systematics report, green depicts low to moderate train flows with ample spare capacity, yellow depicts lines with moderate spare capacity, orange depicts lines with little spare capacity, and red depicts lines that are overloaded to the point of delays etc. What is clear is the extent of surplus capacity across many routes. Since we would have expected 2005 rail traffic levels to have been close to the 2006 peak, and since 2011 levels are still below those of 2006, the implication is, again, that in 2011 the rail system is operating with spare capacity. Exhibit 3-4 illustrates 2005 train activity data in terms of trains per day on each rail corridor. The four cross-border corridors identified are all at the low end of the activity scale ranked at either 0-15 or 15-25 trains per day. This information is consistent with U.S. Department of Transportation data discussed in Section 3.3.2.3 below.

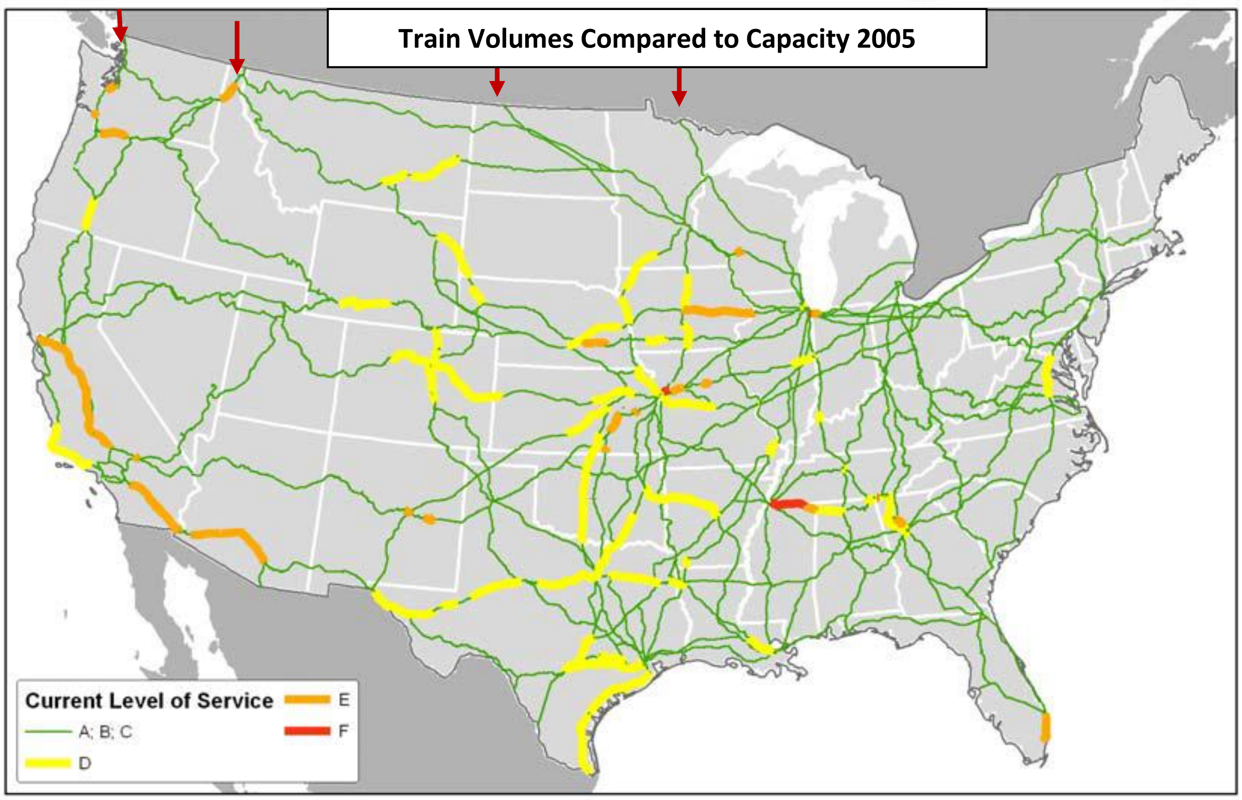

Exhibit 3-3

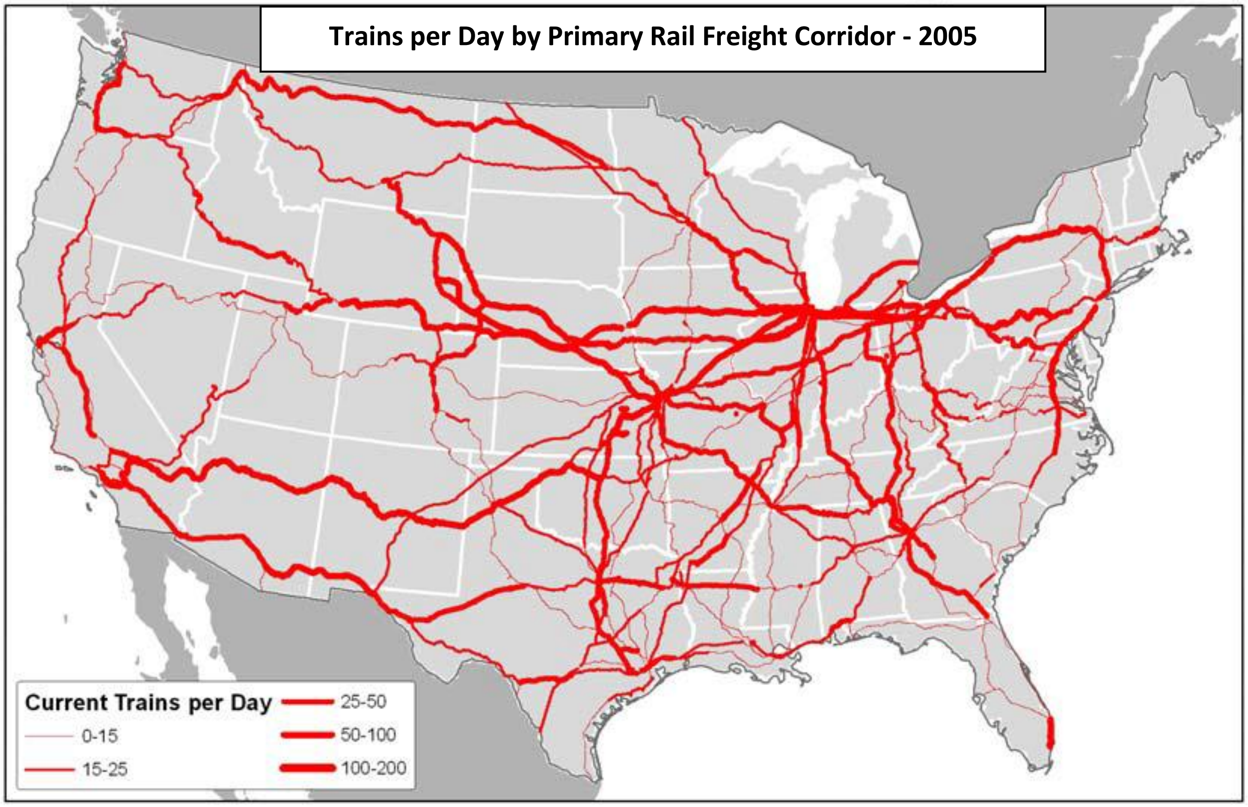

Exhibit 3-4

The picture today is that spare capacity exists in the U.S. rail system. However, the Cambridge Systematics 2007 report projected significant growth in U.S. rail traffic demand through to 2035 and the need for substantial improvements. The cost of improvements needed to accommodate rail freight demand in 2035 was estimated at \$148 billion (in 2007 dollars), i.e. an average of around \$5 billion per year over the 30 years from 2005 to 2035.At \$5 billion per year, the annual rate of investment from 2005 to 2035 appears to be much lower than the \$16 billion per year indicated by the \$480 billion the American Association of Railroads states were spent in the 30 year period from 1980 to 2010. Even if there is a difference in the basis for these two sets of costs, (such as inclusion of maintenance in one set but not the other), the implication is that the U.S. rail system is likely, more so than unlikely, to make the indicated investments to 2035.

On the assumption these investments would be made, Cambridge Systematics projected that the U.S. rail system in 2035 would have volume to capacity ratios better than those observed in 2005, as illustrated in Exhibit 3-5. The implication is that general rail system improvements would likely provide incremental capacity sufficient to accommodate incremental volumes of crude oil moving by train; or alternatively that growing volumes of trains moving oil would lead to system expansions[24].

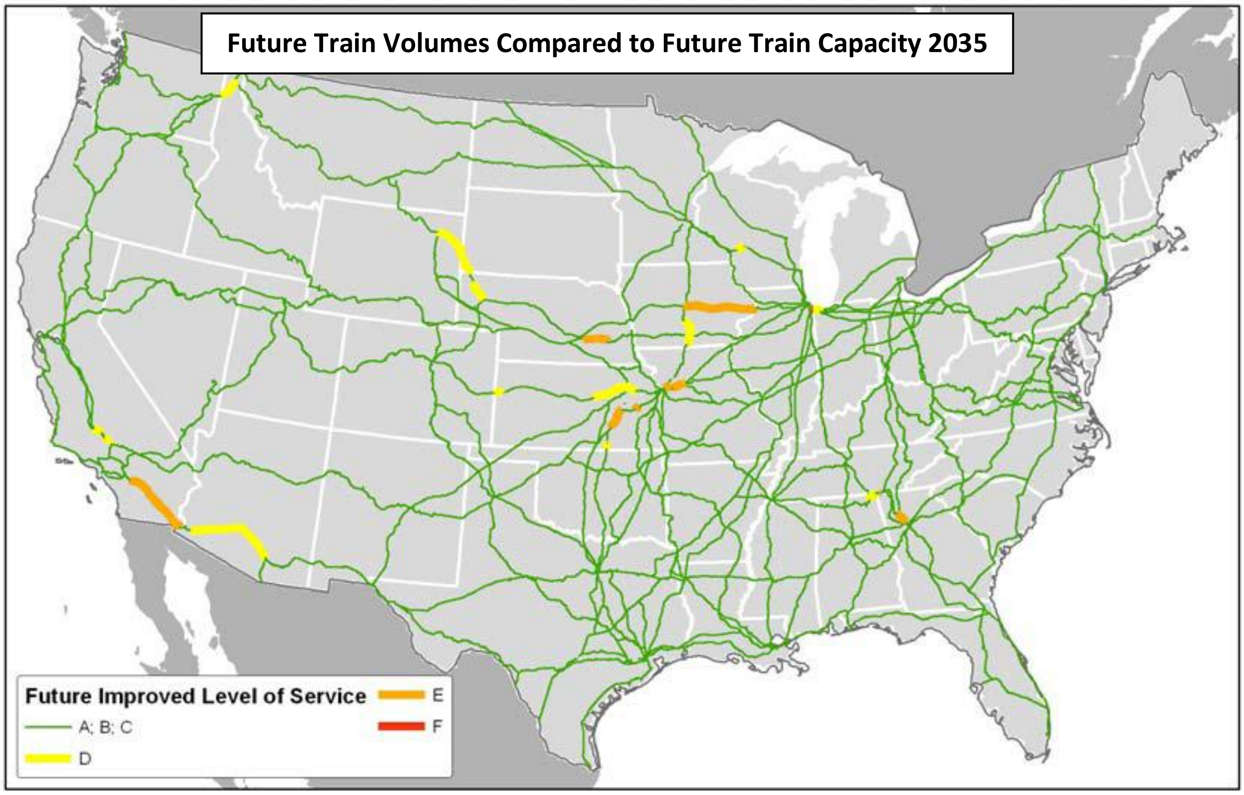

Exhibit 3-5

3.3.2.2 Level of Petroleum Shipping in Total Rail Freight

Another factor affecting the rail sector's ability to accept increased shipments of crude oil is the current scale of oil shipments within the total rail freight market[25]. In the U.S., it is very low. Exhibit 3-6 shows the 2010 make-up of U.S. traffic by type of commodity. It is clear that coal, at over 45%, is the dominant commodity being transported by rail. This compares to 2% of the total for petroleum products. Thus even large absolute increases in rail traffic for transporting crude oil are likely to have relatively small impacts on total commodity traffic. Conversely developments, especially relating to coal, could have a

[24] We note from the Cambridge Systematics report that, *inter alia,* rail line capacity can be doubled or even tripled by upgrading signaling systems, i.e. before any additions to track are considered.

[25] In the United States the Energy Information Administration does not track and report crude oil transportation specifically by rail, only via pipeline and tanker & barge.

significant impact on capacity to move other commodities, including crude oil. Increases in rail (track) capacity to accommodate growth in requirements to move coal, e.g. from the Powder River Basin, could increase ability to move crude oil. Alternatively, increased coal traffic might adversely impact ability to move crude.

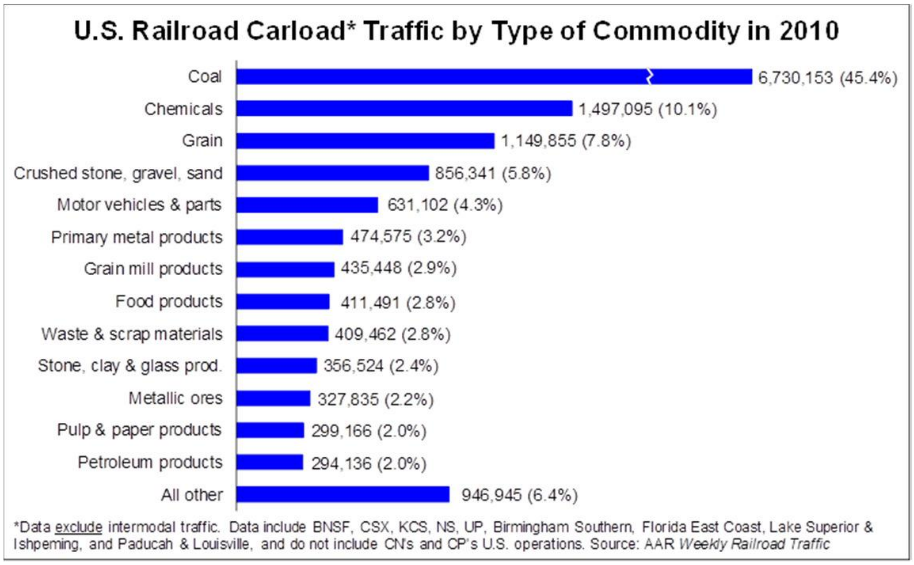

Exhibit 3-6

3.3.2.3 Extent and Capacity of Canada-U.S. Border Crossings

Exhibit 3-3 from the Cambridge Systematics study shows the existence of four primary US/Canada rail corridors located in the states of Washington, Idaho/Montana, North Dakota and Minnesota (red arrows). Exhibit 3-7, taken from U.S. Department of Transportation data[26], shows that these corridors comprise a total of 15 railroad border crossings between Washington State and Minnesota, the likely span of routes for WCSB crude to enter into the USA[27]. Of the 15, four have shown no rail activity since 2006. Two of these are in Washington State, and one each in Minnesota and North Dakota. Analysis of data for each of the 11 crossings that have been active over the past five years, shows that only one crossing has a recent activity of over 10 trains per day, (the International Falls crossing in Minnesota at

[26] U.S. Department of Transportation, Research and Innovative Technology Administration (RITA), Bureau of Transportation Statistics. http://www.rita.dot.gov/

[27] All told, U.S. Department of Transportation data show 30 active rail crossings between Canada and the USA. In addition to the 15 from Washington to Minnesota, 3 are in Michigan and 10 are spread across New York, Vermont and Maine. The final crossing is in Skagway Alaska.

11 trains per day), 6 crossings are running at 3 to 7 trains per day and the remaining 4 crossings are at 2 to less than one train per day.

