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July 5, 2021

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Mr. Patrick Wruck, Commission Secretary

Dear Mr. Wruck:

**Re: FortisBC Energy Inc. (FEI)**

**Project No. 1599152**

**Application for a Certificate of Public Convenience and Necessity for the Okanagan Capacity Upgrade (OCU) Project (Application)**

**Response to the British Columbia Utilities Commission (BCUC) Information Request (IR) No. 3**

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On November 16, 2020, FEI filed the Application referenced above. In accordance with BCUC Order G-1662-21 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 3.

If further information is required, please contact the undersigned.

Sincerely,

**FORTISBC ENERGY INC.**

***Original signed:***

Diane Roy

Attachments

cc (email only): Registered Parties

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## A. PROJECT NEED

**65.0 Reference: PROJECT NEED**
**Exhibit B-2, BCUC IR 5.3**
**Exhibit B-14, BCUC IR 42.2.1, 42.4.1, 42.5, 42.5.1**
**Use Per Customer Peak (UPCpeak)**

In response to British Columbia Utilities Commission (BCUC) Information Request (IR) 42.2.1, FortisBC Energy Inc. (FEI) states:

> Aside from FEI's adjustment to the system design temperature in 2017, the historical record does not show significant variation in residential UPCpeak. Commercial UPCpeak values have slightly increased and show periods of slight upwards and downwards trends. As such, FEI has no basis to conclude that the UPCpeak would increase or decrease materially in the next 10 years.

In response to BCUC IR 5.3, FEI provides the following table:

**ITS Historical $UPC_{peak}$ (GJ/Hr)**

| Year | ITS $UPC_{peak}$ (GJ/Hr) | | |
| --- | --- | --- | --- |
| | RS 1 | RS 2 | RS 3 |
| 2009 | 0.0487 | 0.1763 | 1.8831 |
| 2010 | 0.0479 | 0.1758 | 1.8749 |
| 2011 | 0.0470 | 0.1739 | 1.8718 |
| 2012 | 0.0475 | 0.1857 | 1.9181 |
| 2013 | 0.0485 | 0.1975 | 1.9629 |
| 2014 | 0.0494 | 0.2113 | 2.0586 |
| 2015 | 0.0499 | 0.2155 | 2.1111 |
| 2016 | 0.0502 | 0.2190 | 2.2240 |
| 2017 | 0.0452 | 0.1946 | 2.0447 |
| 2018 | 0.0449 | 0.1937 | 2.0176 |
| 2019 | 0.0448 | 0.1918 | 1.9723 |

ITS - Historical Rate Schedule 1 $UPC_{peak}$

In response to BCUC IR 42.4.1, FEI states:

> The relationship between annual energy savings and peak demand day savings resulting from FEI's current DSM [Demand Side Management] portfolio continues to be uncertain. FEI's analysis of peak demand versus the capacity of the Interior

> Transmission System indicates that the savings on peak day demand from the DSM portfolio that are reflected in current customer consumption used to calculate UPCpeak are currently insufficient to defer the need for the OCU [Okanagan Capacity Upgrade] Project.

In response to IR 42.5, FEI provides the following table:

| Year | Forecast Cumulative Annual Energy Savings (GJ)* | Forecast Gross Annual Energy Demand (GJ)** | Savings as a percentage of Gross Energy Demand |
|---|---|---|---|
| 2019 | 875,933 | 192,899,700 | 0.5 |
| 2020 | 1,796,901 | 193,249,740 | 0.9 |
| 2021 | 2,892,538 | 193,684,523 | 1.5 |
| 2022 | 4,067,599 | 194,132,108 | 2.1 |

*Notes:*

* Values shown are estimated (forecast) annual energy savings as shown in the FEI 2019 to 2022 DSM Expenditures Plan. Cumulative values for 2020 and 2021 were not presented in the DSM Plan and have been estimated here to account for those savings that do not persist through all years of the Plan. Therefore these values are slightly less than the sum of the annual savings for the prior years as shown in the DSM Plan.

** Values shown are from the Annual Demand forecast presented in the 2017 LTGRP, Appendix B, Reference Case Demand forecast.

In response to BCUC IR 42.5.1, FEI states:

> FEI has no data that demonstrate that a relationship between annual energy savings and peak demand reduction across its portfolio is one-to-one as the suggested method assumes…
>
> FEI believes the premise of directly applying annual DSM energy reductions to peak demand is incorrect for the reasons listed below:
>
> …
>
> The relationship between annual energy savings and peak demand reduction is likely to be different among different sectors and rate classes…
>
> When determining the system capacity, the location of peak demand on the system is highly relevant. The assumption that all customers across the system are experiencing the same savings in peak demand is not supported by evidence.

65.1 Please discuss whether FEI's position at this time is that historical UPCpeak trends and values are the only relevant considerations for forecasting the UPCpeak.

**Response:**

FEI's position is that its established method of calculating $UPC_{peak}$ by incorporating the most recent data on current customer consumption, and using those values without variation through the forecast period is the best and most relevant basis for determining peak demand and the need for system capacity upgrades. FEI maintains that the variations in $UPC_{peak}$ in the most recent 10 years in the ITS are not consistent. Attributing any short-term trend in $UPC_{peak}$ over a period of a few years to any particular driver, without the ability to directly verify impacts or benefits on an hourly basis, is speculative. Projecting sustained reductions into a peak demand forecast suggested by short-term $UPC_{peak}$ trends, or speculating on the extent to which future DSM and efficiency measures may reduce peak demand would not be considered prudent planning when applied to an imminent need such as that occurring in the Okanagan region served by the ITS. Applying speculative and hypothetical customer peak load reductions could result in FEI significantly underestimating actual customer demand. Insufficient gas delivery infrastructure to meet customer demand during cold winter conditions could have significant customer impacts and result in serious societal harm, as was experienced in the state of Texas during the February 2021 winter storm.[1]

To reflect more recent changes in customer consumption, FEI refreshes its $UPC_{peak}$ calculation annually to capture current consumption patterns. However, FEI does not “layer on” future subjective scenarios or uncertainties that might occur with the implementation of programs like CleanBC as there is no statistical or objective basis to calculate these impacts. Arbitrarily reducing FEI’s load forecasts would delay the timing of projects and significantly impact FEI’s ability to maintain the level of service expected by customers.

As discussed in the responses to BCUC IR1 4.1 and 4.1.2, in order to make adjustments to $UPC_{peak}$ over the forecast period, FEI would require enhanced metering capability to collect customer consumption data on an hourly basis such as might be provided with the implementation of Advanced Metering Infrastructure (AMI) for FEI’s customers. With advanced metering capability and additional analytics tools, it would be possible to verify incremental changes at a resolution not currently available when calculating peak consumption from monthly billing data. Examination of hourly data collected prior to and after DSM or other efficiency program implementation, and comparisons of various customer types and trends over time, may validate some means of incorporating adjustments to $UPC_{peak}$ in the future. FEI does not currently have the ability to measure such impacts sufficiently to reliably apply any adjustments to peak demand forecasting. Additionally, the increased customer information provided by the AMI project will not be available prior to the forecast capacity deficit which is driving the need for the OCU Project.

Similarly, FEI acknowledges that climate change is occurring; however, FEI maintains that the impact on extreme weather—especially on peak demand during low temperature conditions—is uncertain and that using past extreme weather history is appropriate. FEI does not project changes in future climate when calculating peak demand. As demonstrated in the responses to BCUC IR1 8.3 and RCIA IR2 30.1, the weather in any given year can vary significantly. FEI’s position is that a statistical analysis of past extreme events, rather than speculation on future unrealized possibilities, is the most prudent means of determining the design temperature (extreme weather event) that should determine peak demand.

[1] https://www.dallasnews.com/news/weather/2021/04/30/number-of-texas-deaths-linked-to-winter-storm-grows-to-151-including-23-in-dallas-fort-worth-area/

In its response to BCSEA IR1 3.12 FEI stated:

> Imposing a scenario where peak demand is driven lower as a result of uncertain policy or other pressures could ultimately result in a lower state of readiness and responsiveness to maintaining a robust and reliable transmission system.

The need for the OCU Project is imminent. In responses to information requests for the OCU Project, FEI has, upon request, presented speculative alternate peak demand forecasts assuming DSM savings or reduced design temperatures such as in BCUC IR2 42.5.1, BCUC IR2 43.3.1, BCUC IR2 43.8 and RCIA IR2 31.1. Predominantly, the adjusted forecasts do not change the short-term need for the OCU Project, although they may extend the long-term capacity benefit further into the future. In the response to BCUC IR1 4.2.1, FEI discussed how FEI's traditional peak demand forecast used in the 2017 Long Term Gas Resource Plan, while projecting lower than current forecasted ITS demand, was the closest estimate to the current projected demand of any of the speculative end-use forecasts presented other than the upper bound forecast.

FEI has a responsibility to ensure reliable delivery of energy and, as a result, limits future speculation on peak demand trends.

65.1.1 Please discuss whether FEI considers there are any circumstances where adjustments to the future UPCpeak, on an annual or other basis, would be appropriate.

**Response:**

Please refer to the response to BCUC IR3 65.1.

65.1.2 Please discuss how FEI's approach to calculating the UPCpeak compares to other gas utilities.

**Response:**

FEI periodically meets and collaborates with industry peers to discuss capacity planning issues and processes. While each utility has its own unique methodology, FEI's overall approach to calculating the $UPC_{peak}$ is consistent with that used by other gas utilities in Canada and the United States. For design temperature methodologies, FEI provided a response previously in BCUC IR2 43.5. In estimating the peak demand at the design temperature, commercially available software packages for hydraulic modeling all offer companion modules that analyze customer consumption information collected on a periodic basis (typically from monthly or bimonthly meter readings) by performing temperature regressions to extrapolate daily/hourly customer demand to their system peak design temperatures. The processes used by other utilities would be similar to that used by FEI and described in Section 3.3.1.1 of the Updated Application. FEI does not have detailed knowledge of the specifics of each utility's processes, but expects that based on their unique circumstances and requirements each utility may vary the amount of historical consumption data used and may possibly refresh the information at different intervals than FEI. FEI uses the most recent two years of consumption data and refreshes the $UPC_{peak}$ calculation each year.

Similarly, FEI is aware that many utilities are using measured historical peak values and contract demand values for industrial customers, as does FEI.

65.2 Please confirm, or explain otherwise, that for the years 2017 – 2019 (i.e. the years after the adjustment to the system design temperature, which are used in the calculation of the peak demand forecast) there has been an annual reduction in UPCpeak for all rate schedules.

**Response:**

Confirmed. Overall, $UPC_{peak}$ for all three rate schedules have declined between 2017 and 2019. At the same time, the table also shows that prior to 2016, Rate Schedules 2 and 3 were showing year-over-year increases in $UPC_{peak}$ – which increased substantially more in the period 2014 to 2016 than they declined in the period 2017 to 2019. FEI often observes short-term variations both upwards and downwards in $UPC_{peak}$. Given the lack of statistical validity, FEI does not project any annual changes, either increasing or decreasing, resulting from these variances into the peak demand forecast.

65.2.1 Please describe how the proportion of reduction in the UPCpeak compares to the proportion of annual energy savings from DSM programs in that time.

