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August 30, 2022

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Sara Hardgrave, Acting Commission Secretary

Dear Ms. Hardgrave:

Re: FortisBC Energy Inc. (FEI)

Gas Supply Mitigation Incentive Program (GSMIP) Review and Application to Extend for the Period November 1, 2022 to October 31, 2025 (Application)

FEI hereby applies to the British Columbia Utilities Commission (BCUC) for approval to extend the GSMIP for the period of November 1, 2022 to October 31, 2025. Customers rely on FEI to provide them with safe, reliable and cost effective natural gas service. As a part of delivering on this service mandate, customers and FEI have agreed to operate under various gas supply mitigation incentive programs since 1996 with the common objective of aligning the interests of customers and shareholders.

FEI is currently operating under a GSMIP which was redesigned and became effective for the 2011/12 gas year. The current GSMIP was developed following extensive consultations of a GSMIP Working Group (the Working Group) that was established from a directive by the BCUC in 2011.

The GSMIP redesign was approved on September 22, 2011, pursuant to BCUC Order G-163-11, and was in effect for the 2011/12 and 2012/13 gas years. The GSMIP model has since been approved for renewal and extension for the gas years 2013-2016 pursuant to Order G-174-13 and gas years 2016-19 pursuant to G-141-16.

On June 6, 2019, FEI filed an application with the BCUC seeking approval to extend the GSMIP for a three-year term for period November 1, 2019 to October 31, 2022. On September 26, 2019, the BCUC issued Order G-232-19 approving the extension and directing FEI to file a report providing a comprehensive assessment of the GSMIP, term sheet and model at least 60 days prior to expiry of the approved three-year term.

FEI undertook a series of three workshops in 2022 including participants from BCUC staff, key stakeholders and industry experts in order to review the GSMIP, term sheet and model, seeking feedback and comment to inform the report.

FEI believes the current GSMIP mechanism has worked well since its inception in 2011 and continues to meet its main objective of aligning customer and shareholder interests. The current GSMIP model took considerable time and effort to design with stakeholders and FEI believes that the results demonstrate that it has been working as intended. The model responds well under dynamic and variable market conditions, provides a transparent methodology to validate performance relative to the opportunities in the market, and supports growth in mitigation revenue. GSMIP performance is reported in a clear and timely manner.

In this Application, FEI is seeking approval for the extension of the GSMIP for an additional three-year term from November 1, 2022 to October 31, 2025.

Approval Requested

In this Application, FEI seeks the following approvals:

- FEI is seeking approval to extend the term of the GSMIP for an additional three-year term for the period November 1, 2022 to October 31, 2025.

- Continuation of the existing model and term sheet as provided for under the GSMIP 2022-2025 Term Sheet.

If further information is required, please contact Matt Yasinchuk at 604-576-7052.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Participating Parties to the 2022 GSMIP Review Workshops

FortisBC Energy Inc.

Gas Supply Mitigation Incentive Program (GSMIP) Review and Application to Extend for the Period November 1, 2022 – October 31, 2025

August 30, 2022

Table of Contents

List of Appendices

1. INTRODUCTION AND BACKGROUND

The British Columbia Utilities Commission (BCUC) by Order G-232-19 dated September 26, 2019, approved an extension of the Gas Supply Mitigation Incentive Program (GSMIP) for FortisBC Energy Inc. (FEI or the Company) to October 31, 2022. Order G-232-19 also directed FEI to file a report providing a comprehensive assessment of the GSMIP, term sheet and model at least 60-days prior to expiry of the approved three-year term. The process undertaken by FEI to complete the review as well as the discussion generated with stakeholders helped to inform this report and application for approval of a three-year extension of the GSMIP from November 1, 2022 to October 31, 2023 (Application).

FEI has been operating under a form of incentive program for its gas supply mitigation activities since 1996. The GSMIP incentive mechanism was designed to align the interests of customers and shareholders in the effective management of gas supply costs through mitigation activities, while ensuring a reliable supply of gas to meet the firm load requirements of core customers[1]. As discussed below, FEI is seeking approval to extend GSMIP based on the model that was jointly developed by FEI and other participants in a Working Group over a period of several months in 2011. As part of FEI's assessment in preparing this Application, the GSMIP model was reviewed through stakeholder engagement sessions during 2022 and FEI believes that it has proven to work well under different market conditions since its design while meeting the objectives of the program.

FEI contracts its gas supply resources, which include commodity supply, transportation and storage, in accordance with the Annual Contracting Plan (ACP) on behalf of core customers. This is done with the objective of ensuring an appropriate balance of cost minimization, security, diversity and reliability of gas supply in order to meet the core customer design peak day and annual requirements. The ACP is prepared following an interactive and consultative process with the BCUC throughout the year. Once the BCUC reviews and accepts the ACP, FEI implements the plan accordingly.

Based on the objectives of the ACP it is appropriate to have an incentive program that is based on optimization and mitigation of gas supply and midstream resources to maximize savings to customers and mitigate the midstream rate. GSMIP can coexist with delivery rate setting and, as an incentive mechanism applied to midstream costs, it aims to increase efficiency, reduce costs and enhance performance to the benefit of customers.

Generating significant mitigation revenue for the benefit of customers requires ongoing effort, support and oversight from FEI. This requires FEI to have the right people, policies and procedures in place. Within the Gas Supply group, FEI provides employees with specialized skills in commodity trading, load balancing, regulatory requirements, resource procurement, contract negotiations and counterparty relationship management. FEI provides the back-office support, infrastructure and senior management oversight for accounting, risk, legal, audit, credit and

[1] Rate Schedules 1-7, and 46 customers.

contract management, thus facilitating mitigation activities and creating additional value for customers.

In 2011, the GSMIP was revised based on comprehensive consultations of the Working Group[2] that was established pursuant to the direction of the BCUC. In Order No. G-26-11, the BCUC outlined a set of eight “Guiding Principles” to assist the Working Group in drafting new design objectives and creating a new incentive mechanism. They are:

1. The incentive must demonstratively deliver value to ratepayers and reward ongoing innovation and true value added over and above what is reasonably expected in the normal stewardship of FEI’s business.
2. Execution of the incentive program must not put the prudently planned gas supply portfolio at risk nor promote a departure from prudent gas supply management for core customers’ requirements.
3. The incentive plan should fairly and appropriately align ratepayer and shareholder interests.
4. There should not be an upper limit on FEI’s potential to earn an incentive but there must be a test of reasonableness and the amount earned must be justified.
5. The incentive program should apply to all mitigation activities that use commodity supply resources that represent a cost and risk to ratepayers (i.e. gas supply, storage, transportation).
6. The incentive plan should reward FEI for its innovation rather than for opportunities that arise from events that impact the industry in general (e.g. hurricanes).
7. Any incremental administrative costs must be considered and charged against the benefits of the plan.
8. The incentive payment should be the smallest amount required to obtain the desired core customer benefit.

After extensive consultation and evaluation, the incentive mechanism was redesigned to encourage FEI to maintain a high level of performance on core mitigation activities related to storage, transport, and commodity resale while also maintaining supply reliability for customers. An application for the new GSMIP was supported by all the Working Group participants and was subsequently approved on September 22, 2011, pursuant to Order G-163-11, and was in effect for the period from November 1, 2011 to October 31, 2013 (the 2011/12 and 2012/13 gas years). An application to extend the GSMIP model for the three-year period November 1, 2013 to October 31, 2016 and to include the revenue for mitigation activities FEI performed on behalf of FortisBC Energy (Vancouver Island) Inc. (FEVI) was approved on October 24, 2013, pursuant to Order G-174-13.

[2] Working Group participants: CEC, BCOAPO, BCUC staff, FEI, and external consultant Concentric Energy Advisors.

On December 23, 2015, FEI filed its GSMIP Year End Report for the period from November 1, 2014 to October 31, 2015 (2014/15 GSMIP Report), in accordance with Order G 174-13 and the 2013-2016 GSMIP Term Sheet accepted by Letter L-15-15.

FEI's 2014/15 GSMIP incentive payment of $2,058,642 exceeded the GSMIP incentive payment variance threshold of $1.6 million. The 2013-2016 GSMIP Term Sheet states:

> In order to maintain the confidence of all parties involved with the design of the current GSMIP model, a full review of the mechanism is required if there is a difference during any of the three years in the 2013-2016 term of plus or minus $500,000 from the historical GSMIP payout of $1.1 Million. Once FEI is aware that a $500,000 or greater variance is likely to occur, the Commission will be informed in order to have a timely review of the model. A variance of this magnitude does not mean that the model is not working in its expected capacity; however, a review will be conducted to explain the variances.

The BCUC, in Letter L-2-16 dated March 10, 2016, noted that the 2013-2016 GSMIP Term Sheet expired on October 31, 2016 and stated:

> The Commission considers that the review of the mechanism should be conducted and completed before the expiry date of the current GSMIP. If FEI applies for a GSMIP renewal, a full review of the mechanism can be conducted as part of the regulatory process established to review the GSMIP renewal application. If FEI does not file a GSMIP renewal application by May 6, 2016, the Commission will initiate the review at the beginning of June 2016.

On May 6, 2016, FEI filed an application to extend the GSMIP model and revise the Term Sheet for the Period November 1, 2016 to October 31, 2019 meeting the BCUC requirement of having FEI file a GSMIP renewal on or before May 6, 2016. The BCUC, in Order G-111-16 dated July 14, 2016, determined that a written comment process was warranted and sought stakeholder submissions before establishing any further review process. The British Columbia Public Interest Advocacy Centre, on behalf of British Columbia Old Age Pensioners' Organization et al. (BCOAPO), submitted a letter of comment regarding FEI's proposals. By Order G-141-16 dated August 29, 2016, the BCUC approved the 2016-2019 GSMIP renewal, subject to the terms set out in the order. On September 19, 2016, FEI filed a revised 2016-2019 GSMIP Term Sheet as requested. The BCUC, in Letter L-27-16 dated September 29, 2016, accepted the revised 2016-2019 GSMIP Term Sheet.

FEI believes, for the following reasons, that the current GSMIP model should continue:

1. FEI's gas supply objectives are well established and consistent, and FEI has the firm resources in place per the ACP to meet core load requirements of design day and design year conditions.
2. The GSMIP is a well-designed and robust model that has worked well in dynamic and varying market conditions. The model provides a transparent methodology to validate

performance relative to the opportunities in the market through benchmarking and to support growth in mitigation revenue. Further, GSMIP performance is reported in a clear and timely manner to the BCUC and stakeholders.

3. The current model is the product of a comprehensive review undertaken by the Working Group in 2011 at a considerable cost, time and effort by all participants, and is continuing to work as intended.

4. The current model has generated total mitigation revenue of over $731 million between November 1, 2011 and October 31, 2021, including customer savings of over $711 million, as seen Table 2 (Section 4 below).

As developed by the Working Group, the GSMIP model breaks down mitigation transactions into the following categories: benchmarked mitigation activity, non-benchmarked mitigation activity, storage/forward commodity sales, and new mitigation activity. A more detailed description of each mitigation activity is included in the Application.

2. APPROVALS SOUGHT

In this Application, FEI requests approval of a three-year extension of the GSMIP from November 1, 2022 to October 31, 2025, as set out in the 2022-2025 GSMIP Term Sheet attached as Appendix A of the Application.

A Draft Order is provided in Appendix C.

3. GSMIP MODEL DESCRIPTION

The current GSMIP measures the performance of mitigation efforts in order to determine the appropriate incentive earned by the Company. The detailed model is provided in the Term Sheet in Appendix A and is summarized in this section.

All activities included in the GSMIP are based on mitigation of the gas supply portfolio resources held by FEI pursuant to its ACP, which in turn is reviewed and accepted by the BCUC. These activities have been separated into four categories: benchmarked activities, non-benchmarked activities, storage and forward commodity sales, and new activities. For benchmarked activities, Market Performance Factors (MPF) have been derived to ensure that FEI maintains a high level of performance relative to the market. These include a pricing measure, capacity factor, and market concentration factor. For a further description on MPF please see the Term Sheet in Appendix A.

The incentive payment structure for each category is as follows:

Table 1: Incentive Percentage Structure

	Activity	Incentive Percentage
1	**Benchmarked Activity**	
	Market Performance Factor (MPF) between 100% - 131%	2.45% + 0.05% * (MPF – 100)
	MPF between 131% - 136%	4.00%
	MPF of 136% and greater	4.00% + 0.04% * (MPF – 136)
2	**Non-Benchmarked Activity**	4.00%
3	**New Activity**	12.00%

3.1 *BENCHMARKED ACTIVITY*

Benchmarked activities are cost mitigation activities for which a reasonable market benchmark has been established. Benchmarked activities include daily transportation mitigation, transportation capacity releases, and spot commodity resales. FEI's incentive payout for these activities is directly related to how FEI performs relative to the base utility benchmark, the market performance factor. The more FEI can outperform the base benchmark price, the greater the potential incentive payment.

The list of Benchmarked activities included in the GSMIP Term Sheet includes the following:

- T-South Transportation
- Southern Crossing Pipeline (SCP) Transportation

- Foothills[3] Transportation
- Forward Capacity Releases
- Commodity Resale

3.2 NON-BENCHMARKED ACTIVITY

Non-benchmarked activities are cost mitigation activities for which no reasonable market benchmark can be established.

The list of Non-Benchmarked activities includes the following (including modifications discussed in the Updates to the Model section):

- T-North Transportation
- Cochrane Extraction
- Storage (Park/Loan) Activity
- Forward Commodity Resale
- NOVA[4] Forward Capacity Releases
- T-South Interior Capacity Releases
- NOVA Transportation
- Transportation Asset Management Agreement (AMA)
- Pooling on the NOVA System

3.3 NEW ACTIVITY

Under the current GSMIP model, FEI is encouraged to continually improve and seek out new mitigation activities that are outside the scope of the traditional mitigation activities, while also maintaining security of supply and reliability for customers. Since the new GSMIP model began in the 2011/12 gas year, two new activities were added: Transportation Asset Management Agreement (AMA) and Pooling on the NOVA System. The two new activities have since been added to the Non-Benchmarked activities as no reasonable benchmark could be established. New Activities are not alterations to existing activities and it is difficult to find such opportunities in the market. FEI continues to seek out new activities which it can bring forward for approval.

[3] TC Energy wholly owned subsidiary, FoothillsBC (Foothills).
[4] TC Energy wholly owned subsidiary, NOVA Gas Transmission Ltd. (NOVA).

3.4 *PERFORMANCE MEASUREMENT*

There are two performance measures adopted in the GSMIP model currently in place that were designed to ensure FEI maintains high utilization of its pipeline capacity, and to minimize FEI's impact on market prices at any one location due to FEI's buying or selling position. The outcome of these performance measures could result in a reduction to benchmarked mitigation revenue used to determine the incentive payment.

Capacity Factors

The capacity factor measures FEI's utilized capacity on Westcoast T-South and TC Energy FoothillsBC pipelines relative to the overall pipe capacity factor on those pipelines. If FEI's capacity factor falls below the capacity factor on either pipeline, there would be a reduction in mitigation revenue eligible for an incentive under the GSMIP.

Market Concentration Adjustment

A market concentration adjustment could also be applied to spot transactions that could increase market benchmarked revenue and reduce incentive payout on benchmarked activity. If FEI's market share in any given season at any market hub (Station 2, Sumas, AECO, Kingsgate) exceeds 40 percent of the reported traded volume in the Platts Gas Daily, the prices used to determine the base utility benchmark will be the Platts midpoint price for spot transactions at the market hub, as opposed to the common low and high prices.

4. CURRENT GSMIP REVENUE, INCENTIVE PAYMENT AND 2022 REVIEW

The mitigation revenue that is eligible for inclusion under GSMIP for the purposes of determining the incentive earned by the Company and incentive payments achieved since 2011/12, under the current GSMIP model, are shown below in Table 2.

Table 2: Eligible Mitigation Revenue and Incentive Payment

Gas Contract Year	Eligible Mitigation Revenue	Incentive Earned[1]		Customer Savings	
	$Million	$Million	%[2]	$Million	%[2]
2020/21	$80.58	$2.50	3.11%	$78.08	96.89%
2019/20	$58.38	$1.46	2.50%	$56.92	97.50%
2018/19	$126.22	$3.13	2.48%	$123.09	97.52%
2017/18	$102.60	$2.59	2.52%	$100.01	97.48%
2016/17	$97.18	$2.38	2.45%	$94.80	97.55%
2015/16	$78.15	$2.08	2.66%	$76.07	97.34%
2014/15	$72.25	$2.06	2.85%	$70.19	97.15%
2013/14	$39.47	$1.23	3.12%	$38.24	96.88%
2012/13	$48.82	$1.44	2.95%	$47.38	97.05%
2011/12	$27.70	$0.89	3.21%	$26.81	96.79%
Total	**$731.36**	**$19.76**	**2.70%**	**$711.60**	**97.30%**

Table Notes:

1. Net of fixed adjustment. The fixed deduction of $150,000 was used in 2011-12 and 2012-13 GSMIP years. The fixed deduction of $165,000 was approved in the 2013-2016 GSMIP Application under Order G-174-13. As shown above, this amount is deducted from the gross incentive amount to calculate the incentive payment in 2014/15 and 2015/16. The fixed deduction of $200,000 was approved in the 2016-2019 GSMIP Renewal Application under Order G-141-16, and was deducted from the gross incentive amount to calculate the incentive payment in 2016/17 and 2017/18.
2. Percentage of Total Mitigation Revenues.

The mitigation revenues presented in Table 2 are the mitigation values calculated for the purpose of the GSMIP, but the actual total mitigation that the customers receive in any particular year are higher than the totals presented in Table 2. This is because of how the commodity re-sale benchmark within the GSMIP are reported and tracked and are available in Appendix B.

As seen in Table 2 above, since the implementation of the current GSMIP model in November 2011, it has generated over $731 million dollars in mitigation revenue, including over $711 million in customer savings. The mitigation activities produced an average incentive earned by FEI of approximately 2.70 percent, while returning customer savings of approximately 97.30 percent of eligible revenue. The design of the model has shown to be very robust in dealing with the different market conditions that have unfolded over this timeframe. For example, the Westcoast T-South system moving from a de-contracted environment for firm service to a fully contracted one. In addition, the benchmarking mechanism for those related activities provide a transparent determination of incentive calculations working in both low and high price environments, as well as during periods of supply or demand surplus or constraints. This has been seen in periods of over-production at Station 2 and summer-based T-South maintenance constraints.

Comparatively, and based on Table 1 in Appendix B, Mitigation Activity Summary, for the gas years 2013/14 through 2020/21 the total customer savings when "deemed purchases" for commodity resale are not incorporated, are greater than $1,019 million on total mitigation revenue of $1,037 million. Over the same time period the GSMIP eligible mitigation revenue was $655 million with FEI's incentive payout of just over $17 million.

4.1 *2022 GSMIP REVIEW*

On November 22, 2021 FEI notified the BCUC and key stakeholders that it would be conducting a series of workshops in early 2022 as part of the requirement to undertake a comprehensive review of the GSMIP, seeking participation which would then be used to inform the report. A copy of the stakeholder engagement workshop materials is provided in Appendix D. FEI engaged with intervenor groups, BCUC staff and industry experts in the review process to ensure the objectives and guiding principles upon which the current GSMIP is based, continue to remain appropriate and continue to be achieved.

In addition to BCUC staff, FEI included notification of the stakeholder engagement sessions to the following intervenor groups involved in most FEI proceedings:

- BC Old Age Pensioners' Organization et al;
- BC Sustainable Energy Association;
- Commercial Energy Consumers Association of BC;
- Residential Consumer Intervenor's Association; and
- MoveUP (Movement of United Professionals)

FEI also engaged industry experts from Atrium Economics LLC (Atrium Economics) through a services contract in order to provide comparative research and analysis related to incentive mechanisms across North American natural gas utilities and statistical analysis. Atrium Economics's GSMIP Report for FEI is provided in Appendix E.

An introductory meeting including FEI staff, BCUC staff and key stakeholders from the intervenor groups was held on January 11, 2022. A copy of the meeting attendees and presentation material used for discussion is provided in Appendix D-2.

Workshop No. 1 – FEI Gas Supply Fundamentals

The first session was intended to bring all participants up to a common base level of knowledge by providing an overview of FEI's gas supply portfolio based on the Annual Contracting Plan (ACP), including commodity, transportation and storage resources. Additionally, FEI provided context of regional market conditions and dynamics.

The first workshop was held on February 9, 2022 and a copy of the meeting attendees and presentation material used for discussion is provided in Appendix D-3.

Workshop No. 2 – FEI GSMIP Fundamentals

The second session provided an overview of the current GSMIP, objectives, guiding principles, term sheet and model, including mitigation strategies, performance, organizational requirements, existing mechanisms to demonstrate, quantify and measure the extent to which the GSMIP objectives are achieved and how GSMIP payments are calculated.

The second workshop was held on March 8, 2022 and a copy of the meeting attendees and presentation material used for discussion is provided in Appendix D-4.

Workshops No. 3 – Moving GSMIP Forward

The final session provided an opportunity to discuss ways to enhance and improve the GSMIP, ensuring the continued alignment of objectives for customers, stakeholders and FEI. In addition, any outstanding questions or requests about FEI's gas supply portfolio or GSMIP from the stakeholder group were addressed.

The third workshop was held on March 29, 2022 and a copy of the meeting attendees and presentation material used for discussion is provided in Appendix D-5.

Term Sheet Review

Following the three workshops the stakeholder participants were generally acceptive of and receptive to continuing the GSMIP as currently designed.

The model and incentive mechanism as currently designed have aligned with the objectives and guiding principles as set out for the GSMIP. As discussed in the GSMIP Workshops, presented in Table 2 above and Table 1 in Appendix B, the GSMIP has demonstrably delivered value to ratepayers over the course of the program's existence. Table 2 above illustrates that on average over 97 percent of eligible mitigation revenue is to the benefit of customers, and under 3 percent is incentive payout. The true value to ratepayers is even greater due to the performance benchmarking of commodity resale activities and the inclusion of deemed purchases.

As part of the annual reporting and incentive payment approval, FEI must meet all firm core customer load requirements for the gas year. The GSMIP as designed has ensured the prudent management and optimization of the gas supply portfolio. Examples include upstream pipeline disruptions such as those that occurred on the Westcoast T-South system in 2018 and 2021 causing extended periods of firm capacity restrictions, as well as extreme weather conditions which occur during the winter season. FEI has met all firm core load requirements during the program's existence.

FEI was able to demonstrate that the model and term sheet are transparent through benchmarking and reporting, and the program delivers significant value in terms of cost savings to customers, while providing an appropriate incentive to FEI. Atrium Economics, through research conducted across a variety of North American natural gas utilities, found that the GSMIP model aligns the interests of ratepayers and FEI, and is consistent across the peer group, with the GSMIP providing a more conservative incentive mechanism than others.

Below is discussion of the sections of the GSMIP Term Sheet including changes proposed by FEI (provided in Appendix A) which was reviewed with stakeholders during the workshop series. Overall there are very few suggested changes to the GSMIP Term Sheet at the conclusion of the workshops.

A. Model Design and Term

No changes to the current term of the GSMIP are being requested. FEI seeks a continued three-year term period for the GSMIP model and term sheet from November 1, 2022 to October 31, 2025.

B. Total Mitigation Description

No changes to the current categorization of mitigation activities are being requested. FEI seeks to continue transactions and revenue mitigation activities under the categories of Benchmarked Mitigation Activities, Non-Benchmarked Mitigation Activities and New Mitigation Activities.

C. Transaction Descriptions – Benchmarked Activities

1. Spot Commodity Resale Mitigation
    - No change are being requested to this element. FEI seeks to continue with Spot Commodity Resale Mitigation Revenue calculation utilizing the Deemed Purchase methodology and Platts Gas Daily price indexes.
2. Monthly Commodity Resale Mitigation
    - FEI seeks to add a new Benchmarked Activity and has added this to the Term Sheet (Appendix A). Typically, during the summer months of April through October there are opportunities for FEI to sell forward excess commodity for a monthly term. FEI believes there are times when this is beneficial to customers and the benchmark should be based on the Platts Inside FERC's Gas Market Report – Monthly Bidweek Spot Gas Prices. FEI introduced and discussed the recommendation in Workshops #2 and #3.

3. Benchmarked Transportation Mitigation
   - No changes are being requested. FEI seeks to continue with the Transportation Mitigation Revenue calculation.
4. Capacity Release Mitigation
   - No changes are being requested. FEI seeks to continue with the Capacity Release Mitigation Revenue calculation.
5. Total Benchmarked Mitigation Revenue
   - FEI seeks to continue with the Total Benchmark Mitigation Revenue calculation with the addition of the Monthly Commodity Resale Mitigation activities.

D. Transaction Descriptions – Non-Benchmarked Activities

1. Storage Mitigation and Park and Loan Activity
   - No changes are being requested. FEI seeks to continue with the Storage Mitigation Revenue calculation.
2. T-North Transportation and Capacity Release Mitigation
   - No changes are being requested. FEI seeks to continue with the T-North Transportation and Capacity Release Mitigation calculations.
3. NOVA Transportation Mitigation
   - No changes to the current are being requested. FEI seeks to continue with the NOVA Transportation Mitigation Revenue calculation.
4. NOVA and T-South Interior Forward Capacity Releases
   - No changes are being requested. FEI seeks to continue with the NOVA and T-South Interior Forward Capacity Releases calculation.
5. Liquids Extraction
   - No changes are being requested. FEI seeks to continue with the Liquids Extraction Mitigation Revenue calculation.
6. Forward Commodity Resale Mitigation
   - No changes are being requested. FEI seeks to continue with the Forward Commodity Resale Mitigation Revenue calculation.
7. Transportation Asset Management Agreement (AMA)
   - No changes are being requested. FEI seeks to continue with the Transportation Asset Management (AMA) Revenue calculation.

8. Pooling on the NOVA System
    - No changes are being requested. FEI seeks to continue with the Pooling on the NOVA System Mitigation Revenue calculation.
9. Total Non-Benchmarked Mitigation Revenue
    - No changes are being requested. FEI seeks to continue with the Total Non-Benchmarked Mitigation Revenue calculation.

E. Transaction Descriptions – New Activity

No changes are being requested. FEI seeks to continue with the New Activity Mitigation Revenue calculation.

F. Base Benchmark

1. Spot Market Transactions
    - No changes are being requested. FEI seeks to continue with the use of the Platts Gas Daily published indices in determining the Base Benchmark, including the Platts Common Low, Common High and Midpoint.
2. Forward Market Transactions
    - No changes are being requested. FEI seeks to continue the use of the forward market benchmark prices from One Exchange Corp. (OneX), an independent broker who facilitates forward market transactions among market participants.

      However, FEI believes that due to the nature of the continuing contract with OneX to provide daily forward market curves, it is prudent to include notification of the potential for a change in provider if either party determines it is no longer willing to continue with the contract. As such, FEI had raised the concern in Workshops No. 2 and No. 3 and is including as part of the review the process under which it would follow.

      In the event that FEI is required to change the forward market benchmark price provider, currently OneX, FEI will submit application to the BCUC and seek approval, including:

        - Notice of request to change forward market benchmark price provider
        - Effective Date
        - Details of the new forward market benchmark price provider
        - Supporting discussion for the reason to change
        - Amended Term Sheet with appropriate changes

3. Market Concentration Adjustment

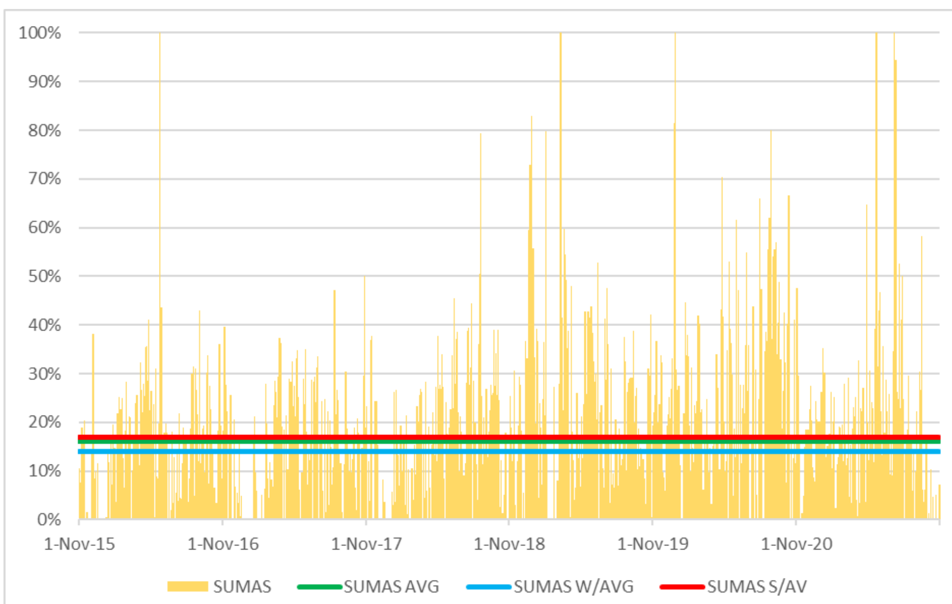
- No changes are being requested. FEI seeks to continue with the Market Concentration Adjustment as provided in the GSMIP 2022-2025 Term Sheet.

  There was discussion during the workshops on the mechanics and validity of the current Market Concentration Adjustment and FEI and Atrium Economics undertook additional analysis to validate the approach. The question raised was whether or not the Market Concentration Adjustment calculation should continue to use FEI's market share as a seasonal average, or whether it should be revised to use FEI's market share as a monthly or daily average.

  FEI's average fixed price market share at each of the four market hubs are provided below, for yearly, winter and summer periods for the timeframe November 1, 2015 through October 31, 2021.

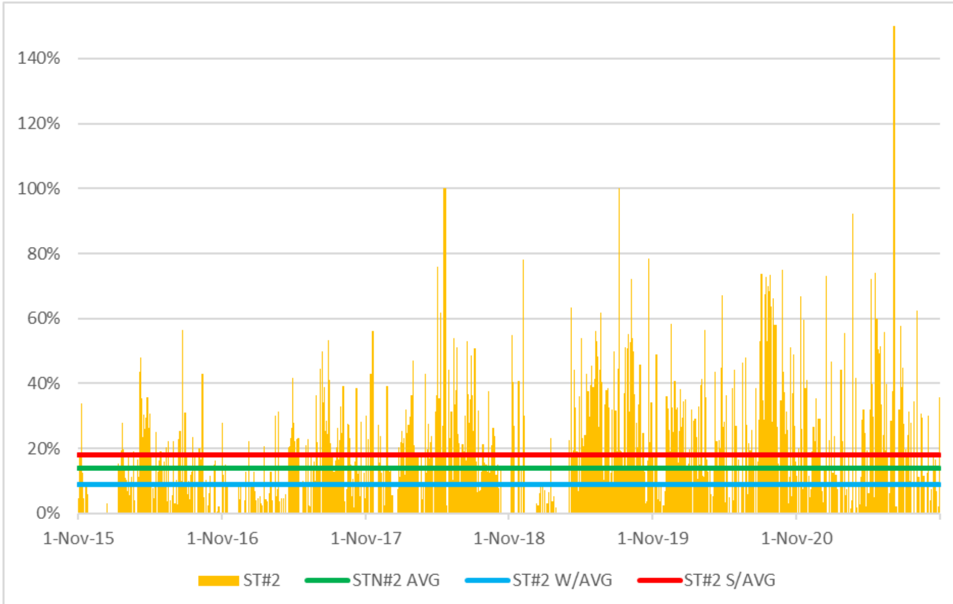
  At the Sumas (Huntingdon) market, Figure 1 below, FEI's fixed price Platts Gas Daily reported market share was 16 percent yearly, 14 percent winter and 17 percent summer.

Figure 1: FEI Fixed Price Market Share Sumas (2015-21)



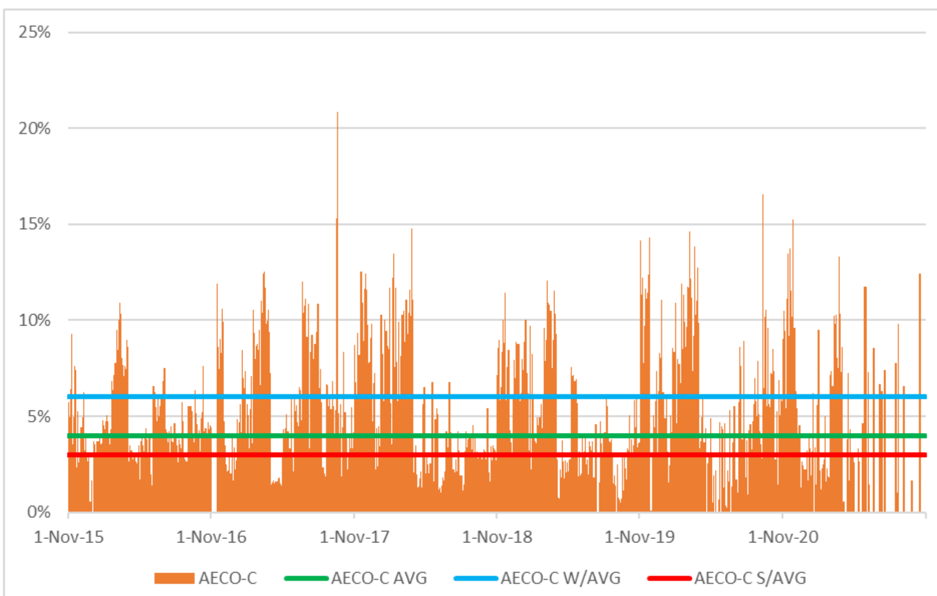
  At the Station 2 market, Figure 2 below, FEI's fixed price Platts Gas Daily reported market share was 14 percent yearly, 9 percent winter and 18 percent summer.

Figure 2: FEI Fixed Price Market Share Station 2 (2015-21)



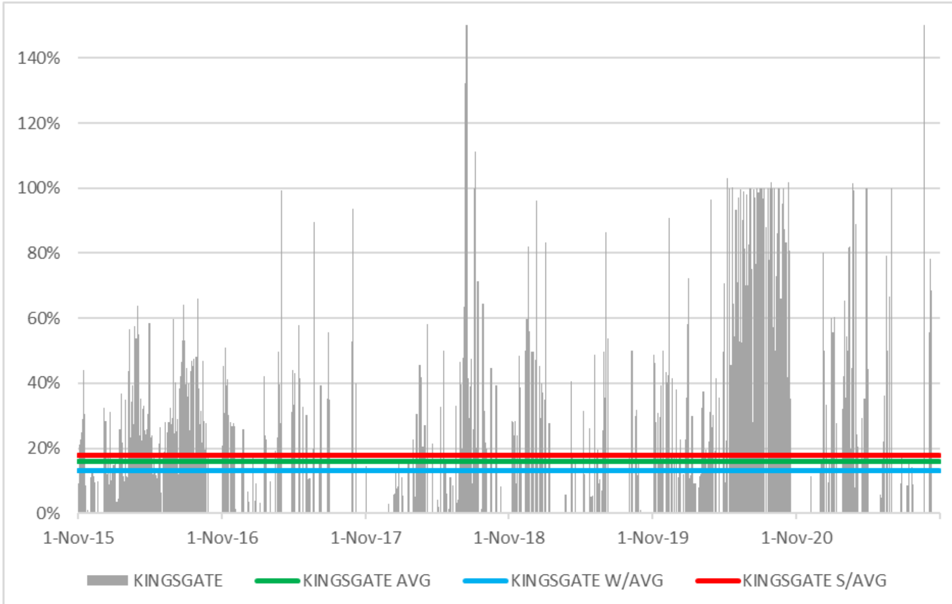
At the AECO-C market, Figure 3 below, FEI's fixed price Platts Gas Daily reported market share was 4 percent yearly, 6 percent winter and 3 percent summer.

Figure 3: FEI Fixed Price Market Share AECO (2015-21)



At the Kingsgate market, Figure 4 below, FEI's fixed price Platts Gas Daily reported market share was 16 percent yearly, 13 percent winter and 18 percent summer.

Figure 4: FEI Fixed Price Market Share Kingsgate (2015-21)



FEI believes it is important to understand that the Market Concentration Adjustment is based on the reported traded volume in Platts Gas Daily. Not every market participant at each market hub is a Platts Gas Daily reporter. There are volumes traded at each location that are not subsequently included in the Platts Gas Daily daily indices. Therefore, under certain conditions over the course of a day or longer period FEI could exceed the 40 percent market share on fixed price reported volumes. But as shown above FEI has not exceeded an average market share over 40 percent for a season.

FEI also undertakes daily index priced purchases and sales at these markets for both term and daily supply. For example, under the ACP FEI purchases 75 percent of its baseload supply at Station 2, with approximately 40 percent of that based on the daily index. Therefore, FEI is cognizant that upward pressure on daily prices has a direct impact on the overall gas costs and ratepayers. FEI approaches daily mitigation activities with the goal to maximize overall value for ratepayers, for example, having a low Station 2 price and a high Sumas price.

Additionally, Atrium Economics undertook sensitivity and correlation analyses to determine the impact of changing the Market Concentration Adjustment threshold of 40 percent from a seasonal basis to either a monthly or daily basis and the impact on FEI's performance. In the Atrium Economics report under Section 4 (Appendix E), it is noted that the original GSMIP working group agreed to use the Herfindal-Hirschman Index (HHI) as the appropriate mechanism to determine market share concentration. HHI is a widely used and commonly accepted measure of market concentration applied in antitrust and competition law. The result of applying the HHI was that market concentration can become an issue when FEI represents 40 percent or more of the reported volume of gas traded at any market hubs used in benchmarking.

Atrium Economics undertook analysis of the market concentration adjustment and its impact of Base Utility Benchmark, Net Revenues as a Percentage of Base Utility Benchmark, Market Performance Factor, Benchmarked Activity Incentive Percentage and Annual Incentive Payment, based on seasonal, monthly and daily market concentration. As provided in Section 4.2 of Atrium Economics's report (Appendix E), the sensitivity analysis for each gas year using data from November 1, 2016 through October 31, 2021 would have resulted in an overall change (decrease) in the Incentive Payment over five years from using seasonal market concentration to monthly market concentration of $67,811 (1.9 percent); and an overall change (decrease) in the Incentive Payment from using seasonal market concentration to daily market concentration of $56,381 (1.6 percent). Table 3 below provides the support for Atrium Economics sensitivities analysis and impact on the Incentive Payment.

Table 3: FEI Fixed Price Market Share Sensitivity Analysis (2016-21)

	Revenue	Base Utility Benchmark			MPF			BAIP			Incentive Payout		
		Seasonal	Monthly	Daily	Seasonal	Monthly	Daily	Seasonal	Monthly	Daily	Seasonal	Monthly	Daily
					= A / B	= A / C	= A / D				= A * H	= A * I	= A * J
Nov16-Oct17	$ 13,332,674	$ 12,999,808	$ 12,999,808	$ 13,008,735	102.6%	102.6%	102.5%	2.58%	2.58%	2.57%	$ 343,720	$ 343,720	$ 343,251
Nov17-Oct18	$ 21,499,902	$ 20,866,841	$ 20,926,005	$ 20,936,474	103.0%	102.7%	102.7%	2.60%	2.59%	2.58%	$ 559,361	$ 556,229	$ 555,677
Nov18-Oct19	$ 51,278,042	$ 53,905,491	$ 55,377,222	$ 54,874,389	95.1%	92.6%	93.4%	2.21%	2.08%	2.12%	$1,131,343	$1,066,525	$1,088,280
Nov19-Oct20	$ 24,788,905	$ 19,784,027	$ 19,782,262	$ 19,901,471	125.3%	125.3%	124.6%	3.71%	3.72%	3.68%	$ 920,878	$ 921,016	$ 911,713
Nov20-Oct21	$ 16,536,106	$ 12,437,503	$ 12,438,476	$ 12,492,408	133.0%	132.9%	132.4%	4.00%	4.00%	4.00%	$ 661,444	$ 661,444	$ 661,444
TOTAL	**$127,435,628**	**$119,993,670**	**$121,523,772**	**$121,213,477**	**106.2%**	**104.9%**	**105.1%**	**2.84%**	**2.78%**	**2.79%**	**$3,616,746**	**$3,548,935**	**$3,560,365**
											Change from Seasonal ($)	$ (67,811)	$ (56,381)
"MPP" - Market Performance Factor											Change from Seasonal (%)	-1.9%	-1.6%
"BAIP" - Benchmarked Activity Incentive Percentage													

Based on the discussion with Stakeholders in the Workshops and the analysis provided by Atrium Economics, FEI believes that there is no requirement to revise the Market Concentration Adjustment from a seasonal market share based approach to either monthly or daily.

G. Base Benchmark Calculation

1. Spot Commodity Resale Benchmark
   - No changes are being requested. FEI seeks to continue with the Spot Commodity Resale Benchmark calculation.
2. Monthly Commodity Resale Mitigation Benchmark
   - This is a new Benchmarked Mitigation Activity. FEI has added the Spot Transportation Mitigation Benchmark calculation.

3. Spot Transportation Mitigation Benchmark
    - No changes are being requested. FEI seeks to continue with the Spot Transportation Mitigation Benchmark calculation.
4. Forward Transportation Mitigation Base Benchmark
    - No changes are being requested. FEI seeks to continue with the Forward Transportation Mitigation Base Benchmark calculation.
5. Spot Capacity Release Base Benchmark
    - No changes are being requested. FEI seeks to continue with the Spot Capacity Release Base Benchmark calculation.
6. Forward Capacity Release Base Benchmark
    - No changes are being requested. FEI seeks to continue with the Spot Commodity Resale Benchmark calculation.
7. Total Base Benchmark
    - No changes are being requested. FEI seeks to continue with the Total Base Benchmark calculation.

H. Capacity Factor Adjusted Total Benchmarked Mitigation Revenue

No changes are being requested. FEI seeks to continue with the Capacity Factor Adjusted Total Benchmarked Mitigation Revenue calculation.

I. Incentive Percentage

1. Benchmarked Activity Incentive Percentage
    - No changes are being requested. FEI seeks to continue with the Benchmarked Activity Incentive Percentage and Market Factor Performance calculation.
2. Non-Benchmarked Activity Incentive Percentage
    - No changes are being requested. FEI seeks to continue with the Non-Benchmarked Activity Incentive Percentage of 4 percent.
3. New Activity Incentive Percentage
    - No changes are being requested. FEI seeks to continue with the New Activity Incentive Percentage of 12 percent.
4. Fixed Adjustment
    - No changes are being requested. FEI seeks to continue with the Fixed Adjustment of $200,000 representing no incentive payment earned on the first $5 million of eligible mitigation revenue.

J. Incentive Payment

No changes are being requested. FEI seeks to continue with the Incentive Payment calculation.

K. Reporting Requirements

No changes are being requested. FEI seeks to continue with the Reporting Requirements including a Winter Report and Year End Report.

5. GSMIP UPDATES & TERM

In this Application, FEI is seeking approval to extend the existing GSMIP for an additional three-year term effective November 1, 2022 through to October 31, 2025.

FEI has recently completed an Energy Trading and Risk Management (ETRM) system replacement project in 2022. During the design phase it was determined that new data feeds for subscriptions will be utilized for market pricing data. As mentioned above, FEI may be required to evaluate alternative sources which may prompt a change in the current GSMIP Base Benchmarks as reported by OneX. If required, at the appropriate time FEI would submit to the BCUC a request to amend the Term Sheet and provide details on the updated Base Benchmark sources.

FEI has demonstrated the structure under the current GSMIP has been effective and appropriate through the prudent management of resources, generation of mitigation revenue and meeting firm core load requirements. The structure has satisfied the guiding principles, such as delivering value to ratepayers, aligning ratepayer and shareholder interests, and managing portfolio risk. The past number of years have demonstrated the model has worked how it was designed to, through changing market conditions, upstream pipeline supply disruptions and extreme weather events. Therefore, FEI submits that a three-year extension to the term of the GSMIP is just and reasonable.

6. CONCLUSION

As summarized in this report and Application, FEI has demonstrated that the GSMIP developed by the Working Group in 2011 is working as it was contemplated, and that customers continue to benefit from commodity, storage and transportation resource mitigation activities. FEI continues to be incented to effectively manage gas supply costs while ensuring a reliable supply of gas to core customers.

As an incentive mechanism, the GSMIP is designed to align the interests of customers and shareholders. FEI contracts for gas supply portfolio resources, pursuant to the ACP, with the objective of ensuring an appropriate balance of cost minimization, security, diversity, and reliability of gas supply in order to meet the core customer design peak day and annual requirements. Once this objective has been met, FEI mitigates gas supply portfolio costs for its customers by actively pursuing opportunities to generate revenue related to transportation, storage, and commodity as part of the overall portfolio optimization.

Since the current GSMIP model began in the 2011/12 gas year, the revenue earned and the incentive payment has varied from year to year based on market conditions and FEI's ability to capture the opportunities presented. However, the model has generated significant customer savings while providing FEI an opportunity to earn an incentive by promoting mitigation activities beyond the core obligation of serving firm load requirements and system balancing. The current GSMIP model took considerable time and effort to design with stakeholders and BCUC staff, is now well-established with minor revisions being sought, and FEI believes that the performance of the GSMIP model over the years and under variable market conditions demonstrates that it continues to work as intended.

The workshop series conducted in 2022 with BCUC staff and key stakeholder groups validated that the model remains aligned to the original objectives and guiding principles. The minor enhancements that FEI is proposing could bring additional benefits to customers while prudently managing portfolio risk. Throughout the workshop series, key stakeholder groups expressed continued support for the GSMIP objectives, model, and benefits for customers.

Based on the review provided in this Application, FEI requests approval to extend the GSMIP with the modifications proposed for the period of November 1, 2022 to October 31, 2025.

Appendix A

TERM SHEET (BLACKLINED AND PROFORMA)

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2022-2025 Gas Supply Mitigation Incentive Program (GSMIP) TERM SHEET

Table of Contents

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2022-2025 GSMIP TERM SHEET

A. MODEL DESIGN AND TERM

The British Columbia Utilities Commission (BCUC) approved, as per Order G-XXX-XX dated Month Day, Year, the extension of the term of the FortisBC Energy Inc. (FEI) Gas Supply Mitigation Incentive Program (GSMIP) for the period from November 1, 2022 to October 31, 2025 (the 2022-2025 GSMIP).

The GSMIP model design incorporates a blended approach of eligible mitigation revenue and a comparison to a base benchmark. FEI's total incentive payment amount is a function of the mitigation revenue achieved as well as the performance of FEI compared to a base benchmark for those mitigation activities where a benchmark applies.

The payment of an incentive payment for any gas contract year under this program is subject to FEI meeting the firm load requirements of its core customers during that year. A gas contract year is from November 1 to the following October 31. The incentive payment FEI shareholders receive under the GSMIP will be reviewed and approved annually by the BCUC. FEI will withdraw the approved incentive amounts from the Midstream Cost Reconciliation Account.

The 2022-2025 GSMIP will be in effect from November 1, 2022 through October 31, 2025, and so will apply for the 2022/23, 2023/24 and 2024/25 gas contract years.

B. TOTAL MITIGATION DESCRIPTION

FEI has surplus gas supply, transportation and storage capacity to sell at certain times of the year when customer demand is less than the amount of resources available. Throughout the contract year, FEI forecasts what resources will be needed for customer demand and then FEI mitigates the remaining assets. FEI mitigates costs for customers by focusing on opportunities to optimize asset utilization for transportation, storage and off-system supply sales. The GSMIP model breaks down the transactions associated with the aforementioned activities into the following categories: Benchmarked Mitigation Activities, Non-Benchmarked Mitigation Activities, and New Mitigation Activities. Combined, these activities are referred to as Total Mitigation.

The calculation of the incentive payment is determined first by applying the applicable percentage to the mitigation revenue in the three different categories, and then the total incentive is adjusted by a fixed adjustment.

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C. TRANSACTION DESCRIPTIONS – BENCHMARKED ACTIVITIES

Benchmarked Activities are those cost mitigation activities for which a reasonable benchmark has been established to measure the relative performance of FEI's cost mitigation efforts against. Current Benchmarked Activities include:

1. Spot Commodity Resale Mitigation: The Commodity Resale transaction only occurs when surplus supply has been purchased in excess of what is needed to serve core load. When FEI has excess purchased supply, FEI has the option to sell it back at the same market hub, or transport it to sell to a downstream market. FEI will look for transactions that yield the highest expected net-back value, given the constraints on what is operationally feasible. The total cost recovery revenue associated with Spot Commodity Resale is the Actual Sales Volume multiplied by the Actual Sales Price. Nevertheless, the Spot Commodity Resale Mitigation Revenue booked to GSMIP is calculated as follows:

*Actual Sales Volumes * Actual Sales Prices*

minus

*Deemed Purchase Volumes * Deemed Purchase Price @ relevant hub*

minus

Transportation Variable Charges

equals

Spot Commodity Resale Mitigation Revenue

The Deemed Purchase Volume is the actual sales volume plus the applicable pipeline fuel volume for transportation from where the gas is available to the sales point.

The Deemed Purchase Price is the reported Platts Gas Daily Common High price on the date of sale at the relevant hub where the surplus gas is available, which is normally Station 2 or NOVA Inventory Transfer (NIT).

> The Platts Gas Daily Common High is the Platts Midpoint plus 50% of the Absolute Range. The Platts Gas Daily Midpoint is the volume-weighted average of all deals reported to Platts at a given market location, excepting any outliers that are not used, and which is reported in Platts *Gas Daily*, a daily industry publication that provides pricing data at major North American interstate and intrastate pipeline market hubs and pooling points. The Absolute Range is the range between the absolute low and absolute high of deals reported, excluding the outliers that are not used.

2. Monthly Commodity Resale Mitigation: The Monthly Commodity Resale transaction occurs when surplus supply has been purchased in excess of what is needed to serve core load. When FEI has excess purchased supply, typically in the summer months between April and October, FEI has the option to sell it back at the same market hub, or transport it to sell to a downstream market. FEI will look for transactions that yield the highest expected net-back value, given the constraints on what is operationally feasible. The total cost recovery revenue

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associated with Monthly Commodity Resale is the Actual Sales Volume multiplied by the Actual Sales Price. Nevertheless, the Monthly Commodity Resale Mitigation Revenue booked to GSMIP is calculated as follows:

*Actual Sales Volumes * Actual Sales Prices*

minus

*Deemed Purchase Volumes * Deemed Purchase Price @ relevant hub*

minus

Transportation Variable Charges

equals

Monthly Commodity Resale Mitigation Revenue

The Deemed Purchase Volume is the actual sales volume plus the applicable pipeline fuel volume for transportation from where the gas is available to the sales point.

The Deemed Purchase Price is the reported Platts Inside FERC's Gas Market Report – Monthly Bidweek Spot Gas Prices, High price for the month at the relevant hub where the surplus gas is available, which is normally Station 2 or NOVA Inventory Transfer (NIT).

3. Benchmarked Transportation Mitigation: FEI can mitigate unutilized transportation capacity by entering into a supply purchase from others at an upstream market and entering into a corresponding sale to others at a downstream market. Benchmarked Transportation Mitigation transactions are those conducted on Westcoast T-South, Foothills, Southern Crossing Pipeline (SCP) and Intra-Alberta NOVA. Only SCP transportation mitigation revenue, on unutilized capacity, that is recorded in the Midstream Cost Reconciliation Account is eligible for GSMIP. The Transportation Mitigation transactions could be a spot market transaction or a forward market transaction. Actual sales volumes are net of pipeline fuel. Transportation Mitigation Revenue for each transaction is calculated as shown below:

*Actual Sales Volumes * Actual Sales Prices*

minus

*Actual Purchase Volumes * Actual Purchase Prices*

minus

Transportation Variable Charges

equals

Transportation Mitigation Revenue

4. Capacity Release Mitigation: FEI may also mitigate unutilized transportation capacity by entering into Capacity Release transactions, whereby FEI releases capacity to a third party who then pays FEI for the right to use its transportation capacity. In a Capacity Release

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transaction, FEI is not responsible for any variable costs when a third party uses the transportation capacity. The Capacity Release transactions could be a spot market transaction or a forward market transaction. Capacity Release transactions are conducted on Westcoast T-South, Foothills and Intra-Alberta NOVA. Capacity Release Mitigation Revenue is calculated for each transaction as the total amount of revenue received for release of the capacity, as shown below:

*Actual Capacity Release Volumes * Actual Capacity Release Prices*

equals

Spot or Forward Capacity Release Mitigation Revenue

5. Total Benchmarked Mitigation Revenue: The Total Benchmarked Mitigation Revenue is calculated as follows:

Spot Commodity Resale Mitigation Revenue

Plus

Monthly Commodity Resale Mitigation Revenue

plus

Benchmarked Transportation Mitigation Revenue

plus

Capacity Release Mitigation Revenue

equals

Total Benchmarked Mitigation Revenue

D. TRANSACTION DESCRIPTIONS – NON-BENCHMARKED ACTIVITIES

Non-Benchmarked Activities are those cost mitigation activities for which no reasonable benchmark has been established to measure the relative performance of FEI's cost mitigation efforts against. Current Non-Benchmarked Activities include:

1. Storage Mitigation or Park and Loan Activity: If FEI has available gas storage capacity and the near price is lower than the forward market price, FEI will enter into a purchase in the nearby month and a sale for a higher price in the forward month. This is referred to as a Park transaction.

   An example of a Park: If June gas prices are $4.50 Cdn/GJ and August prices are $4.80 Cdn/GJ, then FEI can purchase gas in June and forward sell August, to lock in a spread of $.30 Cdn/GJ. FEI would contemplate the transaction so long as it didn't negatively impact its

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ability to fill storage for serving winter customer load, and if the storage carrying costs were less than the value of the price spread between the June purchase and the August sale transactions.

If at any time that FEI has surplus storage capacity relative to projected loads, FEI may elect to sell its inventory to a third party who will pay a premium, and return the inventory to FEI at a future date. This is referred to as a Loan transaction.

The Cost to Carry is the time value of money difference of holding the gas in storage for the given time period, which could be positive or negative.

Storage transactions are conducted using the Aitken Creek storage facility and FEI's Alberta storage assets. Storage transactions can be a single transaction of the difference paid for the Park and Loan exchange or it could be a separate purchase and sale.

For a Park and Loan transacted as a single transaction, the calculation of Storage Mitigation Revenue is shown below:

*Actual Park or Loan Volumes * Actual Park or Loan Prices*

minus

Cost to Carry

equals

Storage Mitigation Revenue

For a Storage transaction that is composed of a purchase and sale transaction, the calculation of Storage Mitigation Revenue is shown below:

*Actual Sales Volumes * Actual Sales Prices*

minus

*Actual Purchase Volumes * Actual Purchase Prices*

minus

Cost to Carry

equals

Storage Mitigation Revenue

2. T-North Transportation and Capacity Release Mitigation: From time to time, FEI may have additional T-North Transportation capacity, which could be mitigated or released. Because there are not significant transactions reported for supply arrangements on T–North, there is no reliable index to use for benchmarking purposes. As a result, transportation mitigation and capacity release transactions on T-North are part of the Non-Benchmarked Activities. The T-

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North Transportation Mitigation Revenue is calculated using the same methodology as the Benchmarked Transportation Mitigation Revenue. The T-North Capacity Release Mitigation Revenue calculation uses the same methodology as the Capacity Release Mitigation Revenue in the Benchmarked Activities.

