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December 14, 2004

British Columbia Hydro and Power Authority  
333 Dunsmuir Street  
Vancouver, BC V6B 5R3

Attention: Mr. Richard Stout, Chief Regulatory Officer

Dear Sir:

**RE: British Columbia Hydro and Power Authority ("BC Hydro")  
Call for Tenders Process ("CFT")**

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As per the communications between Mr. Graeme Simpson and Mr. Mike Davies, Terasen Gas (Vancouver Island) Inc. ("TGVI") hereby authorizes BC Hydro to release the two CFT related reports that TGVI submitted to BC Hydro on September 9, 2004. Specifically, the two reports, which are both attached, are entitled:

1. Assessment of Gas Transportation Requirements for ICP and Potential CFT
2. Assessment of Development Risk for CFT Gas Transportation Requirements

If you have any questions please contact Mike Davies at (604) 592-7836.

Yours very truly,

**TERASEN GAS (VANCOUVER ISLAND) INC.**

*Original signed by Tom Loski*

*For:* Scott A. Thomson

Attachments

cc: Graeme Simpson  
Mike Davies

# ATTACHMENT 1



**Assessment of  
Gas Transportation Requirements for  
ICP and Potential CFT Portfolios**

**Terasen Gas (Vancouver Island) Inc.**

**September 9th, 2004**

**Confidential**

**Assessment of Gas Transportation Requirements for ICP and Potential CFT Portfolios**

Terasen Gas Vancouver Island Inc.  
September 9th, 2004

For more information related to this report please contact:

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## 1. PURPOSE AND SCOPE

On May 7, 2004, BC Hydro (“BCH”) requested that Terasen Gas (Vancouver Island) Inc. (“TGVI”) undertake an assessment to estimate the cost of gas transportation requirements that may be required to serve Island Cogeneration Project (“ICP”), and other facilities which may result from BCH’s call for tender (“CFT”) process.

In response to this request TGVI provided a report, *Assessment of Gas transportation Requirements for ICP and Potential CFT Portfolios* on August 3, 2004. Based on descriptions of ICP and CFT portfolio combinations provided by BCH this report described:

- Incremental requirements for expansion of the TGVI system
- Estimated transportation rates for each combination
- An assessment of Interruptible Transportation capacity

On August 19<sup>th</sup> 2004, BCH extended their May 7<sup>th</sup> request to include an update of interconnection costs and transportation estimates based on information from the firm CFT tenders, as well as an assessment the development risk associated with gas transportation for CFT portfolios for which BCH might have gas supply responsibility. The table at the end of this section contains the revised CFT Portfolios (“Portfolios”) that were provided as part of this extended request.

The purpose of this report is to provide estimates of interconnection and gas transportation costs associated with the revised CFT Portfolios. An assessment of the development risk associated with major gas transportation improvements required to serve the CFT Portfolios shown in Part A of the following table will be provided under separate cover.

**Vancouver Island Call for Tenders - Final Portfolio and Tender Evaluation Lists for Terasen**

Project Code	Location	Capacity (MW)	Primary Fuel	Alternate Fuel	Firm Demand (TJ/Day)	Interruptible Demand (TJ/Day)
A	A - Ladysmith	47	N Gas	Distillate	11.61	
R	R - Duke Point	285	N Gas	n/a	52.15	
S	S - Duke Point	255	N Gas	n/a	45.50	
T	T - Ladysmith	47	N Gas	Distillate	-	11.61
W	W - Duke Point	252	N Gas	n/a	44.58	-
X	X - Duke Point	280	N Gas	n/a	50.64	-

Note: A and T refer to the same project, A is tender with FT gas, T is tender with IT gas.

**Part A - Portfolio Evaluation List**

Portfolio Code	Location	Capacity (MW)	Primary Fuel	Alternate Fuel	Firm Demand (TJ/Day)	Interruptible Demand (TJ/Day)
AW	A - Ladysmith	47	N Gas	Distillate	11.61	
	W - Duke Point	252	N Gas	n/a	44.58	-
	<b>Total</b>	<b>299</b>			<b>56.19</b>	<b>-</b>
R	R - Duke Point	285	N Gas	n/a	52.15	
S	S - Duke Point	255	N Gas	n/a	45.50	
TW	T - Ladysmith	47	N Gas	Distillate	-	11.61
	W - Duke Point	252	N Gas	n/a	44.58	-
	<b>Total</b>	<b>299</b>			<b>44.58</b>	<b>11.61</b>
W	W - Duke Point	252	N Gas	n/a	44.58	-
X	X - Duke Point	280	N Gas	n/a	50.64	-

**Part B - Tender Evaluation List**

Tender Code	Location	Capacity (MW)	Primary Fuel	Alternate Fuel	Firm Demand (TJ/Day)	Interruptible Demand (TJ/Day)
A	A - Ladysmith	47	N Gas	Distillate	11.61	
T	T - Ladysmith	47	N Gas	Distillate	-	11.61

## 2. CAPITAL REQUIREMENTS

Except for Portfolios AW and A, the hydraulic requirements of the CFT Portfolios described in Section 1 are equivalent to portfolios developed for TGVI's August 3<sup>rd</sup> report. The table below contains a cross reference of the CFT Portfolios with those of the August 3<sup>rd</sup> report.

August 19 <sup>th</sup> Portfolios	August 3 <sup>rd</sup> Portfolios
AW	-
R	10b
S	8
TW	8
W	8
X	10b
A	-
T	1b

The incremental facilities required to serve the demand of CFT Portfolio AW and A are shown along with those of the other CFT Portfolios at the end of this section. The planning assumptions used to develop these capital requirements are the same as those described in TGVI's the August 3<sup>rd</sup> report. In Portfolios S, T, and TW, the timing of the 12 km loop has been corrected, timing of the loop has been advanced one year from 2022 to 2021 and now matches the result shown in TGVI's CPCN for the Base +45 forecast.

Portfolio AW requires looping of the Harmac Lateral for 2007 to address a low tail-end pressure condition. While tail-end pressures on the Harmac Lateral in all other Portfolios are sufficient results for Portfolios with R,S,T,W, and X exhibit low tail end-temperatures under some flow conditions. As described in TGVI's August 3<sup>rd</sup> report the requirement for looping is marginal for these Portfolios and has not been included in the capital requirements. While significant changes in gas quality or other assumptions used in the assessment could lead to the requirement for looping, based on current values and historical trends such changes are unexpected.

Forecast demand for TGVI's core market is such that firm service can be offered to serve the CFT Portfolios May 1, 2007 prior to the November 1, 2007 completion of initial capital projects. These capital projects are required to meet TGVI's combined requirement for firm transportation forecast for winter 2007.

Project specific estimates of meter station and interconnecting pipeline costs follow the capital schedules. For the purpose of this assessment it is assumed that these costs will be covered by a non-refundable contribution in aid of construction and therefore they are not included in determining transportation rate estimates. Final treatment of these costs will be subject to British Columbia Utilities Commission ("BCUC") approval.



**Incremental TGVI Facility Requirements**

Year	Portfolios S, TW, W			Portfolios R, X			Portfolio AW		
	Required TGVI Facilities	Forecast Direct Cost (millions 2004\$)	System Fuel (%)	Required TGVI Facilities	Forecast Direct Cost (millions 2004\$)	System Fuel (%)	Required TGVI Facilities	Forecast Direct Cost (millions 2004\$)	System Fuel (%)
2007	LNG, V1U4, V2, V3b, spares	156	4.7%	LNG, V1U4, V2, V3b, spares	156	4.6%	LNG, V1U4, V2, V3b, spares, Harmac Lateral		5.1%
2008			4.7%			4.6%			5.1%
2009			4.7%			4.6%			5.1%
2010			4.8%			4.6%			5.1%
2011			4.8%			4.7%	25.3 km loop d/s WS		5.1%
2012			4.9%			4.7%	11.6 km loop d/s V2		5.1%
2013			4.9%			4.7%	V5		5.1%
2014			5.0%			4.7%			5.1%
2015			5.0%			4.7%			5.1%
2016			5.0%			4.8%			5.1%
2017			5.1%			4.8%			5.1%
2018			5.1%			4.8%			5.1%
2019	25.3 km loop d/s WS	23	5.2%	25.3 km loop d/s WS, V5	43	4.8%			5.2%
2020	V5	20	5.1%			4.9%			5.1%
2021	11.6 km loop d/s V2	12	5.1%	11.6 km loop d/s V2	12	4.9%			5.1%
2022			5.1%			5.0%			5.0%
2023			5.1%			5.0%			5.0%
2024			5.1%			5.1%	18.6 km loop d/s V3, 26.7km loop on TI		4.9%
2025			5.0%			5.1%			4.9%
2026			5.0%			5.1%			4.8%

<b>Legend</b>	d/s	'downstream of'	V2	V2 - Squamish Compressor Station
	km	'kilometre'	V3b	V3b - Secret Cove Compressor Station
	LNG	Mt Hayes LNG Storage Facility	V4	V4 - Texada Compressor Station (retention and upgrades)
	spares	Spare Compressor Engines	V5	V5 - Dunsmuir Compressor Station
	TI	'Texada Island'	WS	'Watershed'
	V1U4	4th unit to VI - Coquitlam Compressor Station		

**Notes**  
System fuel includes compressor fuel plus 0.5% for meter station fuel, 1% for UAF, and LNG fuel

**Incremental TGVI Facility Requirements**

Year	Portfolio T			Portfolio A		
	Required TGVI Facilities	Forecast Direct Cost (millions 2004\$)	System Fuel (%)	Required TGVI Facilities	Forecast Direct Cost (millions 2004\$)	System Fuel (%)
2007	LNG, spares	99	3.5%	LNG, spares	99	4.2%
2008			3.5%			4.2%
2009			3.6%			4.2%
2010			3.6%			4.2%
2011			3.6%			4.3%
2012			3.6%	V2	22	4.3%
2013			3.7%			4.3%
2014			3.7%			4.3%
2015			3.7%			4.4%
2016			3.7%			4.4%
2017			3.8%			4.4%
2018			3.8%			4.4%
2019	V2	22	3.8%			4.4%
2020			3.8%			4.4%
2021			3.9%			4.4%
2022			3.9%			4.4%
2023			3.9%	V3b	20	4.4%
2024			3.9%	V1U4	15	4.5%
2025			4.0%			4.5%
2026			4.0%			4.5%

<b>Legend</b>	d/s	'downstream of'	V2	V2 - Squamish Compressor Station
	km	'kilometre'	V3b	V3b - Secret Cove Compressor Station
	LNG	Mt Hayes LNG Storage Facility	V4	V4 - Texada Compressor Station (retention and upgrades)
	spares	Spare Compressor Engines	V5	V5 - Dunsmuir Compressor Station
	TI	'Texada Island'	WS	'Watershed'
	V1U4	4th unit to V1 - Coquitlam Compressor Station		