**Response:**

During the years 2017 to 2019, there was a proportional decline in $UPC_{peak}$ while DSM energy savings as a percentage of gross annual demand grew. During the years 2014 to 2016, there was no similar relationship; in fact, there was a proportional increase in $UPC_{peak}$ while DSM energy savings as a percentage of gross annual demand grew. It should be noted that over a longer period, growth in annual energy savings as a proportion of gross annual energy demand would be expected to grow as energy savings from new measures that are installed each year get added to those energy savings from measures installed in previous years that remain in service and continue to deliver energy savings each year. This increase in annual energy savings from DSM measures and activities is not translating to a similar consistent decrease in $UPC_{peak}$ over the same period as would be expected if there were a clear relationship between changes in DSM-related annual energy savings and $UPC_{peak}$ reductions.

65.3 Please provide further explanation of the statement: "The relationship between annual energy savings and peak demand reduction is likely to be different among different sectors and rate classes."

**Response:**

To further explain the cited statement, FEI provides the example of industrial and residential demand. Industrial process gas equipment for which demand is unrelated to temperature will have different load profiles than does the demand from residential gas heating appliances. In this example, DSM measures for industrial equipment would have different implications for temperature-related $UPC_{peak}$ than would DSM measures associated with home heating. Similarly, small commercial customers in the food and beverage industry would likely achieve a different level of savings than would a residential strata customer in the same small commercial rate schedule due to the differences in consumption patterns and energy use needs.

65.4 Please provide further explanation of the statement: "The assumption that all customers across the system are experiencing the same savings in peak demand is not supported by evidence." Please identify any specific considerations with respect to customers in the Interior Transmission System (ITS).

**Response:**

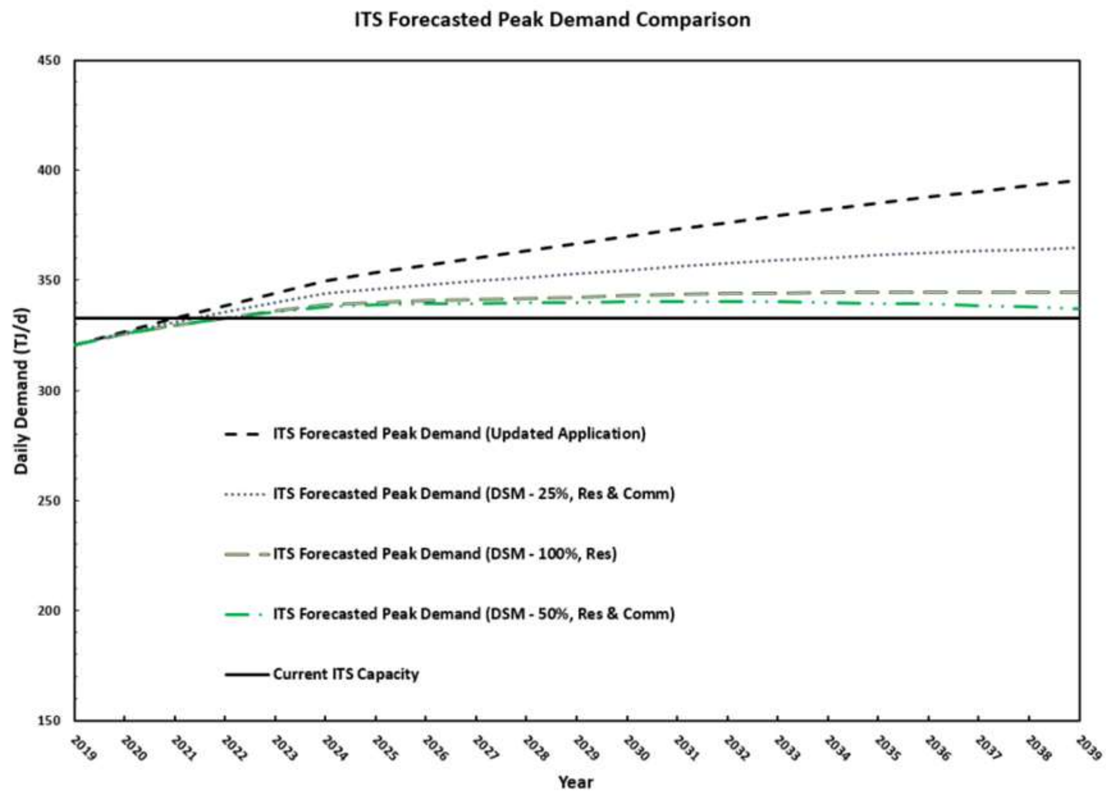
To help explain the quoted statement, FEI compares characteristics of the Lower Mainland service area to the Interior service area. Since the key driver of peak demand is temperature and FEI is a winter peaking utility, the lower winter temperatures experienced in the Interior compared to those of the Lower Mainland have different implications for potential DSM-related savings during peak cold periods between the two service regions. Due to climate differences in these regions, historical building practices have also been different, with Interior service area buildings being constructed with colder temperatures in mind. For example, the $UPC_{peak}$ for the residential rate schedule in the Lower Mainland communities of Vancouver, Burnaby, and New Westminster in the 2019 forecast is 1.61 standard cubic metres per hour, as compared to 1.18 standard cubic metres per hour in the Central Okanagan – even though the design temperature in the latter region is almost 14ºC colder. FEI research indicates that Interior service area homes on average tend to have better insulation and have higher penetration rates of high-efficiency space heating appliances and fewer natural gas fireplaces than Lower Mainland homes. These variations between the two regions create different implications for potential DSM-related peak savings between the two service regions.

**66.0 Reference: PROJECT NEED**

**Exhibit B-14, BCUC IR 42.5.1, 42.5.1.2, 43.2, 50.1**

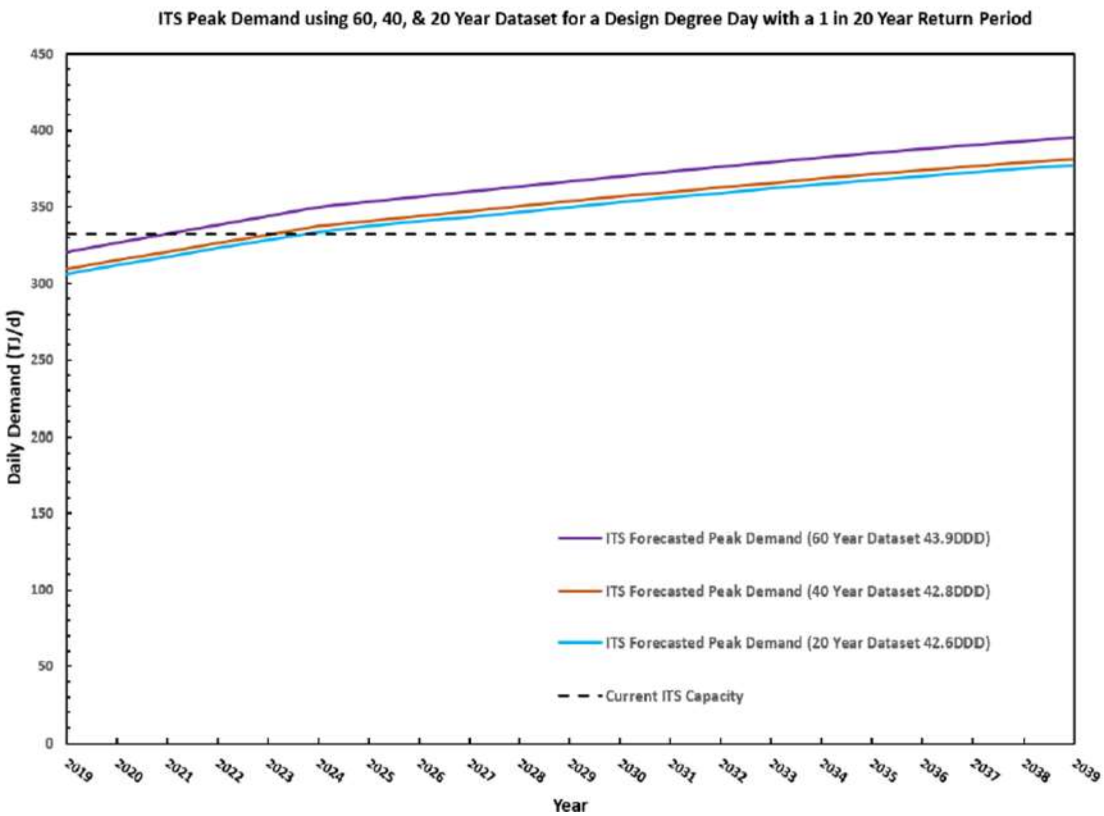
**Peak Demand Scenarios**

In response to BCUC IR 42.5.1, FEI provides the following figure showing peak demand forecasts with hypothetical savings from DSM measures:




In response to BCUC IR 42.5.1.2, FEI states: "At this time, FEI is not able to predict the direction of its annual incremental DSM energy savings beyond 2022."

In response to BCUC IR 43.2, FEI provides the ITS peak demand using a 60, 40 and 20 year dataset:




66.1 Please clarify whether in its response to BCUC IR 42.5.1, the line representing "DSM – 100% Res" is intended to represent residential and commercial customers.

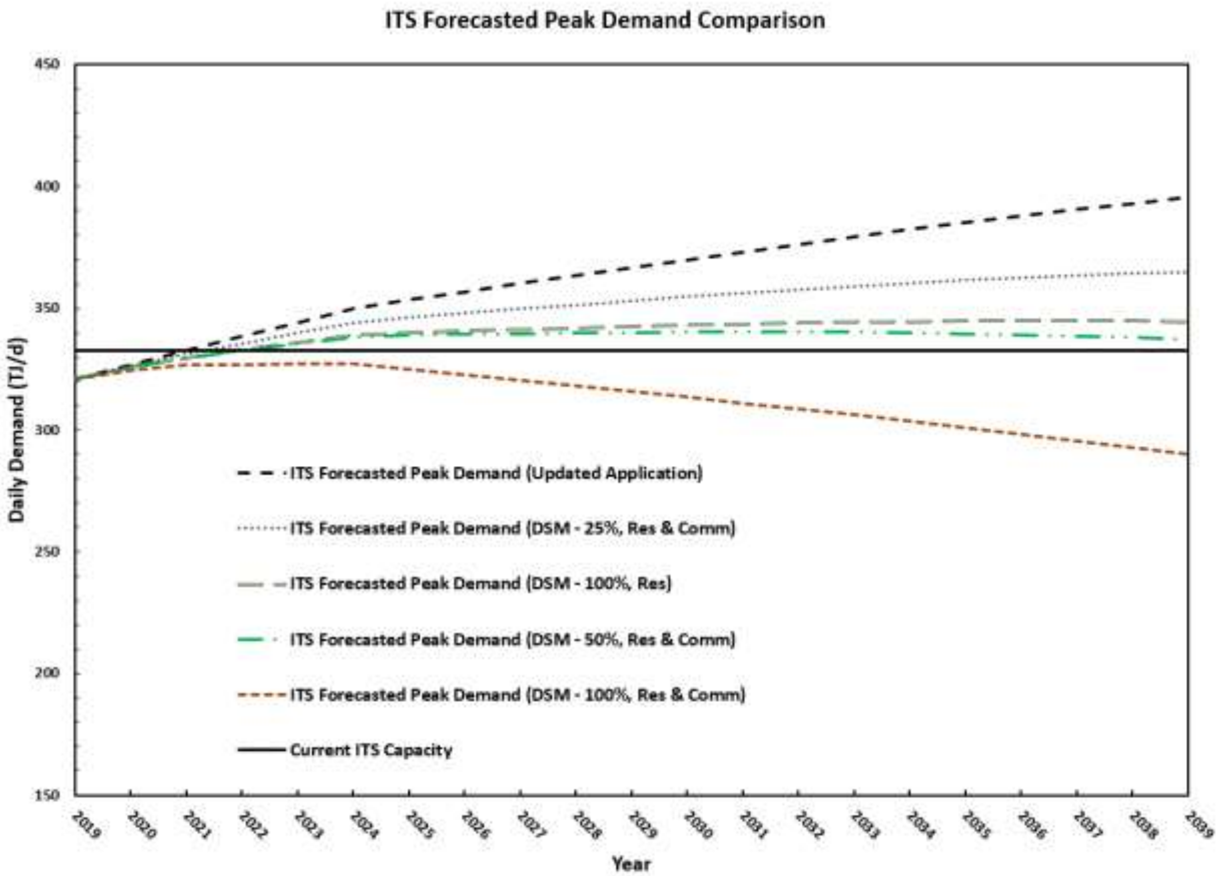
**Response:**

FEI confirms that "DSM – 100% RES" represents the DSM savings applied fully to the residential $UPC_{peak}$ only and is not applied to commercial customers.