3. NOVA Transportation Mitigation: From time to time, FEI may have unutilized NOVA Transportation capacity on the day, which could be released to other shippers. Due to market changes, the transport price difference between NIT to Empress has been fluctuating from positive to negative. The spread between these price points has been largely negative since the winter of 2009, thus resulting in a negative benchmark. Since no reasonable benchmark can be established at this time, NOVA Transportation mitigation will be part of the Non-Benchmarked activities. The NOVA Transportation Mitigation Revenue is calculated using the same methodology as the Benchmarked Transportation Mitigation Revenue.
4. NOVA and T-South Interior Forward Capacity Releases: From time to time, FEI may have unutilized NOVA and T-South Interior capacity (excess capacity in the summer months from April to October). FEI would release this excess capacity for a forward summer month. For NOVA Forward Capacity Releases, there is no forward pricing available at Empress which traditionally would be used as a proxy to establish a benchmark. Similarly, for the T-South Interior Forward Capacity Releases, there is no sales hub near this location to benchmark against. As a result, NOVA and T-South Interior Forward Capacity Releases are part of Non-Benchmarked Activities. The NOVA and T-South Interior Forward Capacity Releases Revenue calculation uses the same methodology as the Capacity Release Mitigation Revenue in the Benchmarked Activities.
5. Liquids Extraction: From time to time, FEI may be able to enter into transactions where a party will pay a portion of the proceeds of the sale of natural gas liquids (such as ethane and propane) that can be extracted from company-owned gas. These transactions occur at processing plants for which there is no reliable index pricing data. As a result, Liquids Extraction is part of the Non-Benchmarked Activities. The Liquids Extraction Mitigation Revenue is the total revenue received by FEI from the natural gas Liquids Extraction contracts that FEI has negotiated.
6. Forward Commodity Resale Mitigation: At times, when FEI has surplus supply and surplus storage capacity, and forward market prices exceed the spot market price and the Cost to Carry, FEI will forward sell surplus commodity. Due to the difficulty in benchmarking storage, and because a Forward Commodity Resale Mitigation transaction utilizes storage capacity, this transaction is similar to a Storage Mitigation transaction and is part of the Non-Benchmarked Activities. The calculation of Forward Commodity Resale Mitigation Revenue for each transaction is as follows:

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*Actual Forward Sales Volumes * Actual Sales Prices*

minus

*Deemed Volumes Purchased * Deemed Purchase Prices*

minus

Net Transportation Costs and Cost to Carry

equals

Forward Commodity Resale Mitigation Revenue

Deemed Volumes Purchased and Deemed Purchase Prices have the same meaning as for the calculation of Spot Commodity Resale Mitigation Revenue, except that the Deemed Purchase Prices will be determined as of the date when the Forward Commodity Resale was entered into.

7. Transportation Asset Management Agreement (AMA): FEI holds firm transportation capacity on NWP. FEI can generate mitigation revenue from the Northwest Pipeline (NWP) capacity under an AMA. Under an AMA, FEI is able maintain full operational flexibility to meet customer load requirements. While FEI is unable to transact buy/sells in the United States (US), by entering into an AMA with a counterparty that can transact in both Canada and the US, this enables FEI to mitigate unutilized transport capacity and generate additional mitigation revenue on behalf of customers. The revenue under the AMA is realized through a monthly demand charge.

   As no reasonable benchmark can be established for these transactions, AMA is classified as a non-benchmarked activity.

8. Pooling on the NOVA System: NOVA allows delivery shippers at any export point to assign their extraction rights to another shipper. This assignment instruction is called “Pooling” whereby the assignor’s extraction rights are then pooled with the assignee’s extraction rights. FEI has developed two opportunities to use pooling to increase mitigation revenues for FEI customers. FEI can pool other shippers’ volumes through its Cochrane Extraction agreement and receive a revenue split for the pooled volumes. FEI can also pool its volume through other counterparties’ extraction arrangements. FEI’s decision to flow through an extraction plant is evaluated based on which transaction will provide greater mitigation revenue and the counterparties’ requirements. As no reasonable benchmark can be established for these transactions, Pooling on the NOVA system is classified as a non-benchmarked activity.

9. Total Non-Benchmarked Mitigation Revenue: Total Non-Benchmarked Mitigation Revenue is calculated as follows:

Storage Mitigation Revenue

plus

T-North Transportation Mitigation Revenue

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plus

T-North Capacity Release Mitigation Revenue

plus

NOVA Transportation Mitigation

plus

NOVA and T-South Interior Forward Capacity Releases

plus

Liquids Extraction Revenue

plus

Forward Commodity Resale Mitigation Revenue

plus

Transportation Asset Management Agreement (AMA) Revenue

plus

Pooling on NOVA System Revenue

equals

Total Non-Benchmarked Mitigation Revenue

E. TRANSACTION DESCRIPTIONS - NEW ACTIVITY

New Activity includes mitigation transactions which FEI does not currently undertake in its management of the portfolio of gas supply contracts, pipeline contracts, storage capacity and liquids extraction transactions. As a result, New Activity refers to mitigation activities that have not been developed yet. New Activity does not include opportunities created by changes to gas supply purchases or pipeline or storage capacities or changes to pipeline or storage tariffs that do not create new services offerings. The mitigation revenue from a New Activity will be calculated in a way that is consistent with the calculation of mitigation revenue for other GSMIP activities.

A New Activity must be approved as such by the BCUC to be included in GSMIP. The mitigation revenue from a New Activity will be calculated from the date that the New Activity transaction first occurred and after a twelve consecutive month period each New Activity will be reclassified to either the Benchmarked or Non-Benchmarked categories as appropriate.

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F. BASE BENCHMARK

The Base Benchmark is designed to measure how FEI performed relative to a conservative base utility for the Benchmarked Activities. FEI's performance relative to the Base Benchmark impacts the percentage amount it earns of the Total Benchmarked Mitigation Revenue booked to GSMIP achieved in the Gas Year. The more FEI can outperform the Base Benchmark, the greater the potential incentive payment. The prices used in determining the Base Benchmark are as follows:

- Spot market transactions to sell will be benchmarked against the reported Platts Common Low price, and spot market transactions to purchase will be benchmarked against the reported Platts Common High prices, at the market point on the date of the transaction. Forward market transactions to sell will be benchmarked against the Bid prices and forward market transactions to purchase will be benchmarked against the Offer prices, as reported by OneX for the market point on the date that the transaction took place. Conversions such as for currency exchange, heating value and quantity will be calculated consistent with conventional gas industry practice.

  As described in the Commodity Resale section above, the Platts Common High is the Platts Midpoint plus 50% of the Absolute Range. The Platts Common Low is the Platts Midpoint less 50% of the Absolute Range. The Absolute Range is the range between the absolute low and absolute high of deals reported, excluding the outliers that are not used.

  Bid is the price on the forward market that a buyer is willing to buy gas and Offer is the price on the forward market that a seller is willing to sell gas. OneX is an independent broker who brings parties together to transact energy forward market transactions among market participants, including utilities, traders, marketers, banks and producers.

  Monthly market transactions to sell will be benchmarked against the reported Platts Inside FERC's Gas Market Report – Monthly Bidweek Spot Gas Low prices, and monthly market transactions to purchase will be benchmarked against the Platts Inside FERC's – Monthly Bidweek Spot Gas High prices, at the market point for the month of the transaction.

- Market Concentration Adjustment: A Market Concentration Adjustment may be used for spot transactions. In the event that FEI's market share in any given season at any market hub exceeds 40% of the reported traded volume in Platts *Gas Daily*, the prices used to determine the Base Benchmark will be the Platts Midpoint price for spot transactions at the market hub. FEI's market share will be calculated as the volume of FEI's reported transactions to Platts compared to the total transactions reported by Platts *Gas Daily* at each of the 4 major hubs: Station 2, Sumas, AECO and Kingsgate. FEI reports all fixed price transactions to Platts.

G. BASE BENCHMARK CALCULATION

1. Spot Commodity Resale Base Benchmark: The Spot Commodity Resale Base Benchmark is calculated as follows:

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*Actual Sales Volumes * Platts Common Low @ relevant hub*

minus

*Deemed Purchase Volumes * Platts Common High*

minus

Transportation Variable Charges

equals

Spot Commodity Resale Base Benchmark

The Deemed Purchase Volumes has the same meaning as for the calculation of the Spot Commodity Resale Mitigation Revenue, and the Platts Common High is for the point where the surplus gas is available, corresponding to the Deemed Purchase Prices.

2. Monthly Commodity Resale Base Benchmark: The Monthly Commodity Resale Base Benchmark is calculated as follows:

*Actual Sales Volumes * Platts Inside FERC's Low @ relevant hub*

minus

*Deemed Purchase Volumes * Platts Inside FERC's High*

minus

Transportation Variable Charges

equals

Monthly Commodity Resale Base Benchmark

The Deemed Purchase Volumes has the same meaning as for the calculation of the Monthly Commodity Resale Mitigation Revenue, and the Platts Inside FERC's High is for the point where the surplus gas is available, corresponding to the Deemed Purchase Prices.

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3. Spot Transportation Mitigation Base Benchmark: The Transportation Mitigation Base Benchmark is calculated as follows:

*Actual Sales Volume * Platts Common Low @ sales hub*

Minus

*Actual Purchase Volume * Platts Common High @ purchase hub*

Minus

Transportation Variable Charges

Equals

Spot Transportation Mitigation Base Benchmark

4. Forward Transportation Mitigation Base Benchmark: The Transportation Mitigation Base Benchmark is calculated as follows:

*Actual Sales Volume * Bid Price @ sales hub*

Minus

*Actual Purchase Volume * Offer Price @ purchase hub*

Minus

Transportation Variable Charges

Equals

Forward Transportation Mitigation Base Benchmark

5. Spot Capacity Release Base Benchmark: The Spot Capacity Release Base Benchmark is calculated as follows:

Actual Capacity Released Volumes Platts Common Low @ relevant sales hub*

Minus

*Actual Capacity Released Volume + relevant pipeline fuel volume) * Platts Common High @ relevant purchase hub*

Minus

Transportation Variable Charges

Equals

Spot Capacity Release Base Benchmark

6. <u>Forward Capacity Release Base Benchmark:</u> The Forward Capacity Release Base Benchmark is calculated as follows:

Actual Capacity Released Volume Bid price @ relevant sales hub*

Minus

*(Actual Capacity Released + relevant pipeline fuel volume) * Offer price @ relevant purchase hub*

Minus

Transportation Variable Charges

Equals

Forward Capacity Release Base Benchmark

7. <u>Total Base Benchmark:</u> Total Base Benchmark is calculated as follows:

Spot Commodity Resale Base Benchmark

Plus

<u>Monthly Commodity Resale Base Benchmark</u>

<u>Plus</u>

Spot Transportation Mitigation Base Benchmark

Plus

Forward Transportation Mitigation Base Benchmark

Plus

Spot Capacity Release Base Benchmark

Plus

Forward Capacity Release Base Benchmark

Equals

Total Base Benchmark

H. <u>CAPACITY FACTOR ADJUSTED TOTAL BENCHMARKED MITIGATION REVENUE</u>

To insure that FEI will be focused on utilizing excess transportation through commodity resales downstream, transportation mitigation or capacity releases, a volumetric benchmark has been established. A Capacity Factor Penalty will be assessed on transportation transactions on a given pipeline for a given season, if FEI's Capacity Factor on that pipeline falls below the overall Benchmarked Pipeline Capacity Factor for that season. The seasonal periods are November-March and April-October. The two pipelines for which there are publicly available capacity factors measuring the flow of gas volumes across the pipeline are Westcoast's T-South segment and TC Energy Foothills system.

In the event FEI's Capacity Factor falls below the capacity factor on either of those pipelines for a particular season, FEI's penalty would be a reduction in revenue eligible for an incentive payment equal to the difference between the Transportation Mitigation Revenue and the corresponding Base Benchmarks for that particular pipeline and season.

The Benchmarked Pipeline Capacity Factor is calculated as the total reported flows on the pipeline segment during the seasonal period divided by the corresponding maximum available flow capacity.

The FEI Capacity Factor is calculated as FEI's total actual flows on the pipeline segment during the seasonal period divided by FEI's total contracted capacity excluding capacity released on the pipeline segment.

In the event that FEI's Capacity Factor for a particular season on an applicable pipeline segment is less than the corresponding Benchmarked Pipeline Capacity Factor, a Capacity Factor Penalty for the applicable pipeline segment and season will be calculated as:

Applicable Benchmarked Transportation Mitigation Revenue

Minus

Applicable Spot Transportation Mitigation Base Benchmark

Minus

Applicable Forward Transportation Mitigation Base Benchmark

Equals

Capacity Factor Penalty for specific pipeline segment and season

The Capacity Factor Adjusted Total Benchmarked Mitigation Revenue is then calculated as:

Total Benchmarked Mitigation Revenue

Minus

All Capacity Factor Penalties for the applicable time period

Equals

Capacity Factor Adjusted Total Benchmarked Mitigation Revenue

An example of the application of the Capacity Factor Penalty where FEI's Benchmarked Revenue is not impacted for T-South capacity for the April 2010 – October 2010 is shown below:

- April 2010 – October 2010 T-South FEI Capacity Factor = 76.36%
- April 2010 – October 2010 T-South Benchmarked Pipeline Capacity Factor = 64.71%

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The FEI Capacity Factor is greater than the Benchmarked Pipeline Capacity Factor, so there is no adjustment to the Total Benchmarked Mitigation Revenue.

An example of the application of the Capacity Factor Penalty where FEI's Benchmarked Mitigation Revenue is impacted for T-South capacity for the April 2009 – October 2009 is shown below:

- April 2009 – October 2009 T-South FEI Capacity Factor = 64%
- April 2009 – October 2009 T-South Benchmarked Pipeline Capacity Factor = 66%

The T-South Pipeline Benchmarked Capacity Factor is greater than the corresponding T-South FEI Capacity Factor. Therefore, for April through October 2009, a Capacity Factor Penalty is calculated as shown below and then applied to the Total Benchmarked Mitigation Revenue.

Applicable T-South Transportation Mitigation Revenues

Minus

Applicable T-South Transportation Base Benchmarks

Equals

T-South Capacity Factor Penalty

I. INCENTIVE PERCENTAGE:

1. Benchmarked Activity Incentive Percentage: The Benchmarked Activity Incentive Percentage is determined from the Market Performance Factor.

   i. Market Performance Factor: The Market Performance Factor is calculated as follows:

Capacity Factor Adjusted Total Benchmarked Mitigation Revenue

divided by

Total Base Benchmark

multiplied by 100 percent

Equals

Market Performance Factor

The Market Performance Factor is expressed as a percentage to one decimal place (e.g. 128.2 percent).

The Market Performance Factor (MPF) is used to determine the Benchmarked Activity Incentive Percentage (BAIP) as detailed below:

For MPF between 100 and 131 %, BAIP = 2.45 % + 0.05 % * (MPF-100)

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For MPF between 131 and 136 %, BAIP = 4.00 %

For MPF of 136 and greater, BAIP = 4.00 + 0.04 % * (MPF -136)

The Benchmarked Activity Incentive Percentage is expressed as a percentage to two decimal places.

2. Non-Benchmarked Activity Incentive Percentage:

For Non-Benchmarked Activities, a constant 4% incentive percentage is applied to the related mitigation revenue.

3. New Activity Incentive Percentage:

For any new mitigation activities that FEI develops and which the BCUC determines is a New Activity, a constant 12% incentive percentage is applied to the related mitigation revenue.

4. Fixed Adjustment

The Total Incentive Payment will include a fixed $200,000 reduction each year. Based on using the target 4% incentive percentage, this reduction equates to no incentive payment earned on the first $5 million of eligible mitigation revenue.

J. <u>INCENTIVE PAYMENT</u>

The Incentive Payment for each gas contract year is calculated as follows:

*Capacity Factor Adjusted Total Benchmarked Mitigation Revenue *
Benchmarked Activity Incentive Percentage*

Plus

*Total Non-Benchmarked Activity Mitigation Revenue * 4 percent*

Plus

*Total New Activity Mitigation Revenue * 12 percent*

Minus

$200,000

Equals

Total Incentive Payment

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K. REPORTING REQUIREMENTS

FEI will provide two reports per annum to the BCUC and notify stakeholders when these reports have been filed with the BCUC. The reports will also be made available, if requested, to stakeholders representing customer groups on a confidential basis.

- The first report will follow the winter period which ends March of each year. This report will consist of all transactions to date with a GSMIP summary to date and discussing the factors, including an update on the market conditions, contributing to the mitigation results. There will be a high level summary of any activities that FEI deems to be "New". FEI will provide a model that breaks out the mitigation revenues and incentive payments.
- In the second report, also referred to as the Year End Report, FEI will provide all transaction data, a GSMIP Summary, and a written report discussing the factors, including the market conditions, contributing to the mitigation results and market changes from the previous year. "New Activities" will be explained in detail along with a comprehensive plan to transition the activity to a "Benchmarked Activity" if possible. A New Activity must be approved as such by the BCUC to be included in GSMIP. The incentive related to New Activities must be approved by the BCUC in the annual review of the GSMIP. Any modifications to the GSMIP model for the upcoming year would need to be presented in the Year End Report of the previous year. Capacity Factor adjustments and Market Concentration measurements will be detailed in the Year End Report as well.

Any incentive payment will be subject to review and approval by the BCUC.

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2022-2025 Gas Supply Mitigation Incentive Program (GSMIP) TERM SHEET

Table of Contents

2022-2025 GSMIP TERM SHEET

A. MODEL DESIGN AND TERM

The British Columbia Utilities Commission (BCUC) approved, as per Order G-XXX-XX dated Month Day, Year, the extension of the term of the FortisBC Energy Inc. (FEI) Gas Supply Mitigation Incentive Program (GSMIP) for the period from November 1, 2022 to October 31, 2025 (the 2022-2025 GSMIP).

The GSMIP model design incorporates a blended approach of eligible mitigation revenue and a comparison to a base benchmark. FEI's total incentive payment amount is a function of the mitigation revenue achieved as well as the performance of FEI compared to a base benchmark for those mitigation activities where a benchmark applies.

The payment of an incentive payment for any gas contract year under this program is subject to FEI meeting the firm load requirements of its core customers during that year. A gas contract year is from November 1 to the following October 31. The incentive payment FEI shareholders receive under the GSMIP will be reviewed and approved annually by the BCUC. FEI will withdraw the approved incentive amounts from the Midstream Cost Reconciliation Account.

The 2022-2025 GSMIP will be in effect from November 1, 2022 through October 31, 2025, and so will apply for the 2022/23, 2023/24 and 2024/25 gas contract years.

B. TOTAL MITIGATION DESCRIPTION

FEI has surplus gas supply, transportation and storage capacity to sell at certain times of the year when customer demand is less than the amount of resources available. Throughout the contract year, FEI forecasts what resources will be needed for customer demand and then FEI mitigates the remaining assets. FEI mitigates costs for customers by focusing on opportunities to optimize asset utilization for transportation, storage and off-system supply sales. The GSMIP model breaks down the transactions associated with the aforementioned activities into the following categories: Benchmarked Mitigation Activities, Non-Benchmarked Mitigation Activities, and New Mitigation Activities. Combined, these activities are referred to as Total Mitigation.

The calculation of the incentive payment is determined first by applying the applicable percentage to the mitigation revenue in the three different categories, and then the total incentive is adjusted by a fixed adjustment.

C. TRANSACTION DESCRIPTIONS – BENCHMARKED ACTIVITIES

Benchmarked Activities are those cost mitigation activities for which a reasonable benchmark has been established to measure the relative performance of FEI's cost mitigation efforts against. Current Benchmarked Activities include:

1. Spot Commodity Resale Mitigation: The Commodity Resale transaction only occurs when surplus supply has been purchased in excess of what is needed to serve core load. When FEI has excess purchased supply, FEI has the option to sell it back at the same market hub, or transport it to sell to a downstream market. FEI will look for transactions that yield the highest expected net-back value, given the constraints on what is operationally feasible. The total cost recovery revenue associated with Spot Commodity Resale is the Actual Sales Volume multiplied by the Actual Sales Price. Nevertheless, the Spot Commodity Resale Mitigation Revenue booked to GSMIP is calculated as follows:

*Actual Sales Volumes * Actual Sales Prices*

minus

*Deemed Purchase Volumes * Deemed Purchase Price @ relevant hub*

minus

Transportation Variable Charges

equals

Spot Commodity Resale Mitigation Revenue

The Deemed Purchase Volume is the actual sales volume plus the applicable pipeline fuel volume for transportation from where the gas is available to the sales point.

The Deemed Purchase Price is the reported Platts Gas Daily Common High price on the date of sale at the relevant hub where the surplus gas is available, which is normally Station 2 or NOVA Inventory Transfer (NIT).

> The Platts Gas Daily Common High is the Platts Midpoint plus 50% of the Absolute Range. The Platts Gas Daily Midpoint is the volume-weighted average of all deals reported to Platts at a given market location, excepting any outliers that are not used, and which is reported in Platts *Gas Daily*, a daily industry publication that provides pricing data at major North American interstate and intrastate pipeline market hubs and pooling points. The Absolute Range is the range between the absolute low and absolute high of deals reported, excluding the outliers that are not used.

2. Monthly Commodity Resale Mitigation: The Monthly Commodity Resale transaction occurs when surplus supply has been purchased in excess of what is needed to serve core load. When FEI has excess purchased supply, typically in the summer months between April and October, FEI has the option to sell it back at the same market hub, or transport it to sell to a downstream market. FEI will look for transactions that yield the highest expected net-back value, given the constraints on what is operationally feasible. The total cost recovery revenue

associated with Monthly Commodity Resale is the Actual Sales Volume multiplied by the Actual Sales Price. Nevertheless, the Monthly Commodity Resale Mitigation Revenue booked to GSMIP is calculated as follows:

*Actual Sales Volumes * Actual Sales Prices*

minus

*Deemed Purchase Volumes * Deemed Purchase Price @ relevant hub*

minus

Transportation Variable Charges

equals

Monthly Commodity Resale Mitigation Revenue

The Deemed Purchase Volume is the actual sales volume plus the applicable pipeline fuel volume for transportation from where the gas is available to the sales point.

The Deemed Purchase Price is the reported Platts Inside FERC's Gas Market Report – Monthly Bidweek Spot Gas Prices, High price for the month at the relevant hub where the surplus gas is available, which is normally Station 2 or NOVA Inventory Transfer (NIT).

3. Benchmarked Transportation Mitigation: FEI can mitigate unutilized transportation capacity by entering into a supply purchase from others at an upstream market and entering into a corresponding sale to others at a downstream market. Benchmarked Transportation Mitigation transactions are those conducted on Westcoast T-South, Foothills, Southern Crossing Pipeline (SCP) and Intra-Alberta NOVA. Only SCP transportation mitigation revenue, on unutilized capacity, that is recorded in the Midstream Cost Reconciliation Account is eligible for GSMIP. The Transportation Mitigation transactions could be a spot market transaction or a forward market transaction. Actual sales volumes are net of pipeline fuel. Transportation Mitigation Revenue for each transaction is calculated as shown below:

*Actual Sales Volumes * Actual Sales Prices*

minus

*Actual Purchase Volumes * Actual Purchase Prices*

minus

Transportation Variable Charges

equals

Transportation Mitigation Revenue

4. Capacity Release Mitigation: FEI may also mitigate unutilized transportation capacity by entering into Capacity Release transactions, whereby FEI releases capacity to a third party who then pays FEI for the right to use its transportation capacity. In a Capacity Release

transaction, FEI is not responsible for any variable costs when a third party uses the transportation capacity. The Capacity Release transactions could be a spot market transaction or a forward market transaction. Capacity Release transactions are conducted on Westcoast T-South, Foothills and Intra-Alberta NOVA. Capacity Release Mitigation Revenue is calculated for each transaction as the total amount of revenue received for release of the capacity, as shown below:

*Actual Capacity Release Volumes * Actual Capacity Release Prices*

equals

Spot or Forward Capacity Release Mitigation Revenue

5. Total Benchmarked Mitigation Revenue: The Total Benchmarked Mitigation Revenue is calculated as follows:

Spot Commodity Resale Mitigation Revenue

Plus

Monthly Commodity Resale Mitigation Revenue

plus

Benchmarked Transportation Mitigation Revenue

plus

Capacity Release Mitigation Revenue

equals

Total Benchmarked Mitigation Revenue

D. TRANSACTION DESCRIPTIONS – NON-BENCHMARKED ACTIVITIES

Non-Benchmarked Activities are those cost mitigation activities for which no reasonable benchmark has been established to measure the relative performance of FEI's cost mitigation efforts against. Current Non-Benchmarked Activities include:

1. Storage Mitigation or Park and Loan Activity: If FEI has available gas storage capacity and the near price is lower than the forward market price, FEI will enter into a purchase in the nearby month and a sale for a higher price in the forward month. This is referred to as a Park transaction.

   An example of a Park: If June gas prices are $4.50 Cdn/GJ and August prices are $4.80 Cdn/GJ, then FEI can purchase gas in June and forward sell August, to lock in a spread of $.30 Cdn/GJ. FEI would contemplate the transaction so long as it didn't negatively impact its ability to fill storage for serving winter customer load, and if the storage carrying costs were less than the value of the price spread between the June purchase and the August sale transactions.

If at any time that FEI has surplus storage capacity relative to projected loads, FEI may elect to sell its inventory to a third party who will pay a premium, and return the inventory to FEI at a future date. This is referred to as a Loan transaction.

The Cost to Carry is the time value of money difference of holding the gas in storage for the given time period, which could be positive or negative.

Storage transactions are conducted using the Aitken Creek storage facility and FEI's Alberta storage assets. Storage transactions can be a single transaction of the difference paid for the Park and Loan exchange or it could be a separate purchase and sale.

For a Park and Loan transacted as a single transaction, the calculation of Storage Mitigation Revenue is shown below:

*Actual Park or Loan Volumes * Actual Park or Loan Prices*

minus

Cost to Carry

equals

Storage Mitigation Revenue

For a Storage transaction that is composed of a purchase and sale transaction, the calculation of Storage Mitigation Revenue is shown below:

*Actual Sales Volumes * Actual Sales Prices*

minus

*Actual Purchase Volumes * Actual Purchase Prices*

minus

Cost to Carry

equals

Storage Mitigation Revenue

2. T-North Transportation and Capacity Release Mitigation: From time to time, FEI may have additional T-North Transportation capacity, which could be mitigated or released. Because there are not significant transactions reported for supply arrangements on T–North, there is no reliable index to use for benchmarking purposes. As a result, transportation mitigation and capacity release transactions on T-North are part of the Non-Benchmarked Activities. The T-

North Transportation Mitigation Revenue is calculated using the same methodology as the Benchmarked Transportation Mitigation Revenue. The T-North Capacity Release Mitigation Revenue calculation uses the same methodology as the Capacity Release Mitigation Revenue in the Benchmarked Activities.

3. NOVA Transportation Mitigation: From time to time, FEI may have unutilized NOVA Transportation capacity on the day, which could be released to other shippers. Due to market changes, the transport price difference between NIT to Empress has been fluctuating from positive to negative. The spread between these price points has been largely negative since the winter of 2009, thus resulting in a negative benchmark. Since no reasonable benchmark can be established at this time, NOVA Transportation mitigation will be part of the Non-Benchmarked activities. The NOVA Transportation Mitigation Revenue is calculated using the same methodology as the Benchmarked Transportation Mitigation Revenue.

4. NOVA and T-South Interior Forward Capacity Releases: From time to time, FEI may have unutilized NOVA and T-South Interior capacity (excess capacity in the summer months from April to October). FEI would release this excess capacity for a forward summer month. For NOVA Forward Capacity Releases, there is no forward pricing available at Empress which traditionally would be used as a proxy to establish a benchmark. Similarly, for the T-South Interior Forward Capacity Releases, there is no sales hub near this location to benchmark against. As a result, NOVA and T-South Interior Forward Capacity Releases are part of Non-Benchmarked Activities. The NOVA and T-South Interior Forward Capacity Releases Revenue calculation uses the same methodology as the Capacity Release Mitigation Revenue in the Benchmarked Activities.

5. Liquids Extraction: From time to time, FEI may be able to enter into transactions where a party will pay a portion of the proceeds of the sale of natural gas liquids (such as ethane and propane) that can be extracted from company-owned gas. These transactions occur at processing plants for which there is no reliable index pricing data. As a result, Liquids Extraction is part of the Non-Benchmarked Activities. The Liquids Extraction Mitigation Revenue is the total revenue received by FEI from the natural gas Liquids Extraction contracts that FEI has negotiated.

6. Forward Commodity Resale Mitigation: At times, when FEI has surplus supply and surplus storage capacity, and forward market prices exceed the spot market price and the Cost to Carry, FEI will forward sell surplus commodity. Due to the difficulty in benchmarking storage, and because a Forward Commodity Resale Mitigation transaction utilizes storage capacity, this transaction is similar to a Storage Mitigation transaction and is part of the Non-Benchmarked Activities. The calculation of Forward Commodity Resale Mitigation Revenue for each transaction is as follows:

*Actual Forward Sales Volumes * Actual Sales Prices*

minus

*Deemed Volumes Purchased * Deemed Purchase Prices*

minus

Net Transportation Costs and Cost to Carry

equals

Forward Commodity Resale Mitigation Revenue

Deemed Volumes Purchased and Deemed Purchase Prices have the same meaning as for the calculation of Spot Commodity Resale Mitigation Revenue, except that the Deemed Purchase Prices will be determined as of the date when the Forward Commodity Resale was entered into.

7. Transportation Asset Management Agreement (AMA): FEI holds firm transportation capacity on NWP. FEI can generate mitigation revenue from the Northwest Pipeline (NWP) capacity under an AMA. Under an AMA, FEI is able maintain full operational flexibility to meet customer load requirements. While FEI is unable to transact buy/sells in the United States (US), by entering into an AMA with a counterparty that can transact in both Canada and the US, this enables FEI to mitigate unutilized transport capacity and generate additional mitigation revenue on behalf of customers. The revenue under the AMA is realized through a monthly demand charge.

   As no reasonable benchmark can be established for these transactions, AMA is classified as a non-benchmarked activity.

8. Pooling on the NOVA System: NOVA allows delivery shippers at any export point to assign their extraction rights to another shipper. This assignment instruction is called "Pooling" whereby the assignor's extraction rights are then pooled with the assignee's extraction rights. FEI has developed two opportunities to use pooling to increase mitigation revenues for FEI customers. FEI can pool other shippers' volumes through its Cochrane Extraction agreement and receive a revenue split for the pooled volumes. FEI can also pool its volume through other counterparties' extraction arrangements. FEI's decision to flow through an extraction plant is evaluated based on which transaction will provide greater mitigation revenue and the counterparties' requirements. As no reasonable benchmark can be established for these transactions, Pooling on the NOVA system is classified as a non-benchmarked activity.

9. Total Non-Benchmarked Mitigation Revenue: Total Non-Benchmarked Mitigation Revenue is calculated as follows:

Storage Mitigation Revenue

plus

T-North Transportation Mitigation Revenue *plus*

T-North Capacity Release Mitigation Revenue

plus

NOVA Transportation Mitigation

plus

NOVA and T-South Interior Forward Capacity Releases

plus

Liquids Extraction Revenue

plus

Forward Commodity Resale Mitigation Revenue

plus

Transportation Asset Management Agreement (AMA) Revenue

plus

Pooling on NOVA System Revenue

equals

Total Non-Benchmarked Mitigation Revenue

E. TRANSACTION DESCRIPTIONS - NEW ACTIVITY

New Activity includes mitigation transactions which FEI does not currently undertake in its management of the portfolio of gas supply contracts, pipeline contracts, storage capacity and liquids extraction transactions. As a result, New Activity refers to mitigation activities that have not been developed yet. New Activity does not include opportunities created by changes to gas supply purchases or pipeline or storage capacities or changes to pipeline or storage tariffs that do not create new services offerings. The mitigation revenue from a New Activity will be calculated in a way that is consistent with the calculation of mitigation revenue for other GSMIP activities.

A New Activity must be approved as such by the BCUC to be included in GSMIP. The mitigation revenue from a New Activity will be calculated from the date that the New Activity transaction first occurred and after a twelve consecutive month period each New Activity will be reclassified to either the Benchmarked or Non-Benchmarked categories as appropriate.

F. BASE BENCHMARK

The Base Benchmark is designed to measure how FEI performed relative to a conservative base utility for the Benchmarked Activities. FEI's performance relative to the Base Benchmark impacts the percentage amount it earns of the Total Benchmarked Mitigation Revenue booked to GSMIP achieved in the Gas Year. The more FEI can outperform the Base Benchmark, the greater the potential incentive payment. The prices used in determining the Base Benchmark are as follows:

- Spot market transactions to sell will be benchmarked against the reported Platts Common Low price, and spot market transactions to purchase will be benchmarked against the reported Platts Common High prices, at the market point on the date of the transaction. Forward market transactions to sell will be benchmarked against the Bid prices and forward market transactions to purchase will be benchmarked against the Offer prices, as reported by OneX for the market point on the date that the transaction took place. Conversions such as for currency exchange, heating value and quantity will be calculated consistent with conventional gas industry practice.

  As described in the Commodity Resale section above, the Platts Common High is the Platts Midpoint plus 50% of the Absolute Range. The Platts Common Low is the Platts Midpoint less 50% of the Absolute Range. The Absolute Range is the range between the absolute low and absolute high of deals reported, excluding the outliers that are not used.

  Bid is the price on the forward market that a buyer is willing to buy gas and Offer is the price on the forward market that a seller is willing to sell gas. OneX is an independent broker who brings parties together to transact energy forward market transactions among market participants, including utilities, traders, marketers, banks and producers.

  Monthly market transactions to sell will be benchmarked against the reported Platts Inside FERC's Gas Market Report – Monthly Bidweek Spot Gas Low prices, and monthly market transactions to purchase will be benchmarked against the Platts Inside FERC's – Monthly Bidweek Spot Gas High prices, at the market point for the month of the transaction.

- Market Concentration Adjustment: A Market Concentration Adjustment may be used for spot transactions. In the event that FEI's market share in any given season at any market hub exceeds 40% of the reported traded volume in Platts *Gas Daily*, the prices used to determine the Base Benchmark will be the Platts Midpoint price for spot transactions at the market hub. FEI's market share will be calculated as the volume of FEI's reported transactions to Platts compared to the total transactions reported by Platts *Gas Daily* at each of the 4 major hubs: Station 2, Sumas, AECO and Kingsgate. FEI reports all fixed price transactions to Platts.

G. BASE BENCHMARK CALCULATION

1. <u>Spot Commodity Resale Base Benchmark:</u> The Spot Commodity Resale Base Benchmark is calculated as follows:

*Actual Sales Volumes * Platts Common Low @ relevant hub*

minus

*Deemed Purchase Volumes * Platts Common High*

minus

Transportation Variable Charges

equals

Spot Commodity Resale Base Benchmark

The Deemed Purchase Volumes has the same meaning as for the calculation of the Spot Commodity Resale Mitigation Revenue, and the Platts Common High is for the point where the surplus gas is available, corresponding to the Deemed Purchase Prices.

2. <u>Monthly Commodity Resale Base Benchmark:</u> The Monthly Commodity Resale Base Benchmark is calculated as follows:

*Actual Sales Volumes * Platts Inside FERC's Low @ relevant hub*

minus

*Deemed Purchase Volumes * Platts Inside FERC's High*

minus

Transportation Variable Charges

equals

Monthly Commodity Resale Base Benchmark

The Deemed Purchase Volumes has the same meaning as for the calculation of the Monthly Commodity Resale Mitigation Revenue, and the Platts Inside FERC's High is for the point where the surplus gas is available, corresponding to the Deemed Purchase Prices.

3. <u>Spot Transportation Mitigation Base Benchmark:</u> The Transportation Mitigation Base Benchmark is calculated as follows:

*Actual Sales Volume * Platts Common Low @ sales hub*

Minus

*Actual Purchase Volume * Platts Common High @ purchase hub*

Minus

Transportation Variable Charges

Equals

Spot Transportation Mitigation Base Benchmark

4. <u>Forward Transportation Mitigation Base Benchmark:</u> The Transportation Mitigation Base Benchmark is calculated as follows:

*Actual Sales Volume * Bid Price @ sales hub*

Minus

*Actual Purchase Volume * Offer Price @ purchase hub*

Minus

Transportation Variable Charges

Equals

Forward Transportation Mitigation Base Benchmark

5. <u>Spot Capacity Release Base Benchmark:</u> The Spot Capacity Release Base Benchmark is calculated as follows:

Actual Capacity Released Volumes Platts Common Low @ relevant sales hub*

Minus

*Actual Capacity Released Volume + relevant pipeline fuel volume) * Platts Common High @ relevant purchase hub*

Minus

Transportation Variable Charges

Equals

Spot Capacity Release Base Benchmark

6. Forward Capacity Release Base Benchmark: The Forward Capacity Release Base Benchmark is calculated as follows:

Actual Capacity Released Volume Bid price @ relevant sales hub*

Minus

*(Actual Capacity Released + relevant pipeline fuel volume) * Offer price @ relevant purchase hub*

Minus

Transportation Variable Charges

Equals

Forward Capacity Release Base Benchmark

7. Total Base Benchmark: Total Base Benchmark is calculated as follows:

Spot Commodity Resale Base Benchmark

Plus

Monthly Commodity Resale Base Benchmark

Plus

Spot Transportation Mitigation Base Benchmark

Plus

Forward Transportation Mitigation Base Benchmark

Plus

Spot Capacity Release Base Benchmark

Plus

Forward Capacity Release Base Benchmark

Equals

Total Base Benchmark

H. CAPACITY FACTOR ADJUSTED TOTAL BENCHMARKED MITIGATION REVENUE

To insure that FEI will be focused on utilizing excess transportation through commodity resales downstream, transportation mitigation or capacity releases, a volumetric benchmark has been established. A Capacity Factor Penalty will be assessed on transportation transactions on a given pipeline for a given season, if FEI's Capacity Factor on that pipeline falls below the overall Benchmarked Pipeline Capacity Factor for that season. The seasonal periods are November-March and April-October. The two pipelines for which there are publicly available capacity factors measuring the flow of gas volumes across the pipeline are Westcoast's T-South segment and TC Energy Foothills system.

In the event FEI's Capacity Factor falls below the capacity factor on either of those pipelines for a particular season, FEI's penalty would be a reduction in revenue eligible for an incentive payment equal to the difference between the Transportation Mitigation Revenue and the corresponding Base Benchmarks for that particular pipeline and season.

The Benchmarked Pipeline Capacity Factor is calculated as the total reported flows on the pipeline segment during the seasonal period divided by the corresponding maximum available flow capacity.

The FEI Capacity Factor is calculated as FEI's total actual flows on the pipeline segment during the seasonal period divided by FEI's total contracted capacity excluding capacity released on the pipeline segment.

In the event that FEI's Capacity Factor for a particular season on an applicable pipeline segment is less than the corresponding Benchmarked Pipeline Capacity Factor, a Capacity Factor Penalty for the applicable pipeline segment and season will be calculated as:

Applicable Benchmarked Transportation Mitigation Revenue

Minus

Applicable Spot Transportation Mitigation Base Benchmark

Minus

Applicable Forward Transportation Mitigation Base Benchmark

Equals

Capacity Factor Penalty for specific pipeline segment and season

The Capacity Factor Adjusted Total Benchmarked Mitigation Revenue is then calculated as:

Total Benchmarked Mitigation Revenue

Minus

All Capacity Factor Penalties for the applicable time period

Equals

Capacity Factor Adjusted Total Benchmarked Mitigation Revenue

An example of the application of the Capacity Factor Penalty where FEI's Benchmarked Revenue is not impacted for T-South capacity for the April 2010 – October 2010 is shown below:

- April 2010 – October 2010 T-South FEI Capacity Factor = 76.36%
- April 2010 – October 2010 T-South Benchmarked Pipeline Capacity Factor = 64.71%

The FEI Capacity Factor is greater than the Benchmarked Pipeline Capacity Factor, so there is no adjustment to the Total Benchmarked Mitigation Revenue.

An example of the application of the Capacity Factor Penalty where FEI's Benchmarked Mitigation Revenue is impacted for T-South capacity for the April 2009 – October 2009 is shown below:

- April 2009 – October 2009 T-South FEI Capacity Factor = 64%
- April 2009 – October 2009 T-South Benchmarked Pipeline Capacity Factor = 66%

The T-South Pipeline Benchmarked Capacity Factor is greater than the corresponding T-South FEI Capacity Factor. Therefore, for April through October 2009, a Capacity Factor Penalty is calculated as shown below and then applied to the Total Benchmarked Mitigation Revenue.

Applicable T-South Transportation Mitigation Revenues

Minus

Applicable T-South Transportation Base Benchmarks

Equals

T-South Capacity Factor Penalty

I. INCENTIVE PERCENTAGE:

1. Benchmarked Activity Incentive Percentage: The Benchmarked Activity Incentive Percentage is determined from the Market Performance Factor.

   i. Market Performance Factor: The Market Performance Factor is calculated as follows:

Capacity Factor Adjusted Total Benchmarked Mitigation Revenue

divided by

Total Base Benchmark

multiplied by 100 percent

Equals

Market Performance Factor

The Market Performance Factor is expressed as a percentage to one decimal place (e.g. 128.2 percent).

The Market Performance Factor (MPF) is used to determine the Benchmarked Activity Incentive Percentage (BAIP) as detailed below:

For MPF between 100 and 131 %, BAIP = 2.45 % + 0.05 % * (MPF-100)

For MPF between 131 and 136 %, BAIP = 4.00 %

For MPF of 136 and greater, BAIP = 4.00 + 0.04 % * (MPF -136)

The Benchmarked Activity Incentive Percentage is expressed as a percentage to two decimal places.

2. Non-Benchmarked Activity Incentive Percentage:

For Non-Benchmarked Activities, a constant 4% incentive percentage is applied to the related mitigation revenue.

3. New Activity Incentive Percentage:

For any new mitigation activities that FEI develops and which the BCUC determines is a New Activity, a constant 12% incentive percentage is applied to the related mitigation revenue.

4. Fixed Adjustment

The Total Incentive Payment will include a fixed $200,000 reduction each year. Based on using the target 4% incentive percentage, this reduction equates to no incentive payment earned on the first $5 million of eligible mitigation revenue.

J. <u>INCENTIVE PAYMENT</u>

The Incentive Payment for each gas contract year is calculated as follows:

*Capacity Factor Adjusted Total Benchmarked Mitigation Revenue **
Benchmarked Activity Incentive Percentage

Plus

*Total Non-Benchmarked Activity Mitigation Revenue * 4 percent*

Plus

*Total New Activity Mitigation Revenue * 12 percent*

Minus

$200,000

Equals

Total Incentive Payment

K. REPORTING REQUIREMENTS

FEI will provide two reports per annum to the BCUC and notify stakeholders when these reports have been filed with the BCUC. The reports will also be made available, if requested, to stakeholders representing customer groups on a confidential basis.

- The first report will follow the winter period which ends March of each year. This report will consist of all transactions to date with a GSMIP summary to date and discussing the factors, including an update on the market conditions, contributing to the mitigation results. There will be a high level summary of any activities that FEI deems to be "New". FEI will provide a model that breaks out the mitigation revenues and incentive payments.
- In the second report, also referred to as the Year End Report, FEI will provide all transaction data, a GSMIP Summary, and a written report discussing the factors, including the market conditions, contributing to the mitigation results and market changes from the previous year. "New Activities" will be explained in detail along with a comprehensive plan to transition the activity to a "Benchmarked Activity" if possible. A New Activity must be approved as such by the BCUC to be included in GSMIP. The incentive related to New Activities must be approved by the BCUC in the annual review of the GSMIP. Any modifications to the GSMIP model for the upcoming year would need to be presented in the Year End Report of the previous year. Capacity Factor adjustments and Market Concentration measurements will be detailed in the Year End Report as well.

Any incentive payment will be subject to review and approval by the BCUC.

Appendix B

MITIGATION ACTIVITY DETAIL

Table 1: Mitigation Activity Summary

	Total for 2020/21		Total for 2019/20		Total for 2018/19		Total for 2017/18		Total for 2016/17		Total for 2015/16		Total for 2014/15		Total for 2013/14	
Mitigation Activity	Mitigation Revenue *(in Millions)*	Incentive Earned	Mitigation Revenue *(in Millions)*	Incentive Earned	Mitigation Revenue *(in Millions)*	Incentive Earned	Mitigation Revenue *(in Millions)*	Incentive Earned	Mitigation Revenue *(in Millions)*	Incentive Earned	Mitigation Revenue *(in Millions)*	Incentive Earned	Mitigation Revenue *(in Millions)*	Incentive Earned	Mitigation Revenue *(in Millions)*	Incentive Earned
BENCHMARKED ACTIVITIES	$ 74.304	3.30%	$ 54.813	2.77%	$ 110.804	2.44%	$ 93.096	2.59%	$ 89.419	2.54%	$ 72.288	2.78%	$ 64.694	2.97%	$ 31.779	3.43%
ACTIVITIES	$ 6.279	4.00%	$ 3.570	4.00%	$ 15.415	4.00%	$ 9.503	4.00%	$ 7.757	4.00%	$ 5.860	4.00%	$ 7.556	4.00%	$ 7.692	4.00%
NEW ACTIVITIES	$ -	12.00%	$ -	12.00%	$ -	12.00%	$ -	12.00%	$ -	12.00%	$ -	12.00%	$ -	12.00%	$ -	12.00%
Eligible Mitigation Revenue	**$80.583**		**$58.383**		**$126.219**		**$102.599**		**$97.176**		**$78.148**		**$72.250**		**$39.471**	
Gross Incentive	$2.703		$1.661		$3.326		$2.790		$2.584		$2.247		$2.224		$1.397	
Less Fixed Deduction	$0.200		$0.200		$0.200		$0.200		$0.200		$0.165		$0.165		$0.165	
GSMIP Incentive Payment	**$2.503**	**3.11%**	**$1.461**	**2.50%**	**$3.126**	**2.48%**	**$2.590**	**2.52%**	**$2.384**	**2.45%**	**$2.082**	**2.66%**	**$2.059**	**2.85%**	**$1.232**	**3.12%**
Total Mitigation Revenue[1]	**$157.680**	**1.59%**	**$118.049**	**1.24%**	**$151.206**	**2.07%**	**$131.239**	**1.97%**	**$134.201**	**1.78%**	**$122.372**	**1.70%**	**$127.663**	**1.61%**	**$94.330**	**1.31%**
Customer Savings (GSMIP)[2]	**$78.080**	**96.89%**	**$56.922**	**97.50%**	**$123.093**	**97.52%**	**$100.009**	**97.48%**	**$94.792**	**97.55%**	**$76.066**	**97.34%**	**$70.191**	**97.15%**	**$38.239**	**96.88%**
Customer Savings (Total)[3]	**$155.177**	**98.41%**	**$116.588**	**98.76%**	**$148.080**	**97.93%**	**$128.649**	**98.03%**	**$131.817**	**98.22%**	**$120.290**	**98.30%**	**$125.604**	**98.39%**	**$93.098**	**98.69%**

1 Total Mitigation Revenue represents the overall mitigation revenue for the gas year and does not account for the "deemed purchases" for Commodity Resale activities benchmarking used to calculate GSMIP Eligible Mitigation Revenue.

2 Customer Savings (GSMIP) represents the net of GSMIP Eligible Mitigation Revenue and GSMIP Incentive Payment.

3 Customer Savings (Total) represents the net of Total Mitigation Revenue and GSMIP Incentive Payment.

Example (2020/21) gas year:

GSMIP Eligible Mitigation Revenue = $80.583 million

FEI's GSMIP Incentive Payment = $2.503 million or 3.11 percent of GSMIP Eligible Mitigation Revenue

Customer Savings on GSMIP Eligible Revenue = $78.080 million or 96.89 percent

Total Mitigation Revenue = $157.680 million

FEI's GSMIP Incentive Payment = $2.503 million or 1.24% of Total Mitigation Revenue

Customer Savings on Total Mitigation Revenue = $155.177 million or 98.41 percent

Appendix C

DRAFT ORDER

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com

P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

ORDER NUMBER
G-xx-22

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
Gas Supply Mitigation Incentive Program Review and Application to Extend
for the Period November 1, 2022 to October 31, 2025

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On August 30, 2022, FortisBC Energy Inc. (FEI) filed a review report and application with the British Columbia Utilities Commission (BCUC), pursuant to section 63 of the *Utilities Commission Act* (UCA), seeking approval for an extension of the Gas Supply Mitigation Incentive Program (GSMIP) for a three-year term for the period November 1, 2022 to October 31, 2025 (Application);

B. By Order G-163-11 dated September 22, 2011, the BCUC approved the FEI GSMIP for the November 1, 2011 to October 31, 2013 period;

C. By Order G-174-13 dated October 24, 2013, the BCUC approved extending the FEI GSMIP for a three-year term for the period November 1, 2013 to October 31, 2016, among other matters;

D. By Order G-141-16 dated August 29, 2016, the BCUC approved extending the FEI GSMIP for a three-year term for the period November 1, 2016 to October 31, 2019;

E. By Order G-232-19 dated September 26, 2019, the BCUC approved extending the FEI GSMIP for a three-year term for the period November 1, 2019 to October 31, 2022 and directed FEI to file a report providing a comprehensive assessment of the GSMIP, term sheet and model at least 60 days prior to expiry of the approved three year term;

F. In the Application, FEI proposes continuing the existing GSMIP term sheet and model, with minor revisions outlined in the Application;

G. The BCUC has reviewed the Application and considers that approval is warranted.

NOW THEREFORE pursuant to section 63 of the *Utilities Commission Act*, the BCUC orders as follows:

1. The Gas Supply Mitigation Incentive Program (GSMIP) extension proposed by FortisBC Energy Inc. (FEI), including the GSMIP, term sheet and model, is approved for a three-year term for the period November 1, 2022 to October 31, 2025.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Appendix D

STAKEHOLDER ENGAGEMENT MATERIALS

FortisBC Energy Inc.
16705 Fraser Highway
Surrey, B.C. V4N 0E8

November 22, 2021

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Joshua O'Neal Joshua.ONeal@bcuc.com;
Aidan Kehoe aidan.kehoe@bcuc.com

BC Old Age Pensioners Association et al (BOAPO)
803-470 Granville Street
Vancouver, BC V6C 1V5

Attention: Leigha Worth ED@bcpiac.org;
Kristin Barham barhamk@bcpiac.org

BC Sustainable Energy Association (BCSEA)
1631 Oakland Avenue
Victoria BC V8T 2L3

Attention: Thomas Hackney thackney@shaw.ca;
William J Andrews
William.j.andrews01@gmail.com

Commercial Energy Consumers Association of BC (CEC)
2900, 595 Burrard Street
P.O. Box 48130 Three Bentall Centre
Vancouver, BC V7X 1J5

Attention: David Craig dwcraig@allstream.net;
Chris Weafer cweafer@owenbird.com

Residential Consumer Intervener's Association (RCIA)
#828 - 1130 W Pender Street
Vancouver BC V6E 4A4

Attention: Peter Helland
director@residentialintervener.com

MoveUP (Movement of United Professionals)
1943 East Hastings Street
Vancouver, BC V5L 1T5

Attention: Jim Quail jquail@aqrlaw.ca

Re: FortisBC Energy Inc. (FEI) Gas Supply Mitigation Incentive Program (GSMIP) Assessment Report

Notice of Workshops

On September 26, 2019, the British Columbia Utilities Commission (BCUC) issued Order G-232-19, approving extension of the GSMIP for the three gas contract years starting November 1, 2019 and expiring on October 31, 2022. Order G-232-19 also directed FEI to file a report providing a comprehensive assessment of the GSMIP, term sheet, and model, and to file that report at least 60 days prior to the expiry of the approved three-year term.

In preparation for the comprehensive assessment, FEI is advising stakeholders that it will be conducting workshop sessions in early 2022 to inform the GSMIP report.

FEI believes it is important to engage intervener groups, BCUC staff and industry experts in this review process to ensure the objectives and guiding principles upon which the current GSMIP is based, continue to remain appropriate and continue to be achieved.

The basis of the current GSMIP was developed by a working group consisting of BCUC staff and intervener representatives in 2011 and approved by the BCUC in Order G-163-11.[1]

FEI plans to conduct a series of three workshops in order to review and assess the GSMIP with participants and gather information to inform FEI's report. FEI will be seeking confirmation of availability from stakeholders and plans to hold the following workshops between January and March 2022 (dates to be determined based upon participant availability):

1. FEI Gas Supply Fundamentals
    - This first session is intended to bring everyone up to a common base level of knowledge by providing an overview of FEI's gas supply portfolio based on the Annual Contracting Plan (ACP), including commodity, transportation and storage resources. Additionally FEI will provide context of regional market conditions and dynamics.

2. FEI GSMIP Fundamentals
    - The second session would provide an overview of the current GSMIP, objectives, guiding principles, term sheet and model, including mitigation strategies, performance, organizational requirements, existing mechanisms to demonstrate, quantify and measure the extent to which the GSMIP objectives are achieved and how GSMIP payments are calculated.

3. Moving GSMIP Forward
    - The final session would provide an opportunity to discuss ways to enhance and improve the GSMIP, ensuring the continued alignment of objectives for customers, stakeholders and FEI.

Following the workshops, FEI will distribute a draft report by May 1, 2022, including the input gathered from workshop participants as well as any additional analysis. FEI intends to file the final report to the BCUC between July 1 and August 1, 2022.

FEI requests your participation in the upcoming workshops in preparation of the final report.

We ask that if you wish to participate in this process, please confirm with me by email or provide contact information for other individual(s) in your organization who will participate by Wednesday, December 1, 2021.

Once the participants have been confirmed, FEI will schedule a brief 30 minute virtual introductory meeting during the week of December 6, 2021.

[1] FEI was directed by BCUC Order G-26-11 to establish a working group to discuss the objectives, guiding principles, structure and parameters of the GSMIP to commence November 1, 2011 and to explore ways to demonstrate, quantify and measure the extent to which the GSMIP objectives are achieved in order to determine the amount of future GSMIP payments. FEI established a working group that included representatives from FEI, BCUC staff, CEC and BCOAPO in addition to a consultant retained by FEI to assist the working group.

If you have any questions or wish to discuss, please do not hesitate to contact me at 604-576-7052 or by email at matt.yasinchuk@fortisbc.com.