**Notes**  
 System fuel includes compressor fuel plus 0.5% for meter station fuel, 1% for UAF, and LNG fuel



**Terasen Gas Vancouver Island - Meter Station Capital Cost Estimates - June 2004**

Project	Station Name / Location	Delivery Location	Design Basis					Equipment					Cost			Total Capital Cost Estimate (\$ Millions 2004)
			MOP	Flow Rate	Inlet Pressure (Nor./Min.)	Outlet Pressure (Set /Min)	Inlet / Outlet Pipe Size	Meter (Type/ Size)	Filter	Line Heater (Y/N)	Pressure Control Valves	Liquid Storage Tank (Y/N)	Direct Capital Cost Estimate (+/- 15%)	Increase Confidence Level (+15%)	Terasen Project Services	
			kPa	Sm3/Hr	kPa	kPa				Btu/Hr						
A	Ladysmith Industrial Park	Peerless Road	14,890	15,400	11,700 / 3,930	5,170 / 3,447	4" / 4"	4" Sonic	4" PECO - 75H	1,500,000 (1,441,192)	Fisher 3" HPT/667	Y	\$1,344,814	\$1,546,536	\$154,654	<b>\$1.70</b>
S or W	Duke Point 1	SE Corner of BCH Power Plant Site	14,890	59,200	11,700 / 3,930	5,170 / 3,447	8" / 8"	6" Sonic	8" PECO - 75H	6,000,000 (5,540,164)	Fisher 6"/6" HPT/667	Y	\$1,916,148	\$2,203,570	\$220,357	<b>\$2.42</b>
R or X	Duke Point 2	SE Corner of BCH Power Plant Site	14,890	68,400	11,700 / 3,930	5,170 / 3,447	8" / 8"	8" Sonic	8" PECO - 75H	6,500,000 (6,401,136)	Fisher 6"/6" HPT/667	Y	\$2,188,655	\$2,516,953	\$251,695	<b>\$2.77</b>

**Terasen Gas Vancouver Island - Interconnecting Pipe Capital Cost Estimates - June 2004**

Project	Station Name / Location	Delivery Location	Design Basis					Pipeline Right of Way			Costs			Total Capital Cost Estimate (\$ Millions 2004)
			MOP	Flow Rate	Inlet Pressure (Nor./Min.)	Pipe Length	Pipe Size	Length	Width	Crossings	Direct Capital Cost Estimate (+/- 15%)	Increase Confidence Level (+15%)	Terasen Project Services	
			kPa	Sm3/Hr	kPa	m	NPS	m	m					
A	Ladysmith Industrial Park	Peerless Road	14,890	15,400	11,700 / 3,930	800	4	617	6	Industrial Park Road "A"	\$479,300	\$551,195	\$55,120	<b>\$0.61</b>
S or W	Duke Point 1	SE Corner of BCH Power Plant Site	14,890	59,200	11,700 / 3,930	600	8	440	6	Pope & Talbot Mill Road	\$655,755	\$754,118	\$75,412	<b>\$0.83</b>
R or X	Duke Point 2	SE Corner of BCH Power Plant Site	14,890	68,400	11,700 / 3,930	600	8	440	6	Pope & Talbot Mill Road	\$655,755	\$754,118	\$75,412	<b>\$0.83</b>

### 3. DETERMINATION OF TRANSPORTATION RATES

As discussed in the August 3<sup>rd</sup> report, decisions regarding the allocation of cost and design of rates required to recover the cost of new facilities will be the subject of a future rate reviews. This section examines the expected transport rate for each portfolio based on the current approved cost allocation methodology and rate design principles for TGVl.

#### 3.1 MODELLING ASSUMPTIONS

The costs to provide service to BC Hydro for the Island Cogeneration Project (ICP) and any new facilities that arise from the CFT were assessed based on the assumption the proposed LNG production and storage facility is completed and put in service in 2007. The use of the LNG facility in conjunction with other TGVl transmission assets was modeled to make the most efficient use of the combined system and thereby minimize costs that need to be recovered from sales and transport customers. The general principles and assumptions were described.

#### 3.2 INDICATIVE TRANSPORTATION RATES

The transport tolls discussed in this section are indicative only and are based on current assumptions on costs, and system loads, as well as the application of cost allocation and rate design methodology based on the current approved principles. Actual tolls will require BCUC approval and will be subject to changes from period to period to reflect changes in costs and market conditions.

Based on the principles and assumptions described in sections 4.1.1 and section 4.2.1 of the August 4<sup>th</sup> report, allocated unit costs and indicative firm transportation rates for Vancouver Island generation loads were evaluated. The results for each of the current CFT portfolios are summarised in Table 3.1 and illustrated in the attached figures.

Currently tolls for firm transportation service are based on a revenue to cost ratio of 1.25, consistent with the BCUC June 5, 2003 Decision on TGVl's 2002 Rate Design Application. In the decision the Commission indicated that this revenue to cost ratio is appropriate given TGVl's current status. The Commission also commented that for a financially healthy and mature utility they would expect the range of revenue to cost ratios to tend toward 0.9 to 1.1, all other objectives satisfied. In TGVl's case, the ability of the utility to narrow the revenue to cost ratio will depend on the ability to maintain competitive rates across all customer classes while maintaining long term financial viability. Factors that must be considered in meeting this objective include recovery of the RDDA, potential elimination of the royalty credit and payback of the Federal/Provincial contribution, as well as the long term relative costs of competitive energies.

For the purposes of this assessment, indicative firm transport tolls shown in table 3.1 have been calculated based on a revenue to cost ratio of 1.25 across the entire planning period, and also where the revenue to cost ratio would move to 1.1 after 2011 when the RDDA is expected to be fully recovered. These two scenarios are also illustrated in the attached graphs.

Table 3.1 also provides the expected levelised transport toll over the 20 year period. The sole purpose of providing this number is to make it easier to compare expected costs between the different scenarios.

### **3.3 INTERRUPTIBLE TRANSPORT RATE**

Currently customer costs for interruptible service are based on a summer IT rate equal to the firm transport rate, and a winter IT rate determined by dividing the firm transport rate by a transmission system load factor calculation, currently set at approximately 73%. At this time, TGVl has not fully assessed whether this mechanism is still appropriate when an LNG storage facility is added into the resource stack.

In principal, however, TGVl will seek to set IT rates to encourage customers to retain and/or contract for firm transportation service. For the purposes of BC Hydro's CFT assessment TGVl recommends that BC Hydro base the IT rate on the current rate formula. In other words, the summer rate would be equal to the firm rate, while the winter rate would be set at approximately 137% of the firm rate.

### **3.4 OTHER CONSIDERATIONS**

#### **3.4.1 *Duct Firing Capacity Alternative***

TGVl understands that firm transport service for duct firing capacity has been included in some of the portfolios. As discussed in the August 4<sup>th</sup> report, if the duct firing is expected to be rarely dispatched, an alternative may be for BC Hydro to contract for available storage capacity. The valuation of the storage service for third parties is estimated to be \$80 per GJ of sendout for 10 day service. Therefore for 10 day storage service for 7 TJ/d would be priced at approximately \$560,000 per annum initial demand charge.

#### **3.4.2 *Coastal Transmission System Wheeling Costs***

The indicative transportation costs that have been calculated for this report include an allocation of TGVl's Wheeling costs across the CTS system on the same basis as allocation of the transmission system costs. To the degree that TGVl does not hold sufficient capacity under the current wheeling agreement with Terasen Gas, it is assumed that it would exercise its right under the agreement to expand its contract demand. Alternatively, TGVl is prepared to consider an arrangement whereby BCH assigns part of its Bypass Transportation Agreement ("BTA") capacity to TGVl. This could result in benefits to BC Hydro through either direct payment for the capacity or through a lower allocation of wheeling costs in the transport toll.

Assessment of CFT Portfolio Requirements

TABLE 3.1  
BCH CFT TOLLING RESULTS FROM  
CFT PORTFOLIO RUNS

**1. Indicative Tolls Based on 1.25 Revenue to Cost Ratio**

**Part A - PORTFOLIO Evaluation List**

<u>BC Hydro</u> CFT Portfolio	<u>TGVI Portfolio</u>	<u>ICP CD</u> GJ/d	<u>CFT CD</u> GJ/d	<u>20 Year</u> Levelized	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
AW	LNG	45	56.19	\$0.931	\$ 0.942	\$ 0.980	\$ 0.938	\$ 0.923	\$ 0.901	\$ 0.868	\$ 0.909	\$ 0.967	\$ 0.969	\$ 0.973
R	LNG	45	52.15	\$0.881	\$ 0.921	\$ 0.974	\$ 0.932	\$ 0.916	\$ 0.896	\$ 0.814	\$ 0.836	\$ 0.847	\$ 0.848	\$ 0.850
S	LNG	45	45.5	\$0.903	\$ 0.955	\$ 1.002	\$ 0.958	\$ 0.942	\$ 0.920	\$ 0.836	\$ 0.859	\$ 0.869	\$ 0.870	\$ 0.872
TW	LNG	45	44.58	\$0.906	\$ 0.956	\$ 1.006	\$ 0.962	\$ 0.946	\$ 0.924	\$ 0.839	\$ 0.862	\$ 0.872	\$ 0.873	\$ 0.875
W	LNG	45	44.58	\$0.906	\$ 0.956	\$ 1.006	\$ 0.962	\$ 0.946	\$ 0.924	\$ 0.839	\$ 0.862	\$ 0.872	\$ 0.873	\$ 0.875
X	LNG	45	50.64	\$0.884	\$ 0.915	\$ 0.976	\$ 0.933	\$ 0.918	\$ 0.897	\$ 0.819	\$ 0.842	\$ 0.852	\$ 0.853	\$ 0.856

**Part B - Tender Evaluation List**

<u>BC Hydro</u> CFT Portfolio	<u>TGVI Portfolio</u>	<u>ICP CD</u> GJ/d	<u>New CD</u> GJ/d	<u>20 Year</u> Levelized	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
A	LNG	45	11.61	\$0.905	\$ 1.024	\$ 1.021	\$ 0.959	\$ 0.932	\$ 0.902	\$ 0.803	\$ 0.893	\$ 0.906	\$ 0.919	\$ 0.919
T	LNG	45	0	\$0.937	\$ 1.037	\$ 1.099	\$ 1.033	\$ 1.004	\$ 0.971	\$ 0.874	\$ 0.898	\$ 0.910	\$ 0.921	\$ 0.920

**2. Indicative Tolls Based on 1.25 R/C Ratio to 2011 and 1.1 R/C Ratio thereafter**

**Part A - PORTFOLIO Evaluation List**

<u>BC Hydro</u> CFT Portfolio	<u>TGVI Portfolio</u>	<u>ICP CD</u> GJ/d	<u>CFT CD</u> GJ/d	<u>20 Year</u> Levelized	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
AW	LNG	45	56.19	\$0.861	\$ 0.942	\$ 0.980	\$ 0.938	\$ 0.923	\$ 0.901	\$ 0.764	\$ 0.800	\$ 0.851	\$ 0.853	\$ 0.856
R	LNG	45	52.15	\$0.816	\$ 0.921	\$ 0.974	\$ 0.932	\$ 0.916	\$ 0.896	\$ 0.716	\$ 0.736	\$ 0.745	\$ 0.746	\$ 0.748
S	LNG	45	45.5	\$0.837	\$ 0.955	\$ 1.002	\$ 0.958	\$ 0.942	\$ 0.920	\$ 0.735	\$ 0.756	\$ 0.765	\$ 0.765	\$ 0.768
TW	LNG	45	44.58	\$0.840	\$ 0.956	\$ 1.006	\$ 0.962	\$ 0.946	\$ 0.924	\$ 0.738	\$ 0.758	\$ 0.768	\$ 0.768	\$ 0.770
W	LNG	45	44.58	\$0.840	\$ 0.956	\$ 1.006	\$ 0.962	\$ 0.946	\$ 0.924	\$ 0.738	\$ 0.758	\$ 0.768	\$ 0.768	\$ 0.770
X	LNG	45	50.64	\$0.819	\$ 0.915	\$ 0.976	\$ 0.933	\$ 0.918	\$ 0.897	\$ 0.721	\$ 0.741	\$ 0.750	\$ 0.751	\$ 0.753