66.1.1 If required, please correct the data in the figure and corresponding table to show the scenario with demand savings from commercial customers included.

**Response:**

The requested figure and corresponding table for this hypothetical and speculative additional scenario are provided below.


ITS Forecasted Peak Demand Comparison
Daily Demand (TJ/d)
450
400
350
300
250
200
150
ITS Forecasted Peak Demand (Updated Application)
ITS Forecasted Peak Demand (DSM - 25%, Res & Comm)
ITS Forecasted Peak Demand (DSM - 100%, Res)
ITS Forecasted Peak Demand (DSM - 50%, Res & Comm)
ITS Forecasted Peak Demand (DSM - 100%, Res & Comm)
Current ITS Capacity
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Year

1

| Year | ITS Forecasted Peak Demand Comparison | | | | |
|---|---|---|---|---|---|
| | Updated Application | DSM - 100% (Res) | DSM - 100% (Res & Comm) | DSM - 50% (Res & Comm) | DSM - 25% (Res & Comm) |
| | TJ/d | TJ/d | TJ/d | TJ/d | TJ/d |
| 2019 | 321 | 321 | 321 | 321 | 321 |
| 2020 | 327 | 326 | 325 | 326 | 326 |
| 2021 | 333 | 330 | 327 | 330 | 331 |
| 2022 | 338 | 333 | 327 | 333 | 335 |
| 2023 | 344 | 336 | 327 | 335 | 340 |
| 2024 | 350 | 339 | 327 | 338 | 344 |
| 2025 | 353 | 340 | 325 | 339 | 346 |
| 2026 | 357 | 341 | 323 | 339 | 348 |
| 2027 | 360 | 341 | 320 | 339 | 350 |
| 2028 | 363 | 342 | 318 | 340 | 351 |
| 2029 | 367 | 342 | 316 | 340 | 353 |
| 2030 | 370 | 343 | 313 | 340 | 355 |
| 2031 | 373 | 343 | 311 | 340 | 356 |
| 2032 | 376 | 344 | 309 | 340 | 358 |
| 2033 | 379 | 344 | 306 | 340 | 359 |
| 2034 | 382 | 344 | 304 | 340 | 360 |
| 2035 | 385 | 345 | 301 | 340 | 361 |
| 2036 | 388 | 345 | 298 | 339 | 362 |
| 2037 | 390 | 345 | 295 | 339 | 363 |
| 2038 | 393 | 345 | 293 | 338 | 364 |
| 2039 | 395 | 345 | 290 | 337 | 365 |

66.2 Please complete versions of the table below for the following scenarios:

- o ITS peak day forecasts in column B using a 60 year, 40 year and 20 year data-set for the calculation of the Design Degree Day (DDD);
- o Capacity shortfall with and without short-term mitigation measures; and
- o DSM savings in column E using the same assumptions as in FEI's response to BCUC IR 42.5.1, and an optional alternate scenario for post-2022 DSM savings (if FEI considers there is a more reasonable forecast assumption for future DSM energy savings following its current 2019 – 2022 plan).

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Year | ITS Peak Day Forecast - 60 Year Dataset | Capacity Shortfall - With Mitigation Measures, Total | Capacity Shortfall - With Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2021 | | | | | |
| 2022 | | | | | |
| 2023 | | | | | |
| 2024 | | | | | |
| 2025 | | | | | |
| 2026 | | | | | |
| 2027 | | | | | |
| 2028 | | | | | |
| 2029 | | | | | |
| 2030 | | | | | |
| 2031 | | | | | |
| 2032 | | | | | |
| 2033 | | | | | |
| 2034 | | | | | |
| 2035 | | | | | |
| 2036 | | | | | |
| 2037 | | | | | |
| 2038 | | | | | |
| 2039 | | | | | |

**Response:**

The requested tables for all scenarios are provided below. FEI has no basis to assess what level of annual DSM savings could reasonably be applied to the peak demand forecast and has therefore not speculated on a DSM scenario beyond what was requested. Please refer to the response to BCUC IR3 65.1 for a more detailed discussion on FEI's position.

**Table 1a: 60 Year Dataset with 25% Residential and Commercial DSM Savings, with Mitigation**

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Year | ITS Peak Day Forecast - 60 Year Dataset | Capacity Shortfall - With Mitigation Measures, Total | Capacity Shortfall - With Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2021 | 333 | -11 | -3.42% | 0.46% | Not required |
| 2022 | 338 | -6 | -1.65% | 0.86% | Not required |
| 2023 | 344 | 0 | 0.04% | 1.28% | 3% |
| 2024 | 350 | 6 | 1.69% | 1.69% | 100% |
| 2025 | 353 | 9 | 2.67% | 2.10% | 127% |

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Year | ITS Peak Day Forecast - 60 Year Dataset | Capacity Shortfall - With Mitigation Measures, Total | Capacity Shortfall - With Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2026 | 357 | 13 | 3.59% | 2.50% | 143% |
| 2027 | 360 | 16 | 4.46% | 2.91% | 153% |
| 2028 | 363 | 19 | 5.35% | 3.32% | 161% |
| 2029 | 367 | 23 | 6.19% | 3.72% | 166% |
| 2030 | 370 | 26 | 7.01% | 4.13% | 170% |
| 2031 | 373 | 29 | 7.81% | 4.53% | 172% |
| 2032 | 376 | 32 | 8.57% | 4.93% | 174% |
| 2033 | 379 | 35 | 9.31% | 5.34% | 174% |
| 2034 | 382 | 38 | 10.01% | 5.74% | 174% |
| 2035 | 385 | 41 | 10.67% | 6.14% | 174% |
| 2036 | 388 | 44 | 11.30% | 6.54% | 173% |
| 2037 | 390 | 46 | 11.89% | 6.94% | 171% |
| 2038 | 393 | 49 | 12.46% | 7.34% | 170% |
| 2039 | 395 | 51 | 13.00% | 7.74% | 168% |

**Table 1b: 60 Year Dataset with 25% Residential and Commercial DSM Savings, without Mitigation**

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Year | ITS Peak Day Forecast - 60 Year Dataset | Capacity Shortfall - Without Mitigation Measures, Total | Capacity Shortfall - Without Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2021 | 333 | 0 | 0.04% | 0.46% | 9% |
| 2022 | 338 | 6 | 1.75% | 0.86% | 202% |
| 2023 | 344 | 12 | 3.38% | 1.28% | 265% |
| 2024 | 350 | 17 | 4.97% | 1.69% | 294% |
| 2025 | 353 | 21 | 5.92% | 2.10% | 282% |
| 2026 | 357 | 24 | 6.81% | 2.50% | 272% |
| 2027 | 360 | 28 | 7.66% | 2.91% | 263% |
| 2028 | 363 | 31 | 8.51% | 3.32% | 257% |
| 2029 | 367 | 34 | 9.33% | 3.72% | 251% |
| 2030 | 370 | 37 | 10.12% | 4.13% | 245% |
| 2031 | 373 | 41 | 10.89% | 4.53% | 240% |
| 2032 | 376 | 44 | 11.63% | 4.93% | 236% |

| A | B | C | D | E | F |
| --- | --- | --- | --- | --- | --- |
| Year | ITS Peak Day Forecast - 60 Year Dataset | Capacity Shortfall - Without Mitigation Measures, Total | Capacity Shortfall - Without Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2033 | 379 | 47 | 12.34% | 5.34% | 231% |
| 2034 | 382 | 50 | 13.01% | 5.74% | 227% |
| 2035 | 385 | 53 | 13.66% | 6.14% | 222% |
| 2036 | 388 | 55 | 14.26% | 6.54% | 218% |
| 2037 | 390 | 58 | 14.83% | 6.94% | 214% |
| 2038 | 393 | 60 | 15.38% | 7.34% | 209% |
| 2039 | 395 | 63 | 15.90% | 7.74% | 205% |

**Table 2a: 40 Year Dataset with 25% Residential and Commercial DSM Savings, with Mitigation**

| A | B | C | D | E | F |
| --- | --- | --- | --- | --- | --- |
| Year | ITS Peak Day Forecast - 40 Year Dataset | Capacity Shortfall - With Mitigation Measures, Total | Capacity Shortfall - With Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2021 | 321 | -23 | -7.22% | 0.46% | Not required |
| 2022 | 326 | -18 | -5.38% | 0.86% | Not required |
| 2023 | 332 | -12 | -3.63% | 1.28% | Not required |
| 2024 | 338 | -6 | -1.92% | 1.69% | Not required |
| 2025 | 341 | -3 | -0.90% | 2.10% | Not required |
| 2026 | 344 | 0 | 0.05% | 2.50% | 2% |
| 2027 | 347 | 3 | 0.96% | 2.91% | 33% |
| 2028 | 351 | 7 | 1.87% | 3.32% | 57% |
| 2029 | 354 | 10 | 2.75% | 3.72% | 74% |
| 2030 | 357 | 13 | 3.61% | 4.13% | 87% |
| 2031 | 360 | 16 | 4.43% | 4.53% | 98% |
| 2032 | 363 | 19 | 5.23% | 4.93% | 106% |
| 2033 | 366 | 22 | 5.99% | 5.34% | 112% |
| 2034 | 369 | 25 | 6.71% | 5.74% | 117% |
| 2035 | 371 | 27 | 7.40% | 6.14% | 120% |
| 2036 | 374 | 30 | 8.05% | 6.54% | 123% |
| 2037 | 377 | 33 | 8.66% | 6.94% | 125% |
| 2038 | 379 | 35 | 9.25% | 7.34% | 126% |
| 2039 | 381 | 37 | 9.82% | 7.74% | 127% |

