WESTCOAST ENERGY INC.

2020 AND 2021 TRANSMISSION TOLL SETTLEMENT

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ARTICLE 1
INTRODUCTION

1.1 Negotiated Settlement

Westcoast Energy Inc. ("Westcoast") and the parties listed in Appendix A (collectively the "Stakeholders") have reached this Settlement Agreement (the "Agreement") regarding the determination of Westcoast's tolls for transmission service in Zones 3 and 4 for the 2020 and 2021 calendar years.

This Agreement is the result of negotiations between Westcoast and the Stakeholders and is entered into on the understanding that no single component of this Agreement is to be construed as representing the position of Westcoast or any of the Stakeholders on the appropriate tolls that would be obtained in the absence of this Agreement. Westcoast and the Stakeholders intend that this Agreement be viewed as a whole, and that no aspect of this Agreement should be considered as acceptable to Westcoast or any of the Stakeholders in isolation from all other aspects of this Agreement.

1.2 Objectives

Westcoast and the Stakeholders intend that this Agreement be interpreted and applied in good faith in a manner consistent with the spirit of the following objectives:

(a) to enhance the viability and competitiveness of the British Columbia natural gas basin by aligning more closely the interests of Westcoast and its shippers through a framework that encourages operating and capital efficiencies;

(b) to provide Westcoast's shippers with toll certainty and stability;

(c) to provide the lowest cost tolls possible while maintaining or improving pipeline service, efficiency, reliability, flexibility and utilization and without compromising safety or the environment;

(d) to maintain the financial integrity of Westcoast; and

(e) to reduce the resources used by Westcoast, its shippers and the Canada Energy Regulator (the "CER") in the traditional regulatory process.

1.3 Disclosure by Westcoast

Westcoast confirms that it has in the revenue requirement and toll information provided to the Stakeholders (including but not limited to the information package provided on October 31, 2019), in its responses to information requests from the Stakeholders (including the responses provided on November 19, 2019, December 11, 2019, January 14 and 16, 2020, March 16, 2020, and April 8, 22, and 24, 2020) with respect to such revenue requirement and toll information and in its settlement proposals, negotiations and discussions with the Stakeholders, provided full and fair disclosure of all relevant financial and accounting information that will or Westcoast reasonably expects may have an impact on Westcoast's revenue requirement in Zones 3 and 4 for 2020 and 2021. The parties recognize that financial and accounting information provided up to the date of this Agreement is based on good faith estimates and forecasts consistent with Westcoast's rate making practices. Westcoast will continue to provide such full and fair disclosure for the remainder of the term of this Agreement. The Stakeholders have relied and will rely in good faith on Westcoast's full and fair disclosure of all such financial and accounting information. Any Stakeholder who subsequently believes that Westcoast has not made such full and fair disclosure of all relevant financial or accounting information, that Westcoast knew or reasonably ought to have known about at the time disclosure should have been made, and such lack of disclosure related to a matter that has a total impact of more than $100,000 per year on Westcoast's revenue requirement in Zones 3 and 4 combined in 2020 or 2021, may raise the matter with the CER and seek appropriate relief, which may include adjustments to the tolls or components of this Agreement.

1.4 Meaning of "Flow-Through"

Westcoast and the Stakeholders agree that the term "flow-through" as used in this Agreement with respect to certain components of Westcoast's revenue requirement means that the cost adjustments, positive or negative, including all associated tax impacts, to the revenue requirement with respect to such components, will be to the account of shippers. The revenue requirement impact of any difference between the forecast and actual cost of those components of the revenue requirement to be treated on a flow-through basis will be recorded in the appropriate deferral account as set out in this Agreement and flowed through to the account of shippers.

1.5 2022 Information

Westcoast agrees to provide to the Stakeholders no later than November 16, 2021 an information package with respect to Westcoast's forecast revenue requirement and tolls in Zones 3 and 4 for 2022 in a form similar to the revenue requirement and toll information contained in the revenue requirement and toll information package provided by Westcoast to the Stakeholders on October 31, 2019.

ARTICLE 2
REVENUE REQUIREMENT

2.1 2020 and 2021 Revenue Requirement

Westcoast's tolls in Zones 3 and 4 will be based on a forecast revenue requirement of $611.502 million (including motor fuel and carbon taxes of $47.870 million) in 2020 and $651.501 million (including motor fuel and carbon taxes of $52.480 million) in 2021, in each case as set out in Appendix B, based on the following and subject to the provisions of this Agreement:

(a) Operating and Maintenance ("O&M") Expenses Excluding Pipeline Integrity O&M Expenses

The O&M expenses, excluding pipeline integrity O&M expenses, in Zones 3 and 4 for 2020 will be $88.000 million, consisting of $67.451 million of Direct O&M expenses and $20.549 million of Non-Direct O&M expenses. The O&M expenses, excluding pipeline integrity O&M expenses, in Zones 3 and 4 for 2021 will be $88.000 million, consisting of $69.776 million of Direct O&M expenses and $18.224 million of Non-Direct O&M Expenses. Direct O&M expenses will consist of all O&M expenses in Zones 3 and 4 other than (i) pipeline integrity O&M expenses and (ii) General and Administrative O&M expenses excluding Field Operation Benefits. Non-Direct O&M expenses will consist of all O&M expenses in Zones 3 and 4 other than (i) pipeline integrity O&M expenses and (ii) Direct O&M expenses.

For each of 2020 and 2021, for any variance between the Direct O&M expenses amounts of $67.451 million and $69.776 million for such year (the "Fixed Amount of Direct O&M expenses") and the actual Direct O&M expenses for such year, the portion of the variance that is:

(i) less than of equal to +/- $4 million from the Fixed Amount of Direct O&M expenses for such year will be shared 50% to the account of Westcoast and 50% to the account of shippers; and
(ii) greater than +/- $4 million from the Fixed Amount of Direct O&M expenses for such year will be 100% to the account of Westcoast.

Any such portion of the variance that is to the account of shippers in 2020 and 2021 will be recorded in the Direct O&M Expenses Deferral Account for amortization in 2021 and 2022, respectively.

Any variance between the Non-Direct O&M expenses amounts of $20.549 million and $18.224 million, respectively, for such year and the actual Non-Direct O&M expenses for such year will be to the account of Westcoast.

(b) Pipeline Integrity O&M Expenses

Pipeline integrity O&M expenses will be treated on a flow-through basis. For the purposes of this Agreement, pipeline integrity O&M expenses are those non-capitalized costs with respect to pipeline integrity programs which include, without limitation, programs related to stress corrosion cracking, geotechnical and hydrotechnical hazards, corrosion and pipeline re-coating necessary to address existing, new or unanticipated pipeline integrity issues.

The pipeline integrity O&M expenses allocated to Zones 3 and 4 are forecast to be $67.594 million in 2020 and $56.006 million in 2021. The revenue requirement impact of any difference between the forecast and actual pipeline integrity O&M expenses incurred by Westcoast in 2020 and 2021 will be recorded in the Pipeline Integrity Deferral Account for amortization in 2021 and 2022, respectively. It is the Stakeholders' expectation that the CER will continue to ensure the prudency of Westcoast's integrity management program and related costs.

(c) Shelley Incident Insurance Recoveries

The 2020 revenue requirement includes a credit of $30.000 million on account of forecast insurance recoveries by Westcoast in relation to the October 9, 2018 rupture of the NPS 36 pipeline between compressor stations 4A and 4B on the T-South system near Shelley, British Columbia (the "Shelley Incident"). Any difference between the forecast and actual Shelley Incident insurance recoveries by Westcoast will be recorded in the Shelley Incident Insurance Recoveries Deferral Account for amortization in the year following the year in which such insurance recoveries are recovered by Westcoast. This Agreement is not intended to limit the positions that may be taken by Westcoast or each of the Stakeholders regarding the Shelley Incident.

(d) CER Cost Recovery Expense

CER Cost Recovery expense will be treated on a flow-through basis. The forecast of CER Cost Recovery expense included in the revenue requirement is $3.111 million for 2020 and $3.111 million for 2021. The revenue requirement impact of any difference between the forecast and actual CER Cost Recovery expense incurred by Westcoast in each of 2020 and 2021 will be recorded in the CER Cost Recovery Deferral Account for amortization in 2021 and 2022, respectively.

(e) Depreciation

For 2020 and 2021, Westcoast's depreciation expense in Zone 3 and 4 will be determined based on the depreciation rates set out in Appendix C. The 2021 forecast of depreciation expense will be adjusted to reflect the adjustments to the rate base for 2021 contemplated by this Agreement.

Westcoast will provide the Stakeholders with an updated depreciation study before June 30, 2021.

(f) Amortization

Westcoast's amortization expense in Zones 3 and 4 will be $(0.578) million in 2020 and $(0.593) million in 2021. Amortization expense includes forecast toll settlement expenses of $150,000, offset by the amortization of contributions in aid of construction. Westcoast's actual toll settlement expenses will consist of all reasonable actual third party costs and disbursements incurred by Westcoast in connection with the negotiation, settlement and obtaining CER approval of this Agreement and in connection with the depreciation study referred to in Section 2.1(e) above. Westcoast's amortization expense in 2020 and 2021 will be adjusted to reflect any difference between the forecast and actual toll settlement expenses (including depreciation study expenses) rounded to the nearest $10,000 incurred by Westcoast.

