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September 11, 2009

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Terasen Gas Inc. ("Terasen Gas")
2010 and 2011 Revenue Requirements and Delivery Rates Application

Response to the British Columbia Utilities Commission ("BCUC" or the "Commission") Information Request ("IR") No. 2

On June 15, 2009, Terasen Gas filed the Application as referenced above. In accordance with Commission Order No. G-89-09 setting out the Regulatory Timetable for the Application, Terasen Gas respectfully submits the attached response to BCUC IR No. 2.

If there are any questions regarding the attached, please contact the undersigned.

Yours very truly,

TERASEN GAS INC.

Original signed:

Tom A. Loski

Attachment

cc (e-mail only): Registered Parties

1.0 Reference: Customer Related Activities

Exhibit B-1, Part III, Section B, Tab 1, pp. 122-124

Customer and Business Facilitation

"Operating Agreements – Terasen Gas signed and had approved 10 interior operating agreements…"

1.1 Provide the number of approved operating agreements by year for 2005-2009 and the forecast number of approved operating agreements by year for 2010-2011.

Response:

During the PBR Period TGI had a total of 13 Operating Agreements approved.[1] Twelve of these were approved in 2006 and one was approved in 2007. The Company anticipates that six will be approved in 2010 and another 4 in 2011.

Under our current Shared Services agreement with TGVI, resources are required to develop and enter into new operating agreements in the TGVI service territory, many of which will expire in 2011.

Notwithstanding the operating agreements that are coming up for renewal, we need to engage with municipalities with which we already have agreements in place to maintain a shared understanding of our agreements.

Maintaining a high level of engagement and interaction with all of our municipalities is critical to preserving our energy delivery service capacity and supporting the efforts of our energy marketing and business development initiatives.

"Community Involvement – Terasen Gas believes it is important to be active in the community, give back to the customers in whose back yards we operate, and have an opportunity for person to person contact with our customers."

[1] As per Page 123 of the Application - Operating Agreements – Terasen Gas signed and had approved 10 interior operating agreements with support from the UBCM, an operating agreement with Westbank First Nation, a Lease In Lease Out ("LILO") agreement with Creston and approved operating terms with Chetwynd.

1.2 Please provide the cost of the TGI community involvement projects for 2008-2011 by year and activity (Corporate Giving, Community Projects, Involvement with Local Government and Other).

Response:

In 2008 Terasen Gas spent $448,184 on Community Involvement. The spending by activity for this year was as follows:

Terasen Volunteers & Employee Give Where You Live Program Donations	- $151,220
Community Investment projects	- $75,574
Local Community Event and Program Sponsorships	-$221,390

In 2009, 2010 & 2011 Terasen Gas forecasts to spend $426,000 in each calendar year on Community Involvement. The Budget Forecast for each of these years is as follows:

Terasen Volunteers & Employee Give Where You Live Program Donations-	$200,000
Community Investment Projects -	$60,000
Local Community Event and Program Sponsorships -	$166,000

Year to date ending July, 2009, Terasen Gas has invested $299,089 on Community Involvement.

Event and sponsorship program investment focus varies from year to year, and aligns our capacity with community events, initiatives and priorities. Our considered support is directed to local government, first nations, non-government organizations, etc. whose leadership is an integral part of the local community sustainability in our service territory.

In 2008 we renewed our focus on employee engagement recognizing person time contributions to community growth in terms of donated time and personal financial contributions. The alignment of our community programs with employee volunteer recognition provides a foundation upon which Terasen Gas can both support and assist their engagement – the result is an incremental impact on the communities we serve.

As a point of comparison (as outlined in the response to BCUC 2.13.3), published BC Hydro contributions for sponsorships and donations were significantly higher.

"Other - TGI kids strategy (presentations in schools around the Lower Mainland), Crosswalk kids program (schools within 200 metres of transmission ROW), Leadership BC Founding sponsor, BC Chamber of Commerce, Municipal Chamber of Commerce involvement, Business excellence awards, Luncheon attendance, Fraser Valley Cultural Diversity Awards, Anmore Day, Belcarra Day , World Rivers Day sponsor, Piper Spit Boardwalk project, Hat's Off…"

1.3 Please provide the cost and number TGI kids strategy and Crosswalk kids program presentations by year for 2005-2011.

Response:

The Terasen "Kids Strategy" which includes the crosswalk program was introduced in 2006. The budget for the program is $15,000 per year.

- 2006/07 school year - 45 presentations & approximately 2,500 students received the presentation
- 2007/08 school year - 33 presentations & approximately 1,500 students received the presentation
- 2008/09 school year - 16 presentations to date & approximately 700 students received the presentation

Forecast for 2010 and 2011 – 33 presentations per year reaching approximately 1,500 students per year.

2.0 Reference: Customer Related Activities

Exhibit B-1, Part III, Section B, Tab 1, p. 124

Customer and Business Facilitation

"Terasen Gas is now on over 12 separate ministry led committees relating to various energy policy actions. Terasen Gas has also met with Ministers, Deputy Ministers and staff in order to educate the government on Terasen Gas's business, and advocating for how the Company can play a role in meeting provincial energy objectives."

2.1 Please provide the 2008-2011 costs by year of participating in ministry committees, educating the government on TGI's business, and advocating for how the Company can play a role in meeting provincial energy objectives.

Response:

TGI does not track time spent by the numerous staff that have involvement in ministry led committees. Reporting at this level of detail is far more granular than the O&M reporting requirements that were determined to be appropriate by the Commission in Order No. G- 153-07, wherein the New Code of Accounts for O&M reporting was approved. As such, the Company is unable to provide annual costs related to this activity. However, TGI estimates that in each of the years the amount of effort on these activities is in excess of 1 person years.

Primarily these committees relate to energy efficiency or energy usage and codes and standards. These committees change regularly and, in addition, the time spent on these committees depends upon the nature of the committee and the committees requirements. TGI makes decisions on committee involvement based upon the type of committee and the potential benefit to TGI customers.

TGI meets with Ministers, Deputy Ministers and government staff both to keep the government apprised of TGI activities as well as for specific activities to support customers demands. For example, TGI may meet with a Ministerial department regarding a LNG truck pilot. Often these meetings are driven by government policy direction and TGI's determination of how these policies may affect TGI's ability to provide service to customers. As such the number of meetings, the TGI staff involved in meetings and the time required for the meetings is not known for the period of the RRA.

2.2 Does the shareholder benefit from TGI's involvement in ministry committees, the education of the government on TGI's business, and TGI advocating for how the Company can play a role in meeting provincial energy objectives? Please discuss.

Response:

Under rate base rate of return regulation, which is the regulatory regime followed in British Columbia, the public utility is to be afforded the opportunity to earn a fair return on its investment in utility assets. This has been acknowledged by the Commission in its March 2, 2006 Decision relating to TGI and TGVI, and elsewhere. TGI and its shareholders receive no mark-up or profit on TGI's expenditures relating to discussions with ministry committees, etc.

The costs associated with discussions with ministries are legitimate costs of operating the utility to serve customers. By being involved with ministry committees and advocating for TGI customers, TGI stays abreast of government policies and changes that may occur, is able to advocate for the right fuel choice and also educates the members of the committees. In a sense this is no different than TGI's sales efforts with developers and customers. Steps directed at encouraging the use of natural gas in the right applications, whether the steps are targeted at government, developers or customers, help to maintain lower delivery costs for customers. Lower delivery costs relative to energy alternatives will help to sustain the Company in the long-term and thereby assisting it in achieving a return on investment that is fair (i.e. fair to both the Company and customers).

2.2.1 How should these benefits and costs be shared between customers and shareholders?

Response:

Please see the response to BCUC IR 2.2.2.

3.0 Reference: Customer Driven Capital

Exhibit B-1, Part III, Section B, Tab 1, pp. 182-183

Installation Crew Configuration

3.1 Please update Table B-1-28: Mains Activity Levels and Cost for the PBR Period to include forecast 2010 and 2011.

Response:

Listed below are mains activity levels and costs for the PBR period as well as a forecast of 2010 and 2011 mains activities and costs:

	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Projection	2010 Forecast	2011 Forecast
Activities (metres)	121,570	156,604	174,003	164,550	157,004	200,167	115,305	105,504	110,213
Workforce:									
Terasen (%)	57%	41%	36%	26%	14%	13%	70%	70%	70%
Contractors (%)	43%	59%	64%	74%	86%	87%	30%	30%	30%
Terasen ($/m)	38	34	44	35	66	66	86	87	89
Contractor ($/m)	30	33	38	51	48	52	55	57	59
Unit Costs ($/metre)	34	33	40	47	51	54	$ 77	$ 79	$ 80
CIACs ($/m)	n/a	0	(4)	(2)	(1)	(1)	(1)	(1)	(1)
Net Combined ($/m)	34	33	36	45	50	53	76	78	79
Expenditures ($millions) (excluding CIAC's)	$4.2	$5.3	$7.4	$8.1	$8.1	$11.0	$ 8.9	$ 8.3	$ 8.8

"In 2007, in response to increasing retirements and demographic challenges within our core/emergency internal workforce footprint, Terasen Gas increased its typical Lower Mainland install crew configuration from 3 to 4 by adding an apprentice."

3.2 Please complete the table below.

2005- 2011 Installation crews

	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Projected 2009	Forecast 2010	Forecast 2011
Avg. Lower Mainland Installation Crew Size							
Avg. Interior Installation Crew Size							
Number of Lower Mainland Installation Crews							
Number of Interior Installation Crews							
Total Number of Lower Mainland Installation Crew Members							
Total Number of Interior Installation Crew Members							
Total Lower Mainland Installation Crew Cost							
Total Interior Installation Crew Cost							

Response:

Distribution is organized to maximize synergies between installation activities, emergency response and operations and maintenance. Employees with "Installation" skill sets listed in the table below are not exclusively assigned to crews. They are also utilized for operations and maintenance activities. Maintaining a roster of multi-tasking employees allows Distribution to efficiently respond to the ups and downs and seasonal variability of work. The crew compliment noted below draws its resources from the pool of employees with "Installation" skill sets (i.e. the rows labeled "Total Number of Installation Crew Members").

	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Projection	2010 Forecast	2011 Forecast
Avg Lower Mainland Installation Crew Size	3	3	4	4	4	4	4
Avg Interior Installation Crew Size	3	3	3	4	4	4	4
Number of Lower Mainland Installation Crews	23	22	22	23	25	24	24
Number of Interior Installation Crews	5	6	6	7	7	7	7
* Total Number of Lower Mainland Installation Crew Members	99	90	98	107	116	114	114
** Total Number of Interior Installation Crew Members	35	34	36	39	39	43	43
Total Lower Mainland Installation Crew Loaded Cost + Vehicle & Backhoe	$188/hr	$191/hr	$249/hr	$263/hr	$274/hr	$295/hr	$310/hr
Total Interior Installation Crew Loaded Cost + Vehicle & Backhoe	$199/hr	$206/hr	$202/hr	$265hr	$274/hr	$285/hr	$301/hr

Notes:

* Multiplying the average Lower Mainland crew size by the number of crews does not equate to the total number of Crew members. A larger pool of employees with installation skill sets is required due to periodic employee non-availability for reasons such as vacation, classroom training, temporary assignments, and to maintain a multi-tasking workforce.

** The comment above applies to the Interior as well. In addition, there are a number of 2-man crews intermittently utilized in the Interior typically in smaller towns. Two-man crews are not included in the above analysis.

4.0 Reference: Customer Driven Capital

Exhibit B-1, Part III, Section B, Tab 1, p. 185

Services

4.1 Please update Table B-1-29: TGI Services/Service Header Mains 2003-2009 to include forecast 2010 and 2011.

Response:

Listed below are service activity levels and costs for the PBR Period as well as a forecast of 2010 and 2011 service activities and costs:

	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Projected	2010 Forecast	2011 Forecast
Net Customer Additions	5,546	11,504	12,420	10,101	9,939	9,256	6,120	5,600	5,850
Gross Customer Additions	12,837	15,549	12,770	13,338	15,533	14,566	9,600	8,784	9,176
Ratio of Service Additions to Gross Customer Additions	0.83	0.85	0.97	0.93	0.70	0.72	0.78	0.78	0.78
Activities:									
Service (risers)	10,697	13,201	12,401	12,525	10,935	10,520	7,510	6,872	7,178
Service Header Mains (metres)	29,082	49,275	48,480	57,360	41,937	48,041	34,589	31,821	33,100
Workforce:									
Services - Terasen (%)	81	68	59	51	57	62	90	90	90
Services - Contractors (%)	19	32	41	49	43	38	10	10	10
Service Headers Main - Terasen (%)	77	45	37	26	18	21	60	60	60
Service Headers Main - Contractor (%)	23	55	63	74	82	79	40	40	40
Unit Costs:									
Services	818	842	944	1,057	1,318	1,410	1,650	1,662	1,736
Service Header Main	51	45	59	55	64	67	76	77	77
All Services $/Service	958	1,008	1,175	1,310	1,562	1,709	2,000	2,014	2,105
CIAC $/Service	-309	-321	-349	-367	-387	-428	-412	146	-84
*Net Combined Unit Cost $/Service	658	687	826	942	1,174	1,281	1,588	2,160	2,021
Expenditures ($millions)									
Services	8.7	11.1	11.7	13.3	14.4	14.8	12.4	11.4	12.6
Services and Vertical Header Mains	1.5	2.2	2.9	3.1	2.7	3.2	2.6	2.4	2.5
Total (Pre-CIACs)	10.2	13.3	14.6	16.4	17.1	18.0	15.0	13.8	15.1
CIACs Services	(3.3)	(4.2)	(4.3)	(4.6)	(4.2)	(4.5)	(3.1)	1.0	(0.6)
Total (After CIACs)	*6.9*	*9.1*	*10.3*	11.8	12.9	13.5	11.9	14.8	14.5

Note 1: In table B-1-29 originally filed in the Application, "**Total (After CIACs)**" in the "**Expenditures**" section was incorrectly stated for 2003-2005. The table above has the corrected numbers.

Note 2: **CIAC Services**: Contributions of $1.0 and ($0.7) million in 2010 and 2011 are anticipated to be lower than the average contributions of $4.2 million over the 2003 – 2008 period due to the elimination of the Service Line Installation Fee (SLIF) in 2008 as per Commission Order G-152-07. Due to the PBR extension for 2008 - 2009, recognition of the SLIF elimination was deferred to 2010 resulting in an understatement of CIAC in 2010 (refer page 467 of the Application). Although we did not charge SLIF to customers (in 2008-2009) we reported in 2008 and 2009 as if we had imposed the charge. This was reversed in 2010 resulting in a negative contribution.

5.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Exhibit B-1, Part III, Section C, Tab 3, p. 229

2011 Energy Efficiency and Conservation Programs ("2011 EEC Programs")

"As noted, Terasen Gas wishes to extend to 2011 the programs approved by the Commission in Order No. G-36-09 for the three year period 2008-2010. The expenditures for 2011 are set to match the forecast expenditures for 2010."

5.1 For each of the programs approved Commission in Order No. G-36-09, please provide a schedule comparing the forecast and actual costs, participants, savings and TRC benefits for 2008-2009.

Response:

Commission Order G-36-09 was issued in April 2009, therefore there are no programs approved in Commission Order No. G-36-09 that were in effect in 2008. In the time between the issuance of the Order and now, TGI has been focused on staffing up the EEC department in order to have the necessary resources needed to commence planning and implementation of the programs approved in the Order. TGI's EEC team is now in place and the implementation of the programs approved in the order is just underway. Forecast and actual costs, participants, savings and benefits for programs approved in Order G-36-09 2008/2009 will be available once the implementation process is complete.

6.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Exhibit B-1, Part III, Section C, Tab 3, p. 229

TGI and TGVI Energy Efficiency and Conservation Application Decision ("EEC Decision"), p. 21

TGI and TGVI Energy Efficiency and Conservation Application ("EEC Application"), Appendix 8, pp. 1 & 6

Conservation Education and Outreach ("CEO") Expenditures

"Terasen is directed to review the CEO program with a view to:

- altering the program to allocate funds away from the mass media campaign and to include other initiatives, with particular attention paid to conservation education within the school system and affordable housing initiatives;
- addressing the apparent imbalance of the residential to commercial expenditure ratio, approximately 30:70, in comparison to the ratio of residential to commercial Achievable Potential GJ impact of approximately 77:23 (Exhibit B-1, p. 45);
- reconsidering the apparent lack of communication expenditures directed in a focused manner to the Commercial Energy Efficiency program,
- reconsidering appropriate attribution of CEO costs to Program Areas and initiatives, and any related impact on Total Resource Cost calculations and rate impacts." (EEC Decision, p. 21)

6.1 Please explain how the proposed 2011 Residential and Commercial CEO expenditures address the CEO directives in the EEC Decision.

<u>Response:</u>

The CEO programs approved in Order No. G-36-09 are currently under development. It is the Company's full intent in developing these programs to comply with the directives regarding expenditure ratios in the Order.

"Connection Planning involves developing a deep understanding of how to best deliver a consistent message amongst the target audience through the strategic deployment of multiple tactics. These tactics may include (but are not limited to):

• Mass Media Advertising (Including online)

• Social Media (Blogs, Social Networks, Social Bookmarking)

• Public Relations

• Events

• Field Team Activities

• Promotions

• Corporate Partnerships

• Website

• Internal Employee Communications"   (EEC Application, Appendix 8, p. 1)

Conservation Education and Outreach

Year One

Element		**Budget**
1.4.1 Research		
	Consumer Research	$75,000.00
	Creative and Message Testing	$70,000.00
	Tracking and Analysis	$150,000.00
	Subtotal	$295,000.00
1.4.2 Mass Media Advertising		
	Television	$1,300,000.00
	Magazine	$250,000.00
	Newspaper	$1,250,000.00
	Radio	$800,000.00
	Online	$85,000.00
	Subtotal	$3,685,000.00
1.4.3 Events		
	Development and Execution	$350,000.00
	Subtotal	$350,000.00
1.4.4 PR		
	Monitoring / Management	$100,000.00
	Subtotal	$100,000.00
1.4.5 Website		
	Design & Development	$200,000.00
	Subtotal	$200,000.00
1.4.6 Internal Launch		
	Materials/Event	$150,000.00
	Subtotal	$150,000.00
1.4.7 Mass Media Production		
	Television (2 Spots)	$350,000.00
	Photography	$25,000.00
	Print (3 Ads)	$25,000.00
	Radio (2 Spots)	$15,000.00
	Online (2 Ads)	$50,000.00
	Subtotal	$465,000.00
TOTAL		$5,245,000.00

6.2 Please provide a breakdown of the proposed $1.445 million for Residential CEO expenditures by program by tactic, element (Research, Mass Media Advertising) and activity (Consumer Research, Television).

Response:

Please see the response to BCUC IR 2.6.1 above. These programs are currently under development, and we expect to start launching them by the end of this year. Further detail will be available once we do so. It should be noted, however, that in accordance with Order No. G-36-09, the Company is not pursuing a mass media strategy in this program area that would incorporate Television.

6.3 Please provide a breakdown of the proposed $1.445 million for Commercial CEO expenditures by program by tactic, element (Research, Mass Media Advertising) and activity (Consumer Research, Television).

Response:

This question is the same as BCUC IR 2.6.2. Please see the responses to BCUC IR 2.6.1 and 2.6.2 above.

6.4 For each Residential and Commercial CEO program, provide a brief description of the program, the objective of the program and breakdown of the program costs by tactic, element (Research, Mass Media Advertising) and activity (Consumer Research, Television).

Response:

Please see the responses to BCUC IR 2.6.1 and 2.6.2.

7.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Exhibit B-1, Part III, Section C, Tab 3, p. 242

Hydrogen Fuel Cell Demonstration Fleet, http://www.bctransit.com/fuelcell/

Natural Gas Vehicles ("NGV") Rate Offerings

"Currently, natural gas compression and refueling service is available at 14 public stations in the Lower Mainland, in additional there are private stations owned by business and municipalities." (Exhibit B-1, Part III, Section C, Tab 3, p. 242)

"BC Transit is leading the way in adopting new technologies that support sustainable practices and reduce greenhouse gas emissions. From introducing North America's first low-floor conventional and double-deck buses, to using biodiesel and hybrid technology within its fleet, BC Transit will deliver the world's first demonstration fleet of hydrogen fuel cell powered buses operating in a single location." http://www.bctransit.com/fuelcell/

7.1 Please provide the number of compression and refueling stations from 2003-2008.

Response:

The following table shows the number of compression and fuelling stations in BC by year. The table also includes privately owned stations as well.

2003	2004	2005	2006	2007	2008	2009
47	44	37	30	28	21	21

Most of the compression and refueling stations are owned by Clean Energy and the decline from 2003 to 2009 is explained by Clean Energy's focus on the California market (please see the response to BCUC IR 1.34.7). We believe additional market opportunities for NGV exists in BC.

7.2 Please provide the in-service date, the forecast cost and actual cost of the most recent compression and refueling station installation.

Response:

Most recent station: Kelowna School District

In service date: May 2009

Forecast Cost: $300,000

Actual Cost: $281,666

For the most recent CNG station, the Kelowna School District ("KSD") expressed interest in natural gas as alternative to diesel for their school bus fleet, and then subsequently bought a natural gas powered bus. TGI was planning to purchase a compressor package for its own Fraser Valley office (FV) to replace the compressor package currently provided by Clean Energy under a service contract until Q1 2010. As an opportunity presented itself to showcase and pilot an NGV compression facility for the KSD, TGI purchased a compression package slated for the FV a year early.

The current arrangement with KSD is that they are being charged for NGV service under Rate Schedule 6 with the requirement that a compression charge will be applied if TGI is granted approval in this proceeding to offer a compression and refueling service. This pilot will run until May 2010 at which point the project will be subjected to an economic test (CS Test) and, if it does not yield a PI of 1.0 or greater or the customer is not willing to agree to a Contribution in Aid of Installation, then the station will be moved to the TGI's FV site where it will replace the CNG package currently provided under contract by Clean Energy. TGI would then size and install the compressor for the KSD yard to meet the CS Test of 1 or above. If for some reason approval for compression is not received in this proceeding, TGI would apply for a tariff supplement to serve this customer so that it could begin to recover the cost from the KSD, i.e. the customer receiving the service on an ongoing basis.

TGI customers are not bearing any risk associated with the installation of the compression facility at Kelowna. The KSD had an immediate need for a compression facility as they had already ordered NGV vehicles. Due to the timing of the revenue requirement application, TGI did not yet have a compression offering available for the customer, but did not want to loose any momentum in the NGV market. To ensure that the customer was able to use their newly acquired NGV's, TGI agreed to install a compressor on the KSD facility on a pilot basis in order to allow KSD to break in its NGV technology equipment. TGI also understands that the Ministry of Education will be purchasing additional buses to test NGV technology using the KSD compressor. As a consequence, it is apparent demand exists to support the compression service.

As noted above, assuming approval is given, TGI will begin charging the customer in 2010 for compression service. Existing TGI customers do not bear any financial risk associated with the installation of the compression facilities in 2009 as the asset is in work in progress attracting AFUDC and has therefore not been included in rate base. In 2010, TGI will be charging KDS for the compression service associated with the asset, or removing the asset and moving to the FV office which will result in cost savings to existing customers of approximately $9000 compared with the CE contract.

7.3 Please provide BC Transit's NGV consumption by year for 2003-2008

Response:

BC Transit (now Translink) utilizes a NGV station in Port Coquitlam. The NGV consumption for this station is presented below.

2002	2003	2004	2005	2006	2007	2008	2009 (YTD)
102,000 Gjs	102,000 Gjs	102,000 Gjs	1,845 Gjs	52,521 Gjs	170,913 Gjs	156,497 Gjs	77,264 Gjs

7.4 Is NGV in competition with the Hydrogen Highway?

Response:

Public perception is that the Hydrogen Highway will compete with both traditional fuels such as gasoline and diesel as well as alternative fuels such as electricity and natural gas. However, the Hydrogen Highway is not a realistic competitive threat and won't be for at least 10-20 years given that the technology is still in its infancy compared to any of the other energy forms.

At present hydrogen is only used in "demonstration projects" because there are major challenges regarding availability, cost and technical performance. Progress on developing markets for hydrogen vehicles has been slow. In contrast, natural gas is a viable alternative for commercial applications today and is price competitive with commonly used fossil fuels like gasoline and diesel. TGI believes that compressed natural gas is a price competitive solution that will lower operating costs and greenhouse gas emissions and save vehicle operating costs.

8.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Exhibit B-1, Part III, Section C, Tab 3, p. 247

Utility System Extension Test Guidelines,

Commission Orders G-126-05 and G-152-07

Natural Gas Vehicles ("NGV") Rate Offerings

"The CS Test, similar to the MX Test, is a twenty year discounted cash flow analysis which compares the present value ("PV") of cash inflows to the PV of the cash outflows from a proposed investment in compression and refueling equipment."

Table C-3-9: CS Test Parameters

Parameter Name	TGI 2009 MX Test Parameters	Proposed CS Test Parameters	Comments for CS Test Parameters
Application Fee - New	$85	Case-specific	Not applicable if gas service received through Rate Schedule 6. Applicable to all other rate schedules to measure volume through compression equipment.
Application Fee - Existing	$25	N/A	Not applicable.
Change of Service Frequency	5	N/A	Not applicable.
Overhead Rate	32.00%	Case-specific	Based on cost of compression equipment.
CCA Class 1	6.00%	20.00%	NGV compression and fueling equiment are Class 8.
Project Life	20	20	Same
Discount Rate	4.20%	4.20%	Same
Fixed SI	N/A	N/A	Same. Not applicable.
Variable SI	$0.16	N/A	Not applicable. Included in MX Test for other rate schedules (i.e. Rate Schedule 6).
Income Tax Rate	30.00%	30.00%	Same
Income Tax Surcharge	N/A	N/A	Same. Not applicable.
Property Tax Rate	1.85%	N/A	Not applicable. Compression equipment similar to station.
Working Capital Rate	0.50%	0.50%	Same
Demand Charge	Rate dependant	N/A	Not applicable.
Fixed O&M	Rate dependant	Case-specific	Based on the model/size of compression equipment
Variable O&M	N/A	N/A	Same. Not applicable.
In Lieu Rate	Rate dependant	N/A	Not applicable. NGV revenues are exempt from property tax.
Fixed Margin	Rate dependant	N/A	Not applicable.
Variable Charge	Rate dependant	5.00 $	Propose $5.00/GJ Compression Rate

8.1 The Commission has reviewed the MX Test methodology, parameters and inputs in various proceedings (Utility System Extension Test Guidelines, Orders G-126-05 and G-152-07). Please discuss the review process that TGI considers appropriate for the review of the CS Test methodology, parameters and inputs.

Response:

TGI is proposing the CS Test in this Application (see page 246) and, accordingly, the initial review of the CS Test is within this proceeding. It appears that a reference to the requested approval for this economic test was inadvertently excluded from section D of the Application where the requested relief is summarized. Item 12(iv) on p.516 should thus be amended to read as follows:

> *"iv. Economic models for evaluating alternative energy extensions for* ***Natural Gas Vehicle service (the 'CS Test')****, geo-exchange, solar thermal and district energy systems, and establishing the regulatory review processes, as set out in Part III, Section C, Tab 3 of the Application." [Emphasis added.]*

As the CS Test contains a wide variety of parameters of which some are common to both the MX Test and CS Test, TGI would anticipate that the Commission will update its review of the CS Test the next time the MX Test is reviewed.

8.2 Please compare the MX Test and CS Test overhead rate methodologies and explain why the CS Test overhead rate is case-specific. Provide a numerical example of a CS Test overhead calculation.

Response:

A customer who applies for natural gas service and compression and refueling service will be assessed under the MX Test and the CS Test.

Each application for natural gas vehicle service will be assessed under the MX Test which includes the service installation up to and including the gas meter. In the MX Test, the Overhead Rate parameter is applied to the capital cost to cover overhead costs associated with operating the business, but which cannot be attributed to specific customers or activities. Examples include the indirect Company costs such as materials procurement, facilities, sales, finance, and administrative support associated with planning and installing main extensions. The Overhead Rate in the MX Test is currently 32% and was also presented in the TGI - TGVI 2008 Main Extension Report Update (dated April 7, 2008).

Each application for compression and refueling service will be assessed under the CS Test which includes the compression and refueling equipment (meter to dispenser). In the CS Test, the proposed Overhead Rate differs from the MX Test because we expect the indirect Company costs for procuring and installing compression and refueling equipment to be a lower cost than for main extensions. The compression and refueling equipment will be purchased and installed as a finished package resulting in less internal resources being required. Since the Company anticipates installing different sizes and models of compression and refueling equipment, we are proposing a project specific Overhead Rate for the CS Test.

A numerical example of a CS Test Overhead Rate is presented below:

Example Customer Operation

- 40 Lift Trucks – Materials Handling Application
- 25,000 GJ consumption

Capital

- $350,000 (Actual Supplier Quote (IMW 50))
- Turnkey scope – Contractor connects into a Terasen Gas meter specific for NGV and installs compression and dispensing equipment to meet defined performance standard.

TGI proposes to use an overhead allowance of 5% in the CS Test. For a site specific $350,000 compression and refueling station, this equates to $17,500 being added to the test. Based on the potential growth that TGI noted in response to BCUC IR 2.68.2 of $13 million to 2013 (or approximately $4.3 million potential growth per year). This equates to potential overhead allowances of $215 thousand per year if TGI were to meet total potential opportunities. This is greater than the funding request for NGV staff made in this application.

As the CNG business grows and the Company gains experience, the indirect costs will be monitored to determine if this rate should be adjusted.

8.3 Please explain why the CS Test and MX Test have the same project life of 20 years.

Response:

TGI believes that a 20 year project life is a reasonable and conservative time period to use for a main extension. When TGI implemented the DCF MX Test in 1994 a 50-yr project life was requested but a 33-yr life was approved. Several years later (in 1996) the generic system extension review took place and the amendments to the MX Test were implemented in 1997, implementing a 20-yr project life. For main extensions the discounted cash flow test was approved under Commission Order G-104-96. The Project Life parameter of 20 years was approved by the Commission and was also presented in the TGI - TGVI 2008 Main Extension Report Update (dated April 7, 2008).

However, even though the MX test and the CS test share a project life of 20 years, there are several key differences. For the compression and refueling service, the Project Life parameter of 20 years is proposed for two main reasons. First, the CS Test load input is based on one customer and their specific needs. This situation leads to a significantly more conservative result, as opposed to a main extension which serves multiple customers with varying needs from the same main. Second, unlike a main that once installed cannot be moved, compression equipment can be moved and redeployed to another location should the customer terminate its contract. The effect of this is that a compressor will be fully optimized for the life of an asset. Therefore TGI believes that it should use the service life of the compression equipment as the project life. The equipment life is estimated to be 20 years based on manufacturer's claims under normal consumption and maintenance conditions.

8.4 Given the uncertainty associated with NGV loads, please explain why the CS Test has the same discount rate as the MX Test. Should the CS Test include a risk premium in addition to the MX Test discount rate?

Response:

With any forecast load, whether is it in the MX Test or the CS Test, we recognize that there is uncertainty. However, the forecast load in the CS Test will have a higher level of accuracy (or less uncertainty) than the MX Test (please see the response to BCUC IR 2.9.2).

For the CS Test we propose the same Discount Rate as in the MX Test to reflect the capital structure of the Company and the relative borrowing costs and allowed ROE. In the MX Test the Discount Rate is used to calculate the net present value of the cash inflows and outflows in the main extension test. The discount rate reflects the capital structure of the Company and the relative borrowing costs and allowed ROE. The discount rate is determined by calculating the cost of capital on a real basis (removing inflation) and after taxes. Several inputs (tax rate, inflation rate, capital structure and the associated interest rates) are required. The Discount Rate in the MX Test is currently 4.2%.

We are proposing to offer the Compression and Refuelling service under TGI and propose the Discount Rate in the CS Test be the same as the MX Test.

The discount rate would therefore be the same regardless of the product offered as the product offering is from the same company. We do not believe that it is reasonable for every different project, or type of service offered, to have a different discount rate. From a Company aspect, we do not believe the offering of a compression and refueling service will increase risk to existing customers on an overall basis. A risk premium could result in new compression customers subsidizing existing customers which TGI believes is not appropriate. Existing customers will already benefit from the addition of NGV load to the system, thereby reducing potential future rate increases. Therefore, we do not believe that it is appropriate for the CS Test to include a risk premium in addition to the MX Test Discount Rate.

8.5 Please compare the MX Test and CS Test Fixed O&M charge methodologies and explain why the CS Test Fixed O&M charge is case-specific. Provide a numerical example of a Fixed O&M charge calculation.

Response:

In the MX Test the Fixed O&M parameter is rate dependent because of varying maintenance programs for different types of services (i.e. leak survey requirements) and different sizes of meters (i.e. meter maintenance).

In the CS Test we are proposing a Fixed O&M parameter which is project specific because we anticipate installing different sizes and models of compression and refueling equipment, thus resulting in different maintenance requirements.

A numerical example of a CS Test Fixed O&M is presented below:

O&M costs for compression equipment are dependent on a number of parameters which include:

- Inlet pressure;
- Horse power driving compression unit;
- Size and number of stages of compressor; and,
- Operating hours.

For each application the proper fit of compression equipment, drive motors and service requirements needs to be determined and this will affect O&M costs, which is why we have proposed it to be project/site specific. As a general rule of thumb, O&M costs average approximately $1 per GJ at these facilities. This unit rates was obtained from Clean Energy and based on their O&M experience from several Vancouver area stations. This unit rate is regarded as being conservative as the Vancouver area stations are underutilized (i.e. the fixed element of the periodic maintenance program is spread over low volume levels). Therefore, if the annual forecast consumption is 12,000 GJ per year, the corresponding Fixed O&M is $12,000 per year (12,000 GJ per year x $1 per GJ).

8.6 Please provide the average service life of the following NGV vehicles:

- School Bus
- Fork Lift
- Garbage hauler
- P/U (Mixed Use)

Response:

The average service life for NGV vehicles is presented below:

NGV vehicle	**Avg. Service Life (years)**
School bus	15 years
Forklift	12 years
Garbage Hauler	8-12 years
P/U (Mixed Use)	10 years

The average service life is based on information from Original Equipment Manufacturers and businesses which own NGV vehicles. These numbers will vary with individual fleet policy and number of kilometers driven. The average service life of a vehicle is important to the customer from a value proposition or life cycle cost aspect. However, the life of the vehicle is irrelevant to the CS Test as the CS test is determining the economics of the compression equipment not the vehicle equipment. Once a customer receives compression equipment, they may add and replace vehicles over the life of the compression equipment.

9.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Exhibit B-1, Part III, Section C, Tab 3, p. 248

Exhibit B-1, Appendix E-2, 2008 TGI-TGVI Main Extension Report ("2008 MX Report"), pp. 3-4

Natural Gas Vehicles ("NGV") Rate Offerings

"The economic test will be based on the $5.00 per GJ compression and refueling rate presented above.

Due to the small number of compressors expected in the early years of this service offering, we propose an individual PI of 1.0 rather than 0.8 used for individual main extensions. This will ensure that, based upon forecast consumption, new compression service customers will recover the costs associated with serving them. Therefore, if the PI is less than 1.0, the customer will be required to provide an upfront contribution in aid of installation as compensation for the revenue shortfall." (Exhibit B-1, Part III, Section C, Tab 3, p. 248)

2008 TGI-TGVI Main Extension Costs

All mains installed in 2008:

MAINS (Total Data Set of 439)

	Forecast Costs	**Actual Costs**	**% Difference**
TGVI	$4,509,905	$5,532,275	18%
TGVI	$2,429,162	$2,901,345	16%
Total	$6,939,068	$8,433,620	18%

(Exhibit B-1, Appendix E-2, 2008 MX Report, p. 3)

2008 TGI-TGVI Main Extension Profitability Index Results

Company	**Average Forecast PI**	**Average Actual PI**
TGI	1.3	1.2
TGVI	1.6	1.4
Combined	1.4	1.2

(Exhibit B-1, Appendix E-2, 2008 MX Report, p. 4)

9.1 Given that on average, the actual Main Extension costs exceed forecast costs and the Average Forecast PI is less than the Average Forecast PI, should the forecast CS Test PI be greater than 1.0 in order to ensure that a revenue shortfall does not occur?

Response:

No, we believe that existing customers are well protected by the proposed test.

As presented on page 248 of the Application, we anticipate a small number of compressor and refuelling equipment installations in the early years of this service offering and believe that an individual PI of 1.0 or greater is appropriate. Further, by having a minimum threshold PI of 1.0, the aggregate PI will inevitably be higher than 1.0.

In addition, we believe the cost estimate and consumption estimate will have a high degree of accuracy (please see the response to BCUC IR 2.9.2). For each compression and refuelling equipment installation, we believe that the variance between the forecast and actual costs will be low because the procurement and installation will be based on quotes provides by external suppliers and installers. The Company intends to review the results on an annual basis and will propose an adjustment to the PI threshold if appropriate.

To address the variance in forecast and actual costs for main extensions, in the 2008 Year End TGI-TGVI Main Extension (Appendix E-2, page 10), the Company has stated that it has implemented a new detailed estimating process for specific types of main extension installations to improve the accuracy of the forecast cost.

9.2 Please provide the expected accuracy of the cost and consumption estimates in the CS Test (i.e. P50, P90).

Response:

The accuracy of the cost estimate for the compression and refueling equipment will be high (P90) because the procurement and installation will be based on quotes provided by equipment suppliers and contract installers.

The accuracy of the consumption estimate in the CS Test will be high (P90) as it will be based on the customer's historical actual fuel consumption and distance travelled which will be used to forecast natural gas consumption.

10.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Exhibit B-1, Part III, Section C, Tab 3, p. 248

TGW - 2005 Resource Plan Update and Application to convert Propane Grid to Natural gas and TGVI - Application to construct Natural Gas Pipeline from Squamish to Whistler, Commercial Energy Consumers Association of British Columbian Submission, p. 7, para. 13

Natural Gas Vehicles ("NGV") Rate Offerings

"The history of the success of NGV vehicles in Terasen's service territory is certainly less than favourable and it is reasonable to assume that it will be less than favourable in Whistler. Again, this highlights the risk of the expensive project being undertaken by the Companies. It is the CEC's submission that it is fair and reasonable that the Companies bear some of the risks of cost overruns or forecasts not being met in this process."

10.1 Please explain how TGI proposes to address Intervenor concerns regarding "cost overruns or forecasts not being met".

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

The Company believes the NGV service and specifically the Compression and Refueling Service will benefit, not harm, existing customers. NGV service will help to offset a declining load by contributing to additional load and overall optimization of the distribution system with the direct benefit of lowering delivery rates for all customers.

As the costs of providing NGV service are legitimate costs of operating the utility for the benefit of customers, customers should bear the risk of the forecast not materializing. However, with respect to the inputs in the CS Test, there will be a high level of certainty on the forecast load and cost estimate (please see the responses to BCUC IR 2.9.1 and 2.9.2). We believe the Compression and Refueling Service will be economical and will not harm existing customers. Similar to MX Tests, the Company is committed to prudently processing CS Tests including securing a Contribution in Aid of Installation or security where required. Similar to the MX Test, the Company intends to review the results on an annual basis and will propose an adjustment to the PI threshold if appropriate.

In addition, the proposed Rate Schedule 6C – Compression and Refueling Service, includes a take or pay type of provision. Section 5.2 of the Rate Schedule 6C addresses consumption shortfalls:

"5.2 Payment on Termination - Upon expiration of the Service Agreement at the end of the term or upon early termination by Terasen Gas, the Customer shall immediately pay

to Terasen Gas any difference between the Gas consumption estimate for such Customer used in the calculation of the economic test and the actual Gas consumption of such Customer until the date of termination multiplied by the compression charge per Gigajoule set out in the Table of Charges."

TGI believes that this clause, while important, will not be a barrier to customers wishing to receive service from TGI as customers who sign up for Compression and Refueling service are already showing commitment by investing in the upfront capital cost of vehicle conversions or in acquiring higher cost OEM vehicles and the forecast load will have a high degree of accuracy (please see BCUC IR 2.9.2). Further, if for an unforeseen reason, the forecast load does not materialize, the Company has the option to redeploy the compression and dispensing assets to customers that can meet the load requirements and the current customer would receive a smaller station that requires a smaller load to achieve the required adjusted load requirements (at the customer's cost). Lastly, Rate Schedule 6C contains a provision for security (Section 2.2) which will further reduce the risk of forecast not being met.

As presented in CEC IR 1.57.1, the Company is proposing a deferral account for the NGV initiatives in recognition that it is in the early stage of market development and as such it is not confident of the number of compressor installations that will occur over the period of the RRA and therefore both capital and revenue numbers are unknown. TGI believes that it is therefore not appropriate to put these costs into rates until after the period of the RRA.

10.2 Will TGI require "take or pay" contracts from NGV Compression and refuelling customers in order to mitigate the risk of load forecasts not being met?

Response:

Please see the response to BCUC IR 2.10.1.

10.3 Do ratepayers bear the cost of NGV project cost overruns and actual consumption being less than forecast consumption?

Response:

Please see the response to BCUC IR 2.10.1.

10.4 Is TGI willing to "bear some of the risks of cost overruns or forecasts not being met"?

Response:

Please see the response to BCUC IR 2.10.1.

11.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Exhibit B-1, Part III, Section C, Tab 3, p. 261

April, 1997 Retail Markets Downstream of the Utility Meter Guidelines ("RMDM Guidelines")

Alternative Energy Offerings and RMDM

"For the purpose of this application, integrated and alternative energies include geo-exchange, solar thermal and District Energy systems. We view each of these alternative energy technologies as

complementary to, or extensions of, the Terasen Gas energy system as these systems more often than not require natural gas as part of the energy solution.

...We believe it is in the best interest of existing and new customers that TGI provide both gas and alternative energy solutions. As such we believe that the requests set forth in this section should be approved to facilitate that development."

11.1 Please discuss the review process that TGI considers appropriate for the review of TGI's proposal to provide alternative energy solutions.

Response:

As stated in TGI's response to BCUC 1.35.1, for clarity, TGI is not seeking approval to expand its core business into areas of alternative energy because such approval is not required. This Application is the appropriate regulatory process to review the following:

- the proposed economic tests,
- the proposed deferral treatment, and
- the proposed regulatory review process for reviewing individual projects and establishing rates for those particular customers.

For each alternative energy project, TGI will be filing the contract with the alternative energy customers with the Commission. The contract will include the terms and conditions of service and the rate (or rates) that the alternative energy customers will be charged. TGI will provide the necessary information to support the rate to be charged, such as capital and operating costs, number of customers (or dwelling units / businesses served), the expected energy load and a cost of service calculation with all relevant cost components (revenues, rate base, O&M, depreciation expense, taxes, return on rate base, overhead allowances, etc.).

Since there will be signed contracts by which the alternative energy service customers agree to the rates and other terms of service, and the rates for each alternative energy project or development will be designed to recover the unique cost of service, TGI believes the regulatory review process for each project can be kept to a minimum and conducted on a streamlined basis. Please see page 262 of the Application.

11.2 File a copy of the RMDM Guidelines.

<u>Response:</u>

A copy of the RMDM Guidelines is included as Attachment 11.2.

11.3 Does a natural monopoly currently exist for alternative energy services?

<u>Response:</u>

A natural monopoly occurs typically when a large supplier is first to market and has a cost advantage over actual or real competitors. Natural monopolies also typically involve extensive infrastructure networks where it is only economic for there to be a single firm providing the service in the relevant market. While many utilities have traditionally been natural monopolies, public utilities are not defined in the *Utilities Commission Act* by reference to a monopoly, natural or otherwise.

While a natural monopoly doesn't currently exist for alternative energy services, once a developer or other customer has selected a provider of heat delivery (i.e. a DES), that customer will likely face contractual impediments (i.e. contract term plus any additional provisions regarding premature discontinuance of service) and practical impediments (i.e. the infrastructure has been installed and is owned by the provider, making it difficult for another DES to be installed) to purchasing energy from another provider, irrespective of whether that other provider supplies electricity, gas or alternative energy. Simply put, once the heat delivery service is installed, there is monopoly power exerted by the provider of this service. While the Commission's jurisdiction is not defined by whether or not a service is subject to competition or whether it is a monopoly, the scope of the definition of "public utility" is consistent with protecting customers from the exercise of monopoly power by third party providers of energy. Please see the response to BCUC IR 2.27.6.

11.4 If alternative energy services are not a natural monopoly, can the utility ratepayer be protected through a transfer pricing policy mechanism if either a division of the utility or a related NRB offers the services?

Response:

As per the response to BCUC IR 2.11.3, TGI does not consider alternative energy services to be a natural monopoly. TGI notes, however, that the provider of alternative energy solutions may have a monopoly over the provision of its services to the customers receiving the service once the facilities are installed. Furthermore, TGI disagrees with the apparent assumption in the question that if alternative energy solutions are not a natural monopoly, then they are then not a regulated service. Please see TGI's responses to BCUC IR 1.24.3 and BCUC IR 2.59.3. In any case, TGI has not proposed to offer alternative energy solutions through an NRB. TGI has proposed to offer these services itself, and has proposed appropriate mechanisms to ensure that alternative energy customers appropriately cover their cost of service. As such, there is no need for a transfer pricing policy.

11.5 Will the use of utility assets or services in the provision of the alternative energy service reduce the risk of utility assets being stranded to the detriment of ratepayers or otherwise provide benefits to ratepayers?

Response:

Please refer to TGI's response to CEC 1.24.2.

Within this Application, TGI has proposed a number of solutions to address the changing environment in which TGI operates. As the question indicates, the Company intends to offer alternative energy solutions in combination with natural gas services, in order to provide a more comprehensive set of energy service options to meet the changing needs and expectations of customers. TGI is seeking to find solutions to make natural gas a part of the energy mix in the long term, while helping to achieve the government's energy and climate change policy objectives.

With the introduction of the new energy solutions described in the RRA, TGI is trying to reduce the exposure that existing natural gas customers would face if TGI were to take a "do nothing approach". All else equal, if volumes decline on the TGI system, the remaining customer base would pay more for TGI delivery service due to an increase in the unit charge per GJ delivered to customers.

One of the objectives behind TGI offering new alternative energy solutions to customers is to spread common costs that exist in the natural gas business to these new alternative energy solutions. The sharing of common costs will be beneficial to existing natural gas customers; however, it is likely to be a number of years before this benefit is materially realized. The alternative energy solutions that TGI has included in the RRA therefore do not immediately reduce the business risk inherent to the natural gas business.

The natural gas business risk will be mitigated to a degree if the Terasen Gas is successful in attracting new business in these alternative energy solutions so that enough shared services costs can be allocated to these new energy alternative solutions over time to help in offsetting the impact of lost throughput on the natural gas systems. It is also the intent that by providing new alternative energy solutions, Terasen Gas will be better able to keep natural gas as part of the solution relating to delivering integrated energy solutions to customers.

11.6 Please provide examples of North American natural gas distribution utilities that are permitted provide alternative energy services and include alternative energy capital costs in gas utility rate base.

Response:

Attachment 11.6 includes a report which demonstrates that while not common, there are energy providers that have started out as natural gas providers and have transitioned into the provision of other energy forms. TGI was not able to determine if the alternative energy services were included in the natural gas rate base.

The fact that it is not common in other jurisdictions at the present time for alternative energy services to be offered to within a traditional utility context does not speak strongly as to whether it is appropriate or inappropriate to do so in BC. Energy legislation, climate change legislation and the policy context in which utilities operate all vary from one jurisdiction to the next. BC's climate change and GHG reduction commitments are very strong and, with so much of the province's electricity coming from hydro sources, the opportunities to obtain GHG reductions from the electric sector are minimal compared to other jurisdictions. The Province has indicated its desire to have public utilities play an important role in implementing its Energy Plan policies. As the province, Canada and the world move into a carbon constrained operating environment, TGI believes that it will become more and more common for utilities in many jurisdictions to offer service for more than one form of energy.

With respect to British Columbia, there is precedent for a utility providing more than one service. Notably, BC Hydro used to provide both electricity and gas service to customers within the same corporate entity. Today, there is still nothing in the Utilities Commission Act that restricts or prohibits a provider of one energy form from providing another energy form. TGI currently provides both natural gas and propane (Revelstoke) service to customers. TGI believes that the provision of more than one form of energy is good for both existing gas customers as well as new customers, whether they are gas or alternative energy customers, and as such, inclusion of the alternative energy service within the gas utility is appropriate. The economic tests developed by TGI and proposed in this Application protect customers by ensuring that the alternative energy customers pay rates based on their cost of service.

11.7 For a specific energy use (heating, hot water), will customers who utilize alternative energy as their primary energy source and natural gas as a secondary energy source, have a lower load factor than customers that utilized natural gas as their primary energy source?

Response:

Potentially. This depends, however, upon the nature of the alternative energy source and the types of other natural gas appliances in the home. Additionally, this is no different than if natural gas customers participate in EEC offerings which could have the effect of changing the load factor. Note that some current natural gas customers will transition to alternative energy sources whether or not TGI is able to provide these services. If TGI provides these services, it is better positioned to ensure that gas is used in the appropriate appliances and the customer's overall energy system is properly configured. In doing so, TGI can ensure that the load factor is as high as possible. If alternative energy is provided by another provider, there would be no benefit from that provider in seeking to maintain the natural gas system load factor and they would not have an interest in promoting gas use as a back-up heating fuel or in other end uses.

12.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Exhibit B-1, Part III, Section C, Tab 3, pp. 265-266 and 443

Exhibit B-1, Appendix J-3

Alternative Energy Offerings – Economic Assessment

"Each installation or combination of installations could have different mechanical equipment and piping infrastructure needs and therefore the cost inputs will vary between projects and as such each service agreement could have different language to reflect the nature of that business arrangement. In addition, each installation's (or customer's) cost may vary significantly and as such end use rates may be very different from one installation to the next." (Exhibit B-1, Part III, Section C, Tab 3, p. 265)

12.1 Please compare the complexity of energy installations (geo-exchange, solar thermal, and district energy system) to a main extension installation. Include the following issues in the comparison:

1. The average cost per installation
2. The work required (installation of a natural gas main, boilers, heat capture systems, solar collection tubes, heat pumps, specifically designed mechanical rooms)
3. Standardized costs versus a unique cost (for each installation
4. The average time required to complete an installation

Response:

TGI's long history of installing gas mains and service lines facilitates the development of standardized costs or the calculation of average installation costs relatively straightforward for the gas system, the work required and the average time to complete and installation. TGI does not have a similar basis for deriving the average cost per installation for alternative energy systems, the work required or the average time required to complete an installation as each project is unique and as such these factors will vary depending upon the installation.

As noted in the response to CEC IR 1.35.6 of the Terasen Utilities ROE application, each alternative energy installation is uniquely configured, and TGI does not have a large number of these installations from which to derive average costs. Further, the service provided through an alternative energy installation is not the same service as natural gas service since the end user will be provided with heat energy and will not have to own or maintain energy conversion equipment such as furnaces or boilers. TGI has addressed the uniqueness of alternative energy installations by proposing that a specific cost of service and unique rate be established for each project or development. Customers will sign a contract agreeing to that rate and the terms of service.

It may be possible in the future when TGI has completed many alternative energy installations to develop standardized tariff offerings for some of the alternative energy services. There may be sufficient similarity in solar thermal installations, for example, that a standard rate can be developed. The approach reflected in the Application is most appropriate for this early stage of development of alternative energy installations.

> "Any geo-exchange, solar-thermal or DES project for which capital costs exceed the Commission approved limit over which TGI projects require a CPCN will proceed via a separate CPCN application. Otherwise, geo-exchange, solar-thermal and DES projects will proceed, with rates for the provision of energy to the customer being determined through the application of the proposed economic assessment." (Exhibit B-1, Part III, Section C, Tab 3, p. 266)

12.2 Given that TGI has not submitted a CPCN application to the Commission for the review of an alternative energy installation, please explain why it is not premature for the Commission to approve the proposed economic assessment and tariff changes.

Response:

TGI believes that it is the appropriate time for the Commission to consider and approve the economic models and tariff changes relating to alternative energy solutions.

First, the proposed economic assessment approach for the various alternative energy installations will employ cost of service analysis and rate-setting principles that have commonly been used in applications to the Commission for natural gas delivery rates and other tariff service offerings as well as for existing alternative energy systems (i.e. Dockside Green, Central Heat, Gateway Falls).

Second, the economic assessment approaches are undergoing a very thorough review as part of this Application (the alternative energy solutions section of the Application has already been the subject of dozens of IRs). As such, TGI believes the Commission will be well able to assess and approve the alternative energy service economic models and tariff changes brought forward by the Company. TGI believes that the Commission should review the economic assessment models within this proceeding rather than waiting for a separate proceeding wherein TGI would be providing similar information.

Third, under the proposed approach, the Commission will review contracts entered between TGI and alternative energy customers, providing additional protection for customers.

The pursuit of alternative energy solutions represents a positive step for customers and the Company, and TGI believes that it is in the public interest for mechanisms to be put in place that will facilitate the development of that opportunity.

12.3 Please explain why the CPCN process is not appropriate for the review of initial alternative energy installations.

Response:

TGI believes that the proposed process will enhance regulatory efficiency while still providing an appropriate level of regulatory scrutiny to alternative energy projects.

First, as stated in the response to BCUC IR 2.12.2, TGI's proposals for the economic assessment of alternative energy projects are being thoroughly reviewed in this proceeding. It is contemplated that projects subsequently brought forward to the Commission would fall within the parameters of these economic tests. The economic tests ensure that the new customer will be paying rates that recover the cost of service, and therefore also ensure that existing customers are protected. The subsequent review of the rate for that project can therefore be streamlined.

Second, TGI believes that since alternative energy customers have agreed to pay the rate(s) specified in the contract, there is little risk of the new customer being prejudiced from a streamlined process to approve the agreed-upon rate pursuant to sections 59-61.

Third, as discussed in the response to BCUC IR 2.11.1, TGI will file appropriate cost of service information to support the determination of the rate agreed to by the alternative energy customer or customers. This will be similar information to what would be filed in a CPCN review process.

The purpose of a CPCN is to ensure that projects undertaken are in the public interest and in particular the interest of customers. The benefits conferred upon customers of TGI –both gas and alternative energy customers– have been described in other responses to information requests. The broader public interest is served by regulatory processes that act to facilitate energy efficiency and GHG emission reduction. TGI believes that its proposal advances the public interest and should be approved.

12.4 If the proposal to increase TGI's CPCN threshold from $5.0 million to $20 million is approved, will any of the 2010-2011alternative energy installations meet the $20 million threshold required for a CPCN application?

Response:

Most alternative energy installations will cost less than the proposed CPCN threshold of $20 million. TGI expects that the $20 million threshold will be exceeded in some cases, particularly by larger district energy system installations.

The benefits associated with a streamlined approval process for projects meeting the economic test are discussed, for instance, in TGI's response to BCUC IR 2.12.3.

13.0 Reference: Operations and Maintenance Expense

Exhibit B-1, Part III, Section C, Tab 6, p. 374

Customer and Stakeholder Behaviors and Expectations

13.1 Please provide TGI's forecast donation and sponsorship costs for 2010 and 2011.

Response:

Please see the response to BCUC IR 2.1.2

13.2 Are the 2010 and 2011 donation and sponsorship costs shared equally between the ratepayers and the shareholder? If not, why not?

Response:

No. Donation and sponsorship costs contained within the Application are recovered from ratepayers, consistent with past practice.

The donation and sponsorship costs are legitimate costs of operating the utility for the benefit of customers. Community Investment is essential to maintaining positive relationships within the community and to be a good corporate citizen within the communities Terasen Gas serves. Apart from the intrinsic value of good corporate citizenship, these investments facilitate community acceptance of TGI's ongoing operations.

TGI is legally entitled to recover from customers through rates the legitimate costs associated with the operation of the utility, as well as be afforded an opportunity to earn a fair return. Requiring the shareholder to incur costs legitimately required for the operation of the utility for the benefit of customers would be inconsistent with the Commission's legal obligations in setting rates for TGI.

13.3 Please provide a schedule showing BCTC, TGI and BC Hydro donation and sponsorship costs for 2007-2009.

Response:

The donation and sponsorship costs for BCTC, BC Hydro and TGI are as follows:

Line No.	$ million	F2007 Actual	F2008 Actual	F2009 Plan	F2010 Plan
	(a)	(b)	(c)	(d)	(e)
1	TGI	0.5	0.5	0.5	0.5
2	BCH	2.1	2.6	2.7	2.7
3	BCTC	0.3	0.6	0.6	0.6

In BCTC's 2009/10 Revenue Requirement Application BCTC proposed a planned Budget of $0.5 million (see Appendix D – pg. D-7). In the Negotiated Settlement (Order Number G-105-08), there was no agreement amongst Parties on the appropriate funding for cost associated with the Community Investment Program and Donations (see page 6 of 25, #13).

Both of these documents can be found at:
http://www.bctc.com/regulatory_filings/revenue_requirements/previous_revenue_requirement/

BCTC has also released a Corporate Responsibility Report for 2008/2009 which contains CI information beginning on page 27.

Based on BCTC and BC Hydro donation and sponsorship costs, TGI believes it is well positioned with an appropriate spending pattern in this regard.

14.0 Reference: Operations and Maintenance Expense

Exhibit B-1, Part III, Section C, Tab 6, p. 364

Exhibit B-1, Part III, Section C, Tab 6, p. 374

B&ITS O&M - Incremental Funding

14.1 For Tables Table C-6-24 and Table C-6-25, please provide breakdowns of the incremental funding by cost driver. Use the same format as Table C-6-18: Distribution Service Enhancement O&M Cost Drivers for 2010 and 2011 vs. Prior Year.

Response:

Category	2010 $ thousands	2011 $ thousands
Inflation	220	429
Accounting Changes	-1,148	1
Budget Transfer	-363	0
Communications	1,298	8
Business Development (Service Enhancement)	258	0
Customer Care & Billing Contract	793	956
Research	267	0
Customer Care & Energy Services	538	3
Customer Sales Service	931	433
Business Development (Customer and Stakeholder Expectations)	2,032	144
Community/Aboriginal/Gov't Rel'ns	525	6
Resource Planning	341	0
Total	**5,692**	**1,980**

15.0 Reference: Operations and Maintenance Expense

Exhibit B-1, Part III, Section C, Tab 6, p. 376

Customer Care Enhancement Project, Appendix G, Angus Reid Strategies Report, p. 8

Customer and Stakeholder Behaviors and Expectations

"As a respected and trusted operator, Terasen Gas believes it must adapt and change to meet growing customer needs and expectations. We must take action to ensure that existing gas customers continue to receive the service they require and that it invests in activities to meet future customer needs."

"**Actual readings and automated meters**: The proposed initiation of automated meter reading will be welcomed by Terasen Gas customers, as the majority feel it is very important to get actual monthly gas

readings and when moving in or out of a home. While they're not prepared to pay an additional surcharge for it, most would be interested in using automated meter reading to better understand their home energy." (Customer Care Enhancement Project, Appendix G, Angus Reid Strategies Report, p. 8)

15.1 What are top 5 TGI customer expectations (safe, reliable, low cost service)?

<u>Response:</u>

TGI conducts regular customer research including customer satisfaction and corporate image studies. However, TGI has not specifically asked customers in recent studies for their top five expectations of the Company. TGI's most suitable recent study to discuss broad customer expectations is the 2008 Corporate Image Study conducted by TNS Global. This study found that "As far as Terasen customers are concerned, the reputation of Terasen rests on the ability of the company to put safety and quality of life issues relating to supply of natural gas and the environment, first on their lists. They applaud Terasen for these qualities." [2]

The study also found that "Customers expect Terasen to generally act in the customer's best interests—whether it is about rates, the environment, safety or other issues. It is apparent that the quality (and cost) of gas supply is uppermost in the minds of these respondents. And, regardless of Terasen's claim that they are only a gas distributor, the customers remain entrenched in the belief that the rates (and even the long term supply of natural gas) is fully within Terasen's span of control." [3]

[2] Corporate Image Study 2008, Final Report, August 2008. TNS Global, Page 30-31
[3] Corporate Image Study 2008, Final Report, August 2008. TNS Global, Page 30-31

The overall sampling error for the 850 total household interviews at the 95% confidence level is approximately ± 3.4%. For example, if 50% of all respondents surveyed stated that they have a natural gas fireplace then we can be sure, nineteen times out of twenty, that if the entire population had been interviewed the proportion would lie between 46.6% and 53.4%.

The following matrix identifies areas that customers identified as important and how they evaluated Terasen performing in these areas.

Exhibit 11: Strategic Improvement Matrix for Customers[4]

	Lower Performance	Higher Performance
	Critical Improvement Areas	***Strengths to be Leveraged***
High Importance	- Offers fair/reasonable rates - Works with environmental protection - Offers programs to help use gas efficiently - Consults about pipeline upgrades - Acts in customer's best interests Works hard to get the best long term rates	- Safety of customers 1st priority - Improves quality of life by ensuring worry free supply of gas - Cares about environment
	Improvement Area	***Less Emphasis***
Lower Importance	- Operates with strong customer orientation in all - Has service personnel responsive and genuine interest - Has effective complaint systems - Is fair and ethical in business - Connects emotionally with customers and the public	- Being a leader in establishing safety practices

It is important to keep in mind that customer expectations change over time and are affected by factors within Terasen's control–such as customer service–and many beyond its control–such as issues in the local and global economy, natural gas commodity prices, prevailing news at the time the study is undertaken and changing customers priorities.

Broadly speaking, customer expectations relate to two main areas, customer service and price competitiveness. To understand the constantly changing needs of customers, Terasen

[4] Corporate Image Study 2008, Final Report, August 2008. TNS Canadian Facts, Page 30-31.

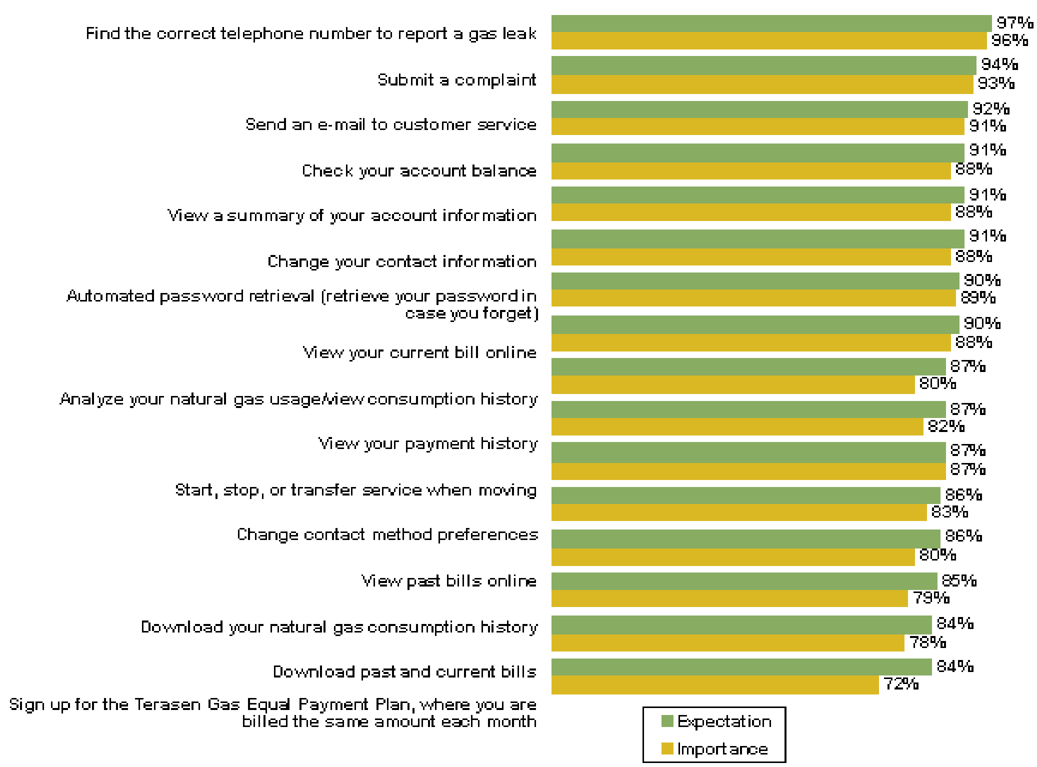
conducts research to understand what customers want and using Customer Satisfaction studies evaluates how well Terasen is doing in delivering services to its customers.

In addition, Terasen Gas also conducts research into specific service options. Terasen Gas believes it is important to ensure that the delivery of online and automated telephone services is at least consistent with the service levels provided by peer organizations that our customers interact with such as BC Hydro, TELUS and Shaw.

The 2009 Angus Reid study conducted for Terasen Gas, evaluated customer expectations of online and automated telephone services and found the following[5].

Online service expectations: Highest expectations were for customer service-related issues: find the correct number to report a gas leak (97%), submit a complaint (94%), send an email to customer service (92%) and change contact info (91%). Account-related issues also had high expectations: check account balance (91%), view summary of account information (91%) and view current bill online (90%).

<u>Online service expectations and importance</u>



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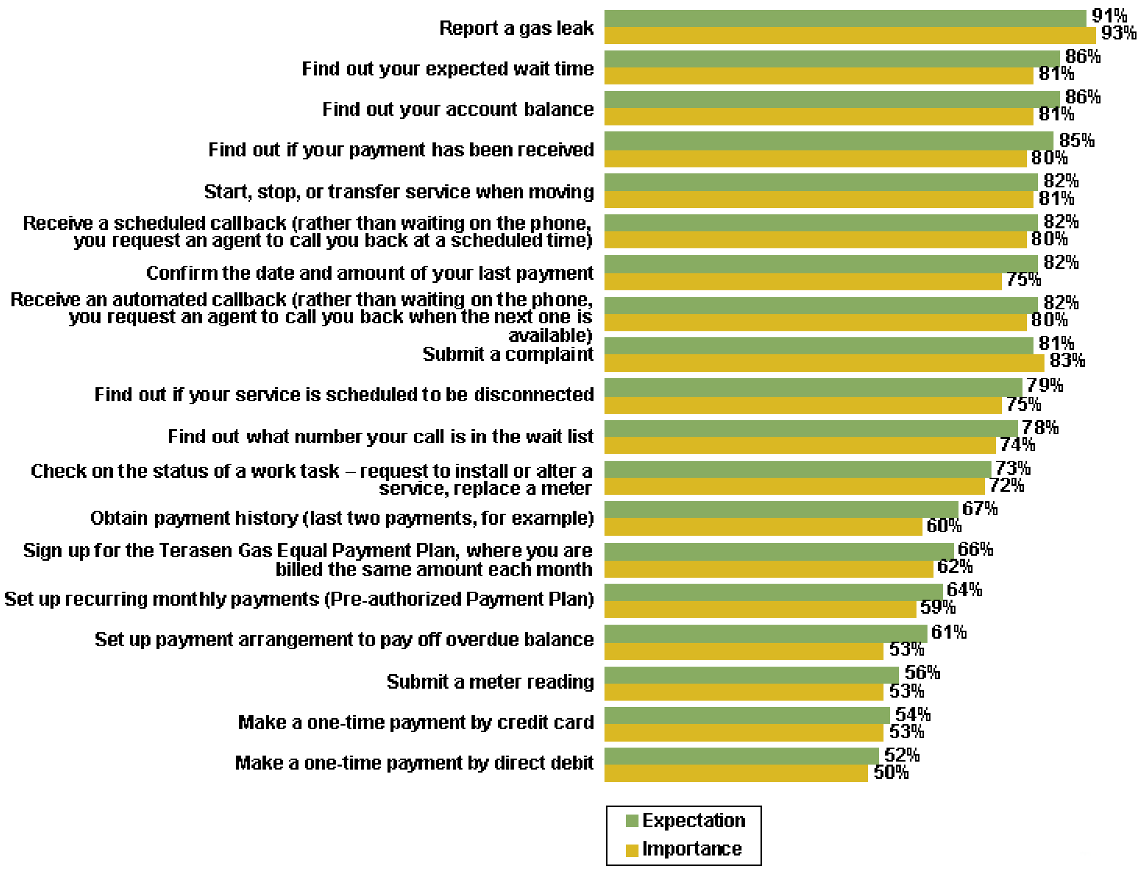
5 Customer Service Enhancements, Final Report, February 27, 2009. Angus Reid Strategies, Pages 16-20, Questions 4-7

Automated telephone service expectations: Highest expectations were: report a gas leak (91%), find out expected wait time (86%), find out account balance (86%) and find out if payment has been received (85%).

Automated telephone service expectations and importance



The overall sampling error for the 823 respondents at the 95% confidence level is plus or minus 3.4%, 19 times out of 20.

This study and similar studies, have found that customers prefer to deal with Terasen Gas by telephone, a live agent and online via the website.

Customer expectations are broad and ever changing, so the relative importance of each service and performance expectation changes with time. Regular research on the different customer segments is conducted so that TGI can adjust its priorities accordingly.

15.2 Has TGI conducted research regarding customers' willingness to pay for the service enhancements proposed in the Application?

Response:

This question is identical to TGVI RRA/RDA BCOAPO IR 1.6.2. This response is similar to the TGI response to that IR, however some minor differences were necessary in order to respond appropriately for TGI.

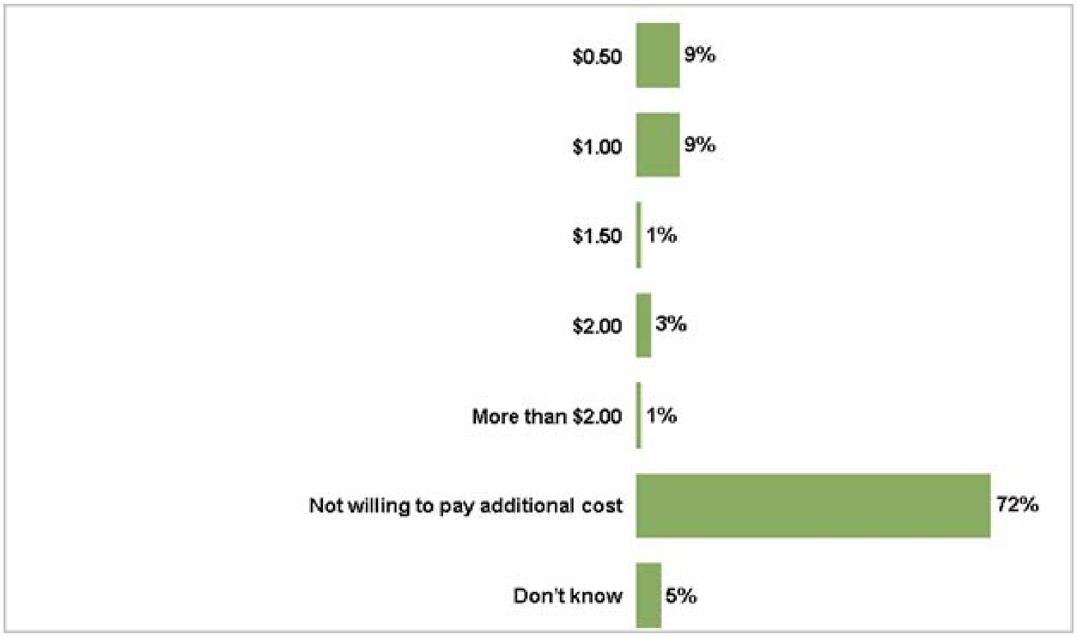
Terasen Gas research has shown that there is a very strong customer preference for having access to further information on consumption. The breadth of research necessary to obtain an in-depth understanding of our customers' willingness to pay for possible information enhancements has not yet been conducted. However, Terasen Gas has commissioned market research from Angus Reid that has provided an initial indication that approximately one third of customers are already willing to pay extra for enhanced consumption information. Based on typical new product/service adoption rates, as discussed below, this initial level of acceptance is a favourable result. Moreover, the result suggests strong future adoption rates.

Research Suggests Strong Interest and an Indication of Willingness to Pay

A recent study conducted for Terasen Gas by Angus Reid Strategies investigated residential customer interest in telephone and online self service information and transactional features and also inquired about customer interest in automated meter reading. This research indicates that almost 9 in 10 customers[6] expect access to enhanced consumption information. Nearly all customers want to reduce their monthly energy bill (7 in 10 strongly agree), while nearly 9 in 10 want to reduce their monthly energy bill and are concerned about their impact on the environment. The survey suggests that 28% of respondents (9% - $.50/month, 9% - $1.00/month, 1% - $1.50/month, 3% - $2/month, 1% - More than $2.00/month) indicate they are willing to pay extra for the information. These results are shown below in Figure 1.

[6] Customer Service Enhancements, Final Report, February 27, 2009. Angus Reid Strategies, Slide 41, Question 22.

Figure 1: Willingness to pay for automated meter reading[7]



Analysis of the Survey Results

The distribution of customers willing versus unwilling to pay for the enhanced information, is consistent with the adoption rates of other new technology. In fact, the early acceptance or willingness to pay on the part of such a significant minority is a strong indicator that broader customer acceptance will follow.

By way of explanation, the customers willing to pay for the enhanced information represent a market segment called "early adopters." The percentage of customers indicating a willingness to pay for the improved information is consistent with the diffusion of other new technology, services or products (Diffusion Theory). The most striking feature of diffusion theory is that, for most members of a social system, the decision to adopt a new technology depends heavily on the innovation-decisions of the other members of the system. "In fact, empirically we see the successful spread of an innovation follows an S-shaped curve. There is, after about 10-25% of system members adopt an innovation, relatively rapid adoption by the remaining members and then a period in which the holdouts finally adopt."[8] It is important to note that the earlier adopters of an innovation profoundly affect the innovation-decisions of later adopters.

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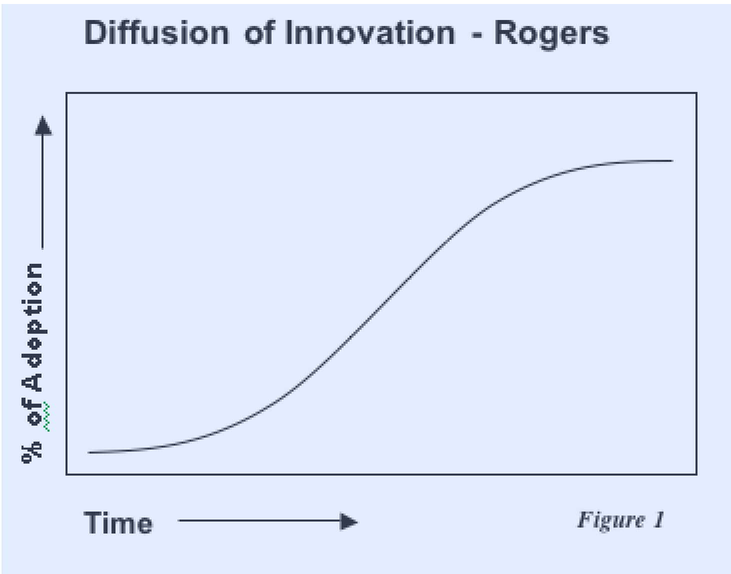
[7] Customer Service Enhancements, Final Report, February 27, 2009. Angus Reid Strategies, Slide 47, Question 27b.

[8] Diffusion of Innovations, Everett Rogers, March 18, 2003, www.stanford.edu/class/symbsys205/Diffusion%20of%20Innovations.htm

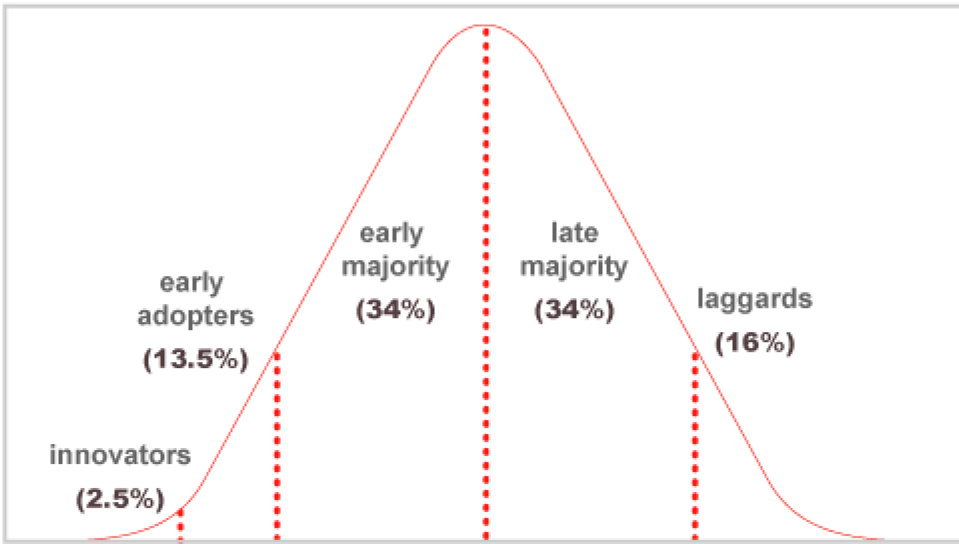
Figure 2: S-Shaped Curve Portrays Technology Adoption[9]



Scholars characterize adoption rates into five categories of system member innovativeness, where innovativeness is defined as the degree to which an individual is relatively earlier in adopting new ideas than other members of a system. These groups are: 1) innovators, 2) early adopters, 3) early majority, 4) late majority, and 5) laggards. Adoption rates for these sub-groups follow a bell curve as follows:

[9] D. Travers Scott, University of Washington
http://homepage.mac.com/dtraversscott/Academics/BlogHistory/Terms.html

Figure 3: Diffusion Model - Consumer Segments[10]



Innovators are eager to give the new product or service a try. The implementation and confirmation stages of the innovators' innovation-decisions are of particular value to the subsequent decisions of potential adopters.

Early adopters use the data provided by the innovators' implementation and confirmation of the innovation to make their own adoption decisions. If the opinion leaders observe that the innovation has been effective for the innovators, then they will be encouraged to adopt. This group earns respect for its judicious, well-informed decision-making, and hence this group is where most opinion leaders in a social system reside. Much of the social system does not have the inclination or capability to remain abreast of the most recent information about innovations, so they instead trust the decisions made by opinion leaders. Additionally, much of the social system merely wants to stay in step with the rest. Since opinion leader adoption is a good indicator that an innovation is going to be adopted by many others, these conformity-loving members are encouraged to adopt.

So a large subsection of the social system follows suit with the trusted opinion leaders. This represents a tipping point, where the rate of adoption rapidly increases. The domino effect continues as, even for those who are cautious or have particular qualms with the innovation, adoption becomes a necessity as the implementation of the innovation-decisions of earlier adopters result in social and/or economic benefit.

The last adopters, laggards, can either be very traditional or be isolates in their social system. If they are traditional, they are suspicious of innovations and often interact with others who also

[10] Proven Models, Diffusion of Innovations, www.provenmodels.com/570.

have traditional values. If they are isolates, their lack of social interaction decreases their awareness of an innovation's demonstrated benefits. It takes much longer than average for laggards to adopt innovations.[11]

From the Internet to cell phones and Ipods, consumers never adopt new products and services at the same rate. The 28% percentage of customers indicating a willingness to pay for the service is consistent with Diffusion Theory. From this perspective, TGVI perceives the market segment currently keen enough to pay for the improved gas consumption tools as very positive, representing a substantial sub-group that acknowledges the societal importance of this investment. However, it should be cautioned that this investigation represents a cursory step towards a full pricing evaluation. In order to keep the overall survey of appropriate duration and scope, the question related to willingness to pay used a survey technique called the contingent valuation method (CVM). This method is designed to assist on matters of resource allocation. The process simply asks respondents how much they would be willing to pay for obtaining a particular good or service. However, a thorough pricing model "…needs input not only from economic theory, but also from several other disciplines, including sociology, psychology, statistics and survey research."[12]

Summary

In summary, almost all customers indicate that they desire enhanced natural gas consumption information. The information will help customers make better decisions about how they use natural gas in the home, and help them make decisions that are better for the environment. It is noted that the breadth of research necessary to obtain an in-depth understanding of our customers' willingness to pay for possible information enhancements has not yet been conducted. However, given the almost 3 in 10 market segment already willing to pay, the high customer preference for the enhanced consumption information and its congruity with generally accepted conservation objectives, TGVI believes providing customers with enhanced consumption information represents an necessary step to assist customers in the efficient and appropriate use of natural gas. The significant segment of "early adopters" will lead the way, adopting the new service first while others start using the information later as the benefits are acknowledged.

[11] Diffusion of Innovations, Everett Rogers, March 18, 2003, www.stanford.edu/class/symbsys205/Diffusion%20of%20Innovations.htm

[12] Determining the value of non-marketed goods by Raymond J. Kopp, Werner W. Pommerehne, Norbert Schwarz. Springer, 1997. Page 235.

16.0 Reference: Operations and Maintenance Expense

Exhibit B-1, Part III, Section C, Tab 6, p. 382

2008 Annual Review of 2009 Revenue Requirements and Rates ("2008 Annual Review"), Section B-2 Service Quality Indicators, p. 11

Customer and Stakeholder Behaviors and Expectations

"Terasen Gas has already added two additional staff in 2009 to this area to meet these ongoing needs, and additional incremental funding for these staff requirements is sought in 2010 and 2011.

…Without ongoing investment in customer information and education, Terasen Gas expects customer complaints (those directed internally and also to the BCUC) to increase, customer satisfaction levels to drop and customer awareness of rates, safety, emergencies and related items to decline."

16.1 Please provide the cost of the two additional staff in 2009 "to meet these ongoing customer needs".

Response:

The cost of the two additional staff, which is included in the 2009 projected O&M expense, is $144,000.

16.2 Please provide the cost of media monitoring and newswire services for 2003-2011 by year. How will TGI determine if these expenditures should continue or be eliminated in future years?

Response:

Newswire services and media monitoring is an important function and provides benefits to customers. The costs have increased over time, broadly speaking, due to increased Company initiatives and regulatory applications that have attracted media attention, government policy developments, and the Company's public safety and damage prevention activities. Further information is provided below.

Media Monitoring & Newswire Costs 2003 - Forecast 2011

	2003	2004	2005	2006	2007	2008	2009 (year end projected)	2010 (forecast)	2011 (forecast)
Media monitoring	23,000	31,000	21,000	22,000	43,000	56,000	63,500	63,500	63,500
News wire services	6,000	5,000	5,000	4,000	8,000	23,000	31,000	31,000	31,000
	29,000	**36,000**	**26,000**	**26,000**	**51,000**	**79,000**	**94,500**	**94,500**	**94,500**

Terasen Gas uses a newswire service to distribute its news releases to media outlets across the service territory in more than 125 communities encompassing TGI, TGVI and TGW operating areas.

News releases are used to get mass media coverage of information about safety, rates, energy efficiency, community involvement and other topics of value to our customers and the communities we serve. Distributing our news releases equitably throughout our 125 service communities is fundamental to the company being a transparent operator by being able to immediately and directly alert the vast amount of media in our service area when new information is available. In turn, the media may elect to report on the information for communication to the public and our customers.

Unlike paid advertising, which guarantees publication of content in its entirety on a set date, the release of information to the media provides no guarantee of publication and the content may only be partially covered or subject to interpretation. However, Terasen only prepares releases that are either news (event-driven, such as a rate change) or public awareness or education opportunities (safety, energy efficiency that are timely and are triggered by news event – seasonal safety information supporting a weather-related event or is new information and therefore newsworthy.)

Since it is the media and not Terasen Gas that communicate the information (from either a Terasen news release or a media request) to our customers and the public, it is in the interest of customers, the public and Terasen Gas that the reporting be monitored for accuracy. When misinformation is reported, Terasen works with the respective media outlet to ensure correct information is published. Media monitoring also allows the company to access *Letters to the Editor* that our customers may have submitted and to prepare a response in a timely manner for publication.

In recent years, energy has become a topic of greater interest to the media and consumers, resulting in the company issuing more news releases. There has also been an increase in media requests that in many cases are not a result of a news release. These requests also result in coverage.

Newswire services and media monitoring costs increased in 2007 primarily due to the start of the Customer Choice program and a change in our pipeline locate practices on Vancouver Island, which created additional education opportunities surrounding safety awareness and damage prevention. Potential flood threat in the spring of 2007 and the Fortis acquisition of Terasen, along with our regular news releases supporting our applications to the British Columbia Utilities Commission (rate changes, etc.), also resulted in a greater number of news releases and media coverage.

In 2008, we continued to increase the number of news releases pertaining to public safety awareness and education activities. This, combined with significant changes to the Provincial government's energy policy, including the Carbon Tax, resulted in greater media requests and coverage.

Terasen Gas will always have a need for media monitoring, as it ensures media coverage about the company is accurate, and gauges the tone and reach of the coverage.

16.3 Given that the April YTD Actual Customer Satisfaction of 79.9 percent is the highest level of customer satisfaction achieved to date, please explain why additional funds for customer information and education are required?

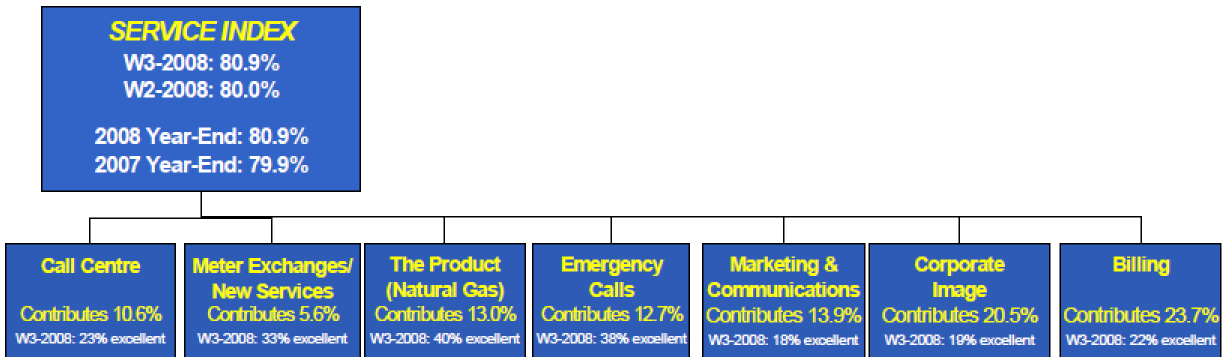
Response:

As noted from the quote above, TGI believes that ***ongoing*** investment in customer information and education is fundamental to the maintenance of its customer satisfaction levels pertaining to customer awareness of rates and safety communications. Increased funding is designed to keep pace with internal requests for communication services to assist in the maintenance of existing customer satisfaction scores. Other funding requests relate to the development and distribution of information designed to keep customers and the public safe.

The Customer Satisfaction score is a composite score for seven primary attributes. It is useful as a metric because it is easy to understand and it effectively relates customer broad-based perceptions of TGI. But the YTD Customer Satisfaction score of 79.9 is a composite that does not reveal the specific, underlying performance of any primary or sub-attribute.

When the current Customer Satisfaction Model was adopted in 2004, it was established that Marketing and Communications contributes 13.9% to the overall customer satisfaction score (see Figure 1). This was calculated by evaluating all seven of attributes in the applicable statistical procedure at the same time. This allowed the research vendor to determine each attributes' contribution to overall satisfaction.

Figure 1: Customer Satisfaction Model



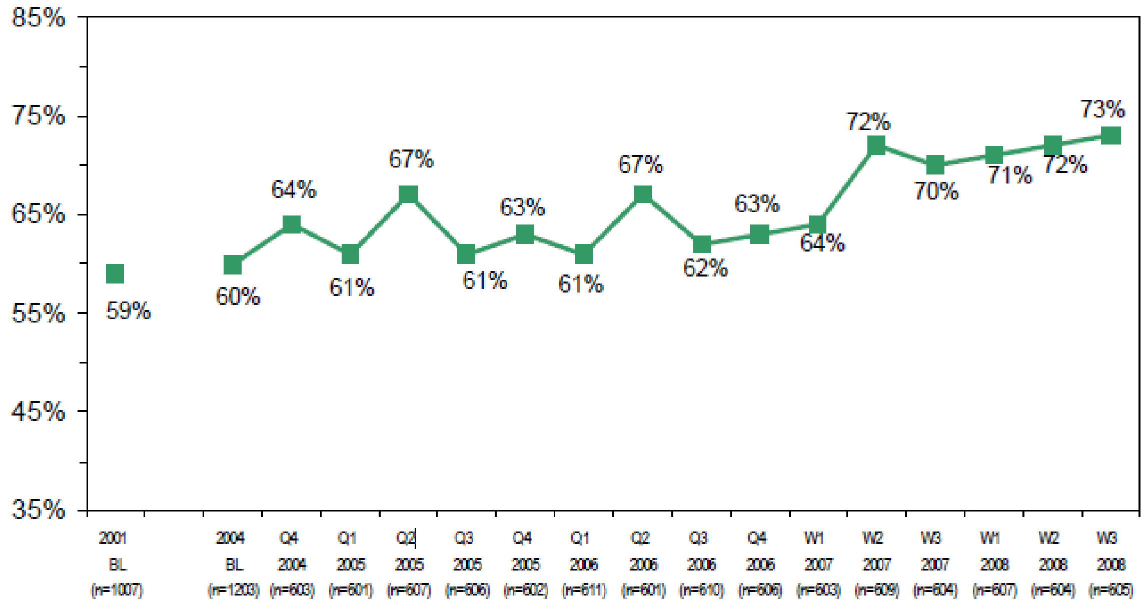
Once the contribution to satisfaction was calculated for each of the primary attributes, influential sub-attributes were identified. How well TGI is performing on the Marketing and Communications attribute is calculated based on the average of scores achieved across seven sub-attributes, including the following:

- informs about energy saving
- explains price of natural gas
- reminds about safety issues
- delivers consistent messages
- easy to understand
- encourages you to take action and save energy
- attention getting ads

Based on this granularity, communication issues must be analyzed in isolation because performance shortcomings can go unnoticed and uncorrected. Degrading performance on one attribute may, for example, be offset by performance on another sub or primary attribute.

A failure to adequately fund necessary communications activity at TGI may well not be evident through the analysis of a high level summary statistic. As shown in Figure 2 below, Terasen Gas still has room for improvement in the delivery of marketing and customer communications. The Wave 3, 2008 score for the attribute was 73%.

Figure 2: Overall Customer Satisfaction with Marketing and Customer Communications[13]



It is also important to understand that even if an attribute is not identified as a significant predictor of satisfaction, it does not mean it is meaningless. Rather, it means that is not important in fostering higher level of overall satisfaction with respect to quality, price competitiveness or value. These types of items are often referred to as "hygienics," or "price of admission" attributes. Safety issues often fall into this category. They're very important to customers, but satisfaction scores seldom improve by enhancing safety programs. In contrast, satisfaction scores can be seriously compromised if a preventable accident takes place for which TGI is held accountable.

Lastly, satisfaction represents an inappropriate measure to evaluate the success of some communication efforts, such as a campaign designed to enhance customer knowledge of natural gas safety issues. Individuals may indicate satisfaction with a campaign, but unless the campaign has educated people to behave differently or grasp an issue, it has not accomplished its goal.

For these reasons, TGI believes that the suggested investment levels to accommodate increasing departmental work demands and enhanced safety communications are prudent and appropriate.

[13] Terasen Gas Customer Satisfaction Survey, Wave 3 2008, Pollara, page 23.

16.4 Please provide the number of safety and emergency incidents from 2003 – 2009 YTD June Actual, by year.

Response:

Please find below Terasen Gas tracking data for emergency calls and third party system damage from 2003 up to the end of July 2009 which is our most recently available reporting period at this writing.

Emergency Call Volumes (Actual by Year)

2003	2004	2005	2006	2007	2008	2009 YTD (July)
91,162	85,286	80,556	87,931	79,491	75,210	40,785

Third Party System Damage (Actual by Year)

2003	2004	2005	2006	2007	2008	2009 YTD (July)
1,459	1,492	1,457	1,508	1,545	1,574	747

"Volatile gas costs and other events beyond the control of Terasen Gas can influence the number of complaints to the Commission. It was agreed as part of the 2004 – 2007 PBR Settlement, that there is no performance threshold for this SQI, but that results would be considered in the context of previous results and consideration would be given to external factors and any relevant uncontrollable events that can influence results." (2008 Annual Review, p, 11)

16.5 Please provide the metrics that TGI uses to measure customer satisfaction levels, customer awareness, safety and emergencies.

Response:

As discussed in Part III, Section B, Tab 1, p. 114 of the Application, Terasen Gas has 10 SQIs that we measure and compare against benchmarks on an annual basis. Also included are two directional indicators that do not have benchmarks, but that are designed to give an understanding of trends that may develop in these areas relating to customer service. The SQI measures encompass customer satisfaction, safety and emergency response.

TGI performance related to these SQIs has been provided in Part III, Section B, Tab 1, Table B-1-4 of the Application and an update showing 2009 year to date results at the end of June 2009 was provided in response to BCOAPO IR 1.15.5. This response is appended below.

In addition to the SQI measures, TGI also conducts research into customer safety and awareness of key messages. This includes public safety awareness and advertising tracking.

TGI's public safety awareness study is conducted to assess the public's awareness and understanding of natural gas safety and measure the impact of our public safety communications. The study results are used to plan future public safety communications.

Advertising tracking studies are conducted to measure the impact of radio and television when advertising activity levels are sufficiently broad to warrant a tracking study. The information collected is used to refine messaging and to provide guidance as to the most effective use of advertising dollars.

BCOAPO IR 1.15.5:

	Performance Indicator	June 2009 YTD Actual
1	**Emergency Response Time** - Time Dispatched to Site - Emergency - Blowing Gas	23:00 minutes
2	**Speed of Answer – Emergency** (% of calls answered within 30 sec.)	98.3%
3	**Speed of Answer – Non-Emergency** (% of calls answered within 30 sec.)	76.7%
4	**Transmission Reportable Incidents**	0
5(a)	**Index of Customer Bills Not Meeting Criteria**	5.23
5(b)	**Percent of Transportation Customer Bills Accurate**	92.3%
6*	**Meter Exchange Appointment Activity**	95.4%
7	**Accuracy of Transportation Meter Measurement First Report**	98.9%
8	**Independent Customer Satisfaction Survey**	80.0%
9	**Number of Customer Complaints to BCUC**	32
10	**Number of Prior Period Adjustments**	14

	Directional Indicators	
1	Leaks per Kilometer of Distribution Mains	0.0014 26
2	Number of Third Party Distribution System Incidents	609

*Note:

Due to improved reporting, Measure 6 has been adjusted to exclude those appointments not met as a result of the customer not being home for their scheduled appointment.

16.5.1 Please provide the results for these metrics by year for 2003 – 2009 YTD June.

Response:

As per BCUC IR 2.16.5, TGI reports on 10 SQIs in total that we measure and compare against benchmarks/previous year results on an annual basis. Table 1 below shows six of these SQIs, and two directional indicators that summarize the Company's performance related to customer satisfaction (CS), safety and emergency response. The results of these metrics are summarized in the following table:

Table 1: Historical SQI Performance Related to CS, Safety and Emergency Response

	Performance Indicator	2003 Annual Actual	2004 Annual Actual	2005 Annual Actual	2006 Annual Actual	2007 Annual Actual	2008 Annual Actual	2003 - 2008 Average	2009 YTD June Actual
1	**Emergency Response Time** - Time Dispatched to Site - Emergency - Blowing Gas	22:00 minutes	21:36 minutes	21:42 minutes	21:30 minutes	20:36 minutes	20:42 minutes	21:35 minutes	23:00 minutes
2	**Speed of Answer – Emergency** (% of calls answered within 30 sec.)	96.3%	97.9%	98.8%	98.6%	98.4%	98.3%	98.0%	98.3%
3	**Transmission Reportable Incidents**	3	3	3	1	1	2	2	0
4	**Independent Customer Satisfaction Survey**	73.9%	73.9%	77.2%	77.9%	79.3%	79.7%	77.0%	80.0%
5	**Number of Customer Complaints to BCUC**	101	191	121	152	130	90	131	32
6	**Number of Prior Period Adjustments**	24	18	14	21	23	15	19	14
	Directional Indicators								
7	Leaks per Kilometer of Distribution Mains	0.0040 134	0.0045 150	0.0034 120	0.0021 76	0.0024 87	0.0016 57	0.0030 104	0.0014 26
8	Number of Third Party Distribution System Incidents	1,459	1,492	1,457	1,508	1,545	1,574	1,506	609

Most SQIs have remained reasonably stable over the reporting period.

Customer Satisfaction is at an historical high (80%). Formal reporting on this score from the market research vendor is unavailable until November 2009.

Customer complaints include Terasen Gas Inc. and Terasen Gas Vancouver Island. Terasen Gas customer complaints to BCUC typically concern disconnects, billing issues, security deposits, meter reading, equal payment plan and other issues. Complaints are not benchmarked. See TGI's response to BCUC IR 16.5.2 for more information on this metric.

TGI did not meet the Emergency Response Time of 21.1 minutes from 2003 to 2006. For the period 2003-2008, TGI marginally missed the target by an average of 15 seconds. This information was shared with stakeholders during each Annual Review.

From 2006 to present we changed our processes in dispatching staff to emergencies resulting in a 1 minute improvement in 2007 & 2008. We will continue to examine areas for improvement in future.

16.5.2 Please provide the expected improvement in these metrics due to ongoing investment in customer information and education expenditures in 2010 and 2011.

Response:

Although TGI has not proposed any SQI metrics within the 2010 and 2011 RRA period, the following response discusses the association between customer communication and education expenditures and the current SQI metrics related to customer satisfaction, safety and emergency response.

The six SQIs and two directional indicators that have been used during the PBR Period to report the Company's performance related to customer satisfaction, safety and emergency response have varying degrees of association with TGI's communication and education expenditures. Performance for the majority of these SQIs is driven by operating procedures and processes; however, third party system incidents (damages), complaints to the Commission and customer satisfaction are impacted by TGI communications activities.

One opportunity to improve SQI performance as a result of communication activities is a potential reduction in third party damages. Increased knowledge of BC One Call and proper safety procedures as might be influenced by additional investment in communication and education should reduce third party damage to our system. However, TGI is unable to assign or forecast a specific quantitative improvement to this metric in response to ongoing investment in customer communication and education activities because third party damages are influenced by other variables, including the level of construction activity.

As noted in the response to BCUC IR 2.16.5.1, customer complaints to the Commission can be impacted by both TGI actions and events that are beyond the Company's control. As discussed in response to BCUC IR 1.133.3:

> *"Informing and educating the public through communication channels in addition to the monthly account statement can assist customers in developing more understanding regarding Terasen Gas and the services we provide to them. Providing more information and education to customers is much more likely to reduce customer complaints from what they otherwise would have been. Communication activities cannot eliminate all customer concerns or complaints; however they can provide customers with additional information and understanding regarding potential issues or concerns. This will lead to a reduction in the number of complaints than those that would have occurred had customers had no information."*

Due to the impact of both internal and external variables on customer complaints to the Commission, TGI cannot provide a certain numeric improvement directly tied to maintaining our ongoing investment in customer information and education.

TGI residential customer satisfaction, which makes up 75% of the overall customer satisfaction SQI result, is also influenced by communication and education activities. As shown in Figure 1 in the response to BCUC IR 2.16.3, the overall residential customer satisfaction score is a composite of seven attributes. Marketing and communications is an important contributor to overall satisfaction; however, the nature of the overall metric and potential variables that can influence overall results prevent TGI from quantifying a specific predicted improvement in the customer satisfaction SQI result due to maintaining ongoing investment in customer communication activities.

TGI undertakes a variety of customer communications and education as part of its service to customers. Communications include activities to ensure customers receive the information they need to manage their bill, and use natural gas safely. Many of the communication activities include items referred to as "hygienics," or "price of admission" attributes that customers expect an organization to provide as a result of the nature of its business. For TGI, safety issues often fall into this category. They're very important to customers, but satisfaction scores seldom improve by enhancing safety programs. In contrast, satisfaction scores can be seriously compromised if a preventable accident takes place for which TGI is held accountable.

SQIs upon which to evaluate the performance of specific communication expenditures were not identified in 2003 when they were first established. In fact, satisfaction represents an inappropriate measure to evaluate the success of some communication efforts, such as a campaign designed to enhance customer knowledge of natural gas safety issues. Individuals may indicate satisfaction with a campaign, but unless the campaign has educated people to behave differently or grasp an issue, it has not accomplished its goal.

The suggested investment levels to accommodate increasing departmental work demands and enhanced safety communications are oriented towards the delivery of ongoing communication and education content. Without these investments, improvements in customer knowledge of natural gas safety, including what to do if they smell gas, or to call before they dig, will not be achieved.

17.0 Reference: Operations and Maintenance Expense

Exhibit B-1, Part III, Section C, Tab 6, p. 364

Exhibit B-1, Part III, Section C, Tab 6, p. 384

B&ITS O&M - Incremental Funding

17.1 For Tables Table C-6-28 and Table C-6-29, please provide breakdowns of the incremental funding by cost driver. Use the same format as Table C-6-18: Distribution Service Enhancement O&M Cost Drivers for 2010 and 2011 vs. Prior Year.

Response:

Service Enhancements for B&ITS vs. Prior Year: ($000's)

		Yr 2010	Yr 2011
Facilities	Building Maintenance	$285.00	($147.00)
Facilities	Lease/ Service contract	$73.00	
Facilities	Restacking	$140.00	($140.00)
Facilities	New headcount	$61.00	
Facilities	Increase Travel & training	$13.00	($13.00)
IT	Incremental Headcount	$505.00	
IT	Headcount transfer from TGVI+ expenses	$103.00	
IT	Incremental Admin expenses	($10.00)	
IT	Hiring Costs		($65.00)
IT	Incremental SW costs	$277.00	$44.00
IT	Incremental Support Services - Infrastructure	$677.00	$123.00
IT	Incremental Support Services - Application	$551.00	$15.00
IT	Pre Buy Normalization	$190.00	$22.00
IT	Cost to Support New capital Projects	$509.00	$631.00
VP	Labor Inflation/other True Ups		$33.00
VP	Other	$20.00	
IT & Business Services	Total	$3,394.00	$503.00
Ops Eng	Location Records[14]	($200.00)	
Ops Eng	Vehicle Lease Adjustment		($22.00)
Ops Engineering	Total	($200.00)	($22.00)
Ops Sup	Mtce Distribution tools., generator	$160.00	
Ops Sup	Meter Shop credit TGVI shared services	$170.00	
Ops Sup	Loss of 3rd Party Revenue	$110.00	
Ops Sup	Other	$19.00	
Ops Sup	Total	$459.00	$0.00
B&ITS total		**$3,653.00**	**$481.00**

[14] In reviewing the details, this item was erroneously categorized as "service enhancement" when it should have been categorized as "code compliance". Service enhancements for B &ITS is understated by $200K but this is offset by code compliance being overstated by $200K.

18.0 Reference: Taxes

Exhibit B-1, Part III, Section C, Tab 7, p. 415

http://www.fin.gov.bc.ca/scp/hst/index.html

Harmonized Sales Tax

"Subject to the approval of the BC legislature and the Parliament of Canada, effective July 1, 2010, the government of British Columbia intends to harmonize its provincial sales tax with the federal Goods and Services Tax to lower costs for business, enhance productivity and create jobs." http://www.fin.gov.bc.ca/scp/hst/index.html

18.1 Please provide schedules showing the impact of the Harmonized Sales Tax on the 2010-2011 revenue requirements and rates.

Response:

The Company is unable to provide the revised financial schedules at this time, although the Harmonized Sales Tax ("HST") is expected to have some impact on working capital requirements for 2010 and 2011, as well as O&M and capital amounts included in cost of service.

The Governments of Canada and B.C. recently announced that an HST will be implemented in B.C. effective July 1, 2010. The information available on the proposed change to HST is very limited; the Company will be unable to estimate the financial impact of the proposed changes with any certainty until HST legislation is available. The government announcement of July 23, 2009 indicated that businesses will be entitled to claim Input Tax Credits ("ITCs") on HST paid. However, large businesses will have their ITCs restricted during the first 8 years of HST implementation. For this reason, TGI expects that some, but not all, of the PST embedded in the Cost of Service will be recoverable by way of input tax credits. TGI is in the process of analyzing the PST cost embedded in O&M and in Capital to better quantify the potential impact of the changes, but has not yet completed this analysis.

On September 1, 2009, the BC Government further announced in its Budget that it proposes to provide a provincially administered HST rebate of the provincial portion of the HST on residential energy, similar to the existing PST exemption for energy purchased for residential use, to reduce the impact of the HST on consumers. This rebate will apply to natural gas for residential use; as a result the effective HST rate on natural gas for residential use is expected to be 5%, the same as the GST rate today. Natural gas for non-residential use will be subject to HST at 12%.

TGI will continue to monitor the progress of the HST legislation and assess the resulting impacts.

19.0 Reference: Taxes

Exhibit B-1, Part III, Sec C, Tab 7, (g) Tax Issues, pp. 415 & 416

Tax Benefits Relating to Prior Periods

"In 2001 and 2002, after the completion of the Southern Crossing Pipeline, roughly $11 million of costs were incurred for landscaping and restoration of the site. For accounting and regulatory purposes, these costs were capitalized to transmission pipeline. For regulatory tax purposes, these costs were added to Undepreciated Capital Costs ("UCC") as part of Class 1, and customers have been receiving the benefit of the Capital Cost Allowance ("CCA") deduction ever since. To date, customers have received the tax benefits relating to $2.8 million of the total $11 million costs. For legal entity tax purposes, however the Company deducted the costs in the years incurred, being 2001 and 2002. The Company's view was that the deductions would be challenged by CRA. For this reason, and because of the large amount involved, the tax benefits were recorded to the balance sheet until such time as CRA completed its audit of 2002. Ultimately, the CRA audit of 2002 was completed in 2007 and no audit adjustments were proposed."

"As a result of these adjustments, customers have received the full benefit on the $2.8 million of costs by way of CCA deduction from 2001 to 2008, and have shared in the remainder of the tax benefit as a result of the 2009 tax deduction."

The table below was prepared by Commission staff under the assumption that $8 million of the expenses were incurred and deducted for tax purposes in 2001 and $3 million in 2002.

	Opening UCC (Class 1, 4%)		Current Year CCA		Federal Tax Rate	Provincial Tax Rate	Sur Tax	Combined Rate	Tax Benefit Received by Ratepayer
2001	$ 8,000,000	*	$ 160,000	^	27.00%	16.50%	1.12%	44.62%	$ 71,392
2002	$ 10,840,000	**	$ 373,600	^	25.00%	13.50%	1.12%	39.62%	$ 148,020
2003	$ 10,466,400		$ 418,656		23.00%	13.50%	1.12%	37.62%	$ 157,498
2004	$ 10,047,744		$ 401,910		21.00%	13.50%	1.12%	35.62%	$ 143,160
2005	$ 9,645,834		$ 385,833		21.00%	12.75%	1.12%	34.87%	$ 134,540
2006	$ 9,260,001		$ 370,400		21.00%	12.00%	1.12%	34.12%	$ 126,380
2007	$ 8,889,601		$ 355,584		21.00%	12.00%	1.12%	34.12%	$ 121,325
2008	$ 8,534,017		$ 341,361		19.50%	11.50%	0.00%	31.00%	$ 105,822
∑2001 - 2008 Tax Benefit Received by Ratepayer	$ 8,192,656		$2,807,344						**$ 1,008,139**
* assumes $8 million addition in 2001									
** assumes $3 million addition in 2002									
^ considered 50% rule for additions									

19.1 Please confirm the amounts incurred and deducted in 2001 and 2002, totalling $11 million and update the table if required.

Response:

Background

Consistent with the CPCN application for the Southern Crossing Pipeline, roughly $11 million of costs were incurred for landscaping and restoration of the pipeline right of way in 2001 and 2002. As forecast in the CPCN, these costs were added to Undepreciated Capital Costs ("UCC") as part of Class 1, for regulatory tax purposes and rate setting and customers have been receiving the benefit of the Capital Cost Allowance ("CCA") deduction ever since. By the time the actual tax returns were prepared for the legal entity in June of 2002, the Company concluded it could deduct the costs as a current expense in the years incurred, being 2001 and 2002. The Company's view was that the deductions were appropriate, but there was some uncertainty regarding whether the deductions would be challenged by CRA. For this reason, and because of the large amount involved, the tax benefits were recorded as a reduction to the carrying value of fixed assets on the balance sheet rather than being recognized in income until such time as CRA completed its audit of 2002. Ultimately, the CRA audit of 2002 was completed in 2007 and no audit adjustments were proposed which will allow the Company to recognize the elimination of the balance sheet item.

Treatment of Differences

In accordance with the terms of the PBR agreement, the recognition of the remaining deductions relating to landscaping costs for regulatory tax purposes in 2009 results in a reduction in the regulatory tax expense and is subject to sharing with ratepayers as opposed to being captured in the tax deferral account. The tax deferral account was established to capture changes in income tax rates and new taxes. These variances are clearly not in the nature of income tax rate changes or new taxes, therefore do not meet the criteria for deferral. Instead these variances, consistent with other variances not captured by the tax deferral account as contemplated in the PBR Agreement, are treated as being subject to earnings sharing.

The Company also views as appropriate that these remaining deductions are shared with customers in the 2009 ESM calculation, and as a result are recognized at the 2009 income tax rate, as opposed to the 2001 and 2002 tax rates. The Company believes that it is reasonable to return these items at the time the benefit is certain and available to be returned to customers. Under the PBR arrangement, such variances are taken into account for Earnings Sharing Mechanism purposes therefore the Company has treated the adjustments consistently with other 2009 variances.

As explained below, ratepayers will receive tax benefits totaling approximately $2.2 million under TGI's approach, while ratepayers would otherwise have been entitled to tax benefits totaling approximately $1.9 million in 2001 and 2002 had there been no uncertainty regarding the tax deductions. While the Company received tax benefits totaling approximately $4.7 million in 2001 and 2002, these were not recognized in income as there was no certainty that these benefits would be sustained. It was therefore appropriate and reasonable to provide the "fallback" tax position to ratepayers, being their treatment as Class 1 costs, until such time as the uncertainty was eliminated.

Calculation of Tax Benefits Received by TGI in 2001 and 2002

For 2001 and 2002, the Company determined that it was appropriate to deduct the costs as landscaping costs for tax purposes. In its tax returns TGI obtained a deduction for landscaping costs of $8,870,920 in 2001 and $2,121,866 in 2002. At the tax rates in effect in 2001 and 2002, the Company obtained benefits of $4.7 million, as calculated on Table 1 below.

Table 1

		Landscaping Deduction	Federal Tax Rate	Provincial Tax Rate	Surtax	Combined Rate	
2001	$ 8,870,920	$ 8,870,920	27.00%	16.50%	(1)	43.50%	$ 3,858,850
2002	$ 2,121,866	$ 2,121,866	25.00%	13.50%	(1)	38.50%	$ 816,918
Tax Benefit Received by Terasen Gas Inc.							$ 4,675,769

(1) Surtax offsets against LCT therefore net tax rate excludes surtax.

In 2001 and 2002, neither Canadian nor US GAAP had any guidance on uncertain tax positions and as such these amounts would not have been considered a contingent liability. Given the reassessment risk related to these amounts, the Company did not recognize any benefit relating to these amounts for financial or regulatory purposes. The unrecognized tax benefits were recorded as a reduction to fixed assets for external financial reporting purposes. The Company did not record a liability for either financial reporting or regulatory reporting purposes.

The tax benefit is reported as a non-regulated credit to fixed assets on the Company's balance sheet, as such it has not been included in the rate base calculations. The balance at December 31, 2008 is $3.6 million.

Calculation of Tax Benefits Received by Ratepayers 2001 – 2008

Given the uncertainty of deducting the landscaping costs, the Company's view at the time was that it was more prudent for ratemaking purposes to treat the costs as Class 1 UCC, rather than pass the full benefit of the landscaping deductions to ratepayers, and subsequently have to claw back the benefits if they were successfully challenged by CRA. The Company thus confirms that the full amount of the tax benefit of $4.7 million was not passed onto ratepayers in 2001 and 2002. Instead, for the reasons described above, the landscaping costs were treated as additions to Class 1 UCC in 2001 and 2002.

The Company confirms that approximately $11 million was recognized as an increase in the regulatory UCC balance in 2001 and 2002, and that during the years 2001 to 2008, ratepayers benefited from the tax benefits of Class 1 CCA associated with the costs. The Company is proposing to recognize the remaining tax benefits in 2009 now that the CRA audit is complete.

CCA taken for regulatory purposes between 2001 and 2008 amounts to approximately $2.8 million, and as a result ratepayers received tax benefits totaling approximately $1.0 million during the period 2001 – 2008. The tax benefit of approximately $1 million was flowed 100% to the ratepayer, since the CCA amounts were known or estimated in advance and included in the determination of rates.

Table 2 below has been adjusted to show actual amounts of landscaping costs incurred, being $8,870,920 in 2001 and $2,121,866 in 2002, for a total of $10,992,786. Note that tax rates for the years 2001 to 2005 have been adjusted to reflect the application of the surtax. In each of these years, any surtax payable was applied to reduce the Large Corporations Tax payable, therefore the net income tax rate effectively excluded the surtax.

Table 2

	UCC subject to CCA (Class 1 4%)	Current Year CCA	Federal Tax Rate	Provincial Tax Rate	Surtax	Combined Rate	Tax Benefit Received by Ratepayer
2001	$ 8,870,920	$ 177,418	27.00%	16.50%	(1)	43.50%	$ 77,177
2002	$ 10,815,368	$ 390,177	25.00%	13.50%	(1)	38.50%	$ 150,218
2003	$ 10,425,190	$ 417,008	23.00%	13.50%	(1)	36.50%	$ 152,208
2004	$ 10,008,183	$ 400,327	21.00%	13.50%	(1)	34.50%	$ 138,113
2005	$ 9,607,855	$ 384,314	21.00%	12.75%	(1)	33.75%	$ 129,706
2006	$ 9,223,541	$ 368,942	21.00%	12.00%	1.12%	34.12%	$ 125,883
2007	$ 8,854,599	$ 354,184	21.00%	12.00%	1.12%	34.12%	$ 120,848
2008	$ 8,500,415	$ 340,017	19.50%	11.50%	0.00%	31.00%	$ 105,405
2001-2008 Tax Benefit Received by Ratepayer	$ 8,160,399	$ 2,832,387					$ 999,558

(1) Surtax offsets against LCT therefore net tax rate excludes surtax.

Proposed Benefits to be Received by Ratepayers in 2009

The proposed tax benefit to be received by ratepayers in 2009 for regulatory purposes is $1,224,060, calculated as follows:

Amount of deductions remaining	$8,160,399
Tax Rate	30.0%
Amount of benefit to be shared	$2,448,120
Amount shared with ratepayers	$1,224,060

In summary, the total benefit to be received by ratepayers is the sum of the benefits received during 2001 – 2008 of $999,558 (as shown in Table 2), and the proposed benefit in 2009 of $1,224,060 (as shown above), for a total of $2,223,618, all as shown in Table 3 below.

Table 3

	CCA	Federal Tax Rate	Provincial Tax Rate	Combined Rate	ESM	Tax Benefit Received by Ratepayer
2001 - 2008 Tax Benefit Received by Ratepayer	$ 2,832,387				N/A	$ 999,558
Proposed 2009 Benefit	$ 8,160,399	19.00%	11.00%	30.00%	50%	$ 1,224,060
Total proposed benefit to Ratepayer						$ 2,223,618

Under Company's approach, the Company will recognize the elimination of the balance sheet item and share $2.4 million of regulated tax benefit with ratepayers through the earnings sharing mechanism.

Benefits Due to Ratepayers under Regulation in 2001 and 2002 Had There Been No Uncertainty Regarding the Tax Treatment of the Landscaping Costs

During 2000, when rates were determined for 2001, the final SCP costs had not yet been determined, therefore TGI had not determined the amount or timing of the landscaping costs. The process of analyzing the SCP costs, and in particular the landscaping costs which were incurred in 2001, for tax purposes was carried out in the Spring of 2002, in time for filing the 2001 tax returns in June 2002. Therefore, 2001 rates were set with the estimated costs included in the Class 1 UCC pool along with other costs relating to the pipeline. The amount of the 2001 landscaping costs was not determined with any certainty until June 2002. Therefore, even had there been no uncertainty regarding the treatment of the costs as deductible landscaping costs, that determination would not have been made in time to be included in the calculation of 2001 rates.

For these reasons, and because the 2001 year was under a PBR arrangement whereby such differences were shared with the ratepayer, ratepayers would have benefited by 50% of the difference in the tax benefit realized by TGI in 2001 ($3.9 million as calculated in Table 1) and the tax benefit of the 2001 CCA realized by ratepayers ($77 thousand as calculated in Table 2).

Ratepayers would have received no benefit for the 2002 variance because 2002 was not a test year, and not subject to a PBR arrangement.

Although TGI does not feel it is a realistic or appropriate assumption, ratepayers would have realized the following benefit had TGI taken the view that there was no uncertainty regarding the tax position:

2001 50% x ($3,838,850 - $77,177) = $1,880,837.
2002 No sharing of variances.
Total ratepayer benefit $1,880,837.

As set out in Table 3, the Company is proposing to provide ratepayers with benefits totaling $2,223,618 in respect of the landscaping cost deductions. Had the Company **not** taken the view that there was some risk in deducting the landscaping costs, ratepayers would have received benefits totaling $1,880,837 (as explained above). Therefore the proposal by the Company provides greater benefits to ratepayers than they would otherwise have been entitled to in 2001 and 2002.

Working Capital

Since income tax expense is an input to the determination of the cash working capital component of rate base, amounts that were incorporated into the determination of income tax expense would have impacted working capital requirements. There was no separate deduction of the difference between what had been claimed for tax purposes related to this item and the treatment of this item in the regulatory schedules, because the tax treatment had not been determined at the time of determining rate base for 2001 and 2002 rate setting purposes. Neither has working capital been adjusted in subsequent years to reflect the remaining balance of the tax benefit.

TGI has also not accumulated interest or AFUDC on this amount. TGI has held the approximately $3.6 million difference between the amount received as a tax benefit in the filing of the Corporate income tax returns and the accumulated tax benefit returned to rate payers in a non-regulated balance sheet account, pending final disposition of the tax returns for the affected years. Since TGI was holding the risk related to this potential assessment, and would have been required to pay interest to CRA had the amounts been determined not deductible in the year(s) incurred, it is appropriate that TGI also not be required to accumulate interest to ultimately be returned to ratepayers, nor should TGI treat the amount as a deduction from rate base. Ratepayers have benefited from the treatment that TGI has pursued, in achieving tax deductions earlier than would have otherwise been the case. TGI took the risk for this approach, and TGI is appropriately crediting the remaining refund back to ratepayers in 2009.

Summary

In summary, it is the Company's view that ratepayers will have shared in the tax benefits related to the landscaping tax deductions in a manner that is fair, appropriate, and consistent with the negotiated and agreed terms of the PBR agreement.

19.2 For the years between 2001 and 2008 please confirm the amount of CCA taken for regulatory purposes agrees to the table above. If amounts differ from calculation above please update the table accordingly.

Response:

Please refer to the Company's response to BCUC IR 2.19.1.

19.3 Please confirm that the total CCA taken for regulatory purposes (not statutory) between 2001 and 2008 amounts to $2.8 million and results in a $1 million tax benefit which has been shared with the ratepayer. If amounts differ from calculation above please update the table accordingly.

Response:

Please refer to the Company's response to BCUC IR 2.19.1.

20.0 Reference: Taxes

Exhibit B-1, Part III, Sec C, Tab 7, (g) Tax Issues, pp. 415 & 416

Tax Benefits Relating to Prior Periods

			Landscaping Deduction		Federal Tax Rate	Provincial Tax Rate	Sur Tax	Combined Rate	
2001	$ 8,000,000		$ 8,000,000		27.00%	16.50%	1.12%	44.62%	$ 3,569,600
2002	$ 3,000,000		$ 3,000,000		25.00%	13.50%	1.12%	39.62%	$ 1,188,600
Tax Benefit Received by Terasen Gas Inc									$ 4,758,200

20.1 The above table was prepared by Commission staff. Please confirm that TGI obtained a deduction for landscaping of $8.0 million in 2001 and $3.0 million in 2002 on its corporate tax returns (T2) filed with Canada Revenue Agency ("CRA"). If amounts differ from calculation above please update the table accordingly.

Response:

Please refer to the response to BCUC IR 2.19.1.

20.2 Please confirm that the tax benefit TGI received in 2001 and 2002 on the landscaping deductions totals $4.8 million. If the amounts differ from the calculation above please update the table accordingly.

Response:

Please refer to the response to BCUC IR 2.19.1.

20.3 Please confirm that the full amount of the $4.8 million tax benefit realized in 2001 and 2002 was not passed onto ratepayers at that time as it was considered an uncertain tax position and could have been challenged by CRA.

Response:

Please refer to the response to BCUC IR 2.19.1.

20.4 Would the uncertain tax position identified above have met the definition of a contingent liability under Canadian GAAP?

Response:

Please refer to the response to BCUC IR 2.19.1.

20.5 Was a liability set up to provide for the uncertain tax position for either financial reporting or regulatory reporting?

Response:

Please refer to the response to BCUC IR 2.19.1.

20.6 If the $11 million deduction had not been considered an uncertain tax position in 2001 and 2002, would ratepayers have benefited in 100 percent of the $4.8 million tax benefit realized byTGI at that time?

Response:

Please refer to the response to BCUC IR 2.19.1.

20.7 Did TGI reduced its working capital by $4.8 million in 2001 / 2002, thereby reducing overall ratebase? If not, why not? Has working capital been adjusted in subsequent years to reflect the remaining balance of the tax benefit?

Response:

Please refer to the response to BCUC IR 2.19.1.

20.8 If working capital was not adjusted, has TGI accumulated AFUDC or interest on this amount to be returned to ratepayers? If so, how much is this amount?

Response:

Please refer to the response to BCUC IR 2.19.1

21.0 Reference: Taxes

Exhibit B-1, Part III, Sec C, Tab 7, (g) Tax Issues, pp. 415 & 416

Tax Benefits Relating to Prior Periods

"The Company proposes to make the following adjustment for regulatory purposes, with the view to dealing with the tax benefit that is still on the Company's balance sheet as of December 31, 2008 as well as eliminating the difference in UCC between the Utility and the legal entity. The remaining UCC balance of $8.2 million is reported as a deduction in the 2009 Timing Difference schedule. The opening UCC is correspondingly reduced by $8.2 million. "

21.1 Terasen states that the there is still a tax benefit on the Company's balance sheet. What balance sheet account is the tax benefit captured in, and what is the amount of the benefit as at December 31, 2008?

<u>Response:</u>

Please refer to the response to BCUC IR 2.19.1.

21.2 What is the proposed treatment to eliminate the balance sheet item identified above?

<u>Response:</u>

Please refer to the response to BCUC IR 2.19.1.

21.3 The table below was prepared by Commission staff. Please confirm that the proposed tax benefit to be received by ratepayers in 2009 for regulatory purposes is $2,457,792. If amounts differ from the calculations below please update the table accordingly.

	Opening UCC (Class 1, 4%)	Current Year CCA	Federal Tax Rate	Provincial Tax Rate	Sur Tax	Combined Rate	Tax Benefit Received by Ratepayer
Proposed 2009 Benefit	$ 8,192,656	$ 8,192,656	19.00%	11.00%	0.00%	30.00%	$ 2,457,797

Response:

Please refer to the response to BCUC IR 2.19.1.

21.4 The table below was prepared by Commission staff. Please confirm that the total benefit to be received by ratepayers is the sum of the benefits received during 2001 – 2008 of $1 million plus the proposed benefit in 2009 of $2.5 million for a total of $3.5 million. If amounts differ from calculation below please update the table accordingly.

	Opening UCC (Class 1, 4%)	Current Year CCA	Federal Tax Rate	Provincial Tax Rate	Sur Tax	Combined Rate	Tax Benefit Received by Ratepayer
∑2001 - 2008 Tax Benefit Received by Ratepayer	$ 8,192,656	$ 2,807,344					**$ 1,008,139**
Proposed 2009 Benefit	$ 8,192,656	$ 8,192,656	19.00%	11.00%	0.00%	30.00%	$ 2,457,797
Total Proposed Benefit to Ratepayer						A	$ 3,465,935

Response:

Please refer to the response to BCUC IR 2.19.1.

21.5 The table below was prepared by Commission staff. Please explain why TGI has only provided the ratepayers with a $3,365,935 benefit on the landscaping deductions taken in 2001 and 2002 when TGI received a $4,748,200 benefit from the deduction.

	Opening UCC (Class 1, 4%)		Current Year CCA		Federal Tax Rate	Provincial Tax Rate	Sur Tax	Combined Rate	Tax Benefit Received by Ratepayer
2001	$ 8,000,000	*	$ 160,000	^	27.00%	16.50%	1.12%	44.62%	$ 71,392
2002	$10,840,000	**	$ 373,600	^	25.00%	13.50%	1.12%	39.62%	$ 148,020
2003	$10,466,400		$ 418,656		23.00%	13.50%	1.12%	37.62%	$ 157,498
2004	$10,047,744		$ 401,910		21.00%	13.50%	1.12%	35.62%	$ 143,160
2005	$ 9,645,834		$ 385,833		21.00%	12.75%	1.12%	34.87%	$ 134,540
2006	$ 9,260,001		$ 370,400		21.00%	12.00%	1.12%	34.12%	$ 126,380
2007	$ 8,889,601		$ 355,584		21.00%	12.00%	1.12%	34.12%	$ 121,325
2008	$ 8,534,017		$ 341,361		19.50%	11.50%	0.00%	31.00%	$ 105,822
∑2001 - 2008 Tax Benefit Received by Ratepayer	$ 8,192,656		$ 2,807,344						**$ 1,008,139**
Proposed 2009 Benefit	$ 8,192,656		$ 8,192,656		19.00%	11.00%	0.00%	30.00%	$ 2,457,797
Total Proposed Benefit to Ratepayer								A	$ 3,465,935
			Landscaping Deduction		Federal Tax Rate	Provincial Tax Rate	Sur Tax	Combined Rate	
2001	$ 8,000,000		$ 8,000,000		27.00%	16.50%	1.12%	44.62%	$ 3,569,600
2002	$ 3,000,000		$ 3,000,000		25.00%	13.50%	1.12%	39.62%	$ 1,188,600
Tax Benefit Received by Terasen Gas Inc								B	$ 4,758,200
Excess of Benefit Received by Terasen Gas Inc as Compared to Ratepayer								A -B	**$ 1,292,265**

* assumes $8 million addition in 2001

** assumes $3 million addition in 2002

^ considered 50% rule for additions

Response:

Please refer to the response to BCUC IR 2.19.1.

22.0 Reference: Rate Base

Exhibit B-1, Part III, Section C, Tab 8, p. 439

http://www.vancouversun.com/news/Legal+loophole+spares+Terasen+from+paying+million/1874044/story.html

Southern Crossing Pipeline Reassessment

"B.C. Supreme Court Justice Arne Silverman has granted Terasen its appeal against a provincial government tax bill, freeing the B.C.-based natural gas distributor from almost $4.5 million in PST it owed for building a natural-gas pipeline in southwestern B.C." http://www.vancouversun.com/news/Legal+loophole+spares+Terasen+from+paying+million/1874044/story.html

"Terasen Gas will continue to collect in a rate base deferral account, the net payment along with costs of appeal, currently estimated at $0.3 million. When the appeal is resolved, the Company will seek a Commission order with respect to the disposition of the deferral account." (Exhibit B-1, Part III, Section C, Tab 8, p. 439)

22.1 Please provide the total Southern Crossing Pipeline Reassessment Deferral Account costs that TGI will seek to recover in rates.

Response:

On August 28, 2009, the Province of B.C. filed an application seeking leave to appeal the decision of the B.C. Supreme Court. Therefore, the resolution of this case is unknown at this time. The final outcome of the appeal may not be known until some time in 2010.

The following table lists the costs recorded in the rate base deferral account as of August 31, 2009.

Assessed tax including interest	$7,083,443
Legal fees	$468,244
Consulting fees	$33,073
Net-of-taxes on legal and consulting fees	$(156,674)
Balance, August 31, 2009	$7,428,086

22.2 How does TGI propose to dispose of the Southern Crossing Pipeline Reassessment Deferral Account?

Response:

As discussed in the response to BCUC IR 2.22.1, although the BC Supreme Court has recently ruled in Terasen Gas' favour, there is likely to be a lengthy appeal process that could last well into 2010. Given the continued uncertainty of the outcome, Terasen Gas does not propose to dispose of the Southern Crossing Pipeline Reassessment Deferral Account at this time.

Instead, TGI proposes to continue to include the account in rate base as has been presented in the financial schedules contained in Tab 13 through the forecast period. When the final disposition of the appeal has been determined, TGI will calculate the impact on revenue requirements that results from the timing difference between when the appeal is resolved and the end of 2011, and return that difference to customers in 2012.

22.3 Please provide schedules showing the impact of the disposition of the Southern Crossing Pipeline Reassessment Deferral Account on the 2010-2011 revenue requirements and rates.

Response:

As discussed in responses to BCUC IR 2.22.1 and 2.22.2, it is not yet possible to determine the ultimate disposition of the Southern Crossing Pipeline Assessment Deferral Account. However, the disposition as proposed in those responses would have no effect on the current 2010-2011 revenue requirement and rate proposals. TGI will calculate the impact on revenue requirements once the appeal is resolved and return that difference to customers in 2012.

23.0 Reference: Certificates of Public Convenience and Necessity ("CPCN")

Exhibit B-1, Part III, Section C, Tab 9, pp. 463-464

CPCN Threshold

"Terasen Gas also respectfully requests the approval to increase the CPCN filing threshold from $5 million to $20 million to improve regulatory efficiency and refocus resources to serve the requirements of new and existing customers. The Company will continue to act in the best interest of customers and demonstrate diligence through its approval process. TGI also believes that a $5 million dollar threshold is too low because it would capture projects that are generally not of a complex or significant nature and that do not warrant the cost and administrative burden on all parties of a separate CPCN Application. TGI believes that the threshold should be raised to $20 million to restrict CPCN Applications to projects that are relatively more complex and significant."

23.1 Confirm that TGI proposes to increase the CPCN Threshold from $5 million (excluding AFUDC) to $20 million (excluding AFUDC).

<u>Response:</u>

Confirmed.

23.2 For 2005-2011, please provide the dollar amount of gross capital additions that equates to a one percent increase in TGI's 2008-20011 revenue requirements. Use the format of the table below.

Capital Additions Revenue Requirements Impact

	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Projected 2009	Forecast 2010	Forecast 2011
Total Revenue Requirements							
1 Percent of Revenue Requirements							
Gross Capital Additions							

Response:

The approved revenue requirements for 2005 through 2008 have been provided in the tables below. The draft table as provided in the question refers to "Actual" for 2005 through 2008; in TGI's case, the term Revenue Requirement is applicable on a test year or approved basis.

Approximate Gross Capital Additions resulting in a 1% Revenue Requirements (excluding cost of gas) Impact.

($Millions)	Approved 2005	Approved 2006	Approved 2007	Approved 2008	Approved 2009	Forecast 2010	Forecast 2011
Total Revenue Requirements	$ 477.9	$ 494.7	$ 488.7	$ 491.0	$ 501.4	$ 540.3	$ 562.8
1% of Revenue Requirements	4.8	4.9	4.9	4.9	5.0	5.4	5.6
Approximate Gross Capital Additions	134.6	141.7	142.9	139.7	145.5	94.9	99.1

Notes:
Revenue requirement excludes cost of gas and is the approved amount for 2005-2009
Change in Depreciation policy in 2010; depreciation begins during inservice year
Assumption that Capital Additions occur on January 1st
Approved Return on Equity and Capital Structure used in calculations for 2005-2009
2009 Approved Return on Equity and Captial Structure used in calculations for 2010 & 2011

When the cost of gas is included in the total revenue requirement, the approximate gross capital additions equivalent to 1% of the revenue requirement are proportionally increased as demonstrated in the table below:

Approximate Gross Capital Additions resulting in a 1% Revenue Requirements (including Cost of Gas) Impact

($Millions)	Approved 2005	Approved 2006	Approved 2007	Approved 2008	Approved 2009	Forecast 2010	Forecast 2011
Total Revenue Requirements (including Cost of Gas)	$ 1,386.8	$ 1,646.2	$ 1,455.6	$ 1,512.8	$ 1,689.4	$ 1,515.9	$ 1,539.4
1% of Revenue Requirements (including Cost of Gas)	13.9	16.5	14.6	15.1	16.9	15.2	15.4
Approximate Gross Capital Additions	390.5	471.4	425.7	430.5	490.6	266.4	271.0

Notes:
Revenue requirement includes cost of gas and is the approved amount for 2005-2009
Change in Depreciation policy in 2010; depreciation begins during inservice year
Assumption that Capital Additions occur on January 1st
Approved Return on Equity and Capital Structure used in calculations for 2005-2009
2009 Approved Return on Equity and Captial Structure used in calculations for 2010 & 2011

23.3 Using a CPCN threshold of $5.0 million, please complete the table below.

$5.0 million CPCN Threshold

	2005	2006	2007	2008	Projected 2009	2010	2011
Gross Capital Additions ($000's)							
Value of CPCNs ($000's)							
Value of CPCNs as a percentage of Gross Capital Additions							
Number of CPCNs							

Response:

The above mentioned table cannot be completed without appearing misleading since some CPCNs were added to Gross Capital Additions over several years. Based on the interpretation that this IR was intended to determine the number of CPCNs granted during the 2005 – 2011 period with a $5 million threshold, TGI offers the following table:

$5.0 million CPCN Threshold

	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Projected 2009	Forecast 2010	Forecast 2011	Total
Gross Capital Additions ($'000s)	158,497	116,868	115,534	119,436	141,987	153,090	134,507	939,920
Residential Unbundling								-
Vancouver Low Pressure Replacement			2,977	7,216	7,289	254		17,736
Distribution Mobile Solution					5,590			5,590
Fraser River Crossing						27,349		27,349
Kootenay River Crossing							6,186	6,186
Huntingdon Station #3							12,398	12,398
Tilbury land purchase								-
Customer Care Enhancement								-
Advanced Metering								-
Value of CPCNs ($'000s)	-	-	2,977	7,216	12,879	27,603	18,584	69,259
								-
Value of CPCNs as a percentage of Gross Capital Additions	0%	0%	3%	6%	9%	18%	14%	7%

Notes:

1. Included are CPCN projects approved during the 2005 - 2009 period and anticipated in 2010 - 2011.
2. Residential Unbundling was a non-rate base deferral and not included in Gross Capital Additions
3. Amount approved for Vancouver Low Pressure Replacement project was $23.7 million.
4. Amount approved for Distribution Mobile Solution includes the allowed 10% contingency.
5. Amount approved for Fraser River Crossing includes the allowed 20% contingency above P50 estimate.

The table above shows that there were 4 CPCNs approved during 2005 – 2009 including Residential Unbundling, Vancouver Low Pressure Replacement, Distribution Mobile Solution, and the Fraser River Crossing. There are 5 projects that are expected to be in excess of $5 million in 2009-2011 including Kootenay River Crossing, Huntingdon Station #3, Tilbury Land Purchase, Customer Care Enhancement, and Advanced Metering. If approved, the Customer Care Enhancement project will be included in Gross Capital Additions in 2012 for approximately $123.7 million. Terasen Gas anticipates filing a CPCN for the purchase of land adjacent to the Tilbury LNG plant in 2009 and its metering technology in 2010. The Company expects the total project cost for its metering technology to exceed the proposed $20 million threshold.

23.4 Using a CPCN threshold of $20.0 million, please complete the table below.

$20.0 million CPCN Threshold

	2005	2006	2007	2008	Projected 2009	2010	2011
Gross Capital Additions ($000's)							
Value of CPCNs ($000's)							
Value of CPCNs as a percentage of Gross Capital Additions							
Number of CPCNs							

Response:

The above mentioned table cannot be completed without appearing misleading since some CPCNs were added to Gross Capital Additions over several years. Based on the interpretation that this IR was intend to determine the number of CPCNs granted during the 2005 – 2011 period with a $20 million threshold, TGI offers the following table:

	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Projected 2009	Forecast 2010	Forecast 2011	Total
Gross Capital Additions ($'000s)	158,497	116,868	115,534	119,436	141,987	153,090	134,507	939,920
Vancouver Low Pressure Replacement			2,977	7,216	7,289	254		17,736
Fraser River Crossing						27,349		27,349
Customer Care Enhancement								-
Advanced Metering								-
Value of CPCNs ($'000s)	-	-	2,977	7,216	7,289	27,603	-	45,085
								-
Value of CPCNs as a percentage of Gross Capital Additions	0%	0%	3%	6%	5%	18%	0%	5%

Notes:
1. Included are CPCN projects approved during the 2005 - 2009 period and anticipated in 2010 - 2011.
2. Amount approved for Vancouver Low Pressure Replacement project was $23.7 million.
3. Amount approved for Fraser River Crossing includes the allowed 20% contingency above P50 estimate.

The table above shows that there were 2 CPCNs approved during 2005 – 2009 (Vancouver Low Pressure Replacement and Fraser River Crossing) and 2 anticipated CPCN approvals in 2010-2011 (Customer Care Enhancement and Advanced Metering) that would meet a $20 million threshold. If approved, the Customer Care Enhancement project will be included in Gross Capital Additions in 2012 for approximately $123.7 million. Terasen Gas also anticipates filing a CPCN for its metering technology in 2010 and expects the total project cost to exceed the $20 million threshold.

23.5 Should the following issues be used by the Commission to determine if a CPCN is required?

1. The impact on a particular community or constituency likely cannot be mitigated to its satisfaction;

2. The risk associated with a project, as established through TGI's corporate risk management framework, is identified as High or Extreme.

Response:

No, TGI believes that tying the CPCN filing threshold to a dollar amount has worked well. TGI is aware that the criteria identified in the question have been cited in the context of other public utilities regulated by the Commission (although TGI is not aware of any circumstance where they were applied). In TGI's case, TGI believes that the use of the proposed monetary threshold is sufficient to ensure that projects reasonably requiring the level of advance (i.e. pre-project) regulatory review inherent in a CPCN application obtain that review.

A dollar amount threshold is simple and easy to apply. The two criteria suggested in the question would add a level of complexity for minimal additional value.

First, the question of whether or not the impact on a particular community or constituency likely cannot be mitigated to its satisfaction adds complexity because there is ambiguity in what constitutes a constituency or community. Further, it is largely subjective as to whether a proposed mitigation measures mitigates impact to the satisfaction of those groups.

Whether or not there is a CPCN application, TGI recognizes that working up front to engage stakeholders contributes to being able to successfully implement projects on time and on budget. TGI is motivated as part of its ongoing operations to seek to address concerns identified by stakeholder, wherever possible. Sometimes addressing all concerns is not possible, even with the smallest or most routine projects. The test identified could result in even very small or routine projects giving rise to a question about whether or not a CPCN is required. TGI does not believe that this is in the interest of customers, who will ultimately bear the added cost of additional regulatory proceedings.

The second issue, using the TGI risk management framework to identify the project risks as high or extreme, is a way for the Company to prioritize risks that it may face. This labeling of risk as High or Extreme to a specific project does not necessarily translate into the size and scope of the project or any particular need for detailed review by the Commission. Projects that are labeled High or Extreme by TGI risk management framework could be projects that are small in dollar amount and relatively straight-forward. Therefore, in TGI view, adding this type of criteria to a CPCN threshold does not lead to an efficient regulatory process.

TGI, as proposed in the Application, proposes that the threshold for a CPCN be moved from $5 million to $20 million and contain no further qualifications than those already established by the Commission.

24.0 Reference: Capital Structure

Exhibit B-1, Part III, Section C, Tab 10, p. 471

Interest Rate Forecast

"The interest expense reflects the Company's projected new issues, projected borrowing costs on new issues and short-term interest rates." (Exhibit B-1, Part III, Section C, Tab 10, p. 471)

24.1 Have credit spreads been falling back toward historical norms over the past six months (i.e., January to June 2009)?

Response:

Without defining "historical norms", TGI is unable to definitively answer the question. However, since 1994 there have been several instances of widening corporate credit spreads, followed by a return to lower levels similar to those seen before the widening. From January to July 2009, credit spreads, as measured for an A rated long term corporate bond issuer such as TGI, have narrowed.

24.2 What is the outlook for credit spreads for the second half of 2009 and into 2010?

Response:

There is no specific forecast for credit spreads. However, TGI does anticipate market participants will remain apprehensive as the global economy recovers from recession. Despite efforts by governments to ease liquidity constraints, uncertainty will continue to hamper credit markets. As a result, we anticipate credit spreads will remain volatile in the near term.

25.0 Reference: Capital Structure

Exhibit B-1, Part III, Section C, Tab 10, p. 472

Interest Expense Forecast

25.1 Please provide the Company's projected new issues, projected borrowing costs on new issues for 2010 and 2011.

Response:

Ultimately, the timing and size of the Company's future debt issues will depend on the outcome of the ROE and Capital Structure application as any increase in equity thickness will be offset by a reduction in new debt issued. However, within the application we assumed the following with respect to new debt issues:

- An issue of $100 million on December 1, 2009, with issue expenses of $1 million, and a coupon rate of 5.65%. This results in incremental interest expense for 2010 and 2011 of $5.783 million, as displayed on Section C, Tab 13, Schedules 64 and 65 Line 11.
- No new issues in 2010.
- An issue of $100 million on July 1, 2011, with issue expenses of $1 million, and a coupon rate of 6.129%. This results in incremental interest expense for 2011 of $3.158 million, all as displayed on Section C, Tab 13, Schedule 65 Line 12.

25.2 For Table C-10-2: Terasen Gas Interest Expense 2010 & 2011 please provide schedules showing the calculation of the Long-Term and Short-Term interest expense.

Response:

The calculation of the short-term interest expense amounts shown in Table C-10-2 are detailed on Section C, Tab 13, Schedules 62 and 63. The calculation shown on Row 11 is the amount of unfunded debt in Column (4) multiplied by the unfunded debt rate in Column (6).

The calculation of the long-term interest expense amounts shown in Table C-10-2 are detailed on Section C, Tab 13, Schedules 64 and 65. The total amount is on Row 26 of those schedules.

26.0 Reference: Depreciation Study and Rates

Exhibit B-1, Part III, Section C, Tab 11, p. 472

Implementation of Depreciation Recommendations

"Implementation of the recommended rates, which are set out in Table C-11-2 below, that were developed using the Average Service Life ("ASL") depreciation methodology and are expected to be compliant with IFRS requirements, would increase the average composite depreciation rate for Terasen Gas plant from approximately 2.7 per cent to 3.4 per cent [refer to line 62 of Table C-11-2], with the annual depreciation expense increasing by approximately $21 million."

26.1 Please compare the proposed the average composite depreciation rate for Terasen Gas plant of 3.4 percent to the average composite depreciation rates for Enbridge Gas Distribution, Union Gas, Gaz Metro and Pacific Northern Gas.

Response:

Please refer to the table below which compares the average composite depreciation rates for Enbridge Gas Distribution, Union Gas, Gaz Metro and Pacific Northern Gas, as provided by a representative from each utility, with Terasen Gas' proposed depreciation rate of 3.4%. It is important to note that the depreciation rates that have been proposed are specific to TGI's situation. The proposed increase in depreciation rates is primarily driven by the past practice of not implementing recommended depreciation rates, which has resulted in a large unrecovered loss. Therefore, TGI does not feel that it is appropriate to compare the proposed depreciation rates to other utilities without a thorough understanding of each utility's specific circumstance.

Company	Average Composite Depreciation Rate
Terasen Gas Inc.	**3.4%**
Enbridge Gas	**4.5%**
Union Gas	**3.3%**
Gaz Metro	**3.1%**
Pacific Northern Gas (West)	**2.81%**

27.0 Reference: Code of Conduct ("COC")

Exhibit B-1, Part III, Section C, Tab 11, p. 499

TGI COC

Directing Utility Customers to NRBs

"However, in situations where the service or product is upstream of the meter, such as providing alternative energy delivery systems that use a number of energy sources including renewable fuels such as geothermal and solar integrated with conventional energy forms of natural gas and electricity, Terasen Gas believes that section (#6) of the Code of Conduct may not apply as the section was developed primarily with the retail marketplace, rather than the upstream of the meter marketplace. " (Exhibit B-1, Part III, Section C, Tab 11, Accounting and Other Policies, p. 499)

"**6. Equitable Access to Services**

Except as required to meet acceptable quality and performance standards, and except for some specific assets or services which require special consideration as approved by the Commission, BCGUL (TGI) will not preferentially direct customers seeking competitively offered services to an NRB or a specific retailer." (TGI COC, p. 4)

27.1 Please file a copy of the TGI COC.

Response:

A copy of the TGI Code of Conduct for the Provision of Utility Resources and Services is included in Attachment 27.1.

27.2 Is TGI seeking Commission confirmation that section 6 of the TGI COC does not apply to services or products that are upstream of the meter?

Response:

No. Please see the response to BCUC IR 2.27.3.

27.3 Is TGI of the view that a COC for services or products upstream of the meter should be developed? Please explain.

Response:

Prior to responding to this question, clarification of the first paragraph of page 499 in the Application is required. This section of the Application was intended to be a review of the COC and whether or not it is still appropriate and whether changes were needed. In the review, TGI looked at section 6 of the COC and stated that it believes that this section may not be applicable to products or services upstream of the meter. TGI is not currently directing customers seeking such products or services to an NRB, but was making an observation of the applicability of the COC to that situation.

At the time that the COC was developed there was concern that TGI provision of services such as furnace repair and maintenance was an unfair competitive offering. As noted in the first paragraph of the COC:

> *"This Code of Conduct (Code) governs the relationships between [Terasen Gas Inc. (Terasen Gas)] and Non-Regulated Businesses (NRBs) for the provision of Utility resources, and conforms with the British Columbia Utilities Commission (Commission) "Retail Markets Downstream of the Utility Meter" (RMDM) Guidelines of April, 1997."*

These activities such as furnace repair and maintenance occur downstream of the meter. Currently, neither TGI, nor any affiliate, provides these types of downstream services.

The provision of alternative energy solutions is primarily for the provision of heat produced from gas, wood, geothermal sources, solar thermal resources (and other heat sources) or a combination of these, and delivered to the customer and metered at the point of delivery. This offering is very different than that of furnace repair or downstream of the meter activities. Further, as noted in response to BCUC IR 1.24.3, TGI believes that the provision of alternative energy should be a regulated offering, no matter who the provider of that service is, so long as that provider meets the legislative definition of a public utility. This will provide transparency in rates and services provided by alternative energy solutions.

As a result of the regulated nature of upstream activities such as alternative energy, TGI does not feel that the COC applies. Further, as there are a number of competitive alternatives for customers from which to choose a provider of alternative energy services, and as there is a COS for rate determination that ensures that existing natural gas customers are not unduly impacted by the provision of alternative energy services, TGI does not believe that a COC for upstream services or products is required.

"Terasen Gas believes that customers seeking services and products upstream of the meter are generally more sophisticated and knowledgeable than the average retail consumer and that choice available in the upstream marketplace is much more limited than in the retail marketplace."

27.4 Please explain why TGI considers the "customers seeking services and products upstream of the meter are generally more sophisticated and knowledgeable than the average retail consumer" and provide any research and analysis that supports this view.

Response:

The retail consumer, to which the RMDM guidelines apply, are primarily end use home owners seeking service for such items as furnace repair and maintenance. The consumer or customer seeking products upstream of the meter such as alternative energy are generally developers, institutional, municipal, commercial and industrial customers. They are typically seeking the provision of energy, have experience in selecting energy systems, and are interested in both the financial and environmental returns on investment.

As shown in response to BCUC IR 1.23.1.1 the residential customer in the IPSOS Reid survey had only a limited understanding of these systems. The customers surveyed in the TNS report, while stating that they had insufficient knowledge to make decisions about the specific solutions, demonstrated that they understood their need for more knowledge and were actively engaged in assessing options regarding alternative energy systems. TGI believes that this demonstrates that this group of customers is more cognizant of energy alternatives than the typical residential customer.

TGI's sales, account management and market development contact is valuable when it comes to dealing with these commercial and institutional customers. Their level of knowledge and sophistication can mean that these customers require more contact and longer sales cycles in order properly to be able to understand and assess projects, be that gas or alternative energy solutions. The staff and incremental costs associated with the $3 million in 2010 and $0.6 million in 2011 are required to not only maintain and grow the natural gas business but to also ensure that customers can be provided with the energy service they require, which could include alternative energy solutions.

27.5 If customers "seeking services and products upstream of the meter are generally more sophisticated and knowledgeable than the average retail consumer", please explain why TGI increased Sales, Account Management, and Market

Development staffing in 2009 and proposes additional increases of $3.0 million in 2010 and $599 thousand in 2011 in order to provide customers with "information and direction on a variety of energy matters".

Response:

Please see the response to BCUC IR 2.27.4

27.6 Please explain why TGI considers the "choice available in the upstream marketplace is much more limited than in the retail marketplace'" and provide any research and analysis that supports this view.

Response:

TGI believes there is a distinction between the services offered in the retail downstream marketplace and the upstream provision of regulated energy. The downstream marketplace consists of providers of furnaces, boilers and other appliances designed to covert commodities such as gas and electricity into a usable form of energy such as heat. Additionally, in the downstream marketplace there are service providers who repair and maintain these appliances. In both of these cases there are a significant number of providers of both these appliances and services and the market is mature. Lastly, this market is not regulated as the customer can change out these appliances at will or seek another provider of repair and maintenance services as required.

The upstream marketplace as described by TGI is for the provision of metered heat to an end use customer. In this case TGI, or another provider of such service, would typically install a central energy system and then deliver the heat through piping to an end use customer (this is most often referred to as a district energy system or DES). While there is competition in this marketplace from emerging local players as well as established energy providers, the nature of the provision of energy is more complex than purchasing a furnace and as such there are not as many providers of this service.

Further, once a developer or other customer has selected a provider of heat delivery (i.e. a DES), that customer will likely face contractual impediments (i.e. contract term plus any additional provisions regarding premature discontinuance of service) and practical impediments (i.e. the infrastructure has been installed and is owned by the provider, making it difficult for another DES to be installed) to purchasing energy from another provider, irrespective of whether that other provider supplies electricity, gas or alternative energy. Simply put, once the heat delivery service is installed, there is monopoly power exerted by the provider of this service. While the Commission's jurisdiction is not defined by whether or not a service is subject to competition or whether it is a monopoly, the scope of the definition of "public utility" is consistent with protecting customers from the exercise of monopoly power by third party providers of energy.

> "As a result, Terasen Gas believes there is no significant advantage conferred to the NRB if customers seeking services upstream of the meter are directed to the NRB by the Utility with consent provided by the customer."

27.7 Has TGI informed the participants in the 1997 Retail Markets Downstream of the Utility proceeding and stakeholders for markets upstream of the meter that TGI proposes to direct utility customers to NRBs for services upstream of the meter, such as alternative energy delivery systems?

Response:

No, TGI has not done so and does not believe it is necessary to do so. TGI is not directing products or services upstream of the meter to an NRB, nor does it intend to do so. Please see TGI's response to BCUC IR 2.27.3.

TGI's intention is for the Company, not an NRB, to offer alternative energy solutions. According to the definition of a "public utility" in the UCA, those services are regulated. TGI does not consider that the RMDM Guidelines have any application to regulated services of this nature being offered within the utility itself.

27.8 Please list the services upstream of the meter that the TGI NRB would provide.

Response:

Please see the response to BCUC IR 2.27.7.

27.9 Please explain how TGI's ratepayers benefit from the Utility directing customer seeking services upstream of the meter to the NRB.

Response:

Please see the response to BCUC IR 2.27.7.

27.10 Is TGI aware of any jurisdictions in North America that permits a gas utility to direct customers seeking services upstream of the meter to its NRB?

Response:

Please see the response to BCUC IR 2.27.7.

27.11 Please explain why "there is no significant advantage conferred to the NRB if customers seeking services upstream of the meter are directed to the NRB by the Utility with consent provided by the customer".

Response:

Please see the response to BCUC IR 2.27.7.

28.0 Reference: Transfer Pricing Policy and Code of Conduct Review

Exhibit B-1, Part III, Section C, Tab 11, p. 499

RMDM Guidelines, Section 5.3

Code of Conduct: Proposed Upstream Services – Customer Awareness

"Terasen Gas believes that customers seeking services and products upstream of the meter are generally more sophisticated and knowledgeable than the average retail consumer and that choice available in the upstream marketplace is much more limited than in the retail marketplace. As a result, Terasen Gas believes there is no significant advantage conferred to the NRB if customers seeking services upstream of the meter are directed to the NRB by the Utility with consent provided by the customer." [Exhibit B-1, Part III, Section C, Tab 11 p. 499]

"iii) No regulated company personnel will preferentially direct customers seeking competitively offered services to an NRB." [BCUC RMDM Guidelines, Section 5.3 iii]

28.1 Please explain how the above statement from the Application is consistent with the quoted sentence from Section 5.3 iii) of the Commission's RMDM Guidelines.

Response:

Please see the response to BCUC IR 2.27.7.

28.2 Please explain whether the "sophisticated and knowledgeable" customers referred to are limited to those within commercial and/or industrial rate classes.

Response:

Please see response to BCUC 2.27.3. With respect to preferential treatment of customers, TGI is not preferentially directing customers to an NRB that provides services downstream of the meter. With respect to competitively offered services upstream of the meter, such as alternative heat delivery services through a DES, TGI is not directing customers to an NRB. TGI's intention is for the Company to provide alternative energy solutions, not an NRB.

28.3 Please explain why a "sophisticated and knowledgeable" customer would need to be directed to a service supplier.

Response:

Please also see TGI's response to BCUC 2.28.2. TGI is not proposing that such a customer needs to be directed to a service supplier. TGI is proposing to offer heat delivery service to these customers and therefore would not be directing the customers anywhere.

28.4 Will the onus be on the customer to disclose, or on TGI to determine, the level of customer awareness of non-affiliate NRB alternatives?

Response:

Please see the response to BCUC IR 2.27.3.

28.5 Does TGI intend to advise customers seeking upstream-from-the –meter, non-gas energy services that there may be alternative service providers in addition to the affiliate NRBs?

Response:

Please see TGI's response to BCUC IR 2.27.3.

29.0 Reference: Transfer Pricing Policy and Code of Conduct Review

Exhibit B-1, Part III, Section C, Tab 11, p. 499

Code of Conduct: Proposed Upstream Services – Alternative Providers

"...in situations where the service or product is upstream of the meter, such as providing alternative energy delivery systems that use a number of energy sources including renewable fuels such as geothermal and solar integrated with conventional energy forms of natural gas and electricity, Terasen Gas believes that section (#6) of the Code of Conduct may not apply as the section was developed primarily with the retail marketplace, rather than the upstream of the meter marketplace." [B-1, Part III, Section C, Tab 11, p. 499]

29.1 Please describe any significant barriers to entry faced by firms intending to deliver each of residential, commercial, and industrial customers with geothermal and/or solar energy produced upstream of the utility meter.

Response:

The significant barriers to entry faced by firms, including TGI, intending to deliver geothermal and/or solar energy produced upstream of the utility meter are common competitive barriers. They include the ability to provide solutions in an efficient and timely manner (i.e., the ability to provide a solution that meets the customer's time requirements), ability to execute on commitments, financial capability, and knowledge of alternative energy systems.

The response to BCUC IR 2.27.3 discusses the fact that, in any event, TGI is not proposing to deliver alternative energy solutions through an NRB.

29.2 Please explain how TGI's existing assets give it advantages, particularly concerning economies of scale, compared to BC Hydro and FortisBC, for delivering integrated energy supplies, given that more addresses in the TGI service area have electrical service than gas service.

Response:

TGI's existing assets and competencies, such as extensive experience with piped energy delivery systems and related gas combustion equipment, give TGI some advantage over providers of electricity such as BC Hydro and Fortis BC. In addition, our natural gas service territory overlaps that of both BC Hydro and Fortis BC.

As noted in the question, there are more addresses in the TGI service that have electric service than gas service. However, TGI does not believe that this has any relation to the competitiveness of an alternative energy service offered by TGI.

30.0 Reference: Transfer Pricing Policy and Code of Conduct Review

Exhibit B-1, Part III, Section C, Tab 11, p. 499

Competition Act, RSC, Section 45

Code of Conduct: Proposed Upstream Services – Impact on Competition

"45. (1) Every one who conspires, combines, agrees or arranges with another person

(a) to limit unduly the facilities for transporting, producing, manufacturing, supplying, storing or dealing in any product,

(b) to prevent, limit or lessen, unduly, the manufacture or production of a product or to enhance unreasonably the price thereof,

(c) to prevent or lessen, unduly, competition in the production, manufacture, purchase, barter, sale, storage, rental, transportation or supply of a product, or in the price of insurance on persons or property, or

(d) to otherwise restrain or injure competition unduly,

is guilty of [an offence]..." [RSC, Competition Act, Sec. 45]

30.1 Please confirm that TGI believes that directing consumers to affiliated NRBs in the proposed manner would not unduly lessen competition.

<u>Response:</u>

TGI is not proposing to direct consumers to an NRB. TGI is proposing to provide alternative energy services as part of the gas utility. TGI confirms its view that the Competition Act would not preclude this activity.

31.0 Reference: Executive Summary

Exhibit B-4, BCUC 1.1.1, p. 1, and BCUC 1.2.4, p. 4

Impact of Forecasted Increases of Natural Gas Prices

As stated on page 1 of TGI's Application: "With this Revenue Requirements Application ("RRA" or the "Application), Terasen Gas Inc. ("Terasen Gas" or "TGI" or the "Company") is seeking an increase in its rates for delivery service for a two-year period commencing January 1, 2010. The increase sought for 2010 is 5.3 per cent, with an additional effective base rate delivery increase of 4.1 per cent (cumulative increase of 9.4 per cent) in 2011. It results in relatively modest changes to the annual bill of an average Lower Mainland residential customer with an approximate net increase of 2.8 per cent or $31 in 2010 and an additional 1.7 per cent or $19 in 2011."

31.1 Please provide a projection of what the impact TGI's increase in rates will have on residential customers during 2010 and 2011 as a result of (a) the proposed base rate delivery increase of 5.3 percent in 2010, and with an additional 4.1 percent increase in 2011; (b) the proposed Return on Equity increase currently before BCUC; and (c) the proposed Capital Structure plan currently before BCUC. Please provide a fully functional electronic spreadsheet similar to that provide in response to BCUC 1.1.1, Attachment 1.1.

Response:

Please see the response to BCUC IR 2.31.2 for a summary of the results. Please see Attachment 31.1 for the fully functional spreadsheet.

In addition to the three independent requests, the combined impact of the 2010 and 2011 Revenue Requirement, Return on Capital and Capital Structure changes has been added to the response and denoted with the tab suffix "combined". This additional information has been provided because the independent results cannot be added together to arrive at the combined impact as a result of two factors:

1. The compounding impact of the combined return on equity and capital structure changes on the earned return
2. A difference in the forecast long term debt assumptions associated with a change in capital structure

The Commission has an obligation in setting rates to provide utility investors with an opportunity to earn a fair return on equity. This obligation must be considered independently of the rate impacts. It should also be recognized that the outcome of the ROE proceeding affects the financial integrity of the Terasen Utilities and it is in customer's interests to have a financially healthy utility.

31.2 Please summarize the answer from the previous question in the following tabular format:

Impact of Price increases on Average Residential Customers - 2010 and 2011

Current Factors that can Influence the Price of Natural Gas	**2010**	**2011**	**Cumulative Increase (%)**	**2010 and 2011 Bill Impact ($)**
Proposed Base Rate Delivery Increase	5.3%	4.1%	9.4%	$50.00
Proposed Return on Equity Increase				
Proposed Capital Structure Plan				
Total				

Response:

As noted in the response to BCUC IR 2.31.1, the independent results cannot be added together to arrive at the combined impact as a result of two factors:

1. The compounding impact of the combined return on equity and capital structure changes on the earned return
2. A difference in the forecast long term debt assumptions associated with a change in capital structure

Therefore, the three rows in the table below are not additive to the total.

Impact of Delivery Rate increases on Average Residential Customers - 2010 and 2011

Current Factors that can Influence the Delivery Rate of Natural Gas	**2010 Delivery Rate Increase**	**2011 Delivery Rate Increase**	**Cumulative Delivery Rate Increase (%)**	**2010 and 2011 Bill Impact ($)**
Proposed Base Rate Delivery Increase	5.3%	4.1%	9.4%	$50.00
Proposed Return on Equity Increase	5.6%	0.0%	5.6%	$27.00
Proposed Capital Structure Plan	1.7%	-0.3%	1.4%	$7.00
Combined Impact	**13.8%**	**3.8%**	**17.6%**	**$87.00**

The percentages provided in the table above represent the increase in the delivery rate component of a customer's natural gas bill and do not reflect the percentage burner tip price increase. The combined impact of the proposed base delivery rate increase, return on equity increase and capital structure plan results in an approximate increase to the burner tip price of natural gas of 6.5% in 2010 and an additional 1.6% in 2011, for a total burner tip price increase of 8.1% for the two year period.

As noted in the response to BCUC IR 2.31.1, the Commission has an obligation in setting rates to provide utility equity investors with an opportunity to earn a fair return on equity. This obligation must be considered independently of the rate impacts. It should also be recognized that the outcome of the ROE proceeding affects the financial integrity of the Terasen Utilities and it is in customer's interests to have a financially healthy utility.

31.3 What is the revenue requirement impact of the above factors for each of 2010 and 2011? Please show your calculations in the form of a fully functional electronic spreadsheet.

Response:

Please refer to the response to BCUC IR 2.31.1 and Attachment 31.3.

31.4 In response to BCUC 1.2.2, TGI has indicated that the price elasticity of demand coefficient for natural gas in British Columbia is 0.21. How has the impact of price increases which have been summarized in the above table been factored into the load forecast for 2010 and 2011?

Response:

Although it is recognized that customers do change their short-term behavior when faced with sudden and significant commodity cost increases, long-term changes in use per customer rates for mature gas utilities are more a function of advances in heating technology and home construction techniques, both of which improve on an ongoing basis regardless of natural gas costs. Sudden increases in natural gas prices may accelerate the decision to purchase more efficient equipment, but once that purchase has been made the impact on consumption (related to the new equipment) is permanent regardless of whether prices later moderate. It is for this reason, and also the fact that it is difficult to isolate demand responses to only price, that TGI uses price elasticity more as a variable to monitor over time rather than adopting it as a driver of demand.

31.5 Please discuss what impact the price increases, that are being proposed by TGI, will have on the competitiveness and demand of natural gas compared to hydro and other alternative forms of energy.

Response:

All else equal (which is a significant assumption in this case), the increases in delivery rates will serve to close the differential between electricity rates and gas rates.[15] However, the Application describes a number of drivers behind the forecast revenue requirement increases in 2010 and 2011, and these reasons necessitate rate increases despite the contribution these increases make to closing the price gap with competing energy sources. In sum, it is an oversimplification to look only at the results of the revenue requirement increase without looking at what is necessitating the increases.

First, a portion of the increases sought are the product of factors such as accounting changes and inflation that are beyond the control of the Company.

Second, as discussed in the response to CEC IR 1.6.1, the competitive position of natural gas versus other alternatives energy forms, including electricity is increasingly influenced by factors beyond just price. Those additional factors include:

- Government policy and legislation intended to reduce GHG emissions (which means generally less consumption of fossil fuels),
- Growing public sentiment ("green") against the use of fossil fuels and in support of reducing GHG emissions,
- Public perception regarding fossil fuel-based energy prices and future carbon taxes. Although natural gas commodity prices are relatively low currently, significantly higher prices and price volatility are in recent memory. Public discussion of climate change and the need to implement carbon taxes or cap and trade regimes to reduce GHG emissions is a daily discussion. This is further compounded by the public perception that BC Hydro

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[15] As a point of clarification the only "price increases" that are proposed in this Application relate to the TGI delivery rates (5.3% in 2010, and 4.1% in 2011). Possible increases or decreases in natural gas commodity prices (referenced in BCUC IR 1.2.4) will be reflected in customer rates as determined by the TGI Quarterly Gas Cost Reports that are filed with the BCUC each quarter.

electricity supply is an "all green solution". TGI believes that perceptions are often as much an influence in public behaviour with respect to energy use as reality is.

- Other trends such as "densification" of urban areas in B.C. (resulting in part from the desire of governments to be greener and reduce GHG emissions). Densification means more multi-family dwellings and less single family detached housing where TGI has had its highest market share.

The changing housing mix, changing government priorities and changing public perceptions mean that natural gas may no longer be the fuel of choice for an ever growing segment of the population within the service area.

The requested increases to delivery rates that are attributable to these factors are necessary and prudent to position the Company to meet the changing needs of our customers and to adapt to the changing business environment in which TGI operates. Ultimately, addressing these needs is required to stay competitive.

32.0 Reference: Price Elasticity

Exhibit B-4, BCUC 1.2.2, p. 3

Natural Gas Price Elasticity of Demand

32.1 Are the price elasticities of demand for natural gas that were provided in response to IR 1.2.2 long or short run elasticities?

Response:

The price elasticities of demand for natural gas that were provided in the response to BCUC IR 1.2.2 are short run elasticities.

33.0 Reference: Price Elasticity

Exhibit B-4, BCUC 1.2.3, p. 3 and BCUC 1.11.1, p. 24

Elasticity of Demand between Natural Gas and Electricity

33.1 Please confirm that the value of 0.01 estimated for the cross-price elasticity of demand between natural gas and electricity is in terms of the change in electricity demand in response to a change in the price of natural gas.

Response:

TGI confirms that the value of 0.01 estimated for the cross-price elasticity of demand between natural gas and electricity, is in terms of the change in natural gas demand in response to a change in the price of electricity.

33.2 Please confirm that a cross-price elasticity of demand of 0.01 implies that a 100 per cent increase in the delivered price of natural gas would result in some customers switching to electricity for some or all of their energy needs such that the demand for electricity aggregated over all customers increases by one per cent.

Response:

TGI confirms that a cross-price elasticity of demand of 0.01 implies that a 100 per cent increase in the delivered price of natural gas would result in an estimated one per cent increase in the demand for electricity. Although the response is typically through long-run changes in equipment purchases (as discussed in the attachment included in TGI's response to BCUC IR 1.2.3 – page 8, 1st paragraph), it would also include short-term responses from those customers who have fuel switching capabilities and also as a result of the purchase and use of portable baseboard heaters.

33.3 Please comment on the results presented in response to the previous question in terms of its support for TGI's view of its short term and long term competitiveness with respect to electricity and TGI's opinion of the importance of maintaining a price advantage over electricity?

Response:

The results presented in the previous question support the assumption that, as natural gas prices rise, there will be an increase in the demand for electricity. Although cross-price elasticity does not indicate the reasons for that increase, an analysis of the operating costs together with the upfront capital and installation costs associated with installing natural gas equipment (as compared to electrical equipment) allows for conclusions to be drawn.

Given the higher upfront capital and installation costs associated with installing natural gas equipment (rather than electrical equipment), the only factor providing some relief to this is the operating advantage natural gas currently has over electricity. But, a reduction in that operating advantage (which would be the case if natural gas prices rose, all else being equal) would lessen that relief, and a reasonable conclusion would be that less natural gas equipment would be installed in the future, as builders/developers and potential customers opt for electrical equipment rather than natural gas equipment. And this would lead to less growth in TGI's customers base, which when combined with the fact that average residential use per customer rates are declining, would ultimately contribute towards lower overall throughput levels on TGI's system, placing upward pressure on delivery rates.

Therefore, TGI's view of its short term and long term competitiveness with respect to electricity, and TGI's opinion of the importance of maintaining a price advantage over electricity are supported not only by the results presented in the previous response, but also through considering the difference in operating costs (between natural gas and electricity), capital costs of equipment, and installation costs. And from this, it is reasonable to conclude that it is important for TGI to maintain its price advantage over electricity.

Please see the response to CEC IR 1.6.1 for a list of other factors besides price, that are impacting TGI's competitive position.

33.4 On page 24, in response to IR 1.11.1 it states, "Electricity prices, when compared to the price of natural gas, provide an indication of the competitive environment in which TGI operates. The competitiveness of natural gas with respect to electricity, as discussed in the Application (pages 56-67), has eroded over the period 1998 to 2008 and this decline, together with the lower capital and installation costs for electric baseboard heaters has led to a more challenging competitive market environment, ultimately placing downward pressure on throughput levels and therefore upward pressure on delivery rates (all else being equal)."

33.4.1 Please reconcile the above statement with the implications of a cross-price elasticity of demand of 0.01 as provided in the response to IR 1.2.3.

Response:

The cross-price elasticity of demand as provided in the response to BCUC IR 1.2.3 provides an indication of the demand response for electricity given a price **change** in natural gas. It does not, however, provide an indication of how the current competitiveness of natural gas with respect to electricity impacts the demand for natural gas. And as discussed in the referenced section above, it is a combination of the diminishing competitiveness of natural gas with respect to electricity and the lower capital and installation costs for electric baseboard heaters that has led to a more challenging competitive market environment.

34.0 Reference: Customer and Stakeholder Expectations

Exhibit B-4, BCUC 1.8.2

Public Safety and Security

"However, TGI observes a shift towards greater interest in public safety and security. It can be demonstrated in several ways in the external environment, such as the development of new standards and regulations (see p. 51 to 55 of Application), new Government policy, extensive media coverage, and even more visible security threats in the industry. These factors are addressed in further detail below."

34.1 Please list by year the natural gas distribution pipeline incidents in Canada and British Columbia from 2003-2009 that resulted in extensive media coverage.

Response:

At Terasen, we do not keep record of media coverage of natural gas distribution pipeline incidents for other companies in Canada. However, a few incidents between 2007 and 2009 demonstrate that media attention can be extensive any time a news story has an element of public safety and security, regardless of whether or not it's directly related to natural gas pipelines. That is to say, that when a news story is about any pipeline or ignition source, the media often will contact Terasen Gas to tie in a public, natural gas safety angle.

In the summer of 2007, a crude oil pipeline owned by Kinder Morgan was struck by a third-party's backhoe in Burnaby B.C. The extent of the damage and dramatic pictures resulted in nation-wide coverage for days and local coverage throughout the aftermath. And though this story did not involve natural gas, Terasen received 33 media calls in the first two days.

In February 2008, three Lower Mainland news stories were featured in only two days. First on February 11th, there was an explosion at a Taco Del Mar on Broadway. While the cause turned out to be arson, initial media reports raised the possibility that it might have been a gas explosion. Then later that day, a third-party line hit near a Vancouver Community College campus caused the campus to be evacuated. Two days later an underground gas leak on Lougheed affected the evening commute, interrupted public transit service on Skytrain and most importantly caused the evacuation of an entire neighborhood, including the Global News TV station.

In April 2008, an unoccupied house in Surrey was the scene of a gas explosion. There was considerable media attention for a period of five days. Until the cause was identified as thieves stealing the copper in the natural gas piping, there was speculation about improperly installed gas appliances or a leak in the line, leading people to be concerned that their homes may be at risk.

In August 2008, a Toronto neighbourhood of more than 10,000 residents was evacuated after a major incident at a propane dealer. Nation-wide media coverage (including the Vancouver Sun) addressed public safety for such facilities in local residential areas.

In the fall of 2008 and continuing into 2009, EnCana's pipeline in Northern B.C. became the target of criminal sabotage activity with several attacks on their pipeline system. Safety and security for residents near EnCana facilities was featured in the media coverage.

In June 2009, Highway 97 outside of Kelowna was closed for several hours when road construction crews hit a major gas line. Media were onsite to interview representatives from Terasen Gas and the fire department. The local newspaper Kelowna Capital News posted a video on their website.

In addition to media coverage of these significant events, local media around British Columbia often covers smaller incidents involving TGI's distribution pipeline being damaged by third party excavators. These events, which may result in traffic disruption, often result in media coverage on the radio and newspaper.

The above recent examples demonstrate the considerable public and media interest in safety and security issues that involve energy and sources of ignition. As a responsible community energy provider, Terasen Gas needs to participate in and monitor the discussion to help educate our customers and British Columbians on safety and security issues and how it may or may not relate to our natural gas service.

34.2 Has TGI conducted customer research regarding customers' growing "public safety and security"? If yes, please provide the results of the research. If not, why not.

Response:

TGI has not conducted research specifically related to "customers' growing interest in public safety and security." The reference to customers' growing interest in the matter is attributable to TGI's observation of the external environment.

As stated in the response to BCUC IR 1.8.2, the terms "public safety" and "security" are being used to refer to a host of activities performed in order to ensure we deliver safe and reliable service to British Columbians. Because the public seldom sees or is even aware of the specific activities Terasen Gas undertakes to ensure safety, market research into the matter remains problematic. For example, the public is generally unaware of activities like aerial or gas leak surveys. However, these activities are undertaken on a regular basis to ensure our system is indeed secure and safe. Asking customers to judge the importance of these activities, or the frequency they are conducted is inappropriate. In general, customers want TGI to undertake those activities that ensure our system is safe and reliable. Moreover, they depend upon Terasen Gas and its regulators to decide the appropriate steps to take.

As shown by the continual introduction of new safety standards and regulations, all reasonable steps to mitigate the potential for personal injury should be implemented. Avoidable mistakes are not acceptable. Beyond the development of new standards and regulations (see p. 51 to 55 of the Application) as stated in TGI's response to BCUC IR 1.8.1, the shift towards greater interest in public safety and security is also demonstrated by the following:

- new government policy;
- extensive media coverage, and;
- highly visible security threats in the industry.

To address the increased demands related to public safety and security, TGI believes the proposed funding is reasonable and prudent.

34.3 Please list TGI customers' top five public safety and security issues.

Response:

Please see the response to BCUC IR 2.34.2. Although TGI researches customer perceptions and understanding of natural gas safety issues regularly, the focus of this research tends to focus on home safety. Several questions are included in the Company's Customer Satisfaction Survey that is conducted three times each year. However, this survey concentrates on establishing customer satisfaction levels associated with our safety communications and emergency response. It does not effectively identify what customers consider the most important safety issues. Bi-annually, TGI has also conducted a Gas Safety Awareness study, as well as a corporate image study in which customers are asked their perceptions regarding public safety. These latter two studies identify top of mind customer concerns and the perceived importance of public safety.

Residential Gas Safety Awareness (2006)[16]

As noted in TGI's response to BCUC IR 2.23.2, in a 2006 survey, 21% of customers identified the potential for gas leaks as the single greatest concern pertaining to the use of natural gas in the home. Explosions represented the next most prominent concern at 14%. This was followed

[16] Residential Gas Safety Awareness Study, Synovate, 2006. Taken from detail on Slide 18.

by fire (11%), and carbon monoxide (4%). Others mentioned were statistically insignificant. These included concerns voiced about earthquakes and the potential for children to burn themselves on a gas fireplace window.

The total results, with a sample size of 600 are accurate to +/-4% at the 95% level of confidence.

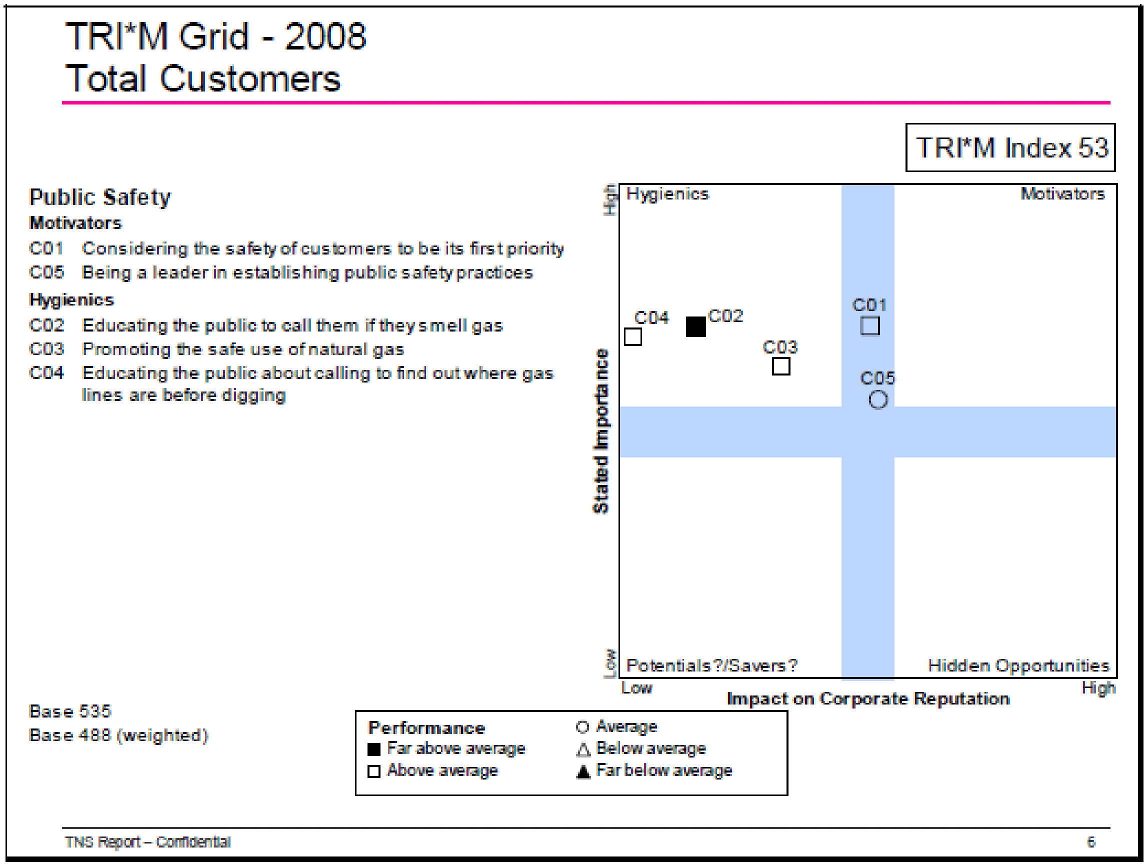
Corporate Image Survey

TGI last conducted its Corporate Image Survey in 2008. At that time, our research partner TNS Global concluded:

> *"As far as Terasen customers are concerned, the reputation of Terasen rests on the ability of the company to put safety and quality of life issues relating to supply of natural gas and the environment, first on their lists. They applaud Terasen for these qualities. However, there is fairly strong criticism regarding Terasen's apparent lack of attention to some important customer service dimensions such as an effort being made to get fair rates, working with environmental groups, helping consumers use gas efficiently.*
>
> *Customers expect Terasen to generally act in the customer's best interests—whether it is about rates, the environment, safety or other issues*."[17]

[17] 2008 Corporate Image Survey, TNS Global, page 30.