**Table 2b: 40 Year Dataset with 25% Residential and Commercial DSM Savings, without Mitigation**

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Year | ITS Peak Day Forecast - 40 Year Dataset | Capacity Shortfall - Without Mitigation Measures, Total | Capacity Shortfall - Without Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2021 | 321 | -12 | -3.63% | 0.46% | Not required |
| 2022 | 326 | -6 | -1.86% | 0.86% | Not required |
| 2023 | 332 | -1 | -0.17% | 1.28% | Not required |
| 2024 | 338 | 5 | 1.49% | 1.69% | 88% |
| 2025 | 341 | 8 | 2.47% | 2.10% | 118% |
| 2026 | 344 | 12 | 3.39% | 2.50% | 136% |
| 2027 | 347 | 15 | 4.27% | 2.91% | 147% |
| 2028 | 351 | 18 | 5.15% | 3.32% | 155% |
| 2029 | 354 | 21 | 6.00% | 3.72% | 161% |
| 2030 | 357 | 24 | 6.83% | 4.13% | 166% |
| 2031 | 360 | 27 | 7.63% | 4.53% | 168% |
| 2032 | 363 | 30 | 8.39% | 4.93% | 170% |
| 2033 | 366 | 33 | 9.13% | 5.34% | 171% |
| 2034 | 369 | 36 | 9.83% | 5.74% | 171% |
| 2035 | 371 | 39 | 10.49% | 6.14% | 171% |
| 2036 | 374 | 42 | 11.12% | 6.54% | 170% |
| 2037 | 377 | 44 | 11.72% | 6.94% | 169% |
| 2038 | 379 | 47 | 12.29% | 7.34% | 167% |
| 2039 | 381 | 49 | 12.83% | 7.74% | 166% |

**Table 3a: 20 Year Dataset with 25% Residential and Commercial DSM Savings, with Mitigation**

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Year | ITS Peak Day Forecast - 20 Year Dataset | Capacity Shortfall - With Mitigation Measures, Total | Capacity Shortfall - With Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2021 | 317 | -27 | -8.36% | 0.46% | Not Required |
| 2022 | 323 | -21 | -6.51% | 0.86% | Not Required |
| 2023 | 328 | -16 | -4.73% | 1.28% | Not Required |
| 2024 | 334 | -10 | -3.01% | 1.69% | Not Required |
| 2025 | 337 | -7 | -1.97% | 2.10% | Not Required |

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Year | ITS Peak Day Forecast - 20 Year Dataset | Capacity Shortfall - With Mitigation Measures, Total | Capacity Shortfall - With Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2026 | 341 | -3 | -1.01% | 2.50% | Not Required |
| 2027 | 344 | 0 | -0.09% | 2.91% | Not Required |
| 2028 | 347 | 3 | 0.84% | 3.32% | 25% |
| 2029 | 350 | 6 | 1.72% | 3.72% | 46% |
| 2030 | 353 | 9 | 2.59% | 4.13% | 63% |
| 2031 | 356 | 12 | 3.42% | 4.53% | 76% |
| 2032 | 359 | 15 | 4.22% | 4.93% | 86% |
| 2033 | 362 | 18 | 5.00% | 5.34% | 94% |
| 2034 | 365 | 21 | 5.73% | 5.74% | 100% |
| 2035 | 368 | 24 | 6.42% | 6.14% | 105% |
| 2036 | 370 | 26 | 7.08% | 6.54% | 108% |
| 2037 | 373 | 29 | 7.70% | 6.94% | 111% |
| 2038 | 375 | 31 | 8.30% | 7.34% | 113% |
| 2039 | 377 | 33 | 8.87% | 7.74% | 115% |

**Table 3b: 20 Year Dataset with 25% Residential and Commercial DSM Savings, without Mitigation**

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Year | ITS Peak Day Forecast - 20 Year Dataset | Capacity Shortfall - Without Mitigation Measures, Total | Capacity Shortfall - Without Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2021 | 317 | -15 | -4.74% | 0.46% | Not required |
| 2022 | 323 | -10 | -2.95% | 0.86% | Not required |
| 2023 | 328 | -4 | -1.23% | 1.28% | Not required |
| 2024 | 334 | 1 | 0.44% | 1.69% | 26% |
| 2025 | 337 | 5 | 1.44% | 2.10% | 69% |
| 2026 | 341 | 8 | 2.37% | 2.50% | 95% |
| 2027 | 344 | 11 | 3.26% | 2.91% | 112% |
| 2028 | 347 | 14 | 4.15% | 3.32% | 125% |
| 2029 | 350 | 18 | 5.01% | 3.72% | 135% |
| 2030 | 353 | 21 | 5.85% | 4.13% | 142% |
| 2031 | 356 | 24 | 6.65% | 4.53% | 147% |
| 2032 | 359 | 27 | 7.42% | 4.93% | 150% |

| A | B | C | D | E | F |
| --- | --- | --- | --- | --- | --- |
| Year | ITS Peak Day Forecast - 20 Year Dataset | Capacity Shortfall - Without Mitigation Measures, Total | Capacity Shortfall - Without Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2033 | 362 | 30 | 8.17% | 5.34% | 153% |
| 2034 | 365 | 32 | 8.88% | 5.74% | 155% |
| 2035 | 368 | 35 | 9.55% | 6.14% | 156% |
| 2036 | 370 | 38 | 10.19% | 6.54% | 156% |
| 2037 | 373 | 40 | 10.79% | 6.94% | 155% |
| 2038 | 375 | 43 | 11.36% | 7.34% | 155% |
| 2039 | 377 | 45 | 11.91% | 7.74% | 154% |

**Table 4a: 60 Year Dataset with 100% Residential DSM Savings, with Mitigation**

| A | B | C | D | E | F |
| --- | --- | --- | --- | --- | --- |
| Year | ITS Peak Day Forecast - 60 Year Dataset | Capacity Shortfall - With Mitigation Measures, Total | Capacity Shortfall - With Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2021 | 333 | -11 | -3.42% | 2.18% | Not required |
| 2022 | 338 | -6 | -1.65% | 4.02% | Not required |
| 2023 | 344 | 0 | 0.04% | 5.83% | 1% |
| 2024 | 350 | 6 | 1.69% | 7.61% | 22% |
| 2025 | 353 | 9 | 2.67% | 9.34% | 29% |
| 2026 | 357 | 13 | 3.59% | 11.04% | 33% |
| 2027 | 360 | 16 | 4.46% | 12.70% | 35% |
| 2028 | 363 | 19 | 5.35% | 14.33% | 37% |
| 2029 | 367 | 23 | 6.19% | 15.93% | 39% |
| 2030 | 370 | 26 | 7.01% | 17.49% | 40% |
| 2031 | 373 | 29 | 7.81% | 19.03% | 41% |
| 2032 | 376 | 32 | 8.57% | 20.54% | 42% |
| 2033 | 379 | 35 | 9.31% | 22.01% | 42% |
| 2034 | 382 | 38 | 10.01% | 23.47% | 43% |
| 2035 | 385 | 41 | 10.67% | 24.88% | 43% |
| 2036 | 388 | 44 | 11.30% | 26.28% | 43% |
| 2037 | 390 | 46 | 11.89% | 27.65% | 43% |
| 2038 | 393 | 49 | 12.46% | 28.99% | 43% |
| 2039 | 395 | 51 | 13.00% | 30.30% | 43% |

**Table 4b: 60 Year Dataset with 100% Residential DSM Savings, without Mitigation**

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Year | ITS Peak Day Forecast - 60 Year Dataset | Capacity Shortfall - Without Mitigation Measures, Total | Capacity Shortfall - Without Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2021 | 333 | 0 | 0.04% | 2.18% | 2% |
| 2022 | 338 | 6 | 1.75% | 4.02% | 44% |
| 2023 | 344 | 12 | 3.38% | 5.83% | 58% |
| 2024 | 350 | 17 | 4.97% | 7.61% | 65% |
| 2025 | 353 | 21 | 5.92% | 9.34% | 63% |
| 2026 | 357 | 24 | 6.81% | 11.04% | 62% |
| 2027 | 360 | 28 | 7.66% | 12.70% | 60% |
| 2028 | 363 | 31 | 8.51% | 14.33% | 59% |
| 2029 | 367 | 34 | 9.33% | 15.93% | 59% |
| 2030 | 370 | 37 | 10.12% | 17.49% | 58% |
| 2031 | 373 | 41 | 10.89% | 19.03% | 57% |
| 2032 | 376 | 44 | 11.63% | 20.54% | 57% |
| 2033 | 379 | 47 | 12.34% | 22.01% | 56% |
| 2034 | 382 | 50 | 13.01% | 23.47% | 55% |
| 2035 | 385 | 53 | 13.66% | 24.88% | 55% |
| 2036 | 388 | 55 | 14.26% | 26.28% | 54% |
| 2037 | 390 | 58 | 14.83% | 27.65% | 54% |
| 2038 | 393 | 60 | 15.38% | 28.99% | 53% |
| 2039 | 395 | 63 | 15.90% | 30.30% | 52% |

**Table 5a: 40 Year Dataset with 100% Residential DSM Savings, with Mitigation**

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Year | ITS Peak Day Forecast - 40 Year Dataset | Capacity Shortfall - With Mitigation Measures, Total | Capacity Shortfall - With Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2021 | 321 | -23 | -7.22% | 2.18% | Not required |
| 2022 | 326 | -18 | -5.38% | 4.02% | Not required |
| 2023 | 332 | -12 | -3.63% | 5.83% | Not required |
| 2024 | 338 | -6 | -1.92% | 7.61% | Not required |
| 2025 | 341 | -3 | -0.90% | 9.34% | Not required |

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Year | ITS Peak Day Forecast - 40 Year Dataset | Capacity Shortfall - With Mitigation Measures, Total | Capacity Shortfall - With Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2026 | 344 | 0 | 0.05% | 11.04% | 0% |
| 2027 | 347 | 3 | 0.96% | 12.70% | 8% |
| 2028 | 351 | 7 | 1.87% | 14.33% | 13% |
| 2029 | 354 | 10 | 2.75% | 15.93% | 17% |
| 2030 | 357 | 13 | 3.61% | 17.49% | 21% |
| 2031 | 360 | 16 | 4.43% | 19.03% | 23% |
| 2032 | 363 | 19 | 5.23% | 20.54% | 25% |
| 2033 | 366 | 22 | 5.99% | 22.01% | 27% |
| 2034 | 369 | 25 | 6.71% | 23.47% | 29% |
| 2035 | 371 | 27 | 7.40% | 24.88% | 30% |
| 2036 | 374 | 30 | 8.05% | 26.28% | 31% |
| 2037 | 377 | 33 | 8.66% | 27.65% | 31% |
| 2038 | 379 | 35 | 9.25% | 28.99% | 32% |
| 2039 | 381 | 37 | 9.82% | 30.30% | 32% |

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2 **Table 5b: 40 Year Dataset with 100% Residential DSM Savings, without Mitigation**

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Year | ITS Peak Day Forecast - 40 Year Dataset | Capacity Shortfall - Without Mitigation Measures, Total | Capacity Shortfall - Without Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2021 | 321 | -12 | -3.63% | 2.18% | Not required |
| 2022 | 326 | -6 | -1.86% | 4.02% | Not required |
| 2023 | 332 | -1 | -0.17% | 5.83% | Not required |
| 2024 | 338 | 5 | 1.49% | 7.61% | 20% |
| 2025 | 341 | 8 | 2.47% | 9.34% | 26% |
| 2026 | 344 | 12 | 3.39% | 11.04% | 31% |
| 2027 | 347 | 15 | 4.27% | 12.70% | 34% |
| 2028 | 351 | 18 | 5.15% | 14.33% | 36% |
| 2029 | 354 | 21 | 6.00% | 15.93% | 38% |
| 2030 | 357 | 24 | 6.83% | 17.49% | 39% |
| 2031 | 360 | 27 | 7.63% | 19.03% | 40% |
| 2032 | 363 | 30 | 8.39% | 20.54% | 41% |

