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March 4, 2021

Residential Consumer Intervener Group
c/o Midgard Consulting Inc.
Suite 828 – 1130 W Pender Street
Vancouver, B.C.
V6E 4A4

Attention: Mr. Peter Helland, Director

Dear Mr. Helland:

Re: FortisBC Energy Inc. (FEI)

Project No. 1599152

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

Response to the Residential Consumer Intervener Group (RCIG) Information Request (IR) No. 1

On November 16, 2020, FEI filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-335-20 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to RCIG IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

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A. Project Need and Justification

1. Reference: Exhibit B-1-2 Section 3 p.18, 22 (pdf 30, 34)

The footnote states "System design temperature is determined for each region by calculating the coldest day which is statistically likely to occur once in a 20-year period. FEI's system is designed to meet the peak demand which would occur during this extreme cold weather event. The statistical 20-year low is calculated using information from local weather stations, and is updated as weather trends change."

1.1 When was the last time the 20-year low used to establish the peak demand in the Central Okanagan was updated?

Response:

The 20-year lows (design temperatures) used to establish peak demand were last updated in 2017. Please refer to the response to BCUC IR1 8.4 for additional discussion.

1.2 Is the 20-year low the same as the 1-in-20 year Design Degree Days referenced on page 22?

Response:

The terms are equivalent in the sense that they represent an equivalent peak demand. The 20-year low is a mean daily temperature expressed in degrees Celsius and is the design temperature used to estimate peak demand. The temperature value is converted to a Degree Day (DD) value using the following formula: $DD = 18^{o}\ C - T_{avg.}$

2. Reference: Exhibit B-1-2 Section 3 p.20 (pdf 32)

"The peak day demand forecast methodology that FEI used to assess the need for the OCU Project is consistent with the methodology FEI has used in previous CPCN applications and long-term resource plans filed with the BCUC."

2.1 If the peak day demand forecast methodology is not exactly as previously used, identify any differences in the methodology and explain why these changes were made.

Response:

FEI's peak demand forecast methodology is unchanged. FEI does not change the method for any specific project.

3. Reference: Exhibit B-1-2 Section 3 p.22,23

"FEI then prepares a 20-year account forecast for all residential and commercial rate schedules at the municipal, LHA [Local Health Authority], and FEI region level. The forecast uses the 20-year household formation (HHF) forecast prepared by BC Stats at the LHA level. The HHF forecast is the forecast of household formations in each LHA. The HHF forecast is provided in terms of year over-year growth rates for each LHA. FEI applies the relevant LHA growth rates to the customer counts in each municipality to develop a 20 year customer forecast for each municipality."

3.1 Confirm whether there is an implicit assumption in the residential customer forecast that the proportion of new households taking gas service matches the current proportion of households taking gas service. If confirmed, justify this assumption. If not confirmed, explain how FEI determines the proportion of new households that take gas service for the purposes of the residential customer forecast at the Local Health Authority level (that is, prior to trueing up with the rate-setting forecast).

Response:

Because many underlying drivers affect the level of FEI net customer additions in a given year, FEI is unable to confirm the extent or impact from any one of these intrinsic drivers (such as the proportion of households taking gas service) on an individual basis on the residential customer forecast.

While FEI does assume that the combined impact from all the intrinsic drivers that affect net customer additions will remain constant at current levels, FEI does not assume that the impact from any single driver, such as the proportion of households taking gas service, matches the prior year's impact from that driver.

The proportion of households taking gas service is affected by a number of factors that can vary from year to year including (but not limited to):

- Multi-family dwellings that contain high numbers of new households, but only a single commercial gas service; and
- Construction of new households in areas not serviced by FEI.

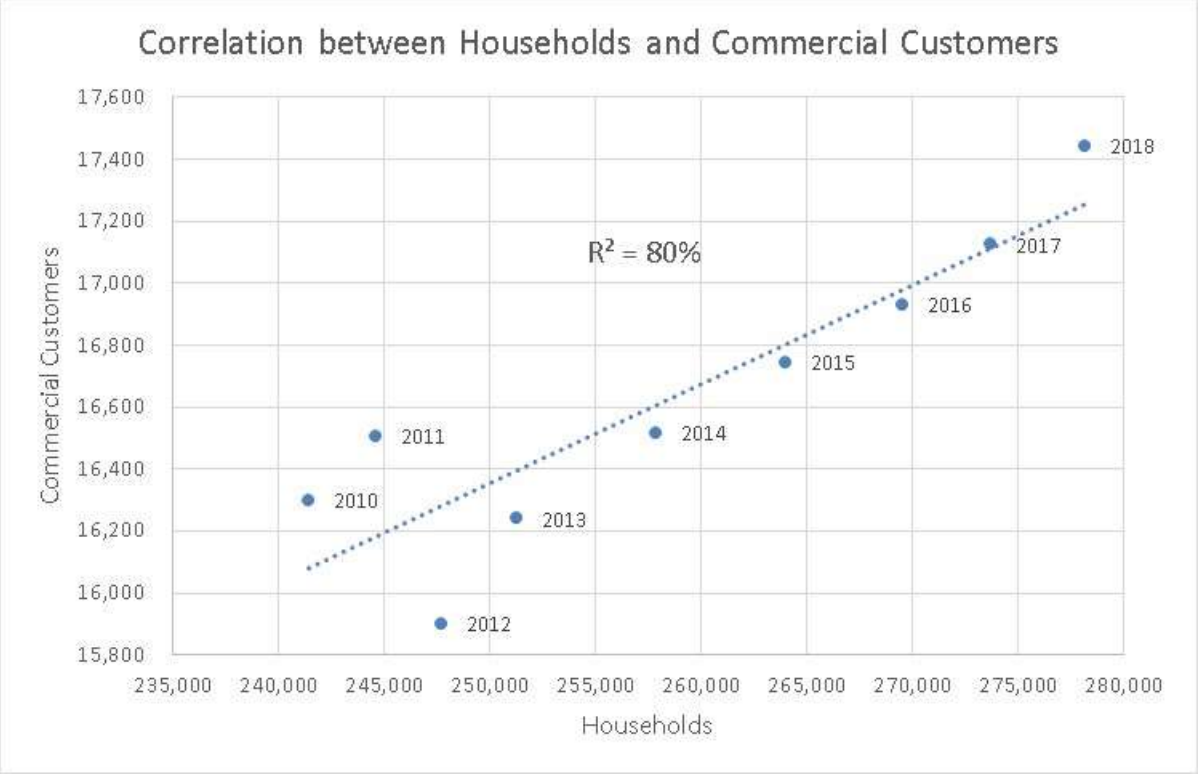
FEI does not determine the proportion of new households that take gas service for the purposes of the residential customer forecast. Rather, FEI applies the relevant LHA growth rates to the customer counts in each municipality to develop a 20-year customer forecast for each municipality as described in Section 3.3.1.2 of the Updated Application.

3.2 Confirm whether, in the first step of FEI's commercial customer forecasting process, FEI applies the household formation growth rate to the numbers of commercial accounts. If confirmed, explain and provide support for the relationship between household formation rates and commercial customer growth rates. If not confirmed, clarify the process.

Response:

Confirmed.

The following plot correlates actual commercial customers from 2010 to 2018 with households for municipalities serviced by the ITS.



The coefficient of determination (R^2) is 80% which indicates a strong correlation.

FEI notes that this strong correlation is expected because areas that are growing in terms of household formations will also require commercial growth to provide services for the growing population.

3.3 Has FEI tried to include other explanatory variables in its forecast of commercial customer growth rates, such as forecasts of GDP growth, as opposed to continuing the recent trend? Explain any FEI analysis in this area and why an approach that includes other explanatory variables is not used.

Response:

FEI last conducted a review of the residential use rate, commercial use rate and commercial customer additions methods in the years spanning 2015 through 2019. In FEI's Annual Review for 2015 Rates Application, FEI's forecasting methods were reviewed in detail by the BCUC, and in its Decision and Order G-86-15, the BCUC directed FEI to review alternative methods for forecasting residential use rates, commercial use rates and commercial customer additions.

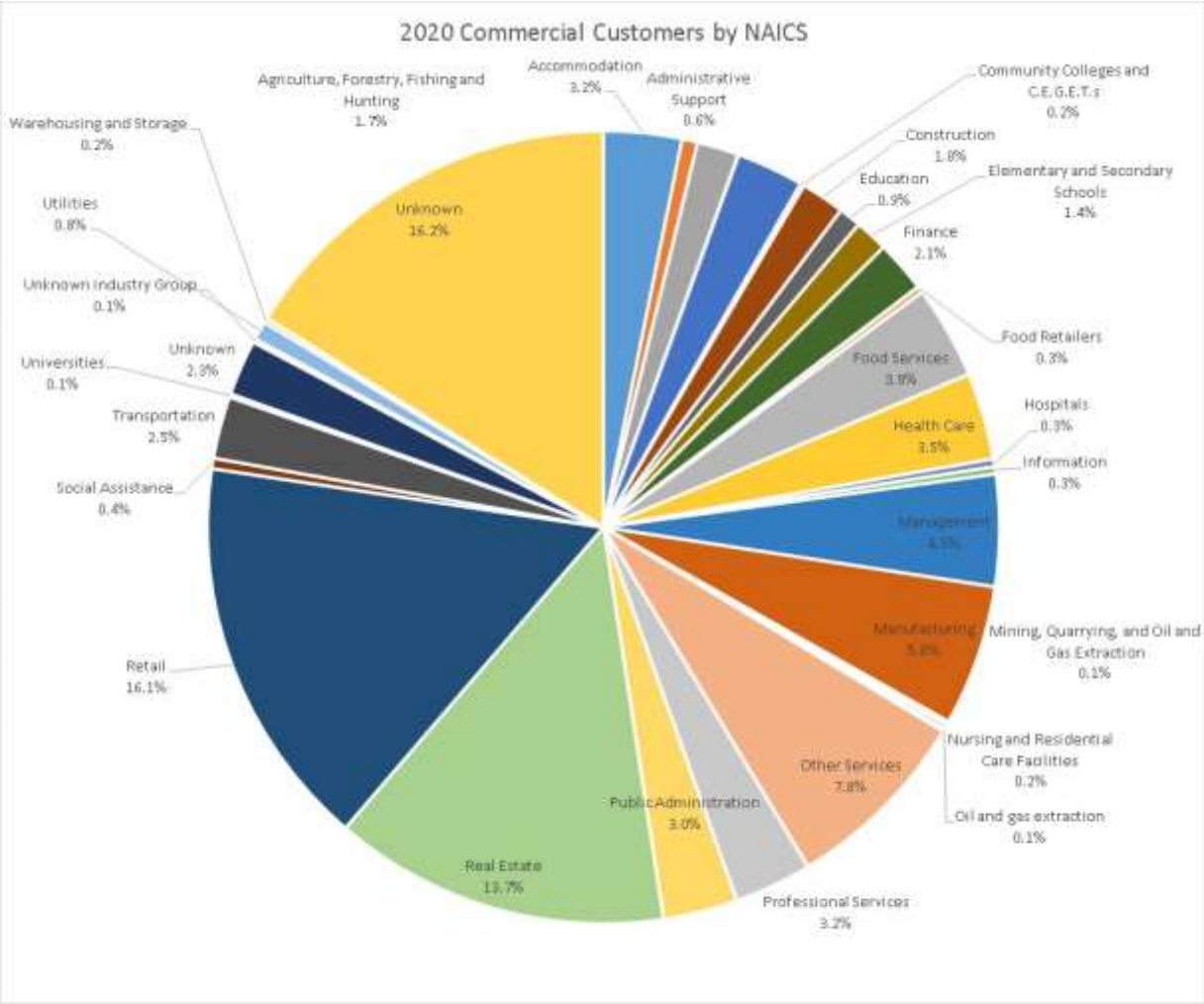
As directed, FEI reviewed a variety of forecasting methods, including a GDP regression. As a result of the initial evaluation process, FEI identified the Exponential Triple Smoothing (ETS) method as the most likely candidate to replace the existing methods, although the data was initially insufficient to determine whether ETS was indeed superior. To further investigate the ETS method, FEI ran parallel forecasts using its existing method and the ETS method and reported the results at each Annual Review from 2016 through 2019. FEI's reports to the BCUC can be found online at the following links:

- Annual Review for 2016 Delivery Rates, Appendix A3 - Demand Forecast Methodology, pg. 192: https://www.bcuc.com/Documents/Proceedings/2015/DOC_44495_B-2_FEI_Annual-Review-2016-Rates-Application.pdf
- Annual Review for 2017 Delivery Rates, Appendix A4 – Forecasting Directives: https://www.bcuc.com/Documents/Proceedings/2016/DOC_46873_B-2_FEI-Annual-Review-2017-Materials.pdf
- Annual Review for 2018 Delivery Rates, Appendix A3 – Demand Forecast Methods: https://www.bcuc.com/Documents/Proceedings/2017/DOC_49752_B-2_FEI_Annual_Review_2018_Rates.pdf
- Annual Review for 2019 Delivery Rates, Appendix A3 – Demand Forecast Methods: https://www.bcuc.com/Documents/Proceedings/2018/DOC_52169_B-2-FEI-Annual-Review-2019-Rates-Appl.pdf

In Appendix B2 of its 2020-2024 Multi-Year Rate Plan (MRP) Application, FEI provided the final result of its investigations into alternative forecasting methods and recommendations. FEI's analysis showed that the existing method for forecasting commercial customer additions was superior to the ETS method, and FEI did not recommend any change to that component of the forecast. Appendix B2 to the MRP Application can be found online at the following link:

https://www.bcuc.com/Documents/Proceedings/2019/DOC_53565_B-1-1-FortisBC-2020-2024-Multi-YearRatePlan-Appendices.pdf

FEI notes that customers are assigned to the various commercial rate schedules based on their annual volume, and not the use that is made of the gas that they purchase. As a result, the commercial rate schedules contain customers from many different segments, which are expected to respond to GDP differently. The following chart shows the 40 different segments relating to FEI commercial customers.



4. Reference: Exhibit B-1-2 Section 3 p.19,20,37 (pdf 31,32,49) Figures 3-7, 3-8, and 4-1

4.1 Confirm whether the ITS forecasted peak demand reflects the impacts of demand-side management initiatives as well as energy efficiency improvements mandated by codes and standards. If not confirmed, provide updated Figures 3 7, 3 8, and 4 1 reflecting the ITS forecasted peak demand net of expected DSM and energy efficiency improvements mandated by codes and standards.

Response:

FEI reflects the impact of demand-side management and energy efficiency improvements in annual demand. With respect to peak demand, to the extent that existing DSM measures and efficiencies influence current consumption, the measures are intrinsically represented in the UPC_{peak} values generated annually and used to construct load forecasts for infrastructure planning. As such, the ITS peak demand forecast and Figures 3-7, 3-8 and 4-1 in the Updated Application reflect the impact of those programs.

Please also refer to the responses to BCUC IR1 5.2, and BCSEA IR1 3.12 and 7.2 for additional discussion on why FEI does not apply possible future impacts from DSM, DSM targeted at peak, energy policy driven pressures related to decarbonization, etc., to reduce or modify the peak demand forecast.

4.2 How does the ITS peak demand forecast incorporate trends of decarbonization of energy systems?

Response:

Please refer to the response to RCIG IR1 4.1.

5. Reference: Exhibit B-1-2 Section 3 p.21,22 (pdf 33,34)

"…the customer billing information and temperature information from the local weather zone index weather stations is reduced to a daily average demand (for the customer in each billing period) and an average mean daily temperature for the corresponding billing period… A linear regression for each customer is performed on this data and the base load and slope (standard meters3/ day/degree Celsius) is calculated."

5.1 Provide the weather sensitivity (m3/day/°C) by rate class (or other grouping as used by FEI in the calculation of weather sensitivity) for each region (Thompson, North and Central Okanagan, and South Okanagan) and as calculated for each of the past five years. A table such as this may be used:

	Thompson		North and Central Okanagan		South Okanagan	
	Residential	Commercial	Residential	Commercial	Residential	Commercial
2015/16						
2016/17						
2017/18						
2018/19						
2019/20						

Response:

The following table provides the sensitivity of energy consumption per day to the Degree Day (DD). It is presented in GJ per day per DD to provide a better comparison to UPC_{peak} values presented in the response to BCUC IR1 5.3. In the units provided, the energy consumption per day increases as DD increases. If expressed as GJ per day per degree Celsius, the values are the same but are negative (i.e. 0.019 GJ per day per DD = minus 0.019 GJ per day per degree Celsius). This is because FEI's customer demand increases as the temperature drops (becomes more negative).

The temperature sensitivity of residential customers is generally similar across all years and regions with a very slight decline over time. There is more variability and no clear trend for commercial customers in each region. There is also a much wider range of uses of gas and smaller groups of customers in the commercial rate schedules used to calculate the average, which contributes to the larger variation in the values for those customers.

Temperature sensitivity used to determine UPC_{peak}

UPC Year	Thompson			North Okanagan and Central Okanagan			South Okanagan		
	Residential	Commercial		Residential	Commercial		Residential	Commercial	
	Rate 1	Rate 2	Rate 3	Rate 1	Rate 2	Rate 3	Rate 1	Rate 2	Rate 3
2015	0.019	0.094	0.703	0.019	0.087	0.830	0.019	0.081	0.754
2016	0.018	0.090	0.748	0.019	0.084	0.826	0.018	0.078	0.873
2017	0.018	0.089	0.753	0.019	0.083	0.837	0.018	0.078	0.893
2018	0.018	0.093	0.692	0.018	0.083	0.785	0.019	0.084	0.837
2019	0.018	0.087	0.687	0.018	0.080	0.727	0.019	0.077	0.812
2020	0.018	0.089	0.735	0.018	0.081	0.732	0.018	0.077	0.833

** Above are average heat load value in GJ/d/DD*

5.2 Explain any significant year-over-year variation in the weather sensitivity.

Response:

Please refer to the response to RCIG IR1 5.1.

6. Reference: Exhibit B-1-2 Section 3 p.24,34 (pdf 36,46)

At page 24: "Under peak demand conditions, gas flows into the central Okanagan from the north from the Westcoast system at Savona where FEI assumes12 a minimum delivery pressure of 4135 kPa (600 psig) and from the south from gas supplied originally from TC Energy at Yahk where FEI assumes a minimum delivery pressure of 4480 kPa (650 psig)."

At page 34: "FEI has established a working agreement with Enbridge to maintain a minimum delivery pressure into Savona of 4480 kPag (650 psig) on peak days."

6.1 Clarify the minimum delivery pressure on peak days into Savona from the Westcoast/Enbridge system.

Response:

FEI determines capacity of the ITS to support peak demand based on 600 psig delivery pressure at Savona. A delivery pressure of 650 psig has been determined as an interim measure to support FEI's short-term mitigation measures prior to the completion of the OCU Project.

6.2 Confirm whether the Current ITS Capacity shown elsewhere in the application, including in Figures 3 7 and 3 8, reflects a delivery pressure of 600 psi or 650 psi at Savona.

Response:

The current ITS capacity shown in Figures 3-7 and 3-8 of the Updated Application reflects a delivery pressure of 600 psig at Savona.

6.3 Does "working agreement" mean a firm contractual obligation on Enbridge to deliver gas at 650 psi on peak days, or is it on a "best efforts" basis?

Response:

This working agreement is not a firm contractual obligation on Enbridge. This is a temporary verbal understanding extended by Enbridge, to cover for rare, short-term occurrences. It will require operational accommodations, including additional planning, coordination and system configuration changes, to allow Enbridge to provide higher pressure of 4480 kPag (650 psig) on

an exceptional and "best efforts" basis. These operational accommodations are at the sole discretion of Enbridge and are not sustainable for frequent or prolonged operations.

6.4 When does the "working agreement" terminate?

Response:

The working agreement is for one specific winter season (October 1, 2022 to March 31, 2023) only.

6.5 Has FEI had discussions with Enbridge or TC Energy about contractually increasing delivery pressures to Savona or Yahk for an extended timeframe? Summarize the results of those discussions.

Response:

Increasing the delivery pressure at Savona to 650 psig would only delay the requirement for the OCU Project for one year and is therefore not a long-term solution to address the need for the Project. Within the context of this CPCN, an increase in Yahk delivery pressure has no bearing on the OCU Project need or justification, since the TC Energy feed is not the system constraint.

FEI has not had discussions with Enbridge about contractually increasing delivery pressure at Savona to 4480 kPa (650 psig) on peak days for an extended timeframe because of the potential capital impact on the Enbridge system and associated toll increases for all shippers including FEI, which could involve a complete revamp of the tariffs. Additionally, regardless of the cost to support this pressure increase, as noted above increasing the delivery pressure at Savona is not a long-term solution to address the ITS capacity shortfall. As such, FEI needs to expand its own system infrastructure to meet peak demand, for increased system reliability, and supply security reasons.

FEI has ongoing engagements with TC Energy regarding contractual delivery pressures and will continue to do so. However, changes in the Yahk delivery pressure would only impact the timing and sizing of a future compression expansion at FEI's Kitchener Compressor station and would not address the capacity constraint driver for the OCU Project.

6.6 How do increased delivery pressures at Savona or Yahk or both affect the ITS capacity? Explain whether increased delivery pressures affect the need date for the new ITS capacity from the OCU.

Response:

Increasing the delivery pressure at Yahk from TC Energy would have no impact on the need and timing of the OCU Project to increase the ITS capacity.

In the response to BCUC IR1 2.5, FEI provided figures showing the ITS pressure decline in the absence of the OCU Project. Figure 2 in that response shows that the impact of a 50 psig pressure increase from Enbridge at Savona is effective for only one year before pressures in the Capacity Shortfall Region return to levels insufficient to support the systems downstream of Polson and Kelowna #1 Gate Stations.

Please also refer to the response to RCIG IR1 6.5 that explains increasing the delivery pressures at Savona or Yahk or both will not address the need for the OCU Project i.e. to increase the ITS capacity over the long-term.

6.7 What are the minimum tariff pressures that Westcoast and TC Energy are each obligated to deliver at Savona and Yahk, respectively?

Response:

The minimum contractual delivery pressure at Savona by Enbridge is 3445 kPag (500 psig).

The minimum contractual delivery pressure at the East Kootenay Exchange (Yahk) by TC Energy is 5512 kPag (800 psig).

6.8 Until what year would the proposed OCU result in sufficient ITS capacity if either Westcoast or TC Energy delivered gas at the minimum tariff pressures to Savona or Yahk, respectively? For how many years would the OCU result in sufficient ITS capacity if both Westcoast and TC Energy delivered at the minimum tariff pressures? What would the next ITS capacity upgrade or upgrades be to address FEI receiving gas at minimum tariff pressures?

Response:

If the Enbridge Westcoast system were to deliver at the minimum contractual delivery pressure of 3,445 kPa (500 psig) at Savona, FEI would currently have insufficient capacity to meet peak demand on a Design Day regardless of whether TC Energy was delivering at its minimum contractual delivery pressure of 5,512 kPag (800 psig) or at the assumed 4,480 kPa (650 psig).

With the Enbridge Westcoast system delivering at its minimum contractual delivery pressure, FEI's compressor station at Savona would require an upgrade to increase the available power at Savona by about 2,500 HP to a total of 5,600 HP to address the peak demand requirement until the OCU Project is constructed.

If the Enbridge Westcoast system delivered at 600 psig until the OCU Project was installed (as FEI currently assumes in determining ITS capacity), and then following the completion of the OCU Project Enbridge dropped to its minimum contractual delivery pressure of 500 psig, FEI's Savona compressor station would have sufficient power to meet the forecasted peak demand until 2031 as currently configured. After that time, the additional compression discussed above would be required at FEI's Savona compressor station.

7. Reference: Exhibit B-1-2 Section 3 p.24 (pdf 36)

"FEI designs the ITS to deliver a minimum inlet pressure of 2415 kPag (350 psig) into the major gate stations serving downstream Intermediate Pressure (IP) systems on a peak day. This minimum pressure is the parameter that defines the ITS capacity limit."

7.1 Does FEI have a minimum distribution pressure criterion (or criteria) at the system extremities? Provide this minimum pressure criterion and explain why FEI established this as the criterion.

Response:

FEI designs the distribution system to ensure that pressures in all areas of the system are greater than the minimum pressure criteria of:

- 70 kPa (10 psig) for areas that serve primarily residential customers; and
- 138 kPa (20 psig) for areas that serve primarily commercial or industrial customers.

Under peak demand, the low pressure areas are generally at the extremities of the system with areas closer to the regulating stations supplying the system having correspondingly higher pressures.

These criteria were established to ensure the distribution system provides sufficient differential pressure for customer meter set regulators to function reliably and deliver gas to customer appliances. When FEI determines that the criteria can no longer be satisfied during forecast peak demand conditions, distribution system capacity upgrades are identified and installed to restore the pressure to acceptable levels above the minimum criteria.

7.2 Based on the minimum pressure criterion at the distribution system extremities, for each of the Lumby, Lavington, and West Kelowna distribution systems, provide the years when this criterion is no longer met, with and without the proposed mitigation measures in Section 4.2.

Response:

FEI would not operate the gas system as proposed in the question as it would be unacceptable due to the safety risks and customer service reliability concerns. The situation described would require that FEI operate the upstream system in an uncontrolled and unpredictable manner. It would also assume that the associated uncontrolled pressure drop and impact on the downstream system could be accepted and reliably calculated, of which FEI has no certainty. The inability of hydraulic modeling tools to numerically converge on a solution for system

locations operating far below their designed inlet and set pressures, indicates that the system would be operating in an unstable and unpredictable manner.

As such, FEI believes that the appropriate criterion for determining when the requirements of the distribution system are not met is when the upstream system is no longer capable of meeting supply requirements. That timing is identified in the Updated Application as the winter of 2021/2022 without short-term mitigation, and the winter of 2023/2024 with short-term mitigation.

7.3 Does FEI have a minimum intermediate pressure criterion at the inlet to IP regulating stations? Provide this minimum pressure criterion and explain why FEI established this as the criterion.

Response:

FEI designs IP systems operating at 2,070 kPa (300 psig) to a minimum 860 kPa (125 psig). This minimum pressure criteria is to allow sufficient inlet pressure to downstream stations that may serve 700 kPa (100 psig) distribution systems. In the Polson and West Kelowna IP systems there are currently no systems operating in that range and FEI can use a lower minimum pressure criteria of 515 kPa for inlet to those downstream stations serving 420 kPa distribution systems.

This minimum pressure criteria ensures sufficient differential pressure for reliable operation of the pressure regulating equipment at the stations. When FEI determines that this criteria is no longer satisfied under forecasted peak demand, distribution system capacity upgrades are identified, planned, and installed to restore upstream pressure to acceptable levels above the minimum criteria.

7.4 Based on the minimum pressure criterion to the inlet of IP regulating stations, for each of Lumby, Lavington, and West Kelowna, provide the year when this criterion is no longer met, with and without the proposed mitigation measures in Section 4.2.

Response:

FEI refers to the Polson and Kelowna #1 Gate Stations as TP/IP regulating stations. FEI assumes the question posed relates to what FEI would refer to as the IP/DP regulating station (district stations) that supply gas at 420 kPa into communities like Lumby, Lavington, and West Kelowna.

If the existing stations were able to operate at an inlet pressure of 515 kPa, this minimum inlet pressure would be reached in the winter of 2023-2024 with mitigation measures in place. This minimum inlet pressure scenario cannot be achieved without mitigation measures as it requires Polson and Kelowna IP Gate stations to operate on a full bypass (as outlined in the short-term mitigation measures) in order to deliver gas in a controlled manner downstream.

Operating at these very low system pressures, four of the six IP/DP stations in the Polson and West Kelowna IP systems would require additional upgrades, and the IP/DP station at Lumby would require a full bypass to survive one additional year through the winter of 2023-2024. These upgrades would otherwise be unnecessary after the OCU Project is installed. This is because, although the pressure in the IP system would remain above the minimum design pressure, the existing IP/DP stations along the system were not designed for supporting peak day flow under the low pressures which would be experienced with these mitigation measures.