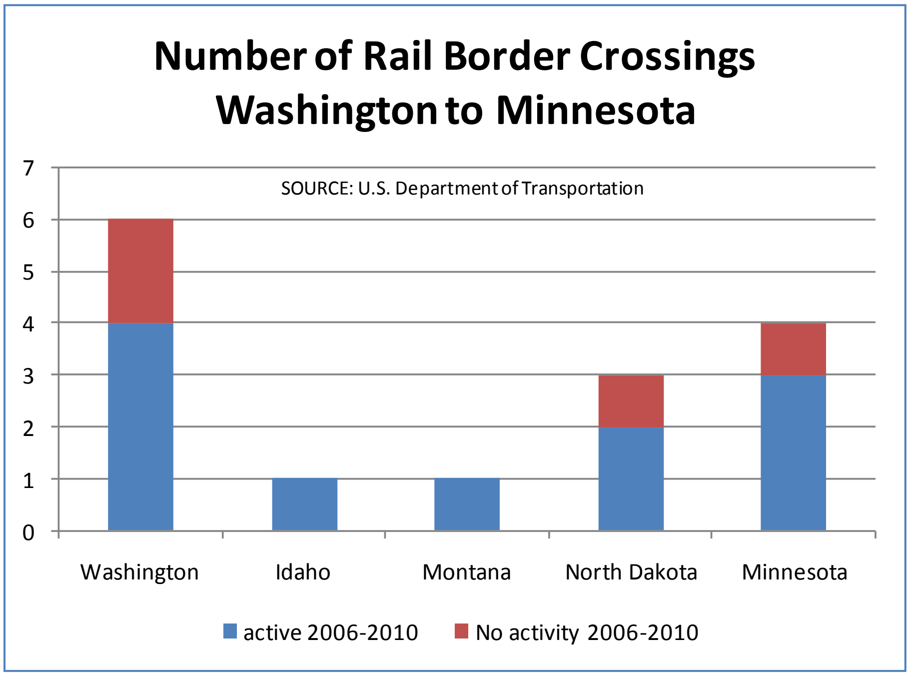

Exhibit 3-7

Data in the Cambridge Systematics report, (Table 4.2), show average capacities of single track rail lines as ranging from 16 to 48 trains-per-day depending on the type of control system in place and whether the track has single or multiple train types running on it. For two track lines, the average capacities are two to three times higher. Even on the assumption that every crossing between Washington and Minnesota is single track, the U.S. Department of Transportation data show the border crossing tracks are essentially all running well below their potential capacity.

Exhibit 3- shows the Department of Transportation data expressed as average trains per day since 1995 by state. Focusing on the recent years, average trains per day per state have been in the range of 2-4 for Washington and Idaho and 1 per day for Montana. North Dakota saw a rough doubling from 6 trains per day in 2005 to 11 in 2007. Conversely, Minnesota has seen a decline from 29 trains per day in 2003 to 18 in 2009/10.

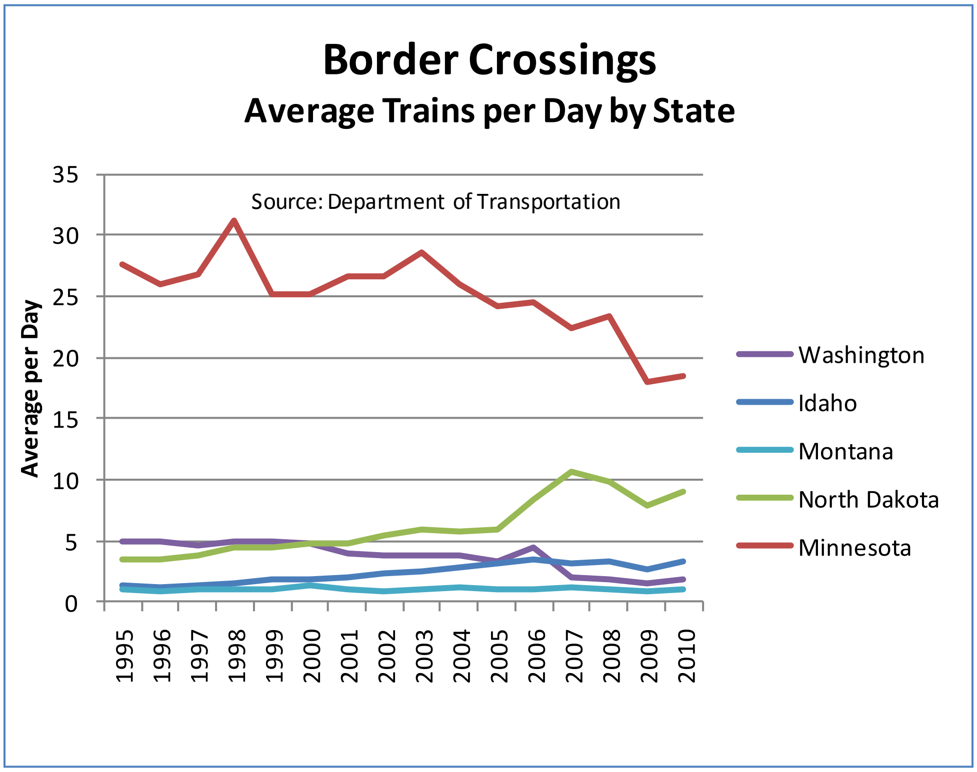

Exhibit 3-8

The number of active train crossings, (11 from Washington to Minnesota per Department of Transportation statistics plus 4 more that may still be open or capable of reactivation if demand exists), the low numbers of trains per day relative to potential line capacity, (even assuming single track and the most basic control systems, every line is operating well below capacity), and also the recent reduction of around 10 trains per day in Minnesota, all indicate that potential exists to add trains for oil transit per while staying within the lines' maximum capacity. On the basis that each crude oil train would be a unit train carrying at least 65,000 barrels, that a quarter to half (3-6) of the crossings took the trains at an average rate of 2-5 trains per day (hence of the order of 7-15 trains total) * 65,000 barrels per train indicates potential to move 0.5 - 1 million b/d of WCSB crude into the USA using existing rail capacity at these existing crossings. In other words, this is the potential that would appear to be available today.

Given the likelihood that unit trains will grow in size over time[28], and that capacity of existing tracks can also be expanded over time by upgrading control systems, the estimate of up to 1 million b/d looks conservative as an estimation of longer term potential. Under our updated "No Expansion" outlook, (see Section 6), cross-border rail capacity would potentially need to grow slowly and steadily over the period from roughly 2016 to 2030. This would allow time for the rail system to adjust. The implication is

[28] 65,000 barrels is at the low end of the size range for unit trains. Especially looking ahead, it expected that train size could increase to 80,000 barrels or more. That larger the size of each unit train, the fewer the trains that would be needed per day for any given level of transit.

that, longer term, volumes possibly appreciably higher than 1 million b/d could be achieved cross-border from Washington to Minnesota using existing tracks. Claims by CN Rail of an ability to move up to 2.6 million b/d to the BC coast alone, (given some 20,000 additional rail cars), tend to reinforce this view. Similarly, the fact that capacity for Bakken crude takeaway transit by rail is expected to be in excess of 700,000 b/d by the end of 2012 from minimal volumes in 2008, and will be achieved using entirely existing mainline tracks, further reinforces that there is potential to achieve high volumes of cross-border movements over time.

Furthermore, U.S. department of Transportation data on cross-border movements by commodity by crossing, as summarized in Exhibit 3-Exhibit 3-, show that most of these border crossings, from Washington to Minnesota, are already carry petroleum into the USA from Canada. We take the Department of Transportation commodity oil category as including oil products (and waxes) as well as crude oil. That said, the data show that crude oil and/or product is moving across 9 of the 11 currently active rail crossings between Washington and Minnesota. Recent volumes have been in the range of around 34,000 to 50,000 b/d; these out of total rail imports from Canada into the USA of around 110,000 b/d.

Rail Imports of Mineral Fuels (Oil and Waxes) from Canada to USA

Port of Entry	2007	2008	2009	2010
Source: U.S. Department of Transportation				
Ports from Washington to Minnesota		*barrels per day*		
Washington - Blaine	8,723	7,773	7,754	6,853
Washington - Sumas	688	968	708	1,085
Idaho - Eastport	5,324	4,575	5,536	7,558
Montana - Great Falls	-	-	-	44
Montana- Sweetgrass	14,603	11,453	8,838	16,739
North Dakota - Pembina	3,492	3,684	4,343	5,246
North Dakota - Portal	29,262	33,059	26,321	21,953
Minnesota - International Falls	15,909	16,946	13,054	12,219
Minnesota - Warroad	14	19	15	10
Subtotal	45,185	50,023	39,390	34,182
Michigan - Port Huron	16,636	19,427	16,867	20,270
Michigan - Detroit	896	1,075	784	891
Subtotal	17,532	20,503	17,651	21,160
East of Michigan	48,853	46,710	43,185	54,863
USA Total	111,570	117,236	100,225	110,204

Exhibit 3-9

Finally, the extent of the rail network, per Exhibit 3-3and as supported by U.S. Department of Transportation data, indicates that either WCSB imports or domestic crude oils can be shipped by rail essentially anywhere in the USA from Washington and California to the Gulf and East Coasts. Current projects, described later in the report, bear this out.

3.3.3 Rail Sector Overview - Canada

3.3.3.1 History & Capacity

The rail industry in Canada has a long standing reputation of being one of the best networks in the world. Canadian railroad companies are in charge of moving over 70 million people and 75% of all surface goods annually[29]. This industry is also considered the third largest rail network in the world and handles the fourth largest volume of goods in the world. As well, it is estimated that 40% of Canadian exports are transported by rail.

The structure of the Canadian rail sector is similar to that of the United States; Canada's rail companies are private sector organizations owned directly by investors and in many cases by their own employees. Their status as publicly traded companies has facilitated their making continuing investments each year. In 2009, Canada's rail businesses invested $1.5 billion in new capital programs, an increase of almost 10% from the previous year.

Like any other industry, the Canadian rail industry was impacted by the global economic slowdown. Freight transportation data in Exhibit 3-10 show that 2009 total carloads were 22% below their 2005 peak. For Fuels & Chemicals, the reduction was 17% below the 2005 peak. Minerals were 44% below 2005. This indicates that, like its counterpart in the USA, the industry has spare capacity that *inter alia* could be used to expand crude oil shipments. Feedback from communications with CN Rail and with the Government of Alberta Director for International Logistics likewise confirm this picture.

[29] 2010 Rail Trends, The Railway Association of Canada, December 2009.

Freight Transportation

Carloads originated by commodity grouping[9]

	Agriculture	Coal	Minerals	Forest Products	Metals	Machinery & Automotive
2000	457,089	370,467	479,240	398,466	282,470	266,912
2001	452,423	349,992	495,078	398,430	250,153	247,438
2002	364,754	342,432	601,004	403,908	289,619	277,288
2003	345,025	327,182	627,288	430,662	284,718	270,411
2004	412,099	337,592	639,764	442,689	326,020	253,003
2005	416,473	353,197	657,410	433,138	295,022	235,480
2006	453,151	321,266	600,823	388,035	362,000	244,395
2007	454,034	349,983	609,422	317,158	359,982	234,830
2008	430,292	324,931	574,645	253,279	369,475	195,308
2009	**474,980**	**277,048**	**368,631**	**182,395**	**273,800**	**148,123**

	Fuels & Chemicals	Paper Products	Food Products	Manufactured & Miscellaneous	Intermodal	Total
2000	445,575	240,624	33,894	68,346	611,765	3,654,848
2001	425,976	237,380	38,322	56,269	646,692	3,598,153
2002	469,514	274,219	30,391	55,624	691,417	3,800,170
2003	474,342	302,994	32,652	51,652	712,377	3,859,303
2004	485,197	333,061	40,587	63,890	722,412	4,056,314
2005	469,655	333,830	44,169	65,629	769,936	4,073,939
2006	470,833	274,092	41,454	66,333	819,552	4,041,934
2007	470,876	252,150	41,822	65,923	832,663	3,988,843
2008	443,125	228,072	42,365	75,160	847,647	3,784,299
2009	**401,141**	**175,693**	**42,232**	**79,445**	**741,807**	**3,165,295**

9. Not all member companies record carloads originated by commodity grouping. The Intermodal counts represent an average load factor that determined the number of carloads reported.

Exhibit 3-10

The Canadian rail industry faces concerns over its tax burden and its ability to compete on a level leveling playing field with U.S. rail. Conversely, as part of the Canadian government's efforts to improve trade flows and the competitiveness of Canada's multi-modal transportation, there are constant developments on the Ontario-Quebec Continental Gateway and Trade Corridor, the Atlantic Gateway and the Asia-Pacific Gateway and Trade Corridor that are benefiting the expansion of the railroad industry. Many of Canada's exports are moved in part by rail. Exhibit 3-11 from CN Rail illustrates the company's domestic and international trade corridors.

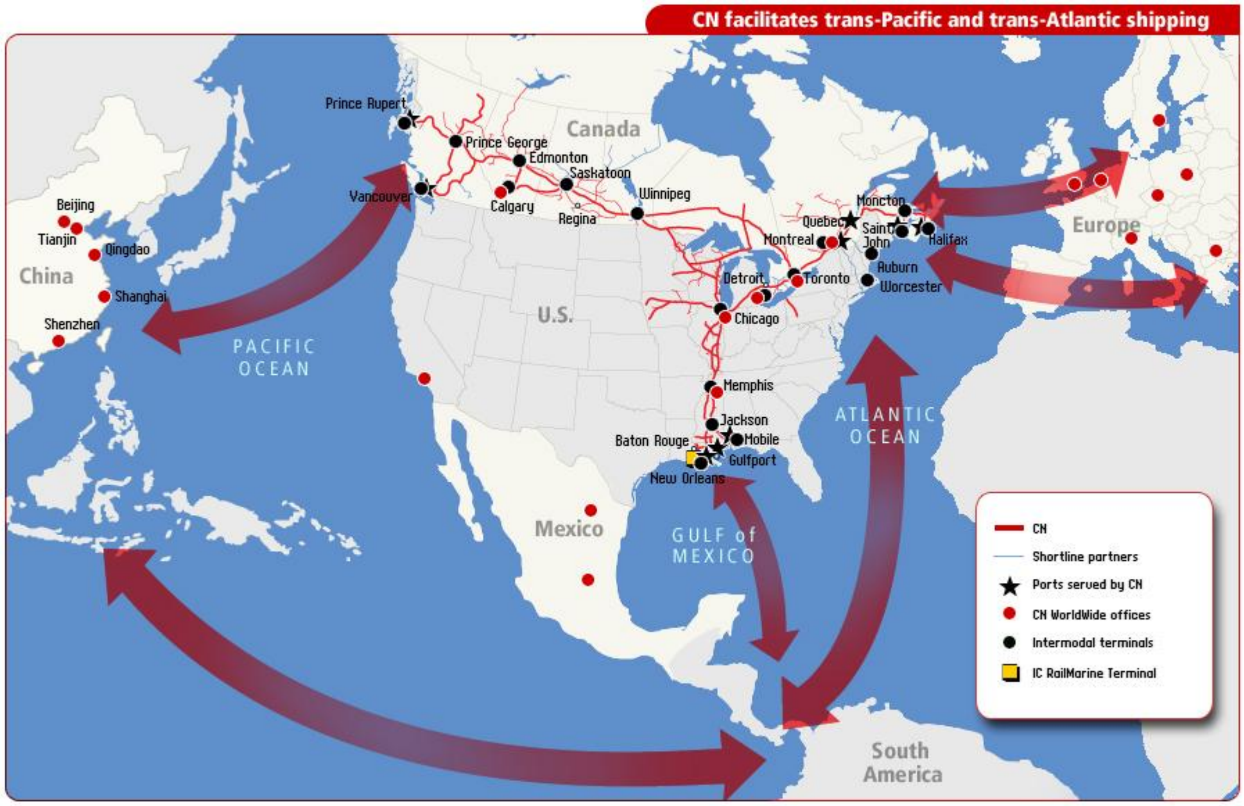

Exhibit 3-11

3.3.3.1 Level of Petroleum Shipping in Total Rail Freight

Data from Statistics Canada, Exhibit 3-12, show around 100,000 b/d of petroleum movements by rail in Canada. This comprises only around 1.5% of the total non-intermodal freight movements within the country. The level is very similar to that in the U.S. (2%). Thus, as for the U.S., gradual increases in oil movements via rail of the order of 100,000 b/d per year over a period of possibly 15 or so years, as envisaged under our updated No Expansion scenario described in Section 6.2, would comprise only a small increase each year in total rail traffic, although there would be more significant impacts on a regional basis.