(g) Property Taxes

Property taxes will be treated on a flow-through basis. The forecast of property taxes included in the revenue requirement is $64.851 million for 2020 and $66.149 million for 2021. The revenue requirement impact of any difference between the forecast and actual property tax expense incurred by Westcoast in each of 2020 and 2021 will be recorded in the Property Tax Deferral Account for amortization in 2021 and 2022, respectively. Westcoast will continue to work with governmental authorities in British Columbia in an effort to reduce property taxes.

(h) Motor Fuel Taxes

Motor fuel taxes will be treated on a flow-through basis and charged and recovered by Westcoast in accordance with the existing methodology. Westcoast will continue to work with governmental authorities in British Columbia in an effort to reduce motor fuel taxes.

(i) Carbon Taxes and Carbon Levies

Carbon taxes and levies will be treated on a flow-through basis and recovered by Westcoast in accordance with the same methodology used by Westcoast to charge and recover motor fuel tax.

(j) Income Tax Expense and Other Taxes

Westcoast's income tax expense in Zones 3 and 4 will be $0.032 million in 2020 and is forecast to be $0.016 million in 2021. The 2021 forecast will be adjusted to reflect the adjustments to the rate base for 2021 contemplated by this Agreement, the income tax impacts in 2021 associated with the 2020 deferral account balances that flow through in 2021 and any other adjustments to the forecast required as a result of this Agreement.

Any changes in Westcoast's tax expense for the 2020 or 2021 tax years resulting from changes in federal or provincial tax regimes including, without limitation:

(i) the introduction of new taxes, including taxes related to greenhouse gases and other air emissions, or the elimination of existing taxes;

(ii) changes in income tax rates, corporate capital tax rates or sales tax rates;

(iii) changes in legislation, regulations, rules, policies, procedures or case law affecting the application or interpretation of tax law, including changes in rules, policies or procedures of the Canada Revenue Agency; or

(iv) reassessments, regardless of whether they are initiated by the competent governmental authority or by Westcoast;

will be treated on a flow-through basis. The revenue requirement impact of any such changes for 2020 or 2021 will be recorded in the Income Tax Expense and Other Taxes Deferral Account for amortization in 2021 and 2022, respectively, provided that if any such change occurs after the term of this Agreement then the revenue requirement impact of such change, positive or negative, will flow through to shippers in the toll year in which such change occurs.

Westcoast will not draw down its booked deferred income taxes in 2020 or 2021.

(k) Gas Substitution Costs

Gas substitution costs, which consist of system gas management costs and swing gas costs, will be treated on a flow-through basis as follows:

(i) For each of 2020 and 2021, system gas management costs are forecast to be $1.080 million. The revenue requirement impact of any difference between the forecast and actual system gas management costs incurred by Westcoast in 2020 and 2021 will be recorded in the System Gas Management Deferral Account for amortization in 2021 and 2022, respectively.

(ii) For each of 2020 and 2021, swing gas costs are forecast to be zero. The revenue requirement impact of any swing gas costs incurred by Westcoast in 2020 or 2021 will be recorded in the Swing Gas Deferral Account for amortization in 2021 and 2022, respectively.

Prior to the expiration of the current system gas management agreement on December 31, 2020, Westcoast will consult with the Toll and Tariff Task Force ("TTTF") regarding the next agreement.

(l) Return on Rate Base

For 2020 and 2021, the deemed capital structure in Zones 3 and 4 will be as follows (subject to any adjustment to the funded and unfunded debt ratios as a result of any expansion facility expenditures in Zones 3 or 4):

	2020	2021
Common Equity	40.00%	40.00%
Funded Debt	56.29%	53.57%
Unfunded Debt	3.71%	6.43%
	100.00%	100.00%

The rate of return on rate base, including the calculation of the funded debt rate and the unfunded debt rate, will be calculated in accordance with the existing CER-approved methodology.

The rate of return on common equity for each of 2020 and 2021 will be 10.1%. Westcoast and the Stakeholders reserve the right to participate in any generic or pipeline specific cost of capital proceeding that is initiated by the CER or others that may affect or be relevant to the determination of Westcoast's cost of capital after the term of this Agreement. For greater certainty, Westcoast and the Stakeholders agree that they will not pursue or support any change to the 10.1% rate of return on common equity or the 40% common equity component of the deemed capital structure that would take effect during the term of this Agreement.

The cost rate for the new $250 million long term debt issue included in the unfunded debt component of the Zones 3 and 4 capital structure in 2020 will be deemed to be equal to what the cost rate would be on November 1, 2020 (the date on which the new long term debt is assumed to be issued) for a new long term debt issue assuming Westcoast's debt is rated A low by DBRS. For 2020, the forecast revenue requirement reflects a forecast deemed long term rate of 3.10% for the new long term debt issue. The revenue requirement impact associated with any change in the 2020 unfunded debt rate as a result of any difference between the forecast and actual timing, principal amount or deemed long term rate of the assumed November 1, 2020 new long term debt issue will be recorded in the Debt Rate Deferral Account for amortization in 2021. The 2020 funded debt rate and the 2020 revenue requirement will be updated to reflect the actual deemed long term rate for the assumed November 1, 2020 new long term debt issue.

The cost rate for the new $300 million long-term debt issue included in the unfunded debt component of the Zones 3 and 4 capital structure in 2021 will be deemed to be equal to what the cost rate would be on November 1, 2021 (the date on which the new long term debt is assumed to be issued) for a new long term debt issue assuming Westcoast's debt is rated A low by DBRS. For 2021, the forecast revenue requirement reflects a forecast deemed long term rate of 3.40% for the new long term debt issue. The revenue requirement impact associated with any change in the 2021 unfunded debt rate as a result of any difference between the forecast and actual timing, principal amount or deemed long term rate of the assumed November 1, 2021 new long term debt issue will be recorded in the Debt Rate Deferral Account for amortization in 2022. The 2021 funded debt rate and the 2021 revenue requirement will be updated to reflect the actual deemed long term rate for the assumed November 1, 2021 new long term debt issue.

The cost rate for short term debt included in the unfunded debt component of the Zones 3 and 4 capital structure in 2020 and 2021 will be equal to Westcoast's actual commercial paper rate each month, provided that if in any month Westcoast does not issue commercial paper then the short term debt rate for that month will be equal to the average for that month of the yield on 30 day Canadian Bankers' Acceptances for each day of that month as reported by Bloomberg Financial Services, plus 20 basis points. The revenue requirement reflects a forecast short term debt rate of 2.10% for 2020 and 2.10% for 2021. The revenue requirement impact associated with any change in the 2020 or 2021 unfunded debt rate as a result of any difference between the forecast and actual short term debt rate in each of 2020 and 2021 will be recorded in the Debt Rate Deferral Account for amortization in 2021 and 2022, respectively.

(m) Waste Heat Project

The Zone 4 revenue requirement will be credited (the "Waste Heat Project Credit") with the shippers' share of any amounts received by Westcoast from Enpower Green Energy Generation Inc. ("Enpower") or any assignee or successor in 2020 and 2021 in respect of Enpower's waste heat electrical generation projects installed at Compressor Stations 6A and 7 on the T-South system, such share being one half, pre-tax, of the "Energy Recovery Fee", all of the "Contract Operating Fee", site lease rent and the monetized value of any "Direct GHG Benefits", all as outlined in TTTF IRS 2006-01 dated March 16, 2006 and TTTF IRS 2006-01-1 dated June 16, 2006. For 2020 and 2021, the amount of the Waste Heat Project Credit is forecast to be $0.572 million in each year. The revenue requirement impact of any difference between the forecast and actual Waste Heat Project Credit in 2020 and 2021 will be recorded in the Waste Heat Project Credit Deferral Account for amortization in 2021 and 2022, respectively.

(n) Miscellaneous Operating Revenue

The Zones 3 and 4 revenue requirement will be credited (the "Miscellaneous Operating Revenue Credit") with the miscellaneous operating revenue received by Westcoast in 2020 and 2021, including forecast revenue associated with Westcoast's maintenance of third party meter stations in T-North, but not including revenue from the Waste Heat Project. For 2020 and 2021, the amount of the Miscellaneous Operating Revenue Credit is forecast to be $1.191 million in each year. The revenue requirement impact of any difference between the forecast and actual Miscellaneous Operating Revenue Credit in 2020 and 2021 will be recorded in the Miscellaneous Operating Revenue Credit Deferral Account for amortization in 2021 and 2022, respectively.