Sincerely,

FORTISBC ENERGY INC.

Matt Yasinchuk
Commercial & Operations Manager

Meeting Summary			
Total Number of Participants	14		
Meeting Title	FEI 2022 GSMIP Review Notice and Introduction		
Meeting Start Time	1/11/2022, 10:28:18 AM		
Meeting End Time	1/11/2022, 10:50:21 AM		
Meeting Id	d4661653-85cc-412a-917d-8bbd6405b952		

Full Name	Join Time	Leave Time	Duration
Hill, Shawn	1/11/2022, 10:28:18 AM	1/11/2022	21m 51s
Ron Amen	1/11/2022, 10:28:26 AM	1/11/2022	21m 43s
Executive Director	1/11/2022, 10:29:07 AM	1/11/2022	20m 59s
Yasinchuk, Matt	1/11/2022, 10:30:04 AM	1/11/2022	20m 12s
Bevacqua, Ilva	1/11/2022, 10:30:22 AM	1/11/2022	19m 47s
Bill Andrews (Guest)	1/11/2022, 10:30:23 AM	1/11/2022	19m 42s
John Taylor	1/11/2022, 10:30:23 AM	1/11/2022	19m 57s
O'Neal, Joshua	1/11/2022, 10:30:38 AM	1/11/2022	19m 34s
Kehoe, Aidan	1/11/2022, 10:30:51 AM	1/11/2022	19m 18s
Tom Feldman	1/11/2022, 10:31:04 AM	1/11/2022	19m 1s
Kristin Barham	1/11/2022, 10:31:13 AM	1/11/2022	18m 54s
Peter Helland	1/11/2022, 10:31:20 AM	1/11/2022	18m 50s
Tom Hackney (Guest)	1/11/2022, 10:33:39 AM	1/11/2022	16m 27s
David Craig	1/11/2022, 10:36:58 AM	1/11/2022	13m 12s

Email	Role	Participant ID (UPN)
Shawn.Hill@fortisbc.com	Presenter	Shawn.Hill@fortisbc.com
ramen@atriumecon.com	Attendee	ramen@atriumecon.com
ED@bcpiac.org	Attendee	ED@bcpiac.org
Matt.Yasinchuk@fortisbc.com	Organizer	Matt.Yasinchuk@fortisbc.com
Ilva.Bevacqua@fortisbc.com	Presenter	Ilva.Bevacqua@fortisbc.com
	Attendee	
jtaylor@atriumecon.com	Attendee	jtaylor@atriumecon.com
Joshua.ONeal@bcuc.com	Attendee	Joshua.ONeal@bcuc.com
Aidan.Kehoe@bcuc.com	Attendee	Aidan.Kehoe@bcuc.com
tfeldman@atriumecon.com	Attendee	tfeldman@atriumecon.com
barhamk@bcpiac.org	Attendee	kbarham@bcpiac.org
phelland@midgard-consulting.com	Attendee	phelland@midgard-consulting.com
	Attendee	
davidc@equifaira.com	Attendee	davidc@equifaira.com

FEI 2022 GSMIP Review

Introductory Meeting (Teams)

January 11, 2022

Energy at work FORTIS BC™

Introduction

- Gas Supply Mitigation Incentive Program
- 2013 to present
- BCUC Order G-232-19
- FEI to file a report providing a comprehensive assessment 60 days prior to October 31, 2022

- FEI recognizes the current slate of regulatory process on the calendar for key stakeholders in 2022

Key Stakeholders

- FEI Gas Supply and Regulatory Staff
- Atrium Economics
- BCUC Staff
- BCOAPO / BCPIAC
- BCSEA
- CEC
- RCIA

Timeline

- Q4 2021
  - Scope of Work
  - Analysis begins
  - Notification to Key Stakeholders
- January to March 2022
  - Stakeholder Workshops
- April to June 2022
  - Report Development
  - Draft Report to Key Stakeholders (May 1)

Timeline

- July to August 2022
  - FEI Internal Review
  - BCUC Submission

Workshop Dates

- Workshop 1
  - FEI Gas Supply Fundamentals

  10:00 AM to 1:00 PM Pacific Feb 7-11 or Feb 14-18

- Workshop 2
  - FEI GSMIP Fundamentals

  10:00 AM to 1:00 PM Pacific Feb 14-18 or Mar 7-11

- Workshop 3
  - Moving GSMIP Forward

  10:00 AM to 1:00 PM Pacific Mar 7-11 or Mar 14-18

Thank you

Energy at work FORTIS BC™

Meeting Summary			
Total Number of Participants	19		
Meeting Title	FEI GSMIP Review - Workshop #1		
Meeting Start Time	2/9/2022, 9:56:50 AM		
Meeting End Time	2/9/2022, 1:07:14 PM		
Meeting Id	7abaaaca-5424-4912-8b30-86e593208f4d		
Full Name	Join Time	Leave Time	Duration
Cumming, Jordan	2/9/2022, 9:56:50 AM	2/9/2022,	3h 10m
Peter Helland	2/9/2022, 9:57:01 AM	2/9/2022,	3h 2m
Gill, Manpreet	2/9/2022, 9:57:26 AM	2/9/2022,	3h 9m
David Craig	2/9/2022, 9:58:34 AM	2/9/2022,	3h 2m
Ron Amen	2/9/2022, 9:59:09 AM	2/9/2022,	3h 7m
Hill, Shawn	2/9/2022, 9:59:12 AM	2/9/2022,	1h 9m
Hill, Shawn	2/9/2022, 11:13:34 AM	2/9/2022,	1h 1m
Hill, Shawn	2/9/2022, 12:18:41 PM	2/9/2022,	48m 31s
Bevacqua, Ilva	2/9/2022, 9:59:13 AM	2/9/2022,	3h 7m
Yasinchuk, Matt	2/9/2022, 9:59:14 AM	2/9/2022,	3h 7m
Vincent, Cory	2/9/2022, 9:59:24 AM	2/9/2022,	3h 7m
Bill Andrews (Guest)	2/9/2022, 9:59:31 AM	2/9/2022,	3h 7m
Chan, King-yi	2/9/2022, 10:00:02 AM	2/9/2022,	3h 7m
Engels, Greg	2/9/2022, 10:00:25 AM	2/9/2022,	3h 6m
O'Neal, Joshua	2/9/2022, 10:00:29 AM	2/9/2022,	3h 6m
John Taylor	2/9/2022, 10:00:32 AM	2/9/2022,	3h 6m
Kehoe, Aidan	2/9/2022, 10:00:38 AM	2/9/2022,	1h 7m
Kehoe, Aidan	2/9/2022, 11:15:27 AM	2/9/2022,	1h 45m
Tom Feldman	2/9/2022, 10:00:51 AM	2/9/2022,	3h 6m
Tom Hackney (Guest)	2/9/2022, 10:01:19 AM	2/9/2022,	2h 52m
Janet Rhodes CEC Consultant (Guest)	2/9/2022, 10:05:10 AM	2/9/2022,	3h 1m
Tom Hackney (Guest)	2/9/2022, 12:54:44 PM	2/9/2022,	12m 21s

Email	Role	Participant ID (UPN)
Jordan.Cumming@fortisbc.com	Presenter	Jordan.Cumming@fortisbc.com
phelland@midgard-consulting.com	Attendee	phelland@midgard-consulting.com
Manpreet.Gill@fortisbc.com	Presenter	Manpreet.Gill@fortisbc.com
davidc@equifaira.com	Attendee	davidc@equifaira.com
ramen@atriumecon.com	Attendee	ramen@atriumecon.com
Shawn.Hill@fortisbc.com	Presenter	Shawn.Hill@fortisbc.com
Shawn.Hill@fortisbc.com	Presenter	Shawn.Hill@fortisbc.com
Shawn.Hill@fortisbc.com	Presenter	Shawn.Hill@fortisbc.com
Ilva.Bevacqua@fortisbc.com	Presenter	Ilva.Bevacqua@fortisbc.com
Matt.Yasinchuk@fortisbc.com	Organizer	Matt.Yasinchuk@fortisbc.com
Cory.Vincent@bcuc.com	Attendee	cory.vincent@bcuc.com
	Attendee	
Kingyi.Chan@bcuc.com	Attendee	kingyi.chan@bcuc.com
Greg.Engels@bcuc.com	Attendee	Greg.Engels@bcuc.com
Joshua.ONeal@bcuc.com	Attendee	Joshua.ONeal@bcuc.com
jtaylor@atriumecon.com	Attendee	jtaylor@atriumecon.com
Aidan.Kehoe@bcuc.com	Attendee	Aidan.Kehoe@bcuc.com
Aidan.Kehoe@bcuc.com	Attendee	Aidan.Kehoe@bcuc.com
tfeldman@atriumecon.com	Attendee	tfeldman@atriumecon.com
	Attendee	
	Attendee	
	Attendee	

Gas Supply Mitigation Incentive Plan (GSMIP) Workshop #1- Gas Market Overview

February 9, 2022

FORTIS BC™

Agenda

- **FEI - Service Area’s, Rates and Bill Components**
- **FEI Business Models**
  - Transport Model
  - Unbundling
- **Customer Rates**
- **North America Overview (Natural Gas Market Place)**
  - Shale Gas
  - Impact to Price (Commodity)
- **Region Overview**
  - Resources and Physical Flow
  - Region poor Load Factor has shaped the regions physical resources
- **ACP Objectives and Principles**
  - Matching load to resource characteristics
- **Regional Market Conditions**
  - How these conditions have shaped FEI ACP
- **ACP - Seasonal/Monthly/Daily Execution**
  - Meeting Demand – Variables involved
  - Mitigation Efforts

Disclaimer

The many units of measure of natural gas…

- Energy (used for pricing and nominations)
- 1 GJ
- 1,000 GJ = 1 TJ
- 1,000 TJ = 1 PJ
- 1 GJ = 0.9478 Dth or MMBtu

- Volume (used for volume and flow rate)
- 1 MMcf = 1,133 GJ
- 1 MMcf = 1,074 Dth or MMBtu
- 1,000 MMcf = 1 Bcf

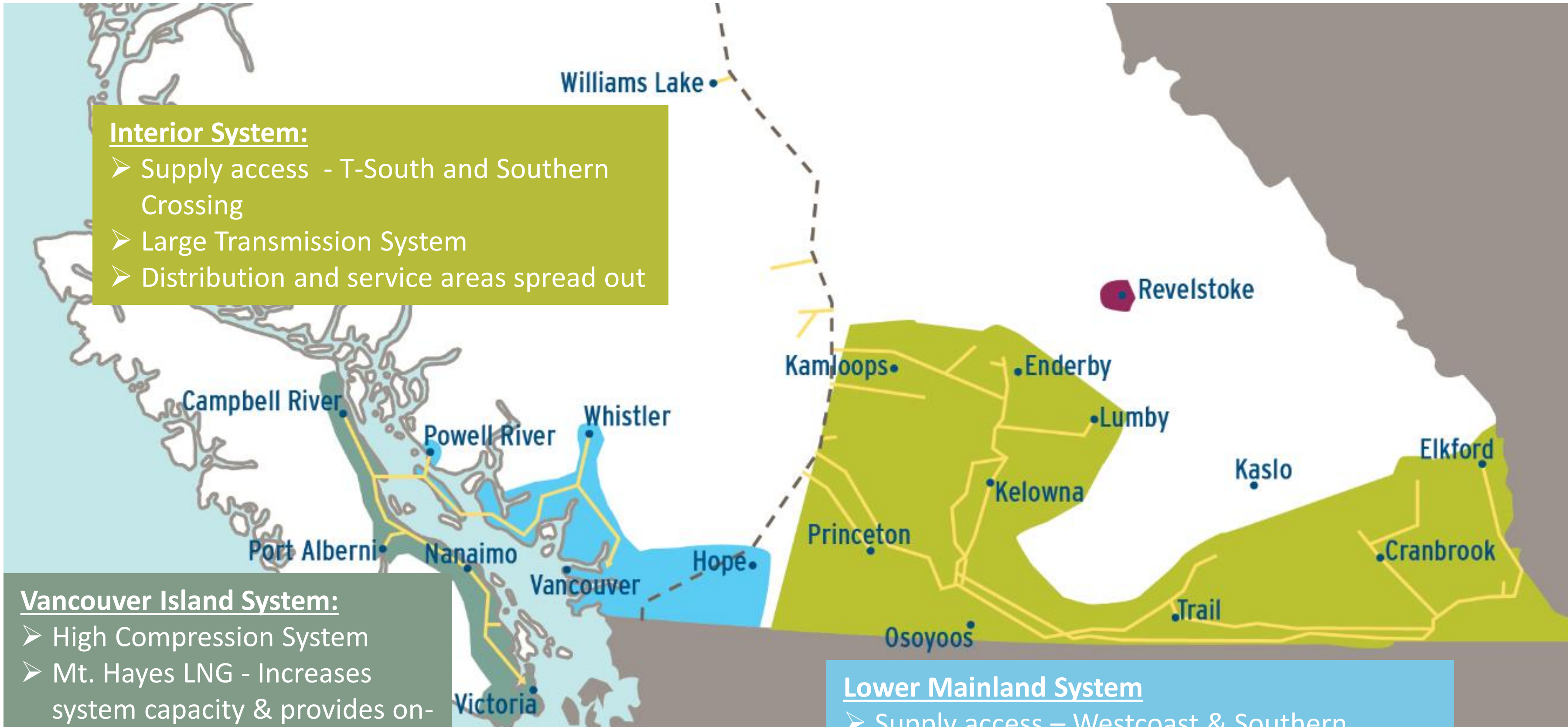
- 40 GJ = 1 $10^3 m^3$

FORTIS BC™

FEI Service Area’s, Rates and Bill Components

FORTIS BC™

FEI's Service Area's and Characteristics



Interior System:

- Supply access - T-South and Southern Crossing
- Large Transmission System
- Distribution and service areas spread out

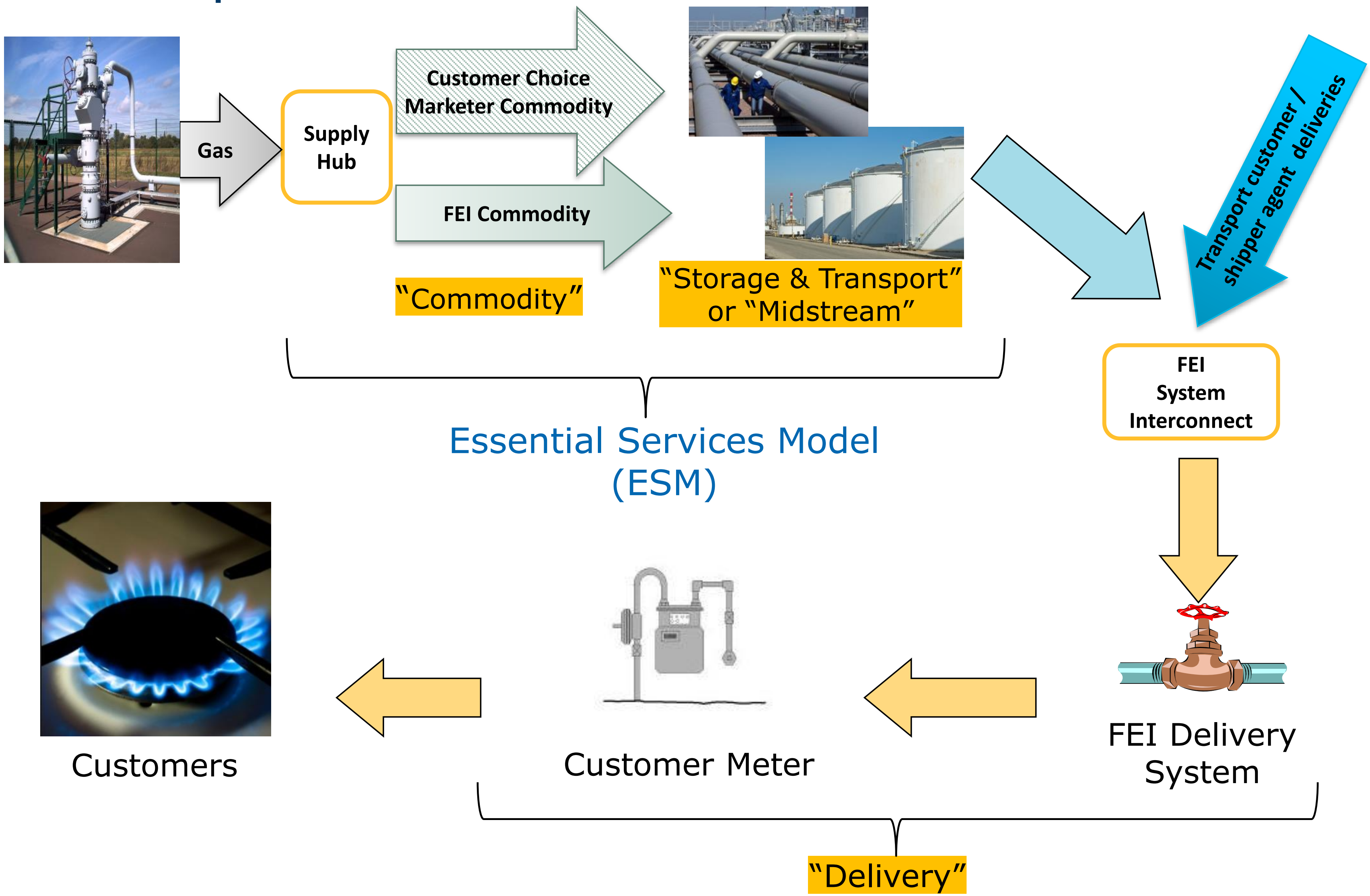
Vancouver Island System:

- High Compression System
- Mt. Hayes LNG - Increases system capacity & provides on-system supply

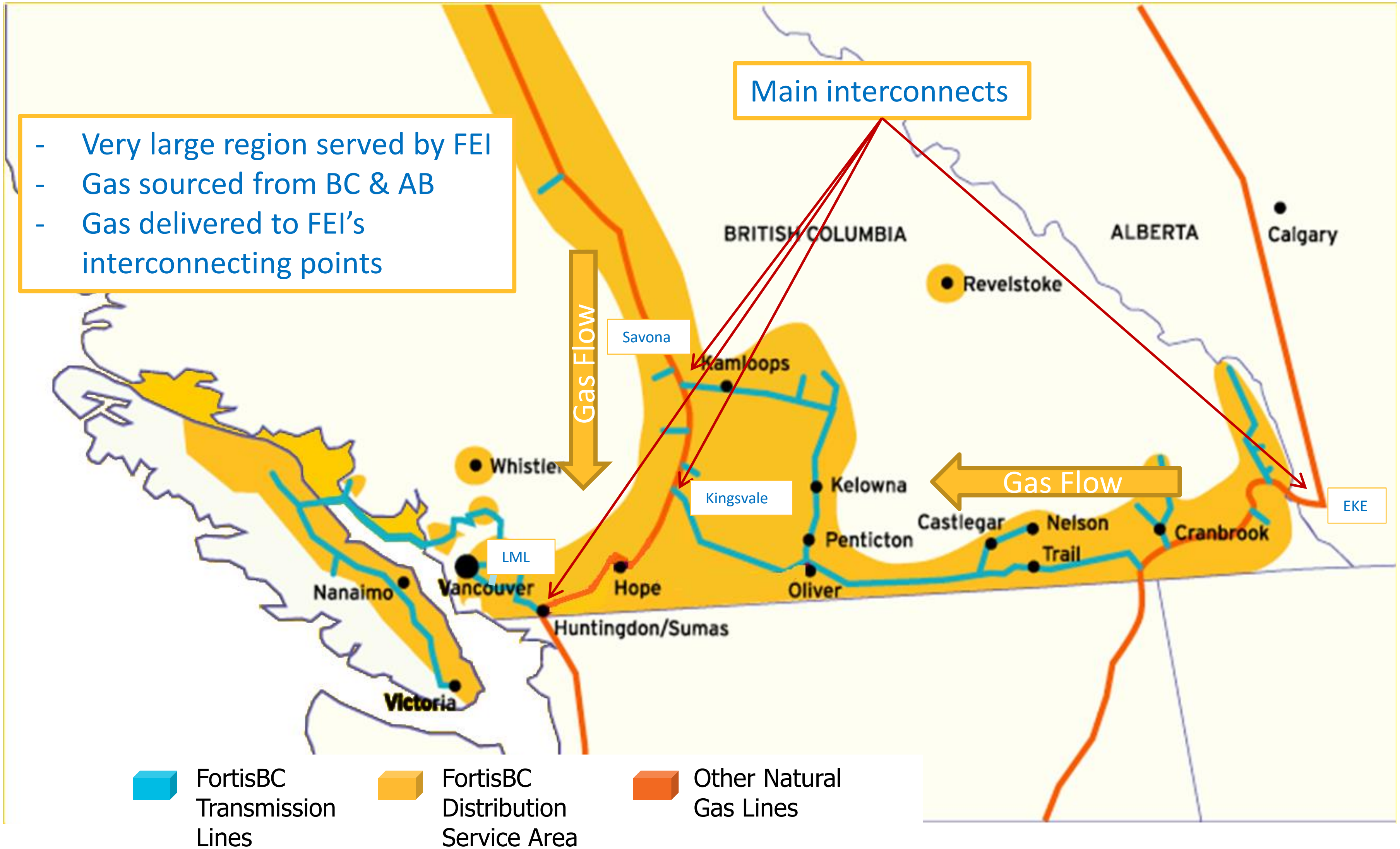
Lower Mainland System

- Supply access – Westcoast & Southern Crossing
- Jackson Prairie and Mist – Off-system Storage
- On-system LNG (Tilbury & Mt.Hayes) for peak & emergencies

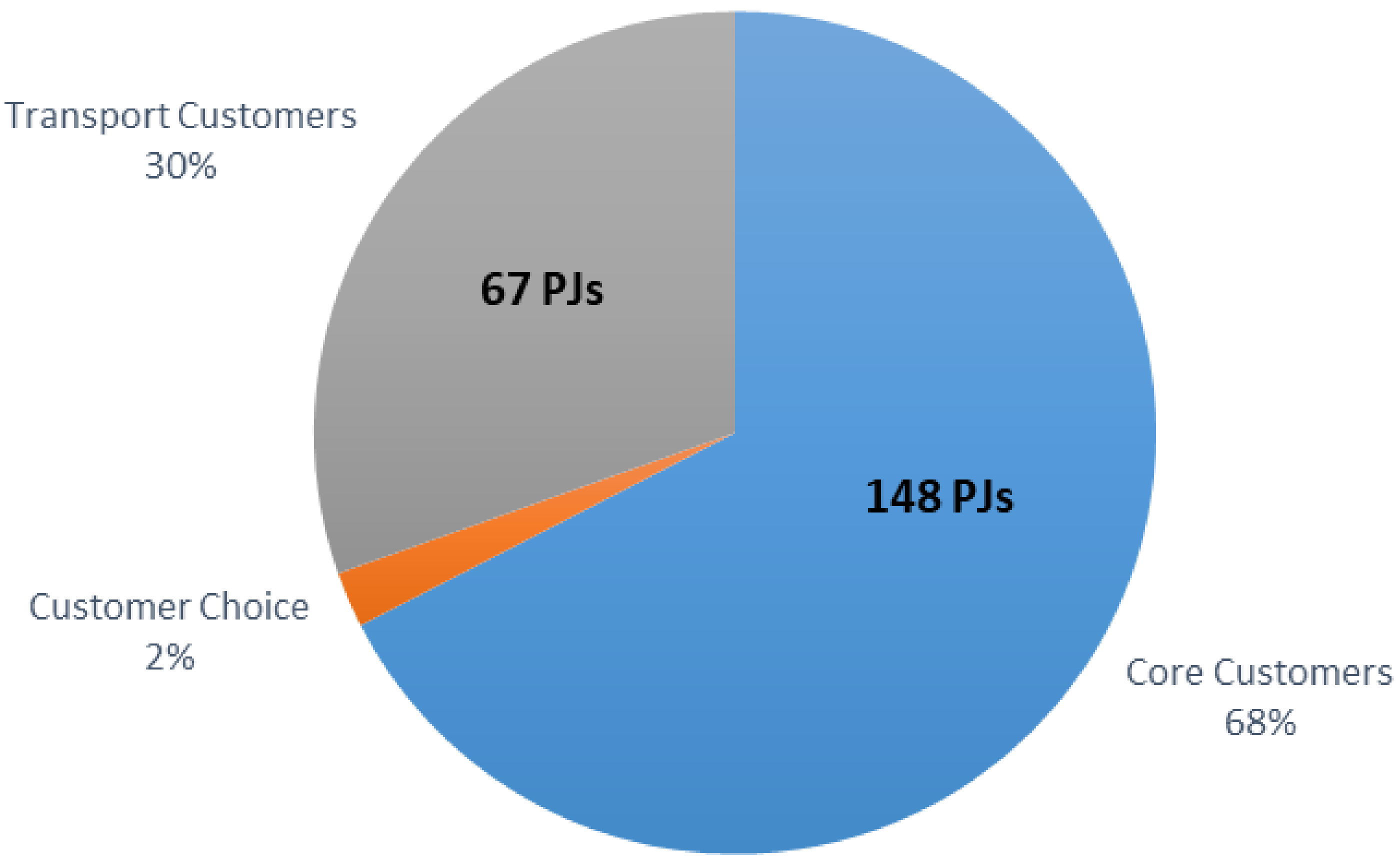
Business Model: Transportation/Bundled/Customer Choice



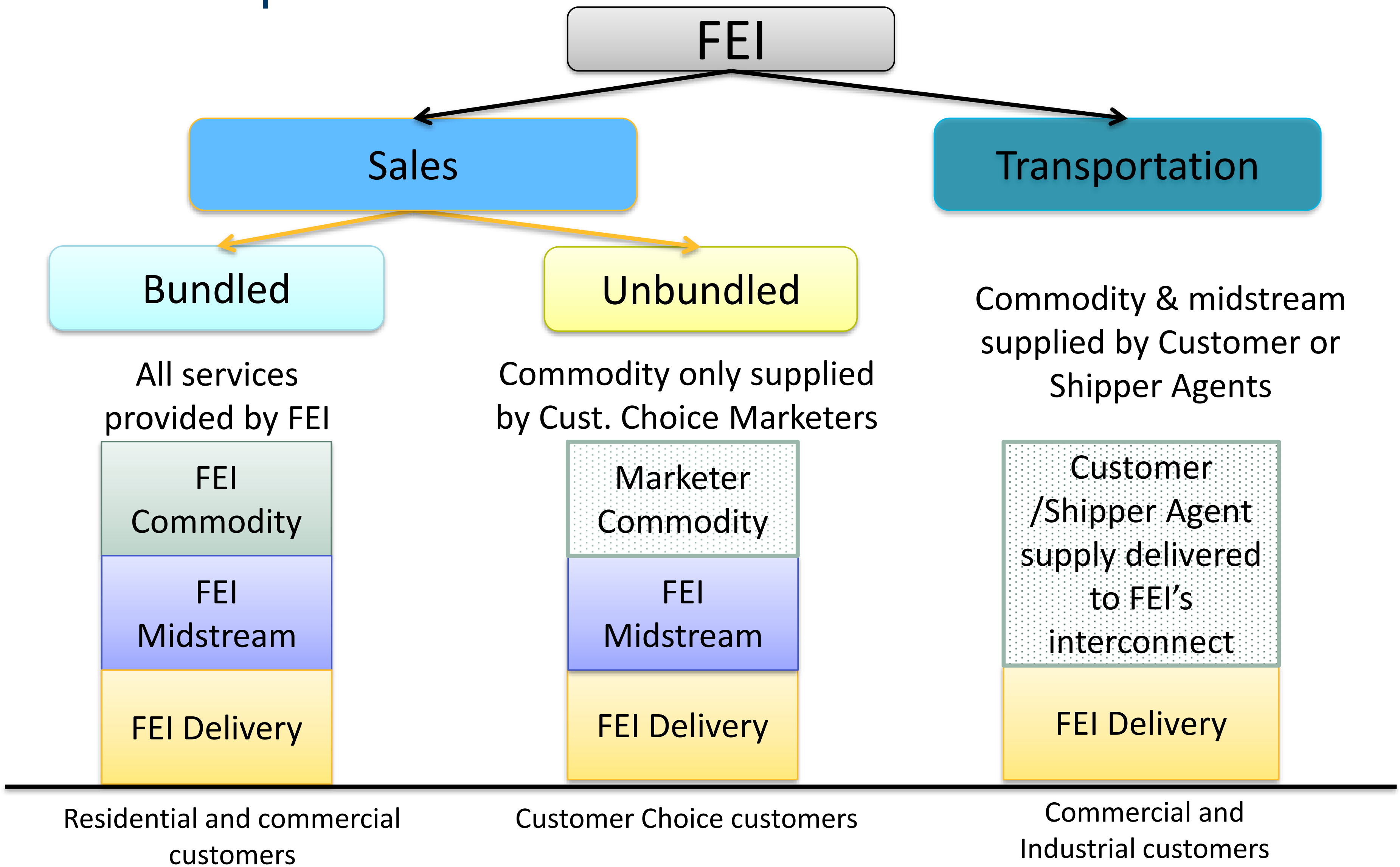
FortisBC Gas System: How it connects to upstream supply?



System Throughput (219 PJs - 2020)



Current FEI Business Model & Bill Components



Gas Supply Costs on Customer Bill

FORTIS BC

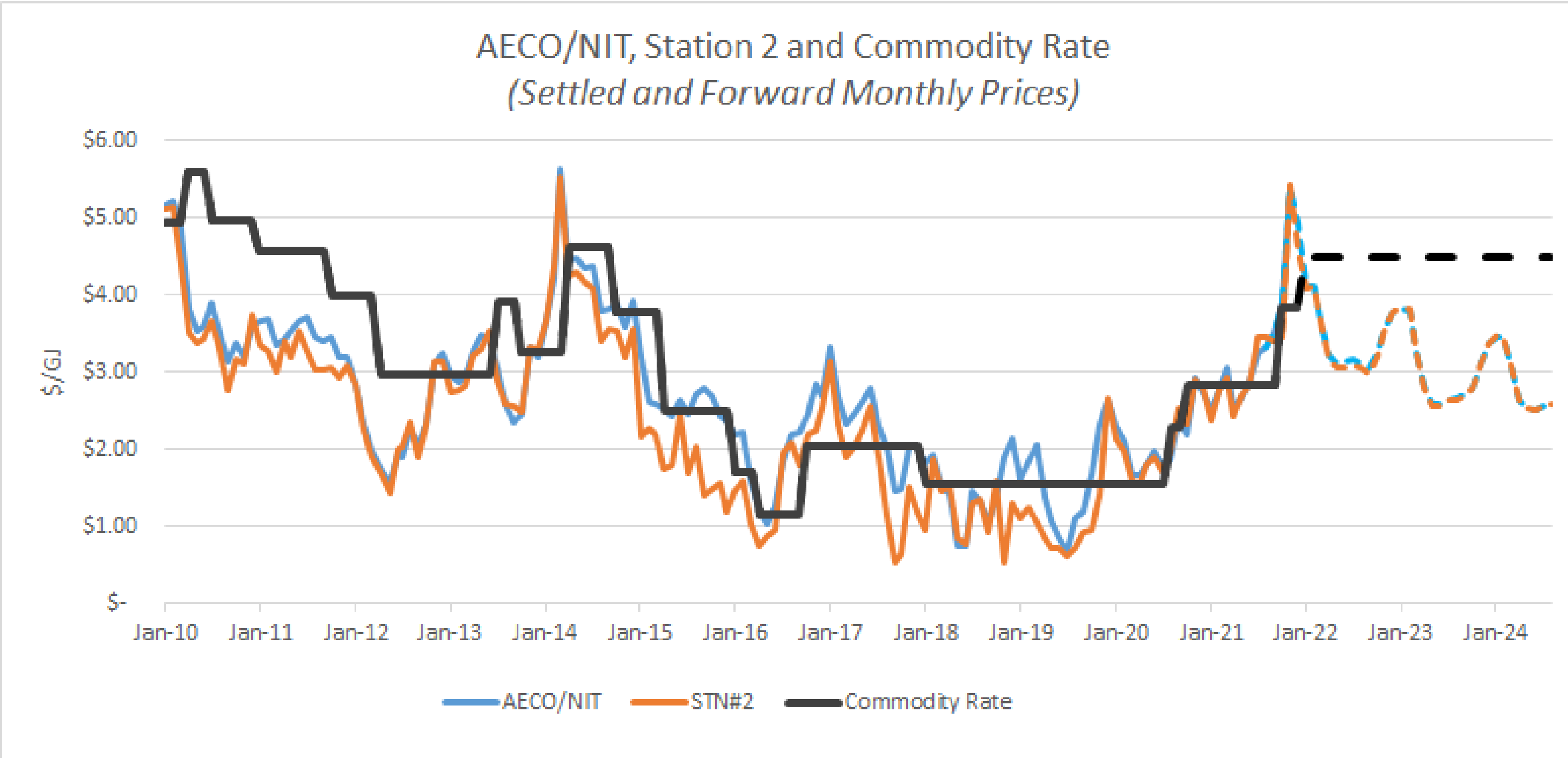
Name:	ANNIE CUSTOMER
Service address:	12345 ANY STREET CRANBROOK
Rate class:	Residential
Billing date:	October 1, 2021

Account number	Due date	Amount
555555	October 22, 2021	$100.73

Previous bill	168.82	
Less payment - Thank you	168.82 CR	
Balance from previous bill		0.00
Delivery charges		
Basic charge (30 days at 0.4261 per day)	12.78	
Delivery (6.4 GJ at 5.024 per GJ)	32.15	
		44.93 *
Commodity charges		
Storage and transport (6.4 GJ at 1.397 per GJ)	8.94	
Cost of gas (6.4 GJ at 3.844 per GJ)	24.60	
		33.54 **‡
Other charges and taxes		
Municipal operating fee (3.09% of * amounts)		2.42 **
Carbon tax (6.4 GJ at 2.3053 per GJ)		14.75 *
Clean Energy Levy (0.40% of * amounts)		0.31
GST (5% of * amounts)		4.78
Please pay		100.73

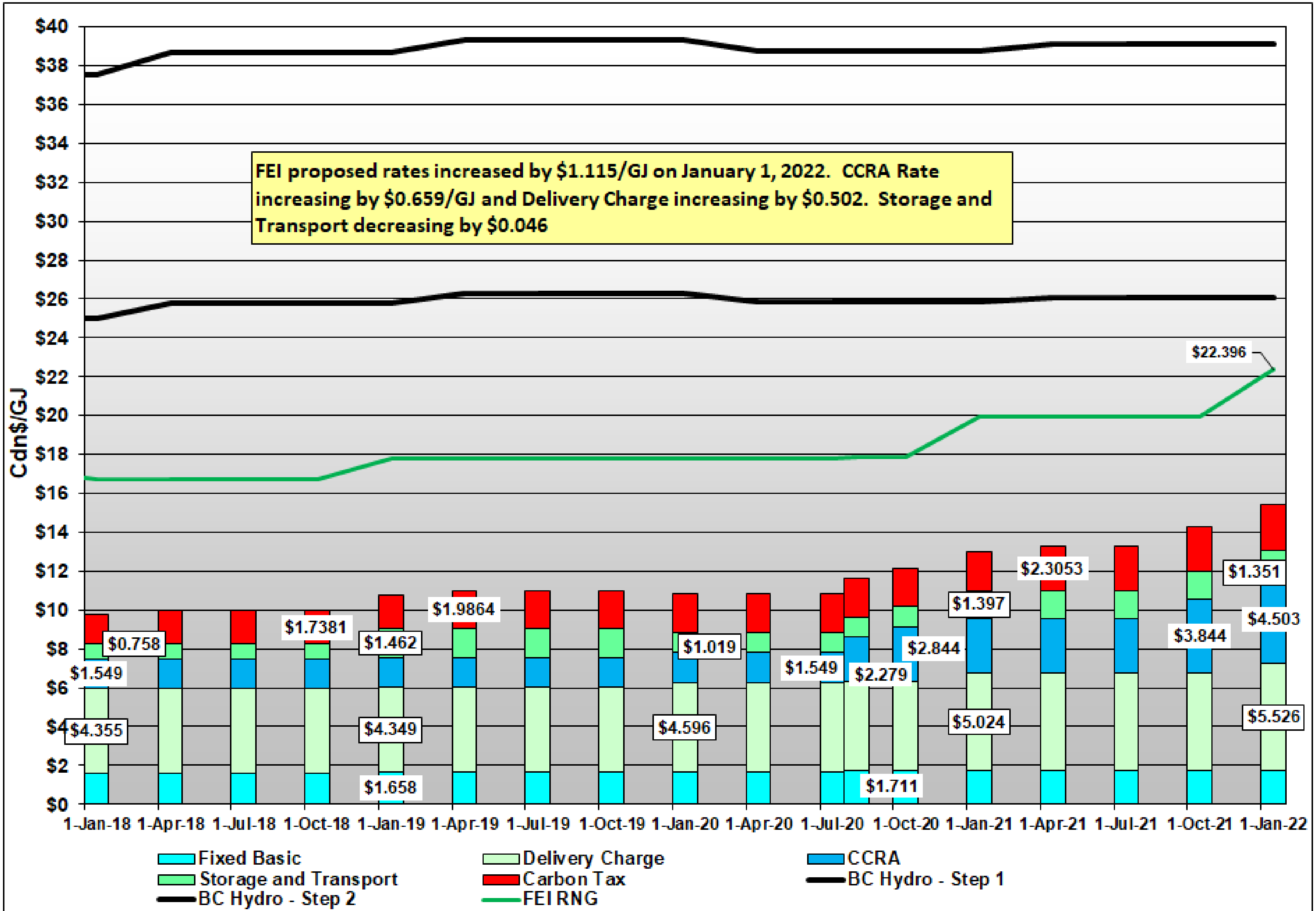
Gas Supply Costs

FEI CCRA vs Market Prices Overtime



- Based on guidelines set by BCUC proposed Commodity Rate to reach $4.503/GJ (+$0.659/GJ) on January 1, 2021

FEI Mainland & VI Residential Rates



Bill Components – Commodity Rate (ie CCRA)

FEI Commodity

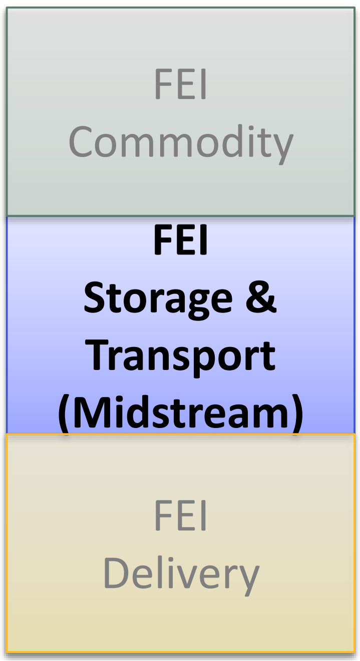
FEI Storage & Transport (Midstream)

FEI Delivery

Consists of:

- Market based rate – flowthrough with no markup
- Annual baseload commodity purchases by FEI
- Station 2 and AECO/NIT supply
- Variable (market) rate offering to customer by FEI
- Reviewed quarterly & subject to quarterly resetting (per BCUC guidelines)

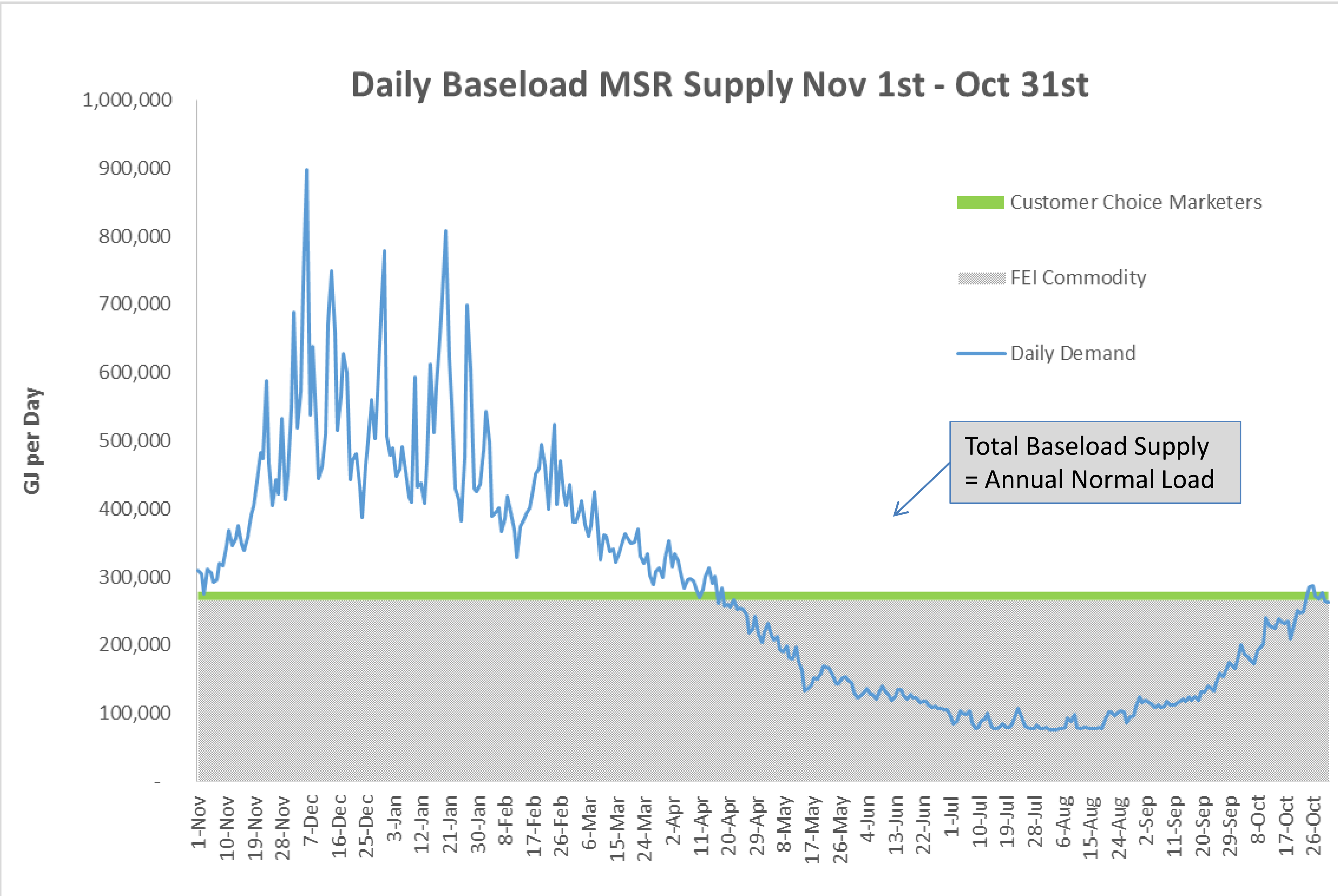
Bill Components – Storage & Transport (Midstream or MCRA) Rate



Consists of:

- Market & Cost-based rate – flowthrough with no markup
- Shaped winter gas supply & seasonal storage
- Upstream pipeline capacity on external pipeline systems
- Shorter duration market area and on-system LNG storage
- Load balancing functions for entire system
- Backstopping functions
- Reviewed quarterly but normally reset annually

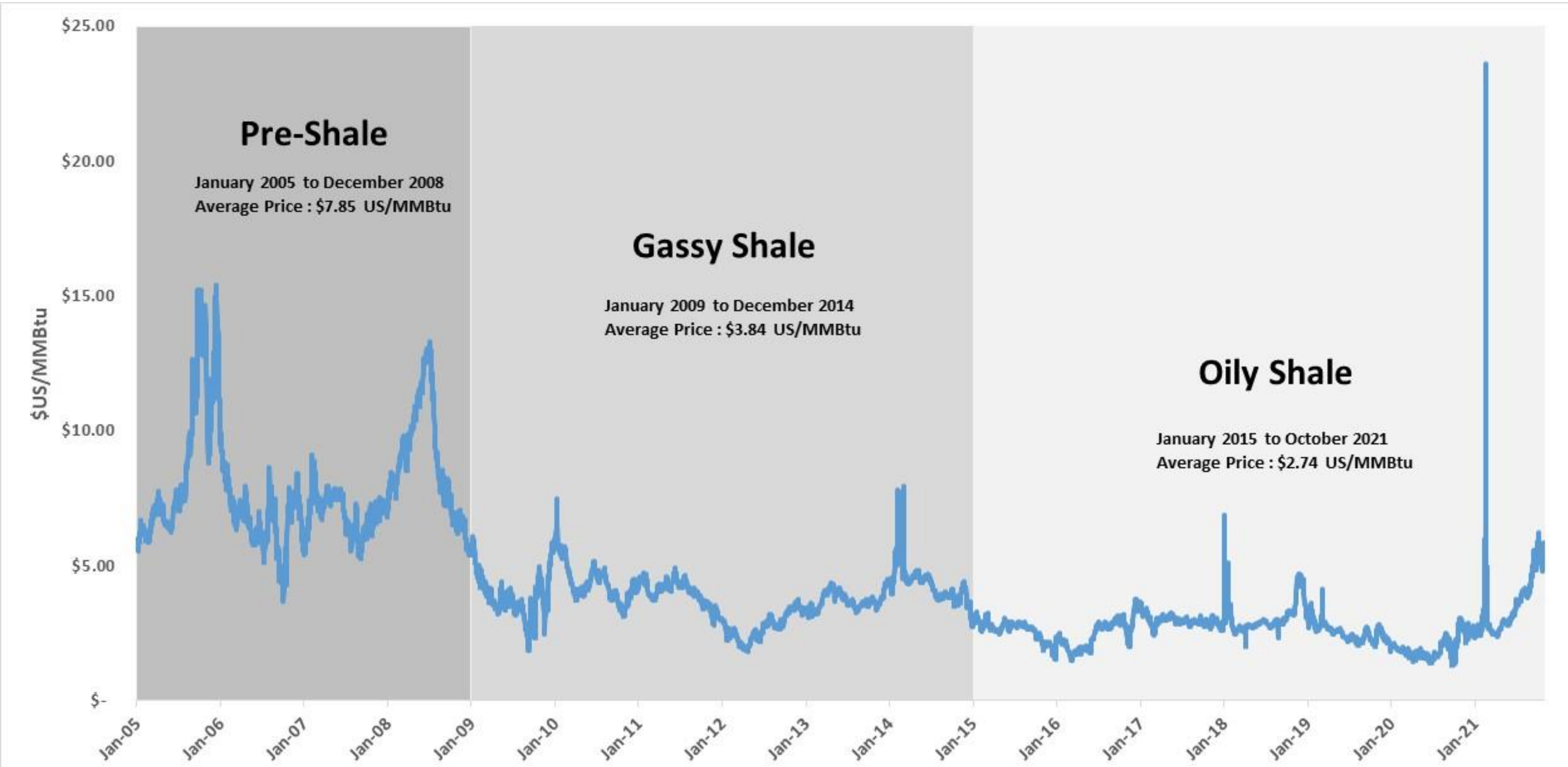
ESM – Marketer Supply Requirement (MSR)



Questions?