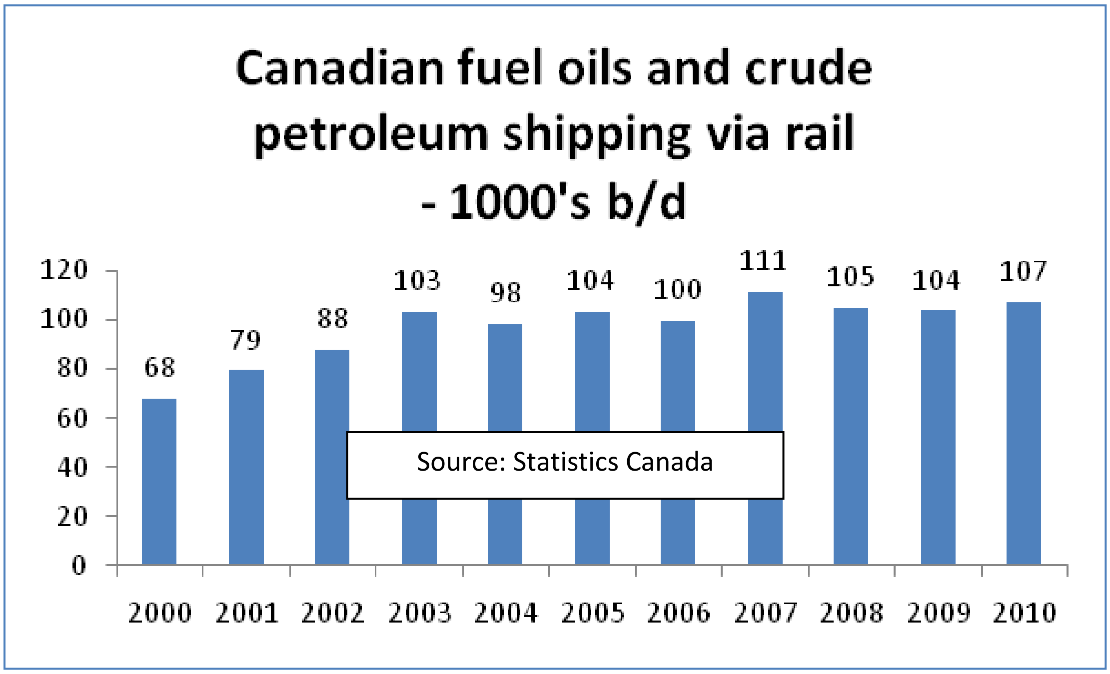

Exhibit 3-12

3.3.4 Rail System Developments - Overview

Both the U.S. and Canadian rail systems are today the focus of substantial developments in crude oil transportation.

Rapid increases in U.S. domestic crude oil production, notably of Bakken crudes in North Dakota and neighboring states, are leading to a surge in rail developments that is carrying capacity to move crude by rail to a new level. Rail, midstream and oil companies are investing heavily in projects that will allow them to move Bakken crude to destinations as widespread as Oklahoma, Texas, Louisiana and California. The increase in Bakken takeaway rail capacity, from a few thousand barrels per day in 2008 to an expected 700,000+ b/d by the end of 2012 indicates the capability of the rail sector to build capacity swiftly and to reach large scale. While limited present-day pipeline capacity is a current economic driver for rail projects, the scale and geographical scope of the current projects imply a perspective by the project developers that rail can compete over time, at least as a complement to pipeline. Reinforcing this is the range of companies that are building capacity to move crude by rail, not only primary and secondary rail companies themselves but also oil companies and midstream organizations.

This rapid development is being under-pinned by industry-wide application of the concept of "unit trains"[30]. With capacity to move typically 60,000 – 80,000 barrels per train and do so usually at a rate per loading/discharge terminal of often one or more trains per day, this system is becoming the standard for moving crude oil. The technology is also being improved leading to the potential for multiple unit train handling at a single terminal, (from 2 up to potentially 5 or more unit trains at a time), also faster loading and unloading. Rail typically also offers lower transit times to market.

In Canada, rail companies are also taking advantage of concerns over rising production combined with perceived limitations in pipeline capacity to offer solutions that will use existing rail track infrastructure to take WCSB crudes both west to the BC coast and south to the USA. Unit train capability is a factor in Canada too. In addition, Canadian rail companies are claiming advantages in that oil sands bitumen can be moved by train either as DilBit or heated but with no diluent, thereby eliminating diluent acquisition and movement costs.

We describe these developments below.

3.3.5 Rail System Developments - USA

Increasing capacity to "take away" Bakken crude oil production is currently a major focus of attention. Rail capacity is garnering a significant share of the total. It is increasing rapidly because of the combination of quickly rising Bakken production, concern over inadequate takeaway pipeline capacity, resulting crude price discounts and incentives for producers to move crude into the markets that will pay higher prices.

Since the railroad industry is deregulated, railroad companies are able to respond to market needs in a short period of time. The rapid development of Bakken takeaway rail capacity and projects is evidence to this effect. Also, investments are relatively moderate by oil industry standards. A typical one-train-per-day unit-train loading terminal, with discharge terminal and tank car rolling stock, may cost of the order of $50-100 million. These cost levels are far below the several billion dollars associated with a major new pipeline project, also the levels for modifications to existing pipelines. They thus enable rail capacity to be developed in a more incremental, staged fashion and avoid the need for large scale, longer term commitments by shippers for a project to go ahead[31]. Even when developed to a scale

[30] A traditional rail movement is likely to include multiple kinds of rail car and commodity in one train, together with pick-ups and drop-offs in potentially several locations. In contrast, a "unit train" is one that is (a) dedicated to a single commodity and therefore type of rail car and (b) generally moves from a single loading point to a single destination using loading and discharge terminals which are purpose designed for the commodity. Associated benefits include greater efficiency and speed in loading and un-loading; faster transit times versus traditional trains, greater scale and improved economics.

[31] Commitment levels sought in pipeline open seasons can often be in the range 100,000 to 400,000 b/d. Rail, in comparison can move in increments of 60,000 – 80,000 b/d; less for unit train terminals designed for less than one

equivalent to a major pipeline, for example the 700,000 b/d capacity for Keystone XL, the capital cost of for rail terminals and rolling stock would still be well below that for the equivalent capacity for a wholly new pipeline. A key reason is, as previously explained, that appreciable additional rail freight can be carried on the existing rail track infrastructure. Track is not the whole story though as rail cars are also a critical factor as are terminals. The current pace of development in the Bakken is creating a surge in demand for rail cars which, at least over the next one to two years, could stretch the ability of the few rail car manufacturers in North America. There is evidence, though, that manufacturers are responding by adding production capacity[32].

Another factor currently favoring rail is short lead times to bring new capacity into service. Permits for construction and expansion appear generally not to be an obstacle and the industry gives an average of only 12 to 18 months to build a new facility; much less than for even a modification to an existing pipeline, which often has a lead time of around 2 years. These factors provide the industry with the flexibility to take opportunities that the crude market is offering at the present with the result that projects to move crude oil to different parts of the country are coming on line at a fast pace.

3.3.5.1 Bakken

It was in the second half of 2008 that Bakken crude was transported via railroad in North Dakota for the first time. Although there are no official figures available, the North Dakota Pipeline Authority (NDPA) estimated that, during 2010, railroads were moving 65,000 b/d of the total crude from this area[33]. As summarized in Exhibit 3-13, by early 2011, rail takeaway capacity had risen to 140,000 b/d. By end 2012, the NDPA estimates total capacity of potentially 750,000 b/d[34]. This equates to a current rail capacity addition rate of around 250,000 b/d per year and indicates a capability by the rail sector to respond and develop rapidly when the need arises.

It also equates to a picture much different from that assessed for Bakken takeaway rail capacity in our 2010 Keystone XL Assessment. Exhibit 7-4, taken from that report, shows that, as of third quarter 2010, we estimated total rail takeaway capacity including projects at 175,000 b/d. Such is the pace of rail development in and relating to the Bakken that the scale of projected capacity is now dramatically higher[35].

train per day. Also, pipeline commitments can be as long as 18 years, unit train rail commitments are usually 1 to 5 years. Standard, multi-commodity, train movements are generally contracted on a "spot" train by train basis.

[32] Greenbrier Books Railcar Orders for $285 Million, John D. Boyd, The Journal of Commerce, August 4, 2011.

[33] North Dakota's Crude Oil Rail Transportation Infrastructure webinar, February, 2011, www.pipeline.nd.gov

[34] Update on North Dakota's Petroleum Transportation Infrastructure webinar, July, 2011 www.pipeline.nd.gov

[35] Had today's expectation for Bakken rail takeaway capacity been built in to the modeling cases we undertook in 2010, it would have modified the results. Broadly, the higher rail capacity would have accommodated the higher projected Bakken production that was also not in the 2010 cases, taking that crude to the U.S. Gulf Coast and other

Bakken Rail Takeaway Capacity - Current Capacity and Announced Projects

Facility/project		Capacity Early 2011 b/d	Expected capacity by end 2012 b/d
Existing			
Various Sites in Minot, Dore, Donnybrook and Stampede, ND		30,000	30,000
EOG Rail, Stanley, ND [1]		65,000	65,000
Dakota Transport Solutions, New Town, ND		20,000	40,000
Musket - Dore, ND		15,000	30,000
Musket - Dickinson, ND		10,000	10,000
Subtotal		**140,000**	**175,000**
Projects			
Hess Rail, Tioga, ND [2]	Operational first half 2012		60,000
Rangeland COLT Hub, Epping, ND	Operational by January 1, 2012		80,000
Savage Services, Trenton, ND	Operational by 2nd Quarter of 2012		72,000
Watco & Kinder Morgan, Dore, ND	Operational by September 1, 2011		60,000
Enbridge, Berthold, ND			31,000
EDOG Logistics - Dickinson Railroad Shipping, ND [3]	Operational by September 1, 2011		200,000
BakkenLink Belfield, ND [4]			72,000
Subtotal			**575,000**
Total capacity		**140,000**	**750,000**

Notes:

[1] Expandable up to 90,000 b/d capacity

[2] Expandable up to 130,000 b/d capacity

[3] The facility could be expanded to handle more than 500,000 b/d if stages 2 to 5 of the project are implemented

[4] This project has not yet been confirmed

Source: North Dakota Pipeline Authority & Musket Corporation

Exhibit 3-13

The following outlines identified developments by company. It includes projects for Bakken takeaway rail capacity and also supporting developments, including relating to destinations across multiple regions. The scope is not comprehensive in that there may be additional projects and companies active which are not described below. Our main aim here is to convey a sense of the level of activity, the geographical scope and the range of participants involved. These developments, as those summarized

U.S. destinations, and backing out light crude imports. To the extent that the higher rail capacity, recognizing the higher Bakken production, had off-loaded Bakken crudes from cross-border pipelines, that would have tended to ease WCSB shut-ins in the No Expansion cases, although the impact may have been limited.

above in Exhibit3-13, were assessed through a combination of literature review, contacts with the NDPA and with several of the companies themselves, as listed in Section 2.3.

3.3.5.1.1 Hess Oil

Hess is investing heavily in oil production in the Bakken and is building a unit train terminal at Tioga, ND. This will have a capacity of 60,000 b/d expandable to 130,000 b/d and is projected to be in service during the first half of 2012[36].

3.3.5.1.2 EDOG Logistics

Another important project in the Bakken area is the Dickinson Railroad Shipping facility operated by EDOG Logistics, LLC. This project is scheduled to start operations in September 2011. Its capacity is initially up to 10 unit trains per week expandable up to 70 unit trains per week. Among its destinations are St. James, LA and others. It will use a contract for rail movements executed with BNSF. Phase 1 is 200,000 b/d. This will be fully operational by late 2012 with possible expansion up to 500,000+ b/d between phases 2 and 5 of the project[37].

3.3.5.1.3 Savage and Kansas City Southern

The Trenton Railport, a Williston Basin Crude & Materials Multiuser Terminal operated by Savage is another current project in the Bakken area[38]. This project is located in the heart of the Bakken Shale development, 5 miles from the Plains/Enbridge Pipeline Terminal.

This is a multiuser facility that will serve: crude oil, proppant, tubular goods, aggregates, NGL and construction materials and various bulk products.

At the same time Savage and Kansas City Southern (KCS) have announced plans for a multi-user rail terminal in Port Arthur, TX. The Terminal, to be known as the Port Arthur Crude Terminal (PACT), will be served by KCS. The project is designed to bring unit train rail service of Bakken crude, as well as other crude supplies from other formations, to the Gulf Coast for distribution to pipeline or refining consumers in Texas. The terminal will feature an extensive rail complex for unit trains and crude oil tank storage. Savage is already working on first level engineering, design and permitting studies and anticipates that the construction may start later this year with the goal of completion in the second quarter of 2012.[39] It has been reported that KCS is already looking at other destinations besides Port

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[36]Hess, Musket Turn to Railroads to Ship Bakken Crude to Market, Aaron Clark, Bloomberg, January 27, 2011.
[37] EDOG Logistics, LLC.
[38]North Dakota's Crude Oil Rail Transportation Infrastructure webinar, February, 2011, www.pipeline.nd.gov.
[39] Savage and Kansas City Southern Enter into Joint Development Agreement to Construct a Unit Train Crude Oil Destination Terminal in Port Arthur, Texas, Business Wire, April 1, 2011.

Arthur, namely Corpus Christi, Texas and points in Mexico. Stated initial capacity for the Port Arthur Crude Terminal is assumed to be at least 50,000 b/d with scope for expansion.

3.3.5.1.4 Watco and Kinder Morgan

Watco and Kinder Morgan recently made an announcement to construct and operate several rail transload facilities in key markets for loading and unloading crude oil along with many other commodities. The network will link several key markets which include Dore, N.D., Stanley, N.D., Stroud Oklahoma and Houston, Texas and, in addition, several strategic loading facilities in the Eagle Ford Shale area in south Texas. Each facility will have the capability of handling large unit train volumes along with manifest commodities such as sand for hydraulic fracturing, pipe and drilling supplies. The Dore facility is projected to start operations September 1, 2011. Stroud will start October 1, 2011 providing access to Cushing, Oklahoma, and the rest of the locations are planned to start operating in the first quarter of 2012[40].

Watco is reported to be already transporting over 50,000 b/d of Bakken crude in conjunction with BNSF[41].

3.3.5.1.5 BNSF

Railroad companies such as BNSF are positioning themselves as leaders in the Bakken region due to the infrastructure that they already have in place. Bakken production has been estimated to reach as much as 1 million b/d by 2015 and BSNF projects its market share at 20% to 25% of the outbound traffic due to their extensive Bakken-area network.[42]

BSNF has already 1,000 miles of track in the region, 61 stations being served and their unit trains currently touch 16 of the 19 oil-producing counties in North Dakota. BSNF estimates it will be working with 8 new unit train facilities by 2012. At the same time BNSF has stated it is prepared to transport 730,000 b/d out of the Bakken to multiple destinations. The company's prime role is to provide and move the trains that will carry the crude.

BSNF is already transporting Bakken crude to the following destinations:

- Stroud, Oklahoma
- Bakersfield, California
- St. James, La. (via a Union Pacific Railroad interchange in Kansas City, Mo.)
- and points in New Mexico and Texas.

[40]Watco and Kinder Morgan announce Crude by Rail network. Media Release, Watco Companies, March 1, 2011.
[41] Oil Returns to U.S. rails, Joshua Schneyer, Reuters, February 4, 2011.
[42] Railroads aim to tap Bakken Shale's vast traffic potential, Jeff Stagl, ProgressiveRailroading.com, May 2011.

3.3.5.1.6 US Development Group

US Development Group has started up a unit train destination terminal in St. James and has plans for expansion to the Texas Gulf (Q4 2011), West Coast, East Coast and potentially Mid Continent. The St.James terminal is located at Plains Marketing's terminal in St. James, has current capacity to handle one train per day (60,000 b/d) and is being expanded to two trains per day (120,000 b/d). The trains are operated by CA Pacific. Currently, each train has 80 cars and can transport 60,000 to 66,000 barrels of crude oil. In the future, the terminal will be able to handle trains with 104 cars, i.e. closer to 80,000 barrels per train. U.S. Development chose St. James because of its premium connection to pipelines in the region such as Capline, LoCap and RedStick.