Figure 3: Important Safety Activities - All Customers[18]



As shown in Figure 1, customers indicated four of five characteristics as being of similar importance. These include:

1. considering the safety of customers to be its first priority;
2. educating the public to call them if they smell gas;
3. educating the public about calling to find our where gas lines are before digging, and;
4. promoting the safe use of natural gas.

"Being a leader is establishing public safety practices," was ranked as moderately important.

[18] 2008 Corporate Image Survey, TNS Global, Slide 6, Page 51.

Through research, safety activities are often found to be "hygienics," or "price of admission" attributes. They are very important to customers, but satisfaction or reputation scores seldom improve by enhancing safety programs. In contrast, satisfaction scores can be seriously compromised if a preventable accident or safety infraction takes place for which TGI is held accountable.

The overall sampling error for the 850 total household interviews at the 95% confidence level is approximately ± 3.4%. For example, if 50% of all respondents surveyed stated that they have a natural gas fireplace then we can be sure, nineteen times out of twenty, that if the entire population had been interviewed the proportion would lie between 46.6% and 53.4%.

35.0 Reference: Customer and Stakeholder Expectations
Exhibit B-4, BCUC 1.8.3
Public Safety and Security

"As there are many synergies at play in delivering upon design, construction, operations and maintenance of pipelines and facilities, including the associated code and standard requirements, it is not possible to isolate the total funding required to meet the ongoing requirements of public safety and security. For 2010 and 2011, Terasen Gas has identified Incremental funding that is attributable to maintaining compliance and managing the associated risks within Codes and Regulations (see Appendix F-8 of the Application)."

35.1 Given that TGI is unable to "isolate the total funding required to meet the ongoing requirements of public safety and security", explain why the incremental funding TGI attributes to maintaining compliance and managing the associated risks within Codes and Regulations cannot be achieved through increased efficiencies and the elimination of activities that are not cost effective.

Response:

When developing the Application Terasen Gas reviewed its existing activities as well as new codes and regulation requirements. Activities cannot be broken down into individual code compliance actions as there are overlapping codes, so funding requirements looked at the costs to deliver each entire activity. Delivery of these activities includes meeting ongoing public safety and security requirements.

Terasen Gas has optimized these activities over the PBR Period, but believes it has realized all of the opportunities it had for substantive efficiency gains during this period and customers and the shareholder have equally realized the benefits of these efficiencies We have, in our view, eliminated all activities that are not cost effective. The Application already reflects these increased efficiencies achieved through the PBR Period, although we will continue to look for additional opportunities for increased efficiencies.

35.2 Please provide the measures that TGI uses to evaluate the effectiveness of its public safety and security expenditures by year for 2006-2009.

Response:

The company measures its effectiveness of public safety awareness programs through its Residential Safety Survey and third party damage statistics. In addition, during the PBR Period, Transmission Reportable Incidents was an SQI and will continue to be a measure used by TGI to monitor its safety performance. Please see the response to BCUC IR 1.95.2.

36.0 Reference: Customer Expectations

Exhibit B-4, BCUC 1.16.1

Exhibit B-1, Part III, Section B, Tab 1, p. 101

Balanced Scorecard

"Success in meeting customer expectations is measured through the use of an index score derived from surveys that measure customer opinions of Terasen Gas and the services provided to its residential, large commercial, builder/developer and small commercial customers. Billing, corporate image and marketing communications are tracked as they are the three most important customer satisfaction drivers for residential customers." (Exhibit B-1, Part III, Section B, Tab 1, p. 101)

36.1 Please provide the target and actual Balance Scorecard Customer Satisfaction scores for 2003-2009 YTD.

Response:

Following are the Balanced Scorecard Customer Satisfaction targets and results for 2003 through 2009 YTD.

Year	Balanced Scorecard Target	Customer Satisfaction Result
2003	77.5%	73.9%
2004	77.5%	73.9%
2005	77.5%	77.2%
2006	78.0%	77.9%
2007	78.0%	79.3%
2008	79.0%	79.7%
2009	79.0%	80.0%[19]

Customer Satisfaction has increased each year throughout the PBR period. As Customer Satisfaction has increased through the period, TGI has increased its Balanced Scorecard target in pursuit of ongoing improvement supporting the Company's focus on operational excellence. TGI believes that success in meeting customer expectations is key to maximizing core volumes and customer growth.

[19] 2009 YTD results are as of July 2009.

37.0 Reference: Disaster Recovery

Exhibit B-4, BCUC 1.17.5

Disaster Recovery Costs

37.1 Please provide a breakdown of the $2.7 million for 2010 Corporate IT DR capital expenditures by project.

Disaster Recovery Costs

<u>Response:</u>

Category	**Cost**
Planning, project management	$ 80,000
Equipment setup	600,000
Equipment – network	190,000
Equipment – servers	683,000
Equipment – Storage	490,000
Equipment – Back-up	356,000
Facilities improvements	97,000
Contingency	204,000
Total	**$ 2,7000,000**

The project has already received executive approval in principle subject to a final review after the detailed design and planning phase has been completed. The above budgeted amounts can only be confirmed at the end of detailed design phase scheduled to be completed in December, 2009. At that point the final budget will go for executive approval in accordance with Terasen Gas' capital governance model. Terasen Gas believes it is appropriate to use these budget figures in the RRA as it is not anticipating a material change from the numbers presented above.

37.2 Please provide a breakdown of the 2010 and 2011 Corporate IT DR O&M expenditures by activity and resource.

Response:

Activity	**Resource**	**2010**	**2011**
Equipment Support	TELUS	$ 195,000	$ 390,000
Network Support	TELUS	94,000	188,000
DR Testing	TELUS		67,000
Contingency		172,000	105,000
Total		**$ 375,000**	**$ 750,000**

The project has already received executive approval in principle subject to a final review after the detailed design and planning phase has been completed. Subject to final executive approval, the project is anticipated to start January of 2010 and take approximately 6 months to complete. The higher contingency number in 2010 is to account for the possibility that the project could complete sooner and therefore the support numbers provided could be higher.

The above budgeted amounts can only be confirmed at the end of detailed design phase scheduled to be completed in December, 2009. At that point the final budget will go for executive approval in accordance with Terasen Gas' capital governance model. Terasen Gas believes it is appropriate to use these budget figures in the RRA as it is not anticipating a material change from the numbers presented above.

38.0 Reference: Customer satisfaction Metrics

Exhibit B-4, BCUC 1.18.1

Exhibit B-1, Part III, Section B, Tab 1, pp. 115-116

http://www.terasengas.com/documents/CACPresentationMay27_2009.pdf, May 27, 2009 Customer Advisory Council Meeting (slides 4-6)

Service Quality Indicators (SQI)

"For example, in 2008, TGI did not meet SQI targets for SQI 3 - non-emergency call answer speeds, 5 a) - the mass market billing index and 5 b) - industrial customer billing accuracy. Up to the end of April 2009, SQIs 5 a) and 5 b) were not meeting performance targets as noted on page 115 of the TGI 2010-2011 Revenue Requirements Application." (Exhibit B-4, BCUC IR 18.1)

38.1 Please file the May 27, 2009 Customer Advisory Council Meeting presentation.

Response:

A copy of the May 27, 2009 Customer Advisory Council meeting presentation is included in Attachment 38.1.

38.2 Please file the latest Service Quality Indicator report.

Response:

Please find below the latest Service Quality Indicator report, which includes results through July 2009.

	Performance Indicator	Benchmark	2003 Annual Actual	2004 Annual Actual	2005 Annual Actual	2006 Annual Actual	2007 Annual Actual	2008 Annual Actual	2003 - 2008 Average	2009 YTD July Actual
1	Emergency Response Time - Time Dispatched to Site - Emergency - Blowing Gas	≤21.1	22:00 minutes	21:36 minutes	21:42 minutes	21:30 minutes	20:36 minutes	20:42 minutes	21:35 minutes	23:18 minutes
2	Speed of Answer – Emergency (% of calls answered within 30 sec.)	≤95.0%	96.3%	97.9%	98.8%	98.6%	98.4%	98.3%	98.0%	98.1%
3	Speed of Answer – Non-Emergency (% of calls answered within 30 sec.)	≥75.0%	76.4%	77.5%	76.9%	78.2%	76.9%	73.8%	76.6%	76.6%
4	Transmission Reportable Incidents	≤2	3	3	3	1	1	2	2	0
5(a)	Index of Customer Bills Not Meeting Criteria	≤5	2.63	1.93	1.97	0.77	2.30	7.53	2.86	4.70
5(b)	Percent of Transportation Customer Bills Accurate	≥99.5%	99.8%	96.6%	99.9%	99.9%	99.5%	94.3%	98.3%	93.4%
6	Meter Exchange Appointment Activity	≥92.2%	92.6%	93.5%	94.3%	94.1%	93.5%	94.5%	93.8%	95.1%
7	Accuracy of Transportation Meter Measurement First Report	≥90.0%	97.4%	98.0%	99.5%	98.1%	98.9%	96.2%	98.0%	99.1%
8	Independent Customer Satisfaction Survey	Compared to prior years	73.9%	73.9%	77.2%	77.9%	79.3%	79.7%	77.0%	80.0%
9	Number of Customer Complaints to BCUC	Compared to prior years	101	191	121	152	130	90	131	35
10	Number of Prior Period Adjustments	Compared to prior years	24	18	14	21	23	15	19	14

	Directional Indicators									
1	Leaks per Kilometer of Distribution Mains	N/A	0.0040 134	0.0045 150	0.0034 120	0.0021 76	0.0024 87	0.0016 57	0.0030 104	0.0016 30
2	Number of Third Party Distribution System Incidents	N/A	1,459	1,492	1,457	1,508	1,545	1,574	1,506	747

38.3 Please confirm that TGI did meet the non-emergency call answer speeds for 2003-2007 and 2009 YTD.

Response:

Confirmed. TGI did meet the target for SQI 3 - non-emergency call answer speed from 2003 – 2007 and is meeting the target for 2009 YTD (through July).

38.4 Please confirm that the 2008 SQI issues related to the 5 a) - the mass market billing index and 5 b) - industrial customer billing accuracy were resolved by a system fix implemented in February 2009 and the correction of a PST / ICE Levy error that was corrected in March 2009.

Response:

The issues in 2008 related to SQI 5 a) – the mass market billing index and 5 b) – industrial customer billing accuracy were not related to the issues in 2009 that were corrected as noted in the above information request. The 2008 issues related to these SQIs were discussed in TGI's 2008 Annual Review, Tab B Section 2.1.3 pages 7-8. Following is an excerpt from the TGI 2008 Annual Review describing the 2008 issues that impacted the billing SQIs.

TGI 2008 Annual Review Excerpt:

"5a) Mass Market Billing Index

A number of issues have contributed to this deficiency. In January of this year Terasen Gas' outsourced print provider declared bankruptcy resulting in delays in billing timeliness beyond the established two day target in both January and February. An interim print provider was identified and customer statements were mailed from Calgary until July of 2008 when a permanent solution was established.

A number of other billing related issues also contributed to the high score experienced year to date. In January 2008, a tax calculation issue was identified and subsequently corrected related to the January 1st GST rate reduction. The proration of GST over year-end 2007, in conjunction with rate changes to other Terasen Gas tariffs, resulted in GST being incorrectly charged on the basic charge component in some circumstances. The dollar magnitude of the error for an individual customer was minor and was corrected on the next statement. The error impacted about 8.5% of all customers billed in January. In August of 2008 an error in data configuration resulted in a number of taxes failing to calculate and bill for five cycle workdays, impacting 28.3% of all bills issued in August. Once the error was discovered it was corrected immediately. The dollar impact of the under billing of taxes was small for those customers impacted. The invoices were reversed and the correction applied to the affected customers' September statement.

5b. Industrial Customer Billing Activity

(Percent of Industrial Customer Bills Accurate)

The issues contributing to the deficiency are similar to the issues impacting mass market billing accuracy as described above. Billing errors related to the implementation of the GST rate change in January resulted in 34% of all industrial accounts requiring correction. Adjustments to correct the GST errors were applied on February statements. In August of 2008 11% of industrial customers were impacted by the data configuration *error. For these customers the errors were reversed and corrected bills sent to customers within three working days of the discovery of the error."*

The 2009 deficiencies noted in the May 27, 2009 Customer Advisory Council Meeting on slides 4 – 6 refer to billing accuracy errors for both mass market and industrial accounts that resulted from a technical upgrade implemented in the fourth quarter of 2008. The corrective actions for these two issues were implemented in February and March of 2009 and the individual accounts have been corrected.

38.4.1 When will the system fix implemented in February 2009 and the correction of a PST / ICE Levy error that was corrected in March 2009 impact the 5 a) - the mass market billing index and 5 b) - industrial customer billing accuracy SQIs?

Response:

The impact of the February 2009 system fix and the March 2009 PST/ICE Levy error correction will be reflected in the 2009 year end SQI results for the mass market billing index (5 a)) and the industrial customer billing accuracy (5 b)) measures. These SQI's are measured monthly for internal purposes but are reported as an annual indicator for external SQI reporting purposes.

39.0 Reference: Business Risk

Exhibit B-4, BCUC 1.16.1

Balanced Scorecard

39.1 Please explain the "Service Quality Indicator" for item 10 - Public Safety.

Response:

The Service Quality Indicators that measure performance related to Public Safety as noted in the Terasen Gas Group Balanced Scorecard item #10 include two performance indicators: SQI 1 – Emergency Response Time and SQI 2 Speed of Answer – Emergency Calls, and the two directional indicators: 1 – Leaks per Kilometer of Distribution Main and 2 – Number of Third Party Distribution System Incidents.

Public safety is a critical area of focus for TGI in all aspects of the Company's operations.

40.0 Reference: EEC and Alternative Energy

Exhibit B-4, BCUC 1.21.1

Utility System Extension Test Guidelines

Rates and Economic Test

"Therefore, the Commission recommends that the Utilities develop a DCF based system extension test and submit it to the Commission. The Commission also recommends that, insofar as is practical, the analysis of system extensions be based on full incremental costs and benefits. Moreover, in reviewing system extension filings, the Commission will consider the time period of the analyses and the extent to which the costs of a system extension are allocated to those customers who cause them." (Utility System Extension Test Guidelines, p. 12)

"Also, TGI believes that the sales and marketing expenditures included in the Application related to developing the alternative energy business are more general in nature than the preliminary investigation costs contemplated for Account 172." (Exhibit B-4, BCUC 21.2)

40.1 Has TGI performed a study to determine the full incremental costs of providing service to alternative energy customers?

Response:

TGI has not performed a study to determine the full incremental cost of providing service to alternative energy customers. TGI has noted in its response to BCUC IR 1.21.2 that alternative energy projects will be characterized by a high degree of uniqueness. There will be differing energy sources (such as geoexchange, solar thermal, biomass, etc. with natural gas backup) in various combinations and a variety of end users (residential, commercial, institutional, industrial, etc.) that are also unique to a particular alternative energy development. The configuration of alternative energy projects will therefore be customized to the particular local requirements. As such it is very difficult to assess through a study what the incremental costs are for such service. The overall costs of such service will be limited by what customers are willing to pay for the benefit they are receiving from the service.

However, until TGI has had time to evaluate the incremental costs associated with providing alternative energy service, TGI proposes to use an overhead allowance of 5% of the capital cost of the alternative energy solution included in the COS (similar to that proposed for the NGV CS Test). For example a DES system with a capital cost of $15 million would have $0.75 million overhead added. If TGI were to get four projects of this size per year, the overhead allowance would exceed the $3 million request for incremental funding for sales, market development and account management activities.

TGI proposes review the allocation as it gains more experience in alternative energy systems for the purposes of considering whether or not the percentage should be changed.

40.2 Will the sales and marketing expenditures included in the Application, related to developing the alternative energy business, be allocated solely to alternative energy customers? If not, why not?

Response:

No, the sales and marketing expenditures included in the Application, related to developing the alternative energy business, will not be allocated solely to alternative energy customers. These are common costs that will be incurred for the benefit of all ratepayers and will therefore be included in TGI's overall sales and marketing O&M in rates. There will be an appropriate allocation made to alternative energy customers as contemplated in the economic models proposed in this Application. Please see the response to BCUC IR 1.19.1, and BCUC IR 2.40.1 for a detailed explanation of this.

41.0 Reference: EEC and Alternative Energy

Exhibit B-4, BCUC 1.24.3

Utility System Extension Test Guidelines

Commission Orders G-126-05 and G-152-07

Rates and Economic Test

"The Commission, in determining just and reasonable rates, must determine the appropriate allocation of costs as between gas customers and customers of the alternative energy solutions. The proposed economic tests are an efficient means of addressing cost allocation issues, modeled on the existing Main Extension (MX) test and previously accepted cost of service tests. The approval of economic tests will facilitate TGI negotiating just and reasonable alternative energy rates in the form of individual contracts entered into with individual customers and filed with the Commission." (Exhibit B-4, BCUC 24.3)

41.1 Has TGI consulted with natural gas and alternative energy stakeholders regarding the determination of appropriate economic tests for alternative energy projects?

Response:

No. TGI considered that this Application would provide an opportunity for TGI to properly and comprehensively articulate the economic tests, as well as the rationale for them. TGI believes that the subsequent process has allowed for a thorough review by the Commission, customers and other stakeholders.

41.2 The Commission has reviewed the MX Test methodology, parameters and inputs in various proceedings (Utility System Extension Test Guidelines, Orders G-126-05 and G-152-07). Please discuss the review process that TGI considers appropriate for the review of the alternative energy economic methodology, parameters and inputs.

Response:

TGI has proposed that the initial review of the alternative energy economic methodology, parameters, and inputs is part of this application and proceeding. Once this initial review has been completed and approved, as discussed in the responses to BCUC IRs 2.11.1 and 2.12.2, TGI expects that alternative energy contracts would be filed for approval of the rate or rates under Sections 59-61 of the UCA. Information will be filed with the contract that demonstrates the cost of service calculations, including cost estimates, number of customers by type, energy volumes and all other relevant parameters and assumptions that provide the basis for the rates to be approved. Given that the initial approval of the tests and methodologies will have already been approved through the RRA proceeding, TGI has proposed that the review process for individual project applications follows a streamlined approach that encourages regulatory efficiency.

TGI would expect to file information periodically on the actual results for the alternative energy projects providing similar information on actuals that were used to establish the rate. Similar to the review of main extensions TGI expects that this periodic review would inform the Company and the Commission as to whether the alternative energy projects are developing in line with forecasts and whether any changes need to be made. Since alternative energy projects may have relatively long development times TGI believes that the cycle of review should be no more frequent than every second year for any particular project. Projects should be reviewed only until they are mature or it is clear that satisfactory results have been achieved.

41.3 Do ratepayers bear the cost of alternative energy project cost overruns and actual consumption being less than forecast consumption?

Response:

The alternative energy ratepayers of a particular alternative energy project will bear the cost of overruns. As noted in the response to BCUC IR 1.33.3 (Exhibit B-4, page 91) there will be provisions in the alternative energy contracts to allow redetermination of the rates based on unanticipated capital costs. The circumstance of cost overruns described in the question is similar in nature to the situation described in BCUC IR 1.33.3. TGI anticipates that contract provisions will deal similarly with cost over-runs.

With respect to actual consumption being less than forecast, TGI notes that alternative energy installations are typically less sensitive to throughput variations since the cost structure is largely fixed. As such the rate structures may be more fixed in nature and the cost concerns related to throughput variations will be correspondingly diminished. With this background, and to provide similar treatment to alternative energy customers as that afforded to customers on natural gas main extensions TGI considers it appropriate that variances from actual consumption for alternative energy projects being above or below forecast should be borne by ratepayers.

However, depending upon the customer and specific alternative energy installation (such as an alternative energy solution that only serves one customer (which is more closely aligned with a bypass type customer), as opposed to a DES that is dependent upon many customers (which is more similar to TGI residential customers), TGI may also consider clauses in the contract for alternative energy service that are similar to Section 5.2 of TGI's proposed Rate Schedule 6C – Payment on Termination. This clause compels the customer to pay the difference between the "gas" consumption estimate used in the economic test and the actual gas use. Note that if the alternative energy rates increased to offset lower consumption this clause would not be needed.

TGI has noted elsewhere that it may be possible in the future to develop standard tariff offerings for alternative energy service when the Company has had more experience with multiple alternative energy installations. If this possibility becomes a reality in the future TGI would also expect that the impacts of cost overruns or throughput variations from individual alternative energy projects would be handled on a pooled basis similar to the way cost and throughput variances for individual natural gas main extensions are handled on a pooled basis.

41.4 For alternative energy projects, is TGI willing to bear some of the risks of cost overruns or forecasts not being met?

Response:

TGI believes that, as is the case with natural gas projects, the costs incurred in providing alternative energy to customers are legitimate costs of providing service to customers. TGI is entitled to recover those costs of service from customers unless they are later found by the Commission to have been imprudently incurred.

TGI does not bear volume forecast risk with natural gas customers and it does not see any reason that this should be different with alternative energy customers. TGI notes that natural gas use rates have been declining over a number of years for various reasons, including customers acquiring more efficient gas appliances or ceasing to use natural gas in some end uses. Also, natural gas customers are free to cease taking natural gas service or to reduce their consumption without penalty. The risk and cost consequences of these usage decreases are borne by all natural gas customers. Likewise, throughput risk for alternative energy systems should be a ratepayer risk.

42.0 Reference: EEC and Alternative Energy

Exhibit B-4, BCUC 1.24.4

Regulation of Alternative Energy

"In Commission Order No. C-22-06 regarding an application by TES for Approval of a CPCN for a Propane Gas Distribution System for Gateway Lakeview Estates, the Commission emphasized the importance of administrative efficiency associated with having diverse customers served by TGI rather than a proliferation of smaller regulated utilities under the Terasen parent:"

42.1 Please confirm that the Commission comments in Order C-22-06 were related to the creation of a propane distribution system and in no way referenced the provision of alternative energy services (geo-exchange, solar thermal and district energy).

Response:

TGI confirms that the decision arose in the context of a propane system. However, TGI disagrees with the implicit suggestion in the question that the Commission's comments and direction in Order No. C-22-06 have no relevance to the provision of alternative energy solutions.

The Commission's comments and direction in Order C-22-06 were aimed at ensuring regulatory efficiency and cost effectiveness from the perspective of customers. The Commission direction to TGI **made no distinction** between propane systems and other systems:

"The Commission notes that most operational and accounting activities related to Gateway Lakeview Estates will be handled by TGI, while Corix will provide meter reading and billing services. The Commission expects that TGI can competently carry out its responsibilities, and there is no evidence that other TGI customers will be adversely affected. Nevertheless, TGI has propane customers in Revelstoke, and ***it is not evident how TES Gateway Lakeview Estates, as a separate small utility, adds value, from the perspective of customers in the resort community, as compared to having these customers served directly by TGI, a separate but larger and related utility.*** *As well, TES has stated, but has provided no support other than reference to the Transfer Pricing Policy and the Shared Service Agreement, that this arrangement ensures that TGI customers do not subsidize the resort community customers.* ***Certainly, it is likely to be less efficient and more costly from the Commission's perspective to regulate a number of small utilities, rather than one larger utility serving the same customers. Going forward, the Commission expects TES and TGI to consider and address this concern when they are developing plans to serve new developments and groups of customers that are in or near TGI´s service area.***

<u>The Commission is not certain that a proliferation of small, but related utilities, all under the same parent, TI or KMI, is necessarily in the public interest.</u>[20]*"(emphasis added).*

The objectives of regulatory efficiency and cost effectiveness are equally applicable in any context where there is a choice available between serving customers through a small stand-alone public utility within the Terasen group of companies and TGI itself. Further, based on the wording of the direction to TGI (i.e. the fact that the Commission in no way restricted its comments to propane utilities), TGI considers that any subsequent attempt by TGI to interpret this decision as only applying to a propane utility would have been inappropriate.

TGI's proposals with respect to alternative energy solutions are consistent with the Commission's comments and direction in Order C-22-06. As stated in the RRA, TGI views "each of these alternative energy technologies [geo-exchange, solar thermal and District Energy systems] as complementary to, or an extension of, the Terasen Gas energy system as these systems more often than not require natural gas as part of the energy solution."[21] The Company expects that, with its alternative energy solutions, it will serve new developments and groups of customers that are in or near TGI's service area. From the perspective of customers and the objective of regulatory efficiency, TGI is the appropriate entity to deliver alternative energy solutions to customers.

[20] APPENDIX A to Order No. C-22-06 December 14, 2006 Page 2 of 7
[21] Exhibit B-1, Part III: Section C – Tab 3 Page 261

43.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

ExhibitB-4, BCUC 1.4.1, BCUC 1.25.3, p.62 and p.63

Biogas

43.1 Section 60, item (II) of the Utilities Commission Act requires the Commission in setting rates to have due regard to a rate that: "encourage public utilities to increase efficiency, reduce costs and enhance performance."

43.1.1 Is it not the primary mandate of the Commission to maintain the lowest utility rates possible while the Commission must only consider the government's energy objectives and the most recent long-term resource plan filed by the utility when it considers applications under section 46 and 71 of the Utilities Commission Act?

Response:

There are two assertions made in the question, and the Company will respond to each, in turn.

The first assertion is that the primary mandate of the Commission is "to maintain the lowest utility rates possible". TGI disagrees with this assertion for the reasons addressed in BCUC IR 2.70.1. Just and reasonable rates require the Commission to consider all of the factors identified in the UCA, and "the lowest utility rates possible" is not one of those factors expressly or impliedly.

The second assertion is that the Commission must only consider the government's energy objectives and the most recent long-term resource plan filed by the utility when it considers applications under sections 46 and 71 of the Utilities Commission Act. The emphasis on "consider" in the question is accurate, as TGI stated in the response to BCUC IR 1.25.3 (p.2). TGI noted in that response that other factors such as the impact on customer rates will also be relevant considerations.

TGI notes, however, that the question does not cite all of the sections to which government's energy objectives apply. The requirement to consider government's energy objectives applies in respect of the CPCN provision (sections 45 and 46), the expenditure schedule provision (section 44.1), the long term resource plan (section 44.2) and the supply contracts provision (section 71). In the absence of a streamlined regulatory process proposed in the Application, biogas upgrading facilities would be governed by the CPCN provision. The energy supply contracts would be governed by section 71. Thus, the Commission must consider government's energy objectives, even where the biogas supply is more expensive than traditional gas supply. Following the pilot phase, the green rate will result in the recovery of cost of service from consumers of biogas, further reinforcing the fairness of the rates.

43.2 TGI has stated in its Application that its intention is to develop a "green rate" that recovers the incremental cost from customers with a desire to purchase biomethane. Why shouldn't the amount of gas customers are willing to purchase through a "green rate" be a limiting factor to determine the amount of alternate energy projects overall that TGI can attach to its system?

Response:

Through the pilot program proposed in this application, TGI is embarking on the initial steps in the development of a new renewable energy source to be proactive in supporting the Government's Energy Objectives, provincial climate change initiatives and the policy actions of the 2007 Energy Plan. As the development of biomethane as a renewable energy source in BC is in the initial stages of development there are many issues to understand and resolve on both the supply side and the demand side. The responses to BCUC IRs 1.35.1 to 1.35.5 explain in detail why TGI believes it is appropriate to proceed with a limited pilot phase of biomethane supply development at the same time as it is developing the green rate offering.

TGI believes that a market exists for biomethane, but the amount of biomethane or green gas that energy consumers in BC are willing to buy will vary based on many factors. Simple economic principles suggest that there will be relationship between the demand for green gas and the price that can be offered. Put simply, the amount of biomethane customers are willing to buy will depend to some extent on the price. There are other factors relating to the way the product is promoted and offered that might affect the amount of demand. For instance, some customers might not wish to contract for all their gas consumption from green gas but they may wish to acquire a portion (such as a blended product) that would enable them to reach a particular target such as, for example, the Province's 33% GHG reduction target.

However, although there are good indications that there is public interest in green gas[22], TGI is uncertain at this point how all these issues will work out with regard to consumer demand for biomethane. For this reason, and others, TGI has proposed a modest pilot program of biomethane supply development so that there is a limited cost exposure to natural gas customers while the green gas offering is being developed.

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[22] IPSOS Reid Study (BCUC IR 1.23.1). Also research obtained by TGI shows that green premiums for electricity have generally ranged from $0.01/ kWh - $0.17/ kWh, a median price of $0.025/ kWh. Source NREL, Green Power Network.

44.0 Reference: Customer Care

B-4, BCUC 1.6.1, par. 1 and BCUC 1.7.1System IT Strategy

"Terasen Gas is not privy to, nor has any influence or control over, the refresh policies or schedules of any other hardware or software that supports the Customer Care system provided to Terasen Gas as a service." (Exhibit, B-4, BCUC 1.6.1, p. 12)

"The Company's customer care function is currently outsourced to CustomerWorks LP." (Exhibit, B-4, BCUC 1.7.1, p.14)

44.1 Please explain who the limited partners are in CustomerWorks LP, and if any are related to TGI.

Response:

The limited partners of CustomerWorks LP are Enbridge Commercial Services Inc., which holds more than two thirds of the partnership, and Terasen Inc., the parent company of TGI, which holds less than one third of the partnership. TGI has contracted with CustomerWorks LP to deliver customer care services through a results-based contract. The contract does not provide TGI with direct management of the activities to deliver the services. Despite Terasen Inc.'s status as a limited partner, the directors of CustomerWorks LP must act in the interests of CustomerWorks LP. TGI expects that this does not include extending to TGI the ability to influence or control matters over which TGI is not entitled to exercise influence or control under the Client Services Agreement.

44.2 Please expand on the contractual arrangement between TGI and CustomerWorks LP, specifically with respect to the lack of communication on refresh policies and schedules, and the inability under the contract to influence or control any of the IT support for the Customer Care system.

Response:

Through its contract management activities, TGI has regular communication regarding the services provided under the Client Services Agreement ("CSA") between CustomerWorks LP and Terasen Gas. These communications include discussion of upcoming activities and future planning. However, as noted in the above-referenced response to BCUC IR 1.6.1, TGI does not have direct access to the refresh policies or schedules related to hardware or software that support the delivery of customer care services. The CSA is a results-based contract. TGI does not directly manage the activities undertaken to provide the services that are delivered under the CSA.

TGI may attempt to influence the delivery of services through its ongoing communications. However, as recipient of a contracted service, TGI does not have the ability to directly control IT support for the Customer Care systems used to deliver the service. Under the CSA, contract terms related to the Customer Care system are included in Schedule B – Billing Support Services. Clause 2.7 (b) notes that systems support will include “operating and maintaining the Customer Systems” used to provide the services under the contract. Clause 3.1 (g) notes that CustomerWorks will “provide Billing Support Services using stable, supportable technical platforms for billing related applications, versioned from time to time to reflect core application upgrades.”

TGI believes that securing direct ownership and control as is proposed in the Customer Care Enhancement Project CPCN Application will address these issues.

45.0 Reference: Customer and Stakeholder Expectations

B-4, BCUC 1.8.2, par. 2

Public Safety and Security

"Public safety and security programs within Terasen Gas are primarily assured by ensuring pipeline and distribution system asset integrity." (Exhibit, B-4, BCUC1.8.2, p.19)

45.1 Please provide details on the TGI funding, related to public safety, directed towards customers, particularly residential customers. Is this represented by the average $304,250 spent per year on Public Safety Awareness referenced in BCUC 1.95.1?

Response:

Public safety messages are relevant to both the general public and customers. People who might not be customers may be in public buildings that use natural gas, such as schools, hospitals, shopping centres, etc. They may also work in areas for which gas safety could at times be relevant, such as landscaping. Therefore, TGI's use of mass media (radio and print) to provide education about natural gas safety applies to customers and non-customers alike.

Printed materials (brochures and info sheets) are made available to customers (online and by phone), but are also distributed at public events such as home shows or other events. The Terasen Gas website is accessible by customers and non-customers.

The only vehicle to communicate solely to our customers is the monthly account statement. Twice a year, the *Get Comfortable* newsletter for residential customers is included in the envelope with the statement. Safety messages are always included in this newsletter at no cost to the OH&S safety communications budget.

A typical breakdown of funding represented by the $340,250 average referenced in the response to BCUC IR 1.95.1 is as follows:

Mass media	88%
Collateral[23] materials	12%

In 2008, funding was spent on the following:

- Mass media safety messages on:
    - Gas odour;

[23] Collateral materials include brochures and other printed information as well as web content.

  - Excavation safety;
  - Call before you dig;
  - Meter safety;
  - Carbon monoxide safety; and,
  - Appliance safety.

- New collateral materials on:
  - Gas odour;
  - Meter safety;
  - Call before you dig;
  - Emergency gas shut-off; and,
  - Flood preparedness.

46.0 Reference: BC Economic Outlook

Exhibit B-4, BCUC 1.11.1 and 1.11.2, pp. 24-26

Economic Indicators and forecasts

On page 73 of the Application, TGI states: "It is critical to assess the economic conditions for the next three years and the impact of it on the business of Terasen Gas in order to ensure that forecasted costs and revenues in this Application are prudent and necessary to meet the evolving needs of the Company's customers."

In support of this statement and in response to BCUC 1.11.1 and BCUC 1.11.2, TGI has identified the primary economic indicators to forecast energy demand in 2010 and 2011. The primary economic indicators identified are Real GDP, energy efficiency behaviour, and housing starts. Supporting variables used by TGI are Can/US Exchange Rate, CPI, Prime Rate, and Conventional 5-yr Mortgage Rates.

46.1 For residential and commercial customers, please provide a table which provides TGI's assessment of the impact of each of these economic indicators on the demand forecast for 2010 and 2011. Please also include a discussion of how TGI incorporated these quantitative considerations into the demand forecast for 2010 and 2011.

Impact of Economic Indicators on Natural Gas Demand Forecast - 2010 and 2011

Economic Indicators	Impact on Energy Demand (PJs)	
	2010	2011
Real GDP		
Housing Starts		
Energy Efficiency Behaviour		
Can/US Exchange rate		
CPI		
Prime Rate 5-yr Mortgage Rate		

Response:

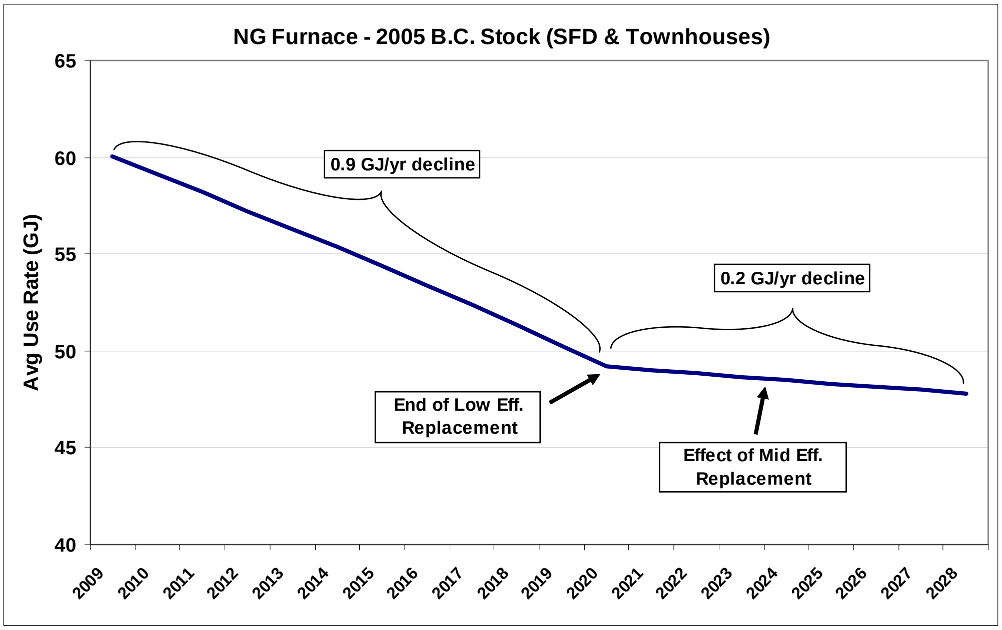
Although each of the above listed economic indicators do influence the demand for natural gas, the intent in presenting the eleven economic indicators within the external context section of the Application (Part III, Section A, Tab 4, Pp 69-76) was not to suggest each was directly related to the demand forecast, but rather to provide a broad range of indicators that together support TGI's assumptions regarding the future economic environment as a whole, and also to support TGI's assertions made in other areas of the Company (such as CPI relating to labour costs, GDP impacting job creation/demand, etc.).

Furthermore, as discussed in TGI's response to BCUC IR 1.11.1, it is challenging to quantitatively estimate (in isolation) the impact each of the economic indicators has on the demand for natural gas. TGI has analyzed those variables in terms of how they impact each of the forecasting components (customer additions, average use per customer, industrial demand) and following is a discussion of how each of the above variables are assumed to impact the demand for natural gas over the 2010 and 2011 forecast period.

As discussed in TGI's response to BCUC IR 1.41.2, GDP growth has the greatest impact on TGI's industrial customers, as fluctuations in GDP typically reflect changes in output or production levels in various sectors, which in turn influence industrial demand. And although GDP likely does impact both residential and commercial demand as well, no formal relationships have been identified, and therefore TGI is only able to state qualitatively that GDP will place downward pressure on overall energy demand over the 2010 and 2011 forecast period.

TGI has estimated the portion of demand in 2010 and 2011 that is attributable to new customer additions, which as discussed in TGI's response to BCUC IR 1.48.4 represent 0.64% and 0.67% of the total energy demand in 2010 and 2011, respectively. When expressed in terms of PJs, the expected impact housing starts will have on demand is estimated to be an increase of approximately 1.0 PJs and 1.1 PJs for 2010 and 2011, respectively. TGI further estimates that, as a result of the continued shift towards more multi-family dwellings in the housing mix, downward pressure will be placed on average use per customer rates (as discussed and illustrated in TGI's response to BCUC IR 1.40.3).

As discussed in TGI's response to BCUC IR 1.41.2, energy efficiency behaviour is considered to be the primary driver behind declining residential average use per customer rates. And although there are many aspects to energy efficiency (thermal envelopes, insulation levels, level of technology employed) the most significant is regarding the retrofit of lower efficiency rated appliances with newer, high efficiency units. The following chart, as illustrated in the 2008 Resource Plan, provides the estimated impact to the average use per customer rates, which when applied to the total number of residential customers results in an estimated decline in consumption of approximately 0.7 PJs per year.



As mentioned above, there are other efficiency-related activities that also impact the demand for natural gas. However, a lack of detailed customer data regarding appliance mix, appliance efficiency levels, and also customer behaviour towards conservation presents a significant challenge when attempting to assess the overall impact energy efficiency behaviour has on the demand for natural gas. Through the development of EEC programs, as outlined in the approved 2008 EEC Application, estimates regarding expected savings in consumption have been provided in TGI's response to BCUC IR 2.56.3. But activities in addition to retrofit activity and EEC programs, such as changes to the thermal envelope, use of advanced technologies (setback thermometers, timers, etc.), and general conservation efforts are not estimable at this time.

The Canada/U.S. exchange rate is another variable likely to impact the demand for natural gas. Although the impact is assumed to be most prevalent in the industrial sector (adding to the difficulties faced by the forestry sector), both the residential and commercial sectors are also impacted as the appreciation of the Canadian dollar (relative to the US dollar) influences exports from British Columbia as well as tourism levels. Quantifying the impact this variable has on the demand for natural gas, as with GDP, is challenging, and TGI has not formalized a relationship between the two at this time.

Both CPI and the Prime Rate / 5-yr Mortgage Rate are variables that indicate future affordability, and therefore are more likely to impact other variables such as housing starts, GDP, and even levels of retrofit activity (more specifically, the purchase of new equipment). Given that, no formal relationship between residential and commercial demand has been made with respect to these two variables, rather they are viewed with an eye for supporting the other economic indicators.

In conclusion, TGI recognizes that there are many factors that influence the demand for natural gas, but is faced with significant challenges when attempting to assess the impact each of those factors has (individually) on consumption levels. Therefore, TGI has employed the use of trending to determine the historical impact those economic variables have had on the demand for natural gas, and then by reviewing the forecasts of those economic variables, TGI is able to validate/adjust the forecast based on the trending analysis when developing the demand forecast.

46.2 Please provide the spreadsheet(s) containing the data, references, and methodology upon which the gas demand forecast for 2010 and 2011 was based. Please include relevant historical data and a discussion of the underlying assumptions. To the extent possible, please provide the level of confidence that TGI has in the demand forecast for 2010 and 2011.

Response:

Please see the response to BCUC IR 2.79.1 and BCUC IR 2.82.1.

46.3 Please discuss whether the forecasting techniques described in previous question have been used in the past. What was the degree of correlation between normalized forecast and actual energy demand?

Response:

The forecasting techniques used in developing the demand forecast for this Application are consistent with those used in the past.

The correlation between overall actual normalized energy demand and the (normalized) forecast figures, calculated based on the data presented in TGI's response to BCUC IR 2.75.2, is 54%. Although the correlation between forecast and actual results provides an indication of how closely the two variables move together, TGI believes a more appropriate indicator to consider is the variance or the two variables over time, not the correlation, which is illustrated in TGI's response to BCUC IR 2.75.2.

47.0 Reference: Tariff Changes

Exhibit B-4, BCUC 1.13.1, p. 28

Innovative Rate Design

47.1 Is TGI aware of any gas distribution utilities in North America that employ a stepped rates design?

Response:

Yes, TGI is aware of other natural gas distribution utilities in North America that employ stepped rate structures for residential and commercial customers within their rate designs. The majority of the utilities identified incorporate a *declining* stepped rate structure, which encourages natural gas consumption through decreasing delivery rates as consumption increases. Customers are incented to use natural gas as the rate per unit decreases as consumption increases, therefore making it difficult to promote conservation and efficiency, as the price signal encourages larger consumption. Please refer to the table below which outlines a sample of natural gas distribution utilities in Canada and the United States that do provide stepped rates.

Utility	Province/State	Residential Rate Structure	Small and Large Commercial Rate Structure
TG (Ft. Nelson)	BC	Declining stepped delivery rates	Declining stepped delivery rates
Union Gas	ON	Declining stepped delivery rates	Declining stepped delivery rates
Enbridge Gas	ON	Declining stepped delivery rates	Declining stepped delivery rates
Gaz Metro	PQ	Declining stepped delivery rates	Declining stepped delivery rates
Southwest Gas Corporation	NV	Declining stepped delivery rates	Uniform delivery rates
Niagara Mohawk Power Corporation (National Grid)	NY	Declining stepped delivery rates	Declining stepped delivery rates
KeySpan Energy (National Grid)	NH	Declining stepped delivery rates	Declining stepped delivery rates
Northern Utilities Natural Gas (Unitil)	NH	Declining stepped delivery rates	Declining stepped delivery rates
Pacific Gas and Electric Company	CA	Inclining stepped delivery rates	Declining stepped delivery rates
Southern California Gas Company	CA	Inclining stepped delivery rates	Declining stepped delivery rates

47.2 If the answer to the previous question is "yes" then please comment on the situational differences between those utilities offering stepped rates and TGI, which is currently not contemplating such a rate structure.

Response:

In this response, TGI deals separately with inclining block rates and declining block rates, which serve different purposes.

As noted in the response to BCUC IR 2.47.1, of the natural gas utilities reviewed that do have stepped rate structures, the majority incorporate a *declining* stepped rate structure, which encourages price signals toward natural gas consumption through decreasing delivery rates as consumption increases. A reason for this approach may be in these cases a number of the utilities are promoting natural gas as a clean energy alternative to electricity produced from coal or natural gas or fuel oil prevalent in those regions.

In its 1993 Rate Design, TGI initiated a change from its declining stepped structure to a uniform structure. The intent during this proceeding was to strike a balanced approach to pricing signals which encouraged energy conservation and efficiency, and this same approach remains in place today.

A small number of the natural gas utilities reviewed in California use an inclining stepped delivery rate structure for residential customers, which has been in place for many years. TGI is not aware of the circumstances that caused the utilities to adopt an inclining block structure. TGI is not aware of other jurisdictions that have chosen to implement this rate structure at this time. The inclining stepped structure is more prevalent for electric utilities where the cost of supply is not priced at marginal cost, but rather at embedded cost. TGI has market-based commodity rates, the rates TGI customers pay for natural gas service is largely composed of the gas costs or commodity cost of natural gas. The market-based natural gas prices serve as a proxy for the marginal cost of supply. This differs from most electric utilities' cost structure which generally reflects supply costs.

In summary, TGI has been pursuing energy conservation and efficiency as part of its rate design objectives for many years. TGI believes it has struck an appropriate balance with its current rate structures which include market based cost of gas pricing and uniform delivery charges. As stated in its response to BCUC IR 1.31.1. Terasen Gas' current rate structures and the proposed rates impacts included in this Application will continue to send price signals that will help to encourage the principle of energy efficiency and conservation to natural gas customers in BC.

48.0 Reference: Business Risk

Exhibit B-4, BCUC 1.17.5

Disaster Recovery

48.1 Please expand on the $650,000 for SCADA in 2009. Is the SCADA funding for an upgrade to the SCADA system or is this amount just for the two DRP sites?

Response:

As part of Terasen Gas' operating practice to ensure that all critical computer systems are kept current and supported, the SCADA system is currently being upgraded at a cost of $1.6 million. Terasen Gas estimates that the overall planning and upgrade of the production system in the Surrey Operations location is approximately 60% of the project cost. The remaining 40% ($650,000) is the effort required to upgrade the existing backup sites in Burnaby and Kelowna. The project, including the upgrades to the backup sites, is in progress and forecasted to be completed by December, 2009.

48.2 Please expand on the $2.7 million for Corporate IT DR in 2010. What assets will result from this capital spend?

Response:

Please refer to the response to BCUC IR 2.37.1 for the cost breakdown. The assets associated with the capital spend are application servers, network equipment (switches, firewalls, servers), storage and backup systems required to support the DRP requirements of the Company.

48.3 Please expand on the $750,000 for Corporate IT DR in 2011. Is this expected to be an on-going cost in future years?

Response:

Please refer to TGI's response to BCUC IR 2.37.2 for a breakdown of O&M costs. As highlighted in the Application,[24] it is critical that Terasen Gas implement and maintain an enterprise-wide strategy to mitigate risk from interruption, regardless of the event. The costs associated with DRP will fluctuate, but will be ongoing. As technology advancements are made

[24] Reference: Business Risk – Disaster Recovery Part III, Section B, Tab 2, Page 205 pars. 3-4

that allow for cost savings to be realized, as with server virtualization, some costs will come down. As Terasen Gas continues to invest in additional applications that will require the need to have DRP capabilities, this will result in higher DRP support costs.

49.0 Reference: Service Quality Indicators

Exhibit B-4, BCUC 1.18.1

Customer Care Service Quality

49.1 Are service penalties paid to TGI by CustomerWorks LP, by CustomerWorks Inc., or by one of the other Accenture subsidiaries?

<u>Response:</u>

For those Service Quality Indictors that parallel the service levels in the outsourcing arrangement with CustomerWorks LP, penalties are assessed and paid in those months where the service level targets are not achieved. This includes the following SQI's:

SQI 2	Speed to Answer – Emergency
SQI 3	Speed to Answer – Non-emergency
SQI 5 a	Residential and Commercial Customer Billing Activity
SQI 5 b	Industrial Customer Billing Activity

The penalties are paid by CustomerWorks LP, with whom TGI has a contract.

50.0 Reference: Growth Opportunities

Exhibit B-4, BCUC 1.19.1

"TGI believes it is appropriate for a utility to spend time and resources on learning-related activities and emerging developments in the utility's field of business. … In the case where the costs are not simply part of sales, marketing and development and are unique to the investigation of or analysis of a new opportunity, utility revenue requirements generally include allowances for spending on items that are in the nature of research and development or preliminary investigations. … Research and development activities are seen as useful in preparing the utility for the future. Alternative energy solutions display similar qualities to those described in the preceding paragraphs." Ref: B-4, p.40, bullets 2-3

50.1 Does TGI view the Alternative Energy work it is undertaking, or any portion of it, as R&D?

Response:

Under International Accounting Standard 38 Intangible Assets, the following definitions are provided:

"Research is original and planned investigation undertaken with the prospect of gaining new scientific or technical knowledge and understanding.

Development is the application of research findings or other knowledge to a plan or design for the production of new or substantially improved materials, devices, products, processes, systems or services before the start of commercial production or use."

Based on these definitions, TGI does not believe that the work undertaken, which is more in the nature of sales and skill development, meets the accounting definition of either research or development.

50.2 What percentage of TGI's total O&M expenditures are the Alternate Energy expenditures?

Response:

As noted in the response to BCUC IR 1.72.2, TGI is not able to accurately estimate the amount spent directly on alternative energy. However, as shown in TGI's response to BCUC IR 2.96.2, approximately $1 million annually for 2010 and 2011 is related to "New Business Consulting", which includes engineering, feasibility studies and outsourced development of alternative energy projects. Under IFRS guidelines, these costs are required to be expensed as incurred. If TGI were not offering alternative energy solutions, it may still require a portion of this amount to provide hybrid energy solutions to developers where TGI did not own the energy system but, by providing the solution, would increase the gas load to the development. This amount of $1 million represents 0.48% of the 2010 Gross Real O&M expenses.

> "For all of the foregoing reasons TGI believes that it is appropriate that all rate payers fund the marketing, sales and development activities of both gas and Alternative Energy Solutions as set out in the Application, based on an appropriate allocation of costs as proposed." (Exhibit B-4, BCUC 1.19.1, p. 41, par. 2)

50.3 Please comment on the concern referenced on page 7 of the TNS Alternative Energy Report in Attachment 23.1.1 that the costs for such research and development in alternative energies would be passed on to consumers through rate increases.

Response:

TGI is not investing in research and development activities and therefore by definition is not seeking to recover these types of costs from customers (please see the response to BCUC IR 2.50.1).

The comments in the TNS report characterized as "concerns" in the question should be considered in context. As part of the interview process with customers, TGI, through TNS, specifically sought out reasons customers would not support a TGI alternative energy solution. In other words the comments were directly solicited rather than unsolicited. As such, the interviewees had to come up with reasons they had for why TGI should not pursue alternative energy. As part of the study, TGI wanted to understand why customers might not want TGI to provide the service so that TGI could address these issues in is sales and project development efforts. Notably, TNS observed that "respondents were hard-pressed to come up with comments" when asked for reasons why Terasen should *not* move into the field of alternative energies.

The entire section of the TNS report is included below:

> *When asked for reasons why Terasen should not move into the field of alternative energies,* ***respondents were hard-pressed to come up comments.*** *Initially, they would typically answer that there was nothing but with continued probing, a few came up with some reasons against the initiative:*

- *Terasen is too large an organization to implement such measures quickly and effectively;*
- *Terasen could corner the market on alternative energy sources and in doing so, create a near monopoly that would increase prices;*

"Terasen has not done well in mitigating the perception that they cornered the market and jacked up the prices."
- Elected Representative

- *The costs for research and development would be passed on to consumers through rate increases."*

These comments point to a few perceptions that TGI will have to address to become successful in the sale and delivery of alternative energy solutions. Overall, however, the message from the TNS report is that the customers interviewed were receptive to Terasen offering alternative energy solutions.

51.0 Reference: New Alternative Energy Offerings

Exhibit B-4, BCUC 1.20.1

Overhead Allowance

"TGI intends to include an appropriate overhead allowance in the alternative energy rate setting Process" (Exhibit B-4, BCUC 1.20.1, p. 42, par.2)

51.1 Will TGI be tracking the sales efforts, account management, market development costs, and revenues for Alternative Energy and reporting them separately? If not, how will the Company know the "appropriate overhead allowance" is sufficient?

Response:

Please see TGI's response to BCUC IR 1.72.2, and BCUC IR 2.40.1. As noted in the Application TGI will be tracking revenues from alternative energy as these will be captured in the deferral accounts.

TGI is proposing to use an initial overhead allocation of 5%. TGI will be tracking sales efforts, account management and market development costs so that TGI can better understand all costing regarding alternative energy and therefore arrive at appropriate overhead allocations. TGI proposes review the allocation as it gains more experience in alternative energy systems for the purposes of considering whether or not the percentage should be changed.

52.0 Reference: New Alternative Energy Offerings

Exhibit B-4, BCUC 1.20.1, p. 42

Recoverability of Costs

52.1 On page 42 it states: "The types of costs such as for sales efforts, account management and market development costs will be sunk costs as far as the economic tests are concerned. As long as the rates for the alternative energy projects are recovering more than the direct incremental annual cost of service, there will be some contribution towards the common costs for sales, account management and market development."

52.1.1 Please confirm whether or not the above statement implies that there will be a residual portion of the above identified sunk costs associated with the development of alternative energy offerings that will be recovered through rates to TGI's traditional natural gas customers.

Response:

The sunk costs referred to are costs associated with providing sales, account management and market development for both gas and alternative energy (please also see the response to BCUC IR 1.72.2). These costs are those that will help customers implement the most appropriate energy system for their needs, be that natural gas related, alternative energy or a combination of both. TGI has therefore proposed in this Application that the incremental O&M costs, for which TGI has sought approval, be recovered in TGI rates from existing customers. However, TGI has also proposed that alternative energy customers be allocated a portion of overhead costs as part of their COS and rate determination under the proposed economic test. By allocating overhead costs in the economic test, that include a portion of the sunk costs that will have already been captured in rates, alternative energy customers will pay rates that will recover some of these sunk costs.

52.1.2 Please explain why it is not appropriate to track all costs associated with the development of alternative energy projects for recovery through rates specific to those alternative energy projects.

Response:

TGI believes that it is unnecessary and impractical to track all costs as separate costs as suggested in the question.

As noted in the response to BCUC IR 1.72.1, TGI does not at this time know the percentage of certain costs, such as marketing and sales costs, that will be attributable to alternative energy projects. Going forward, TGI will be offering both natural gas solutions, alternative energy solutions and solutions that include both applications. As part of the selling process for these solutions, there will be projects in which TGI is successful and those in which it fails. As such there will be costs that are not attributable to any specific project as the project does not go forward. There will also be costs in which, due to the involvement of gas in the solution, it will be very difficult to determine what portion of time was spent on the alternative energy part of the solution. Lastly, in existing gas solutions, TGI does not track sales, account management and market development costs associated with specific services projects and does not charge natural gas customers different rates based upon these costs.

Rather, TGI believes that the most appropriate means of addressing common costs is to use an initial overhead allocation of 5% of the value of alternative energy projects. Additionally TGI will perform an allocation exercise for each alternative energy project as it does for natural gas services today. This will result in tracking of overhead allowances from which TGI can better understand the true overhead allocation for alternative energy projects. As TGI gains more experience in alternative energy systems and as it better understands the allocation of overheads, it may change the overhead allocation percentage

Note that once a project is fully defined and it has been determined that it will move ahead then project development costs can and will be tracked for discrete alternative energy projects, such as District Energy Systems, and those costs will be charged against that project. The means by which common costs are proposed to be addressed in this Application is appropriate and sufficient to ensure that rates for both gas and alternative energy customers are just and reasonable.

53.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Exhibit B-4, BCUC 1.21 and 1.50, pp.43-5 and pp. 50-51

Definition of Gas Utility

TGI states that: “TGI intends to offer energy and heat delivery services to customers where that energy delivery is via a distinct energy system (DES), solar, geothermal, or other energy source, where TGI would own and operate the heat delivery system s and where TGI would charge the end use customer for the delivery of heat.”

TGI also states in response to question BCUC 1.23.1 that: “However, since 2008, TGI has begun to change its corporate focus into becoming a provider of energy rather than simply a natural gas delivery company.”

This change in corporate focus is incompatible with the GAS UTILITY ACT which includes the definition of a gas utility that states: “means a person that owns or operates in British Columbia equipment or facilities for the production, generation, storage, transmission, sale, delivery or furnishing of gas for the production of light, heat, cold or power to or for the public or a corporation for compensation, but does not include a company within the meaning of that word as defined in the National Energy Board Act.”

53.1 Please explain how TGI’s intention to “own and operate the heat delivery services” or to become a provider of energy rather than natural gas alone is compatible with the definition of a gas utility under the GAS UTILITY ACT.

Response:

The Gas Utility Act does not speak to whether or not a "gas utility" can or cannot own and operate heat delivery services or become a provider of energy rather than natural gas alone. Therefore, TGI’s intention to own and operate the heat delivery service or to become a provider of energy rather than natural gas alone is compatible with the Gas Utility Act.

54.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Exhibit B-4, BCUC 1.21.1 and BCUC 1.21.2

Alternative Energy Services Costs

In BCUC 21.1, TGI indicates that "The only costs expensed and charged to rates for alternative energy services to date relate to high level strategy and business planning by senior TGI employees and the costs associated with this Application."

54.1 The original IR question refers to the costs associated with the above TGI statement. Please identify and breakdown the costs expensed to date (i.e. engineering studies, feasibility studies, market / customer research, etc.) and discuss whether these costs (relating to Alternative Energy Services) should be included in Account 172. The original questions do not refer to future / potential costs associated with Alternative Energy Services.

Response:

The definition for Account 172 is as follows:

> *"All expenditures for preliminary surveys, plans, investigations, etc., made for the purpose of determining the feasibility of projects for gas services , and with the costs associated with applications for certificates of public convenience and necessity, board hearings, the acquisition of options to purchase land or land rights to provide a future supply of natural gas, easements and similar items for use in contemplated projects, unless these costs are being tracked separately in another deferral account."*

The only costs to date spent on market/customer research are those studies that were subsequently presented as supporting evidence to IR's asked in this proceeding. Specifically the two studies provided in response to BCUC IR 1.23.1.1 and the study provided in response to BCUC IR 2.11.6. The total cost for these studies is $28,812 including tax.

In TGI's view, account 172 is intended to capture the engineering/technical side of surveys, plans and investigations into providing gas service. As the nature of the studies TGI undertook are related to research of other companies approaches to alternative energy, and research on customer knowledge levels and opinions regarding alternative energy, and are not associated with engineering/technical surveys etc, TGI does not feel that these costs should be included in Account 172.

55.0 Reference: Revenue Requirements and Rate Proposals

Exhibit B-4, BCUC 1.22.1, pp. 47-48

Exhibit B-1, Part III, Section B, Tab 1, p. 133

Operational Performance over the PBR Period

On page 133 of the Application, TGI provides Table B-1-6 which outlines the energy savings and GHG reduction of a number of different energy efficient programs implemented since 2005:

Table B-1-6: Helping Customers Reduce Their Carbon Footprint
TGI DSM Program Energy Savings and GHG Reduction

	2005	**2006**	**2007**	**2008**
Annual savings (GJ)	1,349,762	735,207	1,203,596	612,651
GHG Impact (tonnes, NPV)	68,419	37,268	61,010	31,055

55.1 Please provide a table summarizing the various energy savings programs and the annual savings (GJ) that each program contributed to the annual savings indicated in Table B-1-6.

<u>Response:</u>

Please see the table below. It should be noted that as outlined in the response to BCUC IR 1.22.1, the savings presented in Table B-1-6 represent the NPV of the annual savings over the measure life for each program.

Program Name	Number of Participants Per Year	Savings Per Participant Per Year (GJ)	Gross Annual Savings For Program (GJ) (*participant X savings)*	Net to Gross Ratio	Net Annual Savings For Program (GJ) *(gross X ratio)*	NPV Annual Savings For Program (GJ)	Annual GHG Savings l *(savings X .05069)* (NPV)
2005							
Energy Star Heating Upgrade (Retrofit)	3,500	13.8	48,300	50%	24,150	279,262	14,156
Energy Star Heating Upgrade (New)	600	12.69	7,614	80%	6,091	70,436	3,570
Commercial Energy Assessment Program	84	600	29,400	85%	24,990	244,303	12,384
Efficient Boiler Program (EBP)	45	1,379	70,605	82%	57,896	747,192	37,875
Destination Conservation	16	200	3,200	100%	3,200	8,569	434
Program Portfolio Results	**4,245**					**1,349,762**	**68,419**
2006							
Energy Star Heating Upgrade (Retrofit)	3,563	13.8	49,169	50%	24,584	261,874	13,,274
Energy Star Heating Upgrade New	1,180	9.1	1,073	80%	859	91,504	4,,638
Efficient Boiler Program (EBP)	30	850	25,500	82%	20,910	296,659	15,038
Destination Conservation	4	113	452	100%	452	1,188	61
Commercial Energy Utilization Advisory	18	600	10,800	85%	9,180	83,982	4,257
Program Portfolio Results	**4,795**					**735,207**	**37,268**
2007							
Energy Star Heating Upgrade (Retrofit)	4,316	13.8	59,560	50%	29,780	344,369	17,456
Energy Star Heating Upgrade New	2,981	9.1	27,127	80%	21,701	250,950	12,720
Efficient Boiler Program (EBP)	20	1,379	27,580	82%	22,615	155,041	7,859
Destination Conservation	44	113	4,972	100%	4,972	13,315	675
Commercial Energy Utilization Advisory	100	600	60,000	75%	45,000	439,921	22,300
Program Portfolio Results	**7,461**					**1,203,596**	**61,010**
2008							
Energy Star Heating Upgrade (Retrofit)	2,110	13.8	29,118	57%	16,597	179,709	9,109
Energy Star Heating System Upgrade (No VSM)	1,067	13.8	14,725	57%	8,393	90,876	4,607
Fireplace	1,198	7.75	9,284	76%	7,056	68,532	3,474
Efficient Boiler Program (EBP)	5	6,865*	6,685	82%	5,629	71,961	3,647
Destination Conservation	75	113	8,475	100%	8,475	22,564	1,144
Commercial Energy Utilization Advisory	73	20,479*	20,479	100%	18,431	179,009	9,074
Program Portfolio Results	**4,528**					**612,651**	**31,055**

55.2 On an individual and portfolio basis, please provide details of how energy savings were determined. Please provide calculations and state assumptions.

<u>Response:</u>

The methodology requested is provided in the response to BCUC IR 1.22.1. Please also see TGI's response to BCUC IR 2.55.1.

55.3 If not provided in the previous question, please show TRC results expressed as a net present value NPVTRC of the benefits and costs for each of the energy savings programs which contributed to the savings indicated in table B-1-6. Please provide a fully functioning electronic spreadsheet and a discussion of assumptions used in the calculations.

Response:

Please refer to Attachment 55.3. This spreadsheet presents historical data and assumptions, which have been reviewed in previous Annual Reviews and the EEC proceeding.

55.4 TGI attributes the energy savings detailed in Table B-1-6 of the Application to the existence of TGI's energy efficiency program. Please discuss how changes in HDD over the period 2005 to 2008 were accounted for in order to decouple energy savings from fluctuations in temperature.

Response:

The energy savings indicated in Table B-1-6 of the Application are based on a normal weather year and are stripped of weather fluctuations. The savings are based upon a calculation of participants times savings per participant, with an accounting for free riders. There is no need to decouple energy savings from fluctuations in temperature as the calculations do not include impacts from HDD.

Please see the response to BCUC IR 2.55.1 above.

55.5 On a portfolio basis from 2005 to 2008, please update Table B-1-6 to include "% of Goal" reflecting the relative percentage of savings realized in relation to targets set by TGI prior to initiating the energy savings program.

Response:

Energy savings realized are a function of the number of participants in any given program. Terasen Gas sets goals for participation levels during the program design phase of program development. Participation goals for programs were established as a procedural step in program design starting in for the year 2006 for 2007 programs. Please refer to the response to 2008 TGI Annual Review BCUC IR 1.34.1 below.

2008 TGI Annual Review BCUC IR 1.34.1

"34.0 Reference: Exhibit B-1, Section B-3, Savings Targets, p. 13

34.1 Please show how each of the six listed DSM programs performed versus their savings targets, for 2007.

Response:

Energy savings are a function of the number of participants in a program multiplied by the energy saving per participant. Energy savings per participant were detailed in the table on Page 13 (Exhibit B-1, Section B-3), therefore the Company suggests that it might be more reasonable to look at projected vs. actual numbers of participants for each program in terms of energy savings. Please see the table below, which shows target versus actual program participation for 2007 and 2008.

	2007		2008	
Program Name	**Projected Number of Participants**	**Actual Number of Participants**	**Projected Number of Participants**	**Actual Number of Participants YTD**
Energy Star Heating System Upgrade	4,316	4,854	3,300	1,989
Fireplace Pilot Program	n/a	n/a	625	207
Efficient Boiler Program	20	55	8	4
Destination Conservation	44	45	40	18
Commercial Energy Utilization Advisory	100	111	120	47

Notes to 2008 YTD figures:

- *It should be noted that the Energy Star Heating System Upgrade figures are actual participants to August 2008.*
- *Anecdotal evidence suggests that for the Fireplace Pilot Program, there are a large number of application forms are being batched and held back by program participants until the program ends.*
- *It is anticipated that re-opening the Efficient Boiler Program to boilers for existing buildings (retrofits) will result in strong participation."*

In the table below, a column has been added to reflect actual participation rates as a percentage of the initial program goals set for the 2007 and 2008 reported in the response to BCUC IR 1.34.1 for the 2008 TGI Annual Review Proceeding.

	2007			2008		
Program Name	**Projected Number of Participants**	**Actual Number of Participants**	**%age of Actual Participants vs. Projected**	**Projected Number of Participants**	**Actual Number of Participants YTD**	**%age of Actual Participants vs. Projected**
Energy Star Heating System Upgrade	4,316	4,854	1.12	3,300	3,177	0.96
Fireplace Pilot Program	n/a	n/a	n/a	625	1,198	1.92
Efficient Boiler Program	20	55	2.75	8	5	0.65
Destination Conservation	44	45	1.02	40	45	1.13
Commercial Energy Utilization Advisory	100	111	1.11	120	73	0.61

55.6 Please provide tabular data indicating what the Total Resource Cost (TRC) and Program Administrator Cost (PAC) ratios achieved for TGI's portfolio of energy savings initiatives are for the data detailed in Table B-1-6 of the Application.

Response:

Please refer to the response to BCUC IR 2.55.3.

55.7 Please list reports that give details of the impact evaluations on TGI's energy savings programs since 2005.

Response:

Terasen Gas has completed impact evaluations of our Commercial Energy Assessment, Pilot Fireplace and Energy Star Heating System upgrade programs. We are planning an evaluation of our Efficient Boiler Program in the fall of 2009.

The Pilot Fireplace Program evaluation was completed in March of 2005 and had two types of impacts. The evaluation indicates that customers with decorative fireplaces who were not in the market to replace them were encouraged to replace them as a result of the program pilot and it also encouraged customers who were in the market to move to a more efficient fireplace. Estimated net energy savings from the Pilot are between 2.4 and 2.8 TJs. The free ridership is estimated at 24%.

The evaluation period for the Commercial Energy Assessment impact evaluation was conducted from mid-2005 until June 2007. Evaluation results indicate that 129,000 GJs were saved as a direct result of 35% of program participants implementing recommended changes. An additional 9% of program participants were told in their energy assessments that there were no possible improvements to there current setup. This means that 56% of program participants did not implement any of the recommended changes. The evaluation also indicates that 10% of program participants were "free riders". The impact of the Commercial Energy Assessment was that 57% of program participants who implemented recommended changes saw a distinct reduction in natural gas.

The first phase of the Energy Star Heating System Upgrade evaluated the 2005 to 2007 program and was completed in April of 2008. A second phase, which is a billing analysis study will be completed in the fall of 2009. The first phase of the Energy Star Heating System Upgrade Evaluation report was filed in the response to BCUC IR 1.71.2.1 in the EEC Proceeding as an Attachment.

55.8 Does TGI have a formal Process Evaluation framework for the verification and reporting of energy saving? If "yes", please provide details.

Response:

Please refer to the response to BCUC IR 2.57.1.

56.0 Reference: Revenue Requirements and Rate Proposals

Exhibit B-4, BCUC 1.22.3, p. 49

Operational Performance over the PBR Period

TGI's response forecasts that Energy Savings in 2010 and 2011 will be 3.5 percent and 3.5 percent respectively (cumulative of 7 percent):

	2005	2006	2007	2008	2009P	2010F	2011F
Annual Savings (PJs)	1.35	0.74	1.20	0.61	3 .66	5 .60	5 .60
Actual Demand of Natural gas (PJs)	175.7	170.7	182.7	183.4	167.3	162.0	161.8
Energy Savings (%)	0.80%	0.40%	0.70%	0.30%	2.20%	3.50%	3.50%
Energy Volumes (PJs)	212.0	208.9	221.5	221.9	205.2	200.9	201.0

56.1 Please provide further details, including a tabular summary stating the energy savings (PJs) and NPVTRC for each of the Energy Savings programs that will be contributing to the forecasted savings in 2010 and 2011. Please provide a fully functioning electronic spreadsheet and a discussion of relevant assumptions.

Response:

Please see Attachment 56.1. These spreadsheets are in the same format, and include the same assumptions that were submitted and reviewed in the EEC proceeding, with updates to the avoided cost of energy, discount rates and participation numbers.

In the spreadsheet models, please note that costs characterized as "Administration" would be more accurately characterized as "Non-Incentive costs." In the TGI Plan Summary spreadsheet model, all costs associated with Conservation Education and Outreach, Joint Initiatives, Innovative Technologies and Interruptible Industrial appear as "Administration" or "Non-Incentive" costs. The response to BCUC IR 2.66.3 breaks costs for some of these program areas into Incentive and Non-Incentive costs. Because there are no savings attributed to the Conservation Education and Outreach, Joint Initiatives, Innovative Technologies and Interruptible Industrial program areas in the spreadsheet model, for simplicity's sake, and to avoid making this complex spreadsheet even more complex, all costs associated with these program areas have been put into the "Administration" or "Non-Incentive" cost category.

57.0 Reference: Revenue Requirements and Rate Proposals

Exhibit B-4, BCUC 1.22, pp. 47-49

Operational Performance - Impact Evaluation

57.1 Please explain how each of the energy efficiency programs that are contemplated for 2010 and 2011 will be evaluated by providing a description of the framework and details of both the key individual metrics that will be measured or evaluated, and the processes that will be used to monitor and report the activities and outcomes associated with each of the energy efficiency programs.

Response:

Evaluation of energy efficiency programs was discussed extensively during the EEC proceeding, which approved the energy efficiency expenditures for 2010. It was discussed throughout the initial Application, as well as in numerous responses to information requests. The key metric that will be measured is the cost-effectiveness of EEC programs. This will be done on a portfolio basis and the overall EEC portfolio must have a TRC ratio of 1.0 or higher. This is consistent with the approach approved by the Commission in the EEC Decision earlier this year.

Program evaluations will be designed in two stages. During the program design phase the program evaluation concept is determined. The primary purpose of this is to understand the data that will be required for the evaluation, and to determine how much of this can be collected during program operation, for example, as part of the incentive application. By doing this development prior to program launch, better quality data can be collected and at a lower cost than if evaluation design is left until the time for the evaluation.

Once the program has operated for a sufficient period of time[25], an impact evaluation can be undertaken, and the detailed evaluation will be developed. In the past, TGI evaluations have been conducted by outside consultants who have been selected based on relevant experience and cost. Once selected, the consultant then develops the detailed evaluation plan for review and discussion with TGI. When the plan has been approved, the consultant typically develops any necessary market research (for example with participants and with the relevant trade allies), conducts the analysis and develops a report.

Program Monitoring is the ongoing tracking of program activities, costs and impacts. TGI is currently implementing an integrated Demand Side Management System (DSMS) to provide a central point for data collection, integration with the TGI financial system, and reporting.

[25] This will vary with the program. For programs that involve heating, it is necessary to have at least one year of post installation experience for an adequate number of participants. In the EEC plan, most impact evaluations are planned for the third year.

Reports on DSM activities and results will be extracted from this system and made annually to the BCUC.

57.2 Please describe in detail the extent to which TGI will be following the methodology set out in the California Standards Practice Manual to assess the impact of TGI’s energy efficiency programs. What, if any, variations, additions, or omissions to those standards will TGI be relying upon?

Response:

Please refer also to the response to BCUC IR 2.57.1 above. The California Standard Practice Manual contains information on the Economic Analysis of Demand Side Programs and Projects, commonly known as the California Standards Practice tests. TGI will be calculating the tests in accordance with these standards with the exception that TGI will include the BC Carbon Tax as a participant benefit as approved by the BCUC (EEC Decision - Section 3.5 (pp. 40-41)).

For the purposes of assessing the impact of TGI’s energy efficiency programs, which the Company interprets as meaning “program evaluation” rather than focusing solely on the DSM Economic Tests, the Company will be more closely following the findings from the Final Report of Measurement, Analysis and Reporting Task Force (“MARTF”) of the British Columbia Partnership for Energy Conservation and Efficiency, of which the Commission is a member. At the time of writing, the MARTF report is not finalized for public release, however much of it is based upon the “California Energy Efficiency Evaluation Protocols: Technical, Methodological, and Reporting Requirements for Evaluation Professionals” (California Public Utilities Commission (CPUC) – April 2006). The California document was intended to “. . . guide the efforts associated with conducting evaluations of California’s energy efficiency programs and program portfolios. . .” (CPUC, p1), and it is included in Attachment 57.2. As such, it summarizes “best practices’ for program evaluations. For most evaluation areas, the protocols are classed as Basic, Standard and Enhanced. As evaluations move up the scale from Basic to Enhanced, the level of rigor increases, and so does the cost of the evaluation.

Once the MARTF report is finalized, the Company will file it under separate cover, however one of the primary questions addressed by the MARTF is the question of the level of evaluation required. The draft MARTF report suggests five guidelines for “ex post” evaluations to determine the level of rigor, and hence cost, that is appropriate to invest in a specific program evaluation. These are:

- The program size (in terms of estimated savings or budget) and resulting portfolio risk – if size and risk are large, evaluation should be more rigorous.

- The likelihood of similar programs in the future – if more of such programs are expected in future, evaluation should be more rigorous
- The amount and quality of evaluations for similar programs in BC and other jurisdictions – new types of programs, programs with little evaluation data, and programs operating in a new environment (i.e. higher energy prices) should undergo greater evaluation.
- The level of uncertainty of program savings – if larger uncertainty is inherent, evaluation should be more rigorous Cost of evaluation relative to total program operation costs – resources will be a constraining factor on the level of rigour.

Most evaluations at TGI have used billing data analysis and were based on a "pre-test, post-test, control group model" to determine gross energy savings. Relative to the CPUC Evaluation Protocols, this methodology would straddle both Basic and Enhanced protocols. To determine participant net impact (i.e.: free riders), these evaluations have used combinations of: participant self report; discrete choice analysis; and trade ally reporting. Relative to the CPUC Evaluation Protocols, these methodologies would fall into the Basic, Standard and Enhanced protocols. It is the Company's intent to develop evaluation plans and budgets for each EEC program at the same time as the program designs are completed. Evaluation plans will vary by program, depending on such factors as the overall program budgets and projected savings, program complexity, market maturity and others.

57.3 Depending on the answer of the foregoing questions, please indicate whether TGI has a formulated Evaluation Plan in place or plans to develop one which would:

I. Measure energy efficiency program effects as individual and summative evaluations;

II. Assess the source of the effects, and show how the program can be improved by way of a formative or process evaluation;

III. Measure the level of natural gas savings achieved;

IV. Measure benefit: cost effectiveness;

V. Provide audited evaluation reports;

VI. Provide ongoing feedback, and corrective and constructive guidance regarding the implementation of programs; and

VII. Serve as assessment tools to determine the continuing need for the programs.

Response:

Please see the responses to BCUC IR 2.57.1 and 2.57.2. At the time of program design, an evaluation process appropriate to the program will be developed and budgeted for. The Company will report on evaluation processes for new EEC programs in its Annual EEC Report, to be filed prior to the end of Q1 2010 for 2009 activity.

57.4 As it relates to the evaluation of energy efficiency programs, please provide a budget indicating how much TGI will be spending in 2009, 2010 and 2011 on developing, implementing, and assessing the impact of its energy efficiency programs.

Response:

The budget for program evaluation is as follows:

2009 - $165,000

2010 - $807,000

2011 - $983,000

More information about budget breakdowns can be found in the response to BCUC IR 2.66.3.

57.5 Please indicate whether TGI currently has the necessary in-house human resources to design and implement an evaluation, measurement, and verification process of the proposed energy efficiency programs.

Response:

The Company recognizes the importance of evaluation in considering the effectiveness of EEC programs, and is aware that the increase in EEC budgets with Decision G-36-09 will result in an attendant increase in focus from the Commission and Intervenors on evaluation. Staff development and training on all aspects of EEC, including evaluation, measurement and verification, will be a major focus for the new EEC staffing structure outlined in the response to BCUC IR 1.29.2.2. The hiring process for the new EEC staffing structure was completed in August 2009, and a two and a half day "DSM 101" seminar, which included a module on evaluation, was presented to new and existing EEC staff. There are a number of other resources on which the Company intends to draw in the development and training of EEC staff on all aspects of DSM, such as energy efficiency industry conferences, "brown bag" lunches, webinars and discussions and collaborations with other utilities. There is a conference dedicated to program evaluations, the International Energy Program Evaluation Conference (www.iepec.org), that will likely be a good resource for the development of program evaluation skills. The responsibility for developing the program evaluation process at the time of program development will rest with the Residential, Commercial and Low Income Housing Program Managers, and the plan for program evaluation will form part of the overall program plan that is presented to Senior Management for their review and approval.

As noted in the response to BCUC IR 2.57.1, Terasen Gas has used outside consultants to conduct major evaluations, and will continue to do so in the immediate future. The initial evaluation projects will be structured such that TGI staff will work along side of the consultants in order to obtain a transfer of skills.

Some programs will be conducted in conjunction with other utilities on a joint basis. In the case of these programs, one evaluation would be undertaken for the program on behalf of all the participating utilities, and a decision would be made between the partners who would lead the evaluation, with support in terms of data and funding from the partners. The Company anticipates that this will also result in a transfer of skills between utilities.

Thus TGI anticipates that TGI staff will develop in-house capabilities to design and implement an evaluation, measurement and verification process.

58.0 Reference: EEC and Alternative Energy

Exhibit B-4, BCUC 1.23.1.1 pp. 50-52

Operational Performance - Impact Evaluation

58.1 Please indicate the extent to which TGI's affiliated non-regulated businesses ("NRBs") will participate in upstream or downstream aspects of the energy efficiency programs described in the Application.

Response:

At this time, it is not anticipated that TGI's affiliated NRBs will participate in any aspects of the energy efficiency programs that were reviewed and approved as part of the Company's EEC application, and for which are contemplated in this Application.

59.0 Reference: Alternative Energy Solutions

Exhibit B-4, BCUC 1.23.1.1

Demand for Alternative Energy

"…Since 2008, TGI has begun to change its corporate focus into becoming a provider of energy rather than simply a natural gas delivery company"

59.1 Does TGI agree that regulation of a gas delivery company is to ensure the elimination of duplicate gas infrastructure and hence to ensure the efficient use of pipelines and other gas facilities?

Response:

There are no specific provisions in the *Utilities Commission Act* that state the role of the Commission is to ensure the elimination of duplicate gas infrastructure. Section 27 of the *Utilities Commission Act*, "Joint Use of Facilities," provides for the Commission to "direct that the joint use of conduits, subways, poles, wires or other equipment to be allowed and prescribe[e] conditions of and compensation for the use", which may suggest a legislative support for reduction of redundant utility infrastructure where possible. TGI does not believe that any of its initiatives result in redundant infrastructure, but rather offers additional energy choices to customers to augment the more traditional energy sources such as gas, electricity, propane or fuel oil. In fact by offering alternative energy solutions, which are supplemented with natural gas, the natural gas infrastructure may be better utilized than if natural gas was not part of the solution delivered to customers. This result benefits the natural gas ratepayers.

The core jurisdiction of the Commission is to ensure that public utilities provide energy services that are safe and reliable, and charge rates that are just and reasonable. This is reflected in Commission decisions and court decisions, as discussed in the response to BCUC IR 2.70.1. TGI intends to provide all of its energy services in a safe and reliable manner. The economic tests, which result in an appropriate allocation of costs of service, contribute to ensuring that rates charged by TGI for both gas service and alternative energy are just and reasonable. Please see the response to BCUC IR 1.24.3.

59.2 Does TGI agree that the deregulation of commodity services (i.e. is to allow customers to have a choice in competitive gas products?

Response:

Gas commodity acquired by transportation service customers (TGI Rate Schedules 22, 23, 25, and 27) is obtained from a competitive market in terms of price, and the Commission does not regulate energy supply contracts entered into directly with transportation customers that are not public utilities (section 71(1.1)).

Residential and Commercial unbundling (customers served under TGI's Rate Classes 1U, 2U, and 3U) is not the same as deregulation. Entities with gas marketing licenses are still heavily regulated by the Commission. Gas marketers, however, are free to set their own commodity rates to customers, thereby providing choice for customers. The Gas marketers purchase their commodity supply in a competitive marketplace and the energy supply contracts that govern these commercial transactions are not regulated by the BCUC.

TGI makes two related observations in respect of the analogy apparently being drawn between alternative energy solutions and the supply of gas commodity directly to customers.

First, TGI notes that a key difference between the supplier of commodity and TGI's approach to alternative energy solutions is that TGI will own the infrastructure used to provide the energy to the customer (the customer will typically be large institutions, developers, communities, or municipalities etc.). It is, in this sense, no different than a public utility providing a bundled gas or electricity or propane service to the end user. These assets and services would be subject to regulation regardless of the company providing the service or the owner of the assets, as they would necessarily meet the definition of a public utility under the Act.

Second, the Commission's jurisdiction is not determined by whether or not a service is subject to competition, or whether it is a monopoly. These points are discussed in more detail in the response to BCUC IR 2.59.4.

In sum, TGI believes that it is appropriate for the Company to pursue alternative energy solutions for the benefit of its customers.

59.3 Does TGI agree that there is a fundamental difference between being the "provider of energy" (currently a competitive market) and being a "delivery company" (currently a regulated segment) and that the latter is suggestive and supportive of monopoly operations.

Response:

In the passage quoted in the preamble TGI was stating that it intends to offer alternative energy solutions in conjunction with natural gas. Alternative energy solutions involve both an energy component and a delivery component, as TGI will own and operate the infrastructure just as it does with the natural gas infrastructure.

The difficulty with the distinction being drawn in the question between a "provider of energy" and a "delivery company" is that the distinction is not a determining factor with respect to the jurisdiction of the Commission. Neither of the terms "provider of energy" nor "delivery company" appear in the *Utilities Commission Act.* The "provision of energy" cannot be equated with competition or non-regulation, as the question appears to suggest. BC Hydro and Dockside Green are two examples where the utility provides both energy (commodity) and delivery service to customers. Both of those entities are regulated because they meet the definition of "public utility" in the UCA. A provider of alternative energy solutions will similarly meet the definition of "public utility" and will be subject to regulation regardless of how one characterizes the nature of the business (delivery company or supplier or monopoly or non-monopoly).

59.4 Does the above quoted statement imply that TGI believes that alternative energy solutions should fall under BCUC regulation, hence the Commission would be charged with setting the prices of these alternative energy solutions? Please explain whether TGI believes this to be fair practice and how this would be beneficial to existing ratepayers when other alternative energy service providers are currently operating in a competitive environment.

Response:

Yes, the above quoted statement does suggest that TGI believes that alternative energy solutions should fall under BCUC regulation, and that the Commission would be charged with approving just and reasonable rates for the alternative energy customers as well as for gas customers. Part of this role involves ensuring that proper cost recovery is occurring from the alternative energy customers relating to common costs with the gas business.

The second sentence of the question appears to imply be that the Commission cannot, or should not, regulate the provision of alternative energy solutions because there are either (i) other retail suppliers of geothermal, solar thermal or district energy systems, or (ii) companies other than TGI that might ultimately choose to retain ownership of, or operate, an installed system and charge a rate to customers for the provision of energy. There are a number of other information requests from the Commission that appear to be based on the premise that the service TGI intends to offer is a competitive service and not a monopoly service and hence should not be regulated. The previous question (BCUC IR 2.59.3), for instance, appears to draw an analogy between the provision alternative energy solutions and the unregulated supply of gas commodity directly to end use transportation customers. BCUC IR 2.11.3 asks about whether a natural monopoly exists for alternative energy solutions. There were a variety of these questions in the first round of information requests as well (See for instance BCUC 1.25.3). TGI believes that the position apparently being advanced by these questions is:

- founded on an incorrect premise that the energy service provided to third parties by an owner and operator of geothermal, solar thermal or district energy systems is not monopolistic in nature; and

- inconsistent with the express terms of the *Utilities Commission Act*, which defines the Commission's jurisdiction.

At the outset, it is important to be clear on the nature of the endeavour that TGI is intending to engage in when it comes to alternative energy solutions. TGI will own the equipment itself and sell heat to customers at a Commission-approved rate. (See TGI's response to BCUC IR 1.24.3.) It is entering into a market where primarily sophisticated industrial or commercial customers will agree to pay a rate to another entity (TGI or another entity) for the provision of heat from a district energy, geothermal or solar thermal solution rather than invest themselves in the development of the necessary infrastructure to self-supply. In other words:

- Terasen Gas is not proposing to become involved in the sale of or supply of equipment, nor does TGI believe that the sale of alternative energy equipment and systems should be regulated by the BCUC. Customers purchasing such equipment self-supply their own heat or electricity and are not public utilities under the *Utilities Commission Act.*

- This ownership and operation of the facilities required to deliver energy to the end use customer also distinguishes the TGI model for providing alternative energy solutions from that of the supplier of gas commodity to transportation customers. (See BCUC IR 2.59.3 for further explanation).

In previous answers (see for instance BCUC IR 1.24.3), TGI has made the point the definition of "public utility" is what defines the entities over which Commission's jurisdiction extends. The definition of "public utility" extends to capture, in essence, those entities that own or operate facilities for the purpose of providing energy to third parties for compensation. Neither the term "monopoly", nor "competition" appear anywhere in the Act, and are not the concepts that determine whether an entity is subject to regulation by the Commission.

While the Commission's jurisdiction is not defined by whether or not a service is subject to competition or whether it is a monopoly, the scope of the definition of "public utility" is consistent with protecting customers from the exercise of monopoly power by third party providers of energy. The owner or operator of an alternative energy system, who sells energy from that system to end users for compensation (as TGI proposes to do), is appropriately captured by the definition of "public utility" because it is capable of exercising "monopoly" market power in respect of its customers. Put another way, although there is more than one company that could enter the market to install, own and operate geothermal, solar thermal and district energy systems, and charge a rate to other customers, one must consider the position of the customer once the equipment has been installed and the customer is dependent on that system and the third party provider for energy. The customers that receive services such as space and water heating from another entity will be effectively captive to the rates charged by the entity owning the infrastructure for the life of the contract and, likely, the life of the assets. With respect to district energy system serving a community, for example, TGI or another provider selected by the consumer would have an effective monopoly over the provision of heat to the customers in the community. Customers may come and go from the community, but each would be receiving energy from TGI's installed district energy system. It is exactly this type of service that the Commission is bound to oversee in the public interest.

In this sense, the customer that obtains heat energy from of a third party owner of geothermal, solar thermal and district energy systems is in the same position as an electricity customer of BC Hydro, a gas customer of TGI, a resident of Dockside Green (a regulated public utility providing heat energy produced from a district energy system similar to those being advanced by TGI) or Gateway Village (a propane-based district energy system), or a customer of a host of other entities providing energy services in British Columbia. This point can be illustrated by example. British Columbians living in the service area of TGI and BC Hydro, for instance, usually have a choice between gas and electricity for space heating. Gas and electricity compete for those customers. However, the existence of this competition for customers does not mean that BC Hydro and TGI are not monopolies and should be unregulated. The reason is that once a customer has made a choice of electricity or gas for space and water heating, either BC Hydro or TGI will have an effective monopoly on serving that requirement unless the customer elects to leave the system and incur capital costs to install another type of heating system. A municipality or hospital that obtains heat from a third party owner of its district energy system (such as Central Heat), but is still located within BC Hydro and TGI's (gas) service area will still have the choice to switch from its district energy system to competing offerings such as gas or electricity, but there may be sufficient impediments to making that change to discourage leaving the district energy system even in the face of unjust or unreasonable rate increases. Regulation of the rate charged by district energy system is thus an important aspect of consumer protection. TGI's proposal is to submit a negotiated contract to the Commission for approval as the terms and conditions of service by the utility.

The nature of the regulation that has to date been adopted by the Commission in respect of regulated services provided by the various public utilities in the Province has appropriately varied based on a variety of considerations. Central Heat is an example of "passive regulation" of a relatively small public utility that provides heat energy to customers. Nonetheless, TGI believes that the Commission's jurisdiction over entities that own the alternative energy infrastructure used to provide the energy to the end user is unequivocal.

60.0 Reference: Alternative Energy Solutions

Exhibit B-4, Table 35, Attachment 1.23.1.1, BCUC 1.23.1.1

Alternative Energy Incremental Capital Costs

60.1 Question #5 in Attachment 23.1.1 suggests that the majority of survey respondents would be willing to pay up to 5 percent extra for a home that uses an alternative energy source. Please provide the current average cost of a home in the lower mainland. Please provide the incremental capital costs of each of the proposed alternative energy solutions as a percentage of the average home cost.

Response:

Before answering the question directly TGI observes that it is not proposing to provide a heat delivery service, or sell equipment, to detached homes where that equipment or service is designed to only serve one detached house. TGI is proposing is to provide heat delivery service via a DES to an end user, who in most cases is a commercial or industrial customer or a residential multifamily customer. While it is possible that TGI would provide DES service to a detached home, the costs for this service would be higher than those in a more dense development and therefore it is less likely that this service would be offered.

The question as it is written is more relevant to developers in pricing their housing stock; however, it does suggest customers are willing to pay more in general for alternative energy. The CMHC Q3 housing report states that the average housing price in Vancouver is $555,000

If a customer in a multifamily development received a DES service from a third party, such as hot water or heat, it is likely that the capital cost for the multifamily unit would actually be less than that for a house with conventional energy. That is because some of the capital infrastructure (such as heat generation) now resides outside the house in a central energy plant. As such, the customer would pay ongoing heat delivery charges instead of paying up front capital costs for heating equipment. Lastly, as noted in response to BCUC IR 1.33.2 and 35.1 the cost for delivered energy would be different depending upon the development, but over time would be competitive with traditional energy sources.

61.0 Reference: EEC and Alternative Energy

Exhibit B-4, BCUC 1.23.2

61.1 Why would you expect to have the same number of participants for "hydronic under floor" and "ground source heat pump" programs, as for the other programs, when these two have payback periods of 50 and 137 years?

Response:

While the payback periods are very different, at this point we do not believe that this difference will result in different participation levels.

Hydronic under floor systems are commonly installed in buildings that include premium features and differentiate the building as a superior product. Rarely is the incremental capital cost a major factor to builders or developers who install Hydronic under floor systems in these buildings. However, TGI believes that the proposed incentive will encourage the installation of hydronic under floor systems by builders or developers who would not normally install hydronic systems in buildings that do not include premium features. TGI believes the increased incremental cost over a basic space heating systems such as electric base board or forced air systems is a barrier deterring the installation of hydronic under floor system.

Very few, if any, ground source heat pumps are installed based solely on economic justification. Ground source heat pumps are typically installed for the environmental benefit they provide over carbon based fuels and electric based systems (although environmental benefits also have economic benefits). The incentive we are proposing for this technology is to promote the additional installation of piping and equipment that will permit the system to be integrated easily into a district energy system or other source of energy in the future.

The 137 year payback for a ground source heat pump is misleading, as the cost of the system was compared to a system costing $10,000. Since we are providing incentives for the installation of additional equipment as mentioned in this response, we anticipate the number of participants to be similar for both programs.

The number of participants identified in the response to BCUC IR 1.23.2 is the upper achievable potential number of participants. As these are pilot programs, once we introduce them to the market, we will analyze the participation levels, and then we will be able to begin to forecast levels of participation for the term of the program.

62.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Part III, Section C, Tab 3, Table C-3-2, p. 229

Exhibit B-4, BCUC 1.26.1 and BCUC 1.27.1

"TGI is seeking approval in this Application "for funding in 2011 for program areas outlined in the EEC Application and already approved by the Commission for 2010…". The same benefits for EEC expenditures already approved by the Commission will be derived from the EEC expenditure being requested in this Application for 2011." (Exhibit B-4, BCUC1.27.1, p. 65, par. 2)

62.1 Please confirm the request in this revenue requirements application is for an additional $23.075 million for 2011 as an extension of the programs approved in Order G-36-09, and for new Interruptible Industrial and Innovation Technologies programs for 2010 and 2011 of $9.313 million.

Response:

Confirmed. This information was included in Table C-3-2 on page 229 of the Application and in the table included in the response to BCUC IR 1.27.1.

62.2 In the decision referenced in Order G-36-09, the Commission accepted TGI's proposal for accountability mechanisms and directed Terasen is to file an annual report on its EEC activities. Please confirm when the first report will be available.

Response:

It is anticipated that the first report will be available by March 31, 2010, for activity in 2009. See Program Principle # 6 on page 47 of the Terasen Utilities' EEC Application, which is copied below for ease of reference (emphasis added).

Terasen Utilities' EEC Application Excerpt from page 47

62.3 Please comment on why it is appropriate to extend the EEC program when there has been no evidence of benefits from the program approved under Order G-36-09?

Response:

Program Principle #11 on page 48 of the Terasen Utilities' EEC Application, and copied in BCUC IR 2.62.2, is to have programs that span multiple years to provide some assurance to market actors such as manufacturers, distributors, retailers, installers, engineering firms, architects, developers and government that investments that they make in training, equipment, etc to support EEC activity will be a good long-term investment.

The Company's goal is to support market transformation. The original application, which was for 3 years worth of activity spanning 2008 to 2010, would have afforded the Company the opportunity to launch its 3 year EEC portfolio of new programs. Commission Order No. G-36-09 was issued in April 2009, so in order to have 3 years worth of EEC activity and the resultant certainty in the marketplace around the program areas approved in the Decision, the Company felt that it was appropriate to include a request for funding to extend to 2011 the EEC activity approved in Order No. G-36-09.

The EEC activity put forward in the EEC proceeding, and approved in Order No G-36-09 is supported by the 2007 BC Energy Plan, which included Policy Action #3: "Utilities are to pursue all cost-effective investments in demand side management resources". Clearly there is an expectation on the part of government that utilities will pursue EEC activity; the funding requested in this Application is to continue the EEC activity already approved in Order No. G-36-09. TGI also expects that for the 2012 period forward it will request funding so as to continue its EEC activity.

Prior to the approval of the EEC Application, our customers have had limited access to EEC opportunities. In the years 2005 to 2008, TGI was able to deliver EEC programs to our customers with positive TRC results in spite of a limited budget. The additional funding that we now have available as a result of the Order No. G-36-09 will allow TGI to move forward with new programs which we have projected will produce on a portfolio basis a healthy TRC ratio well above the 1.0 level that we are required to meet. The Company believes that we will be able to provide the best benefit to our customers by being able to assure the energy efficiency marketplace that funding will be in place to support EEC activities in the long term."

"The Companies did not receive approval for expenditures for innovative technologies and the Companies were directed to bring forward projects in this program area for consideration as the projects become more fully developed." (Exhibit B-1, Part III, Section C, Tab 3, p.228)

62.4 Recognizing the Commission direction referenced, please explain why it is appropriate to include in this revenue requirement application the extension and expansion of a specific program that was approved by the Commission as a separate decision outside of the revenue requirements process?

Response:

TGI did not apply for the original EEC funding as part of a revenue requirement application as it was in the middle of the PBR Period. As that settlement is about to expire, and the funding approved via Order No. G-36-09 only covers half of the RRA period, it would be necessary for the Company to apply, by some method, for EEC funding from 2011 forward.

Although the EEC funding is being sought as part of this filing, it is being sought under the same section of the UCA as was the original EEC Application funding. TGI believes that from the aspect of regulatory efficiency it is more desirable to include the extension and expansion of EEC funding (which has already been approved by the Commission) within the RRA rather than filing a separate application part way through the RRA. With the inclusion of these programs, the Company is just extending, with minor revisions, what has already been approved. TGI is also responding to the Commission direction to bring forward projects for consideration once they become more fully developed and, for regulatory efficiency, is doing so within this RRA.

63.0 Reference: Energy Efficiency and Conservation Programs and Alternative Energy Solutions

Exhibit B-4, BCUC 1.27.2, p. 67

Energy Efficiency – TRC Test

On page 67 of TGI's response to BCUC 1.27.2, the following summary of portfolio TRC is provided:

Year	Portfolio TRC Ratio
2010	2.7
2011	2.5

63.1 In tabular form, please provide additional detail for 2010 and 2011 indicating the composition of the individual energy efficiency programs in 2010 and 2011. Please also include projected TRC results for each program expressed as a net present value (NPVTRC) of the benefits and costs over the specified period. Please provide a fully functioning electronic spreadsheet and a discussion of assumptions used in the calculations.

Response:

Please refer to the response to BCUC IR 2.56.1.

64.0 Reference: Energy Efficiency and Conservation Programs and Alternative Energy Solutions

Exhibit B-4, BCUC 1.30.4, pp. 77-78

Energy Solutions

Innovative Technology Measure Name	TRC Ratio	
	2010	2011
Hydronic Baseboards	1.5	1.6
Hydronic Underfloor Systems	0.8	0.8
Combination Systems	1.3	1.4
Solar Thermal	0.3	0.3
Ground Source Heat Pump	0.2	0.2
Overall Innovative Technology Program Area	0.5	0.5

64.1 For the Innovative Technology Measures indentified in response to BCUC 1.30.4, please indicate whether TGI has literature or market information from other jurisdictions in North America or overseas which provide insight into the economic and societal net benefits associated with the Innovative Technology Measures identified.

Response:

No, TGI does not have literature or market information which provides insight into the economic and societal net benefits associated with the Innovative Technology Measures identified.

However, the programs, like other EEC programs are intended to reduce energy usage, which include GHG reductions, and therefore there is a societal benefit from undertaking this and other EEC programs. Further economic and societal net benefits of the portfolio of Innovative Technologies will be identified and defined during the evaluation of the programs.

64.2 For each of the Innovation Technology Measures with a TRC of less than 1.0, please identify and discuss critical limiting technological and economic factors. Over the short to medium term, please discuss what strategies TGI has for mitigating, and possibly overcoming, these limitations.

Response:

Hydronic Underfloor Systems

Hydronic underfloor systems have no technological limiting factors. However, there are additional cost and design factors not associated with conventional forced air or electric baseboard systems . Accommodating the piping loop in the foundation slab requires steps such as: added insulation under the slab; and, an additional 2" footer under the walls that allows for the piping loops to be laid and covered with light-weight concrete.

Space occupied by the boiler, controls and valves is considered by some builders and developers as wasted and un-sellable space. Therefore, hydronic underfloor systems are generally installed in large homes built to include premium features.

TGI has actively promoted hydronic underfloor systems for many years through our marketing and sales teams to builders and developers and will continue to do so over the short and medium term. We have also requested that municipalities determine that floor space occupied by boiler and forced air furnaces not be included in the overall square footage of the buildings with respect to building and lot density.

Solar Thermal

In the past, solar thermal systems have had several technological limiting factors: poor quality products, lack of skilled installers, lack of codes to regulate manufactures and installations of the equipment. Most of the limiting factors no longer exist. Due to improved quality, certification of installers and development of codes and CSA certified equipment, only the cost of the systems is limiting this technology from being a standard component for water heating.

TGI's short term strategy is to provide incentives for this technology to increase the market penetration of solar thermal systems thereby accelerate the reduction in unit cost of the systems. By stimulating the solar thermal market we expect to see significant reductions in natural gas consumption and lower costs of solar thermal systems.

Our mid-term strategy through innovative technologies is to promote the integration of technologies to create very efficient hybrid water heating, space heating & cooling for residential and commercial buildings.

Ground Source Heat Pump

Like solar thermal, improved quality, certification of installers and development of codes and CSA certified equipment no longer limits this technology. However, as these systems are being installed in close proximity to other GSHPs, the systems invariably compete for the same energy stored in the ground, thereby reducing the available energy and increasing the dependency of either gas or electricity to provide heat to the buildings. TGI believes that the GSHP systems must have ablility to be integrated into a shared energy system with multiple buildings.

Unlike the other innovative technologies, TGI is not providing incentives that reduce the installation cost of the system. We are providing incentives to make these systems adaptable to other sources of energy in the future.

Our short term strategy is to ensure buildings with GSHP can be easily integrated to other energy sources or integrated into a shared energy system with multiple buildings interconnected.

Our mid term strategy is to develop or promote the construction of community based District Energy Systems (DES) that will provide the thermal energy required to heat DHW and the interior space of building. Community based DES will allow for the installation of very high efficient and high quality equipment.

65.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Exhibit B-4, BCUC 1.30.4, p. 78

Total Resource Cost Test

65.1 Please restate the TRC ratios presented in the table in the response to BCUC 1.30.4 assuming a price of carbon dioxide of $30, $50 and $70 per tonne.

<u>Response:</u>

TGI would like to confirm that a change in the level of carbon taxes has an impact only on program participants, meaning that only the Participant Cost Test and not the TRC test is affected by these assumed changes in the Carbon Tax. This approach is consistent with the approach outlined in the EEC proceeding. TGI has illustrated below a comparison of the Participant benefit/cost ratios for $30, $50 and $70 beginning in 2013 for the remaining life of the program.

	Participant Cost Ratio					
	Current proposed carbon tax capped at $30 beyond 2013		price of carbon tax capped at $50 beyond 2013		price of carbon tax capped at $70 beyond 2013	
Innovative Technology						
Measure Name	**2010**	**2011**	**2010**	**2011**	**2010**	**2011**
Hydronic Baseboards	2.3	2.3	2.4	2.4	2.6	2.6
Hydronic Underfloor Systems	1.1	1.1	1.2	1.2	1.3	1.3
Combination Systems	2.5	2.5	2.7	2.7	2.9	2.9
Ground Source Heat Pump	0.4	0.4	0.4	0.4	0.4	0.4
Solar Thermal Hot Water	0.3	0.3	0.3	0.3	0.3	0.3
Overall Innovative Technology Program Area	0.6	0.6	0.6	0.6	0.7	0.7

66.0 Reference: Energy Efficiency and Conservation Programs and Alternative Energy Solutions

Exhibit B-4, BCUC 1.31.2, p. 81

EEC Programs

66.1 For the EEC Pilot projects identified in the Application, please provide further details regarding expected outcomes, deliverables, milestones, and budgets for each of the EEC Pilot projects.

Response:

TGI proposes the Innovative Technologies programs be run as pilots that would subsequently provide data to enable the Company to establish, expected outcomes, deliverables and key milestones in the Innovative Technologies area. Program design is not expected to be completed for a several weeks. As part of that process of completing program design TGI will develop further details regarding expected outcomes, deliverables and milestones. However, at this time we are able to provide the following budget information for each of the EEC Pilot projects.

The total budget for the EEC pilot programs is $7,003,125 over two years. The table below itemizes each EEC pilot projects.

$000s	2010	2011	Total
Residential and Small Commercial			
Hydroponic Based Heating Systems	778.125	1556.25	2334.375
Integrated Energy Systems (or Combination Systems)	518.75	1037.5	1556.25
Solar Thermal	518.75	1037.5	1556.25
Ground Source Heat Pumps	518.75	1037.5	1556.25
Total	$2,334.375	$4,668.750	$7,003.125

66.2 Please provide details regarding steps that TGI has taken, or is planning, to monitor and assess EEC Pilot projects throughout 2010 and 2011. To the extent possible, please provide an example of the metrics and reporting formats that TGI will be relying upon to:

I. Measure energy efficiency of the various EEC Pilot projects;

II. Assess results;

III. Describe how the various EEC Pilot programs can be improved, and quantify the outcome;

IV. Measure the level of natural gas savings achieved;

V. Measure benefit: cost effectiveness;

VI. Provide ongoing feedback, and corrective and constructive guidance regarding the implementation of programs; and

VII. Assess whether there is a continuing need for the programs, and justify the assessment.

Response:

The energy efficiency of the various EEC Pilot programs is dependent on the occupants' behavior and educating the occupants how to achieve the greatest benefits and performance from the equipment. Devices that prove real-time energy consumption data also aid in altering behavior by reducing consumption. Although real-time energy consumption data has typically been limited to electrical consumption, TGI is investigating gas and thermal metering technology (sub-metering) that will monitor and report individual appliances consumption of energy on a daily bases for our analysis, as well as possibly provide occupants with real-time energy consumption data.

TGI is also in the process of implementing an integrated Demand Side Management System (DSMS) which will provide a central point for data collection, integration with the TGI financial system reporting for 2010 and beyond. Program managers will input EEC program activity into DSMS to track and monitor program activity and utilize DSMS reports extracted from the system to access program performance. Such performance measures as energy savings, cost-benefit ratio and GHG savings are all captured in DSMS. Program managers will be able to use the reports generated by DSMS to prepare the required annual EEC reporting.

TGI uses pilot programs as a mechanism to access market response, confirm energy and GHG projected savings and to refine program design. Based on feedback that is received from the market during the pilot phase, we are able to make adjustments to program design prior to launch into the general market. Staff uses the results of pilot programs to determine if there is justification for going forward with the program taking into consideration such measures as level of market transformation, level of energy savings and the size of the potential market.

66.3 For the proposed EEC programs in 2010 and 2011, please provide a tabular summary which allocates expense in the following categories: (a) incentives, (b) program design and administration, (c) impact evaluation and reporting, and (d) education and awareness.

Response:

The following table summarizes this information. An amount for gathering of participation numbers (reporting) has been included in the "Design and Administration" category, rather than in the Evaluation category. It must be noted that these are the Company's best estimates of the allocation of expenses by category and that as programs become more developed, program-specific amounts for design and administration, evaluation and education and awareness will be derived. The Company will report in more detail upon amounts for these categories by program in its Annual EEC Report, to be completed before the end of 2010 for programs currently under development. The slight differences between budget amounts in this table and others in the Application and IR responses are due to rounding.

Program Area	2010 ($000)					2011 ($000)				
	Incentives	Design, Administration and Reporting	Evaluation	Education and Awareness	Total	Incentives	Design, Administration and Reporting	Evaluation	Education and Awareness	Total
Energy Efficiency[1]	13289	3520	469	1560	18838	13289	3520	469	1560	18838
Joint Initiatives[1]	1010	63	162	111	1346	1010	63	162	111	1346
Conservation Education and Outreach[2]	0	0	0	2890	2890	0	0	0	2890	2890
Innovative Technologies[3]	1800	176	176	176	2334	3600	353	353	353	4669
Interruptible Industrial[4]	0	430	0	5	435	1750	120	0	5	1875
Totals	16099	4189	807	4743	25843	19649	4056	983	4919	29618

Notes

1. These were approved in G-36-09. Amts for Education and Awareness are for program-specific communications
2. This was approved in G-36-09. As noted in the response to BCUC IR 2.6, this program area is currently under development.
The tactics and programs for CEO will vary fairly widely, resulting in a fairly wide variety of evaluation techniques and as such,
a budget for Evaluation for the CEO program area cannot be provided at this time.
3. As these are pilot programs, and actual costs for D&I, Evaluation and Education and Awareness have been arbitrarily determined
equal allocations of non-incentive amounts between these areas. Over the course of rolling out these pilot programs, these amounts will be refined.
4. The budget for Industrial EEC outlined in Table C-3-4 in Exhibit B-1 does not include an allocation specifically for evaluation,
however it is anticipated that such an expenditure would come from the amounts identified for Incentives, and would be guided by input from
the Industrial DSM Stakeholder group as the Industrial EEC Program is developed.

66.4 For 2010 and 2011, what is the probability that the proposed EEC programs will achieve:

(a) The DSM forecasted budget expenditures; and

(b) The DSM forecasted energy savings?

Please provide confidence levels.

Response:

Note that the expenditures for the original EEC programs (not including Innovative Technologies and Interruptible Industrial EEC) for 2010 have already been approved by Commission Order No. G-36-09, and as such TGI is not seeking approval of these expenditures for 2010.

The EEC budgets for Residential and Commercial Energy Efficiency presented in the Application are based upon the same methodology used to develop the budgets for the EEC programs approved in Commission Order G-36-09. They are developed from the ground up, using assumptions for the amount of incentive needed to spur action on the part of British Columbians, the number of participants that might reasonably be expected for each program, estimates of costs for program administration, promotion and evaluation. The current economic situation makes those assumptions and estimates less certain than they were at the time they were developed in 2008 when the EEC Application was submitted. The Company is in the process of designing the EEC programs approved in Order No. G-36-09 into the marketplace and has not had an opportunity to judge the full impact that the current economic situation is going to have on the EEC activity. Based on feedback from our customers, they are still interested in EEC programs. We are optimistic that customer interest will translate into EEC program participation, and we are hopeful that we will be able to spend the DSM forecasted budget expenditures and achieve the forecasted energy savings resulting from these expenditures.

However, as noted in the response to BCUC IR 1.29.3, as per the financial treatment approved in Order No. G-36-09, over time, only the actual spend of EEC activities will be charged to the EEC deferral account and ultimately be reflected in delivery rates. Therefore customers will not be unduly impacted if TGI does not meet the forecasted expenditure levels for 2010 and 2011.

67.0 Reference: Alternative Energy Solutions

Exhibit B-4, BCUC 1.33.2

Economic Assessment

"Preparing a separate rate category…and accounting for cost if service…protects customers that are not being served by the alternative energy project from being unduly impacted by costs…"

67.1 Please explain the treatment of these sunk capital costs if alternative energy customers leave the system before the end of their contract term. What is the proposed treatment of these potential stranded costs?

Response:

It is unlikely that customers will leave the system before the end of the contract term as TGI envisions that these customers will be end use owners of buildings or suites that will have an ongoing requirement for heat. The only way that they would leave the system is if the building no longer required heat.

However, some customers may be required to sign contracts that could include provisions for a payment for undepreciated assets (similar to the language in TGI Bypass Agreements), whereby a customer or customers will have to make a payment should they leave the system, or be required to pay the difference between forecast consumption and actual consumption similar to Section 5.2 in Rate Schedule 6C. Note however that, other than Bypass customers and customers on other special contracts, natural gas customers are not required to make any payment to leave the system or to reduce their consumption.

68.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Exhibit B-4, BCUC 1.34.1-BCUC 1.34.7, p.96

Natural Gas Vehicles ("NGV")

Compression and Refuelling Service

68.1 What utilities in North America are engaged in the compression and refueling service? What was the target market and did the program benefit existing customers. If the program was subsidized please indicate that as well.

<u>Response:</u>

TGI has information linkages to other utility programs through industry associations such as the Canadian Natural Gas Vehicle Alliance and NGV America. Through discussions with these parties, we are not aware of any other Canadian utilities that offer compression and dispensing services at present, although Gaz Metro is aware of TGI's proposed program and has expressed interest in establishing a similar approach. Through similar discussions, we are aware that there are a number of utilities in the US who provide a complete fueling service, including compression and dispensing services.

Examples of US Utility programs are provided below:

1. National Grid (New York State) – National Grid was formerly known as KeySpan. Their program is described on the US DOE Website as follows:

   "National Grid offers a NGV incentive program that provides rebates for NGVs on a case-by-case basis and special competitive rates for compressed natural gas (CNG) fueling. National Grid will also help secure CNG fueling station financing, and provide technical assistance and other services to NGV fleets on a case-by-case basis. Financial awards are made depending on the fleet size, amount of fuel used, and vehicle type"

2. Questar Gas (Utah) – A description of Questar's services is included on the company's website at http://www.questargas.com/FuelingSystems/NGV/ngv.php

   "Natural Gas Vehicles (NGV's)

   With growing public concern over high gasoline prices, dependence on foreign-oil imports, global warming and air quality, Questar Gas is focused on providing safe, clean-burning natural gas for vehicles.

There are 21 natural gas vehicle (NGV) fueling stations within Questar Gas's service area (19 in Utah and 2 in Wyoming). In addition to these sites, the state of Utah has opened six of its NGV fueling stations to help meet demand.

Questar Gas and the state are working to increase NGV fueling capacity by more than 40 percent over the next several months. Read more information on station updates and Governor Huntsman's initiative to build the I-15 CNG (compressed natural gas) corridor below."

3. DTE Energy (Michigan)

   DTE Energy owns and operates a set of 10 NGV fueling stations providing complete fueling service to the public and to NGV fleets. The company's program is described at http://www.dteenergy.com/businessCustomers/productsPrograms/gas/natGasVehicle.html A listing of their sites is available at: http://www.dteenergy.com/pdfs/fuelingStations.pdf

4. PG&E (California)

   A description of PG&E's NGV program is available at:
   http://www.pge.com/myhome/environment/pge/cleanair/naturalgasvehicles/index.shtml

   "PG&E is actively involved in the development of natural gas as a vehicle fuel. We operate over 1,138 natural gas vehicles in our own fleet. PG&E opened California's first public access natural gas fueling station in March of 1990 in Concord (east of Oakland). We now operate 37 compressed natural gas (CNG) stations, of which more than half are publicly accessible."

There are a number of incentive programs in the US market to encourage the adoption of NGV's. The specific circumstances vary by state and county and TGI does not have detailed information regarding the specific levels of incentives available in each region.

68.2 What is the expected load from the NGV market for the period 2010 to 2015? How many vehicles are in the TGI market currently (cars and trucks) and what is the expected potential growth by 2015?

Response:

TGI has prepared a business plan that looks out to 2013 and is based on our knowledge of the market. The total forecast load, if TGI were successful in its sales targets between 2009 and 2013, is approximately 520,000 GJs. The total target market is approximately 8,600

potential NGV vehicles. The forecast capital asset growth during this period would be approximately $13 million.

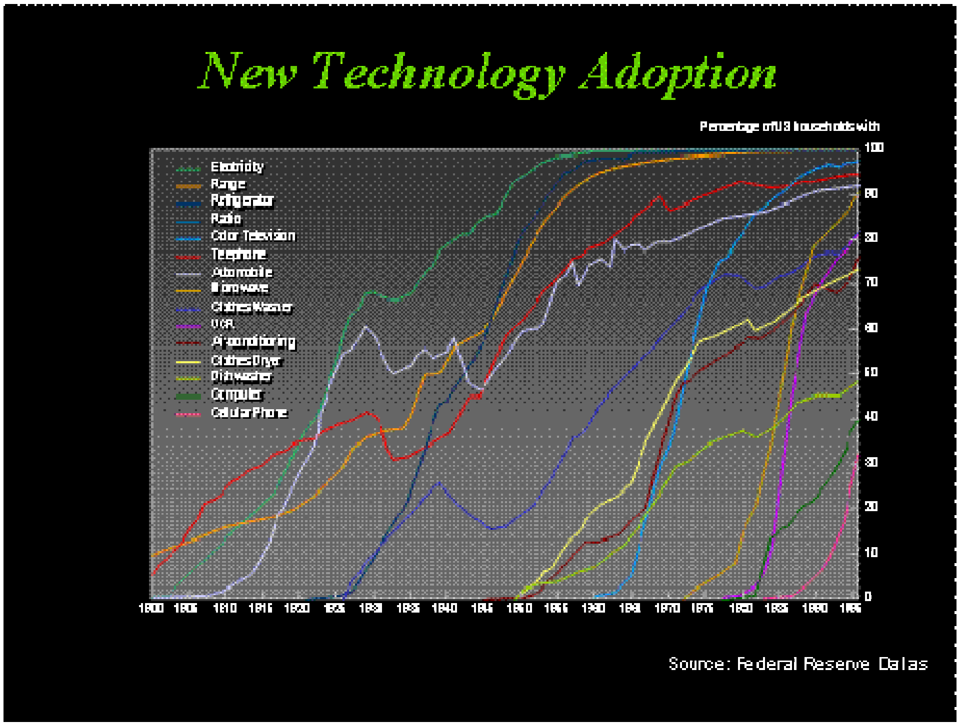
Market Segment	# of Potential Vehicles	Average Vehicle Gj Load	2010 Vehicle Addition	2011 Vehicle Addition	2012 Vehicle Addition	2013 Vehicle Addition	Total Load GJ's	Market Share (Vehicles)
ForkLift	400	200	20	60	60	60	40000	50%
Waste Haulers	2000	1000	0	10	40	20	70000	4%
Municipal	3250	150	15	30	60	60	24750	5%
YVR (mixed load)	200	150	50	50	50	50	30000	100%
Transit Buses	1778	2000		50	50	75	350000	10%
School Buses	1000	200		10	10	20	8000	4%
Total	8628						522750	

68.3 Comment on the relative share of TGI's target transportation market that electric, hybrid and hydrogen fuelled vehicles are expected to have within 5 years. Within 10 years.

Response:

This question is identical to TGVI RRA/RDA BCUC IR 1.71.1.3. This response is identical to the TGVI response to that IR, with the exception of the name change to TGI.

Predicting market share for alternative energy technologies is extremely difficult and highly subjective. Historically, projections for rapid adoption rates have proved to be wildly optimistic. Historical records indicate the adoption of new technologies takes decades – for example the adoption of unleaded fuel in North America took more than 20 years even with a government mandated transition. The exhibit below shows typical adoption rates for new technologies.



Hybrid electric vehicles have recently enjoyed some level of market success and may achieve more than niche penetration over the next 10 years, but it is important to recognize that hybrid's do not necessarily have to be powered by gasoline engines. Therefore, at this point, TGI cannot predict what relative market share natural gas would have compared to electric, hybrid or hydrogen vehicles. However, we believe natural gas vehicles, specifically in the return to home fleet segment, will increase its market share as customers realize the economic and environmental benefits.

68.4 What has been BC Transit's experience with NGV and what are the future plans for NGV buses?

Response:

Public bus transportation experience in BC spans both BC Transit and Translink (through the Coast Mountain Bus Company, an operating subsidiary). Currently, BC Transit serves Vancouver Island and remote BC cities while Translink serves the Greater Vancouver Region. Both have experience with NGV buses.

BC Transit purchased 25 CNG buses in 1994. The 25 vehicles were delivered and placed into service beginning in November 1995. The buses were 12 metre suburban transit coaches built by New Flyer, and were equipped with DDC series 50G engines, and include underfloor CNG tanks. BC Transit purchased the vehicles as a pilot fleet to identify the impacts of regular revenue service with state of the art vehicles. BC Transit has been testing and demonstrating various CNG technologies since 1985. However, the New Flyer/DDC pilot program represented the first large scale adoption of CNG for urban transit use in Western Canada.

The results from the 25 bus pilot fleet are summarized in an April 1997 report developed by Sypher:Mueller International Inc. which is available at:
http://www.llbc.leg.bc.ca/public/PubDocs/bcdocs/335500/fuelchoice.pdf

BC Transit followed up the initial pilot program with a purchase of an additional twenty-five 1998 model year New Flyer buses also powered with Detroit Diesel engines modified for CNG service.

In 1999, the Greater Vancouver Region of BC Transit became the Coast Mountain Bus Company, an operating subsidiary of Translink. In 2006, Translink took delivery of 50 NGV buses powered by the Cummins ISL-C+ engine and a 5 speed Allison B400R5 transmission. These buses remain in the fleet on active service while the Detroit Diesel powered buses have since been removed from the CNG fleet.

Over the time line from the initial pilot program in 1994 to 2009, there have been many advances in the NGV technology being used in the transit fleet. The initial fleet powered by the Detroit Diesel engines were reported to have operating issues such as lower power and high maintenance costs. OEM vendor sources have also indicated that the engine and transmission specifications on these vehicles were not properly matched resulting in non-optimal performance. The second generation buses powered by the C+ class Cummins engines are reported to have had much better performance and reliability.

Translink in early 2009 borrowed a bus powered with the ISL-G engine and performed emission and performance testing. The results were favorable. In 2009, Translink engaged Clean Energy to expand the capacity of the NGV fueling station at the Port Coquitlam facility. This work is scheduled to be completed Jan 2010. It is not clear whether this work has been done in anticipation of expanding the NGV fleet or not.

68.5 What facilities are currently owned or operated by TGI that is related to NGV?

Response:

TGI presently owns and operates small scale fueling assets at the following locations:

- Kelowna School District (please see the response to BCUC IR 2.7.2);
- Kelowna Muster – TGI Service vans;
- Richmond Muster – TGI service vans; and
- Albion Muster – TGI service vans.

68.6 How much money has TGI expended on each of the NGV physical facilities, NGV grant and NGV operating costs to date?

Response:

The following table lists by year from 2000, when the NGV Compression and Dispensing assets for the NGV Marketing program were sold to 4Pro Systems Inc. and the City of Surrey, through 2009 projected the NGV facilities purchased, NGV Grants made and the NGV operating and maintenance expense.

Year	NGV Physical Facilities	NGV Grants: Gross	NGV Grants: Tax Offset	NGV Grants: Net	O & M Expense
2000	$ -	$ 55	$ (24)	$ 31	$ 508
2001	$ -	$ 161	$ (70)	$ 91	$ 302
2002	$ -	$ 141	$ (54)	$ 87	$ 252
2003	$ -	$ 106	$ (39)	$ 67	$ 101
2004	$ -	$ 62	$ (21)	$ 41	$ -
2005	$ -	$ 48	$ (16)	$ 31	$ -
2006	$ -	$ 72	$ (24)	$ 48	$ -
2007	$ -	$ 15	$ (5)	$ 10	$ -
2008	$ -	$ 105	$ (33)	$ 72	$ -
2009P	$ -	$ 80	$ (24)	$ 56	$ -

The year to date actual costs in 2009 for a pilot project in Kelowna is $288,098 for NGV compression and dispensing facilities which are currently still in Work in Process. The projected

2009 plant additions do not include the pilot project in Kelowna. The actual to date NGV Grants in 2009 is $27,500 (gross before tax offset) and there has been no operating and maintenance expense for NGV.

Historical Experience

68.7 How much of the expenditure in physical facilities related to NGV did the Company write off or amortize at an accelerated rate when compression and dispensing business was turned over to a non-regulated business and when Kinder Morgan sold all remaining interest in efuels to Clean Energy?

Response:

In 1999 the Commission approved the disposal of TGI's NGV assets comprising of compression and dispensing equipment (BCUC Order No. G-143-99, dated December 23, 1999). In the Order the Commission approved a recovery of losses for $2,130,000 in a deferred charge account which was to be amortized over ten years. The ten years was approximately the remaining life of the assets. The following table details the accounting of the NGV assets when disposed of in 2000.

		Amount ($000's)
Book Value of Compression & Dispensing Gas Plant in Service		$ 7,402
Less: Accumulated Depreciation		(2,586)
Less: Proceeds on Disposal of Assets		(2,122)
Less: Amount Approved to Charge to Deferred Charges		(2,130)
Less: Write Down of NGV Stations Contributions in Aid of Construction		(108)
Loss on Disposal of Assets		$ 456
Remaining years to retirement		
Gross Book Value		$ 7,402
Less: Accumulated Depreciation		(2,586)
Net Book Value		$ 4,816
Depreciation Rate / Annual Provision	6.67%	$ 494
Remaining Years		10

There was no accelerated amortization of the net asset costs the Commission approved for recovery in deferred charges over ten years. The amount transferred to deferred charges was $2,130,000 and was amortized over ten years at $213,000 per year.

68.8 Please explain if the TGI shareholder was financially responsible for any NGV capital expenditures or NGV related operating expenses prior to the transfer of assets to the non-regulated business and the sale of the remaining NGV interest in efuels?

Response:

The shareholder(s) of Terasen Gas Inc. and its predecessor companies were not directly financially responsible for the NGV assets and operations but would be affected by the results of the NGV investment and contribution to the company's earnings. From the mid 1980's through to 1999 the NGV investments charged to gas plant in service were prudently incurred to provide service and approved by the Commission for cost recovery from utility customers.

As explained in the response to BCUC IR 2.68.7 the loss on disposal of the NGV assets was $456,000 which was charged to income in 2000. In Commission Order G-143-99; $2,130,000 was to be charged to a deferral account (in 2000ff called NGV Compression Equipment Recovery) and amortized over 10 years starting in 2000, which the Company did do.

69.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Exhibit B-4, BCUC 1.34.7, p.99

NGV

TGI states that: *"Management determined that the compression and dispensing business did not fit into the core operations because of significant customer management efforts required."*

69.1 What has changed in management's view that compression and dispensing operations will now be included as a core business?

Response:

The referenced quotation from BCUC IR 1.34.7 refers to TGI's experience in the late 1990s. Since the late 1990's, many changes have occurred in the NGV market which has changed management's view of offering compression and dispensing services as part of its core operations.

First, external changes such as government policy, specifically the BC Energy Plan, have created the need to offer solutions to the transportation sector. We believe one solution is a comprehensive NGV service.

Second, Clean Energy has ignored the market which has created opportunities for the Company to offer compression and dispensing services. The Company believes it is in the best position to meet customer requirements since compression and dispensing services is a natural extension of the natural gas service.

Third, the growth of NGV Original Equipment Manufacturers ("OEM") and improvements in conversion technology has resulted in less reliance on the Company to be involved in the vehicle conversion process. Technology enhancements have led to customers in the transportation sector seeking a complete NGV solution which includes natural gas service (currently offered under Rate Schedule 6 and proposed under Rate Schedule 26) and a Compression and Refueling Service (proposed under Rate Schedule 6C). TGI has the knowledge and experience to install, operate and maintain the equipment which is similar to natural gas distribution equipment.

TGI believes that the combination of these factors represents an emerging opportunity that should be pursued for the overall benefit of existing and future customers. TGI is also faced with a declining load particularly in the industrial sector. By offering a comprehensive NGV service, we will attract additional load which will benefit all TGI customers.

70.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Exhibit B-4, BCUC 1.35.0, p.100

Definition of Core Business Service

TGI states that: *"As noted in response to BCUC 1.24.3, the Utilities Commission Act does not prohibit TGI from providing alternative energy solutions, nor does it give the Commission jurisdiction to prohibit this activity".*

70.1 Section 60, item (III) of the Utilities Commission Act requires the Commission, in setting rates, to have due regard to a rate that: "encourages public utilities to increase efficiency, reduce costs and enhance performance." Why does the Utilities Commission Act not give authority to the Commission to prohibit TGI from providing alternate energy solutions as it is the Commission's mandate to apply regulation to ensure safe, efficient and reliable service at the lowest cost?

Response:

TGI respectfully disagrees that section 60(1)(iii), or any section in the *Utilities Commission Act*, requires the Commission to ensure service is provided "at the lowest cost". The *Utilities Commission Act* does not expressly or implicitly require rates to be set "at the lowest cost". Section 60(1)(iii), cited in the preamble of this information request, is not the only factor that the Commission must consider in setting rates Section 60(1) states:

Section 60(1) In setting a rate under this Act or the regulations

(a) the commission must consider all matters that it considers proper and relevant affecting the rate,

(b) the commission must have due regard to the setting of a rate that

(i) is not unjust or unreasonable within the meaning of section 59,

(ii) provides to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demands, and

(iii) encourages public utilities to increase efficiency, reduce costs and enhance performance.

Section 59(5) provides further explanation for what "unjust" and "unreasonable" mean:

Section 59(5) In this section, a rate is "unjust" or "unreasonable" if the rate is

(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,

(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or

(c) unjust and unreasonable for any other reason.

A "lowest cost" approach to interpreting the Commission's jurisdiction under these provisions of the *Utilities Commission Act* is inconsistent both with the Commission's previous determinations in carrying out its mandate and guidance from the Courts.

As stated in the Commission's Decision dated March 2, 2006 in the Matter of TGI and TGVI's Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism (the "ROE Decision") (at page 7):

> *"The Commission's mandate is to ensure that ratepayers receive safe, reliable and non-discriminatory energy services at fair rates from the public utilities it regulates, and that shareholders of those public utilities are afforded a reasonable opportunity to earn a fair return on their invested capital. The process to establish a fair return and just and reasonable rates is enshrined in the UCA where "the commission must consider all matters that it considers proper and relevant affecting the rate" and in doing so it must have due regard to the setting of a rate that "is not unjust or unreasonable" within the meaning of section 59 (of the Act) [UCA, s.60 (1)(a) and (b)(i)]."*

In the ROE Decision, the Commission rejected (at page 8) the argument that "lowest possible" was the appropriate test for the Commission to apply. The ROE Decision quotes Martland J. of the Supreme Court of Canada in *B.C. Electric Railway Co. Ltd. v. Public Utilities Commission of B.C. et al* [1960] S.C.R. 837, who stated: "The rate to be imposed shall be neither excessive for the service nor insufficient to provide a fair return on the rate base."

As a final example, in the context of sections 45 and 46 of the *Utilities Commission Act*, the Commission has stated: "The task is not to select the least cost project, but to select the most cost-effective project." (Decision dated July 7, 2006 on BCTC's *Application for a Certificate of Public Convenience and Necessity for the Vancouver Island Transmission Reinforcement Project*, at page 15.) While the Commission was not addressing rates specifically, the project costs approved as part of a CPCN application ultimately get recovered in rates and thus the same analysis logically applies to rate setting.

TGI believes that the pursuit of alternative energy solutions will result in the existing assets being used more efficiently and can reduce costs for existing gas customers in the long term.

(Please see TGI's responses to BCUC IRs 1.34.1 and 1.35.1.) The pursuit of alternative energy solutions also provides a contribution to overhead, advances environmental objectives and the government's energy objectives set out in the *Utilities Commission Act.* TGI believes that these are "proper and relevant" factors to consider in establishing just and reasonable rates.

Under TGI's proposal, alternative energy contracts will be filed and approved by the Commission as rates, and those rates will each recognize the cost of providing the alternative energy service to the particular customer. At the same time, gas rates set by the Commission will continue to recognize the cost of providing core gas service to gas customers. As such, TGI believes the rates for its alternative energy solutions will be fair and non-discriminatory.

In sum, TGI believes that the pursuit of alternative energy solutions is in the interest of present and future customers and intends to pursue safe and reliable alternative energy solutions in furtherance of that objective. Existing and future customers benefit from the Commission's approval of just and reasonable rates for gas service and for the provision of alternative energy. The proposed economic tests for alternative energy solutions will simply make the approval of contracts administratively more efficient.

70.2 Will alternate energy projects not be a distraction to a utility's core business (as defined in the GAS UTILITY ACT) impacting efficiency, costs and performance?

<u>Response:</u>

No, alternative energy solutions will not be a distraction to the Company's core gas business. With respect to the advantages associated with NGV, please see the response to BCUC IR 1.34.1. With respect to the advantages associated with geothermal, district energy and solar thermal, please see the response to BCUC IR 1.35.1

With respect to the reference in the question to the *Gas Utility Act*, TGI does not consider the *Gas Utility Act* to have any relevance to this issue. Please see the response to BCUC IR 2.53.1.

71.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Exhibit B-4, BCUC 1.35.1, p. 101

Biogas

71.1 TGI states that: “TGI believes that a market exists for biomethane.” What leads TGI to this conclusion?

Response:

In meetings, sales calls and account management activities with customers and potential customers, interest in this product offering has been expressed. Customers, many of whom are either required to reduce emissions by legislation, or those who are looking to reduce emissions for other business reasons see purchasing biomethane as an option. While no contracts have been signed and customers have not agreed to a price, customers are interested in the option should it become available.

72.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Exhibit B-4, BCUC 1.35.2, pp. 101 - 102

Biogas

72.1 Comment on the appropriateness of basing the maximum price for biomethane on the BC Hydro RIB Step 2 rate versus the avoided cost of natural gas produced from the most expensive sources in BC such as from shale gas or coal bed methane taking into account the price of the associated carbon dioxide emissions.

Response:

This question is the similar to BCUC IR 1.77.1.5 in the TGVI RRA proceeding with the difference being that the question above also references the cost of associated carbon dioxide emissions which was not in the TGVI question.

The TGVI response pointed out that biomethane is effectively a different product than traditional natural gas that will serve to reduce greenhouse gas emissions, displace traditional natural gas, and advance the BC Government's climate change and energy policy objectives. The inclusion of carbon costs with the cost of expensive shale gas or coalbed methane changes the picture somewhat, but TGI continues to believe that using the RIB Step 2 rate is the more suitable approach for the following reasons:

- As stated in the response to BCUC IR 1.35.2 (Exhibit B-4, page 102) "the maximum price was established with reference to BC-based energy supply contract pricing that has been approved by the Commission." The RIB Step 2 rate is readily available public information derived from energy supply pricing of energy sources that biomethane will be competing with. Because of the ready availability of an appropriate comparator, it is expedient to adopt this approach, particularly for a small scale pilot program.
- On the other hand, TGI does not know what the avoided costs are for the most expensive sources of natural gas in BC. While it might be possible to develop an avoided cost estimate for expensive shale gas or coalbed methane and to estimate the cost of the associated carbon emissions, both of these estimates would be the result of a number of assumptions and forecasts and therefore subject to uncertainty. They would not have the benefit of being derived from the actual results of a call for power or having been reviewed and approved in a regulatory proceeding.
- Since the proposed biogas pilot phase is a transitional stage that will be in place only until the green market offering is made available, TGI believes that it is appropriate and expedient to the use of the RIB Step 2 rate to establish the maximum price for biomethane.

73.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Exhibit B-4, BCUC 1.36.1, p. 106

Biogas Pilot Phase Project

On page 106 it states: *"There are two aspects to the staff time used for the development of biogas projects and supply, which will be discussed separately. The first is identification of potential projects, their evaluation and investigations required to determine if the project or supply should be undertaken or acquired. These costs are marketing and sales costs related to providing customers with the service they request (which include both conventional gas and alternative energy) and, in addition, providing energy efficiency education and information. As such, these costs are no different than any other sales, marketing, and development costs that are spread across all customers and as such these costs should not be segregated."*

73.1 Please provide a forecast of the impact on the residential and commercial rates, of the sales and marketing costs associated with the development of biogas projects.

Response:

TGI does not have the sales and marketing costs for biogas projects separated from the sales and marketing costs for other alternative energy initiatives. A small number of staff (five or less) are spending a fraction of their time on biogas project investigation and sales and marketing efforts so the impact on residential and commercial rates is very small.

73.2 Are biogas "customers" TGI suppliers, customers or both (similar to electric net metering customers)?

Response:

TGI will have supply contracts with third parties for either raw biogas where TGI will do the upgrading or upgraded biomethane where a third party has already done the upgrading to pipeline quality gas. TGI considers these parties to be suppliers. Some of the third parties selling raw biogas to TGI may wish to become purchasers of upgraded biomethane but if that was the case it would be through special contract provisions with appropriate compensation in the supply agreement or through separate contractual arrangements (such as through the green rate offering, for example). In some cases, such as at sewage treatment plants, some of the raw biogas is burned for process heat, so the supply contract with TGI will only be for excess biogas.

TGI does not believe that the electricity net metering arrangements are a complete analogy for a biogas supplier producing upgraded biomethane in excess of its own natural gas consumption. This can be illustrated using a sewage treatment plant as an example. A sewage treatment plant may be able to burn raw biogas for process heat, but raw biogas cannot be used in furnaces to heat buildings where staff work. The sewage treatment plant may take natural gas service for the latter purpose. Thus, although it is a source of energy, the raw biogas is a different product than the upgraded biomethane. Another distinction between upgraded biomethane and natural gas is that the biomethane is a carbon-neutral green source of energy while the natural gas is not. In electricity net metering the self-generated electricity may or may not be from a green generation source and the self-generated power is indistinguishable from that coming in from the grid.

73.3 Please explain why identification and investigation of biogas projects (gas supply) are considered a customer service.

Response:

There are several reasons why the costs for the identification and investigation of biogas projects should be considered a customer service and why it is appropriate to keep these costs as part of O&M just as the costs for the identification and investigation of other alternative energy projects are also included in O&M.

Biogas is a new renewable source of alternative energy that will displace natural gas. Solar thermal and geo-exchange are also renewable sources of alternative energy that will displace or reduce natural gas use. The key difference between biogas and the other two alternative energy sources is that upgraded biogas will be distributed to end users through the natural gas distribution system while the other two will not.

The identification and investigation of biogas projects is an activity that will assist in meeting the government's climate change and energy objectives. As stated elsewhere, the province of BC has placed a high importance in these areas by setting binding targets for GHG reductions, by introducing changes to the Utilities Commission Act and developing several pieces of legislation aimed at achieving its objectives. TGI's identification and investigation of biogas projects represents a strand of its efforts to address these important matters on behalf of customers.

A third reason to keep the costs for identification and investigation of biogas projects in the O&M costs is that TGI is seeking in the RRA for a "pilot phase" in the development of this new renewable resource. When the development of biogas markets (for both supply and demand) has reached a sufficient level of maturity it would be appropriate to consider applying similar treatment to the administration costs for biogas supply as is done with the Core Market Administration Expenses for natural gas supply.

74.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Exhibit B-4, BCUC 1.36.2 and 1.36.4, pp.107-108

Biogas Pilot Project

74.1 If there are carbon credits attached to a project are they used to reduce overall customer rates?

Response:

Yes, TGI will include any benefits associated with carbon reduction to reduce the overall impact on customer rates during the pilot phase. This is described on page 261of the Application and demonstrated in Table C-3-11 (Exhibit B-1, page 256) where it is shown that the benefits of avoided carbon taxes will used to reduce the overall cost of the upgraded biomethane in customer rates.

74.2 If biogas projects or all alternative energy are considered as interruptible supply how is this consistent with the Essential Services Model ("ESM") whereby a gas seller is expected to deliver 100 percent of the normal annual demand as commodity, which in the case of TGI is through the CCRA?

Response:

As an initial point TGI does not consider all alternative energy to be interruptible supply. TGI will meet customer demands for heat energy at alternative energy developments with the same reliability that it meets customer demands for natural gas. Meeting this level of reliability will often involve natural gas backup, but customer demand will be met.

With respect to biogas, TGI adopted its proposed treatment of flowing the biomethane costs through the MCRA rather than the CCRA in order to avoid being inconsistent with the Essential Services Model. This was explained in the middle paragraph on page 261 of the Application which is quoted below for convenience:

> *"The main reasons for flowing biomethane costs and volumes through the MCRA are discussed below. The half petajoule maximum of biomethane under Pilot Phase represents less than 0.5 per cent of the overall MCRA purchases and will have only a small impact on the Midstream Cost Recovery Rate. There are many issues to understand and gain experience with during this Pilot Phase. For instance, it is expected that the load profile of upgraded biomethane coming from biogas production facilities into the TGI system will be fairly steady throughout the year but this is not known with*

certainty. The frequency of outages, the magnitude of process fluctuations and variations are all potential sources of variations in the amounts that will ultimately be received into the TGI distribution system. Further, the receipt point of biomethane on the TGI distribution system means that it would not be suitable to treat this supply in the same manner as the baseload supply of marketers or TGI. Commodity volumes provided by marketers or which flow through the CCRA are 100 per cent firm baseload supply that must be delivered in certain proportions at the Station 2, AECO and Sumas hubs. The biomethane volumes from any projects completed during the RRA period will differ in that they will be, in effect, interruptible supply."

The question also appears to imply that Biogas supply contracts and suppliers should be held to the same terms and conditions and delivery requirements as gas marketers supplying gas through the Essential Services Model ("ESM") of the Customer Choice program. TGI does not believe that this comparison is valid. Marketers supplying gas under the ESM operate under a very specific BCUC approved set of supply rules. In contrast, biogas supply contracts will be more similar to other commodity supply contracts TGI undertakes with upstream producers. In addition to the differences between biogas supply and gas delivered by marketers under the ESM as identified in the quoted paragraph above, TGI has also described in BCUC IR 1.35.3 (Exhibit B-4, page 103) the types of counterparties it expects to deal with in biogas projects and how they will be different than typical natural gas industry participants. In most cases the biogas upgrading projects will be ancillary activities to the main business of the counterparties such as farming or running a wastewater treatment plant. These parties will want to recover their costs and a reasonable return on any investment they need to make, but they will not want these secondary activities to interfere with their primary business. All these differences between biomethane supply and the CCRA supply delivered by marketers lead TGI to the conclusion that it is not appropriate for the ESM rules to apply to biogas supply contracts.

75.0 Reference: Gas Sales and Transportation Demand

Exhibit B-4, BCUC 1.38.1, p. 111

Energy Forecast Methodology

75.1 TGI's response to BCUC 1.38.1 states that: "The methodology is consistent with that used in prior years, with the demand forecast being comprised of three components – Customer Additions, Average Use Per Customer, and Industrial Demand." Please describe the implicit limitations of the methodology and discuss the reasons why it is the appropriate method for TGI to use in the forecast of future energy demand.

Response:

The methodology employed by TGI to develop the demand forecast has been used for a number of years because it is the best approach available. There will be limitations inherent in any forecasting methodology, but the current methodology has been demonstrated to perform reasonably well in the past.

The following discusses the limitations for each of the components of the demand forecast, and explains why the current approach is appropriate in light of the limitations.

Customer Additions: The customer additions forecast necessarily requires the use of a proxy for growth. As there is a high degree of correlation between the housing market and growth in TGI's customer base, the CMHC forecast of housing starts serves as an appropriate proxy. In recognition of the fact that there is some margin of error associated with any forecast, TGI reviewed historical forecasts of housing starts from a number of sources to determine which was most accurate, and after completing this review process the CMHC forecast was deemed to have the lowest margin of error. Given this, and the fact that historical customer additions forecasts are reasonable when compared to actual results (as illustrated in TGI's response to BCUC IR 1.38.2), the continued use of the CMHC housing starts forecast as a proxy for growth in TGI's customer base is a reasonable approach.

Use Per Customer: The implicit limitations of the use per customer forecast include the fact that it is primarily based upon a trending analysis, which by its very nature assumes that those factors that have been influencing the demand for natural gas will continue to influence demand for natural gas in the future. And although there may be additional factors influencing demand that have not been captured in this forecast (such as those discussed in TGI's response to BCUC IR 1.40.1), due to the lack of detailed information for its customer base (including information regarding thermal envelopes, housing types, appliance mix, and consumer behaviours) it is not feasible to incorporate those factors into the demand forecast. The other limitation of the use per customer forecast is the fact that it is based upon weather-normalized results, and therefore the forecast is based upon the assumption of normal weather over the forecast period. Although this may seem to be a significant limitation, as TGI considers normal weather to be the rolling ten-year average, long-term trends in weather patterns are incorporated into the forecast. In addition, one of the reasons the Rate Stabilization Adjustment Mechanism (RSAM) account was introduced was to decouple revenues from fluctuations in consumption due to weather. Given that, and in the absence of better, more detailed information around its customer base, the current approach to forecasting average use per customer is the most appropriate methodology, as it incorporates those trends that can be incorporated.

Industrial Demand: The industrial demand forecast is based upon both sector analyses and also direct customer feedback. This approach is consistent with that used in the past, and is appropriate due to the fact that it combines feedback from the end user (who in most cases would be in the best position to estimate future consumption) with industry specific analyses that incorporate the best available information. The main limitation regarding this approach is that during difficult economic times it is likely that some businesses may either curtail operations, temporarily shut down, or close altogether. It is unlikely that the people responding to our industrial survey are in a position to either know or relate to us this information, and as a result the forecast would not reflect these instances. However, forecasting these types of events is very challenging and requires information that is likely confidential and therefore unlikely to be obtained. Given this, TGI is of the view that by performing sector analyses and validating the results with direct customer feedback, the approach to forecasting industrial demand is thorough and reasonable for use in this Application.

Although there are limitations with any methodology to develop a demand forecast, and TGI's methodology is no exception, TGI believes that its approach remains reasonable. It is through the use of methodologies that are consistent with those used in the past, the inclusion of the best available information, and also supported by the fact that historically TGI has done a reasonable job of forecasting the demand for natural gas (as illustrated in TGI's response to BCUC IR 1.38.2 and also BCUC IR 2.75.2), the forecast presented in this Application is both reasonable and appropriate for use in this Application. And although the current methodology is reasonable, TGI continues to work towards gaining more information to use in future forecasts, exemplified through the implementing the Customer Attraction Front End (CAFÉ) reporting tool, considering methodologies employed by other natural gas distribution utilities, and also through the (proposed) use of more frequent Residential End Use Studies.

75.2 Please provide historical information related to TGI's accuracy with respect to forecasting future energy demand one year and two years into the future.

Response:

Over the PBR Period, TGI typically only prepared forecasts one year out (a current year-end projection, and then the following year), and therefore the following table illustrates historical actual (normalized) information compared to TGI's forecast one year out for energy demand over the period 2003 through 2008.

Energy Demand - TGI Residential Customers

	2003	2004	2005	2006	2007	2008
Forecast (PJ)	69.5	73.3	73.6	72.9	73.6	72.0
Actuals (PJ)	72.6	72.0	69.3	70.0	70.6	68.8
Variance (Fcst to Act - PJ)	(3.1)	1.3	4.3	2.9	3.0	3.2
Variance (Fcst to Act - %)	-4%	2%	6%	4%	4%	5%

Energy Demand - Commercial Customers

	2003	2004	2005	2006	2007	2008
Forecast (PJ)	43.0	44.1	45.4	43.8	44.3	46.1
Actuals (PJ)	45.3	45.2	43.9	44.1	45.5	45.9
Variance (Fcst to Act - PJ)	(2.3)	(1.1)	1.5	(0.3)	(1.2)	0.2
Variance (Fcst to Act - %)	-5%	-2%	3%	-1%	-3%	0%

Energy Demand - Industrial Customers

	2003	2004	2005	2006	2007	2008
Forecast (PJ)	65.2	64.8	62.9	62.0	60.4	53.6
Actuals (PJ)	66.2	63.6	63.3	58.3	60.1	55.3
Variance (Fcst to Act - PJ)	(1.0)	1.2	(0.4)	3.7	0.3	(1.7)
Variance (Fcst to Act - %)	-2%	2%	-1%	6%	0%	-3%

The above figures illustrate that the historical forecasts of overall energy demand have been reasonable, as compared to normalized results, for each of the customer classes. In years where the larger variances occur, such as 2003, 2005 and 2006, there are explanations for these. The 2003 forecast was prepared in 2002 while the aftermath of the California energy crisis, and ensuing increased volatility in natural gas prices, was occurring, and TGI did not expect the average UPC to rebound as much as was eventually experienced. The forecast figures for 2005 were prepared in 2004, prior to Hurricane Katrina, and therefore the declining volumes due to that event were not incorporated into the forecast. Finally, the figures in 2006 assumed a rebound in average UPC similar to what was experienced in 2002, however the rebound was not as significant and resulted in an over-estimation of demand.

The above figures illustrate that the historical forecasts of overall energy demand have been reasonable for each of the customer classes. Furthermore, in years where there have been modest increases in the variance of actual to forecast results in the Residential and Commercial customer segments, the Rate Stabilization Adjustment Mechanism (RSAM) account ensures that both the customer and company are made whole with respect to the rate paid for natural gas during that year. Given this, together with the fact that current methodologies are consistent with those used in prior years, have been reviewed and scrutinized through the Annual Review process, and use the best available information at the time of development, the forecasts submitted as part of this Application are both reasonable and appropriate for use in determining delivery rates over the 2010 and 2011 forecast period.

76.0 Reference: Gas Sales and Transportation Demand

Exhibit B-4, BCUC 1.38.2, pp. 112-116

Energy Forecast Methodology

76.1 For the graphs provided on pages 112 to 116, please show the input factors and describe the methodology used to predict Customer Additions, UPC and Total Energy Demand.

Response:

TGI interprets the request for "input factors" to mean the tabular data behind the graphs presented in TGI's response to BCUC IR 1.38.2, and therefore the following tables illustrate the data comparing actual results to appraised (forecast) for customer additions, average use per customer rates, and also energy demand over the period 2003 to 2008.

Customer Additions

	2003	2004	2005	2006	2007	2008
Appraised	6,050	8,500	10,153	12,693	12,999	11,802
Actuals	5,544	11,472	12,429	10,250	9,971	9,253
Variance	(506)	2,972	2,276	(2,443)	(3,028)	(2,549)

Residential (Rate 1) Average Use Per Customer (GJ/year)

	2003	2004	2005	2006	2007	2008
Appraised	100.4	104.7	103.3	100.6	99.8	96.1
Actuals	103.1	102.6	97.4	96.8	96.0	92.5
Variance	2.7	(2.1)	(5.9)	(3.8)	(3.8)	(3.6)

Small Commercial (Rate 2) Average Use Per Customer (GJ/year)

	2003	2004	2005	2006	2007	2008
Appraised	291	300	317	308	314	320
Actuals	304	314	306	314	317	326
Variance	13	14	(11)	6	3	6

Large Commercial (Rate 3) Average Use Per Customer (GJ/year)

	2003	2004	2005	2006	2007	2008
Appraised	3,327	3,342	3,426	3,402	3,394	3,445
Actuals	3,292	3,501	3,388	3,314	3,426	3,406
Variance	(35)	159	(38)	(88)	32	(39)

Commercial Transportation (Rate 23) Average Use Per Customer (GJ/year)

	2003	2004	2005	2006	2007	2008
Appraised	4,931	5,301	4,975	4,977	4,796	4,916
Actuals	4,883	5,113	4,714	4,686	4,778	4,642
Variance	(48)	(188)	(261)	(291)	(18)	(274)

Residential (Rate 1) Normalized Annual Demand (PJ)

	2003	2004	2005	2006	2007	2008
Appraised	69.5	73.3	73.6	72.9	73.6	72.0
Actuals	72.6	72.0	69.3	70.0	70.6	68.8
Variance	3.1	(1.3)	(4.3)	(2.9)	(3.0)	(3.2)

Commercial (Rates 2, 3, 23) Normalized Annual Demand (PJ)

	2003	2004	2005	2006	2007	2008
Appraised	43.0	44.1	45.4	43.8	44.3	46.8
Actuals	45.3	45.2	43.9	44.1	45.5	45.9
Variance	2.3	1.1	(1.5)	0.3	1.2	(0.9)

Industrial Annual Demand (PJ)

	2003	2004	2005	2006	2007	2008
Appraised	66.1	64.3	62.8	60.9	60.2	53.3
Actuals	66.2	63.6	63.3	58.3	60.1	55.3
Variance	0.1	-0.7	0.5	-2.6	-0.1	2.0

As discussed in the Application, the demand forecast is comprised of three components - customer additions, average annual use per customer, and industrial demand. The methodology used to predict customer additions is based upon the CMHC forecast of housing starts, and is described in greater detail in TGI's response to BCUC IR 2.84.2. The forecast of Residential average use per customer rates is based upon a trending analysis of recent historical results, while for commercial customers is based upon sector analyses and then validated through a trending analysis of recent historical results (as discussed in TGI's response to BCUC IR 2.90.2). The industrial demand forecast is based primarily on the sector analyses discussed and illustrated in the Application (with tabular data provided in TGI's response to BCUC IR 1.60.1), and is in the process of being validated against the industrial survey results. Overall, the above tables illustrate the approach taken in forecasting the demand for natural gas provides reasonable estimates of the demand for natural gas.

76.2 How far ahead of the actual result was each projection calculated in the graphs?

Response:

The graphs illustrated in TGI's response to BCUC IR 1.38.2 illustrate year-end actual results typically prepared in the first quarter of each year, and are therefore prepared approximately nine months ahead of the actual results. TGI's response to BCUC IR 2.75.2 illustrates the forecast energy demand that was prepared approximately one year and nine months ahead of actual results.

77.0 Reference: Gas Sales and Transportation Demand

Exhibit B-4, BCUC 1.40.1, p. 118

Exhibit B-1, Part III, Section B, Tab 1, p. 274

Underlying Assumptions

77.1 Please reconcile TGI's statement on page 274 of the Application: "As with prior years, the factors considered in developing the energy demand forecast for this Application include current economic conditions, the housing market, government policies and programs, and also general trends regarding efficiency improvements" with the response given in BCUC 1.38.1 indicating that "The methodology is consistent with that used in prior years, with the demand forecast being comprised of three components – Customer Additions, Average Use Per Customer, and Industrial Demand."

Response:

The statement on page 274 of the Application and the response given in BCUC IR1.38.1 are both correct, as these statements are referring to two distinct items. In the first statement the Company is discussing **factors** considered in developing the demand forecast. The demand forecast is comprised of three **component** pieces, which the Company is discussing in the second statement. These two distinct items coexist and do not need to be reconciled.

Consistent with prior years, the demand forecast is comprised of three components – Customer Additions, Average Use Per Customer, and Industrial Demand. The factors considered in developing the demand forecast (and therefore the components of the demand forecast) include current economic conditions, the housing market, government policies and programs, and also general trends regarding efficiency improvements.

78.0 Reference: Gas Sales and Transportation Demand

Exhibit B-4, BCUC 1.40.2, pp. 119-120 and BCUC 1.53.2

Underlying Assumptions

78.1 TGI's response to BCUC.1.40.2 indicates that there is a trend of declining average use per customer. Despite this, over the past five years, TGI has witnessed an overall increase in consolidated actual use per customer as illustrated in the trend line provided in response to BCUC 1.53.2 (Exhibit B-4, p. 153). Please reconcile.

Response:

TGI's response to BCUC IR 1.40.2 does indicate there is a trend of declining average use per customer, but further indicates the identified trend is based upon normalized actual results (that is, after adjusting to reflect normal weather).

The increase experienced in overall actual use per customer is attributed to colder weather that has been experienced over the past number of years. The Lower Mainland region, where the majority of TGI's customers reside, has experienced an increase in total annual HDD's in each of the last four years, which when combined with similar experiences for the interior regions (although only becoming increasingly colder over the past two years), is what TGI would attribute the increase in actual average use per customer to.

By normalizing actual results, TGI is able to analyze and identify trends (other than weather) that are impacting the demand for natural gas. This methodology is consistent with the approach taken in prior years, is an accepted industry standard (as evidenced by the four attachments included as part of TGI's response to BCUC IR 1.40.2), and has been reviewed and accepted both internally and by the BCUC. Furthermore, the Rate Stabilization Adjustment Mechanism (RSAM) was created so as to ensure fluctuations in average use per customer would not result in either the company or its customers over or under-paying for the natural gas consumed in any given year. It is for those reasons that TGI bases its forecast of average use per customer on normalized actual results.

79.0 Reference: Gas Sales and Transportation Demand

Exhibit B-4, BCUC 1.41.1 and 1.41.2, pp. 123-125

Underlying Assumptions

79.1 Please provide a fully functioning electronic spreadsheet showing the calculations employed by TGI to forecast the demand of natural gas in 2010 and 2011. Please include references to all input data and provide details of underlying assumptions that have been included in the calculations.

<u>Response:</u>

In developing the demand forecast for 2010 and 2011, TGI undertook a significant amount of analysis, but only a portion of that is done using electronic spreadsheets. TGI uses a more sophisticated, customized software tool called the Forecasting Information System (FIS), which allows for additional levels of rigor and also data warehousing capabilities that are not available when using spreadsheets. Additionally, TGI uses a statistical software package, SAS, to perform a significant portion of the analyses completed in developing the demand forecast. Given that, TGI is unable to provide the calculations employed by TGI to forecast the demand for natural gas on a spreadsheet. However, the input data, underlying assumptions, and methodologies have all been provided in the Application itself, Appendix D-1, and also in TGI's responses to BCUC IRs 1.38.1, 1.40.2, 1.41.1-3, 1.45.1-2, and 1.62.1. The approach taken in developing the demand forecast is consistent with that used in prior years, as illustrated in TGI's responses to BCUC IR 1.38.2 and BCUC IR 2.75.2 has performed well in the past, and therefore is both reasonable and appropriate for use in this Application.

80.0 Reference: Gas Sales and Transportation Demand

Exhibit B-4, BCUC 1.43.1, p. 129

Underlying Assumptions

In response to BCUC 1.43.1, TGI prepared the following table (Attachment 43.0):

Estimating the Annual Decline in Average Use Per Customer Resulting From EEC Programs

TGI Residential Customers	2010	2011
Forecast Demand (includes impact of EEC programs)	67,829	67,190
Forecast Avoided Demand (as a result of EEC programs)	127	127
Forecast Demand (excluding impact of EEC programs)	67,956	67,317
Forecast Number of Customers	756,178	760,937
Forecast Average Use Per Customer (including EEC)	89.7	88.3
Forecast Average Use Per Customer (excluding EEC)	89.9	88.5
Estimated Impact on Average UPC from EEC programs	-0.17	-0.17
Impact on Average UPC over Forecast Period	**-0.33**	

80.1 Please provide calculation details and underlying assumptions for Forecasted Avoided Demand of 127 TJ in 2010 and 2011.

Response:

The following table illustrates the calculation details behind the Forecasted Avoided Demand of 127 TJ in 2010 and 2011.

	Annual Participants			Annual Savings (GJ)	
Program	**2010**	**2011**	**Simple Annual Savings per Participant (GJ)**	**2010**	**2011**
TGI Residential New					
FP	3,350	3,350	8.3	27,805	27,805
E* Clothes	2,010	2,010	3.4	6,834	6,834
E* DW	6,030	6,030	2.5	15,075	15,075
TGI Residential Retro					
E* Furnace	0	0	13.8	0	0
E* Fireplace	5,025	5,025	8.3	41,708	41,708
E* Clothes	6,030	6,030	3.4	20,502	20,502
E* DW	6,030	6,030	2.5	15,075	15,075
TGI Residential Total				**126,999**	**126,999**

The number of participants allocated for 2010 was based upon the assumption that 1/3 of the total approved EEC expenditures based on the BCUC Order No G-36-09 occur in 2009, with the remaining 2/3 occurring in 2010. Therefore, 1/3 of the total participants were also allocated to

2009, with the remaining 2/3 being allocated to 2010, and then 2011 is assumed to be a continuation of the 2010 activity levels. When applying the above participation rates to the estimated annual savings per Participant, the total estimated annual savings of 127 TJ is arrived at.

81.0 Reference: Gas Sales and Transportation Demand

Exhibit B-4, BCUC 1.42.3

Underlying Assumptions

"TGI has been capturing virtually all single family dwellings and approximately 20% of multi-family dwellings over that period." (Exhibit B-4, BCUC 1.42.3, p. 128)

81.1 By capture, is TGI is referring to any use of natural gas within a multi-family dwelling or just use for space heating?

Response:

When TGI refers to capture rates for multi-family dwellings, it is referring to the portion of all multi-family dwellings that become customers of TGI, regardless of the end use(s) for natural gas within those dwellings.

81.2 Is data available for the percentage of multi-family dwelling units that use natural gas for fireplaces and/or cooking but not space heating?

Response:

TGI does not have data available to determine the percentage of multi-family dwelling units that use natural gas for fireplaces and/or cooking but not space heating. Preliminary results from the 2008 REUS indicate that approximately 86% of TGI's multi-family dwelling customers use natural gas for space heating, and therefore approximately 14% of TGI's multi-family dwelling customers do not use natural gas for space heating. TGI is able to further estimate that for its multi-family dwelling customers, approximately 13% have a natural gas range, approximately 7% have a natural gas cook top, approximately 4% have a natural gas wall oven, and approximately 10% have a natural gas barbecue. However, these figures do not provide enough information to identify those multi-family dwelling customers that only use natural gas for fireplaces and/or cooking, but not space heating.

81.3 How is the common space in non-captured multi-family dwellings heated?

Response:

TGI does not have data available regarding the common space loads for multi-family dwellings that are not captured. However, in cases where natural gas is used for common space in multi-family dwellings, it is typically done so through a single meter which would be set up as a commercial customer.

82.0 Reference: Gas Sales and Transportation Demand

Exhibit B-4, BCUC 1.45.1, p. 131

Underlying Assumptions

82.1 Please provide graphs and supporting tabular data in the form of an electronic spreadsheet to illustrate the relationship between the demand for natural gas and the statistically significant independent variables that TGI is relying upon in their forecast for natural gas demand in 2010 and 2011.

Response:

The independent variables that TGI is relying upon in its forecast for natural gas demand in 2010 and 2011 are discussed below, for each of the forecast components – customer additions, average annual use per customer, and industrial demand.

Customer Additions: The customer additions forecast considers the forecast of housing starts (as published by the CMHC) to be a good proxy for growth. Attachment 82.1 illustrates the relationship between the housing market and growth in TGI's customer base, which indicates there is a high degree of correlation between the two. Further details regarding the customer additions forecast can be found in TGI's response to BCUC IR 2.90.2.

Use Per Customer: The forecast of average annual use per customer for residential customers was based upon a trend analysis of recent normalized historical data (which has been provided in Appendix D-1, with the forecast data illustrated in TGI's response to BCUC IR 1.54.3). And although there are other variables beyond those stated that impact average consumption levels, as discussed in TGI's response to BCUC IR 1.40.1, further analysis (and information) is required before formal relationships may be developed. For commercial customers, the forecast of average use per customer was developed based on the sector analyses illustrated in the Application, which again trends historical consumption levels in developing the forecast. Due to the fact that spreadsheets were not used in developing the sector analyses (a statistical software package, SAS, was used, as it handles very large data sets – those with more than 65,000 rows of data), TGI is unable to provide this analysis in a spreadsheet. However, the results are illustrated in the Application, and also by region in TGI's response to BCUC IR 1.40.1. It is important to note that weather also plays a significant role in actual use per customer rates. As can be seen in TGI's response to BCUC IR 1.52.3, actual use per customer rates are highly correlated to weather. However, as weather is difficult to predict (especially over the long-term), TGI weather-normalizes consumption data which removes the weather effect and then allows for other factors influencing demand to be more readily identified. By taking this approach, the forecast of demand is then based upon the assumption of normal weather (a rolling ten-year average) over the forecast period. And although fluctuations from normal weather do occur, when considering the RSAM accounts, the financial risk due to weather fluctuations is mitigated for both the customer and the Company.

Industrial Demand: As discussed in the Application, the forecast of industrial demand was developed based on sector analyses (as illustrated in the Application) and is being validated through the industrial survey. The historical and forecast data, by sector, has been provided (in TGI's response to BCUC IR 1.62.1), but as this component of the forecast includes analysis of individual customers' consumption, due to privacy concerns only the sector data is available at this time. Although GDP is certainly considered a good indicator of how the overall industrial sector will perform in the future, attempts to determine a formal relationship between GDP and industrial demand have not resulted in models that either have a good fit or provide reasonable results. As discussed in TGI's response to BCUC IR 2.74.1, however, the current approach is both reasonable and appropriate for use in this Application.

Overall, TGI recognizes the condition of the economy (and therefore the economic indicators) to be significant in terms of impacting the demand for natural gas. But at the same time it is very challenging to quantify the impact/sensitivity various economic indicators may have on the future demand for natural gas. It is for this reason, together with the fact that econometric models are not well-equipped to handle significant economic turmoil such as that experienced recently, that TGI considers the majority of economic indicators as validation tools. By using the economic indicators along with other economic reports and studies (as illustrated in TGI's response to BCUC IR1.40.2), TGI is able to ensure the analyses performed are supported by external factors (i.e. the various trending analyses, use of housing starts as a proxy for growth, industrial sector analyses, etc.). By doing this, TGI has undertaken a thorough approach in developing the demand forecast, one that is both reasonable and appropriate for use in this Application.

82.2 As stated in response to BCUC 1.38.1, the forecasts for 2010 and 2011 energy demand were prepared using methodology that is consistent with previous forecasts submitted to BCUC. Please provide graphical and tabular details illustrating the degree of accuracy of TGI's previous energy demand forecasts.

<u>Response:</u>

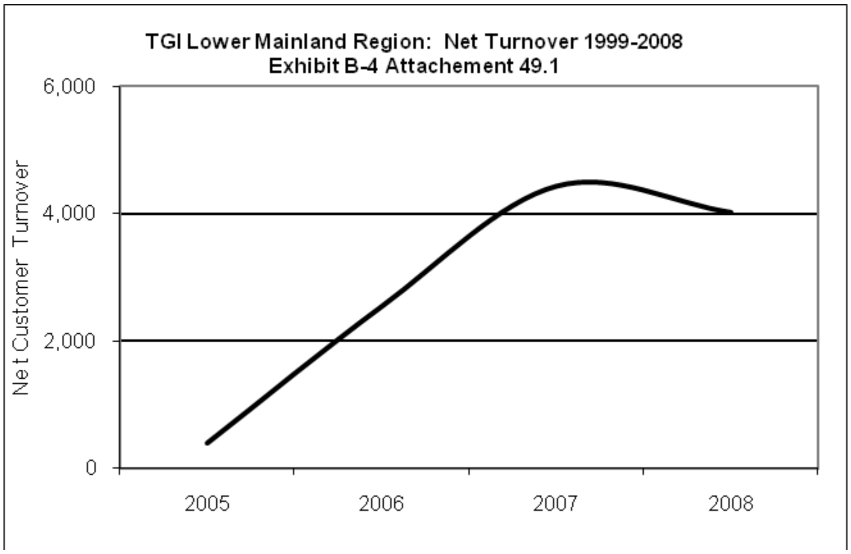
Please see TGI's responses to BCUC IR 1.38.2 and BCUC IR 2.75.2.

83.0 Reference: Gas Sales and Transportation Demand

Exhibit B-4, BCUC 1.49.1, p. 140

Growth Customer Issue

In Attachment 49.1, TGI provides an equivalent graphical illustration of the net turnover of TGI's Lower Mainland Region customer base from 2005 to 2008:



83.1 The graph illustrates a sharp increase in the net turnover of customers over the specified period. To the extent possible, please explain the underlying reasons for the large increase in customer turnover. Please describe any steps that TGI is taking to reduce turnover to lower levels than experienced in the past.

Response:

In investigating the recent trend of increased net customer turnover, TGI has conducted an analysis of the disconnections and reconnections that took place over the period 2006 through 2008. Unlike the similar trend that was experienced from 2002 to 2004 following the implementation of revised credit and collections policies, TGI has not identified a particular trait which would lead to the root cause of the more recent trend.

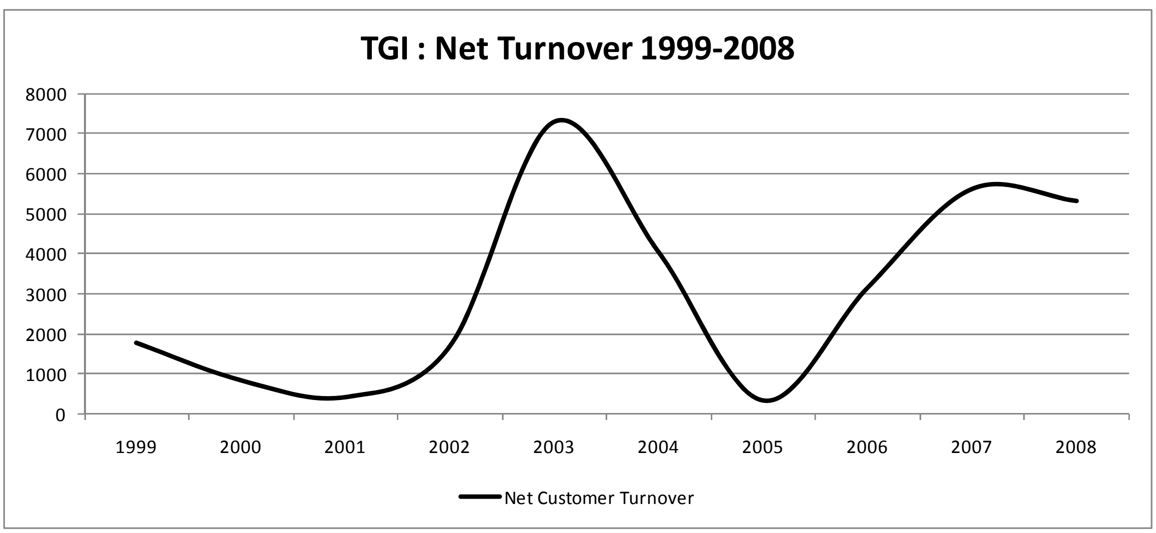
Further analysis of consumption data has also indicated there is not a pattern – the trend appears to be a general increase in net customer turnover. TGI was considering contacting those customers who have left the system (to survey them regarding the reasons behind leaving the system), but as they are no longer customers there are privacy issues with respect to their contact information, and therefore this approach was not feasible.

As the available historical data does not provide a clear indication of the causal factors behind the increase in net customer turnover, and faced with the inability to contact past customers, TGI has taken a number of steps to better understand the drivers of customer turnover. Marketing programs are being established and aimed at reconnecting customers who leave the system, and an exit survey is being implemented to better understand the reasons why customers are leaving. These efforts, combined with ongoing analysis, are expected to provide better information regarding customer turnover and more importantly the factors influencing customer turnover.

83.2 Please update the above graph to include net customer turnover data for 1999 through to 2005.

Response:

TGI's data regarding customer turnover does not provide a regional breakdown prior to 2005, however data for the entire company is available over the requested period. Therefore, the following graph illustrates the total TGI customer turnover over the period 1999 through 2008.



84.0 Reference: Gas Sales and Transportation Demand

Exhibit B-4, BCUC 1.50.3, pp. 143-144

Growth Customer Issue

84.1 Please provide an estimate of the confidence level that TGI has in its 2010 and 2011 forecast of Net Customer Additions.

Response:

TGI considers that its forecast of Net Customer Additions over the 2010 and 2011 forecast period provides a reasonable estimate of its customer growth, but is unable to provide a quantitative confidence level for the forecast. The main reason for this is the fact that no confidence level is available regarding the forecast of housing starts from which TGI bases its forecast of Net Customer Additions. However, given the forecast of Net Customer Additions follows a methodology that is consistent with the approach taken in prior years, the methodology has been reviewed and accepted both internally and by the BCUC, and also the fact that the best available information is used when developing the forecast, it is both reasonable and appropriate for use in this Application. This conclusion is further supported by TGI's response to BCUC IR1.38.2 where actual versus projected results from past years are compared.

84.2 Please provide the calculations used to model Gross and Net Customer Additions to housing starts in the 2010 and 2011 test period.

Response:

Gross customer additions are modeled using the forecast growth rate of housing starts as a proxy for growth in gross customer additions. For 2009 and 2010, the forecast growth in housing starts is obtained from the CMHC's Q1 Housing Now Canada Edition Report, as discussed in TGI's response to BCUC IR 1.42.5. For 2011 the data is obtained from the 2009 B.C. Budget & Fiscal Policy, as CMHC has not yet produced a forecast for this timeframe. This data is illustrated below.

CMHC Q1 Forecast			
	2008	2009	2010
Housing Starts	34,321	22,800	20,700
Growth Rate		**-34%**	**-9%**

B.C. Budget & Fiscal Policy		
	2010	2011
Housing Starts	26,800	27,800
Growth Rate		**4%**

Using the 2008 actual gross additions together with the above growth rates of -34%, -9%, and 4% for 2009, 2010 and 2011 respectively, the forecast of gross customer additions was developed, as illustrated below.

Gross Customer Additions Forecast				
	2008	2009	2010	2011
Housing Starts	14,566	9,600	8,784	9,176
Growth Rate		**-34%**	**-9%**	**4%**

As the trend of increased customer turnover appears to have stabilized in 2008, TGI considered the ratio of net to gross customer additions experienced in 2007 and 2008 (averaged) as being representative of that ratio over the forecast period, and then applied that ratio to the gross customer additions forecast to arrive at the forecast of net customer additions.

	2007	2008	2009	2010	2011
Gross Additions	15,533	14,566	9,600	8,784	9,176
Net Additions	9,939	9,256	6,120	5,600	5,850
Ratio (Net/Gross)	64%	64%	64%	64%	64%

The above illustrated methodology:

- is consistent with the approach taken in prior years in TGI's Commission-approved Resource Plans,
- is consistent with the approach taken in setting rates during the PBR period following each Annual Review, and
- uses the best available information at the time of development.

For those reasons, the forecast of customer additions is both reasonable and appropriate for use in this Application.

85.0 Reference: Gas Sales and Transportation Demand

Exhibit B-4, BCUC 1.52.3 and 1.52.4, pp. 147 – 150 and

TGI/TGVI/TGW 2008 Resource Plan, Appendices E and F

Use per Customer Forecast ("UPC")

85.1 Please explain whether the method used to determine the weather normalized use per customer and energy demand differs from the method used to forecast annual and peak demand as presented in TGI/TGVI/TGW's 2008 Resource Plan.

<u>Response:</u>

The methodology used to determine the weather normalized use per customer (and energy demand) is different from the methodology used to determine peak day demand. However, the methodologies used to determine the weather normalized use per customer, energy demand, and peak day demand in this Application are the same as the methodologies presented in the 2008 Resource Plan.

85.2 Why have different methods been used to determine the weather normalized use per customer as presented in the Application and in the 2008 Resource Plan?

<u>Response:</u>

As discussed in TGI's response to BCUC IR 2.85.1, the method to determine weather normalized use per customer as presented in the Application is the same as that used for the figures presented in the 2008 TGI, TGVI and TGW Resource Plan.

86.0 Reference: Gas Sales and Transportation Demand

Exhibit B-4, BCUC 1.53.3, pp. 153-154

Use Per Customer Forecast

The following factors could be interpreted as indicators leading to increased energy demand during the 2010 and 2011 test period:

i. An 11,400 increase in the total number of customers during the 2010 to 2011 test period (BCUC 1.53.3, pp. 153-154);

ii. A six year general trend of consolidated increase in the actual demand for natural gas amongst TGI's customers (BCUC 1.53.2, p. 152);

iii. A six year general trend of consolidated increase in the use per customer demand for natural gas amongst TGI's customers (BCUC 1.53.2, p. 153); and

iv. TGI's forecast that more than 40,000 new housing starts will occur during the test period (Exhibit B-1, Table C-4-1, p. 277) of which TGI expects to capture virtually all new single family dwelling and 20 percent of multi-family dwellings.

As it relates to the above factors, please reconcile TGI's projections of reduced energy demand in 2010 and 2011. Wherever possible, please provide calculations.

Response:

TGI would agree that the estimated 11,400 increase in total number of customers during the 2010 and 2011 test period will contribute towards increased energy demand on its system, and attributes that increase to the more than 40,000 new housing starts that are expected to occur over this period. In fact, the estimated increase in demand for natural gas was estimated to be approximately 0.64% and 0.67% of total demand for 2010 and 2011, respectively, and was provided in TGI's response to BCUC IR 1.48.4.

As discussed in TGI's responses to BCUC IR 1.58.1, 1.58.2 and 1.58.3 the demand forecast is not based upon the actual use per customer but rather normalized actual use per customer. Although when analyzing actual use per customer one might assume the demand for natural gas is increasing, when the weather is considered it is apparent that the increased consumption is primarily attributed to the colder weather that has been experienced over the past four years. TGI's normal weather is based upon a rolling ten-year average, so the demand forecast does take into account the fact that, more recently, colder weather has been experienced. Furthermore, when analyzing the trend of historical normalized actual demand, the forecast is both in line with that historical trend, and supported by various studies (as included in TGI's response to BCUC IR1.40.2). It is therefore both reasonable and appropriate for use in this Application.

Although the anticipated growth in TGI's customer base over the forecast period is expected to result in increased overall demand, the incremental demand is not enough to offset the declining average use per customer rates that have been experienced over the past decade, and are forecast to continue declining.

87.0 Reference: Gas Sales and Transportation Demand

Exhibit B-4, BCUC 1.54.2, p. 158 and BCUC 1.54.3, p. 159

Use Per Customer Forecast

87.1 BCUC 1.54.2 (p. 158) indicates that the annual average UPC for Rate 1 for Lower Mainland in 2008 was 110.3 GJ. In the Forecast Period 2010 and 2011 TGI indicates that the assumed UPC rate for Rate 1 for the Lower Mainland was 96.7 GJ and 95.3 GJ respectively. The difference between actual UPC rates in 2008 and assumed UPC rates for the test period is approximately 14 percent. Please reconcile these differences.

Response:

Given that 2008 was a colder than normal year, and the fact that TGI bases its forecast of average use per customer on normalized actual results, it is not surprising to see a more significant decline when comparing actual results to the forecast figures. Although the annual average actual UPC for Rate 1 Lower Mainland customers was 110.3 GJ for 2008, the annual average normalized UPC for Rate 1 Lower Mainland customers over that same period was 99.5 GJ. And the differences between the 2008 normalized actual results and the forecast figures are based upon the factors influencing average use per customer rates as discussed in the Application.

87.2 Numerous calculations in the Application depend upon UPC as a critical input variable. On page 1 of the Application TGI states that the assumed UPC is based on 95 GJ: "Based on a typical annual consumption of a Lower Mainland residential customer consuming 95 GJ." Please provide data and calculations in support of using 95 GJ as the average UPC in the Lower Mainland. Please also discuss how a 1 percent change in UPC for Lower Mainland residential customers affects consolidated forecasts for actual and normalized natural gas demand for 2010 and 2011.