(o) Pipeline Abandonment Funding

In connection with the National Energy Board's Land Matters Consultation Initiative, Westcoast is required to collect from shippers and set aside amounts to fund the future cost to abandon its pipeline facilities in Zones 3 and 4. The amount that Westcoast will be required to collect and set aside in each of 2020 and 2021 will be determined in accordance with CER (or National Energy Board) decisions, orders or directions. Pipeline abandonment funding will be treated on a flow-through basis. The forecast revenue requirement for 2020 and 2021 includes $8.492 million as a forecast of the amount that Westcoast will be required to collect and set aside in each of 2020 and 2021 for pipeline abandonment funding. The revenue requirement impact of any difference between the forecast and actual amount of pipeline abandonment funds to be collected by Westcoast from shippers in 2020 and 2021 will be recorded in the Pipeline Abandonment Funding Deferral Account for amortization in 2021 and 2022, respectively.

All reasonable third party costs and disbursements incurred by Westcoast in connection with its participation in Land Matters Consultation Initiative proceedings, including any future CER proceedings or reviews relating to abandonment cost estimates or the pipeline abandonment funding collection and set-aside mechanism, and in maintaining its pipeline abandonment funding collection and set-aside mechanism, will be recorded in the Land Matters Consultation Initiative Deferral Account for amortization in the year following the year in which the costs and disbursements are incurred.

(p) Contract Demand Credits

Effective June 1, 2020, contract demand credits ("CDCs") will be determined in accordance with the amendments to Article 8 of the Westcoast Energy Inc. General Terms and Conditions – Service set out in Appendix D. The amendments to Article 8 are intended to reflect the parties' desire to remove the current entitlement to CDCs when the inability to provide firm service is due to integrity matters, major projects or planned maintenance work. The only other circumstances where Westcoast would be unable to provide firm service would be due to an outage of compressor facilities.

Any CDCs which are incurred by Westcoast in 2020 and 2021 will be included as part of the actual Direct O&M expenses in accordance with Section 2.1(a) above.

ARTICLE 3
RATE BASE

3.1 Rate Base and Maintenance Capital

The forecast average rate base is $2,955.751 million for 2020 and $3,518.439 million for 2021, as set out in Appendix E. These amounts include forecast maintenance capital expenditures transferred to Gas Plant In-Service of $71.104 million ($68.536 million, excluding AFUDC) in 2020 and $55.004 million ($53.748 million, excluding AFUDC) in 2021 (including in the case of each year, forecast general plant additions, AFUDC and ODC and excluding forecast capital expenditures for pipeline integrity). The 2020 and 2021 revenue requirement will not be adjusted for any difference between the forecast and actual maintenance capital expenditures.

3.2 Pipeline Integrity Capital

Pipeline integrity capital costs will be treated on a flow-through basis. For purposes of this Agreement, pipeline integrity capital expenditures are those capital expenditures with respect to pipeline integrity programs which include, without limitation, programs related to stress corrosion cracking, geotechnical and hydrotechnical hazards, corrosion and pipeline re-coating necessary to address existing, new or unanticipated pipeline integrity issues.

The forecast average rate base and revenue requirement includes forecast pipeline integrity capital expenditures transferred to Gas Plant In-Service, including AFUDC, of $49.826 million ($47.134 million, excluding AFUDC) in 2020 and $38.702 million ($37.717 million, excluding AFUDC) in 2021. The revenue requirement impact of any difference between the forecast and actual pipeline integrity capital expenditures incurred by Westcoast in 2020 and 2021 will be recorded in the Pipeline Integrity Deferral Account for amortization in 2021 and 2022, respectively.

3.3 High Pine Expansion Project

Capital expenditures associated with the High Pine Expansion Project, approved by NEB Order XG-W102-024-2016, will be treated on a flow-through basis. The forecast average rate base and revenue requirement includes forecast capital expenditures transferred to Gas Plant In-Service, including AFUDC, of $8.198 million ($8.193 million excluding AFUDC) in 2020 and $1.804 million ($1.802 million excluding AFUDC) in 2021. The revenue requirement impact of any difference between the forecast and actual project capital expenditures incurred by Westcoast in 2020 and 2021, and the revenue requirement impact of any difference between the forecast and actual timing of such capital expenditures and in-service date of the project, will be recorded in the High Pine Expansion Project Deferral Account for amortization in 2021 and 2022, respectively.

3.4 Jackfish Lake Expansion Project

Capital expenditures associated with the Jackfish Lake Expansion Project, approved by NEB Order XG-W102-018-2016, will be treated on a flow-through basis. The forecast average rate base and revenue requirement includes project forecast capital expenditures transferred to Gas Plant In-Service, including AFUDC, of $0.345 million ($0.345 million excluding AFUDC) in 2020 and nil in 2021. The revenue requirement impact of any difference between the forecast and actual project capital expenditures incurred by Westcoast in 2020 and 2021, and the revenue requirement impact of any difference between the forecast and actual timing of such capital expenditures and in-service date of the project, will be recorded in the Jackfish Lake Expansion Project Deferral Account for amortization in 2021 and 2022, respectively.

3.5 Wyndwood Pipeline Expansion Project

Capital expenditures associated with the Wyndwood Pipeline Expansion Project, approved by NEB Order XG-W102-014-2017, will be treated on a flow-through basis. The forecast average rate base and revenue requirement includes project forecast capital expenditures transferred to Gas Plant In-Service, including AFUDC, of $2.748 million ($2.746 million excluding AFUDC) in 2020 and $0.300 million ($0.300 million excluding AFUDC) in 2021. The revenue requirement impact of any difference between the forecast and actual project capital expenditures incurred by Westcoast in 2020 and 2021, and the revenue requirement impact of any difference between the forecast and actual timing of such capital expenditures and in-service date of the project, will be recorded in the Wyndwood Pipeline Expansion Project Deferral Account for amortization in 2021 and 2022, respectively.

3.6 Spruce Ridge Program

Capital expenditures associated with the Spruce Ridge Program, a Zone 3 expansion project approved by National Energy Board Orders XG-W102-032-2018, XG-W102-033-2018 and TG-009-2018, will be treated on a flow-through basis. The forecast average rate base and revenue requirement includes program forecast capital expenditures transferred to Gas Plant In-Service, including AFUDC, of nil in 2020 and $541.362 million ($493.562 million excluding AFUDC) in 2021. The revenue requirement impact of any difference between the forecast and actual program capital expenditures incurred by Westcoast in 2020 and 2021, and the revenue requirement impact of any difference between the forecast and actual timing of such capital expenditures and in-service date of the program, will be recorded in the Spruce Ridge Program Deferral Account for amortization in 2021 and 2022, respectively.

3.7 T-South Reliability and Expansion Program

Capital expenditures associated with the T-South Reliability and Expansion Program, approved by CER Orders XG-021-2019, XG-022-2019, XG-023-2019 and XG-024-2019, will be treated on a flow-through basis. The forecast average rate base and revenue requirement includes program forecast capital expenditures transferred to Gas Plant In-Service, including AFUDC, of $120.847 million ($116.495 million excluding AFUDC) in 2020 and $779.410 million ($719.138 million excluding AFUDC) in 2021. The revenue requirement impact of any difference between the forecast and actual program capital expenditures incurred by Westcoast in 2020 and 2021, and the revenue requirement impact of any difference between the forecast and actual timing of such capital expenditures and in-service date of the program, will be recorded in the T-South Reliability and Expansion Program Deferral Account for amortization in 2021 and 2022, respectively.

3.8 Other Expansion Facilities

The forecast revenue requirement for 2020 and 2021 does not include any capital expenditures or O&M or other expenses by Westcoast on account of any other facilities (“Other Expansion Facilities”) designed to increase the physical and contractible capacity of the Pipeline System in Zone 3 or 4.

Any capital expenditures or O&M or other expenses incurred by Westcoast in 2020 or 2021 on account of any Other Expansion Facilities will be treated on a flow-through basis and the revenue requirement impact associated with any difference between the forecast and actual expenditures and other expenses incurred by Westcoast in 2020 and 2021 on account of any such Other Expansion Facilities, and the revenue requirement impact of any difference between the forecast and actual timing of such expenditures and in-service date of any such Other Expansion Facilities, will be recorded in the Other Expansion Facilities Deferral Account for amortization in 2021 and 2022, respectively.

3.9 Expansion Facilities Approvals

This Agreement does not bind any party to supporting the approval or rolling-in of the costs of expansion facilities.

3.10 Reliability and Maintainability Program

Capital expenditures associated with the Reliability and Maintainability Program will be treated on a flow-through basis. The Reliability and Maintainability Program includes the following components: (i) the CS-6B Compressor Station Upgrade Project approved by NEB Order XG-W102-002-2016, (ii) the CS-8A Compressor Upgrade Project approved by NEB Order XG-W102-044-2015, (iii) the CS-9 Compressor Station Upgrade Project approved by NEB Order XG-W102-008-2016, and (iv) the upgrade of existing small bore crossovers in Zone 4 with 24" crossovers and installation of new crossovers on key pipeline segments in Zone 4, as described in presentations to the TTTF in December of 2014 and June of 2015. The forecast average rate base and revenue requirement includes forecast program capital expenditures transferred to Gas Plant In-Service, including AFUDC, of $2.714 million ($2.712 million excluding AFUDC) in 2020 and nil in 2021. The revenue requirement impact associated with any difference between the forecast and actual capital expenditures incurred by Westcoast in 2020 and 2021 on account of the Reliability and Maintainability Program, and any revenue requirement impact of any difference between the forecast and actual timing of such expenditures and in-service date of any component of the program, will be recorded in the Reliability and Maintainability Program Deferral Account for amortization in 2021 and 2022, respectively.