North America – Gas Overview

Henry Hub (NYMEX) prices (US/MMbtu)



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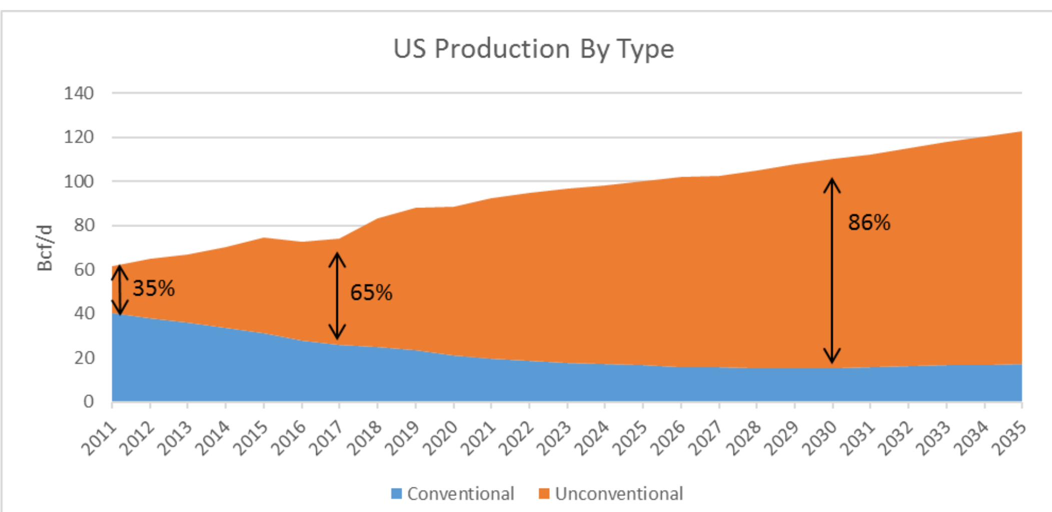
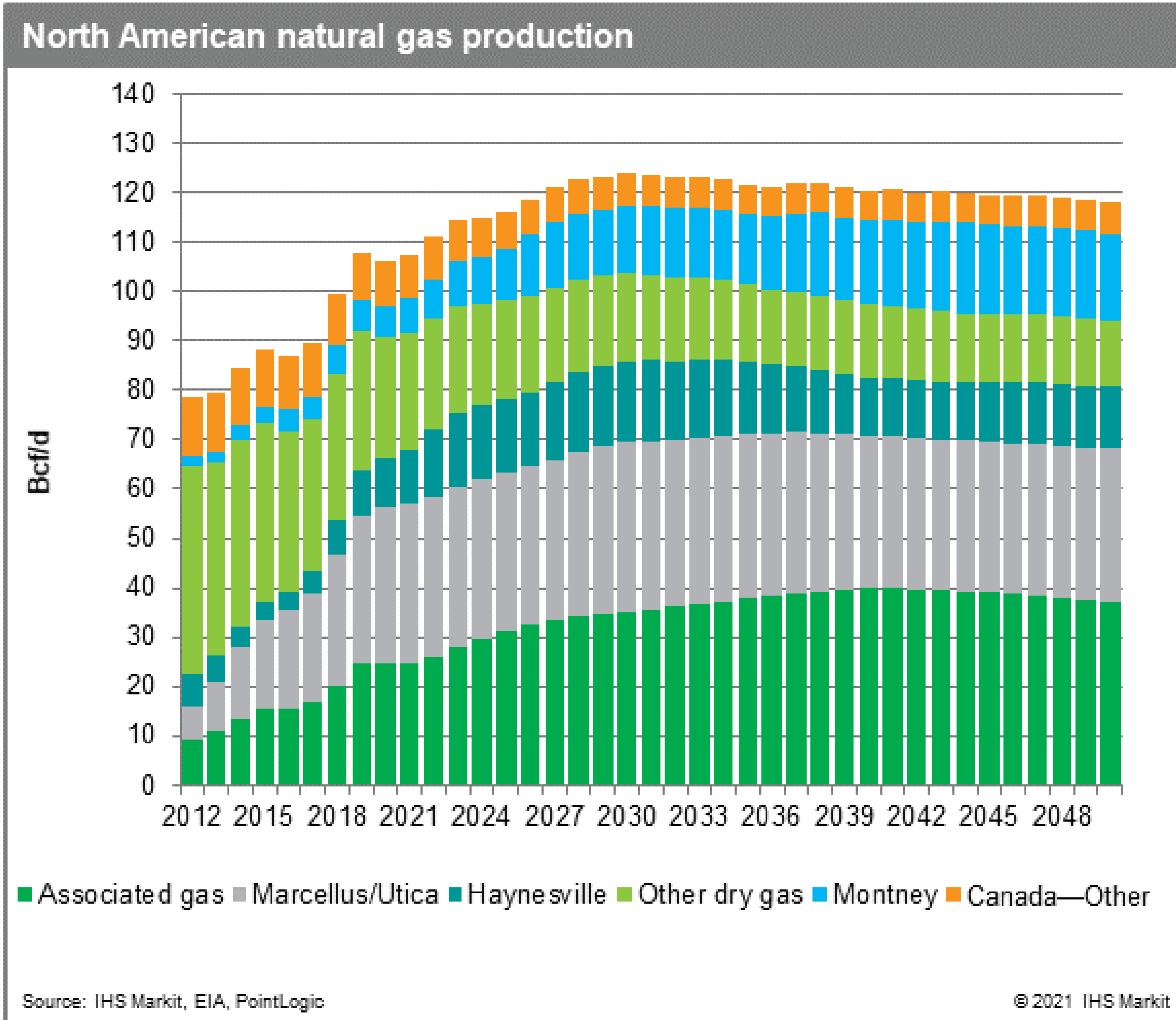
North American Shale Gas Map



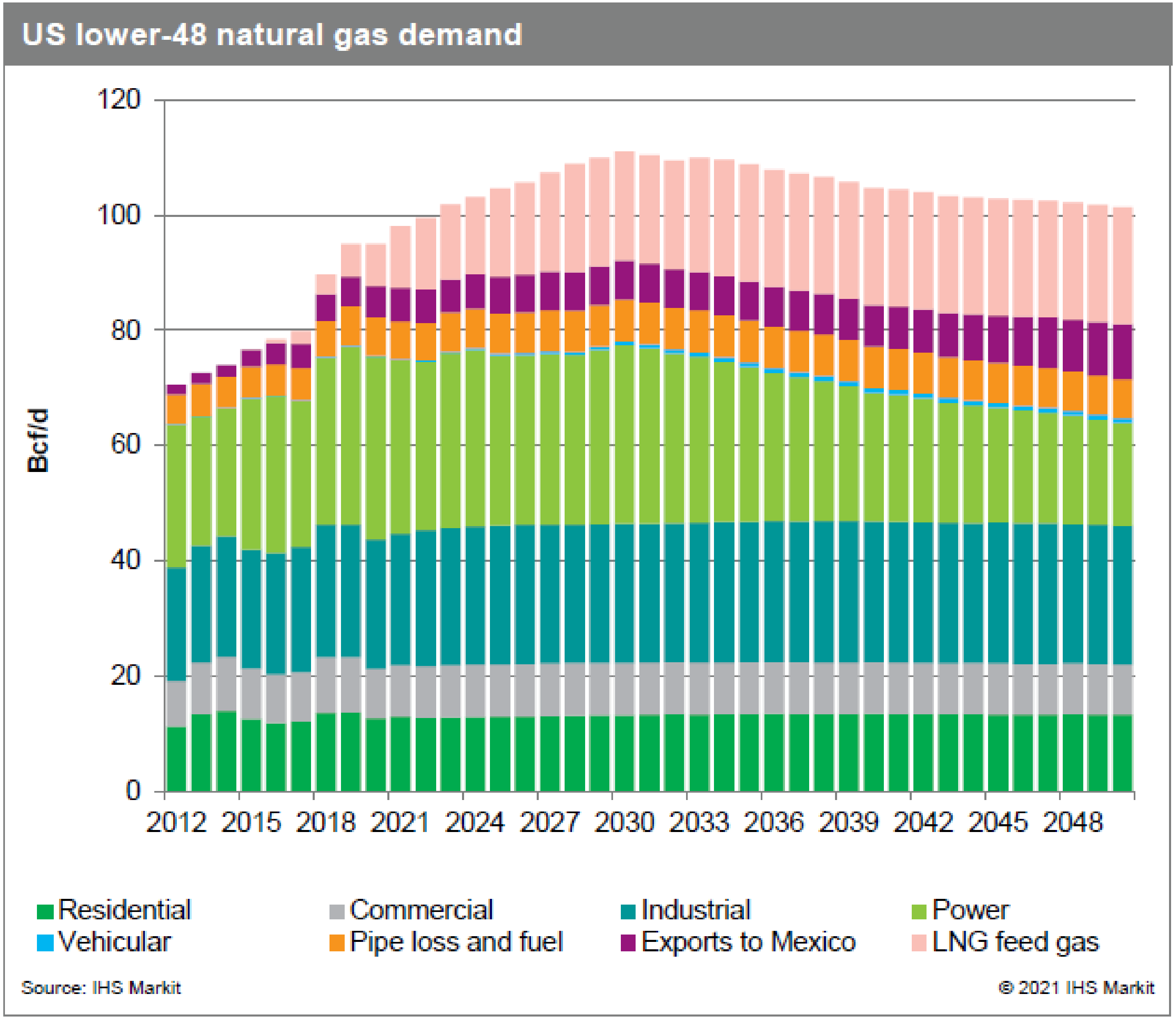
- Shale Gas has unlocked a significant amount of gas and NA is now a net exporter of gas.
- 2013 US was a net importer of natural gas (1.3 Tcf) but have become a net exporter.
- Changing pipeline flows and spurring new developments

Source: WoodMackenzie

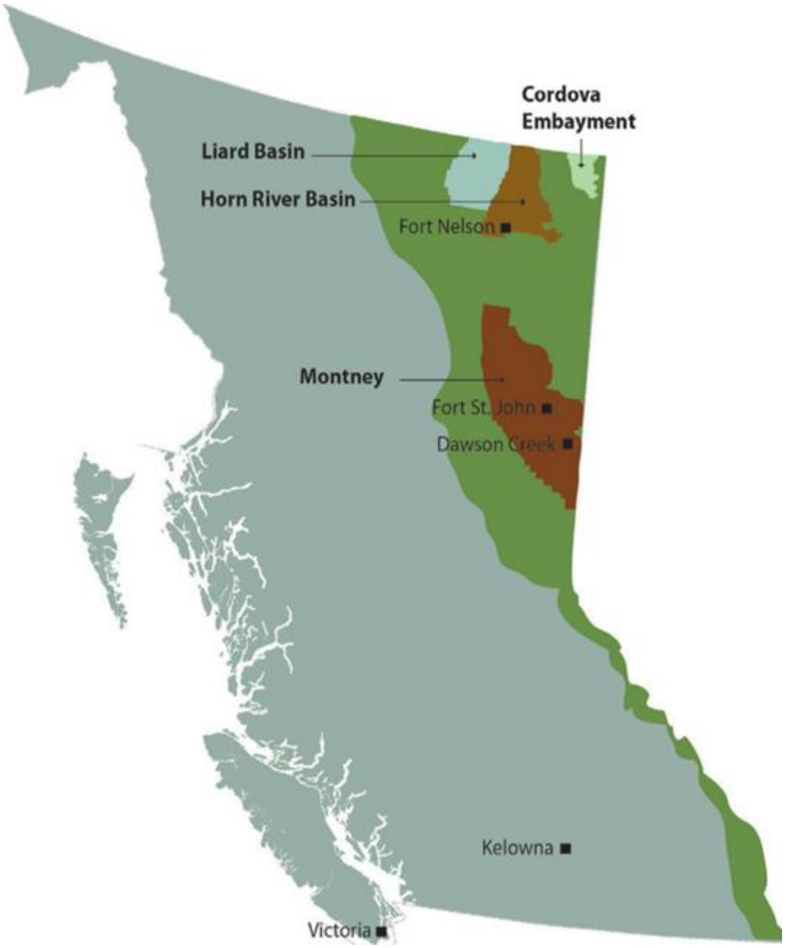
North American Production (US and Canada)

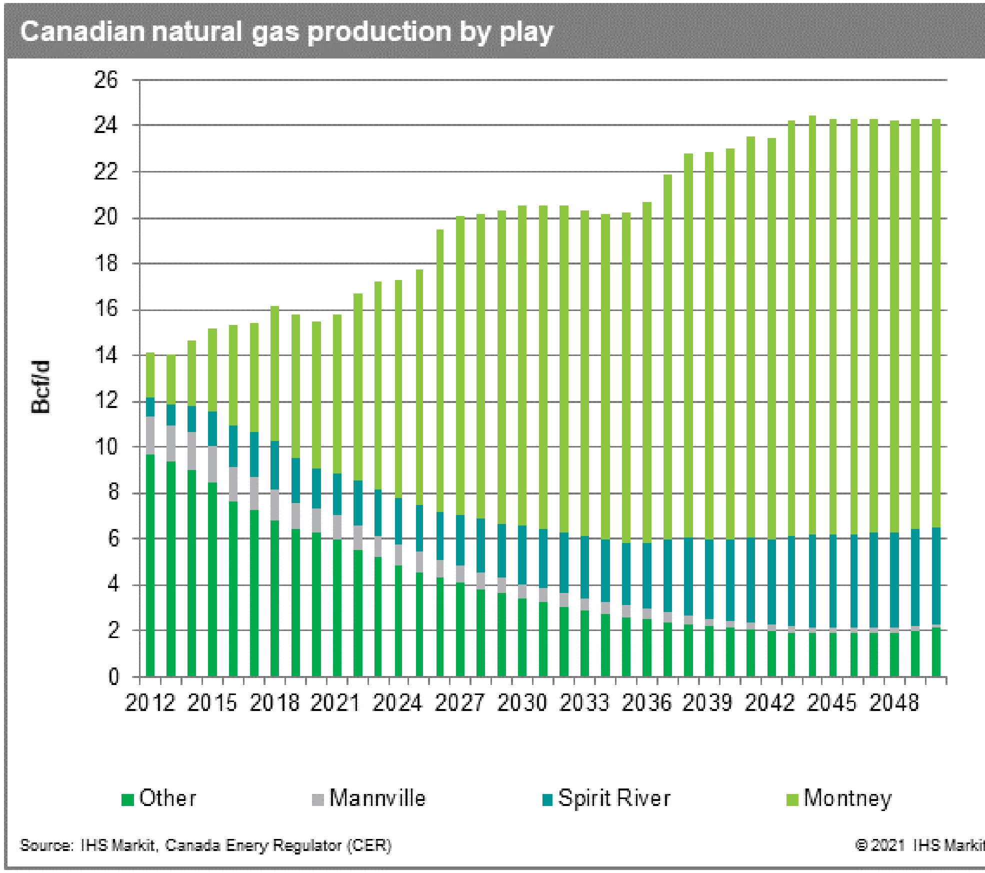


LNG Exports linking NA Gas Market to Other Commodities



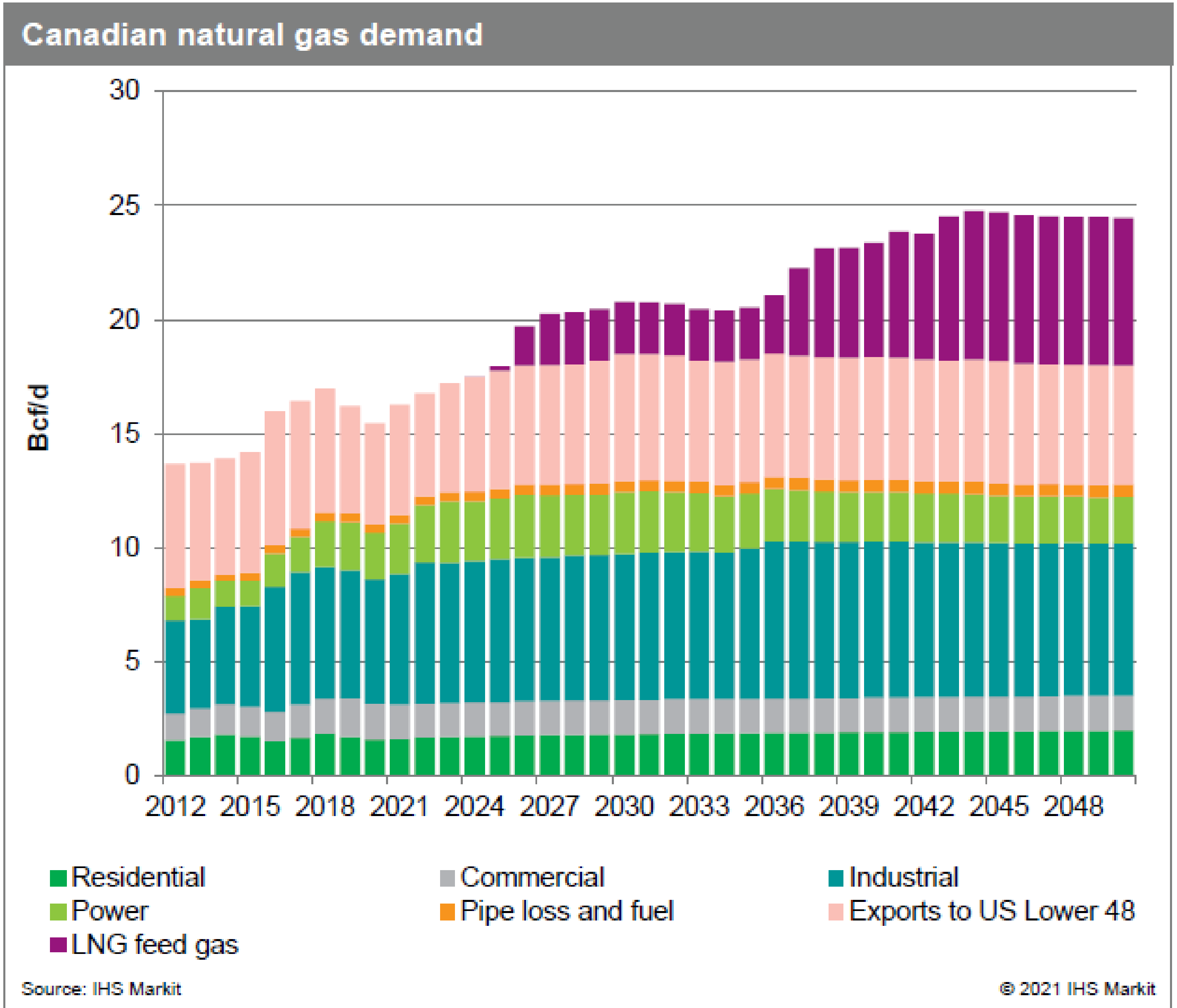
Montney Supply Forecasted To Grow



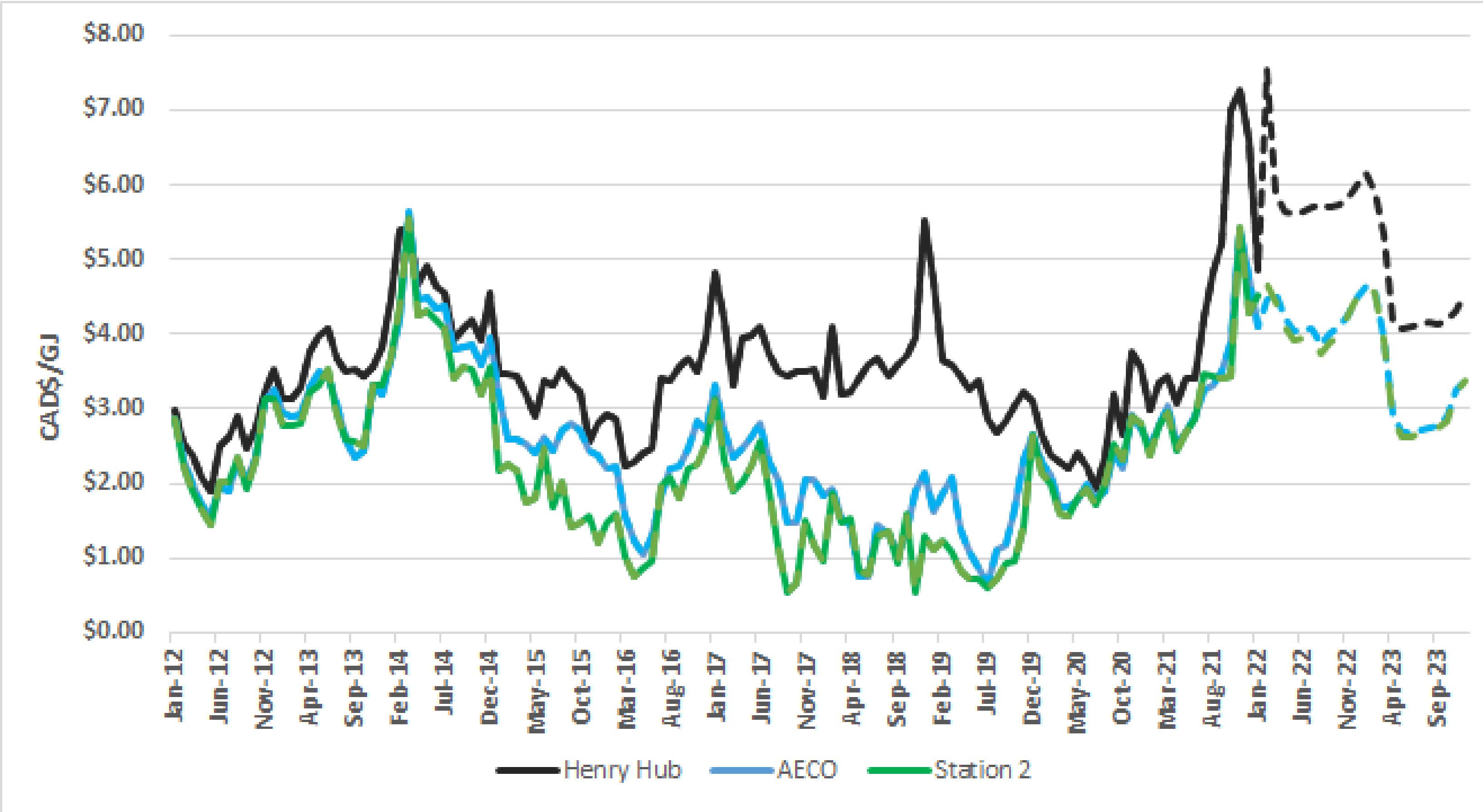


- Montney is a world class supply basin that is forecasted to grow (lots of supply at low cost).

Western Canadian Gas Looking for Outlets



Henry Hub, AECO and Station 2 Prices



- AECO and Station 2 prices widen due to excess supply or constrained volumes

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Summary

- Shale gas has been a game changer
- LNG exports have tied NA natural gas marketplace into other commodities markets worldwide (ie oil/ Asian/Europe)
- Market is always changing both on the supply and demand side which is consistent with price movements up and down over time.

Regional Gas Market Resources and the Annual Contracting Plan (ACP)

Regional Gas Market Resources

<u>Supply Hubs:</u>
- Station 2
- AECO/NIT

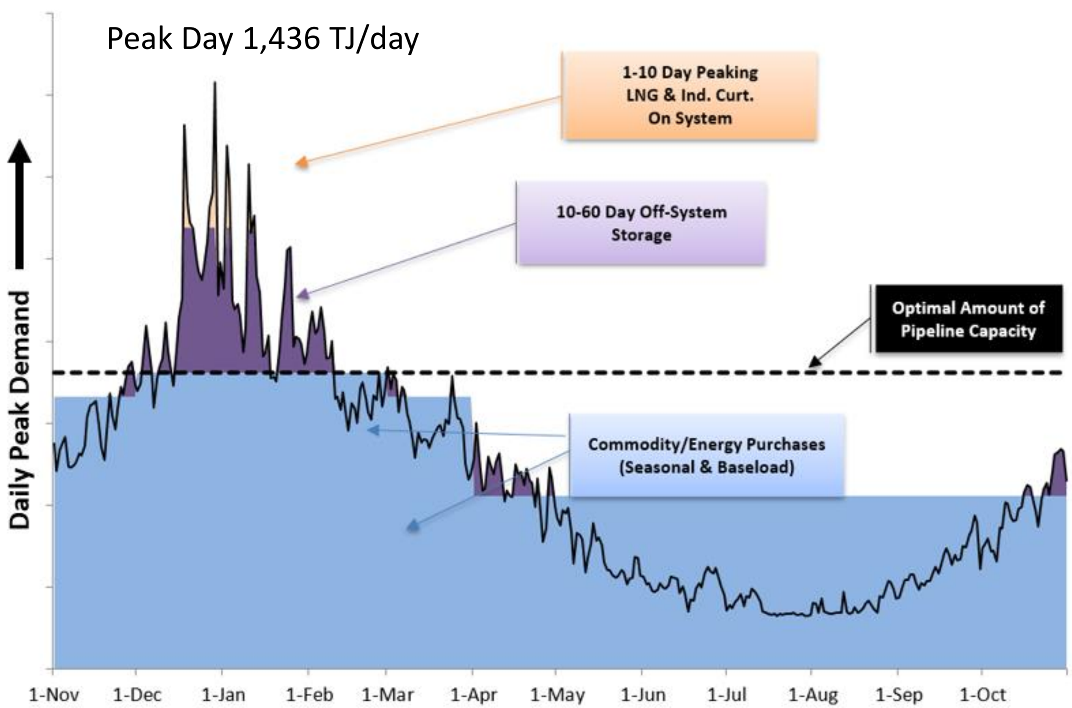
<u>Market Hubs:</u>
- Kingsgate
- Sumas

<u>Seasonal Storage:</u>
- Aitken Creek
- Rockpoint

<u>Market Area Storage:</u>
- Jackson Prairie
- Mist

<u>LNG – Peaking Supply:</u>
- Tilbury
- Mt. Hayes

Annual Contracting Plan



Contract Year	2021/22 (TJ/day)
Total Peak Day Load	**1,436**
Winter Design Load	740
Summer Design Load	271
Average Design Load	**464**
Winter Normal Load	656
Summer Normal Load	237
Annual Daily Normal Load	**411**

<u>Key objectives include balancing:</u>

Security and reliability of gas supply

Diversity of resources, pricing, counterparties

Flexibility

Cost minimization

<u>Challenges:</u>

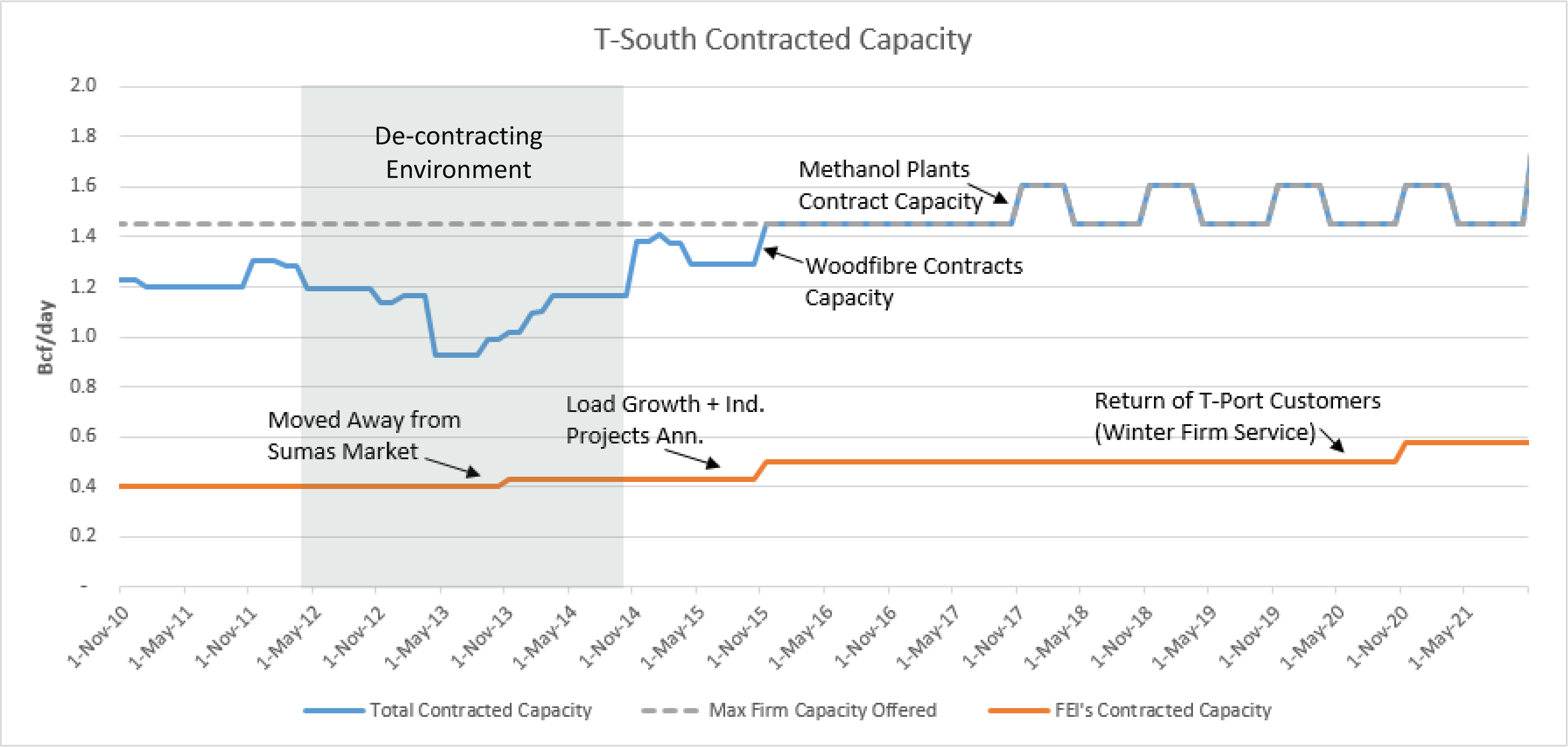
Matching supply to customer load profile

Resource Availability

Changing Market Conditions

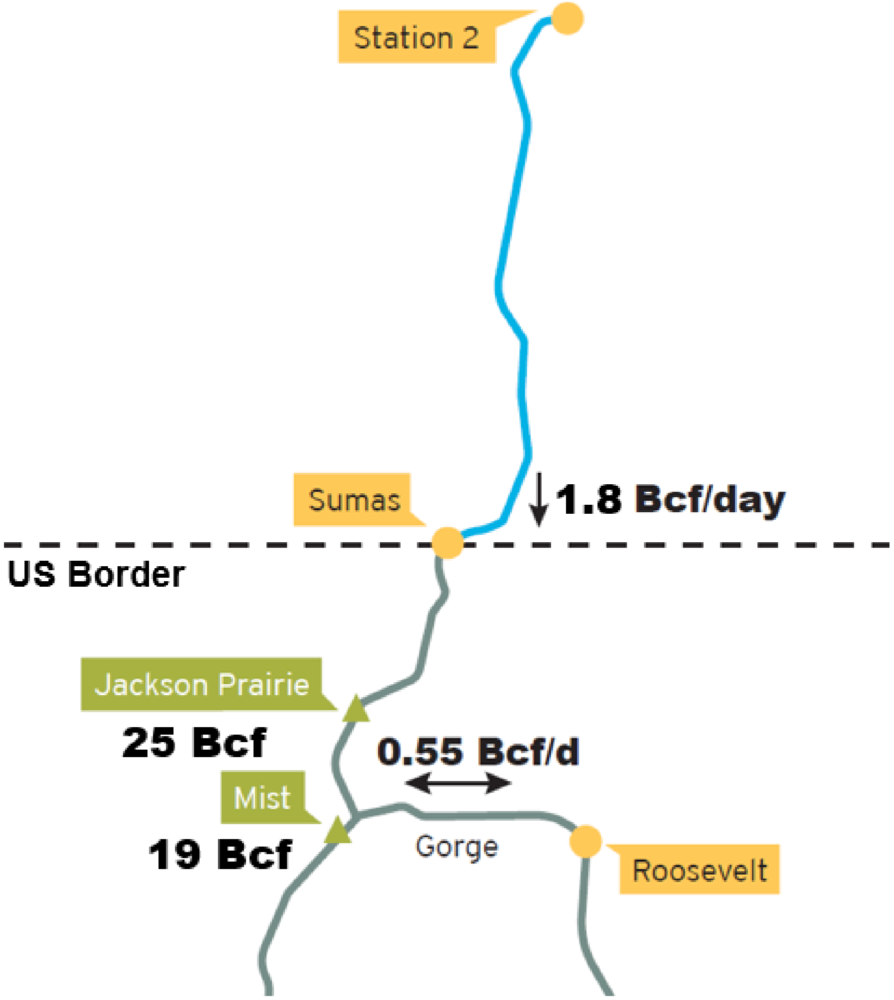
T-South Huntingdon Delivery Capacity

- FEI's ACP Approach to physical and financial risk differs from other regional shippers
- Reflected through the historical contracting on T-South



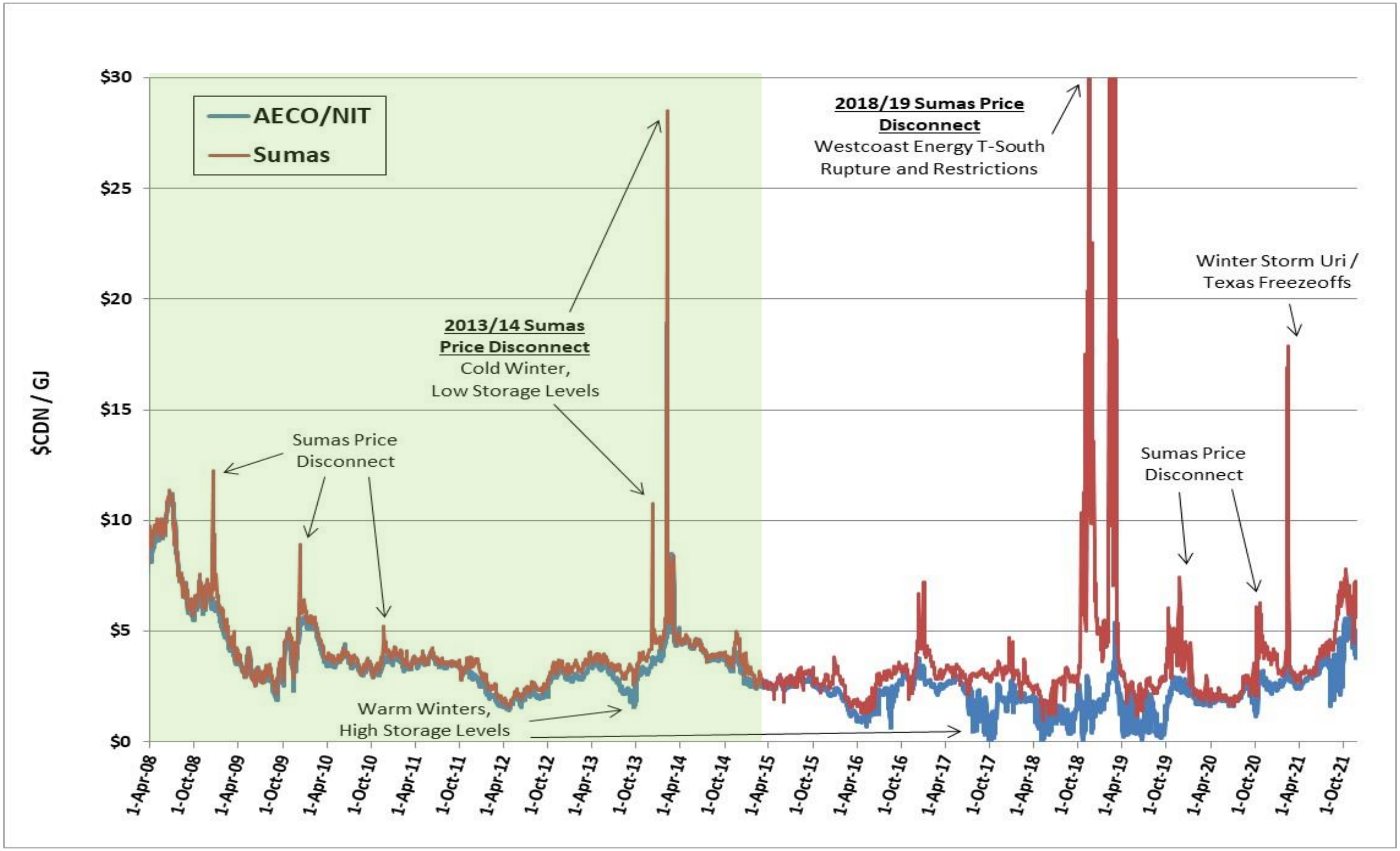
Regional Challenges-
‘Inside the Box’

Regional Challenges-
Seasonal Constraint



- Limited Resources in the Region
- Baseload Resources for I-5 Corridor (Lower Mainland, Seattle, Portland)
- Short Term Assets (JPS/Mist) help with colder than normal weather
- Coincidental winter demand on gas and power systems served by natural gas infrastructure.

Historical Sumas Price Disconnection



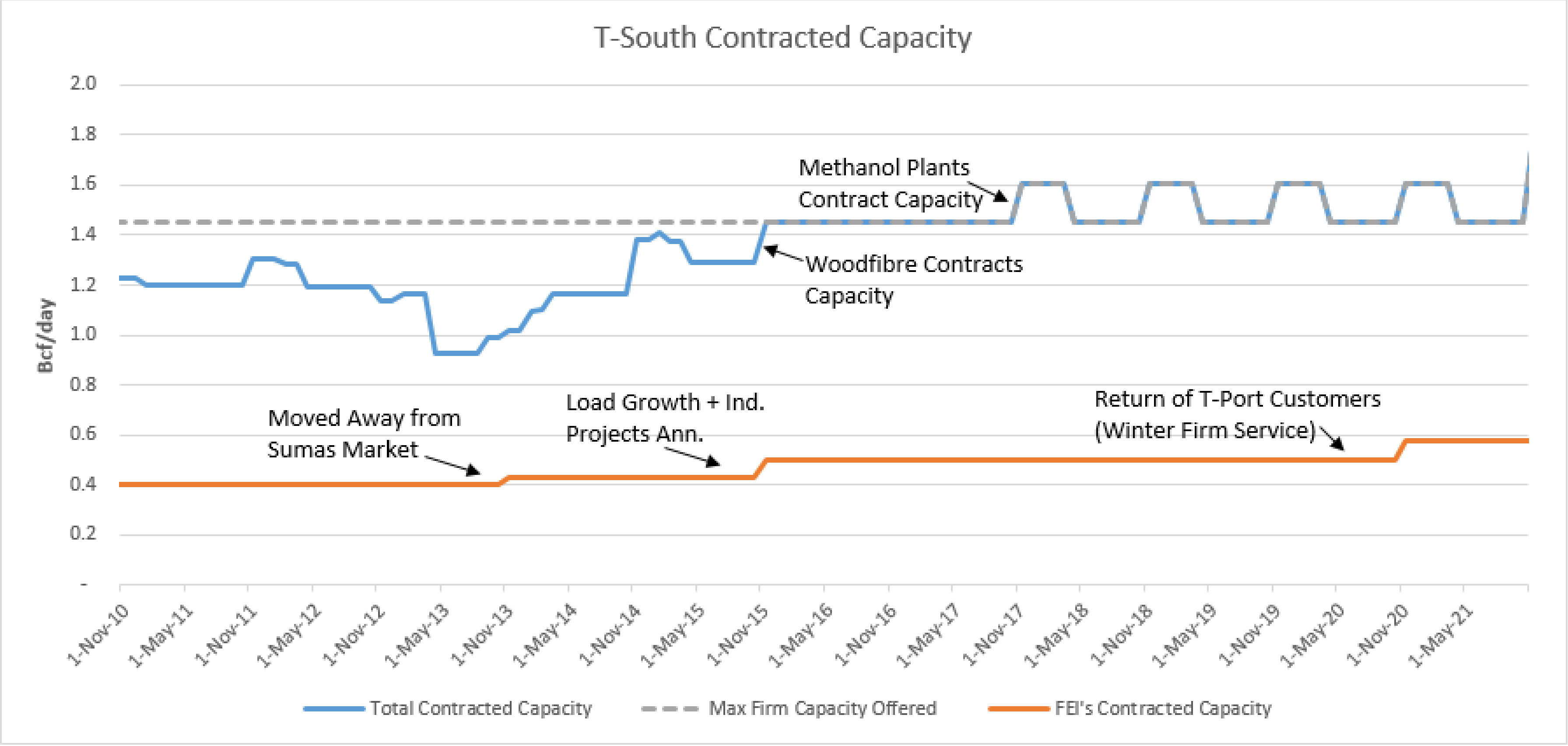
- Historically the Sumas price has periods of volatility during the winter.
- Demand exceeds pipeline capacity for several days
- 2013/14 – Sumas price disconnection becoming worse (FEI perspective)

ACP's Response to Resource Constrained Environment

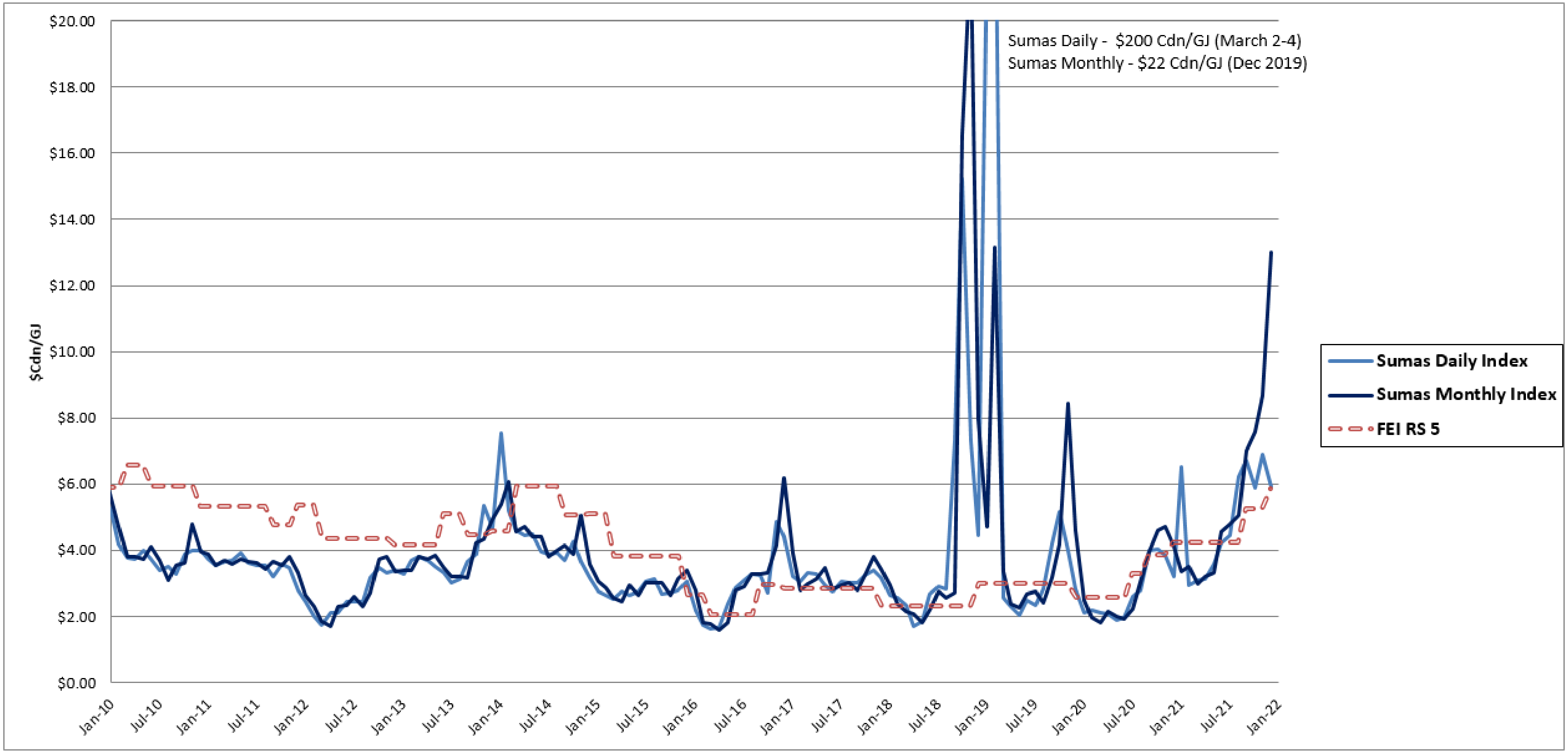
- 2012/13 - Moved away from the Huntingdon marketplace.
    - ***Due to ongoing supply reliability and pricing risks***
- 2014/15 – Secure additional and existing resources in the region (i.e. 75 TJ/day of T-South)
    - Mitigate risk of load growth (35 TJ/day Tilbury liquefaction) and the potential return of transportation service customers to the bundled service
    - Between 2016/17 and 2018/19 FEI allocate excess T-South capacity to Marketers on behalf of transportation service customers.

T-South Huntingdon Delivery Capacity

- T-South became fully contracted in 2015
  - Woodfibre secured T-South capacity in 2015
  - Northwest Innovations secured Winter Firm Service Capacity

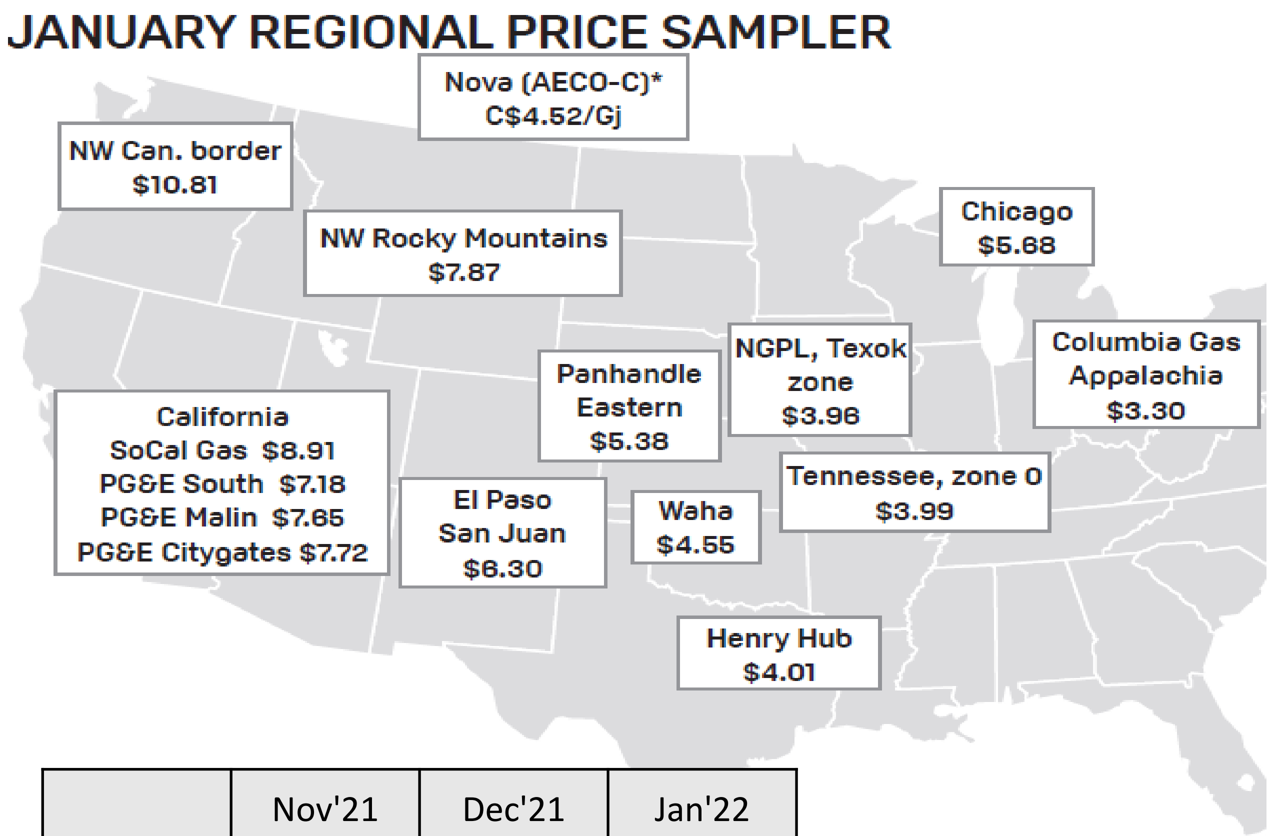


FEI's Rate Compared to Sumas Prices



- <u>The ACP strategy has proven to be at a reasonable cost and has less associated risks</u>

Market Challenges-
‘Outside the Box’

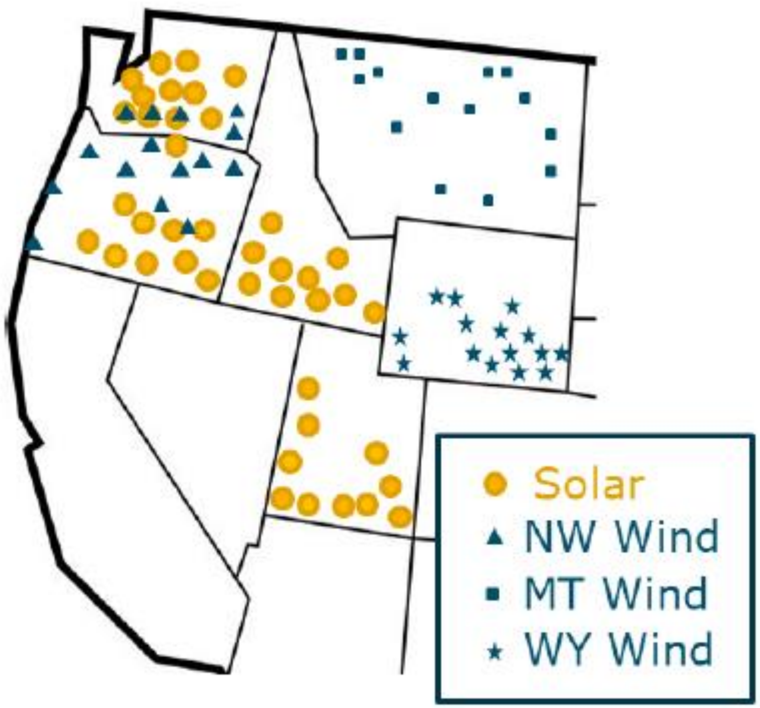


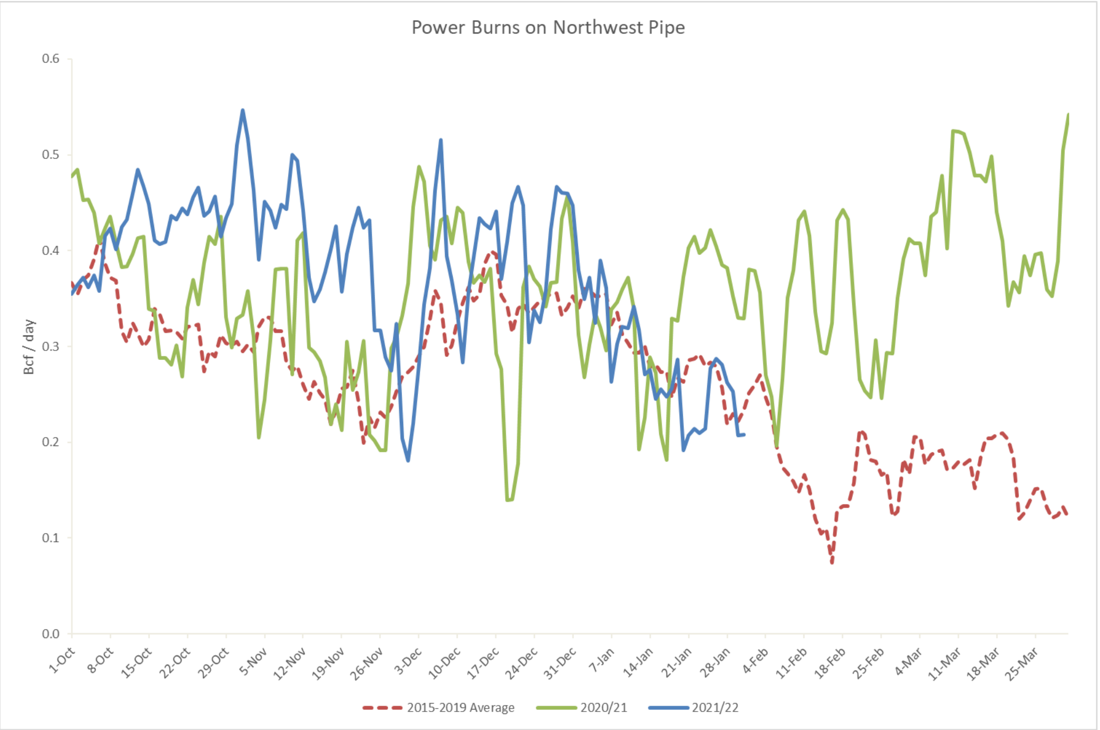
	Nov'21	Dec'21	Jan'22
Sumas	$ 6.47	$ 7.15	$ 10.81
Rockies	$ 6.34	$ 5.78	$ 7.87
NYMEX	$ 6.20	$ 5.45	$ 4.02

*Prices are $US/MMbtu

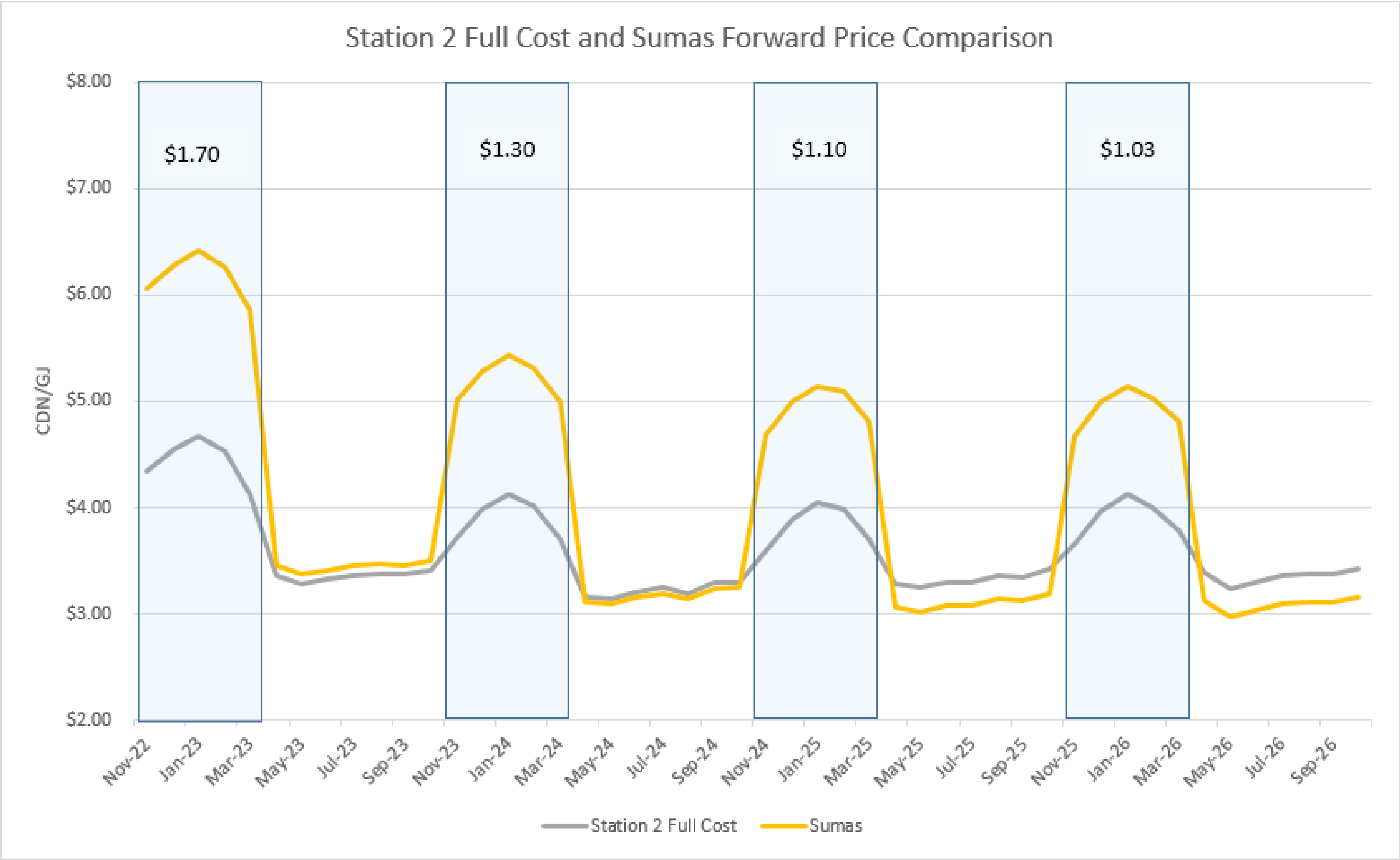
Increasing Demand from Existing Power Plants

- Coal Retirements in Region – No firm resources being added (replaced with renewables)
- Gas and power becoming more interconnected in the region given the increasing reliance on the natural gas infrastructure.
- Could cause higher Sumas prices to signal power plants to use alternative fuel





Sumas Forward Prices



- Future risk in region – Will incremental demand arrive before any pipeline expansion?
  - If so, increased volatility at Huntingdon will likely occur, especially in the winter.
  - This risk has already been priced into the forward prices.

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Gas Supply Resiliency

Resiliency in Regional and FEI's Context

Winter (151 day) Pipeline Supply (Bcf)		
T-South to Huntingdon		272
Gorge		81
	Total	353

Storage Assets		
Jackson Prairie (Washington)		25
Mist (Oregon)		19
On-System Storage (Tilbury & Mt Hayes)		2
	Total	46

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T-South Pipeline Incident (Oct 2018 – Nov 2019)

Phase One – No Flow Event (First 48 hours immediately following the rupture of the 36-inch pipeline)

Phase Two – Refers to 24-day period following first phase where gas supply was severely constrained (~50%)

Phase Three – Refers to 56 week period following second phase where pipeline was restricted to approx. 85% (NEB Order)

Future Projects to Enhance System Resiliency

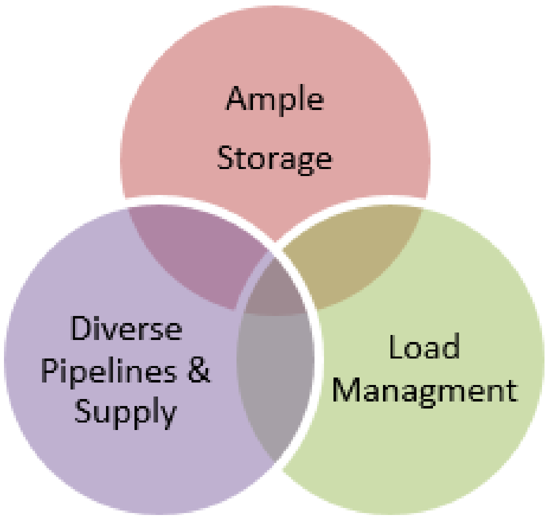
Incident shows multiple solutions are required to improve resiliency:

Phase 1 – "No Flow Event" - FEI requires additional on-system physical resource

1. Filed CPCN Application for a Tilbury Expansion (3 Bcf; 800 MMcf/day of vaporization)
2. Filed CPCN Application for Advanced Metering Infrastructure

Phase 2 – "Pipeline Capacity Restrictions" - FEI requires additional pipeline infrastructure to manage the duration of the supply disruption.