**Part B - Tender Evaluation List**

<u>BC Hydro</u> CFT Portfolio	<u>TGVI Portfolio</u>	<u>ICP CD</u> GJ/d	<u>New CD</u> GJ/d	<u>20 Year</u> Levelized	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
A	LNG	45	11.61	\$0.839	\$ 1.024	\$ 1.021	\$ 0.959	\$ 0.932	\$ 0.902	\$ 0.707	\$ 0.786	\$ 0.797	\$ 0.808	\$ 0.809
T	LNG	45	0	\$0.871	\$ 1.037	\$ 1.099	\$ 1.033	\$ 1.004	\$ 0.971	\$ 0.769	\$ 0.791	\$ 0.800	\$ 0.810	\$ 0.810

Assessment of CFT Portfolio Requirements

TABLE 3.1  
BCH CFT TOLLING RESULTS FROM  
CFT PORTFOLIO RUNS

**1. Indicative Tolls Based on 1.25 Revenue to Cost Ratio**

**Part A - PORTFOLIO Evaluation List**

<u>BC Hydro</u> CFT Portfolio	<u>TGVI Portfolio</u>	<u>ICP CD</u> GJ/d	<u>CFT CD</u> GJ/d	<u>20 Year</u> Levelized	<u>2017</u>	<u>2018</u>	<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>2024</u>	<u>2025</u>	<u>2026</u>
AW	LNG	45	56.19	\$0.931	\$ 0.977	\$ 0.971	\$ 0.946	\$ 0.923	\$ 0.926	\$ 0.893	\$ 0.874	\$ 0.829	\$ 0.917	\$ 0.897
R	LNG	45	52.15	\$0.881	\$ 0.855	\$ 0.851	\$ 0.815	\$ 0.905	\$ 0.908	\$ 0.910	\$ 0.894	\$ 0.855	\$ 0.830	\$ 0.811
S	LNG	45	45.5	\$0.903	\$ 0.877	\$ 0.872	\$ 0.844	\$ 0.871	\$ 0.929	\$ 0.932	\$ 0.916	\$ 0.876	\$ 0.850	\$ 0.830
TW	LNG	45	44.58	\$0.906	\$ 0.880	\$ 0.875	\$ 0.847	\$ 0.874	\$ 0.932	\$ 0.935	\$ 0.919	\$ 0.879	\$ 0.853	\$ 0.833
W	LNG	45	44.58	\$0.906	\$ 0.880	\$ 0.875	\$ 0.847	\$ 0.874	\$ 0.932	\$ 0.935	\$ 0.919	\$ 0.879	\$ 0.853	\$ 0.833
X	LNG	45	50.64	\$0.884	\$ 0.860	\$ 0.856	\$ 0.821	\$ 0.911	\$ 0.914	\$ 0.916	\$ 0.900	\$ 0.860	\$ 0.835	\$ 0.816

**Part B - Tender Evaluation List**

<u>BC Hydro</u> CFT Portfolio	<u>TGVI Portfolio</u>	<u>ICP CD</u> GJ/d	<u>New CD</u> GJ/d	<u>20 Year</u> Levelized	<u>2017</u>	<u>2018</u>	<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>2024</u>	<u>2025</u>	<u>2026</u>
A	LNG	45	11.61	\$0.905	\$ 0.925	\$ 0.919	\$ 0.879	\$ 0.850	\$ 0.818	\$ 0.794	\$ 0.768	\$ 0.811	\$ 0.848	\$ 0.829
T	LNG	45	0	\$0.937	\$ 0.925	\$ 0.918	\$ 0.865	\$ 0.911	\$ 0.879	\$ 0.856	\$ 0.838	\$ 0.817	\$ 0.800	\$ 0.778

**2. Indicative Tolls Based on 1.25 R/C Ratio to 2011 and 1.1 R/C Ratio thereafter**

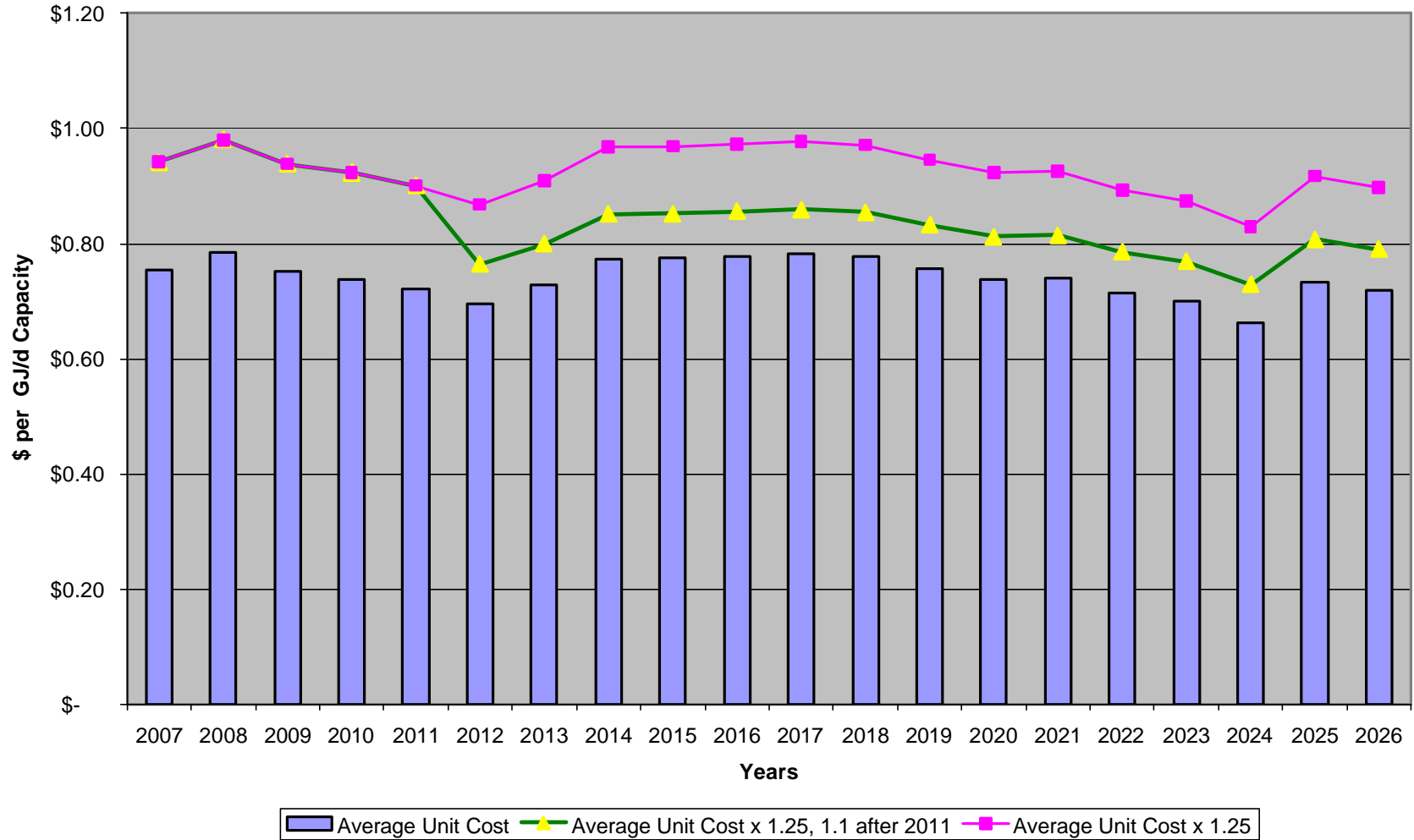
**Part A - PORTFOLIO Evaluation List**

<u>BC Hydro</u> CFT Portfolio	<u>TGVI Portfolio</u>	<u>ICP CD</u> GJ/d	<u>CFT CD</u> GJ/d	<u>20 Year</u> Levelized	<u>2017</u>	<u>2018</u>	<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>2024</u>	<u>2025</u>	<u>2026</u>
AW	LNG	45	56.19	\$0.861	\$ 0.860	\$ 0.855	\$ 0.832	\$ 0.812	\$ 0.815	\$ 0.786	\$ 0.769	\$ 0.729	\$ 0.807	\$ 0.790
R	LNG	45	52.15	\$0.816	\$ 0.752	\$ 0.749	\$ 0.718	\$ 0.797	\$ 0.799	\$ 0.801	\$ 0.787	\$ 0.752	\$ 0.730	\$ 0.713
S	LNG	45	45.5	\$0.837	\$ 0.771	\$ 0.768	\$ 0.743	\$ 0.767	\$ 0.818	\$ 0.820	\$ 0.806	\$ 0.771	\$ 0.748	\$ 0.731
TW	LNG	45	44.58	\$0.840	\$ 0.774	\$ 0.770	\$ 0.745	\$ 0.769	\$ 0.820	\$ 0.823	\$ 0.809	\$ 0.773	\$ 0.751	\$ 0.733
W	LNG	45	44.58	\$0.840	\$ 0.774	\$ 0.770	\$ 0.745	\$ 0.769	\$ 0.820	\$ 0.823	\$ 0.809	\$ 0.773	\$ 0.751	\$ 0.733
X	LNG	45	50.64	\$0.819	\$ 0.757	\$ 0.753	\$ 0.722	\$ 0.802	\$ 0.804	\$ 0.806	\$ 0.792	\$ 0.757	\$ 0.735	\$ 0.718