Response:

The assumed UPC of 95 GJ/year for Lower Mainland Residential customers is based on the forecast average use per customer rate for 2011. As indicated in TGI's response to BCUC IR1.54.3, the forecast UPC for Lower Mainland Residential customers is 96.7 GJ/year and 95.3 GJ/year for 2010 and 2011 respectively. As discussed in the Application, this forecast was developed based on a trending analysis of recent historical actual results, which indicate an approximate 1.4 GJ/year decline in UPC.

TGI has analyzed the impact of a 1 percent change in UPC for Lower Mainland Residential customers has on the consolidated forecasts of natural gas demand for 2010 and 2011, and the following tables illustrate the results.

Current Forecast - Rate 1 Demand (PJ)		
	2010	2011
Lower Mainland Rate 1	50.8	50.3
TGI Rate 1 Consolidated	67.8	67.2

Given that annual demand is derived from the product of use per customer rates and the number of customers, a 1% increase in the UPC will (assuming the customer forecast remains as is) lead to a 1% increase in overall demand. The following table illustrates the revised forecast which assumes a 1% increase in overall demand for Lower Mainland Residential customers.

Revised Forecast - Rate 1 Demand (PJ)		
	2010	2011
Lower Mainland Rate 1	51.3	50.8
TGI Rate 1 Consolidated	68.3	67.7

From the above two tables it can be seen that a 1% increase in the average use per customer for Lower Mainland Residential customers will lead to an approximately 0.7% increase in TGI consolidated Residential demand (for 2010, 68.3 PJ /67.8 PJ = 0.7% and for 2011, 67.7 PJ/67.2 PJ = 0.7%). And although this indicates that fluctuations in consumption levels for Lower Mainland Residential customers will certainly flow through and impact the Company as a whole (given the relative size of the Lower Mainland region), the graphs provided in TGI's response to BCUC IR 1.38.2 illustrate that historically TGI has done a reasonable job in estimating average UPC. Therefore the assumed average annual UPC of 95 GJ/customer is appropriate for use as an input variable for calculations in the Application.

88.0 Reference: Gas Sales and Transportation Demand

Exhibit B-4, BCUC 1.54.2, p. 159

Use Per Customer Forecast

88.1 Please update the table provided in response to BCUC 1.54.2 to include the actual Annual Average Use Per Customer Rate and variance of actual to assumed Annual Average Use Per Customer Rate. Please use the same methodology outlined in response to BCUC 1.54.2.

Response:

The following table illustrates the data presented in TGI's response to BCUC IR1.54.2 together with the assumed Annual Average Use Per Customer Rate that was developed and submitted as part of the 2007 TGI Annual Review (at that time, the 2008 figures were the forecast figures).

Month	Actual Volume (GJ)	Actual Month-End Customers	Actual UPC (GJ/Customer)	Assumed Volume (GJ)	Assumed Month-End Customers	Assumed UPC (GJ/Customer)
Jan-08	8,894,485	517,232	17.2	8,042,000	520,884	15.4
Feb-08	6,831,775	517,477	13.2	6,729,300	521,475	12.9
Mar-08	6,794,179	517,709	13.1	6,293,800	522,058	12.1
Apr-08	5,324,973	517,819	10.3	4,254,200	522,282	8.1
May-08	2,775,751	518,118	5.4	2,775,900	522,356	5.3
Jun-08	2,657,724	518,118	5.1	1,993,400	522,617	3.8
Jul-08	1,837,119	518,075	3.5	1,853,600	523,027	3.5
Aug-08	1,635,252	518,276	3.2	1,533,100	523,508	2.9
Sep-08	2,140,401	518,898	4.1	1,997,100	524,193	3.8
Oct-08	4,163,832	519,584	8.0	4,034,900	525,329	7.7
Nov-08	5,173,517	520,185	9.9	6,015,600	526,524	11.4
Dec-08	8,973,002	521,437	17.2	8,304,100	527,624	15.7
Actual Annual Average Use Per Customer			**110.3**	**Assumed Annual Average Use Per Cus**		**102.8**
		Variance (Assumed to Actual)			**-6.8%**	

TGI would also like to note that although the actual annual average use per customer rate was 110.3 GJ/year, the normalized actual annual average use per customer rate for 2008 was 99.5 GJ/year , which implies a much lower variance of -3.2%. And as TGI bases its forecast of average use per customer on normalized actual results, this would be a more reasonable comparison to the assumed annual average use per customer rate for 2008.

89.0 Reference: Gas Sales and Transportation Demand

Exhibit B-4, BCUC 1.54.4, p. 160

Use Per Customer Forecast

"TGI's response to BCUC 1.54.4 indicates that the "Average Use Per Customer for new customers is approximately 12 percent lower than that for the typical TGI Residential customer."

89.1 Please discuss whether the lower UPC for newer customers is attributable to EEC programs, changes in housing mix, or other factors. Please provide supporting data and calculations wherever possible.

Response:

The lower UPC for newer customers is attributable to many factors, which include improvements in the thermal envelope of homes (improved levels of insulation, energy efficient windows, etc.), improvements in the efficiency of natural gas appliances (furnaces, water heaters, fireplaces, clothes washers, dishwashers, etc.), changes in the housing mix, changes to building codes, public policies and programs, and also changes in general customer behaviours with respect to conservation. These factors have been discussed in TGI's responses to BCUC IR 1.40.1, 1.41.1, 1.41.2, and 1.45.1, and are supported in the various studies filed in TGI's response to BCUC IR 1.40.2.

90.0 Reference: Gas Sales and Transportation Demand

Exhibit B-4, BCUC 1.57.1, p. 163

Commercial Sector Analysis

"The historical data used to assess the consumption patterns on a sector-by-sector basis is slightly different from the data presented in Appendix D-1. The two data sets provide similar information, but due to timing differences in reporting, the structure, and also cycle billing, they do not typically reconcile."

90.1 Please provide a tabular comparison of the demand forecast in 2010 and 2011 using the data presented in Appendix D-1 of the Application to the alternative method based on data extraction from meter reading reports.

Response:

The following table compares the commercial energy demand forecast for 2010 and 2011 based on the data presented in Appendix D-1 against the forecast based on the meter reading reports.

TGI Annual Demand - Commercial Customer Classes (PJ)						
	Monthly Data		Metered Data		Difference	
	2010	2011	2010	2011	2010	2011
TGI Rate 2	24.1	24.3	24.4	24.6	0.3	0.3
TGI Rate 3	17.1	17.3	16.8	17.1	-0.3	-0.2
TGI Rate 23	6.1	6.2	6.1	6.2	0.0	0.0
Total	47.2	47.8	47.3	47.9	0.1	0.1

As can be seen, there is very little difference in the forecast figures when comparing the two methods. The forecast based on the data in Appendix D-1 suggests slightly lower consumption for small commercial customers (Rate 2) and slightly higher consumption for large commercial customers over the forecast period, while transportation demand remains unchanged between the two methodologies.

Although TGI believes either approach results in a reasonable forecast, the added benefit of being able to analyze and forecast the various industry sectors individually (within the commercial customer classes) provides an added level of rigor to the forecast. And for that reason, the approach based on the meter reading data is the most appropriate methodology for use in this Application.

90.2 Please discuss why TGI opted for the approach based on meter reading reports as opposed to the data presented in Appendix D-1.

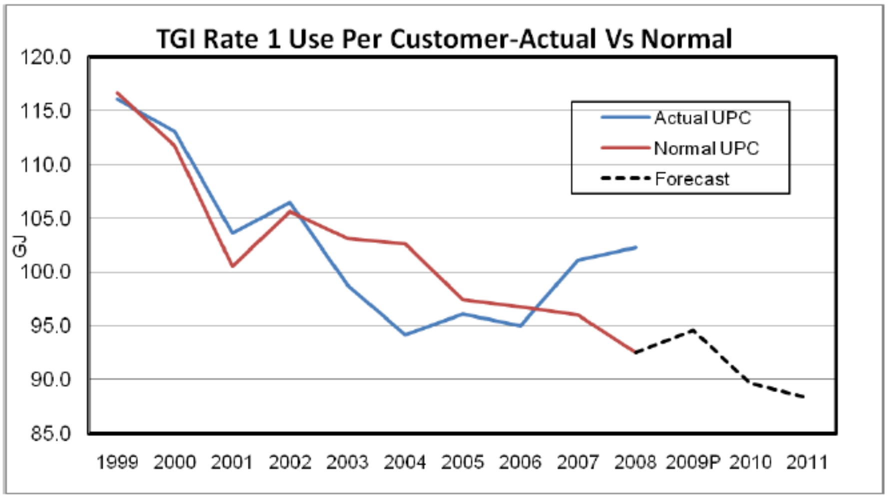
<u>Response:</u>

Please see the response to BCUC IR 2.90.1.

91.0 Reference: Gas Sales and Transportation Demand

Exhibit B-4, BCUC 1.58.1, p. 164

Use Per Customer Forecast



91.1 Please update the above graph to include Actual UPC (projected) through to the end of 2009.

Response:

TGI does not project an Actual UPC when developing its demand forecast. Rather, the forecast of average use per customer rates is developed based on an analysis of historical normalized actual use per customer rates (as discussed in the Application), and that forecast, including the 2009 projection, is illustrated in the above graph.

91.2 For the above graph, please calculate the coefficient of determination (R2) between Actual UPC and Normalized UPC. Based on this calculation, please specify whether the relationship between Actual UPC and Normalized UPC is statistically significant.

Response:

The coefficient of determination, or R-square value, between actual and normalized UPC over the period 1999 through 2008 is approximately 60%. And although this may be statistically significant, this is due to the fact that normalized UPC is simply the actual UPC with the weather effect removed. Therefore, the same factors that influence normalized UPC would also influence actual UPC, with weather fluctuations being the only additional factor influencing actual UPC.

91.3 What is TGI's confidence level for forecasted UPC during the test period?

Response:

Based on the trending analysis TGI performed on normalized actual results, confidence intervals for forecast average use per customer rates have been developed. At a 95% level of confidence, the 2010 forecast use per customer rates are estimated to be 89.7 +/- 0.6% and for 2011 the forecast use per customer rates are estimated to be 88.3 +/- 0.8%. Given this forecast is based upon normalized actual results, it also assumes normal weather over the forecast period. Fluctuations in weather would increase the variability (and therefore the confidence intervals), but at this time TGI is unable to estimate the additional variability that would be attributed to weather fluctuations (from normal).

92.0 Reference: Cost of Gas

Exhibit B-4, BCUC 1.68.1, p.193

Treatment of Costs within the MCRA Related to Southern Crossing Pipeline ("SCP")

92.1 Please confirm (in the absence of service contracts with BC Hydro and Pacific Gas and Electric), that all revenue requirements resulting from the SCP would from the in-service date of the pipeline, in all probability, have been recovered in the TGI delivery charges rather than the gas cost charges.

<u>Response:</u>

Confirmed.

92.2 Please explain the circumstances at the time that the BC Hydro service agreement was cancelled that justified the Commission approval of an overall allocation of $3.6 million against MCRA until November 1, 2010, including the potential impact on the PBR settlement at the time if the approval was not granted.

<u>Response:</u>

As part of Commission Order No. C-11-99 approving the CPCN for SCP, the Commission also approved a Firm Transportation Agreement ("TSA") and Peaking Gas Purchase Agreement ("PGPA") between TGI and BC Hydro. The primary term of 10 years would expire on November 1, 2010, however the agreements allowed for unilateral shipper renewal rights for up to an additional 10 years.

Under the terms of the TSA, BC Hydro contracted for 52.5 mmcfd of firm transportation capacity from the SCP interconnect with TransCanada at Yahk to Huntingdon for annual demand charges of $3.6 million. In return BC Hydro provided TGI access to an equivalent volume of peaking gas at Huntingdon for up to 15 days per year under the associated Peaking Gas Purchase Agreement. As part of these arrangements BC Hydro also negotiated a put option ("Put Option") with Terasen Inc. (then BC Gas Inc.), that allowed BC Hydro the right to assign the TSA and the Peaking Gas Purchase Agreement to Terasen Inc. for the remaining period in the primary term upon 13.5 months notice. Under this scenario, absent any other arrangements, if BC Hydro exercised its option Terasen Inc. would subsequently hold the SCP capacity and be responsible for any demand charges payable to TGI.

In September 2004, BC Hydro notified TGI and Terasen Inc. that it was exercising its Put Option to assign the transportation and peaking service agreements to Terasen Inc. with an effective date of November 1, 2005. At that time TGI evaluated the benefit to its portfolio of midstream resources on the basis that it would assume this SCP capacity on November 1, 2005. TGI concluded that it would result in net savings, or benefit for customers in the range of approximately of $2 to 3 million per annum, relative to the existing portfolio primarily by allowing TGI to avoid demand charges associated with other midstream resources.

The Company subsequently applied to the Commission for approval to terminate the BC Hydro agreements as of November 1, 2005, and to include the 52.5 MMcfd SCP capacity previously held by BC Hydro in its Midstream resource portfolio and make adjustments to its other peaking and transmission capacity resources in a manner that optimized the portfolio. The demand charges previously received from BC Hydro under the TSA had been allocated as revenue and credited in the delivery margin. As a result, the application also sought approval of an annual allocation of $ 3.6 million to be debited against the MCRA with an equal and offsetting allocation to be credited to the delivery margin revenue account for the remainder of the primary term (i.e. ending November 1, 2010). This proposed treatment would effectively keep the delivery margin whole relative to if the agreements had not been terminated, while maintaining net benefits to the MCRA of $2 to 3 million per annum by allowing it to avoid other midstream portfolio costs. Following a written hearing process, the Commission approved the proposed transactions related to the BC Hydro SCP agreements pursuant to Order No. G-98-05.

There would have been no impact to delivery margin or the PBR settlement if the Commission had not approved this transaction. In that case, Terasen Inc. would have retained the rights to the 52.5 mmcfd of SCP capacity and been responsible for the $3.6 million in annual demand charges to TGI previously paid by BC Hydro for the remainder of the primary term (November 1, 2010). Terasen Inc. would have sought to market this capacity or to put other arrangements in place with TGI; however, the same level of net benefits to TGI's midstream portfolio would not have been realized. If at the end of the primary term, Terasen Inc. did not exercise its right to renew the agreements it would no longer be responsible for the $3.6 million in demand charges. In the absence of any other type of arrangement with another party, the annual revenue requirement associated with delivery margin would be $3.6 million higher beginning November 1, 2010.

92.3 Please identify the form in which this approval was granted and clarify why the approval was only granted until November 1, 2010.

Response:

Please see the proceeding response to BCUC IR 2.92.2. As discussed in that response, TGI's 2005 application only requested approval for the accounting treatment of the SCP capacity originally held by BC Hydro for the remaining period of the primary term under the original BC Hydro agreements. The Commission approved the proposed transactions pursuant to Order No. G-98-05. The Order says (item No.6):

> *“The Commission approves the debiting of an annual charge of $3.6 million (based on monthly installments) against the Midstream Cost Reconciliation Account, with an equal and offsetting amount to be credited to the delivery margin revenue account, for a limited period as a unique and unusual transaction in the circumstances of the SCP and the termination of the BC Hydro TSA. The debiting and crediting will commence on either November 1, 2005 or January 1, 2006, as consistent with the amount of BC Hydro/Terasen Inc. TSA revenue that Terasen Gas forecast in its Annual Review submission for 2005, and will end on the earlier of November 1, 2010 or such other date as the Commission may determine.”*

During the review of the 2005 application there was no discussion of the treatment beyond November 1, 2010. However, as provided in TGI's annual contracting plan, the Company intends to continue to use the SCP capacity originally held by BC Hydro when planning its Midstream resource portfolio. As a result, in this RRA the Company is prepared to continue the same accounting treatment where $ 3.6 million is debited against the MCRA with an equal and offsetting allocation to be credited to the delivery margin revenue account on an annual basis. If this accounting treatment is not determined to be appropriate, it would not change TGI's intention to use the SCP capacity when planning its midstream portfolio. The result would be that the MCRA costs would decrease by $3.6 million per year, while delivery margin revenue requirement would increase by $3.6 million per year.

92.4 Please identify all the circumstances in which some or all of the revenue requirements related to TGI facilities are charged to the MCRA or CCRA.

Response:

Please note that TGI is not attempting to reclassify SCP as part of its gas supply portfolio or to directly allocate any of the revenue requirement associated with SCP to the MCRA or CCRA.

Other than the accounting treatment of the $3.6 million for the use of the SCP capacity described in the response to BCUC IR 2.92.2, the only costs charged to TGI MCRA or CCRA that are not associated with commodity or midstream resources are the costs being allocated as part of shared services to the Core Market Administration Expense for 2010 and 2011.

92.5 In the proceeding that resulted in the approval of the SCP, did TGI take the position that a portion of the SCP revenue requirement should be recovered through the gas cost charge? Did the Commission agree with this position?

Response:

No, TGI did not take a position that any of the SCP revenue requirement should be recovered through the gas cost charge. TGI believes that the recovery of all costs associated with SCP cost of service are appropriately recovered through the delivery margin. Recovery of SCP costs through the delivery margin was approved by Commission pursuant to Order No. G-74-00.

Pursuant to Order No. G-51-99, in the approval of the SCP, the Commission also approved transportation service agreements and peaking gas agreements with BC Hydro and PG&E Energy Trading for demand charges of $3.6 million per year each or $7.2 million annually in total. These revenues were included in revenue and effectively resulted in a credit to delivery margin. The PG&E contract was subsequently terminated and replaced with a higher value contract with NW Natural and revenues continue to be treated in the same manner. As described in the response to BCUC IR 2.92.2, upon termination of the BC Hydro agreements, TGI retained the related SCP capacity into its Midstream portfolio and effectively replaced the revenues previously received from BC Hydro by debiting that amount against the MCRA with an equal credit against the delivery margin revenue account. This treatment was approved by the Commission for the period ending November 1, 2010 pursuant to Order No. G-98-05 (please also see the response to BCUC IR 2.92.2).

92.6 The first response that TGI gives in reply to BCUC 1.68.1 appears to attempt to classify SCP as a part of TGI's gas supply portfolio, rather than as part of its pipeline system. Considering the response to the foregoing questions, please explain why the Commission should accept the reclassification.

Response:

TGI is not attempting to reclassify SCP as part of its gas supply portfolio. In the response to BCUC IR 1.68.1, TGI is simply attempting to explain that the 52.5 mmcfd of SCP capacity that had originally been held by BC Hydro continues to provide benefits to the Midstream portfolio as contemplated under the 2005 application, and described in the response to BCUC IR 2.92.2. As TGI intends to continue to plan on the availability of this capacity in its Midstream portfolio, it is prepared to continue the same accounting treatment. If this accounting treatment is not determined to be appropriate, it would not change TGI's intention to use the SCP capacity when planning its Midstream portfolio. If the current accounting treatment were discontinued, the result would be that the MCRA costs would decrease by $3.6 million per year, while delivery margin revenue requirement would increase by $3.6 million per year.

92.7 As BC Hydro did not exercise its option to extend its service agreement, please explain why the second reason in the response to BCUC 1.68.1 is relevant to the discussion at hand. If BC Hydro had exercised its option, it would have paid the $3.6 million per year. If it did not exercise the option, why does TGI think that the MCRA would have become responsible for the charge?

Response:

TGI is not presupposing that MCRA would have become responsible for the charge.

If BC Hydro had continued to hold the service agreements until the end of the primary term and then made a decision not to exercise its option to renew, in absence of any replacement agreement TGI expects that the "default" would be that the $3.6 million be recovered through the delivery margin revenue account.

93.0 Reference: Operations and Maintenance Expenditures

Exhibit B-4, BCUC 1.71.0

2008 O&M

In BCUC 1.71.1, TGI states that the"2008 actual O&M is not an appropriate starting point…because operating environment and activities, management initiatives in 2008 would not be indicative of the same in 2010 and 2011".

In BCUC 1.71.2, TGI states that "TGI has been successful in keeping its operating costs below the formula based amounts throughout the PBR Period…" and "the formula continues to provide a good approximation of what would be an acceptable".

93.1 Please explain why the use of 2008 Approved O&M, which is formula based, as opposed to 2008 Actual O&M is a more appropriate starting point for calculating 2010 and 2011 Forecast O&M?

Response:

The formula (approved) amounts during the PBR Period were based on the 2003 Decision. The 2003 Decision is the last year for which TGI had a full revenue requirement hearing. The forecasts for that year were reviewed through an oral hearing, approved by the Commission, and serve to establish a baseline both for the formula O&M during the PBR Period but also to establish the reasonableness of 2009 through 2011 O&M forecasts. Therefore, the 2008 approved O&M is inclusive of both the baseline 2003 amounts, and also a customer growth and productivity-adjusted inflation factor. By contrast, the 2008 Actual O&M has not been normalized nor subjected to an extensive review to establish its appropriateness as a base for determining if it is reflective of 2010 or 2011 requirements.

It is important to note that although in the referenced IR response, TGI did state that 2008 Approved O&M was a better comparator than 2008 Actual O&M, TGI maintains that neither one of those figures is the most appropriate basis for comparison. In the Application, TGI used the 2003 Decision O&M to review performance and results over the PBR Period and to establish that the 2009 projection and 2010/2011 forecast amounts are reasonable, since that was the last year that was subject to a full revenue requirement review. Throughout Tab 6 of the RRA, TGI has based its discussion of the 2010/2011 forecast O&M on the 2009 projections, using an incremental cost driver approach to an analysis of the forecast years. TGI maintains that the 2003 Decision is the most appropriate starting point for purposes of establishing the reasonableness of 2009 as the base year.

93.2 Does TGI intend to continue the efficient management of operating costs during the 2010 and 2011 test period?

Response:

Yes. As stated on page 200 of the Application "Terasen Gas has a continued need to focus on Operational Excellence, including **managing O&M and capital expenditures effectively and efficiently** [emphasis added] so that it continues to meet the increasing expectations of its customers, regulators and policymaker." TGI intends to continue to manage operating (and capital) costs effectively and efficiently through the 2010 and 2011 forecast period. It is the Company's belief that the forecast operating costs included in this Application are reasonable and prudent and will allow the Company to continue to provide safe, reliable and cost effective service to its customers.

93.3 Is TGI suggesting that the effective management of operating costs during the PBR period is not sustainable and that these efforts cannot be duplicated in 2010 and 2011?

Response:

No. As stated in the response to BCUC IR 2.93.2, TGI intends to continue to manage operating (and capital) costs effectively and efficiently through the 2010 and 2011 forecast period.

During the PBR Period, significant savings were achieved as compared to the formula based O&M, which were shared equally by customers and the Company. The savings that have been achieved early in the PBR Period are generally sustainable in a static environment. However, over time, changes in external requirements (for example increases in the number of customers, changes in customer expectations, codes and regulations, and energy policy) result in increasing O&M requirements to meet those expectations. As described on page 161 of the Application, a number of the efficiencies the Company was able to realize in the early years of the PBR Period "…can only be achieved once, or can only be sustained for a limited period of time before activities need to be resumed and costs need to be incurred." Additionally, as stated in the Application on page 20, "The Company has exhausted opportunities for significant incremental gains under the existing PBR framework."

Finally, as demonstrated in the tables and discussion on pages 346 and 347 of the Application, TGI has been able to retain a significant portion of the savings achieved, even though the opportunity for achieving incremental large scale efficiencies has been exhausted.

94.0 Reference: Operations and Maintenance Expenditures

Exhibit B-4, BCUC 1.71.1

TGI 2008 Annual Review – November 3, 2008 Amended Annual Review Application ("2008 Amended Annual Review"), Section A, Tab 5, Page 2, O&M Expense

2009 O&M

94.1 Please discuss the difference between the Forecast 2009 total O&M in 2008 Amended Annual Review ($173,138) with the 2009 Gross O&M ($186,480), as provided in response BCUC 1.71.1.

Response:

It appears as if the information set out in TGI's response to BCUC IR 1.71.1 has been misinterpreted. As a result, the comparison that has been made in this information request is not comparing like numbers, as one is Allowed Net O&M for 2009 and the other is Actual Gross O&M for 2008.

The Forecast 2009 Total O&M set out in the 2008 Amended Annual Review in the amount of $173,138 is the Allowed Net O&M (not Gross) amount that is calculated per the formula set out under the terms of the 2008-2009 Extension of the 2004-2007 PBR Settlement Agreement.

The amount of $186,480 provided in response to BCUC IR 1.71.1 is TGI's 2008 Actual Gross O&M, not the 2009 Gross O&M , as described in this request. The question included in BCUC IR 1.71.1 had requested that 2008 Actual O&M be used as the starting point for a hypothetical Formulaic calculation of O&M for 2009 – 2011. In the table included in the response to BCUC IR 1.71.1, the line description for the $186,480 that was included under the 2009 column heading is "prior year gross O&M", hence the amount was 2008 Actual Gross O&M.

The difference between the two numbers is due to the fact they are not an "apples to apples" comparison.

95.0 Reference: Operations and Maintenance Expenditures

Exhibit B-4, BCUC 1.72.1

Exhibit B-1, Table C-6-3, Appendix F-1 and Appendix F-4

Forecast 2010 O&M

"Approximately $1.5 million of the forecast O&M costs in 2010 relate to serving new customer growth…"

95.1 In Table C-6-3 of the Application, the dollar increase in O&M costs from Projected 2009 to Forecast 2010 is $14.5 million ($209 million less $195 million, rounded). Please confirm that the $1.5 million increase relating to customer additions referenced above is only representative of 10 percent of the increase in O&M costs ($1.5 million / $14.5 million). Can it be concluded that the remaining 90 percent is generally related to inflation and / or other drivers. Please provide any other explanations.

Response:

In Table C-6-3 of the Application, the dollar increase in O&M costs from Projected 2009 to Forecast 2010 is approximately $14.5 Million. Of this increase, as stated in the response to BCUC IR 1.72.1, approximately $1.5 Million relates to serving Customer Growth. The remaining $13 Million is broken down into Inflation and other drivers in Table C-6-3.

Within the Table, Labour Inflation and Benefits is shown as a separate category. The majority of General Inflation and Customer Growth can be found within the Service Enhancements category of the Table. The remainder of the Service Enhancements Category is as discussed on Page 357 of the RRA.

Apart from Inflation and Customer Growth the majority of the O&M increases are primarily driven by the external situation that TGI faces as it prepares to move forward into 2010 and beyond. The external situation is discussed in depth in Part III, Section A of the RRA.

The external situation highlights identified in Table C-6-3 and stated on Page 348 of the RRA are as follows:

- Government Policy funding requests are for additional resources needed to respond to changes in Government Policy regarding energy efficiency and GHG reduction.
- Code and Regulations funding requirements are driven by Terasen Gas' need to comply with existing codes and anticipated new or changed codes.

- Driving the cost pressures in the category of Customer/Stakeholder Behaviours and Expectations are changes in energy use and impact on the environment, management of First Nations relationships and increasing expectations for customer service delivery
- Demographic challenges regarding Terasen Gas' aging employee workforce require increased efforts to proactively recruit, train and develop, transition, and overall manage our workforce in the coming years
- Accounting Changes and the need to comply with IFRS will affect the classification and timing of costs.

95.2 TGI's Gross O&M increase averages approximately 2.05 percent (Appendix F-1) over the PBR period, which is in-line with the average rate of inflation over the same time. This may be an indication that costs could be effectively controlled to inflationary measures during the PBR. However in the test period, Gross O&M is proposed to increase by 7.4 percent in 2010 and another 4.6 percent in 2011 (see Table C-6-3) while the average inflation during the same period is forecast at around 2 percent (Appendix F-4). Please discuss these observations.

Response:

As indicated in the question, TGI's Actual Gross O&M increase averages approximately 2.05% over the PBR Period which is in line with the average rate of inflation over the same time. In the RRA, in the test period, Gross O&M is proposed to increase by 7.4% percent in 2010 and another 4.6 percent in 2011, while during that same period, the average inflation is around 2%, while labour inflation is forecast at 3%. However, TGI believes that it would be misleading to project the results achieved during the PBR Period to be an indication that (a) costs were effectively controlled to inflationary levels during the PBR Period, or (b) controlling costs to inflationary measures in the test period will not be possible.

Allowed O&M during the PBR period used the 2003 Approved O&M as a base. The base was adjusted annually for inflation as well as customer growth. In recognition of the operational amalgamation of TGI with that of TGVI and TGW during the PBR Period, TGI was further challenged to mine productivity savings during this period. TGI managed its O&M throughout the PBR period in this context, incurring productivity savings that effectively offset customer growth. To the extent that these productivity savings are sustainable, they have been reflected in the test period, thus making customer growth a legitimate O&M pressure during the test period.

With respect to the PBR Period, the referenced O&M increases effectively excluded any and all of what were referred to as Exogenous Factors during the PBR Period. These Exogenous

Factors represent expenses incurred which are considered to be beyond the control of TGI. Pursuant to the PBR Agreement, these expenses were captured in deferral accounts and thereby effectively excluded from O&M where they otherwise would have resided. See Page 197-198 of the RRA for discussion of Exogenous Factors, as well as the following examples of some of the Exogenous Factor treatment during the PBR Period:

- BCUC Levies
- Ontario Securities Commission Compliance Costs
- PST Reassessment re Southern Crossing Pipeline
- Carbon Tax Implementation
- Olympic Security costs

As the PBR Agreement comes to an end, it is consistent and necessary that Terasen Gas reflect the impact of these same factors in the forecast of revenue requirements. As shown on Table C-6-3 of the RRA, the majority of increases in the RRA Period are primarily driven by the external situation that TGI faces as it prepares to move forward into 2010 and beyond. The external situation is discussed in depth in Part III, Section A of the RRA. External factors that would have received exogenous factor treatment under the PBR Agreement are projected into the O&M increases.

The remainder of the increases sought in this Application per Table C-6-3 are Labour Inflation and Benefits, as discussed on Page 349-350, and Service Enhancements as discussed on Page 357 of the RRA. These categories would include the impacts on Pension, Insurance, and Bad Debt of a faltering economy as well as other factors facing TGI as it moves into 2010 and 2011. By contrast, the O&M increases of the PBR Period are reflective of a period of time during which the economy flourished until 2008, stock markets were in a bull cycle until 2008, and the commodity cost of gas first increased and then moderated. This back-drop of favourable conditions resulted in relatively lower O&M expenses during the PBR Period. Expenses such as Pension and Insurance as shown on Table B-1-11, Page 160 of the RRA, and Bad Debt as shown on Table B-1-16 and discussed on Page 170-172 of the RRA, all of which are directionally tied to the back-drop of favourable conditions, registered significant drops during the PBR Period. It would be a mistake to expect these reductions to continue into the future.

The costs set out in the Application are appropriate for the current circumstances facing the Company.

96.0 Reference: Operations and Maintenance Expenditures

Exhibit B-4, BCUC 1.72.2

Customer/Stakeholder Behaviours and Expectations

"$3 million is required for additional sales and development staff to support offerings for natural gas and also new services offering such as geo-exchange, solar, biomass or other thermal energy sources. TGI is not able to accurately estimate the allocation of the $3 million incremental funding between natural gas offerings versus new service offerings (i.e. geo-exchange) as customer requirements are evolving. ... It is this requirement to support our customers' evolving energy use and management needs that TGI is seeking funding for. … A further incremental $0.6 million to the $3 million in 2010 for additional sales and development staff related to supporting gas and new service offerings has been included for 2011." Ref: B-4, p. 215

96.1 Please provide the number of FTE and total costs for the staff performing similar functions in 2008.

Response:

In 2008 there were no staff selling alternative energy solutions; however, there were staff selling both natural gas applications and selling NGV solutions (without TGI being involved in the ownership of compression equipment). TGI's active pursuit of alternative energy solutions post dates 2008. See response to BCUC IR 2.102.5 which outlines all staffing in sales, account management and market development roles for 2008-11.

96.2 Please detail the amounts included in the forecast 2009 costs related to the 9 FTE.

Response:

Please find below a table produced to respond to BCUC IR 2.96.2, 2.96.3 and 2.96.4.

	96.2	96.3	96.4	96.2									
				96.3						96.4			
		*											
	FTE Added			2009	Annualize	2010	2010	2010	2010	2011	2011	2011	2011
Description	2009	2010	2011	Addns	2009 addns	Addns	Expenses	Svc & Other	Total	Salary	Expenses	Svc & Other	Total
Marketing Service Reps		2				91	1		92	2			2
Energy Solutions Manager + expenses	1			91	56		9		156	5			5
CES Experts (NGV) + expenses		2				220	20		240	6			6
CES Expert (NGV) + expenses			1							114	9		123
Comml & Industrial Account Mgrs	2			96	96		8		200	8			8
CES Experts + expenses	3			168	168		30		366	12			12
CES Manager + expenses			1							132			132
Sales Coordinator + expenses	1			48	48				96	3			3
Sales Manager + expenses			1							113	8		121
Project Managers + expenses	2			165	115		22		302	14			14
Project Manager + expenses		1				142	12		154	5			5
Project Manager + expenses			1							147			147
New business consulting								1136	1136				
Asset Management consulting								234	234				
	9	**5**	**4**	**568**	**483**	**453**	**102**	**1370**	**2976**	**561**	**17**		**578**

* Note regarding 96.3: The 2010 incremental $3 million includes 5 FTE. Refer to table in 94.2.2 on page 269 which shows Sales & Business Development as having 9 additions in 2009, 5 additions in 2010, and 4 additions in 2011

96.3 Please separate the $3 million of 2010 incremental funding into specific resources such as labour costs for the 10 FTE.

Response:

Please see the response to BCUC IR 2.96.2.

96.4 Please separate the $0.6 million of 2011 incremental funding into specific resources such as labour costs for the 4 FTE.

Response:

Please see the response to BCUC IR 2.96.2.

97.0 Reference: Operations and Maintenance Expenditures

Exhibit B-4, BCUC 1.72.3

2010-2011 O&M Excluding Accounting Changes

97.1 Given that the accounting changes in O&M are largely due to the change in reporting / accounting treatment of certain expenses, it can be argued that it is not a true indication of business operations. Would TGI agree that the increase in the total proposed O&M forecast without accounting changes is actually 9 percent (from Projected 2009 of $195,079 to Forecast 2010 of $212,731) where inflation is forecast at 1.9 percent and 2.0 percent in 2010 and 2011 respectively.

Response:

As indicated in the response to BCUC IR 1.72.3, the 2010 forecast O&M of $212.7 Million (without Accounting Changes) represents a 9% increase from 2009 where inflation is forecast at 1.9% and 2.0% in 2010 and 2011, respectively. The Table contained in that response further categorizes and quantifies the nature of these expenses as:

- Labour Inflation and Benefits $2,816
- Government Policy $ 592
- Codes and Regulations $5,297
- Customer/Stakeholder Expectations $4,526
- Demographics $ 817
- Service Enhancements $3,604

As explained in the response to BCUC IR 2.95.1, apart from Inflation and Customer Growth, the majority of the O&M increases are primarily driven by the external situation that TGI faces as it prepares to move forward into 2010 and beyond. The external situation is discussed in depth in Part III, Section A of the RRA. The external situation is further categorized and quantified on Page 348 – 405. Please see TGI's response to BCUC IR 2.95.1 for a summary of the external situation as well as TGI's response to BCUC IR 2.95.2 for a comparison of external factors to Exogenous Factors in the current PBR Agreement.

97.2 Can TGI explain why the increase in O&M expenses in 2010 is substantially higher than forecast inflation in the same period?

Response:

The drivers behind the increase in O&M other than non-labour inflation is described in some detail by category on pages 348 through 405 of the Application. Please see the response to BCUC IR 2.97.1

98.0 Reference: Operations and Maintenance Expenditures

Exhibit B-4, BCUC 1.73.1

Per customer O&M

According to the data provided in the chart, it appears that the 2010 forecast Gross O&M per customer ($250) is a 12 percent increase from 2006 Actual O&M per customer ($223). This figure is 16 percent in forecast 2011 compared to 2006. This appears to be a significant increase given that the average increase in Actual O&M expenses between 2006 and2008 is only 0.8 percent.

Customer growth is averaging 0.98 percent increase per year between 2006 and 2011; however O&M is increasing at an accelerated rate.

98.1 Does TGI believe that there should there be a linear relationship between the number of customer increases and the amount of O&M expenses? Please discuss.

Response:

TGI would expect a linear relationship between the increase in the number of customers and the increases in the amount of O&M expense over the long term Customer growth in and of itself, however, does not explain the change in O&M over the period. There are several reasons for this:

During the PBR Period, TGI was not attempting to manage to a base year of 2006, but rather to a base year of 2003. For 2010 – 2011, TGI will be attempting to manage to a base year of 2009.

- The 2006 – 2008 period makes up only a portion of the PBR Period. This period is reflective of a time following the operational amalgamation of TGI with that of TGVI and TGW, following the period when restructuring costs were incurred, and during which benefits tied to economies of scale were realized. These benefits served to dampen other ongoing O&M pressures during that period. To the extent they are sustainable, these benefits have already been reflected in the test period forecasts.
- There are numerous drivers other than Customer Growth that will also drive O&M. Foremost amongst these would be inflation. Also, what is referred to in the RRA as the External Situation. Please refer to BCUC IR 2.95.1 for a brief summary of the External Situation as well as the RRA, Part III, Section A, External Situation Context for a more detailed discussion.
- As discussed in response to BCUC IR 2.95.2, the Exogenous Factor treatment of the PBR Period effectively excluded Exogenous items from O&M by granting them deferral

treatment. During the term of the PBR Period, the Exogenous Factor treatment existed to capture the material impacts of many of the same types of external cost drivers discussed in Part III, Section A, External Situation Context. These are summarized in Table and point form on Page 348 of the RRA. As the PBR Agreement comes to an end, it is consistent and necessary that Terasen Gas reflect the impact of these same factors in the forecast of revenue requirements

- As discussed in response to BCUC IR 2.95.2, the favourable economic back-drop of the PBR Period is not comparable to the uncertain economic conditions of the post PBR Period.

In arriving at the 2010 and 2011 O&M Forecasts, TGI relied upon a number of techniques. In recognition of a linear relation between certain O&M and Customer Growth, TGI employed trend analysis to incorporate growth forecasts into the appropriate sections of the forecast. In addition, TGI also used trend analysis to incorporate inflation into the forecast. When considering the External Situation factors, TGI relied more upon zero based budgeting to reflect those drivers into the appropriate sections of the forecast. TGI believes that the costs included in the Application are reasonable and required to meet the needs of customers in the RRA Period.

99.0 Reference: Operations and Maintenance Expenditures

Exhibit B-4, BCUC 1.74.1

Baseline Expenditures

"…TGI does not believe 2006 actuals is the appropriate starting baseline for comparison…Instead TGI believes the starting point should be the 2003 allowed O&M based…as…that has been used for the purposes of rate setting…an appropriate and reasonable level of base expenditure…would be the 2009 O&M projection…"

99.1 Does TGI agree that there is an "adjusted based O&M" established at each annual review to account for the differences / true-up of customer additions? As such, does TGI agree that it is implicit that rates are adjusted to reflect actual costs during the PBR period?

Response:

During the PBR Period, the Allowed O&M was a formulaic calculation performed on a forecast basis relying upon forecast estimates for Customer Growth and Inflation (off set by Productivity Factor) to inflate a Base Year's O&M. As part of this O&M continuity, the forecast estimates of Customer Growth were replaced with actual results as they became known, thereby creating an 'adjusted base' O&M (as it pertains to Customer Growth). This was done each year as part of the Annual Review process. As such TGI agrees that it is implicit that Allowed O&M was adjusted, on a staggered basis, *to reflect actual results of Customer Growth*. Rates were not otherwise "adjusted to reflect actual costs during the PBR period", as the question would appear to suggest.

The Customer growth adjustment mechanism was a condition of the PBR Agreement. This adjustment mechanism is not considered part of traditional regulated ratemaking practice. TGI continues to believe that the relevant comparator for this application should be the 2003 allowed O&M that was approved by the Commission following a comprehensive hearing, rather than the formula derived O&M employed during the PBR Period.

99.2 Does TGI recognize that there is a degree of uncertainty in 2009 projected figures since the fiscal year has not yet passed and there is a degree of subjectivity in projecting year end balances?

Response:

In developing a base year on which to base 2010 – 2011 forecasts, TGI recognizes that the actual results from 2004 through 2008 are all a result of managing O&M within the spirit of the

PBR Agreement. As such TGI made a conscious decision to use past results as a valuable input to, but not as a basis for, future forecasts. TGI pointed out in Part III, Section B, Tab 1, Page 161 – 162 that there were efficiencies realized during the PBR Period that '*can only be achieved once, or can only be sustained for a limited period of time before activities need to be resumed and costs need to be incurred.'* It is necessary that this reality be recognized in establishing a base year against which to measure future forecasts. The 2009 projections recognize this.

TGI does recognize that there is a degree of uncertainty in 2009 projected figures, given the fiscal year has not yet passed and actual results are not yet known. However, the 2009 projections were arrived at by considering the most recent information available. This would include the 2008 actuals as well as other pressures and opportunities that have since arisen. In recognition of the dynamic environment within which TGI operates, TGI recognizes the importance of considering the very latest information available.

Furthermore, TGI's methodology employed to develop the O&M forecasts for 2010 and 2011 are such as to generate forecasts that are more 'stand alone' in nature as opposed to being closely linked to 2009 projections.

- TGI has considered resource based as well as activity based forecasting techniques. For those O&M components where trend analysis or unit costing is applicable, TGI identified the trends, and then relied upon historical results coupled with future forecasts of these trends or unit costs to drive out the forecasts of those O&M components.
- For those O&M components, many of which were beyond the control of TGI, that were identified as external situation factors (as discussed in Part III, Section A of the RRA, identified and quantified on Table C-6-3 page 348 and discussed in more detail on Page 348 – 404), TGI relied more upon zero based budgeting to forecast their O&M impacts.

TGI is confident that the techniques employed have resulted in a reasonable 2009 projection, and that any uncertainty inherent in these projections will not impair the O&M forecasts for the RRA period.

99.3 Please explain why historical trends, given the availability of actual information, would not be a good indicator of consistent business operations and hence a measurement tool for forecasting future O&M expenses?

Response:

As indicated in the response to BCUC IR 2.99.2, TGI employs a wide range of forecasting techniques in order to ensure an optimal allocation of resources. These include trend analysis, unit costing, activity and resource based forecasting, zero based budgeting, etc. TGI does believe that historical trends are a valuable measurement tool for forecasting certain future O&M expenses. However, TGI does not believe it is appropriate to rely solely upon historical trends in forecasting future O&M, but rather to employ a variety of forecast approaches. This will ensure success in:

- Capturing events, both internal and external, that have transpired since the historical trend was recorded;
- Recognizing that future operating conditions, especially those driven by the external situation (outside of those reflected in the trend analysis) will not mirror those of the past;
- Recognizing that not all O&M can be categorized by one or two trends;
- Capturing the impacts of the dynamic business environment within which TGI operates such as aging infrastructure, technological advances, evolving customer expectations, changing codes and regulations, workforce demographics, etc.

TGI believes that the budgeting approach used in this Application has resulted in an appropriate forecast of the O&M required to continue providing safe, reliable and cost effective service to customers.

100.0 Reference: Operations and Maintenance Expenditures

Exhibit B-4, BCUC 1.75.1 and 1.77.1

Items Deferred during BPR

Maintenance deferred during BPR was $870 thousand and non-maintenance deferred during BPR was $520 thousand. Expensing these costs in 2010 will result in the ratepayer incurring the entire cost whereas the ratepayer had 50 percent of the savings in the year deferred.

100.1 Since these expenditures are managed and prioritized based on a corporate risk profile with higher risk items addressed first, where will these expenditures rank in relation to Customer/Stakeholder Expectations identified in BCUC 1.72.2? Specifically, will these deferred expenditures be acted upon before the Customer/Stakeholder Expectations?

Response:

Before answering the question, TGI wishes to address the statement in the preamble, which appears to overlook the fact that the expenses for maintenance and non-maintenance referred to in the preamble were, and remain, expenses related to the ongoing operation of the utility. As such, they are costs legitimately borne by the customers in their entirety. The deferral of lower risk items as TGI has done is a part of prudent management, which TGI did prior to the PBR Period and during the PBR Period, and will continue to do beyond the PBR Period. The PBR Agreement incentive mechanism allocated benefits from these O&M expense deferrals equally to customers and the shareholder, but the expiry of the PBR Agreement does not have the effect of requiring the shareholder to incur half the cost of expenditures legitimately required for the ongoing provision of service to customers.

Maintenance deferred during the PBR Period in the order of $870K as referenced on Page 357 of the RRA and the response to BCUC IR 1.75.1, and non maintenance deferred in the order of $520K as referenced on Page 161 of the RRA and the response to BCUC IR 1.77.1 have both been prioritized as being necessary expenditures in the 2010 year. Given that these items have evolved over time from a lower risk profile where they were capable of being pragmatically deferred to that of a high risk profile where deferral would involve a high degree of risk, they will be incurred in 2010 and not deferred until 2011 or beyond.

Expenditures classified in the RRA as Customer/Stakeholder Behaviours and Expectations, quantified as $4.5 million on Table C-6-3, and referenced in the response to BCUC IR 1.72.2 are also expected to be incurred in 2010. These expenditures are of a different nature and present a different type of risk profile than those of the preceding paragraph. Based on a corporate risk profile, these expenditures are all categorized as being necessarily incurred in 2010.

In sum, the expenditures included in the Application are for the provision of service to customers and are accordingly appropriately borne by customers. TGI will continue to look for ways to defer non essential expenses, but the expenses included in the Application are necessary for the continued delivery of safe and reliable service to customers.

101.0 Reference: Organization Chart by Department

Exhibit B-4, BCUC 82.0

"We have included headcounts at the departmental level, and have focussed on identifying new positions (i.e. positions that do not already exist at Terasen Gas) that we plan to add in these years." (Exhibit B-4, BCUC 82.0, p.236)

101.1 Please provide organization charts of the entire company for 2009, 2010 and 2011. In the 2009 organization chart identify all positions vacant as of the date of the chart. For the Business and IT Services, Human Resources & Operations Governance, and Marketing & Business Development groups, please identify the positions added in each year using a separate colour or similar identification, different for each year that allows the positions added to be focused on by year. The colour chosen for additions in 2009 should be used for those same positions in the 2010 and 2011 charts, and similarly the colour used for 2010 additions should be used on those same positions in the 2011 charts. Each new position would have a separate box on the organization chart, unless the position titles are the same in which case a single box with the number of next positions would be sufficient.

Response:

Please refer to Attachment 101.1. The organizational charts prepared for this response are based on July 15, 2009 head count data, and the projected additional head counts per year (2009 to 2011) for all divisions. The charts do not reflect any re-organization or reporting changes after July 15, 2009.

2009 Org Charts - Vacancies

Vacancies reported on this chart reflect year end projected vacancies (December 31, 2009), and are indicated in grey throughout.

2009 to 2011 Org Charts - Head Count Additions

2009-2011 head count additions are reflected on these charts in the following manner:

2009 head count additions = Blue

2010 head count additions = Yellow

2011 head count additions = Green

102.0 Reference: Organizational Chart by Department

Exhibit B-4, BCUC 1.82.1

Headcount

"Efforts were made to create charts to the employee level, but this proved to be a very onerous process as we do not normally maintain corporate organizational charts with that level of detail. It is also exceedingly difficult to reconcile headcount on a departmental basis, when operationally our organizational charts combine Terasen Gas employees with Terasen Inc. and Terasen Gas Vancouver Island, and when the employee landscape is constantly changing, depending on vacancies, temporary backfill, short-term and long-term leaves of absence, as well as regular developmental movement throughout the organization."

102.1 Please explain how TGI manages headcount and labour costs, given that it cannot "reconcile headcount on a departmental basis".

Response:

TGI manages headcount and labour costs from a Company-wide perspective and in the context of overall cost management. Corporate organizational charts do not assist our ability to manage headcount and labour costs. Frequent changes in reporting structures, temporary vacancies, leaves of absence and developmental opportunities are difficult to capture in static organizational charts. Headcount is tightly managed through the budgeting process as coordinated by the departmental Operations Financial Analysts (OFAs) in consultation with the various Cost Centre managers. The OFAs also ensure appropriate cross charging and the transfer of budgets between departments when necessary. TGI will continue to manage changes to headcount within the budgeting process to ensure we are able to meet the needs of our customers while still managing our labour costs in an effective manner.

102.2 Please provide the TGI headcount vacancies by year, department (Business System Planning Manager, Infrastructure Planning Manager) and positions for 2008-2011.

Response:

TGI vacancies are summarized in the table below. These are based on actual FTE vacancies as at December 31 of each year. It is important to note that these numbers will be different from our responses to BCUC IR 1.87.1, BCUC IR 1.74.1 and BCUC IR 2.140.1 where the calculations were based on average budgeted FTE amounts and average FTE vacancies. For example, 1 budgeted FTE position which may have been filled from January to September of a given year would equate to .75 FTE in the response to BCUC IR 1. 87.1 and 1.74.1, but would show up as 1 vacant FTE position as at December 31 in the response to this IR, with the exception of positions that are budgeted as part-time.

2008 – 2009 Vacancies as at December 31

GS&T		2008	2009
Pipeline Operations Coast	Distribution Mechanics	2	
Gas Control	Gas Controller	1	
Performance & Compliance	Project Manager	1	
Transmission, Interior	Project Manager		1
Transmission, Interior	Compression Manager, Interior	1	1
Transmission Field Interior	Welder 1	1	
Compression Interior	Millwright	1	
Transportation Services	Marketing Services Representative		1
	Total	**7**	**3**

HR&OG		2008	2009
Employee Development Programs	Engineer in Training (Junior Engineer)	5	
Training	Training Analyst	1	
Training	Instructor	1	
Training	Safety Instructor	1	
HR Advisory Services	HR Generalist	1	
Environment, Health & Safety	Admin Assistant	1	
HR Advisory Services	HR Coordinator, Recruiting	0.6	
HR Advisory Services	Associate HR Advisor	0.6	
	Total	**11.2**	**0**

B&ITS		2008	2009
Corrosion	Tech 4	2	
System Integrity Programs	Integrity Engineer	1	
Drafting	GIS Drafter 1	3	
Drafting	GIS Drafter 2	1	
Engineering	Sr Pipeline Engineer	1	
Machine Shop	Shop Mechanic	2	
Weld Shop	Fitter Welder 1	2	
Weld Shop	Shop Assistant	1	
Warehouse & Delivery	Truck Driver	1	
Warehouse & Delivery	Material Handler	1	
Warehouse & Delivery	Shipper/Receiver	1	
Warehouse & Delivery	Warehouse Manager	1	
Meter Shop	Measurement Mechanic	1	
Warehouse & Delivery	Operations Assistant	0.6	
Data Acquisition	Instrumentation Technician	4	
Facilities	Building Maintenance	1	
Facilities	Office Clerk	1	
Infrastructure Operations	Infrastructure Support Technician	1	
Application Tech Support	Developer	1	
Information Technology Operations	IT Communication	1	
Engineering	Project Manager	2	
Measurement Services	Technologist 3		2
Shops	Machinist		1
Shops	Prefab Mechanic		1
PMO	Project Manager		1
Facilities Mtce	Facilities Maintenance analyst		1
	Total	**29.6**	**6**

M&BD		2008	2009
Business Development	Mgr. Business Development	1	
Business Development	Project Assessment Manager	1	
Customer Management	Admin Assistant	1	
Customer Care	Customer Care Coordinator	1	
Customer Care	Customer Unbundling Admin	2	
Customer Care	C/S Performance Manager	1	
Customer Contact Centre	Customer Service Rep 3	5	
	Total	**12**	**0**

Fin&Reg		**2008**	**2009**
Financial & Regulatory Reporting	Manager, Financial & Regulatory Reporting	1	
Financial Planning	Financial Planning Manager	1	
Financial Planning	Financial Planning Manager	1	
Regulatory Reporting	Senior Rates Analyst	1	
Regulatory Reporting	Financial System Support Analyst	1	
Accounts Payable	Accounts Payable Clerk 2	2	
	Total	**7**	**0**

Distribution		**2008**	**2009**
Reg Manger Int South	Operations Mgr- Trail	1	
Operations Centre	Operations Support Representative	9	
Operations Centre	ICI	5	
Operations Centre	Dispatcher	1	
Distribution North Okanagan	Equipment Operator/Distribution Mechanic	1	1
Distribution Lower Mainland	Distribution Mechanics	11	15
Operation Centre - Pre Req	Surveyor 1		1
Distribution Operations	System Operations Technician		5
Distribution Operations	Customer Service Technicians		3
Distribution Operations	Crew Leaders		4
Distribution Operations	Paving Foreman		1
	Total	**28**	**30**

TGI Projected Vacancies as at December 31, 2010 & December 31, 2011

TGI is projecting that all vacancies will be filled as at December 31 of 2010 & 2011, and therefore forecast 0 year end vacancies for 2010 & 2011.

102.3 For the managers reporting to the Chief Regulatory Officer, please provide the number of employees reporting to each director/manager. Please use the format of the table below.

Chief Regulatory Officer
Number of Employees per Director / Manager

Number of Managers	Title	# of Employees 2008	2009	2010	2011
1	Regulatory Reporting Manager				
2	Director Reg Strategy & Business Analysis				
3	Manager Regulatory Affairs				
	Total				

Response:

The following table displays the full time equivalent (FTE) employees reporting to each of the positions above, as well as to the Tariff & Special Contracts Manager, who has one direct report, and the Chief Regulatory Officer (including his own position) to come to a total FTE number that agrees to the response to BCUC IR 1.112.3.

As discussed in the Application, for 2010 and 2011 we have proposed that the Regulatory Reporting Manager and the 3 Analysts reporting into that position be moved to the CMAE budget for costing purposes, and consequently have been removed from the numbers provided in the table below. However, in preparing the revised responses to BCUC IRs 1.82.1 and 1.82.2, one of the positions was not removed from the organization charts. Therefore the charts provided in response to those IRs show 17 headcount for 2010 and 2011 as opposed to the correct number of 16 as displayed in the table below.

Number of Managers	Title	# of Employees (FTE's) 2008	2009	2010	2011
1	Regulatory Reporting Manager	3	3	0	0
2	Director Reg Strategy & Business Analysis	3.7	4	4	4
3	Manager Regulatory Affairs	0.2	2	4	4
4	Tariff & Special Contracts Manager	1	1	1	1
5	Chief Regulatory Officer & Direct Reports	7.7	8	7	7
	Total	15.6	18	16	16

102.4 For the managers reporting to the Chief Information Officer, please provide the number of employees reporting to each manager. Please use the format of the table below.

Chief Information Officer
Number of Employees per Manager

Number of Managers	Title	# of Employees 2008	2009	2010	2011
1	Business Systems Planning Manager				
2	IT Operating Manager				
3	Infrastructure Planning Manager				
	Total				

Response:

Chief Information Officer

	# of Employees			
	2008	**2009**	**2010**	**2011**
Manager, Business Systems Planning	1	1	2	2
IT Operations Manager	4	5	5	5
Infrastructure Planning Manager	4	4	4	4
Enterprise Application Support & Delivery Manager	21	23	25	25
Application Support & Delivery Manager	12	12	12	12
Application Technical Support Manager	3	3	4	4
Chief Information Officer & Direct Reports	7	9	9	9
Total	52	57	61	61

102.5 For the managers reporting to the Director, Corp. & Marketing Communication, the Director, Customer Management & Sales, the Director Customer Care & Services and the Director, Resource Planning & Market Dev,, please provide the number of employees reporting to each manager. Please use the format of the table below.

Director, XXXXXX
Number of Employees per Manager

Number of Managers	Title	# of Employees 2008	2009	2010	2011
1	Marketing & Customer Communications Manager				
2	Corporate Communications Manager				
3					
	Total				

Response:

Marketing & Communications - # of Employees per Director/Manager.

Director, Corporate Marketing & Communications	# of Employees			
	2008	2009	2010	2011
Marketing & Customer Comm Manager	7	10	10	10
Corporate Communications Manager	1	1	1	1
Director, Corporate Marketing & Communications & Direct Reports	3	4	4	4
Total	**11**	**15**	**15**	**15**

Director, Customer Management & Sales	# of Employees			
	2008	2009	2010	2011
Manager, Commercial & Industrial Marketing	7	12	14	16
Regional Sales Manager	3	3	3	3
Regional Sales Manager	3	3	3	4
Mgr, Commercial & Residential Energy Solutions		3	4	4
Director, Customer Management & Sales & Direct Reports	4	5	5	5
Total	**17**	**26**	**29**	**32**

Director, Customer Care & Services	# of Employees			
	2008	2009	2010	2011
Manager, Customer Care	2	7	11	11
Call Centre Operations Manager	11	16	16	16
Manager, Customer Programs & Research	2	4	4	4
Director, Customer Care & Services & Direct Reports	5	5	5	5
Total	**20**	**32**	**36**	**36**

Director, Resource Planning & Market Development	**# of Employees**			
	2008	**2009**	**2010**	**2011**
Manager, Technical Sales Support	3	3	3	3
Market Development & Analysis Manager	1	2	2	2
Customer & Energy Forecasting Manager	4	4	6	6
Manager, Marketing & Energy Efficiency	5	12	15	15
Director, Resource Planning & Market Development & Direct Reports	13	13	16	17
Total	**26**	**34**	**42**	**43**

103.0 Reference: Operations and Maintenance Expenditures

Codes and Regulations – HROG O&M Increases

Exhibit B-4, BCUC 1.84.1

103.1 Please expand on the role of the Public Safety Manager, including the requirements of the new Integrity Management Plan that requires the addition of this full time resource.

Response:

Terasen Gas has a responsibility to educate the public about the risks associated with its natural gas and propane products. As part of TGI's review of its compliance to the new CSA Z662 requirement for a Safety and Loss Management Plan, we determined that Public Safety Communications needed to be strengthened. The table presented in BCUC IR 1.127.1 outlines key stakeholders and some of the reasons why we would communicate with them. To provide the coordination and guidance necessary to ensure effective communications, the role of Public Safety Manager will be created as identified on pages 14-17 of Appendix F-8, Codes and Regulations of the Application. The bullets below identify the major accountabilities of this new role.

Public Safety Manager

Description

- Develop and/or review corporate standards relating to Public Safety as required.
- Ensure establishment, coordination and maintenance of Public Safety activities and resources related to the integrity management program at Terasen Gas.
- Perform duties of Program Lead for IMP Public Safety program.
- Maintain central repository of organization's public safety initiatives, and other data used in IMP metrics.
- Act as subject matter expert for all Public Safety communications.
- Work with internal and external stakeholders, and Regulators to strive for continued improvement of both customer and public gas safety awareness.
- Participate, lead and/or establish committees focusing on Public Safety.
- Monitor issues and activities concerning Terasen's relationship with regulatory agencies.

- Track changes which could impact Public Safety education requirements, and advising management about future potential and emerging Public Safety issues related to regulatory change.
- Work to strategize with related agencies on province wide multi- stakeholder communication efforts.
- Conduct yearly surveys and research to measure awareness levels and effectiveness of communication methods.
- Analyze and implement results of risk assessments to ensure public safety awareness is focused on areas most at risk
- Provide updates on Public Safety achievements to management as required.
- Manage operating budget related to Public Safety.

Customers, the public and policymakers expect Terasen Gas to have dedicated safety-focused resources like BC Hydro, Saskatchewan Energy and others. This position in public safety awareness allows for an expanded public safety governance program and ensures that public safety awareness programs are coordinated in an effective manner and expanded to increase overall public safety. With the recent inclusion of the need for a safety and loss management plan within CSA Z662, Terasen Gas believes this is the appropriate time to create this position and that the funding requirement of $117 in 2010 is necessary and prudent.

103.2 For items 2 (Business Continuity) and 5 (Emergency Preparedness), please provide the O&M, by year and by resource, separating labour, supplies etc.

<u>Response:</u>

For reference, we have copied the relevant portion of the table referred to in BCUC IR 1.84.1 and have shown the breakdown of supplies, consulting fees and labour for Business Continuity (including Pandemic Preparedness) and Emergency Preparedness during the PBR Period and also for 2010 and 2011.

	2006		2007		2008		2009		2010		2011	
	FTE	$O&M	FTE	$O&M	FTE	$O&M	FTE	$O&M	FTE	$O&M	FTE	$O&M
Business Continuity: Supplies	0	35[1]	0	0	0	0	0	0	0	25[2]	0	25[2]
Business Continuity: Consulting Fees	0	0	0	65	0	125	0	0	0	150	0	60
Business Continuity: Labour	0	15	0	15	0	25	0	30	1	140	0	140
Business Continuity: Total	0	50	0	80	0	150	0	30	1	315	0	225
Emergency Preparedness: Supplies	0	0	0	0	0	0	0	0	0	55[3]	0	25[4]
Emergency Preparedness: Consulting Fees	0	0	0	0	0	0	0	0	0	0	0	0
Emergency Preparedness: Labour	0	0	0	0	0	0	0	0	0	60	0	90
Emergency Preparedness Program[5]	0	0	0	0	0	0	0	0	0	115	0	115

1 Purchase of masks and had sanitizer for pandemic preparation

2 Purchase of hand sanitizers for pandemic preparation

3 Supplies for updating Operations Emergency Centre rooms ($5), preparing emergency contingency worksites ($20) and replace expiring supplies from Emergency Supply Cabinets, such as food, water and first aid supplies ($30)

4 Supplies for updating Operations Emergency Centre rooms ($5) and preparing emergency contingency worksites ($20)

104.0 Reference: Labour Cost

Exhibit B-4, BCUC 1.85.1

Compensation and Benefits

104.1 Please confirm the COPE FTE would be:

COPE	2006	2007	2008	2009P	2010F	2011F
FTE	416	419	430	455	474	480

Response:

The COPE FTE are as follows:

	2006	2007	2008	2009P	2010F	2011F
FTE	416	419	431	455	474	480

It appears that this information was inadvertently omitted from the response to BCUC IR 1.85.1.

104.2 Page 95 of the Terasen 2008 AR lists nine people with titles of Vice President/President of Terasen Gas or Terasen Gas Group. Which are the seven included in the executive salaries of Terasen Gas? Are the remaining two charged to TGI as shared services or any other loading? Do the seven executives receive additional compensation from Terasen Inc. or other entity that is charged to TGI through shared services or other loading? Can you expand on the reason why the average executive compensation appears to have dropped from $500,000 in 2006 to $400,000 in 2010?

Response:

The seven executives included in the Terasen Gas Executive Salaries as reported in Exhibit B-4, BCUC 1.85.1 are: Dwain A. Bell, Vice President, Distribution; Cynthia Des Brisay, Vice President, Gas Supply and Transmission; R.L. (Randy) Jespersen, President and CEO; Jan A. Marston, Vice President Human Resources and Operations Governance; Robert M. Samels, Vice President, Business Services and Technology; Douglas L. Stout, Vice President, Marketing and Business Development and Scott A. Thomson, Vice President, Regulatory Affairs and Chief

Financial Officer. The executive salaries included compensation for the four month transition period for Daryle Britton, Vice President Human Resources and Operations Governance, who retired September 2008.

The executives who are not included in the executive salaries of Terasen Gas are Roger A. Dall'Antonia, Vice President Corporate Development and Treasurer who is an employee of Terasen Inc.; and David C. Bennett, Vice President and General Counsel who is an employee of FortisBC Inc. The charges allocated to Terasen Gas Inc. for their services are included in the management fee.

The executive compensation has been influenced by changes in ownership in 2005 and 2007. In 2005 Kinder Morgan's salary compensation policy contained a $250,000 salary cap which was implemented in December 2005 resulting in a reduction to salaries. Kinder Morgan introduced a Mid Term Incentive plan as a retention strategy in 2006.

The Fortis executive compensation program was implemented by Terasen in 2007. The program is designed to provide competitive levels of compensation, a significant portion of which is dependent upon individual and corporate performance, providing a total compensation package that will attract and retain qualified and experienced executives as well as align the compensation level of each executive to that executive's level of responsibility. The objectives of the annual incentive plan are to reward achievement of short-term financial and operating performance and focus on key activities and achievements critical to the ongoing success of Terasen. Following a formal review of all executive positions conducted by the HayGroup in April 2007, the executive compensation was adjusted to reflect a competitive level for total compensation based on a broad reference group of Canadian Commercial Industrial companies. In order to align Terasen compensation practices with Fortis, there was an elimination of the Mid Term incentive plan introduced by Kinder Morgan.

During the gathering of information in preparation to respond to BCUC IR 2.104.4, it was discovered there was a discrepancy in the reporting of M&E and Executive salaries as provided in BCUC IR 1.85.1. These amounts have been adjusted and the comparison between salary and short term incentive averages are based on the executive compensation as reported in BCUC IR 2.104.4.

Executive compensation including salary and Short Term Incentive, averaged $328,000 in 2006 compared to the forecast average of $441,000 for 2010.

104.3 The mid-term incentive budgets are zero for 2010 and 2011. Please explain why.

Response:

The mid-term retention incentive plan was introduced by Kinder Morgan in January 2006. The plan was designed to provide an incentive to retain services for the long term success of the Company and its shareholder Kinder Morgan. Participants in the plan were required to sign a retention agreement and the participant list and value levels were to be reviewed each July and awards had a 3 year cliff vesting. January 2006 was the initial introduction of the program which provided a one time grant subject to graded vesting (1/3 per annum) and a potentially recurring grant with 3 year cliff vesting award.

Following the acquisition of Terasen by Fortis and in order to align Terasen compensation practices with Fortis, there was an elimination of the retention cash incentive plan introduced by Kinder Morgan. A one time adjustment was made to base salary levels for retention award recipients which was derived taking into account the elimination of the retention cash incentive awards (excluding employee incentive plan – EIP) and consideration of current market positioning. The adjustment for the loss of the retention cash incentive award was provided only to those management employees who had previously participated in the plan. In both cases, targeted total compensation was based on competitive compensation positioning for recipients.

104.4 Please provide the compensation data presented in BCUC 1.85.1 in a working spreadsheet with dollar amounts to at least the nearest $1,000. Please separate the annual salary inflation adjustment from the total salary line.

Response:

During the gathering of information in preparation to respond to BCUC IR 2.104.4, it was discovered there was a discrepancy when separating the M&E and Executive salaries. In order to isolate the financial cost accounts a second report was run, and it has now been discovered that the amounts reported in the response to BCUC IR 1.85.1 included allocations for offsetting entries which produced inaccurate results.

The M&E and Executive salaries have now been reported based on payroll information and provided in a working spreadsheet to the nearest $1,000, including the incremental annual salary inflation identified separately.

The corrected table follows and included in Attachment 104.4 is the working spreadsheet requested.

($ '000)

Compensation Package

M&E & Executive	Actual 2006	Actual 2007	Actual 2008	Projection 2009F	Forecast 2010	Forecast 2011
Total TGI (inlcuding Fort Nelson)						
M&E Salaries	18,575	21,820	22,391	27,362	31,280	32,990
M&E Incremental Annual Inflation	610	95	726	781	844	963
Executive Salaries	1,483	1,589	1,939	1,854	1,937	1,995
Executive Incremental Inflation	14	123	44	83	58	60
M&E Short Term Incentive	2,039	2,165	3,440	4,439	4,705	4,943
Executive Short Term Incentive	798	1,211	1,054	1,086	1,095	1,099
M&E Mid Term Incentive	840	829	383	192	0	0
Executive Mid Term Incentive	1,259	1,244	574	287	0	0
Benefits	2,336	3,517	3,501	4,518	4,796	6,290
Pension	4,465	3,693	1,483	3,012	3,174	3,191
OPEB	8,208	8,289	7,761	5,991	1,109	1,038
Total Compensation	**40,627**	**44,576**	**43,295**	**49,605**	**48,998**	**52,569**
Total TGI O&M Labour 1	**36,995**	**41,161**	**38,581**	**43,087**	**46,479**	**49,646**
includes Salaries, Incentive, Benefits, Pension and OPEB						
Total Labour Charged to Capital, Deferrals and Other	**3,632**	**3,415**	**4,714**	**6,518**	**2,519**	**2,923**
includes Salaries, Incentive, Benefits, Pension and OPEB 2	40,627	44,576	43,295	49,605	48,998	52,569
M&E FTE	**241**	**249**	**265**	**330**	**359**	**370**
Executive FTE	**7**	**7**	**7.7**	**7**	**7**	**7**

COPE	Actual 2006	Actual 2007	Actual 2008	Projection 2009F	Forecast 2010	Forecast 2011
<u>**Total TGI (inlcuding Fort Nelson)**</u>						
Salaries	24,828	24,921	26,531	26,883	29,405	30,622
Step Increases	175	116	147	179	185	191
Incremental Annual Inflation	181	50	596	590	618	676
Short Term Incentive	626	733	761	889	940	1,100
Long Term Incentive	0	0	0	0	0	0
Benefits	3,299	3,430	3,477	3,864	5,259	6,480
Pension	917	-59	-190	-340	754	1,181
OPEB	0	0	0	0	2,358	2,385
Total Compensation	**30,026**	**29,191**	**31,321**	**32,064**	**39,520**	**42,635**
Total TGI O&M Labour 1 includes Salaries, Incentive, Benefits, Pension and OPEB	**22,382**	**21,966**	**23,046**	**24,792**	**29,599**	**32,032**
Total Labour Charged to Capital, Deferrals and Other includes Salaries, Incentive, Benefits, Pension and OPEB 2	**7,644**	**7,225**	**8,276**	**7,272**	**9,921**	**10,603**
FTE	**416**	**419**	**431**	**455**	**474**	**480**

IBEW	Actual **2006**	Actual **2007**	Actual **2008**	Projection **2009F**	Forecast **2010**	Forecast **2011**
<u>Total TGI (inlcuding Fort Nelson)</u>						
Salaries	27,233	26,981	31,143	31,076	31,185	31,996
Incremental Annual Inflation	278	577	712	725	716	718
Step Increases	0	0	0	0	0	0
Short Term Incentive	0	913	920	1,051	1,056	1,053
Long Term Incentive	0	0	0	0	0	0
Benefits	3,378	4,059	4,227	4,710	5,734	6,488
Pension	917	188	-190	-362	851	1,332
OPEB	0	0	0	0	1,853	1,874
Total Compenstion	**31,806**	**32,718**	**36,812**	**37,200**	**41,394**	**43,461**
Total TGI O&M Labour 1 includes Salaries, Incentive, Benefits, Pension and OPEB	**18,559**	**19,926**	**21,201**	**22,301**	**24,870**	**26,559**
Total Labour Charged to Capital, Deferrals and Other includes Salaries, Incentive, Benefits, Pension and OPEB 2	**13,247**	**12,792**	**15,612**	**14,899**	**16,524**	**16,902**
FTE	**398**	**412**	**424**	**458**	**481**	**481**

Notes

1. These amounts are for TGI 3 division and reconcile to the following schedules:
   2006-2008 : reconciles to : Appendix F Page 1
   2009-2011 : reconciles to Part III, Section C, Tab 13, Schedule 28

2. OPEB is included effective 2010

105.0 Reference: Labour – Full Time Equivalents

Business & IT

Exhibit B-1, Part III, Section C, Tab 6, p. 389

Exhibit B-4, BCUC 1.86.2

105.1 Please detail the 8 incremental FTE in 2010 that are in addition to the 5 FTE explained on page 389 of the Application.

Response:

The 5 FTE in 2010 explained on page 389 of the Application were incorrectly categorized as "additional". While these are all new positions, the explanation on page 389 of the application did not explicitly identify one other FTE position that was eliminated due to process improvements so the net impact was four. It also did not explicitly indicate that one of the positions (the IT Technical position) was included in the 2009 year end forecast. This nets to an incremental 3 FTE positions as outlined in Exhibit B-4 BCUC IR 1.86.2.

The additional 10.75 FTEs are detailed below:

- 1 FTE in Operations Engineering to align and integrate our various management systems and programs that we need to meet the requirements of CSA Z662 Clause 10.2.2, Annex N and Annex M (see Appendix F-8: Codes and Regulations Details: page 9.)
- 0.50 FTE in Operations Engineering for an Electrical Engineer to meet increased workload and knowledge transfer related to electrical engineering
- 0.95 FTE related to retirement and knowledge transfer transition in Operations Engineering
- 1 FTE in Operations Engineering is required to file of all compliance related records and to manage the applicable records related processes in order to allow us to demonstrate compliance with Section N.6 of CSA Z662 Annex N (see Appendix F-8: Codes and Regulations Details: page 9.)
- 6.50 FTE in Operations Engineering to process BCOneCall tickets within the 2 day turnaround requirement (see Appendix F-8: Codes and Regulations Details: page 3 - 4.)
- 1 FTE is required in Facilities to meet the operational demands for day-to-day break/fix activities required to maintain the aging facilities.
- 1 FTE is required in Facilities as transitional headcount for two pending retirements

- 1 FTE **reduction** in Operations Support due to the transfer of the position to the Transmission group
- 0.20 FTE **reduction** in Operations Support as a result of changing a full time position to part time

The .75 difference between the above total of 13.75 incremental FTE and the total B&ITS change of 13 FTE shown in Appendix F-2, page 2, entitled "Additional FTE Requirements in 2010 and 2011" is due to rounding.

106.0 Reference: Labour – Full Time Equivalents

Marketing & Business Development

Exhibit B-1, Part III, Section C, Tab 6, p. 377

Exhibit B-4, BCUC 1.86.3

"TGI is not seeking recovery in 2010 or 2011 rates for any project related costs, including any costs related to the build-up of in-house Customer Care capability in preparation to in-source Customer Care operations." (Exhibit B-4, BCUC 1.86.3, p. 13)

"In the shorter term, as reflected in this Application beginning in 2009 and through the 2010/2011 forecast period, the Company will be increasing its efforts to improve the quality of our customer care activities while bridging to an orderly transition for implementation of the new customer care delivery model effective 2012." (Exhibit B-1, Part III, Section C, Tab 6, p. 377)

106.1 There are 5.6 positions added to Customer Care Administration between 2008 and 2011, to manage the CWLP performance and to offer improved services to customers. This appears to be directly related to the under-performance of the out-sourced Customer Care operations. Please explain how this is not related to build-up of in-house Customer Care capability in preparation to in-source Customer Care operations.

Response:

Terasen Gas believes that a higher quality of customer service is required which cannot be achieved through the existing outsourcing arrangement. Regardless of whether the in-sourcing of Customer Care operations is approved, the increase in resources to oversee the existing outsourcing arrangement and the timely resolution of customer complaints and escalations must be addressed.

The more geographically dispersed operating model, as well as the high staff turnover rate experienced by the outsourcer, has also resulted in Terasen Gas needing to increase the degree of audit and oversight related to the outsourced services as well as significantly increasing involvement in initiating and directing changes to support things like new taxes, tax rate changes, Customer Choice business processes, etc.

Should the in-sourcing of Customer Care operations be approved, these resources will likely form part of the new organization in 2012, but the need for them is independent of that Project.

"net new FTE required to meet strategic business objectives, including those approved as part of Commission Order No. G-36-09." (Exhibit B-4, BCUC 1.86.3, p. 247)

106.2 Please provide the specific reference in Order G-36-09 approving the seven EEC FTE positions.

Response:

TGI's reference in the RRA to the approval of seven additional FTE was made in the context that TGI has been able to add staff members as a result of the Order for approved EEC programs. There is no specific reference in Order G-36-09 to approval of seven FTE positions, and the reference should have been "facilitated by the funding approved", rather than "approved".

TGI had indicated in the EEC Application that there was the anticipation that core staff would be increased. The Order approves funding for a specific time period subject to certain conditions, one of which being that the overall program portfolio must maintain a TRC ratio of 1.0 or higher. It is TGI's responsibility to manage the funding appropriately so as to achieve the required TRC ratio. TGI requires sufficient staff to develop, implement and evaluate programs properly in order to ensure that they meet the required TRC levels. Prior to the approval of our EEC Application, TGI had a core staff of four which was supported by staff from other departments within the Company and from outside consultants. Implicit in our increased EEC activity as approved in the Order was the need for TGI to hire staff to develop, implement and evaluate programs. With the increased staffing levels, TGI has taken needed steps to ensure that TGI will be able to deliver EEC programs to our customers as directed by the Order.

107.0 Reference: Labour – Unfilled Vacancies

Exhibit B-4, BCUC 1.87.1

"The vast majority of the vacancies in 2006 and 2007 can be attributed to the IBEW hiring freeze that was imposed pending negotiation of a new collective agreement. … Other than the addition of new positions, vacancies typically occur in response to voluntary and involuntary turnover, which has been averaging 3-5 percent per year. In some cases, contractors, consultants and temporary workers are hired to fill vacant positions on an interim basis." (Exhibit B-4, BCUC 1.87.1, p. 250, par. 2)

107.1 Focussing on the 6 percent vacancies in 2008, what percentage of the 67 FTE positions were filled by contractors, consultants and temporary workers?

Response:

There were 67 FTE positions in 2008 that were not filled. This shortage in resources was offset by hiring contractors and consultants as well as by TGI staff working the equivalent of 54 FTE in overtime. Temporary workers were also utilized but their hours are included in FTE actuals so it is not appropriate to list them as an offset to unfilled vacancies.

2008 unfilled vacancies are listed below by Department complete with an analysis of vacant positions back-filled with contractors and consultants:

	2008 Vacancies	**Filled by Contractors**	**Filled by Consultants**
President	0	0	0
Marketing	9	0	0
Distribution	36	15	0
B&ITS	30	3	5
Gas Supply & Transmission	5	0	0
Human Resources	(16)[1]	0	0
Finance & Regulatory	3	0	0
Total TGI	67	18	5

Of the 67 FTE positions vacant, 23 FTE or 34% was back-filled by contractors and consultants.

[1] These 16 ex-budget positions reflect the hiring of temporary relief clerks in response to requests for temporary help from various departments. Relief clerk costs are paid by the receiving departments, but their headcount is captured in HR. This is also explained in the response to BCUC IR 2.137.1

108.0 Reference: Operations and Maintenance Expenditures

Marketing and Business Development – Government Policy

Exhibit B-4, BCUC 1.93.0

Exhibit B-1, Part III, Section C, tab 6, p. 375

"While some of this information is available online for customers, that information is not sufficiently detailed. … The Forecasting Analysis and Resource Planning department in MKBD has started to provide customers with one-off usage information. … To respond to customer needs for more consumption information and additional forecasting analysis support, MKBD requires $402 thousand in incremental funding in 2010 and an additional $83 thousand in 2011. With the new Customer Information System proposed as part of the CCEP CPCN application, some of the consumption information required may be provided by the new system." (Exhibit B-1, Application, p. 375)

108.1 How much of the consumption information work funded by the $402k in 2010 and $83K in 2011 will be automated as part of the proposed Customer Information system replacement?

Response:

Included in the scope of the CIS project is a requirement to be able to extract and report consumption history. The intent is to build standard extracts that would meet the needs of the majority of customers. Additionally, the project is intending to include much more robust reporting tools to be able to customize special purpose consumption extracts and reports to handle the special needs of our larger institutional customers. Although we cannot confirm that the new CIS will meet all customers' consumption needs, we believe we will have a strong base to be able to handle most requests. Cases requiring more complex requests may require some intervention or development activities. TGI will have the capability to do this in house after the CIS implementation. Thus TGI will see a potion of the consumption work funded by the $402 thousand in 2010 and incremental $83 thousand in 2011 automated as part of the CIS replacement project. Once TGI has received approval for and installed the CIS system it will be in a better position to determine exactly how much of this incremental cost will be reduced.

109.0 Reference: Operations and Maintenence Expense

Exhibit B-4, BCUC 1.94.2.2

Marketing and Business Development

109.1 Please advise whether the employee engaged in EEC activities are the same or separate from the employees who conduct Alternative Energy Service offerings.

Response:

As noted in the response to BCUC IR 1.19.1, the employees involved in Alternative Energy Solutions are primarily Sales, Account Management and Market Development staff. The incremental headcount set out in the table included in the response to BCUC IR 1.94.2.2. under the line description "Sales and Business Development" are those employees who will be involved with Alternative Energy Solutions offerings. The staff involved in EEC activities, shown on a separate line of the same table, while part of the same department as Market Development employees, are separate employees.

109.2 Please describe the specific job duties of the 3 projected incremental individuals related to Government Policy in 2010 and discuss the justification for the increase from 0 to 3 employees.

Response:

The table in BCUC IR 1.94.2.2 only shows the incremental staffing requirements and not the total staff in the Market Development Section of the Customer Solutions and Services group. Therefore the increase is not from 0-3 employees as the increment is three from the full complement of staff in this area. Please see also TGI's response to BCUC IR 2.102.5 for a listing of staff in the Market Development, Forecasting and EEC group. The three additional staff are two Resource Planning Analysts that in part will provide consumption information requests for customers (see also BCUC IR 2.108.1). The other part of their duties will be additional forecasting related work as driven by the changes in government policy. The will be located in the EEC department, but not part of the EEC budget, and will have primary duties such as developing services for customers to help them meet government policy objectives. One identified current project is to develop an on-bill financing option for upgrading gas appliances.

109.3 TGI explains that "EEC costs from April 2009 forward are capitalized not treated as O&M." Please explain the O&M costs related to EEC of $240 thousand, $363 thousand, and $25 thousand in 2009, 2010, and 2011 respectively (figures which are provided in BCUC 1.94.2.2) whereas the related headcount reduces from 7 in 2009 to 0 in 2010 and 2011.

Response:

The response to BCUC IR 1.94.2.2 isolated the costs associated with EEC staff in order to be responsive to the request in BCUC IR 1.94.2.2 to itemize staffing costs for EEC implementation. The costs in the table in BCUC IR 1.94.2.2 are incremental year over year costs for EEC staffing. These are costs that will be deferred and capitalized, as has been noted in the "Offsets" Section of the Table in BCUC IR 1.94.2.2. The related headcount *that is included in O&M* reduces to 0 in 2010 and 2011 because costs associated with that headcount are included in the deferral account and will be capitalized. These amounts have been classified as EEC offsets (deferred) because they are not included in the incremental O&M cost for Customer Service and Sales (which includes EEC) totals. The Company included a projected headcount of seven for the year 2009 because prior to approval of the EEC Application, these costs were included in O&M. None of the EEC staff costs are included in 2010 and 2011 O&M so the headcount in the table in BCUC IR 1.94.2.2 has been reduced accordingly.

110.0 Reference: Customer and Business Facilitation

Exhibit B-4, BCUC 1.97.1

Detailed Customer Information

"TGI canvassed other natural gas utilities to determine if multi-year customer account and usage analysis is provided to customers by the utility and whether this type of service is charged to customers."

110.1 Please provide the amount of customer account and usage information available to TGI's customers (6 months, 1 year).

Response:

Generally, consumption is available for the length of time a customer has received service from TGI at the premises in question from 2002 forward. In other words if a customers has received service at a premise for six, 12, 24 or 48 months, that is the time for which they can access consumption information. Customers typically access this information through Account Online or through the call centre. However, the information they are able to access is rudimentary. The customers can access the following information from Account Online:

- Monthly consumption information for one premise at a time
- Information can be copied into MS Excel

If the customer contacts the call centre they can receive consumption information for one premise at a time. Typically this information is faxed to the customer.

For both Account Online and call centre provided information, the customer is not provided the following:

- Differentiation between actual and estimated readings
- Degree days
- Multiple premise information. No comparison between multiple premises
- Number of days in the billing period
- Large selection range options
- Robust usage analytics. Customers are not provided with multiple usage analytics (such as Crystal Report type analysis) to analyze their consumption.

110.2 Please confirm that TGI is only providing multi-year customer account and usage and not performing analysis of the usage data at the customers' request.

Response:

Confirmed. Note that TGI also has separate EEC programs such as Commercial Audits, available to customers using more than $20,000 in gas per year, that provide not only consumption information as part of the audit, but also analysis of the energy usage in the customer's premise.

111.0 Reference: Operations and Maintenance Expenditures

Exhibit B-4, BCUC 1.97.1 and 1.105.1

"….response from Union Gas confirming that they offer two customer systems – Unionline and MyAccount. Unionline is a system where commercial and industrial have the ability to access historical consumption data … TGI understands that BC Hydro also provides consumption information for free to all customers the cost for which is recovered in rates. … TGI's proposed treatment of these costs to provide these services is reasonable and appropriate due to the fact that all customers need to have ready access to their natural gas consumption history to help them understand their usage, given the provincial focus on using energy efficiently." (Exhibit B-4, BCUC 1.97.1, p, 275)

"...have all caused an increase in demand for consumption information and reporting from the utility and its customers. These additional resources are fully expensed into O&M." (Exhibit B-4, BCUC 1.105.1, p. 290)

111.1 Please confirm the access to historical consumption information provided by the other companies referenced is delivered through their systems and not manually by their staff.

Response:

Not confirmed. For Union Gas historical consumption information is delivered through its customer information system (CIS), however for BC Hydro, TGI understands that this information is provided by both manual staff intervention and by their customer information system technology.

The key point is that customers are seeking information regarding consumption and TGI believes that customers are entitled to receive this service as part of the core TGI service. Once a new customer care solution is functional, TGI will be better able to provide this information to customers. If it is not available or is not a cost effective option, TGI would use a manual process. In either case the customer would have access to information that is core to the service provided for them.

111.2 When TGI has a Customer Information System that will provide customers with access to historical consumption information, will Terasen charge extra for this service?

Response:

No, TGI believes that this is a service that should be provided to all customers and therefore TGI would not charge extra for this service. Rather this service would be paid by all customers through delivery rates.

112.0 Reference: Customer and Business Facilitation

Exhibit B-4, BCUC 1.100.1

July 14, 2009, Open Letter to Union of British Columbia Indian Chiefs Council - Proposed Recognition and Reconciliation Legislation Process-to-Date and Next Steps

http://www.ubcic.bc.ca/News_Releases/UBCICNews07200901.htm

August 25, 2009 Government of British Columbia Speech from the Throne ("Throne Speech"), http://www.leg.bc.ca/39th1st/4-8-39-1.htm

First Nations

"Consequently, on June 25th, the FNLC made a decision to 'set aside' the discussion paper to provide the space and opportunity to carry on an inclusive and cohesive dialogue. The Recognition Working Group ("RWG"), who had been instructed to develop with the Province language that might serve as detailed instructions to legislative drafters, has been directed to stop that work and not engage in any legislative drafting."

http://www.ubcic.bc.ca/News_Releases/UBCICNews07200901.htm

112.1 Please provide the 2010-2011 reductions in TGI's First Nations consultation costs if the Recognition and Reconciliation Act is not enacted.

Response:

There are no reductions in TGI's First Nations consultation costs if the *Recognition and Reconciliation Act* is not enacted. The Government's decision to postpone the introduction of the *Recognition and Reconciliation Act* illustrates the complexity of First Nations issues. As a result, TGI continues to require all the resources we have requested in our application in order to satisfy First Nations concerns and assist the Crown in fulfilling its duty to consult.

112.2 Does the Throne Speech provide an indication of the possible enactment of the Recognition and Reconciliation Act? If so, when?

Response:

The Throne Speech states that "more work must be done before the *Recognition and Reconciliation Act* is introduced to this house. While we develop further understanding, we will continue to press for improvements in other ways." This indicates that the *Act* will not be enacted in the imminent future.

113.0 Reference: Customer and Business Facilitation

Exhibit B-4, BCUC 1.100.1 and BCUC 1.100.2

First Nations

"The Crown has a constitutional duty to consult First Nations. Terasen Gas is not a Crown agent. However, Terasen Gas has a practical need and desire to assist the Crown in discharging its duty to consult First Nations. Consultations undertaken by Terasen Gas assist the Crown in fulfilling its duty to consult." (Exhibit B-4, BCUC 1.100.2)

113.1 Provide an overview of the First Nations potentially affected by TGI proposals to build infrastructure on Crown Lands, including identification of these First Nations and a description of the identification process.

Response:

TGI's current application is for approval of revenue requirements for the purpose of setting delivery rates. It also seeks approval for EEC expenditures. TGI is not seeking approval from the Commission for specific infrastructure proposals or projects, as the question appears to assume. There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the Company, or approving EEC funding, that would trigger the Crown's duty to consult.

The rates approved as a result of this Application will provide the Company with the financial ability to undertake ongoing maintenance and install facilities as part of system extensions. However, a project must first be identified before any First Nations engagement or consultation can occur. The revenue requirement for distribution capital projects such as system extensions are based on forecast and budgeting methodologies that arrive at the expected investment, but are not earmarked for particular projects. The same is true for transmission projects, although TGI is able to describe those projects to a greater extent than distribution projects. In both cases, the approval that is being sought by TGI from the Commission is approval of rates, not project approvals. Prior to taking any steps in respect of a particular project that has been identified, TGI will obtain the relevant provincial and federal permits or approvals. For example, all infrastructure projects on Crown Land require TGI to obtain land tenure prior to construction. Part of this approval process requires the engagement of affected First Nations.

A number of the questions posed in this series of information requests also appear to erroneously assume that TGI has a duty to consult with First Nations. TGI is not a Crown agent, and therefore it does not have a legal duty to consult, as explained in the quoted passage in the preamble. The Commission's review of TGI's First Nations engagement in the context of any regulatory process concerning projects ultimately identified by TGI must recognize this material distinction. TGI's role with respect to First Nations is not the same as BC Hydro's role when it is constructing electric transmission lines, and the focus of the Commission's regulatory inquiry should reflect this difference. TGI's practice, which appropriately reflects the fact that it is a private sector public utility, is to assist the Crown in consulting with First Nations in respect of particular projects that have been identified. The Crown must be satisfied with the level of consultation before granting any provincial or federal permits or approvals necessary for a particular project identified by TGI. TGI's approach to assisting the Crown in consulting with First Nations is set out more fully in the response to BCUC IR 2.113.1.1.

113.1.1 Provide a description of the information and consultation program with affected First Nations, including the names of tribal councils, organizations or individuals consulted and a chronology of the meetings and other contacts communications with these First Nations.

Response:

This is a revenue requirements application for the purpose of setting delivery rates. It also seeks approval for EEC expenditures. TGI is not seeking approval from the Commission for specific infrastructure proposals or projects, as the question appears to assume. There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the Company, or approving EEC funding that would trigger the Crown's duty to consult. Please see the response to BCUC IR 2.113.1.

As TGI identifies particular projects during the RRA period, it will follow its customary approach to identify potentially affected First Nations and engage those First Nations as required as part of assisting the Crown in consulting with First Nations. It is premature to undertake that process until the specific projects have been identified.

TGI's approach to First Nations engagement in respect of projects that it has identified is outlined below.

TGI builds and strengthens relationships with First Nations which are within its service territory on a regular, ongoing basis. When TGI is considering specific projects, it will begin by identifying the First Nations that may be potentially impacted, then will review the Statements of Intent for First Nations in the area that are involved in the treaty process, as well as the reserve information for First Nations in the area, and other readily available ethnographic information. When studies are required to assess archaeological, land use, environmental, or social aspects of First Nations interests, TGI works cooperatively with First Nations to determine what studies are required and who will be engaged to conduct them. The goal is to have potential impacts of a project studied to the satisfaction of both parties. TGI will also seek guidance from the Crown entity that must approve the activities related to its proposed project, such as the Integrated Land Management Bureau, to ensure it has identified all of the potentially impacted First Nations.

TGI's practice is to contact potentially impacted First Nations early in the life of a proposed project. As part of the early contact, TGI will provide written information regarding the proposal and provide opportunities to meet with the First Nations and answer any questions relating to the project. TGI then seeks input from the First Nations such as concerns or clarification relating to the proposed project, including the potential effects on physical, biological and social environments, and aboriginal rights and title or treaty rights. TGI will consider these concerns and where appropriate it will make adjustments to mitigate the effects of the proposed project.

TGI's practice is to try to reach agreements with First Nations that may be significantly impacted by a project, or otherwise accommodate impacts. These agreements have taken many forms, for example, Impact and Benefit Agreements and Memorandums of Understanding.

TGI ensures the Crown is either involved or aware of our progress, to ensure it is aware what steps it has taken to assist in fulfilling the Crown's duty to consult. The assessment of the scope of consultation necessary to maintain the honour of the Crown must be done by the Crown. Although TGI may receive information from First Nations regarding this determination, which it would provide to the Crown, it must defer to the Crown's assessment at the time it is considering approving activities with the potential to impact aboriginal rights or title, or treaty rights.

This process involves a considerable amount of time and resources. However, in order to ensure TGI is able to fulfill its obligations to its customers, it is necessary to assist the Crown to fulfill its duty to consult. It is common for the Crown to rely on consultation undertaken by private sector industry project proponents, of which it has been apprised. Although private sector industry does not have a legal duty to consult, its participation in the consultation process ensures a better outcome for all parties, and allows TGI to build upon its existing strong relationships with First Nations. TGI takes its role in consultations very seriously and always approaches consultations in good faith and with a view to ensuring the proposed project is understood, and potential adverse impacts are minimized. This is ultimately in the best interests of customers, who benefit from the cost effective implementation of projects directed at providing safe, reliable, and efficient service.

TGI's approach to obtaining First Nations consent is to develop ongoing mutually beneficial relationships with the First Nations whose traditional territory has, or could be impacted with natural gas infrastructure. With these relationships developed, new infrastructure project approvals can be obtained from First Nations from time to time more easily, providing benefit to both the First Nation and TGI, and also creating the most cost-effective long term solution for TGI's customers. The alternative would be to rely on the Crown to resolve issues directly with affected First Nations, however this would create unacceptable cost and scheduling uncertainties for TGI.

While the duty to consult with First Nations resides with the Crown, TGI's relationships with First Nations provide the opportunity to communicate with, and engage First Nations in the identification, assessment and mitigation of the impact of TGI's proposed infrastructure on aboriginal rights on their traditional lands. As part of the Crown's approval process to grant land tenure for TGI's infrastructure projects, TGI provides the Crown with detailed progress reporting.

With respect to our general approach to assisting the Crown in discharging its duty to consult, Terasen Gas strongly believes that this approach is both reasonable and appropriate and we carry it out in good faith. Therefore, as set out in our application, we request the Commission to approve the additional resources that we believe is necessary to continue to carry out this approach reasonably and appropriately.

113.1.2 Provide an overview of the ethnographic placement of each of the First Nations.

Response:

TGI is not proposing to build infrastructure. This is a revenue requirements application for the purposes of setting delivery rates. It also seeks approval for an EEC expenditure schedule. There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the Company, or approving EEC funding that would trigger the Crown's duty to consult. Please see the response to BCUC IR 2.113.1.

113.1.3 Identify any group or body that has been representing the First Nation for consultation purposes.

Response:

TGI is not proposing to build infrastructure. This is a revenue requirements application for the purposes of setting delivery rates. It also seeks approval for EEC expenditures. There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the Company, or approving EEC funding that would trigger the Crown's duty to consult. Please see the response to BCUC IR 2.113.1.

113.1.4 Provide copies of notices to affected First Nations advising that TGI proposes to build infrastructure on Crown Lands. Include notices to First Nation indicating how they can raise any concerns related to the construction of infrastructure on Crown Lands.

Response:

TGI is not proposing to build infrastructure. This is a revenue requirements application for the purposes of setting delivery rates. It also seeks approval for EEC expenditures. There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the Company, or approving EEC funding that would trigger the Crown's duty to consult. Please see the response to BCUC IR 2.113.1.

113.1.5 Provide a description of the issues and concerns raised by affected First Nations during consultations.

Response:

TGI is not proposing to build infrastructure. This is a revenue requirements application for the purposes of setting delivery rates. It also seeks approval for EEC expenditures. There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the Company, or approving EEC funding that would trigger the Crown's duty to consult. Please see the response to BCUC IR 2.113.1.

113.1.6 Provide a description of the measures taken or that will be taken to address the issues or concerns raised by affected First Nations and provide an explanation as to why no further action is required to address those issues or concerns.

Response:

TGI is not proposing to build infrastructure. This is a revenue requirements application for the purposes of setting delivery rates. It also seeks approval for EEC expenditures. There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the

Company, or approving EEC funding that would trigger the Crown's duty to consult. Please see the response to BCUC IR 2.113.1.

113.1.7 Provide copies of any agreements or other documents confirming that an affected First Nation is satisfied with consultations and the measures taken or proposed to address the issues related to the project were raised during consultations.

Response:

TGI is not proposing to build infrastructure. This is a revenue requirements application for the purposes of setting delivery rates. It also seeks approval for EEC expenditures. There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the Company, or approving EEC funding that would trigger the Crown's duty to consult. Please see the response to BCUC IR 2.113.1.

113.1.8 Provide a summary of the reasonableness of the First Nations consultation process with respect to TGI proposals to build infrastructure on Crown Lands. Identification and preliminary assessment of potential effects of the project on the physical, biological and social environments or on First Nations and the public, proposals for reducing potentially negative effects and maximizing benefits from positive effects, and the cost to the project of implementing the proposals.

Response:

TGI is not proposing to build infrastructure. This is a revenue requirements application for the purposes of setting delivery rates. It also seeks approval for EEC expenditures. There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the Company, or approving EEC funding that would trigger the Crown's duty to consult. Please see the response to BCUC IR 2.113.1.

113.2 Please provide an assessment of the scope of TGI's duty to consult.

Response:

Terasen Gas does not have a duty to consult. Please see the response to BCUC IR 2.113.1.

113.2.1 Identify the Aboriginal rights, within the meaning of section 35 of the Constitution Act , 1982 that each potentially affected First Nation has asserted in relation to the TGI proposal to build infrastructure on Crown Lands (e.g., the Aboriginal right to harvest wood for domestic purposes within the traditional territory of the First Nation or the right to fish for food, social and ceremonial purposes within the rivers traditionally used by the First Nation for those purposes; or Aboriginal title over the claimed traditional territory).

Response:

TGI is not proposing to build infrastructure. This is a revenue requirements application for the purposes of setting delivery rates. It also seeks approval for EEC expenditures. There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the Company, or approving EEC funding that would trigger the Crown's duty to consult. Please see the response to BCUC IR 2.113.1.

113.3 Identify any judicially recognized Aboriginal rights, rights that the Province of British Columbia has recognized or treaty rights that may be potentially affected by TGI's proposals to build infrastructure on Crown Lands.

Response:

TGI is not proposing to build infrastructure. This is a revenue requirements application for the purposes of setting delivery rates. TGI also seeks approval for an EEC expenditure schedule. There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the Company, or approving EEC funding that would trigger the Crown's duty to consult. Please see the response to BCUC IR 2.113.1.

TGI knows the following treaties exist in British Columbia: Douglas Treaty on parts of Vancouver Island; Maa-nulth Treaty on the West Coast of Vancouver near Tofino; Tsawwassen Treaty in southern Lower Mainland; Treaty 8 in north-eastern British Columbia; and, Nisga'a Treaty in north-western British Columbia. Among these treaties, only the Tsawwassen Treaty and Treaty

8 areas overlap with the TGI service area. For clarity, TGI is not saying that any of its future proposals will potentially impact treaty rights under these treaties, but recognizes that certain First Nations hold treaty rights in certain areas of British Columbia.

Only the Province of British Columbia can inform the Commission of the rights that it has recognized.

There are several instances in British Columbia where aboriginal rights have been judicially recognized. Many of these cases occur at the Provincial Court level as a result of hunting, fishing or other regulatory charges, and are therefore difficult to ascertain. In each instance of a proposed project, TGI endeavours to determine if proven aboriginal rights are exercised in the area of the project. Furthermore, the duty to consult arises when asserted aboriginal rights or title may be impacted, which is why TGI follows the approach that it has set out in the response to BCUC IR 2.113.1. The costs associated with identifying information regarding First Nations are outlined in the Application at page 379.

113.4 Identify the prima facie strength of the asserted or assumed Aboriginal rights. Discuss the potential of TGI's proposals to build infrastructure on Crown Lands to adversely affect the asserted or assumed Aboriginal rights.

Response:

TGI is not proposing to build infrastructure. This is a revenue requirements application for the purposes of setting delivery rates. It also seeks approval for an EEC expenditure schedule. There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the Company, or approving EEC funding that would trigger the Crown's duty to consult. Please see the response to BCUC IR 2.113.1.

113.5 Assess where the approval(s) being sought falls on the Haida spectrum. Indicate whether any advice was sought from another Crown agency with respect to making an assessment of the strength of a First Nation's claim.

Response:

TGI is not proposing to build infrastructure. This is a revenue requirements application for the purposes of setting delivery rates. It also seeks approval for an EEC expenditure schedule. There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the Company, or approving EEC funding that would trigger the Crown's duty to consult as defined by the Haida case. Please see the response to BCUC IR 2.113.1.

113.6 Indicate whether funding was provided to potentially affected First Nations and the purpose of the funding.

Response:

TGI is not proposing to build infrastructure. This is a revenue requirements application for the purposes of setting delivery rates. TGI also seeks approval of an EEC expenditure schedule. There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the Company, or approving EEC funding, that would trigger the Crown's duty to consult. Please see the response to BCUC IR 2.113.1.1 for general information on TGI's consultation policy and approach to assist the Crown in discharging its duty to consult.

113.7 Indicate whether Crown agencies have consulted First Nations in respect of TGI's proposals to build infrastructure on Crown Lands, and if applicable, the issues raised by First Nations in these consultations and how these issues were addressed.

Response:

TGI is not proposing to build infrastructure. This is a revenue requirements application for the purposes of setting delivery rates. TGI also seeks approval of an EEC expenditure schedule. There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the Company, or approving EEC funding that would trigger the Crown's duty to consult. Please refer to the response to BCUC IR 2.113.1.

113.8 Describe how potential effects on asserted or assumed Aboriginal rights were accommodated.

Response:

TGI is not proposing to build infrastructure. This is a revenue requirements application for the purposes of setting delivery rates. TGI also seeks approval of an EEC expenditure schedule.

There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the Company, or approving EEC funding that would trigger the Crown's duty to consult. Please refer to the response to BCUC IR 2.113.1.

113.9 Provide copies of any documents which confirm that an affected First Nation is satisfied with the consultation and accommodation of its rights or interests.

Response:

TGI is not proposing to build infrastructure. This is a revenue requirements application for the purposes of setting delivery rates. TGI also seeks approval of an EEC expenditure schedule. There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the Company, or approving EEC funding that would trigger the Crown's duty to consult. Please refer to the response to BCUC IR 2.113.1.

113.10 Provide evidence that First Nations have been notified of the filing or the filing with the BCUC related to TGI's proposals to build infrastructure on Crown Lands, including how they can raise outstanding concerns with the BCUC before the BCUC makes its decision on the application or filing.

Response:

TGI is not proposing to build infrastructure. This is a revenue requirements application for the purposes of setting delivery rates. It also seeks approval for an EEC expenditure schedule. There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the Company, or approving EEC funding that would trigger the Crown's duty to consult. Please see the response to BCUC IR 2.113.1.

TGI has provided notice to the public generally by means of the publication of notice of this proceeding as required by the Commission's procedural order.

113.11 Provide overall conclusion as to the reasonableness of the consultation process with respect to the application or filing regarding TGI's proposals to build infrastructure on Crown Lands and whether the consultation duty has been discharged. To reach a conclusion, consider the following questions along with evidence to support the response:

Response:

TGI is not proposing to build infrastructure. This is a revenue requirements application for the purposes of setting delivery rates. It also seeks approval for an EEC expenditure schedule. There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the Company, or approving EEC funding that would trigger the Crown's duty to consult. Please see the response to to BCUC IR 2.113.1.

With respect to our general approach to assisting the Crown in discharging its duty to consult, Terasen Gas strongly believes that this approach is both reasonable and appropriate and we carry it out in good faith. Therefore, as set out in our application, we request the Commission to approve the additional resources that we believe is necessary to continue to carry out this approach reasonably and appropriately.

113.11.1 Has the consultation process been carried out in good faith, and was it appropriate and reasonable in the circumstances?

Response:

TGI is not proposing to build infrastructure. This is a revenue requirements application for the purposes of setting delivery rates. It also seeks approval for an EEC expenditure schedule. There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the Company, or approving EEC funding that would trigger the Crown's duty to consult. Please see the response to BCUC IR 2.113.1.

113.11.2 Is final approval being sought on the application or filing from the BCUC?

Response:

TGI is not proposing to build infrastructure. This is a revenue requirements application for the purposes of setting delivery rates. It also seeks approval for an EEC expenditure schedule. There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the Company, or approving EEC funding that would trigger the Crown's duty to consult. Please see the response to BCUC IR 2.113.1.

113.11.3 Are further approvals in respect of the application or filing required from the BCUC?

Response:

TGI is not proposing to build infrastructure. This is a revenue requirements application for the purposes of setting delivery rates. It also seeks approval for an EEC expenditure schedule. There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the Company, or approving EEC funding that would trigger the Crown's duty to consult. Please see the response to BCUC IR 2.113.1.

113.11.4 Have approvals been obtained from provincial and federal agencies? If so, identify any issues raised by First Nations during consultations related to these approvals.

Response:

TGI is not proposing to build infrastructure. This is a revenue requirements application for the purposes of setting delivery rates. It also seeks approval for an EEC expenditure schedule. There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the Company, or approving EEC funding that would trigger the Crown's duty to consult. Please see the response to BCUC IR 2.113.1.

113.11.5 Are there further provincial government and federal government approvals required where there would be opportunities for further Crown-First Nation engagement?

Response:

TGI is not proposing to build infrastructure. This is a revenue requirements application for the purposes of setting delivery rates. It also seeks approval for an EEC expenditure schedule.

There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the Company, or approving EEC funding that would trigger the Crown's duty to consult. Please see the response to BCUC IR 2.113.1.

113.11.6 Where there are unmitigated potential effects on asserted or assumed Aboriginal rights, what is the broader societal value of the project? This responds to the Supreme Court's observation in Haida (para. 50) that "where accommodation is required in making decisions that may adversely affect as yet unproven Aboriginal rights and title claims, the Crown must balance Aboriginal concerns reasonably with the potential impact of the decisions on the asserted right or title and with other societal interests."

Response:

TGI is not proposing to build infrastructure. This is a revenue requirements application for the purposes of setting delivery rates. It also seeks approval for an EEC expenditure schedule. There is no potential for adverse impacts on aboriginal rights and title associated with setting rates for the Company, or approving EEC funding that would trigger the Crown's duty to consult. Please see the response to BCUC IR 2.113.1.

114.0 Reference: Operations and Maintenance Expenditures

Exhibit B-4, BCUC 1.115.1

Outsourcing – Declining performance by AUBPOS/CWLP

"Terasen Gas has existing internal staff that can be recruited into these new roles that would bring a significant base of gas industry and company process knowledge into the area." (Exhibit B-4, BCUC 1.115.1, p. 321)

114.1 What are the current roles of the staff that would be recruited for the Customer Care roles?

Response:

These new roles will be offered internally through an application process. The targeted skill set for these new roles will include excellent communications skills, experience in working directly with customers, and a deep understanding of the gas utility business including the business processes included in the meter to cash life cycle. Terasen Gas is expecting applicants to come from those areas of the company that have current direct relationships with customers including marketing, distribution operations and the service installation centre. The previous positions held by any successful internal applicants will be backfilled by appropriately skilled external candidates.

114.2 How many FTE are expected to be internally recruited and how difficult will it be to recruit externally to replace them in their existing positions?

Response:

The specific number of internal hires has not been determined at this time.

The Company will first look internally to replace any FTEs recruited from our existing employee base who have, or are developing the required industry and Company knowledge. The Company does not anticipate difficulties in hiring externally to replace any of the resulting position vacancies. The Company receives strong interest as an employer and our on-going commitment to employee development will enable us to successfully attract and retain resources. In the event the Company hires externally to fill resulting vacancies, the Company does not anticipate difficulties, as we can help those employees develop specific company or industry knowledge.

115.0 Reference: Operations and Maintenance Expenditures – Codes and Regulations

Exhibit B-4, BCUC 1.118.1

Appendix F-8

115.1 Since cost increases related to the external inflation cost driver amounts to only 0.1 percent, what is the percentage of the other 3 cost drivers as listed on page 1 of Appendix F-8?

Response:

To ensure ongoing compliance to existing codes and anticipated new or changed codes, additional operating and maintenance funding is required. Outside of inflationary needs, there are 3 main drivers to the annual year over year increases (refer to Appendix F-8 of the Application). New or changed code requirements is the largest cost driver, followed by asset age and growth.

A summary of the proportionate percentages of the proposed annual increases for the 3 cost drivers noted above is shown below.

Cost Driver	2010	2011
New or Changed Codes	73%	37%
Asset Age	16%	53%
Growth	11%	10%

116.0 Reference: Codes and Regulations

CSA Z662 for Oil and Gas Pipeline Systems

Exhibit B-4, BCUC 1.125.0 and 1.126.0

"…is not possible to isolate the total funding required to meet the ongoing requirements of CSA Z662. For 2010 and 2011, Terasen Gas has identified Incremental funding that is attributable to CSA Z662." (Exhibit B-4, BCUC 1.126.1, p. 343)

The response to BCUC 1.125.0 discusses various CSA Z662 related work programs over the 2006 to 2009 period.

"The incremental funding required in 2010 and 2011 to ensure continued compliance with CSA Z662 is $4,406,000 and $2,002,000 respectively. A detailed explanation for these expenditures can be found in Appendix F-8 of the Application." (Exhibit B-4, BCUC 1.126.2, p.344)

The detail provided in B-1, Appendix F-8 lists over 50 line items with individual precision to the nearest $1,000.

116.1 As it appears the Terasen budget process can provide better detail than the financial reporting process, please provide the budget detail for the 2006 through 2009 years for the CSA Z662 related programs including those described in the response to BCUC 1.125.0.

Response:

In the period of 2006 to 2009, Terasen Gas incurred costs of $518,000 to develop its Integrity Management Plan (IMP) and plan for its implementation. Work continues in 2009 to address audit findings and to complete activities that require additional work. Terasen Gas is working within the permitted OCG timeline to implement measures to bring the company into full compliance with the requirements of CSA Z662 Annexes M and N. During this 2006 to 2009 period and indeed prior to that time, TGI did not isolate CSA Z662 cost drivers in its budget detail (with the above noted exception), but instead treated CSA Z662 as one of many inputs to be considered when creating and operating our various business processes.

The Integrity Management Program requires a more comprehensive and formalized demonstration of compliance to codes (including CSA Z662). This recent change has resulted in more granular budget detail as it relates to codes.

117.0 Reference: Operations and Maintenance Expenditures

Exhibit B-4, BCUC 1.124, p.339

Code and Regulation Odorant

117.1 Can the purchases of odorant be combined with orders for this material from other utilities to reduce the cost?

Response:

Our purchase of odorant cannot be combined with orders of this material from other utilities to reduce cost because we already purchase odorant in bulk and of sufficient quantity to manage costs down.

118.0 Reference: Codes and Regulations

CSA Z662 – Marketing

Exhibit B-4, BCUC 127.0

Terasen's actual and projected spending on Public Safety Awareness averaged $304,250 per year, with 2009 being less than 2006 and 2008. (Exhibit B-4, BCUC 1.127.1, p. 345)

"Since the last settlement Terasen Gas has undertaken a mass media campaign … and in the first year of the program was able to go from zero awareness to approximately 80 per cent, several months later. The program is now being sustained at a lower level of media..." (Exhibit B-4, BCUC 1.127.2, pp. 347-8)

"We believe as a prudent operator we should explore an incremental step which would be to increase the frequency of our current media plan which relies primarily on radio." (Exhibit B-4, BCUC 1.127.2, p. 348, par. 1)

118.1 Based on the success of the example referenced, why would the Public Safety Awareness budget need to be increased to $1 million (three times the average annual expenditure) for both 2010 and 2011?

Response:

The example cited regarding 0 to 80 per cent was for the Customer Choice program (residential unbundling), not public safety awareness. What it demonstrated was that the right message combined with the right media choice can have significant results. Approximately $5 million were allotted to Customer Choice communications in the first year as part of its implementation. The same is not true of our current state public safety awareness communication funding.

As part of TGI's review of its compliance to the new CSA Z662 requirement for a Safety and Loss Management Plan, we determined that Public Safety Communications needed to be strengthened. The table presented in BCUC 1.127.1 outlines key stakeholders and some of the reasons why we would communicate with them.

Effectively meeting the communication needs identified in this table would require a budget significantly greater than what was requested in this RRA. Therefore, we are implementing a risk-based approach to public safety awareness which has identified that for 2010 public education through radio communications is the top priority.

On an annual basis, TGI will review past performance metrics, prepare target levels, determine appropriate messaging and communications vehicles and develop a public safety awareness plan for the forthcoming year. During the year, the plan would be reviewed against ongoing performance and funding would be shifted to appropriate areas as required.

119.0 Reference: Metering

Exhibit B-4, BCUC 1.134, p. 361

Meter Life Extension

119.1 Compare the average age of TGI's residential meter fleet to that of TGVI, Union Gas, Gaz Metropolitan, Enbridge Gas Distribution, ATCO and Sask Energy and comment on the reasons for any notable differences.

Response:

The average age of the TGI residential meter fleet is 10.8 years compared to the average age of the TGVI residential meter fleet which is 10.3 years. In the preparation of its response to TGVI BCUC- IR 1.121.1, which is associated with the TGVI RRA/RDA, TGI contacted the referenced utilities and asked for the specified information. Unfortunately, to date, Terasen Gas has not received information specific to the average age of the residential meter fleet from any of the utilities referenced, nor does it anticipate that it will receive this information.

From a historical perspective, information shared amongst the gas utilities represented on the CGA Measurement Committee has been provided through discussions which are not formally transcribed. However, these discussions between CGA Measurement Committee members have provided assurance to Terasen Gas that its proactive approach to managing its (and TGVI's) meter fleet is aligned with the best practices identified with the Canadian industry.

119.2 Why was the decision to "operate residential meters to the full life expectancy of 20 years" made only for the period 2006 to 2008?

Response:

The average life expectancy of 20 years for residential meters was not applied for a closed period of three years but instead remains the ongoing target for long term planning by Terasen Gas. In 2006, a decision was made to operate residential meters to a life expectancy of 20 years. The temporary reduction of meter recalls served to bring the demographics of the meter fleet in line with a 20 year life expectancy and resulted in significant Capital and O&M savings (see the response to BCUC IR 2.119.3).

The 20 year life span relates to the Terasen Utilities' experience in average meter life expectancy determined through a statistical sampling monitoring process and validated through discussions with vendors and employees of utilities represented on the Canadian Gas Association Measurement Committee. As such, the data used to determine this target life expectancy was gathered over multiple years to establish trends in residential meter performance which has allowed Terasen Gas to forecast the long term performance of meters currently deployed within its residential meter fleet. Similarly, it is expected that any future adjustment to the targeted average life expectancy for the residential meter fleet will only be done after extensive study of trends in meter performance over an extended period, combined with ongoing discussions with other participants in the gas measurement industry.

"Finally, by temporarily reducing the number of meter recalls during this period, both customers and shareholders were allowed to benefit from the savings in O&M and capital expenditure."

119.3 What are the total savings to customers resulting from the reduction and subsequent increase in O&M and capital expenditures over the period 2006 through 2011?

Response:

For clarity, the reduction was not a deferral. In 2006, a decision was made to operate residential meters to a life expectancy of 20 years. The temporary reduction of 62,203 meter recalls served to bring the demographics of the meter fleet in line with a 20 year life expectancy and resulted in significant Capital and O&M savings as compared to the original policy. There is no subsequent increase in activity or cost in 2010 or 2011 that can be attributed to the temporary reduction in meter exchange activity.

See table below for detailed quantities:

	2006	2007	2008	2009	Cummulative
Meter recalls planned prior to "20 Year" policy change	49,634	49,806	50,647	50,954	201,041
Actual Meter Recalls	28,446	30,417	33,275	*46,700	138,838
Difference in meter recalls	21,188	19,389	17,372	4,254	62,203

* "***Actual Meter Recalls***" are projected for 2009.

Cumulative O&M savings of $1.6 million, of which the customers share was approximately $800 thousand (50%), were as a result of 62,203 fewer customers appointments required for field exchange activity and 21,118 fewer meters recalled for repair. See table below:

	Reduced Activity 2006 - 2009	Unit Cost	O&M Savings 2006 - 2009
Customer appointments	62,203	$ 5.50	$ 342,117
Meters recalled for repair	21,188	$ 59	$ 1,250,092
		Total O&M Savings	$ 1,592,209

Cumulative capital savings of $17.4 million were as a result of 41,015 fewer meters recalled for retirement and replacement. See table below:

	2006	2007	2008	2009	Cummulative
***Capital Cost Projection prior to "20-year" policy change ($millions)**	15.2	15.7	16.2	16.8	63.9
****Actual Capital Costs ($millions)**	11.9	10.3	11.8	***12.5	46.5
Difference ($millions)	3.3	5.4	4.4	4.3	17.4

* "***Capital Cost Projection prior to 20-year policy change***" from 2004 Annual Review for 2005 Revenue Requirements Tab B-1, page 5 Other Regular Capital, "Meters-Replacement"

** "***Actual Capital Costs***" from Part III Section B page 188 of the Application, "Meters - Exchange/Other"

*** Actual Capital Costs for 2009 are projected

Please note that the savings as described in the above tables were determined based on the difference between the original policy and the revised policy, and not based on a calculation of the sharing of actual vs. formula based O&M and capital amounts over the years 2006 to 2009.

120.0 Reference: Metering

Exhibit B-4, BCUC 1.135.2, p. 363

Meter Quality Recall

120.1 Please comment on whether TGI's practice of proactively removing meters from service before they must be removed because an associated sample of meters have failed the Measurement Canada accuracy test is also done to the same extent at Union Gas, Gaz Metropolitan, Enbridge Gas Distribution, ATCO and Sask Energy.

Response:

In the preparation of its response to this information request, TGI contacted the referenced utilities and asked for the specified information in a form suitable for the public record. Three of the utilities provided a response to this request. All of the responses indicated the practice of proactively removing meters from service prior to failure was followed as part of their meter fleet management program. Unfortunately, Terasen Gas has not received the information required to determine the degree to which each utility applies this practice nor does it expect to receive this information.

From a historical perspective, information shared amongst the gas utilities represented on the CGA Measurement Committee has been provided through discussions which are not formally transcribed and offered for public consumption. However, these discussions between CGA Measurement Committee members have provided assurance to Terasen Gas that its proactive approach to managing its (and TGVI's) meter fleet is aligned with the best practices identified with the Canadian industry.

121.0 Reference: Taxes

Exhibit B-4, BCUC 1.143.1

BC Social Services Tax ("PST"), Motor Fuel Tax ("MFT") and Innovative Clean Energy ("ICE ") levy

121.1 Please provide the information required below using the following table.

Year	Total O&M + Capital Expenditures	Total PST (Actual)	PST as a % of Total O&M + Capital Expenditures
2005			
2006			
2007	252,000,000	3,100,100	1.23%
2008	275,000,000	3,600,000	1.31%

Response:

The table has been revised below to include 2005 and 2006, and to make the following revisions to the 2007 and 2008 amounts previously reported.

2007 and 2008 O&M and capital expenditures have been revised to include Fort Nelson division O&M and capital expenditures. This is because the actual PST amounts reported by the TGI information system include Fort Nelson PST, which cannot be extracted from the totals.

In addition, 2007 and 2008 Total PST (Actual) has been revised to correct an error in the amounts previously reported. In a report tabulating PST paid in these years, debits and credits were added together as absolute numbers, therefore the PST totals were slightly overstated.

Year	Total O&M + Capital Expenditures	Total PST (Actual)	PST as a % of Total O&M + Capital Expenditures
2005	$250,000,000	$3,600,000	1.44%
2006	$266,000,000	$2,700,000	1.02%
2007	$253,000,000	$2,900,000	1.15%
2008	$277,000,000	$3,300,000	1.19%

122.0 Reference: Taxes
Exhibit B-4, BCUC 1.147.1
Tax Benefits Relating to Prior Periods

"The Company confirms that the $8.2 million balance is captured in the ESM calculation, but does not confirm that 100% percent of the benefit should go to the ratepayer. This adjustment does not meet the criteria for deferral as set out in Appendix A to Order No. G-51-03 (page 12), which proposes a deferral account to record variances in income tax rates, LCT rates, and new government tax expenses, charges and levies. Under the PBR agreement, sharing a variance that relates to a prior period by way of the Earnings Sharing Mechanism is the appropriate way to deal with a difference that does not meet the criteria for deferral."

122.1 If the $11 million deduction had not been considered an uncertain tax position in 2001 and 2002 would the ratepayer have benefited in 100 percent of the tax benefit realized by TGI at that time?

Response:

Please see the response to BCUC IR 2.19.1.

122.2 Given that the ratepayer would have benefited 100 percent from the $11 million tax deduction in 2001 and 2002 had they not been considered uncertain tax positions why is the ratepayer not entitled to 100 percent of the savings in 2009 when the Company expense the remaining deferred UCC balance of $8.2 million after the CRA audit was completed?

Response:

Please see the response to BCUC IR 2.19.1.

122.3 Terasen has stated that the $8.2 million adjustment does not meet the criteria for deferral and is therefore a prior period adjustment. Please confirm that the $11 million was recognized as an increase in the regulatory UCC balance in 2001 and 2002 and its full impact on rates was deferred until 2009 after the CRA audit was completed.

Response:

Please see the response to BCUC IR 2.19.1.

123.0 Reference: Taxes

Exhibit B-4, BCUC 1.148.1

Changes to CCA Rates

"The Company confirms that the $2.9 million CCA adjustment is captured in the ESM calculation but does not confirm that 100 percent of the benefit should go to the ratepayer.

The CCA rate changes do not meet the criteria for deferral as set out in Appendix A to Order No. G-51-03 (page 12), which proposed a deferral account to record variances in income tax rates, LCT rates, and new government tax expenses, charges and levies.

Under the PBR agreement, sharing a variance that relates to a prior period by way of the Earnings Sharing Mechanism is the appropriate way to deal with a difference that does not meet the criteria for deferral."

123.1 Were the changes to enhance the CCA rates in 2007 and 2008 a result of a change in tax legislation?

Response:

In the RRA, TGI proposes to share differences in tax deductions relating to CCA rate changes which were announced in 2007 but not passed into regulation until 2009. The impact of the changes is an additional tax deduction of $2.9 million for the years 2007 and 2008 combined.

Sharing vs. Tax Deferral

In accordance with the PBR Agreement during the PBR Period, the Company has determined that it is appropriate to share these savings with ratepayers as opposed to capturing the changes in the tax deferral account.

The tax deferral account was established to capture changes in income tax rates and new taxes, which can be positive as well as negative and are not within the Company's control. In particular, changes to income tax rates occur fairly frequently. A change in income tax rates meets the criteria for deferral as set out in Appendix A to Order No. G-51-03, which reads as follows:

> *"Page C13 proposes a deferral account to record variances in property taxes, income tax rates, LCT rates, and any new government tax expenses, charges and levies. Amortization over three years as a flowthrough item. At the Annual Review a forecast of income tax and LCT rates and other tax expenses for the following year will be provided and customers' rates for that following year will be determined on the basis of that forecast."*

Changes in CCA rates are neither changes in "income tax rates" nor new "government tax expenses, charges and levies" therefore do not meet the criteria for deferral specified in the

PBR Agreement. The term "income tax rate" refers to the federal and provincial tax rate that is applied to corporate taxable income to determine taxes payable. On the other hand, CCA rates represent a rate of tax depreciation applied to asset classes.

There are many factors involved in calculating taxes, most of which are not captured by the tax deferral account. For example, each item of taxable revenue and deductible expense will vary between the forecast amounts used for rate setting purposes and the actual amounts. The CCA deduction can vary due to differences in fixed asset additions, differences in classification of assets, and differences in CCA rates. These variances can be positive or negative, and the Company bears a portion of the risk on them.

Past CCA rate changes have generally not had a material impact on income tax expense, and although all the CCA rate changes under discussion were <u>enhancements</u> in the CCA rates, one recent CCA change applicable to pipeline transmission companies provided for a reduction in a CCA rate rather than an enhancement. The long delay between announcement and promulgation of the CCA rate changes in this particular case is also unusual and contributed to the materiality of the change in the CCA amount.

For these reasons, the Company is of the view that the CCA rate changes during the PBR Period are not captured by the tax deferral account as contemplated in the PBR Agreement and are appropriately captured in the achieved return on equity and as such subject to earnings sharing.

Ratepayer Benefit Calculated at 2009 Income Tax Rate

TGI has filed its 2007 and 2008 tax returns to reflect the new CCA rates, resulting in additional CCA of approx. $700 thousand for 2007 and $2.2 million for 2008. The Company has therefore realized the benefits at the higher tax rates in effect in those years. The Company confirms that the tax benefit received by TGI is approximately $239,000 for 2007 and $682,000 for 2008 (total of $921,000). As proposed in the RRA, customers will receive tax benefits totalling $870,000 (see table below). Had these changes been certain at the time of filing the 2007 and 2008 Annual Reports, the ratepayer would have realized an additional $25,400 benefit (50% of $50,840) as a result of the tax benefits being calculated using the higher 2007 and 2008 corporate tax rates rather than the 2009 rates.

The Company believes there should be a distinction between variances that occur in respect of a current year (for example 2009), and variances applicable to prior years which were <u>not known or not certain</u> at the time of making prior year filings.

The Company believes that it is reasonable to return these items, which represent a type of prior period adjustment, at the time the benefit is certain and available to be returned to customers. Under the PBR arrangement, such variances are taken into account for ESM purposes; there is no specific mechanism or process to deal with adjustments relating to prior years, therefore the Company has treated the adjustments consistently with other 2009 variances.

	CCA (1)	Federal Tax Rate	Provincial Tax Rate	Surtax	Combined Rate	Tax Benefit
Tax Benefit at 2007 and 2008 Tax Rates						
2007	$ 700,000	21.00%	12.00%	1.12%	34.12%	$ 238,840
2008	$ 2,200,000	19.50%	11.50%	0.00%	31.00%	$ 682,000
						$ 920,840
TGI Proposed Ratepayer Tax Benefit at 2009 Tax Rates						
2009	$ 2,900,000	19.00%	11.00%	0.00%	30.00%	$ 870,000
Difference						$ 50,840
50% of Difference						$ 25,420

(1) Rounded to the nearest hundred thousand dollars

In summary, it is the Company's view that ratepayers will have shared in the tax benefits related to the CCA rate changes in a manner that is fair, appropriate, and consistent with the negotiated and agreed terms of the PBR agreement.

123.2 If yes, explain why TGI does not consider this to be a variance in income tax rates (CCA rates) that would be captured in the tax deferral account.

Response:

Please see the response to BCUC IR 2.123.1.

123.3 Please explain how a change in tax legislation would qualify as a prior period adjustment whose benefit is shared between the ratepayer and the shareholder.

Response:

Please see the response to BCUC IR 2.123.1.

124.0 Reference: Taxes

Exhibit B-4, BCUC 1.148.3

Changes to CCA Rates

"The Company is of the view that the appropriate tax rate to use is the tax rate in effect at the time the deduction is known with certainty and the benefits are returned to customers."

124.1 When TGI filed its 2008 corporate tax return (T2), was the$2.2 million adjustment included in the CCA deductions?

Response:

Please see the response to BCUC IR 2.123.1.

124.1.1 If yes, was the tax benefit received by TGI $682 thousand ($2.2 million x 2008 corporate tax rate of 31 percent)? BCUC staff has prepared the calculations in the table below. If the response differs from these calculations, please update the table accordingly.

Year	CCA	Federal Tax Rate	Provincial Tax Rate	Sur Tax	Combined Rate	Tax Benefit Received by Ratepayer
Ratepayer Tax Benefit at 2007 and 2008 Tax Rates						
2007	$ 700,000	21.00%	12.00%	1.12%	34.12%	$ 238,840
2008	$ 2,200,000	19.50%	11.50%	0.00%	31.00%	$ 682,000
						$ 920,840
TGI Proposed Ratepayer Tax Benefit at 2009 Tax Rates						
2009	$ 2,900,000	19.00%	11.00%	0.00%	30.00%	$ 870,000
Difference						$ 50,840

Response:

Please see the response to BCUC IR 2.123.1.

124.2 Did TGI amend its 2007 corporate tax return (T2) to reflect the $700 thousand increased CCA deduction?

Response:

Please see the response to BCUC IR 2.123.1.

124.3 If yes, was the tax benefit received by TGI $239 thousand ($700 thousand times the 2007 corporate tax rate of 32.12 percent)? If amounts differ from calculation above please update the table accordingly

Response:

Please see the response to BCUC IR 2.123.1.

124.4 Would the ratepayer have realized an additional $51 thousand benefit if TGI had calculated the increased CCA deduction using the higher 2007 and 2008 corporate tax rates rather than the 2009 rates?

Response:

Please see the response to BCUC IR 2.123.1.

124.5 If TGI realized the benefit of the increased CCA deduction at the higher 2007 and 2008 corporate tax rates would the ratepayer be entitled to the same benefit?

Response:

Please see the response to BCUC IR 2.123.1.

125.0 Reference: International Financial Reporting Standards ("IFRS")

Exhibit B-4, BCUC 1.176.2

Asset Impairment

125.1 BCUC 1.176.2 indicates that TGI has not yet identified cash generating units for purposes of impairment testing of assets. The response also indicates "Impairment tests are required only if there are any indications of impairment at each reporting period. It cannot be determined at this time if upon transition to IFRS an impairment test will be required of Terasen Gas' property, plant and equipment."

IAS 36 outlines the requirements for impairment testing of assets. Paragraph 12 (a) of IAS 36 states "In assessing whether there is any indication that an asset may be impaired, an entity shall consider, as a minimum, the following indications:…during the period, an asset's market value has declined significantly more than would be expected as a result of the passage of time or normal use."

The decline in value of an asset through normal use is typically estimated through the provision of depreciation. However, in the past years, TGI's asset amortization rates were set by commission directive and did not necessary reflect the useful life of the asset. As a result of the recently completed depreciation study, asset amortization rates have been drastically modified resulting in an accelerated amortization.

125.1.1 Does TGI believe that the need for the acceleration in amortization rates is a possible indicator of impairment triggering a valuation test? Include a discussion of the impact of using an amortization period based on regulatory requirement vs. useful life and discuss if this treatment has affecting the value of asset on hand.

Response:

The preamble to the question states that TGI's response to BCUC IR 1.176.2 indicates that TGI has not yet identified cash generating units for purposes of impairment testing of assets. In fact, as indicated in the response to BCUC IR 1.176.1, TGI has been identified as a separate cash generating unit, consistent with the fact that Terasen has completed its assessment and determination of cash generating units.

In a non-regulated company, the need for acceleration in amortization rates may be a possible indicator of impairment triggering a valuation test. However, for a regulated entity a more appropriate indicator of possible impairment is more likely to be its recoverability from ratepayers. For TGI, one of the primary drivers of the acceleration in depreciation rates is the large unrecovered losses that have built up in the plant accounts. Since TGI has never received any indication from the Commission that these amounts will not be recovered in the future (such a determination would, in TGI's view, be inconsistent with the Commission's duty to ensure that TGI has an opportunity to collect sufficient revenues to cover the cost of service and earn a fair return), we do not believe that there is an indication of impairment. The recent exposure draft on rate regulated activities indicates that there may be situations where the net effect of the regulatory assets and regulatory liabilities an entity recognizes will result in significant increases in future rates to be charged to customers. A significant increase in an entity's future rates may create a strong incentive for customers to reduce their consumption or switch to an alternative. When it is not reasonable to assume that an entity will collect sufficient revenues and earn a fair return, this may be an indicator of impairment.

125.1.2 Does TGI believe the inclusion of $132.5M in unrealized losses within the fixed asset subledger, which results in the presentation of the fixed assets at an amount of $132.5M in excess of true carrying value of those assets, is a possible trigger for impairment testing of the fixed assets?

Response:

Note that the first sentence of the preamble is incorrect (please see the response to BCUC IR 125.1.2).

The amount at which TGI's regulatory fixed assets are presented in the Company's financial statements equals the amount at which these assets are carried on its books which is equal to the amount approved for inclusion by the BCUC in determination of rates.

It is accepted regulatory practice as part of group depreciation accounting that gains and losses on asset dispositions are not recognized in income but are instead charged or credited to accumulated depreciation, to be recovered through an adjustment to depreciation rates as part of the next depreciation study. TGI has built up a large unrecognized loss simply because the last depreciation study that was filed by TGI was not implemented. Therefore, the current rates are out of date and have not been updated for many years to recover these asset losses, which continue to grow as depreciation rates continue to be too low to recover the investment in assets over their useful lives. TGI believes that it is appropriate to address this situation in the present Application.

Please see the response to BCUC IR 2.125.1.1 for a discussion of whether the existence of losses and the subsequent requirement to accelerate depreciation rates to recover those losses is a trigger for impairment testing of those assets.

126.0 Reference: Accounting and Other Policy Changes

Exhibit B-4, BCUC 1.177.0

Fair Value of Regulatory Assets

126.1 IASB's Exposure draft regarding regulatory assets, paragraph 12 would required, if adopted as proposed, that initially and each reporting period that regulatory assets and liabilities be measured at present value.

126.1.1 If this exposure draft is adopted, please explain how TGI intends to perform this fair valuation of regulatory assets at adoption.

Response:

Given how recently the exposure draft on Rate Regulated Activities was released, Terasen Gas is still assessing how it will assess the fair value of regulatory assets on adoption of IFRS. The fair value would likely be a combination of a probability weighted expected outcome and the present value of the cash flows from both the regulatory assets and liabilities. We would expect that the fair value and carrying value would be similar assuming that, on transition, all deferral accounts had been approved by the Commission. The Company is still assessing the present value (please see the response to BCUC IR 2.126.1.2) and has not completed the analysis at this time.

126.1.2 Please discuss the likelihood and possible value of the impact of present-valuing these regulatory accounts.

Response:

Given how recently the exposure draft on Rate Regulated Activities was released, Terasen Gas is still assessing how it will present value both regulatory assets and liabilities. However, assuming these are approved rate base assets and they attract a fair return on debt and equity it would not anticipate that there would be any impairment in their carrying value.

126.1.3 Please describe how any adjustment to the opening regulatory balance will be accounted for and how this adjustment would impact rate base.

Response:

As discussed on Page 435 of the Application, the IFRS Transitional Deferral Account would capture any retained earnings adjustments that are required on transition to IFRS, including any adjustments resulting from present value measurement. Since any amounts captured in this deferral account would be included in rate base, no write down in rate base is anticipated. As discussed in the response to BCUC IR 2.126.1.1, TGI and other utilities are still assessing paragraph 12 of the Exposure Draft and how the present value calculation will be determined.

126.1.4 Please discuss if adoption of this exposure draft would require TGI to write down any regulatory accounts due to the uncertainty of future cash flows that will arise out of the balances.

Response:

As indicated in the response to BCUC IR 2.126.1 through 2.126.3, TGI has not yet determined the details of the fair value assessment, but it is likely that any deferral accounts that are approved for inclusion in rate base and for recovery in future rates would not require a write down. For any deferral accounts not included in rate base and not approved for recovery in future rates, TGI would assess the likelihood of recovery in accordance with paragraph B11 of the Exposure Draft on Rate-regulated Activities.

127.0 Reference: Accounting and Other Policy Changes

Exhibit B-4, BCUC 1.177.5

IFRS- Deferral Recovery

127.1 BCUC 1.177.5 indicates that TGI would like to evaluate the recovery of deferral accounts in future periods and that the timeframe of recovery would be best matched to the nature of the underlying adjustment.

127.1.1 Please explain why TGI does not believe that the period of recovery of the IFRS deferral account should not begin in year one of adoption.

Response:

In this RRA, TGI is proposing to determine its rates for both the 2010 and 2011 forecast years. Since TGI is unable to determine what amounts will ultimately be recorded into the IFRS Transitional deferral account, it is unable at this time to forecast an amortization of the balances that could be included in 2010 and 2011 rates. Therefore, it is reasonable and appropriate to commence amortization in 2012 once the components and magnitude of the amounts are known.

127.1.2 Please explain why the period of the recovery should match the underlying nature of the items within the account and not a fixed time frame. Discuss the circumstances resulting in the creation of the IFRS deferral account and explain how this overall policy shift is a direct result of the underlying nature of the accounts affected.

Response:

The items that are expected to be captured in the IFRS Transitional deferral account are set out on page 435 and 436 of the Application. TGI has not put forward any particular proposal at this time for the disposition of the IFRS Transitional deferral account or any of its components. In its response to BCUC IR 1.177.5, TGI was merely providing an example of a possible method for disposing of a particular item in the deferral account. Depending on the composition of the balance, TGI may either recommend splitting the deferral account in 2012 into a number of separate accounts, each with its own fixed time frame for recovery, or maintain one deferral account with a fixed time frame for recovery. In neither case is TGI expecting anything other than a fixed time frame for recovery. The determination will be contingent upon having certainty with respect to the composition of the deferral account balance, which the Company will not have until well into the Forecast period.

128.0 Reference: Accounting and Other Policy Changes

Exhibit B-4, BCUC 1.177.2

Auditor Assessment of IFRS accounting policies

128.1 BCUC 1.177.2 indicates that TGI's auditors have not provided an opinion on any IFRS accounting policy choices and no such opinion is available until the completion of the first fiscal IFRS audit on the year ended December, 2011. However, TGI also indicates that their auditors have been included in IFRS planning.

128.1.1 Please indicate which preliminary accounting policy choices, if any, that your auditors have not yet reviewed in detail at this time.

Response:

While Terasen Gas' auditors have not yet provided an audit opinion, the Company has engaged both either external auditors and a firm of consultants who act as IFRS advisors to Terasen Gas to review the accounting policy choices selected. While Terasen Gas' auditors have not yet audited or provided an opinion on the policy on any IFRS accounting policy choices, they have reviewed the policy choices made and reviewed the selection of accounting policies as presented in this application. Terasen Gas' auditors have not raised concerns regards the Company's policy choices selected to date.

128.1.2 Please discuss any concerns your auditors have raised with regards to your preliminary accounting policy choices, if any.

Response:

Please see the response to BCUC IR 2.128.1.1.

129.0 Reference: Accounting and Other Policy Changes

Exhibit B-4, BCUC 1.178.0

IFRS

TGI is adopting IFRS effective January 1, 2011.

129.1 What are the requirements under IFRS with respect to a Change in Accounting Estimate?

Response:

IAS 8, which deals with Changes in Accounting Estimates, is very similar to current Canadian GAAP with the exception having an "impracticable" exemption which Canadian GAAP does not currently have.

129.2 If TGI was to change its accounting estimate for depreciation, that is, increase the depreciation rates effective January 1, 2011, why would this change in rates be required to be reflected in the 2010 comparative reporting? Please refer to the specific IFRS sections in your response.

Response:

As indicated both in the Application and in the response to BCUC IR 1.177.1, TGI will adopt IFRS effective January 1, 2011 and is required by IFRS to re-state comparative periods (2010) using IFRS standards so the Company is effectively adopting IFRS on January 1, 2010. IFRS 1 states: "An entity's estimates under IFRSs at the date of transition to IFRSs shall be consistent with estimates made for the same date under previous GAAP (after adjustments to reflect any difference in accounting policies), unless there is objective evidence that those estimates were in error." [IFRS 1(31)]. The strong direction for consistency should be interpreted as a requirement not to modify estimates unless they can be shown objectively to be an error. As indicated in IAS 1 (15), if after the date of transition to IFRS, an entity receives information about estimates that it had made under previous GAAP, an entity shall treat that receipt of that information in the same way as non-adjusting events after the reporting period in accordance with IAS 10 Events after the Reporting Period. Based on the above guidance, Terasen Gas has applied for depreciation rates that increase effective January 1, 2010 which is the initial adoption date of IFRS.

129.3 Is the answer different if the change in accounting estimate were done on January 2, 2011?

Response:

As indicated in the response to BCUC IR 2.129.2, Terasen Gas needs to adopt IFRS compliance estimates effective January 1, 2010. IFRS does not allow for a change in estimates on adoption of IFRSs. The 2010 comparatives are being restated to be compliant with IFRS. We effectively adopt IFRS January 1, 2010, not January 1, 2011 or January 2, 2011. TGI does not have a choice about the timing of adoption of IFRS.

129.4 Is the answer different if the Commission directs TGI to continue with the current rates until a specific date in 2011?

Response:

No. TGI does not believe that it is able to implement depreciation rates that are directed by the Commission instead of IFRS compliant depreciation rates in determining the depreciation expense and carrying value of the PP&E. If the Commission were to direct TGI to implement non-IFRS compliant depreciation rates for regulatory purposes, TGI would still be required to record IFRS compliant rates in its financial statements, and the difference would then become a regulatory asset. TGI would then be required to demonstrate the recoverability and fair value of this regulatory asset based on discounted future cash flows. Those future cash flows would not exist absent an expectation of future recovery, and could lead to a write down. Since the original asset costs were prudently incurred in providing utility gas service, TGI would consider this to be an unfair and unreasonable result. This is in accordance with TGI's understanding of the Rate-Regulated Activities Exposure Draft, and through discussions with working groups, consulting and audit firms.

130.0 Reference: Operations and Maintenance Expenditures – Codes and Regulations

Exhibit B-4, BCUC 1.179.1

TPIP

"Terasen has forecast an increase in 2011 to enable the utilization of emerging analysis methodologies …Terasen is anticipating that broader application…and possibly other methods would be prudent…"

130.1 Please provide a more detailed description and the methodology applied in estimating the $555,656 increase in "General" TPIP programs from 2010 to 2011. Please include the specific requirements and additional duties that are required to meet current integrity requirements and how these are expected to change in 2011.

Response:

Terasen Gas continues to develop and refine its Asset Integrity Management Program, and considers continuous improvement to be a fundamental component of an effective program. Techniques used to measure the effectiveness of, increase confidence in, and reduce the uncertainties of integrity-related activities are continually being developed and improved within the pipeline industry and at Terasen Gas. These ongoing continuous improvements and program refinements account for the majority of the increase in "General" program spending between 2010 and 2011.

More specifically, the main focus areas for review will be the In-Line Inspection (ILI) Analysis and Stress Corrosion Cracking Management programs. For example, the Canadian Energy Pipeline Association (CEPA) recently published a 2nd Edition of Stress Corrosion Cracking Recommended Practices. Consistent with other Canadian pipeline operators, Terasen Gas has plans to review current practices to ensure that they are consistent with the revised document. Also identified for continuous improvement is a review of the current probabilistic approach, and an investigation of reliability based methods for defect assessment and ILI re-inspection interval selection. Terasen Gas will also target improvements related to the application of reliability based methods to enhance other hazard management practices.

From 2010 to 2011, reduced activities in specific TPIP programs (i.e. "Cathodic Protection Evaluations", "In-Line Inspections") have been forecast. Fluctuations are expected when risk-based inspection frequencies are adopted; however, this has allowed Terasen Gas to plan some allocation of existing skilled internal staff toward required continuous improvements in 2011, maintaining the same staffing levels as in 2010. In addition, Terasen Gas projects an increase in the number of reliability-based class location change assessments as construction activity levels increase in 2011 compared to 2010 levels.

As specialist engineering consultants will be required to assist internal staff with continuous improvements and engineering assessments, the estimate has been based on completed work believed to be reasonably indicative of the forecast future work.

Approximately $85,000 of the $555,656 increase is to cover a Human Resources-specified annual increase for internal staff as well as an increase for external services related to class location assessments.

130.2 What are the "possible other methods" that could be applied in 2011 to warrant the increase in costs? What is the likelihood that these other methods would come into effect?

Response:

As stated in the response to BCUC IR 2.130.1, continuous improvement activities are a fundamental part of the Terasen Gas Integrity Management Program. Some examples of other identified methods are discussed in that response. We believe ongoing review and improvement is required to keep the Program current, so that it continues to meet our integrity management objectives.

While there is an increase in cost between 2010 and 2011 in the TPIP General Program category related to implementing emerging technologies, the overall TPIP requirement is actually declining between 2010 and 2011 due to reasons explained in TGI's response to BCUC IR 1.179.1. TGI not only believes that the increase in General Programs is prudent and warranted, but that the overall decrease is prudent and warranted.

TGI further believes there is a high likelihood that new and improved methods would come into effect. We believe it is our responsibility to implement an Integrity Management Program that remains current and that considers and incorporates appropriate continuous improvements and industry best practices. While the overall 2011 plan will be further hardened in the coming months (over and above the examples already mentioned), the funding requirement has been developed based on knowledge of industry standard and leading practices, engineering judgment, and the availability of skilled internal resources to complete work and to manage and review work completed by specialist engineering consultants. As explained in the response to BCUC IR 2.130.1, there are reduced activities in specific programs for 2011, which TGI believes is an opportunity to redeploy a small portion of our internal engineering resources to work with specialized consultants with a focus on implementing new methods.

131.0 Reference: Operating and Maintenance Expenditures – Accounting Changes Exhibit B-4, BCUC 1.180.0

Fair Value of Fixed Assets

131.1 BCUC 1.180.6 indicates that TGI does not believe assets are impaired as two recent sales of assets were made at carrying value. However, in BCUC 1. 180.4, TGI indicates that the fixed asset subledger contains unrecognized losses of $132.5M.

131.1.1 Is the $132.5M in deferred losses net of any deferred gains? If so, how much deferred gains exist?

Response:

The amount of $132.5 million referenced in the response to BCUC IR 1.180.4 was incorrect and should have been stated as $131.8 million. This is a net balance of gains and losses, and is composed of a loss balance of $138.1 million offset by a gain balance of $6.3 million.

131.1.2 Please discuss how and over what period these unrecognized amounts accumulated and provide a cumulate total of unrecognized losses from 2006 to 2008.

Response:

TGI's current Asset Management system contains historical records back to 1999. At that time, the loss balance was $15.9 million, and the balance has been growing at an increasing rate since that time, as the depreciation rates that have been approved by the Commission and implemented in TGI's systems have been too low to recover the plant balances over their useful lives. As can be seen from the table below, which shows the build of the balances from 2006 to 2008, the balance will continue to grow until the cumulative impacts of updated depreciation rates result in assets that are fully recovered before retirement.

	Gain/loss Balance
2006	97,664,894
2007	104,820,905
2008	123,774,697

Please see the response to BCUC IR 2.131.1.4 for further information.

131.1.3 Why have these unrecognized amounts been deferred and not recognized into income. Include a discussion of the rational for recognizing some losses or gains and deferring others.

Response:

TGI follows recognized regulatory group accounting procedures in accounting for its property plant and equipment. TGI also adheres to the BCUC Uniform System of Accounts. Under both of these procedures, on retirement of depreciable gas plant, Accumulated Depreciation is charged with the ledger value of the gas plant retired and the cost of removal less amounts recovered for salvage and insurance. It is only in rare cases where the forces of retirement are outside of the forces that were contemplated in determining depreciation rates that gains and losses on depreciable plant would be recognized in income. Therefore, all normal courses gains and losses on retirement of assets are included in accumulated depreciation.

This treatment is appropriate since group depreciation rates are set to recover the asset values over the average service life of the asset group, so that we expect some assets to be retired before their net book value reaches zero; others would be retired after their net book value reaches zero; and overall the gain/loss amount included in accumulated depreciation will have an immaterial value, with any material amounts recovered through changes to future depreciation rates. When depreciation rates are not adjusted to reflect the shorter service lives of assets, as has been the case with TGI, then the loss amount will build in accumulated depreciation.

An excerpt from the BCUC Uniform System of Accounts explains this more fully:

> *“The group system contemplates that some part of the investment in a group of assets probably will be recovered through salvage realizations and that probably there will be variations in the service lives of the assets constituting the group, even among assets of the same class. The depreciation provision determined for the group is a weighted average of the various individual provisions reflecting the individual expectancies of life and salvage for the respective assets in the group. It is not the intention of this classification to require the company to keep records of the accumulated depreciation of each unit of plant. For purposes of analysis, however, each company shall maintain subsidiary records in which accumulated depreciation is subdivided according to the utility department to which applicable, or to each group of gas plant accounts.*
>
> *When the retirement or disposal of any individual asset in a group occurs under circumstances reasonably provided for through accumulated depreciation, it may be assumed such provision has been made. Thus, whether the period of service is less or greater than average, accumulated depreciation attributable to an asset at the time of retirement under such circumstances, is equal to the cost, except for that portion reasonably assumed recoverable through salvage realization.”*

131.1.4 Have any of these unrecognized amounts been determined unrecoverable for regulatory purposes at an earlier point of time?

Response:

No, none of these unrecognized amounts have been determined unrecoverable for regulatory purposes at an earlier point in time. Since they represent investments in utility plant required to continue providing service to customers, and have resulted from inadequate recovery of depreciation from past customers, primarily due to the results of previously recommended depreciation studies not being implemented or included in revenue requirements, there is no basis for them to be determined unrecoverable.

The depreciation rates included in the Depreciation Study filed with this Application include a portion related to the recovery of the unrecognized loss balances. As discussed in the study, it is the main driver behind the increases in rates.

131.1.5 Please describe how and when TGI anticipates these unrecognized amounts will be recognized.

Response:

The depreciation rates included in the Depreciation Study filed with this Application include a portion related to the recovery of the unrecognized loss balances. As discussed in the study, it is the main driver behind the increases in rates.

Please also see the response to BCUC IR 2.131.1.4.

131.1.6 Please clarify if these losses are included in the rate base of TGI?

Response:

These losses are included as a reduction of Accumulated Depreciation, which is included in the rate base of TGI.

132.0 Reference: Accounting and Other Policy Changes

Exhibit B-4, BCUC 1.185.0

Depreciation of assets - Decommissioning costs/net salvage amount

132.1 TGI indicates that "For TGI, the recommendations from the last filed depreciation study which included a provision for removal costs were not implemented due to concerns over the large rate increase at that time, with the exception of the two asset classes, Meters and Meter Installations/Regulators which had rates updated in 2004."

132.1.1 Please confirm that the proposed depreciation rates for the test period include a provision, or decommissioning cost, for asset classes in addition to meters and meter installations/regulators. Please clarify what additional classes you have applied this provision towards within this application

Response:

Confirmed. Please see TGI's response to BCUC IR 1.191.1 for a listing of all asset classes, with net salvage component broken out as per the current depreciation study.

132.1.2 Please quantify what percentage/dollar amount of the incremental increase in the test period depreciation expense is a result of expanding the classes subject to this net salvage provision to include assets other than meters and meter installations/regulators.

Response:

As per response to BCUC IR 1.191.1, approximately $13 million of the recommended depreciation expense is related to net salvage whereas per response to BCUC IR 1.185.1 approximately $1 million of the current depreciation expense is related to net salvage. The change is approximately $12 million.

132.2 Funds collected from rate payers with regards to the decommissioning cost of meter installations and regulators appears to be accumulating as actual costs incurred are substantially lower than the amounts collected from the customers.

Also TGI has indicated that the information system does not track such amounts independent from the depreciation charge.

132.2.1 Please indicate why customer charges have significantly exceeded costs incurred in past years.

Response:

Customer charges are designed to collect the decommissioning/net salvage estimates over the life of the assets on a straight line basis; it is not intended that in any one year the amount collected from customers would equal the amount expended. Therefore, it is expected that in the early years of the life of an asset class, amounts collected will be greater than costs incurred, with the reverse true for the later years. For TGI, since depreciation rates and consequently estimates of net salvage have not been updated since 2004, there have been changes to the net salvage estimates even for those two asset classes which have not been included in rates since that time. The tables in response to BCUC IR 1.191.1 show no net salvage estimate required for either of those two asset classes in the current depreciation study.

132.2.2 Please explain why TGI believes that it is appropriate to accumulate customer funds today for use towards future expenses without taking the time value of money, as is the current practice?

Response:

TGI follows recognized regulatory group accounting procedures in accounting for its property plant and equipment. TGI also adheres to the BCUC Uniform System of Accounts:

> *"There shall be charged monthly to account No. 303, "Depreciation", or other appropriate accounts with concurrent credits to the accounts for accumulated depreciation amounts which will allocate the service value for the plant over its estimated service life in a systematic and rational manner. The service value of the assets, for depreciation purposes, shall be their cost less their estimated net salvage value. Net salvage value means the salvage value less removal costs. The charges for depreciation shall be computed in conformity with the group system under the straight line method at rates approved by the Commission."*

There is no current or historical practice in either recognized group accounting procedures or the Uniform System of Accounts to specifically account for the time value of money through this accounting procedure, but the resulting credit to rate base and the earned return that is calculated on that rate base do implicitly account for the time value of money.

132.2.3 Please describe monitoring mechanisms that TGI utilize to ensure that amounts charged to customers through these provisions are appropriate and not excessive.

Response:

TGI intends to implement the practice of regular reviews of decommissioning provisions through deprecation studies. In each full study, we would look to determine the adequacy of the current reserve and true it up for changes in salvage estimates so that TGI recovers what is required to remove the assets – no more and no less. TGI is now committed through IFRS as well as through regulatory process to have these periodic reviews undertaken. Through the updating and implementation of revised rates, TGI will be able to maintain rates that are appropriate, in the sense that they are not excessive nor are they underrecovering. Consistent underrecovery of depreciation builds a large balance of costs remaining to be recovered in future rates. To avoid exactly this result, TGI believes that its depreciation rates should be updated to reflect the results of the recent depreciation study.

132.2.4 Please describe which other utilities, if any, that use a similar system of negative salvage amounts or a rate for decommissioning costs. Describe asset types it has applied to and rates used by any such utilities

Response:

Through our participation in the Fortis working group, TGI is aware that almost all of the Fortis utilities, representing regulatory jurisdictions across Canada, recover net salvage in a similar manner to TGI.

In addition, TGI, through its association with Gannett Fleming, is aware of these examples of utilities that follow similar systems to recovering net salvage as TGI: Atco Gas, Alta Gas, Atco Electric, Altalink, Enmax. SaskEnergy, TransGas, Manitoba Hydro, Centra Gas Manitoba, Enbridge Gas.

132.3 Please discuss any relevant accounting standards under IFRS which contemplate negative salvage provisions for capital assets. Also include a discussion of how such provisions are allowable under IFRS.

Response:

Please see the response to BCUC IR 1.185.6 where TGI discusses that these future decommissioning costs would be a regulatory liability as allowed under the Exposure Draft on Rate-regulated Activities.

133.0 Reference: Depreciation Study

Exhibit B-4, BCUC 1.201.1

Appendix H-2

"…the deployment of OMR technology, an early stage version of evolving Automatic Meter Reading (AMR) technology, allows TGI also to gain insight and experience working with AMR technology."

133.1 Does this above statement infer that there will be an eventual transition into AMR technology? If so, will there be additional capital cost required for AMR technology above the current OMR system? When does TGI expect this transition to occur?

Response:

TGI is reviewing the viability of a transition into AMR technology. Although not yet complete, TGI's preliminary review suggests that customers will benefit from an AMR technology deployment. In order to support a technology rollout additional capital costs would be required. This would be the subject of a separate CPCN application under the proposed CPCN threshold. The earliest date for this potential filing is 2010.

133.2 Did the OMR deployment project allow for the salvage of the older electro-mechanical meters? If so, was this credit recognized as a capital offset to the OMR capital cost of $410,000? What was the salvage amount, if any?

Response:

Meter salvage credits associated with the OMR deployment project were not specifically targeted as a capital offset to the project.

The proceeds of disposition from all retired meters in a given year are charged to an internal order that settles to Gain and Loss under the Meter asset class and forms part of accumulated depreciation. The value of meter salvage is generally linked to the scrap price of aluminium multiplied by the gross weight of all meters salvaged. The precise salvage amount for any specific meter retirement program cannot be determined because meters are scrapped in bulk and the details of the specific meters that we receive salvage credits for are not provided back to us from the scrap aluminium dealer. Residential meters salvage values have traded in a range of $1 to $3 per meter over the past number of years. Assuming all 2,100 OMR meters were scrapped, the total salvage value is estimated at $4,200 (i.e. 2,100 meters multiplied by average scrap price of $2).

134.0 Reference: Depreciation Study

Exhibit B-4, BCUC 1.201.6

Depreciation Adjustments

"The adjustment to the depreciation expense…results in an annual rate base decrease of approximately $20.8 million per year."

134.1 Please advise how many years this annual adjustment is expected to be on TGI's books?

Response:

The "adjustment to depreciation expense" described in TGI's response to BCUC IR 1.201.6 was intended to convey the amount of the annual increase in depreciation expenses of $20.8 million, resulting from implementation of the depreciation rates set out in the depreciation study included with the Application. TGI expects that the proposed depreciation rates, assuming they are approved, would continue in place until at some future time it is determined that updated depreciation rates are required to address a material change in depreciation estimates.

135.0 Reference: Shared Services Agreement

Exhibit B-4, BCUC 1.202.1

Shared Services Costs

135.1 It appears that the total cost of shared services have increased substantially over the last few years (7.7 percent in 2007, 13.3 percent in 2008, 15.6 percent in 2009, then 20.7 percent in 2010) whereas the Direct Costs retained by TGI has remained relatively stable. Please provide additional detail as to the changes in business activities from year to year that would necessitate the large incremental increases in the Shared Services Costs.

Response:

The total cost of the Shared Services pool as presented in TGI's response to BCUC IR 1.202.1 represent actual results from 2006 through 2008, with projection for 2009 and forecast for 2010 through 2011. As explained in Part III, Section C, Tab 11, Page 494, TGI has completed a review of the Shared Services approach and agreement as part of the RRA. For validation, the Shared Services methodology and the reasonableness of the costs of the Shared Services has been reviewed independently by KPMG to evaluate the suitability of the ensuing Shared Services agreement. Please see Appendix H-4 of the Application for a copy of KPMG's Shared Services Cost Allocation Review. Per Page 3 of that report, '*in conducting this review KPMG verified that the services provided by TGI are operationally necessary, the methodology used to allocate costs is reasonable and the costs allocated are reasonable as compared to market alternatives.*'

The annual increase in costs of the Shared Service Pool is as follows:

- 2007 7.7%
- 2008 5.3% (not 13.3% as indicated in the IR)
- 2009 15.6%
- 2010 20.7%

These increases can be explained as follows:

2007

- Labour and general inflation
- The Banner to Energy Conversion in 2006 resulted in some Customer Care and Distribution services that previously resided outside of the Allocated Cost Pool to now become part of the Allocated Cost Pool and subject to Shared Service allocation.

Whereas these services were previously being performed only for TGI, they now became performed for all 3 utilities.

2008

- Labour and general inflation
- Additional hires to fill vacancies

2009

- Labour and general inflation
- Amalgamation with the Allocated Cost Pool of Meter Shop and Measurement services that were previously billed directly to TGVI as part of a separate contract
- Costs associated with improved and increased service levels provided by additional FTE increases (some to fill vacancies) within the Allocated Cost Pool in the areas of Distribution, Finance and Regulatory, Business and IT Services, Human Resources and Operations Governance, Marketing and Business Development, Gas Supply and Transmission. See Part III, Section B, Tab 1, Page 159 – 177 of the RRA

2010

- Labour and general inflation
- Costs associated with improved and increased service levels primarily driven by the external situation factors that face TGI as it moves into 2010 and 2011. The external situational context is discussed in Part III, Section A of the RRA. Table C-6-3 identifies and quantifies these External Factors with more detailed discussion on Page 348-404

TGI believes the Shared Services costs are fair and reasonable, and the methodology used to allocate costs is reasonable and the costs allocated are reasonable as compared to market alternatives.

136.0 Reference: Shared Services Agreement

Exhibit B-4, BCUC 1.202.2

Appendix H-4

	2006	2007	2008	2009	F2010	F2011
Share Services Cost	42,119	45,470	47,754	55,109	66,533	70,054
Year end Customer Count	821,683	822,598	831,845	837,965	843,565	849,415
% Increase		0.1%	1.1%	0.7%	0.7%	0.7%
Cost / customer	$ 51.26	$ 55.28	$ 57.41	$ 65.77	$ 78.87	$ 82.47
% Increase		7.8%	3.9%	14.6%	19.9%	4.6%

136.1 Table 3.5b in Appendix H-4 illustrates that the number of customers is one of the main cost drivers for Shared Services. In fact, this is the cost driver for ALL functional departments in TGI.

Based on the above calculations, please explain why the increase in the Shared Services Cost per customer in increasing at an accelerated rate while the increase in customer growth has been relatively stable.

Response:

The term 'cost driver' that is referenced in Table 3.5b and discussed further on Page 21 of Appendix H-4 would be better referred to as 'allocator'. Once the Cost Allocation Pool is quantified, the number of customers is utilized to allocate this pool amongst TGI, TGVI, and TGW. The fact that TGI's Shared Service Cost per customer is increasing means that the Cost Allocation Pool has grown at a rate that exceeds customer growth. The Shared Service Cost per Customer changed during the 2006 – 2011 time period primarily because additional services and associated costs were added to the Cost Allocation Pool in each of the years as outlined in the response to BCUC IR 2.135.1.

Attachment 11.2

BRITISH COLUMBIA UTILITIES COMMISSION

Retail Markets Downstream of the Utility Meter

Guidelines

APRIL, 1997

TABLE OF CONTENTS

1.0 INTRODUCTION

On July 10, 1996, the Commission announced a process for the review of the retail market downstream of the utility meter. In particular the Commission sought to examine the forces which are causing utilities to wish to expand the number and kinds of services which they offer and to determine if, and to what extent, utilities and/or their affiliated non-regulated businesses ("NRBs") should be allowed to participate in downstream retail markets.

As an initial step in the review process, the Commission held a workshop on October 16, 1996 at which a variety of parties were given the opportunity to present their views. In addition, the Commission called for written submissions by October 31, 1996, including advice as to what future processes were required to address the issue. Submissions were received from many parties, including utilities, marketers, independent contractors, and customers. After reviewing all the submissions, the Commission determined that this matter could best proceed through a written process. Accordingly, the Commission instructed staff to prepare a position paper on this topic which could then be circulated for discussion by interested parties.

The staff paper, which was released December 16, 1996, reviewed the traditional role of utilities and emerging pressures for changes to this role, provided staff's interpretation of the Commission's jurisdiction with respect to utility or utility-affiliated NRB participation in the downstream market, and summarized the issues and concerns regarding utility participation which had been presented to the Commission. Based on the above, staff concluded that there were likely to be circumstances in which utility participation in the downstream market, either directly or through an NRB using some utility facilities or services ("related-NRB"), would be desirable and other circumstances in which participation should be limited to self-financing, stand-alone, arm's length NRBs using no resources of the utility. Accordingly, the staff position paper proposed a set of principles and guidelines for the Commission to use to assess individual utility proposals to determine which proposals should be pursued using stand-alone NRBs and which could be pursued either by the utility directly or through a related-NRB.

Initial comments to the Commission on the position paper were requested by January 31, 1997. In addition, the process allowed parties to respond to the initial comments of other parties by supplying reply comments to the Commission by February 21, 1997. The Commission received initial comments from 24 parties and replies to the initial comments from six parties. A list of parties providing comments is attached as Appendix 1.

This document summarizes the submissions made with respect to the staff position paper and concludes with the findings of the Commission with respect to the participation of utilities and their NRBs in the retail market downstream of the utility meter.

2.0 THE RETAIL MARKET DOWNSTREAM OF THE UTILITY METER

As discussed in the staff position paper, utilities are generally established in response to natural monopoly conditions. A natural monopoly is said to occur if the provision of a good or service can be provided at lowest cost by a single firm, rather than by two or more firms; i.e., there exist substantial economies of scale. Utilities may also be asked to provide an associated product if its provision by the utility leads to economies of scope; i.e., a single firm is able to produce two or more joint products at a lower unit cost than single firms each producing just one of these products. However, because the provision of the good or service by a single firm leads to the potential of monopoly pricing, utilities are generally regulated with respect to price and service quality. A very broad definition of a public utility is provided in the *Utilities Commission Act* ("the Act") for the purposes of regulation under Part 3 of the Act. The definition has remained unchanged since the 1970s.

Since the mid-1980s, both natural gas and electricity utilities have found that at least some of the services which they have traditionally provided, including commodity sales and energy-efficiency services, can be provided by other non-regulated market participants. As a result, the breadth of true natural monopoly services has decreased even though the range of regulated utility options has greatly expanded to accommodate competitive markets upstream of the utility. This has led to the deregulation of certain commodity components of traditional utility services and reliance for their provision on the competitive market. As well, it has prompted requests for further deregulation of other services still provided by the utility.

One consequence of the growing deregulation of natural gas and electricity utilities has been a movement towards convergence between the markets for natural gas and electricity. One response to this convergence has been the emergence of 'mega-marketers', that is, firms which offer customers a full menu of energy services, including provision of both the natural gas and the electricity commodity, commodity contract marketing, equipment sales, rentals and servicing, and energy efficiency marketing. For those customers who have the technical capability, the emergence of mega-marketers allows them to switch more easily between natural gas, electricity and efficiency measures as prices dictate. For all customers, the emergence of mega-marketers can mean increased convenience through 'one-stop shopping'.

The reduction in the size of the traditional utility domain, as certain services become available from non-regulated suppliers and as mega-marketers become more prominent, has led some utilities to re-evaluate their traditional service offerings. For some utilities, this is leading to a desire to offer services not previously offered by utilities and to move into downstream retail markets not traditionally served by utilities. For others, it is leading to a desire to change the way in which services are offered, notably to offer certain services on a non-regulated basis in the downstream retail market rather than as a regulated tariff item.

The retail market downstream of the utility meter can generally be described as consisting of those goods and services which are related to or support the delivery and/or use of the energy commodity. Figure 1 identifies many of the energy and energy-related products and services contained in the retail market downstream of the utility meter.

Figure 1: Potential Goods and Services Downstream of the Utility Meter

Burner Tip/End-Use Services - Repair and Maintenance - Equipment Sales/Rentals	Billing and Metering[1]
	Meter Services
	Safety and Security Services
DSM Investments	- Carbon Monoxide Detectors - Call Dispatch
Financing	
Warranties	Heating Insurance Services
Energy Management Systems	Commodity Sales

In general, the total range of goods and services potentially provided by energy utilities can be categorized as belonging to one of three areas. Figure 2 depicts these areas as part of the question of determining the proper domain of the utility. These areas are: goods and services which still clearly are defined as core monopoly products (e.g., wires and pipes), competitive products which could best be produced by a variety of players operating within a competitive market (e.g., appliance sales), and debatable/transitional products, i.e., those which are associated with the monopoly core and which may or may not be considered true monopoly activities depending on one's assessment at any given time (e.g., billing/meter information). For example, these products might be provided by the utility as they emerge, later be produced by a mix of utility and unregulated providers as the market grows and eventually be provided solely by the competitive market when the market is mature (e.g., natural gas vehicle conversions). Core monopoly products result primarily from economies of scale or scope and are expected to decrease as a result of advances in technology reducing these economies, competitors' demands for access to the market for these products, customers' demands for more choice and the success of deregulation elsewhere.

1. Some parties argue that the meter/regulator assembly and meter reading information to customers may also become a competitive service. However, in the near term, the utility will require basic meters in its control to verify the quantities of energy transported by the monopoly pipes or wires.

Figure 2

The Domain of the Utility

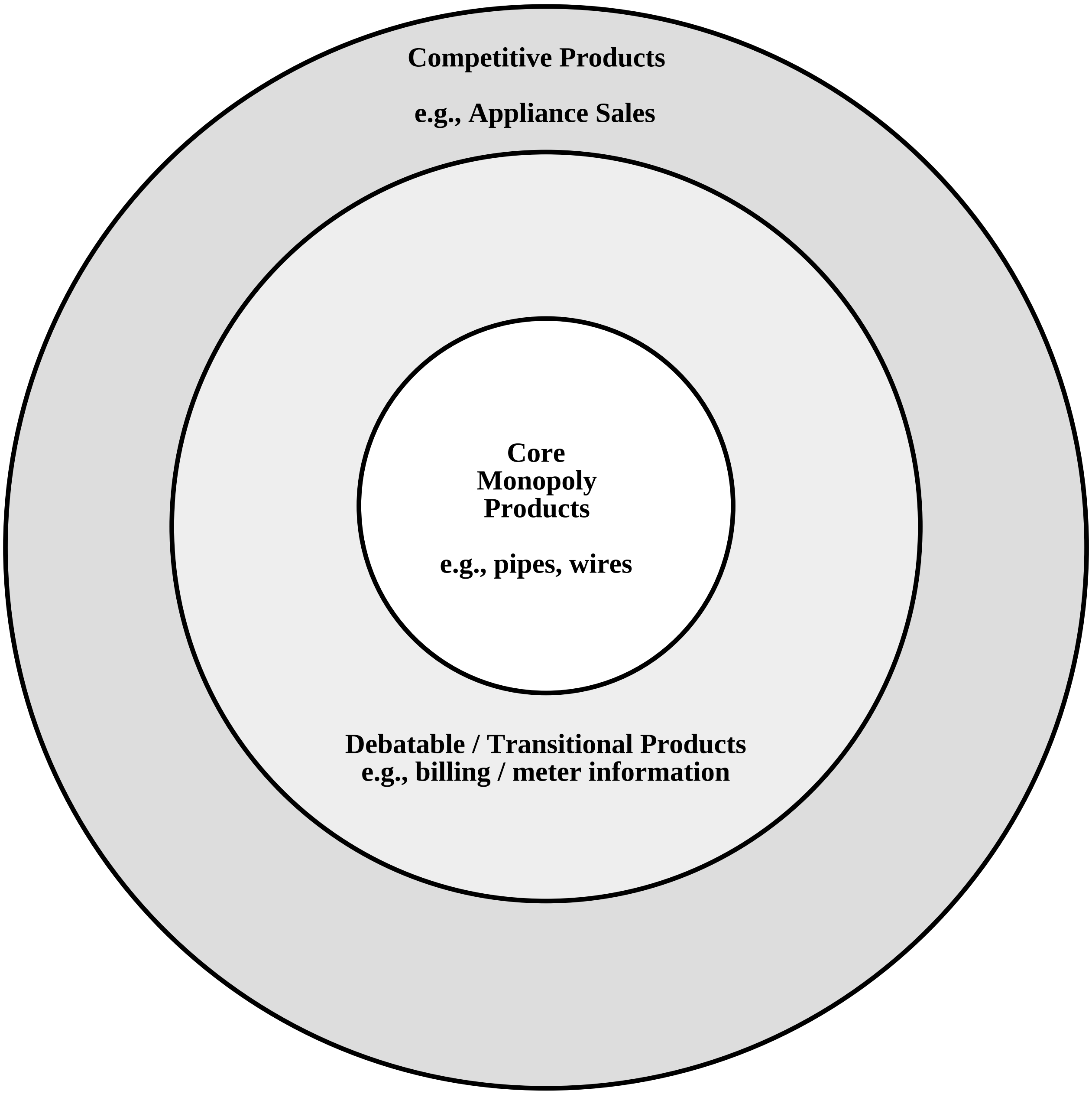


Figure 3: Goods and Services Providers Downstream of the Utility Meter

Heating/Cooling/Plumbing and Electrical Contractors	Mega-Box Stores
	Appliance Retailers
Energy Service Companies ("ESCOs")	Telecom/Cable Companies
Energy Consultants	Financial Institutions
Security Companies	Software Developers
Home Service Retailers	Call/Dispatch Centres
Home Inspectors	B.C. Utilities and NRBs
Hardware/Lumber Stores	Non-B.C. Utilities and NRBs

Figure 3 identifies current and potential service providers of goods and services downstream of the utility meter. These parties vary substantially in size and specialization. Other market participants include traditional customers and other parties such as water/sewer service providers and emergency response providers that might be able to use services which the utility provides 'in-house', (e.g., meter reading, dispatch services).

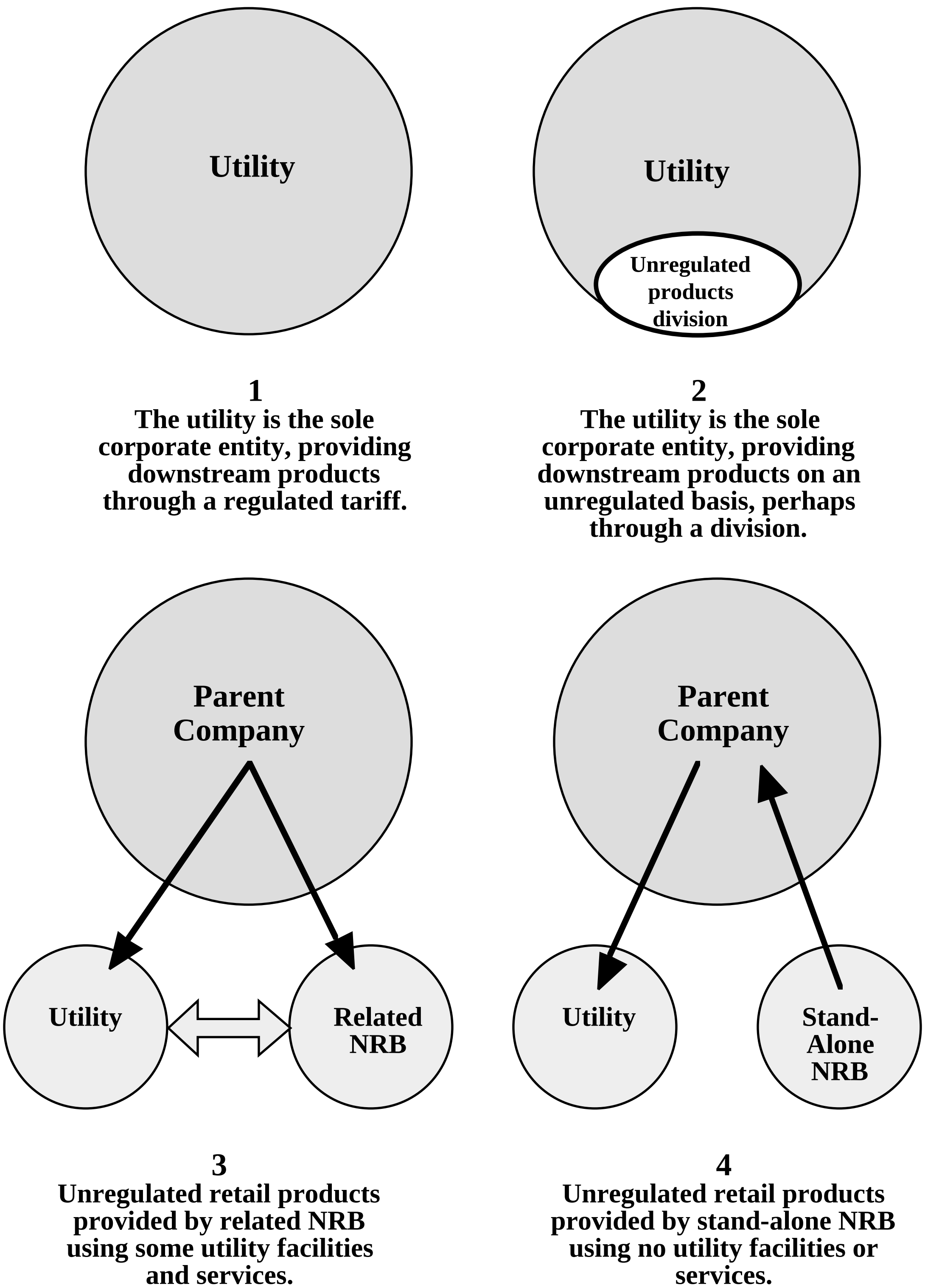
3.0 ROLE OF THE COMMISSION IN THE NEW MARKET PLACE

In British Columbia, regulation of natural gas and electricity utilities is undertaken by the British Columbia Utilities Commission ("BCUC", "the Commission") under the authority of the Act. The Commission’s powers include oversight of utility rates and the utility expenditures responsible for those rates. The staff position paper concluded that these powers give the Commission the ability to define the utility's domain, that is to determine which goods and services the utility will provide, since the utility would be unlikely to offer services for which it cannot recover the costs. As a result, the paper suggested that the Commission has the power to influence the corporate structure under which utility shareholders will participate in the unregulated market.

Four corporate structures, under which retail products and services could potentially be provided, were identified in the staff position paper: i) through the utility as a regulated tariff product; ii) through the utility as a non-regulated product; iii) through an NRB affiliated with the utility either as a subsidiary or through a parent company and using some utility facilities and services; or iv) through an NRB but using no utility facilities or services. These structures are differentiated primarily by the extent to which utility assets and services are used to provide goods and services into the downstream retail market. These four corporate structures are presented in Figure 4.

Figure 4

Potential Corporate Structures



Although the paper suggested that the Commission can determine how the utility or its affiliates participate in the unregulated market, it indicated that the Commission does not have the power to control the activities or to determine what services an NRB will provide **if** the NRB is a self-financing, stand-alone, arm's length affiliate using no resources of the utility. However, where the NRB is not a completely stand-alone entity, the paper suggested that the Commission can exercise control over funding, manpower or other services that may be provided by the utility to the NRB, including the use of shared offices, shared services and manpower charge-out rates.

In either case, the paper stated that the power to oversee utility rates and expenditures confers on the Commission the power to oversee the relationship between the utility and any related-NRB to ensure that no NRB costs are passed on to utility customers. Specifically, the Commission has a duty to ensure that utility ratepayers are, at the very least, not negatively affected by the activities of NRBs. However, the paper indicated that it is less clear whether the Commission has the power to ensure that NRBs receive no benefit from being affiliated to a utility, even if no costs accrue to the utility customers from the affiliation.

As expected, the Commission received a variety of comments concerning the views expressed in the staff position paper. Generally, the utilities argued that the Commission had limited jurisdiction with respect to the issue of utility participation, either directly or indirectly, in downstream retail markets. For example, the British Columbia Hydro and Power Authority ("B.C. Hydro") argued that the Act does not grant jurisdiction to the Commission to regulate competition in downstream retail markets, to restrict a utility in any way from entering the downstream retail market, nor to exercise any sort of jurisdiction over the activities of a stand-alone NRB.