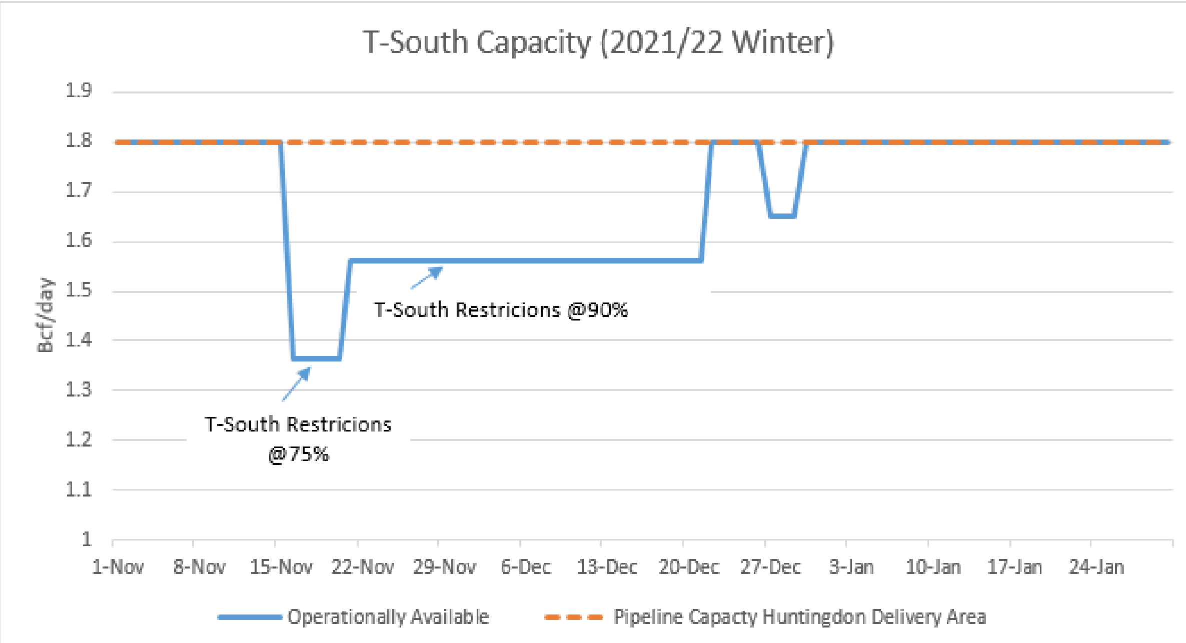
3. Regional Gas Supply Pipeline Solution



Short-Term Considerations

- FEI has mitigated a portion of the risk if a future pipeline incident occurs (phase three of T-South incident)
  - Secured the only opportunity in the marketplace to diversify its portfolio by taking back NW Natural's portion of Southern Crossing Pipeline capacity effective Nov 1, 2020.
  - Holding contingency resources (15% planning margin) to mitigate future risk of supply disruptions.
- Additional resources in the region required to increase gas supply resiliency

Recent Flooding Situation (T-South Impacted)



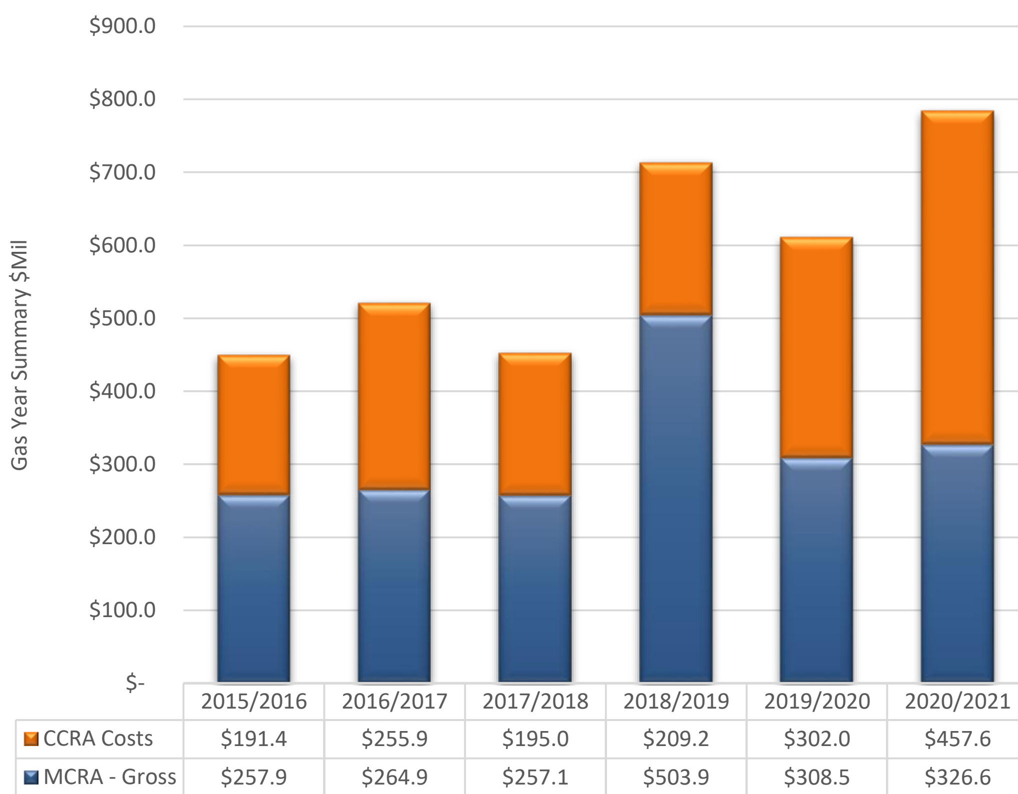
	Dec'21	Jan'22
Sumas	$ 7.15	$ 10.81
Station 2	$ 3.52	$ 3.75
AECO	$ 3.93	$ 3.40

Prices are $US/MMBtu

- Flooding and heavy rain caused Westcoast to isolate a portion of its 30 inch T-South pipeline.
- Pipeline capacity available at the Huntingdon Delivery Area ranged from 75% to 90% until late December.
- FEI's contingency resources allowed FEI to avoid significant cost exposure to its portfolio

Annual Contracting Plan Costs (CCRA & MCRA Gross)

Baseload Supply (CCRA)		
	Daily Volume (MMcf/day)	Total (Bcf)
Station 2	272	99.3
AECO	91	33.2
Seasonal Supply (MCRA)		
	Daily Volume (MMcf/day)	Total (Bcf)
Station 2	86	12.9
AECO	33	2.9
Pipeline Capacity (MCRA)		
	Daily Volume (MMcf/day)	Total (Bcf)
Westcoast - T-South	745	247
Westcoast - T-North	156	57
TC Energy (NGTL)	164	60
TC Energy (Foothills)	161	50
Northwest Pipe	107	7
Storage (MCRA)		
	Daily Volume (MMcf/day)	Total (Bcf)
Aitken Creek	149	22.5
Rockpoint	29	1.8
Jackson Prairie	96	2.5
Mist	105	2.7
Mt Hayes	144	1.4
Tilbury	144	0.6



Summary

- Continue to Contract at Supply Hubs (Station 2 and AECO) instead of Demand Hub (Sumas)
  - Incurred costs for contracting pipeline infrastructure better than alternative
  - Excess Resources help to manage potential gas supply disruptions
- Pricing Risks at Sumas
  - Resource Constraints (Winter)
  - Industrial projects proposed in the region have secured firm pipeline capacity;
  - Increasing demand forecast within FEI's service area and utilities along I-5 corridor;
  - Potential large-scale pipeline expansions in the region could face lengthy delays (Environmental/Regulatory challenges);

Commercial & Operations (Midstream)

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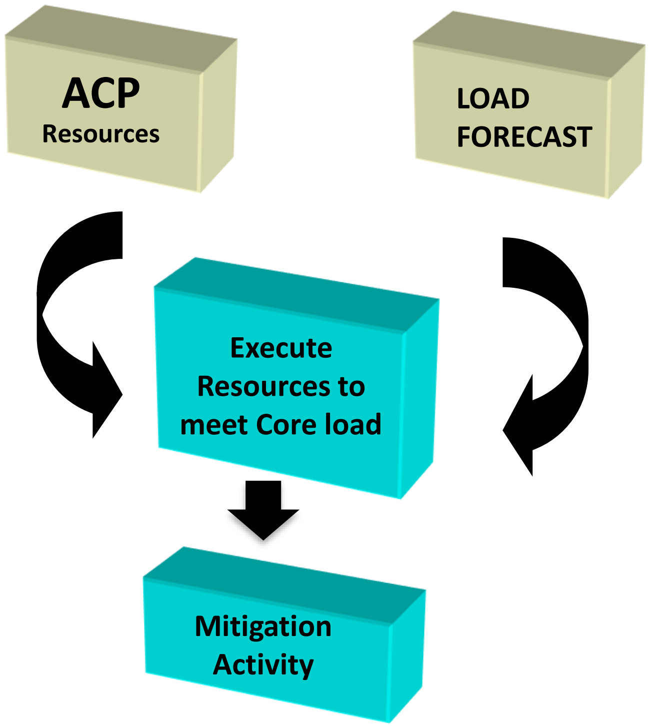
Commercial & Operations Focus

1. ACP Portfolio Optimization
   - Meet Core Load
   - Balance the FEI system at Pipeline Interconnects
   - Seek Mitigation Opportunities

2. Prudent Management of FEI's Resources
   - Commodity
   - Storage
   - Transportation

3. Execute Mitigation Activities (24/7/365)
   - Seasonal
   - Monthly
   - Daily
   - Intra-Day

Commercial & Operations Focus



- Counterparty Relationship Management
  - Contracts, Contacts & Credit
- Operational & Pipeline Conditions (Planned and Unplanned Outages)
  - WEI T-North & T-South
  - TC Energy NGTL & FHBC
  - NWP
  - FEI SCP
- Pipeline Business Rules & Nomination Cycles

- Gas Control 5-Day Load Forecast
- Price & Location (Daily & Forward)
- Time of Year (W/S) & Storage (ACR, AECO, JPS, MIST, MTH, TILB)

ACGS
Aitken Creek Gas Storage

bp

CASTLETON COMMODITIES
INTERNATIONAL

PETRONAS

TD

NW Natural

Ovintiv

Williams

Direct Energy

Chevron

PetroChina Canada

IGI
IGI Resources, Inc.
(a bp Energy Company)

TENASKA

MACQUARIE

Portland General Electric

ENBRIDGE

TC Energy

ConocoPhillips

Canadian Natural

ARC RESOURCES LTD.

UNITED ENERGY TRADING

Goldman Sachs

TOURMALINE

MERCURIA

IDAHO POWER

CIMA
ENERGY LP

TransAlta

PSE
PUGET SOUND ENERGY

Powerex

edf

PACIFIC
CANBRIAM ENERGY

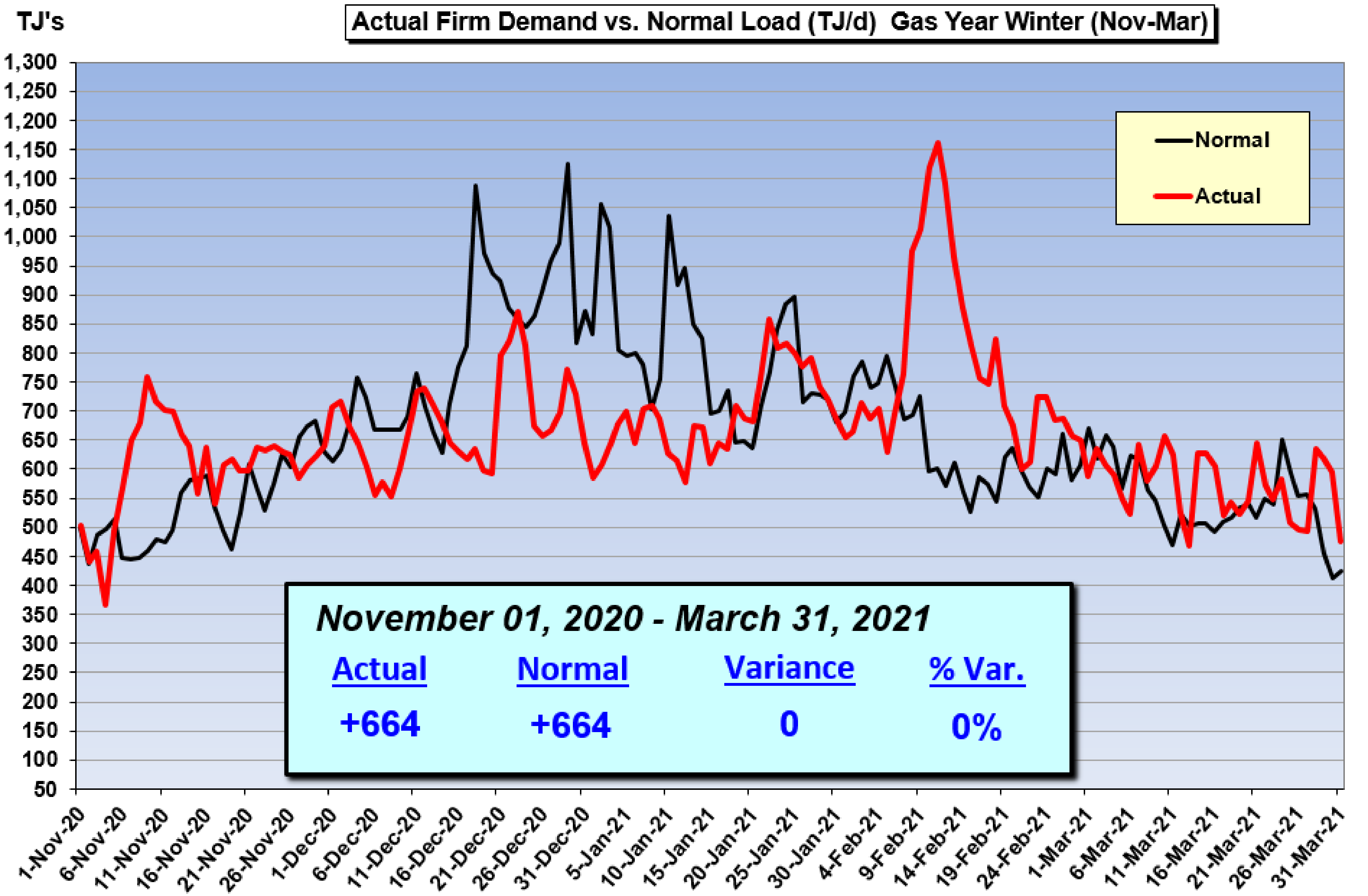
SUNCOR

Shell

CITADEL

AVISTA

ice NGX



** A 1 degree change can result in 30-40 TJ/d change in load

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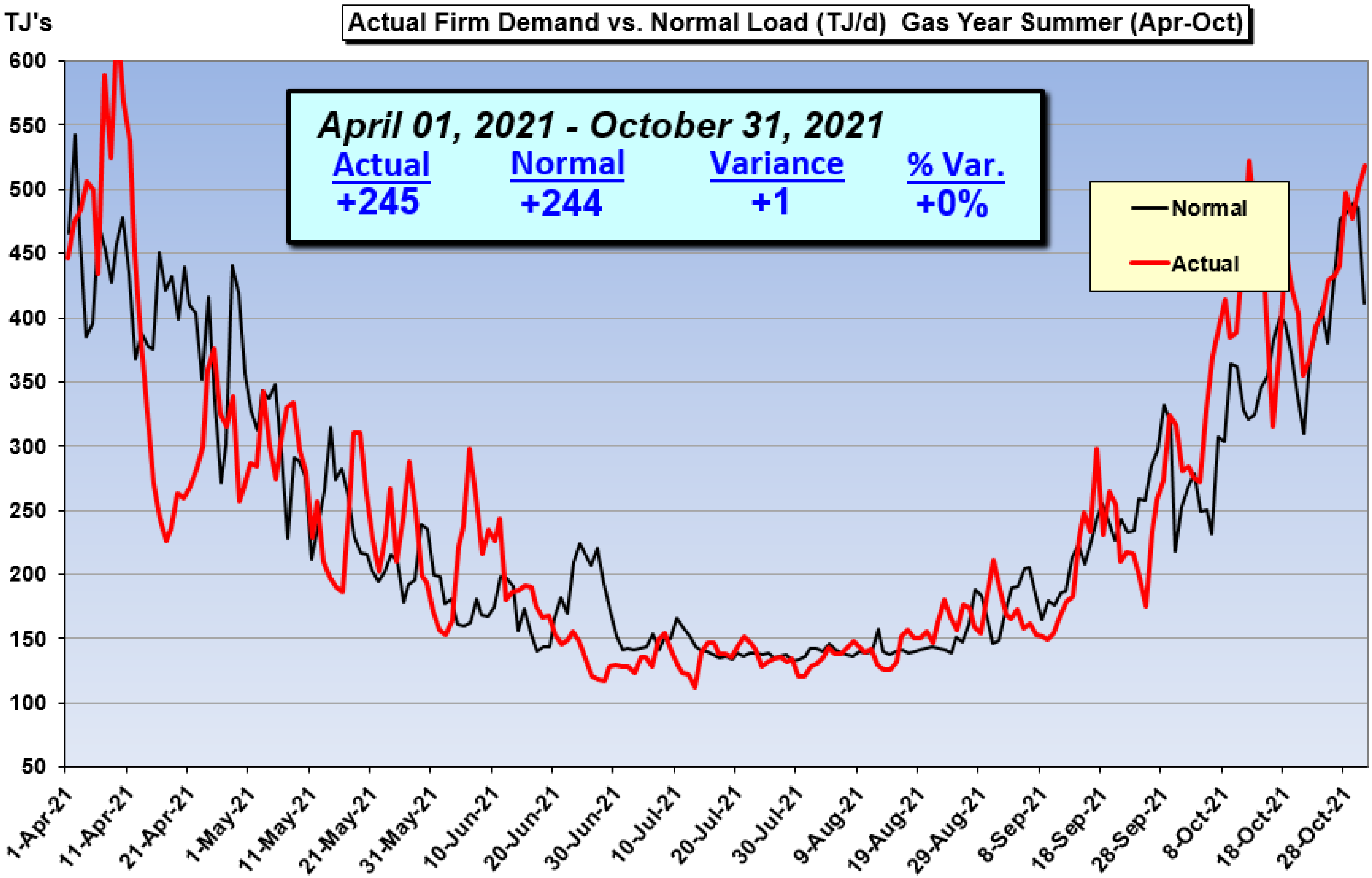

TJ's
Actual Firm Demand vs. Normal Load (TJ/d) Gas Year Summer (Apr-Oct)
April 01, 2021 - October 31, 2021
Actual
+245
Normal
+244
Variance
+1
% Var.
+0%
Normal
Actual
600
550
500
450
400
350
300
250
200
150
100
50
1-Apr-21
11-Apr-21
21-Apr-21
1-May-21
11-May-21
21-May-21
31-May-21
10-Jun-21
20-Jun-21
30-Jun-21
10-Jul-21
20-Jul-21
30-Jul-21
9-Aug-21
19-Aug-21
29-Aug-21
8-Sep-21
18-Sep-21
28-Sep-21
8-Oct-21
18-Oct-21
28-Oct-21

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ACP Execution & Optimization

Meet Core Load

- Seasonally – Nov-Mar vs Apr-Oct

- Daily – 5 gas cycles per day
    - Timely @ 11:00 AM day prior
    - Evening @ 4:00 PM day prior
    - (Intraday) ID1 @ 8:00 AM current day
    - ID2 @ 12:30 PM current day
    - ID3 @ 5:00 PM current day

- CCRA / MCRA Supply
- Firm Transportation Service Capacity
- Upstream, Downstream and On-system Storage

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Preparing for the Gas Day…24 hrs out

Gas Control 5 Day Load Forecast for Tuesday Feb 8 ,2022

LoadType		08 (Tue)	09 (Wed)	10 (Thu)	11 (Fri)	12 (Sat)
	VIP	10 / 3	8 / 3	7 / 2	9 / 1	10 / 4
Base Firm		1,730	1,600	1,700	1,585	1,395
Co Gen		0	0	0	0	0
Fuel		80	80	80	80	80
JV		650	900	900	900	900
Line Pack		200	20	-80	80	65
Mt Hayes		0	0	0	0	0
		2,660	**2,600**	**2,600**	**2,645**	**2,440**
	LML	7 / 6	8 / 5	7 / 2	8 / 3	9 / 3
Base Firm		10,205	9,975	10,938	10,213	9,700
Base Sch 7		625	610	610	610	610
Line Pack		0	0	0	0	0
LNG		0	0	0	0	0
Sch 22		750	800	800	800	800
Sch 23-27		878	878	878	788	757
SIPI		0	0	0	0	0
VIP		2,660	2,600	2,600	2,645	2,440
Auth 14,392 **Short 726**		**15,118**	**14,863**	**15,826**	**15,056**	**14,307**
	INL	6 / 0	7 / 2	6 / -4	5 / -4	5 / -3
Base Firm		3,143	2,613	3,138	3,175	3,100
EKE		-2,579	-2,579	-2,579	-2,579	-2,579
Kingsvale		0	0	0	0	0
Line Pack		0	0	0	0	0
Sch 22		1,700	1,700	1,700	1,700	1,700
Sch 23-27		600	600	600	600	600
Auth 2,677 **Short 187**		**2,864**	**2,334**	**2,859**	**2,896**	**2,821**

	LML	SIPI	Tot	VIP	Sav/Off	KNG	EKE	Tot
GD 08 Auth	14392	0	14392		2677	0	-2579	5256
GC Request	15118	0	15118	2660	2864	0	-2579	5443
Diff +/-	**-726**		**-726**		**-187**			**-187**
GD 07 Auth	14123	234			3363	208	-2990	
Measured	14433	213		2597	2814	513	-2770	
Imbalance	**-310**	**21**			**549**	**-305**	**-220**	

INL Pack 10,733 **Tot Tilbury** 53% 850 MMCF
LML Pack 4280 **Mt Hayes** 42% 666 MMCF
VIP Pack 176 MMCF **INL Offline** 1,864

Pipeline Conditions

Coast is short 726 km3

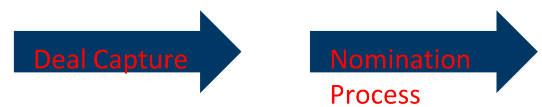
Interior is short 187 km3

Evaluate Supply Sources

- Storage Resources
- Commodity Resources
- Flexibility to Bring on or Shed Gas in the Intraday

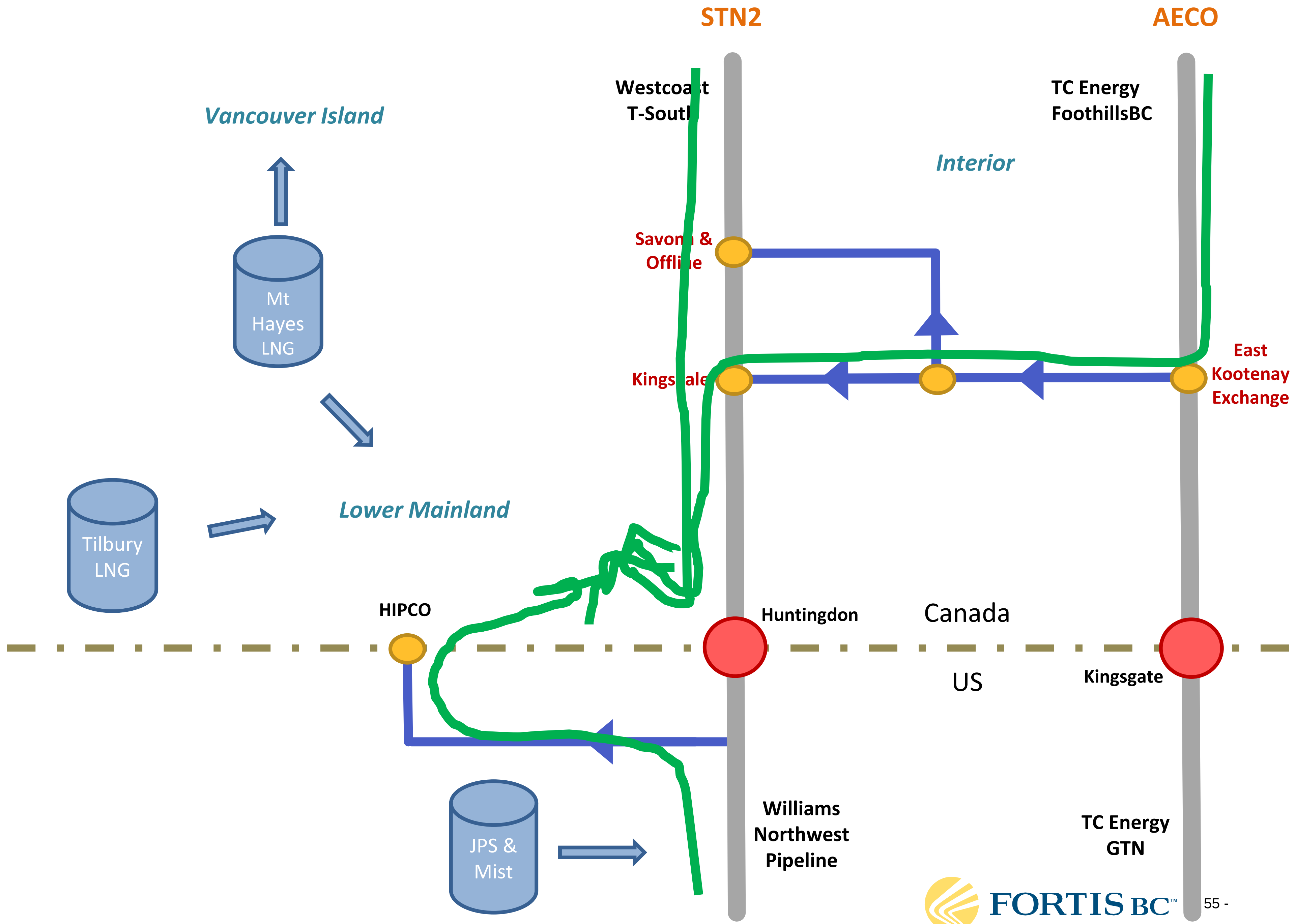
Excess Resources / Maximize Cost Recovery

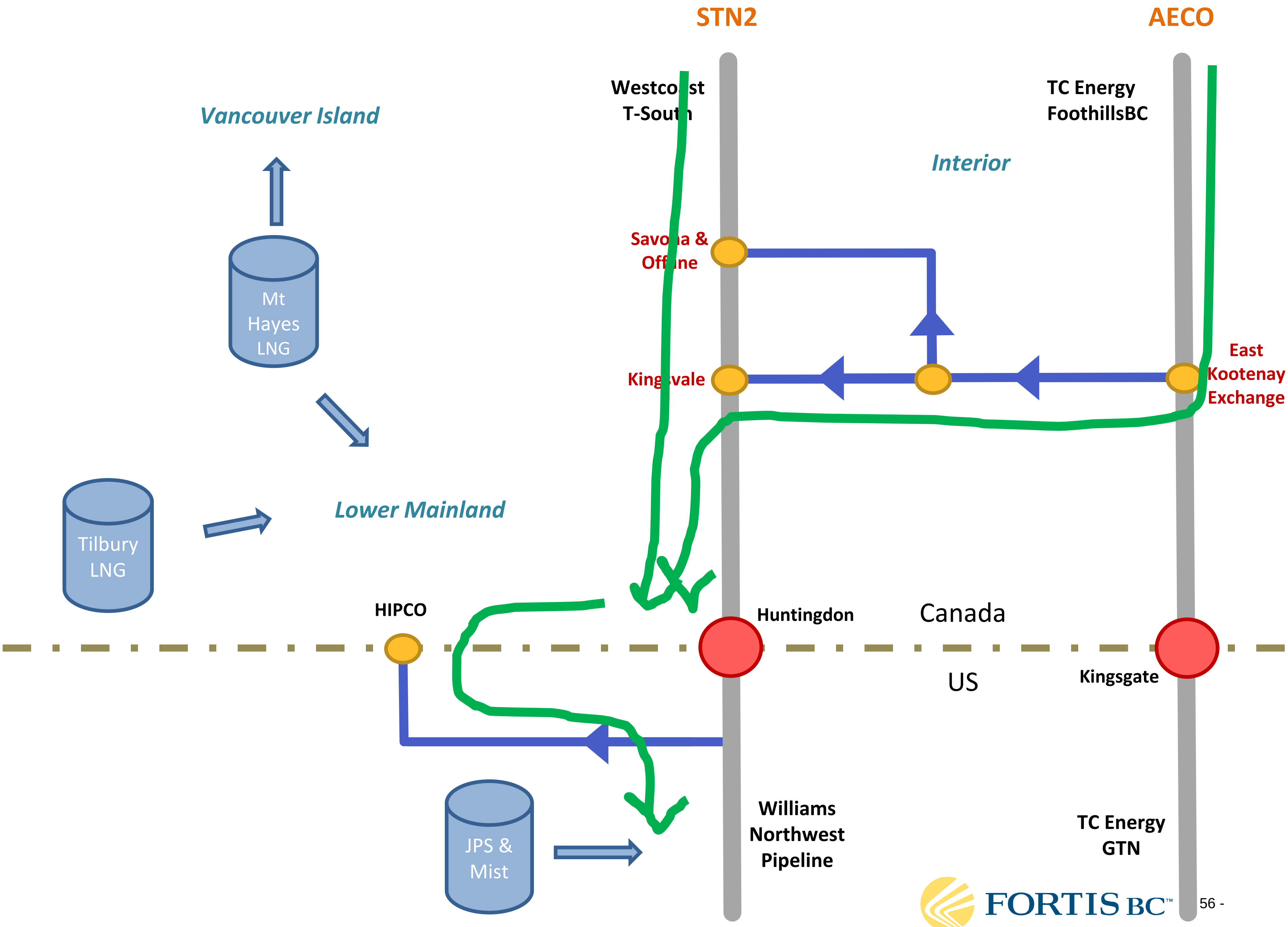
- Commodity Resale
- Transportation Mitigation



Tools that help carry out Midstream Operations

- Contingency Spreadsheet
- Nova Spreadsheet
- Cost Spreadsheet
- Pipeline Nomination System
- 5 Day Forecasts
- ETRM
- ICE Platform


STN2
AECO
Westcoast
T-South
TC Energy
FoothillsBC
Vancouver Island
Interior
Mt
Hayes
LNG
Savona &
Offline
Kingsvale
East
Kootenay
Exchange
Lower Mainland
Tilbury
LNG
HIPCO
Huntingdon
Canada
US
Kingsgate
JPS &
Mist
Williams
Northwest
Pipeline
TC Energy
GTN
FORTIS BC™


STN2
AECO
Westco st
T-Sout h
TC Energy
FoothillsBC
Vancouver Island
Interior
Mt
Hayes
LNG
Savo a &
Off ne
King vale
East
Kootenay
Exchange
Tilbury
LNG
Lower Mainland
HIPCO
Huntingdon
Canada
US
Kingsgate
JPS &
Mist
Williams
Northwest
Pipeline
TC Energy
GTN
FORTIS BC

ACP Execution & Optimization

- EPSQ – Elapsed Pro Rata Scheduled Quantity
  - The cumulative hourly portion of the scheduled quantity that would have theoretically flowed up to the effective time of the Intraday nomination being confirmed.
  - This applies to transportation service as well as storage INJ and WD

	Nomination	EPSQ
Timely:	100000	
Evening:	100000	
		20833
ID1:	100000	
		37500
ID2:	100000	
		54167
ID3:	100000	

ACP Execution & Optimization

Costs

- Fixed (sunk cost)
  - Pipeline Tolls
  - Storage Demand charges

- Variable
  - Fuel – % of every unit (GJ or dth) required to run compressors
  - MFT – Motor Fuel Tax (BC)
  - CT – Carbon Tax (BC)
  - FX – foreign exchange rate (CAD/USD)

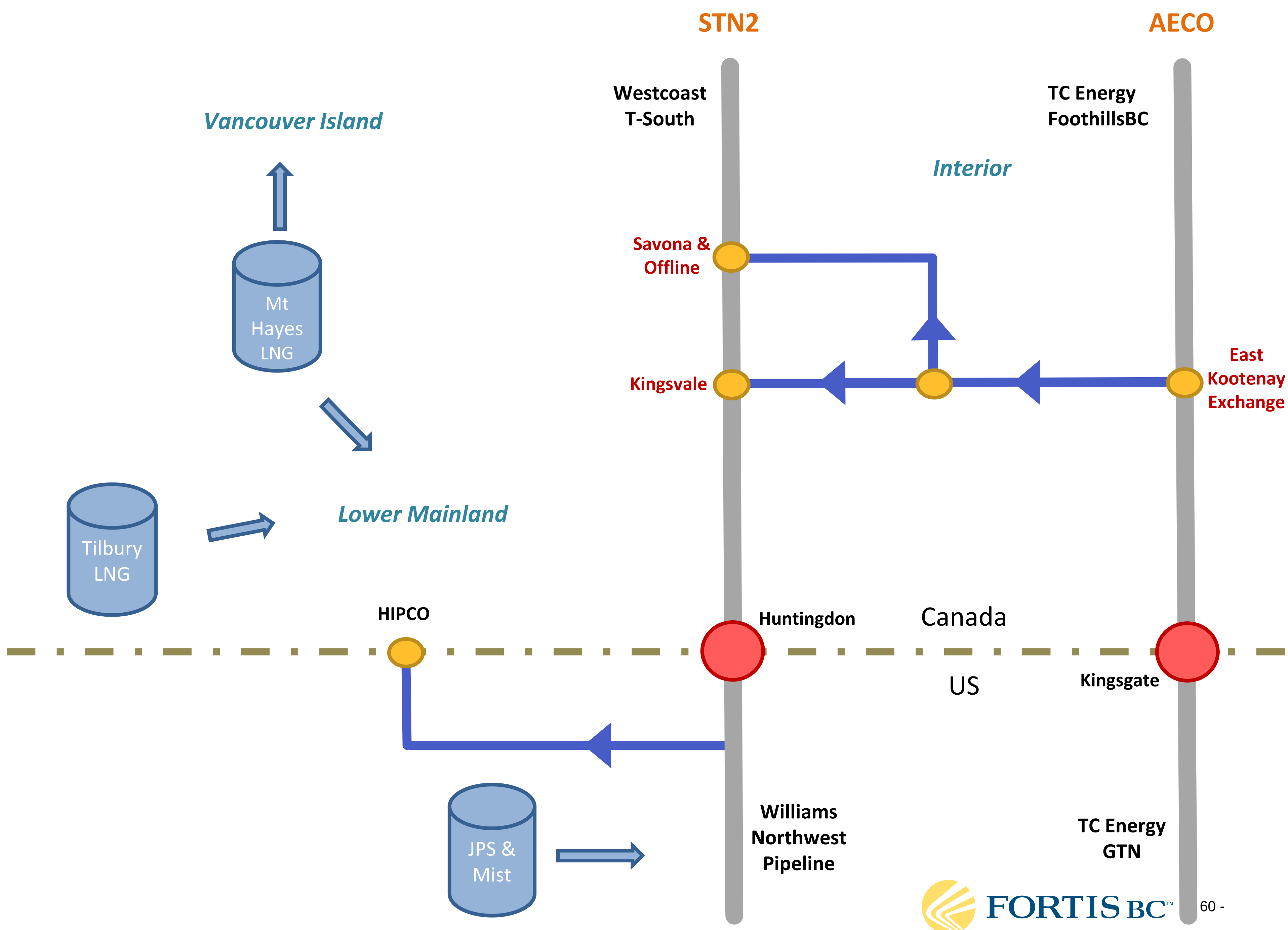
ACP Execution & Optimization

Balance the System

- FEI holds OBAs (Operational Balancing Agreements) at interconnects with third party pipelines:
  - WEI T-South at BCGIND & Offline*
  - WEI T-South at BCG Lower Mainland*
  - WEI T-South at Kingsvale
  - TC Energy FHBC at EKE*
  - NWP at HIPCO

- FEI is the Operator at these locations* and supply is provided by both FEI and Transportation Shipper Agents

- Trend OBAs to zero


STN2
AECO
Westcoast T-South
TC Energy FoothillsBC
Vancouver Island
Interior
Savona & Offline
Mt Hayes LNG
Kingsvale
East Kootenay Exchange
Tilbury LNG
Lower Mainland
HIPCO
Huntingdon
Canada
US
Kingsgate
JPS & Mist
Williams Northwest Pipeline
TC Energy GTN
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ACP Execution & Optimization

Seasonality

- Nov-Mar (Winter – 151 days)
  - Storage WD for supply and meeting load
  - Plan for firm transportation service availability

- Apr-Oct (Summer – 214 days)
  - Storage INJ for summer/winter price differential
  - High probability of firm transportation service restrictions

- Apr & Oct (Shoulder months)
  - FEI has summer transportation service profile
  - High degree of variability in temperature and load

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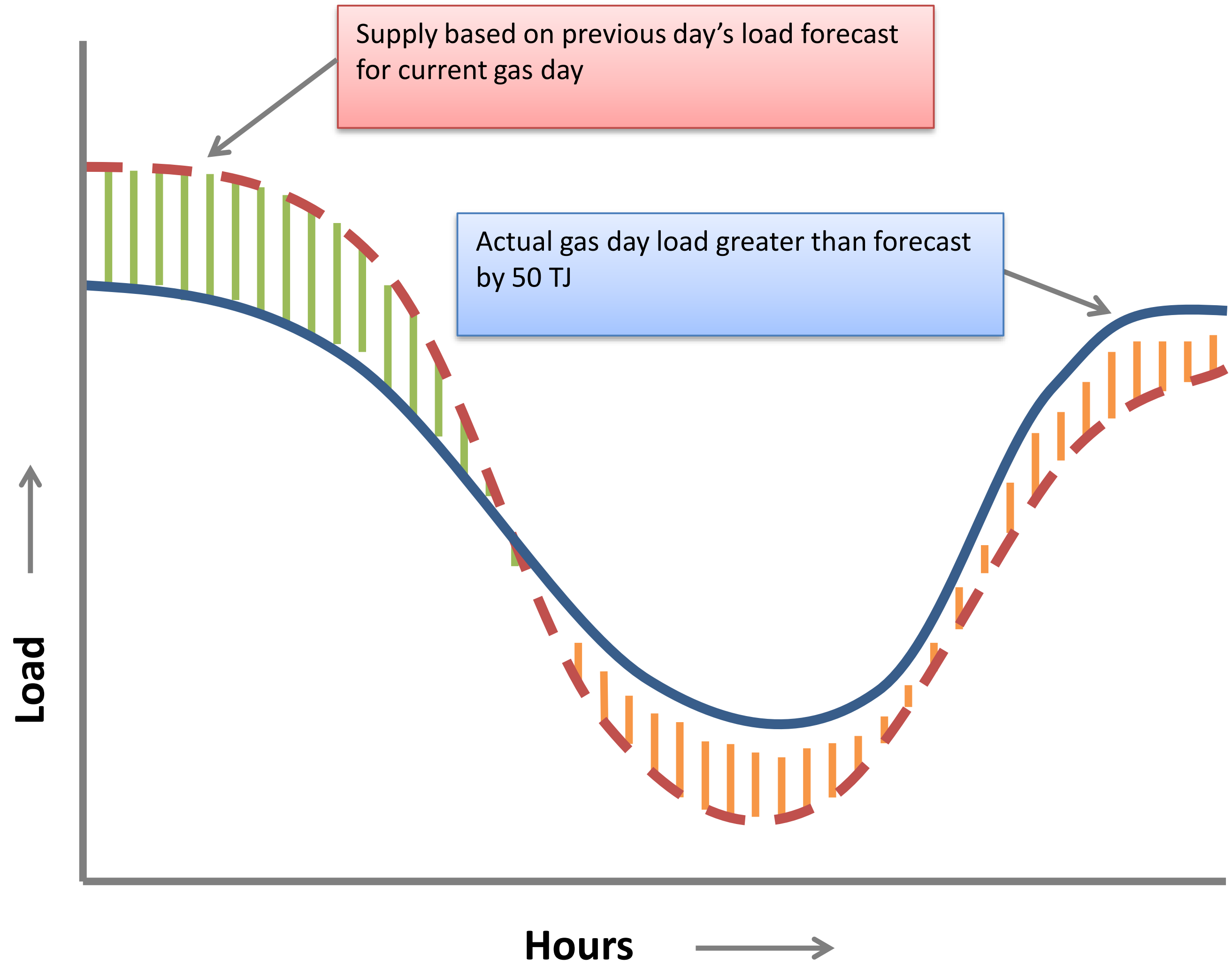
Example - Daily Supply vs. Demand (Intraday Changes)



- Demand dynamics:
  - Changes hourly / peaks
  - Temperature fluctuations throughout the day
  - Industrial customer consumption variances
- Supply flow:
  - Gas nominated day prior
  - Intra-day supply, there is a market
  - Upstream / downstream disruptions
- Daily load balancing:
  - Tight deadlines between final load forecast & placing nominations
  - Midstream assets balance entire system on behalf of all customers

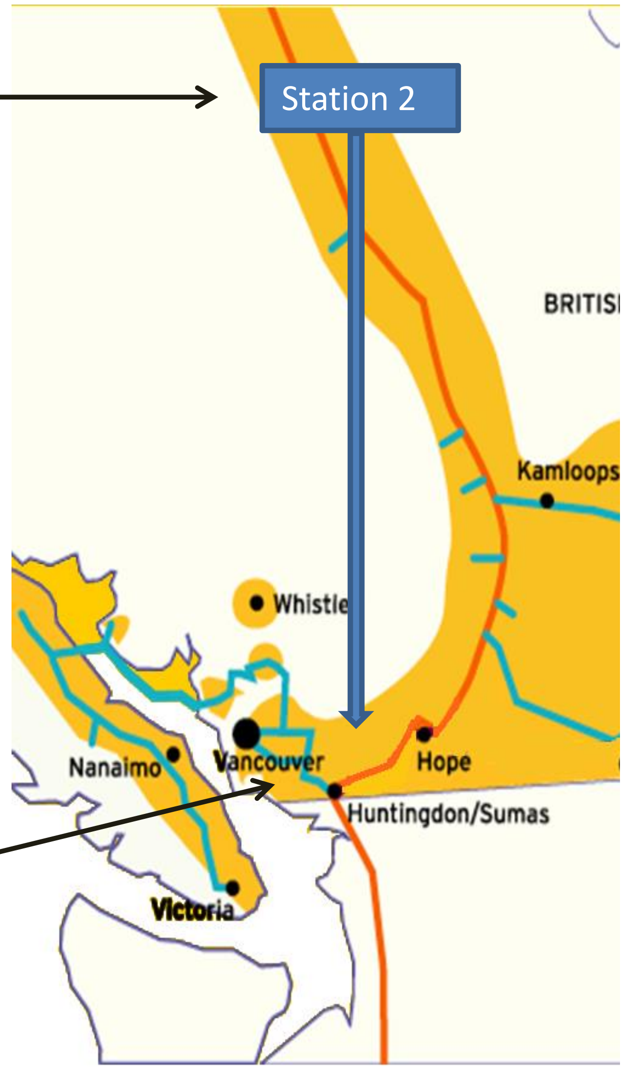
- Hourly measurements via SCADA real-time system

Example – Daily Balancing Activity @ Lower Mainland

ESM supply sources:
- Baseload supply
- Seasonal supply
- Storage supply

Forecast =	700 TJ
Actual =	650 TJ
Supply =	700 TJ
Long =	50 TJ

Supply: Transport customers delivery at LML



Demand dynamics:
- Change hourly / peaks
- Temperature fluctuations throughout the day
- Industrial customer consumption variances

Supply flow:
- Gas nominated day prior
- Intra-day markets
- Upstream / downstream disruptions

Daily load balancing:
- Tight deadlines between final load forecast & placing nominations
- Midstream assets balance entire system on behalf of all customers

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Cold Snap Dec 2021- Intraday Changes

Total LML

IntraCycle Trend

Load Forecast

December	TREND
22-Dec	
23-Dec	
24-Dec	
25-Dec	
26-Dec	
27-Dec	
28-Dec	
29-Dec	
30-Dec	

Cold Snap December 2021

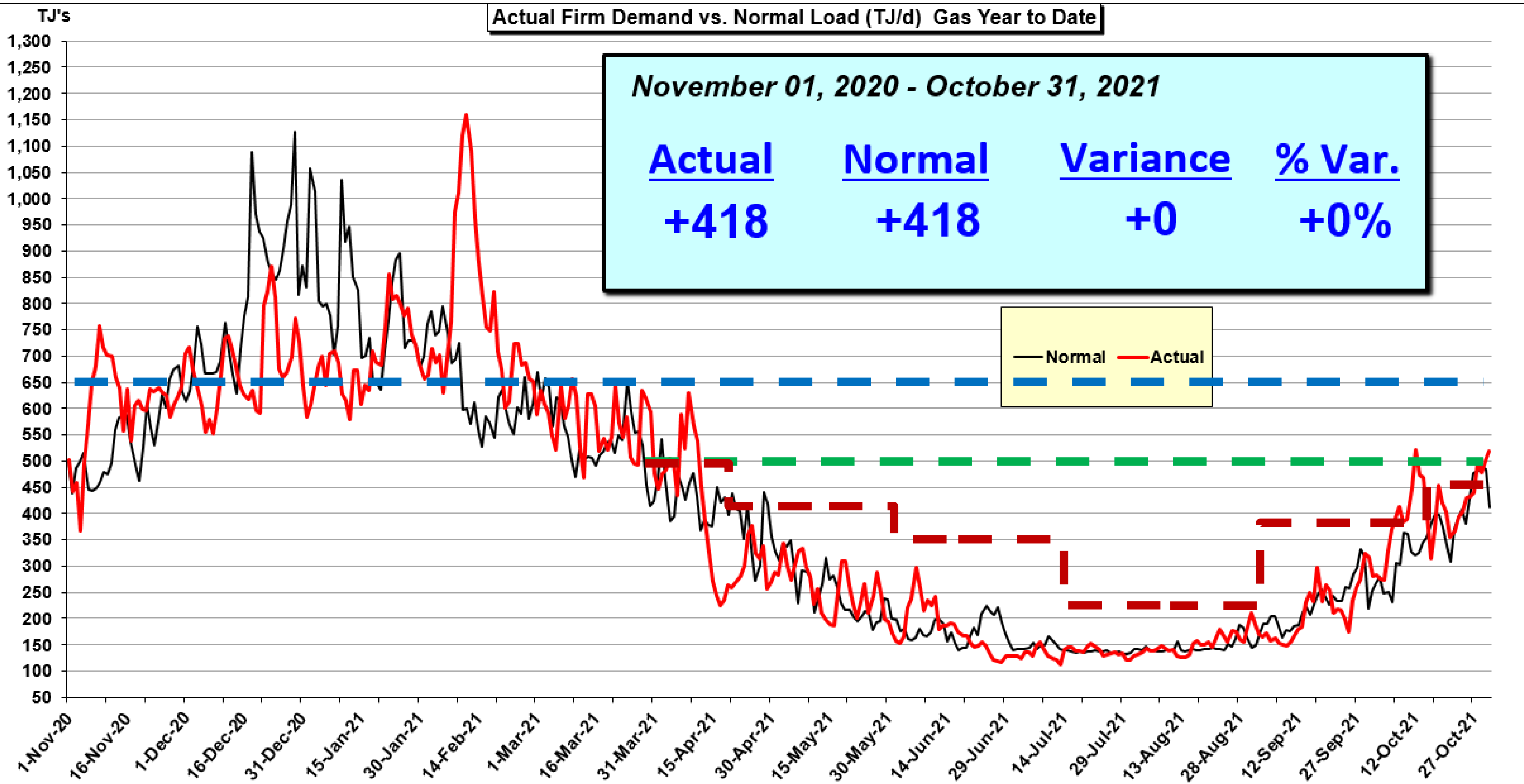
- Dec 22nd the load fluctuated from the Timely Forecast to the Day Ending Number close to 80 TJ
- Monitoring and adjusting throughout the day, we have 3 opportunities during the Gas Day to adjust nominations to match Load.

Mitigation Opportunities

Seasonality

- Nov-Mar (Winter – 151 days)
  - Meet core load / balance system
  - Conservative approach due to load requirements
  - Cognizant of time of year, health of regional assets
  - Predominantly flowing East to West on SCP
  - Daily commodity sales, transportation

- Apr-Oct (Summer – 214 days)
  - Capacity releases (T-South, NOVA, SCP)
  - Park / Loan future months
  - Daily commodity sales, transportation



Optimal T-South LML Capacity Including Contingency

Apr-Oct T-South LML after Capacity Releases

Actual T-South LML after WEI Constraints

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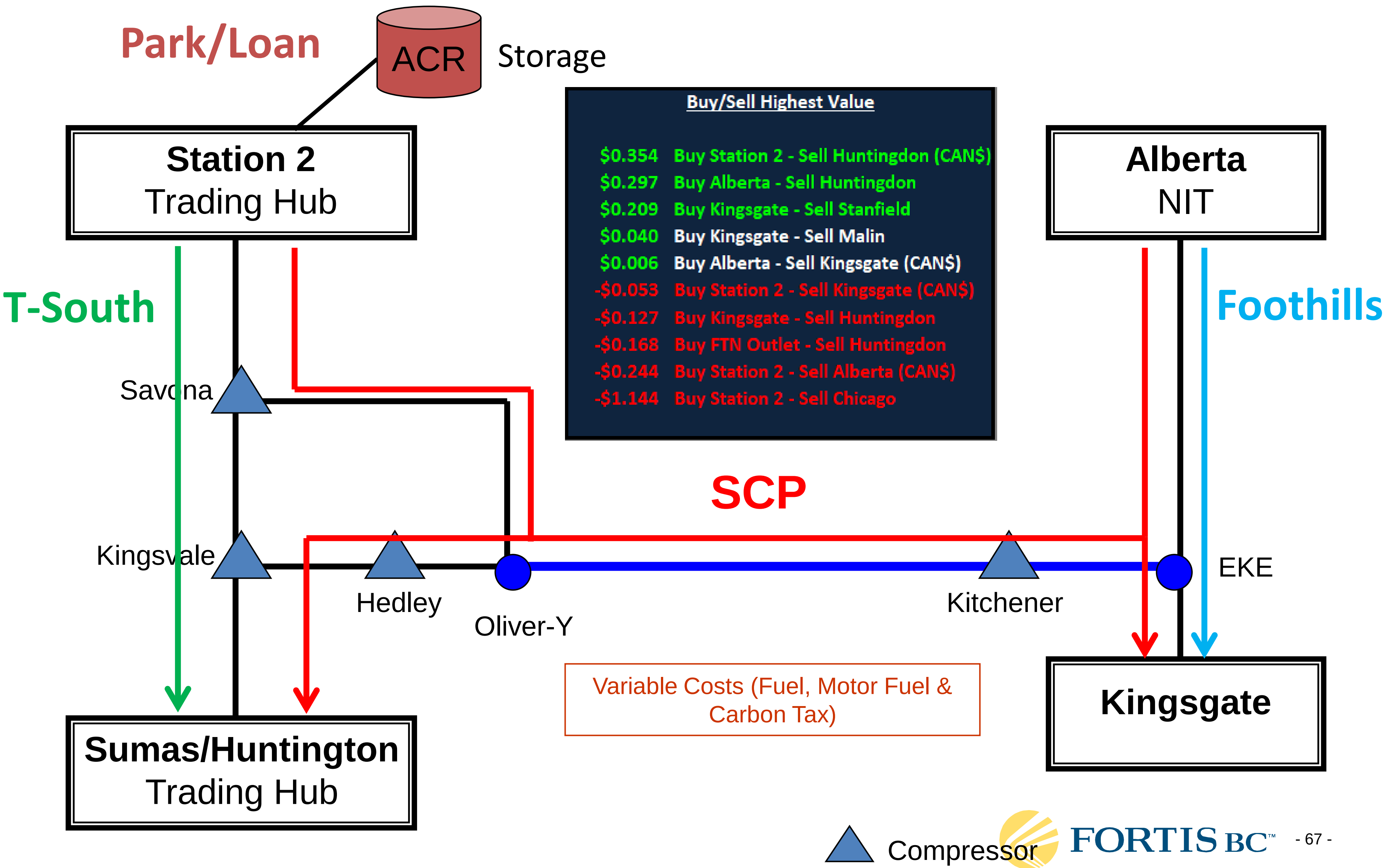
Mitigation Activities



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Mitigation Activities

Park / Loan

- Typically transacted at Stn2, AECO or Huntingdon
  - Leverage storage assets and the INJ / WD profiles in order to capture price differentials
- Example:
    - ND Stn2 @ $3.00 CAD/GJ and Apr22 Stn2 @ $4.50 CAD/GJ
    - Instead of WD 75,000 GJ ND ACR
    - FEI buys 75,000 GJ ND Stn2 and FEI sells 2,500 GJ/d Apr22 Stn2
    - Net before carrying costs $112,500 CAD

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Mitigation Activities

Park / Loan

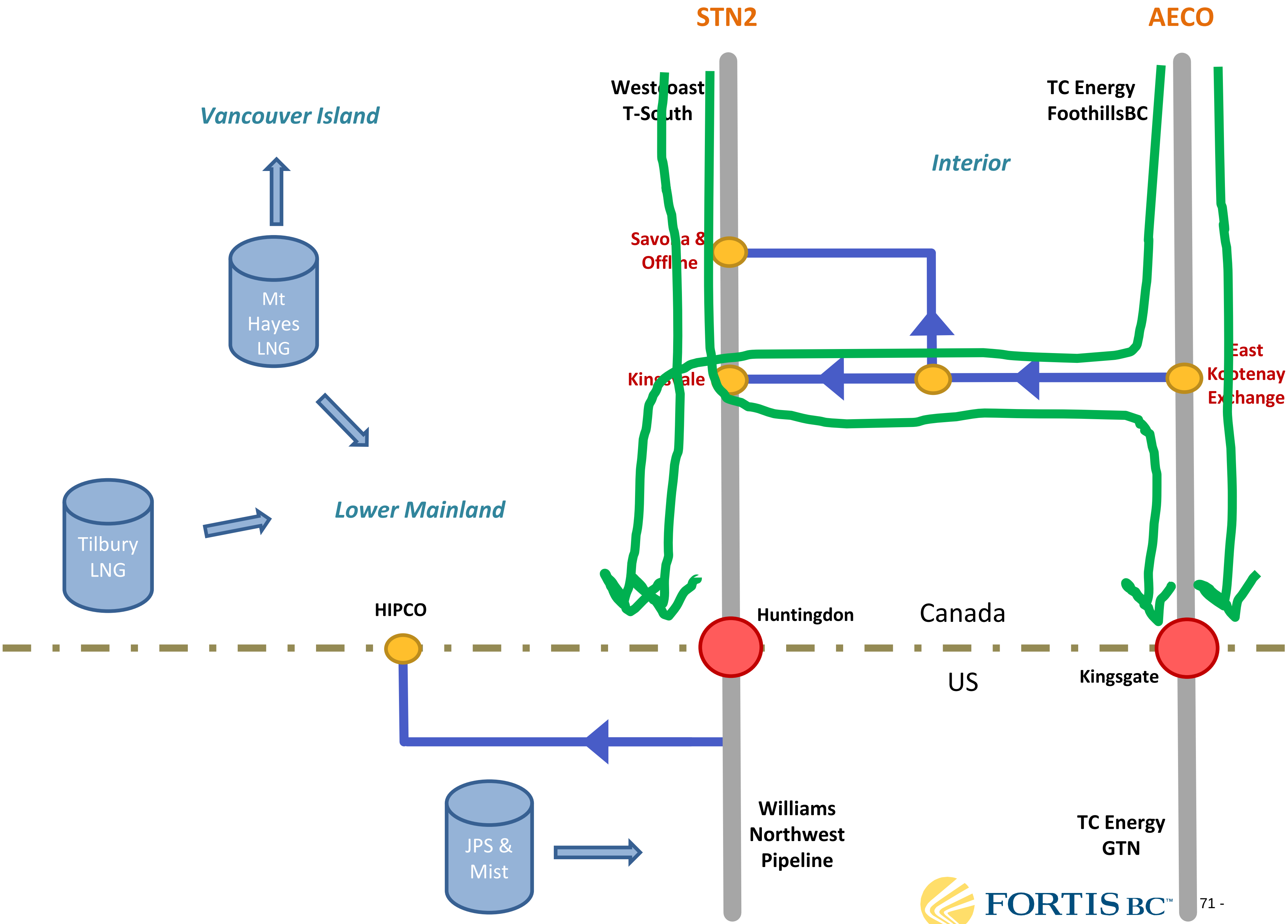
- Example:
  - May22 Hunt @ $3.50 US/mm and Aug22 Hunt @ $5.00 US/mm
  - FEI finds a counterparty willing to transact
  - FEI buys 20,000 mm/d May22 Hunt and FEI sells 20,000 mm/d Aug22 Hunt
  - Net before carrying costs $930,000 US

Mitigation Activities

Transportation

- FEI utilizes open transportation capacity on upstream pipelines to capture price differentials between supply hubs and market centres
- Supply hubs @ Stn2 and AECO
- Market centres @ Huntingdon and Kingsgate
- Could also include points along each path on WEI T-North, WEI T-South, TC Energy FHBC and FEI SCP

- Considerations:
  - Supply price
  - Market price
  - Variable costs


STN2
AECO
TC Energy
FoothillsBC
Vancouver Island
Interior
Mt
Hayes
LNG
Lower Mainland
Tilbury
LNG
HIPCO
Huntingdon
Canada
US
Kingsgate
JPS &
Mist
Williams
Northwest
Pipeline
TC Energy
GTN