Plans for southern terminals include one that may be designed to handle heavy Canadian oil in the form of undiluted bitumen. As stated elsewhere, transit to the terminal would have to be in insulated rail cars equipped with heating coils and the receiving terminal would have to have equipment to generate and deliver steam to the rail cars to reheat the bitumen. The technology is essentially that required for asphalt. (The terminal would also be able to handle DilBit or other crude oils that did not need special heating.)

3.3.5.1.7 NuStar Energy L.P.

NuStar Energy L.P. announced in April that its St. James terminal in Louisiana unloaded its first rail car shipment of Bakken crude oil from North Dakota. NuStar invested $2 million in this St. James facility so it can accept crude oil by rail. The company started bringing approximately 5,000 b/d by rail on a manifest basis, and it has the potential to increase this volume to 10,000 b/d through expansion as producers demand additional market outlets.

NuStar's long-term strategy is to develop a unit train facility to ship inland domestic crude oil as well as Canadian crude oil[43]. NuStar and EOG Resources have entered into a definitive agreement to jointly develop and own a 70,000-barrel-a-day unit train offloading facility in Louisiana to support crude oil transport from various US shale plays. The new project will include rail and unit train unloading facilities, as well as two new storage tanks with a combined capacity of 360,000 barrels of oil. In addition to the 70,000-barrel-a-day capacity, the crude oil receiving terminal will include enough track and other infrastructure to stage another train to await offloading. [44]

[43]NuStar, EOG begin shipping Bakken crude by rail, PLS Midstream News, April 30, 2010, Volume 03, No. 06.
[44]NuStar, EOG Resources to build 70,000 b/d train offloading facility in Louisiana for shale crude, Phaedra Friend Toy, www.pennenergy.com, August 5, 2011.

In other developments, Musket Corp reports it has been sending 15,000 b/d from Bakken to St. James[45], and Union Pacific states that it has been handling increasing volumes of crude between PADD2 and PADD3.

3.3.5.1.8 Rail to the West

The above relate mainly to rail developments that would move crude oil to PADDs 2 and 3. In addition, there are now projects to move crudes west by rail.

3.3.5.1.8.1 Nustar Energy L.P.

In addition to its other rail activities,NuStar also has a project to build a new unit train facility on the West Coast. This will allow shippers to ship crude from the Midwest and Canada to California[46].

3.3.5.1.8.2 Tesoro

Tesoro announced in July its intention to supply crude oil by rail from the Bakken Shale/Williston Basin to its refinery in Anacortes, WA[47]. This refinery is currently receiving from 1,000 to 2,000 b/d of Bakken crude oil. Upon completion of the project, which includes loading and unloading facilities and dedicated unit trains, deliveries are expected to increase up to 30,000 b/d. Once permits are received, the construction of the facility is expected to take between 9 to 12 months and the capital investment is reported to be around $50 million.

3.3.6 Rail System Developments - Canada

3.3.6.1 Oil Sands by Rail

As in the U.S., the idea of shipping sands or conventional crudes in large volume (hundreds of thousands of b/d) via rail has not long been on the table. In comparison to the situation with Bakken crude in the USA, shipment of conventional or oil sands crude in Canada is arguably just now reaching a take-off point. Shipments are still relatively small scale but are expanding. For instance, CN Rail began shipping crude oil in October 2010. Volumes are now ramping up as new receiving terminals in the USA are being developed. The company is currently shipping to the Gulf Coast, California, Washington and Ontario. Canadian Pacific is reported to also be active. The implication is that we could see a growing scale of shipment of WCSB crudes by rail in the next one to two years.

[45] FACTBOX – Several US oil terminals plan to move crude by rail, Joshua Schneyer, Reuters, February 4, 2011.
[46] Rail, Pipeline Solutions to Cushing Bottleneck Proliferate, Beth Heinsohn, Oil Price Information Service, April 22, 2011.
[47] Tesoro, News Release, San Antonio, July 15, 2011.

Shipping oil sands bitumen poses special challenges but these are being met. As mentioned at the beginning of this section, in order to be shipped by pipeline, bitumen has to be combined with diluents or synthetic crudes to lower its viscosity to acceptable levels. This adds to costs since the diluent must be shipped through the line in addition to the bitumen and must increasingly be shipped from destination back to origin to be reused. Claimed advantages of shipping oil sands via rail are that the shipper has options which can cut costs, basically a choice to ship either with diluent as DilBit – but potentially with the opportunity to ship back diluent on the return leg - or to transport heated bitumen in insulated railcars, thereby saving the use of diluent additives. The approach is very similar to shipping asphalt by rail, a technique that is well established. (Medium and heavy crude oils have also been shipped extensively by rail in Russia.) CN Rail, for instance, is shipping both diluted and undiluted bitumen as well as conventional crudes.

Altex Energy Inc.[48] in conjunction with CN Rail have a concept they term "PipelineOnRail" which combines unit train operations with heating oil sands bitumen to avoid diluent use and costs. A challenge exists to convince the market that this can be done, though, since the standard transportation channel to move crude in Canada is pipeline. Yet, in a "No Expansion" situation, the technology and the infrastructure is there and could be taken up.

3.3.6.2 Canadian National Railway

CN Rail is one of the major rail operators in Canada. For several years, it has been building infrastructure and joint ventures that would enable large scale shipment of WCSB crudes, including oil sands.

In 2008, CN saved the only rail link to the Alberta oil sands developments from abandonment. CN bought The Athabasca Northern line for $25 million and made $135 million in track improvements during the following three years[49]. This is one of several examples of how CN built up its position in Northern Alberta to take advantage of its major rail center in Edmonton. CN has invested millions of dollars building a gathering network in Alberta and is now starting to use its extended network to ship oil sands long distance.

From the Edmonton / Fort McMurray area, CN has existing rail lines to the BC ports of Vancouver, Kitimat and Prince Rupert, also cross-border connections into the USA. There are reports of market interest in moving Canadian oil sands to terminals at Prince Rupert and Kitimat on the West Coast for possible transportation to the Pacific Rim. Investments would need to be mainly for terminals and railcars.

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[48] How to get oil sands crude to the coast, minus the wrangling, Alberta Oil – The Business Energy, Bill Sass, February 01, 2011.

[49] CN Takes Back Crucial Alberta Short Line, Interchange, Official Publication of the Railway Association of Canada, Spring 2008.

When the CN/Altex "PipelineOnRail" project was announced in 2009, CN claimed to have the capacity to handle 2.6 million barrels per day of oil products to the West Coast if 20,000 railcars were added to its fleet[50]. CN also pointed out that its then current volume of coal shipments (a) was equivalent to transporting 624,000 b/d of oil and (b) represented only 5% of CN's business; also that to add 10% of the potential oil sands (400,000 b/d) would require from four to six new trains a day. Such an increase would thus add just over 3% to CN's total business and a far smaller percentage to total Canadian rail freight traffic also the traveling time from Alberta to the U.S. Gulf Coast was estimated to take 8-10 days compared with the 40-50 days that the same shipment would take via pipeline.

These statistics indicate that rail would have the potential to replace pipeline expansion under a "No Expansion" situation in Canada. Four to six trains a day to Vancouver would constitute the equivalent of expanding the Trans Mountain via TMX 2 and 3, i.e. by 400,000 b/d. (The Government of Alberta, Director of International Logistics, did advise, though, that general rail congestion in this already busy city and port could act to constrain crude oil movements through Vancouver.) Rail movements on a slightly larger scale to Kitimat would deliver the equivalent of the Northern Gateway pipeline (525,000 b/d). Kitimat is an existing rail/oil port but there are question marks over how welcome additional rail traffic carrying oil would be. A third possibility is the port of Prince Rupert. This port has no current facilities to ship crude oil but is indicated as potentially welcoming the increasing business that crude oil rail transportation would bring to the region. All told, it is plausible to visualize rail shipments of WCSB crude to BC ports that, over time, could reach or (well) exceed 0.5 million b/d, especially in circumstances where pipeline capacity could not be expanded.

CN is also developing options to the south and east, both within Canada and into the USA (Exhibit 3-14). Indicated routes within Canada include to Sarnia on the Great Lakes and to Montreal, both sites of Canadian refineries; also on to the New Brunswick / Nova Scotia region where there are additional refineries.

[50] The 20,000 rail cars CN Rail indicate they would need to add is – very roughly – of a similar order of magnitude to the number of rail cars that will be needed to support the 750,000 b/d of Bakken rail takeaway capacity projected to be in place by the end of 2012. Given that growth is being handled apparently without major constraints on rail car availability and with announced increases in production capacity – and is occurring in the space of 2 to 3 years, we do not see adding 20,000 railcars as major hurdle, especially if conducted over a period of several years.

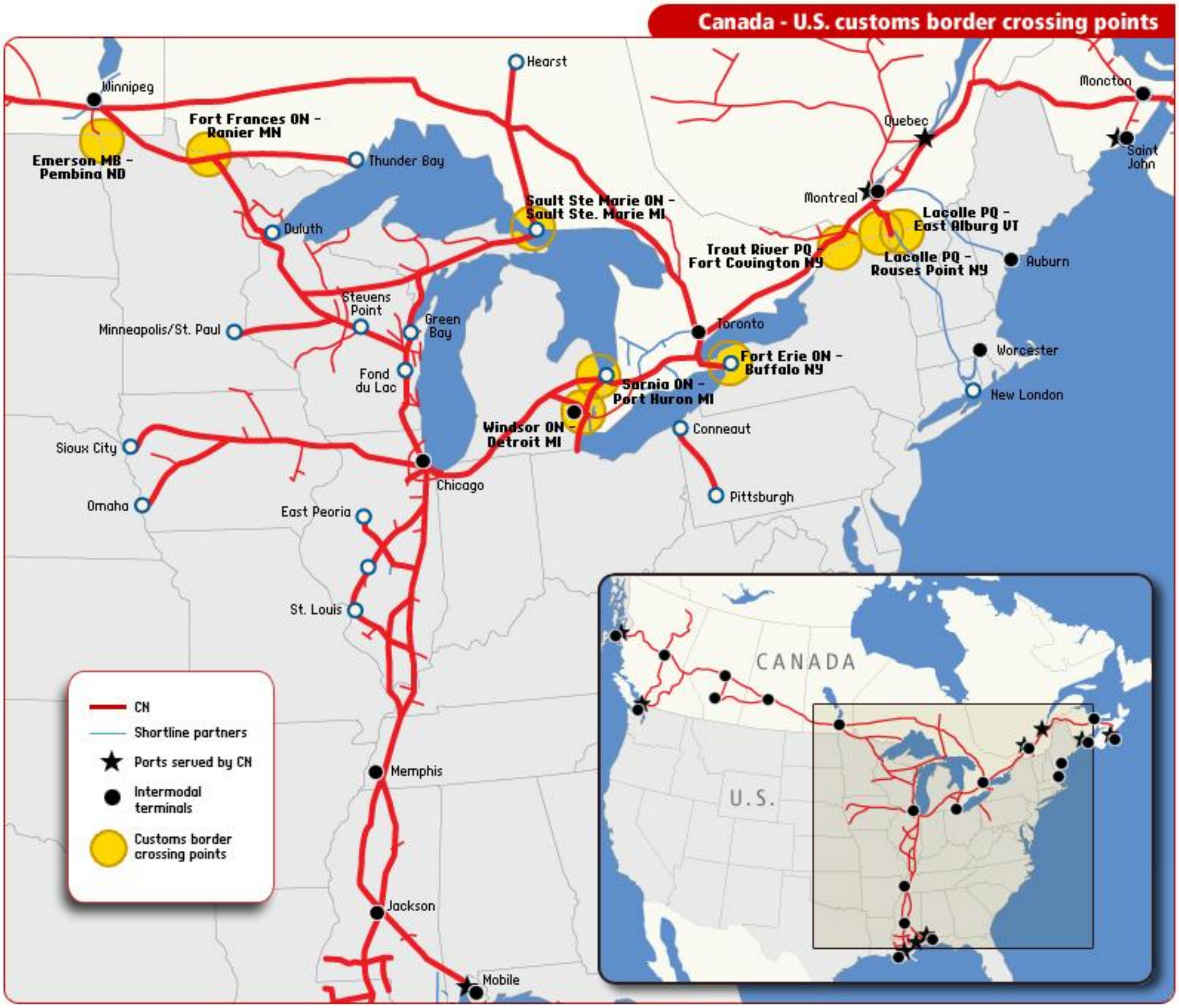


Exhibit 3-14

The company has reported that since October 2010[51], it has provided truck-to-rail services in Willmar, Saskatchewan for Bakken crude destined for points in eastern or western Canada, or in the U.S. Midwest and Gulf Coast. Some Bakken crude is being used as a diluent for bitumen in Alberta's Athabasca oil sands.

CN also is anticipating long-term growth opportunities, including U.S. Bakken crude that might flow into Canada. Although many Canadian refineries currently lack the rail infrastructure necessary to accommodate unit trains, CN's view is that this could change soon as oil companies find it cheaper to process Bakken crude north of the U.S. border.

CN states its current Canadian oil shipments include:

[51] Railroads aim to tap Bakken Shale's vast traffic potential, ProgressiveRailRoading.com, Jeff Stagl, May 2011.

- Light Bakken crude out of Saskatchewan to the U.S. Gulf Coast and to Ontario
- Heavy conventional oil from the Lloydminster area to the U.S. Gulf Coast
- Diluted bitumen from Ft. McMurray to California and Washington
- Undiluted bitumen from Ft. McMurray to California
- Conventional oil within Alberta.

3.3.6.3 Canadian Pacific

While CN is a leading player in developing capability to move WCSB crudes by rail, other proposals are also being put forward, including by Canadian Pacific (CP) which also announced intentions to ship unit trains to U.S. refineries. Both companies claim that rail can be a complement to pipeline, with flexibility to contract to ship smaller volumes for periods shorter than the 10+ years typically required for pipeline commitments and thereby attract the rising number of smaller oil sands producers in Alberta[52]. Further, under a "No Expansion" situation, one would expect the larger oil sands producers to also be interested in rail as a means to maintain their production and market outlets.

3.3.6.4 G Seven Generations Ltd.

At a June 2011 conference[53], a group named G Seven Generations Ltd (G7G) mapped out a proposal to build a new rail line, potentially from Fort McMurray, cross-border to Alaska to link in to the Trans Alaskan Pipeline System (TAPS) at Delta Junction. (See Exhibit 3-15.) The WCSB crude would take advantage of spare capacity on the TAPS pipeline. It would use the lower section of the line down to the port of Valdez (which also has spare capacity) whence the crude would be shipped by tanker.

Claimed advantages are that the line would be able to carry oil but also a range of commodities, that the route would eliminate the need for shipping via Kitimat and that the proposal already has the support of First Nations groups in BC and the Yukon; also from Alaskan tribes along the route. Conversely, the project would entail building more than 2,000 kilometers (1,200 miles) of new rail line with a capital cost for the first phase alone of over $12 billion, i.e. approximately double that for the Northern Gateway pipeline.

[52] Because of the nature of the rail industry and the size of the capital investments, contracts for less than 5 years are enough to justify new loading-unloading facilities.
[53] International Indigenous Energy – Mining Summit July 27-29, 2011, Niagara Falls, Ontario, http://unfnrailco.com/.


Alyeska
Pipeline
(TAPS)
Fairbanks
Delta
Junction
G7G
Generating for Seven Generations
G Seven Generations Ltd.
International INDIGENOUS SUMMIT on
ENERGY & MINING June 27 – 29, 2011
Doyon
Port
MacKenzie
Chugach
United
Yukon FNs
Valdez
Whitehorse
Kaska
Watson Lake
Skagway
Haines
Tahltan
Dene Tha'
Treaty 8
Fort
Nelson
Oil Sands
to
MARKET
Asia
Europe
Wrangell
Gitanyow
Fort McMurray
Gitxsan
Kitwanga
Gitwangak
The United States
of America
CN
ENBRIDGE
Prince Rupert
Kitimat
KINDER MORGAN
Edmonton
4

Exhibit 3-15

3.4 "Tier 3" Projects & Potential for Barge & Tanker Transportation

A wide range of viable opportunities exists for moving potentially substantial volumes of WCSB crudes to a range of markets using barges or tankers either in conjunction with or independent of existing pipelines. Options include:

- moving domestic U.S. and WCSB crudes (already in the U.S.) from U.S. Mid-west pipeline termini to PADD3 refineries via the U.S. Western Rivers (e.g., the Mississippi River system), as is happening today
- potentially moving WCSB crudes across the Great Lakes (if pipelines running within Canada were extended to the Great Lakes or rail movements were employed). Destinations could include U.S. and Canadian refineries on the Great Lakes, U.S. Gulf Coast refineries via onward barge transportation and, via the St. Lawrence Seaway, Canadian refineries at Montreal and in the Maritimes eastern provinces and also international refineries beyond Canada
- potential expansion of movements via tanker from British Columbia ports to the U.S. West and Gulf Coasts (as well as to other destinations, notably Asia).