BC Gas Utility Ltd. ("BC Gas") argued that the Commission has the jurisdiction to oversee the prudency of the provision of resources by the utility to an NRB but has no jurisdiction to constrain an NRB from obtaining resources from the utility or any other market provider. This seems to imply that in BC Gas' view the Commission has responsibility to minimize potential negative impacts on ratepayers but cannot determine what benefits, if any, NRBs or other participants receive from the utility as long as there is no risk of cross-subsidization from ratepayers. In addition, BC Gas stated that the Commission has no jurisdiction to determine the appropriate degree of competition in the market place.

Westcoast Energy Inc. ("Westcoast") also argued that the regulator does not have jurisdiction over the activities of the NRB even if the NRB purchases some support services from the utility. Westcoast stated that the regulator is limited to ensuring that the utility does not, by its behavior or structure, abuse its monopoly position to prevent the development or continuation of a competitive market for those products and services that are not regulated. Westcoast stated that this implies that there should be no cross-subsidization and that NRBs should not be given information which would interfere with fair competition.

Enron Capital and Trade Resources Corp. ("Enron") took a broader view of the Commission's powers, stating that the Commission's powers include the ability to restrict a utility from entering the downstream retail market and to regulate the relationship between the utility and NRBs. In Enron's view, this includes the power to ensure that NRBs receive no benefit from their affiliation with a utility, even if no costs accrue to the utility customer. In this view they were supported by the Heating, Ventilating and Cooling Industry Association ("HVCI").

In response to these submissions, the Commission staff sought a legal opinion on the issue of the Commission's jurisdiction with respect to downstream retail markets. In summary, the opinion stated the following:

1. The Commission does not have the jurisdiction to directly regulate an NRB unless the NRB is itself a public utility, a common carrier, or a common processor.

2. The Commission has the jurisdiction to regulate the relationship between a public utility and an affiliated NRB to the extent that the relationship affects ratepayers. For example, the Commission has the jurisdiction to ensure that an NRB is not 'subsidized' by a public utility to the detriment of ratepayers.

3. The Commission does not, however, have the jurisdiction to regulate the relationship between a public utility and an NRB so as to ensure the relationship does not affect the competitive retail market downstream of the meter. The Commission's jurisdiction is limited to consideration of the effects of the relationship on ratepayers.

4. The Commission has the jurisdiction to regulate retail market downstream of the utility meter ("RMDM") activities by a public utility, but only to the extent that such activities affect ratepayers. Similarly, the Commission has the jurisdiction to prohibit a public utility from participating in RMDM if prohibition is the only reasonable and effective means by which the Commission can mitigate or alleviate any negative effects on ratepayers.

5. Ratepayers do not own a public utility's corporate name. The corporate name is goodwill which is owned by the company. The shareholders have a right to share in the assets of a company, including the corporate name, if the company is dissolved.[1]

4.0 STAFF PROPOSAL: POSITIONS OF PARTIES

This section contains a summary of the views presented in the submissions regarding the staff paper. The Commission's determinations on these issues are provided in Section 5. This allows for a consolidated statement of Commission policy that may be used as a working document for future discussions.

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[1]. Opinion Letter from Boughton, Peterson Yang Anderson dated March 10, 1997.

4.1 Commission Objectives

The Commission staff position paper proposed a set of principles and guidelines to help the Commission make determinations regarding utility and related-NRB participation in the retail market downstream of the utility meter. As a starting point, the paper identified four objectives which staff suggested should guide any determinations the Commission made. These are presented in Figure 5.

Figure 5: Suggested Commission Objectives

There must be no subsidy of unregulated business activities, whether undertaken by the utility or its NRB, by utility ratepayers.
The risks associated with participation in the unregulated market must be borne entirely by the unregulated business activity, that is the risks must have no impact on utility ratepayers.
The most economically efficient allocation of goods and resources should be sought.
Customer choice should be maximized.

These objectives were not seen to be completely mutually achievable in all cases so that it was expected that trade-offs between objectives would need to be made. Further, staff expected that the extent to which the achievement of one objective would preclude the achievement of another would depend on the individual circumstances associated with a proposal. As a result, staff suggested that any proposal by a utility to enter the downstream retail market, either directly or through a related-NRB, should be evaluated by the Commission on a product and utility specific basis.

All parties seemed to be in agreement with the first two objectives identified in the staff position paper, although Pacific Northern Gas Ltd. ("PNG") stated that there should be symmetry between risk and reward so that, if the NRB bore all the risk of the unregulated enterprise, it should also receive all the reward.

However, several parties took issue with the third and fourth objectives identified in the paper. The Consulting Engineers of British Columbia ("CEBC") suggested that the Commission did not have the jurisdiction to pursue either the third or fourth objectives. This was echoed by HVCI who argued that the Commission did not have a mandate to influence the market in any way. In particular, they argued that the Commission's mandate did not extend to exploiting economies of scale or scope, even if their exploitation benefited ratepayers, nor did it extend to the maximization of customer choice. The Mechanical

Contractors Association of British Columbia ("MCABC") suggested that the objectives were unclear while PNG indicated that economic efficiency was difficult to measure objectively.

In contrast, the Consumers Association of Canada (B.C. Branch) et al. ("CACBC (B.C.) et al.") agreed with all four objectives and indicated that priority should be given to maximizing customer choice. Westcoast also appeared to support all four objectives, arguing that customers should be free to choose what they want and that their choice should determine market structure. Westcoast stated that the rights of customers and shareholders to capitalize on potential efficiency gains should also be recognized. PNG also supported the objective of customer choice and noted that a key aspect of customer choice is the quality of service provided, not just the number of providers.

Enron also supported all four objectives but indicated that a fifth objective should be added, namely, the preservation and enhancement of robust competition in downstream markets. Enron argued that preservation and enhancement of robust competition would support economic efficiency and customer choice. In contrast, BC Gas argued that the Commission did not have jurisdiction to preserve or enhance competition so that the objective suggested by Enron should not be accepted.

BC Gas did not take issue with the four objectives put forward by staff but stated that different proposals to move current utility services from the utility to an NRB will affect the objectives differently and that flexibility will be required. Further, BC Gas argued that any statement of objectives adopted by the Commission should include some reference with respect to the Commission pursuing these objectives only in the areas in which it has jurisdiction.

4.2 Choosing a Corporate Structure: Criteria

As shown in Figure 4, the staff position paper identified four corporate structure options under which goods and services could be provided to the downstream retail market. The paper suggested that, for any individual proposal for utility participation in the downstream retail market, the corporate structure which should be chosen was that which best met the four objectives. As shown in Figure 4, these corporate structures are:

i) provision by the utility as a regulated tariff item;
ii) provision by the utility as an unregulated good;
iii) provision by an NRB using some utility resources; and
iv) provision by a completely stand-alone NRB using no utility resources.

In assessing which of the four corporate structure options best satisfies the four objectives discussed above for any particular proposal, the position paper suggested the following criteria.

i) Does a natural monopoly currently exist for the good or service?

ii) If the good or service is not a natural monopoly, can the utility ratepayer be sufficiently protected if either the utility or an NRB offers the good or service?

iii) Are there significant economies of scale or scope associated with the good or service?

iv) Could the provision of the good or service be used to offset assets which would otherwise be stranded?

v) Does there already exist significant customer choice with respect to the good or service?

vi) Is the provision of the good or service by the utility or a related-NRB likely to lead to market dominance abuses in the long term?

Several parties indicated that of the four potential corporate structures identified for the delivery of goods and services to the downstream retail market, only two were acceptable. These were: i) provision by the utility as an regulated tariff item, and iv) provision by completely stand-alone NRBs using no utility resources. Groups such as HVCI and MCABC argued that, unless the good or service were a natural monopoly, utilities should only be allowed to participate in the downstream retail market through a stand-alone NRB using no utility facilities or services. This was seen as providing maximum protection to the ratepayer and is consistent with their view that only the first two of the four staff objectives should be reflected in the Commission's decision making. Further, MCABC argued that given the current level of fiscal restraint in government, it was unlikely that codes of conduct and other watchdog measures could be adequately enforced.

These groups appeared to recognize that using utility resources to provide downstream services could result in the avoidance of stranded utility assets but argued that it would be at the expense of current service providers. CEBC argued that the Commission should not be concerned about the economic well-being of the utility at the expense of the economic well-being of other industry participants, while MCABC argued that reduced utility earnings now should be weighed against years of good, stable earnings. Further, MCABC argued that allowing utilities to compete in the downstream retail market, either directly or through related-NRBs, would lead to a loss of customer choice in the long term.

Enron also argued that utilities should be prohibited from participating in the downstream market other than through stand-alone NRBs except under very exceptional circumstances. Although Enron did not appear to reject the proposed criteria, they argued that restricting participation to stand-alone NRBs was required to mitigate both the risk of cross-subsidization and the risk of anti-competitive behavior by the utility. Further, they argued that, since the only appropriate utility functions were those related to the 'pipes and wires', there was unlikely to be any significant economies of scale or scope to offset the increased risk of a related-NRB. Finally, they argued that they did not believe utility participation would enhance customer choice since any competitive advantage accruing to the NRB from association with the utility would be detrimental to competition. For example, Enron suggested that utility participation in Demand-Side Management ("DSM") programs does not enhance customer choice since it restricts participation by new entrants that could provide the service. Accordingly, Enron asked the Commission to adopt the decision taken by the Manitoba Public Utilities Board, which prohibited utility participation except through completely stand-alone NRBs.[1]

In contrast to the position outlined above, the utilities supported the potential use of related-NRBs to enter the downstream retail market. West Kootenay Power Ltd. ("WKP") agreed that a stand-alone NRB was the best way to protect ratepayers but stated that it might not be ideal in every circumstance. In particular, WKP argued that restricting participation to stand-alone NRBs could prevent achievement of economies of scale or scope, particularly when these economies were linked to core competencies. Accordingly, WKP argued that, when there are substitutes which could provide effective ratepayer protection, these alternatives should be allowed .

BC Gas indicated that it wished to move existing utility services which could or should be provided on a competitive basis out of the utility and into NRBs but indicated that this would need to be done as market conditions permitted. Further, BC Gas indicated that, while it viewed the provision of retail services by a stand-alone NRB as the preferred long-term option, since it prevented any cross-subsidization by utility ratepayers, in the short run it might be necessary to use related-NRBs as a transitional step. BC Gas urged the Commission to provide explicit recognition of the need to permit the 'transitioning' of emerging RMDM products and services from regulated utilities to non-regulated companies. PNG also argued for the use of related-NRBs to avoid stranded costs and stated that the issue of stranded costs was likely to achieve greater importance as the areas of natural monopoly diminished.

BC Gas also expressed concern with how criteria v) and vi) might be applied. With respect to criterion v), BC Gas suggested that, if the utility already has some of the market share of a product or service which is now competitive, the service should be 'transitioned' to the market regardless of the number of competitors. Further, the utility argued that existing and potential customers should be allowed to choose the service they take as well as their service provider.

With respect to criterion vi), BC Gas argued that the Commission has no mandate to determine the potential for long term competitive market abuses, except insofar as the utility's provision of services potentially creates the abuses. Similar views were expressed by WKP, which argued that the

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1. Manitoba Public Utilities Board, *Public Hearing to Review the Guidelines for Acceptable Conduct Between Centra Gas Manitoba In. and its Affiliated Companies*, Order of the Board No. 110/96, released November 4, 1996.

Commission could not consider impacts on unregulated business or unregulated markets when exercising its jurisdiction over services provided by a utility to an NRB.

Westcoast recognized that total separation does provide maximum protection to ratepayers but argued that other factors also needed to be considered. As indicated earlier, Westcoast argued that the rights of consumers and shareholders to capitalize on potential efficiency gains were important. As a result, they argued the degree of corporate separation should reflect individual circumstances.

Westcoast also expressed concern with respect to criterion vi), arguing that the regulator is limited to ensuring the utility does not, by its behavior or structure, abuse its monopoly position to prevent the development or continuation of a competitive market for those products and services which are not regulated. Specifically, they argued that the Commission is confined to ensuring that there is no cross-subsidization and that NRBs are not given information which would interfere with fair competition. In addition, Westcoast stated that market dominance achieved under fair competition and contestable market conditions was not, in and of itself, abusive. Finally, Westcoast argued that forcing a stand-alone NRB structure on utility participation in retail markets was of no value to consumers unless it was the result of customer choice.

Other parties, such as Willis Energy Services ("Willis") and Kanelk Transmission Company ("Kanelk"), argued that participation through stand-alone NRBs should not be required under all circumstances. Willis argued that this could lead to extra costs and that as long as NRBs covered their own costs ratepayers were adequately protected. Kanelk argued that allowing utilities to compete in the downstream retail market increased customer choice.

4.3 Choosing a Corporate Structure: Principles

Finally, the staff position paper suggested that if the six criteria discussed above were accepted, the following principles would be appropriate for making determinations with respect to proposals regarding specific goods and services.

i) If a natural monopoly exists for the good or service, it should be provided as a regulated tariff item (Corporate Structure 1 in Figure 4).

ii) Utility participation in the unregulated downstream market by completely stand-alone NRBs using no utility resources is generally the preferred option since it provides the maximum protection to utility ratepayers (Corporate Structure 4 in Figure 4). Variations from this option should be undertaken only when it can be shown that this option would result in the loss of significant economies of scale or scope, the incurrence of substantial stranded costs for the utility, or undue restriction in customer choice.

iii) The onus should always be on the utility to prove that the benefits associated with the use of utility resources are sufficient to warrant the changed structure. Generally, the Commission would expect to see economies of scale or scope, or the avoidance of stranded costs, only with respect to goods or services which are closely aligned to the utility's core competencies, e.g., billing and meter reading and meter services. Similarly, benefits from increased customer choice are most likely to occur in new and emerging markets or where there are few current providers of the good or service, (e.g., equipment repair services in remote communities).

iv) If the Commission decides to allow the use of utility resources in the provision of the unregulated good or service, the preferred option is through a related-NRB (Corporate Structure 3 in Figure 4). Direct participation by the utility in the provision of an unregulated good or service should be allowed only when the costs associated with forcing the provision through the related-NRB structure would significantly offset the benefits associated with the use of the utility's resources (Corporate Structure 2 in Figure 4).

v) Utilities and their related-NRBs must move unregulated products which use utility resources into stand-alone NRBs as soon as market conditions warrant or the Commission otherwise so determines (Corporate Structure 4 in Figure 4). Utilities will be required to provide periodic proof that the benefits associated with the use of utility services continue to exist.

vi) In all cases, the Commission should consider the long-term effects on the market of utility or related-NRB provision of unregulated goods and services.

All parties appeared to agree that if a good or service were a natural monopoly, it should be provided as a regulated tariff item. MCABC also supported the concept that a completely stand-alone NRB was the preferred option for utility participation in the downstream retail market and that the onus is on the utility to prove why a variation from this structure is desirable. However, MCABC opposed the use of any utility resources in the provision of unregulated goods and services under any corporate structure.

MCABC supported the principle that utilities and their related-NRBs must move unregulated products which use utility resources into stand-alone NRBs as soon as market conditions warrant or when the Commission otherwise so determines. However, MCABC expressed concern that the staff position paper appeared to envision a situation in which the utility would begin a project at ratepayer expense but move it to an NRB once it became profitable, without compensation to the utility. MCABC argued that assets acquired under regulation are not the exclusive property of the company and shareholders but are the shared assets of both the company and ratepayers. Accordingly, it stated that if assets were moved to an NRB, the utility and its ratepayers should be compensated.

As well, MCABC requested that the Commission nullify the 1988 agreement between Inland Natural Gas and its successors and MCABC, regarding appliance sales. Finally, MCABC indicated that the principle that the Commission should consider the long-term effects on the market of utility or related-NRB provision of unregulated goods and services was unclear.

The Association for the Advancement of Sustainable Energy Policy ("AASEP") also was concerned that ratepayers might be made to pay the start-up costs for DSM programs which would then be transferred to NRBs once the programs became profitable. Additionally, AASEP expressed concern that the movement to non-regulated supply would change the type of programs offered, that market failures would not be addressed and that too little DSM would be purchased. Accordingly, AASEP argued that utilities should only be allowed to change DSM programs if they can show that the new programs would deliver equal or greater savings.

Both PNG and BC Gas indicated that they saw the principles set out in the staff position paper as being reasonable, although BC Gas stated that the Commission should make clear that any principles and guidelines adopted by the Commission applied only to the provision of utility resources used to support downstream retail market activities during a transitional period. Similarly, WKP stated that the final principles and guidelines should clearly state that the principles and guidelines are not intended to affect products and services traditionally provided by the utility, such as metering and billing. In addition, BC Gas stated that in its view, in considering long-term effects, the Commission was limited to considering the terms for provision of resources by the utility to a related-NRB and the impact on the utility and its ratepayers, and not to the market generally. This view was supported by the City of New Westminster ("the City") which suggested that the Commission did not have the jurisdiction to consider the effect that utility-provided goods and services could have on the market. In addition, the City argued that the Commission did not have the responsibility to determine when market or other conditions warranted the transfer of a business activity from the utility to an NRB.

Kanelk stated that they did not support the principles set out in the paper since they viewed the Commission's duty to be limited to ensuring that ratepayers do not subsidize non-regulated operations. Accordingly, they argued that each utility should have the flexibility to develop its own corporate structure, as long as it can reasonably demonstrate that the regulated operations are not subsidizing the non-regulated operations.

4.4 Transfer Pricing Policy

The staff position paper suggested that, where utility resources are used to provide unregulated goods and services, either directly or through a related-NRB, the use of the utility resources must comply with a Commission-approved transfer pricing methodology. Further, the paper suggested that the transfer pricing policy should ensure the following:

i) The operating costs of non-regulated activities are not reflected in the utility's cost of service.

ii) The costs of developing new business ventures are charged to and recovered from the NRB.

iii) The accounting costs are transparent and fully recover costs for all services, including overhead, space, employee benefits, inconvenience, and a profit margin where appropriate. If the service provided by the utility to the related-NRB could also be obtained from an independent supplier, the price paid by the related-NRB to the utility should be no less than the competitive market price.

iv) The financial costs of each business are borne by the business. In the exceptional case where the utility provides guarantees, it must be given financial compensation.

All parties appeared to recognize that if the Commission were to allow utility affiliated NRBs to use utility facilities or services, a transfer pricing policy governing these transactions is required. BC Gas stated that ensuring an equitable return to the utility for any services provided, providing appropriate protection to ratepayers and preventing any unfair competitive advantage from being conferred on the related-NRB should be the prime considerations with regard to structuring such a policy. However, BC Gas also argued that the specific components of the transfer pricing policy should be established on an NRB-specific basis to reflect individual circumstances rather than as a blanket policy designed to apply to all circumstances. Accordingly, BC Gas suggested that, in this process, the Commission should establish a general framework to ensure that these goals were met but develop more specific rules when specific applications were brought forward. BC Gas also argued that the transfer pricing policy should specify that there would be periodic reviews for compliance. This was echoed by MCABC, which called for periodic reviews of transactions between the utility and its NRBs.

WKP argued that the transfer pricing policy should simply ensure that the incremental operating cost of non-regulated activities are not reflected in the utility's cost of service. Further, WKP stated that the price at which facilities or services were priced to the NRB should be at their incremental cost of provision. Although the staff position paper contemplated that facilities and services would be charged at the full embedded cost of the facility or service, WKP argued that there was no economic reason to price at anything more than incremental cost. Indeed, WKP argued that to price services above incremental costs would result in ratepayers benefiting at the expense of the NRB customer.

PNG also suggested that the charge which the NRB paid should be based on the incremental or marginal cost of providing the service but added that the charge should also include some return for the utility ratepayer. In this way, PNG argued that the benefits of sharing services or facilities would accrue to both the NRB and the utility rather than going entirely to the utility.

Kanelk indicated that it supported the transfer pricing policy although it suggested that if ratepayers were bearing none of the risks of the non-regulated activities, they should reap none of the rewards. In addition, Kanelk rejected the position that NRBs must be financed separately from the utility, suggesting that this could result in a sub-optimal corporate structure which could adversely affect a utility's ability to compete in the market.

Enron, who had argued that NRBs should be stand-alone except under exceptional circumstances, argued that utilities and their NRBs should be permitted to share overhead administrative services to the extent that such sharing does not allow the exchange of market-sensitive information.

4.5 Code of Conduct

The staff position paper suggested that the utility and its NRB must comply with a Commission-approved code of conduct. The paper suggested that each utility develop its own code of conduct to reflect its particular circumstances and unregulated market offerings, but that all codes should cover employment of utility personal, including career training and development, procedures for contracting for utility services (sharing and costing of resources), treatment of confidential information (management and employees), inter-company procurement and review of information (accounting, allocation and reporting). The policy should also ensure that no financial risk from the unregulated activities accrues to the utility. Specifically, sufficient safeguards should be put in place to protect utility ratepayers from any liability associated with the unregulated activity.

Specific suggestions for inclusion in the code included the following:

i) The regulated company will not provide to the NRB any market-sensitive or confidential information that would inhibit a competitive energy services market from functioning. If customers agree to the release of customer information, it should be provided to anyone for a price based on non-discriminatory access to the information.

ii) No regulated company personnel will state or imply that favoured treatment will be available to customers of the company as a result of using any service of an NRB.

iii) No regulated company personnel will preferentially direct customers seeking competitively offered services to an NRB.

iv) The regulated company will formally advise all employees of expected conduct related to these principles and it will undertake to perform periodic audits of the relationships to ensure compliance with these principles.

v) Complaints by non-affiliated parties about the application of these principles, or any alleged breach thereof, will be brought to the immediate attention of the senior management of the regulated company and subsequently a report of the complaints, and action taken, will be filed with the Commission.

vi) The financing of the utility and NRB will be accounted for entirely separately with the financing costs reflecting the risk profile of each entity.

vii) NRBs will not be allowed to use the utility name as the primary identifier of the company, but can make reference to the name of its parent company on letter head, advertisements, etc.

In those cases where retail customers have direct market access to the commodity, the utility's code of conduct will also include the following provision.

viii) The regulated company will treat all requests for distribution system access for the purpose of direct commodity marketing equitably and according to the requirements approved for direct commodity marketing in British Columbia.

Several parties had comments with respect to the code of conduct. PNG stated that the relationship between utilities and NRBs should be governed by a set of rules which ensure that there is no cross-subsidization between the utility and the NRB and that there is no unfair competition. However, PNG stated that these rules should not preclude the NRB from offering a complete menu of energy solution services.

BC Gas stated that the code of conduct must outline the utility's relationship with its unregulated businesses, including the transfer of information and the provision of resources, that it should ensure the minimization of risks to ratepayers, and that it should ensure that no unfair advantages are created for the NRB. However, BC Gas indicated that these rules may need modification during transition periods and that the level of information sharing between the utility and the NRB should reflect specific circumstances.

Westcoast argued that concerns about cross-subsidization should be dealt with through cost allocation and pre-determined transfer pricing guidelines. In addition, Westcoast argued that rules for affiliated NRBs should not prohibit the affiliated NRB from offering a comprehensive package of services since, to do otherwise, implies customers are precluded from the benefits of a bundled service.

HVCI expressed concern that the staff position paper contemplated each utility writing its own code of conduct. HVCI appeared to be concerned that this would be done without Commission input and that each utility would control what the code of conduct allowed. Enron suggested that the code of conduct should be developed by a working group of all interested parties and that the Commission should set a deadline for its development.

With respect to the first item in the suggested code of conduct, governing the flow of information, Kanelk suggested that it be amended to state that the regulated company will provide confidential information to a third party if requested to do so by the customer, without necessarily making the information available to other third parties. In addition, Kanelk suggested that the utility be allowed to recover the costs of doing so. Enron indicated that the code should include provisions which state that a regulated company should not provide any market information to the NRB unless that information is made available on comparable terms, in terms of price and timing, to other market participants. In contrast, WKP suggested that the code of conduct should only include a statement as to the privacy of the customer information, a statement as to who shall have access to the information, and the fee to be charged to affiliates or any other party requesting such information.

With respect to the second item, that no regulated company personnel will state or imply that favoured treatment will be given if a customer does business with a utility NRB, Enron argued that the code should include a prohibition from condoning or acquiescing in any other person stating or implying that favoured treatment will be available to customers of the regulated company as a result of the customer using any service of, or conferring any benefit directly or indirectly on, an NRB. In addition, Enron stated that the third item in the suggested code, that no regulated company personnel will preferentially direct customers seeking competitively offered services to an NRB, should be modified to state that if a customer or potential customer requests from the regulated company information about products or services offered by an NRB or its competitors in downstream markets, the regulated company may provide such information, including a directory of retailers of the product or service, but shall not promote any specific retailer in preference to any other retailer.

Several parties suggested revisions with regard to the complaint procedure described in the staff position paper. CACBC (B.C.) et al. stated that the code should make provision for periodic reviews with the results forwarded automatically to the Commission. Enron suggested that the code of conduct must be effective and enforceable and expressed doubt that Section 124(4) of the Utilities Commission Act, which allows the Commission the power to impose a penalty of up to $10,000 for failure to comply with a direction of the Commission made under the Act, contained the appropriate or sufficient penalty. Enron suggested that, if the code of conduct were breached, an appropriate penalty would be the loss of use of utility resources for some specified period of time. Enron also argued that the Commission must review and rule on any complaints concerning violations of the code. BC Gas suggested that all complaints should be forwarded to the Commission which will then forward such complaints to the appropriate utility for resolution. BC Gas also argued that flexibility with respect to penalties for non-compliance with the code was needed and that there should not be one penalty for all code violations.

As indicated earlier, Kanelk rejected the position that non-regulated businesses must be financed separately from the utility since they believed this could result in a sub-optimal corporate structure which could adversely affect a utility's ability to compete in the market. However, Enron suggested that the code be expanded to prohibit cross-guarantees or any other form of financial assistance whatsoever being provided directly or indirectly by a utility to its NRB

Significant discussion revolved around the use of the utility name by NRBs. All utilities argued that the right to use the utility name belonged to the shareholders of the utility who had the right to use it as they wished. WKP stated that the value of the name arose from the goodwill with which the company was regarded. As customers do not pay for goodwill in rates, WKP argued that the value of the name accrued solely to shareholders. Westcoast provided a similar argument. In addition, Westcoast maintained that name recognition was not an unfair advantage.

CACBC (B.C.) et al. agreed that NRBs should be allowed to use the utility name since they viewed this as providing information which customers would value. However, they maintained that the NRB should pay for the privilege since the goodwill associated with the name belonged to the utility. If the NRB did not pay for the use of the name, they maintained that this would amount to transferring a valuable asset to the NRB without any compensation. They suggested that independent evaluations be done to establish the value of any particular utility name.

HVCI took a similar position, arguing that the goodwill associated with the use of the utility name arose from items for which ratepayers, through the utility, had paid, including institutional advertising and charitable contributions. HVCI characterized the use of the utility name as a soft but effective cross-over benefit which is inconsistent with the spirit of fair competition. Further, they argued that if the utility were allowed to charge the NRB for the use of the name, the name should be made available to anyone who wished to purchase it.

MCABC also argued that NRBs should not be allowed to use the utility name. They argued that assets, acquired under regulation, are not the exclusive property of the company and shareholders but the shared assets of both the company and the broader shareholders, the rate-paying public. In particular, they argued that the name was an asset of the utility and that the assets of the utility belonged to ratepayers since the assets had been paid for through rates. Further, they argued that the fact that NRBs wanted to use the utility name implied that NRB participation is not viable without it.

With respect to the last item in the proposed code of conduct, that the regulated company will treat all requests for distribution system access for the purpose of direct commodity marketing equitably and according to the requirements approved for direct commodity marketing in B.C., Enron argued that 'equitably' should be defined as follows:

1. A utility must apply any tariff provision relating to utility service in the same manner to the same or similarly situated persons if there is discretion in the application of the provision.

2. A utility must strictly enforce a tariff provision for which there is no discretion in the application of the provision.

3. A utility may not, through a tariff provision or otherwise, give its marketing affiliates or customers of affiliates, preference over non-affiliated companies or customers in matters related to utility service including, but not limited to, scheduling balancing metering, storage, standby service, or curtailment policy.

4. A utility must process all similar requests for utility (service) in the same manner and within the same time period.

In addition to comments on the items in the proposed code of conduct, some parties suggested certain additions. CACBC (B.C.) et al. suggested that the code provide more specific guidance. For example, they argued that the code should include a prohibition of routine movements of personnel between utilities and NRBs by way of transfers or promotions. In addition, Enron stated that the code should require separation of the operating personnel of the NRB from the operating personnel of the utility to the maximum extent possible.

4.6 Other Issues

Certain parties, such as Novagas Clearinghouse Ltd., stated that the commodity function should be removed from the utility since provision of the commodity is not a natural monopoly.

5.0 COMMISSION GUIDELINES WITH RESPECT TO UTILITY OR NRB PARTICIPATION IN DOWNSTREAM RETAIL MARKETS

5.1 Use of Utility Assets and Services in the Downstream Retail Market

5.1.1 Jurisdiction

Based on the submissions received as well as the legal opinion sought by staff, the Commission understands its jurisdiction with respect to the use of utility assets and services to provide unregulated goods and services to be as follows.

The Commission does not have the power to control the activities or to determine what services an NRB will provide if the NRB is a self-financing, stand-alone, arm's length affiliate using no resources of the utility.

The Commission has the jurisdiction to regulate the relationship between a public utility and an affiliated NRB to the extent that the relationship affects ratepayers. The Commission may implement a transfer pricing policy to regulate the interface between the utility and the NRB or may prohibit a utility from providing an NRB with any utility assets and services if, in the Commission's judgment, this is required to protect ratepayers.

The Commission has the jurisdiction to prohibit a public utility from participating in retail markets downstream of the meter if prohibition is the only reasonable and effective means by which the Commission can mitigate or alleviate any negative effects on ratepayers. In this case, the parent corporation of the utility may still decide to create a subsidiary NRB to participate in the retail market downstream of the meter. Alternatively, the Commission may implement a transfer pricing policy to regulate the interface between the regulated and unregulated activities of the utility if in the Commission's opinion this provides ratepayers with sufficient protection.

The Commission supports the general position of staff that determinations regarding the extent and manner in which utility assets and services may be used to provide goods and services to the downstream retail market should be made on a basis which takes into account individual circumstances. However, it is clear from the submissions received and the legal opinion that certain changes to the specific objectives, criteria and principles initially proposed by staff are needed. The objectives, criteria and principles which the Commission intends to use to guide its determinations regarding the extent to which utility assets and services may be used to provide goods and services to the downstream retail market are outlined below.

5.1.2 Objectives

Based on the information received, it is clear that the Commission has jurisdiction to consider the first two objectives given in the staff position paper when considering the extent to which utility assets and services may be used to provide goods and services to the downstream retail market. Conversely, the Commission finds that it has no jurisdiction to consider the impacts of the use of utility assets and services, either directly or through NRBs, on the retail market downstream of the meter. Accordingly, the fourth staff objective, that customer choice should be maximized, and the additional objective proposed by Enron, that robust competition in downstream markets should be preserved and enhanced, are beyond the responsibilities of the Commission in making its determinations.

With respect to the third objective identified by staff, that the most efficient allocation of goods and resources should be sought, the Commission believes that this forms a proper part of its consideration, but only to the extent that ratepayers are affected. Accordingly, the Commission believes that it may consider whether a proposal would enhance or reduce the possibility of stranded utility assets, or otherwise increase the economic efficiency with which utility assets are used for the benefit of ratepayers, but may not consider the implications for economic efficiency with respect to the larger market. The Commission accepts the concern voiced by some parties that a precise measurement of economic efficiency is not possible, particularly when considered from a societal perspective, but expects that it is possible to determine directionally whether a particular proposal enhances or reduces the likelihood of stranded costs or otherwise provides benefits to ratepayers.

Accordingly, the objectives which will guide the Commission's determinations with respect to utility and NRB participation in the retail market downstream of the meter are as follows.

Figure 6: Commission Objectives

There must be no subsidy of unregulated business activities, whether undertaken by the utility or its NRB, by utility ratepayers.
The risks associated with participation in the unregulated market must be borne entirely by the unregulated business activity, that is the risks must have no impact on utility ratepayers.
The most economically efficient allocation of goods and resources for ratepayers should be sought.

In addition, the Commission agrees with staff that greater achievement of one objective may require a lesser achievement of another objective so that trade-offs may be required. The Commission will be the sole arbiter of how the trade-off between objectives should be made in determining the extent and manner in which utility services and assets may be used to participate in the retail market downstream of the utility meter.

5.1.3 Criteria

With regard to the six criteria proposed by staff, the Commission has concluded that they should be revised as follows.

i) Does a natural monopoly currently exist for the good or service?

ii) If the good or service is not a natural monopoly, can the utility ratepayer be sufficiently protected through a transfer pricing policy mechanism if either a division of the utility or a related-NRB offers the good or service?

iii) Will the use of utility assets or services in the provision of the good or service reduce the risk of utility assets being stranded to the detriment of ratepayers or otherwise provide benefits to ratepayers?

In coming to the conclusion that staff criteria three, five and six should not form a basis for its determinations, the Commission finds that it has jurisdiction to consider the impacts, either positive or negative, of the use of utility assets or services in the provision of goods to the downstream retail market, only with respect to utility ratepayers. If the new service is to be provided within the utility, the Commission will consider the appropriateness of this service within the mandate of the public utility.

5.1.4 Principles

Based on its analysis of the submissions, the Commission determines that principle six, that in all cases the Commission should consider the long-term effects on the markets of utility or related-NRB provision of unregulated goods and services, falls outside of its jurisdiction. Similarly, the Commission accepts that the principles must be revised to exclude references to considerations of customer choice.

Accordingly, the Commission accepts that the following principles should govern the choice of corporate structure.

i) If a natural monopoly exists for the good or service, it should be provided as a regulated tariff item (Corporate Structure 1 in Figure 4).

ii) Utility participation in the unregulated downstream market by completely stand-alone NRBs using no utility resources is the preferred option since it provides the maximum protection to utility ratepayers (Corporate Structure 4 in Figure 4). Variations from this option should be undertaken only when it can be shown that this option would result in substantial stranded costs for the utility and/or that a transfer pricing policy mechanism will act to provide sufficient protection for ratepayers.

iii) The onus should always be on the utility to prove that the benefits associated with use of utility resources are sufficient to warrant the changed structure and that the transfer pricing policy mechanism will provide sufficient protection to ratepayers.

iv) If the Commission decides to allow the use of utility resources in the provision of the unregulated good or service, the preferred option is through a related-NRB (Corporate Structure 3 in Figure 4). Direct participation by the utility in the provision of an unregulated good or service should be allowed only when the costs associated with forcing the provision through the related-NRB structure would significantly offset the benefits associated with the use of the utility's resources and it can be shown that a transfer pricing policy mechanism will provide sufficient protection for ratepayers (Corporate Structure 2 in Figure 4).

v) Utilities and their related-NRBs will be encouraged to move unregulated products which use utility resources into stand-alone NRBs as soon as market conditions warrant (Corporate Structure 4 in Figure 4). When a utility-provided product is moved to an NRB, the NRB will be required to pay fair market value to the utility for the assets, including goodwill, associated with the product. In addition, utilities will be required to provide periodic proof that the benefits associated with the use of utility services continue to exist and that ratepayers continue to be sufficiently protected. The Commission will make directions to prohibit the use of utility assets and services in the provision of goods and services downstream of the retail market at any time that it finds it in the interests of ratepayers to do so.

5.2 Transfer Pricing Policy

As indicated above, the Commission's jurisdiction with respect to the extent to which utility assets and services can be used to provide goods and services in the downstream retail market is centred on the protection of ratepayers. Accordingly, the Commission is convinced that any transfer pricing policy must ensure that ratepayers are kept harmless from any excursion by the utility, either directly or indirectly, into the downstream retail market.

The Commission has concluded that the four components of a transfer pricing policy outlined in the staff position paper are essential. In addition, the Commission agrees with groups such as MCABC that the transfer pricing policy should include a requirement for periodic reviews of transactions between a utility and its NRBs.

The Commission does not agree with parties, such as WKP, who argued that the price at which utility assets or services are charged to the NRB should reflect the incremental cost of provision only. These services have value and the NRB should expect to pay for that value. To do otherwise would mean that all the benefits of shared services accrues to the NRB. Accordingly, the Commission concludes that the provision in the staff paper with respect to pricing of assets and services is appropriate.

Generally, costing should recover the fully allocated cost or the incremental cost, whichever is higher. This will ensure that ratepayers will benefit or are not harmed by the transaction. Where the incremental costs are lower than the fully allocated cost, ratepayers should receive a value by pricing above the fully allocated cost towards a market price for the service. In this latter instances, the Commission will need to consider if such services should be provided to all competitors or to the NRB exclusively.

The Commission is not convinced by the argument that the specific components of the transfer pricing policy should be established on an NRB-specific basis to reflect individual circumstances rather than as a blanket policy designed to apply in all circumstances. Although the Commission accepts that there may be provisions required for a gas utility that may not be required for an electricity utility, or vice versa, the Commission will be reluctant to approve any transfer pricing policy which deviates significantly from that which the Commission believes provides the most protection to ratepayers. In all cases, the burden will lie with the utility to prove that deviations are appropriate.

Accordingly, the Commission concludes that a utility's transfer pricing policy should ensure the following:

i) The operating costs of non-regulated activities are not reflected in the utility's cost of service.

ii) The costs of developing new business ventures are charged to and recovered from the NRB.

iii) The accounting costs are transparent and will normally fully recover for all services, including overhead, space, employee benefits, inconvenience, and a profit margin where appropriate. If the service provided by the utility to the related-NRB could also be obtained from an independent supplier, the price paid by the related-NRB to the utility should be no less than the competitive market price and will never be below the incremental cost.

iv) The financial costs of each business are borne by the business. In the exceptional case where the utility provides guarantees, it must be given financial compensation.

v) Utilities will be required to file periodic reports which demonstrate that they are adhering to the transfer pricing policy. The form and timing of the report will be determined by the Commission.

The Commission will require utilities to bring forward for approval proposed transfer pricing policies at the time they bring forward any application to use utility assets or services in the provision of unregulated goods and services in the downstream retail market.

5.3 The Code of Conduct

In order to protect ratepayers, the Commission will require each utility to bring forward for approval a code of conduct for the relationship between the utility and its NRBs or the utility and any division within the utility which offers unregulated goods or services, at the time the utility brings forward any application to use utility assets or services in the provision of unregulated goods and services.

As with the transfer pricing policy, the Commission is convinced that any code of conduct must ensure that ratepayers are kept harmless from any excursion by the utility, either directly or indirectly, in the downstream retail market. Accordingly, the Commission generally does not accept the argument that the code of conduct should be modified during transition periods and that the level of information sharing between the utility and the NRB should reflect specific circumstances. Although the Commission can envision some circumstances in which such a relaxation of the code might be possible without jeopardizing ratepayers, in these circumstances, the burden of proof that such exceptions are justified will lie with the utility. Further, the justifications must lie within the Commission's jurisdiction to consider. In the absence of sufficient evidence by the utility, no relaxation of the code will be allowed.

Many suggestions were received with respect to the specific elements which should be included in the code of conduct. Much of this debate centred around the use of the utility name by NRBs. The Commission is concerned that the use of the utility name by related-NRBs could interfere with the Commission's responsibility to protect ratepayers. The Commission will likely have to rule on this matter on a case by case basis considering the related-NRB function, the potential impact on ratepayers (including confusion between regulated and non-regulated services) and the services provided by the utility at rates to be determined by the Commission.

Based on all the submissions provided, the Commission determines that the code of conduct principles contained in the staff position paper should be modified as follows:

i) The regulated company will not provide to the NRB any market-sensitive or confidential information that would inhibit a competitive energy services market from functioning. If customers agree to a release of customer information to the NRB, it should be provided to other market participants under the same terms and conditions and for the same price. Should an individual customer make a specific request to have information released to a particular third party, it will be released to that party only. The utility will be able to recover from the customer the costs associated with the provision of this information.

ii) No regulated company personnel will state or imply that favoured treatment will be available to customers of the company as a result of using any service of an NRB. In addition, no regulated company personnel will condone or acquiesce in any other person stating or implying that favoured treatment will be available to customers of the company as a result of using any service of an NRB.

iii) No regulated company personnel will preferentially direct customers seeking competitively offered services to an NRB. If a customer, or potential customer, requests from the regulated company information about products or services offered by an NRB or its competitors in downstream markets, the regulated company may provide such information, including a directory of retailers of the product or service, but shall not promote any specific retailer in preference to any other retailer.

iv) The regulated company will formally advise all employees of expected conduct related to these principles and it will undertake to perform periodic audits of the relationships to ensure compliance with these principles. These audits will be performed no less than once a calendar year and filed with the Commission.

v) Complaints by non-affiliated parties about the application of these principles, or any alleged breach thereof, will be brought to the immediate attention of the senior management of the regulated company and subsequently a report of the complaints, and action taken, will be filed with the Commission. The report will be filed with the Commission within one month of the complaint being made.

vi) The financing of the utility and NRB will be accounted for entirely separately with the financing costs reflecting the risk profile of each entity. No cross-guarantees or any form of financial assistance whatsoever should be provided directly or indirectly by a utility to its NRB without approval of the Commission.

vii) Use of the utility name by a related-NRB will require approval by the Commission to ensure that its use will not interfere with the Commission's ability to protect ratepayers.

In those cases where retail customers have direct market access to the commodity, the utility's code of conduct will also include the following provision.

viii) The regulated company will treat all requests for distribution system access for the purpose of direct commodity marketing equitably and according to the requirements approved for direct commodity marketing in British Columbia.

5.4 Other Issues

At this time, the Commission does not intend to address the issue of whether the commodity function should be removed from the utility. Nothing contained in this paper should be interpreted to imply that the commodity function should be removed.

With respect to the request by MCABC to nullify the 1988 agreement between Inland Natural Gas and its successors and MCABC, regarding appliance sales, the Commission will pursue this matter separately from this policy paper.

List of Initial Responses to Commission Staff Paper

1. Association for the Advancement of Sustainable Energy Policy
2. BC Gas Utility Ltd.
3. British Columbia Hydro and Power Authority
4. British Columbia Public Interest Advocacy Centre
5. Brian Donnelly
6. Building Owners and Managers Association
7. City of New Westminster
8. Consulting Engineers of British Columbia
9. Enron Capital and Trade Resources Canada Corp.
10. Heating, Ventilating and Cooling Association of B.C.
11. International Brotherhood of Electrical Workers - Local 213
12. Kanelk Transmission Company Limited
13. Mechanical Contractors Association of B.C.
14. Northwest Pacific Energy Marketing Inc.
15. Novagas Clearinghouse Ltd.
16. Pacific Northern Gas Ltd.
17. Pan Alberta Gas
18. Radian Mechanical Inc.
19. Residential Hot Water Heating Association of B.C.
20. United Association of Journeymen and Apprentices of the Plumbing and Pipefitting Industry of the U.S. and Canada, Local Union 170
21. West Kootenay Power Ltd.
22. Westcoast Energy
23. Westcoast Seismic Protections Co. Ltd.
24. Willis Energy Service

List of Reply Comments to Initial Responses

1. BC Gas Utility Ltd.
2. British Columbia Hydro and Power Authority
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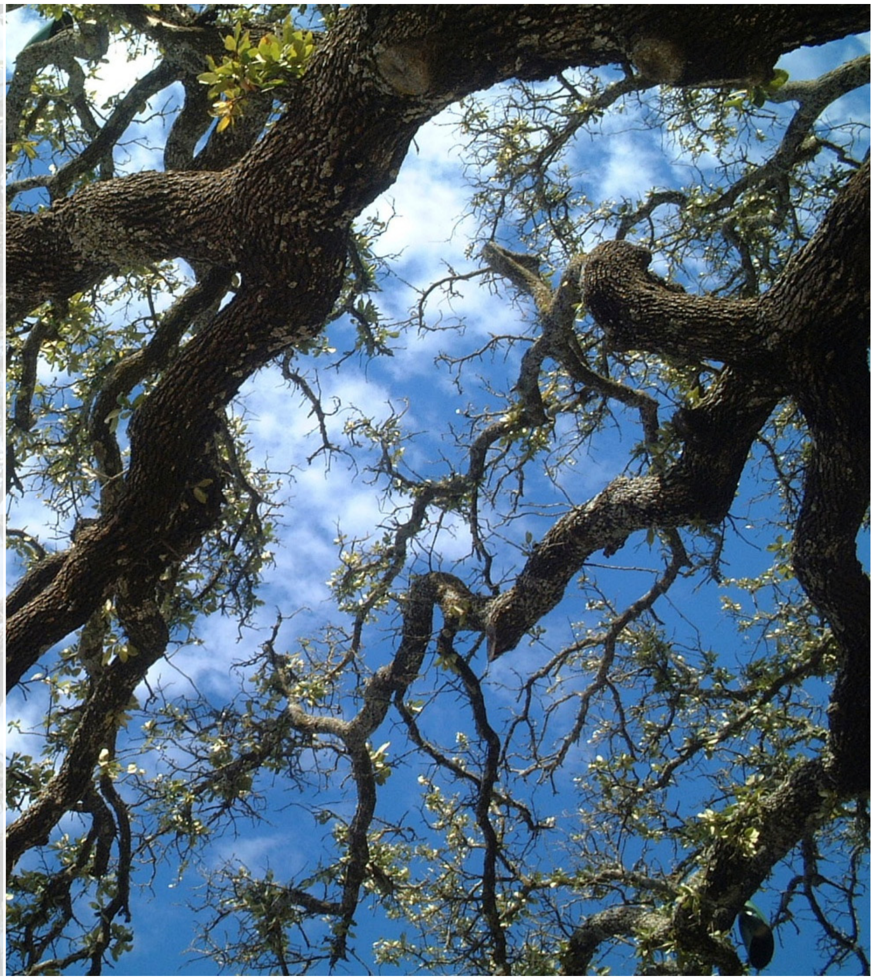
4. Enron Capital and Trade Resources Canada Corp.
5. Heating, Ventilating and Cooling Association of B.C.
6. West Kootenay Power Ltd.

Attachment 11.6

Direct Heat Energy Review

Case Studies and Market Overview

2009



This report outlines and reports the outcome of research into direct heat delivery and a business opportunity for Terasen Gas. The research was done in March and April, 2009 by Friuch Consulting for Terasen Gas under the direction of Jason Wolfe.

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FRIUCH CONSULTING

CONTENTS

EXECUTIVE SUMMARY

Friuch Consulting's services were retained in March, 2009 by Terasen Gas to research international case studies on well established, natural gas marketing companies that have successfully diversified their energy portfolio to include direct use provision of heat to end users through new capacity in solar collector, geothermal and biomass energy. While it was initially thought that the majority of these case studies would come from the EU, the resulting case studies came from the EU, Africa and North America. These case studies are highlighted for their diversity and best practices in bringing direct use heat to market, marketing it and pricing it to incentivize consumers.

This report starts with an examination of the global direct use heating market and focuses on the three biggest sources of direct use energy – biomass, solar and geothermal. Biomass heating generally involves the burning of organic materials such as wood, peat or human waste to create heat. The installed capacity base for biomass heating is enormous and increased interest in the EU in biomass fuel is driving new innovations. Areas affected by Mountain Pine Beetle infestations have the potential to provide abundant biomass fuel.

Solar collector technology uses advanced materials to absorb as much solar energy as possible to heat water which can be used for space heating or hot water requirements within a home or business facility. Despite BC's relatively low solar energy exposure, advances in materials science enables modern solar collectors to extract useful solar energy from even indirect sunlight.

Geothermal energy is the third most common direct use energy source globally with an installed base that is modest but growing. The main challenge limiting large-scale uptake of this technology appears to be the high cost of drilling geothermal wells and then building the infrastructure necessary to deliver steam or hot water to end users. BC has some significant geothermal potential due to its proximity to a fault line but these hot spots are not necessarily located near population densities.

The report highlights case studies of Alliant Energy, Lund Energie, KenGen and Louisville Gas & Electric (LG&E) – all of whom are major gas marketers that are diversifying their energy portfolio to keep up with regulatory compliance and/or to contribute to the public good. Alliant Energy is an American company that helps homeowners install ground-source heat pumps for their homes through a subsidy/refund program. Lund Energie is a municipally-owned energy company that provides geothermal heat energy to most of the downtown core of the City of Lund.

KenGen is the national energy utility for Kenya and has experience installing stand-alone combined heat and power (CHP) geothermal plants for large industrial customers – an opportunity for Terasen to explore. Finally LG&E does not yet have any installed direct use capacity but they have managed to identify a model that puts the burden of responsibility for funding new renewable resources onto consumers who are supportive of the eventual move.

In examining these case studies and the market overview at the beginning of the report, Friuch Consulting analyzed the opportunity to develop direct use heating capacity in BC. The conclusion is that there is a market opportunity in BC for direct use energy but that in all cases; there are public concerns/misconceptions about these technologies that need to be allayed. Friuch Consulting is specifically recommending that Terasen Gas assign a full-time resource to exploring these opportunities and build partnerships with local stakeholder organizations.

PROJECT TEAM

AARON CRUIKSHANK - PROJECT LEAD

The Principal of Friuch Consulting, Aaron Cruikshank is a professional Public Policy Analyst, Researcher and Communications Professional with more than ten years of experience in the field. Over the past six years, Friuch Consulting has delivered policy, public consultation and research services to public sector clients across Canada.

Most recently, Friuch Consulting has been providing project management services to the Asia Pacific Gateway Skills Table in Vancouver, organizational development options for the Resource Training Organization (RTO BC) and new program development research for several departments at the University of British Columbia (UBC). Previous employers include the Science Council of BC, Natural Resources Canada, Dow Chemicals and BC Hydro. Aaron holds a Masters degree in Public Policy from SFU, a Bachelor of Communication (Honours) from SFU.

SEAN PETERS – RESEARCH ASSISTANT

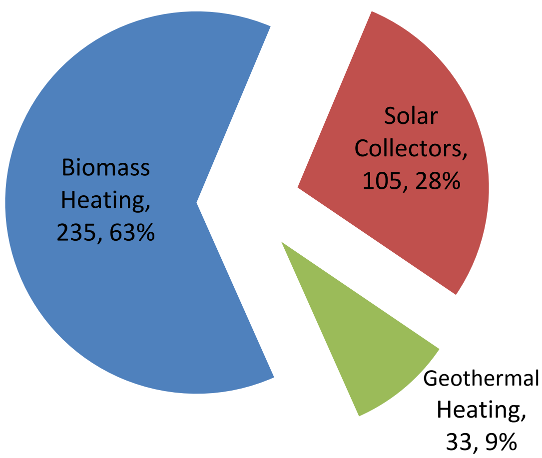
Sean Peters started with Friuch Consulting in early 2009 and is currently working on a number of active projects for the firm. Sean brings unique skills and experience to projects and has ample experience in non-traditional business development. As a founding member and chairperson of the board of directors of Global Agents for Change (Global AFC), he is responsible for the strategic direction and project development of one of Canada's leading youth-based non-profits.

In two short years, Sean has helped grow Global AFC from a small, BC-based non-profit to a sustainable, nationally registered charity that has been recognized by the United Nations as a major force for social change. Sean has a Bachelors degree from SFU in Anthropology and Business.

THE DIRECT USE HEAT MARKET

Direct use of energy is not a new concept in North America and outside of North America; direct use applications are increasingly common. The most common direct use energy source worldwide is biomass heat (burning wood or peat for hot water/heating) followed by solar and geothermal. **Figure 1** shows the Global Installed Hot Water/ Heating Capacity for 2006 in Giga Watts-thermal (GWt)[1].

Figure 1: Global Installed Hot Water/Heating Capacity, 2006, GWt



Traditionally used in developing nations as the only source of heat and cooking energy, biomass heating is essentially a form of stored solar energy. Solar energy feeds photosynthesis which forms renewable (and flammable) organic materials such as wood, straw, peat and animal waste. Biomass heating represents a global installed capacity base of 235 GWt in 2006 and 63% of the total direct use heat market.

Solar thermal collectors typically take the form of solar panels which maximize solar radiation absorption to heat water OR passive solar heating to trap solar energy in an enclosed space.

Geothermal heating leverages thin spots in the earth's crust to generate heat using heat pumps, hot springs and district heating systems. Geothermal solutions have a high initial sticker price compared to solar and biomass heating systems which may account for its relatively low representation as a direct heat source in **Figure 1**. The following sub-sections will explore the market for each of these direct use technologies worldwide. In each case, the application of these technologies to generate heat for customer end use is a well established business model.

BIOMASS HEATING

In major economies (like the UK), biomass heating applications are often combined heat and power (CHP) applications where the biomass fuel is burned to generate electricity and any unused process heat is distributed to end users for industrial or residential application. There has been a big push in the UK to add more biomass heating to the country's energy portfolio through the Carbon Trust's Biomass Heat Accelerator (BHA)[2]. Biomass heating has a long history in EU countries such as Austria, Finland and Denmark.

In Austria, biomass heating is common in district heating setups for villages where installations range from 500 kWt to 30 MWt to heat water that is piped into homes in the village[3]. Auto-fed single-home wood pellet boilers are gaining in popularity in Austria. These small boilers have gained efficiencies comparable to full condensing natural gas boilers and the emissions from these units are very low.

[1] www.ren21.net/**pdf/RE2007_Global_Status_Report.pdf**
[2] http://www.carbontrust.co.uk/technology/technologyaccelerator/biomass.htm
[3] http://www.bioheat.info/pdf/pichl_rakos_at.pdf

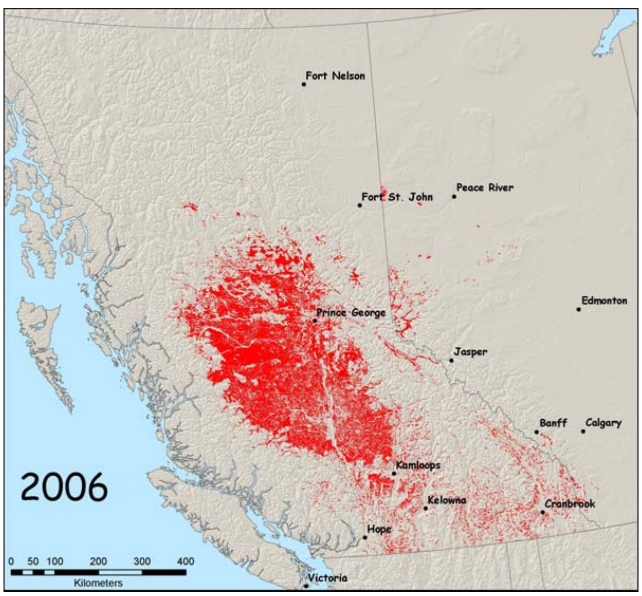
In Finland, many municipalities use biomass district heating systems. There is an excellent case study available for the community of Vörå where nearly all of the heating requirements for the municipality are provided by biomass heating[4]. Finland has taken the interesting step of deregulating the heat market to facilitate "biomass heating entrepreneurship" where farmers and other producers of biomass can start burning their waste materials to sell heat to local municipalities, small industry, hotels and farms with hothouse growing needs[5]. This market is heavily subsidized by the Finnish government. While burning biomass fuel does release carbon dioxide, the materials burned sequester more carbon dioxide while growing than they release while being burned[6]. This results in "very low net lifecycle carbon emissions relative to conventional sources of heating, such as gas, heating oil or electricity". **Table 1** compares a range of lifecycle CO_2 emissions for some of these conventional sources.

Table 1: Lifecycle CO_2 emissions comparison[7]

Space Heating	Kg CO_2/MWh
Biomass (woodchip)	10-23
Ground-source Heat Pump	29-105
Natural Gas	263-302
Fuel Oil	338-369
Fossil Fuel Generated Electricity	712-1102

Clearly, biomass heating has advantages from a lifecycle emissions standpoint over geothermal and natural gas heating – two of the cleaner options available in most jurisdictions. In British Columbia, an increased focus on biomass as an energy source has resulted in the launch of the **BC Bioenergy Network**[8] which is promoting the use of biomass for heating (amongst other applications such as energy production). BC Hydro is currently running a "Bioenergy Call for Power" and hopes to diversify BC's energy portfolio and decrease reliance on imported power. Many of the applicants in this call for power exercise will be burning wood pellets formed from domestic wood waste. With a combined heat and power (CHP) installation, the process heat from these projects could be used as direct heating for nearby businesses and homes.

Figure 2: Total Area Affected by Mountain Pine Beetle in Western Canada (Source: Natural Resources Canada)



There are also a number of Federal and Provincial grants available for businesses and organizations that can create new economic opportunities in communities that have been hit hard by the Mountain Pine Beetle infestation in central BC[9]. Access to the affected woodlots combined with government subsidies makes BC an interesting area for biomass heat exploration.

[4] http://www.managenergy.net/download/biom0203wasberg.pdf
[5] www.senternovem.nl/mmfiles/Motiva%20cases_tcm24-117124.ppt
[6] http://friuch.com/docs/CTG012.pdf
[7] http://www.worldenergy.org/documents/lca2.pdf (see page 41)
[8] http://bcbioenergy.ca
[9] http://mpb.cfs.nrcan.gc.ca/diversification_e.html

The main disadvantages to biomass heating systems is that they take up more space that fossil fuel-burning units and keeping up a steady supply of biomass with an appropriate moisture content at the heating site is a major logistics challenge.

SOLAR COLLECTORS

When most people think of solar energy, they think photovoltaic (PV) panels but PV solar applications only account for 7% (7.8 GW) of global solar energy capacity applications[10]. Solar thermal collectors which enable direct use are much more prevalent and represent 105 GWt of installed capacity worldwide. This 105 GWt represents 28% of all direct use heat energy applications worldwide.

Figure 3: Installed Solar Hot Water/Heating Capacity, Selected Countries, 2006, (105 GWt total)[11]

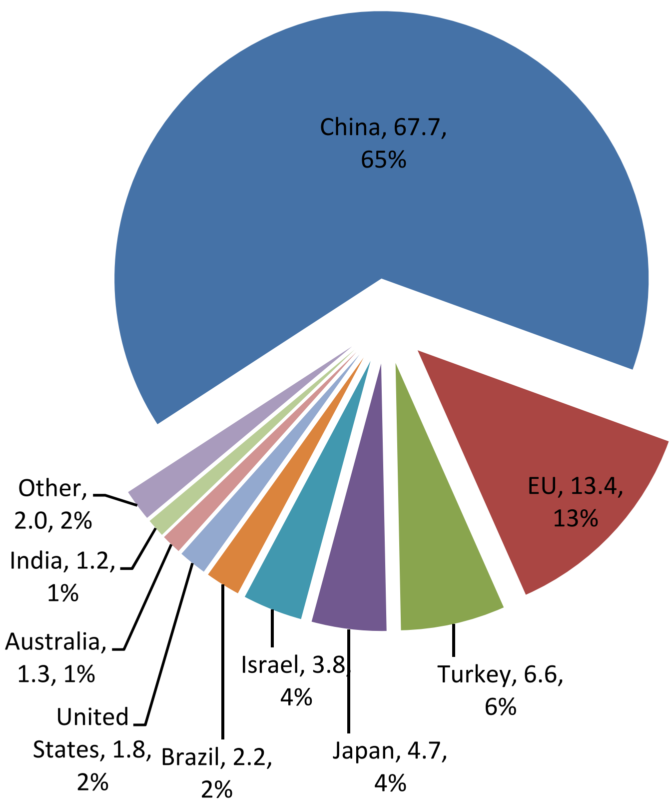


Figure 2 shows that the biggest user of solar thermal collectors is China and the country's demand for solar thermal seems to be increasing. In both 2005[12] and 2006[13], China accounted for over 75% of new solar thermal capacity and has over 10,000 solar equipment manufacturers (in comparison to Canada's 4)[14]. Global solar thermal capacity installations increased by 19% in 2006 while EU solar thermal installations increased by 50% in 2006.

For commercial and residential use, low-temperature solar thermal collectors are the norm. For heating hot water, the technology consists of a non-reflective metal panel with soaks up as much solar energy as possible and heating the water in the unit before storing it in an insulated hot water tank. This technology is well established and in use worldwide.

Passive solar space heating is usually achieved when glazed windows let sunlight into a building and that heat is absorbed, stored, released and distributed by the structure of the home itself.

[10] www.ren21.net/pdf/RE2007_Global_Status_Report.pdf

[11] *ibid*

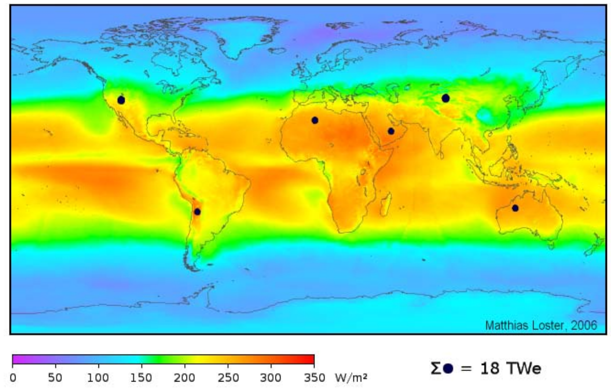
[12] www.ren21.net/pdf/RE_GSR_2006_Update.pdf

[13] www.ren21.net/pdf/RE2007_Global_Status_Report.pdf

[14] http://re.pembina.org/sources/solar

Passive solar systems are typically built into the design of a home and are prohibitively expensive to retrofit after the fact. While British Columbia is relatively solar energy poor compared to some jurisdictions in the US (see Figure 3), **SolarBC**[15] and organizations like it cite that a properly installed solar thermal hot water system can save the average four-person home up to 60% of their energy bill related to making hot water. The BC and Federal Governments also offer generous incentives that cover nearly 50% of the cost of installing the system. The systems, which typically cost under $7,000, can also be financed by a special SolarBC Low Interest Loan.

Figure 4: Average annual solar energy exposure



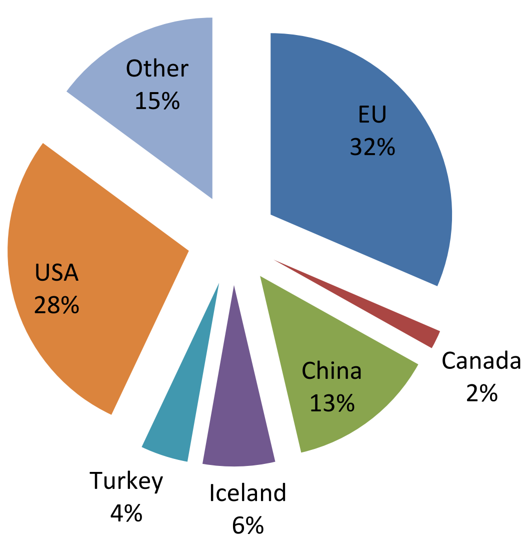
Source: http://www.ez2c.de/ml/solar_land_area/

GEOTHERMAL HEATING

Geothermal heating has the smallest global installed capacity base of these direct use heating technologies (33 GWt in 2006). While geothermal heating plants utilize relatively simple technology, take up very little space and can run 24/7 with little human intervention, the cost of finding and developing a suitable and stable site for high potential geothermal energy has limited large scale development beyond natural hot spring exploitation. For example, a case study from Germany puts the cost of a 35 MWt direct heat geothermal energy project in 2006 at €46 million ($73.5 million CAD)[16]. 42% of the project cost in this case is installing the heat distribution network and another 23% of the project budget is for the drilling stage.

Globally, the biggest users of geothermal heating are the US and China. A figure 5 show a large base in the EU but 43% of this capacity is comes from Sweden whose installed capacity base is roughly the same as China's.

Figure 5: Installed Geothermal Heating Capacity, Selected Countries, 2005, (28 GWt total)



Canada is shown in Figure 5 for comparison but its modest installed capacity base of 461 MWt is comparable to that of Germany, Austria, Italy, Norway and Switzerland.

Turkey is not only a relatively large user of geothermal heat energy but is also a large user of solar heat energy (see Figure 3 on a previous page). Iceland not only uses geothermal power for direct use heat extensively but in 2006, 26.5% of its electricity generation capacity was geothermal as well[17].

[15] www.solarbc.ca
[16] http://geoheat.oit.edu/bulletin/bull28-4/art1.pdf
[17] http://www.os.is/Apps/WebObjects/Orkustofnun.woa/swdocument/20644/Energy_Statistics_2007.pdf

Figure 6: Geothermal Resource Map of British Columbia

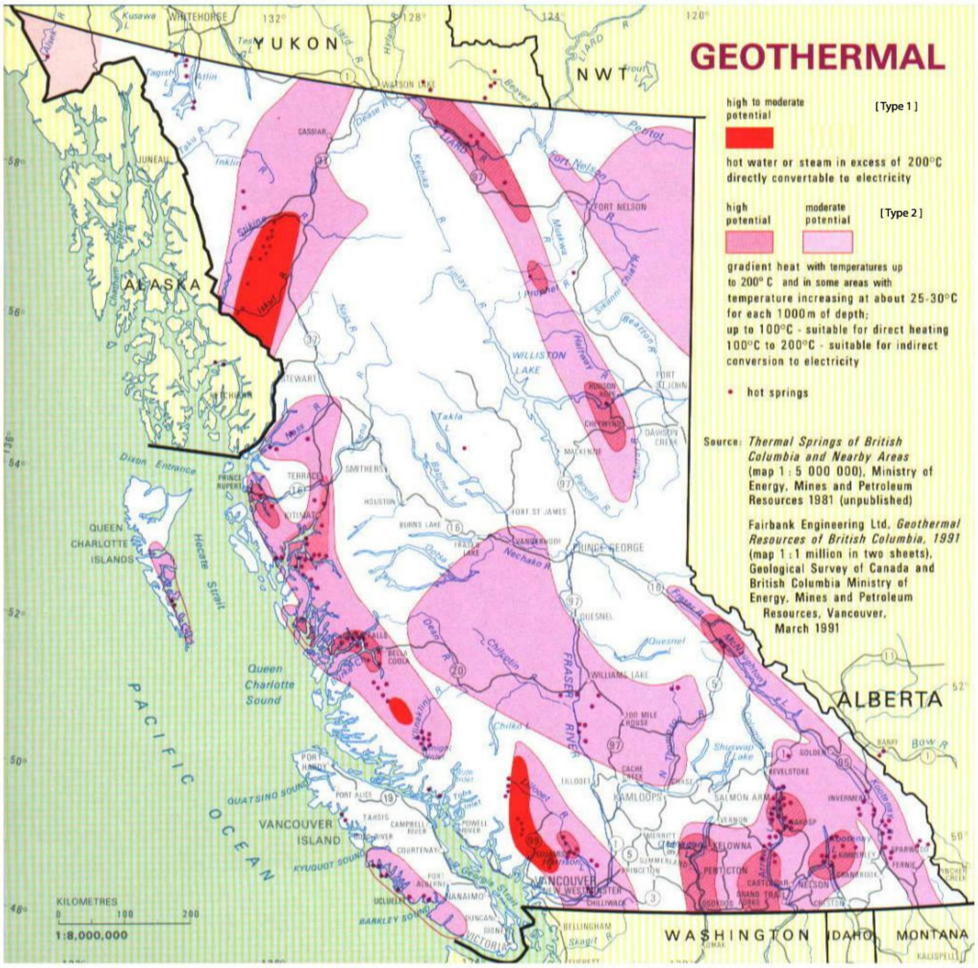


Figure 4 shows a geothermal resource map of BC[18]. The bright red spots are high geothermal potential areas – the kind needed to generate electricity from geothermal steam. The pink areas are cooler geothermal spots more suited for direct use in district heating or industrial process heat. BC has the only active geothermal energy project in Canada – the Meager Mountain volcanic complex near Pemberton, BC is developing geothermal power for electricity generation and hopes to generate 100—250 MW of electricity[19].

The Government of British Columbia currently owns all geothermal resource rights in the province. Surface property owners do not own the rights to geothermal assets underneath surface properties. Anyone wishing to develop a geothermal heat facility would need to obtain a permit from the Ministry of Energy, Mines and Petroleum Resources[20]. Hot springs where the water at the surface is less than 80˚C do not require a permit for development but are not always useful for geothermal heat applications. **GeoExchange BC**[21] is a non-profit industry association that provides information on low-temperature earth energy such as ground-source heat pumps.

[18] A more detailed version of this map is available from the BC Ministry of Energy, Mines and Petroleum Resources: http://www.em.gov.bc.ca/dl/GeoTherm/GeoThermRes_small.pdf
[19] http://www.geopower.ca/
[20] http://www.em.gov.bc.ca/Geothermal/GeothermalRights.htm
[21] http://www.geoexchangebc.com/

CASE STUDIES

Initial research into alternative energy for Terasen Gas resulted in a series of six international case studies showing instances where well established, traditional utility companies (thermal, hydroelectric, water, gas) that have successfully diversified their energy portfolio to include “alternative” energy production capacity in wind, solar, geothermal and other solutions. While this information speaks to the general opportunities and business models for diversifying into non-traditional energy, Terasen Gas was looking for more specific case studies where natural gas companies had diversified into direct provision of heat to end users.

The following case studies include three specific examples of a traditional gas company adding direct heat provision to their energy portfolio and some additional examples of traditional energy companies diversifying their portfolio to include “alternative” energy to facilitate the exploration of the business models. General references for each case study will be listed in the endnotes. Specific references will be provided as footnotes.

ALLIANT ENERGY

Headquarters:	Madison, WI, USA	**In business since:**	1981
Number of Natural Gas Customers:	410,261	**Number of Electricity Customers:**	1 million
Number of Employees:	5,318	**Ticker:**	LNT (NYSE)
Volume of Natural Gas Sold in 2008:	3,113,077 m^3	**Natural Gas Sales as % of Operating Revenues:**	22%

Alliant Energy is a holding company for public utilities that was formed in 1981, when Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL) merged. Combined, these two companies service over 1.4 million customers in Wisconsin, Iowa and Minnesota. Natural Gas for space heating in Wisconsin is a central part of Alliant’s business interests.

Because a large portion of Alliant Energy’s products and services fall under state and federal regulation, Alliant has long been charged with decreasing their combined CO_2 output as well as curbing reliance on fossil fuels. Each year, Alliant Energy reports out on its performance against state-set benchmarks and targets for reducing emissions. To meet their environmental obligations, Alliant Energy has developed a number of incentive programs to encourage customers to proactively install more environmentally friendly products and infrastructure in their homes.

Alliant’s incentive programs are similar to those of Terasen Gas and BC Hydro, targeting high efficiency, full-condensing boilers, environmentally friendly light bulbs, and more efficient appliances (both gas and electric). Additional incentive programs provide rebates for residential, non-profit and corporate clients who install renewable energy infrastructure like geothermal heat pumps on site.

Alliant doesn't actually install, implement or monitor geothermal heat pumps installed at customer's sites, choosing instead to provide a directory of third-party geothermal energy companies that will install residential or commercial products. However, Alliance does provide heavy incentives for these installations and in exchange, claims carbon reductions against these subsidized, customer-purchased geothermal pumps within its regulated environmental profile. Alliant does install and provide service to an appropriate electricity hookup for the third-party geothermal heat pumps it subsidizes.

Alliant customers who which to apply for a geothermal heat pump subsidy have to pre-qualify via a web-based or mail-in form, get a site assessment done on their property and then file for a rebate from Alliant once the project is complete. Rebates and incentives in Minnesota and Iowa are calculated with the following formula:

Geothermal (ground-source heat pumps)
(systems 180,000 BTU or 15 tons or less)
Closed loop: minimum EER = 14.1 and COP = 3.3
Reward = ($300 x tons) + [(EER – 16.2 x $50) x tons]
Open loop: minimum EER = 16.2 and COP = 3.6
Reward = ($300 x tons) + [(EER – 14.1 x $50) x tons]

There is no "standard" rebate because of the formula and other incentive programs that can be leveraged but Alliant's own reporting on the program indicates that the rebate for residential customers is likely just under $5,000 USD. In Wisconsin, these rebate programs are actually handled through Focus on Energy – a state-funded non-profit organization but Alliant markets their program incentives and still applies the CO_2 reductions to their target goals.

Alliant Energy is very transparent in the way that it offers its customers the choice between gas heating, electricity or geothermal/electricity combination heating system. Table 2 (below) was featured in one of their pamphlets on geothermal heating they produced to help customers choose between LNG and geothermal heating in their home[22].

Table 2: Alliant Energy's Risk Assessment for Potential Geothermal Heating Consumers

	Safety	Installation Cost	Operating Cost	Maintenance Cost	Lifecycle Cost
Combustion-based	A concern	Moderate	Moderate	High	Moderate
Heat pump	Excellent	Moderate	Moderate	Moderate	Moderate
GeoExchange	Excellent	High	Low	Low	Low

Alliant also keeps an online profile of some of the more successful cases within residential, business or non-profit/church buildings[23].

[22] http://alliantenergygeothermal.com/Resources/ssLINK/000524
[23] http://alliantenergygeothermal.com/GeothermalInAction/index.htm

LUND ENERGI AB

Headquarters:	Lund, Sweden	**In business since:**	1863
Number of Natural Gas Customers:	2,045	**Number of Electricity Customers:**	156,900
Number of District Heating Customers:	6,938		

Lund Energi AB was formed in 1863 and today exists as a municipally-owned utility company that services communities in Southern Sweden. It predominantly services the City of Lund, but also provides energy and heat for neighbouring Skåne, Lomma, Eslöv, and Hörby areas. Its operations include the production, distribution and sale of electricity and heat, as well as subsidiary operations in telecommunications.

Lund Energi's has focused the majority of its district heating operations in the City of Lund. Lund Energi is seen as a market innovator in renewable energy. Lund Energi first explored district heating in 1963 by setting up district heating infrastructure in Lund's downtown core. Currently, this heating system encompasses the entire downtown urban area and there are plans to expand this network out into residential areas around Lund.

When it was first set up, the district heating system was powered by conventional fuel oil and natural gas furnaces. In the early 80's, hot water was found in the soil under Lund and soon after two geothermal heating plants were commissioned. Total investment in these geothermal heating plants was equivalent to €11.7 million ($18.6 million CAD) amortized over three years.

The wells for these geothermal heat plants were drilled 800 meters down and provide water at a temperature of 21°C. This water is then further heated with electric elements to 80°C; with a coefficient of performance of 3.3 (an input of one kWh of electricity gives an output of 3.3 kWh of heat energy). These two plants have a heat output of 20 and 27 MWt respectively. This system has been recently supplemented by a combined heat and power (CHP) biomass plant outside of the city center that is connected to the downtown grid.

Geothermal currently provides 40% of the heat within the district heating network. Through this structure, customers don't specifically purchase geothermal energy, but those buying into district heating are implicitly receiving a portion of their heating from geothermal sources.

Lund Energi estimates that within five years of installing the geothermal heating plants, they saved 200,000 m^3 of fossil fuels, saving 580,000 tons in CO_2 emissions, 4,000 tons of SOX emissions and 1,400 tons of NOX emissions.

Funding for the geothermal plants was provided in part through cheap government loans for the purpose of decreasing the city's dependence on fossil fuels. This goal was both political and environmental. At the time the project was proposed, the global environmental movement was already beginning to take hold but the Gulf War and fluctuating global oil prices were additional incentives for the development of renewable energy.

Today, customers looking to purchase heat in the Lund or neighbouring areas have a choice between district and gas heating. Instead of selling natural gas or district heating, Lund Energi instead offers “heat” as a product, with sub-choices for the customer as to how they want their heat delivered. In this way, Lund Energi has branded themselves as a “heat provider” instead of a gas utility. The choice to get heat from the district heating system is limited by the customer’s location but as plans to expand the network into the suburban communities moves forward, more and more Lund Energi customers will have this choice.

Installation fees for customers wanting to hook up to the district heating system vary and typically involved excavating a significant portion of a home-owners’ lawn. Lund Energi has a program in which it subcontracts installation, including the repairing of the lawn and garden area. Installation costs vary by location and type of heat. For district heat hookups, up to 30% of the cost (up to 30,000 SEK, $4,270 CAD) is often provided by the provincial government through incentive programs. Both types of heat are paid for through a mixed fixed cost/ usage billing scheme.

Table 3: Billing Schedule for Heat, Lund Energi

	Price per MWh used	Annual Fee	Installation Subsidy?
District Heating	620 SEK ($88 CAD)	3,750 SEK ($534 CAD)	Yes
Natural Gas	685.75 SEK ($97.65 CAD)	315 SEK ($44.85)	No

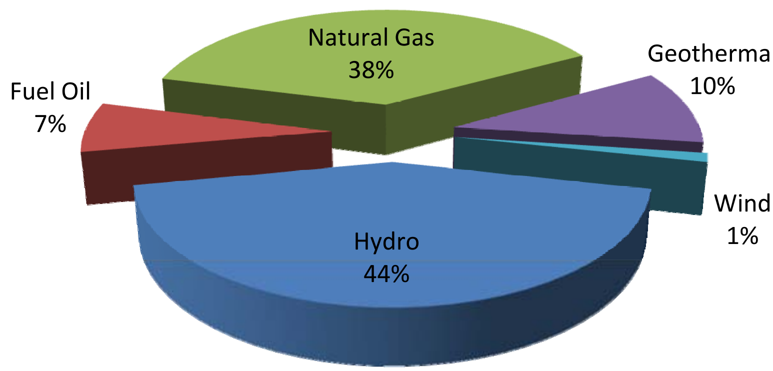
To ease quantification, let’s assume that the average Lund home uses 2 MWh per month of heat energy. At current prices, after factoring in the higher annual fee and the nearly $10,000 CAD installation cost that the consumer must bear, this means that district heating is not price competitive with natural gas. Despite this, demand for the service is high enough that Lund Energie is considering expanding the service into the surrounding suburbs.

One potential reason for consumers’ affinity for geothermal heat is that the cost of the district heating will never go up more than a little while the spot price of natural gas can fluctuate wildly. A major increase in the spot price of gas could make the district heating more competitive. There may also be non-financial reasons for selecting the district energy option.

KENGEN

Headquarters:	Nairobi, Kenya	In business since:	1954
Total installed generation capacity:	1,100 MW	Number of customers:	980,000

Figure 7: KenGen's Energy Portfolio as of December 31, 2008[24]



In 1954, the government-owned Kenya Power Company (KPC) was founded. Acting as both generator and distributor of power within Kenya, KPC was the largest utility company within Kenya and took on initiatives within Uganda as well. From its inception, KPC focused on hydroelectric and geothermal power. Today, hydro makes up 677.3 MW - 72.3 % of KenGen's total generation capacity. When compared to many of the other companies profiled, their capacity may seem small in comparison. However, it's worth remembering that today, energy capacity in Kenya is only 1166 MW total.

While not traditionally a major producer of direct use geothermal energy, KenGen leased a geothermal direct-use thermal pump to Oserian Development Company in 2003. Oserian is one of the largest flower producers in Kenya servicing European markets with "fair trade" flowers. Oserian exports 400 million flowers to Europe annually. In 2003, organizational expansion at Oserian led to a requirement for more heating in their Rift Valley flower facility. Rift Valley was not connected to any petroleum network and other forms of heating drove the costs too high.

Fortunately, Rift Valley is so named because of the tectonic shifting that had left cracks in the earth, producing many geysers and areas ripe for geothermal development. To service Oserian's heating needs, a 2 MW combined heat and power (CHP) geothermal plant was commissioned by KenGen in 2003 (completed in full by 2005), and an additional 2 MW CHP plant was installed in 2007. Initially, this plant serviced three hectares of greenhouse land but has since been expanded to 30 hectares.

To finance the initial project, KenGen leveraged World Bank funding and other sources and then leased the plant back to Oserian. In 2006, KenGen floated 30% of its company on the stock market in an IPO, which provided much-needed funding to expand operations. With some of these funds, it was able to construct and lease a second 2 MW CHP plant to Oserian. According to the 2008 KenGen financial statements, the details of the lease include a 15 year period for each lease at a cost of 15,000,000 Kenyan Shillings ($241,733 CAD) per well, payable up front and written into the financial statements annually on a straight-line basis for the life of the lease.

[24] http://www.kengen.co.ke/Map.aspx

Figure 8: Image of an Oserian Greenhouse heated by Geothermal energy in Rift Valley, Kenya

While geothermal power is seen as the most appropriate form of heat and electricity for many parts of Kenya, the lack of capital within Kenya has been a barrier to further expansion. With increased economic stability and further growth of the Kenyan economy, it is safe to speculate that further developments of this kind will occur in the near future.

KenGen has nearly 30 years of experience with geothermal energy – they installed the first geothermal power station on the African continent between 1981 and 1985. The capacity of this initial project was 45 MW. A second geothermal station was added at this location (Lake Naivasha) in 2000, with project funding coming from the World Bank, the European Investment Bank, KfW of Germany and KPC. The combined capacity of these two stations is roughly 115 MW.

KenGen has also begun exploring wind energy in the early 1990s when the Belgian government donated two Windmaster turbines to KPC with a combined capacity of 350 MW. The units were installed and hooked up to the national grid but in 2005, one of the blades cracked, rendering the turbine inoperable. For undisclosed reasons, KPC did not replace the turbine leaving current wind production at between 150-200 MWs.

In 1997, KPC was vertically unbundled, separating power generation and power distribution in Kenya into two separate companies. In 1998, the generation side of KPC was rebranded as KenGen. This was seen as a major step towards renewable energy in Kenya. The United Nations Industrial Development Organization (UNIDO) used KenGen within a case study of renewable energy schemes within the African continent. UNIDO argued that vertical unbundling allowed KenGen to expand further into renewables while allowing it to become more cost effective. UNIDO promoted this model for other utility companies within Africa.

UNIDO argued that because of the low energy requirements of rural African communities, often wind, hydro and geothermal energy often produce enough energy to serve local communities despite their lower MW output when compared to gas, nuclear or coal. However, Kenya's energy needs are quickly growing and investment today in future generation capacity if economic stability is to be maintained.

In 2006 KenGen floated 30% of the company in an IPO, leaving 70% to be state-owned. This was seen as a further effort to expand capacity and increase efficiency. In contrast to the other case studies examined in this report, KPC has focused on Contrary to the models we've seen KenGen focus on non-renewable forms of energy as a larger percentage of its total energy generation portfolio than renewables.

In March, 2009 KenGen secured a $300 million in a loan from the French government to invest in an additional 500 MW of geothermal capacity by 2012. In the same month, it was also seeking a partner to develop a $900 million coal-powered plant with a capacity for 300 MW. As both remote and central communities join the power grid in Kenya, this mixed approach to increasing generation capacity will likely continue.

LOUISVILLE GAS & ELECTRIC

Headquarters:	Louisville, KY, US	**In business since:**	1838
Number of Natural Gas Customers:	312,146	**Number of Electricity Customers:**	384,139

Louisville Gas was formed in 1838, and sold gas from a local coal plant to fuel gaslights. In 1913, Louisville Gas merged with Louisville Lighting and Kentucky Heating, forming Louisville Gas and Electric (LG&E). In 1998, LG&E acquired KU Energy, which more than doubled the size of LG&E. By 2000, LG&E had been acquired by Powergen, a UK-based energy conglomerate. In 2001, E.On acquired Powergen and its subsidiaries, and today LG&E is held under E.ON US Holdings. It serves 384,139 electric customers, 312,146 gas customers, and has a generation capacity of 3,514 MW. Prior to its acquisition by Powergen, LG&E was the third biggest power marketer in the US and one of the biggest natural gas marketers. In 1996, LG&E was marketing in excess of 38 billion m^3 of natural gas annually[25].

As the environmental movement took hold in the late nineties and early 2000's, LG&E felt increasing pressure to offer renewable energy alternatives to its client base. One option that seemed an easy solution was the expansion of hydroelectric energy, and in 2005 the purchase of the Mother Ann Lee Hydro Station (run-of-river) added potential for LG&E to bring an additional 2 MW of clean power onto the grid. The hydro station was built in 1927 and needs some heavy renovations before it will be operational. The cost of these renovations will increase the delivery cost of energy beyond what is usually charged for energy from coal or thermal plants in Kentucky. Rather than sink substantial capital dollars into renovating the facility, LG&E has a scheme that transfers the cost of this renewable energy to the consumer.

[25] http://www.prnewswire.com/cgi-bin/stories.pl?ACCT=104&STORY=/www/story/81498&EDATE=

LG&E's tagline is *if we do not pay for it, it will not come. Or, we must pay the difference to make the difference.* LG&E estimated that regular energy cost 6 cents, while renewable energy cost 8 cents. Rather than absorbing this price difference, the company began offering carbon credits for the purchase of "green energy" from LG&E. This "green energy" is not from assets owned by LG&E – it is purchased from neighboring states and the proceeds are used for building green energy projects in Kentucky. Blocks of 300 kilowatt hours could be purchased for $5, and households were encouraged to join the program so that for every 300 kWh that they consumed $5 would be added to their bill for "Renewable Energy Certificates".

These funds are currently going towards the renovation of the Mother Ann Lee Hydro Station and in the future, LG&E hopes to expand their generation capacity into biomass and landfill energy. Corporate clients can opt into the program for $13 for 1000 kWh but must commit to 12 month terms. This scheme is unique and has allowed LG&E to continue to expand into renewable energy in a region that would otherwise be unwilling to invest in the necessary infrastructure.

This is an important business case to examine because while LG&E has not delved into direct use heat sales, they have come up with a unique marketing platform that could be replicated by Terasen to raise funds needed to explore geothermal, solar collector and biomass heating capacity. Those customers who are willing to invest in a diversified energy portfolio can do so and those who are unable or unwilling to do so do not have to.

ANALYSIS

This section of the report will look at the case studies identified and the state of the direct use market (biomass, solar collector and geothermal), how it applies to the BC market and how Terasen Gas might explore these opportunities should it decide to pursue direct use heat delivery as a product.

THE MARKET

Despite the attention that geothermal direct use heating gets, it is a far third in terms of installed capacity to biomass and solar collector heating. There are several likely reasons for this:

1. Geothermal heating is expensive to develop and not conveniently located for most markets
2. Biomass heating is ancient technology and easy to sell to consumers
3. Solar collector technology puts control in the hands of consumers and has an extremely positive image amongst the environmentally savvy

A lot of major economies – like the UK and other EU nations – are taking a good look at biomass energy at a time when fossil fuels are increasingly unpopular with consumers and regulatory bodies. Yes, biomass heating is still effectively burning hydrocarbons but the argument in its favour is that from a lifecycle perspective, biomass heating produces a fraction of the CO_2 emissions that fossil fuels do when producing the same amount of energy. There is also the argument that while growing, plant-based biomass energy crops sequester CO_2 and sink emissions from burning fossil fuels (mostly from transportation use). This has led to a situation in some jurisdictions where burning wood pellets or human waste to create heat and electricity is considered "green" or at the very least renewable.

Solar collector heating technology is benefitting from decreasing costs and increasing efficiencies – likely driven by the mass commercialization of this technology in China. In North America and the EU, the decision to add solar collector heating to your home is a very individual decision and empowering for those who have the resources to make the initial capital investment. Like driving a hybrid car, installing solar collector capacity at your home is a status symbol - this makes solar collector technology an easy sell to consumers. The fact that the capital requirements of individual solar collector installs is so miniscule makes campaigns and subsidy/rebate programs based on the technology infinitely scalable from the financial perspective of a large utility company.

As attractive as geothermal power is, the market data and the case studies seem to emphasize that the capital cost of these installations make it cost prohibitive for most energy providers. Geothermal electricity generation is an easier sale than geothermal heating for direct use in many ways. The cost of a geothermal electricity generation facility is smaller because once the electricity is generated, it can be fed into the existing power grid using affordable capital (assuming that the generation plant isn't too far off the grid). When you start to look at greenfield geothermal heating applications, the cost of laying the distribution infrastructure (insulated pipes buried in the ground) can drive the capital cost of an installation up rapidly.

The case of Lund Energie is unique and it should be remembered that the City of Lund already had a steam distribution network laid down in the downtown core that was at one time energized by gas-fired boilers. This would have eliminated a significant portion of the development cost for developing the natural geothermal assets under the city. Their current plans to expand their district heating system to the suburbs would be more capital intensive because it is unlikely the distribution infrastructure existing in the suburbs.

THE USE CASES

There are several interesting trends and tactics to note when looking at the case studies in this report:

THE REGULATORY ENVIRONMENT

In the case of Alliant Energy, there is a regulatory body that mandates energy providers to reduce their carbon footprint. In British Columbia, there has been less pressure to reduce carbon emissions in the energy market because the majority of our electricity generation is hydroelectric and effectively zero emission. Home heating energy in BC is predominantly natural gas which also burns very clean. In other jurisdictions where the most common source of energy for electricity generation is coal or fuel oil, there is a lot of room for improvement.

It is possible to imagine a regulatory environment where carbon footprint reductions aren't necessarily mandated but heavily incentivized. Even the emerging carbon credit market has revenue potential for companies with enough capital. Given the uncertain future of the regulatory environment in BC with regards to emissions and the potential of the carbon trading market, this is a good time for Terasen Gas to begin exploring options to subsidize renewable direct use heating for consumers to take advantage of future carbon footprint legislation.

COMBINED HEAT AND POWER

KenGen saw a market opportunity – geothermal heating for a specific customer who was off the normal energy grid but who had significant power and heating needs. The choice to go geothermal in this case was more a function of where the customer is located than a deliberate strategy to exploit geothermal assets. The lesson to be learned here is that for customers who are significantly isolated or in areas where infrastructure development is lagging commercial development, there is a window of opportunity to introduce an energy solution that is less conventional than a natural gas boiler. Two specific opportunities in BC spring to mind – one that is driven by demand and one that is driven by supply.

The first opportunity – the one driven by demand – revolves around the increase in port activity taking place in and around Prince Rupert and Kitimat, BC. Both jurisdictions are expecting a three-fold increase in bulk and container traffic. Kitimat is building bulk LNG storage and shipping facility that might require process heating and additional electricity capacity beyond what the local Alcan hydroelectric dam can provide. Note on **Figure 6** (the geothermal potential map of British Columbia) that the area around Kitimat and Prince Rupert is a geothermal potential hotspot.

Looking at **Figure 2** (the Mountain Pine Beetle affected are map of British Columbia) it is also clear that Kitimat and Prince Rupert are very close to a massive source of biomass heating fuel. In both cases, there are well established business models highlighted by the case studies where a utility company comes into an area that is underserved or un-served by the existing energy infrastructure, installed and combined heat and power (CHP) generation facility and meets the needs of a specific energy-intensive operation.

The second opportunity – the one driven by supply – is that which is afforded by the Mountain Pine Beetle problem in general. The affected area (see **Figure 2**) is a potentially massive source of wood pellet fuel for direct use biomass heating. There are a number of government agencies and organizations (such as the **BC Bioenergy Network**) that are actively looking for ways to subsidise and encourage economic development in the Mountain Pine Beetle affected area.

Grants and incentive programs that would be available to any company that could leverage the Pine Beetle wood for economic development would significantly lower the start up and ongoing operation costs of a biomass heating installation in British Columbia. Again, for applications where an energy-intensive operation requiring both electricity and process heat is sufficiently removed from the main energy infrastructure grid, there is an opportunity to invest in biomass CHP energy.

GOING UP-MARKET WITH RENEWABLE ENERGY

Another strategy that has emerged from these case studies revolves around how to market and price renewable energy such as solar collector, biomass or geothermal direct use infrastructure. Any new infrastructure put in place to deliver heat as a product is going to require a significant investment. In a regulated energy environment (like British Columbia), obtaining permission to raise rates across the customer base to pay for this new infrastructure will meet with opposition from registered interveners and/or the government.

In the cases of Louisville Gas and Electricity (LG&E) and Lund Energie, the increased cost associated with these renewable sources of energy is made transparent to consumers and marketed in a way that makes consumers feel good about opting in to these sources of energy despite the marginally higher cost (vs. current fossil fuel spot prices). LG&E achieved this by stating their goal to diversify their energy portfolio to include renewable energy and giving consumers the opportunity to buy offset credits to fund the development of renewable energy assets.

Lund Energie, in comparison to LG&E, is also very transparent about the increased cost of geothermal energy and gives consumers the opportunity to hedge their bets with geothermal on the assumption that fossil fuel-based heating will inevitably cost more than geothermal as the spot price of gas fluctuates. In both cases, the success of the marketing campaign revolves around transparency and enabling consumers to make ethical choices.

SUBSIDIES

In nearly every case study, consumers are incentivized to embrace renewable direct use heat energy. A combination of utility rebates, government grants and low-interest loans make it easier for consumers to afford distributed energy applications like rooftop solar collectors or ground-source heat pumps for residential use. The shorter the ROI for the consumer, the more likely they are to embrace the technology. Terasen Gas already has experience with these tactics and a new campaign to promote renewable direct use heating equipment should be able to fit into the company's existing demand-side management campaigns.

BRITISH COLUMBIA

Large scale adoption of solar collector technology in the past was not feasible in most of British Columbia due to the low annual solar exposure the province receives. New materials research has increased the efficiency of solar collectors to the point where they can pull usable solar radiation out of indirect sunlight. The cost of these systems is still high enough that the majority of home owners are unlikely to install one unless there is a major subsidy and the ROI is short enough.

As with most capital improvements for consumers, the ROI needs to be within 3-5 years. That is something to consider when looking at solar collector heating subsidies as a potential market strategy for Terasen Gas. There are existing partners in BC for Terasen to approach if the company decides to pursue solar energy direct use heating to customers.

Geothermal energy certainly has potential for development in British Columbia but the uptake so far in BC gives the impression that there is a good reason why there has been no major development in this area to date. Given the heavy environmental influence in BC, it should come as no surprise that there is significant consumer interest in ground-source heat pump heating and cooling for residential applications in this province. Again, the relatively high cost of these installations and a persistent rumour that ground-source heat pumps don't work well in our humid environment may be stunting demand for geothermal energy in BC.

Biomass heating energy is going to be a harder sell in BC compared to geothermal or solar collector technology because of a widely held public perception that burning anything to create energy results in CO_2 being released into the atmosphere. Consumers in BC are more accustomed to zero emission renewable resources such as hydroelectricity. However, Terasen Gas has been successful at branding natural gas as a "clean burning" fuel and could likely find a way to extend this marketing to a clean burning biomass heating energy plant or biomass CHP plant.

RECOMMENDATIONS

Terasen Gas did not specifically ask for recommendations from Friuch Consulting on how to proceed but after reviewing the case studies and the market opportunities for direct use heat delivery in BC, we are compelled to offer our recommendations. These recommendations are based on the assumption that Terasen Gas has some interest in entering the heat provision market in British Columbia in the foreseeable future:

1. **Begin public education campaign and stakeholder engagement on biomass fuels in conjunction with the BC Bioenergy Network**

   In anticipation of public pushback on any proposed biomass fuel initiatives, we believe that Terasen Gas should start an education campaign on biomass fuel that positions it as a clean, renewable fuel source with major environmental benefits. Some of this work has already been started by the BC Bioenergy Network but this young organization could benefit from the support of an anchor company such as Terasen Gas as much as Terasen could benefit from the legitimacy that their association brings to the issue.

2. **Begin public education campaign and stakeholder engagement on the use of solar collector technology to provide domestic hot water in conjunction with SolarBC**

   As with the case of biomass fuel, there is misinformation or outdated information about the capabilities of solar collector heating technology that could be stopping many consumers from adopting this technology at their homes. SolarBC has already laid some of the groundwork and a partnership between SolarBC and Terasen Gas would be mutually beneficial. We believe that Terasen should explore the potential of this partnership and discuss a joint public campaign focussed on solar education.

3. **Conduct a market assessment of geothermal energy in British Columbia**

   We loathe ruling out this stream of enquiry at this stage despite the identified challenges with developing geothermal heating capacity in BC (or any jurisdiction). The biggest hurdle to developing these assets appears to be the enormous capital outlays required to build the well and distribution infrastructure. Like any infrastructure project – if the benefits outweigh these costs, there is an opportunity. What we are suggesting at this time is that the benefits of developing geothermal heating capacity in BC at this time do not appear to outweigh the anticipated development costs.

   Determining if there is a viable market for geothermal heating in BC is beyond the capabilities of Friuch Consulting and will likely involve require the expertise of geoscientists and someone experienced with geothermal installations. We are recommending that if Terasen Gas is serious about pursuing this technology that they conduct a market assessment of geothermal energy in BC using geothermal subject matter experts as well as market experts that can quantify demand.

4. Establish a unit or sub-unit with Terasen Gas with a mandate to explore these opportunities

We are confident based on our research that there are market opportunities for Terasen Gas to expand into direct use heat provision in BC. Given the support for all three technologies – solar, biomass and geothermal – at the consumer and the government level, the timing is good for Terasen to start exploring these options in a serious manner. One relatively senior staff member with experience in multi-level stakeholder engagement and environmental resource management could start the process for Terasen Gas. This individual might fit best within the Demand Side Management unit at Terasen in the interim since that is where other subsidy/rebate programs reside.

5. Begin planning subsidy/rebate programs and budgets for consumer-level solar, geothermal and biomass heat delivery systems

One of the obvious and scalable ways to enter the renewable heating market is to do what some of the companies in the case studies do – let consumers choose which platform they want to install in their homes and provide subsidies or rebates to lower the cost of installation. In return, Terasen would garner carbon credits which could be sold on the carbon exchange. In the case of a regulatory change, these offsets could be leveraged by Terasen to meet government emissions reduction requirements. In case, some financial planning and resourcing is required within Terasen to determine the scope and scale of any potential subsidy/rebate programs for consumer use of these technologies. We are recommending that this activity be one of the first projects of a newly established unit within Terasen to explore the potential of direct use heat provision.

LIMITATIONS OF THIS RESEARCH

Given the time constraints of this project, Friuch Consulting had to quickly identify and explore a few case studies. With more time and resources, a comprehensive environmental scan of the direct use renewable heating market might have revealed other viable business models for Terasen Gas to explore. That said, we are confident that our research shows there is market potential and that we recommend Terasen explore the market further.

ENDNOTES

These are the research sources for the information contained in this report that are not specifically cited in footnotes.

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LUND ENERGIE AB

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LG&E

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Attachment 27.1

Effective: OCT 16 1997 L-64-1997

BCUC Secretary: *Original signed by R.J. Pellatt*

[Terasen Gas Inc.]

C O D E   O F   C O N D U C T

For Provision of Utility Resources and Services
August 1997

SCOPE

This Code of Conduct (Code) governs the relationships between [Terasen Gas Inc. (Terasen Gas)] and Non-Regulated Businesses (NRBs) for the provision of Utility resources, and conforms with the British Columbia Utilities Commission (Commission) "Retail Markets Downstream of the Utility Meter" (RMDM) Guidelines of April, 1997. The Commission Code of Conduct Principles from the Guidelines are attached as Appendix 'A'.

This Code will govern the use of Utility resources for unregulated activities (products or services for which there are no Commission approved tariffs) including shared services, employment or contracting of Utility personnel, and the treatment of customer, utility, or confidential information. The Code will also determine the nature of the relationship between the Utility and NRBs and the treatment by the Utility of its' NRBs.

The primary responsibility for administering this Code lies with [Terasen Gas], although the Commission has jurisdiction over matters referred to in this Code. The Commission acknowledges that the Utility in the administration of the Code may have to take into account particular circumstances in respect to a particular product or service which is being provided or transferred out of the Utility, and where these issues are at variance with this Code Commission approval will be required. The Code also provides that the Commission may review complaints in relation to the Code.

The [Terasen Gas] Transfer Pricing Policy, dated August 1997, will be used in conjunction with this Code to establish the costs and pricing for Utility resources and services.

This Code supersedes and replaces the [Terasen Gas] Code of Business Conduct dated March 31, 1995. However, this Code does not replace contracts and undertakings between [Terasen Gas] and NRB affiliates in existence prior to approval of the Code.

DEFINITIONS

[Terasen Gas Inc.]	*May be abbreviated as follows: [Terasen Gas], the Utility, or the Company, and may also include employees of the Company.*
Commission	*British Columbia Utilities Commission.*
Guidelines	*Retail Markets Downstream of the Utility Meter Guidelines published by the British Columbia Utility Commission in April, 1997.*
Non-Regulated Business (NRB)	*An affiliate of the Utility not regulated by the Commission or a division of the Utility offering unregulated products and services. "Related NRB" refers to any NRB which is an affiliate of the Utility and which uses any resources of the Utility.*
Ratepayers	*Ratepayers in most cases are considered as a whole rather than one group or rate class.*
RMDM	*Acronym for "Retail Markets Downstream of the Utility Meter", which may include any utility or energy related activity at or downstream of the utility meter.*
Transfer Pricing	*The price established for the provision of Utility resources and services, or the transfer of Utility assets, to an NRB or division of the Utility providing unregulated products and services. Transfer pricing for any Utility resource or service will be determined by applying the [Terasen Gas] Transfer Pricing Policy approved by the Commission.*

<u>APPLICATION OF COMMISSION PRINCIPLES</u>

1. <u>Transfer Pricing</u>

The Utility will conform with the Commission approved [Terasen Gas] Transfer Pricing Policy.

2. <u>Shared Services and Personnel</u>

a) This Code recognizes the need for and potential benefits to the Utility of employee transfers and human resource sharing.

b) [Terasen Gas] may provide shared services to NRBs, including supervision and management, while ensuring that ratepayers will not generally be negatively impacted by Utility involvement. The costs of providing such services will be as agreed upon by both parties and be in accordance with the Commission approved [Terasen Gas] Transfer Pricing Policy.

c) NRBs may contract for any Utility personnel using the Commission approved [Terasen Gas] Transfer Pricing Policy, providing the Utility complies with Section 4 of this Code, Provision of Information by [Terasen Gas Inc.], and no conflict of interest exists which will negatively impact on ratepayers.

3. <u>Transfer of Assets or Services</u>

The price for all transfers of assets or services shall be determined in accordance with the [Terasen Gas] Transfer Pricing Policy approved by the Commission, and the Utility must be able to demonstrate that the benefits to the ratepayer are greater than the cost. The transfer price will reflect the potential for risk (stranded assets, future costs, etc.) and the recall availability of shared or transferred personnel to ensure the Utility receives the appropriate benefit from expertise resident in the Utility. [Terasen Gas] will comply with acceptable business practices if it wishes to purchase assets, goods or services from an NRB.

An appropriate allocation of development costs for products or services as defined in the [Terasen Gas] Transfer Pricing Policy, will be included in the transfer price.

4. <u>Provision of Information by [Terasen Gas Inc.]</u>

[Terasen Gas] will not provide to an NRB any information that would inhibit a competitive energy services market from functioning.

The following should act as a guideline for employees confronted with issues related to the sharing of confidential information:

a) This Code precludes [Terasen Gas] from releasing confidential customer specific information without the consent of that customer. If a customer agrees to a general release of customer specific information, that information must be made available to any market participant who requests it and is willing to pay costs associated with the provision of the information, without discrimination as to access, timing, cost or content. If a customer requests customer specific information be provided to a specific market participant, only that participant may receive the information, subject to payment of associated costs incurred to provide the information.

b) [Terasen Gas] may disclose to any market participant that requests it and is willing to pay the appropriate transfer price customer information that is aggregated or summarized in such a way that confidential information would not ordinarily be ascertained by third parties.

c) [Terasen Gas] may provide or sell any non-customer specific information to any market participant that requests it and is willing to pay the appropriate transfer price.

5. Preferential Treatment

[Terasen Gas] will not state or imply that favoured treatment will be available to customers of the Utility as a result of using any service of an NRB. In addition, no Company personnel will condone or acquiesce in any other person stating or implying that favoured treatment will be available to customers of the Company as a result of using any product or service of an NRB.

6. Equitable Access to Services

Except as required to meet acceptable quality and performance standards, and except for some specific assets or services which require special consideration as approved by the Commission, [Terasen Gas] will not preferentially direct customers seeking competitively offered services to an NRB or a specific retailer.

7. Compliance and Complaints

a) [Terasen Gas] will advise all of its employees of their expected conduct pertaining to this Code, with annual updates for employees who may be directly involved with NRB activities.

b) [Terasen Gas] will monitor employee compliance with this Code by conducting an annual compliance review, the results of which will be summarized in a report to be filed with the Commission within 60 days of the completion of this review.

c) Complaints by third parties about the application of this Code, or any alleged breach thereof, should be addressed in writing to the Company's [Vice-President, Finance & Regulatory Affairs], who will bring the matter to the immediate attention of the Company's senior management and promptly initiate an investigation into the complaint. The complainant, along with the Commission, will be notified in writing of the results of the investigation, including a description of any course of action which will be or has been taken promptly following the completion of the investigation. The Company will endeavour to complete this investigation within 30 days of the receipt of the complaint.

d) Where [Terasen Gas] determines that the complaint is unfounded, the Company may apply to the Commission for reimbursement of the costs of the investigation from the third party initiating the complaint or where this is not possible, for inclusion of those costs in rates.

8. Financing and Other Risks

[Terasen Gas] will not undertake any financing or other financial assistance on behalf of an NRB that exposes utility ratepayers to additional costs or risks, unless appropriate compensation is received by [Terasen Gas] for such financing or other financial assistance, and such financing or other financial assistance is approved by the Commission.

9. Use of Utility Name

[Terasen Gas Inc.] agrees that newly established NRBs engaging in RMDM activities will not use the Utility's name as the primary identifier within British Columbia, and will not use the Utility name in a manner that indicates that Utility resources will support the NRB.

10. Distribution System Access

[Terasen Gas] will treat all requests for distribution system access for the purpose of direct commodity marketing equitably and in accordance with the requirements approved for direct commodity marketing in British Columbia.

11. Amendments

In order to ensure that this Code remains workable and effective, the Company will review the provisions of this Code on an ongoing basis and as required by the Commission, but with a maximum of three years between reviews.

Amendments to this Code may be made from time to time as approved by the Commission.

Appendix 'A'

COMMISSION CODE OF CONDUCT PRINCIPLES

The Commission has established the following principles in the Guidelines which [Terasen Gas] intends to apply to RMDM activities and the Utility's relationships with NRBs.

i) The regulated company will not provide to the NRB any market-sensitive or confidential information that would inhibit a competitive energy services market from functioning. If customers agree to a release of customer information to the NRB, it should be provided to other market participants under the same terms and conditions and for the same price. Should an individual customer make a specific request to have information released to a particular third party, it will be released to that party only. The utility will be able to recover from the customer the costs associated with the provision of this information.

ii) No regulated company personnel will state or imply that favoured treatment will be available to customers of the company as a result of using any service of an NRB. In addition, no regulated company personnel will condone or acquiesce in any other person stating or implying that favoured treatment will be available to customers of the company as a result of using any service of an NRB.

iii) No regulated company personnel will preferentially direct customers seeking competitively offered services to an NRB. If a customer, or potential customer, requests from the regulated company information about products or services offered by an NRB or its competitors in downstream markets, the regulated company may provide such information, including a directory of retailers of the product or service, but shall not promote any specific retailer in preference to any other retailer.

iv) The regulated company will formally advise all employees of expected conduct related to these principles and it will undertake to perform periodic audits of the relationships to ensure compliance with these principles. These audits will be performed no less than once a calendar year and filed with the Commission.

v) Complaints by non-affiliated parties about the application of these principles, or any alleged breach thereof, will be brought to the immediate attention of the senior management of the regulated company and subsequently a report of the complaints, and action taken, will be filed with the Commission. The report will be filed with the Commission within one month of the complaint being made.

vi) The financing of the utility and NRB will be accounted for entirely separately with the financing costs reflecting the risk profile of each entity. No cross-guarantees or any form of financial assistance whatsoever should be provided directly or indirectly by a utility to its NRB without approval of the Commission.

vii) Use of the utility name by a related NRB will require approval by the Commission to ensure that its use will not interfere with the Commission’s ability to protect ratepayers.

In those cases where retail customers have direct market access to the commodity, the utility’s code of conduct will also include the following provision,

> The regulated company will treat all requests for distribution system access for the purpose of direct commodity marketing equitably and according to the requirements approved for direct commodity marketing in British Columbia.

Attachment 31.1

REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)

Attachment 31.3

REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)

Attachment 38.1

Customer Advisory Council Meeting

May 27, 2009

Agenda

8:30 a.m.	Continental Breakfast
9:00 a.m.	Introduction *(Doug Stout)*
9:05 a.m.	Customer Care Update *(Danielle Wensink)*
9:50 a.m.	New Business Opportunities *(John Turner, David Bennett)*
10:35 a.m.	Regulatory Update *(Scott Thomson)*
10:50 a.m.	Projects Update *(Cynthia Des Brisay)*
11:05 a.m.	Closing Remarks

A copy of today's presentation can be found at: www.terasengas.com

Terasen Gas

Customer Care & Services

Danielle Wensink
Customer Care & Services

May 27, 2009

Service Quality Indicators (SQIs)

	Performance Indicator	2009 YTD Actual	2009 Target
1	**Emergency Response Time** - Time Dispatched to Site - Emergency - Blowing Gas	22:00 minutes	**< 21:06 minutes**
2	**Speed of Answer – Emergency** (% of calls answered within 30 sec.)	98.5%	**> 95%**
3	**Speed of Answer – Non-Emergency** (% of calls answered within 30 sec.)	76.8%	**> 75%**
4	**Transmission Reportable Incidents**	0	**< 2**
5(a)	**Index of Customer Bills Not Meeting Criteria**	6.90	**< 5**
5(b)	**Percent of Transportation Customer Bills Accurate**	88.6%	**> 99.5%**
6	**Meter Exchange Appointment Activity**	87.2%	**> 92.2%**
7	**Accuracy of Transportation Meter Measurement First Report**	98.4%	**> 90.0%**
8	**Independent Customer Satisfaction Survey**	79.9%	**N/A**
9	**Number of Customer Complaints to BCUC**	21	**N/A**
10	**Number of Prior Period Adjustments**	11	**< 25**

	Directional Indicators	
1	Leaks per Kilometer of Distribution	0.0009
	Mains	17
2	Number of Third Party Distribution System Incidents	299

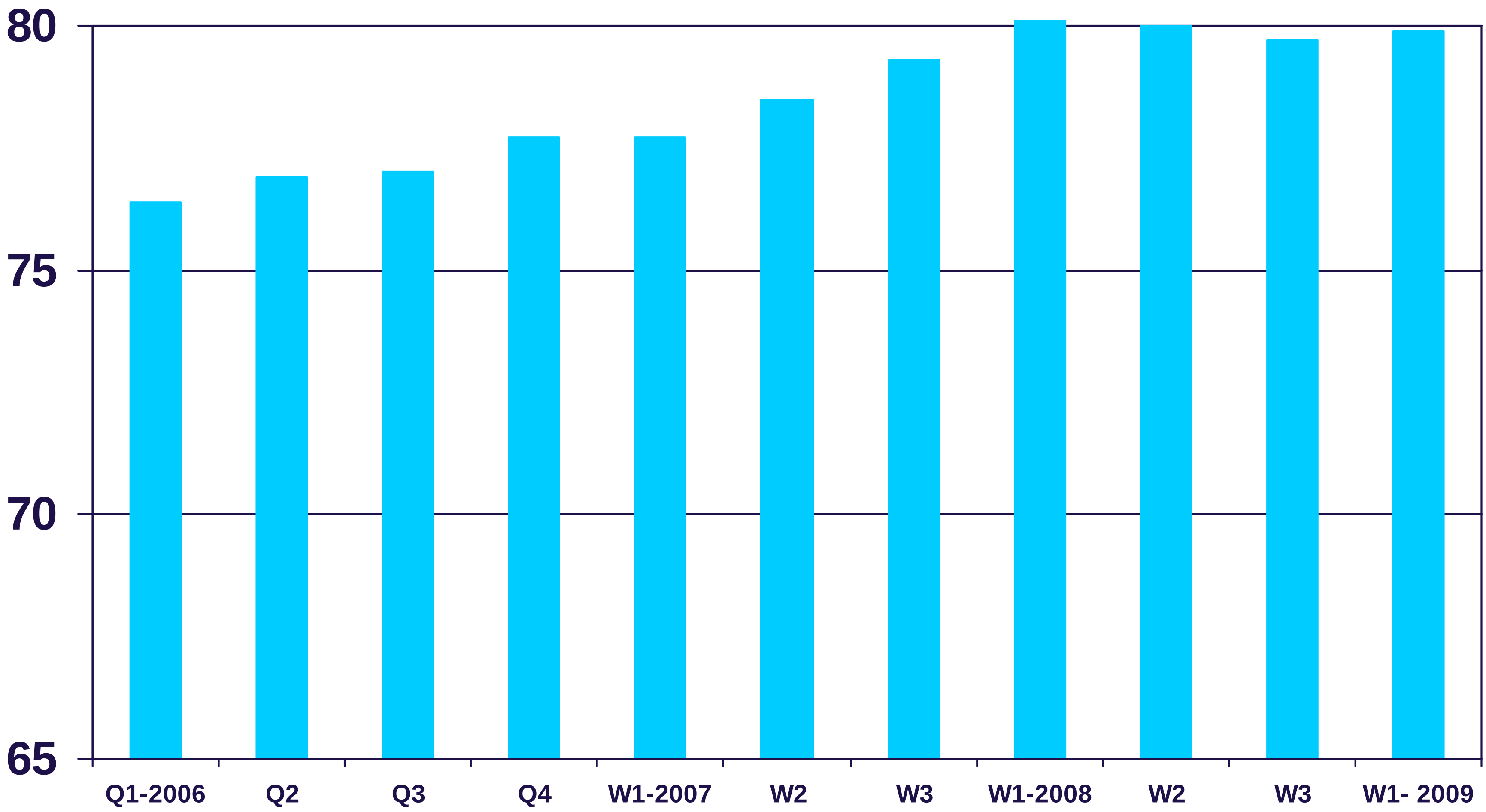
Distribution Measures

- Emergency Response Time
  - *Interior location events driving average response time slightly above target*
    - Outlying communities
    - After hours responses
  - *Construction crews assigned to more complex activities*
    - Can take longer to respond when assigned as first responder
- Meter Exchange Appointment Activity
  - *Activity currently below target due to overbooking of technicians resulting in missed appointments*
    - Fine-tuning appointment scheduling and system capacity within new mobile scheduling system for fieldwork

Billing Measures

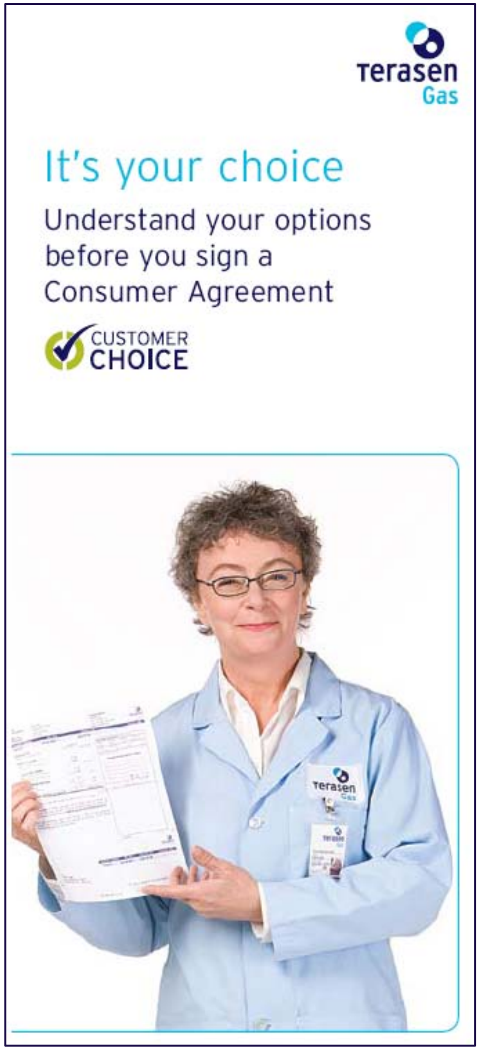
- Mass Market Billing Index & Transportation Billing Accuracy
  - *Year to date results driven primarily by late payment charge calculation error*
    - Result of CIS system technical upgrade late last year
    - Identified in January
    - System fix implemented in February
  - *Secondary impact was a PST / ICE Levy error*
    - Incorrectly charging above to first nations exempt customers
    - Identified and corrected in March

Customer Satisfaction Tracking



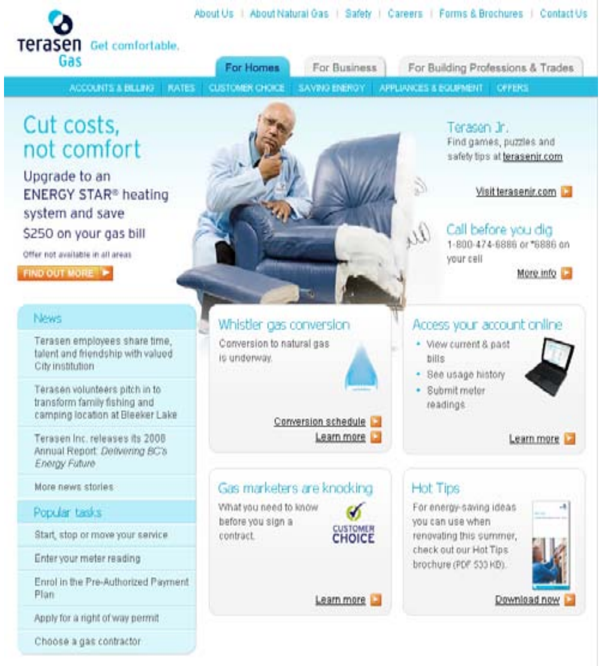
Recent Activities & Events

- Commodity rate adjustment
  - *Jan 1 – Fort Nelson, Revelstoke*
  - *Apr 1 – TGI, Fort Nelson, Revelstoke*
- Customer Choice education
  - *Spring newspaper advertising in 39 community papers*
  - *May bill inserts*
  - *Web advertising*
  - *Bill messages*



Recent Activities & Events

- Radio Campaign
  - *Promoted Energy Efficiency options for renovators*
    - Specific mention of the Furnace Upgrade program
  - *May 4 – May 15*
- Customer Research
  - *Service Channel Expectations & Preferences*
  - *Residential End Use Survey*
  - *Residential Customer Satisfaction Tracking – Wave 2, 2009*



Customer Care Enhancement Project

Danielle Wensink

Customer Care & Services

Project Overview

- Customer Care service delivery in-sourcing
  - *Establish internal call center and billing organization*
  - *Hire, train and house over 350 new employees*
  - *Operational “go live” beginning of 2012*
- In-source technology platforms and business processes
  - *Acquire and implement new CIS solution*

Key Drivers

- Market change
  - *Energy and environment policy changes*
  - *Expanded and more complex customer service offerings*
  - *Customer service expectations increasing*
- Ability to respond limited by existing solution
  - *Existing arrangement limits rapid and cost effective change*
  - *Current technology platform lagging the evolution of alternatives*
  - *Model does not facilitate close “customer touch”*
- Customer expectations and requirements continually change
  - *We need to ensure we can respond to change effectively*

Benefits

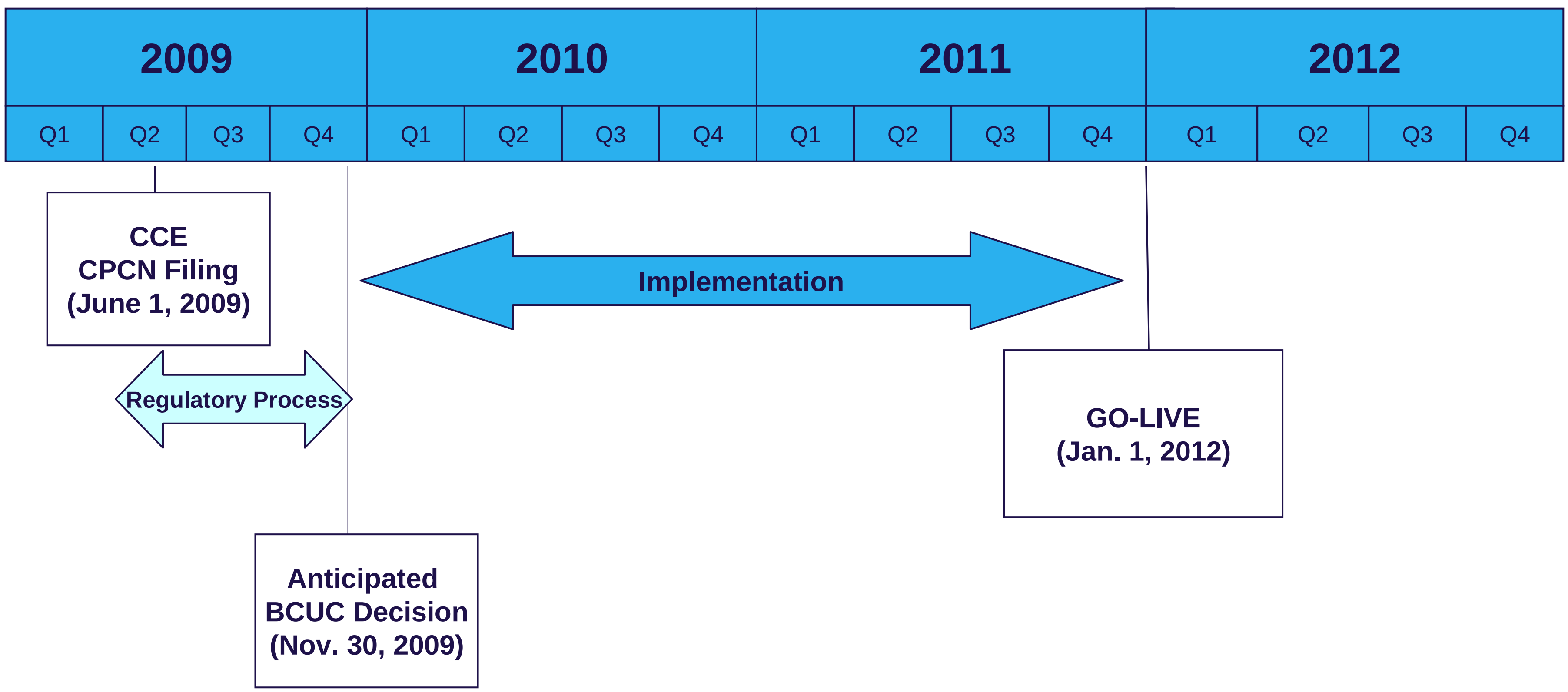
Customers Receive

- ***Greater scope of services***
  - **Improved communication channels**
  - **Enhanced self service options**
- ***Improved service levels***
  - **Regional knowledge**
  - **End to end business understanding**

Terasen Gas Receives

- ***Ownership of critical customer touch points***
- ***Improved capability to respond to increasing service expectations and market change***
- ***Greater control over pace, nature and cost of future change***
- ***Organizational flexibility***

Timeline



2009
2010
2011
2012
Q1
Q2
Q3
Q4
Q1
Q2
Q3
Q4
Q1
Q2
Q3
Q4
Q1
Q2
Q3
Q4
CCE
CPCN Filing
(June 1, 2009)
Regulatory Process
Implementation
Anticipated
BCUC Decision
(Nov. 30, 2009)
GO-LIVE
(Jan. 1, 2012)

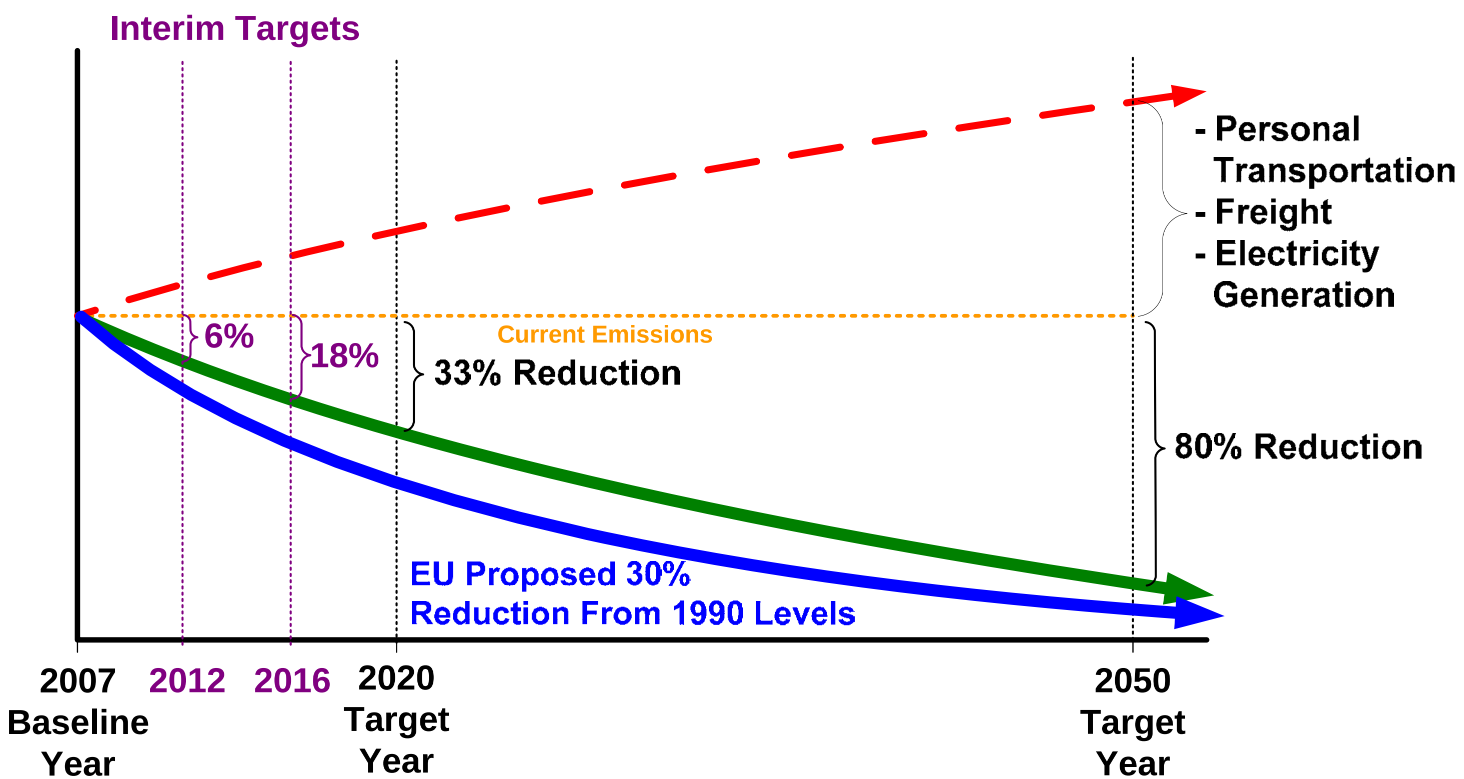
Customer Advisory Committee Community Energy Solutions – Our Growth Strategy
- a "TSN turning point"

John Turner, Director, Customer Management & Sales

David Bennett, Director Resource Planning & Market Development

British Columbia Legislated Targets

- ***Reducing BC's GHG emissions by at least 33% below 2007 levels by 2020 and at least 80% below by 2050***



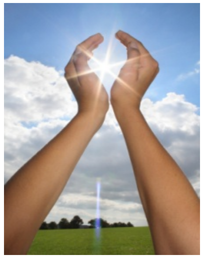
British Columbia Action to Targets

- *Through significant pieces of climate action legislation*
- *Includes carbon tax*

Cap and trade

Landfill Gas

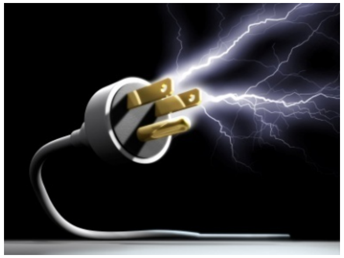
Energy Plan



Green Communities

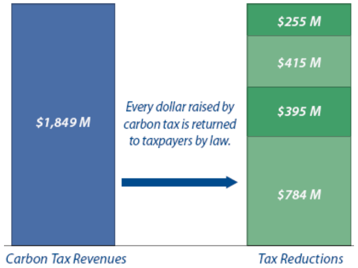
Low Carbon Fuel

Utilities Commission

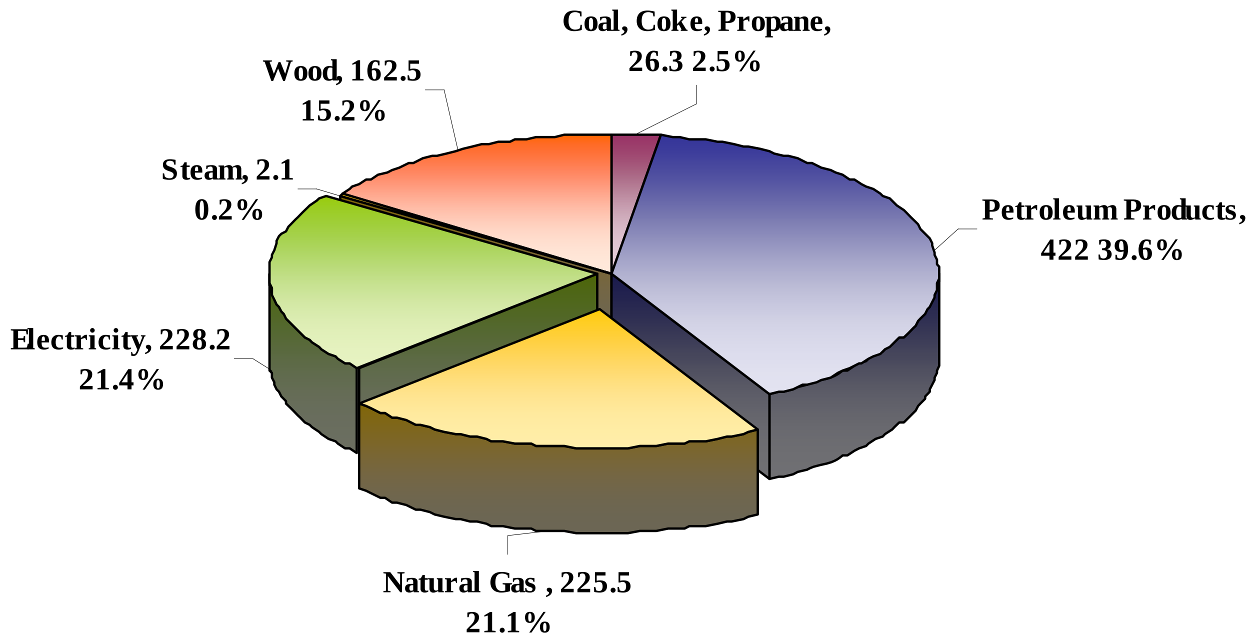


Tailpipe Standard

Carbon Tax Act



BC Energy Mix



Fortis ≈ 10 PJ

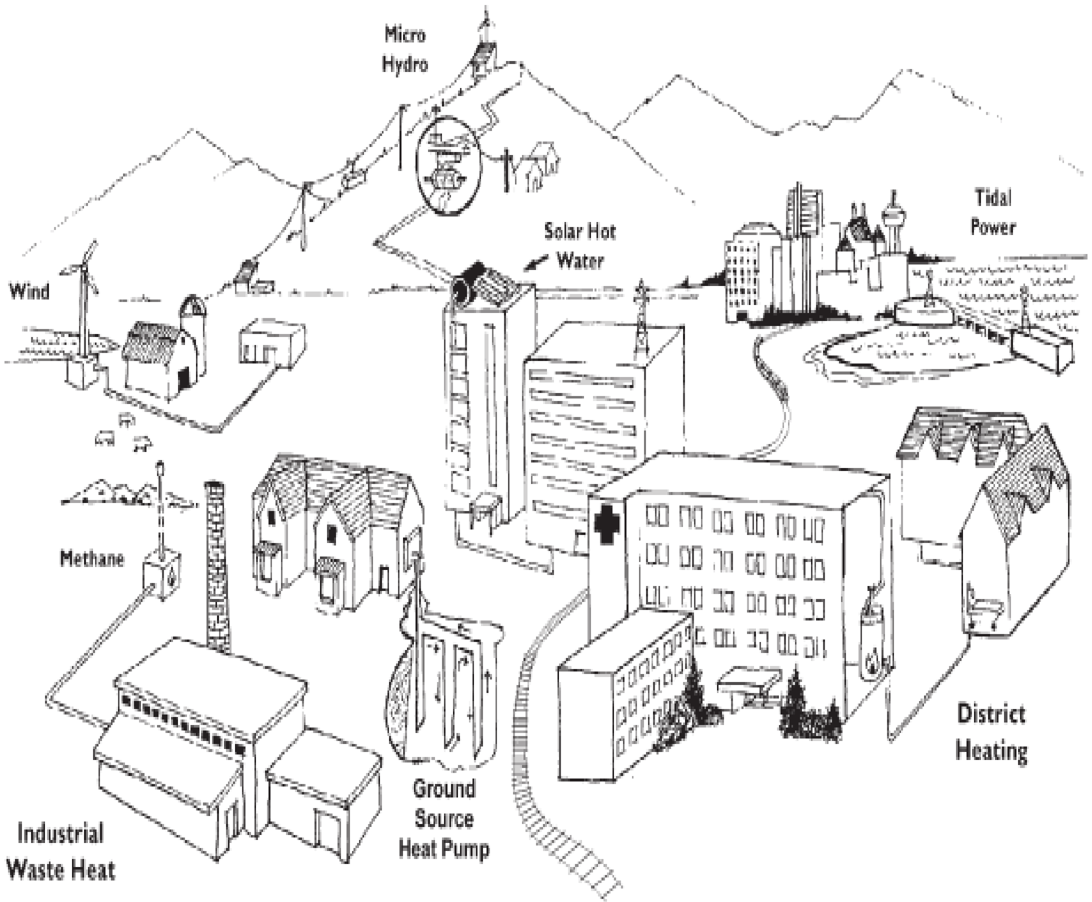
TG ≈ 215 PJ

Source: NRCan 2005 Database

BC Situation Summary & Response

- *BC Situation Summary:*
  - Very significant GHG reductions legislated
  - Equal use of electricity & natural gas today
  - Most of BC electricity is clean low-cost Hydro
  - Desire to preserve low cost electricity rates
- *Response:*
  - Transformation of thermal energy delivery
  - harness alternatives
  - reduce energy use
  - QUEST as an enabler
- *Why Terasen:*
  - Established energy provider in British Columbia

QUEST

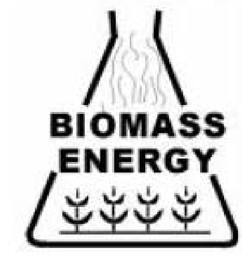


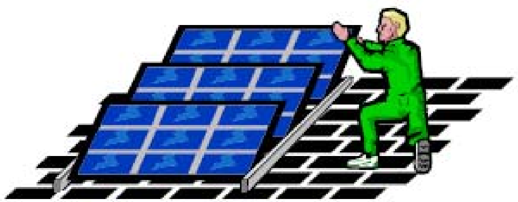
Source: Green Municipalities - A Guide to Green Infrastructure for Canadian Municipalities; prepared for the FCM by the Sheltair Group, May 2001

- Cascading of energy use between customer types
- Smaller scale systems closer to & within buildings
- Integrated with elements of buildings & other infrastructure systems
- Multiple local energy sources
- Augmented by gas & electricity grids
- Over 50% reduction in grid energy use.
- QUEST website:

  www.questcanada.org

Alternative Energy Options





Solar energy

Refrigeration
Waste Heat

Sewer heat

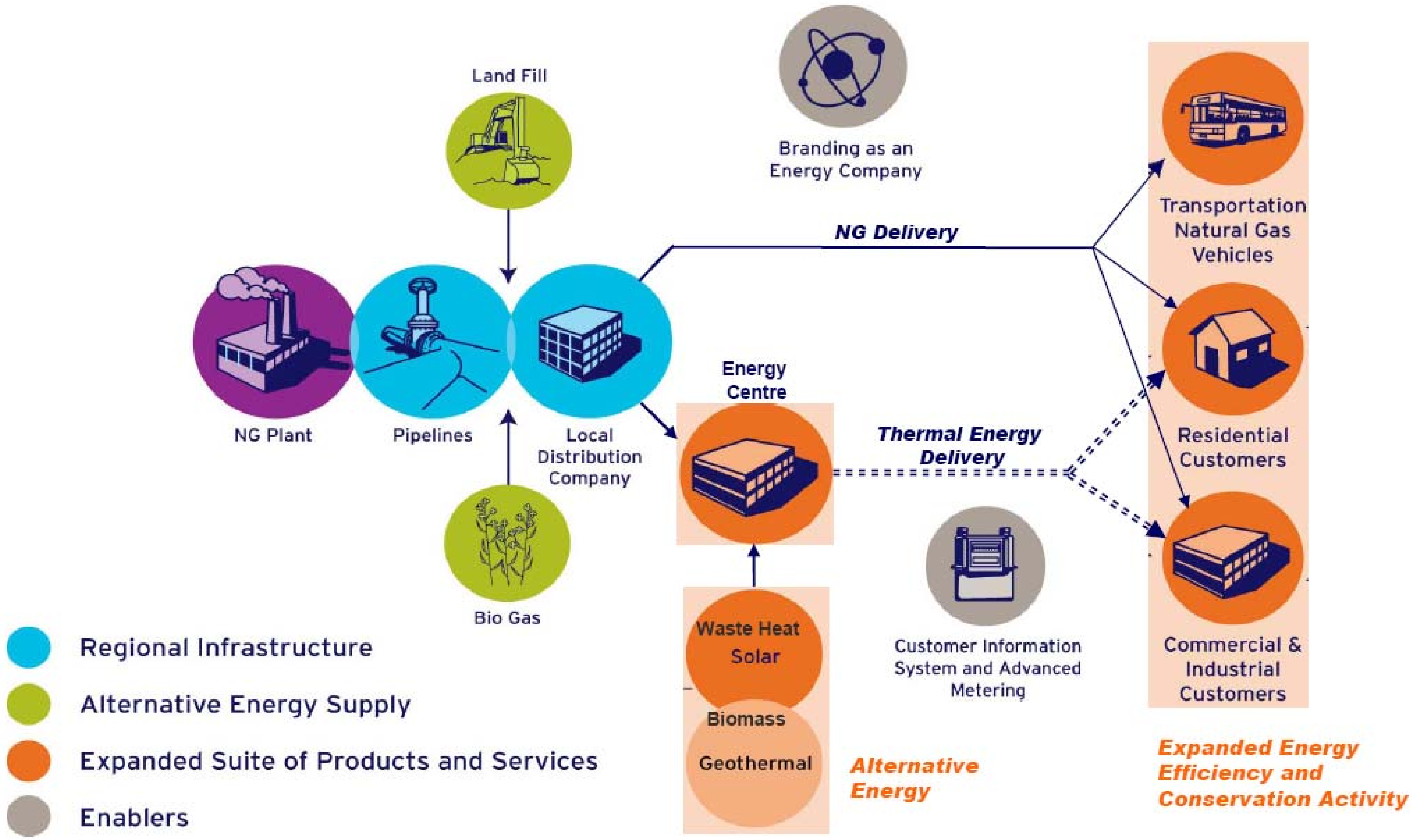
Biogas

(sewage, landfill, agriculture)

Industrial
Waste Heat

Geo-exchange Water or Ground Loop

Terasen Approach

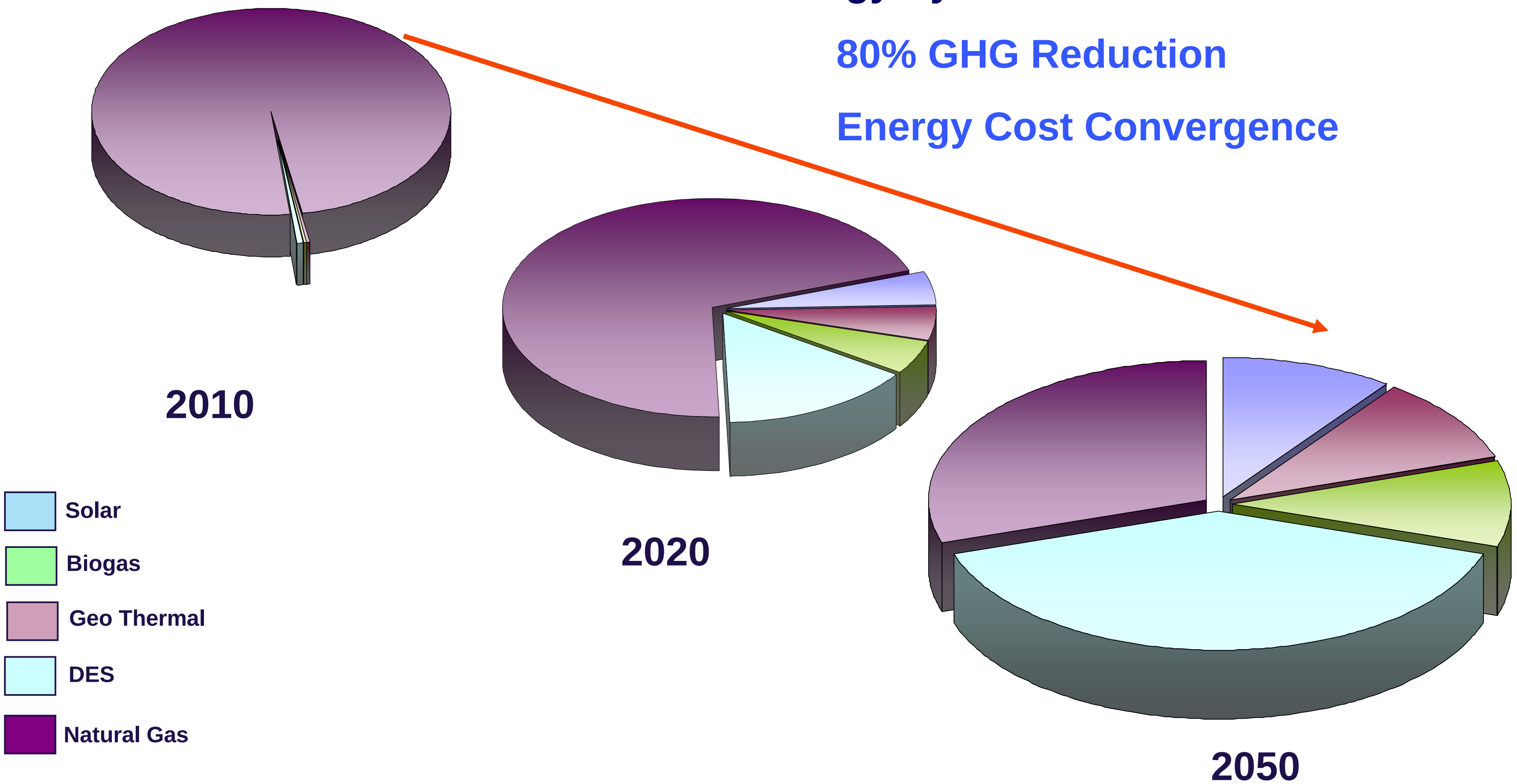


A Carbon Lean and Energy Diverse Future

Energy System Evolution

80% GHG Reduction

Energy Cost Convergence



Biogas

Methane from organic material

Main Sources:

Anaerobic Digester Gas:

- *Waste water treatment plants*
- *Agricultural - farms and dairies*

Landfill Gas:

- *Gas collected from wells installed within landfill sites*

1st Pilot Project at Lions Gate Wastewater Treatment Plant

Transportation Applications for NG

Material Handling Equipment

Yard Trucks

Waste Haulers

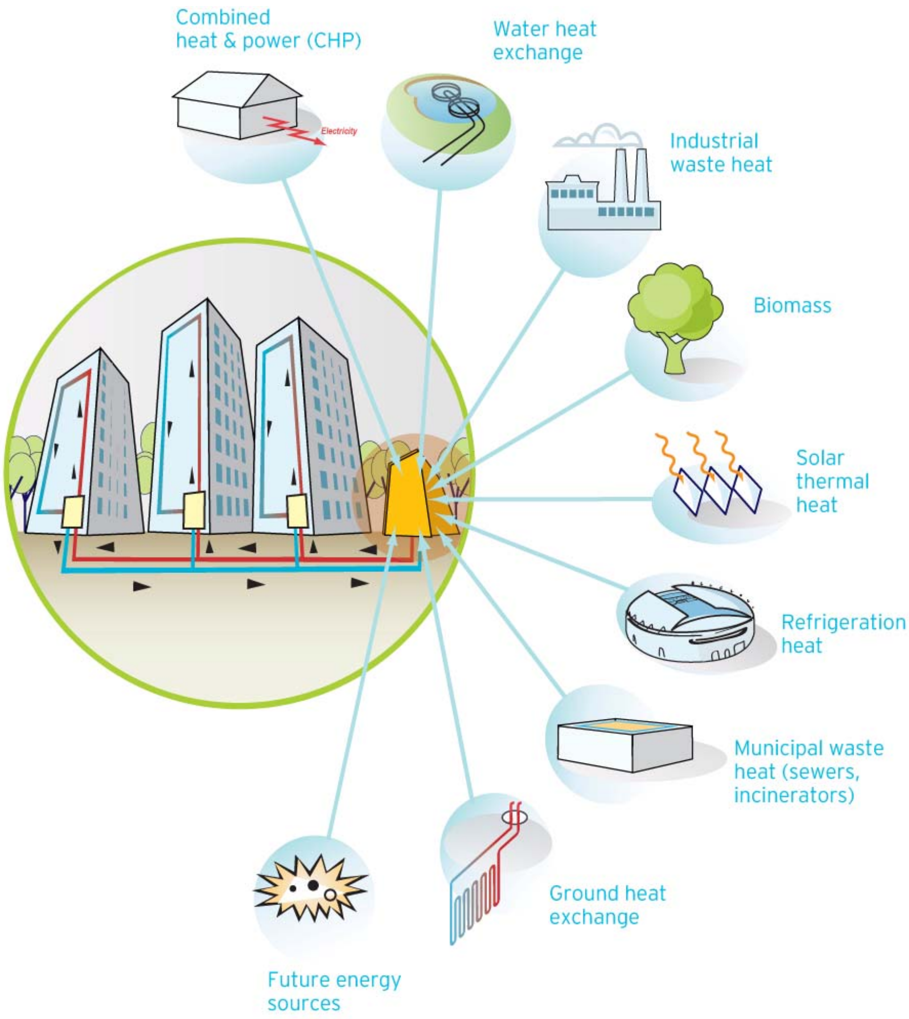
Transit Buses

Class 6/7 Trucks

Class 8 Trucks

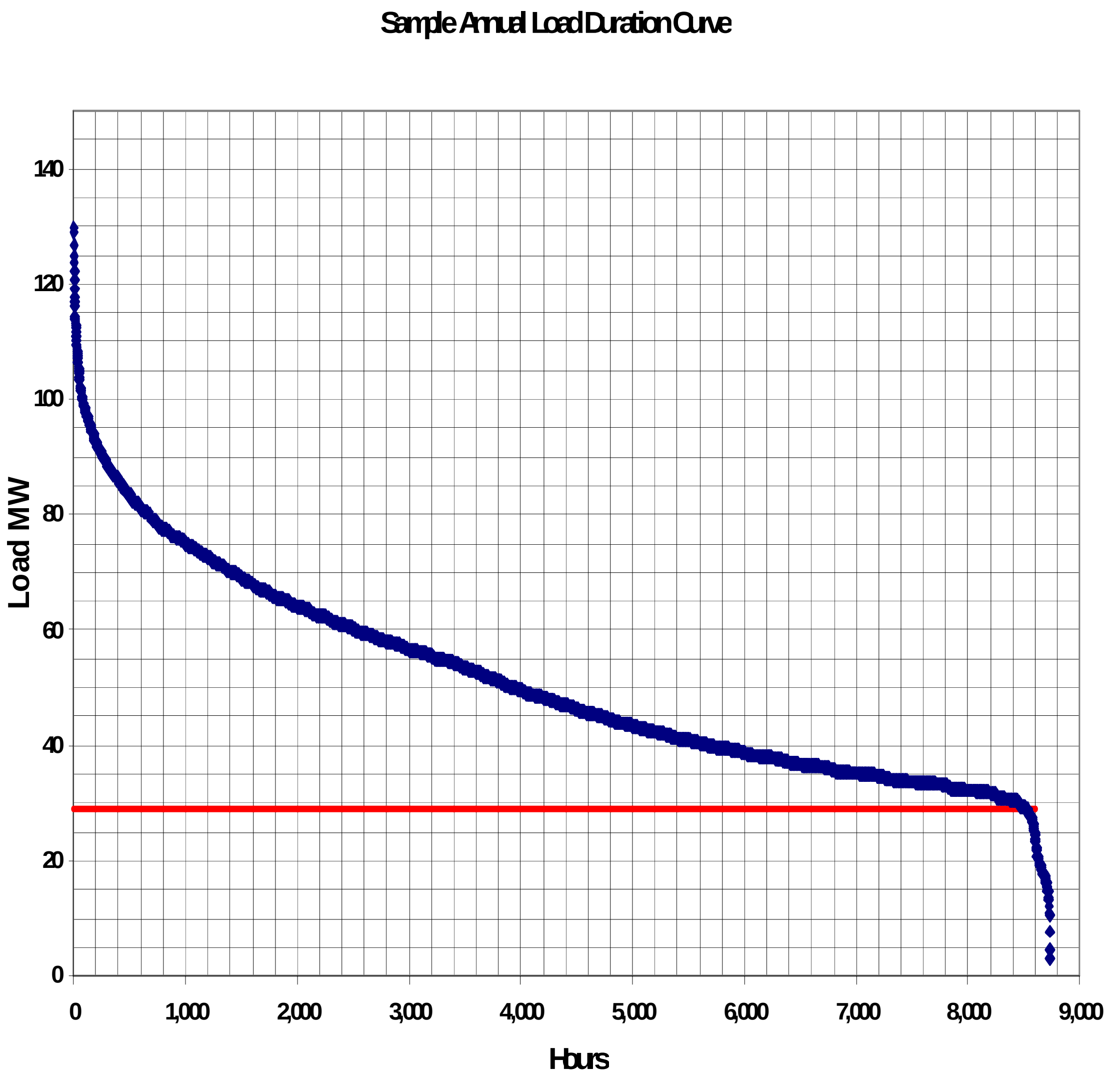
Pilot Project to use Tilbury LNG for Transportation Applications

Harnessing Alternative Energy



- **Thermal Energy Systems:**
  - ***Multiple energy sources***
  - ***Energy Centre generates usable thermal energy***
  - ***Thermal energy delivered via piped water:***
    - **Hot for high-grade heat sources; no cooling**
    - **Ambient for combined heating & cooling**
    - **Chilled for high-grade cooling sources & no heating**
  - ***Scale – one building to complete communities***

Alternative Energy - Cost Implications



Harnessing Alternatives:

- ***High capital cost for Energy Centre***
- ***"Free" energy?***
- ***May not be firm supply***

Outcomes:

- ***Size for base-load only***
- ***Use conventional energy for peaking &/or 100% back-up***
- ***Future flexibility essential for Energy Centre Capital cost barrier***
  - **Terasen can solve**

Terasen Large Scale Alternative Energy System Examples

District Energy for Brownfield Re-development

- Location: Coquitlam, BC
- Type of Development:
  - *89 acre brownfield re-development*
    - **3,700** residential units,
    - 275,000 sq. ft of commercial/retail
    - 600,000 sq. ft. of business park/ light industrial
    - 16 acres of open space, parks and trails.
- Energy System:
  - *District Energy System to incorporate alternative energy sources integrated with natural gas:*
    - Local waste heat (industrial recycling plant)
    - Geothermal from groundwater or earth
    - Possibilities for biomass

Fraser Mills Site Plan

- Environmental Benefits
  - Reduced demand on BC's electricity grid
  - Savings of >8,200 tonnes of GHGs per year (equivalent to removing >2,500 cars from the road)

Terasen Large Scale Alternative Energy System Examples

Individual Geothermal Systems for Residential Development

- Location: Colwood, BC
- Type of Development:
  - *563 unit residential development*
  - *24 buildings*

Aquattro Site

Geothermal drilling

- Energy System:
  - Individual geothermal systems
    - Ground heat extraction integrated with natural gas
    - Progressive installation as community develops
- Environmental Benefits
  - Reduced demand on BC's electricity grid
  - Savings of 2 tonnes of GHGs a year for each 2,000 square foot residential unit

Terasen Large Scale Alternative Energy System Examples

terasen Gas

Expandable Energy System for Urban Infill

- Location: Victoria, BC
- Type of Development:
  - *New & existing buildings*
    - 631 new residential units,
    - 175,000 sq. ft of new commercial/retail
    - Multiple existing buildings adjacent to new development.
- Energy System:
  - *Geothermal system for first two new buildings integrated with natural gas*
  - *Capability to expand to complete District Energy System incorporating waste heat from ice rink for both new & existing buildings.*

Hudson Building

- Environmental Benefits
  - Reduced demand on BC's electricity grid
  - Energy Usage in new buildings is reduced by up to 59% & GHGs by up to 73%

Summary

- **Our approach will maximize our growth opportunities and will be a model for thermal utilities of the 21st century**

1. ***Model works for Terasen & British Columbia***
   - **Spurred by aggressive climate change targets & expectations**
   - **Can meet challenge of low cost clean electricity**
   - **Terasen alternative energy segment is established & growing**
   - **Investment opportunity much higher than traditional gas**

2. ***Utility model applied to integrated gas & alternative thermal energy delivery provides numerous benefits***
   - **Recognizes renewable energy future with flexible platform**
   - **Relieves governments of need to fund alternative energy infrastructure**
   - **Enables governments to meet climate change objectives**
   - **Ensures fair & competitive energy costs for end use customers**
   - **Allows transparent & open regulatory process**

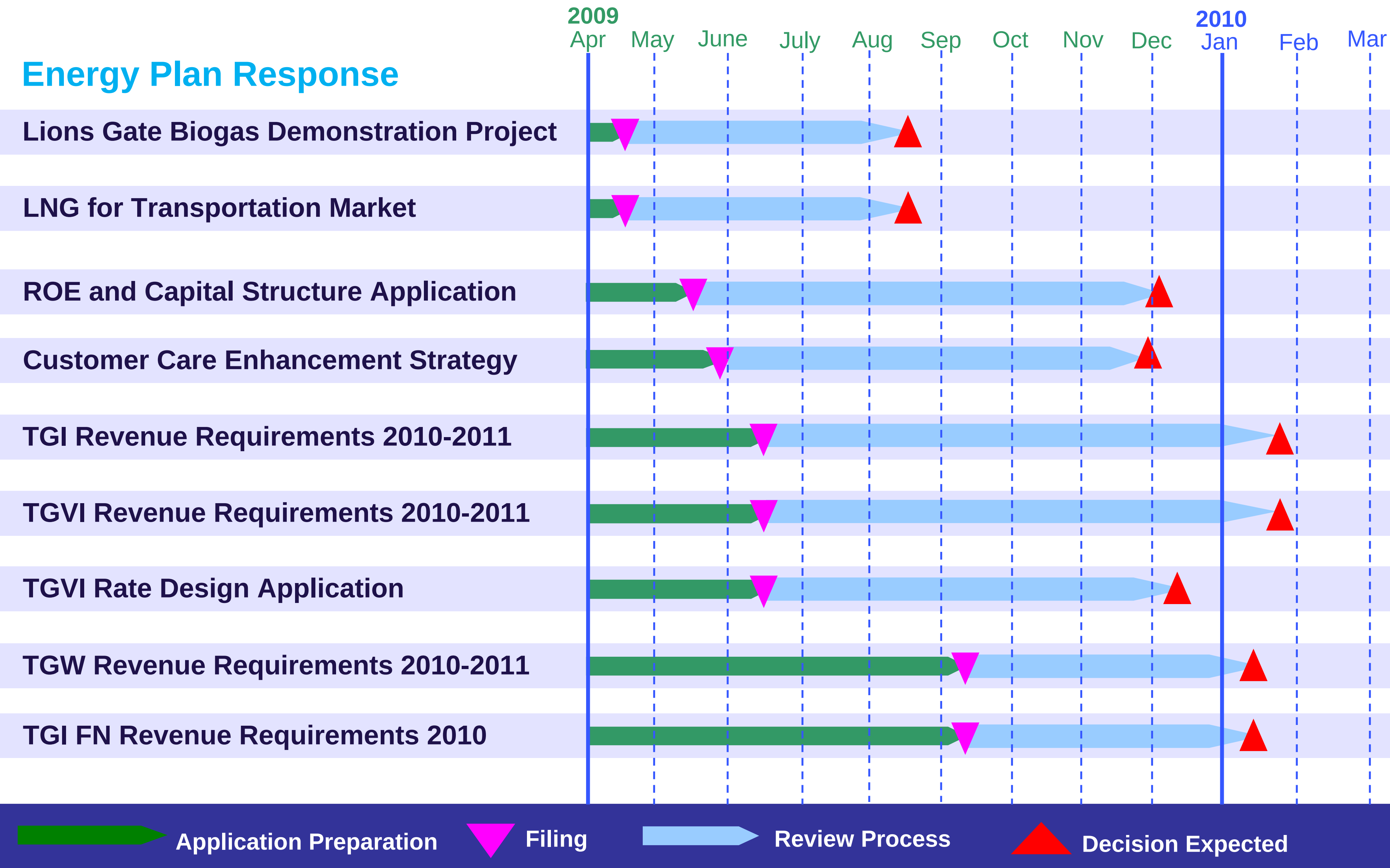
Questions?

Land Fill
Branding as an Energy Company
NG Delivery
Transportation Natural Gas Vehicles
NG Plant
Pipelines
Local Distribution Company
Energy Centre
Thermal Energy Delivery
Residential Customers
Bio Gas
Waste Heat
Solar
Biomass
Geothermal
Customer Information System and Advanced Metering
Commercial & Industrial Customers
Alternative Energy
Expanded Energy Efficiency and Conservation Activity
Regional Infrastructure
Alternative Energy Supply
Expanded Suite of Products and Services
Enablers

Regulatory Calendar

Scott Thomson, Vice President
Regulatory Affairs & CFO

Anticipated Timing and Process – Major Filings
Regulatory Calendar – 2009 and 2010



Status Update of Major Projects

Cynthia Des Brisay, Vice President, Gas Supply & Transmission

Whistler Pipeline and Conversion

- 50 km pipeline extension from Squamish completed and put in service in April 2009
- Conversion commenced on April 29
- Propane System to be decommissioned this fall

Whistler Conversion

Terasen Gas

- 2,150 Residential & 325 Commercial customers
- 14,500 appliances to be converted
- Conversion team 80+ employees and contractors from across the province

Whistler Conversion

- Service area split in 84 sections and conversion of each section completed once work begins
  - Approximately 20 sections completed to date

Whistler Conversion

Westin Hotel

- Example of large commercial customer
- Boilers, Kitchens, and 367 Fireplaces!
- High degree of co-operation & coordination
- Conversion completed in two days

Mount Hayes Storage Facility

Description

- 1.5 bcf storage facility
- 7.5mmcf/d liquefaction
- 150 mmcf/d send-out
- Capital cost $200M
- Serves both Vancouver Island and the Lower Mainland

Mt Hayes Storage Facility

- Groundbreaking in May 2008
- Liquefaction begins April 2011
- Full Commissioning complete Nov 2011
- Currently on budget and on schedule

Mt Hayes Storage Facility

Mt Hayes Storage Facility

- 80 – 120 workers on site
- 20 HCBI workers, remaining workforce 75% local, 25% rest of BC
- First Nation involvement
- To date $27 million in local subcontracts, employment & services

- First Nation involvement in construction, site and pipeline work and other services

Fraser River South Arm Upgrade

- Replacement of twin pipeline crossings using Horizontal drilling
- Cost estimate $27.3M
- Mitigates seismic, river erosion, and dike improvement concerns
- Improves reliability and security of supply for up to 220,000 customers
- Completion by end of 2010

Fraser River South Arm Upgrade

Attachment 55.3

REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)

Attachment 56.1

REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)

Attachment 57.2

STATE OF CALIFORNIA

PUBLIC UTILITIES COMMISSION

505 Van Ness Avenue
San Francisco, California 94102

California Energy Efficiency Evaluation Protocols: Technical, Methodological, and Reporting Requirements for Evaluation Professionals

APRIL 2006

Prepared for the **California Public Utilities Commission**

by **The TecMarket Works Team**

Under Contract with and Directed by the CPUC's Energy Division, and with guidance from Joint Staff

California Energy Efficiency Evaluation Protocols: Technical, Methodological and Reporting Requirements for Evaluation Professionals

{a.k.a. Evaluators' Protocols}

Prepared under direction of the **Energy Division**, with the guidance by **Joint Staff**, for the

California Public Utilities Commission

APRIL 2006

Submitted by

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Steve Kromer
RCx Services, Oakland, California

Lori Megdal, Ph.D.
Megdal & Associates, Acton, Massachusetts

Jane Peters, Ph.D.
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Ridge & Associates, Alameda, California

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Francis Trottier Consulting, Penn Valley, California

Ed Vine, Ph.D.
Energy Program Consultant, Berkeley, California

Acknowledgements

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The Joint Staff (California Public Utilities Commission and the California Energy Commission) provided considerable Protocol development guidance and conducted multiple rounds of reviews of all sections of the Protocols. These individuals and their affiliations are the following:

- Ariana Merlino, Project Manager, Energy Division, California Public Utilities Commission
- Mike Messenger, California Energy Commission

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In addition to the oversight and guidance provided by the above individuals, others within the Energy Division of the California Public Utilities Commission and the California Energy Commission provided valuable contributions and support. For these efforts we thank the following individuals:

- Nancy Jenkins, California Energy Commission
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- Zenaida Tapawan-Conway, Energy Division, California Public Utilities Commission
- Peter Lai, Energy Division, California Public Utilities Commission
- Nora Gatchalian, Energy Division, California Public Utilities Commission
- Jeorge Tagnipes, Energy Division, California Public Utilities Commission
- Sylvia Bender, California Energy Commission

We also wish to thank the California investor owned utilities and their program management and evaluation staff who have attended workshops and provided both written and verbal comments during the Protocol development process. And we wish to thank the public representatives who attended the workshops and provided verbal and written comments. All of these combined efforts helped move the development of the Protocols to a successful completion in a very short period of time.

Lastly, we wish to thank the TecMarket Works Protocol Project Team who under direction from the ALJ and the Joint Staff, and with useful comments from the IOUs and the public, took the Protocols from concept to completion under the oversight of Joint Staff.
This team was made up of the following individuals:

- Nick Hall, Johna Roth, Carmen Best, TecMarket Works

- Sharyn Barata, Opinion Dynamics Corporation
- Pete Jacobs, Building Metrics Inc.
- Ken Keating, Ken Keating and Associates
- Steve Kromer, RCx Services
- Lori Megdal, Megdal & Associates
- Jane Peters, and Marjorie McRae, Research Into Action
- Rick Ridge, Richard Ridge and Associates
- Ed Vine, Edward Vine and Associates
- Francis Trottier, Francis Trottier Consulting

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California Energy Efficiency Evaluation Protocols: Technical, Methodological and Reporting Requirements for Evaluation Professionals

{a.k.a. Evaluators' Protocols}

Introduction

This chapter presents and describes the California Energy Efficiency Evaluation Protocols: Technical, Methodological and Reporting Requirements for Evaluation Professionals (a.k.a. Evaluators' Protocols, referred to hereafter collectively as the Protocols and individually as Protocol) that are designed to meet California's evaluation objectives.

This document is to be used to guide the efforts associated with conducting evaluations of California's energy efficiency programs and program portfolios launched after December 31, 2005. The Protocols are the primary guidance tools policy makers will use to plan and structure evaluation efforts and that staff of the California Public Utilities Commission's Energy Division (CPUC-ED) and the California Energy Commission (CEC) (collectively the Joint Staff), and the portfolio (or program) administrators (Administrators) will use to plan and oversee the completion of evaluation efforts. The Protocols are also the primary guidance documents evaluation contractors will use to design and conduct evaluations for programs implemented after December 31, 2005. This chapter provides an introduction to, and overall guidance for, the use of specific Protocols presented in later chapters of this document.

The Protocols are significantly grounded in the *California Evaluation Framework* of June 2004[1] (*Evaluation Framework)*. The Protocols reference the *Evaluation Framework* and other documents that provide examples of applicable methods. The requirements for conducting evaluation studies, however, are always those stated in the Protocols, which take precedence over other evaluation guidance documents, unless otherwise approved or required by the CPUC. That is, these Protocols are the primary evaluation guidance documents for all types of evaluations presented in these Protocols, however this is not to be construed as limiting the ability of the CPUC or the Joint Staff to evaluate items in addition to or beyond those identified in these Protocols or to use evaluation processes and procedures beyond those presented in these Protocols. While these Protocols are the key guiding documents for the program evaluation efforts, the CPUC and the Joint Staff reserve the right to utilize additional methodologies or approach if they better meet the CPUC's evaluation objectives and when it serves to provide reliable evaluation results using the most cost-efficient approaches available. In addition, the Protocols should be considered a "living" document that may need to be updated and revised from time to time as standard evaluation approaches evolve and as Joint Staff and Administrators gain experience using the Protocols. The CPUC will determine when an update is necessary and what process will be used to complete any updates that the agency deems necessary. Protocol users should always confirm that they are referring to the most recently CPUC-approved and -adopted version, which can be found on the CPUC website.

[1] TecMarket Works, *The California Evaluation Framework* (Southern California Edison Company, 2004). The report can be obtained on the CALMAC Web site at: http://www.calmac.org/search.asp. Enter "California Evaluation Framework" and download the 500-page reference document as an Adobe .pdf file.

Most of the Protocols are designed to function within an evaluation planning process that focuses on the evaluation needs within a given program cycle. This planning process is described in a other documents adopted by the ALJ and the CPUC, and most directly at part of what are known as the Process Protocols.

The Protocols cover several types of evaluation efforts. The evaluation types covered include the following: direct and indirect impact {including the associated measurement and verification approaches (M&V)}, market effects, emerging technology, codes and standards and process evaluations. In addition, the Protocols provide specific guidelines for conducting effective useful life studies and how evaluation samples should be selected. The primary goal of this document is to specify **minimum** acceptable evaluation approaches and the operational environments in which evaluations are conducted. The primary purpose of the Protocols is to establish a uniform approach for:

- Conducting robust and cost-efficient energy efficiency evaluation studies;
- Documenting ex-post evaluation-confirmed (i.e. realized) energy efficiency program and portfolio effects;
- Supporting the performance bases for judging energy efficiency program and portfolio achievements; and
- Providing data to support energy efficiency program and portfolio cost-effectiveness assessments.

The Protocols may have other uses such as providing support for improving ex-ante energy and demand savings estimates.

This document includes a separate Protocol for each of the following categories:

- Impact Evaluation - Direct and Indirect Effects
- Measurement and Verification
- Process Evaluation
- Market Effects Evaluation
- Codes and Standards Program Evaluation
- Emerging Technology Program Evaluation
- Sampling and Uncertainty Protocol (for use in determining evaluation sampling approaches) Reporting Protocol (to guide evaluation data collection and reporting)
- Effective Useful Life Protocol (used to establish the period over which energy savings can be relied upon)

The Protocols also include information on the type of evaluation-related information and support needed from program administrators and implementers in order to conduct the evaluation efforts. The purpose of each of the listed Protocols is described below.

Impact Evaluation Protocol: The Impact Evaluation Protocol prescribes the minimum allowable methods to meet a specified level of rigor that will be used to measure and document the program or program component impacts achieved as a result of implementing energy efficiency programs and program portfolios. Impact evaluations estimate net changes in electricity usage, electricity demand, therm usage and/or behavioral impacts that are expected to produce changes in energy use and demand. Impact evaluations are limited to addressing the direct or indirect energy impacts of the program on participants, including participant spillover impacts. However, while the Protocols provide for the assessment of participant spillover, these results are not to be counted toward program or portfolio energy savings goal accomplishments, and as such are to be distinctly and separately identified in any impact reporting.[2] The impact evaluation studies are also not expected to document program influences on the operations of a market or the program's impacts on non-participants. Program-induced changes that affect non-participants or the way a market operates are addressed in the Market Effects Evaluation Protocol. Results from the impact evaluations will support a cost-effectiveness assessment at the program and portfolio level.

Measurement and Verification (M&V) Protocol: The M&V Protocol is designed to prescribe how field measurements and data collection will be conducted to support impact evaluations, updates to ex-ante measure savings estimates and process evaluations.

Process Evaluation Protocol: The Process Evaluation Protocol is designed to support Administrator (i.e. Investor Owned Utility or IOU) efforts to conduct evaluations that both document program operations and provide the basis for improving the operations or cost-effectiveness of the programs offered within the portfolio.

Market Effects Evaluation Protocol: The Market Effects Evaluation Protocol is designed to guide evaluations conducted to document the various market changes that affect the way energy is used within a market and estimate the energy and demand savings associated with those changes that are induced by sets of program or portfolio interventions in a market.

Codes and Standards Program Evaluation Protocol: The Codes and Standards Program Evaluation Protocol is designed to guide evaluation approaches for codes and standards programs.

Emerging Technology Program Evaluation Protocol: The Emerging Technology Program Evaluation Protocol is designed to guide evaluation approaches for emerging technology programs.

Effective Useful Life Protocol: The Effective Useful Life Protocol is designed to guide evaluation approaches for establishing the effective useful life of program measures, including approaches for evaluating measure retention and technical degradation of measure performance. The effective useful life of a measure is the period of time over which program-induced energy impacts can be relied upon.

[2] The Protocols prescribe minimum requirements for how to conduct and report evaluations. The Performance Basis Protocol takes precedence with regard to including savings toward program or portfolio goals and performance measurement. The most recent CPUC decision will always take precedence and be used for the interpretation and application of the Protocols.

Sampling and Uncertainty Protocol: The Sampling and Uncertainty Protocol is designed to prescribe the approach for selecting samples and conducting research design and analysis in order to identify, mitigate and minimize bias in support of the Protocols identified above.

Reporting Protocols: The Reporting Protocol prescribes the way in which evaluation reports are to be delivered and the way information is to be presented in those reports.

Evaluation Support Information Needed from Administrators: The Protocol document also includes a chapter on the types of information Administrators shall provide to contractors conducting evaluation studies covered by the Protocols.

The four primary types of Evaluation Protocols that cover the majority of California's program offerings are the Impact, M&V, Market Effects and Process Protocols. These are supported by the Sampling and Uncertainty Protocol. However, there are two types of programs that are different enough in their scope and intended results that they require a separate Evaluation Protocol (Codes and Standards and Emerging Technology). As such, two Evaluation Protocols are directed to a specific type of program (Codes and Standards and Emerging Technology), while the remaining Protocols either operate to establish a minimum set of allowable methods for a specific type of evaluation or in support thereof. Any program, program component or set of programs could be included within each of these types of evaluations. The difference lies not in which programs are eligible for which types of evaluations, but in the purpose of and outputs from each of these evaluation types.

The outputs from an impact (and its associated M&V efforts) evaluation are program or program component net energy, demand or behavioral impacts from program participation. Those from a market effects evaluation are energy and demand impacts created by market changes caused by a program or set of programs. While a process evaluation produces the documentation and assessment of program processes, and recommendations to improve them. A program could easily be included in all three types of evaluations. For example, a single program of great significance with respect to the overall portfolio might be directly assessed using impact and process evaluations and also be included in a market effects evaluation for all programs operating in a given market sector.

While it is important to know what is in these Protocols (above), it is also important to know what is not included in these Protocols. These Protocols do not cover the evaluation or research approaches for the following types of programs, efforts or activities:

- Low-income program evaluations;
- Market research for program design, planning or operations;
- Technical, market or other types of potentials studies;
- Meta-evaluations or comparative studies using evaluation study results;
- Demand response programs;
- Renewable energy programs;
- On-site or distributed generation or combined heat and power programs;
- Green house gas or pollution reduction studies;
- Cost-effectiveness methods, approaches or procedures;

- Forecasting methods, approaches or procedures; and
- Public Interest Energy Research (PIER) evaluation efforts.

While it is expected that the Protocols will need to be updated from time to time, it is also expected that new Protocols may need to be added to this document as the need for different types of information evolves. For example, California may need to establish Protocols for crediting greenhouse gas reductions resulting from the energy efficiency program portfolios or for addressing demand response programs that are currently outside the scope of the Protocols.

How The Protocols Were Developed

The Protocols were developed over two different but overlapping three-month timelines involving a number of activities, including presentations to the public and the receipt of public comments and recommendations. The Impact, M&V, Process, Market Effects, Sampling and Reporting Protocols were developed first, and followed by the development of the Codes and Standard, Emerging Technology, and Effective Useful Life Protocols. All of the Protocols were developed using the following approach:

1. The consulting team that the CPUC-ED contracted to develop the Protocols (TecMarket Team) assembled and reviewed comments from previous Protocol and performance basis workshops and comments received during the development of the *Evaluation Framework*;
2. Using the *Evaluation Framework*, previous comments and discussions with the Joint Staff, draft concept Protocol outlines were developed. These concepts were then discussed within a series of meetings with the Joint Staff leading to the development of a set of draft concept Protocols;
3. The draft concept Protocols were presented in public workshops. During the workshops, the attending public was requested to comment on the draft concept Protocols. These comments were recorded and summarized in workshop notes and used to inform Protocol development. At this time, the draft concept Protocols were also placed on the CPUC website for additional public review. An announcement was sent to the CPUC Energy Efficiency service lists advising the public of the workshops and the draft concept Protocol postings. These efforts allowed both attendees and non-attendees of the workshop to review the draft concept Protocols and provide comments;
4. Following the workshop, the TecMarket Team collected comments from both workshop attendees and non-attendees. These comments were distributed to and reviewed by the Joint Staff and the TecMarket Team and used to guide the draft Protocol development efforts;
5. The TecMarket Team developed a set of draft Protocols under the direction of CPUC-ED staff and in consultation with the Joint Staff. The draft Protocols were provided to the Joint Staff for review and comment in order to identify concerns and issues that needed to be addressed in the final draft Protocols. Upon reviewing the draft Protocols, the Joint Staff requested modifications to the Protocols;

6. The TecMarket Team modified the draft Protocols consistent with direction provided by CPUC-ED staff, in consultation with Joint Staff, and provided them to the CPUC-ED project manager for final review and editing;
7. The CPUC-ED project manager submitted the draft Protocols to the ALJ for review and acceptance;
8. The ALJ, in consultation with the CPUC-ED project manager and Joint Staff, reviewed and accepted the final Protocols.
9. The ALJ adopted these Protocols via a Ruling, per the authority delegated her by the CPUC.

In addition to the process outlined above, the first set of Protocols developed (Impact, M&V, Process, Market Effects, Sampling and Reporting) went through an additional round of public review and comment, Joint Staff review and commentary, and CPUC-ED project manager approval and editing process before they were provided in final form to the ALJ for review and acceptance.

How the Protocols Work Together

The Protocols are designed to support the need for public accountability and oversight, the need for program improvements (especially cost-effectiveness improvements) and the documentation of effects from publicly funded or rate-payer funded energy efficiency programs provided in California. The individual Protocols are designed to work together to achieve these goals.

The Impact Evaluation Protocol is meant to guide the design of evaluations that provide reliable ex-post participant-focused net program impacts. These net impacts include peak demand (kilowatts (kW) of electricity), energy (kilowatt-hours (kWh) of electricity and therms of natural gas) and behavioral impacts. The Protocol is focused such that program level impacts can be summed to estimate impacts at the Administrator portfolio level. The Protocol also allows for impact estimates at the program component delivery level (e.g., direct install, participant rebate and information distribution) or at the technology level (e.g., CFLs, motors, HVAC tune-up and refrigerators) when the specific evaluation is meant to acquire these metrics.

The Impact Evaluation Protocol does not operate in isolation from the other Protocols. The M&V Protocol supports impact evaluations and can often serve in a feedback or support role for process evaluations if coordinated to do so. Similarly, the Sampling and Uncertainty Protocol is designed to support impact evaluations, as well as M&V, and process and market effects evaluations by assuring that the sampling designs provide unbiased estimates based on the information needs associated with each evaluation effort. Finally, the Reporting Protocol is designed to support all of the evaluation activities by detailing the information that must be reported for each type of evaluation. The entire evaluation process is facilitated by the additional identification of the information Administrators need to provide the evaluation contractors.

The Protocols, and the evaluations conducted under them, support several efforts. For example, many of the evaluation results, especially the impact evaluation results and the verification aspects of the M&V Protocol, are designed to support program performance assessment, including the performance-based metrics associated with ex-post energy savings and verification of installed measures.

The following diagram provides an overview of how the Protocols work in relationship to each other and the organizations that are responsible for using the Protocols to conduct evaluation research.