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Year | ITS Peak Day Forecast - 40 Year Dataset | Capacity Shortfall - Without Mitigation Measures, Total | Capacity Shortfall - Without Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2033 | 366 | 33 | 9.13% | 22.01% | 41% |
| 2034 | 369 | 36 | 9.83% | 23.47% | 42% |
| 2035 | 371 | 39 | 10.49% | 24.88% | 42% |
| 2036 | 374 | 42 | 11.12% | 26.28% | 42% |
| 2037 | 377 | 44 | 11.72% | 27.65% | 42% |
| 2038 | 379 | 47 | 12.29% | 28.99% | 42% |
| 2039 | 381 | 49 | 12.83% | 30.30% | 42% |

**Table 6a: 20 Year Dataset with 100% Residential DSM Savings, with Mitigation**

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Year | ITS Peak Day Forecast - 20 Year Dataset | Capacity Shortfall - With Mitigation Measures, Total | Capacity Shortfall - With Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2021 | 317 | -27 | -8.36% | 2.18% | Not Required |
| 2022 | 323 | -21 | -6.51% | 4.02% | Not Required |
| 2023 | 328 | -16 | -4.73% | 5.83% | Not Required |
| 2024 | 334 | -10 | -3.01% | 7.61% | Not Required |
| 2025 | 337 | -7 | -1.97% | 9.34% | Not Required |
| 2026 | 341 | -3 | -1.01% | 11.04% | Not Required |
| 2027 | 344 | 0 | -0.09% | 12.70% | Not Required |
| 2028 | 347 | 3 | 0.84% | 14.33% | 6% |
| 2029 | 350 | 6 | 1.72% | 15.93% | 11% |
| 2030 | 353 | 9 | 2.59% | 17.49% | 15% |
| 2031 | 356 | 12 | 3.42% | 19.03% | 18% |
| 2032 | 359 | 15 | 4.22% | 20.54% | 21% |
| 2033 | 362 | 18 | 5.00% | 22.01% | 23% |
| 2034 | 365 | 21 | 5.73% | 23.47% | 24% |
| 2035 | 368 | 24 | 6.42% | 24.88% | 26% |
| 2036 | 370 | 26 | 7.08% | 26.28% | 27% |
| 2037 | 373 | 29 | 7.70% | 27.65% | 28% |
| 2038 | 375 | 31 | 8.30% | 28.99% | 29% |
| 2039 | 377 | 33 | 8.87% | 30.30% | 29% |

**Table 6b: 20 Year Dataset with 100% Residential DSM Savings, without Mitigation**

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Year | ITS Peak Day Forecast - 40 Year Dataset | Capacity Shortfall - Without Mitigation Measures, Total | Capacity Shortfall - Without Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2021 | 317 | -15 | -4.74% | 2.18% | Not required |
| 2022 | 323 | -10 | -2.95% | 4.02% | Not required |
| 2023 | 328 | -4 | -1.23% | 5.83% | Not required |
| 2024 | 334 | 1 | 0.44% | 7.61% | 6% |
| 2025 | 337 | 5 | 1.44% | 9.34% | 15% |
| 2026 | 341 | 8 | 2.37% | 11.04% | 21% |
| 2027 | 344 | 11 | 3.26% | 12.70% | 26% |
| 2028 | 347 | 14 | 4.15% | 14.33% | 29% |
| 2029 | 350 | 18 | 5.01% | 15.93% | 31% |
| 2030 | 353 | 21 | 5.85% | 17.49% | 33% |
| 2031 | 356 | 24 | 6.65% | 19.03% | 35% |
| 2032 | 359 | 27 | 7.42% | 20.54% | 36% |
| 2033 | 362 | 30 | 8.17% | 22.01% | 37% |
| 2034 | 365 | 32 | 8.88% | 23.47% | 38% |
| 2035 | 368 | 35 | 9.55% | 24.88% | 38% |
| 2036 | 370 | 38 | 10.19% | 26.28% | 39% |
| 2037 | 373 | 40 | 10.79% | 27.65% | 39% |
| 2038 | 375 | 43 | 11.36% | 28.99% | 39% |
| 2039 | 377 | 45 | 11.91% | 30.30% | 39% |

**Table 7a: 60 Year Dataset with 50% Residential and Commercial DSM Savings, with Mitigation**

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Year | ITS Peak Day Forecast - 60 Year Dataset | Capacity Shortfall - With Mitigation Measures, Total | Capacity Shortfall - With Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2021 | 333 | -11 | -3.42% | 0.91% | Not required |
| 2022 | 338 | -6 | -1.65% | 1.72% | Not required |
| 2023 | 344 | 0 | 0.04% | 2.53% | 2% |
| 2024 | 350 | 6 | 1.69% | 3.35% | 50% |
| 2025 | 353 | 9 | 2.67% | 4.14% | 64% |

| A | B | C | D | E | F |
| --- | --- | --- | --- | --- | --- |
| Year | ITS Peak Day Forecast - 60 Year Dataset | Capacity Shortfall - With Mitigation Measures, Total | Capacity Shortfall - With Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2026 | 357 | 13 | 3.59% | 4.93% | 73% |
| 2027 | 360 | 16 | 4.46% | 5.71% | 78% |
| 2028 | 363 | 19 | 5.35% | 6.49% | 82% |
| 2029 | 367 | 23 | 6.19% | 7.27% | 85% |
| 2030 | 370 | 26 | 7.01% | 8.04% | 87% |
| 2031 | 373 | 29 | 7.81% | 8.80% | 89% |
| 2032 | 376 | 32 | 8.57% | 9.56% | 90% |
| 2033 | 379 | 35 | 9.31% | 10.32% | 90% |
| 2034 | 382 | 38 | 10.01% | 11.06% | 90% |
| 2035 | 385 | 41 | 10.67% | 11.81% | 90% |
| 2036 | 388 | 44 | 11.30% | 12.54% | 90% |
| 2037 | 390 | 46 | 11.89% | 13.28% | 90% |
| 2038 | 393 | 49 | 12.46% | 14.00% | 89% |
| 2039 | 395 | 51 | 13.00% | 14.72% | 88% |

**Table 7b: 60 Year Dataset with 50% Residential and Commercial DSM Savings, without Mitigation**

| A | B | C | D | E | F |
| --- | --- | --- | --- | --- | --- |
| Year | ITS Peak Day Forecast - 60 Year Dataset | Capacity Shortfall - Without Mitigation Measures, Total | Capacity Shortfall - Without Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2021 | 333 | 0 | 0.04% | 0.91% | 4% |
| 2022 | 338 | 6 | 1.75% | 1.72% | 102% |
| 2023 | 344 | 12 | 3.38% | 2.53% | 134% |
| 2024 | 350 | 17 | 4.97% | 3.35% | 149% |
| 2025 | 353 | 21 | 5.92% | 4.14% | 143% |
| 2026 | 357 | 24 | 6.81% | 4.93% | 138% |
| 2027 | 360 | 28 | 7.66% | 5.71% | 134% |
| 2028 | 363 | 31 | 8.51% | 6.49% | 131% |
| 2029 | 367 | 34 | 9.33% | 7.27% | 128% |
| 2030 | 370 | 37 | 10.12% | 8.04% | 126% |
| 2031 | 373 | 41 | 10.89% | 8.80% | 124% |
| 2032 | 376 | 44 | 11.63% | 9.56% | 122% |

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Year | ITS Peak Day Forecast - 60 Year Dataset | Capacity Shortfall - Without Mitigation Measures, Total | Capacity Shortfall - Without Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2033 | 379 | 47 | 12.34% | 10.32% | 120% |
| 2034 | 382 | 50 | 13.01% | 11.06% | 118% |
| 2035 | 385 | 53 | 13.66% | 11.81% | 116% |
| 2036 | 388 | 55 | 14.26% | 12.54% | 114% |
| 2037 | 390 | 58 | 14.83% | 13.28% | 112% |
| 2038 | 393 | 60 | 15.38% | 14.00% | 110% |
| 2039 | 395 | 63 | 15.90% | 14.72% | 108% |

**Table 8a: 40 Year Dataset with 50% Residential and Commercial DSM Savings, with Mitigation**

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Year | ITS Peak Day Forecast - 40 Year Dataset | Capacity Shortfall - With Mitigation Measures, Total | Capacity Shortfall - With Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2021 | 321 | -23 | -7.22% | 0.91% | Not required |
| 2022 | 326 | -18 | -5.38% | 1.72% | Not required |
| 2023 | 332 | -12 | -3.63% | 2.53% | Not required |
| 2024 | 338 | -6 | -1.92% | 3.35% | Not required |
| 2025 | 341 | -3 | -0.90% | 4.14% | Not required |
| 2026 | 344 | 0 | 0.05% | 4.93% | 1% |
| 2027 | 347 | 3 | 0.96% | 5.71% | 17% |
| 2028 | 351 | 7 | 1.87% | 6.49% | 29% |
| 2029 | 354 | 10 | 2.75% | 7.27% | 38% |
| 2030 | 357 | 13 | 3.61% | 8.04% | 45% |
| 2031 | 360 | 16 | 4.43% | 8.80% | 50% |
| 2032 | 363 | 19 | 5.23% | 9.56% | 55% |
| 2033 | 366 | 22 | 5.99% | 10.32% | 58% |
| 2034 | 369 | 25 | 6.71% | 11.06% | 61% |
| 2035 | 371 | 27 | 7.40% | 11.81% | 63% |
| 2036 | 374 | 30 | 8.05% | 12.54% | 64% |
| 2037 | 377 | 33 | 8.66% | 13.28% | 65% |
| 2038 | 379 | 35 | 9.25% | 14.00% | 66% |
| 2039 | 381 | 37 | 9.82% | 14.72% | 67% |

**Table 8b: 40 Year Dataset with 50% Residential and Commercial DSM Savings, without Mitigation**

| A | B | C | D | E | F |
| --- | --- | --- | --- | --- | --- |
| Year | ITS Peak Day Forecast - 40 Year Dataset | Capacity Shortfall - Without Mitigation Measures, Total | Capacity Shortfall - Without Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2021 | 321 | -12 | -3.63% | 0.91% | Not required |
| 2022 | 326 | -6 | -1.86% | 1.72% | Not required |
| 2023 | 332 | -1 | -0.17% | 2.53% | Not required |
| 2024 | 338 | 5 | 1.49% | 3.35% | 44% |
| 2025 | 341 | 8 | 2.47% | 4.14% | 60% |
| 2026 | 344 | 12 | 3.39% | 4.93% | 69% |
| 2027 | 347 | 15 | 4.27% | 5.71% | 75% |
| 2028 | 351 | 18 | 5.15% | 6.49% | 79% |
| 2029 | 354 | 21 | 6.00% | 7.27% | 83% |
| 2030 | 357 | 24 | 6.83% | 8.04% | 85% |
| 2031 | 360 | 27 | 7.63% | 8.80% | 87% |
| 2032 | 363 | 30 | 8.39% | 9.56% | 88% |
| 2033 | 366 | 33 | 9.13% | 10.32% | 89% |
| 2034 | 369 | 36 | 9.83% | 11.06% | 89% |
| 2035 | 371 | 39 | 10.49% | 11.81% | 89% |
| 2036 | 374 | 42 | 11.12% | 12.54% | 89% |
| 2037 | 377 | 44 | 11.72% | 13.28% | 88% |
| 2038 | 379 | 47 | 12.29% | 14.00% | 88% |
| 2039 | 381 | 49 | 12.83% | 14.72% | 87% |