Please also refer to the response to RCIG IR1 7.2 and 7.6 in this series for discussion on how these systems are impacted if this situation was to occur.

7.5 Confirm whether bypass of IP regulating stations in Lumby, Lavington, and West Kelowna is feasible to maintain sufficiently high outlet pressures into the distribution system. If not, explain why not.

Response:

FEI assumes the question refers to operating FEI's IP/DP regulating stations in Lumby, Lavington, and West Kelowna on full bypass. It is not operationally feasible to manage and monitor multiple station locations operating on bypass, as well as multiple points within the downstream system for signs of pressure collapse. Please also refer to the responses to RCIG IR1 7.2, 7.4, and 7.6 for further discussion on the impacts to IP/DP stations.

7.6 Provide additional details of what happens with the operation of the IP and DP systems when the inlet pressures to the transmission pressure regulating stations (Kelowna #1, Polson) drop below 350 psi.

Response:

FEI recognizes that gate stations serving downstream IP and DP systems, and the IP/DP stations in those systems, do not simply cease to function if pressures reach FEI's design minimum pressure criteria. However, capacity to meet peak demand quickly degrades as

pressure continues to fall each year. This results in an inability to reliably meet peak demand. The 350 psig minimum design criteria is a trigger that corrective action is required. Due to increasing peak demand requirements, system pressures will continue to decline further leading to service outages if not corrected with the OCU Project.

Each facility is unique, with different tolerances to operate reliably at lower pressures. As the pressure ahead of the Polson and Kelowna #1 Gate Stations drops below the minimum pressure criterion of 350 psig, each station has the capability to continue to meet the peak demand requirements and still maintain the downstream system at its maximum operating pressure (MOP). However, this capability is short-lived. As indicated in Figure 1 of the response to BCUC IR1 2.5, the pressure in this region of the ITS is decreasing at a rate of over 40 psig per year under the forecast design day peak demand. As a result, within a year of reaching the minimum pressure criterion, the pressure at the inlet to the stations would be very close to the MOP of the downstream systems (300 psig).

At this low inlet pressure, station equipment would be operating outside of its design parameters. The combined pressure drop through station equipment such as line heaters, filters, and regulator runs would produce a pressure at the station outlet below the station set point and below the MOP of the downstream system. This would erode the capacity of that downstream system. When this occurs, the station is no longer controlling the downstream pressure and pressure losses across the station equipment can grow exponentially. In this uncontrolled state, FEI would be unable to precisely model how severe the pressure decrease would be across the station, and could not reliably predict what the exact impact on the downstream system pressure would be or to what extent customers would be impacted. FEI could not safely and reliably operate the system in this state.

Under its short-term mitigation strategy, FEI's response will be to decrease the station outlet pressure to a lower value, at least 25 psig lower than the inlet pressure. This will re-establish sufficient pressure differential across the station, and restore controlled operation of the station and downstream systems. This action can only be considered because the downstream system currently has enough extra capacity to accommodate this temporary measure. This decrease in set pressure at the gate station discharge reduces the capacity of the downstream system, and therefore reduces the inlet pressure to the IP/DP stations in the system. This will soon create the same type of issue at the IP/DP stations that has been described above for the upstream Kelowna #1 and Polson Gate Stations.

In order to mitigate low pressure in the downstream systems, FEI is planning to install full-capacity bypasses at the gate stations to be operated only if and when peak conditions occur in the last year before the OCU Project is in service. This is the next step in the mitigation strategy, and will be implemented to avoid the pressure drop through the station equipment (25 psig or more as mentioned above) by bypassing the equipment. This can only be safely implemented when inlet pressures at the gate stations drop low enough that they no longer exceed the MOP of the downstream system. To ensure safe operations, this will require close monitoring of the station and downstream system pressures by onsite FEI Operations personnel, as well as by FEI Gas Control.

FEI estimates that pressure on a design peak day in winter 2023/2024 would be below 200 psig at the inlets to the Kelowna #1 and Polson Gate Stations. Even with station bypasses in service at the gate stations, this low pressure would cascade the same issues described above to the downstream IP/DP stations in these systems. This cascading deterioration of station functionality would be too widespread for FEI to manage operationally, likely resulting in widespread service outages.

7.7 Provide FEI's gas planning criteria document or manual, which describes the pressure and velocity criteria used to identify when capacity upgrades are required.

Response:

The table below is an excerpt of FEI design standards that document the minimum system pressures FEI uses to design intermediate pressure and distribution pressure systems including the minimum regulating station inlet pressures allowed. FEI has no documented velocity criteria related to capacity within the transmission system and does not use velocity as a trigger for capacity upgrades. As a guideline, if velocities greater than 20 metres per second were expected to be sustained, FEI would examine the specific conditions further to determine that the capacity implications remain acceptable in terms of rate of pressure drop or potential concerns unrelated to capacity such as pipeline wall erosion are also acceptable. In the ITS, maximum velocities under peak demand are about 10 metres per second or less.

Distribution Set and Delivery Pressures

Table 1: Distribution Set and Delivery Pressures

Intermediate (IP) Pressure System	Maximum Operating Pressures: IP 2070 kPa	IP 2070 psig	IP 1900 kPa	IP 1900 psig	IP 1200 kPa	IP 1200 psig	IP 860 kPa	IP 860 psig
Main Regulator set @:	2070	300	1900	275	1200	174	860	125
Underset Standby Regulator set @:	2055	298	1890	273	1190	172	850	123
Primary Over-pressure protection set @:	2277	330	2090	303	1320	191	946	137
Minimum Station Inlet Pressure:	2420	351	2240	325	1550	225	1205	175
Minimum Tail-end Pressure:	860	125	620	90	515	75	515	75

Distribution (DP) Pressure System:	Maximum Operating Pressures: DP 700 kPa	DP 700 psig	DP 550 kPa	DP 550 psig	DP 420 kPa	DP 420 psig	DP 275 Interior F/Taps kPa	DP 275 Interior F/Taps psig
Main Regulator set @:	700	102	550	80	420	61	275	30
Underset Standby Regulator set @:	690	100	540	78	410	59	N/A	N/A
Primary Over-pressure protection set @:	770	112	605	88	460	67	300	44
Minimum Station Inlet Pressure:	860	125	675	98	515	75	700	100
Minimum Tail-end Pressure:								
Inlet to other stations	515	75	240	35	240	35	N/A	N/A
Inlet to customers	240	35	70	10	70	10	70	10

Propane System:	Maximum Operating Pressures: DP 175 kPa	DP 175 psig
Main Regulator set @:	165	24
Over-pressure Protection set @:	180	26
Minimum Station Inlet Pressure:	275	40
Minimum Tail-end Pressure:	70	10

Customer Delivery Pressure:	Inches W.C. kPa	Inches W.C. In.W.C.	Two Pound kPa	Two Pound Psig	Five Pound kPa	Five Pound psig
Natural Gas	1.75	7	14	2	35	5
Propane	2.75	11	14	2	35	5

7.8 Explain the processes, steps taken, and measured inputs used by FEI to verify the accuracy of its hydraulic system models.

Response:

The following is high-level description of the processes involved with developing an accurate and verified steady-state model. The model reflects the transmission system behaviour based on actual customer daily consumption in winter periods collected from the real-time operation of the transmission system. This enables FEI to verify the accuracy of its hydraulic system model.

Model Building:

FEI builds its hydraulic model using data extracted from FEI's Geographic Information System (GIS) application that is the source of pipeline facility information, including geographic location of pipe nodes (connections), elevation, pipe material and properties, and pipeline length. FEI gathers additional information not included in the GIS system, on pipe internal diameter, material properties such as pipe roughness, station configuration details, and facility information (such as compressor horsepower and efficiency) from documentation of the completed installation. This collected data forms the basis for accurately representing the physical pipeline system in the hydraulic model.

Model Tuning:

FEI tunes the ITS hydraulic model by collecting station flows and pressures across the system on cold winter days from local station meters and available SCADA (supervisory control and data acquisition) data that is sent from stations and facilities in the ITS to FEI's Gas Control centre. Although more complex to execute than explained here, in simple terms the actual flows collected are applied to the hydraulic model, along with the available pressures at the model boundary limits (i.e., at sources such as Savona where the pressures and flows into the modelled system are known), and the model is balanced to calculate pressures in the section being tuned. The pipe efficiencies in the pipe segments are adjusted until the modelled results match the actual field measurements.

The pipe efficiencies calculated then become a permanent attribute of pipe element in the model. This forms the basis of calculating valid pressure responses in the model to reflect the behaviour of the ITS to variations in flow, either real or forecast.

Peak Day and Transient Factors:

Peak hour and transient factors are used to allow FEI to model the ITS using a steady-state hydraulic model that can use peak hour demand at each gate station and convert it so that a steady-state model will match the peak hour results of a transient (time based) model which considers the full daily load cycle (and the effect of line pack).

The peak day factor is determined using actual metered data from stations in the ITS on cold winter days in recent winters. It is the average ratio of the peak hour to the average daily flow. It is used to convert the peak hour demand to a daily flow that represents the real behaviour of customers on the distribution systems served by the ITS.

The transient factor is determined by comparing the peak hour pressure of FEI's tuned transient and steady-state models under a high flow daily load. The transient model incorporates the increase or decrease in line-pack during the day and will therefore model the beneficial effect line pack has on keeping pressure in the system higher while supporting the highest flows of the day (the peak hour demand). After running a transient model to determine the system pressure at peak hour, a steady-state model of the system with the same peak hour flow is run. The steady-state model will produce lower pressures than the transient model at peak hour. The load on the steady-state model is reduced until the pressures in the steady-state model match the peak hour pressures in the transient model. The transient factor is the ratio of the initial peak hour load to the reduced load in the steady state model that produces the same pressure as the transient model.

Field Data Check:

FEI uses the same flow and pressure data from SCADA measurements across the system to match the modelled result on cold winter days with actual measured results. FEI also uses the steady-state models that were used to determine the OCU Project requirements, for modelling the impacts of equipment isolation work in the ITS to support ongoing and routine operations and maintenance activities.

8. Reference: Exhibit B-1-2 Section 3 pp.25,51 (pdf 37,63)

8.1 Provide a map of the VER PEN 323 line that shows the class locations along its length.

Response:

Class location changes cannot be shown clearly on a single map. Please refer to Attachment 8.1 for screen captures which show the full length of the VER PEN 323 pipeline in sections, with Class 1 locations outlined in blue, Class 2 locations outlined in green, and Class 3 locations outlined in dark yellow. Start and end points correspond to metres along the pipeline, starting from the north end of the VER PEN 323 and terminating at the south end of the VER PEN 323, a length of 98,994.444 m or 98.99 km. This information is also provided in the table below.

VER PEN 323 Pipeline Class Locations

Start Station	End Station	Status	Class Rating	Last Survey Date	Comments
0	3521.647	Existing	Class 3	2/18/2021	Class derived solely from dwelling count
3521.647	19112.142	Existing	Class 1	2/18/2021	Class derived solely from dwelling count
19112.142	20488.752	Existing	Class 3	2/18/2021	Class derived solely from dwelling count
20488.752	20562.294	Existing	Class 1	2/18/2021	Class derived solely from dwelling count
20562.294	24915.077	Existing	Class 3	2/18/2021	Class derived solely from dwelling count
24915.077	25160.482	Existing	Class 2	2/18/2021	Class derived solely from dwelling count
25160.482	31880.947	Existing	Class 1	2/18/2021	Class derived solely from dwelling count
31880.947	32353.109	Existing	Class 2	2/18/2021	Class change forced by use & occupancy
32353.109	32405.511	Existing	Class 1	2/18/2021	Class derived solely from dwelling count
32405.511	32913.304	Existing	Class 2	2/18/2021	Class change forced by use & occupancy
32913.304	37089.643	Existing	Class 1	2/18/2021	Class derived solely from dwelling count
37089.643	37886.202	Existing	Class 2	2/18/2021	Class change forced by use & occupancy
37886.202	38290.433	Existing	Class 1	2/18/2021	Class derived solely from dwelling count
38290.433	40398.454	Existing	Class 2	2/18/2021	Class change forced by use & occupancy
40398.454	41237.122	Existing	Class 3	2/18/2021	Class derived solely from dwelling count
41237.122	41327.347	Existing	Class 1	2/18/2021	Class derived solely from dwelling count
41327.347	43858.288	Existing	Class 3	2/18/2021	Class derived solely from dwelling count
43858.288	44174.931	Existing	Class 2	2/18/2021	Class change forced by use & occupancy
44174.931	45604.165	Existing	Class 1	2/18/2021	Class derived solely from dwelling count
45604.165	49100.468	Existing	Class 3	2/18/2021	Class derived solely from dwelling count
49100.468	49160.064	Existing	Class 2	2/18/2021	Class change forced by use & occupancy
49160.064	49751.455	Existing	Class 1	2/18/2021	Class derived solely from dwelling count
49751.455	52822.684	Existing	Class 3	2/18/2021	Class derived solely from dwelling count
52822.684	54052.415	Existing	Class 1	2/18/2021	Class derived solely from dwelling count
54052.415	54985.293	Existing	Class 2	2/18/2021	Class change forced by use & occupancy
54985.293	55410.915	Existing	Class 1	2/18/2021	Class derived solely from dwelling count

Start Station	End Station	Status	Class Rating	Last Survey Date	Comments
55410.915	61272.371	Existing	Class 3	2/18/2021	Class derived solely from dwelling count
61272.371	61318.676	Existing	Class 2	2/18/2021	Class change forced by use & occupancy
61318.676	84676.308	Existing	Class 1	2/18/2021	Class derived solely from dwelling count
84676.308	85815.82	Existing	Class 2	2/18/2021	Class derived solely from dwelling count
85815.82	88915.522	Existing	Class 1	2/18/2021	Class derived solely from dwelling count
88915.522	92170.236	Existing	Class 2	2/18/2021	Class derived solely from dwelling count
92170.236	93177.414	Existing	Class 1	2/18/2021	Class derived solely from dwelling count
93177.414	95022.383	Existing	Class 2	2/18/2021	Class derived solely from dwelling count
95022.383	97810.866	Existing	Class 3	2/18/2021	Class derived solely from dwelling count
97810.866	97935.914	Existing	Class 1	2/18/2021	Class derived solely from dwelling count
97935.914	98994.444	Existing	Class 2	2/18/2021	Class change forced by use & occupancy

8.2 Explain whether any further class location changes on VER PEN 323 will result in further MOP reductions. Are any further class location changes anticipated within the 20-year forecast period?

Response:

Further class location changes do have the potential to cause further MOP reductions, as FEI must remain compliant with CSA Z662. Please also refer to the response to BCUC IR1 9.1, which discusses whether FEI anticipates future class location changes.

8.3 If the MOP on VER PEN 323 line is reduced further, confirm whether further upgrades following the proposed OCU are required within the forecast period and explain what those upgrades would entail.

Response:

FEI is unable to speculate about the location or extent of any further changes to class location that may occur during the forecast period. As discussed in the response to BCUC IR1 9.1, FEI does not have the information necessary at this time to identify and scope potential future upgrades tied to unexpected class location changes.

9. Reference: Exhibit B-1-2 Section 3 p.26 (pdf 38)

9.1 With the proposed compression increase on the Southern Crossing Pipeline in 2029-30, and assuming the proposed OCU proceeds, are there any other capacity projects expected anywhere on the ITS within the 20 year planning horizon? If so, what are they?

Response:

FEI presented its examination of the 20 year capacity requirements for the ITS in the 2017 Long Term Gas Resource Plan (LTGRP). The planning horizon for the 2017 LTGRP spanned from 2016 to 2036. The OCU Project (referred to in the LTGRP as the Okanagan Reinforcement) was the only transmission capacity reinforcement identified for serving the Okanagan area. The updated analysis of the ITS capacity requirements completed for this Application supports that determination.

In examining gas supply infrastructure throughout the Pacific Northwest Region, the 2017 LTGRP also discussed the potential expansion of the Southern Crossing Pipeline project[1]. While this expansion project, if it proceeds, would address the future compression requirements supporting the OCU Project later in the forecast period, its primary need and benefits are to increase capacity to deliver natural gas throughout the greater Pacific Northwest Region and improve security of supply. The project also continues to be examined within the context or other regional market developments that have taken place since the 2017 LTGRP was submitted, including heightened system resiliency considerations and FEI's energy decarbonization commitments. For clarity, this potential pipeline project would not alleviate the capacity constraint identified in the central and north Okanagan or otherwise remove the need for the OCU Project.

[1] The extension of the Southern Crossing Pipeline is referred to in the LTGRP as the Kingsvale to Oliver Reinforcement Project or KORP.

B. Short-Term Mitigation Measures

10. Reference: Exhibit B-1-2 Section 4 p.33 (pdf 45); 2017 Long Term Gas Resource Plan p.ES-8

"Each proposed Project alternative relies on the implementation of short-term mitigation measures to meet forecasted capacity shortfalls in the winters of 2021/2022 and 2022/2023. Following recent years of high growth in customer accounts, FEI's forecasts indicate that the capacity to meet peak demand would be exhausted in the winter of 2021-22 if FEI took no interim measures. This timeframe is prior to the projected completion of the OCU Project. As a result, FEI has examined a number of measures that could assist in managing the projected shortfall and provide some capacity margin without impacting customers served by the system."

10.1 If FEI was aware of the impending capacity shortfall in 2022 on the ITS in its 2017 Long-Term Gas Resource Plan, why is FEI bringing an application for a Certificate of Public Convenience and Necessity now, and not one or more years ago, in order that short-term mitigation measures would not be required or that other alternatives would not be screened out due to lengthy construction schedules?

Response:

Please refer to the response to CEC IR1 2.2 regarding the timing of this Application.

FEI did forecast the upcoming capacity shortfall in time to implement the preferred solution (Alternative 3) to best suit the long-term needs of the ITS. In comparison, Alternatives 1 and 2 carry a high degree of risk (see response to CEC IR1 17.1), while Alternatives 4 (refer to the response to CEC IR1 10.2) and 5 (refer to the response to CEC IR1 11.2) were shown to be significantly more expensive than the least cost option during preliminary screening. Alternative 3 is the most cost-effective solution that addresses the need for the OCU Project and the filing of an application for a CPCN was appropriately timed.

11. Reference: Exhibit B-1-2 Section 4 p.35 (pdf 47)

"To mitigate the forecast capacity shortfall, 1 to 2 large truckloads of CNG per hour (up to 4 – 6 truckloads per day) would be required during a peak demand event by the winter of 2022/2023"

"CNG trucks would be required to travel from a filling point outside of the central Okanagan, where the system has a sufficient gas surplus to allow trucks to fill, to an effective injection point in the central Okanagan. LNG trucks would be supplied from FEI's Tilbury LNG facility in Delta, approximately 400 km from the shortfall region. This CNG/LNG truck traffic would be required during a peak demand event, which corresponds to the most severe winter weather in B.C. Transporting fuel by truck during severe winter weather is a **less cost effective** and reliable method of gas transportation than appropriate and adequate pipeline infrastructure." [emphasis added]

11.1 How many CNG trucks per hour and per day would be required to meet a peak demand event in the winter of 2029/30 if OCU does not proceed?

Response:

Please refer to the response to BCUC IR1 11.2.

11.2 How many LNG trucks per hour and per day would be required to meet a peak demand event in the winter of 2022/23? How many LNG trucks per hour and per day would be required to meet a peak demand event in the winter of 2029/30 if OCU does not proceed?

Response:

Please refer to the response to BCUC IR1 11.1 for a discussion of why LNG trucking is not considered a viable solution to meet the ITS capacity shortfall identified in the Updated Application.

11.3 Confirm whether LNG (or CNG) shipments would be required in years when design day weather is not experienced (or closely approached).

Response:

While LNG or CNG shipments themselves would not be required unless sufficiently cold weather was expected, costs would still be incurred as equipment would be required to remain

on standby in case a cold weather event occurred. Thus, these standby costs would be incurred between November and March. These standby costs include securing the vehicles required to transport the gas in the event they are required, as well as costs necessary to install infrastructure associated with compression and decompression (e.g., piping modifications, electrical upgrades, site preparation, etc.).

For further information, please refer to the response to BCUC IR1 11.1.

11.4 Explain whether CNG trucks could be filled on the peak day at the terminus of the Southern Crossing Pipeline in Oliver (which appears to have surplus capacity). Would this materially affect the capacity and pressure available to Kelowna #1 Gate Station or Polson Gate Station?

Response:

As suggested, the terminus of the Southern Crossing Pipeline in Oliver does have a surplus of capacity, as does the terminus of the OLI PEN 406 in Penticton, as it pertains to the OCU Project. The bottleneck on the transmission system is on the VER PEN 323 pipeline between Penticton and Kelowna.

By filling CNG trucks upstream of the VER PEN 323 pipeline, either at the terminus of the OLI PEN 406 or the Southern Crossing Pipeline and injecting downstream of the bottleneck, the CNG trucks would increase the capacity of the region and improve the capacity and pressure at the Kelowna #1 or the Polson Gate Stations.

However, as mentioned in Section 4.2.5 of the Updated Application and explained in the response to BCUC IR1 11.1, FEI considers this option to have lower reliability and potentially higher safety risks, to be logistically challenging to implement, and adds unnecessary costs to the OCU Project as compared to other pipeline short-term mitigation measures examined to address the capacity shortfall.

11.5 Explain and provide cost details (for example, the approximate capital cost of the required fleet and the approximate cost per journey excluding the commodity cost of the cargo) that show why the costs of trucked CNG or LNG would be less cost effective than the proposed project.

Response:

Please refer to the response to BCUC IR1 11.1.

11.6 Explain why trucked CNG or LNG is not feasible to provide a medium-term solution to the identified capacity shortfalls that would defer the OCU project for five, ten, or more years.

Response:

Please refer to the responses to BCUC IR1 11.1 and 11.2.

12. Reference: Exhibit B-1-2 Section 3 p.26,32, (pdf 38,44)

At page 26: "Based on the current forecast, by the summer of 2029 FEI will need to upgrade the compression capability on the SCP to improve capacity into the Central and North Okanagan. … As the compression requirement to address future capacity needs in the Okanagan is several years beyond the immediate need for the OCU Project, and the optimal location and extent of required additional compression cannot yet be determined, FEI did not include a compressor upgrade in the OCU Project."

At page 32: "All Project alternatives rely on the implementation of short-term mitigation measures to address the possibility of a capacity shortfall during the winters of 2021/2022 and 2022/2023. … While these measures are adequate to provide some capacity margin in the winter of 2021/2022 and 2022/2023, they do not represent a viable long-term solution, and do not provide FEI with sufficient and reliable system capacity starting from the winter of 2023/2024."

12.1 Would the SCP compression upgrade be sufficient on its own to increase capacity of the ITS system, without the OCU Project? Please explain why or why not. If yes, for how many years would the compression upgrade be sufficient?

12.2 What is FEI's best estimate of the shortest timeframe in which the SCP compression upgrade project could be completed?

Response:

Please refer to the response to BCUC IR1 14.3.

12.3 Does Section 4.2 represent a comprehensive list of all possible short-term mitigation measures that could increase ITS system capacity? If yes, please justify. If no, what others are available?

Response:

Yes. FEI was not able to identify any other possible short-term mitigation measures which could be employed to increase the ITS capacity.

12.4 Did FEI analyze the possibility of advancing the timeframe of the SCP compression upgrade such that short-term mitigation measures could support the ITS system until the SCP compression upgrade is completed (thereby eliminating

the need for the OCU Project)? If yes, please provide the conclusions of the analysis. If no, why not?

Response:

Installation of a compression upgrade is not useful without the additional pipeline capacity provided by the OCU Project. Please also refer to the response to BCUC IR1 14.3.

C. Description and Evaluation of Alternatives

13. Reference: Exhibit B-1-2 Section 4 p.52

"The requalification tests are to be performed in accordance with the requirements of CSA Z662:19. These requalification strength tests per the current requirements of chapter 8 of CSA Z662 require a minimum test pressure of 125 percent of the MOP but are limited to a maximum test pressure that results in stresses equivalent to 110 percent SMYS for pipe installed in areas of class location 1 or 2. Similarly, for pipe installed in areas of class location 3 or 4, CSA Z662:19 requires a minimum test pressure of 140 percent of the desired MOP, but are limited to a maximum test pressure that results in stresses equivalent to 110 percent SMYS. However, as the pipe installed in 1957 was subjected to requalification testing only up to 90 percent SMYS at the time of manufacture, FEI's subject matter experts have recommended a maximum test pressure corresponding to pipe stresses of no more than 95 percent SMYS."

13.1 Provide the pipeline test pressures for the VER PEN 323 line that correspond to: 110% SMYS, 95% SMYS, and 90% SMYS.

13.2 What are the pipe grade (i.e. API 5LX42? 5LX46?) and wall thickness(es) of VER PEN 323?

Response:

The table below provides the grade, wall thicknesses, and corresponding pipeline test pressures for various percent of SMYS for the segments requiring recertification tests in Alternative 1 and Alternative 2 on the VER PEN 323 pipeline.

VER PEN 323 Pipeline Details

						Test Pressure (kPa)			
Row	OD (mm)	WT (mm)	Grade (MPa)	Length (m)	% Length	90% SMYS	95% SMYS	100% SMYS	110% SMYS
1	323	5.2	290	33,475	92.4%	8,316	8,778	9,240	10,164
2	323	6.4	290	469	1.3%	10,314	10,887	11,460	12,606
3	323	6.4	359	81	0.2%	12,768	13,478	14,187	15,606
4	323	7.1	359	3	0.0%	14,165	14,952	15,739	17,313
5	323	7.9	290	2015	5.6%	12,764	13,473	14,182	15,600
6	323	8.4	359	23	0.1%	16,759	17,690	18,621	20,483
7	323	9.5	290	143	0.4%	15,310	16,161	17,011	18,713
8	323	9.5	359	35	0.1%	18,953	20,006	21,059	23,165

As discussed in Section 4.6.2.2 of the Updated Application, the majority of the VER PEN 323 pipeline that would be affected by the alternatives for the OCU Project (92.4 percent as shown in Row 1 of the table) had a mill test (pressure test at time of manufacture) that certified the pipe to 90 percent of SMYS, or 8,316 kPa. This is the maximum pressure that the pipe has been

proven to as post-construction pressure testing was limited to 7,281 kPa (or 110 percent of MOP) in accordance with industry standard in 1957. FEI's subject matter experts have determined that recertification tests should not exceed 95 percent of SMYS, or 8,778 kPa in this instance. This forms the upper limit of any recertification pressure test.

To address the Project need, the VER PEN 323 would need to operate at 6,619 kPa. This would require a recertification pressure test that must expose the pipe to at least 8,274 kPa (or 125 percent of the desired MOP) at the highest point in Class Location 1 or 2 areas.

Recertification pressure testing as mentioned above would require limiting the length of each recertification section thus resulting in a large number of individual tests due to the following reasons:

1. The recertification test pressures are close to the maximum pressure that the pipe has experienced in the past;

2. The recertification test pressures are within 500 kPa of the maximum allowable test pressure as recommended by subject matter experts; and

3. The pipe and ground elevation changes along the pipeline route.

Combined, these factors increase the risk of a recertification test failure, and therefore delays associated with repairing and re-testing the segment.

14. Reference: Exhibit B-1-2 Section 4 pp.38-40 (pdf 50-52)

"In order to meet the pressure reinforcement required to avoid capacity shortfalls currently forecast for the winter of 2023/2024, this alternative proposes the replacement of fifteen segments of the existing VER PEN 323 pipeline with new higher strength 323 mm pipeline. The replacement segments would total almost 7.6 km in length, and include multiple road crossings. All replacement segments would be designed such that they would be able to operate at a MOP of 6,619 kPa."

14.1 Are there segments of the VER PEN 323 line that would not be replaced under Alternatives 1 or 2 that could experience a class location change in the future (due to residential, commercial, or industrial development)? Would this force FEI to reduce the MOP back down to 5171 kPa?