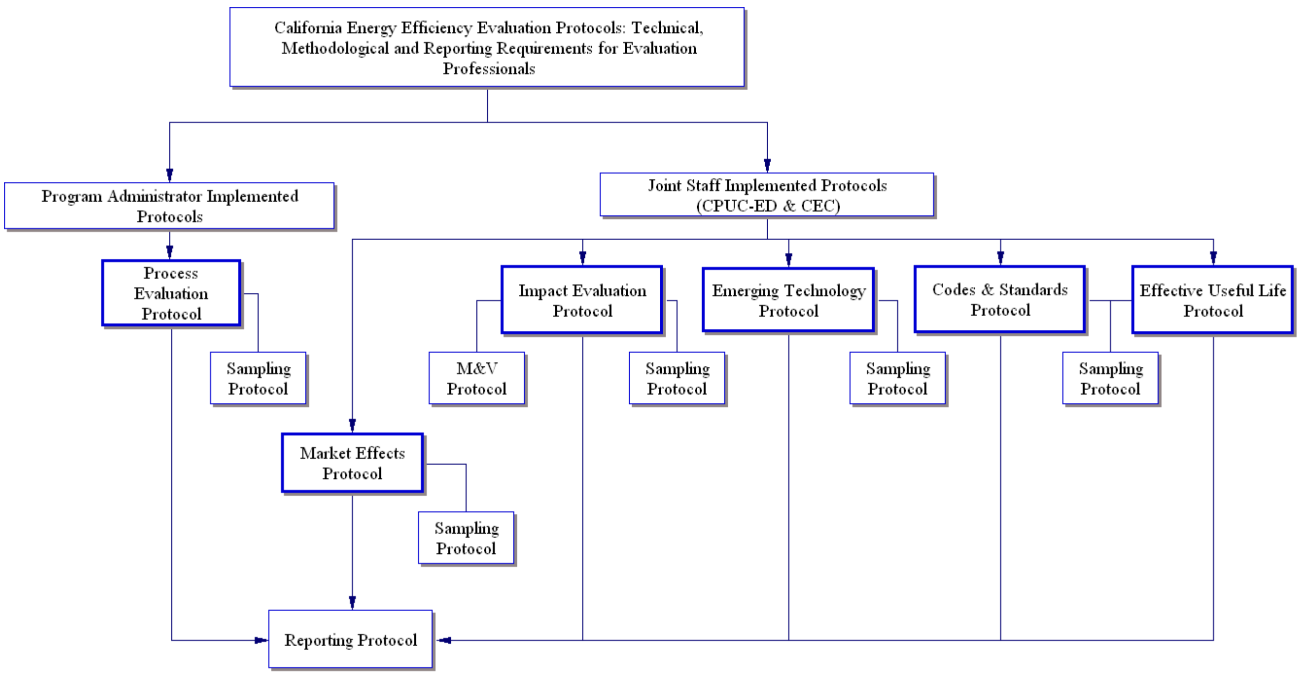

Figure 1. Operational Overview of How the Protocols Relate to Each Other

Note: The Process Evaluation Protocol is a guidance document and is less instructive than the other Protocols that are more prescriptive in design. While the Process Evaluation Protocol does contain required reporting and planning activities, it designates that the key decisions on what, when and how to evaluate are the responsibility of the Administrators.

How the Protocols Meet CPUC Goals

The primary evaluation-related goal of the CPUC is to assess net program-specific energy impacts or the market level impacts of the portfolio of energy efficiency services and to compare these results with the assigned energy savings goals. Similarly, the CPUC must be assured that when an evaluation is conducted it can rely on the findings of that research to accurately reflect the energy benefits available to the citizens of California in exchange for the resources spent. As a result, the following goals are incorporated into the operations of the Protocols:

- To identify the annual energy and peak demand impacts associated with each program offered, for which there are expected savings, over the period of time the program measures are projected to provide net participant energy impacts. This will almost always be for a longer period of time than the program funding cycle;

- To identify the annual energy and peak demand impacts associated with major program delivery mechanisms (e.g., direct install approaches, incentive and rebate approaches, and education, marketing and outreach programs) over the period of time the program measures are projected to provide net participant energy impacts;
- To estimate the annual energy and peak demand impacts associated with each Administrator's portfolio projected over the period of time the program services are expected to provide net energy impacts;
- To compare the evaluation results across programs, types of programs (program groups) and program portfolios to assess their relative performance and cost-effectiveness;
- To identify under-performing program or program components , so they may be improved or withdrawn from the portfolio of services;
- To understand the potential of programs and program services to cost-effectively increase the supply of energy resources for California citizens;
- To understand how programs or program operations can be modified to improve their performance and the overall performance of the portfolios;
- To inform future updates to ex-ante energy and peak demand savings estimates for program planning purposes;
- Provide timely information to improve program design and selection for future program cycles;
- To be able to tailor the evaluation approaches and budgets to meet the need for reliable energy impact and market effects information while minimizing evaluation costs and reducing risks of making poor efficiency supply decisions; and
- To use an objective and transparent evaluation process that assesses the impacts from all types of programs that are expected to provide efficiency resources in California.

The Energy Action Plan, the Energy Efficiency Policy Manual and other related CPUC documents have established aggressive goals for energy efficiency in California. Throughout these guidance documents, it is explicitly recognized that investments in energy savings are uncertain and, hence, carry some risk. The guidance documents emphasize the need for "reliable" savings estimates. Efforts to define "reliable" lead to quantification. To quantify and manage these risks, one must include all relevant and cost-effective sources of information on the performance of the investment <u>and</u> the underlying uncertainty in these data.

To the greatest extent possible, the Joint Staff will seek to allocate evaluation resources to reduce uncertainty in the estimates and evaluations of achieved gross and net savings. The criteria for allocating evaluation resources will be influenced by risk considerations associated with a program's designs and operational characteristics, the expected energy savings, the need to minimize uncertainty in the assessment process and the cost to quantify and manage these risks. The overarching theme in the management of the evaluation effort should follow the IQM risk principle: Identify, Quantify and Manage. This principle is based on the recognition that all estimated savings from energy efficiency and conservation programs (as well as estimated energy and capacity from traditional supply-side resources) include some uncertainty and, consequently, risk. In the past, planners, evaluators and other staff have often relied on single-point savings calculations (e.g., average kWh savings) that were subsequently discounted, based on professional judgment. Risk was not quantified, therefore it could not be effectively managed. By explicitly identifying factors that induce or affect uncertainty and by taking steps towards quantifying that risk, the Joint Staff can make more informed decisions on how to effectively manage the evaluation efforts and reduce the overall risk associated with the efficiency portfolio.

Use of the Evaluation Results to Document Energy Savings and Demand Impacts

There are several Protocol-guided evaluations that provide net energy impacts that will be used to understand program, portfolio and/or statewide energy savings. These are:

- The direct program impact evaluations that document the energy savings associated with the actions taken through program participation, such as when a rebated motor is installed or when a high-efficiency cooling system is upgraded;

- The indirect program impact evaluations that document the behavioral change, and in some cases the energy savings associated with the behavioral changes made as a result of program activities, such as when training is provided to customers. For example, when a customer installs an energy-efficient technology due to exposure to a training program and without any other program assistance;

- Evaluations conducted according to the Codes and Standards Program Evaluation Protocol that provide the net energy impacts associated with a code or standard change; and

- The market effects evaluations that document the net effects of one or more programs on the operations of a market and applies energy savings estimates to these program-induced market changes.

All of these impacts will be assessed for statewide energy and demand impacts. However, for the purposes of crediting individual programs or Administrator program portfolios with energy impacts, only the first three categories of net energy impacts documented in the evaluations will be counted, and not those from market effects evaluations. The evaluations in the first three categories will derive program-specific net energy impacts and will be used to sum up to the investor-owned utility (IOU) portfolio impacts and used to derive the statewide program impacts.

The Evaluation Identification and Planning Process

The program evaluation planning process shall begin with a high-level assessment of the need to evaluate a program or program component. This assessment will consider, among other factors, the importance of the savings to the portfolio and the uncertainty regarding the ex-ante savings estimates. Based on this assessment, the Joint Staff will decide whether each program or program strategy must comply with the Protocols or whether it will be required to comply only with the CPUC's program reporting requirements.

For those programs that will receive a Protocol-guided evaluation, the next series of issues should be addressed to determine if Protocols that cover multiple types of programs or a program-specific Protocol should be used. These focus on specific types or characteristics of programs. If the program is focused on emerging technologies, then the Emerging Technology Program Evaluation Protocol must guide the evaluation. If it is a Codes and Standards Program, then the evaluation must be guided by the Codes and Standards Program Evaluation Protocol. Other types of program evaluations will be guided by the Protocols designed for a wide variety of resource and non-resource programs.

The next question to address is whether the program or program strategy is expected to obtain *direct* energy or demand savings. Producing savings *directly* means that the link between the program activity and the savings is clear, straightforward and relatively fast. These types of programs are often referred to as resource or resource acquisition programs. An example of such a program is an incentive program, such as a single-family rebate program, that offers incentives to residential customers to install efficient equipment. For each participant who receives an incentive, there is the clear expectation that there will be savings based upon the program's direct results in obtaining equipment installations. Information and education programs are examples of programs that do not provide such direct impacts. For these programs, there is a more tenuous link between the program activities and any eventual savings. That is, a training program may or may not result in any savings and the savings that are achieved are not direct. Savings obtained from providing training services depend upon that program inducing some form of behavior change (such as purchase and installation behavior or participation in a more direct efficiency program). This would be *indirect* savings. If a program is one that provides savings *indirectly*, then its evaluation must be guided by the Indirect Impact Evaluation Protocol that explicitly addresses the need to link program-induced behavioral changes to eventual energy and demand impacts. Some programs may intend to produce energy savings by providing behavior change information or education for which an impact evaluation of energy savings is not needed by the CPUC. These evaluations would follow the Indirect Impact Evaluation Protocol and quantify behaviors changed or actions taken, but not move to the step of allocating energy savings to those efforts. Joint Staff will determine which Evaluation Protocols to apply to which programs as part of their evaluation planning efforts.

If the program is defined as one that *directly* produces energy and demand impacts, it must be determined whether it will be guided by the Impact Evaluation Protocol,[3] the M&V Protocol or both. Programs assigned to the M&V Protocol only (not assigned an impact evaluation) will be those for which savings are expected to be relatively small and certain (reliable).

A program with a combination of large and/or uncertain savings must be guided by the Impact Evaluation Protocol. If such programs do not cover any measures that should be specifically evaluated in order to update the Database for Energy Efficiency Resources (DEER) an impact evaluation at the program or program-strategy level (rather than at the technology level) must be planned. However, if the program or program strategy covers measures that should be evaluated

[3] The Impact Evaluation Protocol contains the Indirect Impact Protocol and three others related to estimation of direct savings: the Gross Energy Impact, Gross Demand Impact and Participant Net Impact Protocols. The Impact Evaluation Protocol also often "calls for" the M&V Protocol that provides requirements for M&V-related activities within the impact evaluation methods.

in order to update DEER, it must determined whether there is a *sufficient* number of these measures on which to base a technology-level assessment. If so, evaluators shall develop a measure-level plan to evaluate these technologies, as well as plan an impact evaluation at the program or subprogram level.

If there is an *insufficient* number of a particular measure within a single program, a determination needs to be made whether there is a sufficient number of the measure across the program strategies being addressed within a program group to allow for an evaluation. If so, the evaluator shall develop a measure-level plan to evaluate these technologies. Note that measure-level plans should always be nested within the overall impact evaluation for the program or program strategy.   Ultimately, the evaluator must account for all the energy and demand impacts for a given program or program strategy.

Figure 2 illustrates the high-level overview of the program evaluation planning process for programs, program strategies and measures.

Evaluation Planning Process For Programs, Program Components, And Program Covered Technologies

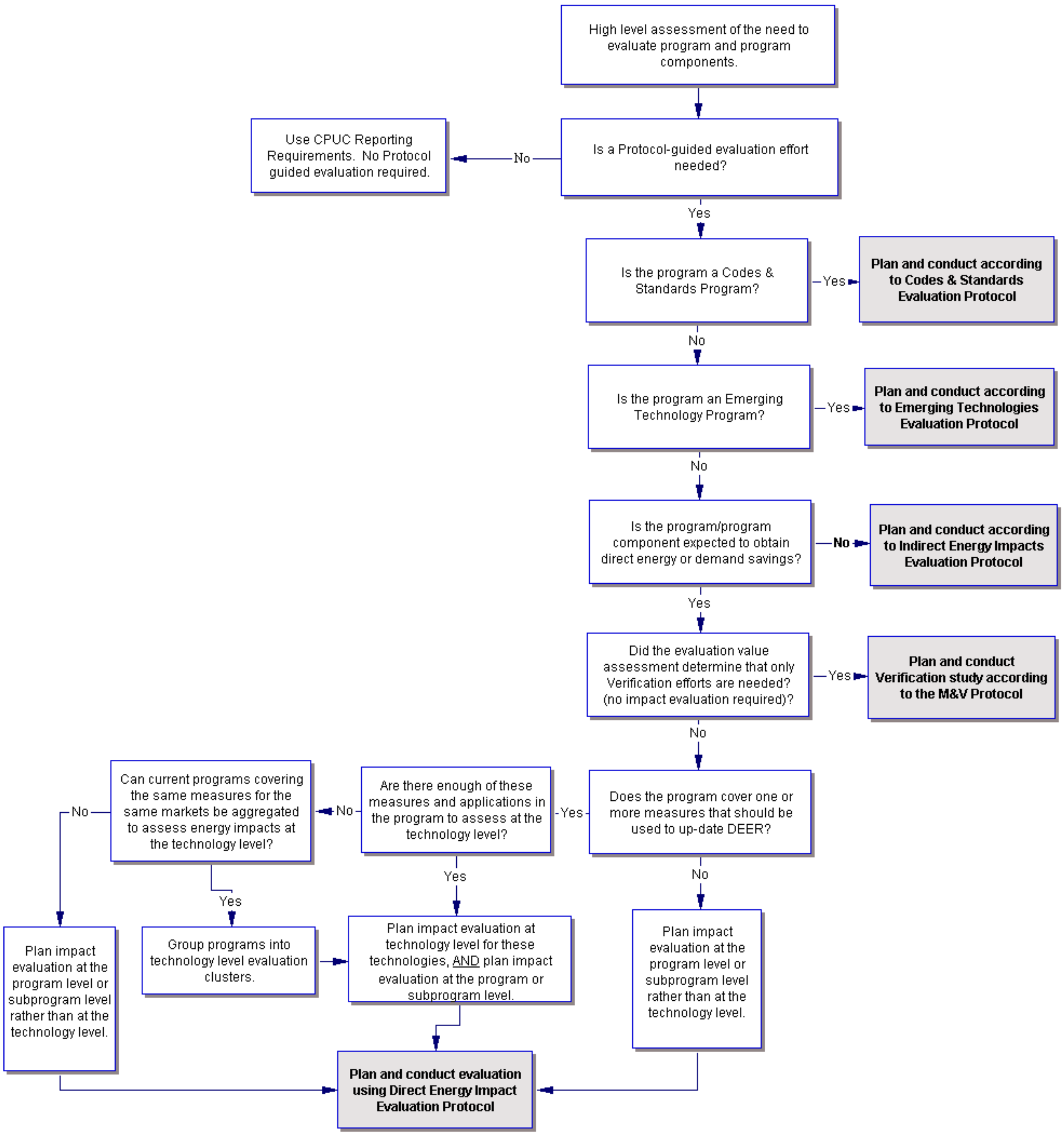

Figure 2. The Program Evaluation Planning Process for Programs, Program Components and Program-Covered Technologies

The procedure is much less structured for determining when to conduct a market effects study. Figure 3 provides a diagram of the related decision process. In this process, the Joint Staff will examine the mix of programs and strategies within the Administrator portfolios and the markets in which they are operating. Markets will be selected for Market Effects Evaluation when the

Joint Staff finds that such an evaluation would provide valuable information for directing program improvements and/or for better assessing the complete impacts from the portfolio of programs. Markets may be selected for a Market Effects Evaluation due to a preliminary assessment that there are substantial investments in that market across programs where potential market effects (including non-participant spillover) could be measured or need to be tracked and/or assessed. Markets can also be selected for a Market Effects Evaluation when one or more programs operating in that market are best evaluated at the market-level due to their overlapping nature or overlapping goals to change how a market operates (sometimes called market transformation goals).

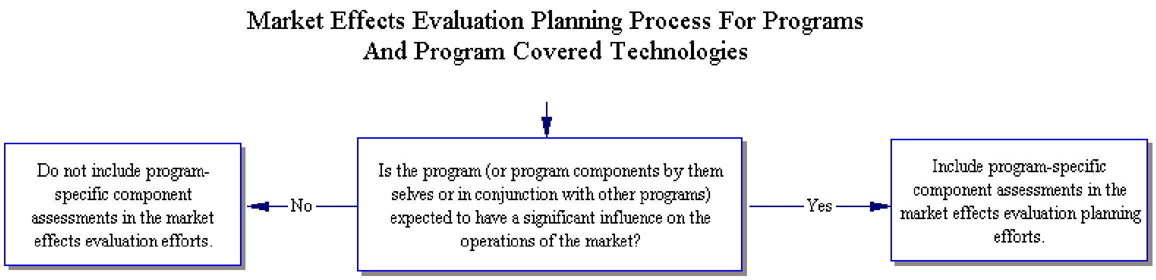

Figure 3. The Market Effects Evaluation Planning Process

Evaluation Rigor and Budgets

The process of setting evaluation priorities and budgets for each type of evaluation effort is as follows:

Impact Evaluations

For impact studies, the Joint Staff will review the Administrator's portfolios and programs and establish evaluation groupings. These groupings will consist of multiple programs having common characteristics that provide evaluation efficiencies in the contracting, supervision and implementation of the evaluation efforts. The groupings will typically include similar types of programs (e.g., residential rebates, commercial rebates, information and education, and marketing and outreach) or markets, so that the evaluation contracts will focus on similar types of programs and program evaluation efforts.

Once the evaluation groups are structured, the Joint Staff will decide which programs (or program components) will receive verification-only analysis, direct impact evaluation or indirect impact evaluation.[4] Each of these will be assigned minimum rigor level requirements along with a budget based on a number of factors listed in the *Evaluation Framework* including:

- The amount of savings expected from each program in the group;
- Whether the programs are expected to grow or shrink in the future;

[4] See the Impact Evaluation Protocol herein for further description of these different types of evaluations and the various protocols and rigor levels within them.

- The uncertainty about expected savings and the risk programs pose to achieving portfolio savings goals; and
- How long it has been since the last evaluation and how much the program has changed in the interim.

In setting the level of rigor and the evaluation budgets for the program groups and the individual programs within each group, the Joint Staff will conduct an evaluation needs assessment to assign a level of evaluation rigor to each program or program component. Based on the analysis and criteria listed above, the Joint Staff will establish appropriate evaluation budgets across the program evaluation groups. These budget levels will be used in the development of Request for Proposals (RFPs) to conduct the evaluation efforts. They will also serve to communicate to evaluation contractors how evaluation efforts will be structured.

From this effort, the Joint Staff will provide a high-level evaluation plan that presents the overall evaluation goals and approaches selected for the program groups. The plan will be updated annually as the evaluations proceed, as the need for information changes and as adjustments to the evaluation rigor or approach are identified. The plans will be presented to the public for review and comment each year prior to their implementation in a public workshop to solicit comments and recommendations from interested stakeholders. Once public comments have been obtained, the plan will be finalized and used to support the evaluation bidding and contracting process.

Once an evaluation is launched, the Joint Staff will monitor evaluation efforts and their progress to ensure that evaluation approaches meet or exceed the evaluation rigor assigned, in order to obtain the most reliable evaluation results within the available budgets.

Process Evaluations

For process evaluations, Administrators are responsible for setting evaluation priorities, budgets, evaluation timing and conducting the evaluation effort. These activities are presented to the CPUC-ED, the CEC and the public via an annual portfolio/program evaluation plan and a public workshop. See the Process Evaluation Protocol for additional details.

Market Effects Evaluations

The Joint Staff is responsible for identifying markets for which market effects evaluations will be conducted. These studies will be planned and budgeted individually in accordance with the information and data reliability needs of the Joint Staff.

Codes and Standards and Emerging Technology Program Evaluations

These two program types require evaluations different enough in their goals and objectives, approaches for accomplishing goals and operational characteristics that this document contains Protocols specifically designed for them. While these two types of programs will be evaluated per their respective Protocols, they may also have other types of evaluation efforts applied, such as process or market effects evaluations.

Evaluation Budgets

Each program group evaluation will have a budget cap within which to carry out a variety of evaluation activities. Efforts to maximize reliability will be carried out within the budget constraints and inevitably involve a number of tradeoffs regarding precision and identifying, mitigating and minimizing potential bias. Additional information and guidance on establishing evaluation budgets is provided in the *Evaluation Framework*[5].

Recommendations for Using the Protocols

The Protocols provide guidance and requirements for planning and conducting California's energy efficiency program evaluations. The Protocols should be used by the Joint Staff and Administrators to structure the evaluation process and associated activities. Joint Staff involved in program evaluation efforts should have an expert understanding of the Protocols. Evaluation staff within Administrator organizations should have the same level of understanding of the Protocols as appropriate to activities in which they have responsibility. All evaluation contractors should be required to have an expert understanding of the Protocols that will directly affect the studies and the methodological approaches they must conduct. It is also recommended that all of these involved parties have a working knowledge of the contents of the *Evaluation Framework* as applicable for the areas in which they work.

When a conflict exists between the *Evaluation Framework* or other reference documents and the Protocols, the Protocols will take precedence unless otherwise approved by the CPUC-ED.

The Detailed Evaluation Work Plan

All program evaluations are required to have a detailed evaluation work plan. In many cases the program evaluation work plans will be clustered within evaluation groupings. However, even within these groupings, there must be a detailed evaluation work plan structured at the program (and in some cases at the program component) level that identifies how the program will be evaluated and the steps to be taken to conduct the evaluation. The evaluation work plan shall include the following components to support an assessment of the adequacy and approach of the evaluation effort:

- Cover page containing the names of the program(s), Administrators and evaluation contractors, date of the evaluation work plan and the program tracking number(s) for program(s) covered in the plan;
- Table of Contents;
- High-level summary overview of the programs and the evaluation efforts;
- Brief description of the program(s) being evaluated including a high level presentation of the program theory. If the program does not have a formal program theory, the evaluation plan should incorporate a brief presentation of the evaluation-assumed program theory so that the Joint Staff may understand the sequence of events leading from program actions and activities to desired results (direct or indirect energy impacts);

[5] TecMarket Works, 74-79.

- Presentation of the evaluation goals and the detailed researchable issues to be addressed in the evaluation. (These will also be presented and discussed in the evaluation reports;)
- Description of how the evaluation addresses the researchable issues, including a description of the evaluation priorities and the use of assigned rigor levels to address these priorities;
- A discussion of the reliability assessment to be conducted, including a discussion of the expected threats to validity and sources of bias and a short description of the approaches planned to reduce threats, reduce bias and increase the reliability of the findings and minimize bias and uncertainty;
- Task descriptions of the evaluation efforts;
- Description of the analysis activities and approaches to be taken:
    - For energy acquisition and procurement programs, include a description of the approach that will be used to estimate kW, kWh and therm impacts for each year over the EUL of program-covered measures, including a description of the approach to be used to adjust the expected impacts for the persistence of the impacts;
    - For information or education programs, include a discussion of the approach that will be used to estimate the actions or behaviors taken and/or knowledge gained that is expected to lead to energy impacts;
    - For process or operational assessments, include a description of the approach used to identify changes that can be expected to improve the cost-effectiveness of or participant satisfaction with the program;
- Description of the M&V efforts (impact evaluations only) including:
    - Reference to International Performance Measurement and Verification Protocol (IPMVP) option[6], if used;
    - Detailed description of the option-specific approach; and
    - Description of any deviations from the IPMVP option, if any;
- Description of the sampling rationale, methods and needed sample sizes.
- Discussion of the specific Performance Basis Metrics that will be reported in the draft and final evaluation plan;
- A definition of the terms "participant" and "non-participant" as it applies to the evaluation being conducted;
- Detailed description of the information that will be needed from the IOUs or from the program-reporting database maintained at the CPUC-ED in order to conduct the evaluation and an estimate of the date that the information will be needed. This same information will be included in evaluation-related data requests;

[6] More information on the IPMVP can be found in the *Evaluation Framework* (148-149), or at the IPMVP Web site at www.ipmvp.org.

- Evaluation activities timeline for the program cycle, including identification of deliverables and deliverable due dates. This should also include early, mid-stream and late cycle feedback deliverables and deliverable dates. (These dates must be coordinated with the information needs of the Joint Staff and their program-portfolio assessment needs schedule;)
- Total program budget, total evaluation budget and a task-level evaluation budget for the study; and
- Contact information for the lead Administrator, lead program manager and evaluation manager, including addresses, telephone numbers, fax numbers and e-mail addresses.

The evaluation work plan should be written in a style and with enough detail that it can be clearly understood by Administrators, policy makers and evaluation professionals, and replicated by other evaluation contractors.

Confidentiality Issues

Confidentiality is an essential part of the evaluation process and is included in this section to set a baseline for how information will be treated within the evaluation efforts. The following aspects of confidentially are incorporated into all evaluations conducted under the guidance of the Protocols.

1. All evaluation contractors will be required to sign confidentiality agreements in order to conduct evaluations funded through the Protocols. These agreements will be incorporated into all evaluation contracts. For impact, market effects, codes and standards, emerging technology and M&V studies, the agreements will be incorporated into contracts awarded by the CPUC or the CEC as appropriate. For process evaluations, the individual Administrators issuing the process evaluation contracts are responsible for incorporating confidentiality agreements. However, evaluation information, including customer-specific information, can be shared across evaluation contractors within the same evaluation team and across teams. However, this data is to be protected from exposure beyond the evaluation teams and all contractors must sign confidentiality agreements prior to the receipt of customer-specific information.

2. All customer-specific information will be treated as confidential and safeguarded from public disclosure. Evaluation contractors are granted access to participant and customer specific information maintained by the Administrators as needed to conduct the evaluation efforts, however, no evaluation contractor will allow participant or customer specific information to be released to individuals or organizations beyond their research team, unless specifically permitted in writing by each customer for which information is to be released. All memoranda, letters, e-mails, reports and databases that are developed or used in the evaluation efforts that contain participant-specific or customer-specific information, whether an individual, a firm or business or an organization, are covered by this confidentiality requirement.

Contacting the Customer

A critical component to the success of any evaluation effort is the maintenance of a supportive relationship between the customer and the many different types of organizations that influence the evaluation effort. IOU representatives, CPUC-ED, CEC, evaluation contractors and others involved in the evaluation efforts need to be diligent in making sure that customers and participants are not over-contacted in support of them. Whenever possible, customer contact initiatives should be coordinated to avoid over-contact. Customer requests to be excluded from evaluation efforts should be respected. Customer complaints associated with evaluation efforts should be reported to the CPUC-ED and the associated Administrator within 48 hours of receipt.

Before customers are contacted by evaluation contractors, their representatives or subcontractors, the prime evaluation contractor will notify the Administrators of the need to do so and work to agree on an approach and timeline that may change from study to study. All final customer contact approaches and contact Protocols should specify customers to be contacted (as an attachment), reasons for the contact, information to be collected, the method of contact and the associated timeline.

Administrators will inform the appropriate individuals within their organizations of any related customer contact.

Impact Evaluation Protocol

Introduction

The Impact Evaluation Protocol is applicable for all programs or program components designated by the Joint Staff for a direct or indirect[7] impact evaluation, especially for those programs claiming energy or demand savings and for those programs that are expected to influence energy-related behaviors and can be linked to energy and/or demand savings. This Protocol is designed to reliably estimate program impacts. Information, education and advertising efforts determined by the Joint Staff to have an indirect impact evaluation are expected, at a minimum, to measure the program-induced behavioral changes, often leading to energy and demand savings estimates.[8]

The Impact Evaluation Protocol is established to ensure that all evaluations of program-specific energy and demand savings, and program-specific impacts are conducted using evaluation methods deemed acceptable based on the assigned level of rigor for that evaluation. The Protocol's list of allowable methods is one component that helps ensure greater reliability in the energy and demand savings estimates from California's energy efficiency efforts. The Joint Staff can assign different levels of rigor to each program, thus allowing the flexibility to allocate evaluation resources according to the needs of the Portfolio given uncertainty in the expected savings, the size of expected savings, the program budget and other criteria. The Joint Staff will instruct evaluation contractors to use specific rigor levels based on its application of the Protocol's decision criteria, and mix of evaluation choices and resource allocations.

Rigor is defined as the level of expected reliability. The higher the level of rigor, the more confident we are that the results of the evaluation are both accurate *and* precise, i.e., reliable. That is, reliability and rigor are synonymous. Reliability is discussed in the Sampling and Uncertainty Protocol and in the *Evaluation Framework* where it is noted that sampling precision does not equate to accuracy. Both are important components in reliability, as used by the CPUC. Each program will be assigned a specific evaluation rigor level for its primary evaluation objectives to guarantee that a minimum standard is met.

"Impact evaluation" refers here to all program-specific evaluations designed to measure program impacts. Impact evaluations attempt to estimate net changes in electricity usage, electricity demand, usage of therms and/or behavioral impacts that are expected to produce changes in energy use. Evaluations conducted according to the Impact Evaluation Protocol are expected to obtain energy or demand savings estimates wherever possible. Impact evaluations of programs or program components designed to directly achieve energy and demand savings should follow the Direct Impact Evaluation Protocol to measure these savings.

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[7] The term "indirect impact evaluation" refers to those program-specific evaluations designed to measure the specific program goals that create an impact that is expected to eventually lead to energy and/or demand savings but where these savings cannot be directly estimated.

[8] This is the minimum expectation. The evaluation research design, however, could surpass this through an experimental or quasi-experimental design that estimates energy and demand savings.

The Indirect Impact Evaluation Protocol should be used for evaluations of those programs or program components primarily designed to obtain behavior changes that will eventually lead to energy and demand savings but do not directly do so within the program. The Indirect Impact Evaluation Protocol is intended for those programs where the primary uncertainty lies in the program's ability to obtain the behavior change(s) targeted by the program. Indirect impact evaluations will, therefore, be linked wherever possible to previously measured energy or demand savings estimates that would yield savings estimates with the same rigor required by the Basic rigor level for impact evaluations described below. This link to reliable stipulated or engineering calculated energy and demand savings estimates is not always possible for behavioral program efforts assigned to receive an impact evaluation. In these cases, an indirect impact evaluation shall be conducted at the Basic rigor level to measure the program-induced impacts, as described below.

This Protocol often refers to a "program or program component." A program component, as defined by this Protocol, is any identifiable portion of a program. This could be a measure, a delivery mechanism, a set of delivery mechanisms or measures, or a set of delivery mechanisms or measures that follow a chain from an activity depicted in a program logic model. The Joint Staff may desire a direct or indirect impact evaluation of a program as well as a separate analysis for the impact evaluation for one of its program components. This might occur, for example, when more detailed evaluation information is needed for a measure for future program planning or to support an update of DEER, a new measure is being piloted or expanded in its use, or a new delivery mechanism has been added.

Impact evaluations are limited to addressing the direct impacts of the program on participants and estimating participant spillover impacts.[9] These studies do not include documenting program influences on the operations of a market or the program's impacts on non-participants. Program-induced changes on the way a market operates or on non-participants are addressed in the Market Effects Evaluation Protocol.

The Impact Evaluation Protocol describes the metrics to be produced from an impact evaluation. This includes the target parameters that must be used as part of developing the evaluation design in order to produce these metrics. This Protocol also presents an overview of how the Impact Evaluation Protocol is integrated with the M&V, Sampling, Market Effects and Reporting Protocols for the implementation of a direct impact or indirect impact evaluation and within the overall system to produce reliable portfolio level evaluated savings estimates. This systematic Protocol-linked process is designed to be part of a proposal selection and evaluation plan review process, which is followed by ongoing management of the evaluation and evaluation reporting.

It is expected that evaluation contractors will respond to requests for proposals (RFPs) for impact evaluations with proposals that meet the standards contained in the Protocols. It is expected that generally accepted statistical methods as published in textbooks used at accredited universities or articles in peer-reviewed journals will be used for parameter estimation from sample data in

[9] For a thorough evaluation, impact evaluations should estimate direct program savings and participant spillover savings. These estimates need to be distinct estimates and not a combined estimate across the two whenever possible. Current CPUC policy, as the Protocols are being developed, states that only program savings and not participant spillover will be counted towards program and administrator goals and performance.

regression-based approaches and for moving from sample estimation to program or population-based estimates. Engineering methods are expected to meet the requirements in the M&V Protocol and follow generally accepted practices as published in engineering textbooks used at accredited universities or articles in peer-reviewed journals along with generally accepted statistical methods (as described above). Evaluation contractors may propose optional methods in addition to Protocol-compliant methods, if the optional methods provide at least as much rigor and accuracy as the Protocol-covered approach.

Audience and Responsible Actors

The audience and responsible actors for this Protocol include the following:

- **Joint Staff Evaluation Planners** will use the Protocol to determine when a direct impact or indirect impact evaluation is appropriate and to assign the level of rigor expected for the study, as input into the evaluation RFPs for impact evaluation contractors, and as background and criteria for use in reviewing impact evaluation plans, managing the impact evaluations and reviewing impact evaluation reports and results;
- **The Evaluation Project Team** will use the Protocol to ensure that their detailed direct impact or indirect impact evaluation plan(s) address(es) key requirements for each program or program component based upon the level(s) of rigor designated by the Joint Staff. They will also use the Protocol to double-check that the Protocol requirements have been met as they conduct, complete and report the impact evaluations;
- **Administrators** will use the Protocol to understand how the impact evaluation will be conducted on their programs and to understand the evaluation data needs to support the impact evaluation. In addition, the Protocol provides background for the Administrator's use to determine when to intervene in the program design and implementation efforts to achieve continued and/or greater efficiency gains;
- **Program Implementers** will use the Protocol to understand the impact evaluation that will be conducted of their programs and program components. Often, they will be required to provide data to support the impact evaluation. The Protocol will also provide background for their use to understand when to intervene to achieve continued and/or greater efficiency gains; and
- **ISO / System planners** will use savings and uncertainty estimates for load forecasting and system planning.

Overview of the Protocol

Protocol Types

The overall Impact Evaluation Protocol contains one subset of 3 Protocols for estimating direct energy and demand impacts and one for estimating indirect impacts.

Direct Impact Evaluation Protocols:

- The <u>Gross Energy Impact Protocol</u> has two levels of rigor (Basic and Enhanced) for developing gross energy estimates;

- The Gross Demand Impact Protocol has two levels of rigor (Basic and Enhanced) for developing gross demand estimates; and
- The Participant Net Impact Protocol has three levels of rigor for developing net impact estimates (Basic, Standard and Enhanced).

The Indirect Impact Evaluation Protocol has three levels of rigor (Basic, Standard and Enhanced). The Basic Rigor level is reserved for those programs or program components that cannot be linked to energy savings but where net behavior changes need to be estimated to measure program impacts. This Protocol includes the requirement that the measured impacts are net impacts (i.e., program-induced).

Rigor

The general rules for how often evaluations need to be conducted are determined by the Joint Staff. The Joint Staff will decide, for each relevant program, if and when the program will receive an impact evaluation. The Joint Staff may choose not to have an impact evaluation conducted for a particular program or program component. When the Joint Staff decides a program will receive an impact evaluation, it also selects whether a direct impact evaluation or indirect impact evaluation is most appropriate and the level of evaluation rigor required. The Impact Evaluation Protocol then establishes the methods appropriate for the given type of impact evaluation and assigned level of evaluation rigor. In this way, the Protocols establish a minimum level of evaluation rigor in order to ensure that the savings estimates produced are at the level of reliability needed to support the overall reliability of the savings in the Administrator's Portfolio and the statewide Portfolio.[10]

Each level of rigor provides a class of allowable methods in order to offer flexibility for the potential evaluation contractors to assess and propose the most accurate and cost-effective methods that meet the Joint Staff's needs. The principle is to provide minimum specifications for a set of options at each rigor level and yet encourage evaluation contractors to use both the art and science of evaluation to develop affordable and quality evaluations that produce reliable savings estimates.

The Joint Staff may assign one rigor level for a program and a different level of rigor for one or more of its program components. When this happens, the evaluation must meet the level of rigor for that program component as assigned (to include meeting the Sampling and Uncertainty requirements) as well as the rigor level for the program as a whole.

The various Protocols and associated rigor levels required for direct impact and indirect impact evaluations are illustrated in Figure 4.

[10] Savings for programs with expected savings could be included in the Portfolio savings estimates based upon an accounting effort that multiplies the number, or verified number, of installations times the latest evaluated savings estimates or deemed savings, as determined more appropriate by Joint Staff. The verified number of installations is the number of program installations based upon the reported number combined with the results of any verification activities required by Joint Staff. (See the M&V Protocol for the description of the Verification Protocol.)

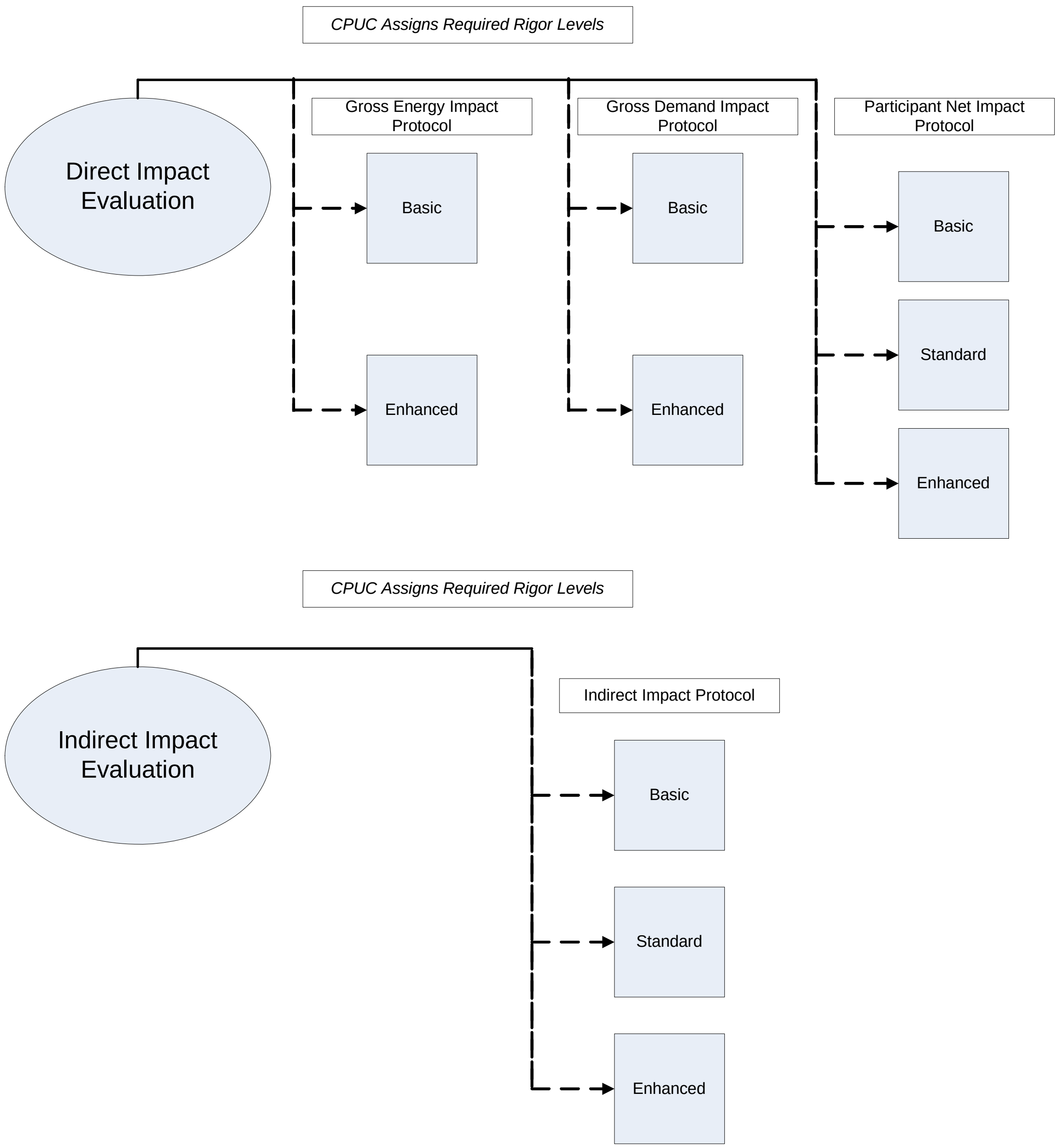

Figure 4. Required Protocols for Direct Impact and Indirect Impact Evaluations

Key Metrics, Inputs and Outputs

Impact evaluations will draw upon data from program databases, program descriptions, DEER databases, work papers developed during program planning, utility demand metering and consumption data for participants and non-participants, utility-, state government- or local government-collected weather data, on-site measurement, monitoring and observational data, survey and interview data collection, and other prior study data and reports. These will be used with the Impact Evaluation Protocol-allowable methods to produce program, program strategy and program component (measure-level, as requested) impact evaluations. These must be conducted using the Joint Staff-approved evaluation plans.

The Impact Evaluation Protocol will guide the estimation of evaluation-adjusted gross and net savings for energy (kWh) and demand (kW) for electricity-using equipment (and behaviors related to electricity-using equipment) and net therm savings for gas-using equipment (and behaviors related to gas-using equipment). The kWh, kW and therm impacts are required to be reported separately for the first year and for each year thereafter over the period of time in which net program-induced savings are expected. The programs' expected savings from program plans, reported savings and the evaluation's estimate of savings will be reported in these annual savings tables. The Reporting Protocol, which all direct impact and indirect impact evaluation reporting must follow, provides further description and table examples.

Because impact evaluations must follow the Sampling and Uncertainty Protocol, evaluators must also assess, minimize and mitigate potential bias and present the achieved level of precision (including relative precision, error bounds, coefficient of variations, standard deviations and error ratios) for interpreting information, summarizing savings and its precision across programs, and providing the information necessary for future evaluation planning. Where precision is calculated from the chaining or pooling of evaluation study efforts, the above precision information should be provided for each study effort as well as the combined result.

When requested by the Joint Staff, impact evaluations must produce the required metrics by delivery mechanism (e.g., rebates and direct install). Where delivery mechanisms differ within a program, this Protocol requires that the impact evaluation be designed, conducted and reported to provide the energy and demand metrics (along with the precision information) for each delivery mechanism, when the Joint Staff identifies delivery method-associated impacts as an evaluation goal.

Evaluations conducted according to the Gross Impact Protocol, Gross Demand Protocol and Participant Net Impact Protocol will produce gross and net kWh, kW and therm impacts. The evaluation analysis results must be used with program database, verification, standard weather information, and other participant and non-participant data, as necessary, to produce program energy and demand savings estimates. Measure effective useful life (EUL) from DEER or as otherwise approved by the Joint Staff will be used to create the required energy and demand impacts for first year and for each year thereafter over the period of time in which savings are expected based upon measure EUL. Any evaluation findings that might call into question the EULs being used must be presented to the Joint Staff when discovered and discussed in the evaluation report. Further description and examples of the required tables are provided in the Reporting Protocol.

All direct impact and indirect impact evaluations are expected to assess and discuss the differences between the ex-ante estimates and the evaluation produced ex-post estimates. To the extent that the data gathered and evaluation analyses conducted can explain the causes for these differences, this must be presented and discussed. Cases in which explaining these differences due to lack of data or problems of interpretation should be noted in the evaluation report.

Energy and Demand Impact Protocols

These are minimum standard Protocols. All methods in a higher class of rigor are allowable as they exceed the minimum criteria. For example, if the program has a Joint Staff assigned rigor of Basic or Standard and the method proposed by the evaluation contractor is an option under a rigor of Enhanced (but is not listed under Basic or Standard), this method is acceptable for meeting the Protocol.

Gross Energy Impact Protocol

The Gross Energy Impact Protocol is summarized in Table 1. Further description, additional requirements, clarification and examples of this Protocol are presented after the table. The methods used and the way in which they are used and reported must meet all the requirements discussed within this section (not just those within the summary table or those within the text) to provide unbiased reliable estimates of program level gross energy impacts in order to comply with the Gross Energy Impact Protocol. The Protocols sometimes reference the *Evaluation Framework* or other documents which provide examples of applicable methods. The requirements, however, are always those stated in the Protocols, which take precedence over all other protocols and evaluation guidance documents in all circumstances, unless otherwise approved or required by the CPUC.

All M&V referred to in the Impact Evaluation Protocol must be planned, conducted and reported according to the M&V Protocol. M&V may be conducted at a higher level of rigor, with more inputs measured or metered, or with greater precision than the minimum shown within the Impact Evaluation Protocol, but not with a lower level of rigor. The M&V Protocol can also be required by the Joint Staff or used by evaluators to enhance other evaluation efforts. For example, an evaluator proposing a Statistically Adjusted Engineering (SAE) regression model may use (or the Joint Staff may require the use of) the M&V Protocol to conduct field measurements on the sample of participants to be included in the SAE model to improve the engineering estimates. This may involve conducting measurement/metering and utilizing IPMVP Option A.

The overall goal of the Direct Impact Evaluation Protocol (which includes the Gross Energy Impact Protocol) is to obtain unbiased reliable estimates of program-level net energy and demand savings over the life of the expected net impact.

Table 1. Required Protocols for Gross Energy Evaluation

Rigor Level	Minimum Allowable Methods for Gross Energy Evaluation
Basic	1. Simple Engineering Model (SEM) with M&V equal to IPMVP Option A and meeting all requirements in the M&V Protocol for this method. Sampling according to the Sampling and Uncertainty Protocol. 2. Normalized Annual Consumption (NAC) using pre- and post-program participation consumption from utility bills from the appropriate meters related to the measures undertaken, normalized for weather, using identified weather data to normalize for heating and/or cooling as is appropriate to measures included. Twelve (12) months pre-retrofit and twelve (12) months post-retrofit consumption data is required. Sampling must be according to the Sampling and Uncertainty Protocol.
Enhanced	1. A fully specified regression analysis of consumption information from utility bills with inclusion/adjustment for changes and background variables over the time period of analysis that could potentially be correlated with the gross energy savings being measured. Twelve (12) months post-retrofit consumption data are required. Twelve (12) months pre-retrofit consumption data are required, unless program design does not allow pre-retrofit billing data, such as in new construction. In these cases, well-matched control groups and post-retrofit consumption analysis is allowable.[11] Sampling must be according to the Sampling and Uncertainty Protocol utilizing power analysis as an input to determining required sample size(s). 2. Building energy simulation models that are calibrated as described in IPMVP Option D requirements in the M&V Protocols. If appropriate, may alternatively use a process-engineering model (e.g., AirMaster+) with calibration as described in the M&V Protocols. Sampling according to the Sampling and Uncertainty Protocol. 3. Retrofit Isolation engineering models as described in IPMVP Option B requirements in the M&V Protocols. Sampling according to the Sampling and Uncertainty Protocol. 4. Experimental design established within the program implementation process, designed to obtain reliable net energy savings based upon differences between energy consumption between treatment and non-treatment groups from consumption data.[12] Sampling must be according to the Sampling and Uncertainty Protocol.

[11] Post-retrofit only billing collapses the analysis from cross-sectional time-series to cross-sectional. Given this, even more care and examination is expected with regard to controlling for cross-sectional issues that could potentially bias the savings estimate.

[12] The overall goal of the Direct Impact Protocols is to obtain reliable net energy and demand savings estimates. If the methodology directly estimates net savings at the same or better rigor than the required level of rigor, then a gross savings and participant net impact analysis is not required to be shown separately.

Basic Rigor

There are two classes of evaluation methods that set the minimum allowable methods for the Gross Energy Impact Protocol Basic rigor level.

Simple Engineering Model (SEM)

The first class of allowable methods is the simple engineering model (SEM). An SEM is equivalent to IPMVP Option A and must be conducted as described in the M&V Protocol. This method is described and a few references are presented in the *Evaluation Framework*[13]. These types of models can be straightforward algorithms for calculating energy impacts for non-weather dependent measures such as energy-efficient lighting, appliances, motors and cooking equipment. Exceptions to this requirement are programs offering comprehensive measure packages with significant measure interactions, to include commissioning and retro-commissioning programs, and new construction programs. Evaluations of these programs conducted using engineering methods must use building energy simulation modeling under IPMVP Option D as described in the Enhanced rigor level of the Impact Protocol.

Sampling for the M&V used in the SEM must be conducted as prescribed in the Sampling and Uncertainty Protocol which includes developing the sample to target a minimum of 30 percent precision at a 90 percent confidence level. Knowledge of the components of the SEM and the propagation of error method must be used to determine what needs to be measured in the SEM to meet this requirement. (See the M&V Protocol for more detail on the related requirements.) In both the evaluation plan and the evaluation report, the inputs selected and the methods selected for the measurement/monitoring must be justified in terms of why they are the factors that provide the most likely unbiased and reliable gross energy impact estimates for the evaluation study being conducted.

Normalized Annual Consumption (NAC)

The second class of allowable methods is normalized annual consumption (NAC) analysis. This is a regression-based method that analyzes monthly kWh or therm consumption data provided by utilities. This method and a few references are presented in the *Evaluation Framework*[14]. The NAC analysis can be conducted using statistical software, such as the Princeton Scorekeeping Method (PRISM), and other statistically based approaches using SAS or SPSS. The NAC method, often using PRISM, has been most often used to estimate energy impacts produced by whole house retrofit programs.

To comply with this Protocol, NAC must normalize consumption for weather effects using a generally accepted set of weather data (from utility weather monitoring stations, National Oceanic & Atmospheric Administration (NOAA) weather monitoring stations or others as used by California energy forecasting and supply analysts). Weather data must be used to normalize for heating and/or cooling as appropriate to the measures included. Final savings estimates must also use weather data to report both actual savings from the weather data used in the analysis and expected annual savings fitted to the CEC climate thermal zone (CTZ) long-term average weather data.

[13] TecMarket Works, 123-129.
[14] Ibid, 105-106.

A minimum of twelve months pre-retrofit and twelve months post-retrofit consumption data is required. However, there might be a number of participants who are excluded from the analysis because they do not have the required minimum of twelve months of pre- and post-consumption data. For example, some populations, because they are more mobile (e.g., rental populations and particularly low-income households), will be less likely to have the required amount of pre- and post-consumption data. An examination should be made on whether the inclusion or exclusion of such participants could potentially bias the results.

Often, a census approach is undertaken for NAC. Where sampling is used, it must follow the Sampling and Uncertainty Protocol.

Enhanced Rigor

There are four classes of allowable methods to meet the minimum requirements for the Gross Energy Impact Protocol Enhanced rigor level. One of these is regression analysis of consumption with specific modeling requirements, two are different engineering-based methods with specific M&V and model calibration requirements, and the fourth is experimental design established within the program implementation process to specifically obtain unbiased reliable estimates of net energy and demand savings.

Regression Analysis

The first class of allowable methods is regression analysis of consumption data provided by utilities that statistically adjusts for key variables that change over time and are potentially correlated with gross or net energy savings. As a way of capturing the influence of weather, evaluators may incorporate weather-normalized consumption as the dependent variable or include heating- and cooling-degree days directly in the model. Other variables that change over time that are often correlated with gross and net energy savings include, among others, the state of the economy (recession, recovery, economic growth),[15] fuel prices, occupancy changes, behavior changes (set-point changes, schedules, usage frequency), changes in operation and changes in schedule. The evaluator is free to select the most appropriate additional variables to include.

The modeler is also free to select the functional form of the model (a variety of linear and non-linear forms) as well as the type of model. A wide variety of model types may be used, including Statistically Adjusted Engineering (SAE) models, Analysis of Covariance (ANCOVA) or fixed-effects models and other regression models. The *Evaluation Framework* presents the SAE model and a few references,[16] and ANCOVA with a few references.[17] These types of impact evaluations have been conducted for residential whole-house, heating and cooling retrofit, refrigerator and water heating replacement, and small and large commercial programs. The Enhanced Gross Impact regression option is not limited to these two types of models. Finally, the testing of alternative specifications is encouraged.

[15] See the discussion on page 118 in the *Evaluation Framework* and the article cited in its footnote 82 for more information and an example.
[16] TecMarket Works, 108-109.
[17] Ibid, 109-111.

Power analysis,[18] results from prior studies on similar programs, and professional judgment are to be used to determine the required sample size. Sampling and analysis and mitigation for uncertainty must be planned and conducted according to the Sampling and Uncertainty Protocol.

The primary consideration in the use of regression analysis to meet the Enhanced Gross Energy Impact Protocol is that the analysis must be designed to obtain reliable energy savings. In order for regression to begin to meet the unbiased element in this requirement, the regression analysis must incorporate and control for background and change variables that might otherwise bias the measurement of the energy savings. There are several ways in which this can be accomplished. One common method is to include participant and non-participant analyses. If this method is selected, particular care and justification must be made for the non-participant group selected and its appropriateness for the program and participant population being analyzed. Secondly, research design and analysis needs to consider whether the analysis is providing gross impact, net impact or something in between that must then be adjusted or analyzed in a second step to produce, at a minimum, reliable unbiased net of free-ridership savings estimates.

Alternatively, surveys of participants and the creation of change variables can be created and incorporated into the regression analysis. Another example would be to create or obtain participant or non-participant change variables from secondary or other aggregate or individual studies of similar/matched populations for inclusion within the regression analysis. The specific method and research design to accomplish this requirement is not specified, but the evaluation plan, analysis and evaluation report must present, justify, discuss and analyze the method and data utilized to accomplish this requirement.

A minimum of twelve months pre-retrofit and twelve months post-retrofit consumption data is required. However, there might be a number of participants who are excluded from the analysis because they do not have the required minimum of 12 months of pre- and post-consumption data. For example, some populations, because they are more mobile (e.g., rental populations and particularly low-income households), will be less likely to have the required amount of pre- and post-consumption data. An examination should be made on whether the inclusion or exclusion of such participants could potentially bias the results.

Twelve months pre-retrofit billing data are required unless the program design does not allow pre-retrofit billing data, such as in new construction. In these cases, well-matched control groups and post-retrofit billing analysis is allowable. Post-retrofit only billing collapses the analysis from cross-sectional time-series to cross-sectional. Given this, even more care and examination is expected with regard to controlling for cross-sectional issues that could potentially bias the savings estimate.

Final savings estimates must report both actual savings from the weather data used in the analysis and expected annual savings fitted to the CEC CTZ long-term average weather data.

[18] Power analysis is a statistical technique to determine sample size requirements to ensure statistical significance can be found. There are several software packages and calculation Web sites that conduct the power analysis calculation. See the Sampling and Uncertainty Protocol for more discussion and reference. Power analysis is only being required in the Protocol for determining required sample sizes. Appendix D provides further detail on using power analysis for developing sample size requirements.

The regression-based methods must use power analysis to plan their sample size (unless census samples are being used). Regression-based methods must also meet the requirements of the Sampling and Uncertainty Protocol. Many of the requirements in the Sampling and Uncertainty Protocol require specific actions and documentation regarding data cleaning, model specification, testing and reporting for regression-based methods.

Engineering Models

The second class of allowable methods is building energy simulation programs calibrated as described in the Option D requirements in the M&V Protocols. This method is described and a few references are presented in the *Evaluation Framework.*[19]

The engineering models that meet the Option D requirements are generally building energy simulation models, as described in the *Evaluation Framework.*[20] This can be applicable to many types of programs that influence commercial, institutional, residential and other buildings where the measures impact the heating, ventilation or air conditioning (HVAC) end-use. This method is often used for new construction programs and building, heating/cooling or shell measure retrofits in commercial and residential programs.

In addition, industrial efforts can include changes in process operations and the appropriate type of model could be a process-engineering model. These are specialized engineering models and software that conduct engineering analysis for industry-specific industrial processes. Where these types of models are more appropriate, the Gross Energy Impact Protocol allows the use of a process engineering model with calibration as described in the M&V Protocols to meet the Enhanced rigor level.

Sampling must be conducted according to the Sampling and Uncertainty Protocol.

Retrofit Isolation Measurements

The third class of allowable methods is the retrofit isolation measurements as described in Option B requirements in the M&V Protocols. This method is used in cases where full field measurement of all parameters for the energy use for the system where the efficiency measure was applied are feasible and can provide the most reliable results in a cost-efficient evaluation. An overview of this method is provided in the *Evaluation Framework.*[21] Applying a variable frequency drive to a constant speed pump in a variable flow pumping application would be a typical example of when this method would likely be used.

Sampling must be conducted according to the Sampling and Uncertainty Protocol.

Experimental Design

The fourth class of allowable methods is experimental design. Experimental design with energy and demand measurement (either consumption data comparison or engineering-based with M&V) comparisons between the treatment and non-treatment groups meets the Enhanced Gross

[19] TecMarket Works, 129-133 and 176-181.
[20] Ibid, 176-181.
[21] Ibid, 166-169.

Energy Impact Protocol rigor level. Experimental design will normally measure net energy and demand impacts and meet the criteria for equal or better rigor for the overall net savings and demand estimates such that the Gross Impact Protocol and the Participant Net Impact Protocol requirements are met. Currently, experimental design has not been widely used within efficiency evaluation. See the *Evaluation Framework*[22] for a description and some examples of potential experimental designs within energy efficiency efforts. Sampling conducted as part of the experimental design must be conducted according to the Sampling and Uncertainty Protocol.

All Gross Energy Impact Methods

All impact evaluations should employ a research design that has properly identified participants made available from the program database(s). The regression methods of pre- and post-consumption and the calibrated engineering model equivalent to Option D could yield results not restricted to the program being evaluated if participation in multiple programs occurs around the same time period or overlaps in influence. This could contribute to double counting at the portfolio level. To avoid this possibility, all Administrators are required to provide data on participation in other programs for all program participants, including when participation occurred. Evaluators are required to ensure that their methodologies and analysis account for any overlap in program participation and measures that could potentially bias the program evaluation results.

All impact evaluations must meet the requirements of the Sampling and Uncertainty Protocol. Regression analysis of consumption data requires addressing outliers, missing data, weather adjustment, selection bias, background variables, data screens, heterogeneity of customers, autocorrelation, truncation, error in measuring variables, model specification and omitted variable error, heteroscedasticity, collinearity and influential data points. Engineering analysis and M&V-based methods are required to address sources of uncertainty in parameters, construction of baseline, guarding against measurement error, site selection and non-response bias, engineering model bias, modeler bias, deemed parameter bias, meter bias, sensor placement bias and non-random selection of equipment or circuits to monitor.

Each item in these lists above must be addressed as they all have the potential to bias the savings estimates. Bias is the greatest threat to the reliability of savings estimates. The primary difference between the Basic and Enhanced rigor levels is that the minimum allowable methods in the Enhanced rigor level directly address or control for the more likely sources of potential bias in that class of methods (e.g., regression-based versus engineering-based). This means that the minimum allowable methods in the Enhanced rigor level are expected to provide more reliable savings estimates than the minimum allowable methods in the Basic rigor level.

All impact evaluations must meet the rigor level assigned. If rigor is assigned for a measure or program component, the rigor level must be met for analysis of that measure or program component. If measure-level analyses are conducted and no rigor level has been assigned for these measures, they may be conducted at either the Basic or Enhanced rigor level as long as the impact evaluation of the program as a whole is designed to achieve its overall target precision

[22] Ibid, 104-105.

level and addresses all of the potential bias issues listed above and described in the Sampling and Uncertainty Protocol.

Experience in energy efficiency program evaluation has shown that there are cases where some methods are more likely to yield defensible results than others for certain sectors or program designs. The Impact Evaluation Protocol does not restrict the methods used to those that have been successfully used previously. However, the Joint Staff will consider this factor in both contractor selection and in the review and approval process of the evaluation plan. Methods proposed that do not have a successful track record must have thorough documentation on how the methods, techniques or data that will be used can be expected to produce reliable savings estimates and how the key personnel conducting this effort are qualified to do so. For example, experience to date in energy efficiency impact program evaluation has generally shown the following:

- NAC methods are most applicable to residential and small commercial efforts where the expected energy savings are at least 10 percent of pre-installation usage;
- NAC methods are not well suited to handle significant issues with heteroscedasticity, truncation, self-selection or changes in background issues (e.g., significant change in economic conditions-large recession, recovery or economic growth);
- SEM methods are not well suited for whole building measures with interactive effects or commissioning/retro-commissioning efforts;
- The heterogeneity and multitude of background variable issues for industrial customers and unique commercial (e.g., ski resorts and amusement parks/facilities) or institutional (e.g., water/wastewater and prisons) customers make the use of any regression-based consumption analysis difficult and potentially less reliable than engineering-based methods;
- Regression-based consumption analyses are less likely to be able to obtain definitive energy savings estimates where the expected energy savings are not at least 10 percent of pre-installation usage; and
- Regression-based consumption analysis is quite difficult for new construction programs due to the lack of pre-retrofit consumption data and the consequential greater burden for controlling for cross-sectional issues for comparing participants and non-participants (and self-selection bias, particularly if the non-participants are any form of rejecters of program participation). New construction program impact evaluations are generally conducted using engineering models (such as those described in IPMVP Option D).

Gross Demand Impact Protocol

The Gross Demand Impact Protocols are summarized in Table 2. Further description, additional requirements, clarification and examples of these Protocols follow the table. For an evaluation to be in compliance with the Gross Demand Impact Protocol, the methods used and the way in which data are used and reported must meet all the requirements discussed within this section. The intent is to provide unbiased reliable estimates of program level demand impacts for those programs that are expected to reduce electricity demand. The Protocols sometimes reference the *Evaluation Framework* which provides examples of applicable methods. The requirements, however, are always those stated in the Protocols, which take precedence over all other protocols and evaluation guidance documents in all circumstances unless otherwise approved or required by the CPUC.

Table 2. Required Protocols for Gross Demand Evaluation

Rigor Level	Minimum Allowable Methods for Gross Demand Evaluation
Basic	Reliance upon secondary data for estimating demand impacts as a function of energy savings. End-use savings load shapes or end-use load shapes from one of the following will be used to estimate demand impacts: 1. End-use savings load shapes, end-use load shapes or allocation factors from simulations conducted for DEER 2. Allocation factors from CEC forecasting models or utility forecasting models with approval through the evaluation plan review process 3. Allocation based on end-use savings load shapes or end-use load shapes from other studies for related programs/similar markets with approval through the evaluation plan review process
Enhanced	Primary demand impact data must be collected during the peak hour during the peak month for each utility system peak. Estimation of demand impact estimates based on these data is required. If the methodology and data used can readily provide 8,760-hour output, these should also be provided.[23] Sampling requirements can be met at the program level but reporting must be by climate zone (according to CEC's climate zone classification). 1. If interval or time-of-use consumption data are available for participants through utility bills, these data can be used for regression analysis, accounting for weather, day type and other pertinent change variables, to determine demand impact estimates. Pre- and post-retrofit billing periods must contain peak periods. Requires using power analysis, evaluations of similar programs, and professional judgment to determine sample size requirements for planning the evaluation. Needs to meet the requirements of the Sampling and Uncertainty Protocol. 2. Spot or continuous metering/measurement of peak pre and post-retrofit during the peak hour of the peak month for the utility system peak to be used with full measurement Option B or calibrated engineering model Option D meeting all requirements as provided in the M&V Protocol. Pre-retrofit data must be adjusted for weather and other pertinent change variables. Must meet the Sampling and Uncertainty Protocol with a program target of 10% precision at a 90% confidence level. 3. Experimental design established within the program implementation process, designed to obtain reliable net demand savings based upon differences between energy consumption during peak demand periods between treatment and non-treatment groups from consumption data or spot or continuous metering.[24] Sampling must be according to the Sampling and Uncertainty Protocol.

[23] This includes the use of 15-minute interval data or Building Energy Simulation models whose output is 8,760 hourly data.

[24] The overall goal of the Impact Protocols is to obtain reliable net energy and demand savings estimates. If the methodology directly estimates net savings at the same or better rigor than the required level of rigor, then a gross savings and participant net impact analysis is not required to be shown separately.

All M&V referred to in the Impact Evaluation Protocol must be planned, conducted and reported according to the M&V Protocol. M&V may be conducted at a higher level of rigor, with more inputs measured or metered, or with greater precision than the minimum shown within the Impact Evaluation Protocol, but not with a lower level of rigor. The M&V Protocol can also be required by the Joint Staff or used by evaluators to enhance other evaluation efforts.

For the purposes of the Gross Demand Impact Protocol, demand impacts must be reported as energy savings estimates for six time periods for each of four months as follows: noon-1 p.m., 1-2 p.m., 2-3 p.m., 3-4 p.m., 4-5 p.m. and 5-6 p.m. for June, July, August and September for each climate zone in which there are program participants. These demand savings are to be estimated using the Typical Meteorological Year from the National Oceanic & Atmospheric Administration (NOAA), the CEC CTZ long-term average weather data, the Administrator's long-term average weather year or the CEC's rolling average weather year.

The Joint Staff may require that specific studies have additional reporting requirements to include reporting at the 8,760-hour level or specific reporting for targeted transmission or distribution areas. These will be decided on a case-by-case basis as part of the work scoping process or during the evaluation planning process. Identification of these requirements and how they will be met will be incorporated into the evaluation plan and will be conducted and reported as approved within the evaluation planning process.

The Gross Demand Impact Protocol has two rigor levels: Basic and Enhanced. The Basic rigor level uses secondary data to allocate gross energy savings to determine demand savings. The Enhanced level requires primary data collection either through field measurement according to the M&V Protocols or using regression analysis of demand or interval consumption data.

Basic Rigor

The Basic rigor level for the Gross Demand Impact Protocol prescribes that at a minimum, on-peak demand savings are estimated based on allocation of gross energy savings through the use of allocation factors, end-use load shapes or end-use savings load shapes. These secondary data can be from DEER, the CEC forecasting model utility end-use load shape data or other prior studies, with those in the latter two categories needing review and approval through the evaluation planning review process.

Enhanced Rigor

The Enhanced rigor level for the Gross Demand Impact Protocol requires primary data from the program participants. This could be interval-metered data, time-of-use (TOU) consumption billing data, from field measurement or from billing demand data. (This latter is only allowable if the issues of when buildings peak versus demand ratchets and peak periods are addressed in the analysis.) Estimation of peak demand savings estimates is required. If the methodology and data used can readily provide 8,760-hour output, these should be provided. Sampling requirements can be met at the program level but reporting must be by climate zone (according to CEC's climate zone classification). The Joint Staff may require a program evaluation to use the Gross Demand Impact Protocol for transmission and distribution (T&D) demand savings as they deem necessary. Demand evaluation requirements and the methods being employed to meet them need to be clear in the evaluation plans and agreed upon through the evaluation planning review process.

A regression model specified to measure program impacts for peak time periods (via analysis of interval data) or TOU/demand[25] consumption metering can be used to estimate program gross demand. This regression analysis must properly account for weather influences that are specific to the demand estimation and other pertinent change variables (e.g., day-type and hours of occupancy). Regression analysis with interval data should focus on obtaining direct demand impacts. If demand consumption data are used, a methodology to estimate demand savings based upon the demand regression analysis must be detailed in the evaluation plan and approved through the evaluation planning review process. Pre- and post-retrofit billing periods must contain peak periods within this analysis. A power analysis in combination with evaluations of similar program and professional judgment must be used to select and justify the proposed sample sizes.[26] The evaluation planning, analysis and reporting must meet the requirements of the Sampling and Uncertainty Protocol.

The second class of primary data collection for the Enhanced Gross Demand Impact Protocol is to conduct field measurement of peak impacts within the evaluation effort. Spot or continuous metering/measurement at peak pre- and post-retrofit will be conducted during the peak hour in the peak month for the utility system peak. These data will be used with one of two engineering modeling approaches: (1) full measurement Option B or (2) calibrated engineering model Option D, where the modeling approach must meet all requirements as provided in the M&V Protocol. An overview of the full measurement Option B method is provided in the *Evaluation Framework.*[27] The calibrated engineering model Option D method is described and a few references are presented in the *Evaluation Framework.*[28] Further information and the specific requirements for the Protocols are provided in the M&V Protocol. Both of these engineering methods need to be designed to a program target of 10 percent precision at a 90 percent confidence level and must meet the requirements of the Sampling and Uncertainty Protocol.

The third class of allowable methods is experimental design with primary data collection. Experimental design with demand measurement comparisons between customers randomly assigned to the treatment and non-treatment groups meets the Enhanced Gross Demand Protocol rigor level. Experimental design will need to measure energy savings during peak periods either through interval data or spot or continuous monitoring of comparison treatment and non-treatment groups to calculate demand savings estimates. Currently, experimental design has not been widely used within efficiency evaluation. The *Evaluation Framework* provides a description and some examples of potential experimental designs within energy efficiency efforts.[29] Sampling conducted as part of the experimental design must be conducted according to the Sampling and Uncertainty Protocol.

[25] If demand billing is used, the research design must address the issues of building demand versus time period for peak and issues with demand ratchets and how the evaluation can reliably provide demand savings estimates.
[26] Power analysis is a statistical technique that can be used (among other things) to determine sample size requirements to ensure statistical significance can be found. There are several software packages and calculation Web sites that conduct the power analysis calculation. Power analysis is only being required in the Protocol for determining required sample sizes. One of many possible references includes: Cohen, Jacob (1989) *Statistical Power Analysis for the Behavioral Sciences*, Lawrence Erlbaum Associates, Inc. Appendix D provides further detail on using power analysis for developing sample size requirements.
[27] TecMarket Works, 166-169.
[28] Ibid, 129-133 and 176-181.
[29] Ibid, 104-105.

Participant Net Impact Protocol

The Participant Net Impact Protocols are summarized in Table 3. Further description, additional requirements, clarification and examples of these Protocols are presented below the table. Being in compliance with the Participant Net Protocol means that the methods used, and the way in which they are used and reported, meet all the requirements discussed within this section. The intent is to provide reliable estimates of program level net energy and demand impacts when combined with the results from work complying with the Gross Energy Impact Protocol and the Gross Demand Impact Protocol. The Protocols sometimes reference the *Evaluation Framework* which provides examples of applicable methods. The requirements, however, are always those stated in the Protocols, which take precedence over all other protocols and evaluation guidance documents in all circumstances, unless otherwise approved or required by the CPUC.

All M&V referred to in the Impact Evaluation Protocol must be planned, conducted and reported according to the M&V Protocol. M&V may be conducted at a higher level of rigor, with more inputs measured or metered, or with greater precision than the minimum shown within the Impact Evaluation Protocol, but not with a lower level of rigor. The M&V Protocol can also be required by the Joint Staff or used by evaluators to enhance other evaluation efforts.

Table 3. Required Protocols for Participant Net Impact Evaluation

Rigor Level	Minimum Allowable Methods for Participant Net Impact Evaluation
Basic	1. Participant self-report.
Standard	1. Participant and non-participant analysis of utility consumption data that addresses the issue of self-selection. 2. Enhanced self-report method using other data sources relevant to the decision to install/adopt. These could include, for example, record/business policy and paper review, examination of other similar decisions, interviews with multiple actors at end-user, interviews with mid-stream and upstream market actors, Title 24 review of typically built buildings by builders and/or stocking practices. 3. Econometric or discrete choice[30] with participant and non-participant comparison addressing the issue of self-selection.
Enhanced	1. "Triangulation" using more than one of the methods in the Standard Rigor Level. This must include analysis and justification for the method for deriving the triangulation estimate from the estimates obtained.

All participant net impact analysis must be designed to estimate the proportion of savings that is program-induced and net of free-ridership estimates (not including spillover savings estimates). This means that it is net of what would have occurred in the absence of the program. The degree to which the research design, selected method, survey instrument design, question wording and model specification can reliably capture this underlying construct is the evaluation's construct

[30] The instrumental-decomposition (ID) method described and referenced in the *Evaluation Framework* (page 145) is an allowable method that falls into this category. A propensity score methodology is also an allowable method in this category as described in: Itzhak Yanovitzky, Elaine Zanutto and Robert Hornik,, "Estimating causal effects of public health education campaigns using propensity score methodology." *Evaluation and Program Planning* 28 (2005): 209–220.

validity. [31] These elements must work together and must be justified based upon how well they address construct validity.

Participant net impact analysis must address the following issues:
Probability that the participant would have adopted the technology or behavior in the absence of the program (participant free-ridership);

- If adopted in the absence of the program, the probability or proportion (partial free-ridership) of expected savings induced by the program given its ability to:
  - Increase the efficiency of what would have been adopted;
  - Make the adoption occur earlier than when it would have occurred; and
  - Increase the quantity of efficient equipment that would have been adopted.
- The estimation of participant net is consistent with decision-making behavior;
- Consistency is assessed to ensure that other forms of bias, such as, centrality bias, are not introduced;
- If survey methods are used, ensuring that survey questions (instrumentation) and techniques are employed to minimize social desirability bias;
- Results that include only free-ridership adjustment are clearly labeled as such;
- Report participant free-ridership and participant spillover separately where the methodologies selected allow this to be done;
- If at least some portion of participant spillover may be embedded within the gross savings estimates cannot be separated out using the estimation method chosen (e.g., a regression approach is used and the spillover behavior is simultaneous with program participation), clearly present why participant spillover may be present within these estimates and a qualitative assessment of whether these might be expected to be significant or not compared to the program savings estimate; and
- If only participant free-ridership is presented in the report without a reporting of participant spillover savings, clearly discuss that this presents a downwardly biased presentation of overall true net savings.

A general discussion of the net-to-gross principals, methods and a few references are presented in the *Evaluation Framework.*[32]

The research design, selected method, survey instrument design or modeling specification(s) must also address participant self-selection bias(es). Overall sample size targets can be by program. However, all survey or interview inquiries concerning participant net (free-ridership and spillover, and application to gross impacts to obtain net savings) need to be conducted and measured by measure or end-use. Considerations of uncertainty should guide the sample stratification plan.

[31] Construct validity refers to the extent to which the operating variable/instrument/survey question accurately taps and properly measures the underlying concept/abstract idea that is designed to be measured.

[32] TecMarket Works, 133-146.

Basic Rigor – Self Reports

Participant self-reports is the minimum allowable Basic rigor level method in the Participant Net Impact Protocol. The development of the survey instrument, scoring for responses, and handling of missing data and inconsistent responses needs to address those issues presented above and according to the Sampling and Uncertainty Protocol. A discussion of these issues can be found in the *Evaluation Framework.*[33]

Like the other approaches to estimating the net-to-gross ratio (NTGR), there is no precision target when using the self-report method. However, unlike the estimation of the required sample sizes when using the regression and discrete choice approaches to estimating the NTGR, the self-report approach poses a unique set of challenges to estimating required sample sizes. These challenges stem from the fact that the self-report methods for estimating free-ridership involve greater issues with construct validity and often include a variety of layered measurements involving the collection of both qualitative and quantitative data from various actors involved in the decision to install the efficient equipment. Such a situation makes it difficult to arrive at a prior estimate of the expected variance needed to estimate the sample size.
Thus, in order to ensure consistency and comparability, and eliminate potential gaming, this Protocol establishes a minimum sample size for the participant self-report method of 300 participant decision-makers for at least 300 participant sites (where decision-makers may cover more than one site) or a census attempt, whichever is smaller.[34] An estimate of the achieved precision for net savings must be reported as well as a detailed description of the method used for its estimation.

Standard Rigor

There are three classes of allowable methods to meet the minimum requirement for Participant Net Impact Protocol Standard rigor level.

Participant / Non-participant Comparison

The first of these is a comparison of participant and non-participant energy consumption that addresses participant self-selection bias. Some of the potential methods to be used are described in the *Evaluation Framework.*[35] The evaluation plan and report need to include an analysis and explanation of why the selected research design, methodology and actual model specification were selected. A power analysis in combination with evaluations of similar program and professional judgment must be used to select and justify the proposed sample sizes.[36]

[33] Ibid, 136-140.
[34] This is considered the best feasible approach at the time of the creation of this Protocol. Alternative proposals and the support and justifications that address all of the issues discussed here on the aggregation of variance for the proposed self-report method may be submitted to Joint Staff as an additional option (but not instead of the Protocol requirements) in impact evaluation RFPs and in Evaluation Plans. Joint Staff may elect to approve an Evaluation Plan with a well justified alternative.
[35] TecMarket Works, 142-145.
[36] Power analysis is a statistical technique to determine sample size requirements to ensure statistical significance can be found. There are several software packages and calculation Web sites that conduct the power analysis calculation. See the Sampling and Uncertainty Protocol for more discussion and reference. Power analysis is only being required in the Protocol for determining required sample sizes. Appendix D provides further detail on using power analysis for developing sample size requirements.

Program-Specific Enhanced Self Reports

The second allowable method is a program-specific enhanced self-report one that draws upon multiple data sources concerning the decision to install/adopt. These could include, for example, record/business policy and paper review, examination of other similar decisions, interviews with multiple actors at the end-user, interviews with mid-stream and upstream market actors, Title 24 review of typical buildings by builders and stocking practices. For commercial/industrial entities multiple decision makers within a firm/corporation could be interviewed, as well as reviews of records and policy documents, and inquiries into decision-making. It also could draw upon either primary data collection or secondary data collection if available on the same California market (from market assessment studies or market effects studies recently completed). The enhanced method could also include engineering components to assist in determining what would have occurred in the absence of the program. Data collected from such multiple sources would be used to triangulate on an estimate of the participant free-ridership and spillover rate for that program. A brief discussion of some of these types of methods and examples is provided in the *Evaluation Framework*.[37]

Like the other approaches to estimating the NTGR, there is no precision target when using the self-report method. However, unlike the estimation of the required sample sizes when using the regression and discrete choice approaches, the self-report approach poses a unique set of challenges to estimating required sample sizes. These challenges stem from the fact that the self-report methods for estimating free-ridership involve greater issues with construct validity and often include a variety of layered measurements involving the collection of both qualitative and quantitative data from various actors involved in the decision to install the efficient equipment. Such a situation makes it difficult to arrive at a prior estimate of the expected variance needed to estimate the sample size. This Protocol, instead, establishes a minimum sample size for end-use participants: a sample of 300 participant decision-makers for at least 300 participant sites (where decision-makers may cover more than one site) or a census attempt, whichever is smaller. Sample sizes of other actors, engineering work or record review need to be described in the evaluation plan and approved through the evaluation planning review process.

Econometric or Discrete-Choice Analysis

The third allowable method in the Standard rigor level is econometric or discrete-choice analysis of participant and non-participants that addresses participant self-selection bias. An overview of some of these methods and a few references can be found in the *Evaluation Framework*.[38] The evaluation plan and report need to include an analysis and explanation of why the selected research design, methodology and actual model specification were selected. A power analysis in combination with evaluations of similar programs and professional judgment must be used to select and justify the proposed sample sizes.

Two of the Standard rigor level methods require comparisons with non-participants. It is important that care be taken for selecting the appropriate comparison group. There is not a single rule about what constitutes an appropriate comparison group, since the selection of the group depends on such factors as type of market transaction, methodology or comparison

[37] TecMarket Works, 141-142.
[38] Ibid, 142-145.

purpose. Yet, this should be carefully considered and the proposed non-participant comparison group and the criteria used in selecting this group should be discussed in the evaluation plan, and reviewed and approved through the evaluation planning review process.

Enhanced Rigor – Comparison of Multiple Approaches

One of the primary concerns with measurements of participant net is of construct validity. Given this, the Enhanced rigor level requires the use of at least two of the Standard rigor level methods to triangulate[39] on an estimate of participant net. This must include analysis and justification for the method for deriving the triangulation estimate, not solely on averages, from the estimates obtained.

Participant net savings evaluation includes the evaluation of free-ridership and participant spillover. Presenting both yields a more accurate picture of what the participant would have done in the absence of the program and the full impacts of the program. The evaluation plan, analysis and report must address how the methods were selected and how the analysis was conducted. Net of free-ridership (Net of FR) estimates must be provided in the evaluation report. Current CPUC policy, as the Protocols are being developed, is that only program savings and not participant spillover will be counted towards program and Administrator goals and performance. These are the Net of FR estimates.

Indirect Impact Evaluation Protocol

The Indirect Impact Evaluation Protocol is the minimum standard Protocol for programs that seek to change the behavior of consumers and for which some level of gross energy and demand savings is expected. These programs are typically information, education, marketing, promotion, outreach or other types that may not have specified energy savings goals, but are still expected to provide energy impacts within their target markets. The Protocol has multiple levels of rigor that can be used to conduct the evaluations. Once a minimum rigor level is assigned for an evaluation, all methods in a higher class of rigor are allowable, as they exceed the minimum criteria. For example, if the program has an assigned the Standard rigor level and the method selected for implementation is an option under the Enhanced rigor level (but is not listed under the Standard rigor level), this method is acceptable for meeting the Protocol.

The Indirect Impact Evaluation Protocol is summarized in Table 4. A discussion of behavioral impact evaluation and selected references are provided in the *Evaluation Framework*.[40] Further description, additional requirements, clarification and examples of this Protocol follow the table. In order to comply with the Indirect Impact Evaluation Protocol the methods used and the way in which they are used and reported must meet all the requirements discussed within this section. The intent is to provide reliable estimates of program level impacts and, when required, gross energy and demand impacts. The Protocols sometimes reference the *Evaluation Framework* and

[39] A strict dictionary definition of triangulation would mean incorporating three measurements. The term is used here to mean a process of analysis that examines at least two measurements and assesses what their differences might mean. Then the best estimate derived from this exam is determined to properly represent the underlying construct to meet construct validity issues to obtain the most reliable estimate from the multiple analyses conducted.

[40] TecMarket Works, 234-242.

other documents which provide examples of applicable methods. The requirements, however, are always those stated in the Protocols, which take precedence over all other protocols and evaluation guidance documents in all circumstances, unless otherwise approved or required by the CPUC.

All M&V referred to in the Impact Evaluation Protocol must be planned, conducted and reported according to the M&V Protocol. M&V may be conducted at a higher level of rigor, with more inputs measured or metered, or with greater precision than the minimum shown within the Impact Evaluation Protocol, but not with a lower level of rigor. The M&V Protocol can also be required by the Joint Staff or used by evaluators to enhance other evaluation efforts.

Table 4. Required Protocols for Indirect Impact Evaluation

Rigor Level	Minimum Allowable Methods for Indirect Impact Evaluation
Basic	An evaluation to estimate the program's net changes on the behavior of the participants is required; the impact of the program on participant behavior.
Standard	A two-stage analysis is required that will produce energy and demand savings. The first stage is to conduct an evaluation to estimate the program's net changes on the behavior of the participants/targeted-customers. The second is to link the behaviors identified to estimates of energy and demand savings based upon prior studies (as approved through the evaluation planning or evaluation review process).
Enhanced	A three-stage analysis is required that will produce energy and demand savings. The first stage is to conduct an evaluation to estimate the program's net impact on the behavior changes of the participants. The second stage is to link the behavioral changes to estimates of energy and demand savings based upon prior studies (as approved through the evaluation planning or evaluation review process). The third stage is to conduct field observation/testing to *verify* that the occurrence of the level of net behavioral changes.

Basic Rigor

In this Protocol, programs or program components are assigned by Joint Staff to receive an Indirect Impact Evaluation if the program's primary goal is to produce behavioral changes. The primary uncertainty within the logic chain of obtaining energy and demand savings from these types of programs is the estimation of the program-induced impact on the behavior of participants. Therefore, the primary focus of the Indirect Impact Evaluation is in evaluating and estimating the program's net impact on behavioral change. This is the primary component for the evaluation research design.

There are several types of research design that could be used for conducting an Indirect Impact Evaluation. There are many social science methodologies that could apply depending upon the program goals, logic, program design and market operation. Guidance for these types of evaluations can be found in the *Evaluation Framework*.[41]

Indirect impact evaluation design, analysis and reporting must address the following issues:

[41] Ibid, 234-242. Much of the guidance provided from the *Evaluation Framework* chapter on Market Transformation Evaluation (pages 245-268) can also provide useful insights and references.

- Expected impacts and the target audience for these impacts;
- How the expected impacts will be measured;
- Identification and measurement of baseline (and where baseline would have been in the absence of the program, i.e., forecasted, dynamic baseline or estimated counter-factual from research design) or identification and measurement of well-matched non-treatment comparison group over time;
- Extent of exposure/treatment and how this is being measured in the evaluation; and
- Self-selection bias and how this is being controlled for to obtain an unbiased estimate of the program-induced impact.

The assessment or development of a program theory and logic model (PT/LM) is recommended.[42] The PT/LM could be particularly useful if expanded to include the expected interactions with the market or the use of behavioral change models. These can be valuable as a foundation for the evaluation research design, researchable questions and basis for developing survey/interview questions. Though a PT/LM is not required, it is an important tool to ensure that the evaluation research design can measure the program's behavioral impacts. A detailed evaluation research design for the Indirect Impact Evaluation is required and must be reviewed and approved through the evaluation planning review process.

All sampling must be done in accordance with the Sampling and Uncertainty Protocol. Any sampling for regression analysis must use power analysis in combination with evaluations of similar program and professional judgment to determine required sample sizes.

Methodologies using a treatment/non-treatment group comparison that include controlling for self-selection are encouraged. Methods could include the enhancement of those methods described in the *Evaluation Framework*.[43] There are also many other methods used in other evaluation fields that could be found to be equally or more valid. One possible example is the use of the propensity scoring method that has been used to evaluate public health campaigns and control for the selectivity bias in treatment levels.[44] The evaluation plan and report need to include an analysis and explanation of why the research design, methodology and actual model specification were selected.

Standard and Enhanced Rigor Levels

In the Standard and Enhanced rigor levels, evaluation studies are conducted to link net behavioral impacts to energy and demand saving impacts based upon prior studies. These prior studies do not need to be previously completed evaluations (however this is preferred if they are available). For example, linking net behavior change savings estimates using DEER will meet the Indirect Impact Evaluation Protocol. Linking savings estimates to past evaluations of similar programs, new engineering models for savings estimates or other studies must be approved by the Joint Staff through the evaluation review process.

[42] Ibid, 30-38 and 45-48.
[43] Ibid, 142-145.
[44] Yanovitzky, Zanutto and Hornik, 209 – 220. Also included (with additional references) in a review of possible net/causality methods for energy efficiency evaluation in: Lisa Skumatz, Dan Violette, and Rose Woods, "Successful Techniques for Identifying, Measuring, and Attributing Causality in Efficiency and Transformation Programs." *Proceedings of the 2004 ACEEE Summer Study in Buildings* (2004): 2.260 – 2.273.

A behavioral impact program (through information, education, training, advertising or other non-monetary incentive efforts) may be part of a portfolio to lead customer/market actors into other programs. This program/program component could be assigned an Indirect Impact Evaluation to determine the impact the program(s) is having on the portfolio and to provide input for the process evaluation of the program. An assignment of the Standard rigor level requires that an impact evaluation be conducted and linked to energy and demand savings estimates. The energy and demand savings, however, would not, in this case, be added to the portfolio level savings unless a method is used and approved by the Joint Staff to ensure that these savings are not double counted with those attributed to other programs.

Four types of impacts from a behavioral change program are shown in Figure 5. Inducing customers into other programs is shown as Path A. Savings from this path are not direct savings due to the information, education, training or advertising program under study. The savings are those obtained through the direct program. However, documenting the impacts of this effort is important to estimate the various components that contribute to generating a portfolio's savings and to aid in making investment decisions. An example might be customers who participate and obtain high-efficiency room air conditioners through a rebate program due to behavioral impacts from the program being evaluated.

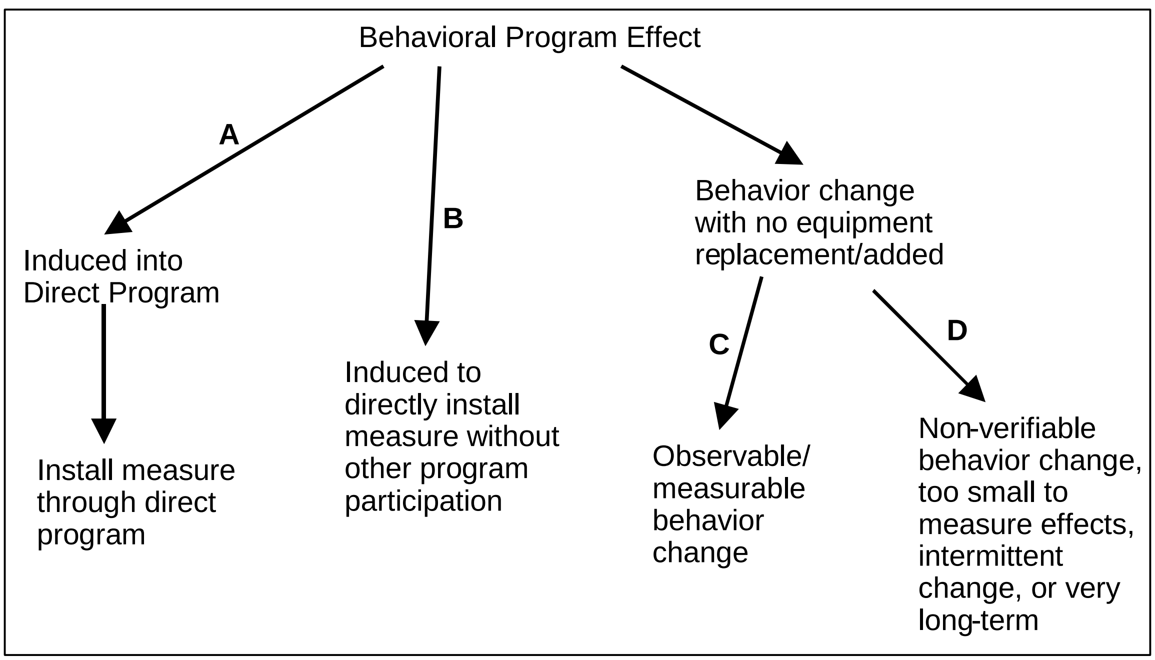

Figure 5. Potential Alternative Behavioral Impact Paths

Programs or program components that directly influence customer behavior to purchase high efficiency replacement equipment or add equipment that can save energy (e.g., timers) are shown as Path B. If assigned an Indirect Impact Evaluation with a Standard or Enhanced rigor level, these programs would be expected to undertake similar evaluation designs to those in Path A. The energy and demand savings for these, however, are *directly* attributable to the program effort being evaluated. The research design may need to estimate and find the proportion of customers that take these actions outside of other programs. An example might be customers who purchase high efficiency room air-conditioning due only to this program and who did not receive any financial incentives from other portfolio efforts to do so.

Path C refers to those program-induced behavioral changes that can be observed or measured but are not tied to equipment replacement or the addition of equipment. This could include such changes as those to business policies regarding energy efficiency, architects' decisions on when to test daylighting alternatives, and/or plant managers' operating and maintenance schedules.

Path D represents behavioral changes that are too small, long-term or intermittent to be cost-efficiently verified through observation, field-testing or surveying with enough reliability to measure any energy and demand impacts. Depending on the level of investment and the advances made in the evaluation of behavioral change, the programs or program components that fall into this category could vary over time. Path D examples include residential behavior of turning off lights, educating children through school programs to changing their energy-use behavior when they are adults, and changes in residential thermostat set points. The Joint Staff will only assign a Basic rigor level for this category if meeting a higher rigor level would not be possible. This could occur because a specific estimate of the degree of the impact cannot be obtained cost-effectively or the link and translation to energy and demand savings is not available or cost-effective to develop.

Every program evaluation is required to demonstrate that the program is accomplishing its primary goals of affecting behavioral change, as stated in its PT/LM.

It is expected that the Indirect Impact Evaluation for paths A, B and C will be assigned either a Standard or Enhanced rigor level depending upon the size of resources being invested and the importance of the anticipated outcomes to the overall success of the portfolio. The indirect impact evaluation for an Enhanced rigor level is distinguished from a Standard rigor level by the requirement to conduct field observation/testing to verify net changes in behavior. For Path D it is expected that only a Basic rigor level will *usually* be assigned. The evaluation design for each path is briefly described below.

Path A: The evaluation design to verify these actions is most straightforward for Path A. Verification through program participation is sufficient given these programs are conducting their own verification and impact evaluation.

Path B: The evaluation design for Path B requires the additional step of finding effected customers. This step would have to be part of the evaluation design when estimating the proportion affected in the impact evaluation. The evaluation plan must propose the research design to accomplish this and be approved within the evaluation planning review process.

Path C: The evaluation research design needed to accomplish an Enhanced rigor indirect impact evaluation following Path C is more challenging. A Path C evaluation plan needs to be presented in enough detail for its logic and potential reliability to be reviewed as part of the evaluation planning review process. Examples of Path C activities include review of pre- and post-program architectural plans, review of government policy, planning and hearing documents and their dates of adoption along with interview support, examination of business policy manuals, and review of business programs created due to education efforts and testing subsequent employee knowledge and reported actions.

Path D: For path D, the Basic level rigor indirect impact evaluation must be used to demonstrate that the program has carried out specific activities that are designed to produce behavioral change.

Guidance on Skills Required to Conduct Impact Evaluations

The Impact Evaluation Protocol includes gross energy and demand impact Protocols, Protocols for participant net impacts and a Protocol for indirect impact evaluation. There are multiple methods within these various Protocols that create the need for different skills depending upon the method that is being used. The method employed determines the skills and experience requirements for that method. The senior, advisory and leadership personnel for an impact evaluation effort must have the specific skills and experience for the method they are leading and the time budgeted for responsible project task leadership and quality control. The degree of involvement needed from senior skilled staff is dependent upon the skill and experience of the mid-level personnel conducting much of the analysis work.

Several of the energy, demand and participant net methods use statistical/econometric methods. These are used with utility demand metering and consumption data, and with data gathered for decision analysis (in the case of discrete choice). The use of statistical/econometric methods requires personnel trained in these methods and/or with significant experience in using them. This experience and/or training must include testing alternative specifications, testing and correcting for violations of regression assumption violations, and using them within the context of program evaluation.

Another class of methods relies on engineering type methods that draw upon the rules of physics to calculate estimates of energy and demand savings. Simple engineering equations can be understood and used by most people with a general science background. Yet, to ensure reliable use of the principles, impact evaluations using the simple engineering model should still use personnel with experience in this area, Certified Energy Managers[45] or personnel with training in mechanical or architectural engineering. Building energy simulation models and process engineering models generally require personnel with a college degree in mechanical or architectural engineering or significant related, equivalent experience. Process engineering models may also require specific engineering experience or research regarding the industrial process or facilities being studied.

There are methods within the Gross Energy Impact Protocol (e.g., enhanced gross energy regression-based (enhanced 1.)) that could employ significant primary survey or interview data collection. The participant net impact methods that employ the self-report and enhanced self-report approaches require similar experience and training. The evaluators using these methods should have sufficient experience implementing surveys, interviews, group interviews and other types of primary data collection activities as are being recommended. They need to have

[45] The Association of Energy Engineers (AEE) offers courses and a certificate for a Certified Energy Manager (CEM).

experience in energy efficiency markets, the social sciences, and interview and survey instrument design, implementation and analysis.

Indirect impact evaluation methods could be based upon survey and interview analysis methods and/or statistical/econometric methods. The evaluators must be trained and experienced in conducting social science research with a strong understanding of assessing and testing causal relationships between exposure to the program and possible outcomes. An important requirement for these evaluators is to have a strong foundation in research design and the ability to create research designs to test for net behavioral impacts of energy efficiency programs.

Summary of Protocol-Driven Impact Evaluation Activities

1	The Joint Staff identifies which programs and program components will receive an impact evaluation and identify the type of impact evaluation(s) to be conducted and at what rigor level.
2	The Joint Staff determines any special needs on a case-by-case basis that will be required from particular program or program component evaluations. CPUC-ED issues request for proposals for impact evaluations, selects evaluation contractors and establishes scope(s) of work.
3	Program theory and logic models (PT/LM), if available, must be reviewed/assessed as needed to properly identify impacts and evaluation elements required to assess net program impacts. Research design and sampling plan developed to meet Protocol requirements at a program or program component basis as designated by the Joint Staff rigor level assignments. This includes meeting requirements from the Sampling and Uncertainty Protocol, M&V Protocol and Reporting Protocol, as are applicable given Impact Evaluation Protocol requirements. Research design and sampling must be designed to meet any of the Joint Staff requirements for additional analyses including, but not limited to, the estimation of net impacts by delivery mechanism, the estimation of transmission and/or distribution benefits, or other areas designated of specific concern by the Joint Staff. Develop Evaluation Plan, submit it to the CPUC-ED and revise as necessary to have an approved Evaluation Plan that meets the Impact Evaluation Protocols.
4	All impact evaluation teams must be staffed so as to meet the skills required for the research design, sampling, appropriate and selected impact evaluation method, uncertainty analysis, and reporting being planned and conducted.
5	Develop precise definitions of participants, non-participants and comparison groups. Obtain concurrence with the CPUC-ED on these definitions which are to be used in developing the research design and sampling plans.
6	All impact evaluations must meet the requirements of the Sampling and Uncertainty Protocol. 6.a There are 2 primary sampling considerations for regression-based consumption analysis. (1) Unless a census is utilized, conduct a power analysis to estimate the required sample size. One may also consider prior evaluations for similar programs and professional judgment (must use all of these for the Enhanced level of rigor); and (2) Must use a minimum of 12 months pre and post-retrofit consumption data, except when program approach does not allow pre-retrofit data (e.g., new construction). 6.b All engineering-based methods must:

	(1) Estimate the uncertainty in all deemed and measured input parameters and consider propagation of error when determining measured quantities and sample sizes to meet the required error tolerance levels; and (2) Use a combination of deemed and measured data sources with sufficient sample sizes designed to meet a 30% error tolerance level in the reported value at a 90% confidence level to meet the Basic rigor level and a 10% error tolerance level at a 90% confidence level for the Enhanced rigor level. 6.c Participant and non-participant comparisons and econometric/discrete-choice methods for Participant Net Impact evaluation will use power analysis combined with examinations of prior evaluation studies for similar programs to derive required sample sizes. 6.d Self-report and Enhanced self-report methods for Participant Net Impact evaluations must at a program level have a minimum sample size of 300 participant decision-makers for at least 300 participant sites (where decision-makers may cover more than one site) or a census attempt, whichever is smaller, (while investigation will be at a measure or end-use level).
7	All impact evaluations must be planned, conducted, analyzed and reported to minimize potential bias in the estimates, justify the methods selected for doing this and report all analysis of potential bias issues as described in the Sampling and Uncertainty Protocol, Impact Evaluation Protocol and M&V Protocol. Primary considerations that must be addressed (based upon method employed) are as follows: 7.a Regression-based consumption analysis must incorporate: (1) Addressing the influence of weather when weather sensitive measures have been included in the program evaluation; (2) Assessing potential bias given inclusion/exclusion issues due to the 12 month pre- and post-retrofit consumption minimum requirement; (3) For the Enhanced rigor level, assess, plan, measure and incorporate background and change variables that might be expected to be correlated with gross and net energy and/or demand savings; (4) Comparison groups must be carefully selected with justification of the criteria for selection of the comparison group and discussion of any potential bias and how the selected comparison group provides the best available minimization of any potential bias; and (5) Interval or TOU consumption data for demand impact analysis must contain the peak period for the utility system peak. If demand billing data is used for demand impact analysis, the research design must address the issues of building demand versus time period for peak and issues with demand ratchets and how the evaluation can reliably provide demand savings estimates. Demand savings must be reported by CTZ. 7.b Engineering-based methods must incorporate: (1) Addressing the influence of weather when weather sensitive measures have been included in the program evaluation; (2) Meeting all the requirements in the M&V Protocol including issues of baseline

	determination; and (3) For the Enhanced rigor level of demand impact analysis using spot or continuous metering/measurement pre- and post-retrofit for the peak hour of the peak month for the utility system peak. Demand savings must be reported by CTZ. 7.c Experimental design must use spot or continuous metering/measurement pre and post-retrofit for the peak hour of the peak month for the utility system peak for determining demand impacts. Demand savings must be reported by CTZ. 7.d Indirect impact analysis must incorporate: (1) Description of expected impacts (direct behavioral and indirect energy and demand impacts) and how they will be measured; (2) Discussion of identification and measurement of baseline; (3) Extent of exposure/treatment and its measurement; (4) Comparison groups must be carefully selected with justification of the criteria for selection of the comparison group and discussion of any potential issues of bias and how the selected comparison group provides the best available minimization of potential bias; and (5) Assessing, planning for and analyzing to control for self-selection bias.
8	Regression analysis of consumption data must address outliers, missing data, weather adjustment, selection bias, background variables, data screens, autocorrelation, truncation, error in measuring variables, model specification and omitted variable error, heteroscedasticity, collinearity and influential data points. These areas must be addressed and reported in accordance with the Sampling and Uncertainty Protocol.
9	Engineering analysis and M&V based methods are required to address sources of uncertainty in parameters, construction of baseline, guarding against measurement error, site selection and non-response bias, engineering model bias, modeler bias, deemed parameter bias, meter bias, sensor placement bias and non-random selection of equipment or circuits to monitor. These areas must be addressed and reported in accordance with the Sampling and Uncertainty Protocol.
10	Develop draft evaluation report to include meeting all requirements in the Reporting Protocol and incorporating the program's performance metrics.
11	Develop final evaluation report in accordance with guidance provided by the Joint Staff. Submit final evaluation report to the CPUC-ED.
12	Once accepted by the CPUC-ED, develop abstracts and post them and report on CALMAC Web site following the CALMAC posting instructions.

Note: The steps included in this evaluation summary table must comply with all the requirements within the Impact Evaluation Protocol.

Measurement and Verification (M&V) Protocol

Introduction

When, in the course of conducting evaluations, it becomes necessary or advisable to collect physical evidence from field installations of energy efficiency technologies, the evaluator must design, document and implement a measurement and verification (M&V) project. M&V will typically be used to support impact studies by providing measured quantitative data from the field. One of the primary uses is to reduce uncertainty in baselines, engineering calculations, equipment performance and operational parameters. However, M&V can be used in process and market effects evaluations as well, when such data are useful for understanding issues such as measure quality and suitability for particular applications, installation practices and quality, baseline equipment efficiency and operation practices, and other issues identified by the process and/or market effects evaluation plan. For the purposes of this Protocol, M&V will cover all field activities dedicated to collecting site engineering information. This includes such activities as measure counts, observations of field conditions, building occupant or operator interviews conducted in-person, measurements of parameters, and metering and monitoring.

How M&V differs from impact evaluation: M&V refers to data collection, monitoring and analysis activities associated with the calculation of gross energy and peak demand savings from individual customer sites or projects. Gross and net impacts at the program level will be guided by the Impact Evaluation Protocol, where results from M&V studies conducted on a sample of sites will be combined with other information to develop an overall estimate of savings by program or program component.[46]

Sources of uncertainty in engineering estimates: Engineering estimates are based on the application of the basic laws of physics to the calculation of energy consumption and energy savings resulting from the implementation of energy-efficient equipment and systems. Engineering models range from simple one-line algorithms to systems of complex engineering equations contained within a building energy simulation program such as DOE-2. Uncertainty in engineering estimates stems from uncertainty in the inputs to an engineering model and the uncertainty in the ability of the algorithms to predict savings.

Uncertainty analysis and M&V planning: Energy efficiency programs utilize a wide range of technical and behavioral tools and concepts as "measures." The likelihood of success of the measure depends on a large number assumptions, many of which can be verified through measurement. Measured data from field studies are used to quantify and reduce the uncertainty in energy and peak demand impact calculations. While this Protocol is written to support the overall goal of creating more reliable savings estimates and forecasts, we recognize that M&V activities must be planned and resources must be allocated to reduce these uncertainties. Uncertainty analysis conducted during the planning phase shall be used to identify the assumptions that have the greatest contribution to the overall savings uncertainty and allocate resources in an appropriate manner to address these uncertainties.

[46] It is possible that some impact evaluations will not require M&V. See the Impact Evaluation Protocol herein for more information.

The development of this Protocol is driven by the desire to create and implement a rational framework to identify and conduct a wide range of M&V activities. As the Joint Staff recognizes that precision is a key requirement in forecasting and reporting, it will seek to allocate resources such that the value of the M&V activities is applied to identify, quantify and manage risk associated with the uncertainty in the expected savings from measures and programs. The Protocol supports the overall M&V goals and priorities established by the Joint Staff:

- Improve reliability of savings estimates;
- Determine whether energy and peak demand savings goals have been met;
- Improve DEER estimates of energy and peak demand savings; and
- Inform future program planning and selection processes.

Audience and Responsible Actors

The audience and responsible actors for this Protocol include the following:

- **Joint Staff Evaluation Planners** should understand the uncertainty in the overall energy and peak demand savings calculations and identify the degree to which field measurements can reduce that uncertainty (at appropriate cost);
- **The Evaluation Project Team** will use field measurements to calculate gross savings estimates and answer specific process and market effects evaluation questions;
- **Administrators and IOUs** will use M&V project results to refine unit savings estimates and/or engineering parameters used in future program planning, and utilize early and mid-stream M&V findings to adjust program priorities within the portfolio;
- **Program Implementers** will use early M&V project results to revise program delivery approaches and measures;
- **Site Owners** should allow access to site for field measurements and may have an interest in the energy savings resulting from efficiency upgrades subject to the M&V effort; and
- **DEER Planners** will use field data to develop, calibrate and generally improve DEER energy and demand savings estimates.

Overview of the Protocol

This M&V Protocol is intended to set guidelines for conducting and reporting field data collection activities in support of energy efficiency program evaluations. The M&V Protocol covers the following issues:

- M&V framework;
- Requirements for installation verification;
- M&V requirements;
- M&V approach examples;

- Project reporting and documentation requirements;
- Sampling strategies; and
- Skills required for conducting M&V activities.

For more information on conducting M&V studies, please refer to the *Evaluation Framework*.[47]

M&V Framework & Language

M&V projects conducted under this Protocol shall adhere to the IPMVP,[48] with additional criteria specified herein. The IPMVP is a flexible framework that allows users to craft M&V plans for specific projects with consideration of:

- The type of contractual arrangement in force;
- The types and quantities of uncertainty in the project savings estimate; and
- The cost to create the M&V plan and conduct all activities in the plan, including:
    - Meter and sensor placement;
    - Data collection; and
    - Data analysis and reporting.

Whereas field measurements are an important component of program impact estimation and the IPMVP is written to allow users flexibility, its application requires a thorough knowledge of measure performance characteristics and data acquisition techniques. Building and energy using facilities in general tend to vary widely in terms of the electrical and mechanical infrastructure that supplies the energy commodity. A measurement strategy that is simple and cheap in one building (such as measuring lighting energy at a main panel) may be much more expensive in a similar building that is wired differently. For this reason, M&V resources, costs and benefits must be called upon and allocated considering site-specific characteristics.

Relationship of the M&V Protocol to Other Protocols

The M&V Protocol is a subset of the Impact Evaluation, Process Evaluation and Market Effects Protocols. M&V activities described within this Protocol are initiated by these three Protocols. Not every evaluation study will require M&V. When M&V is indicated, the M&V Protocol provides the requirements for meeting the various levels of required M&V and points to the applicable pages of the *Evaluation Framework* for more guiding information and references.

Sampling activities conducted within the M&V projects prescribed within this Protocol shall be conducted in accordance with the Sampling Protocol. Impact and process evaluation studies calling for M&V data will include a site selection sampling Protocol.

[47] TecMarket Works, pages 147-204.
[48] The IPMVP provides four options for conducting M&V studies. Option C – Whole Facility, is very close in concept to a statistical billing analysis and it is covered under the Impact Evaluation Protocol to avoid confusion.

Key Metrics, Inputs and Outputs

M&V studies, since they are directed by the Impact Evaluation and/or the Process or Market Effects Protocols, will draw upon the same data sources, such as data from program databases, program descriptions, DEER, work papers provided by program implementers, utility demand metering and consumption data for both participants and non-participants, utility weather data, on-site measurement, monitoring and observational data, survey and interview data collection, and other prior study data and reports. These will be used as directed by the M&V Protocol to produce measure-level energy and peak demand savings for sampled sites as directed by the Impact Evaluation Protocol. The overall information inputs and outputs to the M&V process are shown in Figure 6.

Because M&V studies are required to follow the Sampling and Uncertainty Protocol, evaluators must also assess, minimize and mitigate potential bias and present the achieved level of precision including relative precision, error bounds on M&V results in support of the impact evaluation effort.

All M&V reporting must also follow the Reporting Protocol. Verification-only output metrics are defined as the fraction of installed measures that meet the provisions of the M&V Protocol.

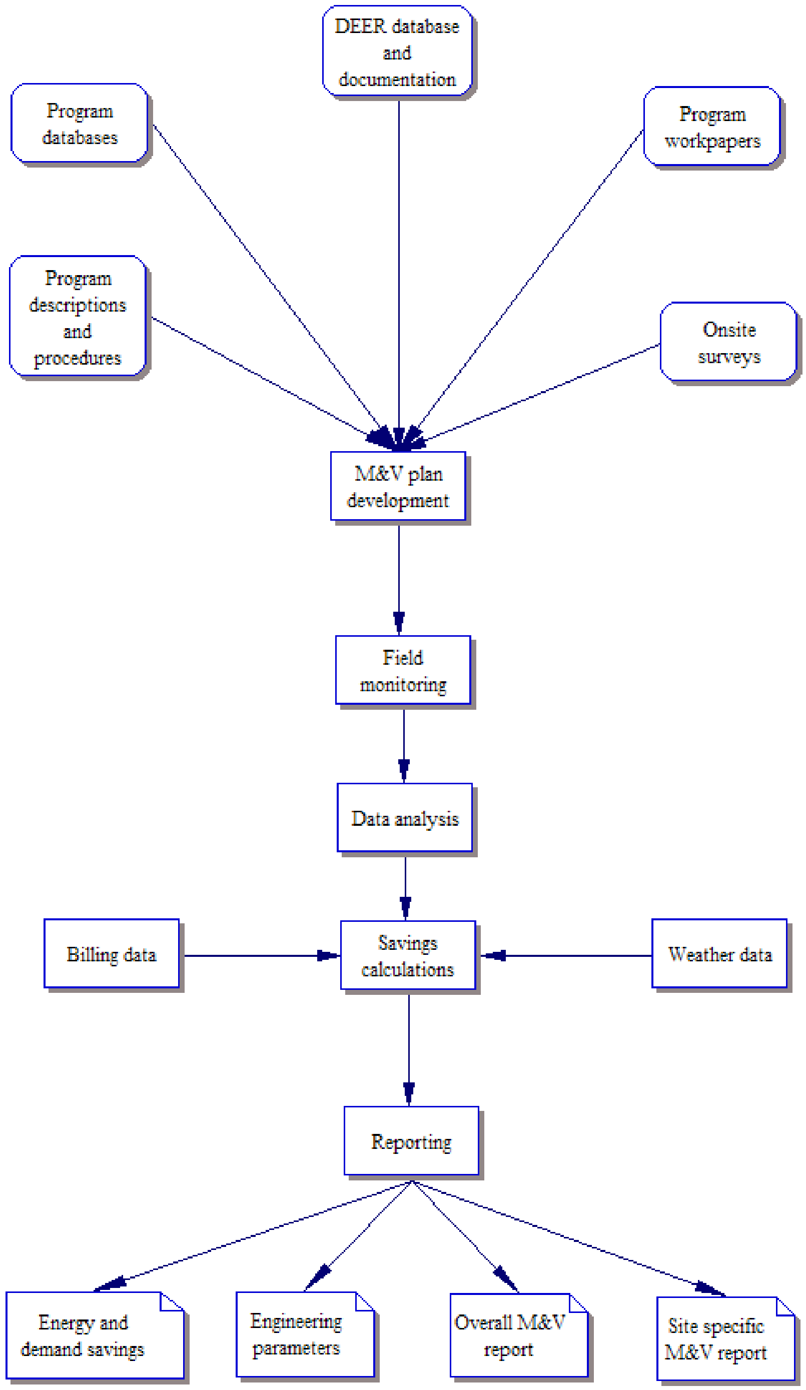

Figure 6. Measurement & Verification Information Flow Diagram

Site-Specific M&V Plan

In requiring the adherence to the IPMVP, this Protocol requires submittal of an M&V plan for each field measurement project undertaken that documents the project procedures and rationale such that the results can be audited for accuracy and repeatability. Within the guidelines established by the IPMVP and the Protocols, there is considerable latitude for the practitioner in developing a site-specific M&V plan and implementing the plan in the field. The M&V contractor shall evaluate the uncertainty in the desired data product and develop a site-specific M&V plan that manages the uncertainty in the most cost-effective manner.

Initial estimates of engineering parameter uncertainties should be used to provide an estimate of the overall uncertainty in the savings calculations. Assumptions used to create initial estimates of parameter uncertainty values should be documented. The contribution of specific engineering parameters to the overall uncertainty in the savings calculations should be identified and used to guide the development of the M&V plan.

The M&V plan must include the following sections:[49]

1. Goals and Objectives;
2. Building Characteristics;
3. Data Products and Project Output;
4. M&V Option;
5. Data Analysis Procedures and Algorithms;
6. Field Monitoring Data Points;
7. Data Product Accuracy (including data acquisition system accuracy and sensor placement issues);
8. Verification and Quality Assurance Procedures (including sensor calibration); and
9. Recording and Data Exchange Format.

The content of each of these sections is described below.

Identify Goals and Objectives: The goals and objectives of the M&V project should be stated explicitly in the M&V plan.

Specify Site Characteristics: Site characteristics should be documented in the plan to help future users of the data understand the context of the monitored data. The site characteristics description should include:

- General building configuration and envelope characteristics, such as building floor area, conditioned floor area, number of building floors, opaque wall area and U-value; window area, U-value and solar heat gain coefficient;
- Building occupant information, such as number of occupants, occupancy schedule, building activities;
- Internal loads, such as lighting power density, appliances, plug and process loads;

[49] See the *Evaluation Framework*, pages 147-153.

- Type and quantity and nominal efficiency of heating and cooling systems;
- Important HVAC system control set points;
- Changes in building occupancy or operation during the monitoring period that may affect results; and
- Description of the energy conservation measures at the site and their respective projected savings.

Specify Data Products and Project Output: The end products of the M&V activity should be specified. These data products should be referenced to the goals and objectives on the project and include a specification of the data formats and engineering units, with reference to the Reporting Protocol Appendix A.

Specify M&V Option: The M&V option chosen for the project should be specified according to the IPMVP consistent with the M&V Protocol.

Specify Data Analysis Procedures and Algorithms: Engineering equations and stipulated values as applicable shall be identified and referenced within the M&V plan. Documentation supporting baseline assumptions shall be provided.

This is a key component of the M&V plan. Often, data are collected without a clear understanding of the later use for the data. This can result in either extraneous data collection and/or missing data during the data analysis step. Fully specifying the data analysis procedures will help ensure that an efficient and comprehensive M&V plan is presented.

Specify Field Monitoring Data Points: The actual field measurements planned should be specified, including the sensor type, location and engineering units. For example:

- For measuring the run-time of a boiler, the field data point description would be: *"Accumulated run-time of draft fan serving boiler number 1, using an inductive run-time logger mounted on the draft fan motor."*
- For measuring air conditioner supply air temperature, the field data point description would be: *Duct air temperature (in degrees Fahrenheit) using a sheathed thermistor sensor located in the supply duct three feet downstream from AC-1.*
- For measuring chilled water temperature, the field data point description would be: *"Chilled water supply temperature measured with a probe-type thermistor inserted in a thermowell."*

Estimate Data Product Accuracy: All measurement systems have error, expressed in terms of the accuracy of the sensor and the recording device. The combined errors should be estimated using a propagation of error analysis and the expected final data product accuracy described.

Specify Verification and Quality Assurance Procedures: Data analysis procedures to identify invalid data and treatment of missing data and/or outliers must be provided.

Specify Recording and Data Exchange Formats*:* Data formats compliant with the data reporting Protocol should be described.

M&V Rigor Levels

Rigor is defined as the level of expected reliability. The higher the level of rigor, the more confident we are the results of the evaluation are both accurate and precise, i.e., reliable. That is, reliability and rigor are treated as synonymous. Reliability is discussed in the Sampling and Uncertainty Protocol and in the *Evaluation Framework*[50] where it is noted that sampling precision does not equate to accuracy. Both are important components in reliability, as used by the CPUC.

In accordance with the Impact Evaluation Protocol, M&V requirements are set according to two levels of rigor. The Joint Staff will set rigor levels for each program according to their overall planning priorities as described in the Impact Evaluation Protocol. Each rigor level provides a set of allowable methods that offers flexibility for the M&V contractor to propose the most cost-effective method considering the conditions prevailing at each sampled site. The principle is to establish a minimum level of evaluation rigor. The M&V contractor is free to propose options providing greater rigor than the minimum specified in this Protocol.

Measure Installation Verification

The objectives of measure installation verification are to confirm that the measures were actually installed, the installation meets reasonable quality standards, and the measures are operating correctly and have the potential to generate the predicted savings. Installation verification shall be conducted at all sites claiming energy or peak demand impacts where M&V is conducted. Installation verification activities may also be specified by the Process or Market Effects Protocols.

Measure Existence

Measure existence shall be verified through on-site inspections of facilities. Measure, make and model number data shall be collected and compared to participant program records as applicable. Sampling may be employed at large facilities with numerous measures installed. As-built construction documents may be used to verify measures such as wall insulation where access is difficult or impossible. Spot measurements may be used to supplement visual inspections, such as solar transmission measurements and low-e coating detection instruments to verify the optical properties of windows and glazing systems.

Installation Quality

Measure installation inspections shall note the quality of measure installation, including the level of workmanship employed by installing contractor toward the measure installation and repairs to existing infrastructure affected by measure installation, and physical appearance and attractiveness of the measure in its installed condition. Installation quality guidelines developed by program implementer shall be used to assess installation quality. If such guidelines are not available, they shall be developed by the M&V contractor and approved by the Joint Staff prior

[50] TecMarket Works, pages 287-314.

to conducting any verification activities. Installation quality shall be determined from the perspective of the customer.

Correct Operation and Potential to Generate Savings

Correct measure application and measure operation shall be observed and compared to project design intent. For example, CFL applications in seldom used areas or occupancy sensors in spaces with frequent occupancy shall be noted during measure verification activities. At enhanced rigor sites, commissioning reports (as applicable) shall be obtained and reviewed to verify proper operation of installed systems. If measures have not been commissioned, measure design intent shall be established from program records and/or construction documents; and functional performance testing shall be conducted to verify operation of systems in accordance with design intent.

M&V Protocol for Basic Level of Rigor

The M&V Protocols for the Basic level of rigor are summarized in Table 5. Further explanations of the provisions of this Protocol follow the table. The M&V contractor is free to propose more rigorous M&V activities during evaluation planning or as directed by the Joint Staff evaluation managers.

Table 5. Summary of M&V Protocol for Basic Level of Rigor

Provision	Requirement
Verification	Physical inspection of installation to verify correct measure installation and installation quality
IPMVP Option	Option A[51]
Source of Stipulated Data	DEER assumptions, program work papers, engineering references, manufacturers catalog data, on-site survey data
Baseline Definition	Consistent with program baseline definition. May include federal or Title 20 appliance standards effective at date of equipment manufacture, Title 24 building standards in effect at time of building permit; existing equipment conditions or common replacement or design practices as defined by the program
Monitoring Strategy and Duration	Spot or short-term measurements depending on measure type
Weather Adjustments	Weather dependent measures: normalize to long-term average weather data as directed by the Impact Evaluation Protocol
Calibration Criteria	Not applicable
Additional Provisions	None

IPMVP Option

The standard M&V Protocol shall conform to IPMVP Option A - Partially Measured Retrofit Isolation.[52] Savings under Option A are determined by partial field measurement of the energy

[51] Exceptions to this provision are programs offering comprehensive measure packages with significant measure interactions; commissioning, and retrocommissioning programs; and new construction programs. Evaluation of measure savings within these programs conducted using engineering methods must follow the Enhanced rigor M&V Protocol and use building energy simulation modeling under IPMVP Option D.

[52] See the *Evaluation Framework*, pages 165-166.

use of the system(s) to which an energy conservation measure (ECM) was applied separate from the energy use of the rest of the facility. Measurements may be either short-term or continuous. Partial measurement means that some parameter(s) affecting the building's energy use may be stipulated, if the total impact of possible stipulation error(s) is not significant to the resultant savings. Savings are estimated from engineering calculations based on stipulated values and spot, short-term and/or continuous post-retrofit measurements. Field-verified measure installation counts applied to deemed savings estimates do not meet the requirements of this Protocol.

Sources of Stipulated Data

Stipulated data may be taken from DEER unit energy savings analysis assumptions, efficiency program work-papers, secondary research, engineering references, manufacturers' catalog data, and/or on-site survey data as applicable. Values and sources for stipulated values must be documented in the M&V plan.

Baseline Definition

The baseline used for M&V activities shall be consistent with the baseline definition used by the program. This may include applicable state and/or Federal efficiency standards for appliance or building energy efficiency, existing equipment efficiency or common replacement or design practices as defined by the program evaluated.

Monitoring Strategy and Duration

Spot or short-term measurements may be used, provided the measurement strategy and duration is sufficient to allow calculation of energy and peak demand savings within the uncertainty bounds prescribed by the Impact Evaluation Protocol. Pre-installation monitoring may be required in some cases to meet the applicable uncertainty requirements.[53] The *Evaluation Framework* provides more information on monitoring strategy and duration.[54]

Weather Adjustments

Impacts of weather-dependent measures shall be normalized to long-term average weather data as directed by the Impact Evaluation Protocol. Weather conditions prevailing during the monitoring period must be reported. Weather data may be obtained from the nearest representative NOAA or utility weather station or collected on-site. Techniques used to perform the weather adjustments must be documented.

M&V Protocol for Enhanced Level of Rigor

The M&V Protocols for the Enhanced level of rigor are summarized in Table 6. Further explanations of the provisions of this Protocol follow the table. The M&V contractor is free to propose more rigorous M&V activities during evaluation planning or as directed by the Joint Staff evaluation managers.

[53] Specific requirements for pre-installation monitoring are not stated in this Protocol, but are a consequence of the uncertainty analysis conducted during M&V planning.
[54] TecMarket Works, 182-188.

Table 6. Summary of M&V Protocol for Enhanced Level of Rigor

Provision	Requirement
Verification	Physical inspection of installation to verify correct measure installation and installation quality. Review of commissioning reports or functional performance testing to verify correct operation
IPMVP Option	Option B or Option D
Source of Stipulated Data	DEER assumptions, program work papers, engineering references, manufacturers catalog data, on-site survey data
Baseline Definition	Consistent with program baseline definition. May include federal or Title 20 appliance standards effective at date of equipment manufacture, Title 24 building standards in effect at time of building permit; existing equipment conditions or common replacement or design practices as defined by the program
Monitoring Duration	Sufficient to capture all operational modes and seasons
Weather Adjustments	Weather dependent measures: normalize to long-term average weather data as directed by the Impact Evaluation Protocol
Calibration Criteria	Option D building energy simulation models calibrated to monthly billing or interval demand data. Optional calibration to end-use metered data
Additional Provisions	Hourly building energy simulation program compliant with ASHRAE Standard 140-2001

IPMVP Option

The Enhanced rigor M&V Protocol shall conform to IPMVP Option B - Retrofit Isolation[55] or IPMVP Option D - Calibrated Simulation.[56] Under Option B, savings are determined by field measurement of the energy use of the systems to which the ECM was applied separate from the energy use of the rest of the facility. Savings are estimated directly from measurements. Stipulated values are not allowed. Under Option D, savings are determined through simulation of the energy use of components or the whole facility. Simulation routines should be demonstrated to adequately model actual energy performance measured in the facility. Savings are estimated from energy use simulation, calibrated with hourly or monthly utility billing data, and/or end-use metering.

Sources of Stipulated Data

Stipulations are not allowed under IPMVP Option B. Under IPMVP Option D, stipulated values used to define the energy simulation model are allowed. Sources of stipulated data may include DEER unit energy savings analysis assumptions, efficiency program work papers, secondary research, engineering references, simulation program default values, manufacturers' catalog data and/or on-site survey data as appropriate. It is impractical to list and reference all data used to define a simulation model. However, model input assumptions that are highly influential in predicting energy and/or peak demand savings shall be identified and documented within the

[55] See the *Evaluation Framework*, pages 166-168.
[56] See the *Evaluation Framework*, pages 176-182.

M&V plan. Simulation program name, full version number including applicable release information, and input files shall be provided as documentation.

Baseline Definition

The baseline used for the M&V activities shall be consistent with the baseline definition used by the program. This may include applicable state and/or federal efficiency standards for appliance or building energy efficiency, existing equipment efficiency or common replacement or design practices as defined by the program evaluated.

Monitoring Strategy and Duration

Monitoring shall be sufficient to capture all operational modes and seasons applicable to measure performance. Pre-installation monitoring may be required in some cases to meet the applicable uncertainty requirements.[57] The *Evaluation Framework* provides more information on monitoring strategy and duration.[58]

Weather Adjustments

Impacts of weather-dependent measures estimated under Option B shall be normalized to long-term average weather data for CEC CTZ in which the site is located. Weather conditions prevailing during the monitoring period must be reported. Weather data may be obtained from the nearest representative NOAA or utility weather station or collected on-site. Techniques used to perform the weather adjustments must be documented. Simulation analysis under Option D shall be conducted using long-term average weather data for CEC CTZ in which the site is located.

Calibration Targets

Building energy simulation models developed under Option D shall be calibrated to monthly energy consumption data. If interval demand data are available, these data shall be used in lieu of monthly energy consumption data. If the modeled floor space area does not match the metered floor space area within ± 20 percent, model calibration is not required. Modelers shall make reasonable attempts to meet the calibration targets listed in Table 7 below. In some cases, forcing a model to meet a particular calibration target may introduce biases in the energy savings estimates. Models not meeting the calibration targets shall be identified and reasons why it is not reasonable to meet these targets must be documented. The Joint Staff may impose additional requirements for short-term end-use monitoring of systems affected by the energy conservation measure during evaluation plan development and review.

Table 7. Model Calibration Targets

Data Interval	Maximum Root Mean Square (RMS) Error	Maximum Mean Bias Error
Monthly	± 15%	± 5%
Hourly	± 30%	± 10%

[57] Specific requirements for pre-installation monitoring are not stated in this Protocol, but are a consequence of the uncertainty analysis conducted during M&V planning.
[58] TecMarket Works, 182-188.

Additional Provisions

Building energy simulation programs used under Option D shall be compliant with ASHRAE Standard 140-2001.[59] For example, a partial list of programs compliant with the Standard is shown in Table 8 below:

Table 8. Programs Compliant with ASHRAE Standard 140-2001 (Partial List)

Program	Sector(s)
Micropas	Residential
DOE-2	Residential and Commercial
EnergyPlus	Residential and Commercial

Software using any ASHRAE Standard 140-complaint program as a calculation engine shall be in compliance with this provision of the Protocol.

M&V Approach Examples

This section provides examples of M&V approaches as they apply to specific measure types and rigor levels. The examples are provided for general guidance; M&V contractors are free to proposed M&V plans that are compliant with the Protocols and make sense for the specific site conditions. Example IPMVP options by measure type and rigor level are shown in Table 9 below:

Table 9. Example IPMVP Options by Measure Type and Rigor Level

Measure Type	Basic Rigor Level	Enhanced Rigor Level
Appliances	A	B
Commissioning and O&M programs	D	D
Comprehensive	D	D
Envelope	D	D
Food Service	A	B
HVAC Controls	D	D
HVAC Equipment Efficiency	A	D
Lighting Controls	A	B
Lighting Efficiency	A	B
New Construction	D	D
Non-HVAC Motor Controls	A	B
Non-HVAC Motor Efficiency	A	B
Process	A	B
Refrigeration	A	D
Water Heating	A	B
Water Pumping/Treatment	A	B

[59] Programs used for non-HVAC simulation, such as industrial processes or refrigeration, do not need to comply with this provision of the Protocol.

Overall Results Reporting

For each M&V project conducted, the M&V contractor must submit a site-specific M&V report. This report is an addendum to the M&V plan submitted prior to conducting field activities and covers the site-specific M&V results and final uncertainty analysis. In addition to the site-specific M&V reports, an overall M&V report shall be filed for each program where M&V activities were conducted within the scope of an individual M&V project contract. The overall M&V report shall include a discussion on the potential sources of bias in the results and steps taken to control and minimize bias, as discussed in the Sampling and Uncertainty Protocol.

Results shall be reported according to the Reporting Protocol and shall conform to the DEER database format as shown in

APPENDIX A. Measure-Level M&V Results Reporting Requirements**.** Energy and peak demand savings resulting from weather dependent measures shall be reported under weather conditions prevailing during the course of the M&V project. These weather conditions shall be reported along with the energy and peak demand impact information. The impacts shall be normalized to standard weather conditions as directed by the Impact Evaluation Protocol.

Sampling Strategies

M&V projects will be conducted on a sample of program participants and non-participants, as directed by the Impact Evaluation Protocol. Samples drawn for M&V projects shall be congruent with the impact evaluation sample or be nested within the impact evaluation sample where possible. Justification for drawing samples for M&V projects independently from the impact evaluation sample must be provided.

Early scheduling of M&V studies to provide feedback to the program implementer shall be considered in the sample design process. Participant samples for M&V activities may need to be drawn in stages, before the full participant population is established. If problems are identified in early M&V activities and corrected by the implementer, follow-up surveys on a sub-sample of sites may be required to verify that the program delivery modifications are effective.

Samples of measures selected for monitoring at a particular site shall be representative of all measures at the site and shall be selected at random. Measures within a building are often grouped according to similar usage patterns, thus reducing the expected variability in the measured quantity within each usage group. Within each usage group, the sample unit may be the individual measure, a particular circuit or point of control as designated by the M&V plan. Sample units shall be selected at random. Systematic sampling with random start is acceptable. The sampling strategy shall address all measures present at the site that are subject to the M&V study. Target uncertainties for sample designs are specified in the Sampling and Uncertainty Protocol.

Skills Required for M&V

Simple engineering equations and simple instrumentation such as run-time data loggers can be understood and used by people with a general science or engineering background.[60] Specific training in the use of building energy simulation programs and instrumentation systems is advised but not required.

Summary of Protocol-Driven M&V Activities

1	Receive input from impact evaluation plan. Receive M&V site selection and expected rigor level from the impact evaluation plan.

[60] The Association of Energy Engineers (AEE) offers a certificate for a Certified Energy Manager (CEM) and a Certified Measurement and Verification professional (CMVP). The material covered in the CEM program is good background for understanding energy engineering concepts addressed by measurement and verification. The CMVP program provides additional training and certification specific to M&V projects.

2	Develop overall M&V plan. The M&V option for each site shall be established according to the rigor assignment and allowable options under the Impact Evaluation Protocol. Project baseline definition with justification shall be reported. Overall M&V planning shall consider the needs of process evaluation studies for measure installation verification and measure performance information. The overall M&V plan shall be submitted for approval to the evaluation project manager as designated by the CPUC-ED.
3	Assess data sources. For each sampled site, the data resources for the engineering analysis must be identified and reviewed. Data sources may include program descriptions, program databases, DEER estimates and underlying documentation, program work papers and on-site surveys. Uncertainties associated with engineering parameters must be estimated. Baseline uncertainties, where not explicitly documented elsewhere, may be informed by professional judgment.
4	Conduct uncertainty analysis. The uncertainty in the estimated savings must be estimated using a propagation of error analysis. The parameters having the greatest influence on the uncertainty must be identified from the propagation of error analysis.
5	Develop site-specific M&V plan according to the outline in the M&V Protocols. The M&V plan must address data collection conducted to reduce uncertainty in the engineering estimates of savings. Sampling of measures within a particular site shall be done in accordance with the Sampling and Uncertainty Protocol. The site-specific M&V plan shall be submitted for review and approval to the evaluation project manager designated by the CPUC-ED prior to commencing field data collection.
6	Conduct pre- and/or post-installation monitoring as indicated by M&V plan. Data collection must be conducted in accordance with the site-specific M&V plan. Changes to the M&V plan resulting from unanticipated field conditions shall be documented and submitted to the evaluation project manager designated by the CPUC-ED.
7	Conduct data analysis and estimate site-specific savings. Conduct analysis of field data and estimate site savings in accordance with site-specific M&V plan. Energy savings estimates for weather-dependent measures shall be normalized to long-term average weather conditions as directed by the Impact Evaluation Protocol.
8	Prepare site-specific M&V report. Prepare a site-specific M&V report for each site used in the analysis that includes the site-specific M&V plan, data collection, data analysis, calculation of measured engineering parameters and overall savings estimates. Calculate the uncertainties associated with energy savings estimates and measurement-derived engineering parameters. The site-specific uncertainty analysis shall include an estimate of the sampling error associated with individual measure sampling within the site, measurement error associated with field data collection and uncertainties associated with any non-measured (deemed) parameters. Potential sources of bias associated with the measurements and engineering analysis shall be identified and steps to minimize the bias shall be reported in accordance with the Sampling and Uncertainty Protocol.
9	Prepare draft overall M&V report. A draft overall M&V project report shall be submitted to the CPUC-ED that meets all the requirements of the Reporting Protocol, demonstrates compliance with the overall M&V plan developed in step 2 and summarizes the results from each site. Site-specific M&V reports shall be included as an Appendix. Raw field data and data analysis results shall be supplied electronically in accordance with the Reporting Protocol.
10	Prepare final overall M&V report. Prepare final overall M&V report in accordance with review comments provided by the Joint Staff.
11	Submit final M&V report. Submit final M&V report and associated datasets to the CPUC-ED.
12	Post final M&V report on the CALMAC Web site. Once accepted by the CPUC-ED, develop abstracts and post them and final M&V report on the CALMAC Web site following the CALMAC posting instructions.

Emerging Technologies Protocol

Introduction

The Statewide Emerging Technologies Program (ETP) is an information-only program that seeks to accelerate the introduction of innovative energy efficient technologies, applications and analytical tools that are not widely adopted in California. The overall objective of the ET Program is to verify the performance of new energy efficiency innovations which can be transferred directly into the marketplace and/or integrated into utility portfolios in support of resource acquisition goals for energy efficiency. Emerging technologies may include hardware, software, design tools, strategies and services. Finally, it is recognized that such programs are expected to have a number of failures[61] (technologies that do not perform as expected) given the inherent risks[62] associated with the technologies selected for investigation.

Because of the absence of energy and demand goals and the longer lead time required to introduce new technologies directly into the market and/or into utility energy efficiency programs, a separate Protocol has been prepared to guide the ETP evaluation. The evaluation approach in this Protocol is theory-driven and is based on monitoring the full range of activities, outputs, and immediate, intermediate and long-range outcomes. This approach explicitly recognizes that while many, if not all, of these outputs and outcomes are difficult, if not impossible, to monetize, they can be documented and monitored over time to assess whether the program is on track to achieve the ultimate impacts[63].

Because the ETP and other similar programs will evolve over time, the ETP Protocol is designed to be flexible so that the evaluation, measurement, and verification (EM&V) requirements will apply not only to the 2006-2008 ETP but to future ETP designs as well. Of course, the ETP Protocols will also evolve as evaluators gain experience in evaluating such programs.

This Protocol insures a minimum level of evaluation rigor in order to ensure stakeholders that the performance of the emerging technology programs is on-track to achieve their longer-term

[61] There are two types of failure: 1) failure of the technology to perform as expected (note: such failures can provide valuable information to members of the various target audiences), and 2) the failure of the utility to select promising technologies such that a reasonable number of new technologies are not being funneled into utility energy efficiency programs. This Protocol will address both types of failure.

[62] Risk involves the exposure to a chance of injury or loss (Random House, 1966). Hardware, software, design tools, strategies and services (products) have varying levels of uncertainty as to whether they will perform as expected. Thus, investing in these products assumes varying levels of risk that the return on these investments might not be fully realized (i.e., there will be a loss).

[63] Unlike the methods identified in the Impact Protocol, the methods for evaluating the benefits of public investment in RD&D and related emerging technology programs are not nearly as advanced. However, it has been recognized by many that stakeholders should not have to wait three to five to ten years before discovering whether projects with relatively long times are successful (Lee, Russell, Gretchen Jordan, Paul Leiby, Brandon Owens, James Wolf (2003); Link, Albert N. (1996); Ruegg, Rosalie and Irwin Feller (2003); Shipp, Stephanie, Aaron Kirtley, and Shawn McKay (2004); U.S. Department of Commerce, Advanced Technology Program, National Institute of Standards and Technology, Technology Administration (2001); U.S. Department of Commerce, Advanced Technology Program, National Institute of Standards and Technology, Technology Administration. (2001)). There is agreement among many researchers that one should be able to identify immediate and intermediate indicators that can reassure stakeholders that the efforts are on track to achieve such objectives as successful deployment of new technologies into utility energy efficiency programs and the bridging of the "chasm", leading eventually to significant energy and demand impacts.

objectives. This Protocol also provides a wide array of allowable methods in order to offer flexibility for the potential evaluation contractors to propose the most reliable and cost-effective methods that meet the Joint Staff's needs for a given set of evaluation objectives.

Audience and Responsible Actors

The audience and responsible actors for this Protocol include the following:

- Joint Staff evaluation planners – will use the Protocol (1) as input into the ETP evaluation RFPs, and (2) as background and criteria for use in reviewing ETP evaluation plans, managing the ETP evaluations, and reviewing ETP evaluation reports and results.
- Evaluation project team – will use the Protocol to ensure that their detailed ETP evaluation plan(s) meets the requirements in the Protocol. They will also use the Protocol to double-check that the Protocol requirements have been met as they conduct, complete and report the ETP evaluations.
- Portfolio administrators – will use the Protocol to understand how the ETP evaluation will be conducted and to understand the evaluation data needs to support the ETP evaluation. In addition, the Protocol provides background for the administrator's use to determine when to intervene in the program design and implementation efforts to achieve continued and/or greater efficiency gains.
- Program implementers – will use the Protocol to understand the ETP evaluation that will be conducted on their programs and program components. Often, they will be required to provide data to support the evaluation.
- PIER Program administrators – will use the Protocol to understand the ETP evaluation because the activities of the PIER are linked to the activities of the ETP. In some cases, they may be required to provide data to support the evaluation.

Key Metrics, Inputs, and Outputs

ETP evaluations will rely on both secondary and primary data related to various indicators associated with program inputs (e.g., budgets and staff), outputs (e.g., technical reports, articles published, and software) and outcomes (e.g., change in awareness, reduction of performance uncertainty and an increase in adoption rates in the targeted population). *Secondary data* can include, among others, data from program databases, program descriptions, Emerging Technologies Coordination Council (ETCC) databases, work papers developed during program planning, technical reports, white papers, conference papers, on-site measurement and monitoring, and other prior study data and reports. *Primary data* can include, among others, observational data (e.g., on-site visits to demonstration sites), surveys and in-depth interviews with members of the various target populations as well as those who host a demonstration project. Peer reviews can also be conducted using independent experts. *Energy and demand impacts are not performance indicators for the ETP since it is an information-only Program*. These longer-term energy and demand impacts are more appropriately the focus of impact evaluations which will be conducted for utility resource acquisition and market transformation programs after the "new" ETP technologies are deployed in these programs. A more complete listing of possible indicators is provided later in this Protocol. Finally, which data to collect and what to report are contingent on the size of the evaluation budget, the indicators identified in the program theory and logic model as being the most important, and the chosen methods.

These data will be used within the ETP Protocol's selected methods, a more detailed sample of which is presented later in this Protocol, and conducted through a Joint Staff approved evaluation plan. Unlike resource acquisition programs which are focused on net energy and demand impacts, the performance of the ETP will be based on the preponderance of evidence associated with the analysis of a relatively large number of diverse indicators.

The actual information included in a given report will vary depending on the methods chosen. The specific information to be reported from each study must be determined by the Joint Staff in close collaboration with the independent evaluator.

Evaluation Planning

Once an independent evaluator is hired, the evaluator must prepare a final detailed evaluation work plan that allocates the study's finite resources to maximize the value and use of the information collected while taking into account the requirements of the ETP Protocol. As part of this plan, the evaluator must specifically address the various sources of potential error that are relevant and explain how the resources allocated to each will mitigate the error[64]. The evaluation should also focus on gathering information on specific project and program goals and expectations early in the program cycle from the administrators so that plans can be made to insure that the necessary data are collected.

When samples are used, the ETP evaluation must follow the Sampling and Uncertainty Protocols. Evaluators must assess, minimize, and mitigate potential bias and present, when relevant, the achieved level of precision (including relative precision, error bounds, coefficient of variations, and standard deviations) for interpreting information. It is expected that the aggregate analysis, described later in this Protocol, of *all* ETP projects must first be conducted in order to inform the sampling plan (e.g., the aggregate analysis should shed some light on useful stratification schemes).

The Joint Staff, and other outside stakeholders as deemed appropriate by the CPUC, will review the evaluation plan submitted and discuss with the independent evaluator any tradeoffs they deem necessary to maximize the reliability of the ETP performance assessment. For example, if surveys are conducted of various target audiences, Joint Staff can decide to increase the sample sizes in order to increase precision, recognizing that other sources of error will receive fewer resources or that additional resources may be required to support the change. Or, Joint Staff can decide to reduce the sample sizes and settle for lower precision in exchange for a greater effort to reduce, for example, non-response bias. In the final plan, evaluation resources will be allocated in a way that is consistent with cost-efficient evaluation, i.e., where evaluation resources are set and allocated at levels that maximize the value received from these resources.

[64] In the pre-1998 Protocols, there was no requirement to address these sources of error in the research plan. Evaluators only had to describe in the final report whether they had to address these various errors and, if so, what they did to mitigate their effects. See Chapter 12 of the *California Evaluation Framework* for further details.

A Sample of Available ETP Evaluation Methods

One of the goals of the ETP Protocol is to combine progress measures for different types of projects in such a way that provides a meaningful assessment of the effectiveness of the ETP program in reaching portfolio level goals like accelerating the introduction of new technologies into utility energy efficiency programs and/or directly into the marketplace. A review of the evaluation literature reveals a number of approaches that could be applied to the ETP evaluation. The following table lists and briefly discusses a number of these methods.

Table 10. Sample of Available ETP Evaluation Methods

Method	Brief Description	Example of Use
Analytical/conceptual modeling of underlying theory	Investigating underlying concepts and developing models to advance understanding of some aspect of a program, project, or phenomenon.	To describe conceptually the paths through which projects evolve or through which spillover effects may occur and validate the underlying theory.
Survey	Asking multiple parties a uniform set of questions about activities, plans, relationships, accomplishments, value, or other topics, which can be statistically analyzed.	To find out how many members of a given target audience have been informed about a given technology through the dissemination efforts of the ETP.
Case study - descriptive	Using single-case or multiple-case designs with single or multiple units of analysis for investigating in-depth a program or project, a technology, or a facility, describing and explaining how and why developments of interest have occurred.	To recount how a particular joint venture (e.g., between the ETP and a customer who hosts a technology demonstration; between the ETP and a manufacturer) was formed, how parties shared research tasks, and why the collaboration was successful or unsuccessful.
Sociometric and social network analysis	Identifying and studying the structure of relationships by direct observation, survey, and statistical analysis of secondary databases to increase understanding of social/organizational behavior and related economic outcomes.	To learn how projects can be structured to increase the diffusion of resulting knowledge.
Bibliometrics - counts	Tracking the quantity of research outputs.	To find how many publications per applied research dollar a technology assessment generated.
Bibliometrics - citations	Assessing the frequency with which others cite publications or patents and noting who is doing the citing.	To learn the extent and pattern of dissemination of a technology assessment's publications and patents.
Bibliometrics - content analysis	Extracting content information from text using techniques such as co-word analysis, database tomography, and textual data mining, supplemented by visualization techniques.	To identify a project's contribution, and the timing of that contribution, to the evolution of a technology.

Historical tracing	Tracing forward from research to a future outcome or backward from an outcome to precursor contributing developments.	To identify apparent linkages between a ratepayer-funded applied research project and something of significance that happens later or has already occurred.
Expert judgment/Peer Review	Using informed judgments to make assessments.	Experts can be called upon to give their opinions about the technical quality and effectiveness of a technology assessment. The experts generally render their verdict after reviewing written or orally presented evidence.

Source: Adapted from Ruegg and Feller (2003)

Protocols Requirements

There is only one level of rigor for the ETP Protocols which has eight required components.

Verification of Basic Achievements

In their 2006-2008 program implementation plans, each utility has established three basic goals that are framed in terms of:

- achieving a certain number of emerging technology application assessments[65],
- updating the Emerging Technology Database, and
- conducting a certain number of meetings annually of the Emerging Technologies Coordinating Council.

A straightforward verification of whether each utility has met these goals must be conducted. The 2006-2008 ETP verification should include:

- obtaining all relevant documentation of technology assessments launched during the program period[66],
- comparing the contents of the Emerging Technology Database before the program period and at the conclusion of the program period, and
- documenting the meetings of the Emerging Technologies Coordinating Council.

Beyond 2008, it is assumed that the utilities will continue have a set of basic goals that are amenable to such simple verification. However, independent evaluators must go beyond the simple verification of whether utilities have achieved these basic goals. The remainder of this Protocol describes those activities that must be conducted as a part of a rigorous and comprehensive evaluation of the ETP.

[65] The technology application assessments may consist of diverse project types including: feasibility studies, simulation analyses, field demonstrations, controlled environment tests, commercial product development, design methodologies and tool development. Some assessments may take up to four years to complete.

[66] Evaluation consultant contracts will include confidentiality and non-disclosure agreements to cover applicable documents.

Program Theory and Logic Model

Prior to the identification and quantification of performance indicators, the ETP program theory and logic model must be developed. The *California Evaluation Framework* of June 2004 defines program theory and makes an important distinction between a program theory and a logic model:

> A program theory is a presentation of the goals of a program, incorporated with a detailed presentation of the activities that the program will use to accomplish those goals and the identification of the causal relationships between the activities and the program's effects. The program theory describes, in detail, the expected causal relationships between program goals and program activities in a way that allows the reader to understand why the proposed program activities are expected to result in the accomplishment of the program goals. A well-developed program theory can (and should) also describe the barriers that will be overcome in order to accomplish the goals and clearly describe how the program activities are expected to overcome those barriers. A program theory may also indicate (from the developers perspective) what program progress and goal attainment metrics should be tracked in order to assess program effects.
>
> Program theories (PT) are sometimes called the program logic model (LM). A stricter definition would be to differentiate the program theory as the textual description while the logic model is the graphical representation of the program theory showing the flow between activities, their outputs, and subsequent short-term, intermediate, and long-term outcomes. Often the logic model is displayed with these elements in boxes and the causal flow being shown by arrows from one to the others in the program logic. It can also be displayed as a table with the linear relationship presented by the rows in the table. The interactions between activities, outputs, and outcomes are critical to understanding the program logic and argue for the need to have, or construct, both a program theory and a program logic model. (p. 31)

A more thorough discussion of program theory and logic models can be found in Chapter 4 of the *California Evaluation Framework*.

Describing the various ETP activities and how these activities interrelate to produce immediate, intermediate, and long-term outputs and outcomes is a necessary first step. These outputs and outcomes can be considered additional objectives beyond the three basic objectives describe above. Once described, the underlying theory must be explicated, i.e., why are these activities expected to achieve these outputs and outcomes. As part of this process, immediate, intermediate, and long-term indicators of progress toward the ultimate goals will be identified. Some of these indicators are easily quantifiable (number of papers and patents, amount of additional investment) and others are somewhat more difficult to quantify (changes in behavior, changes in procedures). *While the indicators pursued by the independent evaluator should be guided by the logic model, there might be other indicators that the CPUC wishes to pursue that are related to objectives other than those explicitly noted in the logic model.*

As a part of the development of the program logic model, the various target audiences for the ETP activities must be identified. Once the program theory and logic model have been developed, future evaluation efforts must review the logic model and theory to determine if changes are needed. Finally, it is recognized that, while there will be a statewide ETP theory and logic model, it is possible that utility-specific program theories and logic models will be required if each utility's ETP deviates in important ways from the statewide theory and logic model.

Aggregate Level of Analysis

The aggregate analysis is designed to achieve two objectives:

- To describe, for each utility, the basic components or elements that make up the ETP and provide the necessary broader context for assessing the performance of the ETP (e.g., budgets, FTEs, types of technology assessments, average duration of projects, collaboration with other institutions/agencies, etc), and
- To determine, for each utility, the extent to which the overarching program and policy objectives have been met (e.g., addressing the needs of all customer sectors, assuming acceptable levels of risk, etc.).

The aggregate analysis involves the analysis of a variety of data collected for *all* of the projects in each utility's ETP portfolio. Such a level of analysis provides a statistical overview of the ETP portfolio (e.g., frequencies, cross tabulations, means etc.) across multiple projects and participants in order to achieve the two objectives listed above. The analysis of these aggregate data will allow one to address a number of contextual, program and policy questions, such as:

1. What are the various sources of funding, (PGC, academic institutions, manufacturers, government agencies, etc.), by type of technology assessment?
2. How many full-time equivalent ETP employees are involved by type of technology assessment?
3. How does PGC funding and co-funding vary by type of technology assessment by sector over time?
4. How does PGC funding and co-funding vary by end use and/or by sector over time?
5. What is the frequency of the various types of technology assessments, by end use, over time?
6. How is risk being balanced (e.g., measures that do not perform as expected versus those that do)?
7. What is the average duration of a technology assessment?
8. Are the technology assessments proportionately focused on sectors and end uses in which there are the greatest expected potential energy and demand benefits?
9. How many technology assessments are launched annually?
10. How many technology assessments are currently active?
11. What percent of the technologies sponsored by the ETP have been deployed into utility energy efficiency program and/or directly into the marketplace?
12. Are there imbalances in the types of projects funded?
13. Are the needs of all the sectors being adequately addressed?

Data for ETP assessment can be collected using a survey of key ETP staff along with extracts from the program database or ETCC database. *Examples* of data that could be collected for the aggregate analysis include:

1. Funding by the PGC and by other entities (authorized budget, invoiced and committed)
2. Stage of development for each technology
3. Specific technologies and end uses
4. Expected long-term energy and demand benefits from each project (provided by ETP program staff and/or the ETCC database) and the possible timeline of those forecast.
5. Project initiation and completion (date on which all work has ceased) dates
6. Failures (technologies that do not perform as expected based on ETP analysis) as a percent of all projects
7. Subjective assessment of risk
8. Targeted sectors and population(s) within that sector,
9. Whether the technology has been deployed into a utility energy efficiency program and/or directly into the marketplace.

The eventual list of key variables will be determined in close collaboration with the CPUC-ED, the independent evaluator and ETP staff.

Implementation Analysis

The final task is to conduct a program- and utility-specific analysis to determine whether there have been any deviations from the program implementation plan, as described in the program theory and logic model. Any deviations from the plan and implementation problems must be explained. This analysis must focus on such issues as the selection process used by ETP managers to select "promising" projects, collaboration between PIER, the ETP, and utility program staff, and unanticipated problems and their resolution. This analysis must be initiated early in the program period so that any necessary corrective guidance can be provided to program administrators on an on-going basis. *Independent evaluators should look for opportunities to collaborate with utilities, which are responsible for conducting process evaluations of the ETP*.

Measure Tracking

Those technologies that have been deployed to utility energy efficiency programs must be tracked over time to determine their adoption rates[67] and resulting energy and demand impacts. Adoption rates and energy and demand impacts are useful indicators of how well the ETP screened promising technologies and developed strategies, in close collaboration with the utility-sponsored energy efficiency programs, to cross the "chasm". The goal of this component of the Protocol is ***not*** to attribute these savings directly to ETP as a resource, but to show a clear trail of which ETP technologies are being accelerated into utility energy efficiency programs. Only by planning for this type of tracking can an evaluation adequately answer the future questions posed by key stakeholders regarding the ultimate impacts of ETP activities.

[67] Adoption rates (e.g. the number of measures adopted on an annual basis) for various measures installed through utility resource acquisition programs and associated energy and demand impacts will be obtained from utility program tracking databases. This is generally considered as distinct from a market penetration rate or a saturation rate.

While the previous five components are focused on the entire ETP, including all of the technology assessments, the next three components focus on samples of projects.

Detailed Analysis of Key Performance Indicators

This component involves the collection of additional data that address a number of areas, such as: 1) knowledge creation, 2) knowledge dissemination 3) technical progress, 4) progress towards commercialization, and 5) the deployment of new measures to utility-sponsored energy efficiency programs. Specifying the indicator variables for the ETP should be guided by the ETP logic model, which identifies short, intermediate, and long-term outcomes associated with diverse projects. Some *examples* of project-level indicators for which data could be collected are:

- knowledge created
    - technical papers
    - articles published
    - technical reports
    - conference presentations
    - fact sheets
    - brochures
- knowledge disseminated
    - technical reports distributed and to whom
    - number and content of workshops and professional forums
    - conference presentations, topics and dates and estimated size of audience
    - number of fact sheets distributed and to whom
    - brochures distributed and to whom
    - websites created (includes hits on the websites and downloads)
    - bibliometric counts
- number of demonstration projects
- performance data collected at demonstration sites
- technical and market barriers overcome, technical milestones met, and significant knowledge gained
- remaining technical and market barriers
- prototypes developed and prototypes passing performance tests
- patents (both filed and granted)
- licenses
- awards for excellence
- interviews with those hosting the demonstration projects
- collaboration with manufacturers
- the number and description of new measures being deployed directly into the marketplace and/or into utility programs.

Depending on the nature of the project, one could also examine the extent to which the project has attracted capital for advancing commercialization objectives, including resources provided by any funding partners.

Finally, for each selected project, the reasons why it was selected must be discussed in terms of the selection criteria. Such topics as the technology's technical and economic energy and demand potential, description of the targeted populations, the identified risk factors, market barriers, the existence of known delivery channels, and the evidence that there was a need to need for a bridging function could be discussed.

All data must be systematically analyzed so that an overall assessment of each utility's ETP with respect to its specific objectives can be conducted by the independent evaluator. These objectives must be determined early in the program cycle, as part of the development of the logic model, so that a plan to gather the necessary data can be designed.

If there are fewer than 30 projects[68] within a given utility during the program period, a census of all projects must be conducted. If there are more than 30 projects, then a random sample of projects must be evaluated. The size of the sample must be determined by the independent evaluator in close collaboration with the Joint Staff. The sample design must be informed by the aggregate analysis. In addition, the sample of projects for each utility should be stratified by size of budget, the level of uncertainty regarding success, or the magnitude of expected benefits. The stratification variable will be selected after the aggregate analysis.

This next two components have two objectives: 1) to conduct a more rigorous assessment of the technical achievements of selected ETP projects through the use of a peer review panel[69], and 2) to provide a more definitive assessment of the extent to which the "chasm", defined as a discontinuity in the product life cycle that occurs from early adopter to the mass market (Moore, 2002)[70], has been bridged. Projects selected for these next two components should be nested within the sample of those selected for Detailed Analysis of Key Performance Indicators.

Peer Review

A random sample of the ETP projects for each utility must be subject to a technical review using the peer review process. For example, such projects as the laboratory testing of refrigeration measures could be subjected to a technical review in order to evaluate the quality of the research process and output (e.g., whether the design of the study was sound, whether the project provided any new insights on the assessed technology). The focus should be on those projects in the highest strata (i.e., those with the largest budgets, the greatest uncertainty regarding success, or the greatest expected benefits identified in the previous component, *Detailed Analysis of Key Performance Indicators.* The number of projects that are peer reviewed for each utility and the extent of each review must be determined based on the size and complexity of projects and the size of the evaluation budget.

[68] A project can cover a variety of activities associated with a technology application assessment including feasibility studies, simulation analyses, field demonstrations, controlled environment tests, commercial product development, design methodologies and tool development. Some assessments may take up to four years to complete.

[69] See the *Peer Review Guide* prepared by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) Peer Review Task Force, 2004.

[70] The chasm separates the early adopters from the early majority. Crossing the chasm requires that those in the early majority receive something that the early adopters do not need, the needed assurances from trusted sources regarding new technologies. Many new products fail because they are not able to cross the chasm in terms of new product design and marketing strategy, from the early market (early adopter) to the mass market (early majority).

Peer reviewers will be selected by the evaluation contractor in close collaboration with the CPUC-ED with input from the utilities. Each potential reviewer will be asked to identify any areas related to this project where a conflict or appearance of conflict could exist and explain the nature of that conflict. A key resource regarding the use of peer reviewers is the "PEER REVIEW GUIDE: Based on a Survey of Best Practices for In-Progress Peer Review." This document was prepared in 2004 by the Office of Energy Efficiency and Renewable Energy (EERE) Peer Review Task Force for U.S. Department of Energy, Energy Efficiency and Renewable Energy.

Target Audience Surveys

To assess the extent to which the chasm is being crossed, surveys[71] of members of the various target audiences (end users and those upstream from the end users including those who request materials, download materials, are directly sent materials, visited demonstration sites, and attended conferences and workshops) must be conducted in order to determine the impact of knowledge dissemination on the targeted populations with respect to any reductions in key market barriers and any subsequent increases in the adoption of ETP technologies. Of course, this requires that in the development of the program logic model the various target audiences for the ETP activities must be identified and that baselines are established so that progress can be measured.

Integration of Results

The results for each utility must be aggregated across the projects examined so that, based on the preponderance of the evidence, conclusions regarding a utility's performance with respect to its entire ETP portfolio can be assessed. These results must then be aggregated across utilities so that the performance of the statewide ETP, based on the preponderance of the evidence, can also be assessed. Various approaches to aggregating performance indicators are available including Keeney and Raiffa (1993), Reugg and Feller (2003), and Shipp et al. (2004).

Reporting of Results

The Emerging Technology Program Evaluation will be reported consistent with the requirements for all evaluation reports described in the Reporting Protocol in the section entitled "Common Evaluation Reporting Requirements." In addition, the following elements should be included in the evaluation reports under the Methods heading.

- Program Theory and Logic Model
- Goal Verification
- Aggregate-Level Analysis
- Implementation Analysis
- Measure Tracking
- Detailed Analysis of Key Performance Indicators
- Peer Review
- Target Audience Surveys

[71] Whenever surveys are based on samples, the *Sampling and Uncertainty Protocols* apply.

These presentations must be provided in enough detail that the differences (if any) in the methodological approach across different technologies and utilities can be understood by the reader. Finally, one must describe the approach for integrating the study results so that the overall performance of the ETP can be assessed.

The Reporting Protocols includes a requirement that all evaluation reports include a presentation of the detailed study findings. This presentation must be provided in enough detail that the different results or findings (if any) can be understood for each technology assessment covered in the study. The report should present the results of each of the required eight components contained in the ETP Protocol. Reports will be provided consistent with the Reporting Protocol.

Summary

The following table provides a summary of the Protocol that can be used to guide the evaluation efforts once the detailed contents of the Protocol are well understood.

Summary of Protocol-Driven Emerging Technology Evaluation Activities

1	Joint staff selects an evaluation contractor to implement the Emerging Technology Program evaluation.
2	The ETP managers, in collaboration with the evaluation contractor and the CPUC-ED, develop logic models and program theories to inform the evaluation plan.
3	The contractor works with the CPUC-ED on the development of the draft evaluation plan (with possible input from the program implementer) consistent with the ETP Protocol. As necessary, the plan must comply with the other Protocols (Impact Evaluation Protocol, Process Evaluation Protocol, Market Effects Protocols, the Sampling and Uncertainty Protocol and the Reporting Protocol) in the development of the evaluation plan and in the implementation and reporting efforts.
4	The CPUC-ED works with the evaluation contractor to finalize and approve an evaluation plan from which the contractor can begin the evaluation effort.
5	The contractor carries out all eight of the required Protocol requirements in order to measures key short, intermediate, and long–range performance indicators identified in the logic model.
6	The contractor reports the results of the final evaluation to the CPUC-ED and Joint Staff consistent with the provisions in the Reporting Protocol.
7	Once the report is accepted by the CPUC-ED, the contactor develops abstracts and posts the report on CALMAC web site following the CALMAC posting instructions.

Note: the steps included in this evaluation summary table must comply with all the requirements within the Emerging Technology Protocol in order to be in compliance. Any deviations from the Protocol must be agreed to by Joint Staff and fully documented within the evaluation plan and in the evaluation report.

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Codes and Standards and Compliance Enhancement Evaluation Protocol

Introduction

This Protocol covers approaches for evaluating codes and standards programs, and for evaluating code compliance enhancement programs. The primary focus of this Protocol is to present the approach for documenting savings from the California Codes and Standards Program and the evaluation of Code Compliance Programs yet to be developed and implemented. The Code Compliance Enhancement Protocol is being added at this time because the IOUs are considering the addition of compliance enhancement programs into their energy efficiency program portfolio. The Compliance Enhancement Program Evaluation Protocol is new and has never before been applied within the evaluation community. As a result it is designed to be flexible, allowing a wide range of approaches to be conducted once they are approved by the Joint Staff.

This Protocol describes how gross and net energy savings will be estimated for programs that change or contribute to a change in building codes or appliance standards that are expected to result in energy savings and programs that are implemented to increase the level of compliance with code requirements. It does not cover process evaluations or other types of evaluations that may address additional research goals. Other sections of the Protocols provide instructions on these studies. This Protocol identifies a series of evaluation-related activities that produce estimates of gross and net energy saving from Codes and Standards Programs and net energy savings from Code Compliance Programs. In addition, this Protocol identifies the audience and responsible actors associated with these evaluation efforts, the key metrics to be produced from the evaluations, the change theories and the logic models that need to detail the assumed causal relationships for achieving the savings, and the evaluation approach that is to be used to estimate gross and net program impacts. These issues are discussed below.

We note early in the Protocols that codes and standards evaluations that follow this Protocol are best contracted prior to and launched at the same time that the CEC is assessing which technologies should be considered for the next round of codes or standards changes. This effort is launched approximately three years before a change begins producing energy savings. The evaluations of the Code Compliance Enhancement Programs should be launched at the same time the programs are first launched so that baseline compliance assessment can be compared to post-implementation changes in compliance.

The evaluation contractor selected to conduct the evaluation of the Codes and Standards Programs will need to realize that the change theories and logic models developed by the program will be adjusted and expanded or contracted from time to time as new change-related causal relationships are identified and as program activities are modified to meet the program's objectives. These conditions will require a multi-year evaluation effort that is timed to the code program's change process rather than the program implementation cycles, so that the evaluation contractor can be charged with the responsibility to evaluate a specific set of assigned code or standard changes. As additional code changes are developed over time, additional evaluation contracts will be awarded to cover the code changes not included in the previous group of evaluated changes. This means that there will be periods of time in which multiple evaluation contracts may be in force to evaluate the program, but these studies will focus on a different set of changes.

The evaluation activities conducted under this Codes and Standards Protocol are established to be both prospective and retrospective. They are designed to assess events and conditions that occur in the future, such as the projected energy savings to be achieved. However, they are also designed to be retrospective, with true-up efforts that look back over time and adjust evaluation findings to reflect actual market conditions. As such the evaluations may be contracted in two phases, with the first phase being the assessment and projection of current and future savings, followed by true-up studies that look back and adjust the projected findings and energy savings to reflect actual construction, retrofit, and purchase patterns.

The evaluations conducted under the Codes and Standards Protocol will need to be staffed and managed to be adaptive to the different stages associated with the different activities of the change process that will occur at different times. The evaluation contractor must be aware that they will need to coordinate with the program administrators to be able to respond to the different efforts and activities with the right evaluation activities at the right time.

Finally, Both the Codes and Standards Protocol and the Compliance Enhancement Protocol included at the end of the Protocol is new to the evaluation industry. As they are used and tested over the next few program cycles it will need to be updated to reflect the experiences of the first sets of evaluations conducted under these Protocols. Likewise, all Protocols need to be updated periodically as new methods and approaches are developed and as the evaluation reporting needs change.

Audience and Responsible Actors

The audience and responsible actors for this Protocol include the following:

- <u>Joint Staff Evaluation Planners</u> – will use the Protocol to develop evaluation RFPs for the impact evaluation contracts to review and supervise the evaluation contractors to assure adherence to the Protocol, to describe the evaluation's focus and approach to the evaluation stakeholders and information consumers, and to meet other needs identified by the Joint Staff.
- <u>Evaluation Contractors</u> – will use the Protocol to develop their detailed evaluation plan in accordance with Protocol requirements and provide unbiased, objective, and independent evaluation results. They will use the Protocol to guide the evaluation effort and to ensure that the Protocol requirements have been met and the evaluation report provides the required information.
- <u>Portfolio Administrators</u> – will use the Protocol to understand how the evaluation will be conducted and what evaluation data needs and efforts are needed to support the evaluation. In addition, the Protocol provides background that administrators can use to determine when to intervene in the program design and implementation efforts to achieve continued and/or greater efficiency gains.

- Program Implementers – will use the Protocol to understand the evaluation that will be conducted on their programs and program components. Often, they will be required to provide data to support the evaluation. The Protocol will also provide background information that implementers can use to understand when to intervene to achieve continued and/or greater efficiency gains.

Key Inputs, and Outputs

There are several key Evaluation Protocol related inputs and outputs including the energy impacts caused by the program-induced changes. This section of the Protocol lists the key information inputs that are needed to conduct the evaluation and the key outputs that will be provided as a result of the evaluation.

Key Inputs
The major evaluation input metrics needed to conduct the evaluation efforts include:

1. Codes and Standards Program Theory and Logic Models,
2. Codes and Standards change descriptions,
3. Technology descriptions,
4. Program activity descriptions,
5. Identification of key codes and standards stakeholders,
6. Identification of the jurisdictions covered by the codes and standards changes,
7. Estimate of pre codes and standards technology adoption or penetration rates before changes to the code are made.

Key Outputs
The major outputs from the evaluation efforts include:

1. A listing of the technologies or practices influenced by the program that experienced an energy efficient code or standard change.
2. A listing of the code and standard changes that will be addressed in the evaluation. (Items 1 and 2 may be the same, but also may be different if the evaluation is addressing a subset of the changes.)
3. An estimate of the influence of the program on the code and standard changes for each technology or practice included in the evaluation.
4. An estimate of the naturally occurring market adoption rates for each technology or practice included in the evaluation.
5. An estimate of the date when each code or standard change would have occurred without the program for each technology or behavior included in the evaluation.
6. An estimate of the level of non-compliance expected for the technologies and practices covered in the evaluation over the period of time that savings are projected.
7. An estimate of gross and net market-level energy impacts for the program as a whole and for each technology and practice covered in the program and for each utility territory funding the program. This estimate of impacts should not exceed a 30-year effects lifetime.

Evaluation Methods

The evaluation of Codes and Standards programs requires an Evaluation Protocol that is guided by the Impact Evaluation Protocol. The primary approach to establishing an energy savings value for the Codes and Standards Program is to assess the energy impacts of the market adoption and decision changes caused by the code or standard change, and then adjust those savings to account for what would have occurred if the program never existed. The evaluation must identify the net energy impacts that can be directly attributed to the program's actions that would not have occurred over the course of the normal non-program influenced operations of the market.

The end result of the application of this Protocol is the identification of the net ex-post energy savings achieved from code and standard changes above and beyond what would naturally occur in the market through normal non-code/standard driven technology adoption behavior and through the normal cycle of codes and standards updating activities. The resulting net program-induced energy savings are the savings that are caused by the program's efforts.

The following sections of this Protocol describe the required efforts for evaluating these programs. We note that the evaluation of the Codes and Standards Program can be accomplished in a single multi-year study incorporating an assessment of the gross energy impacts from the code or standard changes, followed by the application of net adjustment approaches described in this Protocol to produce net effects. These two efforts can also be structured independently, as conducted in the 2005 study by the Heschong Mahone Group. That study relied on the energy impact estimates from previously conducted energy impact studies.

Evaluation Planning

Once an independent evaluator is hired, the evaluator must prepare a detailed evaluation plan that allocates the study's finite resources to maximize the value and use of the information collected. The plan must provide detailed task-level information and fully describe the data collection and analysis approaches that are to be conducted. The plan must be provided in enough detail that it can be replicated to achieve the same conclusions. As part of this plan, the evaluator must specifically address the various sources of relevant potential error and explain how the error will be mitigated[72].

The Impact Evaluation Protocol will guide the gross market-level energy impact estimates, and the Sampling and Uncertainty Protocol will guide the gross market-level energy impact estimates and the approaches for identifying net adjustments to the gross savings. In conducting this evaluation, evaluators must assess, minimize, and mitigate potential bias and, when relevant, present the achieved level of precision (including relative precision, error bounds, coefficients of variation, standard deviations, and error ratios) for interpreting the data.

[72] In the pre-1998 Protocols, there was no requirement to address these sources of error in the research plan. Evaluators only had to describe in the final report whether they had to address these various errors and, if so, what they did to mitigate their effects.

It is expected that a technology and behavior-specific code and standard application potential analysis will first be conducted to establish the population characteristics needed to inform the sampling plans associated with the evaluation. The potential analysis is an assessment that describes the current saturation and penetration of the specific technologies or behaviors that may be evaluated. The study then identifies the remaining potential that will be captured via a code or standard change. Alternatively, the evaluation will use market size estimates prepared by the Codes and Standards Program that have already projected the potential applications remaining in the market. If the program-developed potentials analysis is used, the evaluation contractor must first assess the methodological approach used by the program to determine the suitability for use in the evaluation effort and identify weaknesses in the projections that can influence the accuracy of the evaluation findings. If the assessment is found to be unreliable, the evaluation contractor will work with the Joint Staff to establish a methodology for estimating the market application potential and the characteristics of the markets needed to inform the study's sampling plans. This will help ensure that the gross and net energy impact estimates for the code or standard change is representative of the market in which the changes are to be measured.

The Joint Staff, and other outside stakeholders as deemed appropriate by the CPUC-ED, will review the evaluation plan submitted and discuss with the independent evaluator tradeoffs that are deemed necessary to maximize the reliability of the impact estimates. The Joint Staff can decide to modify the approach as necessary in order to increase precision or to improve the reliability of the study findings, or to have the plan meet budget or timeline considerations.

The evaluation plan will also identify any information that will need to be supplied by the utilities so that they will have advanced notice of what will be requested in an official data request once the study is launched.

Technology-Specific Code and Standard Change Theory

The first step in the evaluation process is to review the codes or standards change theories. The change theory is similar to a program theory, but it focuses on the measures included in the code or standard change, and the theoretical approach that the program is using to bring about the change. The change theory should present a story of how the program moves from the development of a change concept (for example, the need to change the code covering residential sidewall insulation in single family homes) to the completion of the code or standard change and a description of the savings expected. It should also include an estimate of the difference in the penetration of the code or standard-covered technologies between the pre-code adoption market and the post-code adoption market. The change theory should identify the activities that the program undertakes in its efforts to move from a change concept to a successful code or standard change. A code or standard change theory should be developed for each code or standard being changed. For example, if the code change focuses on duct sealing, there should be a duct sealing code change theory that describes the activities that will be used to bring about the change in duct sealing practice. The code and standard change theory should include:

1. A description of the technologies and measures affected by the change and the change being made.

2. A description of the program activities, efforts, and events associated with the change making process.
3. Identification of the key stakeholders the program needs to work with to influence the change, including their names, titles, organizations, addresses, phone numbers and where possible, their e-mail addresses[73]. These should all be key market actors that are (or are expected to be) instrumental in bringing about or helping to bring about the change. These individuals should be grouped by their roles in the change making process (program management and implementation, code review and assessment, case study development, economic impact assessment, environmental impact assessment, market impact analysis, technology availability assessment, supply chain analysis, lobbying, policy review and development, skills analysis, etc.). By providing these examples, we are not suggesting that these classifications be used, but rather demonstrate that some form of responsibility classification be used so that the evaluation contractor understands their individual roles in the change process. Lists of individuals involved in the change efforts and their roles should be maintained throughout the program's implementation efforts and program managers should be ready to provide these lists to the evaluation contractor on request. These interviews will be conducted over the pre- and post-change period.
4. The outputs, products, efforts and activities from the program that are used to cause the change, identifying how they are used to affect or support the change.
5. The incremental and final outcomes from the program's change efforts and activities that have been or are planned to be accomplished.
6. The timelines associated with the program's change efforts, including the adoption dates of each change and the date the change is to apply. We expect that the program change timeline will be multi-year, because code or standard change efforts are launched at least two years before a formal adoption takes place, and at least three years will pass before they become effective in the market.
7. A description of the code and standard that has changed (after the official adoption), and an electronic or hard copy of the parts of the code or standard that are changed, with code or standard reference numbers to allow independent confirmation of the change.
8. A description of the jurisdictions covered and not covered by the code or standard changed, and any conditions that would exempt or prohibit a jurisdiction from implementing the code or standard. This should identify all the significant reasons why a code or standard may not be fully adopted within the jurisdictions affected by the code or standard.
9. A pre-code and standard change description of the penetration levels of the technologies covered in the code or standard in the targeted markets and a description of the expected penetration levels following adoption of the program-influenced code or standard. These penetrations should be provided for each of the markets being targeted for the code or standard.

[73] The names, addresses, and contact information of the people the program works with should be considered confidential information and protected from disclosure.

For assistance in understanding the nature of a program theory and the associated logic models, see the *California Evaluation Framework*, page 30. While the *Framework* does not detail what is included in a change theory, the codes and standards change theory should be similar to a program theory and the supporting logic model. However, the focus of the evaluation of the Codes and Standards Program is not at the program summary level, but instead is developed for each technology/measure targeted by the Codes and Standards Program. It is expected that the change theory for codes and standards programs will include theories on technologies/measures that are being successfully moved or have moved to a code or standard change. This condition allows the evaluation contractor to understand the full nature of the program operations and focus, including the approaches for technologies and measures that move from the concept stage to the code or standard change stage.

The code and standard change theory will be a key document used to guide the evaluation effort. Without the code and standard change theory, the evaluation contractor cannot fully understand the efforts, events, and key individuals that must be considered to develop the evaluation plan. This Protocol recognizes that the change theories will be developed and modified over time, as the program moves through the implementation process. The change theories developed early in the process are expected to be less specific and less "*fleshed-out*" than the theories developed mid-stream and during the final adoptions processes. The evaluation contractor will need to make sure that the change theories used to guide the evaluation efforts are the most recent theories. These Protocols require the program administrators to provide updated program change theories to the evaluation contractors immediately after they are developed or modified. However, the evaluation contractor should also confirm that they are planning the evaluation using the most up-to-date change theories.

Each code and standard change theory should be accompanied by a code and standard logic model that graphically displays each theory. The logic model will include the resources used by the program, the activities of the program, the outputs from the program activities, and the outcomes expected from the changed codes and standards.

These documents will be instrumental in estimating the level of influence of the program on the adoption of the specific codes and standards changes.

The evaluation contractor will request the program theory and logic models from the program administrator(s) immediately after the evaluation contract is negotiated. If the program staff has not developed the theory, the evaluation contractor will notify the program administrator(s) and the CPUC-ED that the code change theory is not available to guide the evaluation planning process and the evaluation planning efforts cannot proceed. At this time, the CPUC-ED will instruct the administrators of the program to develop the code and standard change theories and supportive logic models. The program administrator(s) will then develop the theories and the supporting logic models for the covered technologies.

If the program theories and logic models are not available at the time of the evaluation request, the administrator my elect to hire contractors to develop or help develop these materials. These materials must be delivered to the CPUC-ED within 40 days of the notice and be used to guide the development of the evaluation plan. The development of the evaluation plan should be launched immediately after the evaluation contractor is hired, but not finalized until the program theories and logic models have been delivered and used to guide the evaluation planning efforts. Because program theories and logic models are "living documents" that change as program designs and objectives change, it is important that the most updated theories and models guide the evaluation plan. Alternatively, the CPUC-ED can instruct the evaluation contractor to work with the program managers to develop the change theories and the supporting logic models to guide the evaluation effort. If this step is taken, the Program Administrator must "sign-off" on the accuracy of the theories and the supporting models before they are used to guide the evaluation efforts.

Evaluation Approach

Identify the Evaluation-Covered Codes & Standards

In this effort the evaluation contractor, in coordination with the program administrators and Joint Staff, will identify the specific codes and standards that have been, in some way, influenced by the program's activities, and identify those that will be incorporated into the evaluation effort. This assessment will use the code change theories, logic models and market actor information provided above, in addition to consultations with the program administrators and Joint Staff. Typically, the impact evaluation will focus on 5 to 25 changed portions of applicable codes and/or standards, depending on the number of code or standard changes that have been adopted, however, the actual number may be more or less than this range.

Not all energy-related code or standard changes are caused by or influenced by the Codes and Standards Program(s). These non-program changed codes or standards are not included in the impact evaluation. Similarly, not all codes and standards changes targeted by the program make it into a new code or standard, however the costs of these efforts should be included in the cost effectiveness evaluation of the codes and standards program, even if they have not yet become adopted by one or more jurisdictions.

The codes and standard changes that can be included in the impact evaluation plan and assessed in the evaluation are those for which:

1. The program has developed a code or standard change theory and supportive logic model,
2. The program-covered change has been adopted, or is expected to be adopted by at least one public jurisdiction (city, county, or state) who has made the code or standard a required or voluntary practice, and
3. The change theory provides a reasonable cause and effect relationship leading from a concept stage to an adopted code or standard, indicating that the program's actions can be expected to have a positive influence on the adoption process. If there is disagreement on what constitutes "*a reasonable cause and effect relationship*," Joint Staff will make the decision with advice from the program administrator and the evaluation contractor.

When these conditions exist, an assessment of the impacts of that technology or practice change will be included in the impact evaluation. However, the Joint Staff, after consulting with the program administrators and working in concert with the evaluation contractor, may elect to modify the code and standard changes addressed in the study as a result of expected or projected program actions.

Conduct a Codes and Standards Gross Market-Level Energy Impact Assessment

The evaluation contactor will conduct a load impact evaluation of the savings (kWh, kW, and therms of natural gas) expected from the technologies that are covered by the code and standard changes. This study is a gross market-level assessment that focuses on the total amount of savings that can be expected by the changes, regardless of the cause of those changes. However, this study only focuses on those changes that are targeted by the program and for which the code change theory explicitly identifies as being affected by the program's efforts.

In conducting this study the evaluation contractor will follow the Impact Evaluation Protocol to estimate savings from the technologies affected by the code or standard change. The "Basic Level of Rigor" for estimating gross energy impacts, as identified in the Impact Evaluation Protocol, is to be applied to assessing the gross market-level energy impacts. However, the Joint Staff can stipulate either more or less rigorous methods during the evaluation planning process if there is a need for more accurate savings estimates, if budget or timeline restraints requires a less rigorous approach, or if Protocol-covered evaluation findings that have already estimated the energy impacts for a given technology can be used to estimate market-level gross savings. The goal in establishing this requirement is to have flexibility in the evaluation design process to meet unforeseen barriers to the evaluation, but still establish a default level of rigor for which the estimates can be based. The evaluation contractor will work with the Joint Staff to set rigor levels consistent with the needs of the study, the study timeline and the evaluation resources.