3.11 Pipeline Class Location Upgrades

Pipeline class location upgrade capital expenditures will be treated on a flow-through basis. For purposes of this Agreement, pipeline class location upgrade capital expenditures are those capital expenditures incurred by Westcoast in connection with Westcoast's pipeline class location upgrade program described in Article 8.

The forecast average rate base and revenue requirement includes forecast pipeline class location upgrade capital expenditures transferred to Gas Plant In-Service, including AFUDC, of $44.047 million ($43.605 million excluding AFUDC) in 2020 and $52.030 million ($51.500 million excluding AFUDC) in 2021. The revenue requirement impact of any difference between the forecast and actual pipeline class location upgrade capital expenditures incurred by Westcoast in 2020 and 2021 will be recorded in the Pipeline Class Location Upgrade Program Deferral Account for amortization in 2021 and 2022, respectively.

3.12 Update of 2021 Rate Base and Revenue Requirement

The forecast average rate base and revenue requirement for 2021 will be updated to reflect (i) actual pipeline integrity capital expenditures, actual expansion facility capital expenditures, actual Reliability and Maintainability Program capital expenditures, actual pipeline class location upgrade capital expenditures, and any other compressor upgrade/replacement capital expenditures and any shipper requested capital expenditures in 2020, (ii) the 2020 year-end deferral account balances, (iii) an updated forecast of the capital expenditures for the items listed in (i) above, any other expansion facility capital expenditures, any other compressor upgrade/replacement capital expenditures and any shipper requested capital expenditures in 2021, and (iv) any other adjustments to the forecast required as a result of this Agreement.

3.13 AFUDC Rate

For 2020, the AFUDC rate will be 6.47%. The AFUDC rate for 2021 will be the rate of return on rate base for 2021.

3.14 Material Asset Divestitures

The revenue requirement impact associated with any Zone 3 or 4 asset divestitures by Westcoast in 2020 or 2021 that have the effect of decreasing net plant in service by an aggregate amount of $5 million or more in any such year will be treated on a flow-through basis and recorded in the Material Asset Divestiture Deferral Account for amortization in 2021 and 2022, respectively. Westcoast confirms that as of the date of this Agreement, it has no plans for any material Zone 3 or 4 asset divestitures.

ARTICLE 4
DEFERRAL ACCOUNTS

4.1 Deferral Accounts

Westcoast will maintain for accounting and toll making purposes the cost of service and revenue deferral accounts in 2020 and 2021 set out in Sections 4.2 and 4.3. It is the intent of the parties that the year-end balance of each deferral account will, together with interest thereon, flow through to the account of shippers (and thus be reflected in the calculation of the revenue requirement and the final tolls) for 2021 and 2022, respectively, in accordance with the existing methodology, provided that the Stakeholders will not be precluded from reviewing and making submissions to the CER concerning the reasonableness of the year-end balance of any of the deferral accounts set out in Sections 4.2 and 4.3. In this regard, in the event that the Shelley Incident Insurance Recoveries Deferral Account records total insurance recoveries of less than the $30.000 million credit referenced in section 2.1(c), Westcoast will provide the Stakeholders with access to the final insurance claims adjustment report for the claim.

Interest on the deferral balances will be calculated monthly based on Westcoast’s rate of return on rate base.

4.2 Cost of Service Deferral Accounts

The cost of service deferral accounts will be as follows:

(a) Direct O&M Expenses: This deferral account will record such portion of the variance between the Direct O&M expenses and the Fixed Amount of Direct O&M expenses in 2020 and 2021 that is to the account of shippers, as set out in Section 2.1(a).

(b) Pipeline Integrity: This deferral account will record the revenue requirement impact of any difference between forecast and actual pipeline integrity O&M expenses and capital expenditures, as set out in Sections 2.1(b) and 3.2.

(c) Shelley Incident Insurance Recoveries: This deferral account will record the revenue requirement impact of any difference between the forecast Shelley Incident insurance recovery amount of $30 million that has been credited to the 2020 revenue requirement and the actual amount of such insurance recovered by Westcoast, as set out in Section 2.1(c).

(d) CER Cost Recovery: This deferral account will record the revenue requirement impact of any difference between forecast and actual CER Cost Recovery expense, as set out in Section 2.1(d).

(e) Property Taxes: This deferral account will record the revenue requirement impact of any difference between forecast and actual property tax expense, as set out in Section 2.1(g).

(f) Income Tax Expense and Other Taxes: This deferral account will record the revenue requirement impact of any changes in Westcoast's tax expense resulting from changes in federal or provincial tax regimes, as set out in Section 2.1(j) and Scientific Research and Experimental Development and Capital Cost Review credits, if any.

(g) System Gas Management Costs: This deferral account will record the revenue requirement impact of any difference between forecast and actual system gas management costs, as set out in Section 2.1(k)(i).

(h) Swing Gas Costs: This deferral account will record the revenue requirement impact of any difference between forecast and actual swing gas costs, as set out in Section 2.1(k)(ii).

(i) Debt Rate: This deferral account will record the revenue requirement impact associated with any difference between the forecast and actual long term and short term debt rates, as set out in Section 2.1(l).

(j) Pipeline Abandonment Funding: This deferral account will record the revenue requirement impact of any difference between the forecast and actual amount of pipeline abandonment funds to be collected and set aside by Westcoast in 2020 and 2021, as set out in Section 2.1(o).

(k) Land Matters Consultation Initiative: This deferral account will record the revenue requirement impact of all reasonable third party costs and disbursements incurred by Westcoast in connection with its participation in Land Matters Consultation Initiative proceedings and in maintaining its pipeline abandonment funding collection and set-aside mechanism, as set out in Section 2.1(o).

(l) High Pine Expansion Project: This deferral account will record the revenue requirement impact of any difference between forecast and actual capital expenditures for the High Pine Expansion Project, as set out in Section 3.3.

(m) Jackfish Lake Expansion Project: This deferral account will record the revenue requirement impact of any difference between forecast and actual capital expenditures for the Jackfish Lake Expansion Project, as set out in Section 3.4.

(n) Wyndwood Pipeline Expansion Project: This deferral account will record the revenue requirement impact of any difference between forecast and actual capital expenditures for the Wyndwood Pipeline Expansion Project, as set out in Section 3.5.

(o) Spruce Ridge Program: This deferral account will record the revenue requirement impact of any difference between forecast and actual capital expenditures for the Spruce Ridge Program, as set out in Section 3.6.

(p) T-South Reliability and Expansion Program: This deferral account will record the revenue requirement impact of any difference between forecast and actual capital expenditures for the T-South Reliability and Expansion Program, as set out in Section 3.7.

(q) Other Expansion Facilities: This deferral account will record the revenue requirement impact associated with any other expansion facility expenditures in Zone 3 or 4, as set out in Section 3.8.

(r) Reliability and Maintainability Program: This deferral account will record the revenue requirement impact associated with any difference between the forecast and actual capital expenditures related to the Reliability and Maintainability Program, as set out in Section 3.10.

(s) Pipeline Class Location Upgrade Program: This deferral account will record the revenue requirement impact of any difference between forecast and actual pipeline class location upgrade capital expenditures, as set out in Section 3.11.

(t) Material Asset Divestitures: This deferral account will record the revenue requirement impact associated with any material asset divestitures, as set out in Section 3.14.

(u) Material Changes in Costs: This deferral account will record any changes in costs resulting from:

(i) changes in legislation, regulations or ordinances or the issuance of orders or directives that result in changes to safety, health or environmental requirements (including those relating to greenhouse gases and other air emissions), practices or procedures for Westcoast, to the extent that the aggregate costs exceed $100,000 in any year;

(ii) changes in applicable accounting standards of the Canadian Institute of Chartered Accountants (the “CICA”), if approved by the CER for Westcoast’s accounting and toll making purposes; or

(iii) orders or directives issued by a regulatory authority having jurisdiction, including the CER, to the extent that the aggregate costs exceed $100,000 in any year.

(v) Shipper Requested Programs: This deferral account will record the revenue requirement impact (and any incremental revenue) associated with programs implemented or to be implemented by Westcoast that are voted on by the TTTF and for which the vote result is unanimous or unopposed.

(w) SRED Consulting: This deferral account will record any amount payable by Westcoast to the tax consultant retained by Westcoast to pursue Scientific Research and Experimental Development tax credits. Any tax credits themselves will be recorded in the Income Tax Expense and Other Taxes deferral account in Section 4.2(f).

(x) Compressor Upgrade/Replacement: This deferral account will record the revenue requirement impact associated with any difference between the forecast and actual compressor upgrade/replacement expenditures in Zones 3 or 4, as set out in Section 7.2.