Response:

The potential for, and nature of, future development in the area around the VER PEN 323 pipeline is not known by FEI. It is possible that ongoing development could require a class location change in the future. Should this happen, FEI would have to either reduce the MOP of the pipeline, likely resulting in a capacity shortfall, or upgrade the pipeline in the affected areas.

15. Reference: Exhibit B-1-2 Section 4 pp. 51-53 (pdf 63-65)

FEI raises the concern that a hydrostatic test could open cracks that weaken the pipe, but do not fail until a subsequent hydrostatic test. This results in a test-fail-repair-test repetition.

"Due to limitations on allowable elevation difference on a test section, thirty-three requalification tests would be required in addition to six tests for the replacement segments."

15.1 How many re-tests (e.g. test-fail-repair-test) would FEI consider before re-testing of that segment was abandoned and an alternative approach was implemented? For example, if the same test segment of pipe failed twice, would FEI continue to repair and re-test this segment or would it consider alternative approaches, such as pipe replacement? Would multiple failures cause FEI to reconsider hydrostatic testing of the remaining test segments?

Response:

As discussed in Section 4.6.2.2 of the Updated Application, the section of the VER PEN 323 pipeline between Penticton and Chute Lake needs to remain in service between September 1 and June 1 (9 contiguous months of the year) to meet demand for the region to the north, including Kelowna. This would leave only six months (two three-month windows in each of the years until 2023) to complete all 33 requalification tests and segment replacements.

If FEI chose to pursue Alternatives 1 or 2 and started the requalification tests, and if the test-fail-repair-test cycle started, there would not be sufficient time to implement an alternate approach prior to the end of the three month window, and FEI would be forced to continue the cycle until each failure was repaired and each segment passed, proving the VER PEN 323 pipeline was again fit for service to the newly established Maximum Operating Pressure. Failure to do so would likely result in capacity shortfalls in the service territory north of Penticton.

This lack of confidence in timelines and contingency plans led to the poor scores assigned to Alternatives 1 and 2 in Table 4-5, and as discussed in Section 4.6.2.2 how it pertains to Schedule Risk.

15.2 Do the cost estimates for Alternatives 1 and 2 include the cost to repair any damage from failed hydrostatic testing as well as the cost of subsequent tests?

Response:

Yes, Alternatives 1 and 2 include an allowance for the cost of pipeline repairs and subsequent tests from failed hydrostatic testing.

15.3 What is the approximate cost to repair one failed pipe joint and conduct an additional test on that segment?

Response:

An estimate for an average repair cost, based on a moderately challenging replacement of 18 metres, followed by a revalidation segment test of 1,000 metres is $950 thousand.

The cost to repair a failed requalification test includes several broad activities:

1. Identify the failure location;
2. Clean-up the spill area;
3. Inspect the failure segment and determine repair scope;
4. Replace the failed segment of pipe; and
5. Conduct an additional revalidation test.

Depending of the failure mechanism, locating the failure in a buried pipeline could be challenging. A small leak that causes a failure in the revalidation test could require significant excavation and inspection of the VER PEN 323 pipeline.

If the failure released more than 100 litres of fluid, FEI would be required to report the spill to external regulators. The clean-up costs would vary depending on the overall length of the segment and the impact to the surrounding environment. Any spill would require FEI to follow spill response procedures and may include removal of soils contaminated by hydrocarbons, remediation of any waterways, and ongoing water quality monitoring.

Once FEI had remediated the failure site, FEI would conduct a thorough integrity inspection of the pipe segments on either side of the failure to determine the most appropriate location to conduct the replacement. A minimum replacement length would be six metres and may extend much longer.

The approximate costs to repair the section of failed pipe from hydrostatic testing will vary depending on a number of variables; location, ground conditions, and length of segment repair are examples. FEI's historical averages for repairs on the VER PEN 323 range between $3 thousand per metre for routine replacements to more than $17 thousand per metre for complex replacements.

After FEI completed the repairs to the pipeline, the test segment would require a subsequent requalification test. The costs associated with the retest would be approximately $750 per metre

for the entire revalidation segment length based on 50 percent of the variable costs of the initial revalidation test.

15.4 How many other transmission pipelines has FEI subjected to in-service testing?

Response:

FEI's records indicate that, since 1969, FEI has undertaken approximately six retests of transmission pipelines.

15.5 What has been FEI's experience with these in-service tests? Have there been failures and if so, did the test segment successfully pass the re-test? If the number of tests is large, refine the request by indicating the number of low frequency induction seam welded pipes that have been requalified after having been in service.

Response:

FEI's experience with the retests of transmission pipelines undertaken since 1969 is that during three of the six retests a pipe joint failed along the longitudinal seam.

Of the three retests that had a pipe failure, two of the retests were subsequently tested successfully at the original intended test pressure while the third was completed at a reduced test pressure.

16. Reference: Exhibit B-1-2 Section 4 Tables 4-3, 4-4, 4-6 pp.47-56 (pdf 59-68)

FEI provides the Alternative Evaluation Scoring Definitions and Evaluation Criteria Weighting.

"Asset Management Capability: Criteria within this category measure the success of the alternative in achieving the technical goals of the project now and into the future. As this category assesses the efficacy of the solution in meeting the project objectives, FEI considers this category to be relatively more important, which is reflected in the weighting discussed below."

"System Capacity Increase: Ability of an alternative to increase capacity in the ITS such that supply can be maintained to the Okanagan region under peak demand conditions. Alternatives that provide the greatest capacity increase will score the highest. If two or more alternatives provide a similar capacity increase, the same score is assigned."

"Operational Flexibility: Ability of a project to provide FEI with greater operational flexibility to perform inspection and repair work on its system assets. Projects which extend the window during which FEI can complete such work on sections of the ITS will score the highest."

"Schedule Risk: Ability for an alternative to be completed on schedule, with few identified risks to achieve the scheduled in-service date. Alternatives which can be completed on time will score the highest. Other alternatives are scored lower."

"Financial Evaluation: FEI considered the long term rate impact to FEI's customers to compare the financial impact of the three feasible alternatives. This was completed by evaluating the present value of the incremental revenue requirement as well as the levelized delivery rate impact over the 70-year analysis period for each alternative based on the estimated capital cost and operating cost. For a fair comparison, future incremental sustainment capital and operating expenditures over the 70-year analysis period for each feasible alternative were included in the analysis."

16.1 Confirm whether the same scoring definitions and weightings in Tables 4-3 and 4-4 have been consistently used by FEI in prior pipeline projects. For example, have Ratepayer Impacts been weighted as 30% in prior projects? If not confirmed, explain why not and provide scoring definitions and weightings used in prior projects.

Response:

The drivers, and therefore the evaluation criteria and associated weightings for each project, are based on the specific needs to meet the objectives of that project. Weightings are set based on these specifics, informed by prior similar projects where appropriate. Please also refer to the responses to BCSEA IR1 13.1 and BCUC IR1 22.6.

16.2 Considering that only Alternatives that meet the project objectives reach the scoring evaluation stage, why is the Asset Management Capability category given the greatest weight?

Response:

The Asset Management Capability criteria focuses on the long-term benefits an alternative will provide to the system. Other non-financial criteria focus primarily on the execution phase of the project. FEI considers long-term system impacts to be the most important in terms of selecting the preferred alternative, especially because there are limited opportunities to establish potential long-term benefits.

16.3 Considering that only Alternatives that meet the project objectives reach the scoring evaluation stage, and one of those objectives is the ability to provide sufficient capacity for the 20-year forecast period, confirm whether any advantage that one Alternative has over another in the Asset Management Capability scoring category relates to additional capacity that is only expected to be needed beyond the 20-year forecast period.

Response:

As explained in Section 4.5.1.1 of the Updated Application, the Asset Management Capability criteria and scoring consists of two components: System Capacity Increase, and Operational Flexibility. The noted differential in the Asset Management Capability criteria is entirely due to the relative Operational Flexibility provided by each alternative.

With respect to the System Capacity Increase evaluation, as discussed in the response to BCUC IR1 13.2, there are two bottlenecks associated with the ITS. The first limits gas flowing north from Oliver into the Kelowna and Vernon areas. The second is further upstream and is related to the ability to bring more gas into the ITS from the TC Energy pipeline at Yahk. The scoring of the alternatives, following the screening process, shows that each is sufficient to mitigate the first bottleneck (supply from Oliver north towards Kelowna and Vernon), over the 20 year forecast period. However, each will still require further mitigation to address the bottleneck further upstream. For more information on this constraint, please refer to the response to BCUC IR1 12.1 (options to mitigate the upstream bottleneck through use of the Tilbury LNG Storage Expansion Project) and BCUC IR1 13.1 (effects of the three alternatives on ITS Capacity).

For a discussion regarding Operational Flexibility, please refer to the response to BCUC IR1 22.2.

16.4 Confirm whether the scoring for Operational Flexibility is solely related to FEI's ability to perform maintenance on the OLI PEN 406 and VER PEN 323 lines and stations, and specifically to the time available to perform this maintenance. If not confirmed, clarify and provide additional details of the factors that affect the scoring for Operational Flexibility.

Response:

Not confirmed. The scoring for Operational Flexibility also incorporates the impacts of the alternative on FEI's ability to respond to unexpected situations, as discussed further in the response to BCUC IR1 22.2. It reflects how the window of time available will be lengthened not just for maintenance activities, but for any other situations or conditions which may arise requiring FEI to alter flow in the pipelines. This includes pipeline alterations to serve municipal or developer interests, upgrades of equipment as and when identified by FEI, integrity investigations by in-line inspection assessments, and response to third-party or natural hazards damage to the pipeline.

16.5 Provide the estimated annual cost savings that are expected as a result of the additional Operational Flexibility that is expected with Alternative 3 compared with Alternatives 1 and 2.

Response:

FEI anticipates minimal cost savings on an annual basis from the improved operational flexibility. The primary benefits of operational flexibility are additional options during unforeseen outages (e.g., third-party damage, hydro/geotechnical incidents, etc.) and increased scheduling flexibility for O&M activities without resulting in service outages or costly bypass requirements.

The greater operational flexibility results from Alternative 3 providing a parallel gas flow path through the new 30 km 406 mm pipeline from Oliver to the new Chute Lake Pressure Control Station, should an incident arise on the VER PEN 323 pipeline in this region. By having this pipeline loop, FEI is able to avoid any bypass requirements should a segment of the VER PEN 323 pipeline need to be taken out of service for repairs. This results in a 5 to 10 times reduction in costs if and when these instances occur.

The pipeline loop also improves the efficiency of FEI's in-line inspection activities by providing longer windows during the year in which tools can be run (or the pipeline taken out of service for maintenance or repair activity). These inspections are conducted on a cyclical basis (typically every seven years), so these cost savings are not expected to occur annually, and would instead be reflected in future lower capitalized inspection costs and integrity management activity costs for this pipeline.

16.6 Operational Flexibility has a scoring weight of 20% of the total scoring evaluation (50% of 40%). Given the magnitude of the cost savings (if any) provided by additional operational flexibility, justify why this criterion is given only marginally less weight than Financial (Rate Impact) which has a scoring weight of 30%.

Response:

Operational Flexibility provides FEI with the flexibility to manage unforeseen issues in the future. This benefit is difficult to quantitatively forecast, but is an important long-term benefit to the system. Large-scale operational flexibility can only be improved when undertaking a system expansion project such as the OCU and as such is an important consideration to FEI when evaluating alternatives.

16.7 How would approval and construction of Alternative 1 affect the next capacity upgrade for the ITS? That is, what would change in terms of the next capacity additions (e.g. pipeline expansion, compression addition) compared with the construction of Alternative 3?

Response:

FEI expects that the next required capacity upgrade could be a compression upgrade upstream of the OLI PEN 406 pipeline if any of Alternatives 1, 2, or 3 were selected. However, should Alternative 1 or 2 be selected, they would also require further pipeline installation, either as a shorter subset of Alternative 3 or 4, to produce the same capacity on the system as that which would be provided by Alternative 3 with the compression addition. Please refer to the responses to BCUC IR1 22.1 and BCSEA IR1 11.1 for additional detail.

16.8 Explain whether the three alternatives would have achieved higher, and possibly the same, scores for Schedule Risk if FEI had brought this CPCN application earlier such that there would have been sufficient time to complete all activities without substantial risk to the schedule.

Response:

Alternative 3 would still have received the best score in terms of schedule risk had FEI brought this CPCN application earlier. As further discussed in the response to CEC IR1 17.1, Alternatives 1 and 2 carry a high degree of schedule uncertainty due to unknowns around how the pipeline would respond to revalidation hydrotesting and the limited capacity window which the VER PEN 323 pipeline can be taken out of service. Thus, the risk of a failure to mitigate the forecasted capacity shortfall would be lower, but still present. FEI would not have scored the three alternatives equally in terms of schedule risk had the Project been initiated earlier.

16.9 Is there a risk that hydrotesting of the VER PEN 323 line would not ultimately be successful? How should such a possibility be reflected in the evaluation scoring?

Response:

Please refer to the response to RCIG IR1 15.1. If FEI selected Alternatives 1 or 2, it would have to continue with revalidation hydrotesting of the VER PEN 323 line until it was successfully completed as there would not be sufficient time to seek approval, complete the design, and then construct the preferred option, Alternative 3. Given the limited capacity timeframe wherein the VER PEN 323 pipeline can be removed from service, the risk is that FEI would be unable to supply gas to its customers downstream of Penticton, including Kelowna. This risk was reflected in the Schedule Risk scoring for Alternatives 1 and 2, and further validated FEI's view that Alternative 3 is the preferred solution for the Project.

16.10 Provide the justification for the use of a 70-year period for the financial evaluation.

Response:

The 70-year period for the financial analysis is based on the average service life (ASL) of transmission mains at 65 years as determined in FEI's 2017 Depreciation Study (approved through Order G-165-20), plus five prior years for project planning, regulatory approval, and construction (i.e., 65 + 5 = 70 years). As per the BCUC's CPCN Guidelines, FEI is required to

show the revenue requirements and resulting rate impacts due to the Project. Given that the assets associated with the Project are expected to remain in service over the period of the ASL (assuming no third-party relocation requests, or system alterations for operational or integrity reasons, occur during the period), the assets will continue to impact FEI's revenue requirement and customer rates over the period of ASL. As such, FEI considers it is appropriate to use ASL as the basis of the financial analysis period. FEI also notes that using ASL is consistent with the basis of the analysis period used in FEI's recently filed CPCN Applications such as the Pattullo Gas Line Replacement Project, the Tilbury LNG Storage Expansion Project, and the Coastal Transmission System Transmission Integrity Management Capabilities Project.

16.11 Over what period (for example in a discounted cash flow analysis) does FEI evaluate the economic feasibility of system expansion to serve new customers?

Response:

FEI evaluates the economic feasibility of system extensions to new customers using FEI's Distribution Mains Extension (MX) Test, which calculates the discounted net present value over a period of 40 years. The use of a 40-year period was approved by the BCUC in Order G-147-16.

16.12 Recalculate Table 4-7 (PV of Annual Revenue Requirement, Levelized Rate Impact) using an evaluation period that matches the one used to evaluate economic feasibility for system expansion. Does the different evaluation period change the scoring?

Response:

In responding to this IR, FEI added 5 prior years to the MX Test analysis period to allow for the project development and construction period and then recalculated the PV of annual revenue requirements over a 45-year period. Please refer to the table below (presented in a similar format as Table 4-7 in the Updated Application) for the PV of annual revenue requirements of the three alternatives over a 45-year period.

Even though the PV of the Annual Revenue Requirement and Levelized Rate Impact resulting from this calculation is different from the results in Table 4-7, the order of the Alternatives from lowest to highest has not changed. Alternative 1 continues to have the lowest levelized rate impact to FEI's customers. FEI also notes that the changes in the levelized rate impact from a 70-year analysis period to 45-year analysis period is small. For example, the levelized rate

impact for Alternative 1 changes by $0.002 per GJ from a 70-year analysis period to 45-year analysis period.

	Alternative 1	Alternative 2	Alternative 3
PV of Annual Revenue Requirement ($000s)	191,544	203,711	193,327
Levelized Rate Impact ($/GJ)	0.059	0.063	0.060
Financial / Rate Impact	4	2	3

17. Reference: Exhibit B-1-2 Sections 3,4 Figures 3-6, 3-7, 3-8, 4-1, pp.18-20,37, (pdf 30-32, 49)

17.1 Provide tables with the data points used to create Figures 3-6, 3-7, 3-8, 4-1, and the response to BCUC Information Request 1.13.

Response:

The data points used to create the referenced figures are provided in the tables below.

Year	Figure 3-6 Data (TJ/day)		Figure 3-7 Data (TJ/day)	Figure 3-8 Data (TJ/day)	Figure 4-1 Data (TJ/day)
	ITS Peak Demand (Historical DDD estimate)	ITS Peak Demand – (Forecasted)	Current ITS Capacity	ITS Capacity with OCU	ITS Capacity with Short-Term Mitigation Measures
2009	375	n/a	n/a	n/a	n/a
2010	381	n/a	n/a	n/a	n/a
2011	376	n/a	n/a	n/a	n/a
2012	375	n/a	n/a	n/a	n/a
2013	358	n/a	n/a	n/a	n/a
2014	369	n/a	n/a	n/a	n/a
2015	382	n/a	n/a	n/a	n/a
2016	387	n/a	n/a	n/a	n/a
2017	384	n/a	n/a	n/a	n/a
2018	391	n/a	n/a	n/a	n/a
2019	n/a	321	333	366	344
2020	n/a	327	333	366	344
2021	n/a	333	333	366	344
2022	n/a	338	333	366	344
2023	n/a	344	333	366	344
2024	n/a	350	333	366	344
2025	n/a	353	333	366	344
2026	n/a	357	333	366	344
2027	n/a	360	333	366	344
2028	n/a	363	333	366	344
2029	n/a	367	333	366	344
2030	n/a	370	333	366	344
2031	n/a	373	333	366	344
2032	n/a	376	333	366	344

Year	Figure 3-6 Data (TJ/day)		Figure 3-7 Data (TJ/day)	Figure 3-8 Data (TJ/day)	Figure 4-1 Data (TJ/day)
	ITS Peak Demand (Historical DDD estimate)	ITS Peak Demand – (Forecasted)	Current ITS Capacity	ITS Capacity with OCU	ITS Capacity with Short-Term Mitigation Measures
2033	n/a	379	333	366	344
2034	n/a	382	333	366	344
2035	n/a	385	333	366	344
2036	n/a	388	333	366	344
2037	n/a	390	333	366	344
2038	n/a	393	333	366	344
2039	n/a	395	333	366	344

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Year	BCUC IR1 13.1 Data (TJ/day)					
	ITS Capacity with Alternatives 1, 2, and 3	ITS Capacity with OCU Alternative 4	ITS Capacity with OCU Alternative 5	ITS Capacity with OCU Alternative 1 After Kit B Upgrade	ITS Capacity with OCU Alternative 2 After Kit B Upgrade	ITS Capacity with OCU Alternative 3 After Kit B Upgrade
2009	n/a	n/a	n/a	n/a	n/a	n/a
2010	n/a	n/a	n/a	n/a	n/a	n/a
2011	n/a	n/a	n/a	n/a	n/a	n/a
2012	n/a	n/a	n/a	n/a	n/a	n/a
2013	n/a	n/a	n/a	n/a	n/a	n/a
2014	n/a	n/a	n/a	n/a	n/a	n/a
2015	n/a	n/a	n/a	n/a	n/a	n/a
2016	n/a	n/a	n/a	n/a	n/a	n/a
2017	n/a	n/a	n/a	n/a	n/a	n/a
2018	n/a	n/a	n/a	n/a	n/a	n/a
2019	366	375	381	372	381	397
2020	366	375	381	372	381	397
2021	366	375	381	372	381	397
2022	366	375	381	372	381	397
2023	366	375	381	372	381	397
2024	366	375	381	372	381	397
2025	366	375	381	372	381	397

Year	BCUC IR1 13.1 Data (TJ/day)					
	ITS Capacity with Alternatives 1, 2, and 3	ITS Capacity with OCU Alternative 4	ITS Capacity with OCU Alternative 5	ITS Capacity with OCU Alternative 1 After Kit B Upgrade	ITS Capacity with OCU Alternative 2 After Kit B Upgrade	ITS Capacity with OCU Alternative 3 After Kit B Upgrade
2026	366	375	381	372	381	397
2027	366	375	381	372	381	397
2028	366	375	381	372	381	397
2029	366	375	381	372	381	397
2030	366	375	381	372	381	397
2031	366	375	381	372	381	397
2032	366	375	381	372	381	397
2033	366	375	381	372	381	397
2034	366	375	381	372	381	397
2035	366	375	381	372	381	397
2036	366	375	381	372	381	397
2037	366	375	381	372	381	397
2038	366	375	381	372	381	397
2039	366	375	381	372	381	397

D. Project Description

18. Exhibit B-1-2 Section 5 p.62 (pdf 74)

"Each of the evaluation criterion was given a weighted score as outlined in Table 5-2, in order to quantify the relative merits of each option."

18.1 Confirm whether the route selection evaluation criteria and weighting are consistent with other FEI pipeline projects of similar scope or magnitude as OCU.

18.1.1. If not confirmed, explain how and why the criteria or weighting have changed.

18.1.2. If not confirmed, provide the weighting factors used in recent FEI pipeline projects of similar scope or magnitude as OCU.

18.1.3. If there are no pipeline projects with similar scope and magnitude as OCU, then provide the weighting factors used in pipeline projects with a construction value greater than $10 million undertaken by FEI in recent years.

Response:

Please refer to the response to BCSEA IR1 16.3 for information regarding the use of route selection evaluation criteria in other FEI CPCN applications, BCSEA IR1 16.4 for information regarding the use of route selection weighting in other FEI CPCN applications, and BCSEA IR1 16.5 for information regarding the use of route evaluation scoring descriptions in other FEI CPCN applications.

19. Reference: Exhibit B-1-2 Section 5 pp.70,71 (pdf 82,83)

"It is expected that the existing CP system could be used to provide protection to the new OLI PEN 406 extension; this will be confirmed during detailed design."

19.1 What is the cost impact if the existing cathodic protection system is found to be inadequate to protect the proposed extension to OLI PEN 406 and additional cathodic protection is required? Provide both the capital cost, the ongoing operating and maintenance costs, and the present value of the annual revenue requirement of the additional cathodic protection (on a comparable basis to the annual revenue requirements shown in Table 4-7).

Response:

If FEI determines the existing cathodic protection system to be inadequate to protect the proposed extension to the OLI PEN 406, the only additional equipment required would be an anode bed to be installed at the proposed OP5 Block Valve Station at a capital cost of $50 thousand (2020$). There would be no additional ongoing operating and maintenance costs associated with this installation beyond what was already considered.

The incremental $50 thousand capital expenditure, represents approximately 0.02 percent of the capital costs of the Project in 2020 dollars, and would have no discernible impact on the PV of annual revenue requirements.

20. Reference: Exhibit B-1-2 Section 5 pp.72,74 (pdf 84,86)

"A 1,200 m section of the existing OLI PEN 406 will be deactivated between the Ellis Creek tie-in point and the existing Ellis Creek Pressure Control Station. This will include removing a section of pipe at the tie-in location, welding a cap onto the deactivated section, installing a blind at the inlet to the Ellis Creek Pressure Control Station, purging the line and maintaining a low pressure blanket with nitrogen."

20.1 Describe the purpose(s) and function(s) of the Ellis Creek Pressure Control Station.

Response:

The Ellis Creek Pressure Control Station connects and provides pressure control (regulation) and overpressure protection from the OLI PEN 406 pipeline operating at a maximum operating pressure (MOP) of 7,826 kPa to the VER PEN 323 pipeline operating at an MOP of 5,171 kPa. It also provides seasonal flow control via the SN10-3 block valve into the VER PEN 323 pipeline, allowing control of gas flows either to the north or south.

20.2 Provide the cost of the control station that will be constructed at the terminus of the OLI PEN 406 line near Chute Lake, with a breakdown showing the cost of the pressure regulating equipment (shown separately for each pressure reduction run), line heaters, inlet and outlet valves, pig receiver, filters, telemetry, and overpressure protection.

Response:

A portion of this response is being redacted pursuant to section 18 of the BCUC's Rules of Practice and Procedure as set out in Order G-15-19. The cost information information in the table below is being redacted because the information is commercially sensitive that, if disclosed, could hamper or prejudice FEI's negotiations with contractors on current and future projects.

A confidential version of this response is being filed with the BCUC under separate cover and can be made available to registered parties upon providing a signed Confidentiality Declaration and Undertaking similar to that provided in the Application, Appendix J-3.

The table below provides a breakdown, by operating component, of the estimated cost to construct the Chute Lake Pressure Control Station.

Allocated Cost Breakdown of Chute Lake Pressure Control Station ($000s)

Description	Material	Labour	Other[2]	Total
OLI PEN 406 Pigging Assembly	[redacted]	[redacted]	[redacted]	[redacted]
Main Gas Filter	[redacted]	[redacted]	[redacted]	[redacted]
VER PEN 323 to SN9-3 Pressure Control Run #1	[redacted]	[redacted]	[redacted]	[redacted]
VER PEN 323 to SN9-3 Pressure Control Run #2	[redacted]	[redacted]	[redacted]	[redacted]
VER PEN 323 to SN9-3 Pressure Control Bypass	[redacted]	[redacted]	[redacted]	[redacted]
VER PEN 323 to SN10 Pressure Control Run	[redacted]	[redacted]	[redacted]	[redacted]
VER PEN 323 to SN10 Pressure Control Bypass	[redacted]	[redacted]	[redacted]	[redacted]
VER PEN 323 Valves and tie-in	[redacted]	[redacted]	[redacted]	[redacted]
Catalytic Heaters[3]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Gas Assembly Panel	[redacted]	[redacted]	[redacted]	[redacted]
Power Gas Assembly Panel	[redacted]	[redacted]	[redacted]	[redacted]
Telemetry Building	[redacted]	[redacted]	[redacted]	[redacted]
			Total:	[redacted]

20.3 Provide station design details for the Ellis Creek station in a similar format as Table 5-10 for the portion of the station that reduces the pressure from the OLI PEN 406 line.

Response:

The design details for the Ellis Creek Pressure Control Station are provided in the table below.

Parameter	Value
Peak Hour Station Inlet Gas Flow	200 mmscfd
Minimum Station Inlet Gas Pressure	6,205 kPa
Station Inlet Gas Temperature Range	5 to 20 degC
Gas Molecular Weight	17.16
Peak Flow to VER PEN 323	200 mmscfd

[2] Other costs for the purpose of this estimate include bulk materials, transportation costs, third-party inspection costs and construction support services.

[3] Catalytic Heaters are installed to prevent freeze-off of the fuel gas and power gas assemblies. There are no line heaters installed at the Chute Lake Pressure Control Station.

Parameter	Value
Station Discharge Gas Pressure to VER PEN 323	5,171 kPa
Maximum Gas Velocity	19.5 m/s

20.4 Confirm whether FEI considered relocating and repurposing the station equipment at the Ellis Creek Station to be used at the Chute Lake station. Provide FEI's analysis of the advantages and disadvantages of this approach.

Response:

FEI did not consider relocating and repurposing the station equipment at the Ellis Creek Pressure Control Station for two reasons.

First, FEI must maintain full functionality of the Ellis Creek Pressure Control Station until the new OLI PEN 406 extension is completely commissioned. The commissioning process may take several months due to the potential for odor fade[4] in newly constructed steel pipelines. It would be impractical to attempt to repurpose the equipment when both the Ellis Creek Pressure Control Station and newly constructed Chute Lake Pressure Control Station are required to be operational simultaneously.

Second, FEI plans to deactivate (not abandon) 1.2 km of OLI PEN 406 line between the Ellis Creek tie-in point and the existing Ellis Creek Pressure Control Station. FEI must maintain the functionality of the pressure control and overpressure equipment at the Ellis Creek Pressure Control Station should the line be reactivated.

[4] Odor fade (loss of odorant) can occur when physical and/or chemical processes cause the level of odorant in the gas to be reduced below readily detectable levels. This can occur more often in installations of new gas pipe than in existing pipe.