Both barges and tankers are fully capable of carrying heavy WCSB crudes (as well as lighter crudes) in the form of DilBit and as undiluted bitumen. Transport of DilBit on a barge or tanker is no different from transporting any conventional heavy crude oil and does not require special equipment. Both barge and tanker movements of DilBit are occurring today.

Where oil sands bitumen can be delivered to a barge or tanker in the form of raw bitumen (i.e. with no diluent), as is feasible via rail but not pipeline, it can be transported using additional heating. Inland barges using thermal oil heating systems have for years been employed to move asphalt (which is a close equivalent to raw oil sands bitumen) on the inland waterways. Insulation may be used on a typical double-hulled barge for economic reasons but is not essential due to the common availability of large size, (8 million Btu/hour), thermal oil heaters. Most inland barges can thus be used to move WCSB bitumen with modifications limited to fitting a thermal oil heating system and in tank heating coils. In addition, barges that had not previously been used in crude oil service may also need retrofitting of vapor recovery equipment.

Tankers, as would be used on the Great Lakes and for ocean transit generally have tank steam heaters as standard so that they can carry heavier crudes oils with higher pour points. DilBit would be fall into this category and thus no modifications would be needed. To carry undiluted bitumen, tankers would need to be fitted with an upgraded thermal oil heater system, and also tank insulation, capable of maintaining the bitumen at a higher temperature than that generally needed for heavy conventional crudes or DilBit. The equipment could be built in to a new tanker or installed as a retrofit to an existing tanker. Potential retrofit cost would be less than $10 million and the effect would be to moderately raise the freight rate charged relative to that for transporting conventional heavy crude or DilBit.

3.4.1 Potential for Internal U.S. Barge Transportation

Current data show that the industry is reacting swiftly to pipeline logistics constraints and is in fact making burgeoning barge shipments of crude oil from PADD2 to PADD3. Thus barge is already acting to bypass pipeline constraints out of PADD2; this by working with pipelines into and within PADD2 to take crude out to the Gulf Coast. Significant potential exists to expand this role. Since these barge movements are taking crude oil delivered from pipelines, WCSB oil sands crude shipments are necessarily in the form of DilBit.

EIA data (Exhibit 3-16) illustrate how barge movements that first developed from PADD2 to PADD3 around 2007 and maintained an average level of around 300,000 bbl/month (10,000 b/d) have rapidly accelerated since late 2010 as Canadian/Cushing congestion has become structural. In April 2011, the latest month available, barge movements had reached almost 1.5 million bbl/month, 50,000 b/d, with a strong upward trend. Given time to build extras barges, towboats and dock/transfer facilities, EnSys does not see any reason why the current scale of PADD2 to PADD3 barge movements could not be increased tenfold or more, i.e. to 500,000 b/d or higher.

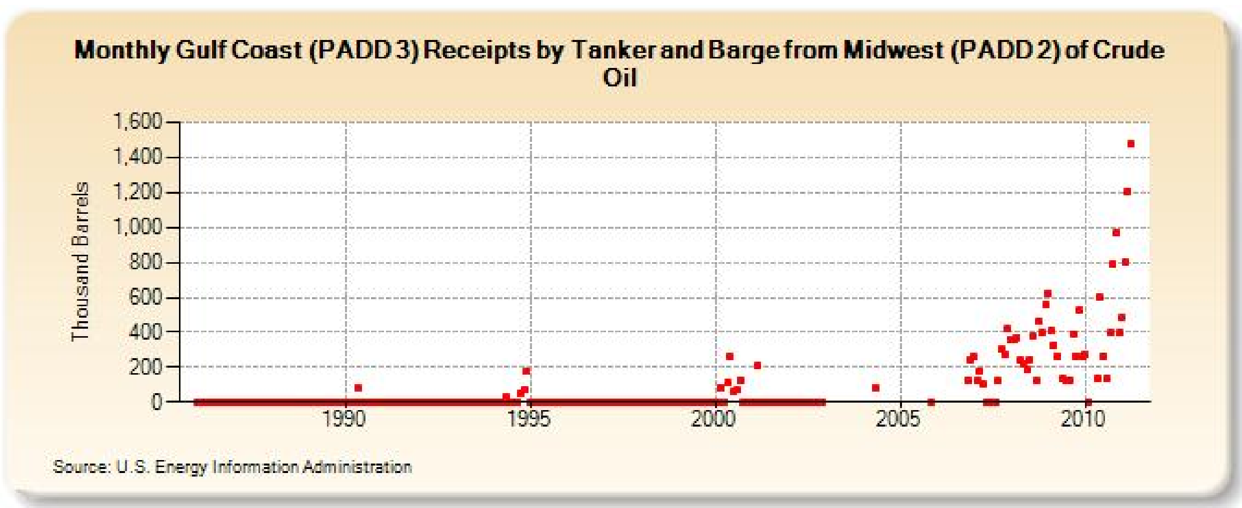


Exhibit 3-16

The following are the main barging options within the U.S.

3.4.1.1 Wood River to Gulf Coast

The primary route for crude oil inland barge movements is from Wood River, IL down the Mississippi River. Barges can be directly loaded from pipeline fed storage terminals at Wood River. Wood River has pipeline connections from Hardisty and Cushing (e.g., Express/Platte and Keystone pipelines from Hardisty and Ozark pipeline from Cushing). Barges on the Mississippi River can move directly to New Orleans area refineries or onward via the Gulf Intracoastal Waterway (GIWW) to virtually all refineries on the Gulf Coast (including Pascagoula and Houston/Port Arthur etc.). The cost of moving crude oil by barge from Wood River to New Orleans area refineries is ~$3.25-$3.75/bbl. Large "double string" unit tows with six 30,000 bbl. barges (carrying up to 180,000 bbl) and 5,000 to 6,000 horsepower towboats can make the move down the Mississippi River, although two barge unit tows are the standard with some four barge unit tows employed.

Adding this barge cost to the estimated pipeline cost from Hardisty to Wood River of approximately $5.40/bbl, and adding a small allowance for short term storage and transfer at Wood River, indicates a total cost to move WCSB crudes from Hardisty to New Orleans area refineries of no more than $10/bbl. The cost to move Cushing crude via Wood River and Mississippi barge to New Orleans area refineries is estimated at under $6/bbl.

Today, the primary constraint in the Wood River to Gulf Coast supply route is the pipeline-to-barge loading facility at Wood River. We understand this facility can readily be expanded. It is also our view that new barges and towboats can readily be added such that Wood River movements could increase tenfold or more[54]. The inland waterway system infrastructure south of Wood River encounters one lock (#27) with ample capacity. It is not until past New Orleans and moving on the GIWW that lock constraints may enter into consideration - but they may limit only the size of the tow as opposed to constraining the total volume moving.

3.4.1.2 Catoosa (Cushing) to the Gulf Coast

Another minor route is emerging for moving crude from Cushing through the port of Catoosa, OK (near Tulsa, OK on the Verdigris River) via the Arkansas River to the Mississippi River. Just as with the Wood River route, the Catoosa barges can move on to New Orleans area refineries or can continue on to the GIWW to reach virtually all Gulf Coast refineries (utilizing the barge loaded at Catoosa). This route, however, requires trucking the crude from Cushing to Catoosa, OK. The size of the tow is also limited on this route due to physical and logistics constraints. This route would typically use a unit tow of two 30,000 bbl barges (probably carrying 45,000 bbls) with a 3,000 horsepower towboat.

[54] Currently, black oil barge utilization is relatively high due in large part to the movement of crude oil on the inland waterways. U.S. barge fabricators can readily build new barges as required (estimated cost for a 30,000 bbl black oil barge is ~$2.5 million). Lead time for construction of a significant number of additional barges and towboats would likely be in the range of 1 – 2 years.

Estimated costs for this movement are as follows:

- Estimated pipeline cost Hardisty to Cushing, around $6/bbl for heavy crude[55]
- Truck from Cushing to Catoosa ~ $3/bbl
- Barge from Catoosa to New Orleans area refineries ~ $7/bbl.

This indicates a cost of moving WCSB crudes from Hardisty to New Orleans area refineries of around $16/bbl[56]. The cost to move crude oil from Cushing via Catoosa and barge to New Orleans is estimated at around $10/bbl.

The current limitation on the use of the Catoosa/inland waterways route is the connection from Cushing to Catoosa. The availability of trucks is insufficient for large volumes to move on this route[57]. For example, it would require over 225 tank trucks (at 9,000 gallon capacity) to assemble a 45,000 bbl unit tow movement (using two 30,000 bbl barges at the Catoosa limiting draft). Also, Cushing has limited truck-loading facilities.

If the transport limitation issue from Cushing to Catoosa, OK were to be relieved (via either a pipeline, rail link or increased truck capacity[58]) it is anticipated both that capacity on this route could be increased and costs reduced. Transit cost from Cushing to Catoosa could possibly be reduced to the order of $0.50 - $1/bbl. Long-run costs (with full capital recovery) for the barge move from Catoosa, OK to New Orleans area refineries would decrease to approximately $5/bbl. Thus total cost could be reduced to around $12 - $13/bbl.

3.4.1.3 Options in Summary

Given the extent of the U.S. inland waterway system, under a "No Expansion" scenario, several options are available for shipping WCSB crudes – once inside the U.S. – and/or Lower 48 crudes - to the Gulf Coast. Options include:

- Wood River via the Mississippi River
- St. Paul, MN via the Upper Mississippi River
- Chicago Area (Calumet) via the Illinois Waterway to the Mississippi River
- Catoosa, OK via the Arkansas and Mississippi River.

[55] CAPP Report, June 2011, Appendix C.
[56] On the basis this reflects a current route "at the margin" to move WCSB heavy crude to the Gulf Coast, it helps explain the level of current WCSB – Mayan price discount.
[57] Availability of drivers qualified under Transportation Security Administration rules to drive trucks carrying hazardous materials such as crude oil is also apparently a constraint.
[58] An existing Enbridge pipeline runs the short distance from Cushing to Tulsa, which is adjacent to Catoosa.

If WCSB crude can reach a point on the US inland waterways system it can be moved by barge to virtually all US Gulf Coast refineries directly. A map of the U.S. inland waterway system (Exhibit 3- Exhibit 3-17, Source: Kirby Corporation) is shown below.

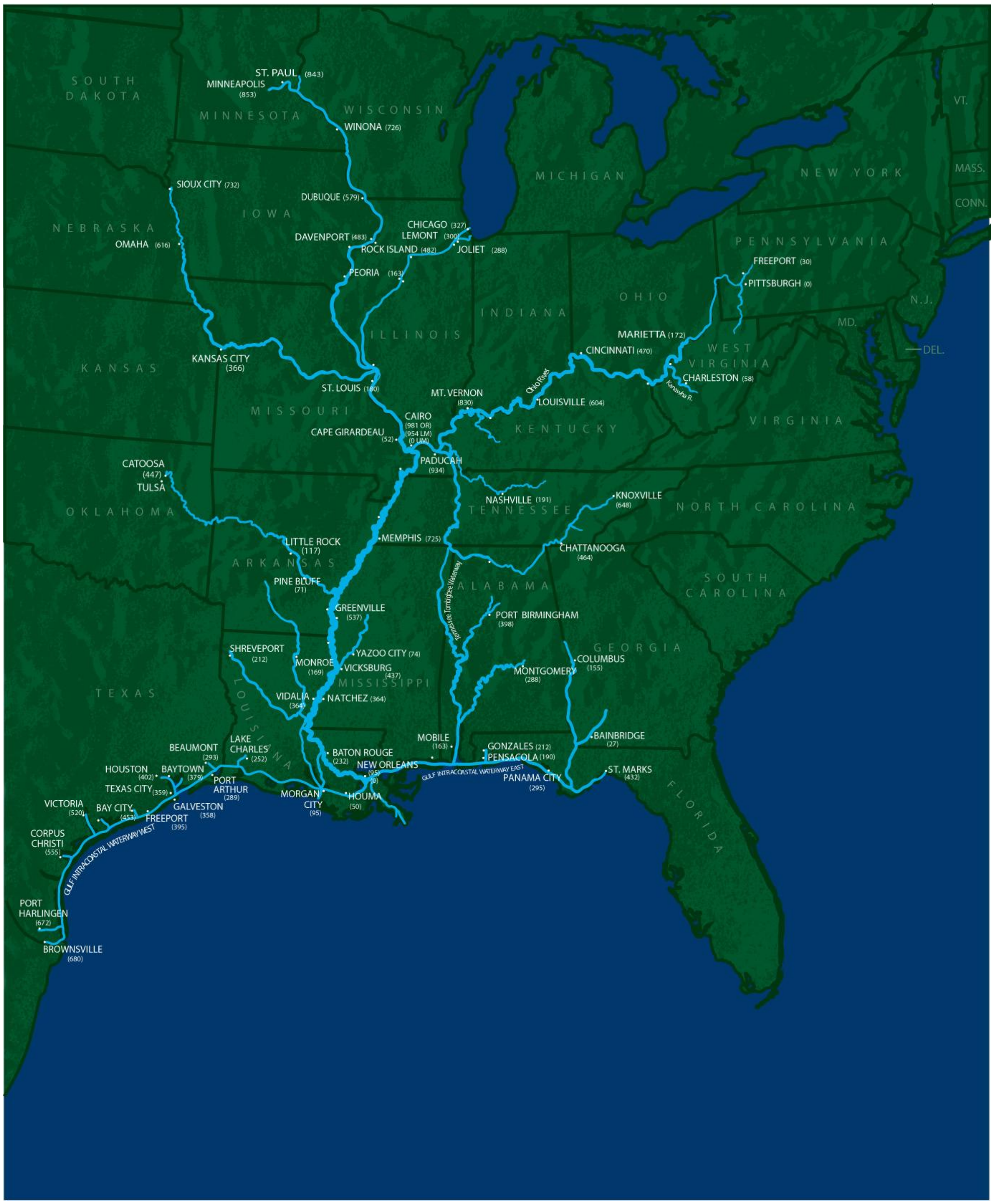


Exhibit 3-17

3.4.2 Potential for Marine Transportation Cross-Border Canada to U.S.

Water-borne cross-border transit of WCSB crudes could be developed if pipelines running within Canada were extended to the Great Lakes (or equivalent rail movements were employed). Once at a Canadian Great Lakes port, marine shipment would be possible to U.S. ports on the Great Lakes. For example, refineries in the Chicago area could receive crude shipments directly (albeit with investment in marine terminals)[59]. Another option, once in the Chicago area, WCSB crudes could be moved via barge down the Illinois Waterway to the Mississippi River, and, if necessary, on to the Gulf Intracoastal Waterway (GIWW) to virtually any New Orleans area or U.S. Gulf Coast refinery.

3.4.3 Potential for Marine Transportation within Canada to Eastern Refineries and International Destinations

Once on the Great Lakes, WCSB crude could equally by shipped to the complex of Canadian refineries at and near Sarnia[60]. These already receive WCSB crudes via the Enbridge Mainline system. However, a route across the Great Lakes would be entirely within Canada and would bypass the south eastern sections of the Mainline system. Once at Sarnia, WCSB crude could be taken via waterway – or by loading onto Line 9 if reversed – to additional refineries at Montreal, potentially backing out imported crudes.

It is also feasible that once it reached the Great Lakes, WCSB crude could be shipped by ocean-going tanker to any deep-water port in the world via the St. Lawrence Seaway. Grain and iron ore already move in bulk along this route and so could WCSB crudes.