**Table 9a: 20 Year Dataset with 50% Residential and Commercial DSM Savings, with Mitigation**

| A | B | C | D | E | F |
| --- | --- | --- | --- | --- | --- |
| Year | ITS Peak Day Forecast - 20 Year Dataset | Capacity Shortfall - With Mitigation Measures, Total | Capacity Shortfall - With Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2021 | 317 | -27 | -8.36% | 0.91% | Not Required |
| 2022 | 323 | -21 | -6.51% | 1.72% | Not Required |
| 2023 | 328 | -16 | -4.73% | 2.53% | Not Required |
| 2024 | 334 | -10 | -3.01% | 3.35% | Not Required |

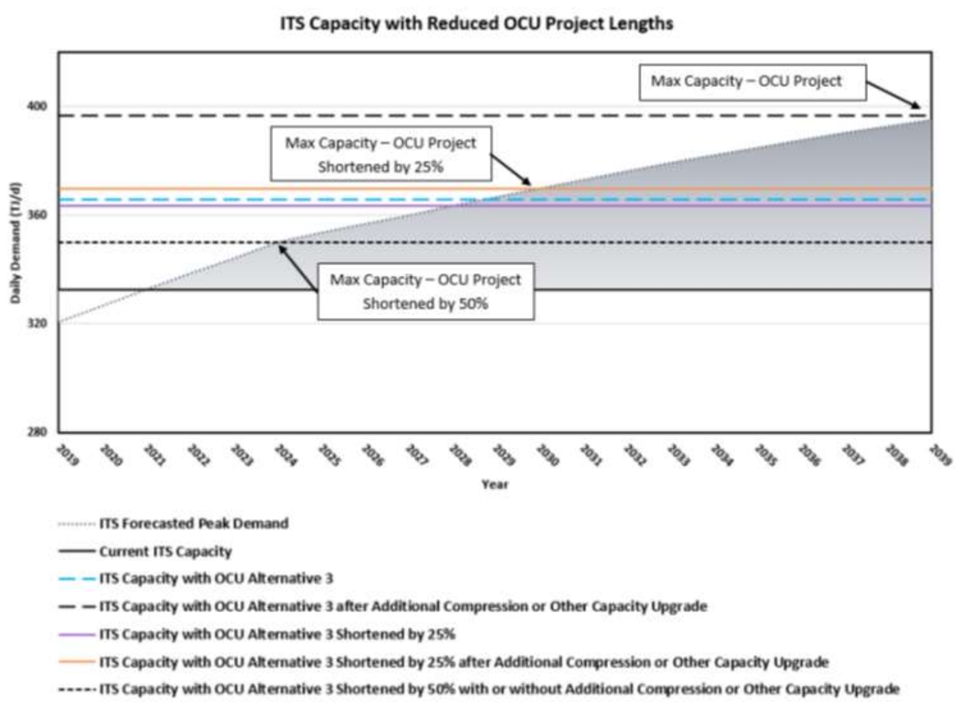
| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Year | ITS Peak Day Forecast - 20 Year Dataset | Capacity Shortfall - With Mitigation Measures, Total | Capacity Shortfall - With Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2025 | 337 | -7 | -1.97% | 4.14% | Not Required |
| 2026 | 341 | -3 | -1.01% | 4.93% | Not Required |
| 2027 | 344 | 0 | -0.09% | 5.71% | Not Required |
| 2028 | 347 | 3 | 0.84% | 6.49% | 13% |
| 2029 | 350 | 6 | 1.72% | 7.27% | 24% |
| 2030 | 353 | 9 | 2.59% | 8.04% | 32% |
| 2031 | 356 | 12 | 3.42% | 8.80% | 39% |
| 2032 | 359 | 15 | 4.22% | 9.56% | 44% |
| 2033 | 362 | 18 | 5.00% | 10.32% | 48% |
| 2034 | 365 | 21 | 5.73% | 11.06% | 52% |
| 2035 | 368 | 24 | 6.42% | 11.81% | 54% |
| 2036 | 370 | 26 | 7.08% | 12.54% | 56% |
| 2037 | 373 | 29 | 7.70% | 13.28% | 58% |
| 2038 | 375 | 31 | 8.30% | 14.00% | 59% |
| 2039 | 377 | 33 | 8.87% | 14.72% | 60% |

**Table 9b: 20 Year Dataset with 50% Residential and Commercial DSM Savings, without Mitigation**

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Year | ITS Peak Day Forecast - 40 Year Dataset | Capacity Shortfall - Without Mitigation Measures, Total | Capacity Shortfall - Without Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2021 | 317 | -15 | -4.74% | 0.91% | Not required |
| 2022 | 323 | -10 | -2.95% | 1.72% | Not required |
| 2023 | 328 | -4 | -1.23% | 2.53% | Not required |
| 2024 | 334 | 1 | 0.44% | 3.35% | 13% |
| 2025 | 337 | 5 | 1.44% | 4.14% | 35% |
| 2026 | 341 | 8 | 2.37% | 4.93% | 48% |
| 2027 | 344 | 11 | 3.26% | 5.71% | 57% |
| 2028 | 347 | 14 | 4.15% | 6.49% | 64% |
| 2029 | 350 | 18 | 5.01% | 7.27% | 69% |
| 2030 | 353 | 21 | 5.85% | 8.04% | 73% |
| 2031 | 356 | 24 | 6.65% | 8.80% | 76% |

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Year | ITS Peak Day Forecast - 40 Year Dataset | Capacity Shortfall - Without Mitigation Measures, Total | Capacity Shortfall - Without Mitigation Measures, Percentage (C/B) | Cumulative DSM Energy Savings as Percentage of Total Energy Demand | Proportion of DSM Energy Savings Needed to Reduce Peak Demand (D/E) |
| | TJ/d | TJ/d | % | % | % |
| 2032 | 359 | 27 | 7.42% | 9.56% | 78% |
| 2033 | 362 | 30 | 8.17% | 10.32% | 79% |
| 2034 | 365 | 32 | 8.88% | 11.06% | 80% |
| 2035 | 368 | 35 | 9.55% | 11.81% | 81% |
| 2036 | 370 | 38 | 10.19% | 12.54% | 81% |
| 2037 | 373 | 40 | 10.79% | 13.28% | 81% |
| 2038 | 375 | 43 | 11.36% | 14.00% | 81% |
| 2039 | 377 | 45 | 11.91% | 14.72% | 81% |

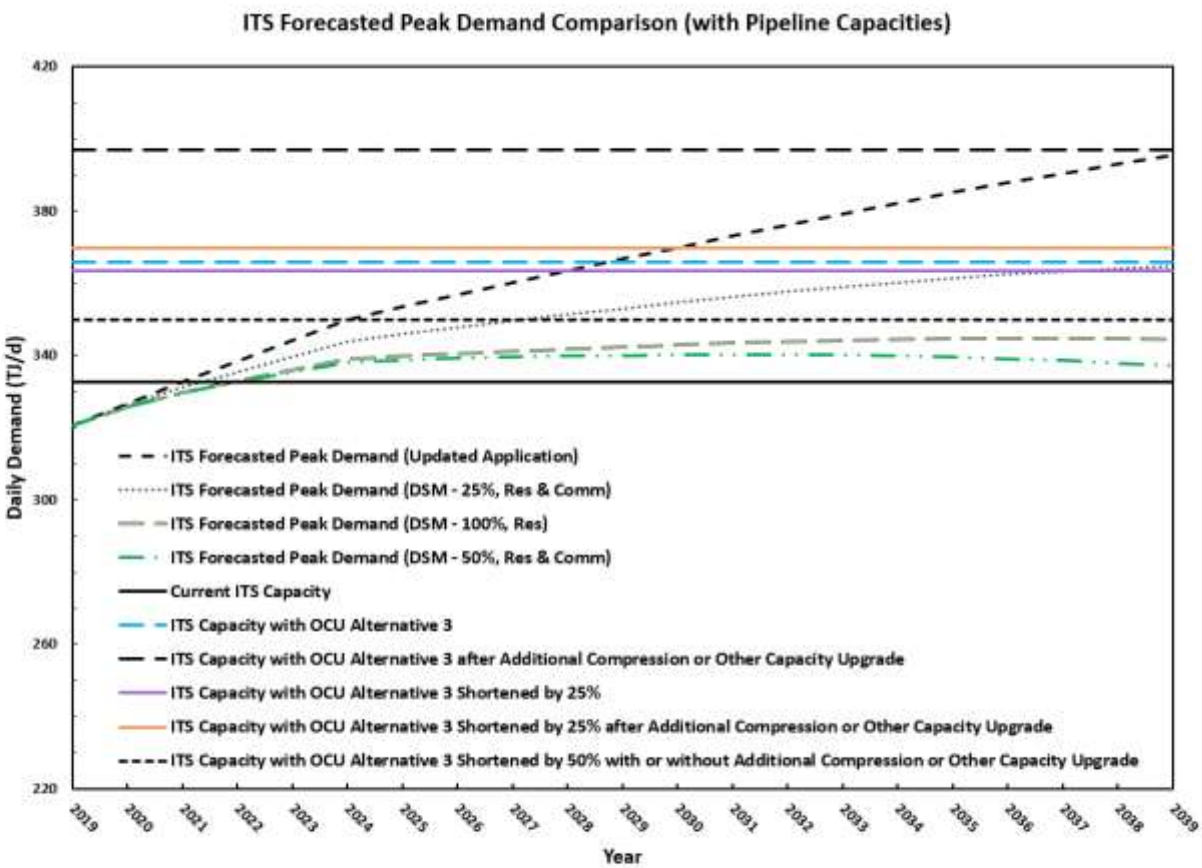
In response to BCUC IR 50.1, FEI provided the graph below illustrating the ITS capacity if the proposed pipeline was shortened by 25 percent or by 50 percent.