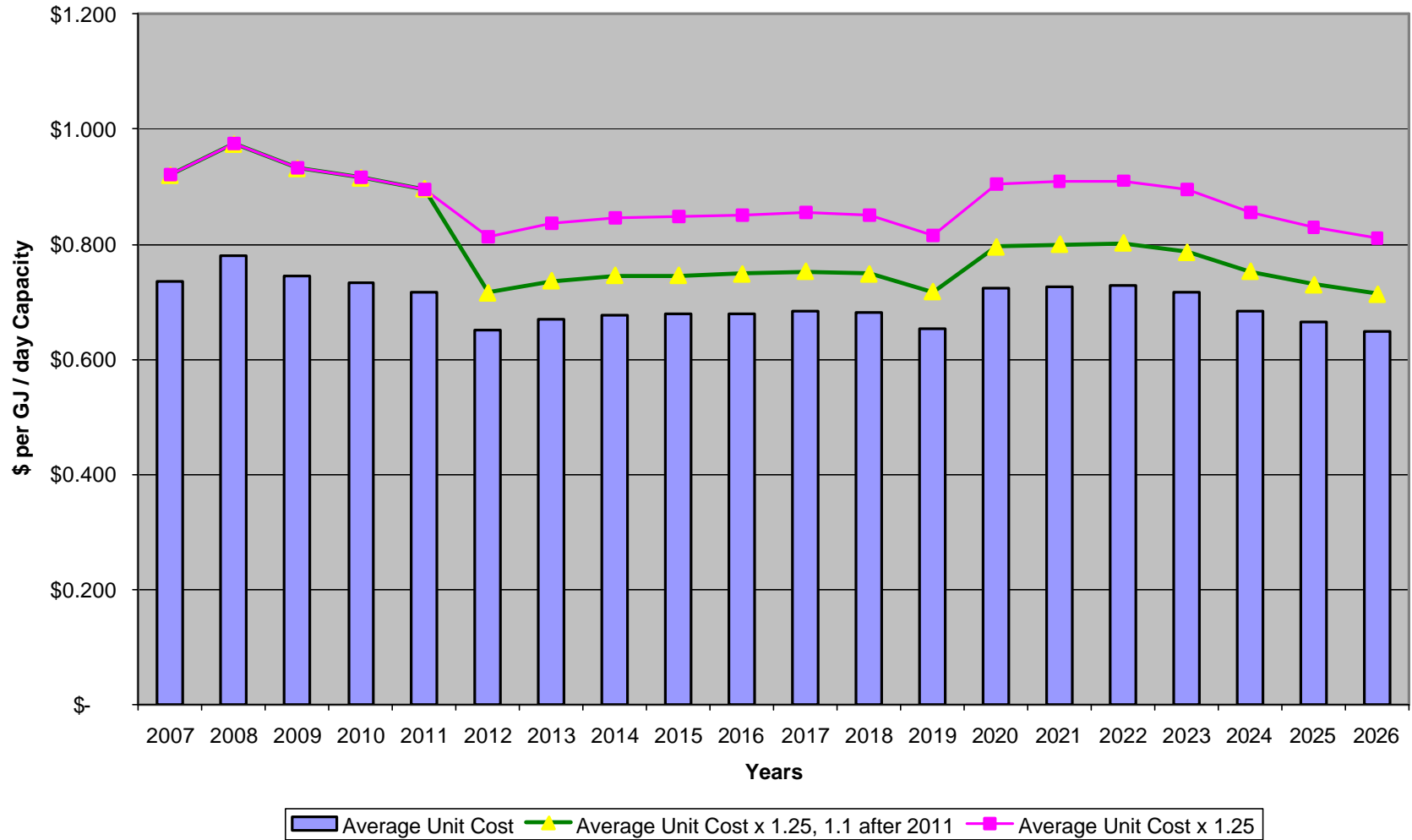
**Part B - Tender Evaluation List**

<u>BC Hydro</u> CFT Portfolio	<u>TGVI Portfolio</u>	<u>ICP CD</u> GJ/d	<u>New CD</u> GJ/d	<u>20 Year</u> Levelized	<u>2017</u>	<u>2018</u>	<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>2024</u>	<u>2025</u>	<u>2026</u>
A	LNG	45	11.61	\$0.839	\$ 0.814	\$ 0.809	\$ 0.773	\$ 0.748	\$ 0.720	\$ 0.699	\$ 0.676	\$ 0.713	\$ 0.746	\$ 0.730
T	LNG	45	0	\$0.871	\$ 0.814	\$ 0.808	\$ 0.761	\$ 0.801	\$ 0.774	\$ 0.753	\$ 0.738	\$ 0.719	\$ 0.704	\$ 0.685

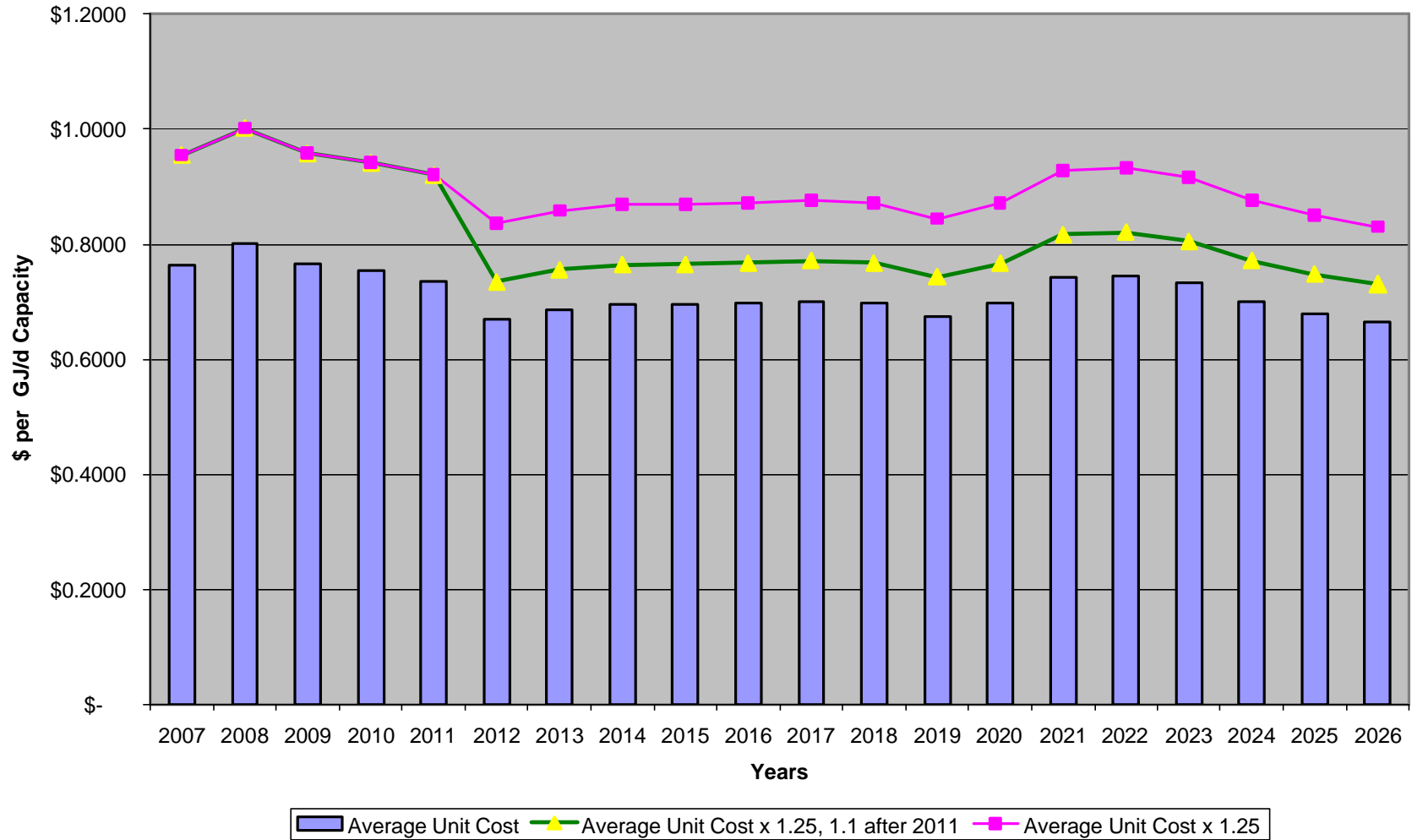
**BCH CFT AW Portfolios  
TGVI LNG Storage Portfolio**



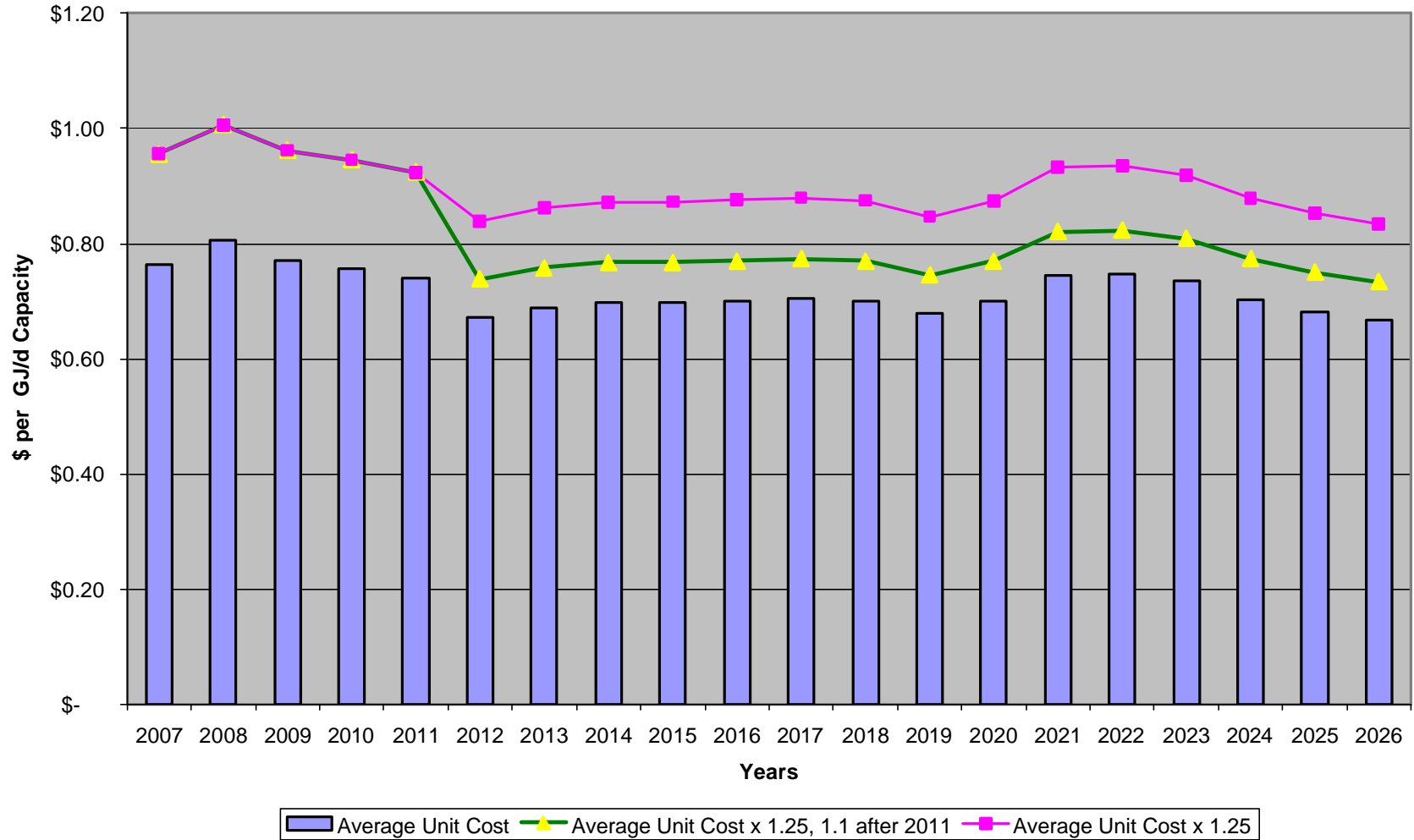
**BC Hydro CFT R Portfolio  
TGVI LNG Storage Portfolio**