21. Reference: Exhibit B-1-2 Section 5 p.74 (pdf 86); BCUC IR 1.30.1

"Please confirm, or explain otherwise, that, after the deactivation of this section of OLI PEN 406, this portion of the assets will also be removed from FEI's ratebase."

21.1 If the deactivated OLI PEN 406 assets will be removed from rate base, confirm whether the Ellis Creek station assets used to interconnect with the OLI PEN 406 line will also be removed from FEI's rate base.

Response:

As explained in the responses to BCUC IR1 30.1 and 30.5, the costs associated with the 1.2 km section of the OLI PEN 406 pipeline will not be removed from rate base. FEI requires the ability to reactivate this section of the OLI PEN 406 for the potential of future integrity management activities which would then require the use of the Ellis Creek Station. As such, after the completion of the OCU Project, the Ellis Creek Station will be deactivated in a similar fashion to the OLI PEN 406 pipeline section with the ability for future reactivation.

22. Reference: Exhibit B-1-2 Section 5 pp.89-91 (pdf 101-103)

"The risk identification process identified a number of risks which were tabulated in the risk register included in Appendix 4 to YPCI's Risk Report (Confidential Appendix C-1)."

22.1 Has FEI undertaken any pipeline projects of similar scope or magnitude as OCU in the past five years? If so, identify them and provide a brief description. If FEI has not undertaken any pipeline projects of similar scope or magnitude as OCU, then identify pipeline projects and provide brief descriptions for projects with capital costs in excess of $50 million.

Response:

A portion of this response is being redacted and Attachment 22.1 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. Financial information in the table is being redacted because the information is commercially sensitive that, if disclosed, could hamper or prejudice FEI's negotiations with contractors on current and future projects. Attachment 22.1 is being filed confidentially as it contains sensitive engineering, operational, and technical information pertaining to FEI's assets, project risks, and potential vulnerability points, the disclosure of which can reasonably be expected to impede or jeopardize the security, safety, and reliability of FEI's system.

A confidential version of this response is being filed with the BCUC under separate cover and can be made available to registered parties upon providing a signed Confidentiality Declaration and Undertaking similar to that provided in the Application, Appendix J-3.

This response addresses RCIG IR1 22.1 to 22.4. The table below provides details on two gas pipeline CPCN projects FEI has undertaken within the past five years that are of a similar magnitude as the OCU Project and in excess of $50 million in estimated capital costs. Both of these projects are currently underway and, as such, final actual project costs are not yet available. FEI conducted Monte Carlo simulations for each of these projects and details on their respective risk funding amounts including contingency, management reserve (if any), and escalation are summarized in the table below.

Project	Description	Capital Cost Estimate (in $millions)*	Risk Funding Estimate (in $millions)
Lower Mainland IP System Upgrade (LMIPSU) Projects approved by BCUC Order C-11-15	To replace two existing IP pipeline segments: 1. Coquitlam Gate IP – To eliminate the identified non-preventable corrosion risks associated with the existing pipeline and addresses other capacity related constraints.	$242.83	• Contingency: [redacted] • Management Reserve: [redacted] • Escalation: [redacted]
	2. Fraser Gate IP – to mitigate the identified seismic vulnerability and associated consequences.	$8.99	• Contingency: [redacted] • Management Reserve: [redacted] • Escalation: [redacted]

Project	Description	Capital Cost Estimate (in $millions)*	Risk Funding Estimate (in $millions)
Inland Gas Upgrades (IGU) Project approved by BCUC Order G-12-20	To implement the most cost-effective integrity management solutions to mitigate the potential for rupture failure on 29 laterals in the Interior region of BC.	$362.9	• Contingency: [redacted] • Management Reserve: [redacted] • Escalation: [redacted]

** As-spent dollars including Allowance for Funds Used During Construction (AFUDC)*

The risk analysis reports for these projects are provided in Confidential Attachment 22.1.

22.2 For the projects in 22.1, if Monte Carlo simulations of the contingency, management reserve, and escalation reserve amounts were undertaken, provide the probabilities of underrun for each of contingency, management reserve, and escalation reserve assumed in each CPCN application. If Monte Carlo simulations were not undertaken, provide the contingency, management reserve, and escalation reserve as proportions of the base estimate assumed in each CPCN application.

Response:

Please refer to the response to RGIG IR1 22.1.

22.3 For the projects in 22.2, provide the amounts of contingency, management reserve, and escalation reserve that were ultimately used to complete the projects, as well as the final costs of the projects in comparison with the costs presented in the corresponding CPCN applications.

Response:

Please refer to the response to RGIG IR1 22.1.

22.4 For FEI's most recent pipeline project of similar scope and magnitude to the OCU, provide the risk register or similar consultant's report on the project risks.

Response:

Please refer to the response to RGIG IR1 22.1.

23. Reference: Exhibit B-1-2 Section 5 p.90-92 (pdf 102-104)

"During the cost validation process outlined in Section 5.10.3, FEI identified that there is a market risk to the Project due to factors such as contractor capacity, the availability of qualified pipeline contractors in 2022 and 2023 and market risk where bids are uncompetitive. FEI considered market prices as a risk that could impact the Project cost and undertook additional analysis."

"The probability of both management reserve risks occurring is low, therefore, FEI will hold one reserve fund to cover the impact should either of the risks occur. Given there are two risks covered by a single management reserve, FEI has chosen to fund the P70 value of the larger risk or $23.6 million."

"Escalation per AACE is 'a provision in costs or prices for uncertain changes in technical, economic, and market conditions over time. Inflation (or deflation) is a component of escalation.'"

23.1 If FEI is addressing the risk of market prices and uncompetitive contractor bids through the management reserve, explain whether addressing the escalation of economic and market conditions with the escalation reserve results in a duplicate provisioning for this risk.

Response:

There is no duplicate provisioning for market risk and escalation. Escalation relates to factors that arise from the overall economic conditions that drive price changes over a period of time such as demand for goods and services, productivity, and labour shortages. The market risk is based on an uncertainty as to contractor workload and availability when the Project is ready for bids. There is likely some correlation in the overall economic conditions which cause escalation that may also impact the market risk of contractor capacity and availability (for example, poor economic conditions could lead to increased contractor availability), but not to the extent that it affects bid pricing in the current economic environment, nor to the extent that it impacts contractor bidding strategies. Please also refer to the response to CEC IR1 36.1.

E. Project Cost Estimate

24. Reference: Exhibit B-1-2 Section 6 pp.96-97 (pdf 108-109)

24.1 Explain whether there are any opportunities to reduce the delivery rate impact on consumers through additional cost deferrals or extensions to the amortization periods of proposed cost deferrals. Discuss the advantages and disadvantages of these opportunities.

Response:

FEI has responded to this question with the understanding that "cost deferrals" is referring to capturing costs in a deferral account rather than deferring the Project itself.

FEI notes that it follows regulatory and accounting guidance to determine whether costs qualify as capital or if they are subject to expense/deferral treatment.

Capital costs associated with the Project must be recorded to gas plant in service to be in compliance with BCUC Orders and the BCUC Uniform System of Accounts.

Costs associated with the filing of the CPCN Application and the preliminary investigation of the alternatives are captured in a non-rate base deferral account. This treatment for these costs is consistent with past CPCN applications approved by the BCUC. If the deferral account is approved by the BCUC as part of the Application, the non-rate base deferral account will be transferred to rate base and the costs will be recovered from FEI's non-bypass ratepayers through amortization. Please refer to the response to BCUC IR1 33.5 on the evaluation of the amortization period for the deferral account.

F. Consultation and Engagement

25. Reference: Exhibit B-1-2 Section 8 p.113

"As a result of FEI's consultation with landowners, FEI was able to make adjustments to the route which ultimately decreased the number of directly impacted landowners from 57 to 38."

25.1 Was FEI able to resolve all the concerns of landowners with respect to the project routing? If not, what concerns expressed by landowners remain unresolved?

Response:

There are three unresolved landowner concerns with respect to the Project routing. Two landowners have requested routing adjustments to minimize impact to their property and the third landowner is concerned about future development work on their land. FEI will continue to work with these landowners to accommodate their requests, if reasonable.

26. Reference: Exhibit B-1-2 Appendix H-2 Stakeholder Consultation Log (pdf 318-322)

Appendix H-2 is a log of stakeholder consultation and identifies a number of communications (letters and emails) that were sent to landowners, residents, and other stakeholders.

26.1 Provide copies of the responses received by FEI to the communications sent to landowners and stakeholders detailed in Appendix H-2.

Response:

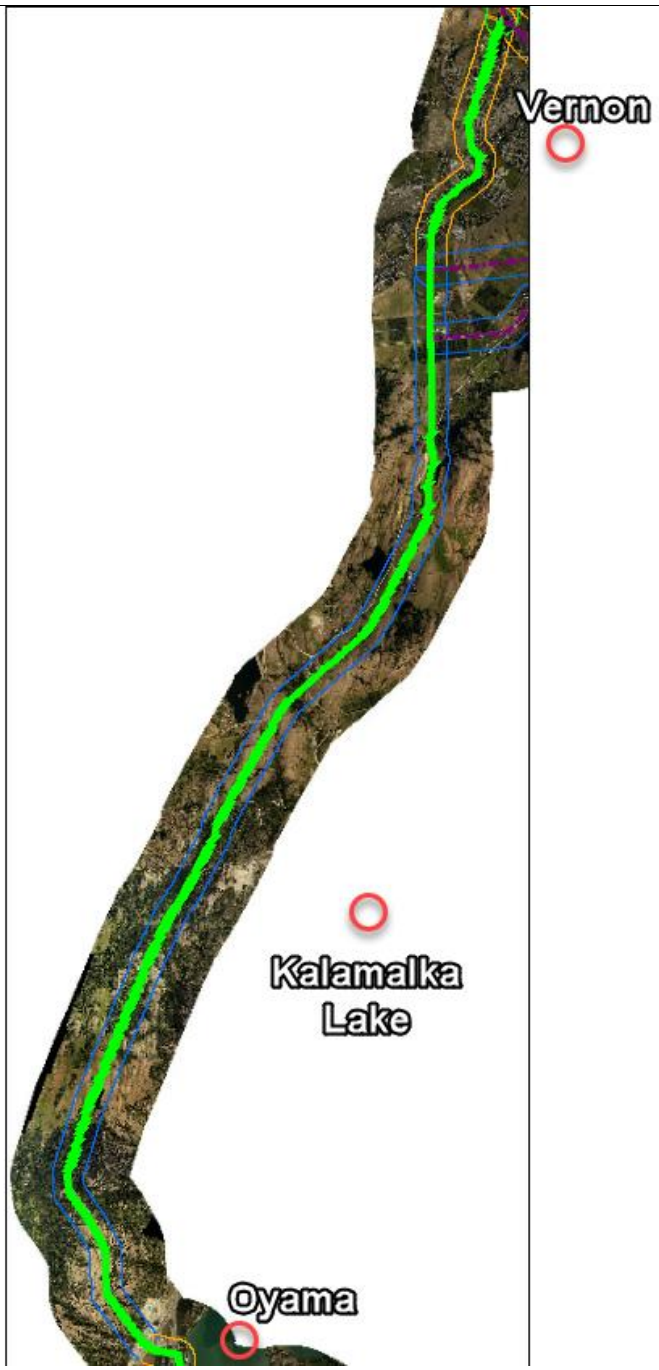
Please refer to Confidential Attachment 26.1 for copies of the email responses received by FEI in response to the communications sent to stakeholders in Appendix H-2. Attachment 26.1 is being filed confidentially with the BCUC pursuant to section 18 of the BCUC's Rules of Practice and Procedure as set out in Order G-15-19, as it contains personal stakeholder information for which FEI does not have the authority or permission to disclose.

No responses were received from directly impacted private landowners as a result of communications activities detailed in Appendix H-2.

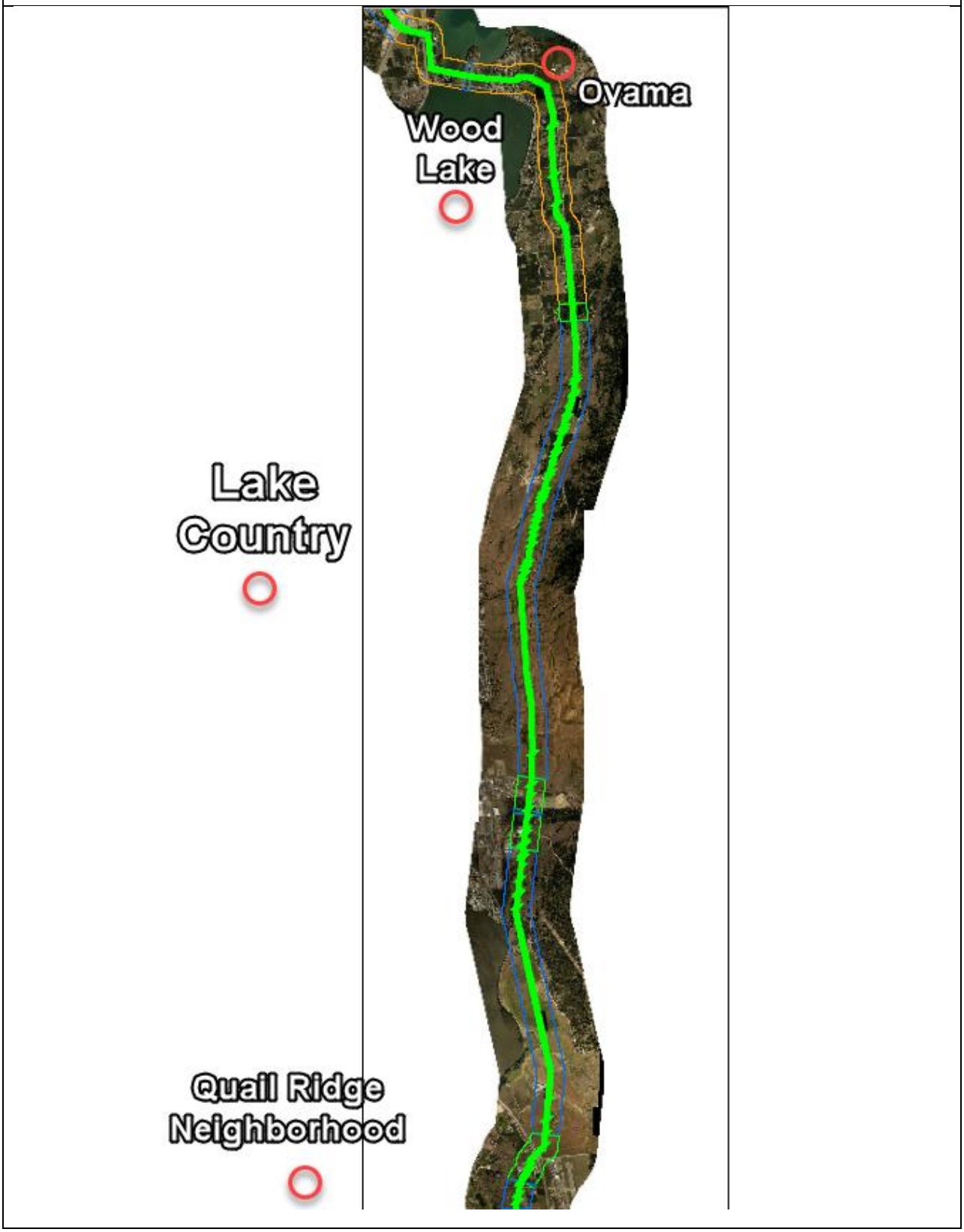
Attachment 8.1

Blue borders: Class 1 / Green : Class 2 / Dark Yellow: Class 3

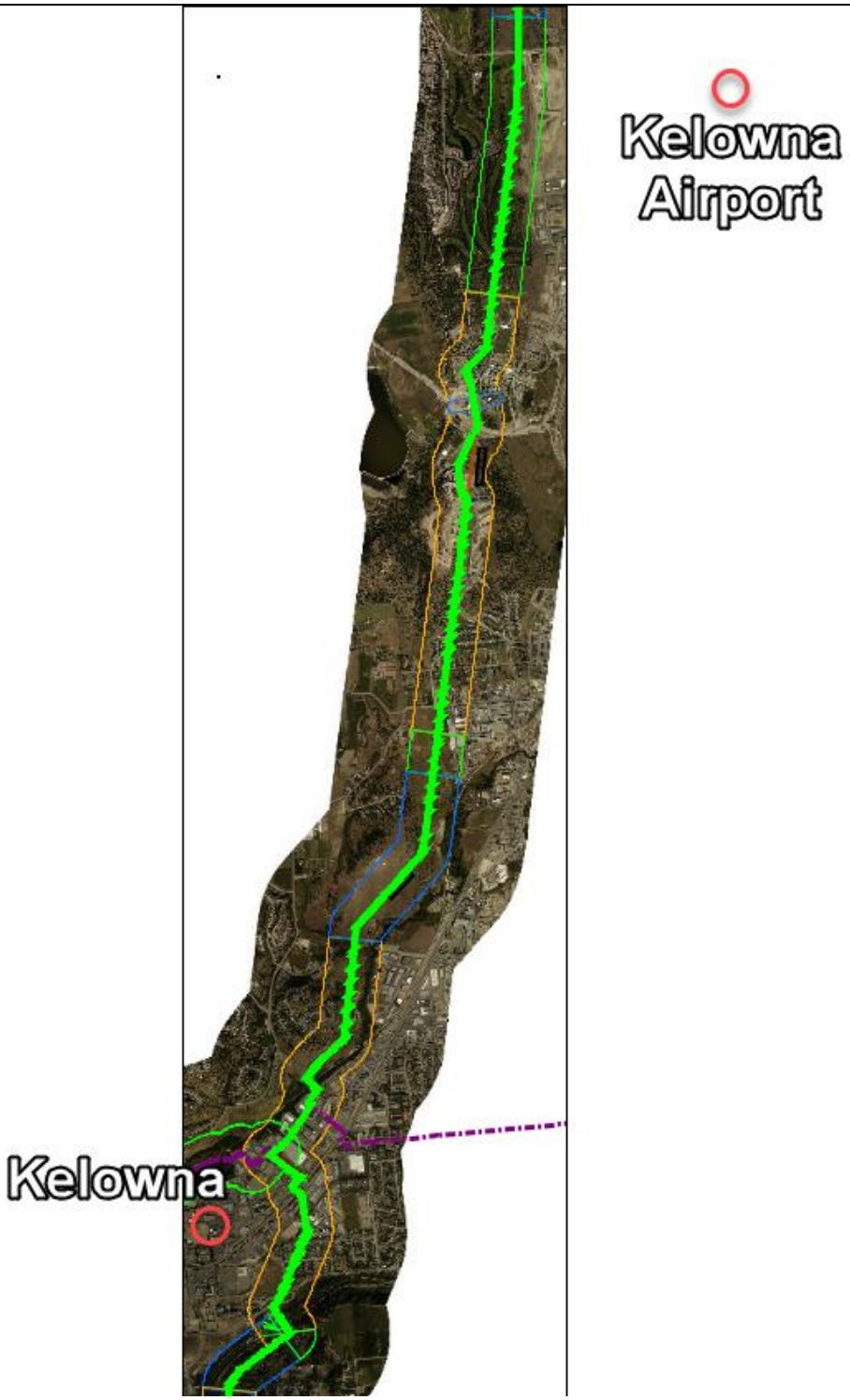
0 - 19112.142 (Class 3 – Class 1)



19112.142 - 38290.433

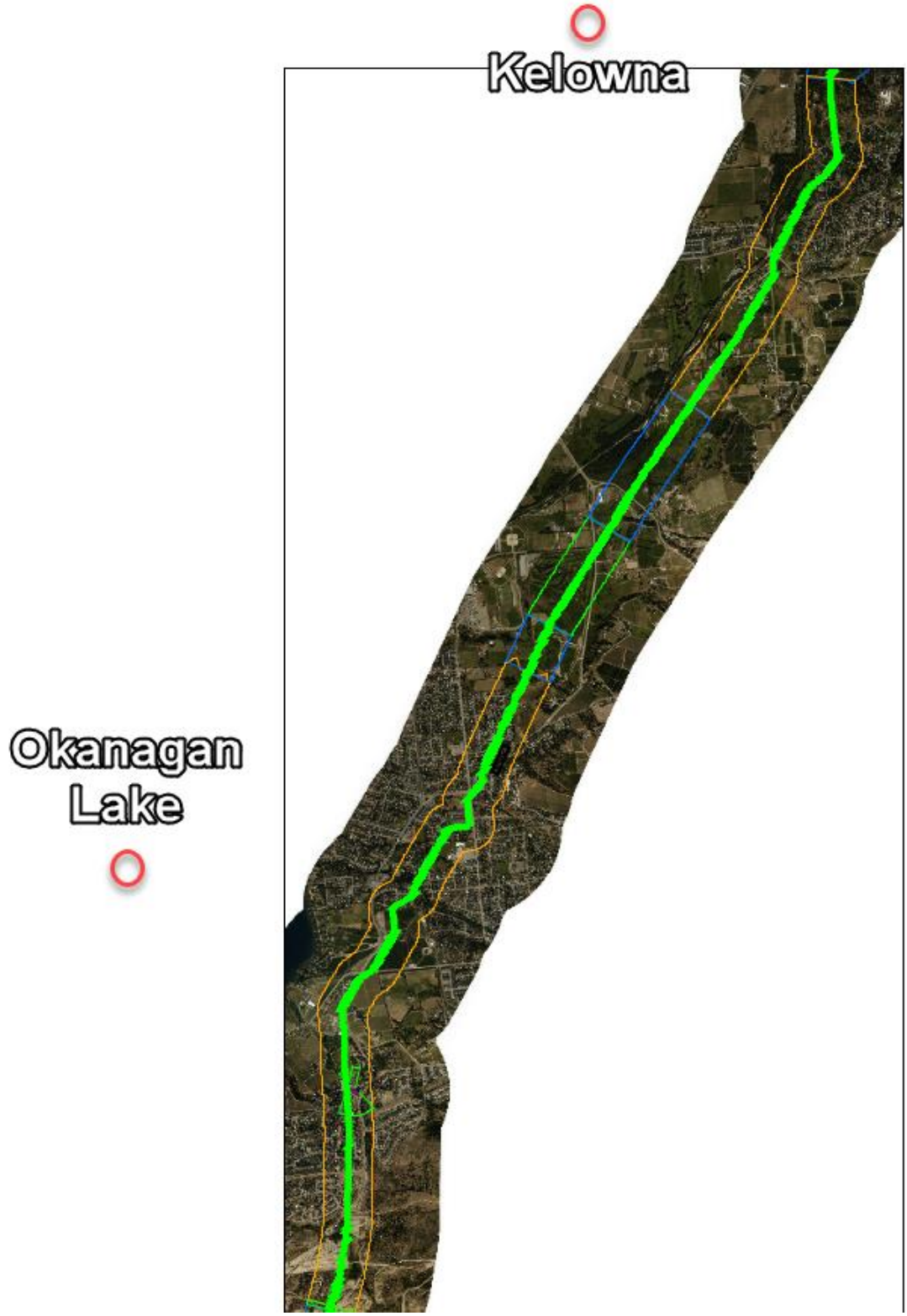


38290.433 - 49751.455



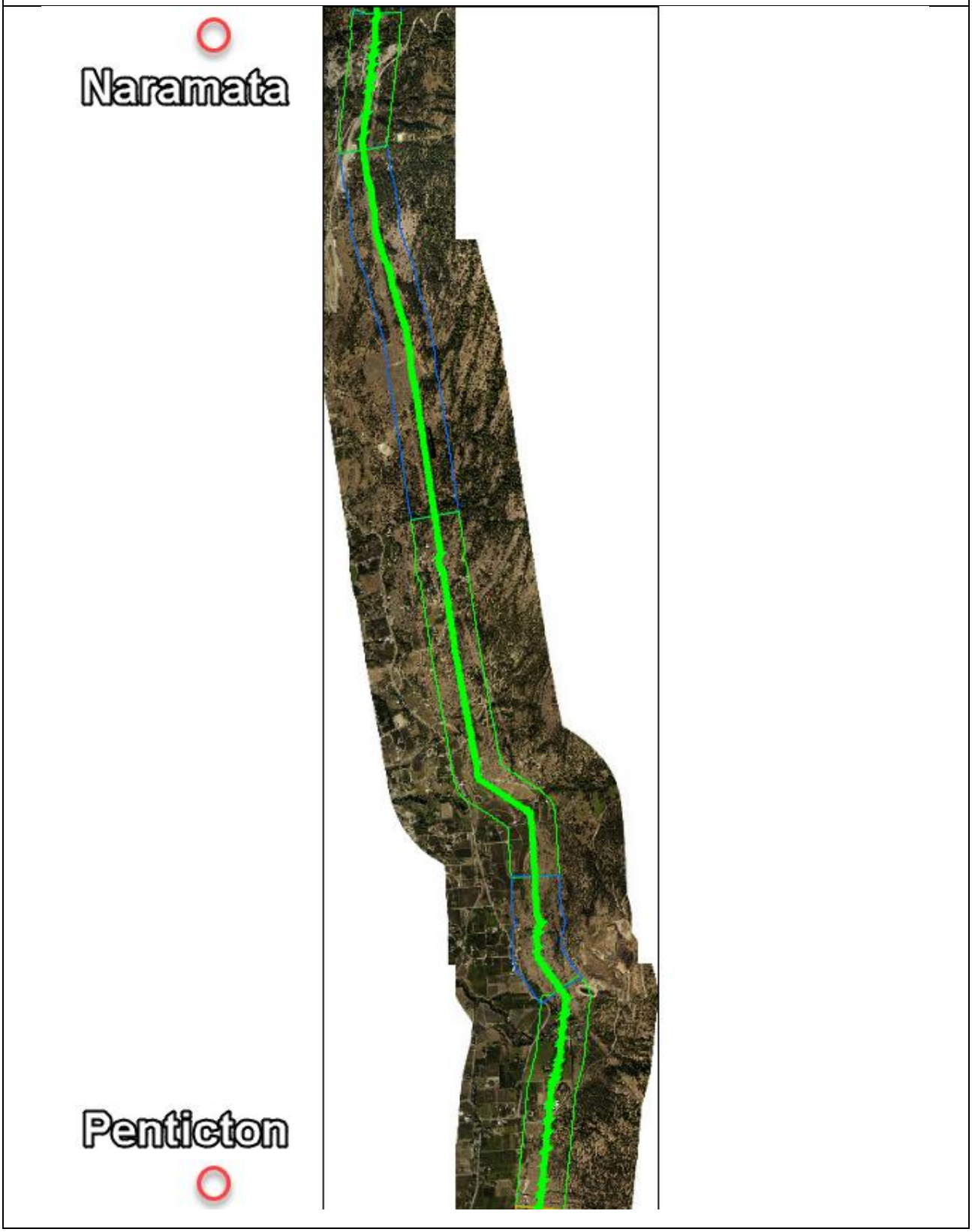
1

49751.455 - 61318.676



61318.676 - 84676.308 (Class 1)