Mitigation Activities

Transportation

- Example:
  - FEI buys 10,000 GJ @ $3.90 CAD/GJ at Stn2
  - Less T-South fuel @ $0.144 CAD/GJ
  - Less MFT + CT @ $0.073 CAD/GJ
  - Delivered cost @ $4.117 CAD/GJ at Hunt
  - FEI sells 9,630 GJ @ $4.56 CAD/GJ at Hunt
  - Recovery T-South Value @ $0.445 CAD/GJ

Daily Prices

February 08, 2022

FX Rate **$1.2700**

Conversion3.02

Fort Nelson Outlet	$3.604	CDN$/GJ	$2.99
Station 2	$3.900	CDN$/GJ	$3.24
Alberta @ NIT	$4.105	CDN$/GJ	$3.41
Huntingdon	$3.790	US$/MMBtu	$4.56
Kingsgate	$3.550	US$/MMBtu	$4.27
Stanfield	$3.850	US$/MMBtu	
Malin	$3.920	US$/MMBtu	
Rockies	$3.950	US$/MMBtu	

Tolls, Fuel, and Variable Costs

Can$ per GJ	Demand Tolls			Fuel	Variable Costs	
	1 Yr Firm Toll	AOS	IT	%	Carbon Tax	MFT
T-South LML	$0.64	$0.70	$0.70	3.70%	$0.06	$0.02
T-North	$0.28	$0.37	$0.37	0.40%	$0.01	$0.00
T-South KV to LML	$0.28	$0.37	$0.37	0.70%	$0.03	$0.01
T-South IND	$0.36	$0.47	$0.47	2.08%	$0.03	$0.01
Foothills	$0.06			1.50%		
SCP				1.20%	$0.01	$0.02
Alliance	~~$1.50~~			~~4.08%~~		
				0.0729%		
	$0.36			3.00%	$0.02	$0.01

Buy Station 2 - Sell Huntingdon

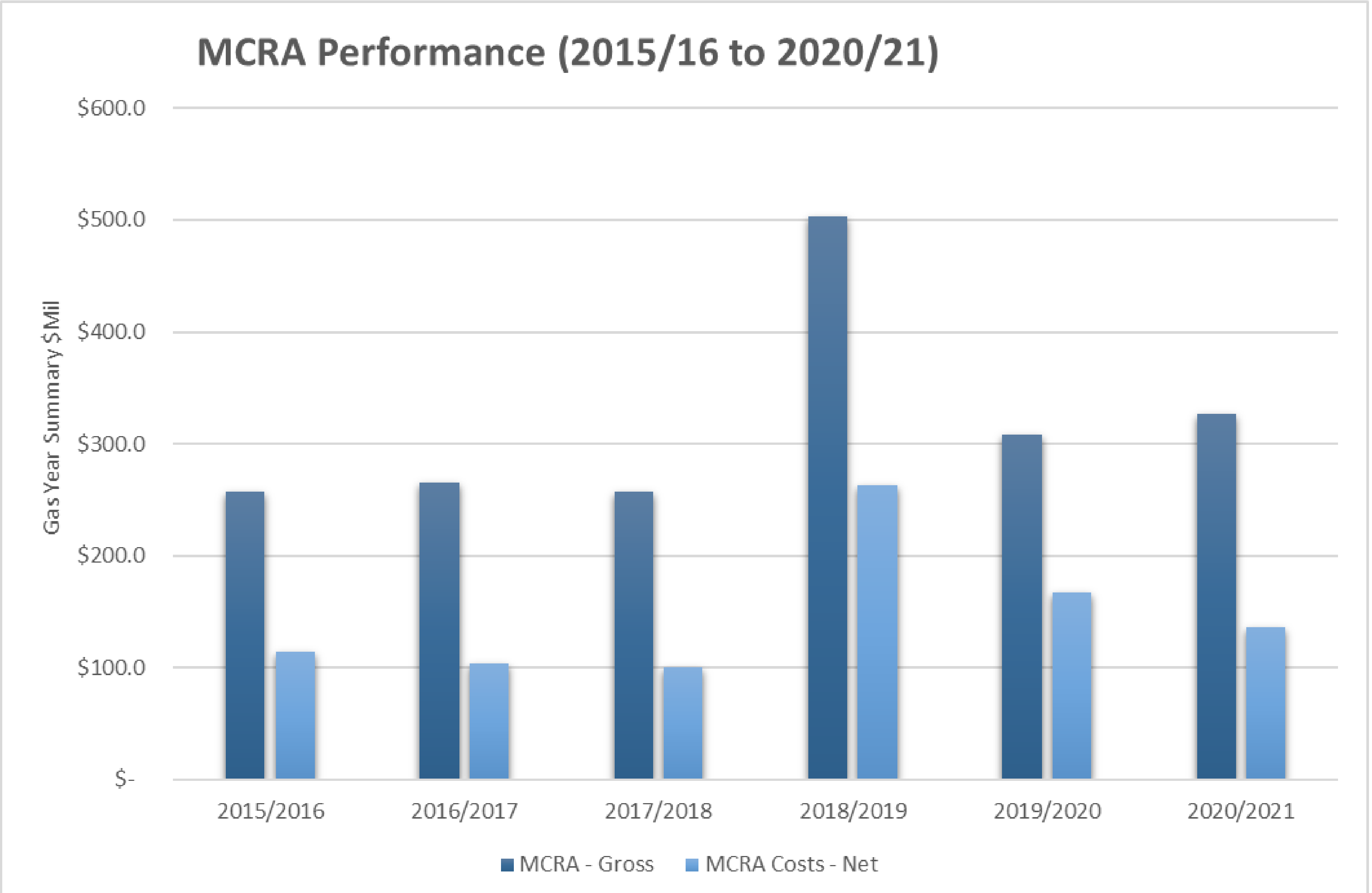
	CDN$/GJ		US$/MMBtu
Station 2	$3.900		**$3.240**
TS LML Firm Demand	$0.000	☐ + Toll	
Fuel (T-South)	$0.144		
MFT & Carbon Tax	$0.073		
Delivered @ Hunt	$4.117		**$3.421**
Positive Value	**$0.445**	**CDN**	**$0.369**
RUN AOS: TS LM	$0.699		
Delivered @ Hunt	$4.816		**$4.001**
No Value on AOS	**$0.25**		**-$0.21**
RUN IT: TS LML	$0.699		
Delivered @ Hunt	$4.816		**$4.001**
No Value on IT	**$0.25**		**-$0.21**

Mitigation Activities

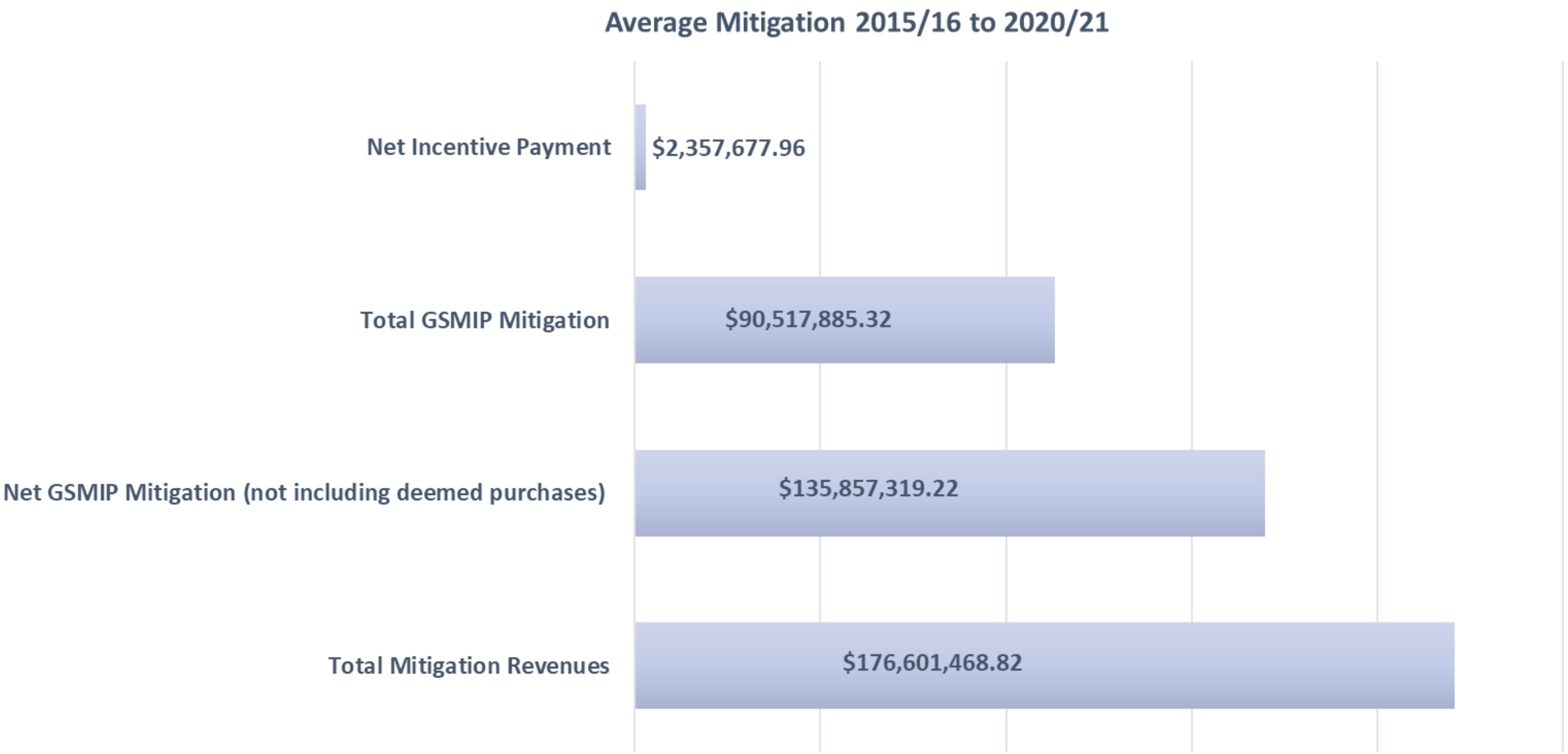
Capacity Release

- For the Apr-Oct (summer) timeframe, FEI undertakes transactions with counterparties to release firm service at market rates
- WEI T-South, TC Energy NOVA ABC, FEI SCP
- Similar to daily transportation mitigation, FEI will use forward price curves for supply hubs, market centres and variable costs to determine the assignment value

Mitigation Activities



Mitigation Activities



Summary

FEI Commercial & Operations focus:

- Meet core load
- Balance the system
- Seek mitigation opportunities

FEI achieves this through:

- ACP execution and optimization
- Prudent management of commodity, storage and transportation resources

Mitigation Activities require:

- Experienced personnel
- Processes and systems
- Management oversight

Next Steps…

Wrapping up GSMIP Workshop #1

- Follow-on questions and take-aways

GSMIP Workshop #2 (Tuesday, March 8/22)

- Objectives
- Guiding Principles
- Term Sheet & Model
- Mitigation Strategies
- Existing Mechanisms to Quantify and Measure
- Other Mechanisms

Meeting Summary	
Total Number of Participants	16
Meeting Title	FEI GSMIP Review - Workshop #2
Meeting Start Time	3/8/2022, 9:56:23 AM
Meeting End Time	3/8/2022, 1:13:22 PM
Meeting Id	3d11255f-1229-41c0-8676-4a3d2416bf3d

Full Name	Join Time	Leave Tim	Duration
Gill, Manpreet	3/8/2022, 9:56:23 AM	3/8/2022,	2h 49m
Yasinchuk, Matt	3/8/2022, 9:58:53 AM	3/8/2022,	2h 47m
Peter Helland	3/8/2022, 9:59:02 AM	3/8/2022,	2h 46m
Bill Andrews (Guest)	3/8/2022, 9:59:02 AM	3/8/2022,	2h 46m
Ron Amen	3/8/2022, 9:59:02 AM	3/8/2022,	2h 46m
Hill, Shawn	3/8/2022, 9:59:10 AM	3/8/2022,	1h 16m
Hill, Shawn	3/8/2022, 11:18:10 AM	3/8/2022,	1h 27m
Kristin Barham	3/8/2022, 9:59:45 AM	3/8/2022,	1m 32s
Kristin Barham	3/8/2022, 10:15:28 AM	3/8/2022,	1h 22m
Chan, King-yi	3/8/2022, 10:00:11 AM	3/8/2022,	2h 45m
Kehoe, Aidan	3/8/2022, 10:00:43 AM	3/8/2022,	1h 12m
Kehoe, Aidan	3/8/2022, 11:21:02 AM	3/8/2022,	1h 24m
O'Neal, Joshua	3/8/2022, 10:00:57 AM	3/8/2022,	2h 44m
David Craig	3/8/2022, 10:00:58 AM	3/8/2022,	2h 44m
Tom Feldman	3/8/2022, 10:00:59 AM	3/8/2022,	2h 44m
John Taylor	3/8/2022, 10:01:33 AM	3/8/2022,	2h 44m
Tom Hackney (Guest)	3/8/2022, 10:01:37 AM	3/8/2022,	2h 43m
Vincent, Cory	3/8/2022, 10:03:12 AM	3/8/2022,	2h 42m
Bevacqua, Ilva	3/8/2022, 10:06:22 AM	3/8/2022,	1h 11m
Bevacqua, Ilva	3/8/2022, 11:23:09 AM	3/8/2022,	1h 50m

Email	Role	Participant ID (UPN)
Manpreet.Gill@fortisbc.com	Presenter	Manpreet.Gill@fortisbc.com
Matt.Yasinchuk@fortisbc.com	Organizer	Matt.Yasinchuk@fortisbc.com
phelland@midgard-consulting.com	Attendee	phelland@midgard-consulting.com
	Attendee	
ramen@atriumecon.com	Attendee	ramen@atriumecon.com
Shawn.Hill@fortisbc.com	Presenter	Shawn.Hill@fortisbc.com
Shawn.Hill@fortisbc.com	Presenter	Shawn.Hill@fortisbc.com
barhamk@bcpiac.org	Attendee	kbarham@bcpiac.org
barhamk@bcpiac.org	Attendee	kbarham@bcpiac.org
Kingyi.Chan@bcuc.com	Attendee	kingyi.chan@bcuc.com
Aidan.Kehoe@bcuc.com	Attendee	Aidan.Kehoe@bcuc.com
Aidan.Kehoe@bcuc.com	Attendee	Aidan.Kehoe@bcuc.com
Joshua.ONeal@bcuc.com	Attendee	Joshua.ONeal@bcuc.com
davidc@equifaira.com	Attendee	davidc@equifaira.com
tfeldman@atriumecon.com	Attendee	tfeldman@atriumecon.com
jtaylor@atriumecon.com	Attendee	jtaylor@atriumecon.com
	Attendee	
Cory.Vincent@bcuc.com	Attendee	cory.vincent@bcuc.com
Ilva.Bevacqua@fortisbc.com	Presenter	Ilva.Bevacqua@fortisbc.com
Ilva.Bevacqua@fortisbc.com	Presenter	Ilva.Bevacqua@fortisbc.com

Gas Supply Mitigation Incentive Plan (GSMIP) Workshop #2

Term Sheet and Model Overview

March 8, 2022

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Agenda

- FEI’s Gas Supply Portfolio – Summary
- North American Gas Supply Incentive Programs (Atrium Economics)
- Guiding Principles
- GSMIP Term Sheet
- GSMIP Model
- GSMIP Prior Performance
- Moving GSMIP Forward

FEI’s Gas Supply Portfolio – Summary

Annual Contracting Plan (ACP)

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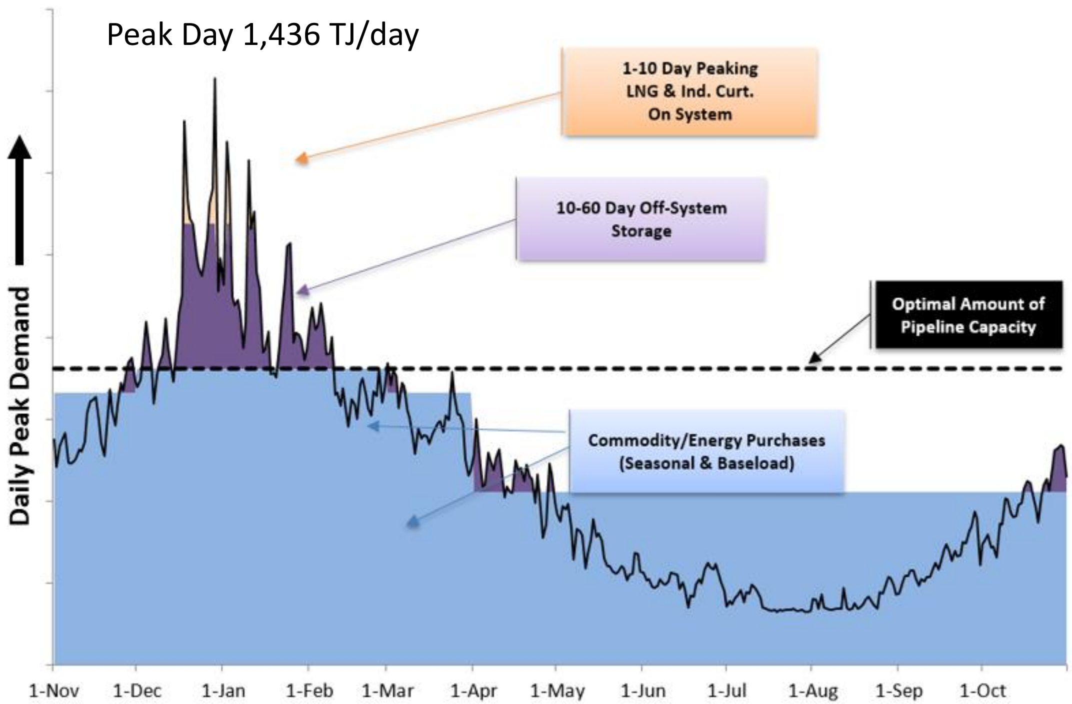
Annual Contracting Plan



Contract Year	2021/22 (TJ/day)
Total Peak Day Load	**1,436**
Winter Design Load	740
Summer Design Load	271
Average Design Load	**464**
Winter Normal Load	656
Summer Normal Load	237
Annual Daily Normal Load	**411**

<u>Key objectives include balancing:</u>

Security and reliability of gas supply

Diversity of resources, pricing, counterparties

Flexibility

Cost minimization

<u>Challenges:</u>

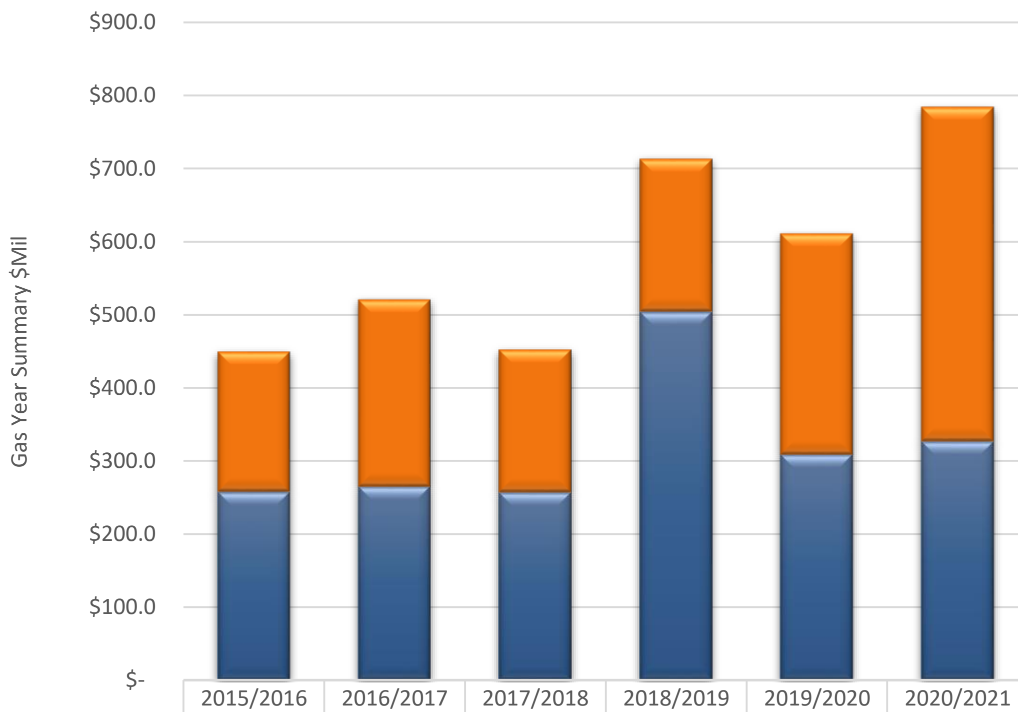
Matching supply to customer load profile

Resource Availability

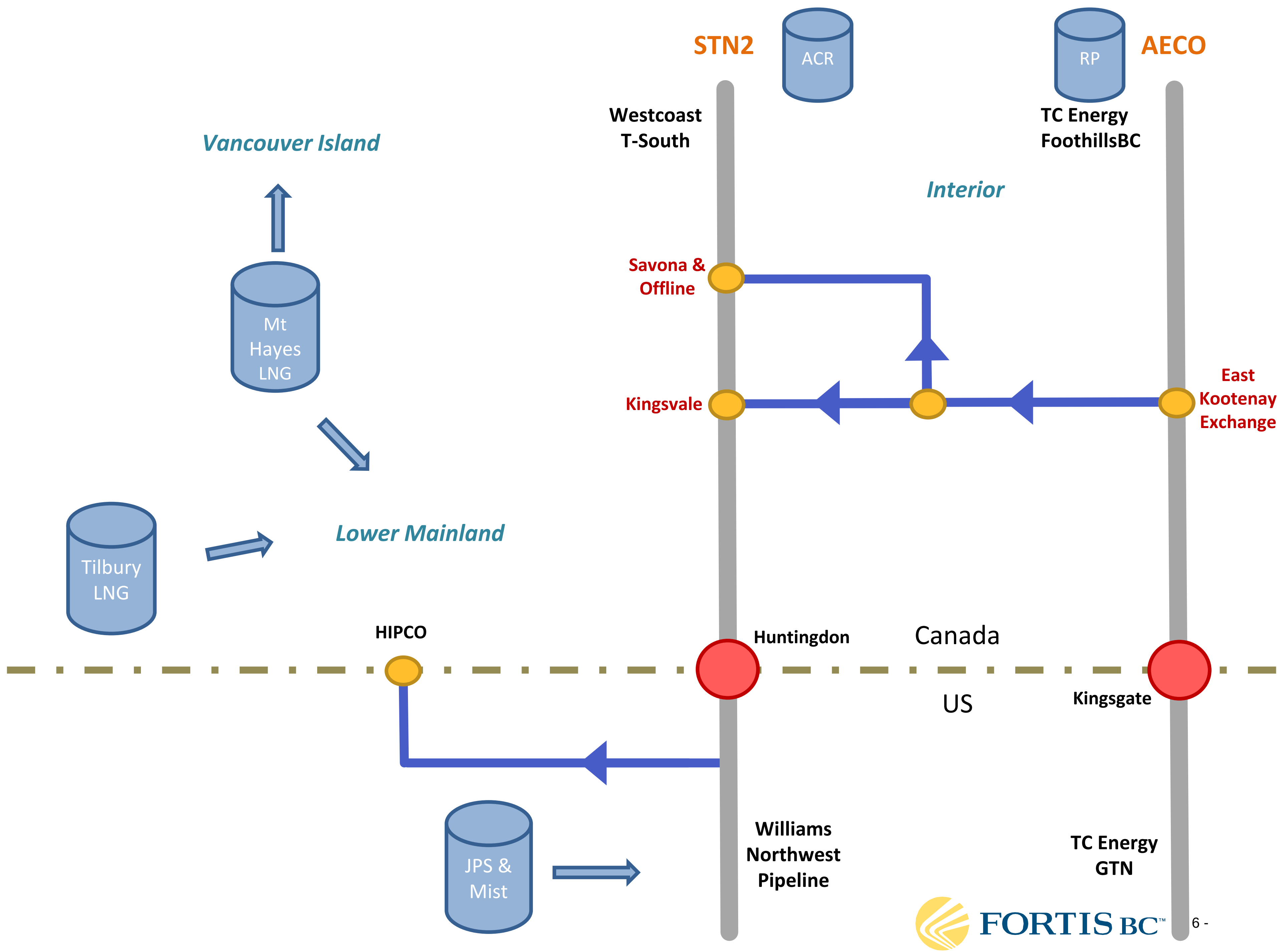
Changing Market Conditions

Annual Contracting Plan Costs (CCRA & MCRA Gross)

Baseload Supply (CCRA)		
	Daily Volume (MMcf/day)	Total (Bcf)
Station 2	272	99.3
AECO	91	33.2
Seasonal Supply (MCRA)		
	Daily Volume (MMcf/day)	Total (Bcf)
Station 2	86	12.9
AECO	33	2.9
Pipeline Capacity (MCRA)		
	Daily Volume (MMcf/day)	Total (Bcf)
Westcoast - T-South	745	247
Westcoast - T-North	156	57
TC Energy (NGTL)	164	60
TC Energy (Foothills)	161	50
Northwest Pipe	107	7
Storage (MCRA)		
	Daily Volume (MMcf/day)	Total (Bcf)
Aitken Creek	149	22.5
Rockpoint	29	1.8
Jackson Prairie	96	2.5
Mist	105	2.7
Mt Hayes	144	1.4
Tilbury	144	0.6



	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021
CCRA Costs	$191.4	$255.9	$195.0	$209.2	$302.0	$457.6
MCRA - Gross	$257.9	$264.9	$257.1	$503.9	$308.5	$326.6



STN2
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Kingsvale
East Kootenay Exchange
Tilbury LNG
Lower Mainland
HIPCO
Huntingdon
Canada
US
Kingsgate
JPS & Mist
Williams Northwest Pipeline
TC Energy GTN

Baseload Supply (Commodity)

- Winter (Nov-Mar)
  - Meet core load
  - Maintain deliverability of storage inventories
  - Sell commodity at highest value market centre
  - Tilbury LNG liquefaction run(s)

- Summer (Apr-Oct)
  - Meet core load
  - Storage facility INJ for refill
    - Aitken Creek, Rockpoint, JPS, Mist
    - Winter / Summer price differential
  - Sell commodity at highest value market centre
  - Mt. Hayes LNG liquefaction run(s)
  - Tilbury LNG liquefaction run(s)

Transportation

- Winter (Nov-Mar)
  - Meet core load
  - Maintain deliverability of storage inventories
  - Daily buy / sell to mitigate open transportation capacity
  - Tilbury LNG liquefaction run(s)

- Summer (Apr-Oct)
  - Meet core load
  - Storage facility INJ for refill
    - Aitken Creek, Rockpoint, JPS, Mist
  - Daily/Monthly/Seasonal buy / sell to mitigate open transportation capacity
  - Mt. Hayes LNG liquefaction run(s)
  - Tilbury LNG liquefaction run(s)

Storage

- Winter (Nov-Mar)
  - Aitken Creek and Rockpoint – seasonal supply
  - LNG, JPS, Mist – peaking supply
  - Maintain deliverability of storage inventories
  - Daily Park / Loan opportunities
  - Tilbury LNG liquefaction run(s)

- Summer (Apr-Oct)
  - Storage facility INJ for refill
    - Aitken Creek, Rockpoint, JPS, Mist
    - Winter / Summer price differential
  - Daily/Monthly Park / Loan opportunities
  - Mt. Hayes LNG liquefaction run(s)
  - Tilbury LNG liquefaction run(s)

North American Gas Supply Incentive Programs

(Atrium Economics)

ATRIUM ECONOMICS
CENTERED ON ENERGY

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Table of Contents

ATRIUM ECONOMICS
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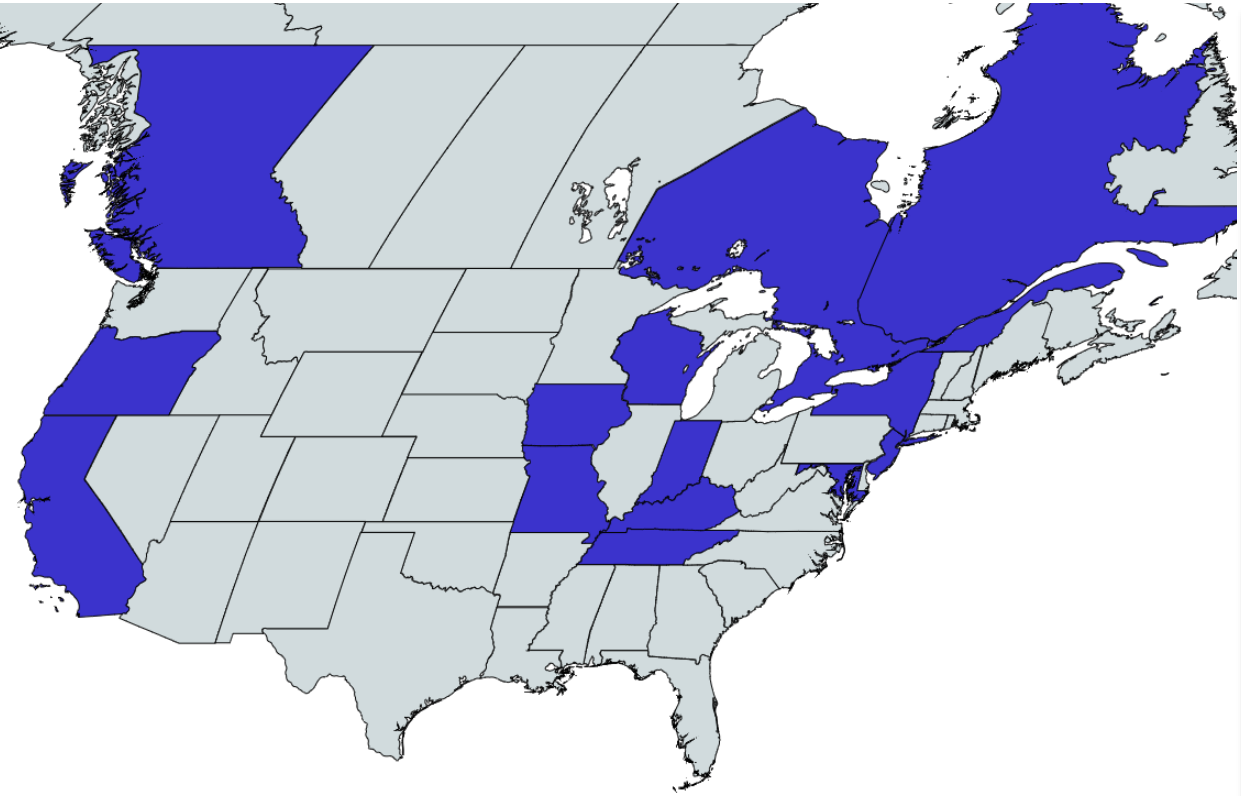
North American Gas Supply Incentive Programs



B.C.: FortisBC
Ontario: Enbridge/Union Gas
Quebec: Gaz Métro
California: PG&E, SoCal Gas, SDG&E
Indiana: NIPSCO
Iowa: MidAmerican
Kentucky: Atmos, NiSource, LG&E
Maryland: BG&E, NiSource
Missouri: Spire
New Jersey: NJ Natural Gas
Oregon: Cascade, NW Natural
Tennessee: Atmos, Chattanooga Gas, Piedmont
Wisconsin: We Energies

ATRIUM ECONOMICS
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Gas Supply Incentive Models around North America

Typical Components Include:

Review Period for Cost Reconciliation - Frequency of program regulatory filings to review performance

- Benchmarked models range between monthly and annual

Tolerance Band for Costs/Savings – How much commodity gas costs rise or fall before revenue and cost sharing occurs

- Benchmarked models range between a low of 97% and a high of 102%

Gas Commodity Benchmark – A benchmark for evaluating program performance

- Benchmarked models use a variety of price indices for measuring performance including: Platts Daily, Natural Gas Intelligence, Inside FERC Gas Market Report, NYMEX Futures, and Natural Gas Week

Revenue Sharing Mechanism – An allocation of savings between customers and the utility

- Benchmarked models range from utility/customer splits of 0/100 to 50/50 and vary depending on tiers within the model and overall performance

ATRIUM ECONOMICS
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Gas Supply Incentive Models around North America

Models Differ Across Jurisdictions Due To:

- Regulatory regimes, program objectives/risk tolerance, underlying assets, geographical scale, upstream pipeline resources, whether they have storage (on system, leased, access to LNG)

Models Work Well When:

- Customer and company incentives are aligned
- Model is transparent and fair
- Underutilized assets are optimized, generating mitigation revenue and reducing the cost of gas

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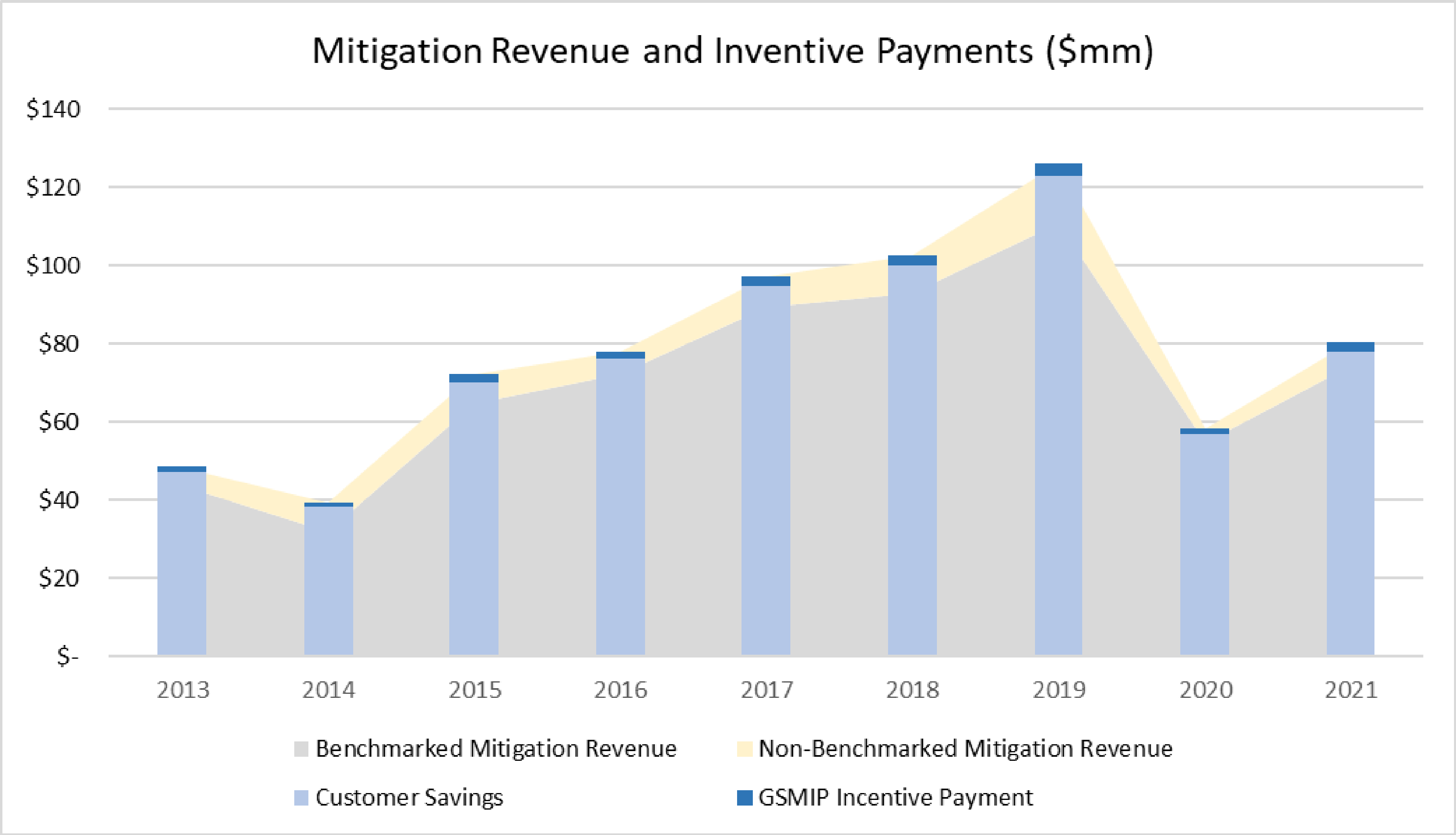
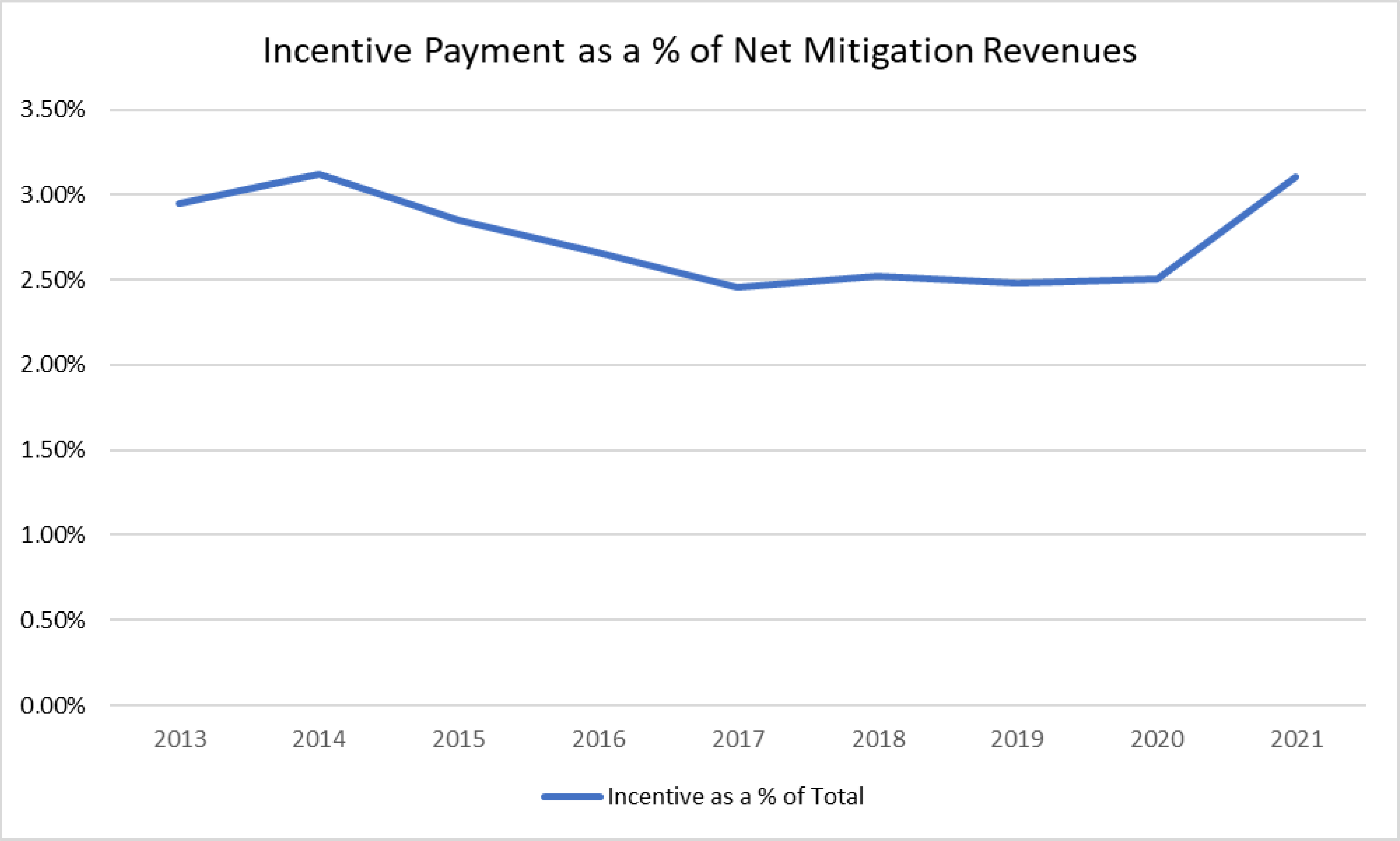
Example: California Incentive Model

Utilities	Mechanism	Sharing	Specifications	Period
SoCal Gas (1995) PG&E (1997) SDG&E (2009)	Portfolio costs include commodity, transportation, and storage. Capacity Release (CR) and Off-System Sales (OSS) are credited to portfolio costs while only 80% of hedging gains/losses are credited to portfolio costs.	Gas Supply Portfolio: 50/50 (utility/customer) sharing over 102% of benchmark (costs); 25/75 sharing under 99% of benchmark (savings); Ratepayers responsible for variances within tolerance band (99%-102%). Portfolio costs include commodity, transportation, and storage. CR and OSS are credited to portfolio costs while only 80% of hedging gains/losses are credited to portfolio costs. Reward is capped at lower of $6 million or 1.5% of actual gas commodity costs	Combination of monthly gas price indices published by Natural Gas Intelligence, Inside FERC Gas Market Report, NYMEX Futures	Monthly Reports, Annual Cost Adjustment

GSMIP Historical Performance



GSMIP Historical Performance



Guiding Principles

Guiding Principles

- BCUC Order G-26-11

- The incentive program must demonstratively deliver value to ratepayers and reward ongoing innovation and true value added over and above what is reasonably expected in the normal stewardship of FEI's business.

- Execution of the incentive program must not put the prudently planned gas supply portfolio at risk nor promote a departure from prudent gas supply management for core customer's requirements.

BCUC Guiding Principles

- The incentive plan should fairly and appropriately align ratepayer and shareholder interests.

- There should not be an upper limit on FEI's potential to earn an incentive but there must be a test of reasonableness and the amount earned must be justified.

- The incentive program should apply to all mitigation activities that use commodity supply resources that represent a cost and risk to ratepayers (i.e. gas supply, storage, transportation).

BCUC Guiding Principles

- The incentive plan should reward FEI for its innovation rather than for opportunities that arise from events that impact the industry in general (e.g. hurricanes).

- Any incremental administrative costs must be considered and charged against the benefits of the plan.

- The incentive payment should be the smallest amount required to obtain the desired core customer benefit.

GSMIP Term Sheet

(included)

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GSMIP Term Sheet

- Aligns with the Guiding Principles
- Developed with Stakeholders
- Categories include:
  - Benchmarked Activities
  - Non-benchmarked Activities
    - Includes Storage and Forward Commodity Resale Activities
  - New Activities

GSMIP Term Sheet

- Market Concentration Adjustment
- Capacity Factor Adjustment
- Market Performance Factor
- Fixed Adjustment
- Winter Report
- Year-end Report*

*Total Eligible Margin is reviewed by Internal Audit to provide reasonable assurance that the FEI share of the GSMIP Total Eligible Margin has been determined in accordance with the Term Sheet

Mitigation Activities

Commodity Resale

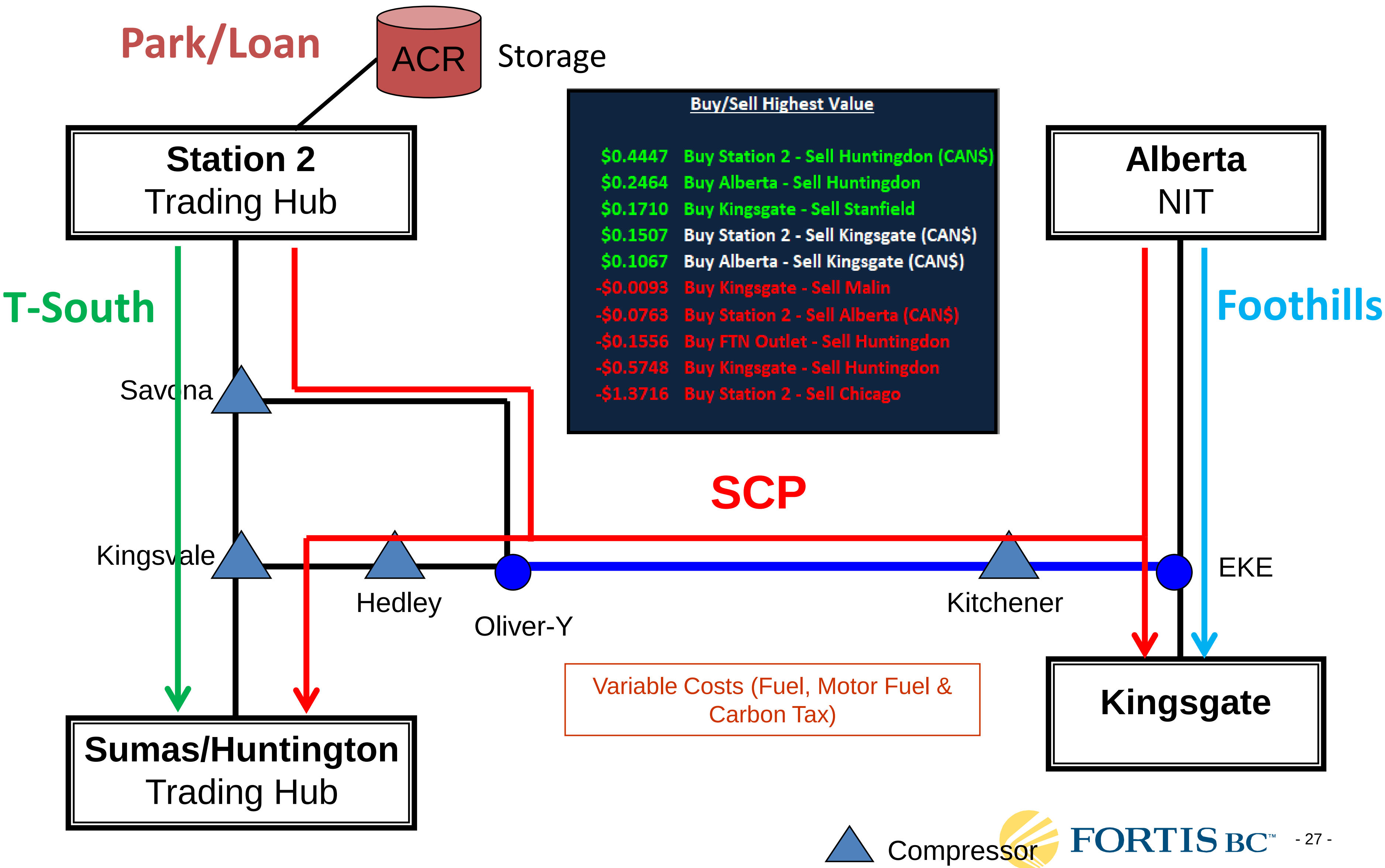
- FEI looks to sell excess commodity at highest value market centre
- Station2, AECO, Huntingdon, Kingsgate
- Benchmarked against Platts Gas Daily
- Deemed purchase at Station2 or AECO

Mitigation Activities

Transportation

- FEI utilizes open transportation capacity on upstream pipelines to capture price differentials between supply hubs and market centres
- Supply hubs @ Station2 and AECO
- Market centres @ Huntingdon and Kingsgate
- Could also include points along each path on WEI T-North, WEI T-South, TC Energy FHBC and FEI SCP
- Benchmarked against Platts Gas Daily

Mitigation Activities



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Daily Prices

February 08, 2022

FX Rate **$1.2700**

Conversion3.02

Fort Nelson Outlet	$3.604	CDN$/GJ	$2.99
Station 2	$3.900	CDN$/GJ	$3.24
Alberta @ NIT	$4.105	CDN$/GJ	$3.41
Huntingdon	$3.790	US$/MMBtu	$4.56
Kingsgate	$3.550	US$/MMBtu	$4.27
Stanfield	$3.850	US$/MMBtu	
Malin	$3.920	US$/MMBtu	
Rockies	$3.950	US$/MMBtu	

Tolls, Fuel, and Variable Costs

Can$ per GJ	Demand Tolls			Fuel	Variable Costs	
	1 Yr Firm Toll	AOS	IT	%	Carbon Tax	MFT
T-South LML	$0.64	$0.70	$0.70	3.70%	$0.06	$0.02
T-North	$0.28	$0.37	$0.37	0.40%	$0.01	$0.00
T-South KV to LML	$0.28	$0.37	$0.37	0.70%	$0.03	$0.01
T-South IND	$0.36	$0.47	$0.47	2.08%	$0.03	$0.01
Foothills	$0.06			1.50%		
SCP				1.20%	$0.01	$0.02
Alliance	~~$1.50~~			~~4.08%~~		
				0.0729%		
	$0.36			3.00%	$0.02	$0.01

Buy Station 2 - Sell Huntingdon

		CDN$/GJ		US$/MMBtu
Station 2		$3.900		$3.240
TS LML Firm Demand	$0.000		☐ + Toll	
Fuel (T-South)	$0.144			
MFT & Carbon Tax	$0.073			
Delivered @ Hunt		$4.117		$3.421
Positive Value		**$0.445**	**CDN**	**$0.369**
RUN AOS:	TS LM	$0.699		
Delivered @ Hunt		$4.816		$4.001
No Value on AOS	**$0.25**			**-$0.21**
RUN IT:	TS LML	$0.699		
Delivered @ Hunt		$4.816		$4.001
No Value on IT	**$0.25**			**-$0.21**

Benchmarked Activities

S&P Global
Platts

GAS DAILY

Tuesday, February 8, 2022

FINAL DAILY PRICE SURVEY - PLATTS LOCATIONS ($/MMBtu)

NATIONAL AVERAGE PRICE: 4.420
Trade date: 08-Feb
Flow date(s): 09-Feb

Powered by ICE

		Midpoint	+/-	Absolute	Common	Vol.	Deals
Rockies/Northwest							
Cheyenne Hub	IGBCO21	3.920	-0.015	3.900-3.960	3.905-3.935	543	100
CIG, Rockies	IGBCK21	3.905	+0.015	3.890-3.940	3.895-3.920	75	22
GTN, Kingsgate	IGBCY21	3.565	-0.040	3.510-3.650	3.530-3.600	87	10
Kern River, Opal	IGBCL21	3.940	-0.035	3.925-3.960	3.930-3.950	476	108
NW, Can. bdr. (Sumas)	IGBCT21	3.800	+0.010	3.780-3.850	3.785-3.820	81	22
NW, Rocky Mtn. Pool	IGBRW21	3.915	+0.045	3.900-3.920	3.910-3.920	25	4
NW, s. of Green River	IGBCQ21	3.915	+0.045	3.900-3.920	3.910-3.920	25	4
NW, Wyo. Pool	IGBCP21	3.905	-0.040	3.880-3.960	3.885-3.925	367	64
PG&E, Malin	IGBDO21	3.925	+0.065	3.900-3.975	3.905-3.945	190	54
Questar, Rockies	IGBCN21	3.900	-0.020	3.900-3.900	3.900-3.900	4	2
Stanfield, Ore.	IGBCM21	3.885	+0.075	3.840-3.950	3.860-3.915	96	24
TCPL Alberta, AECO-C*	IGBCU21	4.100	-0.055	4.050-4.130	4.080-4.120	451	74
Westcoast, station 2*	IGBCZ21	4.040	-0.045	4.000-4.050	4.030-4.050	38	9
White River Hub	IGBGL21	3.925	+0.030	3.910-3.960	3.915-3.940	463	76
Rockies/Northwest regional average	IGIAA00	3.875					

Mitigation Activities

Capacity Release

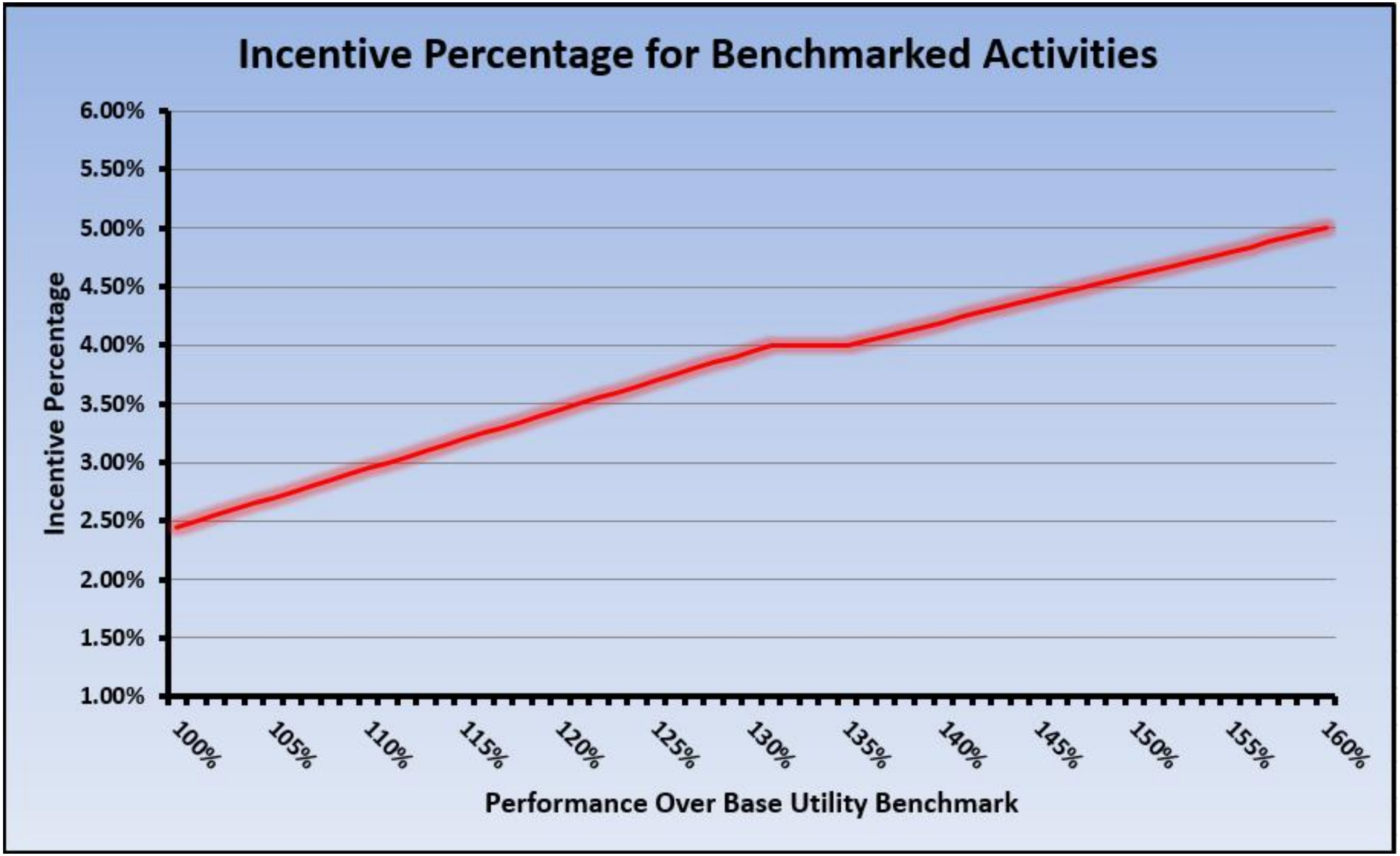
- For the Apr-Oct (summer) timeframe, FEI undertakes transactions with counterparties to release firm service at market rates
- WEI T-South, TC Energy NOVA ABC, FEI SCP
- Similar to daily transportation mitigation, FEI will use forward price curves for supply hubs, market centres and variable costs to determine the assignment value
- Benchmarked against OneExchange forward prices