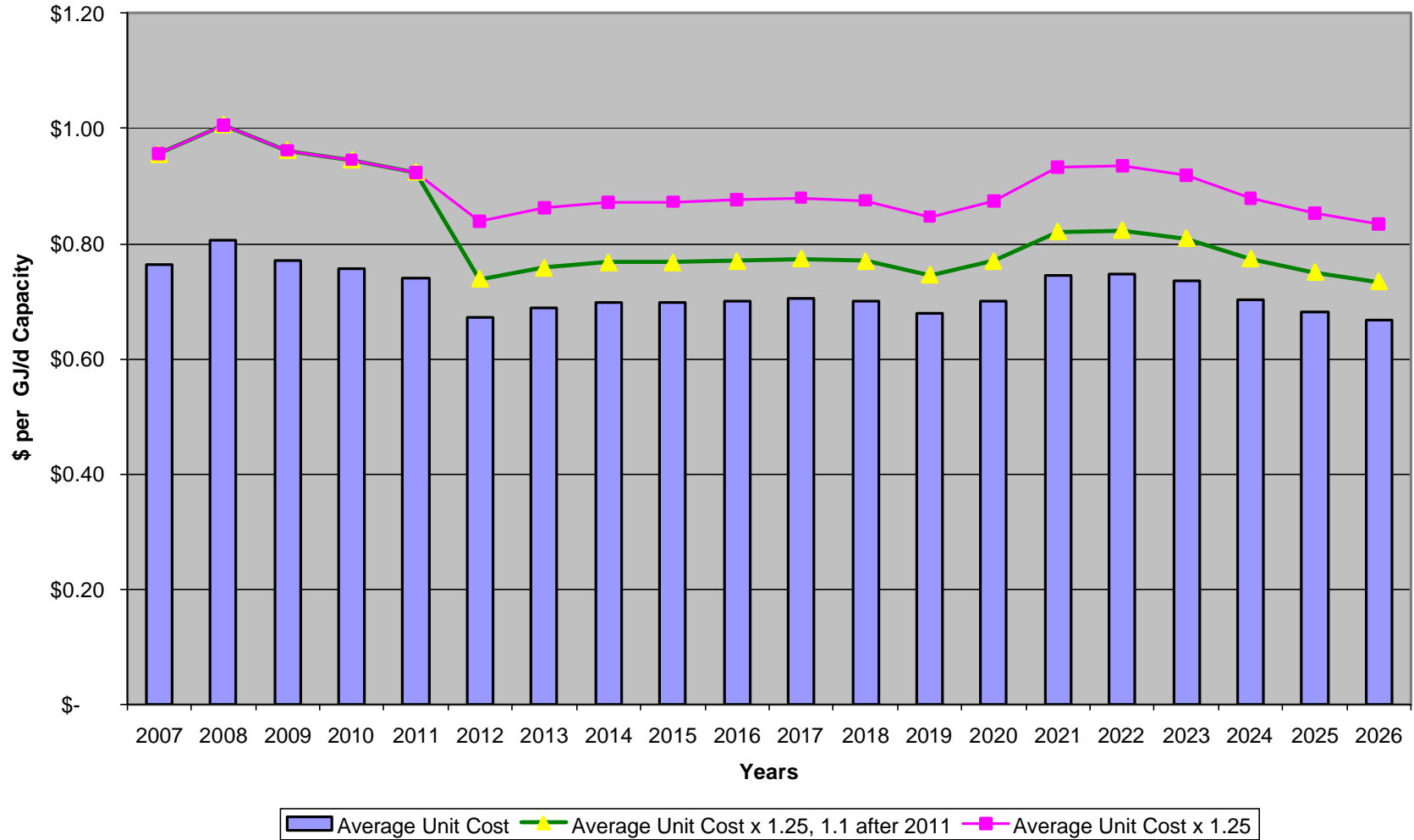
**BCH CFT S Portfolio  
TGVI LNG Storage Portfolio**



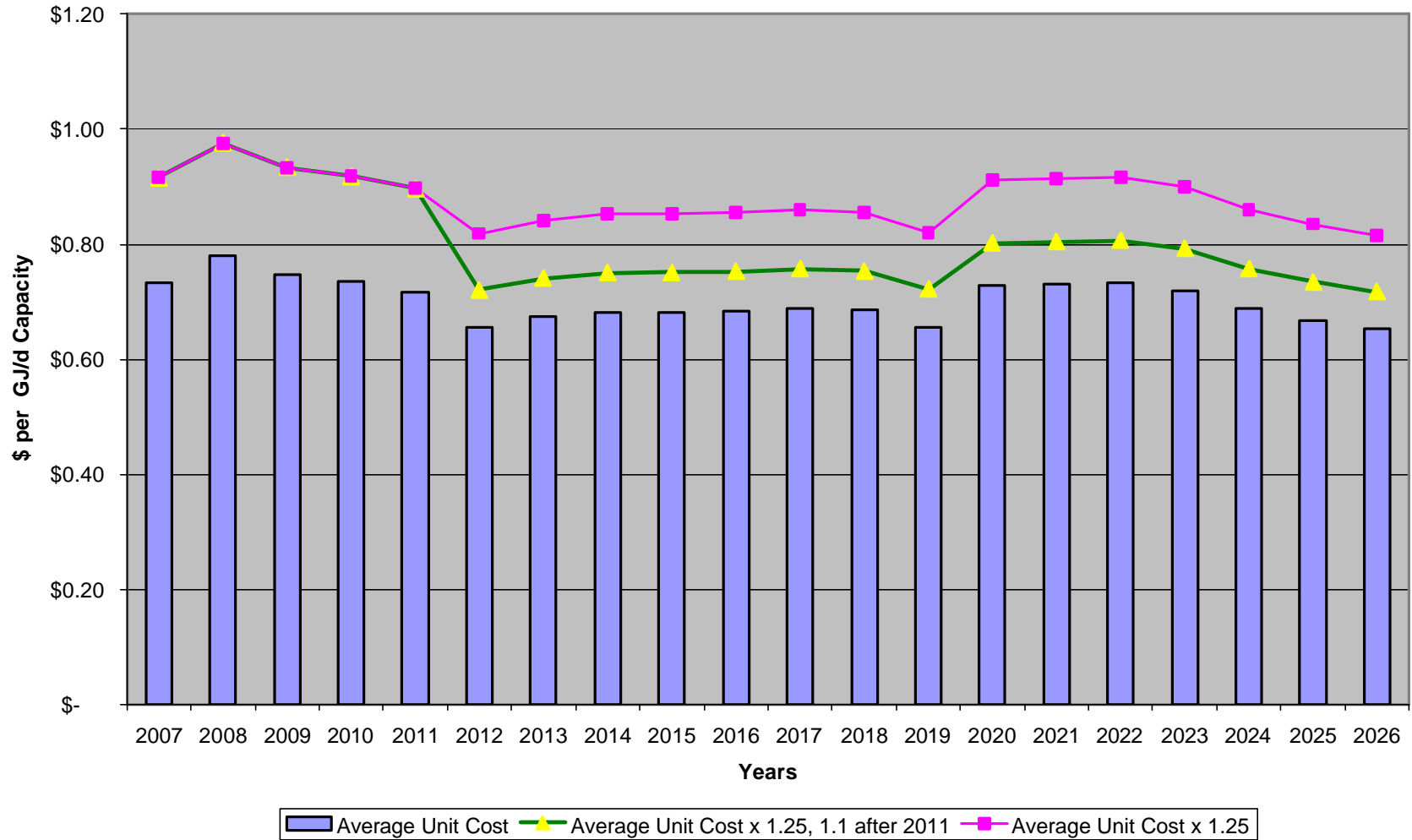
**BCH CFT TW Portfolio  
TGVI LNG Storage Portfolio**



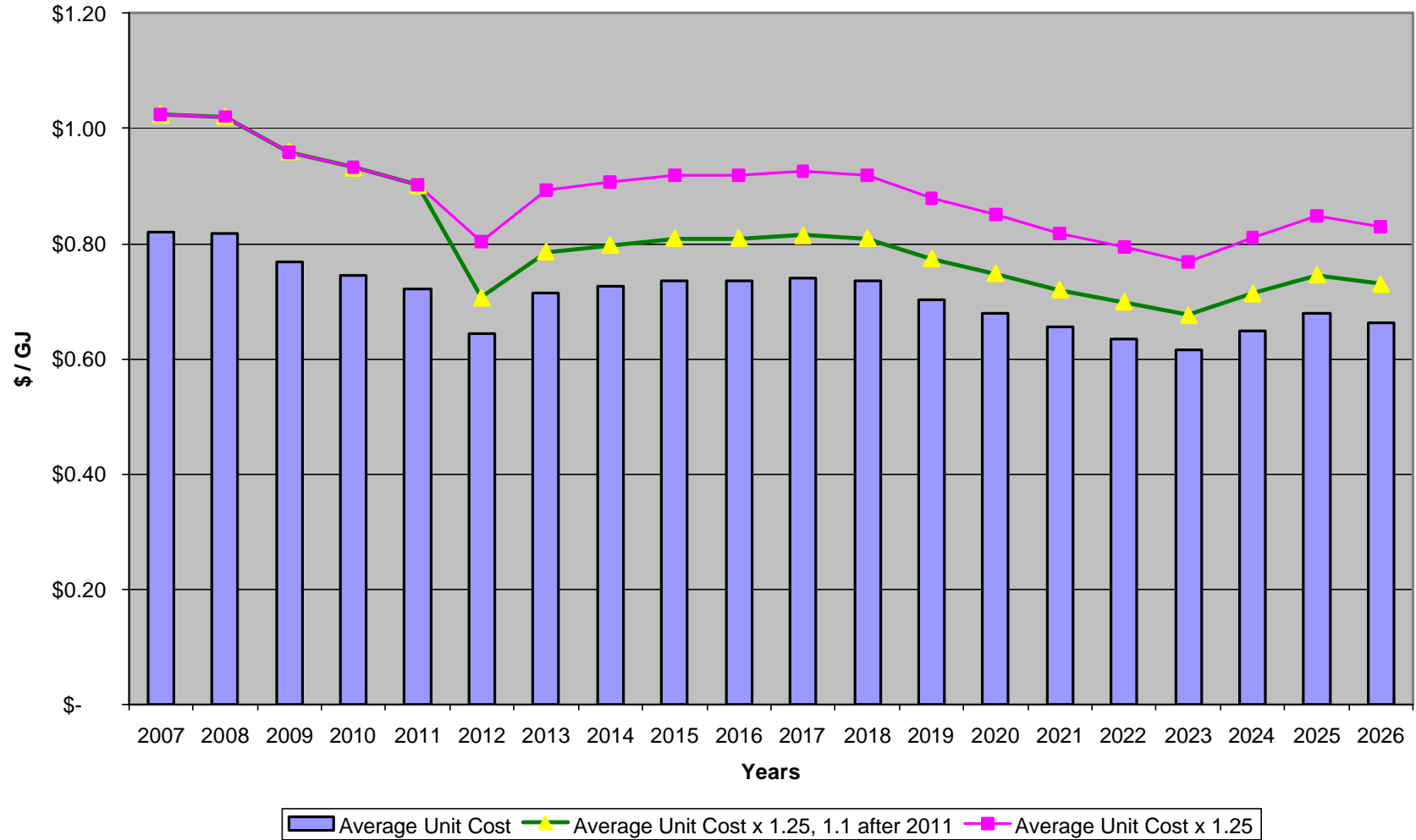
**BCH CFT W Portfolio  
TGVI LNG Storage Portfolio**