84676.308 - 95022.383

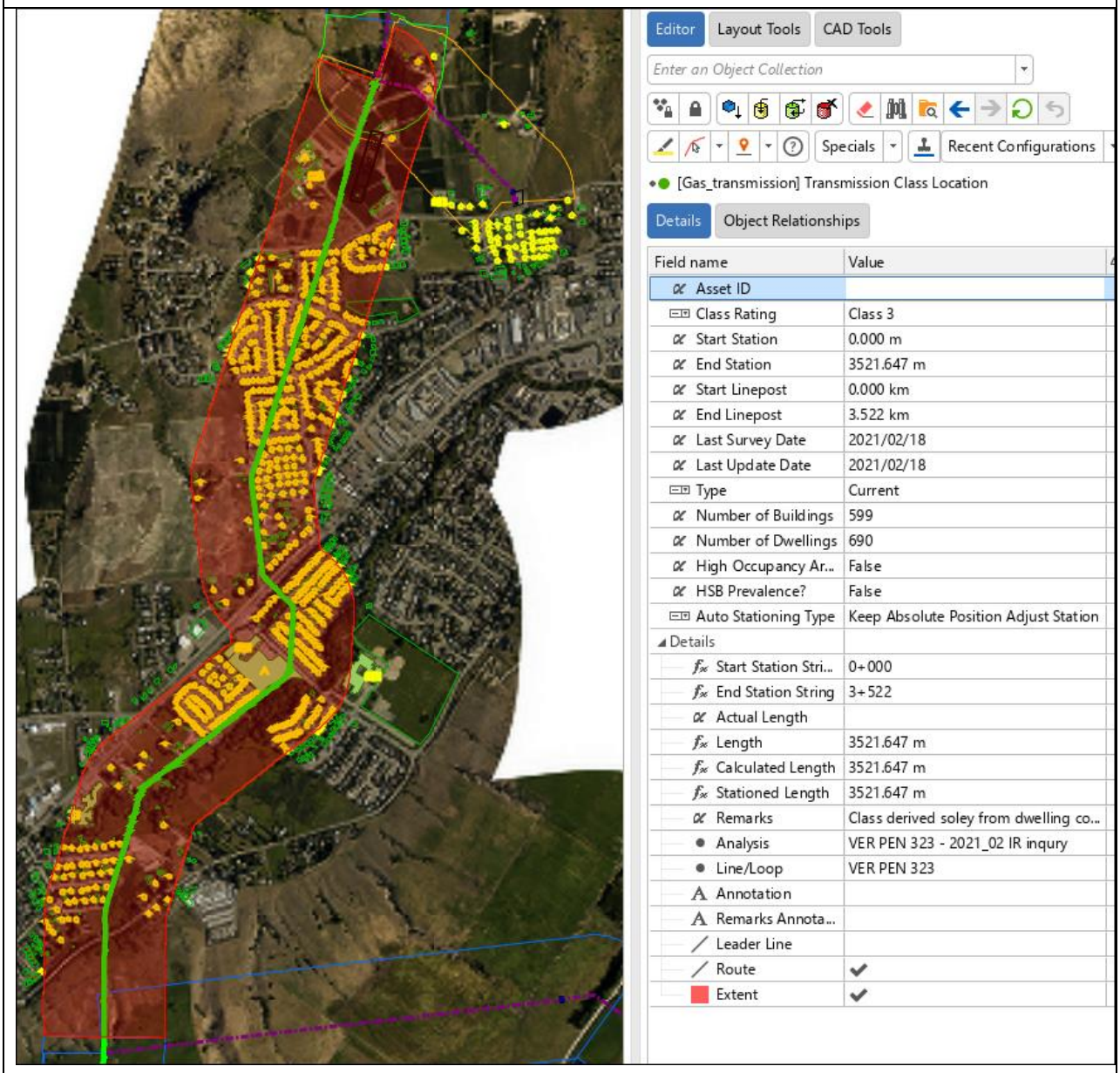


95022.383 - 98994.444

1

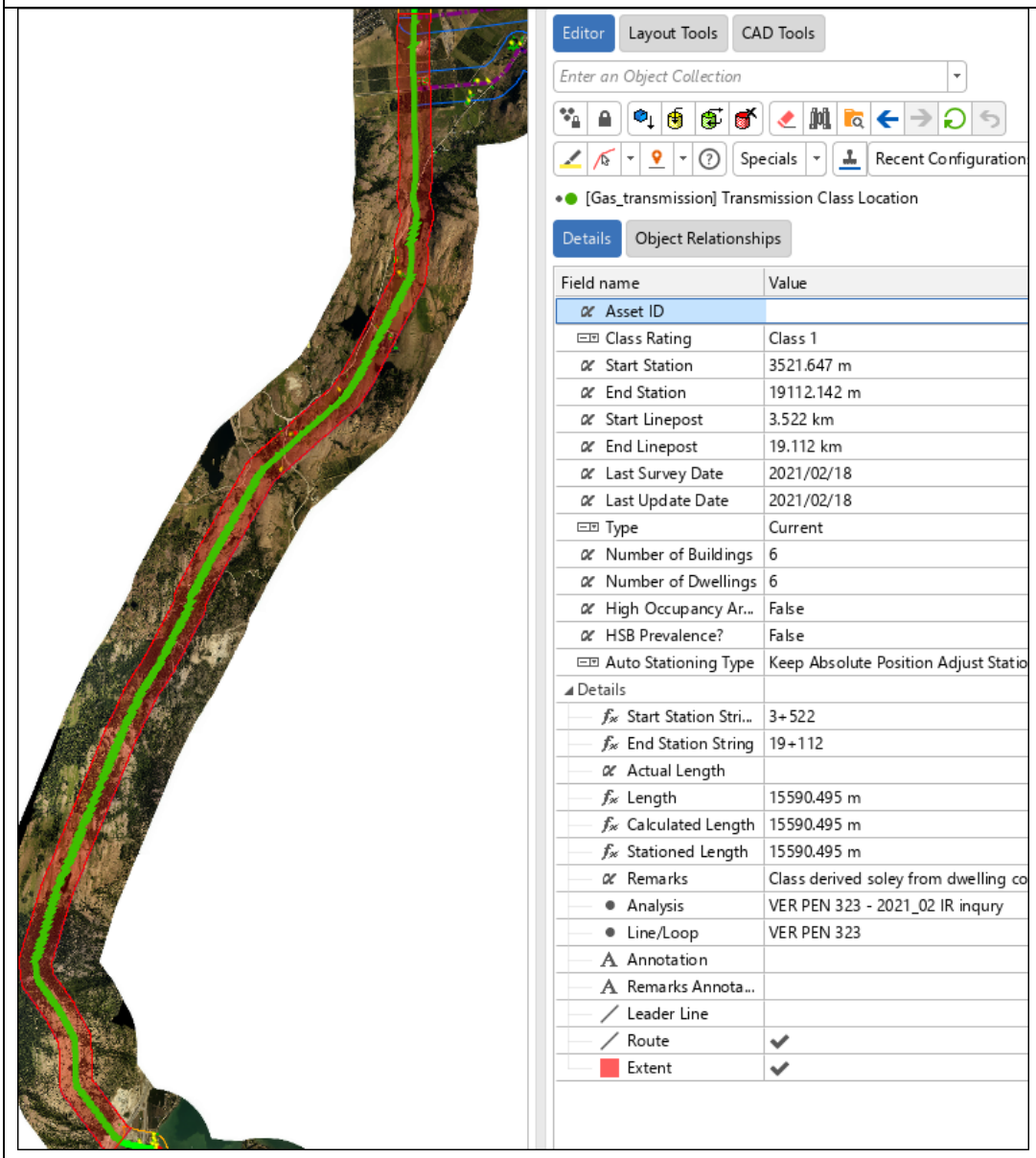
1 Each segment of pipe is also shown by class, below, in more detail.

0 - 3521.647 – Class 3



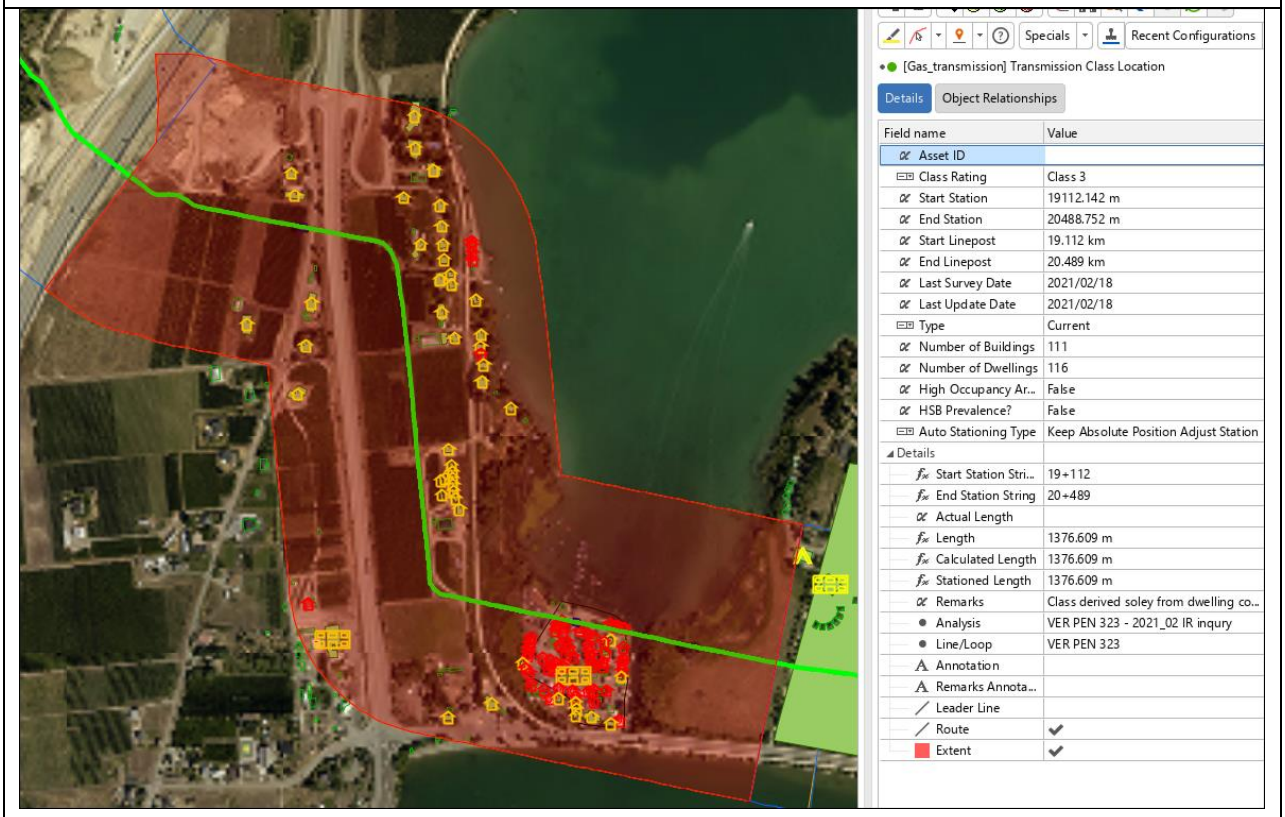
2

3521.647 - 19112.142 – Class 1

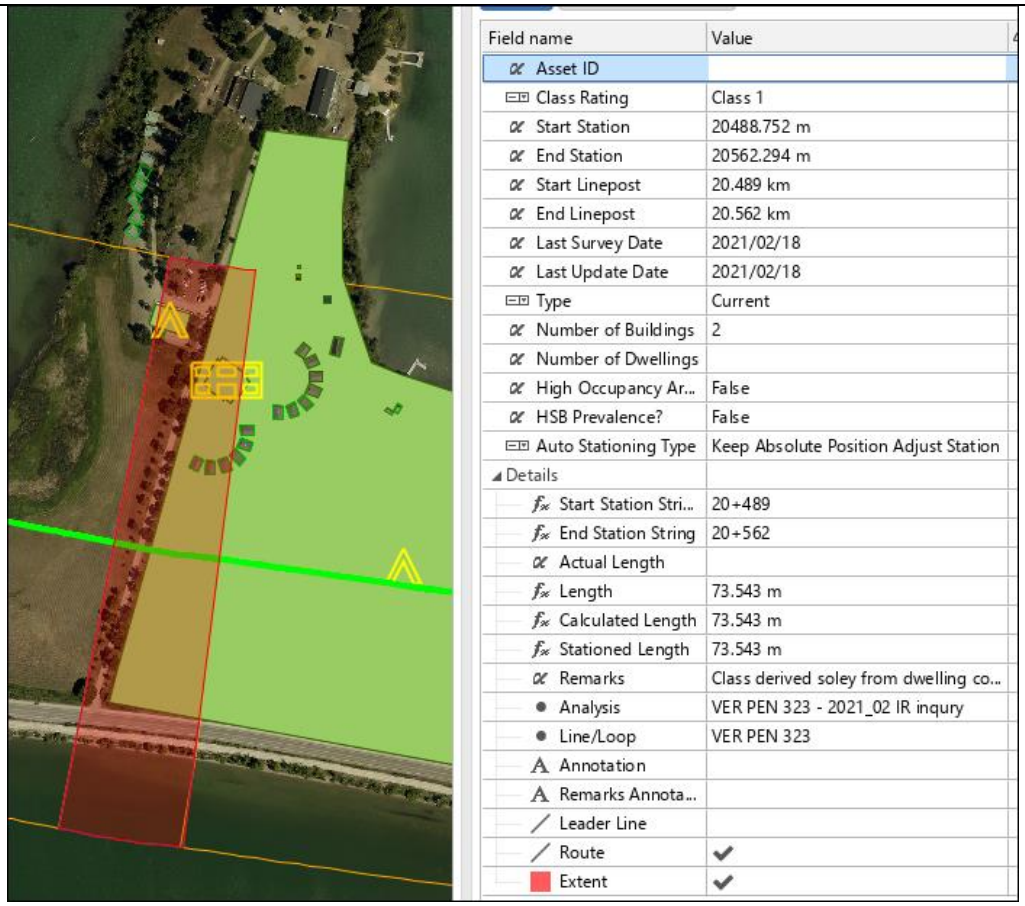


1

19112.142 - 20488.752 – Class 3

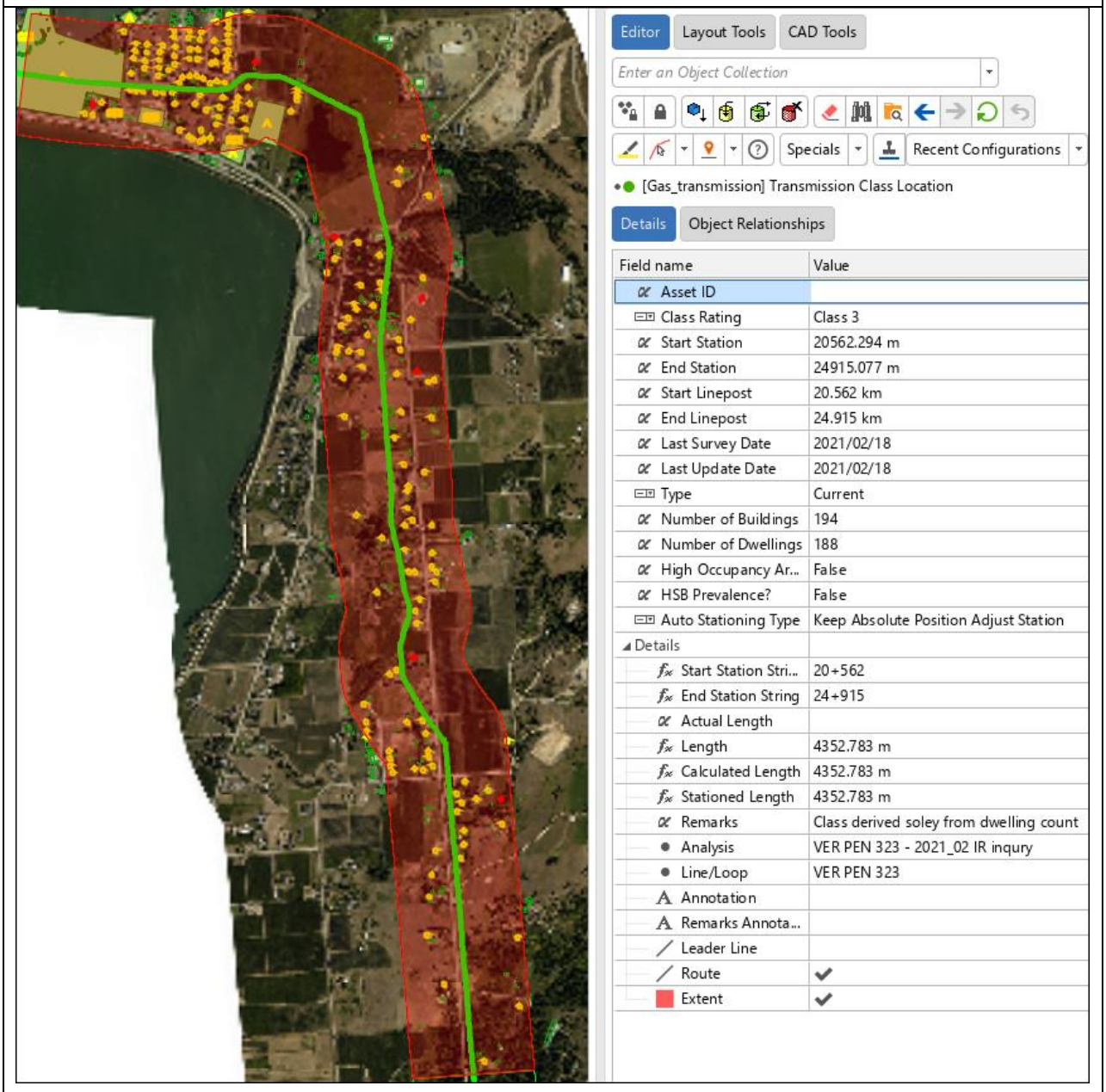


20488.752 - 20562.294 – Class 1



Field name	Value
Asset ID	
Class Rating	Class 1
Start Station	20488.752 m
End Station	20562.294 m
Start Linepost	20.489 km
End Linepost	20.562 km
Last Survey Date	2021/02/18
Last Update Date	2021/02/18
Type	Current
Number of Buildings	2
Number of Dwellings	
High Occupancy Ar...	False
HSB Prevalence?	False
Auto Stationing Type	Keep Absolute Position Adjust Station
Details	
Start Station Stri...	20+489
End Station String	20+562
Actual Length	
Length	73.543 m
Calculated Length	73.543 m
Stationed Length	73.543 m
Remarks	Class derived soley from dwelling co...
Analysis	VER PEN 323 - 2021_02 IR inqury
Line/Loop	VER PEN 323
Annotation	
Remarks Annota...	
Leader Line	
Route	✔
Extent	✔

20562.294 - 24915.077 – Class 3



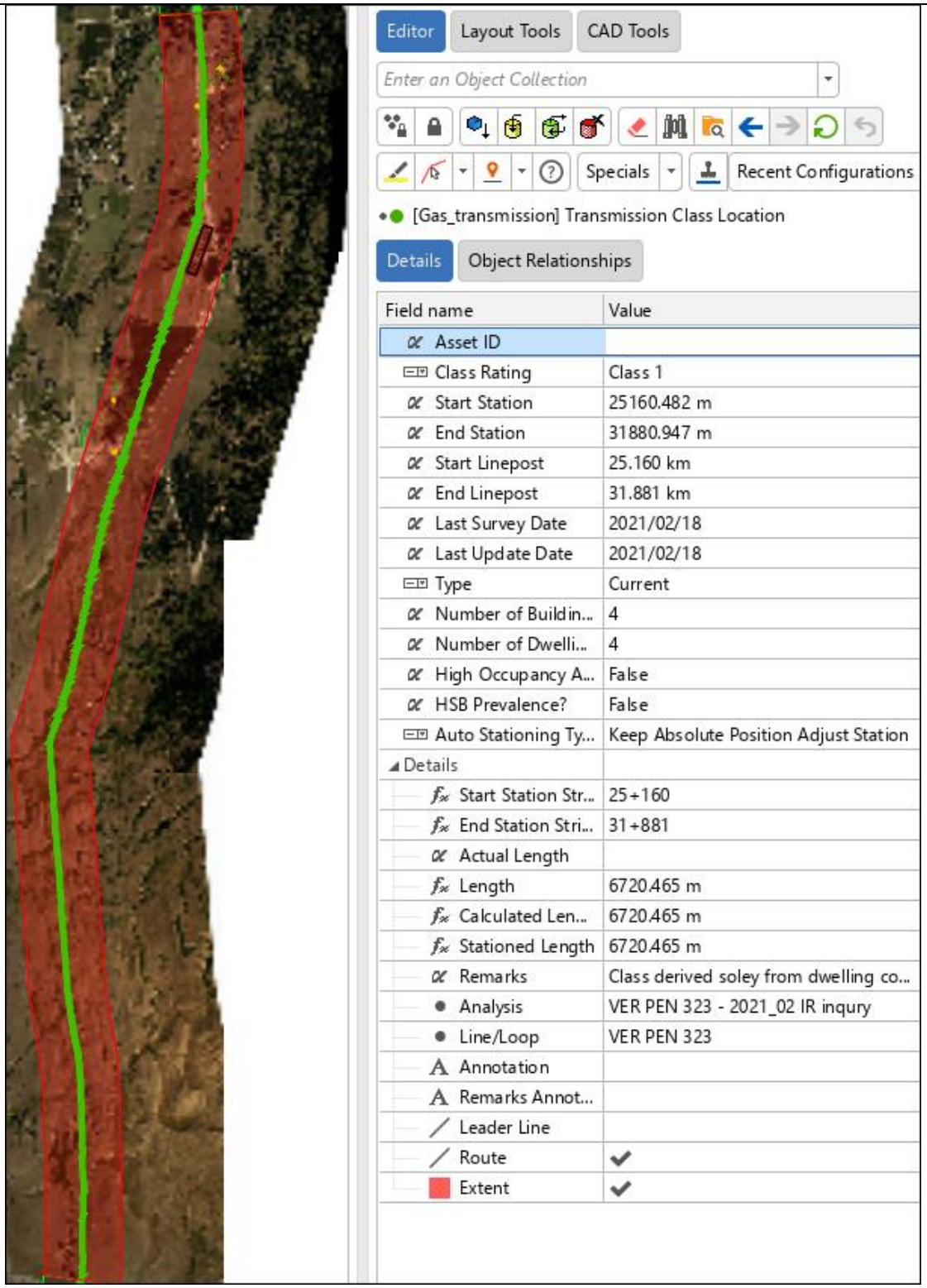
1

24915.077 - 25160.482 – Class 2

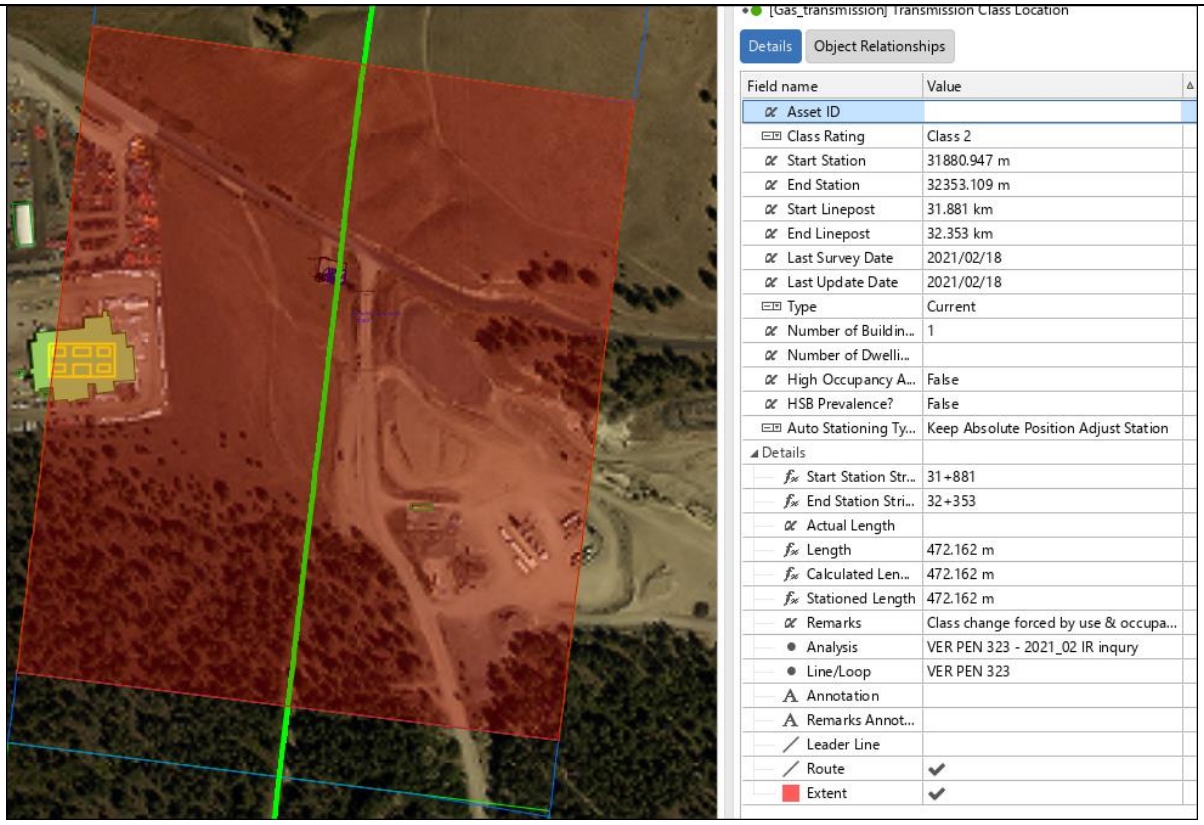
Field name	Value
Asset ID	
Class Rating	Class 2
Start Station	24915.077 m
End Station	25160.482 m
Start Linepost	24.915 km
End Linepost	25.160 km
Last Survey Date	2021/02/18
Last Update Date	2021/02/18
Type	Current
Number of Buildin...	1
Number of Dwelli...	1
High Occupancy A...	False
HSB Prevalence?	False
Auto Stationing Ty...	Keep Absolute Position Adjust Station
Details	
Start Station Str...	24+915
End Station Stri...	25+160
Actual Length	
Length	245.405 m
Calculated Len...	245.405 m
Stationed Length	245.405 m
Remarks	Class derived soley from dwelling co...
Analysis	VER PEN 323 - 2021_02 IR inqury
Line/Loop	VER PEN 323