(y) Capital Cost Review Consulting: This deferral account will record the revenue requirement impact associated with any difference between the forecast and actual costs paid to the tax consultant retained by Westcoast to pursue Capital Cost Review tax credits. Any tax credits themselves will be recorded in the Income Tax Expense and Other Taxes deferral account in Section 4.2(f).

4.3 Revenue Deferral Accounts

The revenue deferral accounts will be as follows:

(a) Contract Demand: This deferral account will record the impact on fixed cost collection resulting from differences between the forecast and actual contract demand allocation units that are used to fix the term differentiated firm service tolls, separately for each of Zone 3 and Zone 4, as set out in Section 5.4.

(b) Discretionary Revenue: This deferral account will record any difference between the forecast and actual revenue from Interruptible Service (“IT”), Authorized Overrun Service (“AOS”), short term firm service and any other discretionary service credited in calculating the 2020 and 2021 demand tolls, separately for each of Zone 3 and Zone 4, as set out in Sections 5.2 and 5.3.

(c) Waste Heat Project Credit: This deferral account will record any difference between the forecast and actual Waste Heat Project Credit credited in calculating the Zone 4 revenue requirement for 2020 and 2021, as set out in section 2.1(m)

(d) Miscellaneous Operating Revenue Credit: This deferral account will record any difference between the forecast and actual Miscellaneous Operating Revenue Credit credited in calculating the Zones 3 and 4 revenue requirement for 2020 and 2021, as set out in Section 2.1(n).

ARTICLE 5
TOLLS

5.1 Toll Design

Westcoast's tolls in Zones 3 and 4 will be calculated in accordance with the toll design approved by the National Energy Board or the CER for Zones 3 and 4, including the changes approved by the National Energy Board in its RHW-1-2005 Reasons for Decision. Westcoast or any Stakeholder may make any toll design proposals for consideration by the TTTF or make toll design applications to the CER for changes in the toll design to become effective during the term of this Agreement.

Westcoast will not offer short term firm service in Zone 3 or Zone 4 during the term of this Agreement unless such proposals are discussed and voted on by the TTTF and for which the vote result is unanimous or unopposed. Westcoast will, subject to the availability of capacity, offer short term firm service in Zone 3 or Zone 4 during the term of this Agreement if such proposals are discussed and voted on by the TTTF and for which the vote result is unanimous or unopposed. Westcoast or any of the Stakeholders may apply to the CER for Westcoast to offer short term firm service for which the TTTF vote result is not unanimous or unopposed, and Westcoast or any of the Stakeholders may oppose or support such applications to the CER.

For each of 2020 and 2021, all revenue collected by Westcoast from IT, AOS and short term firm service in Zone 3 will be for the account of shippers in Zone 3.

For each of 2020 and 2021, all revenue collected by Westcoast from IT, AOS and short term firm service in Zone 4 will be for the account of shippers in Zone 4.

5.2 2020 Tolls

Westcoast's illustrative tolls in Zones 3 and 4 for 2020, as determined pursuant to this Agreement, are set out in Appendix F. Westcoast will as soon as reasonably practicable after Westcoast's actual results are available for 2019 update the 2020 forecast revenue requirement to reflect the actual 2019 year-end cost of service and revenue deferral account balances and apply to the CER for approval of final tolls for 2020 that are (i) in the case of the period from January 1, 2020 to the last day of the month in which the CER gives such approval, equal to the interim tolls approved by CER Order TGI-05-2019 dated December 9, 2019, and (ii) in the case of the period from the first day of the month immediately following the month in which the CER gives such approval to December 31, 2020, based on such updated forecast of the 2020 revenue requirement. Westcoast will consult with and provide the Stakeholders with the opportunity to review and comment on the updated 2020 tolls with the intention that Westcoast and the Stakeholders will agree on the update.

The tolls in Zone 3 for 2020 reflect a credit of $4.000 million for forecast revenue from IT and AOS in Zone 3 in 2020. The tolls in Zone 4 for 2020 reflect a credit of $12.000 million for forecast revenue from IT and AOS in 2020. Any difference between the forecast and actual revenue from IT, AOS and any other discretionary service in 2020 in Zones 3 and 4 will be recorded in the Discretionary Revenue Deferral Account for amortization as agreed upon after the Agreement term.

5.3 2021 Tolls

Westcoast will by December 1, 2020 apply to the CER for approval of interim tolls for Zones 3 and 4 for 2021, based on a forecast of the tolls for 2021, having regard for the adjustments, including the changes in allocation units and the forecast revenue from IT and AOS, contemplated by this Agreement. Such application will include sufficient supporting schedules and explanatory information necessary to establish that the tolls have been determined in accordance with this Agreement. Westcoast will consult with and provide the Stakeholders with the opportunity to review and comment on the 2021 toll filing with the intention that Westcoast and the Stakeholders will agree on the filing. The final form of the 2021 toll filing will be at Westcoast’s discretion, but any Stakeholder may make submissions to the CER regarding appropriate amendments. In preparing such application Westcoast will also consult with the Stakeholders to determine whether the forecast of 2021 pipeline integrity O&M and capital expenditures, pipeline class location upgrade capital expenditures, CER cost recovery expense, property taxes and short term and long term debt rates, expansion facility or compressor upgrade/replacement capital expenditures and O&M and other expenses, and any other flow-through items, should be updated to reflect current information at that time.

The tolls for 2021 will include a credit of $4.000 million in Zone 3 and $12.000 million in Zone 4 for forecast revenue from IT and AOS in 2021. Any difference between the forecast and actual revenue from IT, AOS and any other discretionary service in 2021 in Zones 3 and 4 will be recorded in the Discretionary Revenue Deferral Account for amortization as agreed upon after the Agreement term.

Westcoast will as soon as reasonably practicable after Westcoast’s 2020 actual results are available apply to the CER for final 2021 tolls, and will make any necessary amendments to the 2021 toll application to reflect the actual 2020 results. Westcoast will consult with and provide the Stakeholders with the opportunity to review and comment on the amendments with the intention that Westcoast and the Stakeholders will agree on the amendments.

5.4 Allocation Units

The Contract Demand allocation units used to calculate the illustrative tolls for 2020 set out in Appendix F are the forecast of allocation units in Zones 3 and 4 for 2020 set out in Appendix G. Any variance in Contract Demand revenue in 2020 arising from any difference between the forecast and actual Contract

Demand allocation units in Zones 3 and 4 that are used to fix the term differentiated firm service tolls for 2020 will be recorded in the Contract Demand Deferral Account for amortization in 2021.

The Contract Demand allocation units used to calculate the tolls for 2021 will be forecast by Westcoast at the time it applies to the CER for approval of the 2021 tolls. Westcoast will review the 2021 forecast of Contract Demand allocation units with the Stakeholders with the intention that Westcoast and the Stakeholders will agree on the forecast. Any variance in Contract Demand revenue in 2021 arising from any difference between the forecast and actual Contract Demand allocation units in Zones 3 and 4 that are used to fix the term differentiated firm service tolls for 2021 will be recorded in the Contract Demand Deferral Account for amortization in 2022.

ARTICLE 6
NEW SERVICES AND PRODUCTS

6.1 New Services and Products

New services and products, if any, proposed by Westcoast or any of the Stakeholders in 2020 or 2021 and the treatment of the associated costs and revenues will be considered by the TTTF prior to implementation. Westcoast will implement those new services and products that are voted on by the TTTF and for which the vote result is unanimous or unopposed (including by Westcoast). Westcoast or any of the Stakeholders may apply to the CER for approval to implement those new services and products for which the TTTF vote result is not unanimous or unopposed, and Westcoast or any of the Stakeholders may oppose such applications to the CER.

ARTICLE 7
COMPRESSOR UPGRADE/REPLACEMENT PROGRAM

7.1 Annual Status Report

Westcoast will by the end of the third quarter of each year of the term of this Agreement report to the TTTF on the status of Westcoast’s compressor upgrade/replacement program for Zones 3 and 4. This report will include a presentation to the TTTF outlining the status of work on the upgrade program.

7.2 Compressor Upgrades/Replacements

The forecast revenue requirement for 2020 and 2021 does not include any capital expenditures or O&M or other expenses by Westcoast on account of any compressor upgrades/replacements in Zone 3 or 4, except for forecast capital expenditures associated with the T-South Reliability and Expansion Program, as set out in Section 3.7 and the Reliability and Maintainability Program, as set out in Section 3.10.

Any capital expenditures or O&M or other expenses incurred by Westcoast in 2020 or 2021 on account of any other compressor upgrades/replacements in Zone 3 or 4 will be treated on a flow-through basis and the revenue requirement impact associated with any difference between the forecast and actual expenditures incurred by Westcoast in 2020 and 2021 on account of any such compressor updates/replacements, and any revenue requirement impact of any difference between the forecast and actual timing of such expenditures and in-service date of any such compressor replacement/upgrade, will be recorded in the Compressor Upgrade/Replacement Deferral Account for amortization in 2021 and 2022, respectively.