Mitigation Activities

Park / Loan

- Typically transacted at Stn2, AECO or Huntingdon
- Leverage storage assets and the INJ / WD profiles in order to capture price differentials
- Daily / Monthly / Seasonal

Market Performance Factor



GSMIP Model

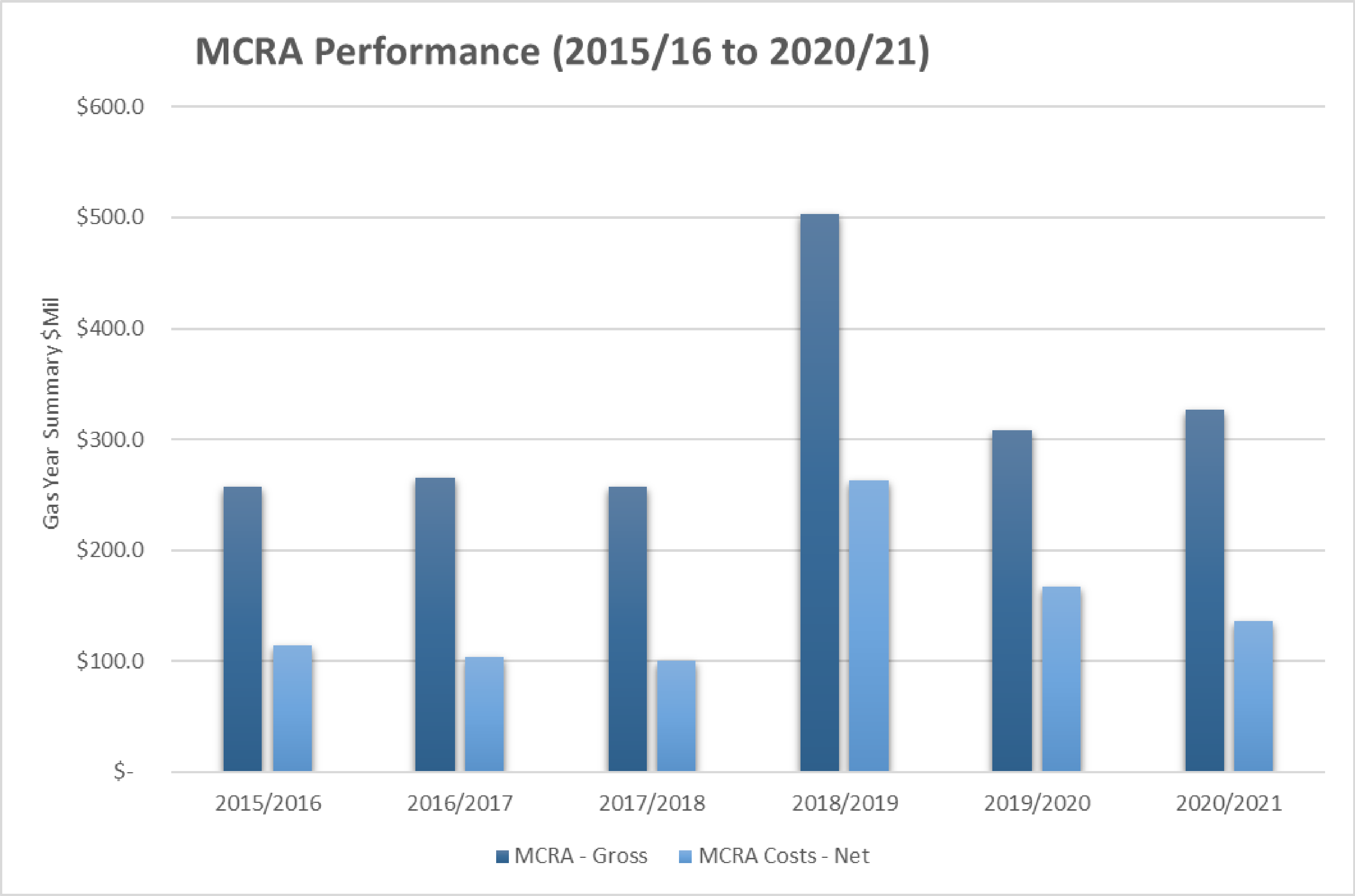
GSMIP Prior Performance

(2015/16 thru 2020/21)

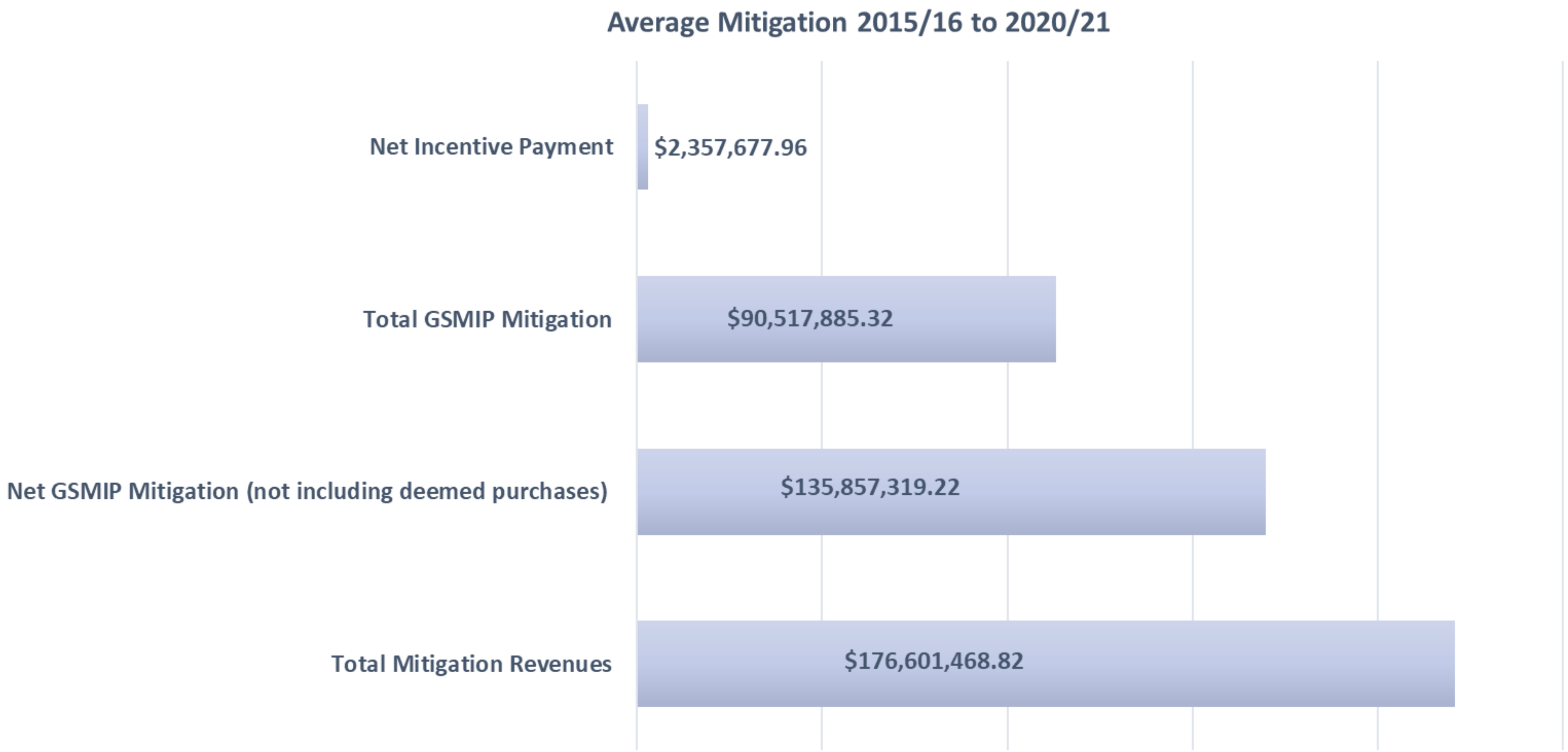
Mitigation Activity	Total for 2020/21		Total for 2019/20		Total for 2018/19		Total for 2017/18		Total for 2016/17		Total for 2015/16	
	Mitigation Revenue *(in Millions)*	Incentive Earned	Mitigation Revenue *(in Millions)*	Incentive Earned	Mitigation Revenue *(in Millions)*	Incentive Earned	Mitigation Revenue *(in Millions)*	Incentive Earned	Net Mitigation Revenue *(in Millions)*	Incentive Earned	Net Mitigation Revenue *(in Millions)*	Incentive Earned
BENCHMARKED ACTIVITIES	**$ 74.304**	**3.30%**	**$ 54.813**	**2.77%**	**$ 110.804**	**2.44%**	**$ 93.096**	**2.59%**	**$ 89.419**	**2.54%**	**$ 72.288**	**2.78%**
NON-BENCHMARKED ACTIVITIES	**$ 6.279**	**4.00%**	**$ 3.570**	**4.00%**	**$ 15.415**	**4.00%**	**$ 9.503**	**4.00%**	**$ 7.757**	**4.00%**	**$ 5.860**	**4.00%**
NEW ACTIVITIES	**$ -**	**12.00%**	**$ -**	**12.00%**	**$ -**	**12.00%**	**$ -**	**12.00%**	**$ -**	**12.00%**	**$ -**	**12.00%**
Total Mitigation Revenue	**$80.583**		**$58.383**		**$126.219**		**$102.599**		**$97.176**		**$78.148**	
Gross Incentive	**$2.703**		**$1.661**		**$3.326**		**$2.790**		**$2.584**		**$2.247**	
Less Fixed Deduction	**$0.200**		**$0.200**		**$0.200**		**$0.200**		**$0.200**		**$0.165**	
GSMIP Incentive Payment	**$2.503**	**3.11%**	**$1.461**	**2.50%**	**$3.126**	**2.48%**	**$2.590**	**2.52%**	**$2.384**	**2.45%**	**$2.082**	**2.66%**
Total Mitigation Revenue*	**$157.680**	**1.59%**	**$118.049**	**1.24%**	**$151.206**	**2.07%**	**$131.239**	**1.97%**	**$134.201**	**1.78%**	**$122.372**	**1.70%**
Customer Savings (GSMIP)	**$78.080**	**96.89%**	**$56.922**	**97.50%**	**$123.093**	**97.52%**	**$100.009**	**97.48%**	**$94.792**	**97.55%**	**$76.066**	**97.34%**
Customer Savings (GSMIP)*	**$155.177**	**98.41%**	**$116.588**	**98.76%**	**$148.080**	**97.93%**	**$128.649**	**98.03%**	**$131.817**	**98.22%**	**$120.290**	**98.30%**

*before deemed purchases on commodity resale

Mitigation Activities



Mitigation Activities



Moving GSMIP Forward

Meeting the Objectives

- Supply security – core load requirement
- Alignment of interests – Customer, Stakeholders, FEI
- Fair and reasonable incentives
- Simplicity – model can be maintained
- Fair and reasonable performance targets
- Transparency – benchmarking, prudent management
- Robustness – model works under different conditions

GSMIP Opportunities

Examples

- Monthly benchmarked for forward commodity resale
  - Platts Inside FERC (IF)

- Revise Forward Capacity Release benchmark provider
  - OneExchange variability from the market

- Stakeholder feedback

Next Steps…

GSMIP Workshop #3 (Tuesday, March 29/22)

Meeting Summary		
Total Number of Participants		13
Meeting Title	FEI GSMIP Review - Workshop #3	
Meeting Start Time	3/29/2022, 9:59:50 AM	
Meeting End Time	3/29/2022, 11:11:11 AM	
Meeting Id	1049c2e7-a74e-4f5e-a08f-76379e1b573a	

Full Name	Join Time	Leave Time	Duration
Hill, Shawn	3/29/2022, 9:59:50 AM	3/29/2022	1h 11m
Gill, Manpreet	3/29/2022, 9:59:54 AM	3/29/2022	1h 11m
Yasinchuk, Matt	3/29/2022, 10:00:00 AM	3/29/2022	1h 11m
Peter Helland	3/29/2022, 10:00:04 AM	3/29/2022	1h 11m
Ron Amen	3/29/2022, 10:00:06 AM	3/29/2022	1h 11m
Engels, Greg	3/29/2022, 10:00:07 AM	3/29/2022	1h 10m
O'Neal, Joshua	3/29/2022, 10:00:10 AM	3/29/2022	1h 10m
Vincent, Cory	3/29/2022, 10:00:27 AM	3/29/2022	1h 10m
John Taylor	3/29/2022, 10:00:27 AM	3/29/2022	1h 10m
Chan, King-yi	3/29/2022, 10:00:33 AM	3/29/2022	1h 10m
Tom Hackney (Guest)	3/29/2022, 10:00:56 AM	3/29/2022	1h 9m
Bevacqua, Ilva	3/29/2022, 10:02:51 AM	3/29/2022	1h 7m
David Craig	3/29/2022, 10:16:13 AM	3/29/2022	54m 58s

Email	Role	Participant ID (UPN)
Shawn.Hill@fortisbc.com	Presenter	Shawn.Hill@fortisbc.com
Manpreet.Gill@fortisbc.com	Presenter	Manpreet.Gill@fortisbc.com
Matt.Yasinchuk@fortisbc.com	Organizer	Matt.Yasinchuk@fortisbc.com
phelland@midgard-consulting.com	Attendee	phelland@midgard-consulting.com
ramen@atriumecon.com	Attendee	ramen@atriumecon.com
Greg.Engels@bcuc.com	Attendee	Greg.Engels@bcuc.com
Joshua.ONeal@bcuc.com	Attendee	Joshua.ONeal@bcuc.com
Cory.Vincent@bcuc.com	Attendee	cory.vincent@bcuc.com
jtaylor@atriumecon.com	Attendee	jtaylor@atriumecon.com
Kingyi.Chan@bcuc.com	Attendee	kingyi.chan@bcuc.com
	Attendee	
Ilva.Bevacqua@fortisbc.com	Presenter	Ilva.Bevacqua@fortisbc.com
davidc@equifaira.com	Attendee	davidc@equifaira.com

Gas Supply Mitigation Incentive Plan (GSMIP) Workshop #3

Moving GSMIP Forward

March 29, 2022

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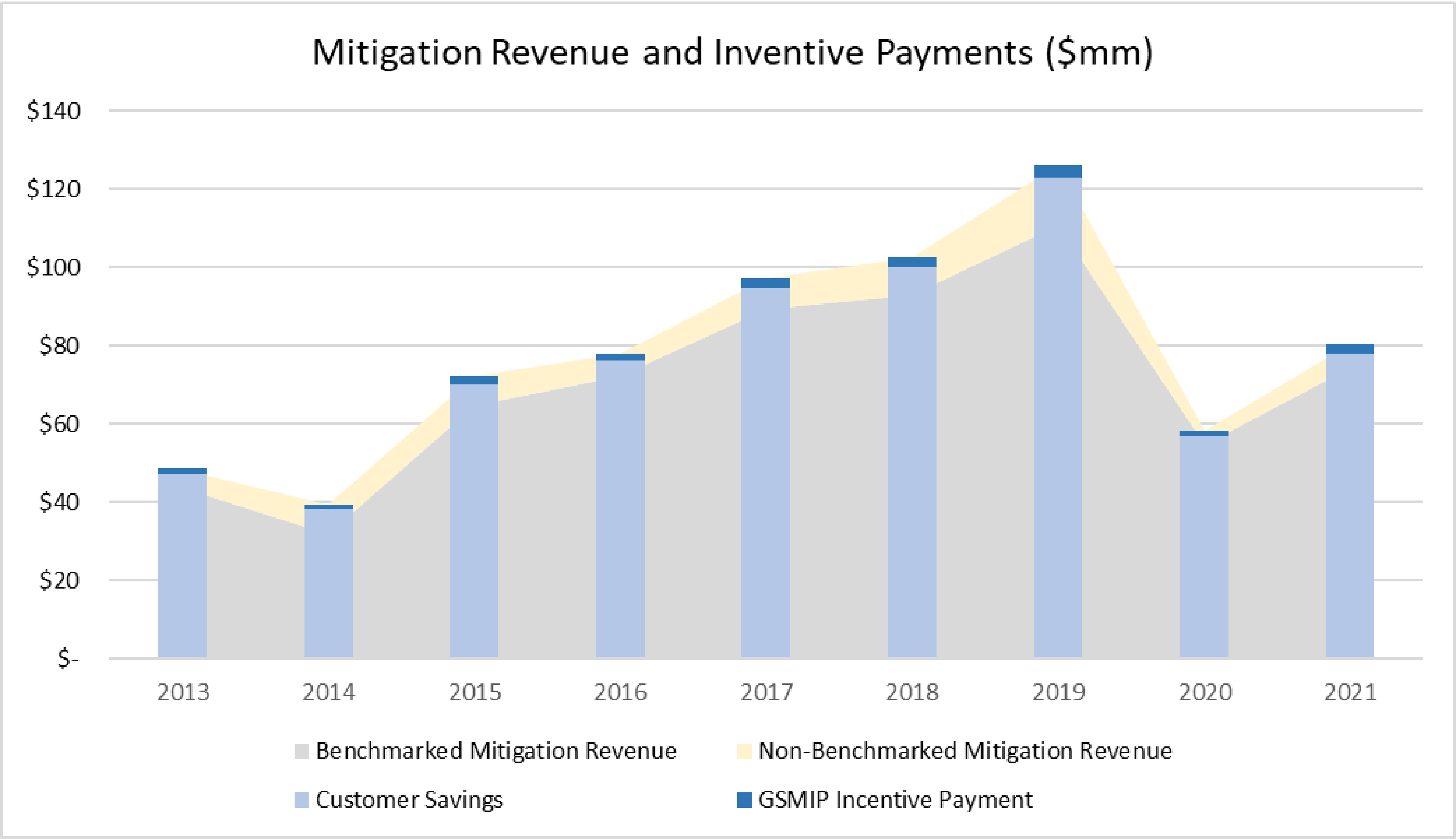
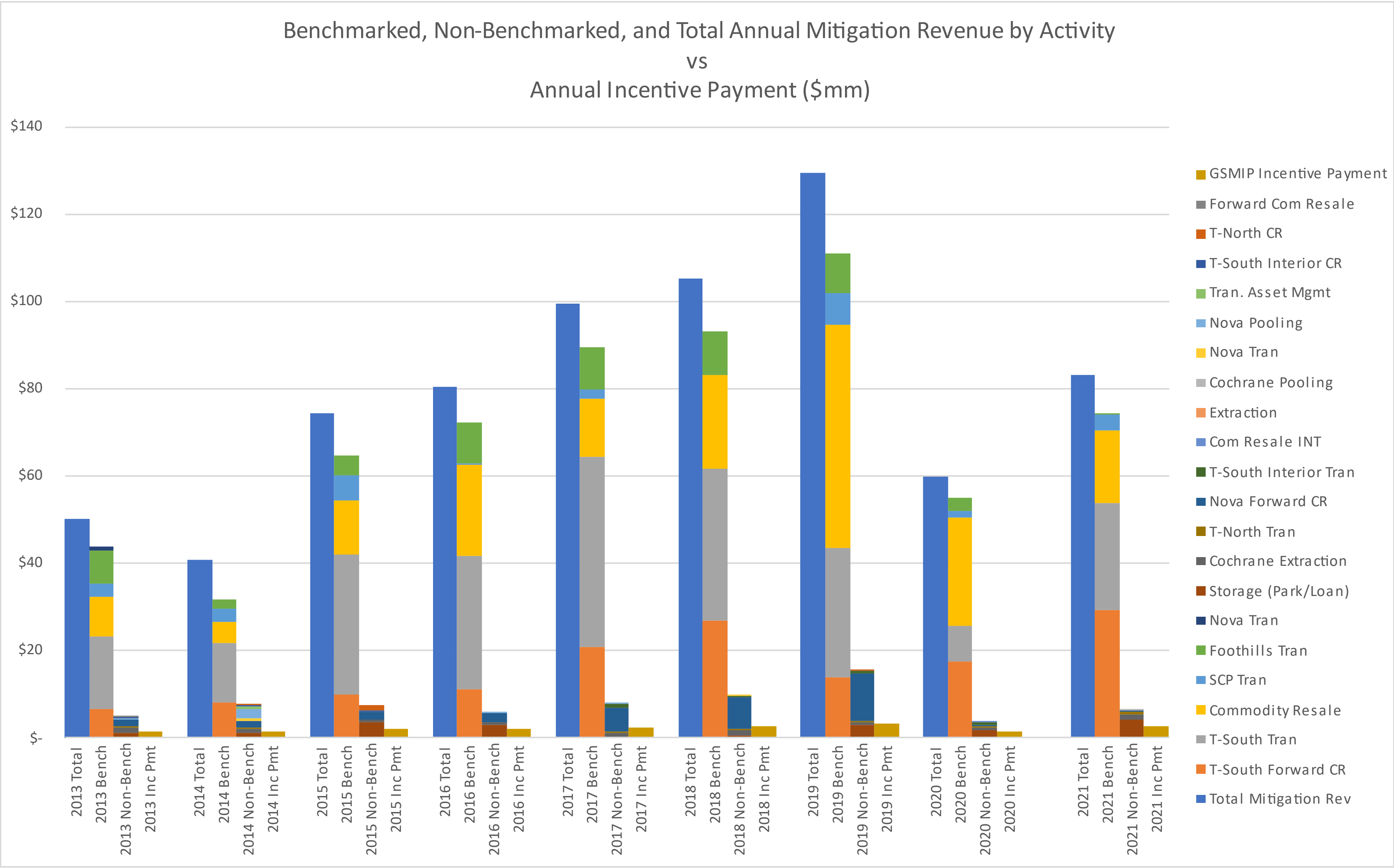
Agenda

- Review Follow-on Items from Workshop #2
- Next Steps
- Stakeholder Feedback

GSMIP Historical Performance


Mitigation Revenue and Inventive Payments ($mm)
$140
$120
$100
$80
$60
$40
$20
$-
2013
2014
2015
2016
2017
2018
2019
2020
2021
Benchmarked Mitigation Revenue
Non-Benchmarked Mitigation Revenue
Customer Savings
GSMIP Incentive Payment



Benchmarked, Non-Benchmarked, and Total Annual Mitigation Revenue by Activity
vs
Annual Incentive Payment ($mm)
$140
$120
$100
$80
$60
$40
$20
$-
2013 Total
2013 Bench
2013 Non-Bench
2013 Inc Pmt
2014 Total
2014 Bench
2014 Non-Bench
2014 Inc Pmt
2015 Total
2015 Bench
2015 Non-Bench
2015 Inc Pmt
2016 Total
2016 Bench
2016 Non-Bench
2016 Inc Pmt
2017 Total
2017 Bench
2017 Non-Bench
2017 Inc Pmt
2018 Total
2018 Bench
2018 Non-Bench
2018 Inc Pmt
2019 Total
2019 Bench
2019 Non-Bench
2019 Inc Pmt
2020 Total
2020 Bench
2020 Non-Bench
2020 Inc Pmt
2021 Total
2021 Bench
2021 Non-Bench
2021 Inc Pmt
GSMIP Incentive Payment
Forward Com Resale
T-North CR
T-South Interior CR
Tran. Asset Mgmt
Nova Pooling
Nova Tran
Cochrane Pooling
Extraction
Com Resale INT
T-South Interior Tran
Nova Forward CR
T-North Tran
Cochrane Extraction
Storage (Park/Loan)
Nova Tran
Foothills Tran
SCP Tran
Commodity Resale
T-South Tran
T-South Forward CR
Total Mitigation Rev

Market Concentration Adjustment

S&P Global
Platts

GAS DAILY

Tuesday, February 8, 2022

FINAL DAILY PRICE SURVEY - PLATTS LOCATIONS ($/MMBtu)

NATIONAL AVERAGE PRICE: 4.670
Trade date: 11-Mar
Flow date(s): 12-Mar—14

Powered by ICE

		Midpoint	+/-	Absolute	Common	Vol.	Deals
Rockies/Northwest							
Cheyenne Hub	IGBCO21	4.315	-0.080	4.265-4.340	4.295-4.335	402	70
CIG, Rockies	IGBCK21	4.295	-0.050	4.280-4.330	4.285-4.310	64	10
GTN, Kingsgate	IGBCY21	4.060	+0.120	4.040-4.080	4.050-4.070	19	4
Kern River, Opal	IGBCL21	4.295	-0.075	4.250-4.350	4.270-4.320	414	96
NW, Can. bdr. (Sumas)	IGBCT21	3.915	-0.130	3.850-4.050	3.865-3.965	267	60
NW, Rocky Mtn. Pool	IGBRW21	4.270	-0.040	4.235-4.300	4.255-4.285	51	16
NW, s. of Green River	IGBCQ21	4.270	-0.040	4.235-4.300	4.255-4.285	51	16
NW, Wyo. Pool	IGBCP21	4.290	-0.060	4.240-4.340	4.265-4.315	210	38
PG&E, Malin	IGBDO21	4.280	-0.010	4.250-4.320	4.265-4.300	208	60
Questar, Rockies	IGBCN21	4.305	-0.050	4.300-4.310	4.305-4.310	28	6
Stanfield, Ore.	IGBCM21	4.145	-0.020	4.120-4.215	4.120-4.170	98	24
TCPL Alberta, AECO-C*	IGBCU21	4.670	-0.010	4.605-4.750	4.635-4.705	336	50
Westcoast, station 2*	IGBCZ21	4.540	-0.050	4.400-4.620	4.485-4.595	68	24
White River Hub	IGBGL21	4.320	-0.055	4.300-4.340	4.310-4.330	510	66
Rockies/Northwest regional average	IGIAA00	4.230					

- Represents the Fixed Price trades at market centre for Next Day
- Not all market participants are Platts reporters, therefore not all FP deals are reported
- FEI reports FP trades to Platts by 1:00 PM for trade / flow dates
- Platts publishes Gas Daily approximately 5:30 PM for trade / flow dates

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Fixed Price Deals

Example

- Trade Date – March 11, 2022
- Flow Dates – March 12-14, 2022

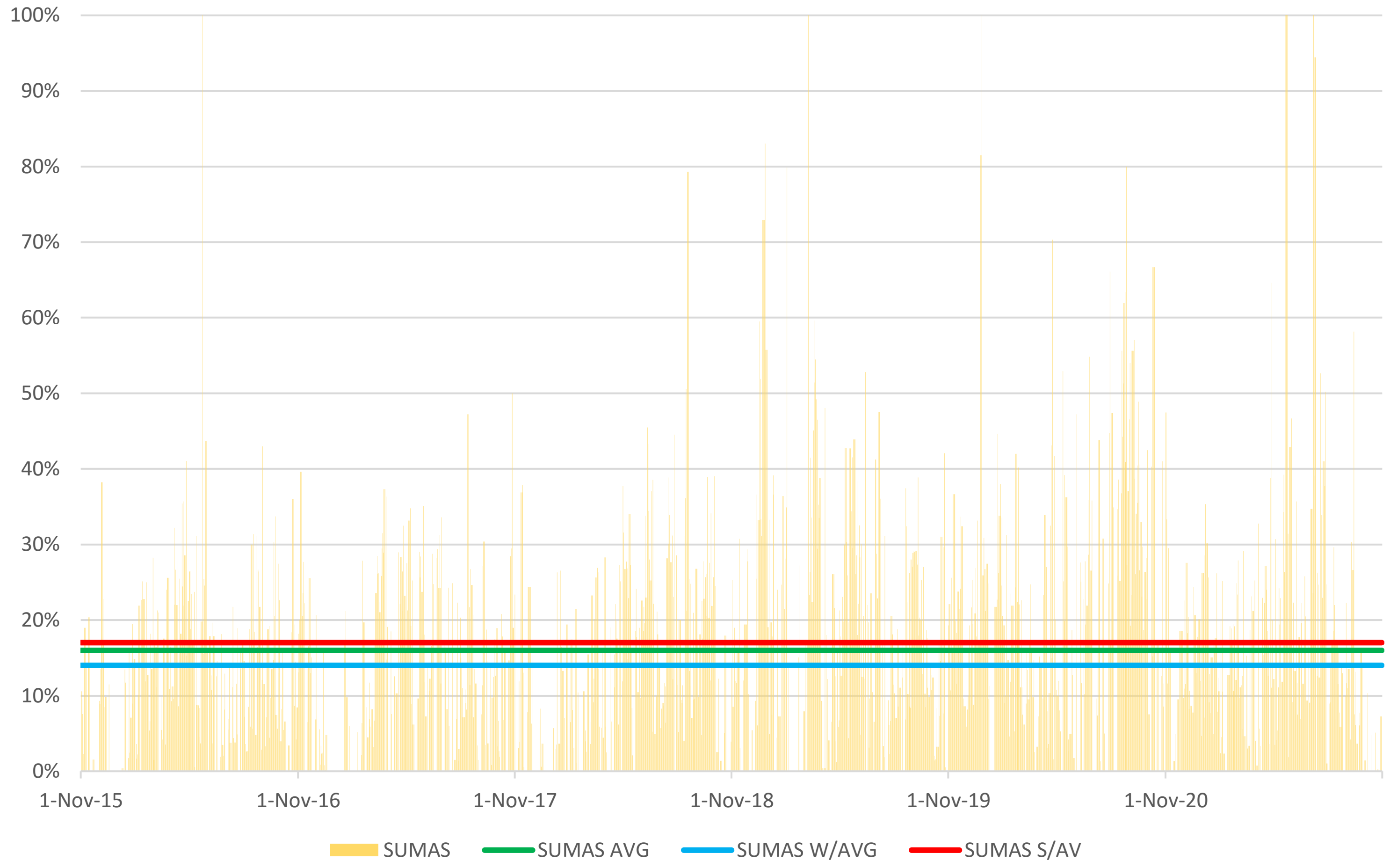
- Platts Gas Daily FP @ Sumas = 267,000 mmBtu

- FEI FP @ Sumas = 138,830 mmBtu (52%)

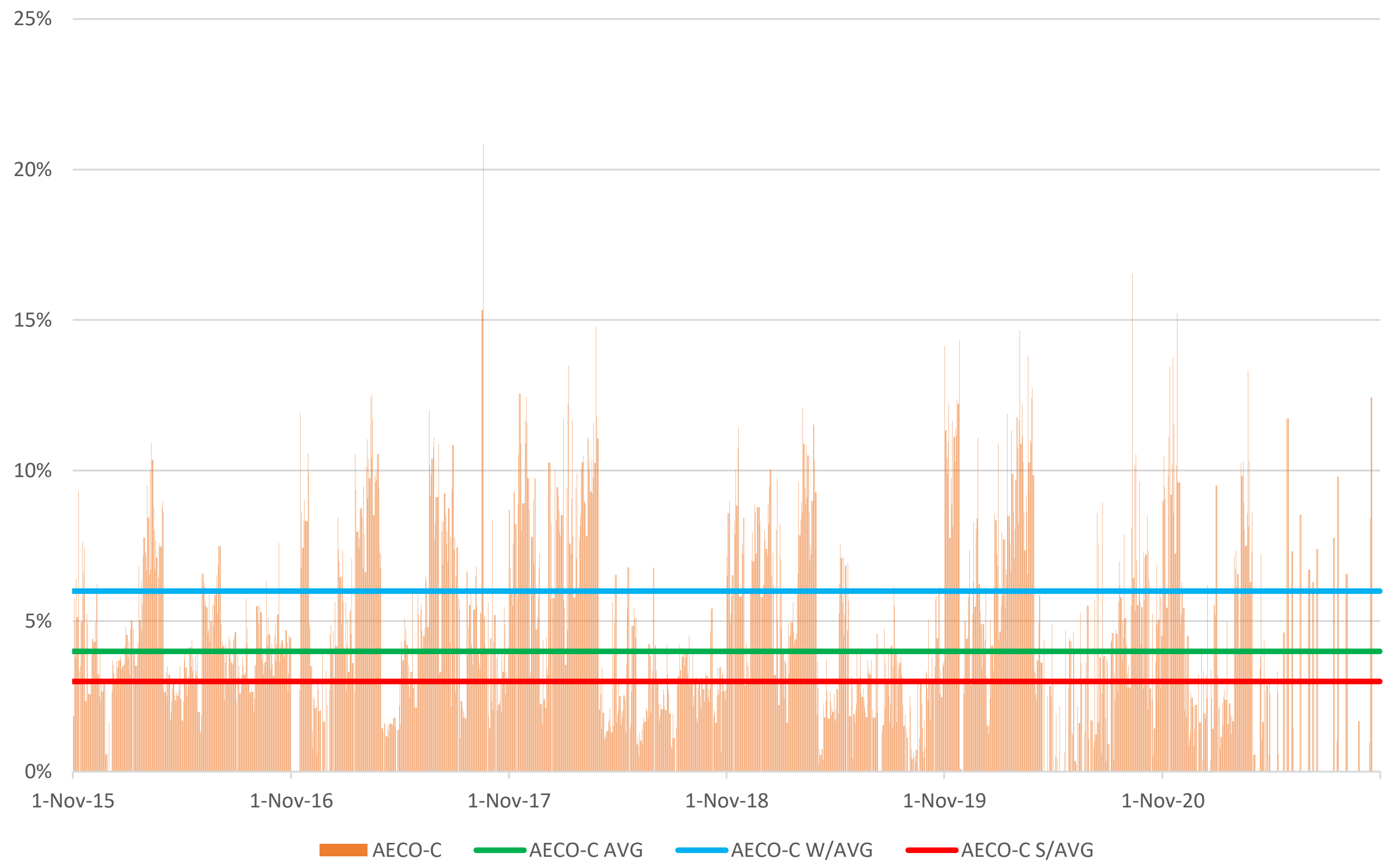
- FEI FP March 14 @ Sumas = 25,000 mmBtu (61%)

- FP trades after reporting deadline are not included in index

Fixed Price Volumes - Huntingdon



Fixed Price Volumes - AECO



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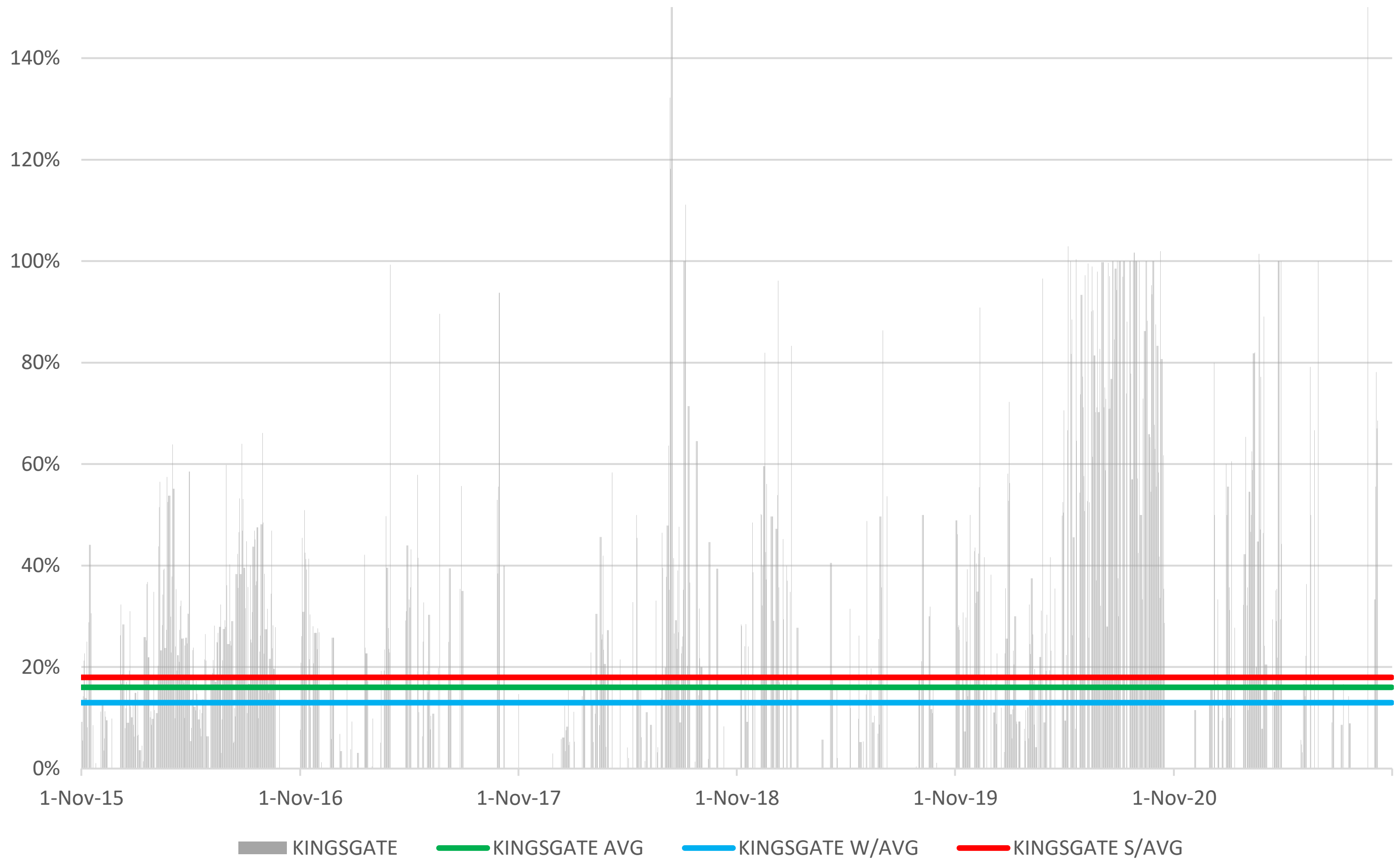
Fixed Price Volumes - Kingsgate



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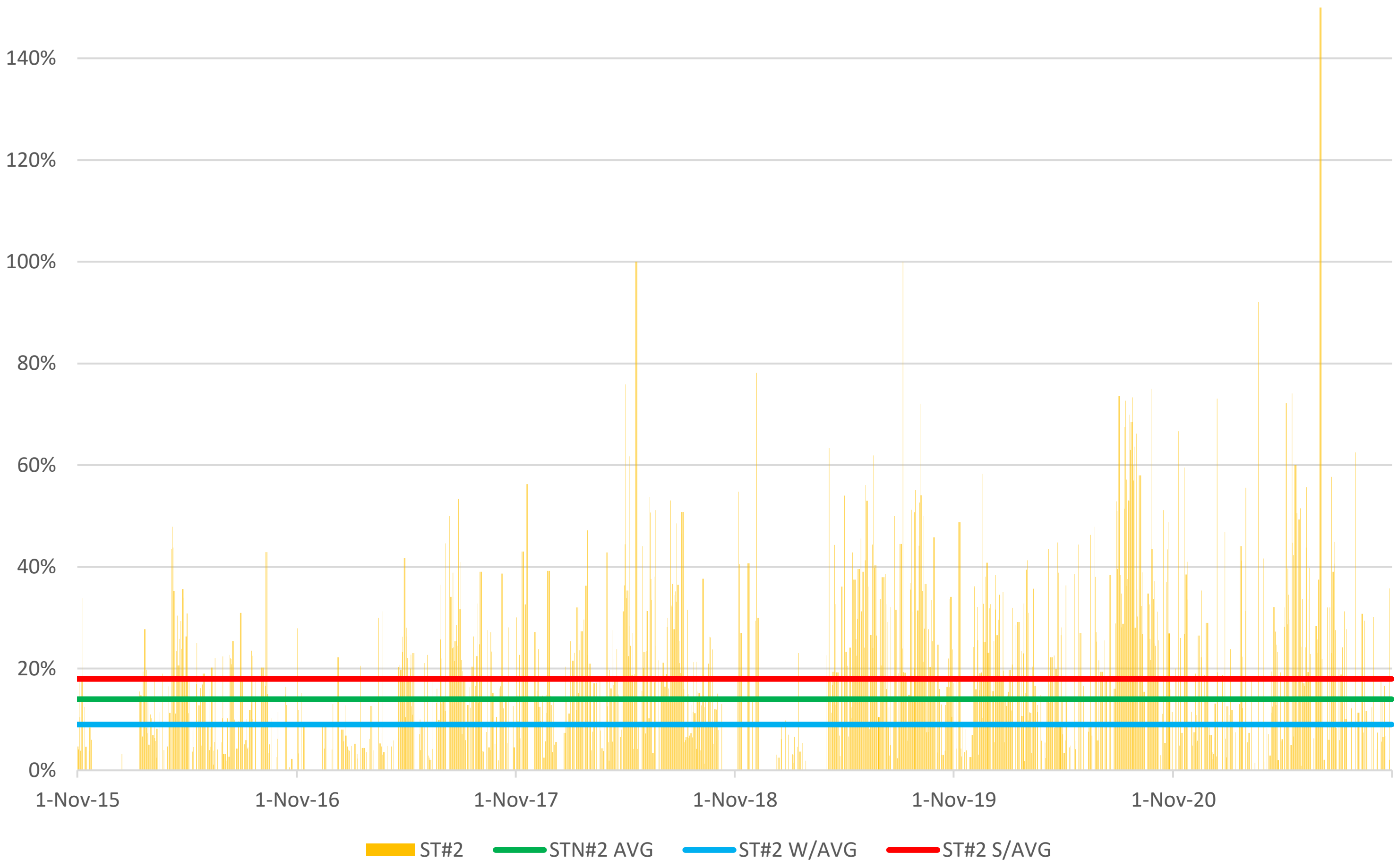
Fixed Price Volumes – Station2



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Deemed Purchases

Transportation Mitigation – FEI Total

Actual Sales Volume * Actual Sales Price

Minus

Actual Purchase Volume * Actual Purchase Price

Minus

Transportation Variable Charges

Equals

FEI Spot Transportation Mitigation Revenue

Transportation Mitigation – Base Benchmark

Actual Sales Volume * Platts Common Low

Minus

Actual Purchase Volume * Platts Common High

Minus

Transportation Variable Charges

Equals

Spot Transportation Mitigation Base Benchmark

Transportation Mitigation

Date	13-Apr-21

FEI Actual

Huntingdon Sale Volume (GJ)	76,146
Huntingdon Sale Price (CAD/GJ)	$ 3.07
FEI Total Hungtingdon (CAD)	$ 233,768.22

$ 36,733.22	FEI Actual Total

Station2 Purchase Volume (GJ)	78,500
Station2 Purchase Price (CAD/GJ)	$ 2.51
FEI Total Station2 (CAD)	$ 197,035.00

Market Total

Huntingdon Benchmark Price (CAD/GJ)	$ 3.046	Platts GD CL
Huntingdon Benchmark Volume (GJ)	76,146	
Huntingdon Benchmark Total (CAD)	$ 231,940.72	

$ 32,943.22	Market Total

Station2 Benchmark Price (CAD/GJ)	$ 2.535	Platts GD CH
Station2 Benchmark Volume (GJ)	78,500	
Station2 Benchmark Total (CAD)	$ 198,997.50	

Commodity Resale – FEI Total

Actual Sales Volume * Actual Sales Price

Minus

Deemed Purchase Volume * Deemed Purchase Price

Minus

Transportation Variable Charges

Equals

FEI Spot Commodity Resale Mitigation Revenue

Commodity Resale – Base Benchmark

Actual Sales Volume * Platts Common Low

Minus

Deemed Purchase Volume * Platts Common High

Minus

Transportation Variable Charges

Equals

Spot Commodity Base Benchmark

Commodity Resale Mitigation

Date	13-Apr-21

FEI Actual

Huntingdon Sale Volume (GJ)	193,452
Huntingdon Sale Price (CAD/GJ)	$ 2.86
FEI Total Hungtingdon (CAD)	$553,272.72

$ 53,882.79	FEI Actual Total (GMSIP)

Deemed Station2 Purchase Volume (GJ)	196,998	
Deemed Station2 Purchase Price (CAD/GJ)	$ 2.54	Platts GD CH
Deemed Total Station2 (CAD)	$499,389.93	

$ 553,272.72	FEI Actual Revenue to MCRA

Market Total

Huntingdon Benchmark Price (CAD/GJ)	$ 2.7898	Platts GD CL
Huntingdon Benchmark Volume (GJ)	193,452	
Huntingdon Benchmark Total (CAD)	$539,692.39	

$ 40,302.46	Market Total

Deemed Station2 Purchase Volume (GJ)	196,998	
Deemed Station2 Purchase Price (CAD/GJ)	$ 2.54	Platts GD CH
Deemed Total Station2 (CAD)	$499,389.93	

Next Steps

- Stakeholder Feedback

- FEI to develop and file application to renew the GSMIP model
  - July to August timeframe

- May include minor modifications that don't deviate from the spirit or intent of the model, such as:
  - Monthly Benchmark for forward commodity resale
    - Platts Inside FERC (IF)
  - Review alternative forward price curve benchmark for Capacity Releases
    - Current provider OneExchange
    - Are comparable benchmarks available if current provider no longer available
    - Provides flexibility without modifying Term Sheet

Appendix E

ATRIUM ECONOMICS GSMIP REPORT

ATRIUM ECONOMICS
CENTERED ON ENERGY

FortisBC Energy Inc.

GSMIP Renewal Application Report

August 24, 2022

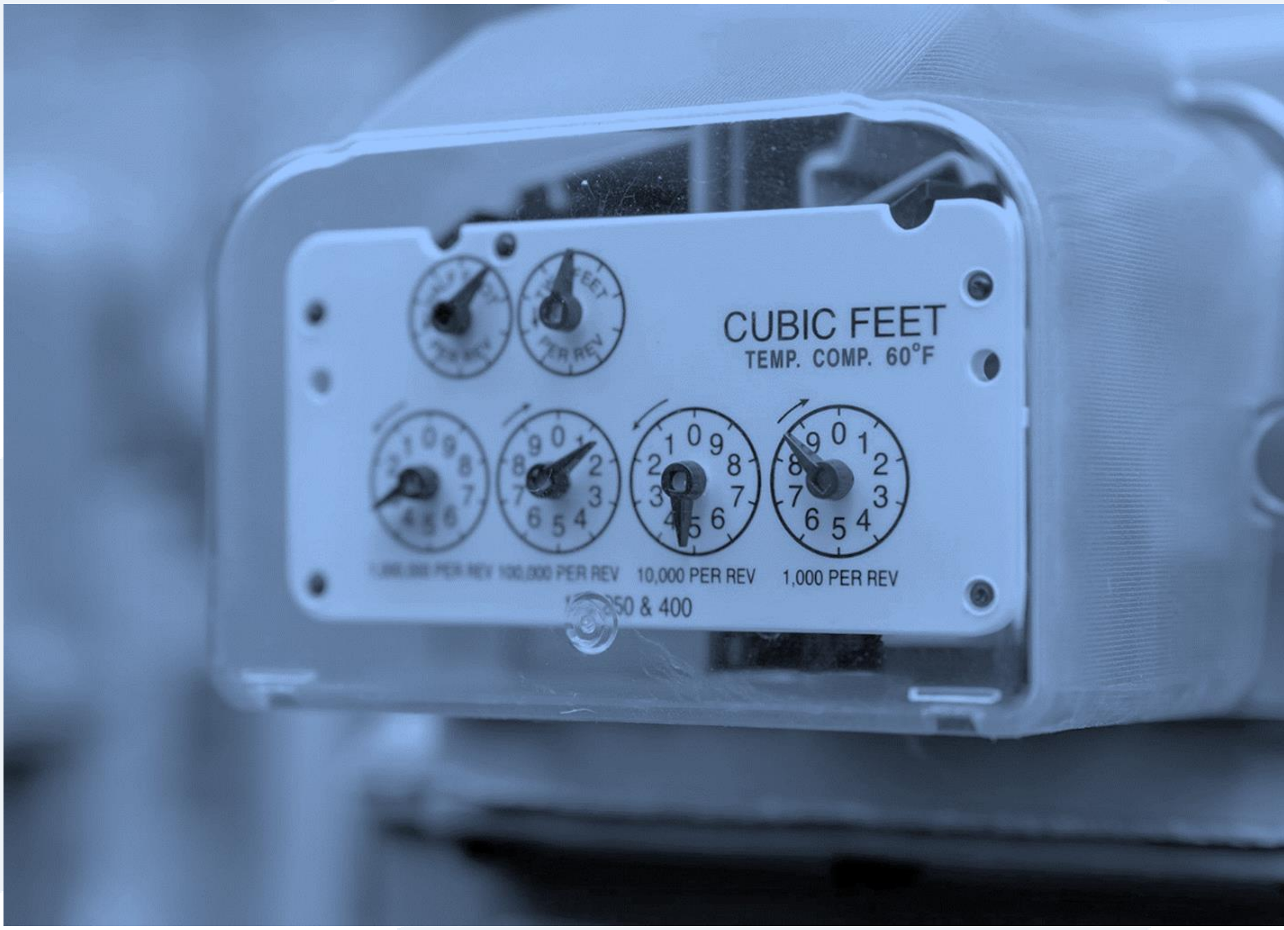


Table of Contents

List of Figures

1 Executive Summary

FortisBC Energy Inc. ("FEI") has been operating under the current Gas Supply Mitigation Incentive Program ("GSMIP") model and term sheet since November 1, 2013. The GSMIP model is a result of the collaborative workshops and consultation between FEI, British Columbia Utility Commission ("BCUC") staff and stakeholders, replacing the previous model ending October 31, 2013. The current GSMIP model has been approved by the BCUC for use in each of the gas years of November 1 to October 31, for the multi-year periods: 2013 to 2016, 2016 to 2019, and 2019 to 2022.

In order G-232-19 approving the most recent GSMIP renewal application, the BCUC directed FEI to file a report providing a comprehensive assessment of the GSMIP, term sheet and model at least sixty days prior to expiration of the approved three-year term of November 1, 2019, to October 31, 2022.

The GSMIP consists of the term sheet which provides the definition, methodology and benchmarking for calculating FEI's performance and mitigation incentive, as well as an Excel model which captures the related data and provides calculations and results. Each year FEI files a Winter Report and Year-end Report with the BCUC, including the model and supporting appendices. The Year-end Report is also audited by FEI's internal audit group, providing a letter of reasonableness to support the mitigation incentive payment to FEI. FEI is moving forward with the comprehensive assessment undertaking and in doing so will continue to engage BCUC staff, stakeholders/intervenors, and third-party industry experts.

Atrium Economics ("Atrium) was asked to 1) evaluate the GSMIP model, its ability to work as originally designed, and historical GSMIP performance, 2) research gas procurement incentive programs ("GPIMs") utilized by gas utilities across North America, and 3) evaluate certain alternative payment calculation scenarios based on stakeholder inquiries/proposals.

This report documents Atrium's findings and, in Appendix A, provides a comprehensive review of GPIMs utilized by utilities across North America. As explained in more detail throughout the report, Atrium finds that:

- The GSMIP model is doing what it was designed to do and FEI's interests are aligned with its ratepayers' interests
- FEI's GSMIP model is consistent with, albeit less lucrative for the utility than, other North American models
- Based on Atrium's sensitivity analyses, market concentration has not resulted in the GSMIP model deviating from its stated purpose.
- Commodity resale mitigation revenue does not materially change when altering the calculation methodology (seasonal/monthly/daily) for market concentration.

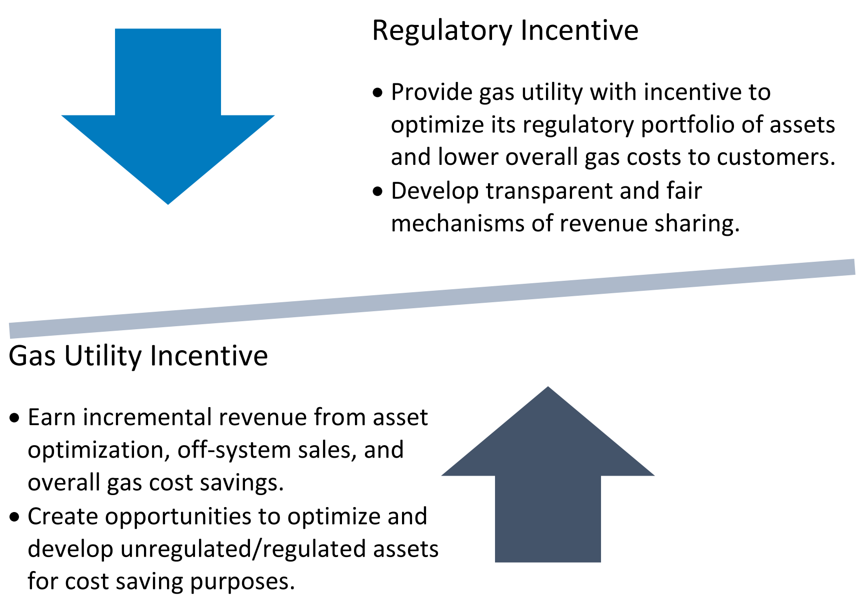
2 North American Gas Procurement Incentive Models

2.1 The Basic Structure of GPIMs

Purpose

A properly designed GPIM must balance risk and reward for the gas utility and its customers. Regulated assets that are designed to meet the gas utility's peak day requirements are, by definition, underutilized at times. The optimization of these assets can generate revenues that under a sharing mechanism can flow back to customers and lower their overall cost of gas. A GPIM allows a portion of those revenues to be retained by the gas utility which incentivizes optimization of these assets while maintaining reliability for peak day needs. Figure 1 depicts the purpose of a GPIM, and the balance of the incentives desired by the regulator and gas utility.

Figure 1 – Purpose of a GPIM



Full and Partial GPIMs

In addition to identifying the key design characteristics among the GPIMs that were identified and researched, Atrium observed that the GPIMs that were reviewed could be grouped into two distinct categories of mechanism types, as indicated below:

a) A "full" GPIM refers to an incentive mechanism that includes all components of a gas utility's supply and capacity portfolio.

b) A “partial” GPIM refers to an incentive mechanism that excludes the gas commodity cost component of the gas utility’s portfolio.