1

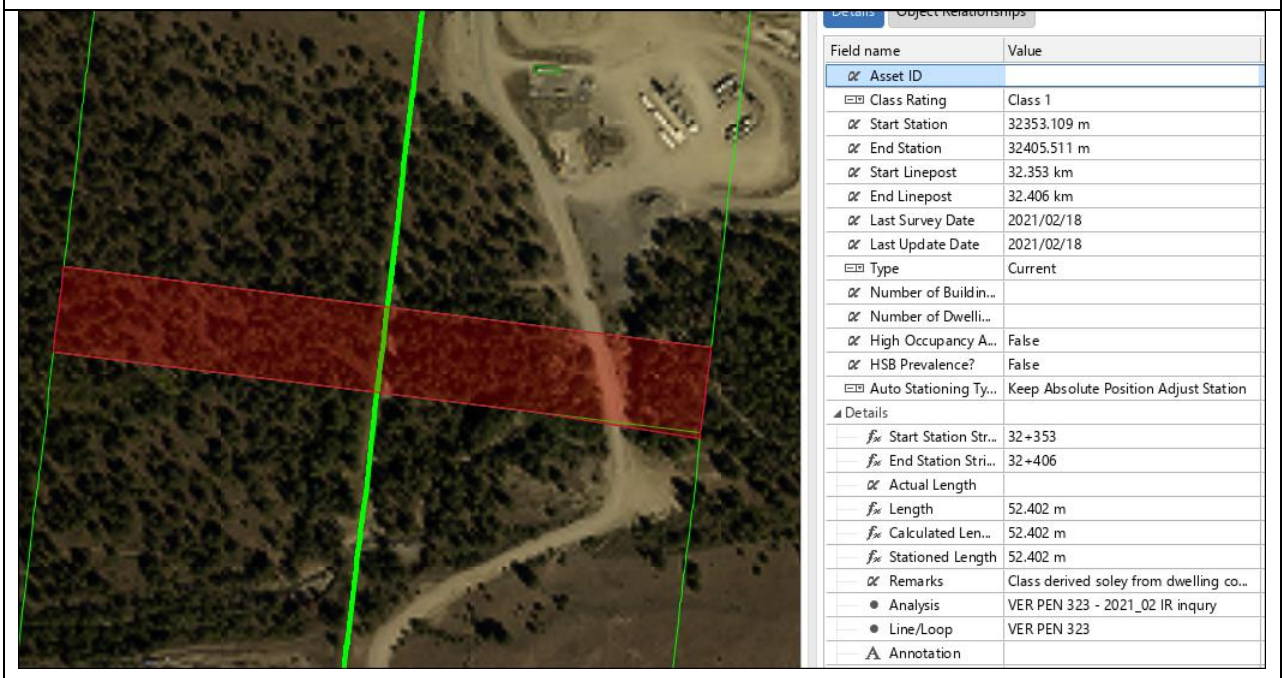
25160.482 - 31880.947 – Class 1



31880.947 - 32353.109 – Class 2

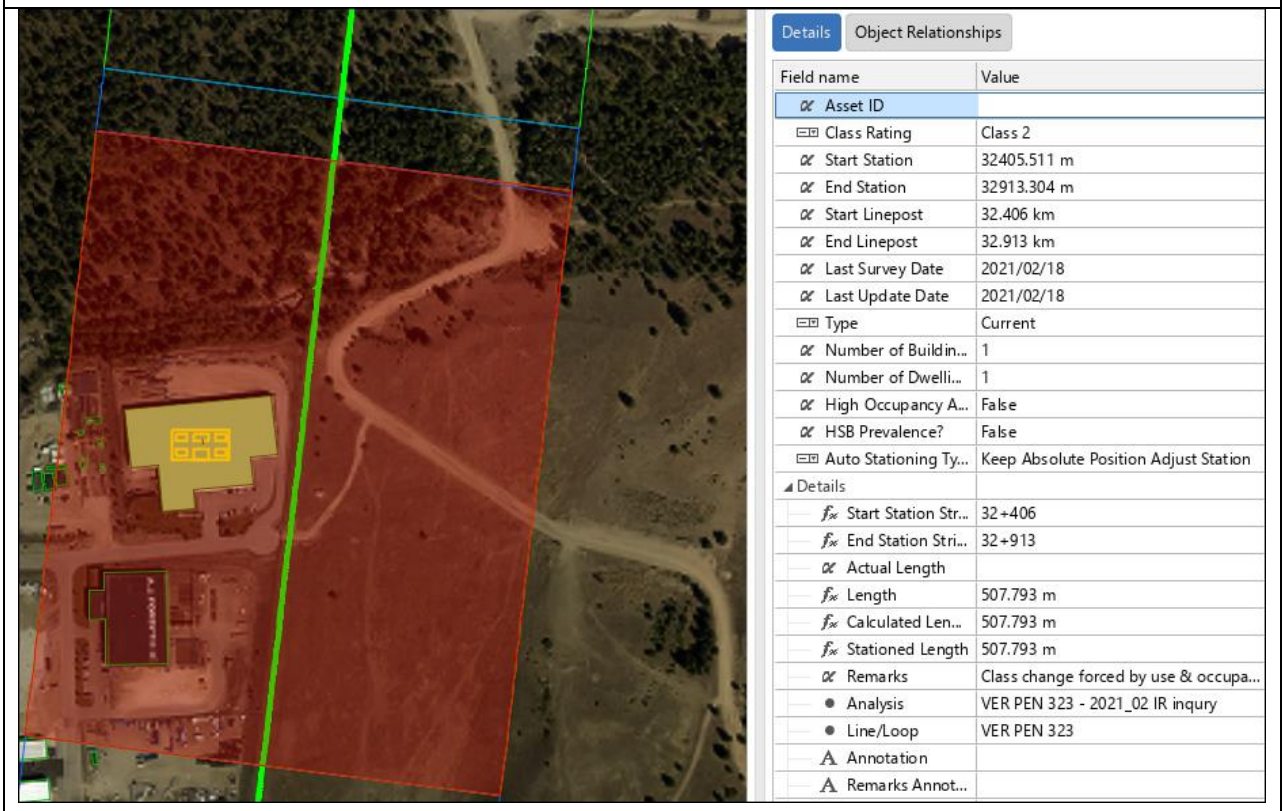


32353.109 - 32405.511 – Class 1



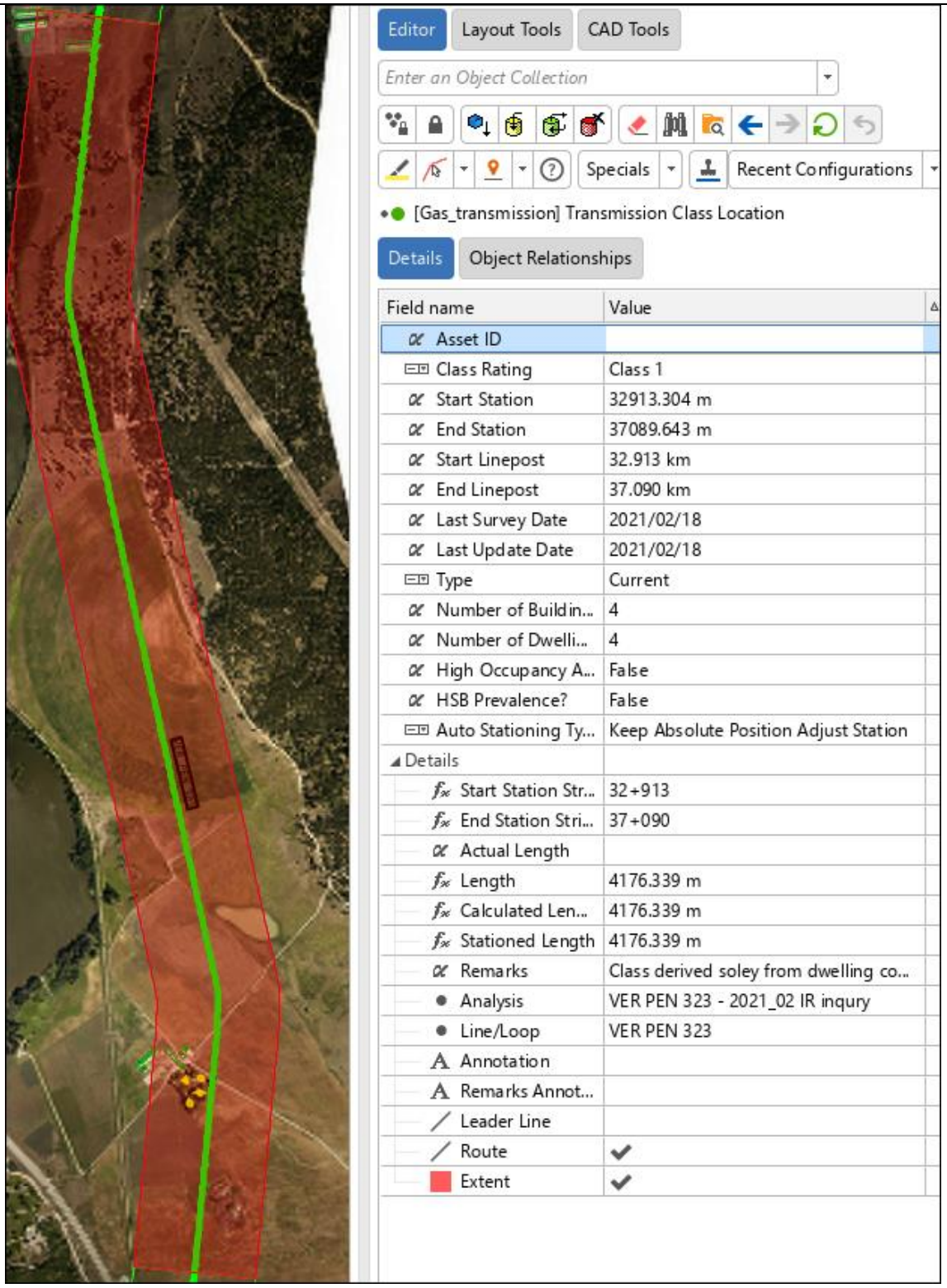
1

32405.511 - 32913.304 – Class 2



1

32913.304 - 37089.643 – Class 1



37089.643 - 37886.202 – Class 2

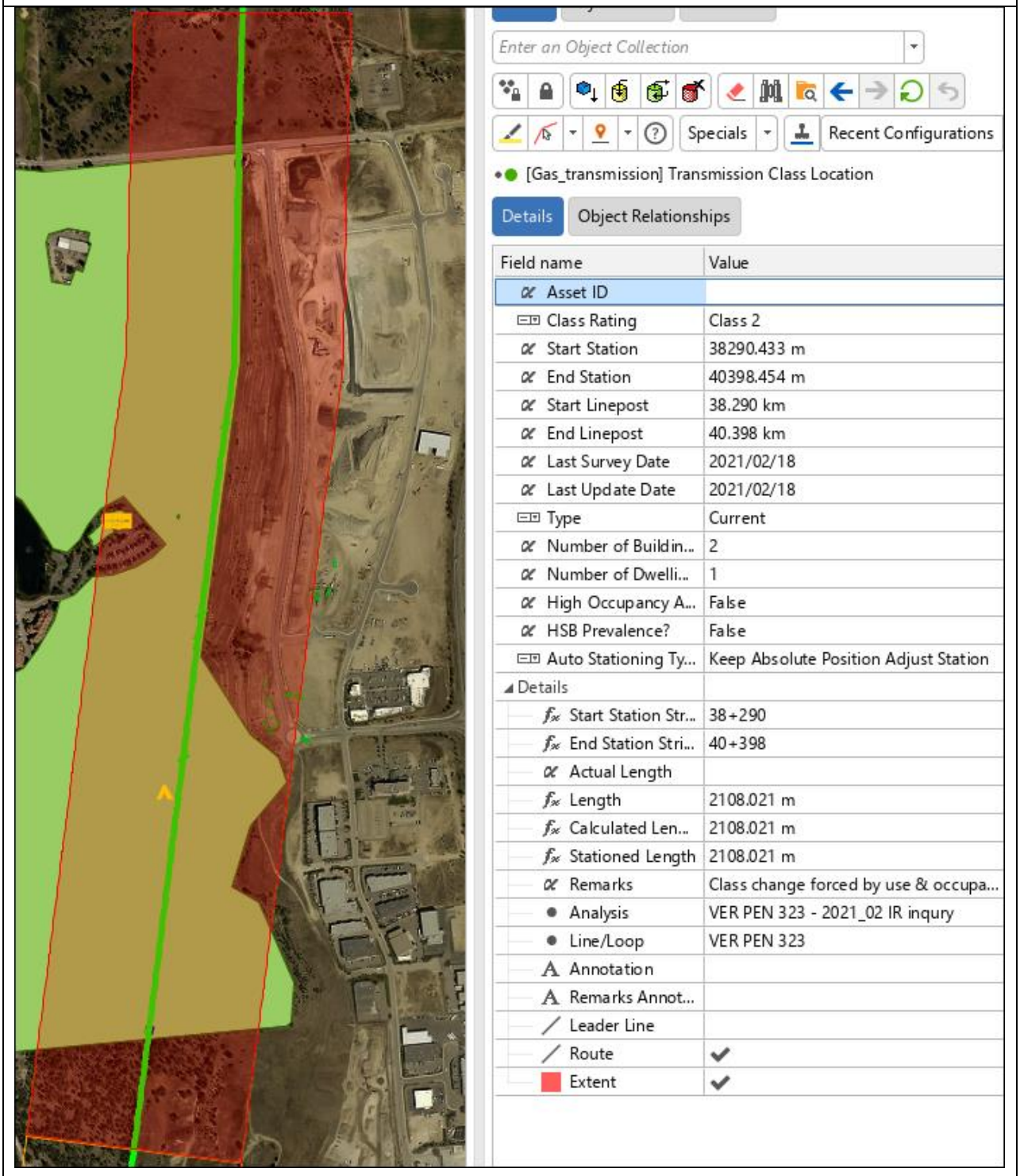
Field name	Value
Asset ID	
Class Rating	Class 2
Start Station	37089.643 m
End Station	37886.202 m
Start Linepost	37.090 km
End Linepost	37.886 km
Last Survey Date	2021/02/18
Last Update Date	2021/02/18
Type	Current
Number of Buildin...	8
Number of Dwelli...	7
High Occupancy A...	False
HSB Prevalence?	False
Auto Stationing Ty...	Keep Absolute Position Adjust Station
Details	
Start Station Str...	37+090
End Station Stri...	37+886
Actual Length	
Length	796.560 m
Calculated Len...	796.560 m
Stationed Length	796.559 m
Remarks	Class change forced by use & occupa...
Analysis	VER PEN 323 - 2021_02 IR inqury
Line/Loop	VER PEN 323
Annotation	
Remarks Annot...	
Leader Line	
Route	✔

37886.202 - 38290.433 – Class 1

Field name	Value
Asset ID	
Class Rating	Class 1
Start Station	37886.202 m
End Station	38290.433 m
Start Linepost	37.886 km
End Linepost	38.290 km
Last Survey Date	2021/02/18
Last Update Date	2021/02/18
Type	Current
Number of Buildin...	3
Number of Dwelli...	3
High Occupancy A...	False
HSB Prevalence?	False
Auto Stationing Ty...	Keep Absolute Position Adjust Station
Details	
Start Station Str...	37+886
End Station Stri...	38+290
Actual Length	
Length	404.231 m
Calculated Len...	404.231 m
Stationed Length	404.231 m
Remarks	Class derived soley from dwelling co...
Analysis	VER PEN 323 - 2021_02 IR inqury
Line/Loop	VER PEN 323

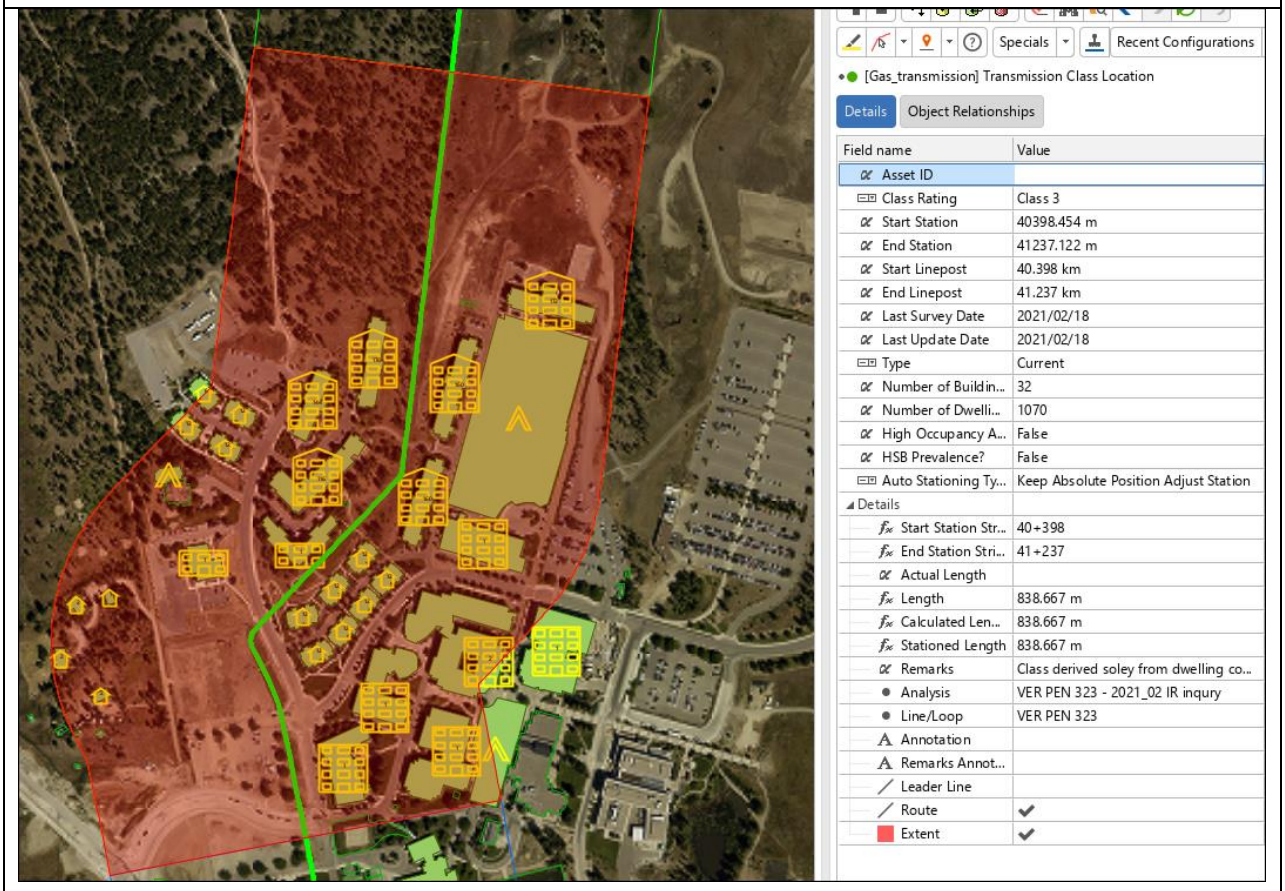
1

38290.433 - 40398.454 – Class 2

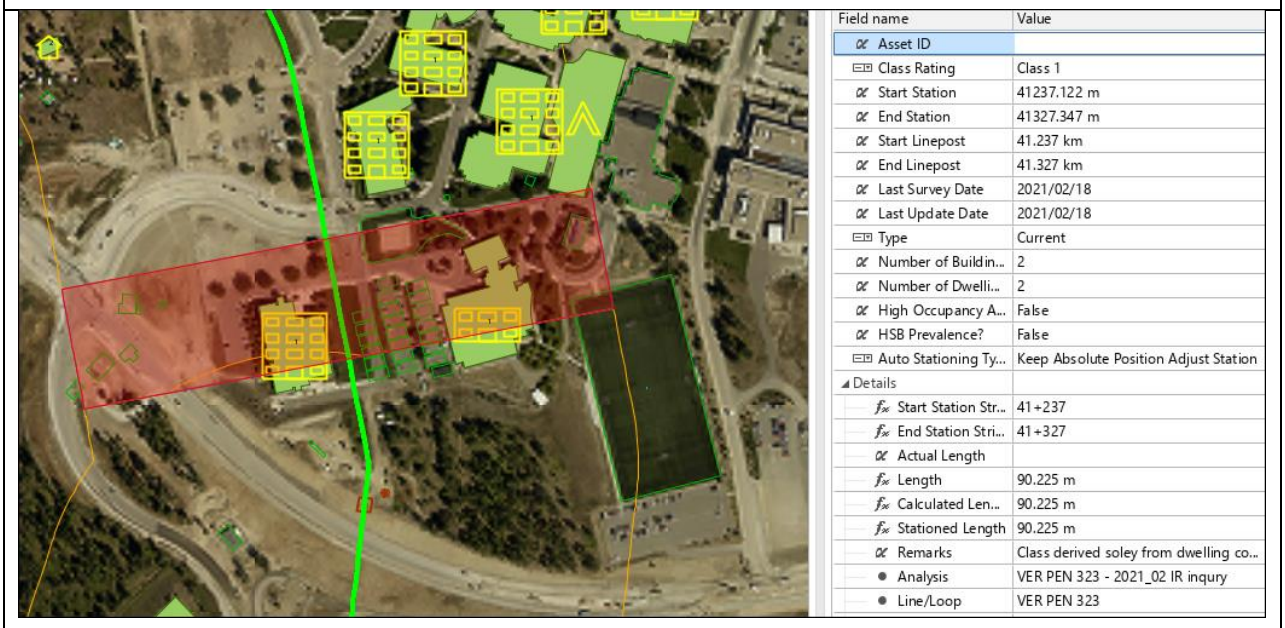


1

40398.454 - 41237.122 – Class 3

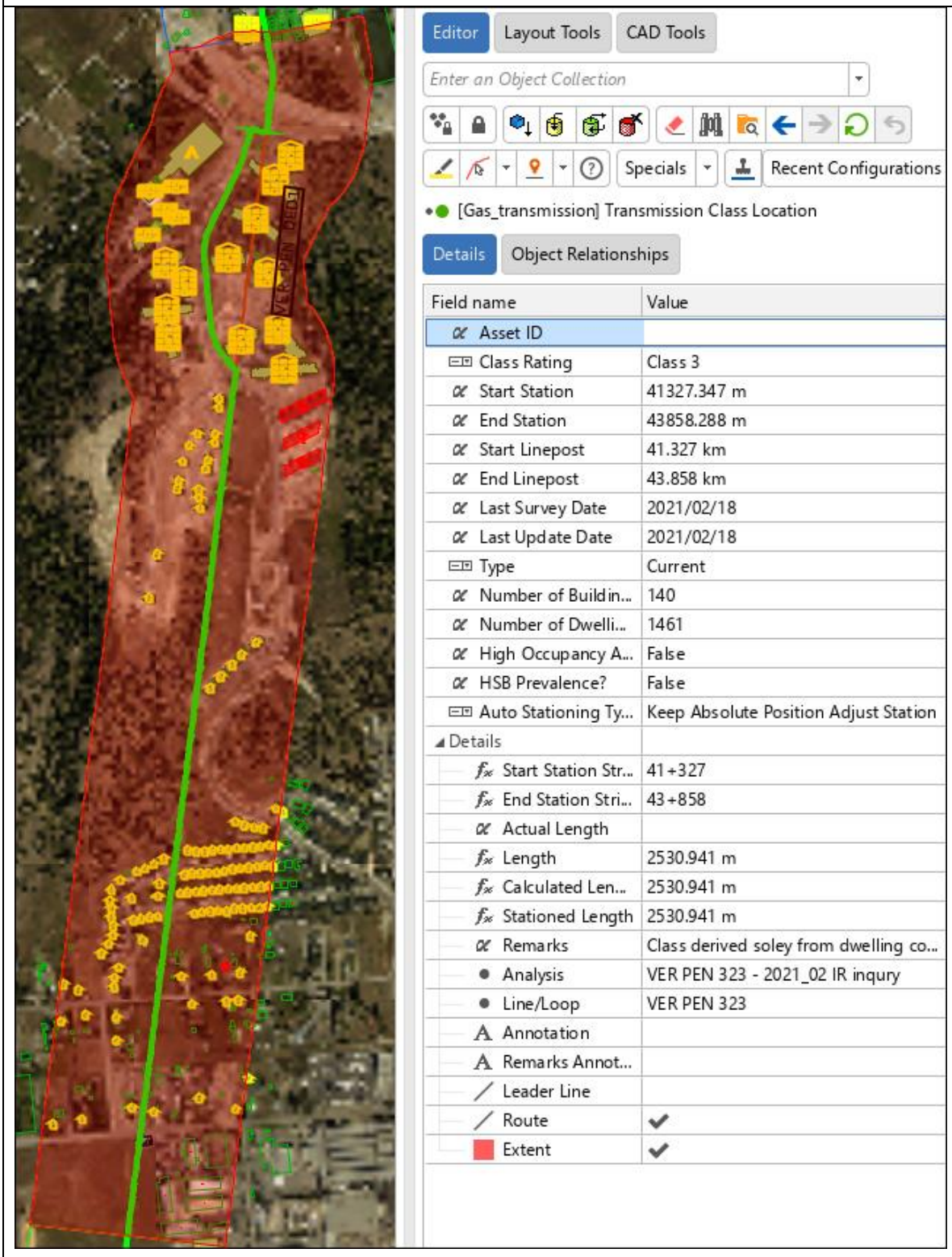


41237.122 - 41327.347 – Class 1



1

41327.347 - 43858.288 – Class 3

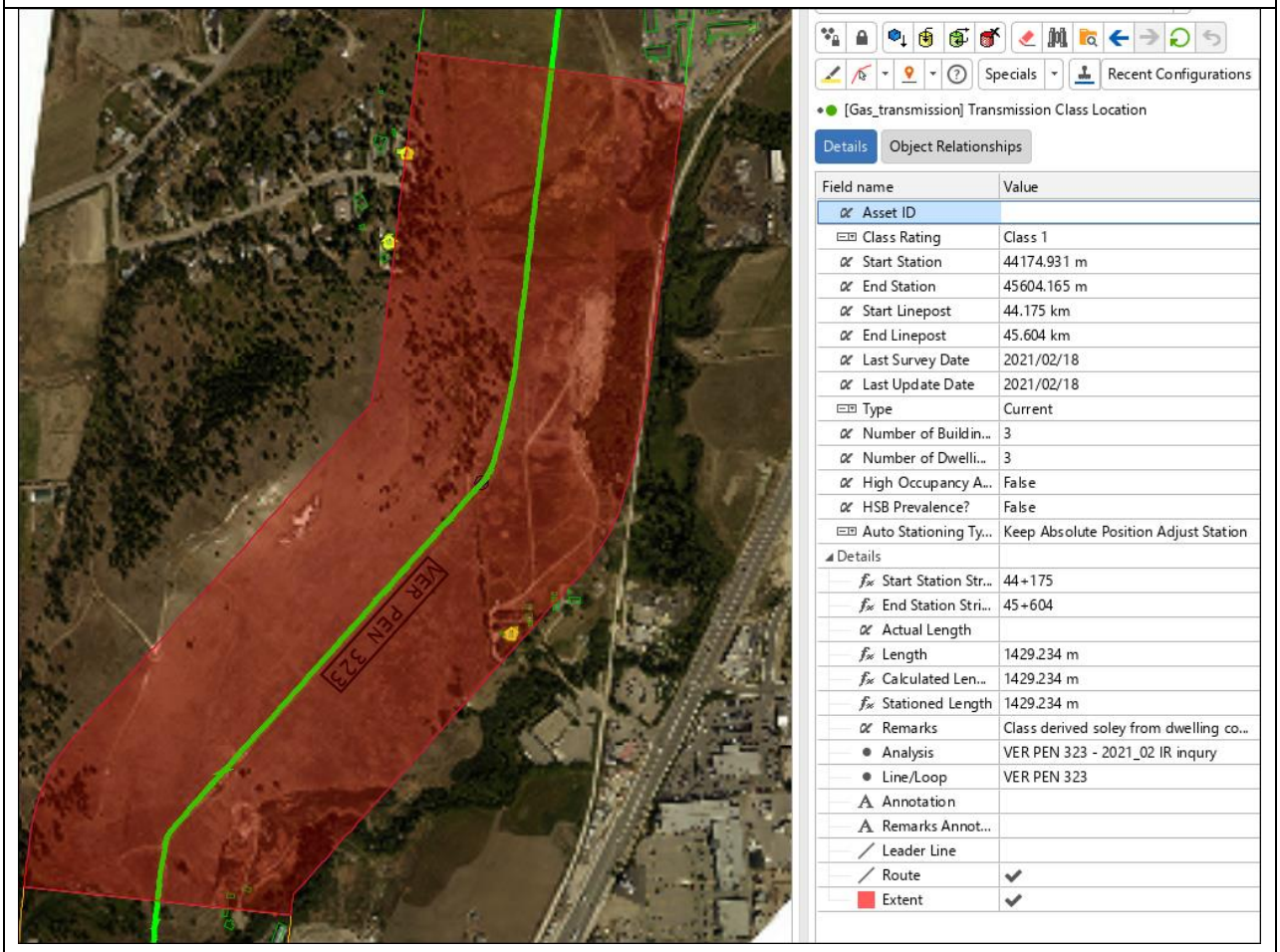


1

43858.288 - 44174.931 – Class 2

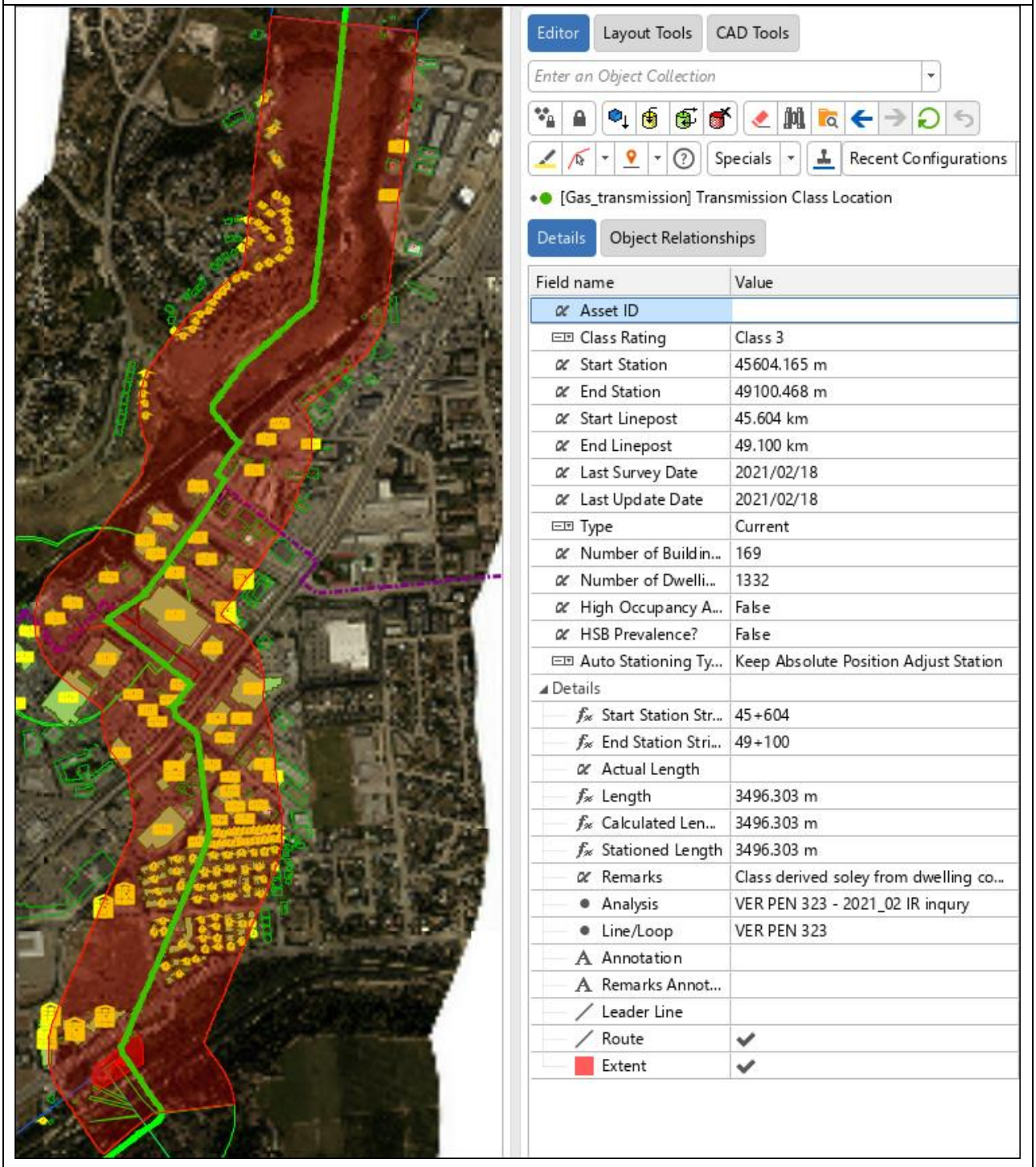
Field name	Value
Asset ID	
Class Rating	Class 2
Start Station	43858.288 m
End Station	44174.931 m
Start Linepost	43.858 km
End Linepost	44.175 km
Last Survey Date	2021/02/18
Last Update Date	2021/02/18
Type	Current
Number of Buildin...	1
Number of Dwelli...	1
High Occupancy A...	False
HSB Prevalence?	False
Auto Stationing Ty...	Keep Absolute Position Adjust Station
Details	
Start Station Str...	43+858
End Station Stri...	44+175
Actual Length	
Length	316.643 m
Calculated Len...	316.643 m
Stationed Length	316.643 m
Remarks	Class change forced by use & occupa...
Analysis	VER PEN 323 - 2021_02 IR inqury
Line/Loop	VER PEN 323