7.3 Emission Reduction Requirements Plan

If during the term of this Agreement, the federal or provincial government imposes or announces an intention to impose mandatory emission reduction requirements or other compliance obligations associated with air emissions (including an emission cap and tradeable permit system) on Westcoast, then Westcoast will, within six months of such imposition or announcement, provide to the TTTF a detailed emission reduction or compliance obligation plan (which plan will include consideration of a compressor upgrade/replacement program) covering a minimum period of five years describing how Westcoast intends to comply with such mandatory emission reduction requirements or compliance obligations. If Westcoast decides to proceed to implement such plan commencing during the term of this Agreement, then Westcoast will make the necessary applications to the CER (including, if necessary, an application for a deferral account to record any costs incurred by Westcoast during the term of this Agreement) and the Stakeholders will be free to take whatever positions they wish to take with respect to Westcoast's application.

ARTICLE 8
PIPELINE CLASS LOCATION UPGRADE PROGRAM

8.1 Pipeline Class Location Upgrade Program

Westcoast has, as a result of population encroachments on its pipeline facilities in Zones 3 and 4, implemented a pipeline class location upgrade program in compliance with the requirements of the National Energy Board Onshore Pipeline Regulations under the *Canadian Energy Regulator Act*. The Stakeholders are concerned by the magnitude, frequency and uncertainty of costs associated with the program, and the resulting impact on transmission tolls. Although the Stakeholders understand and accept that Westcoast cannot control land use adjacent to its right of way, Westcoast will diligently consult with governmental authorities in British Columbia, industry associations, commercial parties and landowners in a proactive effort to reduce the costs of the program after a thorough consideration of cost effective long-term alternatives.

Westcoast will by the end of the third quarter in each of 2020 and 2021 report to the TTTF on the status of the pipeline class location upgrade program. The reports, sponsored by a Westcoast representative with responsibility for overall program strategy, will include:

(a) the status of each class location upgrade project completed and the scope, timing and status of each project to be completed within the following five years;

(b) the actual capital costs of each completed project and the estimated capital costs of each current and future project;

(c) the expected impacts on transmission tolls;

(d) the estimated duration and timeframe of any anticipated outages that may result from program work;

(e) a discussion of best practices and industry trends in managing pipeline class location upgrades; and

(f) a summary and explanation of the alternatives considered by Westcoast for each current and future project, which reflect the long-term nature of the program and proactively mitigate program costs.

In addition to the annual reporting, Westcoast will provide the TTTF with a copy of any notification filed by Westcoast under Section 42 of the National Energy Board Onshore Pipeline Regulations concurrently with the filing of such notification. In addition, Westcoast will provide an update to the TTTF as soon as practical after identifying a new class location upgrade project or determining the need for a material change to a project previously reported to the TTTF. The updates will include the project scope, estimated capital cost, timing and alternatives considered.

ARTICLE 9
OTHER INITIATIVES

9.1 Capacity Benchmarking

Westcoast will report to the TTTF in a timely fashion any positive or negative changes in the contractible capacity of any pipeline segment in Zones 3 and 4 of more than 20 MMcf/d on a cumulative basis compared to the contractible capacity of that segment as of the date of this Agreement. Westcoast will also post any such cumulative change on its bulletin board as a critical notice together with a brief explanation for the change.

ARTICLE 10
GENERAL

10.1 CER Approval

This Agreement is subject to CER approval and Westcoast and the Stakeholders agree that this Agreement will terminate if it is not approved in its entirety by the CER. Westcoast and the Stakeholders also acknowledge that all matters respecting Westcoast's tolls, including the tolls under this Agreement and the ultimate adjudication of any disputes which arise out of this Agreement which cannot be resolved by Westcoast and the Stakeholders in accordance with the terms of this Agreement, will be determined by the CER.

10.2 Application to the CER

Westcoast will, as soon as practical, prepare an application to the CER to give effect to the terms and conditions of this Agreement. Each of the Stakeholders agrees to actively support or not oppose the application and the approval of this Agreement and the tolls determined under this Agreement by the CER.

10.3 Surveillance Reports

Westcoast will file quarterly and year end surveillance reports with the CER with respect to Zones 3 and 4 in accordance with the CER's requirements for Group 1 pipeline companies, supplemented with the following information:

(a) revenue requirement/cost of service summary by Zones 3 and 4 (year-end); and

(b) average rate base summary by Zones 3 and 4 (year-end).

10.4 TTTF Reports

Westcoast will also provide monthly reports to the TTTF covering each of the following with respect to Zones 3 and 4:

(a) discretionary revenue, interruptible volumes and daily volumes;

(b) changes between forecast and actual allocation units and deferral account balances; and

(c) any information presented to the CER regarding pipeline integrity activities (one month following each presentation).

Westcoast will also provide annual reports to the TTTF covering each of the following:

(a) income tax expense;

(b) status of tax assessments and any reassessments;

(c) UCC/capital cost allowance;

(d) long term debt;

(e) short term debt;

(f) capital expenditures shown on pages 19 and 20 of the information package provided by Westcoast to the Stakeholders on October 31, 2019:

(i) forecast versus actual costs;

(ii) material changes in scope and cost of forecast projects;

(iii) summary of projects deferred and new projects added;

(iv) explanation of any cost overruns of greater than 10% from original forecast of projects transferred to gas plant in-service; and

(v) designation of each project as either a maintenance, integrity, compressor upgrade or expansion project; and

(g) forecast and actual pipeline operations direct O&M costs and full time equivalents charged to cost of service.

Westcoast will also provide reports to the TTTF as described in its filing with the CER dated February 28, 2020 [Filing No. C04899], pursuant to the direction received in the GHW-002-2018 Reasons for Decision.

10.5 Audit

If the TTTF votes to conduct an audit and the vote result is unanimous or unopposed (with Westcoast abstaining), then an independent compliance audit(s) by a qualified firm of nationally recognized chartered accountants will be conducted at any time up to the end of 2022 with respect to the determination of final tolls under this Agreement for 2020 and 2021. The external costs of the audit(s) will flow through to the account of shippers. Westcoast will provide the auditors selected to conduct the audit(s) with reasonable access to the source data necessary for the conduct of the audit(s), provided that the auditors will be required to execute and deliver to Westcoast a confidentiality agreement in a form satisfactory to Westcoast pursuant to which the auditors agree to maintain confidential any of the source data identified by Westcoast as confidential.

10.6 Dispute Resolution

In the event of any dispute under this Agreement, including a dispute respecting the determination of tolls and a dispute respecting the application of this Agreement, Westcoast and the Stakeholders will in good faith attempt to resolve the dispute. If a satisfactory resolution cannot be achieved within 30 days, Westcoast or any of the Stakeholders or any shipper may file an application with the CER requesting the CER to adjudicate the matter in dispute. Any such application must also contain a request that the CER deal with the matter in dispute on an expedited basis and may contain a request that tolls be made interim pending the CER’s decision with respect to the matter.

10.7 Right to Initiate Review

The Stakeholders may initiate a review of this Agreement and the determination of Westcoast’s tolls in Zones 3 and 4 under this Agreement if as a result of a corporate reorganization, restructuring, financing, acquisition or sale involving Westcoast there is the potential for a material impact on Westcoast's costs or levels or quality of service in Zones 3 and 4 during the term of this Agreement.

10.8 Further Assurances

Westcoast and each of the Stakeholders will do all such further acts and things as may be reasonably necessary to give full effect to the intent and meaning of this Agreement.

10.9 Compliance with CER Orders

Nothing in this Agreement is intended to preclude Westcoast from complying with any directives or orders of the CER applicable to Westcoast, including any matters currently before the CER.

10.10 Approval Process

Westcoast and the parties listed in Appendix A hereby agree that the foregoing establishes the basis on which Westcoast's tolls for transmission service in Zones 3 and 4 will be determined for the 2020 and 2021 calendar years. The parties listed in Appendix A support this Agreement.

The parties listed in Appendix A agree that the Agreement will also be subject to a vote of the TTTF, the result of which will be included as part of the application for approval filed with the CER.

Dated as of May 13, 2020

Appendix A

List of Stakeholder Parties

Canadian Association of Petroleum Producers

Canadian Natural Resources

Cascade Natural Gas Corporation

Dufour Energy Commodities

Ovintiv Services Inc.

Export Users Group

FortisBC Energy Inc.

Macquarie Energy Canada Ltd.

Petronas Energy Canada Ltd.

Powerex Corp.

Puget Sound Energy

Shell Canada Energy

Tenaska Marketing Canada

Tourmaline Oil Corp.