Key Design Characteristics of GPIMs

Each utility’s GPIM is unique and the basis upon which it is designed reflects the following considerations:

a) The goals and objectives of the program. Is the mechanism focused on reducing total gas supply capacity and commodity resource costs versus providing an incentive for the utility to engage in low-to-high risk/reward gas commodity market transactions whereby net margins gained are shared with customers on some graduated scale? Is reduced gas supply cost volatility a primary goal?

b) How gas cost recovery works with the LDC within its regulatory construct. Are the utility’s gas supply resources fully unbundled except for the utility’s role as the supplier of last resort versus a mixed construct of utility versus marketer supplied commodity only using the utility’s upstream capacity resources? Are large commercial/industrial transportation only customers required to have their third-party suppliers deliver to the utility city-gate under balancing tolerance levels? Is the gas supply incentive mechanism part of a larger performance based regulatory construct?

c) The amount of risk that the company and customers want to take on vis-à-vis the level of risk the regulator will approve will impact the risk/reward profile of the incentive mechanism and should indicate how well the interests of the utility and its customers are aligned.

GPIMs have several key design characteristics that help achieve the balance between risk and reward within the market to which each mechanism applies. Through the research conducted by Atrium, we found that there are several similarities among the various types of GPIMs. These key design characteristics include:

- Review Period for Cost Reconciliation - What is the preferred frequency of GPIM-related regulatory filings to review the periodic performance of the mechanism?
- Tolerance Band for Costs/Savings - How much can commodity gas costs rise or fall before revenue and cost sharing occur?
- Gas Commodity Benchmark – How is the appropriate benchmark determined for purposes of evaluating the actual gas commodity costs incurred by the gas utility?
- Revenue Sharing Mechanism - What is the appropriate sharing percentage for the achieved savings or costs? How should different types of sales or optimization transactions be treated?

- Annual Benefits Achieved - Is there a fixed cap on benefits or is it a percentage of total gas commodity costs?

Figure 2 below provides a listing of the various GPIM design characteristics found in nearly all the approved GPIMs identified by Atrium.

Figure 2 – GPIM Design Characteristics

Key Design Characteristic	Definition	Example(s)
Review Period	The time between filings with the regulatory agency to reconcile costs/savings	• Annual • Quarterly/ Seasonal (Winter/Summer) • Monthly
Tolerance Band	A range of percentages of costs that customers are responsible for. If costs are outside the tolerance band, sharing mechanisms would determine what amounts the utility and its customers receive	Total Costs: • 99%-102% • 99.75%-101.25% • 97.4%-102%
Benchmarking and Sharing Mechanism	Defined sharing percentages between the utility and its customers for cost savings related to gas commodity, and revenues from Off-System Sales (OSS), and Capacity Release (CR) as part of its gas supply portfolio	• Commodity: 50%/50% sharing over 102% of benchmark. 20%/80% (utility/customer) sharing under 99% of benchmark (savings). • Off-System Sales (OSS): 25%/75% CR: 30%/70% (utility/customer)
Gas Commodity Benchmark	A defined methodology to calculate the utility's gas commodity costs based on historical gas purchases locations at published price indices	Volume weighted average of spot/FOM market indices at 2-3 traditional upstream points
Annual Benefits Achieved	Annual benefits the utility was able to recognize and return to shareholders. Often contains a cap on annual benefits achieved.	• Range of annual benefits: $0 - $15 million • Capped at lower of fixed dollar amount or percentage of actual gas commodity costs

2.2 Benchmarking Overview

There isn't necessarily a "one-size fits all" approach to the design and implementation of GPIMs. As discussed above, GPIM programs throughout North America vary in terms of their components and whether they are "full" or "partial" models. Models will vary from jurisdiction to jurisdiction based on regulatory regimes, program objectives/risk tolerance, underlying assets, geographical scale, upstream pipeline resources, and whether they have storage (on system, leased, access to LNG). In general, a model should be designed to balance the risk and reward for the gas utility and its customers. A model works well when:

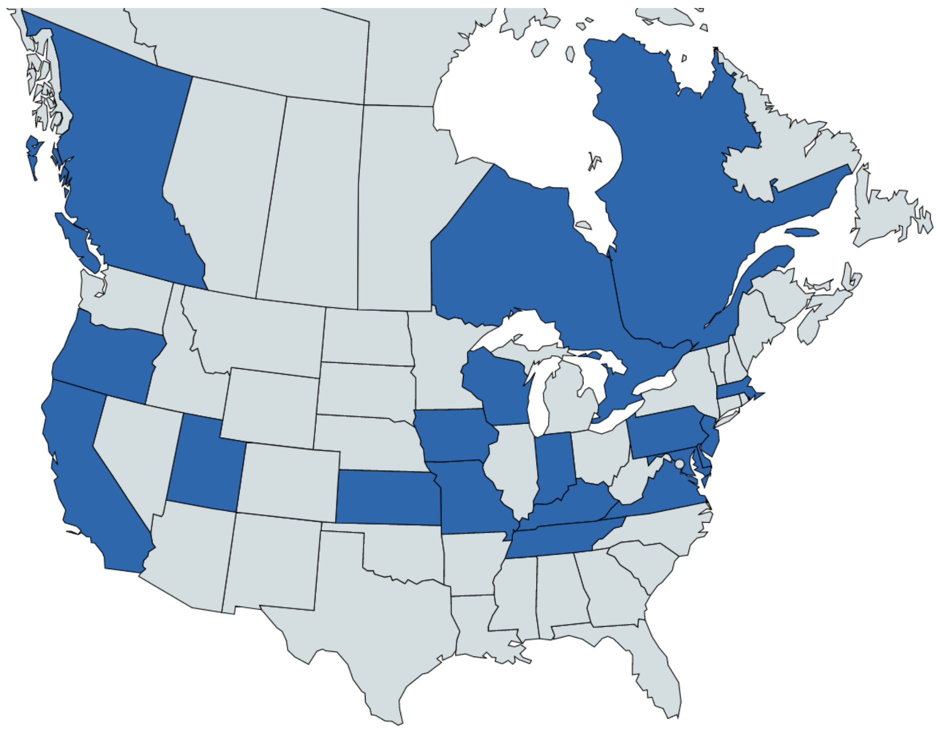
1) Customer and utility objectives and incentives are aligned
2) The model is transparent and fair

3) The GPIM fits well within the suite of mechanisms that the utility uses to recover its cost of service and makes clear to customers how much they are paying for the service they are receiving

4) The program results in the optimization of underutilized assets and generates mitigation revenue that lowers the overall cost of gas to utility customers

Atrium conducted a comprehensive research process to identify GPIMs across the US and Canada. Figure 3 highlights the jurisdictions across North America with GPIMs. In total, there are 39 gas utilities in 18 different provinces and states that have implemented these models. All programs shown on the map have been in continuous operation since their inception. Utilities have implemented them as far back as the mid-1990s and as recently as 2014.

Figure 3 – North American Jurisdictions with GPIMs



Jurisdiction: Utility

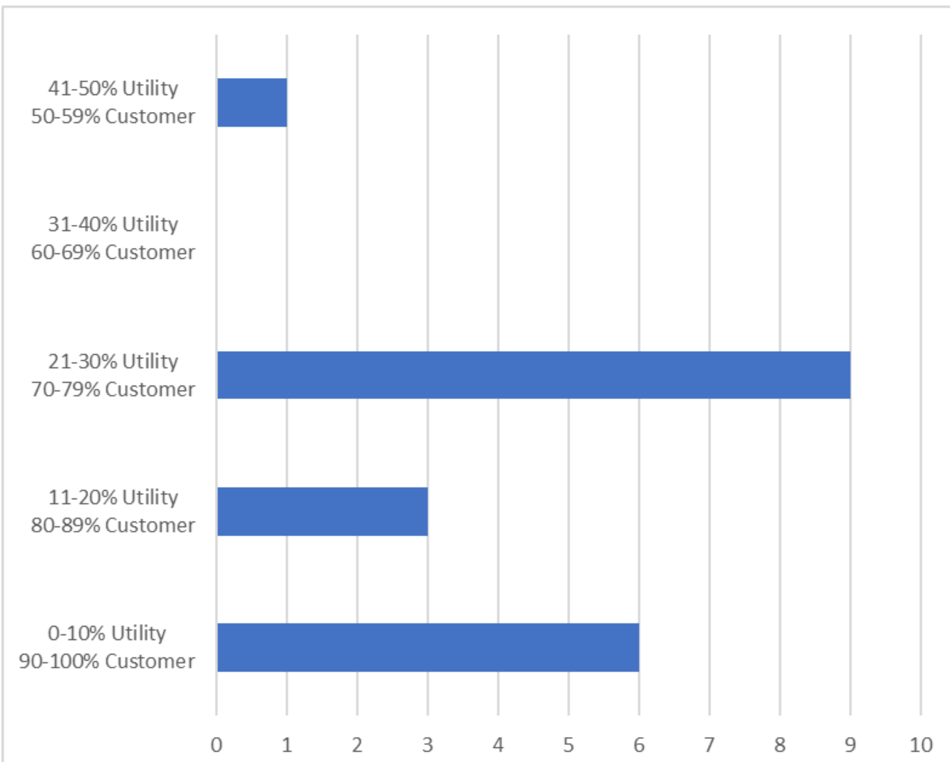
B.C.: FortisBC	Maryland: BG&E, NiSource, Washington Gas
Ontario: Enbridge/Union Gas	Missouri: Spire, MGE
Quebec: Gaz Métro	New Jersey: NJ Natural Gas, South Jersey Gas
California: PG&E, SoCal Gas, SDG&E	Oregon: Cascade, NW Natural, Avista
Delaware: Delmarva	Pennsylvania: NiSource, Ent, Peoples, PECO, PGW
Indiana: NIPSCO	Tennessee: Atmos, Chattanooga Gas, Piedmont
Iowa: MidAmerican, IP&L	Utah: Questar Gas
Kansas: Atmos	Virginia: Washington Gas Light, NiSource
Kentucky: Atmos, NiSource, LG&E	Wisconsin: We Energies

A summary of Atrium's industry research of GPIMs in North America is presented in Appendix A to this report.

2.3 Sharing Mechanisms for Partial GPIMs

As shown in Figure 4, there is a range of sharing mechanisms reflected in partial GPIMs that offer to balance risk and reward and encourage the utility to optimize its portfolio of assets and to reduce overall costs to the customer. While the utilities operate under different market conditions and regulatory regimes, the most frequently observed sharing percentage is 21-30% Utility/70-79% Customer.[1]

Figure 4 – Range and Frequency of Sharing Mechanism Percentages (Partial GPIMs)



2.4 Illustrative Example: California Incentive Model

California is one example of a jurisdiction where gas utilities have implemented this type of incentive program. SoCal Gas, PG&E, and SDG&E all have programs that incorporate commodity, transportation, and storage. It contains all the key components presented earlier: 1) Review period (monthly reports, annual cost adjustments), 2) tolerance band (99%-102%), 3)

[1] Note that while 21-30% Utility/70-79% Customer was the most frequently observed sharing percentage, each utility's sharing percentage can be influenced by the other ratemaking mechanisms in the utility's suite of regulatory tools it uses to recover costs, and these ratemaking mechanisms vary by utility and jurisdiction.

a gas commodity benchmark (Natural Gas Intelligence, Inside FERC Gas Market Report, and NYMEX Futures), and 4) sharing mechanism (a tiered sharing of commodity, transportation and storage mitigation revenues between the utility and customers). Figure 5 summarizes the GPIMs used by California gas utilities.[2]

Figure 5 – California GPIM Models - SoCal Gas (1995), PG&E (1997), SDG&E (2009)

Mechanism	Sharing	Specifications	Period
Portfolio costs include commodity, transportation, and storage. Capacity Release (CR) and Off-System Sales (OSS) are credited to portfolio costs while only 80% of hedging gains/losses are credited to portfolio costs.	Gas Supply Portfolio: 50/50 (utility/customer) sharing over 102% of benchmark (costs); 25/75 sharing under 99% of benchmark (savings); Ratepayers responsible for variances within tolerance band (99%-102%). Portfolio costs include commodity, transportation, and storage. CR and OSS are credited to portfolio costs while only 80% of hedging gains/losses are credited to portfolio costs. Reward is capped at lower of $6 million or 1.5% of actual gas commodity costs.	Combination of monthly gas price indices published by Natural Gas Intelligence, Inside FERC Gas Market Report, NYMEX Futures	Monthly Reports, Annual Cost Adjustment

Again, model or program design will differ from utility to utility and jurisdiction to jurisdiction based on regulatory regimes, program objectives/risk tolerance, underlying assets, geographical scale, upstream pipeline resources, and whether they have storage (on system, leased, access to LNG). California is one example of how gas utilities have designed a model based on its unique circumstances.

2.5 Other Illustrative Examples

Enbridge Gas

Enbridge Gas, based in Ontario, is Canada's largest natural gas storage, transmission, and distribution company. Enbridge provides energy to approximately 3.8 million residents and businesses. Enbridge has a partial GPIM in effect since 2005 that is structured around its extensive gas storage and transportation assets located at or near Dawn. The mechanism

[2] See Appendix A for a summary of all 39 GPIMs across 18 all jurisdictions.

incents Enbridge to optimize transactions related to its upstream transportation capacity, short-term storage, and gas balancing services.

Revenues from storage and transportation optimization activities are split 10% utility, 90% customers (for any revenues exceeding $12 million per year). Capacity release revenues are split 10% utility, 90% customers (only for summer capacity release, geographic gas supply exchange, and storage loans).

Columbia Gas of Maryland

A much smaller utility, Columbia Gas of Maryland (part of NiSource Inc.) has approximately 135,000 customers with 11 Bcf of RCI sales and 25 Bcf of transport. Columbia Gas of Maryland utilizes a full GPIM and a sharing mechanism that includes cost savings and overages, but there is no cap on the incentive.

Commodity-related revenues are split 50% utility, 50% customers above and below the benchmark. From April through October the split applies to all spot gas purchases. From November through March the split applies to spot gas purchases flowing on the FOM. Capacity release revenues are split 10% utility, 90% customers (under $100,000 in net margin per year); 20% utility, 80% customers (over $100,000 in net margins per year). Off system sales are split 20% utility, 80% customers for net margins for planned sales, 50% utility, 50% customers for net margins for incremental sale.

The prices used to determine the benchmarks are the average of the closing gas prices reported for the last 3 days of trading on the NYMEX for the upcoming contract month adjusted by the differential between the average of indices representing prices paid at the Henry Hub and the average of indices representing prices paid at the specific delivery points where the utility purchases gas supplies.

New Jersey Natural Gas Company

The final illustrative example is New Jersey Natural Gas Company with approximately 500,000 customers, 48 Bcf in RCI sales and 18 Bcf in transport. This utility utilizes a partial GPIM that excludes the commodity portion of the utility's gas supply portfolio and focuses on incentives. Specifically, off system sales and capacity release revenues are split 15% utility, 85% customers. Storage revenues above the benchmark are shared 20% utility, 80% customers.

3 GSMIP Historical Performance

3.1 Background

FEI has been operating under a form of incentive program tied to gas supply mitigation activities since 1996. The incentive mechanism was designed to align the interests of customers and the utility in the effective management of gas supply costs through resource contracting and mitigation activities while ensuring a reliable supply of gas to customers. In 2011, the GSMIP was revised based on extensive consultations of a stakeholder group that was established by FEI from direction by the BCUC (the "Working Group"). After six months of consultation and evaluation, the incentive mechanism was redesigned with the objective to encourage FEI to maintain a high level of performance on core mitigation activities related to storage, pipeline transportation, and commodity resale, while also maintaining supply reliability for customers. An application for the new GSMIP was supported by all the Working Group participants and was subsequently approved on September 22, 2011, pursuant to commission order G-163-11, and went into effect for the 2011/12 gas year. The revised GSMIP broke down mitigation transactions into the following categories: benchmarked mitigation activity, non-benchmarked mitigation activity, storage/forward commodity sales (subsequently combined into non-benchmarked activity), and new mitigation activity.

Benchmarked activities are those cost mitigation activities for which a reasonable benchmark has been established against which to measure the relative performance of FEI's cost mitigation efforts. One of these benchmarked activities is spot commodity resale mitigation ("Commodity Resale"). The Commodity Resale transaction only occurs when surplus supply has been purchased in excess of what is needed to serve core load. When FEI has excess purchased supply, it has the option to sell it back at the same market hub or transport it to sell to a downstream market. FEI looks for transactions that yield the highest expected net-back value, given the constraints on what is operationally feasible.[3] The total cost recovery revenue associated with Commodity Resale is the actual sales volume multiplied by the actual sales price.

3.2 Historical Performance

Figure 6 and Figure 7 show GSMIP performance over the last 9 years. In Figure 6, the columns represent total annual mitigation revenues, as shared between customers (in light blue) and the utility (in dark blue on top). The shaded area represents the same annual mitigation revenues but split between revenues generated from benchmarked activities (in gray) and non-

[3] "Net-back value" is the revenue net of incremental costs associated with the transaction (transportation charges).

benchmarked revenues (in yellow). Over the last nine years GSMIP has generated revenues between $40-$120mm.

Figure 6 – GSMIP Net Mitigation Revenue and Incentive Payments

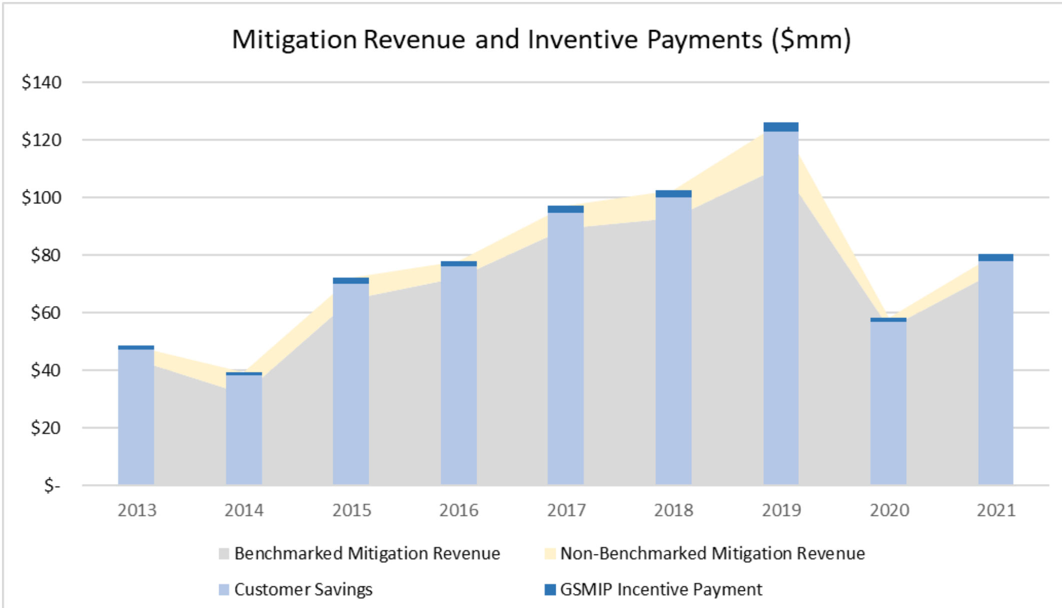
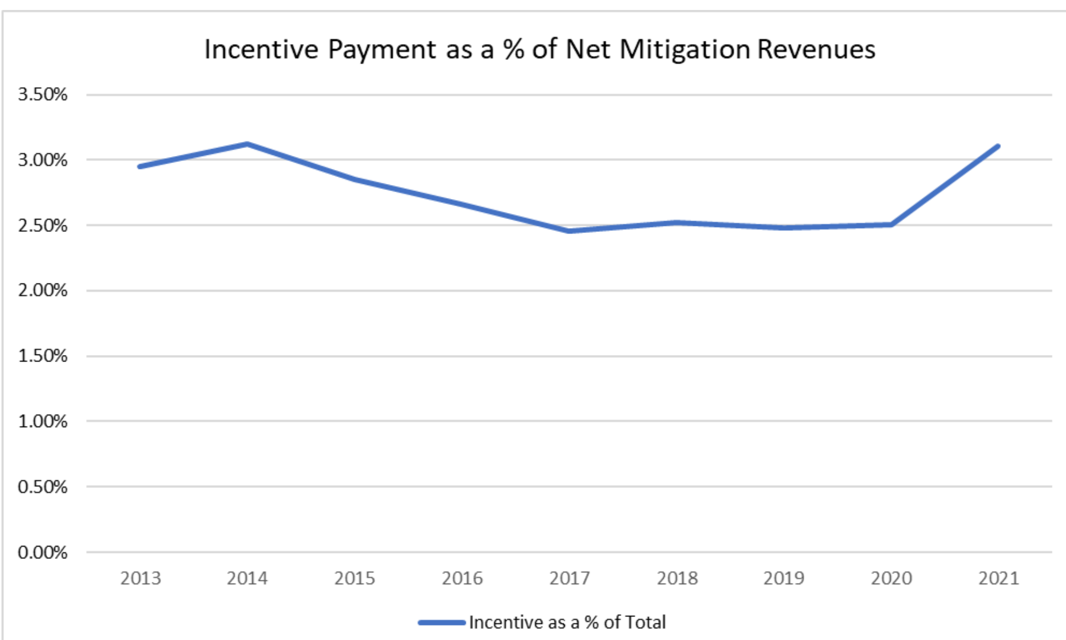


Figure 7 charts the incentive payment to the utility as a percentage of total mitigation revenues. This percentage remained steady over that same period, varying between 2.5% and slightly over 3%. This percentage will vary year to year based on the performance of the benchmarked activities as well as the revenue associated with each category.

Figure 7 – GSMIP Incentive Payments as a % of Net Mitigation Revenues



4 Market Concentration Analysis

4.1 Background

The GSMIP model includes a performance measure that is used to address the potential impact of FEI's market share at the trading hubs where it transacts. Given that the prices used to benchmark FEI's performance are based on all transactions in the marketplace in which FEI is a significant participant, a mechanism was needed when there was market concentration. Therefore, the model incorporated a market concentration measurement for all benchmarked transactions.

FEI typically trades at Sumas, Kingsgate, Station 2, and AECO. The first three of the four market hubs at which FEI transacts have relatively small volumes of trades compared to larger North American market hubs and FEI can represent a significant share of trades executed at these market hubs. If it were deemed that FEI represented too large of a share of any particular market, it would be more likely to achieve the midpoint price ("Midpoint") of that trading point, as opposed to the reported Platts Gas Daily common high price ("Common High") and reported Platts Gas Daily common low price ("Common Low").[4] [5] The Working Group agreed to a market share measurement that used the Herfindahl-Hirschman Index (a widely used economic concept applied in antitrust and competition law) as an appropriate mechanism to determine market concentration. This resulted in the determination that market concentration can become an issue when FEI represents 40% or more of the reported volume of gas traded at any of the hubs that are used in the benchmarking.

To manage this risk, the Working Group determined that using the Midpoint when calculating the benchmark as opposed to the Common Low and Common High would be more appropriate during periods when FEI's transactions exhibited a moderately high degree of market concentration. Trading at a larger share of a particular market hub's transactions should indicate that there is a greater ability to achieve the Midpoint on any given day. The market share calculation would be done on a seasonal basis. If FEI represented 40% or more of reported volume of gas traded in a specific season at a particular hub, then the Midpoint would

[4] When calculating the benchmark, FEI's "deemed sales" use the common low and "deemed purchases" use the common high. Substituting the midpoint in either of those scenarios increases the value of revenues included in the benchmark, decreasing its revenues in excess of the benchmark. Utilizing the midpoint is a limiting factor for the value of the trade when market share is high. All else equal, customers will receive a greater share when using the midpoint to establish benchmark revenues.

[5] The Platts Gas Daily Midpoint is the volume-weighted average of all deals reported to Platts at a given market location, excepting any outliers that are not used. The Platts Common High is the Platts Midpoint plus 50% of the Absolute Range. The Platts Common Low is the Platts Midpoint less 50% of the Absolute Range. The Absolute Range is the range between the absolute low and absolute high of deals reported, excluding the outliers that are not used.

be used for the Base Utility Benchmark Prices in determining FEI's performance, as opposed to the Common Low and High.

4.2 Commodity Resale Mitigation Model

Commodity Resale refers to the selling of commodity contracted pursuant to the Annual Contracting Plan ("ACP") including base load, term and peaking supply, and gas from storage during periods when the amount available exceeds customer requirements. When FEI has excess commodity available to sell, it has the option to sell it at the same market hub at which it was purchased, transport it to sell to a downstream market, or elect to put the commodity into storage for future delivery. FEI looks for transactions that yield the highest expected net-back value, given what is operationally feasible, and what resources may be needed in the future to serve load. The Commodity Resale transaction only occurs when there is surplus supply in excess of what is needed to serve core load. All excess purchased supply that is sold is included in the GSMIP model.

The base benchmark is designed to measure how FEI performed relative to a conservative base utility for the benchmarked activities. FEI's performance relative to the base benchmark impacts the percentage amount it earns of the total benchmarked mitigation revenue booked to GSMIP achieved in the gas year. The more FEI can outperform the base benchmark, the greater the potential incentive payment. Spot market transactions to sell are benchmarked against the reported Platts Common Low price, and spot market transactions to purchase are benchmarked against the reported Platts Common High prices, at the market point on the date of the transaction.

As discussed above, a market concentration adjustment is used for spot transactions. If FEI's market share in any given season at any market hub exceeds 40% of the reported traded volume in Platts Gas Daily, the prices used to determine the base benchmark is the Midpoint for spot transactions at the market hub. Figure 8 shows the number of times over the last five gas years that FEI equaled or exceeded 40% of the market share at the four trading hubs, on a seasonal, monthly, and daily basis.[6]

[6] AE = AECO, S2 = Station #2, KG = Kingsgate, SU = Sumas

Figure 8 – Instances of FEI Market Share of 40% or More

	Seasonal				Monthly				Daily			
	AE	S2	KG	SU	AE	S2	KG	SU	AE	S2	KG	SU
Nov16-Oct17	0	0	0	0	0	0	0	0	0	7	22	4
Nov17-Oct18	0	0	0	0	0	0	1	0	0	28	32	7
Nov18-Oct19	0	0	0	0	0	0	0	1	0	44	34	43
Nov19-Oct20	0	0	0	1	0	1	5	0	0	49	142	50
Nov20-Oct21	0	0	0	0	0	0	1	0	0	37	46	22
Total	0	0	0	1	0	1	7	1	0	165	276	126

4.3 Sensitivities Analyses

During the recent GSMIP stakeholder workshops, some participants raised questions about the way Commodity Resale mitigation revenue is calculated when FEI represents 40% or more of the trading volume at a trading hub. Specifically, stakeholders asked how the mitigation performance and payments would change if market concentration was calculated on a monthly or daily basis, instead of the currently used seasonal calculation. The following section evaluates alternative approaches proffered by stakeholders and compares those results to the current approach to see if the alternative approaches produce materially different results.

Base Utility Benchmark Sensitivities

The Commodity Resale mitigation revenue benchmark is designed to measure how FEI performed relative to a conservative utility basis for the benchmarked activities. FEI's performance relative to the base benchmark impacts the percentage amount it earns of the total benchmarked mitigation revenue booked to GSMIP achieved in the gas year. The more FEI can outperform the base benchmark, the greater the potential incentive payment. Spot market transactions to sell are benchmarked against the reported Platts Common Low price, and spot market transactions to purchase are benchmarked against the reported Platts Common High prices, at the market point on the date of the transaction.

A market concentration adjustment may be used for spot transactions. If FEI's market share in any given season at any market hub exceeds 40% of the reported traded volume in Platts Gas Daily, the prices used to determine the Base Benchmark will be the Midpoint for spot transactions at the market hub. To evaluate the impact of stakeholders' questions about utilizing something other than a seasonal market share concentration metric, we recalculated the benchmark assuming market share was calculated on a monthly and daily basis. Figure 9 shows how the benchmark would change under a monthly and daily calculation methodology.

Figure 9 – Base Utility Benchmark Sensitivities

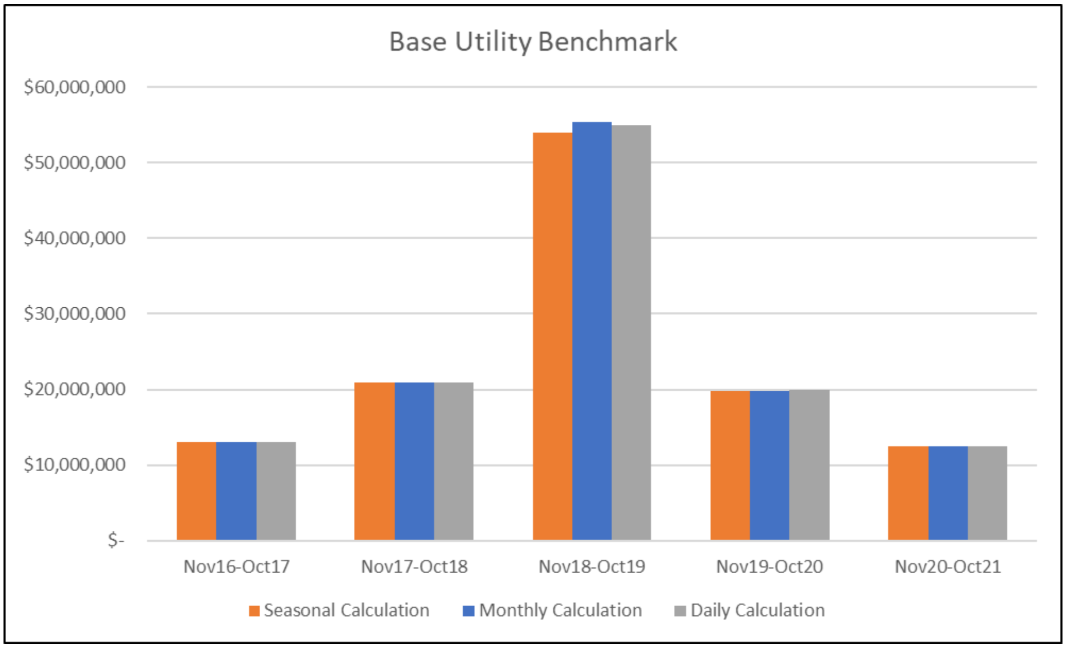
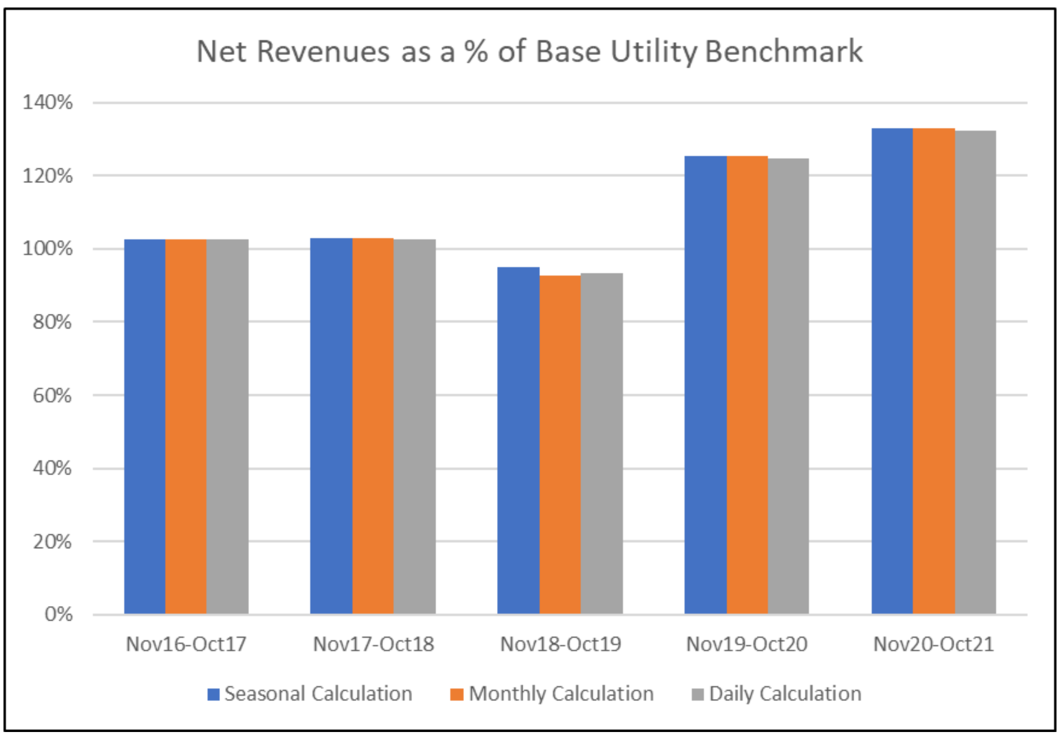


Figure 10 shows how net revenues as a percent of the base utility benchmark would change under a monthly and daily calculation methodology.

Figure 10 – Net Revenues as a % of Base Utility Benchmark Sensitivities



MPF, BAIP, and Incentive Payout Sensitivities

The annual incentive payment ("Incentive Payment") is a function of mitigation revenue, the market performance factor ("MPF") and the benchmarked activity incentive percentage ("BAIP"). The ***MPF*** is calculated as:

$$\text{MPF} = \left[\frac{\begin{array}{c}\text{Capacity Factor Adjusted Total} \\ \text{Benchmarked Mitigation Revenue}\end{array}}{\text{Total Base Benchmark}} \right] \times 100\%$$

The MPF is used to determine the ***BAIP*** which is calculated as:

For MPF between 100 and 131 %, BAIP = 2.45 % + [0.05 % * (MPF-100)]
For MPF between 131 and 136 %, BAIP = 4.00 %
For MPF of 136 and greater, BAIP = 4.00 + 0.04 % * (MPF -136)

The ***Incentive Payment*** is calculated as mitigation revenue multiplied by BAIP.

Figure 11, Figure 12, and Figure 13 show the impact to the MPF, BAIP, and Incentive Payment respectively under a seasonal, monthly, and daily calculation methodology.

Figure 11 – MPF Sensitivities

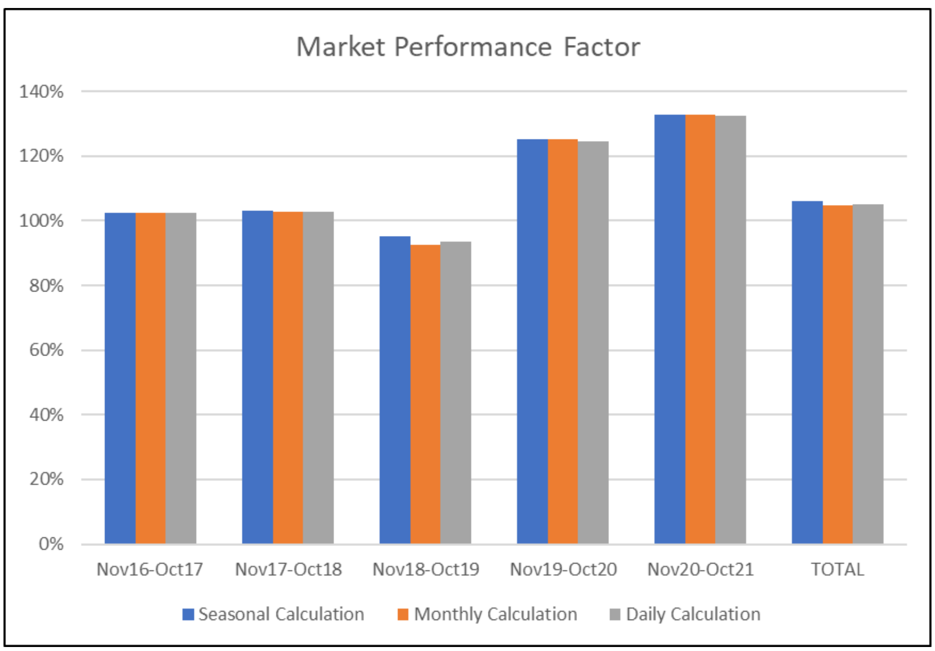


Figure 12 – BAIP Sensitivities

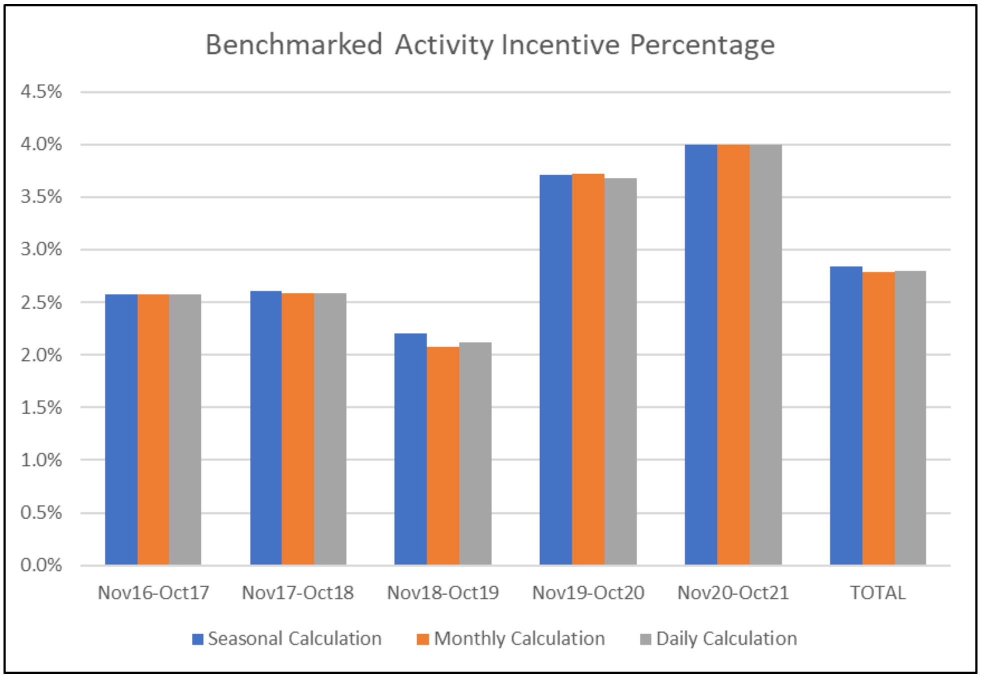
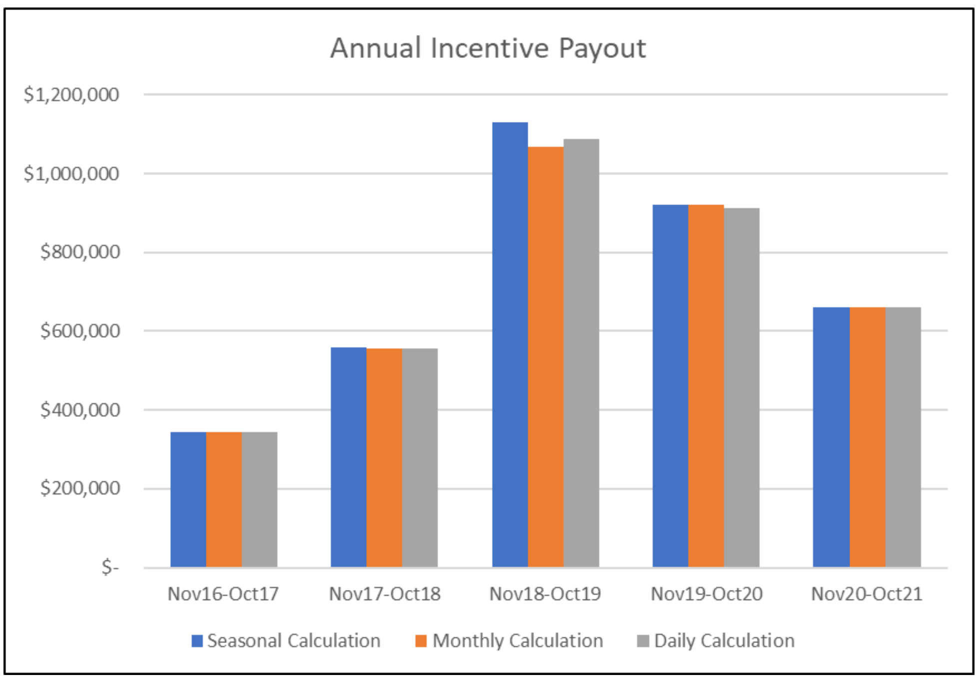


Figure 13 – Incentive Payout Sensitivities



Stakeholders asked how the mitigation performance and payments would change if market concentration was calculated on a monthly or daily basis, instead of the currently used seasonal calculation. As shown in Figure 11, Figure 12, and Figure 13, changing the basis for the market share calculation has little impact on the MPF, BAIP, or the annual inventive payout. Further, moving the test closer to the transaction (monthly, daily) may impede a transaction opportunity that would benefit customers, and in greater proportion than the benefit to the utility. This could have an unintended consequence of limiting the value that a transaction might provide customers, which is far greater than the modest incentive payment that FEI receives.

Finally, it is important to note that even when FEI represents more than 40% of the market, prices at these hubs are dependent on broader market dynamics relating to regional and international supply and demand.

5 Conclusions

- GSMIP is functioning well, and as designed, because:
    - Customer and utility objectives and incentives are aligned
    - The model is transparent and fair
    - The GPIM fits well within the suite of mechanisms that the utility uses to recover its cost of service and makes clear to customers how much they are paying for the service they are receiving
    - The program results in the optimization of underutilized assets and generates mitigation revenue that lowers the overall cost of gas to utility customers
- GSMIP is consistent with, albeit less lucrative for the utility than other North American models and is doing what it was designed to do
- Based on our sensitivity analyses, market concentration has not resulted in the GSMIP model deviating from its stated purpose.
- The calculation of commodity resale mitigation revenue does not materially change when altering the calculation methodology (seasonal/monthly/daily) for market concentration.

6 Appendix A – GPIM Benchmarking Summary

JUR.	UTILITY	START YEAR	T-BAND	BENCHMARKS AND SHARING MECHANISM (UTILITY %/CUSTOMER %)	BENCHMARK SPECIFICATION	REVIEW PERIOD
B.C.	FortisBC	2011	None	Gas Supply Mitigation Incentive Plan (GSMIP) - Commodity, Transportation, CR: Benchmarked Mitigation revenues (capacity factor adjusted) / Total Benchmark * 100% = Market Performance Factor (MPF); MPF falls between tier; generates a different Benchmarked Activity Incentive Percentage (BAIP). MPF between 100 and 131%, = 2.45% + 0.05% * (MPF - 100) MPF between 131 and 136%, BAIP = 4% MPF of 136 and greater, BAIP = 4% + 0.04% * (MPF - 136) Non-Benchmarked Activities = 4% * mitigation revenue New Activity Incentive = 12% * new activity mitigation (determined by Commission) *Fixed adjustment of $165,000 applies to incentive payment **Benchmarked mitigation + non benchmarked mitigation + net activity incentive - $165,000 = incentive payment	Deemed Purchase Price: Platts Gas Daily Common High price at the relevant hub where surplus gas is available which is normally Station 2 or NOVA Inventory Transfer. Platts Common High is the Platts Midpoint plus 50% of the Absolute Range. Deemed Sell Price for Benchmark: Platts Gas Daily Common Low.	Annual
ON	Enbridge/ Union Gas	2005	None	Storage and Transportation Optimization: 10/90 (Optimization revenues (storage + transportation) must exceed $12 million in net revenues for sharing to occur, under $12 million in net revenues the sharing is 0/100)	Not Applicable	Annual
QC	Gaz Métro	2014	None	Capacity Release (CR): 10/90 only for summer capacity release, geographic gas supply exchange and storage loans	Not Applicable	Annual
CA	Pacific Gas and Electric (PG&E)	1997	99% - 102%	Gas Supply Portfolio: 50/50 sharing over 102% of benchmark (costs); 20/80 sharing under 99% of benchmark (savings); Ratepayers responsible for	Volume weighted average of published natural gas price	Monthly Reports,

JUR.	UTILITY	START YEAR	T-BAND	BENCHMARKS AND SHARING MECHANISM (UTILITY %/CUSTOMER %)	BENCHMARK SPECIFICATION	REVIEW PERIOD
				variances within tolerance band. Portfolio costs include commodity, transportation, and storage. CR and OSS are credited to portfolio costs while only 80% of hedging gains/losses are credited to portfolio costs. *Reward is capped at 1.5% of actual gas commodity costs.	indices at PGE's purchase points	Annual Cost Adjustment
CA	Southern California Gas Company	1995	99% - 102%	Gas Supply Portfolio: 0/100 sharing over 102% of benchmark (costs); 25/75 sharing between 99% and 95% of benchmark (savings); 10/90 sharing under 95% of benchmark (savings); Ratepayers responsible for variances within tolerance band. Portfolio costs include commodity, transportation, and storage. CR and OSS are credited to portfolio costs while only 80% of hedging gains/losses are credited to portfolio costs. *Reward is capped at 1.5% of actual gas commodity costs.	Combination of monthly gas price indices published by Natural Gas Intelligence, Inside FERC Gas Market Report, NYMEX Futures	Monthly Reports, Annual Cost Adjustment
CA	San Diego Gas and Electric (SDG&E)	2009	99% - 102%	Gas Supply Portfolio: 50/50 sharing over 102% of benchmark (costs); 25/75 sharing under 99% of benchmark (savings); Ratepayers responsible for variances within tolerance band. Portfolio costs include commodity, transportation, and storage. CR and OSS are credited to portfolio costs while only 80% of hedging gains/losses are credited to portfolio costs. *Reward is capped at lower of $6 million or 1.5% of actual gas commodity costs	Volume weighted average of spot market indices in U.S. Southwest/Rocky Mountain basins and market price index for delivering to CA border	Monthly Reports, Annual Cost Adjustment
DE	Delmarva	2017	None	IT Services 20/80; OSS and CR: 20/80 after first $3M	Not Applicable	Monthly and Annual
IN	NIPSCO	1999	None	Commodity: 50/50 of differences between actual gas costs and a benchmark price Capacity Release (CR): 15/85	Delivery point and index point specific, subject to audit each year (typically mix of FOM for baseload and spot indexes for daily purchases)	Monthly & Quarterly Filing. CR: Filed Annually

JUR.	UTILITY	START YEAR	T-BAND	BENCHMARKS AND SHARING MECHANISM (UTILITY %/CUSTOMER %)	BENCHMARK SPECIFICATION	REVIEW PERIOD
IO	MidAmerican	1995	99.75 % - 101.2 5%	Commodity: 50/50 above or below benchmark; capped at $0.5 million. Off-System Sales (OSS): 50/50; CR: 30/70 *capped at $500,000	A reference price which reflects commodity cost indices, storage, and transportation tariffs approved by FERC, and capacity contracts entered into by the company	Annual
IO	Interstate Power and Light	2005	None	OSS: 50/50, CR: 30/70	Not Applicable	Annual
KA	Atmos Energy	2014	None	CR: 50/50, Southern Star Pipeline Demand Charges: 22/78	Not Applicable	Annual
KY	Atmos Energy	1998	None	Commodity, Transportation, OSS: 30/70 of cost variances up to 2%, 50/50 of variances above 2%	Baseload: the price index will be the appropriate Inside FERC Gas Market Report first of the month price for that particular month. For incremental swing purchases, the published Platts's Gas Daily daily mid-point price for the business day of gas flow will be used as the index.	PGA Filing: Quarterly; PBR Activity: Annual
KY	Columbia Gas of Kentucky (NiSource)	2005	None	Commodity, Transportation, OSS: 30/70 of cost variances up to 2%, 50/50 of variances above 2%	Monthly index: FERC Gas Market; Weekly index: Natural Gas Week; Daily index: Platts Gas Daily	PGA Filing: Quarterly; PBR Activity: Annual
KY	Louisville Gas and Electric(PPL)	1997	None	Commodity, Transportation, OSS: 25/75 up to 3% variance; 50/50 of variances above 3%	FERC FOM midpoint prices on Columbia Gulf Mainline, Columbia Gas App, and TGP 500L depending on purchased volumes	PGA filed Quarterly

JUR.	UTILITY	START YEAR	T-BAND	BENCHMARKS AND SHARING MECHANISM (UTILITY %/CUSTOMER %)	BENCHMARK SPECIFICATION	REVIEW PERIOD
MD	Baltimore Gas & Electric (BG&E)	2000	None	Commodity: 50/50 above or below benchmark level (the difference between the total actual commodity cost of gas purchased and the City Gate Index cost) are shared with customers, OSS: 0/100 for gross margin up to $1 million, 20/80 over $1 million; 50/50 for any gross margins when utility assets are not used for the transaction CR: 0/100 up to $500,000; 10/90 after $500,000,	Average of price quoted in Inside FERC's Gas Market Report and the closing price on the NYMEX for the last 3 days of trading (Bid Week), plus the variable transportation costs from the supply basin to the city gate. Market Gas Commodity Price includes flowing gas, pipeline storage gas, and onsystem LNG.	Monthly Commodity Adjustment; Annual Sharing Adjustment
MD	Columbia Gas of Maryland (NiSource)	2000	None	Commodity: 50/50 above and below the benchmark, April - Oct (all spot gas purchases) and Nov - March (spot gas purchases flowing on the FOM); CR: 10/90 under $100,000 in net margins per year; 20/80 over $100,000 in net margins per year, OSS: 20/80 of net margins for planned sales; 50/50 of net margins for incremental sale	Average of the closing gas prices reported for the last 3 days of trading on the NYMEX for the upcoming contract month adjusted by the differential between the average of indices representing prices paid at the Henry Hub and the average of indices representing prices paid at the specific delivery points where Columbia purchases gas supplies.	Quarterly
MD	Washington Gas	2000	None	Asset Optimization Margins: 0/100 of first $2.6 million, 25/75 for next $3.3 million, 50/50 for all above $5.9 million	Not Applicable - Asset Management Program (Self-Directed)	Annual
MA	Berkshire Gas	2013	None	CR, OSS: 10/90	Not Applicable	Semi-Annual
MA	National Grid	2013	None	CR, OSS: 10/90	Not Applicable	Semi-Annual

JUR.	UTILITY	START YEAR	T-BAND	BENCHMARKS AND SHARING MECHANISM (UTILITY %/CUSTOMER %)	BENCHMARK SPECIFICATION	REVIEW PERIOD
MA	Columbia Gas of MA	2015	None	CR, OSS: 10/90	Not Applicable	Semi-Annual
MO	Spire Missouri Inc.	2005	None	Commodity: 10/90 of savings relative to benchmark up to $3 million OSS, CR: 15/85 of first $2 million, 20/80 of next $2 million, 25/75 of next $2 million, 30/70 of anything above $6 million	Weighted average of iFERC FOM: CEGT (22%), NGPL MidCont (8%), NGPL STX (5%), PEPL (10%), CEGT West (24%), Trunkline LA (+%), Southern Star (12%), and MS River Transmission West (13%)	Quarterly
MO	Missouri Gas Energy (Spire West)	2013	None	OSS and CR: 25/75	Not Applicable	Annual
NJ	New Jersey Natural Gas Co	2002	None	OSS and CR: 15/85 Storage: 20/80 relative to predetermined benchmark	Not Applicable	Annual
NJ	South Jersey Gas	2003	None	OSS and CR: 15/85 Storage: 20/80 relative to predetermined benchmark	Not Applicable	Annual
OR	Cascade Natural Gas (MDU Resources)	2008	None	Commodity: 10/90	Estimated WACOG equals forecasted purchases plus a percentage of distribution LUFG (not to exceed 2%) at adjusted contract prices adjusted for Canadian pipeline published fuel use	Monthly entries, amortized over 12 months
OR	Northwest Natural Gas	2000	None	Commodity: 10/90 Interstate Storage Service, OSS and CR: 80/20	Estimated WACOG equals forecasted purchases plus a percentage of distribution LUFG (not to exceed 2%) at adjusted contract prices adjusted for Canadian pipeline published fuel use	Monthly entries, amortized over 12 months

JUR.	UTILITY	START YEAR	T-BAND	BENCHMARKS AND SHARING MECHANISM (UTILITY %/CUSTOMER %)	BENCHMARK SPECIFICATION	REVIEW PERIOD
OR	Avista Utilities	2008	None	Commodity: 10/90 and CR: 80/20	Estimated WACOG equals forecasted purchases plus a percentage of distribution LUFG (not to exceed 2%) at adjusted contract prices adjusted for Canadian pipeline published fuel use, and by each associated U.S. pipeline's tariffed rate.	Monthly entries, amortized over 12 months
PA	Columbia Gas of Pennsylvania	2002	None	OSS and CR: 25/75	Not Applicable	Annual
PA	Equitable Gas (Peoples Gas Co.)	2013	None	CR: 25/75	Not Applicable	Quarterly
PA	Peoples Gas Company	2013	None	CR: 25/75	Not Applicable	Quarterly
PA	PECO Energy Company	2008	None	OSS: 25/75	Not Applicable	Quarterly
PA	Philadelphia Gas Works	2008	None	OSS and CR: 25/75, Storage AMA: 25/75	Not Applicable	Quarterly
TN	Atmos Energy	2011	97.4% - 102%	Commodity: 25/75 of variance from predetermined benchmark OSS and Capacity Management: 25/75	Monthly: simple average of iFERC and NYMEX for that particular month; Swing: Gas Daily; indices are adjusted for transportation costs to city gate	Annual
TN	Chattanooga Gas (AGLResources)	2002	None	Avoids prudence audit if commodity cost falls under 101% of benchmark; 50/50 of margins from non-regulated customers using company assets (including OSS)	Spot: iFERC "Price of Spot Gas Delivered to Pipelines" at application "Pricing Point"; Swing Purchases: Gas Daily equal to midpoint under "Daily	Annual

JUR.	UTILITY	START YEAR	T-BAND	BENCHMARKS AND SHARING MECHANISM (UTILITY %/CUSTOMER %)	BENCHMARK SPECIFICATION	REVIEW PERIOD
					Price Survey"; Long Term: Spot price index + rolling 3-year avg premium for long term supply reliability; City Gate: indexes adjusted for avoided transportation costs	
TN	Piedmont Natural Gas	2006	None	Commodity: 25/75 of variance from predetermined benchmark (Except gas purchases associated with TETCO Rate Schedule SCT - company allowed to recover all expenses). Benchmark based on a monthly computed price index OSS and Capacity Management: 25/75. *Total company gain or loss capped at $1.6 million	Volume weighted average of spot market indices at key relevant supply basins and market price index for delivering to city-gate	Annual
UT	Questar Gas	1997	None	CR 10/90	Not Applicable	Semi-Annual
VA	Washington Gas Light	2011	None	AMA Revenue Sharing 25/75 after $3.2 million to $6.5 million, 50/50 after $6.5 million	Not Applicable	PGA: Quarterly ACA: Annual
VA	Columbia Gas of Virginia (NiSource)	2007	None	OSS and CR: if margin ≤ $1.5 million, then $1.5 million goes to customers; if margin is between $1.5 million and $2.8 million, then 100% of margin goes to customers; if margin is greater than $2.8 million and less than $3.7 million, then $2.8 million goes to customers; if margin ≥ $3.7 million, then margin is shared 25/75 (the utility also utilizes an AMA which is included in the incentive mechanism)	Not Applicable	PGA: Quarterly ACA: Annual
WI	Wisconsin Gas (WE Energies)	2009	None	Gas Costs below benchmark are returned to customers; if 2% above benchmark PSC may initiate a prudence investigation in order for utility to recover costs.	Confidential	Quarterly