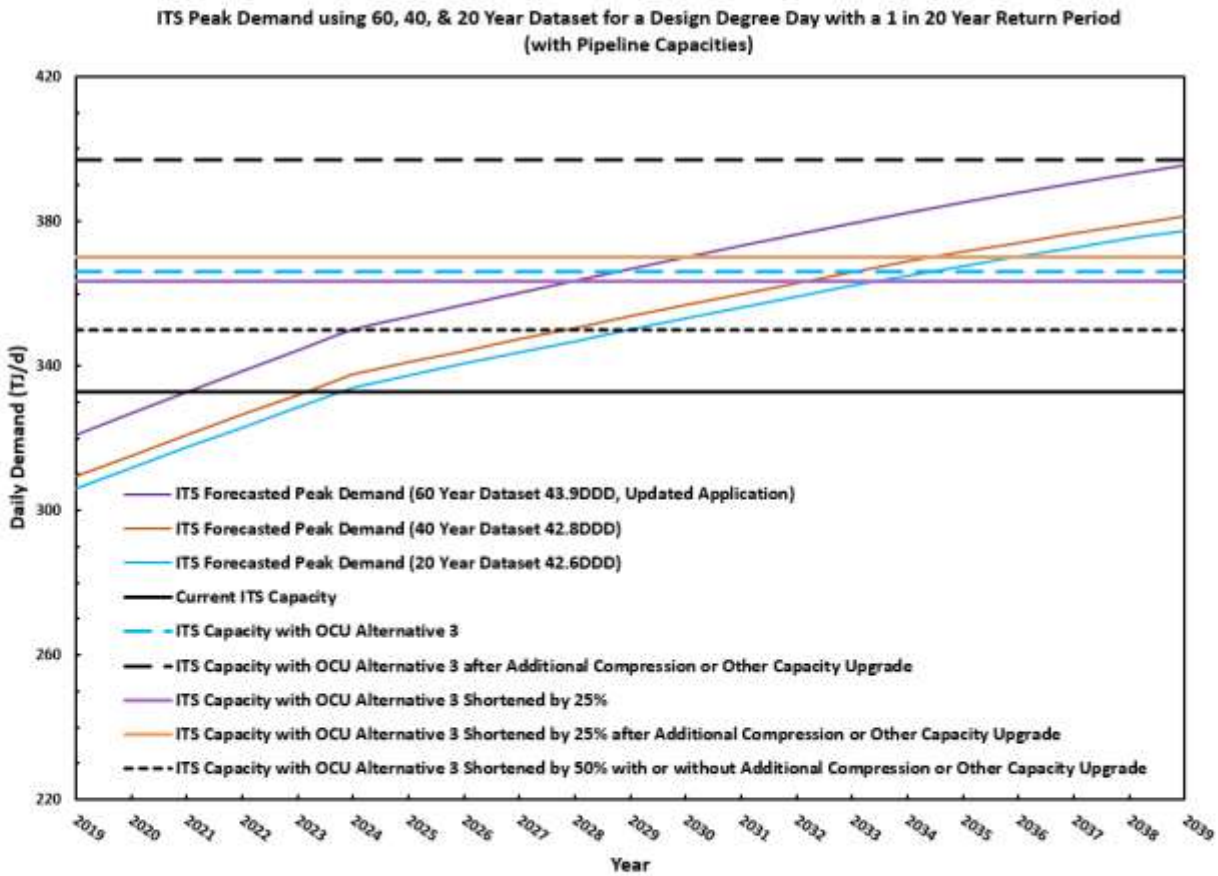


66.3 Please provide versions of the figures provided in response to BCUC IR 42.5.1 and IR 43.2 overlayed with the capacity of the alternatives outlined in the response to BCUC IR 50.1.

**Response:**

The revised figures requested are provided below.






66.3.1 Please also estimate the length of pipeline that would be required to meet each of the peak demand forecasts outlined in BCUC IR 42.5.1 and IR 43.2.

**Response:**

The estimated pipeline lengths for each hypothetical forecast scenario are included in the table below.

**Required OCU Pipeline Length for Hypothetical Peak Demand Forecasts**

| Load Forecast Scenario | Year | Length Required (km) | Original Length (km) | Approximate Length Reduction (percent) | Future Compressor Capacity Upgrade |
| --- | --- | --- | --- | --- | --- |
| DSM 25% Res & Comm | 2039 | 21.6 | 29.7 | 27 | Yes |
| DSM 100% Res | 2039 | 16.7 | 29.7 | 44 | No |
| DSM 50% Res & Comm | 2039 | 14.1 | 29.7 | 53 | No |
| 40 Yrs Dataset | 2039 | 26.3 | 29.7 | 11 | Yes |
| 20 Yrs Dataset | 2039 | 25.8 | 29.7 | 13 | Yes |

## B. PROJECT DESCRIPTION

**67.0 Reference: PROJECT DESCRIPTION**

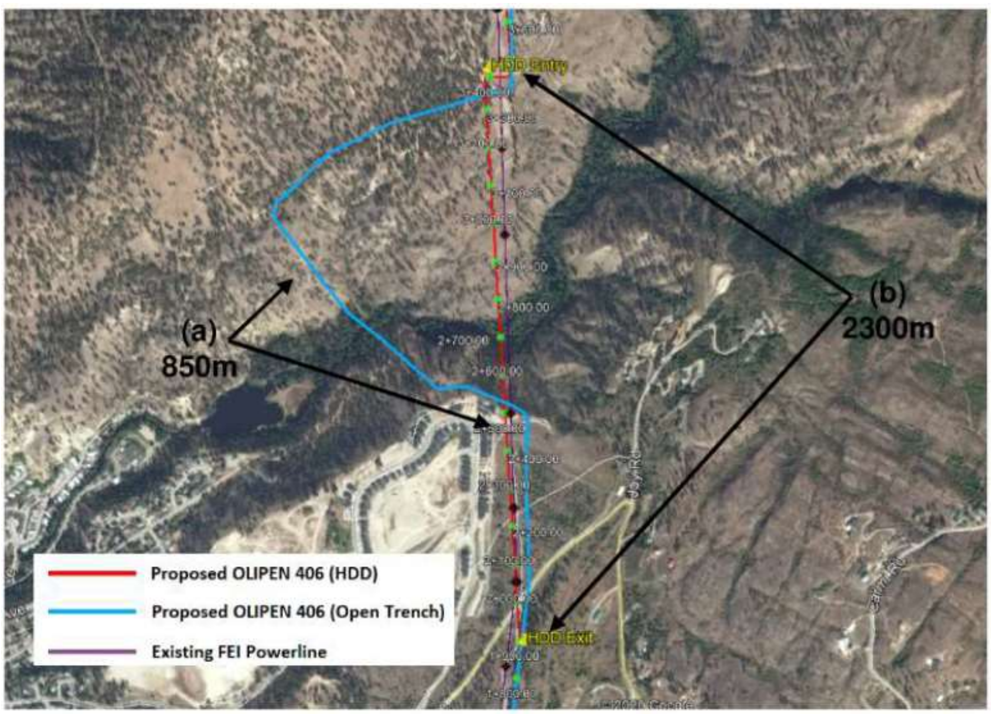
**Exhibit B-14, BCUC IR 54.1; Exhibit B-2, BCUC IR 26.4**

**Penticton Creek Crossing**

In response to BCUC IR 54.1, FEI states:

> In the event that a material change to the proposed route alignment, outside the bounds of the Penticton Creek crossing, is necessary (i.e., a portion of the pipeline cannot be constructed in the approved corridor), FEI will file an application for approval from the BCUC to modify the route at least 90 days before construction is proposed to commence.

In response to BCUC IR 26.4, FEI provides the following map showing the proposed route alignments for horizontal directional drilling (HDD) and open trench crossings of Penticton Creek.




67.1 Please identify the bounds of the Penticton Creek crossing on the map provided in the preamble and explain how these boundaries were determined.

**<u>Response:</u>**

The outer bounds of the Penticton Creek crossing are generally as shown in the image, identified in yellow text as the “HDD Entry” to the north and “HDD Exit” to the south as well as between the blue line identified as “Open Trench” to the west and red line identified as “HDD” to the east.

The bounds of the Penticton Creek crossing area are based on the work completed by various construction and engineering consulting experts and specialists during the development phase to identify an appropriate HDD alignment and open trench alignment across the Penticton Creek Ravine. The HDD alignment presented is the shortest path across the canyon that provides the highest probability of success given the terrain profile, elevation differences, and geological formations between the entry and exit points. The open trench alignment presented was selected based on having the least construction challenges considering the ravine environment, while still adhering to the routing criteria.

As outlined in FEI’s response to BCUC IR1 26.1, if the open trench option proves more feasible than the HDD during detailed design, FEI may proceed with an open trench as the preferred option, with the HDD option as a contingency plan. FEI does not expect any deviations with respect to the HDD alignment and limited, if any, deviations beyond what is outlined in the image included within the preamble, for the open trench option.

67.2 Please discuss whether FEI has identified any potential issues with the proposed route alignments for HDD and open trench crossings that may require a portion of the route alignment to be outside the identified bounds of the Penticton Creek crossing.

**Response:**

FEI has identified one potential issue that is localized near to four homes in the Brent Drive area of Penticton where construction could be challenging due to the close proximity to those homes to the gas line alignment and the steep slopes and terrain. FEI’s project team has identified a civil engineering solution in this location that would stabilize the slopes to allow the alignment to remain within the identified bounds, and is working with geotechnical and construction experts to confirm the solution.

67.3 Please discuss whether FEI has identified any alternative crossing of Penticton Creek which is partially or fully outside the identified bounds.

67.3.1 If yes, please describe the alternative in detail and provide a map showing the route.

**Response:**

FEI has not identified any alternative crossing of Penticton Creek which is partially or fully outside of the bounds identified within the image shown in the map referenced.

## C. DESCRIPTION AND EVALUATIONS OF ALTERNATIVES

**68.0 Reference: DESCRIPTION AND EVALUATIONS OF ALTERNATIVES**

**Exhibit B-14, BCUC IR 50.2**

**Alternative 3 – OLI PEN 406 Extension**

In response to BCUC IR 50.2, FEI states that constructing the OCU Project in phases (i.e. southern portion completed initially and northern portion later) would "ultimately be more costly, less efficient, and more impactful on the stakeholders and Indigenous groups."

68.1 Please provide the additional cost associated with a phased construction of the OCU Project.

**Response:**

Please refer to the response to BCUC IR2 50.2 that discusses the feasibility of completing the proposed pipeline in phases. If the Project was constructed in two phases, FEI would first install 23 km of gas line from the Ellis Creek interconnection point towards Chute Lake. Approximately seven years later, to meet the projected load forecast (capacity), FEI would have to install the remaining 7 km of gas line. Completing the OCU pipeline in two separate phases would result in significant duplicated effort and additional costs to complete the following activities, which are not required if the Project is completed as a single construction phase. These repeated activities and incremental work include:

1. Consultation with all impacted stakeholders and Indigenous groups;
2. CPCN development and application costs;
3. Engineering design and calculation verification;
4. Land acquisition;
5. Permitting;
6. Procurement;
7. Contractor mobilization and demobilization; and
8. Construction of an additional pressure control station and interconnection to the VER PEN 323 pipeline.

FEI did not estimate costs associated with the phased approach to the Project, but based on costs to date incurred on the Project, FEI estimates that the duplicated effort would result in an additional $20 to 30 million of capital costs. Completing the Project as proposed in the Application eliminates the need for phased construction and the additional costs associated with that approach.

68.2 Please describe in detail any efficiency impacts from a phased construction of the OCU Project.

**Response:**

Please refer to the response to BCUC IR3 68.1.

Due to the short duration between when both phases of the Project are required, FEI is not aware of any efficiency impacts from a phased construction approach.

68.3 Please explain why FEI believes that phased construction of the OCU Project would have a greater impact on stakeholders and Indigenous groups.

**Response:**

If the Project was constructed in distinct phases, FEI would largely need to duplicate consultation activities with stakeholders and Indigenous groups. Consulting with these groups twice for essentially the same project, would cause negative impacts by doubling the amount of reviews and inputs in many cases without any offsetting benefit. In addition, FEI believes that the additional interconnect location into the VER PEN 323 would create unnecessary ground disturbance which would be more impactful to stakeholders and Indigenous groups.

By completing the Project as proposed, FEI avoids the need to duplicate consultation efforts with stakeholders and Indigenous groups and minimizes ground disturbance.

Please also refer to the response to BCUC IR3 68.1.

68.3.1 If available, please provide details of any discussion with stakeholders or Indigenous groups related to phased construction of the OCU Project.