44174.931 - 45604.165 – Class 1



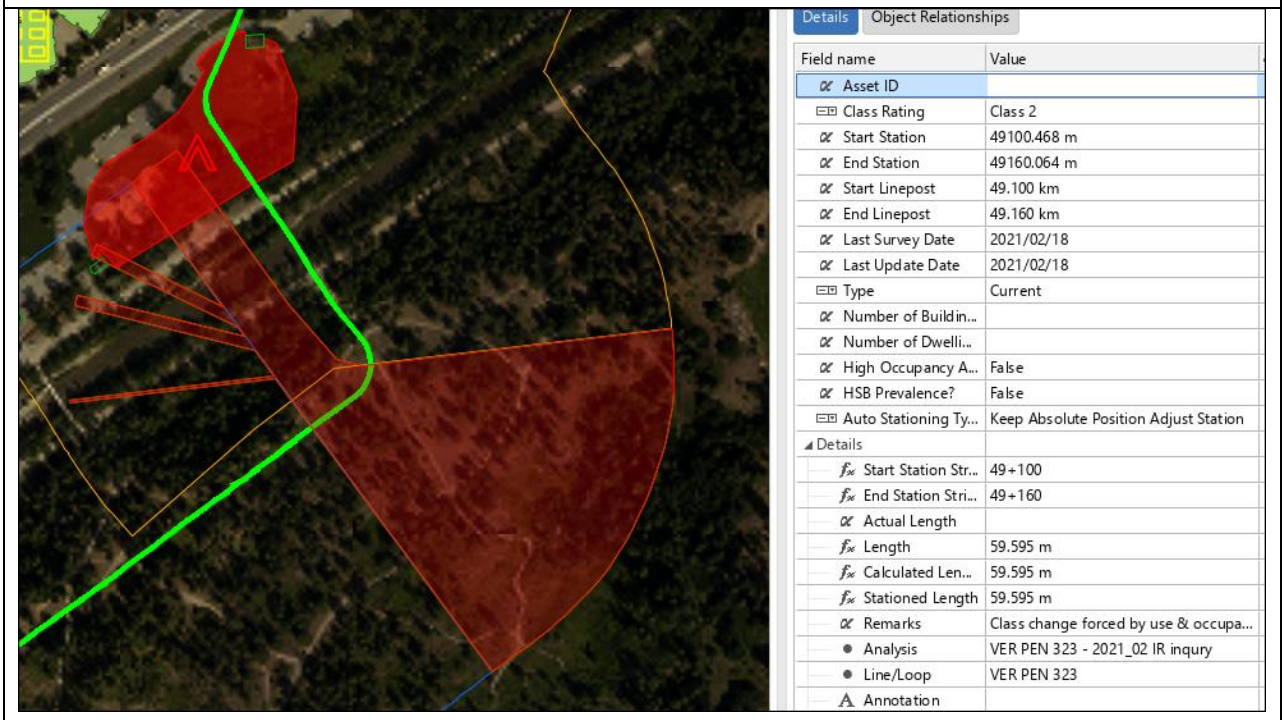
1

45604.165 - 49100.468 – Class 3

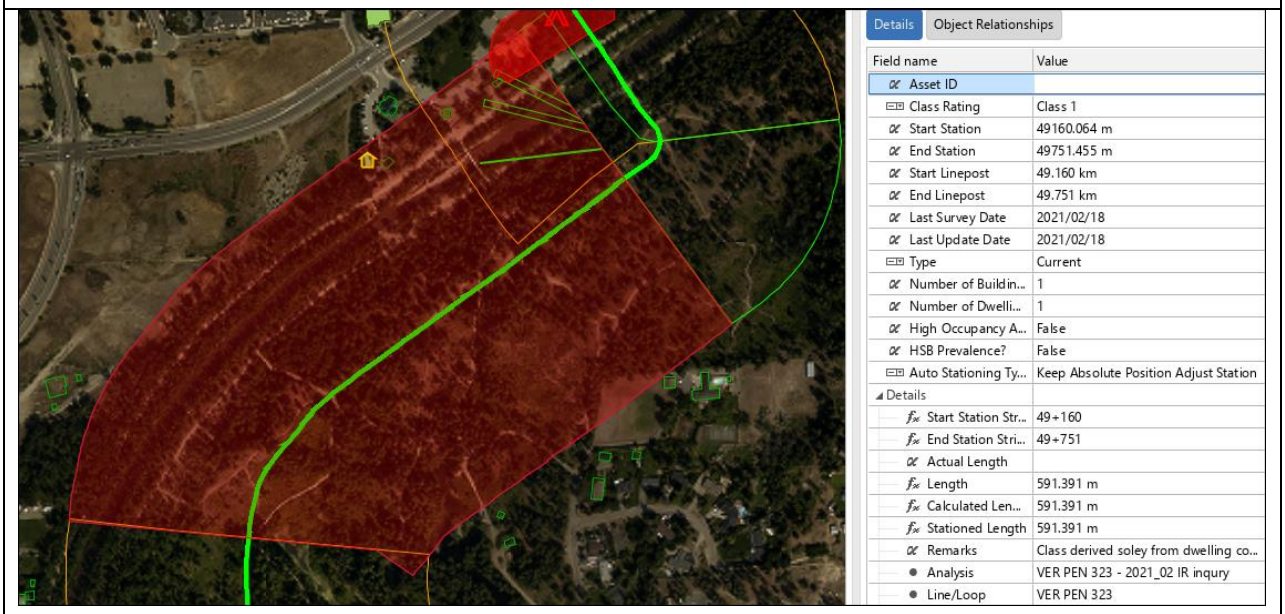


1

49100.468 - 49160.064 – Class 2

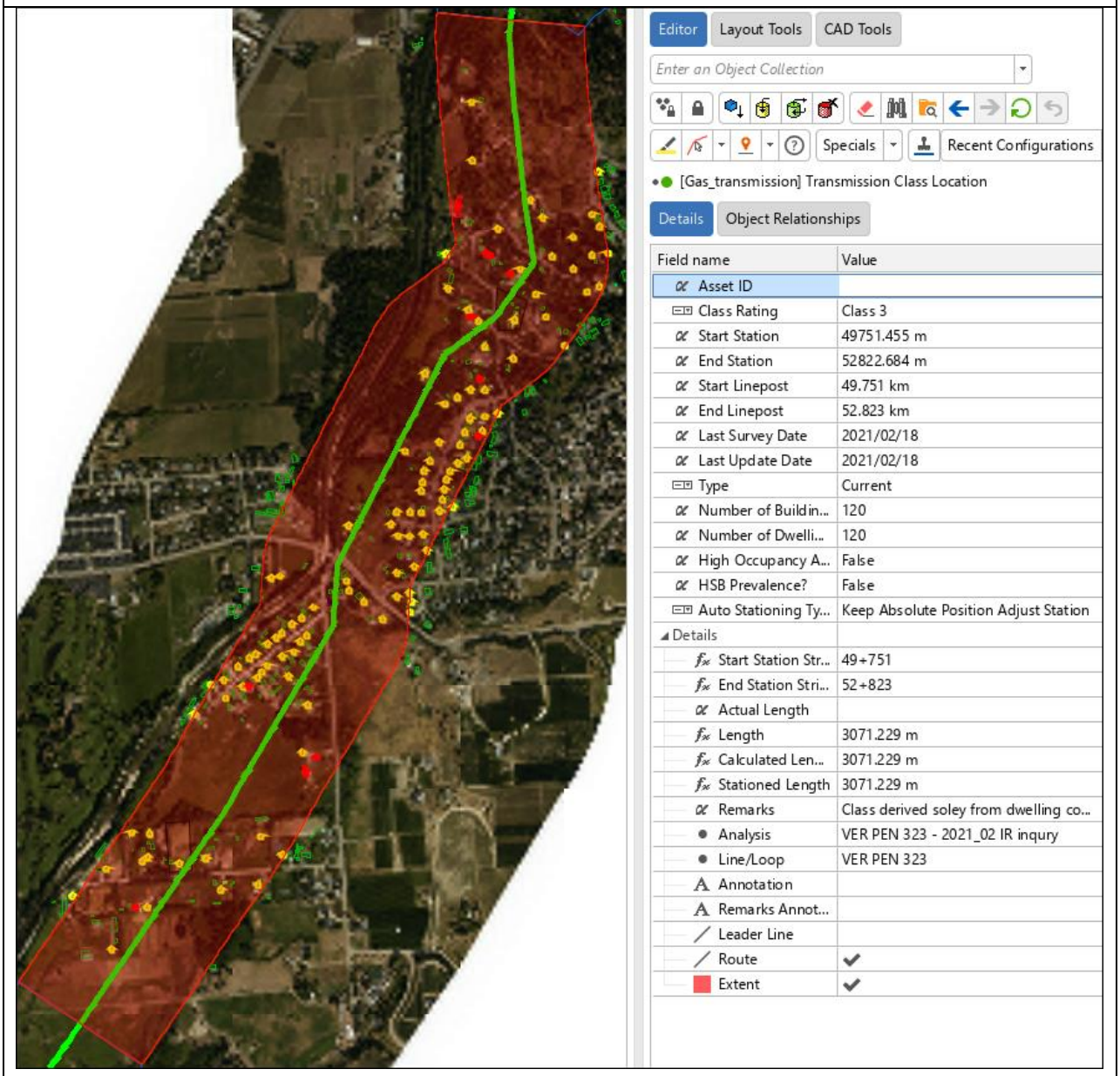


49160.064 - 49751.455 – Class 1



1

49751.455 - 52822.684 – Class 3



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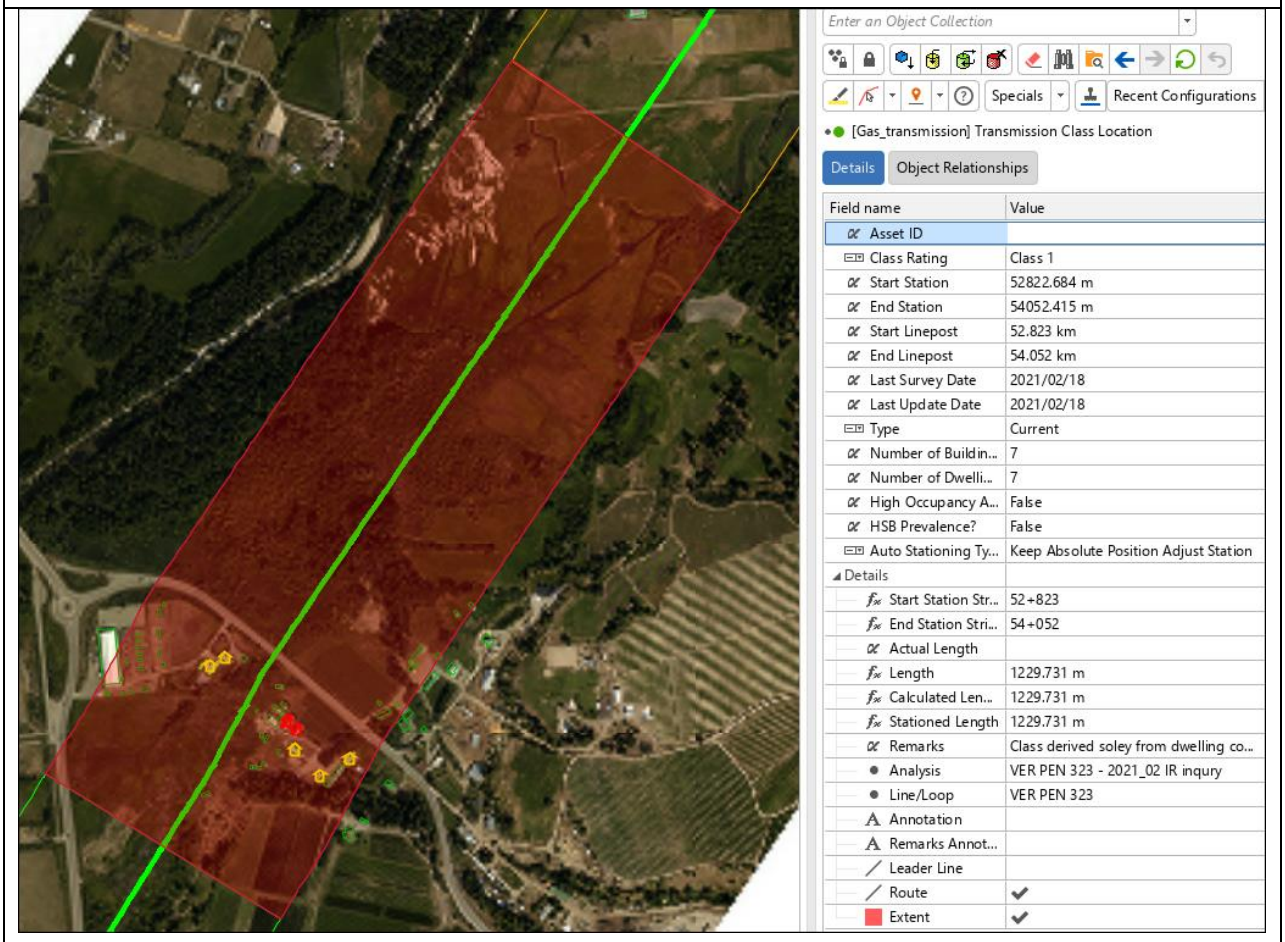
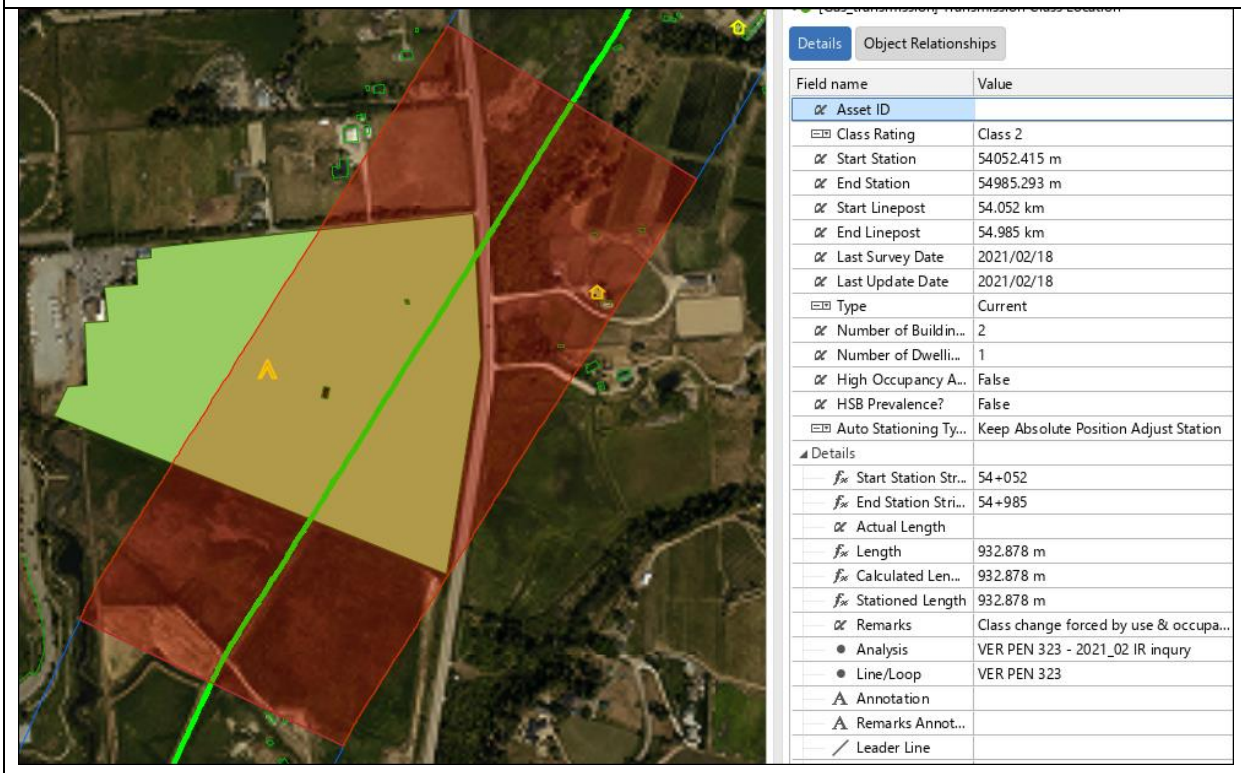
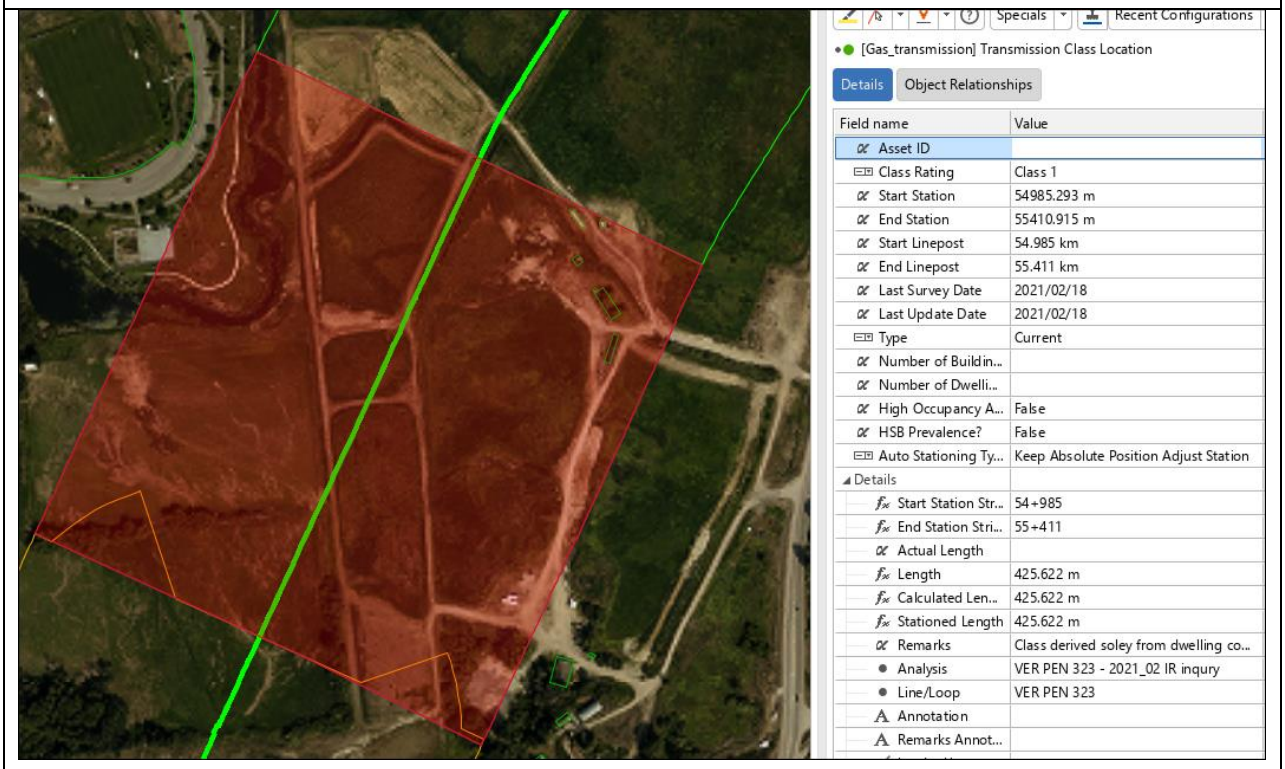
52822.684 - 54052.415 – Class 1