The evaluation contractor may not need to conduct an impact evaluation assessment on a particular technology or practice if that technology or practice has already been evaluated using a reliable impact assessment approach similar to the approaches covered in the Impact Evaluation Protocol (2006). When previous evaluation findings can be directly used or modeled (simulated) to reflect the use and application conditions associated with the changed codes and standards, that approach should be used if it results in a reliable energy savings estimate. Likewise, the evaluation contractor may not need to conduct an impact evaluation on a particular technology or practice if a review of the program's estimates of energy savings, and the supporting documentation and case studies, are found to be reliable. In this case the evaluation contractor should review the program's estimated savings and, in consultation with Joint Staff and the program administrators, discuss the threats to validity associated with the estimation approach and determine if the approach is reliable enough that the evaluation contractor can use the estimates, or if they can be made more reliable through additional engineering adjustments, modeling or modeling changes, additional field M&V, or application testing efforts. The purpose of allowing the use of previous evaluation results and of the program's energy saving estimates is to not expend evaluation resources if reliable energy savings projections can be constructed by using previous work.

If there are no previous impact evaluation studies associated with a specific code or standard change that can be used, or adjusted and used, and if the program's energy savings estimates are found to be unreliable or have significant threats to validity making them unreliable even with addition modeling, M&V efforts, or field testing, the evaluation contractor is to develop a plan to assess the energy savings for that technology or practice using the Impact Evaluation Protocols to develop the evaluation approach.

It is expected that as the Energy Impact Protocol (2006) is adopted and used, more and more technologies will have been evaluated under the Protocols in which the results can be used or adjusted to reflect expected code and standard application conditions, thereby reducing the need for new technology evaluations to feed the codes and standards gross market-level impact estimates.

As noted earlier, the default approach for conducting the market-level energy impact assessment is set at the Basic Level of Rigor as specified in the Impact Evaluation Protocol for estimating gross program impacts unless the Joint Staff or the CPUC-ED has assigned a different level of rigor for a given technology. In making the rigor assignments, the Joint Staff will consider past evaluations and their energy savings estimates for covered technologies and the potential to use these study results, the need for different levels of accuracy in the market-level energy assessment for individual technologies, the available budget to support the assessment and the timeline for the evaluation, in addition to other criteria. These requirements mean that at a minimum:

1. Simple engineering model estimation approaches, or
2. Normalized annual consumption approaches will be used, unless
3. The CPUC-ED or Joint Staff have approved an alternative approach based on the criteria discussed above.

The results of this assessment will be an annual energy savings estimate covering the first year of code or standard adoption for each technology or behavior change covered in the change theory. This estimate will be based on the expected penetration rate associated with each change across the market sectors for which the code or standard change applies, assuming that it would impact all installations covered by the change. In assessing the savings it will be necessary for the evaluation contractor to estimate the increase in adoption of each technology or behavior change resulting from the code or standard change. This assessment will most likely involve the use of projected construction levels grounded on historic construction patterns, estimated retrofits and change-outs driven by normal market forces, and other estimates of change for each of the changes. This annual savings will then be projected into the future to construct a time-sensitive estimate of gross savings.

In assessing the gross market-level energy savings it will be important for the evaluation contractor to understand that the code or standard changes supported by the program's efforts may not be consistent with the newly adopted changes. That is, the program may focus its efforts on a more aggressive or less aggressive energy efficient change to the code or standard than what is actually adopted. As a result, the gross energy savings assessment must focus on the changes made to the <u>adopted</u> codes and standards that were influenced by the program, rather than the changes <u>recommended</u> by the program. Likewise, the evaluation contractor must check to see that the program-influenced changes are still in force. Just as codes can change to be more energy efficient, they can also change to be less energy efficient.

In assessing the gross market savings the evaluation process should disaggregate the savings assessment efforts into the specific installation, construction or purchase changes being made as a result of the code or standard change. This may mean disaggregating the savings analysis into measure groups or small clusters of measure groups rather than aggregating multiple measures and practices into large groups[74].

Once the gross market-level energy impacts are identified, the following approach will be applied to develop an estimate of net program effects.

Estimate the Program's Influence on the Adoption of Codes & Standards

Once the gross market-level energy savings estimates are established, they must be adjusted to account for the influence of the Codes and Standards Program on the code or standard change. The program may be only minimally responsible for a given change, or may have had a significant influence on the code and standard adoption process[75]. For each technology or behavior, the evaluation contractor must establish a percent attribution factor for the savings that can be attributed to the program. These percentages can range from no influence (0% if the program had no tangible influence on the change) to a significant influence potentially approaching 100 percent (if the program was the primary influencing factor driving the change).

A stakeholder interview-based preponderance of the evidence approach will be used for this process. This process will identify key stakeholders and conduct multiple interviews with these stakeholders at different points in time along the adoption path, during both the pre-adoption and post-adoption period.

The evaluation contractor will conduct interviews with a representative sample of the key stakeholders identified earlier (see item 3 in the Technology-Specific Code and Standard Change Theory above) and use the results of these interviews, along with reviews of program materials and documents (including lobbying documents, staff reports, case studies, and staff and stakeholder correspondence as available) and attendance at program meetings and key events associated with the adoption process (to the extent possible and practical) to assign causation percentages for the change to various change agents identified by the stakeholders, including direct or indirect efforts of the program. In making these attribution assignments, the evaluation contractor will want to consider the potential bias of the individuals interviewed and of the information reviewed, and cross-check stated opinions with applicable documents and the opinion of other stakeholders, in order to test the causal relationships between actions and results. The evaluation contractor should make as objective an assignment as possible. The evaluation contractor will assign weights to the opinions of the stakeholders based on a review of all available information (noted above). The contractor will assign higher weights to those who

[74] Note: a previous study aggregated the assessment into one change assessment cluster that represented 66% of the savings even though the change represented different measures, approaches and technologies. The study should disaggregate the assessment to the extent possible and practical given the evaluation needs and resources.

[75] The assignment of attribution of cause is to assess energy savings via the evaluation approach. It is not placed in this Protocol to establish the program's NTG values or to change the ex ante projected savings.

are most likely to have a complete understanding of the change efforts and processes relative to a specific technology or set of technologies and who are more likely able to accurately judge the relative causes of the adoption of the new codes or standards. This will allow the attribution of change to be more informed by those who are in a position to best judge the reasons for the change. Utility and other program staff and contractors hired by the program should be included in the sampling approach and be interviewed. As with these and other individuals interviewed, the evaluation contractor will keep in mind the potential biases that may be associated with any single individual. In the weighting process, significant weights should be applied to the opinions of non-program stakeholders who are instrumental in the statewide jurisdictional decision processes to adopt a code or standard change and to advisors or key stakeholders informing this process. In selecting a sample of interviewees, the Sampling and Uncertainty Protocol should be followed, with the sampling method determined at the individual code or standard change level. The interview process should be structured to conduct both pre-change and post-change interviews.

The interview protocol and the interview guide should be designed to be objective and rely on the opinions of the key stakeholders. The interview guide should be a prompted guide, so that the interviewee is not placed in the position of trying to identify all the different causes for the change. The evaluation contractor will develop a list of program and non-program associated change agents/causes based on a review of the change theories and interviews with a small but adequate sample of evaluation contractor-selected program and non-program stakeholders. The sample selection for these interviews does not have to follow the Sampling and Uncertainty Protocol.

The evaluation contractor will plan the sample selection for the stakeholder interviews to focus on the program-identified stakeholders contained in the change theory documents or other associated documents. However, the evaluation contractor will use a "snowball" sampling approach in which the sampled interviewees will be asked to identify additions to the sample of individuals the interviewee indicates were instrumental in the change consideration or decision process. The evaluation contractor will target an additional 20 percent of the interview sample points to interviewing stakeholders recommended by the interviewees who are not on the change theory stakeholder list. If the evaluation contractor is unable to obtain an additional 20 percent, the contractor will conduct as many of the additional interviews as possible and state in the evaluation report that they were unable to identify or interview an additional 20 percent.

The results from the interviews will be aggregated and used to assign technology and behavior change attribution of the changes caused by the Codes and Standards program. The results of this process will be a percentage distribution of the causes for each change across the stakeholder-identified reasons for the success of the newly adopted code or standard change for each of the technologies or behaviors covered.

It is expected that there will be significant levels of interview overlap across the technologies and behaviors so that a single interview may cover several technologies or behaviors related to a code change or changes. This sampling process assures that adequate samples will be selected for each technology or behavior-associated change and that the attribution will be based on program-identified and stakeholder-identified change agents.

Once the attributions have been established at the technology level, the evaluation contractor will multiply the energy savings for each technology or behavior by the attribution score to identify the gross market-level energy impacts that were caused by the Codes and Standards Program. This savings estimate will be further adjusted to account for net program effects (see below).

The timing of the estimation of the program's influence is critical to the success of the evaluation. The attribution assessment must be started very early in the Codes and Standards Program cycle, but not completed until the adoption process has been completed for the changes being evaluated. The technology or behavior change selections and the associated code and standard development efforts for the 2008 codes and standards began in the fall of 2005 and will continue through early 2006. In order for the attribution efforts to be based on recent knowledge, the interviews must be conducted during the technology selection and demonstration development process (as appropriate) and again when the adoption process is complete. This means that the attribution assessment may need to be launched years before the program experiences its first code or standard associated savings[76].

In assessing the program's influence on the adoption process, the evaluation contractor should consider a number of program and market conditions and activities that influence the adoption process and the associated adoption decisions relative to the individual changes. In considering these changes the Protocols references the Codes and Standards white paper[77] in which different adoption influence weights were used to assign attribution. While this white paper should be examined in the evaluation planning process, the evaluation contractor should be careful not to select program or market condition weighting criteria that correlates with or overlaps among the weighting metrics so that the weighting approach acts to double-count adoption influence across more than one of the weighting criteria.

Estimate Net Program Induced Energy Impact

The gross market-level energy impacts that were caused by the Codes and Standards Program must be adjusted to account for naturally occurring market adoption changes, normally occurring codes and standards revisions, and non-compliance with the new codes and standards. These adjustments are discussed below and need to be made in the order prescribed in this Protocol.

Naturally-Occurring Market Adoption

The first adjustment to the gross energy savings estimate identified above is an adjustment to account for the naturally occurring market adoption rates. New energy efficient products are likely to penetrate and be adopted by at least a portion of the market even without the Codes and Standards Program. As a result, the projected naturally occurring adoption and penetration, which would occur without the program, needs to be subtracted from the program's gross energy impacts.

[76] This means that evaluations of codes and standards programs conducted in the first years following the issuance of this Protocol will be operating in a "catch-up" mode because the program will have already launched the change efforts on which the first evaluation will focus.

[77] Codes and Standards Program Savings Estimate, August 1, 2005 (or most recent revision), Heschong Mahone Group, page 8. CALMAC SCE0241.01.

Naturally occurring adoption rates for premium energy efficient products typically occur in an "*S*" shape pattern that never reaches 100 percent penetration as long as there are alternative technologies in the market. This is especially true when the alternatives are lower cost technologies. Some energy efficient technologies may never capture a majority of the market share without a mandatory code or standard. Others may move to capture the majority of the market without a code or standard. However, there is likely to always be some level of increased penetration of a superior product that delivers benefits to a user, up to a point of product demand saturation, based on the characteristics of the product and the alternative choices in the market. Similarly, some customers never adopt a new product regardless of the benefits of the product. These customers are typically labeled as "laggards" within the technology adoption literature.

This step requires the evaluation contractor to establish expected adoption curves for each technology included in the impact assessment. The evaluation contractor will use a range of approaches to establish the estimated penetration curves, including conducting literature searches on the penetration rates of similar technologies with similar product characteristics, the use of expert opinions on the expected penetration rates in the absence of a requirement to use the technology, relevant market data and other approaches as deemed appropriate in the evaluation planning effort.

The evaluation contactor will then adjust the projected savings to account for the naturally occurring adoption for each technology covered in the assessment.

Non-Compliance Adjustment

The second adjustment to gross savings is an adjustment for non-compliance. Since not all buildings or appliance decision makers will fully comply with the newly adopted codes or standards, these lost savings must be subtracted from the gross estimate.

In the real world, there is often a range of appliances or measures present in the market, some falling below the standard and some above the standard in their energy efficiency levels. Similarly, technologies that do not comply with the new code or standard are often stocked and sold in the market regardless of the requirements adopted. For example, while programmable thermostats are now required in California for most space heating and cooling applications, it is easy to acquire and install non-compliant thermostats because of the stocking and sales patterns of a wide variety of wholesale and retail outlets, including internet sales. In some cases, if permits are not required or obtained, the codes and standards enforcement mechanisms associated with the building inspection process may not be applied, enabling non-approved installations to occur. Likewise, it is difficult to inspect code-covered applications of measures such as insulation once the construction is completed to enforce code compliance, making this measure difficult to inspect and enforce.

In order to comply with the Evaluation Protocol, the evaluation contractor must estimate non-compliance across the technologies being assessed and adjust the anticipated savings for the net non-compliance rate over time. For technologies that do not comply, but are easily available in the market, the non-compliance rate may be high. However, for other technologies that are typically inspected as part of the construction or retrofit process, the non-compliance rate may be low.

To establish the rate of non-compliance the evaluation contractor will conduct interviews with a set of building architects, engineers, contractors, product wholesalers and retailers and installation contractors. The evaluation contactor will design a sample plan consistent with the Sampling and Uncertainty Protocol to match the technologies being assessed. Because compliance is measure-specific, samples will be set at the technology level within each code or standard changed. In developing this adjustment the contractor will need to be sensitive to differences in compliance rates across the state and over time. As a result, the evaluation contractor should consider approaches for adjusting for local differences in compliance rates, such as establishing and using compliance assessment jurisdictions. These approaches will be coordinated with and approved by Joint Staff before they are implemented.

The evaluation contractor will also assess the availability of non-compliant technologies in the market by examining the stocking practices of selected suppliers of the technologies. For example, if a building products supplier stocks 30 percent non-compliant technologies, the non-compliance rate for that technology can be assumed to be 30 percent for their customer market, unless there is evidence to the contrary collected during the interview efforts. The evaluation contactor will suggest ways to conduct the stocking assessment and can include such approaches as visits to suppliers to examine the stocking mix or interviews with suppliers to estimate their stocking mix.

The evaluation contractor will then assess the results of the interviews, the examinations and other assessment approaches suggested by the evaluation contractor and approved by the Joint Staff and estimate the rate of compliance for each technology or behavior change. The estimate will not be a single fixed level, but will be time-adjusted, so that the expected rate of non-compliance will change over time. To arrive at the time-adjusted compliance estimate the evaluation contractor should rely on projections provided by the interviewees.

It is important for the evaluation contractor to focus on identifying net compliance adjustments during this assessment and take into account the pre-change compliance rate for a given change condition. There may be substantial portions of the market that are not in compliance before the change and are not in compliance after the change. Likewise, a non-compliant rate before the program may have the same non-compliant rate after the change. The evaluation contractor is expected to develop plans that provide for net compliance changes over time. The contractor will coordinate with Joint Staff in this effort.

The evaluation contactor will then adjust the projected savings to account for the estimated levels of non-compliance.

Normally-Occurring Standards Adoption

Next an adjustment to the gross savings needs to account for the normally occurring codes and standards change process. A primary effect of the Codes and Standards Program is to accelerate the time it takes for the CEC and other jurisdictional organizations to update current codes and standards or adopt new codes or standards. The CEC employs a three-year update cycle, keeping the standards up-to-date and cost-effective as market conditions change. However, without the Codes and Standards Program resources, the updates might not encompass the same type of technology analysis and change considerations. It is reasonable to assume, therefore, that the standards adopted by the CEC or other jurisdictions would have been adopted in the normal course of events, but over a much longer period of time. The energy savings from the Codes and Standards Program should only include the savings from the codes and standards implemented as a result of the program's efforts for the period of time that they would not be covered by a revised code or standard during the normal course of the update cycle.

In order to establish the estimated time at which the CEC and other jurisdictions would have adopted or created a code or standard without the program, the evaluation contractor must establish a panel of experts who are familiar with and involved in the code change efforts. This panel will consist of CEC program staff, CEC code and standard update staff, code and standard public officials within other jurisdictions, and other experts as deemed appropriate by the evaluation contractor and approved by the CPUC-ED or the Joint Staff. The evaluation contractor will then conduct a minimum two-round Delphi[78] assessment with this expert panel to arrive at a projected date that the CEC would be expected to implement a new code or standard in the absence of program initiatives. This process should cover each technology or behavior in the assessment. It is expected that the size of this panel will be between 10 and 20 experts.

Once the estimated timeline for each code or standard change is established, the energy savings for the technologies and behaviors changed as a result of the code and standard changes will not be counted beyond that projected date, but in no event will the savings be counted beyond a 30-year period. This step sets an end-date for the period of time that savings can be counted for each code or standard change.

Actual Construction and Retrofit True-Up

The energy savings estimates produced from this Protocol are based on a single assessment of the gross energy savings for a single year projected into the future. However, not all years are the same. The economy and other changes (interest rates, unemployment, consumer confidence, etc.) affect the rate at which technologies are adopted and used, and thereby influence energy savings. As a result, it is necessary that the CPUC-ED may elect to periodically issue a new RFP to conduct an update of the projected savings to account for actual savings. When the CPUC-ED requests an update, the evaluation contractor will assess the market and update the savings projections to account for actual construction and adoption.

It is not possible to accurately estimate savings without knowing how much construction was actually accomplished following a code or standard change. There are several ways to adjust the energy savings projections to account for actual construction and a preferred approach is not specified in this Protocol. However, a true-up of actual construction is needed to help increase the accuracy of the savings estimate over time. If the true-up evaluation is conducted in the 5th year following the code change, then the true-up should contain estimates of actual construction for the first 4 years of which permitting and building records could be assessed. Once the evaluation has a history of actual construction, the new projection of future construction (to estimate future savings) can be based on the historical construction. Once the projection is

[78] Delphi assessment is an iterative process that involves repeated rounds of information gathering across a selected group of experts. Responses to one round are summarized and developed to feed the next round of information gathering. The purpose of the Delphi is to seek agreement across the group of experts.

established, the savings can be projected and the adjustments can then be subtracted (or added, depending on actual construction data) from these original projections to obtain net realized past savings and the updated projected future savings based on the updated estimate. When an update is requested the CPUC-ED or the Joint Staff will work with the evaluation contractor to identify an approach to be used. This approach may be based on construction industry statistics (e.g., annual real estate construction estimates), building construction databases (e.g., the Dodge database and/or Construction Industry Research Board (CIRB) reviews of building permits for a set of representative jurisdictions), assessments of sales data if the data can be reliably obtained (a historic problem for sales data collection) or other approaches.

Multiple-Counting of Energy Savings Adjustment

To make sure that the savings from code change covered measures, practices and purchases are not counted more than once, no energy efficiency or demand management/response programs that offers code or standard change covered measures, equipment or practices is permitted to count the savings from these measures, practices or purchases toward their energy savings goals once the codes and standards evaluation has documented the savings from these efforts, unless those savings are from Code Compliance Enhancement programs. The Code Compliance Enhancement Program evaluation will then document savings beyond what is achieved as a result of the code and standards change[79].

Measure Life Adjustments

This Protocol excludes an adjustment for measure life. It is assumed that once a measure is adopted as a result of a code or standard change, the behavior will be repeated until that code or standard is eliminated or updated. However, even if the code change is updated, the savings from the measures are still provided. Likewise, new evaluations will document the increased efficiency of the updated codes or standards. In addition, the inclusion of normal market adoption rate adjustments and normal code and standard change revisions will act to significantly reduce the savings over time. However, the energy savings provided via the use of this Protocol shall not be projected beyond 30 years.

Impacts by Utility Service Territory

Once the statewide estimates of adjusted net savings have been estimated, an allocation of the savings to the utility service territories can be made. This assignment of savings will be based on assigning savings to a utility for measures that are actually installed within their service territory. The allocation will be based on the distribution of new home construction, nonresidential construction square footage, and appliance sales forecasts within each service territory such that the total savings across the territories equals 100% of the adjusted net savings estimated from the program less the savings from the local jurisdictions that had implemented or were in the process of implementing the adoption of changes covered in the scope of the evaluation. This Protocol condition means that the evaluation contractor will need to conduct a survey of at minimum the 20 most populated (or preferably and provided the data is available the 20 jurisdictions with the highest numbers of building-starts) local jurisdictions within each IOU service territory to assess if that jurisdiction was substantially in the process of converting their code or standards to the

[79] See Protocol steps for assessing Compliance Enhancement Programs located at the end of this Protocol.

covered changes or had completed this effort at the time the program was advocating for the change. The evaluation contractor must obtain approval from the Joint Staff on the jurisdictions to be surveyed for each code or standard change. It is expected that there will be substantial overlap among the identified jurisdictions and that most of the targeted jurisdictions will be surveyed for more than one of the program's covered changes. In selecting the local jurisdictions to survey, the evaluation contractor will survey enough jurisdictions to be able to reliably measure the program's net effects.

Because the construction, retrofit and sales markets change over time, this assessment and the adjustment approach will need to be trued-up periodically. These refinements will be specified by the Joint Staff, or the CPUC, in order to allocate savings over time based on market conditions.

Reporting

The evaluation report will be provided in compliance with the Reporting Protocol. A draft report will be provided for review and comment to the stakeholders (see Reporting Protocol). Once comments are provided on the draft report the evaluation contractor will work with the Joint Staff to finalize the report. Once the final report is accepted by the Joint Staff, the evaluation contractor will construct an abstract consistent the instructions contained on the CALMAC.org web site and post the report.

Summary

This Protocol describes a way to estimate the gross and net energy impacts from the Codes and Standards Program. It begins with the review of the program change theory and logic models and the development of an evaluation plan. The implementation of the plan consists of estimates of gross market-level impacts for each technology and behavior adjusted to account for naturally occurring market changes, non-program induced code and standard revisions, and code compliance rates for each technology. The evaluation delivers net impacts for each technology and for the program as a whole, and then distributes the energy impacts to the participating utility companies.

This Protocol is prescriptive in nature, but allows for the use of new techniques or approaches when approved by the CPUC-ED or Joint Staff. As a result, it does not impede the evolution of evaluation approaches.

The Codes and Standards Program Evaluation Protocol is guided by the Impact Evaluation Protocol, the Sampling and Uncertainty Protocol and the Reporting Protocol.

The following table provides a summary of the Protocol that can be used to guide the evaluation efforts once the detailed contents of the Protocol are well understood.

Summary of Protocol-Driven Codes and Standards Evaluation Activities

1	Joint staff selects an evaluation contractor to implement the Codes and Standards Program evaluation.
2	The evaluation contractor reviews the program change theories and the program logic models, identifies the technologies or behaviors that can be evaluated via the Protocol, constructs a draft evaluation plan and submits the plan for approval to the CPUC-ED. The contractor works with the CPUC-ED on the development of the draft evaluation plan and rigor levels. The plan must use the Impact Evaluation Protocol, the Sampling and Uncertainty Protocol and the Reporting Protocol in the development of the evaluation plan and in the implementation and reporting efforts.
3	The CPUC-ED works with the evaluation contractor to finalize and approve an evaluation plan from which the contractor can begin the evaluation effort.
4	The contractor conducts an assessment of the gross market-level energy impacts for each code and standard covered technology or behavior being evaluated consistent with the rigor level assignments.
5	The contractor determines the influence of the program on the adoption of each code and standard covered in the study and allocates adoption attribution. The assessment uses an interview approach for this assessment. This assessment is accomplished as early in the code change cycle as possible but preferably in the technology selection and demonstration phase of the cycle.
6	The contractor estimates naturally occurring code and standard covered technology or behavior adoption rates based on literature reviews and interviews with experts.
7	The contractor adjusts the gross market level energy savings estimates to account for the net adjustment factors for naturally occurring technology adoption, naturally occurring code change, and non-compliance. This approach nets out the influence of non-program-induced impacts from the gross market-level impacts for each technology.
8	The contractor estimates the timeline associated with adoption of a code and standard without the program, using a Delphi approach with an expert panel.
9	The program administrators remove savings estimates from their programs for code-covered measures.
10	The evaluation contractor assesses the construction and sales efforts for each utility company service territory and allocates savings by IOU based on the construction and sales estimates.
11	The contractor reports the results of the evaluation to the CPUC-ED and Joint Staff consistent with the provisions in the Reporting Protocol.
12	Once the report is accepted by the CPUC-ED, the contactor develops abstracts and posts the report on the CALMAC web site following the CALMAC posting instructions.
13	As needed, the CPUC-ED or the Joint Staff can request the evaluation contractor to update and report the actual energy savings over time consistent with the Protocol. Updates can be conducted with a different evaluation contractor than those doing the

	original assessment.

Note: the steps included in this evaluation summary table must be accomplished in accordance with all the requirements within the Codes and Standards Protocol in order to be in compliance.

Code Compliance Enhancement Programs

To conduct energy impact evaluations of programs designed to influence the rate of compliance of code-covered measures the evaluation contractor should not follow the Codes and Standards Program Evaluation Protocol presented above, but should follow this Protocol specifically designed to estimate the energy savings from these programs.

Because the California IOU portfolios have not included code compliance improvement programs in their portfolios, and because these programs have yet to be evaluated to the extent that a standard evaluation approach can be reliably identified, this Protocol allows a wide variety of methods and approaches for assessing the savings from these efforts. After several of these evaluations have been conducted and the success of the approaches documented, a standard approach may be developed and added to the current Protocols. Until that time the following guidance will be used to structure and implement the evaluation of code compliance enhancement programs.

Definition of a Code Compliance Enhancement Program

A Code Compliance Enhancement Program (CEP) is any energy efficiency, demand reduction or demand management program whose primary purpose is to increase the level of customers complying with a code requirement that saves energy (kWh, kW, therms).

What this Protocol is Designed To Do

This Protocol establishes a framework under which CEP programs are to be evaluated to assess energy impacts. This Protocol does not establish program designs, program design criteria or program development approaches.

Code compliance enhancement programs can be incentive programs that are designed to increase compliance by providing incentives to customers to do what is required, educational programs to make customers or trade allies aware of the code and the need for compliance, training programs to train customers or trade allies how to comply, enforcement programs that take enforcement actions against non-compiling property owners, or other types of program designs. These programs may also involve more than one type of delivery strategy.

Joint Staff Responsibilities

Because CEP are not (at this time) part of the suite of energy program services delivered in California, the Joint Staff are responsible for determining when to evaluate a CEP program and how that evaluation should be conducted and reported. However, that evaluation must employ the following approaches unless other approaches are requested and approved by the Joint Staff.

Draft Evaluation Plan

The evaluation contractor will prepare a draft detailed evaluation plan and submit that plan for review and approval to the Joint Staff. The plan should provide for a time-series measurement approach that can be replicated at different times over the implementation period. Joint Staff will review and comment on the evaluation plan and will work with the evaluation contractor to focus the plan on the evaluation objectives of the CPUC. This plan will serve as the approval process for launching the detailed evaluation planning efforts.

Program Theory Review and Assessment

The evaluation contractor will review and assess the program theory provided by the program administrator. This review will be focused on understanding the approach the program is taking to effect a compliance change and the activities that are employed to accomplish the program's objectives. Once the program theory has been assessed the evaluation contractor will modify the draft evaluation plan and submit the plan to Joint Staff for review and approval. One purpose of the program theory review is to allow for the examination or the program theory to feed the evaluation planning process so that the evaluation contractor can identify key measurement points on which the program needs to focus. Once the draft evaluation plan has been updated from the program theory review effort and approved by the Joint Staff the evaluation efforts can be launched.

Pre-Program Compliance Rate

The evaluation contractor will work with the Joint Staff to develop an approach for measuring the pre-program compliance rate for the measures covered by the program. This approach should focus on assessing the condition of the market and taking measurements that allow the evaluation contractor to identify the level of pre-program non-compliance within the geographical areas targeted by the program. The Codes and Standards Evaluation Protocol incorporates instructions on assessing compliance rates for evaluating Codes and Standards programs. These instructions are incorporated into this Protocol as a guidance resource for identifying non-compliance rates during the pre-program period. The Joint Staff and the evaluation contractor are free to develop other methods if, in the opinion of the Joint Staff, the alternative approach can be expected to be more or equally reliable to the approach presented in the Codes and Standards Protocol.

The purpose of this activity is to establish the baseline from which post-program changes in construction practice or measured installed can be assessed. It is expected that this assessment will need to be sensitive to local jurisdictions and changes in compliance within the local jurisdictions. The outcome of this effort will be the identification of the level of compliance for each program-targeted code change within the market sectors and jurisdictions on which the program's efforts are focused.

It is expected that the pre-program compliance rates will be set at some level of detail that will allow the evaluation to identify jurisdictional differences in compliance rates.

Post-Program Compliance Rate

At a period of time to be determined by the Joint Staff the evaluation contractor will again apply the same strategy used to assess pre-program compliance rates within the geographical areas targeted by the programs. These areas on which the evaluation will focus must also be the same areas of the state that the pre-program compliance assessment was focused so that the jurisdictions examined in the pre-program assessment match the jurisdictions examined in the post-program assessment. The primary purpose of this effort is to document the compliance rate after the program has been implemented long enough for an expected change in compliance to be measurable.

The time periods for the post-program compliance rate assessment will be set periodically over the program implementation period to allow results to be tracked over time and reported consistent with the reporting needs of the CPUC. For some measures and programs this may mean an assessment every six months, for others the assessment can be done annually, while for others the assessment may be needed every few years. The evaluation contractor in coordination with the Joint Staff will identify the periods in which the post-program compliance should be assessed.

Adjustment For Naturally Occurring Compliance Change

The natural compliance rate for most code requirements will change over time. Normally, compliance is expected to be lower on the date the change first applies. This is then followed by a period in which compliance rates increase and begin to stabilize as the change is structured into the market and local code officials and trade allies change their approaches to comply with the new code. Because the compliance rates change as a normal course within the market operations, the normal compliance rate that would have occurred without the program must be adjusted out of the calculation for net program compliance changes. The evaluation contractor will work with the Joint Staff to identify an approach for identifying normal compliance change rates. Because these programs have not been implemented or evaluated in the past, a prescribed approach for identifying the rate of naturally occurring compliance is excluded from this Protocol. Joint Staff may wish to employ trade ally surveys, expert panels, code official interviews, measure sales tracking approaches or comparison areas where the program services are not offered. Each of these approaches has their own strengths and weaknesses that should be assessed and considered in the planning process. Joint Staff or the evaluation contractor may wish to suggest other approaches for consideration. However, the Joint Staff must approve the procedures for identifying naturally occurring compliance change before the effort is launched.

Net Program-Induced Compliance Change

Once the pre-program and at least one round of post-program compliance assessments is conducted, the evaluation contractor will assess the net change in compliance across the jurisdictions targeted by the program. The evaluation contractor will work with the Joint Staff to identify the approach to be taken in this assessment, however it is expected that the approach will be a simple jurisdiction controlled net change assessment.

Assessment of Energy Savings

Once the net assessment of change is identified, the evaluation contractor will use the savings estimates provided from the codes and standards program evaluation for the same code covered measures included in the CEP. If the codes and standards evaluation effort is not completed in time for the CEP evaluation, the Joint Staff will decide to delay the completion of the CEP evaluation or launch the impact assessment approach prescribed in the Codes and Standards Evaluation Protocol for assessing net energy impacts from the code covered changes. However the Joint Staff can consider the use of other approaches, such as the assignment of DEER estimated savings for the covered measures, or an engineering-based assessment to estimate the probable energy savings, if these approaches are considered reliable predictors of the savings associated with a specific change. Other approaches can be applied at the request or approval of the Joint Staff, but these methods should focus on obtaining reliable savings estimates consistent with the available evaluation budget and the study timelines.

The net assessment procedures used must take into account the measures that would have been installed or constructed without the CEP program and the energy consumption difference between what would have been installed or constructed compared to the code-required efficiency levels.

Recommendations for Program Changes

The evaluation contractor is also to provide recommendations for program changes that can be developed as a result of the examination of the program theories, and the implementation of the evaluation assessment efforts. While this evaluation is not a process evaluation, the evaluation contractor may be able to provide valuable change recommendations that can be considered by the program administrator.

Cost Effectiveness Assessment

The evaluation contractor will conduct a cost effectiveness assessment using the program cost data reported to the CPUC in the monthly or quarterly program progress tracking cost reports submitted by the administrator to the CPUC. The evaluation contractor will conduct a TRC and a PAC test consistent with the approach provided in the Standard Practice Manual. The results will be reported in the evaluation report.

Reporting of Evaluation Results

The evaluation report should follow the Evaluation Reporting Protocol to meet the timelines and deliverable dates specified in the approved evaluation plan. The deliverable dates will take into consideration the reporting needs of the CPUC across the multi-year program implementation period.

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Effective Useful Life Evaluation Protocol (Retention and Degradation)

Introduction

One of the most important evaluation issues is how long energy savings are expected to last (persist) once an energy efficiency measure has been installed. The Effective Useful Life (EUL) Evaluation Protocol was developed to address this issue and should be used to establish the period of time over which energy savings will be counted or credited for all measures that have claimed savings. This Protocol contains requirements for the allowable methods for three types of evaluation studies: retention, degradation, and EUL analysis studies.

A persistence study measures changes in the net impacts that are achieved through installation/adoption of program-covered measures over time. These changes include retention and performance degradation. The definition of retention as used in this Protocol is the proportion of measures retained in place and that are operable. Effective useful life (EUL) is the estimate of the median number of years that the measures installed under the program are still in place and operable (retained).[80]

The primary purpose of this Protocol is to provide ex-post estimates of effective useful life and performance degradation for those measures whose estimates are either highly uncertain and/or have not been covered in studies over the past 5 years. These results will be used to make prospective adjustments to the measure level EUL estimates and performance degradation estimates for Program Years 2009 and beyond, but will not be used for retroactive adjustments of the performance of the 2006-2008 portfolios.

The Effective Useful Life Evaluation Protocol is established to ensure that all persistence-related evaluations are conducted using evaluation methods deemed acceptable based upon the assigned level of rigor for that evaluation. The identification of allowable methods is one component of this Evaluation Protocol that helps ensure greater reliability in the energy and demand savings estimates from California's energy efficiency efforts. The Joint Staff can assign different levels of rigor for each measure in any study under this Protocol, thus allowing the Joint Staff the flexibility to allocate evaluation resources according to the needs of the Portfolio given uncertainties in the expected savings, the size of expected savings, the program budget and other criteria. The Joint Staff will instruct the evaluation contractors to use specific rigor levels based upon the Joint Staff's application of the decision criteria contained in this Protocol and evaluation resource allocations.

Rigor is defined as the level of expected reliability. The higher the level of rigor, the more confident we are that the results of the evaluation are both accurate *and* precise, i.e., reliable.

[80] These definitions are as in the Glossary. Some are the same and some have been modified from what was used in the prior M&E Protocols. There are, however, inconsistencies across different states in how these terms are used. Evaluators conducting EUL evaluations in California need to be familiar with the current California definitions.

That is, reliability and rigor are synonymous. Reliability is discussed in the Impact Evaluation Protocol, the Sampling and Uncertainty Protocol, and in the *Evaluation Framework* where it is noted that sampling precision does not equate to accuracy. Both precision and accuracy are important components in reliability, as used by the CPUC. Each evaluation study will be assigned a specific evaluation rigor level for its primary evaluation objectives to guarantee that a minimum standard is met.

Past experience presents a few important notes of caution. Many past persistence studies were unable to provide results that were significantly different (statistically) from the ex-ante results, so that most of the current ex-post EULs are the same as the ex-ante estimates. Besides finding relatively high retention rates in most cases, a consistent and important finding in these studies is that a longer period of time is needed for conducting these studies, so that larger samples of failures are available, and so that technology failure and removal rates can be better documented and used to make more accurate assessments of failure rate functions. The selection of what to measure, when the measurements should be launched, and how often they should be conducted are critical study planning considerations that Joint Staff will direct to ensure reliable results are achieved.

Performance degradation includes both (1) technical operational characteristics of the measures, including operating conditions and product design, and (2) human interaction components and behavioral measures. This Protocol refers to these two different components of performance degradation as technical degradation and behavioral degradation, respectively. (Performance degradation studies are also referred to in this Protocol more simply as degradation studies.)

Performance degradation accounts for both time-related and use-related change in the energy savings from an energy efficient measure or practice relative to a standard efficiency measure or practice. It is important to note that the energy savings over time is a difference rather than a straight measurement of the program equipment/behavior. It is the difference over time, between the energy usage of the efficient equipment/behavior and the standard equipment/behavior it replaced that is the focus of the measurement. Energy efficiency in both standard and high efficiency equipment often decreases over time. The energy savings over time is the difference between these two curves. The technical degradation factor is a set of ratios for each year after installation/adoption as the proportion of savings obtained in that year compared to the first-year savings estimate, regardless of the retention estimate or EUL (which is applied separately to obtain overall savings persisted). The technical (or behavioral) degradation factor could be 1.0 for each year in the forecast (often 20-year technical degradation factors are estimated) if the energy efficiency decreases (energy usage increases) by the same percentage each year as the standard equipment. This is the case where technical degradation rates are the same for both types of equipment. The technical (or behavioral) degradation factor would be higher if the efficient equipment holds its level of efficiency longer/better than the standard equipment[81] and lower if there is more relative degradation.

Technical degradation studies may not be routinely required in the 2006-2008 round of EM&V studies because the incremental level of this type of degradation measured in five persistence

[81] This was found to be the case in 3 of the 25 measures studied in the five persistence studies conducted under the prior M&E Protocols: residential d/x air-conditioning, residential refrigerators, and agricultural pumps.

studies from 1995 to 2000 was found to be insignificant for over 95% of measures.[82] Joint Staff, however, may require a technical degradation study at their discretion. These may be needed based upon comments and findings within impact evaluations that discover potential issues with technical degradation, technologies not assessed in the five prior studies, changes in technology for the efficient or standard equipment, or for other reasons. For example, a technical degradation study may be desired for duct sealing which has not been previously studied.

The prior persistence studies included human interaction/behavior in the assessments made for the 25 measures examined. The importance of this may have been most prominent in the assessments of daylighting and energy management systems (EMS). The contribution of longer-term behavioral impacts on energy savings expectations over time could be an issue that still needs further examination, particularly given the greater emphasis being seen on more recent measures that include larger behavioral interaction components. The large human influence in the degradation factors found in EMS may also suggest periodic re-assessment or more field-based measurement studies. Measures that may need to be considered for behavioral degradation studies also include, but are not limited to, commissioning, retro-commissioning, operations and maintenance (O&M) efficiency efforts, programmable thermostats, and specific behavior-based initiatives. Joint Staff will select which measures will receive what types of studies and determine the scope of those evaluation studies focusing on behavioral degradation.

It is expected that evaluation contractors will respond to requests for proposals (RFPs) for retention, EUL, and performance degradation evaluations with proposals that meet the standards contained in this Protocol. The minimum allowable methods, sample criteria, and data collection criteria for these types of evaluations are provided later in this EUL Evaluation Protocol. In their proposal, evaluation contractors may propose (in addition to Protocol compliant methods) optional methods, if the contractor can clearly demonstrate that the optional methods provide at least as much rigor and accuracy as the Protocol-covered approach.

Audience and Responsible Actors

The audience and responsible actors for this Protocol include the following:

- Joint Staff evaluation planners – will use the Protocol to determine: (1) when special studies are needed for evaluating the retention, EUL, and degradation of particular measures, (2) as input into the RFPs for the evaluation of retention, EUL, and degradation, and (3) as background and criteria for use in reviewing retention, EUL, and degradation evaluation plans, managing the retention, EUL, and degradation evaluations, and reviewing retention, EUL, and degradation evaluation reports and results.
- Evaluation project team – will use the Protocol to make sure that the evaluations of the retention, EUL, and degradation of particular measures are based upon the level of rigor(s) designated by the Joint Staff. They will also use the Protocol to double-check that the

[82] These five persistence studies conducted during the prior M&E Protocols and under supervision of the CADMAC Persistence Subcommittee are referred to as Persistence 1 (P1), Persistence 2 (P2), Persistence 3A (P3A), Persistence 3B (P3B), and Neg-TDF Supplement (PNg). These studies covered 25 measures and can be found in the CALMAC searchable database: 2023.pdf, 19980514CAD0006MR.pdf, 2028.pdf, 19990223CAD0003MR.pdf, and 19990223CAD0004MR.pdf.

Protocol requirements have been met as they conduct, complete, and report the retention, EUL, and degradation evaluations.

- Portfolio administrators – will use the Protocol to understand how the retention, EUL, and degradation evaluations will be conducted on their programs, and to understand the evaluation data needs to support the retention, EUL, and degradation evaluations.
- Program Implementers – will use the Protocol to understand how the retention, EUL, and degradation evaluations will be conducted on their programs. Often, they will be required to provide data to support the retention, EUL, and degradation evaluations.
- ISO / System planners – will utilize retention, EUL, and degradation estimates and uncertainty estimates for load forecasting and system planning.

Overview of the Protocol

This section briefly describes the three Protocols contained within the EUL Evaluation Protocol, Protocol rigor levels, key metrics assessed, and assessment inputs and outputs. This section is followed by sections that present the three Protocols that describe the allowable minimum methods for retention, degradation, and EUL studies. The reporting requirements for studies conducted within this Protocol are provided. This is followed by a short section providing guidance on the skills required by evaluators to conduct the type of studies described in this Protocol. The last section provides a brief summary list of the steps needed to comply with the EUL Evaluation Protocol.

Protocol Types

The Effective Useful Life Evaluation Protocol contains three Protocols, each providing the minimum requirements for: (1) retention studies, (2) degradation studies, and (3) EUL analysis studies. Each Protocol has two levels of rigor (Basic and Enhanced).

For each study, Joint Staff and their evaluators should examine opportunities for coordination (e.g., sampling and identifying and marking measures for further study) with impact studies: for example, it may be possible to conduct an analysis of retention for some measures in an impact study, to use the same sample, or use the same sample in a later study. But there are limitations in coordination: e.g., budget, appropriate sample, issues with ensuring random sampling across different objectives, etc. Strategically, it may be best to examine coordination for three different types of coordination: concurrent studies (e.g., examining current program impacts and retention from earlier participation at the same large commercial/industrial sites), past studies (i.e., using samples and information from prior impact studies for later retention or degradation studies), and future studies (e.g., collecting placement/location information or tagging in an impact study in order to assist a future retention study).

An example of how findings from the three types of persistence evaluations would work together to provide a measure's overall persistence is presented graphically in Figure 7.

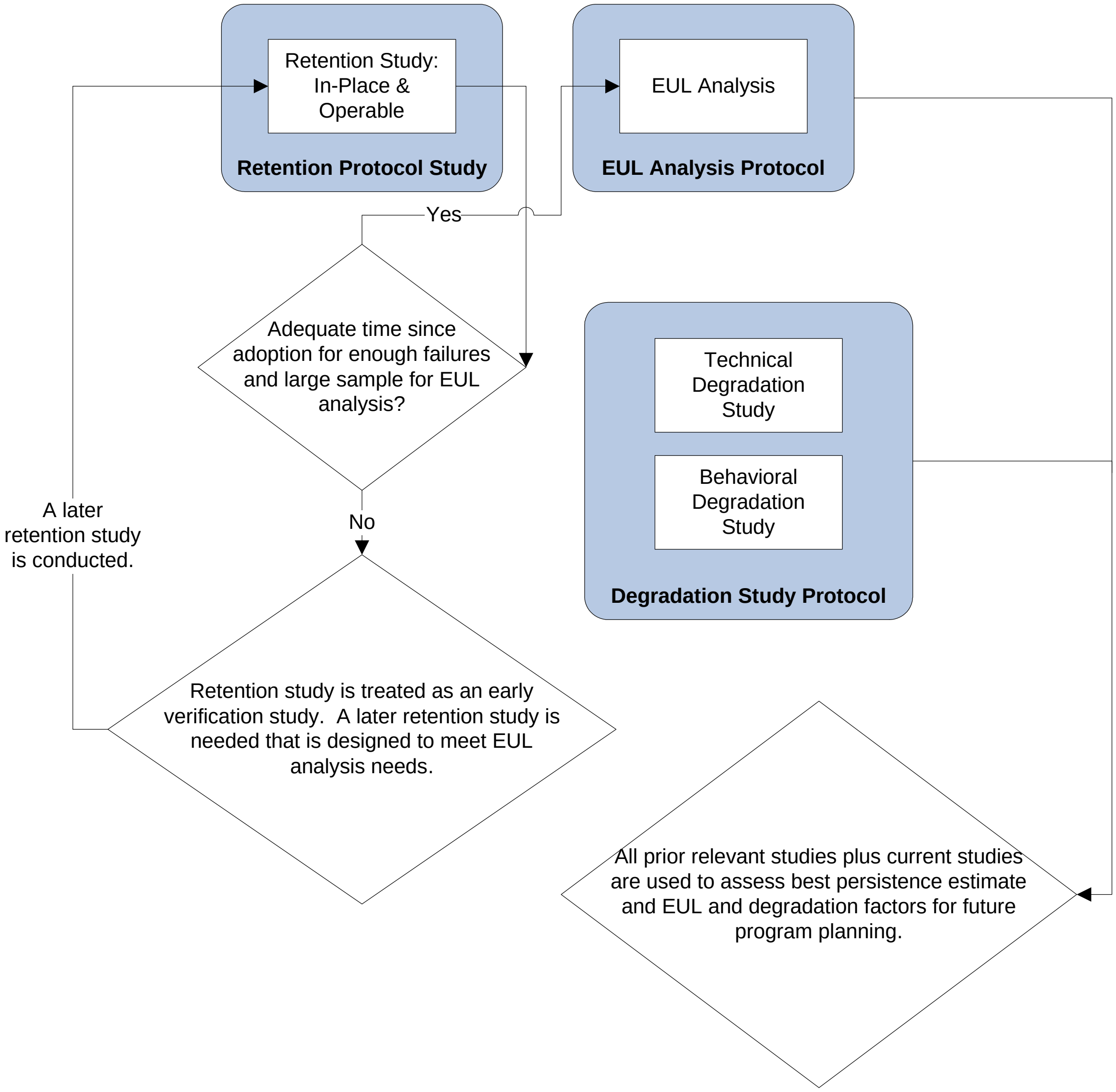

Figure 7. An Example of How Findings Across the Three Types of Studies Would Work Together for Persistence Evaluations

Rigor

When the Joint Staff decides a measure will receive a retention, EUL, and/or degradation evaluation, it also selects the level of evaluation rigor that is required. The Effective Useful Life Evaluation Protocol establishes the methods appropriate for the type of retention, EUL, and degradation evaluation designated to be conducted for the assigned level of evaluation rigor. In this way, the Protocol establishes a minimum level of evaluation rigor in order to ensure that the retention estimates, degradation factors, and EUL estimates produced are at the level of reliability needed to support the overall reliability of the savings in the administrator's Portfolio and the statewide Portfolio.

The level of rigor provides a class of allowable methods in order to offer flexibility for the potential evaluation contractors to assess, and propose the most accurate and cost-effective methods that meet the Joint Staff's needs. The principle is to provide minimum specifications for allowable methods, sample size criteria, and minimum data collection specifications and yet encourage evaluation contractors to utilize both the art and science of evaluation to develop affordable and quality evaluations that produce reliable savings estimates. There are two levels of rigor for each of the three Protocols: Basic and Enhanced, as shown in Figure 8. (The requirements for these rigor levels are described below).

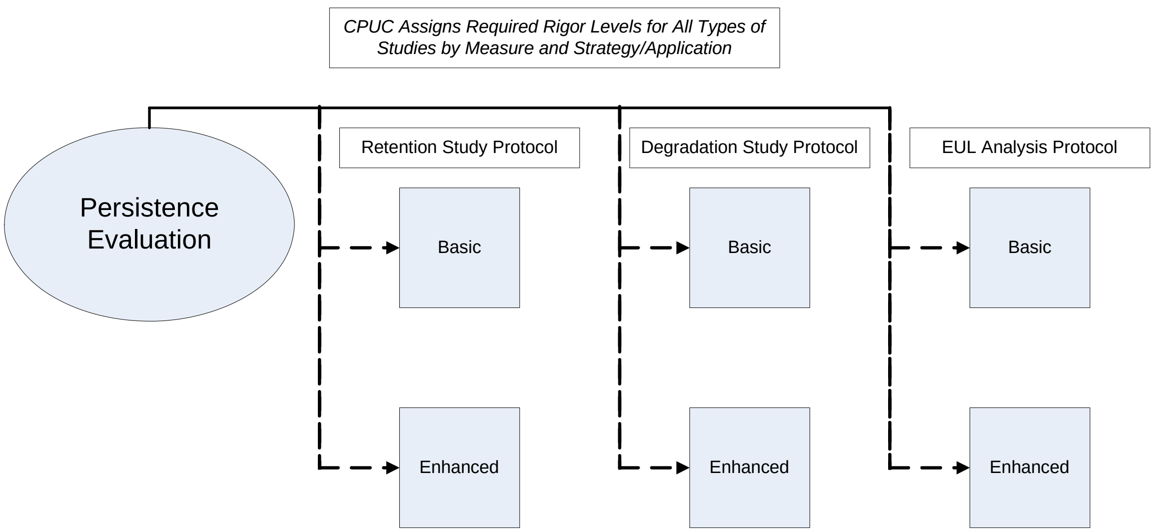

Figure 8. Protocols and Rigor Levels for EUL Evaluations

Joint Staff may assign rigor levels for evaluation studies covered in this Protocol for a measure or group of measures, for a measure within a delivery strategy, sector, or application. Separate retention estimates, degradation factors, and EULs may be required for measures by delivery strategy, sector, and application as assigned by Joint Staff. (Further discussion is provided below.)

Key Metrics, Inputs, and Outputs

Retention, EUL, and degradation evaluations will draw upon relevant data obtained from program databases, program descriptions, DEER database, work papers developed during program planning, on-site measurements, observational data, survey and interview data collection, manufacturers' studies, ASHRAE studies, laboratory studies, and other prior study data and reports. The use of these resources to support the planning and implementation of retention, EUL and degradation studies will help produce more reliable retention, degradation and EUL estimates.

Retention studies will provide the percent of the measures retained, along with clear descriptions of the methods used to determine measure-specific retention rates. In addition, these studies will provide complete definitions of what is considered an "*operable condition*" that constitutes a retained status, and describe the testing criteria used to determine the operable status. Reporting of the retention estimates and degradation factors will also include a clear description of the methods employed and any adjustments made to ensure that the estimates appropriately represent all program installed/adopted measures without bias associated with changes in occupancy or location. The location where the measure was originally located needs to be maintained within a sample, regardless of occupant status, in cases where measures are not moved. For measures/behaviors that can be portable or easily moved, the study will verify the location and use of the measures and determine if they are still being used in a way that provides the projected savings. For the purposes of this Protocol, loss of retention is assumed when participants have moved out and taken the measures with them, unless the study provides reliable installation and energy savings use verification for the retaining of measures within the same utility service territory. (Finding and tracking movers for this purpose, however, is not required.)

Because EUL evaluations must follow the Sampling and Uncertainty Protocol, evaluators must also assess, minimize, and mitigate potential bias and present the achieved level of precision (including relative precision, error bounds, coefficients of variation, standard deviations, and error ratios) for interpreting information, summarizing retention estimates, degradation factors, and EULs and their precision by measure and strategy/application, and providing the information necessary for future evaluation planning. Where precision is calculated from chaining or pooling of evaluation study efforts, the above precision information should be provided for each study effort as well as the combined result.

All studies and evaluations conducted under this Protocol must comply with the reporting requirements contained in this Protocol.

Retention Study Protocol

These are minimum standard Protocols. All methods with higher rigor are allowable as they exceed the minimum criteria. For example, if the measure has a Joint Staff-assigned Basic Rigor and the method proposed by the evaluation contractor is an option under the Enhanced Rigor level, this method will be acceptable for meeting the Protocol if it meets budget and timing constraints. The Enhanced Rigor approach is the preferred approach for all retention studies. The Basic Rigor level may be assigned where this is more reasonable given the technology involved and budget constraints.

The Retention Study Protocol is summarized in Table 11. Further description, additional requirements, clarification, and examples of this Protocol are presented after the table. Being in compliance with the Retention Study Protocol means that the methods used and the way in which they are utilized and reported meet all the requirements discussed within this section (not just those within the summary table or those within the text) to provide unbiased reliable retention estimates. These Protocols sometimes reference other documents that provide examples of applicable methods. However, the operative requirements are only those stated in these Protocols, and not in the other references.

Measure retention studies collect data to determine the proportion of measures that are in place and operational. The primary evaluation components of a measure retention study are research design, survey-site visit instrument design, establishing the definition of an operable status condition, identifying how this condition will be measured, and establishing the data collection and analysis approach. The measure retention estimate can be a straightforward calculation from the data collected. The key planning document associated with the study is the evaluation plan, which presents and discusses the methods for these components, as well as describing the data collection field efforts to be employed to support the data collection approach, and the study reporting to be delivered.

Joint Staff will decide which measures must receive retention studies and whether these studies must be conducted by delivery strategy, sector or other segmentation scheme in order to obtain reliable EUL estimates that can be used as a basis for future program planning. The evaluation contractor is expected to assess these instructions and work with Joint Staff to ensure that the most appropriate and cost-effective retention evaluation design is developed. This should be done as part of the initial evaluation planning and be completed prior to the completion of the final approved Evaluation Plan.

All retention evaluations are required to have a detailed evaluation plan. The evaluation plan needs to include a number of components to support an assessment of the adequacy and approach of the evaluation effort. These include the following components:

- Cover page containing the measures and delivery strategies or applications included in the retention evaluation, program names in the portfolios that include these, program administrators for these programs and their program tracking number(s), evaluation contractor, and the date of evaluation plan.
- Table of Contents.
- High-level summary overview of the measures and delivery strategies or applications included in the retention evaluation, the programs affected, and the evaluation efforts.
- Presentation of the evaluation goals and researchable issues addressed in the evaluation.
- Description of how the evaluation addresses the researchable issues, including a description of the evaluation priorities and the use of assigned rigor levels to address these priorities.
- A discussion of the reliability assessment to be conducted, including a discussion of the expected threats to validity, sources of bias, and a short description of the approaches planned to reduce threats, bias, and uncertainty.
- Task descriptions of the evaluation efforts.
- Review of any related retention and EUL study planning efforts prepared for Joint Staff to include prior estimation of failure sample size requirements, panel retention data needs and availability, and data tagging and collection efforts for these measures.
- Detailed description of the sampling rationale, methods, and sample sizes.
- Detailed description of the definition and methods for determining an operational condition.

- Detailed description of the information that will be needed from the Program Administrators in order to conduct the evaluation that will be included in evaluation-related data requests, including an estimate of date that the information will be needed or for which accessibility to the data is needed.
- Total evaluation budget and a task-level evaluation budget for the study; and
- Contact information for the evaluation manager, including, mail address, telephone numbers, fax numbers and e-mail address.

The evaluation plan should be written in a style and with enough detail that it can be clearly understood by program administrators, policy makers, and evaluation professionals.

Table 11. Required Protocols for Measure Retention Study

Rigor Level	Retention Evaluation Allowable Methods
Basic	1. In-place and operable status assessment based upon on-site inspections. Sampling must meet the Basic Rigor Level requirements discussed in this Protocol and must meet the requirements of the Sampling and Uncertainty Protocol. (The sampling requirements of this Protocol may need to meet the sampling requirements for the subsequent EUL study. See below specification.) 2. Non-site methods (such as telephone surveys/interviews, analysis of consumption data, or use of other data, e.g. from EMS systems) may be proposed but must be explicitly approved by Joint Staff through the evaluation planning process. Sampling must meet the Basic Rigor Level requirements discussed in this Protocol and must meet the requirements of the Sampling and Uncertainty Protocol. (The sampling requirements of this Protocol may need to meet the sampling requirements for the subsequent EUL study. See below specification.)
Enhanced	1. In-place and operable status assessment based upon on-site inspections. Sampling must meet the Enhanced Rigor Level requirements discussed in this Protocol and must meet the requirements of the Sampling and Uncertainty Protocol. (The sampling requirements of this Protocol may need to meet the sampling requirement for the subsequent EUL study. See below specification.)

The analysis of the retention data in either a Basic Rigor or Enhanced Rigor level study must include reporting the retention estimate as found in the study. Nevertheless, an assessment should be included as to whether one model or one brand showed a strong affect on the retention estimate where the exclusion of this model or brand from programs would change the expected resulting EUL by more than 25 percent (25%). If this is suspected prior to completion of the Evaluation Plan, the retention study sampling design and sample sizes may need to be conducted to produce retention estimates for this model or brand separately from that of other models/brands where both retention estimates meet the sampling and precision criteria required for the assigned level of rigor for that retention study. Joint Staff and their evaluators may want to consider whether the retention study sample should be part of an impact evaluation sample, or have separate samples for retention and impacts studies.

Basic Rigor

In-place and operable status assessment based upon on-site inspections is considered the default requirement for retention studies.

The in-place assessment shall be verified through on-site inspections of facilities. Measure, make and model number data shall be collected and compared to participant program records as applicable. As-built construction documents may be used to verify selected measures where access is difficult or impossible (such as wall insulation). Spot measurements may be used to supplement visual inspections, such as solar transmission measurements and low-e coating detection instruments, to verify the optical properties of windows and glazing systems.

Correct measure operation shall be observed and compared to project design intent. Often this observation is a simple test of whether the equipment is running or can be turned on. This can also include, however, changes in application or sector such that the operational nature of the equipment no longer meets project design intent. For example, working gas-cooking equipment that had been installed in a restaurant but is now installed in the restaurant owner's home is most likely no longer generating the expected energy savings and would not be counted as an program-induced operable condition.

Non-site methods (telephone surveys/interviews, analysis of consumption data, or use of other data, e.g. from EMS systems) may be proposed along with a detailed description as to why the proposed method(s) would be reliable for the study measures in their strategies/applications based upon theoretical and past study justifications. All methods, however, must be assessed and approved by Joint Staff through the evaluation planning process and explicit acceptance of proposed non-site methods are required prior to their being used.

The reasons for lack of retention, and the rates of non-retention, should be gathered when feasible for use in developing EUL study designs and future retention studies.

In most cases, there will be a sample size requirement for an EUL study that will be used to determine the sample size requirement for a corresponding retention study since a survival analysis will be based on data collected earlier in a corresponding retention study. Thus, for a given retention time period under study, the sample size for a retention study must meet any prior sample size requirements determined for EUL studies on the proposed measures in these strategies/applications and must meet the requirements of the Sampling and Uncertainty Protocol. However, there are two conditions that could arise that should be addressed:

- If there is no *EUL*-determined required sample size for the retention time period under study and the study retention period is within 30% of the expected EUL, then the sample size required for an EUL study must be calculated in order to determine the retention study sample size requirement. This includes using power analysis at a power of at least 0.7 for the Basic Rigor level to determine the sample size required at a 90% confidence level (alpha set at 0.10), and then deriving the required retention sample size based upon the proportion of the original pool expected to be found in-place and operable (the ex-ante EUL). (See the EUL Analysis Protocol and Appendix D for more information concerning the use of power analysis for determining sample size requirements.)

- If there is no *EUL*-determined required sample size for the retention time period under study and the study retention period is not within 30% of the expected EUL, then the retention study sample size requirement should be based upon the coefficient of variation, standard deviation, and other available estimates of variance for the percent of equipment that is in place and operable from prior studies. The sample size should be large enough to attain a minimum of 30 % precision at the 90% confidence level.

Enhanced Rigor

The in-place assessment shall be verified through on-site inspections of facilities. Measure, make and model number data shall be collected and compared to participant program records as applicable. As-built construction documents may be used to verify measures such as wall insulation where access is difficult or impossible. Spot measurements may be used to supplement visual inspections, such as solar transmission measurements and low-e coating detection instruments, to verify the optical properties of windows and glazing systems.

Correct measure operation shall be observed and compared to project design intent. Commissioning reports (as applicable) shall be obtained and reviewed to verify proper operation of installed systems. If measures have not been commissioned, measure design intent shall be established from program records and/or construction documents; and functional performance testing shall be conducted to verify operation of systems in accordance with design intent. This must also include as assessment of whether changes in application or sector are such that the operational nature of the equipment no longer meets project design intent. For example, working gas-cooking equipment that had been in a restaurant but is now in the restaurant owner's home is no longer meeting project design intent and is no longer generating the expected energy savings.

Analysis of consumption data or use of data from EMS systems may be proposed along with a detailed description as to why the proposed method(s) would be reliable for the study measures in their strategies/applications based upon theoretical and past study justifications. (Telephone surveying or interviewing techniques are not presented as an allowed approach within the Enhanced Rigor level for retention studies.) All methods, however, must be assessed and approved by Joint Staff through the evaluation planning process and explicit acceptance of proposed non-site methods are required prior to their being used.

The reasons for lack of retention, and the rates of these, should be gathered when feasible for use in developing EUL study designs and future retention studies. For example, in one study, the removal rate of refrigerators during the first five years was found to be higher for locations where the consumer moved.[83] It could be expected that as the refrigerator ages the probability for older refrigerators being moved with consumers may decrease. As a result, an improved EUL function would reflect the risk of participants moving with their refrigerators.

[83] This hypothesis, its testing, and consequences were examined in a study by Quantum Consulting and Megdal & Associates in the *Retention Study of Pacific Gas and Electric Company's 1996 and 1997 Appliance Energy Efficiency Programs*, Study ID 373 1R1, March 2001.

In most cases, there will be a sample size requirement for an EUL study that will be used to determine the sample size requirement for a corresponding retention study since a survival analysis will be based on data collected earlier in a corresponding retention study. Thus, for a given retention time period under study, the sample size for a retention study must meet any prior sample size requirements determined for EUL studies on the proposed measures in these strategies/applications and must meet the requirements of the Sampling and Uncertainty Protocol. However, there are two conditions that could arise that should be addressed::

- If there is no *EUL*-determined required sample size for the retention time period under study and the study retention period is within 30% of the expected EUL, then the sample size required for an EUL study must be calculated in order to determine the retention study sample size requirement. This includes using power analysis at a power of at least 0.8 for the Enhanced Rigor level to determine the failure sample size required at a 90% confidence level (alpha set at 0.10) and then deriving the required retention sample size based upon the proportion of the original pool expected to be found in-place and operational. (See the EUL Analysis Protocol and Appendix D for more information concerning the use of power analysis for determining sample size requirements.)

If there is no *EUL*-determined required sample size for the retention time period under study and the study retention period is not within 30% of the expected EUL, then the retention study sample size requirement should be determined based upon the coefficient of variation, standard deviation and other available estimates of variance for the percent of equipment that is in place and operable from prior studies. The sample size should be large enough to attain a minimum of 10 % precision at the 90% confidence level.

Degradation Study Protocol

These are minimum standard Protocols. All methods with higher rigor are allowable as they exceed the minimum criteria. For example, if the measure has been assigned a Basic level of rigor by the Joint Staff and the method proposed by the evaluation contractor is an option under Enhanced, this method will be acceptable for meeting the Protocol. The Enhanced Rigor approach is the preferred approach for all retention studies. The Basic Rigor level may be assigned as is reasonable given the technology involved and budget constraints.

The Degradation Study Protocol is summarized in Table 12. Further description, additional requirements, clarification, and examples of this Protocol are presented after the table. Being in compliance with the Degradation Study Protocol means that the methods used and the way in which they are utilized and reported meet all the requirements discussed within this section (not just those within the summary table or those within the text) to provide unbiased reliable estimates of the technical degradation factor. The Protocols sometimes reference other documents that provide examples of applicable methods. The requirements, however, are always those stated in these Protocols, which take precedence over all others in all circumstances.

Performance degradation studies produce a factor that is a multiplier used to account for both time-related and use-related change in the energy savings of a high efficiency measure or practice relative to a standard efficiency measure or practice. It is important to note that the degradation study is a relative difference measurement between the high efficiency equipment/behavior and the non-high efficiency equipment/behavior over time (and not the relative level of retention). Said in a different way, it is the difference over time between the energy usage of the energy efficient equipment/behavior and the standard equipment/behavior it replaced. Appropriate standard measure comparisons are critical.

Studies must designate and clearly describe all the elements that will be analyzed for the degradation factor produced. If only a technical degradation factor is produced, or only a behavioral degradation factor is produced for a measure that contains both (i.e. when a technical degradation factor and a behavioral degradation factor is associated with the same piece of equipment), this must be clearly noted. If the equipment has both a technical and behavioral degradation factor, and one of these is to come from a previous study or another source, and the other is being addressed in the Protocol-covered study, both factors must be presented in the report, and the analysis must produce a combined factor for that equipment. If only one factor is being produced, the study must clearly describe whether this covers the full degradation factor to be used for that measure or indicate if additional research is needed to establish a more complete/reliable factor that includes both technical and behavioral degradation. For example, a measure that is purely behavioral (e.g., maintenance behavior schedules) would only receive a behavioral degradation factor and this should be clearly described, however, a measure such as a programmable thermostat would need a combined performance degradation factor that incorporates the technical degradation factor for the measure and the behavioral degradation factor associated with the use of the measure as an energy saving device.

Since the degradation factor is the difference between the standard equipment/behavior and that of the program measures, the over time, changes in usage for standard and efficiency must be clearly assessed/measured and reported or the component differences and their changes in usage over time must be explained and assessed/measured.

All degradation evaluations are required to have a detailed evaluation plan. The evaluation plan needs to include a number of components to support an assessment of the adequacy and approach of the evaluation effort. These include the following components:

- Cover page containing the measures and delivery strategies or applications included in the degradation evaluation, program names in the portfolios that include these, program administrators for these programs and their program tracking number(s), evaluation contractor, and the date of evaluation plan.
- Table of Contents.
- High-level summary overview of the measures and delivery strategies or applications included in the degradation evaluation, the programs affected, and the evaluation efforts.
- Presentation of the evaluation goals and researchable issues addressed in the evaluation.
- Description of how the evaluation addresses the researchable issues, including a description of the evaluation priorities and the use of assigned rigor levels to address these priorities.

- A discussion of the reliability assessment to be conducted, including a discussion of the expected threats to validity, sources of bias, and a short description of the approaches planned to reduce threats, bias, and uncertainty.
- Task descriptions of the evaluation efforts.
- Detailed description of the sampling rationale, methods, and sample sizes.
- Detailed description of the methodology to be used for the assessment for both the standard equipment/behavior and that for the efficient equipment/behavior, and the approach to be used for quantifying the difference between these two conditions. This condition applies regardless if the study is determining the EUL by assessing the equipment as a whole unit, or if the assessment is conducted for a key component of the equipment, or if the assessment is based on engineering assumptions about the expected performance or performance life of a component of the equipment.
- Detailed description of the information that will be needed from the Program Administrators in order to conduct the evaluation that will be included in evaluation-related data requests, including an estimate of date that the information will be needed or for which accessibility to the data is needed.
- Total evaluation budget and a task-level evaluation budget for the study; and
- Contact information for the evaluation manager, including, mail address, telephone numbers, fax numbers and e-mail address.

The evaluation plan should be written in a style and with enough detail that it can be clearly understood by program administrators, policy makers, and evaluation professionals.

Table 12. Required Protocols for Degradation Study

Rigor Level	Allowable Methods for Degradation Studies
Basic	1. Literature review required for technical degradation studies across a range of engineering-based literature, to include but not limited to manufacturer's studies, ASHRAE studies, and laboratory studies. Review of technology assessments. Assessments using simple engineering models for technology components and which examine key input variables and uncertainty factors affecting technical degradation. 2. Telephone surveys/interviews with a research design that meets accepted social science behavioral research expectations for behavioral degradation.
Enhanced	1. For technical degradation: field measurement testing. 2. For behavioral degradation: field observations and measurement.

Basic Rigor

Technical degradation studies require a literature review for the measures under study. The literature search should include journal articles, conference proceedings, manufacturer publications, publications of engineering societies (e.g., ASHRAE), national laboratories, and government agencies, and the gray literature (i.e., studies that are not widely published but are available upon request). In addition, technology assessments using simple engineering models for technology components will be conducted. Studies will be conducted that examine key input variables and uncertainty factors affecting technical degradation.

Laboratory testing may be used to determine the technical degradation factor(s) for the Basic Rigor level. Laboratory testing involves the measurement of energy use of both energy efficient and standard equipment over time, but in unoccupied facilities. Laboratory testing must account for the operational conditions expected for installations obtained through the California programs that incorporate the measure in their service mix.

Telephone surveys/interviews with a research design that meets accepted social science behavioral research expectations for behavioral degradation. The use of the term acceptable, in this case, means that the approach and the data collection methods would pass a peer review process using highly experienced professional social science researchers, in such a way that peers would support and defend the approach as being objective and reliable within the ability of the approach selected. The types of questions asked will focus on whether the energy efficient and standard equipment are being used/operated as designed and the reasons for their non-use or changes in use.

Enhanced Rigor

Technical degradation studies at the Enhanced Rigor level require field measurement. Field measurement involves the measurement of energy use for both the energy efficient and the standard equipment over time – these measures would be located in occupied facilities. These measurements must be designed to collect data on the equipment or equipment components in order to reduce the greatest uncertainties associated with the degradation factor estimates and be conducted with sample sizes to allow for 90% confidence and 30% precision in these measurements.

Behavioral degradation studies focus on the observation (and measurement, if applicable) of the use of energy efficient and standard equipment in facilities. The studies can be short term (one-time site visits) or long term (periodic site visits) to assess if the measures are being used as designed. The types of questions asked will focus on whether the energy efficient and standard equipment are being used/operated as designed and the reasons for their non-use or changes in use. The self-reports will be matched with observational data for confirmation. Measurement studies must be designed to collect data to reduce the greatest uncertainties associated with the degradation factor estimates and be conducted on sample sizes to allow for 90% confidence and 30% precision in these measurements.

Effective Useful Life Analysis Protocol

These are minimum standard Effective Useful Life (EUL) Protocols. All methods with higher rigor are allowable as they exceed the minimum criteria. For example, if the measure has a Joint Staff assigned rigor of Basic and the method proposed by the evaluation contractor is an option under Enhanced, this method will be acceptable for meeting the Protocol.

The EUL Analysis Protocol is summarized in Table 13. Further description, additional requirements, clarification, and examples of this Protocol are presented after the table. Being in compliance with the EUL Analysis Protocol means that the methods used and the way in which they are utilized and reported meet all the requirements discussed within this section (not just those within the summary table or those within the text) to provide unbiased reliable estimates of EUL. The Protocols sometimes reference other documents that provide examples of applicable methods. The requirements, however, are always those stated in these Protocols, which take precedence over all others in all circumstances.

The objective of the EUL analysis studies is to estimate the ex-post EUL, defined as the estimate of the median number of years that the measures installed under the program are still in place, operable, and providing savings. Evaluators are expected to develop a plan for estimating survival functions for measures included in the scope of their work. The plan should incorporate an assessment of the study's ex-post EUL compared to the findings of other studies on this measure for this delivery strategy/application and to the EUL contained in the DEER database (if one exists). The study should also provide recommendations for whether the new EUL should be substituted for the existing ex-ante EUL for future program planning or if another DEER category for the measure should be developed. The EUL studies are also required to report the findings from the most recent degradation studies related to the EUL study measures/applications, so that the EUL report is a depository for all current persistence studies for the study measures/applications. This will assist Joint Staff and future evaluators find all relevant persistence information for a measure/application in one location.

Joint Staff will decide which measures must receive EUL studies and whether these studies must be conducted by delivery strategy, sector, or other segmentation scheme in order to obtain reliable EUL estimates that can be appropriately used for various future program planning alternatives. The evaluation contractor is expected to assess these instructions and work with Joint Staff to ensure that the most appropriate and cost-effective evaluation design is developed, so reliable EUL estimates are obtained to meet this purpose. This should be done as part of initial evaluation planning and be completed prior to completion of the Evaluation Plan.

As part of the evaluation plan, the evaluator should propose a method for estimating a survival function and a survival rate of measures installed over time using standard techniques (see below). This should include an identification of factors that might lead to lower survival rates and a discussion of how the confidence intervals for the survival functions derived will be estimated. This should also include a discussion of potential sources of bias in the methods proposed and how these sources of bias will be mitigated.

All EUL analysis evaluations are required to have a detailed evaluation plan. The evaluation plan needs to include a number of components to support an assessment of the adequacy and approach of the evaluation effort. These include the following components:

- Cover page containing the measures and delivery strategies or applications included in the EUL analysis evaluation, program names in the current and past (up to 10 years previous programs) portfolios that include these, program administrators for these programs and their program tracking number(s) if applicable, evaluation contractor for those programs, and the date of evaluation plan.

- Table of Contents.
- High-level summary overview of the measures and delivery strategies or applications included in the evaluation, the programs affected, and the evaluation efforts conducted.
- Presentation of the evaluation goals and researchable issues addressed in the current EUL evaluation being planned.
- Description of how the evaluation addresses the researchable issues, including a description of the evaluation priorities and the use of assigned rigor levels to address these priorities.
- A discussion of the reliability assessment to be conducted, including a discussion of the expected threats to validity, sources of bias, and a short description of the approaches planned to reduce threats, bias, and uncertainty.
- Task descriptions of the evaluation efforts.
- Review of any related EUL study planning efforts prepared for Joint Staff to include prior estimation of failure sample size requirements, panel retention data needs and availability, and data tagging and collection efforts for these measures.
- Detailed examination of related retention studies, assessment of prior and concurrent retention studies and recommendation of what additional data must be collected and, if so, why. If additional data collection is proposed, then a detailed description of the sampling rationale, methods, and sample sizes must be included.
- Detailed description of the information that will be needed from the Program Administrators in order to conduct the evaluation that will be included in evaluation-related data requests, including an estimate of date that the information will be needed or for which accessibility to the data is needed.
- Total evaluation budget and a task-level evaluation budget for the study; and
- Contact information for the evaluation manager, including, mail address, telephone numbers, fax numbers and e-mail address.

The evaluation plan should be written in a style and with enough detail that it can be clearly understood by program administrators, policy makers, and evaluation professionals.

As noted below, we rely on power analysis for helping to differentiate Basic Rigor from Enhanced Rigor (see Appendix D for more discussion and references). Statistical power is the probability that statistical significance will be attained, given that there is a measurable treatment effect. Power analysis is a statistical technique that can be used (among other things) to determine sample size requirements to ensure that statistical significance can be found. Power analysis is a required component in the Protocol to assist in determining required sample sizes.

The Basic level of rigor in the EUL Protocols requires that a 0.70 level of power be planned at the 90% level of confidence. While the Enhanced level of rigor requires that a 0.80 level of power be planned also at the 90% level of confidence. In determining sample sizes in the research planning process, values for key parameters can be varied in an attempt to balance a level of statistical power, the alpha, the duration of the study, and the effect size, all determined with an eye on the budget constraints. The values will probably be unique to each measure selected for study. The differing power requirements between the Basic and Enhanced level of rigor drives up the required sample size to meet the Enhanced Rigor level versus that needed to meet the Basic Rigor level. The results of the power analysis will be combined with professional judgment and past studies to arrive at the required sample sizes. The selected sample size, the results of the power analysis, and the justification for the sample size proposed must be included in the evaluation plan. This evaluation plan must be approved by Joint Staff prior to sample data collection.

Table 13. Required Protocols for EUL Analysis Studies

Rigor Level	Allowable Methods for EUL Analysis Studies
Basic	1. Classic survival analysis (defined below) or other analysis methods that specifically control for right-censored data (those cases of failure that might take place some time after data are collected) must be attempted. For methods not accounting for right-censored data, the functional form of the model used to estimate EUL ("model functional form") must be justified and theoretically supported. Sampling must meet the Basic Rigor Level requirements discussed in this Protocol and must meet the requirements of the Sampling and Uncertainty Protocol. Sample size requirements will be determined through the use of power analysis, results from prior studies on similar programs, and professional judgment. Power analysis used to determine the required sample size must be calculated by setting power to at least at 0.7 to determine the sample size required at a 90% confidence level (alpha set at 0.10). Where other analyses or combined functional forms are used, power analysis should be set at these parameters to determine required sample sizes for regression-based approaches and a 90% confidence level with 30% precision is to be used for non-regression components.
Enhanced	1. Classic survival analysis (defined below) or other analysis methods that specifically control for right-censored data (those cases of failure that might take place some time after data are collected) must be attempted. The functional form of the model used to estimate EUL ("model functional form") must be justified and theoretically supported. Sampling must meet the Enhanced Rigor Level requirements discussed in this Protocol and must meet the requirements of the Sampling and Uncertainty Protocol. Sample size requirements will be determined through the use of power analysis, results from prior studies on similar programs, and professional judgment. Power analysis used will set power to at least to 0.8 to determine the sample size required at a 90% confidence level (alpha set at 0.10). Where other analyses or combined functional forms are used, power analysis should be set at these parameters to determine required sample sizes for regression-based approaches and a 90% confidence level with 10% precision is to be used for non-regression components.

Basic Rigor

Current ex-ante EULs were developed using engineering experience and assumptions, past M&V-related evaluation efforts, and past EUL studies. Engineering analysis and M&V

observations suggest that energy efficiency measures generally last a certain average length of time and then rapidly move out of use as the measures reach their end of life service. However, these approaches have generally not considered retention and behavioral degradation in establishing the EUL estimates. Similarly, a few measures may continue to last significantly beyond their expected lifetime.

An initial approximation for most types of EUL forecasts efforts involve some form of a linear estimate, even if the estimate is not linear during the first years of use, or during the later years. This typically involves trying to fit a line to the observed data and use this to predict EUL estimates. Yet, the engineering experience for efficiency measures suggests that a linear model may not represent the survival function of many energy efficiency measures.

Common alternative models include logistic and exponential models. A variation of the logistic function can be used to describe a pattern of little loss in the early years with increasing loss as the measure approaches its expected life, with a flattening loss occurring thereafter.

The standard cumulative logistic probability function is:

$$Pi = F(Z_i) = F(\alpha + \beta X_i) = 1/(1 + e^{-(\alpha + \beta X_i)})$$

The logistic model is generally used to measure and predict probabilities that an event will occur. This model limits the end points to zero and one. The cumulative logistic, the logistic model, looks like the curve shown in Figure 9.

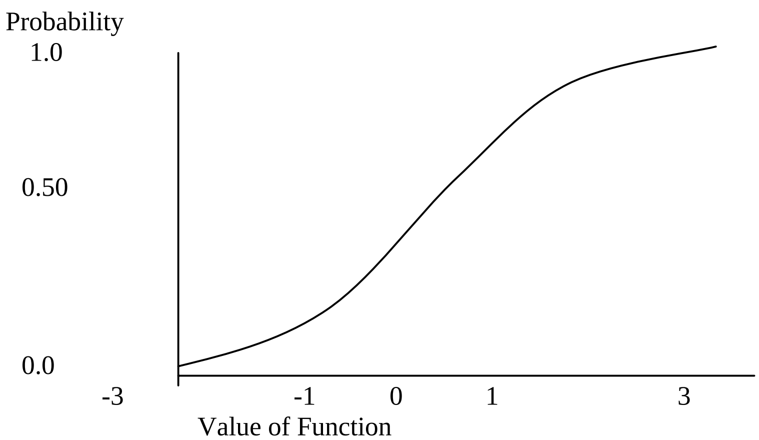

Figure 9. Cumulative Logistic Function

The logistic function that best fits the engineering observations described above relies upon a logistic function of time for identifying the EUL. This is:

$$F(Z_i) = 1-[1/(1 + e^{-(t + EUL)\, b})$$

With the survival function as in Figure 10.

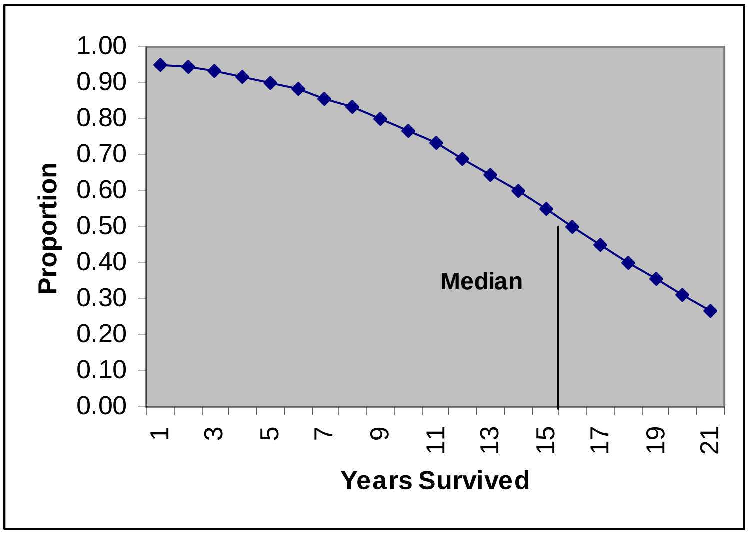

Figure 10. Logistic Survival Function with EUL=15 and b=0.2

Many energy efficiency retention studies examine energy efficiency equipment as being either there or not. This dichotomous scale allows the possibility of using classical survival analysis techniques. These outcomes are dichotomous, that is, they either occur or not and can be measured as zero or one events.

Classic survival analysis is specifically designed to account for the fact that "failures" might take place some time after when data are measured. In the statistical literature, these cases are said to be "right censored" – their failures are not included in the analysis, because the time period was not long enough to include their eventual failure. As a result, estimating the mean or median when data are right censored can provide a biased estimate. Classic survival analysis techniques have been developed that account for this right censorship in the data and are able to provide unbiased estimates. Thus, given enough data, many functional forms of survival analysis models ("model functional forms") can be tested with available survival analysis statistical programs. The regression techniques available allow consideration of right censored data and can handle continuous time data, discrete time data, and other types of data.[84]

[84] Multiple statistical modeling packages (SAS®, Stata®, SPSS®, R®, S+®, and others) provide survival analysis programs. There are several commercial and graduate textbooks in biostatistics that are excellent references for classic survival analysis. One of these used as reference for some of the prior EUL studies in California is the SAS® statistical package and the reference *Survival Analysis Using the SAS® System: A Practical Guide* by Dr. Paul D. Allison, SAS® Institute, 1995. Several model functional forms are available and should be considered for testing. These forms include logistic, logistic with duration squared (to fit expected pattern of inflection point slowing of retention losses), log normal, exponential, Weibull, and gamma. A few of many possible references include: *The Statistical Analysis of Failure Time Data* (Wiley Series in Probability and Statistics) by John D. Kalbfleisch, Ross L. Prentice, Wiley, 2003; *Survival Analysis: A Self-Learning Text* by David G. Kleinbaum, Mitchel Klein, Springer-Verlag New York, LLC, 2005; *Survival Analysis* by David Machin, Wiley, 2006; and *Applied Longitudinal Data Analysis: Modeling Change and Event Occurrence* by Judith D. Singer, John B. Willett, Oxford University Press, 2003.

Given the advantages of classic survival analysis for producing unbiased estimates of the EUL, both levels of rigor require attempting this method where applicable. The high demand for failure data and the need for differentiated data over time to best approximate a reasonable functional form have often meant that these models either did not provide algorithm convergence or produce reasonable results. Accordingly, other methods that specifically control for right censored data not yet well defined or explained must be attempted in its place, if they are appropriate to the hypothesized hazard functional form.

Where a specific method that controls for the issues associated with right censored data <u>cannot</u> be made workable or to produce reasonable results that can be justified, then the evaluator may resort to other methods to estimate the EUL. Nevertheless, the EUL estimate from other methods must either adjust or, at a minimum, discuss the likely potential bias in the EUL estimate given the inability to control for right censored data issues.

Sample size requirements will be determined through the use of power analysis, results from prior studies on similar programs, and professional judgment. Power analysis will set <u>power to at least to 0.7</u> to determine the sample size required at a 90% confidence level (alpha set at 0.10) and then derive the required retention sample size based upon the proportion of the original pool expected to be found in-place and operable (ex-ante EUL) and the desired effect size as determine by Joint Staff. Where other analyses or combined functional forms are used, power analysis should be set at these parameters to determine required sample sizes for regression-based approaches and a 90% confidence level with <u>30% precision</u> is to be used for non-regression components. Sampling and reporting of sampling and uncertainty must meet the requirements of the Sampling and Uncertainty Protocol.

Joint Staff may want to consider whether the EUL study sample should be part of an impact evaluation sample, or have separate samples for EUL and impacts studies. Joint Staff may assign separate retention and EUL analysis studies or joint studies as they find appropriate for the timing of the evaluations and efficiencies between studies.

Enhanced Rigor

All of the analysis requirements for the Basic Rigor level apply to the Enhanced Rigor level.

Sample size requirements will be determined through the use of power analysis, results from prior studies on similar programs, and professional judgment. Power analysis will set <u>power to at least to 0.8</u> to determine the sample size required at a 90% confidence level (alpha set at 0.10) and then deriving the required retention sample size based upon the proportion of the original pool expected to be found in-place and operable (ex-ante EUL) and the desired effect size as determine by Joint Staff. Where other analyses or combined functional forms are used, power analysis should be set at these parameters to determine required sample sizes for regression-based approaches and a 90% confidence level with <u>10% precision</u> is to be used for non-regression components. Sampling and reporting of sampling and uncertainty must meet the requirements of the Sampling and Uncertainty Protocol.

Joint Staff may want to consider whether the EUL study sample should be part of an impact evaluation sample, or have separate samples for EUL and impacts studies. Joint Staff may assign separate retention and EUL analysis studies or joint studies as they find appropriate for the timing of the evaluations and efficiencies between studies.

Reporting Requirements

All EUL evaluations are expected to assess and discuss the differences between the (a) ex-ante EUL estimates from DEER or as otherwise approved by the Joint Staff and (b) the ex-post EUL estimates produced by the EUL evaluation study(ies). To the extent that the data gathered and evaluation analyses conducted can explain the causes for these differences, this must be presented and discussed. The evaluation report should note situations in which explanations are not possible due to lack of sufficient data or problems with interpretation. The EUL evaluation report must also include a recommendation of the EUL for the measure and delivery strategy/application that should be used for future program planning. This recommendation may take the form of recommending the replacement of a DEER EUL or the establishment of a new DEER category.

The EUL studies are also required to report the findings from the most recent degradation studies related to the EUL study measures/applications, so that the EUL report is a depository for all current persistence studies for the study measures/applications. This will assist Joint Staff and future evaluators find all relevant persistence information for a measure/application in one location.

All **reporting under this Protocol** should include the following:

1. Cover page containing the measures and delivery strategies or applications included in the retention evaluation, program names in the portfolios over the last 5 years that include these, program administrators for these programs and their program tracking number(s), evaluation contractor, and the date of evaluation plan.
2. Table of Contents.
3. High-level summary overview of the measures and delivery strategies or applications included in the evaluation, the programs affected, and the evaluation efforts.
4. Presentation of the evaluation goals and researchable issues addressed in the evaluation.
5. Description of how the evaluation addresses the researchable issues, including a description of the evaluation priorities and the use of assigned rigor levels to address these priorities.
6. Detailed description of the data collection and analysis methodology.
7. Current and prior retention results for selected measures given delivery strategy/application and their precision levels at a 90% confidence interval.
8. Retention, degradation, and EUL findings as is appropriate for the study assigned.
9. A discussion of the reliability assessment to be conducted, including a discussion of the expected threats to validity, sources of bias, and a short description of the approaches planned to reduce threats, bias, and uncertainty.
10. Contact information for the evaluation manager, including, mail address, telephone numbers, fax numbers and e-mail address.

In addition to the above, **retention studies** must also include the following:

- Description of initial and final sample of measures still surviving.
- Describe any findings on factors leading to the higher or lower retention rates.
- Description of removal reasons, their distribution, and potential issues created by different removal reasons and the research design and functional forms that should be investigated in future EUL studies for these measures.

In addition to the overall EUL study reporting requirements, **degradation studies** must also include the following:

- Describe any findings on factors leading to the relative degradation rates and absolute degradation rates, if available.
- Describe the impact of degradation on energy savings

In addition to the overall EUL study reporting requirements, **EUL analysis studies** must also include the following:

- Specific equations for survival functions and estimated precision of curve fit.
- Analysis of the ex-post EUL compared to the ex-ante EUL and comparison of to the methods and results from any prior retention, degradation, or EUL studies available for that measure (to include comparisons by delivery strategy and application).
- Recommended EUL for the measure and delivery strategy/application that should be used for future program planning.

Study Selection and Timing

A significant amount of funding has been spent in California conducting EUL studies under the prior M&E Protocols. These studies, completed through 2004, have been reviewed in a recent study (Skumatz et al. 2005).[85] Those measures with useful lives that have been confirmed in the last five years are less likely in need of additional study in the 2006- 2008 study period. Early work by Joint Staff in the EUL planning effort may include an initial study of required EUL sample sizes, review of prior EUL studies and their data collection methods, and an assessment of which measures should be prioritized for which types of studies. Important questions for early EUL planning efforts include the following:

- Which measures should obtain early panel data collection plans?
- Where can data be collected in the future through periodic retention studies that incorporate estimated removal dates prior to the retention study date (prospective studies that use retrospective methods in their site or telephone surveying)? For example, it may

[85] *Revised/Updated EULs based on retention and persistence studies results*, Revised Report, Lisa Skumatz, John Gardner, Skumatz Economic Research Associates, Inc., Superior, CO, 2005. It should be noted that several ninth-year studies have been or are being conducted since the summary report was produced.

be possible to conduct studies on data collected from past years on measures promoted in previous programs for conducting a retention study, or one can simply conduct retention studies on measures installed in the current programs.

- Which long-life measures should have a retrospective analysis conducted for obtaining an EUL estimate?[86] For example, a measure that was included in a previous program currently has an ex-ante EUL of over 7 years, so that obtaining a reliable ex-post EUL estimate in the next three years from a prospective approach would be highly unlikely. However, an ex-post EUL estimate may be obtainable by conducting retrospective analyses on the prior program sites.

The analysis could also include an assessment of the costs, benefits, and removal risks for tagging[87] and/or using radio frequency identification (RFID) chips by program implementers to simplify future retention studies. This information can be used to estimate study costs, timing of study RFPs, and as input into any risk analysis used to allocate resources for EUL studies.

The general rules for how often and what EUL/retention/degradation evaluations need to be conducted are determined by the Joint Staff. The Joint Staff will decide for each measure, if and when the measure will receive a retention study, a degradation study, and/or an EUL evaluation. They will also decide whether the studies need to be conducted for the measure in a single classification or segregated by delivery strategy or application and whether degradation studies will be overall or technology-based or behavior-based. A few examples of when this might occur are: (1) where early removal is a risk due to performance, comfort or aesthetic concerns, (2) when more detailed evaluation information is needed for a measure for future program planning, (3) to support an update of DEER, or (4) a new measure is being piloted or expanded in its use. Joint Staff may assess these situations through risk analysis to determine which types of EUL studies to undertake and when.

Guidance on Skills Required to Conduct Retention, EUL, and Technical Degradation Evaluations

The senior, advisory and leadership personnel for EUL analysis evaluation efforts need to have the specific skills and experience in regression and statistics proving an ability to be able to conduct classic survival analysis and handle EUL functional form and issue analysis, as well as the time budgeted for responsible project task leadership and quality control.

[86] The retention/EUL studies conducted under the prior M&E Protocols included panel studies, one-retention point site visit studies, site and telephone surveys that had field observation estimate, and consumer estimates on prior removal dates. The one-point retention studies generally provided only two time points for the retention analysis. This does not allow for information to help determine the appropriate functional form or for inflection points in removal rates. Panel studies offer the most reliable information but are quite expensive. Periodic site and telephone surveys with consumer estimates of removal dates offer the most cost-effective data if their reliability is sufficient for accurate EUL estimation. Some measures can have retention (in place and operational) reliably measured through telephone surveys (e.g., attic and wall insulation seeking remodeling occurrences) while others may require site visit verification and measurement.

[87] A 1994 study by ASW Engineering and KVD Research Consulting concluded that tagging equipment might not be viable due to retention issues with the tags.

There are methods that could employ significant primary survey or interview data collection. The evaluators using these methods should have sufficient experience implementing surveys, interviews, group interviews, and other types of primary data collection activities as are being recommended.

Engineering or audit skills are needed for site visit operable testing for some measures. The extent of the experience and expertise needed varies with the sophistication of the operational testing. Verification of make, model number, and likelihood that the piece of equipment is the original program installed one can be made by auditors or engineers with experience/training with regard to identification of the type of equipment being examined. Operable verification that uses commissioning reports, energy management system reports, or similar reporting must be reviewed by engineers with experience/training that allows a quality verification effort.

Telephone surveys and interviews need to be conducted by experienced personnel. These studies and their instruments must be designed with personnel with experience in energy efficiency markets, the social sciences, and interview and survey instrument design, implementation and analysis.

Technical degradation studies require senior experienced engineers that are quite familiar with the equipment to be studied, its standard counter-part, and the components, operations, and effects of changes in the operational conditions on the components and function of the equipment. Senior personnel must also have the time budgeted for significant input and review, for responsible project task leadership and quality control. The degree of involvement needed from senior skilled staff is dependent upon the skill and experience of the mid-level personnel conducting much of the analysis work.

Methods for conducting behavioral degradation could be based upon survey and interview analysis methods and/or statistical/econometric methods. The personnel to conduct the work need to have the skills and experience for the method being proposed. The evaluators need to be trained and experienced in conducting social science research with a strong understanding of assessing and testing causal relationships between exposure to the program and possible outcomes. An important requirement is for these evaluators to have a strong foundation in research design and the ability to create research designs to test for net behavioral impacts of energy efficiency programs.

Summary of Protocol-Driven Impact Evaluation Activities

1	Joint Staff will review retention, EUL, and degradation planning information, perhaps through an initial study of (1) prior retention, EUL, and degradation studies and methods, (2) required retention, EUL, and degradation sample sizes, and (3) assessment of data collection methods for the prioritized measure and delivery strategy/application needs. Along with any risk analysis information, Joint Staff will identify which measures by delivery strategy/application will receive which type of retention, EUL, and degradation evaluation, when, and at what rigor level. Joint Staff will determine any special needs on a case-by-case basis that will be required for particular retention, EUL, and degradation evaluations. Joint Staff will develop preliminary RFPs for groups of studies based upon timing of the needed data collection or analysis, similar sectors or issues to be addressed, and requiring similar skill sets. CPUC-ED will issue RFPs for retention, EUL, and degradation evaluations, select evaluation contractors, and establish scope(s) of work.
2	Evaluators will develop a research design and sampling plan to meet Protocol requirements as designated by the Joint Staff rigor level assignments. This includes meeting requirements from the Sampling and Uncertainty Protocol, as are applicable given Effective Useful Life Evaluation Protocol requirements. Research design and sampling must be designed to meet any of the Joint Staff requirements for additional analyses to include but not limited to areas designated of specific concern by the Joint Staff. Evaluators will develop and submit an Evaluation Plan to Joint Staff, and the plan will be revised as necessary to have an approved Evaluation Plan that meets the Effective Useful Life Evaluation Protocol.
3	All retention, EUL, and degradation study evaluation teams (including panel data collection teams) will make sure their teams are appropriately staffed, in order to meet the skills required for the research design, sampling, and selected retention, EUL, and degradation evaluation method, uncertainty analysis, and reporting being planned and conducted.
4	All retention, EUL, and degradation study evaluations will be planned, conducted, and analyzed to minimize potential bias in the estimates (showing the methods for doing this), and evaluators will report all analyses of potential bias issues as described in the Sampling and Uncertainty Protocol.
5	All retention, EUL, and degradation evaluations will be conducted according to the Evaluation Plan and appropriate Protocols.
6	Evaluators will develop the draft evaluation report in accordance to guidance provided by the Joint Staff and reporting requirements in this Protocol.
7	Final evaluation report will be developed in accordance to guidance provided by the Joint Staff, and then submitted to Joint Staff.
8	Once accepted by Joint Staff, abstracts will be developed, and a report will be posted on the CALMAC web site following the CALMAC posting instructions.

Note: the steps included in this evaluation summary table must comply with all the requirements within the Effective Useful Life Evaluation Protocol in order to be in compliance.

Process Evaluation Protocol

Introduction

The Process evaluation is not a required evaluation activity in California. It is, however, often critical to the successful implementation of cost-effective and cost-efficient energy efficiency programs. Process evaluations identify improvements or modifications to a group of programs, individual programs or program components, that directly or indirectly acquire or help acquire, energy savings in the short-term (resource acquisition programs) or the longer-term (education, information, advertising, promotion and market effects or market transformation efforts).

The primary purpose of the process evaluation is an in-depth investigation and assessment of one or more program-related characteristics in order to provide specific and highly detailed recommendations for program changes. Typically, recommendations are designed to affect one or more areas of the program's operational practices. Process evaluations are a significant undertaking designed to produce improved and more cost-effective programs.

This Protocol identifies how process evaluations for California energy efficiency programs, products or services placed into the market during and after the 2006 program year will be conducted. The *Evaluation Framework* is incorporated into this Protocol as a key guidance document for conducting process evaluations. Before applying it, users of this Protocol should have a working knowledge of Chapter 8, "Process Evaluations," of the *Evaluation Framework.* Key references to the process evaluation literature are also found in the *Evaluation Framework*.[88]

In addition, all users of the Process Evaluation Protocol should be familiar with the sampling guidance provided in the Sampling Protocol. While the use of the Sampling Protocol is not required for planning and conducting process evaluations, it provides guidance for process evaluation sampling and sample selection criteria. The Reporting Protocol contained in this document contains the process evaluation reporting requirements and is a part of the Process Evaluation Protocol. The Reporting Protocol helps assure that the reports generated from the process evaluation provide comparable results and recommendations on which program management can act, and, at the same time, meet the CPUC's reporting requirements.

A process evaluation is defined as a systematic assessment of an energy efficiency program, product or service, or a component of an energy efficiency program, product or service, for the purposes of identifying and recommending improvements that can be made to the program to increase the its efficiency or effectiveness in acquiring energy resources while maintaining high levels of participant satisfaction and documenting program operations at the time of the examination. The primary goal of the process evaluation is the development that improve program efficiency or effectiveness that when implemented can be expected, in some direct or indirect way, to improve the cost effectiveness of the program. This definition updates the definition provided in the *Evaluation Framework*.[89]

[88] TecMarket Works, page 205.
[89] Ibid, page 207.

Process Evaluation Responsibilities

While the CPUC- ED must approve all process evaluation contractors, the process evaluations themselves are to be planned, budgeted, designed, implemented and reported under the direction of the Administrators, following the guidance laid out in this Protocol. The Administrators are responsible for the process evaluations for their statewide programs, the Administrator-specific programs implemented within their services areas, the programs conducted by third parties under contract to the Administrators and the programs or services that are procured via a bidding or other contractual processes. The Administrators are responsible for developing the Annual Process Evaluation Plan and obtaining related comments and recommendations from the Joint Staff.

Objectives of the Process Evaluation

The process evaluation's primary objective is to help program designers and managers structure their programs to achieve cost-effective savings while maintaining high levels of customer satisfaction. The process evaluation helps accomplish this goal by providing recommendations for changing the program's structure, management, administration, design, delivery, operations or targets. Consequently, Administrators often want early process evaluation feedback. The process evaluation also provides ongoing feedback to the Administrators that allow them to make timely program changes or to follow the progress of the study or to review early findings. Where appropriate, the process evaluation should test for the use of best practices and determine if specific best practices should be incorporated. It is expected that process evaluations will be needed both in the early stages of the program design and deployment efforts to provide timely feedback to the IOUs on them, and over the life of the program as issues are identified.

Audience and Responsible Actors

This Protocol is to be used by Administrators and their evaluation contractors to conduct process evaluations and by the CPUC-ED to provide ongoing guidance and oversight to the process evaluation activities. The Protocol allows considerable flexibility and judgment by the Administrators to determine when a process evaluation is needed and the issues on which the process evaluation should focus.

The Administrators are responsible for program design, operation and goal attainment for the programs and services funded through their implementation and contracting efforts. They must structure their process evaluation efforts to support these responsibilities.

Other stakeholders should be familiar with the intent and scope of the Protocol to obtain an adequate understanding of the purpose and scope of the process evaluation efforts and how these studies are to be conducted.

Overview of the Protocol

As mentioned previously, this Protocol is specifically designed to work in conjunction with the *Evaluation Framework*. The chapter on process evaluation in the *Evaluation Framework* is a key advisory component of this Protocol.[90]

[90] Ibid, page 205.

This Protocol provides guidance to Administrators on the criteria used to determine if and when to conduct a process evaluation and on the researchable issues targeted by the study.[91] However, Administrators are free to identify additional or different decision criteria.

Because a process evaluation is not a CPUC-required activity, the Administrators will determine if one is to be conducted, when it will occur and the investigative areas on which the evaluation shall focus. As a result, there is no waiver process associated with the Process Evaluation Protocol. However, the Protocols suggest several key investigative areas on which the process evaluation can focus.

Finally, the Protocol presents the types of investigative tools and approaches that can be used to conduct the process evaluation efforts.

As discussed earlier, the Process Evaluation Protocol is linked with other of the Protocols, including the Sampling and Uncertainty Protocol and the Reporting Protocol. These two latter Protocols should be considered sub-components of the Process Evaluation Protocol. However, the Sampling and Uncertainty Protocol is advisory, while the Reporting Protocol is a required component of the Process Evaluation Protocol.

Because there can be overlap between the information collected in the process, market effects and impact evaluations and associated M&V efforts, the process evaluation efforts should be structured to coordinate with other evaluation efforts to the extent practical. This may require cross-organizational coordination. Such coordination minimizes customer contact, maximizes data collection efforts and improves evaluation efficiency. This does not mean that these studies must be inter-linked or consolidated, but it does mean that there will be times when the information collected in one study will be valuable to other studies and times when studies will benefit from a coordinated effort.

In these cases, there will need to be close coordination between the CPUC-ED, the Administrators and the evaluation contractors for the related evaluation efforts. This Protocol does not specify how this coordination should be structured or conducted, but does identify the need for it. However, the Protocol also recognizes that the skill sets needed for conducting a process evaluation are often different than those needed for an impact or market effects study and these differences may limit the extent of the coordination efforts.

Process Evaluation Planning

There are several key issues that should be considered when planning a process evaluation. It is anticipated that most programs will have at least one in-depth comprehensive process evaluation within each program funding cycle (e.g., 2006-2008), but a program may have more or less studies depending on the issues that the IOUs need to research, the timing of the information needed and the importance of those issues within the program cycle.

The process evaluation decision road map in the *Evaluation Framework*[92] identifies several operational conditions that can be considered by the IOUs for targeting a process evaluation.

[91] Ibid, page 220.

The Administrators should assess these criteria annually and other criteria as appropriate to determine if a process evaluation is needed. This annual assessment should be conducted by the IOUs administering the program and reported in an Annual Process Evaluation Plan delivered to the CPUC-ED no later than the first of December, before the start of each program year or the month before the start of a new program when the program does not start at the beginning of a program year.

This annual planning requirement applies to all programs being administered or funded via the Public Goods Charge (PGC) or Procurement program funds for the upcoming program year. While the detailed process planning efforts will not be fully known at the beginning of the program cycle, the plan should present the structure and operations of the detailed planning efforts, identify the key decision criteria to be used to determine if and when a process evaluation will be planned and launched, and present the process evaluation efforts planned at that time. The annual plans developed following the first year would then present the process evaluations planned and launched during the previous year and present the known process evaluation needs for the upcoming year.

Annual Process Evaluation Planning Meeting

For each year of the program cycle, the Administrators shall hold at least one process evaluation planning meeting to review and discuss their process evaluation plans and obtain Joint Staff input to help guide planning efforts. The meeting shall be held between July and November of the year preceding the evaluation period. The Joint Staff will be notified of these meetings at least two weeks in advance of the meeting. The meeting dates, times and locations will be coordinated with the Joint Staff to maximize the attendance potential of the interested parties. During the meeting, the Administrators will present their process evaluation plans and solicit comments. Within two weeks following the meeting, but no later than December 22, the Administrators will finalize their process evaluation plans and submit a final plan to the Joint Staff for its review. The plan does not have to be approved by the CPUC-ED.

The decision for determining if a process evaluation is needed for all programs rests with the Administrators. However, the evaluation planning process must be conducted annually, incorporate the use of the planning meetings discussed above and lead to the submission of an Annual Portfolio Process Evaluation Plan to the Joint Staff for review.

Program managers may want the process evaluation to supplement the program's quality control or quality assurance components, to confirm the installation practice and/or to conduct program reviews and develop recommendations for improvements. Administrators should consider the different functions and benefits of the process evaluation under different potential program grouping scenarios and weigh the associated pros and cons when structuring their process evaluation plans.

The timing of the process evaluation is an important component of the planning process. In some cases, Administrators will want to launch their process evaluations early to help ensure that programs are well designed, are achieving savings shortly after launch and are providing

[92] Ibid, page 222.

effective services. In other cases, Administrators may give the programs time to become established in the market and adopt more routine operational approaches before launching the process evaluation. In still other cases, Administrators may wish to establish an ongoing process evaluation effort so that the program is periodically evaluated over its three-year cycle. This third condition may be more applicable to new programs or programs being provided by a new vendor than to more established programs that have demonstrated their cost-effectiveness and operational efficiencies in earlier studies.

The Annual Process Evaluation Plan submitted to the Joint Staff should indicate the level of resources and budgets devoted to the process evaluation efforts.

The goal of this Protocol is not to require unnecessary process evaluation efforts, but to provide tools to Administrators for the consideration of key decision criteria typically associated with process evaluation efforts and related implementation. Administrators should only plan and launch process evaluations when they are expected to serve as an effective program management tool. The Annual Process Evaluation Plan helps to provide the Joint Staff with a minimum level of assurance that program changes are being effectively assessed and managed and that process evaluations are considered when they can be effectively employed. The decision to conduct a process evaluation is ultimately the Administrators'. These decisions should be conveyed to the CPUC-Ed in the Annual Process Evaluation Plan.

Recommendations for Change

The primary purpose of process evaluation is to develop recommendations for program design or operation changes that can be expected to cost-effectively improve the issues, conditions or problems being investigated. The primary deliverable of all process evaluations is a process evaluation report that presents the study findings and the associated recommendations for program changes (see Reporting Protocol).

Key Issues and Information Covered

Administrators and their need for operational information to improve programs guide the process evaluation effort. This necessarily covers a very wide range of investigative issues that the process evaluation can address. The process evaluation may take on the challenge of evaluating most, if not all, aspects associated with the design or operations of a program in order to improve the energy resources acquired (directly or indirectly) by that program. The process evaluation plan can also address issues applicable to the programs under review over a single year or over multiple years and can examine a wide range of issues, including:

Program Design

- Program design, design characteristics and design process;
- Program mission, vision and goal setting and its process;
- Assessment or development of program and market operations theories and supportive logic models, theory assumptions and key theory relationships - especially their causal relationships; and
- Use of new practices or best practices.

Program Administration

- Program oversight and improvement process;
- Program staffing allocation and requirements;
- Management and staff skill and training needs;
- Program information and information support systems; and
- Reporting and the relationship between effective tracking and management, including both operational and financial management.

Program Implementation and Delivery

- Description and assessment of the program implementation and delivery process;
- Quality control methods and operational issues;
- Program management and management's operational practices;
- Program delivery systems, components and implementation practices;
- Program targeting, marketing and outreach efforts;
- Program goal attainment and goal-associated implementation processes and results;
- Program timing, timelines and time-sensitive accomplishments; and
- Quality control procedures and processes.

Market Response

- Customer interaction and satisfaction (both overall satisfaction and satisfaction with key program components and including satisfaction with key customer-product-provider relationships and support services);
- Customer or participant energy efficiency or load reduction needs and the ability of the program to provide for those needs;
- Market allies interaction and satisfaction;
- Low participation rates or associated energy savings;
- Market allies needs and the ability of the program to provide for those needs;
- Reasons for overly high free-riders or too low a level of market effects, free-drivers or spillover; and
- Intended or unanticipated market effects.

Process Evaluation Efforts

One of the primary purposes of the Process Evaluation Protocol is to ensure an appropriately broad consideration of potential process evaluation issues for each program within the Administrator portfolio and a framework that provides critical evaluation thinking to produce the best overall process evaluation efforts for the portfolio.

Program-Specific Process Evaluation Plans

In addition to the Administrator's Annual Portfolio Process Evaluation Plan, each process evaluation should have a program-specific or program-group-specific detailed process evaluation plan to guide the evaluation efforts. These detailed plans should include the process evaluation approach, identification of program-specific or program group-specific focus of the evaluation efforts, detailed researchable issues to be addressed, activity timing issues and the resources to be used. However, it is the Administrator's responsibility to specifically determine the content and focus of such plans. The detailed program-specific or program-group-specific detailed process evaluation plans do not need to be submitted to the Joint Staff for review.

The Process Evaluation Protocol is designed to balance allowing the CPUC-ED and other stakeholders a level of assurance that there is a minimum set of standards for process evaluations across the portfolios and allowing the necessary flexibility and control for program administration and process evaluation management.

Data Collection and Assessment Efforts

Process evaluation efforts can include a wide range of data collection and assessment efforts, such as:

- Interviews and surveys with Administrators, designers, managers and implementation staff (including contractors, sub-contractors and field staff);
- Interviews and surveys with trade allies, contractors, suppliers, manufacturers and other market actors and stakeholders;
- Interviews and surveys with participants and non-participants;
- Interviews and surveys with technology users;
- Interviews and surveys with key policy makers and public goods charge stakeholders;
- Observations of operations and field efforts, including field tests and investigative efforts;
- Unannounced participation in the program to test operations and operational practices, processes and interactions;
- Operational observations and field-testing, including process related measurement and verification efforts. These can be announced or unannounced;
- Workflow, production and productivity measurements;
- Reviews, assessments and testing of records, databases, program-related materials and tools used;
- Collection and analysis of relevant data or databases from third-party sources (e.g., equipment vendors, trade allies and stakeholders and market data suppliers); and
- Focus groups with participants, non-participants, trade allies and other key market actors associated with the program or the market in which the program operates.

This list of activities is not meant to be exhaustive, but illustrative. Administrators are free to specify other data collection and assessment efforts beyond those listed above. However, in selecting the evaluation approaches to be used, a key consideration is the level of reliability of the study approach and the accuracy of the study findings. All studies are expected to be structured in a way that provides reliable findings on which accurate and reliable recommendations can be developed.

Conducting Investigative Efforts

This section of the Protocol provides guidance on conducting specific investigative efforts typically associated with the process evaluation.

Interviews

Professional process evaluation interviewers should conduct process evaluation interviews. The *Evaluation Framework* provides guidance on the type of training and experience needed by process evaluation staff that conduct interviews.[93] In-depth interviews can be conducted in-person (off-site or on-site) or by telephone. In-person interviews enable the interviewer to gain a deeper understanding of the experience of the interviewee and can lead to more reliable and more comprehensive information gathering than phone interviews. Phone interviews do not allow for the observation of key body signals that serve as clues for the probing process. However, both approaches are equally valid if the questions are well designed and the interviewer is skilled in interviewing techniques. If in-person interviews are not possible given the nature of the study or the location of the interviewee, then telephone interviews can be used. Regardless of the type, interviews should be scheduled in advance and should last an hour or more. Detailed comprehensive process evaluation interviews may last several hours. E-mail interviews are rarely used unless the evaluation professional can easily guide the interview and move it in directions that need additional information or investigative probes. In addition, as technologies that can be used to support the interview effort evolve, there may be additional approaches that can be considered or used, such as web-conferencing or web-interviews. However, in assessing the applicability of these technologies the primary focus should be on allowing the interviewer to be able to manage and focus the interview as it proceeds so that in-depth probes and ancillary follow-up questions can be placed into the interview at the time they are needed.

Group Interviews

The group interview may be used to obtain information from a group of individuals typically having one or more similar characteristics. The focus group, one of the more familiar types of group interviewing techniques, is used to focus on the response to a limited set of issues – such as in product development research. The use of other types of group interviews can be appropriate for evaluation in a limited number of circumstances, for example:

- Obtaining feedback from a group of installers or outreach coordinators who can "focus" on the specific issues of their job or their experience with end-users; and
- Qualitatively investigating issues that will be further explored in quantitative surveys.

Experienced professional evaluation experts must conduct group interviews. All group interviews should be guided by skilled moderators and documented in a way that allows for a

[93] Ibid, page 206.

review of the moderator's instructions to the attendees, the moderator's approach to managing the group and the moderator's instructions, questions and involvement, as well as a detailed understanding of comments provided by all attendees.

A summary report of each group interview containing the above-listed information should be included in the evaluation report. The group interview report should also include a professional interpretation of the results discussing how they will or can be used and a discussion of how the group results will be confirmed or tested quantitatively, if required.

Group interviews are a reliable data collection approach but they do not provide results that can be generalized to a population except when the participants in the group interview are a statistically representative sample of that population. Thus, a focus group (because the participants do not typically constitute a statistically representative sample of the population) is not an acceptable means to quantitatively assess programs, but can, in some circumstances, provide supportive information that can be used in a process evaluation finding. For this reason, they are included as an approved data collection effort within this Protocol when accompanied by other assessment approaches that can quantitatively test their results.

Surveys

Survey efforts that are used to support process evaluations are typically conducted via telephone interviews. However, there will be occasions when other approaches are preferred. For instance, when there are large numbers of participants or non-participants or when the inquiry will benefit from the respondent seeing an illustration, survey techniques could include mail, e-mail or Web-based approaches and other types of surveys. Similarly, small targeted surveys with trade allies or program participants who have provided e-mail addresses for this purpose may be most efficiently conducted using an e-mail/Internet combined survey. There is a great variety of survey techniques and they should be selected according to specific requirements of the data collection effort.

In all cases, professional process evaluation survey designers should construct and test the survey questionnaires to avoid unnecessary bias in question topic or structure, or in the responses received. The questions in the surveys should follow construction practices that result in objectively worded questions with provisions for recording all expected responses. Questions should be structured so that they are single-subject, focused questions. Questions that are typically referred as "double-barreled" questions (containing more than one subject-verb relationship) should be avoided as they bias the information collected.

Most important in implementing any type of survey is to follow the principles of good survey design and implementation such as those developed by Don Dillman.[94] Whether the survey is implemented using the telephone, mail, e-mail or Internet there are a specific methods that should be applied to ensure valid and reliable results. These include repeated contacts with the sample as well as carefully structured invitations to participate and questions.

[94] Dillman, Don A. 2000. *Mail and Internet Surveys: The Tailored Design Method.* New York, NY: John Wiley & Sons. Dillman, Don A. 1978. *Mail and telephone surveys: The Total Design Method*. New York, NY: John Wiley & Sons.

Observations and Field Testing

Field-testing and observations should be done in a way that allows the observation or testing of the program as it would be operating in the absence of the evaluation professional. Observers are to instruct program staff that they are to conduct themselves exactly as they would if the observer were not present. The observing evaluation professional is not to engage in activities that act to change the way the activity would have occurred if the evaluation professional were not there. All key observations and measurements should be documented at the time of the observation or testing.

Unannounced Participation

In some cases, it may be appropriate for the evaluation contractor to enroll in the program to test the program's operations and delivery aspects. When this is designed as part of the evaluation plan, program management is not to be informed of who will be participating, how they will be participating or when that participation will occur. Participation is to be unannounced and field observations and measurements will be conducted without the knowledge of the program staff to the extent practical. This approach can be used for a wide range of programs in which unannounced participation by an evaluation professional can allow the evaluation expert to view the program from the perspective of a typical participant.

Independence

The organization conducting the process evaluation should be independent of the organizations involved in the program design, management and implementation efforts. The evaluation should be conducted as an "arms-length" assessment, such that the process evaluation professionals have no financial stake in the programs or program components being evaluated beyond the contracted evaluation efforts. Similarly, process evaluation professionals should have no financial or financially related interest in the study results or from efforts resulting from the implementation of evaluation recommendations.

Selection of Evaluation Contractors

Administrators are charged with the responsibility to plan, contract, manage and administratively oversee the implementation of the process evaluation efforts consistent with this Protocol. Administrators should focus their contractor selection efforts, so that only professional, skilled process evaluation contractors are solicited for conducting the process evaluations. The CPUC-ED must approve the selection of the evaluation contractors to conduct the studies. The contractor approval process will be structured by the CPUC-ED consistent with the ALJ's decision. This process will be developed outside of this Protocol. Approval by the CPUC-ED will be based on the qualifications of the firms or individuals considered for conducting the studies.

Skills Required for Conducting Process Evaluations

The investigative processes associated with designing, managing and conducting process evaluations focus on a wide range of researchable issues. These issues can range from evaluating the ability of a program's data management system to support the informational needs of the program to assessing if the program is well-designed, managed, targeted, marketed and operated. As a result, the skills needed to conduct process evaluations are varied.

Evaluations that focus on the design and operation of program information systems, for example, need evaluators that understand how information management and information availability influence a program's management, operations, productivity and results. However, the evaluators should also be skilled at designing, developing and implementing information systems in order to recommend changes to improve the program's ability to cost-effectively achieve its goals. Process evaluators who assess program satisfaction levels need to have the skills to identify and analyze different program characteristics that influence satisfaction and be able to identify those characteristics that can be changed to improve satisfaction scores. In the process evaluation, measuring satisfaction is not enough, the study should assess the reasons for the satisfaction scores and identify how to improve these scores without harming the cost-effectiveness of the program.

Similarly, evaluators who focus on assessing program targeting, marketing and promotional operations need to have skills necessary to assess information flow, content and presentation effects as well as the skills associated with understanding how markets and market segments operate and can be influenced through different outreach and promotional efforts. These examples demonstrate the need to match the skills of the process evaluator with the research goals of the specific process evaluation.

It is equally important that process evaluation managers be trained and/or experienced with the tools used in the process evaluation. For example, if a telephone survey is needed, evaluators need to be knowledgeable and experienced in the field of survey research and instrument design. If focus groups are needed, evaluators should be knowledgeable and experienced in the field of focus group design and operation, as well as assessing and applying the results from the focus group.

Because of the diversity of researchable issues associated with conducting process evaluations and the diversity of skills needed to address these issues, it is difficult to define a specific set of skills needed to conduct these evaluations. Instead, this Protocol recognizes that a diverse set of program assessment and information analysis skills are needed across the various investigative issues on which these evaluations typically focus. However, in general, the process evaluator should have the following knowledge and skills:

- Expert knowledge of a wide range of energy efficiency programs and a strong understanding of their operational designs, management practices and program goals;
- Expert knowledge of different process evaluation data collection methods and approaches, and a working knowledge of the process evaluation literature and how evaluation approaches have been applied in the energy efficiency program field;
- Strong analysis capabilities and an expert understanding of cause-and-effect relationships that impact the ability of energy efficiency programs to cost-effectively accomplish their goals, including experience in program theory and logic model construction and assessment;
- Strong understanding of statistical analysis approaches and analytical procedures appropriate for the process evaluation research goals;

- Strong understanding of sampling methods and approaches and the ability to identify potential biases in a sampling approach and to develop control strategies for mitigating levels of bias and improving the reliability of evaluation results; and
- High level of past experience in conducting process evaluations of energy efficiency programs and in reporting the results of these studies.

Market Effects Evaluation Protocol

Introduction

The Market Effects Protocol is designed to measure net market effects at a market level when one or more of the Protocol-covered energy efficiency funded program efforts target a market. Net market effects are those effects that are induced by Protocol-covered energy efficiency programs and are net of market activities induced by non-energy efficiency programs including normal market changes.

The application of the Market Effects Protocol should result in an estimate of the energy (kWh), peak (kW) or therm impacts associated with the net market effects resulting from Protocol-covered energy efficiency program interventions. These net energy market effects are referred to in *A Framework for Planning and Assessing Publicly Funded Energy Efficiency* (*2001 Framework Study)* as "ultimate market effects" or "ultimate indicators" because they are the desired indicator of whether net energy efficiency changes are occurring in the market.[95] The Market Effects Protocol is designed, therefore, to facilitate not just the estimate of net market effects but also, and primarily, the estimate of net energy market effects. That is, a market effects study both quantifies the changes occurring in the market caused by the energy efficiency programs and provides an estimate of the energy impacts associated with them.

The Market Effects Protocol does not apply to the measurement of individual program-level market effects or direct program savings typically used for program-level cost-effectiveness assessments and refinement decisions. Rather the focus of the market effects evaluation is at a market level in which may different energy efficiency programs can operate. Yet, the Protocol applies to program-induced market changes that could be missed or double counted if measured program by program. As a result, the use of the Market Effects Protocol should focus on the effects of groups of programs within a market over multiple program cycles.

Overview of the Market Effects Protocol

This Protocol applies when net market effects are to be estimated at a market rather than program level. Market effects are defined in the *Evaluation Framework* as "[a] change in the structure or functioning of a market or the behavior of participants in a market that result from one or more program efforts. Typically these efforts are designed to increase the adoption of energy efficient products, services, or practice and are causally related to market interventions."[96] This definition, however, was created within the context of guidance for conducting program evaluation of a market transformation style program. A market transformation program is one that is specifically designed and fielded for the purpose of changing the way a market operates so that energy savings are achieved at a market level. That is, these types of programs are designed to focus at the market level. A more effective definition for the Market Effects Protocol for assessing the market effects from multiple programs that may or may not be designed to change market operations is that in *A Scoping Study on Energy-Efficiency Market Transformation by*

[95] Frederick D. Sebold et al. *A Framework for Planning and Assessing Publicly Funded Energy Efficiency*. (Pacific Gas and Electric Company. 2001): 6-4.
[96] TecMarket Works, 429.

California Utility DSM Programs (the Scoping Study): "A change in the structure of a market or the behavior of participants in a market that is reflective of an increase in the adoption of energy-efficient products, services, or practices and is causally related to market intervention(s)."[97] This definition stresses the market rather than the program nature of market effects, and is the working definition for this Protocol.

The *Evaluation Framework* states that "there are no universally accepted definitions within the energy efficiency industry pertaining to what constitutes a program's market."[98] A review of various dictionaries demonstrates that it has multiple meanings. "Market" as used in this Protocol refers to the commercial activity (manufacturing, distributing, buying and selling) associated with products and services that affect energy usage. The specific market focus of each evaluation should be defined as an early activity in scoping each market effects evaluation. The *Evaluation Framework* provides guidance for defining a market and where multiple programs are operating in the same market, again, the primary focus of this Protocol.[99]

Market effects include both short-term and long-term effects. The long-term effects are the most difficult to capture at a program level because they broadly affect a market not just the specific participants in a program or in a grouping of programs. This Protocol targets those long-term effects.

A market-level evaluation effort is recommended when there are multiple statewide or local interventions in a market such as those of California's energy efficiency programs and where other efforts are also acting to change that market. Other efforts can be associated with the normal operations of the market or when other non-California energy efficiency efforts are changing markets, such as with the national ENERGY STAR ® program, manufacturer promotions and retail sales efforts. A market level effort is also appropriate when a single large and particularly effective program is expected to have broad and long-term market effects in a single market.

Figure 11 shows the relationship between program-induced market effects, program market spillover and normal energy efficiency trends in the market. Effects driven by interventions by other organization, as well as the market itself, are all assumed to be within the normal energy efficiency trends of the market.

[97] Joe Eto, Ralph Prahl, and Jeff Schlegel. *A Scoping Study on Energy-Efficiency Market Transformation by California Utility DSM Programs*. (Berkeley, CA: Ernest Orlando Lawrence Berkeley National Laboratory, 1996). LBNL-39059 UC-1322, 9.
[98] TecMarket Works, 250.
[99] Ibid, 250-251.

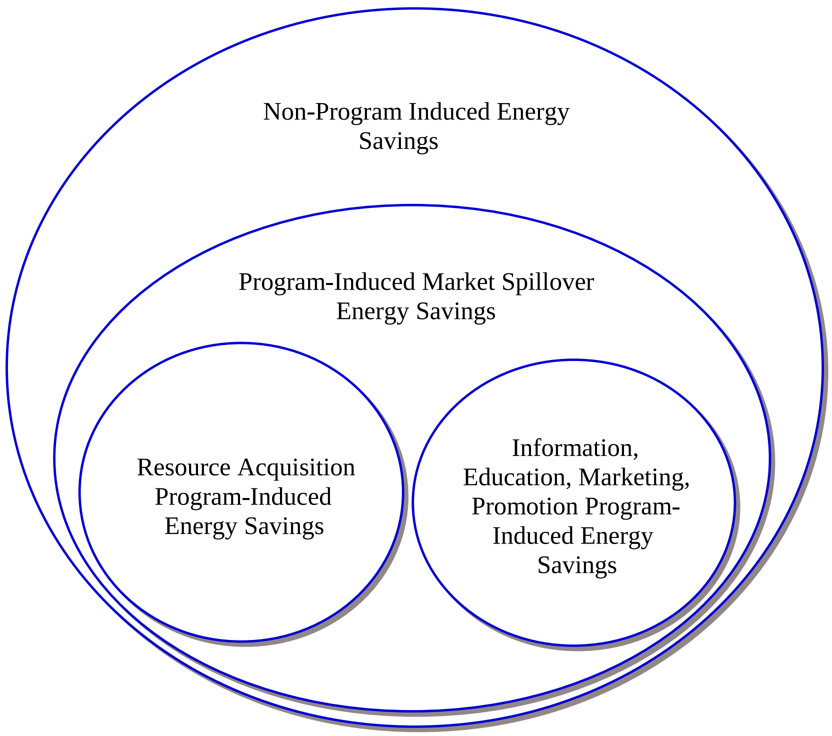

Figure 11. Sources of Energy Efficiency Changes in the Market

There are two types of market effects discussed in the energy efficiency industry. There are those that are occurring now as a result of how programs are changing markets. And there are those that are forecasted to occur later (after the program has been discontinued) due to the changes established or put into motion by the program. The Protocol recognizes that the methodologies to estimate each of these types of market effects can differ and that potential issues of bias that must be identified, mitigated and minimized are also different. The Market Effect Protocol is designed to measure only the current market effects and not those forecasted to occur at some future point.

A great deal of effort has been expended over the past 10-15 years to estimate market effects, yet most of these efforts did not estimate net energy market effects, but concentrated on measurement of indicators such as awareness, sales and changes in practices by market actors. Evaluations estimating net market effects with energy estimates, the focus of this Protocol, are at an early stage of development. A variety of studies have been conducted, but only a limited number at the highest levels of rigor. However, this is a critically important field of research since the market effects of energy savings caused by California's energy efficiency programs are likely to be substantial once documented. Given the early stage of development of methods, it is important that this Protocol encourage the continued advancement of the field and not prescribe or limit methodological approaches.

Key to a successful market effects evaluation will be the initial scoping study. The scoping study will define the market to be studied, develop a market theory to test in the analysis, assess data availability for the market effects study, develop a methodology for additional data collection and recommend an analysis approach. For programs that are specifically designed to change the way a market operates, the program theory should also be considered in developing the initial scoping study. However, for standard programs that are not designed to change market operations, the program theory is not a significant consideration in the development of the scoping study.

Because market effects evaluation is still evolving there are a limited, but clearly defined, set of activities that should be considered. Market effects evaluations should be developed using experimental or quasi-experimental designs whenever possible and the approach should be peer reviewed prior to implementing the study to ensure that it will provide valid and reliable results. Triangulation of data and analysis approaches is preferred when possible and teaming with industry organizations and professionals can be beneficial. The studies should also take into account regional differences within the market being studied and will at times need to move beyond California boundaries to the regional or national level to collect data. Finally, allocation to utility service territory will be a challenge and dependent on data availability, but should be an important consideration in the scoping study.

The Market Effects Protocol and Other Protocols

Often the individual Protocols overlap and are supported by other Protocols. There are three primary output Protocols: Impact, Market Effects and Process Evaluation. There are three Protocols that can be called on to support or provide additional requirements for all the Protocols. These are the Sampling and Uncertainty, Measurement & Verification (M&V) and Reporting Protocols. The guidance provided by the Impact Evaluation, Market Effects and Process Evaluation Reporting Protocols applies to all types of efficiency program evaluations in California. The Sampling and Uncertainty Protocol provides further delineation of sampling and uncertainty assessment and reporting requirements. The M&V Protocol is similarly a reference and supporting Protocol for the Impact Evaluation Protocol and can be used to inform and provide input for a Process Evaluation on issues relating to measure installation and performance.

The Impact Evaluation and M&V Protocols are supporting Protocols to the Market Effects Protocol as related to estimating net energy market effects. At the same time while the Impact Evaluation Protocol addresses net energy effects through estimation of free-ridership and participant spillover, it does not include measurement of non-participant spillover. Non-participant spillover specifically refers to changes in the market that result from program influences and this is appropriately estimated as part of the net market effects.

There is another important integration aspect for the individual Protocols. A complete measurement of program impacts involves combining the results from the market effects evaluations and the program impact and indirect impact studies. The market effects net of program impacts would generally represent the program market level impacts and non-participant spillover. Yet, differences in methodologies and the multitude of program evaluations require careful thought and analysis to ensure that when the impacts are combined adjustments are made to ensure no double counting occurs. At the same time, there are bound to be some programs for which program impacts have been evaluated but their particular market has not (e.g., in cases of niche markets or unique program elements). This would need to be added to reach an estimate of the overall portfolio expected energy and demand savings to be reported to system planners. Familiarity with the Impact Evaluation, M&V, Sampling and Reporting Protocols is recommended to conduct a Protocol-compliant Market Effects Evaluation.

Finally, the Process Evaluation Protocol outlines types of data collection methodologies that should also be considered when conducting primary data collection for estimating market effects. The *Evaluation Framework* provides further detail on data collection methodologies and issues to consider when examining markets, familiarity with which is recommended for designing or conducting a Market Effects Evaluation.[100]

Key Market Effects Inputs and Outputs

Inputs for a market effects evaluation include but are not limited to the following:

- Names and contact information for program staff for the programs identified as targeting the defined market;
- Names and contact information for mid-stream or upstream market actors identified by the Administrator as operating in the defined market;
- Evaluations and market research conducted by the utilities for the defined market during the previous five years;
- Market and program theory documents developed by the Administrators for the programs identified as targeting the defined market;
- Names and contact information for key informants consulted during the development of the programs identified as targeting the defined market; and
- National data on the market from sources such as the US Census Bureau, Energy Information Administration, Consortium for Energy Efficiency, Department of Energy and Environmental Protection Agency.

The Market Effects Protocol will generate an estimate of net energy market effects in kWh and kW in markets for electricity-using equipment and therms in markets for gas-using equipment. These metrics at times will require that the market effects estimates link to the results of the M&V or Impact Evaluation Protocol to provide estimates of energy impacts based on the market effects measured. The market to which these estimates apply will be defined in terms of location, the utilities involved, the equipment and sector, and the program years of interest.

This approach requires that the evaluator estimate what changes would have occurred in the market without the energy efficiency efforts provided by the programs. Because of the uncertainty in the evaluation process, the estimate will likely be a range of probable effects, rather than a point estimate (e.g., confidence intervals). These studies should always include a clear statement of the uncertainty around the range estimate. The Reporting Protocol discusses this issue in greater detail.

[100] TecMarket Works, Chapters 4, 8, 9, 10, 12, and 13.

The outputs will be used to inform the program planning process for the next program cycle, to structure the program planning efforts to maximize net market effects of statewide and Administrator's portfolios, while also maximizing net program-induced energy impacts. The market effects evaluations should be structured to provide market effects impact information prior to June before the end of the program cycle so that the results can be considered in the planning efforts for the next program cycle.

The market effects study results can also be used in comparison with the results of the program evaluation efforts to identify net market energy impacts that are beyond the direct program-induced effects. In addition, results will serve as an estimation range check for the savings projected from the program evaluations. In all cases the total market effects should be a summation of the direct program-induced effects, the normal market changes to become more energy efficient and the non-participant spillover effects. In no cases should the program-induced impacts be greater than the net market effects identified in the market effects evaluations. Given the different methodologies employed, the analysis of the different sets of results, the methodologies used, and their relative advantages and weaknesses must be carefully conducted in order to obtain the most reliable estimates of overall impacts from the energy efficiency programs.

Audience and Responsible Actors

The audience and responsible actors for this Protocol include the following:

- **CPUC-ED and CEC** will use the Protocol to determine when a market effects study is appropriate and to guide the research approach;
- **The Evaluation Contractor Team** will use the Protocol to ensure that their market effects evaluation plan and its conduct address key requirements for a market effects study;
- **Administrators** will use the Protocol to understand the market interactions that are occurring as a result of efforts within a given market and, in part, to determine when interventions should be modified to achieve continued efficiency gains; and
- **Program Implementers** will use the results to assess the reach and success of their program efforts and in part to determine when interventions should be modified to achieve continued efficiency gains.

Steps in Conducting Market Effects Evaluations

The following five primary activities should be conducted in any market effects evaluation. This section describes in some detail what is entailed in each step.

1. Conduct a scoping study to determine optimum data collection and analysis approach for the evaluation;
2. Select a contractor and develop a detailed evaluation plan;
3. Collect baseline and longitudinal indicators;
4. Analyze market effects; and

5. Produce the Market Effects Report.

Scoping Study

The appropriate approach for a market effects study cannot be readily determined without a scoping study to define the market to be studied, develop a market theory to test in the analysis, assess data availability for the market effects study, specify a model of market change, develop a methodology for data collection and recommend an analysis approach.

Scoping studies will require different levels of effort depending on the complexity of the market of interest and the number and types of program interventions in that market. Scoping studies can also be used to determine which markets show promise for reliable and valid market effects evaluation.

The evaluation contractor will be expected to review past studies conducted of the market by the California utilities and other energy organizations. It will not be enough to simply look at the programs being offered during the program years of interest. A thorough review of the CALMAC database for applicable studies and reports as well as interviews with contacts at each utility and program managers will be important. Access to market assessment studies conducted by the utilities will be important to provide a sound understanding of the market conditions prior to program implementation and to support an understanding of market progress and/or contribute to the preponderance of evidence for causality/attribution. The evaluation contractor should also review the potential value of national and regional data sets including data collected by the US Census Bureau and the Energy Information Administration and organizations such as the Consortium for Energy Efficiency. No potential source should be ignored and it is very important that the utilities be cooperative in this effort.

The key activities of the scoping study include defining the scope range and limits of the subject market. The Joint Staff will make an initial determination of the definition of the market by location, utilities involved, sector, and likely equipment and behavior to be included. The scoping study contractor, however, will assess this initial definition and ultimately determine the definition that will yield the most reliable and meaningful results about net market effects of interest. This is a critical first step and requires a full understanding of how the interventions of interest were designed to operate and how the market in which they were launched is perceived to operate.

This process will provide the framework for the development of the market theory and conducting a logic analysis of the interventions, which will be used to guide the market effects evaluation. The logic model and market theory will then be used to develop a list of indicators for tracking market effects. These indicators could be model specifications, a detailed list of indicators to be tracked through baseline and longitudinal data collection efforts or both. The end result of the scoping study is an evaluation plan that details the strategy for the market effects evaluation. Table 14 displays the Protocol for scoping studies for market effects evaluations.

Table 14. Required Protocols for Market Effects Evaluation Scoping Studies

Level of Rigor	Scoping Study Requirements
Basic	Define the market by its location, the utilities involved, the equipment, behaviors, sector and the program years of interest. Develop market theory. Identify available secondary data and potential sources for primary data. Outline data collection and analysis approaches
Enhanced	Define the market by its location, the utilities involved, the equipment, behaviors, sector and the program years of interest. Develop market theory and logic model. Detail indicators. Identify available secondary data and primary data that can be used to track changes in indicators. Outline data collection approach. Recommend hypotheses to test in the market effects study. Recommend the analysis approach most likely to be effective.

Market Theory and Logic Models

The assessment, refinement and/or development of a market theory with logic models are key activities of the scoping study. The *2001 Framework Study*[101] and the *Evaluation Framework*[102] both address the value and process of developing a program or market theory. The evaluation contractor will need to articulate a market theory in order to proceed with baseline measurement for market effects evaluation. At a minimum, this market theory shall describe how the market operates and articulate market assumptions and associated research questions. This must be done at a level of detail sufficient to develop data collection instruments for baseline measurement. If the assessment includes programs that are designed specifically to change the way a market operates the program theory should also be consistent with and embedded in the theory of how the market operates.[103]

Market-level evaluations seek to document the changes in adoption behavior that cause changes in energy savings.[104] It is important, therefore, to clearly articulate the assumed changes in the market, so they can be measured for the market effects study. If this is done properly the market effects evaluation can document changes in adoption, efficiency and provide an estimate of savings. This process also facilitates model specification.

A higher level of rigor is achieved when the market theory can be described in a narrative and/or a graphic logic model. A narrative or graphic logic model permits a greater depth of understanding of the indicators driving anticipated market outcomes. It can also help to identify the various sources of influence on market effects outside of the program efforts. The simplest approach to a logic diagram is to view the boxes as potential measurement indicators and the arrows as a hint to questions regarding causal links, program implementation theory, where to examine underlying behavioral change assumptions, and areas for researchable questions.

[101] Sebold et al., pages 4-2 – 4-6.
[102] TecMarket Works, pages 30-37.
[103] Nicholas P. Hall & John Reed. "Merging Program-Theory and Market-Theory in the Evaluation Planning Process." *Proceedings of the International Energy Program Evaluation Conference* (2001).
[104] Sebold et al., page 6-9, Figure 6-2.

Interviews or workshops should be used to develop the program theory. These should include program managers who understand the program purpose and can articulate the assumptions about how the program will change the market.[105]

The key issues that should emerge from the workshops are program activities, identification of key market actors, assumed market barriers, expected outputs, outcomes and likely indicators of change, alternative hypotheses for change, external influences and causal links within anticipated timelines for achievement. Table 15 displays the Protocol for market theory and logic models.

An important distinction for the program theory/logic model development for a study under this Protocol is that the theory/logic model needs to be for a set of programs and capture both how the individual programs aim/hypothesize to affect the market as well as how they interact and support one another for market changes. The interaction, the degree to which and how to measure their ability to mutually support one another and how they interactively operate within a market are important analysis points and complications for a market level evaluation. Articulating the many assumptions this presents and then examining which are the most critical and how to test them are key to the degree to which the final market effects study will be comprehensive and defensible. A detailed understanding of how the market operates and how the various program interventions change or support that is a fundamental starting point for being able to attribute market changes to a group of programs, i.e., market effects.

Table 15. Required Protocol for Market Theory and Logic Models

Level of Rigor	Market Theory and Logic Model Requirements
Basic	Identification of assumptions about anticipated changes in the market and associated research questions. Market theory should include market operations and conditions, external influences, and assumptions about changes in the market (which could include market operational theory, market structure and function studies, and product and communication flows). Develop program theory and logic models across programs in that market. Analyze across both of these to examine program interventions, external influences and associated research questions. Theories and logic models should be generated through interviews with program staff and a sample of market actors.
Enhanced	Articulate market theory and, if reasonable, develop graphical model of market theory. Market theory should include market operations and conditions, and changes occurring in the market (could include market operational theory, market structure and function studies, and product and communication flows). Develop multiple program theory and logic models for those programs intervening in the market. Integrate the market theory and program theory/logic models to examine external and programmatic influences, assumptions about changes in the market and associated research questions. Theories and logic models should be generated through interviews or workshops with program staff from each of the programs and a sample of a wide variety of market actors. Use a literature review and other studies of these markets and iteration with program staff to ensure thoroughness in measuring the critical parameters for both market development from external influences and market effects.

[105] TecMarket Works, 30-38, 45-49, and 245-254. These sections of the *Evaluation Framework* (and the references provided for both chapters) will help in understanding the goals of program theory and logic models.

Determination of Indicators

The scoping study will determine what indicators should be used to assess market effects. The process emerges from the analysis of the market theory and program logic models but must also include an assessment of available data and primary data collection options. The use of smaller experimental designs imbedded into the program operations or quasi-experimental design is encouraged as a way to improve rigor without significantly increasing data collection costs over what is already required within this Protocol.

The market effects study should estimate what changes would have occurred in the market without program efforts. The indicators are used to draw conclusions about these changes. The focus should be on ultimate market indicators (the indicators of energy changes in the market). In developing the indicators there will be trade-offs that result in a level of rigor for the estimates. The scoping study should, therefore, address the level of rigor for the evaluation. The key considerations for the rigor of market effects estimates are the accuracy of the estimates of energy impacts and the accuracy of the attribution of market effects. The limitations of the market effects evaluation should be clearly articulated relative to these two issues and the scoping study should detail how the recommended approach addresses each.

The scoping study should also state the market assumptions and associated research questions to be addressed by the market effects study. At a market level, there are a variety of interventions that might occur and a variety of approaches that might be used to track and measure change in those interventions and their effect on the market. Table 16 indicates the general types of interventions that can influence change in a market and, therefore, suggests the types of indicators that might be tracked in market effects studies. The scoping study should clearly describe the relevance of the indicators to the market theory and how these indicators can be interpreted to indicate market effects.

Table 16. Types of Market Interventions and Associated Possible Indicators

Intervention Type	Ultimate Market Indicator	Other Indicators
Advertising/Outreach/ Branding	Value of energy savings from sales and/or market share changes for targeted efficient measures	Awareness, source of awareness, intention to purchase, amount of exposure to intervention
Upstream Vendor Incentives	Value of energy savings from sales and/or market share changes for targeted efficient measures	Stocking practices, product availability, price
Trade Ally Training	Value of energy savings from sales and/or market share changes for targeted efficient measures or market share of efficient buildings	Surveys of practices, willingness to implement changes in installation or purchase, recommendation practices
End-user Training	Value of energy savings from sales and/or market share changes for targeted efficient measures or market share of efficient O&M practice	Surveys of practices, willingness to implement changes in operation or purchase
Downstream Incentives	Value of energy savings from sales and/or market share changes for targeted efficient measures	Non-participant awareness of the program, non-participant awareness of program participant experience

Detailed Market Effects Evaluation Plan

Once the scoping study is completed, the CPUC-ED will contract with an evaluator to implement the market effects evaluation. The first task for the evaluator will be to develop a detailed evaluation plan to implement the recommendations in the scoping study.

The *Evaluation Framework* discusses the need and value of an evaluation plan in some detail.[106] It is important that the Market Effects Evaluation Plan clearly documents the results of the scoping study and details the approach that should be taken to conduct the evaluation. The scoping study defines the market, details the market theory and logic and identifies the indicators to be used for tracking market effects. The evaluation plan captures these findings and details the process by which the indicator data will be collected or generated and describes the analysis approach to be used to estimate gross and net market effects and the resulting net energy market effects.

The evaluation plan should include a detailed description of the data collection approach including how indicators will be measured, population estimates and sampling targets. There should be a clear discussion of the analysis strategies and model specification if appropriate, and how the analysis plan will be developed. There should also be a schedule of milestones and deliverables and clear delineation of what information and data sources will be required from the utilities and other California entities.

[106] Ibid, 56-58.

Collection of Baseline and Longitudinal Indicators

Baseline studies are addressed in the *2001 Framework Study*[107] and the *Evaluation Framework.*[108] There are a variety of indicators that might be chosen to track market progress and thus determine whether market effects have occurred. Primary and secondary data are used for indicator studies. Primary data collection must be done carefully and samples used should be determined using the Sampling and Uncertainty Protocol. In those cases where secondary data exist, care should also be taken to understand the manner in which the data were collected to be certain of its appropriateness for market effects estimation. Where available, secondary data often provide a source for estimating market share for both efficient and non-efficient equipment sold in a market and can be the most effective way to obtain data for non-program affected areas.

Primary data collection involves collecting data (such as sales data) directly from actors in the market of interest. These types of studies vary in complexity, but at a minimum, the sample must be representative of the population of market actors. When surveying retailers and distributors, effort also needs to be made to adjust for double counting and to weight sales reports to account for total share of the market (see below). It is also possible to establish baselines for behaviors or energy using equipment by surveying end-users or market actors targeted for training or information services.[109] These types of studies all require that the questions asked enable the analyst to differentiate between sales of efficient and standard equipment or behaviors that improve efficiency over standard practice. Alternatives that provide potentially less biased or more readily accessible or controllable data should be examined. For example, changes in saturation over time might be a worthwhile alternative to sales data in some cases.

A higher level of rigor for primary data collection is achieved by carefully designed studies. For example, the California market share tracking studies for residential equipment are carefully designed to have a panel of participating retailers and distributors whose data can be weighted appropriately to estimate market share. To implement such a data collection effort requires establishing long-term relationships with retailers and distributors to provide sales data on a regular basis. Such studies require that the sample be carefully selected so that reported sales can be properly weighted to account for differential roles in the market by different retailers and distributors. Double counting also has to be avoided since distributors supply retailers. Highest levels of rigor are achieved by using multiple data sources to triangulate on the estimate of market share caused by the program efforts. Table 17 shows the Protocol for indicator studies.

107 Sebold et al., pages 5-2 and 7-1 to 7-36.

108 TecMarket Works, 254-262.

109 Appliance sales have been tracked biennially in Wisconsin since 1993 (Energy Center of Wisconsin, 2004) by asking end-users about their purchases. The 2003 Appliance Sales Tracking Study is available at http://www.ecw.org. The Northwest Energy Efficiency Alliance tracks changes in behaviors for many of their programs by surveying representative samples of end-users and trade allies.

Table 17. Required Protocol for Market Effects Evaluation Indicator Studies

Level of Rigor	Indicator Study Requirements
Basic	Select appropriate market actor group for each indicator, survey representative samples of market actors able to report on each indicator from market experience. A baseline study must be conducted as early as possible. On-going tracking provides the basis for comparisons.
Enhanced	Select appropriate market actor group for each indicator. Conduct longitudinal study of representative samples of market actors able to report on each indicator from market experience. Samples weighted to represent known parameters in the population of interest. A baseline study must be conducted as early as possible, on-going tracking provides the basis for comparisons.

Analysis of Market Effects

The analysis of market effects has several components. First it should be determined if the indicators demonstrate any change in the market at all. This would be the estimation of gross market changes. Causality/attribution (which results in net market effects), sustainability and net energy impacts should then be estimated.

Gross Market Effects

Once the indicators have been collected for time one and time two, the analyst must determine the change in indicators across the time periods. For indicators such as market share and sales, it is reasonable to make direct comparisons. A variety of studies have shown that market share can be tracked directly overtime and these comparisons are fairly straightforward.

For other indicators such as awareness and knowledge, it is possible to make direct comparisons of indicators across time periods, but it is common that the direction and intensity of change in indicators will vary. One method that has been found to be effective in this type of situation is a binomial test.[110]

Estimating Causal Attribution

Causality should be examined to estimate net market effects. The goal of the activity is to estimate the proportion of market changes that can be attributed to program interventions using PGC and procurement funds, as versus those naturally occurring in the market or from interventions using non-PGC and non-procurement funds to arrive at market effects.

There are two primary approaches for estimating causal attribution, one uses a preponderance of evidence approach and the other uses a modeling approach. The ultimate goal for assessment of causal attribution is to avoid retrospective analysis in which contacts are asked to judge what efforts had effects on the market. Retrospective approaches have great potential for bias because contacts are themselves influenced and cannot maintain objective perspectives.

[110] Richard F Spellman, Bruce Johnson, Lori Megdal and Shel Feldman, "Measuring Market Transformation Progress & the Binomial Test: Recent Experience at Boston Gas Company." *Proceedings, ACEEE 2000 Summer Study on Energy Efficiency in Buildings*. (Washington, DC: American Council for an Energy-Efficient Economy, 2000).

Preponderance of Evidence Approach for Attribution

In some cases, it is best to use a "preponderance of evidence" approach to assess the attribution of market effects. In this approach the analyst relies on triangulation from multiple data sources to draw conclusions about the presence and attribution of market effects. This approach is accomplished by interviewing and surveying knowledgeable market actors. Program staff, utility staff and trade allies provide useful information for understanding the context of sales and counts of behavior. Over time, these views provide much of the information needed to draw conclusions about attribution and sustainability. Systematic sampling is very important to ensure that bias is minimized.

A minimum level of rigor requires that samples of trade allies be included in the sampling plan, as they provide a less biased perspective due to their market-centric rather than energy efficiency-centric view. Rigor improves with more comprehensive samples of trade allies and other market actors. A variety of approaches can be used including choice and ranking surveys, focus groups, Delphi surveys and others.[111]

The preponderance of evidence approach is inherently a qualitative analysis process in which the analyst uses multiple points of view to estimate the proportion of market effects that can be attributed to the program interventions. As noted above, the estimate will likely be a range, due in part to the qualitative nature of the analysis, but also to the difficulty in fully specifying all the factors that influence markets. The highest level of rigor relies on informants from multiple perspectives enabling the analyst to triangulate on the market effects. Table 18 shows the Protocol for the preponderance of evidence approach to attribution estimation.

Table 18. Required Protocol for Preponderance of Evidence Approach to Causal Attribution Estimation

Level of Rigor	Preponderance of Evidence Approach Requirements
Basic	A representative sample of market actors surveyed or interviewed to provide self-reports on perceived changes in the market, attribution and the sustainability of those changes.
Enhanced	Quasi-experimental or experimental design with comparison groups using a representative sample of market actors surveyed or interviewed to provide self-reports on perceived changes in the market, attribution and the sustainability of those changes.

Net Market Effects Modeling for Causation

The alternative to a preponderance of evidence approach is to use net effects modeling to control for non-PGC and non-procurement funded activities. In this approach the analyst uses multivariate models or simultaneous modeling systems to estimate net market effects. A variety of methods can be used. Some of these are discussed in Chapter 7 of the *2001 Framework Study,* in which it is suggested that the use of dynamic baselines in which a forecast of market changes are made in time one, using time one data, and then in time two the forecast is tested against the

[111] Sebold et al., 6-23 - 6-25 and 7-5 - 7-7.

actual conditions of time two.[112] Additional methods are being explored and hold a great deal of promise for clarifying the extent of market effects caused by energy efficiency program efforts.

A modeling approach permits the analyst to specify a model of the program theory and to test that model with data gathered in time one and time two. This is a growing area of investigation with a limited number of studies having been completed as of 2005. In constructing such a model, it is important that the model specifications reflect the complexity of the market. This is the greatest challenge for this approach. It is likely that such an approach will require multiple equations to model the various activities that occur in a market and the various points of intervention that energy efficiency programs exert on a market.

Given the early stage of development for this type of approach, it is not possible to determine levels of rigor. Advancements on these methods are being developed as it appears this approach could offer a greater level of rigor, quantification and testing than prior methods.

Estimating Sustainability

Sustainability is the degree to which one can expect the market changes to last into the future. Sustainability is not readily estimated using net effects modeling therefore the preponderance of evidence approach is the most frequently used for estimating sustainability. As with attribution a minimum level of rigor requires that samples of trade allies be included, as they provide a less biased perspective due to their market-centric rather than energy efficiency-centric view. Rigor improves with more comprehensive samples of trade allies and other market actors. A variety of approaches can be used including choice and ranking surveys, focus groups and Delphi surveys.[113] Another valid approach to estimate sustainability is identifying changes in market structure and operations, and how the changed market contains mechanisms to sustain them. This could include examining profitability analyses for important support businesses or business operations and how these are maintained without continued program intervention.

As noted previously, the preponderance of evidence approach is inherently a qualitative analysis process in which the analyst uses multiple points of view to estimate whether the market effects attributed to the program interventions can be expected to continue into the future. The highest level of rigor relies on informants and analyses from multiple perspectives enabling the analyst to triangulate on sustainability. A market with multiple support areas for continued sustainability will have a greater likelihood of having the changed market operation be sustainable.

The result of the estimation of sustainability is a statement on the likelihood of the market effects continuing without the energy efficiency program intervention or with reduced interventions. Given California's current interest in market effects that have recently occurred rather than those forecasted to occur (the focus of market effects estimation efforts in several other states), there is significantly less need for measures of sustainability. This issue, however, is a critical one whenever forecasts of market effects are the dominant evaluation concern.

Market Effects Metrics and Energy Savings

When the net effects modeling or preponderance of evidence approach is used to estimate net market effects, the analysis will result in an estimate of market share for the sales or counts of

[112] Sebold et al., pages 7-1 to 7-36.
[113] Ibid, 6-23 to 6-25 and 7-5 to 7-7.

behavior, or other indicator(s) attributed to the program. The net market effects must then be linked to an estimate of energy savings. The sales and counts of behavior or other indicators used to estimate market effects are linked to the energy savings for those measures or behaviors estimated through the M&V or Impact Evaluation Protocols, or in DEER. Savings estimates are directly applied to net changes in sales, counts of behavior and the like by multiplying the savings term by the associated amount of energy usage for the equipment or behavior of interest.

In some cases when net market effects modeling is used, it is anticipated that energy will be a term in the equation. Therefore, rather than linking the estimated net market effect to a savings estimate, the analyst will use the energy term as the dependent variable that is being modeled. The indicators will be the independent variables specified to explain the energy term.

Reporting

The evaluation report should also address the level of rigor for the study. The key considerations for the rigor of market effects estimates are the accuracy of the energy impact estimates and the accuracy of the attribution of market effects. The limitations of the market effects evaluation should be clearly articulated relative to these two issues.

In addition to estimating net energy market effects, the market effects evaluation report should clearly state the market assumptions and associated research questions addressed by the market effects study. The market effects evaluation report should clearly articulate the logic of the approach - whether using a preponderance of evidence approach to justify net market effects or a regression-based modeling approach.[114] Both approaches should build on the market theory as a hypothesis that was developed earlier in the scoping study.

Market effects evaluations will result in a report documenting the evaluation and its findings. The Reporting Protocol describes the content of the market effects evaluation report. The key aspects of that report include the following:

- Documentation of the market theory and the program theory/logic model as developed in the scoping study including an assessment of the initial market theory and program theory based on the results of the evaluation, and recommendations for a revised market theory/program theory, if needed;
- Documentation of the data collection and analysis process used for the market change indicators, whether the data used were primary data or secondary data. What indicators were used, how the data were assembled, collected and analyzed and the results of the various indicators studies;
- Documentation of the estimation of gross market effects that result from an analysis of the indicators, regression modeling or triangulation of the two;
- Documentation of the process used and results obtained for estimating causal attribution and sustainability and the resulting estimate of net market effects; and

[114] Modeling the market processes and change processes, some sequential and some simultaneous, is encouraged as an enhancement for a regression-based modeling approach over a single-equation model. Any use of a single-equation model must justify the model specification and its ability to capture the critical evaluation elements seen in the market theory and program theory/logic models.

- Documentation of the process used and results obtained when estimating net energy market effects. What energy data were used and how they were linked to the estimate of net market effects.

Guidance on Skills Required to Conduct Market Effects Evaluations

This Protocol suggests that there are two primary strategies for conducting net market energy effects evaluations, each of which can be considered rigorous when well-executed.

A preponderance of evidence approach, in which the analyst relies on triangulation from multiple data sources, is used to draw conclusions about the presence of market effects. While secondary data can be used in this approach, significant primary data collection is expected. The preponderance of evidence approach, therefore, requires skills in designing and implementing survey and interview instruments to collect indicators that correspond to the theory and reflect how the market is thought to operate. The evaluators should have sufficient experience to implement surveys, interviews, group interviews and other types of primary data collection activities. Since energy savings are drawn from impact evaluation results, the firms conducting market effects evaluations should have vast experience in energy efficiency markets, the social sciences. and interview and survey instrument design, implementation and analysis.

The net market effects modeling approach, in which the analyst uses multivariate models to estimate net market effects, can use primary or secondary data, although the use of secondary data has been most common. This type of approach is largely dependent on professional evaluators experienced in regression-based and multivariate modeling. The evaluator must be able to specify a model of the market during the scoping study and then populate the model with secondary and primary data. One approach is to develop a forecast of the market in time one and then test it in time two. Another approach is to take a retrospective approach using secondary data over a multi-year period. Other approaches are still emerging. The major limitation of the net market effect modeling approach is the availability of sufficient data to meet the model requirements. Modeling systems and/or specification that can mirror market operations and program theory interventions have still to be developed. Modeling the market processes and change processes, some of which are sequential while some are simultaneous, is an enhancement to a regression-based modeling approach and is encouraged over a single-equation model Any use of a single-equation model must justify the model specification and its ability to capture the critical evaluation elements seen in the market theory and program theory/logic models. Thus, a scoping study should be used to determine if such an approach is warranted and can be expected to be successful.

Considerations for Conducting a Market Effects Evaluation

The key consideration for conducting a market effects evaluation is determining whether market level effects are expected. As noted previously, programs that operate within a market have ripple effects on other programs operating in that market. Obvious examples are how the United States Department of Energy and the Environmental Protection Agency's ENERGY STAR efforts interact with the California energy efficiency program activities to encourage the adoption of energy-efficient appliances in the residential sector. All states are showing increased adoption of ENERGY STAR appliances, but the question remains as to what part of this market change is induced by the California programs. Another example concerns new residential and commercial construction activities that are affected by the implementation of California's building codes (Title 24) and by California's program activities designed to change construction behaviors and code-covered practices.

A market effects evaluation is appropriate when net market effects are used to justify a program or group of programs,[115] or when net market effects may be of interest to the Joint Staff for a set of programs operating in the same market. At the same time, the Impact Evaluation Protocol does not measure non-participant spillover due to the assessment that these are best measured by market effects evaluations. This means that the full effect of California's investments in energy efficiency programs may not be obtained through the sum of individual program evaluations but, instead, through an analytic derivation from the program-level evaluations and the market effects evaluations. (See the discussion in the Impact Evaluation Protocol on interaction with the Market Effects Protocol.) Market effects evaluations are needed, then, to have the information to derive the full impacts of the California efforts and investment.

As noted previously, determining the "market" is an important step in the scoping study. The Joint Staff will make recommendations for markets in which they expect market effects to be measured. Markets of possible interest to the Joint Staff include, but are not limited to:

- Residential appliance;
- Mass marketing campaigns;
- Residential construction;
- Nonresidential construction;
- Agricultural services;
- Commercial lighting;
- Residential lighting;
- Education (general public and targeted groups, e.g., contractors);
- Training programs; and
- Technical assistance programs.

Summary of Protocol-Driven Market Effects Evaluation Activities

1	Joint staff identifies the markets or market sectors (and the associated set of programs) that will receive a market effects evaluation and identifies the potential approach and rigor level for the scoping study.
2	Joint staff identifies market- or market sector-specific study needs that will be assessed (including program-specific or program group specific study needs) from the evaluation. CPUC-ED issues request for proposals for market effects scoping study, selects the scoping study contractor and establishes a scope(s) of work.

[115] TecMarket Works, 247, Figure 10.1.

3	Evaluation contractor develops scoping study. A scoping study will more finely define the market boundaries for the study, including its location, the utilities involved, the equipment or behaviors to be assessed and the program-influenced years of interest. The scoping study will develop a market theory and a logic model; identify the market change indicators to track; and the available primary and secondary data sources. The study will also identify the hypotheses to test and the data collection approach, and provide a recommended analysis approach and model specification (if appropriate).
4	A market change theory and logic model (MCT/LM) should be developed to identify assumed direction of effects and indicators for measuring effects. The market theory should include market operations and conditions, and changes occurring in the market (could include a market operations theory, market structure and function scenarios, and product and communication flows) The theory and logic model should be generated through interviews or workshops with program staff from each of the programs that are expected to influence the market being assessed and a sample of a wide variety of market actors and should incorporate a literature review.
5	Joint staff reviews the scoping study and determines how to proceed with the Market Effects Evaluation. CPUC-ED issues request for proposals for evaluation contractors, selects the contractor, establishes a final scope(s) of work and negotiates the contract.
6	All market effects evaluation teams must be staffed to meet the skills required for the research design, sampling, appropriate and selected evaluation method, uncertainty analysis and reporting requirements.
7	A research design and sampling plan should be developed to meet Protocol requirements at the market level to meet the Joint Staff assigned study rigor level. This includes meeting requirements from the Sampling and Uncertainty Protocol and the Reporting Protocol, as applicable. The evaluation contractor will develop an Evaluation Plan, submit it to the CPUC-ED and revise as necessary.
8	Indicators studies conducted as part of the Market Effects Evaluation should be based on the results of the scoping study, address the appropriate market actor group(s) for each indicator.
9	All Market Effects Evaluations must meet the requirements of the Sampling and Uncertainty Protocol. The 90/10 level of precision is a minimum precision target for the most important data collection efforts on its most important variables. Which data collection efforts and variables are considered to be the most important will be determined in close collaboration with the CPUC-ED
10	The gross market effects and the estimate of energy savings associated with the market effects should be estimated. Estimation of gross market effects can be as simple as comparing indicators between time one and time two and then multiplying the energy value derived in an M&V supported impact assessment or from DEER, or using a CPUC-ED-approved net energy effects model.
11	Attribution or causality should be addressed to estimate net effects using either a preponderance of evidence approach or a net effects modeling approach. a. For a preponderance of evidence approach a determination of attribution should use quasi-experimental or experimental design with comparison groups using a representative sample of market actors. This may include interviews to provide self-reports on perceived changes in the market, attribution and the sustainability of those changes as well as direct observation or other data to support changes resulting from the program.

	b. For a net effects modeling approach to estimate causality, the model specifications must reflect the complexity of the market. It is likely that such an approach will require multiple equations to model the various activities that occur in a market and the various points of intervention that energy efficiency programs exert on a market.
12	Sustainability should be addressed using a preponderance of evidence approach.
13	Develop draft evaluation report to include meeting all requirements in the Reporting Protocol and incorporating the program's performance metrics.
14	Develop final evaluation report in accordance to guidance provided by Joint Staff.
15	Submit final evaluation report to the CPUC-ED.
16	Once the report is accepted by the CPUC-ED, develop abstracts and post them and the report on CALMAC Web site following the CALMAC posting instructions

Note: The steps included in this evaluation summary table must comply with all the requirements of the Market Effects Evaluation Protocol.

Sampling and Uncertainty Protocol

Introduction

There are some important similarities between the pre-1998 protocols and the 2006 Protocols related to impact and M&V studies. Both sets of protocols focus on obtaining reliable estimates of energy and demand impacts. Reliable estimates are interpreted as estimates that are reasonably accurate and precise, that is, they contain a minimal amount of error from a variety of sources such as sampling error, measurement error, and model misspecification error. The pre-1998 protocols concern the same issues listed in the *Evaluation Framework*:[116]

- Non-response and other forms of selection bias;
- Measurement error;
- Erroneous specification of the statistical model;
- Choosing an inappropriate baseline;
- Self-selection of program participants;
- Misinterpretation of association as causal effects;
- Construct validity;
- Statistical validity;
- Internal validity; and
- External validity.

However, the two protocols also have differences, the two primary of which relate to the number of study types and the degree of precision required for energy-use estimates. The 2006 Protocols must address an additional set of studies that include process evaluations, indirect impact evaluations for education, training and advertising programs, and market effects evaluations. The reliability of information produced by these studies is equally important and must be addressed in the 2006 Protocols.

The pre-1998 protocols require 90/10 precision for estimates of annual energy use while the 2006 Protocols set precision targets[117] whenever possible for a variety of parameters including savings.[118] Precision targets are set rather than required since, as discussed in the *Evaluation Framework* and its cited study of this issue by Sonnenblick and Eto, bias could be much more

[116] See *Evaluation Framework*, 292-294 for examples and definitions of the terms listed here, along with citations to reference documents.

[117] A precision target is a goal established at the beginning of an evaluation based in large part on initial estimates of uncertainty. If an evaluator fails to actually achieve the targeted level of precision, there will be no penalties since the assumptions underlying the sample sizes proposed in each evaluation plan will have been *clearly presented and carefully documented*. A failure to meet the precision target for a given program will only require an adjustment of the input assumptions prior to the next evaluation cycle and, if necessary, a reallocation of evaluation dollars to support increased sample sizes.

[118] The *Evaluation Framework* proposed no precision targets or requirements for savings or for any other parameters associated with such studies as process and market effects evaluations.

important than precision for the reliability of the savings estimates or the cost-effectiveness calculations.[119] In addition, as any evaluation study proceeds, the data collected could contain much more error than originally thought, requiring more resources to be devoted to reducing this bias and fewer resources devoted to achieving the required statistical precision. Or, the variability in the savings could be so great that it would be impossible to meet the precision requirement. The evaluator must have the flexibility to respond to data issues as they arise in order to maximize the reliability of the savings. Therefore, focusing on sample error, while giving relatively little attention to these other sources of error, would compromise the CPUC's objective of obtaining *reliable* estimates of kWh and kW impacts.

Finally, the guidelines regarding sampling and uncertainty must be followed for each utility service territory. For example, precision targets, when specified for a particular level of rigor, must be set for *each* utility service territory.

Precision: Gross and Net Impact, Measurement and Verification, and Verification Activities

There are a number of impact-related activities concerning precision addressed in this section:

- Estimation of gross impacts (including M&V);
- Estimation of net impacts;
- M&V in support of specific measure studies; and
- Verification studies in support of non-Impact Evaluation Protocol gross and net impacts.

The issue of precision for each of these types of analytical studies is addressed in Table 19 through Table 23.

[119] California Framework, p. 296.

Table 19. Required Protocols for Gross Impacts[120]

Rigor Level	Gross Impact Options
Basic	**Simplified Engineering Models**: The relative precision is 90/30[121]. The sampling unit is the premise. The sample size selected must be justified in the evaluation plan and approved as part of the evaluation planning process.
	Normalized Annual Consumption (NAC) Models: There are no targets for relative precision. This is due to the fact that NAC models are typically estimated for all participants with an adequate amount of pre- and post-billing data. Thus, there is no sampling error. However, if sampling is conducted, either a power analysis[122] or justification based upon prior evaluations of similar programs must be used to determine sample sizes. The sample size selected must be justified in the evaluation plan and approved as part of the evaluation planning process.
Enhanced	**Regression**: There are no relative precision targets for regression models that estimate gross energy or demand impacts. Evaluators are expected to conduct, at a minimum, a statistical power analysis as a way of initially estimating the required sample size.[123] Other information can be taken into account such as professional judgment and prior evaluations of similar programs. The sample size selected must be justified in the evaluation plan and approved as part of the evaluation planning process.
	Engineering Models: The target relative precision for gross energy and demand impacts is 90/10. The sampling unit is the premise. The sample size selected must be justified in the evaluation plan and approved as part of the evaluation planning process.

[120] See the Impact Evaluation Protocol for a description of methods and page references in the *Evaluation Framework* for further information and examples.
[121] Also of interest, in addition to the relative precision, are the actual kWh, kW, and therm bounds of the interval.
[122] Statistical power is the probability that statistical significance will be attained, given that there really is a treatment effect. Power analysis is a statistical technique that can be used (among other things) to determine sample size requirements to ensure statistical significance can be found. Power analysis is only being required in the Protocol for determining required sample sizes. There are several software packages and calculation Web sites that conduct the power analysis calculation. One of many possible references includes: Cohen, Jacob (1989) *Statistical Power Analysis for the Behavioral Sciences*, Lawrence Erlbaum Associates, Inc.
[123] Ibid.

Table 20. Required Protocols for Net Impacts

Rigor Level	Net Impacts Options
Basic	For the self-report approach (Option Basic.1), given the greater issues with construct validity and variety of layered measurements involved in estimating participant NTGRs, no relative precision target has been established.[124] To ensure consistency and comparability a minimum sample size of 300 sites (or decision-makers in cases where decision-makers cover multiple sites) or a census[125], whichever is smaller, is required.
Standard	If the method used for estimating net energy and demand impacts is regression-based, there are no relative precision targets. If the method used for estimating NTGRs is regression-based (discrete choice), there are no relative precision targets. In either case, evaluators are expected to conduct, at a minimum, a statistical power analysis as a way of initially estimating the required sample size.[126] Other information can be taken into account such as professional judgment and prior evaluations of similar programs. For the self-report approach (Option Standard.2), there are no precision targets since the estimated NTGR will typically be estimated using information collected from multiple decision-makers involving a mix of quantitative and qualitative information around which a standard error cannot be constructed. Thus to ensure consistency and comparability, for such studies, a minimum sample size of 300 sites (or decision-makers in cases where decision-makers cover multiple sites) or a census, whichever is smaller, is required.
Enhanced	The requirements described for Enhanced apply depending on the methods chosen.

[124] This is considered the best feasible approach at the time of the creation of this Protocol. Like the other approaches to estimating the net-to-gross ratio (NTGR), there is no precision target when using the self-report method. However, unlike the estimation of the required sample sizes when using the regression and discrete choice approaches, the self-report approach poses a unique set of challenges to estimating required sample sizes. These challenges stem from the fact that the self-report methods for estimating free-ridership involve greater issues with construct validity, and often include a variety of layered measurements involving the collection of both qualitative and quantitative data from various actors involved in the decision to install the efficient equipment. Such a situation makes it difficult to arrive at a prior estimate of the expected variance needed to estimate the sample size.
Alternative proposals and the support and justifications that address all of the issues discussed here on the aggregation of variance for the proposed self-report method may be submitted to Joint Staff as an additional option (but not instead of the Protocol requirements) in impact evaluation RFPs and in Evaluation Plans. Joint Staff may elect to approve an Evaluation Plan with a well-justified alternative.

[125] A census is rarely achieved. Rather, one *attempts* to conduct a census, recognizing that there will nearly always be some sites, participants or non-participants who drop out for a variety of reasons such as refusals or insufficient data.

[126] Statistical power is the probability that statistical significance will be attained, given that there really is a treatment effect. Power analysis is a statistical technique that can be used (among other things) to determine sample size requirements to ensure statistical significance can be found. Power analysis is only being required in the Protocol for determining required sample sizes. There are several software packages and calculation Web sites that conduct the power analysis calculation.

Table 21. Required Protocols for Measure-level Measurement and Verification

Rigor Level	M&V Options
Basic	**Simplified Engineering Models**: The target relative precision for gross energy and demand impacts is 90/30. The sample unit may be the individual measure, a particular circuit or point of control as designated by the M&V plan.
Enhanced	**Direct Measurement and Energy Simulation Models**: The target relative precision for gross energy and demand impacts is 90/10. The sample unit may be the individual measure, a particular circuit or point of control as designated by the M&V plan.

Table 22. Required Protocols for Sampling of Measures Within a Site

The target relative precision is 90/20 for each measure selected for investigation. The sampling unit (measure, circuit, control point) shall be designated by the M&V plan. The initial assumption regarding the coefficient of variation for determining sample size is 0.5.

Table 23. Required Protocols for Verification

Rigor Level	Verification Options
Basic	The target relative precision is 90/10. The key parameter upon which the variability for the sample size calculation is based is binary (i.e., Is it meeting the basic verification criteria specified in the M&V Protocol?).
Enhanced	The target relative precision is 90/10. The key parameter upon which the variability for the sample size calculation is based is binary (i.e., Is it meeting the enhanced verification criteria specified in the M&V Protocol?).

Of course, when sampling from any population it should always be assumed that there will be some attrition due to such factors as refusals to participate in a telephone survey or an on-site inspection, or insufficient data. As a result, a larger sample than is actually needed should always be drawn based on the best estimate of expected attrition.

Development of the Evaluation Study Work Plan

For each study in the evaluator's defined set of studies, the evaluator must prepare a detailed evaluation work plan (plan) that allocates resources to maximize reliability for the program group and takes into account that the level of rigor will likely vary by program. In many cases, the evaluator will be required to develop a separate work plan for each program in the study set. In some cases, a draft plan will be required as part of the initial proposal package, in others the evaluator may be required to develop this work plan after the hiring process is complete. As part of this plan, the evaluator must specifically address the various sources of error that are relevant and explain how the resources allocated to each will mitigate the error[127]. They must also estimate the statistical precision that the planned evaluation will achieve. It is also recognized

[127] In the pre-1998 M&E Protocols, there was no requirement to address these sources of error in the research plan. Evaluators only had to describe in the final report whether they had to address these various errors and, if so, what they did to mitigate their effects.

that the targeted precision at the *program level* must be allowed to vary in ways that produce the greatest precision at the *program group level*. For example, in some cases accepting a lower level of precision for programs with small savings might allow for the allocation of greater resources to programs with larger savings, thus increasing the achieved precision for the program group.[128]

The Joint Staff and other outside resources as deemed appropriate by the CPUC will review the evaluation plan submitted and discuss with the independent evaluator any changes they deem necessary to maximize the reliability of the savings estimates at the program group level.[129] The Joint Staff might decide to increase the sample size in order to increase precision, recognizing that other sources of error will receive fewer resources, or they might decide to reduce the sample and settle for lower precision in exchange for a greater effort to reduce non-response bias. In the final plan, the evaluators and Joint Staff will endeavor to allocate their available evaluation resources in such a way as to maximize the reliability of the savings and the value received from the evaluation efforts. In order to more adequately address accuracy and/or precision, once evaluation studies are underway, Joint Staff may adjust the allocation of resources that were initially dedicated to the evaluation of a given program, program group, or study set.

The level of rigor assigned to each program will vary depending on the evaluation priorities and budgets discussed above. However, because each program is somewhat unique with respect to the various sources of bias, there is no specific set of required methods and level of effort for minimizing bias that can be assigned based on the level of evaluation rigor assignment.

At the same time, every impact and indirect impact evaluation plan, analysis and report is expected to seriously address, at a minimum, each and every one of the ten sources of uncertainty listed in the introduction of this section. The assessment of the potential issues, testing, minimization approaches and mitigation efforts are to be discussed in the evaluation plan and carried forward through the evaluation and evaluation reporting. This assessment and reporting needs to include the justification based on prior evaluations, evaluation science and other research (with appropriate citation) that support the evaluation research design decisions made in the evaluation plan and the handling of the issues through the analyses. The reporting should include specific data collection, measurement and handling of each issue at a level of detail that allows the study results to be replicated. Results from tests of alternative methods of data handling should be included. For example, if outliers are dropped from the analysis, the reporting should include the methods used to identify outliers, analysis results with and without outliers, and the justification used in deciding to remove some or all of the outliers. Data cleaning methods and decision rules should be supplied with at least some testing of the analysis impacts produced by varying the primary parameters in these decision rules. Similarly, any sampling and site selection parameters need to be examined for potential bias with appropriate research questions and tests being conducted on key parameters.

[128] See *California Framework*, pp. 305-313 for a description and some examples of how to allocate resources and sample sizes to obtain the smallest possible error bound for a group of programs.
[129] Ibid, 298-300 for a description of calculating error bounds and precision levels for different types of evaluation study integrations.

Process Evaluations

For process evaluations, the focus is on reliability at the program level, with the level of evaluation rigor varying as a function of evaluation priorities and budgets. However, because each program is somewhat unique, with respect to the data being collected and the various sources of bias, there is no specific set of required methods and level of effort for minimizing bias that can be assigned to a program that has been assigned a given level of evaluation rigor.

Requiring 90/10 precision, for example, for all inquiries is very likely infeasible and not cost-efficient because budgets are limited, there is often a large set of evaluation questions to be addressed (i.e., many different questions and parameters for which some level of precision could be desired), not all of which are quantitative, and the information sought from different survey and interview groups might not be equally valuable. For example, one might want to field a small survey to get a sense of the motivation of a particular market actor. Again, it is important for the evaluator to have the flexibility to maximize the reliability of their findings. However, the 90/10 level of precision should be adopted as a minimum precision target for the most important data collection efforts on its most important variables. Which data collection efforts and variables are considered to be the most important for process evaluations will be determined by the independent evaluator in close collaboration with utility EM&V staff.

There are circumstances when it might be desirable to use M&V as input to the analysis of a problem being investigated in a process evaluation. If M&V is not conducted by the Joint Staff evaluations, utility evaluation staff may chose to specify M&V activities within the process evaluation RFP.[130] If the M&V Protocol is used for purposes outside impact, indirect impact and verification analysis, a target precision should, at a minimum, be 30 percent precision at a 90 percent confidence level (or 90/30 precision).

The evaluator must prepare a detailed plan that allocates resources in order to maximize reliability for the findings and for key parameter estimates for each program in the group. As part of this plan, the evaluator must specifically address the various sources of error that are relevant and explain how the resources allocated to each will minimize and/or mitigate the error.[131] They must also estimate the statistical precision that the planned evaluation will achieve on selected primary quantitative measurements.

The Joint Staff and other outside resources as deemed appropriate by the CPUC will review the evaluation plan submitted and discuss with the independent evaluator any changes they deem necessary to maximize the reliability of the findings at the program level. The evaluation staff might decide to increase the sample size in order to increase precision, recognizing that the other sources of error will receive fewer resources. Or it might decide to reduce the sample size and settle for lower precision in exchange for a greater effort to reduce non-response bias. In the final plan, evaluation resources will be allocated in a way that maximizes the reliability of the findings for each program.

[130] Coordination of M&V studies for process and impact purposes is a key issue that must be addressed by the evaluation plans for both process and impact evaluation.

[131] In the pre-1998 Protocols, there was no requirement to address these sources of error in the research plan. Evaluators only had to describe in the final report whether they had to address these various errors and, if so, what they did to mitigate their effects.

Market Effects

The focus is on the market level for market effects evaluations. The level of rigor assigned to a particular market effects study will depend on the evaluation priorities and budgets. However, because each market effects study will be somewhat unique with respect to the data being collected and the various sources of bias, there is no specific set of required methods and level of effort for minimizing bias that can be assigned to a given market effects study.

Requiring 90/10 precision for all estimates, for example, is very likely infeasible and not cost-efficient because budgets are limited, there are often a large set of evaluation questions, outcomes and causal mechanisms to be assessed in a market effects evaluation (i.e., many different questions and parameters for which some level of precision could be desired), and the information sought from different survey, interview groups and data sources might not be equally valuable. For example, one might want to field a small survey to roughly estimate the number of HVAC contractors who actively promote energy-efficient air conditioners. Again, it is important for the evaluator to have the flexibility to maximize the reliability of their findings. However, the 90/10 level of precision should be adopted as a minimum precision target for the most important data collection efforts on its most important variables. Which data collection efforts and variables are considered to be the most important will be determined by the independent evaluator in close collaboration with the CPUC.