Moving WCSB across the Great Lakes from a Canadian port to either a U.S. or Canadian port could easily be handled by the existing lock system. Movements from the Upper Lakes (e.g., Lake Superior) to the Lower Lakes (e.g., Lake Erie) would involve transiting the Poe Lock at Sault Ste. Marie. The Poe Lock currently handles 1,000 foot long (60,000 ton capacity) Lakers (self-unloading dry bulk vessels carrying primarily iron ore) and could handle the same size tankers. Movements to Montreal would be constrained by the St. Lawrence Seaway System (740 feet long with 41 feet draft) and upstream to Montreal size constraints (27 feet draft). This would limit tanker size to 45,000 ton capacity.

The volumes moved on these routes would not be constrained by the water-borne portion of the route as there is ample spare capacity to move volumes as high as 500,000 to 1 million b/d. (We note that the

[59] The three refineries in the Chicago area on Lake Michigan have a combined capacity of 820,000 b/d. They are already connected via pipeline to WCSB supplies but Great Lakes tanker movements could act as a supplement. The same applies to refineries at Detroit (106,000 b/d) and Toledo (330,000 b/d on Lake Erie.

[60] The four refineries at Sarnia plus one at nearby Nanticoke have a combined capacity of 470,000 b/d.

combined capacity of the U.S. and Canadian refineries on the Great Lakes plus the refineries at Montreal exceeds 2.1 million b/d, representing a potentially substantial market for WCSB crudes.) Tanker availability would not be an issue. Currently, there is surplus tanker capacity across essentially all size classes. Over time, the additional tankers needed could readily be built.

3.4.4 Potential for Expanded Tanker Transportation from BC Ports

While not large scale, up to 15,000 b/d of WCSB crudes have moved in recent years from the Westridge dock (Trans Mountain pipeline) in Vancouver via tanker to the U.S. Gulf Coast. Potential future expansions of the existing Trans Mountain pipeline to Vancouver could lead to up to 450,000 b/d of capacity for transit into tankers. Arguably, the main market for these would be Asia. However, especially if cross-border pipeline capacity into the USA were constrained, moving WCSB crudes from Westridge in volume to the Gulf Coast could become attractive.

Using heavy crude as a basis, a present day movement via Trans Mountain to Vancouver and thence on a PANAMAX tanker via the Panama Canal to Houston would have a total freight cost (pipeline tariff plus tanker freight and Panama toll) of around $8.50-9.50/bbl. Recognizing that Kinder Morgan plans to enable future shipment in larger SUEZMAX tankers, and that the Panama Canal Authority is expanding the Canal to take tankers of that size, the rate using a SUEZMAX would be approximately $1/bbl lower. These rates compare to approximately $7/bbl to move heavy crude via pipeline from Hardisty to Houston (and around $7/bbl to northeast Asia). Thus, while in normal markets, a tanker movement from Western Canada would be somewhat more costly than via pipeline, in a scenario where ability to move WCSB crudes by pipeline to the Gulf Coast were constrained, refiners in the Gulf Coast could elect to compete for barrels from BC with refiners in Asia[61]. Given the potential 450,000 b/d dock capacity at Westridge there could be appreciable volumes moved via tanker to the Gulf Coast[62].

In a situation where the Trans Mountain pipeline had been expanded, this route could thus provide an additional means to bypass any constraints on cross-border pipeline capacity from Canada into the USA. Should the Northern Gateway or Northern Leg pipelines be built to Kitimat, these would comprise yet further options to move onward by tanker through the Panama Canal to the Gulf Coast. Since Kitimat is closer to Asia and farther from Panama, the economics for movement via tanker to the Gulf Coast would

[61] Also, if pipeline capacity were to be constrained, then pipeline tariffs could be expected rise, reducing or even eliminating the cost premium to move via tanker.

[62] The U.S. West Coast might also represent an attractive market, closer than the Gulf Coast. A Trans Mountain spur already exists to the refineries in Washington State but short haul marine could act as a supplement. In addition, California could represent a substantial market. There though, as discussed in our Keystone XL Assessment, Law AB32 could prevent oil sands streams from moving into the State. Since conventional WCSB production is projected to decline, and that of oil sands increase, and since California's refineries take mainly heavy crude, there is a potential fit. However, significant movements from British Columbia ports to California would only appear to be an option if either the Low Carbon Fuel Standard under AB32 were to be rescinded or modified or if the carbon footprint of oil sands production were to be reduced.

be worse than for movement from Vancouver to the Gulf Coast, but potentially not enough to deter refiners with few other options.

The same argument would apply in the event rail movements were to be initiated to Vancouver or other BC ports. As discussed in Section 3.3.5.2, existing rail lines run from Fort McMurray and Edmonton (also Hardisty) to Vancouver, Kitimat and Prince Rupert. CN Rail has publicly discussed its ability to use existing rail lines to deliver WCSB crudes to the three BC ports.

3.5 Increased Oil Sands Upgrading

All of the potential developments described above relate to means of transport that could be brought to bear using predominantly existing facilities to increase WCSB crude oil exports in the event of a partial or total blockage of new pipelines. There is another route which would have the same impact – and which is indeed already being put into effect.

In recent years, the proportion of oil sands bitumen being upgraded has declined. Also, much of the projected growth in supply of oil sands streams to market is currently projected to be for bitumen blends, predominantly DilBit. Since 2004, however, there has been a sustained movement to promote the expansion of upgrading capacity within Alberta, this to increase investment, employment and “value added” within the Province. This movement has led to an agreement between the Government of Alberta and a joint venture of North West Upgrading with Canadian Natural Resources Ltd. (the North West Redwater Partnership) for the construction of eventually three facilities that will upgrade bitumen directly into refined products. In February of 2011, all permitting was completed for the first phase. An engineering, procurement and construction contract was let to Jacobs Engineering in July 2011. Construction is scheduled to begin early in 2012 leading to start-up in 2014.

The Redwater upgrader is distinctive in several respects. Firstly, it will process largely the Province’s Royalty-in-Kind bitumen. Secondly, the processing configuration, which is geared to hydro-cracking, will produce predominantly high quality diesel fuel and secondarily naphtha and diluent. Further the design does not rely on natural gas for fuel but rather on gasification of “heavy ends” streams, and it is expected to incorporate CCS to produce a CO_2 stream that will be fed into the Alberta Carbon Trunk Line and then used to enhance recovery at conventional oil fields in Alberta. Because of the processing scheme chosen plus the anticipated CCS, the well-to-wheels life-cycle carbon footprint for the diesel produced is claimed to be comparable to that for production from conventional crude oil.

Each of the three $5 billion phases is to be designed to process 50,000 b/d of bitumen. Because of the “volume gain” associated with the use of hydro-cracking technology, the output of liquids products will, though, total 68,000 b/d, comprising 36,000 b/d of ultra-low sulfur diesel and 32,000 b/d of naphtha and diluent. Thus, if and when all three upgraders are in operation, total WCSB crude oil input would be approximately 150,000 b/d and total liquids output would be approximately 200,000 b/d.

A perception of significant economic risk in building upgrading capacity to process oil sands bitumen has been a factor that has deterred WCSB producers from extending upgrading recently. However, in a "No Expansion" scenario under which options to export oil sands crudes were constrained, the opportunity to follow the path of the North West Redwater Partnership could become more attractive. As stated, the Redwater project itself will eventually remove 150,000 b/d of oil sands that would otherwise have been exported and will replace them with a somewhat larger volume of cleaner products for which (a) there should not be any difficulties in exporting to the U.S. or elsewhere and (b) the life-cycle carbon footprint should be comparable to diesel from conventional crude oil[63].

In short, upgrading directly to products along the lines of the North West Redwater Partnership provides another means to support oil sands production and related exports in the event of "No Expansion" type constraints. To the extent that such upgrading capacity were to be developed and lead to increasing exports of the resulting products into the USA, the shift would have different economic, and thus jobs, as well as logistics impacts compared to increasing exports of the bitumen to U.S. refineries for processing. Upgrading to products in Canada rather than the USA would move upgrading/refining activity and investment to Canada from the USA; also "value added" revenues as the streams exported from Canada to the USA would have the value of refined products rather than low grade crude oil. The vision, to achieve higher levels of "value added", associated investment and jobs in Alberta rather than elsewhere, is an explicit aim of the Albertan government and lobbying groups. Given the long history with upgrading to synthetic crude oil (SCO) and successful operation of the planned Redwater upgraders, this route could, in principle, be used to process oil sands volumes well in excess of 150,000 b/d[64].

[63] Product from the upgraders would likely still have to be exported. Thus the upgraders would not reduce total exported oil volumes but they would reduce exported oil sands volumes. Export facilities for the products would have to be developed but these could include rail as an alternative to pipeline.

[64] In our Keystone XL Assessment Report, EnSys described the "Alberta vision" and associated potential North West Upgrading project (Section 4.2.3) but did not include the project in the modeling analysis as its status was not then finalized. Including the project would have "eased" No Expansion scenario results modestly, depending on the level and timing assumed for associated oil sands upgrading.

4 Economics of Alternative Transport Options

The extent to which industry could adapt to a "No Expansion" situation, and could develop and employ alternative transportation modes, would depend in part on the relative costs of these modes. As stated a number of times in this report, under such a situation, the "opportunity cost" economics of both existing pipeline capacity, opportunities to modify capacity and to use other transport modes, (rail, barge, tanker), would all change versus those that apply under "business as usual". Under a "No Expansion" scenario, higher costs for alternative transport means, such as rail, would become more tolerable. The opportunity cost would be that of averting production shut in of WCSB – and potentially also – U.S. domestic crudes[65]. Adding to storage capacity, as is happening today at Cushing, can provide a short to medium term means to "park" excess/stranded production but it is not a long term solution. That must entail either changing the logistics system to reach markets (Sections 3.1 through 3.5 above) and/or processing the crude oil so that it is no longer transported in its raw form (Section 3.6).

Today, we are seeing the industry increase rail and barge movements in response to pipeline constraints out of PADD2. This is evidence that such movements are economically feasible, at least while pipeline capacity is limited. Exhibit 4-1 summarizes cost estimates made in this report for transport of WCSB DilBit and also raw bitumen from Hardisty, the main origination point, (a) to China via the BC coast and (b) to the Gulf Coast based. The estimates are based on today's economics. It is evident that:

- Comparative costs for moving oil sands bitumen to the Gulf Coast are not straightforward. This is because pipeline viscosity and gravity requirements lead to the need to dilute bitumen whereas it is possible to ship bitumen undiluted via rail – also tanker – with heating. The option to use heat in place of diluent eliminates the need to ship 25-30% of the barrels compared to moving DilBit, and may open up the opportunity to back haul diluent that has found its way to the Gulf Coast via pipeline. Taking into account these factors narrows the gap between rail and pipeline for the cost per barrel of raw bitumen shipped. Rail companies claim that shipping undiluted bitumen with heating is competitive – per barrel of net bitumen – with shipping via pipeline and is cheaper if there is the option to back haul diluent
- Costs for shipping light crude are generally higher for non-pipeline modes. (The fact that well over 90% of crude oil movement in the USA and Canada is via pipeline reflects this.)
- However, costs for non-pipeline modes are not so much higher than those for pipeline as to render them economically infeasible, especially under any form of "No Expansion" situation. Again, current activity to expand rail and barge movements is clear evidence of this. Also, in any "No Expansion" situation, tariffs on pipelines would likely rise as they would tend to run full.

[65] Although the "No Expansion" scenarios as discussed in both this and our prior Keystone XL Assessment report estimate potential shut-in only of WCSB crudes, since WCSB and U.S. Lower 48 crudes share much of the same logistics system, it could be possible under "No Expansion" that production of Lower 48 crudes could also be impacted with potential for shut-ins.

- To move conventional crudes, rail has typically cost up to 50% more "per barrel" than movement by pipeline. However, per barrel tariff is not the sole factor in comparative rail versus pipeline economics. Several additional factors are tending to weigh in favor of rail, supporting today's growing interest in use of this mode to transport Bakken, WCSB and other crudes. "Unit train" technology is improving rail economics; also, increases in rail movements can generally use existing track. The investment to establish one loading and one discharge terminal is a fraction of that for a major pipeline. Projects have shorter lead times (12 – 18 months) and do not appear to incur the permitting difficulties associated with those for pipelines. Thus rail projects can be easier to implement and are more "scalable". A typical modern "unit-train" terminal will have an initial capacity of one unit train per day, equivalent to around 65,000-80,000 b/d, and may be expandable to two up to even ten unit trains per day. Rail also offers faster transit times to market (claims are for 8-10 days from Alberta to the Gulf Coast versus 40-50 via pipeline). Required contract commitment periods are shorter, often 1-5 years versus 10+ years for pipeline, and rail more flexibility in determining destinations based on market conditions.

Approximate Costs of Alternative Routes & Modes for Transporting Heavy WCSB Crude

Stream	Route	Approximate Freight Cost $/bbl	Basis
To BC Coast and on to Asia			
DilBit	Trans Mountain to Vancouver, Aframax to China	$7	Expansion at Westridge to take Suezmax tankers would reduce freight cost by around $0.50/bbl
DilBit	Northern Gateway to Kitimat, tanker to China	$7	Basis is VLCC
DilBit	Rail to Kitimat, tanker to China	$7 - $9	70-75% bitumen, 25-30% diluent
Bitumen	Rail to Kitimat, tanker to China	$8 - $11	Raw bitumen
To Gulf Coast from Edmonton/Hardisty			
DilBit	Pipeline	$7	
DilBit	Pipeline then barge	$12 - $16	via Catoosa

DilBit	Pipeline then barge	$10	via Wood River
DilBit	Trans Mountain pipeline then tanker via Panama	$8.50 - $9.50	Panamax
DilBit	Trans Mountain pipeline then tanker via Panama	$7.50 - $8.50	Suezmax – Panama Canal expanded
DilBit	Rail	$9 - $12	
Bitumen	Pipeline (net cost per barrel of bitumen with cost of returning diluent to Alberta)	$11.50 - $12	Diluent at 30% of DilBit. $6/bbl to return diluent to Alberta
Bitumen	Rail (raw bitumen with heating)	$7 - $10	Cars return empty
Bitumen	Rail (raw bitumen with heating)	$6 - $8	On return, train takes diluent from other sources back from GC to Alberta

Notes:

1. The $7/bbl tariffs quoted above for DilBit Northern Gateway to China and pipeline to Gulf Coast agree with the figures used by Enbridge in recent presentations.
2. Although no firm numbers are publicly available, shipping sources have mentioned that it costs as little as $7/bbl to send crude from Bakken to St. James. This price is for batches of 60,000 barrels or more on unit trains of 100 cars. Smaller loads on manifest cars cost $11/bbl[66]. The implication is that a unit train cost for DilBit from Hardisty to the Gulf Coast could be of the order of $10/bbl. The implied cost per barrel of raw bitumen would be higher because of the heating requirement – but 25-30% fewer barrels would need to be moved.

Exhibit 4-1

[66]Oil Returns to U.S. rails, Joshua Schneyer, Reuters, February 4, 2011.

5 Permitting

Permitting has recently become highly visible as a critical element in determining oil transport developments. It is clear that major new pipelines such as Northern Gateway and Keystone XL are the subject of extensive, complex, and potentially contentious permitting which can materially impact when and whether they are built. Conversely, as one moves from major new pipelines to existing lines and rights-of-way, and to increasing activity on existing rail lines and waterways, permitting for modifications and/or for additional service are generally less extensive and less onerous. This situation is in turn a critical factor affecting how industry could react under any "No Expansion" scenario. Broadly, it means that modifications and service expansions are less likely to be delayed, stopped (or stoppable) because of permitting requirements.

The following instances point to the types of situation likely to apply for different modes of transport.

5.1 Pipelines

Permitting requirements to modify existing pipelines depend on the scope and content of the original permits as written and the modifications being requested by the operator but, generally, are much more limited than those for new lines. Permitting always involves State authorities and may also entail Federal authorities depending on the circumstances.