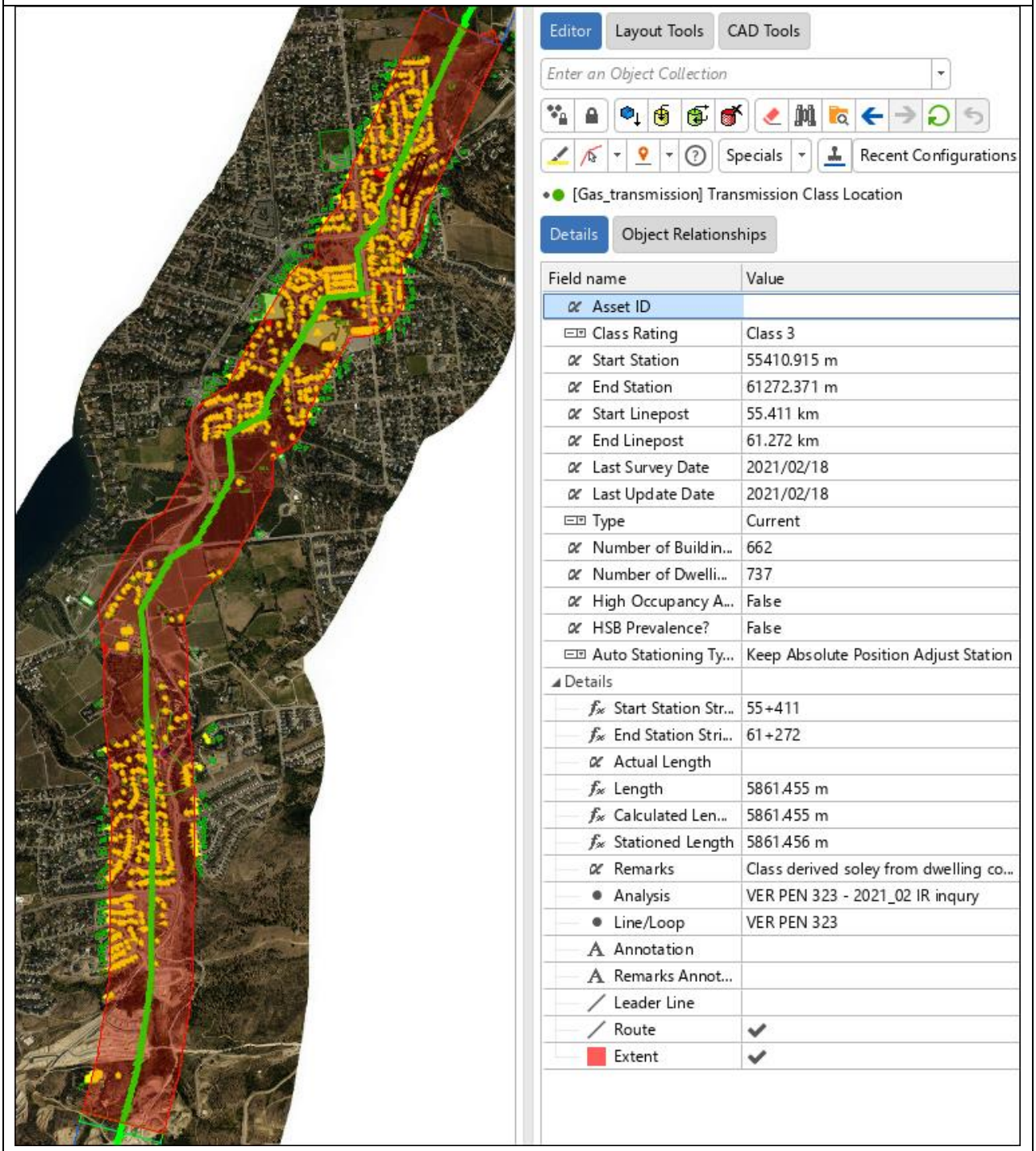
54052.415 - 54985.293 – Class 2



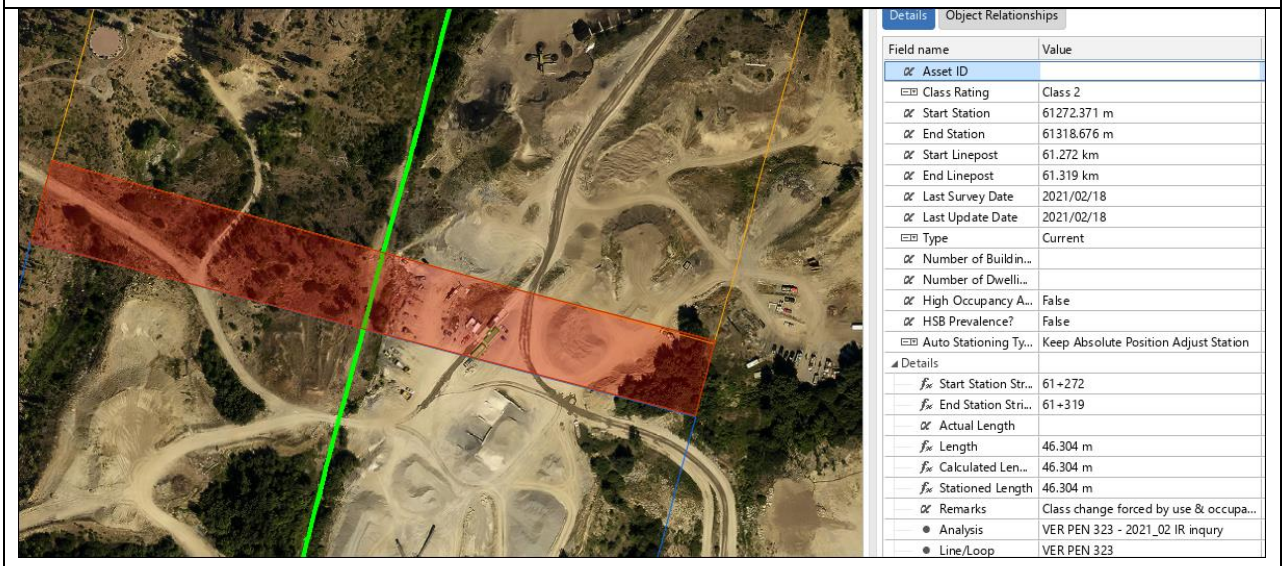
54985.293 - 55410.915 – Class 1



55410.915 - 61272.371 – Class 3

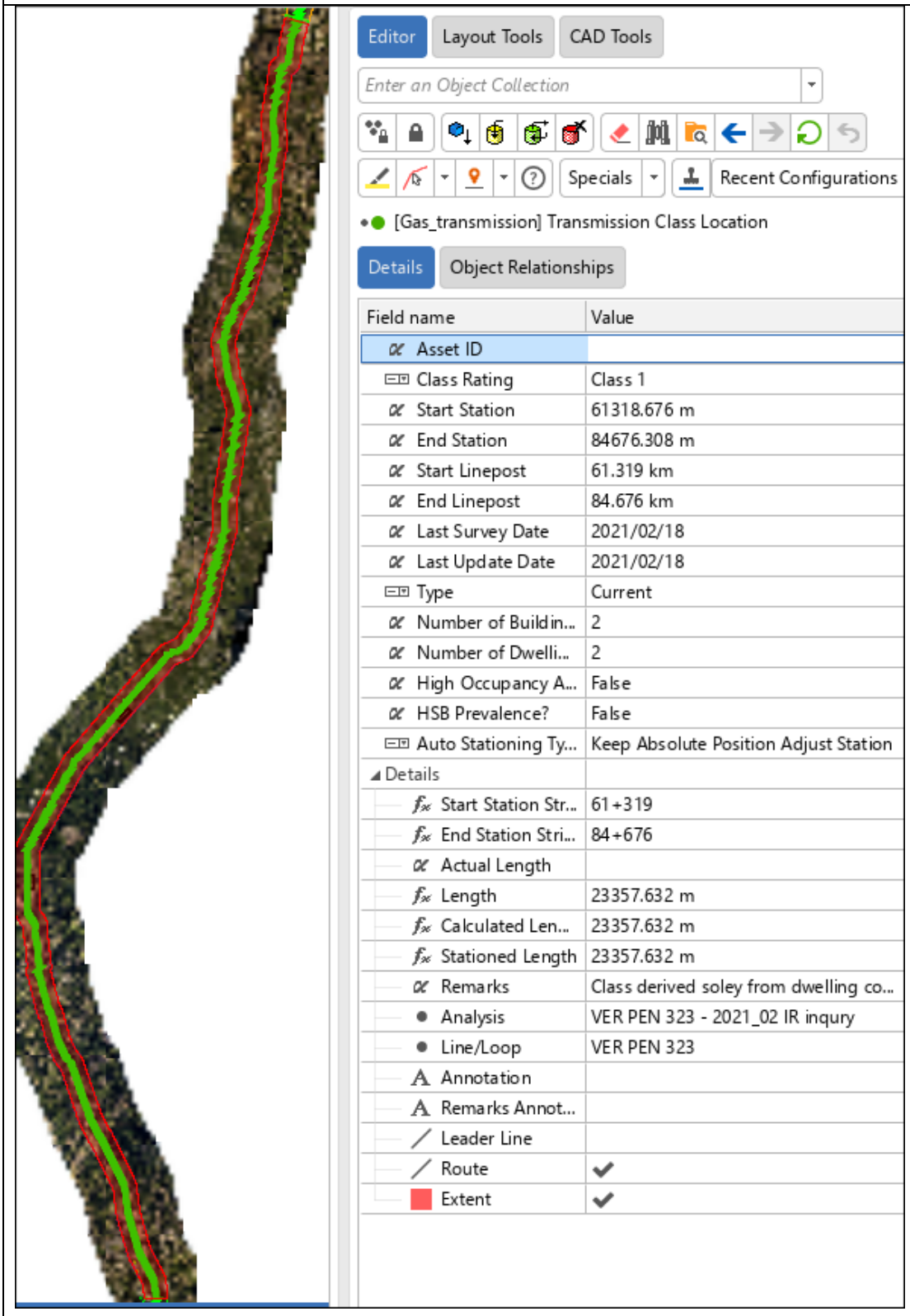


61272.371 - 61318.676 – Class 2

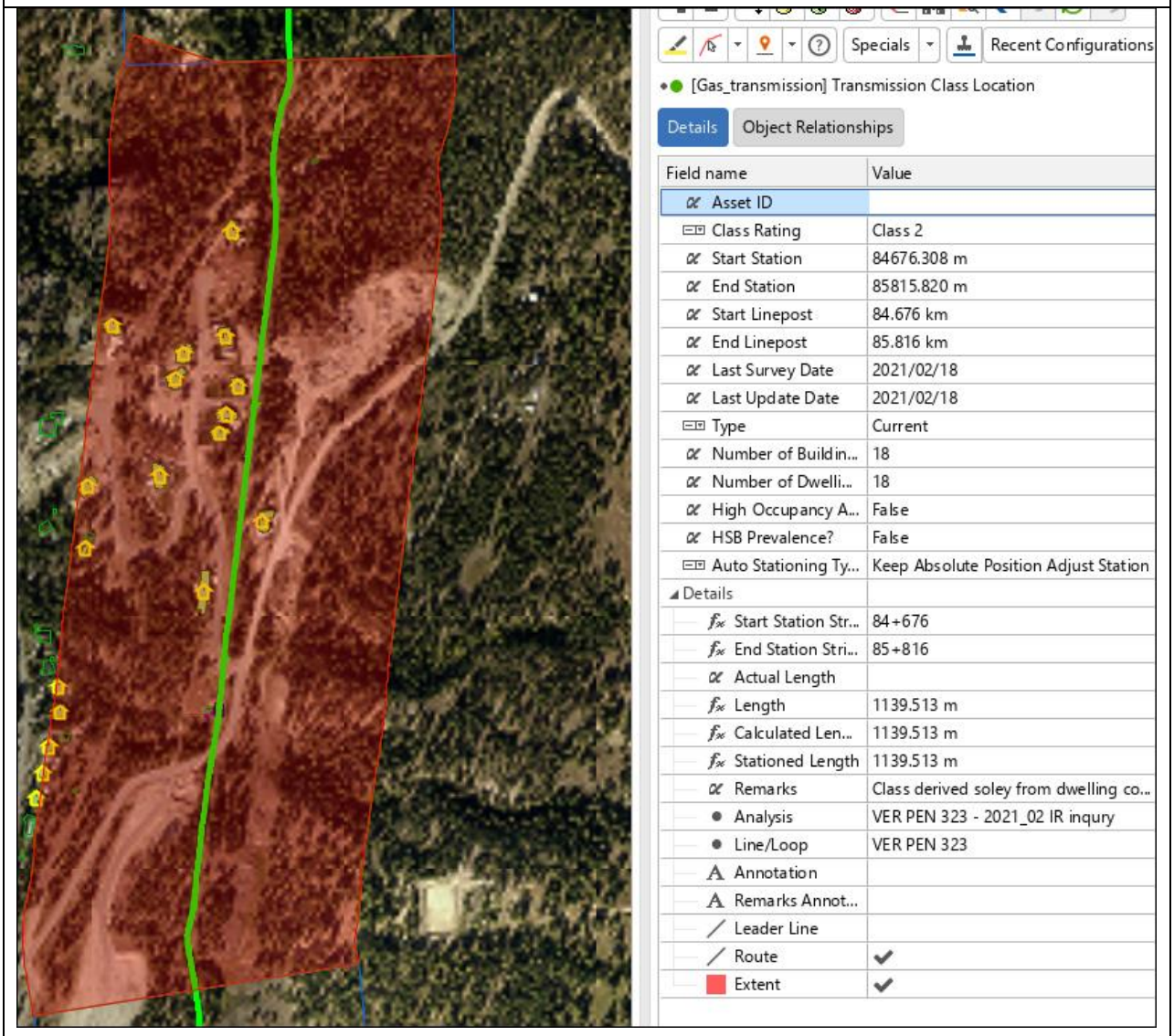


1

61318.676 - 84676.308 – Class 1



84676.308 - 85815.82 – Class 2



1

85815.82 - 88915.522 – Class 1

Specials | Recent Configurations

[Gas_transmission] Transmission Class Location

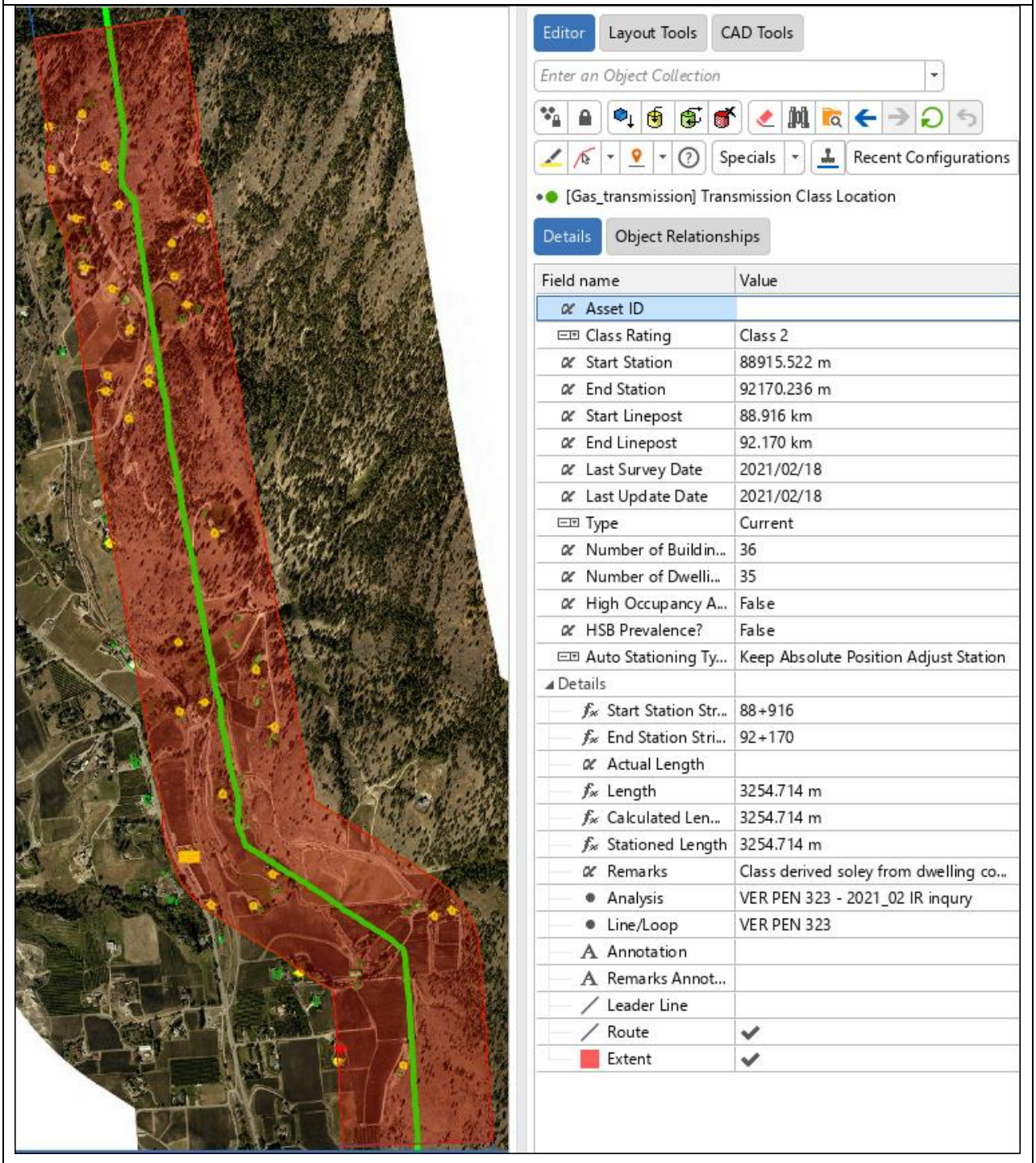
Details | Object Relationships

Field name	Value
Asset ID	
Class Rating	Class 1
Start Station	85815.820 m
End Station	88915.522 m
Start Linepost	85.816 km
End Linepost	88.916 km
Last Survey Date	2021/02/18
Last Update Date	2021/02/18
Type	Current
Number of Buildin...	
Number of Dwelli...	
High Occupancy A...	False
HSB Prevalence?	False
Auto Stationing Ty...	Keep Absolute Position Adjust Station
Details	
Start Station Str...	85+816
End Station Stri...	88+916
Actual Length	
Length	3099.702 m
Calculated Len...	3099.702 m
Stationed Length	3099.702 m
Remarks	Class derived soley from dwelling co...
Analysis	VER PEN 323 - 2021_02 IR inqury
Line/Loop	VER PEN 323
Annotation	
Remarks Annot...	
Leader Line	
Route	✓
Extent	✓

-

1

88915.522 - 92170.236 – Class 2



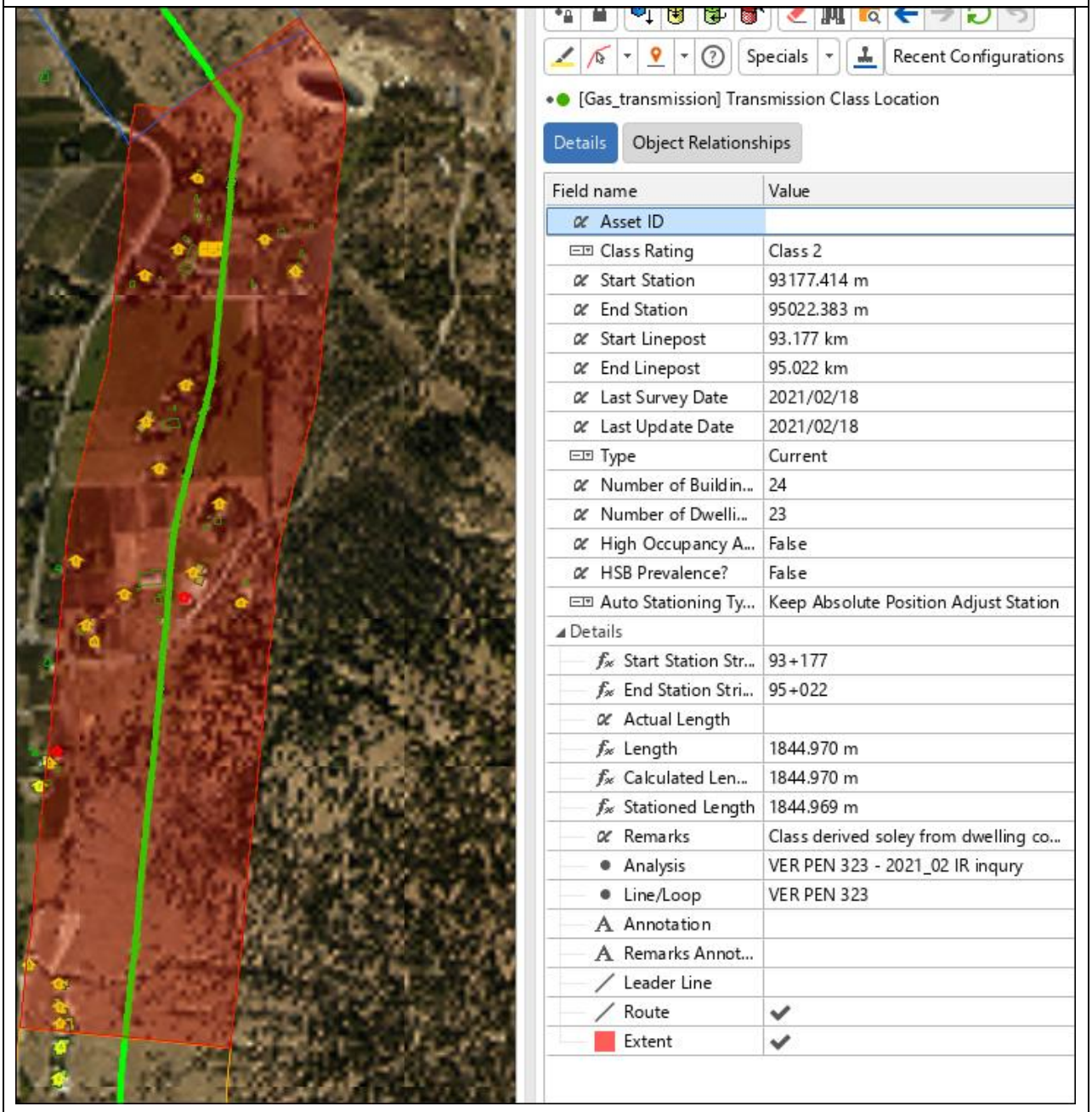
1

92170.236 - 93177.414 – Class 1

Field name	Value
Asset ID	
Class Rating	Class 1
Start Station	92170.236 m
End Station	93177.414 m
Start Linepost	92.170 km
End Linepost	93.177 km
Last Survey Date	2021/02/18
Last Update Date	2021/02/18
Type	Current
Number of Buildin...	1
Number of Dwelli...	1
High Occupancy A...	False
HSB Prevalence?	False
Auto Stationing Ty...	Keep Absolute Position Adjust Station
Details	
Start Station Str...	92+170
End Station Stri...	93+177
Actual Length	
Length	1007.177 m
Calculated Len...	1007.177 m
Stationed Length	1007.177 m
Remarks	Class derived soley from dwelling co...
Analysis	VER PEN 323 - 2021_02 IR inqury
Line/Loop	VER PEN 323
Annotation	
Remarks Annot...	
Leader Line	
Route	✓
Extent	✓

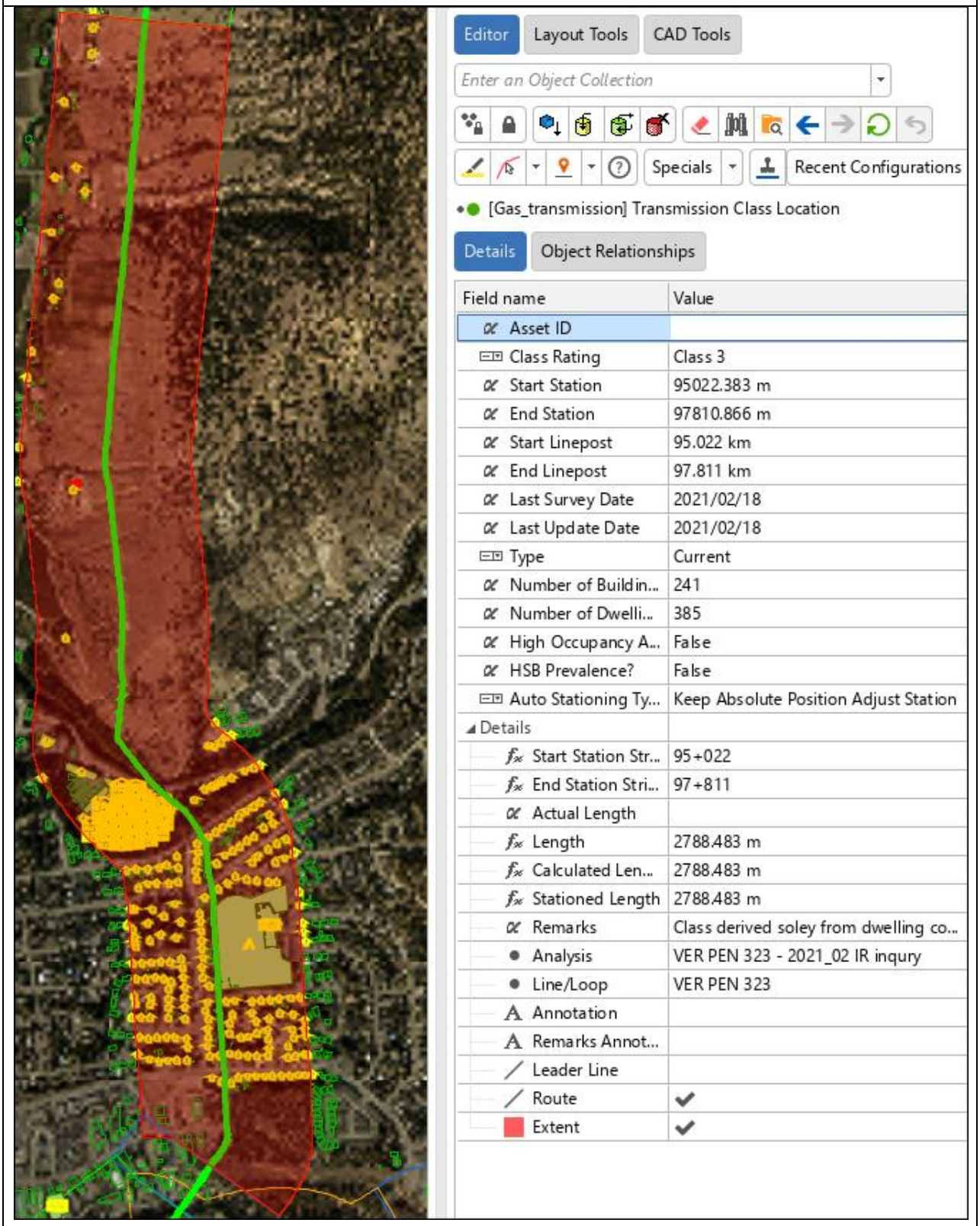
1

93177.414 - 95022.383 – Class 2



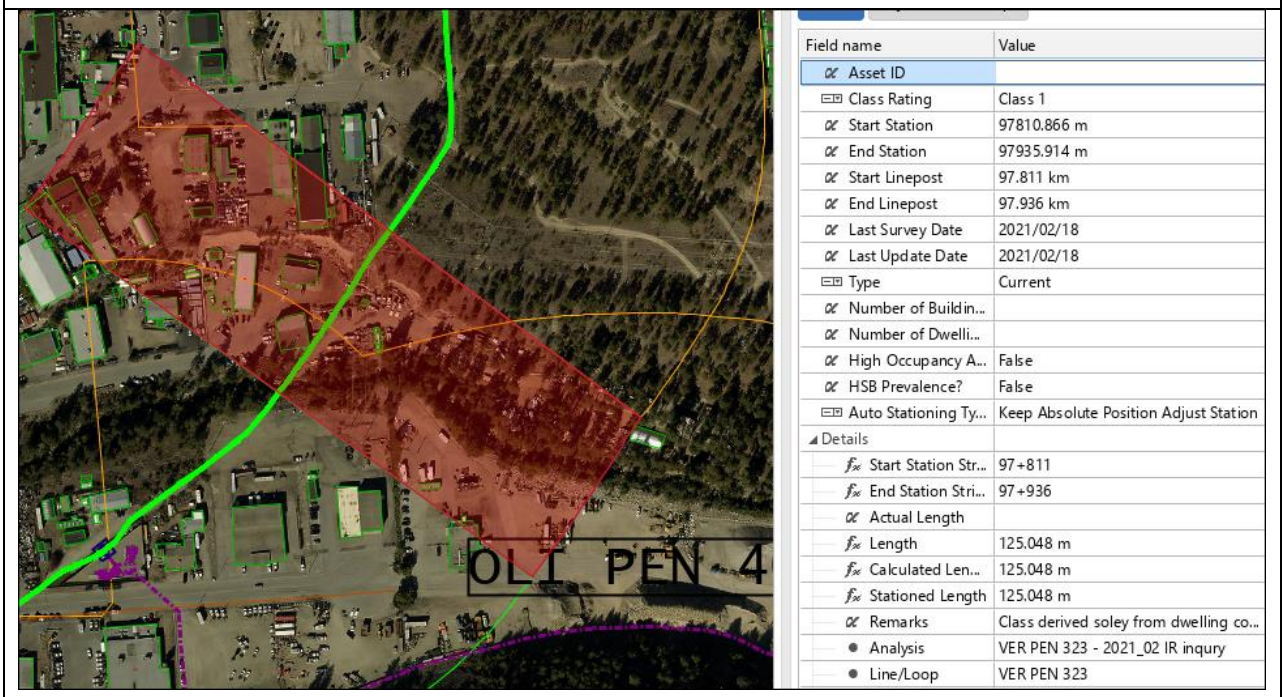
1

95022.383 - 97810.866 – Class 3

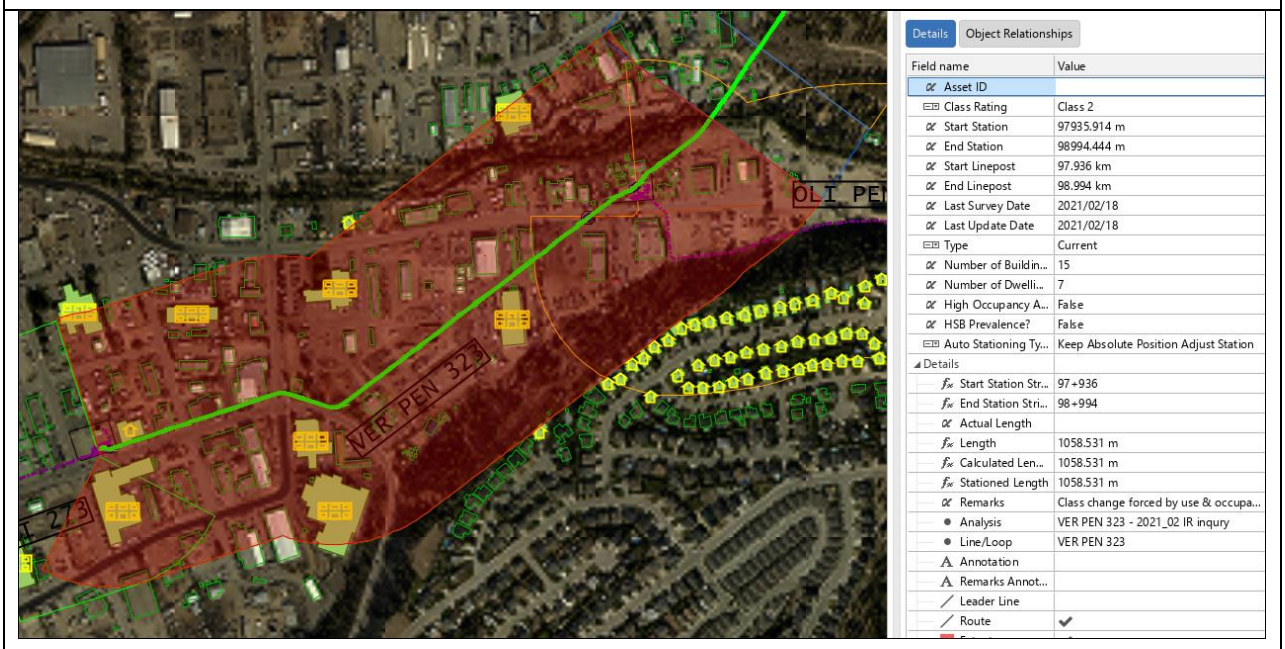


1

97810.866 - 97935.914 – Class 1



97935.914 - 98994.444 – Class 2



2
3

Attachment 22.1

FILED CONFIDENTIALLY

Attachment 26.1

FILED CONFIDENTIALLY