The evaluator must prepare a detailed evaluation plan that allocates resources in order to maximize reliability of market-level estimates. As part of this plan, the evaluator must specifically address the various sources of error that are relevant and explain how the resources allocated to each will minimize and/or mitigate the error (e.g., non-response bias, measurement error, and self-selection bias).[132] They must also estimate the statistical precision that the planned evaluation will achieve on key estimates and for the overall estimate of market effects (to include the propagation of error).

The Joint Staff and other outside resources as deemed appropriate by the CPUC will review the evaluation plan submitted and discuss with the independent evaluator any changes they deem necessary to maximize the reliability of the estimates at the market level. For example, The Joint Staff might decide to increase the sample size or budget in order to increase precision for specific parameters or study elements, recognizing that the other sources of error will receive fewer resources. Or it might decide to reduce the sample and settle for lower precision in exchange for a greater effort to reduce non-response bias. In the final plan, evaluation resources will be allocated in a way that maximizes the reliability of the market-level estimates.

System Learning

The hallmark of any learning system is that feedback is processed and any necessary course corrections are made. Once a particular evaluation is launched, it's certainly possible that mid-course adjustments will be made to the initial plan to maximize savings reliability. For example,

[132] In the pre-1998 Protocols, there was no requirement to address these sources of error in the research plan. Evaluators only had to describe in the final report whether they had to address these various errors and, if so, what they did to mitigate their effects.

the coefficients of variation (CVs)[133] for certain key parameters, measures, end-uses or programs might actually be smaller than anticipated or the random and/or systematic measurement error might be worse. As data are collected and assessed, decisions can be made regarding the reallocation of resources.

Once a particular study is completed or all the studies within a given group are completed, the CPUC-ED, utility EM&V staff and the independent evaluators can review the achieved precision and the results of efforts to minimize bias and recommend how evaluation resources can be reallocated for the next evaluation cycle.

Acceptable Sampling Methods

It is rarely possible, for a variety of different reasons, to conduct a census of any population (e.g., program participants, programs non-participants or lighting vendors).[134] Especially in a state the size of California, this is due largely to the fact that many of the populations are quite large and the cost of attempting a census study would be prohibitive. Instead, random samples drawn from these populations are almost always used as a way to estimate various characteristics of these populations. The specific approaches to maximizing precision are left up to the independent evaluator. For example, one can choose from a variety of sample procedures recognized in the statistical literature, such as sequential sampling, cluster sampling, multi-stage sampling and stratified sampling with regression estimation. There are many available books on sampling techniques that can be used as reference.[135]

Skills Required for Sampling & Uncertainty

Population database work and simple random sampling (or census) do not require an advanced statistics background. Other more complex sample designs require basic training and/or experience in statistics to ensure that the methods are understood and applied correctly. Those conducting and reviewing this work should have at least basic graduate statistics or equivalent experience with a mentor in this area. The skills required for addressing the uncertainty associated with the various methods for estimating the gross and net energy and demand impacts as well as the net impacts are described as part of the Impact Protocols.

Audience and Responsible Actors

- **Program Evaluators** should understand and implement this Protocol. They also need to be able to correctly estimate the expected precision and accuracy. Based on the achieved precision and accuracy, they must recommend any reallocation of evaluation resources going forward;
- **CPUC-ED CEC and Utility EM&V Staff** should understand this Protocol and be able to correctly interpret the expected and achieved levels of precision and accuracy in order to

[133] The sample standard deviation divided by the sample mean. See page 320 of the *Evaluation Framework*.
[134] In process evaluations, a census is possible in some more limited populations such as staff and program contractors.
[135] The two cited in the *Evaluation Framework* are 1) Cochran, William G. *Sampling Techniques*. New York: John Wiley & Sons, 1977 and 2) Sarndal, Carl-Eric, Bengt Swensson and Jan Wretman. *Model Assisted Survey Sampling*. New York: Springer-Verlag, 1992.

accept or reject any recommendations regarding the reallocation of evaluation resources going forward; and

- **Utility System Planners** should be able to understand the achieved precision and accuracy and the overall reliability of the savings in order to assess their resource value.

Key Metrics and Information Covered

All evaluation reports must contain a variety of information regarding the sample design and implementation as well as a variety of information regarding the various sources of bias encountered and efforts to mitigate them. These are outlined below.

Sample Size and Precision

Whenever estimates are based on a sample in any evaluation, the following information, as appropriate, must be reported:

- The definition of the population from which the sample was drawn;
- The sample design (e.g., simple random, stratified random and two-stage);
- The assumptions and related documentation upon which the initial sample size calculations were based (e.g., CV for key inputs in an engineering algorithm, CV for proportion of audit participants who adopt recommendations, the specified statistical power, effect size, confidence level and alpha level);
- The details of how the initial sample sizes were calculated to achieve the agreed upon level(s) of precision;
- The achieved precision around program-level gross and net kWh, kW, and therm impacts, key process evaluation measurements, and other program impacts such as attitude change and knowledge gains;
- The confidence intervals specified in terms of the kWh, kW, and therm impacts;
- The details of how the achieved sample size was used to calculate the precision; and
- Response rate and attrition and any suspected non-response bias and efforts to address it.[136]

Validity and Research Design

- Discuss threats to internal validity (the extent to which alternative potential causes of the measured effect have been ruled out within the analysis);[137]
- Discuss threats to external validity (the extent to which the analysis results found for a sample are true for the population and the program overall);[138] and

[136] See "Definitions of Response, Refusal, and Cooperation Rates" prepared by the Council for Marketing and Opinion Research and the "CASRO Guidelines for Survey Research Quality," prepared by the Council of American Survey Research Organizations (www.casro.org).
[137] See *Evaluation Framework*, pp. 292-295 and 425.
[138] Ibid, 292-295 and 421.

- Discuss assessment of construct validity and potential remaining issues of construct validity for the primary evaluation outputs (the extent to which the measurement (and instrumentation, such as survey wording) captures the underlying abstract idea).[139]

Accuracy

Regression models:

- Describe procedures used for the treatment of outliers, missing data points and weather adjustment;
- Describe what was done to control for selection bias, if suspected;
- Describe what was done to control for the effects of background variables, such as economic and political activity that may account for any increase or decrease in consumption in addition to the program itself;
- Describe procedures used to screen data for inclusion into the final analysis dataset. Show how many customers, installations or observations were eliminated with each screen. The reviewer should be able to clearly follow the development of the final analysis dataset;
- Regression statistics: For all final models, provide standard regression statistics in a tabular form;
- Specification: Refer to the section(s) of the study that present the initial and final model specifications that were used, the rationale for each, and the documentation for the major alternative models used. In addition, the presentation of the specification should address, at a minimum, the following issues:
    - Describe how the model specification and estimation procedures recognize and address heterogeneity of customers (i.e., cross-sectional variation);
    - Describe how the model specification and estimation procedures recognize and address changes in factors that affect consumption over time (i.e., time series variation), apart from program effects;
    - Describe how the model specification and estimation procedures recognize and address the fact that participants self-select into that status, and discuss the effects of self-selection on model estimates whether or not self-selection is treated explicitly;
    - Describe how truncation within the data and regression towards the mean within the participant population (e.g., within low-income populations) is tested for, the results of this test, and how model specification and estimation procedures recognize and address these issues;
    - Discuss the factors, and their associated measures, that are omitted from the analysis, and any tests, reasoning or special circumstances that justify their omission; and

[139] Ibid, 292-298 and 414.

  - Describe how the model specification can be interpreted to yield the measurement of program impacts.

- Error in measuring variables: Describe whether and how this issue was addressed, and what was done to minimize the problem;
- Autocorrelation: Describe any autocorrelation problems and the solutions specifically taken to address the problem. Specific identification and mitigation diagnostics should be presented, including differing treatment for sub-groups, if any;
- Heteroscedasticity: Describe the diagnostics carried out, the solutions attempted and their effects. If left untreated, explain why;
- Collinearity: Describe procedures used to address the problem of collinearity, and the reasons for either not treating it or treating it to the level that it was;
- Influential data points: Describe the influential data diagnostics that were used, and how the identified outliers were treated;
- Missing data: Describe the methods used for handling missing data during the analysis phase of the study; and
- Precision: Present the methods for the calculation of standard errors for key parameters such as gross impacts, net impacts, NTGRs, and key process and market effects measurements.

Engineering Models Including M&V

- Describe the primary sources of uncertainty in deemed and measured parameters used in engineering models;
- Describe the construction of the baseline. Include assessment and description of how the selection of baseline affects the development of gross impacts versus net impacts. Baseline definitions shall be consistent with those used in the net analysis;
- Discuss efforts to guard against measurement error associated with the various M&V data collection efforts;
- Discuss site selection and potential non-response bias, any tests performed to assess potential bias across and within site measurements, and potential effects of any remaining concerns in this area;
- Describe any potential measurement or bias issues associated with the measurement approaches and tools used as they apply to specific program parameters and estimates:
  - Engineering model bias – systematic under- or over-prediction of effects of a measure by an engineering model;
  - Modeler bias – the systematic under- or over-prediction of effects of a measure by a building energy simulation (e.g., DOE-2) modeler. Also includes the random under- or over-prediction of effects of a measure by a building energy simulation (e.g., DOE-2) modeler;
  - Deemed parameter bias – systematic deviation in a deemed parameter used in an engineering model;

- Meter bias – systematic error in meter and/or sensor;
- Sensor placement bias – systematic over- or under-prediction of measured quantity due to sensor placement (could be combined with above); and
- Non-random selection of equipment and/or circuits to monitor.

Summary of Sampling and Uncertainty Protocol

A summary of these Protocols is not provided here. Rather, in the summaries provided at the end of the other Protocols (Impact, M&V, Emerging Technology, Codes and Standards, Effective Useful Life and Market Effects), the relevant elements of the Sampling and Uncertainty Protocols are discussed.

Evaluation Reporting Protocol

Introduction

The Evaluation Reporting Protocol identifies the information that must be incorporated in the different types of evaluation reports and specifies how it is to be reported. This is accomplished by first identifying the common information required across all evaluation reports. Then the Protocol describes additional information and presentation formats for each of the types of evaluation reports.

The reporting information contained in this Protocol is that which support the program evaluation efforts. There are other reporting requirements associated with program status, progress and financial reporting not covered in this Protocol for which Administrators are responsible. For information relating to program status, progress and financial reporting the reader is referred to the CPUC-ED.

Report Delivery Dates

The delivery dates for each evaluation report must be identified in each program evaluation plan. Both the report delivery dates and changes to these dates must be approved by the CPUC-ED. The scheduling of the all draft and final evaluation reports must consider the timing of the information needs of the key stakeholders including the CPUC-ED, the CEC and the portfolio Administrators, so that the evaluation results can be provided in time to use the results to support program "performance basis" assessments and to support future program design and evaluation planning. This requirement does not imply that only two reports (one draft and one final) will be required from the evaluation contractor. It is expected that each evaluation will have multiple reporting periods across the multi-year study period. Each evaluation plan will detail the deliverables to be provided within the study scope and the due dates for each deliverable. Once the final reports are approved by the Joint Staff, the evaluation contractor will deliver the electronic and hard copy reports and post the final evaluation report on the CALMAC Web site consistent with the instructions detailed in this Protocol.

Common Evaluation Reporting Requirements

This section of the Reporting Protocol presents the reporting requirements specifying the information that must be reported in the various types of draft, draft-final and final evaluation reports. Typically these requirements apply to the evaluation contractors conducting the studies and preparing the reports.

The present Reporting Protocol is different than previous California reporting protocols. In addition to new evaluation reporting requirements, there are also performance basis reporting metrics that need to be reported when applicable. The evaluation contractors are responsible for knowing what information is required in their evaluation reports and for conducting the evaluation efforts in a way that provides the required information. The evaluation contractor will coordinate with the CPUC-ED to identify the performance basis reporting metrics to be included in each evaluation and structure the evaluation plan to meet those requirements. Final negotiated study-specific evaluation budgets will be structured to meet this Protocol requirement.

The following reporting requirements apply to all evaluation reports produced from studies of California's energy efficiency programs including process, impact and market effects evaluations.

The reporting requirements included in this Protocol are minimum requirements. Each program evaluation may have additional reporting requirements that are specified in the approved evaluation plan. For example, an evaluation plan may require that the evaluation report provide "designated units of measure" reporting at the program level. These units may include items such as kWh savings/square foot of commercial building served or kW savings/square foot of home served. These may also be structured so that the reporting requirements are more defined, such as kWh savings/square feet of commercial building conditioned space served, or kW savings/square foot of occupied space, heated space, cooled space, or other criteria.

1. **Draft reports are to be provided in electronic formats**. Draft and final-draft energy and load impact reports, M&V reports, codes and standards reports, emerging technology reports, effective useful life reports and draft market effects evaluation reports will be provided to the Joint Staff in electronic file formats consistent with the file format requirements provided in this Protocol for final reports (see below). Draft process evaluation reports will be provided in formats determined by the Administrators requesting the studies.

2. **At least 10 copies of all final evaluation reports must be submitted in bound hard copy format on recycled paper using double-sided printing to minimize the use of paper.** No less than four hard copies should be provided to the CPUC-ED, two hard copies to the CEC, three hard copies to the Administrator(s) for the program(s) being evaluated and one hard copy to the program implementation manager (whether a contractor or employee of the Administrator) of the program being evaluated. The Administrator and the Joint Staff can request that evaluation contractors provide additional copies as appropriate or can advise the evaluation contractors that fewer hard copies are needed. This requirement serves as the minimum deliverable of the final evaluation reports in bound hard copy format unless specified differently for an individual study.

3. **All final reports will be provided to the CPUC-ED, the CEC and the Administrators in unprotected (no password restrictions) electronic formats and protected formats that can be made available to the public.** The electronic formats must be provided in two software versions with each report provided in a single electronic file. The unprotected electronic reports must be provided in Microsoft Word®. The protected formats should be provided in Adobe® formats in a version that is loadable/readable by the organization contracting for the study. The electronic files must be named in a way that allows the recipients to understand the program or the group of programs on which the evaluation reports. Examples of acceptable file names include the following:
    a. 06 PG&E Mass Market Process Eval.pdf
    b. 06-08 SCE Res Programs Impact Eval.doc
    c. 06 SCE Appliance Recycling Process Eval.pdf
    d. 06-07 Statewide Multi-Family Programs Impact Eval.doc

Evaluation contractors conducting energy impact studies will also provide Microsoft Excel files presenting the energy savings (kW, kWh, therms) from direct or indirect impact, codes and standards, or market effects studies as described in this Protocol (see Sample Reporting Tables at the end of this Protocol).

4. **Within five days of the submission and acceptance of the final evaluation report, the organization providing the report must post it and its abstract on the CALMAC Web site using the posting instructions provided by CALMAC at the time of posting.** The abstract posted on the CALMAC site should be the one included within the final evaluation report located just after the title page. Care should be taken in developing the abstract to allow the CALMAC search engines to easily find the report when system users conduct key-word searches. Upon posting, CALMAC will distribute an e-mail announcement of the availability of the report to the CPUC's energy efficiency docket list-serve and to the CALMAC distribution list.

5. **All evaluation reports must contain the following information on the report cover of both the electronic and hard copy files.**
    a. Report title that reflects the type(s) of evaluation(s) being conducted (e.g., Energy and Demand Impact Evaluation, Process Evaluation, Effective Useful Life Evaluation, Codes and Standards Program Evaluation, Market Effects Evaluation, or Market Effects Evaluation);
    b. Official name of the program(s) as recorded in the CPUC's program tracking system (EEGA), including the program cycle identifier (e.g., 2006-2008, 2009-2011);
    c. Official CPUC/EEGA tracking number(s) of the program(s) being evaluated;
    d. Date of the evaluation report;
    e. Name of the organization conducting the evaluation;
    f. Name of the organization administering the evaluation;
    g. Name of the organization administering the program; and
    h. Name of the organization implementing the program.

6. **The title page of both hard copy and electronic formats must include the following information:**
    a. The same information provided on the report cover, plus the following:
    b. Name of the organization conducting the evaluation and full contact information for the evaluation lead(s) responsible for the study;
    c. Name of the organization administering the evaluation and full contact information for the lead Administrator; and

d. Name of the organization implementing the program and full contact information for the lead program director or manager.

(Contact information should include individual's name, address, phone number, fax number and e-mail address.)

7. **Abstract.** Following the title page, the report will include a report abstract. The abstract should be developed consistent with the "Report Summary" development instructions for posting on the CALMAC Web site. The abstract should be less than 200 words (or consistent with current CALMAC guidance) and include important key words that allow CALMAC's Web site's search engines to locate the report during routine searches.

8. **Evaluation reports should include, at a minimum, the following sections:**

    a. Cover
    b. Title Page
    c. Abstract
    d. Table of Contents
    e. Executive Summary - this section should very briefly present a review of the evaluation findings and the study's recommendations for program change, this should typically be no more than 1-3 pages. The findings and recommendations included in the summary should reference the primary text location within the report where each finding or recommendation is analyzed and presented.
    f. Introduction and Purpose of the Study - this section should give a summary overview of the evaluation and the evaluation objectives and researchable issues. This section should discuss if each of the researchable issues presented in the evaluation plan was addressed in the evaluation report and identify if any issues were not addressed and provide the reason why not.
    g. Description of Programs Covered in Study - this section should provide a description of the program(s) being evaluated in enough detail that readers can understand the program(s) and have an understanding of the program and program components that delivered the evaluation identified effects. The program description should also include the counts of the number of participants at the end of each program year for each program, and estimates of the technical potential (measure counts) for each measure covered by the program. This market potential should estimate the number of units that could be installed by the program if the technical potential was achieved for each measure covered by the program within the program's target market. The technical potential should be provided by the program Administrator and should be included in the data request delivered to the Administrators. If the Administrator does not provide the data, the report should so stipulate, identifying the data requested and the reason why the data could not be provided. If the Administrator cannot provide the requested technical potential data, the report may not be able to discuss the technical potential and the fraction of this potential achieved by the program.

h. Study Methodology - this section should describe the evaluation approach in enough detail to allow a repetition of the study in a way that would produce identical or similar findings. See additional content information below.
i. Reliability Assessment of the Study Findings – this should include a discussion of the threats to validity and sources of bias and the approaches used to reduce threats, reduce bias and increase the reliability of the findings, and a discussion of study findings precision levels.
j. Detailed Study Findings - this section presents the study findings in detail.
k. Recommendations for Program Changes - this section should be a detailed identification and discussion of the recommended changes, including the anticipated cost of the recommended change and the expected effect of the change on the operations and cost-effectiveness of the program(s).
l. Appendix A - appendix A should be a presentation of the performance metrics identified by the CPUC-ED that apply to the types of programs being evaluated and a presentation of the evaluation's assessment of the performance of the program for each of the performance metrics covered in the evaluation plan.
m. Appendix B - appendix B should present and discuss the success and timing of the data requests provided to the Administrators and the amount of time between the response and the receipt of the requested data. This section should discuss the success in obtaining the information needed to conduct the evaluations and identify any request made that were not provided in accordance with the provisions in this Protocol. If information was requested and not provided, the appendix should discuss the implications of not obtaining the data on the accuracy and reliability of the study findings. (Information that is maintained in the CPUC-ED program-reporting database can be obtained from the CPUC-ED and does not need to be collected from the IOUs.)

The **Study Methodology** section must include the following:

a. Overview of the approach;
b. Questions addressed in the evaluation;
c. The Protocols and rigor levels assigned to the study;
d. Description of the study methodology;
e. How the study meets or exceeds Protocol requirements;
f. How the study addresses issues presented in the Protocols regarding the methods;
g. Sampling methodology;
h. Expected precision or power analysis results (as required by the Sampling & Uncertainty Protocol);
i. Sample descriptions (including population characteristics, contact information availability and sample disposition rates);
j. Description of the baseline;
k. Sources of baseline data;
l. Description of measures; and

m. Assumptions on measure performance (including data sources).

The **Reliability Assessment** section of the report should focus its presentation and discussion on the targeted and achieved precision levels for the key findings presented, the sources of uncertainty in the approaches used and in the key findings presented, and a discussion of how the evaluation was structured and managed to reduce or control for the sources of uncertainty. All potential threats to validity given the methodology used, as presented in the Sampling & Uncertainty Protocol, must be assessed and discussed. This section should also discuss the evaluator's opinion of how the types and levels of uncertainty affect the study findings. Findings also need to include information for estimation of required sample sizes for future evaluations and recommendations on evaluation method improvements to increase reliability, reduce or test for potential bias and increase cost efficiency in the evaluation study(ies).

The **Recommendations for Program Changes** section on need only be added when changes have been identified during the evaluation process. In general, impact evaluation studies will have the fewest program change recommendations. Market effects evaluations should provide recommendations that the evaluation contractor thinks will improve the ability of the program(s) to influence market change. Process evaluations will typically have recommendations, as generating recommendations that increase the cost-effectiveness of the program(s) is the primary purpose of conducting the process evaluation.

The evaluation reports should generally be written for a wide range of individuals, including individuals not familiar with evaluation approaches or the field's specialized terminology. Technical information needed to report methodologies used for research design, sampling, impact analysis, M&V efforts, regression and engineering analysis, bias detection, bias correction and other technical areas must be reported and should not be avoided to ensure readability by a wider range of audience. A summary of the methodology, findings and decisions covering these issues should be written for a wider audience, however the more technical details relating to these reporting categories must also be provided.

9. **Databases and analysis datasets are the property of the State of California and should be provided to the CPUC-ED within 10 working days of the acceptance of the final evaluation report.** Database and analysis datasets shall be delivered in commonly accepted formats, such as SPSS®, SAS®, ASCII formatted or defined fields, tab or comma delimited, ASCII text, Microsoft Excel®, Microsoft Access®, dBase™ or other similarly commonly available formats. Non-common proprietary databases are not acceptable deliverable formats. Database suppliers should negotiate with the CPUC on a format structured during the evaluation planning process. Databases and analysis datasets should be provided in electronic formats with data dictionaries that describe the fields and field formats. The databases and analysis databases should be named so that they can be linked to the program being evaluated and the evaluation report presenting the findings. They should be provided so that the CPUC or their consultants can duplicate the analysis effort. If the data in the database or in the

analysis datasets is modified from the data that was collected the modifications should be disclosed.

Performance Basis Evaluation Reporting Metrics

In addition to the above-identified common reporting requirements, each evaluation should also report, in a table format, those metrics associated with the CPUC-ED's performance basis reporting requirements that are collected during the evaluation effort. While not all evaluations will collect and report all of the CPUC-ED performance basis metrics needed by the CPUC-ED, those metrics that are collected or assessed within the evaluation effort should be reported in the draft and final evaluation reports. The performance basis metrics that the evaluation should report, if collected or assessed as part of the evaluation effort are listed in Appendix C. Each evaluation contractor should identify the performance basis metrics that will be collected and assessed during the evaluation planning effort and identify those metrics that will be reported in the draft and final evaluation reports

Evaluation Type Specific Reporting Requirements

The following reporting requirements are in addition to the reporting requirements noted above and are presented for each type of evaluation and evaluation effort.

Energy Impact Evaluations and Supporting M&V Efforts

The energy impact evaluation report must focus on reporting the gross and net achieved energy savings and demand reduction that can be expected as a result of the program's efforts for each program year and for the program at the end of the program cycle in accordance with the progress of the evaluation within the program cycle. The impacts should be reported for each full calendar year (2006, 2007, 2008 and totaled for all years within a program cycle (2006-2008) over the effective useful life (EUL) of the measures installed or the behaviors changed. The reporting should assume a full year of measure use for the year in which the measures are installed. This avoids partial year reporting during the year of installation and at the end of the EUL. That is, a program that installs measures that have an effective measure life of 10 years installed in 2006, would report 10 years of savings for that measure with the first full year being 2006, regardless of the date that the measures were installed during 2006. For programs that have a mix of measures with different EULs, the savings projections will reflect the end-of-EUL drop-offs so that the projected savings represent only those savings that are expected in a specific year. When the CPUC-ED specifies that an evaluation will assess measure-level savings, the assessment should target the measures approved by the CPUC. In some cases this will encompass all of the measures included in the program and, in other cases, it will include only some specific measures.

The reported savings need also be net of interactive effects. For example, if lighting measures are installed there may be a corresponding decrease or increase in HVAC costs. Or if there are therm savings that produce an increase in electric consumption, these conditions need to be incorporated into the net effects estimate.

Savings also need to be reported by the CEC's five Climate Thermal Zones (CTZ) used for assessing Title 24 compliance, within the zones that have evaluation-study-covered program participants.[140] This does not mean that M&V sampling needs to be conducted at the CTZ level, but that impact and supporting M&V results must be modeled so that the impacts are reported for each of the climate zones in which participants appear. However, the Joint Staff may request specific studies report impacts by each of the 16 climate zones in which participants appear if this requirement is in the approved evaluation plan. The CEC will provide the CTZ maps, address and geo-code matches to each climate zone and weather data to the evaluation contractors on request. Reporting also must be provided for each IOU when a program is provided in more than one IOU service territory.

Every energy impact evaluation report should include the following information:

1. **CPUC approved program ex-ante net and gross, kW, kWh and therm savings goals** recorded at the beginning of the program funding cycle and any modifications to these goals made during the funding cycle. These should be the energy savings targets for the programs included in the Administrator's portfolio filings approved by the CPUC and any changes to these goals resulting from adjustments made. If the goals have changed during the funding cycle, a brief discussion of the reasons for the change should be reported also. Goals should be reported for each calendar year in which impacts are projected.

2. **The Administrator-generated annual gross kW, kWh and therm savings.** These should be the energy and demand savings estimates that the Administrator reports to the CPUC-ED as achieved against the CPUC-approved goals.

3. **Evaluation projected annual gross and net MW (megawatt) impacts** measured for each calendar year for each year over the EUL of the measures installed or behaviors taken. Gross and net demand savings must be reported for six time periods over each of four months as follows: noon–1 p.m., 1–2 p.m., 2-3 p.m., 3-4 p.m., 4-5 p.m. and 5-6 p.m. for June, July, August and September, for each climate zone for which there are program participants. These demand savings are to be estimated using the CEC's five CTZs used for assessing Title 24 compliance. This metric represents the evaluation contractor's best estimate of the gross and net program-induced participant-based MW impacts. This metric is to be reported separately for total program savings and broken out by program-induced direct and indirect (as appropriate to each study) impacts and for participant spillover effects, if any. If the evaluation is designed to deliver measure-level kW (reported as MW) savings, the savings will be reported for each measure included in the measure-level assessment. In addition, the effects are to be reported for the measure as a whole and for both direct and indirect program effects and participant spillover effects. In addition to these reporting requirements the Joint Staff may identify additional kW reporting requirements for specific studies during the program evaluation planning process. The demand impacts are those that can be documented at the time of the evaluation and they are not to include projected impacts as a result of actions not yet taken. These impacts are not to include market effects or non-participant spillover kW effects, but instead focus only on the impacts from participants who take

[140] California Climate Zones, The climate zones used for this purpose are the California Energy Commission's five Climate Thermal Zones used for assessing Title-24 compliance unless specified differently by the CPUC-ED during the program planning process. In some case it may be necessary to require reporting by each of the 16 SCE Climate Thermal Zones, also referred to as the 16 Title 24 climate zones.

advantage of the program's offerings and who may replicate those actions in their facilities. If the evaluation contactor determines that MW impacts increase or degrade over time, the annual projections of impacts must incorporate that increase or degradation factor and explain the cause, the reliability and the measurement approach for documenting the increase or degradation rate. (See tables below for example of reporting formats.) Participant spillover is to be reported in the evaluation, but will not be credited for the purposes of goal accomplishment at this time.

4. **Evaluation projected annual MWh (megawatt-hours) gross and net savings** measured for each calendar year for each year over the EUL of the measures installed or behaviors taken. Savings should be reported for the program as a whole and for each of the CEC's five CTZs used for assessing Title 24 compliance in which the program operates. This metric represents the evaluation contractor's best estimate of the energy savings that will occur because of the actions of the program. There are three reporting metrics associated with this requirement. The annual MWh savings are to be reported for the program as a whole and separately, for both program participation-based direct and indirect savings, and for participant-spillover-based savings. If the evaluation is designed to deliver measure-level savings, the savings will be reported for each measure included in the measure-level assessment. The savings are those that can be documented at the time of the evaluation and they are not to include projected savings as a result of actions not yet taken. These savings are not to include market effects or non-participant spillover savings, but instead focus only on the savings from participants (direct and spillover) that take advantage of the program's offerings. If the evaluation contactor determines that savings increase or degrade over time, the annual projections of savings must incorporate that increase or degradation factor and explain the cause, the reliability and the measurement approach for documenting the increase or degradation rate. (See tables below for example of reporting formats.) Participant spillover is to be reported in the evaluation, but will not be credited for the purposes of goal accomplishment.

5. **Evaluation-projected annual gross and net therms (100,000 BTU/therm or 100 cubic feet of methane) of natural gas savings** measured for each calendar year for each year over the EUL of the measures installed or behaviors taken. This metric represents the evaluation contractor's best estimate of the energy savings that will occur because of the actions of the program. The annual therm savings are to be reported separately to include program participation-based savings plus participant spillover based savings, if any and totaled for program savings. However, participant spillover will not be counted toward the program or portfolio goal achievements. The savings are those that can be documented at the time of the evaluation and they are not to include projected savings as a result of actions not yet taken. If the evaluation is designed to estimate measure-level savings, the savings will be reported for each measure included in the measure-level assessment. These savings are not to include market effects, participant or non-participant spillover savings estimates, but instead focus only on the savings from participants that take advantage of the program's offerings. If the evaluation contactor determines that savings increase or degrade over time, the annual projections of savings must incorporate that increase or degradation factor and explain the cause, the reliability and the measurement approach for documenting the increase or degradation rate. (See tables below for example of reporting formats.)

The Energy Impacts Protocol requires the evaluation contractor to estimate annual gross and net impacts over the EUL of the installed technologies or the behavior change-induced actions. For measures like CFLs, the expected life of the impacts may only be a couple of years, while for building design changes, the impacts may be over 30 years or more if the evaluation determines that the changes would not have occurred in the absence of the program offerings. It is the responsibility of the evaluation contractor to establish evaluation designs and approaches that allow these metrics to be reported in the evaluation report. One of the primary reasons that these metrics are required is so that portfolio energy and load impact curves can be generated for each program, for each IOU and for the portfolio as a whole. These savings are not to include non-participant savings that may have been influenced by the program's operations or the spillover caused in the non-participant population as a result of the program. They are to include participant spillover or participant action replications that result as a function of program participation. However, participant spillover savings are not to be counted toward program or portfolio goal achievements.

6. **Measure counts per participant.** This metric is incorporated into the reporting criteria so that the evaluation report provides a presentation of the types of measures taken by the program participants and the number of those actions taken per participant. This metric is to be retrospective and report only the actions taken as a result of the program at the time of the evaluation. However, the evaluation should true up these metrics at the end of each program year so that they can be reported for each program year (see sample reporting sheet at the end of this Protocol). The assessment should be based upon tracking system reviews and informed by the impact evaluation and the supportive M&V efforts. It can also be supported by the process evaluation efforts, if there is coordination among the evaluation efforts. The evaluation study can also separately report projected actions to be taken, if approved in the evaluation plan.

7. **Measure counts versus program goals**. This metric is incorporated into the reporting criteria so that the evaluation report provides a presentation of the evaluation verified program accomplishments relative to measure installation goals. This metric is to be retrospective and report only the actions taken as a result of the program at the time of the evaluation. It should be based upon tracking system reviews and informed by the impact evaluation and the supportive M&V efforts. It can also be supported by the process evaluation efforts, if there is coordination among the evaluation efforts. The evaluation study can also report projected actions to be taken, if approved in the evaluation plan.

8. **Measure-level savings**. If the evaluation plan is structured to provide measure-level or behavior-level savings estimates, these metrics should be reported for the covered measures. Not all program evaluation plans will be focused at the measure or behavior level. However, for those that are, as a result of the Joint Staff evaluation prioritization efforts, the savings should be reported at the measure or behavior level. In these cases, the program evaluation report should specify the program offering and design conditions that lead to the measure-level savings and the measure use conditions that affect the savings. The purpose of this requirement is to be able to update the DEER database estimates by changing current estimates, as new data are developed and add new measure classifications to the DEER

database when it is apparent that the program design and operational conditions affect the level of energy and demand savings.

9. **Measurement reliability metrics.** Results and all measurement reliability information must be reported at the program level, program group level and for any program component or delivery mechanism with a designated separate level of rigor or as designed in the approved evaluation plan. In addition, the following data reliability metrics should be reported for the energy impact estimates provided in the evaluation report.
    a. Precision level at the 90% confidence level of the direct participation energy savings (kWh/MWh);
    b. Precision level at the 90% confidence level of the participant spillover energy impacts (kWh/MWh) (if available separately given the methodology selected);
    c. Precision level at the 90% confidence level of the direct demand energy impact (kW/MW);
    d. Precision level at the 90% confidence level of the participant spillover demand impacts (kW/MW) (if available separately given the methodology selected);
    e. Coefficient of variation (CV) or standard deviations (SD) and means on the realization rate(s) for the program's energy effects and for all strata in any stratified sampling effort; and
    f. P values for all energy impact estimates (kW, kWh, therms).
10. **Savings comparison**. The report should include a presentation and discussion of the CPUC approved program goals compared to the estimated realized savings from the evaluation findings (this should be expanded in the Appendix described below).

11. **Appendix C**. Appendix C should present, assess and discuss the similarities and differences between Administrator savings assumptions and projections, and the results of the evaluation findings. This discussion should identify what assumptions were confirmed and not confirmed, and identify recommended changes to the assumptions that Administrators use to project savings.

12. **Appendix D.** Appendix D should present the weather data used to conduct the evaluation, including the heating and cooling degree-days used in the study, if any.

Note: See end of Reporting Protocol chapter for examples of energy impact reporting tables.

Measurement and Verification (M&V)

1. **M&V plan and reporting requirements**. For impact evaluations that are supported by measurement and verification (M&V) efforts, the evaluation report should present the program-specific M&V plan in enough detail that the plan can be replicated. The plan should describe and/or discuss:

    a. How the M&V samples were identified and selected;

b. How the M&V activities were used to support the impact assessment;
c. Any disagreement between the sampling plan and the sampling approach used, and how the difference influences the reliability of the study findings;
d. Sampling and measurement bias issues and how these biases can be expected to influence the impact estimates;
e. How the biases were controlled or mitigated in the M&V efforts and what statistical or measurement approaches were used to adjust the M&V data to inform the impact estimates; and
f. How the M&V results were used to estimate net program energy impacts.

Justification for the identification and selection of the baseline is required. An assessment and discussion of the baseline selected and its consistency of use for gross and net impacts must be included.

Site-specific M&V plans prepared during the course of the study shall be provided in an Appendix to the impact evaluation report. The site-specific M&V plan shall include all topics specified in the M&V Protocol, including assumptions used for stipulated parameters, the source of the assumptions and uncertainties associated with the M&V study results. Measure-level M&V results shall be reported according to the applicable DEER-compatible format listing in Appendix A of the M&V Protocol. Energy and peak demand savings resulting from weather dependent measures shall be reported under weather conditions prevailing during the course of the M&V project. These weather conditions shall be reported along with the energy and peak demand impact information. The impacts shall be normalized to standard weather conditions consistent with the CEC CTZ long-term average weather conditions for the climate zone in which the site is located.

2. **M&V analysis database.** The M&V analysis database(s) will be provided to the CPUC-ED upon delivery of the evaluation report. Site-specific M&V results shall be reported electronically according to database formats established by the Joint Staff compatible with EEGA and DEER databases. Field data shall be supplied in a non-proprietary format, such as ASCII text, Microsoft Excel, Microsoft Access, dBase or XML for inclusion in an M&V data warehouse. Proprietary databases are not acceptable deliverable formats. Building characteristics data collected during on-site surveys shall be reported according to the International Alliance for Interoperability (IAI) Industry Foundation Class (IFC), ifcXML or aecXML formats; Green Building XML (gbXML) format or other electronic data formats as designated by the Joint Staff. The Joint Staff will establish procedures to submit, receive and store M&V database(s) within a data repository. Because the databases will, by their very nature consist of customer-specific information, they will be secured and safeguarded against public release. Evaluation contractors will be informed of these instructions during the evaluation planning process.

Emerging Technology Program Evaluations

The Emerging Technology Program Evaluation will be reported consistent with the requirements for all reports described in this Protocol under Common Evaluation Reporting Requirements (above). In addition, the following elements should be included in the evaluation reports under the Methods heading.

- Program Theory and Logic Model
- Goal Verification
- Aggregate-Level Analysis
- Implementation Analysis
- Measure Tracking
- Detailed Analysis of Key Performance Indicators
- Peer Review
- Target Audience Surveys

These presentations must be provided in enough detail that the differences (if any) in the methodological approach across different technologies and utilities can be understood by the reader. Finally, one must describe the approach for integrating the study results so that the overall performance of the ETP can be assessed.

The Reporting Protocols includes a requirement that all evaluation reports include a presentation of the detailed study findings. This presentation must be provided in enough detail that the different results or findings (if any) can be understood for each technology assessment covered in the study. The report should present the results of each of the required eight components contained in the ETP Protocol. Reports will be provided consistent with the Reporting Protocol.

Codes and Standards Program Evaluations

The Codes and Standards Program Evaluation will be reported consistent with the requirements for all reports described above (Common Evaluation Reporting Requirements) and shall also present the following information.

1. **Change theories.** The report should present each of the code or standard change theories in an appendix to allow the reader to understand the theory behind the change achieved. The report should include a brief summary of the change theories in the text of the report.
2. **Change timelines.** The report should present a timeline associated with the program's efforts employed to influence changes for each code or standard change influenced by the program. The timeline should begin with the time at which the code targeting and selection effort was launched and end with the code adoption date. The code adoption date should be followed by the date that the change takes effect.
3. **Overview of the program activities that caused the change.** The report should provide a discussion of the activities and events that are wholly or in part responsible for the program-induced changes.
4. **Summary code or standard changes.** The report should present a summary of the change to the code or standard caused by the actions of the program. The summary should be detailed enough for the reader to understand the change that occurred and the significance of the change to the level of savings predicted.
5. **Jurisdictions.** The report should discuss the jurisdictions covered and not covered by the changes for each change included in the study.

6. **Listing of meetings, events, activities and documents.** The report should present a listing of each of the meetings, events, and activities attended or monitored by the evaluation contractor to support the evaluation effort and a listing of the documents reviewed to support the study.
7. **Interviewees.** The report should provided the titles of all interviewees providing information used in the analysis. The contractor should report the names of the interviewees in an accompanying memorandum, but not place the names of these individuals in the final public document. Note: individual interview results should be treated as confidential information.
8. **Pre-change penetration rates.** The report should present the pre-change technology adoption or penetration rates reported by the program.
9. **Naturally occurring market adoption.** The report should describe the approach for estimating the naturally occurring code and standard changes and the results of applying the approach for each change.
10. **Attribution approach and results.** The report should discuss the program attribution analysis approach and results of that approach for each change covered in the study.
11. **Gross market-level energy impacts.** The report should present the approach for estimating the gross market-level energy impacts for each change and provide the results of that analysis.
12. **Net market-level energy impacts.** The reports should present the net energy impact adjustment approach and the results of that approach so that the reader can understand the influence of each adjustment on the resulting net savings. The contractor should report net savings for each change and report the resulting net savings on the reporting spreadsheets (see Sample Reporting Tables).

Market Effects Evaluations

The reporting for the market effects evaluation must include the following information.

1. **Market theory integrated with program theory.** The report should clearly present and describe the market theory and, if constructed, the market logic model. The program and market theory should be integrated so that the anticipated net market effects (those market effects induced by program interventions) can be more readily perceived within the context of the market theory. This will provide a more comprehensive framework from which to conduct the market effects evaluation. The market theory and program theory(ies) should provide the following information:

   a. The **market theory** should be described in detail, including how the markets operates, its structure and scope, and how the various energy efficiency interventions are expected to change the market. The market theory should include how other market actors, activities and interventions are functioning to change the market that may work in sync or in opposition to the energy efficiency programs. The market theory should present a comprehensive view of how the market operates and address how, when, where, why and under what conditions market effects are expected to occur. The report should identify the specific changes in the market that can be observed and measured if the market is being changed. The market theory should describe the individual questions that were asked and the indicators or metrics monitored to assess when, how and to what degree the market is being changed and it should identify key market conditions that influence market change and the rates of change.

b. **Program theory.** If one or more of the programs expected to cause changes to the operations of a market is designed specifically to cause a market effect (change in the operations of a market defined for the evaluation), the report should present and describe the program theory(ies). The evaluation report should present and discuss the program theory used by program managers to structure their change efforts and explain how the program theory was used to focus the evaluation efforts. If a program logic model is developed it should be presented. The program theory should present how the program's operations lead to observable and measurable market effects. It should show the resources placed into the market, how they are placed, the resulting planned activities and the anticipated outcomes (the end effects) from those activities. The program theory should identify the key market metrics or measurement points that are expected to change as a result of the program's efforts and actions.

2. **Assessment of gross measure or behavior change.** The report should present and describe how the gross level of measure and/or behavior change in the market is being measured and confirmed through data collection, change measurements or change verification efforts. The report should identify any primary or secondary data used to estimate baseline or current condition measure or behavior use status. The report should describe how both baseline market conditions and current conditions are quantified and how gross measure or behavior-use conditions are being estimated. The report should discuss the reliability of these estimation methods and the various threats to the validity and accuracy of the estimation approach. The report should present the results of a Monte Carlo or other risk assessment approach that examines the difference in report conclusions that would occur if the key assumptions in the establishment of the gross measure or behavior change vary within reasonable levels of variance. This activity should result in the assignment of gross measure use or behavior change conditions that have resulted in the market as a result of all market effects, including program induced and non-program induced effects, and the presentation of the degree of variance that could be expected within those measurement conditions.

3. **Gross and net market change attribution assignments.** The report should explain the rationale behind the study's approach for identifying and allocating causal actions and activities across the market change metrics and change indicators and identify how net program-induced market change will be identified. The report should present the sources of market change and describe how allocation of the cause of the change is being proportioned across the various change agents (program and non-program influenced), so that all observed changes in the market are assigned to one or more reasons for the observed change. The report should present and discuss the proportioning approach and any data weighting or assignment systems used, and justify why the assignment approach is reliable and representative of how the market works. The report should discuss any inconsistencies between the allocation approach and the market theory discussed earlier.

4. **Net market change**. The report should present the results of applying the attribution assessment with the gross measure or behavior change assessment (previous two reporting activities) to identify the net program-induced measure or behavior changes and to identify the programs or program events that are included in the program-related attribution assignments. This assessment will identify the proportion of the market change that is caused by the program(s).

5. **Assignment of energy impacts**. The report is to present the results of the assignment of energy impacts resulting from applying energy and demand impacts associated with the net measure changes in the market that are caused by the program's efforts. The accepted practice for this assignment is to use the energy and demand savings for the covered technologies or behaviors reported in the latest DEER update. For measures not included in the DEER update, the evaluation will report the best engineering assessment estimation approach for the technologies or behaviors not included in the DEER database as guided by the results of the most recent evaluations of those technologies, if any, with appropriate references and justification for their applicability to this analysis. If a net effects modeling approach is used the steps of the process must be clearly described in a manner consistent to permit the analysis to be repeated by other researchers.

Process Evaluations

The process evaluation report shall include the following reporting requirements in addition to the common evaluation reporting requirements presented earlier:

1. **Detailed program description.** While all evaluation reports are to have a description of the program(s) covered in the evaluations, the process evaluation report must present a detailed operational description of the program that focuses on the program components being evaluated. Use of a program flow model is highly recommended. The reader of the report must be able to understand the operations of the program being evaluated in significant enough detail that they can understand the components of the program that would be affected by the program change recommendations.

2. **Program theory.** The process evaluation should include a presentation of the program theory. The program theory should, when possible, be the theory developed or approved by the Administrators. If the Administrators have not developed a program theory, they should be provided with the opportunity to develop the theory for inclusion in the evaluation report. If the detailed program theory is not available or cannot be provided in time for the evaluation report due date, the evaluator should include a summary program theory built from the evaluation team's program knowledge. This theory does not have to be approved or reviewed by the Administrator to be included in the evaluation report. The purpose of this requirement is to have a complete program description in the evaluation report and provide the Administrators the opportunity to provide the included program theory, but not to burden the Administrator with the development of the program theory or logic models if they have not already been developed. If the evaluation contractor develops the program theory or the associated logic model, it should be noted as such and complete enough for the reader to

understand the environment in which the program recommendations are to be placed, but does not need to be a finely detailed program theory or logic model.

3. **Support for recommended program changes**. While all evaluation reports are expected to have a section on recommended program changes, identifying these recommendations is one of the primary purposes of the process evaluation report. All recommendations need to be adequately supported, per the Protocol requirements. Each recommendation should be included in the Executive Summary and then presented in the Findings text along with the analysis conducted and the theoretical basis for making the recommendation. The Findings section should include a description on how the recommendation is expected to help the program, including the expected effect implementing the change will have on the operations of the program. The Findings section should include a discussion on how the recommended change can be made, who should be responsible for making the change and the expected cost and benefits of the change. If the information to conduct a cost-benefit forecast/prediction for the recommended changes is collected as part of the approved evaluation plan, the report should include a cost-benefit assessment of the recommendation so that the cost of the change can be compared to the expected benefits.

4. **Detailed presentation of findings.** A detailed presentation of the findings from the study is required. The Findings should convey the conditions of the program being evaluated and should be presented in enough detail that any reader can understand them and the associated implications to the cost-effective operations of the program. (See 3 above for more details on content requirements of the Findings section.)

Effective Useful Life Evaluations

The Effective Useful Life Evaluation will be reported consistent with the requirements for all reports described above (Common Evaluation Reporting Requirements) and shall also present the following information.

All EUL evaluations are expected to assess and discuss the differences between (a) the ex-ante EUL estimates from DEER or as otherwise approved by the Joint Staff and (b) the ex-post EUL estimates produced by the EUL evaluation study(ies). To the extent that the data gathered and evaluation analyses conducted can explain the causes for these differences, this must be presented and discussed. The evaluation report should note situations in which explanations are not possible due to lack of sufficient data or problems with interpretation. The EUL evaluation report must also include a recommendation of the EUL for the measure and delivery strategy/application that should be used for future program planning. This recommendation may take the form of recommending the replacement of a DEER EUL or the establishment of a new DEER category.

The EUL studies are also required to report the findings from the most recent degradation studies related to the EUL study measures/applications, so that the EUL report is a depository for all current persistence studies for the study measures/applications. This will assist Joint Staff and future evaluators in finding all relevant persistence information for a measure/application in one location.

All reporting under the **Effective Useful Life** Protocol should include the following:

11. Cover page containing the measures and delivery strategies or applications included in the retention evaluation, program names in the portfolios over the last 5 years that include these, program administrators for these programs and their program tracking number(s), evaluation contractor, and the date of evaluation plan.
12. Table of Contents.
13. High-level summary overview of the measures and delivery strategies or applications included in the evaluation, the programs affected, and the evaluation efforts.
14. Presentation of the evaluation goals and researchable issues addressed in the evaluation.
15. Description of how the evaluation addresses the researchable issues, including a description of the evaluation priorities and the use of assigned rigor levels to address these priorities.
16. Detailed description of the data collection and analysis methodology.
17. Current and prior retention results for selected measures given delivery strategy/application and their precision levels at a 90% confidence interval.
18. Retention, degradation, and EUL findings as is appropriate for the study assigned.
19. A discussion of the reliability assessment to be conducted, including a discussion of the expected threats to validity, sources of bias, and a short description of the approaches planned to reduce threats, bias, and uncertainty.
20. Contact information for the evaluation manager, including address, telephone numbers, fax number and e-mail address.

In addition to the above requirements, **retention** studies must also include the following:

2. Description of initial and final sample of measures still surviving.
3. Description of any findings on factors leading to the higher or lower retention rates.
4. Description of removal reasons, their distribution, and potential issues created by different removal reasons and the research design and functional forms that should be investigated in future EUL studies for these measures.

In addition to the overall EUL study reporting requirements, **degradation studies** must also include the following:

1. Describe any findings on factors leading to the relative degradation rates and absolute degradation rates, if available.
2. Describe the impact of degradation on energy savings

In addition to the overall EUL study reporting requirements, **EUL analysis studies** must also include the following:

1. Specific equations for survival functions and estimated precision of curve fit.

2. Analysis of the ex-post EUL compared to the ex-ante EUL and comparison of to the methods and results from any prior retention, degradation, or EUL studies available for that measure (to include comparisons by delivery strategy and application).
3. Recommended EUL for the measure and delivery strategy/application that should be used for future program planning.

Additional Information

1. All evaluation reports are public property and are owned by the State of California.
2. No reports or other deliverables will contain information that allows examiners of the final delivered reports and databases to be able to identify individual residential or non-residential customers or their energy consumption, energy demand or energy costs. Individual customer or participant information is to be treated as confidential information and protected by confidentiality agreements. Customer-specific information will be safeguarded from public access.
3. Customer information developed in the evaluation efforts or used to support the evaluation efforts will be maintained for a limited period of time consistent with the needs of the evaluation efforts and to support time-series or time-sensitive analysis, but will not be indefinably maintained. All customer-specific information will be maintained and protected from disclosure for as long as there is an evaluation plan covering the use of the data to support an evaluation effort. Once there is no evaluation plan covering the use of the customer-specific data, it will be deleted or discarded in the following ways:
    a. Electronic data files will be deleted from electronic storage systems;
    b. Hard copy data files will be shredded and recycled or discarded if they cannot be recycled;
    c. Electronic data file medium (e.g., DVDs, CD, electronic tape) will be shredded and recycled or discarded if it cannot be recycled; and
    d. Other materials containing customer-specific information will be rendered unreadable and recycled or discarded.
4. The CPUC-ED will develop a data archive plan for the housing, maintenance, supervision and protection of evaluation-related data. The data archival plan shall support the segregation of data by the type of the data stored (e.g., program participation data, market description information, customer metered data and evaluation analysis data). These examples are provided to be exemplary only and are not intended to identify or define the categories within the archive plan.

Sample Reporting Tables

The following section of the Protocols provides the reporting tables that are to be completed by the evaluation contractors and provided in hard copy format in an appendix, and electronic format with the evaluation reports. A more complete set of tables will be provided by the Joint Staff in Microsoft Excel formats for evaluation contractors to use to report study results following the approval and distribution of the Reporting Protocol. Energy impacts should be reported for each program. In addition, energy impacts should be reported as specified in each approved evaluation plan. In some cases this will require energy impact reporting by delivery strategy or other approach. It is important that the evaluation study reports the total savings for the programs being evaluated so that full credit for the energy savings impacts can be recorded for each program.

Example Megawatt Reporting Table (1) – Program Wide MW savings across all climate thermal zones

This table reports the total program participation megawatts saved across all climate zones in which the program was offered. If the program covers more than one IOU territory, tables for each IOU should also be reported. Separate MW savings tables should be prepared for the months of June, July, August and September. See Reporting Protocol for additional information. Table reports the Administrator-forecasted MW savings (gross and net), the Administrator-reported MW savings (gross and net) and the evaluation-reported gross, net of free-riders and spillover MW savings.

Total Program MW Savings																
PG&E Residential Direct Install Widget Program																
Program ID #: 1234-06																
All Program Measures																
Climate Zone: All Program Covered Climate Zones						**June of 2006 Evaluation Projected Demand Impacts** (MW average weekday across periods)										
Savings Timeline		Administrator forecasted ex-ante MW (CPUC approved)	Administrator forecasted ex-ante MW (CPUC approved)	Administrator reported ex-ante MW	Administrator reported ex-anti MW	Noon-1PM			1PM-2PM			2PM-3PM			3PM-4PM	
Program Year	Calendar Year	Gross	Net of Freeriders	Gross	Net of Freeriders	Gross	Net of Freeriders	Participant Spillover	Gross	Net of Freeriders	Participant Spillover	Gross	Net of Freeriders	Participant Spillover	Gross	Net of Freeriders
1	2006															
2	2007															
3	2008															
4	2009															
5	2010															
6	2011															
7	2012															
8	2013															
9	2014															
10	2015															
11	2016															
12	2017															
13	2018															
14	2019															
15	2020															
16	2021															
17	2022															
18	2023															
19	2024															
20	2025															
Add more rows if approved in evaluation plan																

Example MW Reporting Table (2) – Program MW savings for a specific climate zone.

This table provides an example of a CEC thermal climate zone (CTZ)-specific MW savings reporting table. (CEC CTZ-1).

Total Program MW Savings																	
PG&E Residential Direct Install Widget Program																	
Program ID #: 1234-06																	
All Program Measures																	
Climate Zone: CEC CTZ 1																	
Savings Timeline		Administrator forecasted ex-ante MW (CPUC approved)	Administrator forecasted ex-ante MW (CPUC approved)	Administrator reported ex-ante MW	Administrator reported ex-anti MW	**June of 2006 Evaluation Projected Demand Impacts** (MW average weekday across periods)											
						Noon-1PM			1PM-2PM			2PM-3PM			3PM-4PM		
Program Year	Calendar Year	Gross	Net of Freeriders	Gross	Net of Freeriders	Gross	Net of Freeriders	Participant Spillover	Gross	Net of Freeriders	Participant Spillover	Gross	Net of Freeriders	Participant Spillover	Gross	Net of Freeriders	Participant Spillover
1	2006																
2	2007																
3	2008																
4	2009																
5	2010																
6	2011																
7	2012																
8	2013																
9	2014																
10	2015																
11	2016																
12	2017																
13	2018																
14	2019																
15	2020																
16	2021																
17	2022																
18	2023																
19	2024																
20	2025																
Add more rows if approved in evaluation plan																	

The savings reported in this table are only those that occur within thermal climate zone (CTZ) 1. These tables are for reporting program MW impacts in specific CTZs for programs offered and with participants in more than one CTZ.

Example MW Reporting Table (3) – Measure-specific, program wide MW – all climate zones

This table provides an example of the reporting requirements for individual measures assessed in the evaluation study if the evaluation plan is approved to address measure assessments. It presents the measure-specific program savings for "*Measure X*" for all climate zones. In this example the measure-specific impacts are provided at the program level, not at the climate zone level. In some cases, if the evaluation plan specifies it, impacts may be required to be reported at the climate zone level.

Measure Specific MW Savings

PG&E Residential Direct Install Widget Program
Program ID #: 1234-06
Measure X
Climate Zone: All Program Covered Climate Zones

Savings Timeline		Administrator forecasted ex-ante MW (CPUC approved)	Administrator forecasted ex-ante MW (CPUC approved)	Administrator reported ex-ante MW	Administrator reported ex-anti MW	**June of 2006 Evaluation Projected Demand Impacts** (MW average weekday across periods)											
						Noon-1PM			1PM-2PM			2PM-3PM			3PM-4PM		
Program Year	Calendar Year	Gross	Net of Freeriders	Gross	Net of Freeriders	Gross	Net of Freeriders	Participant Spillover	Gross	Net of Freeriders	Participant Spillover	Gross	Net of Freeriders	Participant Spillover	Gross	Net of Freeriders	Participant Spillover
1	2006																
2	2007																
3	2008																
4	2009																
5	2010																
6	2011																
7	2012																
8	2013																
9	2014																
10	2015																
11	2016																
12	2017																
13	2018																
14	2019																
15	2020																
16	2021																
17	2022																
18	2023																
19	2024																
20	2025																
Add more rows if approved in evaluation plan																	

Example Megawatt hours Reporting Table (4) – Program Wide annual MWh impacts

This table provides an example of the table to be used for reporting program wide MWh savings. In this case the table is for all program measures across all CEC CTZ covered by the sample program.

Total Program MWh Savings									
PG&E Residential Direct Install Widget Program **Program ID#: 1234-06** **All Program Measures** **Climate Zone: All Program Covered Climate Zones**		Administrator forecasted ex-ante MWh savings (CPUC approved)	Administrator forecasted ex-ante MWh savings (CPUC approved)	Administrator reported ex-ante MWh savings	Administrator reported ex-anti MWh savings	Evaluation Estimated Annual MWh savings	Evaluation Estimated Annual MWh savings	Evaluation Estimated Annual MWh savings	Evaluation Estimated Annual MWh savings
Savings Timeline		Gross	Net of Freeriders	Goss	Net of Freeriders	Gross	Freeriders	Participant Spillover	Net of Freeriders
Program Year	Calendar Year								
1	2006								
2	2007								
3	2008								
4	2009								
5	2010								
6	2011								
7	2012								
8	2013								
9	2014								
10	2015								
11	2016								
12	2017								
13	2018								
14	2019								
15	2020								
16	2021								
17	2022								
18	2023								
19	2024								
20	2025								
Add more rows if approved in the evaluation plan.									

Example Natural Gas Reporting Table (5) – Program wide annual Therms of natural gas savings

This sample table is used to report the total program energy savings in therms of natural gas for a sample program.

Total Program Therm Savings									
PG&E Residential Direct Install Widget Program Program ID#: 1234-06 All Program Measures Climate Zone: All Program Covered Climate Zones		Administrator forecasted ex-ante therm savings (CPUC approved)	Administrator forecasted ex-ante therm savings (CPUC approved)	Administrator reported ex-ante therm savings	Administrator reported ex-anti therm savings	Evaluation estimated therm savings	Evaluation estimated therm savings	Evaluation Estimated therm savings	Evaluation Estimated therm savings
Savings Timeline		Gross	Net of Freeriders	Goss	Net of Freeriders	Gross	Freeriders	Participant Spillover	Net of Freeriders
Program Year	Calendar Year								
1	2006								
2	2007								
3	2008								
4	2009								
5	2010								
6	2011								
7	2012								
8	2013								
9	2014								
10	2015								
11	2016								
12	2017								
13	2018								
14	2019								
15	2020								
16	2021								
17	2022								
18	2023								
19	2024								
20	2025								
Add more rows if approved in the evaluation plan.									

Example Measure Count Reporting Table (6) – Units installed by program year

This table provides an example of the table to be used to report the number of measures the Administrator projects to be installed over the program cycle and the number of measures estimated via evaluation efforts to be installed. As the evaluation contractor conducts the evaluation, the results of interviews, surveys, monitoring and verification efforts will allow the contractor to estimate the number of units to be installed for each of the measures offered through the program. This table is to be provided in each of the impact evaluation reports to the extent it can be completed at the time of the evaluation effort. In addition, after the last year of the program cycle, the evaluation contractor is to complete this table for each year in the program cycle, summing the total evaluation estimated installs for the program cycle and assess the difference between the Administrator-projected installs and the evaluation-estimated installs.

Measure Counts Reporting								
PG&E Residential Direct Install Widget Program	CPUC-ED Approved Units of Measure							
Program ID#: 1234-05 (use CPUC approved standard measure descriptions)	Total 2006-2008 program administrator projected units to be installed	2006 Evaluation estimated total units installed	2006 Evaluation estimated average units per participant	2007 Evaluation estimated total units installed	2007 Evaluation estimated average units per participant	2008 Evaluation estimated total units installed	2008 Evaluation estimated average units per participant	Total 2006-2008 Evaluation estimated units installed
Measure A								
Measure B								
Measure C								
Measure D								
Measure E								
Measure F								
Measure G								
Measure H								
Measure I								
Measure J								
Measure K								
Measure L								
Measure M								
Measure N								
Etc.								
Etc.								
Add more lines if needed.								

The above tables are examples of the energy impact reporting tables to be provided from the evaluation efforts. A final, more comprehensive set of tables will be developed by the Joint Staff and distributed by the CPUC-ED once the Protocols are approved. The tables will be developed in Microsoft Excel so that they can be populated by the evaluation contractors and reported in the evaluation reports and delivered as separate Excel files.

Evaluation Support Information Needed From Administrators

This section of the Protocols presents the types of information that the Administrators will need to provide in support of the evaluation efforts. Not all of the information listed below will be needed for all evaluations. Rather, each evaluation will need a somewhat different set of information from the types of information presented in this chapter. In some specific cases the evaluation contractor may need to request information that is not detailed below in order to conduct an evaluation. As noted in the above individual Protocols, each evaluation plan will describe the type of information that the evaluation contractors need to complete their study. This allows the Administrators to have an advanced notice of the type of information that will be requested via a formal data request and an understanding of how the data is to be used in the evaluation study. In requesting data from the Administrators the evaluation contractors should first determine if the data needed is available in the CPUC-ED's program tracking and reporting database. If the required information is available from the CPUC-ED's database, evaluation contractors should obtain it directly from the CPUC-ED.

The information needed from the Administrators is considered basic program and participant tracking information. However the Joint Staff realizes that there may be circumstances when the requested information is not available from the Administrators or may be not be available in electronic formats. If an Administrator is unable to provide the requested information for a specific program, the Administrator will advise the organization requesting the information and the Joint Staff that the information is not available and explain the reasons why. If the requested information is available only in hard copy records, the Administrator will inform the requesting evaluation contractor and the Joint Staff and they will come to an agreement on the what information should be provided and in what format.

It is expected that the Administrators will respond to all evaluation data requests within 30 working days by providing as much of the requested information covered in this Reporting Protocol as possible, in formats agreed upon by the Administrators and the evaluation team leads. It is expected that information not covered in this Reporting Protocol, but that is necessary to conduct the evaluation in accordance with approved evaluation plans, will also be provided within 30 working days of the receipt of a data request. If this timeline cannot be met by the Administrators, the Administrators will provide the requesting organization and the CPUC-ED with an explanation of why the timeline cannot be met and work with the CPUC-ED and the evaluation contractor to establish a mutually agreed upon delivery timeline. The Administrator will inform the CPUC-ED's evaluation manager when the requested data has been provided to the evaluation contractor.

It is the Administrator's responsibility to establish and maintain program-tracking systems that are capable of supporting the evaluation efforts and of meeting the requirements specified in this Protocol. Joint Staff

All evaluation-related data requests will be provided to the appropriate Administrator(s) and the CPUC-ED at the same time. No evaluation contractor will contact customers or participants for evaluation information without the approval of the CPUC-ED and at least 15 days advanced notification provided to the appropriate Administrator(s).

The Joint Staff understands that in some cases the data requested may not be available from the Administrator and it will the responsibility of the Administrator, the CPUC-ED, the CEC or the evaluation contractor to collect the needed data. When the needed data is not available from the Administrators, the evaluation plan should address how the data will be collected. Again, the evaluation contractors should consider the information available in the CPUC-ED's program tracking database to determine what data needs to be collected from the Administrators and what data can be collected directly from the CPUC-ED's program tracking database.

The evaluation contractor will limit all data requests to information critical to the success of the evaluation. Information requests will be for enough data to successfully conduct the study at the needed population sample sizes, but will not over-request sample points beyond what is needed to conduct the evaluation. Evaluation data requests will need to plan for sample erosion due to a wide variety of conditions.

All measure information must be reported by the Administrators and the evaluation contractor by the CPUC-ED-approved measure description list so that identical measures are described using the same terms and definitions. If no list exists at the time of this Protocol, the Joint Staff will develop a uniform measure description list that all parties will use (IOUs, contractors, third-party providers, CPUC-ED, CEC and other stakeholders) and distribute that list via the CPUC-ED's web page and the energy efficiency list serve. The descriptions will include an official identifier and an abbreviated term that can be used in tracking systems, tables and charts where space is limited.

Most Administrators will find that the reporting requirements are consistent with the type of information that evaluation contractors have requested in the past. However, there are some examples of information detailed below that may not be routinely maintained for each program or updated on a regular basis. As a result, there may be some specific parts of a data request that the Administrators will be unable to provide. In general, the Administrators are responsible for providing the Administrator-collected or implementer-collected information requested by the evaluation contractors to allow the evaluations to be conducted consistent with the evaluation plans approved by the Joint Staff or by the CPUC-ED.

The following data should be readily available from the Administrators.

Program Information

1. Full program descriptions, including operational or procedures manuals and activities descriptions and description of implementation territories;
2. Detailed descriptions of tracking system and tracking system operations, including data dictionaries;
3. Program management and staff names, titles, work locations, phone numbers, fax numbers, e-mail addresses;

4. Program theories and associated logic models if developed. If not developed a statement that they have not been developed with a projected date of delivery of the completed theories and logic models;
5. Market operations theories describing the operations of the markets in which the program operates and, if available, a description of how the program is to change the operations of the market;
6. A description of the size of the market targeted by the program, and a description of the baseline conditions at the measure/behavior level and a discussion of how the program is expected to change baseline measure/behavior conditions, if available;
7. A description of the pre-program technical potential at the measure/behavior level and a projection of the remaining technical potential at the end of the program cycle, if available; and
8. When the program relies on key market actors, trade allies and other stakeholders to deliver or support the program in order to reach the energy saving or outreach goals, the Administrator should provide a listing, description of and contact information for these individuals/organizations.

Participant Data

For the purposes of this Protocol a participant is defined as an individual or an organization that receives a program service or financial incentive. For most programs, participants are clearly defined in the program tracking systems. However, there are times when a participant is not clearly defined or is not easily identified. The CPUC-ED expects that the Administrators will focus efforts on collecting participant information to the extent possible and practical for various types of programs or program services. Participants in resource programs are generally easy to identify as they directly receive a service or a financial incentive. Participants in other programs, such as marketing and outreach programs can be harder to identify and report. This Protocol does not act to require all programs to identify all participants. However when participant information is collected by the Administrators or their subcontractor, much of this information will be of value to the evaluation efforts. It is to the responsibility of the Administrators to work with their subcontractors to assure that when possible and practical the following information should be collected and maintained.

The following participant data should be available in electronic form with supporting database dictionaries to the evaluation teams on request.

Non-residential program data requests for end-user focused programs

1. Name of program(s) or program component(s);
2. Name of firms participating in program or program component;
3. Service turn on date;
4. Primary and secondary NAIC codes associated with the participants if available;
5. Extent to which customer is a repeat participant or a participant in other programs over the previous five years, if available or accessible;
6. Pre-participation measure and measure-use information, descriptions and conditions;
7. Address(es) of the participating firms or key participation decision makers;

8. Address(es) where program-related action is taken or for the services received;
9. Listing or description of actions taken or services received for each location by measure and end-use according to standard measure and end-use definitions established herein. These lists and descriptions should, to the extent possible, be standardized so that all Administrators use the same term for the same measure;
10. Individual participation contact information for each location to include:
    a. First and last name;
    b. Address;
    c. Phone number;
    d. Fax number (if collected); and
    e. E-mail address (if collected).
11. Dates of key action/activity/installation steps associated with program participation:
    a. Program enrollment date(s);
    b. Rebate or incentive payment date(s);
    c. Measure install dates;
    d. Date of training received; and
    e. Post-installation measure inspection dates.
12. Financial assistance amounts paid to participant by measure or action taken;
13. Project description information;
14. Estimated savings for actions taken;
15. Summary characteristics of building on which actions are taken or the operational environment in which measures are installed if collected;
16. Account and meter numbers and consumption histories from utility bills from all relevant meters for at least twelve months prior to program enrollment date and through to current period. Note: The evaluation contractor will work with the IOUs to understand what metered data is available for which types of customers and the formats and time intervals associated with the metered data;
17. Rate classification; and
18. The size and operational characteristics of the market in which the program is to operate including the number of covered technologies operating in the market and their expected normal failure, change-out or replacement rates.

Residential program data requests for end-user focused programs

1. Name of program(s) or program component(s) of the participation;
2. Type of building or structure associated with the participant or the participation;
3. Pre-participation measure and measure use information, descriptions and conditions;
4. Service turn on date;
5. Name of individual enrolling in the program or receiving service;
6. Address of the participant;
7. Extent to which customer is a repeat participant or a participant in other programs over the previous five years, if available or accessible;

8. Address where action is taken or for the services received;
9. Listing or description of actions taken or services received according to standard measure and end-use definitions;
10. Individual participation contact information to include:
    a. First and last name;
    b. Address;
    c. Phone number;
    d. Fax number;(if available and collected); and
    e. E-mail address (if available and collected).
11. Dates of key action/activity/installation steps associated with program participation:
    a. Program enrollment date(s);
    b. Rebate or incentive payment date(s);
    c. Measure install dates;
    d. Date of training received; and
    e. Post-installation inspection dates.
12. Financial assistance amounts paid to participant by measure or action taken;
13. Project description information;
14. Estimated savings for actions taken;
15. Account numbers and meter numbers and consumption histories from utility bills for all relevant meters for at least twelve months prior to program enrollment date and through to current. Note: The evaluation contractor will work with the IOUs to understand what metered data is available for which types of customers and the formats and time intervals associated with the metered data;
16. Rate classification; and
17. The size and operational characteristics of the market in which the program is to operate including the number of covered technologies operating in the market and their expected normal failure, change-out or replacement rates.

Non-participant or rejecter data for end-user focused programs

1. Description of program services offered to customer;
2. Date of offering or contact;
3. Method of contact;
4. Name of contact;
5. Address of contact;
6. Phone number of contact (if known); and
7. E-mail of contact (if known).

Program data for mid-stream and upstream focused programs

1. Name of program(s) or program component(s);
2. Name of firms participating in program or program component;
3. Primary and secondary NAIC codes associated with the participants if available;

4. Extent to which customer is a repeat participant or a participant in other programs over the previous five years, if available or accessible;
5. Pre participation/measure and measure use information, descriptions and conditions;
6. Address of the participating firms or key participation decision makers;
7. Address(es) where action is taken or for the services received;
8. Listing or description of actions taken or services received for each location;
9. Individual participation contact information to include:
    a. First and last name (if known);
    b. Address;
    c. Phone number;
    d. Fax number (if collected); and
    e. E-mail address (if collected).
10. Dates of key action/activity/installation steps associated with program participation:
    a. Program enrollment date(s);
    b. Rebate or incentive payment date(s);
    c. Date of training received; and
    d. Dates, numbers and types of material received.
11. Financial assistance amounts paid to participant by action taken;
12. End-user information as is made available to the program;
13. The size and operational characteristics of the market in which the program is to operate including the number of covered technologies operating in the market and their expected normal failure, change-out or replacement rates; and
14. Names and copies of previous evaluations and market research efforts used by the program to plan and structure program offerings and implementation efforts.

Program data for information, education and advertising-focused programs

1. Name of program(s) or program component(s);
2. Target population description, size, source of identifying information and lists of population members used in outreach activities. The size and operational characteristics of the market in which the program is to operate including the number of covered technologies operating in the market and their expected normal failure, change-out or replacement rates;
3. Contact information where individual participants are identified to include:
    a. First and last name of key contacts for each location (if known);
    b. Address of individual contacts;
    c. Phone number of individual contacts;
    d. Fax number of individuals (if collected); and
    e. E-mail address of individuals (if collected).
4. Marketing materials by numbers, types and distribution;
5. Education or Media plan as is appropriate;

6. Execution records for training held; information venues used; program participation agreements, commitments or other similar agreements; post-buy analysis; and other documentation of actual output;
7. Records for dates, number, location, target audience and attendance of events held, Web site hits, call-in numbers and rates, reach, frequency, Gross Rating Points, impressions, click through rate, composition, coverage, earned media, value of public service announcements, and other tracking and monitoring information the program maintains, as appropriate to the effort and for each wave, campaign and targeted effort. Include definitions and calculation methods for monitoring statistics used;
8. End-user information available to the program; and
9. Names and copies of previous evaluations and market research efforts used by the program to plan and structure program offerings and implementation efforts.

Storage and Disposal of Customer Information Used in the Evaluation

Customer information received to support the evaluation efforts will be maintained for a limited period of time consistent with the needs of the evaluation efforts and to support time-series or time-sensitive analysis, but will not be maintained indefinitely. All customer-specific information will be maintained and protected from disclosure for as long as there is an evaluation plan covering the use of the data to support an evaluation effort. Once there is no evaluation plan covering the use of the customer-specific data, it will be deleted or discarded within 3 years in the following ways:

1. Electronic files will be deleted from electronic storage systems;
2. Hard copy files will be shredded and recycled or discarded if it cannot be recycled;
3. Electronic medium (e.g., DVDs, CD, electronic tape) will be shredded and recycled or discarded if it cannot be recycled; and
4. Other materials containing customer-specific information will be rendered unreadable and recycled or discarded.

APPENDIX A. Measure-Level M&V Results Reporting Requirements

Measure-level results from M&V studies shall be reported as unit savings estimates (kWh/unit, kW/unit, therm/unit) normalized in terms consistent with DEER as described below or as amended by CPUC-approved revision of this Appendix.

Table 24. Measure-Level Impact Reporting Requirements

Measure Category	Measure Subcategory	Normalization Units	Measures included
Agricultural	Irrigation	Nozzle	Low pressure nozzles
		Acre of land	Micro irrigation conversion
	Greenhouse	Sq ft of glazing	Heat curtain, IR film
Clothes Dryer	Efficient dryer	Dryer	Efficient clothes dryers
Commercial Cooking	Equipment	Equipment	Griddles, fryers, warming cabinets, steamers
Commercial Refrigeration	Controls	Design evaporator tons	Floating head pressure and suction pressure controls
		Case linear feet	Case lighting controls
		Motor	Case and cooler fan controls
	Equipment	1000 SF of sales area	Refrigerant holdback valves
		Design compressor tons	VSD on compressor
		Design evaporator tons	Oversized condensers, sub cooling, compressor and condenser change outs
		Case linear feet	Case covers, reach-in conversions, case replacements
		Motor	Efficient evaporator fan motors
		Cooler	Door closers
		Door	Anti-sweat heater elimination
		Freezer	Door closers
	Maintenance	Design evaporator tons	Refrigeration system maintenance
Hot Water	Circulation Pump	1000 SF of building	Hot water recirculation pumps and pump controls
	Clothes washer	Clothes washer	Efficient clothes washers
	Dishwasher	Dishwasher	Efficient dishwashers
	Faucet aerators	Household	Faucet aerators
	Heat pump water heater	Water heater	Heat pump water heaters
	Efficient water heater - residential	Water heater	Storage type water heaters
	Efficient water heater - commercial	1000 SF of building	Storage type water heaters
	Low flow showerhead	Showerhead	Low flow showerheads

Measure Category	Measure Subcategory	Normalization Units	Measures included
	Pipe wrap	Household	Hot water pipe insulation and heat traps
	Point of use water heater	1000 SF of building	Instantaneous water heaters
HVAC	Controls	Tons	Economizer retrofit and repair
		1000 SF of building	Programmable thermostats, energy management systems, time clocks, space heating hot water and chilled water loop temperature control
	Equipment	1000 SF of building	Ventilation rate changes, evaporative coolers, air to air heat recovery, commercial furnaces and boilers
		kBtu/hr of furnace capacity	Residential furnaces
		Nameplate motor hp	Efficient motors in HVAC applications, 3 way to 2 way valve conversions on chilled water and space heating hot water coils, variable frequency drives
		Tons	High efficiency packaged AC and heat pumps, high efficiency chillers, waterside economizers, evaporative ventilation air pre-coolers
Lighting	Ballast	Fixture	Dimming ballasts
	CFL lamps	Lamp	Screw-in and hardwire compact fluorescent lamps
	De-lamp	Fixture	All interior lighting fixture types
	Exit sign	Exit sign	LED exit signs
	Exterior lighting	Lamp	HID lamps for exterior lighting applications
	Linear fluorescent	Fixture	High efficiency fluorescent lighting fixtures with T-8 or T-5, linear or U-Tube lamps
	Metal halide	Lamp	High efficiency metal halide lamps
	Occupancy sensor	Sensor	Occupancy sensors for interior lighting applications
	Photocell	Photocell	Photocell controls for exterior lighting applications
	Time clock	Time clock	Time clock controls for interior or exterior lighting applications
	Lighting controls - general	kW controlled	Other general purpose interior lighting control systems
	LPD reduction	kW reduced	Efficient lighting design providing reduced lighting power density
Interior Plug Loads	Copy machine	Copy machine	Efficient copy machine
	Equipment	kW reduced	Use of efficient office equipment resulting in equipment power density reduction
Miscellaneous	Motors	Motor	Efficient non-HVAC motors
	Vending machine	Machine	Efficient vending machines and vending machine controllers
Pools	Pool pump	Pump	Efficient pool pumps and pool pump controllers

Measure Category	Measure Subcategory	Normalization Units	Measures included
Residential Refrigeration	Refrigerator	Refrigerator	Efficient residential refrigerators or refrigerator/freezers
	Freezer	Freezer	Efficient residential freezers
Shell	Shell	1000 SF of building	Weatherization, air leakage sealing
	Fenestration	100 SF of window	High performance windows, skylights and glazing systems
	Insulation	1000 SF of insulation	Insulation, cool roofs
	Equipment	1000 SF of building	Whole-house fans

APPENDIX B. Glossary of Terms[141]

ACCURACY - An indication of how close a value is to the true value of the quantity in question. The term could also be used in reference to a model or a set of measured data, or to describe a measuring instrument's capability.

ACHIEVABLE POTENTIAL - The amount of savings that can be achieved due to specific program designs and delivery approaches, including program funding and measure incentive levels. Achievable potential studies are sometimes referred to as Market Potential studies.

ADMINISTRATOR - A person, company, partnership, corporation, association or other entity selected by the CPUC and any subcontractor that is retained by an aforesaid entity to contract for and administer energy efficiency programs funded in whole or in part from electric or gas Public Goods Charge (PGC) funds. For purposes of implementing PU Code Section 381.1, an "administrator" is any party that receives funding for and implements energy efficiency programs pursuant to PU Code Section 381. Similarly, a person, company or other entity selected to contract and administer energy efficiency programs funded by procurement funds.

ANALYSIS OF COVARIANCE (ANCOVA) MODELS - A type of regression model also referred to as a "fixed effects" model. This model allows each individual to act as its own control. The unique effects of the stable, but unmeasured characteristics of each customer are their "fixed effects" from which this method takes its name. These fixed effects are held constant.

ASHRAE - American Society of Heating, Refrigerating and Air- Conditioning Engineers

AUTOCORRELATION - The breakdown in the assumptions that the errors in regression analysis are uncorrelated due to correlation in the error term across observations in a time-series or cross-series, the error in one time period is directly correlated to the error in another time period or cross-sectional category. First-order serial correlation is when that correlation is with the error in the subsequent/preceding time period. The correlation can be positive or negative.

BASELINE DATA - The measurements and facts describing facility operations and design during the baseline period. This will include energy use or demand and parameters of facility operation that govern energy use or demand.

BASELINE FORECAST - A prediction of future energy needs which does not take into account the likely effects of new efficiency programs that have not yet been started.

BASELINE MODEL - The set of arithmetic factors, equations or data used to describe the relationship between energy use or demand and other baseline data. A model may also be a simulation process involving a specified simulation engine and set of input data.

[141] Terms defined as used herein and within the context of energy efficiency evaluation.

BASELINE PERIOD - The period of time selected as representative of facility operations before retrofit.

BEHAVIORAL DEGRADATION FACTOR - A multiplier used to account for time-related change in the energy savings of a high efficiency measure or practice relative to a standard efficiency measure or practice due to changes in behavior in relation to the measure or practice.

BILLING DATA - Has multiple meanings. Metered data obtained from the electric or gas meter used to bill the customer for energy used in a particular billing period. Meters used for this purpose typically conform to regulatory standards established for each customer class. Also used to describe the data representing the bills customers receive from the energy provider and also used to describe the customer billing and payment streams associated with customer accounts. This term is used to describe both consumption and demand, and account billing and payment information.

BILLING DEMAND - The demand used to calculate the demand charge cost. This is very often the monthly peak demand of the customer, but it may have a floor of some percentage of the highest monthly peak of the previous several months (a demand "ratchet"). May have other meanings associated with customer account billing practices.

BRITISH THERMAL UNIT (Btu or BTU) - The standard measure of heat energy. It takes one Btu to raise the temperature of one pound of water by one degree Fahrenheit at sea level. For example, it takes about 1,000 BTUs to make a pot of coffee. One Btu is equivalent to 252 calories, 778 foot-pounds, 1055 joules and 0.293 watt-hours. Note: the abbreviation is seen as "Btu" or "BTU" interchangeably.

BUILDING COMMISSIONING - Building commissioning provides documented confirmation that building systems as constructed function in accordance with the intent of the building designers and satisfy the owner's operational needs.

BUILDING ENERGY EFFICIENCY STANDARDS - California Code of Regulations, Title 24, Part 2, Chapter 2-53; regulating the energy efficiency of buildings constructed in California.

BUILDING ENERGY SIMULATION MODEL - Computer models based on physical engineering principals and/or standards used to estimate energy usage and/or savings. These models do not make use of billing or metered data, but usually incorporate site-specific data on customers and physical systems. Building Simulation Models usually require such site-specific data as square footage, weather, surface orientations, elevations, space volumes, construction materials, equipment use, lighting and building occupancy. Building simulation models can usually account for interactive effects between end-uses (e.g., lighting and HVAC), part-load efficiencies and changes in external and internal heat gains/losses. Examples of building simulation models include ADM2, BLAST and DOE-2.

BUILDING ENVELOPE - The assembly of exterior partitions of a building that enclose conditioned spaces, through which thermal energy may be transferred to or from the exterior, unconditioned spaces or the ground. (See California Code of Regulations, Title 24, Section 2-5302.)

CADMAC - See CALIFORNIA DEMAND-SIDE MANAGEMENT MEASUREMENT ADVISORY COUNCIL.

CALIFORNIA MEASUREMENT ADVISORY COUNCIL (CALMAC) - An informal committee made up of representatives of the California IOUs, CPUC, CEC and NRDC. CALMAC provides a forum for the development, implementation, presentation, discussion and review of regional and statewide market assessment and evaluation studies for California energy efficiency programs conducted by member organizations using Public Goods Charge funds.

CALIFORNIA DEMAND-SIDE MANAGEMENT MEASUREMENT ADVISORY COUNCIL (CADMAC) - An informal committee made up of utility representatives, the Office of Ratepayer Advocates and the CEC. The purpose of the committee is to: provide a forum for presentations, discussions and review of Demand Side Management (DSM) program measurement studies underway or completed; to coordinate the development and implementation of measurement studies common to all or most of the utilities; and to facilitate the development of effective, state-of-the-art Protocols for measuring and evaluating the impacts of DSM programs.

CALIFORNIA ENERGY COMMISSION (CEC) - The state agency established by the Warren-Alquist State Energy Resources Conservation and Development Act in 1974 (Public Resources Code, Sections 25000 et seq.) responsible for energy policy. Funding for the CEC's activities comes from the Energy Resources Program Account, Federal Petroleum Violation Escrow Account and other sources. The CEC has statewide power plant siting, supply and demand forecasting, as well as multiple types of energy policy and analysis responsibilities.

CALIFORNIA PUBLIC UTILITIES COMMISSION (CPUC) - A state agency created by constitutional amendment in 1911 to regulate the rates and services of privately owned utilities and transportation companies. The CPUC is an administrative agency that exercises both legislative and judicial powers; its decisions and orders may be appealed only to the California Supreme Court. The major duties of the CPUC are to regulate privately owned utilities, securing adequate service to the public at rates that are just and reasonable both to customers and shareholders of the utilities; including rates, electricity transmission lines and natural gas pipelines. The CPUC also provides electricity and natural gas forecasting, and analysis and planning of energy supply and resources. Its headquarters are in San Francisco.

CALMAC – See CALIFORNIA MANAGEMENT MEASUREMENT ADVISORY COUNCIL.

CAPACITY - The amount of electric power for which a generating unit, generating station or other electrical apparatus is rated either by the user or manufacturer. The term is also used for the total volume of natural gas that can flow through a pipeline over a given amount of time, considering such factors as compression and pipeline size.

CEC - See CALIFORNIA ENERGY COMMISSION.

CHANGE MODEL - A type of billing analysis designed to explain changes in energy usage. This can take the form of having the change in energy consumption (pre versus post) as the dependent variable (e.g., December pre-retrofit usage – December post-retrofit usage) or having consumption as the dependent variable and pre-retrofit consumption as one of the independent variables.

CLIMATE THERMAL ZONE (CTZ) – A geographical area in the state that has particular weather patterns. These zones are used to determine the type of building standards that are required by law.

CLTD – See COOLING LOAD TEMPERATURE DIFFERENCE.

COEFFICIENT OF VARIATION - The sample standard deviation divided by the sample mean (cv = sd/y). See page 320 of the *Evaluation Framework*.

COINCIDENT DEMAND - The metered demand of a device, circuit or building that occurs at the same time as the peak demand of the building or facility or at the same time as some other peak of interest, such as a utility's system load. This should properly be expressed so as to indicate the peak of interest, e.g., "demand coincident with the building peak."

COMMERCIALIZATION - Programs or activities that increase the value or decrease the cost of integrating new products or services into the electricity sector.

COMMISSIONING - See BUILDING COMMISSIONING.

COMPARISON GROUP - A group of customers who did not participate in a given program during the program year and who share as many characteristics as possible with the participant group.

COMPREHENSIVE - A program or project designed to achieve all cost-effective energy efficiency activities in individual buildings, usually including multiple energy efficiency measures.

CONDITIONAL DEMAND ANALYSIS (CDA) - A type of billing analysis in which observed energy consumption is estimated as a function of major end-uses, often portrayed as dummy variables for their existence at the customer residence/facility.

CONDITIONED FLOOR AREA - The floor area of enclosed conditioned spaces on all floors measured from the interior surfaces of exterior partitions for nonresidential buildings and from the exterior surfaces of exterior partitions for residential buildings. (See California Code of Regulations, Title 24, Section 2-5302.)

CONDITIONED SPACE - Enclosed space that is either directly or indirectly conditioned. (See California Code of Regulations, Title 24, Section 2-5302.)

CONDITIONED SPACE, DIRECTLY - An enclosed space that is provided with heating equipment that has a capacity exceeding 10 Btus/(hr-ft^2) or with cooling equipment that has a capacity exceeding 10 Btus/(hr-ft^2). An exception is if the heating and cooling equipment is designed and thermostatically controlled to maintain a process environment temperature less than 65° F or greater than 85° F for the whole space the equipment serves. (See California Code of Regulations, Title 24, Section 2- 5302.)

CONDITIONED SPACE, INDIRECTLY - Enclosed space that: (1) has a greater area weighted heat transfer coefficient (u-value) between it and directly conditioned spaces than between it and the outdoors or unconditioned space; (2) has air transferred from directly conditioned space moving through it at a rate exceeding three air changes/hour.

CONSERVATION - Steps taken to cause less energy to be used than would otherwise be the case. These steps may involve, for example, improved efficiency, avoidance of waste, and reduced consumption. Related activities include, for example, installing equipment (such as a computer to ensure efficient energy use), modifying equipment (such as making a boiler more efficient), adding insulation and changing behavior patterns.

CONSTRUCT VALIDITY - The extent to which an operating variable/instrument accurately taps an underlying concept/hypothesis, properly measuring an abstract quality or idea.

CONTENT VALIDITY - The extent to which an operating measure taps all the separate sub-concepts of a complicated concept.

CONVERGENT VALIDITY - When two instruments/questions/measurement methods obtain similar results when measuring the same underlying construct with varying questions/approaches.

COOLING DEGREE DAYS - The cumulative number of degrees in a month or year by which the mean temperature is above 18.3°C /65° F.

CORRELATION COEFFICIENT - A measure of the linear association between two variables, calculated as the square root of the R2 obtained by regressing one variable on the other and signed to indicate whether the relationship is positive or negative.

COST-EFFECTIVENESS - An indicator of the relative performance or economic attractiveness of any energy efficiency investment or practice when compared to the costs of energy produced and delivered in the absence of such an investment. In the energy efficiency field, the present value of the estimated benefits produced by an energy efficiency program as compared to the estimated total program's costs, from the perspective of either society as a whole or of individual customers, to determine if the proposed investment or measure is desirable from a variety of perspectives, e.g., whether the estimated benefits exceed the estimated costs. See also TOTAL RESOURCE COST TEST – SOCIETAL VERSION and PARTICIPANT COST TEST.

CPUC - See CALIFORNIA PUBLIC UTILITIES COMMISSION.

CTZ – See CLIMATE THERMAL ZONE.

CUSTOMER - Any person or entity responsible for payment of an electric and/or gas bill to and with an active meter serviced by a utility company (refers to IOU customers herein).

CUSTOMER INFORMATION - Non-public information and data specific to a utility customer that the utility acquired or developed in the course of its provision of utility services.
CV – See COEFFICIENT OF VARIATION.

DATABASE FOR ENERGY-EFFICIENT RESOURCES (DEER) – A database sponsored by the CEC and CPUC designed to provide well-documented estimates of energy and peak demand savings values, measure costs, and effective useful life (EUL) all with one data source. The users of the data are intended to be program planners, regulatory reviewers and planners, utility and regulatory forecasters, and consultants supporting utility and regulatory research and evaluation efforts. DEER has been designated by the CPUC as its source for deemed and impact costs for program planning.

DAYLIGHTING - The use of sunlight to supplement or replace electric lighting.

DEER – See DATABASE FOR ENERGY-EFFICIENT RESOURCES.

DEMAND - The time rate of energy flow. Demand usually refers to electric power and is measured in kW (equals kWh/h) but can also refer to natural gas, usually as Btu/hr, kBtu/hr, therms/day or ccf/day.

DEMAND (Utility) - The rate or level at which electricity or natural gas is delivered to users at a given point in time. Electric demand is expressed in kilowatts (kW). Demand should not be confused with load, which is the amount of power delivered or required at any specified point or points on a system.

DEMAND BILLING - The electric capacity requirement for which a large user pays. It may be based on the customer's peak demand during the contract year, on a previous maximum or on an agreed minimum. Measured in kilowatts.

DEMAND CHARGE - The sum to be paid by a large electricity consumer for its peak usage level.

DEMAND RESPONSIVENESS - Also sometimes referred to as load shifting. Activities or equipment that induce consumers to use energy at different (lower cost) times of day or to interrupt energy use for certain equipment temporarily, usually in direct response to a price signal. Examples include interruptible rates, doing laundry after 7 p.m., and air conditioner recycling programs.

DEMAND SAVINGS - The reduction in the demand from the pre-retrofit baseline to the post-retrofit demand, once independent variables (such as weather or occupancy) have been adjusted for. This term is usually applied to billing demand, to calculate cost savings or to peak demand, for equipment sizing purposes.

DEMAND SIDE MANAGEMENT (DSM) - The methods used to manage energy demand including energy efficiency, load management, fuel substitution and load building. See LOAD MANAGEMENT.

DIRECT ENERGY SAVINGS (DIRECT PROGRAM ENERGY SAVINGS) - The use of the words "direct savings" or "direct program savings" refers to the savings from programs that are responsible for the achievement of specific energy efficiency goals. Typically these are thought of as resource acquisition programs or programs that install or expedite the installation of energy-efficient equipment and which directly cause or help to cause energy efficiency to be achieved. Rebate, incentive or direct install programs provide direct energy savings.

DIRECT INSTALL or DIRECT INSTALLATION PROGRAMS - These types of programs provide free energy efficiency measures and their installation for qualified customers. Typical measures distributed by these programs include low flow showerheads and compact fluorescent bulbs.

DIRECTLY COOLED SPACE is an enclosed space that is provided with a space-cooling system that has a capacity exceeding 5 Btu/(hr×ft^2), unless the space-cooling system is designed and thermostatically controlled to maintain a space temperature less than 55°F or to maintain a space temperature greater than 90°F for the whole space that the system serves.

DIRECTLY HEATED SPACE is an enclosed space that is provided with wood heating or is provided with a space-heating system that has a capacity exceeding 10 Btu/(hr×ft^2) unless the space-heating system is designed and thermostatically controlled to maintain a space temperature less than 55°F or to maintain a space temperature greater than 90°F for the whole space that the system serves.

DISTRIBUTED GENERATION - A distributed generation system involves small amounts of generation located on a utility's distribution system for the purpose of meeting local (substation level) peak loads and/or displacing the need to build additional (or upgrade) local distribution lines.

DOUBLE-BARRELED QUESTIONS - A poorly worded questionnaire item, which actually asks two questions at the same time, thereby not allowing unique and accurate interpretation of the results.

DRY-BULB TEMPERATURE - A measure of the sensible temperature of air.

DSM - See DEMAND SIDE MANAGEMENT.

ECM – Energy Conservation Measure. See MEASURE and ENERGY EFFICIENCY MEASURE.

EDUCATION PROGRAMS - Programs primarily intended to educate customers about energy-efficient technologies or behaviors or provide information about programs that offer energy efficiency or load reduction information or services.

EFFECTIVE USEFUL LIFE (EUL) - An estimate of the median number of years that the measures installed under a program are still in place and operable.

EFFICIENCY - The ratio of the useful energy delivered by a dynamic system (such as a machine, engine or motor) to the energy supplied to it over the same period or cycle of operation. The ratio is usually determined under specific test conditions.

ELECTRIC PUBLIC GOODS CHARGE (PGC) - Per Assembly Bill (AB) 1890, a universal charge applied to each electric utility customer's bill to support the provision of public goods. Public goods covered by California's electric PGC include public purpose energy efficiency programs, low-income services, renewables, and energy-related research and development.

EM&V - Evaluation, Measurement, Monitoring and Verification.

EMISSIVITY - The property of emitting radiation; possessed by all materials to a varying extent.

EMITTANCE - The emissivity of a material, expressed as a fraction. Emittance values range from 0.05 for brightly polished metals to 0.96 for flat black paint.

END-USE (MEASURES/GROUPS) - Refers to a broad or sometimes narrower category that the program is concentrating efforts upon. Examples of end-uses include refrigeration, food service, HVAC, appliances, envelope and lighting.

ENERGY CONSUMPTION - The amount of energy consumed in the form in which it is acquired by the user. The term excludes electrical generation and distribution losses.

ENERGY COST - The total cost for energy, including such charges as base charges, demand charges, customer charges, power factor charges and miscellaneous charges.

ENERGY EFFICIENCY - Using less energy to perform the same function. Programs designed to use energy more efficiently - doing the same with less. For the purpose of this paper, energy efficiency programs are distinguished from DSM programs in that the latter are utility-sponsored and financed, while the former is a broader term not limited to any particular sponsor or funding source. "Energy conservation" is a term that has also been used but it has the connotation of doing without in order to save energy rather than using less energy to perform the same function and so is not used as much today. Many people use these terms interchangeably.

ENERGY EFFICIENCY IMPROVEMENT - Reduced energy use for a comparable level of service, resulting from the installation of an energy efficiency measure or the adoption of an energy efficiency practice. Level of service may be expressed in such ways as the volume of a refrigerator, temperature levels, production output of a manufacturing facility or lighting level/square foot.

ENERGY EFFICIENCY MEASURE - Installation of equipment, subsystems or systems, or modification of equipment, subsystems, systems or operations on the customer side of the meter, for the purpose of reducing energy and/or demand (and, hence, energy and/or demand costs) at a comparable level of service.

ENERGY EFFICIENCY OF A MEASURE - A measure of the energy used to provide a specific service or to accomplish a specific amount of work (e.g., kWh/cubic foot of a refrigerator, therms/gallon of hot water).

ENERGY EFFICIENCY OF EQUIPMENT - The percentage of gross energy input that is realized as useful energy output of a piece of equipment.

ENERGY EFFICIENCY PRACTICE - The use of high-efficiency products, services and practices or an energy-using appliance or piece of equipment, to reduce energy usage while maintaining a comparable level of service when installed or applied on the customer side of the meter. Energy efficiency activities typically require permanent replacement of energy-using equipment with more efficient models. Examples: refrigerator replacement, light fixture replacement, cooling equipment upgrades.

ENERGY MANAGEMENT SYSTEM - A control system (often computerized) designed to regulate the energy consumption of a building by controlling the operation of energy consuming systems, such as the heating, ventilation and air conditioning (HVAC), lighting and water heating systems.

ENERGY RESOURCES PROGRAM ACCOUNT (ERPA) - The state law that directs California electric utility companies to gather a state energy surcharge/kilowatt-hour of electricity consumed by a customer. These funds are used for operation of the CEC. As of January 1, 2004, the surcharge is set at $0.0003/kWh.

ENERGY SAVINGS - The reduction in use of energy from the pre-retrofit baseline to the post-retrofit energy use, once independent variables (such as weather or occupancy) have been adjusted for.

ENGINEERING APPROACHES - Methods using engineering algorithms or models to estimate energy and/or demand use.

ENGINEERING USEFUL LIFE - An engineering estimate of the number of years that a piece of equipment will operate if properly maintained.

ERPA - See ENERGY RESOURCES PROGRAM ACCOUNT.

ERROR - Deviation of measurements from the true value.

EUL - See EFFECTIVE USEFUL LIFE.

EVALUATION - The performance of studies and activities aimed at determining the effects of a program; any of a wide range of assessment activities associated with understanding or documenting program performance or potential performance, assessing program or program-related markets and market operations; any of a wide range of evaluative efforts including assessing program-induced changes in energy efficiency markets, levels of demand or energy savings and program cost-effectiveness.
EX-ANTE SAVINGS ESTIMATE – Administrator-forecasted savings used for program and portfolio planning purposes as filed with the CPUC, from the Latin for "beforehand."

EX-POST EVALUATION ESTIMATED SAVINGS - Savings estimates reported by the independent evaluator after the energy impact evaluation and the associated M&V efforts have been completed. If only the term "ex-post savings" is used, it will be assumed that it is referring to the ex-post evaluation estimate, the most common usage, from the Latin for "from something done afterward."

EX-POST (PROGRAM) ADMINISTRATOR-ESTIMATED SAVINGS - Savings estimates reported by the Administrator after program implementation has begun (Administrator-reported ex post), from the Latin for "from something done afterward."

EX-POST (PROGRAM) ADMINISTRATOR-FORECASTED SAVINGS – Savings estimates forecasted by the Administrator during the program and portfolio planning process, from the Latin for "from something done afterward."

EXTERNAL VALIDITY - The extent to which the association between an independent variable and a dependent variable that is demonstrated within a research setting also holds true in the general environment.

FREE-DRIVER - A non-participant who adopted a particular efficiency measure or practice as a result of a utility program. See SPILLOVER EFFECTS for aggregate impacts.

FREE-RIDER - A program participant who would have implemented the program measure or practice in the absence of the program.

GAS PUBLIC GOODS CHARGE (PGC) - Created by AB1002 in 2000, an unbundled rate component included on gas customer bills to fund public purpose programs including those for energy efficiency, low-income, and research and development.

GIGAWATT (GW) - One thousand megawatts (1,000 MW), one million kilowatts (1,000,000 kW) or one billion watts (1,000,000,000 watts) of electricity. One gigawatt is enough to supply the electric demand of about one million average California homes.

GIGAWATT-HOUR (GWH) - One million kilowatt-hours of electric power.

GLAZING - A covering of transparent or translucent material (typically glass or plastic) used for admitting light.

GROSS AREA - The area of a surface including areas not belonging to that surface (such as windows and doors in a wall).

GROSS LOAD IMPACT - The change in energy consumption and/or demand that results directly from program-related actions taken by participants in a DSM program, regardless of why they participated. Related to Gross Energy Impact and Gross Demand Protocols.

HEAT CAPACITY - The amount of heat necessary to raise the temperature of a given mass one degree. Heat capacity may be calculated by multiplying the mass by the specific heat.

HEAT GAIN - An increase in the amount of heat contained in a space, resulting from direct solar radiation, heat flow through walls, windows and other building surfaces, and the heat given off by people, lights, equipment and other sources.

HEAT LOSS - A decrease in the amount of heat contained in a space, resulting from heat flow through walls, windows, roof and other building surfaces and from exfiltration of warm air.

HEAT PUMP - An air conditioning unit which is capable of heating by refrigeration, transferring heat from one (often cooler) medium to another (often warmer) medium and which may or may not include a capability for cooling. This reverse-cycle air conditioner usually provides cooling in summer and heating in winter.

HEAT TRANSFER - Flow of heat energy induced by a temperature difference. Heat flow through a building envelope typically flows from a heated or hot area, to a cooled or cold area.

HETEROSCEDASTICITY – Unequal error variance. In statistics, a sequence or a vector of random variables is heteroscedastic if the random variables in the sequence or vector may have different variances. This violates the regression assumption of constant variance (the variance of the errors is constant across observations or homoscedastic). Typically, residuals are plotted to assess this assumption. Standard estimation methods are inefficient when the errors are heteroscedastic. A common example is when variance is expected to be greater on a variable measurement for larger firms than for smaller firms.

HOMOSCEDASTIC (HOMOSCEDASTICITY) - Constant error variance, an assumption of classical regression analysis. See also HETEROSCEDASTICITY.

HORSEPOWER (HP) - A unit for measuring the rate of doing work. One horsepower equals about three-fourths of a kilowatt (745.7 watts).

HVAC - Heating Ventilation and Air Conditioning.

HVAC SYSTEM - The equipment, distribution network and terminals that provides either collectively or individually the processes of heating, ventilating or air conditioning to a building.

IMPACT EVALUATION - Used to measure the program-specific induced changes in energy and/or demand usage (such kWh, kW and therms) and/or behavior attributed to energy efficiency and demand response programs.

IMPACT YEAR - Depending on the context, impact year means either (a) the twelve months subsequent to program participation used to represent program costs or load impacts occurring in that year, or (b) any calendar year after the program year in which impacts may occur.

IMPLEMENTATION THEORY - A theory describing how a program should be structured and implemented and the theoretical rationale supporting the reasons for the program structure and the implementation approach.

IMPLEMENTER - An entity or person selected and contracted with or qualified by a program Administrator or by the CPUC to receive PGC funds for providing products and services to customers.

INCENTIVES - Financial support (e.g., rebates, low-interest loans) to install energy efficiency measures. The incentives are solicited by the customer and based on the customer's billing history and/or customer-specific information.

INDEPENDENT VARIABLES - The factors that affect the energy and demand used in a building but cannot be controlled (e.g., weather or occupancy).

INDIRECT ENERGY SAVINGS (INDIRECT PROGRAM ENERGY SAVINGS) - The use of the words "indirect savings" or "indirect program savings" refers to programs that are typically information, education, marketing or outreach programs in which the program's actions are expected to result in energy savings achieved through the actions of the customers exposed to the program's efforts, without direct enrollment in an program that has energy savings goals.

INFORMATION PROGRAMS - Programs primarily intended to provide customers with information regarding generic (not customer-specific) conservation and energy efficiency opportunities. For these programs, the information may be unsolicited by the customer. Programs that provide incentives in the form of unsolicited coupons for discount on low cost measures are also included.

INSULATION, THERMAL - A material having a relatively high resistance of heat flow and used principally to retard heat flow. See R-VALUE.

INTEGRATED PART-LOAD VALUE (IPLV) - A single number figure of merit based on part-load EER or COP expressing part-load efficiency for air conditioning and heat pump equipment on the basis of weighted operation at various load capacities for the equipment.

INTERNAL VALIDITY - The extent to which alternative explanations can be eliminated as causes for an observed association between independent and dependent variable(s) within a research setting/sample.

INTERNATIONAL PERFORMANCE MEASUREMENT AND VERIFICATION PROTOCOL (IPMVP) – The IPMVP provides an overview of current best practice techniques available for verifying results of energy efficiency, water efficiency, and renewable energy projects in commercial and industrial facilities. It may also be used by facility operators to assess and improve facility performance. The IPMVP is the leading international standard in M&V protocols. It has been translated into 10 languages and is used in more than 40 countries.

INVESTOR-OWNED UTILITY (IOU) - A private company that provides a utility, such as water, natural gas or electricity, to a specific service area. California investor-owned utilities are regulated by the CPUC.

IPMVP – See INTERNATIONAL PERFORMANCE MEASUREMENT AND VERIFICATION PROTOCOL.

JOULE - A unit of work or energy equal to the amount of work done when the point of application of force of 1 Newton is displaced 1 meter in the direction of the force. It takes 1,055 joules to equal a British thermal unit. It takes about 1 million joules to make a pot of coffee.

kBtu – One thousand (1,000) British Thermal Units (Btu). See also BRITISH THERMAL UNIT.

KILOWATT (kW) - One thousand (1,000) watts. A unit of measure of the amount of electricity needed to operate given equipment. On a hot summer afternoon a typical home with central air conditioning and other equipment in use might have a demand of four kW each hour.

KILOWATT-HOUR (kWh) - The most commonly used unit of measure indicating the amount of electricity consumed over time; one kilowatt of electricity supplied for one hour.

LEVEL OF SERVICES - The utility received by a customer from energy-using equipment. Level of service may be expressed, for example, as the volume of a refrigerator, an indoor temperature level, the production output of a manufacturing facility, or lighting levels/square foot.

LOAD - The amount of electric power supplied to meet one or more end-user's needs. The amount of electric power delivered or required at any specified point or points on a system. Load originates primarily at the power-consuming equipment of the customer. Load should not be confused with demand, which is the rate at which power is delivered to or by a system, part of a system, or a piece of equipment.

LOAD DIVERSITY - The condition that exists when the peak demands of a variety of electric customers occur at different times. The difference between the peak of coincident and noncoincident demands of two or more individual loads. This is the objective of "load molding" strategies, ultimately curbing the total capacity requirements of a utility.

LOAD FACTOR - The ratio of the amount of electricity a consumer used during a given time span and the amount that would have been used if the usage had stayed at the consumer's highest demand level during the whole time. The term also is used to mean the percentage of capacity of an energy facility - such as a power plant or gas pipeline - that is utilized in a given period of time. The ratio of the average load to peak load during a specified time interval.

LOAD IMPACT - Changes in electric energy use, electric peak demand or natural gas use.

LOAD MANAGEMENT - Steps taken to reduce power demand at peak load times or to shift some power demand to off-peak times to better meet the utility system capability for a given hour, day, week, season, or year. Load management may be obtained by persuading consumers to modify behavior, by using equipment that regulates or controls electric consumption or by other means.

LOAD SHAPE - The time-of-use pattern of customer or equipment energy use. This pattern can be over a day (24 hours) or over a year (8760 hours).

LOAD SHAPE IMPACTS - Changes in load shape induced by a program.

LOGIC MODEL - The graphical representation of the program theory showing the flow between activities, their outputs and subsequent short-term, intermediate and long-term outcomes. Often the logic model is displayed with these elements in boxes and the causal flow being shown by arrows from one to the others in the program logic. It can also be displayed as a table with the linear relationship presented by the rows in the table.

LOW-E - A special coating that reduces the emissivity of a window assembly, thereby reducing the heat transfer through the assembly.

LUMEN - A measure of the amount of light available from a light source equivalent to the light emitted by one candle.

LUMENS/WATT - A measure of the efficacy of a light fixture; the number of lumens output/watt of power consumed.

MAIN METER - The meter that measures the energy used for the whole facility. There is at least one meter for each energy source and possibly more than one per source for large facilities. Typically, utility meters are used, but dataloggers may also be used as long as they isolate the load for the facility being studied. When more than one meter per energy source exists for a facility, the main meter may be considered the accumulation of all the meters involved.

MARKET - The commercial activity (manufacturing, distributing, buying and selling) associated with products and services that affect energy usage.

MARKET ACTORS - Individuals and organizations in the production, distribution and/or delivery chain of energy efficiency products, services and practices. This may include, but is not limited to, manufacturers, distributors, wholesalers, retailers, vendors, dealers, contractors, developers, builders, financial institutions, and real estate brokers and agents.

MARKET ASSESSMENT - An analysis function that provides an assessment of how and how well a specific market or market segment is functioning with respect to the definition of well-functioning markets or with respect to other specific policy objectives. Generally includes a characterization or description of the specific market or market segments, including a description of the types and number of buyers and sellers in the market, the key actors that influence the market, the type and number of transactions that occur on an annual basis and the extent to which energy efficiency is considered an important part of these transactions by market participants. This analysis may also include an assessment of whether or not a market has been sufficiently transformed to justify a reduction or elimination of specific program interventions. Market assessment can be blended with strategic planning analysis to produce recommended program designs or budgets. One particular kind of market assessment effort is a baseline study, or the characterization of a market before the commencement of a specific intervention in the market, for the purpose of guiding the intervention and/or assessing its effectiveness later.

MARKET BARRIER - Any characteristic of the market for an energy-related product, service or practice that helps to explain the gap between the actual level of investment in, or practice of, energy efficiency and an increased level that would appear to be cost-beneficial to the consumer.

MARKET EFFECT - A change in the structure or functioning of a market or the behavior of participants in a market that result from one or more program efforts. Typically these efforts are designed to increase in the adoption of energy-efficient products, services or practices and are causally related to market interventions.

MARKET EVENT - The broader circumstances under which a customer considers adopting an energy efficiency product, service or practice. Types of market events include, but are not necessarily limited to: (a) new construction, or the construction of a new building or facility; (b) renovation, or the updating of an existing building or facility; (c) remodeling, or a change in an existing building; (d) replacement, or the replacement of equipment, either as a result of an emergency such as equipment failure or as part of a broader planned event; and, (e) retrofit, or the early replacement of equipment or refitting of a building or facility while equipment is still functioning, often as a result of an intervention into energy efficiency markets.

MARKET PARTICIPANTS - The individuals and organizations participating in transactions with one another within an energy efficiency market or markets, including customers and market actors.

MARKET POTENTIAL - See ACHIEVABLE POTENTIAL.

MARKET SECTORS - General types of markets that a program may target or in which a service offering may be placed. Market sectors include categories such as Agricultural, Commercial, Industrial, Government and Institutional. Market sectors help the CPUC assess how well its portfolio of programs is addressing the variety of markets for energy efficiency products and services in the state.

MARKET SEGMENTS - A part of a market sector that can be grouped together as a result of a characteristic similar to the group. Within the residential sector are market segments such as renters, owners, multi-family and single-family. These market segments help the CPUC assess how well its portfolio of programs is addressing the variety of segments within the markets served.

MARKET THEORY - A theoretical description of how a market operates relative to a specific program or set of programs designed to influence that market. Market theories typically include the identification of key market actors, information flows and product flows through the market, relative to a program designed to change the way the market operates. Market theories are typically grounded upon the information provided from a market assessment but can also be based on other information. Market theories often describe how a program intervention can take advantage of the structure and function of a market to transform the market. Market theories can also describe the key barriers and benefits associated with a market and describe how a program can exploit the benefits and overcome the barriers.

MARKET TRANSFORMATION - A reduction in market barriers resulting from a market intervention, as evidenced by a set of market effects, that lasts after the intervention has been withdrawn, reduced or changed.

MEASURE (noun) - A product whose installation and operation at a customer's premises results in a reduction in the customer's on-site energy use, compared to what would have happened otherwise. See also ENERGY EFFICIENCY MEASURE.

MEASURE (verb) - Use of an instrument to assess a physical quantity or use of a computer simulation to estimate a physical quantity.

MEASURE RETENTION – The degree to which measures are retained in use after they are installed. Measure retention studies assess the length of time the measure(s) installed during the program year are maintained in operating condition and the extent to which there has been a significant reduction in the effectiveness of the measure(s).

MEASURED SAVINGS - Savings or reductions in billing determinants, which are determined using engineering analysis in combination with measured data or through billing analysis.

MEGAWATT (MW) - One thousand kilowatts (1,000 kW) or one million (1,000,000) watts. One megawatt is enough energy to power 1,000 average California homes.

MEGAWATT HOUR (MWh) - One thousand kilowatt-hours. This amount of electricity would supply the monthly power needs of 1,000 typical homes in the Western U.S. (This is a rounding up to 8,760 kWh/year/home based on an average of 8,549 kWh used/household/year. (U.S. DOE EIA, 1997 annual/capita electricity consumption figures.))

METER - A device used to measure some quantity, for example, electrical demand, electrical energy, temperature and flow. A device for measuring levels and volumes of a customer's gas or electricity use.

METERED DATA - Data collected at customer premises over time through a meter for a specific end-use or energy-using system (e.g., lighting and HVAC), or location (e.g., floors of a building or a whole premise). Metered data may be collected over a variety of time intervals. Usually refers to electricity or gas data.

METERED DEMAND - The average time rate of energy flow over a period of time recorded by a utility meter.

METERING - The collection of energy consumption data over time at customer premises through the use of meters. These meters may collect information about kWh, kW or therms, with respect to an end-use, a circuit, a piece or equipment or a whole building (or facility). Short-term metering generally refers to data collection for no more than a few weeks. End-use metering refers specifically to separate data collection for one or more end-uses in a building, such as lighting, air conditioning or refrigeration. What is called "spot metering" is not metering in this sense, but is an instantaneous measurement (rather than over time) of volts, amps, watts or power factor to determine equipment size and/or power draw.

METRIC - A point of measurement. Any point of measurement that can be defined, quantified and assessed.

MODEL - A mathematical representation or calculation procedure that is used to predict the energy use and demand in a building or facility or to estimate efficiency program savings estimates. Models may be based on equations that specifically represent the physical processes or may be the result of statistical analysis of energy use data.

MONITORING (equipment or system) - Gathering of relevant measurement data over time to evaluate equipment or system performance, e.g., chiller electric demand, inlet evaporator temperature and flow, outlet evaporator temperature, condenser inlet temperature, and ambient dry-bulb temperature and relative humidity or wet-bulb temperature, for use in developing a chiller performance map (e.g., kW/ton vs. cooling load and vs. condenser inlet temperature).

MULTICOLLINEARITY - When two or more independent variables in a regression model are highly correlated with each other producing high standard errors for the regression parameter. The mathematics of a regression model fail if there is perfect collinearity, an exact linear relationship between two or more independent variables. If the correlation between independent variables is higher than either has with the dependent variable, the problems of multicollinearity are highly likely.

NAIC - North American Industry Classification.

NATURAL CHANGE - The change in base usage over time. Natural change represents the effects of energy-related decisions that would have been made in the absence of the utility programs by both program participants and non-participants.

NET LOAD IMPACT - The total change in load that is attributable to the utility DSM program. This change in load may include, implicitly or explicitly, the effects of free-drivers, free-riders, state or federal energy efficiency standards, changes in the level of energy service and natural change effects.

NET-TO-GROSS RATIO (NTGR) - A factor representing net program load impacts divided by gross program load impacts that is applied to gross program load impacts to convert them into net program load impacts. This factor is also sometimes used to convert gross measure costs to net measure costs.

NEW CONSTRUCTION - Residential and nonresidential buildings that have been newly built or have added major additions subject to California Code of Regulation Title 24, the California building standards code.

NON-PARTICIPANT - Any customer who was eligible but did not participate in the utility program under consideration in a given program year. Each evaluation plan should provide a definition of a non-participant as it applies to a specific study.

NONRESIDENTIAL – Used to describe facilities used for business, commercial, agricultural, institutional and industrial purposes.

NONRESIDENTIAL BUILDING - Any building which is heated or cooled in its interior and is of an occupancy type other than Type H, I or J, as defined in the Uniform Building Code, 1973 edition, as adopted by the International Conference of Building Officials.

NORMALIZATION - Adjustment of the results of a model due to changes in baseline assumptions (non-independent variables) during the test or post-retrofit period.

NTGR – See NET-TO-GROSS RATIO.

NULL HYPOTHESIS – See SIGNIFICANCE TEST.

OCCUPANCY SENSOR - A control device that senses the presence of a person in a given space, commonly used to control lighting systems in buildings.

ORIENTATION - The position of a building relative to the points of a compass.

P-VALUE – See PROBABILITY-VALUE.

PARTICIPANT - An individual, household, business or other utility customer that received a service or financial assistance offered through a particular utility program, set of utility programs or particular aspect of a utility program in a given program year. The term "service" is used in this definition to suggest that the service can be a wide variety of services, including financial rebates, technical assistance, product installations, training, energy efficiency information or other services, items or conditions. Each evaluation plan should present the definition of a "participant" as it applies to a specific study.

PARTICIPANT TEST - A cost-effectiveness test intended to measure the cost-effectiveness of energy efficiency programs from the perspective of electric and/or gas customers (individuals or organizations) participating in them.

PARTIES OR INTERESTED PARTIES - Persons and organizations with an interest in energy efficiency that comment on or participate in the CPUC's efforts to develop and implement ratepayer-funded energy efficiency programs.

PEAK DEMAND - The maximum level of metered demand during a specified period, such as a billing month or during a specified peak demand period.

PEAK DEMAND PERIOD - Noon to 7 p.m. Monday through Friday, June, July, August and September.

PEAK LOAD - The highest electrical demand within a particular period of time. Daily electric peaks on weekdays occur in late afternoon and early evening. Annual peaks occur on hot summer days.

PERFORMANCE DEGRADATION - Any over time savings degradation (or increases compared to standard efficiency operation) that includes both (1) technical operational characteristics of the measures, including operating conditions and product design, and (2) human interaction components and behavioral measures.

PERSISTENCE STUDY - A study to assess changes in net program impacts over time (including retention and degradation).

PGC - See PUBLIC GOODS CHARGE.

PORTFOLIO - All IOU and non-IOU energy efficiency programs funded through the PGC that are implemented during a program year or cycle.

POST-BUY ANALYSIS - A comparison of the actual advertising schedule run to the original expectations of the schedule as purchased, considering adherence to buy specifications, actual audience achieved as measured by audience ratings services when available, and conformity to standard industry practices. The term is used primarily in relation to broadcast media (and more frequently performed for TV schedules than for radio), but a similar type of stewardship should be performed for purchases of print and outdoor media as well

POST-RETROFIT PERIOD - The time following a retrofit during which savings are to be determined.

POWER ANALYSIS - A power analysis, executed when a study is being planned, is used to anticipate the likelihood that the study will yield a significant effect and is based on the same factors as the significance test itself. Specifically, the larger the effect size used in the power analysis, the larger the sample size; the larger (more liberal) the criterion required for significance (alpha), the higher the expectation that the study will yield a statistically significant effect. The probability-value (p-value) provided by the significance test and used to reject the null hypothesis, is a function of three factors: size of the observed effect (e.g., gross energy savings), sample size and the criterion required for significance (alpha, the level of confidence). These three factors, together with power, form a closed system – once any three are established, the fourth is completely determined. The goal of power analysis is to find an appropriate balance among these factors by taking into account the substantive goals of the study and the resources available to the researcher.

PRACTICE - Generally refers to a change in a customer's behavior or procedures that reduces energy use (e.g., thermostat settings and maintenance procedures).

PRACTICE RETENTION STUDY - An assessment of the length of time a customer continues the energy conservation behavioral changes after adoption of these changes.

PRECISION - The indication of the closeness of agreement among repeated measurements of the same physical quantity. In econometrics, the accuracy of an estimator as measured by the inverse of its variance.

PROBABILITY-VALUE (P-VALUE) - The probability of obtaining a finding at least as "impressive" as that obtained, *assuming* the null hypothesis is true, so that the finding was the result of chance alone. The p-value is provided by the significance test and used to reject the null hypothesis, and is a function of three factors: size of the observed effect (e.g., gross energy savings), sample size and the criterion required for significance (alpha, the level of confidence). These three factors, together with power, form a closed system – once any three are established, the fourth is completely determined.

PROCESS EVALUATION - A systematic assessment of an energy efficiency program for the purposes of documenting program operations at the time of the examination, and identifying and recommend improvements that can be made to the program to increase the program's efficiency or effectiveness for acquiring energy resources while maintaining high levels of participant satisfaction.

PROCESS OVERHAUL - Modifications to industrial or agricultural processes to improve their energy use characteristics.

PROGRAM - An activity, strategy or course of action undertaken by an implementer or Administrator using PGC funds. Each program is defined by a unique combination of program strategy, market segment, marketing approach and energy efficiency measure(s) included.

PROGRAM (IMPLEMENTATION) CYCLE - The period of time during which programs are funded, planned and implemented. Can be an annual cycle, a bi-annual cycle or other period of time.

PROGRAM DESIGN - The method or approach for making, doing or accomplishing an objective by means of a program.

PROGRAM DEVELOPMENT - The process by which ideas for new or revised energy efficiency programs are converted into a design to achieve a specific objective.

PROGRAM PENETRATION - The level of program acceptance among qualified customers.

PROGRAM MANAGEMENT - The responsibility and ability to oversee and guide the performance of a program to achieve its objective.

PROGRAM STRATEGIES - Refers to the type of method deployed by the program in order to obtain program participation. Some examples of program strategies include: rebates, codes, performance contracting and audits.

PROGRAM THEORY - A presentation of the goals of a program, incorporated with a detailed presentation of the activities that the program will use to accomplish those goals and the identification of the causal relationships between the activities and the program's effects.

PROGRAM YEAR (PY) - The calendar year approved for program implementation. Note that program years can be shorter than 12 months if programs are approved after the beginning of a calendar year (after January 1 of a given year).

PROGRAMMABLE CONTROLLER - A device that controls the operation of electrical equipment (such as air conditioning units and lights) according to a pre-set time schedule.

PROJECT - An activity or course of action undertaken by an implementer involving one or multiple energy efficiency measures, usually at a single site.

PROJECT DEVELOPMENT - The process by which an implementer identifies a strategy or creates a design to provide energy efficiency products, services and practices directly to customers.

PUBLIC GOODS CHARGE (PGC) (Electric) - Per Assembly Bill (AB) 1890, a universal charge applied to each electric utility Customer's bill to support the provision of public goods. Public goods covered by California's electric PGC include public purpose energy efficiency programs, low-income services, renewables, and energy-related research and development.

RATIO ESTIMATOR (SAMPLING METHOD) - A sampling method to obtain increased precision by taking advantage of the correlation between an auxiliary variable and the variable of interest to reduce the coefficient of variation.

REBATES - A type of incentive provided to encourage the adoption of energy-efficient practices, typically paid after the measure has been installed. There are typically two types of rebates: a Prescriptive Rebate, which is a prescribed financial incentive/unit for a prescribed list of products, and a Customized Rebate, in which the financial incentive is determined using an analysis of the customer's equipment and an agreement on the specific products to be installed. Upstream rebates are financial incentives provided for manufacturing, sales, stocking or other per unit energy-efficient product movement activities designed to increase use of particular type of products.

REBOUND EFFECT – SEE TAKEBACK EFFECT

REGRESSION MODEL - A mathematical model based on statistical analysis where the dependent variable is regressed on the independent variables which are said to determine its value. In so doing, the relationship between the variables is estimated statistically from the data used.

RELIABILITY - When used in energy evaluation refers to the likelihood that the observations can be replicated.

REMODELING – Modifications to or the act of modifying the characteristics of an existing residential or nonresidential building or energy-using equipment installed within it.

RENEWABLE ENERGY or RENEWABLE RESOURCES or RENEWABLE ENERGY RESOURCES- Renewable energy resources are naturally replenishable, but flow-limited. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Some (such as geothermal and biomass) may be stock-limited in that stocks are depleted by use, but on a time scale of decades or perhaps centuries, they can probably be replenished. Renewable energy resources include: biomass, hydro, geothermal, solar and wind. Renewable resources also include some experimental or less-developed sources such as the use of ocean thermal, wave and tidal action technologies. Utility renewable resource applications include bulk electricity generation, on-site electricity generation, distributed electricity generation, non-grid-connected generation and demand-reduction (energy efficiency) technologies.

RENOVATION - Modification to the characteristic(s) of an existing residential or nonresidential building, including but not limited to windows, insulation and other modifications to the building shell.

REPLACEMENT - Refers to the changing of equipment either due to failure, move to more efficient equipment or other reasons near the end of product life or earlier. Often used to refer to a move to a more energy-efficient product that replaces an inefficient product.

RESEARCH AND DEVELOPMENT (R&D) - Research is the discovery of fundamental, new knowledge. Development is the application of new knowledge to develop a potential new service or product. Basic power sector R&D is most commonly funded and conducted through the Department of Energy (DOE), its associated government laboratories, university laboratories, the Electric Power Research Institute (EPRI) and private sector companies.

RESIDENTIAL BUILDING - Means any hotel, motel, apartment house, lodging house, single dwelling or other residential building that is heated or mechanically cooled.

RESIDENTIAL CUSTOMER – Utility customers with accounts for existing single-family residences, multi-family dwellings (whether master-metered or individually metered) and buildings that are essentially residential but used for commercial purposes, including but not limited to time shares and vacation homes.

RETAIL MARKET - A market in which electricity and other energy services are sold directly to the end-use customer.

RETENTION (MEASURE) - The degree to which measures are retained in use after they are installed.

RETROFIT - Energy efficiency activities undertaken in existing residential or nonresidential buildings where existing inefficient equipment is replaced by efficient equipment.

RETROFIT ISOLATION - The savings measurement approach defined in IPMVP Options A and B, and ASHRAE Guideline 14 that determines energy or demand savings through the use of meters to isolate the energy flows for the system(s) under consideration.

RIGOR - The level of expected reliability. The higher the level of rigor, the more confident we are the results of the evaluation are both accurate and precise, i.e., reliable. That is, reliability and rigor are treated as synonymous. Reliability is discussed in the Sampling and Uncertainty Protocol and in the *Evaluation Framework* where it is noted that sampling precision does not equate to accuracy. Both are important components of reliability, as used in this Protocol.

SAE - See STATISTICALLY ADJUSTED ENGINEERING MODELS.

SAMPLE DESIGN - The approach used to select the sample units.

SAMPLING ERROR - An error which arises because the data are collected from a part, rather than the whole of the population. It is usually measurable from the sample data in the case of probability sampling.

SAVINGS MEASUREMENT APPROACH - The estimation of energy and demand savings associated with an energy efficiency measure for a piece of equipment, a subsystem or a system. The estimated savings are based on some kind of measured data from before and after the retrofit and may be calculated using a variety of engineering techniques.

SERIAL CORRELATION - See AUTOCORRELATION.

SERVICE AREA - The geographical territory served by a utility.

SETBACK THERMOSTAT - See THERMOSTAT, SETBACK.

SHADING - The protection from heat gains due to direct solar radiation. Shading is provided by permanently attached exterior devices, glazing materials, and adherent materials applied to the glazing or an adjacent building for nonresidential buildings, hotels, motels and high rise apartments, and by devices affixed to the structure for residential buildings. (See California Code of Regulations, Title 24, Section 2-5302.)

SHADING COEFFICIENT (SC) - The ratio of solar heat gain through fenestration, with or without integral shading devices, to that occurring through unshaded 1/8 in. thick clear double strength glass. See also SOLAR HEAT GAIN COEFFICIENT.

SHGC - See SOLAR HEAT GAIN COEFFICIENT.

SIGNIFICANCE TEST – Traditionally, data collected in a research study is submitted to a significance test to assess the viability of the null hypothesis. The null hypothesis is a term that statisticians often use to indicate the statistical hypothesis tested. The purpose of most statistical tests is to determine if the obtained results provide a reason to reject the hypothesis that they are merely a product of chance factors. For example, in an experiment in which two groups of randomly selected subjects have received different treatments and have yielded different means, it is always necessary to ask if the difference between the obtained means is among the differences that would be expected to occur by chance whenever two groups are randomly selected. In this example, the hypothesis tested is that the two samples are from populations with the same mean. Another way to say this is to assert that the investigator tests the null hypothesis that the difference between the means of the populations, from which the samples were drawn, is zero. If the difference between the means of the samples is among those that would occur rarely by chance when the null hypothesis is true, the null hypothesis is rejected and the investigator describes the results as statistically significant.

SIMPLE RANDOM SAMPLING - A method of selecting n sample units out of the N population such that every one of the distinct N items has an equal chance of being selected.

SIMPLIFIED ENGINEERING MODEL - Engineering equations used to calculate energy usage and/or savings. These models are usually based on a quantitative description of physical processes that describe the transformation of delivered energy into useful work such as heat, lighting or motor drive. In practice, these models may be reduced to simple equations that calculate energy usage or savings as a function of measurable attributes of customers, facilities or equipment (e.g., lighting use = watts X hours of use). These models do not incorporate billing data and do not produce estimates of energy savings to which tests of statistical validity can be applied.

SNAPBACK EFFECT – SEE TAKEBACK EFFECT

SOLAR HEAT GAIN - Heat added to a space due to transmitted and absorbed solar energy.

SOLAR HEAT GAIN COEFFICIENT (SHGG) - The ratio of the solar heat gain entering the space through the fenestration area to the incident solar radiation.

SOLAR HEAT GAIN FACTOR - An estimate used in calculating cooling loads of the heat gain due to transmitted and absorbed solar energy through 1/8”-thick, clear glass at a specific latitude, time and orientation.

SOLAR HEATING AND HOT WATER SYSTEMS - Solar heating or hot water systems provide two basic functions: (1) capturing the sun's radiant energy, converting it into heat energy and storing this heat in insulated storage tank(s); and (2) delivering the stored energy as needed to either the domestic hot water or heating system. These components are called the collection and delivery subsystems.

SPILLOVER - Reductions in energy consumption and/or demand in a utility's service area caused by the presence of the DSM program, beyond program related gross or net savings of participants. These effects could result from: (a) additional energy efficiency actions that program participants take outside the program as a result of having participated; (b) changes in the array of energy-using equipment that manufacturers, dealers and contractors offer all customers as a result of program availability; and (c) changes in the energy use of non-participants as a result of utility programs, whether direct (e.g., utility program advertising) or indirect (e.g., stocking practices such as (b) above or changes in consumer buying habits). Spillover impacts are to be evaluated via the Impact Evaluation Protocols (participant spillover) or by the Market Effects Protocol (non-participant spillover), but spillover impacts are not to be counted toward goal achievements at this time.

SPURIOUSNESS OR SPURIOUS CORRELATION - The apparent association between two variables that is actually attributable to a third variable outside the current analysis, probably a common precedent variable.

STAKEHOLDERS - In program evaluation, stakeholders refer to the myriad of parties that are impacted by a program. Stakeholders include: regulatory staff, program designers, implementers and evaluators, energy producers, special interest groups, potential participants and customers.

STANDARD DEVIATION - The square root of the variance.

STATEWIDE MARKETING AND OUTREACH PROGRAMS - Programs that convey consistent statewide messages to individual consumers through a mass-market advertising campaign.

STATEWIDE PROGRAM - A program available in the service territories of all four large California IOUs, with identical implementation characteristics in all areas, including incentives and application procedures.

STATISTICAL ANALYSIS - Extrapolation of sample data up to the population, calculation of error bounds.

STATISTICAL COMPARISONS - A comparison group of customers serving as a proxy of what program participants would have looked like if the program had not been offered.

STATISTICAL POWER - The probability that statistical significance will be attained, given that there really is a treatment effect. From Lipsey, Mark W. *Design Sensitivity: Statistical Power for Experimental Research*. Newbury Park, CA: SAGE Publications, 1990.

STATISTICALLY ADJUSTED ENGINEERING (SAE) MODELS - A category of billing analysis models that incorporate the engineering estimate of savings as a dependent variable. The regression coefficient in these models is the percentage of the engineering estimate of savings observed in changes in energy usage. For example, if the coefficient on the SAE term is 0.8, this means that the customers are on average realizing 80 percent of the savings from their engineering estimates.

STRATIFIED RANDOM SAMPLING – A sampling method in which the population is divided into X units of subpopulations that are non-overlapping and together comprise the entire population, called strata. A simple random sample is taken of each strata to create a sample based upon stratified random sampling.

STRATIFIED RATIO ESTIMATION - A sampling method that combines a stratified sample design with a ratio estimator to reduce the coefficient of variation by using the correlation of a known measure for the unit (e.g., expected energy savings) to stratify the population and allocate sample from strata for optimal sampling.

SUPPLY-SIDE - Activities conducted on the utility's side of the customer meter. Activities designed to supply electric power to customers, rather than meeting load though energy efficiency measures or on-site generation on the customer side of the meter.

SURVIVAL ANALYSIS - Survival analysis is a class of statistical methods for studying the timing of events or time-to-event models. Originally these models were developed for medical research where the time to death was analyzed, hence the name survival analysis. These statistical methods are designed to work with time-dependent covariates and censoring. Time dependent covariates are independent variables whose impacts on the dependent variable vary by not only its occurrence but also its timing. Censored data refers to not knowing when something occurred because it is before your data collection (left-censored) or has yet to occur at the time of data collection (right-censored).

SYSTEM - A combination of equipment and/or controls, accessories, interconnecting means and terminal elements by which energy is transformed so as to perform a specific function, such as HVAC, service water heating or illumination.

TAKEBACK EFFECT – A change in energy using behavior that yields an increased level of service and that occurs as a result of taking an energy efficiency action.

TECHNICAL DEGRADATION FACTOR - A multiplier used to account for time- and use-related change in the energy savings of a high efficiency measure or practice relative to a standard efficiency measure or practice due to technical operational characteristics of the measures, including operating conditions and product design.

TECHNICAL POTENTIAL - The complete penetration of all measures analyzed in applications where they were deemed technically feasible from an engineering perspective.

TEMPERATURE - Degree of hotness or coldness measured on one of several arbitrary scales based on some observable phenomenon (such as the expansion).

THERM - One hundred thousand (100,000) British thermal units (1 therm = 100,000 Btu).

THERMOSTAT - An automatic control device designed to be responsive to temperature and typically used to maintain set temperatures by cycling the HVAC system.

THERMOSTAT, SETBACK - A device containing a clock mechanism, which can automatically change the inside temperature maintained by the HVAC system according to a pre-set schedule. The heating or cooling requirements can be reduced when a building is unoccupied or when occupants are asleep. (See California Code of Regulations, Title 24, Section 2- 5352(h).)

TIME-OF-USE (TOU) METER - A measuring device that records the times during which a customer uses various amounts of electricity. This type of meter is used for customers who pay time-of-use rates.

TIME-OF-USE (TOU) RATES - Electricity prices that vary depending on the time periods in which the energy is consumed. In a time-of- use rate structure, higher prices are charged during utility peak-load times. Such rates can provide an incentive for consumers to curb power use during peak times.

TOTAL FLOOR AREA is the floor area (in square feet) of enclosed space on all floors of a building, as measured at the floor level of the exterior surfaces of exterior walls enclosing the space.

TOTAL RESOURCE COST TEST – SOCIETAL VERSION - A cost-effectiveness test intended to measure the overall cost-effectiveness of energy efficiency programs from a societal perspective.

TOU – See TIME-OF-USE METER and TIME-OF-USE RATES.

TRIANGULATION - Comparing the results from two or more different data gathering or measurement techniques on the same problem to derive a "best" estimate from the analysis of the comparison.

UA - A measure of the amount of heat that would be transferred through a given surface or enclosure (such as a building envelope) with a 1° F temperature difference between the two sides. The UA is calculated by multiplying the U-value by the area of the surface (or surfaces).

UNCERTAINTY - The range or interval of doubt surrounding a measured or calculated value within which the true value is expected to fall within some degree of confidence.

UNCERTAINTY ANALYSIS - (a) A procedure or method by which the uncertainty of a measured or calculated value is determined; (b) the process of determining the degree of confidence in the true value when using a measurement procedure(s) and/or calculation(s).

UNCONDITIONED SPACE - A space that is neither directly nor indirectly conditioned space, which can be isolated from conditioned space by partitions and/or closeable doors. (See California Code of Regulations, Title 24, Section 2-5302.)

UPGRADE (Electric utility) - Replacement or addition of electrical equipment resulting in increased generation or transmission capability.

UPSTREAM PROGRAMS - Programs that provide information and/or financial assistance to entities in the delivery chain of high-efficiency products at the retail, wholesale or manufacturing level.

UTILITY METER - The meter used to calculate a monthly energy and/or demand charge at a specific utility/customer connection; more than one may be installed per customer and per site due to different supply voltages, capacity requirements, physical separation distances, installation periods or for specific customer requirements or utility programs.

U-VALUE or U-FACTOR - A measure of how well heat is transferred by the entire window - the frame, sash and glass - either into or out of the building. U-value is the opposite of R-value. The lower the U-factor number, the better the window will keep heat inside a home on a cold day.

VALIDITY - The extent to which any measuring instrument measures what it is intended to measure.

VENTILATION - The process of supplying or removing air by natural or mechanical means to or from any space. Such air may or may not have been conditioned or treated.

WATT - A unit of measure of electric power at a point in time, as capacity or demand. One watt of power maintained over time is equal to one joule/second. Some Christmas tree lights use one watt. The watt is named after Scottish inventor James Watt and is capitalized when shortened to W and used with other abbreviations, as in kWh.

WATT-HOUR - One watt of power expended for one hour. One thousandth of a kilowatt-hour.

WEATHERSTRIPPING - Specially designed strips, seals and gaskets installed around doors and windows to limit air leakage.

WET-BULB TEMPERATURE - The temperature at which water, by evaporating into air, can bring the air to saturation at the same temperature. Wet-bulb temperature is measured by a wet-bulb psychrometer.

WHOLE-BUILDING CALIBRATED SIMULATION APPROACH - The savings measurement approach defined in IPMVP Option D and ASHRAE Guideline 14, which involves the use of an approved computer simulation program to develop a physical model of the building in order to determine energy and demand savings. The simulation program is used to model the energy used by the facility before and after the retrofit. The pre- or post-retrofit models are developed by calibration with measured energy use and demand data and weather data.

WHOLE-BUILDING METERED APPROACH - The savings measurement approach defined in IPMVP Option C and ASHRAE Guideline 14 that determines energy and demand savings through the use of whole-facility energy (end-use) data, which may be measured by utility meters or data loggers. This approach may involve the use of monthly utility billing data or data gathered more frequently from a main meter.

ZONE - A space or group of spaces within a building with any combination of heating, cooling or lighting requirements sufficiently similar so that desired conditions can be maintained throughout by a single controlling device.

APPENDIX C. Performance Basis Metrics

This section identifies the performance basis metrics that the CPUC-ED will use to assess the performance of the Administrator's energy efficiency programs. These metrics are to be provided by the Administrators to the CPUC-ED.

When an evaluation plan indicates that one or more of the following metrics will be collected, assessed or reported within an evaluation effort, the evaluation contractor will report the performance basis metrics for each program being evaluated and for the aggregation of programs when the evaluation includes more than one program. The performance basis metrics are to be reported in an appendix to the evaluation plan entitled Performance Basis Metric Reporting. The evaluation contractor is to work with the Joint Staff during the evaluation planning efforts to identify the performance basis metrics that are to be reported within the evaluation effort.

The following is a list of the performance basis metrics that are reported by the program administrators to be considered for inclusion in the evaluation reports. The decision of which metrics to include in the evaluation reports will be made by the Joint Staff and provided to the evaluation contractor. The evaluation contractor is to coordinate with Joint Staff to assure that the appropriate performance basis metrics are included in the evaluation reports.

1. Measure installation counts reported by the program.
2. Program costs reported by the program.
3. Measure-specific unit Energy Savings reported by the program.
4. Measure-specific installations by program delivery strategy reported by the program.
5. Program administrator estimates of Gross Energy Savings.
6. Program administrator estimated net-to-gross ratios by measure and delivery strategy.
7. Program administrator estimates of net energy savings.
8. Load factors or daily load shapes used to transform annual savings estimates into peak
9. savings estimates.
10. Incremental measure costs.

Appendix D. A Primer for Using Power Analysis to Determine Sample Sizes

Power is the probability that you will detect an "effect" that is there in the true population that you are studying. Put another way, the power of a statistical test of a null hypothesis is the probability that it will lead to a rejection of the null hypothesis when it is false, i.e., the probability that it will result in the conclusion that the phenomenon exists. The "effect" could be a difference between two means, a correlation between two variables (r), a regression coefficient (b), a chi-squared, etc. Power analysis is a statistical technique that can be used (among other things) to determine sample size requirements to ensure that statistical significance can be found. This appendix provides an overview of using power analysis for determining required sample sizes. It provides references and an example of using power analysis for this purpose.

Power analysis is a required component in several of the Energy Efficiency Evaluation Protocols to *assist* in determining required sample sizes for the allowable methods that use any type of regression analysis. The regression-based methods within the Impact Protocol[142] and the Effective Useful Life Evaluation Protocol (Retention and Degradation) (e.g., survival analysis) must use power analysis to plan their sample size (unless census samples are being used). (Regression-based methods must also meet the requirements of the Sampling and Uncertainty Protocol.)

In all of the Protocols, where power analysis is required it is one of up to three inputs to be used for the determination of sample size for a non-census regression study. Each Protocol states that power analysis, results from prior studies on similar programs, and professional judgment are to be used to determine the required sample size. Sample size planning is an important component in the evaluation planning activity. The proposed sample size(s) must be within the evaluation plan submitted and approved by Joint Staff prior to undertaking sample data collection.

There are many possible references for power analysis and over the last decade it has become a standard component of graduate statistics courses. The seminal work was conducted by Jacob Cohen and the classic text cited is his 1988 *Statistical Power Analysis for the Behavioral Sciences*. Power analysis can be used for many things but is only being required in the Protocol for determining required sample sizes.

There are several software packages and calculation Web sites that conduct the power analysis calculation. The National Institute of Health provided funding to BioStat, Inc. to create stand-alone software to conduct power analysis calculations. The current version of this software is called Power and Precision™ and is offered for sale by Biostat™ (www.PowerAnalysis.com). The major statistical software packages that evaluators are likely to use for conducting regression-based analyses have incorporated components that conduct power analysis. For

[142] These include the Gross Energy Impact Protocol, Gross Demand Impact Protocol, Participant Net Impact Protocol, and the Indirect Impact Protocol. All of these have at least one minimum allowable method that is regression-based. Regression-based methods discussed in these Protocols include, but are not limited to, multiple regression (econometric analysis), Analysis of Covariance (ANCOVA), and discrete choice (logistic regression).

example, it is included in SPSS® and in the 9.1 versions of SAS® along with the SAS/STAT® package (Power and Precision module).

A brief overview of the parameters to be input for conducting power analysis for the purpose of determining required sample size for the primary regression model types primarily used within energy efficiency evaluation is provided below. This is followed by an example where power analysis is conducted to determine the required sample size for a survival analysis (the preferred methodology for effective useful life analysis). This example illustrates how the sample size requirement varies according to different input parameters.

A small list of references is provided at the end of this Appendix.

Basics of Power Analysis and the Protocols

There is some variation in the parameters and the set-up required to use power analysis to determine sample requirements for different types of analyses. There are some that are common to all power analysis. There are four common parameters that create a closed system for power analysis. These are:

- Alpha
- Power
- Effect size
- Sample size

Alpha is the criterion required to establish statistical significance. For consistency across studies, these Protocols have called for 90% confidence level (precision) and then varied the error tolerance based upon the rigor level assigned. A 90% precision equates to an alpha of 0.10. This represents the probability or proportion of studies that would result in a Type I error, where the researcher rejects the null hypothesis when it is in fact true. For consistency with the precision requirements elsewhere in the Protocols, the alpha should be set at 0.10 when using power analysis to determine the required sample size.

Power is the probability that one find a statistically significant effect (when in reality there is one), assuming the effect size, sample size, and alpha criteria. It is common to set power from 0.7 to 0.9. The EUL Analysis Protocol sets the minimum power to 0.7 for the Basic rigor level and 0.8 for the Enhanced rigor.

The effect size is the expected magnitude of the effect. However, effect size will be expressed differently depending on the unit of measurement of the variables involved and on the type of analysis being performed.

In determining sample sizes in the research planning process, values for these parameters can be varied in an attempt to balance a level of statistical power, the alpha, and the effect size, all determined with an eye on the budget constraints. In the end, the results of the power analysis will be combined with professional judgment and past studies to arrive at the required sample sizes.

For multiple regression, analysis of covariance (ANCOVA), and logistic regression, there are three parameters that one can vary when determining the required sample size:

- Alpha
- Power
- Effect size

For survival analysis, there is a fourth parameter that can be varied, the duration of study. Survival analysis depends upon failures to estimate the function of when failure will occur taking into account that for many of the sites failures will not have yet been observed (i.e., the data is right-censored, the point of failure is not determined for many in the sample). The later the study (i.e., the greater the duration), the greater the power since a greater duration increases probability that more failures will be observed. For the same alpha, effect size, and power, a study that plans to collect retention data close to the ex-ante EUL (the median measure life) will require fewer sample points than a study conducted earlier.

We conclude this brief introduction with a list of power facts.

- The more stringent the significance level, the greater the necessary sample size. More subjects are needed for a 1% level test than for a 5% level test.
- Two-tailed tests require larger sample sizes than one-tailed tests. Assessing two directions at the same time requires a greater investment. (At the same time, good science requires that a one-tail test is only used when there is strong proof that it is appropriate to do so and not being used for the purpose of making it simpler to pass a statistical significance test.)
- The smaller the critical effect size, the larger the sample size. Subtle effects require greater efforts.
- The larger the power required, the larger the necessary sample size. Greater protection from failure requires greater effort.
- The smaller the sample size, the smaller the power, i.e., the greater the chance of failure.
- If one proposed to conduct an analysis with a very small sample size, one must be willing to accept a high risk of finding no statistically significant results, or be operating in an area in which the critical effect size is quite large.

Example of Varying Parameters and Estimating Required Sample Size for Survival Analysis through Power Analysis

The basic level of rigor in the EUL Protocols requires that a 0.70 level of power be planned at the 90% level of confidence. While the enhanced level of rigor requires that a 0.80 level of power be planned also at the 90% level of confidence. An exercise was conducted using Power and Precision™ software to provide an example of the use of power analysis to set required sample size and to demonstrate the impact of the different power level requirements on sample size requirements.[143]

Two hypothetical situations were created around an energy efficiency measure with an ex-ante median EUL of 8 years.

- In the first situation, a researcher is interested in setting up a study to detect an effect size (a delta) of two years in both directions. In other words, our ex-post estimate around an 8 year median EUL finding would be 6 years to 10 years.
- In the second situation, a researcher is interested in setting up a study to detect an effect size (a delta) of only one year in both directions. In other words, our ex-post estimate around an 8 year median EUL finding would be 7 years to 9 years.

In both cases it was assumed that the effect was selected as the smallest effect that would be important to detect, in the sense that any smaller effect would not be of any substantive significance. It is also assumed that the effect size is reasonable, in the sense that an effect of this magnitude could be anticipated in this field of research.

The conditions of the study were as follows:

- A two-tailed test was used since it is possible that the ex-post EUL could be higher or lower than the ex-ante EUL.
- The computation assumes an attrition rate of zero. This means that all sites will be followed until the measure is no longer operational or is not there (the terminal event) or until the study ends.
- This study assumes a condition in which subjects are entered during a given program period and then followed until either (a) the terminal event occurs, or (b) the study ends causing us not to know how long the equipment will last in all those sites that still have operational equipment (i.e., the site is randomly right-censored). The study design calls for all subjects to be accrued before the study begins, with the retention study to occur at 5 years after the program year under study (a follow-up period of 5 years). In other words, all subjects in the sample will be followed for a maximum of 5 years.
- The alpha level was set at 0.10. (This equates to 90% precision.)
- This study systematically varied two levels of power (0.70 and 0.80) to examine the impacts of varying the required power on the subsequent required sample size.
- Finally, this study systematically varied two levels of effect size to examine the impact of alternative effect size requirements. Both assumed that the ex-ante EUL was 8 years. For the ex-post EUL we first assumed 10 years, which means that the delta between ex-ante and ex-post is two years. We then assumed 9 years, which means that the delta between ex-ante and ex-post is only one year, a much smaller effect.

Table 25 below shows the effect on sample sizes of varying both the effect and the power. The differences looking from one column to the other column demonstrate the differential impact of

[143] Produced by Biostat™. Information available at: www.PowerAnalysis.com

requiring a power of 0.7 versus 0.8. Looking from row to row demonstrates the impact on sample size requirements of desiring to obtain a one-year effect versus a two-year effect (for the 8 year ex-ante survival analysis).

Table 25. Sample Sizes as a Function of Alpha and Power

	Power	
Effect	**0.70**	**0.80**
1 Year	1,050	1,400
2 Years	320	420

As one can see, at alphas of 0.70 and 0.80, the sample sizes increase by approximately 33 percent for a one-year effect size and 31.3 percent for a two-year effect size. Increasing the power requirement from 0.70 to 0.80 increases the required sample size by approximately one-third. However, as one moves from the effect of one year to two years, the required sample sizes increase by approximately 230 percent, from 320 to 1,050 for a power of 0.7 and from 420 to 1,400 for a power of 0.8. Clearly, the impact of a smaller effect is greater than the impact of increasing the power.

While we have attempted to keep the example simple so that the effect of moving from the standard to the enhanced level of rigor can be clearly seen, we note that there are four parameters that one can adjust for determining the required sample size. These are the:

- Duration of study (the post 5-year study assumption in our example.)[144]
- Alpha (The precision level which we set at 90% confidence, as is done throughout the evaluation Protocols, which provides an alpha of 0.1.)
- Power
- Effect size

Consider the case in which the effect is one year at a power of 0.80, requiring a sample size of 1,400. If one chose an alpha of 0.20 (as was done in the pre-1998 Protocols for the EUL analysis) and extended the follow-up period from 5 years to 7 years, then the sample size is reduced to 770.

In determining sample sizes in the research planning process, values for these parameters can be varied in an attempt to balance a level of statistical power, the alpha, the duration of the study, and the effect size, all determined with an eye on the budget constraints. The values will probably be unique to each measure selected for study. In the end, the results of the power analysis will be combined with professional judgment and past studies to arrive at the required sample sizes.

[144] The closer the study is to the ex-ante EUL the lower the sample size requirement since finding enough failures to complete the analysis is a primary component of sample size requirement and the ability to obtain a survival analysis result.

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Lipsey, Mark W. (1990) *Design Sensitivity: Statistical Power for Experimental Research*. Newbury Park, CA: SAGE Publications.

Statistical Package for the Social Sciences, SPSS® (See SPSS.com)

Statistical Analysis Software (SAS®)

Appendix E. Summary Tables for All Protocols

The following tables are provided as a quick reference to the summary tables found in the Protocols.

Summary of Protocol-Driven Impact Evaluation Activities

Required Protocols for Gross Energy Evaluation	
Rigor Level	**Minimum Allowable Methods for Gross Energy Evaluation**
Basic	1. Simple Engineering Model (SEM) with M&V equal to IPMVP Option A and meeting all requirements in the M&V Protocol for this method. Sampling according to the Sampling and Uncertainty Protocol. 2. Normalized Annual Consumption (NAC) using pre- and post-program participation consumption from utility bills from the appropriate meters related to the measures undertaken, normalized for weather, using identified weather data to normalize for heating and/or cooling as is appropriate to measures included. Twelve (12) months pre-retrofit and twelve (12) months post-retrofit consumption data is required. Sampling must be according to the Sampling and Uncertainty Protocol.
Enhanced	1. A fully specified regression analysis of consumption information from utility bills with inclusion/adjustment for changes and background variables over the time period of analysis that could potentially be correlated with the gross energy savings being measured. Twelve (12) months post-retrofit consumption data are required. Twelve (12) months pre-retrofit consumption data are required, unless program design does not allow pre-retrofit billing data, such as in new construction. In these cases, well-matched control groups and post-retrofit consumption analysis is allowable.[145] Sampling must be according to the Sampling and Uncertainty Protocol utilizing power analysis as an input to determining required sample size(s). 2. Building energy simulation models that are calibrated as described in IPMVP Option D requirements in the M&V Protocols. If appropriate, may alternatively use a process-engineering model (e.g., AirMaster+) with calibration as described in the M&V Protocols. Sampling according to the Sampling and Uncertainty Protocol. 3. Retrofit Isolation engineering models as described in IPMVP Option B requirements in the M&V Protocols. Sampling according to the Sampling and Uncertainty Protocol. 4. Experimental design established within the program implementation process, designed to obtain reliable net energy savings based upon differences between energy consumption between treatment and non-treatment groups from consumption data.[146] Sampling must be according to the Sampling and Uncertainty Protocol.

[145] Post-retrofit only billing collapses the analysis from cross-sectional time-series to cross-sectional. Given this, even more care and examination is expected with regard to controlling for cross-sectional issues that could potentially bias the savings estimate.

[146] The overall goal of the Direct Impact Protocols is to obtain reliable net energy and demand savings estimates. If the methodology directly estimates net savings at the same or better rigor than the required level of rigor, then a gross savings and participant net impact analysis is not required to be shown separately.

Required Protocols for Gross Demand Evaluation	
Rigor Level	**Minimum Allowable Methods for Gross Demand Evaluation**
Basic	Reliance upon secondary data for estimating demand impacts as a function of energy savings. End-use savings load shapes or end-use load shapes from one of the following will be used to estimate demand impacts: 1. End-use savings load shapes, end-use load shapes or allocation factors from simulations conducted for DEER 2. Allocation factors from CEC forecasting models or utility forecasting models with approval through the evaluation plan review process 3. Allocation based on end-use savings load shapes or end-use load shapes from other studies for related programs/similar markets with approval through the evaluation plan review process
Enhanced	Primary demand impact data must be collected during the peak hour during the peak month for each utility system peak. Estimation of demand impact estimates based on these data is required. If the methodology and data used can readily provide 8,760-hour output, these should also be provided.[147] Sampling requirements can be met at the program level but reporting must be by climate zone (according to CEC's climate zone classification). 1. If interval or time-of-use consumption data are available for participants through utility bills, these data can be used for regression analysis, accounting for weather, day type and other pertinent change variables, to determine demand impact estimates. Pre- and post-retrofit billing periods must contain peak periods. Requires using power analysis, evaluations of similar programs, and professional judgment to determine sample size requirements for planning the evaluation. Needs to meet the requirements of the Sampling and Uncertainty Protocol. 2. Spot or continuous metering/measurement of peak pre and post-retrofit during the peak hour of the peak month for the utility system peak to be used with full measurement Option B or calibrated engineering model Option D meeting all requirements as provided in the M&V Protocol. Pre-retrofit data must be adjusted for weather and other pertinent change variables. Must meet the Sampling and Uncertainty Protocol with a program target of 10% precision at a 90% confidence level. 3. Experimental design established within the program implementation process, designed to obtain reliable net demand savings based upon differences between energy consumption during peak demand periods between treatment and non-treatment groups from consumption data or spot or continuous metering.[148] Sampling must be according to the Sampling and Uncertainty Protocol.

[147] This includes the use of 15-minute interval data or Building Energy Simulation models whose output is 8,760 hourly data.

[148] The overall goal of the Impact Protocols is to obtain reliable net energy and demand savings estimates. If the methodology directly estimates net savings at the same or better rigor than the required level of rigor, then a gross savings and participant net impact analysis is not required to be shown separately.

Required Protocols for Participant Net Impact Evaluation	
Rigor Level	**Minimum Allowable Methods for Participant Net Impact Evaluation**
Basic	1. Participant self-report.
Standard	1. Participant and non-participant analysis of utility consumption data that addresses the issue of self-selection. 2. Enhanced self-report method using other data sources relevant to the decision to install/adopt. These could include, for example, record/business policy and paper review, examination of other similar decisions, interviews with multiple actors at end-user, interviews with mid-stream and upstream market actors, Title 24 review of typically built buildings by builders and/or stocking practices. 3. Econometric or discrete choice[149] with participant and non-participant comparison addressing the issue of self-selection.
Enhanced	1. "Triangulation" using more than one of the methods in the Standard Rigor Level. This must include analysis and justification for the method for deriving the triangulation estimate from the estimates obtained.

Required Protocols for Indirect Impact Evaluation	
Rigor Level	**Minimum Allowable Methods for Indirect Impact Evaluation**
Basic	An evaluation to estimate the program's net changes on the behavior of the participants is required; the impact of the program on participant behavior.
Standard	A two-stage analysis is required that will produce energy and demand savings. The first stage is to conduct an evaluation to estimate the program's net changes on the behavior of the participants/targeted-customers. The second is to link the behaviors identified to estimates of energy and demand savings based upon prior studies (as approved through the evaluation planning or evaluation review process).
Enhanced	A three-stage analysis is required that will produce energy and demand savings. The first stage is to conduct an evaluation to estimate the program's net impact on the behavior changes of the participants. The second stage is to link the behavioral changes to estimates of energy and demand savings based upon prior studies (as approved through the evaluation planning or evaluation review process). The third stage is to conduct field observation/testing to *verify* that the occurrence of the level of net behavioral changes.

Summary of Protocol-Driven Impact Evaluation Activities	
1	The Joint Staff identifies which programs and program components will receive an impact evaluation and identify the type of impact evaluation(s) to be conducted and at what rigor level.
2	The Joint Staff determines any special needs on a case-by-case basis that will be required from particular program or program component evaluations. CPUC-ED issues request for proposals for

[149] The instrumental-decomposition (ID) method described and referenced in the *Evaluation Framework* (page 145) is an allowable method that falls into this category. A propensity score methodology is also an allowable method in this category as described in: Itzhak Yanovitzky, Elaine Zanutto and Robert Hornik,, "Estimating causal effects of public health education campaigns using propensity score methodology." *Evaluation and Program Planning* 28 (2005): 209–220.

	impact evaluations, selects evaluation contractors and establishes scope(s) of work.
3	Program theory and logic models (PT/LM), if available, must be reviewed/assessed as needed to properly identify impacts and evaluation elements required to assess net program impacts. Research design and sampling plan developed to meet Protocol requirements at a program or program component basis as designated by the Joint Staff rigor level assignments. This includes meeting requirements from the Sampling and Uncertainty Protocol, M&V Protocol and Reporting Protocol, as are applicable given Impact Evaluation Protocol requirements. Research design and sampling must be designed to meet any of the Joint Staff requirements for additional analyses including, but not limited to, the estimation of net impacts by delivery mechanism, the estimation of transmission and/or distribution benefits, or other areas designated of specific concern by the Joint Staff. Develop Evaluation Plan, submit it to the CPUC-ED and revise as necessary to have an approved Evaluation Plan that meets the Impact Evaluation Protocols.
4	All impact evaluation teams must be staffed so as to meet the skills required for the research design, sampling, appropriate and selected impact evaluation method, uncertainty analysis, and reporting being planned and conducted.
5	Develop precise definitions of participants, non-participants and comparison groups. Obtain concurrence with the CPUC-ED on these definitions which are to be used in developing the research design and sampling plans.
6	All impact evaluations must meet the requirements of the Sampling and Uncertainty Protocol. 6.e There are 2 primary sampling considerations for regression-based consumption analysis. (3) Unless a census is utilized, conduct a power analysis to estimate the required sample size. One may also consider prior evaluations for similar programs and professional judgment (must use all of these for the Enhanced level of rigor); and (4) Must use a minimum of 12 months pre and post-retrofit consumption data, except when program approach does not allow pre-retrofit data (e.g., new construction). 6.f All engineering-based methods must: (3) Estimate the uncertainty in all deemed and measured input parameters and consider propagation of error when determining measured quantities and sample sizes to meet the required error tolerance levels; and (4) Use a combination of deemed and measured data sources with sufficient sample sizes designed to meet a 30% error tolerance level in the reported value at a 90% confidence level to meet the Basic rigor level and a 10% error tolerance level at a 90% confidence level for the Enhanced rigor level. 6.g Participant and non-participant comparisons and econometric/discrete-choice methods for Participant Net Impact evaluation will use power analysis combined with examinations of prior evaluation studies for similar programs to derive required sample sizes. 6.h Self-report and Enhanced self-report methods for Participant Net Impact evaluations must at a program level have a minimum sample size of 300 participant decision-makers for at least 300 participant sites (where decision-makers may cover more than one site) or a census attempt, whichever is smaller, (while investigation will be at a measure or end-use level).

7	All impact evaluations must be planned, conducted, analyzed and reported to minimize potential bias in the estimates, justify the methods selected for doing this and report all analysis of potential bias issues as described in the Sampling and Uncertainty Protocol, Impact Evaluation Protocol and M&V Protocol. Primary considerations that must be addressed (based upon method employed) are as follows: 7.e Regression-based consumption analysis must incorporate: (6) Addressing the influence of weather when weather sensitive measures have been included in the program evaluation; (7) Assessing potential bias given inclusion/exclusion issues due to the 12 month pre- and post-retrofit consumption minimum requirement; (8) For the Enhanced rigor level, assess, plan, measure and incorporate background and change variables that might be expected to be correlated with gross and net energy and/or demand savings; (9) Comparison groups must be carefully selected with justification of the criteria for selection of the comparison group and discussion of any potential bias and how the selected comparison group provides the best available minimization of any potential bias; and (10) Interval or TOU consumption data for demand impact analysis must contain the peak period for the utility system peak. If demand billing data is used for demand impact analysis, the research design must address the issues of building demand versus time period for peak and issues with demand ratchets and how the evaluation can reliably provide demand savings estimates. Demand savings must be reported by CTZ. 7.f Engineering-based methods must incorporate: (4) Addressing the influence of weather when weather sensitive measures have been included in the program evaluation; (5) Meeting all the requirements in the M&V Protocol including issues of baseline determination; and (6) For the Enhanced rigor level of demand impact analysis using spot or continuous metering/measurement pre- and post-retrofit for the peak hour of the peak month for the utility system peak. Demand savings must be reported by CTZ. 7.g Experimental design must use spot or continuous metering/measurement pre and post-retrofit for the peak hour of the peak month for the utility system peak for determining demand impacts. Demand savings must be reported by CTZ. 7.h Indirect impact analysis must incorporate: (6) Description of expected impacts (direct behavioral and indirect energy and demand impacts) and how they will be measured; (7) Discussion of identification and measurement of baseline; (8) Extent of exposure/treatment and its measurement;

	(9) Comparison groups must be carefully selected with justification of the criteria for selection of the comparison group and discussion of any potential issues of bias and how the selected comparison group provides the best available minimization of potential bias; and (10) Assessing, planning for and analyzing to control for self-selection bias.
8	Regression analysis of consumption data must address outliers, missing data, weather adjustment, selection bias, background variables, data screens, autocorrelation, truncation, error in measuring variables, model specification and omitted variable error, heteroscedasticity, collinearity and influential data points. These areas must be addressed and reported in accordance with the Sampling and Uncertainty Protocol.
9	Engineering analysis and M&V based methods are required to address sources of uncertainty in parameters, construction of baseline, guarding against measurement error, site selection and non-response bias, engineering model bias, modeler bias, deemed parameter bias, meter bias, sensor placement bias and non-random selection of equipment or circuits to monitor. These areas must be addressed and reported in accordance with the Sampling and Uncertainty Protocol.
10	Develop draft evaluation report to include meeting all requirements in the Reporting Protocol and incorporating the program's performance metrics.
11	Develop final evaluation report in accordance with guidance provided by the Joint Staff. Submit final evaluation report to the CPUC-ED.
12	Once accepted by the CPUC-ED, develop abstracts and post them and report on CALMAC Web site following the CALMAC posting instructions.

Note: The steps included in this evaluation summary table must comply with all the requirements within the Impact Evaluation Protocol.

Summary of Protocol-Driven M&V Activities

Summary of M&V Protocol for Basic Level of Rigor	
Provision	**Requirement**
Verification	Physical inspection of installation to verify correct measure installation and installation quality
IPMVP Option	Option A[150]
Source of Stipulated Data	DEER assumptions, program work papers, engineering references, manufacturers catalog data, on-site survey data
Baseline Definition	Consistent with program baseline definition. May include federal or Title 20 appliance standards effective at date of equipment manufacture, Title 24 building standards in effect at time of building permit; existing equipment conditions or common replacement or design practices as defined by the program
Monitoring Strategy and Duration	Spot or short-term measurements depending on measure type
Weather Adjustments	Weather dependent measures: normalize to long-term average weather data as directed by the Impact Evaluation Protocol
Calibration Criteria	Not applicable
Additional Provisions	None

Summary of M&V Protocol for Enhanced Level of Rigor	
Provision	**Requirement**
Verification	Physical inspection of installation to verify correct measure installation and installation quality. Review of commissioning reports or functional performance testing to verify correct operation
IPMVP Option	Option B or Option D
Source of Stipulated Data	DEER assumptions, program work papers, engineering references, manufacturers catalog data, on-site survey data
Baseline Definition	Consistent with program baseline definition. May include federal or Title 20 appliance standards effective at date of equipment manufacture, Title 24 building standards in effect at time of building permit; existing equipment conditions or common replacement or design practices as defined by the program
Monitoring Duration	Sufficient to capture all operational modes and seasons
Weather Adjustments	Weather dependent measures: normalize to long-term average weather data as directed by the Impact Evaluation Protocol
Calibration Criteria	Option D building energy simulation models calibrated to monthly billing or interval demand data. Optional calibration to end-use metered data
Additional Provisions	Hourly building energy simulation program compliant with ASHRAE Standard 140-2001

[150] Exceptions to this provision are programs offering comprehensive measure packages with significant measure interactions; commissioning, and retrocommissioning programs; and new construction programs. Evaluation of measure savings within these programs conducted using engineering methods must follow the Enhanced rigor M&V Protocol and use building energy simulation modeling under IPMVP Option D.

Summary of Protocol-Driven M&V Activities	
1	Receive input from impact evaluation plan. Receive M&V site selection and expected rigor level from the impact evaluation plan.
2	Develop overall M&V plan. The M&V option for each site shall be established according to the rigor assignment and allowable options under the Impact Evaluation Protocol. Project baseline definition with justification shall be reported. Overall M&V planning shall consider the needs of process evaluation studies for measure installation verification and measure performance information. The overall M&V plan shall be submitted for approval to the evaluation project manager as designated by the CPUC-ED.
3	Assess data sources. For each sampled site, the data resources for the engineering analysis must be identified and reviewed. Data sources may include program descriptions, program databases, DEER estimates and underlying documentation, program work papers and on-site surveys. Uncertainties associated with engineering parameters must be estimated. Baseline uncertainties, where not explicitly documented elsewhere, may be informed by professional judgment.
4	Conduct uncertainty analysis. The uncertainty in the estimated savings must be estimated using a propagation of error analysis. The parameters having the greatest influence on the uncertainty must be identified from the propagation of error analysis.
5	Develop site-specific M&V plan according to the outline in the M&V Protocols. The M&V plan must address data collection conducted to reduce uncertainty in the engineering estimates of savings. Sampling of measures within a particular site shall be done in accordance with the Sampling and Uncertainty Protocol. The site-specific M&V plan shall be submitted for review and approval to the evaluation project manager designated by the CPUC-ED prior to commencing field data collection.
6	Conduct pre- and/or post-installation monitoring as indicated by M&V plan. Data collection must be conducted in accordance with the site-specific M&V plan. Changes to the M&V plan resulting from unanticipated field conditions shall be documented and submitted to the evaluation project manager designated by the CPUC-ED.
7	Conduct data analysis and estimate site-specific savings. Conduct analysis of field data and estimate site savings in accordance with site-specific M&V plan. Energy savings estimates for weather-dependent measures shall be normalized to long-term average weather conditions as directed by the Impact Evaluation Protocol.
8	Prepare site-specific M&V report. Prepare a site-specific M&V report for each site used in the analysis that includes the site-specific M&V plan, data collection, data analysis, calculation of measured engineering parameters and overall savings estimates. Calculate the uncertainties associated with energy savings estimates and measurement-derived engineering parameters. The site-specific uncertainty analysis shall include an estimate of the sampling error associated with individual measure sampling within the site, measurement error associated with field data collection and uncertainties associated with any non-measured (deemed) parameters. Potential sources of bias associated with the measurements and engineering analysis shall be identified and steps to minimize the bias shall be reported in accordance with the Sampling and Uncertainty Protocol.
9	Prepare draft overall M&V report. A draft overall M&V project report shall be submitted to the CPUC-ED that meets all the requirements of the Reporting Protocol, demonstrates compliance with the overall M&V plan developed in step 2 and summarizes the results from each site. Site-specific M&V reports shall be included as an Appendix. Raw field data and data analysis results shall be supplied electronically in accordance with the Reporting Protocol.
10	Prepare final overall M&V report. Prepare final overall M&V report in accordance with review comments provided by the Joint Staff.
11	Submit final M&V report. Submit final M&V report and associated datasets to the CPUC-ED.
12	Post final M&V report on the CALMAC Web site. Once accepted by the CPUC-ED, develop abstracts and post them and final M&V report on the CALMAC Web site following the CALMAC posting instructions.

Emerging Technology

Summary of Protocol-Driven Emerging Technology Evaluation Activities	
1	Joint staff selects an evaluation contractor to implement the Emerging Technology Program evaluation.
2	The ETP managers, in collaboration with the evaluation contractor and the CPUC-ED, develop logic models and program theories to inform the evaluation plan.
3	The contractor works with the CPUC-ED on the development of the draft evaluation plan (with possible input from the program implementer) consistent with the ETP Protocol. As necessary, the plan must comply with the other Protocols (Impact Evaluation Protocol, Process Evaluation Protocol, Market Effects Protocols, the Sampling and Uncertainty Protocol and the Reporting Protocol) in the development of the evaluation plan and in the implementation and reporting efforts.
4	The CPUC-ED works with the evaluation contractor to finalize and approve an evaluation plan from which the contractor can begin the evaluation effort.
5	The contractor carries out all eight of the required Protocol requirements in order to measures key short, intermediate, and long–range performance indicators identified in the logic model.
6	The contractor reports the results of the final evaluation to the CPUC-ED and Joint Staff consistent with the provisions in the Reporting Protocol.
7	Once the report is accepted by the CPUC-ED, the contactor develops abstracts and posts the report on CALMAC web site following the CALMAC posting instructions.

Codes and Standards

Summary of Protocol-Driven Codes and Standards Evaluation Activities	
1	Joint staff selects an evaluation contractor to implement the Codes and Standards Program evaluation.
2	The evaluation contractor reviews the program change theories and the program logic models, identifies the technologies or behaviors that can be evaluated via the Protocol, constructs a draft evaluation plan and submits the plan for approval to the CPUC-ED. The contractor works with the CPUC-ED on the development of the draft evaluation plan and rigor levels. The plan must use the Impact Evaluation Protocol, the Sampling and Uncertainty Protocol and the Reporting Protocol in the development of the evaluation plan and in the implementation and reporting efforts.
3	The CPUC-ED works with the evaluation contractor to finalize and approve an evaluation plan from which the contractor can begin the evaluation effort.
4	The contractor conducts an assessment of the gross market-level energy impacts for each code and standard covered technology or behavior being evaluated consistent with the rigor level assignments.
5	The contractor determines the influence of the program on the adoption of each code and standard covered in the study and allocates adoption attribution. The assessment uses an interview approach for this assessment. This assessment is accomplished as early in the code change cycle as possible but preferably in the technology selection and demonstration phase of the cycle.
6	The contractor estimates naturally occurring code and standard covered technology or behavior adoption rates based on literature reviews and interviews with experts.
7	The contractor adjusts the gross market level energy savings estimates to account for the net adjustment factors for naturally occurring technology adoption, naturally occurring code change, and non-compliance. This approach nets out the influence of non-program-induced impacts from the gross market-level impacts for each technology.
8	The contractor estimates the timeline associated with adoption of a code and standard without the program, using a Delphi approach with an expert panel.
9	The program administrators remove savings estimates from their programs for code-covered measures.
10	The evaluation contractor assesses the construction and sales efforts for each utility company service territory and allocates savings by IOU based on the construction and sales estimates.
11	The contractor reports the results of the evaluation to the CPUC-ED and Joint Staff consistent with the provisions in the Reporting Protocol.
12	Once the report is accepted by the CPUC-ED, the contactor develops abstracts and posts the report on the CALMAC web site following the CALMAC posting instructions.

	posts the report on the CALMAC web site following the CALMAC posting instructions.
13	As needed, the CPUC-ED or the Joint Staff can request the evaluation contractor to update and report the actual energy savings over time consistent with the Protocol. Updates can be conducted with a different evaluation contractor than those doing the original assessment.

Effective Useful Life

Required Protocols for Measure Retention Study	
Rigor Level	**Retention Evaluation Allowable Methods**
Basic	1. In-place and operable status assessment based upon on-site inspections. Sampling must meet the Basic Rigor Level requirements discussed in this Protocol and must meet the requirements of the Sampling and Uncertainty Protocol. (The sampling requirements of this Protocol may need to meet the sampling requirements for the subsequent EUL study. See below specification.) 2. Non-site methods (such as telephone surveys/interviews, analysis of consumption data, or use of other data, e.g. from EMS systems) may be proposed but must be explicitly approved by Joint Staff through the evaluation planning process. Sampling must meet the Basic Rigor Level requirements discussed in this Protocol and must meet the requirements of the Sampling and Uncertainty Protocol. (The sampling requirements of this Protocol may need to meet the sampling requirements for the subsequent EUL study. See below specification.)
Enhanced	1. In-place and operable status assessment based upon on-site inspections. Sampling must meet the Enhanced Rigor Level requirements discussed in this Protocol and must meet the requirements of the Sampling and Uncertainty Protocol. (The sampling requirements of this Protocol may need to meet the sampling requirement for the subsequent EUL study. See below specification.)

Required Protocols for Degradation Study	
Rigor Level	**Allowable Methods for Degradation Studies**
Basic	1. Literature review required for technical degradation studies across a range of engineering-based literature, to include but not limited to manufacturer's studies, ASHRAE studies, and laboratory studies. Review of technology assessments. Assessments using simple engineering models for technology components and which examine key input variables and uncertainty factors affecting technical degradation. 2. Telephone surveys/interviews with a research design that meets accepted social science behavioral research expectations for behavioral degradation.
Enhanced	1. For technical degradation: field measurement testing. 2. For behavioral degradation: field observations and measurement.

Required Protocols for EUL Analysis Studies	
Rigor Level	**Allowable Methods for EUL Analysis Studies**
Basic	1. Classic survival analysis (defined below) or other analysis methods that specifically control for right-censored data (those cases of failure that might take place some time after data are collected) must be attempted. For methods not accounting for right-censored data, the functional form of the model used to estimate EUL ("model functional form") must be justified and theoretically supported. Sampling must meet the Basic Rigor Level requirements discussed in this Protocol and must meet the requirements of the Sampling and Uncertainty Protocol. Sample size requirements will be determined through the use of power analysis, results from prior studies on similar programs, and professional judgment. Power analysis used to determine the required sample size must be calculated by setting power to at least at 0.7 to determine the sample size required at a 90% confidence level (alpha set at 0.10). Where other analyses or combined functional forms are used, power analysis should be set at these parameters to determine required sample sizes for regression-based approaches and a 90% confidence level with 30% precision is to be used for non-regression components.
Enhanced	1. Classic survival analysis (defined below) or other analysis methods that specifically control for right-censored data (those cases of failure that might take place some time after data are collected) must be attempted. The functional form of the model used to estimate EUL ("model functional form") must be justified and theoretically supported. Sampling must meet the Enhanced Rigor Level requirements discussed in this Protocol and must meet the requirements of the Sampling and Uncertainty Protocol. Sample size requirements will be determined through the use of power analysis, results from prior studies on similar programs, and professional judgment. Power analysis used will set power to at least to 0.8 to determine the sample size required at a 90% confidence level (alpha set at 0.10). Where other analyses or combined functional forms are used, power analysis should be set at these parameters to determine required sample sizes for regression-based approaches and a 90% confidence level with 10% precision is to be used

	for non-regression components.

Summary of Protocol-Driven Impact Evaluation Activities	
1	Joint Staff will review retention, EUL, and degradation planning information, perhaps through an initial study of (1) prior retention, EUL, and degradation studies and methods, (2) required retention, EUL, and degradation sample sizes, and (3) assessment of data collection methods for the prioritized measure and delivery strategy/application needs. Along with any risk analysis information, Joint Staff will identify which measures by delivery strategy/application will receive which type of retention, EUL, and degradation evaluation, when, and at what rigor level. Joint Staff will determine any special needs on a case-by-case basis that will be required for particular retention, EUL, and degradation evaluations. Joint Staff will develop preliminary RFPs for groups of studies based upon timing of the needed data collection or analysis, similar sectors or issues to be addressed, and requiring similar skill sets. CPUC-ED will issue RFPs for retention, EUL, and degradation evaluations, select evaluation contractors, and establish scope(s) of work.
2	Evaluators will develop a research design and sampling plan to meet Protocol requirements as designated by the Joint Staff rigor level assignments. This includes meeting requirements from the Sampling and Uncertainty Protocol, as are applicable given Effective Useful Life Evaluation Protocol requirements. Research design and sampling must be designed to meet any of the Joint Staff requirements for additional analyses to include but not limited to areas designated of specific concern by the Joint Staff. Evaluators will develop and submit an Evaluation Plan to Joint Staff, and the plan will be revised as necessary to have an approved Evaluation Plan that meets the Effective Useful Life Evaluation Protocol.
3	All retention, EUL, and degradation study evaluation teams (including panel data collection teams) will make sure their teams are appropriately staffed, in order to meet the skills required for the research design, sampling, and selected retention, EUL, and degradation evaluation method, uncertainty analysis, and reporting being planned and conducted.
4	All retention, EUL, and degradation study evaluations will be planned, conducted, and analyzed to minimize potential bias in the estimates (showing the methods for doing this), and evaluators will report all analyses of potential bias issues as described in the Sampling and Uncertainty Protocol.
5	All retention, EUL, and degradation evaluations will be conducted according to the Evaluation Plan and appropriate Protocols.
6	Evaluators will develop the draft evaluation report in accordance to guidance provided by the Joint Staff and reporting requirements in this Protocol.
7	Final evaluation report will be developed in accordance to guidance provided by the Joint Staff, and then submitted to Joint Staff.
8	Once accepted by Joint Staff, abstracts will be developed, and a report will be posted on the CALMAC web site following the CALMAC posting instructions.

Summary of Protocol-Driven Market Effects Evaluation Activities

Required Protocols for Market Effects Evaluation Scoping Studies	
Level of Rigor	**Scoping Study Requirements**
Basic	Define the market by its location, the utilities involved, the equipment, behaviors, sector and the program years of interest. Develop market theory. Identify available secondary data and potential sources for primary data. Outline data collection and analysis approaches
Enhanced	Define the market by its location, the utilities involved, the equipment, behaviors, sector and the program years of interest. Develop market theory and logic model. Detail indicators. Identify available secondary data and primary data that can be used to track changes in indicators. Outline data collection approach. Recommend hypotheses to test in the market effects study. Recommend the analysis approach most likely to be effective.