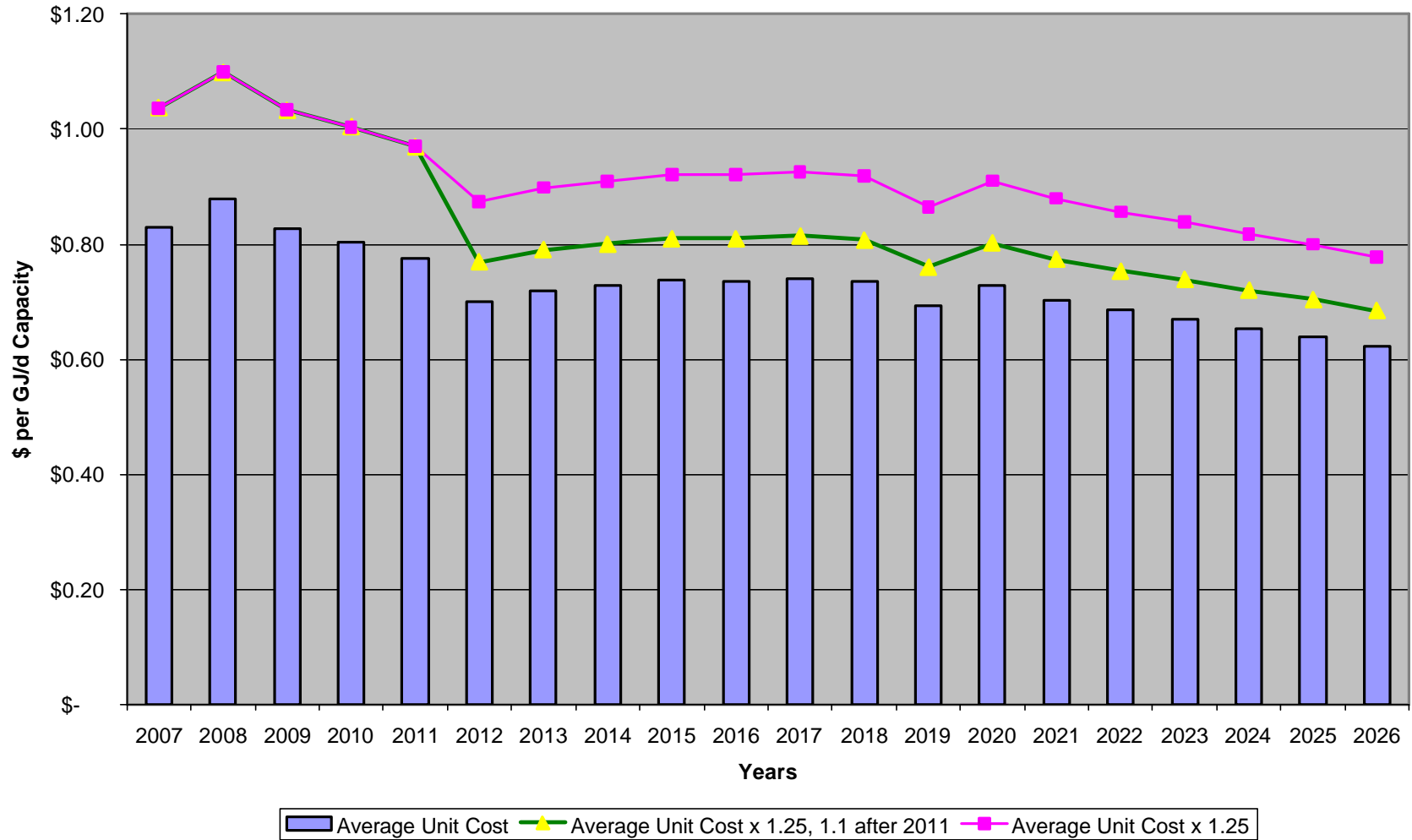
**BCH CFT X Portfolios  
TGVI LNG Storage Portfolio**



**BCH CFT A Portfolio  
TGVI LNG Storage Portfolio**



### BCH CFT T Portfolio TGVI LNG Storage Portfolio



#### 4. INTERRUPTIBLE TRANSPORTATION (IT)

Two of the Portfolios include project T which is designated to be served on an interruptible basis. By its very nature the availability of this service is unpredictable and it is not considered in planning long-term facilities. In practice the availability of IT service depends on many factors not considered in this study. For example, availability to a particular customer is often limited by the demand for IT service from other customers, or operational decisions that may limit throughput capacity. However, it is reasonable to expect that installed pipeline capacity will often exceed total firm demand requirements. For these two Portfolios the following tables show the forecast duration that installed pipeline capacity could exceed firm demand:

- These tables identify the first day that excess occurs and the first day that the excess is sufficient to meet the combined demand of projects designated for IT service.
- The hydraulic model was used to estimate the excess in 2008 and the year before the next capacity upgrade. The values shown in italics are extrapolated between these two points.
- Results are based on design year weather assumptions. Under normal or average weather these events would be expected to occur approximately 5 days earlier.

## Portfolio TW

YEAR	LNG Storage	
	Portfolio TW Capital Schedule	Nth Coldest Day to begin supply to Project "T" Nth Coldest Day to fully supply Project "T"
2007	LNG @ Mt.Hayes, V1-Unit 4, V2 Squamish, V3b Secret Cove	
2008		25 68
2009		31 75
2010		36 82
2011		42 89
2012		47 96
2013		53 103
2014		58 110
2015		64 117
2016		69 124
2017	75 131	
2018	80 138	
2019	25.3 km Loop d/s Watershed V5 Dunsmuir 11.6 km loop d/s V2	
2020		
2021		
2022		
2023		
2024		
2025		
2026		

## Portfolio T

YEAR	LNG Storage		
	Portfolio T Capital Schedule	Nth Coldest Day to begin supply to Project "T"	Nth Coldest Day to fully supply Project "T"
2007	Add LNG @ Mt Hayes		
2008		25	57
2009		30	65
2010		36	73
2011		41	80
2012		46	88
2013		52	96
2014		57	104
2015		62	112
2016		67	119
2017	73	127	
2018	78	135	
2019	Add V2 Squamish Compressor		
2020			
2021			
2022			
2023			
2024			
2025			
2026			

# ATTACHMENT 2



**Assessment of Development Risk  
for  
CFT Gas Transportation Requirements**

**Terasen Gas (Vancouver Island) Inc.**

**September 9, 2004**

**Confidential**

## **Assessment of Development Risk for CFT Gas Transportation Requirements**

Terasen Gas Vancouver Island Inc.  
September 9, 2004

For more information related to this report please contact:

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## 1. PURPOSE AND SCOPE

On May 7, 2004, BC Hydro (“BCH”) requested that Terasen Gas (Vancouver Island) Inc. (“TGVI”) undertake an assessment to estimate the cost of gas transportation requirements that may be required to serve Island Cogeneration Project (“ICP”), and other facilities which may result from BCH’s call for tender (“CFT”) process.

In response to this request TGVI provided a report, *Assessment of Gas transportation Requirements for ICP and Potential CFT Portfolios* on August 3, 2004. Based on descriptions of ICP and CFT portfolio combinations provided by BCH this report described:

- Incremental requirements for expansion of the TGVI system
- Estimated transportation rates for each combination
- An assessment of Interruptible Transportation capacity

On August 19<sup>th</sup> 2004, BCH extended their May 7<sup>th</sup> request to include an update of interconnection costs and transportation estimates based on information from the firm CFT tenders, as well as an assessment the development risk associated with gas transportation for CFT portfolios for which BCH might have gas supply responsibility. The table at the end of this section contains the revised CFT Portfolios (“Portfolios”) that were provided as part of this extended request.

The purpose of this report is to provide the information required by BCH to assess the development risk associated with major gas transportation improvements required to serve the CFT Portfolios. An update of interconnection costs and transportation estimates will be provided under separate cover.

The content of this report is based upon information supplied by consultants and equipment suppliers as well as TGVI and Terasen Gas’s (“TGI”) considerable experience in operating, upgrading and maintaining existing LNG facilities as well as constructing compression facilities. Recent TGVI compression projects include the 3rd unit addition at V1 Station in Coquitlam in 1998, the new V3 Port Mellon Compressor station in 1999 and the new the TGI Langley station in 2000, and the new V4 compressor station on Texada Island in 2001.

**Vancouver Island Call for Tenders - Final Portfolio and Tender Evaluation Lists for Terasen**

Project Code	Location	Capacity (MW)	Primary Fuel	Alternate Fuel	Firm Demand (TJ/Day)	Interruptible Demand (TJ/Day)
A	A - Ladysmith	47	N Gas	Distillate	11.61	
R	R - Duke Point	285	N Gas	n/a	52.15	
S	S - Duke Point	255	N Gas	n/a	45.50	
T	T - Ladysmith	47	N Gas	Distillate	-	11.61
W	W - Duke Point	252	N Gas	n/a	44.58	-
X	X - Duke Point	280	N Gas	n/a	50.64	-

Note: A and T refer to the same project, A is tender with FT gas, T is tender with IT gas.

**Part A - Portfolio Evaluation List**

Portfolio Code	Location	Capacity (MW)	Primary Fuel	Alternate Fuel	Firm Demand (TJ/Day)	Interruptible Demand (TJ/Day)
AW	A - Ladysmith	47	N Gas	Distillate	11.61	
	W - Duke Point	252	N Gas	n/a	44.58	-
	Total	299			56.19	-
R	R - Duke Point	285	N Gas	n/a	52.15	
S	S - Duke Point	255	N Gas	n/a	45.50	
TW	T - Ladysmith	47	N Gas	Distillate	-	11.61
	W - Duke Point	252	N Gas	n/a	44.58	-
	Total	299			44.58	11.61
W	W - Duke Point	252	N Gas	n/a	44.58	-
X	X - Duke Point	280	N Gas	n/a	50.64	-

## 2. EXISTING TRANSMISSION SYSTEM

Natural gas is received by TGVI at its V1 Compressor Station in Coquitlam from TGI. The delivery pressure for transmission to customers is increased to 2,160 psig maximum operating pressure through three gas turbine-compressor units at the V1 Compressor Station, one gas turbine-compressor unit at the V3 Port Mellon Compressor Station on the Sunshine Coast and one gas turbine-compressor unit at the V4 Kiddie Point Compressor Station on Texada Island. Natural gas is transported through 615 km of pipeline, including dual marine crossings of the Georgia and Malaspina Straits, to various metering and pressure regulating stations located near customers and communities being served. Operating pressure is reduced at these stations from 2,160 psig to 500 psig or less, depending on load and customer requirements.

### 3. PROPOSED CAPITAL ADDITIONS

Except for Portfolio AW the hydraulic requirements of the CFT Portfolios described in Section 1 are equivalent to portfolios developed for TGVI's August 3<sup>rd</sup> report. The table below contains a cross reference of the CFT Portfolios with those of the August 3<sup>rd</sup> report.

Aug 19th portfolios	Aug 3rd portfolios
AW	-
R	10b
S	8
TW	8
W	8
X	10b

The incremental facilities required to serve the demand of CFT Portfolio AW are shown along with those of the other CFT Portfolios at the end of this section. The planning assumptions used to develop these capital requirements are described in TGVI's the August 3<sup>rd</sup> report.

Common to all CFT Portfolios is the 2007 requirement for the Mt. Hayes LNG Storage Facility, upgrades to the V1 (Coquitlam) compressor station, as well as new compressor stations at V2 (Squamish) and V3b (Secret Cove). In addition to these requirements, Portfolio AW also requires looping of the Harmac Lateral for 2007 to address a low tail-end pressure condition. For the purpose of this report these projects are considered to be the major components of gas transmission infrastructure improvements required to serve the CFT Portfolios. Given the lead time allowed and conventional nature of the other expansion elements shown in the capital plans, their development risk is not considered in this assessment.

While tail-end pressures on the Harmac Lateral in Portfolios R, S, TW, W, and X are sufficient results for these Portfolios exhibit low tail end-temperatures under some flow conditions. As described in TGVI's August 3<sup>rd</sup> report the requirement for looping is marginal for these Portfolios and has not been included in the capital requirements. While significant changes in gas quality or other assumptions used in the assessment could lead to the requirement for looping based on current values and historical trends such changes are unexpected.

Forecast demand for TGVI's core market is such that firm service can be offered to serve the CFT Portfolios May 1, 2007 prior to the November 1, 2007 completion of initial capital projects elements. These capital projects are required to meet TGVI's combined requirement for firm transportation forecast for winter 2007.

### Incremental TGVI Facility Requirements

Year	Portfolios S, TW, W	Portfolios R, X	Portfolio AW
	<b>Required TGVI Facilities</b>	<b>Required TGVI Facilities</b>	<b>Required TGVI Facilities</b>
2007	LNG, V1U4, V2, V3b, spares	LNG, V1U4, V2, V3b, spares	LNG, V1U4, V2, V3b, spares, Harmac Lateral
2008			
2009			
2010			
2011			
2012			25.3 km loop d/s WS
2013			11.6 km loop d/s V2
2014			V5
2015			
2016			
2017			
2018			
2019	25.3 km loop d/s WS	25.3 km loop d/s WS, V5	
2020	V5		
2021	11.6 km loop d/s V2	11.6 km loop d/s V2	
2022			
2023			
2024			18.6 km loop d/s V3, 26.7km loop on TI.
2025			
2026			

<b>Legend</b>	d/s	'downstream of'
	km	'kilometre'
	LNG	Mt Hayes LNG Storage Facility
	spares	Spare Compressor Engines
	TI	'Texada Island'
	V1U4	4th unit to VI - Coquitlam Compressor Station
	V2	V2 - Squamish Compressor Station
	V3b	V3b - Secret Cove Compressor Station
	V4	V4 - Texada Compressor Station (retention and upgrades)
	V5	V5 - Dunsmuir Compressor Station
	WS	'Watershed'

## 4. LNG STORAGE PROJECT

TGVI has filed a CPCN application with the BCUC for a 1.0 Bcf LNG storage facility to be constructed at a location known as Mount Hayes, approximately 6 km northwest of Ladysmith on Vancouver Island. Details for this project, including schedules and permit requirements can be found in the CPCN application.