Appendix B

2020 and 2021 Revenue Requirement ($000)

NO.	PARTICULARS	2020 TEST YEAR	ADJUSTMENTS	2021 TEST YEAR
		(E)	(F)	(G)
1	OPERATING AND MAINTENANCE EXPENSES	125,594	18,412	144,006
2	CER COST RECOVERY	3,111	-	3,111
3	DEPRECIATION	133,373	21,643	155,016
4	AMORTIZATION	(578)	(16)	(593)
5	TAXES OTHER THAN INCOME TAXES	112,721	5,908	118,629
6	GAS SUBSTITUTION COSTS	1,080	-	1,080
7	MISCELLANEOUS OPERATING REVENUE	(1,763)	-	(1,763)
8	PIPELINE ABANDONMENT FUNDING	8,492	-	8,492
9	INCOME TAX EXPENSE	32	(16)	16
10	RETURN ON RATE BASE	191,138	32,368	223,506
11	COST OF SERVICE	573,202	78,299	651,501
12	DEFERRALS	38,300	(38,300)	-
13	REVENUE REQUIREMENT	611,502	39,999	651,501
14	FIXED COSTS	563,632	35,389	599,021
15	VARIABLE COSTS	47,870	4,610	52,480
16	REVENUE REQUIREMENT	611,502	39,999	651,501

Appendix C
2020 and 2021 Depreciation Rates ($000)

		2020 TEST YEAR			2021 TEST YEAR		
CER ACCT No.		AVERAGE DEPRECIATION BASE	DEPRECIATION RATES	DEPRECIATION EXPENSE	AVERAGE DEPRECIATION BASE	DEPRECIATION RATES	DEPRECIATION EXPENSE
461	Land rights	4,127	0.00	-	4,146	0.00	-
462	Compressor structures	56,273	2.03	1,142	56,620	2.03	1,149
463	Measuring structures	2,174	4.63	101	2,184	4.63	101
465	Mains	2,690,916	2.66	71,466	2,888,440	2.66	76,700
466	Compressor equipment	1,496,023	3.18	47,574	1,934,246	3.18	61,509
467	Measuring equipment	73,361	9.54	6,999	76,420	9.54	7,291
		4,322,874		127,281	4,962,057		146,750
MISC	Miscellaneous Facilities	(98)	2.96	(3)	(36)	2.96	(0)
TOTAL PIPELINE PLANT		4,322,776	2.94	127,278	4,962,021	2.96	146,750
482	Structures and Improvements:	23,995	4.18	1,002	24,197	4.17	1,008
483	Office Furniture and Equipment:	15,511	19.90	3,087	25,279	19.94	5,040
484	Transportation and Equipment:	6,269	15.20	953	7,428	15.23	1,131
485	Heavy Work Equipment	191	4.70	9	191	4.70	9
486	Tools and Work Equipment	6,108	5.00	305	6,133	5.00	307
488	Communication Equipment	7,195	10.00	719	7,195	10.00	719
489	Other Equipment	380	5.00	19	1,051	5.00	53
TOTAL GENERAL PLANT		59,649	10.22	6,095	71,474	11.57	8,267
TOTAL PLANT		4,382,425	3.04	133,373	5,033,495	3.08	155,017

Appendix D

Tariff Amendments

ARTICLE 8
CONTRACT DEMAND CREDITS – COMPRESSOR OUTAGES

8.01 Firm Service, Zone 3. Subject to Sections 8.03 and 8.04, if and to the extent Westcoast is unable to provide a Shipper with any Firm Transportation Service – Northern, Temporary Firm Service or Short Term Firm Service in Zone 3 held by the Shipper for any day in a month due to an outage of compressor facilities in Zone 3~~,~~ then the Shipper will be entitled to a credit determined for any such day in accordance with the following provisions:

(a) if no notice respecting a restriction in service was in effect prior to the time specified in Section 4.11 for giving of nominations in the Intra-Day 1 Nomination Cycle for any such day, the Shipper will be entitled to a credit in respect of that day equal to the product obtained by multiplying the applicable Daily Demand Toll by the amount, if any, by which the sum of (i) the volume of residue gas nominated in good faith by the Shipper in the Timely and Evening Nomination Cycles, up to a volume equal to that determined by multiplying the Contract Demand by the applicable Transmission Reliability Percentage, and (ii) the additional volume of residue gas nominated in good faith by the Shipper in the Intra-Day 1 Nomination Cycle, up to a volume equal to that determined by multiplying the difference between the Contract Demand and the volume of residue gas so nominated in the prior Nomination Cycles by two-thirds and by the applicable Transmission Reliability Percentage, exceeds the actual volume of residue gas for which Westcoast authorized such service on that day; and

(b) if Westcoast gave a notice that such service was restricted to a volume less than the Contract Demand and such notice was in effect at the time specified in Section 4.11 for the giving of nominations in the Intra-Day 1 Nomination Cycle for any such day, the Shipper will be entitled to a credit in respect of that day equal to the product obtained by multiplying the applicable Daily Demand Toll by the amount, if any, by which (i) the average of the daily volumes of such Firm Transportation Service – Northern, Temporary Firm Service and Short Term Firm Service authorized by Westcoast for the Shipper, up to a volume equal to that determined by multiplying the Contract Demand by the applicable Transmission Reliability Percentage, for the immediately preceding three days on which there was no such restriction on such service, exceeds (ii) the greater of the actual volume of residue gas for which Westcoast authorized such service on that day and the Contract Demand available for such service on such day as specified in the notice relating to the restriction given by Westcoast to all shippers in accordance with Section 20.05 of the General Terms and Conditions.

8.02 Firm Service, Zone 4. Subject to Section 8.03, if and to the extent Westcoast is unable to provide a Shipper with any Firm Transportation Service - Southern or Short Term Firm Service in Zone 4 held by the Shipper for any day in a month due to an outage of compressor facilities in Zone 4~~,~~ then the Shipper will be entitled to a credit determined for any such day in accordance with the following provisions:

(a) if no notice respecting a restriction in service was in effect at the applicable time specified in Section 4.11 for the giving of nominations in the Intra-Day 1 Nomination Cycle for any such day, the Shipper will be entitled to a credit in respect of that day equal to the product obtained by multiplying the applicable Daily Demand Toll by the amount, if any, by which the sum of (i) the volume of residue gas nominated in good faith by the Shipper in the Timely and Evening Nomination Cycles, up to a volume equal to that determined by multiplying the Contract Demand by the applicable Transmission Reliability Percentage, and (ii) the additional volume of residue gas nominated in good faith by the Shipper in the Intra-Day 1 Nomination Cycle, up to a volume equal to that determined by multiplying the difference between the Contract Demand and the volume of residue gas so nominated in the prior Nomination Cycles by two-thirds and by the applicable Transmission Reliability Percentage, exceeds the actual volume of residue gas for which Westcoast authorized such service on that day; and

(b) if Westcoast gave a notice that such service was restricted to a volume less than the Contract Demand and such notice was in effect at the time specified in Section 4.11 for the giving of nominations in the Intra-Day 1 Nomination Cycle for any such day, the Shipper will be entitled to a credit in respect of that day equal to the product obtained by multiplying the applicable Daily Demand Toll by the amount, if any, by which (i) the average of the daily volumes of such Firm Transportation Service - Southern and Short Term Firm Service authorized by Westcoast for the Shipper, up to a volume equal to that determined by multiplying the Contract Demand by the applicable Transmission Reliability Percentage, for the immediately preceding three days on which there was no such restriction on such service, exceeds (ii) the greater of the actual volume of residue gas for which Westcoast authorized such service on that day and the Contract Demand available for such service on such day as specified in the notice relating to the restriction given by Westcoast to all shippers in accordance with Section19.05 of the General Terms and Conditions.

8.03 Exceptions. A Shipper ~~shall~~ will not be entitled to any credits under Sections 8.01 ~~and~~ or 8.02, if or to the extent that the inability of Westcoast to provide any Firm Service to the Shipper resulted from:

(a) the failure of the Shipper to nominate the full Contract Demand available for such service as specified in the notice relating to the restriction given by Westcoast;

(b) the failure of the Receiving Party to confirm that it will take delivery of the gas to be delivered by Westcoast to or for the account of the Shipper or to take delivery of the volume of gas authorized by Westcoast at the Delivery Point at the applicable pressure prescribed in these General Terms and Conditions;

(c) the inability of Westcoast to confirm to its satisfaction pursuant to Section 3.06(g) that the Shipper, or the Receipt Point Operator on its behalf, will be capable of fulfilling its obligations under Sections 4.14 and 4.15 or the failure by the Shipper or the Receipt Point Operator on its behalf, to deliver gas to Westcoast at the Receipt Point in accordance with these General Terms and Conditions; ~~or~~

(d) the inability of Westcoast to authorize or provide service in any other Zone of the Pipeline System by reason of an event or circumstance occurring in that other Zone~~.~~; or

(e) an outage of compressor facilities required to accommodate Pipeline System expansion work or compressor upgrades or other reliability-related work undertaken by Westcoast.

8.04 Service to the Straddle Plant Delivery Point. For the purposes of determining the amount of any Contract Demand Credits in accordance with Section 8.01 in respect of Firm Transportation Service – Northern, Temporary Firm Service or Short Term Firm Service with a Delivery Point at the Straddle Plant Delivery Point, the volume differential to be used in the calculation of those credits shall be a volume of gas equal to the product obtained by multiplying the applicable volume differential specified in Section 8.01 by the Straddle Plant Shrinkage Factor.