Required Protocol for Market Theory and Logic Models	
Level of Rigor	**Market Theory and Logic Model Requirements**
Basic	Identification of assumptions about anticipated changes in the market and associated research questions. Market theory should include market operations and conditions, external influences, and assumptions about changes in the market (which could include market operational theory, market structure and function studies, and product and communication flows). Develop program theory and logic models across programs in that market. Analyze across both of these to examine program interventions, external influences and associated research questions. Theories and logic models should be generated through interviews with program staff and a sample of market actors.
Enhanced	Articulate market theory and, if reasonable, develop graphical model of market theory. Market theory should include market operations and conditions, and changes occurring in the market (could include market operational theory, market structure and function studies, and product and communication flows). Develop multiple program theory and logic models for those programs intervening in the market. Integrate the market theory and program theory/logic models to examine external and programmatic influences, assumptions about changes in the market and associated research questions. Theories and logic models should be generated through interviews or workshops with program staff from each of the programs and a sample of a wide variety of market actors. Use a literature review and other studies of these markets and iteration with program staff to ensure thoroughness in measuring the critical parameters for both market development from external influences and market effects.

Required Protocol for Market Effects Evaluation Indicator Studies	
Level of Rigor	**Indicator Study Requirements**
Basic	Select appropriate market actor group for each indicator, survey representative samples of market actors able to report on each indicator from market experience. A baseline study must be conducted as early as possible. On-going tracking provides the basis for comparisons.
Enhanced	Select appropriate market actor group for each indicator. Conduct longitudinal study of representative samples of market actors able to report on each indicator from market experience. Samples weighted to represent known parameters in the population of interest. A baseline study must be conducted as early as possible, on-going tracking provides the basis for comparisons.

Required Protocol for Preponderance of Evidence Approach to Causal Attribution Estimation	
Level of Rigor	**Preponderance of Evidence Approach Requirements**
Basic	A representative sample of market actors surveyed or interviewed to provide self-reports on perceived changes in the market, attribution and the sustainability of those changes.
Enhanced	Quasi-experimental or experimental design with comparison groups using a representative sample of market actors surveyed or interviewed to provide self-reports on perceived changes in the market, attribution and the sustainability of those changes.

Summary of Protocol-Driven Market Effects Evaluation Activities	
1	Joint staff identifies the markets or market sectors (and the associated set of programs) that will receive a market effects evaluation and identifies the potential approach and rigor level for the scoping study.
2	Joint staff identifies market- or market sector-specific study needs that will be assessed (including program-specific or program group specific study needs) from the evaluation. CPUC-ED issues request for proposals for market effects scoping study, selects the scoping study contractor and establishes a scope(s) of work.
3	Evaluation contractor develops scoping study. A scoping study will more finely define the market boundaries for the study, including its location, the utilities involved, the equipment or behaviors to be assessed and the program-influenced years of interest. The scoping study will develop a market theory and a logic model; identify the market change indicators to track; and the available primary and secondary data sources. The study will also identify the hypotheses to test and the data collection approach, and provide a recommended analysis approach and model specification (if appropriate).
4	A market change theory and logic model (MCT/LM) should be developed to identify assumed direction of effects and indicators for measuring effects. The market theory should include market operations and conditions, and changes occurring in the market (could include a market operations theory, market structure and function scenarios, and product and communication flows) The theory and logic model should be generated through interviews or workshops with program staff from each of the programs that are expected to influence the market being

	assessed and a sample of a wide variety of market actors and should incorporate a literature review.
5	Joint staff reviews the scoping study and determines how to proceed with the Market Effects Evaluation. CPUC-ED issues request for proposals for evaluation contractors, selects the contractor, establishes a final scope(s) of work and negotiates the contract.
6	All market effects evaluation teams must be staffed to meet the skills required for the research design, sampling, appropriate and selected evaluation method, uncertainty analysis and reporting requirements.
7	A research design and sampling plan should be developed to meet Protocol requirements at the market level to meet the Joint Staff assigned study rigor level. This includes meeting requirements from the Sampling and Uncertainty Protocol and the Reporting Protocol, as applicable. The evaluation contractor will develop an Evaluation Plan, submit it to the CPUC-ED and revise as necessary.
8	Indicators studies conducted as part of the Market Effects Evaluation should be based on the results of the scoping study, address the appropriate market actor group(s) for each indicator.
9	All Market Effects Evaluations must meet the requirements of the Sampling and Uncertainty Protocol. The 90/10 level of precision is a minimum precision target for the most important data collection efforts on its most important variables. Which data collection efforts and variables are considered to be the most important will be determined in close collaboration with the CPUC-ED
10	The gross market effects and the estimate of energy savings associated with the market effects should be estimated. Estimation of gross market effects can be as simple as comparing indicators between time one and time two and then multiplying the energy value derived in an M&V supported impact assessment or from DEER, or using a CPUC-ED-approved net energy effects model.
11	Attribution or causality should be addressed to estimate net effects using either a preponderance of evidence approach or a net effects modeling approach. c. For a preponderance of evidence approach a determination of attribution should use quasi-experimental or experimental design with comparison groups using a representative sample of market actors. This may include interviews to provide self-reports on perceived changes in the market, attribution and the sustainability of those changes as well as direct observation or other data to support changes resulting from the program. d. For a net effects modeling approach to estimate causality, the model specifications must reflect the complexity of the market. It is likely that such an approach will require multiple equations to model the various activities that occur in a market and the various points of intervention that energy efficiency programs exert on a market.
12	Sustainability should be addressed using a preponderance of evidence approach.
13	Develop draft evaluation report to include meeting all requirements in the Reporting Protocol and incorporating the program's performance metrics.
14	Develop final evaluation report in accordance to guidance provided by Joint Staff.

15	Submit final evaluation report to the CPUC-ED.
16	Once the report is accepted by the CPUC-ED, develop abstracts and post them and the report on CALMAC Web site following the CALMAC posting instructions

Sampling and Uncertainty

Required Protocols for Gross Impacts	
Rigor Level	**Gross Impact Options**
Basic	**Simplified Engineering Models**: The relative precision is 90/30[151]. The sampling unit is the premise. The sample size selected must be justified in the evaluation plan and approved as part of the evaluation planning process.
	Normalized Annual Consumption (NAC) Models: There are no targets for relative precision. This is due to the fact that NAC models are typically estimated for all participants with an adequate amount of pre- and post-billing data. Thus, there is no sampling error. However, if sampling is conducted, either a power analysis[152] or justification based upon prior evaluations of similar programs must be used to determine sample sizes. The sample size selected must be justified in the evaluation plan and approved as part of the evaluation planning process.
Enhanced	**Regression**: There are no relative precision targets for regression models that estimate gross energy or demand impacts. Evaluators are expected to conduct, at a minimum, a statistical power analysis as a way of initially estimating the required sample size.[153] Other information can be taken into account such as professional judgment and prior evaluations of similar programs. The sample size selected must be justified in the evaluation plan and approved as part of the evaluation planning process.
	Engineering Models: The target relative precision for gross energy and demand impacts is 90/10. The sampling unit is the premise. The sample size selected must be justified in the evaluation plan and approved as part of the evaluation planning process.

[151] Also of interest, in addition to the relative precision, are the actual kWh, kW, and therm bounds of the interval.
[152] Statistical power is the probability that statistical significance will be attained, given that there really is a treatment effect. Power analysis is a statistical technique that can be used (among other things) to determine sample size requirements to ensure statistical significance can be found. Power analysis is only being required in the Protocol for determining required sample sizes. There are several software packages and calculation Web sites that conduct the power analysis calculation. One of many possible references includes: Cohen, Jacob (1989) *Statistical Power Analysis for the Behavioral Sciences*, Lawrence Erlbaum Associates, Inc.
[153] Ibid.

Required Protocols for Net Impacts	
Rigor Level	**Net Impacts Options**
Basic	For the self-report approach (Option Basic.1), given the greater issues with construct validity and variety of layered measurements involved in estimating participant NTGRs, no relative precision target has been established.[154] To ensure consistency and comparability a minimum sample size of 300 sites (or decision-makers in cases where decision-makers cover multiple sites) or a census[155], whichever is smaller, is required.
Standard	If the method used for estimating net energy and demand impacts is regression-based, there are no relative precision targets. If the method used for estimating NTGRs is regression-based (discrete choice), there are no relative precision targets. In either case, evaluators are expected to conduct, at a minimum, a statistical power analysis as a way of initially estimating the required sample size.[156] Other information can be taken into account such as professional judgment and prior evaluations of similar programs. For the self-report approach (Option Standard.2), there are no precision targets since the estimated NTGR will typically be estimated using information collected from multiple decision-makers involving a mix of quantitative and qualitative information around which a standard error cannot be constructed. Thus to ensure consistency and comparability, for such studies, a minimum sample size of 300 sites (or decision-makers in cases where decision-makers cover multiple sites) or a census, whichever is smaller, is required.
Enhanced	The requirements described for Enhanced apply depending on the methods chosen.

[154] This is considered the best feasible approach at the time of the creation of this Protocol. Like the other approaches to estimating the net-to-gross ratio (NTGR), there is no precision target when using the self-report method. However, unlike the estimation of the required sample sizes when using the regression and discrete choice approaches, the self-report approach poses a unique set of challenges to estimating required sample sizes. These challenges stem from the fact that the self-report methods for estimating free-ridership involve greater issues with construct validity, and often include a variety of layered measurements involving the collection of both qualitative and quantitative data from various actors involved in the decision to install the efficient equipment. Such a situation makes it difficult to arrive at a prior estimate of the expected variance needed to estimate the sample size.
Alternative proposals and the support and justifications that address all of the issues discussed here on the aggregation of variance for the proposed self-report method may be submitted to Joint Staff as an additional option (but not instead of the Protocol requirements) in impact evaluation RFPs and in Evaluation Plans. Joint Staff may elect to approve an Evaluation Plan with a well-justified alternative.

[155] A census is rarely achieved. Rather, one *attempts* to conduct a census, recognizing that there will nearly always be some sites, participants or non-participants who drop out for a variety of reasons such as refusals or insufficient data.

[156] Statistical power is the probability that statistical significance will be attained, given that there really is a treatment effect. Power analysis is a statistical technique that can be used (among other things) to determine sample size requirements to ensure statistical significance can be found. Power analysis is only being required in the Protocol for determining required sample sizes. There are several software packages and calculation Web sites that conduct the power analysis calculation.

Required Protocols for Measure-level Measurement and Verification	
Rigor Level	**M&V Options**
Basic	**Simplified Engineering Models**: The target relative precision for gross energy and demand impacts is 90/30. The sample unit may be the individual measure, a particular circuit or point of control as designated by the M&V plan.
Enhanced	**Direct Measurement and Energy Simulation Models**: The target relative precision for gross energy and demand impacts is 90/10. The sample unit may be the individual measure, a particular circuit or point of control as designated by the M&V plan.

Required Protocols for Sampling of Measures Within a Site
The target relative precision is 90/20 for each measure selected for investigation. The sampling unit (measure, circuit, control point) shall be designated by the M&V plan. The initial assumption regarding the coefficient of variation for determining sample size is 0.5.

Required Protocols for Verification	
Rigor Level	**Verification Options**
Basic	The target relative precision is 90/10. The key parameter upon which the variability for the sample size calculation is based is binary (i.e., Is it meeting the basic verification criteria specified in the M&V Protocol?).
Enhanced	The target relative precision is 90/10. The key parameter upon which the variability for the sample size calculation is based is binary (i.e., Is it meeting the enhanced verification criteria specified in the M&V Protocol?).

Attachment 82.1

REFER TO LIVE SPREADSHEET

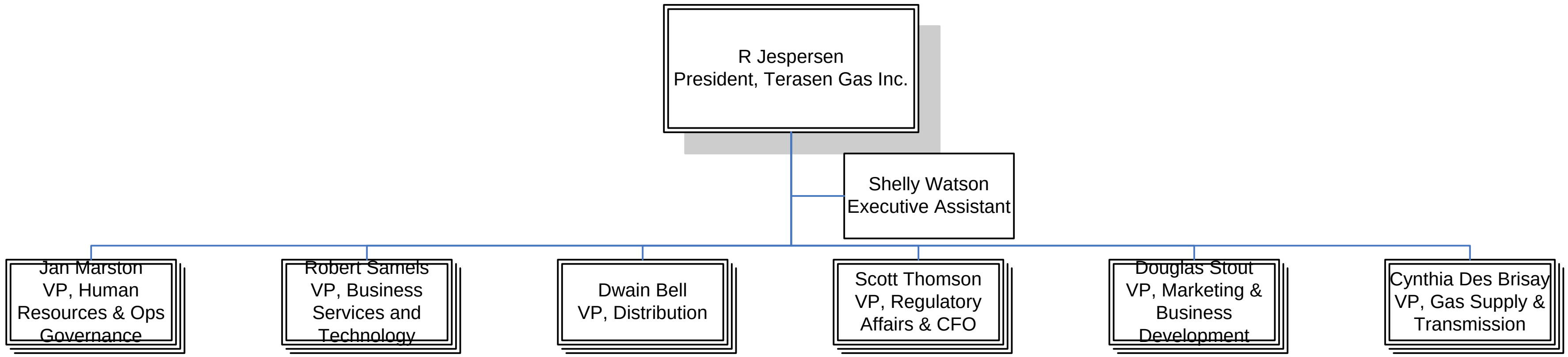
(accessible by opening the Attachments Tab in Adobe)

Attachment 101.1

Legend

2009 Vacancies

TERASEN GAS INC.



TERASEN GAS INC.

BUSINESS & IT SERVICES

2009

Legend

- 2009 Vacancies

- VP, Business Services and Technology
  - Executive Assistant
  - Director, Operations Support
  - Director, Operations Engineering
  - Manager, Facilities Planning & Maintenan
  - Procurement Manager
  - Chief Information Officer
  - Project Director
  - I&CT Contract & Finance Co-ordinator
  - Project Director
  - Manager, Project Management Office

TERASEN GAS INC.

BUSINESS & IT SERVICES

Legend

2009 Vacancies

Director, Operations Support

Measurement Services Manager

- Measurement Services Business Analyst
- Technologist 4 - Quality Assurance WL
- Techt 3 - Measurement Technologies
- Measurement Business Analyst
- Operations Support Assistant
- Measurement Technologies Ass't
- Operations Support Assistant
- Operations Support Assistant
- Techt 3 - Measurement Technologies
- Technologist 3
- Technologist 3

Meter Shop Manager - Penticton

- Measurement Mechanic 2 - Interior
- Measurement Technician - Int
- Measurement Technician
- Measurement Mechanic 1 - Interior
- Measurement Mechanic 2
- Measurement Mechanic 1 - Interior
- Measurement Mechanic 1
- Measurement Mechanic 1 - Interior
- Measurement Mechanic 2
- Measurement Mechanic
- Measurement Shop Ldr- Interior
- Measurement Shop Ldr- Interior
- Measurement Shop Ldr- Interior
- Measurement Mechanic
- Measurement Mechanic 2
- Measurement Mechanic 1 - Interior
- Measurement Mechanic 1 - Interior
- Painter
- Measurement Technician

Data Acquisition and Logistics Manager

- Tech't 3 Instrumentation & Communication
- Tech't 3 Instrumentation & Communication
- Material Truck Driver (Coast)
- Materials Truck and Trailer Operator
- Measurement Analyst 2
- Measurement Analyst 2
- Material Truck Driver (Coast)
- Tech't 3 Instrumentation & Communication
- Techt 3 - Measurement Technologies
- Measurement Mechanic 1 - Coastal
- Material Handler (Coastal)
- Material Handler (Coastal)
- Inventory Analyst 2
- Material Handler (Coastal)
- Technologist 4 - Measurement
- Material Handler (Coastal)
- Techt 3 - Instrumentation
- Tech't 3 Instrumentation & Communication
- Measurement Analyst 2
- Materials Shipper/Receiver
- Recycling Mechanic
- Yard Foreman
- Stores Leader (Coastal)
- Tech't 3 Instrumentation & Communication
- Techt 3 - Measurement Technologies
- Material Handler (Coastal)
- Material Truck Driver (Coast)
- Materials Shipper/Receiver
- Material Handler (Coastal)
- Communication Specialist
- Measurement Analyst 2
- Materials Truck and Trailer Operator
- Material Truck Driver (Coast)
- Material Handler
- Warehouse & Delivery Leader
- Instr & Data Acquisition Support Adminis
- Material Handler (Coastal)
- Instrumentation & Communications WL
- Inventory Analyst 2
- Tech't 3 Instrumentation & Communication
- Tech't 3 Instrumentation & Communication
- Material Handler (Coast)
- Measurement Analyst 2

Manufacturing Service Manager

- Prefab Mechanic
- Machinist
- System Operations Technician - Coastal
- Fitter Welder 1
- Operations Support Assistant
- Fitter Welder 1
- Fitter Welder 1
- Shop Mechanic 1 - Prefab
- Shop Assistant
- Fitter Welder 1
- Fitter Welder 1
- Shop Assistant
- Shop Mechanic 1 - Prefab
- Painter
- Shop Mechanic 1 - Prefab
- Shop Mechanic 2 - Machine
- Fitter Welder 1
- Shop Mechanic 1 - Prefab
- Shop Assistant
- Shop Mechanic 1 - Machine
- Fitter Welder 1
- Prefab Mechanic
- Welder
- Prefab Mechanic
- Shop Mechanic 1 - Prefab
- Shop Assistant
- Mechanical Foreman-Machine Shop
- Shop Mechanic 2 - Prefab
- Fitter Welder 1
- Fitter Welder 1
- Mechanical Foreman - Prefab
- Painter Bridging to Retirement
- Fitter/Welder 1
- Shop Mechanic 2 - Machine Shop
- Shop Mechanic 1 - (Weld Shop)
- Shop Assistant
- Shop Assistant
- Shop Mechanic 1 - Machine
- Fitter Welder 1
- Shop Mechanic 1 - Prefab
- Design Machinist
- Mechanical Foreman-Welding
- Shop Mechanic 1 - Machine
- Fitter Welder 1

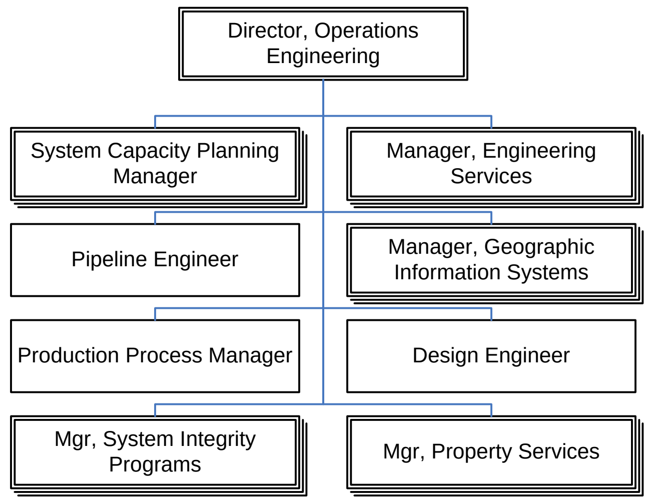
TERASEN GAS INC.

BUSINESS & IT SERVICES

2009

Legend

2009 Vacancies



TERASEN GAS INC.

BUSINESS & IT SERVICES

2009

Legend

2009 Vacancies

- System Capacity Planning Manager
  - Technologist 2 - Capacity Planning
  - Technologist 3 - Capacity Planning
  - Technologist 1 - Capacity Planning
  - Technologist 3 - Capacity Planning
  - Technologist 4 - Capacity Planning
  - System Planning Engineer
  - Technologist 2 - Capacity Planning
  - Technologist 3 - Capacity Planning

TERASEN GAS INC.

BUSINESS & IT SERVICES

2009

Legend

- 2009 Vacancies

- Manager, Engineering Services
  - Technologist 3 - Pipeline Design/Drafter
  - Process Engineer
  - Technologist 3 - Plant Design/ Drafter
  - Engineering Secretary
  - Techt 4 - Instrumentation Design
  - Techt 4 - Instrumentation Design
  - Technologist 3 - Pipeline Design/Drafter
  - Design Engineer
  - Project Engineer - Pipelines
  - Engineering Co-op Student
  - Engineering Co-op Student
  - Technologist 4 - Plant Design
  - Engineering Secretary
  - Project Engineer
  - Technician 3 - Laboratory
  - Engineering Secretary
  - Techt 4 - Electrical Design
  - Technologist 3 - Plant Design/ Drafter
  - Project Engineer
  - Techt 3 - Measurement Technologies
  - Project Engineer
  - Project Engineer
  - Technologist 4 - Plant Design

TERASEN GAS INC.

BUSINESS & IT SERVICES

2009

Legend

- 2009 Vacancies (shaded box)

Manager, Geographic Information Systems

- Engineering Drafter 2
- GIS Drafter 1
- Engineering Drafter 3
- QA/QC Technician
- AM/FM Data Conversion Clerk 2
- Engineering Drafter 2
- GIS Drafter 1
- GIS Drafter 3
- GIS Drafter Leader
- Drafter 1
- Co-op Student
- Tech 3-Geographic Info Systems
- GIS Drafter 1
- GIS Drafter 2
- GIS Drafter 2
- GIS Drafter 2
- Engineering Drafter 3
- GIS Drafter 1
- GIS Drafter 1
- GIS Drafter 1
- Engineering Clerk
- Engineering Drafter 3
- QA/QC Technician
- Engineering Drafter 2
- Engineering Administration Manager
- GIS Drafter 3
- Engineering Drafting Work Leader
- Drafter 1
- GIS Drafter 1
- Tech 3-Geographic Info Systems
- GIS Drafter 1
- Engineering Drafter 3
- Engineering Clerk
- Operations Support Representative 2
- GIS Drafter 3
- **Data Integrity Manager**
  - Operations Support Representative 2
  - Operations Support Representative 2
  - Operations Support Representative 2
  - Operations Support Representative 3
  - Operations Support Representative 2
  - Operations Support Representative 2
  - Operations Support Representative 2
  - Operations Support Representative 2
  - Operations Support Representative 2
  - Operations Support Representative 2
  - Operations Support Representative 2
  - Operations Support Representative 2
  - Operations Support Rep Work Leader
  - Operations Support Representative 2
  - Operations Support Representative 2
  - AM/FM Completions Work Leader
  - Operations Support Representative 2
  - Operations Support Representative 2
  - Operations Support Representative 2
  - Operations Support Representative 3
  - Operations Support Representative 3
  - Operations Support Representative 2
  - Operations Support Representative 2
  - Operations Support Representative 3
  - Operations Support Representative 2
  - Operations Support Representative 3
  - Operations Support Representative 2
  - Operations Support Representative 2
  - Operations Support Representative 2
  - Operations Support Representative 2

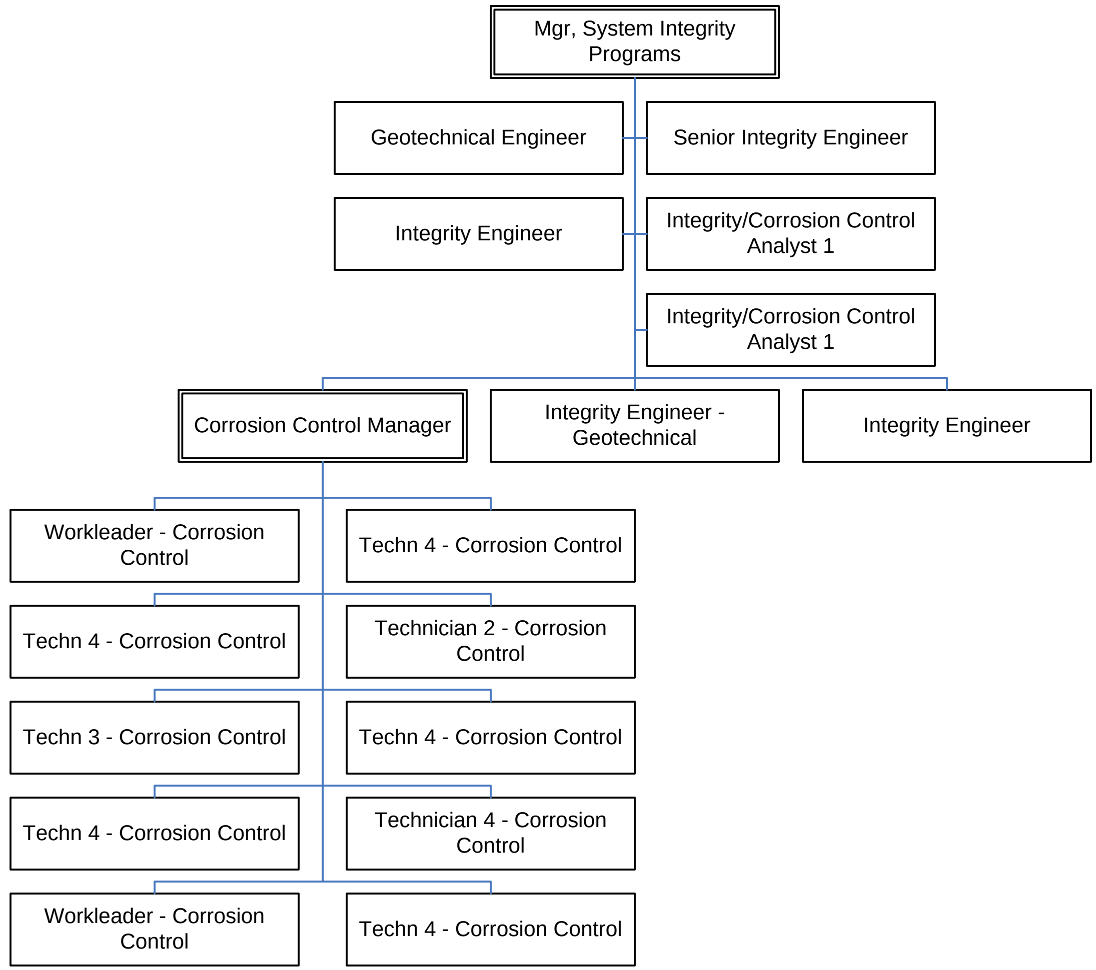
TERASEN GAS INC.

BUSINESS & IT SERVICES

2009

Legend

2009 Vacancies



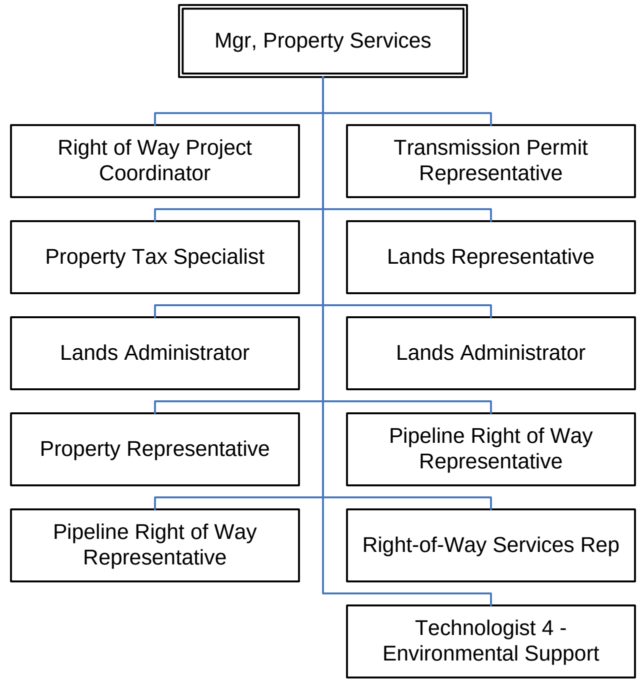
TERASEN GAS INC.

BUSINESS & IT SERVICES

2009

Legend

2009 Vacancies



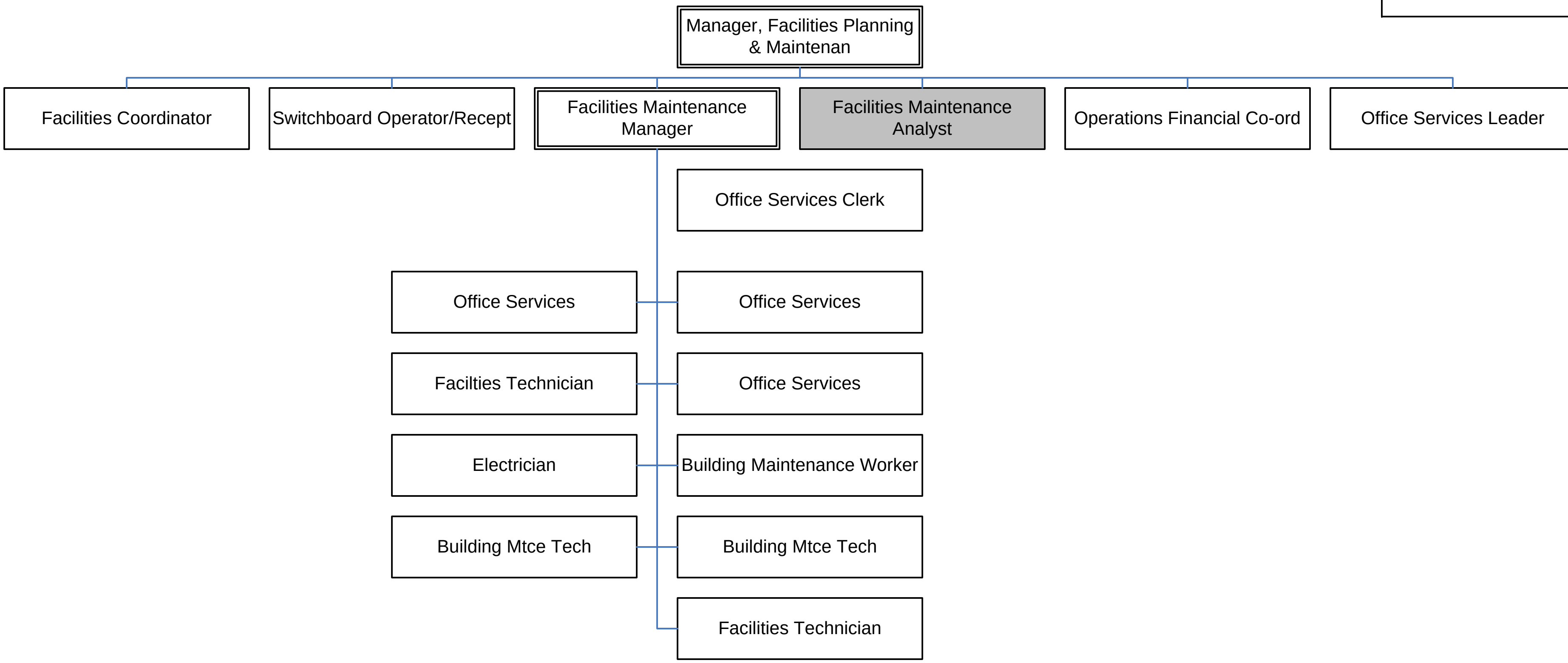
TERASEN GAS INC.

BUSINESS & IT SERVICES

2009

Legend

2009 Vacancies



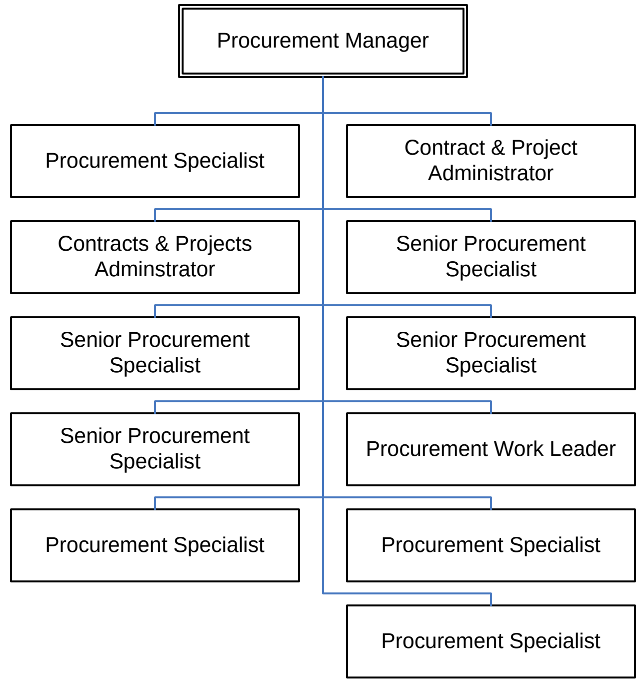
TERASEN GAS INC.

BUSINESS & IT SERVICES

2009

Legend

2009 Vacancies



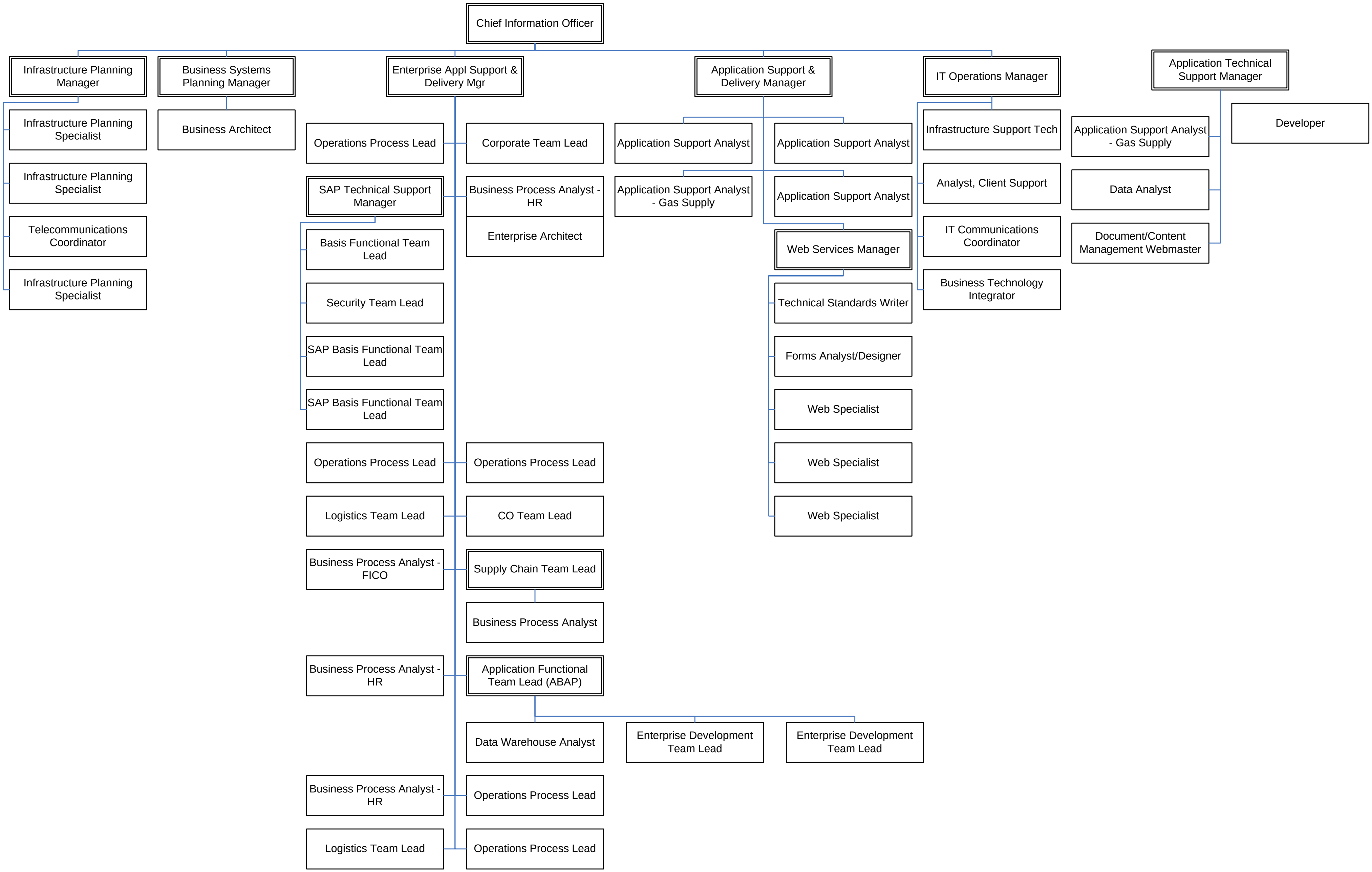
TERASEN GAS INC.

BUSINESS & IT SERVICES

2009

Legend

2009 Vacancies



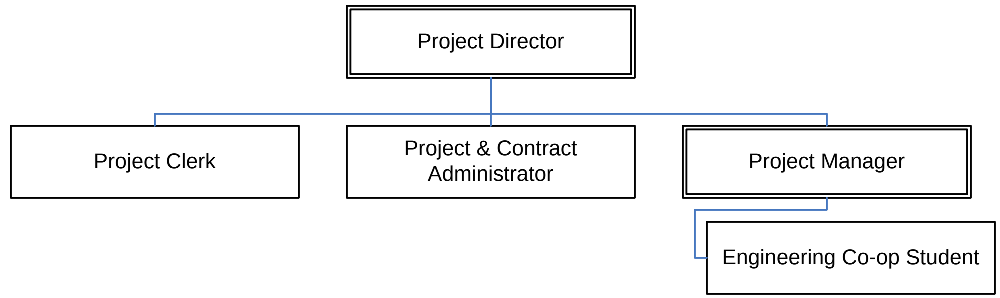
TERASEN GAS INC.

BUSINESS & IT SERVICES

2009

Legend

2009 Vacancies



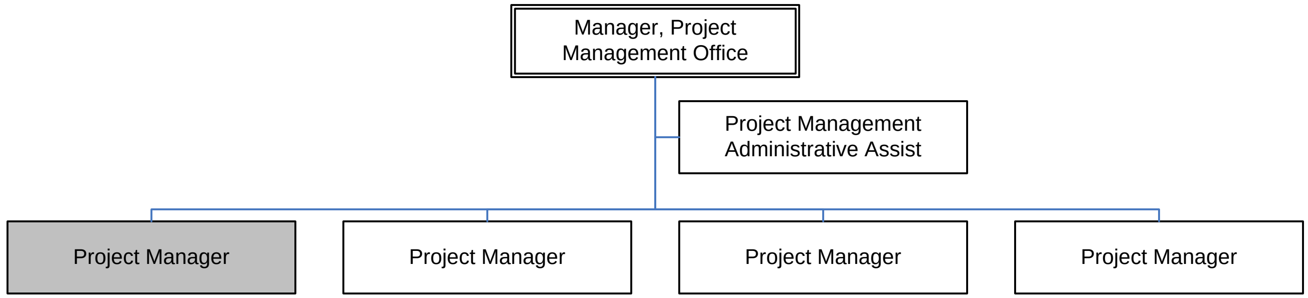
TERASEN GAS INC.

BUSINESS & IT SERVICES

2009

Legend

2009 Vacancies



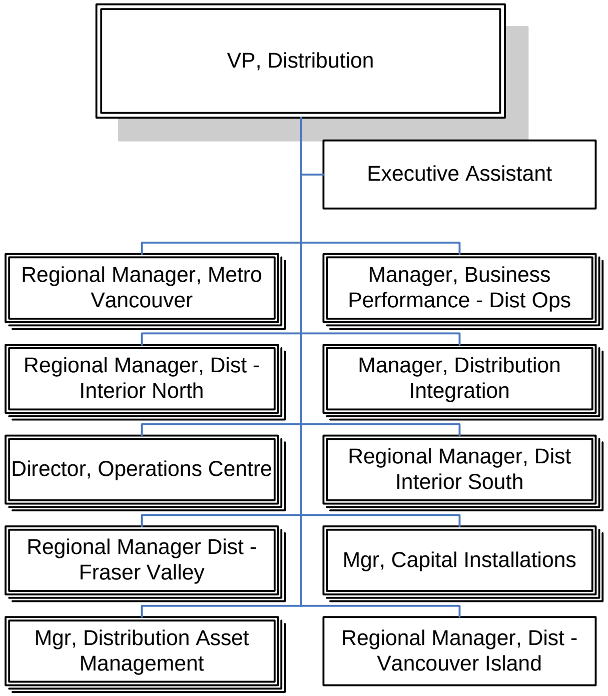
TERASEN GAS INC.

DISTRIBUTION

2009

Legend

2009 Vacancies



TERASEN GAS INC.

DISTRIBUTION

2009

Legend

- 2009 Vacancies

Regional Manager, Metro Vancouver

- **Distribution Manager**
  - Clean-up Truck Driver
  - Crew Leader
  - Clean-up Truck Driver
  - Crew Leader
  - Crew Leader
  - Crew Leader
  - Equip Operator/DM
  - Distribution Mechanic - Coast
  - Distribution Mechanic - Coast
  - Equip Operator/DM
- **Operations Manager**
  - Customer Service Technician 1
  - System Operations Technician - Coastal
  - System Operations Apprentice
  - Customer Service Technician 1
  - System Operations Technician - 18
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 2
  - Customer Service Technician 1
  - System Operations Technician - 18
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 2
  - System Operations Technician - Coastal
  - Customer Service Technician 2
- **Distribution Manager**
  - Distribution Apprentice
  - Distribution Apprentice
  - Distribution Apprentice
  - Crew Leader
  - Distribution Apprentice
  - Crew Leader
  - Distribution Apprentice
  - Distribution Mechanic - Coast
  - Distribution Apprentice
  - Distribution Mechanic - Coast
  - Distribution Apprentice
  - Crew Leader
  - Distribution Apprentice
  - Distribution Apprentice
  - Distribution Apprentice
  - Distribution Apprentice
  - Distribution Service Agent
  - Distribution Apprentice
- **Installation Manager**
- **Distribution Manager**
  - Crew Leader
  - Crew Leader
  - Distribution Mechanic
  - Distribution Mechanic
  - Distribution Mechanic
  - Distribution Mechanic
  - Distribution Mechanic
  - Crew Leader
  - Distribution Mechanic - Coast
  - Distribution Mechanic
  - Distribution Mechanic
  - Distribution Mechanic - Coast
  - Equip Operator/DM
- **Operations Manager - Vancouver**
  - Customer Service Technician 2
  - Customer Service Technician 1
  - Customer Service Technician 1
  - System Operations Technician - Coastal
  - Customer Service Technician 1
  - System Operations Technician - Coastal
  - Distribution Service Agent
  - Customer Service Technician 1
  - System Operations Technician - Coastal
  - Customer Service Technician 1
  - System Operations Technician - Coastal
  - System Operations Apprentice
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - System Operations Technician - 18
  - Customer Service Technician 1
  - Customer Service Technician 2
- **Operations Manager - Squ/Whi**
  - Customer Service Technician 1
  - Customer Service Technician 1

Legend

2009 Vacancies

TERASEN GAS INC.

DISTRIBUTION

2009

Manager, Business Performance - Dist Ops

Distribution Operations Analyst

TERASEN GAS INC.

DISTRIBUTION

2009

Legend

- 2009 Vacancies

- Regional Manager, Dist - Interior North
  - Installation Manager - Kamloops
    - Welder 1 (Crew Leader Arc)
    - Equip Operator/DM
    - Distribution Mechanic - Inter
    - Distribution Service Agent
    - Distribution Mechanic - Inter
    - Welder 1 (Crew Leader Arc)
    - Distribution Mechanic - Inter
  - Operations Manager - Kamloops
    - Customer Service Technician 1
    - System Operations Technician
    - Customer Service Technician 1
    - Customer Service Technician 2
    - System Operations Technician
    - Customer Service Technician 1
    - Customer Service Technician 1
    - Customer Service Technician 1
    - Operations Technician
    - System Operations Technician
    - Customer Service Technician 1
    - Customer Service Technician 2
    - Customer Service Technician 1
  - Install/Operate Manager - Revelstoke
    - Customer Service Technician 1
    - Distribution Service Agent
    - Customer Service Technician 1
    - Customer Service Technician 1
    - Customer Service Technician 2
  - Distribution Manager
    - Customer Service Technician 1
    - Measurement & Controls Technician 1
    - Customer Service Technician 1
    - Measurement & Controls Technician 1
    - Customer Service Technician 1
    - Customer Service Technician 1
    - Customer Service Technician 1
    - Customer Service Technician 1
    - Operations Technician
    - Customer Service Technician 2
    - Customer Service Technician 1
    - System Operations Technician - 18
    - Customer Service Technician 1
    - Customer Service Technician 1
    - System Operations Technician
  - Installation Manager - Prince George
    - Distribution Apprentice
    - Equip Operator/DM
    - Distribution Mechanic - Inter
    - Welder 1 (Crew Leader Arc)
    - Distribution Apprentice
    - Labourer
    - Distribution Mechanic - Inter
    - Equip Operator/DM
    - Distribution Service Agent
    - Welder 1 (Crew Leader Arc)
  - Install/Operate Manager - Ft Nelson
    - Customer Service Technician 1
    - Customer Service Technician 2
    - Customer Service Technician 1
    - Customer Service Technician 1
  - Special Assignment Manager

The timing for filling these vacancies is subject to the training capacity of the organization to accept these new hires; likely early 2010 rather than late 2009.

In the meantime Distribution will continue to utilize contractors and overtime to fill the resource gap.

- Distribution Mechanics (15)
- Customer Service Technicians (3)
- Crew Leader (4)
- Paving Foreman (1)
- System Operations Technician (5)
- Equipment Operator/DM (1)

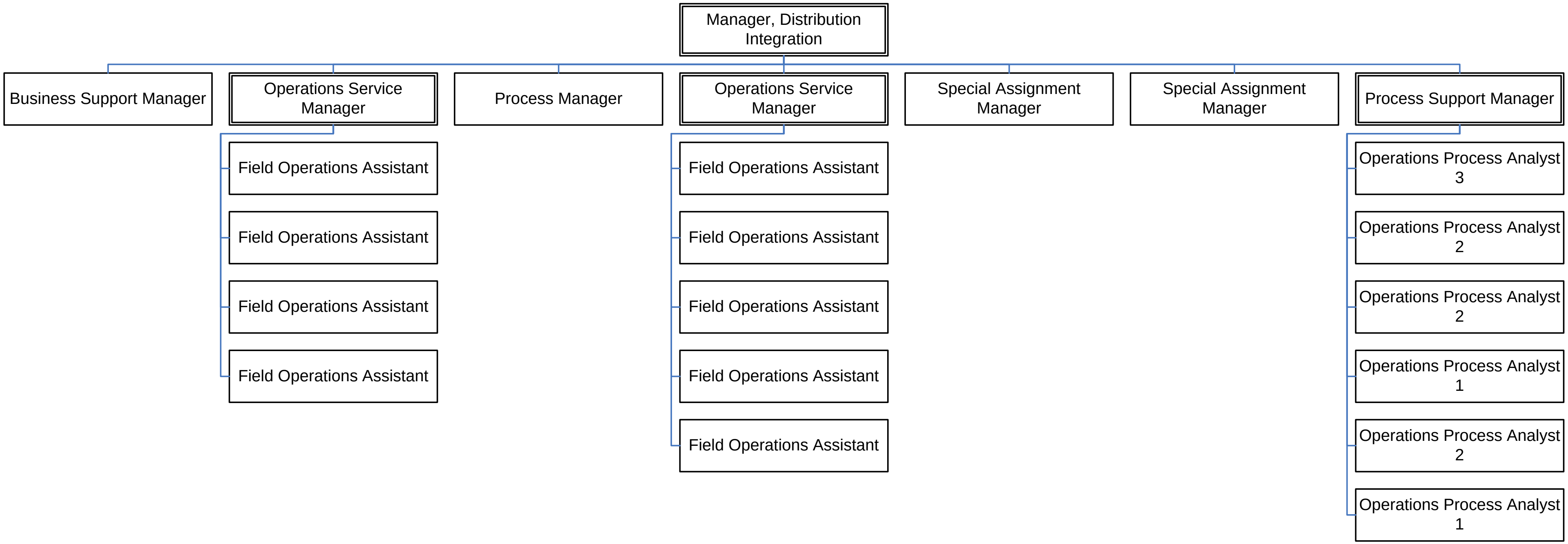
TERASEN GAS INC.

DISTRIBUTION

2009

Legend

2009 Vacancies



TERASEN GAS INC.

DISTRIBUTION

2009

Legend: 2009 Vacancies

- Director, Operations Centre
  - Installation Centre Manager - IC2
    - Planning & Design Technologist 2
    - Planning & Design Technologist 2
    - Planning & Design Technologist 2
    - Planning & Design Technologist 2
    - Planning & Design Technologist 2
    - Planning & Design Technologist 2
    - Planning & Design Technologist 2
    - Planning & Design Technologist 2
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    - Planning & Design Technologist 2
    - Planning & Design Technologist 2
    - Planning & Design Technologist 2
    - Planning & Design Technologist 2
    - Planning & Design Technologist 2
    - Planning & Design Technologist 2
    - Operations Support Representative 3
    - Techt 4 - Project Specialist
    - Planning & Design Technologist 2
  - Dispatch Manager
    - Operations Support Representative 3
    - Operations Support Representative 3
    - Dispatcher
    - Operations Support Representative 3
    - Operations Support Representative 3
    - Operations Support Representative 3
    - Operations Support Representative 3
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    - Operations Support Representative 3
    - Operations Support Representative 3
    - Dispatcher
    - Operations Support Representative 3
    - Operations Support Representative 3
    - Operations Support Representative 3
    - Dispatcher
    - Operations Support Representative 3
    - Dispatcher
  - Emergency Support Manager
    - Emergency & Operations Representative
    - Emergency & Operations Representative
    - Emergency & Operations Representative
    - Emergency & Operations Representative
    - Emergency & Operations Representative
    - Emergency & Operations Representative
    - Emergency & Operations Representative
    - Emergency & Operations Representative
  - Pre-Requisite Manager
    - T & D Surveyor 1
    - Operations Support Representative 2
    - Operations Support Representative 3
    - T & D Surveyor
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Representative 2
    - T & D Surveyor 1 (2009 Vacancies)
    - Operations Support Representative 2
    - T & D Surveyor 1
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Representative 3
    - Operations Support Representative 3
    - T & D Surveyor 2
    - Operations Support Rep Work leader
  - Planning & Design Work leader (M&E Relief)
    - Install Centre IC1
    - Install Centre IC1
    - Install Centre IC1
    - Install Centre IC1
    - Install Centre IC1
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  - Resource Planning Manager
    - Resource Management Co-ordinator
    - Operations Support Representative 1
    - Resource Management Co-ordinator
    - Resource Management Co-ordinator
    - Operations Support Representative 1
    - Resource Management Co-ordinator
    - Resource Management Co-ordinator
    - Resource Management Co-ordinator
    - Operations Support Representative 1
    - Resource Management Co-ordinator
  - Closing Manager
    - Operations Support Representative 3
    - Operations Support Representative 3
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    - Operations Support Representative 3
    - Operations Support Representative 1
    - Operations Support Representative 3
    - Operations Support Representative 3
    - Resource Management Co-ordinator
    - Operations Support Representative 3
    - Operations Support Representative 3

TERASEN GAS INC.

DISTRIBUTION

2009

Legend

- 2009 Vacancies

- Regional Manager, Dist Interior South
  - Install/Operate Manager - Vernon
    - Distribution Service Agent
    - Distribution Mechanic - Inter
    - System Operations Technician
    - Crew Leader
    - Customer Service Technician 1
    - Distribution Apprentice
    - Customer Service Technician 1
    - Customer Service Technician 1
    - Equip Operator/DM
    - Distribution Mechanic - Inter
    - Distribution Mechanic - Inter
    - Welder 1
    - System Operations Technician
  - Installation Manager - Kelowna
    - Distribution Apprentice
    - Distribution Mechanic - Inter
    - Crew Leader Arc (Welder 1)
    - Distribution Apprentice
    - Equip Operator/DM
    - Crew Leader Arc Welder 1
    - Equip Operator/DM
    - Crew Leader
    - Equip Operator/DM
  - Install/Operate Manager - Cranbrook
    - System Operations Technician
    - Distribution Apprentice
    - Crew Leader
    - Distribution Mechanic - Inter
    - Welder 1 (Crew Leader Arc)
    - Customer Service Technician 1
    - Customer Service Technician 1
    - Measurement & Controls Technician 1
    - Customer Service Technician 1
    - Distribution Service Agent
    - Customer Service Technician 1
    - Sr Sales & Service Technician
    - Distribution Mechanic - Inter
    - Customer Service Technician 1
  - Installation Manager - Trail
    - Equip Operator/DM
    - Distribution Mechanic - Inter
    - Customer Service Technician 1
    - Customer Service Technician 1
    - Equip Operator/DM
    - Customer Service Technician 1
    - System Operations Technician - 18
    - Sr Sales & Service Technician
    - Customer Service Technician 1
    - Welder 1
    - Customer Service Technician 1
    - System Operations Technician - 18
  - Distribution Manager
    - Distribution Service Agent
    - Customer Service Technician 1
    - Customer Service Technician 1
    - Customer Service Technician 1
    - System Operations Apprentice
    - Customer Service Technician 1
    - Customer Service Technician 1
    - Customer Service Technician 1
    - Customer Service Technician 2
  - Install/Operate Manager - Penticton
    - Welder 1
    - Customer Service Technician 1
    - Distribution Apprentice
    - Equip Operator/DM
    - Distribution Apprentice
    - Distribution Mechanic - Inter
    - Customer Service Technician 1
    - Welder 1
    - Customer Service Technician 1
    - Customer Service Technician 1
    - System Operations Technician
    - Customer Service Technician 2

TERASEN GAS INC.

DISTRIBUTION

2009

Legend

- 2009 Vacancies

Regional Manager Dist - Fraser Valley

- **Installation Manager - Langley**
  - Distribution Mechanic
  - Distribution Mechanic
  - Distribution Mechanic
  - Distribution Mechanic - Coast
  - Crew Leader
  - Distribution Apprentice
  - Distribution Mechanic
  - Distribution Mechanic
  - Distribution Mechanic
  - Field Operations Assistant
  - Distribution Mechanic
  - Distribution Mechanic
  - Crew Leader
  - Crew Leader
  - Distribution Apprentice
  - Distribution Mechanic - Coast
  - Distribution Mechanic - Coast
  - Distribution Mechanic
  - Distribution Mechanic - Coast
  - Field Operations Assistant
  - Distribution Mechanic
  - Distribution Mechanic
  - Distribution Apprentice
- **Distribution Manager**
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 2
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - System Operations Technician - Coastal
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - System Operations Technician - Coastal
  - Customer Service Technician 2
  - Customer Service Technician 1
  - System Operations Technician - 18
  - Customer Service Technician 1
  - Customer Service Technician 1
- **Operations Manager - Surrey**
  - System Operations Technician - Coastal
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - System Operations Apprentice
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - System Operations Technician - 18
  - Customer Service Technician 1
  - Customer Service Technician 1
  - System Operations Technician - 18
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - System Operations Technician - Coastal
  - Customer Service Technician 1
  - Customer Service Technician 1
- **Installation Manager - Coquitlam**
  - Distribution Mechanic - Coast
  - Crew Leader
  - Distribution Mechanic - Coast
  - Distribution Mechanic - Coast
  - Distribution Mechanic - Coast
  - Distribution Mechanic - Coast
  - Distribution Mechanic - Coast
  - Distribution Mechanic 2
  - Crew Leader
  - Distribution Mechanic - Coast
  - Distribution Mechanic - Coast
- **Distribution Manager**
  - Distribution Mechanic - Coast
  - Paving Foreman
  - Crew Leader
  - Crew Leader
  - Distribution Mechanic - Coast
  - Crew Leader
  - Equipment Operator 1 (Coastal)
  - Distribution Mechanic - Coast
  - Distribution Mechanic - Coast
- **Installation Manager - Surrey**
  - Crew Leader
  - Crew Leader
  - Crew Leader
  - Distribution Mechanic - Coast
  - Distribution Mechanic/ Excavator

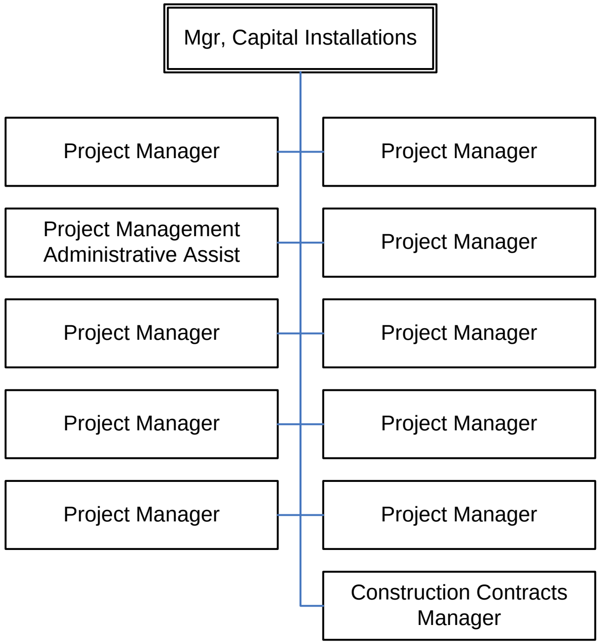
TERASEN GAS INC.

DISTRIBUTION

2009

Legend

2009 Vacancies



TERASEN GAS INC.

DISTRIBUTION

2009

Legend

- 2009 Vacancies

- Mgr, Distribution Asset Management
  - Dist Assets & Improvements Manager
    - Maintenance Analyst
  - Operations & Maintenance Manager
    - Engineering Co-op Student
    - Operations Support Representative 3
    - Maintenance Analyst
    - Maintenance Analyst
    - Maintenance Analyst
  - Asset Optimization Manager
  - Damage Prev & Emerg Serv Manager
    - Claims Adjuster 1
    - Damage Prevention Co-ordinator

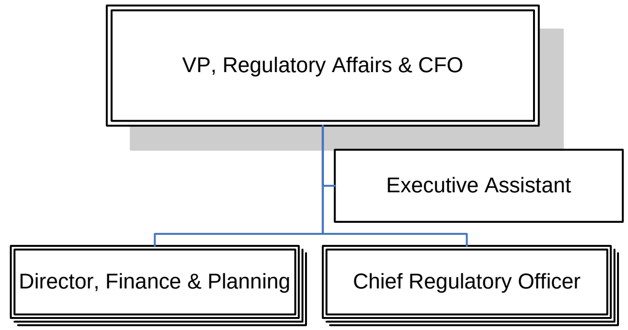
TERASEN GAS INC.

FINANCE & REGULATORY

2009

Legend

2009 Vacancies



TERASEN GAS INC.

FINANCE & REGULATORY

2009

Legend

2009 Vacancies

- Director, Finance & Planning
  - Manager, Financial Planning & Control
    - Operations Financial Planning Manager
      - CMO Manager
      - Management Reporting Manager
        - Operations Financial Co-ord
        - Operations Financial Analyst
        - Operations Financial Analyst
        - Operations Financial Co-ord
        - Operations Financial Analyst
        - Operations Financial Analyst
        - Operations Financial Co-ord
        - Operations Financial Analyst
    - Financial Planning Manager
      - Financial Accounting/ Credit Analyst
    - Financial Planning Manager
      - Senior Regulatory Work Leader
  - Mgr, Financial & Regulatory Reporting
    - Financial Reporting Manager
      - Financial Accounting Clerk 4
      - Financial Accounting Clerk 4
      - Financial Accounting Clerk 3
      - Financial Accounting Analyst
      - Financial Accounting Clerk 3
    - Financial Reporting Manager
      - Financial Accounting Analyst
      - Financial Accounting Clerk 4
    - Asset Accounting Manager
      - Asset Accounting Analyst 2
      - Asset Accounting Analyst 1
      - Asset Accounting Analyst 1
    - Financial Process & Support Manager
      - Accounts Payable Support Clerk
      - Accounts Payable Clerk 2
      - Accounts Payable Leader
      - Financial Accounting Clerk 3
      - Accounts Payable Clerk 2
      - Credit Card Program Administrator
      - Credit Card Administrator
      - Accounts Payable System Support Analyst
      - Accounts Payable Clerk 2
      - Accounts Payable Clerk 2
      - Accounts Payable Clerk 2
    - Financial Accounting Analyst

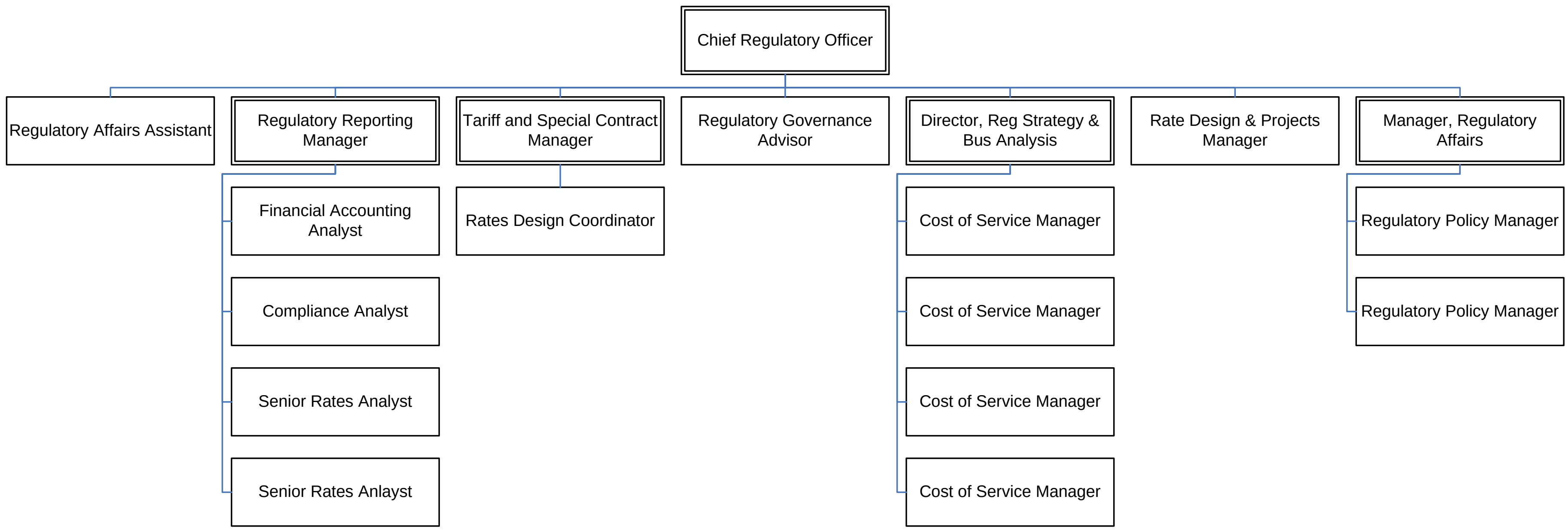
TERASEN GAS INC.

FINANCE & REGULATORY

2009

Legend

2009 Vacancies



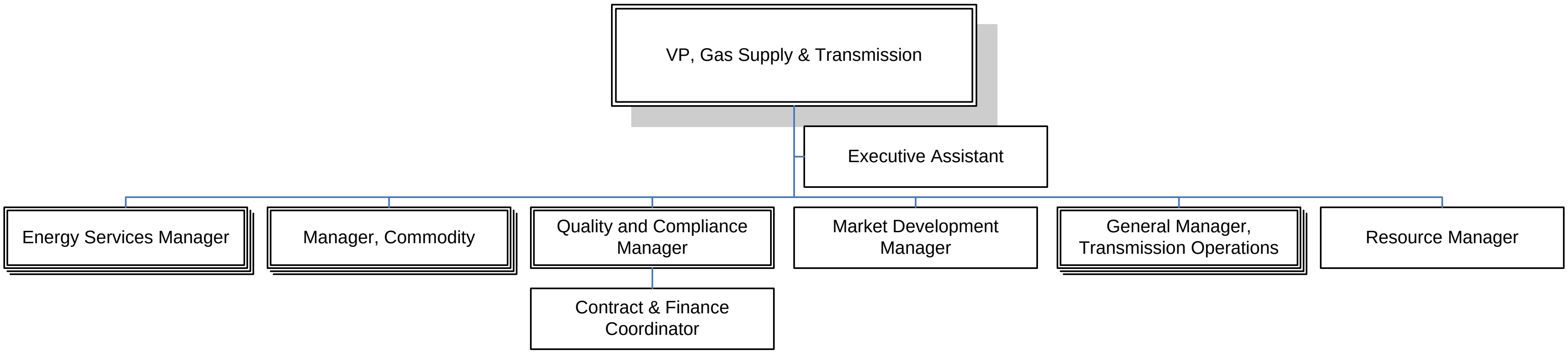
TERASEN GAS INC.

GAS SUPPLY & TRANSMISSION

2009

Legend

2009 Vacancies



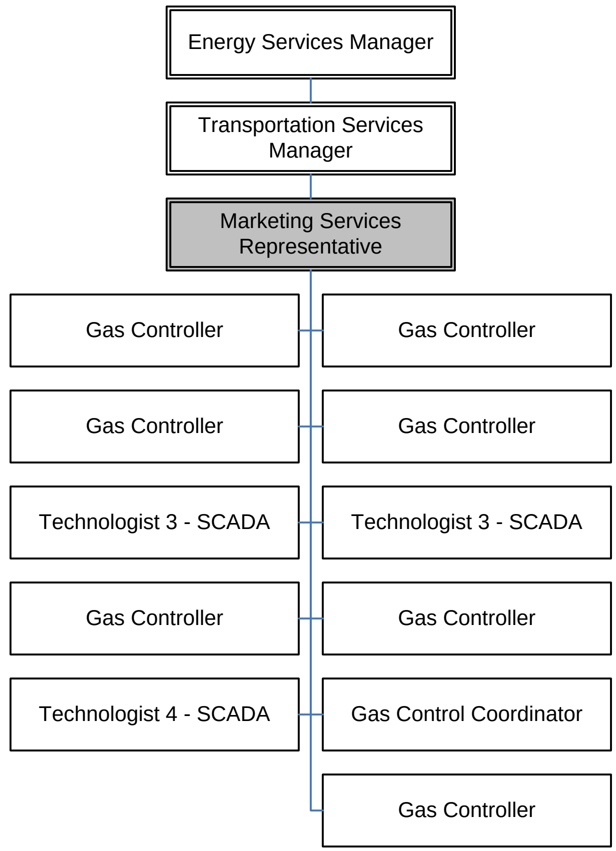
TERASEN GAS INC.

GAS SUPPLY & TRANSMISSION

2009

Legend

2009 Vacancies



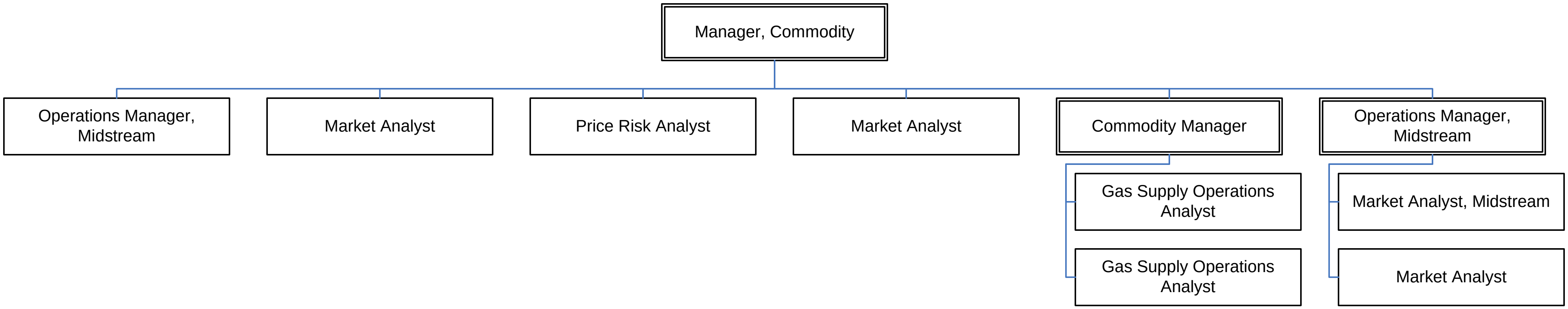
TERASEN GAS INC.

GAS SUPPLY & TRANSMISSION

2009

Legend

2009 Vacancies



TERASEN GAS INC.

GAS SUPPLY & TRANSMISSION

2009

Legend

- 2009 Vacancies

- General Manager, Transmission Operations
  - Mgr, Transmission (Interior)
    - Budget & Costing Clerk 1 (Int)
    - Project Manager
    - Quality and Compliance Manager
      - Pipeline & Right of Way Inspector
      - Pipeline & Right of Way Inspector
    - Pipeline Operations Manager, Interior
      - Welder 1
      - Welder 1
      - Distribution Mechanic
      - Operations Technician
      - Distribution Mechanic - Inter
      - Equip Operator/DM
      - Equipment Operator P
    - (blank)
  - Manager, Compression Operations
    - Field Operations Assistant
    - Compression & Controls Technician 1
    - Millwright
    - Compression & Controls Technician 1
    - Compression & Controls Technician 1
    - Compression & Controls Technician 1
    - Compression & Controls Technician 1
    - Compression & Controls Technician 1
    - Compression & Controls Technician 1
    - Compression & Controls Technician 1
    - Compression & Controls Technician 1
    - Millwright
  - LNG Plant Manager
    - LNG Plant Operator 1
    - LNG Plant Operator 1
    - LNG Plant Operator 1
    - Technologist 4 - LNG Plant
    - LNG Plant Operator 1
    - LNG Plant Operator 1
    - LNG Plant Operator 1
    - LNG Plant Operator 1
    - LNG Plant Operator 1 (Trainee)
    - LNG Plant Operator 1
    - LNG Plant Support Clerk
    - LNG Technologist
  - Mgr, Transmission Assets & Improvement
    - M&E Relief
    - Business Performance Analyst
    - Engineer
    - Transmission Compliance Assistant
  - Pipeline Operations Manager (Coast)
    - Distribution Mechanic - Coast
    - Distribution Mechanic - Coast
    - Pipeline & Right of Way Inspector
    - Pipeline & Right of Way Inspector
    - Distribution Mechanic - Coast
    - Distribution Mechanic - Coast
    - Crew Leader
    - Pipeline & Right of Way Inspector
    - Distribution Mechanic - Coast
    - Crew Leader
    - Distribution Mechanic - Coast
    - Pipeline & Right of Way Inspector WL
    - Distribution Mechanic - Coast

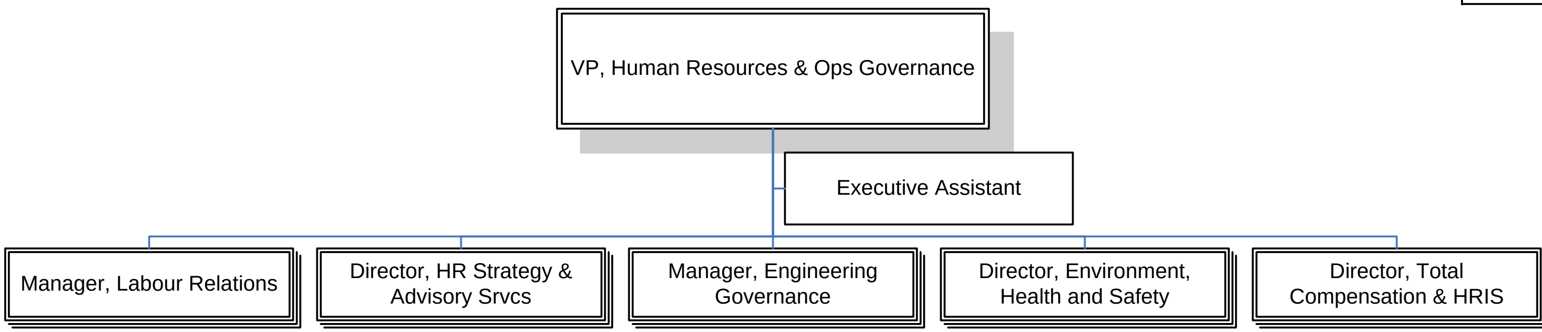
TERASEN GAS INC.

HUMAN RESOURCES & OPERATIONS GOVERNANCE

2009

Legend

2009 Vacancies



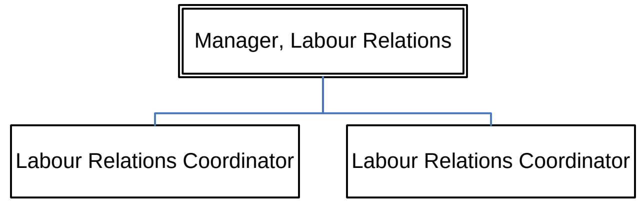
TERASEN GAS INC.

HUMAN RESOURCES & OPERATIONS GOVERNANCE

2009

Legend

2009 Vacancies



TERASEN GAS INC.

HUMAN RESOURCES & OPERATIONS GOVERNANCE

2009

Legend

2009 Vacancies

- Director, HR Strategy & Advisory Srvcs
  - HR Advisor
    - HR Coordinator - Disability
    - HR Coordinator Disability
    - Associate Human Resources Advisor
  - HR Advisor
    - Associate Human Resources Advisor
  - HR Advisor
    - Associate Human Resources Advisor
  - Recruiting Manager
    - HR Coordinator, Recruiting
    - HR Coordinator, Recruiting
    - HR Coordinator, Recruiting
    - Relief Clerk (Street Team) (5 positions)
    - Relief Clerks (52 positions)

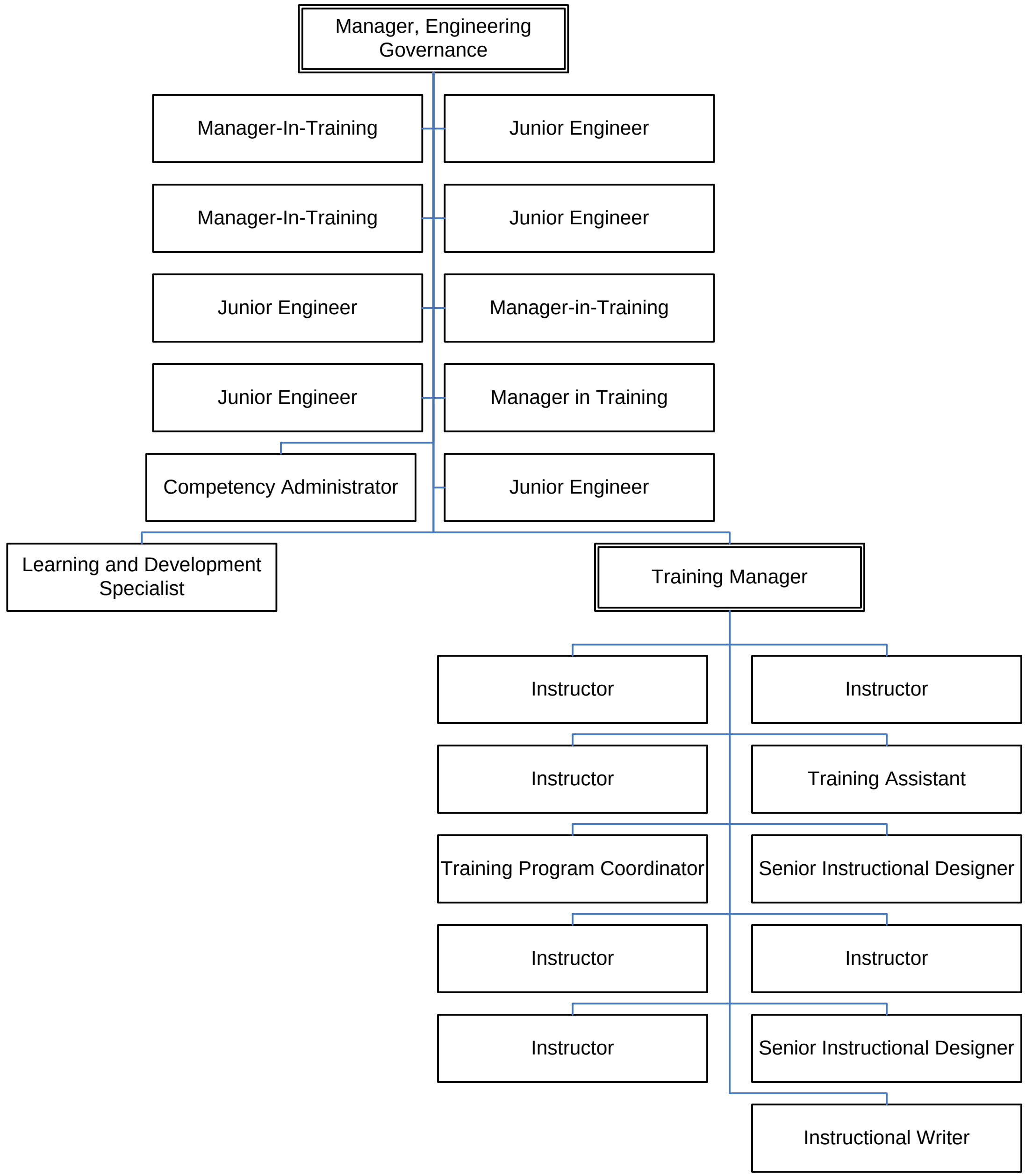
TERASEN GAS INC.

HUMAN RESOURCES & OPERATIONS GOVERNANCE

2009

Legend

2009 Vacancies



TERASEN GAS INC.

HUMAN RESOURCES & OPERATIONS GOVERNANCE

2009

Legend

2009 Vacancies

- Director, Environment, Health and Safety
  - Sustainability Manager
  - Operations Compliance Auditor
  - Administrator, Environment Health Safety
  - Environmental Affairs Manager
    - Environmental Program Manager
    - Environmental Program Manager
  - OH&S & Corporate Security Manager
    - Health & Safety Advisor
  - Emergency Planning & Public Safety Mgr
    - Emergency Preparedness Coordinator
  - Business Continuity Manager

TERASEN GAS INC.

HUMAN RESOURCES & OPERATIONS GOVERNANCE

2009

- Director, Total Compensation & HRIS
  - Manager, HRIS/Payroll
    - HRIS Associate Analyst
    - Payroll Administrator
    - M&E Payroll Analyst
    - Operations Wage Time Clerk
    - Time Administrator
    - HR Representative, Employee Services
    - Time Administrator
    - Payroll Administrator
  - Manager, Compensation, Benefits & EServ
    - Compensation & Benefits Analyst, HR
    - HR Coordinator, Employee Services
    - HR Representative, Employee Services
    - HR Representative, Employee Services
  - Corporate Pension Manager
    - Pension Coordinator
    - Pension Coordinator

Legend

2009 Vacancies

TERASEN GAS INC.

MARKETING & BUSINESS DEVELOPMENT

2009

Legend

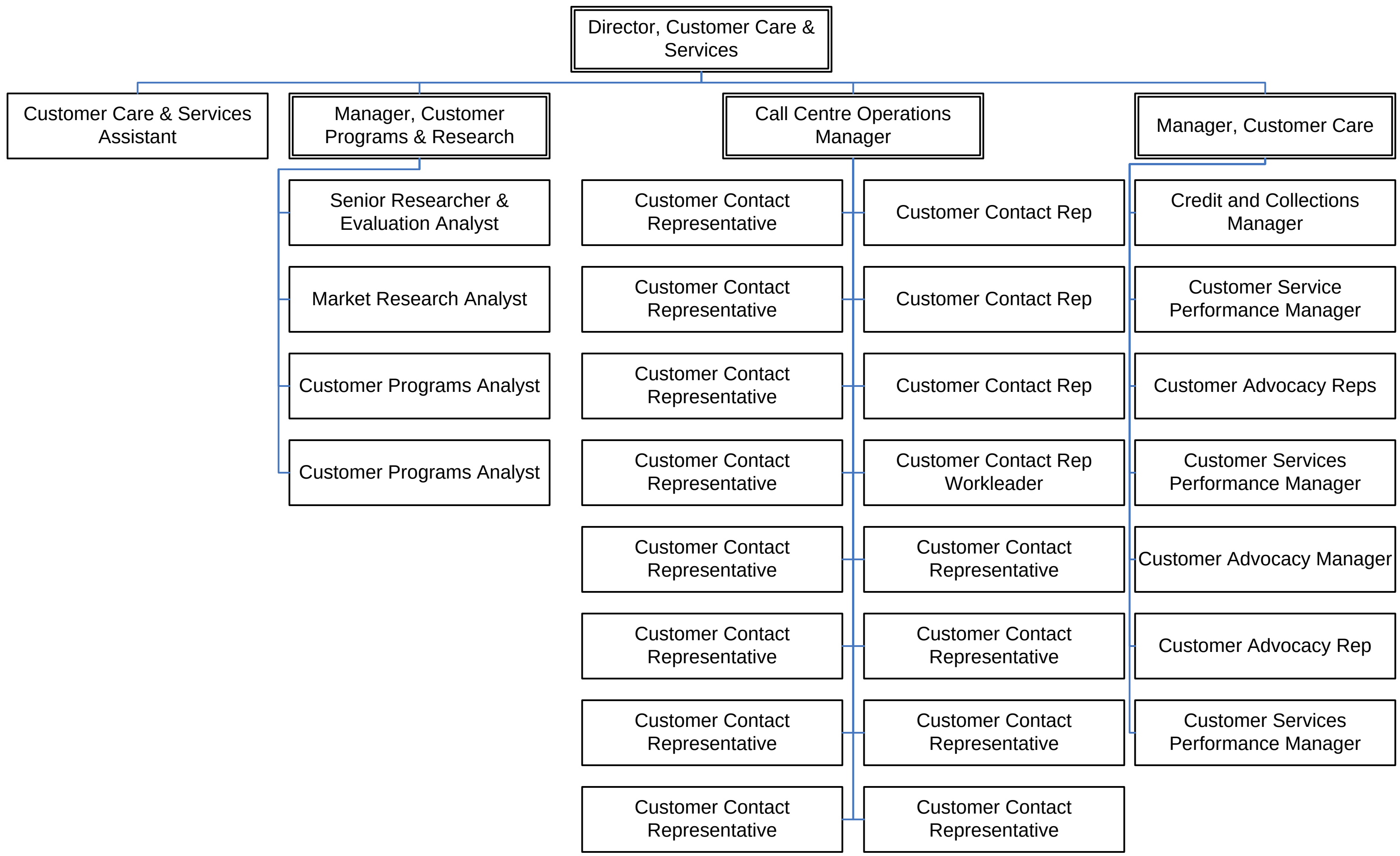
- 2009 Vacancies

- VP, Marketing & Business Development
  - Executive Assistant
  - Director, Customer Care & Services
  - Director, Com/Aboriginal/ Govt Relations
  - Director, Resource Planning & Market Dev
  - Director, Customer Management & Sales
  - Director, Corp & Marketing Communication

TERASEN GAS INC.
MARKETING & BUSINESS DEVELOPMENT
2009

Legend

2009 Vacancies



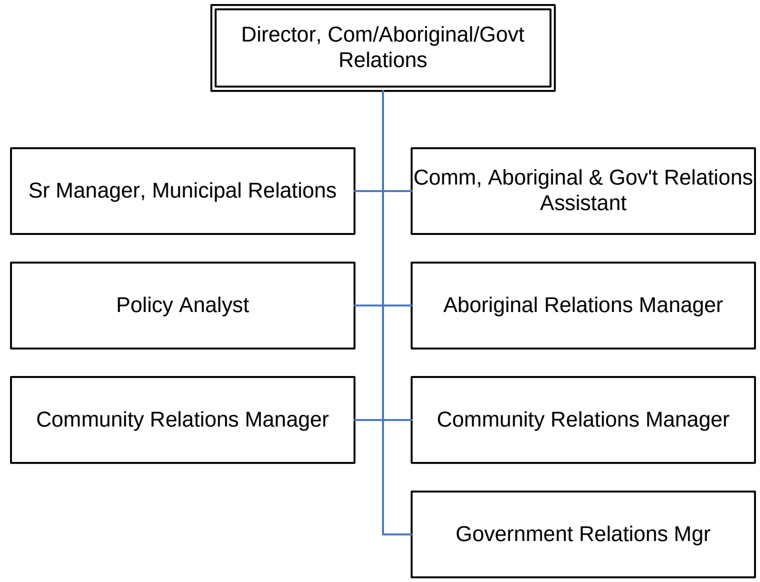
TERASEN GAS INC.

MARKETING & BUSINESS DEVELOPMENT

2009

Legend

2009 Vacancies



TERASEN GAS INC.

MARKETING & BUSINESS DEVELOPMENT

2009

Legend: 2009 Vacancies

- Director, Resource Planning & Market Dev
  - Gas Load Control Clerk 2
  - Project Assessment Manager
  - Business Development Manager
  - Business Development Manager
  - Manager, Business Development
  - Integrated Resource Planning Manager
  - Manager, Operations & Project Assessment
  - Business Development Manager
  - Manager, Technical Sales Support
    - Energy Utilization & Efficiency Manager
    - Energy Technology Specialist
    - Techt 4 - Energy Utilization
  - Market Development Analysis Manager
    - Business Development Analyst
    - Business Development Analyst
  - Customer & Energy Forecasting Manager
    - Forecast Analyst
    - Forecast Analyst
    - Forecast Analyst
    - Process Support Analyst
  - Manager, Marketing & Energy Efficiency
    - EEC Pgm Mgr, Comm'l
    - EEC Pgm Mgr., Low Income Housing
    - EEC Pgm Mgr., Qualified Dealer
    - EEC Administrator
    - Mkt'g Pgm Specialist, Low Income Housing
    - Mkt'g Pgm Specialist, Comm'l
    - EEC Communications & Outreach Manager
    - Marketing Co-op Student
    - Mkt'g Pgm Specialist, Educ & Outreach
    - Mkt'g Pgm Specialist, Res
    - DSM Program Development Lead
    - EEC Pgm Mgr, Res

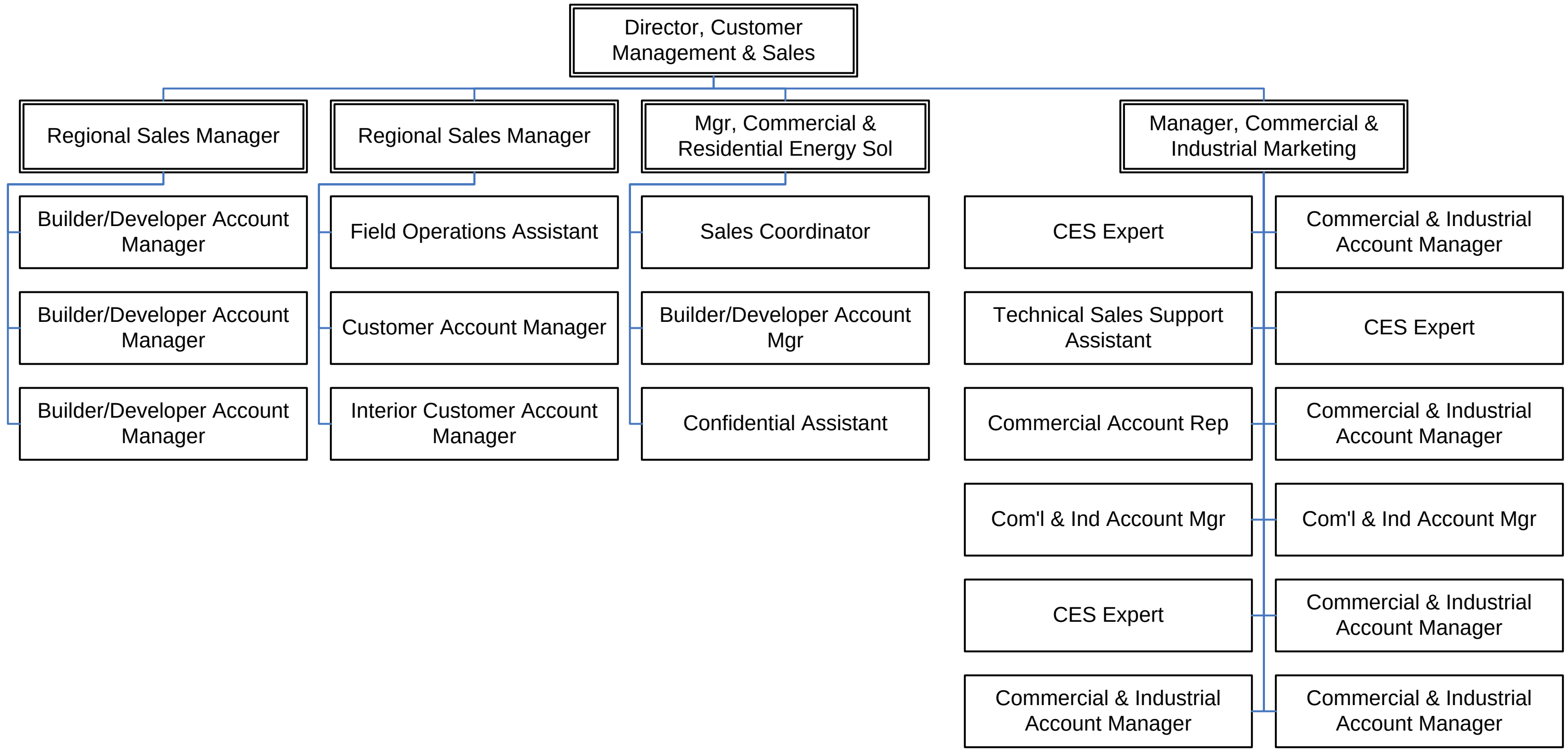
TERASEN GAS INC.

MARKETING & BUSINESS DEVELOPMENT

2009

Legend

2009 Vacancies



TERASEN GAS INC.

MARKETING & BUSINESS DEVELOPMENT

2009

Legend

- 2009 Vacancies

- Director, Corp & Marketing Communication
  - Confidential Assistant
  - Marketing & Customer Communications Mgr
    - Lead Designer, Communication Srvcs
    - Communications Coordinator
    - Internal Communications Writer
    - Communications Coordinator
    - Communications Coordinator
    - Corporate Communications Mgr
    - Designer, Communication Services
    - Writer/Researcher
    - Internet Communications Mgr
    - Communications Coordinator
  - Corporate Communications Manager
    - Communications Specialist

TERASEN GAS INC.

- R Jespersen
  President, Terasen Gas Inc.
  - Shelly Watson
    Executive Assistant
  - Jan Marston
    VP, Human Resources & Ops Governance
  - Robert Samels
    VP, Business Services and Technology
  - Dwain Bell
    VP, Distribution
  - Scott Thomson
    VP, Regulatory Affairs & CFO
  - Douglas Stout
    VP, Marketing & Business Development
  - Cynthia Des Brisay
    VP, Gas Supply & Transmission

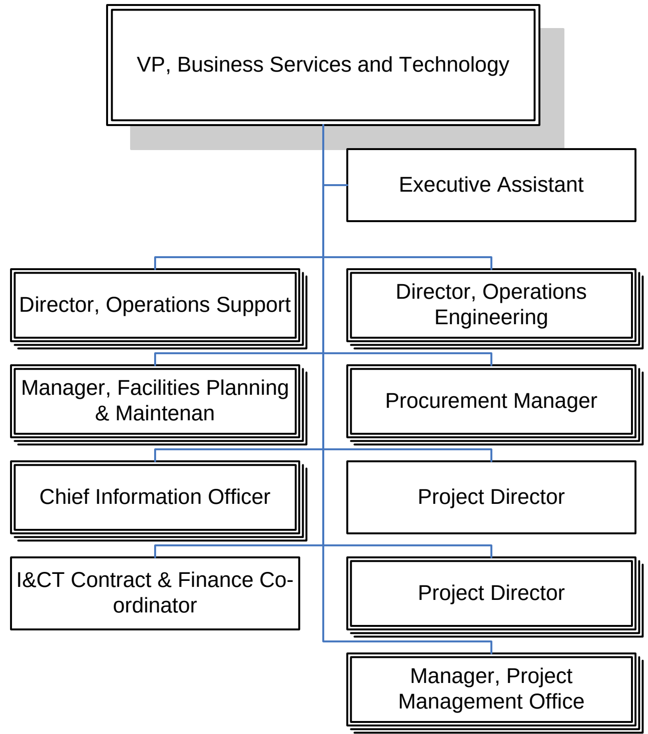
TERASEN GAS INC.

BUSINESS & IT SERVICES

2009 to 2011

Head Count Legend

- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count



TERASEN GAS INC.

BUSINESS & IT SERVICES

2009 to 2011

Head Count Legend

- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count

Director, Operations Support

Measurement Services Manager

- Measurement Services Business Analyst
- Technologist 4 - Quality Assurance WL
- Techt 3 - Measurement Technologies
- Measurement Business Analyst
- Operations Support Assistant
- Measurement Technologies Ass't
- Operations Support Assistant
- Operations Support Assistant
- Techt 3 - Measurement Technologies
- Technologist 3
- Technologist 3

Meter Shop Manager - Penticton

- Measurement Mechanic 2 - Interior
- Measurement Technician - Int
- Measurement Technician
- Measurement Mechanic 1 - Interior
- Measurement Mechanic 2
- Measurement Mechanic 1 - Interior
- Measurement Mechanic 1
- Measurement Mechanic 1 - Interior
- Measurement Mechanic 2
- Measurement Mechanic
- Measurement Shop Ldr-Interior
- Measurement Shop Ldr-Interior
- Measurement Shop Ldr-Interior
- Measurement Mechanic
- Measurement Mechanic 2
- Measurement Mechanic 1 - Interior
- Measurement Mechanic 1 - Interior
- Painter
- Measurement Technician

Data Acquisition and Logistics Manager

- Tech't 3 Instrumentation & Communication
- Tech't 3 Instrumentation & Communication
- Material Truck Driver (Coast)
- Materials Truck and Trailer Operator
- Measurement Analyst 2
- Measurement Analyst 2
- Material Truck Driver (Coast)
- Tech't 3 Instrumentation & Communication
- Techt 3 - Measurement Technologies
- Measurement Mechanic 1 - Coastal
- Material Handler (Coastal)
- Material Handler (Coastal)
- Inventory Analyst 2
- Material Handler (Coastal)
- Technologist 4 - Measurement
- Material Handler (Coastal)
- Techt 3 - Instrumentation
- Tech't 3 Instrumentation & Communication
- Measurement Analyst 2
- Materials Shipper/Receiver
- Recycling Mechanic
- Yard Foreman
- Stores Leader (Coastal)
- Tech't 3 Instrumentation & Communication
- Techt 3 - Measurement Technologies
- Material Handler (Coastal)
- Material Truck Driver (Coast)
- Materials Shipper/Receiver
- Material Handler (Coastal)
- Communication Specialist
- Measurement Analyst 2
- Materials Truck and Trailer Operator
- Material Truck Driver (Coast)
- Material Handler
- Warehouse & Delivery Leader
- Instr & Data Acquisition Support Adminis
- Material Handler (Coastal)
- Instrumentation & Communications WL
- Inventory Analyst 2
- Tech't 3 Instrumentation & Communication
- Tech't 3 Instrumentation & Communication
- Material Handler (Coast)
- Measurement Analyst 2

Manufacturing Service Manager

- Machinist
- Welder
- System Operations Technician - Coastal
- Fitter Welder 1
- Operations Support Assistant
- Fitter Welder 1
- Fitter Welder 1
- Shop Mechanic 1 - Prefab
- Shop Assistant
- Fitter Welder 1
- Fitter Welder 1
- Shop Assistant
- Shop Mechanic 1 - Prefab
- Painter
- Shop Mechanic 1 - Prefab
- Shop Mechanic 2 - Machine
- Fitter Welder 1
- Shop Mechanic 1 - Prefab
- Shop Assistant
- Shop Mechanic 1 - Machine
- Fitter Welder 1
- Prefab Mechanic
- Prefab Mechanic
- Prefab Mechanic
- Shop Mechanic 1 - Prefab
- Shop Assistant
- Mechanical Foreman-Machine Shop
- Shop Mechanic 2 - Prefab
- Fitter Welder 1
- Fitter Welder 1
- Mechanical Foreman - Prefab
- Painter Bridging to Retirement
- Fitter/Welder 1
- Shop Mechanic 2 - Machine Shop
- Shop Mechanic 1 - (Weld Shop)
- Shop Assistant
- Shop Assistant
- Shop Mechanic 1 - Machine
- Fitter Welder 1
- Shop Mechanic 1 - Prefab
- Design Machinist
- Mechanical Foreman-Welding
- Shop Mechanic 1 - Machine
- Fitter Welder 1

TERASEN GAS INC.

BUSINESS & IT SERVICES

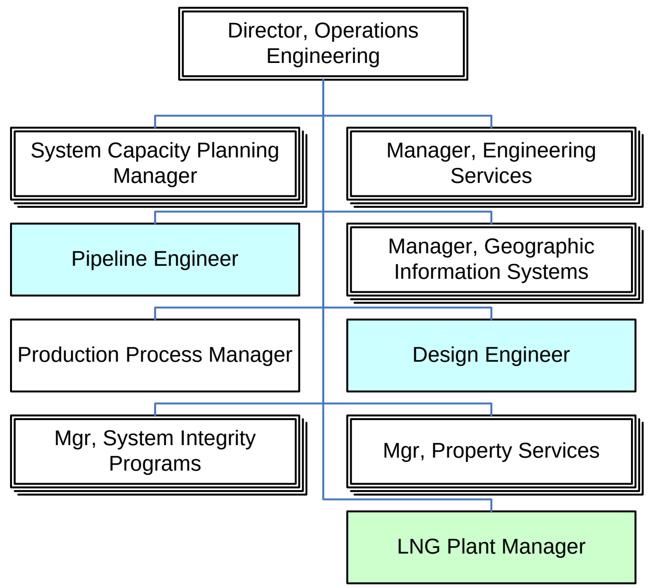
2009 to 2011

Head Count Legend

2009 Added Head count

2010 Added Head count

2011 Added Head count



TERASEN GAS INC.

BUSINESS & IT SERVICES

2009 to 2011

Head Count Legend

- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count

System Capacity Planning Manager

- Technologist 2 - Capacity Planning
- Technologist 3 - Capacity Planning
- Technologist 1 - Capacity Planning
- Technologist 3 - Capacity Planning
- Technologist 4 - Capacity Planning
- System Planning Engineer
- Technologist 2 - Capacity Planning
- Technologist 3 - Capacity Planning

TERASEN GAS INC.

BUSINESS & IT SERVICES

2009 to 2011

Head Count Legend

- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count

Manager, Engineering Services

- Technologist 3 - Pipeline Design/Drafter
- Process Engineer
- Technologist 3 - Plant Design/ Drafter
- Engineering Secretary
- Techt 4 - Instrumentation Design
- Techt 4 - Instrumentation Design
- Technologist 3 - Pipeline Design/Drafter
- Design Engineer
- Project Engineer - Pipelines
- Engineering Co-op Student
- Engineering Co-op Student
- Technologist 4 - Plant Design
- Engineering Secretary
- Project Engineer
- Technician 3 - Laboratory
- Engineering Secretary
- Techt 4 - Electrical Design
- Technologist 3 - Plant Design/ Drafter
- Project Engineer
- Techt 3 - Measurement Technologies
- Project Engineer
- Project Engineer
- Project Engineer
- Technologist 4 - Plant Design
- Techt 4 - Instrumentation Design
- Operations Records Compliance
- Technologist 4 - Plant Design

TERASEN GAS INC.

BUSINESS & IT SERVICES

2009 to 2011

Head Count Legend
- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count

- Manager, Geographic Information Systems
  - Engineering Drafter 2
  - GIS Drafter 1
  - Engineering Drafter 3
  - QA/QC Technician
  - AM/FM Data Conversion Clerk 2
  - Engineering Drafter 2
  - GIS Drafter 1
  - GIS Drafter 3
  - GIS Drafter Leader
  - Drafter 1
  - Co-op Student
  - Tech 3-Geographic Info Systems
  - GIS Drafter 1
  - GIS Drafter 2
  - GIS Drafter 2
  - GIS Drafter 2
  - Engineering Drafter 3
  - GIS Drafter 1
  - Engineering Clerk
  - GIS Drafter 1
  - GIS Drafter 1
  - Engineering Clerk
  - Engineering Drafter 3
  - QA/QC Technician
  - Engineering Drafter 2
  - Engineering Administration Manager
  - GIS Drafter 3
  - Engineering Drafting Work Leader
  - Drafter 1
  - GIS Drafter 1
  - Tech 3-Geographic Info Systems
  - GIS Drafter 1
  - Engineering Drafter 3
  - Engineering Clerk
  - Operations Support Representative 2
  - GIS Drafter 3
  - Data Integrity Manager
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Representative 3
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Rep Work Leader
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Representative 2
    - AM/FM Completions Work Leader
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Representative 3
    - Operations Support Representative 3
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Representative 3
    - Operations Support Representative 2
    - Operations Support Representative 3
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Representative 2
    - Operations Support Representative 2

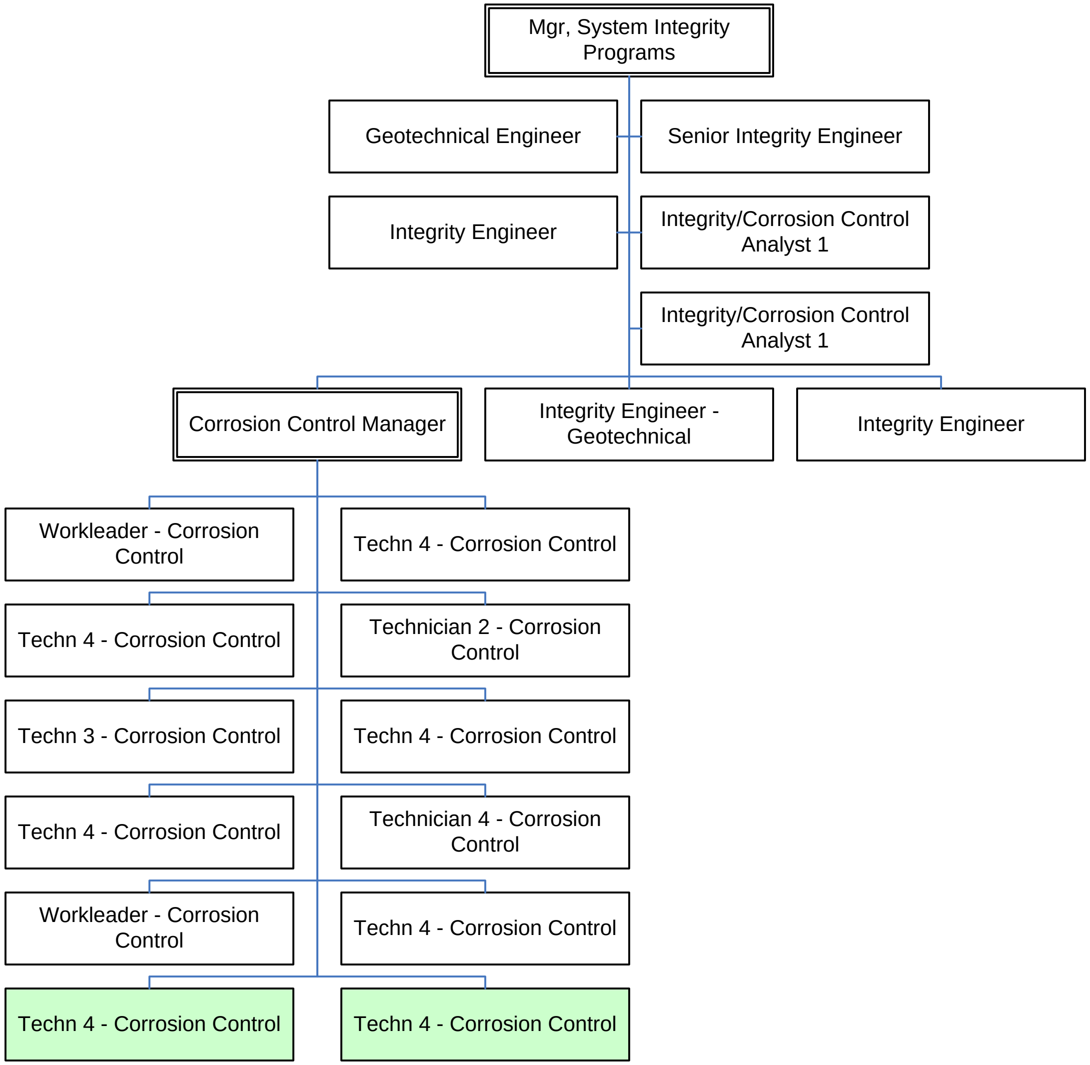
TERASEN GAS INC.

BUSINESS & IT SERVICES

2009 to 2011

Head Count Legend

- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count



TERASEN GAS INC.

BUSINESS & IT SERVICES

2009 to 2011

Head Count Legend

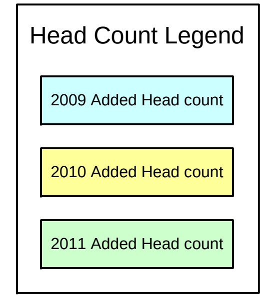
- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count

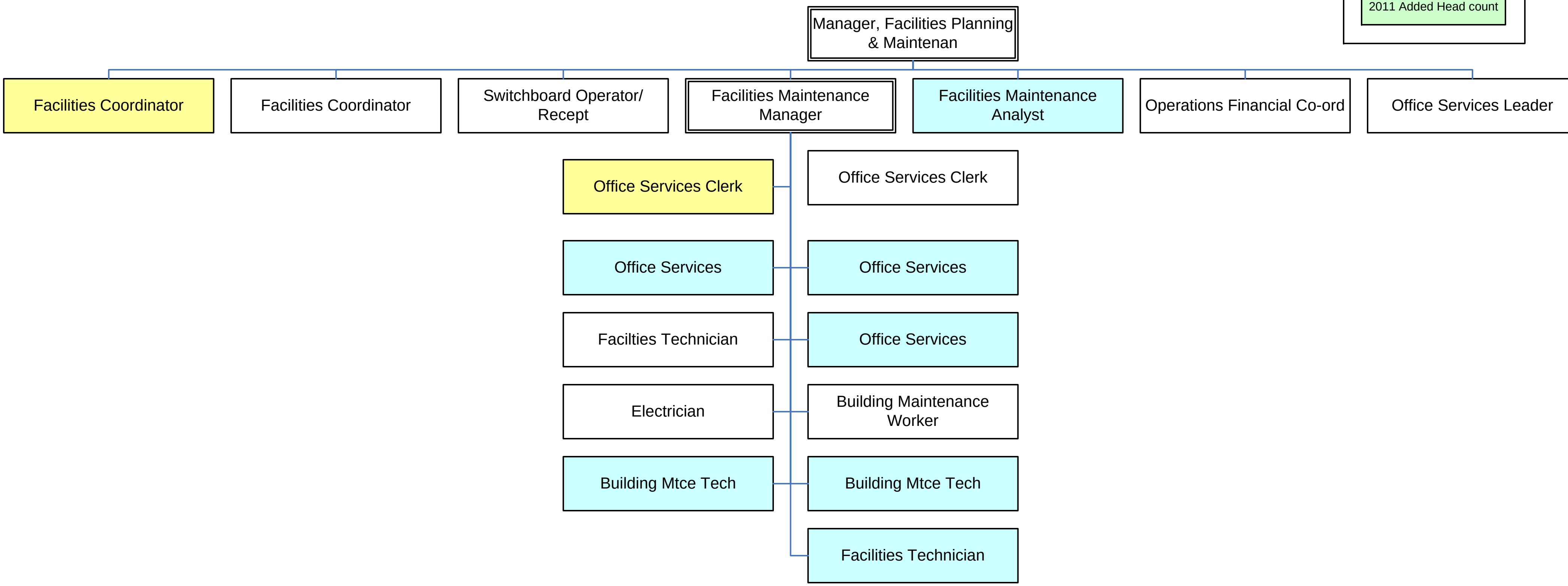
- Mgr, Property Services
  - Right of Way Project Coordinator
  - Transmission Permit Representative
  - Property Tax Specialist
  - Lands Representative
  - Lands Administrator
  - Lands Administrator
  - Property Representative
  - Pipeline Right of Way Representative
  - Pipeline Right of Way Representative
  - Right-of-Way Services Rep
  - Property Representative
  - Technologist 4 - Environmental Support

TERASEN GAS INC.

BUSINESS & IT SERVICES

2009 to 2011

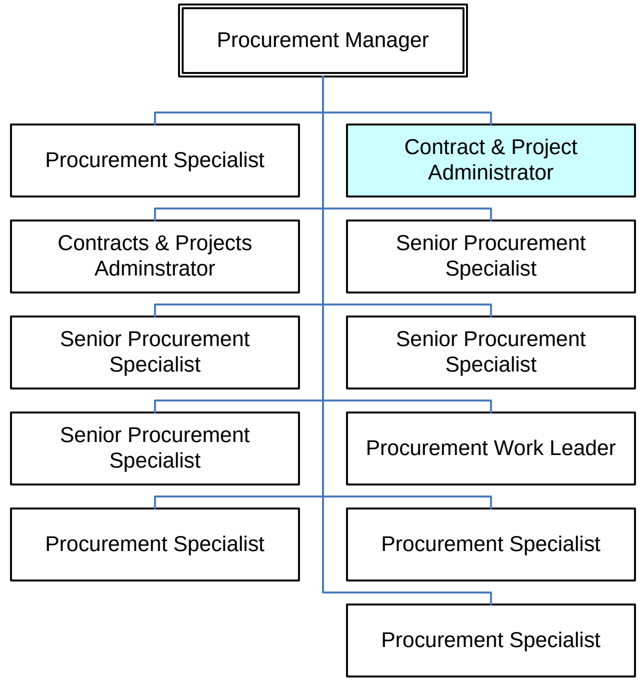




TERASEN GAS INC.

BUSINESS & IT SERVICES

2009 to 2011



Head Count Legend

2009 Added Head count

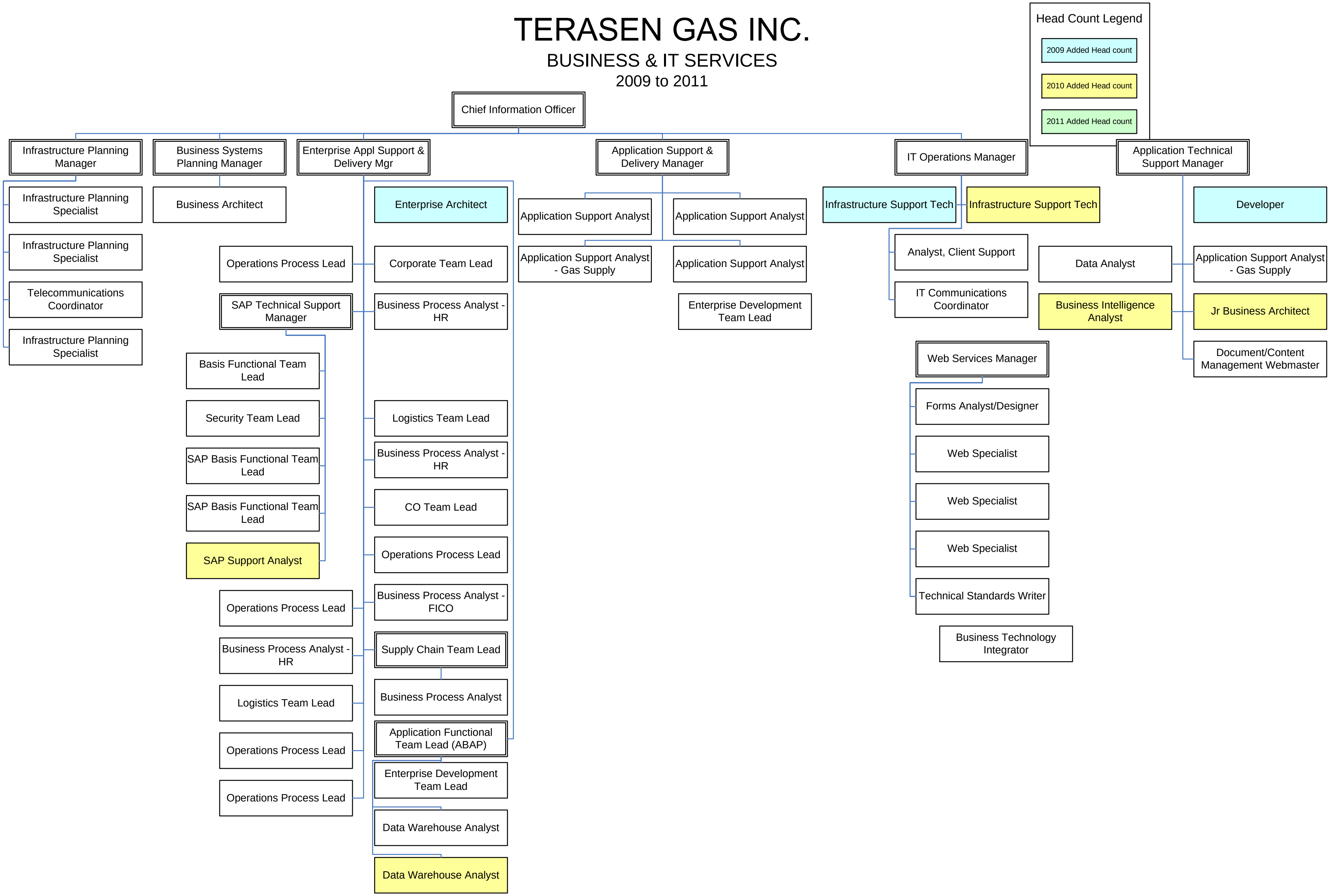
2010 Added Head count

2011 Added Head count

TERASEN GAS INC.

BUSINESS & IT SERVICES

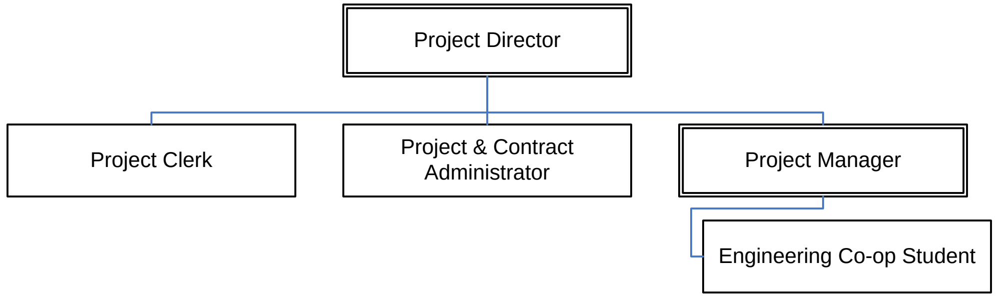
2009 to 2011

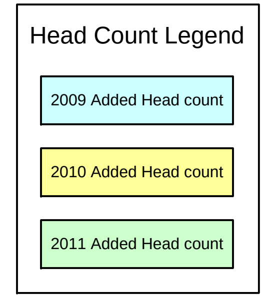


TERASEN GAS INC.

BUSINESS & IT SERVICES

2009 to 2011





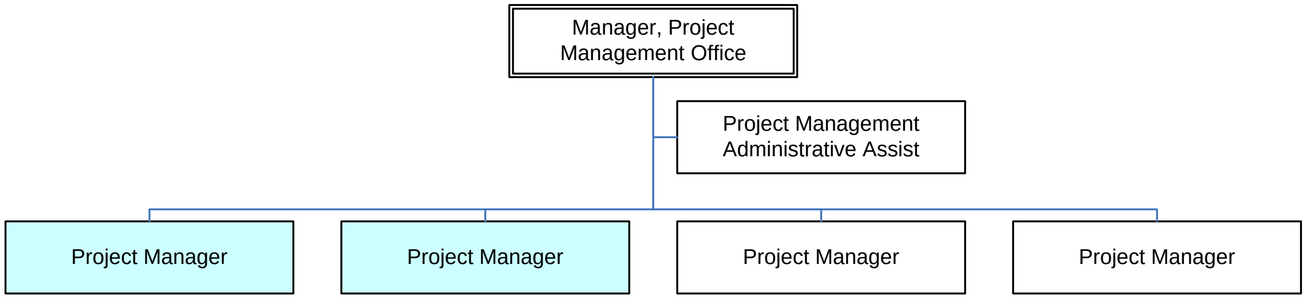
TERASEN GAS INC.

BUSINESS & IT SERVICES

2009 to 2011

Head Count Legend

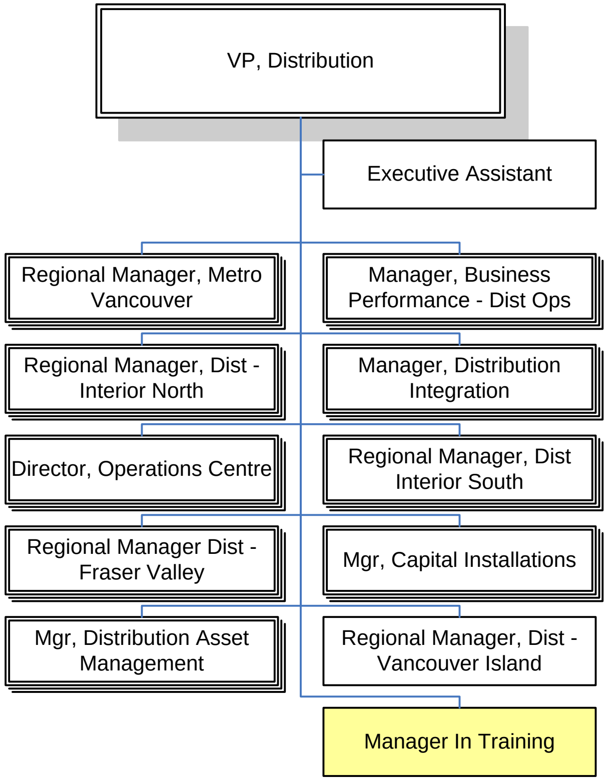
- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count

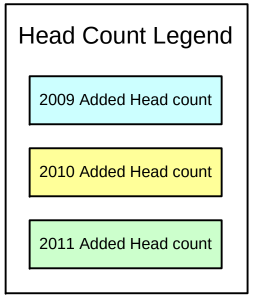


TERASEN GAS INC.

DISTRIBUTION

2009 to 2011





TERASEN GAS INC.

DISTRIBUTION

2009 to 2011

Head Count Legend
- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count

Regional Manager, Metro Vancouver

- **Distribution Manager**
  - Clean-up Truck Driver
  - Crew Leader
  - Clean-up Truck Driver
  - Crew Leader
  - Crew Leader
  - Crew Leader
  - Equip Operator/DM
  - Distribution Mechanic - Coast
  - Distribution Mechanic - Coast
  - Equip Operator/DM
- **Operations Manager**
  - Customer Service Technician 1
  - System Operations Technician - Coastal
  - System Operations Apprentice
  - Customer Service Technician 1
  - System Operations Technician - 18
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 2
  - Customer Service Technician 1
  - System Operations Technician - 18
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 2
  - System Operations Technician - Coastal
  - Customer Service Technician 2
- **Distribution Manager**
  - Distribution Apprentice
  - Distribution Apprentice
  - Distribution Apprentice
  - Crew Leader
  - Distribution Apprentice
  - Crew Leader
  - Distribution Apprentice
  - Distribution Mechanic - Coast
  - Distribution Apprentice
  - Distribution Mechanic - Coast
  - Distribution Apprentice
  - Crew Leader
  - Distribution Apprentice
  - Distribution Apprentice
  - Distribution Apprentice
  - Distribution Apprentice
  - Distribution Service Agent
  - Distribution Apprentice
- **Installation Manager**
- **Distribution Manager**
  - Crew Leader
  - Crew Leader
  - Distribution Mechanic
  - Distribution Mechanic
  - Distribution Mechanic
  - Distribution Mechanic
  - Distribution Mechanic
  - Crew Leader
  - Distribution Mechanic - Coast
  - Distribution Mechanic
  - Distribution Mechanic
  - Distribution Mechanic - Coast
  - Equip Operator/DM
- **Operations Manager - Vancouver**
  - Customer Service Technician 2
  - Customer Service Technician 1
  - Customer Service Technician 1
  - System Operations Technician - Coastal
  - Customer Service Technician 1
  - System Operations Technician - Coastal
  - Distribution Service Agent
  - Customer Service Technician 1
  - System Operations Technician - Coastal
  - Customer Service Technician 1
  - System Operations Technician - Coastal
  - System Operations Apprentice
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - System Operations Technician - 18
  - Customer Service Technician 1
  - Customer Service Technician 2
- **Operations Manager - Squ/Whi**
  - Customer Service Technician 1
  - Customer Service Technician 1

TERASEN GAS INC.

DISTRIBUTION

2009 to 2011

Head Count Legend

2009 Added Head count

2010 Added Head count

2011 Added Head count

Manager, Business Performance - Dist Ops

Distribution Operations Analyst

TERASEN GAS INC.

DISTRIBUTION

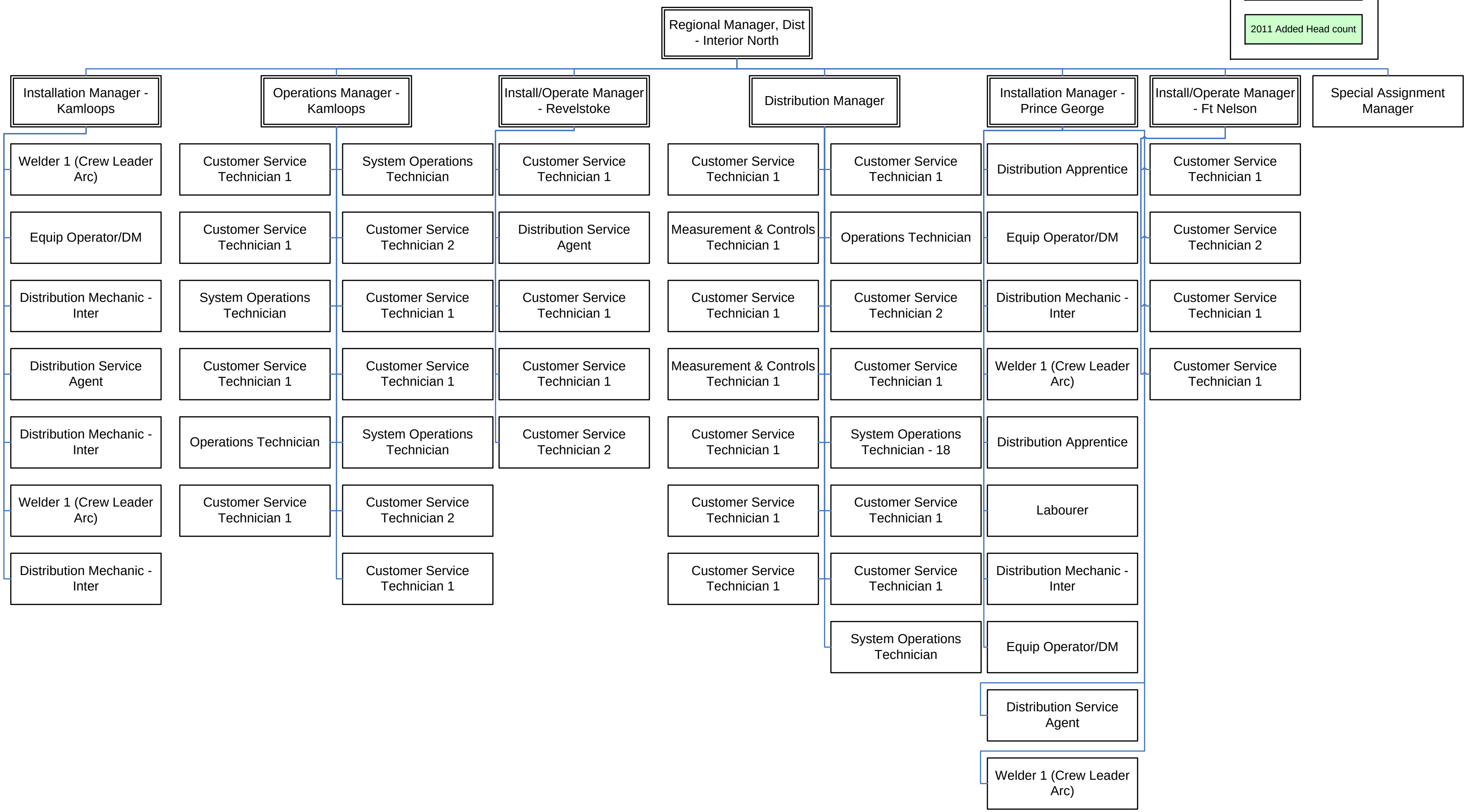
2009 to 2011

Head Count Legend

2009 Added Head count

2010 Added Head count

2011 Added Head count



TERASEN GAS INC.

DISTRIBUTION

2009 to 2011

Head Count Legend
- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count

- Manager, Distribution Integration
  - Business Support Manager
  - Operations Service Manager
    - Field Operations Assistant
    - Field Operations Assistant
    - Field Operations Assistant
    - Field Operations Assistant
  - Process Manager
  - Operations Service Manager
    - Field Operations Assistant
    - Field Operations Assistant
    - Field Operations Assistant
    - Field Operations Assistant
    - Field Operations Assistant
  - Special Assignment Manager
  - Special Assignment Manager
  - Process Support Manager
    - Operations Process Analyst 3
    - Operations Process Analyst 2
    - Operations Process Analyst 2
    - Operations Process Analyst 1
    - Operations Process Analyst 2
    - Operations Process Analyst 1

TERASEN GAS INC.

DISTRIBUTION

2009 to 2011

Head Count Legend
- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count

Director, Operations Centre

- **Installation Centre Manager - IC2**
  - Planning & Design Technologist 2
  - Planning & Design Technologist 2
  - Planning & Design Technologist 2
  - Planning & Design Technologist 2
  - Planning & Design Technologist 2
  - Planning & Design Technologist 2
  - Planning & Design Technologist 2
  - Planning & Design Technologist 2
  - Planning & Design Technologist 2
  - Planning & Design Technologist 2
  - Planning & Design Technologist 2
  - Planning & Design Technologist 2
  - Planning & Design Technologist 2
  - Planning & Design Technologist 2
  - Planning & Design Technologist 2
  - Operations Support Representative 3
  - Techt 4 - Project Specialist
  - Planning & Design Technologist 2
- **Dispatch Manager**
  - Operations Support Representative 3
  - Operations Support Representative 3
  - Dispatcher
  - Operations Support Representative 3
  - Operations Support Representative 3
  - Operations Support Representative 3
  - Operations Support Representative 3
  - Dispatcher
  - Operations Support Representative 3
  - Operations Support Representative 3
  - Dispatcher
  - Operations Support Representative 3
  - Operations Support Representative 3
  - Operations Support Representative 3
  - Dispatcher
  - Operations Support Representative 3
  - Dispatcher
- **Emergency Support Manager**
  - Emergency & Operations Representative
  - Emergency & Operations Representative
  - Emergency & Operations Representative
  - Emergency & Operations Representative
  - Emergency & Operations Representative
  - Emergency & Operations Representative
  - Emergency & Operations Representative
  - Emergency & Operations Representative
- **Pre-Requisite Manager**
  - T & D Surveyor 1
  - Operations Support Representative 2
  - Operations Support Representative 3
  - T & D Surveyor
  - Operations Support Representative 2
  - Operations Support Representative 2
  - Operations Support Representative 2
  - Operations Support Representative 2
  - T & D Surveyor 1
  - Operations Support Representative 2
  - Operations Support Representative 2
  - Operations Support Representative 3
  - Operations Support Representative 3
  - T & D Surveyor 2
  - Operations Support Rep Work leader
- **Planning & Design Work leader (M&E Relief)**
  - Install Centre IC1 (17)
  - Install Centre IC1
  - Install Centre CIA
  - Install Centre IC1 (16)
- **Resource Planning Manager**
  - Resource Management Co-ordinator
  - Operations Support Representative 1
  - Resource Management Co-ordinator
  - Resource Management Co-ordinator
  - Operations Support Representative 1
  - Resource Management Co-ordinator
  - Resource Management Co-ordinator
  - Resource Management Co-ordinator
  - Operations Support Representative 1
  - Resource Management Co-ordinator
  - Operations Support Representative 1
  - Operations Support Representative 1
  - Operations Support Representative 1
  - Operations Support Representative 1
- **Closing Manager**
  - Operations Support Representative 3 (10)
  - Operations Support Representative 3
  - Operations Support Representative 3
  - Operations Support Representative 3
  - Operations Support Representative 3
  - Operations Support Representative 1
  - Operations Support Representative 3
  - Operations Support Representative 3
  - Resource Management Co-ordinator
  - Operations Support Representative 3
  - Operations Support Representative 3

TERASEN GAS INC.

DISTRIBUTION

2009 to 2011

Head Count Legend

- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count

Regional Manager, Dist Interior South

- **Install/Operate Manager - Vernon**
  - Distribution Service Agent
  - Distribution Mechanic - Inter
  - System Operations Technician
  - Crew Leader
  - Customer Service Technician 1
  - Distribution Apprentice
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Equip Operator/DM
  - Distribution Mechanic - Inter
  - Distribution Mechanic - Inter
  - Welder 1
  - System Operations Technician
- **Installation Manager - Kelowna**
  - Distribution Apprentice
  - Distribution Mechanic - Inter
  - Crew Leader Arc (Welder 1)
  - Distribution Apprentice
  - Equip Operator/DM
  - Crew Leader Arc Welder 1
  - Equip Operator/DM
  - Crew Leader
  - Equip Operator/DM
- **Install/Operate Manager - Cranbrook**
  - System Operations Technician
  - Distribution Apprentice
  - Crew Leader
  - Distribution Mechanic - Inter
  - Welder 1 (Crew Leader Arc)
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Measurement & Controls Technician 1
  - Customer Service Technician 1
  - Distribution Service Agent
  - Customer Service Technician 1
  - Sr Sales & Service Technician
  - Distribution Mechanic - Inter
  - Customer Service Technician 1
- **Installation Manager - Trail**
  - Equip Operator/DM
  - Distribution Mechanic - Inter
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Equip Operator/DM
  - Customer Service Technician 1
  - System Operations Technician - 18
  - Sr Sales & Service Technician
  - Customer Service Technician 1
  - Welder 1
  - Customer Service Technician 1
  - System Operations Technician - 18
- **Distribution Manager**
  - Distribution Service Agent
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - System Operations Apprentice
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 2
- **Install/Operate Manager - Penticton**
  - Welder 1
  - Customer Service Technician 1
  - Distribution Apprentice
  - Equip Operator/DM
  - Distribution Apprentice
  - Distribution Mechanic - Inter
  - Customer Service Technician 1
  - Welder 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - System Operations Technician
  - Customer Service Technician 2

TERASEN GAS INC.

DISTRIBUTION

2009 to 2011

Head Count Legend

- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count

Regional Manager Dist - Fraser Valley

- **Installation Manager - Langley**
  - Distribution Mechanic
  - Distribution Mechanic
  - Distribution Mechanic
  - Distribution Mechanic - Coast
  - Crew Leader
  - Distribution Apprentice
  - Distribution Mechanic
  - Distribution Mechanic
  - Distribution Mechanic
  - Field Operations Assistant
  - Distribution Mechanic
  - Distribution Mechanic
  - Crew Leader
  - Crew Leader
  - Distribution Apprentice
  - Distribution Mechanic - Coast
  - Distribution Mechanic - Coast
  - Distribution Mechanic
  - Distribution Mechanic - Coast
  - Field Operations Assistant
  - Distribution Mechanic
  - Distribution Mechanic
  - Distribution Apprentice
- **Distribution Manager**
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 2
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - System Operations Technician - Coastal
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - System Operations Technician - Coastal
  - Customer Service Technician 2
  - Customer Service Technician 1
  - System Operations Technician - 18
  - Customer Service Technician 1
  - Customer Service Technician 1
- **Operations Manager - Surrey**
  - System Operations Technician - Coastal
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - System Operations Apprentice
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - System Operations Technician - 18
  - Customer Service Technician 1
  - Customer Service Technician 1
  - System Operations Technician - 18
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - Customer Service Technician 1
  - System Operations Technician - Coastal
  - Customer Service Technician 1
  - Customer Service Technician 1
- **Installation Manager - Coquitlam**
  - Distribution Mechanic - Coast
  - Crew Leader
  - Distribution Mechanic - Coast
  - Distribution Mechanic - Coast
  - Distribution Mechanic - Coast
  - Distribution Mechanic - Coast
  - Distribution Mechanic - Coast
  - Distribution Mechanic 2
  - Crew Leader
  - Distribution Mechanic - Coast
  - Distribution Mechanic - Coast
- **Distribution Manager**
  - Distribution Mechanic - Coast
  - Paving Foreman
  - Crew Leader
  - Crew Leader
  - Distribution Mechanic - Coast
  - Crew Leader
  - Equipment Operator 1 (Coastal)
  - Distribution Mechanic - Coast
  - Distribution Mechanic - Coast
- **Installation Manager - Surrey**
  - Crew Leader
  - Crew Leader
  - Crew Leader
  - Distribution Mechanic - Coast
  - Distribution Mechanic/ Excavator

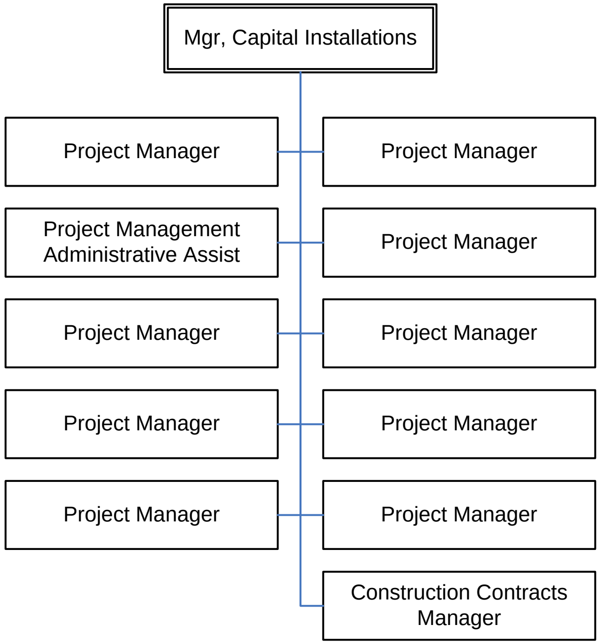
TERASEN GAS INC.

DISTRIBUTION

2009 to 2011

Head Count Legend

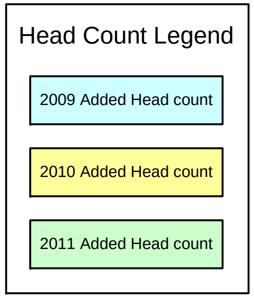
- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count

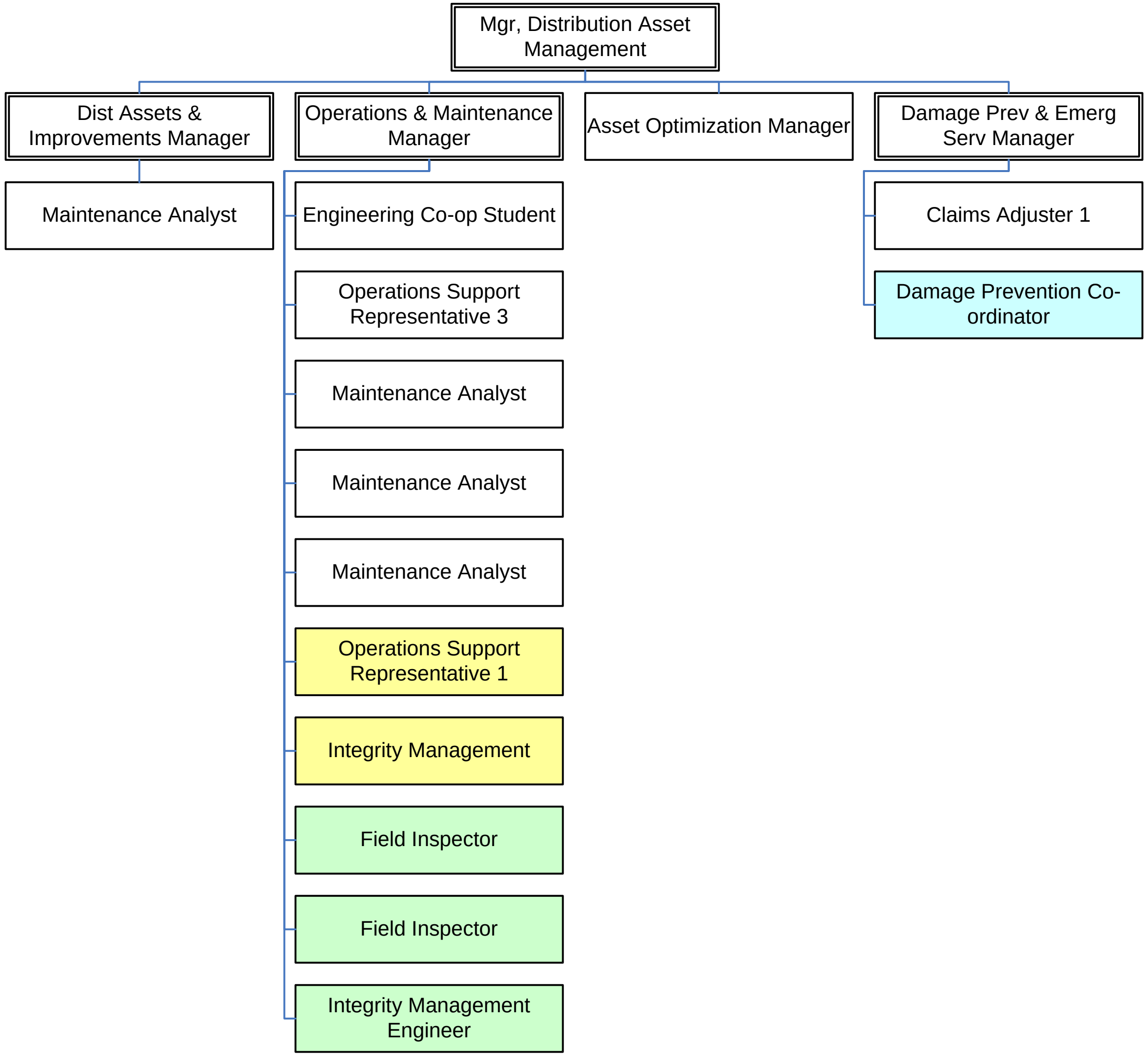


TERASEN GAS INC.

DISTRIBUTION

2009 to 2011





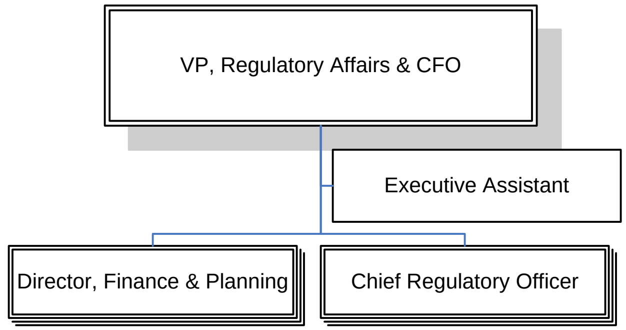
TERASEN GAS INC.

FINANCE & REGULATORY

2009 to 2011

Head Count Legend

- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count



TERASEN GAS INC.

FINANCE & REGULATORY

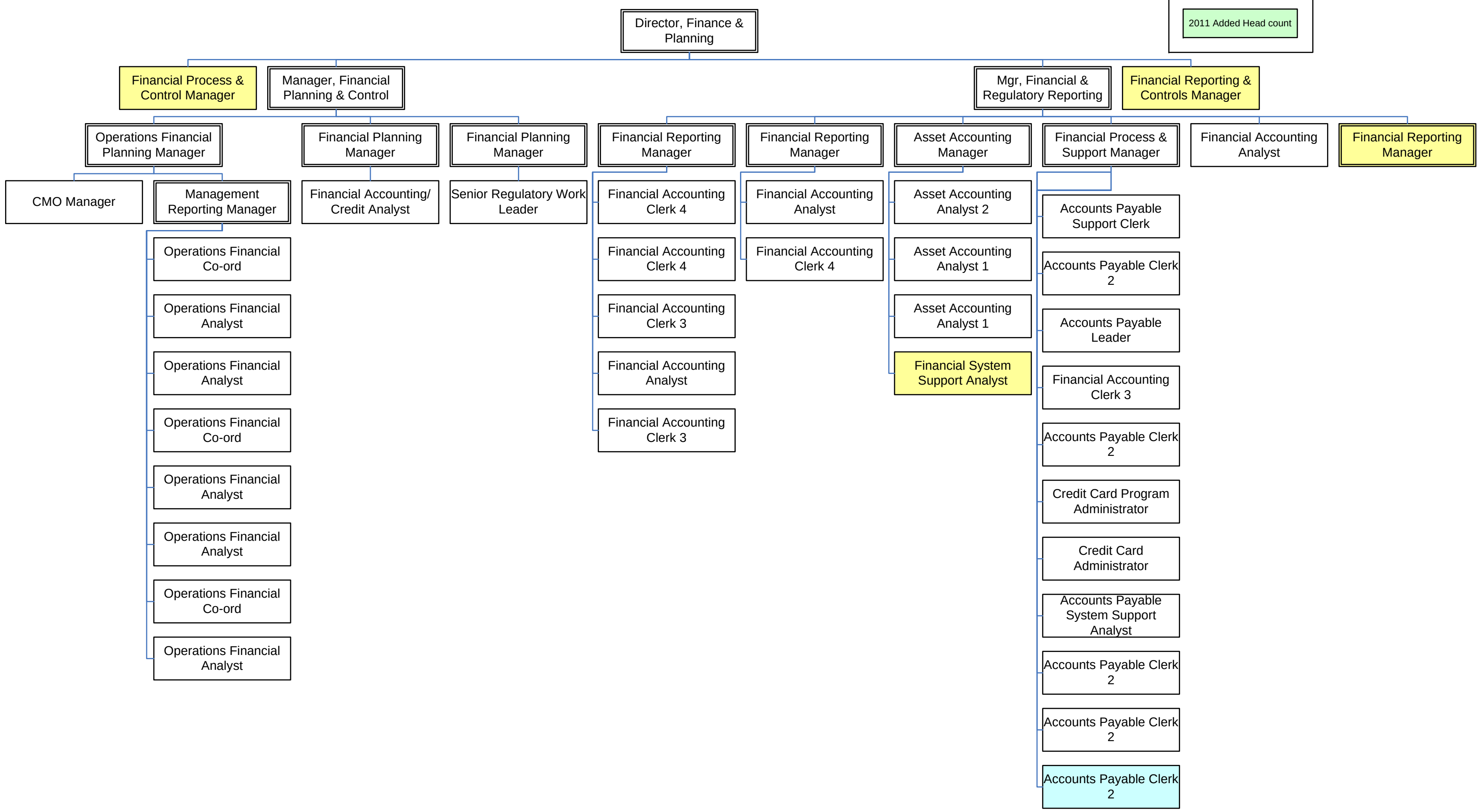
2009 to 2011

Head Count Legend

2009 Added Head count

2010 Added Head count

2011 Added Head count



TERASEN GAS INC.

FINANCE & REGULATORY

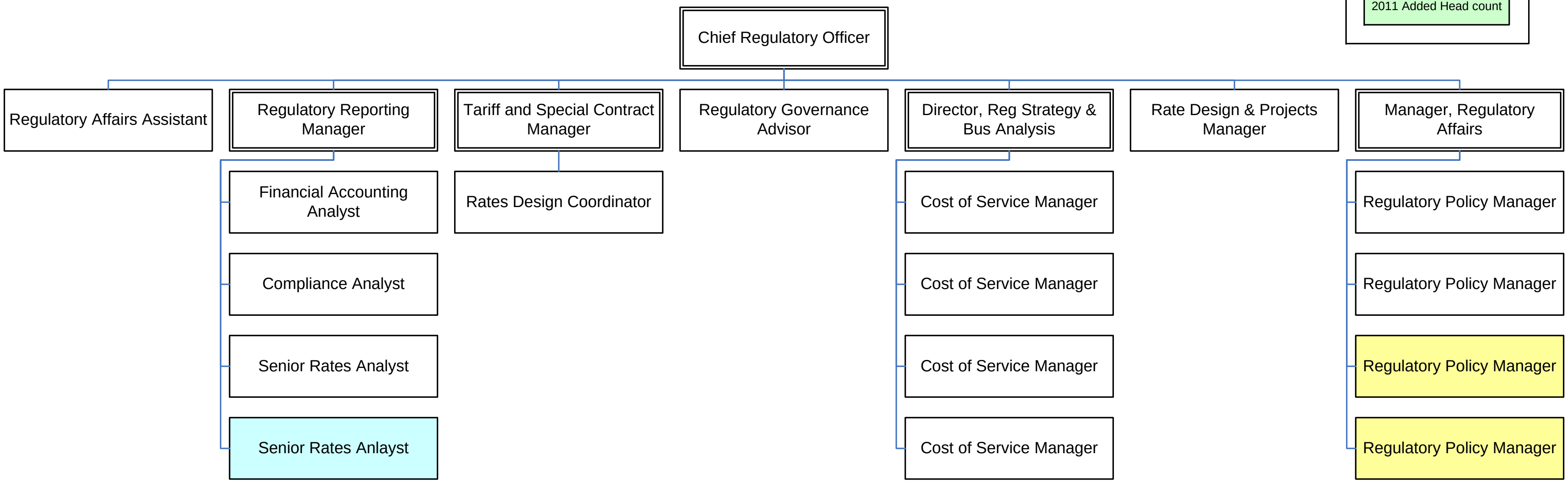
2009 to 2011

Head Count Legend

2009 Added Head count

2010 Added Head count

2011 Added Head count



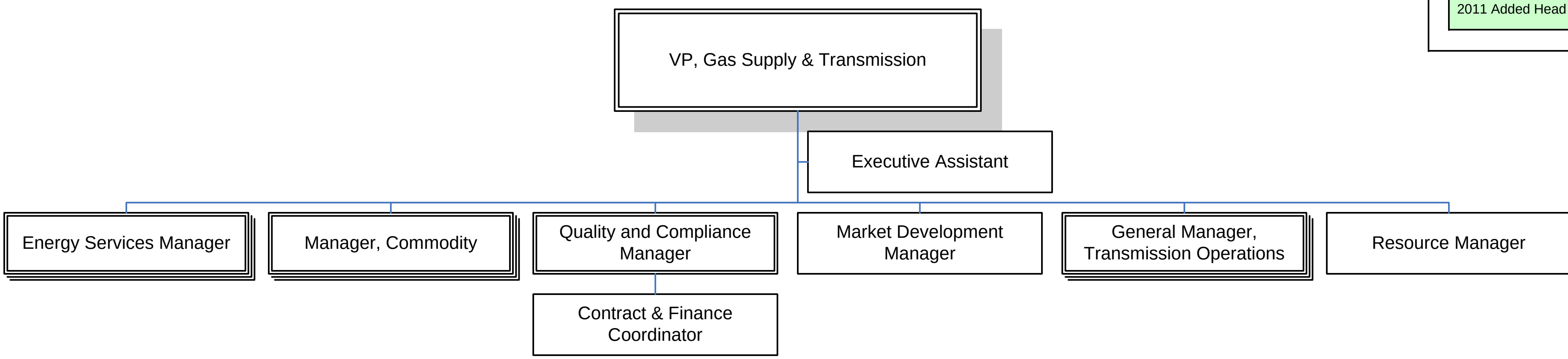
TERASEN GAS INC.

GAS SUPPLY & TRANSMISSION

2009 to 2011

Head Count Legend

- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count



TERASEN GAS INC.

GAS SUPPLY & TRANSMISSION

2009 to 2011

Head Count Legend

- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count

- Energy Services Manager
  - Transportation Services Manager
    - Marketing Services Representative
      - Gas Controller
      - Gas Controller
      - Gas Controller
      - Gas Controller
      - Technologist 3 - SCADA
      - Technologist 3 - SCADA
      - Gas Controller
      - Gas Controller
      - Technologist 4 - SCADA
      - Gas Control Coordinator
      - Gas Controller

TERASEN GAS INC.

GAS SUPPLY & TRANSMISSION

2009 to 2011

Head Count Legend

- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count

- Manager, Commodity
  - Operations Manager, Midstream
  - Market Analyst
  - Price Risk Analyst
  - Market Analyst
  - Commodity Manager
    - Gas Supply Operations Analyst
    - Gas Supply Operations Analyst
  - Operations Manager, Midstream
    - Market Analyst, Midstream
    - Market Analyst

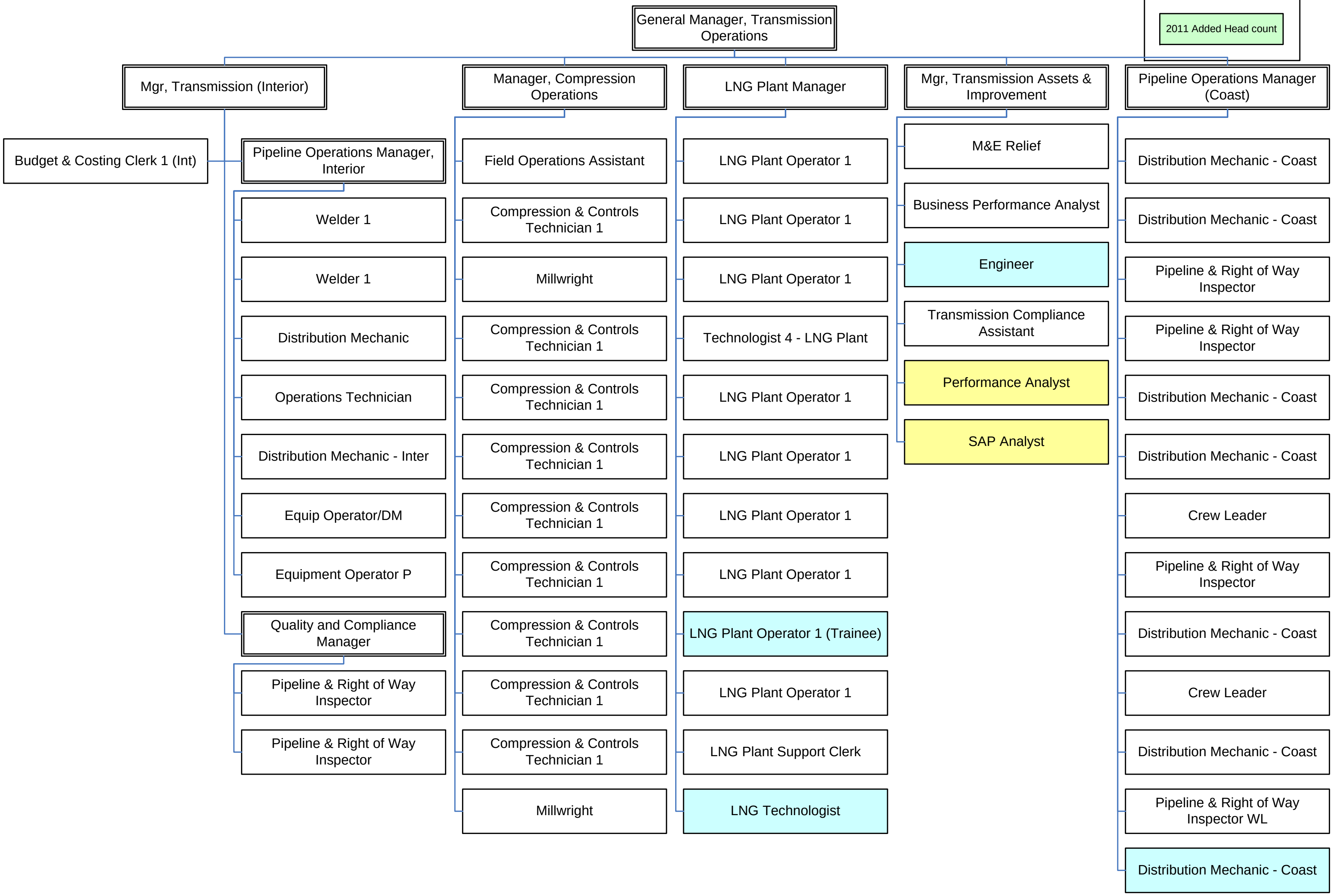
TERASEN GAS INC.

GAS SUPPLY & TRANSMISSION

2009 to 2011

Head Count Legend

- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count



TERASEN GAS INC.

HUMAN RESOURCES & OPERATIONS GOVERNANCE

2009 to 2011

Head Count Legend

- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count

VP, Human Resources & Ops Governance

- Executive Assistant
- Manager, Labour Relations
- Director, HR Strategy & Advisory Srvcs
- Manager, Engineering Governance
- Director, Environment, Health and Safety
- Director, Total Compensation & HRIS

TERASEN GAS INC.

HUMAN RESOURCES & OPERATIONS GOVERNANCE

2009 to 2011

- Manager, Labour Relations
  - Labour Relations Coordinator
  - Labour Relations Coordinator

Head Count Legend

- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count

TERASEN GAS INC.

HUMAN RESOURCES & OPERATIONS GOVERNANCE

2009 to 2011

- Director, HR Strategy & Advisory Srvcs
  - HR Advisor
    - HR Coordinator - Disability
    - HR Coordinator Disability
    - Associate Human Resources Advisor
  - HR Advisor
    - Associate Human Resources Advisor
  - HR Advisor
    - Associate Human Resources Advisor
  - Recruiting Manager
    - HR Coordinator, Recruiting
    - HR Coordinator, Recruiting
    - HR Coordinator, Recruiting
    - Relief Clerk (Street Team) (5 positions)
    - Relief Clerks (52 positions)

Head Count Legend

- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count

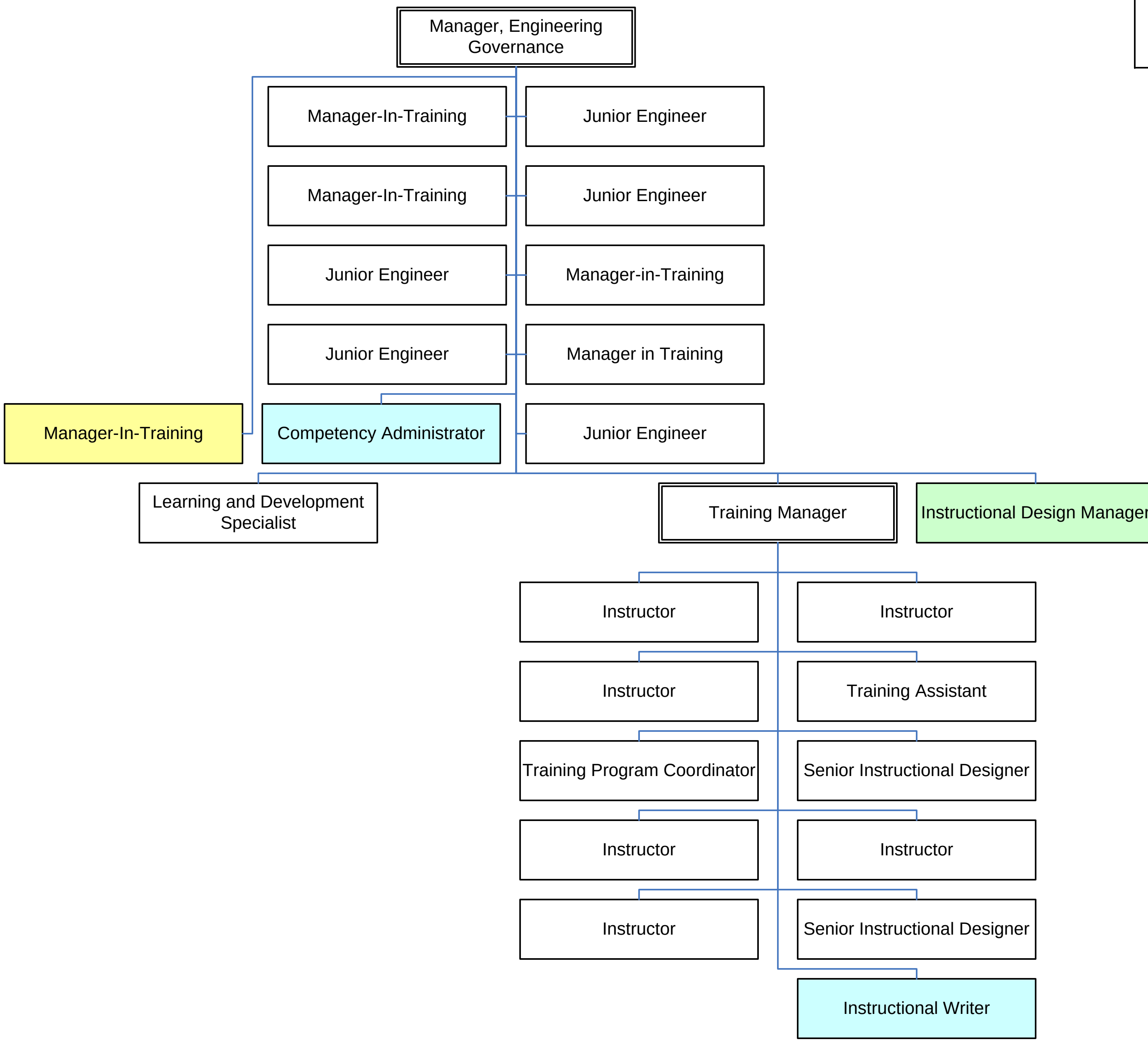
TERASEN GAS INC.

HUMAN RESOURCES & OPERATIONS GOVERNANCE

2009 to 2011

Head Count Legend

- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count



TERASEN GAS INC.

HUMAN RESOURCES & OPERATIONS GOVERNANCE

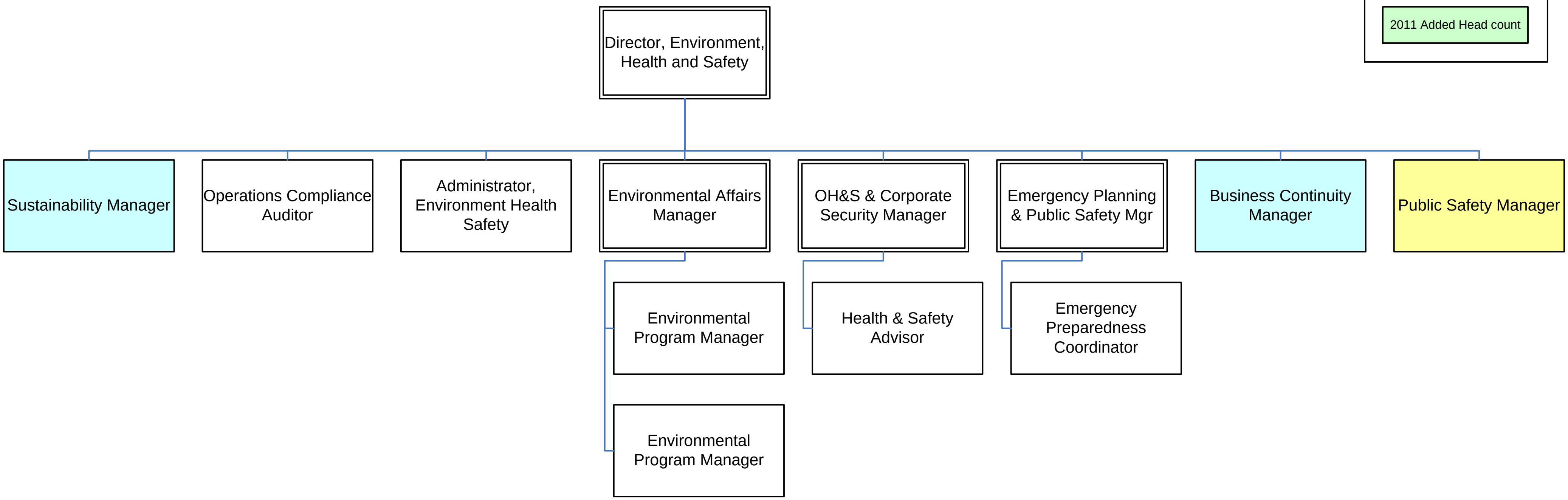
2009 to 2011

Head Count Legend

2009 Added Head count

2010 Added Head count

2011 Added Head count



TERASEN GAS INC.

HUMAN RESOURCES & OPERATIONS GOVERNANCE

2009 to 2011

Head Count Legend

- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count

- Director, Total Compensation & HRIS
  - Manager, HRIS/Payroll
    - HRIS Associate Analyst
    - Payroll Administrator
    - M&E Payroll Analyst
    - Operations Wage Time Clerk
    - Time Administrator
    - HR Representative, Employee Services
    - Time Administrator
    - Payroll Administrator
  - Manager, Compensation, Benefits & EServ
    - Compensation & Benefits Analyst, HR
    - HR Coordinator, Employee Services
    - HR Representative, Employee Services
    - HR Representative, Employee Services
    - Compensation Analyst
  - Corporate Pension Manager
    - Pension Coordinator
    - Pension Coordinator

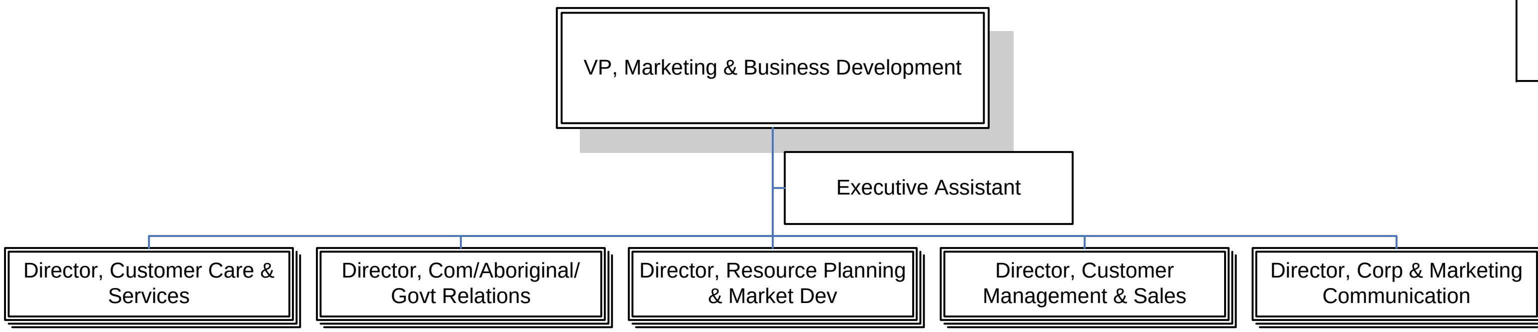
TERASEN GAS INC.

MARKETING & BUSINESS DEVELOPMENT

2009 to 2011

Head Count Legend

- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count



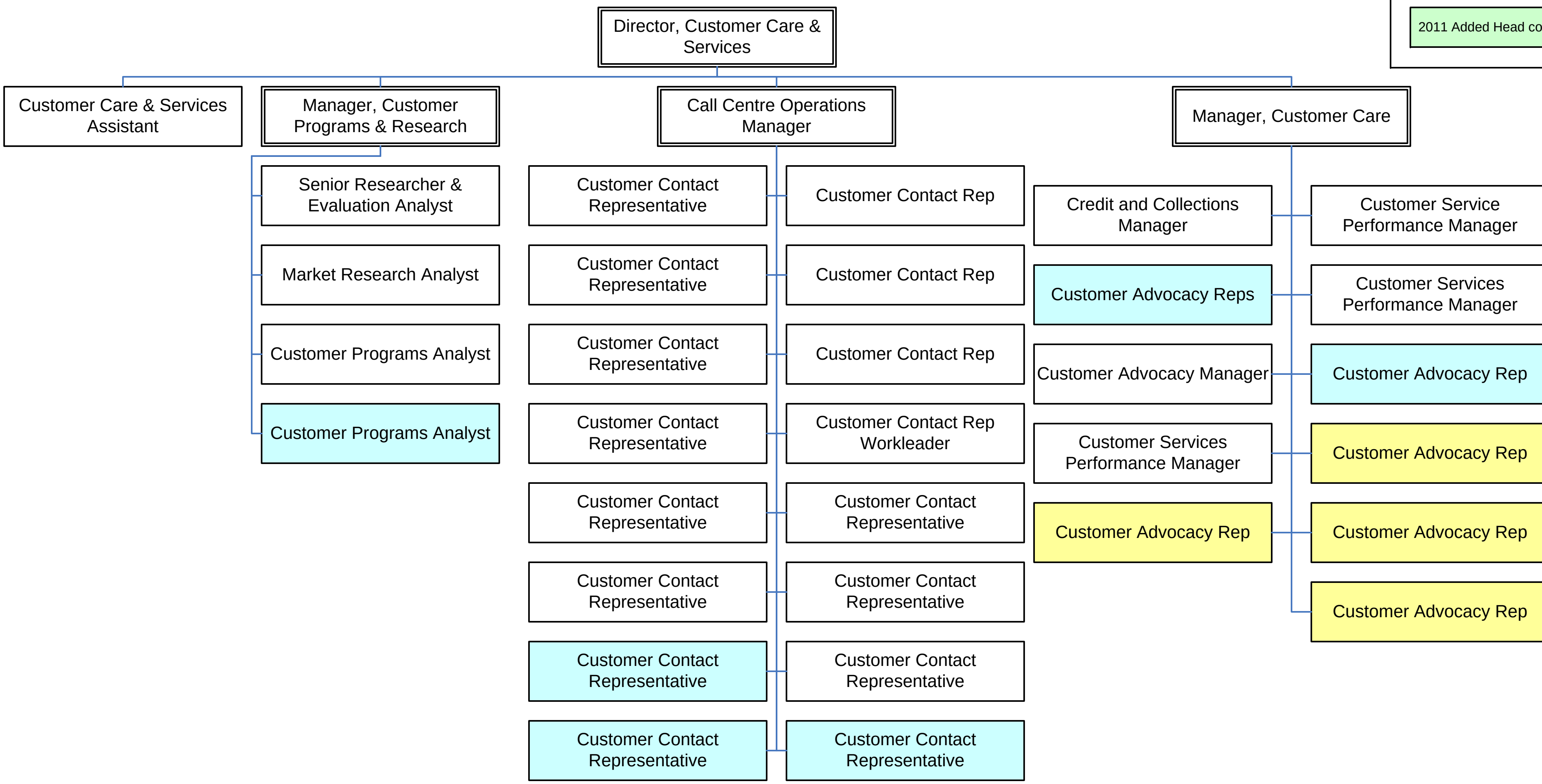
TERASEN GAS INC.

MARKETING & BUSINESS DEVELOPMENT

2009 to 2011

Head Count Legend

- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count



TERASEN GAS INC.

MARKETING & BUSINESS DEVELOPMENT

2009 to 2011

Head Count Legend

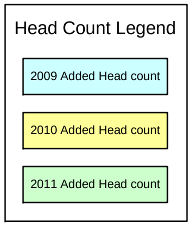
- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count

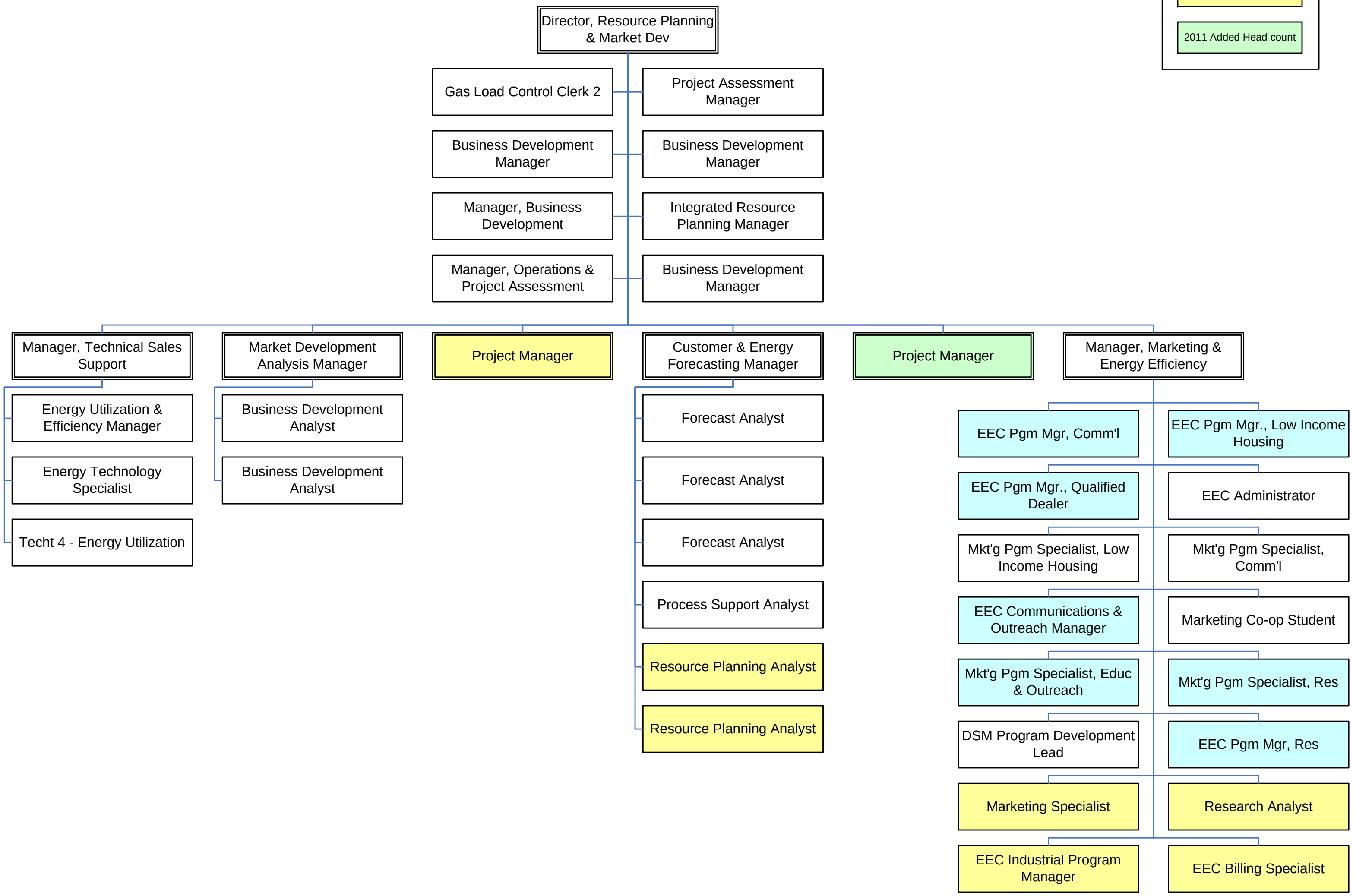
- Director, Com/Aboriginal/ Govt Relations
  - Sr Manager, Municipal Relations
  - Comm, Aboriginal & Gov't Relations Assistant
  - Policy Analyst
  - Aboriginal Relations Manager
  - Community Relations Manager
  - Community Relations Manager
  - First Nations Relations Manager
  - Government Relations Mgr

TERASEN GAS INC.

MARKETING & BUSINESS DEVELOPMENT

2009 to 2011





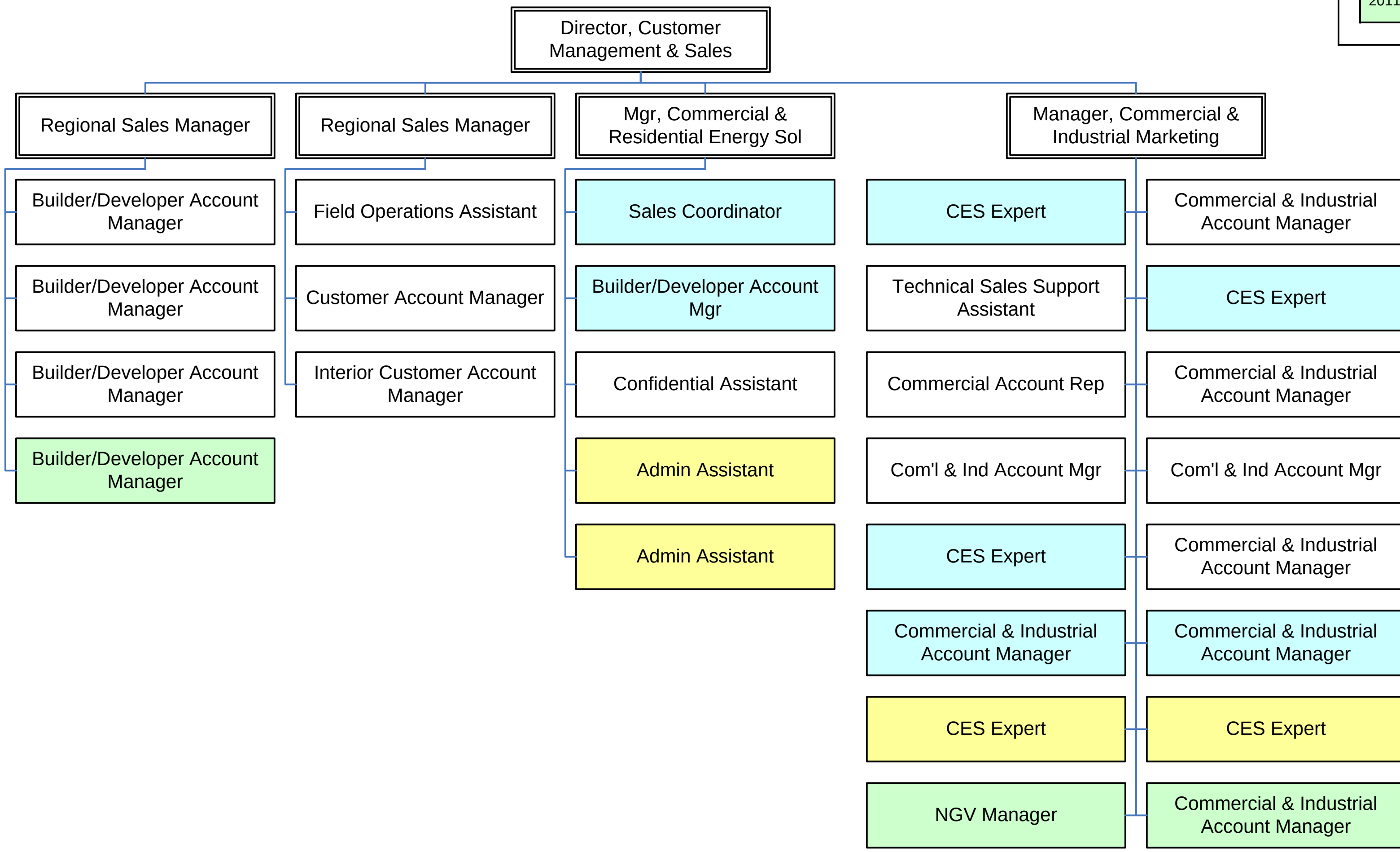
TERASEN GAS INC.

MARKETING & BUSINESS DEVELOPMENT

2009 to 2011

Head Count Legend

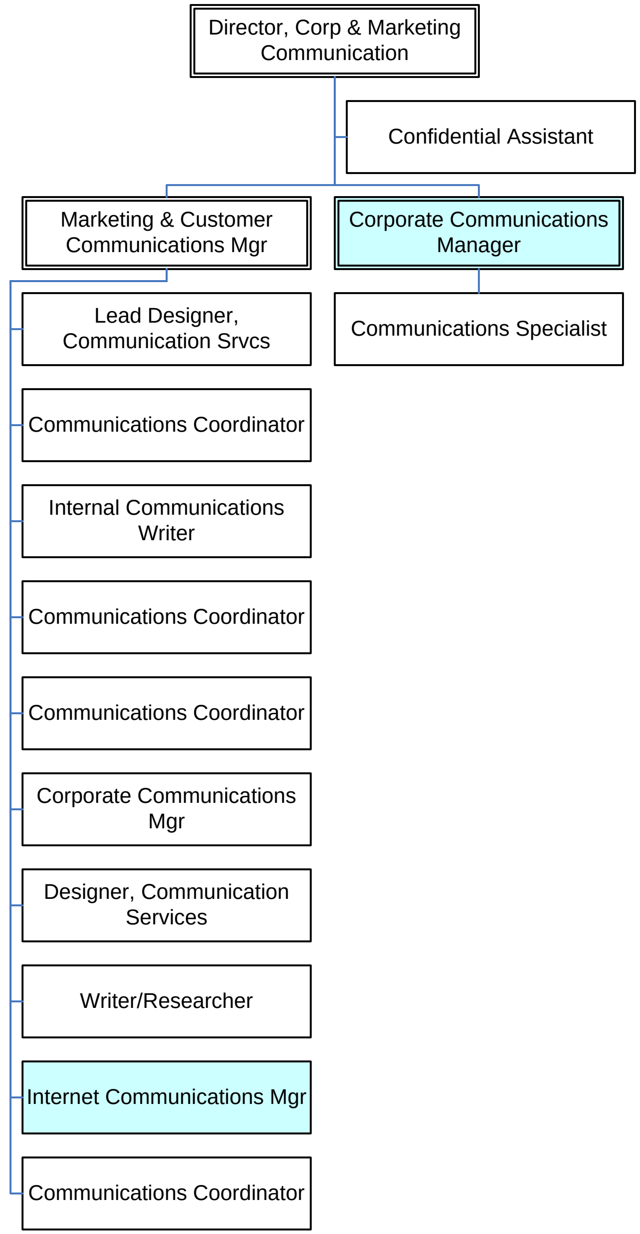
- 2009 Added Head count
- 2010 Added Head count
- 2011 Added Head count



TERASEN GAS INC.

MARKETING & BUSINESS DEVELOPMENT

2009 to 2011



Head Count Legend

2009 Added Head count

2010 Added Head count

2011 Added Head count

Attachment 104.4

REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)