### 4.1. LNG STORAGE DEVELOPMENT STATUS

TGVI is confident the facility can be constructed and placed into service by November 01, 2007 based on the following;

- The property has received appropriate zoning approval from the Cowichan Valley Regional District (CVRD) following completion of an environmental assessment and significant public consultation.
- A TGVI Environmental and Social Review (ESR) has been completed and filed with the Oil and Gas Commission (OGC) in support of an application for crown land acquisition (see below.) No difficulties in acquiring any required provincial government agency permits in the required timeline are anticipated.
- Neither a Federal nor Provincial environmental review is required to be undertaken for the LNG project.
- A two year option for the purchase of the property at Mt. Hayes has been executed with the landowner.
- First Nations consultation has been initiated and an agreement has been reached with the Chemanius First Nation (CFN) to negotiate a memorandum of understanding between TGVI and the CFN for the development of the project.
- An application to the OGC for license of occupation to crown land for pipelines and LNG plant buffer zone have been made. Referral has been made to the Chemanius First Nation. OGC approval in advance of construction requirements is expected to be relatively straightforward.
- An application for a CPCN has been filed with the BCUC and a hearing and decision are anticipated before year end.
- TGVI is in negotiation with LNG design/build contractors for the construction of the LNG facility to begin approximately January 1, 2005 with a construction completion date of June 15, 2007. The contractors are comfortable with the proposed timetable. One contractor will be selected in early September to begin the design and be prepared to make applications to the OGC for design approval and Leave to Construct and commence construction in spring of 2005.
- Filling of the tank is scheduled to commence immediately following construction with a minimum of 1/3 tank fill to be completed by November 1, 2007.

### 4.2. LNG PROJECT SCHEDULE AND MITIGATION OF DELAYS

The schedule for the LNG project is based on meeting BCH's forecast requirements for winter 2007. The LNG project schedule described in Section 13 of TGVI's CPCN Application anticipates regulatory approval of the project by January 1, 2005 to allow the time required to have a partially filled tank and facility ready for use in winter 2007. This project schedule represents the critical path of activities required to meet forecast requirements for 2007.

In the unlikely event that the LNG facility is not ready on time, TGVI has a range of alternatives which to pursue to ensure that at least 30 TJ/d of firm service is available for the CFT Portfolios during 2007. In conjunction with capacity from planned compression expansion the alternatives to meet a shortfall in 2007 resulting from delay of the LNG project could include:

- Contracted demand reductions with BCH related to ICP
- Contracted demand reductions with the JV under the existing Peaking Gas Management Agreement or other arrangements
- Advancement of other capital projects

While the alternative employed would depend on the specific nature of the delay and the requirements of the CFT Portfolio, the table below provides one example whereby contracted demand reductions could be used to ensure 32 TJ/d of firm service for Portfolios R, S, W, and X without the LNG facility in 2007. In this table “source” represents the source of the contracted reduction, “extent” represents the capacity that would be available to the customer. Based on forecast demand requirements “duration” represents the number of days that a reduction would be required during the November to March winter period and “energy” represents the total amount of reduction required over the winter.

Source	Extent (TJ/d available)	Duration (days)	Energy (TJ)
JV	17	5	85
ICP	>35	22	110
CFT	>32	5	26

Many other combinations of contracted demand reduction are possible, and up to 40 TJ/d of firm capacity can be provided for the CFT under similar circumstances with full curtailment of ICP. In addition to contracted demand reduction alternatives, alternative capital solutions are also available to mitigate delay of the LNG facility. For example, Appendix 4 of TGVI’s CPCN Application contains alternative capital programs for serving a 45 TJ/d load at Duke Point without reliance on the LNG facility.

## 5. COMPRESSOR PROJECTS

### 5.1. DESIGN CONSIDERATIONS AND RESULTS

The size, in terms of horsepower, and physical location of the facility upgrades on the transmission system affects the incremental system capacity derived from the facility. Extensive computer-aided hydraulic modeling of the transmission system based on the spectrum of possible long term load forecasts has identified the best size and locations for the compression upgrades. As well as satisfying the hydraulic criteria, the location must also satisfy various biophysical and human environmental factors.

The results of the hydraulic analysis indicate that two new compressor stations one located upstream of the town of Squamish (V2) and one in Secret Cove on the Sunshine Coast (V3B) plus a compressor unit addition at TGVI's existing Coquitlam facility (V1), could be required to be in service by November 2007 to meet anticipated system capacity requirements. As well, all cases assume that the existing Texada (V4) compressor station is retained in 2004 and upgraded prior to 2007.

The stations will all be designed to a maximum operating pressure of 2,160 psig (14,893 kPa). A single Solar Taurus 60 gas turbine engine and associated equipment will be installed at V2 and V3B while a single Solar Taurus 70 will be installed at the existing V1 Coquitlam station. The new V2 and V3B compressor stations and V1 addition will be constructed using similar general equipment assemblies and will require similar commissioning activities

All design and construction will be in accordance with TGVI's specifications and comply with the standards of the Pipeline Act of British Columbia and all applicable standards and codes. Typically, the acquired site size is a minimum of 10 acres, with approximately 7 acres requiring clearing. The stations will all be designed for semi-attended operation with unit self-protecting and fail-safe control systems. The stations will be equipped with a gas and fire detection system, as well as an emergency shutdown system both automatic and manual, pressure relief valves, and a common station venting system.

The planning estimates assume that Solar gas fired turbine units will also be used at the new stations in order to be compatible with existing equipment. Table 1 summarizes the various compression horsepower addition and location options:

<b>Location</b>	<b>Equipment</b>	<b>Horsepower Added</b>
Existing V1 Station, Coquitlam	Additional T70 Compressor Unit	10,300
New V2 Station, Squamish	New T60 Compressor	7,800
New V3(b) Station, Secret Cove	New T60 Compressor	7,800
Existing "Temporary" V4 Station, Texada Island	Retention & Infrastructure Upgrades	0

The following map graphically represents TGV1's transmission system and the proposed locations of each of these compressor additions.

Map 1



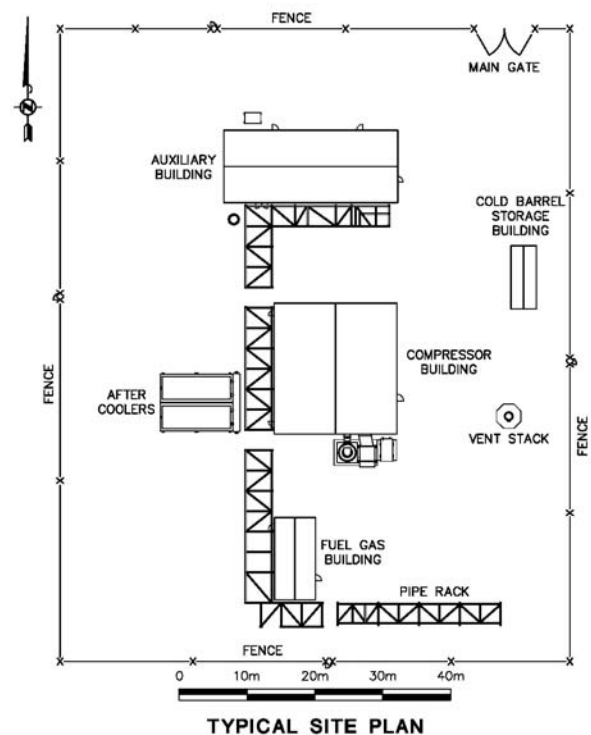
\* The V5 Dunsmuir is not a near-term requirement for any of the portfolios.

### 5.1.1. V1 Coquitlam Compressor Station Upgrade (Km 0, 12" Mainland)

At this existing station a Solar T70 turbine compressor unit is proposed to be added to the existing three units which comprise of two Solar Centaur 50s units and one Solar Taurus 70 unit.

### 5.1.2. V2 Squamish Compressor Station and V3B Secret Cove Compressor Station

The design of these two new compressor stations will be based on designs typical of TGI's existing facilities as illustrated below



A typical compressor station will consist of the following:

- The Compressor Building sized to accommodate the gas turbine and compressor unit.
- The Auxiliary Building will consist of a control room, auxiliary equipment room, storage facilities, washroom and work area. The auxiliary equipment room will house the generator set, the heating boilers and the air compressors.
- The Fuel Gas Building will house the fuel gas filter, heater and regulator modules.
- The Cold Barrel Building will provide dry cold storage of operating fluid barrels.

The typical compressor station's major equipment is as follows:

- One gas turbine driven centrifugal compressor unit

- One station inlet scrubber will remove any liquid or solid particles from the gas stream. Liquids and solids removed by the scrubber will be collected into an atmospheric storage tank and will be trucked off site routinely for recycling by a licensed operator.
- One forced air gas after-cooler to cool hot gas from the discharge of the compressor unit prior to the gas entering the pipeline.
- One fuel gas (natural gas used as fuel by the compressor unit, electrical generators and heating boilers).
- One fuel gas heater to heat the fuel gas to prevent hydrates in the gas from freezing off pressure reduction valves
- Other equipment including, air compressors, air dryers and air receivers to supply and store the compressor station's compressed air requirements, standby generator to supply the compressor station's emergency back-up electrical power requirements, heating boilers to supply the compressor station's process and space heating requirements and other appurtenances.

### **5.1.3. V4 Kiddie Point Station Upgrade**

This existing compressor station has a single Solar T60 compressor unit. No additional compression is required at this site as part of the proposed upgrade. Instead, upgrades relate to creating more permanent facilities to house the skid mounted facilities that currently exist. The majority of cost associated with the V4 station upgrade relates to TGVI's retention of the compressor station through repayment to BCH of the BCH capital funding and relocation of equipment if required as outlined in the Compressor Facility Agreement (CFA) as noted in BCUC Order C-6-01, Item H. Subject to BCH entering into a long term gas transportation service agreement with TGVI for service to the Island Cogeneration Plant, TGVI plans to exercise the station retention on or before the expiry of the CFA on October 31, 2004

## **5.2. REGULATORY REVIEW AND APPROVALS**

Two key agencies regulate the construction and upgrade of compressor stations:

- The British Columbia Utilities Commission (BCUC)
  - An application for a Certificate of Public Convenience and Necessity (CPCN) will be made to the BCUC for the proposed works. The timing and content of such application(s) depends upon the actual loads realized including those resulting from the CFT process
- The British Columbia Oil and Gas Commission (OGC)
  - TGVI will also apply directly to the Oil and Gas Commission (OGC) for a permit covering engineering design and for a Leave to Construct pursuant to the Pipeline Act prior to commencing construction and after all public notices and consultations have been made. As well, TGVI will apply to the OGC for licence of occupation for crown lands and for other provincial agency permits which are managed by the OGC.