**Response:**

During the development phase of the Project, FEI contemplated a phased construction execution strategy. FEI discussed this approach as an option with various stakeholders (City of Penticton, Regional District Okanagan Similkameen, etc.) and as outlined in Appendix I-4, with

Indigenous groups (primarily the Penticton Indian Band and Westbank First Nation) on June 17, 2020.

However, as outlined in FEI's response to CEC IR2 62.1, as the Project development activities progressed and mitigation measures were developed to address the short-term capacity constraints (as discussed in Section 4.2 of the Updated Application), FEI determined that the Project is needed to be completed prior to the winter 2023/24, thereby eliminating the need for a phased construction approach.

# D. CONSULTATION

**69.0 Reference: CONSULTATION**

**Exhibit B-14, BCUC IR 64.2**

**Expropriation**

In response to BCUC IR 64.2, FEI states:

> FEI has not been required to expropriate land rights with respect to any recent CPCN applications, including the Inland Gas Upgrades project which is currently underway. The OCU Project is unique due to the amount of new right-of-way to be acquired. Information on expropriation costs and process was determined through consultation with legal counsel, and considered in both the Project cost estimate and schedule.
>
> FEI considers land acquisition timelines within the overall Project schedule. Allowances are made for uncertainties arising from land acquisition activities. If FEI is unable to negotiate an acceptable agreement, FEI would rely on acquisition through expropriation as the last resort. As a legal process, expropriation timelines can be uncertain, and alternative scenarios are considered with regards to potential impacts on scheduling. For example, FEI may consider phasing work away from an expropriation property until access is granted.

69.1 Please provide an update (confidentially if necessary) on progress with respect to landowner negotiations.

**Response:**

A portion of this response is redacted pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-15-19. The redaction has been made as it contains commercially sensitive information that, if disclosed, may prejudice negotiations with other parties in future contract negotiations. A confidential version of this response is being filed with the BCUC under separate cover.

FEI has acquired [redacted] out of 40 of the SRWs required to construct the OCU Project. [redacted] SRW acquisitions remain outstanding, [redacted] of which are in the final negotiations. FEI expects to acquire these [redacted] SRWs in the near future; however, there are [redacted] private properties that continue to present challenges and FEI is considering final options for acquiring an SRW on those properties, including expropriation if necessary.

69.1.1 Where expropriation remains a possibility, please provide additional details (confidentially) on the properties with respect to number, length of right of way sought, and current land-use.

**Response:**

This response is being filed confidentially pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-15-19. FEI requests that the response be kept confidential as it contains commercially sensitive information that, if disclosed, may prejudice negotiations with other parties or in future contract negotiations.

[redacted]

69.2 In the event that expropriation is required, please discuss the contingency that has been provided for in terms of both timing and project cost.

**Response:**

A portion of this response is redacted pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-15-19. The redaction has been made as it contains commercially sensitive information that, if disclosed, may prejudice negotiations with other parties in future contract negotiations. A confidential version of this response is being filed with the BCUC under separate cover.

While it is FEI's practice when developing CPCN applications to acquire land rights (through option agreements) prior to filing of the CPCN application, there are some circumstances where not all land rights required for the project are secured at the time of filing the application. From the time of filing a CPCN application until the time of receiving the BCUC's decision, there is typically a one year period to complete project planning activities which include resolving land and right of way issues. FEI uses this time during the CPCN review process to further manage and control project activities and risk.

Once the CPCN is granted, there is the potential for delays if expropriation activities are not completed prior to construction on subject properties. FEI identified this event as a critical project specific risk to the construction schedule. This risk during construction was individually assessed to have a high impact of approximately [redacted] of delay and the net effect of the risk, if it happens, is included in the Project's schedule contingency of [redacted] (P50 value) as shown in Table 5, Appendix C-2. This schedule impact translates to an expected cost impact of approximately [redacted], as shown in Table 6, Appendix C-2. This cost [redacted] is included within the contingency cost outlined in Table 4, Appendix C-2 of [redacted] (P50) and therefore this schedule contingency's expected impact is included within the Project's overall contingency amount.

For clarity, because cost and schedule are integrated in the risk analysis, the costs associated with the schedule contingency are included in the Project cost contingency.

69.3 Should any of the expropriations be challenged, please discuss the possible impacts on the project in terms of cost and timing, should alternative scenarios, such as phasing work away from the contested properties, be required.

**<u>Response:</u>**

A portion of this response is redacted pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-15-19. The redaction has been made as it contains commercially sensitive information that, if disclosed, may prejudice negotiations with other parties in future contract negotiations. A confidential version of this response is being filed with the BCUC under separate cover.

Please refer to the response to BCUC IR3 69.1. FEI expects that it may need to expropriate land rights on up to [redacted] private properties [redacted] and that the route will not need to deviate away from the current alignment. The following provides an overview of the anticipated impact to the Project, should the expropriation process be required to acquire the necessary land rights.

[redacted]

[redacted]

[redacted]

[redacted]

**70.0 Reference: CONSULTATION**

**Exhibit B-1-2 (Updated Application), Appendix I-4; Exhibit B-14, BCUC IR 62.1**

**Indigenous Engagement and Consultation**

Appendix I-4 of the Updated Application includes Indigenous engagement logs prior to October 2020.

In response to BCUC 62.1, FEI updated Appendix I-4 to include engagement activities since filing the Updated Application.

70.1 Please provide an updated version of Appendix I-4 to include any engagement activities since responding to BCUC IR 62.1.

**<u>Response:</u>**

The following table lists the engagement activities that have occurred since providing a response to BCUC IR2 62.1.

| Date | Engagement Type | Indigenous Community | External Representative | FEI Representative | Summary |
| --- | --- | --- | --- | --- | --- |
| 29-Apr-21 | E-Mail | Penticton Indian Band | Natural Resources (NR) Director;<br>Policy and Planning (PP) Director | Jayms Morrison, Indigenous Relations (IR) Manager | FEI sent a letter to PIB requesting their views on FEI filing the PIB-led Use and Occupancy Mapping (OUMS) interim report, Cultural and Heritage Resources Assessment (CHRA) & Archaeological Overview Assessment (AOA-PIB) final Reports, and Environmental Overview Assessment (EOA-PIB) to the BCUC.<br><br>PIB said they received the question and will respond. |
| 12-May-21 | E-Mail | Penticton Indian Band | Legal Counsel | Legal Counsel | PIB responded to FEI's April 29, 2021 e-mail regarding reports and said they continue to review the request and requested that the reports not be filed with the regulator. |
| 14-May-21 | E-Mail | Penticton Indian Band | PP Director | IR Manager | PIB sent drafts of the final UOMS, TEKK, and CHRA reports, and said they could be submitted to the BCUC confidentially. |
| | | | | | |
| 1-Jun-21 | E-Mail | Penticton Indian Band | NR Director<br>PP Director | IR Manager;<br>Archaeology Contractor | FEI contractor gave notice of June 22, 2021 AIA fieldwork start date. PIB confirmed receipt and said they would arrange participation. |
| 14-Jun-21 | E-Mail | Penticton Indian Band | NR Director | IR Manager;<br>Environmental Contractor | FEI contractor invited PIB to participate in field work to augment the field work completed in August 2020 regarding watercourse crossings and bird observations. |
| 14-Jun-21 | E-Mail | Penticton Indian Band | NR Director | IR Manager;<br>Archaeology Contractor | FEI contractor sent an update that fieldwork will be starting June 22, as to not start on National Indigenous Peoples Day. PIB and FEI arranged a phone call to discuss the field work. |

| Date | Engagement Type | Indigenous Community | External Representative | FEI Representative | Summary |
|---|---|---|---|---|---|
| 15-Jun-21 | E-Mail | Penticton Indian Band | NR Director<br>NR Manager<br>PP Director | IR Manager; Community and Indigenous Relations (CIR) Manager | FEI responded to PIB's April 7, 2021 and May 25, 2021 letters regarding the Investigative Use Permit. The response letter summarized:<br>- the meaningful engagement between FEI and PIB on the Project, which began in June, 2019 and continued consistently through to December, 2020, and was based on the capacity funding agreement (CFA) signed by both parties in June, 2021;<br>- that FEI continued to attempt engagement with PIB throughout 2021, but PIB has been unable to meet;<br>- that FEI remains committed to meeting with PIB to discuss any concerns, potential mitigations, or any other areas of interest;<br>- archaeology work would be completed in each of the IUP test pit / bore hole locations before any surface disturbance occurred;<br>- the scope and nature of work the BCOGC IUP permit allows FEI to conduct, and an estimate timeline for that work;<br>- that FEI cannot pause the BCOGC IUP application process and subsequent IUP field work, set to begin June 22, 2021.<br>The letter also requested a meeting with PIB to discuss concerns PIB may have with the proposed geotechnical assessment and the PIB reports. |
| 16-Jun-21 | E-Mail | Penticton Indian Band | NR Director<br>NR Manager<br>PP Director | IR Manager<br>CIR Manager | FEI responded to PIB's April 7, 2021 letter regarding the Penticton Creek OGC application saying that the application will not be made and instead it will be made as a part of the larger, full-scope application. |

| Date | Engagement Type | Indigenous Community | External Representative | FEI Representative | Summary |
|---|---|---|---|---|---|
| 16-Jun-21 | E-Mail | Penticton Indian Band | NR Director<br>NR Manager<br>PP Director | IR Manager<br>CIR Manager | PIB confirmed receipt of the June 16, 2021 email and letter regarding the Penticton Creek HDD OGC Permit Application. |
| 17-May-21 | E-Mail | Westbank First Nation | Referrals Officer | IR Manager | WFN requested FEI identify which studies were completed in preparations for the Project, because they would like to review the environmental reports. |
| 28-May-21 | E-Mail | Westbank First Nation | Referrals Officer | IR Manager | FEI sent the reports to WFN, as requested on May 17, 2021. |
| 1-Jun-21 | E-Mail | Westbank First Nation | Archeology Supervisor/ Researcher (AS); Archaeology Project Coordinator (APC) | IR Manager;<br>Archaeology Contractor | FEI sent an email giving heads up of June 22, 2021 AIA fieldwork start date. |
| 4-Jun-21 | E-Mail | Westbank First Nation | Referrals Officer | IR Manager | WFN asked if there was any capacity funding available for the project for WFN to review reports and participate in field studies.<br>FEI responded that there is capacity funding available, and sent the Capacity Funding Agreement where the details of the funding are provided. |
| 14-Jun-21 | E-Mail | Westbank First Nation | AS<br>APC | IR Manager;<br>Archaeology Contractor | FEI contractor sent an update that fieldwork will be starting June 22, as to not start on National Indigenous Peoples Day. |
| 15-Jun-21 | E-Mail | Westbank First Nation | AS<br>APC | IR Manager;<br>Archaeology Contractor | WFN confirmed participant with FEI contractor in response to June 14, 2021 email |
| 4-May-21 | E-Mail | BC OGC; Lower Similkameen Indian Band | First Nations Liaison Assistant | IR Manager | The BCOGC said they spoke with LSIB, who said that the project is within PIB's area of responsibility, and that they will support any comments or requests brought forth by PIB. |

1

In addition, the PIB and FEI have agreed to the following statement regarding their discussions which are not included in the above table:

> The PIB and FEI are currently in discussions regarding the proposed OCU Project. The discussions are exploring Project impacts, mitigations and opportunities, to determine whether PIB's consent may be possible for the proposed Project. The fact that these discussions are occurring cannot be interpreted as PIB's willingness to approve the Project.