5.1.1 Cross-Border Pipelines

Whether existing cross-border pipelines would require modifications to their Presidential Permits in order to expand capacity depends upon the details of the additional work necessary to expand capacity, and the details of the Presidential Permit for each pipeline. There is precedent for existing cross-border pipelines expanding capacity without need for substantial modifications to the existing Presidential Permit or other new permits. With respect to existing cross-border pipelines, the permitting and environmental reviews for the Keystone Mainline were all carried out based on the expanded capacity of 591,000 b/d, not the initial 435,000 b/d according to the Department of State. Thus, when TransCanada moved to expand the line almost immediately after start-up, essentially no additional permitting was required.

It is possible that other existing cross-border pipelines could similarly be expanded without the need for substantial new permits or modifications to existing permits. A case in point is Alberta Clipper. This line was reportedly reviewed at its initial 450,000 b/d capacity but recognizing the intention to expand to

800,000 b/d. The view of Enbridge is that permitting requirements for Alberta Clipper expansion would be minor because modifications would entail only adding horsepower at existing pump stations.

EnSys understands from the U.S. Department of State that a determination of whether modifications to any existing pipeline's Presidential Permit would be required to expand the capacity of that pipeline could only be made in the context of a specific proposal regarding potential expansion.

A similar picture potentially applies to the older cross-border lines, Enbridge Mainline, Express, Rangeland and Bow River. Depending on the content of the original permits and the modifications being requested, additional permitting is likely to be limited.

5.1.2 Domestic Pipelines

For modifications to existing U.S. domestic pipelines, permitting generally rests with the relevant authorities in each state the line passes through. Permitting is still appreciable but generally not as difficult or as long as for new lines. A major reason is that often such key aspects as environmental impact statements require little modification or may have been undertaken on the basis of the potential eventual capacity.

For domestic pipelines within Canada, we understand there is a lengthy permitting process under the auspices of the National Energy Board. Even for pipeline operating/contractual modifications, it is apparently necessary to obtain NEB approval, viz. the current application by Kinder Morgan to modify the volumes and related contracts for movements over the Westridge dock. Nevertheless, the same principle appears to apply as in the USA, that permitting is not as onerous on existing lines.

5.2 Rail

Regarding rail, for new tracks crossing the international border, the U.S. Department of State is responsible for granting Presidential Permits for the border crossing under Executive Order 11425, the same executive order that granted the U.S. Department of State authority over liquids pipelines. New tracks being constructed in the United States would also likely require approval of the Surface Transportation Board under 49 U.S.C. § 10901, and, depending upon the route, may require additional federal or state approvals. The scope of any environmental review would depend upon the details of the specific proposal for new construction.

As to shipping items on existing tracks, including crude oil or bitumen, there do not appear to be any restrictions other than standard customs/border inspection clearing, filing necessary NAFTA paperwork

(DilBit shippers need to specify what diluent originated in North America, and what diluent is foreign-sourced), etc. There are no other permit requirements.

5.3 Barge (Inland)

There are no permitting requirements directly relating to expanding oil movements on inland waterways. Permitting requirements relate only to each vessel, which must comply with Coast Guard and other related requirements.

5.4 Tanker (International)

For international tanker movements, the situation is the same as with barges, namely it is the vessel that must be in compliance. There are no permits required on voyages. However, where modifications to and expansions of marine terminals are being requested, local permitting is generally required. Again, an example is Kinder Morgan's need to work with Port Metro Vancouver to obtain approvals to use larger vessels and increase tanker traffic through the Port in association with plans for Trans Mountain expansion.

6 Update to Conclusions on No Expansion Scenarios

As stated in prior sections of this Report, our 2010 Keystone XL Assessment for the U.S. Department of Energy (DOE) projected the potential impacts on WCSB production and exports, also U.S. refining and oil markets, of "KXL", "No KXL" and "No Expansion" scenarios. One "No Expansion" scenario, which here we refer to as Total No Expansion, curtailed all pipeline capacity expansion beyond that in operation today in 2011. The second scenario, Partial No Expansion, allowed expansion of selected existing pipelines, namely Trans Mountain to the BC coast (+400,000 b/d) and pipelines from PADD2 to PADD3. An implicit assumption underlying the No Expansion cases analyzed in our study for DOE was that future capacity expansion to export WCSB crudes would rely almost entirely on pipelines. We did not assess in depth the potential for rail and/or barge to move beyond a limited scale in transporting WCSB – or U.S. domestic – crude oils.

In this report, we have both updated our view on announced projects that would modify existing pipelines and have considered the broader potential for modifications to existing lines. We have also undertaken an assessment of the potential for rail, barge/tanker and also directing upgrading to product, in their own right and viewed as alternative modes that could be relevant under a "No Expansion" situation. Broadly, in this update, we have considered rail, barge, tanker and upgrading as options that would be available under both Total and Partial No Expansion scenarios. Modifications to existing pipelines were considered an available option only under Partial No Expansion. The net effect of this update and re-assessment is a changed perspective based on the evidence of a wider range of options than was previously allowed for.

6.1 Prior No Expansion Scenarios

The two No Expansion scenarios examined in our Keystone XL Assessment had the following key characteristics:

Total No Expansion:

- WCSB production started to be impacted around 2020 because at that stage all available pipeline capacity to the BC coast and cross-border was full.
- Onward pipeline transit of WCSB crudes from PADD2 to PADD3 was constrained to today's levels of around 100,000 b/d.
- In order to maximize use of cross-border pipeline capacity, which had limited options for onward movements to Eastern Canada and PADD3, in the modeling, PADD2 refineries invested

to absorb maximum amounts of WCSB crude, around 2.3 mbd versus around 1.7-1.8 mbd across other cases.

- The net effect was that, versus all other cases except the Partial No Expansion case, WCSB production was reduced by 0 mbd in 2020, 0.36 mbd in 2025 and 0.75 mbd in 2030. This difference was observed for cases both with and without the KXL pipeline.

Partial No Expansion:

- As stated above, this variant allowed for 400,000 b/d of Trans Mountain TMX 2 and 3 expansion to the BC coast and for pipeline capacity to be added if and as required from PADD2 to PADD3.
- Under this scenario, WCSB production was not affected until after 2025. By 2030, shut-in reached 0.25 mbd versus all other cases except the No Expansion case. This difference was observed for cases both with and without the KXL pipeline.

6.2 Updated No Expansion Perspective

Our updated view is different. Firstly, the CAPP 2011 Growth Outlook projects higher WCSB supply than did the 2010 CAPP Outlook we used for our 2010 Keystone XL Assessment. CAPP 2011 Growth Outlook has WCSB supply to markets higher by 0.085 mbd in 2015, 0.46 mbd in 2020 and 0.57 mbd in 2025. From this we would estimate the difference for 2030 could be approximately 0.68 mbd[67]. The implication of the CAPP 2011 outlook is that, in the absence of any expansion of non-pipeline transport modes, pressure on pipeline capacity limits would come earlier than assessed in the 2010 Keystone XL Assessment, potentially before 2020. Applying the CAPP 2011 Outlook to our prior Total No Expansion cases, which implicitly assumed no expansion of non-pipeline transport modes, would increase the potential WCSB shut-in to approximately 0.2-0.4 mbd by 2020, 0.9 mbd by 2025 and 1.4 mbd by 2030. Under Partial No Expansion conditions, and no expansion of non-pipeline transport modes, projected WCSB shut-in could still be zero at 2020, around 0.3-0.5 mbd by 2025 and 0.9 mbd by 2030.

Higher production from the Bakken and other U.S. Lower 48 regions is now projected versus what we had assumed in our 2010 study[68]. To the extent Bakken crudes compete with Canadian crude oil for space on cross-border pipelines, they could take up capacity and further reduce the cross-border surplus capacity for moving WCSB crudes from Canada to PADD2[69]. Thus the estimates made above, leading to potential shut-in of 1.4 mbd of WCSB crudes by 2030 may be low (again assuming no further expansion in non-pipeline transport). It is important to note that, since domestic and WCSB crudes do compete for capacity on pipelines, the net effect of a "No Expansion" situation could be for both WCSB and U.S.

[67] The CAPP projections run only to 2025 and had to be extrapolated to 2030 in our study for the U.S. Department of Energy.

[68] This was based on the EIA Annual Energy Outlook 2010 Reference case. We made adjustments to this to increase Bakken projected production but not to the levels of up to 1 million b/d now anticipated.

[69] At least two proposals exist for feeder pipelines from the Bakken that would tie in to Enbridge Mainline or the existing Keystone line.

domestic crude production to be impacted. In other words, while we have only allowed for shut-in of WECSB crudes in our No Expansion scenarios, it is possible such scenarios could lead to shut-ins of U.S. domestic as well as WCSB crude production.

As in our prior study, this update reaffirms our view that several pipeline options exist aside from Keystone XL to deliver WCSB crudes to market. If anything, the number of announced projects has increased since 2010 and most of these are for expansions or reversals to existing pipelines. The update thus reinforces the view expressed in our Keystone XL Assessment report that, while Keystone XL offers a high capacity and "shovel ready" route to move a total of initially up to 700,000 b/d and later up to 830,000 b/d of WCSB, Bakken and Midcontinent crudes to the Gulf Coast, if it were not built (as in our No KXL scenario) then, over time, broadly comparable pipeline capacity would evolve. (The economic / market drivers would be the same.) Whether or not the Keystone XL pipeline would be built, the result would be broadly similar flows, including to PADD3, subject as before to developments in capacity west to the BC coast.

More critically, this update expands our view on the alternative – non pipeline - capacity that could be put in place (and potentially would be economic) to move WCSB and domestic crudes, also to fully upgrade WCSB bitumen, in the event of Total or Partial No Expansion limits on pipeline capacity. It is now evident that, in addition to still existing cross-border pipeline capacity:

- **Rail** could play a key role in moving WCSB crudes west to the BC coast, to Ontario, cross-border from WCSB to the U.S. and from PADD2 to PADD3.
    - From the BC coast, rail-delivered WCSB crudes could move to either Asia, the West Coast of the USA, the Gulf Coast or other markets via tanker.
    - Movements to the Gulf Coast, either directly via rail and/or indirectly via the BC coast and tanker, would both bypass limits on cross-border pipeline capacity.
    - Shipment to and export via Valdez is also a possibility.
    - WCSB crudes are already being moved by rail to the U.S. Midwest, U.S. Gulf and West Coasts and to Ontario.
- **Barge** could play a central role in moving WCSB crudes to the Gulf Coast once inside the U.S. (in PADD2) As is happening today, barge movements would take up incremental crude delivered cross-border by utilizing the existing spare WCSB to PADD2 pipeline capacity and transport the WCSB crudes on to the Gulf Coast,. Barge would thus act to bypass limits on pipeline capacity from PADD2 to PADD3.
- **Tanker** traffic on the Great Lakes could provide means to transport WCSB crudes to the Chicago area, to refineries at Sarnia and Montreal and to international markets via the St. Lawrence Seaway[70].
    - In addition, Great Lakes tankers linking to inland U.S. barges could provide a means to move WCSB crudes to the Gulf Coast.

[70] In order for tanker routes across the Great Lakes to function, either existing pipelines within Canada would have to be extended to the Great Lakes (likely Lake Superior) and/or rail deliveries would be needed.

  - Expanded tanker movements from the BC coast, fed by either expansion of existing pipeline capacity and/or rail could supply additional WCSB crudes to the U.S. West and Gulf Coasts[71], as well as to markets in other world regions
- **Upgrading** oil sands bitumen directly to finished product in Alberta could also play a role, reducing WCSB oil sands crude oil export volumes and leading potentially to a shift in upgrading/refining from the USA to Canada.

In Exhibit 6-1, we have summarized options for incremental WCSB transport and upgrading that could be brought to bear, especially under Total or Partial No Expansion constraints. While there is uncertainty in the volumes of WCSB crudes that could be handled by these modes, our view is that rail, barge, tanker and upgrading together offer more than enough capacity to offset the increased potential for WCSB shut-in under the assumptions of the No Expansion scenarios in the 2010 Keystone XL Assessment updated with CAPP's upward revision in its 2011 Growth Outlook. Our conservative view is that, over time, rail, barge, tanker should be able to provide at least 2 million b/d of capacity to export WCSB crude oils; this utilizing existing spare cross-border pipeline capacity but otherwise assuming no pipeline capacity expansions at all beyond what currently exists in 2011. An optimistic view is that these three modes, potentially supplemented by full oil sands upgrading to product, could deliver capacity much above 2 million b/d.

Under the assumptions of the Total No Expansion scenario updated with the CAPP 2011 Growth Outlook, alternative transportation and upgrading would have to deliver up to approximately 0.4 mbd of combined export and processing capacity by 2020, rising to 1.4 mbd by 2030. Should these volumes be pressured upward by rising Lower 48 production competing for capacity on cross-border pipelines, we still believe – as stated above - that the alternative modes would be able to deliver adequate incremental capacity over time.

At 1.4 mbd by 2030 under the updated assumptions of the Total No Expansion scenario, the implied annual rate of capacity increase needed is of the order of 100,000 b/d per year from around 2016 to 2030. The North West Redwater Partnership alone is scheduled to add 150,000 b/d over eight or so years, leaving approximately 1.25 mbd to be met by other means in a Total No Expansion scenario[72]. Doubling the upgrading to product, as might happen under "No Expansion", would reduce the 1.25 mbd to 1.1 mbd. As stated in Section 3.6, the finished products produced would likely still need to be exported but (a) they would not pass through the crude oil logistics system and (b) our presumption is that means would be found to export them.

Upgrading potential is dwarfed though by that of rail. If the burden of delivering alternative capacity of 1.25 mbd by 2030 under conditions of the Total No Expansion scenario were to fall entirely on rail, we believe this requirement could be met. To deliver 1.25 mbd of rail movement capacity, the sector

[71] Recent (2009) tanker movements from Vancouver to the Gulf Coast were running at 15,000 b/d.
[72] The potential for North West Redwater upgrading was acknowledged in our 2010 Keystone XL Assessment report but we did not build the development into our projections and modeling because, at the time, the projects had not been fully authorized.

would have to employ approximately 20 unit trains per day moving out of the WCSB. The regional impact on Western Canadian rail shipping could eventually become significant but, per year, it would equate to adding or expanding 1-2 unit trains and terminals, with associated rail cars etc., this over a 10-15 year period to 2030. This pace of rail capacity expansion, around 100,000 b/d per year, is less than half that being experienced today in the Bakken.

As is already evident today, WCSB crudes could be moved by rail cross-border to the U.S. Midwest, Gulf and also West Coasts, and internally to Eastern Canada. In addition, rail movements to the BC coast and to the Great Lakes would provide access to tankers which could deliver WCSB crudes onward to markets in Asia, the U.S. West and Gulf Coasts, U.S. and Canadian refineries on and near the Great Lakes, also international Atlantic Basin markets.

Conventional WCSB crudes would move in conventional rail cars. For moving oil sands bitumen by rail, there would be a choice, again as today, to ship either DilBit in conventional cars or raw bitumen in insulated cars with heating. Both methods have been used for years for shipping oil sands bitumen out of Canada and are well proven. Moving raw bitumen by rail eliminates the 25-30% diluent that is present in DilBit and consequently has economic advantages versus moving DilBit by either rail or pipeline.

It is also evident that barge can play (as it is today) an important supporting role in moving WCSB – and domestic – crudes to Gulf Coast markets. Barge movements, such as are growing today especially on the Mississippi, would bypass and relieve the 100,000 b/d PADD2 to PADD3 constraint that is in our Total No Expansion cases[73]. It would in turn avoid the situation that occurred in those cases in our 2010 Keystone XL Assessment where PADD2 refining was adapted to an extreme, and uneconomic, extent in order to absorb WCSB crude that could not get out of the PADD. Rather, it would allow a more reasonable situation wherein WCSB and domestic crudes could flow to the Gulf Coast. In other words, barge would work in concert with existing cross-border pipelines to (a) enable them to run to their full capacity and (b) enable WCSB – and domestic - crudes to be moved in volume from PADD2 to PADD3.