The compression facilities do not trigger either a federal or provincial statutory environmental assessment. Several provincial statutes govern typical requirements such as:

- The Waste Management Act for storage and handling of specific materials and for air emissions,
- The Forest Act for authorization to cut trees on crown land

- The Forest Practices Code Act for permits to construct forest roads where required on crown land
- The Heritage Conservation Act for archaeological assessment
- The Water Utility Act for sourcing hydro test water
- The Wildlife Act in regard to harassment and protection of wildlife
- The Land Act regarding site acquisition
- The Pipeline Act regarding design, construction and operation of the compression facilities

Federal statutes that govern typical requirements include:

- The Migratory Birds Convention Act to protect nesting birds

Given the proposed location of the compressor stations discussed in the Lands Approval section following, and the limited environmental impact anticipated at these locations, no significant issues are anticipated under any of the above referenced Acts, with only minor permits required in certain instances which are readily obtainable.

### **5.3. AIR EMISSIONS APPROVALS**

The proposed compressor stations may require air emission permits under section 10 of the Provincial Waste Management Act. Legislative authority to issue air emission permits for such facilities rests with the OGC for Squamish and Secret Cove and with the GVRD for V1 Coquitlam. TGVI plans to use 'dry' low NOx (DLN) technology to minimize emissions. The DLN technology easily achieves permit requirements. Typically, such permits and/or permit modifications take approximately four months to process including any required public consultation, and can be done coincidentally with other planning and construction activities.

### **5.4. LAND ACQUISITION AND APPROVALS (INCLUDING PUBLIC AND FIRST NATIONS CONSULTATION)**

#### ***5.4.1. V1 Coquitlam Compressor Station Upgrade***

No additional property is required to accommodate this addition and relatively minor improvements are needed as a fourth unit was anticipated in the design of the existing third unit compressor building and related works. No specific public or First Nations consultation is required in respect of land rights.

While the typical project schedule as described allows 2 years for project completion, given the existing level of preparation, this project could be accelerated to target completion within one year if necessary, subject to the delivery of the compressor package in that time frame.

#### ***5.4.2. V2 Squamish Compressor Station***

TGVI has located a privately held property in the District of Squamish currently zoned Heavy Industrial located approximately 400 meters north of existing Squamish meter station. The zoning suitability for the proposed compressor station has been confirmed with the District of Squamish. TGVI is in negotiations to purchase the subject property and anticipates completing the purchase agreement in 2004.

No significant issues are anticipated with the site. A public information session will be held when appropriate. First Nations communication process has been initiated, but given the nature of the site, First Nations consultation is not expected to be an issue. Given the location and jurisdiction of the site, no difficulties are anticipated in regard to the public or First Nations.

The location of the proposed site within the District of Squamish is shown below.

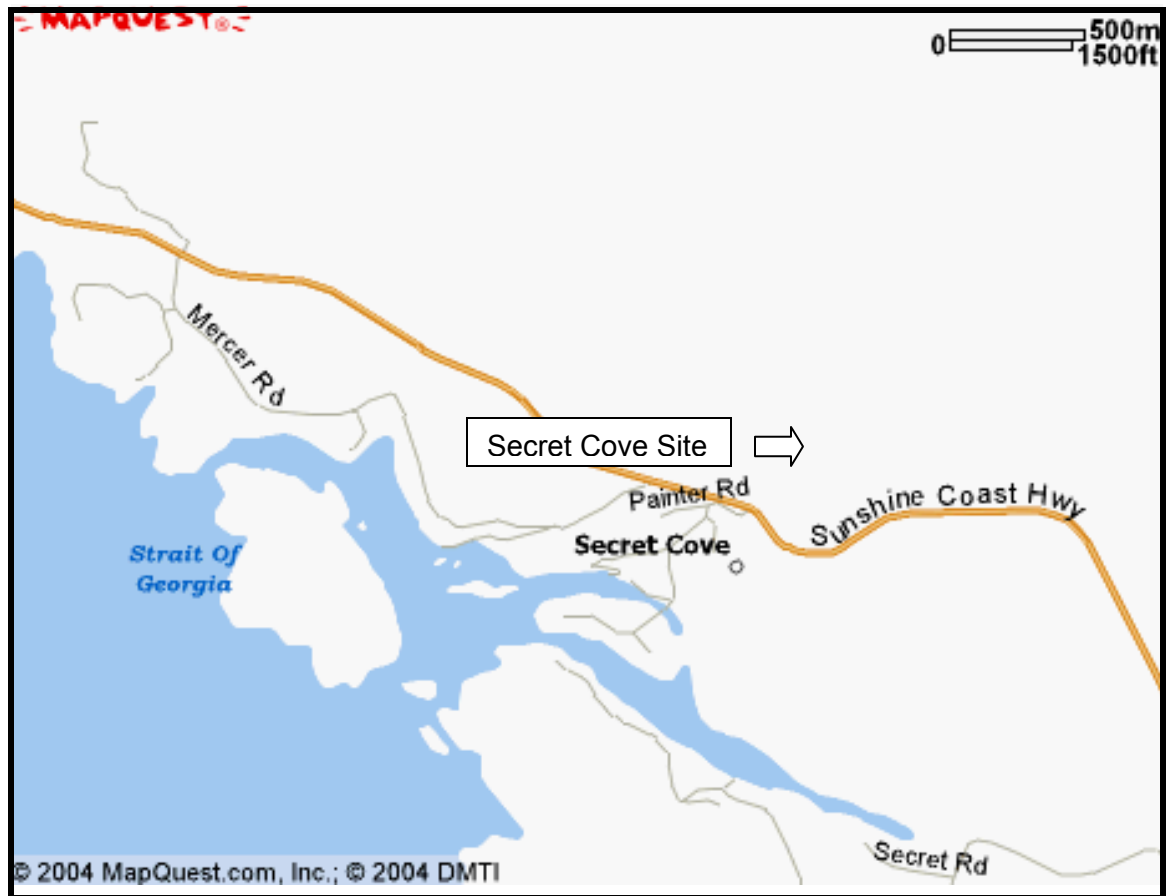


**5.4.3. V3B Secret Cove Compressor Station**

TGVI has held a License of Occupation for a crown land site for the V3B station for a number of years. Through consultation with the Crown, TGVI has initiated the process to convert the License of Occupation into a Crown Grant in order to be able to continue to hold interest in the site. As part of the process, TGVI has confirmed the zoning suitability with the Regional District.

No significant issues are anticipated with the site. First Nations consultation process has been initiated and the Sechelt First Nation has responded favorably, indicating they are ready to engage in consultation and negotiation when TGVI is ready. TGVI is confident an understanding can be reached with the Sechelt First Nation for the construction of the facility.

The location of the proposed site in relation to the community of Secret Cove is shown below.



#### 5.4.4. V4 Kiddie Point Station Upgrade

As this is an existing facility with only minor upgrades required no significant issues are anticipated at this site.

### 5.5. SCHEDULE

Following is a typical schedule for the construction of a new compressor station or the addition of compression at an existing station. In both cases, the timeline to construct these upgrades is two years or less from initial approvals. If required, compressing the timeline may be possible, particularly if the compressor package vendor is able to reduce delivery times. Public consultation, First Nations consultation and commencement of approvals etc. can all commence in the year preceding start of design giving ample time for completion to meet the 2 year design and construction schedule.

Project activities include land acquisition, public consultation, external approvals, detailed engineering design, drawings, equipment purchasing, off-site module fabrication, site preparation, installation, testing and commissioning.

Assessment of CFT Portfolio Requirements
 

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The following table outlines the schedule for design and construction of the compression facilities, site acquisition, public and First Nations consultation are typically undertaken concurrently with these activities. In the case of the subject proposed stations at V1, V2 and V3B, TGV1 either holds the sites or will complete acquisition by late 2004 or early 2005.

<b>Date</b>	<b>Timeline</b>	<b>Activity</b>
Nov. 2004	Earliest Project Start	
Nov. 2005	Latest Project Start	Public, First Nations consultation and regulatory approvals Receive Engineering Bid Packages
	Start + 1 Month	Award Engineering Contract
	Start + 7 Months	Order Compressor Components
Nov. 2006	Start + 12 Months	Issue Construction Drawings for Tender
	Start + 13 Months	Award Construction Contract
	Start + 16 Months	Begin Construction
	Start + 21 Months	Complete Building Construction
		Commissioning
Nov. 2007	Start + 24 Months	Compressor Start Up

## 6. HARMAC LATERAL

### 6.1. ROUTING AND ROW REQUIREMENTS

The proposed lateral follows the existing line to Harmac with only local minor deviations to avoid recent developments and to allow for the crossing of the Nanaimo river. A portion of the existing route can be utilized for all but the last few hundred meters at Harmac where a new 18.3 meter easement is required. Additional easements varying in widths from 6.1 to 12.2 meters will be required supplemented by temporary working space along the abutting sections.

### 6.2. DESIGN CONSIDERATIONS AND RESULTS

Based on the requirements identified in the hydraulic modeling assessment the proposed loop will be an NPS 12 pipeline with a maximum operating pressure of 2160 psig.

### 6.3. REGULATORY REVIEW AND APPROVALS

The proposed looping project involves the same two agencies as the compressor stations, the BCUC and OGC, and many of the same approvals and/or aspects as defined in Section 5. In addition to the provincial statutes identified as governing compressor stations, the following additional statutes may also apply to the pipeline:

- Agricultural Land Commission Act for construction on agricultural land
- Fish Protection Act for water crossings
- Water Act for work in an about a stream

In addition to the federal statutes identified as governing compressor stations, the following additional statutes will also apply to the pipeline:

- Fisheries Act for protection of fish and fish habitat
- Navigable Waters Protection Act for water crossings
- Canadian Environmental Assessment Act (CEAA) for screening review

Characteristics of the project are such that the CEAA involvement would only be a low level "screening" that would be part of the Department of Fisheries and Oceans contribution under the Fisheries Act. Approximately 3 to 4 months are anticipated for field studies followed by approximately 5 months for the CEAA review process.

Given the project is a loop of the existing lateral with limited environmental impact anticipated along the route, no significant issues are anticipated under any of the above referenced Acts.

### 6.4. LAND ACQUISITION AND APPROVALS (INCLUDING PUBLIC FIRST NATIONS CONSULTATION)

TGVI has good relationships with landowners along the existing right of way and no significant land acquisition issues are anticipated. While no specific public information session or consultation with the Snuneymuxw First Nations with respect to the pipeline loop has been initiated, no difficulties are anticipated. TGVI is confident that agreement can be reached with the Snuneymuxw and landowners for the construction of this pipeline loop.

## 6.5. SCHEDULE

A typical schedule for the construction of the Harmac Lateral along the existing route is provided below. The Snuneymuxw First Nations and public consultation as well as the work toward various approvals would start in advance of actual detailed field routing and the environmental studies required for this linear project.

Key project activities include land acquisition, public and First Nations consultations, regulatory agency approvals, material procurement and the tendering, installation, testing and commissioning of the pipeline and related appurtenances.

The following table outlines the schedule for the key activities involved in the pipeline portion of the project:

<b>Date</b>	<b>Timeline</b>	<b>Activity</b>
Nov/04	Earliest Project Start	
Mar/05	Latest Project Start	Public and First Nations consultations Start Landowner contacts, detailed routing and right of way "footprint"
	Start + 1 month	Start field environmental & archaeological studies including CEAA Scoping
	Start + 2 months	Start preliminary engineering (river crossings)
	Start + 4 months	Start OGC Application process
	Start + 8 months	Start detailed engineering
Jan/06	Start + 10 months	Order Major materials
	Start + 12 months	Start ROW Clearing tendering process
	Start + 15 months	Begin ROW Clearing
		Start pipeline construction tendering process
	Start + 16 months	Begin pipeline construction
	Start + 20 months	Complete construction
Start + 21 months	Commissioning and start-up	