Appendix E

2020 and 2021 Average Rate Base

LINE NO.	PARTICULARS	2020 TEST YEAR	ADJUSTMENTS	2021 TEST YEAR
		(A)	(B)	(C)
1	GAS PLANT IN SERVICE	4,529,791	717,070	5,246,861
2	ACCUMULATED DEPRECIATION	(1,542,259)	(132,096)	(1,674,356)
3	NET PLANT IN SERVICE	2,987,532	584,974	3,572,506
4	CONTRIBUTIONS IN AID OF CONSTRUCTION	(10,006)	330	(9,676)
5	PLANT INVESTMENT	2,977,526	585,304	3,562,830
6	MATERIALS AND SUPPLIES	21,818	(804)	21,015
7	LINE PACK GAS	4,617	-	4,617
8	PREPAID EXPENSES	(59,317)	(4,258)	(63,575)
9	DEFERRALS	17,554	(17,554)	(0)
10	DEFERRED INCOME TAXES	(10,926)	-	(10,926)
11	AVERAGE RATE BASE EXCLUSIVE OF CASH WORKING CAPITAL	2,951,273	562,688	3,513,961
12	CASH WORKING CAPITAL	4,478	-	4,478
13	AVERAGE RATE BASE	2,955,751	562,688	3,518,439

Appendix F

Transmission Tolls

$\$/10^3m^3$/month	2019 Final	2020 Interim	2020 Forecast	2021 Forecast
Firm Transportation Service - North				
Shorthaul	16.98	16.69	16.01	18.02
Longhaul	244.58	240.36	230.51	259.55
Firm Transportation Service - South				
Pacific Northern Gas Delivery Point	139.72	136.20	131.99	139.72
Inland Delivery Area	344.15	335.50	325.10	344.15
Huntingdon Delivery Area	616.73	601.21	582.59	616.72
Terasen Kingsvale to Huntingdon	272.57	265.72	257.49	272.58

¢/Mcf/day	2019 Final	2020 Interim	2020 Forecast	2021 Forecast
Firm Transportation Service - North				
Shorthaul	1.58	1.55	1.49	1.68
Longhaul	22.78	22.32	21.41	24.17
Firm Transportation Service - South				
Pacific Northern Gas Delivery Point	13.01	12.65	12.26	13.01
Inland Delivery Area	32.05	31.16	30.20	32.05
Huntingdon Delivery Area	57.44	55.84	54.11	57.44
Terasen Kingsvale to Huntingdon	25.39	24.68	23.91	25.39

Transmission Tolls with Term Differentiated Rates
($\$/10^3m^3$/month)

Firm Transportation Service - North								
Segment	**2019 Final**	**2019 Final TDR**	**2020 Interim**	**2020 Interim TDR**	**2020 Forecast**	**2020 Forecast TDR**	**2021 Forecast**	**2021 Forecast TDR**
Shorthaul								
1 Year		18.27		17.95		17.22		19.42
2 Year	16.98	17.73	16.69	17.43	16.01	16.72	18.02	18.85
3 Year		17.20		16.91		16.21		18.29
4 Year		17.02		16.73		16.05		18.10
5 Year +		16.85		16.56		15.88		17.91
Longhaul								
1 Year		263.03		258.52		247.92		279.61
2 Year	244.58	255.37	240.36	250.99	230.51	240.70	259.55	271.47
3 Year		247.70		243.46		233.48		263.32
4 Year		245.15		240.95		231.08		260.61
5 Year +		242.60		238.44		228.67		257.89

Firm Transportation Service - South								
Segment	**2019 Final**	**2019 Final TDR**	**2020 Interim**	**2020 Interim TDR**	**2020 Forecast**	**2020 Forecast TDR**	**2021 Forecast**	**2021 Forecast TDR**
Pacific Northern Gas Delivery Point								
1 Year		154.22		146.20		141.69		150.10
2 Year	143.81	149.73	136.20	141.94	131.99	137.56	139.72	145.73
3 Year		145.24		137.69		133.43		141.36
4 Year		143.74		136.27		132.06		139.90
5 Year +		142.24		134.85		130.68		138.44
Inland Delivery Area								
1 Year		379.88		360.12		349.00		369.72
2 Year	354.23	368.81	335.50	349.63	325.10	338.83	344.15	358.96
3 Year		357.75		339.14		328.67		348.19
4 Year		354.06		335.65		325.28		344.60
5 Year +		350.37		332.15		321.89		341.01
Huntingdon Delivery Area								
1 Year		680.74		645.34		625.41		662.56
2 Year	634.79	660.92	601.21	626.55	582.59	607.19	616.72	643.26
3 Year		641.09		607.75		588.97		623.96
4 Year		634.48		601.48		582.90		617.53
5 Year +		627.87		595.22		576.83		611.10
Winter 5 Year+		941.81		892.83		865.25		916.65
Terasen Kingsvale to Huntingdon								
1 Year		300.87		285.22		276.41		292.84
2 Year	280.56	292.10	265.72	276.91	257.49	268.36	272.58	284.31
3 Year		283.34		268.61		260.31		275.78
4 Year		280.42		265.84		257.62		272.93
5 Year +		277.50		263.07		254.94		270.09

Transmission Tolls with Term Differentiated Rates
(¢/mcf/day)

Firm Transportation Service - North

Segment	2019 Final	2019 Final TDR	2020 Interim	2020 Interim TDR	2020 Forecast	2020 Forecast TDR	2021 Forecast	2021 Forecast TDR
Shorthaul								
1 Year	1.58	1.70	1.55	1.67	1.49	1.60	1.68	19.42
2 Year		1.65		1.62		1.55		18.85
3 Year		1.60		1.57		1.51		18.29
4 Year		1.59		1.55		1.49		18.10
5 Year +		1.57		1.54		1.47		17.91
Longhaul								
1 Year	22.78	24.50	22.32	24.01	21.41	23.03	24.17	279.61
2 Year		23.78		23.31		22.36		271.47
3 Year		23.07		22.61		21.69		263.32
4 Year		22.83		22.38		21.46		260.61
5 Year +		22.59		22.15		21.24		257.89

Firm Transportation Service - South

Segment	2019 Final	2019 Final TDR	2020 Interim	2020 Interim TDR	2020 Forecast	2020 Forecast TDR	2021 Forecast	2021 Forecast TDR
Pacific Northern Gas Delivery Point								
1 Year	13.01	13.96	12.65	13.58	12.26	13.16	13.01	13.98
2 Year		13.55		13.18		12.78		13.57
3 Year		13.15		12.79		12.39		13.16
4 Year		13.01		12.66		12.27		13.03
5 Year +		12.87		12.52		12.14		12.89
Inland Delivery Area								
1 Year	32.05	34.38	31.16	33.45	30.20	32.41	32.05	34.43
2 Year		33.38		32.47		31.47		33.43
3 Year		32.38		31.50		30.53		32.43
4 Year		32.05		31.17		30.21		32.09
5 Year +		31.71		30.85		29.90		31.76
Huntingdon Delivery Area								
1 Year	57.44	61.61	55.84	59.94	54.11	58.09	57.44	61.71
2 Year		59.82		58.19		56.39		59.91
3 Year		58.03		56.45		54.70		58.11
4 Year		57.43		55.86		54.14		57.51
5 Year +		56.83		55.28		53.57		56.91
Winter 5 Year+		85.24		82.92		80.36		85.37
Terasen Kingsvale to Huntingdon								
1 Year	25.39	27.23	24.68	26.49	23.91	25.67	25.39	27.27
2 Year		26.44		25.72		24.92		26.48
3 Year		25.65		24.95		24.18		25.68
4 Year		25.38		24.69		23.93		25.42
5 Year +		25.12		24.43		23.68		25.15

Appendix G
Transmission Allocation Units

10^3m^3/day	2019 Final	2020 Interim	2020 Forecast	2021 Forecast
Firm Transportation Service - North				
Shorthaul	3,726.3	2,098.6	2,098.6	1,785.3
Longhaul	79,656.3	80,808.7	81,068.2	74,341.3
Firm Transportation Service - South				
Pacific Northern Gas Delivery Point	1,981.0	1,888.9	1,888.9	1,428.6
Inland Delivery Area	6,331.3	6,331.3	6,331.3	6,331.3
Huntingdon Delivery Area	40,913.2	40,924.1	40,924.1	42,269.8
Terasen Kingsvale to Huntingdon	2,974.4	2,974.4	2,974.4	2,974.4

MMcf/day	2019 Final	2020 Interim	2020 Forecast	2021 Forecast
Firm Transportation Service - North				
Shorthaul	132	74	74	63
Longhaul	2,812	2,853	2,862	2,624
Firm Transportation Service - South		0	0	
Pacific Northern Gas Delivery Point	70	67	67	50
Inland Delivery Area	224	224	224	224
Huntingdon Delivery Area	1,444	1,445	1,445	1,492
Terasen Kingsvale to Huntingdon	105	105	105	105