The above options, rail, tanker and barge, plus full upgrading, would provide adequate capacity to move and handle WCSB and domestic crudes under a Total No Expansion scenario. Under Partial No Expansion, (essentially a scenario which constrained only the development of new pipelines), the opportunity to modify existing pipelines would also come into play. Here it is evident that significant expansion opportunities exist to the BC coast, cross-border and within the USA; also from the U.S. Midwest to Eastern Canada. Fully expanding Trans Mountain to Vancouver (i.e. TMX 2 and 3 but no Northern Leg) would add 0.4 mbd and Alberta Clipper expansion 0.35 mbd cross-border; a total of 0.75 mbd from these two projects alone. To achieve a total 1.25 mbd of capacity expansion out of Western Canada by 2030 without building new pipelines as assumed in the Total No Expansion scenario, expansion of other existing cross-border pipelines could provide additional contributions. Should those

[73] This constraint is based on the fact that the only currently existing pipeline from PADD2 to PADD3 is the Pegasus line which has approximately 100,000 b/d capacity.

not reach the 0.5 mbd needed in the Partial No Expansion scenario after capacity from TMX and the Alberta Clipper is added, rail would be available as a cross-border supplement.

In summary, our update has shed light on the scope for options that exist beyond new pipelines and has reaffirmed our view that both Partial and Total No Expansion scenarios have a low probability. This update renders it even more difficult to visualize a situation where the US/Canadian crude oil logistics system would be constrained, other than for short periods, sufficient to shut in WCSB production.

Potential for Main Alternative Transport Developments under No Expansion Scenarios

Mode	Potential		
	Total No Expansion	**Partial No Expansion**	Notes
Existing Pipelines			
To BC coast	Already at maximum	Expandable	1
Cross-border	Available spare capacity only	Expandable	2, 3
PADD2 to PADD3	Already at maximum	Expandable	4
Rail			
To BC coast	Yes	Yes	
Cross-border	Yes	Yes	
PADD2 to PADD3	Yes	Yes	
Internally to Eastern Canada & Great Lakes	Yes	Yes	
Barge/Tanker			
To BC coast	n.a.	n.a.	
Cross-border western U.S.	n.a.	n.a.	
PADD2 to PADD3	Yes	Yes	
Great Lakes to Eastern Canada	Yes	Yes	
Great Lakes to U.S. refineries on the Lakes	Yes	Yes	
Great Lakes to U.S. Gulf Coast refineries via onward barge	Yes	Yes	
Upgrading	Yes	Yes	5

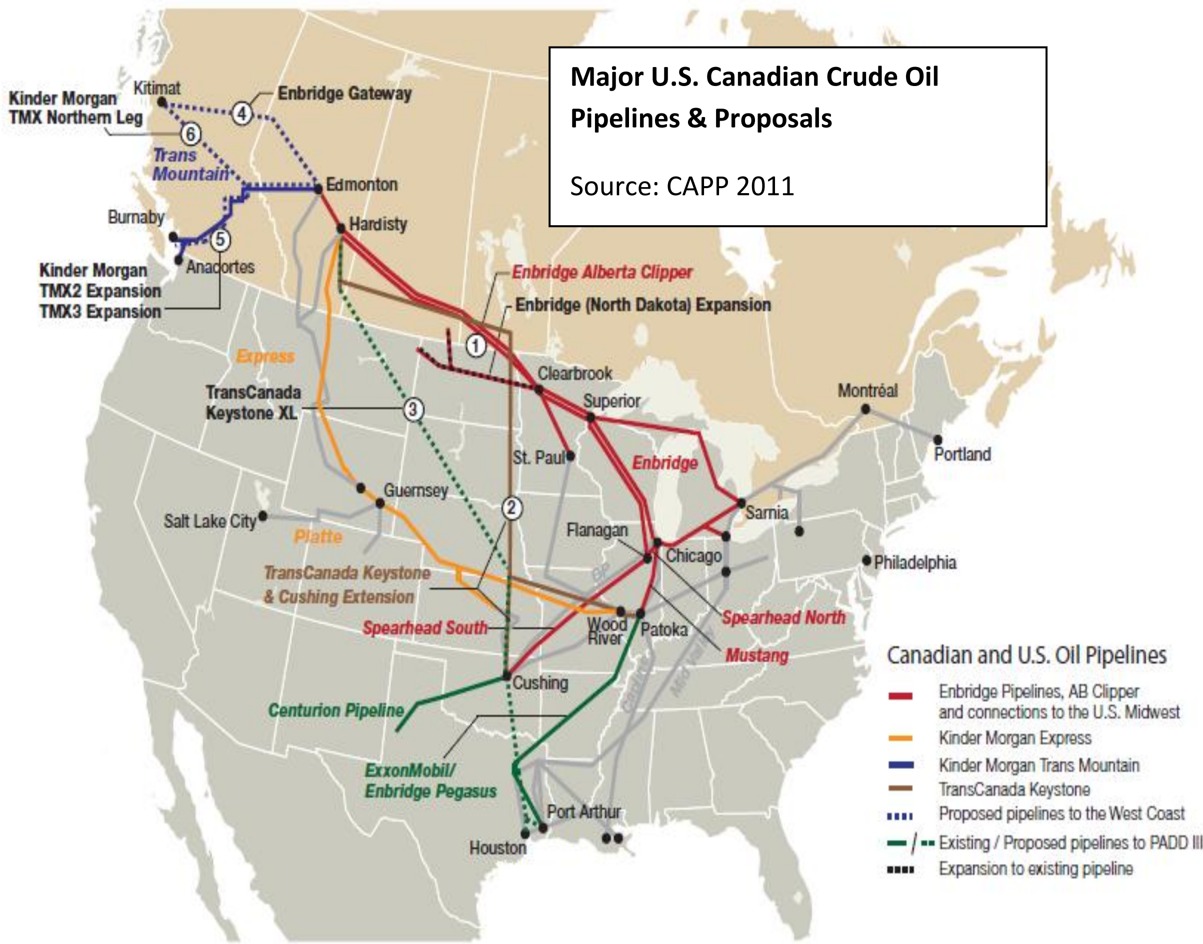
Notes:

6. Trans Mountain excluding Northern Leg.
7. Existing spare capacity cross-border.
8. Alberta Clipper expansion of 0.35 mbd, possible expansions on other lines.
9. Including Double E, Magellan Longhorn reversal, Enbridge Monarch. Expansions/reversals possible on other lines.
10. Upgrading of at least 0.15 mbd per North West Redwater Partnership.

Exhibit 6-1

7 Appendix – Background Data from EnSys Keystone XL Assessment Report

Set out below are exhibits taken from EnSys' 2010 Keystone XL Assessment Report that set out information pertaining to Keystone XL and related projects as of third quarter 2010.



Major U.S. Canadian Crude Oil Pipelines & Proposals

Source: CAPP 2011

Exhibit 7-1

Keystone / XL Capacities & Phasing

	Phase I	Phase II	Phase III	Phase IV	
	Base / Mainline(1)	Cushing Extension	Gulf Coast Segment	Steele City Segment (Northern Line)	
Part of KXL	no	no	**yes**	**yes**	
Keystone Pipeline Segment	Capacity in thousand bpd				Line Diameter
Hardisty to Steele City (MainLine)	435	591	591	591	30"/34"/30" (2)
Hardisty to Steele City (KXL)				700	36"
TOTAL Hardisty to Steele City (3)	**435**	**591**	**591**	**1291**	
Steele City to Wood River/Patoka	435	591	591	591	30"
Steele City to Cushing	0	591	591	700	36"
TOTAL out of Steele City	**435**	**591**	**591**	**1291**	
Lines operate		either/or batch	either/or batch	simultaneous	
Cushing to Gulf Coast					
Cushing to Nederland/(Houston spur)	**0**	**0**	**700**	**700**	36"
Commercial Operations Start Date	July 2010	Q1 2011	Q1 2013	Q1 2013	
Ability to Drop off Crudes at Cushing	no	yes	yes	yes	
Ability to Pick up Crudes at Cushing	no	(4)	(4)	(4)	
Ability to Pick up Bakken Crudes	no	no	no	(5)	
Net Totals					
WCSB to PADD2	435	591	591	1291	
PADD2 to PADD3 (USGC)	0	0	700	700	

Notes:

1. TransCanada use the term "Mainline" to describe the initial ("Base") Keystone system
2. 30" then 34" line in Canada, 30" in USA.
3. Potential eventual total Keystone capacity is stated as 1.5 mbd with likely 900,000 bpd to Gulf Coast.
4. Interest in picking up crudes at Cushing to move to GC being assessed under Cushing Market Link open season. Being offered for Q1 2013.
5. Interest in picking up Bakken crudes as XL line passes through Montana/Dakotas being assessed under Bakken Market Link open season. Being offered for Q1 2013.
6. The Bakken and Cushing Marketlink proposals are stated by TransCanada as not being part of KXL per se.

Exhibit 7-2

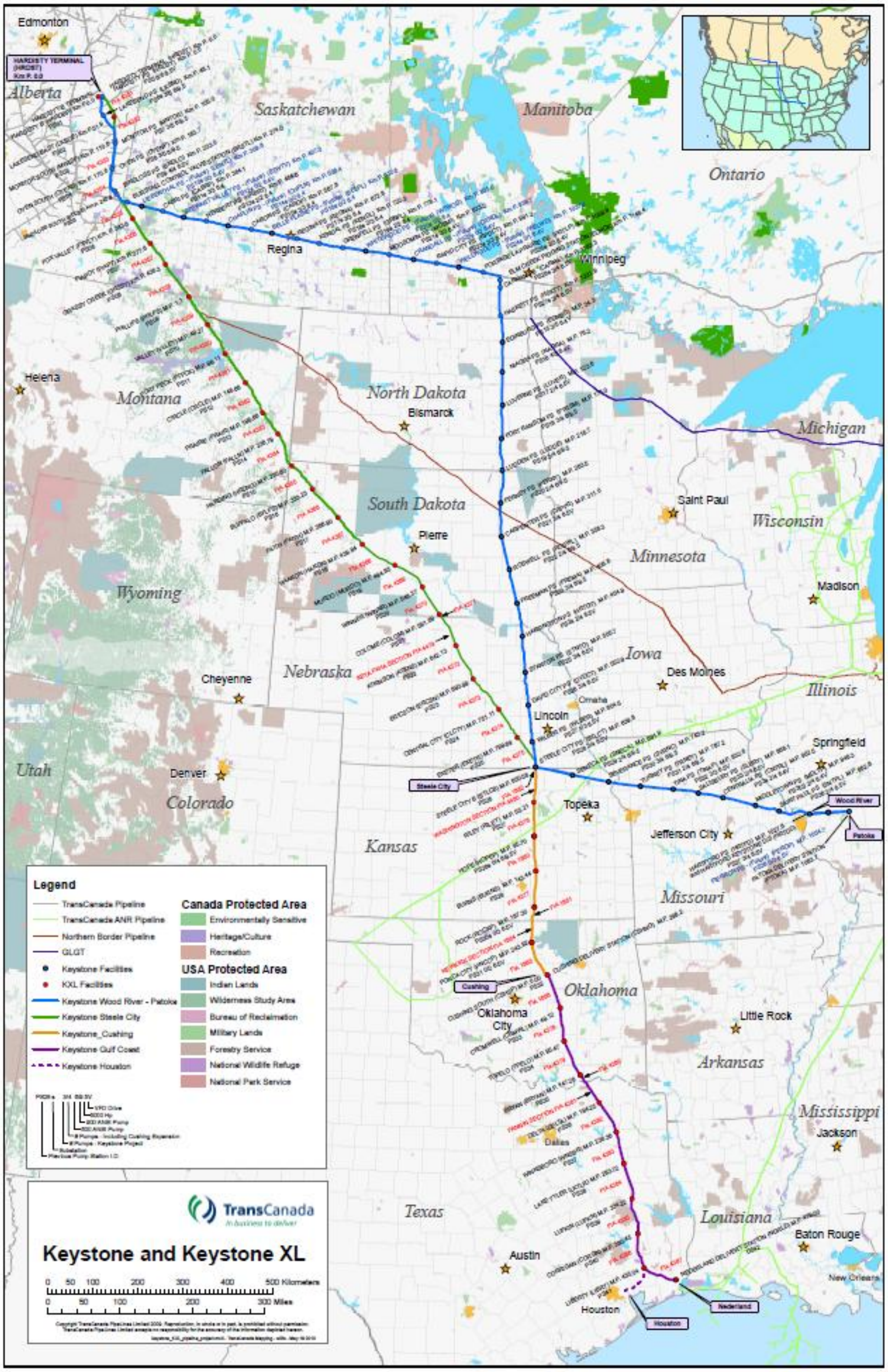

Alberta
Saskatchewan
Manitoba
Ontario
Montana
North Dakota
South Dakota
Minnesota
Wisconsin
Michigan
Wyoming
Nebraska
Iowa
Illinois
Utah
Colorado
Kansas
Missouri
Oklahoma
Arkansas
Mississippi
Texas
Louisiana
Edmonton
Regina
Winnipeg
Helena
Bismarck
Pierre
Saint Paul
Madison
Des Moines
Cheyenne
Lincoln
Omaha
Denver
Topeka
Jefferson City
Springfield
Oklahoma City
Little Rock
Jackson
Dallas
Austin
Houston
Baton Rouge
New Orleans
Steele City
Wood River
Patoka
Cushing
Nederland
Legend
TransCanada Pipeline
TransCanada ANR Pipeline
Northern Border Pipeline
GLGT
Keystone Facilities
KXL Facilities
Keystone Wood River - Patoka
Keystone Steele City
Keystone_Cushing
Keystone Gulf Coast
Keystone Houston
Canada Protected Area
Environmentally Sensitive
Heritage/Culture
Recreation
USA Protected Area
Indian Lands
Wilderness Study Area
Bureau of Reclamation
Military Lands
Forestry Service
National Wildlife Refuge
National Park Service
TransCanada
Keystone and Keystone XL
0 50 100 200 300 400 500 Kilometers
0 50 100 200 300 Miles

Exhibit 7-3

Bakken Crude Takeaway Capacity - Current & Projects

Current		capacity bpd
Tesoro Mandan refinery		58,000
Pipeline		
Butte pipeline (to PADD4 refineries)		118,000
Enbridge North Dakota line to Clearbrook and PADD2 refineries		161,500
Rail		
EOG, Stanley ND to Cushing OK, (started up Dec 2009)	Dec 2009	65,000
Dakota Transport Systems, New Town ND to St. James LA	Dec 2010	20,000
Smaller facilities in ND		30,000
Total Current Takeaway Capacity from North Dakota & Eastern Montana (1)		**452,500**

Projects	**Planned in Service Date**	
Pipeline		
Enbridge Portal Reversal, Berthold ND to Enbridge Mainline at Cromer, Manitoba	Q1 2011	25,000
Enbridge Sour Service Cancellation on North Dakota line to Mainline at Clearbrook MN	Q1 2011	28,500
Butte Expansion (to PADD4)	Q1 2011	32,000
Butte Loop (to PADD4)	Q1 2012	50,000
Plains North American Bakken North Project, Trenton ND to Enbridge Mainline and/or Keystone Mainline at Regina Saskatchewan	Q4 2012	50,000
Enbridge Bakken Expansion, Berthold ND to Enbridge Mainline at Cromer, Manitoba (3)	Q1 2013	120,000
Keystone XL Bakken Interconnect, Baker MT (4)	Q1 2013	100,000
Rail		
Hess, Tioga ND (5)	Q1 2012	60,000
Total Potential Additions		**465,500**
Total Current Plus Potential Additions		**918,000**
Total Current Plus Potential Additions - Pipelines Only		**743,000**

Notes:

1. Excludes variable truck takeaway that currently ranges from 0 to 25,000 bpd.
2. Project entails construction of a new line from Trenton ND, 50,000 bpd capacity expandable to 75,000 bpd, tieing in to the PAA 77,000 bpd Wascana pipeline that would be reversed to run north to Regina Saskatchewan. Sources: PAA website and Downstream Today.com. Project announced November 2010.
3. Ultimate 300,000 bpd capacity.
4. Estimate of tie-in capacity. Could be higher. Related Quintana BakkenLink project would of itself have 100,000 bpd capacity for gathering Bakken crudes and moving to Baker ND for tie-in to KXL line. Quintana projected start-up date is Q1 2013.
5. 120,000 bpd stated ultimate capacity.
6. Primary source for above data: North Dakota Pipeline Authority, North Dakota Petroleum Council Annual Meeting, Justin J. Kringstad, Sept 23, 2010, Minot, ND

Exhibit 7-4